Evaluation of PG&E's 2014 Gas Distribution GRC Filing

Prepared for

The Safety and Enforcement Division

The California

Public Utilities Commission

Prepared by

Cycla Corporation

May 16, 2013

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0 Executive Summary

0.1 Objective

An objective of the California Public Utilities Commission (CPUC) is to require pipeline facility operators subject to CPUC rate regulation to explicitly consider risk in deciding which safety improvements to propose in their General Rate Case (GRC) filings. Given the magnitude of the change required both within Pacific Gas and Electric Company (PG&E) and CPUC to meet this objective, the CPUC expects that the PG&E 2014 GRC filing represents but a first step in a deliberate evolution in the way the utility identifies and evaluates the value of safety improvements. The endpoint of this evolution will be a risk-informed decision process leading to rate case filings that include knowledgeable consideration of the best means to produce superior safety performance. In moving toward attaining its objective, the CPUC has commissioned Cycla Corporation (Cycla) to evaluate the PG&E 2014 gas distribution GRC filing.

0.2 Requirement to Perform a System-Wide Risk Assessment

In his March 5, 2012 letter, Paul Clanon (Executive Director, CPUC) directed PG&E (Tom Bottorff, Senior VP, Regulatory Affairs) to "*perform and provide a risk assessment of its entire system … and a comparison to industry best practices.*" The letter further directed that "*PG&E should* (provide in its GRC filing) *a risk assessment of its physical system as well as a description of and a justification for the company's risk mitigation programs and policies.*" This letter was a clear statement that attaining the CPUC objective will require pipeline operators to explicitly consider risk in deciding which safety improvements to present, and to document how risk was considered in informing decisions on risk control measures included in their GRC filings.

Preparation of the PG&E 2014 GRC filing was initiated on October 21, 2011, and does not explicitly include such a risk assessment and justification of its risk mitigation programs and policies. At the time of the letter from Executive Director Clanon, PG&E had already made significant progress in developing its risk mitigation program and in documenting that program in its 2014 distribution GRC filing. While the PG&E GRC filing is not fully responsive to Executive Director Clanon's directive, PG&E is currently working to assemble the data and develop models necessary to do a system-wide risk assessment.

0.3 Approach

The CPUC charged Cycla with evaluating the 2014 PG&E gas distribution GRC filing to determine how well it addresses the directive in the March 5 letter from Paul Clanon. To fulfill this charge, we evaluated how well PG&E incorporated risk characterization in selecting the set of safety improvements it proposes to undertake. Cycla's primary focus was on determining how the utility's decision processes incorporated an understanding of safety risk in deciding how best to improve the safety of its gas distribution system through changes both to the pipeline system and to how PG&E manages that system. We did not attempt to evaluate whether the costs proposed in the GRC filing should be allowed or disallowed.

In fulfilling our charge, Cycla addressed three basic questions:

1. What criteria should be used by CPUC to evaluate whether an operator has produced an adequate risk-informed GRC filing?
2. How does the 2014 PG&E GRC filing measure up against these criteria?
3. Are the activities proposed by PG&E necessary, is their scope appropriate, and is the proposed implementation pace reasonable?

In answer to the first question, Cycla developed a comprehensive set of criteria, based on widely accepted international risk management standards. These criteria are documented in this report in Attachment 3. In answer to the second question, we evaluated PG&E's GRC filing against these criteria, providing the basis for the findings of this report. Our evaluation was based on the material PG&E submitted in support of its 2014 gas distribution general rate case, supplemented by information provided by PG&E in response to the extensive set of questions listed in Attachment 7. In answering the third question, we carried out an experience-based analysis of the necessity, scope and implementation pace of the safety-related activities proposed in the GRC filing.

0.4 Findings

Cycla's findings are shown below and discussed in greater detail in Section 6.

1. *The PG&E filing does not fully satisfy the criteria established for an acceptable risk-informed budget proposal*. This is not surprising since the filing was developed prior to development of the criteria. PG&E used processes and tools available at the time it began preparation of its rate case. Many were well suited for the purpose for which they were used, while others will require considerable additional work to suit their purpose and satisfy the criteria.
2. *PG&E's GRC filing does provide a reasonable foundation for satisfying the criteria in the future*. The processes and tools used by PG&E to develop its 2014 gas distribution GRC filing are clearly works in progress. PG&E is developing new management and decision-support tools and systems and overhauling existing systems that, if developed to full maturity, will provide a strong basis for its overall risk-informed resource allocation process.
3. *The model PG&E used to characterize risk for the GRC filing, originally developed to support compliance with the distribution integrity management program (DIMP) regulation, fails to satisfy many of the evaluation criteria*. The model uses historic data on repaired leaks as the primary indicator of likelihood, and applies a consequence factor to each leak to establish a risk score. When properly validated and populated with verified data, this model can be useful in informing certain decisions on selection of risk control measures (RCMs). However, this model does not fully satisfy the evaluation criteria. PG&E is considering one or more new models for future development that may better satisfy these criteria.
4. *Verified data on system characteristics affecting risk were not available to support preparation of the GRC filing*. A major deficiency in the PG&E approach resulted from the acknowledged fact that verified data on system characteristics affecting risk were not available at the time preparation of the rate case was initiated. In the face of this deficiency, PG&E has made extensive use both of the knowledge and experience of subject matter experts (SMEs) on its staff, and of analysis of the most recent five years of data on repaired leaks, including available information on the factors that led to and influenced the consequences of these leaks. Expert opinion was elicited using a consistent proceduralized approach.
5. *PG&E's process for identifying candidate RCMs was fairly thorough*. The major drivers for the process included PG&E management commitments to:
   i. Satisfy external requirements and recommendations following the San Bruno tragedy,

ii. Elevate its safety performance to the top quartile of the industry on key measures of safety and reliability through application of industry best practices,

iii. Manage system-specific risks identified by PG&E.

The process was complicated principally by the proprietary nature of information on industry best practices assembled by the trade associations, by incomplete input on candidate RCMs from SMEs, and by the absence of a systematic analysis of system-specific risks supporting identification of related RCMs.

6. *Many of the activities proposed by PG&E are designed to address major deficiencies in data, evaluation models and systems for managing its facilities safely which are the critical foundation upon which other needed improvements will build.* As pointed out in independent evaluation reports by the National Transportation Safety Board (NTSB) and the Independent Review Panel (IRP) commissioned by the CPUC, PG&E has fallen behind much of the pipeline industry in its system data (completeness, accuracy, availability, and accessibility) and data management systems, as well as in its gas operations control system and its risk management processes. While these independent findings were focused on PG&E's gas transmission system, they apply equally well to its gas distribution system. Correcting these deficiencies will be costly, but is essential to provide the critical foundation for identifying and managing other needed improvements.
7. *Selection of the overall set of RCMs included in the GRC filing does not appear to have been constrained either by annual budget assumptions or by an annual risk reduction goal*. The only constraint appears to be PG&E's ability to develop qualified personnel to implement selected RCMs. In addition, the impact of the RCMs on system risk was not characterized, so the relationship between resources required and the magnitude of risk reduction expected is unknown.
8. *PG&E has presented no analysis to demonstrate the incremental value of each of its leak reduction projects.* Many of the RCMs presented in the GRC filing involve multiple and diverse means to control a single important source of risk - the number of leaks present in the system. However, PG&E does not explicitly address the incremental value of each of these leak reduction projects.
9. *In general, the overall approach PG&E took for estimating required funding levels for the identified risk reduction measures was reasonable and forecasted expenditures were not grossly overestimated*. The PG&E GRC filing includes capital cost forecasts that reflect significant cost efficiencies; not all of the specific actions needed to achieve these forecast efficiencies have yet been identified. Cost savings may be realized in the future by taking further advantage of economies of

scale and, especially for labor-intensive projects, through use of qualified contractors to supplement employees.

10. *PG&E's implementation schedule for identified RCMs is very aggressive*. Such an aggressive schedule will require significantly increased annual costs in the near-term. PG&E has not demonstrated that the proposed implementation schedule represents the best approach to phasing in new control measures. With one exception, alternative implementation schedules were not considered.
11. *PG&E's GRC filing does not present a clear logical linkage between safety risks and activities intended to control them.* While organization of GRC filing documentation does facilitate understanding of the major activities PG&E wishes to pursue, it fails to clarify the linkage between safety risks and the activities designed to control them.

0.5 Recommendations

Cycla offers the following recommendations to the CPUC in the belief they will support achievement of the CPUC objective to develop a framework within which facility operators subject to CPUC rate regulation will be required to explicitly consider safety risk in deciding which safety improvements to incorporate in their general rate case filings.

1. *Develop, communicate, and implement a multi-year plan to continue the evolution of risk-informed rate case budgeting*.
2. *Finalize the set of criteria against which GRC filings will be measured in the future, and then imbed these criteria in regulation*.
3. *Require PG&E to document its corresponding multi-year program to satisfy CPUC criteria*.
4. *Require PG&E to develop, track, and report on a set of specific performance metrics designed to measure the safety improvements actually achieved by its proposed activities*.
5. *Establish a monitoring program to track PG&E progress in implementing activities funded through the 2014 GRC deliberation*.
6. *Work together with the Pipeline and Hazardous Materials Safety Administration (PHMSA), other state safety regulators, and the pipeline industry to promote advancements in pipeline system risk modeling*.

7. *Work together with PHMSA, other state safety regulators, and the pipeline industry to promote exchanges of information on industry best practices that have demonstrated superior impact on safety performance*.
8. *Work to improve the balance between operator flexibility and accountability by focusing on greater transparency and CPUC oversight of budget revisions*.
9. *Determine how best to ensure that PG&E is developing and expanding its knowledge base of system and operational characteristics on which risk characterization is critically dependent*.
10. *Determine how best to use operator risk characterization developed in support of rate case filings to strengthen appropriate safety advocacy by the CPUC.*

These findings and recommendations are discussed in more detail in Section 6 of this report.

1 Introduction

1.1 Background

Since the tragic accident on September 9, 2010 involving a Pacific Gas and Electric Company (PG&E) gas transmission line in San Bruno, PG&E has been driven to improve safety by its management's commitments[1] to:

i. Satisfy external requirements and recommendations following the San Bruno tragedy,
ii. Elevate its safety performance to the top quartile of the industry on key measures of safety and reliability through application of industry best practices, and
iii. Manage system-specific internally-identified risks.

External recommendations include: the Independent Review Panel (IRP) commissioned by the CPUC whose final report was issued June 8, 2011[2]; and the National Transportation Safety Board (NTSB) whose final report was adopted August 30, 2011[3]. External requirements include the California State legislature - Senate Bill 705 was signed on October 11, 2011[4] and those imposed by the California Public Utilities Commission (CPUC) and the federal Distribution Integrity Management Program (DIMP) regulation[5]. PG&E management has described achieving safety and reliability performance in the top quartile of the industry as a major corporate objective. Identifying and determining how best to manage system-specific risks is a major objective of the activities described in the 2014 gas distribution General Rate Case (GRC) filing. In addition to the GRC filing for PG&E's distribution pipeline system (filed on November 15, 2012), internal PG&E management response to the San Bruno accident and to the requirements and recommendations from the external bodies includes: the Distribution Integrity Management Program (DIMP) Risk Management Procedure (RMP-15, Revision 2 approved on July 29,

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[1] PG&E Gas Safety Plan, Filed with the CPUC, June 29, 2012.
[2] Report of the Independent Review Panel, Prepared for the CPUC, Jacobs Consultancy, June 8, 2011.
[3] National Transportation Safety Board, Pacific Gas and Electric Company, Natural Gas Transmission Pipeline Rupture and Fire, San Bruno, California, September 9, 2010, Accident Report NTSB/PAR-11/01, PB2011-916501.
[4] Natural Gas Service and Safety, California Senate Bill 707, Chaptered by the Secretary of State, Chapter 522, Statutes of 2011, October 7, 2011.
[5] 49 C.F.R Part 192, Subpart P.

2011); and the Gas Safety Plan[6] (approved by PG&E management on June 29, 2012) describing its current and committed work to improve the safety of its gas systems.

Since the San Bruno tragedy PG&E management has been placed under a public, regulatory, and internal management microscope nearly unprecedented in the pipeline industry. The gas distribution GRC filing represents the first plan describing how PG&E's gas distribution system will deal with the lessons from this scrutiny in the context of a formal rate case proceeding. Capital spending and Operational and Maintenance (O&M) activities spelled out in the GRC filing are broad in scope and expensive. Many represent the foundation on which future safety improvements will be built. Others represent diverse approaches to address the same set of risks.

1.2 Objective

An objective of the CPUC is to develop a framework within which pipeline facility operators subject to CPUC rate regulation will be required to explicitly consider risk in deciding which risk control measures (RCM) to advocate in their GRC filings. Given the magnitude of the change required to meet this objective, the CPUC expects that the 2014 PG&E gas distribution GRC filing will represent a first significant step in a deliberate evolution in the way the utility identifies and evaluates the value of safety improvements then decides which improvements to implement. The endpoint of this evolution is envisioned to be a risk-informed decision process leading to rate case filings by California pipeline operators that include knowledgeable consideration of the best means demonstrated to produce superior safety performance. In moving toward attaining its objective, the CPUC has commissioned Cycla to carry out this evaluation of the PG&E 2014 gas distribution GRC filing.

1.3 Requirement to Perform a System-Wide Risk Assessment

In his March 5, 2012 letter, Paul Clanon (Executive Director, CPUC) directed PG&E (Tom Bottorff, Senior VP, Regulatory Affairs) to "*perform and provide a risk assessment of its entire system … and a comparison to industry best practices.*" The letter further directed that "*PG&E should* (provide in its GRC filing) *a risk assessment of its physical system as well as a description of and a justification for the company's risk mitigation programs and policies.*" This letter was a clear statement that attaining the CPUC objective will require pipeline operators to explicitly consider risk in deciding which safety

[6] PG&E Gas Safety Plan, Filed with the CPUC, June 29, 2012.

improvements to present, and to document how risk was considered in informing decisions on risk control measures included in their GRC filings.

Preparation of the PG&E 2014 GRC filing was initiated on October 21, 2011, and does not explicitly include such a risk assessment and justification of its risk mitigation programs and policies. At the time of the letter from Executive Director Clanon, PG&E had already made significant progress in developing its risk mitigation program and in documenting that program in its 2014 distribution GRC filing. While the PG&E GRC is not fully responsive to Executive Director Clanon's directive, PG&E is currently working to assemble the data and develop models necessary to do a system-wide risk assessment.

1.4 Approach

The CPUC charged Cycla Corporation (Cycla) with evaluating the 2014 PG&E gas distribution GRC filing to determine how well it addresses the directive in the March 5 letter from Executive Director Clanon. To fulfill this charge, we have evaluated how well PG&E incorporated risk characterization in selecting the set of safety improvements it proposes to undertake. Cycla's primary focus was on determining how the utility's decision processes incorporated an understanding of safety risk in deciding how best to improve the safety of its gas distribution system through changes both to the pipeline system and to how PG&E manages that system. We did not attempt to evaluate whether the costs proposed in the GRC filing should be allowed or disallowed.

In fulfilling our charge, Cycla addressed three basic questions:

1. What criteria should be used by CPUC to evaluate whether an operator has produced an adequate risk-informed GRC filing?
2. How does the 2014 PG&E GRC filing measure up against these criteria?
3. Are the activities proposed by PG&E necessary, is their scope appropriate, and is the proposed implementation pace reasonable?

In answer to the first question, Cycla developed a comprehensive set of criteria, based on widely accepted international risk management standards. These criteria are documented in Attachment 3 to this report. In answer to the second question, we evaluated PG&E's GRC filing against these criteria, providing the basis for the findings and recommendations of this report. Our evaluation, described in

Section 4, was based on the material PG&E submitted in support of its 2014 Gas Distribution general rate case, supplemented by information provided by PG&E in response to the extensive set of questions listed in Attachment 7. In answering the third question, we carried out an experience-based analysis of the necessity, scope and implementation pace of the safety-related activities proposed in the GRC filing. This analysis is described in Section 5.

1.5 Report Structure

This report describes the Cycla evaluation of PG&E's 2014 GRC filing against evaluation criteria, which we developed as part of the evaluation. Section 2 provides the context for this evaluation by summarizing the major activities included in the PG&E filing, along with a summary of the major contributors to costs. Section 3 describes the development of the evaluation criteria, which are presented in Attachment 3. Section 4 presents the results of the evaluation of PG&E's 2014 GRC filing, including evaluation of the process used by PG&E to develop the filing. Section 5 presents the results of the evaluation of the projects and costs proposed in the GRC filing, focusing on project necessity, scope and implementation pace. Finally, Section 6 presents our findings and recommendations resulting from the evaluation.

In addition, seven attachments are included:

Attachment 1 Definitions and Acronyms
Attachment 2 Standards and Other Material Informing Development of Criteria for Risk-Informed Resource Allocation Process
Attachment 3 Evaluation Criteria for a GRC Filing
Attachment 4 Risk-Informed Decision Making: Balancing Risk Reduction and Cost
Attachment 5 Evaluation of the PG&E Probabilistic Risk Algorithm
Attachment 6 Evaluation of Activities Presented in PG&E's 2014 GRC Filing
Attachment 7 Listing of Information Requested from PG&E

2 Discussion of Major GRC Cost Components

Table 1 shows the major cost components, both capital and operational, described in PG&E's 2014 gas distribution GRC filing, along with a high-level summary of the factors underlying the increased costs, and insights we gleaned from review of available cost-benefit analyses reported by PG&E and contained in PG&E responses to questions[7]. The bases against which PG&E compared proposed costs in the filing were recorded capital and O&M expenditure data from 2011. PG&E has acknowledged that 2011 recorded expenditures are significantly greater than those in the CPUC Decision Regarding the 2011 distribution GRC[8]. For capital improvements, PG&E has recorded expenditures in 2011 of $308 million, which is $50 million more than provided for in the CPUC Decision. For O&M activities, PG&E has recorded expenditures in 2011 of $233 million, which is $37 million more than provided for in the CPUC Decision. The costs included in the 2014 GRC filing will lead to a rate increase for a typical residential customer of over 15%.

As shown in the table, the major additions to capital expenditures include: increased rate of pipe replacement from 30 miles per year to 180 miles per year, building additions, and completion and staffing of the new gas distribution operations control center. The major contributors to increased O&M costs include:

- Increased frequency of leak survey, including increased repair costs, from once per five years to once per three years;
- Increased staffing to reduce the response time to customer leak notifications;
- Cross-Bored Sewer project; and
- Increased mark and locate costs.

The table also summarizes the cost savings projected in PG&E's benefit-cost analysis and provided by PG&E in response to Cycla questions. PG&E has included[9] significant cost efficiencies in the capital forecast in its GRC filing. The table below notes those specific efficiencies that have been identified and quantified to date (see Chapter 8 in the table). PG&E has indicated it is working toward finding

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[7] GRC2014-Ph-I_DR_Cycla_013-Q03 and GRC2014-Ph-I_DR_Cycla_012-Q18.

[8] The authorized expenditures were established in the CPUC Decision Regarding 2011 GRC, D.11-05-018 (May 13, 2011). This includes a Major Work Category for expenses incurred to comply with the DIMP regulation, to be implemented through a one-way balancing account with a $60 million cap over the period 2011-2013.

[9] GRC2014-Ph-I_DR_Cycla_013-Q03.

specific improvements leading to an additional $60 million in capital efficiencies that have already been incorporated in its capital forecast.

Table 1 Basis for Cost Increases

Cost Components by Chapter in GRC Filing	Capital Cost Addition (Forecast 2014 – Recorded 2011)	Operating Cost Increase (Forecast 2014 – Recorded 2011)	Major Factors Underlying Identified Cost Increases	Insights from Business Case or Cost-Benefit Analysis[10] (PG&E-3 Working Papers)
2. Systems Operations Gas Control	$62.2M (11.64%)	$12.9M (5.55%)	Consolidate and upgrade control center - centrally control 826 hydraulically independent systems in 58,000 sq. mi • Shifts philosophy from "monitor & respond" to "monitor & prevent" • Provide additional instrumentation for monitoring pipe parameters	• Numerous non-quantified benefits listed • Replace paper charts ($405K savings in 2014) • Decrease dig-in events ($116K savings in 2014) • Financial benefits (expenses) estimated in the Business Case are $3.9M (time frame not specified) • Business Case capital savings are estimated to be 1% to 5% over a 5 to 10 year period
3. Gas Distribution Mapping & Records	--	$15.2M (6.54%)	Annual costs to collect, standardize, and index gas distribution system as-built drawings	• Numerous non-quantified benefits listed • Financial benefits estimated in the Business Case are $0.3M in 2014; supplemental analysis estimates ultimate (2017) cost savings from records collection and Pathfinder of ~$8 million per year
4. Gas Distribution IMP	--	$22.6M (9.72%)	Largest contributors – Cross-Bored Sewer Project and staffing increases to support DIMP	• Cross-Bored Sewer - No costs avoided or reduced • DIMP - Numerous non-quantified benefits listed • Supplemental analysis estimates cost savings on the Cross-Bored Sewer project of $0.75 million per year

[10] In no case were benefits predicted based on a quantitative risk analysis that demonstrated reduced accident frequency or reduced accident consequences; in several situations PG&E did not have data to support estimation of anticipated cost savings or cost avoided.

Cost Components by Chapter in GRC Filing	Capital Cost Addition (Forecast 2014 – Recorded 2011)	Operating Cost Increase (Forecast 2014 – Recorded 2011)	Major Factors Underlying Identified Cost Increases	Insights from Business Case or Cost-Benefit Analysis[10] (PG&E-3 Working Papers)
5. Pipe, Meter & Other Preventive Maintenance (PM)	$0.2M (0.04%)	$24.5M (10.54%)	• Locate & Mark cost increases driven by increased number required and benchmark on % addressed within 48 hours • Preventive Maintenance cost increase driven by required operational enhancements and technology advances	• Numerous non-quantified benefits listed • Supplemental analysis estimates ultimate (2016) cost savings of ~$9 million per year, principally associated with productivity improvements
6. Leak Survey & Repair	--	$79.0M (33.98%)	Major contributors to cost increases: • Leak survey cost increases ($14.0M) driven by increased leak survey frequency (once per 5 yrs. to once per 3 yrs.) • Corrective Maintenance cost increases ($64.8M) driven by increased survey frequency, increased detection sensitivity, and shorter time to repair certain leaks leading to increased repair needs	• Numerous non-quantified benefits listed • Total savings from aligning leak survey and atmospheric corrosion inspections - anticipated to be $2.7M in 2014 • Supplemental analysis estimates total cost savings of ~$11 million per year, principally associated with productivity improvements in leak survey and repair
7. Gas Field Services & Response	$14.1M (2.64%)	$36.8M (15.83%)	• Operating cost increase driven by (a) response time goals, (b) repairs necessitated by increased frequency of leak surveys, (c) additional atmospheric corrosion remediation, (d) staff increases to address more regulator replacements • Capital costs driven by regulators being replaced and capitalized labor to replace regulators	• Numerous non-quantified benefits listed Decreased response time not expected to result in costs avoided or reduced • Supplemental analysis estimates total cost savings of ~$5 million per year, principally associated with productivity improvements resulting from GSR relocation and shift changes

Cost Components by Chapter in GRC Filing	Capital Cost Addition (Forecast 2014 – Recorded 2011)	Operating Cost Increase (Forecast 2014 – Recorded 2011)	Major Factors Underlying Identified Cost Increases	Insights from Business Case or Cost-Benefit Analysis[10] (PG&E-3 Working Papers)
8. Gas Distribution Capital & Investment Planning	$310.9M (58.20%)	--	Cost increase driven by increase in replacement of mains and associated services from 30 miles/yr. to 180 miles/yr.	• Numerous non-quantified benefits listed • No cost reductions are anticipated • Cost avoidance associated with pipe replacement was estimated to be $1.16M in 2014 • Cost savings associated with remote monitoring of CP are expected to be offset by increased costs of corrective work • Supplemental analysis estimates total cost savings from identified improvements of ~$40 million, principally associated with improved construction methods, improved work and resource management, and construction management efficiencies
9. New Business & Work for Others	$45.1M (8.44%)	($0.1M) (0.04%)	Capital costs driven largely by forecast for economic recovery and associated increase in requests for connects (from 12,258 to 33,228)	• Apparently not considered amenable to cost-benefit analysis
10. Technical Training and R&D	--	$15.2M (6.54%)	Cost increase driven by Expanded Tech Training Program - develop or enhance 19 tech training programs	• Numerous non-quantified benefits listed • No apparent cost reduction

Cost Components by Chapter in GRC Filing	Capital Cost Addition (Forecast 2014 – Recorded 2011)	Operating Cost Increase (Forecast 2014 – Recorded 2011)	Major Factors Underlying Identified Cost Increases	Insights from Business Case or Cost-Benefit Analysis[10] (PG&E-3 Working Papers)
11. Gas Operations Technology Costs	$40.7M (7.62%)	$18.7M (8.04%)	Major contributor to operating cost increase - gas distribution Asset Management. - Pathfinder Project ($10.3M) Major contributors to capital costs include: • GD Asset Mgmt. (Pathfinder Project ($16.7M); Enhancements to Estimator Toolsets ($3.4M)) • Public Safety & IM Technology ($1.0M Public Safety Initiatives; $1.6M Reg. Reporting Reqmts.; $8.0M Gas Service Rep Radios) • Gas Operations ($2.3M) • Mobile Platform Technology ($10.7M)	• Numerous non-quantified benefits (both cost and non-cost) listed for Pathfinder Project • Numerous non-quantified benefits listed • Quantified benefits described in the Pathfinder Business Case are estimated to be $1.2M in 2015, increasing to $3.6M in 2017
12. Gas Operations - Other	$61.0M (11.42%)	$7.7M (3.31%)	Major contributor - Building projects (12 major and 25 minor building projects) - accommodate staff increases, co-location of staff, new training facility, consolidated dispatch & control center, backup operations facility for emergencies	• Numerous non-quantified benefits listed
Total	$534.2M (100%)	$232.5M (100%)		

3 Development of Evaluation Criteria

Cycla developed evaluation criteria as the basis both for evaluating the PG&E GRC filing and to provide initial criteria for future development of risk-informed budgeting processes by PG&E and other California pipeline operators. We developed the evaluation criteria considering available standards as well as our experience in industries where extensive use is made of risk characterization to inform resource management decisions. The principle standards we considered were:

- Risk management - Principles and Guidelines (ISO 31000:2009)
- Risk management - Risk assessment techniques (IEC/ISO 31010:2009)
- Risk management - Vocabulary (ISO GUIDE 73:2009)
- Asset Management - Part 1: Specification for the Optimized Management of Physical Assets (PAS 55-1: 2008)
- Asset Management - Part 2: Guidelines for the Application of Publicly Available Specification (PAS) 55-1 (PAS 55-2:2008)

We considered several additional standards and documented experience with their application in developing the criteria. These additional sources are listed in Attachment 2.

We structured the criteria around ten process elements which, in our experience, comprise the key sequence of steps in a risk-informed resource allocation process. The ten process elements are shown in Figure 1. The elements include:

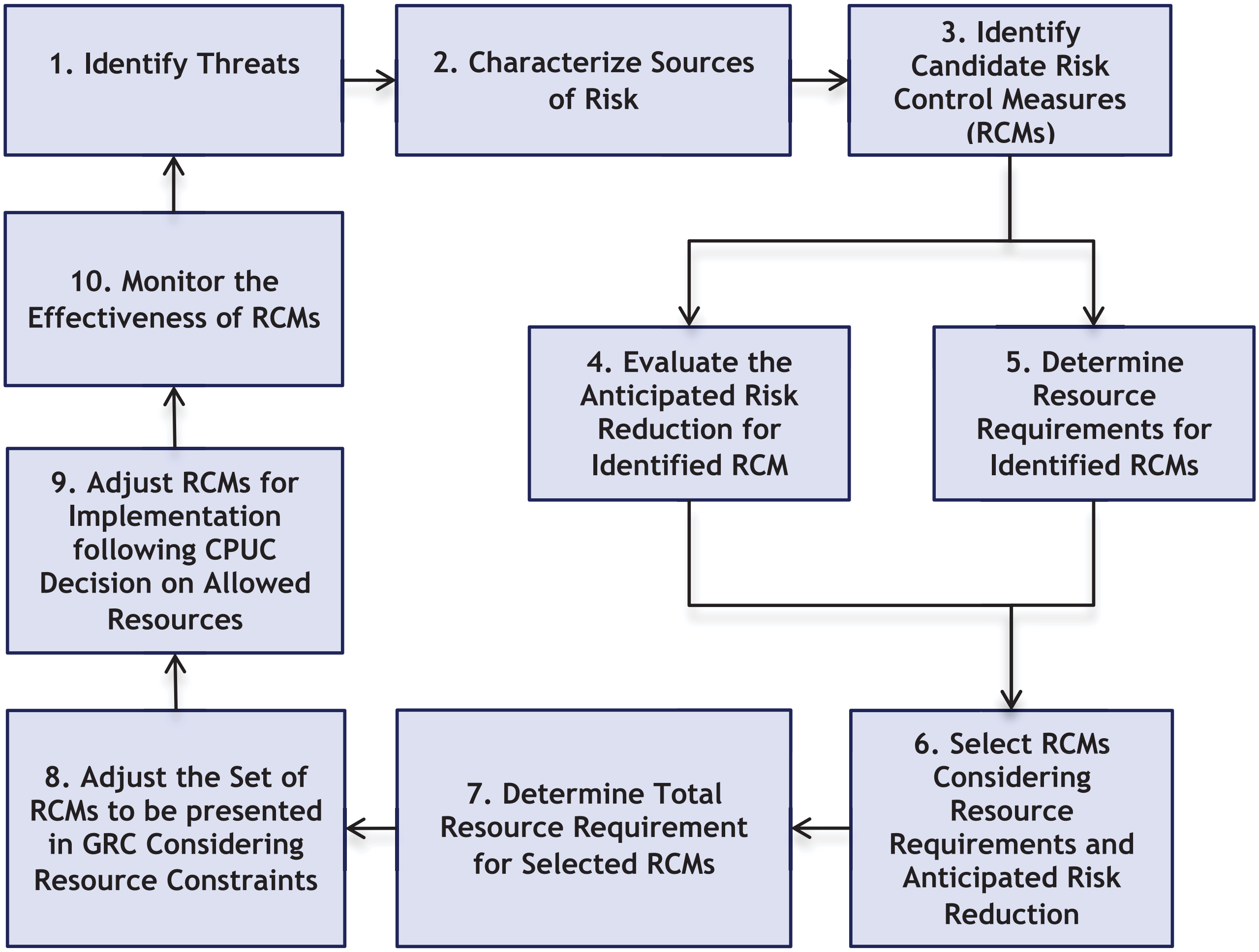
1. Identify the threats having the potential to lead to safety risk;
2. Characterize the sources of risk;
3. Characterize the candidate measures for controlling risk;
4. Characterize the effectiveness of the candidate risk control measures (RCMs);
5. Prepare initial estimates of the resources required to implement and maintain candidate RCMs;
6. Select RCMs the operator wishes to implement (based on anticipated effectiveness and costs associated with candidate RCMs);
7. Determine the total resource requirements for selected RCMs;
8. Adjust the set of selected RCMs based on real-world constraints such as availability of qualified people to perform the necessary work;

9. Document and submit the General Rate Case filing, on which the CPUC decides the expenditures it will allow, and, based on CPUC decision, adjust the operator's implementation plan;
10. Monitor the effectiveness of the implemented RCMs and, based on lessons learned, begin the process again.

Attachment 4 discusses the choices of processes and risk characterization tools to support the critical CPUC role of deciding how much risk reduction is affordable. This attachment includes discussion of the concept of As Low As Reasonably Practicable (ALARP) as one way to address the issue of "how much is enough."

The criteria organized under these ten elements and used in the evaluation of the PG&E GRC filing are presented in Attachment 3.

Figure 1 Elements of a Risk-Informed Resource Allocation Process



4 Evaluation of PG&E GRC Filing

4.1 Overview

This evaluation of the PG&E 2014 gas distribution GRC filing is an initial step in attainment of the CPUC end objective: to promote development of a framework within which facility operators subject to CPUC rate regulation will be required to explicitly consider risk in deciding which safety improvements (or risk control measures – RCMs) to present, and to document how risk was considered in informing decisions on RCMs included in their GRC filings. To support attainment of this objective, Cycla developed a comprehensive set of criteria based on widely accepted international risk management standards against which we have evaluated PG&E's 2014 gas distribution GRC filing and the processes on which that filing was based. The criteria used in this evaluation are presented in Attachment 3.

Because we developed the evaluation criteria, after PG&E had completed its filing, the following classification scheme was used to indicate the status of PG&E's process development as presented in the GRC filing and in related documentation Cycla requested to support this evaluation:

A. Fully satisfies evaluation criteria;
B. Partially satisfies and provides a foundation for future satisfaction of the evaluation criteria;
C. Does not address the criteria.

We have based this evaluation on the material PG&E submitted in support of its 2014 gas distribution rate case, supplemented by information provided in response to questions posed to PG&E (see Attachment 7). The results of this evaluation, shown below, provide the basis for the findings we have developed.

4.2 Evaluation against the General Criteria for an Operator's Overall Risk-Informed Resource Allocation Process

<u>Evaluation Result - Partially satisfies and provides a foundation for future satisfaction of the evaluation criteria</u>. PG&E is developing new management and decision-support systems and overhauling existing systems that, if developed to full maturity, will provide a strong basis for its overall risk-informed resource allocation process.

The Context

PG&E is a large company with several lines of business (LOB). One of these LOBs, gas distribution, is subject to rate regulation by the CPUC. A major corporate level responsibility for PG&E is to ensure that (a) enterprise-level risks are recognized and satisfactorily addressed, and (b) lines of business have sound programs and sufficient personnel to recognize and manage operational risks. To address these responsibilities, PG&E initiated development of its corporate-level Enterprise Risk Management (ERM) system in 2006, and more recent initiated efforts to develop Operational Risk Management (ORM) systems.

Both PG&E's ERM and ORM systems are works in progress. Insights from the tragedy at San Bruno caused PG&E to begin overhaul of its ERM system in late 2011. To guide development of its ORM systems, PG&E completed an internal standard in early 2012. Neither PG&E's ERM nor ORM system is a mature management system. PG&E is in the process of implementing its ORM system in gas operations, and is integrating that system with the corporate-level ERM system. Existing documentation describes these programs, including positional responsibilities and committees that operate within and oversee the systems. A thorough audit will be necessary to provide the CPUC assurance that the new PG&E management systems are functioning as documented.

The Gas Operations Risk and Compliance Committee (RCC) has responsibilities throughout the ORM system, including: identifying threats at the operational level, approving risk analysis and risk mitigation strategies, and tracking progress on risk mitigation activities. The RCC is also responsible for identifying significant risks that satisfy threshold criteria for submission to the corporate-level Risk Policy Committee.

