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ALJ	:	Bushey
Witness	:	Pocta

DIVISION OF RATEPAYER ADVOCATES
CALIFORNIA PUBLIC UTILITIES COMMISSION

DRA Report on the Pipeline Safety Enhancement Plan of Pacific Gas and Electric Company

Policy – Cost Recovery

San Francisco, California
January 31, 2012

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POLICY – COST RECOVERY

I. INTRODUCTION

This exhibit sets forth the policy testimony and recommendations of the Division of Ratepayer Advocates (DRA) pertaining to the recovery by Pacific Gas and Electric Company (PG&E) of the costs of its proposed Pipeline Safety Enhancement Plan (PSEP).

PG&E has requested incremental revenue requirements of $247.3 million in 2012, $220.8 million in 2013 and $300.6 million in 2014.[1] This amounts to total revenues of $768.8 million over the currently adopted base margin amounts for the recovery of expenses and investment associated with its PSEP.[2] The annual revenue requirement includes expenses, return on investments and associated costs for PG&E's proposed:

1. Pipeline Modernization Program,
2. Valve Automation Program,
3. Pipeline Record Integration Program,
4. Interim Safety Enhancement Measures,
5. Program Management Office,
6. Contingency.

PG&E addresses cost recovery in Chapter 8 of its Prepared Testimony. Among other things, PG&E proposes that the Commission:

- Adopt PG&E's forecast capital expenditures and expenses, deem these costs reasonable, and authorize PG&E to recover these costs in rates.

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[1] R.11-02-019, Pacific, Gas and Electric Company, Prepared Testimony, p. 9-2.

[2] R.11-02-019, Pacific, Gas and Electric Company, Prepared Testimony, p. 9-2.

- Adopt a cost allocation proposal in which PG&E shareholders would fund 2011 Implementation Plan expenses and capital related revenue requirements forecast at $220.7 million and $1.4 million respectively, and customers would fund the final three years.
- Authorize PG&E to establish a Gas Pipeline Expense Balancing Account.
- Approve, with modifications, PG&E's May 5, 2011 request to establish the Natural Gas Transmission Pipeline Safety and Reliability Memorandum Account.

PG&E is not seeking cost recovery to validate the Maximum Allowable Operating Pressure (MAOP) of post-1970's pipelines. If complete documentation of a strength test for post-1970 pipe segments cannot be located, PG&E will strength test these post 1970s pipe segments at shareholder expense.

II. SUMMARY OF RECOMMENDATIONS

DRA recommends the following with respect to cost recovery:

1. Ratepayers should not be responsible for any incremental costs, expenses or return on investment associated with PG&E's PSEP prior to PG&E's next Gas Transmission and Storage (GT&S) rate case proceeding. All expenses incurred prior to 2015 should be borne by PG&E shareholders. Any expenses and recovery of capital investment associated with PG&E's gas transmission and storage operations for 2015 and ensuing years may be requested by PG&E in its next GT&S rate case in conjunction with the policy pertaining to specific investments as discussed in Items 2, 3, and 4 below.
2. PG&E shareholders should be entirely responsible for all expenses associated with hydrostatic testing and / or associated pipeline replacements of those transmission pipelines installed in 1955 and subsequent years.

3. PG&E shareholders should be entirely responsible for all expenses associated with the hydrostatic testing of pipelines installed between 1935 and 1955.
4. For new investment related to PG&E's PSEP of those pipelines originally installed between 1935 and 1955, the rate of return on equity (ROE) should be adjusted downward by 200 basis points.

III. THE SAN BRUNO GAS PIPELINE EXPLOSION

In a PG&E Press Release issued by PG&E on Tuesday December 13, 2011, PG&E "stated that it is liable for the fatal natural gas pipeline accident in San Bruno in September 2010."

The National Transportation Safety Board (NTSB) in its Pipeline Accident Report adopted on August 30, 2011 regarding the PG&E Natural Gas Transmission Pipeline Rupture and Fire, San Bruno, California September 9, 2010 (NTSB Report), concluded "that the rupture of Line 132 was caused by a fracture that originated in the partially welded longitudinal seam of one of six short pipe sections which are known in the industry as "pups." The fabrication of five of the pups in 1956 would not have met generally accepted industry quality control and welding standards then in effect, indicating that those standards were either overlooked or ignored. The weld defect in the failed pup would have been visible when it was installed."[3]

The NTSB determined, "that the probable cause of the accident was the Pacific Gas and Electric Company's (PG&E) (1) inadequate quality assurance and quality control in 1956 during its Line 132 relocation project, which allowed the installation of a substandard and poorly welded pipe section with

[3] NTSB Report, p. x.

a visible seam weld flaw that, over time grew to critical size, causing the pipeline to rupture during a pressure increase stemming from poorly planned electrical work at the Milpitas Terminal; and (2) inadequate pipeline integrity management program, which failed to detect and repair or remove the defective pipe section".[4]

The NTSB Report found that "PG&E's pipeline integrity management program, which should have ensured the safety of the system, was deficient and ineffective because it—

- Was based on incomplete and inaccurate pipeline information.
- Did not consider the design and materials contribution to the risk of a pipeline failure.
- Failed to consider the presence of previously identified welded seam cracks as part of its risk assessment.
- Resulted in the selection of an examination method that could not detect welded seam defects.
- Led to internal assessments of the program that were superficial and resulted in no improvements".[5]

In its Incident Investigation Report released on January 12, 2012, the Consumer Protection & Safety Division (CPSD) of the Commission "finds that PG&E violated the Public Utilities Code, several federal and state pipeline safety regulations and failed to follow accepted industry standards. The investigation revealed that the incident was caused by PG&E's failure to follow accepted industry practice when constructing the section of pipe that failed, PG&E's failure to comply with integrity management requirements, PG&E's inadequate record keeping practices, deficiencies in PG&E's SCADA

[4] NTSB Report, p. xii.

[5] NTSB Report, p. xi.

system and inadequate procedures to handle emergencies and abnormal conditions, PG&E's deficient emergency response actions after the incident, and a systematic failure of PG&E's corporate culture to emphasize safety over profits."[6]

IV. DISCUSSION OF DRA RECOMMENDATIONS

A. Recommendation 1: PG&E Customer Rates Should Not Be Increased Prior to the Next GRC for PSEP costs

1. Increasing PG&E's Revenues is Inconsistent with Test Year Ratemaking

Consistent with forecast test year ratemaking, the authorized revenues adopted in a General Rate Case (GRC) is intended to fund all of the costs of providing service and operating the utility system during the period covered. How the funds are ultimately spent is largely left to the acumen of the utility's management. The utility has the ability to manage its costs in a manner it deems appropriate and can take advantage of numerous methods and implement new internal policies to control costs:

> The general concept of test year ratemaking is to authorize a rate level based on a reasonable forecast of various revenues and costs. Once rates are set, the utility has the discretion and responsibility to spend its funds in the most cost effective manner to provide safe and reliable service.[7]

Allowing PG&E to recover any additional revenue prior to the next GT&S rate case is contrary to forecast test year ratemaking and the Gas Accord V Settlement Agreement. The Commission generally does not approve specific costs in its GRC

[6] California Public Utilities Commission, Consumer Protection & Safety Division, Incident Investigation Report, September 9, 2010 PG&E Pipeline Rupture in San Bruno, California; Released January 12, 2012; p. 1.

[7] SCE Test Year 2006 GRC, D.06-05-016, p. 223

decisions, but approves a reasonable forecast of a future test year revenue requirement. The utility has numerous options at its disposal to control and manage its costs effectively. It is the exclusive decision of PG&E management and its Board whether it will avail itself of these options, or alternatively shirk its responsibility to manage its costs as best as possible within the parameters of the existing GRC.

The Commission provides utilities an opportunity to earn a fair rate of return on investment. It is not a guarantee. The various regulatory, business, and other risks are a consideration in establishing a fair rate of return on equity. It is the responsibility of utility management and its Board to make appropriate decisions and manage the utility's costs and unforeseen risks between GRCs. The acquiescence of the Commission to provide additional rate relief to PG&E between GRCs for recovery of costs associated with any programs that may be initiated between GRCs is not a provision of test year ratemaking. To provide any such relief will transfer the risk of operating the utility from shareholders, utility management and its Board to utility ratepayers.

