BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

# OPENING BRIEF OF THE DIVISION OF RATEPAYER ADVOCATES

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## TABLE OF CONTENTS

Page

## TABLE OF AUTHORITIES

Page

### CPUC Decisions



### California Public Utilities Code



### Federal Regulations

## TABLE OF ACRONYMS

| | |
|---|---|
| AACEI | Association for the Advancement of Cost Engineering International |
| AGA | American Gas Association |
| AFUDC | Allowance for Funds Used During Construction |
| AMI | Advanced Metering Infrastructure |
| ASA | American Standard Association |
| ASME | American Society of Mechanical Engineers |
| BEAR | Berkeley Engineering And Research, Inc. |
| CPSD | Consumer Protection and Safety Division |
| DOE | U.S. Department of Energy |
| DRA | Division of Ratepayer Advocates |
| FERC | Federal Energy Regulatory Commission |
| GAO | U.S. Government Accountability Office |
| GARP | Generally Accepted Record-Keeping Principles |
| GIE or Gulf | Gulf Interstate Engineering |
| GIS | Geographic Information System |
| GPRP | Gas Pipeline Replacement Plan |
| GRC | General Rate Case |
| GTAM | Gas Transmission Asset Management |
| HCA | High Consequence Area |
| HDD | Horizontal Directional Drilling |
| INGAA | Interstate Natural Gas Association of America |
| MAOP | Maximum Allowable Operating Pressure |
| MOP | Maximum Operating Pressure |
| NTSB | National Transportation Safety Board |
| PG&E | Pacific Gas and Electric Company |
| PHMSA | Pipeline and Hazardous Materials Safety Administration |
| PNNL | Pacific Northwest National Laboratory |
| PSEP | Pipeline Safety Enhancement Plan |
| QRA | Quantitative Risk Assessment |
| ROE | Return On Equity |
| RT | Reporter's Transcript |
| SDG&E | San Diego Gas & Electric Company |
| SCADA | Supervisory Control and Data Acquisition |
| SoCal Gas | Southern California Gas Company |
| TIMP | Transmission Integrity Management Program |
| TURN | The Utility Reform Network |

# I. INTRODUCTION AND SUMMARY OF RECOMMENDATIONS

Pursuant to Rule 13.11 of the Commission's Rules of Practice and Procedure (Rules), and the schedule set by Administrative Law Judge Maribeth Bushey, the Division of Ratepayer Advocates (DRA) submits this Opening Brief on Pacific Gas and Electric Company's (PG&E) application for approval of its Natural Gas Transmission Pipeline Replacement or Testing Implementation Plan submitted on August 26, 2011 pursuant to Commission Decision (D.) 11-06-017, and for ratepayer funding for the majority of the estimated costs of the proposed plan.

## A. Background

The Commission issued D. 11-06-017 in response to the San Bruno gas explosion that resulted in the death of eight people, injured 58, and destroyed 38 homes, and the subsequent "urgent recommendations" issued by the National Transportation and Safety Board (NTSB) early in its investigation of that disaster.[1] It ordered all California natural gas transmission operators to prepare comprehensive plans to pressure test or replace all of their gas pipelines for which they have no evidence of a prior pressure test. [2] The order provided that alternatives "that demonstrably achieve the same standard of safety" as testing or replacement may also be proposed.[3] PG&E was ordered to "continue to work on its determination of Maximum Allowable Operating Pressure through pipeline features analysis" as previously ordered.[4] The Commission's order to validate the

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[1] D.11-06-017, p. 3. The NTSB's final report was issued on August 30, 2011, after the Commission opened this proceeding. *National Transportation Safety Board, Pipeline Accident Report, Pacific Gas and Electric Company, Natural Gas Transmission Pipeline Rupture and Fire, San Bruno, California, September 9, 2010, adopted August 30, 2011* (NTSB Report). The NTSB Report is incorporated by reference into Ex. 121 (testimony of Thomas Long) and is properly within the record of this proceeding. As the Commission determined in the Order Instituting Rulemaking 11-02-019, p. 12, note 6: "We will take official notice of the record in other proceedings, including the investigation of PG&E's gas system record-keeping, in our ratemaking determination." This determination was affirmed in D.11-06-017, p. 23: "As we indicated in [the Order Instituting Rulemaking 11-02-019], we intend to take official notice of the record in other proceedings, including the investigation of PG&E's gas system record-keeping (R.11-02-016), in our ratemaking determination."

[2] D.11-06-017, p. 1.

[3] Id.

[4] Id.

maximum allowable operating pressure of all pipelines was a response to the NTSB's "justifiable alarm" that many of PG&E's records regarding the gas lines involved in the San Bruno gas explosion were materially inaccurate:

> … this project to validate [maximum authorized operating pressure] was set in motion by the NTSB's justifiable alarm at PG&E's records being inconsistent with the actual pipeline found in the ground in Line 132.[5]

The Commission issued D.11-06-017 in an effort to ensure safe operation of all gas pipelines and rebuild the Commission's and the public's trust in the safety of PG&E's operations.[6] It directed the utilities to include in their plans cost estimates and proposed ratemaking treatment and rate impacts.[7] PG&E alone was directed to propose a cost allocation between shareholders and ratepayers.[8]

### B. PG&E's Proposed Plan

PG&E filed its pipeline testing and replacement plan, which it calls its "Pipeline Safety Enhancement Plan" or "PSEP," on August 26, 2011. Phase 1 of the PSEP is to be completed by 2014 and includes four major components: "pipeline modernization"; recordkeeping improvements; valve automation; and "interim safety enhancement measures." PG&E estimates the cost of Phase 1 at $ 2.2 billion (including return on capital investment through 2014 only), and seeks ratepayer funding for $5 billion of that.[9] Of that amount, PG&E proposes to collect $768.7 million in incremental ratepayer funding (incremental to the revenue requirement authorized in its most recent rate case) between 2012 and 2014 (approximately $223 million of that would be for recordkeeping improvement).[10] The total cost includiong return on capital investment over the life of

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[5] D.11-06-017, p. 17.

[6] D.11-06-017, p. 17.

[7] Id., Ordering paragraphs (OP) 9 and 10.

[8] Id., OP 10.

[9] Ex. 2, PG&E Direct Testimony, p. 8-4, Table 8-4.

[10] Ex. 2, PG&E Direct Testimony, p. 5-4, Table 5-1. PG&E is not seeking funding for its Records Correction Program activities conducted in 2011.

the assets (40 or 45 years) would be at least $5 billion.[11] Shareholders would absorb expenses incurred in 2011 and the hydrotesting expenses for some of the pipelines. PG&E has estimated that Phase 2 (which could be submitted in its rate case application to be filed in 2014) will cost between $6.8 billion and $9 billion.[12]

### C. DRA Recommendations

**Ratemaking and cost allocation** issues applicable to the entire plan are addressed in Section II. DRA urges the Commission to require shareholders to absorb most of the costs of Phase 1 because the San Bruno disaster should not become an opportunity for profit and it is important that the financial consequences of PG&E's mismanagement of its pipeline system be borne by the company, not ratepayers.

**PG&E's request for ratepayer funding for its recordkeeping projects** is addressed in Section III. DRA opposes any incremental ratepayer funding for this purpose because managing pipeline records is a core aspect of operating gas pipelines safely, and PG&E has been amply funded over the years to operate its pipeline system safely and reliably. We now know that PG&E's failure to manage information about its gas pipelines properly has made it impossible to operate safely. One investigator for the Commission's Consumer Protection and Safety Division found that (1) "the pipe failure and explosion on Line 132 in San Bruno on September 9, 2010 may have been prevented had PG&E managed its records properly over the years" and (2) "PG&E's entire integrity management program is an exercise in futility because PG&E lacks the basic records necessary to provide fundamental data required for the successful use of the integrity management risk model. Therefore, PG&E has been operating, and continues to operate, without a functional integrity management program."[13] PG&E has utterly failed to manage its pipeline information competently. It should now take responsibility for

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[11] Ex. 149, DRA Testimony, Chap. 9, pp.28-29 ($5.5 billion over 45 years); 8 RT 743-744 and 840-841 (Bottorff).

[12] Ex. 149, DRA Testimony, Chap. 9, p. 2 and note 5.

[13] Ex. 45, Felts Report, p. 49.

setting up a functional information management system without further burdening ratepayers.

The **Pipeline Modernization Plan** is addressed in detail Section IV. DRA's analysis, as well as TURN's, show that the plan is seriously flawed. The Commission should require that its major deficiencies be corrected without interrupting the safety work that is now underway. In short, the plan is deficient because:

- It does not define project scope with sufficient accuracy or certainty to support any decision on cost recovery.
- The Commission and the public cannot have confidence that the highest priority safety work has been prioritized correctly for Phase 1.
- PG&E relied on unreliable and incomplete data which PG&E is in the process of correcting; the plan should be updated based on the new and corrected data.
- The "decision tree" used to determine which projects are the highest safety priority needs to be corrected and then re-run using more complete and reliable data.
- PG&E has deviated from its decision tree outcomes to accelerate many non-priority projects into Phase 1 and has omitted some that should be included. PG&E also proposes to increase capacity on some lines without a safety justification. Adding non-priority projects to Phase 1 expands scope and costs to Phase 1, adds risk, and makes it less likely that the highest priority safety work will get done expeditiously.
- PG&E's request for an across-the-board 20% contingency is unsupported and unreasonable.

In sum, the proposed pipeline plan needs more work and requires continuing Commission oversight. DRA makes specific recommendations to meet both of these needs in Section IV.

The **Valve Automation** proposal is addressed in Section V. DRA recommends that investments be made where the actual safety gains are real and worth the cost.

Finally, although DRA's overarching recommendation is to require PG&E to absorb most of the costs of Phase 1, DRA recognizes that the Commission may reject this recommendation and authorize ratepayer funding nevertheless. Given that possibility, DRA has included recommendations that apply only if cost recovery is authorized. These recommendations are presented in Section VI.

## II. THE COMMISSION SHOULD NOT ENABLE PG&E TO PROFIT FROM THE SAN BRUNO EXPLOSION

In the wake of the most deadly utility tragedy in California history, caused in large part by utility mismanagement, PG&E requests the Commission to approve a special surcharge by which ratepayers will pay $768.7 million in *new* rates between 2012 and 2014 to upgrade its gas transmission system. Under PG&E's proposal, it would ultimately collect approximately $5 billion in rates for Phase I of its PSEP through imposition of the surcharge over 45 years.[14] In sum, the San Bruno explosion showed us that PG&E's gas transmission pipeline records are so unreliable – they contain so many material omissions or inaccuracies – that PG&E cannot safely maintain its gas transmission system. Among other things, PG&E has no idea how many of its lines have been repaired in the past, which lines are due for replacement, and which lines can wait. Thus, PG&E must recreate its gas system records from the ground up through a comprehensive review of original records, where available, testing or replacement of facilities where they are not, and development of new computer systems to record and manage this information.

These activities comprise PG&E's proposed PSEP, which is intended to correct the multitude of PG&E deficiencies contributing to the San Bruno explosion that were revealed by the NTSB and the Commission Independent Review Panel investigations.[15]

Concurrent with PG&E's mismanagement of its gas system records, PG&E reaped massive profits from its gas operations. Since 1999 PG&E has collected nearly $500 million in revenue *above* its authorized return on equity from its gas transmission and

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[14] Ex. 149, DRA Testimony, Chap. 9, p.12; pp.28-29; Ex. 2, PG&E Direct Testimony, p. 8-4, Table 8-4; 8 RT 743-744 and 840-841.

[15] The NTSB and Independent Review Panel reports are available, respectively, at: http://www.ntsb.gov/doclib/reports/2011/PAR1101.pdf and http://www.cpuc.ca.gov/NR/rdonlyres/85E17CDA-7CE2-4D2D-93BA-B95D25CF98B2/0/cpucfinalreportrevised62411.pdf. Additional reports on the violations arising specifically from the San Bruno explosion and PG&E's recording keeping deficiencies are available, respectively, at http://www.cpuc.ca.gov/PUC/sanbrunoreport.htm and http://www.cpuc.ca.gov/NR/exeres/23FF3E35-EE5C-4ABE-BF5A-429FF244B03E,frameless.htm?NRMODE=Published.

storage operations.[16] That PG&E could be so mismanaged and yet so profitable reflects PG&E's success in putting profits before safety. The Commission needs to put a stop to this. It must let the company bear the financial consequences of its mismanagement.

In this section of its brief, DRA makes policy recommendations to ensure that PG&E does not profit from its past mismanagement which resulted in chaotic pipeline records and the San Bruno explosion.

### A. The Commission Should Reject PG&E's Proposal To Raise Rates Between Rate Cycles

To pay for Phase 1 of its PSEP, PG&E seeks a special surcharge to collect $5 billion from ratepayers over 45 years.[17] In response to the requirement in D.11-06-017 that PG&E consider cost sharing, PG&E initially proposed that its shareholders pay for all PSEP costs incurred in 2011.[18] Thus, of the total costs of $2.183 billion that PG&E anticipates for Phase I, PG&E estimates that shareholders will pay $224.2 million.[19]

PG&E's proposal to increase customer rates should be rejected because:

1. Section 463 of the California Public Utilities Code requires disallowance of costs resulting from unreasonable utility errors and omissions;
2. PG&E is proposing to charge ratepayers a second time for work funded in prior rates;
3. Increasing PG&E's revenues between rate cases is inconsistent with test year ratemaking principles;
4. PG&E's proposed surcharge disrupts the balance of the bargain struck in Gas Accord V;
5. PG&E can and should implement cost control measures between GRCs;
6. PG&E's gas transmission and storage operations have been very profitable while maintenance was deferred and safety neglected; and

[16] Ex. 42, Overland Report, pp. 5-2, 5-3.

[17] Ex. 2, PG&E Direct Testimony, p. 1-17, Table 1-4.

[18] Ex. 2, PG&E Direct Testimony, p. 1-17, Table 1-4. PG&E's cost sharing proposal has varied throughout the proceeding. This issue is discussed further in Section II.B. below.

[19] Ex. 149, DRA Testimony, Chap. 8, p. 12.

7. PG&E has failed to meet its burden of justifying additional rate increases for pipeline safety work between rate case cycles.

Each of these issues is addressed, in turn, below.

### 1. Section 463 Requires Disallowance of Increased Costs Resulting From Unreasonable Utility Errors and Omissions

Section 463 requires the Commission to disallow direct and indirect expenses related to the unreasonable errors or omissions of a utility costing more than $50 million:

> [T]he commission shall disallow expenses reflecting the direct or indirect costs resulting from any unreasonable error or omission relating to the planning, construction, or operation of any portion of the corporation's plant which cost, or is estimated to have cost, more than fifty million dollars ($50,000,000) ….

The Commission has relied upon § 463 and its general ratemaking authority on many occasions to disallow requests for costs resulting from unreasonable utility errors and omissions, and should do so here.[20]

Here, PG&E seeks $5 billion in ratepayer funding to correct decades of unreasonable errors and omissions, including failure to maintain accurate and complete pipeline records, and failure to test and or replace its pipelines consistent with a functional integrity management system. To evade the requirements of § 463, PG&E argues that its PSEP is not designed to correct past errors or omissions.[21] This argument is not credible.

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[20] *See, e.g.*, *Re Pacific Gas and Electric Company* (1998) 83 CPUC 2d 208 (D.98-11-067, affirming disallowance of $100 million from recoverable Diablo Canyon nuclear plant sunk costs, based on an admitted error by contractors during the plant's construction); *Re Southern California Edison Company* (1994) 53 CPUC 2d 452 (D.94-03-048, disallowing costs associated with an accident and explosion at a coal slurry generating plant that killed six utility employees); *Re Pacific Gas and Electric Company* (1985) 18 CPUC 2d 700 (D.85-08-102, disallowing costs based on managerial imprudence and inadequate attention during construction of Helms Pumped Storage Project); *Re Southern California Edison Company* (1985) 17 CPUC 2d 470 (D.85-03-087, disallowing repair costs associated with defective steam generator equipment at San Onofre Nuclear Generating Station Unit 1); *Re Southern California Edison Company* (1986) 22 CPUC 2d 124 (D. 86-10-069, disallowing $344.6 million in construction costs of SONGS units 2 and 3 as a result of imprudence and unreasonable delays in completion of the project).

[21] Ex. 21, PG&E Rebuttal Testimony, p. 1-2.

As described in Section I above, PG&E's PSEP was filed pursuant to D.11-06-017, which sought to address the PG&E errors and omissions the NTSB identified in its safety recommendations. But for those errors and omissions, there would be no need for PG&E's PSEP. Further, while PG&E insists that its PSEP is not designed to correct its past errors or omissions, it fails to identify what *other* plan is therefore intended to address those errors or omissions. That is because it cannot. The PSEP is designed to, and hopefully will, correct those errors and omissions. Thus, § 463 – which applies to both direct and indirect costs resulting from errors and omissions – requires that the costs be disallowed.

### 2. PG&E Proposes To Charge Ratepayers A Second Time For Work Funded in Prior Rates

Similar to its argument that its PSEP is not intended to correct its prior record keeping deficiencies, PG&E asserts throughout its testimony that it is not proposing to charge customers a second time for work that was previously funded in rates.[22] PG&E must make this argument because it admits that it cannot charge customers twice for work that they have already paid for.[23] Thus, ignoring all prior funding received in its rate cases for maintenance of its gas transmission system, updates to its information technology systems, and development and maintenance of its gas transmission integrity management system, PG&E insists the PSEP includes only "new" costs to meet "new" regulatory requirements.[24]

The legal argument explaining why the obligation to maintain complete and accurate records is not new is set forth in Section III below. In sum, in light of the NTSB and CPSD findings regarding the state of PG&E's records and integrity management system, which reveal decades of PG&E mismanagement of these programs, PG&E's argument lacks credibility. Because PG&E's PSEP will, hopefully, correct these deficiencies, and because PG&E ratepayers have been paying PG&E to maintain accurate

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[22] See, e.g., Ex. 21, PG&E Rebuttal Testimony, pp. 1-6 through 1-9, and 11-14 through 11-20.

[23] Ex. 21, PG&E Rebuttal Testimony, p. 1-6.

[24] Issues of historic embedded funding are addressed in Section III below.

and complete records for years, PG&E is, in fact, asking ratepayers to pay twice for something they have already paid for. On this basis, PG&E's surcharge cannot be justified.

### 3. Increasing PG&E's Revenues Between Rate Cases Is Inconsistent With Test Year Ratemaking Principles

Increasing PG&E's revenues between general rate cases (GRCs) is inconsistent with test year ratemaking principles. Test year ratemaking provides that revenues authorized in a utility's GRC are 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 utility's management. The utility has the ability to manage its costs in a manner it deems appropriate and it can take advantage of numerous methods and internal policies to control costs, and to earn profits above its authorized rate of return. The Commission explained this basic rule of test year ratemaking in its decision on Southern California Edison Company's (SCE) 2006 GRC:

> 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.[25]

The Commission established PG&E's existing rates consistent with test year ratemaking principles and there is no reason to violate those principles now. In fact, adhering to those principles will ensure that PG&E does not profit from the San Bruno explosion.

All of the investigations regarding the explosion on the PG&E system identify decades of PG&E record keeping mismanagement as a contributing factor. These findings alone are enough to justify a Commission finding that any costs incurred before the next round of PG&E GRCs should be borne by PG&E shareholders. Thus, the Commission should direct PG&E management to identify internal solutions to address

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

the expenses and investment associated with ensuring PG&E's safe operation of its gas systems until its next GRC.

### 4. PG&E's Surcharge Disrupts The Bargain Struck In Gas Accord V

PG&E's proposal to raise rates by imposing a new surcharge on its customers disrupts the balance of the bargain struck by the parties in the Commission-adopted settlement of PG&E's last gas transmission and storage rate case – "Gas Accord V."[26]

Gas Accord V included approximately 26 parties representing almost every facet of the natural gas market, including small and large end-use customers, marketers, interstate pipelines, municipal utilities, and independent storage providers. These diverse parties balanced their various interests and individual positions in agreeing to the settlement. Given the significant number of parties involved, efforts to arrive at an equitable balance were considerable.

Gas Accord V established PG&E's gas transmission and storage rates for the years 2011-2014. The parties reasonably anticipated that they would not be subject to interim rate increases. Section 12.1 of settlement agreement – entitled "Rate Certainty" - provided that the negotiated rates would not be subject to adjustment during the Settlement Period and precluded any party from making a proposal to adjust the agreed upon rates:

> 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. …
>
> Nothing in this Settlement Agreement shall prevent PG&E from making adjustments to services, capacity assignments, cost allocations, rates or the like in order to comply with Commission orders in other proceedings. No Settlement Party shall make any proposal that would conflict with or alter any term of this Settlement Agreement, and the

[26] D.11-04-031 approved the Gas Accord V settlement and included the settlement agreement as Appendix A to the decision.

> Settlement Parties shall not support proposals of others that would do the same.[27]

The parties also negotiated when PG&E could file for its next rate increase. Section 2.3 of the settlement agreement provides that PG&E will file its next gas transmission and storage rate case no sooner than Monday, February 3, 2014. Section 2.4 provides for an interim rate increase if new rates are not in place by January 1, 2015.

