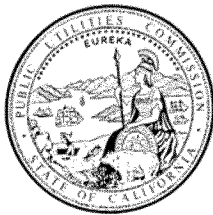


Docket	:	<u>R.11-02-019</u>
Exhibit Number	:	<u>DRA - 02</u>
Commissioner	:	<u>Florio</u>
ALJ	:	<u>Bushey</u>
Witness	:	<u>Pocta</u>



**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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ATTACHMENT A – AMERICAN STANDARD CODE FOR PRESSURE PIPING

ATTACHMENT B - QUALIFICATIONS

1 **POLICY – COST RECOVERY**

2 **I. INTRODUCTION**

3
4 This exhibit sets forth the policy testimony and recommendations of the
5 Division of Ratepayer Advocates (DRA) pertaining to the recovery by Pacific Gas
6 and Electric Company (PG&E) of the costs of its proposed Pipeline Safety
7 Enhancement Plan (PSEP).

8
9 PG&E has requested incremental revenue requirements of \$247.3 million in
10 2012, \$220.8 million in 2013 and \$300.6 million in 2014.¹ This amounts to total
11 revenues of \$768.8 million over the currently adopted base margin amounts for the
12 recovery of expenses and investment associated with its PSEP.² The annual
13 revenue requirement includes expenses, return on investments and associated
14 costs for PG&E’s proposed:

- 15 1. Pipeline Modernization Program,
16 2. Valve Automation Program,
17 3. Pipeline Record Integration Program,
18 4. Interim Safety Enhancement Measures,
19 5. Program Management Office,
20 6. Contingency.

21
22 PG&E addresses cost recovery in Chapter 8 of its Prepared Testimony.
23 Among other things, PG&E proposes that the Commission:

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

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.

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

10
11 PG&E is not seeking cost recovery to validate the Maximum Allowable
12 Operating Pressure (MAOP) of post-1970's pipelines. If complete documentation of
13 a strength test for post-1970 pipe segments cannot be located, PG&E will strength
14 test these post 1970s pipe segments at shareholder expense.

16 **II. SUMMARY OF RECOMMENDATIONS**

17 DRA recommends the following with respect to cost recovery:

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

- 1 3. PG&E shareholders should be entirely responsible for all expenses
2 associated with the hydrostatic testing of pipelines installed between 1935
3 and 1955.
4 4. For new investment related to PG&E's PSEP of those pipelines originally
5 installed between 1935 and 1955, the rate of return on equity (ROE)
6 should be adjusted downward by 200 basis points.
7

8 **III. THE SAN BRUNO GAS PIPELINE EXPLOSION**
9

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

13
14 The National Transportation Safety Board (NTSB) in its Pipeline Accident
15 Report adopted on August 30, 2011 regarding the PG&E Natural Gas
16 Transmission Pipeline Rupture and Fire, San Bruno, California September 9,
17 2010 (NTSB Report), concluded "that the rupture of Line 132 was caused by
18 a fracture that originated in the partially welded longitudinal seam of one of six
19 short pipe sections which are known in the industry as "pups." The fabrication
20 of five of the pups in 1956 would not have met generally accepted industry
21 quality control and welding standards then in effect, indicating that those
22 standards were either overlooked or ignored. The weld defect in the failed
23 pup would have been visible when it was installed."³
24

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

³ NTSB Report, p. x.

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

6
7 The NTSB Report found that “PG&E’s pipeline integrity management
8 program, which should have ensured the safety of the system, was deficient
9 and ineffective because it—

- 10 • Was based on incomplete and inaccurate pipeline information.
- 11 • Did not consider the design and materials contribution to the risk of a
12 pipeline failure.
- 13 • Failed to consider the presence of previously identified welded seam
14 cracks as part of its risk assessment.
- 15 • Resulted in the selection of an examination method that could not detect
16 welded seam defects.
- 17 • Led to internal assessments of the program that were superficial and
18 resulted in no improvements”.⁵

19
20 In its Incident Investigation Report released on January 12, 2012, the
21 Consumer Protection & Safety Division (CPSD) of the Commission “finds that
22 PG&E violated the Public Utilities Code, several federal and state pipeline
23 safety regulations and failed to follow accepted industry standards. The
24 investigation revealed that the incident was caused by PG&E’s failure to
25 follow accepted industry practice when constructing the section of pipe that
26 failed, PG&E’s failure to comply with integrity management requirements,
27 PG&E’s inadequate record keeping practices, deficiencies in PG&E’s SCADA

⁴ NTSB Report, p. xii.

⁵ NTSB Report, p. xi.