In Decision (D.) 11-04-031, the Commission adopted the Gas Accord V Settlement Agreement which resolved the numerous issues in PG&E's recent natural gas transmission and storage (GT&S) application for 2011 through 2014. Although it was not an all-party settlement, there were approximately 26 parties representing essentially every facet of the natural gas market, including small and large end-use customers, marketers, interstate pipelines, municipal utilities, and independent storage providers. A very diverse cross section of interested parties entered into the Gas Accord V Settlement Agreement. These diverse parties were required to balance their various interests and individual positions in agreeing to the settlement. Given that there were a significant number of parties involved in negotiating the settlement agreement, the efforts to arrive at an equitable balance were considerable.

The intent of the settlement is that the rates and revenue increases negotiated will serve as a budget for PG&E for the 4 years of 2011-2014. The Commission recognized this aspect of the settlement: “[t]he Gas Accord V establishes the revenue requirements and the rates for PG&E’s GT&S services for this four-year rate cycle. The revenue requirements and rate agreed to in the Gas Accord V Settlement represent a compromise by the various parties of their positions on many different issues”. [8]

The Commission adopted a Settlement Agreement in PG&E’s Test Year (TY) 2011 GRC.[9] This Settlement Agreement included approximately 18 parties. Similar to the Gas Accord V Settlement, the GRC Settlement established revenue increases for the years 2011 – 2013. This Settlement represented a compromise by the various parties of their positions on many different issues.

The Commission has previously recognized the imbalance and inequity created if a utility is able to request additional funding for purported incremental work. In D.96-12-066, the Commission recognized this inequity and deemed PG&E’s request as failing “the test of fundamental fairness”:

> “PG&E’s request does not pass the test of fundamental fairness … Here PG&E has selected a handful of accounts where it asserts additional revenues are needed and asks for a rate increase without offering to balance any higher costs with savings it might generate elsewhere …. If PG&E can be expected to incur savings in other areas that would offset the higher costs at issue here, then it would not be reasonable to authorize a higher revenue requirement. It is also possible that savings would outweigh new costs and the reasonable revenue requirement would be reduced.”[10]

[8] D.11-04-031, p. 2.

[9] D.11-05-018, pp. 2, 86, 88-101.

[10] D.96-12-066, 69 CPUC 2d, p. 695.

The inequity described in D.96-12-066 is an important consideration to recognize in light of PG&E's cost recovery request in this case relative to the settlement of its TY 2011 GRC and the Gas Accord V Settlement Agreement. The other intervening parties entered into give and take in arriving at those settlement agreements. These other parties are not now able to selectively identify costs that were included in the revenue requirements negotiated in those settlements and reevaluate them in light of this new request. The other settling parties are not able to drill down into and reevaluate the settlement figures to identify new reductions, savings, and/or adjustments to decrease the previously agreed upon revenue requirement. For example, in the TY 2011 GRC Settlement, there was a reduction of $45 million to reflect parties' arguments regarding the Short Term Incentive Plan (STIP).[11] The STIP is an annual variable pay plan or cash incentive program for its management employees (supervisory, non-supervisory, and senior management) and non-union employees in its clerical classifications. It is intended to tie PG&E's performance and business unit areas to customer service, productivity, reliability, safety and cost savings.[12]

In light of PG&E's additional cost recovery request in this proceeding, a settling party may now believe that ratepayer funding of STIP should be lower than that embedded within the settlement or no ratepayer funding is appropriate. However, these parties cannot selectively choose to reduce various costs incorporated within the two settlement agreements. It is this inequity that the Commission addressed in D.96-12-066. Ultimately, PG&E's management is responsible for reducing costs and identifying operational efficiencies in order to stay within its authorized revenue requirement or put its shareholders at risk for cost recovery and/or the impact on earnings. Denying PG&E's incremental cost recovery request provides PG&E that incentive, while by contrast acceding to the PG&E

[11] D.11-05-018, Attachment 1, p.1-12.

[12] A.09-12-020; Exhibit DRA-14, pp. 3, 4.

request prior to its next GRC permits utility management to forego taking responsibility for these financial and other decisions.

The Commission has previously commented on the nature of this regulatory compact in Decision 85-03-042 where it stated,

> "Ratemaking is not, nor has it been, an exact science that guarantees perfect results from all perspectives." and "If ratemaking ever becomes so conceptually upside down that utility management loses the economic incentive to exercise its business acumen, California will be in a sad posture and will suffer under a utility management which is lethargic with a "cost plus" mentality."[13]

The Commission stated in Decision 96-12-066,

> "Just as it is inconsistent with this ratemaking philosophy to reduce the base revenue requirement between general rate cases when costs go down, it is inconsistent (and counterproductive) to selectively grant the utility interim increases in areas it finds its costs may be going up."[14]

It is recognized that there have been issues in regards to money being authorized for expenditures and not being spent by utilities.[15] Nonetheless, PG&E's rates have been established according to the existing regulatory compact pursuant to the recent GRC and GT&S proceedings. The policy being proposed in this report is entirely consistent with the existing regulatory framework and compact. In this case, the San Bruno explosion on the PG&E system and inability to identify pipeline records led to the Gas Safety Order Instituting Rulemaking (OIR), the subsequent independent evaluation and need for reevaluation of PG&E's gas pipeline system. The NTSB Report has provided additional evidence regarding inadequacies in PG&E's pipeline integrity management program. These factors are reason enough

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[13] Decision 85-03-042, 17 CPUC2d 246, 254; Decision 96-12-066, 69CPUC2d 693, 694.

[14] Decision 96-12-066, 69CPUC2d, p. 694.

to support a Commission finding that any costs incurred prior to the next PG&E GT&S GRC should be borne by PG&E shareholders.

One of the primary concerns identified subsequent to the San Bruno explosion by various government entities has been PG&E's lack of records and proper record maintenance associated with its natural gas system including but not limited to hydrostatic testing which has been an industry standard for over 75 years.[16] The San Bruno explosion and PG&E's gas system recordkeeping are inextricably linked to the Gas OIR and resulting costs associated with PG&E Implementation Plans submitted pursuant to this rulemaking. A basic lack of verifiable records to assure the integrity of the pipeline system is one element that gives rise to a need for new hydrostatic tests and potentially additional investment in new pipeline. PG&E is responsible for identifying solutions to address the expenses and investment associated with ensuring safe gas operations rather than simply looking to ratepayers as deep pockets to finance this significant project. The Commission should hold PG&E management responsible for this undertaking.

2. Decision Regarding the Gas Accord V Settlement

In D.11-04-031, the Commission addressed PG&E's natural gas transmission and storage (GT&S) application (A.09-09-013) for the years 2011 through 2014. In Ordering Paragraph 1 of the decision, the Commission granted the August 20, 2010 "Joint Motion of Settlement Parties for Approval of 'Gas Accord V' Settlement" and adopted the terms contained in the Gas Accord V Settlement Agreement, which is attached to the decision.

According to the terms of the Settlement Agreement approved by D.11-04-031, the rates are not subject to adjustment during the Settlement Period:

(continued from previous page)
15 Decision 11-05-018, pp 26-31, 98-100.

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"The rates specified in this Settlement Agreement are not subject to adjustment during the Settlement Period except as provided herein, or as agreed to by the Settlement Parties and approved by the Commission", and

"No Settlement Party shall make any proposal that would conflict with or alter any term of this Settlement Agreement, and the Settlement Parties shall not support proposals of others that would do the same."[17]

After agreeing to these terms, PG&E now proposes to implement a surcharge to its customers' rates for what are essentially backbone and local transmission expenses and investments. PG&E's proposal would circumvent the traditional allocation of backbone and local transmission costs to these unbundled rate components by implementing a customer surcharge to recover these costs. This proposed surcharge is a transparent attempt to increase customer rates for backbone and local transmission related activities without allocating them directly to the proper unbundled services. The rate proposal of PG&E is a thinly veiled effort to circumvent the Gas Accord allocation process and Settlement Agreement. The proposed surcharge is a rate increase for gas transmission related services. Any increase in customers' rates for backbone and local transmission related services, even if it is via a separate surcharge, represents a rate adjustment and conflicts with the terms of the Settlement Agreement.