After agreeing to these highly negotiated settlement terms, which the Commission approved in D.11-04-031, PG&E now proposes a new surcharge to raise rates. It claims that Section 12.1 permits it to raise rates because it must do so "in order to comply with Commission orders in other proceedings."[28] PG&E explains that "Decision 11-06-017 ordered PG&E to submit the PSEP and to propose rates associated with the costs of implementation of the new safety standards adopted in the decision."[29]

It is true that D.11-06-017 ordered PG&E to submit an implementation plan, and directed PG&E and the other gas utilities to address "proposed ratemaking." But D.11-06-017 did not *require* PG&E to propose rate increases. Given PG&E's settlement of Gas Accord V – approved by the Commission only two months before issuance of D.11-06-017 – PG&E's argument that it is not constrained by its rate agreement in Gas Accord V is hollow.

The San Bruno explosion occurred in September 2010. By the time of the Gas Accord V settlement – more than six months later - PG&E was well aware of the NTSB's findings regarding its record keeping deficiencies, and the Commission orders to address these deficiencies.[30] PG&E knew it was going to incur significant costs to address these deficiencies involving its gas transmission system. Had it intended to pass these charges on to customers, it should have made this clear in Gas Accord V. It is disingenuous for

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

[28] Ex. 21, PG&E Rebuttal Testimony, p. 1-20.

[29] Ex. 21, PG&E Rebuttal Testimony, p. 1-20.

[30] D.11-06-017, pp. 2-9, provides this chronology of events.

PG&E to now argue that these "new" costs must be added to the rates it settled on in Gas Accord V.

Gas Accord V permits PG&E to file a new rate application in two years. At that time, PG&E is free to request expenses and capital additions associated with its PSEP for the years 2015 and beyond, and return on capital investment made prior to that year. Until then, it is inconsistent with Gas Accord V and test year ratemaking principles for the Commission to approve PG&E's proposed surcharge outside of the rate case cycle. PG&E has provided no adequate justification for such a significant deviation from both law and policy, and its request should therefore be denied.

### 5. PG&E Management Can And Should Implement Cost Control Measures Between GRCs

As described in DRA's testimony, PG&E's rate of return on equity compensates PG&E for regulatory, business, and other risks in between rate cases.[31] Once that rate of return is established, the utility's management is responsible for managing costs and risks between rate cases. Under these ratemaking principles, PG&E's management is responsible for reducing costs and identifying operational efficiencies in order to stay within its authorized revenue requirement and protect shareholder interests.

Holding PG&E to these ratemaking principles will reinforce the efficiencies behind these basic ratemaking principles and communicate that PG&E management must be accountable for its past decisions. Denying PG&E's request for additional ratepayer funding in between rate cases gives PG&E management the incentive to properly manage risk going forward; granting it would allow PG&E management to evade responsibility for its decisions.

The Commission has commented on the important incentive created by holding management accountable for its decisions:

> 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

[31] Ex. 143, DRA Testimony, Chap. 2, pp.18-20.

> will suffer under utility management which is lethargic with a "cost plus" mentality.[32]

PG&E has failed to adequately explain why it should not be held accountable for its decisions here.

PG&E management has the ability to control costs and move monies from one P&GE budget to another, and the Commission should encourage PG&E to make these choices for itself. For example, PG&E has a Short Term Incentive Plan which awards incentive payments to certain management employees, on top of their salaries. There is some ratepayer funding of this program embedded in GRC rates and some shareholder funding of the program. PG&E paid approximately $81 million through this plan in the 2010 plan year. This payout is a discretionary expense that management controls. Thus, PG&E management could elect to move some of these funds to the PSEP program. Requiring PG&E management to make such hard decisions will provide the proper incentive for PG&E to meet its PSEP goals efficiently using existing funding sources, rather than through an injection of ratepayer funds.

#### 6. PG&E's Gas Transmission And Storage Operations Have Been Very Profitable While Maintenance Was Deferred And Safety Neglected

PG&E is a large utility with significant financial resources. As the Commission recognized recently in the Rancho Cordova gas explosion penalty decision:

> PG&E serves approximately 4.3 million natural gas customers and 5.2 million electric customers in a northern California service territory that covers 43% of the state. PG&E reported 2010 operating revenues of $ 13.841 billion.[33]

PG&E's gas transmission and storage operations have been very profitable for over a decade. A CPSD-commissioned audit report, issued December 30, 2011 (Overland Report) confirms this.[34] The Overland Report concludes that PG&E has

[32] Decision 85-03-042, 17 CPUC 2d 246, 254.

[33] D.11-11-001, p. 40.

[34] Ex. 42, "Focused Audit of Pacific Gas and Electric Gas Transmission Pipeline Safety-Related

earned significantly more than the "reasonable rate of return" authorized in its gas transmission and storage rate cases for well over a decade. Specifically:

- PG&E's gas transmission operation and maintenance *expenses* were *five percent lower* than the amounts adopted in its rate cases over the period 1997 to 2010;
- PG&E's total gas capital *expenditures* were *six percent lower* than adopted in its rate cases over the period 1997 to 2010; and
- PG&E's gas transmission and storage operations have been very profitable since the Gas Accord Structure was implemented in March 1998. During that time, those *revenues exceeded* the amount needed to earn the *authorized rate-of-return by $430 million*.[35]

According to the Overland Report, the actual rate of return on equity (ROE) earned by PG&E on its gas transmission and storage operations between 1999 and 2010 significantly exceeded the authorized ROE in ten of the twelve years in the study period. The Overland Report concludes that PG&E earned surplus revenues of an average of $36 million a year over the period, which PG&E could have used to improve gas safety. While the report expressly recognizes that its numbers are estimates, it concludes that PG&E's actual earnings significantly exceeded the authorized levels over the study period.[36]

Based on the Overland Report, CPSD recommends that PG&E use the nearly $500 million in excess revenues it has earned since 1999 to fund various gas maintenance and safety operations before it seeks ratepayer funding going forward.[37] While funding deferred maintenance in this manner is probably justified, DRA has proposed a more

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Expenditures for the Period 1996 to 2010" by Overland Consulting, dated December 30, 2011 (Overland Report).

[35] Ex. 42, Overland Report, p. 1-1.

[36] Ex. 42, Overland Report, p. 5-3 ("Some of the inputs into the ROE analysis are estimates. The estimates do not have a significant impact on the overall results, and refining the estimates further would not change the overall conclusion that PG&E's actual earnings significantly exceed the authorized levels over the study period.").

[37] CPSD San Bruno Report, p. 168 ("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. (Source Overland Report, page 5-2, Table 5-2.)").

comprehensive approach grounded in basic ratemaking principles, as described in this section.

The findings in the Overland Report support DRA's recommendations. According to that report, in the majority of the years from 1999 to 2010, PG&E's earnings exceeded its authorized ROE. Under the ratemaking system used in California, PG&E was not expected to refund those excess earnings.

PG&E is now faced with the opposite situation: It may incur costs that may result in a lower ROE than that authorized in its last gas transmission and storage rate case. PG&E's current risk of earning less than its authorized ROE – a risk which PG&E management can mitigate – should be viewed in light of the fact that PG&E has earned substantially more than its authorized ROE for over a decade.

The Commission has recognized that the possibility of realizing a lower rate of return than that authorized is part of the regulatory compact:

> 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 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.[38]

In sum, it would be unfair to permit PG&E shareholders to keep profits generated in "good years" and to require ratepayers to pay more in "bad years" to protect shareholders from potential negative impacts and risk. In particular, ratepayers should not be required to pay more when utility costs have increased due to imprudent management. Again, it is important that the financial consequences of utility mismanagement be borne by the company, as required by Public Utilities Code § 463. PG&E should not be granted a rate increase in this proceeding.

[38] Decision 09-03-025, p 324.

### 7. PG&E Has Failed To Meet Its Burden Of Justifying Additional Rate Increases For Pipeline Safety Work Between Rate Case Cycles

Pursuant to § 454, PG&E has the burden of proving that its rate increase is justified:

> … no public utility shall change any rate or so alter any classification, contract, practice, or rule as to result in any new rate, except upon a showing before the commission and a finding by the commission that the new rate is justified.

Pursuant to § 451, all utility rates and charges must be just and reasonable:

> All charges demanded or received by any public utility … for any product or commodity furnished or to be furnished or any service rendered shall be just and reasonable. Every unjust or unreasonable charge demanded or received for such product or commodity is unlawful.[39]

PG&E has failed to demonstrate that its proposed surcharge is justified, or that it is just and reasonable.

## B. PG&E Should Pay For All Pressure Testing Of Lines Installed Since 1935

PG&E should pay for all pressure tests for PG&E gas lines installed since 1935 because pressure testing has been an industry standard since that time. As a prudent manager of its system, PG&E should have pressure tested many if not most lines over the years, and should have kept records of those tests, as well as other maintenance history.[40] As a utility with a statutory obligation to operate its system safely,[41] PG&E had an obligation to comply with industry standards developed to ensure safe operation of pipeline systems, including retention of all records required for safe operation. Further,

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[39] *See also* Pub. Utils. Code § 728 ("Whenever the commission, after a hearing, finds that the rates or classifications, demanded, observed, charged, or collected by any public utility for or in connection with any service, product, or commodity, or the rules, practices, or contracts affecting such rates or classifications are insufficient, unlawful, unjust, unreasonable, discriminatory, or preferential, the commission shall determine and fix, by order, the just, reasonable, or sufficient rates, classifications, rules, practices, or contracts to be thereafter observed and in force.").

[40] Ex. 143, DRA Direct Testimony, Chap. 2, pp. 20-21 and Appendix A; see also Section III.D below regarding General Order 28.

[41] Pub. Utils. Code § 451.

Commission General Order 28 has expressly required PG&E to retain certain records, which would have included pressure test records, since 1912.

PG&E initially argued that ratepayers should be responsible for costs to pressure test or replace all of PG&E's gas transmission lines installed before 1970 for which it does not have pressure test records. PG&E based this argument on the "grandfathering" provision of the 1970 federal regulations that permitted it to meet the pressure testing requirement for lines installed before 1970 by relying upon a maximum allowable operating pressure (MAOP) established based upon 5 years of operational data, 49 CFR § 192.619(c).[42]

When DRA accurately observed that the Commission's General Order 112 had required PG&E to pressure test all pipeline segments installed since July 1, 1961, PG&E agreed that it would be responsible for the costs of testing all lines installed after that date.[43] PG&E then argued in its rebuttal testimony that it had no obligation to pressure test lines installed before July 1, 1961 because General Order 112 permitted it to grandfather lines installed before that date. Thus, PG&E seeks to shift the costs of the PSEP to ratepayers for all lines installed before July 1, 1961 on the basis that it had no obligation to pressure test its lines before that date, and no obligation to retain the records of those lines which were pressure tested.[44]

PG&E's continued reliance on grandfathering as a reason for not pressure testing its earlier installed lines, or for not saving records where a pressure test occurred, is misplaced for multiple reasons. First, PG&E has had a statutory obligation to maintain and operate its system safely since 1909.[45] A gas transmission system cannot be operated

[42] Ex. 2, PG&E Direct Testimony, p. 1-13.

[43] Notwithstanding PG&E's offer to pay for pressure testing of lines installed since July 1, 1961, PG&E has not updated its estimate for its related Records Validation Program, discussed in Section III below.

[44] Ex. 21, PG&E Rebuttal Testimony, p. 10-13 ("In the case of transmission pipe installed in California after July 1961, I agree that if no pressure test records can be found then PG&E should be bear [sic] the expense of pressure testing.")

[45] California Public Utilities Commission, Consumer Protection and Safety Division, Incident Investigation Report, September 9, 2010 PG&E Pipeline Rupture in San Bruno, California, released January 12, 2012 (CPSD San Bruno Report), p. 5. The CPSD San Bruno Report was supplemented and submitted as CPSD's testimony in I.12-01-007 on March 16, 2012. The CPSD San Bruno Report is

safely without knowing the pressure tolerance of the lines making up that system. Thus, conducting a pressure test and retaining the results of that test are critical to the safe operation of a gas transmission system.

Second, PG&E represented to the Commission at the time that General Order 112 was adopted that it *complied* with industry standards.[46] Those standards have recommended that all gas pipelines be pressure tested since 1935. PG&E has since affirmed that its practice was to follow ASA B31.1.8-1955, including pre-service testing.[47] Thus, PG&E claims that it was following industry standards by 1955. PG&E's witness agreed that the 1955 standards required operators to keep records of pressure tests (among other pipeline records),[48] and that to qualify for "grandfathered" status under the 1970 regulations, an operator needed to retain records about the pipeline's characteristics and history.[49] Thus, it is inappropriate for PG&E to argue that it had no obligation to pressure test, or retain records of those tests, on lines installed before 1961.

Third, PG&E has had an obligation under the Commission's General Order 28 to retain certain records, such as pressure test records, since 1912.[50] General Order 28, reissued in December 1947, requires PG&E to retain "[a]ll records, contracts, estimates, and memoranda pertaining to original cost of property and to Additions and Betterments

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properly within the record of this proceeding. As the Commission determined in the Order Instituting Rulemaking 11-02-019, p. 12, note 6: "We will take official notice of the record in other proceedings, including the investigation of PG&E's gas system record-keeping, in our ratemaking determination." This determination was affirmed in D.11-06-017, p. 23: "As we indicated in [the Order Instituting Rulemaking 11-02-019], we intend to take official notice of the record in other proceedings, including the investigation of PG&E's gas system record-keeping (R.11-02-016), in our ratemaking determination."

[46] Ex. 151, issued December 28, 1960 and effective July 1, 1961, p. 4, describes the position of the respondents, PG&E and others: "… the gas utilities in California voluntarily follow the American Standards Association (ASA) code for gas transmission and distribution piping systems." PG&E has since confirmed this assertion. See Section III discussion below.

[47] Ex. 75, PG&E Data Response to DRA 045, Q/A 7(a).

[48] 10 RT 1111, Howe/PG&E.

[49] 10 RT 1117, Howe/PG&E.

[50] Ex. 150, DRA Testimony, General Order Numbers 28 and 58.

…"[51] If PG&E had properly retained records associated with the cost of hydrostatic testing; those records would verify that a test was performed on the pipeline.

PG&E's witness acknowledged that General Order 28 requires utilities to maintain records pertaining to "additions and betterments" and "depreciation and replacement of equipment and plant."[52] There is also, evidence, described in Section III below, that PG&E retained some records of this type.[53] Thus, it is inappropriate for PG&E to suggest it had no obligation to retain pressure test records on lines installed before 1961.

Fourth, pressure testing of gas transmission pipelines has been an industry standard for over 75 years – since 1935. Thus, as a responsible utility, PG&E should have been pressure testing its lines since at least 1935.

In sum, PG&E cannot rely upon its right to "grandfather" to claim that it was not required to pressure test, or retain records of pressure testing, for lines installed before 1961. PG&E's failure to pressure test its lines installed before 1961, or to retain pressure test records, is an unreasonable error or omission which PG&E, not its ratepayer, must fun. DRA recommends that PG&E be held responsible for the costs associated with pressure testing (or its functional equivalent) for all pipeline installed after 1935 where PG&E can not locate records showing a test was performed in accordance with industry standards.

### C. If PG&E Opts To Replace Rather Than Test Pipelines Installed On Or After 1955, PG&E Should Bear The Cost

Where PG&E must replace a line installed after 1955 with a new pipeline, PG&E shareholders should pay. While PG&E may argue about the applicability of industry standards adopted in 1935, PG&E has claimed it followed industry standards established in 1955, and that those standards required pressure testing and retention of test records.

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[51] Ex. 150, DRA Testimony, General Order 28 reissued December 22, 1947.

[52] 10 RT 1204-1205 and 1207-1208, Howe/PG&E. See also further discussion of General Order 28 in Section III herein.

[53] See Ex. 45, Felts Report, pp. 32-33. From at least 1929, PG&E retained engineering documents related to completed projects in Job Files, but it did not include this information in the "Master" Job Files. This critical information was discarded or misplaced as early as 1980 and continuing through 1996.

Thus, it is clear that PG&E recognizes that it had an obligation to pressure test gas lines by 1955, and to retain those pressure test records.

### D. If PG&E Opts To Replace Pipelines Installed Before 1955, It Should Earn A Reduced Return On Equity On Those Replacements

Where PG&E decides to replace (rather than test) a line installed before 1955 with a new pipeline, PG&E should earn a reduced return on equity. 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 associated with the capital improvement. DRA's proposal:

- Strikes an equitable balance between ratepayers and shareholders.
- Recognizes that transmission pipelines installed between 1935 and 1955 should have been pressure tested pursuant to industry standards, and records maintained.
- Recognizes that pipelines installed before 1955 will be more than 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 depreciation purposes.
- Considers that any pre-1955 transmission pipelines that are replaced will be replaced with a new transmission pipeline constructed using modern 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.

DRA's proposed adjustment of 200 basis points to PG&E's ROE for pre-1955 pipeline replacements should be made to the rate base calculation in future proceedings. This calculation could be applied to PG&E's Summary of Earnings in various ways. One way could involve a two-step process: (1) 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) use the resulting revenue requirement to reduce the GRC base margin/revenue requirement.

The 200 basis point adjustment would apply specifically to the pipeline investments associated with the PSEP for ten years after replacement. This proposal would result in an approximately 17% adjustment to PG&E's existing rate of return on equity for its new facilities. 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 investments associated with replacing pre-1955 pipeline in the PSEP.

This proposal is consistent with the policy and directives set forth in the Commission's rulemaking opening this proceeding, which expressly contemplated the possibility of adjustments to PG&E rate of return.[54] PG&E would have the means to undertake the highest priority safety work (most of it remedial) but would also experience some of the financial consequences of its mismanagement.

### E. PG&E's Cost Sharing Proposal Would Permit PG&E To Profit From the San Bruno Explosion And Is Unfair To Ratepayers

Decision 11-06-017 directed PG&E to include a "proposed cost allocation between shareholders and ratepayers" in its PSEP[55] In response, PG&E proposed that its shareholders pay for all PSEP costs incurred up to the end of 2011 and that all remaining costs for "2012 and beyond" be included in rates:

> Under PG&E's proposal, the shareholder sharing amount is equal to the costs expended in 2011 and there is no ongoing financial loss that would be applied to gas safety investments made in 2012 and beyond.[56]

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

[55] D.11-06-017, p. 23.

[56] Ex. 2, PG&E Direct Testimony, pp. 1-13 to 1-15, quotation from p. 1-15.

This proposal results in shareholders paying approximately $224.2 million of the Phase 1 PSEP costs.[57] In exchange, PG&E customers will pay over $10 billion in total PSEP revenue requirements to PG&E over the next 45 years.[58]

PG&E argues that this shareholder contribution is appropriate for two reasons: (1) it puts PG&E on an "equal footing" with the state's other gas utilities, all of whom must comply with the Commission's end to the grandfathering provisions;[59] and (2) "a one-time, upfront shareholder sharing amount" is "preferable to an ongoing allowance" and properly aligns ratemaking policies with public safety.[60]

PG&E's sharing proposal fails to address multiple issues that the Commission must consider in its own evaluation.

- PG&E's proposal does not compare its proposed shareholder contribution to the over $10 billion in contributions it expects from ratepayers:
- PG&E's proposal does not consider PG&E's role in the events that led to the Commission order PG&E to validate the MAOP of all its pipelines.
- PG&E's proposal does not consider that state law and Commission policy preclude the Commission from including either direct or indirect costs to correct PG&E's unreasonable errors and omissions in rates.
- PG&E's proposal does not acknowledge that, if adopted, it would create a continuing *disincentive* for utilities to proactively invest in safety.
- PG&E's proposal for ratepayers to assume $5 billion in PSEP costs would reward PG&E for nearly 30 decades of mismanagement.
- PG&E would profit from rather than learn from, the San Bruno explosion.

For all of these reasons, PG&E's cost sharing proposal is unacceptable to ratepayers and should be unacceptable to the Commission.

[57] Ex. 149 DRA Testimony, Chap. 9, p. 12. PG&E claims its shareholders will pay approximately $539 million in Phase 1 PSEP costs. See Ex. 2, PG&E Direct Testimony, p. 1-14. This number, as discussed at Ex. 149 DRA Testimony, Chap. 9, pp. 39-40, improperly includes costs associated with the San Bruno explosion.

[58] PG&E has estimated that Phase 2 of its PSEP will cost between $6.8 billion and $9 billion. Ex. 149, p. 2 and note 5.

[59] Ex. 2, PG&E Direct Testimony, p. 1-14.

[60] Ex. 2, PG&E Direct Testimony, p. 1-15.

## III. PG&E SHAREHOLDERS – NOT RATEPAYERS – SHOULD PAY FOR PG&E'S RECORDS CORRECTION PROGRAM

### A. PG&E Seeks Over $200 Million In Ratepayer Funding To Correct Record Keeping Deficiencies

PG&E seeks $222.8 million in ratepayer funding for two projects necessary to correct major deficiencies in its gas pipeline records.[61] PG&E justifies this request for ratepayer monies by arguing that the NTSB's requirement that PG&E only rely on "traceable, verifiable, and complete" records is a "new" requirement.[62] PG&E is wrong.

PG&E has had an obligation to maintain complete, accurate, and accessible records, which is the same as maintaining "traceable, verifiable, and complete" records, pursuant to state laws and regulations in place for over 100 years, industry standards in place since 1955, and federal regulations in place since 1970. As every investigation into the causes of the San Bruno disaster has established, PG&E has failed to meet any reasonable record keeping standard, and must now bring its pipeline records up to date and make them accessible.