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

6 **IV. DISCUSSION OF DRA RECOMMENDATIONS**

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

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

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

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

22 Allowing PG&E to recover any additional revenue prior to the next GT&S rate
23 case is contrary to forecast test year ratemaking and the Gas Accord V Settlement
24 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

1 decisions, but approves a reasonable forecast of a future test year revenue
2 requirement. The utility has numerous options at its disposal to control and manage
3 its costs effectively. It is the exclusive decision of PG&E management and its Board
4 whether it will avail itself of these options, or alternatively shirk its responsibility to
5 manage its costs as best as possible within the parameters of the existing GRC.
6

7 The Commission provides utilities an opportunity to earn a fair rate of return
8 on investment. It is not a guarantee. The various regulatory, business, and other
9 risks are a consideration in establishing a fair rate of return on equity. It is the
10 responsibility of utility management and its Board to make appropriate decisions and
11 manage the utility's costs and unforeseen risks between GRCs. The acquiescence
12 of the Commission to provide additional rate relief to PG&E between GRCs for
13 recovery of costs associated with any programs that may be initiated between GRCs
14 is not a provision of test year ratemaking. To provide any such relief will transfer the
15 risk of operating the utility from shareholders, utility management and its Board to
16 utility ratepayers.
17

18 In Decision (D.) 11-04-031, the Commission adopted the Gas Accord V
19 Settlement Agreement which resolved the numerous issues in PG&E's recent
20 natural gas transmission and storage (GT&S) application for 2011 through 2014.
21 Although it was not an all-party settlement, there were approximately 26 parties
22 representing essentially every facet of the natural gas market, including small and
23 large end-use customers, marketers, interstate pipelines, municipal utilities, and
24 independent storage providers. A very diverse cross section of interested parties
25 entered into the Gas Accord V Settlement Agreement. These diverse parties were
26 required to balance their various interests and individual positions in agreeing to the
27 settlement. Given that there were a significant number of parties involved in
28 negotiating the settlement agreement, the efforts to arrive at an equitable balance
29 were considerable.
30

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

8
9 The Commission adopted a Settlement Agreement in PG&E’s Test Year (TY)
10 2011 GRC.⁹ This Settlement Agreement included approximately 18 parties. Similar
11 to the Gas Accord V Settlement, the GRC Settlement established revenue increases
12 for the years 2011 – 2013. This Settlement represented a compromise by the
13 various parties of their positions on many different issues.

14
15 The Commission has previously recognized the imbalance and inequity
16 created if a utility is able to request additional funding for purported incremental
17 work. In D.96-12-066, the Commission recognized this inequity and deemed
18 PG&E’s request as failing “the test of fundamental fairness”:

19 “PG&E’s request does not pass the test of fundamental fairness ... Here
20 PG&E has selected a handful of accounts where it asserts additional
21 revenues are needed and asks for a rate increase without offering to balance
22 any higher costs with savings it might generate elsewhere If PG&E can be
23 expected to incur savings in other areas that would offset the higher costs at
24 issue here, then it would not be reasonable to authorize a higher revenue
25 requirement. It is also possible that savings would outweigh new costs and
26 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.

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

17
18 In light of PG&E's additional cost recovery request in this proceeding, a
19 settling party may now believe that ratepayer funding of STIP should be lower than
20 that embedded within the settlement or no ratepayer funding is appropriate.
21 However, these parties cannot selectively choose to reduce various costs
22 incorporated within the two settlement agreements. It is this inequity that the
23 Commission addressed in D.96-12-066. Ultimately, PG&E's management is
24 responsible for reducing costs and identifying operational efficiencies in order to stay
25 within its authorized revenue requirement or put its shareholders at risk for cost
26 recovery and/or the impact on earnings. Denying PG&E's incremental cost recovery
27 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.

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

3
4 The Commission has previously commented on the nature of this regulatory
5 compact in Decision 85-03-042 where it stated,

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

12 The Commission stated in Decision 96-12-066,

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

17
18 It is recognized that there have been issues in regards to money being
19 authorized for expenditures and not being spent by utilities.¹⁵ Nonetheless, PG&E’s
20 rates have been established according to the existing regulatory compact pursuant
21 to the recent GRC and GT&S proceedings. The policy being proposed in this report
22 is entirely consistent with the existing regulatory framework and compact. In this
23 case, the San Bruno explosion on the PG&E system and inability to identify pipeline
24 records led to the Gas Safety Order Instituting Rulemaking (OIR), the subsequent
25 independent evaluation and need for reevaluation of PG&E’s gas pipeline system.
26 The NTSB Report has provided additional evidence regarding inadequacies in
27 PG&E’s pipeline integrity management program. These factors are reason enough

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

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

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

3
4 One of the primary concerns identified subsequent to the San Bruno
5 explosion by various government entities has been PG&E's lack of records and
6 proper record maintenance associated with its natural gas system including but not
7 limited to hydrostatic testing which has been an industry standard for over 75
8 years.¹⁶ The San Bruno explosion and PG&E's gas system recordkeeping are
9 inextricably linked to the Gas OIR and resulting costs associated with PG&E
10 Implementation Plans submitted pursuant to this rulemaking. A basic lack of
11 verifiable records to assure the integrity of the pipeline system is one element that
12 gives rise to a need for new hydrostatic tests and potentially additional investment in
13 new pipeline. PG&E is responsible for identifying solutions to address the expenses
14 and investment associated with ensuring safe gas operations rather than simply
15 looking to ratepayers as deep pockets to finance this significant project. The
16 Commission should hold PG&E management responsible for this undertaking.

