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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Authority, Among Other Things, to Increase Rates and Charges for Electric and Gas Service Effective on January 1, 2014 (U39M).	Application 12-11-009 (Filed November 15, 2012)
And Related Matter.	Investigation 13-03-007

ADMINISTRATIVE LAW JUDGE'S RULING MAKING AVAILABLE FINANCIAL AUDIT REPORT ON GAS DISTRIBUTION SYSTEM

On January 22, 2013, the assigned Commissioner issued a Scoping Memo in this proceeding regarding the Pacific Gas and Electric Company (PG&E) General Rate Case application for authority to increase its gas and electric revenue requirements for test year 2014. As directed in the Scoping Memo, by ruling dated May 17, 2013, two reports prepared under the direction of the Safety and Enforcement Division (SED) were issued. This ruling provides a third report prepared under the direction of SED which covers the results of a financial audit of PG&E's Gas Distribution System.

As also noted in the Scoping Memo, this report attached to this ruling, together with the two previous reports, are being issued pursuant to the directive of the Commission's Executive Director on March 5, 2012, and in anticipation of

PG&E's testimony, which was to include a risk assessment of its gas distribution, and electric distribution and generation systems. A follow-up workshop has been scheduled for June 12, 2013, at 10:00 a.m., in the Commission Courtroom, State Office Building, 505 Van Ness Avenue, San Francisco, CA 94102, to provide parties the opportunity to ask questions or seek clarifying information regarding these three reports. If necessary, SED consultants can be made available to testify on the contents of their reports during the scheduled evidentiary hearings.

IT IS RULED that pursuant to the assigned Commissioner's Scoping Memo previously issued in this proceeding, the report on the financial audit of Pacific Gas and Electric Company's Gas Distribution System, attached to this ruling, is hereby provided to parties and are made a part of the record. Any party seeking access to the supporting workpapers, which contain designated confidential information, should contact Mitchell Shapson (Shapson@cpuc.ca.gov) or (415) 703-2727.

Dated May 31, 2013, at San Francisco, California.

/s/ RICHARD SMITH for
Thomas R. Pulsifer
Administrative Law Judge

ATTACHMENT

Focused Financial Audit of The Pacific Gas & Electric Company's Gas Distribution Operations

Prepared For

The Safety and Enforcement Division Of The California Public Utilities Commission

Prepared by

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May 31, 2013

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Schedule 6-1 - Gas Distribution Year End Rate Base, Excluding SmartMeter, 2002 to 2010

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List of Acronyms	
Acronym	**Description**
A&G	Administrative and General
AA	Arthur Andersen & Company
AA	Aldyl-A
ALS	Accelerated Leak Re-Survey Project
B&V	Black & Veatch
BT	Business Transformation
CC&B	Customer Care and Billing
CEO	Chief Executive Officer
CFCA	Core Fixed Cost Account
CGI	Combustible Gas Indicator
CPA	Cathodic Protection Areas
CPSD	Consumer Protection and Safety Division
CPUC	California Public Utility Commission
CSRP	Copper Service Replacement Program
DRA	Division of Ratepayer Advocates
ECDA	External Corrosion Direct Assessments
ED	Energy Delivery
EO	Engineering and Operations
FERC	Federal Energy Regulatory Commission
GasCAP	Gas Compliance Assurance Process
GasFM	Gas Facilities Management System
GEMS	Gas Electric Mapping System
GIS	Geographic Information System
GO	General Order
GPCM	Gas Preventative and Corrective Maintenance Project
GPRP	Gas Pipeline Replacement Program
GRC	General Rate Case
GSR	Gas Service Representative
GSR	Gas Service Records
GSRB	Gas Safety and Reliability Branch
GT&D	Gas Transmission & Distribution
GT&S	Gas Transmission and Storage
GTSI	Gas Transmission Systems, Inc.
HCA	High Consequence Areas
HFI	Hydrogen Flame Ionization Pack
IQI	Interim Quality Improvement Initiative
IRP	Independent Review Panel
ISSP	Isolated Steel Services Program
IT	Information Technology
LOB	Line Of Business
LTD	Long-Term Disability
M&C	Maintenance and Construction
M&L	Mark and Locate
MAOP	Maximum Allowable Operating Pressure
MPP	Meter Protection Program

List of Acronyms	
Acronym	**Description**
MPR	Material Problem Report
MWC	Major Work Category
NDFCA	Non-Core Distribution Fixed Cost Account
NTSB	National Transportation Safety Board
O&M	Operations and Maintenance
OPC	Operating Plan Committee
ORI	Operational Reporting Initiative
PBOP	Post-Retirement Benefits Other than Pension
PGA	Purchased Gas Account
PHMSA	Pipeline and Hazardous Materials Safety Administration
PIP	Performance Incentive Plan
PM	Preventative Maintenance
PV	Priority Valve
PWC	PriceWaterhouseCoopers
QA	Quality Assurance
QBR	Quarterly Business Review
QC	Quality Control
RMC	Resource Management Center
ROE	Return On Equity
ROR	Rate of Return
SBI	San Bruno Incident
SED	Safety and Enforcement Division
SCADA	Supervisory Control and Data Acquisition
SME	Subject Matter Expert
SOE	Statement of Earnings
STIP	Short-Term Incentive Plan
T&D	Transmission and Distribution
T&R	Transmission and Regulation
TURN	The Utility Reform Network
USA	Universal Service Alert
USRB	Utilities Safety and Reliability Branch
WAVG	Weighted Average
WMS	Work Management System

1. Executive Summary

This report contains the results of a financial audit of the Pacific Gas & Electric Company's (PG&E) gas distribution operations conducted by Overland Consulting (Overland) on behalf of the Safety and Enforcement Division (SED) of the California Public Utilities Commission (the Commission).

Key Findings

PG&E identified serious deficiencies in its gas distribution operations in 2007 and 2008. The deficiencies were pervasive across technical functions and geographical locations. PG&E's maintenance, leak survey and mapping functions were critically deficient. PG&E's damage prevention and integrity management functions were inadequate.

Executive leadership, process controls, internal communication, staffing, training, supervision, record keeping, auditing, information systems, asset knowledge, metrics reporting, and data analysis were all deficient. The result was substandard work quality and widespread non-compliance with PG&E's own standards.

PG&E significantly underfunded its gas distribution operations prior to 2008. Resource constraints were a significant root cause of the deficiencies. At the same time, the profits made by the gas distribution operations exceeded the levels authorized by the Commission.

Key findings of the audit include:

- PG&E identified serious deficiencies in its gas distribution operations in 2007 and 2008. The evidence suggests the deficiencies date back to the mid-1990s. Management failed to detect, or chose to ignore, these deficiencies until employees publicly raised issues at PG&E's annual shareholders meeting in April 2007.
- PG&E underfunded and understaffed its gas distribution operations from the mid-to-late 1990s through 2007. Resource constraints were a significant contributing factor to the deficiencies in management, policies and procedures.
- PG&E began corrective actions starting in October 2007. However, these corrective actions produced mixed results, as demonstrated by PG&E's own internal reviews.
- PG&E's actual O&M expenses were 13% lower than adopted from 1999 to 2007. The underspending averaged $18 million a year during that period. Spending increased in 2008 and again in 2009 as PG&E implemented corrective actions. From 2008 through 2010, actual O&M was 25% higher than adopted.
- Actual capital expenditures were 6.5% lower than adopted from 1999 to 2010. PG&E spent $168 million less than adopted during that twelve-year period. The underspending was concentrated in safety-related categories. Safety-related capital expenditures were 13.3% lower than adopted.
- PG&E's gas distribution operations earned an average actual return-on- equity (ROE) of 12.7% from 2003 to 2010 stated on a regulatory basis. PG&E's authorized ROE averaged

11.3% over the same period. PG&E's gas distribution revenues were $202 million higher than the amount needed to earn its authorized ROE over the eight-year study period.

The pervasiveness of the deficiencies demonstrates that their ultimate root cause was ineffective or unresponsive executive management. The executives in charge of PG&E's gas distribution operations placed excessive emphasis on cost containment and inadequate emphasis on work quality and public safety prior to 2008.

Chapter 2 - Background and Approach

The catalyst for the audit was the gas transmission pipeline rupture that occurred in a residential area of San Bruno, California, on September 9, 2010. The natural gas released by the rupture ignited and caused a fire that destroyed 38 homes and damaged 70. Eight people were killed and many more were injured. The investigations following the San Bruno Incident uncovered serious deficiencies in the management of PG&E's gas operations.

Overland conducted a focused audit of PG&E's gas transmission operations on behalf of the SED in 2011. The SED retained Overland to conduct a focused financial audit and retrospective review of the management practices of PG&E's gas distribution operations in May 2012. The scope of the distribution audit largely mirrored the scope of the transmission audit.

The objectives of the audit included:

- Comparing actual gas distribution O&M expenses and capital expenditures for the years 1999 to 2010 to the amounts adopted in PG&E's General Rate Cases and documenting the reasons for significant differences between the actual and adopted amounts;
- Comparing the actual return-on-equity earned by PG&E's gas distribution operations to its authorized return-on-equity from 2003 to 2010;
- Reviewing gas distribution staffing levels and operational metrics for evidence of resource constraints from 2003 through 2010;
- Reviewing PG&E's budget process and internal planning documents for evidence that gas distribution resources were constrained for financial reasons from 2003 through 2010; and
- Reviewing PG&E's internal documents for indications of gas distribution management deficiencies and estimating the impact of such deficiencies on actual spending from 2003 through 2010.

Overland conducted a comprehensive review of relevant documents produced in response to 757 discovery questions initiated during the audit.

This report is largely based on the responses and materials produced by PG&E through the discovery process, which are assumed to be correct and accurate for the purposes of the analysis findings and conclusions contained herein.

Chapter 3 - O&M Expenses

PG&E's actual gas distribution O&M expenses were lower than adopted in every year from 1999 to 2006. Actual O&M was higher than adopted in 2007 through 2010. Over the twelve-year study period, actual O&M was 3.1% lower than adopted.

During 1999 to 2007, actual spending was 12.9% lower than adopted. The underspending averaged $17.7 million per year during that period. Resource constraints imposed by management were a significant contributing factor to the underspending.

PG&E identified significant management deficiencies in its gas operations in late 2007 and initiated corrective actions. Actual O&M increased by 12.5% in 2008 and 37.6% in 2009. During the 2008 to 2010 timeframe, actual gas distribution O&M was 25.4% higher than adopted. The increased spending in 2008 to 2010 included costs incurred to reduce the backlog of work that had built up over prior years when funding was inadequate.

Chapter 4 - Capital Expenditures

Actual capital expenditures were 6.5% lower than adopted from 1999 to 2010. PG&E spent $168 million less than adopted over the twelve-year study period.

The underspending was concentrated in the 1999 to 2002 time period. PG&E spent $282 million less than adopted during those years. PG&E spent $114 million more than adopted from 2003 to 2010.

The underspending was concentrated in safety-related categories. Actual safety-related capital expenditures were 13.3% lower than adopted. Safety-related capital expenditures were $159 million lower than adopted from 1999 to 2010.

Safety-related capital expenditures were lower than adopted in every year from 1999 to 2006, except for 2003. Safety-related capital expenditures were $274 million lower than adopted in the 1999 to 2006 timeframe. Safety-related capital expenditures were $115 million higher than adopted in 2007 to 2010.

Chapter 5 - Long-Term Gas Safety Programs

PG&E had the following long-term gas safety programs during the audit period:

- Gas Pipeline Replacement Program (GPRP);
- Copper Services Replacement Program (CSRP);
- Meter Protection Program (MPP); and
- Isolated Steel Services Program (ISSP).

The GPRP and CSRP were much larger than the MPP and the ISSP.

PG&E assigned a relatively low funding priority to long-term gas safety programs during the audit period. PG&E generally viewed long-term safety programs as discretionary spending that could be deferred to

meet its overall budget targets. The GPRP, MPP and ISSP were poorly funded during the audit period. The CSRP began in 2006 and was adequately funded.

The Gas Pipeline Replacement Program was established in 1985 as a 20-year program. By 2004, the program duration had been extended to 30 years. Pipeline segments are selected for replacement under the GPRP using a risk based "Priority Value" (PV). The PV considers the segment's leak history. Pipeline segments are added or removed from the program each year as an additional year of leak history is added to the analysis. The miles remaining to be replaced under the GPRP declined very slowly after 2003 for three reasons. First, management reduced funding for the program. Second, pipeline replacements were concentrated in high cost areas. Third, PG&E's leak survey process did not find many leaks prior to 2008 because it was critically deficient. PG&E improved its leak survey process in 2008 and found many more leaks. That increased PV values and added more miles to the program.

The study period for Overland's comparison of actual and adopted spending was 1999 to 2010. Overland requested that PG&E provide a comparison of actual and adopted GPRP spending for 1987 to 1998 because underspending was an issue in prior General Rate Cases. Based on the information provided by PG&E, GPRP spending was 14% lower than adopted from 1987 to 1998. GPRP spending was 23% lower than adopted from 1999 to 2010.

PG&E did not include the Copper Services Replacement Program in its 2007 GRC application because management approved the program after the application was filed. The capital expenditures adopted in the 2007 GRC did not include any funding for the CSRP. Actual CSRP spending totaled $146 million from 2007 to 2010.

PG&E diverted some of the GPRP funding adopted in the 2007 GRC to the CSRP in 2007 through 2010. On a combined basis, GPRP and CSRP spending was 6.7% lower than adopted over the twelve-year study period. The comparison shows a distinct pattern over time. During 1999 to 2006, spending was $157 million lower than adopted. During 2007 to 2010, combined spending was $96 million higher than adopted.

PG&E established the Meter Protection Program in 1990 to identify and protect gas meters that did not conform to meter protection standards. The program was initially scheduled for completion in 2008. PG&E currently anticipates completion in 2013. Progress on the MPP slowed significantly after 1997. During 1998 to 2010, the average annual number of meters protected was 62% lower than the annual average from 1990 to 1997. Very few meters were protected in 2009 and 2010. Actual MPP spending was 61% lower than adopted during the twelve-year study period.

The Isolated Steel Services Program was initiated in late 2001 as a multi-year program to be completed in 2012. The key ISSP metric is the number of services tested in the field. As of December 2010, PG&E had only field tested 33% of the locations that required testing. Actual ISSP spending was 14% lower than adopted from 2003 through 2010.

Chapter 6 - Return On Equity

PG&E's total gas operations consist of two parts: (1) distribution; and (2) gas transmission and storage (GT&S). PG&E's total gas operations earned an average actual return-on-equity of 12.8% during 2003 to 2010, stated on a CPUC regulatory basis. That exceeded the level authorized by the Commission. PG&E's Commission authorized ROE averaged 11.3% over the same period.

PG&E's distribution operations were modestly less profitable than its GT&S operations. The gas distribution ROE averaged 12.7% and the GT&S ROE averaged 13.2% over the eight-year study period.

PG&E's total gas revenues were $400 million higher than the level needed to earn its authorized ROE over the study period. The surplus revenues were divided fairly evenly between distribution and GT&S. PG&E's gas distribution operations had $202 million in surplus revenues over the study period, while its GT&S operations had $198 million in surplus revenue.

Chapter 7 - Staffing and Metrics

PG&E reduced its gas distribution staffing by 29% between December 1996 and December 2010. During the same period, the number of gas distribution customers increased by 15%. The large headcount reductions reflect resource constraints imposed in gas distribution during this period.

PG&E's leak surveys discovered abnormally few leaks from 2003 to 2007. PG&E's leak survey metrics demonstrate that its leak survey practices were critically deficient prior to 2008.

During 2003 to 2007, 63% of the Grade 1 leaks repaired by PG&E were initially discovered by customers.[1] That metric demonstrates the poor quality of PG&E's leak survey practices during those years.

During 2003 to 2008, 17% of priority Grade 2 leak rechecks resulted in the leak being upgraded to Grade 1, which is an indication of quality problems in the original leak grading process during those years.

PG&E did not have reliable metrics for late leak repairs, late locates and late regulator station and valve inspections at any point during the audit period. PG&E's excavator dig-in rates reflect significant deficiencies in its damage prevention program prior to 2008.

Material Problem Reports (MPRs) are used to track problems caused by defective materials or products. The low volume of MPRs collected from 1995 to 2000 demonstrates that PG&E was not proactively collecting information about gas distribution materials problems in those years. The low numbers of MPRs submitted in 2001 to 2007 demonstrate that MPR reporting was inadequate in those years. PG&E's mapping backlog metrics indicate staffing shortages in the Mapping Department during the 2007 through 2010 timeframe.

[1] Leaks caused by excavator dig-ins are excluded from the metric because the discovery of dig-in damage is not a function of leak survey quality.

Chapter 8 - Budget Process

Gas and electric distribution funding was prioritized jointly during the audit period. That forced gas distribution work to compete for funding with electric distribution work in the prioritization process. The documentation for the 2008 to 2010 budget years demonstrated that gas safety spending was given a relatively low priority during that period. The priority assigned to gas safety requirements in the 2003 to 2007 budget processes is completely undocumented.

PG&E's budget documentation was inadequate throughout the audit period. The PG&E budget process started with initial budget targets set by senior management. The basis for those targets was poorly documented. The next major step was the submission of initial budget requests by the various organizations included in the budget. PG&E did not retain the gas distribution initial budget requests for the 2003 through 2008 budget years. PG&E cannot show how the budget requests in those years were prioritized. The gas distribution budget requests in 2009 and 2010 were poorly documented.

The budget requests were reviewed and adjusted by a central budget committee and senior management. Those processes were completely undocumented.

Chapter 9 - Planning Document Review

Overland reviewed PG&E's available planning documents for 2003 to 2010 for evidence that gas distribution resources were constrained for financial reasons. The planning documents demonstrate a heavy emphasis on cost reduction and on limiting spending to budgeted amounts. The planning documents contain little discussion of public safety. Conversely, the planning documents prepared after the San Bruno Incident demonstrate a striking change in emphasis towards public safety and away from cost reduction.

The 2003 to 2005 planning documents contained benchmarking tables that compared PG&E to other gas distribution utilities. The comparisons demonstrated that PG&E was spending significantly less than its peers on gas distribution O&M. PG&E was also repairing far fewer leaks than its peers.

The 2003 to 2006 planning documents contained tables listing key gas distribution initiatives. The initiatives demonstrated a heavy emphasis on cost reduction. Cost reduction was a primary goal in 10 of the 18 initiatives. The key metrics reported in the planning documents emphasized cost reduction rather than public safety or work quality.

Chapter 10 - Management Deficiencies, 1993 to 2007

Chapters 10 to 13 provide a narrative history of the gas distribution management deficiencies identified by PG&E. Chapter 10 covers 1993 through 2007.

PG&E commissioned two consultant reviews of its preventative maintenance programs in 1995. The consultant reports contain findings that were echoed repeatedly in internal and external reviews

prepared in 2007 and later years. The 1995 consultant reports, and PG&E's 1997 internal compliance reviews, demonstrate the long history of the gas distribution management deficiencies.

PG&E implemented significant workforce reductions in 1993 and 1994. PG&E continued to reduce its gas distribution workforce through 2010. The workforce reductions contributed to the significant work quality issues identified by PG&E in 2007 and subsequent years.

Employee complaints about work practices and staffing levels prompted two significant internal audits in 2007. The first was an internal audit of leak detection in the North Bay and North Coast Divisions. The second was an internal audit of regulator station and valve maintenance in Marin County. The internal audits discovered critical deficiencies in leak survey and maintenance practices. PG&E's internal follow-up investigations demonstrated the deficiencies were pervasive throughout its system.

The internal audit of leak detection in the North Coast Division prompted PG&E to repeat its prior leak surveys in Sonoma County. The resurvey process led to the discovery of systematic leak survey training and operator qualification deficiencies.

PG&E conducted a study of its leak grading process in October 2007. The study conclusively demonstrated that PG&E's leak grading standards were not being applied consistently in the field.

Chapter 11 - Management Deficiencies, 2008

During 2008, PG&E expanded its investigation into management deficiencies, enhanced its leak survey process, and committed to surveying its entire system for leaks by December 2010.

PG&E determined that its prior leak survey process was ineffective. PG&E identified a number of root causes for the leak survey deficiencies, including inadequate planning, supervision and staffing. During the period 1999 to 2006, the number of Grade 1 leaks discovered by leak surveys decreased by 68%. That should have triggered a critical review of the leak survey process but did not because PG&E failed to analyze its leak survey results.

PG&E retained a consulting firm, Exponent, to conduct a system-wide audit of regulator station and valve maintenance. Exponent identified pervasive system-wide deficiencies in PG&E's maintenance practices, including: PG&E's written standards were not widely understood or followed; maintenance practices were not consistent across divisions; employees were performing activities based on their own personal determinations of the proper work methods; PG&E did not have an accurate gas distribution asset registry; the asset lists maintained by the divisions were incomplete and inaccurate.

The records prepared to document maintenance activities were inadequate. The records did not provide much information about the work that was done. This lack of information in the records raised doubts about the quality of the work. The lack of objective reliable data to verify work completion was an important control weakness.

Supervision of regulator station and valve maintenance was inadequate. The supervisors did not have enough time to adequately supervise all of the activities within their work scope. Some supervisors were not qualified. The poor quality of the maintenance records demonstrated that supervisor records reviews were ineffective. Prior Quality Assurance audits had failed to identify the systematic and recurring non-compliance with PG&E's standards documented by Exponent.

Exponent concluded that a lack of accountability at multiple levels of PG&E's organization contributed to the deficiencies. PG&E did not have adequate communication channels for employees to raise concerns. Field personnel felt they had little influence on management above their immediate supervisor.

PG&E retrained its leak surveyors and enhanced its leak survey process in March 2008. The leak surveys conducted after that date found much higher leak rates. PG&E initiated a survey of a statistical sample of mains and services in five divisions. Those surveys found much higher leak rates. PG&E concluded that the leak surveys conducted prior to March 2008 were deficient and initiated a project to survey its entire system using the enhanced process by December 2010. The results of the leak surveys conducted after March 2008 conclusively demonstrated that PG&E's prior leak survey practices were critically deficient.

PG&E did not have an accurate gas distribution asset register at any point during the audit period. PG&E's integrity management organization did not have the information needed to prepare reliable risk assessments. The information was trapped in records that could not be searched electronically. PG&E initially planned to develop a gas distribution asset register and work management system (WMS) by December 1998. PG&E's plans to implement an asset register and WMS were repeatedly delayed during the audit period.

Chapter 12 - Management Deficiencies, 2009 and 2010

PG&E continued to investigate management deficiencies, practices and procedures, and implement corrective actions in 2009 and 2010. Exponent reviewed the existing process controls for six key gas distribution functions and found a variety of deficiencies. Exponent's process review demonstrated that many of the problems identified in its regulator station and valve audit were also prevalent in other key functions. PG&E management concluded that the problems were pervasive and initiated the Operational and Human Performance Plan to improve proficiency in core gas distribution functions.

A Geographic Information System (GIS) is a prerequisite for an effective gas distribution integrity management program. PG&E does not have a gas distribution GIS. PG&E initiated its first gas distribution GIS development project in February 2005. The effort was terminated in 2007. PG&E's second effort was terminated in 2011. PG&E currently plans to implement a gas distribution GIS by 2014.

PG&E conducted internal audits of its leak detection and damage prevention programs in 2009. The audits found significant deficiencies. A subsequent quality assurance audit of the damage prevention program found additional critical deficiencies.

PG&E retained a consultant to assess the staffing adequacy in its local gas distribution T&R Departments in 2009. The T&R Departments are responsible for regulator station, valve and cathodic protection maintenance. The assessment concluded the departments were understaffed by 26%.

PG&E discovered critical deficiencies in its record keeping for service lines installed by residential sub-division developers. Many of the records the developers were required to provide were missing. The problem was pervasive system-wide. The root causes included widespread non-compliance with PG&E's standards, inadequate record management controls, inadequate auditing and poor communications among departments.

PG&E retained a consultant to assess 100% of the leak survey documentation for its Accelerated Leak Re-Survey Project. The consultant found discrepancies on nearly all of the documents.

The SED's Gas Safety and Reliability Branch (GSRB) conducts periodic safety inspections of PG&E's gas distribution divisions. PG&E conducts internal records reviews before each inspection. PG&E began sharing the results of its internal records reviews with the GSRB in early 2009. The internal reviews identified thousands of violations in 2009 and 2010. PG&E acknowledged that the high number of internal review findings in those years was unacceptable. The results of the pre-inspection internal reviews demonstrate the pervasive nature of the gas management deficiencies.

Chapter 13 - Management Deficiencies, 2011 and 2012

PG&E hired an experienced executive from outside the company to reform its gas operations in 2011. The company expressed a strong commitment to improving its gas operations in 2011 and 2012. However, PG&E's internal documents demonstrated that many of the deficiencies discovered in prior years continued to exist in 2011 and 2012.

PG&E issued the report of an internal audit of its leak repair and leak monitoring processes in April 2011. The audit found that PG&E was not adequately monitoring leak downgrade trends. Data quality controls for the leak database were critically deficient. The records for approximately ten percent of the leak repairs that required a soap test did not contain any indication that the test was performed. Approximately 5% of the leak repair records were missing. Supervisors were not reviewing leak recheck logs. The audit demonstrated that many of the leak repair process deficiencies discovered in 2007 and 2008 had not been corrected as of April 2011.

PG&E issued the report of an internal audit of its leak survey program in July 2011. That report identified significant deficiencies in metrics reporting. PG&E's monthly reports and leak survey dashboards were incomplete and some of the metrics had not been updated for several months. Two of

the metrics had been shown on the dashboard with no data for about a year. PG&E began work on the Operational Reporting Initiative (ORI) in February 2009. The ORI was focused on improving leak survey and repair metrics. The July 2011 internal audit report demonstrated the ineffectiveness of the ORI.

PG&E implemented the Gas Compliance Assurance Process (GasCap) in July 2011. GasCap replaced the prior Interim Quality Initiative (IQI). The IQI was implemented in April 2008 in an attempt to correct critical deficiencies in supervision and metrics reporting. PG&E's internal GasCap justification documents demonstrated the ineffectiveness of the IQI. Supervisor field work observations, supervisor records reviews and compliance metrics reporting all continued to suffer from serious deficiencies under the IQI.

PG&E's new Executive Vice President for Gas Operations, Mr. Nick Stavropoulos, authored PG&E's gas turnaround plan in October 2011. The plan divided PG&E's gas operations into 20 processes and classified the current state of each process. Ten of the twenty processes were classified as inadequate. An additional nine processes were classified as threshold, the next category above inadequate. The plan concluded that PG&E needed to make "wholesale changes" in its gas operations.

PG&E retained a consultant, PWC, to review its mapping function. PWC's report was issued in January 2012. The report identified numerous critical deficiencies. Staffing, training, supervision, communications, record keeping, metrics, information systems and leadership were all inadequate. Leadership placed excessive emphasis on meeting production goals and not enough emphasis on work quality. Work quality was substandard.

PG&E issued the report of an internal audit of its damage prevention program in February 2012. The audit followed up on deficiencies identified in a prior audit report, issued 33 months earlier. The February 2012 report demonstrated a clear lack of progress in addressing the deficiencies identified in the prior report.

The SED filed two reports in PG&E's gas transmission record keeping investigation proceeding in March 2012. The reports concluded that "in lay terms, PG&E's record keeping was in a mess" prior to the San Bruno Incident. Gas transmission records were "scattered, disorganized...and difficult, if not impossible, to access in a prompt and efficient manner." The reports concluded that PG&E's gas transmission integrity management risk assessment model had little value because the data used to populate the model was incomplete and inaccurate.

Chapter 14 - Root Cause Analysis

PG&E identified serious management deficiencies in its gas distribution operations in 2007 and 2008. Management largely failed to detect, or chose to ignore, these deficiencies until employees publicly raised their concerns about operating practices at PG&E's annual shareholders meeting in April 2007.

PG&E began corrective actions in October 2007. The corrective actions had mixed results, as demonstrated by PG&E's internal reviews. After the San Bruno Incident, PG&E replaced most of its gas distribution executive management and is currently in the process of reforming its gas distribution operations.

Key safety-related functions were inadequate during most of the audit period. PG&E's leak survey program was ineffective prior to 2008, as demonstrated by survey results. PG&E's leak grading practices were inconsistent. The process for responding to customer odor complaints was inadequate.

PG&E's maintenance practices were critically deficient as demonstrated by Exponent's system-wide audit of regulator station and valve maintenance. The damage prevention program was inadequate as demonstrated by PG&E's dig-in rates and internal reviews. The company's mapping process was critically deficient as demonstrated by PWC's review and PG&E's internal audits.

PG&E's processes for collecting and organizing information about its gas distribution facilities were inadequate. PG&E did not have an accurate Asset Register or GIS at any point during the audit period. Much of PG&E's asset knowledge was trapped in records that could not be electronically searched. As a result, integrity management risk assessments required labor intensive manual records searches.

Record keeping practices were inadequate throughout the audit period. PG&E's maintenance and leak survey records were incomplete and inaccurate. PG&E's leak data base lacked effective data quality controls. Records were frequently missing and PG&E did not have controls to assure that its records were complete.

With one exception, PG&E's long-term gas safety programs were poorly-funded throughout the audit period. Management viewed long-term gas safety programs as discretionary spending that could be deferred to meet financial targets.

Several recurring circumstances emerged from the review of management deficiencies that explain, at least partially, the pervasiveness and root causes of the deficiencies. Overland developed these conditions into root cause findings to provide insight into audit period spending patterns.

Overland identified the following eight root causes for the deficiencies in gas distribution management, policies and procedures:

- Insufficient management emphasis on work quality and public safety;
- Ineffective communications between management and the field and among departments;
- Inadequate direction of the work methods used by field employees;
- Inadequate staffing and other resources;
- Ineffective supervision and quality control;
- Inadequate quality assurance;

- Failure to collect and organize critical operating data; and
- Failure to analyze the data that was available.

The pervasiveness of the deficiencies demonstrates that their ultimate cause was ineffective executive management. The executives in charge of PG&E's gas distribution operations placed excessive emphasis on cost containment and failed to properly manage the operations.

The following combination of factors fostered inconsistent work practices and an organizational emphasis on cost containment over work quality:

- Ineffective executive management;
- Insufficient resources;
- Poor internal coordination and communications;
- Inadequate direction of work methods;
- Ineffective supervision;
- Inadequate record keeping;
- Ineffective process controls;
- Inadequate asset knowledge;
- Ineffective auditing;
- Inadequate information systems;
- Inadequate metrics reporting; and
- Failure to analyze operating data.

The result was substandard work quality, compromising gas operations and public safety standards. The same factors allowed the substandard work quality to continue for years before it was identified and corrected. As of the time of this audit report, some of the identified conditions remain open and are subject to ongoing remediation efforts.

The pervasive nature of the management deficiencies demonstrated the need to conduct an integrated root cause analysis to identify common underlying causes, such as ineffective executive management, excessive emphasis on cost reduction, or inadequate emphasis on work quality. PG&E did not prepare an integrated root cause analysis. Some of the executives directly responsible for gas transmission and distribution were dismissed after the SBI and subsequent CPUC investigations. However, concerns about PG&E's corporate culture remain.

2. Background and Approach

This Chapter describes the objectives of the audit and Overland's approach to accomplishing those objectives. The Chapter also provides some basic background information regarding the project and the circumstances leading to this audit.

Background Information

Gas Distribution Overview

PG&E's gas system consists of transmission, storage and distribution systems.[1] The transmission system delivers gas from interconnections with interstate pipelines at the California/Oregon border on the north and the Arizona/California border on the south to PG&E's local distribution areas. The distribution system transports the gas from the interconnection with the transmission system to the customer's home or business. The transmission system operates at a higher pressure than the distribution system.[2]

The storage system interconnects with PG&E's transmission system and consists of large underground gas storage reservoirs. PG&E injects gas into the storage system when end-use demand is low and withdraws gas from the storage system when demand is high. The storage system allows PG&E to more economically meet the peak demands of end-use customers.

The distribution system consists of distribution mains, regulator stations, gas flow control valves, customer service lines and customer meters. Distribution mains transport gas from the interconnection with the transmission system to the customer service line. Local distribution mains are buried in rights-of-way that typically run parallel to streets. Customer service lines connect the distribution main to customer meter. The meter is typically attached to, or very close to, the customer's house or other structure.

Distribution regulator stations are located on the distribution mains near the interconnection with the transmission system. The regulator stations reduce operating pressure to distribution levels. Regulator stations are frequently located in underground vaults. Regulator station equipment includes regulators, filters, valves, vaults and piping.

Gas flow valves are located on the distribution mains to isolate segments when failures occur or when the segment must be depressurized for construction or maintenance.

The following table shows the physical qualities of each type of facility in PG&E's distribution system as of 2009.

[1] PG&E's gas system also includes a small amount of gathering facilities.

[2] The transmission system operates above 60 psi. The distribution system operates at or below 60 psi. OC-480, Attachment 31, page 24.

Table 2-1 - PG&E Distribution System, Physical Quantities

PG&E Distribution System Physical Quantities		
Description	Unit	Quantity
Distribution Mains	Miles	41,274
Service Lines	Number	3,257,464
Gas Meters	Number	4,500,000
Regulator Stations	Number	2,650
Gas System Valves	Number	16,000
Source: Response to Discovery, OC-480, Attachment 31, page 26.		

Delivery capacity must increase to serve new customers, and obsolete or dangerous facilities must be replaced. This requires capacity planning, standards, design and construction functions. Materials used in construction must be qualified to assure that they meet the design standards.

Safety risks must be identified and analyzed through an integrity management process. Programs, such as the Gas Pipeline Replacement Program or Meter Protection Program, must be developed and implemented to manage identified risks.

Regulator stations and valves must be periodically inspected and maintained. Mains and services can be made of either metal or plastic. Metal lines must be cathodically protected to prevent failures due to corrosion. Cathodic protection is accomplished by running a slight electric current through the line. The current causes a sacrificial anode to corrode instead of the line. Cathodic protection equipment must be monitored, inspected and repaired periodically.

Mains and services must be surveyed periodically to find leaks. The surveys are performed by technicians who walk the lines with gas detection equipment. The frequency of the leak surveys is determined by gas safety regulations. Natural gas is odorized to allow customers to detect gas leaks by smell. Customers are encouraged to call the utility when they smell gas. The utility must have a system for responding to customer-initiated leak calls. After leaks are identified they must be repaired or monitored depending on the severity of the leak.

Excavation by third parties can damage underground gas facilities. The utility must have a process for locating and marking underground facilities to allow third parties to safely excavate near gas facilities.

All of the construction and maintenance functions require mapping and record keeping. Maps must be accurate and accessible. A system asset registry must be maintained to track key parameters such as location, age, material type, size and maintenance history. Gas service records must be maintained for each service line. Maintenance records must be maintained for regulators, valves and cathodic protection equipment. Leak survey and leak repair records must be maintained to allow trend analysis and document regulatory compliance.

These various activities need work management systems to schedule the work and identify non-compliance.

Internal controls are needed to assure compliance with company policies and external safety rules. Significant controls include:

- Adequate resources to perform the work;
- Written standards and procedures;
- Training and operator qualification;
- Supervision and quality control;
- Work management systems to schedule and track completion of work;
- Reporting, metrics and trend analysis;
- Quality assurance audits; and
- Root cause analysis of failures.

The standardization of work processes and materials is important to managing safety risks. Non-standard designs, materials and work methods increase system complexity and the risk of misunderstandings between employees and work groups.

The San Bruno Incident

On September 9, 2010, PG&E's local gas transmission line 132 ruptured in a residential area in San Bruno, California. That event is referred to as the San Bruno Incident (SBI). The natural gas released by the rupture ignited and caused a fire that destroyed 38 homes and damaged 70. Eight people were killed and many more were injured.[3]

CPUC and Legislative Actions in Response to SBI

The Commission and the California State Legislature initiated a series of actions following the SBI. Those actions are summarized below:

- On September 13, 2010, the Commission directed PG&E to take several steps including:[4]
  - Reducing the operating pressure on Line 132 by 20 percent;
  - Conducting an integrity assessment of all gas facilities in the San Bruno area;
  - Conducting an accelerated leak survey of all transmission lines;
  - Evaluating customer leak complaint response times and effectiveness;
  - Preparing a plan for a complete safety inspection of the entire PG&E gas transmission system; and
  - Reviewing valve locations to identify where it would be prudent to replace manually-operated valves with automated valves.

[3] NTSB Accident Report, Released September 25, 2011, page 1.
[4] Letter from CPUC Executive Director to PG&E's President, dated September 13, 2010.

- On September 23, 2010, the CPUC commissioned an Independent Review Panel (IRP) to investigate the SBI and recommend improvements in PG&E's gas safety practices. On the same day, the Commission also ordered PG&E to review the accuracy of the location classifications assigned to transmission pipeline segments.[5]

- On December 16, 2010, PG&E was ordered to reduce the pressure on certain pipelines to 20% below the Maximum Allowable Operating Pressure.[6]

- On January 3, 2011, PG&E was ordered to comply with two urgent safety recommendations issued by the National Transportation Safety Board (NTSB). Those recommendations were to:[7]
  - Aggressively and diligently search for records for all PG&E transmission lines that had not previously been hydro-tested and were located in Class 3 and Class 4 locations and for High Consequence Area (HCA) lines in Class 1 and 2 locations; and
  - Use the records to determine the valid Maximum Allowable Operating Pressure for the lines.

- On February 24, 2011, the CPUC required PG&E to limit the operating pressures on transmission lines installed before 1970 that were located in HCAs and certain other areas if they had not previously been hydro-tested.[8]

- On February 24, 2011, the CPUC initiated Rulemaking R.11-02-039 to examine, on a state-wide basis, whether new safety and reliability rules should be adopted for gas pipelines.

- On February 24, 2011, the CPUC initiated Investigation I.11-02-016 to determine if PG&E's gas record keeping violated safety rules.

- On April 14, 2011, the CPUC ordered PG&E to provide semi-annual "Gas Transmission and Storage Safety" reports to track safety-related expenditures.[9]

- On May 5, 2011, the Commission ordered PG&E to file two new periodic reports to enhance regulatory oversight of PG&E's spending prioritization decisions, the Budget Report and the Gas Distribution Pipeline Safety Report.[10]

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[5] Commission Resolution L-403. The location classifications trigger additional safety requirements for pipelines located in areas with high population densities.

[6] CPUC Resolution L-410, January 13, 2011.

[7] CPUC Resolution L-410, January 13, 2011.

[8] NTSB Accident Report, September 26, 2011, page 73. Operating pressures were also reduced for lines that had previously been hydro-tested if the records of the tests were not reliable, verifiable or complete.

[9] Gas Accord V Decision, D.11-04-031, April 14, 2011, page 58.

[10] 2011 GRC Decision, D.11-05-018, pages 30 and 31.

- On May 30, 2011, the Commission's Safety and Enforcement Division (SED) retained Overland Consulting (Overland) to conduct a focused audit of PG&E's gas transmission safety-related expenditures over the period 1996 to 2010.[11]

- On June 9, 2011, the CPUC ordered all gas operators to develop a Natural Gas Transmission Pipeline Comprehensive Pressure Testing Plan to achieve the goal of orderly and cost effectively testing or replacing all transmission lines that had not previously been hydrostatically pressure tested.[12]

- On June 30, 2011, PG&E issued its Class Location Study Report. PG&E concluded that the location classifications of 173 miles should be changed to a higher class.[13]

- On October 7, 2011, the Governor signed five gas safety bills into law.[14]
  - Senate Bill (SB) 705 required gas utilities to develop a gas safety plan. SB 705 required the Commission to adopt, modify or reject the gas safety plans by December 31, 2012.
  - Senate Bill (SB) 44 addressed emergency response standards and procedures.
  - Assembly Bill 54 required gas utilities to demonstrate that the revenue requirements they requested in their General Rate Cases were sufficient to meet safety standards. AB 54 also prohibited gas utilities from recovering any fines or penalties for safety violations in customer rates.
  - Senate Bill 216 required the installation of automatic or remote-controlled valves on high risk transmission lines.
  - Senate Bill 879 mandated balancing account treatment for integrity management costs authorized in utility rate cases. SB 879 required any authorized but unspent funds to be returned to ratepayers with interest.

- On November 10, 2011, the CPUC initiated investigation proceeding I.11-11-009 to determine if PG&E's pipeline class location designations violated safety rules.

- On December 2, 2011, the CPUC adopted a new citation program for gas safety rule violations. The citation program delegates specified authority to the SED to issue citations and levy fines for violations.[15]

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[11] Overland Consulting, Focused Audit of Pacific Gas & Electric Gas Transmission Pipeline Safety-Related Expenditures, December 30, 2011, page 2-6. Prior to January 1, 2013, the name of the SED was the Consumer Protection and Safety Division (CPSD).

[12] D.11-06-017.

[13] Letter from PG&E Vice President, Regulatory Relations to CPUC Executive Director, dated June 30, 2011 and page 4 of the Attached Report.

[14] Resolution ALJ-274, page 3.

[15] Resolution ALJ-274.

- On January 12, 2012, the SED issued its SBI Incident Investigation Report. The Commission initiated investigation proceeding I.12-01-007 on the same day to determine if the SBI was the result of safety rule violations.

- On January 17, 2012, the SED fined PG&E $17 million for failing to leak survey portions of its gas distribution system in Contra Costa County. PG&E was fined an additional $3 million on the same day for failure to comply with a CPUC pipeline records search directive.[16]

- On March 5, 2012 and March 21, 2012, the SED submitted reports in the PG&E gas pipeline recordkeeping proceeding. The reports identified significant deficiencies in PG&E's record keeping practices.[17]

- On May 15, 2012, the SED submitted its investigative report in the class location investigation proceeding.[18]

- On December 20, 2012, the CPUC approved PG&E's gas transmission Pipeline Safety Plan. The plan requires PG&E to pressure test 783 miles of pipeline, replace 186 miles and upgrade 199 miles to allow for in-line inspection. The decision also requires the installation of 228 automated valves.[19]

The Commission's Consumer Protection and Safety Division (CPSD) officially changed its name to the Safety and Enforcement Division (SED) on January 1, 2013. This report uses the new name to describe actions taken by the CPSD prior to the name change.

Independent Review Panel Report

The IRP issued its report on June 8, 2011. The IRP report contains numerous findings and recommendations. The Commission highlighted the following IRP findings in the December 2012 Decision that approved PG&E's gas transmission safety plan:[20]

> *[The IRP] found numerous deficiencies in PG&E's data collection and management, with resulting defects in Integrity Management, that undermine the safety of PG&E's gas system operations....*

[16] Resolution ALJ-277, April 19 2012.
[17] I.11-02-016. CPSD Records Management Report (Duller/North) and the Report and Testimony of Margaret Felts.
[18] I.11-11-009, CPSD Investigative Report into the Operations and Practices of PG&E's Natural Gas Transmission Pipeline System in Locations with Higher Population Densities, May 25, 2012.
[19] D.12-12-030, page 3.
[20] D.12-12-030, December 20, 2012, pages 7 to 9.

[The IRP] concluded that PG&E's Integrity Management Program lacked effective executive leadership, and that "perpetual organizational instability," including corporate bankruptcy, had undermined PG&E's ability to meet its integrity management responsibilities. The Panel found that PG&E had excessive levels of management, comprised largely of non-engineering personnel including telecommunications, legal and finance executives, who primarily focused on financial performance. The Panel found that PG&E lacked robust data and document information management systems that impeded the needed quality assurance/quality control to accurately characterize pipeline threats and risk. Addressing multiple threats to a particular pipeline and monitoring third-party activities were also noted as deficiencies.

The following IRP findings are particularly relevant to this audit:

- PG&E's top management placed excessive emphasis on financial performance. There was a lack of management focus on system integrity management.[21]

- The breakdown of PG&E's integrity management function was a result of a series of compromises in the quantity and quality of resources dedicated to the transmission system.[22]

- Engineering staffing shortages caused bottlenecks in the integrity management process.[23]

- PG&E failed to understand the critical technical and managerial aspects of pipeline integrity management and did not create an environment where excellence was demanded.[24]

- PG&E focused its efforts on integrity management compliance rather than on being an industry leader in pipeline safety. Operating a safe system requires more than compliance with minimum safety requirements.[25]

- The total amount of funding available to the gas transmission business for capital expenditures was financially driven. Under PG&E's capital budgeting process, any work that was not necessary for regulatory compliance could arguably be deferred.[26]

[21] Independent Review Panel Report, June 8, 2011, page 7.
[22] Independent Review Panel Report, June 8, 2011, page 27.
[23] Independent Review Panel Report, June 8, 2011, page 11.
[24] Independent Review Panel Report, June 8, 2011, page 27.
[25] Independent Review Panel Report, June 8, 2011, page 9.
[26] Independent Review Panel Report, June 8, 2011, page 53.

- Given the emphasis on cost controls, it does not appear there was any encouragement or support for a more comprehensive approach to integrity management.[27]

National Transportation Safety Board Accident Report

The federal National Transportation Safety Board (NTSB) is responsible for reviewing pipeline safety incidents. The NTSB conducted an extensive investigation of the SBI. The NTSB's findings concerning the SBI were adopted on August 31, 2011. The NTSB's Accident Report was released on September 26, 2011 (The NTSB Report). The NTSB Report contains numerous findings and recommendations. The following findings are particularly relevant to this audit:

- The probable cause of the SBI was: (1) inadequate quality assurance and control in 1956 during the Line 132 relocation project, which allowed the installation of substandard and poorly welded pipe with a visible seam weld flaw; and (2) an inadequate integrity management program, which failed to detect and repair (or remove) the defective pipe.[28]

- There were multiple deficiencies in PG&E's operations, including emergency response, system control and data acquisition, public awareness program, quality control and integrity management.[29] The multiple, recurring deficiencies are evidence of a systematic problem.[30]

- A visual inspection of the pipe installed in the 1956 relocation project would have detected the defects. The quality control for the project was insufficient to prevent the defective pipe from entering service.[31]

- PG&E's pipeline integrity management program, which should have ensured the safety of the system was deficient and ineffective because it:[32]
  - Was based on incomplete and inaccurate information;
  - Did not adequately consider the design and materials contribution to the risk of pipeline failure;
  - Failed to consider the presence of previously identified seam cracks in its risk assessment of Line 132;
  - Resulted in the selection of an examination method for Line 132 that could not detect the welded seam defects; and
  - Led to internal assessments of the program that were superficial and resulted in no improvements.

[27] Independent Review Panel Report, June 8, 2011, page 53.
[28] NTSB Accident Report, September 26, 2011, page XXI.
[29] NTSB Accident Report, September 26, 2011, page 88.
[30] NTSB Accident Report, September 26, 2011, page XI.
[31] NTSB Accident Report, September 26, 2011, page 96.
[32] NTSB Accident Report, September 26, 2011, page XI.

- In many cases, PG&E's pipeline records contained assumed values for key pipeline parameters. The records also contained many obvious errors.[33]

- PG&E's failure to consider evidence of seam defects discovered during the construction and operation of Line 132, and its under-weighting of the manufacturing defect threat, resulted in PG&E selecting an assessment method for Line 132 that was incapable of detecting seam flaws.[34]

- The character and quality of PG&E's operations indicate that the SBI was an organizational accident, rather than an isolated incident. PG&E did not effectively utilize its resources to define, implement, train, and test proactive management controls to ensure the safety of its pipelines.[35]

Organizational accidents have multiple contributing causes, involve people at numerous levels with a company, and are characterized by a pervasive lack of proactive measures to ensure adoption and compliance with a safety culture.[36]

SED Incident Investigation Report

The SED issued its SBI Incident Investigation Report on January 12, 2012.[37] The SED determined that the SBI was the direct result of multiple violations of federal and state gas safety regulations and PG&E's failure to follow accepted industry standards.

The SED concluded that the SBI was caused by a combination of the following contributing factors:[38]

- PG&E's failure to follow accepted industry practices when it constructed Segment 180 in 1956;

- PG&E's failure to comply with integrity management requirements;

- PG&E's inadequate record keeping practices;

- Deficiencies in PG&E's SCADA system and inadequate procedures related to the work at the Milpitas Terminal and PG&E's failure to comply with its own procedures;

- PG&E's deficient emergency response actions after the incident; and

[33] NTSB Accident Report, September 26, 2011, page 108.
[34] NTSB Accident Report, September 26, 2011, page 112.
[35] NTSB Accident Report, September 26, 2011, page 117.
[36] NTSB Accident Report, September 26, 2011, page 117.
[37] CPSD Incident Investigation Report, September 9, 2010 PG&E Pipeline Rupture in San Bruno California, Released January 12, 2013.
[38] CPSD Incident Investigation Report, January 12, 2013, page 3.

- PG&E's corporate culture emphasizing profits over safety.

The report of Overland's focused audit of gas transmission expenditures (Overland Transmission Report) was attached to the SED Investigation Report.

The Overland Transmission Report included the following key findings:[39]

- PG&E's actual gas transmission O&M expenses were five percent lower than amounts adopted in GT&S rate cases over the period 1997 to 2010. Actual transmission O&M was lower than adopted in all but one of those years. The consistent underspending on transmission O&M had negative implications for gas safety.

- PG&E's actual total GT&S capital expenditures were six percent lower than adopted over the period 1997 to 2010. During the period 2003 to 2010, actual capital expenditures in safety-related categories were $35 million higher than the adopted amounts.

- PG&E's GT&S operations have been very profitable since the Gas Accord structure was implemented in March 1998. During that time, GT&S revenues have exceeded the amount needed to earn the authorized rate-of-return by $430 million.

- PG&E placed excessive emphasis on meeting financial goals set by executive management in its budgeting process.

- Gas safety funding was heavily constrained in the 2008, 2009 and 2010 budget process. Integrity management and maintenance project budgets were viewed as discretionary funding that could be reduced to meet the overall budget targets set by executive management.

- PG&E reduced Integrity Management expenses in 2008, 2009 and 2010 by deferring projects and changing the assessment method for some projects from ILI to ECDA. Resource constraints were the driving force behind the deferrals and assessment method changes.

- PG&E's focus in 2008 through 2010 was on minimum compliance with integrity management rules rather than on gas safety excellence. PG&E reduced Integrity Management expense funding to the minimum amount needed to maintain compliance feasibility.

[39] Overland Transmission Report, December 30, 2011, page 1-1. The amounts shown above were modified slightly during the course of the SBI Investigation proceeding. The amounts shown above are the original amounts.

Overland concluded that the low priority that PG&E gave to safety and reliability in the 2008 through 2010 budget processes was well outside of standard industry practice.[40]

Overland determined that the actual return on equity (ROE) earned by GT&S operations averaged 14.2% during the 1999 to 2010 time period. PG&E's authorized return on equity averaged 11.2% over the same period.[41]

Financial and Management Audits Ordered in D.12-04-010

The CPUC issued D.12-04-010 on April 20, 2012 in the Gas Safety Rulemaking OII.[42] The decision ordered management and financial audits of the gas safety related programs of PG&E, San Diego Gas & Electric Company and Southern California Gas Company.

In that decision, the CPUC indicated:[43]

> *...[Our] efforts [since SBI] have not fully addressed safety-related culture and whether we should adopt enhanced standards for safety representations to the Commission. To initiate this review, we order financial and management audits of the gas corporations, beginning with PG&E.*

The decision indicates the financial audits will "include, but will not be limited to, comparing the authorized gas safety expenditures and capital investments to actual recorded amounts, and the rationale for any deviations."[44]

The Decision indicates the scope of the financial audits will include, but not be limited to, a comparison of authorized and actual spending for each utility's "last two authorized General Rate Case Cycles." The scope of the financial audits also includes a review of the each utility's actual earnings over the audited period. The Decision indicates "we stress that our purpose in this review is to ensure that actual authorized safety projects have been implemented..." [45]

The Decision indicates:[46]

> *Our ultimate goal is to review, and where necessary, improve existing systems for safe gas utility operations. Our purpose is not to invite or consider specific capital or expense projects, but rather to inspect the overall management system in place and resulting*

[40] Overland Transmission Report, December 30, 2011, page 1-1.
[41] Overland Transmission Report, December 30, 2011, page 1-3. Overland revised the actual ROE to 14.3 percent in its rebuttal testimony in the SBI Investigation proceeding.
[42] I-11-02-019.
[43] D.12-04-010, page 2.
[44] D.12-04-010, page 3.
[45] D.12-04-010, page 22.
[46] D.12-04-010, page 22.

management culture and the Commission's oversight role in achieving the obligation of safe operations.

Finding of Fact 5 indicates "financial audits are necessary to ensure that the Commission-approved revenue requirement is being used appropriately by California's natural gas system operators." [47]

Objectives and Approach

Overland Audit Objectives

The SED retained Overland to conduct a focused financial audit and retrospective review of the management practices of PG&E's gas distribution operations in May 2012.

The objectives of Overland's focused audit were to:

- Compare actual gas distribution capital expenditures for the years 1999 to 2010 to the amounts adopted in PG&E's General Rate Cases;
- Compare actual gas distribution operations and maintenance (O&M) expenses for the years 1999 to 2010 to the amounts adopted in PG&E's General Rate Cases;
- Investigate reasons for variances between the actual and adopted amounts;
- Review PG&E's budget process and internal management reports for evidence that gas distribution resources were constrained for financial reasons during the years 2003 to 2010;
- Review gas distribution staffing levels and operational metrics for evidence of resource constraints during the years 2003 to 2010; and
- Review the financial performance of PG&E's gas distribution business over the period 2003 to 2010 to determine if earnings were sufficient to support investments in safety.

The scope of the distribution audit largely mirrored the scope of the transmission audit conducted by Overland. The scope was expanded relative to the transmission audit in the following two areas to address issues identified in the transmission audit:

- Closer scrutiny of the role of executive management in the budget process; and
- Detailed review of the significant gas distribution management deficiencies described in Chapter 7 of the Overland Transmission Report.

[47] D.12-04-010, page 25.

The scope of the distribution audit is consistent with the financial audit ordered in D.12-04-010. The increased emphasis on executive management's role in the budget process is consistent with the emphasis placed on reviewing management culture. The detailed review of historical gas distribution management deficiencies is consistent with the emphasis on management culture and the emphasis on determining if authorized gas safety programs were actually implemented.

PG&E spent over $100 million during the audit period to address the gas distribution management deficiencies it identified in 2007 and 2008. Those expenditures increased actual expenses relative to the adopted amounts. D.12-04-010 requires the financial audit to examine the rationale for deviations between authorized and actual expenses. Generally these deficiencies in management, policies, and procedures were the impetus for significant deviations between authorized and actual expenses in those years.

D.12-04-010 indicates the financial audits will address, but not be limited to, the utility's last two rate case cycles. PG&E's last two completed rate case cycles covered the period 2003 to 2010. Overland's reviews of budgeting, metrics and earnings address that period. Overland expanded the comparison of actual versus adopted expenditures to include the 1999 GRC rate case cycle at the request of SED.

Overland utilized a detailed approach that included reviewing a large volume of contemporaneous documents. The number of documents reviewed in the audit was driven by the relatively long audit period and the pervasive nature of the gas distribution management deficiencies. Overland submitted 757 discovery questions during the audit.[48]

Comparisons of Actual and Adopted Spending (Chapters 3 and 4)

Overland compared actual and adopted gas distribution functional O&M and capital expenditures over the audit period. Overland focused on gas distribution functional costs because those categories contain PG&E's gas distribution safety-related costs.

PG&E provided recorded gas distribution O&M and capital expenditures amounts from its accounting system. Overland adjusted the recorded O&M expense to exclude costs that are not recoverable under the CPUC's ratemaking policies. The adjustments removed SBI response and Rancho Cordova Incident costs and certain other costs attributable to mismanagement.

The recorded capital expenditures amounts provided by PG&E included cost of removal expenditures.[49] Overland included adopted removal cost expenditures in its adopted capital expenditures to be consistent with the recorded costs included in the comparison.

[48] Overland continued the discovery numbering used in the Transmission Audit because many of the transmission responses were relevant to the distribution audit. As a result, many of the discovery responses cited in this report have numbers higher than OC-757.

[49] Cost of removal expenditures are the costs incurred to physically remove plant that has been retired. Cost of removal is charged to the Accumulated Reserve for Depreciation under the Commission's Uniform System of Accounts.

PG&E's gas distribution rates are set in its General Rate Cases (GRCs). The comparison includes the following three GRC cycles.

Table 2-2 - Gas Distribution Comparisons - General Rate Case Cycles

Gas Distribution Comparisons General Rate Case Cycles	
GRC Test Year	Rate Years
1999	1999 to 2002
2003	2003 to 2006
2007	2007 to 2010

GRCs are commonly denoted by the test year used in the case. For example, the second GRC shown above is referred to as the 2003 GRC even though it set rates for four years. The 1999 GRC was a fully litigated case. The rates adopted in the 2003 and 2007 GRCs were established by settlements.

Each of the rate case cycles included in the audit period consisted of a test year and three subsequent years. The rate increases implemented in the subsequent years are referred to as attrition rate increases. The subsequent years are referred to as Attrition Years. The GRCs include a detailed cost-of-service analysis for the test year. The adopted rates for the Attrition Years are not based on a detailed cost-of-service analysis.

The 1999 GRC Decision did not authorize any attrition rate increases. The attrition rate increases adopted in the 2003 and 2007 GRC settlements were negotiated amounts. The 2003 and 2007 GRC settlements do not explain the cost basis for the attrition rate increases. The adopted O&M and capital expenditures values for the Attrition Years must be imputed from the available evidence.

Overland used a consistent approach to identifying adopted O&M and capital expenditures across the three GRC cycles. We identified the adopted test year values from the applicable decision or settlement. Attrition Year values were calculated by escalating the test year values. The escalation reflected the overall increase in customer rates resulting from attrition rate increases granted for those years.

Long-Term Gas Safety Projects (Chapter 5)

PG&E had four primary long-term public safety related programs during the audit period. Those programs were the:[50]

- Gas Pipeline Replacement Program (GPRP);
- Copper Services Replacement Program (CSRP);
- Meter Protection Program (MPP); and
- Isolated Steel Services Program (ISSP).

[50] The MPP and ISSP are relatively small.

Overland focused on those programs consistent with the Commission's emphasis on reviewing the implementation of authorized safety programs.

The GPRP originated in 1985 and the MPP originated in 1990. We expanded the time period reviewed for those programs to provide insight into the history and objectives of those programs.

Return on Equity (Chapter 6)

Overland's review of PG&E's actual financial performance focused on determining the actual return on equity (ROE) earned by PG&E's gas distribution operations over the study period.

Overland used the following measurement standard for determining the actual ROE.

> Actual return on equity should reflect recorded results stated on a basis consistent with Commission ratemaking policies.

Costs that are excluded from rates under the Commission's ratemaking policies should necessarily be excluded from the ROE analysis. Overland focused on material known ratemaking adjustments. Overland did not attempt to conduct rate case audits of each year in the study period. Overland's approach is described in more detail in Chapter 6.

Staffing and Metrics (Chapter 7)

Overland asked PG&E to provide a variety of operational metrics for its gas distribution operations covering the period 2003 to 2010. In many instances, the data provided by PG&E was incomplete because it did not consistently track the metrics over the study period. Overland reviewed the data provided by PG&E for reasonableness but did not audit the data.

Overland reviewed the metrics for evidence of safety-related resource constraints. Chapter 7 presents selected metrics. The metrics were selected based on their perceived reliability and relevance to public safety.

Budget Process (Chapter 8)

Overland reviewed PG&E's budget process over the period 2003 to 2010 for evidence of resource constraints impacting safety. Overland also attempted to review the role of senior management in setting budget targets and approving final budgets. PG&E was not able to provide much of the information requested by Overland.

Planning Document Review (Chapter 9)

Overland reviewed gas distribution planning documents over the period 2003 to 2010 for evidence of safety-related resource constraints and submitted follow-up discovery. Overland's approach was to survey the available documentation and focus on the most readily apparent indications of resource adequacy.

Management Deficiencies (Chapters 10 to 13)

PG&E identified serious management deficiencies in its gas distribution operations in 2007 and 2008. PG&E expended over $100 million on corrective actions in 2008 through 2010. Evaluating and assessing actual spending during the study period required a working understanding of those deficiencies because: (1) they were, at least partially, a consequence of resource constraints in 2007 and earlier years; and (2) they were the rationale for very significant spending in 2008 through 2010.

Chapters 10 to 13 provide a narrative history of deficiencies in management, policies and procedures, which were found to be significant. Preparing a comprehensive analysis of all of the potential evidence was not deemed necessary to accomplish Overland's audit objectives. Overland's approach was to document the most significant and readily available evidence. This abridged history provides an adequate foundation to address the audit objectives.

Chapters 10 to 13 are organized chronologically to provide a sense of the overall situation and PG&E's responses to operational and safety deficiencies. Organizing the discussion by functions, such as preventative maintenance, would have been appropriate if Overland were trying to prove specific violations of safety rules but that was not Overland's objective. Rather our objective was to provide insight into the consequences of PG&E's past underspending and the reasons for the large increases in spending that occurred in 2008 through 2010.

Root Cause Analysis (Chapter 14)

A number of recurring circumstances emerged from the review of management deficiencies that explain, at least partially, the scope and root causes of the deficiencies addressed in this report. Overland developed these conditions into findings to provide insight into audit period spending patterns.

Overland did not attempt to develop a comprehensive set of root cause findings that addressed all of the deficiencies in gas distribution management including its policies and procedures, as this was not necessary to accomplish the audit objectives. Our approach was to develop a set of findings, based on the available evidence, that was sufficient to generally demonstrate the factors driving spending and the reasonableness of actual expenditures.

Overland did not attempt to fully develop every element of each root cause finding at a detailed level. The discovery required to do that would not have been practical within the scope and schedule of the audit. However, the evidence amply supports Overland's findings for the purposes for which they were used in the audit, particularly when they are viewed collectively.

The management audit of PG&E ordered in D.12-04-010 will focus on current management. This financial audit is retrospective in nature, focusing on historical management issues to provide insight into resource constraints and spending patterns during the audit period. This financial audit is intended to complement, rather than duplicate, the work performed in the management audit.

3. O&M Expenses

Introduction

This Chapter compares PG&E's adopted and actual gas distribution operations and maintenance (O&M) expenses for the period 1999 to 2010. This Chapter also reviews trends in gas distribution O&M over the same period.

The Chapter is organized into the following sections:

- Recorded Gas Distribution O&M;
- Adjustments to Recorded O&M;
- Adopted O&M;
- O&M Comparison;
- O&M Comparison by GRC Cycle; and
- PG&E O&M Comparison.

The following table compares PG&E's actual and adopted distribution O&M expenses.

Table 3-1 - Comparison of Actual and Adopted Gas Distribution O&M, 1999 to 2010

Comparison of Actual and Adopted Gas Distribution O&M 1999 to 2010 Dollars in Thousands			
Year	Actual	Adopted	Difference
1999	113,878	141,024	(27,146)
2000	115,396	141,024	(25,628)
2001	108,077	141,024	(32,947)
2002	116,023	141,024	(25,001)
2003	116,242	127,843	(11,601)
2004	111,070	130,400	(19,330)
2005	122,348	133,334	(10,986)
2006	130,333	138,267	(7,934)
2007	138,256	136,650	1,606
2008	155,589	139,450	16,139
2009	214,159	142,250	71,909
2010	165,286	145,050	20,236
Total	1,606,657	1,657,340	(50,683)
Source: Schedule 3-3. Actual is recorded/adjusted.			

Actual O&M was lower than adopted in every year from 1999 to 2006. Actual was higher than adopted in every year from 2007 to 2010. Over the twelve year study period actual was 3.1% lower than adopted.

During the period 1999 to 2007, actual spending was 12.9% lower than adopted. The underspending averaged $17.7 million per year during that period. Resource constraints imposed by management were a significant contributing factor to the underspending during those years.

Actual spending increased by 12.5% in 2008 and by 37.6% in 2009. Those increases reflected PG&E's response to the significant gas distribution management deficiencies identified in late 2007 and 2008.

During the period 2008 to 2010, actual spending was 25.4% higher than adopted. The overspending averaged $36.1 million during that period. The increased spending in 2008 to 2010 included costs incurred to reduce the backlog of work that had built up during prior years when funding was inadequate.

Recorded Gas Distribution O&M

PG&E's gas distribution O&M costs are recorded in FERC Accounts 871 to 894. Schedule 3-1 shows PG&E's recorded distribution O&M costs by FERC Account for the years 1999 to 2010. Schedule 3-2 shows the recorded costs by Major Work Category (MWC).[1]

PG&E's gas distribution O&M increased at an annualized average rate of 2.0% a year between 1999 and 2006. PG&E's 2006 gas distribution O&M included approximately $12 million in implementation costs for the Business Transformation program.[2] Without that spending, the average annual growth rate would have been 0.63% over the period 1999 to 2006.[3]

Gas distribution O&M increases over time as a result of price inflation and system growth. The following tables show selected inflation and system growth metrics for the period 1999 to 2006.[4]

Table 3-2- Inflation Measures - Average Annual Increase

Inflation Measures - Average Annual Increase 1999 to 2006	
Description	Percent
Wage Increases (Union) Granted by PG&E	3.53
Consumer Price Index - All Urban	2.49
Average of Two Measures	3.01
Source: Response to Discovery, OC-307 and US Department of Labor.	

[1] Schedules 3-1 and 3-2 also show Overland's adjustments to recorded O&M.

[2] Response to Discovery, OC-932

[3] Response to Discovery, OC-932. Growth rate of 0.63 is the growth rate excluding MWC AB. The Business Transformation Project is described in Chapter 10.

[4] The inflation measures shown below may understate the impact of inflation on gas distribution costs. PG&E's 2008-2010 3-Year Operating Plan notes that gas distribution materials prices grew at an average rate of 14% a year between 2004 and 2007, OC-64, Attachment 2, page 7

Table 3-3 - System Growth Measures - Average Annual Increase

System Growth Measures - Average Annual Increase 1999 to 2006	
Description	Percent
PG&E Miles of Distribution Mains	1.39
PG&E Number of Services	1.42
Average of Two Measures	1.40
Source: Response to Discovery, OC-858, Gas Statistical Reports.	

Inflation and system growth are additive. The inflation and system growth metrics suggest that gas distribution O&M should have grown at an average annual rate of approximately 4.4% during 1999 to 2006. The actual rate of 2.0% during that period results largely from resource constraints.

PG&E discovered significant management deficiencies in its gas operations in 2007 and 2008. Gas distribution O&M increased significantly in 2008 and 2009 as a result of the actions PG&E took to correct those deficiencies. With those increases, gas distribution O&M increased at an annualized average rate of 4.0% between 1999 and 2010.[5]

1999 to 2006

PG&E's gas safety related O&M expenses increased at a low rate during the period 1999 to 2006. The following table shows average annualized growth rates during that period for selected MWCs.

Table 3-4 - Annualized Average Increases

Annualized Average Increases Selected Gas Safety-Related MWCs 1999 to 2006		
MWC	Description	Percent
DE	Leak Survey	(0.3)
DD/DC	Field Services (GSRs)	2.9
DF	Mark & Locate	(0.1)
DG	Cathodic Protection	(3.3)
EX	Meter Protection Program	22.0
FG	Operate System	2.1
FG	Preventative Maintenance	0.2
FI	Corrective Maintenance	(2.0)
GF	Mapping	(6.7)
GG	Engineering - Planning & Ops	3.8
Source: Response to Discovery, OC-393.		

[5] Schedule 3-1, based on recorded amounts, not recorded/adjusted.

Leak survey, mark & locate, cathodic protection, corrective maintenance and mapping all had lower spending in 2006 than in 1999. Preventative maintenance spending only increased by $121 thousand between 1999 and 2006. The costs in those MWCs are largely safety-related. The Meter Protection Program (MPP) shows a large percentage increase because spending in 1999 was very low. PG&E only spent $340 thousand on the MPP in 1999.[6]

2006 to 2010

Recorded gas distribution O&M increased by 34.4% between 2006 and 2010. The following table compares 2006 and 2010 O&M by MWC.

Table 3-5 - Gas Distribution Recorded O&M, Comparison of 2006 and 2010 Costs by MWC

Gas Distribution Recorded O&M Comparison of 2006 and 2010 Costs by MWC Dollars in Thousands				
MWC	**Description**	**2006**	**2010**	**Increase**
DD/DC	Field Service (GSRs)	43,393	60,186	16,793
DE	Leak Survey	4,588	24,868	20,280
DF	Mark & Locate	10,103	9,492	(612)
DG	Cathodic Protection	6,452	7,682	1,231
EX	Meter Protection Program	1,365	72	(1,293)
FG	Operate Distribution System	2,668	3,321	653
FH	Preventative Maintenance	7,152	15,744	8,592
FI	Corrective Maintenance	14,741	39,866	25,124
FM/JV	Information Technology	591	491	(100)
GF	Gas Mapping	1,324	48	(1,276)
GG	Planning and Operations Engineering	2,022	2,157	135
GM	Customer Appliance Testing	2,025	2,540	515
HY/EY	Meter Maintenance	9,446	(7,374)	(16,820)
LK/EW	Work Requested by Others	8,590	7,624	(966)
AB/FJ	Miscellaneous & Business Transformation	12,221	448	(11,774)
BI	Buildings	370	1,472	1,103
KF	SBI Response	0	1,095	1,095
Various	Various Other MWCs	3,698	6,069	2,371
	Total	130,749	175,801	45,052
Source: Schedule 3-2. Amounts are the recorded values, not recorded/adjusted amounts.				

Field Service expense includes the costs of PG&E's Gas Service Representatives (GSRs). GSRs are part of PG&E's Customer Service Organization. GSRs respond to customer service requests, including odor complaints. GSRs also perform some meter maintenance work. GSR labor costs are primarily charged to MWC DD, Field Services and MWC HY, Meters. The following table compares Field Services and Meters expense in 2006 and 2010.

[6] The MPP is described in Chapter 5

Table 3-6 - Field Services and Meters O&M Expenses

Field Services and Meters O&M Expenses Comparison of 2006 and 2010 Costs Dollars in Thousands				
MWC	**Description**	**2006**	**2010**	**Increase**
DD/DC	Field Service (GSRs)	43,393	60,186	16,793
HY/EY	Meter Maintenance	9,446	(7,374)	(16,820)
	Total	52,839	52,812	(27)
Source: Schedule 3-2.				

On a combined basis, Field Services and Meters expenses were virtually unchanged between 2006 and 2010. That is consistent with the changes in GSR headcount during that period. The average GSR headcount was 773 in 2006 and 724 in 2010.[7] The 6.3% decrease in headcount was more than offset by wage increases.

The large increase in Field Services expense and the large decrease in Meters expense between 2006 and 2010 were caused by accounting errors that mis-classified labor costs between Field Services and Meters. PG&E revised its accounting procedures to properly classify the costs on a prospective basis in August 2010. Meters expense was negative in 2009 and 2010 because the credits recorded in the Meters MWC to transfer meter installation costs to capital MWCs were determined independently and were not affected by the accounting classification errors. As a result, the credits exceeded the total costs charged to the Meters MWC.[8]

Field Services expenses also increased because the GSRs spent a larger percentage of their time responding to customer odor complaints in 2009 and 2010. The Accelerated Leak Re-Survey Project (ALS) and associated repairs increased public awareness of gas leak issues. As a result, PG&E received more odor complaints. PG&E's improved odor complaint investigation process added about 15 minutes to each field call.[9]

The increase in Field Services costs in 2010 compared to 2009 also reflected overtime worked after the San Bruno Incident (SBI). The SBI occurred in September 2010. The GSRs performed safety checks in the San Bruno service area after the incident.[10]

Leak survey costs were 5.4 times the 2006 amount in 2010. The increase reflects the improvements in the leak survey process made in 2008 and the ALS.[11] The ALS was completed in April 2010. PG&E surveyed a total of 876,694 services in 2010 and 760,890 services in 2006. The number of services surveyed in 2010 was 15.2% higher than the number surveyed in 2006.[12]

[7] Chapter 7. Average of beginning and ending headcount for the year. Includes both GSRs and Dispatch.
[8] Response to Discovery, OC-1130.
[9] Response to Discovery, OC-834.
[10] Response to Discovery, OC-834.
[11] The ALS began in October 2008. The ALS is described in Chapter 11.
[12] Chapter 7.

PG&E tracked the costs of the leak surveys done under the ALS. The cost of the ALS surveys was $5.5 million in 2010.[13] The improved leak survey process significantly increased the amount of time required to survey a given area. Total leak survey costs increased by $20.3 million in 2010 compared to 2006. Most of that increase was attributable to the improved leak survey process.

PG&E retained a consulting firm, Exponent, to conduct a system-wide audit of regulator station and emergency valve maintenance in 2008. The audit discovered significant deficiencies in PG&E's preventative maintenance programs. PG&E implemented corrective actions in 2008 and 2009. The corrective actions included improved preventative maintenance procedures in 2009 and 2010. The increase in preventative maintenance costs in 2008 to 2010 reflects the audit costs and improved procedures.[14]

Recorded 2009 and 2010 preventative maintenance costs also included $15.6 million for the operator training, MetFit couplings investigation, odor call response tools and training and WMS data validation initiatives described in the Gas Matters Section of this Chapter.

Leak repairs account for approximately 80% of PG&E's gas distribution corrective maintenance costs. The ALS and improved leak survey process caused a large increase in the number of leak repairs in 2008 to 2010 compared to prior years. PG&E repaired 7,666 leaks in 2006 and 19,510 leaks in 2010.[15] The number of leaks repaired in 2010 was 2.55 times number repaired in 2006. Corrective maintenance expenses in 2010 were 2.70 times the amount in 2006.

Meter Protection Program (MPP) expense was very low in 2010 because PG&E placed a relatively low priority on the MPP in 2010. PG&E reduced MPP funding to very low levels to fund other higher priority work.[16]

The gas mapping costs charged to MWC GF were significantly lower in 2007 through 2009 than in prior years for three reasons. First, PG&E combined its electric and gas mapping organizations into one department in the second half of 2006 as part of the Business Transformation (BT) process and implemented process improvements that reduced costs. Second, PG&E reduced spending on mapping in 2007 in anticipation of the implementation of the BT Geographic Information Systems (GIS) initiative. Third, PG&E revised the procedure for allocating mapping support costs between expense and capital. The costs charged to MWC GF fell to very low levels in 2010 because of a change in accounting procedures.[17]

[13] Table 3-8, Accelerated Leak Survey plus ALS Quality Control. Excludes ALS project management.
[14] Response to Discovery, OC-778.
[15] Chapter 7.
[16] Chapter 5.
[17] Response to Discovery, OC-933.

MWC AB costs included approximately $12 million in 2006 for the Business Transformation (BT) program. The decrease in MWC AB costs was caused by the termination of the BT project in December 2007.[18]

Adjustments to Recorded O&M

The comparison of actual and adopted O&M should exclude costs that are not recoverable under the CPUC's rate-making policies. Overland's gas distribution O&M comparison incorporates the following adjustments to PG&E's recorded gas distribution O&M expenses:

- Exclude Rancho Cordova and San Bruno Incident related costs that are not recoverable under CPUC ratemaking policies;
- Exclude Gas Matters costs that are not recoverable under the CPUC's ratemaking policies; and
- Exclude distribution O&M expenses recovered through GT&S rates to match the scope of the O&M expenses adopted in the 2007 GRC.

The following table shows the adjustments by year.

Table 3-7 - Adjustments to Recorded Gas Distribution O&M

Adjustments to Recorded Gas Distribution O&M Dollars in Thousands					
Year	GT&S Expense Transfer	Rancho Cordova	San Bruno Incident	Gas Matters	Total
2003	(310)	0	0	0	(310)
2004	(365)	0	0	0	(365)
2005	(408)	0	0	0	(408)
2006	(416)	0	0	0	(416)
2007	(424)	0	0	0	(424)
2008	(426)	(29)	0	(10,157)	(10,612)
2009	(427)	(486)	0	(36,847)	(37,760)
2010	(427)	0	(2,259)	(7,829)	(10,515)
Total	(3,203)	(515)	(2,259)	(54,833)	(60,810)
Source: Overland Analysis					

The adjusted recorded O&M expenses are referred to as actual O&M expenses in this Chapter.[19]

GT&S Expense Transfer

Beginning in 2003, a relative small portion of gas distribution O&M was recovered through PG&E's Gas Transmission & Storage (GT&S) rates. GT&S rates are set in separate GT&S rate cases. The costs assigned to GT&S are excluded from PG&E's GRCs. The GT&S Expense Transfer adjustment reduces recorded O&M to match the scope of the O&M expenses adopted in PG&E's 2003 and 2007 GRCs.

[18] Response to Discovery, OC-932.
[19] The unadjusted recorded O&M expenses are referred to as recorded O&M expenses.

Rancho Cordova

On December 24, 2008, an explosion and fire caused by a gas leak destroyed a house in Rancho Cordova. One person was killed and five other people were hospitalized. Two adjacent homes were severely damaged. The Commission determined that the Rancho Cordova incident was the direct result of multiple violations of safety rules and fined PG&E $38 million.[20]

PG&E charged $515,000 of Rancho Cordova incident costs to gas distribution O&M in 2008 and 2009.[21] Those costs are the direct result of gas safety rule violations and should be excluded from actual O&M.

San Bruno Incident

On September 9, 2010, a massive explosion and fire caused by a local transmission line rupture killed eight people and injured many more. The fire destroyed 38 homes and damaged 70. That event is referred to as the San Bruno Incident (SBI). The Commission's Consumer Protection and Safety Division (CPSD) released its Incident Investigation Report for the SBI on January 12, 2012. The CPSD determined that the SBI was the direct result of multiple violations of safety rules. The Commission is currently considering the appropriate penalties or other possible remedies for those violations.[22]

The Commission required PG&E to initiate a number of safety measures in 2010 in response to the SBI. Most of the costs of those measures were charged to Transmission O&M Accounts. PG&E charged $2.26 million of SBI response costs to Gas Distribution O&M.[23] Those costs are the direct result of gas safety rule violations and should be excluded from actual O&M.

Gas Matters Recorded Costs

PG&E discovered serious management deficiencies in its gas distribution operations in 2007 and 2008. Those deficiencies are described in Chapters 10 to 14.

PG&E referred to the deficiencies and related corrective actions as Gas Matters in its internal documents. PG&E tracked the costs associated with the Gas Matters using planning orders. The Gas Matters costs tracked by PG&E are summarized below.

[20] The Rancho Cordova Incident is described in Chapter 11.
[21] Response to Discovery, OC-784.
[22] The SBI is described in Chapters 2 and 12.
[23] Response to Discovery, OC-395, Attachment 7, Tab SB_Cost.

Table 3-8 - Gas Matters Costs Tracked by PG&E

Gas Matters Costs Tracked by PG&E Gas Distribution O&M Dollars in Thousands				
Description	2008	2009	2010	Total
Accelerated Leak Survey	6,155	23,357	4,984	34,496
ALS Quality Control	228	606	475	1,309
Routine Leak Survey Quality Control	228	606	475	1,309
Leak Surveyor Re-Training	1,024	1,488	0	2,512
ALS Leak Repairs	107	25,208	1,942	27,257
Sonoma County Re-Survey Leak Repairs	2,876	866	46	3,788
Meter Set Leak Repairs	130	3,037	267	3,434
Regulator Station and Valve Audit Costs	2,536	3,837	459	6,832
Regulator Station and Valve Audit Repairs	83	2,056	695	2,834
Operator Training Development	34	5,963	135	6,132
Operational Reporting Initiative	0	2,708	46	2,754
Odor Call Response Tools & Training	0	2,773	0	2,773
SAP Work Management System	0	3,702	1,079	4,781
Aldyl-A Pipe Analysis and Data Collection	24	273	81	378
Cross-Bored Sewers Analysis	191	393	89	673
Gas Matters Management & Other Issues	131	5,503	1,215	6,849
Emerging Gas Issues	29	2,905	270	3,204
Total	13,776	85,281	12,258	111,315
Source: Response to Discovery, OC-874. Excludes payroll taxes and employee benefits.				

The ALS Leak Survey costs consist of the costs of conducting the accelerated leak surveys.[24]

PG&E implemented quality control verification surveys on a sample basis in March 2009 to test the quality of the work done by its leak surveyors.[25] The verification surveys were performed by contractors immediately after the original survey was completed. The ALS Quality Control and Routine Leak Survey Quality Control costs reflect the costs of developing the leak survey quality control program and the costs of conducting the verification surveys.[26]

PG&E conducted a special leak resurvey of its facilities in Sonoma County as a result of an internal audit of leak survey practices in its North Coast South Division. The leak resurvey started in late November 2007 and was completed in March 2008. The costs of the leak repairs resulting from the resurvey were tracked separately from the ALS leak repairs because the Sonoma County resurvey occurred prior to the approval of the ALS.[27] The Sonoma County resurvey is described in Chapter 10.

[24] Response to Discovery, OC-479.

[25] Response to Discovery, OC-413, Attachment 12, page 7.

[26] Response to Discovery, OC-1044. The leak survey QC costs were tracked in a single order that combined the costs for ALS and PG&E's previously scheduled routine leak surveys. PG&E estimates that 50% of the quality control costs were attributable to the ALS and 50% were attributable to previously scheduled routine leak surveys.

[27] Response to Discovery, OC-877.

PG&E identified "systemic" training and operator qualification issues during the Sonoma County leak resurvey.[28] PG&E implemented a program to retrain its leak surveyors. The Leak Surveyor Re-Training costs reflect the costs of the retraining.[29]

The ALS leak repairs costs consist of the cost of repairing the leaks found in the ALS.[30] The 2010 ALS leak repair costs shown above may not include all leaks discovered in the ALS. The response to discovery question OC-1058 indicates some ALS leak repair costs were charged to other orders.

The revised leak survey procedures used in 2008 and 2009 resulted in a large increase in the number of meter set leak repairs. Prior to 2008, meter set leak repairs were not tracked separately. PG&E established a separate planning order in 2008 to track meter set leak repair costs.[31]

An internal audit revealed significant problems in PG&E's preventative maintenance program in October 2007. After the internal audit report was issued, PG&E retained Exponent to conduct a system-wide audit of its regulator station and valve maintenance. The Exponent audit was conducted in 2008 and identified a large number of deficiencies in gas distribution work practices.[32] The Regulator Station and Valve audit costs shown above are the costs associated with conducting the audit.[33]

The Exponent audit identified the need to make a significant number of equipment repairs. The Regulator Station and Valve Audit Repairs costs shown above are the costs of making those repairs.[34]

PG&E completed an assessment of its existing operator qualification and training program in 2008. The assessment "exposed significant deficiencies in the controls and rigor of the processes."[35] PG&E developed an initiative to improve training for gas distribution supervisors and crews. The initiative also included providing the training to PG&E's Transmission & Regulation (T&R) supervisors and developing and implementing an operator qualification record keeping system. The Operator Training Development costs shown above are the costs of that initiative.[36]

The Operational Reporting Initiative (ORI) was implemented to improve leak survey and M&L metrics reporting. The ORI also included providing EZ Tech phone devices to M&L locators to allow real-time access to records in the field and tracking of the locator's position. The ORI is described in Chapter 12.

PG&E identified significant deficiencies in the process its GSRs used to respond to customer odor calls. The GSRs were not equipped with the proper equipment for indoor leak investigations. PG&E initiated a

[28] Response to Discovery, OC-714, Attachment 1, page 5.
[29] Response to Discovery, OC-875.
[30] Response to Discovery, OC-879.
[31] Response to Discovery, OC-877.
[32] Response to Discovery, OC-293, Attachment 1. The Exponent audit is described in Chapter 10.
[33] Response to Discovery, OC-876.
[34] Response to Discovery, OC-876.
[35] Response to Discovery, OC-672, Attachment 2.
[36] Response to Discovery, OC-1045 and OC-940, Attachment 1, page 8.

Odor Call Response Initiative in 2009 to correct the deficiencies. The Odor Call Response Tools & Training costs shown above include $2.2 million for new leak evaluation and repair tools. The remainder is for process improvement and training.[37]

PG&E struggled with implementing a Work Management System (WMS) for gas distribution preventative maintenance throughout the audit period. The lack of reliable and complete asset lists was a significant problem that hindered the development of a workable WMS. PG&E started on a long process of pilot programs and phased implementation of the WMS in 2008. The process included extensive data validation efforts. PG&E's efforts to develop a workable WMS are described in Chapter 11. The SAP Work Management System costs shown above are the costs of the data clean-up and validation work performed in 2009 and 2010.[38]

The Aldyl-A and Cross-Bored Sewers costs shown in the previous table are for distribution integrity management risk assessment work. The Cross-Bored Sewers project identified high risk locations where PG&E may have inadvertently bored through a sewer line using directional boring tools and inserted a gas line through the sewer line. The Aldyl-A project included collecting samples of the various types of Aldyl-A pipe in use in PG&E's system and testing the pipe to determine the expected remaining life of the pipe.[39]

The Gas Matters Management and Other Issues category included the following components.

Table 3-9 - Gas Matters Management & Other Issues Costs Tracked by PG&E

Gas Matters Management & Other Issues Costs Tracked by PG&E Gas Distribution O&M Dollars in Thousands				
Description	2008	2009	2010	Total
Gas Matters and ALS Project Management	163	3,926	48	4,137
Risk Analysis	0	693	957	1,650
Standards Revisions	0	197	28	225
Service Records Validation	0	939	34	973
Work Tracking Tools	0	290	199	489
Exclude Payroll Taxes and Employee Benefits	(32)	(542)	(51)	(625)
Total Gas Distribution O&M	131	5,503	1,215	6,849
Source: Response to Discovery, OC-874 and OC-1046.				

PG&E established separate Gas Matters and ALS project offices. The project management costs are the costs for those project management teams.[40]

[37] Response to Discovery, OC-1047.
[38] Response to Discovery, OC-876 and OC-940, Attachment 1, page 9.
[39] Response to Discovery, OC-940, Attachment 1, pages 13 and 14.
[40] Response to Discovery, OC-1046.