The 2014 PG&E distribution GRC filing was prepared based on two complementary sets of inputs. One source was the DIMP through which a set of Programs and Activities to Address Risks (PAAR) was developed. Another source was the work identified through the Investment Planning (IP) organization that considered ongoing work as well as existing commitments. These inputs were assigned priority values and integrated into the GRC filings by assigned Chapter Witnesses, who worked with teams of knowledgeable employees to review assumptions, ensure priority items are covered, and make necessary adjustments. This process was designed to ensure that key risks as well as outstanding commitments were addressed through activities, both capital and O&M, specified in the GRC filing.

The evaluation presented below describes how PG&E's management processes address the ten general criteria and criteria associated with the ten process elements documented in Attachment 3.

Evaluation against General Criteria

The processes PG&E used to address safety risk for its GRC filing were principally those associated with its DIMP supplemented by consideration of issues identified by various outside evaluation groups and PG&E management. PG&E's efforts to develop and implement asset management and operational risk management systems are just beginning. The risk characterization tool supporting DIMP, built around data on leaks repaired, was used to identify the major contributors to risk which were then the focus for identifying RCMs. The DIMP process and tools are not yet capable of evaluating the risk reduction capability of identified RCMs. The DIMP team has identified measures to monitor overall trends in safety resulting from implementation of the set of RCMs.

System segments used in the DIMP process were geographic plats, which are not necessarily aligned with the physical characteristics of the pipeline system that affect risk. Uncertainties in data and models were not explicitly treated in development of RCMs addressed by the GRC filing. Because of the limitations in processes and tools described above, PG&E was unable to clearly relate the cost of RCMs to their anticipated impact on risk. Therefore an optimized allocation of resources was not possible.

A fundamental requirement included in the Distribution Integrity Management Program (DIMP) regulation (§ 192.1007) is "(a) *Knowledge.* An operator must demonstrate an understanding of its gas distribution system developed from reasonably available information." This requirement is reflected in General Evaluation Criterion 5. Knowledge of the system is a critical part of any risk characterization or risk management process. Knowledge is built on an understanding of the physical characteristics of the pipeline system, but does not end there. Continuing efforts are required to maintain current knowledge of system characteristics potentially affecting risk. This is especially true for operators of pipeline systems that have been constructed over many decades, some parts of which may have been acquired from other operators accompanied by incomplete or questionable data on system characteristics, operating history, and the current physical condition. Maintaining accurate and current knowledge of the system requires an ongoing learning process involving, at a minimum, the following activities:

- *Determination of root causes of events* – Root causes should be determined at a level consistent with the potential for contributing to a better understanding of safety risks related to the system or equipment and how it is operated. Root cause analysis of very complex events often has the potential to reveal important risk drivers ranging from combinations of "interactive" threats whose presence magnifies risk, to management and cultural factors potentially affecting the risk of the entire pipeline system.

- *Analysis of failure data* – For distribution systems the richest source of data on factors affecting system risk is leak data. PG&E has relied heavily on these data to develop its understanding of system safety risk. The criticality of this data dictates that the operator needs to assure itself and its regulators that the basis on which leak causes are identified is sound. This would include having clear procedures for determining the "cause" of each leak, along with training and qualification of those individuals who determine these causes.
- *Opportunistic evaluation of the important system characteristics* – During the course of operating its pipeline system, an operator frequently excavates small segments. Each excavation is an opportunity for the operator to confirm or update its understanding of the material, fabrication technique, and condition of the exposed segment and, potentially, other segments in the same vicinity. Failure to take full advantage of these learning opportunities, including acting on lessons learned, can have catastrophic consequences.
- *Risk characterization* – A well designed risk characterization process will involve investigations that contribute to an operator's knowledge of the segments of its pipeline system that represent the highest risk. The process may be as simple as characterizing risk based on leak history as PG&E did in its initial DIMP risk characterization; or more complex, involving identification of the combinations of system and operational characteristics that have historically contributed to high leak rate; or very complex, involving quantitative characterization of risk using more complex logic models.
- *Maintenance of accurate records incorporating changes to the system and its operating procedures* – Any approach to characterizing risk of a pipeline system depends on the accuracy of records of system characteristics and operation. Timely incorporation of changes in these records is a key part of the management of change. Discrepancies between information in a risk model and the characteristics of the actual system can invalidate results of the model, or even cause them to be misleading.

PG&E has acknowledged deficiencies in its system knowledge, and several of the activities in the GRC filing are designed to address these deficiencies. The Cycla overview of the past five years of CPUC reportable gas distribution incident data[11] (involving nearly three hundred incident reports) raised several

[11] CPUC General Order 112-E (Section 122.2) goes beyond federal incident reporting requirements by requiring reporting of incidents involving media coverage; incidents involving escaping gas and exceeding $1,000 in property damage; and incidents involving fire, explosion or underground dig-ins.

questions related to the above learning activities that should be included in a continuing process evaluation by the CPUC. These include:

- *Incident root cause follow-up* – Numerous thirty day incident reports, the final report operators are required to submit for a typical reportable incident, that we evaluated indicated that the root cause of the incident had not yet been determined. Discussion with CPUC revealed uncertainty related to follow-up by CPUC to clarify these root causes, and by PG&E to capture related lessons as potential or emerging threats in its operational risk management system.
- *Incomplete characterization of incident causes* – We identified several incident reports in which the incident cause was not captured in the appropriate check box, but review of the narrative did include sufficient information to characterize the cause. Since data analysis often relies on checked boxes rather than narrative descriptions, this oversight reduces easy access to insights from incidents.
- *Unknown follow-up on excavation damage incidents* – In numerous cases all the actions identified as necessary for correct pipeline marking were carried out, but excavation damage occurred anyway. In most of these situations the narrative revealed the cause to be "lack of care" in using hand excavation near the marked pipeline. This seems to be an area in which effort to identify and communicate to excavators more rigorous ways to excavate near marked pipelines might reduce the frequency of excavation damage.
- *Incident reporting that misrepresents incident trends* – Reported incidents included two categories that seem unrelated to pipeline safety. These are "fire first" incidents in which a fire leads to a gas leak that feeds the fire, and incidents reported <u>only</u> because media was present to cover the event. While reporting these "incidents" is no doubt useful, including such events in trending reports seems to misrepresent the actual number of incidents that occur, and possibly to distort the relative contribution of various threats to risk inferred from analysis of incidents.

4.3 Evaluation against Criteria Associated with Individual Elements

1. *<u>Identify threats to pipeline integrity</u>*

<u>Evaluation Result - Partially satisfies and provides a foundation for future satisfaction of the evaluation criteria</u>. PG&E's threat identification process satisfies most threat identification criteria. The exceptions are treatment of "interactive threats" and use of root cause analysis, both of which PG&E defines differently from the evaluation criteria.

PG&E has identified threats through the processes supporting its DIMP program. The main information sources for the threat identification process are analysis of data on leaks that have been removed from the system, and the knowledge and experience of employees. The threat identification process involves seven Threat Steering Committees composed of field-based subject matter experts (SMEs) along with analysis of reported causes of repaired leaks to identify threats in three categories: known threats (those known to cause at least 0.5% of leaks repaired in the PG&E system), potential threats (non-leaking, identified by experts and evaluation of industry experience), and emerging threats (those known to cause less than 0.5% of leaks repaired in the PG&E system, but often high consequence leaks). Threats identified through analysis of leak data are characterized by the leak cause, the type of facility where the leak was experienced, and type of asset experiencing the leak. An example of a known threat would be a corrosion leak in a distribution main. Emerging and potential threats are classified by threat category, potential sub-threat and discovery source. An example of an emerging threat would be incorrect operation associated with cross boring, identified through industry experience. An example of a potential threat would be natural force damage associated with a tsunami, identified by SMEs.

While PG&E's process includes "interactive threats," the definition it uses (i.e., failure mechanisms acting on resident features) is different from that in the criteria, leading to the possible exclusion of some interactive threats (e.g., a seismic event acting on an embrittled main, or increased likelihood of over pressurization caused by insufficient redundancy of overpressure protection, or uncorrected 3rd party mechanical damage to a pipeline that increases its susceptibility to external corrosion).

PG&E specifically includes root cause analysis in its DIMP process description. However, it defines the term differently from the evaluation criteria, leading to uncertainty regarding PG&E's causal factor evaluation of hazardous leaks and incidents. In addition, root cause analysis has been identified as a key part of the PG&E DIMP process, but related analysis had not yet been initiated at the time of this evaluation.

The PG&E process for identifying threats has considered industry experience as well as PG&E-specific experience. SMEs identify threats based on analysis of leak data and their own experience. These threats are accepted as valid by the Gas Operations Risk and Compliance Committee (RCC).

To the degree unique characteristics of the system were considered in identifying threats, it was done through the input of SMEs, since integrated documentation of segment-by-segment system characteristics is not yet available. The only evidence of analysis designed to identify system-specific threats is the causal analysis done to better understand select incidents.

2. *Characterize the sources of risk*

Evaluation Result - Partially satisfies and provides a foundation for future satisfaction of the evaluation criteria. The model PG&E used to characterize risk for the GRC filing, while useful, fails to satisfy many of the evaluation criteria. One or more of the new models being considered for future development may better satisfy the evaluation criteria.

There are several risk models either in use or under development to evaluate or characterize risk in the PG&E gas distribution system. The model most influential in developing safety activities for its GRC filing is the DIMP Risk Model. The various models in use or under development include:

- *The Corporate-Level Risk Evaluation Tool* (RET) - which is part of the enterprise risk management system and is built into the "Risk Register." The RET is not an investigative tool, but is used to assemble information in support of Investment Planning. The primary inputs to risk evaluation using this model are based on subjective expert opinions supplemented by leak data analysis (discussed below). Both probabilities and consequences are characterized as high/medium/low (H/M/L) each associated with numeric scores. Risk decision attributes in the RET and their weightings are
    - Public & Employee Health & Safety (30%)
    - Compliance/Legal/Regulatory (5%)
    - Environmental (5%)
    - Financial (30%)
    - Customer Service (25%)
    - Corporate Reputation (5%)

  The resulting risk scores do not clearly establish which proposed activities were selected primarily to mitigate safety risk, versus to mitigate risk associated with other attributes.
- *The DIMP Risk Model* - which is currently a limited application tool used to identify major risks based on analysis of leak repair data. This approach was adopted for DIMP when PG&E determined

that their developing knowledge of the distribution infrastructure would not support use of the Probabilistic Risk Algorithm (see below).

- *The Probabilistic Risk Algorithm* - which is under development in support of a GIS-based infrastructure management process. The development of this algorithm is strongly tied to completion of the Pathfinder project, which is designed to capture infrastructure characteristics at a level of detail necessary to understand the pipeline system and to characterize its risk. We evaluate this model against the evaluation criteria in Attachment 5.

The regulatory requirement behind PG&E's DIMP Risk Model is the Federal regulation published on December 4, 2009[12], with a requirement that "No later than August 2, 2011 a gas distribution operator must develop and implement an integrity management program that includes a written integrity management plan…" A major requirement of this regulation, one on which the remaining requirements build, is to "identify the characteristics of (the operator's) pipeline's design and operations, and the environment in which it operates, which are necessary to assess applicable threats and risks". In spite of the fact that this requirement was issued in late 2009, PG&E had not, at the time of this evaluation, assembled the data necessary to support risk characterization of system segments selected based on consistent risk characteristics. In the absence of these data, PG&E has, as described below, employed data on repaired leaks to support characterization of segment risk.

PG&E used the risk characterization model developed for the DIMP program (RMP-15, Rev 2) to support preparation of the GRC filing. That model uses five years of historic data on repaired leaks as the indicator of likelihood, and applies a consequence factor (a mathematical combination of subjectively defined "points" for each identified consequence-related factor) to each leak to establish a risk score. Calculated risks associated with each known threat were combined to yield a relative level of risk associated with each threat. The relative risks associated with emerging and potential threats are determined subjectively by SMEs based on their knowledge of the system and its susceptibility to known threats. Analysis of the system-wide leak repair data indicates the following contributions to risk: excavation damage (~52%), material or weld failure (~19%), corrosion (~12%), equipment failure (~7%), other outside forces (~4%), incorrect operation (~2%), and natural force damage (~1.6%).

The DIMP risk characterization model, when properly validated and populated with verified data, can be useful in informing decisions regarding priority of pipe segments and fittings for replacement, and

[12] 74 FR 63934.

regarding locations to increase the frequency of leak surveys. This risk characterization model is designed to identify segments most likely to leak in the future based on where past leaks have occurred. While the model is useful in many applications, it has several deficiencies measured against the evaluation criteria, including:

- The model uses data on repaired leaks but not data on pipeline and system characteristics that potentially contribute to risk. This deficiency does not adversely impact the usefulness of the model in applications such as those discussed above, but does seriously limit its usefulness in investigating the potential future impact of emerging threats.
- The current model is structured around and populated with leak repair data for system plats. While system plats are a useful geographic basis for subdividing the system, there is no assurance that the characteristics of pipe and fittings in an individual plat are consistent from the perspective of risk. For example, a single plat may include pipe or fittings made from different materials and installed at different times. Thus risk characterization at the plat level fails to support investigation of system characteristics contributing to risk.
- By itself, the current DIMP Risk Model can inform only a limited set of decisions on the value of a spectrum of risk control measures. Decisions that it can support include prioritization of pipe for replacement and selection of segments for increased leak survey frequency (except as impacted by the model segment structure discussed above). An example of a decision it cannot inform is determining the incremental value of various RCMs all designed to reduce the number of undetected hazardous leaks in the system.
- As currently designed the DIMP risk model is not capable of *investigating* contributors to risk that are not readily apparent from operating history (e.g., potential and emerging threats), nor of evaluating the effectiveness of existing RCMs.
- The DIMP Risk Model is not capable of identifying and evaluating the contribution to risk from scenarios with the potential to produce exceptionally high consequences, even beyond those experienced to date.
- Uncertainties are not treated in the current model, nor does it appear capable of supporting sensitivity analysis.

Since the DIMP Risk Model is based on data on leaks repaired and has no separate predictive capability, its validity is tied to the validity of the leak data on which it is based.

None of these deficiencies represents a fatal flaw in the potential usefulness of the current DIMP Risk Model. If it were restructured around pipe segments with consistent risk characteristics, and used in conjunction with a geographic information system (GIS) system populated with verified data on system characteristics potentially affecting risk, it could be useful as one in a suite of qualitative and quantitative tools informing resource allocation decisions.

Other than by soliciting the perspectives of SMEs and analyzing incident causes, PG&E has performed no analysis designed to identify system-specific risks.

3. *Identify candidate risk control measures (RCMs)*

Evaluation Result - Partially satisfies and provides a foundation for future satisfaction of the evaluation criteria. PG&E's process for identifying candidate RCMs is limited principally by the difficulty of accessing proprietary information on industry best practices through trade associations, by incomplete input on candidate RCMs from SMEs, and by the absence of a systematic analysis of system-specific risks leading to the definition of related RCMs.

Building on an understanding of the important threats and risks identified using the DIMP Risk Model, the PG&E DIMP program is responsible for identifying Risk Control Measures – RCMs (or Programs and Activities Affecting Risk - PAAR - in PG&E terminology.) The first step is identifying risks at a level that allows selection of appropriate RCMs. At present this is accomplished by identifying opportunities for improvement of major programs that have been developed to address historic risks. For example, excavation damage represents the single largest contributor to risk in PG&E's distribution system. To improve its damage prevention program, PG&E is focusing its resources on the program itself (including improved mapping records, increased public awareness, excavation outreach program, and interaction with repeat offenders), gas meter protection, and excess flow valve installation (required by regulation). Similarly PG&E identified opportunities to improve its leak management program, inspection program, pipe and appurtenance replacement program, technology system and process improvements, and technology and research programs.

The need for improvement in each program was based on the need to address identified risks and to improve performance relative to the industry. PG&E identified measures to affect the desired improvements by surveying industry best practices, considering acceleration of programs already in place, and seeking out innovative technologies to address recognized risks and performance deficiencies. Examples of activities included in the GRC filing from each category include:

- Addressing recognized risks – the cross-bored sewer inspection program and the gas meter protection program,
- Applying industry best practices – the centralized distribution operations control center and increased gas service representative staffing to reduce response time to customer notification of gas leaks to perform in the top quartile in the industry,
- Accelerating existing programs - increasing the frequency of leak surveys from once every five years to once every three years,
- Deploying innovative technologies – application of the Picarro leak surveyor.

PG&E identified industry best practices or the company's ranking against comparable gas distribution companies through a combination of interaction with the American Gas Association (AGA) and benchmarking operators with strong performance. Information from AGA programs is proprietary and accessible only by member utilities that participate in the program.

In some cases RCMs were identified to address existing recognized deficiencies in management systems and to respond to external mandates. Examples include: the Pathfinder project (existing deficiency in location-specific understanding of gas distribution system characteristics), and the centralized systems operation gas control center (recommendation from both the CPUC-commissioned Independent Review Panel – IRP and the NTSB)[13].

Evaluation of the effectiveness of existing RCMs is complicated by the fact that many of the control measures are designed to impact the same performance characteristic (e.g., number of hazardous leaks identified and repaired[14] is affected by several RCMs together with means used to detect them). This difficulty is a continuing problem for all operators. In evaluating the effectiveness of the new Picarro surveyor, PG&E is doing controlled tests to evaluate the new surveyor against historic survey techniques. Preliminary results seem promising, and continuing results will likely impact deployment decisions.

[13] These evaluations were specifically focused on PG&E's gas transmission system, but are equally valid for its gas distribution system.
[14] The more meaningful effectiveness measure is the number of unidentified hazardous leaks in the system which must be indirectly inferred from data on leaks detected.

SMEs play a key role in identifying candidate RCMs. However, in the absence of a structured process focusing on risks to seek out candidate RCMs, input from SMEs can be incomplete. Evidence includes the failure to identify increasing the frequency of regulator internal inspections as a candidate RCM. This measure could be implemented quickly and modified as appropriate in the future when other measures planned to mitigate overpressure events have been completed.

4. Evaluate the anticipated risk reduction for identified RCMs

Evaluation Result - Partially satisfies and provides a foundation for future satisfaction of the evaluation criteria. Only in very limited cases has PG&E attempted to evaluate the anticipated risk reduction from RCMs. Most noteworthy is the application of an internally-developed analysis tool to estimate the increased number of hazardous leaks located by application of candidate RCMs.

The primary basis for selecting RCMs in its GRC filing was PG&E's search for industry best practices combined with pursuing promising new technologies. Demonstration of the effectiveness of industry best practices was not attempted, apart from the fact that operators with strong safety performance have adopted these practices as part of their effort to go beyond minimum regulatory compliance to improve the safety of their operations.

The PG&E GRC filing does not describe in detail the process it will use in translating rate case allowable costs into detailed implementation decisions such as which pipe segments to replace. Nor does it include a systematic analysis of the impact of uncertainties in sources of risk and in RCM performance on its decisions regarding which control measures to select. Absent detailed knowledge of future implementation decisions, PG&E would be unable to evaluate the associated risk reduction.

The cost benefit analysis PG&E prepared in support of its GRC filing (included both in Working Papers provided as part of the GRC filing and in Business Cases provided in response to Cycla information requests) qualitatively describes the anticipated impact of the planned RCMs. This narrative was clear and seemed persuasive. However, the quantitative aspect of the reported cost-benefit analysis was not complete since PG&E focused its benefits analysis only on potential for cost savings. Modest cost savings were predicted in the vast majority of cases. The major desired benefits from most proposed improvements are reductions in risk or improvements in reliability. The quantitative benefit resulting from lower risk typically comes in the form of reduced accident frequency and lower safety and economic consequences. PG&E did not attempt to estimate these benefits.

Federal regulatory agencies are required to estimate the reduced health, safety and economic consequences associated with promulgation of a new regulation, but this sort of analysis is not typically performed by an operator – at least not by operators of hazardous facilities in the US. One exception is the US nuclear power industry in which long-standing requirements for the performance of quantitative risk assessments have ensured operators have the quantitative risk assessment tools necessary to support quantitative cost-benefit analysis. Comparable risk assessment tools do not exist in the pipeline industry, either in the US or in Europe, where cost-benefit analysis is often required in the design or modification of potentially hazardous facilities.

At present PG&E's risk characterization in support of implementation decisions is largely qualitative. The priority groupings identified in PG&E Investment Planning process and used by gas distribution program managers to categorize the proposed work, capital projects and expense programs (O&M activities) are the following:

- Mandatory: Work that is required to maintain system safety, mandated by rule or regulation (e.g., CPUC or Federal Energy Regulatory Commission), or is essential to maintaining the Company's business operations.
- Priority 1: Work that is deemed critical to the Company's operational goals and that could not be deferred without impact to system operations or reliability.
- Priority 2: Work that would have a moderate impact on the Company's operational goals but for which deferral may be considered.
- Priority 3: Work that is necessary to successfully realize the Company's long-term objectives but for which deferral may be considered.

While these priority groupings have only a subjective relationship to the anticipated risk reduction associated with RCMs, they are PG&E's top-level basis for implementation decisions. At present PG&E uses the significance of the risk being addressed (as estimated using leak repair data) together with the opinion of its SMEs, informed by the experience of industry leaders, as the basis for implementation decisions within priority categories 1, 2 and 3.

One area does exist in which PG&E attempted quantitative characterization of risk. PG&E used a tool it developed to estimate the anticipated increase in leaks identified for repair (as a proxy for the change in the population of Grade 1 leaks remaining in the system) to evaluate the impact of different combinations of RCMs designed to reduce these leaks. This analysis showed nearly a 33% increase in the number of identified Grade 1 leaks associated with use of the Picarro surveyor along with increasing the leak survey frequency from once per five years to once per three years[15].

5. *Determine resource requirements for identified RCMs*

Evaluation Result - Partially satisfies and provides a foundation for future satisfaction of the evaluation criteria. Costs were estimated using standard industry practice, including consideration of past experience. PG&E's GRC filing includes operating and capital cost forecasts that reflect significant cost efficiencies. However, PG&E has not uniformly considered possible additional efficiencies resulting, for example, from the use of outside contractors to supplement its internal work force.

Costs associated with expanded use of previously applied RCMs were developed by scaling historic unit costs, including consideration of efficiencies resulting from process improvements, and including limited consideration of economies of scale associated with proposed expansion of workload (e.g., increased rate of main replacement), and efficiencies associated with lessons learned while applying new technologies (e.g., the Picarro surveyor). Cost efficiencies are summarized in Table 1.

Examples of cost efficiencies incorporated in PG&E's GRC filing for capital projects include[16]:

- Increased use of directional boring rather than trenching (~$19.7 million);
- Use of improved resource planning and strategic contracting (~$11.3 million);
- Improved construction management (~$5.6 million);
- Reduce steps in construction process, especially related to improving continuity of customer service (~$3.2 million).

As part of its cost development process for the GRC filing, PG&E considered how it might achieve efficiencies in implementing some RCMs. An example PG&E-identified efficiency was relocating gas

[15] PG&E response to questions; GRC2014-Ph-1_DR_Cycla_014-Q07; March 14, 2013.
[16] PG&E response to questions; GRC2014-Ph-1_DR_Cycla_013-Q03; March 20, 2013.

service representatives to be closer to customers, thereby reducing the PG&E response time to customer reported gas leaks, and decreasing the number of GRCs required to do so.

PG&E prepared business cases for most, but not all, projects. For major projects, PG&E prepares Major Business Cases in which cost uncertainties are considered, project implementation risks are evaluated, and some consideration is given to alternative approaches.

While some of the anticipated increased efficiencies may result in savings beyond the three years considered in GRC filing, they should be clearly documented for explicit consideration in future rate case filings.

6. *Select RCMs considering resource requirements and anticipated risk reduction*

Evaluation Result - Partially satisfies and provides a foundation for future satisfaction of the evaluation criteria. PG&E has identified RCMs to address major contributors to risk, but has not attempted to demonstrate that relative resource commitments are appropriate given the magnitude of risk being addressed.

Projects described in the GRC filing were selected to address identified risks, including risks for which PG&E performance has been poor relative to the industry. Industry best practices were identified as prime candidates for RCMs to address major risks. Business cases were developed for most RCMs selected, with the level of detail related to the cost of implementation.

In each of the major business cases evaluated, PG&E included an analysis of alternatives which considered the net present value (NPV) of the alternatives as well as how well they satisfied the project objectives. Not all RCMs were the subject of business case development. For example, the shift from a leak survey frequency of once per five to once per three years was not developed in a business case, nor was a business case developed for the pipe replacement program.

Additionally, RCMs designed to address the same system risks (e.g., the numerous RCMs designed to reduce the number of hazardous leaks in the system) were not treated together in a business case, thereby missing the opportunity to determine the most effective way to phase in application of these measures.

PG&E explicitly considered how well existing risk management programs and risk control activities are working in determining where changes were required. For example, one program intended to address the highest risk threat (excavation damage) is the damage prevention program. PG&E's analysis of damage causes has shown that the largest contribution is a failure of excavators to call the underground service alert system prior to digging. Such a call would result in the infrastructure being located and marked before excavation begins. Failure to call has led to 66% of excavation damages. For the 34% of excavation damages resulting from other factors, approximately 63% were caused by locate errors and 19% by mapping inaccuracy. These facts suggest that RCMs with the greatest potential to reduce risk from excavation damage would be those designed to (a) increase assurance that excavators call the underground service alert system well before beginning excavation, and (b) improve the speed and accuracy of pipe location and marking. Numerous RCMs in the GRC filing are aimed at these improvements. However, resources committed to implementation of these RCMs seem disproportionately low considering the high relative contribution to risk associated with excavation damage.

7. <u>Determine total resource requirements for selected RCMs</u>

<u>Evaluation Result - Partially satisfies and provides a foundation for future satisfaction of the evaluation criteria</u>. PG&E determined required resources by adding resources required to implement the complete set of identified RCMs, constrained principally by practical limitations on the number of qualified personnel. No obvious attempt was made to balance requested resources against the magnitude of the individual contributors to risk being addressed.

Decisions on the level of funding to request in the GRC filing were made by an overall "leveling process" carried out by the Gas Distribution Governance and Sanctioning Committee. These decisions were influenced by consideration of (i) historical forecasts, (ii) activities required for regulatory compliance, (iii) implementation of commitments, and (iv) industry best practices obtained from benchmarking and through AGA-sponsored interactions with other operators. Some of the activities in the GRC filing provide the necessary foundation for improving PG&E's understanding of its system and strengthening risk management. Decisions were typically supported by business cases. Qualitative or quantitative risk analysis results were not a significant determining factor.

Costs associated with the set of RCMs selected were justified by the need to use industry best practices to reach the corporate goal of performing in the top quartile of the industry in measures of safety and reliability. To some degree this element was addressed in conjunction with staff expansion constraints discussed in element number 8 below. A specific example is the main replacement program, which was sized not based on the risk being addressed but based on practical limitations on the number of qualified personnel.

8. *Adjust the set of RCMs to be presented in the GRC considering resource constraints*

Evaluation Result - Partially satisfies and provides a foundation for future satisfaction of the evaluation criteria. PG&E appears to have selected RCMs constrained only by its ability to hire qualified personnel to implement them. The use of qualified contractors to supplement PG&E staff did not appear to be consistently considered.

Most RCM implementation decisions were reached based on the need to implement the desired scope as quickly as possible considering constraints on qualified staff. One example is the time required to implement the new centralized gas distribution control center. The Major Business Case showed this project could be implemented with slightly higher net present value (NPV) if its scope were significantly reduced, and a slightly lower NPV if it were implemented over a longer time period. In other words, in this case scope reduction would have resulted in savings while lengthening the project implementation time would have cost more. Another example - the proposed replacement of pipe and fittings experiencing leak rates one sigma or more above the system average - led to a recommendation to increasing the rate of pipe replacement from 30 miles per year (in 2011) to 180 miles per year during the three years covered by the GRC. This rate of replacement, which will require fifteen (15) years to replace all the high leak rate pipe, was decided upon based on a practical evaluation of the rate at which PG&E can hire, train and qualify the staff needed to support pipe replacement. Significant use of qualified contractors was not considered.

9. *Adjust RCMs for implementation following PUC decision on allowed resource*

Evaluation Result - Partially satisfies and provides a foundation for future satisfaction of the evaluation criteria. The description of the PG&E process for adjusting operational plans to reflect CPUC rate case decisions appears to satisfy a majority of the criteria. The basis for selecting activities within these broadly established priority categories is not yet clear. CPUC monitoring of implementation of this process together with the decisions resulting from its application seems appropriate. Broadened use of balancing accounts to address cost uncertainties and to facilitate management of newly recognized risks should also be considered.

At the time of the evaluation the CPUC had not yet completed its deliberation and made a decision on the 2014 rate case. However, it is clear, both from the GRC filing itself and from recently submitted semi-annual Gas Distribution Pipeline Safety Reports that, while the rate case decision establishes the constraints on allowable expenditures and on general areas of expenditure, detailed decisions on exactly how allowed funds are expended are made annually by PG&E. The process for making these decisions is documented in PG&E's Gas Distribution Pipeline Safety Report dated September 30, 2011, covering the first half of 2011.

Detailed implementation decisions are made as part of a PG&E-wide operating plan development process. Key factors in the decision process include compliance with regulations and consideration of how best to address safety and reliability of service. To develop the annual operating plan, responsible managers gather information on needed work, establish preliminary work plans and associated budgets, and establish priorities using the four priority categories described above under element 4. Work in priority categories 1 through 3 are further prioritized based on major company attributes, including but not limited to safety and service reliability. Based on established priorities, PG&E program managers develop a proposed budget and operating plan for the upcoming year. Proposed budgets and operating plans are then reviewed, adjusted and approved by senior corporate officers comprising the Operating Plan Committee. If the approved budget is different from that requested, line of business management adjusts operating plans consistent with activity priorities, with any unfunded activities deferred for consideration in future years.

While the PG&E process seems consistent with the criteria, the priority levels are too coarse to allow differentiation among activities in making practical implementation decisions. This requires establishing priorities for activities within each category. While the process for this lower-level priority setting was not described in the initial Gas Distribution Pipeline Safety Reports, the DIMP program is expected to contribute to determining the priority for some activities, such as selection of specific segments to be replaced.

10. Monitor the effectiveness of risk control measures

Evaluation Result - Partially satisfies and provides a foundation for future satisfaction of the evaluation criteria. PG&E metrics and processes for monitoring the effectiveness of the set of selected RCMs appear to be at too high a level to satisfy most of the evaluation criteria. No evidence currently exists that the effectiveness of individual RCMs can be effectively monitored. CPUC oversight of PG&E's development and use of these metrics seems appropriate.

PG&E has established a set of metrics that are reported in its monthly Business Plan Review. The metrics in this document are reported compared to established targets, and are color coded (green/yellow/red) to focus on metrics requiring management attention. In addition, the industry quartile in which PG&E performance falls is reported for select "goal metrics." Some of the reported metrics are designed to characterize PG&E's level of activity in key areas. For example, there are metrics describing the percent of miles strength tested and the percent of miles replaced. The metrics reported in the PG&E Business Plan Review are at too high a level to support monitoring the effectiveness of individual RCMs.

In addition to the metrics noted above, PG&E has identified a number of performance metrics for collection and analysis by the DIMP Risk Management team. These metrics include measures to evaluate system performance (principally leak rate data) as well as performance of PAARs. In addition to metrics required by the DIMP regulation, PG&E collects and analyzes data on the number of hazardous leaks eliminated/repaired categorized by material, as well as information from investigations and inspections, and data on line marking and 3rd party dig-ins. The DIMP Engineering and Risk Management Teams use these metrics in their annual review cycle to evaluate DIMP performance. Where data indicate both poor performance (defined as an increasing trend in leaks repaired) and high risk (defined as leak rate for a threat in a segment two sigma greater than the PG&E system average) a root cause analysis is to be performed. To date root cause analyses have not been performed.

In addition to the above metrics, PG&E requires completion of basic event reports for non-human failures, human failures or procedural errors, and "near hits." This information is available for analysis as part of the annual DIMP program evaluation.

5 Summary of GRC Project and Cost Evaluation

5.1 Introduction

This section describes the results of our evaluation of the necessity, the appropriateness of scope, and the implementation pace of the activities described in PG&E's GRC filing. Table 2 below summarizes the results of this evaluation. Sections 5.2 through 5.12 present supporting narrative focusing on the reasonableness of the approach PG&E has taken to estimating the funding levels for the areas selected for risk reduction; and whether the risk reduction approaches appear sufficient in light of what other operators are doing to address similar risks.

The following characteristics were used to evaluate the appropriateness of scope and implementation pace of the proposed RCMs summarized in Table 2.

Necessity

A. Supports establishment of a critical foundation (information, tools, systems) on which to understand and manage risk.
B. Addresses major contributor to risk - whether we believe the activity is principally focused on:
    i. Safety risk,
    ii. Operational efficiency,
    iii. Reliability risk.
C. Reflects industry best practice or movement toward best practice.
D. Addresses compliance with safety requirements.
E. Addresses major external findings (e.g., IRP, NTSB) or new legislative requirements.

Appropriateness of Scope

F. Scope consistent with scope of practices employed by best operators.
G. Staffing consistent with scope.

Pace of Implementation

H. Reflects a reasonable activity scale-up or phase-in rate.

I. Pace constrained by available resources (e.g., management, qualified personnel).

J. Available resources are focused on highest risks.

By necessity, many of the judgments expressed in this section are based on the experience of the evaluators rather than on a comprehensive analysis of industry performance and practices. More detailed evaluation of activities in the PG&E GRC filing is provided in Attachment 6.