PG&E has no justification for these record keeping deficiencies – and it has not tried to provide one. It has received funding through decades of general rate cases (GRCs) to maintain its records and update and consolidate its databases, including moving paper records into electronic formats. For example, PG&E has charged rate payers for nearly three decades to operate a records-based integrity management system that was supposed to prioritize pipeline inspection, repairs and replacements. Investigations after the San Bruno explosion have revealed that these systems were fatally flawed when they were created because much of the information needed for them to function was either incorrect or missing, and that PG&E ignored every opportunity to correct these errors over nearly 30 years. PG&E now seeks to shift the costs of creating a

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[61] Ex. 2, PG&E Direct Testimony, p. 5-4, Table 5-1. PG&E is not seeking funding for its Records Correction Program activities conducted in 2011.

[62] PG&E insists that it is performing the Records Validation Program "in order to comply with this new requirement, not to 'compensate for prior recordkeeping deficiencies.'" Ex. 21, PG&E Rebuttal Testimony, p. 11-4.

new records-based integrity management system to its ratepayers, claiming that its "Pipeline Records Integration Program" or "PRIP" – which is more appropriately called a "Records Correction Program" – is a "new" program to meet "new" regulatory requirements. The Commission must look behind PG&E's rhetoric and see that what it proposes is nothing but a clean up of its failed programs. State law and Commission policy do not permit PG&E to pass these costs on to ratepayers.

PG&E's PRIP, which DRA refers to here as PG&E's "Records Correction Program" consists of two parts. PG&E seeks $107.1 million in ratepayer funding to replace missing information and to confirm or correct existing information it uses to establish the maximum allowable operating pressure (MAOP) on each segment of its 6,761 mile gas transmission system. DRA refers to this part of PG&E's program as the "Records Validation Project."

PG&E also seeks $115.7 million in ratepayer funding to consolidate these "validated" or "corrected" records with other information regarding PG&E's gas transmission system into its Geographic Information System (GIS) and SAP database systems to make this information available across multiple PG&E data bases. PG&E refers to this project as the "Gas Transmission Asset Management" or "GTAM" project. DRA refers to this project as the "Database Update Project" – because that is what it is, an update to PG&E's existing databases. Together, these two projects constitute PG&E's $222.8 million request for a Records Correction Program.[63]

### B. PG&E's Request For Supplemental Ratepayer Funding Should Be Denied

PG&E's entire funding request for its Records Correction Program should be denied because: (1) the obligation to maintain "traceable, verifiable and complete" records is not a new standard and (2) PG&E's Records Correction Program is the type of program that PG&E should have been implementing previously, given decades of

[63] PG&E's Records Correction Program is described in Ex. 2, PG&E Direct Testimony, Chapters 5 and 6, and Ex. 21, PG&E Rebuttal Testimony, Chapters 10 and 11.

ratepayer funding provided to PG&E in its general rate cases (GRCs) for records and database maintenance.

The following table sets forth PG&E's Records Correction Program funding request, and DRA's recommendation:

**Comparison of Funding Proposals for PG&E's Records Correction Program**[64]

| Description | PG&E 2011 Costs Estimates to be Funded by Shareholders | PG&E Proposed 2012 - 2014 Costs to be Funded by Ratepayers | DRA Recommended Ratepayer Funding |
|---|---|---|---|
| Records Validation | $55.2 | $107.1 | $0 |
| Database Update | 7.9 | $115.7 | $0 |
| Total | $63.1 | $222.8 | $0 |

### C. PG&E Has Failed To Manage Its Records

There is no question that PG&E has failed, over multiple decades, to maintain its high pressure gas transmission pipeline records. These record keeping failures contributed to the San Bruno explosion and have, among other things, resulted in a dysfunctional pipeline integrity management system so that PG&E does not know enough about its pipeline system to prioritize inspection, repair, and replacement of those pipelines.[65] Commission consultants have thus concluded that PG&E's high pressure gas pipeline system poses a threat to both its employees and the public.[66]

[64] Ex. 148, DRA Testimony, Chap. 8, p. 3.

[65] Ex. 45, Felts Report, p. 49; NTSB Report, p. xi.

[66] Ex. 45, Felts Report, p. 25; Ex. 46, Duller & North Report, p. 1-11.

### 1. PG&E's Record Keeping Failures Contributed To the San Bruno Explosion

Every investigation of the San Bruno explosion has concluded that PG&E's recording keeping deficiencies contributed to that accident and have diminished pipeline safety.[67]

PG&E's record keeping failures, and their pivotal role in the San Bruno explosion, were quickly evident to the NTSB. As the Commission's consultants on the Record Keeping Investigation (I.11-02-016) summarized, this "was only the tip of the iceberg":

> In the immediate aftermath of the 30" gas transmission line explosion in San Bruno on September 9, 2010, [PG&E] told the [NTSB] it was a seamless pipe that had failed. PG&E based this statement on data from its electronic Geographic Information System (GIS), the primary source of information about the design and construction of its pipeline system. Of course, anyone viewing the remains of the pipe section lying on the ground in San Bruno could clearly see that the pipe had split along a longitudinal seam. This initial bit of bad data was only the tip of the iceberg.[68]

Within three months of the accident, in recognition of the dangers posed by PG&E's record keeping deficiencies, the NTSB issued an "urgent safety recommendation" that PG&E survey all of its gas transmission records to ensure that PG&E calculated maximum allowable operating pressure for a pipeline using only "traceable, verifiable, and complete" records.[69]

In the NTSB's later report regarding the causes of the San Bruno explosion, PG&E's record keeping failures played a significant role. The NTSB concluded that the explosion was caused by a gas pipe that was defective when PG&E installed it in 1956,

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[67] Ex. 46, Duller & North Report, p. 1-11, lines 13-17.

[68] Ex. 45, Felts Report, p. 1, lines 2-19.

[69] On January 3, 2011, the NTSB issued multiple "Safety Recommendations" to PG&E, this Commission, and the United States Department of Transportation, Pipeline and Hazardous Materials Safety Administration (PHMSA). As summarized in D.11-06-017 at 2, the Safety Recommendations included substantially the same descriptions of findings by NTSB as a result of the initial stages of its investigation of the San Bruno pipeline rupture and fire. The two Safety Recommendation letters (reflecting safety recommendations P-10-1 and P-10-2 through 4) are available at http://www.ntsb.gov/recsletters/DisplayLetters.aspx?FolderYR=2011

and that the defect "would have been visible when it was installed."[70] The NTSB identified two probable causes for the accident. The first was PG&E's "inadequate quality assurance and quality control" which allowed installation of the defective line in 1956.[71] The second was PG&E's "inadequate pipeline integrity management program" – a records-based program – which "failed to detect and repair or remove the defective pipe section."[72]

PG&E's pipeline integrity management program is only as good as the records it contains.[73] The NTSB 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 inaccurate and incomplete, was missing mission critical information, and was not designed to consider the most relevant information – such as pipeline design, materials, and repair history - when determining how to prioritize repairs and replacements.[74] As a result, the NTSB concluded that PG&E's integrity management program "led to internal assessments .... that were superficial and resulted in no improvements."[75]

CPSD released its own report on the causes of the San Bruno explosion on January 12, 2012.[76] It too found that PG&E's record keeping deficiencies played a key role in the disaster. Similar to NTSB, CPSD found that the San Bruno explosion 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, [and] PG&E's inadequate record keeping practices..."[77] CPSD identified other causes for the disaster, including deficiencies in PG&E's Supervisory Control and Data

[70] NTSB Report, p. x.

[71] NTSB Report, p. xii.

[72] NTSB Report, p. xii.

[73] See, e.g., Ex. 45, Felts Report, pp. 24-25 ("The combined lack of data, assumed, unknown values, and questionable quality of the data entered into the model spreadsheet, suggests the model is of only minimal practical use and is more likely entirely useless in calculating total risk.").

[74] NTSB Report, p. xi.

[75] NTSB Report, p. xi.

[76] CPSD San Bruno Report, p. 1.

[77] CPSD San Bruno Report, p. 1.

Acquisition (SCADA) system, inadequate emergency response and procedures, and "a systemic failure of PG&E's corporate culture to emphasize safety over profits."[78]

### 2. PG&E's Record Keeping Failures Are Pervasive Because It Had No Formal Record Keeping Systems In Place

On February 24, 2011 – following the NTSB's urgent safety recommendations regarding PG&E's records – the Commission opened a formal investigation into PG&E's record keeping practices to determine whether PG&E violated any state laws, Commission orders, or other rules or requirements, I.11-02-016. The investigation was not limited to the San Bruno explosion, but sought to "review and determine whether PG&E's recordkeeping practices for its entire gas transmission system have been unsafe and in violation of the law."[79] Based on "generally accepted record-keeping principles" (GARP), the Commission's consultants concluded that PG&E's records management was "sub-standard."[80] Under GARP, "sub-standard" is defined as "[a]n environment where record-keeping concerns are either not addressed at all, or are addressed in a very ad hoc manner."[81] The consultant reports identify record keeping deficiencies throughout PG&E's gas transmission system, covering decades and compromising PG&E's integrity management system, which determined a replacement cycle for its gas transmission lines.[82]

The Commission's consultants concluded that "PG&E's recordkeeping was in a mess and had been for years" and that PG&E could have addressed these issues if PG&E had put the right people, process and systems in place over time…." In sum, PG&E had no formal records management program in place:

> In lay terms, PG&E's recordkeeping was in a mess and had been for years. Gas transmission records and safety-related

[78] CPSD San Bruno Report, p. 1.

[79] Order Instituting Investigation 11-02-016, p. 1.

[80] Ex. 46, Duller & North Report, p. 1-8.

[81] Ex. 46, Duller & North Report, p. 1-8, note 7.

[82] Ex. 45, Felts Report, and Ex. 46, Duller & North Report.

> documents were scattered, disorganized, duplicated, and were difficult if not impossible to access in a prompt and efficient manner. The accuracy, completeness and quality of any of PG&E's digital datasets derived from its hardcopy pipeline records were at risk as PG&E did not have a complete and comprehensive master set of all job folders and files in one place that they could consult as they compiled their data. From the 1950's to date, PG&E has been aware of their legal records retention requirements. While they documented their legal requirements, their implementation of their retention standards was rather more subjective. In some instances, key record series, such as their pipeline history files were 'lost' or inadvertently destroyed.
>
> The recordkeeping issues identified in this report could have been addressed if PG&E had put the right people, process and systems in place over time, and had provided clear records management guidance, direction with senior management support to improve the way that its different offices and teams manage their records and share information. The creation of a formal records management program with supporting records management policies, procedures, systems and training would have ensured that appropriate attention and protection was given to PG&E documents, so that the evidence and information they contain could have been retrieved more efficiently and effectively.[83]

The Commission's consultants observed that PG&E sought $222.8 million in ratepayer monies between 2012 and 2014 to fund its Records Correction Program. They did not support PG&E's proposal: "As consultants, we suggest that these costs are excessive, and we cannot support PG&E's request for them regardless of their total."[84]

[83] Ex. 46, Duller & North Report, p. 1-10.

[84] Ex. 46, Duller & North Report, p. 1-11.

### D. Traceable, Verifiable and Complete Is Not A New Record Keeping Standard – It Is A Clarification Of The Existing Standard That Records Must Be Complete, Accurate and Accessible

#### 1. PG&E's Record Keeping Failures Prompted the NTSB To Emphasize That Records Must Be "Traceable, Verifiable, and Complete"

NTSB's urgent recommendation that PG&E survey all of its gas transmission records to ensure that PG&E calculated maximum allowable operating pressure for a pipeline using only "traceable, verifiable, and complete" records was in direct response to the discovery of PG&E's record keeping failures. The Commission recognized this fact when it adopted D.11-06-017, requiring PG&E to submit a records correction plan to the Commission:

> This project to validate MAOP was set in motion by the NTSB's *justifiable alarm* at PG&E's records being inconsistent with the actual pipeline found in the ground in Line 132. The pipeline features data for Line 132 were not missing; the recorded data were factually inaccurate. Records containing inaccurate pipeline features are fundamentally different from simply missing records. *Curing PG&E's unreliable natural gas pipeline records was the obvious goal of the NTSB's recommendation to obtain "traceable, verifiable, and complete" records and, with reliably accurate data, calculate a dependable MAOP.*[85]

PG&E argues that the NTSB established a "new" record keeping standard when it stated that gas pipeline records must be "traceable, verifiable, and complete."[86] PG&E is wrong. Had PG&E's records been accurate, complete, and accessible, the NTSB would not have found it necessary to spell out this plain-as-day requirement.

Faced with "justifiable alarm" regarding the absolute unreliability of PG&E's records, the NTSB sought to emphasize that PG&E's gas pipeline records must be accurate, complete, and accessible. It used the words "traceable, verifiable, and complete" to clarify the obvious - that it was not enough for a single PG&E record to

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[85] D.11-06-017, p.17 (emphases added).

[86] See, e.g., Ex. 21, PG&E Rebuttal Testimony, pp. 10-2 to 10-13.

reflect, for example, that a pipe was seamless. There needed to be something more - something "traceable or verifiable" to back up that data point. The standard was not a new one. Rather, it was an articulation of the obvious, which was evidently not so obvious to PG&E – that pipeline records must be accurate, complete, and accessible to the people who need them.

### 2. Existing Laws, Regulations, Industry Standards, PG&E Policies, and Common Sense All Required PG&E To Maintain Traceable, Verifiable and Complete Records

In no event can PG&E's record keeping deficiencies be blamed on an absence of laws, regulations, standards, or policies – because they all required PG&E to maintain its records, in many cases for the life of the facility, or longer. Only an absence of common sense suggests that PG&E's high pressure gas pipeline system records did not need to be retained.

In arguing that the obligation to maintain "traceable, verifiable and complete" records is a new one, PG&E forgets that it has had a statutory obligation to maintain and operate its system safely for over 100 years,[87] and that maintaining accurate, complete, and accessible records of its pipeline system is critical to operating its system safely.[88] PG&E also overlooks the multiple regulations, industry standards, and its own policies that have expressly required it to maintain its records.

Both the Commission's investigation into PG&E's record keeping practices and the Commission's separate investigation into the causes of the San Bruno explosion focus on these requirements. Had PG&E complied with the applicable laws, regulations, standards and policies, we would not be here today.

[87] See footnote 90, *supra*.

[88] Pub. Utils. Code § 451.

### a) Existing Laws, Regulations, Industry Standards and Common Sense Required PG&E To Retain Its Pipeline Records

As recognized in D.11-06-017, issued in this proceeding: "The duty to furnish and maintain safe equipment and facilities is paramount for all California public utilities."[89] Pursuant to Public Utilities Code Section 451, each public utility in California must maintain and operate its system safely:

> Every public utility shall furnish and maintain such adequate, efficient, just and reasonable service, instrumentalities, equipment and facilities…as are necessary to promote the safety, health, comfort, and convenience of its patrons, employees, and the public.[90]

It is not a mystery, nor has it been a mystery for as long as gas utilities have existed, that natural gas is an explosive material, transporting natural gas is a highly dangerous activity, and that it therefore requires a high degree of care to safely operate a high pressure gas pipeline system. Further, it does not take an engineer to recognize that in order to maintain and operate its high pressure gas pipeline system safely, PG&E needed to preserve records regarding its gas pipeline facilities, including: their size, where they were located, when they were installed, pressure test and any other test records, injury records, repair records, manufacturing records, and any other records that would provide information about the history or structural condition of a gas pipeline. Thus, PG&E's obligations to maintain and operate its system safely under § 451, and common sense, dictated that PG&E would need to maintain records regarding its facilities for the life of its facilities.

In addition to the obvious need to retain gas pipeline facility records for the life of the facility in order to safely operate a high pressure gas pipeline system, the

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[89] D.11-06-017, p. 16.

[90] Pub. Utils. Code § 451; see also CPSD San Bruno Report, p. 5 ("Section 451, which has been in effect since 1909 when California began regulating utilities, requires all public utilities to provide and maintain 'adequate, efficient, just, and reasonable' service and facilities as are necessary for the 'safety, health, comfort, and convenience' of its customers and the public.")

Commission's General Order 28 has expressly required PG&E to retain certain records, which would have included pressure test records, since 1912.

PG&E's regulatory expert dismisses the import of General Order 28, claiming that it was only "a document preservation requirement" and that it "appears to have everything to do with substantiating expenditures on capital improvements, and nothing to do with pipeline safety."[91] PG&E's expert testimony misses the point.[92]

General Order 28 requires PG&E to retain "[a]ll records, contracts, estimates, and memoranda pertaining to original cost of property and to Additions and Betterments …" If PG&E had "preserved" its records regarding the cost of pressure testing its gas lines, as required under General Order 28, those records could now be used to verify that a test was performed on the pipeline. One of the primary reasons PG&E is undertaking its Records Correction Program is to determine through "traceable, verifiable, and complete" records whether a pipe has been pressure tested, and if no evidence of testing exists, to either test or replace the pipe.

Further, from at least 1929, PG&E retained engineering documents related to completed projects in Job Files, but it did not include this information in the "Master" Job Files. This critical information was discarded or misplaced as early as 1980 and continuing through 1996.[93] Thus, it appears that PG&E was aware of its record retention obligations or needs and attempted to comply with them, in some cases, for nearly 50 years.

Industry standards also required the retention of original pipeline records. The 1955 ASA standards required the retention of as-built drawings, design, construction, and test records ***for the life of the pipeline***.[94] They also described record keeping

[91] Ex. 21, PG&E Rebuttal Testimony, p. 10-10.

[92] See, e.g., 10 RT 1204-1210, Howe/PG&E.

[93] Ex. 45, Felts Report, pp. 32-33 ("PG&E has a history of destroying or discarding important records. Despite requirements that date back to 1912 (by California regulations) and 1970 (by Federal regulations) to retain facility related records permanently, PG&E readily admits that records may have been discarded or misplaced as early as 1980 and continuing through 1996.")

[94] CPSD San Bruno Report, p. 62; Ex. 143, DRA Testimony, Chap. 2, pp. 27-28 and Attachment A, pp. 12, 15 (ASA B31.8-1955, page 50, Section 841.417 establishes record keeping requirements, which have

requirements regarding welding procedures and welder qualifications.[95] PG&E's witness agreed that the 1955 ASA standards required both pressure testing and retention of test records, and begrudgingly agreed that industry standards are not "irrelevant."[96]

General Order 112 requirements for the maintenance and operation of gas facilities, based on the ASA standards, have been in place since 1961. At the time that General Order 112 was being considered, PG&E represented that it was complying with those industry standards.[97]

General Order 112 provides that the responsibility to maintain records lies with the utility and that the records shall be available for inspection at all times by the Commission.[98] Section 302 of General Order 112 requires a utility to maintain all records related to its facilities:

> Specifications for material and equipment, installation, testing and fabrication shall be maintained by the utility.

Section 303 of General Order 112 requires a utility to retain records regarding maximum actual operating pressure:

> Plans covering operating and maintenance procedures, including maximum actual operating pressure to which the lines is intended to be subjected, shall be maintained by the utility.

Federal regulations adopted in 1970 establishing formal utility requirements for gas transportation safety also required PG&E to retain its high pressure gas pipeline

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not changed since 1955).

[95] CPSD San Bruno Report, p. 62.

[96] See 10 RT 1110-1112, Howe/PG&E.

[97] Ex. 143, DRA Testimony, Chap. 2, p. 23 quoting from Ex. 75, PG&E Data Response to DRA-045, Q/A 7: "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."; see also p. 26 and note 42 ("PG&E's stated practice was to follow ASA B31.1.8-1955, including pre-service testing, and [sic] informed the Commission in 1960 that it adhered to the ASA code for gas transmission and distribution piping systems.")

[98] General Order 112, Chapter III, Section 301.

facility records.[99] 49 CFR Part 192 requires maintenance of certain gas related records and record-keeping throughout its sub-parts. For example both sub part M – Maintenance 192.709 – Transmission Lines: Record Keeping and subpart N Qualification of Pipeline Personnel 192.807 – Record Keeping, give a retention period for the disposition of the records relating to specific items.

All of these laws and regulations required PG&E to retain accurate and complete records in a readily accessible manner, many for the life of the facilities. Given the opportunity, PG&E has failed to explain why it would be exempted from these requirements.[100]

#### b) PG&E's Pipeline Integrity Management System Required PG&E To Retain Its Pipeline Records

PG&E's obligation to develop and maintain a functional integrity management system has also required it to maintain records regarding its high pressure gas transmission facilities for the life of those facilities.

Since 2004, federal regulations have required all pipeline operators to implement a Transmission Integrity Management Program (TIMP) to assess and manage the integrity of all gas transmission pipelines in High Consequence Areas (HCAs).[101] TIMPs use pipeline facility data such as age, material, and repair history, to prioritize pipelines for repair and/or replacement. While the specific TIMP regulatory requirement is relatively new, PG&E's obligation to maintain and operate its system safely is not.

In 1984, 20 years before the federal TIMP requirement, PG&E proposed a "Gas Pipeline Replacement Plan" (GPRP) to prioritize the replacement of various gas transmission lines. A year earlier, PG&E had hired Bechtel to develop a methodology and database to prioritize replacement of transmission line segments and distribution mains. Bechtel proposed to use a probability analysis to predict the segments that posed

[99] See, e.g. CPSD San Bruno Report, p. 62.