The Gas Matters project office included a risk analysis team that was responsible for scanning the gas distribution system and identifying additional risks that warranted further investigation or comparison. The Risk Analysis costs shown above are the costs for that team.[41]

PG&E discovered significant problems with its record keeping for gas service records in 2008 and 2009. Those problems are described in Chapter 12. PG&E conducted a review and validation of its gas service records in 2009.[42]

Work Tracking was a sub-project within the ALS project office that focused on utilizing better tools for tracking ALS work completion.[43]

The Emerging Gas Issues category shown in Table 3-8 included the following components.

Table 3-10 - Emerging Gas Issues Costs Tracked by PG&E

Emerging Gas Issues Costs Tracked by PG&E Gas Distribution O&M Dollars in Thousands				
Description	2008	2009	2010	Total
Rancho Cordova Investigation	34	600	0	634
Plastic Pipe Testing	0	425	(20)	405
MetFit Couplings Investigation	0	1,905	303	2,208
Gas Supplier Quality Program Development	0	310	(3)	307
Exclude Payroll Taxes and Employee Benefits	(5)	(335)	(10)	(350)
Total Gas Distribution O&M	29	2,905	270	3,204
Source: Response to Discovery, OC-874 and OC-1048.				

The Rancho Cordova investigation costs shown above are included in the separate Rancho Cordova adjustment discussed previously. The plastic pipe testing involved testing samples of plastic pipe.[44]

PG&E identified several leaks caused by the failure of MetFit mechanical couplings installed on 2" diameter plastic pipe in 2005 through 2008. The failures resulted from fractures of a stainless steel compression ring caused by severe pitting corrosion of the ring. PG&E removed over 200 MetFit couplings in 2009 to 2011 for testing. The failures were not the result of PG&E work quality issues.[45]

Gas Matters Adjustments

Some of the Gas Matters costs are the direct result of mismanagement. For example, the accelerated leak survey project would not have been required if the initial routine surveys had been adequate.

[41] Response to Discovery, OC-1046. The response to OC-940, Attachment 1, page 10, implies that the Risk Analysis costs included the review of Gas Engineering's quality control processes conducted by Exponent in 2009. The Exponent quality control review is described in Chapter 12.

[42] Response to Discovery, OC-876.

[43] Response to Discovery, OC-1046.

[44] Response to Discovery, OC-876.

[45] Response to Discovery, OC-1126.

Some of the Gas Matters costs would have been incurred under reasonable management practices. Overland did not find any evidence that the management deficiencies increased the total number of physical leaks occurring on the system. The leak survey deficiencies delayed the discovery of the leaks, but did not increase the total number of leak repairs made during the twelve year study period.

Overland classified the gas matters costs into two categories:

- Costs that would have been incurred at some point during the study period under reasonable management practices; and
- Costs that would not have been incurred under reasonable management practices.

The costs included in the second category are the direct result of mismanagement and are not recoverable under the Commission's rate-making policies. Overland excluded those costs from the actual costs used in its O&M comparisons.

Overland's Gas Matters adjustment is shown below by component and year.

Table 3-11 - Adjustment to Eliminate Non-Recoverable Gas Matters Costs

Adjustment to Eliminate Non-Recoverable Gas Matters Costs Gas Distribution O&M Dollars in Thousands				
Description	2008	2009	2010	Total
Accelerated Leak Survey	6,155	23,357	4,984	34,496
ALS Quality Control	228	606	475	1,309
Leak Surveyor Re-Training	1,024	1,488	0	2,512
Regulator Station and Valve Audit Costs	2,536	3,837	459	6,832
Regulator Station and Valve Audit Repairs	83	2,056	695	2,834
Gas Matters Management & Other Issues	131	5,503	1,215	6,849
Total	10,157	36,847	7,828	54,832
Source: Response to Discovery, OC-874. Excludes payroll taxes and employee benefits.				

The adjustment eliminates 49% of the Gas Matters costs tracked by PG&E.

Overland eliminated the ALS survey costs and leak survey re-training costs because those costs would not have been necessary if the initial surveys and training had been adequate.

The Exponent audit was the direct result of the serious deficiencies in regulator station and valve preventative maintenance discovered in PG&E's 2007 Internal Audit of the maintenance practices in its North Bay Division.[46] The Exponent audit identified numerous deficiencies in PG&E's gas distribution work practices. The repair costs associated with the audit are a direct result of those deficiencies.

[46] The internal audit is described in Chapter 10.

The costs of the Gas Matters and ALS project offices, including the Gas Matters risk analysis team, are a direct consequence of prior deficiencies in PG&E's gas distribution work practices. The gas service records validation project was the direct result of deficiencies in PG&E's record keeping practices.

Adopted O&M

Overland compared adopted and actual gas distribution O&M over the period 1999 to 2010. The comparison includes the following three GRC cycles.

Table 3-12 - General Rate Case Cycles

General Rate Case Cycles	
GRC Test Year	Period
1999	1999 to 2002
2003	2003 to 2006
2007	2007 to 2010

Overland identified the test year O&M expenses adopted in the 1999, 2003 and 2007 GRCs. The other nine years in the study period are referred to as Attrition Years in this Chapter. Overland escalated the adopted amount for the applicable test year to determine adopted O&M in the Attrition Years.

PG&E was not granted any attrition rate increases for gas distribution in 2000, 2001 or 2002. The adopted O&M amounts for those years equal the 1999 adopted test year values.

PG&E was granted attrition rate increases in 2004, 2005 and 2006. Overland escalated the 2003 test year adopted value to determine the adopted amounts in those years. The escalation factor in a given year equaled the percentage increase in customer rates produced by the attrition increases implemented in that year. PG&E was also granted attrition rate increases in 2008, 2009 and 2010. The adopted values in those years were calculated using the same approach.

The following table shows the calculation of the adopted amounts for 2004, 2005 and 2006.

Table 3-13 - Calculation of Adopted Gas Distribution O&M Expenses, 2004, 2005 and 2006

Calculation of Adopted Gas Distribution O&M Expenses 2004, 2005 and 2006 Dollars in Thousands			
Year	Prior Year Adopted	Increase Factor	Current Year Adopted
2004	127,843	1.0200	130,400
2005	130,400	1.0225	133,334
2006	133,334	1.0370	138,267
Source: Overland Analysis.			

The escalation calculations for 2008, 2009 and 2010 are shown below.

Table 3-14 - Calculation of Adopted Gas Distribution O&M Expenses, 2008. 2009 and 2010

Calculation of Adopted Gas Distribution O&M Expenses 2008, 2009 and 2010 Attrition Years Dollars in Thousands			
Year	Prior Year Adopted	Increase Factor	Current Year Adopted
2008	136,650	1.02049	139,450
2009	139,450	1.02008	142,250
2010	142,250	1.01969	145,050
Source: Overland Analysis.			

Schedule 3-3 shows PG&E's adopted O&M expense by FERC account. Schedule 3-3 also contains the comparison of actual and adopted O&M by FERC account for the study period.

The MWC structure was relatively new when PG&E filed its 1999 GRC Application. O&M issues were litigated in the 1999 GRC based on FERC Accounts instead of MWCs. As a result, adopted O&M is not available by MWC for 1999, 2000, 2001 or 2002.[47] Schedule 3-4 shows PG&E's adopted O&M by MWC for the period 2003 to 2010. Schedule 3-4 also contains the comparison of actual and adopted O&M by MWC for the same period.

O&M Comparison

The following table compares PG&E's actual and adopted distribution O&M expenses. The actual amounts are the recorded/adjusted amounts developed earlier in this Chapter.

[47] Response to Discovery, OC-949.

Table 3-15 - Comparison of Actual and Adopted Gas Distribution, O&M, 1999 to 2010

Comparison of Actual and Adopted Gas Distribution O&M 1999 to 2010 Dollars in Thousands			
Year	Actual	Adopted	Difference
1999	113,878	141,024	(27,146)
2000	115,396	141,024	(25,628)
2001	108,077	141,024	(32,947)
2002	116,023	141,024	(25,001)
2003	116,242	127,843	(11,601)
2004	111,070	130,400	(19,330)
2005	122,348	133,334	(10,986)
2006	130,333	138,267	(7,934)
2007	138,256	136,650	1,606
2008	155,589	139,450	16,139
2009	214,159	142,250	71,909
2010	165,286	145,050	20,236
Total	1,606,657	1,657,340	(50,683)
Source: Schedule 3-3. Actual is recorded/adjusted.			

Actual O&M was lower than adopted in every year from 1999 to 2006. Actual was higher than adopted in every year from 2007 to 2010. Over the twelve year study period actual was 3.1% lower than adopted.

During the period 1999 to 2007, actual spending was 12.9% lower than adopted. The underspending averaged $17.7 million per year during that period.

Actual spending increased by 12.5% in 2008 and by 37.6% in 2009. Those increases reflected PG&E's response to the significant gas distribution management deficiencies identified in late 2007 and 2008.

During the period 2008 to 2010, actual spending was 25.4% higher than adopted. The overspending averaged $36.1 million during that period. The increased spending in 2008 to 2010 included costs incurred to reduce the backlog of work that had built in prior years when funding was inadequate.

O&M Comparison by GRC Cycle

1999 GRC Cycle

The following table shows the differences between adopted and actual O&M for the 1999 GRC cycle by FERC Account.

Table 3-16 - Comparison of Actual and Adopted O&M - 1999 GRC Cycle

Comparison of Actual and Adopted O&M - 1999 GRC Cycle Actual Over/(Under) Adopted 1999 to 2002 Dollars in Thousands						
Account	Description	1999	2000	2001	2002	Total
871	Load Dispatching	(411)	(389)	(399)	(387)	(1,586)
874	Mains & Services Expense	1,912	408	590	2,328	5,238
875/876	Measuring & Regulating Station Expense	(179)	(543)	3,340	2,537	5,155
878	Meter & House Regulator Expense	519	951	(1,012)	183	641
879	Customer Installation Expense	(17,596)	(11,140)	(14,271)	(13,230)	(56,237)
880	Other Expenses	(6,369)	(7,414)	(11,980)	(8,027)	(33,790)
886	Maint. of Structures & Improvements	(1,216)	(1,216)	(1,216)	(1,216)	(4,864)
887	Maintenance of Mains	754	(2,685)	(3,032)	(2,267)	(7,230)
889/890	Maint. of Measuring & Reg. Stations	1,732	2,543	2,684	2,442	9,401
892	Maintenance of Services	(2,782)	(2,422)	(2,146)	(1,967)	(9,317)
893	Maint. of Meters & House Regulators	535	(81)	(2,230)	(1,483)	(3,259)
894	Maintenance of Other Equipment	(4,045)	(3,640)	(3,275)	(3,914)	(14,874)
	Total	(27,146)	(25,628)	(32,947)	(25,001)	(110,722)
Source: Schedule 3-3.						

Total gas distribution O&M was 19.6% lower than adopted during the 1999 GRC cycle. The forecast of gas distribution O&M costs adopted in PG&E's 1999 GRC was based on historical recorded costs in 1996 and prior years.[48] PG&E's gas distribution headcount was 2,386 as of December 1996. The gas distribution headcount was an even 2,000 as of December 2002.[49] The 16% reduction in staffing that occurred between 1996 and 2002 contributed to the underspending shown above.

Customer Installation Expense includes the costs of work performed on customer premises, except for the meter and house regulator expenses recorded in Accounts 878 and 893.[50] Customer Installation Expense consists primarily of the costs of responding to customer service requests and odor complaints. That work is performed by PG&E's Gas Service Representatives (GSRs). PG&E reduced its GSR staffing levels by 9% between December 1998 and December 2002.[51]

PG&E's testimony in the 2003 GRC indicates it reduced Customer Installation Expenses in 2000 by reducing overtime costs through better management and by reassigning some work previously done by GSRs to lower paid meter readers.[52]

Account 880, Other Expenses, includes the costs of preparing distribution maps and records, and operations expenses not included in the scope of the other operations expense accounts. Overland

[48] D.00-02-046, February 17, 2000, pages 218 and 224.
[49] Chapter 7. Both figures exclude the GSRs in PG&E's Customer Service organization.
[50] PG&E 2011 GRC Testimony, PG&E-2, page 4-4.
[51] Chapter 7.
[52] PG&E 2003 GRC Testimony, PG&E-3, page 4-4.

asked PG&E to explain why Customer Installation Expenses and Other Expenses (Account 880) were significantly lower than adopted in 1999 to 2002. PG&E's response indicates:[53]

> *[T]he forecasts for the 1999 GRC were done in 1997...Since the values were forecasts of future spending, they were subject to changes. Much of the observed differences between the expense forecasts and actual expenditures were related to non-emergency customer requests for service (e.g. pilot relights) which was not under PG&E's control. Other observed differences can be attributed to changes in PG&E's business priorities, which resulted in changes in actual work performed.*

2003 GRC Cycle

The following table shows the differences between adopted and actual O&M by MWC for the 2003 GRC cycle.

Table 3-17 - Comparison of Actual and Adopted Gas Distribution O&M by MWC, 2003 GRC Cycle

Comparison of Actual and Adopted Gas Distribution O&M by MWC
2003 GRC Cycle
Actual Over/(Under) Adopted
Dollars in Thousands

MWC	Description	2003	2004	2005	2006	Total
DD/DC	Field Service (GSRs)	(5,397)	(4,587)	(4,122)	(1,980)	(16,086)
DE	Leak Survey	279	(230)	(305)	(584)	(841)
DF	Mark & Locate	(395)	275	658	(1)	537
DG	Cathodic Protection	1,248	2,054	585	(119)	3,768
DN	Training	(141)	(369)	(421)	(536)	(1,466)
EX	Meter Protection Program	240	820	(333)	(902)	(174)
FG	Operate Distribution System	62	(208)	(275)	(27)	(449)
FH	Preventative Maintenance	465	219	(471)	266	479
FI	Corrective Maintenance	(2,751)	(2,771)	(3,290)	(4,659)	(13,471)
FM/JV	Information Technology	(4,427)	(4,484)	(4,190)	(5,659)	(18,760)
GF	Gas Mapping	181	(4)	(439)	(917)	(1,180)
GG	Planning and Operations Engineering	(30)	(235)	(101)	(84)	(451)
GM	Customer Appliance Testing	(1,669)	(2,979)	(3,176)	(2,942)	(10,766)
HY/EY	Meter Maintenance	(3,875)	(9,006)	(8,661)	(7,603)	(29,145)
LK/EW	Work Requested by Others	3,894	3,972	4,385	4,534	16,785
AB/FJ	Miscellaneous & Business Transformation	738	(1,009)	10,164	12,087	21,980
BI	Buildings	0	401	931	370	1,702
CG	Clean Air Transportation	(557)	(1,928)	(1,886)	(1,976)	(6,348)
CM	Operate Gas Transmission System	15	1	(39)	(112)	(135)
Various	Various Other MWCs	232	406	(74)	(1,043)	(479)
None	Costs Not Assigned to an MWC	287	331	77	3,953	4,648
	Total	(11,601)	(19,331)	(10,986)	(7,934)	(49,851)

Source: Schedule 3-4.

[53] Response to Discovery, OC-915, OC-916, OC-917, OC-918.

Total gas distribution O&M was 9.4% lower than adopted during the 2003 GRC cycle.

Actual field services expenses were 9.3% below adopted during the four-year 2003 GRC Cycle. PG&E's 2003 GRC forecast included 725 GSRs.[54] The average actual GSR headcount during the 2003 GRC cycle was 677.[55] The average actual GSR headcount was 6.6% lower than PG&E's forecast.

Actual corrective maintenance expenses were 18% lower than adopted during the 2003 GRC cycle. Leak repairs account for approximately 80% of the costs charged to corrective maintenance. Corrective maintenance costs were lower than adopted during the 2003 GRC rate cycle because leak repair costs were lower than the levels forecasted in the 2003 GRC.[56]

The Meter Maintenance MWC includes the cost of corrective and preventative maintenance on customer meters.[57] Under the FERC's Uniform System of Accounts the cost of installing refurbished meters is charged to expense while the cost of installing new meters is capitalized.

PG&E initially charges the labor costs for installing new and refurbished meters to the Meter Maintenance MWC. PG&E records a monthly accounting entry to transfer the costs of installing new meters to plant. The underspending in 2004, 2005 and 2006 was largely the result of an accounting change. PG&E refined its method of allocating total meter installation costs between new and refurbished meters in 2004. The change significantly increased the percentage of the total meter installation costs charged to capital. In its 2003 GRC application, PG&E forecasted that 39% of the gross charges to the Meter Maintenance MWC would be capitalized. In 2004 the actual capitalization percentage was 58%.[58]

Customer appliance testing is performed in conjunction with PG&E's energy efficiency programs. The customer appliance tests are conducted by GSRs. The GSRs test the ambient air quality inside each residence participating in the energy efficiency programs and perform a carbon monoxide test on each gas appliance to make sure they are operating safety. If a house fails the tests, it is not eligible for energy efficiency measures that reduce outside air infiltration.[59] Actual customer appliance testing expenses were 56% below the adopted levels during the 2003 GRC cycle.

MWC AB included the costs of implementing PG&E's Business Transformation process in 2005 and 2006. Those costs were excluded from the 2003 GRC. The BT spending accounts for the overspending in MWC AB in 2005 and 2006.[60]

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[54] PG&E 2003 GRC Testimony, PG&E-3, page 4-7.
[55] Average of December 2003, 2004, 2005 and 2006 headcounts.
[56] PG&E 2003 GRC Testimony, PG&E-2, page 13-46 and PG&E 2007 GRC Testimony, PG&E-4, page 15-39.

[57] The Meter Maintenance MWC also includes other Meter Program costs such as the costs of operating PG&E's Meter Test and Repair Facility.
[58] PG&E's 2003 GRC Testimony, Exhibit PG&E-2, page 10-15 and PG&E's 2007 GRC Testimony, Exhibit PG&E-4, page 10-16.
[59] PG&E 2003 GRC Testimony, PG&E-2, page 13-47.
[60] Response to Discovery, OC-932.

Information Technology expenses were 78% lower than adopted over the four year 2003 GRC cycle. The adopted amounts included costs for enhancing the Work Management System (WMS) and the Gas and Electric Mapping System (GEMS).[61] The WMS is discussed in Chapter 11. The GEMS is discussed in Chapter 12. Actual costs were lower than adopted because PG&E reduced gas distribution information technology funding to fund higher priority work.[62]

Clean Air Transportation costs were incurred to promote the use of natural gas fired vehicles. The Clean Air Transportation program was eliminated in 2004.[63]

2007 GRC Cycle

The following table shows the differences between adopted and actual O&M by MWC for the 2007 GRC cycle.

Table 3-18 - Comparison of Actual and Adopted Gas Distribution O&M by MWC, 2007 GRC Cycle

Comparison of Actual and Adopted Gas Distribution O&M by MWC
2007 GRC Cycle
Actual Over/(Under) Adopted
Dollars in Thousands

MWC	Description	2007	2008	2009	2010	Total
DD/DC	Field Service (GSRs)	2,848	3,662	7,448	10,482	24,441
DE	Leak Survey	1,219	4,903	12,682	13,882	32,686
DF	Mark & Locate	(1,362)	23	(1,813)	(2,817)	(5,970)
DG	Cathodic Protection	813	1,314	1,703	529	4,360
DN	Training	(567)	(559)	(573)	(584)	(2,282)
EX	Meter Protection Program	(2,547)	(2,258)	(2,926)	(3,190)	(10,921)
FG	Operate Distribution System	85	240	178	339	842
FH	Preventative Maintenance	1,042	3,510	19,958	7,079	31,590
FI	Corrective Maintenance	(732)	14,737	49,567	20,683	84,256
FM/JV	Information Technology	(1,042)	(1,142)	(1,283)	(2,708)	(6,175)
GF	Gas Mapping	(1,209)	(1,426)	(1,654)	(2,192)	(6,481)
GG	Planning and Operations Engineering	(549)	113	(449)	(212)	(1,097)
GM	Customer Appliance Testing	(107)	(117)	(493)	(236)	(954)
GZ	Research & Development	968	419	259	97	1,743
HY/EY	Meter Maintenance	(2,870)	(6,170)	(12,391)	(17,515)	(38,943)
LK/EW	Work Requested by Others	651	684	426	(1,031)	730
AB/FJ	Miscellaneous & Business Transformation	10,459	(1,710)	(165)	(764)	7,821
BI	Buildings	(6,340)	(6,904)	(6,329)	(5,928)	(25,501)
CM	Operate Gas Transmission System	(82)	2,038	470	(338)	2,088
Various	Various Other MWCs	68	(946)	(2,426)	(1,083)	(4,387)
None	Costs Not Assigned to an MWC	859	5,727	9,718	5,742	22,046
	Total	1,606	16,139	71,909	20,236	109,892

Source: Schedule 3-4.

Actual gas distribution O&M was 19.5% higher than adopted during the 2007 GRC cycle.

[61] PG&E 2003 GRC Testimony, PG&E-2, pages 13-68 to 13-71 and pages 12-13 to 12-16.
[62] Response to Discovery, OC-1127.
[63] Response to Discovery, OC-920.

Actual Field Services and Meter Maintenance costs were impacted by an offsetting mis-classification of expenses between those two categories. On a combined basis, actual Field Services and Meters expense was $14.5 million lower than adopted.[64] Actual combined Field Services and Meters expense was 6.3% lower than adopted.

Actual leak survey costs were 2.5 times the adopted leak survey costs, even after eliminating the ALS, because PG&E implemented significant enhancements to its leak survey process starting in 2008.

Mark & Locate costs were 12.5% lower than adopted. Cathodic protection costs were 15.7% higher than adopted.

Meter Protection Program expenses were $10.9 million lower than adopted because PG&E placed a relatively low priority on funding meter protection work during the 2007 GRC cycle.[65]

Preventative Maintenance expenses were 116% higher than adopted, even after eliminating the costs associated with Exponent's audit, because PG&E improved its preventative maintenance procedures in 2009 and 2010. In addition, actual 2009 and 2010 preventative maintenance costs include $15.6 million for the Gas Matters operator training, MetFit couplings investigation, odor call response tools and training and WMS data validation initiatives.

Actual corrective maintenance costs were 125% higher than adopted because PG&E repaired many more leaks in 2008 through 2010 than the levels anticipated in the 2007 GRC. The increase in leak repairs was caused by the ALS and the implementation of leak survey process enhancements in 2008.

Actual information technology costs were 50% lower than adopted. The largest component of the gas distribution Information Technology costs adopted in the 2007 GRC was the Gas Preventative and Corrective Maintenance project (GPCM).[66] The GPCM project consisted of developing and implementing a new asset register and WMS for gas distribution to replace GasFM.[67] The GPCM was rolled into the Business Transformation Project in 2006.[68] PG&E's efforts to implement a gas distribution asset register and WMS are described in Chapter 11.

Gas Mapping actual costs were lower than adopted for the three reasons described in the Recorded O&M Section of this Chapter.

PG&E proposed an extensive company wide building maintenance and refurbishment effort in its 2007 GRC. Approximately 26% of the costs of the program were allocated to gas distribution.[69] PG&E spent

[64] The misclassification was described in the recorded cost section of this chapter.

[65] Chapter 5.
[66] PG&E 2007 GRC Testimony, PG&E-4, pages 14-11 and 15-40.
[67] Chapter 11.
[68] Response to Discovery, OC-600, Attachment 1 and OC-1144.
[69] PG&E 2007 GRC Testimony, PG&E-7, Chapter 7.

significantly less on the company wide program in 2007 through 2010 than its 2007 GRC forecast. Actual gas distribution Building expense was 89% lower than adopted because PG&E reduced funding for that work to fund other higher priority work.[70]

Actual Miscellaneous and Business Transformation costs were $10.5 million higher than adopted in 2007 because PG&E excluded Business Transformation costs and savings from its 2007 gas distribution O&M forecasts.[71]

According to PG&E, costs not assigned to an MWC are typically the result of allocations and chargebacks that are less than $1. The small dollar costs are bundled together and reported in the not assigned category for FERC O&M reporting.[72] The not assigned category is not included in the forecasts considered in PG&E's GRCs. Actual "Not Assigned to an MWC" costs totaled $22 million during the 2007 GRC cycle. Overland did not investigate the reasons for the relative high level of those costs.

PG&E's O&M Comparison

PG&E provided its comparison of actual and adopted O&M on May 9, 2013.[73] The following table shows the comparison provided by PG&E.

[70] Response to Discovery, OC-1129.
[71] Response to Discovery, OC-932 and PG&E 2007 GRC Testimony, PG&E-1, pages 1-18 and 2-11.

[72] Response to Discovery, OC-500.
[73] OC-1059. Overland did not audit PG&E's comparison because it was received very late in the audit process. Overland did not submit any discovery requests to clarify the basis for PG&E's comparison because the responses would not have been received in time to incorporate them into this report.

Table 3-19 - PG&E's Comparison of Actual and Adopted Gas Distribution O&M

PG&E's Comparison of Actual and Adopted O&M Gas Distribution Functional 1999 to 2010			
Year	Actual	Adopted	Difference
1999	112,582	139,288	(26,706)
2000	113,895	139,288	(25,393)
2001	106,320	139,288	(32,968)
2002	114,670	139,288	(24,618)
2003	115,676	129,301	(13,625)
2004	110,791	131,887	(21,096)
2005	122,104	134,862	(12,758)
2006	130,137	139,837	(9,700)
2007	138,023	136,651	1,372
2008	165,507	139,452	26,055
2009	251,463	142,252	109,211
2010	175,362	145,053	30,309
Total	1,656,530	1,656,447	83
Source: Response to Discovery, OC-1059.			

PG&E concluded that actual gas distribution functional O&M was $83,000 higher than adopted over the twelve-year study period. Overland found that actual O&M was $50.7 million lower than adopted over the same period. Overland reduced actual O&M by $57.6 million to eliminate non-recoverable Gas Matters, SBI and Rancho Cordova costs. PG&E did not make those adjustments. The Gas Matters, SBI and Rancho Cordova adjustments account for most of difference between the two comparisons.

The following table compares PG&E's actual O&M to Overland's actual (recorded/adjusted) O&M.

Table 3-20 - Comparison of PG&E and Overland Actual O&M

Comparison of PG&E and Overland Actual O&M Gas Distribution Functional 1999 to 2010			
Year	PG&E	Overland	Difference
1999	112,582	113,878	(1,296)
2000	113,895	115,396	(1,501)
2001	106,320	108,077	(1,757)
2002	114,670	116,023	(1,353)
2003	115,676	116,242	(566)
2004	110,791	111,070	(279)
2005	122,104	122,348	(244)
2006	130,137	130,333	(196)
2007	138,023	138,256	(233)
2008	165,507	155,589	9,918
2009	251,463	214,159	37,304
2010	175,362	165,286	10,076
Total	1,656,530	1,606,657	49,873
Source: Tables 3-15 and 3-19			

The following table shows the components of the differences by year.

Table 3-21 - Differences Between PG&E and Overland Actual O&M

Differences Between PG&E and Overland Actual O&M PG&E Actual O&M Higher / (Lower) than Overland Gas Distribution Functional 1999 to 2010							
Year	MWC CG	GT&S Transfer	Account 871	MWC BX	Overland Adjustments	Rounding & Unlocated	Total
1999	(1,038)	0	(248)	0	0	(10)	(1,296)
2000	(1,231)	0	(270)	0	0	0	(1,501)
2001	(1,496)	0	(260)	0	0	(1)	(1,757)
2002	(1,082)	0	(272)	0	0	1	(1,353)
2003	0	310	(281)	(596)	0	1	(566)
2004	0	0	(279)	0	0	0	(279)
2005	0	0	(244)	0	0	0	(244)
2006	0	0	(196)	0	0	0	(196)
2007	0	0	(233)	0	0	0	(233)
2008	0	0	(243)	0	10,186	(25)	9,918
2009	0	0	0	0	37,333	(29)	37,304
2010	0	0	0	0	10,088	(12)	10,076
Total	(4,847)	310	(2,526)	(596)	57,607	(75)	49,873
Source: Overland Analysis. Note: Overland Adjustments Column excludes the GT&S Expense Transfer Adjustment.							

MWC CG is covers the Clean Air Transportation Program. PG&E excluded the costs of that program from its adopted and recorded values during the 1999 GRC cycle. Overland included the program in both its actual and adopted values. The adopted and recorded values largely offset in Overland's comparison.

PG&E reduced recorded O&M for the GT&S Expense Transfer starting in 2004. Overland's GT&S Expense Transfer adjustment starts a year earlier, in 2003, because the costs were excluded from adopted test year O&M in the 2003 GRC.

PG&E excluded FERC Account 871, Load Dispatching, from actual O&M.[74] PG&E did not explain the basis for that exclusion. Account 871 should be included in actual O&M because it is included in adopted O&M.

PG&E reduced 2003 actual O&M to exclude MWC BX, Transmission Maintenance. Overland included those costs because they were charged to gas distribution functional O&M accounts in 2003.

PG&E's adopted O&M amounts are compared to Overland's adopted O&M amounts in the following table.

Table 3-22 - Comparison of PG&E and Overland Adopted O&M

Comparison of PG&E and Overland Adopted O&M Gas Distribution Functional 1999 to 2010			
Year	PG&E	Overland	Difference
1999	139,288	141,024	(1,736)
2000	139,288	141,024	(1,736)
2001	139,288	141,024	(1,736)
2002	139,288	141,024	(1,736)
2003	129,301	127,843	1,458
2004	131,887	130,400	1,487
2005	134,862	133,334	1,528
2006	139,837	138,267	1,570
2007	136,651	136,650	1
2008	139,452	139,450	2
2009	142,252	142,250	2
2010	145,053	145,050	3
Total	1,656,447	1,657,340	(893)
Source: Tables 3-15 and 3-19			

Overland included the Gas Public Purpose Program (PPP) Unbundled Cost Category (UCC) in its adopted O&M during the 1999 GRC cycle. PG&E excluded the PPP UCC from its adopted amounts.

[74] Account 871 did not have any recorded costs in 2009 or 2010. Schedule 3-1
.

Overland's adopted O&M is lower than PG&E's adopted O&M during the 2003 GRC cycle because Overland used a more detailed approach to escalating test year adopted O&M from 2000 to 2003 dollars.

Schedule 3-1

Pacific Gas & Electric Company
Gas Distribution Functional O&M by FERC Account
Recorded and Recorded/Adjusted
1999 to 2010
Dollars in Thousands

Acct	Description	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Total
871	Load Dispatching	248	270	260	272	281	279	244	198	235	245	0	0	2,532
874	Mains & Services Expense	15,961	14,457	14,639	16,377	15,236	15,790	16,103	16,660	18,481	30,476	50,925	36,204	261,309
875/876	Measuring & Regulating Station Expense	1,149	785	4,668	3,865	5,508	2,097	2,342	3,735	3,530	2,654	1,440	2,125	33,898
878	Meter & House Regulator Expense	3,026	3,458	1,495	2,690	1,479	273	39	998	(898)	(4,127)	(3,798)	(12,690)	(8,055)
879	Customer Installation Expense	37,183	43,639	40,508	41,549	39,598	39,857	41,272	45,784	52,559	54,334	58,963	63,207	558,453
880	Other Operations Expenses	14,178	13,133	8,567	12,520	15,795	14,667	25,764	26,710	26,239	18,048	22,783	15,401	213,805
886	Maint. of Structures & Improvements	0	0	0	0	36	1	1,090	333	773	600	20,104	5,247	28,184
887	Maintenance of Mains	19,352	15,913	15,566	16,331	15,003	16,097	14,452	14,860	16,068	19,911	23,324	21,764	208,641
889/890	Maint. of Measuring & Reg. Stations	5,155	5,966	6,107	5,865	7,147	6,258	6,160	6,571	6,556	8,306	9,208	10,436	83,735
892	Maintenance of Services	9,253	9,613	9,889	10,068	9,449	10,143	10,426	10,411	11,467	31,386	66,268	32,409	220,782
893	Maint. of Meters & House Regulators	6,853	6,237	4,088	4,835	5,255	6,039	4,827	4,485	3,670	4,363	2,702	1,703	55,057
894	Maintenance of Other Equipment	1,520	1,925	2,290	1,651	1,765	(66)	37	4	0	5	0	(5)	9,126
	Total	113,878	115,396	108,077	116,023	116,552	111,435	122,756	130,749	138,680	166,201	251,919	175,801	1,667,467

Adjustments

Acct	Description	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Total
871	Load Dispatching	0	0	0	0	0	0	0	0	0	0	0	0	0
874	Mains & Services Expense	0	0	0	0	0	0	0	0	0	(6,194)	(21,744)	(4,752)	(32,690)
875/876	Measuring & Regulating Station Expense	0	0	0	0	0	0	0	0	0	0	0	0	0
878	Meter & House Regulator Expense	0	0	0	0	0	0	0	0	0	0	0	0	0
879	Customer Installation Expense	0	0	0	0	0	0	0	0	0	0	0	(1,182)	(1,182)
880	Other Operations Expenses	0	0	0	0	0	0	0	0	0	(773)	(4,475)	(759)	(6,007)
886	Maint. of Structures & Improvements	0	0	0	0	0	0	0	0	0	0	(8,126)	(1,680)	(9,806)
887	Maintenance of Mains	0	0	0	0	0	0	0	0	0	(1,001)	(1,743)	(729)	(3,473)
889/890	Maint. of Measuring & Reg. Stations	0	0	0	0	(310)	(365)	(408)	(416)	(424)	(504)	(875)	(825)	(4,127)
892	Maintenance of Services	0	0	0	0	0	0	0	0	0	(2,140)	(797)	(586)	(3,523)
893	Maint. of Meters & House Regulators	0	0	0	0	0	0	0	0	0	0	0	(2)	(2)
894	Maintenance of Other Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0
	Total	0	0	0	0	(310)	(365)	(408)	(416)	(424)	(10,612)	(37,760)	(10,515)	(60,810)

Adjusted Recorded

Acct	Description	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Total
871	Load Dispatching	248	270	260	272	281	279	244	198	235	245	0	0	2,532
874	Mains & Services Expense	15,961	14,457	14,639	16,377	15,236	15,790	16,103	16,660	18,481	24,282	29,181	31,452	228,619
875/876	Measuring & Regulating Station Expense	1,149	785	4,668	3,865	5,508	2,097	2,342	3,735	3,530	2,654	1,440	2,125	33,898
878	Meter & House Regulator Expense	3,026	3,458	1,495	2,690	1,479	273	39	998	(898)	(4,127)	(3,798)	(12,690)	(8,055)
879	Customer Installation Expense	37,183	43,639	40,508	41,549	39,598	39,857	41,272	45,784	52,559	54,334	58,963	62,025	557,271
880	Other Operations Expenses	14,178	13,133	8,567	12,520	15,795	14,667	25,764	26,710	26,239	17,275	18,308	14,642	207,798
886	Maint. of Structures & Improvements	0	0	0	0	36	1	1,090	333	773	600	11,978	3,567	18,378
887	Maintenance of Mains	19,352	15,913	15,566	16,331	15,003	16,097	14,452	14,860	16,068	18,910	21,581	21,035	205,168
889/890	Maint. of Measuring & Reg. Stations	5,155	5,966	6,107	5,865	6,837	5,893	5,752	6,155	6,132	7,802	8,333	9,611	79,608
892	Maintenance of Services	9,253	9,613	9,889	10,068	9,449	10,143	10,426	10,411	11,467	29,246	65,471	31,823	217,259
893	Maint. of Meters & House Regulators	6,853	6,237	4,088	4,835	5,255	6,039	4,827	4,485	3,670	4,363	2,702	1,701	55,055
894	Maintenance of Other Equipment	1,520	1,925	2,290	1,651	1,765	(66)	37	4	0	5	0	(5)	9,126
	Total	113,878	115,396	108,077	116,023	116,242	111,070	122,348	130,333	138,256	155,589	214,159	165,286	1,606,657

Source for Recorded is OC-393
Source for Adjustments is Overland Workpapers

Pacific Gas & Electric Company
Gas Distribution Functional O&M by MWC
Recorded and Recorded Adjusted
1999 to 2010
Dollars in Thousands

Recorded

MWC	Description	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Total
DD/DC	Field Service (GSRs)	35,573	40,706	39,587	38,407	36,555	38,204	39,632	43,393	49,675	51,448	56,193	60,186	529,560
DE	Leak Survey	4,668	4,982	4,926	4,726	5,061	4,648	4,683	4,588	6,424	17,623	43,552	24,868	130,748
DF	Mark & Locate	10,201	8,215	8,577	11,456	8,948	9,805	10,402	10,103	10,236	11,858	10,259	9,492	119,551
DG	Cathodic Protection	8,154	5,606	5,513	6,655	7,325	8,252	6,922	6,452	7,552	8,191	8,718	7,682	87,022
DN	Training	1,221	1,038	501	388	510	295	258	168	(16)	3	0	0	4,367
EX	Meter Protection Program	340	545	964	1,141	2,336	2,958	1,853	1,365	526	878	273	72	13,253
FG	Operate Distribution System	2,304	2,189	2,042	2,769	2,552	2,332	2,323	2,668	2,896	3,108	3,103	3,321	31,605
FH	Preventative Maintenance	7,031	6,419	5,856	6,432	6,831	6,713	6,169	7,152	7,627	12,925	36,639	15,744	125,539
FI	Corrective Maintenance	16,953	17,530	18,083	16,885	15,186	15,525	15,418	14,741	15,591	31,477	68,614	39,866	285,869
FM/JV	Information Technology	6,408	4,698	679	2,364	1,351	1,410	1,837	591	1,971	1,933	1,854	491	25,587
GF	Gas Mapping	2,155	1,804	1,912	2,223	2,253	2,109	1,722	1,324	902	728	543	48	17,722
GG	Planning and Operations Engineering	1,558	1,556	1,473	1,813	1,917	1,751	1,930	2,022	1,682	2,390	1,874	2,157	22,123
GM	Customer Appliance Testing	1,600	1,623	1,589	2,867	2,923	1,705	1,614	2,025	2,507	2,551	2,229	2,540	25,772
GZ	Research & Development	(0)	0	0	0	0	0	0	0	968	419	259	97	1,743
HY/EY	Meter Maintenance	12,348	12,403	11,219	12,216	11,815	7,047	7,787	9,446	6,701	3,592	(2,439)	(7,374)	84,762
LK/EW	Work Requested by Others	1,142	3,624	3,571	5,762	7,644	7,797	8,296	8,590	8,805	9,005	8,914	7,624	80,773
AB/FJ	Miscellaneous & Business Transformation	437	575	(867)	(2,659)	862	(883)	10,293	12,221	11,602	(544)	1,024	448	32,510
BI	Buildings	0	0	0	0	0	401	931	370	631	210	928	1,472	4,942
CG	Clean Air Transportation	1,038	1,231	1,496	1,082	1,273	(61)	23	4	0	0	0	0	6,086
CM	Operate Gas Transmission System	269	289	277	292	301	292	258	196	233	2,359	797	(5)	5,558
KF	SBI Response	0	0	0	0	0	0	0	0	0	0	1	1,095	1,095
Various	Various Other MWCs	327	213	164	321	622	803	331	(623)	1,307	319	(1,135)	234	2,883
None	Costs Not Assigned to an MWC	142	149	516	885	287	331	77	3,953	859	5,727	9,718	5,742	28,386
	Total	113,867	115,396	108,077	116,024	116,552	111,434	122,756	130,749	138,680	166,201	251,919	175,801	1,667,457

Adjustments

MWC	Description	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Total
DD/DC	Field Service (GSRs)	0	0	0	0	0	0	0	0	0	0	0	0	0
DE	Leak Survey	0	0	0	0	0	0	0	0	0	(7,408)	(25,451)	(5,460)	(38,319)
DF	Mark & Locate	0	0	0	0	0	0	0	0	0	0	0	0	0
DG	Cathodic Protection	0	0	0	0	0	0	0	0	0	0	0	0	0
DN	Training	0	0	0	0	0	0	0	0	0	0	0	0	0
EX	Meter Protection Program	0	0	0	0	0	0	0	0	0	0	0	0	0
FG	Operate Distribution System	0	0	0	0	0	0	0	0	0	0	0	0	0
FH	Preventative Maintenance	0	0	0	0	0	0	0	0	0	(2,695)	(9,826)	(1,675)	(14,196)
FI	Corrective Maintenance	0	0	0	0	0	0	0	0	0	(83)	(2,056)	(1,858)	(3,997)
FM/JV	Information Technology	0	0	0	0	0	0	0	0	0	0	0	0	0
GF	Gas Mapping	0	0	0	0	0	0	0	0	0	0	0	0	0
GG	Planning and Operations Engineering	0	0	0	0	0	0	0	0	0	0	0	0	0
GM	Customer Appliance Testing	0	0	0	0	0	0	0	0	0	0	0	0	0
GZ	Research & Development	0	0	0	0	0	0	0	0	0	0	0	0	0
HY/EY	Meter Maintenance	0	0	0	0	(310)	(365)	(408)	(416)	(424)	(426)	(427)	(427)	(3,203)
LK/EW	Work Requested by Others	0	0	0	0	0	0	0	0	0	0	0	0	0
AB/FJ	Miscellaneous & Business Transformation	0	0	0	0	0	0	0	0	0	0	0	0	0
BI	Buildings	0	0	0	0	0	0	0	0	0	0	0	0	0
CG	Clean Air Transportation	0	0	0	0	0	0	0	0	0	0	0	0	0
CM	Operate Gas Transmission System	0	0	0	0	0	0	0	0	0	0	0	0	0
KF	SBI Response	0	0	0	0	0	0	0	0	0	0	0	(1,095)	(1,095)
Various	Various Other MWCs	0	0	0	0	0	0	0	0	0	0	0	0	0
None	Costs Not Assigned to an MWC	0	0	0	0	0	0	0	0	0	0	0	0	0
	Total	0	0	0	0	(310)	(365)	(408)	(416)	(424)	(10,612)	(37,760)	(10,515)	(60,810)

Recorded / Adjusted

MWC	Description	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Total
DD/DC	Field Service (GSRs)	35,573	40,706	39,587	38,407	36,555	38,204	39,632	43,393	49,675	51,448	56,193	60,186	529,560
DE	Leak Survey	4,668	4,982	4,926	4,726	5,061	4,648	4,683	4,588	6,424	10,215	18,101	19,408	92,429
DF	Mark & Locate	10,201	8,215	8,577	11,456	8,948	9,805	10,402	10,103	10,236	11,858	10,259	9,492	119,551
DG	Cathodic Protection	8,154	5,606	5,513	6,655	7,325	8,252	6,922	6,452	7,552	8,191	8,718	7,682	87,022
DN	Training	1,221	1,038	501	388	510	295	258	168	(16)	3	0	0	4,367
EX	Meter Protection Program	340	545	964	1,141	2,336	2,958	1,853	1,365	526	878	273	72	13,253
FG	Operate Distribution System	2,304	2,189	2,042	2,769	2,552	2,332	2,323	2,668	2,896	3,108	3,103	3,321	31,605
FH	Preventative Maintenance	7,031	6,419	5,856	6,432	6,831	6,713	6,169	7,152	7,627	10,230	26,813	14,069	111,343
FI	Corrective Maintenance	16,953	17,530	18,083	16,885	15,186	15,525	15,418	14,741	15,591	31,394	66,558	38,008	281,872
FM/JV	Information Technology	6,408	4,698	679	2,364	1,351	1,410	1,837	591	1,971	1,933	1,854	491	25,587
GF	Gas Mapping	2,155	1,804	1,912	2,223	2,253	2,109	1,722	1,324	902	728	543	48	17,722
GG	Planning and Operations Engineering	1,558	1,556	1,473	1,813	1,917	1,751	1,930	2,022	1,682	2,390	1,874	2,157	22,123
GM	Customer Appliance Testing	1,600	1,623	1,589	2,867	2,923	1,705	1,614	2,025	2,507	2,551	2,229	2,540	25,772
GZ	Research & Development	(0)	0	0	0	0	0	0	0	968	419	259	97	1,743
HY/EY	Meter Maintenance	12,348	12,403	11,219	12,216	11,505	6,682	7,379	9,030	6,277	3,166	(2,866)	(7,801)	81,559
LK/EW	Work Requested by Others	1,142	3,624	3,571	5,762	7,644	7,797	8,296	8,590	8,805	9,005	8,914	7,624	80,773
AB/FJ	Miscellaneous & Business Transformation	437	575	(867)	(2,659)	862	(883)	10,293	12,221	11,602	(544)	1,024	448	32,510
BI	Buildings	0	0	0	0	0	401	931	370	631	210	928	1,472	4,942
CG	Clean Air Transportation	1,038	1,231	1,496	1,082	1,273	(61)	23	4	0	0	0	0	6,086
CM	Operate Gas Transmission System	269	289	277	292	301	292	258	196	233	2,359	797	(5)	5,558
KF	SBI Response	0	0	0	0	0	0	0	0	0	0	1	(0)	0
Various	Various Other MWCs	327	213	164	321	622	803	331	(623)	1,307	319	(1,135)	234	2,883
None	Costs Not Assigned to an MWC	142	149	516	885	287	331	77	3,953	859	5,727	9,718	5,742	28,386
	Total	113,867	115,396	108,077	116,024	116,242	111,069	122,348	130,333	138,256	155,589	214,159	165,286	1,606,647

Source for Recorded is OC-393
Source for Adjustments is Overland Workpapers

Pacific Gas & Electric Company
Comparison of Actual and Adopted
Gas Distribution Functional O&M by FERC Account
1999 to 2010
Dollars in Thousands

Actual (Recorded/Adjusted)

Acct	Description	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Total
871	Load Dispatching	248	270	260	272	281	279	244	198	235	245	0	0	2,532
874	Mains & Services Expense	15,961	14,457	14,639	16,377	15,236	15,790	16,103	16,660	18,481	24,282	29,181	31,452	228,619
875/876	Measuring & Regulating Station Expense	1,149	785	4,668	3,865	5,508	2,097	2,342	3,735	3,530	2,654	1,440	2,125	33,898
878	Meter & House Regulator Expense	3,026	3,458	1,495	2,690	1,479	273	39	998	(898)	(4,127)	(3,798)	(12,690)	(8,055)
879	Customer Installation Expense	37,183	43,639	40,508	41,549	39,598	39,857	41,272	45,784	52,559	54,334	58,963	62,025	557,271
880	Other Operations Expenses	14,178	13,133	8,567	12,520	15,795	14,667	25,764	26,710	26,239	17,275	18,308	14,642	207,798
886	Maint. of Structures & Improvements	0	0	0	0	36	1	1,090	333	773	600	11,978	3,567	18,378
887	Maintenance of Mains	19,352	15,913	15,566	16,331	15,003	16,097	14,452	14,860	16,068	18,910	21,581	21,035	205,168
889/890	Maint. of Measuring & Reg. Stations	5,155	5,966	6,107	5,865	6,837	5,893	5,752	6,155	6,132	7,802	8,333	9,611	79,608
892	Maintenance of Services	9,253	9,613	9,889	10,068	9,449	10,143	10,426	10,411	11,467	29,246	65,471	31,823	217,259
893	Maint. of Meters & House Regulators	6,853	6,237	4,088	4,835	5,255	6,039	4,827	4,485	3,670	4,363	2,702	1,701	55,055
894	Maintenance of Other Equipment	1,520	1,925	2,290	1,651	1,765	(66)	37	4	0	5	0	(5)	9,126
	Total	113,878	115,396	108,077	116,023	116,242	111,070	122,348	130,333	138,256	155,589	214,159	165,286	1,606,657

Adopted

Acct	Description	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Total
871	Load Dispatching	659	659	659	659	262	267	273	283	301	307	313	319	4,961
874	Mains & Services Expense	14,049	14,049	14,049	14,049	15,040	15,341	15,686	16,266	18,333	18,709	19,085	19,461	194,117
875/876	Measuring & Regulating Station Expense	1,328	1,328	1,328	1,328	2,462	2,511	2,567	2,662	2,543	2,595	2,647	2,699	25,998
878	Meter & House Regulator Expense	2,507	2,507	2,507	2,507	3,951	4,030	4,121	4,273	331	338	345	352	27,769
879	Customer Installation Expense	54,779	54,779	54,779	54,779	46,544	47,475	48,544	50,340	49,441	50,454	51,467	52,480	615,861
880	Other Operations Expenses	20,547	20,547	20,547	20,547	17,093	17,435	17,828	18,488	19,634	20,036	20,438	20,840	233,980
886	Maint. of Structures & Improvements	1,216	1,216	1,216	1,216	0	0	0	0	6,971	7,114	7,257	7,400	33,606
887	Maintenance of Mains	18,598	18,598	18,598	18,598	16,013	16,333	16,700	17,318	15,258	15,571	15,884	16,197	203,666
889/890	Maint. of Measuring & Reg. Stations	3,423	3,423	3,423	3,423	7,060	7,201	7,363	7,636	5,862	5,982	6,102	6,222	67,120
892	Maintenance of Services	12,035	12,035	12,035	12,035	9,276	9,462	9,675	10,033	11,104	11,331	11,558	11,785	132,364
893	Maint. of Meters & House Regulators	6,318	6,318	6,318	6,318	7,599	7,751	7,925	8,218	6,858	6,999	7,140	7,281	85,043
894	Maintenance of Other Equipment	5,565	5,565	5,565	5,565	2,543	2,594	2,652	2,750	14	14	14	14	32,855
	Total	141,024	141,024	141,024	141,024	127,843	130,400	133,334	138,267	136,650	139,450	142,250	145,050	1,657,340

Actual Over / (Under) Adopted

Acct	Description	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Total
871	Load Dispatching	(411)	(389)	(399)	(387)	19	12	(29)	(85)	(66)	(62)	(313)	(319)	(2,429)
874	Mains & Services Expense	1,912	408	590	2,328	196	449	417	394	148	5,573	10,096	11,991	34,502
875/876	Measuring & Regulating Station Expense	(179)	(543)	3,340	2,537	3,046	(414)	(225)	1,073	987	59	(1,207)	(574)	7,900
878	Meter & House Regulator Expense	519	951	(1,012)	183	(2,472)	(3,757)	(4,082)	(3,275)	(1,229)	(4,465)	(4,143)	(13,042)	(35,824)
879	Customer Installation Expense	(17,596)	(11,140)	(14,271)	(13,230)	(6,946)	(7,618)	(7,272)	(4,556)	3,118	3,880	7,496	9,545	(58,590)
880	Other Operations Expenses	(6,369)	(7,414)	(11,980)	(8,027)	(1,298)	(2,768)	7,936	8,222	6,605	(2,761)	(2,130)	(6,198)	(26,182)
886	Maint. of Structures & Improvements	(1,216)	(1,216)	(1,216)	(1,216)	36	1	1,090	333	(6,198)	(6,514)	4,721	(3,833)	(15,228)
887	Maintenance of Mains	754	(2,685)	(3,032)	(2,267)	(1,010)	(236)	(2,248)	(2,458)	810	3,339	5,697	4,838	1,502
889/890	Maint. of Measuring & Reg. Stations	1,732	2,543	2,684	2,442	(223)	(1,308)	(1,611)	(1,481)	270	1,820	2,231	3,389	12,488
892	Maintenance of Services	(2,782)	(2,422)	(2,146)	(1,967)	173	681	751	378	363	17,915	53,913	20,038	84,895
893	Maint. of Meters & House Regulators	535	(81)	(2,230)	(1,483)	(2,344)	(1,712)	(3,098)	(3,733)	(3,188)	(2,636)	(4,438)	(5,580)	(29,988)
894	Maintenance of Other Equipment	(4,045)	(3,640)	(3,275)	(3,914)	(778)	(2,660)	(2,615)	(2,746)	(14)	(9)	(14)	(19)	(23,729)
	Total	(27,146)	(25,628)	(32,947)	(25,001)	(11,601)	(19,330)	(10,986)	(7,934)	1,606	16,139	71,909	20,236	(50,683)

(3.06)

Source for Recorded/Adjusted is Schedule 3-1
Source for Adopted is Overland Workpapers

Pacific Gas & Electric Company
Comparison of Actual and Adopted
Gas Distribution Functional O&M by MWC
2003 to 2010
Dollars in Thousands

Adjusted / Recorded

MWC	Description	2003	2004	2005	2006	2007	2008	2009	2010	Total
DD/DC	Field Service (GSRs)	36,555	38,204	39,632	43,393	49,675	51,448	56,193	60,186	375,287
DE	Leak Survey	5,061	4,648	4,683	4,588	6,424	10,215	18,101	19,408	73,127
DF	Mark & Locate	8,948	9,805	10,402	10,103	10,236	11,858	10,259	9,492	81,103
DG	Cathodic Protection	7,325	8,252	6,922	6,452	7,552	8,191	8,718	7,682	61,095
DN	Training	510	295	258	168	(16)	3	0	0	1,219
EX	Meter Protection Program	2,336	2,958	1,853	1,365	526	878	273	72	10,263
FG	Operate Distribution System	2,552	2,332	2,323	2,668	2,896	3,108	3,103	3,321	22,302
FH	Preventative Maintenance	6,831	6,713	6,169	7,152	7,627	10,230	26,813	14,069	85,605
FI	Corrective Maintenance	15,186	15,525	15,418	14,741	15,591	31,394	66,558	38,008	212,422
FM/JV	Information Technology	1,351	1,410	1,837	591	1,971	1,933	1,854	491	11,439
GF	Gas Mapping	2,253	2,109	1,722	1,324	902	728	543	48	9,628
GG	Planning and Operations Engineering	1,917	1,751	1,930	2,022	1,682	2,390	1,874	2,157	15,722
GM	Customer Appliance Testing	2,923	1,705	1,614	2,025	2,507	2,551	2,229	2,540	18,093
GZ	Research & Development	0	0	0	0	968	419	259	97	1,743
HY/EY	Meter Maintenance	11,505	6,682	7,379	9,030	6,277	3,166	(2,866)	(7,801)	33,372
LK/EW	Work Requested by Others	7,644	7,797	8,296	8,590	8,805	9,005	8,914	7,624	66,675
AB/FJ	Miscellaneous & Business Transformation	862	(883)	10,293	12,221	11,602	(544)	1,024	448	35,024
BI	Buildings	0	401	931	370	631	210	928	1,472	4,942
CG	Clean Air Transportation	1,273	(61)	23	4	0	0	0	0	1,238
CM	Operate Gas Transmission System	301	292	258	196	233	2,359	797	(5)	4,431
KF	SBI Response	0	0	0	0	0	0	1	(0)	0
Various	Various Other MWCs	622	803	331	(623)	1,307	319	(1,135)	234	1,858
None	Costs Not Assigned to an MWC	287	331	77	3,953	859	5,727	9,718	5,742	26,694
	Total	116,242	111,069	122,348	130,333	138,256	155,589	214,159	165,286	1,153,283

Adopted

MWC	Description	2003	2004	2005	2006	2007	2008	2009	2010	Total
DD/DC	Field Service (GSRs)	41,952	42,791	43,754	45,373	46,827	47,786	48,745	49,704	366,932
DE	Leak Survey	4,782	4,878	4,988	5,172	5,205	5,312	5,419	5,526	41,282
DF	Mark & Locate	9,343	9,530	9,744	10,104	11,598	11,835	12,072	12,309	86,535
DG	Cathodic Protection	6,077	6,198	6,337	6,571	6,739	6,877	7,015	7,153	52,967
DN	Training	651	664	679	704	551	562	573	584	4,968
EX	Meter Protection Program	2,096	2,138	2,186	2,267	3,073	3,136	3,199	3,262	21,357
FG	Operate Distribution System	2,490	2,540	2,598	2,695	2,811	2,868	2,925	2,982	21,909
FH	Preventative Maintenance	6,366	6,494	6,640	6,886	6,585	6,720	6,855	6,990	53,536
FI	Corrective Maintenance	17,937	18,296	18,708	19,400	16,323	16,657	16,991	17,325	141,637
FM/JV	Information Technology	5,778	5,894	6,027	6,250	3,013	3,075	3,137	3,199	36,373
GF	Gas Mapping	2,072	2,113	2,161	2,241	2,111	2,154	2,197	2,240	17,289
GG	Planning and Operations Engineering	1,947	1,986	2,031	2,106	2,231	2,277	2,323	2,369	17,270
GM	Customer Appliance Testing	4,592	4,684	4,790	4,967	2,614	2,668	2,722	2,776	29,813
GZ	Research & Development	0	0	0	0	0	0	0	0	0
HY/EY	Meter Maintenance	15,380	15,688	16,040	16,633	9,147	9,336	9,525	9,714	101,463
LK/EW	Work Requested by Others	3,750	3,825	3,911	4,056	8,154	8,321	8,488	8,655	49,160
AB/FJ	Miscellaneous & Business Transformation	124	126	129	134	1,143	1,166	1,189	1,212	5,223
BI	Buildings	0	0	0	0	6,971	7,114	7,257	7,400	28,742
CG	Clean Air Transportation	1,830	1,867	1,909	1,980	0	0	0	0	7,586
CM	Operate Gas Transmission System	286	291	297	308	315	321	327	333	2,478
KF	SBI Response	0	0	0	0	0	0	0	0	0
Various	Various Other MWCs	390	397	405	420	1,239	1,265	1,291	1,317	6,724
None	Costs Not Assigned to an MWC	0	0	0	0	0	0	0	0	0
	Total	127,843	130,400	133,334	138,267	136,650	139,450	142,250	145,050	1,093,244

Actual Over / Under Adopted

MWC	Description	2003	2004	2005	2006	2007	2008	2009	2010	Total
DD/DC	Field Service (GSRs)	(5,397)	(4,587)	(4,122)	(1,980)	2,848	3,662	7,448	10,482	8,355
DE	Leak Survey	279	(230)	(305)	(584)	1,219	4,903	12,682	13,882	31,845
DF	Mark & Locate	(395)	275	658	(1)	(1,362)	23	(1,813)	(2,817)	(5,432)
DG	Cathodic Protection	1,248	2,054	585	(119)	813	1,314	1,703	529	8,128
DN	Training	(141)	(369)	(421)	(536)	(567)	(559)	(573)	(584)	(3,749)
EX	Meter Protection Program	240	820	(333)	(902)	(2,547)	(2,258)	(2,926)	(3,190)	(11,094)
FG	Operate Distribution System	62	(208)	(275)	(27)	85	240	178	339	393
FH	Preventative Maintenance	465	219	(471)	266	1,042	3,510	19,958	7,079	32,069
FI	Corrective Maintenance	(2,751)	(2,771)	(3,290)	(4,659)	(732)	14,737	49,567	20,683	70,785
FM/JV	Information Technology	(4,427)	(4,484)	(4,190)	(5,659)	(1,042)	(1,142)	(1,283)	(2,708)	(24,934)
GF	Gas Mapping	181	(4)	(439)	(917)	(1,209)	(1,426)	(1,654)	(2,192)	(7,661)
GG	Planning and Operations Engineering	(30)	(235)	(101)	(84)	(549)	113	(449)	(212)	(1,548)
GM	Customer Appliance Testing	(1,669)	(2,979)	(3,176)	(2,942)	(107)	(117)	(493)	(236)	(11,720)
GZ	Research & Development	0	0	0	0	968	419	259	97	1,743
HY/EY	Meter Maintenance	(3,875)	(9,006)	(8,661)	(7,603)	(2,870)	(6,170)	(12,391)	(17,515)	(68,091)
LK/EW	Work Requested by Others	3,894	3,972	4,385	4,534	651	684	426	(1,031)	17,515
AB/FJ	Miscellaneous & Business Transformation	738	(1,009)	10,164	12,087	10,459	(1,710)	(165)	(764)	29,801
BI	Buildings	0	401	931	370	(6,340)	(6,904)	(6,329)	(5,928)	(23,800)
CG	Clean Air Transportation	(557)	(1,928)	(1,886)	(1,976)	0	0	0	0	(6,348)
CM	Operate Gas Transmission System	15	1	(39)	(112)	(82)	2,038	470	(338)	1,953
KF	SBI Response	0	0	0	0	0	0	1	(0)	0
Various	Various Other MWCs	232	406	(74)	(1,043)	68	(946)	(2,426)	(1,083)	(4,866)
None	Costs Not Assigned to an MWC	287	331	77	3,953	859	5,727	9,718	5,742	26,694
	Total	(11,601)	(19,331)	(10,986)	(7,934)	1,606	16,139	71,909	20,236	60,039

Note: Adopted O&M by MWC not available for 1999 to 2002

Source for recorded/adjusted O&M is Schedule 3-2
Source for adopted is Overland Workpapers

4. Capital Expenditures

Introduction

This Chapter compares PG&E's adopted and actual gas distribution capital expenditures for the period 1999 to 2010. This Chapter also comments on trends in safety-related capital expenditures over the same period.

The Gas Pipeline Replacement Program (GPRP) and the Copper Services Replacement Program (CSRP) accounted for a large share of PG&E's capital expenditures during the study period. Those programs are discussed in more detail in Chapter 5.

The Chapter is organized into the following sections:

- Recorded Capital Expenditures;
- Adopted Capital Expenditures;
- Capital Expenditures Comparison;
- Other Imputation Methods; and
- PG&E's Capital Expenditures Comparison;

During the twelve-year study period, actual gas distribution functional capital expenditures were 6.5% lower than adopted. PG&E spent $168 million less than adopted over the entire study period.

The underspending was concentrated in 1999 to 2002. During those years, PG&E spent $282 million less than adopted. PG&E spent $114 million more than adopted in 2003 to 2010.

The underspending was concentrated in safety-related categories. Actual safety-related capital expenditures were 13.3% lower than adopted. Safety-related capital expenditures were $159 million lower than adopted during 1999 to 2010.

Safety-related capital expenditures were lower than adopted in every year from 1999 to 2006, except for 2003. Safety-related capital expenditures were $274 million lower than adopted in 1999 to 2006. Safety-related capital expenditures were $115 million higher than adopted in 2007 to 2010.

Recorded Capital Expenditures

Scope of Analysis

The plant costs included in gas distribution rate base in PG&E's General Rate Cases (GRCs) consist of common, general and functional plant. Common plant is used jointly by PG&E electric and gas operations. PG&E's headquarters building is an example of common plant. PG&E also includes transportation equipment (vehicles) plant costs in common plant.[1] PG&E allocates common plant between electric and gas functions in its GRCs.

[1] PG&E FERC Form 1, page 356.

Gas general plant is recorded in FERC Plant Accounts 389 to 399 and consists largely of buildings, tools and work equipment.[2] PG&E allocates those costs between storage, transmission and distribution in its GRCs.

Functional gas distribution plant is recorded in FERC Accounts 374 to 387. Functional gas distribution plant consists largely of mains, regulator stations, services and meters. Those costs are directly assigned to gas distribution in PG&E's GRCs.

The scope of this chapter excludes common plant and gas general plant. Those categories were excluded because they are allocated between multiple functions in the GRCs and because they do not include significant gas distribution safety-related costs.

PG&E tracks its capital expenditures by Major Work Categories (MWCs). The following MWCs are included within the scope of gas distribution functional plant capital expenditures.

Table 4-1 - Gas Distribution Functional Capital Expenditures, Major Work Categories

Gas Distribution Functional Capital Expenditures Major Work Categories	
MWC	Description
14A	Gas Pipeline Replacement Program
14B	Copper Services Replacement Program
27	Meter Protection Program
29	New Business (Customer Connects)
47	Capacity
50	Reliability
51	Work Requested by Others
52	Emergency Repair (Emergency Response)
74	Meters
Source: Response to Discovery, OC-392 and OC-1109.	

Total Recorded Costs

The following table shows total recorded gas distribution functional plant capital expenditures by year.

[2] PG&E's recorded gas general plant totaled $81 million as of December 31, 2010. 2010 FERC Form 2, page 209.

Table 4-2 - Total Recorded Capital Expenditures, Gas Distribution Functional, 1999 to 2010

Total Recorded Capital Expenditures Gas Distribution Functional 1999 to 2010 Dollars in Thousands	
Year	Amount
1999	172,350
2000	164,328
2001	166,614
2002	177,256
2003	188,607
2004	167,860
2005	190,952
2006	209,766
2007	209,532
2008	238,918
2009	250,461
2010	282,786
Total	2,419,430
Source: Response to Discovery, OC-392 and OC-928, Supplemental.	

PG&E's gas distribution functional capital expenditures were $183.6 million in 1998. PG&E constrained its capital expenditures in 1999 and 2000 largely due to uncertainty caused by the delay in issuing the 1999 GRC Decision. PG&E constrained its capital spending in 2001 and 2002 primarily because of the California Energy Crises.

Total expenditures were only 14% higher in 2007 than they were in 1998. That equates to an annualized rate of increase of 1.5% – below the rate of inflation and system growth. The consumer price index increased by 28% between July 1998 and July 2007.[3] The total number of gas distribution customers increased by 15% between December 1998 and December 2007.[4]

The $23 million increase in 2005 was largely attributable to a $15.5 million increase New Business spending.[5] The $19 million increase in 2006 was largely caused by a $12 million increase in Gas Pipeline Replacement Program Spending.

The higher levels in 2008 to 2010 reflect increased CSRP, Reliability, Meters and Work Requested by Others (WRO) spending, offset by a reduction in spending on New Business.

Schedule 4-1 shows actual functional gas distribution capital expenditures by MWC and year for the study period.[6]

[3] CPI All Urban Index, US Department of Labor, Bureau of Labor Statistics.
[4] 1998 and 2007 FERC Form 2 Reports, page 301.
[5] New Business costs are primarily the costs of connecting new residential subdivisions to the gas system.
[6] The same schedule contains the comparison of actual and adopted capital expenditures.

Recorded Costs - GPRP and CSRP

The GPRP and CSRP are long-term public safety programs. The following table shows recorded GPRP and CSRP spending by year.

Table 4-3 - Recorded Capital Expenditures, GPRP and CSRP

Recorded Capital Expenditures GPRP and CSRP Dollars in Thousands			
Year	GPRP	CSRP	Total
1999	56,167	0	56,167
2000	52,929	0	52,929
2001	61,914	0	61,914
2002	63,143	0	63,143
2003	71,888	0	71,888
2004	47,936	0	47,936
2005	46,968	0	46,968
2006	59,074	1,094	60,168
2007	56,189	20,727	76,916
2008	62,154	43,471	105,625
2009	60,476	39,036	99,512
2010	62,401	42,300	104,701
Total	701,239	146,628	847,867
Source: Response to Discovery, OC-392 and OC-428.			

PG&E reduced GPRP spending in 2004 and 2005 to fund other higher priority work.[7] PG&E constrained GPRP funding in 2007 to 2010 to fund the CSRP. The factors impacting actual GPRP and CSRP funding are discussed in detail in Chapter 5.

Recorded Costs - Other Safety Related MWCs

The Reliability, Meter Protection Program and Emergency Repair MWCs contain safety-related costs.

The following table shows the recorded costs in those MWCs.

[7] Response to Discovery, OC-943.

Table 4-4 - Recorded Capital Expenditures, Other Safety Related MWCs

Recorded Capital Expenditures Other Safety Related MWCs Dollars in Thousands			
Year	MPP	Reliability	Emergency
1999	113	10,005	831
2000	572	12,375	(112)
2001	463	13,614	127
2002	342	13,228	77
2003	128	13,935	120
2004	31	10,215	402
2005	33	11,307	95
2006	0	12,128	286
2007	15	10,844	256
2008	73	14,146	375
2009	17	28,576	249
2010	15	34,198	1,057
Total	1,802	184,571	3,763
Source: Recovery to Discovery, OC-392 MPP is Meter Protection Program.			

The costs of the Meter Protection Program (MPP) are largely charged to expense. During the study period, MPP program O&M expenses totaled $13.2 million.[8] The MPP is discussed in Chapter 5.

Reliability spending reflects the costs of maintaining the existing delivery capacity of the system. Reliability includes the costs of installing equipment to improve system reliability and the costs of replacing aging facilities that have reached the end of their useful lives.

The Reliability MWC includes all of PG&E's gas distribution safety-related functional capital expenditures that are not included in the GPRP, CSRP, MPP and Emergency Repair MWCs.

PG&E's policy is to replace rather than repair services when underground leaks are discovered on steel service lines.[9] Reliability spending includes the costs of replacing services.

Reliability spending did not increase significantly between 1999 and 2007. Reliability spending was lower on average in 2005 to 2007 than it was in 1999 to 2001.[10]

Reliability spending increased in 2009 and 2010 for two reasons. First, PG&E replaced more services in those years because it improved its leak survey process in 2008 and conducted a special re-survey of large portions of its system in late 2008 through early 2010. Second, PG&E conducted an extensive audit

[8] Chapter 3.
[9] Response to Discovery, OC-406, Attachment 28, page 2.
[10] Three year averages used to smooth year-to-year fluctuations.

of its regulator station and valve maintenance programs in 2008. The audit identified the need for numerous repairs. The repairs increased Reliability capital spending in 2009 and 2010.[11]

Emergency Repair spending consists of the costs of replacing damaged or failed facilities, including capital repairs of leaks caused by third party excavator dig-ins. Emergency Repair spending totaled $3.8 million over the twelve year study period.

Recorded Costs - New Business and Capacity

The following table shows recorded spending for the New Business and Capacity MWCs by year.

Table 4-5 - Recorded Capital Expenditures, New Business and Capacity

Recorded Capital Expenditures New Business and Capacity Dollars in Thousands		
Year	New Business	Capacity
1999	67,113	3,157
2000	59,289	3,218
2001	50,336	3,697
2002	57,387	3,258
2003	58,774	6,787
2004	60,117	6,099
2005	75,641	9,063
2006	75,522	11,599
2007	67,920	8,149
2008	46,372	12,063
2009	39,788	8,403
2010	21,948	14,675
Total	680,207	90,168
Source: Response to Discovery, OC-392.		

New Business spending consists primarily of the cost of installing distribution mains and services within new housing developments.[12] New Business spending is driven by the pace of residential subdivision development. Housing permits are a leading indicator of New Business spending. A reduction in housing permits produces a reduction in New Business spending with about a one-year lag. The decreases in New Business spending in 2007 through 2010 reflected the large decreases in housing permits that occurred in 2006 through 2009.[13]

[11] Response to Discovery, OC-946. The Accelerated Gas Leak Re-Survey Project and the Exponent Regulator Station and Valve audit are discussed in Chapter 11.

[12] PG&E 2011 GRC Testimony, PG&E-3, pages 6-19 and 6-40.

[13] PG&E 2011 GRC Testimony, PG&E-3, page 6-13.

Capacity spending reflects the costs of increasing system delivery capacity to meet load growth. The increase in Capacity spending in 2003, 2004 and 2005 reflected investments made to provide capacity needed to serve new customers. Higher Capacity spending continued in 2006 to 2010 after residential growth subsided because of the need to increase capacity to serve growth in isolated or constrained areas.[14]

The primary metrics for the Capacity MWC are the number of feet of new main installed and number of district regulator stations installed. Those metrics are shown below:

Table 4-6 - Capacity MWC Metrics

Capacity MWC Metrics Feet of Main Installed and District Regulator Stations Installed 2000 to 2010		
Year	Main - Feet	Stations
2000	35,055	12
2001	38,422	11
2002	43,312	8
2003	76,275	4
2004	49,476	5
2005	57,166	9
2006	50,647	9
2007	42,985	8
2008	58,789	10
2009	24,100	4
2010	81,067	6
Source: Response to Discovery, OC-688.		

Recorded Costs - Meters and WRO

The following table shows the recorded spending for the Meters and Work Requested by Others (WRO) MWCs by year.

[14] Response to Discovery, OC-945.

Table 4-7 - Recorded Capital Expenditures, Meters and Work Requested by Others

Recorded Capital Expenditures Meters and Work Requested by Others Dollars in Thousands		
Year	Meters	WRO
1999	19,297	15,667
2000	18,349	17,708
2001	18,985	17,478
2002	20,619	19,202
2003	18,883	18,092
2004	30,975	12,085
2005	33,492	14,353
2006	30,547	19,516
2007	29,444	15,988
2008	33,160	27,104
2009	47,011	26,905
2010	63,979	42,213
Total	364,741	246,311
Source: Response to Discovery, OC-392 and OC-928, Supplemental.		

The Meters MWC consists of the costs of the meters used to measure the customer's gas usage. The MWC includes the costs of purchasing new meters and the installation costs for new meters. The installation costs for refurbished meters are charged to O&M expense.

Meters spending increased in 2004 because PG&E changed its methodology for allocating installation costs between new and refurbished meters. The new methodology assigned a much higher percentage of total meter installation costs to capital expenditures.[15]

Meter spending increased in 2009 and 2010 primarily due to the Accelerated Leak Re-Survey Project. The ALS identified large numbers of leaks on meter sets. That increased the number of meter replacements in 2009 and 2010.[16]

WRO includes the cost of relocating facilities to accommodate street, highway and other governmental projects. WRO spending was significantly higher in 2008, 2009 and 2010 because of the road improvement projects funded under California Ballot Proposition 1B. That proposition was approved in November 2006 and authorized the issuance of approximately $20 billion in state general obligation bonds for specific transportation programs. The federal American Recovery and Reinvestment Act

[15] Chapter 3.
[16] Response to Discovery, OC-1147. The ALS is described in Chapter 11.

passed in 2009 also increased funding for road work.[17] California Department of Transportation infrastructure spending was approximately 50 percent higher in 2009 than in 2007.[18]

Adopted Capital Expenditures

PG&E's adopted gas distribution capital expenditures are shown by MWC and year on Schedule 4-1.

Overland's approach to determining adopted capital expenditures mirrored the approach it used to determine adopted O&M expenses.[19] Overland identified the test year capital expenditures adopted in the 1999, 2003 and 2007 General Rate Cases. The other nine years in the study period are referred to as Attrition Years in this Chapter. Overland escalated the adopted amount for the applicable test year to determine the adopted capital expenditures in the Attrition Years.

PG&E was not granted any gas distribution attrition rate increases for the 2000, 2001 and 2002 Attrition Years. Overland set the adopted capital expenditures in those years equal to the 1999 test year adopted amount for that reason.

PG&E was granted attrition rate increases in 2004, 2005 and 2006. Overland escalated the 2003 test year adopted values to determine the adopted amounts in those years. The escalation factor in a given year equaled the percentage increase in customer rates produced by the attrition increase implemented for that year. PG&E was also granted attrition rate increases in 2008, 2009 and 2010. The adopted values in those years were calculated using the same approach.

The following table shows the calculation of the adopted amounts for 2004, 2005 and 2006.

Table 4-8 - Calculation of Adopted Gas Distribution Capital Expenditures, 2004, 2005 and 2006 Attrition Years

Calculation of Adopted Gas Distribution Capital Expenditures 2004, 2005 and 2006 Attrition Years Dollars in Thousands			
Year	Prior Year Adopted	Increase Factor	Current Year Adopted
2004	181,824	1.0200	185,460
2005	185,460	1.0225	189,633
2006	189,633	1.0370	196,649
Source: Overland Analysis.			

[17] Response to Discovery, OC-947.
[18] PG&E 2011 GRC Testimony, PG&E-3, pages 6-51 and 6-52.
[19] Chapter 3

The escalation calculations for 2008, 2009 and 2010 are shown below.

Table 4-9 - Calculation of Adopted Gas Distribution Capital Expenditures, 2008, 2009 and 2010 Attrition Years

Calculation of Adopted Gas Distribution Capital Expenditures 2008, 2009 and 2010 Attrition Years Dollars in Thousands			
Year	Prior Year Adopted	Increase Factor	Current Year Adopted
2008	211,409	1.02049	215,739
2009	215,739	1.02008	220,074
2010	220,074	1.01969	224,406
Source: Overland Analysis.			

Capital Expenditures Comparison

The following table compares PG&E's total actual and adopted gas distribution functional capital expenditures by year.

Table 4-10 - Comparison of Actual and Adopted Capital Expenditures

Comparison of Actual and Adopted Capital Expenditures Gas Distribution Functional Dollars in Thousands			
Year	Actual	Adopted	Difference
1999	172,350	240,572	(68,222)
2000	164,328	240,572	(76,244)
2001	166,614	240,572	(73,958)
2002	177,256	240,572	(63,316)
2003	188,607	181,824	6,783
2004	167,860	185,460	(17,600)
2005	190,952	189,633	1,319
2006	209,766	196,649	13,117
2007	209,532	211,409	(1,877)
2008	238,918	215,739	23,179
2009	250,461	220,074	30,387
2010	282,786	224,406	58,380
Total	2,419,430	2,587,482	(168,052)
Source: Schedule 4-1.			

Actual capital expenditures were 6.5% lower than the adopted amounts over the 12 year study period. The differences varied greatly by GRC cycle. Actual capital expenditures were $282 million lower than adopted during the 1999 GRC cycle (1999 to 2002). During the 2003 GRC cycle, actual capital expenditures were $4 million higher than adopted. During the 2007 GRC cycle, actual capital expenditures were $110 million higher than adopted.

The 1999 GRC Decision was not issued until February 2000. According to PG&E, the uncertainty caused by the delay in issuing the decision caused it to reduce capital expenditures in 1999 below the levels it

requested in the 1999 GRC.[20] PG&E managed its expenditures in 1999 to minimize its exposure to the underrecovery of investments. PG&E's 2000 budgets were set before the 1999 GRC Decision was issued. As a result, 2000 spending was also impacted by the uncertainty.[21]

The California energy crises began in mid-2000. PG&E began implementing cash conservation measures in December 2000 and filed for bankruptcy in April 2001. The Commission approved PG&E's plan of reorganization in December 2003.[22] The California energy crises and resulting bankruptcy caused PG&E to limit its actual capital expenditures in 2000, 2001 and 2002.

Schedule 4-1 shows the differences between actual and adopted capital expenditures by MWC and year. PG&E's safety-related capital expenditures are included in the GPRP, CSRP, MPP, Reliability and Emergency Repair MWCs. The underspending during the study period was concentrated in the safety-related MWCs.

Schedule 4-2 shows the differences between actual and adopted safety-related capital expenditures by year and MWC. Actual safety-related capital expenditures were 13.3% lower than adopted over the twelve-year study period. Safety-related capital expenditures were $159 million lower than adopted during that period.

Safety-related capital expenditures were lower than adopted in every year from 1999 to 2006, except for 2003. Safety-related capital expenditures were $274 million lower than adopted from 1999 to 2006, and $115 million higher than adopted from 2007 to 2010.

Comparison - GPRP and CSRP

The following table shows the differences between actual and adopted spending for the GPRP and CSRP by year.

[20] Response to Discovery, OC-728, supplemental response.
[21] PG&E Rebuttal Testimony in 2003 GRC, PG&E-20, pages 1-1 and 1-2.
[22] Chapter 10.

Table 4-11 - Difference Between Actual and Adopted Capital Expenditures, Gas Pipeline and Copper Services Replacement Programs

Difference Between Actual and Adopted Capital Expenditures Gas Pipeline and Copper Services Replacement Programs Actual Higher / (Lower) Than Adopted Dollars in Thousands			
Year	GPRP	CSRP	Total
1999	(28,006)	0	(28,006)
2000	(31,244)	0	(31,244)
2001	(22,259)	0	(22,259)
2002	(21,030)	0	(21,030)
2003	3,988	0	3,988
2004	(21,322)	0	(21,322)
2005	(23,848)	0	(23,848)
2006	(14,362)	1,094	(13,268)
2007	(14,304)	20,727	6,423
2008	(9,783)	43,471	33,688
2009	(12,906)	39,036	26,130
2010	(12,426)	42,300	29,874
Total	(207,502)	146,628	(60,874)
Source: Schedule 4-1.			

Actual GPRP spending was lower than adopted in all but one of the years included in the study period. GPRP spending was 22.8% below adopted over the twelve year study period.[23] On a combined basis, actual spending for the GPRP and CSRP was 6.7% lower than adopted over the 12 year study period.

PG&E filed its 2007 GRC Application in December 2005. PG&E developed the CSRP in mid-2006 and made its initial presentation to the Commission safety staff concerning the program in August 2006.[24] PG&E did not include the CSRP in the capital expenditures it requested in the 2007 GRC because the program had not been authorized by management when it prepared its GRC application. As a result, the CSRP was not included in the capital expenditures adopted in the 2007 GRC.

[23] The GPRP and CSRP are discussed in more detail in Chapter 5.
[24] Chapter 5.

Comparison - Other Safety Related MWCs

The following table shows the differences between actual and adopted spending for PG&E's other safety-related capital MWCs.

Table 4-12 - Difference Between Actual and Adopted Capital Expenditures, Other Safety-Related MWCs

Difference Between Actual and Adopted Capital Expenditures Other Safety-Related MWCs Actual Higher / (Lower) Than Adopted Dollars in Thousands				
Year	MPP	Reliability	Emergency	Total
1999	(1,182)	(21,077)	(4,565)	(26,824)
2000	(723)	(18,707)	(5,508)	(24,938)
2001	(832)	(17,468)	(5,269)	(23,569)
2002	(953)	(17,854)	(5,319)	(24,126)
2003	(572)	(1,284)	(80)	(1,936)
2004	(683)	(5,308)	198	(5,793)
2005	(697)	(4,565)	(114)	(5,376)
2006	(757)	(4,331)	69	(5,019)
2007	(702)	(5,416)	47	(6,071)
2008	(659)	(2,447)	162	(2,944)
2009	(729)	11,650	21	10,952
2010	(746)	16,938	835	17,027
Total	(9,235)	(69,869)	(19,513)	(98,617)
Source: Schedule 4-1. MPP is Meter Protection Program.				

Other safety-related capital spending was 34.1% below adopted over the twelve year study period. Most of the difference between actual and adopted occurred in 1999 to 2002.

Reliability spending was higher than adopted in 2009 and 2010 because of increased spending on service line replacements and the costs of making the repairs identified in the 2008 audit of regulator station and valve maintenance.

MPP spending was lower than adopted because PG&E placed a relatively low priority on the MPP during the audit period.[25]

Comparison - Capacity and New Business

The following table shows the differences between actual and adopted spending for the Capacity and New Business MWCs.

[25] Chapter 5.

Table 4-13 - Difference Between Actual and Adopted Capital Expenditures, New Business and Capacity

Difference Between Actual and Adopted Capital Expenditures New Business and Capacity Actual Higher / (Lower) Than Adopted Dollars in Thousands			
Year	New Business	Capacity	Total
1999	(6,646)	(2,239)	(8,885)
2000	(14,470)	(2,178)	(16,648)
2001	(23,423)	(1,699)	(25,122)
2002	(16,372)	(2,138)	(18,510)
2003	3,068	3,002	6,070
2004	3,297	2,238	5,535
2005	17,542	5,115	22,657
2006	15,273	7,505	22,778
2007	6,266	(3,383)	2,883
2008	(16,545)	295	(16,250)
2009	(24,393)	(3,602)	(27,995)
2010	(43,496)	2,434	(41,062)
Total	(99,899)	5,350	(94,549)
Source: Schedule 4-1.			

New Business spending was lower than adopted in 2008 through 2010 because economic conditions caused a decrease in residential subdivision development.

Comparison - Meters and WRO

The following table shows the differences between adopted and actual spending for the Meters and Work Requested by Others MWCs.

Table 4-14 - Difference Between Actual and Adopted Capital Expenditures, Meters and WRO

Difference Between Actual and Adopted Capital Expenditures Meters and Work Requested by Others Actual Higher / (Lower) Than Adopted Dollars in Thousands			
Year	Meters	WRO	Total
1999	330	(4,837)	(4,507)
2000	(618)	(2,796)	(3,414)
2001	18	(3,026)	(3,008)
2002	1,652	(1,302)	350
2003	(2,081)	742	(1,339)
2004	9,592	(5,612)	3,980
2005	11,628	(3,742)	7,886
2006	7,874	752	8,626
2007	(2,441)	(2,671)	(5,112)
2008	622	8,063	8,685
2009	13,819	7,481	21,300
2010	30,134	22,407	52,541
Total	70,529	15,459	85,988
Source: Schedule 4-1.			

Meter spending was higher than adopted in 2004 through 2006 because of a change in the method used to determine the percentage of total meter installation costs charged to capital expenditures. Meter spending was higher that adopted in 2009 and 2010 because the ALS increased the number of meter replacements in those years.

WRO spending was higher than adopted in 2008 through 2010 because of an increase in government spending on transportation projects.

Other Imputation Methods

Overland reviewed two other approaches to imputing adopted capital expenditures in Attrition Years. The first was to use forecasts submitted by PG&E for those years in its GRCs. The second was to impute capital expenditures using a revenue requirements model that targeted the authorized return on equity.

PG&E Forecasts

One reason to compare actual and adopted capital expenditures is to determine the extent to which PG&E actually invested in plant consistent with its representations to the Commission in its GRCs. PG&E's representations concerning Attrition Year capital expenditures are contained in the forecasts that it filed for those years in its GRCs.

PG&E did not submit any Attrition Year gas distribution capital expenditures forecasts in the 1999 GRC.

PG&E filed its 2003 GRC Application in November 2002. That application included a gas distribution capital expenditures forecast for 2002. The following table compares PG&E's forecast to Overland's adopted values for 2002.

Table 4-15 - Comparison of PG&E 2002 Forecast in 2003 GRC to Overland 2002 Adopted

Gas Distribution Capital Expenditures Comparison of PG&E 2002 Forecast in 2003 GRC to Overland 2002 Adopted Dollars in Thousands				
MWC	Description	PG&E Forecast	Overland Adopted	Difference
14	Gas Pipeline Replacement Program	66,349	84,173	(17,824)
27	Meter Protection Program	1,222	1,295	(73)
29	New Business (Customer Connects)	58,600	73,759	(15,159)
47	Capacity	4,000	5,396	(1,396)
50	Reliability	14,599	31,082	(16,483)
51	Work Requested by Others	18,000	20,504	(2,504)
52	Emergency Response	200	5,396	(5,196)
74	Meters	19,535	18,967	568
	Total	182,505	240,572	(58,067)
Source: PG&E 2003 GRC Workpapers for PG&E-6, WP pages 8-5 and 8-6.				