17 18 **2. Decision Regarding the Gas Accord V Settlement**

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

25
26 According to the terms of the Settlement Agreement approved by D.11-04-
27 031, the rates are not subject to adjustment during the Settlement Period:

¹⁶ (continued from previous page)
Decision 11-05-018, pp 26-31, 98-100.

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

4 “No Settlement Party shall make any proposal that would conflict with or alter
5 any term of this Settlement Agreement, and the Settlement Parties shall not
6 support proposals of others that would do the same.”¹⁷

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

20
21 According to Section 2.3 of the Settlement Agreement, PG&E will file its next
22 GT&S rate case by Monday, February 3, 2014. Section 2.4 states that should
23 approved rates not be in place for GT&S services by January 1, 2015, then the
24 interim rates will be equal the rates in effect on December 31, 2014 plus a 2 percent
25 escalator for backbone, local transmission, storage and customer access charge

¹⁶ (continued from previous page)

See Attachment A.

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

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

5
6 The Commission Should Deny PG&E's Proposed Rate Surcharge as it can
7 Adversely Impact Customers and a Properly Functioning Gas Market

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

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

25 There are many options that PG&E may pursue in order to effectively manage
26 its costs between rate cases. It is the responsibility of PG&E's management to best
27 determine how to manage and implement internal policy and measures to effectively
28 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.

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

5
6 PG&E has various ways in which to control costs and management has
7 complete discretion in this respect to establishing budgets and expenditures within
8 numerous programs and functions. As previously mentioned, PG&E has an STIP.
9 There is some ratepayer funding of the STIP embedded in GRC rates and some
10 shareholder funding of the program. PG&E management has discretion on how to
11 establish measures and payouts for this program. For example, in the 2010 Plan
12 Year, the actual payout for the company-wide STIP was approximately \$81 million.
13 PG&E management can decrease STIP payout to fund critical operational expenses.
14 This payout is a discretionary expense which management has the ability to control.

16 **4. PG&E's Gas Transmission & Storage Operations Have** 17 **Been Very Profitable**

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

- 24 • PG&E's actual transmission O&M expenses were five percent lower
25 than amounts adopted in GT&S rate cases over the period 1997 to
26 2010.
- 27 • PG&E's actual total GT&S capital expenditures were six percent lower
28 than adopted over the period 1997 to 2010.
- 29 • PG&E's GT&S operations have been very profitable since the Gas
30 Accord Structure was implemented in March 1998. During that time,

1 GT&S revenues have exceeded the amount needed to earn the
2 authorized rate-of-return by \$430 million.¹⁹

3
4 According to the Overland Report the actual rate of return on equity (ROE)
5 earned by GT&S operations over the period 1999 to 2010 significantly exceeded the
6 authorized ROE in ten of the twelve years in the 1999 to 2010 study period.
7 According to the report, the surplus revenues averaged \$36 million a year over the
8 period, which PG&E could have used to improve gas safety. Although this report
9 asserts that its figures are estimates, it concludes that PG&E's actual earnings
10 significantly exceeded the authorized levels over the study period.²⁰

- 11
12 In its Incident Investigation Report, CPSD has proposed,
- 13 • PG&E should use the \$39,257,000 in previously authorized rate recovery for
14 pipeline transmission operations and maintenance that it failed to spend since
15 1997 to fund future pipeline transmission operation and maintenance before it
16 seeks additional ratepayer funds going forward.
 - 17 • Regarding PG&E's gas transmission and storage operations, PG&E under
18 spent \$95,372,000 for capital expenditures since 1997; PG&E should use
19 these previously authorized ratepayer funds to fund future gas transmission
20 and storage capital expenditures before it seeks additional ratepayer funds
21 going forward.
 - 22 • PG&E should use the \$429,841,000 in revenue collected since 1999 that is
23 above and beyond what it required to earn its authorized return on equity to
24 fund future gas transmission and storage operations before it seeks additional
25 ratepayer funds going forward.²¹

26

¹⁹ Overland Report, p. 1-1.

²⁰ Overland Report, pp. 5-2, 5-3.

²¹ CPSD Incident Investigation Report, p. 168.