Table 2 Evaluation of Necessity, Scope and Implementation Pace[17]

Cost Components by Chapter in GRC Filing	Cost Addition	Necessity of Cost Component	Scope of Cost Component	Implementation Pace of Cost Component
2. Systems Operations Gas Control	Capital - 62.2M (11.64%) Operating - 12.9M (5.55%)	• Supports establishment of a critical system which helps the operator understand and manage emergency situations • Addresses major contributors to risk by attempting to prevent incidents associated with leaks, third party damage, and pressure excursions • Contributes to operational efficiency by concentrating effort in a single location • Supports integration of engineering input into operations decisions • Reflects industry best practice, and addresses intent of IRP and NTSB findings	• Scope consistent with practices employed by best operators • Staffing consistent with reasonable implementation time frame, which may prove to be optimistic due to the complexity of installing the large number (4,300) of remote monitoring pressure points, numerous remotely controlled valves, and automating regulator stations	• The time allocated for achieving operability including developing new procedures and training operators in a new control environment may be greater than currently forecast
3. Gas Distribution Mapping & Records	Capital - 0 Operating - 15.2M (6.54%)	• Supports establishment of a critical information foundation needed to understand and manage risk • Addresses a major contributor to risk - poor and incomplete records	• Scope consistent with practices employed by best operators • Staffing consistent with scope	• Reflects a reasonable scale-up and phase-in rate • Potentially constrained by PG&E's ability to staff up from 60 to 85 mappers

[17] The Cost addition column is the 2014 forecast cost minus the 2011 recorded cost

Cost Components by Chapter in GRC Filing	Cost Addition	Necessity of Cost Component	Scope of Cost Component	Implementation Pace of Cost Component
		• Addresses a major external finding to maintain complete central repository for records.		
4. Gas Distribution IMP	Capital - 0 Operating - 22.6M (9.72%)	• Supports establishment of a critical management decision support system needed to understand and manage risk • Addresses significant potential contributor to risk - damage of gas lines intersecting sewer lines in which a direct leak path to individual dwellings would result • Addresses compliance with new USDOT DIMP requirements • Reflects movement toward top quartile industry performance in improved mark-out and locate response	• Scope consistent with practices employed by best operators, especially by addressing a major potential risk associated with intersecting gas lines and sewer pipes • Staffing consistent with reasonable implementation time	• Reflects a reasonable activity scale-up pace
5. Pipe, Meter & Other Preventive Maintenance (PM)	Capital - 0.2M (0.04%) Operating - 24.5M (10.54%)	• Addresses a major contributor to risk - damage prevention • Addresses compliance with safety requirements	• Scope consistent with practices employed by best operators	• Staffing consistent with forecasted work activity level
6. Leak Survey & Repair	Capital - 0 Operating - 79.0M (33.98%)	• Activity addresses a major contributor to risk by improving early detection and repair of hazardous leaks • Deals with an area in which	• PG&E asserts these RCMs reflect industry best practice • Evaluation of the relative importance of the several proposed RCMs designed to reduce hazardous leaks	• The best phase-in rate of the several proposed RCMs designed to reduce hazardous leaks is not evaluated

Cost Components by Chapter in GRC Filing	Cost Addition	Necessity of Cost Component	Scope of Cost Component	Implementation Pace of Cost Component
		PG&E performance is poor - in the third quartile of the industry performance	(e.g., pipe replacement, accelerated leak surveys, greater leak sensitivity in surveys, accelerated leak repair, rapid response to reported leaks) is absent • PG&E could consider the relative effectiveness of different combinations of RCMs designed to reduce the number of hazardous leaks, including focusing accelerated leak surveys on the most leak-prone pipe segments	
7. Gas Field Services & Response	Capital - 14.1M (2.64%) Operating - 36.8M (15.83%)	• Addresses a major contributor to safety risk - emergency response to leaks reported by the public • Reflects movement toward PG&E's goal to achieve top-quartile performance within the industry • Addresses compliance with safety requirements	• Emergency response time goals are consistent with performance of best operators • Staffing consistent with reasonable implementation time frame and has been optimized by relocating staff and adjusting shifts to reflect public reporting profiles	• Increase in GSRs reflects a reasonable activity scale-up • The need for increasing the staffing by 120 people to achieve the desired response time goals has not been evaluated
8. Gas Distribution Capital & Investment Planning	Capital - 310.9M (58.20%) Operating - 0	• The replacement of leak prone pipe supports a critical element of PG&E's DIMP and how it manages risks • Replacement activity is principally focused on safety risk, but also contributes to operational efficiency and to system	• Scope is generally consistent with practices employed by best operators • The cost associated with PG&E's proposed acceleration of its regulation station replacement and upgrading program seems reasonable • With the exception of monitoring of critical bonds, the remote CP	• PG&E's justification for the number of miles of pipe to be replaced was based on resource constraints, not on a comprehensive risk evaluation • PG&E needs to consider the optimum pace of pipe replacement considering the impact of removing high risk pipe from its system. The

Cost Components by Chapter in GRC Filing	Cost Addition	Necessity of Cost Component	Scope of Cost Component	Implementation Pace of Cost Component
		reliability • Industry trends are toward more rapid replacement of high risk equipment and piping	monitoring program is principally intended to improve operational efficiency • To reduce the risk of customer outage, PG&E proposes to significantly reduce the number of customers covered in its emergency valve sectionalizing program	proposed resource-constrained replacement program is appropriate only in the near-term
9. New Business (NB) & Work at the Request of Others (WRO)	Capital - 45.1M (8.44%) Operating - (0.1M) (0.04%)	• Work under this activity is principally driven by forecasts of economic activity and the need to perform work requested by others • PG&E has no options to performing NB and WRO work	• The scope is consistent with reasonable forecasts of economic activity	• Reflects a reasonable activity scale-up
10. Technical Training and R&D	Capital - 0 Operating - 15.2M (6.54%)	• Strengthening of PG&E's training programs addresses a contributor to safety risk - operator error. • PG&E's training program is being improved to address recommendations from the CPUC and the NTSB. • Reflects movement toward industry best practice • Addresses compliance with safety requirements	• Scope consistent with practices employed by best operators	• Reflects a reasonable activity phase-in rate
11. Gas Operations Technology Costs	Capital - 40.7M (7.62%) Operating -	• Supports establishment of a critical information system foundation that is vital to understand and manage risk	• Scope consistent with practices employed by best operators. • Several technology expenditures are designed to reduce risk by providing	• Although ambitious in scope, the proposed activities reflect a reasonable activity phase-in rate

Cost Components by Chapter in GRC Filing	Cost Addition	Necessity of Cost Component	Scope of Cost Component	Implementation Pace of Cost Component
	18.7M (8.04%)	• Included are gas distribution asset management tools (Pathfinder), public safety-focused tools (DIMP risk management), and mobile platform technology • Activities are principally focused on safety risk and to a lesser extent on operational efficiency • Addresses compliance with safety requirements (DIMP) • Addresses major external finding (IRP) and new legislative requirement (Senate bill 705 section 961 of the Public Utilities Code.)	improved and more accessible information to decision makers both in the office and in the field • Mobile platform technology supports the migration from paper based to electronic based systems for the gas distribution workforce	
12. Gas Operations - Other	Capital - 61.0M (11.42%) Operating - 7.7M (3.31%)	• Includes a mix of projects, several of which support establishment of critical foundations to understand and manage risk such as the new gas control center, "hot" backup control center, and new training center • Reflect movement toward industry best practices (centralized control center and training center).	• The scope of the new centralized gas control center, the "hot" backup control center, and new training facility are consistent with practices employed by best operators • Several other projects while useful to support staffing increases and technology initiatives, might represent candidates for delay	• The forecasts and work activities associated with headquarters consolidation, new gas control center, and new training center, reflect reasonable activity phase-in rates • The pace of implementation of the "hot" backup control center may be ambitious, especially considering the complexities associated with making the new control center fully operational
Total	Capital - 534.2M			

Cost Components by Chapter in GRC Filing	Cost Addition	Necessity of Cost Component	Scope of Cost Component	Implementation Pace of Cost Component
	(100%) Operating - 232.5M (100%)			

5.2 Chapter 2 System Operations Gas Control

Approach to Estimating Required Funding

This chapter is concerned with the expenses and capital costs needed to better control the gas system. Included are completion of the proposed new centralized control center including a "hot" back-up facility (the building costs are discussed in Chapter 12), additional personnel to staff the control room, additional personnel for gas engineering to support the gas system, additional expenditures to automate some the pressure and flow readings on the gas distribution system, additional expense costs for maintenance of the new system, and some contractor costs to assist in maintaining the control instrumentation and IT investment.

The scope of this activity is consistent with that undertaken by the best operators. Activity staffing is consistent with the proposed implementation time frame, which may prove difficult to meet because of the need to install the large number (4,300) of remote monitoring pressure points, numerous remotely controlled valves, and automating regulator stations. The time allocated for achieving operability including training operators in a new control environment may be greater than currently forecast. Cost estimation of such a complex project is difficult. PG&E appears to have considered the major elements of cost in its estimate. PG&E may wish to consider stretching the time for construction and implementation of the "hot" back-up control center/dispatch facility.

Apparent Adequacy of Risk Reduction Measures

A centralized distribution system operations control center will support PG&E's understanding of and ability to manage emergency situations. It will not only address major contributors to risk by attempting to prevent incidents associated with leaks, third party damage, and pressure excursions, but will also facilitate integration of engineering input into operational decisions. Additionally, it will address findings from the NTSB and the IRP which focus on the gas transmission system, but apply equally well to the gas distribution system.

Currently most large gas distribution operators have central control rooms. Thus, PG&E is proposing to conform to current industry practice. However, PG&E is proposing to install a large number of monitoring points that will present significant challenges to the control room staff. Detailed procedures describing how alarm management will be handled are not presented, possibly not yet developed. Training to provide the necessary number of new and retrained employees will be a significant undertaking. The goal of anticipating and preventing gas incidents or emergencies on the distribution system is worthy. However, achieving this goal will require not only a central gas control room, but also well-designed emergency operating procedures, an effectively trained staff, clear requirements for verification of the indicated event, and clear authority to initiate automatic control action from the control room. Effective emergency response from the control room will require integrating the monitoring system with trend analysis of key parameters to facilitate rapid decision making by control room personnel.

5.3 Chapter 3 Gas Distribution Mapping and Records

Approach to Estimating Required Funding

PG&E operates approximately 42,000 miles of gas distribution main and 3.3 million gas service lines (serving 4.3 million end user accounts). These are depicted on over 21,000 distribution maps. To maintain up-to-date mapping and records, PG&E will eliminate the backlog of system mapping field updates and intends to complete future mapping updates within 30 days. To accomplish this work, PG&E expects to use 60 mappers during 2012 and forecasts increasing that number to 85 mappers in 2013 and beyond. Their job will be to collect, scan and archive documents and maps into the enterprise wide gas records center and further support the implementation of Pathfinder[18] (additional costs for Pathfinder are in Chapter 11). To accomplish this work, PG&E forecasts its 2014 gas distribution mapping expenses to be $16.199 million of which $14.1 million is due to the records collection and scanning project, and $2.099 million is forecast for base mapping expenses.

This evaluation determined that the major cost items were reasonable. PG&E has provided justification for the improvements in its approach to gas distribution mapping and records. The approach PG&E has taken in forecasting the required funding levels to implement the processes affecting mapping and records was

[18] The Pathfinder project which includes further development of its GIS geospatial model that tracks, records and stores all distribution asset data, is intended to enhance the amount, quality and type of information PG&E collects, stores and manages for its gas distribution system and related processes. PG&E expects Pathfinder to improve and expand access to asset data, reduce data entry errors and provide for integrating the data enabling improved analyses within its distribution integrity management program.

reasonable and forecasted expenditures were not grossly overestimated. The major potential constraint appears to be PG&E's ability to scale up from 60 to 85 mappers.

Apparent Adequacy of Risk Reduction Measures

This activity supports establishment of a critical information foundation needed to understand and manage risk, and addresses a major contributor to risk resulting from poor and incomplete records. The activity also addresses a major external finding regarding the need to develop and maintain a complete central records repository. The scope of this work is consistent with practices employed by best operators, and reflects a reasonable phase-in rate.

Accurate, timely, up to date mapping and data management systems are required to support safe and reliable operations including installing, locating, maintaining, operating, and retiring gas distribution piping facilities. The gas distribution mapping function tracks the size, material type, location, configuration, and other essential information used in asset management processes. This information is also critical to meaningful characterization of the risk of the distribution system. Inadequate mapping and records management was a contributing factor to the gas transmission line explosion at San Bruno. In addition, inaccurate location information is a significant contributing factor to excavation damage, which is the largest contributor to PG&E distribution system risk.

5.4 Chapter 4 Gas Distribution Integrity Management Program (DIMP)

Approach to Estimating Required Funding

PG&E's DIMP program is intended to comply with USDOT regulations contained in Subpart P of Chapter 49 of the code of Federal Regulations Part 192 (49CFR192) published in the Federal Register December 4, 2009. PG&E forecasts expenses for its DIMP program to be $47.3 million in 2014, $22.6 million higher than PG&E's 2011 recorded amount of $24.7 million, a 91.5% increase in expense related expenditures. The DIMP program is intended to build upon a thorough understanding of the system, support characterization of the major contributors to risk, and result in the identification and implementation of a set of risk control measures. The DIMP program, its underlying data, and its supporting tools are works in progress. The largest individual costs described in Chapter 4 are associated with the Cross-Bored Sewer project and staffing for the DIMP project itself. Costs of RCMs to address risks identified in the DIMP effort are included in several other chapters.

The scope and staffing of the DIMP program appear consistent with those used by high performing operators. This evaluation determined that the major cost items were reasonable; PG&E has provided justification for associated improvements in its integrity management approach. The overall approach PG&E took for estimating required funding levels for the identified risk reduction measures was reasonable and forecasted expenditures were not grossly overestimated.

Apparent Adequacy of Risk Reduction Measures

As described, the DIMP program moves toward full compliance with recently issued USDOT requirements while supporting establishment of a critical management systems foundation to understand and manage risk. In addition it addresses one significant potential contributor to risk - damage to gas lines intersecting sewer lines in which a direct leak path to buildings would result from a line rupture. Line rupture could occur as a result of periodic sewer line cleaning. It also reflects movement toward industry best practice associated with improved line mark-out and response time performance.

Several critical elements of the DIMP process noted above are currently being developed to maturity. Absent mature processes and tools, many of the funding requests in the current GRC filing rely heavily upon the knowledge and experience of its SMEs to identify threats, characterize associated risks, and identify RCMs. Risk characterization supporting DIMP has involved analysis of data on leaks repaired over the past five years. Risk control measures appear to have been identified for major historic sources of system leaks. These measures are addressed throughout the GRC filing, but especially in Chapters 2, 3, 4, 6, 7, 8 and 11.

Overall the current state of PG&E's proposed actions under its DIMP program appears to have addressed its highest known risks, proposed reasonable RCMs, and adequately forecasted costs to accomplish those activities.

5.5 Chapter 5 Pipe, Meter and Other Preventive Maintenance

Approach to Estimating Required Funding

The major maintenance-related costs described in this chapter are: locate and mark, cathodic protection, protecting meter locations (which includes some capital), and other preventive maintenance. The two minor contributors are meter protection and inspection, which concerns installing meter barriers to prevent vehicles from damaging gas meters, and an account called managing energy efficiency, which includes natural gas vehicle (NGV) fueling facility maintenance activities.

The largest driver for the increased overall cost is that the projected number of locates to be worked is 412,992 in 2014 as compared with an actual 313,557 in 2011. PG&E has stated that it intends to complete all locate and mark requests with an on time percentage of 99.4%, which they have described as a top-quartile performance target (PG&E on time performance in 2011 was 98.9%).

The second largest maintenance expense element is called Preventive Maintenance. It involves inspection, painting and repair, and has several components: 1) gas mains; 2) regulator stations; 3) services; 4) main valves, 5) service valves; 6) special projects; 7) atmospheric corrosion; and 8) other or miscellaneous.

The scope and staffing of this activity appear consistent with practices employed by top performing operators. The projected number of locates results from significant projected increases in construction and infrastructure activity, and may be a little high. However, PG&E should have reasonably accurate projections since much construction will involve one or more energy sources that they would supply or have to relocate.

Apparent Adequacy of Risk Reduction Measures

Excavation damage caused by dig-ins, a major cause of gas leaks and failures, has several different causes. One cause is not having a timely locate and mark which PG&E is addressing by improving upon their timeliness of responding to requests. Another cause is having obsolete and out of date maps for use by the locating personnel and PG&E is attempting to improve on this (see write up on Chapter 3 for specific changes being implemented). Yet another cause is an excavator not requesting a “locate and mark” and this is also being addressed via excavator education and possible regulatory action. PG&E is proposing a number of significant activities to reduce the excavation damage risk and thus improve the gas system safety. The use of multiple measures to address excavation damage is justified because that threat is the largest contribution to PG&E distribution system risk. Several specific activities are focused on addressing factors contributing to this risk. This chapter also addresses costs to address other risk contributors such as improved cathodic protection and protection of above ground meters from vehicular damage.

Many maintenance items that are required by regulation and have a significant impact on system risk are also addressed in this chapter. Because of PG&E's history of over pressure events, regulator maintenance, remediation and replacement are critical items in reducing the risk. An RCM apparently not considered was increasing the frequency of PG&E's internal regulator inspections which should reduce the risk of an over pressure event while measures requiring more time are being implemented.

5.6 Chapter 6 Leak Survey and Repair

Approach to Estimating Required Funding

Leak survey and repair costs are projected to increase because PG&E is moving from a 5 year survey period to a 3 year survey period, and because they will be repairing Grade 2 leaks faster and will start repairing above ground Grade 3 leaks. Costs are driven by increased frequency of leak survey and the need to repair the associated larger number of identified leaks in a short time frame. In addition, PG&E is deploying the Picarro leak surveyor which has been demonstrated to have greater sensitivity, leading to more leaks identified for repair.

Leak repair is dependent on how many and what grades of leaks are discovered during a leak survey, and how many are reported to the company by the general public or public officials (gas company employees also report leaks). The leak repair costs have several components that cover the different type of leaks that need to be repaired. The components are: 1) regulator station leaks; 2) main valve leaks; 3) main leaks; 4) above ground service leaks; 5) cathodic protection repairs; 6) main dig ins; 7) service dig ins; 8) over build (non-capital); 9) below ground service leaks; and 11) other/miscellaneous. The largest estimated changes between the baseline year of 2011 and the GRC year of 2014 are in main leaks and below ground service leaks which increase by 230% and over 4,000% respectively.

For the reasons cited above, it is apparent that costs for leak repairs will increase. The magnitude of this cost increase can only be estimated, and PG&E's proposed use of a one-way balancing account will deal with the possibility they have overestimated the number of required repairs. PG&E has not attempted to evaluate the best phase-in rate of the several proposed RCMs designed to reduce the number of hazardous leaks (e.g., pipe replacement, accelerated leak surveys, greater leak sensitivity in surveys, accelerated leak repair, rapid response to reported leaks), not all of which are addressed in this chapter. Neither have they evaluated the relative effectiveness of different combinations of RCMs designed to reduce the number of hazardous leaks, including focusing accelerated leak surveys on the most leak-prone pipe segments.

Apparent Adequacy of Risk Reduction Measures

Leaks in a distribution system represent the most significant source of system risk. As such, operators expend significant resources to identify and repair leaks, typically focusing on repairing the highest Grade leaks in the shortest time. Leak management improvements are particularly important for PG&E since they are in the third quartile of the industry in leaks per mile of distribution main.

PG&E characterizes leaks using four grades, adding a Grade 2+ to the three used by many operators. Since regulation requires Grade 1 leaks to be repaired immediately, further reducing leak-related risks requires locating these leaks more quickly and repairing Grade 2 leaks as quickly as possible. Many operators also repair of Grade 3 leaks following their discovery even though there is no requirement to do so. PG&E has proposed to repair above ground Grade 3 leaks quickly. While these leaks are the cheapest and easiest leaks to repair and represent a major source of customer concern, early repair may result in only a minimal risk reduction. Early repair of these leaks may be a source of efficiency, since fewer rechecks will be required. Grade 2 leaks have the potential to become hazardous over time and thus early repair could lead to a significant risk reduction.

The fast and efficient identification and repair of Grade 1 and 2 leaks can be a major driver to reduce risk and improve gas system safety. An aggressive leak survey and repair program coupled with a targeted pipe replacement program (see discussion in Chapter 8) should reduce the risk of incidents and result in a safer gas system with a lower risk to customers, the general public and company employees. These programs have a major effect on how the company is perceived since leaks are noticeable to customers, who associate them with incidents.

Given the range of leak management strategies available, it would seem that identifying and evaluating various strategies from a cost and risk reduction perspective would be an essential step in changing strategies. While PG&E has yet to develop a quantitative risk assessment tool, it would seem that this evaluation could be done, using leaks identified and repaired as a proxy for risk, with available tools PG&E has developed to estimate changes in the number of leaks requiring repair.

While the measures proposed by PG&E will lead to lower risk, PG&E should consider the costs and benefits of moving Type 2 and 2+ leaks to a six month repair schedule from the proposed fifteen month schedule.

5.7 Chapter 7 Gas Field Services and Response

Approach to Estimating Required Funding

PG&E's goal is to improve its response time to customer reports of odor to achieve top-quartile performance within the industry. It is also treating all reports as requiring immediate response. Rapid response to reports of odor is important because this is often the first indication an operator has of a leaking line that could lead to an incident.

PG&E has recognized that field response by gas service representatives (GSRs) can greatly affect risk and the safety of the gas system. Their goal is that GSRs respond to 99% of the immediate odor complaints in 60 minutes and resolve 75% of them in 30 minutes. Starting in 2014 they also will make all odor complaints immediate and keep the same response time goals. To achieve these goals PG&E has proposed to increase the number of GSR's by over 120 individuals between 2012 and 2014. PG&E states that they currently use the best practices of automated dispatch, GPS in the vehicles, round the clock shifts in order to minimize the response time to an odor complaint. Another best practice used elsewhere in the industry by top performing operators which is being considered by PG&E is the use of split shifts (shifts that may start late and overlap with another shift), and changing the manpower levels on shifts with the seasons based on history of odor reports.

Based on PG&E's average cost of $200K per employee, the additional GSR costs for 2012 will be $8 million per year and in 2014 will be $24 million per year. This cost is a large percentage of the almost 50%

increase in the Field Services expense costs between the baseline year of 2011 and 2014. PG&E expects that staffing changes are consistent with achieving the desired response time, and has indicated staffing has been optimized by relocating staff and adjusting shifts to reflect public reporting profiles. The impact of scaling up staffing level by the full 120 people on response time goals has not been demonstrated.

Another component of the Field Services organization is work on atmospheric corrosion remediation and replacing customer regulators. PG&E started a new regulator replacement program in 2012. The program is anticipated to continue through the GRC years and consists of replacing residential and commercial regulators and non IRV (internal relief valve) commercial regulators.

Apparent Adequacy of Risk Reduction Measures

This activity addresses a major contributor to safety risk - emergency response to leaks reported by the public. It also reflects movement toward PG&E's goal to achieve top-quartile performance within the industry, and addresses compliance with safety requirements, 192.615.

PG&E has moved the GSRs into the gas organization from customer service and has set a goal of improving their response to odor complaints. This change is intended to reduce the risk and has been adopted by operators in several others states over the past ten years. PG&E is also using the GSRs to perform some service regulator repairs and to do leak repairs on meter headers. Both of those activities will also reduce risk. Lastly, all odor complaints will now be handled as requiring immediate response, again something many operators have been doing for years. To accomplish these improvements PG&E is adding GSR staff and has relocated staff to be closer to customers to facilitate both responsiveness and efficiency. The costs associated with increased staffing are high but the risk reduction should be significant.

5.8 Chapter 8 Gas Distribution Capital and Investment Planning

Approach to Estimating Required Funding

This program includes all of the major equipment replacement costs. It includes the main replacement program for old and leak prone steel and the plastic replacement program, in addition to regulator station replacement and abandonment. With the exception of monitoring of critical bonds, the remote CP monitoring program addressed here is principally intended to improve operational efficiency. In addition, PG&E is proposing to significantly reduce the number of customers covered in its emergency valve sectionalizing program thereby reducing the risk of customer outage.

PG&E has indicated that decisions on selection of individual segment to be replaced will be made as part of the annual operations planning process. PG&E has also indicated they need the information being assembled for the Pathfinder program to support selection of segments for replacement. Since historic replacement costs have been developed based on district-wide average costs, PG&E did not attempt a detailed analysis of costs of segment replacement in different areas (e.g., urban, paved suburban, residential). Estimated costs seem consistent with historical experience, reflecting the questionable assumption that replacing more piping per year will not lead to significant efficiencies.

Apparent Adequacy of Risk Reduction Measures

Replacement of leak-prone pipe is considered critical to efforts to reduce PG&E distribution system risk. PG&E's selection of the amount of pipe to be replaced annually was based on its ability to hire, train and qualify staff. The regulator station replacement and abandonment (replacing small district regulators and farm taps with distribution mains) should also reduce the risk of over pressure incidents since more up to date regulators will be installed. The PG&E capital plan appears to cover all of the necessary items. While it is difficult to determine to what degree additional funding would reduce the risk or improve system safety, qualified in-house personnel seem to constrain the maximum replacement rate. PG&E needs to determine the optimum pace of pipe replacement considering the impact of removing high risk pipe from its system. The proposed resource-constrained replacement program is appropriate only in the near-term.

5.9 Chapter 9 New Business (NB) and Work at the Request of Others (WRO)

Approach to Estimating Required Funding

This chapter describes PG&E's forecast of anticipated work in the NB/WRO Programs. Under its tariffs and franchise agreements' obligation to serve, PG&E must perform work at the request of its customers. This Chapter includes the costs of building new mains, services, and regulators for the regulator change out program and for new installations. This work is broken down into two major categories:

- NB – Installing gas infrastructure to serve new customers and increased load for existing customers, and
- WRO – Relocating PG&E's gas mains and services at the request of governmental agencies

This Chapter also identifies the work requested by others to relocate its gas facilities that may interfere with primarily governmental agency projects.

PG&E forecasts a 2.4% decrease in expense from $6.15 million expended in 2011 to $6.0 million in 2014, and an 8.44% increase of $45.1 million from $82.9 million during 2011 in capital expenditures to $128 million in 2014.

PG&E has a detailed process to forecast its anticipated new business work, and work expected to be requested by others due to potential interference. Tariffs and franchise agreements determine whether PG&E absorbs the cost or shares the cost of this work. PG&E has metrics to track its new business performance. PG&E relies on historic experience, and unit costs for estimating resources required performing these functions.

Apparent Adequacy of Risk Reduction Measures

PG&E relocates its gas facilities when that work is requested by others generally to avoid interfere with others' projects. The potential risks PG&E addresses are to:

- Ensure the work performed by third parties meet its standards and specifications and in all respects satisfy the gas safety requirements contained in the gas safety code, and
- Prevent or avoid interference with or damage to its existing gas distribution facilities from work being performed by governmental agencies and others.

PG&E did not identify or separate out the risks associated with poor response to overseeing NB work performed by others, nor did PG&E identify the risks associated with not performing its WRO relocation work prior to others' construction projects. PG&E does not have other options or choices in performing NB and WRO work.

5.10 Chapter 10 Technical Training and Research and Development

Approach to Estimating Required Funding

This chapter addresses the expenses for training and research and development (the capital portion for training is covered in Chapter 12 - buildings). PG&E performed a benchmarking effort to determine how the current PG&E training program rated against some of the best operators in industry. From this benchmarking, PG&E determined that they needed to significantly change and enhance their gas training to meet the new technology challenges for their employees and because of an aging workforce that needs to be replaced.

A second element of this chapter, research and development (R&D), covers PG&E participation in and support of various gas distribution and transmission research organizations. PG&E specifically points to PRCI (Pipeline Research Council International), NYSEARCH (the research arm of Northeast Gas Group), and OTF-GTI (outdoor infrastructure test facility of the Gas Technology Institute) as organizations that they propose become involved with so they can influence development and have access to the latest technology.

Training cost estimates were based on number of courses and anticipated staffing, while R&D estimates were based on industry practice with the selected R&D implementers.

Apparent Adequacy of Risk Reduction Measures

Strengthening of PG&E's training programs addresses a contributor to safety risk - operator error. PG&E is revising its training program as a result of recommendations from the CPUC and the NTSB, as well as consideration of best practices in industry. Some of the recent incidents at PG&E have indicated that their people needed more specialized training to perform their respective job responsibilities. Additionally, since PG&E is advancing its technology base, they need to train their workforce to use and maintain these new technologies. Enhanced and improved training will improve the quality of work performance thereby reducing the risk of an incident. The new gas control center is an example of an ambitious undertaking for which new procedures and training in their application will be critical to successful implementation.

The R&D projects being funded deal with many of the problems that PG&E has experienced in the past such as integrity management, leak survey, damage prevention, and risk management. Since PG&E is a funding partner in these projects, they have the opportunity to evaluate and use the newly developed technology and tools before other operators. They also have the opportunity to assist in the development and guide the research organization in achieving the ultimate goals of the research. For a company with a gas distribution system the size of PG&E, involvement in R&D programs will, in the long run, reduce risk and improve gas system safety.

5.11 Chapter 11 Gas Operations Technical Costs

Approach to Estimating Required Funding

This chapter describes the priority technology projects that PG&E is implementing to improve safety, compliance and operations of its gas distribution operations. Included are gas distribution asset management tools (Pathfinder), public safety-focused tools (DIMP risk management), and mobile platform technology. Mobile Platform Technology supports the migration from paper based to electronic based systems for the gas distribution workforce.

Projects' cost estimates generally appear to have sufficient justification; forecast costs developed using PG&E's application development concept estimating tool applying standard industry practices for IT project estimating appear to provide sufficient funding for the projects. Forecasted expenditures did not appear to be grossly overestimated. Although the activities are ambitious in scope, they reflect a reasonable phase-in rate.

Apparent Adequacy of Risk Reduction Measures

Several technology expenditures are designed to reduce risk by providing improved and more accessible information to decision makers both in the office and in the field. In addition, they support establishment of a critical information system foundation that is vital to understand and manage risk.

Pathfinder - The IRP recommended PG&E improve its use of technology, incorporating industry best practices, for records and asset management. PG&E technology application in a number of areas is intended to meet the needs identified in Senate bill 705 section 961 of the Public Utilities Code. PG&E's Pathfinder project builds on the gas transmission asset management project introducing mobile technology to convert gas processes from paper-based to electronic. It will provide centralized recordkeeping practices along with ability to integrate information across multiple databases which will improve the operator's knowledge of system components and help support its distribution integrity management process.

In the public safety, integrity management and regulatory reporting areas, the associated technology improvements PG&E is implementing include the DIMP probabilistic risk algorithm, which will be able to access information from various databases to identify assets with higher safety risks for potential RCMs. Software applications will allow access to information converted from legacy systems; integrate DIMP with SAP (PG&E's primary data source) thereby presenting all relevant data in one location; and determine efficient mitigative measures to address PG&E's risks (e.g., efficient scheduling of leak surveys).

Mobile Platform Technology – This project supports the migration efforts from paper based to electronic based systems, specifically deploying mobile solutions to the remainder of the gas distribution workforce. It also covers the work associated with replacing existing devices to better adapt the mobile devices to the work being performed.

The individual technology projects PG&E identified in this GRC generally were reasonable and support PG&E's priorities to improve public safety, understand conditions on its system, improve productivity, enhance employee access to and availability of information, provide accurate information to first responders, and improve its responses to emergency situations. PG&E's asset knowledge management department performed benchmarking which was the basis for selecting these improvements.

5.12 Chapter 12 Gas Operations Building Projects, AGA Fees and PAS 55 Certification

Approach to Estimating Required Funding

This chapter describes PG&E's Gas Operations support forecasted costs for incremental building projects, AGA membership fees, and costs to obtain and maintain PAS 55 Certification of best in class asset management practices.

Drivers for the various major building projects are associated with headquarters consolidation, new gas control center, “hot” backup control center, new training center, additional LNG/CNG operations centers, upgrades to operations centers at various field locations, a new Gas Service Center at Roseville, and paving projects at various field office and operations centers. The pace of implementation of the “hot” backup control center may be ambitious, especially considering the complexities associated with making the new control center operational.

The methods PG&E used in developing individual major project estimates appeared reasonable and justified, generally based on identifying a work item and assigning a unit cost.

PG&E expects that by achieving PAS 55 Certification it will be able to demonstrate it is meeting a 28 point requirement specification for establishing and verifying an integrated and optimized management system for all types of its physical assets. Among the requirements of the PAS 55 Certification is the need to develop and implement a risk management program. The method of developing a forecast for PAS 55 Certification funding appears reasonable.

Apparent Adequacy of Risk Reduction Measures

Drivers for the various major building projects are associated with headquarters consolidation, new gas control center, “hot” backup control center, new training center, additional LNG/CNG operations centers, upgrades to operations centers at various field locations, a new Gas Service Center at Roseville, and paving projects at various field office and operations centers. Several of these facility additions or improvements are necessary to support staffing and technology initiatives described elsewhere in the GRC filing, and should be viewed as part of the risk reduction expected to result from implementation of those activities. The new gas control center, the “hot” backup control center, and new training facility are consistent with practices employed by the best gas distribution operators. AGA membership is necessary to have relatively easy access to industry best practices. As described above, PAS 55 Certification will increase assurance that strong asset and risk management systems are in place and functioning at PG&E.

6 Findings and Recommendations

6.1 Findings

1. *The PG&E filing does not fully satisfy the criteria established for an acceptable risk-informed budget proposal*. This is not surprising since the filing was developed prior to development of the criteria. PG&E used processes and tools available at the time it began preparation of its rate case. Many were well suited for the purpose for which they were used (such as the processes used to identify risk control measures), while others will require considerable additional work to suit their purpose and satisfy the criteria (such as the risk characterization tools).

2. *PG&E's GRC filing does provide a reasonable foundation for satisfying the criteria in the future*. The processes and tools used by PG&E to develop its 2014 GRC filing are clearly works in progress. PG&E is developing new management and decision-support tools and systems and overhauling existing systems that, if developed to full maturity, will provide a strong basis for its overall risk-informed resource allocation process. Significant activities include: (a) an organizational commitment to develop management systems and processes that will allow certification to the PAS 55 asset management standard; (b) an effort to assemble, validate, and capture in a useable data base details of the pipeline system characteristics needed to understand current risks and anticipate developing risks; and (c) an on-going effort to develop a risk characterization tool capable of informing future decisions on required resources and how best to deploy these resources to achieve PG&E's multi-year goal to improve performance to the top quartile of the industry performance on key measures of safety and reliability.

3. *The model PG&E used to characterize risk for the GRC filing, originally developed to support compliance with the distribution integrity management program (DIMP) regulation, fails to satisfy many of the evaluation criteria*. The model uses historic data on repaired leaks as the primary indicator of likelihood, and applies a consequence factor to each leak to establish a risk score. When properly validated and populated with verified data, this model can be useful in informing certain decisions on selection of risk control measures (RCMs). However, the model does not fully satisfy the evaluation criteria. PG&E is considering one or more new models for future development that may better satisfy these criteria.

PG&E used the risk characterization model developed for the DIMP program (described in RMP-15, Rev 2) to support development of the GRC filing. The model was designed to identify segments most likely to leak in the future based on where past leaks have occurred. It uses five years of historic data on repaired leaks as the primary indicator of likelihood, and applies a consequence factor to each leak to establish a risk score. This process leads to an assigned risk for each leak. This risk characterization model, when properly validated and populated with verified data, may be useful in informing decisions regarding priority of pipe segment and fitting replacement, and regarding locations for increased leak survey frequency.

PG&E is currently developing a probabilistic risk algorithm. As currently documented, this algorithm is potentially part of a risk characterization approach supporting a risk-informed decision process. By itself, however, it does not appear to be sufficient as a future risk characterization approach supporting the full range of decisions described in the evaluation criteria. See Attachment 5 for our evaluation of this model.

4. *Verified data on system characteristics affecting risk were not available to support preparation of the GRC filing*. A major deficiency in the PG&E approach resulted from the acknowledged fact that verified data on system characteristics affecting risk were not available at the time preparation of the rate case was initiated. In the face of this deficiency, PG&E has made extensive use both of the knowledge and experience of subject matter experts (SMEs) on its staff, and of analysis of the most recent five years of data on repaired leaks, including available information on the factors that led to and influenced the consequences of these leaks. Expert opinion was elicited using a consistent proceduralized approach.