The 2002 forecast included in PG&E's 2003 GRC Application was 24% lower than the adopted 1999 test year amount. The 1999 adopted values were set in a fully litigated rate case. The lower 2002 forecast in the 2003 GRC indicates a substantial reduction in PG&E's spending plans compared to the levels adopted in the 1999 GRC.

Actual gas distribution functional plant capital expenditures were $177 million in 2002. PG&E's 2002 forecast was filed in November 2002 and may have been significantly influenced by actual 2002 spending.

PG&E did not submit any Attrition Year capital expenditures forecasts in its 2003 GRC. PG&E's filed its 2007 GRC Application in December 2005. The application included a capital expenditures forecast for 2006. The following table compares PG&E's 2006 forecast to Overland's adopted values.

Table 4-16 - Comparison of PG&E 2006 Forecast in 2007 GRC to Overland 2006 Adopted

Gas Distribution Capital Expenditures Comparison of PG&E 2006 Forecast in 2007 GRC to Overland 2006 Adopted Dollars in Thousands				
MWC	Description	PG&E Forecast	Overland Adopted	Difference
14	Gas Pipeline Replacement Program	63,473	73,436	(9,963)
27	Meter Protection Program	586	757	(171)
29	New Business (Customer Connects)	59,726	60,249	(523)
47	Capacity	10,591	4,094	6,497
50	Reliability	14,250	16,459	(2,209)
51	Work Requested by Others	17,482	18,764	(1,282)
52	Emergency Response	200	217	(17)
74	Meters	30,697	22,673	8,024
	Total	197,005	196,649	356
Source: PG&E 2007 GRC Workpapers for PG&E-2, WP page 8-6 and Overland Analysis.				

PG&E's 2006 forecast in the 2007 GRC was slightly higher than Overland's adopted amount for 2006. Overland concluded that its 2006 adopted capital expenditures were reasonably consistent with PG&E's 2006 forecast.

PG&E's 2007 GRC Application included gas distribution capital expenditures forecasts for 2008 and 2009. The following table compares those forecasts to Overland's adopted amounts.

Table 4-17 - Comparison of PG&E 2008 & 2009 Forecasts in 2007 GRC to Overland Adopted Amounts

Gas Distribution Capital Expenditures Comparison of PG&E 2008 & 2009 Forecasts in 2007 GRC to Overland Adopted Amounts Dollars in Thousands			
MWC	Description	PG&E Forecast 2008	PG&E Forecast 2009
14	Gas Pipeline Replacement Program	69,915	73,029
27	Meter Protection Program	722	749
29	New Business (Customer Connects)	59,113	58,443
47	Capacity	11,806	13,464
50	Reliability	18,253	20,038
51	Work Requested by Others	18,726	19,381
52	Emergency Response	204	205
74	Meters	32,764	34,028
	Total PG&E Forecast	211,503	219,337
	Overland Adopted	215,739	220,074
	Difference	(4,236)	(737)
	Percentage Difference	(1.96)	(0.33)
Source: PG&E 2007 GRC Workpapers for PG&E-2, WP page 8-6 and Overland Analysis.			

PG&E's 2008 and 2009 forecasts in the 2007 GRC were slightly lower than Overland's adopted amounts for those years.

PG&E filed its 2011 GRC Application in December 2009. That application included a gas distribution capital expenditures forecast for 2010. The following table compares PG&E's 2010 forecast to Overland's adopted values.

Table 4-18 - Comparison of PG&E 2010 Forecast in 2011 GRC to Overland 2010 Adopted

Gas Distribution Capital Expenditures Comparison of PG&E 2010 Forecast in 2011 GRC to Overland 2010 Adopted Dollars in Thousands				
MWC	Description	PG&E Forecast	Overland Adopted	Difference
14	Gas Pipeline Replacement Program	100,657	74,827	25,830
27	Meter Protection Program	100	761	(661)
29	New Business (Customer Connects)	45,100	65,444	(20,344)
47	Capacity	11,000	12,241	(1,241)
50	Reliability	23,350	17,260	6,090
51	Work Requested by Others	24,084	19,806	4,278
52	Emergency Response	282	222	60
74	Meters	38,681	33,845	4,836
	Total	243,254	224,406	18,848
Source: PG&E 2011 GRC Workpapers for PG&E-2, WP 9-10 and 9-11 and Overland Analysis.				

PG&E's 2010 forecast in the 2011 GRC was 8.4% higher than Overland's 2010 adopted amount. As such, Overland's 2010 adopted capital expenditures are conservative.

Targeted Return on Equity Approach

Overland calculated Attrition Year O&M expenses and capital expenditures by escalating test year values based on the increases in customer rates granted in the Attrition Years. That approach is referred to as the Escalation Approach in the remainder of this Chapter.

Under the Escalation Approach, the adopted capital expenditures amount is determined independently from earnings. Under the Escalation Approach, the return on equity (ROE) in the Attrition Years is a residual value that is calculated based on adopted revenues, expenses and rate base.

Overland considered an approach that uses net plant additions as the residual value in the Attrition Years. That approach is referred to as the Targeted ROE approach in this Chapter. Under the Targeted ROE approach, the earned ROE is held constant by adjusting the level of adopted capital expenditures in each Attrition Year.

Under the Targeted ROE approach, adopted net plant additions are imputed using a revenue requirements model based on test year values and the authorized attrition rate increases. Attrition year

expenses increase at the same rate as authorized revenue requirements.[26] Adopted net plant additions are calculated by solving the model for the values that produce the authorized ROE.

The Targeted ROE approach does not directly solve for adopted gas distribution functional capital expenditures in the attrition years. Instead, it solves for total net plant additions, including common plant additions. Adopted functional capital expenditures must be inferred from total net plant additions.

The key assumption underlying the Targeted ROE Approach is that net plant additions are the residual value, adjusted to maintain the Company's ROE at the authorized level during Attrition Years. In other words, the Targeted ROE Approach assumes that any shortfall in earnings that would otherwise occur should be addressed by reducing adopted plant additions. The key assumption underlying the Targeted ROE approach is completely unsupported. Overland rejected the Targeted ROE approach primarily for that reason.

The Escalation Approach assumes ROE is the residual value that varies when the attrition rate increases do not produce the authorized ROE. Overland calculated the ROE's produced by the Escalation Approach to determine if they were reasonable. The results are shown below.[27]

Table 4-19 - Return on Equity Produced by Escalation Approach in Attrition Years

Return on Equity Produced by Escalation Approach In Attrition Years Amounts in Percentages			
Year	Escalation Approach ROE	Authorized ROE	Percent of Authorized
2000	8.16	10.60	77
2001	6.41	10.60	60
2002	4.88	10.60	46
2004	10.61	11.22	95
2005	10.10	11.22	90
2006	10.07	11.22	90
2008	11.06	11.35	97
2009	10.79	11.35	95
2010	10.53	11.35	93
Note: Authorized ROE is Test Year Value From Applicable GRC.			
Source: Overland Analysis.			

[26] With the exception of depreciation and income tax expenses. Those expenses are calculated from the other Attrition Year values using the standard approaches for calculating depreciation and income taxes.

[27] The calculations used the same revenue requirements model as the Targeted ROE Approach. The model was modified to make capital expenditures an input and solve for ROE.

2003 and 2007 GRC Cycles

The Commission granted attrition rate increases in the 2003 and 2007 GRC cycles. The ROEs produced by the Escalation Approach during those rate cycles are clearly adequate.

The Commission's intent is unstated. The Commission may have intended any shortfall in earnings in the Attrition Years to produce a reduction in the ROE for those years. In other words, the Commission may have expected PG&E's actual ROE to be lower in the Attrition Years than it was in the test year.

The Targeted ROE approach assumes the Commission intended to reduce adopted capital expenditures to avoid the relatively small reductions in ROE produced by the Escalation Approach in the 2003 and 2007 GRC cycles. Overland did not identify any basis for singling out capital expenditures as the only item that should be reduced to produce the authorized ROE during those Attrition Years. The 2003 and 2007 GRC Decisions do not authorize PG&E to reduce capital expenditures in the Attrition Years based on the adopted attrition rate increases.

1999 GRC Cycle

PG&E was not granted any gas distribution attrition rate increases in the 1999 GRC cycle. The Escalation Approach holds capital expenditures constant in 2000, 2001 and 2002 at the 1999 Test Year level. The Escalation Approach produces ROEs in those years that are significantly lower than the authorized ROE.

The Targeted ROE approach produces the following adopted functional gas distribution capital expenditures during the 1999 GRC cycle.

Table 4-20 - Gas Distribution Functional Capital Expenditures Produced by Targeted ROE Approach, 2000 to 2002

Gas Distribution Functional Capital Expenditures Produced by Targeted ROE Approach 2000 to 2002 Dollars in Thousands	
Attrition Year	Amount
2000	0
2001	79,962
2002	122,457
Total	202,419
3 Year Average	67,473
Source: Overland Analysis.	

The Targeted ROE approach produces average annual gas distribution functional capital expenditures of $67.4 million during the three Attrition Years. The comparable 1999 test year adopted value was $240.6 million. The capital expenditures produced by the Target ROE approach are 72% lower than the 1999 test year value over the three year attrition period.

A minimum level of capital expenditures is required for safety and reliability. The capital expenditures produced by the Targeted ROE Approach are well below the minimum level.

The test year capital expenditures adopted in the 1999 GRC include $73.8 million for connecting new customers to PG&E's system. The total average annual capital expenditures produced by the Targeted ROE approach are lower than the 1999 adopted amount for the New Business MWC.

PG&E considers the costs of connecting new customers to its system to be mandatory spending. If those costs are assumed to be funded, that does not leave any funding for GPRP, capacity, reliability, meters, and WRO spending. The 1999 GRC Decision does not contain any indication the Commission intended to eliminate funding for major components of PG&E's capital program, including the GPRP, in the Attrition Years. The Targeted ROE Approach produces unreasonable results for the 1999 GRC Attrition Years.

The Escalation Approach produces low ROEs during the 1999 GRC Attrition Years. However, the indicated ROEs are not outside of the range of tolerable results. The same cannot be said for the adopted capital expenditures produced by the Targeted ROE approach. For the reasons given, the 1999 GRC cycle results produced by the Escalation Approach are more reasonable than the results produced by the Targeted ROE Approach.

PG&E's Capital Expenditures Comparison

PG&E provided its comparison of actual and adopted gas distribution functional capital expenditures on May 9, 2013.[28] PG&E's comparison covers the years 2003 to 2010.[29] The following table shows PG&E's comparison.

Table 4-21 - PG&E's Comparison of Actual and Adopted Capital Expenditures

PG&E's Comparison of Actual and Adopted Capital Expenditures Gas Distribution Functional 2003 to 2010			
Year	Actual	Adopted	Difference
2003	190,617	181,825	8,792
2004	167,859	97,376	70,483
2005	190,951	171,059	19,892
2006	209,767	194,417	15,350
2007	209,977	212,057	(2,080)
2008	239,475	156,610	82,865
2009	252,439	191,212	61,227
2010	276,853	188,049	88,804
Total	1,737,938	1,392,605	345,333
Source: OC-1059			

[28] Response to Discovery, OC-1059.

[29] PG&E's comparison for the 1999 GRC cycle was prepared at a total capital expenditures level, including common and general plant. PG&E's comparison does not provide sufficient detail to identify gas distribution functional actual and adopted capital expenditures for the years 1999 through 2002.

PG&E concluded that its actual capital expenditures were $345 million higher than adopted over the eight-year study period. Overland concluded that actual capital expenditures were $114 million higher than adopted over the same period. Almost all of that difference is attributable to the methodology that PG&E used to estimate Attrition Year capital expenditures.

The following table compares PG&E's adopted capital expenditures to Overland's adopted values.

Table 4-22 - Comparison of PG&E and Overland Adopted Capital Expenditures

Comparison of PG&E and Overland Adopted Gas Distribution Functional Capital Expenditures 2003 to 2010			
Year	PG&E	Overland	Difference
2003	181,825	181,824	1
2004	97,376	185,460	(88,084)
2005	171,059	189,633	(18,574)
2006	194,417	196,649	(2,232)
2007	212,057	211,409	648
2008	156,610	215,739	(59,129)
2009	191,212	220,074	(28,862)
2010	188,049	224,406	(36,357)
Total	1,392,605	1,625,194	(232,589)
Source: Tables 4-10 and 4-21			

PG&E's 2003 and 2007 test year adopted values are very close to Overland's adopted values. Overland's 2007 adopted value is lower because PG&E did not correct the error in the Settlement Agreement discussed on page 81 of the 2007 GRC Decision.[30]

PG&E estimated adopted capital expenditures during the Attrition Years based on the approved attrition year rate increases "such that the capital related elements of the revenue requirement (depreciation, return and taxes)...escalate at the rate of growth of the authorized revenue requirement."[31]

Overland did not audit PG&E's calculations of Attrition Year adopted capital expenditures because they were received very late in the audit process.[32] PG&E's methodology appears to be premised on the Targeted ROE Approach. Overland did not use that approach for the reasons stated previously in this Chapter.

PG&E's approach to calculating Attrition Year adopted capital expenditures is inconsistent with the approach used by the Commission in PG&E's 1996 GRC Decision. That Decision compared actual and adopted Gas Pipeline Replacement Program capital expenditures for 1993, 1994 and 1995. The last two

[30] D.07-03-044, page 81, footnote 82. The $648,000 difference has two components. The first is the $624,000 error correction described on page 81 of the 2007 GRC Decision. The second is a $24,000 rounding difference in the allocation of total company capitalized A&G to gas distribution functional capital expenditures.

[31] Response to Discovery, OC-1059.

[32] Overland did not submit any discovery questions to clarify PG&E's methodology because the responses would not have been received in time to incorporate them into this report.

years in the comparison were Attrition Years. The 1996 GRC Decision indicates the 1994 and 1995 Attrition Year GPRP adopted capital expenditures were identical in amount to the 1993 test year adopted value.[33]

PG&E's rebuttal testimony in the 2011 GRC contained estimates of the Attrition Year capital expenditures adopted in the 2007 GRC.[34] PG&E's current approach is inconsistent with the approach it used to determine the 2008, 2009 and 2010 Attrition Year adopted capital expenditures reported in its 2011 GRC rebuttal testimony.[35] In the 2011 GRC, PG&E determined that its 2008 and 2009 adopted capital expenditures equaled the Attrition Year forecasts it submitted for those years in the 2007 GRC.[36]

PG&E's and Overland's actual capital expenditures are similar over the study period, as shown below.

Table 4-23 - Comparison of PG&E and Overland Actual Capital Expenditures

Comparison of PG&E and Overland Actual Gas Distribution Functional Capital Expenditures 2003 to 2010			
Year	PG&E	Overland	Difference
2003	190,617	188,607	2,010
2004	167,859	167,860	(1)
2005	190,951	190,952	(1)
2006	209,767	209,766	1
2007	209,977	209,532	445
2008	239,475	238,918	557
2009	252,439	250,461	1,978
2010	276,853	282,786	(5,933)
Total	1,737,938	1,738,882	(944)
Source: Tables 4-10 and 4-21			

Overland's actual capital expenditures were taken directly from discovery responses provided by PG&E, without any adjustments. The actual expenditures used in PG&E's comparison do not agree with its prior discovery responses.

[33] D.95-12-055, December 20, 1995, page 56.
[34] PG&E 2011 GRC Rebuttal Testimony, PG&E-18, Chapter 1, Attachment G, page 01G-22.
[35] Response to Discovery, OC-690.
[36] Those forecasts are shown on Table 4-17.

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Pacific Gas & Electric Company
Comparison of Actual and Adopted
Gas Functional Capital Expenditures by MWC
1999 to 2010
Dollars in Thousands

Actual (Recorded)

MWC	Description	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Total
14	Gas Pipeline Replacement Program	56,167	52,929	61,914	63,143	71,888	47,936	46,968	59,074	56,189	62,154	60,476	62,401	701,239
14	Copper Services Replacement Program	0	0	0	0	0	0	0	1,094	20,727	43,471	39,036	42,300	146,628
27	Gas Meter Protection Program	113	572	463	342	128	31	33	0	15	73	17	15	1,802
29	New Business	67,113	59,289	50,336	57,387	58,774	60,117	75,641	75,522	67,920	46,372	39,788	21,948	680,207
47	Capacity	3,157	3,218	3,697	3,258	6,787	6,099	9,063	11,599	8,149	12,063	8,403	14,675	90,168
50	Reliability	10,005	12,375	13,614	13,228	13,935	10,215	11,307	12,128	10,844	14,146	28,576	34,198	184,571
51	Work Requested by Others	15,667	17,708	17,478	19,202	18,092	12,085	14,353	19,516	15,988	27,104	26,905	42,213	246,311
52	Emergency Repair	831	(112)	127	77	120	402	95	286	256	375	249	1,057	3,763
74	Meters	19,297	18,349	18,985	20,619	18,883	30,975	33,492	30,547	29,444	33,160	47,011	63,979	364,741
	Total	172,350	164,328	166,614	177,256	188,607	167,860	190,952	209,766	209,532	238,918	250,461	282,786	2,419,430

Adopted

MWC	Description	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	TOTAL
14	Gas Pipeline Replacement Program	84,173	84,173	84,173	84,173	67,900	69,258	70,816	73,436	70,493	71,937	73,382	74,827	908,741
14	Copper Services Replacement Program	0	0	0	0	0	0	0	0	0	0	0	0	0
27	Gas Meter Protection Program	1,295	1,295	1,295	1,295	700	714	730	757	717	732	746	761	11,037
29	New Business	73,759	73,759	73,759	73,759	55,706	56,820	58,099	60,249	61,654	62,917	64,181	65,444	780,106
47	Capacity	5,396	5,396	5,396	5,396	3,785	3,861	3,948	4,094	11,532	11,768	12,005	12,241	84,818
50	Reliability	31,082	31,082	31,082	31,082	15,219	15,523	15,872	16,459	16,260	16,593	16,926	17,260	254,440
51	Work Requested by Others	20,504	20,504	20,504	20,504	17,350	17,697	18,095	18,764	18,659	19,041	19,424	19,806	230,852
52	Emergency Repair	5,396	5,396	5,396	5,396	200	204	209	217	209	213	218	222	23,276
74	Meters	18,967	18,967	18,967	18,967	20,964	21,383	21,864	22,673	31,885	32,538	33,192	33,845	294,212
	Total	240,572	240,572	240,572	240,572	181,824	185,460	189,633	196,649	211,409	215,739	220,074	224,406	2,587,482

Actual Above / (Below) Adopted

MWC	Description	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	TOTAL
14	Gas Pipeline Replacement Program	(28,006)	(31,244)	(22,259)	(21,030)	3,988	(21,322)	(23,848)	(14,362)	(14,304)	(9,783)	(12,906)	(12,426)	(207,502)
14	Copper Services Replacement Program	0	0	0	0	0	0	0	1,094	20,727	43,471	39,036	42,300	146,628
27	Gas Meter Protection Program	(1,182)	(723)	(832)	(953)	(572)	(683)	(697)	(757)	(702)	(659)	(729)	(746)	(9,235)
29	New Business	(6,646)	(14,470)	(23,423)	(16,372)	3,068	3,297	17,542	15,273	6,266	(16,545)	(24,393)	(43,496)	(99,899)
47	Capacity	(2,239)	(2,178)	(1,699)	(2,138)	3,002	2,238	5,115	7,505	(3,383)	295	(3,602)	2,434	5,350
50	Reliability	(21,077)	(18,707)	(17,468)	(17,854)	(1,284)	(5,308)	(4,565)	(4,331)	(5,416)	(2,447)	11,650	16,938	(69,869)
51	Work Requested by Others	(4,837)	(2,796)	(3,026)	(1,302)	742	(5,612)	(3,742)	752	(2,671)	8,063	7,481	22,407	15,459
52	Emergency Repair	(4,565)	(5,508)	(5,269)	(5,319)	(80)	198	(114)	69	47	162	31	835	(19,513)
74	Meters	330	(618)	18	1,652	(2,081)	9,592	11,628	7,874	(2,441)	622	13,819	30,134	70,529
	Total	(68,222)	(76,244)	(73,958)	(63,316)	6,783	(17,600)	1,319	13,117	(1,877)	23,179	30,387	58,380	(168,052)

Source for Actual is OC-392
Source for Adopted is Overland Workpapers

Pacific Gas & Electric Company
Comparison of Actual and Adopted
Gas Functional Capital Expenditures, Safety-Related MWCs
1999 to 2010
Dollars in Thousands

Actual (Recorded)

MWC	Description	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Total
14	Gas Pipeline Replacement Program	56,167	52,929	61,914	63,143	71,888	47,936	46,968	59,074	56,189	62,154	60,476	62,401	701,239
14	Copper Services Replacement Program	0	0	0	0	0	0	0	1,094	20,727	43,471	39,036	42,300	146,628
27	Gas Meter Protection Program	113	572	463	342	128	31	33	0	15	73	17	15	1,802
50	Reliability	10,005	12,375	13,614	13,228	13,935	10,215	11,307	12,128	10,844	14,146	28,576	34,198	184,571
52	Emergency Repair	831	(112)	127	77	120	402	95	286	256	375	249	1,057	3,763
	Total	67,116	65,764	76,118	76,790	86,071	58,584	58,403	72,582	88,031	120,219	128,354	139,971	1,038,003

Adopted

MWC	Description	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	TOTAL
14	Gas Pipeline Replacement Program	84,173	84,173	84,173	84,173	67,900	69,258	70,816	73,436	70,493	71,937	73,382	74,827	908,741
14	Copper Services Replacement Program	0	0	0	0	0	0	0	0	0	0	0	0	0
27	Gas Meter Protection Program	1,295	1,295	1,295	1,295	700	714	730	757	717	732	746	761	11,037
50	Reliability	31,082	31,082	31,082	31,082	15,219	15,523	15,872	16,459	16,260	16,593	16,926	17,260	254,440
52	Emergency Repair	5,396	5,396	5,396	5,396	200	204	209	217	209	213	218	222	23,276
	Total	121,946	121,946	121,946	121,946	84,019	85,699	87,627	90,869	87,679	89,475	91,272	93,070	1,197,494

Actual Above / (Below) Adopted

MWC	Description	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	TOTAL
14	Gas Pipeline Replacement Program	(28,006)	(31,244)	(22,259)	(21,030)	3,988	(21,322)	(23,848)	(14,362)	(14,304)	(9,783)	(12,906)	(12,426)	(207,502)
14	Copper Services Replacement Program	0	0	0	0	0	0	0	1,094	20,727	43,471	39,036	42,300	146,628
27	Gas Meter Protection Program	(1,182)	(723)	(832)	(953)	(572)	(683)	(697)	(757)	(702)	(659)	(729)	(746)	(9,235)
50	Reliability	(21,077)	(18,707)	(17,468)	(17,854)	(1,284)	(5,308)	(4,565)	(4,331)	(5,416)	(2,447)	11,650	16,938	(69,869)
52	Emergency Repair	(4,565)	(5,508)	(5,269)	(5,319)	(80)	198	(114)	69	47	162	31	835	(19,513)
	Total	(54,830)	(56,182)	(45,828)	(45,156)	2,052	(27,115)	(29,224)	(18,287)	352	30,744	37,082	46,901	(159,491)

(13.32)

Source for Actual is OC-392
Source for Adopted is Overland Workpapers

5. Long-Term Gas Safety Programs

Introduction

This Chapter reviews PG&E's spending on the following long-term gas safety programs:.

- Gas Pipeline Replacement Program (GPRP);
- Copper Services Replacement Program (CSRP);
- Meter Protection Program (MPP); and
- Isolated Steel Services Program (ISSP).

The primary purpose of all four of these programs has been to improve public safety.

PG&E assigned a relatively low funding priority to long-term gas safety programs during the audit period. PG&E generally viewed long-term gas safety programs as discretionary spending that could be deferred to meet its overall budget targets. The GPRP, MPP and ISSP were poorly funded throughout the audit period. The CSRP began in 2006 and was adequately funded.

The GPRP was established in 1985 as a 20 year program. By 2004 the program duration had been extended to 30 years. Progress was slow during the audit period. The amount of pipe remaining to be replaced only decreased by 71 miles between December 2003 and December 2010. Progress was slow during that seven year period because PG&E only retired 195 miles of GPRP pipe while adding 124 miles to the program.

Pipeline segments are selected for replacement under the GPRP using a risk based "Priority Value" (PV). The PV considers the segment's leak history. Pipeline segments are added or removed from the program each year as an additional year of leak history is added to the analysis. PG&E's leak survey practices were critically deficient prior to 2008. PG&E added 96 miles to the GPRP in 2008 through 2010 because it improved its leak survey practices and found more leaks.

The study period for Overland's comparison of actual and adopted spending is 1999 through 2010. Overland requested that PG&E provide a comparison of actual and adopted GPRP spending for 1987 to 1998 because underspending was an issue in prior GRCs. Based on the information provided by PG&E, GPRP spending was 14 percent lower than adopted in 1987 to 1998. GPRP spending was 23 percent lower than adopted in 1999 to 2010.

PG&E did not include the CSRP in its 2007 GRC application because management approved the program after the application was filed. The capital expenditures adopted in the 2007 GRC did not include any funding for the CSRP. Actual CSRP spending totaled $146 million in 2007 to 2010.

PG&E diverted some of the GPRP funding adopted in the 2007 GRC to the CSRP in 2007 through 2010. On a combined basis, GPRP and CSRP spending was 6.7 percent lower than adopted during the twelve year study period. The comparison shows a distinct pattern over time. During 1999 to 2006 combined

spending was $157 million lower than adopted. During 2007 to 2010, combined spending was $96 million higher than adopted.

PG&E established the MPP in 1990 to identify and correct meter locations that did not conform to meter protection standards. The program was initially scheduled for completion in 2008. PG&E currently anticipates completing the program in 2013. Progress on the MPP slowed significantly after 1997. During 1998 to 2010, the annual average number of meters protected was 62 percent lower than the average in 1990 to 1997. Very few meters were protected in 2009 and 2010. Actual MPP spending was 61 percent lower than adopted during the twelve year study period.

The ISSP was initiated in late 2001 as a multi-year program to be completed in 2012. The key ISSP metric is the number of services tested in the field. As of December 2010, PG&E had only field tested 33 percent of the services that required field testing. Actual spending on the ISSP was 14 percent lower than adopted from 2003 to 2010.

Gas Pipeline Replacement Program

PG&E's senior management approved the Gas Pipeline Replacement Program in September 1984. The GPRP was initially implemented in January 1985.[1] The GPRP was implemented to replace aging gas pipe throughout PG&E's system.[2] The initial program scope consisted of:[3]

- Cast Iron Distribution Mains;
- Steel Distribution Mains installed prior to 1931; and
- Steel Transmission Mains with Pipe Joint Configurations and Girth Welds that did not meet modern standards.

The purpose of the GPRP was to improve public safety. PG&E requested funding for the GPRP in its 1987 General Rate Case (GRC). The Commission approved PG&E's funding request and required PG&E to submit annual status reports for the program.

Program Scope 1987 to 2001

The first annual status report was the 1987 GPRP Annual Report submitted on March 31, 1988. That report showed the following total program miles and costs by type:

[1] 1988 GPRP Annual Report, page 1-1.
[2] 1987 GPRP Annual Report, page A-1.
[3] 1987 GPRP Annual Report, page B-1.

Table 5-1 - Gas Pipeline Replacement Program, Life of Project Scope

Gas Pipeline Replacement Program Life of Project Scope - As of March 1988 Dollars in Millions		
Description	Miles of Main	Cost in 1987 Dollars
Distribution - Cast Iron	816	786
Distribution - Steel	1,690	926
Transmission	659	565
Total	3,165	2,277
Source: GPRP 1987 Annual Progress Report, Page A-2. Includes miles replaced in prior years.		

PG&E removed 824 miles from the GPRP scope in 1988. The reductions consisted of a 578 mile reduction in the distribution steel category and a 222 mile reduction in transmission mains.[4] The changes reduced the total estimated program cost to $1.97 billion in 1988 dollars.

PG&E re-evaluated the scope of the distribution program in 1993, and the transmission program in 1994. Those re-evaluations and other changes resulted in modest scope increases. The distribution program increased by 55 miles between 1992 and 1994. The transmission program increased by 87 miles between 1992 and 1995.[5]

The total program scope remained unchanged until 2000, when PG&E removed the remaining 212 miles of transmission from the program. The miles removed from the GPRP were included in PG&E's newly created transmission Risk Management program.[6]

Program Scope Changes in 2002

PG&E reduced the total program scope by 226 miles in 2002. The following table shows the scope reduction by component:[7]

[4] 1987 GPRP Annual Report, page B-5 and 1988 GPRP Annual Report, page 1-1.
[5] 19992 and 1995 GPRP Annual Reports, Figure 1.
[6] Response to Discovery, OC-101.
[7] Transmission was removed from the program in 2000. The scope changes discussed in the remainder of this section all relate to distribution.

Table 5-2 - GPRP Total Program Scope Changes, 2002

GPRP Total Program Scope Changes 2002		
Description	Type	Miles
Reporting Methodology Change	Retired	31
Reporting Methodology Change	Remaining	42
Priority Value Criteria Change	Remaining	(384)
Pipe Vintage Change (1931 - 1940)	Remaining	86
Rounding		(1)
Total		(226)
Source: Response to Discovery, OC-1076.		

Prior to 2002, PG&E calculated total miles retired to date and miles remaining to be replaced by adjusting the values reported in the prior GPRP annual report for the miles retired in the current year. The total program scope equaled the miles retired plus the miles remaining. Under that approach, total program scope remained constant unless a specific adjustment was made to the miles remaining.[8]

PG&E changed its reporting methodology in 2002. Under the new methodology, PG&E queried the GPRP data base each year to determine the number of miles retired to date and the number of miles remaining to be completed. Total program scope continued to equal the sum of those two values. The data base queries produced results that were different than the results produced by the prior method. The data base queries increased the miles retired by 31 miles and the remaining miles by 42 miles. The net impact of the change in reporting method was a total GPRP program scope increase of 73 miles.[9]

PG&E expanded the scope of the program in 2002 to include the consideration of all pipe constructed before 1941. Previously, the GPRP was limited to pipe installed before 1931.[10] Including the 1931 to 1940 pipe vintages added 86 miles to the remaining miles.[11]

PG&E also established a minimum risk value threshold for the pipe to be replaced under the program. The risk value was referred to the as the Priority Value (PV). Pipe below the threshold was removed from the miles remaining to be replaced. Changing the PV criteria reduced the remaining miles by 384 miles.[12]

Program Scope Changes in 2003

PG&E increased the program scope by 499 miles in 2003. The following table shows the total scope increase by component:

[8] Response to Discovery, OC-1071.
[9] Response to Discovery, OC-1071.
[10] Response to Discovery, OC-1071.
[11] Response to Discovery, OC-1076 and 2002 GPRP Annual Report, page 3.
[12] Response to Discovery, OC-1076 and 2002 GPRP Annual Report, page 3.

Table 5-3 - GPRP Total Program Scope Changes, 2003

GPRP Total Program Scope Changes 2003		
Description	Type	Miles
Post-1930 Pipe Retired in Non-GPRP Projects	Retired	262
Other Pipe Retired in Non-GPRP Projects	Retired	330
Other Pipe Retired in Non-GPRP Projects	Remaining	(100)
Other Changes	Remaining	7
Total		499
Source: Response to Discovery, OC-1077.		

PG&E expanded the scope of the GPRP to include the 1931 to 1940 plant vintages in 2002. PG&E increased the remaining miles in 2002. In 2003, PG&E added 262 miles to the miles retired to date to reflect 1931 to 1940 vintage pipe that had been previously retired under non-GPRP projects.

PG&E had previously retired 330 miles of pre-1931 vintage pipe in other projects that were not part of the GPRP. PG&E increased the number of miles retired to date by 330 miles in 2003 to reflect those retirements. Only 100 of the 330 miles were included in PG&E's prior tabulation of the miles remaining to be retired as of December 2002. PG&E removed those 100 miles from the remaining miles in 2003.[13]

Adding the 592 miles retired in non-GPRP projects to the miles retired only increased the total program scope by 492 miles because 100 of the miles were also removed from the remaining miles.[14]

Scope Changes 2004 to 2010

The PV values used to identify the pipe segments remaining to be replaced are based, in part, on the segment's leak history. The PV values change each year as an additional year of leak history is added to the analysis. The changes in the PV values resulted in relatively modest ongoing changes to the miles remaining to be replaced under the GPRP.[15] The total GPRP program scope increased by 22 miles between December 2003 and December 2007.[16]

PG&E's September 21, 2009 Gas System Issues presentation to the CPUC Staff noted that the leak survey deficiencies discovered in 2007 and 2008 could potentially impact the scope of the GPRP. The presentation indicated:[17]

> *PG&E recently revised our leak grading criteria, and this enhanced criterion is being used to resurvey all distribution gas pipelines in our system. Since gas leak statistics are part*

[13] Response to Discovery, OC-1077.
[14] 2003 GPRP Annual Report, page 6.
[15] Response to Discovery, OC-1075.
[16] 2003 and 2007 GPRP Annual Reports, Figure II.
[17] Response to Discovery, OC-426, Attachment 5, page 5.

> *of the algorithm used to determine gas pipeline replacement work priority values, we have already identified additional pipeline segments not previously included in the initial 1987 GPRP scope. These pipeline segments will be prioritized for replacement as part of the continuous pipeline integrity management program. There is likely to be a significant increase in higher priority pipeline segments as a result of the system wide resurvey.*

The total program scope increased by 101 miles between December 2007 and December 2010.[18]

Program Duration

The GPRP was a 20-year program when it was approved by the Commission in 1987. By March 1994, the program duration had been extended to 25 years, with a completion date of December 2009.[19]

PG&E notified the Commission that it was extending the GPRP to a 30-year program in March 2004. The revised completion date was 2014.[20] The 2003 GPRP Annual Report states:

> *While PG&E has made consistent progress over the last 19 years, PG&E no longer forecasts program completion by the end of 2009. The majority of the remaining work is in the City of San Francisco. PG&E will need to extend program completion by 4-5 years principally because of the high cost of reconstruction in San Francisco, the capacity of PG&E's workforce, and the need to manage the work in San Francisco to minimize the disruption of...customers.*

The expected completion date for all divisions other than San Francisco remained 2009.

PG&E notified the Commission that it was extending the completion date for the other divisions to 2014 in April 2007. The completion dates were extended because of the need to allocate funds to the Copper Services Replacement Program.[21]

Regulatory History

The Commission discussed the GPRP in a series of GRC Decisions starting with the 1987 GRC. The Commission stressed the importance of the GPRP. Another recurring theme addressed in these Decisions was PG&E's failure to spend all of the funding approved by the Commission.

[18] 2007 and 2010 GPRP Annual Reports, Figure II.
[19] 1993 GPRP Annual Report, pages 1-4 and II-9.
[20] 2003 GPRP Annual Report, pages 2 and 11.
[21] 2006 GPRP Annual Report, pages 2 and 3.

1987 GRC

PG&E's 1987 GRC Decision includes the following description of the GPRP:[22]

> *[A]s PG&E's system has aged, the need to replace pipelines has increased. In response, in 1984, PG&E established a major program to eliminate, under a system-wide schedule, the deteriorating gas piping systems.*
>
> *PG&E's program calls for the replacement of over 2,000 miles of steel transmission and distribution lines and over 800 miles of cast iron distribution main over a 20-year period. According to PG&E, the replacement of these lines will enhance the safety and reliability of the gas piping system and will reduce leak repair expenses as high-maintenance piping is eliminated.*

The Commission's Safety Branch recommended accelerating the GPRP to a 15-year program. PG&E argued that accelerating the program to 15 years was not logistically feasible. The Commission adopted PG&E's proposed 20-year plan and indicated it would review the need to shift to a 15-year program in PG&E's next GRC.

1993 GRC Decision

The Commission's Division of Ratepayer Advocates (DRA) proposed reductions to PG&E's requested GPRP expense and capital spending in the 1993 GRC. The 1993 GRC Decision indicates:[23]

> *DRA has recommended a reduction in test year 1993 expenditures for this program...The primary reason for DRA's suggested reductions...is a comparison of what PG&E actually spent on GPRP as opposed to what it has forecasted since 1988. DRA is convinced that PG&E consistently overstated the amounts needed to perform the different categories of work...DRA argues that the one undeniable fact about the trend of GPRP expenses is that PG&E has consistently recovered more in rates than it has spent for O&M costs.*

The Decision rejected DRA's proposed adjustments. The Decision states:[24]

> *On this program we must agree with PG&E as to both the importance and necessity of moving forward with the gas pipeline replacement program as quickly as possible. The 1989 Loma Prieta earthquake certainly showed us the importance of PG&E replacing its old pipes throughout the city of San Francisco. In fact, perhaps if the Marina District had its pipelines replaced, some of the problems that erupted in that neighborhood as a result of the earthquake may not have occurred. In any event, we want PG&E to move forward with this program with due diligence. Because of that desire, it would be*

[22] Response to Discovery, OC-963, D.86-12-095, December 22, 1986, page 80.
[23] D.92-12-057, December 16, 1992, 47 CPUC2d 143, 282.
[24] D.92-12-057, December 16, 1992, 47 CPUC2d 143, 283.

> *unreasonable for us to authorize less money than PG&E believes it needs to keep this program on track...*

The Decision noted that "the GPRP was established in 1984 to replace, according to a 20-year schedule, deteriorating gas pipeline systems" and stated:[25]

> *By authorizing the dollars PG&E requests for all accounts that deal with the gas pipeline replacement program, it is our fervent hope that PG&E actually spends the money on the program. We agree that this program is an important element of seismic safety improvement and urge PG&E to exercise due diligence in not only keeping the program on its targeted time line, but where feasible, speeding up the program.*

1996 GRC Decision

In the 1996 GRC Decision, the Commission rejected PG&E's GPRP expense and capital expenditures requests and adopted amounts equal to the actual costs incurred in 1993.

The Decision stated:[26]

> *In PG&E's last general rate case, like here, DRA argued that PG&E's request for the GPRP had been consistently overstated in past years and that PG&E had consistently recovered significantly more in rates than it spent on the program.*
>
> *In spite of consistent underspending in previous years, we granted PG&E's full funding request over DRA's objections on the basis that PG&E should continue replacing old pipelines "as quickly as possible" in the interest of safety. We stated our expectations that PG&E should use the authorized funds for their intended purpose, and even accelerate the pace of the program.*
>
> *Between the time we issued the last general rate case decision and the filing of this one, PG&E has fallen short of our stated expectations. Over a three-year period, it spent nearly $28 million less than it received in rates for program expenses and $56.2 million less than it received in rates for the program's capital costs. (Table omitted)*
>
> *PG&E supports higher funding levels in 1996 because it states its intent to replace pipe in high-cost neighborhoods. PG&E made the same argument three years ago. We adopted its requested funding assuming that PG&E would undertake the work. If it has not, we are not inclined to require ratepayers to pay for the work a second time.*
> *PG&E explains that it could not continue the program at its targeted pace because union agreements precluded it from hiring outside contractors to undertake the work.*

[25] D.92-12-057, December 16, 1992, 47 CPUC2d 143, 283.
[26] D.95-12-056, December 20, 1995, page 55.

However, PG&E required outside contractors only because it laid off or offered early retirement to employees who might have undertaken the work.

Notwithstanding PG&E's underspending of budgeted funds in this program in every year since 1985, PG&E has kept the program on target: after 40% of the program's timeline has elapsed, PG&E has completed 39% of the program. Apparently we have funded this program at levels that are higher than required to fulfill program goals. With this in mind, we believe that PG&E should be able to continue its targeted level of construction with less funding. We grant PG&E $4.3 million for (expense) and $77.2 million in capital costs, the same amounts as PG&E spent in 1993. With this funding, PG&E shall maintain the pace of its program, consistent with the goals of completing targeted replacements by the end of 2009.

1999 GRC

The 1999 GRC only addressed the distribution component of the GPRP. The transmission component was excluded because gas transmission rates were set in separate Gas Accord proceedings.[27]

PG&E requested test year capital expenditures of $78 million for the GPRP and ORA recommended $70 million.

The Decision noted that the distribution component of the GPRP was lagging behind schedule. PG&E needed to replace distribution pipe at an average rate of more than 86 miles per year to complete the program by 2009. In the first 13 years of the program, PG&E only replaced distribution pipe at an average rate of 72 miles per year.[28]

The Decision stated:[29]

...[W]e note that PG&E has consistently spent less than authorized amounts on the program throughout its existence, and as recently as 1998 was on track to spend up to 25% less than the $78 million estimate it advances in this GRC...

The persistence of this pattern of underspending combined with PG&E's ability to keep the program generally on schedule (on a combined transmission and distribution basis) leads us to suspect that its forecast may be higher than appropriate. However, the

[27] The Gas Accord was a Settlement that established separate rates for gas transmission services. The initial Gas Accord rates were effective in March 1998.

[28] D.00-02-046, February 17, 2000, page 231.

[29] D.00-02-046, February 17, 2000, page 231.

> *relatively small difference between ORA's and PG&E's forecasts for the distribution component leads us to conclude that PG&E's forecast for 1999 is reasonable.*

The adopted 1999 test year value of $78 million referenced in the Decision was stated in 1997 dollars and did not include certain capitalized overhead costs. The adopted 1999 test year GPRP capital expenditures were $84.2 million stated in 1999 dollars.[30]

2003 GRC

The 2003 GRC Decision adopted a comprehensive distribution settlement. The Decision and related settlement do not contain any discussions of the GPRP.[31]

2007 GRC

The 2007 GRC Decision adopted a settlement that resolved most of the issues in the case, including GPRP funding. The Settlement adopted PG&E's 2007 Test Year GPRP distribution capital expenditures request of $68.4 million.

The Decision stated:[32]

> *PG&E's request...for 2007 was based on the remaining scope of the program, PG&E's schedule commitment to the Commission, and pipe replacement costs. PG&E contended that its requested funding would allow PG&E to complete the remaining 250 miles of the highest risk pipe in PG&E's system by 2009 for all areas outside of San Francisco and by 2014 for San Francisco.*

The Decision concluded:[33]

> *The amount provided by the Settlement for GPRP capital spending is well above the historical four-year average adjusted for inflation.*
>
> *The GPRP is a high-priority program that affects public safety and the reliability of PG&E's Gas Distribution System. We conclude that it is reasonable for the Settlement to provide substantially increased funding for this program. Therefore, we will approve the Settlement outcome for Gas Distribution capital expenditures with the condition that PG&E uses all of the funds provided by the Settlement for the GPRP for this purpose. If PG&E fails to do so, it should provide a detailed explanation in its next GRC.*

[30] Response to Discovery, OC-1067.
[31] D.04-05-055, May 17, 2004.
[32] D.07-03-044, March 15, 2007, page 82.
[33] D.07-03-044, March 15, 2007, page 83.

2011 GRC

The 2011 GRC Decision adopted a comprehensive gas distribution settlement. The settlement adopted PG&E's gas distribution capital expenditures forecast without reductions.[34]

GPRP Metrics

The goal of the GPRP is to remove high risk transmission and distribution mains from service. The metric used to measure progress towards that goal is the cumulative number of miles of GPRP mains retired from service.

PG&E's GPRP Annual Reports show 2,479 GPRP miles retired from service as of December 2010. The following table shows those miles by year and type.

Table 5-4 - GPRP Miles Retired

GPRP Miles Retired 1985 to 2010			
Year	Distribution	Transmission	Total
1985	28	30	58
1986	62	27	89
1987	79	35	114
1988	93	13	106
1989	66	12	78
1990	75	16	91
1991	90	31	121
1992	92	18	110
1993	79	10	89
1994	60	9	69
1995	40	18	58
1996	82	20	102
1997	77	20	97
1998	85	20	105
1999	70	10	80
2000	64	0	64
2001	55	0	55
2002	53	0	53
2003	55	0	55
2004	34	0	34
2005	36	0	36
2006	25	0	25
2007	22	0	22
2008	28	0	28
2009	27	0	27
2010	23	0	23
Adjustments	636	54	690
TOTAL	2,136	343	2,479
Source: 1993 to 2010 GPRP Annual Reports.			

[34] D.11-05-018, May 5, 2011, Attachment 1, page 1-16.

PG&E cannot assign the adjustments to individual years. The adjustments relate primarily to the miles that PG&E added to the 2003 cumulative miles retired to date for pipe that was retired in projects that were not part of the GPRP.[35]

The following table shows the distribution adjustments by the year in which they were made.

Table 5-5 - Adjustments to GPRP Distribution Miles Completed

Adjustments to GPRP Distribution Miles Completed By Year	
Year	Miles
1994	13
1996	2
2002	31
2003	592
2004	(7)
2007	(1)
2008	2
2009	2
2010	2
Total	636
Source: Response to Discovery, OC-1071.	

The 2002 and 2003 adjustments were previously discussed in the 2002 and 2003 Program Scope Changes sections of this Chapter. The 2002 adjustment reflects the change in reporting methodology. The 2003 adjustment reflects the pipe previously replaced in non-GPRP projects. The 2003 adjustment includes some miles that were never eligible for replacement under the GPRP.

PG&E calculates the total scope of the GPRP by adding its tally of miles retired to date to the miles remaining to be replaced under the program. Under that definition, the scope of the distribution program was 2,369 miles as of December 2010. As of that date, 9.8% of those miles remained to be replaced.[36]

PG&E changed the miles remaining to be replaced as new leak information became available. After 2003, the number of miles retired only marginally exceeded the number of miles added to the program. As a result, the miles to be replaced in future years declined very slowly in the 2004 to 2010 time period. The following table shows the decline in miles remaining to be replaced by year for 1999 to 2010:

[35] Response to Discovery, OC-1071.
[36] 2010 GPRP Annual Report, Figure 1, miles remaining to be replaced of 233 divided by total miles of 2,369.

Table 5-6 - GPRP Distribution Miles Remaining to Be Replaced

GPRP Distribution Miles Remaining to Be Replaced 1999 to 2010				
Year	Prior Year	Retirements	Adjustments	Year End
1999	956	(70)	0	886
2000	886	(64)	(1)	821
2001	821	(55)	(4)	762
2002	762	(53)	(257)	452
2003	452	(55)	(93)	304
2004	304	(34)	7	277
2005	277	(36)	11	252
2006	252	(25)	1	228
2007	228	(22)	9	215
2008	215	(28)	20	207
2009	207	(27)	27	207
2010	207	(23)	49	233
TOTAL	NA	(492)	(231)	NA
Source: 1998 to 2010 GPRP Annual Reports.				

The 2002 and 2003 adjustments to the remaining miles were described previously. The 2002 adjustment was the result of three changes.

- A change in reporting methodology;
- The addition of 1931 to 1940 vintage pipe; and
- The removal of pipe that did not meet PG&E's revised PV criteria.

The 2003 adjustment consisted of the removal of 100 miles of pipe previously retired in non-GPRP projects and the addition of 7 miles of pipe based on changes in priority values.

The miles remaining to be replaced only declined by 71 miles between December 2003 and December 2010, even though PG&E retired 195 miles of GPRP pipe during that period. The average decline in that period was 10.1 miles per year.

The following table shows PG&E's GPRP capital expenditures and miles of main retired by year for 1998 to 2010.[37]

[37] Overland obtained capital expenditures data for 1998 through 2011 in OC-392. 1985 through 1997 are excluded from the table because they were outside of the audit period and Overland did not collect detailed cost information for those years.

Table 5-7 - Gas Pipeline Replacement Program, Actual Capital Expenditures Per Mile of Pipe Retired

Gas Pipeline Replacement Program Actual Capital Expenditures Per Mile of Pipe Retired Gas Distribution 1998 to 2010 Dollars in Thousands			
Year	Actual	Miles	Cost/Mile
1998	59,915	85	705
1999	56,167	70	802
2000	52,929	64	827
2001	61,914	55	1,126
2002	63,143	53	1,191
2003	71,888	55	1,307
2004	47,936	34	1,410
2005	46,968	36	1,305
2006	59,074	25	2,363
2007	56,189	22	2,554
2008	62,154	28	2,220
2009	60,476	27	2,240
2010	62,401	23	2,713
Total	761,154	577	1,319
Source: Chapter 4 and Response to Discovery, OC-392 (1998 Spending).			

The average cost per mile retired was $1.3 million over the 13-year period. The cost per mile retired increased from $705,000 in 1998 to $2.7 million in 2010. The cost of replacing pipe is much higher in San Francisco than in other areas. The rising cost per mile reflects a shift to projects in San Francisco during the later years of the program.

As of December 2003, PG&E had retired 1,942 miles of distribution main, including 391 miles in the San Francisco Division.[38] San Francisco accounted for 20 percent of the miles retired through 2003.[39] As of December 2003, 304 miles of distribution main remained to be retired, including 212 miles in the San Francisco Division. San Francisco accounted for 70 percent of the miles remaining to be replaced as of December 2003.[40]

The low number of miles retired in 2006 to 2010 is the result of GPRP spending constraints and the high cost of replacing mains in San Francisco.

Actual and adopted GPRP costs are compared in a subsequent section of this Chapter that addresses the GPRP and CSRP jointly.

[38] The miles retired amounts include the 2002 and 2003 adjustments.
[39] 2003 GPRP Annual Report, page 15.
[40] 2003 GPRP Annual Report, page 15.

Copper Services Replacement Program

CSRP History

The pipe that connects the distribution main to a customer's house or business is referred to as the "service line." Typically, a service line only delivers gas to one customer. Services lines are frequently referred to as "services."

PG&E installed a relatively small number of service lines made of copper on its system during the 1930s to late-1960s. In 2006, approximately 78,000 of PG&E's 3.8 million gas services were made of copper. Aging copper service lines are prone to internal corrosion caused by the chemical reaction between the copper surface of the pipe with sulfur in the gas and external corrosion caused by moisture.[41]

PG&E initiated a program in mid-2006 to replace high risk copper services. PG&E presented the program to the CPUC Staff on August 25, 2006. The estimated cost of the program was $125 million. The program scope consisted of replacing 30,900 services. The proposed completion date was year-end 2011.[42]

PG&E filed its 2007 GRC Application in December 2005. PG&E did not include the CSRP in application because the program had not yet been approved by management. The capital expenditures adopted in the 2007 GRC did not include any funding for the CSRP.[43]

During 2006, PG&E developed the program and surveyed its records to refine the project's scope. PG&E also conducted a pilot in the East Bay Division. PG&E replaced 74 services in 2006 as part of the pilot. PG&E rolled out the program to the East Bay, Peninsula and DeAnza Divisions in 2007.[44]

By November 27, 2007, the scope of the program had expanded to 42,300 services and the completion date had been extended to the end of 2013.[45]

CSRP Costs and Metrics

The goal of the CSRP is to remove high risk copper service lines from service. The metric used to measure progress towards that goal is the cumulative number of CSRP services replaced.

The following table shows the number of CSRP services replaced by year from 2007 to 2011 and the total financial costs of the program.[46]

[41] Response to Discovery, OC-426.
[42] Response to Discovery, OC-426, Attachment 1.
[43] PG&E 2011 GRC Testimony, December 2, 2005, PG&E-3, pages 19-6 and 19-7.
[44] Response to Discovery, OC-427, Attachment 2.
[45] Response to Discovery, OC-427, Attachment 3.
[46] Response to Discovery, OC-428. The total financial costs shown in the table vary from the CSRP capital expenditures included in the comparison of actual and adopted costs because they come from a different source and are impacted by timing. and scope differences.

Table 5-8 - Copper Services Replacement Program, Total Financial Cost and Services Replaced

Copper Services Replacement Program Total Financial Cost and Services Replaced 2007 to 2011			
Year	Cost ($000)	Services	Unit Cost
2007	22,084	3,494	6,321
2008	42,615	6,536	6,520
2009	38,551	6,026	6,397
2010	41,076	6,206	6,619
2011	51,083	7,723	6,614
Total	195,409	29,985	6,517
Source: Response to Discovery, OC-428. Total Financial Cost is different than actual capital expenditures.			

PG&E replaced 22,262 services from 2007 from 2010. That represented approximately 53% of the 42,300 services included in the program. PG&E replaced an additional 7,723 services in 2011.[47] As of December, 31, 2011, approximately 70% of the services had been replaced.

GPRP and CSRP Comparison of Adopted and Actual Spending

GPRP - 1987 to 1998

The study period for Overland's comparison of adopted versus actual spending is 1999 to 2010. Overland requested that PG&E provide a comparison of adopted versus actual GPRP spending for 1987 to 1998 because underspending on the program was an issue in prior GRCs.

The following table shows the information provided by PG&E.[48]

[47] Response to Discovery, OC-428.

[48] Response to Discovery, OC-425. The comparison provided by PG&E does not show any adopted amounts for Attrition Years. The Attrition Year adopted amounts shown on the table are the test year values for the Applicable GRC cycle.

Table 5-9 - GPRP Comparison of Actual and Adopted Spending, 1987 to 1998

GPRP Comparison of Actual and Adopted Spending 1987 to 1998 Dollars In Thousands			
Year	Actual	Adopted	Difference
1987	81,100	92,600	(11,500)
1988	77,300	92,600	(15,300)
1989	72,700	92,600	(19,900)
1990	79,000	79,000	0
1991	97,600	79,000	18,600
1992	86,800	79,000	7,800
1993	81,500	106,800	(25,300)
1994	70,800	106,800	(36,000)
1995	42,900	106,800	(63,900)
1996	86,700	81,500	5,200
1997	79,200	81,500	(2,300)
1998	74,800	81,500	(6,700)
Total	930,400	1,079,700	(149,300)
Source: Response to Discovery, OC-425, Includes Distribution and Transmission.			

PG&E spent $149 million less than the adopted amounts for the GPRP over the 12-year period. The underspending equaled 14 percent of the adopted total.

The actual spending amounts were taken from the GPRP Annual Reports.[49] The adopted amounts reflect the test year values adopted in PG&E's 1987, 1990, 1993 and 1996 GRCs. PG&E did not apply any escalation to the adopted amounts because the Commission's decisions did not adopt any specific GPRP amounts for attrition years.[50] Overland did not review the attrition rate increases granted during 1988 to 1998 to determine if the Attrition Year adopted values should be increased.[51]

The comparison includes gas distribution and transmission. The comparison also includes GPRP expense and capital amounts. Prior to 1994, PG&E charged a significant portion of the GPRP program costs to O&M expense.[52] PG&E changed its GPRP accounting policies in 1994. The change significantly reduced

[49] Response to Discovery, OC-425. The actual spending amounts for 1987 to 1992 were taken from the 1993 GPRP Annual Report which included corrections to those years.

[50] Response to Discovery, OC-425.

[51] Overland did not review the attrition rate increases granted in 1988 to 1998 because those years fell outside of its audit period. The Attrition years are 1988, 1989, 1991, 1992, 1994, 1995, 1997 and 1998. If, for purposes of illustration only, the adopted amounts in those years were escalated at 3 percent annually, adopted GPRP costs would increase by $33 million over the 12-year study period.

[52] Prior to 1994, PG&E charged the following costs of performing the following activities to expense: (1) relocating existing facilities, including gas meters; (2) bringing existing services and meters up to current codes and standards; (3) maintaining service to customers during construction; (4) coordination with various agencies and other utilities; and (5) engineering. D.91-12-036, Section 16.5.1.1.

the portion of total program costs charged to expense.[53] PG&E continued to charge meter relocation costs to expense after 1994. In 2000 and 2001, PG&E's recorded GPRP expenses averaged $356,000 per year.[54] PG&E began capitalizing the costs of meter relocations in 2007. After 2007, recorded GRC expenses consisted of very small amounts for program administration.[55]

GPRP - 1999 to 2010

The following table compares PG&E's actual and adopted GPRP distribution capital expenditures by year from 1999 to 2010.

Table 5-10 - GPRP Comparison of Actual and Adopted Spending, 1999 to 2010

GPRP Comparison of Actual and Adopted Spending Distribution Capital Expenditures 1999 to 2010 Dollars in Thousands			
Year	Actual	Adopted	Difference
1999	56,167	84,173	(28,006)
2000	52,929	84,173	(31,244)
2001	61,914	84,173	(22,259)
2002	63,143	84,173	(21,030)
2003	71,888	67,900	3,988
2004	47,936	69,258	(21,322)
2005	46,968	70,816	(23,848)
2006	59,074	73,436	(14,362)
2007	56,189	70,493	(14,304)
2008	62,154	71,937	(9,783)
2009	60,476	73,382	(12,906)
2010	62,401	74,827	(12,426)
Total	701,239	908,741	(207,502)
Source: Chapter 4.			

Actual GPRP spending was less than adopted in all but one year. GPRP spending was 23% below adopted over the 12-year study period.

GPRP and CSRP Combined - 1999 to 2010

PG&E reduced GPRP spending from 2007 to 2010 to fund the CSRP. The following table shows the differences between actual and adopted capital expenditures for the GPRP and CSRP on a combined basis for the years 1999 to 2010.[56]

[53] Response to Discovery, OC-378, Attachment 1, Testimony of William B. Marcus on Behalf of TURN, in 1999 GRC A.07-12-020, July 16, 1998, pages 6 through 10 and Attachment 8.

[54] Response to Discovery, OC-382, PG&E Testimony in 2003 GRC, PG&E-2, page 13-40.

[55] Response to Discovery, OC-387, PG&E Testimony in 2007 GRC, PG&E-4, page 16-16.

[56] Gas distribution amounts only. Transmission is excluded.

Table 5-11 - GPRP and CSRP Combined, Difference Between Actual and Adopted Capital Expenditures

GPRP and CSRP Combined Difference Between Actual and Adopted Capital Expenditures Actual Higher / (Lower) Than Adopted Dollars in Thousands			
Year	GPRP	CSRP	Total
1999	(28,006)	0	(28,006)
2000	(31,244)	0	(31,244)
2001	(22,259)	0	(22,259)
2002	(21,030)	0	(21,030)
2003	3,988	0	3,988
2004	(21,322)	0	(21,322)
2005	(23,848)	0	(23,848)
2006	(14,362)	1,094	(13,268)
2007	(14,304)	20,727	6,423
2008	(9,783)	43,471	33,688
2009	(12,906)	39,036	26,130
2010	(12,426)	42,300	29,874
Total	(207,502)	146,628	(60,874)
Source: Overland Analysis.			

On a combined basis, actual spending for the GPRP and CSRP was 6.7% lower than adopted over the 12 year study period.

The comparison displays a distinct pattern over time. Actual spending was $157 million lower than adopted during 1999 through 2006 and $96 million higher than adopted in 2007 through 2010.

GPRP and CSRP Actual Spending Trends

GPRP expenditures and mileage were lower in 1993 "due primarily to the unavailability of sufficient construction resources." The resource shortages were "the result of PG&E's corporate reorganization and work force reduction which began in February 1993."[57]

The 1999 GRC Decision was not issued until February 2000. According to PG&E, the uncertainty caused by the delay in the decision caused it to reduce capital expenditures in 1999 below the levels requested in the 1999 GRC.[58] PG&E's 2000 budgets were set before the 1999 GRC Decision was issued. As a result, 2000 spending was also impacted by the uncertainty.[59]

[57] 1993 GPRP Annual Report, pages I-2.
[58] Response to Discovery, OC-728, Supplemental.
[59] PG&E 2003 GRC Rebuttal Testimony, PG&E-20, pages 1-1 and 1-2.

The California energy crises began in mid-2000. PG&E began implementing cash conservation measures in December 2000 and filed for bankruptcy in April 2001. The California energy crises and resulting bankruptcy caused PG&E to limit its actual capital expenditures from 2000 to 2002.[60]

The preliminary GPRP capital budget target for 2004 was set at $68.3 million in October 2003. The preliminary target had already been reduced by $4.5 million "to help offset capital needs in electric distribution." The Target was based on retiring 49 miles of GPRP pipe in 2004.[61]

Actual 2004 GPRP spending was $47.9 million.[62] That was $20.4 million less than the reduced preliminary budget target of $68.3 million. PG&E retired 33.9 miles of GPRP pipe in 2004.[63]

The Spring 2004 GPRP Program Review discussion of Program Challenges indicated "GPRP is required to be completed by the end of 2009. However, program budget and work saturation in SF division will extend the program by 4-5 years."[64]

The Fall 2004 GPRP Program Review noted that the number of miles replaced under the GPRP would be significantly lower in 2004 than in 2003 because of "reduced budget in 2004 and majority of work in high cost area."[65]

PG&E's Testimony in the 2007 GRC provides the following explanation for why GPRP expenditures were reduced in 2003 and 2004:[66]

> *PG&E experienced higher than expected expenditures for safety, compliance and new customer connection work in 2003 and 2004. In an effort to remain within the capital and expense expenditure levels imputed from the 2003 GRC Settlement Agreement, Distribution Operations adjusted work where possible by focusing on work in the higher priority categories. Specific areas where PG&E reduced levels of work were pole replacement and GPRP. PG&E reduced lower priority pole replacement and some GPRP work based on the judgment that such reductions would not affect safety or significantly impact reliability in the near term.*

[60] Chapter 10.
[61] Response to Discovery, OC-537, Attachment 2.
[62] Response to Discovery, OC-392.
[63] Response to Discovery, OC-102, Attachment 9, PG&E 2004 GPRP Annual Report, page 8.
[64] Response to Discovery, OC-406, Attachment 14.
[65] Response to Discovery, OC-406, Attachment 19.
[66] Response to Discovery, OC-679 and PG&E Exhibit (PG&E-4) in 2007 General Rate Case, December 2, 2005, Volume 1 of 2 page 1-28.

The approved GPRP budget for 2005 was $58.3 million.[67] Actual 2005 GPRP spending was $47.0 million.[68]

GPRP expenditures were lower in 2004 and 2005 than in prior years because of the "need to make capital investments in other critical areas."[69] The other higher priority work in 2004 was mandatory new business work and work requested by others.[70]

In 2005, the other higher priority work was mandatory new business work, electric line/substation capacity and electric underground cable replacement. The electric capacity and cable replacement work was non-mandatory. That work was considered to be a higher priority than GPRP in the judgment of PG&E management.[71]

The Fall 2005 GPRP Program Review discussion of program challenges indicated "SF Division resources (estimating and construction) significantly impacted by concurrent GPRP, Rule 20A and Underground Cable Replacement."[72]

T&D requested a GPRP capital budget of $62.1 million in 2006. The approved budget was $56.8 million. The approved budget included a $1.2 million increase for a change in accounting for A&G capitalization that was not included in the $62.1 million budget request. Once that change was accounted for the approved budget was $6.6 million lower than the request.[73]

The GPRP program manager's November 30, 2005 email indicated the approved 2006 budget of $56.8 million represented "a net budget reduction of approximately $6.8 million from the budget request and $8.1 million from my original forecast of funding needed to keep the program on schedule."[74] Actual GPRP capital spending was $59.1 million in 2006.

The Fall 2006 GPRP Program Review discussion of program challenges indicated "estimating is currently being delayed by staffing shortages." Another program challenge was "funding re-prioritized to other high priority work."[75]

[67] Response to Discovery, OC-537, Attachment 4.
[68] Response to Discovery, OC-392.
[69] 2004 GPRP Annual Report, page 5 and 2005 GPRP Annual Report, page 5.
[70] Response to Discovery, OC-475.
[71] Response to Discovery, OC-476.
[72] Response to Discovery, OC-406, Attachment 29. Rule 20A is tariff for burying overhead electric lines at the request of a governmental entity.
[73] Response to Discovery, OC-537, Attachment 8a.
[74] Response to Discovery, OC-537, Attachment 9.
[75] Response to Discovery, OC-406, Attachment 34.

The Fall 2006 Program indicated that the number of miles of new pipe installed under the GPRP was expected to increase from an average of 30 miles per year in 2005 and 2006 to 54 miles in 2007. The increase in 2007 was due to "work being deferred in 2004, 2005 and 2006. As a result, more work must be completed in 2007-2009 in order to complete the program on schedule."[76]

The Fall 2006 Program Review discussion of top risks noted:[77]

> *In 2004 - 2006 GPRP (was) deferred into the 4th quarter to balance resources. This...resulted in the work not being completed in favor of funding higher priority work such as New Business and WRO (work requested by others). In order to prevent this work from being deferred, proper resources must be devoted to estimating and constructing GPRP work earlier in the year.*

After the capital budget was established for the year, the work was planned at a project level by month and the individual projects were rolled up to understand how the work was distributed between months. The first iteration of the rolled-up plan usually showed significantly more work in the 2nd and 3rd quarters than in the 4th quarter of the year. As a result, some projects had to be moved from the 2nd and 3rd quarters to the 4th quarter to match the available resources. GPRP projects were generally given a lower priority than the other projects scheduled for the 2nd and 3rd quarters. GPRP projects were frequently shifted to the 4th quarter for that reason. As a result, GPRP work tended to be scheduled for the 4th quarter of the year. When other higher priority projects scheduled for the 2nd and 3rd quarters experienced delays and cost overruns, GPRP projects scheduled for the 4th quarter were deferred to future years.[78]

Electric capacity and reliability capital work was scheduled for the first and second quarters so it could be completed prior to the summer peak demand season. The majority of the planned gas work was scheduled for the 3rd and 4th quarters of the year to balance division resources.[79]

PG&E initiated the Copper Services Replacement Program (CSRP) in 2006. On May 31, 2006, T&D requested a planning order to track CSRP costs. The email containing that request indicates an overall goal of funding $3 million in copper services replacements in 2006. T&D proposed to fund that amount by taking $2 million from the GPRP and $1 million from gas distribution reliability capital spending.[80] Actual 2006 CSRP spending was $1.1 million.[81]

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[76] Response to Discovery, OC-406, Attachment 34.
[77] Response to Discovery, OC-406, Attachment 34.
[78] Response to Discovery, OC-537.
[79] Response to Discovery, OC-406, Attachment 45, page 4.
[80] Response to Discovery, OC-537, Attachment 12.
[81] Response to Discovery, OC-428.

PG&E did not include the CSRP in the funding it requested in the 2007 GRC. PG&E began diverting some of the GPRP funding approved in that case to the CSRP in 2007.

The 2006 GPRP Annual Report, dated April 30, 2007, states:[82]

> *To address other high priority gas pipeline replacement needs, PG&E has begun redistributing some funding and resources originally targeted for the GPRP to other gas distribution facilities of equal or greater value. In 2007, the additional area of focus is on copper service replacements. The copper services targeted for replacement are higher priority than the GPRP pipe replacement that is being rescheduled. Overall the 2007 capital expenditure forecast on the GPRP and copper services exceeds the GPRP capital expenditure forecast of the 2007 rate case.*

Actual 2007 CSRP spending was $20.7 million.[83] The Fall 2007 Program Review indicated:[84]

> *$12.1 million in GPRP funding is being deferred from 2007 into 2008. This funding covers some high priority and all medium and low priority GPRP work outside of San Francisco.* ***This creates risk to public safety related to aging infrastructure (pipelines are more than 70 years old) and higher leak rates than system average. This also presents a risk of failing to meet program deadline committed to CPUC...Deferral of work in future years will result in a wave of escalated resource needs for 2011-2014 to meet program deadline...Potential for lawsuit or civil penalties in case of catastrophic failure of GPRP-vintage facilities. (emphasis added)***

The 2007 GPRP budget deferrals were made to fund the CSRP.[85]

The September 20, 2007 presentation to management on the gas distribution integrity management program (DIMP) regulatory and financial requirements recommended a substantial increase in the combined funding for the GPRP and CSRP. The presentation noted that the current GPRP spending level was not sufficient to complete the program by 2014. The presentation included the following discussion of funding challenges:[86]

[82] Response to Discovery, 2006 GPRP Annual Report, page 2.
[83] Response to Discovery, OC-428.
[84] Response to Discovery, OC-406, Attachment 37.
[85] Response to Discovery, OC-540.
[86] Response to Discovery, OC-430, Attachment 8.

> *The average annual (GPRP) spend needs to increase to $77.6 million in order to meet 2014 completion date. The currently authorized...(2007) amount is $21.8 million below the estimated resources required to complete the program as committed....*
>
> *Additional annual authorization of $41 million needed for next five years to replace copper services on proposed schedule (2012 completion).*
>
> *Additional potential threats continue to be identified as part of DIMP, and we will be obligated to address them as they are identified.*
>
> *Current GRC funding only supports $70 million for GPRP spend (2007 imputed amount) and no amounts were requested for expanded integrity efforts or risks as they are identified.*
>
> *Need to set the stage for expanded DIMP in future regulatory proceedings including the 2011 GRC.*

The presentation indicated GPRP funding was often reduced during the year because of the need to fund other work. The presentation indicated "this is contrary to distribution integrity management practices and future GRC support."[87]

The presentation recommended combined GPRP and CSRP funding of $111 million in 2008.[88] The recommendation was sufficient to complete the CSRP by year-end 2012 and complete the GPRP by year-end 2014. The recommendation was not adopted.[89]

The 2008 approved budget for the two programs was $100.0 million.[90] Actual capital expenditures for the two programs totaled $105.6 million in 2008.[91]

The initial 2008 budget request for the GPRP was $75.2 million. The 2008 approved budget was $59.8 million.[92] The request was reduced to the budgeted amount by deferring $12.1 million in GPRP projects to future years and by assuming $3.3 million in savings resulting from the business transformation project.[93]

[87] Response to Discovery, OC-430, Attachment 8, Slide titled Current GPRP Spend Under Regulatory Imputed Amount.
[88] Response to Discovery, OC-430, Attachment 8, Slide titled Approval Requested.
[89] Response to Discovery, OC-588.
[90] Response to Discovery, OC-588, Attachment 1.
[91] Response to Discovery, OC-392, MWC 14 total.
[92] Response to Discovery, OC-588, Attachment 1.
[93] Response to Discovery, OC-542 and OC-588, Attachment 1.

The Spring 2008 Program Review indicated:[94]

> *$15.1 million in GPRP funding is being deferred from 2008 into future years. This funding covers the majority of GPRP outside of San Francisco, including some jobs that have already been estimated. This creates a risk to public safety related to aging infrastructure (pipelines are more than 70 years old) and higher leak rates than system average. This also presents a risk of failing to meet program deadline commitments to the CPUC...Deferral of this work into future years will result in a wave of escalated resource needs for 2011-2014 to meet program deadlines. Significant risks of failing to meet program commitment deadlines to replace deteriorating facilities and increased risk to public safety. Potential for lawsuit of civil penalties in case of catastrophic failure of GPRP-vintage pipe.*

The Spring 2008 Program Review discussion of challenges noted:[95]

> *The current estimating backlog and bottleneck is having adverse effects on gas distribution capital work. For (the GPRP) estimating is having a large impact on the work available for construction in San Francisco. If projects do not begin to come out of estimating in a more timely fashion, there is a risk that critical projects...will not be completed in 2008. This is also having an impact on resources in San Francisco. Projects are being overstaffed because there is not enough work on the horizon to keep all crews productive and busy....*

PG&E closed the Morgan Hill Resource Management Center (RMC) in June 2009, eliminating 77 estimator positions. PG&E reduced estimator headcount from 779 in January 2006 to 627 in July 2009.[96] By early 2010 the estimating bottleneck was causing significant work flow issues. The division construction crews were only able to keep about 60 percent of their schedules full because work packages were not available in a timely manner. That improved to 90 percent by the summer of 2010.

The August 31, 2010 T&D Quarterly Business Review (QBR) includes the following description of the situation in mid- March 2010.[97]

[94] Response to Discovery, OC-406, Attachment 38.

[95] Response to Discovery, OC-406, Attachment 38.

[96] Response to Discovery, OC-67, Attachment 7, September 2, 2009 Quarterly Business Review, pages 100 and 108. The estimator headcount includes both electric and gas.

[97] Response to Discovery, OC-873, Attachment 2, page 6.

> *Shortfall in work available for scheduling - work packages not visible, statuses unclear, lack of transparency into work pipeline...Unclear roles / responsibilities and weak controls inhibiting more thoughtful and holistic approach to planning and managing work.*

The CSRP budget was $40 million in 2009. PG&E reduced the budget by $1.5 million in August 2009 to fund electric capital work. PG&E suspended the CSRP in October 2009 to keep the program within budget.[98] PG&E's CSRP goal at the beginning of 2009 was to replace 6,500 services. PG&E only replaced 6,026 services in 2009.[99]

Actual GPRP spending from 2007 to 2010 was lower than the levels adopted in the 2007 GRC because GPRP funding was diverted to the CSRP. PG&E's 2011 GRC Testimony indicated:[100]

> *...[I]n late 2006, a risk algorithm similar to GPRP was used to evaluate the risk associated with copper services relative to the facilities within the GPRP...The algorithm assigned an equivalent relative risk ranking for copper services and GPRP qualified pipe. Consequently, PG&E made the decision to establish a new CSRP and fund it using money originally targeted for the GPRP and other work.*

PG&E continued to allocate the majority of the approved GPRP expenditures to the GPRP. The combined GPRP and CSRP expenditures exceeded the adopted GPRP value by a significant amount over the period 2007 through 2010.

Meter Protection Program

Background

PG&E established the Meter Protection Program (MPP) in 1990 to identify and correct gas meter locations that do not conform to PG&E's standards for gas meter protection. The MPP focuses on mitigating two risks. The risk that a meter could be hit by a motor vehicle, causing a leak; and the risk that an inaccessible service valve would prevent PG&E from shutting-off gas flow to the meter in an emergency.[101]

[98] Response to Discovery, OC-406, Attachment 43 and OC-545.
[99] Response to Discovery, OC-428.
[100] PG&E 2011 GRC Testimony, PG&E-3, page 19-6.
[101] Response to Discovery, OC-455.

PG&E surveyed all of its 3.4 million meters in 1990 and identified 431,767 meter locations that needed further evaluation.[102] Those meters are referred to as MPP locations in the remainder of this Chapter.

The number of locations changed periodically over the life of the program because of data base corrections and the addition of new locations. As of December 2010, PG&E had identified a total of 401,542 locations.[103]

PG&E inspects each location and determines whether protective measures are needed. Protective measures include installing barrier posts to protect the meter, installing service valves in accessible locations and relocating the meter.

PG&E completed the inspection of all of the locations included in the program in 2004.[104] After 2004, only new locations were inspected.[105]

Most locations did not require protective measures. PG&E had inspected all of the locations included in the program as of December 2010. Only 26% of the inspected locations required protective measures.[106]

The program was initially scheduled for completion in 2008. PG&E extended the completion date for the program to 2016 in March 2004.[107] PG&E accelerated the completion date to 2013 during 2011.[108]

The costs of installing barrier poles and service valves are charged to expense. The costs of relocating services are capitalized. Approximately 90 percent of the program's costs are charged to expense.

Regulatory History

The Commission approved the MPP in PG&E's 1990 GRC. The purpose of the program was to "bring all gas meters up to current safety codes."[109] The adopted total funding for the program was $4.96 million for the 1990 test year. The Commission required PG&E to file annual progress reports for the program.[110]

[102] Response to Discovery, OC-1068, Attachment 2, MPP 1991 Annual Report, page 3.
[103] Response to Discovery, OC-1068, Attachment 14, 2010 MPP Annual Report, page 2.
[104] Response to Discovery, OC-456, Attachment 2, 2004 MPP Annual Report, page 5.
[105] PG&E's 2007 GRC Testimony, PG&E-4, page 16-17.
[106] Response to Discovery, OC-1068, Attachment 14, 2010 MPP Annual Report, pages 3 and 5.
[107] 2003 MPP Annual Report, page 2 and 2004 MPP Annual Report, cover letter.
[108] PG&E's 2014 GRC Testimony, PG&E-3, page 5-26 and OC-406, Attachment 52, pages 4 and 5.
[109] D.89-12-057, December 20, 1989, pages 142 and 143.
[110] According to PG&E, the 1990 funding was adopted with the understanding that it would be 35 percent expense and 65 percent capital. OC-1068, Attachment 2, MPP 1990 Annual Report, page II-5.

The Commission stressed the importance of the MPP in PG&E's 2007 GRC Decision. PG&E requested $3.246 in MPP expense. TURN recommended a small reduction. The 2007 GRC Decision stated:[111]

> *We decline to adopt TURN's proposal to reduce funding for the MPP by $0.359 million. The MPP is a vital public safety program, and we want to ensure it is fully funded. Given the importance of the MPP to public safety, we expect PG&E to utilize all of the $3.246 million of annual funding...for the MPP for that purpose only. If PG&E fails to do so, it should provide a detailed explanation in its next GRC.*

MPP Metrics

MPP locations can be completed by two methods: (1) cleared by inspection; or (2) implementing protective measures. A location is cleared by inspection when the PG&E inspects the location and determines that protective measures are not needed.

The key metrics for the MPP are the number of inspections completed and the number of units protected. The following table shows the number of inspections completed by year through 2010.

[111] D.07-03-044, March 15, 2007, page 80.

Table 5-12 - Meter Protection Program, Number of Locations Inspected

Meter Protection Program Number of Locations Inspected 1990 to 2010	
YEAR	Locations
1990	13,239
1991	24,302
1992	21,078
1993	21,795
1994	6,299
1995	36,757
1996	29,569
1997	11,326
1998	4,099
1999	18,338
2000	25,570
2001	85,066
2002	42,043
2003	12,867
2004	4,957
2005	3,840
2006	291
2007	512
2008	967
2009	549
2010	52
TOTAL	363,516
Source: Response to Discovery, OC-456, Attachment 8.	

The inspection metrics shown above were provided by PG&E in the response to discovery request OC-456. The annual amounts agree with the current year inspections shown in the MPP Annual Reports. The 2010 MPP Annual Report shows 401,540 cumulative inspections through December 2010. Overland did not investigate the reasons for the difference of 48,035 locations.

The average unit cost charged to program expense for inspections is about $20 per location.[112] Based on that estimate, the 363,516 inspections shown above had a total cost of approximately $7.3 million.

The number of inspections decreased substantially in 2006 because PG&E completed inspections of almost all of the identified MPP locations by that time.

[112] Response to Discovery, OC-456, Attachment 8

The following table shows the number of units protected by year through 2010.

Table 5-13 - Meter Protection Program, Number of Locations Protected

Meter Protection Program Protective Measures Completed - Number of Locations 1990 to 2010			
YEAR	Posts	Valves & Relocations	Total
1990	3,392	562	3,954
1991	6,001	589	6,590
1992	4,601	1,376	5,977
1993	9,291	1,384	10,675
1994	3,031	334	3,365
1995	1,542	142	1,684
1996	8,242	793	9,035
1997	3,841	525	4,366
1998	1,489	165	1,654
1999	980	46	1,026
2000	1,845	466	2,311
2001	313	544	857
2002	1,472	322	1,794
2003	5,533	62	5,595
2004	6,071	216	6,287
2005	2,343	974	3,317
2006	1,905	295	2,200
2007	685	222	907
2008	2,186	17	2,203
2009	176	0	176
2010	70	2	72
TOTAL	65,009	9,036	74,045
Source: Response to Discovery, OC-456, Attachment 8. Valves refers to the installation of an accessible emergency shut-off valve for the service.			

As of December 2010, the MPP included 103,663 locations that required protective measures. PG&E had completed 71% of those measures as of December 2010.[113]

[113] Response to Discovery, OC-1068, Attachment 14, 2010 MPP Annual Report, page 2 is the source for the total number of locations requiring protective measures. The 2010 Annual Report indicates that protective measures had been completed for 75,101 locations. That exceeds the number reported in the response to OC-456 by 1,056. Using the completed protective measures from the 2010 MPP Annual Report increases the completion percentage to 72 percent.

Progress on the MPP slowed down significantly after 1997. During the period from 1990 to 1997, PG&E completed protective measures for an average of 5,706 locations per year. During the period 1998 to 2010, PG&E only protected an average of 2,185 locations per year. The number of locations protected in 2009 and 2010 was much lower.

Comparison of Adopted and Actual Expenditures

Inspection costs and barrier post and shut-off valve installation costs were charged to O&M expense. The costs of relocating services were capitalized.[114] The following table shows the MPP's actual program costs for 1999 to 2010 by year.[115]

Table 5-14 - Actual MPP Costs

Actual MPP Costs 1999 to 2010 Dollars in Thousands			
Year	O&M Expense	Capital	Total
1999	340	113	453
2000	545	572	1,117
2001	964	463	1,427
2002	1,141	342	1,483
2003	2,336	128	2,464
2004	2,958	31	2,989
2005	1,853	33	1,886
2006	1,365	0	1,365
2007	526	15	541
2008	878	73	951
2009	273	17	290
2010	72	15	87.
Total	13,251	1,802	15,053
Source: Response to Discovery, OC-392 and OC-393. MWC EX and MWC 27.			

[114] PG&E's 2014 GRC Testimony, PG&E-3, page 5-26.

[115] The O&M expenses are gas distribution expenses stated on a FERC basis. They exclude payroll taxes and employee benefits.

The following tables shows the adopted MPP costs by year for the same period.

Table 5-15 - Adopted MPP Costs

Adopted MPP Costs 1999 to 2010 Dollars in Thousands			
Year	O&M Expense	Capital	Total
1999	1,577	1,295	2,872
2000	1,577	1,295	2,872
2001	1,577	1,295	2,872
2002	1,577	1,295	2,872
2003	2,096	700	2,796
2004	2,138	714	2,852
2005	2,186	730	2,916
2006	2,267	757	3,024
2007	3,073	717	3,790
2008	3,136	732	3,868
2009	3,199	746	3,945
2010	3,262	761	4,023
Total	27,665	11,037	38,702
Source: Overland Analysis, and Chapters 3 and 4.			

The differences between actual and adopted MPP costs are shown below by year.

Table 5-16 - Difference Between Actual and Adopted MPP Costs

Difference Between Actual and Adopted MPP Costs Actual Over / (Under) Adopted 1999 to 2010 Dollars in Thousands			
Year	O&M Expense	Capital	Total
1999	(1,237)	(1,182)	(2,419)
2000	(1,032)	(723)	(1,755)
2001	(613)	(832)	(1,445)
2002	(436)	(953)	(1,389)
2003	240	(572)	(332)
2004	820	(683)	137
2005	(333)	(697)	(1,030)
2006	(902)	(757)	(1,659)
2007	(2,547)	(702)	(3,249)
2008	(2,258)	(659)	(2,917)
2009	(2,926)	(729)	(3,655)
2010	(3,190)	(746)	(3,936)
Total	(14,414)	(9,235)	(23,649)
Source: Prior two tables, Actual minus Adopted.			

Total actual spending was less than adopted during all but one of the years in the 12-year study period. Total actual MPP spending was 61% lower than adopted over the study period.

Planning Documents

The Spring 2003 MPP Program Review indicated that one challenge facing the program was "division resources to perform the MPP are hard to obtain."[116]

The Fall 2003 MPP Program Review showed a 2004 expense budget request of $6.6 million for the MPP.[117] The Spring 2004 MPP Program Review showed a 2004 expense budget of $4.6 million. The 2004 budget was 30 percent below the initial request. The Program Drivers/Challenges section indicated: "PG&E committed to complete the MPP by the end of 2008...At current and anticipated future funding levels, the program will not be complete by 2008."[118]

The Fall 2004 MPP Program Review showed a 2005 budget request for the MPP of $4.1 million of expense and $0.6 million of capital. The program goals section noted "Program was extended from 2008 to 2016 in the 2003 Annual Report to the CPUC." Program challenges included "resources are not consistently available or allocated to perform the work." The Fall 2005 MPP Program Review listed the same challenge.[119]

PG&E's 2011 GRC Testimony stated:[120]

> *Preventative maintenance work was determined to be a higher priority than MPP in 2007 by PG&E. Preventative maintenance was determined to be mandatory and/or high risk due to prescriptive timeframes provided in regulations to perform maintenance on the gas system. The MPP received a lower priority since deferral of work beyond 2007 would have involved less risk. Preventative maintenance activities that required additional funding in 2007 included, leak survey and cathodic protection.*

The Fall 2006 MPP Program Review listed the following program challenge for 2007 "work postponed to the 4th quarter due to resource constraints, and funding re-prioritized to address other high priority work." Top risks to the program included:[121]

[116] Response to Discovery, OC-406, Attachment 5.
[117] Response to Discovery, OC-406, Attachment 9. Dollars are SAP basis expense dollars which include payroll taxes and employee benefits.
[118] Response to Discovery, OC-406, Attachment 15.
[119] Response to Discovery, OC-406, Attachments 21 and 30.
[120] PG&E 2011 GRC Testimony, PG&E-3, page 19-20.
[121] Response to Discovery, OC-406, Attachment 35.

> *Resources not allocated to complete the work: In 2005 and 2006, spending on the MPP has decreased substantially compared to previous years. This is due to lack of resources devoted to completing the work. If this trend continues, we will be unable to compete the program on schedule.*
>
> *Increased regulatory scrutiny of MPP: The CPUC has recently shown interest in the MPP's schedule and individual decision process. With the decline in work being completed in the last two years, if this trend continues moving forward, the CPUC may chose to intervene in order to ensure this work gets completed.*

The Fall 2007 Gas Distribution Expense Program Review showed a 2008 expense budget for the MPP of $1.0 million. That was substantially lower than the 2007 budget of $3.0 million. The Challenges/Risks facing the expense program included:[122]

> *Maintaining funding and resource commitments for long term projects, like the Meter Protection Program and Isolated Steel Services Program, throughout the year and over the lifetimes of the programs. To balance construction resources, this work often gets pushed to the end of the year and then funding or resource constraints eliminate the work altogether.*

The risk discussion for the MPP indicated:[123]

> *PG&E has committed to the CPUC to install protections on all identified facilities by 2016. To stay on track for a 2016 completion, $3.6M in protection is required, but only $1 million is preliminarily funded. Underfunding, or not funding, this program puts PG&E at risk that: the program will not finish on time, significantly increased funding will be needed in later years, or PG&E will be unable to obtain adequate funding through the GRC for this program because of reduced spending levels. Additionally the consequences associated with a car accident involving an unprotected meter may be severe.*

The list of priorities for 2009 and beyond included "complete the Meter Protection Program on time: The MPP is scheduled to be completed by 2016 to ensure compliance with a CPUC agreement. Deferral of work in 2008 will put this date in jeopardy, or require significantly increased resources in later years."[124]

[122] Response to Discovery, OC-406, Attachment 36.
[123] Response to Discovery, OC-406, Attachment 36.
[124] Response to Discovery, OC-406, Attachment 36.