[100] Ex. 148, DRA Testimony, Chap. 8, pp. 16-17.

[101] 49 CFR Part 192, Subpart O.

the highest risk based on the segment's physical characteristics. Those projects with the highest risk numbers were considered more likely to fail and cause significant injury to people and property; thus segments with the highest risk numbers were prioritized for repair or replacement. PG&E and Bechtel refined this model over the next 20 years and this model became the basis for PG&E's TIMP.[102]

All of PG&E's integrity management work – over nearly three decades – has been funded by ratepayers through rates.[103]

Aware of the need to justify this ratepayer investment, PG&E's 1990 Annual Progress Report on its Gas Pipeline Replacement Plan emphasized that by replacing highest priority pipes first, it was maintaining a safe operating system in the most cost effective manner possible.[104] "What PG&E did *not* say in its report was that it did not have adequate historical data about its pipeline system to populate the required data fields in a risk assessment model so it would produce accurate and useful results."[105]

More troubling, PG&E *knew* that its database errors and omissions posed significant problems to the validity of its integrity management program. PG&E issued an internal memo in 1985 when it was populating the integrity management database, requesting assistance in filling in missing data.[106] Despite the lack of data, PG&E and Bechtel continued to develop the model, and in some instances, made assumptions to overcome the lack of data.[107] For example, the Commission's consultants explain that PG&E often did not have accurate age data for its facilities because it used the date of installation to calculate the age of the pipe, and PG&E often re-used older pipe within the PG&E system. Thus, older pipe was listed as newer because its age was the date of its most current installation. Regarding critical leak data, Bechtel reported that PG&E's

[102] See, e.g., Ex. 45, Felts Report, pp. 17-18.

[103] See, e.g., Ex. 45, Felts Report, p. 18, note 78; Decision 11-04-031, Appendix A, Gas Accord V Settlement Agreement, Section 7.3, p. 8.

[104] Ex. 45, Felts Report, p. 18.

[105] Ex. 45, Felts Report, pp. 18.

[106] Ex. 45, Felts Report, p. 19.

[107] Ex. 45, Felts Report, p. 19.

engineers expressed little confidence in the accuracy of PG&E's leak data, believing the leak history was under-recorded. Knowing this, and instead of looking to original sources of information, Bechtel relied upon its own experience that the number of leaks in any given transmission line segment rarely exceeds two, and it assumed for modeling purposes that a transmission line segment would have no more than two leaks.[108] Significantly, PG&E's job files show many segments with many more than two leaks.[109]

Had PG&E attempted to proactively populate its database with complete and accurate information in the 1980s when it hired Bechtel to develop its integrity management program, or if it had taken action at any time after that to do so, even with information learned over the years, we would not be here today. Instead, the Commission's consultants have found that PG&E's data base has historically contained, and continues to contain, so much missing and/or inaccurate data that the integrity management system itself poses a safety threat:

> The pipes most likely to fail are not being identified accurately due to a lack of relevant, accurate, complete and accessible data. Thus, PG&E's current integrity management program itself presents a safety risk to PG&E's field and station employees and the public.[110]

The Commission's consultants have pored over PG&E's integrity management database and have found material errors and omissions at every turn, including evidence of intentionally destroyed data, lost data, and PG&E policies requiring data retention that were ignored and eventually rescinded.

The Commission's consultants reviewed all of the records required to create an accurate and useful integrity management model. Almost all of these records are required to be maintained for the life of the facility, and in some instances, for the life of the facility plus 6 years.[111] The Commission's consultants found the following material

[108] Ex. 45, Felts Report, pp. 19-20.

[109] Ex. 45, Felts Report, p. 20.

[110] Ex. 45, Felts Report, pp. 24-25.

[111] Ex. 45, Felts Report, pp. 15-16.

errors and omissions associated with each aspect of the data PG&E has used to populate its integrity management system:[112]

- Historical Information Missing: Because PG&E is missing historical data about its pipelines, it must use erroneous and incomplete (assumed and/or of unknown quality) information in its integrity management models. This lack of information has resulted in the assignment of incorrect risk priorities (for replacement and assessments) to pipeline segments.[113]
- Early Pipeline Records Missing Or Lacking Detail: Many early pipeline drawings are missing and many others lack certain details and supporting documentation cannot be found.[114]
- Pipeline History Files Discontinued and Now Missing: While PG&E policy in place for at least two decades required retention of critical pipeline history files for the life of the pipeline, this policy was discontinued in 1987. The files were apparently discarded.[115]
- Job Files Incomplete and Disorganized: From at least 1929, PG&E retained engineering documents related to completed projects in Job Files, but it did not include this information in the "Master" Job Files. This critical information was discarded or misplaced as early as 1980 and continuing through 1996.[116]
- Many Design and Pressure Test Records Missing: PG&E is missing pipeline and pressure test records required to be retained for the life of the pipeline and vital to PG&E's successful implementation of its integrity management program.[117]
- Weld Maps and Inspection Records Mostly Missing or Incomplete: Despite PG&E's written policies to create and manage weld records, weld maps and inspection records for PG&E's transmission pipelines, which would normally be a source of key pipeline data for the integrity management model, are mostly missing.[118]

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[112] Ex. 45, Felts Report, pp. 26-47.

[113] Ex. 45, Felts Report, pp. 28-29.

[114] Ex. 45, Felts Report, p. 29.

[115] Ex. 45, Felts Report, pp. 29-31.

[116] Ex. 45, Felts Report, pp. 32-33 ("PG&E has a history of destroying or discarding important records. Despite requirements that date back to 1912 (by California regulations) and 1970 (by Federal regulations) to retain facility related records permanently, PG&E readily admits that records may have been discarded or misplaced as early as 1980 and continuing through 1996.").

[117] Ex. 45, Felts Report, pp. 33-34.

[118] Ex. 45, Felts Report, pp. 35-38.

- Operating Pressure Records Missing, Incomplete, or Inaccessible: PG&E generally has no "life of the plant" record of operating pressure for the life of its pipelines and PG&E lost pressure records for all of 1999.[119]
- Leak Records Incomplete, Disorganized and Inaccessible: Notwithstanding the fact that Bechtel concluded that leak information is one of the most important sources of information for integrity management, PG&E has failed to maintain its leak records in a manner that makes the information readily accessible and states that it cannot retrieve leak data prior to 1970.[120]
- No Tracking System for Salvage and Reused Pipe: PG&E has a practice of salvaging pipe when it is removed from the ground. However, over the years, PG&E moved pipe (often in service for many years) from one location to another, but did not keep track of where the pipe was reinstalled in the system, making it impossible to determine the age of pipe in any segment.[121]

Based on these discoveries, the Commission's consultants made two findings regarding PG&E's record keeping: (1) "the pipe failure and explosion on Line 132 in San Bruno on September 9, 2010 may have been prevented had PG&E managed its records properly over the years" and (2) "PG&E's entire integrity management program is an exercise in futility because PG&E lacks the basic records necessary to provide fundamental data required for the successful use of the integrity management risk model. Therefore, PG&E has been operating, and continues to operate, without a functional integrity management program."[122]

#### c) PG&E's Own Policies Required It To Retain Its Pipeline Records

In addition to the statutory, regulatory, and common sense requirements to retain its high pressure gas transmission line facility records, PG&E had internal policies in place requiring retention of those records.

As early as 1967, PG&E described for the Commission its "standard procedure" for maintaining pipeline data pursuant to Chapter V of General Order 112-B. PG&E

[119] Ex. 45, Felts Report, pp. 38-39.

[120] Ex. 45, Felts Report, pp. 39-43.

[121] Ex. 45, Felts Report, pp. 43-47.

[122] Ex. 45, Felts Report, p. 49.

provided details regarding the types of pipeline information it retained and its retention method:

> Although some data, such as original and test information and special surveys, are filed by main number, the majority of the data developed to record replacement, reconditioning, leakage, and other operating and maintenance activities are filed in numerical sequence, depending upon the type record and the system used in a particular division. Reference to these numbers, quite often with a brief description, is posted to the pipeline plat sheets. This serves as an index to the history files and presents a graphical representation of the maintenance and repair activity. Some divisions also post to a full size or reduced size wall map for a better overall review.[123]

By 1969, PG&E had formalized this policy into Standard Practice 463.7, which required a pipeline history file to contain the following information:

a. Pipeline or main number;

b. Dates of original installation and subsequent changes requiring work orders;

c. Design and construction data covering the original installation and subsequent revisions requiring work orders or GM estimates;

d. MAOP of each section;

e. Type of protective coating originally or subsequently installed and the existing condition of the coating;

f. Cathodic protection installations showing locations, ratings, and installation dates;

g. Record of pipeline or main inspections;

h. Record of pipeline or main leakage surveys and repairs;

i. Record of location class surveys;

j. Record of pipeline or main sections where hoop stress corresponding to MAOP exceeds that permitted for new pipelines or mains in the particular class location;

k. Initial or most recent strength test data;

[123] Ex. 45, Felts Report, p. 29 quoting from PG&E document P3-10005(b), p. 244.

l. Special studies and surveys made as a result of unusual operating or maintenance conditions, such as earthquakes, slides, floods, failures, leakage, internal or external corrosion or substantial changes in cathodic protection requirements;

m. Annual summary of existing condition of pipelines and mains based upon available records as per Exhibit A; and

n. Specifications for materials and equipment, installation, testing, and fabrication shall be included or cross-referenced to this file.[124]

Standard Practice 463.7 also required that these files be retained ***for the life of the facility***.[125] If PG&E had been doing what it told the Commission it was doing in 1967, or if it had followed its own Standard Practice 463.7, we would not be here today. The pipeline history files created under Standard Practice 463.7 would have provided an ongoing record of each pipeline in PG&E's system. However, when the Commission's consultants asked PG&E to produce the pipeline history files, PG&E could not explain what had happened to the pipeline history files or Standard Policy 463.7. Rather, PG&E stated that it "no longer maintains Pipeline History Files" and that it "believes" the standard practice became inoperative in the early 1990s when PG&E initiated its transition to its electronic GIS.[126] Left wondering, the Commission's consultants discovered a memo produced by PG&E, dated October 9, 1987, that discontinued Standard Policy 463.7 with no explanation.

### E. Ratepayers Have Funded PG&E's Faulty Record Keeping For Decades

As set forth in detail below, PG&E has received, and continues to receive, ratepayer funding in its general rate cases to maintain its gas pipeline records and its integrity management system. PG&E argues that its Records Correction Program – comprised of the Records Validation Project and the Database Update Project – is a "new" program pursuant to "new" regulatory requirements. Thus, notwithstanding its

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[124] Ex. 45, Felts Report, pp. 29-30 quoting from PG&E document P2-400, pp. 90-91.

[125] Ex. 45, Felts Report, p. 30, note 118.

[126] Ex. 45, Felts Report, p. 31.

claims to the contrary, PG&E seeks to charge ratepayers twice for work it should have done before.[127] The Commission must look behind PG&E's rhetoric and see that what it proposes is nothing but a clean up of its failed programs. As described in Section II above, state law and Commission policy do not permit PG&E to pass these costs on to ratepayers.

### 1. PG&E Has Received Ample Funding In Its Rate Cases To Pay For Its Records Correction Program

PG&E has received more than ample funding in its 2011 GRC and the Gas Accord V settlement of its gas transmission and storage rate case to fund its Records Correction Program. PG&E was authorized an increase for 2011 of $450 million or an 8.1% increase over previously authorized levels in its 2011 GRC.[128] It was further authorized post-test year attrition increases of $180 million in 2012 and $185 million in 2013. Gas Accord V authorized $514.2 million for 2011, $541.4 million for 2012, $565.1 million for 2013, and $581.8 million for 2014.[129] PG&E has failed to demonstrate that its authorized funding levels in its 2011 GRC and Gas Accord V are insufficient to pay for its Records Correction Program activities. In fact, a review of PG&E's earnings between 1999 and 2010 reveals just the opposite.

As described in Section II above, the Overland Report commissioned by CPSD explains that PG&E's gas transmission and storage operations have been "highly profitable" between 1999 and 2010, but that PG&E failed to utilize its surplus revenues to "improve gas safety." The report states:

> PG&E's GT&S revenues were $430 million higher than the amounts needed to earn the authorized return during the twelve-year study period. The surplus revenues averaged $36 million a year. PG&E could have used the surplus revenues,

[127] Ex. 21, PG&E Rebuttal Testimony, pp. 1-4 to 1-9.

[128] D.11-05-018, p.2.

[129] D.11-04-031, p.9.

> at least in part, to improve gas safety. Instead, PG&E chose to use the surplus revenues for general corporate purposes.[130]

Thus, PG&E has failed to use its authorized funding and surplus revenues to properly maintain its pipeline records, or to correct them when it discovered deficiencies. PG&E's request for additional ratepayer funding to correct its record keeping deficiencies is unreasonable and should be denied.

With regard to the Records Validation Project, which PG&E represents is nearly complete, PG&E once again argues that it is a "new" project and that the cost is "incremental" to what was included in Gas Accord V.[131] Once again, PG&E is wrong.

The activities associated with the Records Validation Project include "collecting and verifying the pipeline strength tests and pipeline features data necessary to validate and re-calculate the MAOP for PG&E's gas transmission pipelines and pipeline system components."[132] Consistent with the discussion in Section III.D.2 above, "collecting and verifying" data regarding pressure tests and various pipeline "features" are the same activities associated with prudent gas safety record keeping. These activities mirror the collection of the types of records PG&E purported to retain pursuant to its abandoned Standard Practice 463.7, and these activities are part of the normal, routine and on-going maintenance activities already funded by ratepayers. It would be inappropriate to charge ratepayers twice to address these activities.

Although PG&E's 2011 GRC and Gas Accord V do not specifically identify monies for natural gas transmission record keeping, there is no question that PG&E receives funding for these activities to provide safe and reliable service. PG&E admitted that Gas Accord V included funding for integrity management and other gas safety work when specifically asked by the Administrative Law Judge working on that case. PG&E explains:

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[130] Ex. 42, Overland Report, p.1-3.

[131] Ex. 2, PG&E Direct Testimony, p. 5-14.

[132] Ex. 2, PG&E Direct Testimony, p. 5-1.

> … [A]fter the Gas Accord V Settlement was submitted to the Commission, but before its approval, the Administrative Law Judge issued a ruling requesting that parties comment on the adequacy of the proposed settlement agreement in light of the "pipeline safety, integrity, and reliability concerns raised by the San Bruno natural gas incident". In PG&E's September 20, 2011 response to this question, PG&E stated that "the settlement provides sufficient funds for PG&E to conduct the integrity management and pipeline safety and reliability work PG&E had forecast would be necessary during the rate case period, namely 2011 through 2014".[133]

Thus, to the extent that PG&E has already been paid to maintain its gas transmission records and its integrity management system, it has embedded funding for these activities. Ratepayers should not be required to pay twice to fix PG&E historic deficiencies in performing this work.

### 2. PG&E Has Missed Multiple Opportunities To Correct Its Record Keeping Errors and Omissions

As documented throughout this brief, PG&E has failed to maintain accurate, complete and accessible information about its gas transmission pipelines for at least 30 years, and probably longer. The San Bruno explosion is not the first time that PG&E was put on notice of its significant record keeping deficiencies. In 1981, the NTSB investigated a gas pipeline leak in San Francisco where PG&E took 9 hours and 10 minutes to stop the flow of gas because it could not locate one emergency valve due to inaccurate records.[134] In 1984 Bechtel advised PG&E of the significant problems presented to its risk analysis by missing pipeline data, and the need for additional research to resolve these "uncertainties":

> During the data collection process, the area engineers were sometimes confronted with the problem of missing records that prevented them from finding variable values. In these

[133] Ex. 88, PG&E Data Response to DRA-004, Q/A 1(e), p. 10. PG&E also clarified that Gas Accord V did not include sufficient funds to do the thorough safety inspection of PG&E's gas transmission system required by the Ruling or sufficient funds to pay for any additional work ordered by the Commission. *Id.* See also Ex. 148, DRA Testimony, Chap. 8, pp. 13-15.

[134] NTSB Report, p. 81.

> cases, **an "unknown" entry was inputted into the data base and the failure probability analysis immediately assumed the worst case.** The worst case values were then multiplied by their respective hazard values and the result was displayed under the "uncertainty" column of the computer output (see Appendix A). **These uncertainty values are intended to serve as a flag signaling the necessity to confirm these assumptions through more extensive research.** This extended research will take place on only those lines whose high risk values justify the additional time and effort...**Clearly the result of any risk analysis is entirely dependent upon the quality of information accessed. The presence of unknowns and highly suspect data variables combined with the lack of mathematical precision in the evaluation of risk parameters places limitations on the applicability of the risk values.**[135]

Based on this information, PG&E should have made the necessary corrections to its pipeline records to ensure that it had accurate and complete records to inform its pipeline replacement program. But it did not.

The NTSB agrees that PG&E was put on notice of its record keeping deficiencies several times over many decades:

> [M]any of the organizational deficiencies were known to PG&E, as a result of previous pipeline accidents in San Francisco in 1981, and in Rancho Cordova, California, in 2008. As a lesson from those accidents, PG&E should have critically examined all components of its pipeline installation to identify and manage the hazardous risks, as well as to prepare its emergency response procedures. If this recommended approach had been applied within the PG&E organization after the San Francisco and Rancho Cordova accidents, the San Bruno accident might have been prevented.[136]

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[135] Ex. 148, DRA Testimony, Chap. 8, pp. 11-12 (emphases added), quoting from the Preliminary Report by Bechtel Petroleum, Inc, performing Engineering Consulting Services for PG&E, on Pipeline Replacement Program Transmission Line Risk Analysis (dated January 1984), pp.1 and 13 and 14. The Bechtel Report is available on the Commission's website at http:/www.cpuc.ca.gov/NR/rdonlyres/E75846A0-FAD1-4A0C-AACF-C176D9F8DD7B/0/TransmissionLineRiskAnalysis1984.pdf

[136] NTSB Report, pp. 117-118 (citations omitted).

PG&E has not learned from its past mistakes, and it has not efficiently utilized authorized ratepayer funding to aggressively correct its gas transmission pipeline records in the last 30 years.

The Commission must hold PG&E fully accountable for its failure to utilize its past authorized funding to maintain complete, accurate, and accessible operating records on its gas pipeline system.

### 3. PG&E Ratepayers Have Paid Multiple Times For Database Update Projects

PG&E seeks $115.7 million in ratepayer funding to upgrade and consolidate its existing information technology systems to make the records generated by its Records Validation Project accessible to those who need them. PG&E explains that it "has in place foundational technology infrastructure to manage its gas transmission system data"[137] and that its current database upgrade project - GTAM - will "[m]aintain reliable information by consolidating the information and functionality of the different gas transmission systems into SAP and GIS, PG&E's core enterprise systems (the Core Systems)".[138] In support of its Database Upgrade Project, PG&E explains that it "will substantially upgrade its gas transmission processes and record management infrastructure, allowing it to transition away from reliance on traditional paper records and to consolidate data into integrated, core data managements systems."[139]

Predictably, PG&E claims that this database upgrade is "incremental" to the upgrades previously funded through its GRCs and should therefore be funded by ratepayers.[140] Once again, PG&E is wrong.

PG&E's proposed "Gas Transmission Asset Management Project" or "GTAM" is nothing more than a database upgrade that should be funded through GRC monies. Database system upgrades, enhancements to PG&E's core systems such as its GIS and

[137] Ex. 2, PG&E Direct Testimony, p. 5-19.

[138] Ex. 2, PG&E Direct Testimony, p. 5-20.

[139] Ex. 2, PG&E Direct Testimony, p. 5-1.

[140] Ex. 2, PG&E Direct Testimony, p. 5-30.

SAP database systems, and computer and laptop upgrades are part of on-going and routine operation and maintenance activities; funding for such activities is requested and authorized in PG&E's GRCs.[141]

PG&E has received significant amounts of funding in its last three GRCs, spanning nearly a decade, to "consolidate," "upgrade" and "enhance" its existing information technology systems.[142] Thus, it has historical embedded costs from these completed projects that can be reallocated to address its proposed database consolidation activities.

To the extent that PG&E is required to do additional work not contemplated at the time of its last GRC, it should allocate historic embedded funds from completed projects and discontinued information technology work to this project. In no event should ratepayers be assessed a special surcharge to fund these database upgrades.

A review of PG&E's Database Upgrade Project request reveals that its activities are the same types of activities that have previously been funded by PG&E's GRCs. PG&E's Database Upgrade Project forecast includes $16.2 million for hardware, including 800 laptops, and $10.1 million for "software licenses for existing software packages, such as SAP…"[143] PG&E's request is unreasonable because it does not consider past funding for similar software and hardware. For example, in PG&E's 2011 GRC, PG&E's IT Business Unit requested $4 million to implement mobile hand-held devices and requested an additional $11.6 million to upgrade hand-held computers for PG&E's field force.[144]

PG&E has also received funding in prior GRCs to consolidate its core systems – GIS and SAP. When DRA asked PG&E to explain why consolidation only became

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[141] PG&E confirmed that its Database Upgrade Project or "GTAM" is an upgrade to its GIS and SAP systems. 12 RT 1645, Whelan/PG&E.