   PG&E has included a major effort in its 2014 GRC filing to address deficiencies in data and data management. The Pathfinder project and related activities are intended to address this need.

5. *PG&E's process for identifying candidate RCMs was fairly thorough*. The major drivers for the process included PG&E management commitments to:
   a. Satisfy external requirements and recommendations following the San Bruno tragedy,
   b. Manage system-specific risks identified by PG&E,
   c. Elevate its safety performance to the top quartile of the industry on key measures of safety and reliability through application of industry best practices.

The process was complicated principally by the proprietary nature of information on industry best practices assembled by the trade associations[19], by incomplete input on candidate RCMs from SMEs, and by the absence of a systematic analysis of system-specific risks supporting identification of related RCMs.

The PG&E 2014 distribution pipeline GRC filing presents a number of RCMs in the listing of activities submitted for funding during the period from 2014 through 2016. These RCMs are generally designed to address one or more of the following drivers:

a. <u>*Satisfy External Requirements and Recommendations*</u>

   Measures designed to bring the operator into compliance with state and federal pipeline safety requirements - The DIMP regulation requires an operator to develop its integrity management program based first on a thorough understanding of its system. An example of measures designed to strengthen PG&E's understanding of its system included in PG&E's 2014 GRC filing is development of a gas distribution asset management system, including the Pathfinder project and associated system data collection and validation. Another example from PG&E's GRC filing, one with broader implications to all aspects of safety and risk management, is implementation of its DIMP.

   Measures designed to respond to legislative mandates and recommendations from review groups - The Independent Review Panel (IRP) commissioned by the CPUC following the accident at San Bruno recommended that PG&E should study its (gas transmission) control system to identify improved shutdown capability, and implement results from the study (Recommendations 5.5.3.2 and 5.5.3.3). Additionally, the IRP recommended that PG&E should strengthen its data and information management system (Recommendations 5.3.4.1 and 5.3.4.2). In response to the first pair of IRP recommendations, PG&E is implementing a centralized gas distribution control center, including access to system data and emergency procedure, and the capability to remotely operate key isolation valves. The Pathfinder project is the principal effort PG&E plans to undertake to address the second pair of IRP recommendations.

b. <u>*Manage System-Specific Risks Identified by PG&E SMEs*</u> – Example of measures identified by operator SMEs to prevent or mitigate incidents include the pipeline and fitting replacement program,

[19] The AGA facilitates collection of two types of proprietary information of enormous potential value to a utility in determining the need to improve its performance and in deciding how best to achieve desired improvements: first is performance data in which the rank of participating operators is identified relative to other participating operators; second is data on operating practices used by the operators with the highest level of performance.

and accelerated leak repair activities resulting from reduced time during which Grade 2 leaks are to be repaired.

c. <u>*Industry Best Practices and Innovative Technologies*</u> – PG&E has identified performance in the top quartile of the industry in measures of safety and reliability as a major corporate objective. Consistent with outside direction, implementing industry best practices and innovative technologies is the approach PG&E has chosen to achieve this objective. Examples from PG&E's GRC filing include:

    i. Increased frequency of leak surveys,
    ii. Deployment of the Picarro leak survey technology,
    iii. Increased number of gas service representatives to reduce its response time to customer reported leaks,
    iv. Implementation of a centralized gas distribution control center including the capability to remotely operate key isolation valves.

Many of the RCMs included in its distribution pipeline GRC filing are driven by PG&E's effort to identify and deploy the best available practices in the industry to reduce its system risk. This approach was mandated by California Senate Bill 705 (signed on October 11, 2011) which requires in Section 961 (b) (1) *Each gas corporation shall develop a plan for the safe and reliable operation of its commission-regulated gas pipeline facility* … and (c) *The plan … shall be consistent with best practices in the gas industry and with federal pipeline safety statutes* … As noted above, the March 5, 2012 letter from Executive Director Clanon also directed PG&E to perform a comparison to industry best practices.

PG&E has sought, through interaction with the American Gas Association and through the conduct of operator benchmarking, to identify industry best practices. This effort was complicated by the need to publicly identify the basis for selected practices and the proprietary nature of information that is assembled and maintained by the AGA.

6. *Many of the activities proposed by PG&E are designed to address major deficiencies in data, evaluation models and systems for managing its facilities safely which are the critical foundation upon which other needed improvements will build.* As pointed out in independent evaluation reports by the National Transportation Safety Board (NTSB) and the Independent Review Panel (IRP) commissioned by the CPUC, PG&E has fallen behind much of the pipeline industry in its system data (completeness, accuracy, availability, and accessibility) and data management systems, as well as in its gas operations control system

and its risk management processes. While these independent findings were focused on PG&E's gas transmission system, they apply equally well to its gas distribution system. Correcting these deficiencies will be costly, but is essential to provide the critical foundation for identifying and managing other needed improvements.

7. *Selection of the overall set of RCMs included in the GRC filing does not appear to have been constrained either by annual budget assumptions or by an annual risk reduction goal*. The only constraint appears to be PG&E's ability to develop qualified personnel to implement selected RCMs. In addition, the impact of the RCMs on system risk was not characterized, so the relationship between resources required and the magnitude of risk reduction expected is unknown.

   Lessons from accidents and subsequent evaluations over the past several years have underlined the need for PG&E to implement wide ranging safety improvements. The 2014 gas distribution GRC filing appears to include a fairly thorough listing of improvements designed to address recognized deficiencies. In at least one case, increasing the rate of replacement of high risk pipe from 30 to 180 miles per year, the only constraint applied appears to be the rate at which PG&E can increase staffing to support pipe replacement. While this is a valid constraint, PG&E has not yet attempted to develop a risk-informed position on the optimal rate of pipe replacement.

8. *PG&E has presented no analysis to demonstrate the incremental value of each of its leak reduction projects.* Many of the RCMs presented in the GRC filing involve multiple and diverse means to control a single important source of risk - the number of leaks present in the system. However, PG&E does not explicitly characterize the incremental value of each of these leak reduction projects.

   The GRC filing includes multiple and diverse means to control the population of leaks present in the system. Examples of these measures include: deployment of the much more sensitive Picarro leak surveyor; increasing the frequency of leak surveys from once per five years to once per three years; requiring repair of Grade 2 leaks within fifteen months of their identification; accelerating the rate of recheck of Grade 3 leaks; performing annual surveys of pipes considered to be high risk; and eliminating leak-prone pipe and fittings by accelerating the replacement from 30 to 180 miles per year. Each of these measures is expected to contribute to reducing leaks present and forming in the system. This multi-measure effort may be justified based on the fact that the PG&E distribution system is in the third quartile of industry system leak rate performance (best operators are in the first quartile). PG&E has carried out analysis evaluating the incremental impact of some of these measures on the number of hazardous leaks expected to be identified and repaired. In response to a question posed by Cycla as part of this evaluation, PG&E showed that the combined impact of more frequent leak surveys together with the deployment of the Picarro surveyor will be to increase the number of hazardous leaks identified by more than 32%. However, PG&E has not attempted to use this analysis capability to evaluate the incremental contribution to risk reduction of the measures listed above as the basis for selecting the best and most cost effective mix of measures to achieve its objective.

9. *In general, the overall approach PG&E took for estimating required funding levels for the identified risk reduction measures was reasonable and forecasted expenditures were not grossly overestimated*. While PG&E's GRC filing includes capital cost forecasts that reflect significant cost efficiencies, not all of the specific actions needed to achieve these forecast efficiencies have been identified. Cost savings may be realized in the future by taking increased advantage of economies of scale and, especially for labor-intensive projects, through use of qualified contractors to supplement employees.

10. *PG&E's implementation schedule for identified RCMs is very aggressive*. Such an aggressive schedule will require significantly increased annual costs in the near-term. PG&E has not demonstrated that the proposed implementation schedule represents the best approach to phasing in new control measures. With one exception (the Centralized Gas Distribution Control Center), alternative implementation schedules were not considered.

    The optimization of the various means for reducing system leaks, discussed in Finding 8, is one candidate for examination of alternative phase-in schedules.

11. *PG&E's GRC filing does not present a clear logical linkage between safety risks and activities intended to control them.* While organization of GRC filing documentation does facilitate understanding of the major activities PG&E wishes to pursue, it fails to clarify the linkage between safety risks and the activities designed to control them.

    In his March 5, 2013 letter to PG&E, Executive Director Clanon directed that "…PG&E should give a risk assessment of its physical system as well as a description of and a justification for the company's risk mitigation programs and policies…" PG&E's response to this directive would be much easier to understand if the GRC filing included a section describing the linkage among: identified risks, the relative importance of these risks, activities designed to control these risks, costs associated with these control measures, and indicators PG&E proposes to monitor to evaluate the effectiveness of selected control measures.

6.2 Recommendations

Cycla offers the following recommendations to the CPUC in the belief they will support achievement of the CPUC objective to develop a framework within which facility operators subject to CPUC rate regulation will be required to explicitly consider safety risk in deciding which safety improvements to incorporate in their general rate case filings.

1. *Develop, communicate, and implement a multi-year plan to continue the evolution of risk-informed rate case budgeting*. The current evaluation of the PG&E GRC filing against a set of safety risk-related criteria represents a significant first step by the CPUC in introducing safety risk as a significant consideration in rate cases. Modifying the rate setting process will require a significant evolution in (a) utility tools and processes supporting preparation of GRC filings, (b) regulatory evaluation of rate case filings, (c) regulatory oversight of the commitments implicitly made during rate setting, and (d) monitoring changes to those commitments resulting from new information on resource requirements and emerging safety risks. A constructive starting point for this evolution would be development of a detailed plan describing CPUC objectives and how those objectives will be satisfied. In addition to many of the elements in other recommendations listed below, the plan should include CPUC staffing requirements, staff development plans, plans for developing regulations to drive the process, and plans for development of guidance for use both in training evaluators on how to review utility filings and in communicating expectations on the form and content of GRC filings to covered utilities. To the degree the CPUC intends the new criteria to apply to the diverse set of California utilities whose rates it regulates, planning should explicitly address all the above issues for each covered industry segment.

2. *Finalize the set of criteria against which GRC filings will be measured in the future, and then imbed these criteria in regulation*. The next logical step in the evolution of risk-informed rate case preparation is obtaining agreement on the set of criteria against which GRC filings will be evaluated in the future, and then imbedding these criteria in regulation. Three activities are necessary: first deciding the range of rate-regulated utilities to be covered by the criteria; second obtaining agreement within the CPUC on a set of

criteria that are reasonable and enforceable; and third interacting with the public and other stakeholders to ensure the criteria are reasonable, appropriate and sufficient. The resultant criteria could then be used as the basis for promulgating new regulatory requirements.

3. *Require PG&E to document its corresponding multi-year program to satisfy CPUC criteria*. This evaluation has found that PG&E has failed to satisfy many of the criteria against which its GRC filing was evaluated. This is not surprising given the fact that the criteria were developed subsequent to PG&E submitting its rate case documentation. However, once the CPUC has finalized the set of criteria to serve as the basis to guide future rate case development, it could require PG&E to develop a multi-year program plan describing how it intends to address identified deficiencies. This program plan should be in a form that allows the CPUC to evaluate its completeness and then to monitor PG&E progress in implementation.

4. *Require PG&E to develop, track, and report on a set of specific performance metrics designed to measure the safety improvements actually achieved by its proposed activities*. As part of an effort to introduce more active and substantive oversight of the performance of PG&E's resource management process, the CPUC could identify and establish a set of process measures and performance metrics - beyond those currently required to be reported by regulation - that would be suitable for PG&E to monitor, assemble, track, and report upon. Examples of process measures include evidence of: conformance with commitments agreed upon following the decision on rate cases, progress in replacing high risk mains, and trends in the number of leaks removed whose cause is characterized as "other." Examples of performance measures include evidence of: progress in reducing the population of hazardous leaks in the system (which may need to be indirectly inferred from leak survey data), progress in reducing the total leak population in the system, trends in the grades of leaks being identified in surveys, and trends in the number of near hits being recorded in its excavation damage prevention program. Periodic reporting of such process measures and performance metrics would support effective evaluation and oversight by the CPUC.

   The most direct evidence of the current condition of the PG&E distribution system is the number of and trends in leaks identified and leaks repaired. CPUC interactions with PG&E could focus on better understanding of how these data are validated and used in identification of high risk areas and in support of decisions on management of these risks. Specific areas on which to focus include: how does PG&E ensure the reported causes of leaks removed from its system are valid; does PG&E determine the percentage of leaks by cause identified and reported by: leak survey, excavator reports, employee reports, and by the public? Since the highest risk predicted by the DIMP risk model is associated with leaks caused by excavation damage, the fraction of those leaks reported by the excavator should indicate the effectiveness of company efforts to communicate to excavators the importance of identifying hits, both those that result in leaks and those that do not.

5. *Establish a monitoring program to track PG&E progress in implementing activities funded through the 2014 GRC deliberation*. An initial step moving toward risk informed decision making, would involve PG&E development of a listing of activity priorities for both O&M activities and capital improvements. If the resources approved in the GRC process are less than PG&E forecasted to accomplish all of its safety and other business related projects and activities, this priority list could then be considered by both CPUC staff and PG&E in determining which O&M and capital improvement activities will be implemented.

   Whatever the outcome of the CPUC deliberation on PG&E's GRC filing, key decisions on the details of which specific activities to implement (e.g., which segments will be replaced, where accelerated leak rate surveys will be conducted, which cathodic protection (CP) test stations or systems will be remotely monitored) will be made subsequent to that final decision. The tools and processes supporting those PG&E decisions have typically not been identified. A mechanism for CPUC to monitor specific decision-making subsequent to GRC approval could prove useful. While the current semiannual reporting of accomplishments is useful, it lacks the forward looking aspect needed for the CPUC to involve itself in decisions before implementation.

6. *Work together with the Pipeline and Hazardous Materials Safety Administration (PHMSA), other state safety regulators, and the pipeline industry to promote advancements in pipeline system risk modeling*. The need for improved risk characterization tools and methods is industry-wide. Sharing of information about practical approaches to characterizing safety risk consistent with the evaluation criteria could greatly improve the way future risk-informed GRC filings are developed. This might be done in conjunction with ongoing PHMSA efforts to strengthen integrity management program requirements.

7. *Work together with PHMSA, other state safety regulators, and the pipeline industry to promote exchanges of information on industry best practices that have demonstrated superior impact on safety performance*. CPUC interactions with PHMSA, other state regulators and the pipeline industry trade associations would support a more comprehensive and open process for assembling, evaluating, and communicating industry best practices. Proprietary considerations that have impeded past efforts to open this process and share its results will need to be addressed.

8. *Work to improve the balance between operator flexibility and accountability by focusing on greater transparency and CPUC oversight of budget revisions*. PG&E has often reallocated resources agreed upon in a rate case to other areas not addressed in the rate case. While resource reallocation may be justified in the light of new information on risks and needs, it seems inappropriate when used to address issues recognized or in progress prior to filing of a GRC. It is important to ensure that risks specified in the 2014 GRC filing are the areas in which funds are expended, and that PG&E addresses the risks identified by expending requested resources as identified. However, a process for folding new information on risks into decisions PG&E can and should be able to make on resource reallocation would seem to be appropriate.

   Flexibility is often needed to reallocate funds among projects to better improve safety; however, the operator must also be accountable for completing the projects that formed the basis for the GRC. PG&E has proposed limited use of one-way balancing accounts to allow ratepayers refunds if costs are lower than estimated. This is especially important for highly uncertain activities (e.g., how many additional leaks requiring repair will the various enhancements in leak survey and reduced leak repair timing identify). The extensive use of one-way balancing accounts seems to strongly encourage PG&E and other regulated utilities to overestimate required O&M funds in their GRC filings. It would appear that selective use of two-way balancing accounts would encourage more realistic cost estimates in the GRC filings, while potentially improving safety by removing administrative barriers to the utility addressing risks as they are recognized during the three years covered by a typical rate case decision. Clearly more active and substantive involvement by the CPUC would be required to make implementation of this recommendation a constructive step. For the current rate case, recognition that past reliance on one-way balancing accounts has likely resulted in cost overestimates should lead, at least during the next three years, to consideration of even more extensive use of one-way balancing accounts. Candidate areas for one-way balancing accounts in the current proceeding include, but are not limited to, costs associated with providing new services and costs associated with leak survey (i.e., enhanced using the Picarro surveyor and increased survey frequency from once per five years to once per three years.)

9. *Determine how best to ensure that PG&E is developing and expanding its knowledge base of system and operational characteristics on which risk characterization is critically dependent*. Many of the PG&E processes contributing to developing a sound understanding of the distribution system and how it fails that

Cycla examined during this evaluation were in the early stages of development. Important processes include:

a. Determination of root causes of events;
b. Analysis of failure data;
c. Opportunistic evaluation of the important system characteristics;
d. Risk characterization; and
e. Maintenance of accurate records incorporating changes to the system and its operating procedures.

These processes need to be monitored as they are developed to maturity to ensure that PG&E is using available sources to strengthen its understanding of risks associated with the key physical and operational characteristics of its system. In addition, the CPUC should consider examining its internal monitoring of PG&E learning processes in the following areas discussed in Section 4.2.

a. Incident root cause follow-up;
b. Incomplete characterization of incident causes;
c. Unknown follow-up on excavation damage incidents;
d. Incident reporting that misrepresents incident trends.

10. *Determine how best to use operator risk characterization developed in support of rate case filings to strengthen appropriate safety advocacy by the CPUC.* As pointed out by Christopher Hart, Vice Chairman of the NTSB, in his partial concurrence with the NTSB Report on the San Bruno accident[20], there is the potential for conflict when the agency charged with regulating rates is the same agency as is charged with regulating safety. In particular Mr. Hart said "…we (the NTSB) will need to pay attention to the extent, if any, to which safety improvements are encouraged or discouraged by the economic regulator; and we will need to look at this issue in situations in which the economic regulator and the safety regulator are in the same agency, as they are in this instance…" Conflicts similar to this, when perceived as being poorly managed, have led to the separation of agencies responsible for safety regulation of the nuclear power industry (separating the Nuclear Regulatory Commission from the old Atomic Energy Commission), and separation of the functions in the safety regulation of offshore petroleum drilling and production operations (creation within the Department of the Interior of the Bureau of Safety and Environmental Enforcement from the Minerals Management Service following the massive oil spill at British Petroleum's Deepwater Horizon drilling platform). In these two situations organizational separation was prompted by perceived conflicts between safety regulation and industry promotion, but the potential for conflicts also exists

[20] NTSB Accident Report on the PG&E Natural Gas Transmission Pipeline Rupture and Fire, San Bruno, California; NTSB/PAR-11/01; page 137.

between safety and rate regulation. Carefully managed and staffed, the CPUC initiative kicked off by the March 5, 2012 letter from Executive Director Clanon to PG&E has the potential to further strengthen the internal advocacy for safety within the CPUC to allow the agency's safety and rate regulatory functions to work together more effectively.

Attachment 1 - Definitions & Acronyms

Definitions

Terms Used in the Report

Effectiveness – In the evaluation criteria the term "effectiveness" as applied to a risk control measure (RCM) is used to mean the extent to which use of the RCM contributes to reducing pipeline risk.

Industry Best Practices - Industry Best Practices can be defined as that set of practices, beyond minimal safety regulations, that have been demonstrated in practice to produce superior safety results.

Risk characterization – A process involving development of sufficient information at the segment level on the sources contributing to the probability and potential consequences of events affecting risk to inform risk management decisions.

Threats – Phenomena (e.g., corrosion, embrittlement) or occurrences (e.g., excavation damage, seismic events, auto collision with meter sets, operator error) which alone or in combination have the potential to give rise to or contribute to risk.

Terms in General Use

Risk: The effect of uncertainty on objectives; often expressed in terms of a combination of the likelihood of occurrence of an event and associated event consequences (Definition from ISO Guide 73:2009)

Likelihood: The frequency of an event leading to adverse consequences (Definition derived from ISO Guide 73:2009)

Consequence: The impact or outcome of an event affecting objectives; often expressed in terms of human health and safety impacts, economic damage, and/or environmental damage (Definition derived from ISO Guide 73:2009)

Risk Assessment: The overall process of risk identification, risk analysis, and risk evaluation (Definition from ISO Guide 73:2009)

Risk Identification: The process of finding, recognizing and describing risks (Definition from ISO Guide 73:2009)

Risk Analysis: Process to comprehend the nature of risk and to determine the level of risk (Definition from ISO Guide 73:2009)

Risk Evaluation: Process of examining the results of risk analysis to determine whether the risk and/or its magnitude is acceptable or tolerable (Definition derived from ISO Guide 73:2009)

Risk Management: Coordinated activities, beginning with risk assessment, to inform and implement decisions designed to direct and control an organization with regard to risk (Definition derived from ISO Guide 73:2009)

Risk Management Process: Systematic application of management policies, procedures and practices to the activities of communicating, consulting, establishing the context, and identifying, analyzing, evaluating, treating, monitoring and reviewing risk (Definition from ISO Guide 73:2009)

Risk Treatment: Process to modify risk; can involve removing the risk source, changing the likelihood, or changing the consequences (Definition derived from ISO Guide 73:2009)

Monitoring and Review: Process of continually observing risk status to identify change from the expected performance level, and to determine the effectiveness of the treatment of risk (Definition derived from ISO Guide 73:2009)

Risk Register: Record of information about identified risks (Definition from ISO Guide 73:2009)

Residual Risk: Risk remaining after risk treatment (Definition from ISO Guide 73:2009)

Acronyms

AGA – American Gas Association

ATM C – Atmospheric Corrosion

CADD – Computer-Added Design Drafting

CPUC – California Public Utilities Commission

DIMP – Distribution Integrity Management Program

ERM - Enterprise Risk Management (system)

GEMS – Gas and Electric Mapping System

GIS – Geographic Information System

GPRP – Gas Pipeline Replacement Program

GRC – General Rate Case

GSR – Gas Service Representative

HIS – Hydraulically Independent Systems

HSE – Health and Safety Executive (UK safety regulator)

IP – Investment Planning (PG&E Organizational Element)

IRP – Independent Review Panel (evaluation commissioned by CPUC)

IRV – Internal Relief Valve

LOB – Line of Business

MWC – Major Work Category

NB – New Business

NGV – Natural Gas Vehicles

NPV – Net Present Value

NTSB – National Transportation Safety Board

O&M – Operation and Maintenance

ORM - Operational Risk Management (system)

PAAR - Programs and Activities to Address Risks

PAS – Publicly Available Specification

PG&E – Pacific Gas and Electric Company

PM – Preventive Maintenance

PRCI – Pipeline Research Council International

RCC – Gas Operations Risk and Compliance Committee (PG&E)

RCM – Risk Control Measure

R&D – Research and Development

RET – Risk Evaluation Tool (PG&E Corporate-Level Tool)

RTU – Remote Terminal Unit

SME – Subject Matter Expert

WRC – Work at the Request of Others

Attachment 2 - Standards and Other Material Informing Development of Criteria for Risk-Informed Resource Allocation Process

1. Risk management - Principles and Guidelines (ISO 31000:2009)
2. Risk management - Risk assessment techniques (IEC/ISO 31010:2009)
3. Risk management - Vocabulary (ISO GUIDE 73:2009)
4. Asset Management - Part 1: Specification for the Optimized Management of Physical Assets (PAS 55-1: 2008)
5. Asset Management - Part 2: Guidelines for the Application of Publicly Available Specification (PAS) 55-1 (PAS 55-2:2008)
6. Risk and emergency preparedness analysis, NORSOK standard Z-013 Rev. 2, 2001-09-01
7. Guidelines on Risk Assessments and Safety Statements; Published by the Health and Safety Authority, Dublin (January 2006)
8. Guidelines for the Development and Application of Health, Safety and Environmental Management Systems, the Oil Industry, International Exploration and Production Forum, Report No. 6.36/210, July 1994
9. Directive 2012/18/EU of the European Parliament and of the Council (4 July 2012) on the control of major-accident hazards involving dangerous substances – Seveso Directive III – Note, this Directive explicitly excludes pipelines
10. A Risk Management Standard, Federation of European Risk Management Associations (FERMA), 2003
11. Safety Goals for the Operation of Nuclear Power Plants; US Nuclear Regulatory Commission (NRC), Policy Statement, 1986
12. Modifications to the Reactor Safety Goal Policy Statement, US Nuclear Regulatory Commission (SECY-00-0077, March 30, 2000)
13. Letter, the Advisory Committee on Reactor Safety (ACRS) to the Nuclear Regulatory Commission (NRC) Chairman, August 15, 1996
14. Perspectives on Risk Acceptance Criteria and Management for Offshore Applications – Application to A Development Project; Terje Aven, Jan Erik Vinnem, and Frank Vollen; International Journal of Materials & Structural Reliability Vol.4, No.1, March 2006, 15-25
15. UK Health and Safety Executive (HSE) web site; HSE is the safety regulator for most industrial facilities in the United Kingdom; (Assessment Principles for Offshore Safety Cases, HSE, March 2006)
16. The Nuclear Regulatory Commission (NRC) backfit rule (10 CFR 50.109)

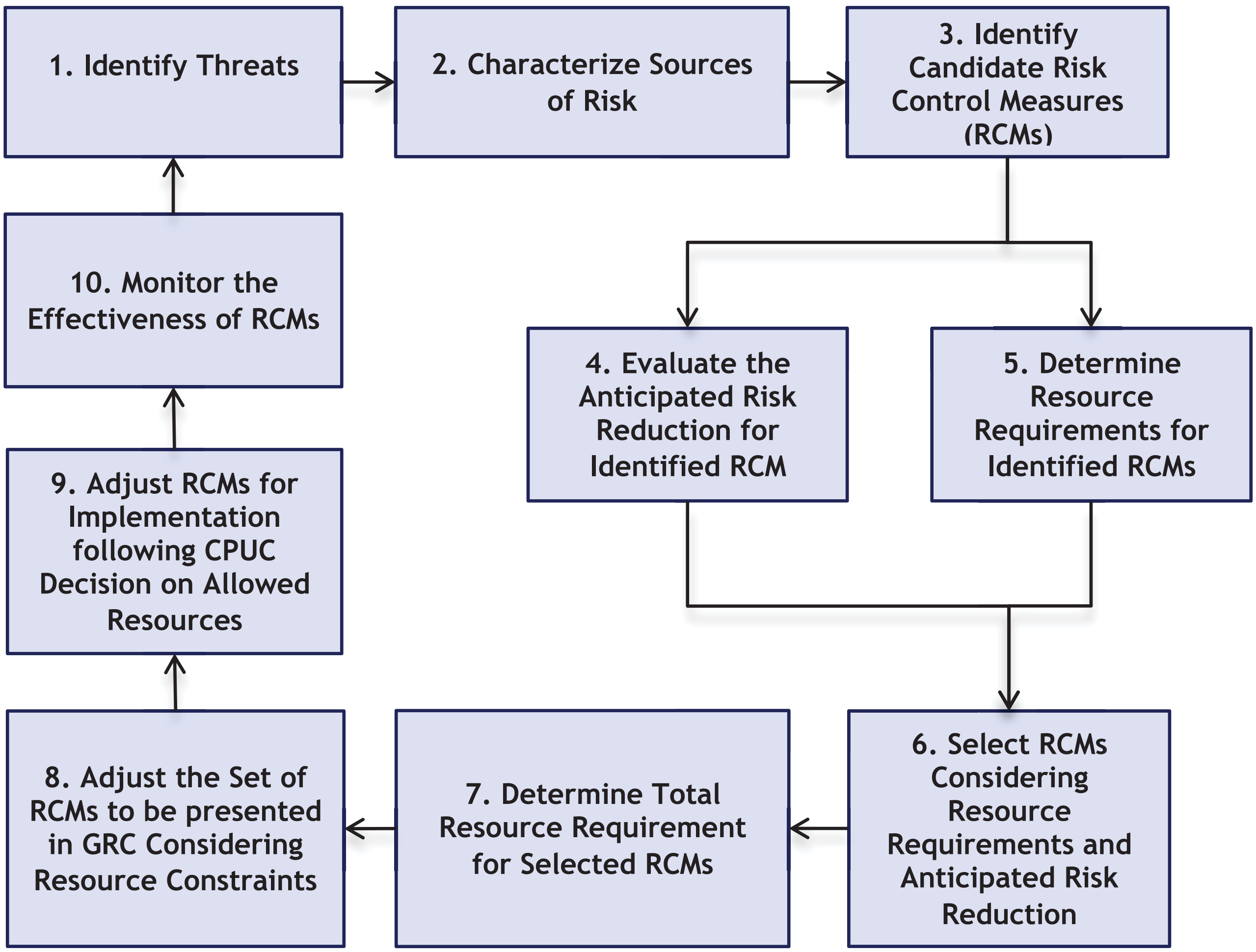
17. An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis, US NRC, Regulatory Guide 1.174, Revision 1, November 2002

Attachment 3 - Evaluation Criteria for a General Rate Case Filing

As the basis for this evaluation, Cycla Corporation has developed a comprehensive set of criteria, based on widely accepted international risk management standards, against which PG&E's risk management program was evaluated. These criteria have provides the basis for the current evaluation and should be used to guide future development of processes and tools for use in developing rate case filings. The standards and supporting material considered in developing the evaluation criteria are presented in Attachment 2.

Figure 3-1 describes the ten process elements involved in a risk-informed resource allocation process. Such a process is the recommended way for an operator to develop the basis for and justify the necessity and reasonableness of risk control measures (RCMs) it includes in a General Rate Case filing. A set of criteria for each of these ten process elements is presented below. These criteria are appropriate for guiding the development of the operator's rate case filing and for use by the CPUC in evaluating the content of a GRC filing.

Figure 3-1 Elements of a Risk-Informed Resource Allocation Process



These ten elements comprise the key sequence of steps in a risk-informed resource allocation process.

As shown in Figure 3-1, the ten process elements include:

1. Identify the threats having the potential to lead to safety risk;
2. Characterize the sources of risk;
3. Characterize the candidate measures for controlling risk;
4. Characterize the effectiveness of the candidate risk control measures (RCMs); in parallel with
5. Prepare initial estimates of the resources required to implement and maintain candidate RCMs;
6. Select RCMs the operator wishes to implement (based on anticipated effectiveness and costs associated with candidate RCMs);
7. Determine the total resource requirements for selected RCMs;

8. Adjust the set of selected RCMs based on real-world constraints such as availability of qualified people to perform the necessary work;
9. Document and submit the General Rate Case filing, on which the CPUC decides the expenditures it will allow, and, based on CPUC decision, adjust the operator's implementation plan;
10. Monitor the effectiveness of the implemented RCMs and, based on lessons learned, begin the process again.

One subtlety in this process is that the plan reviewed and approved by the CPUC typically includes funds allocated to one or more sets of control measures for which implementation details are decided by the operator as part of an annual planning process (e.g., exactly which segments to replace within an overall plan to replace a specified amount of the highest risk pipe). These operating decisions can and should be made using appropriate elements and applicable tools from the overall process.

Evaluation Criteria

The following general criteria apply to an operator's overall risk-informed resource allocation process (These general criteria are typically reflected in the specific criteria for each process element below).

1. An operator must develop, document, implement and maintain a risk-informed resource allocation process for the ongoing identification, evaluation and management of asset-related risks. The process must include identification, selection, implementation and effectiveness monitoring of risk control measures (RCMs) throughout the life cycle of the pipeline system.
2. Executive management must be involved to ensure that the risk-informed resource allocation process seeks out and considers safety risks, and that resource decisions adequately address recognized safety risks.
3. The results from application of an operator's risk-informed resource allocation process must provide support for the safety-related proposals in its periodic General Rate Case (GRC) filings.
4. The risk-informed resource allocation process documentation must include a description of the procedure for making decisions on selection of RCMs proposed in the GRC, including enumerating responsibilities for implementing this procedure.
5. The risk-informed resource allocation process must include means by which an operator monitors the overall effectiveness of its efforts to control risk and the effectiveness of individual RCMs using a documented set of leading and lagging indicators that are periodically reviewed for appropriateness.

6. One critical source of information both on sources of risk and on the effectiveness of measures to control risk in pipeline systems is data on the location and underlying causes of various types of failures affecting system integrity. An operator must thoroughly evaluate, understand and make appropriate use throughout the process of its understanding of the root causes of a spectrum of events ranging from system leaks to serious incidents.
7. Communication and consultation with both internal and external stakeholders must take place in support of the risk-informed resource allocation process.
8. An operator must subdivide its system into segments defined to include pipe or equipment having uniform characteristics affecting risk, and must verify that the data on these characteristics is complete, accurate and up-to-date.
9. When data, model or asset condition uncertainties contribute to significant uncertainty in its risk characterization, an operator must identify and implement means to reduce these uncertainties, and must evaluate the impact of these uncertainties on the RCMs proposed in its GRC.
10. All individuals performing activities in support of the risk-informed resource allocation process must have the knowledge and experience needed to perform their function.

General Rate Case (GRC) Filing

Criteria for GRC filings are listed below for each of the ten process elements of the risk-informed resource allocation process shown in Figure 1. For each of the ten process elements, three types of criteria are provided:

- Requirements for how the process element must be implemented;
- Requirements for how the implementation of the process element must be documented, including the data and models used;
- Requirements for how the results of each process element must be documented.

1. *Identify threats to pipeline integrity*

a. An operator must develop and implement a process for identifying all credible and foreseeable threats to system assets that considers overall industry experience and company-specific experience.
b. An operator's process for identifying threats must consider unique characteristics of its system (e.g., material of construction, soils, installation practices, joining technique, age-related issues) and physical location (e.g., seismicity, slope stability, potential for erosion of ground cover, levels of third party construction activity).
c. An operator's process for identifying threats must seek out interactive threats (i.e., combinations of threats that represent distinctive contributors to risk); analysis to determine the root cause of leaks and incidents must be used in this search for interactive threats.
d. An operator must determine and document the relative contribution of each identified threat to its leak and incident experience.
e. People with system and threat-specific knowledge and experience must be actively involved in identifying threats and reviewing the completeness of identified threats
f. Threat identification must not be a one-time step, but must be a continuing process that considers:
    i. On-going operating experience (e.g., event reports, close calls, root cause analysis) of an operator and of the industry as a whole;
    ii. Changes in other factors affecting risk (e.g., weather-related, geologic factors, asset aging).
g. Specific applicable threats must be identified for each identified segment.
h. An operator's documentation of its process must include:
    i. Industry and operator-specific sources used in threat identification;
    ii. Role of system and subject matter experts in threat identification;
    iii. Methods and models used to identify and characterize system and location-specific threats.
i. An operator's documentation of its results must include:
    i. Threats identified from industry experience;
    ii. Threats identified by consideration of the unique characteristics of an operator's system and its physical location;
    iii. Interactive threats;
    iv. The relative contribution of each identified threat to its leak and incident experience.