According to Section 2.3 of the Settlement Agreement, PG&E will file its next GT&S rate case by Monday, February 3, 2014. Section 2.4 states that should approved rates not be in place for GT&S services by January 1, 2015, then the interim rates will be equal the rates in effect on December 31, 2014 plus a 2 percent escalator for backbone, local transmission, storage and customer access charge

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(continued from previous page)

16 See Attachment A.

17 D.11-04-031, Appendix A, Gas Accord Settlement Agreement, Section 12.1 Rate Certainty, p. 19.

rates. In approximately two years, PG&E will be able to incorporate into its GT&S application an updated request for expenses and capital additions associated with the PSEP for the years 2015 and beyond, and capital investment made prior to that year.[18]

The Commission Should Deny PG&E's Proposed Rate Surcharge as it can Adversely Impact Customers and a Properly Functioning Gas Market

A rate surcharge for backbone and local transmission costs will adversely impact all of PG&E's end-use customers. The recovery of any backbone costs via a rate surcharge will serve to place increased pressure on customer rates relative to allocating the costs to the backbone service. There are various reasons for this. The primary one is that there is a fully functional liquid, transparent city-gate market in the PG&E service territory. In order for this market to function properly, costs should continue to be allocated to the appropriate unbundled service. This will serve to affect the prices in the gas market. Depending on market conditions, the costs associated with backbone services can impact prices back to the production area which is commonly referred to as a net back. The end-use customers benefit by the fact that the backbone rate serves as one among a chain of components in a complex gas commodity market that impacts the price of natural gas that is bought and sold at both the PG&E city gate and the production basins. In the future, it is imperative that backbone related costs continue to be allocated to the backbone rates consistent with the principles and policy of the Gas Accord.

3. It is the Responsibility of PG&E Management to Implement Cost Control Measures between GRCs

There are many options that PG&E may pursue in order to effectively manage its costs between rate cases. It is the responsibility of PG&E's management to best determine how to manage and implement internal policy and measures to effectively control costs. It is not the Commission's responsibility to provide rate increases

[18] This is according to the parameters of other prospective proposals made in this exhibit.

between rate cases in order to shield PG&E shareholders from the effects of PG&E's management of its costs and expenditures. An increase to customer rates between GRCs has the effect of insulating the utility from the consequences of its decisions and actions.

PG&E has various ways in which to control costs and management has complete discretion in this respect to establishing budgets and expenditures within numerous programs and functions. As previously mentioned, PG&E has an STIP. There is some ratepayer funding of the STIP embedded in GRC rates and some shareholder funding of the program. PG&E management has discretion on how to establish measures and payouts for this program. For example, in the 2010 Plan Year, the actual payout for the company-wide STIP was approximately $81 million. PG&E management can decrease STIP payout to fund critical operational expenses. This payout is a discretionary expense which management has the ability to control.

4. PG&E's Gas Transmission & Storage Operations Have Been Very Profitable

PG&E's GT&S operations have been very profitable according to a report issued by Overland Consulting on December 30, 2011. The report entitled "Focused Audit of Pacific Gas and Electric Gas Transmission Pipeline Safety-Related Expenditures for the Period 1996 to 2010" (Overland Report) submitted to the Commission' CPSD identified a number of Key Findings with the Executive Summary. Some of these Key Findings include among other things:

- PG&E's actual transmission O&M expenses were five percent lower than amounts adopted in GT&S rate cases over the period 1997 to 2010.
- PG&E's actual total GT&S capital expenditures were six percent lower than adopted over the period 1997 to 2010.
- PG&E's GT&S operations have been very profitable since the Gas Accord Structure was implemented in March 1998. During that time,

> GT&S revenues have exceeded the amount needed to earn the authorized rate-of-return by $430 million.[19]

According to the Overland Report the actual rate of return on equity (ROE) earned by GT&S operations over the period 1999 to 2010 significantly exceeded the authorized ROE in ten of the twelve years in the 1999 to 2010 study period. According to the report, the surplus revenues averaged $36 million a year over the period, which PG&E could have used to improve gas safety. Although this report asserts that its figures are estimates, it concludes that PG&E's actual earnings significantly exceeded the authorized levels over the study period.[20]

In its Incident Investigation Report, CPSD has proposed,

- PG&E should use the $39,257,000 in previously authorized rate recovery for pipeline transmission operations and maintenance that it failed to spend since 1997 to fund future pipeline transmission operation and maintenance before it seeks additional ratepayer funds going forward.
- Regarding PG&E's gas transmission and storage operations, PG&E under spent $95,372,000 for capital expenditures since 1997; PG&E should use these previously authorized ratepayer funds to fund future gas transmission and storage capital expenditures before it seeks additional ratepayer funds going forward.
- PG&E should use the $429,841,000 in revenue collected since 1999 that is above and beyond what it required to earn its authorized return on equity to fund future gas transmission and storage operations before it seeks additional ratepayer funds going forward.[21]

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[19] Overland Report, p. 1-1.

[20] Overland Report, pp. 5-2, 5-3.

[21] CPSD Incident Investigation Report, p. 168.

As described in this exhibit, DRA has taken a different approach in its proposed cost recovery proposal than that suggested by CPSD. However, DRA's proposal is fully supported by the information and data within the Overland Report. According to that report, in the majority of the years from 1999 to 2010, PG&E's earnings were in excess of its authorized ROE. PG&E was not expected to refund the earnings generated in excess of the authorized ROE in the ensuing years.

PG&E is now faced with a converse scenario in which it may incur costs in excess of those authorized by the Commission in the last GT&S rate case. If this is the case, then PG&E could earn less than its authorized ROE. As in the past, GT&S revenues and rates have been established in the most recent rate case for the years 2011, 2012, 2013 and 2014. PG&E has been provided the opportunity to earn its authorized ROE. PG&E's risk if earnings fall below its authorized ROE should be balanced with the fact that it has realized earnings above its ROE in previous years.

According to the Overland Report, there have been many years in the recent past that PG&E has earned in excess of its authorized ROE for its GT&S business.[22] There is the opportunity to earn its ROE that a utility such as PG&E is provided when revenues and rates are established within a rate case. The Commission authorizes revenues in a general rate case based on a forecast of various expenses and capital expenditures. There are many factors and variables that may impact the difference between the actual and forecast levels of expenses and capital investment in the rate case cycle. In some years, these factors may impact the utilities' ROE in either a positive or negative manner, which represents an equitable and balanced risk. The Commission has previously recognized this in stating:

"Test year ratemaking is not a guarantee of full recovery or of fully expending the amounts as forecast. The "regulatory compact" is that in exchange for a

[22] Overland Report, p.5-2.

reasonable opportunity of earning a fair return, ratepayers pay the adopted rates and the utility does what is necessary to provide safe and reliable service."[23]

It is inequitable to ratepayers to permit PG&E shareholders to keep the extra revenues and profits generated in "good years" and to require ratepayers to pay more in "bad years" to protect shareholders from potential negative impacts and risk. PG&E should not be granted a revenue and rate increase in this OIR.

5. The Absence of Incremental Revenue and Rate Increase Should Not Impact PG&E's Ability to Operate its System

DRA's policy recommendations in this case should not impact PG&E's ability to operate its system properly, its financial viability, or its ability to attract capital. For example, the financial implications of DRA's proposal on PG&E are much less than those associated with one corporation involved in the recent Deepwater Horizon accident in the Gulf of Mexico.

Anadarko Petroleum Corporation (Anadarko) is engaged in the exploration, development, production and marketing of natural gas, crude oil, condensate and natural gas liquids. The company also engages in the gathering, processing, and treating of natural gas and the transporting of natural gas, crude oil and natural gas liquids.[24]

In April 2010, the Macondo well in the Gulf of Mexico was discovered to have hydrocarbon accumulations. Then during suspension operations, the well blew out, an explosion occurred on the Deepwater Horizon drilling rig, and the drilling rig sank, resulting in the release of hydrocarbons into the Gulf of Mexico. Eleven people lost

[23] Decision 09-03-025, p 323.