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

7
8 PG&E is now faced with a converse scenario in which it may incur costs in
9 excess of those authorized by the Commission in the last GT&S rate case. If this is
10 the case, then PG&E could earn less than its authorized ROE. As in the past, GT&S
11 revenues and rates have been established in the most recent rate case for the years
12 2011, 2012, 2013 and 2014. PG&E has been provided the opportunity to earn its
13 authorized ROE. PG&E's risk if earnings fall below its authorized ROE should be
14 balanced with the fact that it has realized earnings above its ROE in previous years.

15
16 According to the Overland Report, there have been many years in the recent
17 past that PG&E has earned in excess of its authorized ROE for its GT&S
18 business.²² There is the opportunity to earn its ROE that a utility such as PG&E is
19 provided when revenues and rates are established within a rate case. The
20 Commission authorizes revenues in a general rate case based on a forecast of
21 various expenses and capital expenditures. There are many factors and variables
22 that may impact the difference between the actual and forecast levels of expenses
23 and capital investment in the rate case cycle. In some years, these factors may
24 impact the utilities' ROE in either a positive or negative manner, which represents an
25 equitable and balanced risk. The Commission has previously recognized this in
26 stating:

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

²² Overland Report, p.5-2.

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

3
4 It is inequitable to ratepayers to permit PG&E shareholders to keep the extra
5 revenues and profits generated in “good years” and to require ratepayers to pay
6 more in “bad years” to protect shareholders from potential negative impacts and risk.
7 PG&E should not be granted a revenue and rate increase in this OIR.

8
9 **5. The Absence of Incremental Revenue and Rate Increase**
10 **Should Not Impact PG&E’s Ability to Operate its System**

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

16
17 Anadarko Petroleum Corporation (Anadarko) is engaged in the exploration,
18 development, production and marketing of natural gas, crude oil, condensate and
19 natural gas liquids. The company also engages in the gathering, processing, and
20 treating of natural gas and the transporting of natural gas, crude oil and natural gas
21 liquids.²⁴

22
23 In April 2010, the Macondo well in the Gulf of Mexico was discovered to have
24 hydrocarbon accumulations. Then during suspension operations, the well blew out,
25 an explosion occurred on the Deepwater Horizon drilling rig, and the drilling rig sank,
26 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.

1 their lives in the explosion and subsequent fire and other sustained personal injuries.
2 The Macondo well was plugged on September 19, 2010.²⁵

3

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

8

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

20

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

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.

1 by Anadarko is likely more costly²⁸ than the costs likely to be incurred by PG&E for
2 pipeline safety work in the aftermath of the San Bruno explosion.

3
4 Anadarko generated sales revenues of \$10.8 billion in 2010, \$8.2 billion in
5 2009, \$14.8 billion in 2008, and \$11.7 billion in 2007. Anadarko generated operating
6 income of \$1.8 billion in 2010, \$377 million in 2009, \$5.6 billion in 2008, and \$7.9
7 billion in 2007 with net income attributable to shareholders of \$761 million in 2010
8 and -\$135 million in 2009.²⁹

9
10 PG&E generated operating revenues of \$13.8 billion in 2010 and \$13.4 billion
11 in 2009. PG&E reported earnings from operations at \$1.331 billion in 2010 and
12 \$1.22 billion in 2009 with consolidated income available for shareholders of \$1.1
13 billion in 2010 and \$1.22 billion in 2009.³⁰ The lower 2010 figure was impacted by
14 costs relating to the natural gas transmission accident in San Bruno. A comparison
15 of the two companies shows that Anadarko generates revenues slightly below the
16 level generated by PG&E with operating income somewhat more variable. The
17 financial impact of DRA's cost recovery proposal in this proceeding is very
18 reasonable when contrasted to the Settlement Agreement impact on Anadarko.

19
20 **6. PG&E is Compensated for Various Risks In its Cost of**
21 **Capital through the currently Adopted Rate of Return on**
22 **Equity**

23 In D.07-12-049, the Commission adopted a rate of return of 8.79% for PG&E.
24 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.

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

3 **Table 2-1**
4 **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%

5

6

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

16

17 The Commission considered regulatory risk which, according to the decision,
18 “pertains to new risks that investors may face from future regulatory actions that we,
19 and other regulatory agencies, might take. Examples include the potential
20 disallowances of operating expenses and rate base additions ...” The Commission
21 concluded that perceived California regulatory risks warranted a 10 basis point
22 upward adjustment to the base ROE ranges. The base ROE ranges are the
23 different forecasts developed by various parties using financial models. Based on
24 the financial, business and regulatory risks discussion and the application of
25 informed judgment, the Commission concluded that the ROE ranges adopted
26 warranted a cumulative 60 basis point upward adjustment for PG&E. The same

1 analysis concluded that the adopted ROEs be set at the upper end of the ROE
2 range found just and reasonable.