The Fall 2008 Expense Program Review includes the following discussion of the MPP:[125]

> *In 2008 there is not enough funding to complete enough work to stay on track to complete the program on time. In 2007, $1.23M was ultimately allocated for this work and in 2008 $1M has been allocated though a spend of approximately $3M per year is required to complete the program on time. So far in 2008, this program has not completed enough units and is under-running financially because program management is having difficulty gaining traction and support in the divisions to get work prepared and done, this issue is being rectified.*

The Fall 2008 Expense Program Review noted that the then current funding levels for the MPP in the three-year operating plan were only 30 percent of what was needed to complete the program on time.[126]

PG&E reduced MPP spending from 2007 to 2010 to fund higher priority gas preventative maintenance work.[127] The initial 2009 and 2010 gas distribution expense budgets did not include any MPP expense.[128]

The September 2009 T&D Quarterly Business Review noted:[129]

> *Long Term Gas Distribution Projects - GPRP, meter protection and isolated steel services programs require steep step-up in spending in 2011 and beyond to met regulatory commitments (a significant business issue); only copper service program tracking to complete on schedule.*

In its 2011 GRC Testimony, PG&E forecasted MPP expense of $0.87 million in 2010 and $5.19 million in 2011. PG&E indicated the 2011 increase was sufficient to "keep the program on schedule for completion by the end of 2016."[130]

PG&E's August 2011 Budget Report, submitted in compliance with the 2011 GRC Decision, indicated the GRC Settlement adopted $1.2 million in MPP expense and PG&E's 2011 MPP expense budget was $0.2 million. The Budget Report indicated the 2011 budget was lower than the adopted value "primarily due to decision not to pursue non-critical meter protection work in 2011 to support higher priority work."[131]

[125] Response to Discovery, OC-406, Attachment 39.
[126] Response to Discovery, OC-406, Attachment 39.
[127] Response to Discovery, OC-452.
[128] Response to Discovery, OC-408, Attachment 1, the initial budget for MWC EX was zero in both years.
[129] Response to Discovery, OC-67, Attachment 7, page 73.
[130] PG&E 2011 GRC Testimony, December 21, 2009, PG&E-3, page 19-22.
[131] Budget Report in Compliance with D.11-05-018, August 3, 2011, page 2-19.

The Gas Distribution 2012-2014 Budget Request and Plan, dated November 2011, showed a 2012 expense budget of $20 million for the MPP. The 2012 budget reflected a "commitment to complete work in current data base by 2013."[132] The 2013 MPP expense plan was also shown as $20 million. The magnitude of the MPP expense forecasts for 2012 and 2013 demonstrates the extent to which the program was behind schedule in prior years.

PG&E's 2014 GRC Testimony shows program completion in 2013. PG&E's expense and capital forecasts in the 2014 GRC show substantial MPP costs in 2012 and 2013. PG&E's 2012 and 2013 expense forecasts include $12 million per year for the MPP. PG&E's 2012 and 2013 capital forecasts include $1.0 million per year for the MPP.[133]

The MPP program metrics and PG&E's internal planning documents demonstrate that PG&E placed a relatively low priority on the MPP during 1998 through 2010. PG&E placed a higher priority on the MPP starting in 2011, after the San Bruno Incident.

Isolated Steel Services Project

PG&E initiated the Isolated Steel Services Project (ISSP) in late 2001.[134] PG&E determined that many steel service risers installed prior to 1980 were isolated from cathodic protection. The purpose of the ISSP was to identify the isolated steel services and bring them under cathodic protection over a ten-year period ending in 2012.[135]

PG&E identified 640,826 services as potentially being isolated. Under the ISSP, PG&E verifies cathodic protection for 100 percent of the services installed prior to 1976 and verifies a statistically valid sample of services installed from 1976 through 1979.[136]

As of December 2010, PG&E had completed 25 percent of the 640,826 services included in the ISSP.[137] As of November 2012, PG&E was confident that the ISSP would be completed by the end of 2012.[138]

Field Survey Metric

The ISSP uses a three-step approach. The first step is a review of records conducted in the office to identify services requiring testing in the field. The second step is field survey. The third step is restoring cathodic protection to isolated services.

[132] Response to Discovery, OC-406, Attachment 52, pages 4 and 5.
[133] PG&E 2014 GRC Testimony, PG&E-3, pages 5-26 to 5-28.
[134] PG&E 2003 GRC Testimony, PG&E-2, page 13-26.
[135] Response to Discovery, OC-456, Attachment 1, page 3.
[136] Response to Discovery, OC-456, Attachment 1, page 3.
[137] Response to Discovery, OC-458, Attachment 7.
[138] PG&E 2014 GRC Testimony, November 15, 2012, PG&E-2, page 5-17.

The field survey is conducted by attaching an interrupter on the rectifier of the cathodic protection area system that causes a pulsating signal on all connected services. If the signal cannot be detected on the service, it is an isolated service.[139]

Some of the potential locations do not require a field survey. As of June 4, 2010, PG&E estimated that field surveys would be required for 310,000 locations over the life of the ISSP.[140]

The following table shows the number of locations field surveyed by year.

Table 5-17 - Isolated Steel Services Program, Services Field Surveyed by Year

Isolated Steel Services Program Services Field Surveyed by Year 2001 to 2010	
Year	Services
2001	4,329
2002	7,955
2003	12,796
2004	6,678
2005	5,101
2006	5,246
2007	22,415
2008	34,518
2009	459
2010	2,519
TOTAL	102,016
Source: Response to Discovery, OC-700.	

According to PG&E, the number of services fluctuated from year-to-year because "PG&E had the discretion to complete this work within the ten year period, and the services inspected varied...based upon balancing other priority work that came up throughout the year."[141]

As of December 2010, PG&E had completed field surveys for approximately one-third of the locations that required testing. PG&E surveyed an additional 13,469 services in 2011.[142]

Comparison of Adopted and Actual Expenses

The ISSP costs are charged to O&M expense. The following table compares adopted and actual ISSP costs for the period 2003 to 2010.

[139] Response to Discovery, OC-458, Attachment 1.
[140] PG&E 2011 GRC Rebuttal Testimony, PG&E-18, page 28-30.
[141] Response to Discovery, OC-700.
[142] Response to Discovery, OC-700.

Table 5-18 - Isolated Steel Services Program, Comparison of Adopted and Actual Expenses

Isolated Steel Services Program Comparison of Adopted and Actual Expense SAP Basis Dollars in Thousands			
YEAR	Actual	Adopted	Difference
2003	470	925	(455)
2004	422	944	(522)
2005	255	965	(710)
2006	799	1,000	(201)
2007	1,597	635	962
2008	1,049	648	401
2009	811	662	149
2010	128	675	(547)
TOTAL	5,531	6,454	(923)
Sources: Actual is OC-899. Adopted is Overland Analysis.			

PG&E spent $923,000 less than the adopted expenses over the eight-year period. The underspending equaled 14 percent of the adopted amounts.

The Fall 2005 Expense Program Review indicated PG&E reduced the work done under the ISSP in 2004 to fund higher priority work.[143]

The Fall 2007 Expense Program Review indicated:[144]

> *PG&E has committed to completing the Isolated Steel Services program by 2012. To stay on track for a 2012 completion, $3.0 million in 2008 is required, but only $1.3 million is preliminarily funded. Underfunding this program puts PG&E at risk that preventable corrosion leaks will occur, the program will not finish on time, significantly increased funding will be needed in later years, or PG&E will be unable to obtain adequate funding through the GRC for this program because of reduced spending levels.*

The Fall 2007 Expense Program Review noted that completion of the ISSP was required to comply with long-standing safety regulations.[145]

[143] Response to Discovery, OC-406, Attachment 28, page 2.
[144] Response to Discovery, OC-406, Attachment 36.
[145] Response to Discovery, OC-406, Attachment 36, page 3.

PG&E reduced spending on the ISSP in 2008 to 2010 to fund higher priority leak survey and cathodic protection work. According to PG&E, the ISSP was assigned a lower priority in those years, because deferral of the work involved less risk.[146]

PG&E requested $5.8 million in 2011 funding for the ISSP in its 2011 GRC. The 2011 GRC Settlement adopted a 2011 expense amount of $1.2 million for the ISSP.[147]

PG&E increased ISSP spending significantly in 2011 and 2012 to meet its commitment to the CPUC to complete the project by the end of 2012.[148] Actual ISSP expense was $3.0 million in 2011 and $8.3 million in January through June 2012.[149]

The Gas Distribution 2012-2014 Budget Request and Plan dated November 2011, requested a $12 million budget for the ISSP in 2012 up from $3.9 million in 2011. The higher budget was needed to:[150]

> *Complete the Isolated Steel Services Program to satisfy the CPUC commitment by the end of 2012. Initially 650k locations, to complete 420k locations in 2012.*

The magnitude of the budget increase required for 2012 demonstrates the extent to which the program was behind schedule in prior years.

Internal Audit Reports

PG&E reviewed aspects of the ISSP in two internal audits. The first Internal Audit Report, dated April 30, 2009, reviewed controls for a variety of distribution integrity management programs, including the ISSP. The report indicated there was confusion about the expected completion date of the program. The program manager advised Internal Auditing that the program would not be completed until 2015 or 2016 at the current pace. The Internal Audit report also noted that the statistical sampling plan for the ISSP could not be considered statistically valid because key information was not available.[151]

[146] Response to Discovery, OC-457.

[147] 2011 GRC PG&E Rebuttal Testimony of Ed Wong on Gas Distribution Expense, PG&E-18, page 28-5 and 2011 GRC Settlement Agreement, page 1-5.

[148] Response to Discovery, OC-457.

[149] Response to Discovery, OC-887.

[150] Response to Discovery, OC-406, Attachment 52, page 5.

[151] Response to Discovery, OC-432, Attachment V

The second internal audit focused on controls over the ISSP. The July 29, 2011 Audit Report concluded:[152]

> *Overall, we conclude that controls over the ISSP are not adequate. In particular, we noted the Utility was not able to provide documentation to support completed ISSP work.*
>
> *In addition, the utility lacks a detailed plan describing how it will complete the program by the 2012 year-end commitment date...*

The Internal Audit Report indicated "[t]here is no process or control for ensuring that the necessary documentation is maintained in an effective way...The lack of supporting documentation prevents Utility management from knowing whether ISSP work was in fact completed and carried out according to program requirements..."[153]

The July 2011 Internal Audit Report noted that PG&E didn't perform any ISSP field work from January 2010 through May 2011. The program had restarted, but PG&E did not have a detailed plan to complete the ISSP by the end of 2012.

[152] Response to Discovery, OC-432, Attachment GG.
[153] Response to Discovery, OC-432, Attachment GG.

6. Return on Equity

Introduction

This Chapter compares the actual and authorized returns on equity (ROE) earned by PG&E's gas distribution operations over the period 2003 to 2010. This Chapter also includes comparisons of adopted and actual revenues and rate base.

PG&E's gas operations consist of distribution and gas transmission and storage (GT&S). PG&E's total gas operations earned an average actual ROE of 12.8% during the period 2003 to 2010, stated on a CPUC regulatory basis. PG&E's authorized ROE averaged 11.3% over the same period.[1]

PG&E's gas distribution operations were modestly less profitable than its GT&S operations over the study period. The gas distribution ROE averaged 12.7% and the GT&S ROE averaged 13.2% over the eight-year study period.

PG&E's total gas revenues were $400 million higher than the level needed to earn its authorized ROE over the study period. The surplus revenues were divided fairly evenly between distribution and GT&S. PG&E's gas distribution operations had $202 million in surplus revenues over the study period, while its GT&S operations had $198 million in surplus revenue. The distribution surplus revenues averaged $25 million per year during the eight year study period.

Approach Used to Determine Actual ROE

Background - Return on Investment Metrics

Two different measures of investment return are used to analyze the profitability of regulated utilities. The first measure is rate of return (ROR) on rate base. ROR is calculated by dividing utility operating income by rate base. ROR represents the average rate of return the utility earned on its rate base regardless of how it was financed (debt or equity).[2]

Return on common equity (ROE) represents the rate of return earned on the common equity the utility has invested in its rate base. ROE is calculated using the following multi-step approach:

- Subtract the weighted cost of debt and preferred stock from the ROR to determine ROR available for common equity.; and
- Divide ROR available for common equity by the common equity ratio to determine return on equity.[3]

[1] Response to Discovery, OC-28.

[2] Response to Discovery, OC-820, Attachment 1.

[3] The equity ratio is based on the total capitalization used to calculate the utility's authorized rate of return. The total capitalization reflects the dollar amount of capital invested in the utility by source (debt, preferred stock or common equity). The common equity ratio is calculated by dividing the common equity component by the total capitalization.

Operating income and rate base are the key values needed to determine actual ROR and ROE.

Background - PG&E's FERC Form 2 and Annual SOE Reports

PG&E does not regularly monitor the profitability of its gas distribution operations on a stand-alone basis, and does not prepare monthly or annual gas distribution income statements.[4]

PG&E's accounting system tracks the recorded operating income earned by its gas operations. PG&E reports its recorded total gas operating income in its annual FERC Form 2 reports (Form 2).[5] The gas operating income reported in the Form 2 includes transmission, storage and distribution.

The operating income amounts reported in the Form 2 do not necessarily reflect CPUC rate-making policies. The Form 2 gas operating income must be adjusted to reflect the Commission's rate-making policies to derive actual CPUC regulated-basis operating income.

PG&E prepares annual Statements of Earnings (SOE) reports. The SOE reports are one page reports with separate columns for electric operations and gas operations. The amounts shown for gas operations include gas transmission, storage and distribution.[6]

PG&E attaches the most recent SOE report to its GRC Applications pursuant to the Commission's Rules of Practice and Procedure.[7] The SOE reports show total gas operating income, rate base and ROR. The SOE reports do not show ROE.

PG&E prepares monthly and annual rate base reports. Those reports show total utility recorded rate base by rate-making categories, including gas distribution. The annual rate base reports are referred to as the WAVG rate base report because they show the weighted average (WAVG) rate base for the year.[8] The rate base values reported on the SOE reports agree with the values reported on the WAVG rate base reports for most years.[9]

The starting point for the gas operating income amounts shown on the SOE reports is the gas utility income statement included in PG&E's Form 2. PG&E calculates the SOE operating income amounts by adjusting the gas operating revenues and expenses reported in the Form 2.

PG&E SOE Policy

Prior to 2010, PG&E did not have a written policy concerning SOE adjustments. PG&E prepared a policy statement for the SOE in 2010. The policy statement indicates "The SOE must use as a starting point the

[4] Response to Discovery, OC-394.
[5] PG&E's FERC Form 2 reports are available on its company web-site, PGE.com, under the regulatory cases tab.
[6] Response to Discovery, OC-394.
[7] Rules 3.2(a)(5) and 3.2(a)(6).
[8] Response to Discovery, OC-83 and OC-140.
[9] The three exceptions are 2004, 2008 and 2010. OC-517 and OC-829.

amounts in the ....Form 2... The amounts in the ....Form 2 must be adjusted to conform to ratemaking practice."[10]

PG&E's policy is to remove significant out-of-period expenses from the SOE that are "not reflective of the reported year's operations."[11] PG&E's policy is to also remove costs related to major adverse incidents, such as the San Bruno Incident, to the extent that they are expected to be recovered through insurance proceeds in future years.[12]

PG&E's policy is to include operating expenses in the SOE that are not recoverable in rates if they are properly included in operating expenses under the Commission's accounting policies. For example, PG&E does not eliminate Short-Term Incentive Pay (STIP) costs that are not funded in rates.[13] Similarly, PG&E does not eliminate holding company charges that are not recoverable under the Commission's rate-making policies.[14]

PG&E includes some costs in the SOE that are charged to below-the-line non-operating accounts on its books. PG&E's policy indicates:[15]

> *PG&E is at risk for certain Commission authorized capital projects when forecast costs exceed the authorized cap. When this happens, PG&E records an entry (on the SOE) to write off (the costs to above the line) Operations and Maintenance (expense) because this plant is used to provide utility services to customers.*

PG&E did not consistently apply its 2010 policy during the audit period. PG&E made very few adjustments to the gas operating income reported in the FERC Form 2 prior to 2010.[16]

Overland Approach

Actual ROE should reflect recorded results stated on a basis consistent with the Commission's rate-making policies.

Overland started with the gas operating income reported in the Form 2 and the rate base reported on PG&E's WAVG rate base reports and made adjustments to those values to reflect CPUC rate-making policies.

[10] Response to Discovery, OC-820, Attachment 1.
[11] Response to Discovery, OC-820, Attachment 1.
[12] Response to Discovery, OC-820, Attachment 1.
[13] Response to Discovery, OC-820, Attachment 1.
[14] Response to Discovery, OC-989.
[15] Response to Discovery, OC-820, Attachment 1.
[16] Response to Discovery, OC-395.

Examples of the types of adjustments made by Overland include:

- Restate Form 2 income tax expense to reflect the Commission's income tax normalization policy;
- Restate Form 2 employee benefits expenses to reflect the Commission's rate-making policies for Post-Retirement Benefits Other than Pension (PBOP) and Long-Term Disability (LTD) benefits; and
- Reclassify San Bruno Incident injuries and damages liability accruals to below-the-line expense.

Overland did not adopt PG&E's policy of including non-recoverable costs in operating expenses and rate base, nor did we adopt PG&E's policy of eliminating large out of period items, with limited exceptions.[17]

Separating Distribution and GT&S Operating Income

PG&E's gas operations consist of two basic components, distribution and gas transmission and storage (GT&S). Gas distribution rates are set in PG&E's General Rate Cases (GRCs). GT&S rates are set in separate GT&S rate cases. Determining the actual ROE earned by gas distribution requires separating recorded total gas operating income and rate base into distribution and GT&S components.

PG&E's WAVG rate base reports show separate rate base amounts for gas distribution and GT&S. Overland used those values to separate total gas operations rate base into distribution and GT&S.

PG&E's accounting system does not separate gas operating income into gas distribution and GT&S components. PG&E cannot provide recorded stand-alone gas distribution operating income for any of the years included in the study period.

Overland requested an analysis of the profitability of PG&E's gas distribution operations for each year in the study period. PG&E's response indicated it does not monitor the profitability of its gas distribution operations on a stand-alone basis. PG&E provided its annual Summary of Earnings (SOE) reports as the best available analysis of actual gas earnings.[18]

Overland calculated actual GT&S operating income as part of its prior Gas Transmission Audit. Overland used those amounts to separate total gas operating income into GT&S and distribution components. Overland determined recorded gas distribution operating income by subtracting GT&S operating income from total recorded gas operating income.[19]

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[17] Overland adjusted 2003 and 2004 recorded results to reflect the results of the 2003 GRC decision in the proper period. Overland used tax return basis book/tax temporary differences in its regulatory basis income tax expense calculations. That effectively reclassified estimating differences to the proper period.

[18] Response to Discovery, OC-394.

[19] The GT&S operating income amounts were determined in the Gas Transmission Audit in a manner that was generally consistent with the calculation of total gas operating income in this audit. However, there are some differences in the adjustments made to A&G expenses. Only about 17% of total gas A&G is allocated to GT&S. The misclassifications of A&G expenses between distribution and GT&S resulting from the differences are relatively small.

Treatment of Balancing Accounts

Overland's ROE analysis was not restricted to costs that are included in PG&E's GRCs. Some of PG&E's costs are recovered through separate rate-making mechanisms referred to as balancing accounts. Those costs are generally excluded from PG&E's GRCs. For example, gas supply costs are excluded from PG&E's GRCs because they are recovered through the Purchased Gas Account (PGA). Similarly, Smart Meter costs were excluded from PG&E's GRCs during the audit period because Smart Meter revenue requirements were recovered through the Smart Meter Project Balancing Account.

PG&E cannot separate its recorded gas distribution results into GRC and balancing account categories.[20] In theory, balancing account revenues and costs largely offset because the balancing account rate mechanisms adjust revenues to match actual recoverable costs over time. Overland did not separately analyze balancing account revenues and costs for those reasons. Overland included balancing account revenues and the associated costs in its determination of total gas operating income and rate base.

Overland's GT&S operating income excludes balancing account revenues and costs. As a result, Overland's gas distribution operating income includes all GT&S balancing account revenues and costs. The principal GT&S balancing account is the Hazardous Substance Mechanism.

ROE Comparison and Surplus Revenues

The following table compares the actual and authorized ROE for PG&E's total gas operations by year.

Table 6-1 - Total Gas Operations, Comparison of Actual and Authorized Return on Equity

Comparison of Actual and Authorized Return On Equity Total Gas Operations 2003 to 2010			
Year	Actual	Authorized	Difference
2003	11.91	11.22	0.69
2004	13.63	11.22	2.41
2005	12.67	11.22	1.45
2006	14.13	11.35	2.78
2007	12.17	11.35	0.82
2008	12.93	11.35	1.58
2009	12.18	11.35	0.83
2010	13.04	11.35	1.69
Average	12.83	11.30	1.53
Source: Overland Analysis.			

The average distribution ROE was modestly lower than the GT&S ROE over the study period. The following table compares the actual distribution and GT&S ROEs.

[20] Response to Discovery, OC-505.

Table 6-2 - Comparison of Actual Gas Distributions and GT&S Return on Equity

Comparison of Actual Gas Distribution and GT&S Return on Equity 2003 to 2010		
Year	Distribution	GT&S
2003	14.50	8.24
2004	14.60	12.24
2005	12.22	13.30
2006	14.18	14.05
2007	10.15	15.26
2008	11.90	14.65
2009	11.02	14.27
2010	12.92	13.25
Average	12.69	13.16
Source: Overland Analysis.		

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The following table compares the actual distribution ROE to PG&E's authorized ROE.

Table 6-3 - Comparison of Actual and Authorized Gas Distribution Return on Equity

Comparison of Actual and Authorized Gas Distribution Return on Equity 2003 to 2010			
Year	Actual	Authorized	Difference
2003	14.50	11.22	3.28
2004	14.60	11.22	3.38
2005	12.22	11.22	1.00
2006	14.18	11.35	2.83
2007	10.15	11.35	(1.20)
2008	11.90	11.35	0.55
2009	11.02	11.35	(0.33)
2010	12.92	11.35	1.57
Average	12.69	11.30	1.39
Source: Overland Analysis.			

PG&E's actual gas revenues exceeded the amount needed to earn its authorized return on equity by $400 million during the eight year study period. The following table shows the surplus revenues by year and type.

Table 6-4 - Gas Operations Surplus Revenues, Distribution and GTS

Gas Operations Surplus Revenues Distribution and GT&S 2003 to 2010 Dollars in Thousands			
Year	Distribution	GT&S	Total
2003	54,532	(34,865)	19,667
2004	57,601	12,110	69,711
2005	18,050	26,061	44,111
2006	52,121	34,319	86,440
2007	(23,686)	50,344	26,658
2008	12,184	43,543	55,727
2009	(8,083)	39,247	31,164
2010	39,382	26,820	66,202
Total	202,101	197,579	399,680
Source: Overland Analysis.			

The amount of revenue needed to earn PG&E's authorized ROE is sometimes referred to as PG&E's actual revenue requirement. PG&E's actual gas distribution revenues exceeded its actual gas distribution revenue requirement by $202 million during the study period.

Distribution ROE Trends

The distribution ROEs show a distinct pattern by GRC cycle. The 2003 GRC cycle covered the years 2003 through 2006. The distribution ROE averaged 13.88% during the 2003 GRC cycle. The 2007 GRC cycle covered 2007 to 2010. During those years, the distribution ROE averaged 11.50%.

That pattern is generally consistent with the comparisons of gas distribution functional adopted and actual O&M and capital expenditures in Chapters 3 and 4. The following table summarizes the results of those comparisons for the 2003 to 2010 period.

Table 6-5 - Differences Between Actual and Adopted Gas Distribution Functional O&M and Capital Expenditures

Differences Between Actual and Adopted Gas Distribution Functional O&M and Capital Expenditures Actual Over / (Under) Adopted Dollars in Thousands		
Year	O&M	Capital
2003	(11,601)	6,783
2004	(19,330)	(17,600)
2005	(10,986)	1,319
2006	(7,934)	13,117
2007	1,606	(1,877)
2008	16,139	23,179
2009	71,909	30,387
2010	20,236	58,380
Total	60,039	113,688
Chapters 3 and 4.		

During the 2003 GRC cycle, actual gas distribution functional O&M was $50 million below adopted. During the 2007 GRC cycle, actual functional O&M was $110 million higher than adopted.

During the 2003 GRC cycle, actual gas distribution functional capital expenditures were $3.6 million higher than adopted. During the 2007 GRC cycle, actual gas distribution capital expenditures were $110 million higher than adopted.

Functional O&M and capital expenditures only account for a small percentage of the total gas distribution revenue requirement. The differences between adopted and actual gas distribution functional O&M and capital expenditures do not entirely explain the changes in gas distribution ROE for that reason.

In the 2007 GRC, adopted gas distribution functional O&M only accounted for 26% of total adopted gas distribution O&M. Customer Accounts and Services expenses (Customer Related O&M) accounted for 36% and A&G expense accounted for another 38%. Gas distribution functional O&M only accounted for 13% of the total gas distribution revenue requirement adopted in the 2007 GRC.[21]

Isolating the factors impacting distribution ROE is difficult because significant portions of PG&E's total costs are recovered through balancing accounts. Recorded A&G and Customer Related O&M expenses include significant costs that are not recovered through GRC rates. As a result, they cannot be compared directly to the amounts adopted in the GRCs.

Overland's comparison of adopted and actual capital expenditures excludes common and general plant. Depreciation and Taxes also impact surplus revenues.[22]

Comparing actual and adopted A&G, Customer Related O&M and Tax expenses was beyond the scope of the audit. Similarly, comparing actual and adopted capital expenditures for common and general plant was beyond the scope of the audit.

The actual gas distribution ROE is relatively stable from year to year. It is not practical to attribute small changes in ROE to specific events using the available evidence collected in the audit.

Gas distribution ROE is lower in 2007 than in 2006. That reduction coincides with the effective date of the rates adopted in the 2007 GRC .

The gas distribution ROE was lower in 2009 primarily because actual gas distribution functional O&M increased by $59 million in 2009. That increase reflected an increase in leak repair costs. The high level

[21] 2007 GRC Decision D.07-03-044, Appendix C, page C-42.

[22] Income tax temporary differences accounted for under the flow thru method can significantly impact operating income.

of leak repair costs in 2009 was the result of improvements in PG&E's leak survey process and the Accelerated Leak Re-Survey Project (ALS).[23]

The distribution ROE increased in 2010 largely because actual gas distribution functional O&M declined by $49 million relative to 2009. The largest element of that decline was a reduction in leak repair costs.[24]

GT&S ROE Trends

The 2003 GT&S ROE was low because of adverse market conditions. GT&S actual revenues were $74 million lower than the adopted GT&S revenue requirement because of warmer than normal winter weather, reduced gas-fired generation due to increased hydro-electric generation and a weak economy.[25]

GT&S ROE was higher than adopted during the eight year study period because:

- Actual GT&S revenues exceeded authorized revenue requirements by $155 million;[26]
- Actual GT&S O&M expenses were $35 million lower than adopted; [27]
- Actual GT&S capital expenditures were $95 million lower than adopted; and[28]
- GT&S rates were not reduced in 2008, 2009 and 2010 to reflect the federal bonus tax depreciation adopted as part of federal economic stimulus.[29]

The term "decoupling" is used in the utility industry for using balancing account rate mechanisms to adjust revenues over time to eliminate differences between actual revenues and adopted revenue requirements. The Commission has not implemented decoupling for most GT&S rates. The high GT&S ROEs during the study period were mainly due to the difference between actual revenues and adopted revenue requirements.

Summary of Adjustments

The following table summarizes the adjustments that Overland made to PG&E's recorded gas operating income stated in terms of revenue requirement impacts.[30]

[23] Chapter 3. Actual costs reflect the adjustments that Overland made to recorded values.

[24] Chapter 3.

[25] Rebuttal Testimony of CPSD Witness Harpster in SBI Investigation I.12-01-007, August 20, 2012, page 9 and OC-334. In addition, market uncertainty regarding the Kern River expansion reduced firm transmission sales as market participants waited to see how the new capacity would impact prices.

[26] Rebuttal Testimony of CPSD Witness Harpster in SBI Investigation I.12-01-007, August 20, 2012, page 9

[27] Rebuttal Testimony of CPSD Witness Harpster in SBI Investigation I.12-01-007, August 20, 2012, page 7.

[28] Rebuttal Testimony of CPSD Witness Harpster in SBI Investigation I.12-01-007, August 20, 2012, page 8.

[29] Overland Transmission Report, page 5-3.

[30] Overland only made one adjustment to the rate base amounts reported on PG&E's WAVG rate base reports. That adjustment was the Line 401 Plant Disallowance. The revenue requirement shown below for that adjustment includes the total revenue requirement impact of that adjustment.

Table 6-6 - Summary of Adjustments, Revenue Requirement Impact

Summary of Adjustments Revenue Requirement Impact Thousands of Dollars		
Description	Years	Revenue Requirement
Income Tax Adjustments	All	133,857
PBOP and LTD	All	(7,252)
Line 401 Plant Disallowance	All	(50,857)
Chromium Remediation Costs	2003 to 2009	(42,643)
Chromium Litigation Costs	All	(10,773)
Short Term Incentive Pay Plan	All	(72,088)
Holding Company Charges	2003 to 2008	(49,462)
Bankruptcy Costs	2003	(3,855)
Incentive Revenue	2005	25,500
Chromium Litigation Damages Accrual	2005 & 2007	(159,295)
Accounting Classification Correction	2007	578
Rancho Cordova Costs	2008 to 2010	(3,571)
Gas Matters Costs	2008 to 2010	(60,192)
SBI Litigation Damages Accrual	2010	(214,050)
SBI Response Costs	2010	(38,186)
Total		(552,289)
Source: Overland Analysis.		

Income Taxes

Overland adjusted the gas department income tax expenses reported on PG&E's Form 2 to reflect the results of a regulatory basis income tax calculation. The regulatory basis income tax calculations start with pre-tax operating income and reflect an interest deduction calculated using the interest synchronization method.

The income taxes reported on the Form 2 reflect PG&E's book tax accruals. The book tax accruals required adjustment for the following reasons:[31]

- The book accruals reflected several large mis-classifications of book/tax temporary differences between electric and gas operations;[32]
- The book accruals reflected mis-classifications between above-the-line operating and below-the-line non-operating taxable income;[33]
- The book accruals were impacted by timing differences caused by the use of estimated temporary difference amounts for book accrual purposes; and
- The book accruals did not fully reflect the Commission's income tax normalization policy.[34]

[31] Response to Discovery, OC-787 provides the book income tax accrual calculations.
[32] Response to Discovery, OC-794, OC-1041, OC-1043, OC-1102, OC-1114, OC-1115, OC-1125.
[33] Response to Discovery, OC-1111, OC-995, OC-828, OC-786 and OC-787. The book accruals start with pre-tax net income, including non-operating income and expenses.
[34] Response to Discovery, OC-787.

PG&E's book accruals reflect estimates of the book/tax temporary differences for the current year. The final amounts are determined when PG&E prepares its tax return in the subsequent year. PG&E records a "book to return" adjustment in the following year to true up the estimates. Overland corrected the classification errors and estimating differences by substituting tax return basis calculations provided by PG&E for the book accrual calculations.[35]

The Commission has a long-standing policy of requiring flow-through accounting for book/tax temporary differences to the extent permitted by tax law, with limited exceptions.[36] Overland's regulatory basis income tax calculations reflect the CPUC income tax normalization policy.

The income tax adjustment increases actual revenue requirements by $166 million in 2003. The income tax adjustment reduces revenue requirements by $33 million in 2004 through 2010. The large adjustment in 2003 corrects a misclassification of income tax expense between electric and gas operations recorded on PG&E's books in 2003.[37]

PBOP and LTD

The CPUC's rate-making policy for pensions, post-retirement benefits other than pensions (PBOPs) and Long-Term Disability (LTD) costs is to reflect those costs in rates on a contribution basis rather than an accrual basis.

The PBOP and LTD expenses reported in the Form 2 are stated on an accrual basis.[38] PG&E makes adjustments on its SOE reports to restate PBOP and LTD expenses to conform with the Commission's rate-making policy. PG&E provided the adjustment amounts used by Overland.[39]

Line 401 Plant Disallowance

The 1996 Gas Accord I Settlement capped the plant costs included in rate base for PG&E's gas transmission Pipeline Expansion Project (Line 401) at a level that was $65 million below the actual cost of construction. PG&E did not remove the disallowed Line 401 costs from its plant accounts. PG&E excludes the disallowed plant costs from rate base in its GT&S rate applications.[40]

The rate base amounts reported in PG&E's WAVG rate base reports reflect the full construction cost of Line 401. The Line 401 Plant Disallowance adjustment reduces rate base, depreciation expense and property tax expense to eliminate the disallowed costs.[41]

[35] Response to Discovery, OC-1124 and OC-1135 provide most of the tax return basis information.
[36] Pacific Bell, D.04-02-063, pages 104 and 105.
[37] Response to Discovery, OC-1102 and OC-1114. PG&E made an adjustment on its 2003 SOE to correct the allocation.
[38] The pension expenses reported in the Form 2 are stated on a contribution basis.
[39] Response to Discovery, OC-987, revised; OC-1032, revised; OC-1033, revised and OC-1100, revised.
[40] Response to Discovery, OC-144.
[41] Response to Discovery, OC-161.

Hinkley Chromium Litigation and Remediation Costs

PG&E's Hinkley gas transmission compressor station discharged significant amounts of chromium into the environment over many years. The resulting ground water contamination caused substantial damages to third parties who sued PG&E. The litigation was settled in 2006 and PG&E paid $295 million to the plaintiffs. PG&E elected not to seek recovery of the damages payments in rates.[42]

The Chromium litigation damages accrual adjustment eliminates the damages costs charged to expense during the study period.[43]

PG&E charged Hinkely toxic tort and personal injury litigation costs to A&G Account 923, Outside Services, during the study period.[44] The litigation costs should have been charged to below-the-line accounts, consistent with the treatment given to the damages awards. The Chromium litigation cost adjustment transfers those costs to below the line accounts.

PG&E was required to remediate the environmental damage caused by the chromium emissions at Hinkley. PG&E elected not to request recovery of the remediation costs in rates.[45]

PG&E charged the Hinkley remediation costs to above-the-line operating expense accounts prior to 2006. PG&E changed its accounting in 2006 and began charging the remediation costs to below-the-line expense accounts. PG&E changed its accounting "to properly reflect these non-recoverable costs as borne solely by shareholders."[46]

As a result of an accounting error, some remediation costs were charged to above-the-line accounts in 2006 to 2009.[47] The Chromium Remediation Cost adjustment transfers the costs recorded in above-the-line accounts during 2003 to 2009 to below-the-line accounts.[48]

Short-Term Incentive Pay

The Commission has a policy of limiting the short-term incentive pay (STIP) costs included in rates to fifty percent of the payout target for the year. The policy recognizes that incentive pay benefits both shareholders and ratepayers. [49]

DRA proposed adjustments in PG&E's 2003 and 2007 GRCs to reflect the Commission's policy. Both cases were resolved by settlements. The settlements adopted substantial reductions in A&G expenses

[42] PG&E 2006 Form 2 Report, page 123.52, Notes to Financial Statements, Chromium Litigation.
[43] A substantial portion of the damages amount was accrued before the start of the study period.
[44] Response to Discovery, OC-148, OC-775 and OC-1084.
[45] Response to Discovery, OC-148.
[46] Response to Discovery, OC-983.
[47] Response to Discovery, OC-980, OC-981 and OC-983.
[48] PG&E accrues estimates of the remediation costs it expects to incur in future years and adjusts the estimates as conditions changes. The Chromium Remediation Cost adjustment amounts vary significantly from year to year because they are impacted by those adjustments.
[49] The Commission described the policy in PG&E's 1999 GRC Decision D.00-02-046, on page 256.

compared to PG&E's requested amounts but did not explicitly address the disposition of the proposed STIP adjustments.[50]

The 2011 GRC was also resolved by a settlement. The 2011 GRC Settlement explicitly adopts a $45 million reduction in STIP costs.[51]

Overland's STIP adjustment conforms PG&E's recorded STIP expenses to the Commission's STIP rate-making policy. The adjustment reclassifies 50% of PG&E's STIP expense to below-the-line accounts.

Holding Company Charges

PG&E is owned by a holding company, PG&E Corporation. PG&E Corporation charges most of its costs to PG&E. PG&E records the holding company charges as an expense in A&G Account 923, Outside Services.

The Commission has a long-standing policy of limiting the holding company charges included in rates to costs that are reasonable and necessary for the provision of utility service.[52] PG&E's recorded expenses do not conform with that policy.

Overland's holding company adjustment reduces PG&E's recorded expenses to conform with the Commission policy. The adjustment reduces the recorded costs in each year to an estimated allowable level. The estimated allowable level is an approximation based on the positions taken by DRA and PG&E in the 2003 and 2007 GRCs. Overland's holding company adjustments are approximations that are not based on a detailed analysis of the specific charges in each year.

DRA proposed substantial disallowances of holding company costs in the 2003 and 2007 GRCs.[53] The 2003 and 2007 GRCs were both resolved through comprehensive rate settlements. The estimated allowable costs for each year were set equal to the average of the DRA and PG&E comparison exhibit positions in the applicable GRC.

PG&E's recorded holding company charges were much lower in 2009 and 2010 than in prior years.[54] Overland did not make holding company adjustments in 2009 or 2010 for that reason.

[50] 2003 GRC D.04-05-055, Sections 7.4.2 and 7.4.3 and 2007 GRC Decision D.07-03-044, page 158.

[51] D.11-05-018, Attachment 1, page 1-12. The $45 million is a total utility amount.

[52] The Commission described its holding company policies in PG&E's 1999 GRC Decision, D.00-02-046, page 276 and 277.

[53] 2003 GRC ORA Administrative and General Expenses and Allocations Report, Chapters 7, 8 and 9; and 2007 GRC DRA Report on the Results of Operations, DRA-10, Administrative and General Expenses, Chapter 10-K.

[54] Response to Discovery, OC-1060 and OC-1082.

Incentive Revenue

The Commission grants incentive revenues to shareholders under some programs to encourage behavior that is beneficial to ratepayers. PG&E's policy is to record incentive revenues in below-the-line non-operating income accounts.[55]

The Commission approved $25.5 million in incentive revenues for PG&E's gas energy efficiency programs in 2005.[56] The incentives covered the period 1994 to 2001. PG&E recorded the $25.5 million as above-the-line operating revenue in 2005.[57] The incentive revenue adjustment reduces 2005 operating revenues by $25.5 million to reclassify the incentive revenues to non-operating income, consistent with PG&E policy.

Rancho Cordova Incident

On December 24, 2008, an explosion and fire caused by a gas leak destroyed a house in Rancho Cordova. One person was killed and five other people were hospitalized. The Commission determined that the Rancho Cordova incident was the direct result of multiple violations of safety rules and fined PG&E $38 million.[58]

PG&E charged the fine to a below-the-line expense account.[59] PG&E charged $3.6 million of Rancho Cordova related costs to above-the-line gas operating expenses in 2008 through 2010.[60] Those costs are the direct result of gas safety rule violations and are not recoverable in rates under the Commission's rate-making policies.

Gas Matters Costs

PG&E discovered serious management deficiencies in its gas distribution operations in 2007 and 2008. Those deficiencies are described in Chapters 10 to 14. PG&E referred to the deficiencies and related corrective actions as Gas Matters in its internal documents.

PG&E tracked the costs associated with the Gas Matters. Approximately 50% of the Gas Matters costs would not have been incurred under reasonable management practices. Costs that are the direct result of mismanagement are not recoverable under the Commission's rate-making policies. The Gas Matters adjustment eliminates costs that are the direct result of mismanagement. The Gas Matters adjustment is developed and explained in Chapter 3.

[55] Response to Discovery, OC-1081.
[56] D.05-10-041.
[57] Response to Discovery, OC-815.
[58] The Rancho Cordova Incident is described in Chapter 11.
[59] Response to Discovery, OC-784.
[60] Response to Discovery, OC-1108 and OC-784.

San Bruno Incident

On September 9, 2010, a massive explosion and fire caused by the rupture of a local gas transmission line killed eight people and injured many more. The fire destroyed 38 homes and damaged 70. That event is referred to as the San Bruno Incident (SBI). The Commission's Consumer Protection and Safety Division (CPSD) issued its incident report for the SBI on January 12, 2012. The CPSD determined that the SBI was the result of multiple violations of safety rules. The Commission is currently considering appropriate penalties or other remedies for those violations.[61]

PG&E recorded $283 million in total expenses associated with the SBI in 2010. Of that total, $26 million was charged to electric operating expenses, $252 million was charged to gas operating expenses, and $8 million was charged to below-the-line expense.[62]

The SBI gas operating expenses consisted of two components, a $214 million net injuries and damages accrual and $38 million in other expenses.[63] The Commission required PG&E to initiate a number of safety measures in 2010 in response to the SBI. Most of the $38 million in other SBI expenses were for the implementation of those safety measures.

The SBI was a direct result of gas safety rules violations. The SBI costs recorded in 2010 are not recoverable in rates under the Commission's rate-making policies. The SBI adjustments reduce 2010 pre-tax operating expenses by $252 million to reclassify SBI expenses to below-the-line accounts.

Comparison to PG&E SOE Reports

The following table compares the total gas operations RORs shown on PG&E's SOE reports to the RORs calculated by Overland.

Table 6-7 - Total Gas Operations Actual Rate of Return, Overland Compared to PG&E Statement of Earnings

Total Gas Operations Actual Rate of Return Overland Compared to PG&E Statement of Earnings 2003 to 2010			
Year	Overland	SOE	Difference
2003	9.57	7.13	2.44
2004	9.71	8.64	1.07
2005	9.52	8.64	0.88
2006	10.23	9.44	0.79
2007	9.21	9.44	(0.23)
2008	9.62	8.90	0.72
2009	9.23	8.25	0.98
2010	9.68	8.18	1.50
Average	9.60	8.58	1.02
Source: Overland Analysis.			

[61] The SBI is described in Chapter 2.

[62] Response to Discovery, OC-395, Attachment 7, Tab SB_costs, includes an additional $2.9 million for MWC KF charges not included in the OC-395 tabulation.

[63] The net accrual amount is the gross accrual net of payments made in 2010.

PG&E's SOE reports were not reliable during the audit period for a number of reasons. PG&E made very few adjustments to the operating income reported in the Form 2 prior to 2010. PG&E cannot locate the workpapers supporting its 2003 SOE and the workpapers for the 2004 SOE are incomplete.[64]

PG&E did not make adjustments on its 2003, 2004 and 2008 SOEs to reflect the Commission's ratemaking policies for PBOP and LTD expenses. The adjustments that PG&E made in the other five years were not calculated correctly. [65]

PG&E did not reduce rate base to eliminate the disallowed Line 401 plant costs. PG&E did not reduce its recorded A&G expenses to reflect the Commission's policies for incentive pay and holding company costs.

The income tax expenses reported on the SOEs were incorrect because they did not fully reflect the Commission's income tax normalization policies. The income tax expenses also reflected mis-classifications between electric and gas operations and between operating and non-operating income.

PG&E did not remove all non-recoverable chromium remediation and litigation costs from the operating expenses reported on its SOEs. PG&E did not remove the non-recoverable Gas Matters costs attributable to mismanagement from its SOEs. PG&E only eliminated a portion of the non-recoverable SBI expenses from its 2010 SOE.

PG&E wrote off $16 million in gas distribution Smart Meter plant costs in 2010. The write-off reflected the difference between actual program plant costs to date and an agreed upon regulatory cost cap. PG&E recorded the write-off in a below-the-line expense account on its books. PG&E included the write-off in above-the-line operating expenses on its 2010 SOE report.[66] The costs were written off because they were not recoverable in rates. PG&E's SOE adjustment to move the write-off to above-the-line operating expense was improper.

PG&E sometimes records accounting adjustments in the current year that are corrections to prior year results. PG&E refers to those adjustments as out-of-period adjustments because they relate to a prior period. PG&E made several adjustments on its SOE to eliminate out-of-period adjustments recorded in the current year. PG&E did not restate the SOE for the prior year when it removed the out-of-period items from the current year. As a result, operating income was mis-stated over the combined eight year study period.

PG&E's 2003 GRC Decision was not issued until May 2004.[67] PG&E recorded accounting adjustments in June 2004 to retroactively apply the Decision to its January 1, 2003 effective date.

[64] Response to Discovery, OC-395.
[65] Response to Discovery, OC-395, OC-987, OC-1032, OC-1033 and OC-1100.
[66] Response to Discovery, OC-822 and OC-395.
[67] D.04-05-055, dated May 27, 2004.

The 2003 GRC Decision increased 2003 test year gas distribution revenues by $52 million and reduced 2003 test year gas distribution depreciation expense by $56.5 million.[68] The June 2004 accounting adjustments increased 2004 pre-tax gas operating income by $108 million to correct the revenues and depreciation expenses recorded in 2003.[69]

PG&E made an adjustment on its 2004 SOE report to eliminate the June 2004 accounting adjustments because they were out-of-period.[70] PG&E did not revise its 2003 SOE to reflect the higher 2003 revenues and lower 2003 depreciation expenses authorized in the 2003 GRC Decision. The net impact of that error was an understatement of pre-tax operating income by $108 million over the two year period. Overland reduced 2004 operating income and increased 2003 operating income by equal and offsetting amounts in its analysis.

Revenue Comparison

Total Gas Operations and Gas Distribution

PG&E has several significant gas balancing accounts, including the following:

- Gas supply - Purchased Gas Account;[71]
- Hazardous substance clean-up and litigation - Hazardous Substance Mechanism;[72]
- Smart meter revenue requirements - SmartMeter Project Balancing Account;[73] and
- Energy efficiency - Energy Efficiency Balancing Account.[74]

The balancing accounts recover a significant portion of PG&E's gas operations revenue requirements. The total gas operating revenues reported in the Form 2 include the balancing account revenues.

Balancing account revenues are excluded from PG&E's GRCs. The costs recovered through the balancing accounts are also excluded from the GRCs.[75]

The concept of adopted revenues does not apply to the balancing accounts. PG&E cannot compare its recorded total gas operating revenues to adopted amounts because most of its balancing accounts do not have adopted amounts. Overland did not prepare a comparison of gas distribution adopted and recorded balancing account revenue for the same reason.

The revenues that recover the revenue requirements adopted in PG&E's GRCs are referred to as GRC revenues. PG&E has two balancing accounts that true-up its recorded GRC revenues to the revenue

[68] D.04-05-055 and OC-745. The decision adopted lower depreciation rates. The lower depreciation rates reduced 2003 gas distribution depreciation expense by $56.4 million compared to the amounts actually recorded in 2003 using the old rates.

[69] Response to Discovery, OC-745.

[70] Response to Discovery, OC-745 Response to Discovery.

[71] Response to Discovery, OC-56.2

[72] Response to Discovery, OC-175.

[73] Response to Discovery, OC-1008.

[74] Response to Discovery, OC-507.

[75] Response to Discovery, OC-505.

requirements adopted in the GRCs – the Core Fixed Cost Account (CFCA) and the Non-Core Distribution Fixed Cost Account (NDFCA). The CFCA accounts for 97% of PG&E's total gas distribution revenue requirement.[76]

The CFCA and NDFCA implement rate decoupling for GRC revenues. PG&E does not prepare monthly reports to monitor its recorded gas distribution GRC revenues because the CFCA and NDFCA eliminate all variances between recorded revenues and adopted gas distribution GRC revenues.[77] Overland did not prepare a comparison of adopted and recorded gas distribution base revenues for the same reason. The gas distribution surplus revenues identified by Overland do not include any significant amounts for variances between adopted and recorded gas distribution GRC revenues.

GT&S Revenue Comparison

PG&E's GT&S rates did not include balancing accounts to true up the difference between actual and adopted base revenues during the study period.

The following table compares actual and adopted GT&S revenues over the study period.

Table 6-8 - GT&S Comparison of Actual and Adopted Revenues

Gas Transmission and Storage Comparison of Actual and Adopted Revenues 2003 to 2010 Dollars in Thousands			
Year	Actual	Adopted	Difference
2003	378,690	453,017	(74,327)
2004	428,893	438,834	(9,941)
2005	448,007	429,276	18,731
2006	476,716	437,393	39,323
2007	490,691	445,667	45,024
2008	498,851	449,415	49,436
2009	515,034	461,819	53,215
2010	508,324	474,266	34,058
Total	3,745,206	3,589,687	155,519
Source: Rebuttal Testimony of CPSD Witness Harpster, I.12-01.007, August 20, 2012, page 9			

Actual GT&S revenues exceeded the adopted level by $155.5 million over the eight year study period. That excess contributed directly to the GT&S surplus revenues previously discussed in this Chapter. GT&S recorded revenues were significantly lower than adopted in 2003 because of warmer than normal winter temperatures, higher than normal hydro-electric generation and a weak economy.[78]

[76] Response to Discovery, OC-397.
[77] Response to Discovery, OC-396.
[78] Response to Discovery, OC-334. Increased hydro-electric generation reduces the demand for gas because it reduces gas-fired electricity generation.

GT&S recorded revenues were higher than adopted in 2005 to 2010 because actual revenues from parking and lending services significantly exceeded the revenue requirement allocated to those services in GT&S rate cases.[79]

Rate Base Comparison

Gas Distribution - Year End Rate Base

Actual ROE is calculated using the weighted average (WAVG) Rate Base for the applicable year. Because the rate base is a twelve month average, plant additions are not fully reflected in rate base until they have been in service for a year. The lag created by the averaging process makes it more difficult to associate changes in the WAVG rate base with specific causal factors.

Comparing rate base at two specific dates provides a more understandable basis for analyzing rate base changes. Schedule 6-1 shows PG&E's gas distribution actual year-end (December 31) rate base for 2002 through 2010.[80]

PG&E's year-end rate base was 1% lower in December 2005 than it was in December 2002. Rate base fell slightly over that three year period because gross plant additions were roughly equal to depreciation expense and deferred income tax expense.

Rate base grew at an annualized rate of 3.4% in 2006 through 2010. Rate base grew during that period because PG&E increased its gas distribution functional capital expenditures for the reasons described in Chapter 4. The higher capital expenditures were partially offset by higher accumulated deferred income taxes. PG&E also increased its working capital estimate by approximately $50 million in 2007.

Accumulated deferred income taxes increased because of the federal bonus tax depreciation included in the federal economic stimulus programs adopted in February 2008, February 2009 and September 2010.[81]

Gas Distribution - Comparison of Actual and Adopted

The following table compares PG&E's gas distribution adopted and actual gas distribution rate base for the period 2003 to 2010.

[79] Rebuttal Testimony of CPSD Witness Harpster in SBI Investigation Docket I.12-01-007, August 20, 2012, Chapter 19.

[80] The schedule excludes Smart Meter Costs because the revenue requirement for those costs is recovered through a balancing account.

[81] Response to Discovery, OC-992 and PG&E's 2014 GRC Testimony, Exhibit PG&E-2, page 12-2. The stimulus programs allowed bonus depreciation for property placed into service in 2008, 2009 and 2010.

Table 6-9 - Comparison of Gas Distribution Actual and Adopted Rate Base

Comparison of Actual and Adopted Rate Base Gas Distribution Excluding Smart Meter Project 2003 to 2010 Dollars in Thousands			
Year	Actual	Adopted	Difference
2003	2,055,437	2,077,996	(22,559)
2004	2,062,630	2,119,556	(56,926)
2005	2,050,426	2,167,246	(116,820)
2006	2,098,294	2,247,434	(149,140)
2007	2,248,809	2,195,839	52,970
2008	2,312,769	2,240,832	71,937
2009	2,412,534	2,285,828	126,706
2010	2,417,580	2,330,836	86,744
Source: Overland Analysis.			

Overland calculated adopted rate base using the same approach as adopted O&M and adopted capital expenditures. Overland identified the test year rate base adopted in the 2003 and 2007 GRCs. Overland escalated the adopted test year amounts to determine adopted rate base in the Attrition Years. Overland's approach is described in greater detail in Chapters 3 and 4.

The following table shows the calculation of the adopted rate base amounts for 2004, 2005 and 2006.

Table 6-10 - Calculation of Adopted Gas Distribution Rate Base, 2004, 2005 and 2006 Attrition Years

Calculation of Adopted Gas Distribution Rate Base 2004, 2005 and 2006 Attrition Years Dollars in Thousands			
Year	Prior Year Adopted	Increase Factor	Current Year Adopted
2004	2,077,996	1.0200	2,119,556
2005	2,119,556	1.0225	2,167,246
2006	2,167,246	1.0370	2,247,434
Source: Overland Analysis.			

The escalation calculations for 2008, 2009 and 2010 are shown below.

Table 6-11 - Calculation of Adopted Gas Distribution Rate Base, 2008, 2009 and 2010 Attrition Years

Calculation of Adopted Gas Distribution Rate Base 2008, 2009 and 2010 Attrition Years Dollars in Thousands			
Year	Prior Year Adopted	Increase Factor	Current Year Adopted
2008	2,195,839	1.02049	2,240,832
2009	2,240,832	1.02008	2,285,828
2010	2,285,828	1.01969	2,330,836
Source: Overland Analysis.			

The Attrition Year adopted amounts should be viewed as approximations as opposed to being the result of a detailed analysis of the individual components of rate base.

The gas distribution rate base amounts shown above do not include PG&E's Smart Meter Project. The revenue requirement for the Smart Meter Project was recovered through a balancing account during the study period.[82] The balancing account adjusts rates to reflect actual Smart Meter costs. Overland excluded the Smart Meter project from the gas distribution rate base comparison because it was not included in the rate base amounts adopted in PG&E's GRCs.[83]

Over the eight year study period, the average difference between the recorded and adopted gas distribution rate base amounts was very small. Actual rate base was lower than the adopted level in 2003 through 2006, and was higher than adopted in 2007 to 2010. Over the eight year study period, the average actual rate base was only $886 thousand lower than the average adopted rate base.

Gas Transmission and Storage

The following table compares PG&E's adopted and actual GT&S rate base by year.

[82] The Smart Meter balancing account began in 2007. The Smart Meter project was excluded from rate base in PG&E's 2007 GRC.

[83] The Smart Meter project was included in the revenues, expenses and rate base used to calculate PG&E's actual gas distribution ROE.

Table 6-12 - GT&S Comparison of Actual and Adopted Rate Base

Gas Transmission and Storage Comparison of Actual and Adopted Rate Base 2003 to 2010 Dollars in Thousands			
Year	Actual	Adopted	Difference
2003	1,444,565	1,460,241	(15,676)
2004	1,435,257	1,452,044	(16,787)
2005	1,425,855	1,454,012	(28,157)
2006	1,446,459	1,481,493	(35,034)
2007	1,466,990	1,509,493	(42,503)
2008	1,502,151	1,549,838	(47,687)
2009	1,533,565	1,666,821	(133,256)
2010	1,605,478	1,789,983	(184,505)
Source: Rebuttal Testimony of CPSD Witness Harpster, I.12-01.007, August 20, 2012, page 12.			

The GT&S rates charged in 2008 through 2010 were adopted in the March 2007 Gas Accord IV settlement.[84] Actual GT&S rate base was much lower than the adopted values in 2009 and 2010 because that settlement did not reflect the federal bonus tax depreciation included in the federal economic stimulus programs adopted in February 2008, February 2009 and September 2010.[85]

[84] The GA IV Settlement was adopted in D.07-09-045, dated September 20, 2007.
[85] Response to Discovery, OC-178.

Schedule 6-1

Pacific Gas & Electric Company
Gas Distribution Year End Rate Base
Excluding SmartMeter
2002 to 2010
Dollars in Thousands

Description	2002	2003	2004	2005	2006	2007	2008	2009	2010
Plant in Service	5,302,397	5,462,320	5,597,526	5,730,088	5,965,734	6,186,683	6,386,894	6,633,792	6,825,675
Accumulated Reserve for Depreciation	(3,014,111)	(3,194,391)	(3,252,404)	(3,378,520)	(3,521,990)	(3,676,563)	(3,824,171)	(3,974,236)	(4,129,384)
Net Plant in Service	2,288,286	2,267,929	2,345,122	2,351,568	2,443,744	2,510,120	2,562,723	2,659,556	2,696,291
Working Capital	14,954	8,292	9,073	8,930	11,125	62,138	63,694	64,153	64,790
Tax Reform Act Adjustments	44,939	48,773	50,224	50,841	57,393	68,418	70,331	110,782	106,547
Customer Advances	(18,023)	(20,342)	(29,485)	(30,578)	(40,219)	(41,822)	(37,218)	(37,271)	(29,041)
Deferred Income Taxes	(205,330)	(224,167)	(276,480)	(282,463)	(291,831)	(316,358)	(251,551)	(311,713)	(370,227)
Deferred Investment Tax Credits	(32,237)	(30,561)	(29,198)	(28,124)	(26,897)	(25,589)	(24,229)	(23,113)	(21,775)
Total Rate Base	2,092,589	2,049,924	2,069,256	2,070,174	2,153,315	2,256,907	2,383,750	2,462,394	2,446,585

Source: OC-141

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7. Staffing and Metrics

Introduction

This Chapter reviews PG&E's staffing levels and operational metrics for evidence of safety-related resource constraints. The Chapter includes the following Sections:

- Headcount;
- Leak Survey and Repair;
- Valve and Regulator Station Maintenance;
- Corrective and Preventative Maintenance Backlogs;
- Mark and Locate;
- Cathodic Protection;
- Material Problem Reports; and
- Mapping Backlog.

PG&E reduced its gas distribution staffing by 29% between December 1996 and December 2010.[1] During the same period, the number of gas distribution customers increased by 15.5%. The large headcount reductions are a primary indication of resource constraints in gas distribution.

PG&E's leak surveys discovered very few leaks in 2003 to 2007. PG&E's leak survey metrics demonstrate that its leak survey practices were critically deficient prior to 2008.

From 2003 to 2007, 63% of Grade 1 leaks were discovered through the investigation of customer odor complaints. That metric demonstrates the poor quality of PG&E's leak surveys during those years.

From 2003 to 2008, 17% of Grade 2+ leak rechecks resulted in the leak grade being upgraded to Grade 1. That reflects quality problems in the original leak grading process during those years.

PG&E did not have reliable metrics for late leak repairs, late locates and late regulator station and valve inspections at any point during the audit period. PG&E's excavator dig-in rates demonstrate significant deficiencies in its damage prevention program prior to 2008.

Material Problem Reports (MPRs) are used to track problems caused by defective materials or products. The very low numbers of MPRs collected in 1995 to 2000 demonstrate that PG&E was not proactively collecting information about gas distribution material problems in those years. The low numbers of MPRs submitted from 2001 to 2007 imply that MPR reporting was inadequate in those years.
PG&E's mapping backlog metrics imply staffing shortages in the mapping department in 2007 through 2010.

[1] Excludes Gas Service Representatives in the Customer Service Organization. The GSR and dispatch headcount declined by 19 percent between 1998 and 2010.

Headcount

PG&E's Transmission and Distribution Organization (T&D) was responsible for operating and maintaining its electric and gas distribution and transmission systems during the audit period. The organization structure changed periodically but the same basic work groups were responsible for maintaining PG&E's gas distribution system.

The following table shows the T&D organization headcount allocated to gas distribution by year for 1996 to 2011.

Table 7-1 - Gas Distribution Year-End Headcount By Type

Gas Distribution Year-End Headcount By Type 1996 to 2011			
Year	Union	Other	Total
1996	2,218	168	2,386
1997	2,332	233	2,565
1998	2,248	282	2,530
1999	1,910	247	2,157
2000	1,868	203	2,071
2001	1,843	245	2,088
2002	1,734	266	2,000
2003	1,859	240	2,099
2004	1,731	222	1,953
2005	1,760	212	1,972
2006	1,688	195	1,883
2007	1,622	198	1,820
2008	1,586	218	1,804
2009	1,520	203	1,723
2010	1,511	179	1,690
2011	1,534	253	1,787
Source: Response to Discovery, OC-403 and OC-404.			

The total gas distribution headcount fell by 29% between December 1996 and December 2010. During the same period, the number of gas distribution customers increased by 15.5%.[2] The large headcount reductions result from resource constraints in gas distribution beginning in 1999.

The gas distribution T&D Organization headcounts shown above do not include the Gas Service Representatives (GSRs) included in PG&E's Customer Service organization. GSRs respond to customer service requests, including odor complaints and requests for appliance pilot relights. The GSRs also maintain the customer meter.

[2] PG&E FERC Form 2 reports for 1996 and 2010, page 301.

The GSRs are included in the Customer Service organization because they work inside the customer's residence or place of business and are in frequent contact with customers. The Customer Service organization also includes the dispatchers who schedule the work done by the GSRs.

The following table shows the headcounts for the GSRs and associated dispatchers by year.

Table 7-2 - Gas Service Representatives and Dispatch Employees, Year-End Headcount

Gas Service Representatives and Dispatch Employees Year-End Headcount 1998 to 2011			
Year	GSRs	Dispatch	Total
1998	774	110	884
1999	778	113	891
2000	725	109	834
2001	710	107	817
2002	703	110	813
2003	696	113	809
2004	656	109	765
2005	657	104	761
2006	699	86	785
2007	665	91	756
2008	646	91	737
2009	637	95	732
2010	620	96	716
2011	638	94	732
Source: Response to Discovery, OC-1132, Note dispatch includes scheduling.			

The number of GSRs declined by 14% between 1998 and 2007. During that same period, the number of PG&E customers increased by 14.7%.[3] The decline in GSR staffing implies resource constraints.

The number of GSRs declined further from 2008 to 2011. PG&E attributes that decline to the SmartMeter program. The installation of new SmartMeters reduced the amount of routine gas meter work done by the GSRs. In addition, process improvements increased GSR productivity.[4]

The dispatch headcount remained relatively stable between 1998 and 2005. PG&E consolidated its dispatch operations in 2006. The consolidation reduced the number of dispatch centers from 13 to 2 and reduced dispatcher headcount by approximately 20%.[5]

[3] PG&E 1998 and 2007 FERC Form 2 reports, page 301.
[4] Response to Discovery, OC-1132.
[5] Response to Discovery, OC-1132.

Leak Survey and Repair

Leak Survey - Miles of Mains and Number of Services

The following table shows the total miles of distribution mains surveyed by PG&E by type of survey and year.

Table 7-3 - Miles of Distribution Mains Leak Surveyed

Miles of Distribution Mains Leak Surveyed 2003 to 2011				
Year	Routine	Special	ALS	Total
2003	9,780	1,280	0	11,060
2004	10,524	854	0	11,378
2005	10,100	1,638	0	11,738
2006	10,101	418	0	10,519
2007	10,877	768	0	11,645
2008	9,356	760	733	10,849
2009	9,874	278	13,766	23,918
2010	8,140	534	2,034	10,708
2011	10,814	161	0	10,975
Total	89,566	6,691	16,533	112,790
Source: Response to Discovery OC-698. ALS is Accelerated Leak Survey Project.				

Most of the miles surveyed under the Accelerated Leak Survey Project (ALS) were surveyed in 2009.

Special leak surveys are required for a variety of reasons. Special leak surveys are performed when the pressure rating of a section of the gas distribution system is increased. Special surveys are also completed after major natural events that have the potential to create leaks, such as earthquakes and landslides. Special leak surveys are also conducted prior to major municipal street paving projects so leaks can be repaired before new asphalt is applied. The number of miles of main included in special leak surveys is highly variable from year to year. The Eureka earthquake was one reason why 2010 special leak survey miles were higher in 2010 than in 2009 and 2011.[6]

[6] Response to Discovery, OC-1079.

The number of services surveyed is shown below by year.

Table 7-4 - Number of Services Leak Surveyed

Number of Services Leak Surveyed 2003 to 2011				
Year	Routine	Special	ALS	Total
2003	639,345	48,407	0	687,752
2004	770,721	22,479	0	793,200
2005	698,591	23,654	0	722,245
2006	745,832	15,058	0	760,890
2007	750,225	16,904	0	767,129
2008	715,929	16,802	57,883	790,614
2009	786,870	9,953	1,086,654	1,883,477
2010	715,729	NA	160,965	876,694
2011	856,551	NA	0	856,551
Total	6,679,793	153,257	1,305,502	8,138,552
Source: Response to Discovery, OC-699; NA is not available.				

PG&E stopped tracking the number of services surveyed in special surveys in 2010.[7]

Leak Repairs By Grade

PG&E evaluates the leaks discovered in its system and assigns a grade to the leak. The grades reflect the public safety hazard level associated with the leak. PG&E's procedures specify maximum repair intervals and maximum recheck intervals for leaks that have not yet been repaired.

The following table shows the repair and recheck intervals required by PG&E's procedures during the audit period.

Table 7- 5 - Description of PG&E Leak Grades

Description of PG&E Leak Grades 2003 to 2010			
Grade	Description	Repair Time	Re-Check
1	Hazardous, Requires Immediate Repair	Same Day	Not Applicable
2+	Priority Non-Hazardous, Requires Repair within 90 days	3 Months	Not Applicable
2	Non-Hazardous, Requires Repair within 18 months	18 Months	Six Months
3	Non-Hazardous , Expected to Remain Non-Hazardous	None	Next Survey
Source: Response to Discovery, OC-1097, Attachments 1 and 3.			

PG&E's procedures required rechecking Grade 3 leaks in the next scheduled regular survey. The leak survey frequency for most gas distribution facilities is once every five years.

The leak grades are reassessed when the repairs are completed.

[7] Response to Discovery, OC-699.

PG&E's primary leak metric is leaks repaired. The following table shows total distribution leaks repaired by grade during the audit period.

Table 7-6 - Distribution Leak Repairs by Grade

Distribution Leak Repairs by Grade 2003 to 2011					
Year	Grade 1	Grade 2+	Grade 2	Grade 3	Total
2003	5,926	1,214	1,142	52	8,334
2004	6,179	1,203	1,004	33	8,419
2005	5,838	1,181	896	36	7,951
2006	5,582	1,245	798	41	7,666
2007	5,662	1,454	815	60	7,991
2008	7,925	8,084	1,414	98	17,521
2009	12,107	24,664	19,383	165	56,319
2010	7,485	8,933	2,629	463	19,510
2011	6,385	4,694	5,128	376	16,583
Total	63,089	52,672	33,209	1,324	150,294
Source: Response to Discovery, OC-903.					

The large increases in leak repairs after 2007 are the result of two factors. First, PG&E implemented an improved leak survey process in 2008. The improved process discovered more leaks than the prior process. Second, PG&E conducted the ALS from 2008 to 2010.

ALS - Leak Indications

The following table shows the leak indications discovered in the ALS by initial leak grade.

Table 7-7 - Accelerated Leak Survey Project Leak Indications

Accelerated Leak Survey Project Leak Indications By Year and Grade				
Grade	2008	2009	2010	Total
1	137	4,649	454	5,240
2+	1,446	11,102	611	13,159
2	86	21,102	3,116	24,304
3	163	2,784	344	3,291
Meter Set	5,698	77,529	6,095	89,322
Total	7,530	117,166	10,620	135,316
Source: Response to Discovery, OC-904.				

Leak indications are higher than leak repairs for two reasons. First, not all leaks are repaired in the year of discovery. Second, some leak indications are subsequently determined not to be leaks.

Non-hazardous meter set leaks are not graded. The meter set leaks shown above are non-hazardous above ground leaks on the riser or meter set.[8]

[8] Response to Discovery, OC-445, Attachment 2.

The number of Grade 2 leaks discovered in the ALS is 7.4 times higher than the number of Grade 3 leaks. Overland did not investigate the reasons for the low numbers of Grade 3 leaks discovered in the ALS.

Grade 1 Leaks by Method of Discovery

Leaks can be discovered through leak surveys or investigations of customer odor complaints. Leaks can also be the result of a dig-in by a third party excavator or a PG&E crew.

The following table shows the number of Grade 1 leaks repaired on PG&E's distribution system by the method of discovery.[9]

Table 7-8 - Grade 1 Leaks By Method of Discovery

Grade 1 Leaks By Method of Discovery Gas Distribution 2003 to 2011					
Year	Survey	Odor Call	Dig-In	Other	Total
2003	464	1,743	3,252	425	5,884
2004	340	1,850	3,318	608	6,116
2005	283	1,761	3,089	653	5,786
2006	352	1,540	3,035	572	5,499
2007	545	1,363	2,791	531	5,230
2008	3,013	1,834	2,197	818	7,862
2009	6,866	1,989	1,720	1,474	12,049
2010	2,592	1,817	1,613	1,362	7,384
2011	1,735	1,671	1,596	1,318	6,320
Total	16,190	15,568	22,611	7,761	62,130
Source: Response to Discovery, OC-905 and OC-906.					

PG&E's entire system had been surveyed using the enhanced leak survey process by December 2010. Over the nine-year period ending in 2011, PG&E's surveys found 16,190 Grade 1 leaks. That is an average of 1,799 Grade 1 leaks per year. The number of Grade 1 leaks discovered by survey in 2011 is close to the nine year average. The 2011 results reflect a normal baseline level of annual survey results.

The low numbers of Grade 1 leaks discovered by survey in 2003 to 2007 were the result of critical deficiencies in PG&E's leak survey program. The surveys in 2003 to 2007 failed to detect large numbers of leaks that existed when the surveys were done. The higher than normal levels from 2008 to 2010 reflect the temporary leak detection "bubble" that occurred when leaks that were missed in prior surveys were found using the enhanced leak survey process.[10]

The 2003 to 2007 surveys found an average of 397 Grade 1 leaks per year. The 2011 surveys found 1,735 Grade 1 leaks. That implies the deficient surveys missed an average of approximately 1,300 Grade

[9] The number of Grade 1 leaks reported in the response to OC-903 is 1 percent higher than the number reported in the responses to OC-905 and OC-906 over the nine year study period. Overland has not investigated the reason for that difference.

[10] Response to Discovery, OC-669, Attachment 1.

1 leaks per year in 2003 to 2007. PG&E's leak survey metrics demonstrate that its leak survey practices were critically deficient prior to 2008.

Percentage of Grade 1 Leaks Discovered by Customer

The percentage of leaks discovered through customer odor complaints provides an indication of the quality of the leak surveys.[11] The following table shows the percentage of Grade 1 leaks discovered by customers during the audit period.

Table 7-9 - Percentage of Grade 1 Leaks Discovered by Customers, Excluding Dig In Leaks

Percentage of Grade 1 Leaks Discovered by Customers Excluding Dig - In Leaks 2003 to 2011			
Year	Total	Odor Call	Percentage
2003	2,632	1,743	66
2004	2,798	1,850	66
2005	2,697	1,761	65
2006	2,464	1,540	63
2007	2,439	1,363	56
2008	5,665	1,834	32
2009	10,329	1,989	19
2010	5,771	1,817	31
2011	4,724	1,671	35
Source: Response to Discovery, OC-905 and OC-906. Total excludes Dig-In leaks.			

During 2003 to 2007, 63% of Grade 1 leaks were discovered through the investigation of customer odor complaints. That metric demonstrates the poor quality of PG&E's leak surveys during those years.

PG&E significantly improved its leak survey process in 2008. During the period from 2008 to 2011, only 28% of Grade 1 leaks were discovered through customer odor complaints.

Priority Grade 2 Leaks by Method of Discovery

Priority Grade 2 leaks are referred to as Grade 2+ leaks. The following table shows gas distribution Grade 2+ leak repairs by method of discovery.

[11] Leaks discovered through investigations of dig-ins are excluded from the analysis because the discovery of dig-in leaks is not a function of leak survey quality.

Table 7-10 - Priority Grade 2 Leaks By Method of Discovery

Priority Grade 2 Leaks By Method of Discovery Grade 2+ Distribution Leaks 2003 to 2011					
Year	Survey	Odor Call	Dig-In	Other	Total
2003	437	551	12	193	1,193
2004	487	518	8	184	1,197
2005	318	564	4	275	1,161
2006	344	631	0	243	1,218
2007	581	529	0	219	1,329
2008	7,056	624	1	328	8,009
2009	23,294	718	0	491	24,503
2010	7,648	602	1	407	8,658
2011	3,406	663	0	449	4,518
Total	43,571	5,400	26	2,789	51,786
Source: Response to Discovery, OC-909 and OC-910.					

The percentage of Priority Grade 2 leaks discovered by customers is shown below.

Table 7-11 - Percentage of Priority Grade 2 Leaks Discovered by Customers

Percentage of Priority Grade 2 Leaks Discovered by Customers Grade 2+ Leaks Excluding Dig-In Leaks 2003 to 2011			
Year	Total	Odor Call	Percentage
2003	1,181	551	47
2004	1,189	518	44
2005	1,157	564	49
2006	1,218	631	52
2007	1,329	529	40
2008	8,008	624	8
2009	24,503	718	3
2010	8,657	602	7
2011	4,518	663	15
Source: Response to Discovery, OC-909 and OC-910. Total excludes Dig-In leaks.			

The total number of Priority Grade 2 leaks discovered by customers remained relatively constant during the study period. The number discovered in PG&E's leak surveys increased dramatically after 2007.

Grade 1 Leaks By Cause

When repairs are made, PG&E assigns each leak to a leak cause category. The following shows Grade 1 distribution leak repairs by year and cause.

Table 7-12 - Grade 1 Leaks Repairs by Leak Cause

Grade 1 Leaks Repairs by Leak Cause Gas Distribution 2003 to 2011							
Year	Atmospheric Corrosion	Construction Defect	Excavation Dig-In	External Corrosion	Material Failure	Other	Total
2003	471	572	3,252	540	192	857	5,884
2004	610	606	3,318	426	222	934	6,116
2005	627	582	3,089	405	195	888	5,786
2006	530	621	3,035	331	193	789	5,499
2007	527	705	2,791	308	188	711	5,230
2008	800	1,597	2,197	530	415	2,323	7,862
2009	1,309	3,383	1,720	1,216	909	3,512	12,049
2010	734	1,586	1,613	827	510	2,114	7,384
2011	608	1,219	1,596	718	433	1,746	6,320
Total	6,216	10,871	22,611	5,301	3,257	13,874	62,130
Source: Response to Discovery, OC-907 and OC-908. Other includes unknown and other smaller categories.							

Dig-ins were the largest cause of Grade 1 leaks in every year except 2009, when construction defect was the largest cause. Grade 1 dig-in leaks declined steadily throughout the study period. Part of that decline is attributable to reductions in the number of third party excavations caused by economic conditions.

The construction defect category was much higher from 2008 through 2011 than it was from 2003 to 2007. The "other" category also increased significantly during those years.

Open Leaks and Leak Rechecks

Open leaks are leaks that have been discovered but have not yet been repaired. The following table shows the number of open leaks on PG&E's gas distribution system by Grade as of December 31 of each year from 2002 to 2010.

Table 7-13 - Open Leaks By Grade as of Year-End

Open Leaks By Grade as of Year-End 2002 to 2010				
Year	Grade 2+	Grade 2	Grade 3	Total
2002	114	1,747	16,256	18,117
2003	123	1,920	15,935	17,978
2004	121	1,516	16,268	17,905
2005	113	1,276	15,427	16,816
2006	126	1,137	15,133	16,396
2007	249	1,857	14,156	16,262
2008	2,144	2,848	15,261	20,253
2009	3,466	21,972	15,358	40,796
2010	913	11,141	37,720	49,774
Source: Response to Discovery, OC-1096.				

The ALS began in October 2008. The level of Grade 2 open leaks was very high as of December 2009. The increase in open Grade 2 leaks in 2009 was apparently a result of the ALS. The ALS did not find many Grade 3 leaks. The average open number of Grade 3 leaks as of December 31, 2009 was below the average for 2002 through 2008.

PG&E only repaired 2,629 Grade 2 leaks in 2010.[12] The decrease in the number of open Grade 2 leaks and the increase in the number of Grade 3 open leaks in 2010 was largely the result of leak grade changes. PG&E downgraded 13,079 Grade 2 leaks to Grade 3 in 2010 as a result of leak rechecks. PG&E only upgraded 939 Grade 3 leaks to Grade 2 in 2010. The net result was a transfer of 12,140 leaks from Grade 2 to Grade 3.[13]

PG&E's standards require it to recheck open Grade 2+, 2 and 3 leaks periodically. The following table shows the number of rechecks conducted each year.

Table 7-14 - Distribution Leak Re-Checks by Original Leak Grade

Distribution Leak Re-Checks by Original Leak Grade 2003 to 2010				
Year	Grade 2+	Grade 2	Grade 3	Total
2003	578	3,390	5,538	9,506
2004	550	3,410	5,171	9,131
2005	587	2,843	6,035	9,465
2006	663	2,491	4,690	7,844
2007	679	2,403	5,844	8,926
2008	3,332	4,435	6,731	14,498
2009	6,730	9,077	9,261	25,068
2010	3,255	34,157	6,663	44,075
Total	16,374	62,206	49,933	128,513
Source: Response to Discovery, OC-884. Excludes 8,205 rechecks where initial grade was unknown.				

The high number of Grade 2 leak rechecks in 2010 is consistent with the high number of leaks initially classified as Grade 2 in 2009 as part of the ALS.

The number of rechecks in a year divided by the average number of leaks open during the year provides a crude indicator of leak recheck frequency. Overland estimated the average number of open leaks for each year using the current year-end and prior year-end balances. The following table shows the number of leaks divided by the average number of open leaks by grade.

[12] Response to Discovery, OC-903.
[13] Response to Discovery, OC-884.

Table 7-15 - Number of Rechecks per Average Open Leak

Number of Rechecks per Average Open Leak 2003 to 2010			
Year	Grade 2+	Grade 2	Grade 3
2003	4.88	1.85	0.34
2004	4.51	1.98	0.32
2005	5.02	2.04	0.38
2006	5.55	2.06	0.31
2007	3.62	1.61	0.40
2008	2.78	1.89	0.46
2009	2.40	0.73	0.60
2010	1.49	2.06	0.25
Source: Response to Discovery, OC-1096 and OC-884.			

Most gas distribution facilities are leak surveyed at least once every five years. The low rates of Grade 3 rechecks is consistent with PG&E's policy of rechecking Grade 3 leaks during the next regular survey.[14]

PG&E's standards require Grade 2+ leaks to be repaired within 90 days. PG&E's standards do not specify a leak recheck interval for Grade 2+ Leaks. Overland did not investigate the reason for the decline in the Grade 2+ recheck rate from 2007 through 2010.

PG&E's standards require Grade 2 leaks to be rechecked every six months and to be repaired within 18 months. The low Grade 2 leak recheck rate in 2009 may reflect the timing of leak discovery in the ALS.[15]

Leak Upgrades

The rechecks frequently result in changes to the leak grade. The following table shows the number of leaks that were upgraded to Grade 1 from lower original grades.

[14] For facilities that are surveyed once every five years, the expected number of rechecks per open Grade 3 leak is 0.20.

[15] Overland's crude method of calculating the average number of open leaks may not accurately reflect the timing of leak discovery. Overland did not investigate the reason for the lower Grade 2 leak recheck rate in 2009.

Table 7-16 - Leaks Upgraded to Grade 1 via Re-Checks by Original Leak Grade

Leaks Upgraded to Grade 1 via Re-Checks by Original Leak Grade 2003 to 2010				
Year	Grade 2+	Grade 2	Grade 3	Total
2003	70	148	31	249
2004	70	96	27	193
2005	105	73	36	214
2006	114	83	36	233
2007	102	74	42	218
2008	629	279	136	1,044
2009	502	297	350	1,149
2010	243	230	145	618
Total	1,835	1,280	803	3,918
Source: Response to Discovery, OC-884.				

During the eight-year study period, 3,918 leaks were upgraded from a lower original grade to Grade 1 as a result of leak re-checks. Some upgrades are the result of errors made in the original leak grading process. Others are the result of changes in physical conditions. The percentage of leaks upgraded provides an indication of the original leak grading quality.

The following table shows percentage of rechecks resulting in an upgrade to Grade 1 by the original grade of the leak.

Table 7-17 - Percentage of Re-Checks Resulting in Upgrade to Grade 1 Leak

Percentage of Re-Checks Resulting in Upgrade to Grade 1 Leak Shown by Original Grade 2003 to 2010				
Year	Grade 2+	Grade 2	Grade 3	Total
2003	12.1	4.4	0.6	2.6
2004	12.7	2.8	0.5	2.1
2005	17.9	2.6	0.6	2.3
2006	17.2	3.3	0.8	3.0
2007	15.0	3.1	0.7	2.4
2008	18.9	6.3	2.0	7.2
2009	7.5	3.3	3.8	4.6
2010	7.5	0.7	2.2	1.4
Source: Response to Discovery, OC-884. Total excludes 8,205 rechecks where initial grade was unknown				

During 2003 to 2008, 17% of Grade 2+ leak rechecks resulted in the leak grade being changed to Grade 1. That implies quality problems in the original leak grading process during those years.

Leaks Repaired Late

PG&E's standards require the repair of Grade 1, 2+ and 2 leaks within a specified time period. The number of leaks repaired late is a key compliance metric.

Overland requested PG&E's leaks repaired late metrics for nine years on December 28, 2012. PG&E provided the metrics 139 days later, on May 17, 2013. The following table shows the late leak repairs reported in PG&E's response.

Table 7-18 - Late Leak Repairs by Grade

Late Leak Repairs by Grade 2003 to 2011				
Year	Grade 1	Grade 2+	Grade 2	Total
2003	2	2	0	4
2004	0	5	0	5
2005	1	2	2	5
2006	3	5	6	14
2007	1	11	4	16
2008	6	62	4	72
2009	2	93	5	100
2010	2	50	6	58
2011	0	9	9	18
Total	17	239	36	292
Source: OC-960				

The following table shows the late leak repairs as a percentage of total leak repairs during the period.

Table 7-19 - Percentage of Leaks Repaired Late by Grade

Percentage of Leaks Repaired Late By Grade 2003 to 2011				
Description	Grade 1	Grade 2+	Grade 2	Total
Leaks Repaired Late	17	239	36	292
Total Leaks Repaired	63,089	52,672	33,209	148,970
Percent Repaired Late	0.027	0.454	0.108	0.196
Source: OC-960 and Table 7-6				

According to PG&E, it repaired 99.8 percent of all leaks within the time required by PG&E's standards during the nine-year study period.[16]

The late leak repair indications produced by PG&E's leak database, IGIS, are not reliable because they do not account for leak grade changes. As a result, labor intensive manual processes were required to respond to Overland's request for late leak repair metrics.[17]

IGIS records the date the leak was initially discovered, the date the leak was repaired, and the final leak grade. Grade changes must be accounted for when determining if a leak was repaired late. IGIS does not

[16] Overland received the response to OC-960 on May 17, 2003, two weeks before this report was filed in PG&E's 2014 GRC. Overland did not audit the data reported by PG&E in the response to OC-960.

[17] Response to Discovery, OC-960.

track the information needed to make that determination. PG&E addressed that issue by identifying all leak indications in IGIS that were potentially repaired late and conducting a labor intensive manual review of the grade changes occurring over the life of each of the leak indications. That required reviewing the A-Forms for all of the grade changes.[18]

The amount of work required to produce late leak repair metrics for this audit demonstrates that PG&E's reporting and monitoring of late leak repair metrics was seriously deficient during the audit period.

Valve and Regulator Station Maintenance

Maintenance activities are classified into two types - corrective and preventative. Regularly scheduled maintenance activities designed to keep equipment in good operating condition are referred to as preventative maintenance. Corrective maintenance consists of repairs of equipment that has failed or is in poor operating condition.

Leak repairs are an example of corrective maintenance. Annual regulator station inspections are an example of preventative maintenance.

Corrective Maintenance

PG&E tracks the number of corrective repairs made to regulator stations and valves. The following table shows those repairs by year.

Table 7-20 - Corrective Maintenance, Regulator Station and Valve Repairs

Corrective Maintenance Regulator Stations and Valve Repairs 2000 to 2011			
Year	Main Valve Repairs	Regulator Station Repairs	Service Valves Replace/Repair
2000	196	905	3,119
2001	460	811	4,476
2002	444	1,067	4,316
2003	345	890	4,934
2004	328	905	5,900
2005	373	989	5,958
2006	464	1,106	5,868
2007	399	1,094	5,855
2008	383	742	9,143
2009	509	542	14,298
2010	351	1,296	8,635
2011	271	1,372	8,881
Source: Response to Discovery, OC-684, OC-685 and OC-687.			

[18] Response to Discovery, OC-960.

Main valve repairs were higher than normal in 2009 because of repairs required by the regulator and valve audit conducted by Exponent.[19] That audit is described in Chapter 11.

Regulator station repairs were lower than normal in 2008 and 2009 because maintenance resources were diverted to repairing leaks discovered in the Accelerated Leak Survey and other work.[20]

Service valves are frequently replaced when they are found to be leaking. Service valve replacements and repairs increased in 2008 to 2011 because PG&E discovered more service valve leaks during those years. More leaks were found because PG&E improved its leak survey process and implemented the ALS.[21]

Preventative Maintenance

PG&E is required to inspect all emergency valves annually. Emergency valves are valves that are required to shut off gas flow to an emergency shutdown zone. The estimated average time required for an inspection is 50 minutes per valve.[22]

The following table shows the number of emergency valves inspected by year.