[142] See, e.g. Ex. 77, PG&E Data Response to DRA-004, Q/A 4(i); and Ex. 84, PG&E Data Response to DRA-004, Q/A 4(p). See also 12 RT 1646-1648, Whelan/PG&E.

[143] Ex. 2, PG&E Direct Testimony, pp.5-28 and 5-29.

[144] Ex. 148, DRA Testimony, Chap. 8, p. 32.

important after the San Bruno explosion, PG&E replied that it has been using GRC funding for ten years to consolidate its core systems, including GIS and SAP:

> In several instances during the past 10 years, PG&E has addressed the implementation, maintenance and upgrade of core enterprise IT systems in its General Rate Cases (GRCs). … PG&E's core enterprise systems play a very important role in effectively and efficiently maintaining its gas transmission pipeline system. Because it is such an important consideration, PG&E has consistently updated, consolidated and upgraded its core information management systems to help PG&E maintain a safe and reliable gas pipeline system…[145]

PG&E's response demonstrates that it has requested and received funding in past GRCs and gas transmission and storage rate cases for various database consolidation projects, yet here it fails to consider and incorporate these historical costs into its GTAM forecast.

Further, it is clear that one of the reasons that PG&E has so much work to do in updating and integrating its databases is because the systems it has previously developed are so riddled with errors that they cannot be migrated into its new database. CPSD's report on PG&E's PSEP made the same observation:

> PG&E has admitted that some of the information in the existing GIS system is not sufficiently detailed to permit analysis of MAOP and other data attributes. **Consequently, to some extent the expense associated with originally populating the GIS will need to be duplicated. Since PG&E's existing GIS and Pipeline Records Program cannot be relied upon as a comprehensive and accurate source of gas transmission information, costs concessions in the [Records Correction Program] should be considered to compensate for duplicative efforts.**[146]

Thus, PG&E must undertake its Database Upgrade Project because all of the other database upgrades it has performed with ratepayer funding were done wrong. These

[145] Ex. 77, PG&E Data Response to DRA-004, Q/A 4(i).

[146] Technical Report of the Consumer Protection and Safety Division Regarding Pacific Gas and Electric Company's Pipeline Safety Enhancement Plan, filed in this proceeding on December 23, 2011, (CPSD PSEP Report), p. 13.

failings of PG&E's information technology systems are errors and omissions by PG&E. The cost consequences of these errors and omissions cannot legally be imposed on ratepayers. as discussed in Section II above.

#### 4. PG&E's Request For Ratepayer Funding For Its Records Correction Program Is Unreasonable

As described above, PG&E fails to justify its request for $222.8 million for its Records Correction Program and therefore, as set forth in Section II above, it must be rejected.

DRA's Testimony describes in detail the deficiencies in PG&E's Records Correction Program forecasts.[147] In sum:

- PG&E's forecasts are highly speculative;
- PG&E's forecasts are not substantiated;
- PG&E's forecasts do not account for historic embedded costs; and
- PG&E's forecasts include costs for misclassified line segments that shareholders should pay because they should have been studied in 2011.

In addition, PG&E revised its position on its PSEP funding request in its rebuttal testimony.[148] This change in position impacts all of PG&E's forecasts, which should be rerun in the event the Commission considers any ratepayer funding for PG&E's Records Correction Program.

## IV. PG&E'S PROPOSED PSEP PIPELINE MODERNIZATION PLAN NEEDS MORE WORK AND ONGOING COMMISSION OVERSIGHT

The PSEP Pipeline Modernization Plan (referred to in this section as simply "PSEP") as proposed by PG&E on August 26, 2012 is flawed and should not be approved in its current form. It currently does not define project scope with sufficient accuracy or certainty to support any approval of for cost recovery from ratepayers. The PSEP is best viewed as a work in progress that requires continuing Commission oversight and should

[147] Ex. 148, DRA Testimony, Chap. 8.

[148] Ex. 21, PG&E Rebuttal Testimony, p. 10-13 ("In the case of transmission pipe installed in California after July 1961, I agree that if no pressure test records can be found then PG&E should be bear [sic] the expense of pressure testing.").

be updated by PG&E as it obtains new information from the MAOP validation project and detailed project engineering.

DRA in its prepared testimony offered a set of recommendations to build on PG&E's proposed PSEP by providing for fast-track evaluation of 2012 proposed PSEP work (so high-priority work can be performed as soon as feasible) while developing a more accurate Phase 1 plan.[149] DRA's initial recommendations included a proposed timeline with specific dates for action items; those dates have since passed. In addition, PG&E indicated during evidentiary hearings that it is currently unable to update the PSEP Pipeline Plan based on new data from the MAOP validation project due to incompatibility between MAOP and PSEP databases.[150] Therefore, while DRA continues to support its original recommendations, in the event PG&E cannot find a way to update the PSEP using the new data, DRA offers the following alternative to maximize pipeline safety and project cost-effectiveness. This alternative recommendation is based on PG&E's assertion that detailed project engineering is required to accurately determine the scope and cost of PSEP projects, and that a better estimate of PSEP scope and cost will only be available after the PSEP has been partially implemented. To address the great uncertainty about scope and criteria for inclusion of projects in Phase 1, DRA recommends that the Commission require PG&E to file an advice letter within 45 days of a decision in this proceeding providing guidelines, protocols and procedures to address the following issues, which ultimately drive the scope and aggregate cost of mitigation[151]:

a. Deviations from decision tree outcome/mitigation due to new data
b. Deviations from decision tree outcome/mitigation due to PG&E engineering judgment
c. PG&E implementation of the "ors" in the decision tree
d. Acceleration of segments into Phase 1
e. Expenditures to increase piggability
f. Diameter increases for reasons other than piggability

[149] Ex. 144, DRA Testimony, Chap. 3, pp. 114-117.

[150] 11 RT 1436, ll. 5-10, Hogenson/PG&E.

[151] Mitigation in this context refers to the actions taken by PG&E to remove, or reduce to an acceptable level, risks posed by threats to pipeline integrity. Pipeline replacement, hydrotesting, and in-line inspection (ILI) are examples.

g. Line relocations
h. Engineering Condition Assessment (ECA)

Even if the Commission disagrees with DRA's overarching finding that the PSEP as proposed fails to define project scope with sufficient accuracy or certainty to support cost recovery authority, the Commission should recognize that significant scope changes may occur during detailed project engineering. For this reason, DRA's alternative recommendation remains applicable in that it would help decrease the extent of scope changes after the PSEP is adopted; define to the degree possible allowable scope changes; and define a process for review and approval of changes in scope. Defining the scope of work with as much certainty as possible would facilitate effective risk management and cost containment.

### A. PG&E's PSEP Should Be Corrected and Updated

#### 1. The Scope Is Not Accurately and Completely Defined

As proposed by PG&E, the PSEP does not accurately define the scope of work that ultimately will be performed. PG&E's PSEP supports Advancement of Cost Engineering International (AACEI) Class 4 cost estimates,[152] and "at the time of cost estimation, PG&E typically defined between 5 percent and 15 percent of the project's scope."[153]

##### a) The PSEP Is Based on Inaccurate Data

PG&E's PSEP as currently proposed is based on inaccurate data, and therefore does not accurately prioritize mitigation or allow accurate estimates of PSEP costs. The PSEP Pipeline Plan requires pipeline data to prioritize mitigations through its decision tree, and to allocate cost responsibility between shareholders and ratepayers. The accuracy and effectiveness of the plan is highly dependent on whether the data used to

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152 Ex. 2, PG&E Direct Testimony, p 3-39: "Class 4 estimates are generally prepared based on limited information and subsequently have fairly wide accuracy ranges… actual project costs could vary from -30 to +50 percent of estimated given significant unknowns…."

153 Ex. 2, PG&E Direct Testimony, p. 3-39.

develop it is complete and correct. PG&E filed its PSEP on August 26, 2011, while it was still in the midst of its MAOP validation process and, thus, had to use whatever data was available at the time to develop the PSEP. DRA analyzed the data PG&E used to produce the PSEP Pipeline Plan and considered the impacts of anomalous data on:

*application of the decision tree;

* assignment of segments to projects;

* application of the correct unit costs;

* allocation of costs to PG&E shareholders; and

* PG&E's contingency request.[154]

**DRA's most important finding regarding data PG&E used to develop the PSEP is that it is not verified, accurate, and traceable data**. Generally, the PSEP is based on pipeline characteristics data that was in PG&E's GIS database as of January 3, 2011, and pressure test data from the MAOP validation project as of April 30, 2011.[155] DRA has recommended that PG&E re-run its decision tree using accurate data, but PG&E indicated that it cannot do this because "[w]e're challenged with that [because our existing GIS and new MAOP data ] system does not talk, we can't electronically pass information today from that Intrepid system into our GIS system. It's a separate database that we have not been able to establish a communication."[156]

Instead, PG&E plans to review the results of MAOP validation efforts and the class location of segments on a project-by-project basis, "incorporat[ing] a data validation phase into the preliminary project engineering work scope."[157] During hearings, CPSD asked if PG&E had a process to provide "some confidence as to things are still progressing based on the highest priority [based on updated MAOP data]," and PG&E's witness replied, "We are working on that…."[158] DRA anticipates that it will be difficult

[154] Ex. 144, DRA Testimony, Chap. 3, pp. 18-29.

[155] Ex. 144, DRA Testimony, Chap. 3 pp. 20-21.

[156] 11 RT 1436, ll. 5-10, Hogenson/PG&E.

[157] Ex. 21, PG&E Rebuttal Testimony, p. 3-10.

[158] 11 RT 1437, ll. 18-28, Hogenson/PG&E.

to verify PG&E's engineering practices on an ongoing basis, but nevertheless offers its "alternative" recommendation described above in case the Commission adopts PG&E's proposal without requiring PG&E to re- run the decision tree in 2012.

Even if the CPUC adopts a process to ensure that project engineering is based on verified, accurate, and traceable data, the question of project priority remains. The Commission in D.11-06-017 directed PG&E and the other gas utilities to prioritize densely populated and high consequence areas: "The Implementation Plan should start with pipeline segments located in Class 3 and Class 4 locations and Class 1 and Class 2 high consequence areas, with pipeline segments in other locations given lower priority for pressure testing."[159] On cross-examination, PG&E acknowledged that pending changes in HCA classifications "will change the scope of Phase 1."[160] In other words, PG&E currently does not have a clearly defined Phase 1 Plan.

Inaccurate data significantly impacts the cost of mitigation regardless of the decision tree used, since under PG&E's proposal the average cost per mile of replacement is approximately 10 times higher than the cost of hydrotesting.[161] PG&E's decision tree, even with the modifications recommended by DRA, determines whether to test or replace pipe based on an evaluation of % SMYS and class location. The former is dependent on pipe features being updated by the MAOP validation team and the latter depends on accurate class location assignments. Because PG&E's proposed PSEP is based on incorrect or unreliable pipeline features and class location data, PG&E's estimate of the scope of replacement and hydrotest projects cannot be accurate.[162]

[159] D.11-06-017, p.20.

[160] 11 RT 1449, ll. 8-12, Hogenson/PG&E.

[161] Ex. 144, DRA Testimony, Chap. 3, p. 48, Table 9.

[162] Examples are provided in Exhibit 144. MAOP data impacts are discussed at pages 25-28, and one particular example relative to cost allocation is provided on pages 83-84. HCA reclassification impacts are discussed on pages 28-29.

#### b) The PSEP Recommends Incorrect Mitigation and Priority for Certain Threats

DRA and its consultant BEAR analyzed PG&E's decision tree and found that it recommends the incorrect mitigation and priority for certain types of pipeline threats. DRA's primary recommendations to correct these errors are as follows:[163]

##### i) Project Prioritization Should Consider Post-1955 Pressure Tests.

Any post-1955 pressure test, regardless of duration, should count towards prioritizing segments as Phase 1 projects. DRA in its prepared testimony recommended: "Rather than query whether a Subpart J test has been conducted (at 1H, Manufacturing Threats), the query should include any post-1955 strength test."[164] This recommendation applied to the prioritization of segments for Phase 1 and contemplated that "Phase 2 will address updating all tests to Subpart J standards."[165] Subsequently, DRA reviewed a recent study by Kiefner & Associates that found:

> Pressure tests performed before 1970 without an 8-hr hold test should still be considered a valid pressure test to prove the pressure carrying capability of the pipeline. The lack of an 8-hr leak test is immaterial, because leaks would have been found over the subsequent life of the pipeline by the operator through surveys, or by customers by the odorant in the gas.[166]

During hearings, PG&E clarified that decision points in its decision regarding whether a "sub-part J" test has been performed consider both correct pressure ratio, and minimum duration:

> Question: So it is fair to say that two key elements of the pressure test are those minimum ratios as you explain and the minimum duration of one hour?
> Answer: Correct.
> Question: That's what your decision – your database actually looks for to ensure whether that question is satisfied or not as far as the pressure test elements?

[163] Ex. 144, DRA Testimony, Chap. 3, pp. 33-34.

[164] Ex. 145, DRA Testimony, Chap. 4, p.11.

[165] Exhibit 145, p.11, ll.611-12.

[166] Ex. 58, Kiefner & Associates, Inc., Study questions specified hydrotest hold time's value, Oil & Gas Journal, March 5, 2012, p. 8.

Answer: Correct.[167]

PG&E also clarified that it is not seeking to re-test pipe segments with valid records of the correct pressure ratio and minimum duration of one hour:

> We make no differentiation in the decision tree because we believe that a pressure test in 1965, I use that as an example, we tested a pipeline in 1965 and we did it per General Order 112 and we tested it for one hour or more, it was a successful test, we don't believe you have to go back and re-test it again because it wasn't for eight hours.[168]

DRA supports this interpretation of D.11-06-019. As Ordering Paragraph 3 states: "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 for a pressure test."

**ii) Class 2 Locations Should Not Be Included By Default When Defining High Consequence Pipe Locations.**

PG&E's decision tree treats Class 2 locations the same as class 3 and 4 when prioritizing segments. This was confirmed by PG&E on cross examination: "[W]hen we developed our decision tree, we made a decision to include Class 2 urban area pipelines in our decision as well and say should we be including that in our priority one work."[169] In DRA's view, PG&E's decision tree includes all Class 2 segments as high priority, not merely "Class 2 urban area pipelines." DRA noted that including all Class 2 segments as high priority is inconsistent with the Commission's directives in D.11-06-017,[170] and recommended that only a limited number of "connected class 2" segments be included in Phase 1.[171] This change is reflected in DRA consultant BEAR's revised decision tree.[172]

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[167] 11 RT 1466, ll. 12-21, Hogenson/PG&E.

[168] 11 RT 1474, ll. 20-28, Hogenson/PG&E.

[169] 11 RT 1450, ll. 20-24, Hogenson/PG&E.

[170] Ex. 145, DRA Testimony, Chap. 4, p. 8, referring to Ordering Paragraph 4 in D.11-06-017.

[171] Ex. 145, DRA Testimony, Chap. 4, p.10..

[172] Ex. 144, DRA Testimony, Chap. 3, p. 35,.

### iii) Outcome M2 Should Be Omitted

DRA also recommends that replacement be removed as a default Phase 1 action for manufacturing threats.[173] This recommendation is also made by TURN.[174] PG&E acknowledges that strength testing is the preferred method for addressing manufacturing threats:

> Question: Isn't it correct that the – Part 192 of the Federal Regulations and the incorporated operating procedures under B31.8S state that strength testing is the proper means for assessing and mitigating manufacturing threats?
> Answer: It is the most prevalent way to assess for those threats, but it's not an absolute.[175]

PG&E also acknowledges that decision tree outcome has a major impact on PSEP costs:

> Question: Now are you aware that about two-thirds of the capital budget you've proposed for the pipeline project results from this single Decision Tree Box M2?
> Answer: I don't know the percentage, but the percentage seems reasonable that you've quoted.[176]

### iv) Decision Point 2F Should Be Omitted

Finally, DRA recommends removal of decision point 2F:

> BEAR is in agreement with Kiefner & Associates, Inc that the pipe features listed in the Fabrication & Construction Threats branch are primarily susceptible to failure from axial rather than hoop stresses. Consequently, a hydrostatic test is not well suited for evaluating the condition of these features. For this reason, BEAR recommends removing this Subpart J query.[177]

173 Ex. 144, DRA Testimony, Chap. 3, p. 35..

174 Ex. 131, TURN Testimony (Kuprewicz), pp. 19-21.

175 12 RT 1512, ll. 2-10, Hogenson/PG&E.

176 12 RT 1513-14, Hogenson/PG&E.

177 Ex. 145, DRA Testimony, Chap. 4, p.12.

While this recommendation increases the cost of Phase 1 mitigation, DRA believes it is required to properly address construction and fabrication threats. TURN makes a similar recommendation.[178]

#### c) The Decision Tree Should Be Modified As Proposed by DRA

DRA's revised decision tree should be adopted. To correct the deficiencies identified above, DRA consultant BEAR revised PG&E's decision tree.[179] BEAR's revised decision tree results in a net reduction in segments requiring Phase 1 replacement, an increase in required Phase 1 hydrotests, and an overall reduction in required Phase 1 mitigation.[180] BEAR's modifications to the decision tree result in a pipeline evaluation that has less risk than the PG&E decision outcomes, while simultaneously reducing scope and costs.[181]

### 2. PG&E Does Not Follow Its Own Criteria for Prioritizing Pipeline Segments

#### a) PG&E Subjectively Deviates from Decision Tree Outcomes and Mitigations

PG&E's current plan relies extensively on the exercise of "proper engineering judgment" with few criteria or protocols to guide said evaluation.

Even though the PSEP provides a detailed list of pipe segments to be included in Phase 1 projects, it is a draft plan aimed at providing ACEE class 4 cost estimates. It is based on inaccurate and incomplete data, a decision tree which has been challenged by parties, and PG&E interpretations of D.11-06-017 which have also been challenged by parties. PG&E acknowledges to some degree that the PSEP as filed was a draft plan, created the data available at the time, and that "PG&E must complete detailed design engineering, pipeline routing and permitting before it can further define the project's

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[178] Ex. 131, TURN Testimony (Kuprewicz), pp. 22-23.

[179] Ex. 144, DRA Testimony, Chap. 3, p. 35; Ex. 145, DRA Testimony, Chap. 4, pp. 10-13.

[180] Ex. 144, DRA Testimony, Chap. 3, p. 36; Ex. 145, DRA Testimony, Chap. 4, p. 14.

[181] Ex. 145, DRA Testimony, Chap. 4, p. 21.

scope and thus more accurately estimate costs."[182] The following issues will significantly impact the scope and cost of the PSEP, should the Commission approve the current plan:

- Changes in decision tree outcome/mitigation due to new data and PG&E judgment
- PG&E implementation of the "ors" in the decision tree
- Acceleration of segments into Phase 1
- Increased pipe diameter to increase capacity and piggability
- Line relocations and capacity expansion.

In prepared testimony, DRA recommended that PG&E more accurately define the scope of the PSEP before requesting Commission approval.[183] DRA continues to support this recommendation, while also acknowledging that scope changes may occur during detailed project engineering. DRA's updated recommendations serve to: 1) decrease the extent of scope changes that occur after the PSEP is approved; 2) define to the degree possible allowable scope changes; and 3) define a process for review and approval of changes in scope. How DRA's recommendations would help further these objectives is explained next.

As discussed, the mitigation required according to the decision tree criteria will change based on new data. Mitigation may not be necessary where valid pressure test records are found; the decision whether to hydrotest or replace a line may change based on information about pipe attributes and class location; and determinations of whether segments are high priority risks that need to be addressed in Phase 1 may change.

Even if the Commission opted for a decision tree that prescribed the type and timing of mitigation based on set criteria, thereby reducing discretion and subjective judgments, new information may be uncovered during detailed project design which should be used to make changes in scope.

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182 Ex. 2, PG&E Direct Testimony, p. 3-39.

183 Ex. 144, DRA Testimony, Chap. 3, pp. 116-118.

In any event, PG&E's decision tree is not prescriptive and allows considerable discretion. During hearings, PG&E highlighted that its decision tree includes a critical footnote stating: "Decision Trees Do Not Imply Final Decisions. Should Always be Combined with Practical Judgment."[184] Thus, PG&E has reserved the right to deviate from its own decision tree based on its subjective judgment, rather than in accordance with adopted criteria. PG&E witness Hogenson confirmed as much on cross-examination:

> Question: [D]o I understand correctly that you're now saying that based on engineering judgment, you may choose to do a strength test rather than automatically replace?
> Answer: That is correct.[185]

The Line 132 project provides an example of a subjective deviation from the decision tree that does not increase pipeline safety. For Line 132, PG&E elected to deviate from the decision tree and hydrotest a line requiring replacement pursuant to its decision tree (outcome F2),[186] even though PG&E acknowledges that hydrotesting does not offer complete mitigation of the fabrication threat that led to this outcome, and additional mitigation will be required.[187] In this example, PG&E's exercise of "practical judgment" resulted in a less safe outcome than would have occurred if it followed its own decision tree criteria, and the only justification given is that PG&E had previously committed to pressure test the line.[188] These inconsistencies and variations between over-planning and under-planning leading to less safe conditions are extremely worrisome and underscore the need to require PG&E to rework its PSEP.

PG&E has provided no record evidence about any guidelines, protocols, or procedures that might define "practical judgment" and ensure the correct mitigation based on a set of pipe data, regardless of whether PG&E Engineer A or PG&E Engineer

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[184] 11 RT 1401, ll.15-20, Hogenson/PG&E, referring to Ex. 2, PG&E Direct Testimony, Attach. 3A.