[24] Anadarko Petroleum Corp.; 10-Q Quarterly report pursuant to sections 10 or 15(d); Filed on 10/31/2011; Filed Period 09/30/2011; p.7.

their lives in the explosion and subsequent fire and other sustained personal injuries. The Macondo well was plugged on September 19, 2010.[25]

BP Exploration & Production Inc. (BP), the operator of Mississippi Canyon Block 252 in which the Macondo well is located, is funding claims and coordinating clean-up efforts. BP invoiced Anadarko $6.1 billion for what it considers to be Anadarko's share of costs related to these clean up activities.[26]

In October 2011, Anadarko and BP entered into a settlement agreement, mutual releases and an agreement to indemnify, whereby Anadarko and BP agreed to a mutual release of claims against each other relating to the Deepwater Horizon events (Settlement Agreement). Pursuant to the Settlement Agreement, Anadarko agreed to pay $4.0 billion in cash and transfer its interest in the Lease to BP. BP agreed to accept this consideration in full satisfaction for its claims against Anadarko for $6.1 billion of invoices to the date of the agreement and to forego all future costs from Deepwater Horizon events. BP also fully indemnified Anadarko against various claims and actions related to the event. The Settlement Agreement did not indemnify Anadarko against fines and penalties, punitive damages, shareholder, derivative or security loss claims.[27]

Although one can identify differences and similarities between the two incidents, namely the Gulf spill described above and the San Bruno incident, it is not the intent of this exhibit to develop and describe those. Rather it is to show financial related similarities between the companies and that the $4 billion settlement incurred

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[25] Anadarko Petroleum Corp.; 10-Q Quarterly report; Filed on 10/31/2011; p.7.

[26] Anadarko Petroleum Corp.; 10-Q Quarterly report; Filed on 10/31/2011; p.7.

[27] Anadarko Petroleum Corp.; 10-Q Quarterly report; Filed on 10/31/2011, p. 8.

by Anadarko is likely more costly[28] than the costs likely to be incurred by PG&E for pipeline safety work in the aftermath of the San Bruno explosion.

Anadarko generated sales revenues of $10.8 billion in 2010, $8.2 billion in 2009, $14.8 billion in 2008, and $11.7 billion in 2007. Anadarko generated operating income of $1.8 billion in 2010, $377 million in 2009, $5.6 billion in 2008, and $7.9 billion in 2007 with net income attributable to shareholders of $761 million in 2010 and -$135 million in 2009.[29]

PG&E generated operating revenues of $13.8 billion in 2010 and $13.4 billion in 2009. PG&E reported earnings from operations at $1.331 billion in 2010 and $1.22 billion in 2009 with consolidated income available for shareholders of $1.1 billion in 2010 and $1.22 billion in 2009.[30] The lower 2010 figure was impacted by costs relating to the natural gas transmission accident in San Bruno. A comparison of the two companies shows that Anadarko generates revenues slightly below the level generated by PG&E with operating income somewhat more variable. The financial impact of DRA's cost recovery proposal in this proceeding is very reasonable when contrasted to the Settlement Agreement impact on Anadarko.

6. PG&E is Compensated for Various Risks In its Cost of Capital through the currently Adopted Rate of Return on Equity

In D.07-12-049, the Commission adopted a rate of return of 8.79% for PG&E. That decision found a rate of return on equity (ROE) of 11.35% to be just and

[28] This is based on current comparable information of costs presented to date.

[29] Anadarko Petroleum Corp.; 10-Q Quarterly report pursuant to sections 10 or 15(d); Filed on 10/31/2011; Filed Period 09/30/2011.

[30] PG&E Corporation and Pacific Gas and Electric Company 2010 Annual Report.

reasonable for PG&E. The detailed composition of PG&E adopted cost of capital is set forth in Table 2-1.

Table 2-1
PG&E Cost of Capital

	Capital Ratio	Cost Factor	Weighted Cost
Long Term Debt	46.00%	6.05%	2.78%
Preferred Stock	2.00%	5.68%	0.11%
Common Stock	52.00%	11.35%	5.90%
Total	100.00%		8.79%

In arriving at the adopted ROE, the Commission evaluated financial models as a starting point to arrive at a fair ROE. Decision 07-12-049 considered additional risk factors not specifically included in the financial models, namely financial, business and regulatory risks. Regarding business risk, the Commission stated, "An increase in business risk can be caused by a variety of events that include deregulation, poor management, a failed marketing campaign and greater fixed costs in relationship to sales volume", and considered these risks in its adopted ROE. The decision ultimately added a 50 basis point premium to the ROE for debt leverage, debt equivalence and procurement risk.

The Commission considered regulatory risk which, according to the decision, "pertains to new risks that investors may face from future regulatory actions that we, and other regulatory agencies, might take. Examples include the potential disallowances of operating expenses and rate base additions …" The Commission concluded that perceived California regulatory risks warranted a 10 basis point upward adjustment to the base ROE ranges. The base ROE ranges are the different forecasts developed by various parties using financial models. Based on the financial, business and regulatory risks discussion and the application of informed judgment, the Commission concluded that the ROE ranges adopted warranted a cumulative 60 basis point upward adjustment for PG&E. The same analysis concluded that the adopted ROEs be set at the upper end of the ROE range found just and reasonable.

The 2007 Cost of Capital decision considered all the various business and regulatory risks which contributed to the adopted ROE. The Commission did not establish an adopted ROE for PG&E at the mid-point of financial models. The decision arrived at the adopted ROE for PG&E by starting at the upper end of the ROE range found just and reasonable (9.7% to 10.9%) and adding an additional 60 basis points to that figure. As described in the decision, the Commission adopted an ROE of 11.35%. Therefore, the Commission action has already considered and compensated PG&E for financial, business and regulatory risks between GRC cycles.

B. Recommendation 2: PG&E Should Be Financially Responsible for All Costs Associated with Hydrostatic Testing of its Natural Gas Pipelines

On June 9, 2011, the Commission issued D.11-06-017 which ordered all California natural gas transmission operators to develop Implementation Plans for Commission consideration to achieve the goal of orderly and cost effective replacement or testing all natural gas transmission pipelines that have not been pressure tested. These plans may include alternatives that demonstrably achieve the same standard of safety. The decision concludes that a pressure test record must include all elements required by the regulations in effect when the test was conducted. For pressure tests conducted prior to the effective date of General Order 112, one hour is the minimum acceptable duration.

The pressure testing of natural gas transmission pipelines has been an industry standard for over 75 years. DRA recommends that PG&E be held responsible for the costs associated with hydrostatic testing for all transmission pipelines installed after 1935 in the absence of records that show a test was performed in accordance with industry standards.

Attachment A to this exhibit provides information pertaining to the American Standard Code for Pressure Piping. The attachment provides a summary of the development of national codes and standards for pressure piping. The American Standards Association (ASA) developed the first national code for pressure piping in 1935. This code included specifications for hydrostatic tests of gas piping systems.

The ASA Code was created among other things to serve as a standard of reference for minimum safety requirements by equipment manufacturers, architects, engineers, erectors, and others concerned with pressure piping. The Code specified requirements for pressure testing after installation of pipelines. The Code specified all piping systems classified as Division 1 to be capable of withstanding a hydrostatic test of one and one-half times the normal service pressure. Various modifications were made throughout ensuing years. Most notable was the 1955 Code changes in which ASA: (1) divided the gas systems into class locations from Divisions and (2) specifically identified record keeping requirements for hydrostatic testing.

The ASA industry codes provide clear guidance to gas utilities regarding the requirements for hydrostatic testing of mains and pipelines located and operating in different location classes. The hydrostatic testing should have been performed by pipeline operators consistent with industry standards representing the minimum safety requirements as of the date the pipeline was installed. The records associated with hydrostatic tests should have been retained and kept on file by the pipeline operator.

For many years, the Commission has had a General Order which directed utilities to retain all records pertaining to the original cost of property and additions and betterments. Commission General Order (GO) 28 was approved on September

12, 1912 and became effective October 10, 1912. The GO was reissued on December 22, 1947. The GO states,

> "That each and every public utility and common carrier subject to the jurisdiction of this Commission, … shall from the date of October 10, 1912, preserve all records, memoranda and papers supporting each and every entry in the following general books of such public utilities and common carriers: …
>
> Also:
>
> All records, contracts, estimates and memoranda pertaining to original cost of property and to Additions and Betterments…"

If PG&E had properly retained records associated with the cost of hydrostatic testing; that would also allow for verification that a test was performed on the pipeline. There is evidence that in instances, PG&E has retained some records.