Table 7-21 - Preventative Maintenance, Emergency Valves Inspected

Preventative Maintenance Emergency Valves Inspected 2000 to 2011	
Year	Main Valves Inspected
2000	9,913
2001	7,743
2002	7,266
2003	7,019
2004	7,040
2005	6,510
2006	6,749
2007	7,158
2008	7,321
2009	6,830
2010	7,424
2011	6,017
Source: Response to Discovery, OC-682.	

[19] Response to Discovery, OC-685.
[20] Response to Discovery, OC-684.
[21] Response to Discovery, OC-701.
[22] Response to Discovery, OC-663, Attachment 1, Appendix A-5.

PG&E evaluates the boundaries of its emergency shutdown zones every year. As a result the number of valves that must be inspected fluctuates from year-to-year.[23]

PG&E is required to conduct two different types of regulator station inspections. Each station must undergo an "A" inspection annually. The A inspections do not include disassembly of the regulator for the inspection of internal parts. The stations must also undergo less frequent "B" inspections. The "B" inspections include disassembly and the inspection of internal parts. Most stations undergo a "B" inspection every eight years.[24]

The following table shows the number of regulator station inspections by year and type.

Table 7-22 - Preventative Maintenance, Regulator Station Inspections by Type

Preventative Maintenance Regulator Station Inspections by Type Number of Runs Inspected 2003 to 2011		
Year	Type A	Type B
2003	3,091	530
2004	3,345	553
2005	3,243	396
2006	3,260	455
2007	3,550	447
2008	3,101	617
2009	3,068	568
2010	NA	NA
2011	NA	NA
Source: Response to Discovery, OC-681; NA is not available.		

The estimated average required time for a Type A inspection is 6 hours. The estimated time required for a Type B inspection is 16 hours.[25]

Prior to 2010, valve and regulator station inspections were tracked by each local office using off-line spreadsheets. PG&E implemented a centralized Work Management System for regulator station and valve preventative maintenance in 2010. The new system does not track regulator station inspections by type. PG&E is currently working on developing the capability to track regulator station inspections by type.[26]

[23] Response to Discovery, OC-682.
[24] Response to Discovery, OC-663, Attachment 1, Appendix A-2.
[25] Response to Discovery, OC-663, Attachment 1, Appendix A-5.
[26] Response to Discovery, OC-681.

PG&E's standards include required inspection intervals for regulator stations and emergency valves. Late regulator station and valve inspections are a key compliance metric. PG&E did not have a late inspections metric prior to the implementation of the Interim Quality Initiative (IQI) in March 2008.[27] Under the IQI, the late inspections metrics were gathered through unreliable manual "self-reporting" processes at the local level.[28]

Corrective and Preventative Maintenance Backlogs

Automated work management systems track jobs (or work tickets) from creation to disposition. The number of open jobs at a given point of time is referred to as the backlog. An increasing backlog is indicative of staffing shortages.

The backlog can be expressed as a number of days. The number of days in the backlog is calculated by dividing the backlog by the average number of tickets created in a day. Overland requested the number of corrective and preventative maintenance jobs created and completed during each year of the audit period and the number of open jobs at the end of each year. The information was needed to analyze trends in PG&E's preventative and corrective maintenance backlogs.

PG&E did not provide the requested information. PG&E could not provide the preventative maintenance information because it did not have an automated work management system prior to 2010. PG&E's gas distribution divisions tracked preventative maintenance work completion on manual spreadsheets prior to 2010.[29]

PG&E completed the implementation of a work management system for corrective maintenance in 2008. The following table shows PG&E's corrective maintenance backlogs for 2009, 2010 and 2011.

Table 7-23 - Corrective Maintenance Backlogs

Corrective Maintenance Backlogs As of December 31, 2009, 2010 and 2011 Number of Days in Backlog			
Type	2009	2010	2011
Cathodic Protection	56	44	35
Valves on Mains	65	89	76
Regulator Stations	142	91	64
Source: Response to Discovery, OC-686, OC-685, OC-684, OC-683.			

[27] Response to Discovery, OC-446 and OC-641, Attachment 2.

[28] Response to Discovery, OC-632, Attachment 2, page 16. The deficiencies in the IQI are discussed in Chapter 13 in the Gas Compliance Assurance Process section.

[29] Response to Discovery, OC-687.

The relatively high corrective maintenance backlogs in 2009, 2010 and 2011 are an indication that the large numbers of leak repairs made in those years limited the resources available for other corrective maintenance work.

Mark and Locate

Prior to 2007, PG&E's used a paper process with multiple hand-offs to manage Mark & Locate (M&L) requests. The only M&L metrics PG&E tracked from 2003 to 2006 were the total number of Universal Service Alert (USA) tickets received and the number of leak repairs resulting from dig-ins. Those metrics were tracked by each local office on off-line spreadsheets.[30] PG&E implemented an electronic mark and locate ticket management system in 2007. PG&E began tracking at fault dig-ins and late locates in 2007.[31]

The ratio of dig-ins to USA tickets provides insight into the effectiveness of a utility's damage prevention program. A high dig-in rate implies the utility's excavator outreach program is ineffective or its locators are not properly marking underground facilities.

The following table shows PG&E's dig-in rates for 2000 to 2011.[32]

Table 7-24 - Dig-Ins Per 10,000 USA Tickets

Mark & Locate Metrics Dig-Ins Per 10,000 USA Tickets 2003 to 2011			
Year	USA Tickets	Dig-Ins	Per 10,000
2000	500,109	3,106	62
2001	508,237	3,346	66
2002	598,227	3,293	55
2003	663,325	3,275	49
2004	711,476	3,324	47
2005	538,274	3,035	56
2006	510,258	3,031	59
2007	523,391	3,338	64
2008	512,682	2,272	44
2009	481,662	1,954	41
2010	470,254	1,988	42
2011	509,949	1,896	37
Source: PG&E 2014 GRC Testimony, PG&E-3, page 5-9.			

Several factors should be considered when reviewing the dig-in rates shown above. First, the USA tickets include both electric and gas M&L requests. The dig-ins only include gas distribution dig-in leak repairs. That creates a mismatch between the scope of the USA tickets and the dig-ins.

[30] Response to Discovery, OC-444.
[31] Response to Discovery, OC-444.
[32] PG&E 2014 GRC testimony, November 15, 2012, Exhibit PG&E-3, Page 5-9.

Second, about one third of the USA tickets do not result in a locate by PG&E.[33] Third, the number of USA tickets decreased in 2005 because of a change in USA ticket rules.[34]

The dig-in rates averaged 57 per 10,000 USA tickets from 2000 through 2007 and 41 per 10,000 USA tickets in 2008 to 2010. The dig-in rate was 40 percent higher from 2000 through 2007 than from 2008 to 2010. That reflects significant deficiencies in PG&E's damage prevention program prior to 2008.[35]

The number of USA tickets was significantly reduced in 2005 by a rule change. The dig-in rates for 2000 to 2004 would have been even higher if the new rules had been in effect during those years. Reducing the number of USA tickets from 2000 to 2004 by 10% increases the average rate from 2000 through 2007 to 61 dig-ins per 10,000 USA tickets.

Dig-In Rate Benchmarking

PG&E uses a different metric when it compares its M&L performance to other utilities. For those comparisons, PG&E uses a total damages rate. That rate includes both electric and gas dig-ins and is expressed in terms of excavation damages per 1,000 USA tickets. The total damages rate avoids the mismatch created by comparing gas dig-ins to total electric and gas USA tickets.[36]

The March 2008 Charter for PG&E's Damages Prevention Committee notes that "PG&E's underground facility damage frequency is fourth quartile when compared to other gas utilities."[37]

PG&E compared its total damages rate to six other combination electric and gas utilities in June 2008.

The following table shows the total damages rates for PG&E and the comparison group.

[33] Response to Discovery, OC-406, Attachment 44, page 7. Approximately one third of USA tickets are for excavations that do not involve any PG&E facilities or are for excavations performed by PG&E.

[34] PG&E 2014 GRC Testimony, November 15, 2012, Exhibit PG&E-3, Page 5-9. In 2005, the life of an M&L ticket was extended from 14 days to 28 days. That reduced the overall volume of USA tickets significantly by reducing the number of renewal tickets submitted by excavators. Most of the renewal tickets did not require remarking because the excavator had maintained the original marks. The change reduced the number of tickets without a corresponding reduction in marking costs. The main impact of the change was reducing administrative costs. 2007 GRC D.07-03-070, page 70.

[35] Mark & Locate is part of PG&E's damage prevention program. Excavator education is also part of the damage prevention program.

[36] PG&E cannot divide its total USA tickets into gas and electric amounts because only one locator is dispatched when both electric and gas facilities are involved. OC-1106.

[37] Response to Discovery, OC-595, Attachment 1.

Table 7-25 - Underground Damages Per 1,000 Excavation Requests

Underground Damages Per 1,000 Excavation Requests PG&E Benchmark Comparison to Other Utilities 2004 to 2006			
Description	2004	2005	2006
Six Utility Average (Excludes PG&E)	2.49	2.58	2.37
PG&E	6.13	7.34	7.12
Source: Response to Discovery, OC-595, Attachment 4, page 19.			

The benchmarking results are a reflection of significant deficiencies in PG&E's damage prevention program.

Discovery question OC-1104 requested PG&E's total damages rate by year for the audit period. The following table shows the data provided by PG&E.[38]

Table 7-26 - Total Damages Rate per 1,000 USA Tickets

Mark & Locate Total Damages Total Damages Rate per 1,000 USA Tickets 2003 to 2009			
Year	USA Tickets	Damages	Rate
2003	623,822	4,047	6.49
2004	697,168	5,112	7.33
2005	562,451	5,162	9.18
2006	533,783	4,007	7.51
2007	554,702	3,589	6.47
2008	544,764	2,641	4.85
2009	481,662	2,046	4.25
Source: Response to Discovery, OC-1104.			

PG&E's 2008 benchmarking study indicates the industry average total damages rate was 4.1 per 1,000 USA tickets. PG&E's total damages rate averaged 7.39 from 2003 to 2007, indicating significant deficiencies in PG&E's damage prevention program during those years.

[38] Response to Discovery, OC-1104. PG&E used data from its RiskMaster database to provide consistent data across the years. The RiskMaster data is reasonably consistent with the data reported in the benchmarking study and PG&E's 2014 GRC testimony, but varies somewhat because of timing issues. The RiskMaster USA ticket data for 2010 and 2011 excluded tickets that were automatically closed because they did not require any action by PG&E. The table shown below excludes 2010 and 2011 for that reason. Using the RiskMaster total damages data and the USA ticket data from PG&E's 2014 GRC testimony produces a 2010 total damages rate of 4.45 and a 2011 total damages rate of 3.68.

PG&E's average rate from 2003 through 2007 was 80% higher than the industry average. If PG&E's total damages rate had equaled the industry average, it would have experienced 9,732 fewer total damages during that five year period.

The total damages rate improved dramatically in 2008 and 2009, but remained slightly above the industry average.

Late Locates

PG&E is required to complete locates within 48 hours of receiving the USA ticket. The late locate metric reflects the percentage of tickets that were not completed within 48 hours. If the excavator agrees to an extension of the 48 hour requirement, the locate is not counted as late if it is completed by the agreed upon extended date.

PG&E initiated a late locates metric in May 2007.[39] The following table shows that metric by year for 2007 to 2011.

Table 7-27 - Percentage of Locates Competed Late

Percentage of Locates Completed Late 2007 to 2011	
Year	Percent
2007	7.1
2008	4.4
2009	0.7
2010	1.0
2011	1.3
Source: Response to Discovery, OC- 444, Attachments 1,6,7,8 and 9.	

PG&E's late locates metrics for 2007 to 2011 are not accurate for two reasons. First, some locators manipulated the statistics by claiming an excavator had agreed to an extension when, in reality, no negotiations had taken place.[40]

Second, a programing error in PG&E's M&L ticket management system "halted the time clock feature as soon as the ticket was opened, which resulted in a ticket being shown as complete prior to when the work had actually been completed."[41] The time clock was halted just by opening the record without performing any work or reaching an agreement with the excavator to extend the deadline. Once the time clock was halted, it did not restart and the locate was not counted as late if the work was completed more than 48 hours after the ticket was received.

[39] Response to Discovery, OC-595, Attachment 3, page 5.
[40] Chapter 12 and OC-490, Attachment 5, NCR20 report.
[41] Response to Discovery, OC-632.

The programming error was not corrected during the study period. PG&E conducted an internal audit of its gas damage prevention program in early 2012. The audit report describes the programming error and indicates "interviews with employees in the damage prevention program confirmed that this deficiency has not yet been corrected."[42]

Cathodic Protection

The following table shows selected cathodic protection work completion units by year for 2000 to 2011.

Table 7-28 - Cathodic Protection Work Completion Units

Cathodic Protection Work Completion Units 2000 to 2011			
Year	Pipe to Soil Reads	CP Areas Re-surveyed	CP Areas Diagnosed
2000	77,813	543	3,149
2001	74,761	570	2,880
2002	66,717	566	2,980
2003	64,442	535	3,178
2004	58,771	662	3,342
2005	56,398	759	3,292
2006	56,131	494	3,094
2007	55,580	539	3,042
2008	53,766	398	2,843
2009	56,785	452	2,791
2010	58,543	572	3,481
2011	62,528	527	3,494
Source: Response to Discovery, OC-700. CP Areas Diagnosed are also referred to as Trouble Shooting.			

When viewed in combination, the units indicate a moderate decrease in cathodic protection work from 2007 to 2009.

PG&E currently has 3,201 cathodic protection areas.[43] The following table shows the number of cathodic protection areas that were down and required restoration as of the end of each year from 2003 to 2010.

[42] Response to Discovery, OC-432, Attachment LL, February 10, 2012 report titled Audit of Gas Damage Prevention Program, page 2.

[43] Response to Discovery, OC-892.

Table 7-29 - Cathodic Protection Areas Down

Cathodic Protection Areas Down As of December 31st 2003 to 2011	
Year	Areas
2003	160
2004	213
2005	191
2006	176
2007	191
2008	219
2009	200
2010	270
2011	399
Source: Response to Discovery, OC-892.	

The 399 areas down as of December 2011 represented 12% of the total number of areas. The increase in 2010 and 2011 may reflect a deterioration in system condition or the omission of downed areas from the counts reported for prior years.

Material Problem Reports

Material Problem Reports (MPRs) are used to track leaks and other equipment problems caused by defective materials or products. The following table shows the number of gas distribution MPRs by year.

Table 7-30 - Gas Distribution, Material Problem Reports

Gas Distribution Material Problem Reports 1995 to 2011	
Year	Number
1995	99
1996	109
1997	91
1998	79
1999	119
2000	111
2001	258
2002	328
2003	309
2004	352
2005	311
2006	298
2007	262
2008	533
2009	853
2010	900
2011	720
Source: Response to Discovery, OC- 1107.	

Prior to 1994, PG&E used a manual paper based process to generate and submit MPRs. In 1994, the MPR reporting process was moved to an electronic platform. However, the process was not widely understood or used. As a result, very few MPRs were submitted in 1995 through 1999.[44]

PG&E incorporated MPR reporting into the A-Form process in 2000. In 2001, PG&E added the MPR reporting process to its Intranet. Those changes increased MPR reporting. The ALS and associated process improvements increased MPR reporting from 2008 to 2011.[45]

The low numbers of MPRs filed from 1995 to 2000 demonstrate that PG&E was not proactively collecting information about gas distribution material problems during that period. The ALS was completed in April 2010, with leak repairs continuing into 2011. The number of MPRs submitted in 2011 may be somewhat elevated by MPRs submitted during the leak repair process. The number of MPRs averaged 303 per year from 2001 to 2007. The number submitted in 2011 exceeded that average by 417. That implies MPR reporting was inadequate from 2001 to 2007.

[44] Response to Discovery, OC-578. The process required each user to install a new program on their computers.
[45] Response to Discovery, OC-578.

Mapping Backlog

The mapping backlog reflects the job packages sent to mapping that have not yet been posted to PG&E's maps. Prior to 2007, the backlog was only tracked in terms of hours of planned work. PG&E began tracking both the number of jobs and the number of planned hours included in the backlog in 2007.[46]

PG&E completed an internal audit of the controls over its mapping metrics in October 2009. That audit identified significant problems with the metrics.[47] The audit concluded that the hours of planned work backlog metric was susceptible to manipulation because mapping employees could revise the planned hours at any time, even after the work was completed. Mapping supervisors were not monitoring the changes employees made to the planned hours but suspected they were inappropriately changing the planned hours to improve the actual to planned hours ratio which was the department's primary productivity metric. [48]

Mapping employees were manipulating the cycle time and backlog metrics by entering incorrect dates into the system for when the job was received. For some jobs, the receipt dates in the system were weeks after the jobs were physically received by mapping.[49]

The October 2009 internal audit report concluded:

> *Without adequate controls to prevent and monitor potentially inappropriate changes to planned hours and track untimely movement of jobs into Mapping, management cannot rely on the integrity of data and may have false assurance that Mapping's performance is timely.*

The following table shows the number of gas distribution jobs submitted to the mapping department by year and the backlog of unmapped jobs at year end for 2007 to 2010.

[46] Response to Discovery, OC-629.
[47] Response to Discovery, OC-432, Attachment Y. The audit report is described in Chapter 12.
[48] Response to Discovery, OC-432, Attachment Y.
[49] Response to Discovery, OC-432, Attachment Y.

Table 7-31 - Gas Distribution Mapping Backlog

Gas Distribution Mapping Backlog 2007 to 2010			
Year	Jobs Submitted	Backlog at Year End	Days in Backlog
2007	9,857	2,235	83
2008	4,481	1,645	134
2009	7,525	975	47
2010	5,504	1,214	81
Source: Response to Discovery, OC-629.			

The high backlogs are an indication of staffing shortages in the mapping department from 2007 through 2010.

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8. BUDGET PROCESS

Introduction

This Chapter reviews PG&E's budget process and provides recommendations to improve budget documentation. This Chapter also reviews the budget prioritization of gas distribution costs during the audit period.

Gas and electric distribution funding needs were prioritized in a joint process during the audit period. Gas distribution work competed with electric distribution work for funding in the prioritization process.

The available documentation for the 2008 to 2010 budget years demonstrates that PG&E gave a relatively low priority to gas safety spending in those years. The priority given to gas safety in the 2003 to 2007 budget processes is completely undocumented.

PG&E's budget documentation was inadequate throughout the audit period. The budget process started with initial budget targets set by senior management. The basis for the initial budget targets was poorly documented. The next major step in the process was the submission of initial budget requests by the various organizations included in the budget. PG&E did not retain the gas distribution initial budget requests for the 2003 through 2008 budget years. PG&E cannot show how the budget requests in those years were prioritized. The gas distribution budget requests for 2009 and 2010 were poorly documented.

The initial budget requests were reviewed and adjusted by a central budget committee and senior management. Those processes were completely undocumented. PG&E did not retain the initial approved budgets for most of the years in the study period. PG&E cannot provide the initial approved gas distribution expense budgets by MWC for 2003, 2004, 2005, 2007 or 2008.

The Chapter concludes with six recommendations for improving PG&E's budget documentation.

Budget Process

Budget Process Overview

PG&E's annual budget process included the following basic steps during the audit period:

Table 8-1 - Budget Process Time Line

Budget Process Time Line	
Time Frame	Description
June	Executive management sets initial budget targets for each Line of Business (LOB)
July to September	Each LOB submits its own budget request to the central budget committee
Late November	The central budget committee and executive management approve the budget and issue the annual Budget Letter
December	Each LOB allocates its approved expense and capital budget to Programs, MWCs and projects.
January 1	Detailed budget entered into SAP as of January 1
Source: Response to Discovery, OC-40, OC-208 and OC-407. Time frames varied from year to year.	

Gas distribution was included in the electric and gas distribution LOB budget during the audit period. The distribution LOB budget was managed by PG&E's Transmission and Distribution (T&D) organization. The T&D organization also managed the electric and gas transmission LOB budgets.

The name of the central budget committee changed for the 2009 budget year. Prior to that year, the committee was the budget working group. Beginning with the 2009 budget year the Operating Plan Committee was the central budget committee.[1]

Initial Budget Targets

Executive management set initial targets for each line of business in the June time frame. The initial targets consisted of two numbers for each line of business, an expense target and a capital expenditures target. The budget targets for the distribution LOB were not divided into electric and gas components.[2]

2003 to 2008 Initial Budget Targets

PG&E did not set initial budget targets for the 2003 or 2004 budget years. The targets set for the 2005 through 2008 budget years were based on the expense and capital amounts adopted in PG&E's General Rate Cases and other regulatory proceedings.[3]

2009 and 2010 Initial Budget Targets

The initial budget targets for the 2009 and 2010 budget years were set equal to the spending targets for those years contained in the then current approved T&D three-year operating plan.

[1] Response to Discovery, OC-40 and OC-440.
[2] Response to Discovery, OC-208.
[3] Response to Discovery, OC-208.

PG&E began preparing three-year operating plans in 2008. The first T&D plan was approved in February 2008 and covered the years 2008 to 2010.[4] The T&D plan included expense and capital targets for 2009. The 2009 targets were initially set using the amounts adopted in PG&E's General Rate Case and other regulatory proceedings.[5]

The 2009 spending targets in the operating plan were presented only at a summary level, with one amount for distribution expense and one amount for distribution capital expenditures for each year.[6] The initial 2009 budget targets were taken directly from the February 2008 operating plan.[7]

The second T&D three-year operating plan was approved in March 2009. The March 2009 plan included expense and capital expenditures targets by MWC for 2009, 2010 and 2011.[8] The March 2009 plan did not explain the basis for the 2010 targets. The initial 2010 budget targets were taken directly from the March 2009 plan.

PG&E's June 1, 2009 Quarterly Business Review Kick-off presentation included a one-page slide entitled "Business Unit Constraint Setting." The slide showed a five-line total company 2010 income statement with two lines for expenses, Business Unit Expense and Corporate Items Expense. The slide included the following description of how the Business Unit Expense amount was calculated:[9]

- Earnings per Share target set by Senior Management;
- Revenues and Corporate items budgets are compiled; and
- Remaining difference drives the Business Unit Spending Constraint.

The 2010 initial budget targets equaled the Business Unit Expense shown on the Slide.[10] The 2010 budget targets were apparently based on an earnings per share target set by senior management.

Initial Budget Targets - Summary

The initial budget targets set by management significantly influenced the distribution budget requests submitted by the T&D organization throughout the audit period. According to PG&E, the initial budget targets for 2005 to 2009 were based on the funding levels adopted in PG&E's general rate cases.

In 2010, the initial targets were driven by an earnings per share target set by senior management. The consideration of financial objectives in the setting of initial targets for 2003 through 2009 is undocumented.

[4] Response to Discovery, OC-64. The T&D Plan consisted of a 49-page presentation.
[5] Response to Discovery, OC-67, Attachment 2, page 11.
[6] Response to Discovery, OC-67, Attachment 2.
[7] Response to Discovery, OC-208 and OC-67, Attachment 2, page 15 and 16.
[8] Response to Discovery, OC-67, Attachment 4.
[9] Response to Discovery, OC-207, Attachment 8, page 26.
[10] Response to Discovery, OC-207, Attachment 8, page 52 shows the initial budget targets by LOB. The total agrees to the Business Unit Expense amount shown on Attachment 8, page 26.

Initial Budget Requests

T&D prepared its budget request after receiving the initial budget targets. T&D allocated the initial targets for distribution to programs. Each individual program manager prepared a work plan and budget request for their programs. The work plans typically consisted of a separate spreadsheet for each program. Once the spreadsheets were developed, the work was prioritized. Gas and electric distribution were prioritized together because they were both governed by PG&E's General Rate Case process and because they were combined for purposes of the company-wide budget process.[11] As a result, gas distribution work competed directly with electric distribution work for funding.

The internal T&D Finance Team reviewed the program work plans, approved the distribution LOB budget requests, and submitted the budget requests to the Finance Department.

The initial budget requests for 2009 and 2010 were submitted on tables referred to as prioritization templates. PG&E provided the 2009 and 2010 prioritization templates.[12] The gas distribution program reviews and prioritization templates are the only available record of the budget plans reviewed by the T&D Finance Team.[13]

PG&E did not retain the initial budget request documents submitted by T&D for the 2003 to 2008 budget years.[14] PG&E was not able to find or recreate the initial budget requests for those years at a MWC Level.[15]

The gas distribution program review documents contained summaries of the expense budget requests for 2004 and 2005 that combined multiple MWCs.[16] PG&E was not able to find any record of the gas distribution budget requests for 2003, 2006, 2007 or 2008. During the course of the audit, Overland found depictions of the initial budget requests for 2006 and 2008 by MWC in other documents.[17]

2008 Initial Budget Request

The T&D program managers prepared a comparison of the 2008 target guidance received from management to T&D's forecasted "2008 needs" in late October 2007.[18] The comparison distributes the initial expense and capital targets to MWCs and compares the targets to T&D's budget request.[19]

The comparison includes the following gas distribution expense amounts.

[11] Response to Discovery, OC-439.
[12] Response to Discovery, OC-407 and OC-895.
[13] Response to Discovery, OC-676. The Program Reviews as described in Chapter 9.
[14] Response to Discovery, OC-407 and OC-895.
[15] Response to Discovery, OC-407.
[16] The program reviews are described in Chapter 9.
[17] Response to Discovery, OC-537 and OC-763.
[18] Response to Discovery, OC-542, Attachment 1.
[19] Response to Discovery, OC-763.

Table 8-2 - Comparison of 2008 Initial Expense Budget Target to T&D Request

Comparison of 2008 Initial Expense Budget Target to T&D Request Gas Distribution Programs Dollars in Thousands				
MWC	Description	Target	Request	Difference
DE	Leak Survey	8,049	10,139	(2,090)
DF	Mark & Locate	26,644	30,421	(3,777)
DG	Cathodic Protection	7,789	10,893	(3,104)
EX	Meter Protection Program	0	3,615	(3,615)
FG	Operate Gas System	2,436	2,936	(500)
FH	Preventative Maintenance	17,037	17,423	(386)
FI	Corrective Maintenance	17,049	17,089	(40)
GG	Gas Engineering	2,642	2,642	0
	Total	81,646	95,158	(13,512)
Source: Response to Discovery, OC-542, Attachment 2. MWC GZ - R&D excluded to match the scope of the comparison of the 2008 request to the 2008 approved budget.				

The comparison identifies the following additional required expense funding over the target amounts.

Table 8-3 - Additional Required Expense Funding Over 2008 Target Amounts

Additional Required Expense Funding Over 2008 Target Amounts Gas Distribution Programs Dollars in Thousands		
MWC	Description	Amount
DE	One Additional Special Copper Leak Survey	1,200
DE	Accelerated Leak Survey	6,000
DG	Isolated Steel Services Program	1,296
DG	Remote Pipe to Soil Monitoring Equipment	500
EX	Meter Protection Program	3,615
FH	Non-Recurring Repairs and Uprates	200
FH	Preventative Maintenance Rework	400
FI	Leak Repairs Associated with Accelerated Survey	4,000
GZ	R&D Funding for High Priority Projects	700
	Total	17,911
Source: Response to Discovery, OC-542, Attachment 2.		

The comparison includes the following comments about the additional required funding for the MPP.

> *Meter Protection work is a commitment PG&E had made to the CPUC and at least a minimum amount of work must be done. The 2008 request of $3.6 million represents the funding required to complete the program on schedule. Any reduction below $3.6 million may delay the completion date or require significantly increased funding levels in future years.*

The T&D request included $3.0 million for the Isolated Steel Services Program (ISSP). The comparison indicated that if additional funding above the target was not provided, the ISSP budget would be reduced by $1.3 million below the requested amount to fund higher priority work.[20] Those cuts would require additional funding in future years to complete the ISSP on time.

The comparison shows the following gas distribution capital amounts.

Table 8-4 - Comparison of 2008 Initial Capital Budget Target to T&D Request

Comparison of 2008 Initial Capital Budget Target to T&D Request Gas Distribution Programs Dollars in Thousands				
MWC	Description	Target	Request	Difference
14	Gas Pipeline Replacement Program	91,177	147,588	(56,411)
27	Meter Protection Program	0	771	(771)
47	Capacity	10,359	11,342	(983)
50	Reliability	9,171	16,749	(7,578)
52	Emergency Response (Leak Repairs)	201	202	(1)
78	Buildings	0	1,870	(1,870)
	Total	110,908	178,522	(67,614)
Source: Response to Discovery, OC-542, Attachment 2.				

The GPRP target covered the Copper Services replacement program and pipeline replacements in San Francisco. Pipeline Replacements in all other divisions were not funded.[21]

The MPP capital funding was not needed because the expense funding for the program had been eliminated. Without the expense funding, the capital projects could not be implemented.

The Capacity target was insufficient to fund 8 projects in the Diablo, Sacramento and San Jose divisions that had previously been deferred from 2007 to 2008.

The Building request was for the construction of a new underground facilities training yard named Simulate City. That facility could not be funded at the target levels. The comparison indicated the facility was “badly needed.” The 2007 Internal Audit review of the leak survey program in Marin County had demonstrated “the urgent need to fund this project.”[22]

The $7.6 million shortfall in Reliability spending eliminated funding for several distribution integrity management programs and also “affected completion of main replacement, valve replacement, and some regulator replacement projects related to reliability.”[23]

[20] Response to Discovery, OC-542, Attachment 2.
[21] Response to Discovery, OC-542, Attachment 2.
[22] Response to Discovery, OC-542, Attachment 2.
[23] Response to Discovery, OC-542, Attachment 2.

The comparison identified $4.5 million of additional required funding over the target level for integrity management projects. The additional required funding consisted of:

- $1 million for the Aldyl-A plastic main replacement initiative;
- $2 million for the replacement of K-type regulators with internal components made of copper; and
- $1.5 million for corrective work identified in the recent internal review of regulators and valves in the North Bay Division.

The expense and capital comparisons demonstrate that distribution integrity management programs, including the MPP and ISSP, were assigned a relatively low priority in the 2008 budget process.

2009 Initial Budget Request

The initial budget request for the 2009 is documented on the prioritization template dated July 14, 2008. The template includes electric and gas distribution expense and capital.[24]

The template is organized into the following four priority-based tiers.

Table 8-5 - 2009 Gas Distribution Budget Request, Priority-Based Tiers

2009 Gas Distribution Budget Request Priority-Based Tiers	
Tier	Description
1	Under 95% of Target
2	95% to 100% of Target
3	100% to 105% of Target
4	Above 105% of Target
Source: Response to Discovery, OC-895, Attachment 1.	

The purpose of the tiers was to provide visibility concerning the work that would not be funded if the expense budget was set at a level that did not include the tier.

The template provided sufficient detail to identify the gas distribution expense request by Tier and MWC:

[24] Response to Discovery, OC-895, Attachment 1

Table 8-6 - 2009 Gas Distribution Expense Budget Request by Tier

2009 Gas Distribution Expense Budget Request by Tier Budget Year 2009 Dollars in Thousands						
MWC	Description	Tier 1	Tier 2	Tier 3	Tier 4	Total
DE	Leak Survey	8,777	2,230	9,425	4,208	24,640
DF	Mark and Locate (includes electric)	30,653	400	0	400	31,453
DG	Cathodic Protection	10,392	300	0	2,446	13,138
EX	Meter Protection Program	3,409	0	0	724	4,133
FG	Gas Operations	2,516	0	0	0	2,516
FH	Preventative Maintenance	13,983	2,500	0	8,789	25,272
FI	Corrective Maintenance	22,649	250	7,372	3,406	33,677
GF	Gas Mapping	1,425	75	75	0	1,575
GG	Gas Engineering	3,748	0	0	0	3,748
	Total	97,552	5,755	16,872	19,973	140,152

Source: Response to Discovery, OC-895, Attachment 1. MWC GZ - R&D excluded to match the scope of the comparison of the 2009 request and 2009 approved budget.

Tier 1 work was classified as mandatory on the template. The following table shows the gas distribution expense items included in Tier 2.

Table 8-7 - 2009 Gas Distribution Expense Budget Request, Priority Tier 2 Detail

2009l Gas Distribution Expense Budget Request Priority Tier 2 Detail Budget Year 2009 Dollars in Thousands		
MWC	Description	Tier 2
Leak Survey (DE)	Copper Leak Survey	1,230
Mark & Locate (DF)	Reduce Late Locates	400
Cathodic Protection (DG)	System Maintenance	300
Preventative Maintenance (FH)	Safety Projects	450
Leak Survey (DE)	Quality Control	1,000
Preventative Maintenance (FH)	Gas Issues Resolution	750
Preventative Maintenance (FH)	Regulator Station & Valve Audit	1,000
Corrective Maintenance (FI)	Regulator & Valve Audit Repairs	250
Preventative Maintenance (FH)	Cross Bored Sewers (DIMP)	300
Gas Mapping (GF)	Support	75
Total		5,755

Source: Response to Discovery, OC-895, Attachment 1.

The Tier 3 expense items are shown below.

Table 8-8 - 2009 Gas Distribution Expense Budget Request, Priority Tier 3 Detail

2009 Gas Distribution Expense Budget Request Priority Tier 3 Detail Budget Year 2009 Dollars in Thousands		
MWC	Description	Tier 3
Leak Survey (DE)	Resurvey Divisions	9,425
Corrective Maintenance (FI)	Leak Repairs for Resurvey	7,372
Gas Mapping (GF)	Support	75
Total		16,872
Source: Response to Discovery, OC-895, Attachment 1.		

The template was submitted in July 2008 before PG&E made the decision to proceed with the Accelerated Leak Survey Program. The Tier 3 resurvey work was contingent on the results of an analysis of leak survey quality that was in progress when the template was prepared.[25]

The Tier 4 expense items are shown below.

Table 8-9 - 2009 Gas Distribution Expense Budget Request, Priority Tier 4 Detail

2009 Gas Distribution Expense Budget Request Priority Tier 4 Detail Budget Year 2009 Dollars in Thousands		
MWC	Description	Tier 4
Preventative Maintenance (FH)	Cross Bored Sewers (DIMP)	2,700
Mark & Locate (DF)	Reduce Late Locates	400
Preventative Maintenance (FH)	SAP Asset Registry Updates	150
Leak Survey (DE)	Resurvey Locators Who Failed Assessment	4,208
Corrective Maintenance (FI)	Leak Repairs for Resurvey Failed Assessments	4,745
Preventative Maintenance (FH)	Operator Qualification Procedures	1,200
Preventative Maintenance (FH)	Protect Unlocatable Facilities	500
Preventative Maintenance (FH)	Aldyl-A Replacement Program (DIMP)	1,200
Preventative Maintenance (FH)	Meter Coefficient Correction	1,700
Cathodic Protection (DG)	Remote Pipe-to-soil Monitoring Devices	500
Cathodic Protection (DG)	Isolated Steel Services Program - Accelerate	1,946
Meter Protection Program (EX)	MPP Acceleration	724
Total		19,973
Source: Response to Discovery, OC-895, Attachment 1. MWC GZ excluded to match the scope of the summary table.		

PG&E identified significant deficiencies in its leak survey program in 2007 and 2008. PG&E initiated a company-wide suspension of all leak survey activities on March 24, 2008 to allow all of its surveyors to complete a mandatory three-day training class on leak survey procedures.[26] After the training, PG&E tested the surveyors to re-establish their qualifications to do survey work. Only 69 percent of the surveyors who conducted foot surveys passed the test. The re-qualification rate for surveyors who used

[25] Response to Discovery, OC-895, Attachment 1.
[26] Response to Discovery, OC-480, Attachment 22.

Optical Mobile Devices was only 34 percent.[27] The re-survey costs included in Tier 4 cover the cost of redoing the surveys previously done by the surveyors who failed the skills tests.

The 2009 initial budget request for gas distribution capital is shown below by Tier and MWC.[28]

Table 8-10 - 2009 Gas Distribution Capital Budget Request by Tier

2009 Gas Distribution Capital Budget Request by Tier Budget Year 2009 Dollars in Thousands					
MWC	Description	Tier 1	Tier 2	Tier 3	Total
14	Gas Pipeline Replacement Program	90,600	6,300	23,100	120,000
27	Meter Protection Program	50	0	0	50
29	New Business	64,265	0	0	64,265
47	Capacity	11,500	0	0	11,500
50	Reliability	15,800	0	3,100	18,900
51	Work Requested by Others	20,175	0	0	20,175
52	Emergency Response	200	0	0	200
78	Manage Buildings - Simulate City	1,000	0	0	1,000
	Total	203,590	6,300	26,200	236,090
Source: Response to Discovery, OC-895, Attachment 1.					

Approximately 25% of the request for the GPRP was included in Tiers 2 and 3. The template does not explain the basis for dividing the GPRP between tiers.

The 2009 prioritization templates demonstrate that PG&E assigned a relatively low priority to some gas safety-related costs in 2009.

2010 Initial Budget Request - Expense

The July 17, 2009 expense and capital prioritization templates provide the initial 2010 budget requests for the distribution LOB. The templates include both electric and gas distribution programs. The total shown on the expense template equals 109.5 percent of the target. The template provides sufficient detail to identify the gas distribution expense request by MWC and the related priority codes.[29]

The total amounts included on the expense template for gas distribution are shown below by MWC and priority code.

[27] Response to Discovery, OC-972, Attachment 1, April 29 QBR Presentation.
[28] Gas distribution did not have any Tier 4 costs.
[29] Response to Discovery, OC-407, Attachment 4.

Table 8-11 - 2010 Gas Distribution Expense Budget Request by Priority Code

2010 Gas Distribution Expense Budget Request by Priority Code Dollars in Thousands						
MWC	Description	Mandatory	Priority 1	Priority 2	Priority 3	Total
DE	Leak Survey	18,949	0	756	0	19,705
DF	Mark & Locate	24,602	0	0	6,319	30,921
DG	Cathodic Protection	8,357	880	0	0	9,237
EX	Meter Protection	0	860	0	0	860
FG	System Operations	2,960	0	0	0	2,960
FH	Preventative Maint.	17,030	4,078	0	0	21,108
FI	Corrective Maint.	55,428	1,000	1,628	14,333	72,389
GG	Capacity Planning	2,946	0	0	0	2,946
GF	Gas Mapping	329	1,083	0	189	1,601
	Total	130,601	7,901	2,384	20,841	161,727
Note: MWCs GM, Natural Gas Vehicle Fueling Stations; and GZ, R&D, excluded to match scope of the comparison of the 2009 request and 2009 approved budget.						
Source: Response to Discovery, OC-407, Attachment 4. .						

The amounts assigned to priority code one are shown below.

Table 8-12 - 2010 Gas Distribution Expense Budget Request, Priority Code One Detail

2010 Gas Distribution Expense Budget Request Priority Code One Dollars in Thousands		
MWC	Description	Amount
DG	Isolated Steel Services Program	880
EX	Meter Protection Program	860
FH	Safety Repairs (Largely Vault Repairs)	1,000
FH	Regulator Station and Valve Repairs	1,000
FH	Operator Qualification Project	1,000
FH	Integrity Management Projects	1,338
FH	Regulator Station Diagrams	540
FG	Emerging Gas Issues	200
GF	Gas Mapping Work	1,083
	Total	7,901
Source: Response to Discovery, OC-407, Attachment 4.		

The priority code one integrity management projects were Aldyl-A, Cross-Bored Sewers, and Installation of Marker Balls on Unlocatable facilities.

The priority code two work related entirely to an Accelerated Leak Survey timing issue. When the template was prepared in the fall of 2009, PG&E was exploring the possibility of accelerating the survey of 50,000 services planned for 2010 into 2009. Doing the work in 2009 would reduce the 2010 leak survey and leak repair budget. The mandatory portion of the budget reflected the work that would be done in 2010 if PG&E was able to accelerate the 50,000 services into 2009. The priority code two work reflected the additional costs PG&E would incur in 2010 if it was not able to accelerate the work into 2009.[30]

[30] Response to Discovery, OC-407, Attachment 4.

The mark and locate priority code three work increased the budget request to reflect more pessimistic assumptions concerning productivity and M&L ticket volumes.

The corrective maintenance priority code three work is shown below.

Table 8-13 - 2010 Gas Distribution Expense Budget Request, Priority Code Three Corrective Maintenance Detail

2010 Gas Distribution Expense Budget Request Priority Code Three Corrective Maintenance Detail Dollars in Thousands		
MWC	Description	Amount
FI	Accelerate Grade 2 Leak Repairs	8,795
FI	More pessimistic unit cost assumptions	5,538
	Total	14,333
Source: Response to Discovery, OC-407, Attachment 4.		

The 2010 expense prioritization template demonstrates that PG&E assigned a relatively low priority to integrity management projects in 2010. Those projects were included in the bottom quartile of the gas distribution prioritizations shown on the template.[31]

2010 Initial Budget Request - Capital

The 2010 capital prioritization template provides the initial budget request by MWC and priority code. The following table shows the gas distribution request.

Table 8-14 - 2010 Gas Distribution Capital Budget Request by Priority Code

2010 Gas Distribution Capital Budget Request by Priority Code Dollars in Thousands					
MWC	Description	Mandatory	Priority 1	Priority 2	Total
14	Gas Pipeline Replacement Program	0	63,900	4,170	68,070
14	Copper Services Replacement Program	0	41,757	0	41,757
27	Meter Protection Program	0	100	0	100
29	New Business	50,100	0	0	50,100
47	Capacity	11,000	0	0	11,000
50	Reliability	18,350	5,000	2,000	25,350
51	Work Requested by Others	24,084	0	0	24,084
52	Emergency Response	282	0	0	282
	Total	103,816	110,757	6,170	220,743
Source: Response to Discovery, OC-895, Attachment 2.					

The Gas Pipeline and Copper Services Replacement Programs account for 94 percent of priority codes 1 and 2.

The Reliability MWC priority code 1 work consists of two components. The first is $3.0 million for capital work resulting from the Exponent audit of regulator stations and valves. The second is $2.0 million for

[31] Mandatory work was 80 percent of total shown on the template. The integrity management projects were included in priority code one, and were not considered mandatory work.

replacement of services with a high likelihood of leakage. The Reliability MWC priority code 2 amount is for additional capital work resulting from the Exponent audit.[32]

The 2010 capital prioritization template demonstrates that PG&E placed a relatively low priority on long-term gas safety programs in the 2010 budget process.

Management Review and Approval

Prior to the 2009 budget year, the LOB budget requests were submitted to the Chief Financial Officer and Budget Working Group.[33] After the fall program reviews were completed in September, the Budget Working Group proposed an overall utility budget to the utility Management Committee. The Management Committee finalized its budget recommendation in late November or early December and reviewed their recommendation with the CEO. After the CEO review, the recommended budget was submitted to the Board of Directors for approval.[34]

The approved budgets were communicated to the LOBs in the annual Budget Letter in late November or early December. The budget letters provide two amounts for each LOB, a total expense budget and a total capital budget. PG&E did not retain the Budget Letters for 2003 or 2004. T&D management was responsible for allocating the approved distribution LOB budget to programs, MWCs and organizations.[35]

PG&E did not retain the budget requests submitted to the Budget Working Group. The program reviews and prioritization templates are the only available records of the requests reviewed by the Budget Working Group.[36]

The management committee did not approve detailed budgets. Instead, the Management Committee approved a total expense and a total capital budget amount for each LOB.[37]

The only available records of the budget materials reviewed by the management committee are the program reviews and prioritization templates.[38] The Management Committee did not document the basis for its recommendations. The only documentation of the Management Committee recommendation is the annual Budget Letter.[39]

Senior management and the CEO reviewed the budget at a LOB level only. The review of the distribution LOB did not separate gas and electric distribution. The documents provided to the CEO were similar in detail to the annual Budget Letter.[40]

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[32] Response to Discovery, OC-895, Attachment 2.
[33] Response to Discovery, OC-40.
[34] Response to Discovery, OC-40 and OC-42.
[35] Response to Discovery, OC-40.
[36] Response to Discovery, OC-703, OC-678 and OC-598.
[37] Response to Discovery, OC-705.
[38] Response to Discovery, OC-678.
[39] Response to Discovery, OC-705, OC-706 and OC-707.
[40] Response to Discovery, OC-708.

The names of the review committees changed for the 2009 budget year, but the process remained basically the same. The T&D budget requests were submitted to the newly created Operating Plan Committee (OPC) instead of the Budget Working Group. The first meeting of the OPC was held in May 2008.[41]

The Operating Plan Committee focused mainly on company-wide items. The Operating Plan Committee did not have many specific discussions about gas distribution matters.[42]

The OPC meeting materials do not contain the T&D budget requests. The OPC meeting materials for 2008 through 2010 only contain a limited number of brief items pertaining to gas distribution. The materials primarily address changes to the 2009 budget that occurred during the budget year.[43]

During the June to October time frame, the Finance Department analyzed various financial scenarios at an enterprise level. The analysis produced enterprise earnings targets that were considered in the budget approval process.[44]

The OPC and senior management conducted a series of meetings in the August to October time frame to review the LOB budget requests and enterprise earning targets. The final summary level budgets were approved by management in late October or early November. The prioritization templates are the only records of the budget requests reviewed during that process. The annual Budget Letters are the only documentation of the budgets approved by the OPC and senior management.[45] The basis for those approvals is undocumented. The impact of the enterprise wide earnings targets on the approved budgets is not documented.

The budgets continued to be approved at a LOB-only level. T&D continued to be responsible for distributing the approved distribution budget to programs, MWCs and divisions.[46]

Initial Approved Budgets

The Budget Letters provided the total amount of the approved expense and capital budgets for the distribution LOB. The Budget Letters did not divide those amounts into gas and electric amounts.[47] PG&E did not retain any other, more detailed, documentation of the approved budget.

[41] Response to Discovery, OC-208.
[42] Response to Discovery, OC-440.
[43] Response to Discovery, OC-440.
[44] Response to Discovery, OC-208.
[45] Response to Discovery, OC-706.
[46] Response to Discovery, OC-208 and OC-408.
[47] Response to Discovery, OC-42.

After T&D received the Budget Letter, it distributed the approved budget to Programs, MWCs and projects. PG&E cannot provide the initial approved gas distribution budgets by MWC for 2003, 2004, 2005, 2007 and 2008.[48]

The initial budgets are entered into PG&E's SAP system as of January 1. The gas distribution budgets change throughout the year as budgeted amounts are transferred between programs or additional funds are authorized. When changes are made during the year, they are entered into SAP and replace the initial budget amounts. As a result, the initial approved budget amounts are no longer contained in PG&E's accounting system.[49]

The SAP system contains year-end budgets for all years included in the audit period. In theory, the initial approved budgets for those years could be recreated by adjusting the year-end budget amounts in SAP to eliminate changes made during the year. However, this was not possible as PG&E does not have a record of the changes made during the year. The Spring program reviews include some budget information for 2004, 2006 and 2008. However, that information is incomplete and does not necessarily represent the initial approved budget.[50]

Comparison of Expense Requests To Approved Budgets

T&D's budget requests were prepared after it received initial expense and capital targets from management. T&D's budget requests were influenced by those targets and do not represent requests based solely based on complying with PG&E's operating standards.

Overland attempted to compare the gas distribution expense budget requests to the initial detailed budgets for each year. The purpose of the comparison was to provide insight into the extent to which resources were constrained for financial reasons. Although the budget requests do not represent an unconstrained view of funding needs, they are the only available proxies for gas distribution resource needs from the point of view of the organizations responsible for doing the work.

The data only allows a comparison of the initial expense request and the initial approved budget in three years, 2006, 2009 and 2010. PG&E cannot provide the initial budget request in 2003, 2004, 2005 or 2007. PG&E cannot provide the initial approved budget by MWC in 2003, 2004, 2005, 2007 or 2008.

The Spring 2008 gas distribution expense program review shows the gas distribution budget as of the date of the review. Overland prepared an additional fourth comparison using those amounts as a proxy for the 2008 initial approved budget.

[48] Response to Discovery, C-408.
[49] Response to Discovery, OC-408.
[50] Response to Discovery, OC-497.

2006 Comparison

The following table compares the 2006 initial gas distribution expense budget request to the approved budget.

Table 8-15 - Comparison of 2006 Expense Budget Request to the Initial Approved Budget

Comparison of Expense Budget Request to the Initial Approved Budget Year 2006 Dollars in Thousands				
MWC	Description	Budget	Request	Difference
DE	Leak Survey	5,591	5,986	(395)
DF	Mark & Locate	26,742	28,481	(1,739)
DG	Cathodic Protection	7,670	8,196	(526)
EX	Meter Protection Program	2,990	3,339	(349)
FG	Operate System	1,893	2,479	(586)
FH	Preventative Maintenance	9,342	8,576	766
FI	Corrective Maintenance	13,183	14,559	(1,376)
GF	Gas Mapping	1,620	2,545	(925)
GG	Capacity Planning	2,192	2,794	(602)
	Total	71,223	76,955	(5,732)
Source: Request is OC-537, Budget is OC-408.				

The initial approved budget was 7.4% lower than the budget request in 2006. Most of that difference was in Mark & Locate and Corrective Maintenance.

2008 Comparison

The following table compares the 2008 initial gas distribution expense budget request to the budget shown in the Spring 2008 Program Review.

Table 8-16 - Comparison of 2008 Expense Budget Request to the Budget Shown in the Spring 2008 Program Review

Comparison of 2008 Expense Budget Request to the Budget Shown in Spring 2008 Program Review Dollars in Thousands				
MWC	Description	Budget	Request	Difference
DE	Leak Survey	13,470	10,139	3,331
DF	Mark & Locate	29,879	30,421	(542)
DG	Cathodic Protection	7,709	10,893	(3,184)
EX	Meter Protection Program	997	3,615	(2,618)
FG	Operate System	2,412	2,936	(524)
FH	Preventative Maintenance	17,359	17,423	(64)
FI	Corrective Maintenance	22,784	17,089	5,695
GG	Capacity Planning	2,614	2,642	(28)
	Total	97,224	95,158	2,066
Source: Request is OC-542, Budget is OC-497; Excludes Gas Mapping and R&D.				

The budget amounts shown above were taken from the Spring 2008 gas distribution expense program review. The budget amounts are 2.2 percent higher than the initial request. The leak survey and corrective maintenance budgets are significantly higher than the initial request. That may reflect an emerging recognition of the extent of corrective actions required to address the gas distribution management deficiencies identified in the fall of 2007. The approved budgets for the other MWCs were 10.2% lower than the initial request.

PG&E increased the 2008 gas distribution expense budget by $20.5 million in mid 2008 as a result of the 2008 Budget Replan process. The increase covered the cost of additional corrective actions required to address gas distribution management deficiencies discovered in 2007 and 2008. The 2008 budget Replan process is described in Chapter 9.

2009 Comparison

The following table compares the 2009 initial gas distribution expense budget request to the initial approved budget.

Table 8-17 - Comparison of 2009 Expense Budget Request to the Initial Approved Budget

Comparison of Expense Budget Request to the Initial Approved Budget Year 2009 Dollars in Thousands				
MWC	Description	Budget	Request	Difference
DE	Leak Survey	19,161	24,640	(5,479)
DF	Mark & Locate	28,695	31,453	(2,758)
DG	Cathodic Protection	8,227	13,138	(4,911)
EX	Meter Protection Program	0	4,133	(4,133)
FG	Operate System	2,504	2,516	(12)
FH	Preventative Maintenance	16,401	25,272	(8,871)
FI	Corrective Maintenance	39,064	33,677	5,387
GF	Gas Mapping	1,600	1,575	25
GG	Capacity Planning	2,867	3,748	(881)
	Total	118,519	140,152	(21,633)
Source: Response to Discovery, OC-895, Budget is OC-408.				

The 2009 initial approved expense budget was 15.4% lower than the initial request.

PG&E's Board of Directors approved a $90 million increase in the 2009 expense budget in February 2009 to address critical gas distribution management deficiencies. Most of the additional funding was for the Accelerated Leak Re-Survey program and associated leak repairs. The February 2009 funding request is described in Chapter 12.

2010 Comparison

The following table compares the 2010 initial gas distribution expense budget request to the initial approved budget.

Table 8-18 - Comparison of 2010 Expense Budget Request to the Initial Approved Budget

Comparison of Expense Budget Request to the Initial Approved Budget Year 2010 Dollars in Thousands				
MWC	Description	Budget	Request	Difference
DE	Leak Survey	17,832	19,705	(1,873)
DF	Mark & Locate	25,892	30,921	(5,029)
DG	Cathodic Protection	8,600	9,237	(637)
EX	Meter Protection Program	0	860	(860)
FG	Operate System	2,992	2,960	32
FH	Preventative Maintenance	16,161	21,108	(4,947)
FI	Corrective Maintenance	42,587	72,389	(29,802)
GF	Gas Mapping	1,356	1,601	(245)
GG	Capacity Planning	2,856	2,946	(90)
	Total	118,276	161,727	(43,451)
Source: Response to Discovery, OC-407, Budget is Response to Discovery, OC-408.				

The initial approved budget was 26.9% lower than the request in 2010. Most of that difference was in Corrective Maintenance. That difference was caused by timing. Corrective Maintenance includes leak repairs. The request was prepared in July 2009 while the 2010 budget was approved in late 2009. When the request was prepared, PG&E spread the leak repair costs associated with the Accelerated Leak Re-Survey Program over 2009 and 2010. A substantial portion of the repairs that were originally planned for 2010 were subsequently accelerated into 2009. That caused the 2010 corrective maintenance budget to be significantly lower than the original request.[51]

The Mark & Locate (M&L) budget was lower than the initial request because of a reduction in the number of M&L requests from excavators forecasted for 2010. When the request was prepared, PG&E anticipated a higher volume of M&L tickets than the level expected when the budget was approved.[52]

Budget Documentation Conclusion

PG&E's budget documentation was inadequate throughout the audit period. PG&E did not retain the budget requests submitted by T&D for the first six years in the audit period. PG&E cannot provide the initial budget requests by MWC for 2003, 2004, 2005 or 2007.

[51] Response to Discovery, OC-408, Attachment 1.
[52] Response to Discovery, OC-408, Attachment 1.

PG&E cannot show how the costs included in the 2003 through 2008 budget requests were prioritized. PG&E cannot provide a breakdown of the requested amounts for those years by priority code.[53]

The budget request documentation for 2009 and 2010 consists of budget prioritization tables. PG&E did not provide any documents that explain the basis for the amounts shown on the prioritization tables. For example, the staffing assumptions underlying the 2009 and 2010 budget requests are not documented.

The budget requests were reviewed by a central budget committee and senior management. That review process is completely undocumented. PG&E did not retain the documents reviewed during the approval processes. The only documentation of the results of the approval processes is the annual Budget Letter. The Budget Letters combine electric and gas distribution budgets into one amount for expense and one amount for capital. The Budget Letters do not describe the basis for the approved budgets.

PG&E did not retain the initial approved budgets in effect at the beginning of the budget year. As a result, PG&E had to reconstruct the initial approved budgets from Program Review and other documents. PG&E could not provide the initial approved budgets by MWC for 2003, 2004, 2005, 2007 or 2008.

Budget Documentation Recommendations

Overland recommends the following improvements in PG&E's budget documentation.

- PG&E should document the basis for the initial budget targets set by management.
- Gas distribution should prepare an unconstrained budget request.
- Gas distribution should document the basis for its budget requests.
- PG&E's central budget committee should document the basis for its budget recommendation to management.
- Management should document the basis for the approved budget.
- Gas distribution should document the changes to its budget that occur during the budget year.

Overland's recommendations are the product of its retrospective review of PG&E's budget process and may not reflect the current state of PG&E's budget process. Overland's recommendations are an extension of the analysis described in the earlier sections of this Chapter and are not intended to be a comprehensive set of recommendations. The CPSD retained consultants in the 2014 GRC to review PG&E's corporate goal setting and resource prioritization on a prospective basis. Overland's recommendations are intended to complement the recommendations made by those consultants.

[53] Response to Discovery, OC-895.

Initial Budget Targets

The budget targets set by executive management have a significant influence on the budget requests submitted by the organizations that actually do the work. The basis for the budget targets should be documented to provide insight into the management priorities reflected in PG&E's gas distribution budgets.

The targets should include separate gas distribution expense and capital amounts. Management should be required to approve a report that explains the basis for the gas distribution targets. The report should explain the methodology and assumptions used to determine the targets and provide the underlying data. The report should compare the targets to the gas distribution expenses and capital expenditures adopted in PG&E's most recent GRC and explain how the adopted amounts were considered in the target setting process.

The report should explain how financial goals were considered in the target setting process. The financial goals should be documented and explained in the report. The report should also explain how the approved target is consistent with public safety and work quality goals.

The report should explain how staffing levels and major initiatives were considered in the target setting process. The report should include a "budget walk" that reconciles the targets to the approved budget for the current year.[54]

Unconstrained Budget Request

Gas distribution should submit two budget requests to the central budget committee, an unconstrained request and a constrained request.

The unconstrained request should show the funding required to do the work that the organization recommends for completion in the budget year. The constrained request should show the work that would be done if the budget is constrained to the initial target set by management.

Comparing the approved budget to gas distribution's unconstrained budget request provides insight into resource adequacy and spending priorities. PG&E's current budget process does not include an unconstrained budget request.

The unconstrained request should not be determined by a mechanical formula, such as 105 percent of the target set by management. The unconstrained request should also not be an impractical wish list.

The unconstrained view should reflect the costs of implementing industry best practices over a reasonable time horizon. Developing the unconstrained view need not involve detailed studies of

[54] A budget walk starts with the budget for the current year and adds or subtracts major items to derive the budget target for the upcoming year.

industry best practices or initiatives that have not already been considered internally. The program managers should document the overall approach and assumptions used to develop the unconstrained request for their respective programs.

The program manager should solicit input from the distribution division superintendents and engineering leads regarding unconstrained resource needs. The unconstrained requests should be linked to and tested by periodic assessments of staffing adequacy based on work load studies.

Gas Distribution Budget Request Report

The documentation of the gas distribution's initial budget requests during the audit period consisted solely of cryptic 2009 and 2010 budget prioritization tables. The tables do not adequately document the basis for the prioritizations shown on the tables. The tables are not accompanied by any narrative explanation of the trade-offs made in the prioritization process.

Gas distribution should prepare a report that explains the basis for its initial unconstrained and constrained budget requests. The report should explain the methodology used to determine the requested amounts and the major assumptions underlying the requests.

The report should include tables showing the constrained and unconstrained requests by MWC and priority code. The report should explain the basis for the priority code assignments. Separate tables should be prepared for expense and capital. The report should include tables that show the costs assigned to each priority code by MWC and item.

The report should include the staffing plan underlying the request. The staffing plan should show gas distribution staffing by department and division under the constrained and unconstrained requests. The report should also identify and describe the major initiatives included in the two requests.

The report should identify and explain the initiatives and other items included in the unconstrained request that are excluded from the constrained request. The report should explain the reasons for excluding each item from the constrained request and the resulting impact on gas distribution work quality and public safety.

The report should identify and explain the amounts included in the requests for long-term gas safety programs, such as the meter protection program. The report should explain the basis for the requested amounts for those programs.

The report should include a budget walk that explains the differences between the approved budget for the current year and the constrained request. The report should include a second "request walk" that explains the differences between the constrained request and the unconstrained request.

Central Budget Committee Approval

The Central Budget Committee should be required to approve a report that documents the basis for the gas distribution expense and capital budgets it recommends to executive management. The report should be provided to executive management with the recommendation.

The report should explain the methodology and assumptions used to derive the recommended budget from the gas distribution budget requests. The report should explain significant variances between the unconstrained gas distribution request and the recommended budget. The report should include a staffing plan showing the recommended gas distribution headcount by department and division.

The report should explain how the recommended budget is consistent with public safety and work quality goals. The report should explain the extent to which the recommended budget was constrained for financial reasons. The report should identify all significant issues or uncertainties that management should consider in its review of the recommendation, particularly public safety or work quality issues.

Management Approval

Management should be required to approve a report that documents the basis for their approval of the gas distribution expense and capital budgets. The report should explain all variances between the budget committee's recommendation and the approved budget.

The report should explain how the approved budget is consistent with public safety and work quality goals. The report should explain the extent to which the approved budget was constrained for financial reasons.

Tracking Changes During the Budget Year

In PG&E's 2011 GRC, the Commission required two new periodic reports to enhance regulatory oversight of PG&E's spending prioritization decisions. The first report is the Budget Report. The Budget Report covers electric distribution, gas distribution and electric generation. The Budget Report is filed in March after the completion of the initial budget for the current year. The budget report documents the initial approved gas distribution budget by MWC. The second report is the Gas Distribution Pipeline Safety Report . The Safety Report is filed every six months. The Safety Report includes comparisons of adopted and actual gas distribution expense and capital spending.[55]

During the audit period, PG&E was not able to track changes to the initial approved budgets that occurred during the budget year. Gas distribution should prepare a table that provides a roll forward of the initial approved budget to the final year-end budget by MWC.

[55] D.11-05-018, pages 30 and 31.

The table should start with the initial approved budget by MWC and end with the final year-end budget. The table should include separate columns that show the changes made to the budget by the date they were made. PG&E should document the circumstances and basis for each change.

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9. Planning Document Review

Introduction

Overland reviewed PG&E's available planning documents for 2003 to 2010 for evidence that gas distribution resources were constrained for financial reasons. This Chapter contains the results of that review.

Chapter 5 reviews PG&E's long-term gas safety projects. Chapter 8 addresses PG&E's budget process.

The 2003 to 2010 planning documents demonstrate a heavy emphasis on cost reduction and on limiting spending to budgeted amounts. The 2003 to 2010 planning documents contain very little discussion of public safety. The planning documents prepared after the San Bruno Incident demonstrate a striking change in emphasis towards public safety and away from cost reduction.

The 2003 to 2005 planning documents contained benchmarking tables that compared PG&E to other gas distribution utilities. The comparisons demonstrated that PG&E was spending significantly less on gas distribution O&M expenses than its peers. PG&E was also repairing far fewer leaks than its peers.

The 2003 to 2006 planning documents contained tables listing key gas distribution initiatives. The initiatives demonstrated a heavy emphasis on cost reduction. Cost reduction was a primary goal of 10 of the 18 initiatives.

The key metrics reported in the planning documents emphasized cost reduction rather than public safety or work quality.

Planning Document Background

Overview

The primary planning documents reviewed by Overland were:

- Gas Distribution Program Reviews (2003 to 2010);
- Customer Service (Field Services) Program Reviews (2003 to 2005);
- T&D Quarterly Business Reviews (2008 to 2010); and
- T&D Three-Year Operating Plans (2008 to 2010).

Gas distribution was part of PG&E's Transmission and Distribution (T&D) organization throughout the audit period. The T&D organization was responsible for electric and gas distribution and transmission. The functions overseen by T&D were organized into programs. The budgeting process for each program was managed by a program manager.

During the 2003 to 2007 budget years, program reviews were the centerpiece of the planning process. The program reviews were semi-annual presentations to PG&E's finance department. The presentations were made on standardized templates for each program.[1]

PG&E implemented its new three-year operating plan process in 2008. T&D continued to prepare program reviews and they were used internally within T&D, but they were no longer part of the enterprise wide management process.[2] Instead of program reviews, T&D made Quarterly Business Review (QBR) presentations to PG&E's Finance Department.

QBRs were not prepared prior to 2008. The initial T&D Three-Year Operating Plan was prepared in February 2008 and covered the years 2008 to 2010.[3]

The T&D program reviews and QBRs did not include the gas service representatives (GSRs) responsible for customer service calls because the GSRs are part of PG&E's Customer Service organization. The GSRs were included in the Customer Service organization field services program reviews. PG&E provided the field services program reviews for 2003 to 2005. Field services program reviews and QBR materials were not produced in 2006 to 2010.[4]

Gas Distribution Program Reviews

PG&E does not have gas distribution program review documents for Spring 2006, Spring 2007 and Fall 2008. Those program reviews were not conducted or, if they were, PG&E could not locate the documents for those reviews.[5]

T&D prepared the following spring and fall gas distribution program documents in 2003 through 2006:[6]

- Gas Distribution Expense;
- Gas Distribution Capital;
- Pipeline Replacement Program; and
- Meter Protection Program.

PG&E did not prepare separate GPRP and MPP program review documents during 2007 to 2010. During those years, gas distribution only had two program reviews, one for expense and one for capital.

The 2003 to 2006 program review documents use standardized templates entitled Program Profiles. The templates consisted of tables organized into sections. The format varied somewhat from year to year but generally included the following major sections:[7]

[1] Response to Discovery, OC-406.
[2] Response to Discovery, OC-406.
[3] Response to Discovery, OC-64.
[4] Response to Discovery, OC-970.
[5] Response to Discovery, OC-406.
[6] Response to Discovery, OC-406. The capital program reviews did not include meters or work requested by others.
[7] Response to Discovery, OC-406, Attachments 2 through 35.

- Challenges;
- Key Initiatives;
- Key Metrics;
- Benchmark Data; and
- Financial Performance.

The templates for the 2003 to 2006 program reviews were three to six pages in length depending on the program. The templates were occasionally supplemented with more lengthy addendums.

The templates changed in 2007. The Fall 2007 templates were titled 2008 Program Forecast. The Spring 2008 program review templates were titled 2008 Program Reviews. The Fall 2007 and Spring 2008 program review templates were all 3 pages in length.[8]

By the Spring of 2009, templates were no longer used and the program reviews consisted of presentation documents. The Spring 2009 gas distribution capital and expense presentations were each 25 pages in length. By the Spring of 2010 the presentations were much shorter. The Spring 2010 expense presentation had five pages, and the capital presentation had 18 pages.[9]

Quarterly Business Reviews

The primary planning documentation for the 2008 to 2010 budget years were the Transmission and Distribution (T&D) QBR presentations and the three-year operating plans. PG&E provided QBR presentation documents for eleven QBR meetings held in 2008 to 2011.[10] PG&E only conducted three T&D QBR meetings in 2010. PG&E only held one QBR meeting in 2011.[11]

The QBRs presentations address electric and gas transmission and distribution. The presentations are status updates rather than detailed planning documents. Gas distribution matters were only discussed at a high level. The QBR presentations generally did not document the basis for budgeting and spending decisions.

The QBR presentations for meetings held in 2008 and 2009 averaged about 60 pages in length.[12] The presentations for meetings held in 2010 and 2011 averaged 15 pages.

Three-Year Operating Plans

The T&D three-year operating plans address all of T&D's operations, including electric distribution and transmission. The plans are designed to assist management in aligning operational, financial and regulatory planning.[13]

[8] Response to Discovery, OC-406, Attachments 36 through 39.
[9] Response to Discovery, OC-406, Attachments 47 and 48.
[10] Response to Discovery, OC-67, OC-873 and OC-972.
[11] Response to Discovery, OC-873.
[12] Response to Discovery, Counting the May 2008 Replan presentation as part of the 2008 QBR 2 presentation.
[13] Response to Discovery, OC-67, Attachment 1.

The 2008 Three-Year Operating Plan was issued in February 2008 and covered the years 2008 to 2010. The documentation for that plan consisted of a 49-page presentation.[14] The tables included in the presentation provided summary spending plans for electric and gas distribution on a combined basis. The tables did not show separate amounts for gas distribution.

The T&D 2009 Three-Year Operating Plan was issued in March 2009 and covered the years 2009 to 2011. The documentation for that plan consisted of a 97-page presentation. The March 2009 document included more detail than the February 2008 document.[15]

T&D did not prepare a separate document for its 2010 Three-Year Operating Plan. The plan was summarized in the September 2009 QBR presentation.[16]

Benchmarking (2001 to 2004)

The Spring 2003 through Fall 2005 expense program reviews included benchmarking tables that compared PG&E to other gas distribution utilities. The benchmarking comparisons implied resource constraints in PG&E's gas distribution operations and demonstrated that PG&E was repairing far fewer leaks than its peers.[17]

The data included in the tables was taken from two annual benchmarking studies. The first study (Study A) was based on annual surveys of approximately 20 gas distribution utilities. The second study (Study B) used data taken from FERC Form 2 reports for approximately 75 gas distribution utilities.[18]

The following table shows the metric for leaks repaired per mile of distribution main from Study A.

Table 9-1 - Leaks Repaired on Mains Per 100 Miles of Main

Leaks Repaired on Mains Per 100 Miles of Main Benchmarking Study A 2001 to 2003			
Year	PG&E	Median	PG&E - Percent of Median
2001	4	24	16.7
2002	4	14	28.6
2003	2	20	10.0
Source: Response to Discovery, OC-522, OC-528, OC-532.			

[14] Response to Discovery, OC-67, Attachment 4.
[15] Response to Discovery, OC-67, Attachment 4.
[16] Response to Discovery, OC-971.
[17] Response to Discovery, OC-406, Attachments 3, 7, 12, 18, 24 and 28.
[18] The sources of the two studies are treated as confidential information in this report at PG&E's request.

PG&E discovered serious deficiencies in its leak survey program in 2007 and 2008. Those deficiencies caused large numbers of leaks to go undetected. That explains PG&E's very low leak repair rates in 2001 to 2003.[19]

The O&M cost per customer metrics from Study A are shown below.

Table 9-2 - O&M Costs Per Customer

O&M Costs Per Customer Benchmarking Study A 2001 to 2004			
Year	PG&E	Median	PG&E - Percent of Median
2001	12.17	23.92	50.9
2002	13.59	33.93	40.1
2003	13.42	31.25	42.9
2004	13.47	30.84	43.7
Source: Response to Discovery, OC-522, OC-528, OC-532, OC-536.			

The O&M cost per mile metrics from Study A are shown below.

Table 9-3 - O&M Costs / Miles of Mains and Services

O&M Costs / Miles of Mains and Services Benchmarking Study A 2001 to 2004			
Year	PG&E	Median	PG&E - Percent of Median
2001	690	807	85.5
2002	780	1,143	68.2
2003	755	1,284	58.8
2004	775	1,087	71.3
Source: Response to Discovery, OC-522, OC-528, OC-532, OC-536.			

The O&M metrics demonstrate that PG&E spent significantly less on O&M than other gas distribution utilities during 2001 to 2004. PG&E is the second largest gas distribution utility in the United States.[20] PG&E's spending metrics benefit from the economies of scale created by its large size.

[19] Chapter 7.

[20] Energy Information Agency Report titled Distribution of Natural Gas: The Final Step in the Transmission Process, June 2008, page 9. The largest gas distribution utility is the Southern California Gas Company.

In Study B, the distribution O&M cost per customer was calculated by dividing distribution O&M, as reported on the FERC Form 2, by the number of customers. That metric is shown below:[21]

Table 9-4 - Distribution O&M Per Customer

Distribution O&M Per Customer Benchmarking Study B 2002 to 2004			
Year	PG&E	Median	PG&E - Percent of Median
2002	29.59	55.11	53.7
2003	29.59	55.08	53.7
2004	27.74	53.08	52.3
Source: Response to Discovery, OC-522, OC-528, OC-532, OC-536.			

The Study B distribution O&M per Mile of Main metrics are shown below:

Table 9-5 - Distribution O&M Per Mile of Distribution Main

Distribution O&M Per Mile of Distribution Main Benchmarking Study B 2002 to 2004			
Year	PG&E	Median	PG&E - Percent of Median
2002	2,979	3,152	94.5
2003	2,950	3,101	95.1
2004	2,777	2,974	93.4
Source: Response to Discovery, OC-522, OC-528, OC-532, OC-536.			

PG&E has approximately 100 customers for every mile of distribution main. The median utility in Study B has about 60 distribution customers per mile of main.[22] PG&E's distribution O&M costs per mile of main are increased by its relatively high customer density.

The benchmarking studies imply resource constraints in PG&E's gas distribution operations in 2001 through 2004.

Cost Reduction Emphasis (2003 to 2006)

The 2003 to 2006 expense program reviews included a list of the top drivers/challenges for the program. The following four items were listed consistently in those years:

[21] The O&M expenses used to calculate the O&M per customer metric in Study B have a broader scope than the expenses used in Study A. As a results, O&M per customer is higher under the Study B metric.

[22] Response to Discovery, OC-532, Supplement 2, Attachment 2.

Table 9-6 - Gas Distribution Expense Program Drivers/Challenges

Gas Distribution Expense Program Drivers/Challenges Listed in 2003 to 2006 Program Reviews	
No.	Description
1	A high level focus on gas safety compliance both internal and external to PG&E
2	Completing all required maintenance work with an essentially flat budget while absorbing inflation and additional units of work
3	Increasing dig-in volumes
4	Aging Infrastructure
Source: Response to Discovery, OC-406, Attachment 28.	

Key Initiatives

The key initiatives listed in the expense program reviews demonstrate an emphasis on cost reduction. The expense program reviews listed the following 18 key initiatives over the four-year period 2003 to 2006:

Table 9-7 - Key Initiatives Listed in Expense Program Reviews

Key Initiatives Listed in Expense Program Reviews 2003 to 2006		
Description	First	Last
New Leak Survey Technology (OMD)	Spring 2003	Spring 2003
Division Engineering Audits	Spring 2003	Spring 2003
Non-Recurring Expense Projects - Prioritization System	Spring 2003	Spring 2003
Rectifier Grounding Project	Spring 2003	Fall 2005
Gas Preventative and Corrective Maintenance System	Spring 2003	Fall 2005
Damage Prevention - Reduce Dig-ins	Spring 2003	Fall 2005
Damage Prevention - Improve Dig-in Billing Performance	Spring 2003	Fall 2005
Mark & Locate - Cost Reduction	Fall 2003	Fall 2003
Mark & Locate - Improve Process	Fall 2003	Fall 2006
Isolated Steel Services Project	Spring 2003	Fall 2005
Best Practices Implementation	Spring 2003	Spring 2004
Leak Grading - Repair Cost Reduction	Spring 2003	Fall 2004
Cathodic Protection - Remote Monitoring Technology	Spring 2003	Fall 2006
Unit Cost Targets - Refinement	Fall 2003	Spring 2004
Atmospheric Corrosion Program - Mains & Services	Fall 2003	Spring 2005
Leak Survey & Repair - Cost Reduction	Fall 2003	Fall 2005
Mark & Locate Training Facility (Simulate City)	Fall 2005	Fall 2005
Gas Asset Registry	Fall 2006	Fall 2006
Source: Response to Discovery, OC-406, Attachments 3, 7, 12, 18, 24, 28 and 33.		

The Leak Survey Technology initiative expanded the use of optical mobile devices in foot-survey areas. The purpose of the initiative was cost reduction.[23]

The Division Engineering Audits initiative consisted of audits of the "unit counts" for regulator stations, valves and leak survey miles in all gas distribution divisions. The unit counts were used for planning purposes. The audits revealed inaccuracies in unit counts and resulted in improved unit accuracy for 2003.[24]

The Non-Recurring Expense Projects initiative implemented a system-wide cross prioritization system for funding non-recurring expense projects.[25]

The Rectifier Grounding initiative addressed a problem found in GO audits of distribution rectifiers. The initiative included inspections of 3,891 rectifiers and associated repairs. The goal was to complete the project in 2004.[26]

The Gas Preventative & Corrective Maintenance System (GPCM) initiative was initially called the FM Work Management initiative. The initiative included implementing preventative and corrective maintenance in the SAP Work Management module. The initiative also included implementing a mobile work management solution and an asset registry.[27] The goals of the initiative included improved compliance tracking, unit cost tracking, resource management and maintenance history analysis.[28]

The Fall 2003 program review indicated a December 2007 target completion date for the GPCM initiative. The Fall 2004 Program Review indicated the GPCM completion date had been delayed to December 2009. The plan to pilot the mobile solution at the end of 2004 had been deferred to the end of 2006. The initiative was delayed because of 2005 funding limitations.[29]

The Damage Prevention - Reduce Dig-ins initiative included training, excavator education, audits and root cause analysis. One of the initiative's goals was cost reduction. The initiative was expected to result in a 6 percent reduction in dig-in repair costs in 2004.[30]

The Damage Prevention - Improve Billing Performance was a cost reduction initiative to increase reimbursement rates for dig-ins caused by excavators.[31]

[23] Response to Discovery, OC-406, Attachment 3, page 1.
[24] Response to Discovery, OC-406, Attachment 3, page 1.
[25] Response to Discovery, OC-406, Attachment 3, page 1.
[26] Response to Discovery, OC-406, Attachment 3, page 2.
[27] Response to Discovery, OC-406, Attachment 7.
[28] The GPCM is described in more detail the discussion of Work Management Systems in Chapter 11.
[29] Response to Discovery, OC-406, Attachment 18, page 4.
[30] Response to Discovery, OC-406, Attachment 24.
[31] Response to Discovery, OC-406, Attachment 12, page 4.

The Mark & Locate Cost Reduction Initiative sought to reduce costs by implementing best practices. The initiative targeted savings of $1.0 million in 2004.[32]

The Mark & Locate Process Improvement initiative included redefined service area boundaries, improvements to computer hardware and software, and placing mobile devices in service vehicles to allow mobile M&L ticket dispatch. One of the initiative's goals was cost reduction. Mobile dispatch was expected to save $500,000 per year on an on-going basis.[33]

The Isolated Steel Services Project was a ten-year initiative that began in 2002. The ISSP project is described in Chapter 5. The primary purpose of the ISSP was to improve public safety.[34]

The Leak Grading and Repair Cost Reduction initiative sought to reduce costs by reducing the number of leaks that were assigned a Grade that required a repair to be made.[35] The Fall 2003 Program Review indicated the initiative was expected to save $1.5 million in 2003. The savings were expected to continue in future years at an average rate of $1.2 million per year.[36] The Spring 2004 Program Review indicated the number of leak repairs made in 2003 was 20 percent lower than 2002, partially because of the initiative.[37]

The Cathodic Protection - Remote Monitoring Technology initiative sought to reduce costs by installing remote monitoring equipment. The initiative was expected to produce annual savings of $360,000 by 2008.[38]

The Unit Cost Targets - Refinement initiative focused on improving the hours per unit of work metrics used to set budget targets. The purpose of the metrics was to reduce costs by improving efficiency.[39]

The Best Practices Implementation initiative sought to reduce costs by improving workforce efficiency. The initiative reduced the amount of mapping time per Mark & Locate tag from 8.18 minutes per tag to 6.63 minutes per tag in 2002 with further improvement to 5.93 minutes per tag in 2003.[40]

The Atmospheric Corrosion Program initiative included developing systems, procedures and standards for inspections and repairs required by the newly mandated atmospheric corrosion program. The purpose of the initiative was public safety.[41]

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[32] Response to Discovery, OC-406, Attachment 7, page 1.
[33] Response to Discovery, OC-406, Attachment 28, page 4.
[34] Response to Discovery, OC-406, Attachment 28.
[35] Response to Discovery, OC-525.
[36] Response to Discovery, OC-406, Attachment 7.
[37] Response to Discovery, OC-406, Attachment 12. The initiative is described in more detail in Chapter 11.
[38] Response to Discovery, OC-406, Attachment 33, page 1.
[39] Response to Discovery, OC-406, Attachment 12, page 2.
[40] Response to Discovery, OC-406, Attachment 3 and OC-406, Attachment 7.
[41] Response to Discovery, OC-406, Attachment 7, page 4.

The Leak Survey & Repair - Cost Reduction initiative focused on developing process improvements for leak survey and repair needed to meet unit cost targets.[42] The Spring 2004 program review stressed the need to "focus on leak survey and repair as a high opportunity area for the Gas M&O expense program."[43] The initiative included internal benchmarking between divisions. Divisions with high unit costs were asked to implement best practices to drive down their unit costs.[44]

The Fall 2005 Program Review indicated one component of the initiative was replacing rather than repairing leaking services. Service replacements are charged to plant while repairs are charged to expense. Replacing rather than repairing services would reduce leak repair expenses. Another component of the initiative included "championing the optimal use of the OMD mobile leak survey units." A third component was using electronic mapping for leak survey.[45]

The Mark & Locate Training Facility initiative involved the construction of a hands-on training facility for Mark & Locate, Leak Survey and Cathodic Protection. The purpose of the initiative was public safety. The initiative was also expected to increase workforce efficiency through better training.[46]

The Gas Asset Registry initiative included the completion of the asset registry in 2006. The Fall 2006 program review indicates: "In order to transition to a paperless process it will be critical to maintain the registry in 2007 until the transition occurs." The targeted completion date for the initiative was shown as December 2009 in the Fall 2006 Program Review.[47]

The 2003 to 2006 expense initiatives demonstrate a heavy emphasis on cost reduction. Cost reduction was a primary goal for 10 of the 18 initiatives.

Key Metrics

The 2003 to 2006 expense program reviews included a table on key metrics. The tables for 2004 and 2005 contained eleven metrics.[48] Seven of those metrics were unit cost metrics. The goal of the unit cost metrics was to "improve cost performance."[49] The Key Metrics tables showed target levels for each metric. The unit cost target levels were used to encourage increased workforce productivity.

[42] Response to Discovery, OC-406, Attachment 7.
[43] Response to Discovery, OC-406, Attachment 12, page 5.
[44] Response to Discovery, OC-530.
[45] Response to Discovery, OC-406, Attachment 28, page 2.
[46] Response to Discovery, OC-406, Attachment 28, page 2.
[47] Response to Discovery, OC-406, Attachment 33, page 1. PG&E's efforts to create a gas distribution Asset Register are described in Chapter 11. The 2006 initiative described above apparently refers to the work Gas Engineering did in 2006 and 2007 to import GasFM asset lists into SAP.
[48] The 2003 and 2006 Key Metrics tables contain fewer metrics.
[49] Response to Discovery, OC-406, Attachment18, page 6, related program goal for each of the unit cost metrics is "improve cost performance."

The non-unit cost metrics were:

- Number of dig-ins per 10,000 USA tags;
- Corrosion leaks per 100 miles (five-year average);
- Number of leak repairs on mains; and
- Number of leak repairs on services.

The goal of the "number of leak repairs" metrics was to improve cost performance.[50] PG&E set annual targets for the metrics. Actual performance was considered to be better than the target when the number of leak repairs was below the targeted number.

Internal audit questioned the wisdom of having a metric that encouraged employees to find fewer leaks. The April 8, 2008 Internal Audit report entitled Controls for Gas Leak Detection indicated:[51]

> *The Utility tracks the number of leaks per mile of gas pipe as a performance metric in each division in order to help quantify pipeline reliability and measure the effectiveness of the pipeline program. For the past several years, division employees have been tasked with finding ways to drive this number down. In this metric, fewer leaks are preferred and, mathematically, the most direct way to reduce the leak rate is to reduce the number of leaks found. As such, the leak per mile performance metric creates a disincentive to maximize the number of leaks found on survey.*

PG&E "recognized that this metric could theoretically operate as a disincentive to implementing an aggressive leak survey program" and eliminated the metric in 2008.[52]

The goal of nine of the eleven key metrics was cost reduction. The key metrics emphasized cost reduction rather than public safety or work quality.

Cost Reduction Emphasis (2007 to 2010)

PG&E discovered serious deficiencies in its leak survey and gas maintenance practices in 2007 and implemented corrective actions. PG&E reduced gas distribution reliability capital spending to fund some of that work. The Fall 2007 capital program review indicated:[53]

> *Approximately $6.5 million of reliability-related work deferred due to discovery of corrective actions as part of internal audit of North Bay after budget requests were completed, as well as less funding allocated than was included in the initial 2008 reliability*

[50] Response to Discovery, OC-406, Attachment18, page 6, the related program goal for each of the two metrics is improve cost performance.
[51] Response to Discovery, OC-432, Attachment O, page 9.
[52] Response to Discovery, OC-618.
[53] Response to Discovery, OC-406, Attachment 37, page 2, MWC 50 risks.

request. Deferral of this work will result in no reliability-related main replacement work, and only 43% of regulator replacements in 2008. At this funding level, it is possible that compliance-related work will be at the margin, and equipment issues with the potential to impact public safety may not be resolved.

Actual electric and gas distribution expenses were $40.9 million higher than budgeted in the first quarter of 2008 because of severe winter storms in January and February.[54]

The 2008 T&D capital and expense budgets included $86 million in expected savings from the Business Transformation (BT) process. By April 29, 2009, T&D determined that a realistic estimate of the BT savings in 2008 was $5 to $15 million.[55]

PG&E began a 2008 Budget "Replan" process in March 2008 to reset the 2008 budget consistent with current expectations.[56] The Replan effort included 8 initiatives to reduce costs by improving productivity.[57]

On May 30, 2008, T&D submitted its 2008 Replan request to management. The replan presentation requested an additional $93 million to $126 million in gas and electric distribution expense. The lower end of the range reflected mandatory work that had to be completed in 2008. The upper end of the range included the mandatory work plus $33 million in discretionary work that could be deferred to 2009.[58]

PG&E's Operating Plan Steering Committee approved the $93 million Replan request for the mandatory work.[59]

The Replan presentation indicated the distribution requests were necessary to offset:[60]

- A $16 million reduction in expected BT savings;
- $29 million in additional costs associated with BT, including BT stabilization costs;
- $36 million in expense for January storms;
- $39 million for additional gas work; and
- $22 million in higher costs for electric work.

The higher costs were partially offset by rescheduling $7 million of gas maintenance and $1 million of electric maintenance from 2008 to 2009.[61]

[54] Response to Discovery, OC-972, Attachment 1, April 29, 2009 QBR presentations, page 56.
[55] Response to Discovery, OC-972, Attachment 1, April 29, 2009 QBR presentations, page 18.
[56] Response to Discovery, OC-972, Attachment 1, April 29, 2009 QBR presentations, page28.
[57] Response to Discovery, OC-972, Attachment 1, April 29, 2009 QBR presentations, page 44.
[58] Response to Discovery, OC-972, Attachment 2, pages 4 and 11.
[59] Response to Discovery, OC-67, Attachment 5, March 4, 2009 QBR, page 3.
[60] Response to Discovery, OC-972, Attachment 2, page 11.
[61] Response to Discovery, OC-972, Attachment 2, page 4.