2. *Characterize the sources of risk*

a. An operator's risk characterization methodology must use available data and results from root cause analysis to enhance its understanding of the factors that alone or in combination affect the likelihood and consequences of potential accidents.

b. An operator must characterize and understand risk using quantitative methodologies where possible, in addition to qualitative methods, or a combination these methodologies.

c. When its understanding of threats, risks and the effectiveness of candidate risk control measures can be enhanced by the use of quantitative analysis of event likelihood and/or consequences, and when supporting data are available, then an operator must use appropriate quantitative methodologies.

d. In its risk characterization approach an operator must assemble and integrate data on factors affecting both event probability and potential event consequences at the segment level.

e. An operator must validate its risk characterization methodology in light of incident, leak, and failure history information. Validation must ensure the risk assessment methods produce a risk characterization that is consistent with an operator's and industry experience, including evaluations of the factors causing or contributing to past incidents, as determined by root cause analysis or equivalent means.

f. An operator's risk characterization methodology must be capable of informing decisions affecting implementation of new or expanded use of RCMs. The methodology must support:
    i. Evaluating the anticipated effectiveness of candidate RCMs in reducing risk;
    ii. Determining segment-specific and threat-specific survey or assessment frequency;
    iii. Ranking segments for application of RCMs

g. An operator's risk characterization approach must be designed to:
    i. Identify risk contributors that are not readily apparent from operating history;
    ii. Lead to better understanding of the nature of the threat; the failure mechanisms; the effectiveness of currently utilized RCMs; and means to prevent, mitigate, or reduce associated risks;
    iii. Evaluate the likelihood of failure associated with each individual threat or risk factor, and each unique combination of threats or risk factors that interact at a common location;
    iv. Identify and evaluate the contribution to risk from scenarios with the potential to produce exceptionally high consequences, even beyond those experienced to date.

h. An operator must characterize the level of uncertainty associated with factors affecting event probability and potential consequences, including uncertainties associated with missing or suspect data.

i. An operator must characterize risk using processes that are sufficiently well documented to assure consistent results independent of the qualified individuals doing the characterization.

j. When the subjective judgments of individuals are used in the risk characterization, an operator must provide training or independent validation to compensate for possible bias.

k. In quantitative risk characterization, techniques to estimate probability must include one or more of the following:

    i. Use of relevant historical data;

    ii. Logic modeling such as fault tree analysis and event tree analysis;

    iii. A systematic and structured process for eliciting expert judgment to estimate probabilities of factors contributing to events.

l. Results from any risk characterization methodology must be documented and presented in a manner that is meaningful to decision makers and operating staff.

m. People with system and threat-specific knowledge and experience must review the results of risk characterization in their areas of experience for completeness and quality.

n. An operator's documentation of its process must include:

    i. Description of both qualitative and quantitative models used to characterize risk (both the likelihood and the consequences of events) including how these models are used to support decisions on:

        1. Which threats require mitigation,

        2. Selection of RCMs,

        3. The locations of RCMs (including pipe segments to be replaced), and

        4. The anticipated impact of RCMs on risk;

    ii. Sources of data used to support the methods and models, including how these data have been validated;

    iii. The level of uncertainty associated with these data;

    iv. Role of system and subject matter experts in characterizing risk.

o. An operator's documentation of its results must include threat-by-threat and segment-by-segment risk and the characteristics (or factors) contributing to that risk.

3. *Identify candidate risk control measures (RCMs)*

a. An operator's models and processes used in identifying candidate RCMs must:
   i. Identify candidate RCMs for each identified risk;
   ii. Characterize the effectiveness of its existing RCMs;
   iii. Assemble and evaluate available information on industry best practices and their effectiveness in addressing identified risks by using benchmarking conducted in-house or through a 3rd-party contractor, or by demonstrating the applicability of industry-wide benchmarking studies;
   iv. Identify and consider innovative practices or technologies for controlling identified risks;
   v. Identify RCMs to address new external mandates (e.g., new regulations, findings of oversight agencies);
   vi. Identify RCMs to address existing deficiencies in management and IT systems and data needed to support their use;
   vii. Evaluate the anticipated effectiveness of RCMs based on actual experience, testing, or analysis.
b. An operator's process for identifying candidate risk control measures must include specialized expert input on measures to control risks for which limited industry experience exists (e.g., seismic, ground movement, water flow exposing pipeline). If the needed expertise is not available in-house, an operator must use outside experts.
c. Candidate RCMs must address the risks to be controlled and may be either measures identified through industry benchmarking or measures an operator currently uses.
d. An operator's documentation of its process must include:
   i. Description of the sources included in identifying RCMs;
   ii. Description of the breadth of application of identified RCMs, whether broadly used throughout the industry, or employed by operators in the top quartile of performance, or innovative measures currently undergoing effectiveness evaluation.
e. An operator's documentation of its results must include:
   i. Description of the candidate RCMs identified and the threats they are designed to control;
   ii. Description of the basis for determining that candidate RCMs will be effective in controlling risk.

4. *Evaluate the anticipated risk reduction for identified RCMs*

   a. An operator must describe the specific ways that the candidate RCMs are expected to reduce the likelihood or consequences of identified risks.
   b. For each identified risk, an operator must evaluate the demonstrated or anticipated effectiveness of candidate RCMs in reducing the risk and characterize the uncertainty in the anticipated effectiveness of candidate RCMs.
   c. An operator's documentation of its process must include:
      i. The basis for key decisions, including: decisions on which threats or consequences must be better controlled, decisions on which RCMs should be used, and decisions on exactly where in its system an operator should apply a particular RCMs (e.g., which parameters will be remotely monitored, which pipe segments or components will be replaced, which segments will be surveyed for leaks more frequently);
      ii. Description of available information on the effectiveness of candidate RCMs, both in an operator's system and across the industry;
      iii. Approach to considering uncertainty in assessing the effectiveness of selected RCMs.
   d. An operator's documentation of its results must include its evaluation of the anticipated risk reduction associated with each identified RCM, and the associated uncertainty.

5. *Determine resource requirements for identified RCMs*

   a. An operator must determine resource requirements for each identified RCM:
      i. Cost estimates must reflect historic experience with the cost of implementing and maintaining candidate RCMs;
      ii. For RCMs that are an expansion of an operator's current operation or maintenance program (e.g., more frequent leak surveys, more rapid response to leak reports), cost estimates must include determination of "unit resource requirement" based both on historic experience and on consideration, including survey of available industry experience, of how best to reduce the cost of RCM implementation.
   b. An operator's documentation of its process must include the basis for determining resources required to implement selected RCMs.
   c. An operator's documentation of its results must include the resources to implement and maintain individual selected RCMs.

6. *Select RCMs considering resource requirements and anticipated risk reduction*

a. An operator must ensure decisions regarding which risk control measures (RCMs) to implement are guided by the following principles:
    i. Selection of RCMs must consider current information on industry best practices, their application, and their effectiveness;
    ii. Selection of RCMs must consider both identified risks and costs of applicable control measures.
b. An operator must base its justification of the need for an RCM either on a quantitative comparison to a pre-defined acceptable risk threshold or on movement toward a desired end state such as performance in the top quartile of the industry achieved by appropriate adoption of industry best practices.
c. If an operator justifies the need for a RCM based on movement toward a desired end state by adoption of best industry practices, it must:
    i. Demonstrate a comprehensive knowledge of those practices applicable to the threats affecting its system;
    ii. Evaluate the effectiveness of the practices selected for implementation;
    iii. Continuously monitor and contribute to the evolution of industry best practices, including providing evidence of the effectiveness (e.g., through trade associations) of RCMs it has implemented.
d. An operator must evaluate the impact of uncertainties associated with the data and the methods and models used to characterize risk on the decisions affecting the need for and selection of RCMs.
e. An operator's documentation of its process must include the basis for selecting RCMs.
f. An operator's documentation of its results must include:
    i. RCMs selected and the basis for their selection;
    ii. Major uncertainties and how they are being addressed.

7. *Determine total resource requirements for selected RCMs*

a. In deciding the appropriate level of resources to expend to address known risks, an operator must determine the cumulative cost of all selected RCMs.
b. An operator's documentation of its process must include a description of the process for determining the total resource requirements for selected RCMs.

c. An operator's documentation of its results must include the resources required to implement each of the selected sets of RCMs.

8. *Adjust the set of RCMs to be presented in the GRC considering resource constraints*

a. In determining the appropriate level of resources to expend to implement selected RCMs, an operator must identify and apply known constraints on its ability to implement changes related to each RCM, including:
    i. The trained personnel available to carry out the work and the ability to increase and retain these personnel;
    ii. The ability to manage and control system and operational changes with existing and anticipated personnel;
    iii. The necessary implementation sequence and time required to implement selected RCMs.
b. An operator's documentation must include a description of the process used to determine and apply resource constraints to adjust the extent of implementation of the set of selected RCMs.
c. An operator must develop and document a risk management plan that defines projects, schedules, and required resources. The risk management plan should include a priority list of RCMs that allows the CPUC to ascertain which measures will not be implemented if the requested level of funding is not allowed.

9. *Adjust RCMs for implementation following PUC decision on allowed resource*

a. In developing its implementation plan, an operator must maximize the impact of available resources on known and anticipated risks within the constraints imposed by the CPUC rate case decision
b. An operator's documentation of its process must include a description of how adjustments to its implementation plan are made.
c. An operator must document the resulting implementation plan and anticipated schedule in a form that supports monitoring by the CPUC, including description of the basis for ongoing decisions on adjustments to or refinement of the plan.

10. Monitor the effectiveness of risk control measures

a. An operator must identify metrics for use in monitoring the effectiveness of individual RCMs as well as of the aggregate set of existing, new, and modified RCMs.
b. An operator's monitoring and improvement processes must ensure that RCMs are effective in achieving the anticipated risk reduction.
c. An operator's monitoring and improvement processes must include a description of how the overall risk-informed resource management process is modified to reflect implementation lessons.
d. An operator must establish a process to evaluate and report upon its compliance with commitments made in each General Rate Case.
e. An operator’s documentation of its process must include a description of the means to be used to monitor the effectiveness of selected RCMs as well as the aggregate impact of RCMs on overall risk.
f. An operator’s documentation of its results must include:
    i. The indicators and/or metrics selected to monitor future trends in RCM performance and contribution of each RCM to risk reduction;
    ii. The baseline value for selected indicators and/or metrics and how it was established.

Attachment 4 – Risk-Informed Decision Making: Balancing Risk Reduction and Cost

Introduction

A major issue the CPUC must address in introducing explicit consideration of safety risk in the rate making process is *how much should a utility spend to reduce safety risk?* While there are numerous approaches used around the world to answer this question, some would be extremely difficult to apply in the pipeline industry, and some could lead to an answer whose implications would be unacceptable to policy makers and to the public. Since all candidate approaches necessarily incorporate some form of risk characterization, this section will first consider how risk characterization might *inform* the decision on "how much is enough", versus how it might be used *as the basis* for this decision. Secondly, the difficulties in characterizing risk for pipeline systems will be discussed. Next, an approach used broadly in the safety regulation of hazardous facilities in Europe and in safety regulation of US nuclear facilities will be described. A candidate approach on how to best answer the question which seems to deal with practical implementation difficulties is then described. Finally, a brief summary of the current state of quantitative risk assessment in the pipeline industry is presented, which underlines the inapplicability of index models to informing many of the decisions necessary in characterizing the effectiveness of measures to control risk.

Risk-Based vs. Risk-Informed

A "risk-informed budgeting process" is a logically structured decision-making process that utilizes the best available information concerning the likelihood and potential consequences of system-specific failure mechanisms ("risks") to identify and allocate limited resources among a set of improvement projects (e.g., changes in current system design and/or improved operational practices) that most efficaciously reduces the current level of risk.

In an ideal world, the likelihoods and consequences of all significant risks can be known and quantified with a high degree of accuracy, and can be integrated into a unified single quantitative measure of overall system risk. Similarly, the impacts of each proposed improvement project on all the various risks can be well-defined and the overall quantitative impact on total system risk can be calculated. In this ideal situation, monetary values can be assigned to each type of consequence being considered (e.g., deaths, injuries, property damage, environmental degradation) and an overall "risk-reduction benefit" for each project can be calculated. This monetized benefit can then be compared to the monetary cost of the proposed project. By taking into account other practical scheduling issues (e.g., resource constraints, procurement or training time), a portfolio of projects (a "budget") can then be developed that optimizes risk reduction given the resources available. Alternatively, the magnitude of resources required to meet a “risk goal” can be determined. This represents the idealized Quantitative Risk Assessment (QRA) "risk-based" budget.

Unfortunately, very few, if any, systems that operate in the real world come close to this idealized analytical situation. There are often significant unknowns and uncertainties in many of the data inputs, technical models, and decision algorithms. These various unknowns and uncertainties combine to limit the ability to produce a useful absolute measure of risk (or risk reduction) that can be monetized and compared to projected cost increases. Therefore, all practical budgetary processes have to acknowledge and appropriately accommodate the unknowns and uncertainties in both the sources of current risks and the impact of proposed projects on these risks. Given these unknowns and uncertainties, requiring a purely quantitative assessment of risk has the potential to obscure a full understanding of risks and lead to implementation of risk reduction measures that can lead to a false sense of security.

While absolute quantitative risk data may not be available for all inputs to the process, using the *best available information* on risk and risk reduction will contribute significantly to the quality and justifiability of a budgetary process. In some portions of the analysis this best available information might be a quantitative absolute risk (e.g., this specific accident will happen X times a year and result in Y deaths and Z injuries). But in other cases this quantitative information may be unavailable or so highly uncertain that the best available information might be an expert's opinion on the level of risk (or the risk-reduction impact of a particular project), or analysis of available data on proxies for risk, such as hazardous leaks present in a gas distribution system. The overall budgetary process therefore has to combine supportable quantitative information (where it exists) with more qualitative, subjective, or relative risk information. Supportable quantitative information is used where it is available and where it enlightens or informs the decision-making process. But where such data are unavailable or highly uncertain, they must be supplemented by, or replaced with, more subjective or qualitative information. Such a real-world process leads to a "risk informed" rather than a "risk-based" budget.

Difficulties in Characterizing Pipeline Risk

Quantitative risk assessment has been successfully applied in characterizing the level of safety and in evaluating safety improvements for single-location facilities such as nuclear power plants, chemical refineries, and off-shore petroleum production facilities. However, its application is more problematic for facilities such as gas transmission and gas distribution facilities. Reasons for this distinction include the following:

1. The single-location facilities noted above typically ensure safe operation through multiple diverse and redundant controls, combined with formal procedures through which the operating staff interacts with these controls in preventing and managing accidents;
2. Diverse and redundant controls lend themselves to quantitative risk analysis because multiple failures of the control systems are typically required to cause an accident resulting in significant off-site health and safety consequences, and because the population exposed to the consequences can be determined ;
3. The failure events included in the risk models are predominantly "success/failure" component-related events such as failure of a valve to open on demand or failure of a pump to start, for which significant data exists or can be produced to establish accurate probabilities of failure.
4. Well-developed methodologies and data exist to quantitatively characterize the failure rate of the controls as well as the potential for common modes of failure which can reduce the aggregate reliability of the set of controls.

Pipeline systems in contrast differ for the following reasons:

1. Pipelines are subject to single failures with the potential to cause severe consequences depending on where in the system the failure occurs.
2. While deficiencies in multiple control measures often contribute to these single failures or exacerbate their consequences, the distributed nature of these control measures (e.g., cathodic protection, pipe coating) together with limited data on their local condition make local quantification of failure probability quite difficult.
3. Pipeline failures are also often caused by long-developing material degradation, or slowly deteriorating control measures, rather than more discrete success/failure conditions.
4. The understanding of “interactive failures” is at best rudimentary.
5. Detailed knowledge of the physical characteristics and condition of the pipeline system together with the environment in which it resides at each individual location are often unavailable.

These factors make quantitative analysis of the risk of geographically distributed pipeline systems very challenging. In fact, even countries in which risk assessment is mandated in the design, operation and modification of virtually all hazardous facilities, such as the United Kingdom (UK) and most European countries, pipelines are not subject to risk assessment or safety studies by government regulation[21].

The Principle of ALARP and its Application

One way operators and regulators outside the US have agreed upon to determine the right balance between safety improvement and resource expenditure is the "As Low as Reasonably Practicable" (ALARP) principle. This principle is fundamental to the regulation of hazardous facilities in the UK and other European countries. In essence, it involves weighing a change in level of risk against the trouble, expressed in time and money, needed to control it.

At the core of ALARP is the concept of "reasonably practicable" which, once defined, allows regulators to establish the basis for operator decisions without the need for excessively prescriptive regulation. One principle means in Europe for evaluating whether a safety improvement is "reasonably practicable" has been cost-benefit analysis, supported by a quantitative risk assessment (QRA) to evaluate the benefits. In practice, application of the cost-benefit analysis has evolved to be based on the premise that a safety improvement is reasonably practicable unless its costs are *grossly disproportionate* to the benefits realized. Formalized risk-based cost-benefit analysis requires not only performance of a QRA, but also that benefits expected from a safety improvement be monetized (i.e., expressed in terms of dollars or euros). Monetizing benefits usually requires expressing the value of a human life in monetary terms, then deciding what multiple on the value of a human life is judged to be *grossly disproportionate* to the costs incurred. In the offshore petroleum drilling and production industry in the North Sea, the value of a human life has been set at one million pounds, and decision making on whether the cost of a safety improvement is *grossly disproportionate* is typically based on a value of human life of six million pounds (i.e., a factor of six greater).

Even if it were possible to rigorously quantify risk in support of cost-benefit analysis, the resultant answer on how much is enough to spend on safety risk reduction may not be acceptable to safety regulators, to the public, or even to utilities. As an example, over the past 26½ years PG&E has experienced 51 incidents on its gas

[21] HSE Research Report 82/94, Risks from Hazardous Pipelines in the United Kingdom, Arthur D Little, 1995.

distribution system with injuries or fatalities leading to a total of 60 injuries (2.26/yr.) and 17 fatalities (0.64/yr.). These consequences exclude the San Bruno tragedy since that incident resulted from the rupture of a gas transmission line. The monetized cost of these fatalities and injuries (assuming injuries ~ 20% of monetized fatality cost; 1.6 $/£ x £6 million per fatality[22]) is $278.4 million or $10.5 million per year. The ratio of property damage costs reported for gas distribution incidents over the past five years (2008-2012) to total monetized fatality and injury costs is 0.0414. Using this figure to adjust the monetized fatality and injury costs from PG&E experience yields a justifiable annual expenditure on an ALARP cost-benefit basis of $10.9 million. So analyses based purely on the monetization of past public safety and economic consequences often seriously underestimate the social and economic consequences of pipeline accidents, and therefore lead to a grossly inadequate safety budget. The other indirect consequences (e.g., loss of shareholder value, fines, liability settlements, loss of near-by property value), and intangible societal consequences (e.g., loss of confidence, degraded customer relations, regulatory uncertainty) of accidents, as well as all of the other economic consequences to the pipeline operator, are very difficult to identify, much less to accurately quantify, with any confidence.

Since deciding whether a risk control measure is ALARP based on cost-benefit analysis can be challenging, requiring operators and regulators alike to exercise judgment, the British regulator (The Health and Safety Executive - HSE) often decides by referring to industry best practices, which are established by a process of discussion with stakeholders to arrive at a consensus on what is ALARP.

An alternate way to establish a total budget is to look to the risk control practices currently used by the top industry performers as a proxy for "acceptable level of risk" and "reasonably practicable". The rationale for this approach is that the current best industry practices represent the outcome of a well-accepted legal and technical process that is based on a foundation of safety practices established in existing regulation, supported by national consensus technical standards, and then strengthened by operators making deliberate decisions, considering costs and benefits, to exceed these minimum requirements and standards. By the mere fact that they have been selected, funded, and implemented at public-regulated facilities, industry best practices are *de facto* judgments made by both regulators and industry that these activities are reasonable and practicable. As discussed above, in many European countries the level of risk that results from implementation of the best industry practices is considered to be as low as reasonably practicable.

[22] This value of a life of £6 million is the figure typically used in the UK in making ALARP cost-benefit decisions.

Candidate Approach to Justifying a Safety Budget

The ultimate question in justifying a safety budget based on risk considerations is "How much risk reduction is required?" An alternative way to pose the question is "How much expenditure can be justified to reduce risk?"

An approach to answering this question that embodies the ALARP principle includes the following steps. The element(s) of a risk-informed resource allocation process from Section 3 and Attachment 3 that relate to each step are shown in parenthesis.

1. Identify the threats and characterize the risk of the system using an appropriate mix of quantitative and qualitative tools (Element 1 and 2).
2. Identify a list of potential activities designed to address the identified risks, including (Element 3):
    a. Activities required to comply with current regulations,
    b. Activities required to respond to recommendations from external audits, investigations, etc.
    c. Activities suggested by the operator's internal risk management processes
3. Compare the potential risk control projects to approaches used by the best operating companies in the industry to manage similar risks (Element 3).
4. Potential projects with the following characteristics are deemed "reasonable and practical" (Element 3):
    a. It significantly mitigates a risk that has been identified as a non-trivial contributor to overall system risk.
    b. It raises operator safety practice or capability to a level that has been deemed reasonable and practical by the best safety performing operators in the industry
5. An implementation schedule for the selected risk control projects is then established through consideration of practical and reasonable constraints. Including (Element 8):
    a. The ability of the operator to implement the projects in a quality manner
    b. Necessary chronological sequencing of projects
    c. Where practical, scheduling projects that address higher risks before those that address lesser risks

Risk Characterization in the Pipeline Industry Today

Currently the vast majority of pipeline operators, both transmission and distribution, use very simple models to characterize risk. Typically these are index models which were developed as tools to evaluate and risk-rank pipeline segments as part of operator integrity management programs. An index model is a semi-quantitative method that supports the collection and analysis of location-specific data for the routine causes of pipeline failure, as well as consequences of failures at different locations along the pipeline.

Index models typically include a number of different design, operation, and maintenance variables that can affect the likelihood of pipeline failure, as well as variables that reflect conditions surrounding the line (e.g., population density, or sensitive environmental resources) that could determine the relative consequences of a pipeline failure. Numerical scores are assigned to the variables in the model based on the available data. These numerical scores are then combined according to a subjective assessment of their importance (using "weighting factors"), and an "index" or "score" is calculated. The scores characterizing the likelihood of a failure are combined with those relating to consequences to arrive at a composite score representing the risk presented by each segment. Significant differences exist among index models with respect to the variables that are included in the measurements of likelihood and consequence, how these variables are measured, and how they are weighted.

Index models have many well-documented deficiencies in their ability to inform integrity-related decisions beyond ranking segments for assessment. In particular they are not well suited for evaluating alternative risk control measures, for integrating data on factors potentially contributing to risk in a way that contributes to operator understanding of risk, or for systematic investigation of the factors contributing to risk.

Going forward there are some limitations to the full use of QRA in the pipeline industry. Most of the limitations result from currently inadequate data and modeling techniques. This inadequacy is partly the outcome of a chicken-and-egg situation. Until there are requirements or demonstrated economic incentives for high quality risk assessments, and specifically for quantitative risk assessments, the data necessary to support these assessments and the underlying technical modeling capabilities will not be developed. Over time, driven by regulatory necessity, the data and modeling techniques will improve. What is difficult, or impossible, today, may be very feasible in a few years under regulatory directives.

Attachment 5 – Evaluation of the PG&E Probabilistic Risk Algorithm

The PG&E DIMP Probabilistic Risk Algorithm has not been used either in support of the DIMP program to date or to inform the GRC filing. It is, however, a major candidate for future risk model development at PG&E. In the absence of process documentation that describes how the algorithm is intended to be used, it is hard to be definitive about the suitability of the algorithm in supporting a risk-informed process. However, some tentative conclusions can be drawn based on the available documentation indicating how the algorithm estimates quantitative risk levels for pipeline segments based on pipeline characteristics. As currently documented, this algorithm is potentially part of a risk characterization approach in the context of a risk-informed decision process. By itself, however, it would not be sufficient as a future risk characterization approach and could not support the full range of decisions described in the evaluation criteria.

The PG&E algorithm models the risk associated with pipeline segments as the product of the probability of failure (PoF) and consequence of failure (CoF), plus a separate term that represents the risk from low pressure regulator failure (considered to be a very low probability event with potentially very high consequences). The model calculates PoF as a function of the probabilities of seven failure causes. The probability of each individual cause is a function of variables reflecting characteristics of the pipe or the surrounding area that are evaluated using data or subjective judgment. PoF is calculated in units of "probability of failure per plat-year". The use of plats as pipe segments seems inconsistent with the need to subdivide the pipe into segments having similar risk characteristics.

The algorithm calculates CoF as a function of variables representing impacts on different classes of "receptors", including the population, property, the environment, product loss, and service interruption, along with a constant multiplier to represent "indirect" costs such as "…corporate reputation, increased regulatory oversight, and future business implications." CoF is calculated in "consequence units", which are not defined further in the model documentation, and have no obvious relationship to monetized consequence costs.

The PG&E risk model appears to be an improvement beyond so-called "index models," principally because the model attempts to actually produce a risk estimate as a function of probability and consequence levels, rather than calculate a unit-less index. Also, the threat-specific probability estimates that make up the PoF calculation are based in some cases on how actual physical characteristics of the pipe and the surrounding area influence the failure probability. Examples of this are pipe wall thickness and operating pressure. The algorithm includes equations that use these variables, interacting with other quantities such as corrosion or cracking rates, to estimate a failure probability.

However, the current version of the PG&E model and the input data used to perform risk calculations will require additional development before it can meet the criteria for a risk characterization model supporting an effective risk-informed process. Evaluation against the criteria for risk characterization where the PG&E algorithm seems to fall short is provided below.

Requirement 2.a – "… risk characterization methodology must use available data and results from root cause analysis to enhance its understanding of the factors that alone or in combination affect the likelihood and consequences of potential accidents…" Currently, the model inputs rely heavily on default values. For the model to be useful for segment- specific risk analysis, more segment-specific data will have to be used. Also, the model does not appear to capture interactive effects among threat categories, so the effect of "combinations" of risk factors could not be analyzed. An example is outside mechanical damage to a pipeline that increases its susceptibility to external corrosion.

Requirement 2.d – "…an operator must assemble and integrate data on factors affecting both event probability and potential event consequences at the segment level…" The model develops risk estimates based on "plats," which are defined geographic areas containing pipe segments. There is no assurance that "plats" are the appropriate "segments" for characterizing risk. Therefore, decisions on implementing risk control measures (RCMs), or other risk-based decision making, could require a different segmentation of the pipeline system.

Requirement 2.e - "…an operator must validate its risk characterization methodology in light of incident, leak, and failure history information…" Because of the large number of variables and the fairly complex modeling of failure causes, the model should be subject to a robust validation. The validation that has been performed appears to rely solely on subject matter expert evaluation of the reasonableness of the segment ranks for each threat as predicted by the model. This is a reasonable first step in validation, but fails to demonstrate that the algorithm is capable of investigating system risk characteristics and contributing to the operator's understanding of the sources of risk. Most important, the validation that was performed did not validate the algorithm's calculation for PoF based on pipeline segment characteristics against incident, leak, and failure history.

Requirement 2.f - the risk characterization methodology must be capable of supporting the following decisions:

i. Evaluating the anticipated effectiveness of candidate RCMs in reducing or managing risk;
ii. Determining segment-specific and threat-specific inspection or assessment frequency and scheduling;
iii. Ranking segments for application of RCMs.

With respect to "i" above, it appears that the algorithm could be useful for evaluating *some* RCMs, namely those that impact variables that are represented in the models. The ability of the PG&E risk algorithm in satisfying this criterion depends on the nature of the RCMs being considered. If the effects of RCMs can be captured by changes to variables reflecting pipeline physical or operational characteristics included in the model, then the model may be used to evaluate the RCM by considering the risk levels before and after implementation of the RCM. Some categories of RCMs that would be difficult to evaluate include:

- RCMs defined to reduce the probability of failure due to specific natural hazards
- RCMs defined to mitigate the consequences of pipeline releases.

The reason these two types of RCMs would be difficult to evaluate is that the variables used to calculate associated risk for these areas do not appear to be easy to relate to changes that might result from implementation of the RCMs.

With respect to "ii" above, it does *not* appear that the model could be used to evaluate inspection or assessment frequency without further modeling, because the effects of inspections or assessments appear to be represented by default constants in the model and inspection or assessment frequency is not an explicitly defined variable.

With respect to "iii" above, it is unclear whether the model could be used to set some general priorities for pursuing RCMs in different pipeline segments or geographic areas. One reason for this uncertainty is the high number of variables throughout the model that are represented by default constants, so that a valid segment-specific ranking might not be achievable. Furthermore, some variables related to potential weaknesses in the pipe due to manufacture, construction, and operation are currently "inactive" in the algorithm (p. 12) and would not enter into the risk calculation, potentially invalidating the results for segments where these factors are significant and distorting the relative risk ranking of pipeline segments.

Requirement 2.g – "…an operator's risk characterization approach must be designed to:

i. Identify risk contributors that are not readily apparent from operating history;

ii. Lead to better understanding of the nature of the threat; the failure mechanisms; the effectiveness of currently utilized RCMs; and means to prevent, mitigate, or reduce associated risks;

iii. Evaluate the likelihood of failure associated with each individual threat or risk factor, and each unique combination of threats or risk factors that interact at a common location;

iv. Identify and evaluate the contribution to risk from scenarios with the potential to produce exceptionally high consequences, even beyond those experienced to date…"

The algorithm does not meet the requirements stated under "iii" and "iv" above. With respect to "iii" above, the algorithm does not appear to address interactive threats. With respect to "iv", the CoF calculation does not appear to include varying consequence levels, including high-consequence scenarios, except possibly through analysis of the risk from low pressure regulator failure, which seems to require further development in the current version of the algorithm.

Requirement 2.h - "…an operator must characterize the level of uncertainty associated with factors affecting event probability and potential consequences, including uncertainties associated with missing or suspect data…" The model documentation refers to some kind of uncertainty consideration in section 1.3, where "levels of conservatism" are discussed. However, it is not clear how extensive this treatment of uncertainty is and, as discussed below, the way the conservative values are applied may not be appropriate for informing decisions on RCMs. More extensive treatment of uncertainty is necessary, particularly because of the large number of default values used to populate the model and the use of subjective values for key model variables.

Requirement 2.k - "…techniques to estimate probability must include one or more of the following:

i. Use of relevant historical data;

ii. Logic modeling such as fault tree analysis and event tree analysis;

iii. A systematic and structured process for eliciting expert judgment to estimate probabilities of factors contributing to events."

The PG&E model utilizes a large number of assumed default values and a significant number of subjective values to populate the models. These default and assumed values are constant across all pipeline segments. There is no documentation of how these values are derived, so there is no assurance with regard to the model's ability to satisfy criterion "iii" above.

Some additional observations on the model documentation:

i. (p. 5, “Level of Conservatism”). Depending on how the risk model calculations are intended to be applied, it may *not* be appropriate to use “P99” (more conservative, vs. “P50” values) data “for risk management”. If, for example, the risk calculations are intended to be applied to ranking segments for corrective actions, inspections, repair or replacement, then ranking according to P99 may not be optimal for allocating resources to achieve risk reduction. The best approach depends on the potential effect of the uncertainty in the variable values on decisions. It appears to be preferable to perform sensitivity analysis to determine which variables with uncertain data significantly impact decisions to be informed by the risk assessment results. If data collection or other activities to obtain information and reduce uncertainty can be carried out cost effectively, then these activities should be part of continuing model development.

ii. (p. 6, section 2.1). The equation for risk uses a simple product of probability of failure (PoF) and consequences of failure (CoF) as part of equation, implying a uniform level of expected consequences for all threats. Incident data for gas transmission and hazardous liquid pipelines shows varying consequence levels for events related to different threats. In fact, the leak-rate based risk characterization model PG&E used in support of DIMP explicitly considered threat-by-threat variations in anticipated consequences. It would be appropriate to modify the algorithm to reflect a varying consequence profile for different threats.

iii. (p. 33) The CoF population receptors equation is a product of six different factors. The equation appears not to combine variables in consistent units and does not appear to produce a parameter expressed in meaningful units that could be evaluated for risk-informed decision-making. Default constant values are assumed for many of the consequence index variables. There do not seem to be any variables related to operator actions that could be taken to reduce consequences.

Attachment 6 - Evaluation of Activities Presented in PG&E's 2014 GRC Filing

Introduction

This attachment presents the project and cost evaluation of activities described in the PG&E gas distribution 2014 GRC filing. It is structured around the eleven chapters of PG&E-3 and associated working papers. The evaluation has two objectives: first to assess the reasonableness of the approach PG&E has taken to estimating the funding levels for the areas selected for risk reduction, and second to evaluate whether the risk reduction approach appears sufficient in light of what other operators are doing to address similar risks. By necessity many of the judgments expressed in this section are based on the experience of the evaluators rather than on a comprehensive statistical analysis of industry performance and practices.

Chapter 2 – System Operations Gas Control

This chapter addresses the expenses and capital needs projected for the gas distribution control center. Both capital and O&M activities were initiated in 2012. Costs in the 2014 GRC filing are principally for additional personnel to staff the control room, additional personnel for gas engineering to support the gas system, additional expenditures to automate some pressure and flow readings on the gas distribution system (as well as additional expense costs for maintenance of the new system), and contractor costs to assist in maintaining the control instrumentation and IT investment.

PG&E is building a new centralized gas distribution control room which will be adjacent to the dispatch center and the gas transmission control room. Currently the control room operations are spread out in the districts and there is no central location where all of the information from the gas distribution system can be viewed and evaluated. In addition to centralizing the control of the gas distribution system, PG&E is proposing to install additional pressure and control systems in the new control room to be able to monitor and operate the gas distribution system remotely and to be able to prevent or reduce the impacts of - rather than react to - incidents. Besides the added expenses to staff the control room, PG&E plans to add personnel in several gas engineering functions such as gas planning to improve system safety, reduce risk and improve reliability of the gas distribution system. The expense budget is proposed to increase 180% between 2011 and 2014 with the majority of the increase in staffing and operating the new control room and some additions to the engineering staff. The other two components of this cost element, Regulator Operations and Main and Service Operations are projected to increase at less than the anticipated inflation rate from the baseline year (2011) to the initial GRC year (2014).

The capital expenditures for the control room and the associated automatic controls and regulation are significantly higher than past expenditures. In addition to the gas control center/dispatch center, PG&E is forecasting costs for providing a hot backup[23] control center facility including mirror image of data at a remote location (the building costs for the control center and the "hot" back-up are covered in Chapter 12) and the cost of custom software to monitor the system. Projected capital costs for the control room and associated instrumentation are discussed below.

The new control room will have the capacity to monitor 4,300 pressure points (in the baseline year only 900 points are being monitored). In addition to monitoring pressures at regulator stations, the new system will monitor flows and will automate many of the regulator stations so the valves can be repositioned and the settings changed remotely from the control room. Automation will also be increased on all of the hydraulically independent systems (HIS) on the PG&E gas distribution system so that there is at least one remote pressure device on each system. The installation of these pressure and flow monitors will eliminate the need to deploy and maintain 500 manual chart recorders on the system. The new electronic pressure monitors will require additional maintenance. PG&E has estimated that these costs will reach almost $1.1 million per year in 2014 and will increase in subsequent GRC years as a result of installation of additional devices. An additional $0.7 million is being projected for remote terminal units (RTUs) and new flow control devices. At a cost of $160 per man-hour these new maintenance costs equate to approximately seven additional technicians. The staffing of the new control room will also increase the head count with no associated staff reduction in the operating divisions.