In response to an NTSB request for construction records for the 1948 portion of the Line 132 project, PG&E provided more than 18,000 pages of records, including material orders, accounting records, specifications, foreman journal entries, and radiography receipts. The foreman's log from the 1948 construction project noted several instances of construction damage, including dents and dent repairs. After the 1948 installation, the 20- and 24-inch segments of Line 132 were tested for leaks in accordance with the construction contract by introducing air at 100 psig[31] and using a soap and water solution on girth welds. According to construction records, as a final check before introducing gas, the 20- and 24-inch segments were pressured to 100 psig with air and held for 48 hours. Gas was introduced into the 30-inch portion of the line upon completion, and the line was checked "for leaks and breaks."[32]

[31] To define psig is pounds per square inch, gauge.

[32] NTSB Accident Report, September 9, 2010; p. 25.

PG&E has stated that it "believes that after adoption of American Society of Mechanical Engineers (ASME) standard ASA B31.1.8-1955, PG&E's practice was to follow ASA B31.1.8-1955, including pre-service testing.[33] Commission Decision 61269 issued on December 28, 1960, in describing the position of the respondents, PG&E and others stated the following "… the gas utilities in California voluntarily follow the American Standards Association (ASA) code for gas transmission and distribution piping systems."[34]

Industry standards pertaining to hydrostatic testing were first implemented on a national basis in 1935 and continued to be updated and modified through the ensuing years. PG&E and all the natural gas pipelines in California should have adhered to these minimum safety standards[35] when installing gas transmission facilities in California and retained records of the testing. The fact that PG&E did not do so and/or failed to retain appropriate engineering records is no reason to burden the PG&E ratepayers with the cost of testing now due to the oversight.

PG&E issued a Class Location Study on June 30, 2011. According to the study, 172.1 miles of its natural gas transmission lines were identified as being located in areas of lower population density than was actually the case. The Class Location Study also identified 54.2 miles of natural gas transmission pipeline that were erroneously classified as Class 1 when they were actually Class 2 locations. The Class Location Study identified 52.1 miles of pipeline that were erroneously classified as class 1 when they were actually Class 3 locations. The Class Location Study identified 0.4 miles of pipeline segments that were erroneously classified as class 1 when they were actually Class 4 locations. The Class Location Study identified 64.4 miles of pipeline that were erroneously classified as Class 2 when

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[33] PG&E Response to PG&E Data Request No. DRA 045-07, Answer 7 a.

[34] D.61269, p. 4.

[35] Page 11 of the July 1935 Code "is intended to set minimum safety requirements … but not the best practice known to the art."

they were actually class 3 locations. The Class Location Study identified 1.0 mile of pipeline segments that were erroneously classified as Class 3 when they were actually Class 4 locations. [36] Another reason why PG&E should be responsible for the costs associated with hydrostatic testing is because it has misidentified the class locations of its natural gas transmission pipelines.

These erroneous classifications may have impacted how transmission pipelines have been previously inspected under the Gas Transmission Pipeline Integrity Management Program (TIMP). The Federal Department of Transportation's Pipeline Integrity Rule for Gas Transmission Pipeline Integrity Management was effective February 14, 2004. This rule requires operators of gas transmission pipelines to identify threats to their pipelines in High Consequence Areas (HCAs), analyze the risk posed by these threats, collect information about the physical condition of their pipelines, and take actions to minimize applicable threats and integrity concerns before pipeline failures occur.

There are three methods that are typically used to perform the assessments: (1) external corrosion direct assessment (ECDA), (2) in-line inspection (ILI), and (3) hydrostatic test. ECDA is a process used to identify external corrosion defects before they affect the structural integrity of the pipeline segment. The ILI is an internal pipeline inspection method using specialized inspection tools called "smart pigs" that travel inside the pipeline to collect information about the pipeline. The hydrostatic test is typically performed immediately after construction and prior to placing the pipeline in service, and is done by filling the pipeline with water at a pressure greater than the maximum allowable operating pressure for a fixed period of time.[37] The current procedures for hydrostatic testing are described by the U.S.

[36] California Public Utilities Commission Order Instituting Rulemaking, November 10, 2011, I.11-11-009, p 7. PG&E Class Location Study at p.4.

[37] A.10-12-005 / 006; Exhibit DRA-44, p. 76.

Department of Transportation Pipeline & Hazardous Materials Safety Administration in Subpart J – Test Requirements.

PG&E should be held responsible for the costs associated with hydrostatic testing due to the fact that it is deferred maintenance. According to the NTSB, PG&E's pipeline integrity management program, which should have ensured the safety of the system, was deficient and ineffective.[38] Among other things, the NTSB stated that this deficient and ineffective program led to internal assessments of the program that were superficial and resulted in no improvements.[39]

The transmission integrity program requires all transmission pipelines to be assessed by December 31, 2012. After the pipeline is assessed, it must be reassessed no later than every 7 years thereafter. PG&E ratepayers have funded the TIMP through rates and annual funding is included in current rates.[40]

In many instances, hydrostatic testing could and/or should have been performed as part of the integrity program. For example in the case of the ruptured pipeline, the CPSD Incident Investigation Report stated that:

> "There were a number of deficiencies in PG&E's data gathering and analysis process that resulted in a flawed understanding of Line 132 HCA segments. First, PG&E failed to gather all relevant leak data on Line 132 and integrate it into its Geographic Information System (GIS) … Third, per the Ntsb Report, PG&E did not consider known longitudinal seam cracks dating to the 1948 construction and at least one other leak, which occurred in 1988, on a long seam of the 1948 portion of pipe."

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[38] NTSB Pipeline Accident Report, pp. xi, 125.

[39] NTSB Pipeline Accident Report, p. xi.

[40] Decision 11-04-031; Appendix A, Gas Accord V Settlement Agreement, Section 7.3, p.8.

"PG&E also failed to identify the unstable manufacturing threat on Line 132 segments, which resulted in an improper assessment method being used on Segments 180 and 181 (and other segments). Had PG&E properly identified the threat of potentially unstable manufacturing defects, it would have been required to use an assessment technology capable of assessing this threat."[41]

PG&E's stated practice was to follow ASA B31.1.8-1955, including pre-service testing,[42] and informed the Commission in 1960 that it adhered to the ASA code for gas transmission and distribution piping systems. In some cases where there is a need to conduct hydrostatic tests, it is work that should or could have been previously performed and as such it is deferred maintenance. Regarding deferred maintenance, the Commission has stated:

"For us to authorize Edison's recovery of deferred maintenance expense would establish an undesirable precedent, whereby the utility is effectively guaranteed that it can earn (or exceed) it's authorized rate of return, regardless of its operating efficiency or inefficiency, simply by curtailing current maintenance activities, in the assurance that they could be refinanced later through recovery of deferred maintenance expenses in a succeeding rate case. This would create a perverse incentive for the utility to defer needed maintenance in the future. Consequently, we will disallow recovery of the $34.6 million requested for deferred maintenance activities in 1983 and 1984. Our disallowance of this expense for test year ratemaking purposes does not relieve Edison of its responsibility to maintain the operating efficiency of its utility plant in a timely manner. Indeed, we expect Edison to fulfill that responsibility more conscientiously in the future."[43]

41 CPSD Incident Investigation Report, p. 26.

42 PG&E Response to PG&E Data Request No. DRA 045-07, Answer 7 a.

43 10 CPUC 2d 155,186; D.82-12-055.

For the reasons described above, all costs of hydrostatic testing associated with PG&E's Implementation Plan and pipelines installed since 1935 with no appropriate records showing that a hydrostatic test was properly performed, should be borne by PG&E's shareholders.

C. Recommendation 3: PG&E should bear the cost of investment for pipeline replacements of those transmission pipelines installed in 1955 and subsequent years associated with its Implementation Plan

D. Recommendation 4: An adjustment should be made for pipeline replacements associated with the Implementation Plan of those transmission lines installed prior to 1955. For these investments, a 200 basis point decrease in PG&E's rate of return on equity should be calculated. The resulting amount should be made as an adjustment (decrease) to PG&E rate base in the Summary of Earnings calculation.

For the investment in new pipeline to replace existing gas transmission pipeline associated with PG&E's Implementation Plan that was installed after 1955, the investment cost should be entirely borne by PG&E shareholders. For any pipeline installed subsequent to 1955, the ASA Code clearly stated that records should be retained for hydrostatic tests.