The Replan request for gas distribution mandatory work was $21 million. The following table shows the gas distribution mandatory work by item:

Table 9-8 - 2008 Budget Replan, Gas Distribution Request Mandatory

2008 Budget Replan Gas Distribution Request - Mandatory Dollars in Thousands	
Description	Amount
Restore Meter Protection Program Budget	1,000
Resurvey & Repair Grade 2 Leaks - Statistical Sample	1,900
Complete Resurvey & Leak Repair - One Division	7,200
Regulator Station & Valve Audit with Repairs	3,600
Leak Surveyor Re-qualification Program	600
Additional Employees to Address Gas Issues	900
Gas Issues Committee Resources	600
Restore Isolated Steel Services Program Budget	1,200
Restore Cross-Bored Sewer Assessment Budget	1,000
Lower Productivity for Routine Compliance Work	2,500
Total	20,500
Source: Response to Discovery, OC-972, Attachment 2, page 17.	

The first step of the Replan process was redistributing the existing 2008 budget to the highest priority work. The original 2008 budgets for the Meter Protection and the Isolated Steel Services Programs were eliminated in that step. The request for mandatory work restored the budgets for those programs to their original levels.

The following table shows the Replan discretionary request for gas distribution by item:

Table 9-9- 2008 Budget Replan, Gas Distribution Request Discretionary

2008 Budget Replan Gas Distribution Request - Discretionary Dollars in Thousands	
Description	Amount
Resurvey & Leak Repair - Retraining Failures	2,400
Resurvey & Repair - OMD/RMD Assessment Failures	6,200
Sonoma County Grade 2 Leak Repairs	1,500
Repair Grade 2 Leaks - Statistical Sample Resurvey	900
Isolated Steel Services Program - Additional Services	3,700
Meter Protection Program	2,800
Total	17,500
Source: Response to Discovery, OC-972, Attachment 2, page 17.	

The mandatory request only included funds for reviewing a single year of the work performed by surveyors who failed their reassessments after retraining. The discretionary request expanded that review to include two years of the surveyors' prior work.[62]

OMD and RMD are devices attached to vehicles that are used to conduct mobile leak surveys. PG&E tested the surveyors who used those devices and a significant number failed the tests. The discretionary request included funding to re-survey the work done by the surveyors who failed the tests.

The additional Meter Protection Program funds represented work that had been requested but was not funded during the original 2008 budget process.[63]

T&D also requested approval of an additional $23 million contingency for gas distribution. The contingency covered the costs of conducting complete re-surveys for two additional divisions and the associated leak repair costs.[64]

The May 2008 presentation for the Replan request indicated T&D was considering a variety of "productivity ideas" to help offset the increased costs. The ideas under consideration included:[65]

- Maintain hiring controls in 2008;
- Improve productivity for mark & locate, leak survey and leak repair;
- Reduce non-essential training hours;
- Address competency issues (e.g. skills training);
- Impose work rules to best practices;
- Reduce attendance at conferences; and
- Reduce meetings in the field.

By November 2008, T&D had implemented hiring controls.[66] The T&D 2009 Operating Plan, issued in March 2009, indicated "strict hiring controls to remain in place through 2009; VP level approval required to fill any vacancy."[67]

The 2009 budget assumed significant increases in productivity compared to 2008 actual levels. The 2009 budget assumed that mark & locate productivity would increase by 20 percent and routine leak survey productivity would increase by 11 percent.[68] The 2009 budget assumed a 7 percent improvement in leak repair productivity compared to the 2008 Replan budget.[69]

[62] Response to Discovery, OC-972, Attachment 2, page 17.
[63] Response to Discovery, OC-972, Attachment 2, page 17.
[64] Response to Discovery, OC-972, Attachment 2, page 4.
[65] Response to Discovery, OC-972, Attachment 2, page 40.
[66] Response to Discovery, OC-67, Attachment 3, page 50.
[67] Response to Discovery, OC-64, Attachment 4, page 93.
[68] Response to Discovery, OC-972, Attachment 3, page 31.
[69] Response to Discovery, OC-67, Attachment 3, page 33.

The September 2009 QBR presentation indicated the adopted gas distribution expense targets for 2010 assumed significant improvements in productivity compared to current levels. The 2010 targets assumed productivity increases of 20 percent for mark & locate; 18 percent for leak survey and 17 percent for leak repair.[70]

The May 2009 QBR presentation indicated that electric and gas distribution capital spending were expected to be $49.8 million over budget in 2009 because of higher than anticipated capital repair work and work requested by others. The presentation showed $49.8 million in offsets that had been identified to keep capital spending within budget. The offsets included the deferral of $6.1 million in Copper Services Replacement Program spending and $3.7 million in Gas Pipeline Replacement Program Spending.[71]

The September 2009 QBR presentation indicated that base gas and electric expenses were expected to be $19.7 million over budget. Gas distribution deficiency corrective actions were expected to be $15.3 million over their separate expense budget.[72]

The unfavorable variance in the base distribution expense budget was caused by higher than expected emergency repair costs and routine leak survey and repair costs.[73] The variance reflected $55.1 million of cost increases reduced by $35.4 million in offsets identified by T&D. The cost increases included $18.1 million in routine leak survey and repair costs and $1.9 million of additional gas maintenance costs. The offsets included deferring $3.7 million in gas maintenance work.[74]

The unfavorable variance for the separate gas issues expense budget was caused by lower than expected productivity and higher than expected leak find rates in the Accelerated Leak Re-survey Program (ALS).[75]

The September 2009 QBR presentation indicated T&D was planning to submit a $15.3 million continency request to the Operating Plan Steering Committee to cover the $15.3 million shortfall in gas distribution management issues funding.[76]

The September 2009 T&D QBR presentation indicated T&D had taken the following additional actions to offset expense increases:[77]

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[70] Response to Discovery, OC-67, Attachment 7, page 33. Improvement assumed compared to actual levels in the first seven months of 2009. The presentation shows a productivity increase of 14 to 20 percent for leak repair. The average for that range in 17 percent.

[71] Response to Discovery, OC-972, Attachment 3, pages 55 and 56.

[72] Response to Discovery, OC-67, Attachment 3, page 4.

[73] Response to Discovery, OC-67, Attachment 3, pages 8 and 13.

[74] Response to Discovery, OC-67, Attachment 3, page 13.

[75] Response to Discovery, OC-67, Attachment 3, page 32.

[76] Response to Discovery, OC-67, Attachment 5, page 10.

[77] Response to Discovery, Partial list. Does not include all cost reduction actions listed in the September 2009 T&D QBR.

Table 9-10 - Actions Taken to Offset Expense Forecast Overrun

Actions Taken to Offset Expense Forecast Overrun September 2009 T&D Quarterly Business Review
Stricter Hiring Controls
Reduce Consulting and Contractor Spend
Reduce Discretionary Costs
Eliminate Non-Essential Training
Eliminate Discretionary Overtime
Focus on Gas Leak Repair Productivity Improvements
Eliminate Non-Mandatory Routine Leak Repairs
Source: Response to Discovery, OC-67, Attachment 7, Page 16.

The 2008 through 2010 Planning Documents placed a heavy emphasis on cost containment. The documents contained very little discussion of public safety issues.

Corporate Culture

The T&D 2008 Three-Year Operating Plan listed several challenges facing T&D. The challenges included employee commitment and morale.[78]

Another challenge was the lack of functional integration between organizations. The plan noted that "organizations / functions plan and act as silos." Another challenge was "lack of strict adherence to standards and procedures." Operational data was also listed as a challenge. The plan noted:[79]

> *Function does not have all of the operational data it would like, and data that is available is difficult to access / interpret. Need to ensure that the culture and processes support a more information driven management.*

One of the key initiatives included in the T&D 2008 Three-Year Operating Plan was employee engagement. The purpose of the initiative was to increase employee confidence in Energy Delivery leadership.[80]

The March 4, 2009 T&D QBR presentation listed several "2008 Lessons Learned / Insights." The first item on the list was:[81]

> *Realization of fundamental gaps in competence, processes and accountability (e.g., gas matters, network transformers, safety violations, audit findings)...Launched Operational and Human Performance Initiative to address core safety, conformance and quality issues.*

[78] Response to Discovery, OC-64, Attachment 2, February 2008, page 10.
[79] Response to Discovery, OC-64, Attachment 2, February 2008, page 40.
[80] Response to Discovery, OC-64, Attachment 2, February 2008, page 45.
[81] Response to Discovery, OC-67, Attachment 5, page 12.

The May 29, 2009 QBR Presentation included a "T&D Get Well Plan" with tasks in the following three areas:[82]

- Gas Matters;
- Electric Reliability; and
- Operational & Human Performance Improvement / Productivity.

The Gas Matters section of the T&D Get Well Plan was to be completed by December 2010 and included:[83]

- 100% System-Wide Resurvey;
- Critical Leaks Repaired;
- One-Time Programmatic Items;
- Steady-State Going Forward - Utility Stable (Leak Survey, Mark & Locate);
- Compliance to State, Federal Regulations:
  - Meter Protection Program;
  - GPRP / Copper Services; and
  - Isolated Steel Services.
- 3-year vs 5-year Resurvey Cycle to be proposed in GRC; and
- Distribution Integrity Management.

The Operational and Human Performance Improvement / Productivity section of the Get Well Plan was to be completed by the end of 2011 and included:

- Achieving Proficiency in:
  - Safety;
  - Conformance; and
  - Quality.
- Achieve Productivity Embedded in Operating Plan; and
- Communication and Culture Change.

The planning documents prepared after the San Bruno Incident place a far greater emphasis on public safety than the documents prepared prior to the SBI. The Gas Operations 2012 Three-Year Operating Plan indicated a goal of operating with zero public safety impacts and near-hits. Key initiatives included:[84]

- Ensure Public Safety;
- Comply with Spirit and Letter of State, Federal and Local Regulations and Commitments; and
- Restore Confidence in the Gas System.

The Ensure Public Safety initiative included instilling a culture of system integrity within the Gas Operations organization.

[82] Response to Discovery, OC-972, Attachment 3, page 8.
[83] Response to Discovery, OC-972, Attachment 3, page 8.
[84] Response to Discovery, OC-873, Attachment 3, September 7, 2011, page 1.

PG&E significantly increased its gas operations headcount after 2010. The 2012 Gas Operations Three-Year Operating Plan showed headcount increasing from 2,190 in December 2009 to a planned level of 2,660 in December 2012. The 2012 planned headcount was 21.5 percent higher than the December 2009 actual headcount.[85]

The 2012 Three-Year Operating Plan requested large increases in gas distribution funding between 2010 and 2012. Actual 2010 distribution expense was $155 million. The funding request for 2012 expense was $215 million. Actual 2010 distribution capital spending was $216 million. The funding request for 2012 capital was $334 million. Much larger increases were requested for gas transmission.[86]

The 2012 Three-Year Operating Plan requested a $13 million increase in expense funding for the Isolated Steel Service Program in 2012 to allow completion by the end of 2012. The plan requested a $7.6 million increase in expense funding for the Meter Protection Program to allow completion in 2014. The 2012 Three-Year Operating Plan also requested an increase in expense of $13 million to decrease the time allowed for Grade 2 leak repairs and Grade 3 leak rechecks.[87]

The 2012 Gas Operations plan demonstrates a striking change in emphasis towards public safety and away from cost reduction.

[85] Response to Discovery, OC-873, Attachment 3, September 7, 2011, page 9. Gas operations includes both distribution and transmission.

[86] Response to Discovery, OC-873, Attachment 3, September 7, 2011, page 9.

[87] Response to Discovery, OC-873, Attachment 3, September 7, 2011, page 10.

10. Management Deficiencies 1993 to 2007

Introduction

Chapters 10 through 13 provide a narrative history of the gas distribution management deficiencies identified by PG&E during the audit period. The Chapters are organized chronologically. This Chapter covers the 1993 to 2007 time period.

PG&E commissioned two consultant reviews of its preventative maintenance programs in 1995. The consultant reports contain findings that were echoed repeatedly in internal and external reviews prepared in 2007 and later years. The 1995 consultant reports, and PG&E's 1997 internal compliance reviews, demonstrate the long history of PG&E's gas distribution management deficiencies.

PG&E implemented significant workforce reductions in 1993 and 1994. PG&E continued to reduce its gas distribution workforce through 2010. The workforce reductions contributed to significant work quality issues identified by PG&E in 2007 and subsequent years.

Employee complaints about work practices and staffing levels prompted two significant internal audits in 2007. The first was an internal audit of leak detection in the North Bay and North Coast Divisions. The second was an internal audit of regulator station and valve maintenance in Marin County. The internal audits discovered critical deficiencies in leak survey and maintenance practices. PG&E's follow-up investigations demonstrated the deficiencies were pervasive throughout its system.

The internal audit of leak detection in the North Coast Division prompted PG&E to repeat its prior leak surveys in Sonoma County. The resurvey process led to the discovery of systematic leak survey training and operator qualification deficiencies.

PG&E conducted a study of its leak grading process in October 2007. The study conclusively demonstrated that PG&E's leak grading standards were not being applied consistently in the field.

1993 to 1998

1993 and 1994 Workforce Reduction Programs

PG&E announced a work force reduction program in February 1993. PG&E terminated 3,016 employees under the program in 1993. The 1993 workforce reduction program reduced gas distribution O&M expenses by $12.1 million on an annualized basis.[1]

[1] Response to Discovery, OC-3, PG&E Testimony in 1996 GRC, Exhibit PG&E-7, pages 16-4 and 8-9.

PG&E announced a second work force reduction program in August 1994. The 1994 workforce reduction goal was to eliminate another 2,500 positions by the end of 1995. The 1994 program was expected to reduce gas distribution O&M expenses by $5.2 million.[2]

PG&E's total O&M expenses were approximately $134 million a year before the two workforce reduction programs.[3] The two workforce reduction programs reduced PG&E's distribution O&M expenses by approximately 13%.[4]

1995 Maintenance Studies - AA

PG&E's service territory was hit with severe winter storms in January and March 1995. More than one million customers lost power during the storms. The outages prompted PG&E to commission two consultant reviews of its electric and gas maintenance programs.[5] The studies were conducted by Arthur Andersen & Company (AA) and Black & Veatch (B&V). The reports of both studies were issued in August 1995.

The AA study reviewed PG&E's gas and electric preventative maintenance (PM) programs. AA concluded that the gas distribution PM process was generally well managed and that PG&E's divisions were in compliance with existing PM standards. The basis for that conclusion was:[6]

- The Commission's gas safety audit process and the resulting compliance and record keeping culture;
- The existence of the GasFM system to track and schedule PM activities; and
- The Gas Pipeline Replacement Program (GPRP).

AA concluded that the electric PM program was not in compliance with company standards.[7]

AA identified the following primary issues:[8]

- Inadequate emphasis and direction in enforcing standards;
- Inadequate measures to evaluate performance;
- Continually declining resources were detrimental to the execution of the PM programs; and
- Inadequate communication.

[2] Response to Discovery, OC-3, PG&E Testimony in 1996 GRC, Exhibit PG&E-7, pages 16-4 and 8-10.
[3] Response to Discovery, OC-3, PG&E Testimony in 1996 GRC, Exhibit PG&E-7, page 16-8. The recorded/adjusted costs were adjusted to eliminate the savings that occurred in 1993.
[4] Total savings of $17.354 million divided by 1993 recorded/adjusted costs of $134.3 million.
[5] PG&E 1999 GRC Decision, D. 00-02-046, page 125).
[6] Response to Discovery, OC-731, Attachment 1, pages 4 and 5.
[7] Response to Discovery, OC-731, Attachment 1, page 5.
[8] Response to Discovery, OC-731, Attachment 1, page 7.

AA noted that oversight and execution of the gas and electric PM programs was fragmented between the centralized Technical & Construction Services organization and the decentralized divisions. That resulted in dual accountability for overall PM.

AA's findings included the following:

- Continual reductions in annual preventative maintenance budgets resulted in underfunding future preventative maintenance programs.[9]
- Inadequate communication inhibits the success of the preventative maintenance program....The "cut cost at any costs or we'll find someone who will" philosophy may have created the single biggest barrier to effective upward communications.[10]
- The condition of the gas and electric distribution system was not known at all Company reporting levels.[11]
- Gas and electric PM was not sufficiently communicated as a key component of an efficient asset management plan.[12]
- The frequency of reorganizations and personnel changes had an unfavorable effect on the effectiveness of the gas and electric PM programs. The changes resulted in a lack of clarity of responsibility and accountability.[13]
- Key performance metrics were not in place to adequately inform management of gas and electric distribution system condition and the effectiveness of the PM programs.[14]
- The link between service reliability and PM funding was not evident in the annual budget process. The reductions in PM budgets implemented in prior years did not demonstrate an understanding of the potential degradation in service quality resulting from under funding PM programs.[15]
- The distribution divisions had little to no input into budgeting decisions made by the General Office. PM programs were treated as controllable costs that could be reduced to achieve overall division budget targets.[16]
- PM programs were budget-driven not service reliability-driven, leading to the deferral or elimination of programs.[17]
- PM programs appear to have been insufficiently funded.[18]
- Performance Incentive Plan (PIP) targets encourage employees to spend less than their allocated amount of dollars, increasing the risk of deferring or discontinuing gas and electric PM.[19]

[9] Response to Discovery, OC-731, Attachment 1, page 7.
[10] Response to Discovery, OC-731, Attachment 1, page 7.
[11] Response to Discovery, OC-731, Attachment 1, page 7.
[12] Response to Discovery, OC-731, Attachment 1, page 24.
[13] Response to Discovery, OC-731, Attachment 1, page 24.
[14] Response to Discovery, OC-731, Attachment 1, page 25.
[15] Response to Discovery, OC-731, Attachment 1, page 27.
[16] Response to Discovery, OC-731, Attachment 1, page 27.
[17] Response to Discovery, OC-731, Attachment 1, page 28.
[18] Response to Discovery, OC-731, Attachment 1, page 28.
[19] Response to Discovery, OC-731, Attachment 1, page 28.

- Field personnel were confused about the distinction between mandated standards and discretionary guidelines. Some field personnel were under applying standards and over applying guidelines because of this confusion.[20]
- Management could not differentiate between gas and electric PM programs in terms of how they contributed to division objectives and overall company goals because of inadequate information resources. Coupled with the lack of key performance measures, that made it difficult to evaluate a program's effectiveness or compliance.[21]
- PM standards, until recently, were viewed as unfunded mandates. Resource requirements and funding sources were not adequately identified during the program development stage.[22]
- Divisions unilaterally spent a significant portion (approximately 28%) of Gas Pipeline Replacement Program funds on replacements that did not qualify for the program.[23]
- There was considerable disparity in the adequacy of PM programs across the Divisions and Districts. Generally divisions were not complying with PM requirements. Some Districts had stopped performing PM, and managed maintenance in a 100% reactive mode.[24]
- PM was routinely given a low priority ranking in scheduling daily crew assignments.[25]
- PM activities in several Divisions and Districts were lagging because of low headcount.[26]
- The majority of gas and electric PM jobs were not properly inspected by supervisors.[27]
- First line supervisors were overwhelmed by their scope of responsibilities, including low value administrative functions.[28]
- Compliance with PM standards was not consistently or uniformly tracked by the divisions. As a result, system condition was unknown at the overall and divisional level.[29]
- Performance measures were not adequate to determine whether the gas and electric PM programs were meeting division objectives or the overall company mission.[30]
- Equipment performance was not monitored. PG&E did not have a predictive maintenance system.[31]
- Record keeping for PM activities was not consistent across divisions.[32]
- Periodic compliance reviews were not conducted to determine if employees were complying with standards.[33]

[20] Response to Discovery, OC-731, Attachment 1, page 30.
[21] Response to Discovery, OC-731, Attachment 1, page 30.
[22] Response to Discovery, OC-731, Attachment 1, page 31.
[23] Response to Discovery, OC-731, Attachment 1, page 48.
[24] Response to Discovery, OC-731, Attachment 1, page 52.
[25] Response to Discovery, OC-731, Attachment 1, page 52.
[26] Response to Discovery, OC-731, Attachment 1, page 52.
[27] Response to Discovery, OC-731, Attachment 1, page 52.
[28] Response to Discovery, OC-731, Attachment 1, page 52.
[29] Response to Discovery, OC-731, Attachment 1, page 54.
[30] Response to Discovery, OC-731, Attachment 1, page 54.
[31] Response to Discovery, OC-731, Attachment 1, page 54.
[32] Response to Discovery, OC-731, Attachment 1, page 54.
[33] Response to Discovery, OC-731, Attachment 1, page 54.

- First Line supervisors did not conduct any formal follow-ups on jobs to ensure the jobs were being performed in compliance with standards.[34]

In summary, AA found fragmented responsibilities, resource constraints, poor communications, poor metrics, and a lack of quality control and quality assurance.

AA recommended that PG&E:[35]

> *Commit the appropriate level of resources to effectively implement preventative maintenance programs....Seek and provide dollar and workforce levels that provide a realistic opportunity to meet preventative maintenance requirements.*

AA recommended that PG&E change the way PM was prioritized in the resource allocation decisions:[36]

> *Preventative maintenance....can no longer be viewed as the "control valve" for managing overall division expenditures to budget; all employees must view preventative maintenance as "mandated" and share in identifying and implementing process changes that result in increased efficiencies....*

AA recommended that PG&E develop and implement a Workforce Management System (WMS). AA estimated that an effective WMS could increase productivity by 10% to 20% by optimizing the deployment of field personnel and other resources.[37]

1995 Maintenance Studies - B&V

B&V conducted a comprehensive technical assessment of PG&E's distribution PM practices. B&V developed a set of recommendations to "move PG&E toward a best-in-class standing."[38]

The B&V study consisted largely of a review of written procedures and benchmarking to other utilities. B&V did not conduct extensive interviews of field personnel. Those types interviews were performed by AA.

B&V developed separate recommendations for gas and electric maintenance. B&V's gas recommendations included:[39]

[34] Response to Discovery, OC-731, Attachment 1, page 55.
[35] Response to Discovery, OC-731, Attachment 1, page 8.
[36] Response to Discovery, OC-731, Attachment 1, page 32.
[37] Response to Discovery, OC-731, Attachment 1, page 62.
[38] Response to Discovery, OC-731, Attachment 2, Executive Summary, page 1.
[39] Response to Discovery, OC-731, Attachment 2, Recommendations, page 25.

> *Facilities Data and Information Management - PG&E should develop a networked computer database and information system to provide for convenient and reliabile access to data and information about the preventative maintenance standards and procedures, the maintenance program itself and the distribution system and facilities for which the program is charged with maintaining. The data must above all be collected, recorded, and structured in a consistent and convenient manner that provides for ready and reliable access....*
>
> *...PG&E should consider investing in the development of a program maintenance planning tool...This...would include gas distribution systems and provide tracking of facility and equipment inspections...*

B&V recommended integrating the maintenance system with the Geographic Information System that was under development in 1995.[40]

> *PG&E should develop an interface with the AM/FM system being contemplated...to provide further insights into maintenance issues on a geographical basis...An important feature of the GIS connection will be the ability to quickly locate installed facilities of a similar or identical nature to resolve recalls or identified component problems.*

B&V also recommended that PG&E should:[41]

> *Develop better techniques for the collection and data entry of field information. This could include a variety of alternatives from using preprinted forms that can be scanned...to using intelligent hand held computer devices. This improvement is necessary to assure more consistent, timely and reliable data and will undoubtedly improve the marginal quality of information currently being collected, using manual process.*

B&V's other gas recommendations included:[42]

> *PG&E should conduct a company-wide audit to determine current state of the system. This information can be used to develop an overall plan...complete with a resource loaded schedule.*
>
> *PG&E should analyze overall system maintenance requirements and work force deployment to determine adequacy of staffing, uniformity of workload, and the*

[40] Response to Discovery, OC-731, Attachment 2, Recommendations, page 27.
[41] Response to Discovery, OC-731, Attachment 2, Recommendations, page 27.
[42] Response to Discovery, OC-731, Attachment 2, Recommendations, page 28.

effectiveness of using a combination of divisions and company-wide maintenance forces along with contractor forces.

PG&E should develop an inventory of gas facilities at the system, component or material level to (improve) maintenance management and enable dynamic tracking of performance and inspection data.

Other Recommendations are summarized as follows:

- Conducting a preventative maintenance audit "to determine if there is any lack of consistent inspection and documentation practices across the Company;"[43]
- Improvements to PG&E's gas training and operator qualification programs;[44]
- PG&E should consider development of an automated Work Management System and an audit of paperwork, forms, procedures and retention of records;[45]
- PG&E should consider having contractors leak survey its system periodically to provide a basis for assessing the quality of the surveys done by PG&E employees;[46] and
- PG&E should consider using contractors to perform the Mark & Locate function. If contractors were not used, PG&E should consider establishing "an in-house locating force with a more uniform procedure."[47]

1999 GRC Testimony and 1997 Internal Maintenance Audits

The Office of Ratepayer Advocates (now DRA) retained MHB Technical Consultants (MHB) to review electric and gas distribution maintenance expenses in PG&E's 1999 GRC. MHB's gas distribution testimony included the following major findings:[48]

- PG&E historically under expended maintenance costs adopted by the Commission.
- External and internal audits raise serious doubts regarding the efficiency and effectiveness of PG&E's management of maintenance activities.

MHB determined that:[49]

For the eight year period from 1987 to 1994, PG&E underspent the CPUC adopted gas distribution maintenance expense level by over $55 million in 1996 dollars. Thus, during the eight year period, PG&E underexpended the adopted expense level by the equivalent of over one year of adopted expenses.

[43] Response to Discovery, OC-731, Attachment 2, Recommendations, page 29.
[44] Response to Discovery, OC-731, Attachment 2, Recommendations, page 29.
[45] Response to Discovery, OC-731, Attachment 2, Recommendations, page 31.
[46] Response to Discovery, OC-731, Attachment 2, Recommendations, page 31.
[47] Response to Discovery, OC-731, Attachment 2, Recommendations, page 32,
[48] Response to Discovery, OC-378, Attachment 1, Direct Testimony of Richard B. Hubbard, Evaluation of Proposed Gas Distribution Maintenance Expenses, 1999 GRC Docket No. 97-12-020, June 8, 1998.
[49] Response to Discovery, OC-378, Attachment 1, Hubbard Testimony, page 7.

Gas distribution maintenance spending over the eight year period was 14% less than adopted. PG&E spent more on gas maintenance than the adopted amount in 1995 and 1996. Over the ten year period 1987 to 1996, PG&E's actual gas distribution maintenance spending was 7.3% lower than adopted.[50]

PG&E overspent slightly on gas distribution operations expenses during the 1987 to 1996 time period. Over that ten year period, PG&E's actual total gas distribution O&M expenses were 1.7% lower than adopted.[51]

MHB's management finding was based on the August 1995 AA and B&V maintenance studies and internal reviews conducted by PG&E in 1997. Overland requested the internal reviews discussed in MHB's testimony. PG&E's response provided four of the seven division compliance reviews conducted in 1997.[52]

The division compliance reviews were three-day records reviews conducted by PG&E's Technical Services Department. The reports provide a list of findings supported by specific examples. The reports do not include tabulations that count the nonconforming records, but most of the findings were supported by numerous examples.

Selected findings are summarized below:[53]

- Sections of mains and services not leak surveyed within the required time period.
- Grade 2 and 3 leaks not graded according to standards.
- Grade 2 leaks not repaired or rechecked within the required time period.
- Grade 3 leak re-checks not performed within the required time period.
- List of distribution mains to be patrolled not reviewed annually and some patrols not performed on time.
- No process for eliminating inactive services and stub services.
- Emergency valves not maintained within the required time period.
- District regulator stations not maintained within the required time period.
- Maintenance forms not completed correctly to show work performed.
- Regulator station settings too high to prevent system from exceeding MAOP.
- Relief valve calculations incorrect or not performed within the required time period.
- Pressure recorders not calibrated within the required time period.
- Pipeline markers not placed in areas identified as needing a marker.
- Cathodic protection areas (CPAs) with pipe-to-soil readings below standards not corrected within the required time period.
- Leaks repair forms not completed correctly. Leak data base not updated correctly. Some leaks not assigned leak numbers or entered into the data base.

[50] Response to Discovery, OC-378, Attachment 1, Hubbard Testimony, page 7.
[51] Response to Discovery, OC-378, Attachment 1, Hubbard Testimony, pages 14 to 16.
[52] Response to Discovery, OC-732, PG&E was not able to locate the other three reviews.
[53] Response to Discovery, OC-732, Attachments 1 through 4.

- Cathodic Protection records not updated when changes were made.
- Valve maintenance records not updated when valves were replaced or removed.
- District regulator station Data Sheets not updated when station was altered.

The number of violations found in the 1997 division compliance reviews implied significant deficiencies in gas distribution management.

PG&E also provided the 1997 internal compliance review of its gas emergency response plan. The summary of findings indicates:[54]

> *Implementation of the...emergency plan...is inconsistent and incomplete in some cases. The findings suggest that management attention to completing preparedness activities for gas emergencies is needed to minimize potential hazards to the public...*

Specific findings included:

- 56% of (division) headquarters followed the employee skill assessment process outlined in the gas emergency plan.
- 76% of headquarters provided training in all the required topics.
- 39% of headquarters provided all emergency response personnel with all of the required training.
- 12% of headquarters had implemented the required liaisons with emergency services agencies.
- 76% of the items reviewed to verify the availability of needed resources in emergencies were satisfactory.
- 47% of headquarters had documented their procedures for emergency response personnel mobilizations.
- 72% of the items reviewed to verify that headquarters properly conducted emergency drills were satisfactory.
- There was no formal process for evaluating the effectiveness of the emergency response planning process for gas emergencies.

The internal reviews demonstrated the need to make improvements in PG&E's gas distribution operations in 1997.

1999 to 2006

Headcount Reductions

PG&E reduced the headcount in its gas distribution organizations by 13% between December 1996 and December 2000.

[54] Response to Discovery, OC-732, Attachment 5.

The headcount reductions continued through the end of 2010. The December 2010 gas distribution headcount was 29% lower than the December 1996 headcount.

The following tables shows the total headcount in PG&E's gas distribution operations by year.

Table 10-1 Total Gas Distribution Headcount

Total Gas Distribution Headcount As of Year - End 1996 to 2010	
Year	Total
1996	2,386
1997	2,565
1998	2,530
1999	2,157
2000	2,071
2001	2,088
2002	2,000
2003	2,099
2004	1,953
2005	1,972
2006	1,883
2007	1,820
2008	1,804
2009	1,723
2010	1,690
Source: Response to Discovery, OC-403 and OC-404	

The employees who respond to customer services calls are referred to as Gas Service Representatives (GSRs). The distribution operations headcounts shown above do not include the GSRs because they are part of PG&E's Customer Service organization. The following table shows the total GSR headcount by year.

Table 10-2 Gas Service Representatives and Dispatch Employees, Year - End Headcount

Gas Service Representatives and Dispatch Employees Year-End Headcount 1998 to 2011			
Year	GSRs	Dispatch	Total
1998	774	110	884
1999	778	113	891
2000	725	109	834
2001	710	107	817
2002	703	110	813
2003	696	113	809
2004	656	109	765
2005	657	104	761
2006	699	86	785
2007	665	91	756
2008	646	91	737
2009	637	95	732
2010	620	96	716
2011	638	94	732
Source: Response to Discovery, OC-1132, Note dispatch includes scheduling.			

Customers are encouraged to call PG&E when they smell gas. The GSRs also respond to customer odor complaints. The number of GSRs declined by 17.6% between 1998 and 2011.

California Energy Crises

PG&E began implementing cash conservation efforts in December 2000 in response to the California energy crises. The initial actions were expected to produce $180 million in savings during the first six months of 2001 and included:[55]

- Laying off approximately 180 temporary agency contract workers and union hiring hall employees;
- Implementing a hiring freeze;
- Reducing department budgets by an additional $40 million;
- Deferring an additional $118 million of expenditures;
- Freezing merit pay increases for non-union employees; and
- Deferring contributions to PG&E's long-term disability and nuclear decommissioning funds.

On January 11, 2001, PG&E announced it was suspending its common and preferred stock dividends. PG&E also announced that it would reduce costs by an additional $180 million over the first six months of 2001 by deferring capital expenditures and by laying off an additional 325 contract workers and hiring

[55] D.01-03-029, March 15, 2001, page 16. A.00-11-056.

hall employees. The additional layoffs included 200 distribution and transmission operations employees.[56]

PG&E also announced that it intended to take the following additional measures if its cash flow problems were not resolved:

- Deferring additional capital expenditures;
- Suspending incentive pay for management employees; and
- Laying off an additional 675 contract workers and hiring hall employees.

The additional 675 employees targeted for layoffs included a mix of electric and gas distribution and transmission employees, as well as technical contractors.[57]

The Commission ordered PG&E to rescind the force reductions on March 15, 2001 to the extent they adversely impacted service quality and reliability.[58]

PG&E filed for bankruptcy on April 6, 2001.[59] The Commission approved PG&E's Plan of Reorganization in December 2003.

Distribution O&M Expense

The following table shows PG&E's total distribution O&M expenses by year for 1996 to 2010.

[56] D.01-03-029, March 15, 2001, page 16.
[57] D.01-03-029, March 15, 2001, page 19.
[58] D.01-03-029, March 15, 2001, page 38.
[59] PG&E 2000 SEC 10-K Report, page 52.

Table 10-3 Total Recorded Gas Distribution O&M Expense

Total Recorded Gas Distribution O&M Expense 1996 to 2010 Dollars in Thousands	
Year	Total
1996	140,130
1997	149,258
1998	117,924
1999	113,867
2000	115,396
2001	108,077
2002	116,019
2003	116,552
2004	111,435
2005	122,755
2006	130,553
2007	138,680
2008	166,200
2009	251,919
2010	175,800
Source: FERC Form 2, page 324.	

PG&E's recorded distribution O&M expenses fell by 19 percent between 1996 and 1999. Distribution O&M grew at an annual average rate of 2.0% between 1999 and 2006. The Consumer Price Index increased on average by 2.5% per year between 1999 to 2006. The number of customers served by PG&E's system grew at an average rate of 1.4% during the same period. Inflation and system growth have an additive impact on O&M expenses. The relatively slow growth in O&M expenses during that period implied gas distribution resource constraints.[60]

Distribution O&M did not return to its 1996 level until 2008. The increases from 2008 and 2009 reflect spending on the Accelerated Gas Leak Resurvey Program (ALS) and associated leak repairs.[61]

Business Transformation Process

PG&E implemented the Business Transformation (BT) Process from 2004 to 2007. BT was a strategy to integrate business processes across organizational lines, deploy new technologies, and instill cultural change.[62]

The initial BT study began in 2004 and led to a number of initiatives focused largely on PG&E's customer service, energy delivery, supply chain and information technology functions.[63] The energy delivery

[60] Chapter 3.
[61] The ALS is described in Chapter 11.
[62] Response to Discovery, OC-115.
[63] Response to Discovery, OC-55.

function included electric and gas distribution. By the end of 2006, 77 initiatives had been approved across the Company as part of BT.

In 2006, PG&E struggled with the scope and breadth of the BT initiatives and managing the complexities of integrating and implementing multiple process and technology changes at the same time. The BT was terminated in December 2007, after the completion of many of the initiatives. Several incomplete initiatives were transferred to the relevant lines of business at that time and were no longer considered to be part of BT.[64]

The Energy Delivery Immediate Opportunity and Energy Delivery Early Release initiatives focused on improving business processes, centralizing jobs and people and introducing some technology enhancements. Those initiatives included the Supervisor in the Field Initiative and the creation of six Resource Management Centers (RMCs). The RMCs consolidated some functions that had previously been spread over 70 local offices.[65]

The BT Foundational Release was a comprehensive technology project designed to improve the tools and processes used to initiate, design and schedule gas and electric construction work. The BT Foundational Release was more technology-focused.

PG&E experienced significant difficulties with the implementation of the BT Foundational Release after its roll-out in October 2007. As a result of the difficulties, estimating productivity dropped to low levels, and Technical Services was unable to create jobs for the crews. Through an aggressive stabilization effort in early 2008, PG&E was able to improve estimating throughput and reduce the backlog of work.[66]

The BT Foundational Release included an SAP upgrade. As a result of the upgrade, the Foundational Release disabled the ability of PG&E's Transmission and Distribution (T&D) organization to track work unit completion and unit costs in SAP. That severely limited T&D's ability to assess production and productivity.[67]

PG&E's May 30, 2008 T&D 2009 - 2011 Operating Plan Presentation indicated:[68]

> *Currently do not have ability to accurately plan, track and manage work. Lost ability to plan, track and manage work with roll-out of BTF (limited previously existing functionality lost with October 2007 SAP upgrade - $1 million to reverse, expected by end of September)*

[64] Response to Discovery, OC-55.
[65] Response to Discovery, OC-55.
[66] PG&E 2011 GRC Testimony, Exhibit 8, page 12A-1.
[67] Response to Discovery, OC-972, Attachment 1, April 28, 2008 T&D Quarterly Business Review, page 33. Note T&D included both electric and gas operations.
[68] Response to Discovery, OC-972, Attachment 2, page 3.

T&D implemented manual tracking of 115 key units in 2008, but the manual tracking was time consuming and unreliable.[69]

T&D initiated an SAP upgrade in 2008 to address the problems. T&D regained the ability to track 55 key units in January 2009. Unit cost tracking improved over the course of 2009.[70]

Prior to the foundational release, BT was expected to produce $86 million in savings in 2008 in the T&D organization. Most of the expected savings were capital expenditures savings. The actual savings were much lower. In April 2008, the T&D organization estimated BT would produce $5 to $15 million in savings in 2008.[71]

The BT Geographic Information System (GIS) and Mobile releases were not implemented prior to the termination of the BT process in December 2007. PG&E put the GIS initiative on hold in October 2007.[72]

The purpose of the Enterprise Mobile program was to standardize PG&E's existing mobile computing platforms and expand the use of mobile technology to the portions of the field workforce that were using paper-based processes. After the termination of BT in December 2007, PG&E adopted a multi-year deployment approach for the program.[73]

San Rafael Employee Allegations

In March 2005, employees in PG&E's San Rafael Service Center made allegations about what they considered to be improper gas distribution leak survey and leak repair practices. The allegations were made through calls to PG&E's internal audit department and its compliance and ethics hotline.[74] In addition, the CPUC received an anonymous call with similar complaints.

Internal Audit conducted an investigation of the allegations and issued a report on September 14, 2005.[75] The allegations focused on the activities of an individual gas construction supervisor. The supervisor was alleged to have:

- Improperly downgraded leaks;
- Falsified leak repair inspection records;
- Pressured leak surveyors to downgrade leaks;
- Falsified leak repair records;
- Falsified a gas stub cut-off record; and
- Repaired a dig-in leak without conducting the required pressure test.

[69] Response to Discovery, OC-67, Attachment 3, T&D November 6, 2008 Quarterly Business Review, page 42, and OC-972, Attachment 1, page 33.
[70] Response to Discovery, OC-67, Attachment 7, September 2, 2009 T&D QBR, page 22.
[71] Response to Discovery, OC-972, Attachment 1, T&D April 29, 2008 QBR, page 18.
[72] PG&E's efforts to develop a gas distribution GIS are discussed in chapter 12.
[73] PG&E 2011 GRC Testimony, Exhibit-8, page 12A-6.
[74] Response to Discovery, OC-480, Attachment 20.
[75] Response to Discovery, OC-432, Attachment E.

Internal Audit could not validate all of the allegations with certainty. In light of all of the evidence, Internal Audit determined that the individual gas supervisor had made false statements during the investigation and was the "least credible" of all of the people it interviewed. Internal Audit determined that the supervisor had falsified leak repair records and had repaired the dig-in leak without conducting the required pressure testing. The findings resulted in the dismissal of the San Rafael gas distribution supervisor.

Internal Audit conducted a review of internal controls for documenting leak repairs as a follow-up to the San Rafael investigation. That audit concluded that quality control procedures for leak repairs needed to be strengthened.[76] Internal Audit recommended strengthening controls for completing and reviewing the "A-Forms" used to document leak repairs.

Internal Audit of Gas and Electric Maintenance Practices

Internal Audit conducted a review of PG&E's gas and electric distribution maintenance practices in 2006 as part of its normal audit plan. The January 31, 2007 Audit Report concluded that PG&E's controls over the maintenance process were effective to ensure that maintenance work was completed on time.[77]

The Audit Report noted that PG&E did not have a complete inventory of all of its gas distribution assets and the lack of an inventory adversely impacted maintenance planning. The Audit Report included the following discussion of maintenance records:[78]

> *Interviews...indicate that missing records for maintenance...are an infrequent, but ongoing problem. Recent audits...have also reported findings of missing or incomplete maintenance records. In almost every case, the missing records could be recreated from some combination (of other sources), but this process is time-consuming, inefficient, and expensive. The reoccurrences of this finding indicates that even when individual maintenance records are restored, the root cause of the missing records has not been fully addressed.*

The Management Action Plan for the audit required a root cause analysis of the reasons for incomplete or missing maintenance records. The root cause was not determined.[79]

The audit report described PG&E's goal of reducing third party excavator dig-ins on its gas lines. The report indicated "because many of the at-fault dig-ins result from incomplete record keeping, it may be possible to achieve a large reduction in at-fault dig-ins by correcting...maintenance documentation problems."

[76] Response to Discovery, OC-432, Attachment F.
[77] Response to Discovery, OC-432, Attachment J.
[78] Response to Discovery, OC-432, Attachment J, page 3.
[79] Response to Discovery, OC-594.

2007

San Rafael Employee Allegations

In January through April 2007, San Rafael employees made a number of allegations of improper gas distribution practices. Some of the allegations were made during the question and answer session at PG&E's Annual Shareholder meeting.[80] The allegations and complaints included:

- Over-pressure events at two gas regulator stations were not reported to the CPUC, and the stations and down -stream equipment were not inspected for damage after the events. Pressure station recording charts were altered to prevent discovery of the incident.
- Unapproved work methods were used for leak repairs.
- Vehicle-mounted leak survey equipment was not detecting leaks.
- Staffing shortages resulted in maintenance work not being completed in a timely manner.
- When gas service representatives investigate leak reports received from customers and find a non-hazardous leak, they report the leak and an M&C crew is supposed to be assigned to grade the leak. There was no process to ensure that the M&C crew actually graded the leak.

PG&E's Internal Audit Department investigated the allegations and issued a report on June 27, 2007. Internal Audit concluded that:[81]

- The over-pressure events were not reportable to the CPUC.
- The events did not cause any equipment damage.
- The down-stream equipment was not inspected for damage on a timely basis. The inspections did not occur until after employees complained to the supervising gas engineer.
- One downstream pressure recording chart was intentionally disabled.
- Several maintenance records for one of the stations were incomplete or missing.
- Supervisor review of maintenance records was inadequate.
- Several employees questioned the thoroughness of regulator station inspections.
- Prior inspection reports were inconsistent with the actual physical conditions observed at the stations.
- Gas maintenance crews at San Rafael had used unapproved gas repair work methods for years.

The Audit Report indicates:

> *These latest allegations, when put in context with all the other allegations over the past several years, highlight some workplace culture issues at the San Rafael Service Center*

[80] OC-480, Attachment 20.
[81] OC-432, Attachment K.

> *that are inconsistent with our company values...These include a long-standing distrust among and between employees, ignoring warning signs about problem supervisors, and a belief by employees that raising issues within the company's established channels is ineffective and that problems only get resolved when they are brought to management's attention by people outside the company.*

On June 25, 2007, Energy Delivery executive management made a "deep dive" presentation to PG&E's Chairman on gas issues.[82] The presentation reviewed the allegations made by San Rafael employees and provided PG&E's initial evaluation of the allegations.

On August 6, 2007, the Senior Vice President - Energy Delivery presented management's initial assessment of the allegations to the Audit Committee of PG&E's Board of Directors.[83] The presentation indicated:

- The gas maintenance program was fundamentally sound;
- Resources devoted to conducting (maintenance) work in San Rafael may not have been adequate;
- There were deficiencies in controls and procedures; and
- There were deficiencies in the leadership in San Rafael.

The presentation indicated:

> *Many of the employee concerns have been raised for several years and have not been adequately addressed. This problem appears to have been attributable, in part, to a failure of leadership in the San Rafael office to accept and address the concerns raised by employees.*

In mid-2007, PG&E received allegations that the acting San Rafael T&R Supervisor had falsified maintenance records while working as an M&C mechanic in 2004, 2005 and 2006. PG&E's Corporate Security Department issued their investigation report on those allegations on September 7, 2007, and the employee was dismissed on September 18, 2007.[84]

Internal Audit of Gas Leak Detection

On October 24, 2007, Internal Audit issued the following two audit reports:

- Review of Gas Leak Detection in North Bay and North Coast Divisions.[85]
- Field Audit of Gas Regulator Stations and Valves in Marin County.[86]

[82] Response to Discovery, OC-480, Attachment 14.
[83] Response to Discovery, OC-607, Supplemental.
[84] Response to Discovery, OC-432, Attachment N.
[85] Response to Discovery, OC-432, Attachment M.
[86] Response to Discovery, OC-432, Attachment N.

The San Rafael Service Center is part of the North Bay Division. San Rafael is located in Marin County. The Santa Rosa Service Center is part of the North Coast Division. Santa Rosa is located in Sonoma County, approximately 55 miles north of San Francisco.

The Leak Detection audit identified deficiencies in PG&E's program for using vehicle-mounted leak survey equipment, including procedures, training, operator qualification, equipment installation and software updates. This audit also identified some inappropriate responses to customer odor complaints where Gas Service Representatives (GSRs) classified leaks as non-hazardous that were subsequently determined to be Grade 1 leaks.[87]

The Santa Rosa leak survey program historically relied very heavily on vehicle-mounted leak survey equipment. The mobile equipment had found very few leaks since it was introduced in 1999. Prior to 1999, the leak surveys found a far higher volume of leaks. PG&E's standards required supervisors to review leak rate trends to identify problems. The Santa Rosa supervisor failed to do any trend analysis or investigate the cause of the low leak detection rates.

Santa Rosa line employees informed local management of the low leak find rates several times over a multi-year period. Local management failed to give the issue adequate attention. The employees had a perception that "[s]upervision did not want leaks found."[88]

PG&E standards also required the leak survey supervisor to review all leak survey maps and reports for accuracy, proper leak grading, and completeness. There was no evidence that the Santa Rosa Supervisor performed those tasks.

The corrective action plan for the audit recommended an accelerated leak survey of the Sonoma County gas distribution facilities.

Internal Audit of Gas Regulator Station and Valves in Marin County

The field audit of gas regulator stations and valves included physical inspections and records reviews for all 32 regulator stations in Marin County. The audit found missing, incomplete, inaccurate or inconsistent documentation for 30 of the 32 stations. The audit also included inspections and records reviews for all 352 distribution and transmission emergency valves in Marin County.[89]

The field inspections revealed a wide range of physical problems. Many of the physical problems required immediate corrective action. The physical problems included:[90]

[87] OC-432, Attachment M, page 13 and OC-606.
[88] OC-648, Attachment 1, Executive Talking Points, January 10, 2008, page 1.
[89] OC-432, Attachment N.
[90] Response to Discovery, OC-432, Attachment N, page 2.

- Corroded and unsafe vault access ladders;
- Regulator assemblies that failed to "lock up" (i.e. operate to halt gas flows when required to do so by down stream conditions);
- Stations that had missed required inspection dates;
- Maintenance procedures that were documented as performed which were impossible to perform because of the physical configuration of the equipment;
- Sulfur and debris accumulation in regulators;
- Regulator assemblies taken out of service and left in the field for years without backup;
- Regulator assemblies leaking gas into vaults;
- Clogged filter elements;
- Broken vault doors and covers;
- Poor station housekeeping;
- Corrosion of pipes, valves, controls and instrumentation;
- Obsolete regulation and filtration equipment;
- Inoperable valves;
- Valves without identification tags or markings, or with incorrect tags;
- Valves without stop indexes (making it difficult to determine by sight whether the valve is open or closed);
- Valves that had been paved over or buried in soil;
- Rusted, deteriorated, and obsolete valve assemblies; and
- One valve that was not listed on company maps or records.

The physical conditions observed in the inspections necessitated maintenance overhauls of 18 of the 32 stations.[91]

The audit concluded that supervisor review of maintenance work was inadequate in the San Rafael Service Center. The T&R supervisors "pre-signed" approvals of work that had not yet been performed on blank maintenance records. There was little evidence that supervisor observations of field work were effective in monitoring the quality of the work.[92]

Prior Quality Assurance audits were not effective. The prior audits did not include sufficient physical inspections of work to detect the scale of the problems found in the internal audit.

The overtime hours reported by T&R maintenance employees appeared to be excessive. Given the physical condition of the assets, the levels of overtime reported appeared to be unjustifiable. During the physical inspections, the audit team performed numerous maintenance tasks in much less time than employees charged to the same jobs in the past.

[91] Response to Discovery, OC-648, Attachment 1, page 1.
[92] Response to Discovery, OC-432, Attachment N, page 4.

Several employees had previously raised concerns about work practices in San Rafael with local management. The employees indicated that local management had ignored or downplayed their complaints. Employees in San Rafael had the perception that "[m]anagement has a low regard for quality."[93]

Internal Audit Corrective Actions Plans

The Leak Detection and Regulator Station/Valve Internal Audit reports included corrective action plans. Notable corrective action plan items included:[94]

Table 10-4 Internal Audit Corrective Action Plans

Internal Audit Corrective Action Plans October 24, 2007		
Audit	Item	Description
LD	2	Develop "Simulate City" training facility (underground facility training yard)
LD	3	Develop training for first line supervisors
LD	12	Reinforce requirement for supervisors to review leak survey documents and leak rate trends.
LD	14	Perform a leak resurvey of Sonoma County system
LD	20	Perform root cause analysis of leak survey issues
LD	24	Re-evaluate the training, tools and effectiveness of Gas Service Representatives for leak evaluation.
RV	1	Improve operator qualification controls
RV	6	Discontinue practice of supervisors "pre-signing" approvals
RV	10	Develop a method to track the status of all gas compliance requirements (SAP Work Mgmt System)
RV	13	Improve quality assurance audits
RV	14	Conduct system-wide audit of regulator station maintenance
RV	18	Perform a root cause analysis of regulator station and valve maintenance deficiencies
Note: LD is leak detection audit. RV is regulator station and valve audit		
Source: Response to Discovery, OC-413, Attachment 7.		

The corrective action plans were presented to the Board of Directors Audit Committee on October 29, 2007.[95]

[93] Response to Discovery, OC-648, Attachment 1, Executive Talking Points, January 10, 2008, page 1.
[94] Items are paraphrased for conciseness and readability.
[95] Response to Discovery, OC-480, Attachment 21.

PG&E provided the internal audit reports to the CPSD Utility Safety & Reliability Branch at meetings held on November 2, 2007 and November 16, 2007.[96] PG&E made a commitment to the CPUC to improve its quality control process in November 2007.[97]

Leak Grading Process Improvement Project

PG&E initiated a project to analyze and improve its leak grading process in October 2007. The project utilized the "lean six sigma" methodology.[98] The purpose of the project was to identify opportunities to improve leak grading system-wide.[99]

The project included a "gauge repeatability and reproducibility" exercise. PG&E developed a number of gas leak grading scenarios that should have been assigned a leak grade of 1 (Grade 1 Scenarios) or 2+ (Grade 2+ Scenarios) under PG&E's standards. A sample group of qualified leak surveyors were asked to grade each scenario.[100] The leak surveyors assigned the following grades to the Grade 1 Scenarios.

Table 10-5 Lean Six Sigma Leak Grading Analysis, Grade 1 Scenarios

Lean Six Sigma Leak Grading Analysis Grade 1 Scenarios Grades Assigned by Sample Group of Leak Surveyors	
Grade Assigned	Percent
1	53
2+	22
2	13
3	5
No Answer	7
Source: Response to Discovery, OC-449, Attachment 2 and OC-635.	

The qualified leak surveyors only correctly graded 53% of the Grade 1 Scenarios. The leak surveyors assigned the following grades to the Grade 2+ Scenarios.

[96] Response to Discovery, OC-413, Attachments 3 and 4.
[97] Response to Discovery, OC-638, Attachment 1.
[98] Response to Discovery, OC-440, Attachment 1.
[99] Response to Discovery, OC-480, Attachment 24.
[100] Response to Discovery, OC-635.

Table 10-6 Lean Six Sigma Leak Grading Analysis, Grade 2+ Scenarios

Lean Six Sigma Leak Grading Analysis Grade 2+ Scenarios Grades Assigned by Sample Group of Leak Surveyors	
Grade Assigned	Percent
1	58
2+	14
2	12
3	8
No Answer	8
Source: Response to Discovery, OC-449, Attachment 2 and OC-635.	

The qualified leak surveyors assigned a grade of 1 to 58% of the scenarios that should have been given a grade of 2+.

The April 24, 2008 project update includes the following Findings:[101]

- Performance is very low compared to PG&E's standards;
- Low level of repeatability;
- Operators assigned a grade below the standard in 20 to 40% of the occurrences. Additional effective training is essential;
- Some surveyors demonstrated an inadequate understanding of the standard and graded hazardous leaks as non-hazardous;
- Inconsistent use of Leak Survey Logs;
- Surveyors typically grade leaks "higher" when uncertain; and
- Inconsistent application of Grade 2+.

The results of the analysis conclusively demonstrated that operators were not consistently applying leak grading standards. The root cause was that the company's standards were complex and impractical for day-to-day field use.[102]

Sonoma County Leak Survey and Surveyor Re-Training

The Sonoma County leak resurvey commenced in late November 2007 and was completed on March 21, 2008.[103] The resurvey found approximately 3,602 reportable leaks, including 949 Grade 1 leaks. In addition to the reportable leaks, the survey found over 5,000 leaks on customer meter sets.

[101] Response to Discovery, OC-449, Attachment 2.
[102] Response to Discovery, OC-449, Attachment 1.
[103] Response to Discovery, OC-480, Attachment 22.

PG&E identified "systemic" training and operator qualification issues during the Sonoma County leak survey.[104] All of the surveyors assigned to the project were tested on the leak survey and leak grading processes. As a result of the testing, and subsequent field observations, management concluded that:

- There was inconsistency in the application of leak survey procedures between divisions and surveyors; and
- All leak survey personnel should be retrained on PG&E's leak survey procedures.

PG&E initiated a company-wide suspension of all leak survey activities on March 24, 2008 to allow all of its surveyors to complete a mandatory three-day training class on leak survey procedures.[105]

PG&E tested the surveyors after they completed the three-day training class. Of the 125 surveyors tested on Hydrogen Flame Ionization devices, 69% passed.[106] PG&E tested 57 leak surveyors on Remote Methane Leak Detection devices and 62% passed. Only 34% of the 51 surveyors tested on Optical Methane Detection (OMI) devices passed.[107]

[104] Response to Discovery, OC-714, Attachment 1, page 5.

[105] Response to Discovery, OC-480, Attachment 22.

[106] Hydrogen Flame Packs are the hand held units used in leak surveys that are conducted on foot. Hydrogen Flame Packs are PG&E's primary leak detection device. RMD devices use lasers and can be vehicle mounted or hand held. OMD devices are typically mounted on a vehicle and are used to find gas leaks on pipes located under roads.

[107] Response to Discovery, OC-972, Attachment 1, April 28, 2008 T&D Quarterly Business Review, page 14 and page 5 of the Key Takeaways document.

11. Management Deficiencies - 2008

Introduction

Chapters 10 through 13 provide a narrative history of the gas distribution management deficiencies identified by PG&E during the audit period. This Chapter covers the year 2008.

During 2008, PG&E expanded its investigation into the deficiencies, enhanced its leak survey process and committed to surveying its entire system for leaks using an enhanced process by year-end 2010.

PG&E determined that its prior leak survey process was ineffective. PG&E identified a number of root causes for the leak survey deficiencies, including inadequate planning, supervision and staffing. During the period 1999 to 2006, the number of Grade 1 leaks discovered by leak surveys decreased by 68 percent. That should have triggered a critical review of the leak survey process, but did not because PG&E failed to analyze its leak survey results.

PG&E retained a consulting firm, Exponent, to conduct a system-wide audit of regulator station and valve maintenance. Exponent identified pervasive system-wide deficiencies in PG&E's maintenance practices. PG&E's written standards were not widely understood or followed. Maintenance practices were not consistent across divisions. Employees were performing activities based on their own personal determination of the proper work methods. PG&E did not have an accurate gas distribution asset registry. The asset lists maintained by the divisions were incomplete and inaccurate.

The records prepared to document maintenance activities were inadequate. The records did not provide much information about the work that was done. The lack of information recorded on the records raised doubts about the quality of the work. The lack of objective reliable data to verify work completion was an important control weakness.

Supervision of regulator station and valve maintenance was inadequate. The supervisors did not have enough time to adequately supervise all of the activities within their work scope. Some supervisors were not qualified. The poor quality of the maintenance records demonstrated that supervisor records reviews were not effective. Prior Quality Assurance audits had failed to identify the systematic and recurring non-compliance with PG&E standards documented by Exponent.

Exponent concluded that a lack of accountability at multiple levels of PG&E's organization contributed to the deficiencies. PG&E did not have adequate communication channels for employees to raise concerns. Field personnel felt they had little influence on management above their immediate supervisor.

PG&E retrained its leak surveyors and enhanced its leak survey process in March 2008. The leak surveys conducted after that date found much higher leak rates. PG&E initiated a survey of a statistical sample of mains and services in five divisions. Those surveys found much higher leak rates. PG&E concluded that the leak surveys conducted prior to March 2008 were deficient and initiated a project to survey its

entire system using the enhanced process by December 2010. The results of the leak surveys conducted after March 2008 conclusively demonstrated that PG&E's prior leak survey practices were critically deficient.

PG&E did not have an accurate gas distribution asset register at any point during the audit period. PG&E's Integrity Management organization did not have the information needed to prepare reliable risk assessments. The information was trapped in paper records that could not be searched electronically. PG&E initially planned to develop a gas distribution asset register and Work Management System (WMS) by December 1998. PG&E's plans to implement an asset register and WMS were repeatedly delayed during the audit period.

Organizational Changes

PG&E formed a "Gas Matters" committee in January 2008 to oversee initiatives designed to improve its gas operations. The primary purpose of the committee was to oversee the implementation of the internal audit corrective action items.[1]

PG&E consolidated its gas engineering, asset management and technical services organizations into a single Gas Transmission and Distribution (Gas T&D) organization on January 31, 2008. The changes were designed to: (1) provide clear roles and responsibilities; and (2) focus the organization on measuring and improving performance.[2]

On July 1, 2008, PG&E realigned the Gas T&D organization to increase the focus on the ongoing Gas Matters and implement the philosophy of distribution integrity management.[3] The realignment included the creation of an interim project team to focus on the Gas Matters initiatives. The Gas Matters team issued executive status reports for the initiatives beginning in October 2008 and ending in August 2010.[4]

Statistical Sample of Divisions with Suspect Leak Trends

PG&E conducted a review of leak trends in all 17 of its divisions to identify divisions that were reporting low leak find rates. Based on that review, PG&E initiated leak surveys of statistical samples of mains and services in five divisions on March 24, 2008.[5]

PG&E completed the analysis of the results in August 2008. The results were unfavorable. The sample re-surveys found significantly higher leak rates than prior routine surveys. The leak rate for the sample

[1] Response to Discovery, OC-413 narrative and Attachment 6.
[2] Response to Discovery, OC-518, Attachment 1.
[3] Response to Discovery, OC-518 and OC-399, Attachment 3.
[4] Response to Discovery, OC-92, Supplemental.
[5] Response to Discovery, OC-480, Attachment 22, The five divisions were Yosemite, Sierra, Peninsula, Fresno and North Valley.

survey was 5.5 leaks per 1,000 services. The leak rate for the original routine surveys was 1.6 leaks per 1,000 services.[6]

Interim Quality Improvement Initiative

PG&E made a commitment to the CPUC to improve its gas quality control processes in November 2007. PG&E implemented the Interim Quality Improvement (IQI) process in April 2008.[7]

The IQI was implemented to standardize all gas self-assessments and reviews and to improve the quality of PG&E's gas maintenance, inspection and repair programs. The IQI targeted the six highest risk gas maintenance work areas:[8]

- Leak Survey and Repair;
- Gas Valves;
- District Regulation Stations;
- Cathodic Protection;
- Damage Prevention (M&L); and
- Customer Metering.

The IQI required supervisors to:

- Perform at least one field observation of work a month for each major work task within the supervisor's scope;
- Conduct ongoing reviews of maintenance records; and
- Verify the employees under their supervision had the required operator qualifications on a monthly basis.

The IQI also required the supervisors and divisions to report compliance metrics on a monthly basis. The compliance metrics were self-reported using manual processes.

The IQI was inadequate for a number of reasons and was replaced by the Gas Compliance Assurance Process (GasCAP) in July 2011.[9] The deficiencies in the IQI are described in Chapter 13 in the section addressing GasCap implementation.

South Sacramento Investigation

In the spring of 2008, PG&E's Law Department undertook an investigation of maintenance practices in the southern portion of the Sacramento Division. The investigation included a 100 percent review of the regulator station and valve maintenance records in that area. PG&E has asserted that the results of the

[6] Response to Discovery, OC-656.
[7] Response to Discovery, OC-660, Attachment 1.
[8] Response to Discovery, OC-638, Attachment 2, page 3.
[9] Response to Discovery, OC-636, Attachment 1.

internal investigation are confidential attorney work product, and PG&E declined to provide the results to Overland on that basis.[10]

The April 29, 2008 T&D Quarterly Business Review Presentation identified a Sacramento Division regulator and valve audit that was scheduled for completion on May 31, 2008. The audit included 20 regulator stations and 94 valves.[11] That audit was apparently the internal investigation undertaken by the Law Department.

Root Cause Analysis - Leak Detection

Senior management requested that Internal Audit provide an analysis of the management controls for PG&E's gas leak detection program to determine if the problems discovered in Santa Rosa and San Rafael could exist in other divisions. The results of that analysis are contained in the April 9, 2008 Internal Audit report entitled Controls for Gas Leak Detection.[12]

Internal Auditing reviewed leak detection planning, resourcing, supervision and monitoring controls and found deficiencies in each area. The report found that:

- Controls are insufficient to ensure that gas leak surveying is planned to effectively identify leaks and to reduce safety risks;
- Controls are inadequate to ensure that leak detection work is properly staffed and resourced;
- Controls around first-line supervision are insufficient to ensure that leak detection work is carried out in compliance with Utility standards; and
- Monitoring controls are insufficient to determine the system-wide performance of the leak detection program.

The report concluded that at least some of the problems discovered in the North Bay and North Coast divisions may have also existed in other divisions. Internal Audit classified the control deficiencies identified in the analysis as "high risk" issues.

During the period 1999 to 2006, the number of Grade 1 leaks found by leak surveys decreased by 68% system wide. Leak surveyors found 1,062 Grade 1 leaks in 1999. In 2006, leak surveyors only found 338 Grade 1 leaks.[13] The large decrease in the leak find rate should have triggered a critical review of the leak survey planning process.[14]

[10] Response to Discovery, OC-938 and OC-480, Attachment 59, page 3.
[11] Response to Discovery, OC-972, Attachment 1, page 14.
[12] Response to Discovery, OC-432, Attachment O.
[13] Several factors impacted this comparison besides leak survey effectiveness, including the Gas Pipeline Replacement Program and changes to leak grading criteria.
[14] Response to Discovery, OC-432, Attachment O, page 2.

Leak Surveys are performed by gas fieldmen. The surveyors grade the leaks they find. The same employees also perform other work such as: (1) mark & locate; and (2) assisting crews with repairs. Because their other work was time sensitive and difficult to forecast, leak survey work was frequently postponed when other work arose. The postponements created pressure to complete leak survey work at the end of the month to meet compliance deadlines. This approach sent the message that leak surveying was not a high priority and encouraged taking short cuts.[15]

Gas Service Representatives (GSRs) were dispatched as first responders when customers call in to report leaks. The GSRs did not have the equipment needed to find and grade outdoor gas leaks. If the leak was outdoors, the GSR called in a crew from the Division Maintenance & Construction (M&C) organization to locate and grade the leak. The controls over that hand-off were poor. The forms used to make the hand-off were not numbered or tracked. There were no controls to ensure that M&C actually provided the assistance requested by the GSR. The organizational division of work, coupled with poor controls over the hand-offs, prevented a comprehensive investigation and timely resolution of some customer leak calls.

When GSRs identified an outdoor leak and determine it is hazardous, they were required to stand-by until the M&C crew arrives. This put the GSR behind schedule. A portion of the GSRs employee evaluation was based on meeting scheduled appointment times. Some GSRs attempted unauthorized leak repairs on hazardous leaks to avoid the delays in getting to their next appointment. Some GSRs responded to routine appointments before responding to leak calls to improve their on-time appointment metrics.[16]

The report identified a number of serious deficiencies in gas survey supervision, including:[17]

- Many gas leak survey supervisors did not have sufficient experience;
- Leak survey supervisors did not have sufficient time to adequately perform supervisory functions; and
- Leak survey supervisors rarely observed work in the field.

The report described the following defect in incentives created by PG&E's leak survey metrics:[18]

> *The utility tracks the number of leaks per mile as a performance metric in each division...For the past several years, division employees have been tasked with finding ways to drive this number down. In this metric, fewer leaks are preferred and, mathematically, the most direct way to reduce the leak rate is to reduce the number of leaks found. As such, the leak per mile performance metric creates a disincentive to maximize the number of leaks found on survey.*

[15] Response to Discovery, OC-432, Attachment O, page 3.
[16] Response to Discovery, OC-432, Attachment O, page 5.
[17] Response to Discovery, OC-432, Attachment O, page 6.
[18] Response to Discovery, OC-432, Attachment O, page 9.

PG&E eliminated the use of the leaks per mile metric as an incentive in 2008.[19]

The report noted that leak surveys are one of the primary processes for validating the accuracy of gas asset maps. The leak surveyor is supposed to report any discrepancies they encounter between the maps and conditions they encounter in the field. The 2008 Sonoma County resurvey identified a 59-unit housing development built in 1994 that was not on the utility's maps. The resurvey counted over 5,000 gas services that had not been counted or reported in earlier surveys.[20]

Root Cause Analysis - Regulator Stations and Valves

The October 2007 Corrective Action Plan for the Internal Audit of Regulator Station and Valve Maintenance in Marin County required a root cause analysis for the deficiencies discovered in the audit.

The Corrective Action Item for the root cause analysis had a planned completion date of March 31, 2008. On March 20, the Gas Matters Project Manager sent an email to PG&E's Director of Gas Engineering asking for direction on how to proceed with the Corrective Action Item. The Director of Gas Engineering's March 12, 2008 response indicates:[21]

> *I have read and provided input to the [Leak Detection] "controls" report prepared by the [Lead Internal Auditor].*
>
> *I believe the 4 control deficiencies identified pertaining to leak survey apply to the reg. station and valve deficiencies as well...I don't believe we need to initiate any further effort to resolve this issue. I believe it would simply be semantics in whether it is reg. station or leak survey...*
>
> *I hate to see us initiate another effort unless we sincerely feel there is a different issue to solve.*

The Lead Internal Auditor's March 24, 2008 response to the Director of Gas Engineering's email indicates:[22]

> *I take your point, in that many of the underlying causes of the failures in the leak survey program (planning deficiencies, inadequate supervision, not listening to employees) also apply to the T&R side of the house, and in that sense, writing a whole separate report would be duplicative. Clearly, we all have enough high-priority work ahead of us in the next few months that we should avoid do-overs whenever possible.*

[19] Response to Discovery, OC-618.
[20] Response to Discovery, OC-432, Attachment O, page 10, footnote 17.
[21] Response to Discovery, OC-611, Attachment 1. Corrected the spelling of the word semantics.
[22] Response to Discovery, OC-611, Attachment 1.

However, I also think it would be worthwhile to spend some time thinking about those places where there are differences in the two situations. For example, the issues noted on replacement parts....and I think it might be helpful to analyze the controls around spare parts management to see if any early warning signals (e.g. why haven't we bought any replacement parts for reg. stations this year or last?) can be built into the process.

In other words, I agree the leak survey controls report can serve as a good baseline for T&R, but I'd like to see someone do an additional "compare and contrast" type of analysis for the specific T&R issues, to make sure there aren't any control gaps specific for T&R I haven't already called out.

PG&E determined that the controls issues identified in the Leak Detection Controls Report largely applied to the regulator station and valve maintenance deficiencies and did not prepare a separate root cause analysis for those deficiencies.[23]

According to PG&E, the April 2008 Internal Audit report titled Controls for Gas Leak Detection report satisfied the requirement for a root cause analysis of the deficiencies found in the internal audit of Marin County regulator station and valve maintenance.[24]

Targeted Leak Downgrades Report

The T&D organization developed an initiative in the spring of 2003 to reduce leak repair costs by reducing the number of leaks that were assigned a grade that required the leak to be repaired. The initiative was listed as a key initiative in the Spring and Fall 2003 Program Reviews. The purpose of the initiative was to reduce costs by making leak grading more consistent between divisions.[25]

The initiative was expected to save $1.5 million in 2003. The savings were expected to continue at an average rate of $1.2 million per year.[26] The Spring 2004 Program Review indicated the number of leak repairs made in 2003 were 20% lower than in 2002, partially because of the initiative.[27]

T&D initiated a new IGIS monthly report in August 2003 that flagged the number of Grade 2 and Grade 2+ leaks scheduled for repair with atmospheric gas content readings that fell outside of specified thresholds.[28] The report included a "target number of leaks for downgrade" based on the leak data in IGIS and an assumption that 25% of the Grade 2 and Grade 2+ leaks that fell outside of the specified thresholds should be downgraded.[29]

[23] Response to Discovery, OC-609.
[24] Response to Discovery, OC-413, Attachment 7.
[25] Response to Discovery, OC-406, Attachment 3, page 3, item 7; OC-406, Attachment 7, page 4, item 7 and OC-525.
[26] Response to Discovery, OC-406, Attachment 7, pages 1 and 4.
[27] Response to Discovery, OC-406, Attachment 12, page 6.
[28] The IGIS database includes the gas content readings made by the leak detection equipment used to grade the leak.
[29] Response to Discovery, OC-525, Attachment 1, Active Leaks Report.

The report calculated the potential cost savings that would be produced by downgrading the targeted number of leaks. The initial report showed $1.25 million in potential savings based on the leaks that were in the June 30, 2003 leak repair queue.[30] The reports showed the targeted downgrades and cost reductions at a local office level and were available to all IGIS users, including the supervisors responsible for the leak repairs.

On April 9, 2008, a member of PG&E's mapping department faxed the monthly report for March 2008 to the Lead Internal Auditor for the Controls For Gas Leak Detection Report. The fax cover sheet indicated:[31]

> *This report has existed for years and sets the tone or encourages actions by local supervisors and managers geared to reducing leak grades to Grade 3 leaks, rather than repairing, Grade 2 & 2+ leaks. Please note the current "Forecast of Excessive Leaks Scheduled for Repair" in Santa Rosa District projects that there are currently 1,356 leaks that could be downgraded for a "Potential Avoided Costs" of $2,375,702. The report even suggests that there are 68.75 leaks targeted for downgrade [in Santa Rosa]. This type of report and its perceived message that it is OK to downgrade leaks bolstered by reduced maintenance budgets has help foster our current situation. For management, they were able to meet budget targets and get their bonuses in the process. It was a win/win for the managers, but not for the actual Leak Survey process or the real needs of our facility maintenance programs. (This is not just my belief or opinions, but also those of some management employees I have spoken with in the past.)*

Santa Rosa was the focus of the October 2007 leak survey internal audit. PG&E's Vice President Gas Transmission and Distribution terminated the report on April 10, 2008.[32]

2008 Budget Replan

PG&E's actual electric and gas distribution spending was $40.9 million higher than budgeted in the first quarter of 2008 because of severe winter storms in January and February. In addition, PG&E determined that the Business Transformation savings reflected in 2008 transmission and distribution budgets were unrealistic. PG&E began a 2008 Budget "Replan" process in March 2008 to reset the 2008 budget consistent with revised expectations.[33]

On May 30, 2008 T&D submitted its 2008 Replan request to management. The request sought an additional $94 million to $126 million in 2008 expense funding for electric and gas distribution. The request included funding for gas management deficiency corrective actions authorized after 2008 budget was set. The 2008 Budget Replan is described in more detail in Chapter 9.

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[30] Response to Discovery, OC-525, Attachment 1.

[31] Response to Discovery, OC-964, Attachment 1. The Lead Auditor had previously asked the employee to provide a sample copy of the report. The fax responded to that request.

[32] Response to Discovery, OC-964, Attachment 1.

[33] Response to Discovery, OC-972, Attachment 1, April 29, 2009 Quarterly Business Presentation, pages 18, 44 and 56.

AEGIS Leak Detection Review

PG&E's liability insurance carrier, AEGIS, conducted an underwriting risk assessment of PG&E over a three day period in November 2007. GSRs are the first responder for customer odor complaints. AEGIS noted that PG&E's GSRs were equipped with a Gas Trac leak detection instrument for leak investigations conducted inside the customer's structure. AEGIS noted the "Gas Trac has no scale readouts and cannot determine if the sample is hazardous or a combustible gas."[34]

AEGIS recommended that PG&E equip its GSRs with Combustible Gas Indicators (CGIs). AEGIS noted the "CGI is a qualitative (measures combustible gas), and a quantitative (measures percentages of gas in the atmosphere) tool." AEGIS had made a similar recommendation in its 2003 risk assessment. The 2003 risk assessment noted "[a] Combustible Gas indicator is the instrument of choice" for inside leak investigations.[35]

PG&E retained AEGIS to conduct a review of its Gas Leak Detection program. The review was conducted over a three day period in May 2008. The May 30, 2008 two page letter report characterizes the review as a "cursory evaluation." AEGIS concluded that "in many respects PG&E's procedures for managing the safe transportation of natural gas are above average when compared to similar companies."[36]

AEGIS made the following recommendations:[37]

- Underground leaks should be graded with a Combustible Gas Indicator and a probe bar "at the time of detection." PG&E's current practice of grading underground leaks based on surface readings taken by Hydrogen Flame Ionization Instruments (HFI) was questionable. The vast majority of gas utilities used CGIs to grade underground leaks.
- PG&E should recheck grade three leaks annually. PG&E's current practice of checking Grade 3 leaks at the next annual survey resulted in some leaks not being rechecked for five years. The initial Grade 3 recheck for underground leaks should use a CGI.
- GSRs should be equipped with CGIs when responding to odor complaints. The report notes most gas companies equip the workers that respond to odor complaints with CGIs.
- PG&E should review the leak history of the Aldyl-A pipe installed on its system to determine if the pipe should be leak surveyed more frequently.
- PG&E should consider improving the content of its training for leak grading.

According to AEGIS, HFIs are a search tool, not a leak grading tool. All underground leaks detected through surface readings taken with an HFI should be confirmed and graded with a CGI and probe bar.[38]

[34] Response to Discovery, OC-624, Attachment 1, page 22.
[35] Response to Discovery, OC-624, Attachment 1, page 21, 22 and 24.
[36] Response to Discovery, OC-614, Attachment 1.
[37] Response to Discovery, OC-614, Attachment 1, page 2. Some of the recommendations made by AEGIS are not listed below. OC-614, Supplement 2, Attachment 1, is a June 27, 2008 update to the AEGIS letter report which includes some additional recommendations.
[38] Response to Discovery, OC-897, Attachment 1, pages 10, 15 and 19.

PG&E adopted a new subsurface leak investigation and grading practice in 2009. The new practice required the use of a CGI and probe bar to grade underground leaks. PG&E provided the following explanation for that change.[39]

> *Based on utility benchmarking, PG&E identified Subsurface Leak Investigation and Grading as an industry best practice, and adopted this practice in 2009. PG&E's prior practice was to grade leaks based on above ground readings utilizing a Hydrogen Flame Ionization Gas Detector (HFI). PG&E determined that [the new procedure was] a more accurate method to identify hazards and grade leaks. The process involves using an HFI to detect initial gas readings. A probe device is then used to create bar holes so that a Combustible Gas Indicator (CGI) can be used to determine the concentration of gas, and the extent of gas migration or possible hazard. The process better defines the location of the leak and the migration pattern to the most outer edge of the gas cloud/plume. This allows the surveyor to accurately grade the leak based on concentration, proximity to structures, public exposure, and likelihood of migration and future hazard.*

Odor Call Response Leak Grading Analysis

In May 2008, PG&E conducted an analysis of its leak grading process for customer odor calls. The analysis used the lean six sigma methodology.[40]

The analysis reviewed the process used when GSRs responded to leak calls, determined the leak was an outdoor leak, and handed off responsibility for the leak to M&C. One of the purposes of the analysis was to "ensure that PG&E was not walking away from a potentially hazardous leak" when responsibility was transferred to M&C.[41]

M&C grades the leaks as follows:[42]

- Grade 1 - Hazardous, requires immediate repair;
- Grade 2+ - Priority non-hazardous, requires repair within 90 days;
- Grade 2 - Non-hazardous, requires repair within 18 months; and
- Grade 3 - Non-hazardous, repair not required.

The analysis reviewed a sample of 181 leaks that the GSRs initially classified as non-hazardous during the first four months of 2008, and identified 47 leaks that were subsequently graded hazardous (Grade 1) by M&C. For those leaks, the average number of days between the initial check conducted by the GSR and the subsequent repair was 8.7 days. PG&E's standards required Grade 1 leaks to be repaired immediately.[43]

[39] Response to Discovery, OC-585.
[40] Response to Discovery, OC-450, Attachment 1.
[41] Response to Discovery, OC-450, Attachment 1, page 1.
[42] Response to Discovery, OC-1097, Attachments 1 and 3.
[43] Response to Discovery, OC-450, Attachment 1, page 3.

PG&E's policy was to repair all leaks found in odor call investigations within three weeks regardless of grade, as customers were aware of the leaks. The average repair time for the leaks that were not subsequently upgraded to Grade 1 was 8 days.[44]

The analysis noted inconsistencies in the processes used to notify M&C of the need to grade non-hazardous leaks. Prior to January 2008, the GSRs notified M&C by calling the local office clerk. PG&E implemented a new process in January 2008. Under the new process, the GSRs were required to initiate a case in the Customer Care case management system when they found a non-hazardous leak. The local office clerks checked that system periodically and notified M&C field personnel of the need to grade the leak. The analysis noted inconsistencies between divisions in the application of the new process.

The leaks initially classified as non-hazardous by the GSRs were recorded in the IGIS leak database as Grade 2+, pending grading by M&C. The initial grade of 2+ recorded in IGIS was not consistently updated to reflect the new grade assigned by M&C. The analysis noted that PG&E did not have a process to reconcile the cases created in the case management system to the leak grade and repair data recorded in the IGIS system.[45]

Odor Call Response - Internal Audit

Internal Auditing evaluated the effectiveness of PG&E's process for responding to customer gas odor calls. The audit report was issued on July 28, 2008. The GSRs responded to 178,000 customer leak complaint calls in 2007.[46]

PG&E implemented a new process for notifying M&C of unrepaired leaks identified by GSRs in January 2008. The new process required the GSRs to initiate a case in the Customer Care and Billing (CC&B) Case Management System. The audit focused on how gas leaks were investigated and resolved by GSRs and the new process for reporting unrepaired leaks to M&C. The audit found that the GSRs were not consistently following the new process for initiating cases in the CC&B Case Management System.

The management action plan for the audit indicated that some GSRs did not fully understand the importance of complying with the new procedures. The action plan included steps to "re-educate" the GSRs on the procedures and to implement a new case type in the case management system to effectively track gas leak referrals to M&C.[47]

[44] Response to Discovery, OC-450, Attachment 1, page 4.
[45] Response to Discovery, OC-450, Attachment 1, pages 7 and 8.
[46] Response to Discovery, OC-432, Attachment Q, page 1.
[47] Response to Discovery, OC-621, Supplemental, Attachment 1.

Regulator Station and Valve Maintenance Audits

PG&E retained a consulting firm, Exponent, to conduct the system-wide audit of regulator station maintenance required by the October 2007 Corrective Action Plan. The audit included both regulator stations and emergency valves.[48]

Exponent spent approximately two weeks at each of PG&E's 17 Divisions conducting interviews and reviewing maintenance records. The first division audit began on May 25, 2008 and the last division audit was completed on September 12, 2008. The audit was primarily a records review. Exponent conducted a limited number of physical inspections of regulators and valves as time permitted.[49]

The audit used a sampling approach. Exponent reviewed the records for a sample of 1,275 regulator stations and 1,975 emergency valves. PG&E's system has 2,839 regulator stations and approximately 9,675 emergency valves. Exponent reviewed the records for approximately 45% of the regulator stations and 20% of the emergency valves maintained by PG&E's distribution divisions. They performed cursory field assessments of the physical condition of 217 regulator stations and 34 emergency valves.[50]

Exponent issued draft audit reports for each individual division approximately one week after the field work was completed for the division.[51] PG&E received all 17 Division reports by October 30, 2008.[52] Exponent also prepared a system-wide audit report. The system-wide report was dated May 2009.[53]

The records review identified 28 stations and 21 valves that were currently past their required inspection dates.[54] That equated to 60 non-compliant stations and 105 non-compliant valves system wide.[55] Many of the non-compliant stations and valves missed their required inspection dates because repairs needed to be performed before the inspection could not be completed. The repairs were not performed on a timely basis. As a result, the inspection could not be completed by the required date.

Exponent's audit scope was limited to the current compliance status of equipment. The interviews conducted by Exponent revealed the following four examples of significant past non-compliance with inspection requirements:[56]

- Prior to approximately 2006, some equipment was not maintained as required in the North Bay Division;
- Prior to approximately 2005, some equipment was not maintained as required in the Central Coast Division;

[48] Response to Discovery, Emergency valves are required to shut off gas flow to an emergency shutdown zone.
[49] Response to Discovery, OC-293, Attachment 1, page 1.
[50] Response to Discovery, OC-293, Attachment 1, page 7.
[51] Response to Discovery, OC-413, Attachment 14, page 15.
[52] Response to Discovery, OC-92, Supplemental, Attachment 1, Oct. 30, 2008, Gas Matters Executive Status Report.
[53] Response to Discovery, OC-293, Attachment 1, Cover Page.
[54] Response to Discovery, OC-413, Attachment 18, Division Closure Statements.
[55] If the non-compliance rates for Exponent's samples held true for the entire population of stations and valves.
[56] Response to Discovery, OC-293, Attachment 1, page A-36.

- Prior to approximately 2003, some valves were not maintained as required in the DeAnza Division; and
- A number of valves missed compliance dates at the end of 2007 in the Yosemite Division.

The Exponent audit reports identified a large number of deficiencies in gas distribution work practices. The deficiencies can be organized into the following categories:

- Standards and work practices;
- Maintenance records;
- Supervision and quality control;
- Quality assurance;
- Asset registry;
- Corrective maintenance;
- Resource adequacy; and
- Leadership and culture

Standards and Work Practices

PG&E's written standards were not widely understood or followed in the field. Therefore, it was unlikely that the standards were being followed as written.[57]

The process for communicating new standards or changes to existing standards was ineffective. New or updated standards frequently did not reach front line personnel and when they did, they were not interpreted consistently across the company.[58]

Many of the employees actually performing the maintenance work did not treat the written standards as requirements that must be followed. Instead of relying on standards, they relied heavily on prior training and verbal communications. During interviews, many employees said their work practices reflected what they were taught in training classes, even if the training classes occurred years earlier.

When asked to explain the basis for their work practices, many employees indicated they did the work the way "so and so said to do it." Instead of relying on written instructions, the employees used the procedure recommended by the person they most agreed with, trusted or who gave them the answer they wanted to hear.[59]

The lack of specifics in the standards resulted in inconsistent work practices between divisions. The Exponent system-wide report identified the following examples of inconsistent work practices among divisions:[60]

[57] Response to Discovery, OC-293, Attachment 1, page 3.
[58] Response to Discovery, OC-293, Attachment 1, page A-4.
[59] Response to Discovery, OC-293, Attachment 1, page A-2.
[60] Response to Discovery, OC-293, Attachment 1, Appendix A. The Exponent system wide audit report includes additional examples of inconsistencies that are not listed below.

- Some conduct full external ("A") inspections of regulator stations prior to performing an internal ("B") inspection. Others do not.
- Some require that a regulator be capable of providing a full "bubble tight" lock up to pass an inspection. Others only require an "operational" lock up.
- Some lubricate all valves during every annual valve inspection. Others do not lubricate certain types of valves unless they are difficult to operate.[61]
- Some switch the primary and stand by runs during annual inspections of dual run stations. Others do not.
- If an unscheduled station internal "B" inspection is performed to address an operating issue, some delay the next regularly scheduled B inspection. Others conduct the next inspection on the pre-existing schedule.
- Some allow station inspections to proceed if the station "fire valve" is inoperable. Others do not.[62]
- PG&E Standards require the collection of station pressure data for a 16-hour period beginning immediately after the inspection is completed. Some begin the data collection period immediately following the completion of the inspection. Others delay the start of the collection period.

It was evident during the audit that many maintenance practices are not consistent across divisions and that employees were performing activities based on their own determination of the proper methods and procedures.[63]

Maintenance Records

The records prepared to document maintenance activities were inadequate. The amount of effort required to locate maintenance records for the audit varied significantly by division, and documents were frequently missing.