3
4 The 2007 Cost of Capital decision considered all the various business and
5 regulatory risks which contributed to the adopted ROE. The Commission did not
6 establish an adopted ROE for PG&E at the mid-point of financial models. The
7 decision arrived at the adopted ROE for PG&E by starting at the upper end of the
8 ROE range found just and reasonable (9.7% to 10.9%) and adding an additional 60
9 basis points to that figure. As described in the decision, the Commission adopted an
10 ROE of 11.35%. Therefore, the Commission action has already considered and
11 compensated PG&E for financial, business and regulatory risks between GRC
12 cycles.

13
14 **B. Recommendation 2: PG&E Should Be Financially**
15 **Responsible for All Costs Associated with Hydrostatic**
16 **Testing of its Natural Gas Pipelines**

17 On June 9, 2011, the Commission issued D.11-06-017 which ordered all
18 California natural gas transmission operators to develop Implementation Plans for
19 Commission consideration to achieve the goal of orderly and cost effective
20 replacement or testing all natural gas transmission pipelines that have not been
21 pressure tested. These plans may include alternatives that demonstrably achieve
22 the same standard of safety. The decision concludes that a pressure test record
23 must include all elements required by the regulations in effect when the test was
24 conducted. For pressure tests conducted prior to the effective date of General Order
25 112, one hour is the minimum acceptable duration.

26
27 The pressure testing of natural gas transmission pipelines has been an
28 industry standard for over 75 years. DRA recommends that PG&E be held
29 responsible for the costs associated with hydrostatic testing for all transmission

1 pipelines installed after 1935 in the absence of records that show a test was
2 performed in accordance with industry standards.

3
4 Attachment A to this exhibit provides information pertaining to the American
5 Standard Code for Pressure Piping. The attachment provides a summary of the
6 development of national codes and standards for pressure piping. The American
7 Standards Association (ASA) developed the first national code for pressure piping in
8 1935. This code included specifications for hydrostatic tests of gas piping systems.

9
10 The ASA Code was created among other things to serve as a standard of
11 reference for minimum safety requirements by equipment manufacturers, architects,
12 engineers, erectors, and others concerned with pressure piping. The Code specified
13 requirements for pressure testing after installation of pipelines. The Code specified
14 all piping systems classified as Division 1 to be capable of withstanding a hydrostatic
15 test of one and one-half times the normal service pressure. Various modifications
16 were made throughout ensuing years. Most notable was the 1955 Code changes in
17 which ASA: (1) divided the gas systems into class locations from Divisions and (2)
18 specifically identified record keeping requirements for hydrostatic testing.

19
20 The ASA industry codes provide clear guidance to gas utilities regarding the
21 requirements for hydrostatic testing of mains and pipelines located and operating in
22 different location classes. The hydrostatic testing should have been performed by
23 pipeline operators consistent with industry standards representing the minimum
24 safety requirements as of the date the pipeline was installed. The records
25 associated with hydrostatic tests should have been retained and kept on file by the
26 pipeline operator.

27
28 For many years, the Commission has had a General Order which directed
29 utilities to retain all records pertaining to the original cost of property and additions
30 and betterments. Commission General Order (GO) 28 was approved on September

1 12, 1912 and became effective October 10, 1912. The GO was reissued on
2 December 22, 1947. The GO states,

3 “That each and every public utility and common carrier subject to the
4 jurisdiction of this Commission, ... shall from the date of October 10, 1912,
5 preserve all records, memoranda and papers supporting each and every
6 entry in the following general books of such public utilities and common
7 carriers: ...

8 Also:

9 All records, contracts, estimates and memoranda pertaining to original cost of
10 property and to Additions and Betterments...”

11
12 If PG&E had properly retained records associated with the cost of hydrostatic
13 testing; that would also allow for verification that a test was performed on the
14 pipeline. There is evidence that in instances, PG&E has retained some records.

15 In response to an NTSB request for construction records for the 1948 portion
16 of the Line 132 project, PG&E provided more than 18,000 pages of records,
17 including material orders, accounting records, specifications, foreman journal
18 entries, and radiography receipts. The foreman’s log from the 1948 construction
19 project noted several instances of construction damage, including dents and dent
20 repairs. After the 1948 installation, the 20- and 24-inch segments of Line 132 were
21 tested for leaks in accordance with the construction contract by introducing air at 100
22 psig³¹ and using a soap and water solution on girth welds. According to
23 construction records, as a final check before introducing gas, the 20- and 24-inch
24 segments were pressured to 100 psig with air and held for 48 hours. Gas was
25 introduced into the 30-inch portion of the line upon completion, and the line was
26 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.