[185] 12 RT 1507-1508, Hogenson/PG&E.

[186] Ex. 21, PG&E Rebuttal Testimony, p. 3-34.

[187] 11 RT 1403, ll.6-15, Hogenson/PG&E.

[188] Ex. 21, PG&E Rebuttal Testimony, p. 3-33.

B is designing a project. PG&E should have consistent, objective standards to ensure the pipeline threats are correctly addressed, regardless of where a pipe is located, and which PG&E engineering group is responsible for mitigation.

In addition, many Phase 2 decision outcomes provide two mitigation options, some of which do not include criteria for selecting between them. For example, PG&E decision tree outcome M5 provides for hydrotest or replacement,[189] but PG&E does not provide criteria upon which to decide if the pipe segment should be replaced or hydrotested.[190]

#### b) PG&E Accelerates Segments to Phase 1 Without Justification

DRA's testimony shows that approximately one-third of PSEP pipe replacement and hydrotest costs are **not** required based on PG&E's decision tree.[191] Some of the optional costs requested are for segments that required a different mitigation (e.g., hydrotest versus replacement per the decision tree), but the majority are for segments where Phase 2 mitigation was specified. Based on its PSEP, PG&E requests approximately $200 million for segments that already have a valid pressure test record and do not require mitigation based on D.11-06-017.[192]

DRA provided in its testimony illustrative cost calculations based only on segments that require Phase 1 mitigation pursuant to BEAR's revised decision tree.[193] To be clear, DRA is not opposed to expanding the scope of Phase 1 if that is necessary from a safety standpoint. In fact, DRA supports selective acceleration of segments into Phase 1, but only where a logical and defensible justification is provided. The cost structure of hydrotests provides greater opportunities for acceleration for economic reasons compared

[189] Ex. 2, PG&E Direct Testimony, Attach. 3A.
[190] Ex. 2, PG&E Direct Testimony, p. 3B-15.
[191] Ex. 144, DRA Testimony, Chap. 3, pp. 45-46.
[192] Ex. 144, DRA Testimony, Chap. 3, pp. 45, 47. This figure is the sum of costs for decision tree outcomes C4, C5, C6, and C7 from Tables 7 and 8.
[193] Ex. 144, DRA Testimony, Chap. 3, pp. 112-113.

to replacement projects.[194] In some situations, incorporating the hydrotesting of existing lines as part of hydrotests required for pipe replacement projects could provide cost savings,[195] and in some "neighbor segment situations" acceleration could be justified.[196] DRA does, however, oppose unjustified acceleration.

Acceleration must also be considered in light of D.11-06-017 calling for "alternatives that demonstrably achieve the same standard of safety"[197] as replacing or testing pipe segments. On cross-examination, PG&E's witness explained PG&E's position on the issue: "So our thinking on this concept was that there may be a point in time that the CPUC might be willing to accept improved in-line inspection technology that can actually inspect the pipeline for manufacturing defects or long seam defects. Today they don't."[198]

However, Section 3 of PG&E's decision tree provides for the possibility of the Commission's adopting such alternatives in the future.[199] In addition, Southern California Gas (SoCalGas) and San Diego Gas & Electric (SDG&E) in their PSEP application propose to analyze the data obtained through the in-line inspection process to validate transverse field inspection (TFI) tools as an equivalent means to assess the strength of in-service pipelines.[200] If SoCalGas and SDG&E perform this analysis and it validates their hypothesis, it is possible that the Commission could approve in-line inspection (ILI) as an alternative to hydrotesting for certain types of threats before PG&E completes Phase 1. Moreover, while there are exceptions, ILI is generally less expensive

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[194] Ex. 144, DRA Testimony, Chap. 3, pp. 46-47.

[195] Ex. 144, DRA Testimony, Chap. 3, pp. 47-48.

[196] Ex. 144, DRA Testimony, Chap. 3, p. 41; Ex. 145, DRA Testimony, Chap. 4, p. 13.

[197] D.11-06-017, p. 1.

[198] 11 RT 1418, ll. 17-23, Hogenson/PG&E.

[199] For example, outcome C3 applies to pipes without a documented pressure test, and provides for the option of "ILI and CIS." Ex. 2, PG&E Direct Testimony, p. 3B-28.

[200] R.11-02-019, Amended Pipeline Safety Enhancement Plan of Southern California Gas Company and San Diego Gas & Electric Company Pursuant to D.11-06-017, Requiring All California Natural Gas Transmission Operators to File a Natural Gas Transmission Pipeline Comprehensive Pressure Testing Implementation Plan, Dec. 2, 2011, p. 22.

than hydrotests, and hydrotests are generally less expensive than replacement.[201] Therefore, if the Commission subsequently determines that ILI is a safe alternative to hydrotest or replacement for certain threats, accelerating segments into Phase 1 hydrotest and replacement projects could result in more expensive mitigation overall, not just a temporal cost shift from Phase 2 to Phase 1.

#### c) PG&E Replaces Pipeline to Increase Capacity and Piggability Without Justification

Decision 11-06-017 mandates: "The Implementation Plan must **consider** retrofitting pipeline to allow for inline inspection tools…."[202] PG&E relied on this statement to propose "to make **every** gas transmission pipeline that operates at or greater than 30 percent SMYS piggable."[203] This goal extends well beyond the Commission's direction, and has significant cost implications because PG&E uses it as the basis for two methods that increase costs: segment replacement where replacement is not required by the decision tree, and to increase the diameter of lines replaced. These projects appear to be unnecessary add-ons to the highest priority safety work identified through the decision tree. If PG&E wants to add capacity or to replace segments that are not a priority from a safety standpoint, those proposals should be made in the general rate case, not added to the PSEP scope of work.[204]

PG&E's states, "the DRA proposed reduction in pipe replacement miles will have a negative effect on miles of pipe made piggable compared to PG&E's PSEP."[205] PG&E also states, "projects like L-108, L-109, L-210A, L-111A, L-118A are a few examples of

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[201] Ex. 144, DRA Testimony, Chap. 3, p.48. Table 9 shows that PG&E's average costs for replacement are approximately 10 times greater than hydrotest, which are in turn approximately 10 times more expensive than ILI. Exceptions occur for hydrotests of short pipe segments, and where extensive upgrades are required to perform an ILI, even though Table 9 shows that even the lowest hydrotest cost ($248 per mile) is more expensive than the most expensive combination of ILI with upgrades ($60 plus $158 equals $218 per mile).

[202] D.11-06-017, p. 32, Ordering Paragraph 8, emphasis added.

[203] Ex. 2, PG&E Direct Testimony, p.3-24, emphasis added.

[204] This is particularly true since "piggable is not well defined, as discussed below and in section IV.E.

[205] Ex. 21, PG&E Rebuttal Testimony, p.3-21.

the increased pipeline piggability resulting from the proposed Phase 1 PSEP projects."[206] Project L-108 is a good example of how PG&E's piggability goal increases Phase 1 costs. In this project, PG&E plans to replace 13,601 feet of pipe based on one 92-foot segment being slated for replacement by its decision tree.[207] The remaining 13,509 feet of this part of Line 108 has been pressure tested (decision tree outcomes C4, C5 and C7) and PG&E provided no evidence of capacity constraints on this line, so the only rationale supporting replacement is increasing piggability. PG&E indicated on cross examination that there are ILI tools that can work with a 6" diameter difference, but PG&E has not provided evidence on whether an ILI tool **cannot** work in the 8" difference between the existing 16" line and the 24" line it proposes for replacement.[208] Even if such a tool is not currently available, PG&E did not provide cost information comparing replacement of the entire 2.58 miles of pipe for approximately $10 million[209] with the cost of selectively removing ILI obstacles in the existing 16" line, installing a separate pig launch and receiver, and running a separate pig on this section.[210] Again, the Commission did not direct PG&E to make all of its lines piggable; rather, the Commission directed utilities to make their pipeline systems safe.

PG&E's proposed PSEP includes many increases in pipe diameter which greatly increase costs. For example, PG&E's proposed "all-in" cost for a 24" line is 48% more than the cost for a 16" line.[211] **PG&E is proposing diameter increases for nearly 37% of lines it proposes to replace**: 16.4% is to use standard size 24" pipe, which PG&E

[206] Ex. 21, PG&E Rebuttal Testimony, p.3-21.

[207] Ex. 8, PG&E Workpapers, p. WP 3-63.

[208] 11 RT 1426, ll.14-19.

[209] The segment requiring replacement, 162.2, constitutes less than 1% of the length of this line, so nearly all of the requested $10.2 million applies to the other segments.

[210] This assumes a 24" pig is used upstream and downstream of this section.

[211] Ex. 2, PG&E Direct Testimony, p. 3E-15 (using non-congested costs, $515 per foot divided by $347 per foot).

does not justify quantitatively, and 20.6% is to increase piggability and increase capacity.[212]

Regarding the "piggability" rationale for expansion, DRA has four concerns. First, PG&E does not have criteria to define "piggable." "ILI" is a generic term for the use of multiple tools, and PG&E indicates that "some industry available… 'Smart Pigs' can accommodate minor variations in pipeline diameter, typically 15 to 25 percent,"[213] but also that it is "not aware a transverse [TFI] tool that can actually work in a multidiameter pipeline."[214] PG&E should have a procedure or protocol to ensure that replacement of pipes or valves actually results in lines that are piggable with the ILI tool required to detect a particular threat. PG&E was asked three times on cross-examination if it had "written criteria that PG&E developed to ensure that the replacement project support ILI in the future" but a straight answer was never provided.[215]

Second, ILI brings high technology into a mature and relatively stagnant industry. Adoption of TIMP in 2004, actions by the Commission in the aftermath of the San Bruno explosion, and federal attention on pipeline safety should combine to provide huge market incentives for existing companies and entrepreneurs to refine existing ILI tools, develop new ILI tools and applications, and new techniques for analyzing and utilizing data obtained through ILI. Now is not the correct time to replace pipelines for the primary purpose of increasing "piggability," since definitions of "piggable" could likely change significantly, even before 2014.

DRA's remaining concerns are that PG&E has provided no evidence that it needs additional capacity as requested in the PSEP, and that PSEP requests for the diameter increases requested do not always increase piggability. For the Line 21F project, for example, PG&E seeks to "increase the pipeline diameter from 12-inch to 16-inch pipe for

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[212] Ex. 21, PG&E Rebuttal Testimony, p. 3-24, Table 3-1.

[213] Ex. 21, PG&E Rebuttal Testimony, p.3-23.

[214] 11 RT 1426-27, Hogenson/PG&E.

[215] 11 RT 1397-99, Hogenson/PG&E.

the dual benefit of increased ILI feasibility and system capacity" on Line 21F.[216] On cross examination, DRA asked: "Does PG&E have a written plan to upgrade all of Line 21F to 16-inch diameter?" PG&E's witness responded: "No, we do not, not that I'm aware of. We do not have a written plan to update 21F to 16-inch diameter."[217] DRA also asked: "Does PG&E have an analysis showing increased demand on this line that will be limited by the current 12.75-inch line diameter?"[218] PG&E responded that planning engineers "***will*** look" at this and they "***can*** tell us" what is needed,[219] but the language is in the future tense, indicating what ***may*** be done. PG&E has provided no evidence that the decision to upgrade line 21F was based on an analysis showing that larger pipe is required.

With regard to piggability, PG&E stated in prepared testimony that "all things being equal, pigability of a 12-inch line or a 16-inch line should be roughly the same"[220] and that 12" segments were to be replaced to "minimize the number of diameter changes in the proposed run"[221] to increase the piggability of the line. However, PG&E's proposed replacements actually increased the number of diameter changes from 19 to 20.[222]

For Line 108, PG&E maintains that it included 13,000 feet for construction efficiency[223] but PG&E does not explain any further why it omitted Segment 141, with a length of 5,179 feet, that also has a diameter of 16" and that BEAR recommended to be replaced.[224] While PG&E justifies adding large segments for efficiency, piggability and

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[216] Ex. 21, PG&E Rebuttal Testimony, p. 3-28.

[217] 11 RT 1384, ll.17-21, Hogenson/PG&E.

[218] 11 RT 1388, ll. 11-14, Hogenson/PG&E..

[219] 11 RT 1388-89, Hogenson/PG&E.

[220] 11 RT 1380, ll.1-3, Hogenson/PG&E.

[221] Ex. 21, PG&E Rebuttal Testimony, p. 3-28.

[222] 11 RT.1380-82, Hogenson/PG&E. The number of diameter changes based on the current configuration and PG&E's proposed configuration can be verified using PG&E's PSEP database. Ex. 56, PG&E Data Response to DRA-008, Q/A 28, Oct. 6, 2011. .

[223] 12 RT 1585-86, Hogenson/PG&E..

[224] Ex. 147, DRA Testimony, Chap. 6, p. 26.

capacity, it does not explain how leaving a long, sandwiched 16" segment would allow it to proceed with its stated plan.

#### d) PG&E Relocates Lines Without Justification

DRA's opening testimony describes projects on two lines in the Central Valley, L118A and L111, where the PSEP includes $5 million to re-route lines, and millions more to increase the capacity by four times.[225] PG&E provided only two confidential PowerPoint presentations prepared in 2007 and 2009 that offer minimal details for this multi-million dollar project.[226] PSEP projects should be efficiently planned, and account for future growth, but all requests that lead to increased costs should be justified with detailed demonstrations of need. PG&E has not provided the required level of support for Line 118A/Line 111, or for Line 21F, as discussed above.

### 3. PG&E Should Provide Justification for Changes to the PSEP's Scope and Costs

The Commission should require PG&E to submit changes that need to be made to the PSEP since its initial iteration in August 2011. Within 45 days of a final decision in this proceeding, PG&E should file an advice letter providing the guidelines, protocols and procedures PG&E will follow to address the following issues, which ultimately drive the scope and aggregate cost of mitigation:

- Deviations from decision tree outcome/mitigation due to new data
- Deviations from decision tree outcome/mitigation due to PG&E engineering judgment
- PG&E implementation of the "ors" in the decision tree
- Acceleration of segments into Phase 1
- Expenditures to increase piggability
- Diameter increases for reasons other than piggability
- Line relocations
- Engineering Condition Assessment

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[225] Ex. 144, DRA Testimony, Chap. 3, pp. 56-57. PG&E proposes to replace 12" pipe with 24" pipe, which increases the cross sectional area four times and capacity proportionally. PG&E's "all-in" unit costs for the larger line are approximately 50% more and increase the project cost to over $20 million.

[226] Ex. 144, DRA Testimony, Chap. 3, p. 57; Ex. 56, PG&E Data Response to DRA-037, Q/A 1, Dec. 22, 2011.

### B. If the Commission Authorizes Cost Recovery for Hydrotesting Contrary to DRA's Recommendation, It Should Use DRA's Cost Estimates Rather Than PG&E's

As discussed in Section II, above, PG&E should bear the costs of pressure testing any of its natural gas pipelines installed after 1935. However, if the Commission rejects DRA's recommendation and authorizes PG&E to recover pressure test costs from ratepayers, the unit costs developed by DRA should be adopted instead of those proposed by PG&E. Specifically, DRA recommends that the Commission adopt:

* specific variable ("all-in") costs;

* fixed costs for the first test section in a project (Mob/Demob);

* fixed costs for additional test sections in a project (Move Around); and

* test head costs.

The Commission should specify the types of costs that are included within each of these unit costs, which are treated as contingency items, and which are to be borne by PG&E shareholders.

#### 1. Unit Costs Should Be Adopted Instead of Aggregate or Average Hydrotest Costs

Given the absence a well-defined and accurate project scope, DRA recommends adopting unit rather than aggregate or average hydrotest costs. A reasonable estimate of the scope of Phase 1 hydrotesting cannot be determined until the Commission resolves such issues as the appropriate decision tree to use and the appropriate criteria for accelerating low priority segments into Phase 1. Even then, PG&E would have to re-run the decision tree and re-define projects using the adopted criteria and updated MAOP data. Without an accurate scope, the Commission cannot determine what is a reasonable estimate of aggregate PSEP hydrotest costs.

Average test costs are very difficult to compare, and therefore accurate unit costs must be used. DRA in its prepared testimony provided data on average per mile hydrotest costs from the American Gas Association (AGA), the Interstate Natural Gas Association of America (INGAA) and other sources showing that PG&E's average hydrotest cost fall into the high range of oil and gas industry averages.[227] DRA also showed that PG&E's HCA transmission lines are generally small, with an average diameter of 19.8 inches, which indicates that PG&E's average costs should be at the low end of national averages.[228] While this data can be used to provide an overall check of PG&E current request and actual costs in the future, DRA does not recommend using average costs for estimating hydrotest costs because the costs are highly dependent on the number of test projects, and the length of each test section. This is due to the significant fixed costs discussed below. In addition, the Move Around and Test Head charges vary according to the diameter of the pipe, such that PG&E's proposed total fixed cost per project with a single test section ranges from $715,000 for the smallest diameter pipes to $1.04 million for the largest. This large fixed cost makes short test sections very expensive, on a per mile basis, compared to longer sections, as illustrated in the following table:[229]

| Size | Move | Mob | Test Head | "All-in" $/foot | Length (miles) | Total Cost | | $/mile |
|---|---|---|---|---|---|---|---|---|
| 36 | $ 500,000 | $ 500,000 | $ 40,000 | $ 59 | 0.1 | $1,071,152 | | **$ 10,711,520** |
| 36 | $ 500,000 | $ 500,000 | $ 40,000 | $ 59 | 0.5 | $1,195,760 | | **$ 2,391,520** |
| 36 | $ 500,000 | $ 500,000 | $ 40,000 | $ 59 | 1 | $1,351,520 | | **$ 1,351,520** |
| 36 | $ 500,000 | $ 500,000 | $ 40,000 | $ 59 | 5 | $2,597,600 | | **$ 519,520** |

This trend exists in PG&E's historic cost data ($205k to $11 million per mile[230)] and the PG&E PSEP request ($248k to $14 million per mile[231)]. DRA's proposed costs per mile would also be higher for shorter sections than for longer sections tested. The

[227] Ex. 147, DRA Testimony, Chap. 6, pp. 9-11.

[228] Ex. 144, DRA Testimony, Chap. 3, p.72.

[229] All data for 36" nominal pipe from Ex. 2, PG&E Direct Testimony, p. 3E-17.

[230] Ex. 61, PG&E Data Response to DRA-026, Q/A 1, attach. 2, Dec. 6, 2011. PG&E costs per foot multiplied by 5280 to get per mile costs.

[231] Ex. 2, PG&E Direct Testimony, p.3-42, ll.1-2. PG&E costs per foot multiplied by 5280 to get per mile costs.

Commission must therefore ensure that all unit costs, fixed and variable, in addition to average costs, are reasonable.

### 2. DRA's Revised Fixed Costs Should Be Used for Cost Recovery Purposes

#### a) Fixed Costs Comprise a Significant Portion of Hydrotest Cost

"Fixed costs" are tasks that are required for every test and are relatively independent of the length of pipe, such as taking the line out of service, installing test heads, tying the line back in and restoration of service. "Variable costs" are tasks that vary in proportion to the length of the line, such as filling the line with water, drying the line and disposing of the water. Most variable costs also vary with the diameter of the pipe, since this determines the volume of water and drying air required.

PG&E's hydrotest cost model, developed by Gulf Interstate Engineering (Gulf) is based on certain fixed and variable costs, which are calculated on a unit basis and then applied on a project level based on the scope of each project. PG&E's aggregate hydrotest cost request is based primarily on application of the unit costs summarized on page 3E-17 of PG&E's prepared testimony.[232] PG&E proposes four separate unit costs including a variable cost per foot that varies with pipe diameter ("all-in" rate), fixed costs that vary with pipe diameter (Test header charge and Move Around charge), and a fixed cost per project (Mob/demob). The application and use of these unit costs in Gulf's hydrotest cost model are described in DRA's prepared testimony.[233] DRA illustrated the relative magnitude of the cost drivers for PG&E's proposed hydrotest program in the following figure, where 100% is equal to the overall proposed cost of $405 million:[234]

Figure A – PSEP Hydrotest Cost Breakdown

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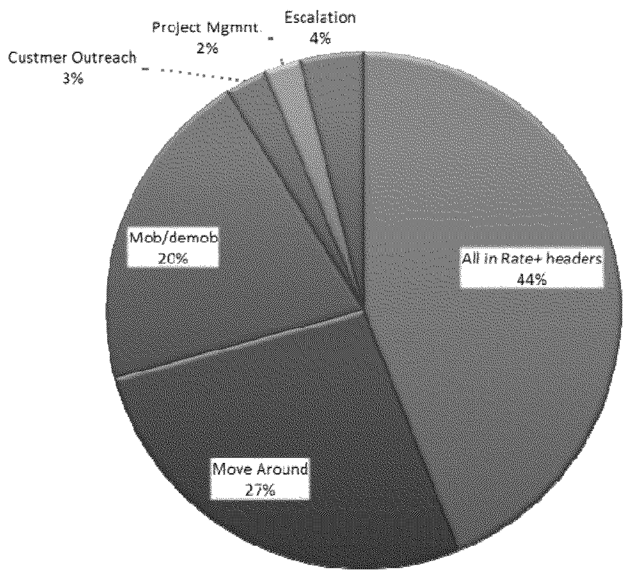
[232] Customer outreach, project management, and escalation costs are added on top of the project specific costs at fixed percentages.