The records for many inspections did not provide much information about the work that was done. The lack of information recorded on the records raised doubts about the quality of the work and created an environment in which it was easy to falsify records. Exponent concluded that the lack of objective and reliable data to verify that maintenance work was performed was a very important control weakness.[64]

[61] In some divisions plug valves were not lubricated during annual valve maintenance unless they were difficult to operate. Plug valve refers to the valve design, not the function of the valve. PG&E's current policy is to lubricate plug valves annually. PG&E 2011 GRC Testimony, Exhibit PG&E-3, page 18-25.

[62] Fire valves are located outside the vault and are used to cut off gas flow to station in the event of a fire. Fire valves protect the crew members who are inside the vault during maintenance.

[63] Response to Discovery, OC-293, Attachment 1, page A-37.

[64] Response to Discovery, OC-293, Attachment 1, page A-9.

The inspection records were frequently incomplete. Many of the fields on the maintenance forms were left blank. Calibration records for test equipment were frequently missing. Several divisions continued to use obsolete forms long after they had been superceded by new forms.

The local offices maintain station and valve folders. The folders are important maintenance records because they are a primary source of information about individual stations and valves. The station folders should include the station diagram, station data sheet, and station maintenance record. PG&E did not have any standards governing the contents of the folders.[65]

Some folders lacked the required information. Many of the station diagrams were inadequate. Many of the data sheets were incomplete. Some of the station data sheets were inconsistent with the station diagram.[66]

Supervision and Quality Control

Supervision of regulator and valve maintenance was inadequate. Station and valve maintenance activities were supervised by Transmission and Regulation (T&R) supervisors. The T&R supervisors had too many other responsibilities to effectively supervise station and valve maintenance. The other responsibilities included customer connections, customer meters, leak survey and corrosion control. The T&R supervisors did not have enough time to adequately supervise all of the activities within their scope of work.[67]

Some supervisors were not qualified. They did not have the experience or training needed to understand the technical aspects of the work they were responsible for supervising. According to Exponent, the T&R supervisor position was viewed internally as an overly burdensome thankless job. Most T&R Supervisors worked long hours. Qualified and experienced employees had other options and avoided seeking or accepting the T&R supervisor positions. The T&R supervisor positions had significant turnover.[68]

Field supervision of work was inadequate. Time constraints and paper work limited the amount of time that T&R supervisors could spend on field inspections.

Supervisors were tasked with reviewing maintenance records for completeness and accuracy. Many maintenance forms lacked required supervisor approvals. Some of the supervisors did not have sufficient knowledge of maintenance work practices to identify work defects through a records review.[69] The poor quality of the maintenance records demonstrated that the supervisor records reviews were not effective.

[65] Response to Discovery, OC-293, Attachment 1, page A-11.

[66] Examples of the station data sheets and station maintenance records are available on the CPUC website, Pipeline Documents page. The attachments to the 2009 PG&E San Francisco GO-112 Audit Report includes completed examples of the regulator station data sheets and the station maintenance record forms.

[67] Response to Discovery, OC-293, Attachment 1, pages A-31 to A-33.

[68] Response to Discovery, OC-293, Attachment 1, pages A-31.

[69] Response to Discovery, OC-293, Attachment 1, pages A-32.

Quality Assurance

Quality assurance audits were ineffective. Prior QA reviews failed to identify the systemic and recurring non-compliance with PG&E standards noted in the Exponent audit.[70]

PG&E did not have a system-wide quality assurance organization. The division gas engineers were responsible for performing compliance reviews. Those reviews were compromised because the division gas engineers were, in some instances, auditing work they had participated in as technical advisors. Having division gas engineers perform the compliance reviews negatively impacted the working relationship between gas engineering and the field.[71] Field personnel were hesitant to bring problems to the attention of division gas engineers because the engineers were also the auditors.

The compliance reviews emphasized records reviews in the office over field inspections and analysis of work practices. Field inspections were not conducted on a regular basis.[72] The field inspections were not sufficient to identify discrepancies between maintenance records and physical conditions in the field.

Asset Registry

Gas distribution facilities should be tracked in an asset registry. The asset registry provides an inventory of the distribution facilities that can be used to verify that inspection requirements are met.

PG&E's divisions used the Gas Facilities Management (FM) System as their asset registry. The equipment lists contained in the FM system were used to schedule inspections. Each division independently operated its own independent FM system. There was no system-wide standardized method for accessing or editing the information in the FM systems for the individual divisions.[73]

The individual division FM systems were not standardized across the divisions. The divisions used different terminology and methods for listing equipment. Some divisions listed each individual valve. Other divisions combined multiple valves located in close proximity into a single listing.[74]

Exponent questioned the accuracy of the equipment lists included in the FM systems. Exponent observed that:[75]

> *[The FM] lists were created some time in the past based on the regulator station and valve folders that were available at the time. It does not appear as though these lists have been verified against what is actually in the field or on the drawings.*

[70] Response to Discovery, OC-293, Attachment 1, pages A-33.
[71] Response to Discovery, OC-293, Attachment 1, pages A-34.
[72] Response to Discovery, OC-293, Attachment 1, pages A-34.
[73] Response to Discovery, OC-293, Attachment 1, pages A-13.
[74] Response to Discovery, OC-293, Attachment 1, pages A-13.
[75] Response to Discovery, OC-293, Attachment 1, pages A-12.

Exponent noted that the FM equipment lists were incomplete because they did not include HPR-type district regulator stations. Employees indicated in interviews that PG&E had several thousand HPR-type regulator stations that were not on the FM list and were not being maintained by PG&E.[76]

Exponent concluded that most regulator stations, other than the HPR-type stations, were probably on the FM lists because T&R employees were generally aware of all regulator stations. Exponent had less confidence that the valve lists were complete. Exponent noted:[77]

> *Originally, the audit team was informed that there were approximately 1,700 emergency valves in the Sacramento Division. During the audit, 595 valve folders were identified. This large discrepancy is evidence that a single verified source for the number of emergency valves may not exist.*

Exponent found that eight divisions did not have a process to verify the equipment lists in FM by cross-checking with other information. The equipment lists in six divisions were incomplete, outdated or inconsistent.[78] Exponent concluded that the lack of a validated asset registry was a significant deficiency in PG&E's station and valve maintenance program.

Corrective Maintenance

Corrective maintenance refers to equipment repairs. Exponent concluded the corrective maintenance process was inadequate for two reasons:[79]

- Some repair work was not preformed in a timely manner; and
- PG&E did not have a system for tracking the status and backlog of corrective maintenance jobs.

The FM system was not used to track corrective maintenance. The local T&R supervisors and clerks manually tracked corrective maintenance using paper forms. Leak repairs were tracked in the IGIS system.[80] Exponent recommended implementing a formal centralized process for tracking corrective maintenance jobs.[81]

Exponent observed that inspections were frequently delayed because repairs required before the inspection that could be completed were not made on a timely basis. The Exponent report provided several examples of overdue corrective maintenance. Exponent concluded that over the long term,

[76] Response to Discovery, OC-293, Attachment 1, page A-14. HPRs are high pressure regulators that are used when gas is taken off of transmission lines to serve small numbers of customers in rural areas.
[77] Response to Discovery, OC-293, Attachment 1, pages A-13.
[78] Central Coast, DeAnza, East Bay, Sacramento, Stockton, and Yosemite, OC-413, Attachment 18.
[79] Response to Discovery, OC-293, Attachment 1, page A-17.
[80] Response to Discovery, OC-890.
[81] Response to Discovery, OC-293, Attachment 1, page A-17.

corrective work had not been performed in a timely manner to met the objectives of the maintenance program.[82]

Exponent indicated:[83]

> *Interviews indicate frustration among T&R personnel that corrective work related to safety and compliance is not being performed in a timely manner. Interviews indicate that other means are utilized when equipment replacement or upgrade requests are denied...*
>
> *Repeatedly denying requested compliance and safety related repairs could eventually have an adverse impact on the performance, reliability and integrity of the gas distribution system, as well as reduce the motivation and morale of...T&R employees...*

The "other means" used when equipment replacement requests were denied included: (1) diverting components ordered for new customer installations; (2) unofficial trades of spare parts between service yards; and (3) salvaging or scavenging parts from equipment taken out of service.[84]

Resource Adequacy

Exponent concluded that some locations did not have sufficient staffing to perform all of the necessary work.[85] The audit identified several instances where budget constraints resulted in non-compliance with inspection requirements.[86] Exponent recommended that PG&E evaluate the long-term funding needs of each of its T&R organizations and provide adequate funding.[87]

Leadership and Culture

Exponent concluded that a lack of accountability at multiple levels of PG&E's organization contributed to the deficiencies identified during the audit.[88] The assignment of the responsibility for maintaining compliance with standards was not clear.

The division of responsibilities between gas engineering and field personnel was not clearly defined or consistently implemented across divisions. Interactions between Gas Engineering and T&R employees were inefficient and ineffective in some locations. [89] The poor communication and lack of specified

[82] Response to Discovery, OC-293, Attachment 1, page A-24.
[83] Response to Discovery, OC-293, Attachment 1, page A-25.
[84] Response to Discovery, OC-293, Attachment 1, page A-25.
[85] Response to Discovery, OC-293, Attachment 1, page A-27.
[86] Response to Discovery, OC-293, Attachment 1, page A-29.
[87] Response to Discovery, OC-293, Attachment 1, page A-26.
[88] Response to Discovery, OC-293, Attachment 1, page A-17.
[89] Response to Discovery, OC-293, Attachment 1, page A-34.

engineering responsibilities reduced morale in the field and inhibited the reporting of potential issues to Gas Engineering.[90]

In some divisions, gas engineers did not have adequate knowledge of current conditions in the field or maintenance practices. That lack of knowledge inhibited Gas Engineering's ability to propose needed improvements to the system.[91]

PG&E did not have a system for sharing lessons-learned and implementing corrective actions on a system-wide basis. There was no mechanism to communicate good work practices or work process deficiencies across the divisions.[92]

PG&E did not have an adequate system to communicate and document compliance issues and ensure that corrective actions were implemented. Exponent recommended that PG&E establish a "robust corrective action system for reporting, handling and analyzing non-conformances."[93]

PG&E did not have adequate communication channels for employees to raise concerns. The employees interviewed by Exponent were not aware of any system to voice their concerns. When field employees did raise a concern, they did not receive any feedback on the resolution of the issue, resulting in frustration. Field personnel felt they had little influence on management above their first line supervisor.[94] Communication channels for field employees to raise issues outside of their localized division seemed rare to non-existent.

The lack of an "ear to hear" and the lack of feedback when concerns are raised, can have a very negative effect on employee motivation. In that situation, some employees will "do their job and go home." That situation may also engender an attitude among poor performing employees that the system can be manipulated.[95]

Leadership was inadequate in some local service yards. In some remote yards it was not clear who was leading the maintenance effort. The responsible T&R supervisors were not able to spend significant time in those locations. Sometimes other personnel essentially adopted an informal leadership role to make up for the lack of supervision. In certain locations, no one informally assumed the leadership role. When leadership was lacking, personnel were more likely to skip inspections or perform work incorrectly.[96]

[90] Response to Discovery, OC-293, Attachment 1, page A-30.
[91] Response to Discovery, OC-293, Attachment 1, page A-30.
[92] Response to Discovery, OC-293, Attachment 1, page A-18.
[93] Response to Discovery, OC-293, Attachment 1, page A-27.
[94] Response to Discovery, OC-293, Attachment 1, page A-27.
[95] Response to Discovery, OC-293, Attachment 1, page A-37.
[96] Response to Discovery, OC-293, Attachment 1, page A-35.

Exponent identified 506 corrective work repairs that needed to be implemented on facilities in the field. During 2009, the Divisions self-identified an additional 423 corrective work repairs similar to those identified by Exponent. In total, Exponent and the divisions identified 929 required corrective work repairs on regulator stations and valves. Most of the corrective items were completed in 2009. PG&E budgeted $2.0 million in expense and $3.8 million in capital expenditures for the corrective work repairs.[97]

Accelerated Leak Survey

PG&E retrained its leak surveyors and enhanced its leak survey procedures in March 2008. The routine leak surveys conducted after that date found significantly higher leak rates than prior surveys across the system.

PG&E compared the number of leaks found during the first seven months of 2008 to the number found in 2003. The total number of leaks found in 2008 was 152% higher than in 2003. The number of grade 1 leaks found in 2008 was 141% higher.[98]

PG&E concluded that the leak surveys it conducted prior to March 2008 were deficient based on the following:[99]

- The higher leak rates found in 2008;
- The results of the Sonoma County resurvey; and
- The results of the leak survey statistical sample of five divisions.

Prior to March 2008, PG&E's leak survey process was poor, resulting in inadequate leak detection.[100]

In August, 2008, PG&E decided to accelerate the survey of gas facilities that were previously scheduled for survey in 2011 and 2012.[101] The accelerated survey is referred to as the Accelerated Gas Leak Resurvey Project (ALS).

Most of PG&E's gas facilities are on a five-year leak survey cycle. The routine leak surveys scheduled for 2008, 2009 and 2010 covered the facilities previously surveyed in 2003, 2004 and 2005. Accelerating the 2011 and 2012 routine surveys would result in all of PG&E's gas facilities being surveyed using the enhanced process by December 2010.[102]

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[97] Response to Discovery, OC-92, Supplemental, Gas Matters Executive Status Report, March 1, 2010 Reporting Period, page 2.

[98] Response to Discovery, OC-855 and OC-882. PG&E selected 2003 for the comparison because most PG&E gas facilities are on a five year leak survey cycle. Most of the facilities surveyed in 2008 were previously surveyed in 2003.

[99] Response to Discovery, OC-480, Attachment 26.

[100] Response to Discovery, OC-574, Attachment 1, page 8.

[101] Response to Discovery, OC-714.

[102] Response to Discovery, OC-480, Attachment 26.

The decision to implement ALS was communicated to the CPUC Utility Safety and Reliability Branch on September 17, 2008.[103] The CPUC staff recommended accelerating completion to December 2009.[104]

The ALS began on October 13, 2008 and was completed on April 2, 2010.[105] The following table summarizes the facilities surveyed in the ALS by year.

Table 11-1 - Accelerated Gas Leak Resurvey Project, Mlles of Main and Number of Services

Accelerated Gas Leak Resurvey Project Miles of Mains and Number of Services 2008 to 2010		
Year	Mains	Services
2008	733	57,883
2009	13,766	1,086,654
2010	2,034	160,965
Total	16,533	1,305,502
Source: Response to Discovery, OC-698 and OC-699.		

The accelerated and routine surveys conducted in 2008 to 2010 found much higher leak rates than the prior surveys.

The following table shows the total leak repairs and grade 1 leak repairs resulting from surveys by year.

Table 11-2 - Leak Repairs Found by Survey, Total and Grade 1

Leak Repairs Found by Survey Total and Grade 1 2003 to 2011		
Year	Total Leaks	Grade 1 Leaks
2003	1,799	464
2004	1,592	340
2005	1,269	283
2006	1,295	352
2007	1,849	545
2008	11,448	3,013
2009	49,685	6,866
2010	13,444	2,592
2011	10,553	1,735
Source: Response to Discovery, OC-903, OC-905 and OC-906.		

PG&E's entire system had been surveyed using the enhanced leak survey process by the end of 2010. Over the nine-year period, an average of 10,326 total leaks and 1,799 Grade 1 leaks were discovered per

[103] Response to Discovery, OC-714.
[104] Response to Discovery, OC-480, Attachment 26.
[105] Response to Discovery, OC-480, Attachment 26 and OC-904, Attachment 1, Accelerated Gas Leak Resurvey Project - Final Report, April 15, 2010.

year. The 2011 amounts are very close to the nine-year averages. The 2011 results reflect a normal baseline level of annual leaks.

The numbers of leaks repaired in 2003 to 2007 were significantly below the normal baseline level because PG&E's leak surveys were deficient. The surveys in 2003 to 2007 failed to detect large numbers of leaks that existed when the surveys were done. The higher than normal levels in 2008 to 2010 reflected the temporary leak detection "bubble" that occurred when the leaks that were missed in 2003 to 2007 were found using the enhanced leak survey process in 2008 to 2010.[106]

The 2003 to 2007 surveys found an average of 397 Grade 1 leaks a year. In 2011, 1,735 Grade 1 leaks were found by survey. That implies the deficient surveys missed an average of approximately 1,300 Grade 1 leaks per year in 2003 to 2007. PG&E's leak survey results in 2008 to 2011 demonstrate that PG&E's leak survey practices were critically deficient prior to 2008.

Integrity Management Controls - Internal Audit

Internal Audit issued a report entitled "Audit of Gas Distribution Integrity Management Controls" on October 24, 2008. The audit reviewed control issues pertaining to risk management. The audit found that PG&E's controls were not adequate in the following areas:[107]

- Locating at-risk assets and assessing the pervasiveness of at-risk assets in the system;
- Tracking distribution assets and managing related maintenance activities;
- Assuring the adequacy of key integrity management processes; and
- Managing gas distribution system knowledge.

PG&E's distribution system was documented on paper-based maps that could not be queried. As a result, PG&E could not readily assess the pervasiveness of threats such as Aldyl-A and copper pipes or determine the location of the threats.

In the absence of a Geospatial Information System (GIS), gathering the data needed for risk assessments was labor intensive and unreliable. PG&E initiated work on a GIS for gas distribution as part of the Business Transformation process. That work was put on hold in late 2007 to reassess business priorities.[108]

[106] Response to Discovery, OC-669, Attachment 1.
[107] Response to Discovery, OC-432, Attachment S.
[108] Chapter 12.

The Audit Report indicated:[109]

> *The utility currently lacks effective methods to track gas distribution assets, such as pipes, regulators, and valves, and associated maintenance activities. As a result, it cannot readily: (1) ensure that maintenance activities cover all applicable assets; and (2) monitor and substantiate the work it completes without manually reviewing documentation....*
>
> *Gas Engineering began work two years ago to establish an "asset registry" in SAP and recently completed populating it. It is now transitioning to an integrated (SAP-based) maintenance scheduling system to address the issues described above...*

Gas Engineering planned to complete a pilot program to evaluate the new asset registry and maintenance scheduling system. Gas Engineering expected to develop a plan by the end of February 2009 for deploying the system company-wide.

Gas Engineering completed an integrity management risk assessment earlier in 2008. That required significant effort over the course of several months to read maps manually to obtain information needed for the assessment. The Audit Report indicated: [110]

> *In the absence of complete and accurate asset information, and reliable data about their operating condition, [Gas Engineering] had to rely on subject matter experts to conduct the assessments. This condition (1) compromises the utility's ability to substantiate risk assessment results and risk management decisions, and (2) highlights the utility's exposure to knowledge management risks.*
>
> *Gas Engineering was aware of the deficiencies in its risk assessment approach and of its lack of evidence to support the basis for existing mitigation plans, and was in the process of formulating solutions.*

Asset Register and Work Management System

PG&E's gas distribution Asset Register and Work Management System (WMS) were inadequate throughout the audit period. PG&E identified the need to improve its existing processes but failed to make the improvements in a timely manner.

An Asset Register is a data base that contains records for each individual item of equipment in the system. The data base records document the design and maintenance history of the equipment. Asset

[109] Response to Discovery, OC-432, Attachment S, page 3.
[110] Response to Discovery, OC-432, Attachment S, page 5.

Registers provide a basis for scheduling preventative maintenance and are used to analyze integrity management risks.

Work Management Systems are used to schedule maintenance work and to track the status of the work, including compliance with gas safety rules. The asset lists and maintenance histories included in the Asset Register are linked to the WMS and are used to schedule recurring preventative maintenance.

PG&E's primary gas distribution Asset Register and WMS during most of the audit period was the Gas Facilities Management (GasFM) system. GasFM was initially installed in 1988 and was last updated in 1995. GasFM was managed on a decentralized basis. Each Division had its own version of GasFM. The division level Gas FM systems were not integrated. GasFM did not produce any system-wide reports.[111]

GasFM included distribution equipment asset lists. GasFM used the asset lists to generate monthly reports showing the preventative maintenance scheduled for completion in the upcoming month.[112]

GasFM did not include corrective maintenance. Corrective maintenance was scheduled and tracked using paper-based processes at the local level. Corrective work requests were initiated on paper forms and the work was scheduled and tracked by the local T&R supervisor or clerk. Corrective maintenance was not tracked in an electronic data base. The corrective maintenance work management processes were not automated, with the exception of leak repair. Leak repair was tracked using the IGIS system.[113]

Arthur Andersen and Black & Veatch both recommended the implementation of new WMS systems in their 1995 preventative maintenance reviews. Black & Veatch also recommended the development of an Asset Register.[114]

PG&E filed its 1999 GRC Application in September 1997. PG&E's testimony described a new WMS to be completed in 1998.[115] The new WMS was to be used to schedule all maintenance work for electric and gas distribution. The testimony indicated:[116]

> *Current engineering, maintenance and construction work for gas and electric distribution is done without the use of an automated work management system and at a level that does not provide work planning, feedback and results at the individual job level.*

[111] Response to Discovery, OC-662.
[112] Response to Discovery, OC-662.
[113] Response to Discovery, OC-890.
[114] Chapter 10.
[115] PG&E Testimony in 1999 GRC, PG&E-3, page 7C-11.
[116] PG&E Testimony in 1999 GRC, PG&E-3, page 7C-12.

The Commission adopted capital additions of $24.8 million for the WMS in the 1999 GRC. The Commission also adopted an estimate of $30.8 million in combined electric and gas distribution annual capital and expense savings for the WMS.[117]

The WMS project was intended to be a replacement for the existing GasFM system. The WMS project included creating a new gas distribution asset register and implementing a WMS for gas distribution preventative and corrective maintenance.[118]

PG&E implemented a new enterprise accounting system, SAP, in 1996.[119] PG&E planned to use SAP for the new Asset Registry and WMS.[120]

The WMS project described in PG&E's 1999 GRC testimony was terminated after the testing phase was completed. The WMS was not rolled out to gas distribution.[121] The replacement of GasFM was deferred to allow PG&E's Information and Technology Services Department to focus on other programs with urgent compliance commitments to the CPUC.[122] PG&E could not provide the actual development costs incurred on the project before its termination.[123]

PG&E filed its 2003 GRC Application in November 2002. PG&E apparently had implemented SAP WMS for some electric distribution organizations by that time. PG&E requested funding for SAP WMS ongoing support and maintenance in its 2003 GRC. The request indicated its 2002 O&M forecast included $499,000 to "add gas distribution....work and user groups to the WM system." Planned enhancements for 2003 included integrating the gas leaks data base into WM to streamline the gas leak tracking process.[124]

PG&E authorized the Gas Preventative and Corrective Maintenance Project (GPCM) in 2004. The GPCM project consisted of developing and implementing a new Asset Register and work management tools for gas distribution in SAP to replace GasFM. The project was originally scheduled for completion in June 2006.[125]

The objective of the GPCM project was to "implement an electronic asset management system for gas facilities maintained by the Gas T&R (Transmission & Regulation) Department." The GPCM was designed

[117] 1999 GRC D.00-02-046, February 17, 2000, pages 435 and 436.
[118] Response to Discovery, OC-1140 and OC-1143.
[119] 1999 GRC D.00-02-046, February 17, 2000, page 452.
[120] Response to Discovery, OC-1143.
[121] Response to Discovery, OC-1140.
[122] Response to Discovery, OC-535, Attachment 1, page 2.
[123] Response to Discovery, OC-1142.
[124] PG&E 2003 GRC Testimony, PG&E-2, pages 13-69 and 13-70.
[125] Response to Discovery, OC-535, Attachment 1, pages 1 and 5.

to be fully integrated with SAP. The GPCM included a mobile solution for T&R work. Under the GPCM, SAP would be the asset registry system of record for gas distribution facilities.[126]

The total forecasted cost for the GPCM project was $9.1 million. The GPCM was conservatively expected to increase labor productivity by 9%. The project was expected to produce annual savings of approximately $2.2 million a year. The expected project payback period was approximately 10 years.[127]

The 2004 project authorization request included the following list of "drawbacks" of GasFM:[128]

- Labor-intensive manual entry is required on maintenance forms, and redundant input of data is necessary into other electronic systems;
- Maintenance is not well integrated within the SAP WM process for effective resource and order management;
- No centralized equipment asset registry exists. Only limited asset information is available in GasFM. Much of the facility information is only on paper forms, stored in local offices, which makes asset reporting laborious;
- There is no complete disaster recovery program. Servers are backed up, but a fire at the local headquarters could destroy all details of compliance;
- There is no consistency in the use of the GasFM system and data. Each division used the system in different ways, and records data in different formats; and
- There is a lack of centralized hardware and software support for the existing system.

Features of the GPCM included:[129]

- A generic, time based, SAP WM notification and order process for preventative and corrective work;
- Work assignments defined by specific orders, documenting units and time worked;
- A user-friendly front-end for scheduling and job assignment through SAP;
- A comprehensive mobile solution to support field work, which provides maps, drawings, standards & bulletins, and an electronic maintenance form and data sheet to simplify data entry; and
- Standard reports, and ad hoc query systems, at both the division level, and across PG&E, to monitor trends and provide analytical data for planning and decision making.

Specific benefits of GPCM included the "creation of a central Record of Assets for major gas equipment." Another specific benefit was "[b]etter information to do the job; all relevant information regarding the equipment or task will be available to the field personnel."

[126] Response to Discovery, OC-535, Attachment 1, page 2.
[127] Response to Discovery, OC-535, Attachment 1, pages 5 and 7.
[128] Response to Discovery, OC-535, Attachment 1, page 2.
[129] Response to Discovery, OC-535, Attachment 1, pages 2 and 3.

PG&E filed its 2007 GRC Application in December 2005. PG&E requested funding for the GPCM in that case. PG&E included $3.0 million in gas distribution expense in its 2007 test year forecast for the GPCM. The 2007 capital expenditures forecast also included $1.9 million for the mobile computing devices needed for the GPCM mobile solution.[130]

The GPCM project was replaced by the Business Transformation Work Scheduling and Manage Assets and Job Closing projects (MAJC) in 2006. The MAJC consisted of creating an Asset Register in SAP with preventative maintenance planning capabilities.[131] The work scheduling project included scheduling gas distribution corrective and preventative maintenance.

As part of BT, Gas Engineering began work in 2006 to establish an Asset Register in SAP. The SAP Asset Register was initially populated in 2007 by importing the asset lists contained in GasFM into SAP. The GasFM asset lists did not include all of the attributes that PG&E wanted to include in the Asset Register. PG&E is continuing to import and validate additional asset attribute information into the Asset Register in 2013. PG&E plans to complete the transition to the new SAP Asset Register in 2015.[132]

The software selected for the new WMS was the SAP Plant Maintenance module (SAP WMS). PG&E implemented SAP WMS for gas distribution corrective maintenance as part of the BT Foundational Releases in October 2007.[133]

Implementing a WMS for corrective maintenance is less complex than implementing a WMS for preventative maintenance. Corrective maintenance is initiated through an affirmative work request from the field. Preventative maintenance work is initiated by analyzing information in the Asset Registry and applying maintenance scheduling rules. PG&E planned to implement preventative maintenance in SAP WMS in January 2008. However, the October 2007 roll out of corrective maintenance did not go well, and PG&E decided to postpone the rollout of preventative maintenance. PG&E indicated:[134]

> *PG&E decided to postpone the rollout of preventative maintenance...until change management issues had been resolved, processes had been updated, procedures aligned, and preventative maintenance could be piloted to help ensure a successful implementation. PG&E began piloting preventative maintenance using SAP in October 2008.*

PG&E started on a long process of pilot programs and phased implementation of the preventative maintenance WMS both by technical work function and by division.

[130] PG&E 2003 GRC Testimony, PG&E-4, page 15-40.
[131] Response to Discovery, OC-600, Attachment 1.
[132] Response to Discovery, OC-623.
[133] Response to Discovery, OC-891.
[134] Response to Discovery, OC-891.

Asset Registers are an important prerequisite for an effective distribution integrity management program. PG&E's Distribution Integrity Management Steering Team held its first meeting on March 4, 2008. The materials for that meeting included an update on program status. The update indicates:[135]

> *Knowledge of the system ...PG&E's information systems on gas distribution are diverse and difficult to access. Much information resides on paper records in regional offices or was developed to address specific threats such as: Gas Pipeline Replacement Program, Meter Protection Program, and Copper Services Replacement Program. Complete central inventories of pipe and fitting information do not exist.*

Gas Engineering had populated the Asset Register in 2007 by importing asset lists from GasFM. The GasFM information in the Asset Register was incomplete and outdated. PG&E repopulated the Asset Register in 2009 and 2010 by importing the GasFM data a second time and integrating the Asset Register with other systems so the information was updated on an ongoing basis.[136]

The first pilot started in October 2008. The pilot covered regulator station and valve preventative maintenance in the San Francisco and Stockton Divisions.[137] PG&E implemented the SAP preventative maintenance WMS for distribution regulator stations and valves in all of its Divisions on a rolling basis between October 2008 and July 2009.[138]

PG&E filed its 2011 GRC Application in December 2009. PG&E's testimony on its work management systems covered electric and gas on a combined basis and was both brief and vague.[139] PG&E's capital expenditures forecast included $31 million in 2012 and $21 million in 2013 for electric and gas "work management."[140]

PG&E rolled out SAP WMS on a system-wide basis for gas distribution cathodic protection in December 2009. The roll-out also included local transmission regulator stations, valves and instruments. The December 2009 roll-out did not go well and was stopped in the first quarter of 2010.[141]

Problems with the December 2009 roll-out included:

- Asset registry not completely updated;
- Divisions were not prepared;
- Organization structure not ready for roll out;

[135] Response to Discovery, OC-582, Attachment 1, Outline of Distribution Integrity Management Program, February 21, 2008, page 2.
[136] Response to Discovery, OC-646, Attachment 1.
[137] Response to Discovery, OC-599.
[138] Response to Discovery, OC-717, Attachment 1, page 8.
[139] PG&E 2011 GRC Testimony, PG&E-3, page 1-38.
[140] PG&E 2011 GRC Testimony, PG&E-7, page 2A-7.
[141] Response to Discovery, OC-717, Attachment 1, page 5.

- SAP Database errors existed;
- Errors and incomplete information in uploaded files;
- Cathodic Protection validation files were not included in upload; and
- Cathodic Protection application was not totally functional because the action plan module was not ready.

PG&E initiated a stabilization process in 2010 to clean up the Asset Register data and validate the output of the SAP WMS. PG&E assigned Gas Asset Strategists to its divisions on a rolling basis to implement the stabilization process. The process included:[142]

- Printing out one year of work tickets from SAP WMS;
- Validating the SAP work tickets by comparing them to GasFM and the paper maintenance records; and
- Reviewing the SAP work tickets with the local T&R Supervisors.

The schedule for the stabilization process extended into 2011. The Stabilization process was not limited to the items included in the December 2009 roll-out. The Stabilization process included verifying the reliability of the SAP records for distribution regulator stations and valves.[143]

As of November 2010, PG&E planned to fully implement SAP WMS for cathodic protection by November 2011 and for instruments and local transmission regulator stations and valves by December 2012.[144]

After the stabilization process is completed, PG&E plans to expand SAP WMS to include additional technical functions, such as leak survey, meters, SCADA, vaults, and non-emergency valves.

PG&E filed its 2014 GRC Application on November 15, 2012. PG&E's testimony includes extensive discussion of its Pathfinder Project. That project appears to include some of the same functions as the SAP Asset Registry and SAP WMS.[145] Overland did not analyze the Pathfinder project because it was initiated after the end of the audit period.

The GasFM system was installed in 1988 and had significant limitations. Both Arthur Andersen and Black and Veatch recommended implementing a gas distribution WMS in 1995. PG&E recognized the need to replace GasFM and included a WMS project in its 1999 GRC Application. That project was terminated. PG&E approved a replacement project in 2004 with a scheduled completion date of June 2006. That plan proved to be unrealistic because PG&E did not have reliable and complete asset data.

[142] Response to Discovery, OC-717, Attachment 1, page 6.
[143] Response to Discovery, OC-718, page 3.
[144] Response to Discovery, OC-413, Attachment 21, page 15.
[145] PG&E 2014 GRC Testimony, PG&E-3, page 3-8.

PG&E is still working on completing the gas distribution Asset Register and WMS. PG&E is continuing to transition additional maintenance activities to the new gas distribution WMS. The Asset Register is expected to be completed in 2015.

Rancho Cordova Incident

On December 24, 2008, an explosion and fire caused by a gas leak destroyed a house in Rancho Cordova. One person was killed and five other people were hospitalized. The injured included a PG&E crew member and a local firefighter. Two adjacent homes were severely damaged.[146]

Rancho Cordova is a suburb of Sacramento. The gas leak occurred when a repair that was made in 2006 failed. The repair failed because it was made with pipe that was not designed or approved for use in a gas distribution system and was not installed properly. The unapproved pipe was incapable of passing the pressure test required for repairs. The required pressure test was not performed when the repair was made in 2006. After the explosion, PG&E fired the foreman that made the repair and two supervisors.

The investigation of the explosion revealed serious deficiencies in quality control for leak repairs. Supervisor review of the 2006 gas leak repair was ineffective. The repair documentation did not show any evidence of a pressure test. The supervisor records review failed to identify that deficiency.

PG&E received a customer odor call four hours prior to the explosion and dispatched a CSR to investigate. The CSR found the leak, determined it was hazardous, and called in a repair crew. The repair crew was delayed by a variety of problems and did not arrive until immediately prior to the explosion.

The CPUC determined that the explosion was the result of multiple violations of safety rules and fined PG&E $38 million.[147]

[146] Response to Discovery, OC-658, Attachment 1, NTSB Pipeline Accident Brief.
[147] D.11-12-061, December 1, 2011.

12. MANAGEMENT DEFICIENCIES - 2009 AND 2010

Introduction

Chapters 10 to 13 provide a narrative history of the gas distribution management deficiencies identified by PG&E during the audit period. This Chapter covers the years 2009 and 2010.

PG&E continued to investigate management deficiencies and implement corrective actions in 2009 and 2010. Exponent reviewed the existing process controls for six key gas distribution functions and found a variety of deficiencies. Exponents' process review demonstrated that many of the problems identified in its regulator station and valve audit were also prevalent in other key functions. PG&E management concluded that the problems were pervasive and initiated the Operational and Human Performance Plan to improve proficiency in core gas distribution functions.

A Geographic Information System (GIS) is a prerequisite for an effective gas distribution integrity management program. PG&E does not have a gas distribution GIS. PG&E initiated its first gas distribution GIS development project in February 2005. That effort was terminated in 2007. PG&E's second effort was terminated in 2011. PG&E now plans to implement a gas distribution GIS in 2014.

PG&E conducted internal audits of its leak detection and damage prevention programs in 2009. The audits found significant deficiencies. A subsequent quality assurance audit of the damage prevention program found additional critical deficiencies.

PG&E retained a consultant to assess the staffing adequacy in its local gas distribution T&R departments in 2009. The T&R departments are responsible for regulator station, valve and cathodic protection maintenance. The assessment concluded the T&R departments were understaffed by 26 percent.

PG&E discovered critical deficiencies in its record keeping for service lines installed by residential subdivision developers. Many of the records that the developers were required to provide were missing. The problem was pervasive system-wide. The root causes included widespread non-compliance with PG&E's standards, inadequate record management controls, inadequate auditing and poor communication between departments.

PG&E retained a consultant to assess 100 percent of its ALS leak survey documentation. The review found discrepancies on nearly all of the documents.

The Commission's Gas Safety and Reliability Branch (GSRB) conducts periodic safety inspections of PG&E's gas distribution divisions. PG&E conducts internal records reviews before each inspection. PG&E began sharing the results of those internal records reviews with the GSRB in early 2009. The internal reviews identified thousands of violations in 2009 and 2010. PG&E acknowledged that the high number of internal review findings in those years was unacceptable. The results of the pre-audit internal reviews demonstrate the pervasive nature of the gas management deficiencies.

2009

Process Controls Review

PG&E retained Exponent in 2008 to evaluate the current state of Gas Engineering's processes, practices and metrics in the following areas:[1]

- Mark & Locate;
- Leak Survey;
- Cathodic Protection;
- Measurement;
- Regulation[2]; and
- Control.[3]

The objectives of the review were to ensure that quality control was built into the processes. Exponent interviewed 65 PG&E employees for the review. The consultants presented their results in a presentation on January 19, 2009.[4]

The consultants prepared lists of existing barriers to implementing an effective quality control process. The general barriers listed for the standards and procedures area were:[5]

- Standard knowledge is low and therefore the intended process may not be followed consistently;
- New standards and work practices are introduced with limited field input and little testing by field experts and users;
- Interpretation of Standards varies; and
- Training and implementation are not coordinated, resulting in inconsistent application.

Work verification barriers included:[6]

- Maintenance and inspection tasks are typically performed by one individual, and there is little or no independent field check of work;
- Some supervisors are not familiar enough with the work to perform an effective review of the quality of the work;
- Until recently, Operator Qualification was "grandfathered" with no requirement for periodic refresher training; and
- The technical work verification responsibilities of the T&R supervisors may be too broad.

Exponent concluded the corrective work process was not effective because the process had too many steps and because there was no formal notification of completed work. Work processes in general were

[1] Response to Discovery, OC-420, Attachment 22, page 3. Page 7 identifies the members of the Exponent - Affinity team. Original does not have page numbers. Page numbers added by Overland. Presentation cover sheet is page 1.
[2] Regulation is the process of controlling gas pressure through the use of regulator stations.
[3] Control is the process of controlling the direction of gas flows through the use of valves.
[4] Response to Discovery, OC-413, Attachment 22. Page 7 lists the interviews.
[5] Response to Discovery, OC-413, Attachment 22, page 9.
[6] Response to Discovery, OC-413, Attachment 22, page 10.

hampered by excessive paperwork and long cycle times for administrative processes. The consultants noted that documentation, data accuracy and timeliness were not given priority in the processes.[7]

The interfaces between organizations and work groups were common weak spots in the quality processes. There was no feedback when work was handed over to another group. Lessons learned were not formally exchanged between divisions.[8]

There was a general lack of field understanding of "in process" quality metrics. Metrics were not being used to improve negative trends or avoid future problems. The purpose of the metrics was not clear to Supervisors and Superintendents. They regarded metrics as being punitive measures rather than as tools to improve the process.[9]

When field tasks are performed by single individuals with very limited checking and verification, processes must be in place to minimize the possibility of human error. Some of the causes of human error in that situation include time pressure, distractions, overconfidence, unclear instructions, changing requirements and fatigue. Exponent recommended a quality control approach that relied on:[10]

- Consistent training and qualifications for employees;
- Consistent and clear instructions and requirements to ensure repeatable performance;
- Qualified supervisors who identify potential errors through records reviews and field observations;
- Trending of metrics; and
- Quality assurance audits.

Exponent's Quality Control process review demonstrated that many of the problems reported in Exponent's regulator station and valve audit also applied to other areas such as leak survey and mark & locate.

Funding Request to Address Gas Distribution System Deficiencies

In February 2009, management submitted a recommendation to the Board of Directors for approval of a one-time program to resolve a number of "critical deficiencies" in the gas distribution system. The scope of the program included:[11]

- Completion of the system-wide Accelerated Leak Survey;
- Completion of regulator station and valve corrective work; and
- Implementation of consistent system-wide processes and controls with performance reporting capability.

[7] Response to Discovery, OC-413, Attachment 22, page 11.
[8] Response to Discovery, OC-413, Attachment 22, page 12.
[9] Response to Discovery, OC-413, Attachment 22, page 13.
[10] Response to Discovery, OC-413, Attachment 22, page 14.
[11] Response to Discovery, OC-669, Attachment 1, document titled One-Time Acceleration of Work to Address Deficiencies in the Gas Distribution System, page 1.

The estimated cost of the program in calendar year 2009 was $90.1 million.

The Board presentation for the funding request indicates:[12]

> *After the 2007 Annual Meeting of Shareholders, Internal Auditing and utility management investigated a series of allegations by employees and determined that a comprehensive corrective action plan was required...*
>
> *The initial findings reported by the employees were found in two PG&E Divisions. PG&E management conducted extensive investigations of its leak survey and six critical maintenance practice areas and found similar deficiencies. Management concluded that the issues were pervasive system wide. In the area of leak survey, the critical findings indicated that hazardous leaks have been significantly under reported and have compromised the confidence in the effectiveness of prior leak survey practices.*

Management proposed to accelerate corrective actions in the following six "major areas of concern" during 2009:[13]

- Gas leak survey and repair;
- Odor response and investigation;
- Operator qualification and training;
- Quality assurance and controls;
- Regulator station and valve maintenance; and
- Distribution integrity management.

The quality assurance and quality controls corrective actions included the development of a new work management system for preventative maintenance. The Board Presentation indicates:[14]

> *The gas distribution preventative maintenance (PM) program currently lacks adequate control mechanisms to actively manage maintenance work to ensure compliance with Federal regulations and/or PG&E Standards. This work has been performed to date using paper records and has been maintained and managed in the local offices. Management cannot easily query or access the records and the system cannot be validated without reviewing every paper record in the local offices. The utility must develop and implement SAP-based Preventative Gas Maintenance capabilities...This effort is fundamental to assuring compliance and is necessary to insure there are adequate controls and oversight in the performance of critical maintenance functions.*

[12] Response to Discovery, OC-669, Attachment 1, document titled One-Time Acceleration of Work to Address Deficiencies in the Gas Distribution System, page 1.

[13] Response to Discovery, OC-669, Attachment 1, document titled One-Time Acceleration of Work to Address Deficiencies in the Gas Distribution System, page 1.

[14] Response to Discovery, OC-669, Attachment 1, document titled One-Time Acceleration of Work to Address Deficiencies in the Gas Distribution System, page 4.

The following table shows the funding request by category.

Table 12-1 - One Time Funding Request for Corrective Actions

One Time Funding Request for Corrective Actions Gas Distribution System Deficiencies Dollars in Millions	
Category	Amount
Accelerated Leak Survey and Repair	46.4
Accelerated Leak Survey Contingency	20.4
Odor Response	5.0
Operator Qualification and Training	7.5
Quality Assurance and Controls (includes SAP WMS)	4.8
Regulator Stations and Valves	4.0
Distribution Integrity Management	2.0
Total	90.1
Source: Response to Discovery, OC-669, Attachment 1. Does not reflect July update.	

Chapter 3 describes the additional O&M expenses that PG&E incurred to address the gas management deficiencies that PG&E identified in 2007 and 2008.

Operational and Human Performance Improvement Plan

On February 18, 2009, management presented the Operational and Human Performance Improvement Plan to PG&E's Board of Directors.[15] The initial Board Presentation for the plan indicates:

> *Management (has) identified certain operational and human performance shortcomings in the Utility's business...the particular focus of the plan in ensuring proficiency in the core operational work of the Gas and Electric Transmission and Distribution (T&D) business...*
>
> *The Plan will be a series of initiatives designed to improve the basic standards, procedures, technical skills, control systems and management capabilities for T&D work.*

The Plan focused on improvements in the following areas:[16]

- Standards and procedures;
- Process design and execution;
- Skills training;

[15] Response to Discovery, OC-481, Attachment 3.
[16] Response to Discovery, OC-481, Attachment 3.

- Supervision and management;
- Quality control;
- Quality assurance;
- Performance metrics; and
- Culture

The Plan included developing a disciplined and rigorous culture of zero tolerance for safety violations and non-compliance, with a commitment to work quality.

The Plan included 30 interrelated initiatives. The initial focus was on fundamental high-risk work processes where there was room for significant improvement. On the electric side the Plan focused initially on grounding and switching. On the gas side the initial focus was on leak surveys, leak repairs, and mark & locate activities.[17]

Initiatives applicable to gas distribution included:

Table 12-2 - Operational and Human Performance Improvement Plan

Operational and Human Performance Improvement Plan Selected Initiatives Applicable to Gas Distribution	
ID No.	Description
EW01	Skills assessment and training for gas front-line supervisors
GM01	Gas leak resurvey project (ALS)
GM05	Gas employee skills enhancement and training
TD01	Improved processes for gas high-risk safety and compliance functions
TD03	Establish independent Quality Assurance and Quality Control organizations
TD06	Ongoing skill and competency testing and validation for bargaining unit employees
TD09	Establish Centralized Gas Methods and Procedures Group
TD21	Work management information system
TD07	Enterprise Mobile Solution to support work processes executed in the field
TD10	Geographic Information System for distribution
TD32	T&D core competency and organization review
TD11	End to end process governance model - process owners
Source: Response to Discovery, OC-481, Attachment 4.	

[17] Response to Discovery, OC-481, Attachment 4.

PG&E did not track the costs of implementing the initiatives.[18]

The TD01 initiative focused on improving work method compliance and controls for the following six key gas maintenance work categories:[19]

- Corrosion control;
- Leak survey;
- Mark & locate;
- Valve maintenance;
- Regulator station maintenance; and
- Measurement (Metering)

The initiative was needed to address the following problems:[20]

- Inconsistent application of work practices for high risk gas maintenance processes;
- Lack of clear definition of personnel and organizational responsibilities.

The initiative included establishing and rolling out new work methods, standards and procedures, along with the associated training, controls and metrics.[21]

Geographic Information System (GIS)

Geographic Information Systems (GIS) integrate common database operations (querying and statistical analysis) with the visualization and geographic benefits offered by maps.[22]

A GIS is a prerequisite for an effective gas distribution integrity management program. GIS integration is a key to all of the elements of distribution integrity management.[23]

PG&E began developing a gas transmission GIS in the mid-1990s. The gas transmission GIS database was largely populated by 1998.[24]

PG&E did not have a gas distribution GIS during the audit period. Prior to 2003, PG&E's gas distribution maps were maintained in paper form. PG&E began implementing the Gas and Electric Mapping electronic mapping platform (GEMS) in 2003. GEMS is an AutoCad-based system. GEMS was implemented by scanning PG&E's existing paper maps and registering the map image into GEMS. The scanned maps were images that could not be queried. The scanning process was completed in 2005.[25]

[18] Response to Discovery, OC-1052.
[19] Response to Discovery, OC-459.
[20] Response to Discovery, OC-459, Attachment 1.
[21] Response to Discovery, OC-498, Attachment 1, page B-2.
[22] Response to Discovery, OC-107.
[23] Response to Discovery, OC-430, Attachment 5, last page.
[24] Response to Discovery, OC-107.
[25] PG&E 2011 GRC Testimony, PG&E-3, page 16-7.

The Business Transformation GIS Project began in February 2005. The purpose of the BT GIS Project was to implement an Enterprise GIS. The BT GIS Project included electric and gas distribution and transmission. PG&E had completed the Plan, Analyze and Design phases and was in the midst of the Build, Test and Deploy phase when the project was discontinued in October 2007.[26]

The BT GIS project was terminated because other major technology projects were being implemented, and PG&E believed GIS would impose too much change on employees at the same time.[27] The October 2007 termination date coincides with the BT Foundational Release, which did not go well.

During the course of the BT GIS Project, PG&E did not update the legacy systems that were going to be replaced by the new GIS, including GEMS. During that time the legacy systems were only minimally maintained.[28]

In April 2008, PG&E initiated a project to stabilize the legacy systems including GEMS. The preliminary business case for the stabilization project indicated that GEMS maintenance was deferred and the system needed to be updated to current software versions to maintain vendor support. The current GEMS software was AutoCad 2000i. The GEMS software needed to be updated to AutoCad 2009. The Oracle data base software used by GEMS also needed to be updated. In addition the GEMS servers were past their life cycles and needed to be replaced.[29]

PG&E's Board of Directors approved the Operational and Human Performance Improvement Plan in February 2009. The plan included an initiative to develop a plan to implement an Enterprise GIS system.[30]

PG&E's March 2009 Enterprise GIS Solution Blueprint Presentation indicates PG&E planned to use the Land Base data model developed in the BT GIS Project for the new Enterprise GIS System. The model was populated with geographical data purchased from a vendor and periodically updated under a subscription service. PG&E planned to switch from the prior land base data provider to TeleAtlas.[31]

The GIS Blueprint indicates the mapping processes used by individual mapping offices were inconsistent. Individual mapping offices used different geographic coordinate systems and mapping symbols. The GEMS maps varied greatly in their positional accuracy.[32]

The facility coordinates used by the mapping offices did not correspond with the GIS land data base. The facility coordinates on the maps did not correspond with the coordinate systems used by commercially

[26] Response to Discovery, OC-583, Attachment 1, page 1.
[27] PG&E 2011 GRC Testimony, PG&E-3, page 16-8.
[28] Response to Discovery, OC-583, Attachment 1, page 1.
[29] Response to Discovery, OC-583, Attachment 1, page 1.
[30] Response to Discovery, OC-481, Attachment 4 and OC-583, Attachment 1, page 5.
[31] Response to Discovery, OC-481, Attachment 4, page 12.
[32] Response to Discovery, OC-583, Attachment 3, pages 8 and 17.

available GPS devices. That made it difficult for field forces to find equipment in the field.[33]
The 2009 scope included implementing a temporary gas distribution GIS by manually inputting data into the existing gas transmission GIS software.[34] PG&E intended to use the temporary GIS to conduct high-level analysis for distribution integrity management.

The GIS Blueprint noted that the data available for distribution integrity management analysis was currently very limited. "The only way to determine where different pipe types are (located) is by manually looking through thousands of maps and tracking on paper."[35]

The temporary gas distribution GIS would allow mappers to manually input data about pipelines and other facilities for use in distribution integrity management analysis and projects.[36]

PG&E filed its 2011 GRC Testimony in December 2009. The testimony included an extensive discussion of a new GIS project, the Automated Mapping and Facilities Management (AM/FM) project. The purpose of the project was to deliver an enterprise GIS. The total project cost was forecasted to be $63 million. The project was forecasted to be completed in 2012.[37]

The July 2010 business case for the Base GIS Project indicated that PG&E was generally lagging behind its peers in the implementation of an enterprise GIS.[38] The Base GIS business plan indicated:

> *The objective of the Base GIS Project is to gather and represent certain key data regarding PG&E gas and electric facilities into a single electronic repository that will provide much of the asset information (e.g. location proximity, size, connectivity to other assets, etc) necessary to enable a wide variety of core business functions.*

The Base GIS Project consisted of creating a fully functioning GIS populated with existing data from legacy systems. The scheduled completion date for the project was December 2013. The total estimated cost of the project was $69 million.[39]

The July 2010 business case indicates the Base GIS Project was a prerequisite foundation for obtaining the following benefits:[40]

- Consolidating the mapping and asset data puts an improved structure in place to manage record quality and integrity, and allows improvements in the way that asset records are managed and controlled from a compliance perspective.

[33] Response to Discovery, OC-583, Attachment 3, page 15.
[34] Response to Discovery, OC-583, Attachment 3, page 14.
[35] Response to Discovery, OC-583, Attachment 3, page 16.
[36] Response to Discovery, OC-583, Attachment 3, page 16.
[37] PG&E 2011 GRC Testimony, PG&E-3, pages 16-7 and 16-10.
[38] Response to Discovery, OC-583, Attachment 2, page 10.
[39] Response to Discovery, OC-583, Attachment 1, pages 3 and 10.
[40] Response to Discovery, OC-583, Attachment 1, pages 3 and 4.

- Enhancing field worker capabilities through real-time display of asset locations and characteristics on mobile devices, the ability to conduct real-time mapping updates in the field.
- Driving material improvements in data analysis and query capabilities for gas and electric distribution assets – "unlocking" the data currently trapped in static scanned maps.
- Enabling mapping productivity improvements through additional automation of the mapping process, thereby allowing mapping resources to focus on higher-value data analysis work.

The July 2010 business case noted that "[m]uch of PG&E's spatial and connectivity information on the Gas & Electric distribution assets is trapped in over 80,000 static, scanned images of maps drawn anywhere from 20-100 years ago on various coordinate schemes and requires manual/visual review to query."[41]

Converting the asset data on the scanned maps and paper records for inclusion in the GIS database was a major component of the Base GIS Project. The July 2010 business case indicates the data conversion process would occur over a 24 to 36 month period.[42]

The current gas distribution data consisted primarily of drawings and images. The data conversion process would transform the data from drawings with labels and symbols to database objects in GIS. The conversion represented a substantial improvement in the data because it would significantly enhance PG&E's ability to analyze the data. [43] The gas distribution data conversion process was scheduled for completion in December 2012.[44]

The September 2010 and November 2010 Automated Mapping and Facilities Management (AM/FM) update presentations discuss the status of the Base GIS and associated Business Enablement Projects. The Business Enablement projects were in addition to the Base GIS and enabled specific functions such as gas distribution integrity management.

The November 2010 update indicated the Base GIS was scheduled for completion in December 2013. The update indicates gas distribution data conversion started in October 2010 and was scheduled for completion in December 2013. The distribution integrity management enablement project was scheduled for completion in the fourth quarter of 2015. The total cost estimate for the Base GIS was $69 million.[45]

PG&E paused the Base GIS project in December 2010 to consider changes in project requirements associated with changes in the Gas Operations organization.

[41] Response to Discovery, OC-583, Attachment 1, page 4.
[42] Response to Discovery, OC-583, Attachment 2, page 5.
[43] Response to Discovery, OC-583, Attachment 2, page 19.
[44] Response to Discovery, OC-583, Attachment 2, page 33.
[45] Response to Discovery, OC-872, Attachment 2, pages 6, 8 and 19.

The pause was implemented after the gas distribution GEMS maps were edge mapped and aligned to the GIS coordinate system.[46]

During the pause, PG&E determined that:[47]

- A robust data validation process was required for each division;
- GIS data requirements needed to be more specific and detailed to support distribution integrity management; and
- Maintenance and inspection information needed to be integrated by linking the GIS to other systems.

PG&E concluded that the GIS functionality needed to be expanded to reflect additional attributes including asset condition.

The AM/FM project was terminated in September 2011 and re-launched as separate electric and gas projects.[48] The new gas distribution GIS project was entitled the Pathfinder Project. PG&E filed its 2014 GRC Application in November 2012. PG&E's testimony in that case includes an extensive description of the Pathfinder Project.

GIS is one of the main components of the Pathfinder Project. The project includes converting asset information that is currently in paper records and the GEMS system into the GIS database. The project also includes consolidating information in SAP and linking SAP to the GIS to permit distribution integrity risk assessments using information across SAP and the GIS.[49]

PG&E's total cost forecast for the Pathfinder Project is $93 million. The project includes six phases. The last phase is scheduled for completion in 2015.[50] The gas distribution GIS is expected to be functional by the end of 2014.[51]

During the audit period, PG&E lagged behind its peers in the implementation of gas distribution GIS. PG&E initiated its first gas distribution GIS project in February 2005 as part of the BT process. That effort was terminated in 2007. PG&E's second effort, the AM/FM project, was terminated in 2011. PG&E now plans to implement a gas distribution GIS in 2014.

[46] PG&E 2014 GRC Testimony, PG&E-3, page 3-10.
[47] PG&E 2014 GRC Testimony, PG&E-3, page 3-10.
[48] PG&E 2014 GRC Testimony, PG&E-3, page 3-10.
[49] PG&E 2014 GRC Testimony, PG&E-3, page 11-12.
[50] PG&E 2014 GRC Testimony, PG&E-3, page 11-15.
[51] PG&E's 2014 GRC testimony does not provide a schedule for the six phases. However, PG&E-3, page 3-18 indicates GEMS will be retired in 2014. GIS will replace GEMS.

Operational Reporting Initiative

Work on the Leak Survey and Repair Operational Reporting initiative began in February 2009. The initiative was part of a broader PG&E effort to develop an operational reporting system.[52]

The initial focus of the project was developing the capability to track and report the leak survey and leak repair performance metrics. Once the leak survey process was in place, the initiative was expanded to include Mark & Locate. The purpose of the initiative was to enhance quality control and reporting on the status and trends associated with leak survey, leak repair and mark & locate activities.[53]

The March 9, 2009 Leak Survey & Leak Repair Reporting Improvement Initiative presentation indicates that the need for management "to have their finger on the pulse" of leak survey and repair work was imperative. T&D management requested an assessment of leak survey and repair reporting in late 2008.[54]

The presentation includes the following "current state assessment:"[55]

> *The current state is composed of highly fragmented data collection efforts, resulting in data which is housed in a decentralized fashion, rendering any holistic analysis of the work itself difficult.*

The current state assessment noted that the data analysis process was inconsistent. PG&E did not have any metrics measuring the quality of the work performed.

Key leak survey data was not being collected consistently across the divisions. Leak survey data was not stored in a fashion that allowed for fast or accurate analysis. Data entry timeliness and accuracy was a problem. There was a lack of visibility into surveyor training.[56]

With regard to leak repair, although a large number of data fields were gathered to describe the leaks, analysis of that data was limited. Repair quality was not measured.[57]

The current data collection and metrics reporting processes involved a high level of manual effort.[58] The initiative included creating a central repository for leak survey and leak repair data and processes to ensure the consistency of that data. The initiative also included establishing metrics to measure the quality of leak survey and leak repair work. The initiative included the creation of scorecards and dashboards to provide a holistic view of the health of the leak survey and repair programs.[59]

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[52] Response to Discovery, OC-413, narrative, page 16.
[53] Response to Discovery, OC-413, narrative, page 16.
[54] Response to Discovery, OC-671, Attachment 2, page 2.
[55] Response to Discovery, OC-671, Attachment 2, page 3.
[56] Response to Discovery, OC-671, Attachment 2, page 3.
[57] Response to Discovery, OC-671, Attachment 2, page 3.
[58] Response to Discovery, OC-671, Attachment 2, page 9.
[59] Response to Discovery, OC-671, Attachment 2, page 4.

The ORI also included providing EZ Tech phone devices to locators to allow real-time reporting. The EZ Tech phones included GPS-based tracking devices to allow supervisors to track the locator's position.[60]

Odor Call Response Initiative

PG&E initiated an odor call response improvement initiative in early 2009 in response to the Rancho Cordova incident.[61] The major components of the initiative included:[62]

- Providing PG&E's 600 GSRs with new combustible gas indicators (CGIs) that were capable of measuring gas content in the air;
- Improving its odor response procedures; and
- Training the GSRs on the new procedures and equipment.

The CGIs were acquired and distributed in May and June 2009.[63] The training was conducted in April through June 2009. The training included improved procedures for conducting outdoor leak investigations.[64]

The responsibility for grading outdoor leaks did not change. Outdoor leak grading continued to be assigned to M&C crews.

Mark & Locate - Internal Audit

Internal Audit reviewed the effectiveness of PG&E's mark and locate (M&L) program as part of its 2009 audit plan. The report for the audit was issued on April 30, 2009.[65]

The audit identified several control weaknesses. M&L activities depend on accurate maps of PG&E's underground facilities. The controls to ensure the maps were up-to-date were not adequate. Some information the locators needed was omitted from the maps.

Locators submit Field Discrepancy reports when they find mapping errors. Mapping uses those reports to correct the maps. The Mapping Department had an un-managed backlog of Field Discrepancy reports that had not been mapped.

The audit identified weaknesses in supervision and training. A lack of training and supervision had led locators to record their activities inaccurately. The Audit Report noted that Gas Engineering had recently implemented the Interim Quality Improvement program to improve supervision. Supervision had also recently been improved by assigning dedicated M&L supervisors to each division. Improvements planned for the remainder of 2009 included training for M&L supervisors and providing tracking devices (EZ Tech GPS phones) to locators to enhance oversight.

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[60] Response to Discovery, OC-671, Attachment 3 and OC-940, Attachment 1, page 5.
[61] Response to Discovery, OC-413, narrative.
[62] Response to Discovery, OC-646, Attachment 1.
[63] Response to Discovery, OC-646, Attachment 1.
[64] Response to Discovery, OC-413, Attachment 29.
[65] Response to Discovery, OC-432, Attachment U.

The audit noted that M&L work was managed in a decentralized manner and that had resulted in inconsistent work practices and performance monitoring deficiencies. The audit report indicated that "without standard work practices and complete monitoring, the utility cannot assure the quality and timely completion of M&L activities."[66] The management action plan for the audit includes the preparation of a Damage Prevention Manual to standardize work practices.

Internal Audit concluded that root cause investigations for at-fault dig-ins were inadequate. Rather than assessing root causes, the investigations focused on documenting the event and related repair work. The lack of effective root cause analysis limited visibility into systemic issues.

Integrity Management Program Oversight - Internal Audit

Internal Audit reviewed oversight controls for gas distribution integrity management programs as part of its 2009 audit plan. The review focused on the following programs:[67]

- Damage Prevention;
- Pipeline Public Awareness;
- Gas Pipeline Replacement Program;
- Copper Services Replacement Program;
- Cross-Bored Infrastructure;
- Meter Protection Program;
- Interim Quality Initiative;
- Isolated Steel Services Program;
- Cathodic Protection; and
- Regulator and Valve Audits.

The report for the audit was issued on April 30, 2009. The report concluded that:[68]

> *[M]onitoring controls for appraising the progress and effectiveness of integrity management programs are not adequate. Overall, monitoring and reporting controls over key programs [are] fragmented, incomplete, and not conducive to managing the [gas distribution integrity management] program.*

Leak Survey Audits

Internal Audit and Quality Assurance partnered in a review of leak survey controls in 2009. Both organizations issued reports for the review in July 2009. The review focused on the Fresno, Sacramento and San Jose divisions and included the Accelerated Leak Survey and routine leak survey programs.[69]

[66] Response to Discovery, OC-432, Attachment U, page 4.
[67] Response to Discovery, OC-432, Attachment V.
[68] Response to Discovery, OC-432, Attachment V, page 2.
[69] Response to Discovery, OC-432, Attachment X and OC-490, Attachment 2.

Internal Audit found that controls over the leak survey program were not adequate. Monitoring was inadequate because PG&E had not sufficiently analyzed leak rate trends in 2008 and 2009.

The ALS included next day re-surveys on a sample basis. PG&E adequately investigated differences in the Grade 1 leaks identified in the original and verification surveys. PG&E did not investigate the differences for leaks below Grade 1. The corroboration rate for non-Grade 1 leaks was only 29 percent during a recent period.[70] There was no process to determine root causes or take corrective actions when non-Grade 1 leaks were found in the verification surveys that had not been found by the original surveyor. The effectiveness of the leak survey program could not be validated without a root cause analysis of the low corroboration rate for non-Grade 1 leaks.

Internal Audit concluded that controls over leak survey documentation were not effective. The auditors reviewed 282 gas leak survey records and found missing or incorrect data on 53 percent of the records.[71] The QA audit report indicated:[72]

> *Although record-keeping of leak survey activities is poor, based on interviews and the field reviews, the audit team felt confident that the actual leak surveys were being performed as expected. However, there is a disconnect between performance of leak surveys and demonstrating the results through PG&E's paper-based records.*

Supervisory reviews of leak survey records were ineffective. Surveyors are supposed to mark each facility surveyed on the plat sheet as they do the work. Approximately 20 percent of the plat sheets included facilities that had not been marked as surveyed. Gas Supervisors are supposed to review the plat sheets to ensure that all facilities were surveyed and return the sheets to the surveyors to correct any errors or omissions. The auditors did not find any evidence that the supervisors had taken steps to resolve the plat sheet marking omissions identified in the audit.

The leak survey supervisor in the Fresno division had not reviewed any completed survey maps in 2009. A facility map that was incorrectly printed "blank" was signed off as having been surveyed by the surveyor. The supervisor review did not identify that obvious documentation error. The facilities that should have been shown on the map were not actually surveyed. When the auditors discovered the error, the plat map was just a few days away from missing its compliance deadline.[73]

Some leak survey documentation had been discarded. The Fresno division discarded leak survey logs for days when the surveyor did not find any leaks.

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[70] Response to Discovery, OC-432, Attachment X, page 4. The corroboration rate is calculated by dividing the number of matching leaks in the two surveys by the total number of leaks found in the surveys.

[71] Response to Discovery, OC-432, Attachment X, page 6.

[72] Response to Discovery, OC-490, Attachment 1, Condition Report CR-002.

[73] Response to Discovery, OC-490, Attachment 2, Condition Report CR-007.

Four plat maps in the San Jose divisions were found to have exceeded the maximum 63-month leak survey frequency. The QA audit report indicates "due to a loss in productivity due to more careful surveys...a loss of [qualified] personnel...and limited availability due to non-survey tasks, Division employees are pushing the 63 month time limit for conducting surveys."

Quality Assurance and Quality Control Organizations

PG&E established small independent Quality Control and Quality Assurance organizations within its electric and gas T&D organization during the second and third quarters of 2009.

The Quality Assurance organization included both electric and gas teams. The gas team was established during the summer of 2009 and included a headcount of five positions.[74] Funding for the gas team organization was constrained in 2009 because of "PG&E funding issues." Some requested resources were diverted to an initiative to improve gas and electric work methods and procedures.[75] The gas team participated in audits of the gas leak survey and damage prevention programs in 2009.

The Quality Control organization developed QC processes, including sampling methodologies. The QC organization was responsible for overseeing the implementation and monitoring of QC activities throughout the T&D organization.

The QC organization was organized into gas and electric groups. The initial scope document for the organization shows a headcount of 16 for the gas group, including 8 positions for the accelerated leak survey verification re-surveys.[76] The gas QC group focused on leak survey, leak repairs, open leak grading and M&L activities in 2009 and 2010.[77] The gas QC group was also responsible for overseeing the Interim Quality Improvement process.

Work Force Reductions and Cost Controls

T&D implemented organizational cost containment measures to partially offset the increase in costs caused two large winter storms in early 2008 and by the ALS and associated leak repairs. By November 2008, T&D had implemented hiring controls.[78] The T&D 2009 Operating Plan, issued in March 2009, indicates "strict hiring controls to remain in place through 2009; VP approval required to fill any vacancy."[79]

[74] Response to Discovery, OC-461, narrative and Attachment 1.
[75] Response to Discovery, OC-461 and OC-494.
[76] Response to Discovery, OC-460, Attachment 1.
[77] Response to Discovery, OC-460.
[78] Response to Discovery, OC-67, Attachment 3, page 50.
[79] Response to Discovery, OC-67, Attachment 4, page 93.

By September 2009, T&D also had cost containment measures to reduce contractor spending and other discretionary spending. The measures included eliminating non-essential training, discretionary overtime and non-mandatory routine leak repairs.[80]

In August 2009, PG&E began a company-wide workforce reduction initiative that was completed in March 2010. The initiative reduced PG&E's total headcount by 493 positions. That represented about 2 percent of PG&E's total headcount.[81]

At the time of the reductions, gas distribution operations were included in two organizations - Energy Delivery (ED) and Engineering and Operations (EO). The following table shows the distribution of the reductions by area.[82]

Table 12-3 - 2009 Work Force Reduction Program

2009 Work Force Reduction Program Headcount Reductions Actual	
Organization	Total
Corporate Services	140
Energy Delivery	101
Customer Care	101
Engineering & Operations	72
Diablo Canyon	46
Shared Services	29
Other	4
Total	493
Source: Response to Discovery, OC-464, Attachment 1.	

ED and EO accounted for 35 percent of the reductions.[83] The 2009 hiring freeze and workforce reductions had a significant impact on gas distribution staffing. Total gas distribution headcount declined by 114 positions between December 2008 and December 2010. That represented a reduction of 6.3 percent.[84]

Mapping - Internal Audit

Internal Audit reviewed controls over electric and gas mapping. The review focused on the process for posting newly constructed facilities to existing maps. The audit report for the review was issued on October 22, 2009.[85]

[80] Response to Discovery, OC-67, Attachment 7, page 16.
[81] Response to Discovery, OC-115 and OC-464.
[82] Most of the shared services reductions were in materials management, environmental services and fleet.
[83] Response to Discovery, OC-464 provides a list of the 493 positions that were eliminated. Overland identified 30 positions that could be directly associated with gas distribution and transmission operations. The list included many ED and EO positions that could not be directly identified as electric or gas positions.
[84] Chapter 7. The headcount was 1,804 as of December 2008 and 1,690 as of December 2010.
[85] Response to Discovery, OC-432, Attachment Y.

The Mapping Department has approximately 240 employees. During the first six months of 2009, Mapping posted approximately 21,000 new facilities to its maps.

Once Mapping receives a construction job package it takes an average of 120 days for it to post the new facility on its maps. Mapping does not consistently receive construction job packages on a timely basis. Only 38 percent of the construction job packages were received within 30 days after construction was completed and 34 percent of the job packages were received more than 90 days after the completion of construction.[86] Mapping prioritized posting based on the date the job was received, not the date construction was completed. Jobs that take 90 days to receive and 120 days to post were not mapped until 7 months after construction was completed.

Mark & Locate activities depend on complete up-to-date maps. Mapping had a process to pre-post unmapped construction jobs to maps based on job estimates it received prior to construction. During interviews, mapping supervisors indicated that process was a high priority. However, there was no formal requirement to post planned construction jobs to maps and there was no effective process to track the pre-posting of planned construction jobs.

Organizational Changes in 2009

On September 1, 2009, PG&E reorganized its gas engineering and technical support organizations. The reorganization was implemented to transition from the current "Gas Issues" model to the end state Integrity Management model.[87]

The Energy Delivery Maintenance and Construction (M&C) organization was divided into separate Electric and Gas M&C organizations effective January 1, 2010.[88] The purpose of the reorganization was to support improved line-of-sight and accountability.[89]

2010

Gas Employee Training

The February 2009 Operational and Human Performance Improvement plan included an initiative entitled Gas Employee Skills Enhancement and Training.

[86] Response to Discovery, OC-432, Attachment Y, page 2.
[87] Response to Discovery, OC-519, Attachment 1.
[88] Response to Discovery, OC-757, Attachment 3, page 1.
[89] Response to Discovery, OC-399, Attachment 3, and response to Independent Review Panel discovery question IRP-12- Q3.

The purpose of the initiative was to:[90]

> *Develop and deliver training programs to provide gas crews with additional skills and qualifications in order to increase the effectiveness and the operating flexibility of the existing workforce.*

The scope of the initiative included six major risk areas:[91]

- Corrosion;
- Mark & Locate;
- Measurement;
- Regulation;
- Leak Survey; and
- Valves.

The initiative included the following major components:[92]

- Developing detailed task lists for six major risk areas;
- Developing task documents for each task and sub-task containing detailed step-by-step procedures;
- Developing detailed checklists and job aides for each area; and
- Developing modified and updated training policies, plans and programs.

The task lists were completed in late September 2009.[93] The curriculum, job aids and checklists were largely completed in 2009 and finalized in 2010. The checklists were introduced as standard operating procedures for maintenance and construction in 2010.[94]

The training was needed to ensure that the individuals who perform tasks were truly qualified and capable of performing the task. Management completed a full assessment of PG&E's existing Operator Qualification (training) program in 2008. That assessment "exposed significant deficiencies in the controls and the rigor of the processes."[95]

[90] Response to Discovery, OC-489, Attachment 1, page B-2.
[91] Response to Discovery, OC-672, Attachment 2.
[92] Response to Discovery, OC-672, Attachment 1.
[93] Response to Discovery, OC-672, Attachment 1.
[94] Response to Discovery, OC-657, Attachment 2.
[95] Response to Discovery, OC-672, Attachment 2.

Supervisor Skills Assessment and Training

The February 2009 Operational and Human Performance Improvement plan included an initiative entitled Skills Assessment for Gas Front-Line Supervisors and Development of Technical Training Program. The purpose of the initiative was to:[96]

> *Define the level of technical competence required for front-line gas supervisors (and) develop a training program to achieve that level of technical competence.*

The primary focus of the initiative in 2009 was leak survey, leak repair and M&L. The initiative included an assessment of each individual supervisor's existing skills. The initiative also included the development of training courses for:

- Division Superintendents;
- Area Directors;
- T&R Supervisors;
- Gas Construction Supervisors; and
- M&L / Leak Survey Supervisors.

PG&E noted:[97]

> *[A] key finding of the system-wide regulator & valve audit and from subsequent supervisor training was that all supervisors are not technically proficient in their responsibilities....A rigorous training program with development plans is needed for the...(T&R) supervisor position in each Division.*

The initiative was completed in the fourth quarter of 2009.[98]

T&R Workload Analysis

PG&E retained a consultant, Gas Transmission Systems, Inc. (GTSI), to conduct a workload assessment of PG&E's Gas Transmission and Regulation (T&R) departments at a district level. The district T&R departments are located in the local offices that are part of PG&E's gas distribution divisions.

The study compared existing and required staffing levels for a sample of five districts. T&R departments are responsible for gas distribution preventative and corrective maintenance on valves, regulator

[96] Response to Discovery, OC-489, Attachment 1, page B-1.
[97] Response to Discovery, OC-672, Attachment 2, page 7.
[98] Response to Discovery, OC-481, Attachments 1 and 6.

stations, mains, services, meters and cathodic protection equipment. They also provide support for construction jobs performed by other departments.[99]

The T&R departments are staffed with M&C employees and Corrosion Mechanics. The five divisions included 9 Corrosion Mechanics and 18 M&C employees.[100]

GTSI estimated the hours required for preventative maintenance by determining the number of valves, regulator stations and other types of equipment in each district and applying inspection intervals and estimates of the number of hours required to perform each type of inspection (unit hours).

GTSI used a manual process that considered several inputs to determine the equipment counts in each district. The manual process was required because the equipment counts in the GasFM system did not agree with the counts in the recently created SAP asset registry. The discrepancies in the data were attributed to the fact that the validation of the asset registry was not complete when the study was prepared in early 2010.[101]

The corrective maintenance workload was estimated based on interviews with the T&R supervisors. GSTI considered using historical data to estimate the corrective workload. That approach proved not to feasible because SAP had not tracked corrective work for a long enough period of time to provide adequate data.[102]

GTSI determined the existing Corrosion Staffing was within 1% of the required level. GTSI determined that the M&C positions were understaffed by 39%. The following table summarizes the results of the study.

Table 12-4 - T&R Department Workload Analysis

T&R Department Workload Analysis Summary of Results Five Districts Combined			
Description	Corrosion	M&C	Total
Current Employees	9	18	27
Hours Per Employee	2,008	2,008	2,008
Available Hours	18,072	36,144	54,216
Required Hours	18,215	50,169	68,384
Deficiency	143	14,025	14,168
Deficiency Percent	0.8	38.8	26.1
Source: Response to Discovery, OC-663.			

[99] Response to Discovery, OC-663, Attachment 1, pages 6 to 8 and Appendix A-5.
[100] Response to Discovery, OC-663, Attachment 1, page 4.
[101] Response to Discovery, OC-663, Attachment 1, page 6.
[102] Response to Discovery, OC-663, Attachment 1, page 6.

GTSI's required hours reflect its independent estimate of the unit hours required to complete a given task. GTSI asked the T&R supervisors in the districts to provide their own estimates of the required unit hours for each task. The supervisors' unit hour estimates were much higher than GTSI's estimates. The supervisors' estimates indicated corrosion staffing should be increased by 69% and M&C staffing should be increased by 207%.[103]

GTSI concluded that:[104]

> *Previous organizational structures did not provide sufficient focus on the work area. Several initiatives are underway at PG&E that will have a positive effect. The recent M&C realignment will increase focus and accountability on T&R performance and improve communications from the field to senior management. Also the new GT&D Process Owner organization will provide a needed link between Maintenance Management, Engineering, Budgeting and task performance.*
>
> *Annual budgets should be strongly tied to the level of required maintenance, corporate initiatives and expected performance.*

GTSI noted that:[105]

> *There is a noticeable reluctance for qualified candidates to pursue the T&R Supervisor position. Contributing factors may be; lack of career progression opportunities beyond the T&R supervisor; lack of incentive for union represented employees to become exempt; and a concern that achieving company expectations may not be tenable given resource constraints.*

PG&E increased its gas T&R staffing in response to the analysis. PG&E created and filled 58 M&C apprentice positions within T&R in 2011 and 2012.[106]

The T&R workload assessment demonstrated that PG&E's gas distribution T&R departments were significantly understaffed in early 2010.

The T&R workload assessment is the only substantive assessment of gas distribution staffing adequacy prepared by PG&E during the period 2007 to 2011. PG&E did not prepare any other analyses during that period that independently estimated gas distribution staffing requirements. PG&E did periodically

[103] Response to Discovery, OC-663, Attachment 1, page 6.
[104] Response to Discovery, OC-663, Attachment 1, page 5.
[105] Response to Discovery, OC-663, Attachment 1, page 5.
[106] Response to Discovery, OC-663, 23 of the new apprentice positions were created to offset attrition and other internal employee movement.

compare actual staffing levels to the levels required to accomplish the work included in its approved budgets.[107]

Damage Prevention - QA Audit

The new QA organization conducted an audit of PG&E's damage prevention program during the fourth quarter of 2009. The audit reviewed written standards and included field and records reviews in four divisions. The audit report was issued in March 2010 after the comment period ended.[108]

The audit resulted in a large number of findings and observations. They included:

- PG&E's written damage prevention plan was incomplete. PG&E's plan only covered facility marking. The plan did not address the other required elements of the program.
- PG&E's process for implementing standby observations of excavations near critical gas facilities was ineffective.
- Stand-by personnel did not inspect exposed pipelines during excavations as required by PG&E's standards.
- Supervisor field observations of M&L activities were either not being conducted or not being documented as required by the Interim Quality Initiative.
- Some locators were manipulating the M&L on-time locate metric by falsely claiming that excavators had agreed to time extensions.
- Distribution pipeline markers were in poor condition and were not being repaired because of resource constraints.
- PG&E did not have an effective process for informing M&L supervisors of the lessons learned as a result of root cause analysis of dig-ins occurring in other divisions.
- PG&E's processes for managing non-compliant excavators were inadequate.
- M&L locators were not marking the wire that extended from the cathodic protection rectifier to the anode.
- Approximately 8 percent of locates were performed by employees who were not identified on the records for the locate. The operator qualification of those employees could not be verified.

Stand-by is required when excavations occur within close proximity to critical gas facilities. The locator informs the excavator of the stand-by requirement after marking the facilities. The excavator is supposed to call to arrange stand-by before excavation beings. PG&E did not have any process to follow up with excavators when they failed to call to make the arrangements.

PG&E did not have any consistent process to document stand-by activities. QA reviewed a sample of 45 M&L tickets shown as requiring standby in the IRTHnet system. QA was not able to locate any

[107] Response to Discovery, OC-486, OC-487 and OC-488.
[108] Response to Discovery, OC-490, Attachment 4.

documentation that the stand-by was performed for 37 of those tickets. The Diablo Division was not included in the samples because it did not have any process for documenting stand-by activities.[109]

The stand-bys are not performed by the locators. Other division employees are dispatched to standby when the excavation occurs. The auditors determined that the process for handing off stand-by responsibilities from M&L to the other groups was ineffective. The notification process was informal and inconsistent. The audit identified multiple examples of required standbys that were not performed. For several of the examples, the other group claimed it was never notified of the need to perform the stand-by.

PG&E's procedures require standby personnel to inspect all facilities exposed during excavations and to document the results on PG&E's "A-Form." The auditors could not locate any A-Forms for standby inspections. During interviews, supervisors indicated that the inspections were not performed because they were either unaware of the requirement or did not have sufficient staffing to perform inspections. The inspections are required by 49 CFR 192.459. The audit determined that the non-compliance rate with that requirement was 100 percent.[110]

The Interim Quality Improvement initiative required supervisors to conduct at least one field observation per month of every significant work task within the scope of responsibilities. The observations were supposed to be documented on field observation verification forms referred to as WOW forms. The divisions tabulated the number of WOW forms and reported that number on a monthly IQI report. The audit attempted to review the WOW forms and found many were missing. The Sacramento Division could not find any of the 22 WOW forms shown on its monthly reports for July through September. The Diablo Division excluded Damage Prevention from its WOW forms. The WOW forms for the Yosemite Division did not have sufficient information to verify their reliability. The audit found that "field verifications are inconsistently executed by the supervisors in the divisions...audited."[111]

The audit noted that approximately 4 percent of the M&L tickets in PG&E's tracking system indicated the required completion date had been extended through negotiations with the excavator. The auditors reviewed 42 of the 396 tickets that were listed as negotiated in September 2009. The auditors determined that the majority of the tickets were entered into the system as "negotiated" without any negotiations with the excavator. In those cases, new "negotiated" start times for the locate were entered into the system to avoid having them go overdue.[112]

[109] Response to Discovery, OC-490, Attachment 5, NCR03.
[110] Response to Discovery, OC-490, Attachment 5, NCR12.
[111] Response to Discovery, OC-490, Attachment 5, OBS16.
[112] Response to Discovery, OC-490, Attachment 5, NCR20.

The new "negotiated" start times were typically entered into the tracking system within 90 minutes of when the ticket would have otherwise become overdue. Audit interviews confirmed that some M&L employees entered tickets into the system as "negotiated" without actually negotiating a new start time with the excavator specifically as a "work around" to avoid having the ticket become overdue. [113] The manipulation of the on-time locate metric made M&L performance appear to be better than it actually was. That, in turn, potentially resulted in the failure to identify and correct M&L staffing shortages.

Pipeline markers are required at road crossings and other areas to make the public aware of the presence of underground gas pipelines. The audit found that PG&E's processes to identify, document and correct pipeline marker deficiencies were inadequate. The auditors observed numerous pipeline markers in advanced stages of disrepair during their field work. The audit report indicated that at every location they visited, interviews indicated (a) the lack of a process to identify and track damaged or missing pipeline markers, and (b) the lack of funding to repair pipeline markers. The audit found that damaged or missing pipeline markers were "quite prevalent" in the system.[114]

Missing Gas Service Records

PG&E standards require each customer service to be documented on a gas service record. Among other things, the gas service record documents material specifications and the results of the initial pressure test. Services for new residential subdivisions can be installed either by PG&E crews or contractors hired by the developer. When developers install the services, they are required to provide completed gas service records and as-built drawings to PG&E before the facilities can be pressurized with natural gas.[115]

In July 2008, a Fresno Division construction supervisor received approximately 2,500 gas service records from an unidentified source. The records related to 23 new residential subdivisions in which the developer installed the gas services. Many had incomplete information.[116]

PG&E determined that all 348 developer-installed subdivision projects in the Fresno Division during the period 2002 to 2008 should be reviewed. PG&E provided a tabulation of projects that included 1,293 active services and 1,270 stub services. Stub services are installed for vacant lots within the sub-division. PG&E only had gas service records for 47 percent of the active services. PG&E did not have gas service records for any of the stub services.[117]

[113] Response to Discovery, OC-490, Attachment 5, NCR20.
[114] Response to Discovery, OC-490, Attachment 5, NCR15.
[115] Response to Discovery, OC-561, Attachment 2.
[116] Response to Discovery, OC-670.
[117] Response to Discovery, OC-670, Attachment 4. The scope of the tabulation is unclear.

PG&E could not locate as-built drawings or pressure test records for many of the projects. PG&E identified the company inspectors for the projects. In October 2009, PG&E sent form letters to the inspectors with an attached list of their projects with missing records. The letter indicated:[118]

> *As part of an individual line extension project, the application or its installation contractor should have returned a complete copy of the actual construction "as-built" drawings....In some cases this did not happen or the drawings are incomplete. Knowing the exact location of the gas service facilities will assist PG&E in the case of future maintenance projects or for locating pipelines for excavators (USA). So, if you still have in your files construction drawings for any of the attached projects, please initial in the column under the heading construction drawings." We will contact you later to arrange pick up for the drawings.*
>
> *You may not have any construction drawings for these projects, but you may have notes or remember that the applicant or its contractors performed a pipeline pressure test during the construction. If you either witnessed the test or saw a copy of the contractors test record, please initial the column under the heading "pressure test." if you can recall (or if your notes show) the approximate date, please note it next to your initials for that job under the heading headed "date."*

PG&E conducted a special leak resurvey in 2009 of the subdivisions in the Fresno Division with missing records.[119]

PG&E expanded its review to include other divisions. The expanded study used the Lean Six Sigma methodology. The final report for the study was issued in August 2010.[120]

The study reviewed 100 percent of the services installed by residential developers from 2004 to 2009 in four divisions. The study determined that 12 percent of the applicable gas service records were missing.[121] The study reviewed a sample of gas service records in eight other divisions and concluded that the record issues in those divisions were similar to those found in the four divisions that were subject to a 100 percent records review.

PG&E's inspectors did not always know or enforce PG&E's standards and sometimes allowed gas facilities to be pressurized without receiving the required records from the developer.[122] The study noted that "little auditing" was done to assure that the gas service records were created.

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[118] Response to Discovery, OC-670, Attachment 2.
[119] Response to Discovery, OC-670.
[120] Response to Discovery, OC-561, Attachment 1.
[121] Response to Discovery, OC-561, Attachment 1, page 22.
[122] Response to Discovery, OC-561, Attachment 1, page 36.

PG&E did not have a reliable efficient way to verify that a gas service record had been created for all services. The study concluded:[123]

> *The root cause for problems for mishandling of documents are multiple and include the following: There is minimal process in place to track the progress of the job or location of critical documents. This has been exacerbated by the diverse locations and the requirement to transfer documents to multiple parties. Some employees are not familiar with the overall document handling process or the importance of the documents. Standards are not consistently followed or even known. There are issues with communication between parties, and there is little oversight or cradle to grave responsibility for the jobs.*

ALS Record Keeping Review

PG&E retained a consultant, Gas Transmission Systems, Inc., to review record keeping for the Accelerated Gas Leak Resurvey Project. The review was conducted in the first and early second quarter of 2010.[124]

The scope of the review included 100 percent of the survey records for the ALS. PG&E's ongoing routine surveys were not included in the review.