Section 841.417 under the Records Section of the 1955 ASA Code states, "The operating company shall maintain in its file for the useful life of each pipeline and main, records showing the type of fluid used for test and the test pressure."[44] Therefore, even if for some reason an entity was remiss in the past regarding keeping appropriate records for the hydrostatic tests performed in the past, the ASA code adopted in 1955 makes it crystal clear that records for hydrostatic tests are to

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[44] ASA B31.1.8-1955, Section 841.417, p. 50.

be maintained for the useful life of the pipeline and main. This was 20 years after the initial ASA Code adopting hydrostatic tests were adopted in 1935. Any utility that hadn't been following the industry standard for hydrostatic testing and keeping accurate records of the test in its files should have been doing so by 1955. PG&E's ratepayers had nothing to do with PG&E's failure to follow the industry standard. Any investment associated with PG&E's Implementation Plan, that is required to replace existing gas transmission pipeline installed subsequent to 1955 should be borne entirely by PG&E shareholders.

For the investment in new pipeline to replace existing gas transmission pipeline (associated with PG&E's Implementation Plan) that was installed prior to 1955, there should be an adjustment made to rate base and any associated expenses. DRA proposes a 200 basis point decrease to the authorized rate of return on equity. This adjustment will mitigate the impact of the investment on ratepayers while not placing the entire burden upon PG&E. There should also be a 20% adjustment to expenses that are incurred and associated with the capital improvement. DRA's proposal:

- Strikes an equitable balance between ratepayers and shareholders.
- Recognizes that transmission pipelines installed prior to 1955 and after 1935 should have been properly hydrostatically tested pursuant to industry standards, and records maintained.
- Recognizes that pipelines installed prior to 1955 will be in excess of 60 years old by 2015.
- Recognizes that transmission pipelines that are properly maintained can continue to operate safely well beyond the average economic life used for purposes of depreciation.
- Gives consideration to the fact that any pre-1955 transmission pipelines which are replaced, will be replaced with a new transmission pipeline constructed with the latest state of the art materials and construction techniques.

- Strikes a fair balance given the circumstances leading to the proposed PSEP and the acceleration of pipeline replacement that may occur pursuant to the plan relative to the status quo average annual pipeline investment.

In consideration of the various factors that are summarized above, DRA's proposed adjustment of 200 basis points to PG&E's ROE should be made to the rate base calculation in future proceedings. The calculation can be made to the Summary of Earnings through different methods. One such method would be a two-step process: 1. to run a separate Results of Operations model with a 200 basis point adjustment applied to the new capital investment associated with the pre-1955 plant investment to develop a summary of earnings adjustment, and 2. the resulting revenue requirement would reduce the GRC base margin / revenue requirement.

The calculation would apply specifically to the pipeline investments associated with the PSEP over the ensuing 10 years. Assuming the current rate of return on equity, the adjustment is approximately 17% to PG&E's existing rate of return on equity. If PG&E's rate of return on equity were to decrease, then the adjustment would be higher relative to the rate of return. The overall decrease to total rate of return on equity will be much lower since the adjustment applies only to the specific investments associated with replacing pre-1955 pipeline in the Implementation Plan.

The proposal is consistent with the policy and directives set forth in the Commission's rulemaking. R.11-02-019 states, "The extraordinary safety investments required for PG&E's gas pipeline system and the unique circumstances of the costs of replacing the San Bruno lines are situations where this Commission may use its ratemaking authority to, for example, reduce PG&E's rate of return on specific plant investments or impose a cost sharing requirement on shareholders.

We will consider these, and other ratemaking mechanisms, in this proceeding."[45] The proposals of DRA are both equitable and responsive to the Commission's directives.

[45] R.11-02-019, pp. 11-12.

ATTACHMENT A – AMERICAN STANDARD CODE FOR PRESSURE PIPING

American Standard Code for Pressure Piping:

Power, Gas and Air, Oil, District Heating, Refrigeration, Fabrication Details, Materials

1935

The first national code for pressure piping was issued in 1935 by the American Standards Association and sponsored by the American Society of Mechanical Engineers. The need for a national code on pressure piping became evident during the period of 1915 to 1925. The Power Piping Society was the first to publish a standard specification for power piping in 1915. Numerous parties also published technical papers dealing with pressure piping. A committee appointed by the Ohio State Department of Industrial Relations issued a draft for a state code for pressure piping titled "Code of Safety Rules and Regulations Covering the Installation of High and Low Pressure Steam Piping" in 1925.[46]

As a result of the distribution of the draft for an Ohio state code, many interested groups believed that the need for a national code for pressure piping was needed. In 1926, the American Society of Mechanical Engineers requested the American Standards Association (ASA) to develop an American Standard for pressure piping.[47]

The ASA issued the first national Code for Pressure Piping: Power, Gas and Air, Oil, and District Heating in 1935 (B31). The ASA Code for Pressure Piping (ASA Code) represents a standard of minimum safety requirements for: (1) the selection of suitable materials and reference to standard specifications by which they may be secured, (2) the designation of proper dimensional standards for the elements comprising piping systems, (3) the design of the component parts as well as the assembled unit including necessary supports, (4) the

[46] ASA Code for Pressure Piping-1935, Foreword, page 2

[47] ASA Code for Pressure Piping-1935, pages 2 and 3

erection of these systems, and (5) the test of the elements before erection and of the completed systems after erection. The ASA Code was created to serve as a guide to state and municipal authorities in the drafting of their regulations and as a standard of reference for minimum safety requirements by equipment manufacturers, architects, engineers, erectors, and others concerned with pressure piping.[48]

Section 2 of the ASA Code contains a section for Gas and Air Piping Systems that covers the design, manufacturer, installation, and tests of piping systems intended for conveying only air, fuel gas, or illuminating gas. This section includes city gas distribution systems, cross-country transportation systems, piping in gas manufacturing plants, in gas or air compressing stations, and in process plants.[49]

The ASA Code divides the gas and air piping systems into two divisions based on the difference in hazard involved.

(1) Division 1 includes all gas and air piping systems constructed (a) in power, industrial, and gas manufacturing plants wherever located and (b) anywhere within the boundaries of cities and villages.

(2) Division 2 includes all gas and air piping systems constructed (a) in compressing stations, and cross-country transportation systems and (b) outside the boundaries of cities and villages, and gas and air piping systems not included in Division 1.[50]

The ASA Code specifies Hydrostatic Tests for Division 1 before erection in which valves and fittings shall be capable of withstanding a hydrostatic shell test,

[48] ASA Code for Pressure Piping-1935, page 11

[49] ASA Code for Pressure Piping-1935, page 45, Section 201 and 202

[50] ASA Code for Pressure Piping-1935, page 45 and 46, Section 203

made before erection, equal to one and one-half times the maximum working gas or air pressure.[51]

The ASA Code also specifies Hydrostatic Tests for Division 1 after erection (welded pipe lines) in which all piping systems containing welded joints shall be capable of withstanding a hydrostatic test of one and one-half times the normal service pressure.[52]

The ASA Code specifies Hydrostatic Tests for Division 2 before erection in which valves and fittings in piping systems shall be capable of withstanding a hydrostatic test pressure of not less than one and one-half times the maximum working pressure for which the valves and fittings are rated.[53]

1942

The American Standards Association (ASA) issued the second national Code for Pressure Piping: Power, Gas and Air, Oil, District Heating, Refrigeration, Fabrication Details, and Materials in 1942.

The 1942 ASA Code extensively revised and brought up to date the 1935 ASA Code for Pressure Piping as necessitated by the significant changes in piping which had taken place since 1935. Some of the significant changes in piping since the ASA Code was published in 1935 were the increased importance of welded joints; standard dimensions have been prescribed for factory-made butt-welding and socket-welding fittings and their use has become common practice; welding-end valves with welded bonnets have been developed and adopted; pressures and temperatures have advanced to new high points; and new material specifications and dimensional standards have been formulated. The 1942 ASA Code revised several sections of the code as well as

[51] ASA Code for Pressure Piping-1935, page 55, Section 222 (a)
[52] ASA Code for Pressure Piping-1935, page 55 and 56, Section 222 (b)
[53] ASA Code for Pressure Piping-1935, page 57, Section 223 (a)

added a new section on refrigeration piping systems and a new chapter on welded branch connections, and fabricated or cast specials to the fabrication detail section.[54]

Section 2 of the ASA Code specifies that "every valve and fitting shall be capable of withstanding an internal hydrostatic mill test without showing failure, leakage, distress, or distortion other than elastic distortion at a pressure not less than one and one-half times the maximum working pressure for which the manufacturer guarantees it."[55]

The ASA Code also requires pressure testing after installation. The ASA Code states, "Every gas and air piping system shall be capable of withstanding a test pressure of:

(1) 150 percent of the maximum service pressure, for systems within the scope of Division 1 and

(2) 50 psi greater than the maximum service pressure, for systems within the scope of Division 2.