[233] Ex. 144, DRA Testimony, Chap. 3, pp. 61-62, 65-66.

[234] Ex. 144, DRA Testimony, Chap. 3, p. 70. $405 includes $392 million of proposed ratepayer funding and $11.8 million of proposed shareholder funding.




This figure shows that according to PG&E's cost model, the primary cost drivers are the All-in rate, Move Around charge, and Mob/Demob charge.[235] The figure also shows that a majority of hydrotest costs are not included in the "all-in" rate. DRA does not dispute that fixed costs are a significant portion of a hydrotest.

DRA determined through discovery and analysis that PG&E used a hybrid approach to establishing unit costs, in which a "bottom up" approach was provided to establish the variable all-in rate, while fixed costs were apparently established based on PG&E historic costs. DRA's analysis shows that PG&E has not adequately defined or justified a majority of its proposed hydrotest unit costs.

#### b) PG&E's Fixed Costs Are Ill-defined and Unsupported.

DRA agrees conceptually with a fundamental premise of PG&E's hydrotest cost estimate: some costs should be relatively constant or "fixed" regardless of the length of pipe tested. However, PG&E has provided no support for its proposed fixed costs, which

[235] DRA workpaper "DRA WP TCR-5, DRA Hydro calib for Jan 31 tsmy.xlsx" shows that the category "All in Rate = headers" in this figure includes approximately $170 million for the all-in charge, and $8 million for the test header charge. Including this data in the figure would show that 42% of hydrotest costs are due to "all-in" costs.

account for 47% of proposed hydrotest costs, as shown in Figure A above. PG&E's hydrotest fixed costs, per project with a single test section, include the following:[236]

- Mobilization/Demobilization (Mob/Demob) - $500,000
- Move around/Test section (Move Around charge) - $200,000 to $500,000
- Fabricate Test Header Charge (Test Head Charge) - $15,000 to $40,000

The Move Around and Test Head charges vary according to the diameter of the pipe, such that the proposed total fixed cost per project with a single test section ranges from $715,000 for the smallest pipe diameters to $1.04 for the largest.

PG&E describes its fixed costs as follows:

> A mobilization/demobilization surcharge of $500k (based on conversations with PG&E) has been added per project and a move around surcharge based on pipe diameter range… has been added for each additional test section within a defined project. These surcharges include the costs for moving construction equipment and personnel to and from each site, excavating bell holes at each end of the test section, and returning the site to in-situ conditions.[237]

Four points should be noted in this description. First, the Test Head Charge is not discussed. Second, the description states that a move around surcharge has been added for each *additional* section within a defined test. Third, PG&E does not differentiate between the tasks included in the Move Around charge compared to the Mob/Demob charge.[238] Finally, the Mob/Demob surcharge was provided by PG&E, not derived by Gulf. These will be discussed below for each particular type of fixed cost.

PG&E's testimony and workpapers do not show how PG&E derived the specific fixed unit costs used in the PSEP cost estimate, and DRA undertook extensive discovery in an attempt to understand the basis of PG&E's cost model and how its unit costs were

[236] Ex. 2, PG&E Direct Testimony, p. 3E-17. Note that multiple Move Around charges are applied for projects containing multiple test sections.

[237] Ex. 2, PG&E Direct Testimony, p. 3E-8.

[238] One interpretation of this statement is that both charges cover the same set of costs, and that the Move Around charge is an optional charge applied as required for projects with more than one test section. This is not how the charge was applied.

derived. PG&E's first data request response on the issue indicated that "pipe cleaning, water handling/storage/disposal… and drying of the pipeline" were included in the Mob/Demob charge; however, each of these is very clearly included in the "all-in" cost.[239] DRA also asked PG&E to "provide workpapers in excel format supporting each unit cost for Test and ILI projects, as shown on page 3E-17 of the testimony."[240] PG&E provided no workpapers in response.[241] DRA then asked in a subsequent data request:

> Please provide a table listing all the cost elements involved in a hydrotest, and assign each to one of the four unit costs listed above, and in PG&E testimony at 3E-17… Provide supporting documentation which shows that the table… is consistent with the Gulf cost estimating model used by PG&E for the PSEP.[242]

PG&E in response provided a table of 46 specific costs, most of which showed that the cost was included in multiple unit costs, such as Mob/Demob and Move Around, or Mob/Demob and All-in costs.[243] PG&E did not include specific cost numbers or a showing that the table was consistent with PG&E's specific unit cost requests. The table also continued to propagate uncertainty about what is included in all-in versus fixed costs, showing Engineering Design and permitting for water disposal as fixed Mob or Move costs when these tasks are explicitly included in the all-in cost.[244] On cross-examination, PG&E witness Hogenson confirmed that PG&E could not show how its unit costs were derived:

> Q: Did PG&E provide similar workpapers that derive the costs for mob/demob move around and fabricate test headers?
> A: PG&E provided DRA several data request responses regarding the cost estimating that was done for our hydro testing projects, and there were several to try to quantify how the cost assignments would be made to each one of the

[239] Ex. 56, PG&E Data Response to DRA-026 Q/A 6, Dec. 5, 2011.

[240] Ex. 56, PG&E Data Response to DRA-055 Q/A 3, Jan. 6, 2012.

[241] Ex. 56, PG&E Data Response to DRA-055 Q/A 3, Jan. 6, 2012.

[242] Ex. 56, PG&E Data Response to DRA-070 Q/A 7, Feb. 27, 2012.

[243] Ex. 56, PG&E Data Response to DRA-070 Q/A 7, Feb. 27, 2012.

[244] Ex. 56, PG&E Data Response to DRA-055 Q/A 3, Jan. 6, 2012, attach. 1, sections 5.0 and 7.0.

categories. We didn't specifically have the detail at the level that you specified when we developed our hydrotesting costs for existing pipelines.[245]

…

ALJ BUSHEY: But as you sit here right now you can't put your finger on exactly where the calculations are?

A: I cannot.[246]

PG&E did not provide a "bottom up" calculation of its fixed unit costs that considered the "number of personnel that would be on the job, the number of pieces of equipment, the hours that they would work in a given day, what equipment rental costs would be."[247] Instead, PG&E provided the following limited explanation:

> The historical cost data was used to develop the cost estimating algorithms used to create the Implementation Plan filing cost forecast for pipe replacement and strength testing, and then used to confirm that the estimating algorithm results was similar to the results of the unit cost database across a range of projects.[248]

This is not an adequate justification for PG&E's fixed unit costs for three reasons. First, PG&E did not provide the algorithms they claim to have used.[249] As such, they have failed to provide verifiable evidence that their unit costs are actually based on historical data. Second, PG&E's "historical cost data" consists of a sample size of 11 tests performed between 2000 and 2009.[250] PG&E acknowledges this as a limitation: "While the process above [using historic data to develop unit costs] applied to both pipe replacement and hydrotest costs, the hydrotest database is very small. Therefore, the [unit costs for] small diameter hydrotest[s] were validated with a combination of

[245] 11 RT p.1443, ll. 15-27, Hogenson/PG&E.

[246] 11 RT 1447, ll. 12-15, Hogenson/PG&E.

[247] 11 RT 1407, ll. 6-10, Hogenson/PG&E, referring to how Gulf generated replacement project cost estimates.

[248] Ex. 61, PG&E Data Response to DRA-026, Q/A 1, Dec. 6, 2011.

[249] 11 RT 1412-13, Hogenson/PG&E.

[250] Ex. 61, PG&E Data Response to DRA-026, Q/A 1, attach. 2, Dec. 6, 2011.

historical data and engineering assessment."[251] PG&E, however, provides no insight into the "engineering assessment" it used. Third, PG&E's hydrotest database provides only the total costs for each project, with no breakdown of individual costs that could be considered as components of either fixed (Mob or Move) or variable (all-in) costs.

PG&E has not provided the derivation of the fixed costs for its hydrotest cost estimate such that DRA, other parties and the Commission can verify these critical values.

**c) DRA's Revised Mob/Demob Charge Should Be Used for Cost Recovery Purposes**

If the Commission authorizes ratepayer recover, it should use the revised version of DRA's Mob/Demob Charge. PG&E's proposed $500,000 "Mob/Demob" charge is excessive compared to DRA's "bottom up" calculations.

This charge includes the fixed costs incurred for projects involving a single test section, and for the main test section for projects with multiple sections. Specifically, this charge includes moving all equipment and materials to the test site, equipment setup, excavating the pipe ends, and returning the site to pre-test conditions. The welding costs required to tie in the test heads, then return the line to service, which could be considered as a fixed cost, are included in the all-in rate calculated by DRA witness Delfino Engineering.[252]

In contrast to PG&E's baseless and opaque estimates for hydrotest fixed costs, DRA provided transparent calculations by Delfino Engineering, a firm with over four decades of pipeline engineering experience with many of the largest gas and oil companies in the world.[253] Mob/Demob was estimated using a bottom-up estimate that considers the specific amount of excavating required and equipment needed for each hydrotest. For the cost to excavate each end of the pipeline, Delfino used a figure supplied by PG&E in response to a question regarding ILI costs, and scaled it for the size

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[251] Ex. 61, PG&E Data Response to DRA-026, Q/A 1, Dec. 6, 2011..

[252] Ex. 146, DRA Testimony, Chap. 5, p.2-5.

[253] Ex. 146, DRA Testimony, Chap. 5, pp. 2-6 to 2-9.

of holes required for a hydrotest.[254] Delfino Engineering calculated Mob/Demob costs of $85,600 to $139,400 based on the size of pipe to be tested, and the resulting scope of excavation required.[255] In its prepared testimony, DRA used a simplified version of these costs in its illustrative cost adjustment calculations.[256]

PG&E only challenged one element of DRA's estimate of Mob/Demob costs, and errs in its criticism. In rebuttal, PG&E states that "Mr. Delfino assumes that PG&E can just truck the water offsite and return for another load. He is silent about where he assumes PG&E is taking the load."[257]This is an incorrect statement, since Mr. Delfino actually stated that "cleaned water can be hauled to another hydrotest or pumped into the next test segment."[258] Mr. Delfino included a water disposal cost as part of his "all-in" cost calculation, as did PG&E, which is on par with PG&E's 2011 actual disposal costs for long lines that did not contaminated with mercury.[259] PG&E also stated that "Mr. Delfino's cost estimates do not reflect all the work and equipment actually needed to correctly manage water from hydrotesting a gas pipeline, and therefore, underestimates the costs."[260] It appears the PG&E is not familiar with the CETCO filtration system quoted by Mr. Delfino which allows a faster water treatment option overall, and which does not require the equipment rental costs and ROW required of PG&E's proposal, which requires enough Baker tanks to hold the entire volume water used for a test section.[261]

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[254] The estimated costs in the last line of the table on page 2-7 of Exhibit 146 are for a single hole, which must be doubled to obtain excavation and shoring costs per test section.

[255] Ex. 146, DRA Testimony, Chap. 5, p. 2-8.

[256] Ex. 144, DRA Testimony, Chap. 3, p.79,.

[257] Ex. 21, PG&E Rebuttal Testimony, p.4-6.

[258] Ex. 146, DRA Testimony, Chap. 5, p. 2-2..

[259] Ex. 146, DRA Testimony, Chap. 5, p. 2-5, second line of table shows $.50 per gallon to haul water away. PG&E indicated a 2011 cost of $.48 per gallon (Ex. 56, PG&E Data Response to DRA-026 Q/A 4, p.2, final line of the table).

[260] Ex. 21, PG&E Rebuttal Testimony, p. 4-7.

[261] Ex. 146, DRA Testimony, Chap. 5, p.2-2.

In fact, PG&E lacks the experience to reasonably challenge an industry expert like Mr. Delfino PG&E Witness Campbell had very limited knowledge of the basis of PG&E's hydrotest cost estimate,[262] was involved primarily in gas marketing prior to 2011,[263] and prior to this he participated in only 10-20 hydrotests over an 11 year period.[264] PG&E witness Hogenson acknowledged that "neither one of us [PG&E or Gulf] had a lot of experience in pressure testing existing pipelines."[265]

As discussed. PG&E has failed to justify its requested $500,000 Mob/Demob charge, which accounts for 20% of its proposed hydrotest costs. PG&E has neither provided a "bottom up" derivation of this charge nor shown the algorithms or other evidence tying historic test costs to this specific request. There are indications that some test costs are included both in this charge and in the "all-in" and "Move Around" costs.

In contrast, DRA has provided a transparent derivation of its Mob/Demob fee, and clearly showed what is included in this charge. The derivation is based on a "+40%" estimate which provides a significant level of conservatism. DRA recommends the Commission adopt the Mob/Demob charges calculated by DRA witness Delfino:[266]

| | 12" and under | 14" to 20" | 22" to 28" | 30" to 42" |
|---|---|---|---|---|
| Mob/ Demob Charge per Project | $85,600 | $87,600 | $110,800 | $139,400 |

262 13 RT, 1802, ll. 2-17, Campbell/PG&E..

263 13 RT 1852, ll. 15-19, Campbell/PG&E..

264 13 RT 1856, ll. 12-23, Campbell/PG&E..

265 13 RT 1405, ll. 25-27, Campbell/PG&E..

266 Ex. 144, DRA Testimony, p. 79. These costs differ from the cost adjustments used for illustrative cost calculations in DRA's prepared testimony. The previously submitted numbers were adjusted upward to $160,000 for all pipe sizes because DRA did not understand that these were "+40%" values where the calculations were performed

#### d) DRA's Revised Move-Around Charge Should Be Used for Cost Recovery Purposes

PG&E's proposal for a "Move Around" charge is conceptually reasonable, but is excessive and incorrectly applied. PG&E errs in applying one extra Move Around charge for each hydrotest project, inflating aggregate costs by approximately $50 million. DRA recommends that only "n-1" Move Around charges be applied for projects with "n" test sections.

PG&E describes the Move Around Charge as:

> From past experience, we understood that if a project required multiple tests, each additional site would not require the same initial set up cost as the first test, so we captured this with a "Move Around / Test Section Charge" which comes in less expensive that the "Mob/Demob Charge" except for the 30" to 42" size classification."[267]

PG&E did not provide derivations for its fixed costs in response to DRA discovery requests, and Move Around charges are no exception. These costs are only described verbally as a variation of Mob/Demob charges. In addition, PG&E fails to explain why this charge should be the same as the basic Mob/Demob charge for large pipes, but "as little as" $200k for small pipes. In contrast, DRA provides transparent calculations. For move around costs, Delfino started with its calculated Mob/Demob cost, then adjusted downward based on the assumption that PG&E was able to "leap frog" equipment from one test to the next. This was accomplished by including only one excavation per additional test section rather than two, and using 60% of the other costs including in Delfino's Mob/Demob costs.[268] The resulting cost ranges from $44.7k to $76.7k which are approximately 55% of Delfino's Mob/Demob costs for all pipe sizes.

PG&E also *applies* the Move Around charge incorrectly in its cost model. DRA notes that for projects with a single test section, fixed costs "for moving construction equipment and personnel to and from each site, excavating bell holes as each end of the

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267 Ex. 56, PG&E Data Response to DRA-061, Q/A 4, Jan. 23, 2012.

268 Ex. 146, DRA Testimony, Chap. 5, pp. 2-9 to 2-10.

test section, and returning the site to in-situ conditions" are covered by the Mob/Demob charge, which PG&E estimates at $500,000 per project. A Move Around Charge is only required for projects with multiple test sections, where additional test-setups (e.g., excavation of two new bell holes to access the test ends) are required and additional fixed costs will be incurred. Therefore Move Around charges should only be applied to projects with multiple test sections, and more specifically applied for "n-1" test sections, where "n" is the number of test section in a project.[269] Instead, PG&E assigns the Move Around charge "n" times for every test.[270] This erroneously adds the cost of one extra Move Around charge to each and every project. DRA estimates that this error increases the total PSEP hydrotest cost request by approximately $50 million.[271]

DRA's recommended Move Around charges based on the assumption that "leap-frogging" can be used for subsequent test sections are:

| | 12" and under | 14" to 20" | 22" to 28" | 30" to 42" |
|---|---|---|---|---|
| Move Around Charge per Additional Test Section | $44,700 | $45,700 | $59,400 | $76,700 |

These costs differ from the cost adjustments used in DRA's opening testimony for the same reasons discussed for the Mob/Demob charge above.

DRA has not evaluated how many "Move Arounds" could take advantage of such a leapfrog relative to those that would require two new excavations for a non-contiguous

[269] Ex. 144, DRA Testimony, Chap. 3, pp. 16-18.

[270] An example of a test with single test section is project SP-3 TEST. Exhibit 9, page WP 3-760 shows that only one test section is required ( 7th column) and page WP 3-759 shows 1 Move around and 1 Mob/Demob charged to the project (in the 22" to 28" section). An example of a test with multiple test sections is project L-21B TEST. Exhibit 9, page WP 3-775 shows that 4 test sections are required (7th column) and page WP 3-X774 shows 4 Move around and 1 Mob/Demob charged to the project (in the 14" to 20" section).

[271] The Move Around Charge ranges from $200,000 to $500,000, so one extra charge for each of the 165 projects adds a cost of $33 million if all pipe were small, to $83 million if all pipes were large. DRA did not determine the cost impact based on the actual pipe sized in each test.

segment. For additional test sections within a project where leap frogging is not possible, DRA's Mob/Demob charge should be used.

#### e) PG&E's Requests for New Test Heads and Test Headers Should Be Rejected

PG&E has an existing fleet of test heads and has provided inadequate justification for its parallel requests for capital and expenses for new test heads. Temporary test heads and test caps are also not required for every hydrotest. Therefore both requests for new test heads should be denied. Contingency funds should be used to fund any projects requiring temporary test heads or test caps. Temporary test heads should be designed to achieve the optimum balance of fabrication costs and number of re-uses.

PG&E's test head costs reflect the lack of detail in an ACEE Class 4 estimate. DRA in its prepared testimony raised the potential issue of PG&E requesting duplicate and excessive costs for test head based on the following:[272]

- PG&E currently has 50 pairs of test heads in stock.
- PG&E has requested \$6.7 million of capital to build 12 new pairs of test heads to support PSEP.
- PG&E has requested between \$2.5 and \$6.6 million of expenses to build additional disposable test heads for each hydrotest.[273]

DRA's prepared testimony also shows that PG&E did not adequately justify its capital and expense requests for test heads, or define how these expenditures were required given the existing stock.

Two developments have occurred since that analysis was presented. First, DRA reviewed data request responses and determined that the unit costs for test head expenses

[272] Ex. 144, DRA Testimony, pp. 66 and 109-111.

[273] PG&E has requested between \$15,000 and \$40,000 for each of the 165 hydrotests, as defined in its prepared direct testimony, Ex. 2, at page 3E-17. The range cited reflects the upper and lower bound of aggregate costs based on this range. DRA workpaper "DRA WP TCR-2, DRA Hydro model run for Jan 31 tsmy.xlsx" calculated the actual request for disposable test heads to be \$4.3 million based on the pipe sizes in the PSEP.

($15,000 to $40,000 per test) were provided by ARB, PG&E's California contractor.[274] The ARB quote fails to provide any support for its proposed costs, but the inclusion of these costs is significant since ARB's quote provides the most essential and consistent baseline costs. This conflicts with the second development, which is PG&E's rebuttal testimony implying that the expensed test heads are used primarily to cap taps in the test section. PG&E states:

> Mr. Roberts' suggestion is based on an incorrect assumption that a hydrostatic test only involves two test heads on either end of the test. In fact, the need to manage multiple taps in addition to the two test ends requires additional tools and equipment, and must be included in a hydrotest cost forecast.[275]

If DRA incorrectly assumed that a hydrotest only has two test heads, it is largely due to information provided by PG&E, including its first presentation to the Commission,[276] a field visit for test T-121,[277] and PG&E's database of existing test heads,[278] all of which refer to a "pair" of test heads. Even if PG&E intends that the requisite pair of test heads will generally be permanent test heads, from stock or the 12 new capital pairs, its request for a fixed cost per project to cap taps is incorrect. Some lines will have multiple taps to cap, but others will have none. This defines "tap caps" as a contingency item, not a fixed and constant cost as provided in the ARB quote. In addition, PG&E's standards allow that even temporary test heads to be used more than once, and if designed to support test pressures without exceeding 72% SMYS, they can be used indefinitely.[279] Since PG&E has not provided the derivation of its test head cost requests, DRA assumes that the

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[274] Ex. 56, PG&E Data Response to DRA-061, Q/A 1, attach. 1, p. 3, Jan. 25, 2012.

[275] Ex. 21, PG&E Rebuttal Testimony, p. 4-7.

[276] May 6, 2011 CPUC Hydrostatic Test Symposium, Slide 41 title. Presentation available at: http://www.cpuc.ca.gov/PUC/events/hydrotesting.htm.

[277] Ex. 108, PG&E L-303, T-121 Hydrostatic Test Procedure (redacted), p. 14. Step 36 states "Install the test heads at Location A and Location B as shown on the design drawings."

[278] Ex. 106, PG&E Data Response to DRA-026 Q/A 19. The attachment shows pairs of test heads as indicated by the ID numbers in column 2, such as the final pair listed, 36861a and 36861b.