PG&E is also increasing the staffing of some support organizations such as gas planning to improve the gas clearance process and provide more timely feedback when emergencies require changes to the configuration of the gas systems (such as shutting emergency valves or sectionalizing/isolating areas due to leaks or natural disasters). Overall the expense costs of setting up a centralized gas distribution control room are significant, and while there should be a noticeable improvement in the timeliness of reaction to system incidents and

[23] The "hot" back-up will be a mirror image (75% of the San Ramon facility with multiple redundant power, data, cooling paths, and redundant components) to be activated when an emergency or major disaster event disrupts or prevents the use of the primary Control Center. Total hot back-up project cost $33.7 million.

emergencies, the goal of preventing such "events[24]" - equipment failures, gas outages and gas releases - will be difficult to attain.

Proposed changes should reduce the risk by allowing the control room staff to identify an incident early, but their ability to diagnose the cause of the problem and react quickly will determine the extent of risk reduction. Overall performance improvements will be affected by the approach PG&E takes to manage the significant increase in number of alarms the control room will receive, and how well their gas operators at the control panels are trained. A complete analysis considering PG&E's past performance would be needed to determine the degree of risk reduction associated with the gas distribution control room. No such comprehensive analysis was presented in the GRC filing.

The new control and related equipment represent significant capital costs. The major costs for this program are associated with installing electronic telemetry and control units at regulator stations, distribution mains and distribution services (for pressure measuring). Additional costs are associated with the software and hardware to integrate the data and display it on the control panel, and to have a hot mirror image at a separate location in the event of a disaster in the control room (the control room will have power from at least two sources and backup generation).

The three largest cost components are regulator station monitoring (pressure and flow) and control (remote controlled valves), regulator station monitoring (pressure and some flow monitoring but no control), and main location pressure monitoring. The number of units to be installed for each component is significant since PG&E is behind other operators in the installation of electronic pressure and flow controls at regulator stations and remote monitoring of low pressure points (and monitoring of their HIS areas). The deployment of these units will begin in 2012 and reach a steady installation rate in 2013 through 2016. PG&E has escalated the cost for equipment and installation using standard escalation factors, but has not taken economies of scale or learning curve efficiencies into account in their estimates.

This is an extremely ambitious program and there are many roadblocks that could delay its completion. of the major potential roadblock is the software needed to integrate all of this data and present it to the control operators in a comprehensible form. Gas system safety should improve and risk should be reduced when the

[24] See definition of "event" contained in footnote 4 on page 2-5 of PG&E Exhibit 3.

control system is completely functional, provided gas controllers have adequate procedures and training to address the expected number of false alarms or alarms that are unrelated to gas system incidents or emergencies.

The cost of this system is very large and the potential reduction in risk, which PG&E did not attempt to characterize, should be commensurate with the cost. Most gas distribution operators have central control rooms for both gas transmission and gas distribution. However, the number of monitoring points that PG&E is proposing will complicate alarm management. Many employees will need to be trained; this training will be critical to achieving the advertised project benefits. Attaining the goal of anticipating and preventing gas incidents or emergencies will depend on integrating a monitoring program with trend analysis to facilitate rapid decision making.

Chapter 3, Gas Distribution Mapping and Records

Summary

The gas distribution mapping function tracks the size, material type, location, configuration, and other essential information used in asset management processes. Accurate, timely, up to date mapping and data management systems are required to support safe and reliable operations including the installation, maintenance, operations, locating, and retirement of gas distribution piping facilities. This data is also critical to risk characterization. As part of the process to separate its Gas Operations from its Electric Operations line of businesses, PG&E will separate the gas distribution mapping and records necessary for management of these assets. As part of this separation process, PG&E will work to ensure consistency of records, records quality, and complete information on gas distribution assets. To maintain up to date mapping and records, PG&E will eliminate the backlog of system mapping field updates, and going forward intends to complete mapping updates within 30 days. To accomplish this work, PG&E expects to use 60 mappers during 2012 and forecasts increasing that number to 85 mappers in 2013 and beyond to collect, scan and archive documents and maps into the enterprise wide gas records center and further support the implementation of Pathfinder, discussed under Chapter 11

PG&E based its mapping resource requirements to accomplish this work on historic work output of its mappers, the nature of the work required of its mappers, the volume of work anticipated, and the labor rates of its mappers and supervision. Forecasts of staffing requirements appear to adequately address the anticipated work. This evaluation determined that the major cost items were reasonable. PG&E has provided justification for the improvements in its approach to gas distribution mapping and records. The approaches PG&E has taken in forecasting the required funding levels to implement the processes affecting mapping and records were reasonable and forecasted expenditures were not grossly overestimated. Alternatives to hiring, developing, and maintaining an in house staff of 85 mappers were not presented.

Discussion and Background

Inadequate mapping and records management appears to be a contributing factor to the San Bruno explosion[25]. Accurate, timely, up to date mapping and data management systems are required to support safe and reliable operations including installing, maintaining, operating, locating, and retiring gas distribution piping facilities. PG&E's 42,000 miles of gas distribution main and 3.3 million gas service lines (serving 4.3 million end user accounts) are depicted on over 21,000 distribution maps.

While PG&E is transitioning to separate its Gas Operations from its Electric Operations line of businesses, it must separate and separately maintain mapping and records necessary for management of these assets. Separating from electric operations will facilitate the needed focus on consistency of records, records quality, and overall knowledge of gas distribution assets.

Mappers update maps and databases whenever facilities in the field are constructed, modified or replaced. This work involves updating the gas and electric mapping system (GEMS), and updating electronic databases including SAP, Asset Register and Tangible Property Listing. Alternatives considered for the approach to this work include centralized scanning and remote local scanning of maps and records. Scanning documents at remote locations was estimated to lead to a prohibitive cost.

PG&E based its mapping resource requirements to accomplish this work on the historic work output of its mappers, the nature of the work required of its mappers, the volumes of work anticipated and the labor rates of

[25]The Independent Review Panel on page 63 of its report stated that having a plan for data management is a requirement of the pipeline integrity management regulations and is essential for assuring integrity threats are addressed. PG&E provided erroneous data because of a lack of: (1) robust data and document information management systems to archive historical data, and (2) processes to capture emerging information about the underground gas system. There is a lack of coordination between field personnel and engineering management regarding which data are to be collected and where and how records are to be preserved.

its mappers and supervision[26]. Forecasts of its resource requirements appear to adequately address the work anticipated.

The Pathfinder project is discussed further in Chapter 11. It includes further development of PG&E's GIS geospatial[27] model that tracks, records and stores all distribution asset data, is intended to enhance the amount, quality and type of information PG&E collects, stores and manages for its gas distribution system and related processes. PG&E expects Pathfinder to improve and expand access to asset data, reduce data entry errors and provide for integrating the data enabling improved analyses within its distribution integrity management program.

The project will support PG&E's efforts to identify high priority work, prioritize and carry out that work to reduce risk to the public. Total 2013-2014 costs of the records collection and mapping update project is $51.7 million.[28] To accomplish this work, PG&E forecasts its 2014 gas distribution mapping expenses to be $16.199 million of which $14.1 million is due to the records collection and scanning project, and $2.099 million is forecast for base mapping expenses.

PG&E is implementing a records quality program to measure the quality of its gas distribution maps. These measures appear to be reasonable for the project undertaken as well as to address the risks of inaccurate maps in the field.

This evaluation determined that the major cost item estimates were reasonable. PG&E has provided justification for the improvements in its approach to gas distribution mapping and records. The approach PG&E has taken in forecasting the required funding levels to implement the processes affecting mapping and records were reasonable and forecasted expenditures were not grossly overestimated.

Degree of Risk and Benefit

Accurate maps and records are critical to many operational functions, as well as fundamental to PG&E's ability to characterize the risk of its system. The risk associated with inaccurate maps and records is expected to be

[26] See Exhibit 3 Chapter 3 pages 3-5 thru 3-8, and Work Papers Exhibit 3 Chapter 3 pages WP 3-5 thru WP 3-19.
[27] PG&E began implementing a base GIS project in 2008 known as its Automated Mapping and Facilities Management (AM/FM) project. In September of 2011, this AM/FM system was integrated in the current GIS/facilities management approach as part of the Pathfinder project.
[28] See WP 3-7 line 22.

high because of its impact on damage prevention. Leaks resulting from excavation damage were shown in PG&E's DIMP analysis to be the greatest contributor to system risk. The safety benefit of having a central repository for accurate up to date maps and records for sharing information with others (e.g., city and county development projects and external agencies), for responding to mark-out requests and providing accurate timely mark-out locations of its gas facilities to help avoid dig-ins and damages to gas lines by construction excavations is high. Benefits also include improved safety by ensuring accurate records for information sharing throughout PG&E, use and analyses by operations during leak surveys and leak repair activities, improved analyses by engineering staff including workforce management, work and asset management, planning and risk assessment and management, minimizing storage requirements and costs, and providing repeatable, defensible records for retrieval and dissemination of recorded information.

Development of a GIS geospatial model to assist in asset management, to track, record and store distribution asset data, material specifications and maintenance/inspection history is an industry best practice. PG&E has recognized that its use of GIS needs to be an enabling technology that provides decision support across the entire asset lifecycle. Achieving an updated mapping cycle time of 30 days or less is also an industry best practice. Adopting such industry methods for centralized records managements is expected to reduce operating costs and provide traceable, verifiable and complete records.

Analysis of alternative approaches to hiring 85 in house mappers, such as contracting out the work, was not provided; nor was a productivity or efficiency factor applied to forecast staffing. PG&E has determined that it will achieve productivity gains without loss of quality after a period of time centralizing and scanning gas distribution documents to its system resulting in a reduction in forecasted expenses for the project[29]. The justification for the need to retain 85 mappers once the backlog is cleared up (to achieve and maintain a 30 day mapping update cycle, as well as support GIS updates and requests for information) is unclear. Retaining a workforce of 85 mappers to support a 30 day mapping update cycle as well as to support the Pathfinder project requires additional justification. PG&E asserts that efficiencies associated with Pathfinder will be offset by an increase in data collection and accuracy requirements.[30] No analysis backs up this assertion. The costs associated with hiring 85 mappers should be attached to a two-way balancing account to ensure the funds are expended for this purpose.

[29] GRC2014-Ph-I_DR_Cycla_013-Q03.
[30] See footnote 12 on page 3-17 of exhibit 3.

Conclusion and Recommendation

Accurate, timely, up to mapping and data management systems are required to support safe and reliable operations. Accurate data are also fundamental to risk characterization.

The need to maintain a central repository of accurate up to date records and maps to support gas distribution asset management is sufficient to justify the project. Reduced system risks, especially associated with accurate mark-outs to avoid third party damages, and improve engineering data for various analyses, provide further justification.

The need for PG&E to separate its gas and electric distribution mapping and records is justified and necessary for management of these assets. This separation will provide needed focus on consistency of records, records quality, and overall knowledge of gas distribution assets.

PG&E will eliminate the backlog of system mapping field updates and intends to complete mapping updating within 30 days. To accomplish this work, PG&E expects to use 60 mappers during 2012 and forecasts increasing that number to 85 mappers in 2013 and beyond.

This evaluation determined that the major cost items were reasonable. PG&E has provided justification for the improvements in its approach to gas distribution mapping and records.

PG&E based its mapping staff requirements to accomplish this work on its historic work output of its mappers, the nature of the work required of its mappers, the volumes of work anticipated and labor rates of its mappers and supervision. Forecasts of its staffing requirements appear to adequately address the proposed work. The approach PG&E has taken in forecasting the required funding levels to implement the processes affecting mapping and records were reasonable and forecasted expenditures were not grossly overestimated.

Alternatives to hiring, developing, and maintaining an in house staff of 85 mappers were not presented.

The forecasted expense associated with retaining 85 mappers to maintain a 30 day mapping update cycle in addition to the work involved to support the Pathfinder project needs further justification. The costs associated with hiring 85 mappers should be attached to a two-way balancing account to ensure the funds are expended for this purpose.

Chapter 4, Gas Distribution Integrity Management Program

Summary

We have evaluated PG&E's gas DIMP as presented in PG&E's GRC filing Exhibit 3 Chapter 4. PG&E's DIMP program is intended to comply with USDOT regulations contained in Subpart P of Chapter 49 of the code of Federal Regulations Part 192 (49CFR192) published in the Federal Register December 4, 2009. PG&E forecasts expenses for its DIMP program to be $47.3 million in 2014, $22.6 million higher than PG&E's 2011 recorded amount of $24.7 million, a 91.5% increase in expense related expenditures.[31] As described here, these costs include some but not all costs associated with the RCMs identified as needed by the DIMP. Costs of other safety improvements are presented in Chapters 2, 3, 4, 6, 7, 8 and 11. The major costs described in this chapter include: additional staffing for the DIMP effort, the Cross-Bored Sewer project, and emergent work designed to ensure stable pressures in PG&E's low pressure distribution system. PG&E has provided justification for the improvements in its integrity management approach. The approach PG&E took to estimating required funding levels for the identified risk reduction measures was reasonable, and forecasted expenditures were not grossly overestimated.

PG&E is in the process of upgrading its risk management program[32] and is moving toward use of risk-informed asset management process. PG&E is planning further development of a new probabilistic risk algorithm, which is expected to utilize Pathfinder's upgraded mapping and databases. Continued development of PG&E's probabilistic risk algorithm is intended to strengthen the justification for implementation of its risk management activities. The 2015 date would include testing and proving related processes[33].

Other specific risk-mitigating activities addressed by DIMP and described in this and other chapters include those focused on: reducing the risk of damage to its lines by improving accuracy of and response to locate and mark out requests by contractors; working with contractors to improve their requests for mark outs before they dig; reducing damage due to 3rd party construction and boring practices by implementing its Cross-Bored Sewer

[31] See Exhibit 3, chapter 4 page 4-1.
[32] See Exhibit 1, chapter 4, page 4-1.
[33] Interview with PG&E Christine Cowsert 2-25-2013.

project; increasing leak surveys along with using more sensitive leak detection equipment; reducing emergency response time to leaks and repairing leaks sooner; repairing plastic tee caps; evaluating effectiveness of corrosion mitigation; and the hiring of integrity management program staff to support continued DIMP program development.

PG&E's proposed actions under its DIMP program appear reasonable, focusing activities on its highest risks. Risk-reduction benefits of mitigation measures have not typically been quantified, nor have alternative measures always been identified or evaluated. Comparisons with industry implemented best practices have been used as justification for many risk reduction activities. Within the scope of this review, no additional risks were identified that PG&E needs to address.

Discussion and Background

PG&E is in the process of upgrading its Risk Management Program. As part of this effort, PG&E is adopting what it identifies as industry-leading practices in response to recommendations and new requirements imposed following the San Bruno explosion, including the report of the Independent Review Panel (IRP) Report which addressed risk management and identified areas for improvement, and Senate Bill 705 that proposed Section 963 (c) in the Public Utilities Code. In its GRC filing, PG&E has identified mitigation activities to address significant risks.

PG&E has provided justification for the improvements in its integrity management approach; overall the approaches PG&E took for estimating required funding levels for the identified risk reduction measures were reasonable and forecasted expenditures were not grossly overestimated.

The work to be accomplished and the costs to accomplish that work are discussed in work papers supporting Chapter 4. Some program cost estimates have greater detail than others, such as the Cross-Bored Sewer project and the plastic service tee cap repairs. Some program costs have too little detail to judge their adequacy or whether the forecasted expenses represent over-estimates, such as the corrosion mitigation and related studies, and other emergent work projects. Additionally, for some programs it is not possible to determine, based on PG&E's current justification, what level of activity is appropriate to achieve performance consistent with top performers in the distribution pipeline industry.

PG&E's Distribution Integrity Management Program Plan

RMP-15 Revision 2 summarizes PG&E's current approach to distribution integrity management. PG&E has identified threats and used a model that applied five years of leak repair data to characterize the relative risk associated with these threats. Risk reduction measures are proposed to address those integrity risks within this GRC filing.

PG&E's current approach to risk characterization does not support evaluation of: the relative priority of the individual control measures, the relationship between the costs of control measures and risks being controlled, and the level of risk reduction expected from the proposed control measures. PG&E is still in the process of developing a comprehensive risk informed decision support tool. PG&E's target date for implementing its probabilistic risk algorithm is 2015. The tool would utilize Pathfinder's upgraded mapping and databases.

PG&E plans to increase the number of employees from 9 to 20 working on its distribution integrity management program. The increase in the number of personnel appears reasonable[34] and adequate to accomplish identified activities.

DIMP-Related Risk Reduction Activities

Several activities designed to lower PG&E system risk, by improving system integrity, are described in other chapters. A major example is the PG&E pipe replacement program, addressed in Chapter 8. PG&E will continue to eliminate materials with the highest leak rates by replacing its cast iron mains, its older steel mains and service lines, and its copper service lines. PG&E will also focus its replacement actions on first generation plastic mains, its oldest Aldyl "A" plastic pipe. Through this replacement programs, PG&E expects to lower the leak rate of its highest leaking mains and service lines to its system average of leak rate 0.16 per mile. This leak rate is in the 3rd quartile of comparable gas distribution companies. Pipe replacement alone will not lead to performance in the top quartile of distribution operators, so PG&E has planned additional actions.

The safety code requires periodic leak surveys. At a minimum, leak surveys of the gas distribution system are required every 5 years. PG&E has proposed to increase the leak survey frequency from once every five years

[34] See WP supporting the increase in DIMP employees, exhibit 3 Chapter 4 page WP 4-20 thru WP 4-22.

to once every three years[35], and to reduce the time after discovery until leaks are repaired. PG&E has also proposed increasing the sensitivity of the leak detection instruments used in those surveys by deploying a new leak survey technology called the Picarro surveyor. These actions are discussed in more detail in Chapter 6. PG&E further proposes reducing the time it takes to respond to reports of leaks (emergency response time) as well as to repair leaks more quickly than they have in the past.

Reducing the risk from system leaks does not necessarily require implementation of all of the risk reduction measures PG&E has proposed. PG&E might consider deploying these risk reduction measures in stages to support determination of the best and most cost-effective approach to reduce risks.

Damage caused by excavation activities represents the largest risk to PG&E's gas distribution system. PG&E proposes damage prevention activities to reduce damage to its lines by: eliminating lines that intersect with sewer lines via its Cross-Bored Sewer project; increasing the effectiveness of its response to pipeline locate requests; and encouraging contractors to call for a mark-out well in advance of their excavations. Accurate up to date records for facilities, which are critical to reducing excavation damage, will be provided through the Pathfinder project.

Prolonging the life of steel facilities by effective cathodic protection of steel mains and service lines is an important aspect of reducing the risk from external corrosion leaks. PG&E has proposed additional activities to monitor and evaluate the effectiveness of cathodic protection. PG&E's proposed efforts in this area are reasonable and funding levels appear adequate.

Ensuring pressure levels are properly controlled by PG&E's district regulators is an activity identified under the emergent work category of risks as needing to be addressed. Specifically, PG&E proposes reducing the water impacts on its vulnerable district regulator stations to ensure stable pressures in its low pressure distribution systems. This risk reduction program and forecast expenses appears reasonable to address the associated risks identified in the GRC filing.

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[35] PG&E will continue to conduct annual leak surveys of its business districts (more congested areas and areas with wall to wall paving), as well as

Chapter 5 – Pipe, Meter, and Other Preventive Maintenance (PM)

Introduction

This chapter addresses maintenance expenses. The cost components treated in the chapter are activities associated with locate and mark, cathodic protection, protecting meter locations (which includes some capital), other preventive maintenance (which includes several components), and maintenance of natural gas vehicle (NGV) facilities.

The principle cost elements described in this chapter are locate and mark, cathodic protection, and other preventive maintenance. Meter protection and inspection and energy efficiency represent minor contributors to cost.

Major Program Elements

One of the larger contributors to the expenses in this chapter is "locate and mark". This element, designed to reduce excavation damage to facilities, covers the costs for locating and marking PG&E facilities and thus also includes electric and gas transmission. Per the work papers and budgets, electric locate and mark costs range between 61% and 49% of the total[36]. The gas distribution line of business costs are roughly $12.4 million in 2011 and $21.3 million in 2014[37]. Responsibilities for locate and mark are integrated across two lines of business, so cost transfers from the gas distribution rate payers to electric and gas transmission rate payers must be accurate and timely. The costs declined from 2008 to 2011 and then are projected to increase (mainly due to increasing requests resulting from a recovering economy). The rise in activity from 2011 to 2014 is projected to result in a 31% increase in the number of locate and mark requests which results from additional construction and infrastructure spending. PG&E's 2011 cost of providing this mandated service was $82.65 per worked locate and is projected to increase to $89.00 in 2014. In 2011 hosting fees are included in this work category but are taken out prior to 2014 and moved into another account.

[36] This percentage may be in error because it does not appear that benefit costs or payroll tax costs are apportioned between the two lines of business but may fully reside in the Gas Distribution budget.
[37] Includes unallocated benefits and payroll taxes for the program (WP5-9).

The largest driver for the increased overall cost is that the projected number of locates to be worked[38] are 412,992 in 2014 as compared with an actual 313,557 in 2011. PG&E has stated that they intend to complete all locate and mark requests with an on time percentage of 99.4% which they believe is an industry best practice (on time performance in 2011 was 98.9%). Dig-ins is a major cause of gas leaks and failures and has several different causes. One cause is not having a timely locate and mark which PG&E is addressing by improving upon their timeliness of responding to requests. Another cause is having obsolete and out of date maps used by the locating personnel; PG&E is attempting to improve on this (see write up for Chapters 3 and 11 for specific changes being implemented). Another cause is an excavator not requesting a locate and mark and this is also being addressed via excavator education and possible regulatory action. PG&E is attempting to reduce this risk by improving the timeliness of the locate and mark activity, having up to date and accurate maps for the locators to use and continuing excavator education.

The only comment on this cost element is that the projected increase in construction and infrastructure activity is very uncertain.

The cathodic protection (CP) element of the maintenance expense budget is a mandated safety program designed to reduce the number of corrosion-related failures on steel mains and services. The requirements include providing sufficient protection to these facilities and periodically monitoring them on a proscribed minimum period. For mains under impressed current rectifiers, readings must be taken six times per year with a period of no longer than 75 days. For sacrificial anode protected facilities, the readings must be taken once per year with a period of no longer than 15 months. For short independently protected sections (both mains and services) readings must be taken once every 10 years. For above ground facilities, inspections for atmospheric corrosion must be done once every 3 years. When a facility is found to be out of compliance, federal regulations specify that compliance should be restored as soon as possible, but no longer than before the next reading (which has been interpreted as 12 months).

Even with the addition of inflation, the estimated cost of monitoring the CP systems installed is projected to drop from 2011 to 2014. The cost of taking each reading is estimated to increase from $57 per reading to $63 per reading. The number of readings is projected to decrease from 62,528 (2011) to 39,555 (2014) because of the remote monitoring program. The cost per reading is a blended number consisting of bi-monthly rectifier

[38] A worked locate and mark is one that an individual does the function in the field; some recorded requests are canceled or are duplicates or may be for locations where there are no gas facilities present per system maps.

readings, annual readings and readings from isolated facilities (10% of which are required to have readings in any given year). Although not mentioned, the drop in CP reading could also be a result of replacing some pre-1940 steel with plastic or steel that only requires annual readings or increasing use of remote monitoring. The cost of $57 per reading seems reasonable.

The second component of the CP expense element is CP trouble shooting which is projected to increase as a result of inflation and number of units. The average trouble shooting cost in 2011 was $1,323 (3,494 jobs) and is projected to be $1,435 (4,594 jobs) in 2014. The increase in jobs is based on a faster response to out of compliance readings since many systems will have remote monitors installed. The cost and the escalation seem reasonable. Responding more quickly to out of compliance readings should reduce the risk and improve gas system safety since there should be less time for corrosion to reduce the wall thickness of these steel mains and services.

Rectifier maintenance activity appears to be unchanged during the period of 2012 through 2014. Prior to 2012, this item was included in the CP monitor account and thus was not tracked independently. Where a major overhaul of a rectifier system is needed, it is typically capitalized (see the CP element in Chapter 8). No data was provided for 2011 but for 2012 the unit cost per rectifier maintenance visit was $155 (and based on costs of $0.686 million, there were 4,426 units. For 2014 the unit cost used the inflation factors to yield $164 per unit and the number of units remained the same. These costs appear to be reasonable but the constant number of rectifiers being maintained initially seems inappropriate. Over time because of the capital program to rehabilitate failing systems, the number of rectifiers needing maintenance should decrease.

PG&E stated that they resurvey CP systems having out of compliance readings and that these resurveys can be short, modified short or a full resurvey. In 2011 PG&E resurveyed 527 systems at a unit cost of $3,557 and project resurveying 502 systems at a unit cost of $3,859 in 2014. This yields an identical cost for both years of $1.9 million. PG&E states that they intend to resurvey each system at least once every six years. Again, this activity should help reduce the risk of external corrosion since noncompliant readings should be discovered and remediated.

The isolated service program, a CPUC mandated program, is being accelerated to be completed in 2013 prior to the start of the GRC period. This program involves examination of isolated service risers and repair or replacement as appropriate to reduce the likelihood of corrosion leaks. The program involves installation of a small sacrificial anode to protect the riser if it is not being cathodically protected. This will reduce the risk of a leak and thus improve gas system safety. Since these leaks are typically next to houses, accelerating the schedule seems appropriate from a risk reduction standpoint.

The last maintenance expense element is called Preventive Maintenance. It has several components: 1) gas mains; 2) regulator stations; 3) services; 4) main valves, 5) service valves; 6) special projects; 7) atmospheric corrosion; and 8) other or miscellaneous. Expenditures for a few of these components appear to be fairly steady. Service valve costs peaks in 2013 but then resume a slower growth in 2014. Other/Miscellaneous almost quadruples in 2013 and remains at that rate in 2014. Special projects and atmospheric corrosion also increase significantly between 2011 and 2014 but each of these costs is fairly small when compared to the entire expense budget for 2014. As a whole, this component of the expense budget does increase by slightly more than 70% but the additional costs are relatively small compared to the total expense budget.

Main preventative maintenance (PM) includes painting and repairing of above ground mains, repairs (excluding leak repairs) to all mains, patrolling of mains, and other miscellaneous non capital repair work to existing mains. PG&E projected 2,186 main PM jobs for the period and has escalated the $606 per job by their standard factors between 2011 and 2014. These are intended to locate and fix problems and therefore contribute to risk reduction.

PG&E's regulator preventive maintenance includes the yearly external inspection and the maximum of once every eight years internal inspection of all district regulators. Federal and State regulations require that operators inspect district regulators yearly and many operators do external and running tests and internal inspections on a frequent basis. A best practice is to have a shorter maximum time between internal inspections (which include installing new internal parts such as diaphragms and gaskets every two years); some operators use maintenance records to predict the time to failure and schedule inspections before that time. PG&E has estimated the cost of doing regulator PM as $1,606 in 2011 based on actual costs of doing 3,774 stations. In the period between 2011 and 2014 the costs are being escalated using the PG&E normal escalation factors while the units drop to 3,725. The cost seems high especially since most regulator PM does not include an internal inspection (no break down between internal and external inspections or the percentage of internal inspections was given in the work papers). By increasing the frequency of its internal inspections PG&E should be able to reduce the risk of an over pressure event. Considering the over pressure problems that PG&E has experienced, reviewing their regulator maintenance program seems appropriate.

Similar to the main PM, the service PM program is used to make non capital repairs on service lines (except for service valves which have a separate program). PG&E anticipates slightly less than 1,500 to slightly less than 1,650 services needing maintenance at a cost of slightly more than $1,600 to $1,900 each in the years after 2011. It is impossible to determine if this is a reasonable cost since the "maintenance" can be one of any number of things that may range from minor PM to partially rebuilding of the service.

Main valves are required to be periodically operated if they are needed to shut down an area during an emergency. PG&E has a capital program to replace and add new main valves; this expense program is for minor maintenance such as greasing the valve, cleaning out the valve box and operating the valve (as required by regulation). Per PG&E the number of valves needing PM in 2011 was historically low at approximately 6,000 and they are anticipating 7,000 valves needing PM in the years 2012 through and including 2014. The cost of doing this maintenance is initially slightly more than $200 each and is inflated using the standard factors over the period to a cost of $224. This cost seems reasonable. As in other situations, since this PM is "as needed", there should be no change in the risk.

The service valve PM program is designed to remediate leaking and inoperative service valves to a fully operational state without any leaks. In 2011 PG&E believes that less than a normal number of valves were identified as needing maintenance, so for 2012 through 2014 they have added 500 valves bringing the total to slightly more than 9,300. The cost per valve was slightly more than $200 each and is inflated over the period. This seems like a reasonable cost but it does depend on what specific actions are being taken for each valve: greasing, core replacement, or a total replacement of the valve. Increasing the number of valves being maintained should lower risk.

PG&E is estimating that Special Projects will increase by 11 times from less than $0.4 million per year to over $4 million per year. This account is used for any non DIMP maintenance that is identified. Some examples that PG&E has listed are regulator vault lids, replacement of small non-capitalized regulators, pumping water out of vaults after heavy rains, and the costs associated with uprating MAOP.

The Atmospheric Corrosion (ATM C) component will change once the Picarro leak surveyor is fully deployed since the leak survey personnel will not be available to do atmospheric corrosion inspections on meter sets and piping. This will require a new group to be used for this maintenance. The costs of this component are anticipated to increase from $1.5 million to $4.7 million between 2011 and 2014. Doing ATM C inspections every three years is a regulatory requirement. No decrease in the risk or improvement in gas system safety will result from this change. The ATM C has changed in that a dedicated group is being used to paint and maintain facilities subject to ATM C. The costs of the new ATM C program seem high and having a dedicated group do the work may not be as cost effective as having other groups assigned the work especially if they are nearby or doing the inspections. Additional work that remediates ATM C will reduce the risk of a failure thereby increasing gas system safety.

Minor Cost Contributors (Meter Protection and Inspection, NGV Maintenance)

The two minor cost contributors are meter protection and inspection which concerns installing meter barriers to prevent vehicles from damaging gas meters, and managing energy efficiency includes NGV maintenance. The meter protection program was started as part of an agreement with the CPUC to correct deficient conditions on the system by protecting gas meters from damage. Originally the program was to be completed in 2016 but PG&E is speeding up the program to have it completed in 2013 so it will not be a factor in the GRC period. The costs between 2011 and 2014 while significantly increased are still relatively small.

The second minor contributor is called NGV maintenance in some areas and 'managing energy efficiency' in other areas but is concerned with the maintenance of PG&E's natural gas filling stations for company vehicles. Estimates were developed by the engineering group and are based on their best judgments. The costs increase by 26% but the overall impact on costs is relatively minor between the test year and the GRC period. Although not stated in the work papers, some of the cost increase must result from capital expenditures to upgrade and modernize existing facilities (see Chapter 8, Capital). There is essentially no risk reduction since this activity is focused on emergency efficiency.

Chapter 6 – Leak Survey and Repair

Introduction

This chapter describes the expenses to perform the mandated and enhanced leak survey and repair operations on the gas distribution system. The PG&E leak survey has been undergoing continual change prior to GRC period therefore no valid baseline exists. In the late 2000's there were issues[39] with the quality of the leak surveys being performed and the entire system was resurveyed after individuals were qualified using new and more effective training methods. Then PG&E decided to reduce the time between surveys from 5 years in non-business districts to 3 years so that leak survey personnel could perform atmospheric corrosion inspections on meter sets and above ground piping when doing leak surveys. The new Picarro leak surveyor, which is being introduced, will allow mobile leak survey rather than walking survey for services and mains. This new technology is being phased in system-wide after initial trials. PG&E is also changing some of the criteria they use for leak repairs, such as repairing above ground non dangerous Grade 3 leaks within 15 months (currently these leaks do not have to repaired but do have to be periodically resurveyed). PG&E is also moving the repair period for Grade 2 leaks to 15 months from 18 months, and recheck below-ground Grade 3 leaks every 15 months rather than every 5 years.

The increase in leak survey costs from the baseline year to the start of GRC period is almost 140%. The first element of the leak expense is leak survey. The cost of leak survey is only a smaller component of the total leak management cost. The majority of this cost is for leak grading and repair. The split in 2014 between survey and repair is projected to be 25% to 75%. In earlier years the survey costs were relatively higher. The reason for this shift is that PG&E anticipates that the mobile Picarro surveyor will be more efficient and will identify more leaks, and that PG&E will begin repairing Grade 3 above-ground leaks within 15 months rather than resurveying every 5 years.

The major cost components of the leak survey element are: 1) leak survey; 2) special leak survey; 3) downgrade with no repair; 4) rechecks; 5) customer calls; and 6) other or miscellaneous. Between the baseline year of 2011 and the start of the GRC in 2014, survey expenses are projected to increase from slightly less than $20 million to almost $34 million or a 71% increase.

Among these elements, the largest cost is the survey itself. Between 2011 and 2013 most costs are unchanged but are projected to increase significantly beginning in 2014. Leak survey costs are projected to increase by 56% and recheck costs by 37%. Recheck costs are driven by the length of time it takes to repair certain Grade 2 leaks or in the case of Grade 3 leaks, the time before the main is replaced or the leak degrades until it must be

[39] There were concerns regarding the classification of the type of leak and urgency for repairs.

repaired[40]. The cost for leak survey is expected to decrease in the final years of GRC period due to the new technology but these decreases are projected to be offsets by other proposed changes. These offsets result from more Grade 2 and Grade 3 leaks being identified, having another organization carry out the 3 year atmospheric corrosion inspections of meter sets and above grade piping, and the need to do more rechecks due to increased population of Grade 3 leaks. Normal survey costs in both the baseline period and the first year of the GRC period are slightly greater than $15 per service surveyed[41]. The major projected changes result from changing to 3 year leak survey cycle from a 5 year cycle. Costs for resurvey of over $200 per service are projected to increase over the period covered by the GRC.

As described above, PG&E proposes to implement several changes in leak management that will reduce risk and improve gas system safety. PG&E has not attempted to estimate the impact on risk resulting from more frequent survey of below ground Grade 3 leaks. It would be useful to compare the costs and risk impacts from increased survey frequency of below ground Grade 3 leaks with those resulting from decreasing the time for repairs of all Grade 2 leaks to less than the 6 month recheck period. Grade 3 leaks are not hazardous and their rate of transition to hazardous leaks would be expected to be much lower than for Grade 2 leaks.

Leak repair costs are dependent on how many and what grade of leaks are discovered during leak surveys, or are reported to the company by employees, the general public or public officials. The components of the leak repair element are: 1) regulator station leaks; 2) main valve leaks; 3) main leaks; 4) above ground service leaks; 5) cathodic protection repairs; 6) main dig ins; 7) service dig ins; 8) over build (non-capital); 9) below ground service leaks; and 10) other/miscellaneous. The largest estimated changes between the baseline year of 2011 and the GRC year of 2014 are in main leaks and below ground service leaks of 230% and over 4,000%.