A test made after installation may be made with air or gas pressure which for systems within the scope of Division 1 need not exceed 120 per cent of the maximum allowable working pressure, and for systems within the scope of Division 2 shall not exceed 120 per cent of the maximum allowable working pressure."[56]

1944 and 1947

In 1944, the American Standards Association (ASA) made changes and additions to the 1942 ASA Code for Pressure Piping in Supplement Number 1:

[54] ASA Code for Pressure Piping-1942, page 7, Introduction

[55] See ASA Code for Pressure Piping-1942, page 54, Section 222 (a)

[56] See ASA Code for Pressure Piping-1942, page 62, Section 223

American Standard Code for Pressure Piping. In 1947, the American Standards Association (ASA) made further changes and additions to the 1942 ASA Code for Pressure Piping in Supplement Number 2: American Standard Code for Pressure Piping. These supplements introduced new dimensional and material standards, a new formula for pipe wall thickness, and more comprehensive requirements for instrument and control piping.[57] These supplements did not modify the pressure testing of piping systems.

1951

The American Standards Association (ASA) issued the national Code for Pressure Piping: Power, Gas and Air, Oil, District Heating, Refrigeration, Fabrication Details, Materials, and Appendix in 1951. Continuing increases in the severity of service conditions and concurrent developments of new materials and designs equal to meeting these higher requirements, pointed to the need for more extensive changes in the code. Because of the wide field involved, over 30 to 40 different engineering societies, government bureaus, trade associations, institutes and the like have one or more representatives on the sectional committee, plus a few "members at large" to represent general interests.[58]

Following the reorganization of Sectional Committee B31 in 1948, an intensive review of the 1942 code resulted in: (1) a general revision and extension of requirements to agree with present day practice; (2) the revision of references to existing dimensional standards and material specifications and the addition of references to new ones; and (3) the clarification of ambiguous or conflicting requirements. The ASA Code was designated as an American Standard in 1951 with the designation B31.1-1951.[59]

[57] ASA Code for Pressure Piping-1951, Foreword
[58] ASA Code for Pressure Piping-1952, Foreword
[59] ASA Code for Pressure Piping-1952, Foreword

Section 2 of the ASA Code continues to group the gas and air piping systems into Division 1 and Division 2.

The ASA Code specifies that before installation, every valve and fitting (except steel butt-welding fittings and special fittings fabricated by welding) to be capable of withstanding without failure, leakage, distress, or distortion other than elastic distortion an internal hydrostatic pressure of one and one-half times the maximum service pressure for which the manufacturer guarantees it.[60]

The ASA Code also specifies pressure testing after installation. The Code states, "Every piping system within the scope of this section shall be capable of withstanding a test pressure of:

(1) 150 percent of the maximum service pressure, for systems included in Division 1 and

(2) 50 psi greater than the maximum service pressure, for systems included in Division 2.

Where an internal fluid pressure test is made after installation, it shall not exceed 150 per cent of the maximum allowable working pressure for a system included in Division 1 or 50 psi greater than the maximum service pressure or 120 per cent of the maximum allowable working pressure, whichever is greater, for a system included in Division 2."[61]

1952

The American Standards Association (ASA) issued the first edition of the American Standard Code for Pressure Piping, Section 8, Gas Transmission and Distribution Piping Systems in 1952. Section 8 provides an integrated document

[60] ASA Code for Pressure Piping-1951, page 27

[61] ASA Code for Pressure Piping-1951, page 28, Section 223 (a) and (b)

for gas transmission and distribution piping that would not require cross-referencing to other sections of the Code.[62]

The ASA B31.1.8 Code prescribes the minimum requirements for the design, fabrication, installation, testing, and operation of piping systems for conveying substantially noncorrosive combustible gases. B31.1.8 includes piping in cross-country gas transportation systems, in gas compressing stations, and in gas distribution systems, as well as the elements of such piping, including for example, the pipe, valves, fittings, flanges, bolting, gaskets, and components such as gas storage lines, automatic valve reservoirs, and pulsation dampeners constructed of pipe and/or fittings.[63]

B31.1.8 requires hydrostatic pressure testing before installation. B31.1.8 requires every cast-iron pipe manufactured for use in piping systems within the scope of this section shall be subjected to and safely withstand an internal hydrostatic mill test without showing failure, leakage, or distress at a pressure not less than provided in the appropriate specification of those enumerated in paragraph 826 of B31.1.8 and not greater than that which would produce a stress equal to one-half the tensile strength. B31.1.8 provides other hydrostatic testing specifications for pipes made of materials other than cast iron.[64]

B31.1.8 also requires pressure testing of every piping system after installation. B31.1.8 requires that every piping system shall be capable of withstanding after installation an internal fluid pressure of

(a) 50 psi greater than the maximum service pressure for systems in cross-country gas transportation systems and gas compressing stations extending through sparsely populated or rural territories within the legal boundaries of cities or villages

[62] ASA B31.8-1952, Foreword
[63] ASA B31.8-1952, page 11
[64] ASA B31.8-1952, page 12

(b) 150 per cent of the maximum service pressure for systems in piping systems within the legal boundaries of cities or villages.

If an internal fluid pressure test is made after installation, it shall not exceed 50 psi greater than the maximum service pressure or 120 per cent of the maximum allowable working pressure, whichever is greater, for a system included in cross-country gas transportation systems and gas compressing stations or 150 per cent of the maximum allowable working pressure for a system included in piping systems within the legal boundaries of cities or villages.[65]

1955

The ASA organized a new Sectional Committee B31 in 1952 to revise Section 8. In 1955, the ASA issued the second edition of the American Standard Code for Pressure Piping, Section 8, Gas Transmission and Distribution Piping Systems.[66] The Sectional Committee B31 invited some 30 to 40 different engineering societies, government bureaus, trade associations, institutes and the like have one or more representatives on the sectional committee, plus a few "members at large" to represent general interests.[67]

Roscoe D. Smith, a representative of Pacific Gas and Electric Company, is listed as a Subgroup Chairman of the Storage in Pipe for Subcommittee No. 8 on Gas Transmission and Distribution Piping.[68]

Section 8 covers the design, fabrication, installation, inspection, testing, and the safety aspects of operation and maintenance of gas transmission and distribution systems, including gas pipelines, gas compressor stations, gas metering and regulating stations, gas mains, and gas services up to the outlet of

[65] ASA B31.8-1952, page 14, Section 807 (c,1) and (c,2); page 26, Section 824
[66] ASA B31.8-1955, Foreword
[67] ASA B31.8-1955, page 6
[68] ASA B31.8-1955 pages 2 and 3

the customer's meter set assembly. Section 8 also includes the requirements for gas storage equipment of the closed pipe type fabricated or forged from pipe or fabricated from pipe and fittings, and gas storage lines.[69]

Section 8 covers the conditions of use of the elements of the piping systems such as the pipe valves, fittings, flanges, bolting gaskets, regulators, pressure vessels, pulsation dampeners, and relief valves.[70] The requirements of Section 8 are adequate for safety under conditions normally encountered in the gas industry. The ASA intends that all work performed within the scope of Section 8 shall meet or exceed the safety standards prescribed in Section 8.[71]

This is the first time that ASA no longer divides the gas and air piping systems into Divisions and instead divides the systems into Class locations. Section 8 provides different requirements for different class locations.

1. Class 1 locations include waste lands, deserts, rugged mountains, grazing land, and farm land, and combinations of these.

2. Class 2 locations include areas where the degree of development is intermediate between Class 1 locations and Class 3 locations. Fringe areas around cities and towns, and farm or industrial areas where the one-mile density exceeds 20 or the ten-mile density index exceeds 12 fall within this location class.

3. Class 3 locations include areas subdivided for residential or commercial purposes where, at the time of construction of the pipeline or piping system, 10% or more of the lots abutting on the street or right-of-way in which the pipe is to be located are built upon, and a Class 4 classification is not called for. Areas completely occupied by

[69] ASA B31.8-1955, page 8, Section 804.1
[70] ASA B31.8-1955, page 8, Section 804.2
[71] ASA B31.8-1955, page 8, Section 804.4

commercial or residential buildings with the prevalent height of three stories or less can be classified as Class 3.