1 PG&E has stated that it “believes that after adoption of American Society of
2 Mechanical Engineers (ASME) standard ASA B31.1.8-1955, PG&E’s practice was to
3 follow ASA B31.1.8-1955, including pre-service testing.”³³ Commission Decision
4 61269 issued on December 28, 1960, in describing the position of the respondents,
5 PG&E and others stated the following “... the gas utilities in California voluntarily
6 follow the American Standards Association (ASA) code for gas transmission and
7 distribution piping systems.”³⁴

8 Industry standards pertaining to hydrostatic testing were first implemented on
9 a national basis in 1935 and continued to be updated and modified through the
10 ensuing years. PG&E and all the natural gas pipelines in California should have
11 adhered to these minimum safety standards³⁵ when installing gas transmission
12 facilities in California and retained records of the testing. The fact that PG&E did not
13 do so and/or failed to retain appropriate engineering records is no reason to burden
14 the PG&E ratepayers with the cost of testing now due to the oversight.

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

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.”

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

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

15 There are three methods that are typically used to perform the assessments:
16 (1) external corrosion direct assessment (ECDA), (2) in-line inspection (ILI), and (3)
17 hydrostatic test. ECDA is a process used to identify external corrosion defects
18 before they affect the structural integrity of the pipeline segment. The ILI is an
19 internal pipeline inspection method using specialized inspection tools called "smart
20 pigs" that travel inside the pipeline to collect information about the pipeline. The
21 hydrostatic test is typically performed immediately after construction and prior to
22 placing the pipeline in service, and is done by filling the pipeline with water at a
23 pressure greater than the maximum allowable operating pressure for a fixed period
24 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.

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

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

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

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

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

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.

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

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

13 “For us to authorize Edison’s recovery of deferred maintenance expense
14 would establish an undesirable precedent, whereby the utility is effectively
15 guaranteed that it can earn (or exceed) it’s authorized rate of return,
16 regardless of its operating efficiency or inefficiency, simply by curtailing
17 current maintenance activities, in the assurance that they could be refinanced
18 later through recovery of deferred maintenance expenses in a succeeding
19 rate case. This would create a perverse incentive for the utility to defer
20 needed maintenance in the future. Consequently, we will disallow recovery of
21 the \$34.6 million requested for deferred maintenance activities in 1983 and
22 1984. Our disallowance of this expense for test year ratemaking purposes
23 does not relieve Edison of its responsibility to maintain the operating
24 efficiency of its utility plant in a timely manner. Indeed, we expect Edison to
25 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.

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

5

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

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

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

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

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

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

9
10 For the investment in new pipeline to replace existing gas transmission
11 pipeline (associated with PG&E's Implementation Plan) that was installed prior to
12 1955, there should be an adjustment made to rate base and any associated
13 expenses. DRA proposes a 200 basis point decrease to the authorized rate of
14 return on equity. This adjustment will mitigate the impact of the investment on
15 ratepayers while not placing the entire burden upon PG&E. There should also be a
16 20% adjustment to expenses that are incurred and associated with the capital
17 improvement. DRA's proposal:

- 18 • Strikes an equitable balance between ratepayers and shareholders.
- 19 • Recognizes that transmission pipelines installed prior to 1955 and after
20 1935 should have been properly hydrostatically tested pursuant to
21 industry standards, and records maintained.
- 22 • Recognizes that pipelines installed prior to 1955 will be in excess of 60
23 years old by 2015.
- 24 • Recognizes that transmission pipelines that are properly maintained can
25 continue to operate safely well beyond the average economic life used
26 for purposes of depreciation.
- 27 • Gives consideration to the fact that any pre-1955 transmission pipelines
28 which are replaced, will be replaced with a new transmission pipeline
29 constructed with the latest state of the art materials and construction
30 techniques.

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

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

13
14 The calculation would apply specifically to the pipeline investments
15 associated with the PSEP over the ensuing 10 years. Assuming the current rate of
16 return on equity, the adjustment is approximately 17% to PG&E's existing rate of
17 return on equity. If PG&E's rate of return on equity were to decrease, then the
18 adjustment would be higher relative to the rate of return. The overall decrease to
19 total rate of return on equity will be much lower since the adjustment applies only to
20 the specific investments associated with replacing pre-1955 pipeline in the
21 Implementation Plan.

22
23 The proposal is consistent with the policy and directives set forth in the
24 Commission's rulemaking. R.11-02-019 states, "The extraordinary safety
25 investments required for PG&E's gas pipeline system and the unique circumstances
26 of the costs of replacing the San Bruno lines are situations where this Commission
27 may use its ratemaking authority to, for example, reduce PG&E's rate of return on
28 specific plant investments or impose a cost sharing requirement on shareholders.

- 1 We will consider these, and other ratemaking mechanisms, in this proceeding.”⁴⁵
- 2 The proposals of DRA are both equitable and responsive to the Commission’s
- 3 directives.