Since these costs are difficult to characterize, PG&E has proposed a one way balancing account which would refund unexpended funds to the rate payers in the subsequent year.

[40] Grade 1 leaks are deemed hazardous and dangerous and must be repaired immediately; Grade 2 and 2+ leaks are not currently hazardous or dangerous but could become so and usually must be repaired within a certain time frame which PG&E has moved to 15 months; and Grade 3 leaks are not hazardous or dangerous and are not believed to ever become so and thus do not have to be repaired but do have to be rechecked on a very long schedule (5 years in CA but PG&E is reducing this time to 15 months for below grade leaks and repairing above ground Grade 3 leaks in 15 months).

[41] PG&E instituted this metric to better track productivity and to be able to show the results in a meaningful manner to the survey personnel.

General Comment

Other than preventing leaks in the first place, it would seem that the greatest impact on leak-related risk would come from repairing Grade 2 leaks as quickly as possible[42] and then repairing Grade 3 leaks. However, given the range of leak management strategies available, it would seem that identifying and evaluating various strategies from a cost and risk reduction perspective would be an essential step in changing strategies. While PG&E has yet to develop a quantitative risk assessment tool, it would seem that this evaluation could be done, using leaks identified and repaired as a proxy for risk, with available tools PG&E has developed to estimate changes in the number of leaks requiring repair. PG&E has reported some initial risk reduction analyses associated with phasing in use of the Picarro leak detection instrument[43].

Chapter 7 – Field Services and Response

This chapter addresses the expenses of gas field service staff and first responders to incidents or odor complaints. The gas service representatives (GSR) respond to various customer demand work including odor complaints, relighting appliances, meter and regulator changes, and gas turn-ons and turn-offs. They can also perform atmospheric corrosion remediation and service regulator leak repairs.

PG&E has recognized that response by GSR members can greatly affect the safety of its gas system. As part of their objective to achieve performance in the top quartile of the industry, they have proposed that GSR staff respond to 99% of the immediate odor complaints in 60 minutes and respond to 75% in 30 minutes. Starting in 2014 they also will also classify all odor complaints as requiring an immediate response. To achieve these objectives, PG&E has proposed to increase the number of GSR's by over 120 between 2012 and 2014. PG&E asserts that they currently use the best practices of automated dispatch, GPS in the vehicles, and round the clock shifts to minimize the time to respond to an odor complaint. PG&E has also relocated its GRC staff to reduce time to respond to its customers. Other best performing operators are improving responsiveness to customer odor complaints with minimal impact on cost by several means including: using split shifts (shifts that may start late and overlap with another shift), changing the manpower levels on shifts with the seasons based on odor

[42] Grade 1 leaks, by regulation, must be repaired immediately.
[43] See PG&E data response to DR_Cycla_014-Q07, and its Leak Repair and Forecast Model response to Cycla_013-Q21.

complaint reports, and crossing district boundaries to have the closest GSR respond. PG&E has begun implementing some of these approaches[44].

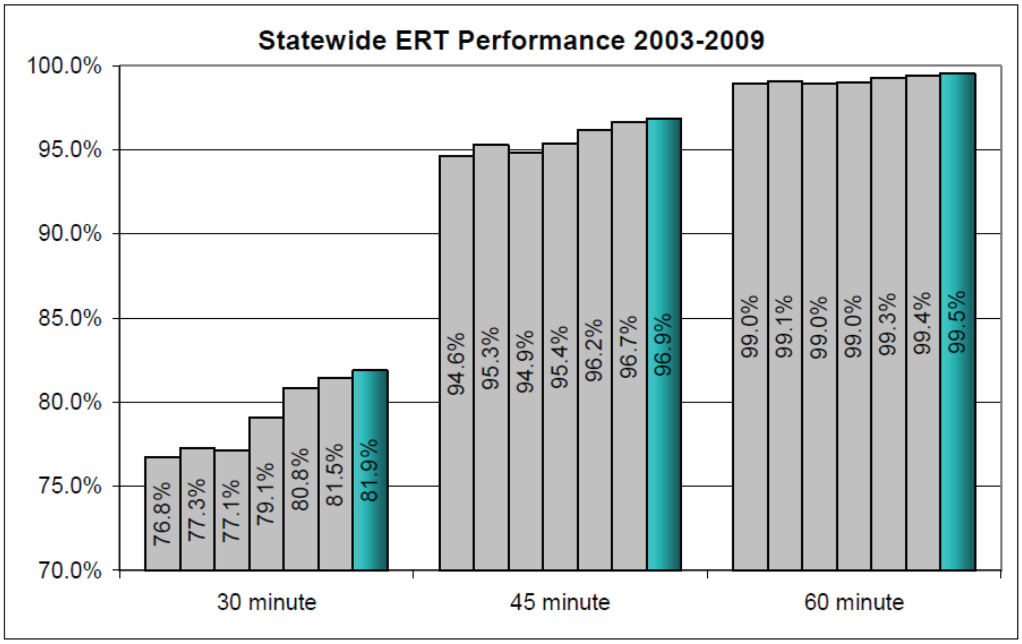
Based on PG&E's average cost of $200K per year per employee, the additional GSR costs for 2012 will be $8 million per year and in 2014 will be $24 million per year. This cost is a large percentage of the almost 50% increase in the Field Services expense costs between the baseline year of 2011 and the first year of the GRC of 2014.

Based on industry experience, the risk of an incident will decrease and gas system safety will improve as a result of improving response times to odor complaints, treating all odor complaints as requiring immediate response, and completing minor repairs on gas facilities located at the customer's location (atmospheric corrosion remediation and above grade leak repairs). The goals that PG&E has proposed are typical of those in other states and are considered industry best practice. Some states apply a penalty to the rate of return for operators that miss their respective goals and some others offer a bonus for performance exceeding the goal.

Data from all of the operators in New York State for 2009 are presented in the figure below[45]. The operators in NY range from highly urban utilities in New York City to rural small operators along the Canadian border. NY operators have minimized the need for additional GSR personnel to meet their targets by use of cost effective methods such as cross training and split shifts.

[44] See Exhibit 3 chapter 7, page 7-18.; and GRC2014-Ph-I_DR_Cycla_013-Q03Atch01.
[45] Data are contained in the 2009 annual report of the New York PSC.

Figure 6-1 Statewide Emergency Response Time (ERT) Performance 2003-2009



The percentage increase between the baseline year 2011 and the start of the GRC period, 2014, is approximately 38% with the largest percentage increases in gas cut-off (stop) work ($3.1 million to $10.5 million). Gas leak and emergency (odor complaints) costs are also projected to increase by $7 million in the period and pilot relight work also increases by slightly less than $6 million. The other/misc. account goes to zero from a credit of slightly less than $5 million in 2011. The cost per unit for each of the cost components addressed in this chapter escalated considerably between 2010 and 2011 while the number of units did not change drastically. These changes seem to imply that inefficiencies associated with adding personnel in 2011 may have occurred. Between 2011 and 2014 the number of units of work remains constant except for gas turn-off (stop) which climbs from just over 41K to just over 116K. Unit costs generally track the stated inflation rate but there is an increase above the inflation rate between 2013 and 2014.

Based on the data from the NYS Public Service Commission, meeting the 2014 goals will just improve PG&E performance to a level where the NY operators were in 2003.

An expense-related activity of the GSRs is minor non-capital repair work on meters and meter piping when they are at a customer location. The backlog of work is projected to be reduced between 2012 and 2014 leading to the expenses being reduced. For both of these programs the reduction in units is almost 50% and cost per unit is changed based on the inflation factor PG&E is using. Reducing the backlog will reduce the risk and improve gas system safety since potential problems are being eliminated.

Another activity of the Field Services organization is selected capital work. This work typically consists of replacing service regulators on residential and commercial customers. PG&E has started a new regulator replacement program in 2012 and thus the units being replaced are projected to increase over the period prior to the GRC years. The program is anticipated to continue through the GRC years and consists of replacing residential and commercial regulators and non- internal relief valve (IRV) commercial regulators.

The cost for a residential regulator replacement in 2011 was a blended cost with commercial regulators so no determination of units and cost per unit can be made. Starting in 2012 PG&E estimates the cost to replace a residential regulator at $182 and inflates this cost though the GRC period. This cost does not seem to consider that many of these replacements could be done when a GSR is at the location to address another issue. Starting in 2012 PG&E is going to replace non-IRV commercial regulators at a cost of nearly $700 each (regulator costs are charged to another account and are not included in these numbers for both commercial and residential regulators). The number of program units in 2013 jumps from 2,924 (in 2012) to 20,000 and remains at that rate throughout the GRC period. Unit costs are adjusted each year for the inflation factor, and no efficiency factor is applied when the replacement rates increases. It seems that efficiencies will be introduced as the GSR staff identifies ways to save time as the volume of replacements increases from less than 3K to 20K.

Chapter 8 – Capital Program

PG&E is proposing a significant (240%) increase in the capital program between the test year 2011 and the GRC years 2014 through 2016. The three principle drivers for the cost increase are pipe replacement, gas distribution reliability improvements and high pressure (HP) regulator replacement. All three of these cost drivers have elements designed to reduce risk.

PG&E's capital program was running between $100 million and $150 million until 2011. PG&E has proposed to increase the spending on replacing not only leak prone piping but also related services, poorly performing regulators, and adding mains for reinforcement and reliability. Capital spending is projected to increase for each of these programs. PG&E has separated the gas distribution capital program into seven major categories: tools; distribution main replacement; distribution replacement or convert customer HP regulators; NGV infrastructure;

distribution capacity improvement; distribution reliability improvement; and distribution leak and emergency replacement.

The pipe replacement program is increasing from a 30 mile per year rate to a 180 mile per year rate. Of this, the major replacement component will be poorly performing (leaking and rupturing) pre 1973 Aldyl-A plastic pipe (~100 miles per year). The second component is pre-1940 steel mains (60 miles per year) and the remaining 20 miles per year will result from emergency jobs and other replacements as needed. Even with this significant increase in pipe replacement, PG&E will take at least 15 years to remove all of the poorly performing pipe materials from its system. The two identified materials in addition to cast iron (which should be totally removed prior to 2014) have the highest leak rates among PG&E's main materials.

Minor Contributors to the Capital Program

Capital Tools and Equipment, NGV Station Infrastructure, and Distribution Capacity - The increase in capital tool and equipment costs in 2012 is to equip the new GSRs with the latest leak detection equipment; the increase in 2013 is to provide sufficient vehicles for the new capital and expense work on the distribution system. These increases are not projected to continue into the GRC years being evaluated and the rate of spending is anticipated to be at a new normal, but higher than the level prior 2011.

The capital spending for Natural Gas Vehicle (NGV) station infrastructure remains level throughout the entire 10 year period ending in 2016. The largest contributor in this category in the GRC years is compressor refurbishing to keep the facilities up to date and compatible with the new NGV technologies.

Gas distribution capacity addition is also at a level spending rate from 2010 through the GRC period. This component is driven by additions to the gas system and increases forecast by the marketing group. Included in this category are mains and regulator stations. Of note is that the cost per foot in 2011 was $163 which was increased to $250 (and subsequently inflated) in 2012 and all future years. No justification for this increase was provided other than the volume of main installation decreased from 2010. For the cost estimation of regulator stations, the unit cost was reduced from nearly $900K each in 2011 to near $500K each in 2012. The number of stations estimated for each year has a small variation but it is not significant when compared to the entire capital program for the GRC years.

The effect of this spending increase for capital tools and NGV facilities on reducing risk is minor, however, it will facilitate some of the capital and expense related work needed to improve the overall gas system safety. The state and federal governmental bodies have made reducing vehicle emissions and promoting energy independence a priority and thus natural gas vehicles are the preferred method of transport and having sufficient up to date refueling facilities is a priority. This is a national trend and many states mandate the use of NGV type vehicles wherever possible and practical.

Major Contributors to the Capital Plan

Distribution Pipeline Replacement Program - The Gas Distribution Pipeline Replacement Program (GPRP) has several major components which are: 1) cast iron and pre-1940 steel main replacement; 2) copper service replacements; and 3) pre-1973 Aldyl-A plastic main replacement. The mileage of main replaced under GPRC and plastic components of this program are projected to rise from 30 miles per year to 160 miles per year (20 additional miles will be from a multitude of other programs including emergency replacements, leak replacements, work for others).

Very modest economies of scale are projected for the steel pipe replacement program, except for 8.5% in 2012. This is contrary to what other operators have experienced when they have ramped up a multiyear replacement program. For the plastic replacement program there is a reduction in price per foot when the rate goes from less than a mile to 50 miles but no additional reductions are projected to result from doubling the replacement rate to 100 miles per year for multiple years. Again the modest impact of economies of scale is unexpected, so the estimates for the cost per foot seem high. The table below[46] presents some actual and estimated costs for replacement costs in east coast areas. These costs compare with projected pipe replacement costs of $516 per foot in 2014 to $538 per foot in 2016 by PG&E.

[46] Numbers in this table were assembled from rate case filings by several utilities in the northeast and mid-Atlantic regions; while the specific utility sources are proprietary, the cost figures are not.

Table 6-1 Bare Steel and Cast Iron Replacement Costs (inflation at 2% per year)[47]

	Class 3 South New England	Class 4 Northeast	Class 3 Northeast	Class 3 & 4 Northeast	Class 3 Mid Atlantic
2009		$680	$264	$305	
2010	$253	$694	$269	$311	
2011	$258	$707	$275	$317	$175
2012	$263	$722	$280	$324	$179
2013	$268	$736	$286	$330	$184
2014	$274	$751	$291	$337	$188
2015	$279	$766	$297	$343	$193
2016	$285	$781	$303	$350	$198

The replacement rate for most operators shown in the above table was less than 20 miles per year. The class 4 Northeast is a major metropolitan area with a cost of living adjustment (1.1) being compared to San Francisco. The mileage being replaced by this operator is around 1 mile annually.

Pipe replacement costs are higher than what PG&E is projecting only in the business district in one of the most congested cities in the country. PG&E tracks costs in each of its seventeen divisions, but does not differentiate among urban and rural areas in gathering pipe replacement cost data. Cost forecasts were developed using historical Division averages. This approach is reasonable given that PG&E has not selected the specific segments it will replace during the GRC period. However, PG&E costs are high relative to most of the pipe replacement costs in Class 3 areas of the East Coast, which are nearly $200 per foot less than PG&E's.

Although the Aldyl-A leak problem exists across the country, the east coast operators have not instituted a special replacement program for it to date and replacements are made as leaking plastic is discovered. Therefore there are no other operator metrics against which to compare the PG&E cost. However, because PG&E costs are slightly higher than the Class 3 locations where bare steel and cast iron are being replaced, its replacement costs appear somewhat higher than expected. The table below[48] of northeast suburban and rural town and suburban annual main replacement programs show that the PG&E forecast plastic main replacement costs appear higher[49].

[47] The first cost in each series is the actual cost reported by the operator and the subsequent costs are inflated by 2% per year thereafter.
[48] Numbers in this table were assembled from rate case filings by several utilities in the northeast; while the specific utility sources are proprietary, the cost figures are not.
[49] For 2013.

Table 6-2 Operator Environment

Operator Environment	Miles	$/Foot
Suburban - Northeast	60	$208
Rural Town /Suburban - Northeast	30	$190
PG&E Plastic Program	50	$307

There are several approaches that PG&E could use to reduce the cost per foot of replacement, all involving increased use of outside contractors. PG&E could put the program out for multiyear bidding from qualified contractors using multipliers for different areas in their service territory and ranges for footages to be replaced. East coast operators use this method to partner with contractors to obtain the best pricing along with consistent high quality. The contractors respond favorably to this type of bidding because it is a multiyear contract and they can obtain equipment and train personnel for the long term. PG&E has indicated they are beginning to use this sort of "strategic contracting[50]." Another alternative is use a mixture of company labor and contractors to assist such as contracting out low-skilled work (trenching, backfill, pipe laying, paving) but using company labor for tie-ins and service work. The work papers did not specify if company or contractors would be installing any or all of the replacement mains and services. Discussion with PG&E personnel indicated that PG&E crews perform all main installations.

The decision on how much pipe to replace appears to have been made based principally on the rate at which a qualified force could be assembled during the period covered by the GRC. At the proposed replacement rate, replacing pipe currently considered to be high risk pipe will require fifteen years. PG&E has not indicated how it will decide on the specific segments it will replace during the period covered by the GRC.

One metric the CPUC could use to evaluate whether the most leak prone mains are being replaced would be the overall leak rate on the targeted pipe population. Other states have imposed certain conditions on the main replacement program, including penalties if leak rates do not drop or if minimum footages are not replaced each year.

Replace or Convert High Pressure Regulators - The project to replace or convert high pressure regulators (a combination of small district regulators and farm taps on the transmission system) started in 2009 and is anticipated to be completed in 2015. PG&E has 4,700 of these small regulator stations and has determined that most should be rebuilt. The replacement program begins with 529 stations in 2009, and moves to 1,200 stations

[50] GRC2014-Ph-I_DR_Cycla_013-Q03Atch01.

in 2012, and projects 1,000 stations per year for years 2013 through and including 2015. The projected unit cost in 2014 and 2015 is $51K and $52K while the actual cost in 2011 was $37K per unit. Some of these small regulators will be replaced by new distribution main to supply the customer while other customers may be tied into existing distribution mains. PG&E anticipates that 1,800 of the original 4,700 regulators can be eliminated thereby eliminating potential areas for leaks and atmospheric corrosion and improving the gas system safety. No cost factors for replacing vs. eliminating by running new distribution mains was provided, therefore the validity of the cost estimate is difficult to evaluate. The drastic change in costs from 2012 ($35K per regulator) to 2013 ($50K per regulator) was justified by PG&E by the distance between the regulators being rebuilt and by the judgment that more regulators will be rebuilt rather than being addressed by placement of new distribution mains.

Distribution Reliability - This program has eight (8) major components: 1) main replacements including converting low pressure to high pressure; 2) service replacements; 3) regulator stations; 4) cathodic protection (CP) systems; 5) CP remote monitors; 6) overbuilds; 7) others; and 8) starting in 2014 installation of additional shutdown/system isolation valves.

PG&E states it has 700 miles of low pressure main of which 64 miles are either cast iron or pre-1940 steel. During the GRC period, 2014 to 2016, PG&E plans to replace 15 miles[51] of low pressure main with high pressure main at a cost of $516 per foot in 2014 and 15 miles in each subsequent GRC year. As mentioned in the earlier paragraph on GPRP (Distribution Main Replacement), the costs for main replacements seems high especially since not all the replacements will take place in San Francisco but will be spread out to Sacramento, Stockton and Fresno areas. The main replacement costs for the reliability-focused project comprises 40% of the program in 2014 and is the biggest component of the entire program.

Gas service line replacements are another major component of the program comprising about 11% of the 2014 total. PG&E is estimating that approximately 1,700 services will be replaced because of leaks or other issues during each year of the GRC. The estimated cost to replace these services is over $8,200 each in 2014 and is escalated in the subsequent GRC years. This cost seems high based on similar costs for a mid-Atlantic utility in a generally urban/suburban area. Those costs were between $4,500 and $5,500 per service. In 2011 PG&E used a 5 year average to develop a cost of $7,700 per service with a range of costs from $6,200 to $8,000. There

[51] This is in addition to the 160 miles identified in MWC 14, Distribution Main Replacement (GPRP) which consists of 60 miles of pre-1940 bare steel and cast iron and 100 miles of Aldyl-A plastic.

could be considerable economies of scale as well as possible cost savings associated with use of contractors under a multi-year contract for some part of this work.

PG&E is proposing to increase its regulation station replacement and upgrading program from approximately 60 stations per year to 70 stations. The 70 stations represent approximately 2.5% of the total distribution regulator station population. The cost per station is increasing from $242K per station in 2011 to $257K or slightly more than 2% per year. Another practice that east coast utilities are using to control costs is to have a contractor pre-build much of the station piping in the vault prior to installing the vault in the ground (and for above ground facilities, pre-building much of the piping prior to delivery to the job location).

Over the last several years PG&E has experienced numerous over pressure events some of which have been attributed to obsolete and poorly performing regulator stations. Another factor that may have contributed is that the regulator station maintenance schedule specifies a full inspection and internal maintenance only every eight years where many other operators perform such preventative maintenance on much shorter time period, some as short as every two years. The historical data in the working papers shows that in 2007 the replacement rate was less than 10 stations increasing each year until 2014 when 70 stations are to be replaced. Based on the cost estimates that PG&E provided vs. cost estimates for 'new' regulator stations, it appears that the replacement may only include the valves and controls.

To reduce gas system safety risk, a combination of capital replacements and improved maintenance is needed. The PG&E GRC testimony does not specify how many poorly performing or obsolete regulator stations exist in the system and what basis was used to select 70 per year for replacement.

The next component is the cathodic protection (CP) system capital reliability program. This program is for the installation of both deep well and shallow impressed anode CP systems to bring existing steel mains into compliance with safety requirements of the California PUC and federal DOT regulations. Since PG&E has stated they are going to improve the response to poor readings (and will also install remote monitors), they have anticipated that the percentage of CP systems recognized as performing poorly will increase. Low CP readings can lead to increased external corrosion which in turn can lead to main and service failures (leaks). A properly maintained CP system should reduce corrosion-caused leaks.

PG&E has not provided information on the type of activities included under the miscellaneous component in the reliability program.

PG&E proposes to change its emergency valve program. Current PG&E sectionalizes up to 40,000 customers while it is proposing to use a 5,000 to 10,000 customer count[52]. The PG&E emergency valve program has two principle objectives: to be able to isolate a problem without affecting too many customers, and to be able to shed some gas load in an emergency so that service to the majority of the customers can be preserved. The number of customers sectionalized affects both objectives. Included in the first objective is reducing the number of valves that must be closed to assure total isolation. The new maximum is 20 valves to assure full isolation. To satisfy these new objectives, PG&E estimates that they will need to install over 3,100 valves. PG&E has asserted that approximately 3,100 new valves provide the best cost benefit. Many other operators use the 5,000 to 10,000 customer count as a guideline for isolation valve planning. The cost to relight and re-gas 40,000 customers after an isolation event is considerable. The re-gas process may include new meters, new regulators, purging mains, purging individual services and then relighting each gas appliances. Restoring gas service after an emergency is a time consuming process and must be done carefully to ensure customer and public safety. PG&E is estimating $25K in 2012 dollars for each valve and plans to add over a 1,000 valves in each year from 2014 through 2016. The basis for this estimate is unclear. Without more specifics it is difficult to evaluate the appropriateness of this cost estimate. These changes will reduce system risk and improve system reliability.

The remote CP monitoring program may have questionable value from an economic and risk perspective. Other operators have started remote CP monitoring but have found the benefits are minor compared to added costs. A well run manual read program coupled with fast response to "down" or out of compliance readings can have the same impact on gas system safety as having all CP readings monitored remotely. Many operators have automated monitoring of critical systems and critical bonds[53] to be aware immediately when the proper amount of CP is not being provided. What they have found is that the cost of maintenance of the remote monitors can exceed the cost of taking manual readings.

PG&E has estimated a cost of $1,600 per unit in 2012 which seems reasonable. They appear to have a contractor doing the work who will also collect the data. They have not estimated failure rate and costs of

[52] In downtown metropolitan areas the customer count is 500 to take multistory buildings with single customers into account.
[53] A bond can be a switch that allows current to flow one way or a bond between two CP systems.

maintaining units. The improvement to gas system safety will be greatest on the critical facilities which should be automated first. The major improvement to gas system safety results from drastically reducing CP down time from as much as 60 days.

Another component of the reliability capital program is called overbuilds, which are the capital costs that PG&E incurs when a main or a service must be relocated out of the way of a building or other facility (this account does not include main or service movements due to municipal or state road or other infrastructure developments). The budgeted amount is based on the $4.9 million spent in 2011 and is inflated for the GRC period. No determination on the appropriateness of the cost estimate can be made and since this involves moving gas infrastructure that may be damaged or become inaccessible for repairs the associated risk is high. While less cost effective in increasing gas system safety than replacing high risk mains, these activities are necessary and do improve safety.

Chapter 9, New Business (NB) and Work at the Request of Others (WRO)

Summary

This chapter describes PG&E's forecast of anticipated work in the NB/WRO Program. Under its tariffs and franchise agreements' obligation to serve, PG&E must perform work at the request of its customers. The new business work category includes the costs of building new mains[54], services, and regulators for the regulator change out program and for new installations. This work is broken down into two major categories:

- NB – Installing gas infrastructure to serve new customers and increased load for existing customers, and
- WRO – Relocating PG&E's gas mains and services at the request of governmental agencies

The WRO work category identifies the work requested by others to relocate its gas facilities that may interfere with primarily governmental agency projects.

PG&E forecasts a 2.4% decrease in expense from $6.15 million expended in 2011 to $6.0 million in 2014, and a 54.4% increase of $45.1 million from $82.9 million during 2011 in capital expenditures to $128 million in 2014.

[54] Gas distribution capacity expansion work to provide service to new customers is recorded as plant additions under MWC 47.

Discussion and Background

PG&E's work to install gas infrastructure (new mains and new services and regulators) serving new customers (new business or NB) as well as to provide increased load for existing customers is identified in this chapter of the GRC. The second type of work described in this chapter is that associated with work involving relocating its gas facilities when requested by others (WRO). The work includes customer interface, design, engineering, job cost estimation, contract preparation, construction, inspection of any third party work and facility mapping.

Aside from new business work for which PG&E has an obligation specified in its tariffs to provide for its customers, PG&E relocates its gas facilities when that work is requested by others generally to avoid interference with others' projects. The potential risks PG&E addresses are to ensure the work performed by third parties meet its standards and specifications and in all respects satisfy the gas safety requirements contained in the gas safety code, and to prevent or avoid interference with or damage to its existing gas distribution facilities from work being performed by governmental agencies and others.

Under the new business work category, PG&E developed its expense and capital expenditure forecasts using economic growth projections from independent economic forecasting firms and historical NB/WRO unit costs[55]. PG&E used new building permit and housing start forecast data from Moody's Investor Service (Moody's)/Economy.com and IHS Global Insight in the preparation of its NB/WRO program expenditure forecast. PG&E has found these economic indicators to be strong predictors of new residential and non-residential connections to PG&E distribution system and very accurate in the past. This trending approach was not as reliable in the recent past during the economic downturn and the beginning of the recovery. During 2006-2010 NB activity decreased; in late 2011 residential housing increased. PG&E applied a lag to these new business connects to housing starts and new business permits for 2012, and using a similar approach were within 0.4% of forecast[56]. PG&E monitors the volume by type of work using MAT[57] codes in its SAP system to analyze trends and changes for NB and WRO capital and expense categories. NB capital expenditures are forecasted [58]by calculating the product of projected volume of work (# of new connects based on housing start

[55] See Exhibit 3, Chapter 9 page 9-3.
[56] Interview with PG&E's Nina Bubnova and Gary Quast 2-26-2013.
[57] MAT codes help identify work activity and units of work such as feet of pipe and number of services.
[58] See Tables 9-12 & 9-13, Exhibit 3, Chapter 9 page 9-16, 17 for PG&E's forecast of capital expenditures.

and building permit forecast data[59]) and unit costs (based on historical averages adjusted to 2011 dollars and applying escalation rates and productivity related adjustments).

The gas WRO work category covers the capital expenditures for relocating gas distribution main and service facilities at the request of a governmental agency or another third party (e.g., customers and developers). This type of work depends on funding available to government agencies for road widening and other infrastructure improvements as well as the method of cost sharing contained in franchise agreements. When work is requested by government agencies, the cost is usually borne by PG&E. If the request is from the California DOT (CalTrans), costs are usually shared. Customer requests for relocations are usually borne by the customer. The mix of partial reimbursements associated with a portion of this work impacts the ability of PG&E to accurately forecast its expenditure needs. This difficulty results from the large number of governmental jurisdictions, changes in government project funding and limited long-term information on upcoming projects.[60] Forecasts for the WRO work category are developed by identifying and aggregating:

- WRO expenditures anticipated for NB developments (index) in consideration of changes in NB expenditures,
- Non-reimbursed WRO expenditures anticipated as a result of government forecasted spending (information from the state budget for CalTrans is used as an index which is closely tied to bond funding[61]), and
- Expenditures anticipated for large specific projects unrelated to CalTrans work as this work becomes known to PG&E.

PG&E relocates its facilities in advance of work by governmental agencies. The forecasted spending for the years 2014 thru 2016 for these three categories is: $45 million and $49 million each for the last two years[62].

One key metric PG&E uses to track its NB performance (productivity is difficult to track due to the varying nature of projects), is construction hours per service broken down into the following categories:

- Subdivision service completions
- Gas service cut-offs at the main

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[59] A six month lag factor is applied to housing permit data as building permits are issued in advance of construction.
[60] See Exhibit 3 Chapter 9 page 9-19.
[61] This spending projection tied to funding approved by California voters (Proposition 1B in 2006), doubled state highway and freeway infrastructure spending for an extended period of time. See Exhibit 3 chapter 9 page 9-23.
[62] See Table 9-22 Exhibit 3 Chapter 9 page 9-26, and Work Papers Exhibit 3 page WP 9-22 Table 9-19.

- Gas service alterations,
- Gas service cut-offs at the property line.

The trend in each category for the period 2009 thru 2011 indicates productivity improvements.[63] Other metrics are project satisfaction based on surveys and customer complaints. Results over the 2009 thru 2011 period show customer satisfaction trending up and customer complaints trending down. One additional metric instituted in 2011 is commitments met which generally apply to longer term projects. Results are limited since the data is for less than one year, but show commitments met in a range from 83% to 92%.[64] No metrics were provided for the WRO work category. By tracking its hours spent in various new business subcategories, PG&E is monitoring its associated costs. It did not provide specific cost comparisons between years to demonstrate the costs are reasonable, but the associated hours appear to be accomplishing this goal.

PG&E did not identify or separate out the risks associated with poor response to overseeing NB work performed by others, nor did PG&E identify the risks associated with not performing its WRO relocation work prior to others' construction projects. PG&E does not have other options or choices in performing NB and WRO work.

The methodology for developing associated forecasted spending appears to be reasonable. Details of actual spending levels are provided in the work papers. Specific units in evaluating NB related work are provided in the table in Exhibit 3. Cost estimates reflect historic experience, and PG&E's documentation of its process adequately include the basis for determining the personnel required to perform the work. PG&E's practices in this area compare favorably with industry practices.

Conclusions and Recommendations

PG&E has a detailed process to forecast its anticipated new business work, and work expected to be requested by others due to potential interference. Tariffs and franchise agreements determine whether PG&E absorbs the cost of shares the cost of this work. PG&E has metrics to track its new business performance. PG&E relies on historic experience, and unit costs for estimating resources required performing these functions.

[63] See Table 9-3 Exhibit 3 Chapter 9 page 9-6.
[64] See Table 9-6 Exhibit 3 Chapter 9 page 9-8.

Chapter 10 – Technical Training and Research

This chapter addresses expenses for training and research and development (the capital portion for training facilities is covered in Chapter 12). PG&E performed a benchmarking effort with other gas operators to determine how the current PG&E training compared with some of the best in industry operators. From this benchmarking effort, PG&E determined that they needed to significantly change and enhance their gas training to meet the new technology challenges for their employees and because of an aging workforce[65] that needs to be replaced. The challenge is how to effectively train new young workers so they can be as productive as possible and how to pass along the experience of the older workers before they retire. A second element of this chapter is research and development which covers PG&E participation in and support of various gas distribution and transmission research organizations. PG&E specifically identifies PRCI (Pipeline Research Council International), NYSEARCH (the research arm of Northeast Gas group), and OTF-GTI (the outdoor infrastructure test facilities of the Gas Technology Institute) as organizations that they propose to team with to be able to gain access to the latest technology.

PG&E's benchmarking efforts and the report of the CPUC Risk Assessment Unit (March, 2012) highlighted many of the deficiencies in the technical training program at PG&E's training academy. Instilling a "safety first" culture within the entire PG&E gas organization is one important objective. With the continual downsizing and early retirements, the company has lost a considerable knowledge base and using OJT (on the job training) is no longer sufficient. Additionally, in this GRC request, PG&E is attempting to add new technology so they can become a top quartile operator. Use of all this technology will require training (some of the new technologies are pressure and flow control devices, remote control valves, upgraded regulator stations with regards to valves and controls, and Picarro leak surveys). PG&E plans to embark on rigorous training agenda to upgrade its technical training. This will require that development of training be given priority and that the applicable members of the workforce be re-trained and re-qualified. PG&E proposes to develop or enhance 99 training courses between 2011 and 2016. The costs for these new or enhanced programs are spread over 2012 through 2016.

Training costs are projected to increase from $0 in 2011 to above $12 million in 2014. PG&E has accelerated training course development and now is planning to have spent $9 million in 2012. Some of the 99 new or

[65] In numerous management audits and reviews of utility companies, the aging workforce is common thread and most operators have a large group of experienced and senior workers, both management and trades, already at or near retirement age.

enhanced training courses are applicable to gas transmission and those costs should not be included in the gas distribution line of business costs - as it currently appears to be. Since PG&E has estimated the cost for developing or enhancing each course, splitting out the costs applicable to gas transmission should be straightforward.

PG&E is implementing its training program as a result of recommendations from the CPUC, the NTSB, and best practices in industry. Some of the recent incidents have indicated that PG&E people needed more specialized training to improve performance of their job responsibilities. Additionally, PG&E needs to train their workforce to use and maintain the new technologies it is embracing. Enhanced and improved training will reduce the risk of an incident and will improve gas system safety. Developing and nurturing a culture that puts "safety first" will also reduce risk and improve system safety. These are the goals of the new technical training program for gas at PG&E.

The gas distribution Research and & Development (R&D) budget at PG&E was essentially non-existent in 2011. Starting 2012 at under $0.5 million, the budget for gas distribution increases to $2.5 million in 2014.

Many of the R&D projects are applicable to both gas distribution and gas transmission and their costs will be shared. The projects being funded focus on many of the issues that PG&E has had problems with in the past such as integrity management, leak survey, damage prevention, and risk management. Since PG&E is a funding partner to these projects, they have the opportunity to evaluate and use of newly developed technology or tools before other operators. They also have the opportunity to assist in the development and guide the research organization toward goals that address their needs. For a company with a gas distribution system the size of PG&E, having funding for new technology to assist in solving problems will ultimately improve gas system safety.

Chapter 11, Gas Operations Technology Costs

Summary

This chapter describes the priority technology projects that PG&E is implementing to provide safety, compliance and operational improvements to its gas distribution operations.

The individual technology projects PG&E identified in the 2014 GRC appear to be reasonable and support PG&E's priorities to improve public safety, understanding of conditions on its system, improve productivity, enhance employee access to and availability of information, provide accurate information to first responders, and improve its responses to emergency situations. The technology projects will continue to support PG&E's migration from paper based processes to electronic systems.