4. Class 4 locations include areas where multistory (4 or more floors above ground) buildings are prevalent and where there may be numerous other utilities underground.[72]

Section 841.41 specifies that all pipelines, mains and services shall be tested after construction. This is the first time the ASA uses the specified minimum yield strength (SMYS) term. All pipelines and mains to be operated at a hoop stress of 30% or more of the specified minimum yield strength of the pipe shall be given a field test to prove strength after construction and before being placed in operation.

1. Pipelines and mains located in Location Class 1 shall be tested either with air or gas to 1.1 times the maximum operating pressure or hydrostatically to at least 1.1 times the maximum operating pressure.
2. Pipelines or mains located in Location Class 2 shall be tested wither with air to 1.25 times the maximum operating pressure of hydrostatically to at least 1.25 times the maximum operating pressure.
3. Pipelines and mains in Location Classes 3 and 4 shall be tested hydrostatically to a pressure not less than 1.4 times the maximum operating pressure.
4. Hydrostatic testing of mains and pipelines in Location Classes 3 and 4 do not apply if at the time the pipeline or main is first ready for test, one or both of the following conditions exist:

[72] ASA B31.8-1955, pages 36 and 37, Section 841

a. The ground temperature at pipe depth is 32º F. or less, or might fall to that temperature before the hydrostatic test could be completed, or

b. Water of satisfactory quality is not available in sufficient quantity.

c. In such cases an air test to 1.1 times the maximum operating pressure shall be made.[73]

Section 841.42 specifies that steel piping that is to operate at stress less than 30% of the SMYS but in excess of 100 psi in location classes 2, 3, and 4 shall be tested to at least 1.5 times the maximum operating pressure.[74]

Record Keeping Requirements:

This is the first time that ASA specifies record keeping of each pipeline and main. Section 8 requires that the operating company shall maintain in its file for the useful life of each pipeline and main, records showing the type of fluid used for test and the test pressure.[75]

1958

The ASA issued a new version of American Standard: Gas Transmission and Distribution Piping Systems (ASA B31.8) in 1958.

[73] ASA B31.8-1955, pages 48 to 50, Section 841.41
[74] ASA B31.8-1955, page 50, Section 841.42
[75] ASA B31.8-1955, page 50, Section 841.417

Roscoe D. Smith, a representative of Pacific Gas and Electric Company, is again listed as a Subgroup Chairman of the Storage in Pipe for Subcommittee No. 8 on Gas Transmission and Distribution Piping.[76]

The strength testing requirements and record keeping requirements in Section 841 remains the same as the ASA B31.8 standards issued in 1955.

1963

The ASA issued a new version of American Standard: Gas Transmission and Distribution Piping Systems (ASA B31.8) in 1963.

Roscoe D. Smith, a representative of Pacific Gas and Electric Company, is listed as an Officer and Vice Chairman for Section Committee No. 8 on Gas Transmission and Distribution Piping.[77]

Section 841.41 specifies that all pipelines, mains and services shall be tested after construction. All pipelines and mains to be operated at a hoop stress of 30% or more of the specified minimum yield strength of the pipe shall be given a field test to prove strength after construction and before being placed in operation.

1. Pipelines and mains located in Location Class 1 shall be tested either with air or gas to 1.1 times the maximum operating pressure or hydrostatically to at least 1.1 times the maximum operating pressure.

2. Pipelines or mains located in Location Class 2 shall be tested wither with air to 1.25 times the maximum operating pressure of hydrostatically to at least 1.25 times the maximum operating pressure.

[76] ASA B31.8-1958, pages 2 and 3

[77] ASA B31.8-1963, pages iii and iv

3. Pipelines and mains in Location Classes 3 and 4 shall be tested hydrostatically to a pressure not less than 1.4 times the maximum operating pressure.[78]

4. Hydrostatic testing of mains and pipelines in Location Classes 3 and 4 do not apply if at the time the pipeline or main is first ready for test, one or both of the following conditions exist:

   a. The ground temperature at pipe depth is 32º F. or less, or might fall to that temperature before the hydrostatic test could be completed, or

   b. Water of satisfactory quality is not available in sufficient quantity.

   c. In such cases an air test to 1.1 times the maximum operating pressure shall be made.[79]

Section 841.42 specifies the tests required to prove strength for pipelines and mains to operate at less than 30% of the specified minimum yield strength (SMYS) of the pipe, but in excess of 100 psi. Steel piping that is to operate at stresses less than 30% of the SMYS in location Class 1 in which gas or air is the test medium, a leak test shall be made at a pressure in the range of 100 psi to that required to produce a hoop stress of 20% of the minimum specified yield, or the line shall be walked while the hoop stress is held at approximately 20% of the specified minimum yield.[80]

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[78] ASA B31.8-1963, pages 31 and 32, Section 841.412

[79] ASA B31.8-1955, page 32, Section 841.413

[80] ASA B31.8-1963, page 33, Sections 841.42 and 841.433

Record Keeping Requirements:

The record keeping requirements in Section 841 remains the same as the ASA B31.8 standards issued in 1955.[81]

[81] ASA B31.8-1963, page 33, Section 841.417

ATTACHMENT B - QUALIFICATIONS

QUALIFICATIONS AND PREPARED TESTIMONY
OF
ROBERT MARK POCTA

Q.1. Please state your name and address.

A.1. My name is Robert Mark Pocta. My business address is 505 Van Ness Avenue, San Francisco, California, 94102.

Q.2. By whom are you employed and in what capacity?

A.2. I am employed by the California Public Utilities Commission in the Energy Cost of Service and Natural Gas (ECOS/NG) Branch of the Division of Ratepayer Advocates (DRA) as a Program Manager.

Q.3. Please provide a brief description of your educational background and professional experience.

A.3. I graduated from Purdue University in May 1979, with a Bachelor of Science degree in Civil Engineering. In 1982, I became registered as a Professional Civil Engineer in the State of California.

I was employed by the California Department of Transportation from June 1979 to October 1980. In November 1980, I transferred to the Commission and worked in the Water Branch of the Public Staff Division until December 1984. My responsibilities included preparing estimates of revenues, expenses, taxes and rate base in numerous rate case applications of Class A water utilities. From January 1985 to August 1986, I worked in the Energy Operational Costs Branch on a number of energy-related rate applications.

I began to work in the Fuels Branch in September 1986 and was promoted to a Program and Project Supervisor in 1988. I served in various capacities as both a witness on technical and policy issues and a project manager in regulatory proceedings. These proceedings included natural gas industry investigations, rulemakings and restructuring, natural gas policy, utility mergers, incentive regulation, cost allocation, reasonableness reviews, capacity brokering, need for new interstate pipelines, natural gas vehicles, and natural gas procurement. I have testified as an expert witness many times before the Commission in various proceedings and have testified before the California Energy Commission. I have also submitted prepared testimony and appeared as an expert witness on behalf of the Commission at the Federal Energy Regulatory Commission in proceedings involving interstate gas pipeline companies.

My current administrative responsibilities include overall program planning, supervising the work of the ECOS/NG Branch Supervisors and their subordinates, overseeing the production of various reports on utility General Rate Case (GRC) and natural gas proceedings, controlling the quality of work performed by the Branch, developing policy on GRC and natural gas matters, and coordinating the branch work with other DRA branches. I have been responsible for managing all GRC proceedings filed at the Commission for the last ten years. I have represented DRA in various settlement negotiations, including the PG&E 2003, 2007 and 2011 GRCs, the Sempra utilities 2004 and 2008 GRCs, PG&E Gas Accord proceedings, PacifiCorp GRCs, Sierra Pacific GRCs, Southwest Gas' 2009 GRC, the Comprehensive Gas OII Settlement Agreement for Southern California Gas Company (SoCalGas) and San Diego Gas & Electric Company (SDG&E), the SoCalGas "Global Settlement" and settlements of cost allocation proceedings. I have coordinated DRA's participation in the development and modifications of gas procurement incentive mechanisms for SoCalGas and PG&E.

Q.4. What is the area of your responsibility in this proceeding?

A.4 I am sponsoring Exhibit DRA-02, Policy – Cost Recovery.

Q.5 Does this conclude your prepared direct testimony?

A.5 Yes, it does.