⁴⁵ R.11-02-019, pp. 11-12.

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**ATTACHMENT A – AMERICAN STANDARD CODE FOR
PRESSURE PIPING**

1 **American Standard Code for Pressure Piping:**
2 **Power, Gas and Air, Oil, District Heating, Refrigeration, Fabrication Details,**
3 **Materials**

4 **1935**

5 The first national code for pressure piping was issued in 1935 by the
6 American Standards Association and sponsored by the American Society of
7 Mechanical Engineers. The need for a national code on pressure piping became
8 evident during the period of 1915 to 1925. The Power Piping Society was the
9 first to publish a standard specification for power piping in 1915. Numerous
10 parties also published technical papers dealing with pressure piping. A
11 committee appointed by the Ohio State Department of Industrial Relations issued
12 a draft for a state code for pressure piping titled “Code of Safety Rules and
13 Regulations Covering the Installation of High and Low Pressure Steam Piping” in
14 1925.⁴⁶

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

20 The ASA issued the first national Code for Pressure Piping: Power, Gas
21 and Air, Oil, and District Heating in 1935 (B31). The ASA Code for Pressure
22 Piping (ASA Code) represents a standard of minimum safety requirements for:
23 (1) the selection of suitable materials and reference to standard specifications by
24 which they may be secured, (2) the designation of proper dimensional standards
25 for the elements comprising piping systems, (3) the design of the component
26 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

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

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

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

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

18 (2) Division 2 includes all gas and air piping systems constructed (a) in
19 compressing stations, and cross-country transportation systems and
20 (b) outside the boundaries of cities and villages, and gas and air piping
21 systems not included in Division 1.⁵⁰

22 The ASA Code specifies Hydrostatic Tests for Division 1 before erection in
23 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

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

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

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

11 **1942**

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

15 The 1942 ASA Code extensively revised and brought up to date the 1935
16 ASA Code for Pressure Piping as necessitated by the significant changes in
17 piping which had taken place since 1935. Some of the significant changes in
18 piping since the ASA Code was published in 1935 were the increased
19 importance of welded joints; standard dimensions have been prescribed for
20 factory-made butt-welding and socket-welding fittings and their use has become
21 common practice; welding-end valves with welded bonnets have been developed
22 and adopted; pressures and temperatures have advanced to new high points;
23 and new material specifications and dimensional standards have been
24 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)

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

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

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

12 (1) 150 percent of the maximum service pressure, for systems within the
13 scope of Division 1 and

14 (2) 50 psi greater than the maximum service pressure, for systems within
15 the scope of Division 2.

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

21 1944 and 1947

22 In 1944, the American Standards Association (ASA) made changes and
23 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

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

8 **1951**

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

18 Following the reorganization of Sectional Committee B31 in 1948, an
19 intensive review of the 1942 code resulted in: (1) a general revision and
20 extension of requirements to agree with present day practice; (2) the revision of
21 references to existing dimensional standards and material specifications and the
22 addition of references to new ones; and (3) the clarification of ambiguous or
23 conflicting requirements. The ASA Code was designated as an American
24 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

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

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

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

11 (1) 150 percent of the maximum service pressure, for systems included in
12 Division 1 and

13 (2) 50 psi greater than the maximum service pressure, for systems
14 included in Division 2.

15 Where an internal fluid pressure test is made after installation, it shall not
16 exceed 150 per cent of the maximum allowable working pressure for a system
17 included in Division 1 or 50 psi greater than the maximum service pressure or
18 120 per cent of the maximum allowable working pressure, whichever is greater,
19 for a system included in Division 2."⁶¹

20 **1952**

21 The American Standards Association (ASA) issued the first edition of the
22 American Standard Code for Pressure Piping, Section 8, Gas Transmission and
23 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)

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

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

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

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

22 (a) 50 psi greater than the maximum service pressure for systems in
23 cross-country gas transportation systems and gas compressing stations
24 extending through sparsely populated or rural territories within the legal
25 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

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

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

9 **1955**

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

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

20 Section 8 covers the design, fabrication, installation, inspection, testing,
21 and the safety aspects of operation and maintenance of gas transmission and
22 distribution systems, including gas pipelines, gas compressor stations, gas
23 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

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

4 Section 8 covers the conditions of use of the elements of the piping
5 systems such as the pipe valves, fittings, flanges, bolting gaskets, regulators,
6 pressure vessels, pulsation dampeners, and relief valves.⁷⁰ The requirements of
7 Section 8 are adequate for safety under conditions normally encountered in the
8 gas industry. The ASA intends that all work performed within the scope of
9 Section 8 shall meet or exceed the safety standards prescribed in Section 8.⁷¹