Project cost estimates generally appear to have sufficient justification. Forecast costs developed using PG&E's application development concept estimating tool, which applies standard industry practices for IT project estimating, appears to provide sufficient funding for the projects.

Forecasted expenditures did not appear to be grossly overestimated; however they lend themselves to a two way balancing account for rate treatment purposes.

Some of the 2014 GRC technology projects lacked details concerning alternatives, comparisons and quantification of benefits of its selected technology improvements. Technology project costs compared with test year 2011 are shown in the table below.

Table 6-3 Technology Project Costs

2011 expended ($ million)	2014 Forecasted ($ million)	Difference From 2011 ($ million)
0.5 - expenses 3.0 - capital	19.2 43.7	18.7 40.7

Discussion and Background

PG&E is implementing technology improvements to its gas distribution operations to improve how it serves its customers and meet its legal and regulatory requirements. The company compared current PG&E technology with similar utilities, and identified technology priorities for implementation that will enhance safety, improve gas operations, improve data quality, facilitate compliance with laws and regulations, and improve productivity[66]. In selecting technology applications, PG&E considered potential alternatives that were industry tested. The 2014 GRC application lacked details on alternatives considered and on the anticipated benefits of

[66] See Exhibit 3 Chapter 11 pages 11-6, and 11-8.

its selected technology improvements. PG&E sought out alternative technologies by performing benchmarking with other utilities. PG&E used the concept estimating tool in their IT cost forecasts. PG&E plans to use a Request for Proposal (RFP) process to ensure project costs are competitive, and to employ appropriate project oversight at each stage of project development from approval through implementation[67]. Total capital costs for the GRC period is forecasted as $92.6 million, and expenses for 2014 are forecasted as $19.2 million. The discussion below covers the justifications for individual projects, how they fit within PG&E's long term plans to improve its commitment to safety consistent with best practices as Senate bill 705 requires, to improve access to and availability of data, and to migrate from paper based systems to controlled electronic records systems.

Pathfinder - The IRP recommended[68] PG&E improve its use of technology relative to industry best practices regarding records and asset management practices. PG&E technology application in a number of areas meets the needs identified in Senate bill 705 section 961 to the Public Utilities Code[69]. The Pathfinder project builds on the gas transmission asset management project introducing mobile technology to convert gas processes from paper based to electronic. This will provide for centralized recordkeeping processes along with ability to integrate information across multiple databases which will improve PG&E's knowledge of system components and help support its distribution integrity management process.

PG&E began developing its automated mapping and facilities management (AM/FM) project in 2011 to gather and represent key data in electronic format prior to determining how it would perform risk assessments. Since that time, the gas distribution portion of the AM/FM project has transitioned to the Pathfinder project[70]. Work completed as of November 2012 includes baseline Computer-Aided Design Drafting (CADD) images – geospatial locate CADD maps. The next steps involve digitizing CADD images, collecting information from paper records and converting to digital form and system integration work.

The Pathfinder project converts gas distribution asset and maintenance information from legacy[71] and paper based systems to the SAP and GIS systems. It includes key information about mains, services, valves, and regulators. Pathfinder will also consolidate information into SAP, link SAP and GIS databases permitting risk assessment tools to utilize information from both systems. The basis for determining staffing required to

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[67] See Exhibit 3 Chapter 11 pages 11-41.
[68] See IRP report recommendations on pages 58 and 63.
[69] See Senate Bill 705 proposed sections 961 (b) and (d).
[70] See discussion of limitation of the AM/FM project – Exhibit 3, chapter 11 page 11-11.
[71] Gas distribution information is currently in paper records or in CADD system called the Gas and Electric Mapping System (GEMS).

implement the Pathfinder project, and supporting work papers include man day estimates and related costs; alternatives considered for each aspect of the program are presented, and cost benefits and non-cost benefits. The documentation appears reasonable.

Details of key PG&E benchmarking findings and application of technology related to Pathfinder development are described below.

- Separate Geographic Information Systems (GIS) are best maintained for transmission and distribution asset data. PG&E is implementing a geometric data model GIS as part of Pathfinder, and phasing in its data migration from paper and legacy systems, as foundational to business process improvements. The Pathfinder project has six phases to mitigate project development risks.
- To provide a single consistent source of record for asset data, PG&E is linking and integrating GIS information, SAP accounting information, work management systems and asset registry, with maintenance and inspection information. This allows assessments based on installed components and knowledge about the condition of the pipe and combines technology and business process improvements in a single program.
- In its implementation, PG&E is piloting the technology for one or two divisions, stabilizing the new system, and then deploying it across its system. In its pilot phase, metric results (quality, employee adoption and productivity) are collected to verify desired results are being achieved before going system wide.

In addition to the Pathfinder project, PG&E is implementing other technologies to improve distribution operations that include the following.

- *Estimator Toolset Enhancements, Graphic Work Design Tool* – This technology allows distribution designs to be completed in the GIS platform, enables estimators to plan distribution work within GIS, ties job estimate information into the mobile tool used by field crews, improves data quality and productivity with crews entering information directly into the system of record. It will reduce time required to make updates to as built maps which will assist in responding to customer calls. Forecast cost estimates are broken down in terms of labor, infrastructure, training and other costs. Non cost benefits are discussed. The documentation appears reasonable.
- *Compass Enablement* – This viewing platform technology allows users to see an integrated view of multiple GIS databases on one screen, enabling access and organization of data without the need to open multiple

GIS systems. This will be especially useful for locate and mark crews by providing ready access to more accurate information at the job site.

- *Technical Information Library Re-Platform* – This technology was created to support migration of information (such as Standards, Bulletins and job aids that communicate how work should be performed) from the existing library to the new document management system into the mobile tool set. This allows all PG&E gas operations employees including mobile access, electronic access to current up to date technical library, and to reference documents standards and specifications.
- *GEMS RE-Write* – This technology enhances the productivity of mappers by enabling system user access to tools in the mapping process. GEMS needs to be updated to keep the system functioning until PG&E's new mapping system is running and a part of Pathfinder. The justification and the methodology for forecasting costs for the project appear reasonable.

Public Safety, Integrity Management and Regulatory Reporting associated technology improvements PG&E is implementing include:

- In the future DIMP program, PG&E is expecting to use a risk management program to run risk algorithms accessing information from various databases to identify assets with higher safety risks for potential mitigation measures. Software applications will allow risk management to access information converted from legacy systems, integration of DIMP software with SAP, PG&E's primary data source, enabling all of its relevant data in one location, extract interrelated data, and determine efficient mitigative measures to address its risks.
- Irthnet is an application designed to manage Underground Service Alert (USA) call tickets. Implementation of irthnet will provide for more efficient management of excavator locate and mark out requests, USA call tickets, to help prevent excavation damages to PG&E facilities. The documentation of costs appears reasonable for these technology improvements.
- Pipeline Safety Initiatives is made up of a few technology projects such as a pilot program for pipeline vibration monitoring sensors to identify potential dig-ins and construction based damages, damage prevention real time methods to monitor and evaluate construction activities in proximity to gas lines, and PG&E's emergency management portal for real time staff/crew locating and delivering real time information about the gas distribution system in case of an emergency event. The estimate is $0.5 million in expenses, with an additional anticipated $1 million in capital expenditures for each of the years 2014 thru 2016. PG&E's forecast estimates are developed with PG&E's concept estimating tool for developing application concepts. These proposals and the justifications of these concepts appear to lack details.

- PG&E identified the regulatory need to make DIMP IT and GIS/SAP system changes. The estimate is $400,000 in expenses for 2014 and $1.6 million in capital expenditures for each year 2014 thru 2016. No further details or justification was provided. This proposal based on potential future reporting requirements lacks sufficient justification at this time.
- The final project presented under the Public Safety and Integrity Management section is a proposal to provide radios to enable backup communication with Gas Service Representatives during emergencies to help improve response when their normal cellular service is congested or where cellular service is otherwise not available. The documentation appears reasonable for this technology improvement.

The following lists Gas Operations forecasted technology project needs[72].

- *Gas Control Center Radio System* – An existing SCADA field network on 17 mountain top locations with base radios using the Multiple Address System (MAS) technology serves primarily the Gas Transmission pipeline system. This proposed activity expands coverage to provide connectivity to distribution regulator stations, valves and ERX stations. This involves installing 5,000 radios, adding 55 new mountain top and lower elevation sites to provide coverage for new and existing devices, purchasing 900 megahertz licensed radio spectrum[73], installing microwave systems and battery backup equipment. Forecast cost documentation appears reasonable for this technology improvement
- *Gas Control Information Technology Applications* – As PG&E builds out its gas distribution control center function, it needs to develop and install a series of software applications for its support of operations personnel. The capital expenditures ($1.7 million) are identified for 2012, with $0.212 million forecast for expenses in 2014, $0.219 million and $0.225 million for the years 2015 and 2016. These applications benefit safety of gas system operations, and justifications appear reasonable[74].
- *Pipe to Soil Monitors project* covers the cost of cell phone service fees to improve monitoring of cathodic protection. The project will provide timely information about the condition of cathodic protection and will alert field crews to respond in a timely manner reducing the time cathodic protection is lost on distribution pipe segments. PG&E plans to have 6,000 units in place by 2016 phased in over time.
- *Gas Operations IT Enhancements* include a series of IT systems and tools[75] that PG&E plans to modify to improve PG&E's gas distribution data collection, planning and customer assistance as follows:

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[72] See Exhibit 3 Chapter 11 pages 11-24 thru 11-31.
[73] Unlicensed spectrum is open to general public use and resolution of interference can be costly.
[74] See work papers Exhibit 3 Chapter 11 pages WP 11-67 thru WP 11- 70.
[75] Work papers exhibit 3 chapter 11 pages WP 11-71 thru WP 11-75 contains cost justification and non-cost benefits.

- *Mobile Platform Technology* – This project supports the migration efforts from paper based to electronic based systems, specifically addressing deploying mobile solutions to the remainder of the gas distribution workforce. It also covers the work associated with replacing existing devices to better adapt the mobile device to the work being performed. At present mobile devices have been provided to Leak Survey and Locate and Mark crews. The remaining crews addressed in this GRC for the years 2014 thru 2016 involve deploying mobile devices various other work crews. Costs forecast are based on recent deployment and appear reasonable.
- *Mobile Device Replacement/Upgrade* – This addresses the issue of units damaged in the field, or replacing or modifying the device with a different device that better fits the nature of work being performed. Costs appear reasonable.
- *Mobile O&M Leak Survey, Repair and Replacement* – This addresses forecasted expense of $0.5 million during 2014 for the operating and maintenance support of the implemented software for the leak survey.
- *First Responder Portal* – This addresses the provision of information to first responders for routine communications, training events and for use in emergencies.
- *Upgrades to FAS Interfaces for Gas Distribution* - This projects will upgrade and streamline the communication and dispatching software/architecture allow direct communication into the field automated system (FAS) to dispatch gas service representatives in response to alarms from the gas distribution Control Center.
- *Testing and Conforming Application to Vendor Upgrades* – This addresses upgrades to new versions of software or modifications to PG&E systems to conform to changes in vendor software, and includes upgrade to the GIS interface with SAP scheduled in 2014. Forecasted capital expenditures appear reasonable.

Costs – The principal driver of costs for PG&E's gas distribution asset management technology application is the Pathfinder project which will be completed in 2015. PG&E's 2014 gas distribution technology expense forecast is $19.2 million[76], $18.7 million greater than the 2011 base year recorded expenses of $0.5 million.

Over the 2014 thru 2016 period, PG&E's capital forecasted expenditures for the technology area is $43.7 million in 2014, $34.2 million in 2015 and $14.6 million in 2016[77]. This 2014 capital forecast is approximately $40.7 million greater than the 2011 base year capital expenditures of $3.0 million.

[76] Work papers exhibit 3 chapter 11, page WP 11-1, line 2.

Conclusions and Recommendations

The individual technology projects PG&E identified in this GRC generally were reasonable and support PG&E's priorities to improve public safety, understanding the conditions of its system, productivity, enhance employee access and availability of information, provide accurate information to first responders and improve its responses to emergency situations. PG&E's asset knowledge management department performed benchmarking with other gas utilities to identify and adopt the type of technologies that would yield benefits to its utility operation.

The technology projects will continue to support PG&E's migration from paper based processes to electronic systems, from non-integrated mobile devices to more integrated platforms, and promote a more complete understanding of system conditions, characteristics, and controls fostering safe operating practices including the ability of field crews to field validate data entered into records systems.

Projects' cost estimates generally appear to have sufficient justification; forecast costs developed using PG&E's application development concept estimating tool apply standard industry practices for IT project estimating appear to provide sufficient funding for the projects. Forecasted expenditures did not appear to be grossly overestimated, however they lend themselves to a two way balancing account for rate treatment purposes to ensure funds allocated for projects are controlled and spent in the improved technologies area.

Some of the 2014 GRC technology projects lacked details concerning alternatives, comparisons and quantification of benefits of its selected technology improvements.

Chapter 12 Gas Operations Building Projects, AGA Fees and PAS 55 Certification

Summary

This chapter describes PG&E's forecasted Gas Operations support costs for incremental building projects, AGA membership fees, and costs to obtain and then maintain Publicly Available Specification (PAS) 55 Certification for best in class asset management practices.

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[77] Work papers exhibit 3 chapter 11, page WP 11-15, line 2.

Drivers for the various major building projects are associated with headquarters consolidation, new gas control center, "hot" backup control center, new training center, additional LNG/CNG operations centers, upgrades to operations centers at various field locations, a new Gas Service Center at Roseville, and paving projects at various field office and operations centers.

The methods PG&E used in developing individual major project estimates appeared reasonable and justified, generally based on identifying a work item and assigning a unit cost.

PG&E is planning actions to regain public and regulatory trust. As part of that process it intends to demonstrate it is has adopted best industry practices. PG&E expects that as part of achieving PAS 55 Certification, it will be able to demonstrate it is meeting a 28 point requirement specification for establishing and verifying an integrated and optimized management system for all types of its physical assets. The method of developing a forecast for PAS 55 Certification funding needs appears reasonable.

AGA membership is important to allow PG&E access to best industry practices; associated fees are reasonable.

Total costs associated with these three activities are shown below.

Table 6-4 Associated Costs

2011 Expended ($ million)	2014 Forecasted ($ million)	Difference From 2011 ($ million)
(0.2) - expense 0.5 - capital	7.4 61.5	7.6 61.0

Discussion and Background

Building Projects

In this section, PG&E addresses the need for carrying out 12 major[78] and 45 minor building projects. The total dollar amount of minor building projects ranges from $2 million in 2014, up to $2.4 million in 2015 and back to $2.0 million in 2016. The total value of capital expenditures for major building projects peaks during 2014 at $59.5 million slows to $45.15 million in 2015 and settles back down to a five year low of $21.3 million in 2016. Drivers for the various major building projects are associated with headquarters consolidation, new gas control center, "hot" backup control center, new training center, additional LNG/CNG operations centers, upgrades to operations centers at various field locations, a new Gas Service Center at Roseville, and paving projects at various field office and operations centers. A brief description follows for some of the major building projects[79].

- Consolidating Gas Operations headquarters offices in San Ramon[80], to accommodate increased engineering, operations, construction and technical staff and to consolidate paper records for joint use until the new electronic records is in place. Total project cost $47.5 million.
- Consolidating the Gas Control Center[81] and the Dispatch Center to promote efficient communications during emergencies. Total project cost $27.3 million.
- Creation of a "Hot" Backup[82] Control Center[83] mirror image (75% of the San Ramon facility with multiple power, data, cooling paths, and redundant components) to be activated when an emergency or major disaster event disrupts or prevents the use of the primary Control Center. Total project cost $33.7 million.
- Development of a new gas training center building (Gas Academy[84]), to address expanded training needs of employees with capability of hands on simulation of emergency events such as carbon monoxide, leak investigation, pipeline integrity testing, repair techniques and other asset maintenance activities including new technologies and associated procedures. Total project cost $59.5 million.

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[78] Major building project is a project where the capital expenditure and expense components total $1.0 million or more. Minor building projects are those with a combined project forecast less than $1.0 million.
[79] For further details of major building projects see Exhibit 3 chapter 12 pages 12-5 thru 12-9, and Work Papers supporting exhibit 3 chapter 12 pages WP 12-7, WP 12-13, WP 12-22 thru 12-79.
[80] See Exhibit 3 chapter 12 page 12-6, and Work Papers Exhibit 3 chapter 12 pages WP 12-22 thru WP 12- 26.
[81] See Exhibit 3 chapter 12 page 12-6, and Work Papers Exhibit 3 chapter 12 pages WP 12-27 thru WP 12- 32.
[82] Hot Backup describes a facility with duplicative operational ability of a primary location, in standby mode to be activated in an emergency, to address security needs.
[83] See Exhibit 3 chapter 12 page 12-6, and Work Papers Exhibit 3 chapter 12 pages WP 12-33 thru WP 12- 37.
[84] See Exhibit 3 chapter 12 page 12-6, and Work Papers Exhibit 3 chapter 12 pages WP 12-38 thru WP 12- 44.

- Constructing a new Roseville Service Center[85] located between Sacramento and Auburn field offices in an area experiencing customer growth. Total project cost $24.2 million.
- Constructing three new LNG/CNG operations centers to facilitate PG&E's growing fleet of LNG/CNG trailers and associated equipment, and increasing the number of LNG/CNG operations teams from 12 people supporting 50 locations in 2011 to 50 employees supporting over 250 locations. Costs are broken down into project activities such as design, site improvement, cost per sq. ft., ISTS, building, etc. Total cost per sq. ft. = $43.73.
- Permanent office facility in Antioch to accommodate growth and replace trailers. - $8.4 million.
- Permanent building at Vaca Dixon Substation due to health and safety concerns. -$4.7 million.
- Replacement of main building at Oroville Service Center to provide for additional space needs. Forecast completion 2013 at $3.1 million.
- Office building for engineering group at San Jose Dado St. Office to provide for additional space needs. Forecast completion 2013 at $2.0 million.
- San Carlos Service Center Building to provide for additional space needs for the Peninsula Transmission and Regulating group. Forecast completion 2014 at $4.7 million.
- Paving of Lakeville Substation to address maintenance and dust concerns. Total cost $1.5 million.

In addition to the major building projects listed above, PG&E is planning 45 minor[86] building projects to support gas distribution activities. Items of work, units of measurement and cost per unit used in developing individual cost estimates were provided.

Costs for most major building projects were generally estimated for field buildings at $450 per square foot, reduced from a generic SF cost of $486[87] per/sq. ft., and included experience and judgment based estimates for lease of additional space to accommodate personnel during construction and reconstruction as well as relocation of personnel. Paving costs were estimated at $11 per square foot, reduced from a generic SF cost of $15 based on gas operations experience and judgment.

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[85] See Exhibit 3 chapter 12 page 12-7, and Work Papers Exhibit 3 chapter 12 pages WP 12-51 thru WP 12- 55.
[86] See Work Papers Exhibit 3 chapter 12 pages WP 12-14 thru WP 12-19 for a list of project descriptions and project justifications.
[87] See generic building estimate detailed breakdown Work Papers Exhibit 3 chapter 12 pages WP 12-83 thru WP 12- 85.

PG&E's approach to develop forecast costs for the projects appeared to be reasonable in developing funding levels for the selected projects.

PAS 55 Certification[88]

A key element of Gas Operations' long-term gas distribution safety plan is the development of a long-term asset management plan. As a best practice, Gas Operations is pursuing an asset management certification offered by the British Standards Institute under its Publicly Available Specification (PAS) 55[89]. By achieving PAS 55 Certification, PG&E hopes to establish the processes needed to regain public and regulatory trust and demonstrate it is applying best practices to improve its performance. PG&E expects to be able to demonstrate it is meeting a 28 point requirement specification for establishing and verifying an integrated and optimized management system for all types of its physical assets. The 28 point requirements imbed specific principles of what good asset management means, including accomplishing life cycle planning, risk management, cost/benefit, customer focus and sustainability, and to verify they are actually being delivered within its day to day activities. PG&E plans to achieve PAS 55 Certification in the summer of 2014. Central to PG&E's pursuit of PAS 55 certification is the requirements of Section 4.4.7[90] that lays out a number of issues concerning the application of sound risk management practices. PG&E will have to show it is sustainably managing its risks, assets, and expenditures over a defined life cycle, and ensuring alignment of Gas Operations' strategic plan, its gas asset management policy, standards, objectives and work plans. To accomplish certification, PG&E will have to provide a clear audit trail for its risk based decision making and demonstrate it is allocating expenditures on asset investments that provide the best value.

The certification process includes an initial readiness assessment, a certification audit and a recurring annual re-certification audit, all conducted by a recognized accreditation firm. Beginning in 2014, PG&E will use Lloyds Register, an independent auditing organization, to audit documented processes, procedures as well as field practices and activities to determine if the standard is met. After PG&E achieves certification by mid-2014, it will be required to undergo annual audits to retain certification.

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[88] See WP – 12-82, Exhibit 3 Chapter 1 pages 1-18 thru 1-20.

[89] PAS 55 will become International Standard of Operation (ISO) 55001. The ISO standard would require enhanced Board level engagement expectations, more direction on asset management strategy development, and elevated financial expectation regarding responsible asset management.

[90] See Exhibit 3 chapter 12 page 12-12.

PG&E is forecasting a cost of $0.5 million[91] in 2014 to achieve initial certification and expects to incur on-going annual costs to maintain certification in 2015 and beyond. PG&E's documentation of its process to forecast its expenses related to PAS 55 certification includes an estimation of the number of days the consultant will be required and the daily rate of the consultant. The approach PG&E has taken is reasonable and justified in estimating required funding levels for this activity.

AGA Fees

AGA membership fees are set by the AGA and billed to member utilities. These membership fees include lobbying and non-lobbying costs for both gas transmission and gas distribution. PG&E's GRC filing has only included non-lobbying AGA membership fees for gas distribution. PG&E forecasts AGA membership dues on an average of the expenses of a member company for the past 3 years, and an expected increase of 7% for 2013[92]. Accordingly, PG&E's expense forecast for AGA Fees is $0.3 million for 2014.

Benefits for participating as an AGA member include working with other AGA member gas utilities to address common concerns and enhance their understanding of practices needed to achieve operational excellence. A major benefit is the opportunity to share other members' ideas of how to operate the safest, most reliable and cost effective gas distribution system and have access to member company employees experts at natural gas companies throughout the US and Canada.

AGA collects and compiles an enormous amount of natural gas industry data and information. From this extensive database, AGA members are able to take advantage of information on their performance relative to other operators and on operational best practices. By participating in AGA's Operations and Engineering Best Practices program, members have access to data the program participants submit and practices deemed by AGA to be the leading operating, engineering and construction practices. Companies lead roundtables to explain their techniques to the other Best Practices participants keeping members current on the newest practices and technologies in their fields.

PG&E's forecasted expenses appear reasonable and justified. Due to the number of major and minor projects identified in the GRC proposal, approval of funding levels should be tied to a two way balancing account for

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[91] See Exhibit 3 Work Papers chapter 12 page WP 12-82.

[92] See Exhibit 3 Work Papers chapter 12 page WP-80.

rate treatment purposes to ensure funds allocated for building projects are controlled and spent in the building projects area.

Conclusions and Recommendations

The methods PG&E used in developing individual major project estimates appeared reasonable and justified, generally based on identifying a work item and assigning a unit cost. No alternatives were presented or evaluated in the GRC proposal.

Drivers for the various major building projects are associated with headquarters consolidation, new gas control center, “hot” backup control center, new training center, additional LNG/CNG operations centers, upgrades to operations centers at various field locations, a new Gas Service Center at Roseville, and paving projects at various field office and operations centers.

Approval of funding levels should be tied to a two way balancing account for rate treatment purposes to ensure funds allocated for building projects are controlled and spent in the building projects area.

PG&E hopes to regain public and regulatory trust in part by demonstrating it is implementing industry best practices to improve its performance. PG&E expects that by achieving PAS 55 Certification, it will be able to demonstrate it is meeting a 28 point requirement specification for establishing and verifying an integrated and optimized management system for all types of its physical assets. The method of developing a forecast for PAS 55 Certification funding needs appears reasonable.

Forecast for AGA fees appear reasonable.

Attachment 7 – Listing of Information Requested from PG&E

Inquiry Set 1 (November 19, 2012)

1. What will PG&E have completed from the time of the event at San Bruno until the beginning of the period covered by the GRC (e.g., verification of system design & materials, updating system data, modifying pipeline systems)?
2. Provide a description of details of risk evaluation and risk management standard(s) (e.g., Operational Risk Management (ORM) Standard which outlines requirements for risk identification and evaluation), methodology and results (PG&E-1, pp. 4-3 & 4-8).
3. Describe the approach to deciding on priorities, especially changes in O&M activities and capital improvements for 2014.
4. Describe any applications of the DNV International Safety Rating System (PG&E-1, p 4-3) in the rate case development (e.g., what is the evaluation framework, what was learned through its application to the PG&E risk management program).
5. Provide documentation of cost basis for work in the GRC and the relationship between costs and work being proposed.
6. Provide a description of the process expected to be used to change risk management priorities during the GRC period, including communication with the CPUC.
7. Provide a description of the implementation status the ORMP and its anticipated status at the beginning of the period covered by the 2014 GRC.
8. Provide documentation on PG&E "asset management strategy" and PG&E's "risk algorithm" (PG&E-3, page 4-3).
9. Provide documentation on PG&E's "Distribution Integrity Management Program algorithm" (PG&E-3, page 4-5).
10. Provide a copy of PG&E's Risk Management Procedure", RMP-15 (PG&E-3, page 4-6).
11. Provide a copy of RMI-G, "DIMP Risk Algorithm Validation" (PG&E-3, page 4-9).

Inquiry Set 2 (December 20, 2012)

1. Provide all documents, including slide packages that were distributed during discussions at PG&E's offices on December 19, 2012.
2. Provide a process flow diagram for how the 2014 GRC Gas Operations forecast was developed, including explicit responsibilities for key decisions affecting the GRC.
3. Provide a process flow diagram, including explicit responsibilities for key decisions affecting future work, for how work plans/budgets will be developed in the future.
4. Provide a description of the process of developing the overall GRC forecast as well as the LOB forecasts (this should amplify on the flow diagram and describe where & how planning constraints are applied).
5. Provide a summary description of the process (including responsibilities) used in "Overall Leveling" and "Portfolio Optimization" supporting investment planning and the GRC request.
6. Provide the timeline for development of the GRC, including the points in time when expanded direction was received from the CPUC (e.g., the "Clanon Letter").
7. Provide example business cases/alternative analysis documents submitted to the Governance and Sanctioning Committee that supported the GRC forecast.
8. Provide the "Investment Planning" priorities assigned to the GRC forecast items (i.e., mandatory, critical, moderate impact, and necessary but deferrable).
9. Provide a copy of the AGA letter summarizing best practices information.
10. Provide business cases for the Distribution Systems Operations Gas Control Center; the Gas Distribution Pipeline Replacement Program; Gas Distribution Mapping and Records; Leak Survey and Repair; and Increased Gas Service Representative Staffing.
11. Provide a description of the Probabilistic Risk Algorithm under development as part of the Distribution Integrity Management Program, including anticipated development schedule.
12. Provide the guidance used by the LOBs for the Session 1/Session 2/Session D submissions.
13. Provide the Session 1, Session 2 and Session D submissions from Gas Operations.
14. Provide a description, including implementation status, of the initiatives PG&E put in place in response to the Independent Review Panel Report.
15. Provide risk evaluation instructions/guidance from the Risk organization to the LOBs.
16. Provide examples of "Root Cause Analysis" carried out in relating the DIMP effort to the GRC filing (e.g., in understanding the effectiveness of existing controls)
17. Provide a copy of the report prepared by Det Norske Veritas.

18. Provide summary-level documentation of PG&E efforts to improve the efficiency of key safety-related activities (e.g., related to improving responsiveness to emergency calls, related to leak surveys & atmospheric corrosion inspections).

Inquiry Set 3 (January 16, 2013)

1. Please provide estimates for the dates by when you expect to respond to questions in the second information request.
2. Please provide the material handed out and discussed at the January 10 meeting.
3. Please provide a summary of PG&E efforts to improve efficiency for the activities you are proposing to expand (e.g., leak detection, leak repair, pipe replacement) to better manage pipeline safety, along with the estimated efficiencies you expect to realize from these improvements (e.g., magnitude of reduced unit costs of activities), and efficiencies anticipated beyond the period covered by the GRC resulting from maturation of the processes.
4. As part of its best practices program does AGA ever attempt to gather information on practices that improve efficiency of safety-related activities?
5. Given that the root cause analysis process has not yet been implemented, how has PG&E evaluated the *anticipated safety improvement effectiveness* of the practices it has proposed implementing in the 2014 GRC?
6. Have you selected measures to use in evaluating the effectiveness of the improvements you are proposing to implement in the 2014 GRC? If so, please send documentation on these measures, where possible associated with the planned improvement being evaluated/characterized.
7. Please provide a listing of the processes for which you have assigned "process owners" along with any specific responsibilities identified/documented for these individuals.
8. In his presentation on the new leak detection system, Mr. Redding outlined a "vision" for how he expects to obtain future improvements in integration of work processes related to leak detection, repair, replacement, meter change-out, and regulator replacement. If this vision has been documented (even as a relational diagram), please provide the documentation.

Inquiry Set 4 (February 26, 2013)

Leaks

1. Please confirm the statement made on 02/25 by Louis Krannich regarding the basis for selecting 180 miles per year of pipe for replacement, in particular the impact of skilled resource constraints on this decision.
2. What system average leak rates has PG&E experienced for the most recent 5 year period?
3. PG&E has stated that it is currently in the third quartile of the industry in average leak rate for its system. Please provide documentation supporting this statement. Describe how PG&E's system average leak rates compare with other similar companies. In determining how much pipe to replace each year, has PG&E assembled and used industry leak rate (or leak repair) data to describe the relationship between leak rates experienced by operators with the best safety performance (i.e., top quartile) and those applicable to various types and vintages of distribution pipe material in PG&E's system?
4. If PG&E has made estimates, please provide the anticipated leak rate, either total leaks or leaks per mile of main that PG&E anticipates attaining when the 540 miles of main are replaced in 2016 (180 miles per year for 3 years).
5. During discussions on February 25, PG&E has stated it is in the top 10% of the industry in percent of leaks identified by survey rather than by customer and employee reports (82% found by leak survey). Please document this result, including describing the grades of leaks considered in developing the results. Has the possibility that this experience is related to insufficient odorant been evaluated?
6. Describe PG&E's view on the reliability of the data on leak rates used in selection of replacement segments.
7. Provide a copy of PG&E's quantitative analysis concerning the level of risk reduction (or an associated proxy variable such as reduced population of undetected Grade 1 leaks) associated with increasing the frequency of leak surveys and with the application of the Picarro survey technology.
8. Provide a representative copy of the monthly leak reports PG&E uses to help track its leak management efforts
9. Does PG&E have data/analysis regarding the rate at which leaks get worse? If so, provide it, including how many leaks are re-graded from type 3 to type 2, 2+ or 1; and from 2 to 2+ or 1; and from 2+ to 1 each year.
10. Describe how PG&E determined the appropriate Picarro phase-in time frame and the associated number of contractor crews that will use the Picarro Surveyor detection instrument during that phase-in.

Pipe Replacement

11. In its cost estimates, how has PG&E considered possible cost efficiencies in bidding pipe replacement work to contractors? What are potential savings? What constraints are there on using contractors?
12. It appears PG&E bases its pipe replacement priorities on leak rates. Please explain how PG&E will use leak rates going forward to determine which specific mains to replace considering possible changes in observed rates from changes in detection methodology.

Risk Algorithm

13. During discussions on February 25, Christine Cowsert Chapman indicated that PG&E has not yet decided upon the quantitative risk characterization tool it will develop for use with Pathfinder data. This is not entirely consistent with the earlier indication that PG&E will proceed with development of the DIMP Probabilistic Risk Algorithm (strengthened index model) described in GRC2014-Ph-I_DR_Cycla_012-Q11Atch01. Please confirm that the decision on what tool to further develop has not yet been made and describe the schedule for tool selection and development.
14. Please provide a copy of the DNV report reviewing PG&E's probabilistic risk algorithm referenced in the 02/25 meeting.
15. In forecasting PG&E's cost of pipe replacement, describe how PG&E has incorporated variations in the cost per foot to replace pipeline in various areas (e.g., inner city, urban, suburban, semi-rural, rural, paved areas, unpaved areas). For example, what percent of its system pipe replacement candidates are in highly populated areas, with the potential for paved roadways? Alternatively, please document the basis for the statement from the 02/25 meeting that the appropriate way to estimate costs for repair of leaks in various environments (e.g., urban, residential) is to use average system-wide historic costs.
16. Provide a list or table of replacement rates and costs per foot for PG&E's 17 Divisions.
17. With the ramp up in miles of main to be replaced, what analysis has PG&E performed to justify continuing to use in house PG&E crews versus bidding some portion out to cost justified contractors?
18. Has PG&E identified whether there would be a cost benefit to bidding pipe replacement jobs to contractors?

Other

19. Please provide slide material handed out at the 02/25 meeting.
20. Describe the extent of PG&E's remaining pipe candidates for conversion from low to high pressure and if/how risks associated with this effort are being identified and addressed.
21. Please provide the leak repair forecasting model.
22. Please provide documentation on the relative contribution to hazardous leaks and to incidents associated with each of the threats considered.
23. The PG&E GRC filing seems not to include significant activities designed to reduce excavation damage to its system (beyond the very important programs to better characterize the location and features of its pipeline system). Please describe new activities being pursued to reduce excavation damage, and how they address recognized deficiencies in the current controls.
24. Several projects were identified for which the major purpose seemed to be improving efficiency or labor utilization. Please confirm that the continuous CP monitoring project is in that category (which will impact the locations where continuous monitoring is implemented) and identify other similar projects.
25. Are remote electronic monitors being installed on rectified as well as distributed anode protected distribution CPAs? What percent of the system is rectifier protected vs. protected by a distributed anode? How were locations determined as to where to install the remote monitors?
26. Please describe the method PG&E used to develop the costs for automating cathodic protection readings?
27. On page WP 8-28, please describe the source of the tabulated escalation factors for the years 2014-2016 of 2.3%, 1.8%, and 2.5% respectively. Please describe PG& justification of these factors in its forecasts.
28. Identify the basis (and provide a copy of the analysis) used by PG&E for projecting the expected increase in the number of deficient cathodic protection readings from 5.6% of readings in 2011 to 11.6% in 2014.
29. Provide a flow chart that describes the work management portion of how DIMP will use the data from the mobile leak survey technology.
30. Automating monitoring of CP will allow deficiencies to be identified and corrected more quickly. Please describe the anticipated impact of decreasing the time of temporary loss of CP on the risk of corrosion leaks?

Inquiry Set 5 (April 9, 2013)

1. Please provide the complete content of the incident report summaries from the final incident report forms submitted to the CPUC for the past five years.