Record keeping practices differed greatly between the local offices. In some areas, the consultants had to organize the records before they could be reviewed. The inconsistencies in record keeping and filing practices impacted the consultant's ability to stay on schedule.[125]

The Executive Summary of the consultant's report indicated:[126]

> *Discrepancies of some type were observed on nearly all of the records reviewed. The condition of the records indicated lack of clear responsibility as to who was responsible for ensuring they were complete and accurate...The focus was on completing the survey, with record review a secondary priority. The sheer volume of records and leaks appears to have overwhelmed some mapping departments and work priorities did not allow time to perform detailed records reviews.*

[123] Response to Discovery, OC-561, Attachment 1, page 45.
[124] Response to Discovery, OC-896, Attachment 1.
[125] Response to Discovery, OC-896, Attachment 2.
[126] Response to Discovery, OC-896, Attachment 2.

The consultant's report noted:[127]

> *Initially, there appeared to be little structure around the ALS with respect to conventions to use in completing records...As the program progressed, clarifications on work procedures and processes were communicated and ...incorporated into the ALS program.*
>
> *The lack of standardized procedures at the beginning of the ALS program and continued evolution of procedures over the course of the ALS contributed to the inconsistencies and discrepancies observed in the records and could affect PG&E's ability to use the ALS as a base survey.*

The consultant report indicated:

> *The potential impact of the observed discrepancies on the ability to provide proof of proper leak survey varied in significance. Many discrepancies appeared to have low significance....Other discrepancies appeared to be more significant and could impact the ability to provide proof of survey or PG&E's ability to use the ALS as a base survey. Examples include leaving data fields in the top portion of the leak survey stamp blank, improper or incomplete documentation of CGIs (Can't get in's), missing logs or plats, facilities not highlighted on the plat to show they were surveyed and lack of agreement between recorded data on the plat, leak stamp, and associated leak logs.*

The ALS records were not required to comply with gas safety regulations because PG&E was maintaining its regular five-year survey schedule for all of the facilities included in the ALS. If the ALS were to be used as a base survey to reset the five-year clock for future routine surveys, all of the significant discrepancies noted in the review would need to be remedied to bring the ALS into compliance.

San Bruno Incident

On September 9, 2010, PG&E's local gas transmission line 132 ruptured in a residential area in San Bruno, California. The natural gas released by the rupture ignited and caused a fire that destroyed 38 homes and damaged 70. Eight people were killed and many more were injured.[128] Local transmission lines are maintained by PG&E's gas distribution divisions. San Bruno is located in the Peninsula division.

[127] Response to Discovery, OC-896, Attachment 2.
[128] NTSB Accident Report, September 26, 2011, page 1.

Pre-Audit Internal Document Reviews

The Commission's Gas Safety and Reliability Branch (GSRB) conducts periodic gas safety inspections of PG&E's gas distribution divisions pursuant to General Order (GO) 112-E. The audits typically review maintenance activities for a two-year period. [129]

PG&E conducted informal pre-audit internal reviews of the gas maintenance records in the divisions for many years. In 2009, PG&E implemented a more "robust internal review program" for the pre-audit reviews.[130] PG&E has provided the results of its internal reviews to the GSRB at the beginning of each audit since early 2009.[131]

The scope of the time period covered by the internal reviews matches the CPUC audit period. The internal reviews audit large samples of maintenance records and identify instances of non-compliance with PG&E's standards. The findings are provided to local management, and corrective actions are implemented.[132]

The GSRB's audit reports for eight division audits conducted in 2010 include a table summarizing the violations of gas safety rules found in PG&E's internal reviews. The following table summarizes those violations.[133]

[129] Response to Discovery, OC-861 are the audit reports and PG&E's responses for audits conducted in 2007 - 2010.

[130] Response to Discovery, OC-861, Attachment 219, page 1.

[131] Response to Discovery, OC-961. Prior to 2013, the GSRP was named the Utilities Safety and Reliability Branch (USRB).

[132] Response to Discovery, OC-961.

[133] The table only includes audits that had an internal review summary in the GSRB audit report. The 2010 GO 112-E audits of the East Bay, North Bay, North Valley and Sacramento Divisions were excluded because the GSRB audit report did not include a summary of the PG&E internal review findings.

Table 12-5 - PG&E Pre-Audit Internal Reviews, Summary of Findings, Audits Conducted in 2010

PG&E Pre-Audit Internal Reviews Summary of Findings Audits Conducted in 2010	
Division	Violations
Central Coast	6,095
De Anza	1,276
Kern	511
Mission	4,314
Peninsula	812
San Jose	2,004
Stockton	1,578
Yosemite	1,182
Total	17,772
Source: Response to Discovery, OC-861, Attachments 116, 119, 142, 158, 209, 215, 218 and 221.	

According to PG&E, the high number of internal review findings was unacceptable.[134] The findings were described on internal review summaries prepared by PG&E. The combined summaries for the reviews conducted in 2009, 2010 and 2011 were approximately 200 pages in length.[135] The internal reviews demonstrated the pervasiveness of the gas distribution management deficiencies noted in prior internal audits and quality assurance audits.

The internal review findings are a mix of minor and more significant items. The following tables provides examples of the findings concerning leak survey, leak repair and regulator station and valve maintenance.[136]

[134] Response to Discovery, OC-861, Attachments 120, 159, 216 and 222.
[135] Response to Discovery, OC-962.
[136] The examples are divided into three tables to facilitate page breaks.

Table 12-6 - PG&E Pre-CPUC Audit Internal Reviews, Examples of Findings, Part 1

PG&E Pre-CPUC Audit Internal Reviews Examples of Findings Part 1		
Division	Period	Finding
Diablo	2007 & 2008	122 services surveyed late in 3-year copper services survey
Diablo	2007 & 2008	5 leaks repaired late
Diablo	2007 & 2008	19 leaks checked late
Diablo	2007 & 2008	231 A-Forms with missing or inaccurate information
Diablo	2007 & 2008	28 district regulator stations needing painting or with poor pipe condition
East Bay	2007 & 2008	One Grade 1, Fifteen Grade 2 and 93 Grade 3 leaks repaired or rechecked late
East Bay	2007 & 2008	One plat map not surveyed in ten years (16 services)
East Bay	2007 & 2008	344 out of 500 A-Forms with missing or inaccurate information
East Bay	2007 & 2008	7 emergency valves missing 2008 and prior maintenance records
North Coast	2007 & 2008	Santa Rosa business district survey not completed on time
Sierra	2006 & 2007	30 plat maps left off leak survey schedule
Sierra	2006 & 2007	9 emergency valves not inspected on time
Central Coast	2008 & 2009	314 instances of no documentation of leak survey supervisor review
Central Coast	2008 & 2009	106 leak repairs with missing, erroneous or unclear pressure test information
Central Coast	2008 & 2009	3 regulator station inspections not completed on time
Central Coast	2008 & 2009	59 annual valve inspections late or not documented
Source: Response Discovery, OC-962.		

Table 12-7 - PG&E-CPUC Audit Internal Reviews, Examples of Findings, Part 2

PG&E Pre-CPUC Audit Internal Reviews Examples of Findings Part 2		
Division	Period	Finding
De Anaza	2008 & 2009	113 leaks survey plat maps without evidence of supervisor review
De Anaza	2008 & 2009	37 leaks rechecked late in 2009
De Anaza	2008 & 2009	4 leak repairs made without required pressure test
De Anaza	2008 & 2009	196 A-Forms with missing, inaccurate or outdated information
De Anaza	2008 & 2009	In general, corrosion control maintenance documents were incomplete or inaccurate
De Anaza	2008 & 2009	3 regulator station inspections not completed on time
De Anaza	2008 & 2009	6 regulator stations unable to perform operational lock-up
De Anaza	2008 & 2009	29 regulator stations with incomplete/ inaccurate maintenance records, data sheets or diagrams
De Anaza	2008 & 2009	12 valves missed annual maintenance
East Bay	2008 & 2009	27 leak repairs with inadequate or missing pressure test documentation
East Bay	2008 & 2009	5 emergency valves inspected late
Fresno	2008 & 2009	23 leak repairs with inadequate or missing pressure test documentation
Fresno	2008 & 2009	125 external corrosion leak repairs without pipe-to-soil readings
Fresno	2008 & 2009	MAOP Records are disorganized
Fresno	2008 & 2009	Most regulator stations have at least one valve with no documentation of pressure rating
Fresno	2008 & 2009	No pressure rating indicated in records for distribution valves
Mission	2008 & 2009	31 Plat maps not leak surveyed on time
Mission	2008 & 2009	10 leak repairs performed late
Mission	2008 & 2009	52 leak rechecks performed late
Mission	2008 & 2009	24 regulator stations where components listed on data sheet do not match diagrams
Mission	2008 & 2009	19 regulator stations missing pressure charts for 2008/2009 maintenance
Mission	2008 & 2009	6 employees who performed valve maintenance were not operator qualified
Source: Response to Discovery, OC-962.		

Table 12-8 - PG&E Pre-CPUC Audit Internal Reviews, Examples of Findings, Part 3

PG&E Pre-CPUC Audit Internal Reviews Examples of Findings Part 3		
Division	Period	Finding
North Bay	2008 & 2009	748 "can't get in" services surveyed late
North Bay	2008 & 2009	5,724 feet of difficult to survey main surveyed late
North Bay	2008 & 2009	17 leaks repaired late
North Bay	2008 & 2009	19 A-forms with missing or inaccurate information
North Bay	2008 & 2009	87 district regulator stations have data sheet issues
North Bay	2008 & 2009	21 valves maintained late or not properly documented in 2008
Peninsula	2008 & 2009	8 plat maps not surveyed
Peninsula	2008 & 2009	165 A-forms contained incomplete, inaccurate or outdated information
Peninsula	2008 & 2009	76 regulator stations with incomplete/inaccurate maintenance records, data sheets or diagrams
Sacramento	2008 & 2009	In general, leak information not recorded properly on plat maps
Sacramento	2008 & 2009	4 regulator stations inspections not complete on time
Sacramento	2008 & 2009	9 valves not inspected on time
San Jose	2008 & 2009	126 instances of leak surveys performed late
San Jose	2008 & 2009	31 leaks not repaired or downgraded on time
San Jose	2008 & 2009	73 leaks not rechecked on time
San Jose	2008 & 2009	5 leak repairs made without required pressure test
San Jose	2008 & 2009	153 A-forms that contained incomplete, inaccurate or outdated information
Stockton	2008 & 2009	101 instances of leak surveys performed late
Stockton	2008 & 2009	791 instances of maps missing mapping sign-off
Stockton	2008 & 2009	8 leak repairs made without required pressure test
Yosemite	2008 & 2009	8 instances of leak surveys performed late
Yosemite	2008 & 2009	6 regulator stations inspected late
Source: Response to Discovery, OC-962.		

The GSRB audit of the Sacramento division found 40 Grade 2+ leaks that were repaired late in 2009 and an additional 42 leaks that were rechecked late in the same year. PG&E's response to the audit indicated the leaks were repaired or checked late "as a result of poor oversight and late work assignments" by supervisors. To prevent recurrence, the supervisors were replaced in January 2010.[137]

[137] Response to Discovery, OC-861, Attachment 2.13, page 6

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13. Management Deficiencies - 2011 and 2012

Introduction

Chapters 10 to 13 provide a narrative history of the gas distribution management deficiencies identified by PG&E during the audit period. This Chapter covers the years 2011 and 2012.

PG&E hired an experienced executive from outside the company to reform its gas operations in 2011. PG&E expressed a strong commitment to improving its gas distribution operations in 2011 and 2012. However, PG&E's internal documents demonstrated that many of the deficiencies discovered in prior years continued in 2011 and 2012.

PG&E issued an internal audit report on its leak repair and leak monitoring processes in April 2011. The audit found that PG&E was not adequately monitoring leak downgrade trends. Data quality controls for the leak database were critically deficient. The records for approximately ten percent of the leak repairs that required a soap test did not contain any indication that the test was performed. Approximately five percent of the leak repair records were missing. Supervisors were not reviewing leak recheck logs. The audit demonstrated that many of the leak repair process deficiencies discovered in 2007 and 2008 had not been corrected by April 2011.

PG&E issued an internal audit report on its leak survey program in July 2011. The report identified significant deficiencies in metrics reporting. PG&E's monthly reports and leak survey dashboards were incomplete and some of the metrics had not been updated for several months. Two of the metrics had been shown on the dashboard with no data for about a year. PG&E began work on the Operational Reporting Initiative (ORI) in February 2009. The ORI was focused on improving leak survey and repair metrics. The July 2011 internal audit report demonstrated the ineffectiveness of the ORI.

PG&E implemented the Gas Compliance Assurance Process (GasCap) in July 2011. GasCap replaced the prior Interim Quality Initiatives (IQI). The IQI was implemented in April 2008 in an attempt to correct critical deficiencies in supervision and metrics reporting. PG&E's internal GasCap justification documents demonstrated the ineffectiveness of the IQI.

PG&E's new Executive Vice President - Gas Operations, Nick Stavropoulos, authored PG&E's gas turnaround plan in late October 2011. The plan classified the current state of twenty gas operations processes. Ten of the twenty processes were classified as inadequate. An additional nine processes were classified as threshold, the next category above inadequate. The plan concluded that PG&E needed to make "wholesale changes" in its gas operations.

PG&E retained a consultant, PWC, to review its mapping function. PWC's report was issued in January 2012. The report identified numerous critical deficiencies. Staffing, training, supervision, communications, record keeping, metrics, information systems and leadership were all inadequate.

Leadership placed excessive emphasis on meeting production goals and not enough emphasis on work quality. Work quality was substandard.

PG&E issued an internal audit report on its damage prevention program in February 2012. The audit followed up on the deficiencies identified in a prior audit report, issued 33 months earlier. The February 2012 report demonstrates a clear lack of progress in addressing the deficiencies identified in the prior report.

The Commission's Safety and Enforcement Division (SED) filed two reports in PG&E's gas transmission record keeping penalty proceeding in March 2012. The reports concluded that "in lay terms, PG&E's record keeping was in a mess" prior to the San Bruno Incident. Gas Transmission records were "scattered, disorganized...and difficult, if not impossible, to access in a prompt and efficient manner." The reports concluded that PG&E's gas transmission integrity management risk assessment model had little value because the data used to populate the model was incomplete and inaccurate.

2011

CPUC and Legislative Actions in Response to SBI

The San Bruno Incident (SBI) occurred on September 9, 2010. The CPUC undertook a large number of actions to verify and improve the safety of PG&E's transmission system after the SBI. The actions began almost immediately after the incident and are still in progress. The actions are described in Chapter 2.

Leak Repair Process - Internal Audit

PG&E conducted an internal audit of the gas transmission and distribution leak repair process in the first quarter of 2011. The audit report was issued on April 28, 2011. The audit assessed controls for managing leak repairs and leak rechecks. The audit reviewed a sample of leaks repaired in the fourth quarter of 2010.[1]

The audit report indicates:[2]

> *Overall, we conclude that controls for managing and repairing leaks need strengthening. In particular, we found that the utility needs to enhance controls for: (1) validating the accuracy of the recheck process; (2) ensuring accurate entry of data into IGIS and retention of source documentation; (3) reviewing and approving leak repair forms; (4) correcting known errors in IGIS; and (5) ensuring that leak survey and repair personnel are qualified for assigned duties.*

[1] Response to Discovery, OC-432, Attachment CC, page 1.
[2] Response to Discovery, OC-432, Attachment CC, page 2.

PG&E's guidelines require leak survey supervisors to critically review leak recheck logs for accuracy, proper grading and completeness. Internal auditing found "very few instances" where the supervisor review was documented. The supervisors interviewed during the audit confirmed they did not review recheck logs.[3]

The audit report indicates:[4]

> *We noted a significant number of errors on recheck logs, and also leak grades that were in conflict with utility grading guidelines. The errors included required fields that were left blank and incorrect reason codes.*

The inaccurate leak grades mainly involved assigning a grade that was higher than the grade required by PG&E's standards. In these cases, the customer was aware of the leak and wanted the repair to be completed quickly. The leak grade was increased to accelerate the repair. The audit report noted that "customer involvement issues should be handled by requesting an early repair date, not by grading the leak incorrectly."

The auditors concluded that PG&E did not adequately monitor leak grade changes on a system wide basis. Reports of leak downgrades were prepared, but no one monitored leak downgrade trends in the divisions to detect potential abuse. For example, no one monitored leak downgrades that occurred just prior to the otherwise required repair date. Improperly downgrading leaks could be used as a method to manipulate leak repair metrics.[5]

Mapping enters leak repair and leak recheck data into the IGIS from the original paper copies of the A-Forms and recheck logs. Mapping retains the original documents for use in future audits. The audit reports noted:[6]

> *Currently, there are no controls over the quality of data entered into IGIS or for ensuring retention of original documents. Mapping was unable to find about five percent of the A-Forms and approximately seven percent of the recheck documents we requested.*

Internal Auditing compared the original documents to the information in IGIS for a sample of leaks. About ten percent of the leak records in IGIS contained at least one data entry error. The report indicates:[7]

[3] Response to Discovery, OC-432, Attachment CC, page 2.
[4] Response to Discovery, OC-432, Attachment CC, page 2.
[5] Response to Discovery, OC-432, Attachment CC, page 3.
[6] Response to Discovery, OC-432, Attachment CC, page 3.
[7] Response to Discovery, OC-432, Attachment CC, page 3.

> *The most prevalent errors included: (1) incorrect grades entered into IGIS; (2) explanatory reason codes not input correctly; and (3) inconsistent data entered into IGIS from the A-Form or recheck document. In one location, we observed five repairs where the mapper input supervisor review data into IGIS, even though the field was blank on the A-Form.*

The report indicates:[8]

> *We noted reluctance by mappers to return incomplete or inaccurate documents to the leak (survey) supervisor in most locations we visited, which is a key control over the quality of documentation produced by surveyors.*

The A-Form documents the soap test performed to confirm that a leak repair has eliminated the leak. For the repairs requiring a soap test, the test was not documented on over 10 percent of the applicable A-Forms. The A-Forms are supposed to be reviewed by both the supervisor and mapping for completeness. The audit report notes:[9]

> *The failure to document such tests raises questions as to whether the tests were actually performed. In addition, a lack of supervisory review bypasses an important control in the process.*

The audit found that:[10]

> *The Utility lacks a documented process to ensure that every gas leak repair task is performed or supervised by personnel who have the applicable operator qualification. Because the employee operator qualification database is currently in transition to a new system, we were unable to match recent leak repair tasks to that database.*

The audit demonstrated that many of the leak repair process deficiencies discovered in 2007 and 2008 had not been corrected as of April 2011.

2011 Organizational Realignment

On May 5, 2011, PG&E announced a major realignment of its distribution operations. The realignment separated PG&E's gas transmission and distribution operations from its electric distribution operations. PG&E also announced that it had retained Nick Stavropoulos to lead the new Gas Operations organization. Prior to joining PG&E, Mr. Stavropoulos was Executive Vice President and Chief Operating Officer of National Grid's gas distribution operations in the Northeastern United States.[11]

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[8] Response to Discovery, OC-432, Attachment CC, page 4.
[9] Response to Discovery, OC-432, Attachment CC, page 4.
[10] Response to Discovery, OC-432, Attachment CC, page 6.
[11] PG&E News Release, May 5, 2011, PG&E names Nick Stavropoulos to Lead Utility Natural Gas Operations as Executive Vice President.

PG&E's gas and electric operations were separated to create a more accountable gas organization with the authority, resources and mandate to completely reform its gas management practices. By the end of August 2011, PG&E had hired more than 90 new gas engineers, as well as additional project managers, mappers and other employees, through a major nationwide recruiting effort.[12]

The new Gas Operations Organization was structured to clarify roles and responsibilities. The key departments in the new organization were Asset Knowledge Management, Standards and Policies, Public Safety & Integrity Management, Project Engineering & Design, Distribution Maintenance & Construction, Investment Planning and Gas System Operations.[13]

Leak Survey Internal Audit

PG&E conducted an internal audit of its leak survey program during the second quarter of 2011. The audit was focused on the processes and controls for: (1) monitoring the program; (2) assessing leak survey quality; (3) verifying operator qualification; and (4) maintaining leak survey standards and procedures. The report for the audit was issued on July 28, 2011.[14]

The report indicates:[15]

> *Overall, we conclude that the utility's controls over the gas leak survey program need strengthening. While the Utility has improved its leak survey program significantly during the past few years, we found some gaps in the design or operation of controls pertaining to: (1) leak survey quality assessments, (2) metrics used to monitor survey results, (3) preventing non-qualified surveyors from performing surveys, and (4) the leak survey standard and work procedures.*

PG&E implemented quality control verification surveys on a sample basis in March 2009 to test the quality of the work done by its leak surveyors.[16] The verification surveys were performed by contractors immediately after the original survey was completed. The verification surveys were the primary control for monitoring survey quality.[17]

PG&E's Short-Term Incentive Plan (STIP) included a metric for the number of "failed QC assessments." In 2010, the STIP target was 11 or fewer failed assessments. Failed QC assessments were defined as a verification survey that discovered a Grade 1 leak missed in the original survey which should have been found by a prudent and qualified surveyor. PG&E conducted a root cause analysis of each missed Grade 1 leak to identify the failed QC assessments.

[12] PG&E News Release, August 20, 2011, PG&E Statement Following NTSB Hearing.
[13] Response to Discovery, OC-401.
[14] Response to Discovery, OC-432, Attachment FF.
[15] Response to Discovery, OC-432, Attachment FF, page 1.
[16] Response to Discovery, OC-413, Attachment 12, page 7.
[17] Response to Discovery, OC-432, Attachment FF, page 2.

During 2009, the verification surveys found 40 Grade 1 leaks that were not found in the original survey. PG&E determined that 33 of the 40 missed Grade 1 leaks would not have been found by a prudent and qualified surveyor in the original survey. Internal auditing found gaps in the process used to determine if an assessment had failed. There was a "lack of clearly defined responsibilities for approving the decision" to assign a grade of pass or fail to the missed Grade 1 leak. The basis for the final conclusion was poorly documented in many cases.[18]

The audit found significant deficiencies in the reporting of leak survey metrics. The metrics were reported in weekly and monthly SAP reports and a one page monthly dashboard.[19]

The monthly reports included metrics that were not up-to-date, accurate or populated. The main scorecard had not been updated in seven months. The outdated scorecard continued to show that 69 of the 113 employees who performed leak surveys did not have the required operator qualifications. The tables that were supposed to contain the results of the QC verification surveys were blank.[20]

The monthly dashboards did not contain adequate information about leak survey results. The dashboard only included one metric that directly measured leak survey effectiveness. The dashboard did not include any data for two metrics that had been listed on the dashboard since April 2010. One of the blank metrics was the percentage of Grade 1 leaks found by customers.[21]

The report concludes that:[22]

> *When metrics are not complete, accurate, and up-to-date, the Utility cannot establish valid baselines and measure performance trends that will help drive improved survey effectiveness. In addition, it may signal that management isn't reviewing the metrics and/or considering the results seriously.*

PG&E began work on the Operational Reporting Initiative (ORI) in February 2009. The ORI was focused on improving leak survey and repair metrics. The deficiencies identified in the July 2011 audit report demonstrated the ineffectiveness of the ORI.

[18] Response to Discovery, OC-432, Attachment FF, page 3.
[19] Response to Discovery, OC-432, Attachment FF, page 4.
[20] Response to Discovery, OC-432, Attachment FF, page 5.
[21] Response to Discovery, OC-432, Attachment FF, page 5. Chapter 7 discusses the significance of that metric .
[22] Response to Discovery, OC-432, Attachment FF, page 5.

The report includes the following discussion of operator qualification.[23]

> *We found that the Utility lacks a process to prevent non-qualified personnel from surveying gas facilities. We also noted that there is no clear, centralized process that validates surveyor qualification.*
>
> *As part of our work, we reviewed leak records in IGIS from January 1, 2010 to March 23, 2011. Using this data, we verified that leaks were recorded by surveyors who were noted as being qualified in the Utility's training server. However, this detective analysis was cumbersome to perform, and since it was based on leaks recorded in IGIS, it was limited to testing only surveyors who had found leaks, and did not include any surveyors who completed surveys but didn't find leaks.*

The report concluded that PG&E lacked controls needed to prevent unqualified personnel from conducting leak surveys. The absence of an automated process for checking the qualifications of surveyors increased the risk that surveys would be conducted by non-qualified employees.

Independent Review Panel Report

The CPUC commissioned an Independent Review Panel (IRP) on September 23, 2010 to investigate the SBI and to recommend improvements in PG&E's gas safety practices. The IRP issued its report on June 8, 2011. The IRP's findings are discussed in Chapter 2.

Gas Compliance Assurance Process (GasCAP)

PG&E implemented the Gas Compliance Assurance Process (GasCAP) in July 2011. GasCAP is a quality control and compliance assurance process for PG&E's gas Maintenance and Construction (M&C) and Engineering and Operations (EO) organizations.[24]

[23] Response to Discovery, OC-432, Attachment FF, page 6.
[24] Response to Discovery, OC-638, Attachment 1.

The key components of GasCAP are:

Table 13-1 - GasCAP Key Components

GasCAP Key Components
Description
Field Observations by Supervisors
Compliance Units Reporting
Internal Records Review
Commitment Tracking Reporting
Operator Qualification Review
Compliance Review Meetings
Feedback on Findings, Trends and Corrective Actions
Source: Response to Discovery, OC-638, Attachment 1.

GasCap replaced the Interim Quality Improvement (IQI) initiative that had been implemented in April 2008. The IQI had proven to be deficient for the following reasons:[25]

- Insufficient number of field observations required;
- No records review other than the supervisors' review;
- Inconsistent records reviews;
- Inconsistent documentation of records reviews and field observations;
- No formal reviews of adherence with IQI process;
- No analysis conducted to identify compliance trends. Compliance trends not communicated;
- No analysis conducted to determine if issues are local or systemic;
- IQI participant roles not clear;
- Manual data collection and reporting processes not efficient; and
- Self-reported compliance metrics not accurate or timely.

The IQI required supervisors to perform at least one field observation of work per month in each of the major work processes within the supervisor's scope. The purpose of the field observations was to verify that the work was in compliance with company standards. GasCap requires supervisors to conduct 12 field observations per month. Under IQI, the field observations were documented on paper forms. GasCap introduced a new computer based application for documenting and tracking the observations.[26]

The IQI required supervisors to conduct ongoing reviews of maintenance records. The records reviews proved to be inconsistent and poorly documented. GasCap requires a 100 percent records review of the

[25] Response to Discovery, OC-638, Attachment 2, pages 4 and 5.
[26] Response to Discovery, OC-638, Attachment 2, page 14.

twelve highest risk gas maintenance work processes. The GasCap records reviews are conducted by internal or external compliance auditors using established protocols.[27]

PG&E retained a consultant, Gas Transmission Systems, Inc. (GTSI), to conduct a complete review of 2011 and 2012 maintenance records in the following six high risk processes.[28]

Table 13-2 - GasCAP Areas Selected for Complete Review

GasCap Areas Selected for Complete Review of 2011 and 2012 Records
Description
Leak Survey and Repair
Gas Valves
District Regulation Stations
Cathodic Protection
Damage Prevention
Customer Metering
Source: Response to Discovery, OC-638, Attachment 2, page 19.

Under IQI, supervisors were responsible for self-reporting maintenance work that was out of compliance with company standards, such as the number of valves inspected late. The self-reporting proved to be inconsistent and inaccurate, as demonstrated by audit findings. GasCap replaced the self-reporting with data gathered during the records reviews and automated reporting from IGIS and SAP.[29]

The IQI required self-reporting of progress towards accomplishing commitments resulting from internal and external compliance audits and other sources. The self-reporting proved to be inconsistent and inaccurate, as demonstrated by audit findings. GasCap included a new system for tracking compliance commitments.[30]

National Transportation Safety Board Accident Report

The federal National Transportation Safety Board (NTSB) is responsible for reviewing pipeline safety incidents. The NTSB conducted an extensive review of the SBI. The NTSB's findings concerning the SBI were adopted on August 31, 2012. The NTSB's findings are described in Chapter 2.

[27] Response to Discovery, OC-638, Attachment 1, page 4.
[28] Response to Discovery, OC-638, Attachment 2, page 19.
[29] Response to Discovery, OC-638, Attachment 2, page 16.
[30] Response to Discovery, OC-638, Attachment 1, page 4.

Cupertino and Roseville Incidents - Aldyl-A Pipe

A gas leak resulted in a fire at a 422 unit townhouse complex in Cupertino on August 31, 2011. The gas leaked from a crack in a 2 inch gas distribution main tee and migrated into the garage of one of the townhouses and was ignited by the pilot light of a water heater in the garage.[31]

The plastic tee was made from Aldyl-A (AA) pipe. No one was injured but the townhouse was destroyed. The property damage was approximately $610,000.[32] The local fire department notified PG&E of the fire at 12:28 pm. A Gas Service representative saw the smoke and arrived six minutes later. A repair crew arrived at 12:51 pm. Gas flow to the fire was shut off at 2:35, two hours and seven minutes after PG&E was initially notified of the fire. The length of time required to shut-off the gas was extended because of the configuration of the distribution system in the complex. Three different locations had to be excavated and squeezed-off before the gas flow could be stopped.[33] PG&E leak surveyed the complex after the fire and found six additional leaks.[34]

AA pipe is know to be susceptible to stress cracks. The federal Pipeline and Hazardous Materials Safety Administration (PHMSA) issued advisory bulletins concerning AA pipe in 2002 and 2007. PG&E had approximately 7,900 miles of AA main and approximately 739,000 AA services in its system as of September 2011.[35] PG&E evaluated the material properties of AA pipe during 2009, 2010 and 2011 and decided that an "all encompassing replacement program would not be necessary." As of September 2011, PG&E's plan was to monitor the leak history of AA pipe segments and selectively replace segments based on that leak history and other risk factors.[36]

On September 27, 2011, the rupture of a 4 inch gas distribution main made of AA caused a large fire in Roseville. No one was injured but the rupture forced the closure of a busy commercial intersection for 12 hours.[37]

In mid-October 2011, PG&E announced plans to replace all 1,231 miles of the AA pipe installed on its system prior to 1973. [38]

Gas Operating Plan - September 2011

As noted in Chapter 9, PG&E's internal planning documents prepared after the SBI place a far greater emphasis on public safety than the documents prepared before the SBI.

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[31] Response to Discovery, OC-957 and OC-480, Attachments 29 and 32.
[32] Response to Discovery, OC-956.
[33] Response to Discovery, OC-956.
[34] Response to Discovery, OC-957, Attachment 1.
[35] Response to Discovery, OC-957, Attachment 19.
[36] Response to Discovery, OC-957, Attachments 9, 20, 21 and 24.
[37] San Francisco Chronicle, September 28, 2011, article titled New PG&E Blast Involved Problematic Plastic.
[38] Bay Area News Group, October 14, 2011, article titled PG&E to Replace More than 1,200 Miles of Faulty Gas Pipeline Across California.

Gas Operations made a presentation to management regarding its 2012-2014 Operating Plan on September 7, 2011. That presentation identifies the following organizational goals:[39]

- Operate with zero public safety incidents and near-hits;
- Operate with zero employee injury/illness incidents and near-hits;
- Deliver gas to meet customers' needs reliably and responsively;
- Restore public confidence in the safety and integrity of the gas system; and
- Provide excellent customer service and achieve revenue goals.

The presentation identifies the following six key initiatives to ensure public safety.[40]

- Instill a culture of system integrity and one that reports and learns from near-hits;
- Mitigate the highest risks on the Distribution System by implementing the Distribution Integrity Management Plan;
- Mitigate the highest risks on the Transmission System by implementing Transmission Integrity Management Plan;
- Implement records validation and GIS upgrade;
- Implement Control Room Management Initiatives; and
- Develop and Implement a Corrective Action Program.

The Operating Plan presentation includes a key initiative to "Comply with Spirit and Letter of State, Federal and Local Regulations and Commitments." The presentation identifies six key initiatives to restore confidence in the gas system including meeting its commitments to the CPUC for established system testing and upgrade programs.[41]

The Gas Operations 2012 to 2014 Operating Plan included large staffing increases. The Gas Operations headcount was forecasted to increase from 2,190 in 2009 to 2,660 in 2012.[42]

The Operating Plan presentation indicated that Gas Operations was requesting $215 million in gas distribution expense funding in 2012. That represented an increase of 33 percent over the approved 2011 budget. The 2012 funding request for gas distribution capital was $334 million. That represented an increase of 51 percent.[43]

Leak Survey Internal Audit - October 2011

PG&E conducted an internal audit of its leak survey program during the third quarter of 2011. The audit focused on the processes and controls for: (1) planning leak survey work; (2) verifying the data used for the planning; (3) establishing metrics; and (4) documenting results. The audit report was dated October 26, 2011.[44]

[39] Response to Discovery, OC-873, Attachment 3, page 1.
[40] Response to Discovery, OC-873, Attachment 3, page 1.
[41] Response to Discovery, OC-873, Attachment 3, page 2.
[42] Response to Discovery, OC-873, Attachment 3, page 9.
[43] Response to Discovery, OC-873, Attachment 3, page 9.
[44] Response to Discovery, OC-432, Attachment HH, page 1.

The audit report concluded:

> *Overall, we concluded that the Utility's processes and controls for gas leak survey are not adequate to ensure accurate, consistent, and efficient execution of the leak survey program. In particular, the Utility needs to improve controls in the following areas: (1) consider increasing the frequency of leak survey in high-risk areas, (2) validating key data used to plan the survey, (3) measuring and reporting appropriate work performance metrics, (4) moving from paper-based to electronic record-keeping systems; (5) improving procedures for supervisors to verify completed survey work; and (6) establishing minimum documentation retention requirements for completed surveys.*

In 2008, Internal Auditing had recommended considering increased leak survey frequencies for three categories of pipe: (1) pipe located in seismically active areas; (2) pipe made of obsolete materials such as Aldyl-A; and (3) pipelines with known corrosion or leak histories. The October 2011 report indicated:[45]

> *(The) Utility has continued to plan leak survey work based on minimum regulatory requirements, and has not incorporated those risk factors into its planning process in order to increase leak survey frequency, where appropriate.*

Leak survey planning is heavily dependent on input data, such as distribution plat maps. The report indicated experience had shown that the distribution plat maps used for leak survey planning "may be out of date, incorrect, or in some cases, missing altogether." The report concluded that PG&E did not have a process to validate the distribution plat maps used for planning and documenting leak surveys.[46]

The report included the following description of the leak survey documentation process.

> *The Utility has approximately 22,000 plat maps, and copies of those maps are the primary documentation for facilities surveyed each year. The Mapping and Records Department must prepare duplicate copies for surveyors to take into the field, along with paper copies of daily leak logs and leak sign-off sheets, and paper copies of "can't get in" (CGI) sheets for scheduling additional visits. Once surveys are completed, hand-marked maps are forwarded to leak survey supervisors for approval, and then provided back to Mapping and Records so the leaks found on the surveys can be manually entered into IGIS....The leak survey process is based almost entirely on paper documentation, with hand entry of data and multiple hand-offs between departments.*

[45] Response to Discovery, OC-432, Attachment FF, page 2.
[46] Response to Discovery, OC-432, Attachment FF, page 3.

Internal Auditing noted that "little progress has been made over the past several years in leveraging technology to convert records into an electronic format." The report concludes:[47]

> *Preparing, assigning, collecting, handing-off, and processing large volumes of paper records for leak survey work makes consistency of the process...more challenging as well as being more prone to the risk of errors or misplaced documentation.*

The audit report found that PG&E had not established minimum standards for leak survey record keeping requirements. The lack of standards increased the risk of inadequate leak survey documentation.

Gas Turnaround Plan

The October 26, 2011 Document titled "The Gas Turnaround Plan" was authored by PG&E's Executive Vice President, Gas Operations, Nick Stavropoulos. The introduction to the plan indicates "Upon my arrival at PG&E, it became immediately clear that we have a tremendous amount of work to do to get our gas business to a level of dependable, predictable, credible performance."[48]

The Gas Turnaround Plan identifies the following top 10 priorities:

Table 13-3 - Gas Turnaround Plan, Top 10 Priorities

Gas Turnaround Plan Top 10 Priorities	
No.	Description
1	Build a culture that puts public and personal safety first
2	Establish a clear organizational structure
3	Engage workforce and recruit talent
4	Rebuild integrity management process
5	Develop accurate asset knowledge
6	Achieve full regulatory compliance (rebuild trust)
7	Create and implement consistent standards, work methods and procedures
8	Establish an investment planning process
9	Improve gas transmission system control and build distribution control system
10	Revamp Quality Assurance/Quality Control capability
Source: Response to Discovery, OC-493, Attachment 1.	

The Gas Turnaround Plan identifies 20 gas operations processes and classifies the current state of each process at PG&E relative to industry standards. Four classifications are used in the analysis -- inadequate, threshold, advanced and leading. Only one of PG&E's current processes was classified as advanced or leading. The following table shows the classification for each process.

[47] Response to Discovery, OC-432, Attachment FF, page 5.
[48] Response to Discovery, OC-493, Attachment 1.

Table 13-4 - Gas Turnaround Plan, Processes - Current State

Gas Turnaround Plan Processes - Current State	
Process	Current State
Data/Asset Knowledge Management	Inadequate
System Operations & Control	Threshold
Investment Planning	Inadequate
Materials Management	Threshold
Damage Prevention (Mark & Locate)	Threshold
Resource Management (Work Management)	Inadequate
Instrumentation & Regulation	Inadequate
Mandated Programs (Leak Survey)	Threshold
Leak/Emergency Response	Threshold
Quality (QA/OC)	Inadequate
Personal (Employee)Safety	Threshold
Training	Threshold
Process Safety (Public Safety)	Inadequate
Public Safety & Emergency Preparedness (Emergency Response)	Inadequate
Excavation Technology	Advanced
Public Works Coordination	Threshold
Fleet	Threshold
Integrity Management	Inadequate
Project Management	Inadequate
Workforce Engagement, Planning, Development and Recruiting	Inadequate
Source: Response to Discovery, OC-493, Attachment 1.	

The plan notes that "knowledge of our assets is not at an acceptable level, and the systems to support management of asset information do not exist or are inadequate.[49]

The current state description for Data/Asset Knowledge Management indicates:[50]

> *People - Field personnel do not consistently provide information to mapping for update, and data that is submitted is frequently incomplete or incorrect. Mapping group appears to be significantly understaffed for workload.*
>
> *Process - Limited capability to access data for reporting purposes. Resource limitations due to normal incoming work and exacerbated by San Bruno response have driven backlogs to over 1 year in some regions, leading to information in GIS or other systems that is not representative of actual field conditions.*

[49] Response to Discovery, OC-493, Attachment 1, page15.
[50] Response to Discovery, OC-493, Attachment 1, page 19.

Technology - Limited availability of data in GIS; transmission only, no consistent distribution GIS. No electronic capability for field personnel to view GIS information while on the job site, and no simple/electronic capability to report required mapping corrections.

The current state description for Integrity Management indicates:[51]

People - Don't have a clear understanding of integrity and do not apply it consistently for assessing integrity and planning accordingly.

Process - Disjointed with unclear understanding of who the asset owner is and where the process is done. Responsibility for integrity resides in various parts of the organization.

The current state description for Investment Planning indicates:

People - Limited knowledge of appropriate long-term planning strategy.

Process - No fully integrated process currently exists for investment planning. Projects are added to investment plan ad hoc and are not put through a thorough risk assessment. No overall development of the investment plan, only done in bits and pieces. Historically influenced by interest in reducing spend.

The current state description for Damage Prevention describes the EZtech phones used by M&L locators as "antiquated."

Process Safety involves "instituting measures, systems and policies to protect people/environment and reduce the chance of low probability/high consequence incidents." The current state description for Process Safety indicates:[52]

People - No awareness of process safety at any level in the organization, and very little focus on public safety. Safety in general is considered equal to compliance.

Process - No process exists to monitor or improve upon process safety issues.

Resource Management involves "managing in-year work plan and coordinating all resources required to execute the work plan..." The current state description for Resource Management indicates: [53]

People - All work managed by regional (local) operations. Work planners and schedulers exist, but in some instances field workers plan work individually as a result of lack of trust that schedulers and planners know enough about gas work to plan effectively.

[51] Response to Discovery, OC-493, Attachment 1, page 21.
[52] Response to Discovery, OC-493, Attachment 1, page 29.
[53] Response to Discovery, OC-493, Attachment 1, page 34.

> *Process - Resource management process to match a fully developed investment plan (both capital and expense) non-existent. M&C (Maintenance & Construction Organization) has multiple sources of work, none of which are coordinated. When budgets are cut or spent, remaining planned work is deferred...Because there is not an integrated system with resources, chances are likely that important planned work is deferred or completed inefficiently. Lack of up-front planning results in too much work in some regions and not enough work in others.*

The Training current state assessment indicates: [54]

> *People - Many employees feel that training is inadequate, especially technical training for journeymen level employees and leadership training.*
>
> *Process - No effective process in place to proactively identify and implement training needs.*

The Fleet current state assessment indicates:

> *Technology - No on board mobile solution. This prevents an evolution away from paper based systems reducing employee productivity.*

The Workforce Engagement current state assessment indicates "current workforce in some areas/levels feels alienated from the company and unable to contribute to improvements."[55]

The conclusion section of the Gas Turnaround Plan indicates:[56]

> *PG&E's Gas Operations function needs to make a wholesale change in the way it conducts business, from how it is organized to the technology that is used to get work done....*
>
> *..It is not enough to remain in compliance with the current regulations; it is OUR responsibility to provide assurance that we are doing everything we can to maintain a safe system, and to drive a self-critical culture that continually re-evaluates how the ever-changing industry will require us to change the way we run our system. Compliance is a minimum. Our job is to not only understand and adhere to compliance requirements, but to determine what the standard of performance will be for PG&E.*

[54] Response to Discovery, OC-493, Attachment 1, page 36.
[55] Response to Discovery, OC-493, Attachment 1, page 37.
[56] Response to Discovery, OC-493, Attachment 1, page 12.

2012

Leak Survey Penalties

On December 30, 2011, PG&E self-reported to the Commission that it had failed to conduct leak surveys of the facilities on 16 plat maps in accordance with gas safety regulations. The facilities were located in PG&E's Diablo Division in Contra Costa County. The 16 plat maps included 13.83 miles of gas distribution mains and 1,242 services. The mains and services had not been leak surveyed within the five year time frame required by federal gas safety regulations.[57]

PG&E met with the Commission's Safety and Enforcement Division (SED) on January 4, 2012 to discuss the violations. PG&E's presentation for the meeting indicates the root causes of the violations were a lack of controls and Quality Assurance within the mapping process. PG&E informed the SED that is was initiating a system-wide audit to determine if similar violations had occurred in other areas.[58]

The SED issued a Citation for Violations on January 27, 2012. The citation included a fine of $16.76 million.

PG&E self-reported additional leak survey violations on February 1, 2012 [59] PG&E's February 1, 2012 letter to the SED indicates:

> *PG&E discovered that plat maps were not consistently added to the leak survey schedule as the maps were updated or created. As a result, some facilities were not regularly leak surveyed. The procedure for incorporating plat maps into the leak survey schedule lacked an adequate quality control process.*

The following table shows the facilities that PG&E failed to leak survey in a timely manner. [60]

Table 13-5 - Leak Survey Violations Self Reported by PG&E

Leak Survey Violations Self-Reported by PG&E In December 2011 and February 2012 Facilities Left Out of Leak Survey Schedule			
Report	Maps	Miles of Main	Services
Initial	16	13.83	1,242
Additional	50	13.45	608
Total	66	27.28	1,850
Source: Response to Discovery, OC-673, Attachment 1 and OC-619, Attachment 1.			

[57] CPUC Resolution ALJ-277, April 19, 2012, pages 1 and 2.

[58] Response to Discovery, OC-673, Attachment 1. Prior to January 1, 2013, the SED was named the Consumer Protection and Safety Division (CPSD).

[59] Response to Discovery, OC-674.

[60] Response to Discovery, OC-674 and OC-619. The additional violations shown in OC-619 exceed the number reported to the CPSD on February 1, 2012. PG&E apparently updated the analysis after February 1, 2012. The table shows the updated. amounts from OC-619.

PG&E appealed the amount of the $16.76 million fine assessed by the Citation. PG&E's appeal was denied in Commission Resolution ALJ-277, dated April 19, 2012. That resolution indicated:[61]

> *PG&E's offenses were severe. Leak surveys are the primary industry tool to detect and correct gas leaks before they become serious. Moreover, leak survey data provides critical information that gas operators must consider in determining the need and schedule for necessary maintenance or replacement. Federal regulations require such surveys....not less than every five years. The facilities here were not leak surveyed until December 2011, even though some were first installed more than 18 years earlier.*
>
> *The potential public harm from these violations was great. The violations were significant with the capacity for serious injury to persons and property, as demonstrated by the 2008 Rancho Cordova explosion and the 2010 San Bruno explosion.*

The resolution concluded that PG&E should have discovered the violations much earlier. The resolution stated:[62]

> *These violations were avoidable. PG&E had multiple opportunities to detect and correct the violations before December 2011. For example, some facilities were installed as early as 1993, resulting in several missed leak surveys with multiple opportunities for an alert PG&E survey crew, supervisor or higher management to question why some areas were not surveyed. Further, over time multiple services were added to existing facilities on many of the plat maps at issue here. With each completed installation, PG&E was presented with another opportunity to add the plat map to its leak survey schedule. PG&E missed each opportunity. Moreover, any quality control PG&E may have had in place clearly failed.*

The resolution noted that the 2007 internal investigation of leak survey deficiencies in Sonoma County, the ALS, the Rancho Cordova explosion and the San Bruno explosion provided additional opportunities to discover the violations.[63]

PWC Gas Mapping Organization Review

PG&E retained PriceWaterhouseCoopers (PWC) to assess its records and information management practices. The assessment began in mid-November 2011.[64]

[61] Resolution ALJ-277, page 6.
[62] Resolution ALJ-277, page 7.
[63] Resolution ALJ-277, page 7.
[64] CPUC Docket I. 11-02-016, TURN Testimony of Thomas Long, Appendix B.

The PWC review addressed PG&E's entire Gas Operations organization. PWC issued a preliminary draft report on the Gas Mapping Organization on January 18, 2012.[65] The PWC mapping report identifies a large number of critical deficiencies in PG&E's mapping processes.

Gas distribution mapping is performed in local offices by mapping groups that consist of one to ten employees at each location. PWC visited 18 of the local mapping organizations.[66]

The PWC mapping report lists a large number of recurring observations, or themes. The observations pertaining to governance included.[67]

- There is a lack of formal, defined Governance structure (roles and responsibilities), policies and procedures over the management of records and information, and
- Some Mappers feel more invested in getting the work done faster (i.e. increasing production) and less invested in quality control, employee education, training, and communication due to pressures around metrics and production levels by which they have been measured...Metrics lack focus on quality, and as a result, Mappers feel this only drives the behavior to focus on moving the work "out the door."

PWC's observations in the morale and incentive area included:[68]

- Employee morale is inconsistent across offices. In some offices, the mapping group is upbeat and tight knit even with the frustration of the day-to-day challenges they encounter; in other offices, more frustration (including feelings of anger and sadness) was evident in the assessment discussions. Gas Mappers expressed the sincere desire to do a quality job although they do not feel enabled, contributing to decreased employee morale...Many noted that until recent organizational changes, they had never seen their Director or Manager at their field location.
- There is distrust in the overall gas and corporate leadership, and little faith that new change will benefit employees in the field, but instead is for the benefit of management. Mappers feel that there has been a lack of true meaningful action and follow-up in the past for various initiatives, and that gas senior leadership does not have a true understanding of the mapping work. Mappers expressed a lack of faith that true change can be affected across the larger gas organization.
- Many Mappers refer to Business Transformation as a turning point that devalued the Mapper position. Several years ago the company announced the cutting of Distribution Mapper positions from 217 down to 75 in advance of rolling out the new GIS system which was intended to offset this staff reduction by increasing productivity. This

[65] Summary of Information Management Key Themes, Gas Mapping Organization, Item 27 on the list of footnote exhibits to the CPSD Record keeping Report of Paul Duller and Alison North.

[66] PWC Mapping Report, January 18, 2012, page 6.

[67] PWC Mapping Report, January 18, 2012, page 6.

[68] PWC Mapping Report, January 18, 2012, page 7.

communication concerned the mapping (workforce), and many experienced Mappers left.

- Employees feel that there is a stigma / perception that mapping is not a priority area of focus, and that leadership does not take an active role in staying connected with the field offices....
- Collaboration between groups that work together and share information with one another (construction, mapping, etc) is weak and employees are not incentivized to assist other groups. There is little accountability held to groups that supply Mapping with data, to ensure that they provide quality work packets to be mapped.
- ...The annual (employee performance) review process...could be improved. There is little review of work performed, little tracking of performance metrics, and many Mappers indicated they feel there is little incentive for a job well done or conversely, repercussions for poor performance.

PWC's observations concerning resource constraints included:[69]

- Supervisors often cover several offices that may be located across a large geographical area. As a result, there may be no physical supervisory presence at some offices during a given day or week.
- Supervisors are spread to thin, and often can't provide the support, guidance, education and communication to their leads, Mappers and other members. In addition, the supervisors and leads continue to be assigned more and more responsibilities.
- Across the offices, Mappers consistently reported that there is a lack of necessary resources to keep up with the workload and to catch up on the backlog....
- Mapping backlog is evident in some offices, although true backlog (unmapped jobs) cannot be accurately quantified at this time. In several offices, there are job files that simply cannot be mapped as they were originally received with missing information...One (office) noted that a development's map, now 25 years old, is missing 12 houses that exist on a certain street. Another Mapper noted that he is currently working on a job that was executed in 2005.
- Mappers lack a clearly documented and effective issue resolution process. Job frustrations may be communicated to supervisors, but supervisors have little power to implement change or get decisions made on behalf of the Mappers. For some processes or systems, there is no clear point person, or the role at corporate has changed several times, so issues go unresolved.
- There are perceived inconsistencies in not only what is expected of Mappers as to their role and responsibilities, but also in the manner and practice that work is carried out across the various sites (offices).

[69] WC Mapping Report, January 18, 2012, page 8.

- ...There is a high turnover rate in the clerical staff at the RMCs (Resource Management Centers), which contributes to inconsistencies in some of the work performed.

PWC's observations in the Training and Education area included:[70]

- PG&E currently lacks a robust new hire/on-boarding training for Mappers. Most training is received on-the-job and new employees are taught how their specific office performs mapping rather than a formal standard process across all of Gas Distribution Mapping.
- There is a lack of SME (Subject Matter Expert)/technical support and training in the field and in the offices.
- The mapping training program contains modules that demonstrate outdated techniques (ink and vellum)...There is a consistent view that the program was outdated upon release and even more recent applicable components are not sufficient to train the Mappers. It was noted that 3 of the 8 modules contain largely outdated mapping practices...
- Little to no training on widely used systems (SAP, GEMS, SharePoint, IGIS, ECTS, ect) is available for the larger mapping population...when training does occur...it is often perceived to be ineffective...[71]

PWC's observations concerning Standards, Procedures and Reference Materials included:[72]

- The Mapping Manual is currently outdated and does not include current standards. It has not been updated since the late 80s/early 90s and does not incorporate the update bulletins that are now issued...
- Bulletins are periodically sent out via email, but a comprehensive location with all the most current mapping standards is not readily available or known to exist...

The estimators who prepare job packages for completed construction projects are located at regional Resource Management Centers (RMCs). PWC observed:[73]

> *There is a perceived lack of standards around processes and procedures at the RMC which sometimes results in inconsistencies around what information is included in job folders. The job folders that are sent from the RMC back to Mappers often contain duplicative and unnecessary information. Mappers spend time removing and disposing of unnecessary information from the job folders.*

[70] PWC Mapping Report, January 18, 2012, page 9.

[71] ECTS is PG&E's Enterprise Compliance Tracking System. ECTS was developed after the San Bruno Explosion to provide compliance and regulatory support during the subsequent investigation. CPSD Records Management Report, pg. 6-87.

[72] PWC Mapping Report, January 18, 2012, page 11.

[73] PWC Mapping Report, January 18, 2012, page 11.

Residential housing developers have the option of using contractors to install mains and services in new housing developments. PWC observed that:[74]

- Mappers cited an overall lack of controls over contractors for completeness, consistency, and quality of work. Contractors were more frequency cited as presenting difficulties in obtaining complete and accurate job files...
- For third party installations...there is an expectation that they complete Gas Service Records (GSR) to document the work performed. The third party (contractors) are not familiar with the GSR and there is no consistent process to ensure they are gathering and providing the information needed for the Mappers to post the jobs, or complete the GSR.

PWC's observations pertaining to Leak Survey procedures included:[75]

- Some offices mentioned that they knew of existing services and mains that are not on the map and therefore, may not have been leak surveyed. It was noted that there has recently been an effort to quickly identify, review and remediate this issue.
- PG&E lacks standardization around documentation of the leak survey process in terms of documents received from the field, tracking mechanisms, hard copy document storage, and general process by which leak surveys are executed.
- The perception of some Mappers is that individuals in the field conducting leak surveys do not fully understand what information is required by the Mappers to process and post the jobs.

PWC's other observations pertaining to procedures included:[76]

- Mappers report that there is a lack of process and controls for field personnel submitting map corrections. The process to map corrections varies by locations, although the offices that were asked (by PWC) reported using the standard map correction form...
- Standardization of job folders and the order of documents, such as a formal file plan, do not exist. Each office's practices for management and storage of job folders vary.
- Some location have a backlog of job folders. The backlog is either work that still remains to be mapped due to a lack of resources, or work that is yet to be mapped due to lack of information from the field...
- General perception of construction by the Mappers is that there is a lack of focus on paperwork quality and completeness, and there is no accountability or repercussions for incomplete paperwork...Mappers often feel as if they are doing part of construction's

[74] PWC Mapping Report, January 18, 2012, page 12.
[75] PWC Mapping Report, January 18, 2012, page 12.
[76] PWC Mapping Report, January 18, 2012, pages 13 and 14.

job by filling in or chasing down information that construction should have completed in the field.

PWC's observations concerning record storage included:[77]

- The storage conditions of physical documents vary greatly from office to office. Field site observations included documents housed in boxes, file cabinets, desktops, inboxes, off-site locations, adjacent buildings, and external storage sheds/containers.
- The location of certain records is often based on institutional knowledge of the local staff and varies from location to location.

PWC's observations about mapping metrics included:[78]

- There is a feeling that the unintended consequence by how metrics and processes have been set up in a siloed manner contribute to a sense of production numbers over quality. Mappers serve a large quality review function but are under increasing pressure to complete work within a certain time period or risk poor metrics. This focus is perceived to be on quantity over quality...

PWC observations concerning the availability of information included:[79]

- Many Mappers indicated they are spending at least half of their day searching for information (e.g. items that should have been placed into A-forms, GSRs and other forms, maps, job files...) rather than actually performing core mapping functions. This contributes to a significant loss of production time that could be spent on posting jobs and conducting quality control checks.
- Location and organization of physical records varies by location and is often only known to a few individuals performing the filing....

PWC found serious problems with the information systems used by Mapping. "Comments from the gas Mappers indicate that systems overall are not well integrated, contain duplicate information and have significant data integrity (accuracy and completeness) issues."[80]

PWC's observed that:

> *For IT system infrastructure and connectivity issues, many Mappers expressed that they have given up on the PG&E IT help line since they perceive a lack of subsequent action and resolution to the issues presented. It was also communicated that there was a lack*

[77] PWC Mapping Report, January 18, 2012, page 14.
[78] PWC Mapping Report, January 18, 2012, page 15.
[79] PWC Mapping Report, January 18, 2012, page 16.
[80] PWC Mapping Report, January 18, 2012, page 17.

of sufficient and knowledgeable IT support for Mappers and for technical systems used and relied upon in the field.

Gas distribution maps are maintained in electronic form on the Gas and Electric Mapping System (GEMS). GEMS was populated by scanning the mylar maps previously used by PG&E into the GEMS system. PWC's observations concerning GEMS included:[81]

- Serious system performance and stability issues have been impacting the ability of Mappers to post jobs, pull maps, etc. Among other things, this is also causing low morale, frustration, and lack of productivity amount Gas Distribution Mappers. Every office...reported this to varying degrees. GEMS crashing has become the "new normal" for the mapping workforce.
- GEMS users experience multiple crashes per day, long load times, and inability to batch print jobs because print settings have to be manually set for each map....
- Some map scans in GEMS are of poor quality and unreadable; most distribution mapping offices retain and use the original mylar drawings to combat this issue. This causes divergence in the information as some use the updated GEMS map, and others use the outdated mylar print. GEMS is generally acknowledged as the system of record, with mylar maps still an important reference that supplements the information contained in GEMS.
- Labels or symbology on maps may differ from division to division. For example, there is a lack of standard for valve numbering procedures.

PWC's report identified numerous critical deficiencies in PG&E's mapping function. Staffing, training, supervision, communications, record keeping, metrics, information systems and leadership were all inadequate. The deficiencies negatively impacted work quality. The focus was on production over work quality.

SED Record Keeping Report

The SED filed two reports in the PG&E gas pipeline record keeping penalty proceeding in March 2012.[82] The reports focused on PG&E's gas transmission operations. The first report addressed records management and was sponsored by Paul Duller and Alison North (Records Management Report).[83] The second report reviewed PG&E's record keeping practices from an engineering perspective and was sponsored by Margaret Felts (Felts Report).[84]

[81] PWC Mapping Report, January 18, 2012, page 17.
[82] I.11-02-016. Prior to January 1, 2013, the SED was named the Consumer Protection and Safety Division (CPSD)
[83] Records Management within the Gas Transmission Division of Pacific Gas and Electric Company, March 5, 2012.
[84] Report and Testimony of Margaret Felts, I.11-02-016, dated March 12, 2012.

The Felts Report concluded that PG&E had not maintained important historical records that included design, construction, leak repair and operational data.[85]

The Felts Report concluded that the results of PG&E's transmission integrity management risk assessment model were not reliable because accurate data was not available to populate the model.[86]

> *While the number of documents produced by the integrity management program is impressive, a review of the actual spreadsheet model reveals an unimpressive model that simply adds up data entries and assigned points based on simple calculations to arrive at a total risk number for each segment. The combined lack of data, assumed, unknown values, and questionable quality of the data entered into the model spreadsheet, suggests the model is of only minimal practical use and is more likely entirely useless in calculating total risk.*

The Felts report is highly critical of PG&E's management of the A-Forms used to track gas leaks. The report concludes that "PG&E's A-Form reports are poorly managed, inconsistent and incomplete."[87]

The Records Management Report concluded that:[88]

> *In lay terms, PG&E's record keeping was in a mess (prior to the San Bruno explosion) and had been for years. Gas transmission records and safety-related documents were scattered, disorganized, duplicated, and were difficult if not impossible to access in a prompt and efficient manner.*

The Records Management Report concluded that PG&E had "lost control of its physical records storage" as demonstrated by the level of effort required to retrieve records for the post-San Bruno MAOP Records Validation Project.[89]

The Conclusion Section of the Records Management Report indicates:

> *Within PG&E's Gas Transmission Division the records management practices were unsound and led to inefficient and unsafe working practices. PG&E's failure to ensure that complete and accurate information was available at the right time contributed towards creating a safety risk to the general public. While the San Bruno pipeline*

[85] Felts Report, page 28.
[86] Felts Report, page 24.
[87] Felts Report, page 40.
[88] CPSD Records Management Report, page 1-10.
[89] CPSD Records Management Report, page 6-69.

rupture and fire cannot be attributed simply to inadequate records management, PG&E's failure to manage the Gas Transmission Division's information in a systematic and controlled manner was a contributing factor....

...This report, and its findings and conclusions, are consistent with the findings and conclusions of the NTSB, The Blue Ribbon Panel, and PG&E itself. Each may have reached its findings and conclusions based on different considerations and perspectives. However, each has concluded that PG&E's record keeping practices have been deficient and have diminished pipeline safety.

Damage Prevention - Internal Audit

PG&E conducted an internal audit of its damage prevention program in late 2011. The audit report was issued on February 10, 2012.[90] The audit followed up on the deficiencies noted in the 2009 internal audit of damage prevention.[91]

The audit report indicates:[92]

Overall, we conclude that the Utility's processes and controls for damage prevention are not adequate to ensure accurate, consistent, and efficient execution of the damage prevention program. In particular, the Utility needs to improve controls in the following areas: (1) mark and locate; (2) pre-construction meetings and standbys; (3) line marker signage; (4) aerial pipeline patrols; (5) managing excavators who don't comply with damage prevention rules; (6) plastic gas service replacement installations; and (7) protecting pipelines from wheel loading damage from extremely heavy vehicles that may drive over them.

The audit report identifies the following problem with PG&E's mark and locate metrics:[93]

In 2009 and 2010, IA and QA noted that (the) processes used to establish the on-time performance of the Utility's mark and locate program had a system glitch, in that the time clock feature of the software would be halted just by opening the record without performing the work or documenting an agreement with the excavator to postpone the work. As a result, the reports for on-time performance generated using this software showed a 99 percent on-time response for 2010 that cannot be relied upon. Interviews

[90] Response to Discovery, OC-432, Attachment LL.

[91] The 2009 audit report was issued on April 30, 2009 and is contained in OC-432, Attachment U. The 2009 audit is discussed in Chapter 12.

[92] Response to Discovery, OC-432, Attachment LL, page 2.

[93] Response to Discovery, OC-432, Attachment LL, page 2.

> *with employees in the damage prevention program confirmed this deficiency has not yet been corrected.*

Internal auditing received reports from field employees in 2011 that indicated that mark and locate tickets in certain divisions were several weeks behind schedule. The audit report indicates:[94]

> *Discussions with management confirmed that unexpectedly high demand for mark and locate services coupled with shortages of employees qualified to perform the work had resulted in tickets worked three to four weeks late in these divisions.*
>
> PG&E cannot quantify the extent to which locates were behind schedule in 2011 because its late locates metric was not reliable in 2011.[95]

The 2009 internal audit of the damage prevention program found that PG&E did not have adequate controls to ensure that required pre-construction field meetings and construction standbys for high risk excavations were performed and documented. The February 2012 report indicates "our interviews with employees in the damage prevention program confirmed this deficiency has not yet been corrected."[96]

The February 2012 audit report indicates PG&E discontinued its non-compliant excavators program in 2009 and did not have any plans to re-implement the program. The report notes that:[97]

> *Without a comprehensive program to manage non-compliant excavators, the Utility faces an increased risk that already identified non-compliant parties will continue to damage Utility assets during their underground excavations.*

The February 2012 damage prevention internal audit report was issued 33 months after the 2009 audit report. The February 2012 report demonstrates a clear lack of progress in addressing the deficiencies identified in the April 2009 report.

SED Report on Pipeline Class Locations

Federal pipeline safety rules require PG&E to classify its gas transmission lines based on the potential consequences of an explosion. The classifications are referred to as class locations and are based on the characteristics of the pipeline and the population density of the surrounding area.[98]

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[94] Response to Discovery, OC-432, Attachment LL, page 3.
[95] Response to Discovery, OC-632 and OC-432, Attachment LL.
[96] Response to Discovery, OC-432, Attachment LL, page 3.
[97] Response to Discovery, OC-432, Attachment LL, page 6.
[98] CPSD Class Location Report, May 25, 2012, page 2.

Designating a pipeline segment into a higher risk class location category triggers significant additional operating and inspection requirements for the segment. Mis-classifying a segment into a risk category that is to low creates a significant public safety hazard because pipelines in higher risk categories are required to operate with a higher safety margin.[99]

The Commission directed PG&E to review its gas transmission class location designations on September 13, 2011, shortly after the San Bruno explosion. PG&E provided the final results of its system wide class location study to the Commission on April 2, 2012.[100] PG&E changed 1,192 pipeline segments, totaling 159 miles, to a higher risk category (class up changes) as a result its study.[101]

PG&E is required to perform a class location study whenever an increase in population density indicates the need for a study. PG&E is required to patrol its gas transmission pipelines periodically. Those patrols provided an opportunity to observe population growth around the pipeline and initiate a class location study. PG&E had failed to conduct class location studies for many of the misclassified segments when the population density of the areas surrounding the pipeline increased.

The SED issued its Investigative Report concerning the class locations changes on May 25, 2012.[102] The SED concluded that PG&E missed many opportunities to identify the need for class location studies based on population growth in the areas surrounding the pipelines.

The SED Report concluded that PG&E committed 3,062 code violations. The SED concluded:[103]

> *...[T]he link between patrolling, class location analysis, and continuing surveillance was ineffective or non-existent. These problems resulted in a complete breakdown in PG&E's compliance with class location regulations and procedures....*

2014 GRC Application

PG&E submitted its 2014 GRC Application on November 15, 2012. Public Safety is the central theme of PG&E's Application. PG&E's summary of the case indicates:[104]

> *One important legacy of the San Bruno tragedy has been a reexamination of PG&E's approach to safety and the implementation of improvements to our programs, processes*

[99] CPSD Class Location Report, May 25, 2012, page 15. Prior to January 1, 2013, the SED was named the Consumer Protection and Safety Division (CPSD).

[100] CPSD Class Location Report, May 25, 2012, page 7.

[101] CPSD Class Location Report, May 25, 2012, pages 9 and 14.

[102] CPSD Investigative Report into the Operations and Practices of Pacific Gas and Electric Company's Natural Gas Transmission Pipeline System in Locations with Higher Population Density, I.11-11-009, May 25, 2012.

[103] CPSD Class Location Report, May 25, 2012, page 56.

[104] PG&E 2014 GRC Testimony, PG&E -1, page 1-3.

> *and culture. Reflecting our new direction, we have made safety improvements, as well as risk assessment and mitigation, the foundation of this GRC.*
>
> According to PG&E's summary of the case, PG&E is focused on a "back to basics" strategy to improve its operations.[105]

PG&E's summary of the case notes:[106]

> *We have hired hundreds more gas engineers and field employees to drive improvements in the integrity of our gas distribution system. These additional resources have helped us complete almost 5 million gas inspections and replace about 33 miles of gas main lines in the last year alone. We have plans to hire over 1,400 more people in our gas organization through 2014, which among other things, will enable us to increase - by a factor of six - the miles of gas lines that we can replace in a year as well as increase the number of gas emergency first responders to more quickly address safety issues.*

PG&E requested very large increases in gas distribution expense and capital funding in its 2014 GRC compared to its 2011 recorded costs.[107]

PG&E Gas Transmission Safety Plan

The Commission adopted a gas transmission safety plan for PG&E on December 20, 2012. The plan is focused on gas transmission and was mandated by Senate Bill 705.[108]

The approved plan consisted of two main parts, a pipeline testing and modernization program and a records management improvement program. The first part required PG&E to:[109]

- Pressure test 783 miles of transmission pipeline;
- Replace 186 miles of transmission pipeline;
- Upgrade 199 miles of transmission pipeline to allow for in-line inspection; and
- Install 288 automated valves.

The plan required pressure testing of all lines that did not have pressure testing records, either because the tests were not performed or the records for prior tests were missing. PG&E did not seek recovery of pressure testing costs for lines installed after 1961 because pressure testing of those lines was required by federal gas safety rules. PG&E adopted a policy of pressure testing lines in 1955 consistent with

[105] PG&E 2014 GRC Testimony, PG&E -1, pages 1-1 and 1-2.
[106] PG&E 2014 GRC Testimony, PG&E -1, page 1-2.
[107] PG&E 2014 GRC Testimony, PG&E-3, page 1-1.
[108] D.12-12-030. Chapter 2 describes SB 705.
[109] D.12-12-030, page 3.

industry standards. The Commission prohibited PG&E from recovering the costs of pressure testing pipelines installed after 1955 because the need to test the lines was a result of PG&E's failure to retain pressure testing records for those lines.[110]

The Commission concluded that "PG&E has imprudently managed its gas system records such that extensive remedial work is now needed to correct past deficiencies." The Commission required PG&E to implement the record management improvement program but prohibited PG&E from recovering the costs from ratepayers. Cost recovery was denied because the need for the improvements was caused by PG&E's past imprudent management of its gas system records.[111]

The Commission concluded:[112]

> *PG&E's safety journey will require a lasting commitment to decision-making based on sound engineering analysis with implementation across all aspects of PG&E's natural gas system operations. While PG&E has presented a promising beginning, this Commission will require that PG&E diligently proceed toward the goal of zero significant events.*
>
> *The record in this proceeding has brought to light three operational areas where significant and immediate action is required - PG&E's quality control, field oversight, and integration of information from on-going operations into the Integrity Management Program. Ensuring that natural gas system management is meeting quality standards and translating corporate directives into actionable information for field personnel are essential components of a safe natural gas system....*
>
> *The record also shows serious deficiencies in PG&E's Integrity Management Programs, some of which may be caused by the unreliability of its quality control and field oversight. The testing and replacement actions we order today should provide substantial and dependable input to the Integrity Management program baseline assessments. We also order PG&E to comply with the Independent Review Panel's and NTSB's recommendations for improving its Integrity Management programs.*

The line that ruptured in the SBI was a local transmission line. PG&E's distribution divisions maintain its local transmission lines. The deficiencies in quality control and field oversight noted by the Commission are equally applicable to gas distribution operations.

[110] D.12-12-030, pages 59 to 61.
[111] D.12-12-030, page 87.
[112] D.12-12-030, page 50.

14. Root Cause Analysis

Introduction

Several recurring themes emerged from the review of past management deficiencies that explain, at least partially, the pervasiveness and root causes of the deficiencies. Overland developed the themes into root cause findings to provide insight into audit period spending patterns. This Chapter presents those findings.[1]

The evidence of serious deficiencies in the management of PG&E's gas distribution operations during the audit period is overwhelming.[2] Management largely failed to detect, or chose to ignore, the deficiencies until employees publically raised their concerns about operating practices at PG&E's annual shareholders' meeting in April 2007.

PG&E began corrective actions in October 2007. The corrective actions had mixed results, as demonstrated by PG&E's internal reviews. After the San Bruno Incident (SBI), PG&E replaced most of its gas distribution executive management and is currently in the process of reforming its gas distribution operations.[3]

Several key safety-related functions were inadequate during most of the audit period. PG&E's leak survey program was ineffective prior to 2008, as demonstrated by survey results. PG&E's leak grading practices were inconsistent. PG&E's process for responding to customer leak complaints was inadequate.

PG&E's maintenance processes were critically deficient as demonstrated by Exponent's system-wide audit of regulator station and valve maintenance. PG&E's damage prevention program was inadequate as demonstrated by PG&E's dig-in rates and internal reviews. The Company's mapping processes were critically deficient as demonstrated by PWC's review and PG&E's internal audits.

PG&E's processes for collecting and organizing information about its gas distribution facilities were inadequate. PG&E did not have an accurate Asset Register or GIS at any point during the audit period. Much of PG&E's asset knowledge was trapped in records that could not be electronically searched. As a result, integrity management risk assessments required labor intensive manual records searches.

Record keeping practices were inadequate throughout the audit period. PG&E's maintenance and leak survey records were incomplete and inaccurate. PG&E's leak survey data base lacked effective data quality controls. Records were frequently missing and PG&E did not have controls to assure that its records were complete.

[1] The approach Overland used to develop the root cause findings is explained in Chapter 2.
[2] Chapters 10 to 13 provide a detailed history of the management deficiencies.
[3] Response to Discovery, OC-711.

With one exception, PG&E's long-term gas safety programs were poorly-funded throughout the audit period.[4] Management viewed long-term gas safety programs as discretionary spending that could be deferred to meet budget targets.[5]

Root Cause Findings

Overland identified the following eight root causes for the deficiencies in gas distribution management:

- Insufficient management focus on work quality and public safety;
- Ineffective communications between management and the field and among departments;
- Inadequate direction of the work methods used by field employees;
- Inadequate staffing and other resources;
- Ineffective supervision and quality control;
- Inadequate quality assurance;
- Failure to collect and organize critical operating data; and
- Failure to analyze the data that was available.

The pervasiveness of the deficiencies demonstrates that their ultimate cause was ineffective executive management. The executives in charge of PG&E's gas distribution operations placed excessive emphasis on cost containment and failed to properly manage the operations.

Insufficient Management Focus

PG&E's gas distribution executive management was focused on meeting financial goals during the audit period, as described in Chapter 9. Prior to the implementation of corrective actions starting in late 2007, the primary objective of most gas distribution initiatives was cost reduction. The metrics used by management were focused on reducing unit costs instead of improving work quality.

Employees had the impression that quality was not a high priority for management. PG&E's mappers believed management was focused on production, not quality.

Management did not demonstrate a serious commitment to gas safety excellence. There was very little focus on public safety. Safety was equated to compliance with the minimum requirements set forth in federal gas safety rules. Compliance was viewed as the performance standard, not the minium starting point for public safety.

The metrics emphasized by management reinforced the impression that management was focused on production over quality. Field supervisors did not understand the metrics and viewed them as punitive. The leak repair metric encouraged employees to find fewer leaks. One cost reduction initiative included a monthly report to encourage supervisors to downgrade leaks. The on-time appointment metric for

[4] Chapter 5. The exception was the Copper Services Replacement Program.
[5] Chapter 5.

Gas Service Representatives encouraged them to minimize the time spent on leak investigations. Work quality metrics were generally not tracked.

Leak surveys are a critical component of a gas safety program. Leak survey was treated as low priority work. Leak surveyors were frequently diverted to other work and were then pressured to complete their scheduled surveys by end of month to meet compliance deadlines.

PG&E's budget process combined the prioritization of electric and gas distribution spending. As a result, gas distribution projects competed with electric projects for funding. Long-term gas safety projects were viewed as discretionary spending and were given a relatively low priority in the budget prioritization process.[6]

The leadership in some local areas was inadequate as demonstrated by PG&E's own internal audits and Exponent's system-wide audit of regulator station and valve maintenance. The deficiencies in local management amplified the emphasis on production over quality.

Ineffective Communications

Communications between management and employees were inadequate. Employee complaints about work quality issues were dismissed without corrective actions. Employees had the impression their complaints were ignored. Field employees felt they had little influence on management above their first line supervisor.

Communications between departments and locations were frequently inadequate. Gas Engineering did not communicate effectively with some divisions. Gas Engineering was out of touch with actual conditions in the field. Gas distribution did not have an effective system for communicating lessons learned and best practices across the divisions.

When work was handed off from one department to another, the receiving department frequently did not provide the originating department with any feedback concerning the quality of the information they provided or the disposition of the work. For example, mapping did not communicate effectively with construction or leak survey. There was a general lack of accountability for the quality of the information sent to mapping by other departments.

Processes were poorly coordinated between departments. Departments acted as silos instead of participants in integrated processes.

[6] Chapters 5 and 8.

Inadequate Direction of Work Methods

Management directs the work methods used by field employees through standards, procedures and training. The work methods used in PG&E's gas distribution divisions were inconsistent because the field employees did not receive adequate direction.

PG&E's standards were not well understood in the field. The standards were overly complex and poorly communicated. Changes to the standards were introduced with limited field input and were not adequately tested before they were issued. Changes to standards were not effectively communicated to the field. Documentation and record keeping standards were largely nonexistent.

PG&E's divisions were generally managed as independent operating units during the audit period. The combination of decentralized management and inadequate directions from the central office resulted in inconsistencies in work practices across the divisions.

The maintenance work methods used by the divisions were inconsistent between divisions, as demonstrated by Exponent's system-wide audit of regulator station and valve maintenance. Leak survey work methods were inconsistent, as demonstrated by the Sonoma County resurvey. Leak grading standards were inconsistently applied. Mark & Locate practices varied by location. PG&E's local mapping offices used different symbols and coordinate systems. Record keeping practices were also inconsistent across divisions and departments.

Training was inadequate. Prior to 2009, operator qualification was grand-fathered with no requirement for refresher training. PG&E's leak surveyors had to be retrained in 2008. Training for the employees in PG&E's local Transmission & Regulation groups was inadequate. PG&E did not have a training program for new T&R supervisors, even though many did not have a technical background in the areas they were responsible for supervising.

PG&E's training for mappers was seriously outdated. Training on the information systems used by the mappers was largely nonexistent. Many employees felt PG&E's training programs were inadequate.

Inadequate Staffing and Other Resources

PG&E implemented significant work force reduction programs in 1993 and 1994. Those programs reduced PG&E's gas distribution expenses by 13 percent on an annualized basis. PG&E continued to reduce its gas distribution headcount throughout most of the audit period. PG&E's total gas distribution headcount declined by 29 percent between December 1996 and December 2010.

The large staffing reductions and substandard quality of the work performed by gas distribution imply significant staffing shortages during the audit period.

PG&E conducted a workload analysis of the T&R departments responsible for regulator station and valve maintenance in 2010. The analysis concluded that the T&R departments were understaffed by 26

percent. The subgroup responsible for regulator station and valve maintenance was understaffed by 39 percent.

Leak surveyor staffing was inadequate prior to 2008. The leak survey staffing shortages continued after 2008 because of the increased time required by PG&E's enhanced leak survey procedures. PG&E's internal reviews also indicated staffing shortages in mapping, estimating and mark & locate.

PG&E recognized that its prior staffing levels were inadequate in 2011. Gas Operations requested a headcount increase of 21 percent in 2012 compared to its actual 2009 year end headcount.

The tools and supplies provided to gas distribution were also inadequate. The deficiencies in gas distribution information systems are discussed in a subsequent finding.

The Exponent system-wide audit of regulator station and valve maintenance commented on the negative impact that resource shortages were having on the divisions. The Exponent audit identified several instances where budget constraints resulted in non-compliance with inspection requirements. Exponent recommended that PG&E evaluate the long-term funding needs of each of its T&R organizations and provide adequate funding. Exponent indicated:

> *Interviews indicated frustration among T&R personnel that corrective work related to safety and compliance is not being performed in a timely manner. Interviews indicate that other means are utilized when equipment replacement or upgrade requests are denied....*
>
> *Repeatedly denying requested compliance and safety related repairs could eventually have an adverse impact on the performance, reliability and integrity of the gas distribution system, as well as reduce the motivation of...T&R employees...*

The "other means" used when equipment replacement requests were denied included: (1) diverting components ordered for new customer installations; (2) unofficial trades of spare parts between service yards; and (3) salvaging or scavenging parts from equipment taken out of service.

Gas Service Representatives were not equipped with the proper equipment for indoor leak investigations prior to 2009. Leak surveyors are responsible for grading the leaks they find. The surveyors were not equipped with the industry standard tools for leak grading prior to 2009. The divisions did not have the resources needed to repair pipeline location markers required by safety regulations.

PG&E's repair crews did not have mobile computing terminals in their vehicles. As a result, PG&E's repair processes used inefficient and unreliable paper based systems. PG&E's October 2011 Gas Turnaround Plan describes the EZtech phones used by M&L locators as "antiquated."

Ineffective Supervision and Quality Control

First line supervision is the key to quality control. PG&E's supervisors did not adequately review the work performed by the employees they supervised. The supervisors were overburdened and did not have sufficient time to properly supervise the work. Some supervisors were not qualified to review the work performed by the employees they supervised.

Field supervisors perform two types of quality control reviews, document reviews and work observations. The document reviews performed by the supervisors were ineffective as demonstrated by the lack of documentation for the reviews and the high noncompliance rates found in subsequent audits. Supervisors rarely performed work observations.

PG&E did not have an effective leak survey quality control program prior to 2009, when it implemented follow-up verification surveys on a sample basis. Black & Veatch recommended having contractors periodically perform leak surveys as a quality control measure almost 15 years earlier in its 1995 preventative maintenance report. The results of the Accelerated Leak Re-Survey Project conclusively demonstrated that PG&E's leak survey quality control procedures were critically deficient prior to 2008.

Quality control also includes verifying that the employees tasked with doing a job are qualified to do the work. PG&E did not have an effective process for verifying operator qualifications during most of the audit period.

PG&E's quality control procedures for record keeping and data entry were inadequate. Records were frequently missing or incomplete. Many records were missing data in required fields. PG&E did not have effective processes for identifying the missing or incomplete records. Data entry errors were common and PG&E did not have processes to identify and correct the errors.

Preventative maintenance records were frequently inadequate to determine the quality of the work performed and in some instances were inadequate to verify that the work was actually done. Regulator station data sheets and operating diagrams included conflicting information.

PG&E did not have a process for validating the distribution plat maps used for leak survey planning. As a result, PG&E failed to include some plat maps in its leak surveys for very long periods of time. PG&E did not have any controls to ensure that it had received required records for new services installed by housing developers.

Inadequate Quality Assurance

Gas distribution did not have a separate quality assurance group prior to the summer of 2009. The initial authorized headcount for the gas QA team was five positions. QA funding was constrained in 2009 for budget reasons.

Prior to the creation of the independent QA team, Gas Engineering conducted periodic compliance reviews. The compliance reviews were not adequate to detect the systemic and recurring non-compliance with PG&E standards discovered in Exponent's audit of regulator station and valve maintenance. The compliance reviews did not discover the critical deficiencies in PG&E's leak survey program.

The compliance reviews were largely records reviews. The compliance reviews did not include sufficient numbers of field observations to identify noncompliant work methods and discrepancies between maintenance records and physical conditions in the field.

Failure to Collect and Organize Critical Operating Data

PG&E's gas distribution information systems were inadequate throughout the audit period. The GasFM system was an antiquated local system that had many flaws. PG&E did not have an effective gas distribution work management system for most of the audit period. PG&E did not have a gas distribution Geographic Information System at any point during the audit period. PG&E's CAD-based mapping system, GEMS, was inadequate, poorly maintained and experienced daily "system crashes."

PG&E's gas distribution asset knowledge was inadequate throughout the audit period. PG&E did not have an accurate asset register at any point during the audit period.

Much of PG&E's gas distribution asset information was trapped in paper records that could not be search electronically. As a result, the information was not accessible in a timely manner. Intensive manual processes were required to collect the data needed to conduct integrity management risk analysis.

The inability to access information electronically also prevented PG&E from verifying the completeness and accuracy of its paper records. Summary information was fragmented and inconsistent because it was gathered from different sources, for different purposes, at different times.

PG&E's processes for collecting and reporting gas distribution operating data were inadequate for most of the audit period. Key metrics were gathered through unreliable manual processes.

The reporting of key metrics was sporadic and incomplete as described in Chapter 7. Preventative and corrective maintenance work order backlogs are a key metric for evaluating staffing adequacy. PG&E cannot provide those metrics for most of the audit period. Late locates is a key metric for evaluating the adequacy of mark & locate staffing, PG&E did not have a reliable late locates metric at any point during the audit period.

Late regulator station and valve inspections are a key compliance metric. PG&E did not have a late inspections metric prior to the implementation of the Interim Quality Initiative (IQI) in March 2008. Under the IQI the late inspections metrics were gathered through an unreliable manual "self-reporting"

process at the local level. PG&E did not have any metrics to measure leak survey, leak repair or mapping work quality during most of the audit period.

Late leak repairs are another key compliance metric. PG&E tracked leak repairs in its IGIS system. However, the late leak repair indications produced by IGIS were not accurate because they did not properly account for leak grade changes. As a result, labor intensive manual processes were required to prepare accurate late leak repair metrics. The amount of work required to produce late leak repair metrics for this audit demonstrated that PG&E's reporting and monitoring of late leak repairs was seriously deficient during the audit period.[7]

PG&E created metrics dashboards for leak survey and mark & locate in 2009 as part of the Operational Reporting Initiative. However, the dashboards were not maintained and the metrics included on the dashboards were incomplete and outdated.

Failure to Analyze Available Data

Management failed to analyze the data that was available. Management failed to analyze trends and missed key "red flags" that should have prompted corrective actions.

PG&E's leak surveys identified very few leaks in 2003 to 2007. The low leak discovery rates should have prompted a through review of PG&E's leak survey program, but management failed to initiate a review in a timely manner. The percentage of leaks discovered as a result of customer leak complaint calls is a key metric for evaluating leak survey quality. During 2003 to 2007, customers discovered far more Grade 1 and priority Grade 2 leaks than PG&E's leak surveyors found. After PG&E improved its leak survey processes in 2008, the surveyors found significantly more leaks than customers found. Gas distribution management failed to identify the deficiencies in PG&E's leak survey program because it failed to analyze the available data.

The lack of key operating metrics, such as work order backlogs and late locates, increased the difficulty of evaluating staffing adequacy. Given the lack of data, management should have commissioned periodic workload analysis to evaluate staffing levels in critical functions, similar to the T&R workload analysis prepared in early 2010. Management failed to conduct any meaningful workload analysis prior to that study.

PG&E conducted a root cause analysis of the deficiencies identified in the October 2007 Internal Audit report on leak survey practices in Santa Rosa. PG&E discovered significant deficiencies in several other core processes in 2007 through 2011. PG&E did not conduct any formal root cause analyses for those deficiencies.[8]

[7] Chapter 7.
[8] Response to Discovery, OC-416 and OC-710.

Conclusion

The following combination of factors fostered inconsistent work practices and an organizational emphasis on cost containment over work quality:

- Ineffective executive management;
- Insufficient resources;
- Poor internal coordination and communications;
- Inadequate direction of work methods;
- Ineffective supervision;
- Inadequate record keeping;
- Ineffective process controls;
- Inadequate asset knowledge;
- Ineffective auditing;
- Inadequate information systems;
- Inadequate metrics reporting; and
- Failure to analyze operating data.

The result was substandard work quality, compromising gas operations and public safety standards. The same factors allowed the substandard work quality to continue for years before it was identified and corrected. As of the time of this audit report, some of the identified conditions remain open and are subject to ongoing remediation efforts.

The pervasive nature of the management deficiencies demonstrated the need to conduct an integrated root cause analysis to identify common underlying causes, such as ineffective executive management, excessive emphasis on cost reduction, or inadequate emphasis on work quality.

PG&E did not prepare an integrated root cause analysis.[9] Some of the executives directly responsible for gas transmission and distribution were dismissed after the SBI and subsequent CPUC investigations. However, concerns about PG&E's corporate culture remain.

[9] Response to Discovery, OC-711.

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