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

- 13 1. Class 1 locations include waste lands, deserts, rugged mountains,
14 grazing land, and farm land, and combinations of these.
- 15 2. Class 2 locations include areas where the degree of development is
16 intermediate between Class 1 locations and Class 3 locations. Fringe
17 areas around cities and towns, and farm or industrial areas where the
18 one-mile density exceeds 20 or the ten-mile density index exceeds 12
19 fall within this location class.
- 20 3. Class 3 locations include areas subdivided for residential or
21 commercial purposes where, at the time of construction of the pipeline
22 or piping system, 10% or more of the lots abutting on the street or
23 right-of-way in which the pipe is to be located are built upon, and a
24 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

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

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

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

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

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

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

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

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

- 1 a. The ground temperature at pipe depth is 32° F. or less, or
2 might fall to that temperature before the hydrostatic test could
3 be completed, or
- 4 b. Water of satisfactory quality is not available in sufficient
5 quantity.
- 6 c. In such cases an air test to 1.1 times the maximum operating
7 pressure shall be made.⁷³

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

11 Record Keeping Requirements:

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

16 **1958**

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

19

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

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

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

6 **1963**

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

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

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

- 17 1. Pipelines and mains located in Location Class 1 shall be tested either
18 with air or gas to 1.1 times the maximum operating pressure or
19 hydrostatically to at least 1.1 times the maximum operating pressure.
- 20 2. Pipelines or mains located in Location Class 2 shall be tested wither
21 with air to 1.25 times the maximum operating pressure of
22 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

- 1 3. Pipelines and mains in Location Classes 3 and 4 shall be tested
2 hydrostatically to a pressure not less than 1.4 times the maximum
3 operating pressure.⁷⁸
- 4 4. Hydrostatic testing of mains and pipelines in Location Classes 3 and 4
5 do not apply if at the time the pipeline or main is first ready for test, one
6 or both of the following conditions exist:
- 7 a. The ground temperature at pipe depth is 32° F. or less, or
8 might fall to that temperature before the hydrostatic test could
9 be completed, or
- 10 b. Water of satisfactory quality is not available in sufficient
11 quantity.
- 12 c. In such cases an air test to 1.1 times the maximum operating
13 pressure shall be made.⁷⁹

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

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

1 Record Keeping Requirements:

2 The record keeping requirements in Section 841 remains the same as the
3 ASA B31.8 standards issued in 1955.⁸¹

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

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ATTACHMENT B - QUALIFICATIONS

1 **QUALIFICATIONS AND PREPARED TESTIMONY**
2 **OF**
3 **ROBERT MARK POCTA**
4
5

6 Q.1. Please state your name and address.
7

8 A.1. My name is Robert Mark Pocta. My business address is 505 Van Ness
9 Avenue, San Francisco, California, 94102.
10

11 Q.2. By whom are you employed and in what capacity?
12

13 A.2. I am employed by the California Public Utilities Commission in the Energy
14 Cost of Service and Natural Gas (ECOS/NG) Branch of the Division of
15 Ratepayer Advocates (DRA) as a Program Manager.
16

17 Q.3. Please provide a brief description of your educational background and
18 professional experience.
19

20 A.3. I graduated from Purdue University in May 1979, with a Bachelor of Science
21 degree in Civil Engineering. In 1982, I became registered as a Professional
22 Civil Engineer in the State of California.
23

24 I was employed by the California Department of Transportation from June
25 1979 to October 1980. In November 1980, I transferred to the Commission
26 and worked in the Water Branch of the Public Staff Division until December
27 1984. My responsibilities included preparing estimates of revenues,
28 expenses, taxes and rate base in numerous rate case applications of Class A
29 water utilities. From January 1985 to August 1986, I worked in the Energy
30 Operational Costs Branch on a number of energy-related rate applications.
31

32 I began to work in the Fuels Branch in September 1986 and was promoted to
33 a Program and Project Supervisor in 1988. I served in various capacities as
34 both a witness on technical and policy issues and a project manager in
35 regulatory proceedings. These proceedings included natural gas industry
36 investigations, rulemakings and restructuring, natural gas policy, utility
37 mergers, incentive regulation, cost allocation, reasonableness reviews,
38 capacity brokering, need for new interstate pipelines, natural gas vehicles,
39 and natural gas procurement. I have testified as an expert witness many
40 times before the Commission in various proceedings and have testified before
41 the California Energy Commission. I have also submitted prepared testimony
42 and appeared as an expert witness on behalf of the Commission at the
43 Federal Energy Regulatory Commission in proceedings involving interstate
44 gas pipeline companies.
45

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

18
19 Q.4. What is the area of your responsibility in this proceeding?

20
21 A.4 I am sponsoring Exhibit DRA-02, Policy – Cost Recovery.

22
23 Q.5 Does this conclude your prepared direct testimony?

24
25 A.5 Yes, it does.