[279] Ex. 103, PG&E Gas Standard A-37, p. 3, section B(2).

request for an excessive number of test heads is due to the rough nature of the ACEE Class 4 estimate.

### 3. DRA's Revised All-in Cost Should Be Used for Cost Recovery Purposes

#### a) PG&E's All-in Costs Are Excessive.

PG&E's all-in costs are too high because they include excessive indirect charges, contingency items, and costs which should be borne by PG&E shareholders.

PG&E states: "Strength test project costs are based on unit rate input provided by a local construction company supplemented by Gulf experience."[280] PG&E has confirmed that the local construction company is ARB, Inc.[281] In response to DRA's discovery request, PG&E provided four workpapers which derive the "all-in" costs for each of the four pipe diameter ranges shown on page 3E-17 of PG&E's prepared testimony.[282] A comparison of ARB and Gulf cost estimates shows that ARB's estimates for "Clean and Dry" and "Fill and Hydro Test" were used directly in the Gulf calculations of "all-in" costs as "construction costs."[283] While minimal definition or support was provided for the ARB cost estimates, the task names suggest that they include the key variable costs incurred in a hydrotest, such as water management.

DRA in its prepared testimony provided a cost estimate for a similar set of variable costs, which are illustrated below with ARB's variable costs, and Gulf's total all-in costs:[284]

Figure B – Comparison of Hydrotest All-in Cost Estimates

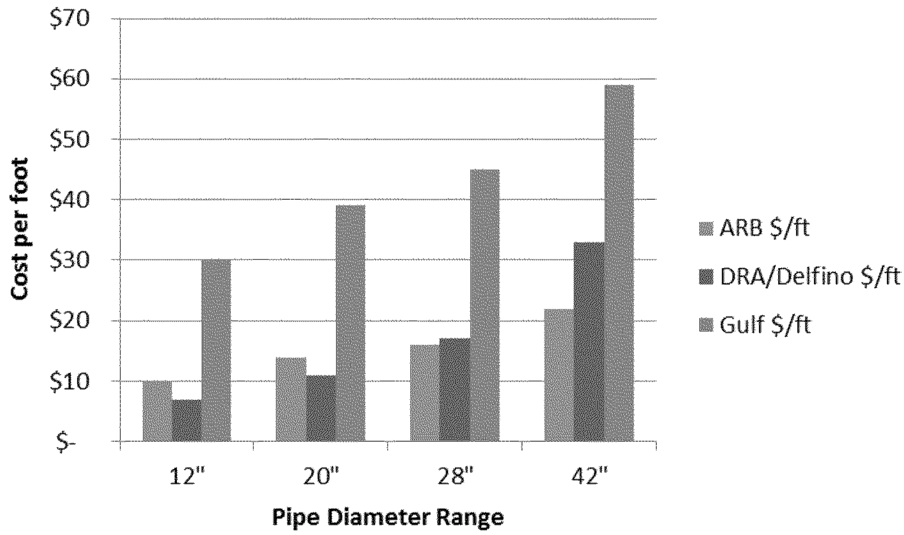
[280] Ex. 2, PG&E Direct Testimony, p. 3E-8.

[281] Ex. 56, PG&E Data Response to DRA-061, Q/A 1, attach. 1, p. 3, Jan. 25, 2012.

[282] Ex. 56, PG&E Data Response to DRA-055 Q/A 3, attach. 1-4, Jan. 6, 2012.

[283] Ex. 56, PG&E Data Response to DRA-061, Q/A 1, attach. 1, p. 3, Jan. 25, 2012; , Ex. 56, PG&E Data Response to DRA-055 Q/A 3, attach. 1-4, Level 3 estimate, section 2.6, Jan. 6, 2012.

[284] DRA data from Ex. 145, DRA Testimony, Chap. 4, p. 2-6; ARB data from Ex. 56, PG&E Data Response to DRA-061, Q/A 1, attachm. 1, p, 3, Jan. 25, 2012 (this figure shows fill, test, clean, and dry costs divided by 5,000 ft); Gulf costs from Exx 2, PG&E Direct Testimony, p. 3E-17.



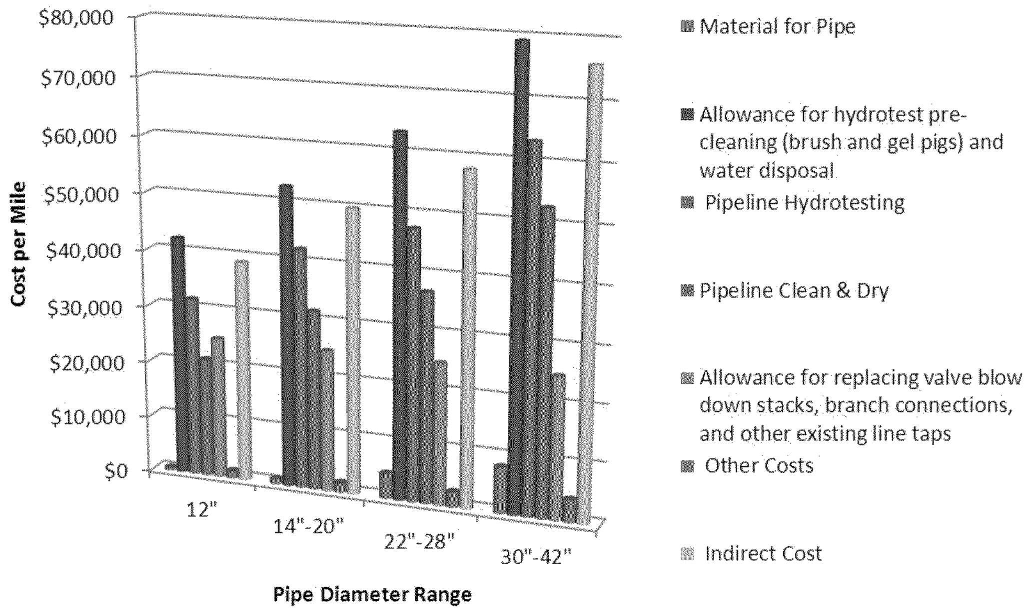

While this chart shows that DRA's variable costs are comparable with those provided by ARB for three of the four diameter ranges, DRA's estimate is a "+40%" value designed to account for "known unknowns," while PG&E adds a contingency separately.

To generate the "all-in" costs, Gulf added a number of direct and indirect charges on top of ARB's estimate.[285] DRA provided a summary of the cost elements in Gulf's cost estimates and a graph illustrating their relative magnitude:[286]

Figure C – Breakdown of PG&E Hydrotest "all-in" cost components

[285] Ex. 56, PG&E Data Response to DRA-055 Q/A 3, attach. 1-4, Jan. 6, 2012.

[286] Ex. 147, DRA Testimony, Chap. 6, pp. 13-14.




DRA's analysis of Gulf's cost estimates revealed problems with both direct and indirect cost elements. In contrast to DRA's cost estimates, key assumptions underlying the PG&E's hydrotest cost estimate are not provided, such as the number of cleaning runs included in the pre-cleaning allowance and water disposal requirements.[287] Without these assumptions, it is impossible to determine the costs that should be covered by Gulf's baseline estimate, and which should be covered by the contingency request.

In addition, PG&E includes a material cost for pipe, which should be covered as part of separate capital requests for "Emergency pipe replacement,"[288] "Post Strength Test Emergency [Pipe] Replacement,"[289] or as part of the fixed hydrotest costs if this material is for test heads or tie-ins.

Indirect costs and pre-test cleaning costs are discussed below.

[287] The table of assumptions given on page 3E-14 applies to pipe replacement only. This is indicated by columns for congestion class, which are not applicable to hydrotest costs, and an AFUDC rate of 7.58%, rather than the 5.24% rate Gulf applied erroneously for hydrotests. Note that the appendices to Attachment 3E include numerous duplications: 3E-14 duplicates 3E-12; 3E-15 duplicates 3E-13; and 3E-17 duplicates 3E-16.

[288] Ex, 9, PG&E Workpapers, p. WP 3-557. This is for short test sections where PG&E determines it is less expensive to replace pipe than to test it.

[289] Ex, 9, PG&E Workpapers, p. WP 3-559. This provides for repairs of test sections, estimated to occur in 1% of the planned test mileage.

### i) Indirect Costs

PG&E includes indirect costs totaling nearly 31% of the direct costs, as shown below. PG&E has acknowledged that a 5.24% charge for AFUDC was an error,[290] so there is agreement that the All-in rate should be reduced by at least this amount. Limited or no support is provided for the indirect rates applied by Gulf:[291]

- Engineering and Design, 10% – Gulf Historical Database
- Land and Right-of-Way, 6% – Client (PG&E) provided
- Construction Management and QA/QA, 5% - no justification provided
- Regulatory Permits, 3% - no justification provided
- PG&E Labor, 1.5% – Client (PG&E) provided

PG&E witness Hogenson stated on cross-examination that "neither one of us [PG&E and Gulf] had a lot of experience in pressure testing existing pipelines," so it is unclear how Gulf historic costs, or PG&E's could have been used to accurately determine these rates.[292] While neither DRA nor other parties provided explicit alternatives to these indirect rates, DRA witness Delfino noted that they "are more in tune with pipeline replacement than hydrotesting," and implied that they are excessive by excluding them from his estimate. There are other indications that indirect costs are excessive. First, a 5% construction management fee is applied to direct costs, in addition to the 2.5% project management fee added to all projects,[293] and the separate $415 million of capital and expenses requested for the Program Management Office.[294] Second, Gulf does not use the 3% fee for engineering and design stated in testimony, but rather a figure of 10% which is more than three times higher, without any explanation or support.[295] PG&E and

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[290] Ex. 21, PG&E Rebuttal Testimony, p.3-47.

[291] Ex. 56, PG&E Data Response to DRA-055 Q/A 3, attach. 1-4 (Level 3 estimates, Indirect costs), Jan. 6, 2012. Note that PG&E labor is 10% of engineering and construction management, which are 15% of direct costs combined. Therefore, PG&E labor is 1.5% of the direct costs (10% of 15%).

[292] 11 RT 1405, ll. 25-27, Hogenson/PG&E.

[293] Ex. 2, PG&E Direct Testimony, p. 3E-9.

[294] Ex. 2, PG&E Direct Testimony, p. 7-2, Table 7-1.

[295] Ex, 2, PG&E Direct Testimony, p. 3E-9.

Gulf have the same limited experience/ historic costs to draw upon in determining indirect rates as they did to set fixed costs. Also, PG&E provides no definition of the tasks it will perform within the 1.5% rate for "PG&E labor," and makes no attempt to justify the specific rate used.[296]

### ii) Pre-cleaning Costs

PG&E includes an allowance for pre-test cleaning and water disposal, which constitutes the single largest variable hydrotest cost. These costs should not be charged to ratepayers.

#### (a) Pre-test Pipe Cleaning Should Not Be Charged to Ratepayers

DRA witness Delfino stated that pre-cleaning of pipes is a maintenance task which should not be included as a hydrotest cost.[297] PG&E witness Campbell disagrees, stating "what Mr. Delfino describes is a common practice for an oil or product pipeline, but an unusual practice for an integrated gas transmission and distribution system."[298] Mr. Campbell did not survey either integrated gas transmission and distribution system operators or product pipeline operators[299] to develop this conclusion, worked in gas marketing rather than engineering from 1994 to 2011,[300] and is not aware if he is a member of AGA, INGAA, or any other pipeline industry organizations.[301] In contrast, Mr. Delfino is an expert pipeline engineer with experience spanning four decades, multiple continents, and both on and off-shore projects. Mr. Campbell also stated that an INGAA report discusses the need to clean lines prior to hydrotesting, but this report is not

[296] Ex, 2, PG&E Direct Testimony, pp. 3E-9 to 3E-9. Section 2.6 on indirect costs does not mention a "PG&E Labor" charge.

[297] Ex. 146, DRA Testimony, Chap. 5, p. 2-4.

[298] Ex. 21, PG&E Rebuttal Testimony, p. 4-3.

[299] 13 RT 1814-15, Campbell/PG&E.

[300] 13 RT 1849, Campbell/PG&E..

[301] 13 RT 1815, 1820-21, Campbell/PG&E...

cited in his testimony, nor does it appear to be in the record.[302] Finally, 49 CFR 192 Subparts J and L do not require pipe cleaning prior to a hydrotest.

#### (b) Pipe Cleaning Costs Should Treated as a Contingency Item

If pipe cleaning costs are charged to ratepayers, these costs should be scrutinized and treated as a contingency item, not a cost included in the baseline estimate. If the Commission disregards the above evidence and finds that ratepayers should pay some portion of the cost to clean contaminated pipes and/or cleaning hydrotest effluent water, a number of issues raised in this proceeding must be resolved. The first is whether contamination must be removed from the pipe through multiple pig runs prior to testing, or whether contaminants in the post-test effluent water can be removed through filtration prior to water disposal or reuse in another test. According to PG&E witness Campbell, the former was required for sections of Line 132 which ran above Crystal Springs reservoir because the San Francisco Public Utilities Commission (SFPUC) required PG&E to "clean the water to turbidity levels and drinking water standard levels before the test."[303] DRA notes that a major rupture of lines in the watershed will carry soil and debris downslope and increase the turbidity of the reservoir regardless of the level of pipe cleaning performed by PG&E. But even if PG&E is correct that SFPUC permit requirements require extensive pre-cleaning, this should only be required in watershed areas, which constitute only a fraction of the length of Lines 109 and 132.[304] More importantly, Mr. Campbell responded "No" when asked if any other entity required PG&E to clean the wastewater to those standards.[305]

Second, for the situations where it is appropriate to treat wastewater after the hydrotest, as opposed to pre-cleaning the line, the most efficient method should be used.

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[302] 13 RT 1814, ll.6-11, Campbell/PG&E.

[303] Ex. 21, PG&E Rebuttal Testimony, p. 4-6; 13 RT 1816-17, Campbell/PG&E..

[304] Ex. 9, PG&E Workpapers, pp. WP 3-598 to WP 3-602 (Line 109); Ex. 10, PG&E Workpapers, pp. WP 3-1345 to WP 3-1347 (Line 132).

[305] 13 RT 1817, ll. 4-6, Campbell/PG&E.

The most efficient option is to reuse the water on another test, but this will not be possible in every case. Where it is not, DRA's cost estimate included post-test filtration via a CETCO system, and PG&E did not challenge the cost of this system, or its ability to remove the contaminants PG&E has encountered to date.[306] PG&E's cost estimate does not define the required water treatment requirements assumed in the development of the baseline estimate, nor does it specify the method PG&E will use to clean waste water to the disposal requirements. PG&E should use the least expensive pipe/water cleaning method possible, but it does not appear that it has investigated all available options.[307]

A third issue is the extent to which pipe cleaning was included in PG&E's baseline cost estimates and contingency requests. PG&E's prepared testimony, workpapers and estimates from ARB and Gulf provide no assumptions or basis for pipe cleaning costs, such as the number of cleaning runs or water disposal requirements. The only evidence presented was in hearings, when PG&E asked its own contingency witness Caletka:

> Q: Do you recall what the allowance was for how many cleaning runs PG&E would do prior to a hydrotest?
> A: In the discussions we had about that topic, the assumption was one, as I recall, [it was] basically you do one cleaning run, and then you're in hydrotest mode. And water management was assuming if the water was contaminated."[308]

If correct, this was a poor assumption based on many references where cleaning runs are referred to in the plural sense. For example, an AGA report states that pipe cleaning "is typically accomplished by running cleaning **pigs** through the segment. The results of these **runs** will be used to determine if additional cleaning **pigs** are necessary, or if chemical cleaning agents must be used."[309] The potential need for multiple pig runs is also supported in the PSEP hydrotest manual A-37, which states that "[w]hen cleaning **runs** are complete, the pipeline segment is setup in test configuration and prepared to fill

[306] Ex. 146, DRA Testimony, p. 2-2.

[307] See, e.g, 13 RT 1799, ll. 9-15,Campbell/PG&E.

[308] 15 RT 2130, ll. 17-25, Caletka/PG&E.

[309] Ex. 21, PG&E Rebuttal Testimony, pp. 4-4 to 4-3, emphasis added.

with water."[310] Moreover, the test specific procedure for test T-121 includes providing 24 cleaning pigs and three types of cleaning fluids,[311] and provides for additional cleaning runs as follows: "The Test Supervisor shall consult with the Environmental Field Specialist to determine if another chemical solution and/or water wash run is required,"[312] and a data sheet is provided to record data for up to eight cleaning runs.[313] Based on these guidelines and procedures, and the substantial cleaning cost requested, DRA believes it is highly unlikely that the base estimate was based on only a single cleaning run. In addition, PG&E witness Caletka stated that contingency includes "what a reasonable estimator, a competent contractor could have foreseen in their experience," and also that the risk of ten cleaning runs "wasn't a risk that was anticipated."[314] PG&E's estimator Gulf stated that "[c]onstruction management of pipelines and station facilities has been a core competency at Gulf since our formation in 1953."[315] Given Gulf's self-stated expertise in pipeline construction, and PG&E's long history of operating gas pipelines, it seems unreasonable that the PG&E team failed to include multiple cleaning runs in either the baseline estimate or the contingency request.

The final issue relates to the extent, causes, and impacts of high levels of contamination PG&E experienced in 2011 hydrotests, particularly mercury.[316] PG&E does not know the extent of Mercury it found in 2011. PG&E witness Campbell stated that mercury was found in 40% of 2011 tests,[317] but PG&E witness Hogenson reported that "approximately 57% of the segments tested in 2011 presented mercury-related schedule delays."[318] Mr. Campbell does not know if mercury poses a public health

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[310] Ex. 103, PG&E Gas Standards A-34 and A-37, p. 40, emphasis added.

[311] Ex. 108, PG&E L-303, T-121 Hydrostatic Test Procedure (redacted), p. 5.

[312] Ex. 108, PG&E L-303, T-121 Hydrostatic Test Procedure (redacted), p. 10, step 20.

[313] Ex. . 108, PG&E L-303, T-121 Hydrostatic Test Procedure (redacted), p. 13.

[314] 15 RT 2131, ll. 4-9, Caletka/PG&E.

[315] Ex. 2, PG&E Direct Testimony, p. 3D-7.

[316] Ex. 21, PG&E Rebuttal Testimony, p. 4-4; 13 RT 1817, ll. 4-6, Campbell/PG&E.

[317] 13 RT 1798, ll. 9-10 and 1818, ll. 7-10, Campbell/PG&E..

[318] Ex. 56, PG&E Data Response to DRA-026-04, Q/A 4, Dec. 5, 2011, p. 2.

risk,[319] how the mercury got in the lines,[320] whether other operators have this problem,[321] and whether PG&E's gas standards include specifications for mercury.[322] Mr. Campbell has been too busy to investigate this issue and can only speculate about the extent of mercury in PG&E's lines.[323] PG&E may argue that this is only one witness's knowledge, but PG&E selected Mr. Campbell to engineer and plan the 2011 hydrotest program, and he is the expert PG&E put forth to on hydrotest issues. The bottom line is that PG&E has gas standards to control what goes into its system,[324] and it is responsible for pressure measurement and recording equipment within the system that contains mercury.[325] PG&E shareholders should cover the costs of removing contaminants from PG&E's lines, and the Commission should consider opening an investigation into whether mercury in PG&E's lines poses a public health threat through either combustion in customer equipment or operations such as hydrotesting.

While the focus of discussion to date has been on mercury, similar questions need to be addressed for other contaminants, particularly whether the presence of particular contaminants is indicative of corrosion, leaking seals, or other maintenance problems.

#### (c) Pipe Connection Hardware Costs Should Be Treated as a Contingency Item

PG&E's proposed allocation for pipe connection hardware costs is ill-defined, potentially duplicative with a separate capital request, and should be scrutinized and treated as a contingency item. PG&E's all-in cost includes an "allowance for replacing valve blow down stacks, branch connections, and other existing line taps" which is fixed at $25,000 per mile.[326] As shown in Figure B above, this fixed allowance has a greater

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319 13 RT 1797, ll. 24-27, Campbell/PG&E..
320 13 RT 1798, ll. 12-14, Campbell/PG&E..
321 13 RT 1857, ll. 13-16, Campbell/PG&E.
322 13 RT 1798, ll. 18-20, Campbell/PG&E.
323 13 RT 1859, ll. 3-17, Campbell/PG&E.
324 13 RT 1798, ll. 15-17, Campbell/PG&E..
325 13 RT 1858, ll.7-16, Campbell/PG&E.
326 Ex. 56, PG&E Data Response to DRA-055 Q/A 1, all attachments, Level 3 estimate, section 2.6.

impact on the all-in cost of small pipes (16%) compared to large pipes (8%).[327] This allowance, and the assumptions used to quantify it, is not defined in PG&E testimony, workpapers, or responses to DRA discovery requests. Without such definition, it is impossible to tell if this request overlaps, or is duplicative with PG&E requests $11.4 million for "50 valves annually in 2012 – 2014" to "isolate the section of pipe to be strength tested and perform multiple tests at the same time."[328]

In addition, not every pipeline segment that is to be hydrotested will require these replacements.[329] Therefore, the replacement of connections to the pipelines should be treated as a contingency cost, if they are authorized for recovery.

#### b) A Revised Version of DRA's All-in Cost Should Be Adopted

DRA's calculation of the basic variable costs are similar to those provided by ARB and used by PG&E in the PSEP. The primary difference between DRA's and PG&E's proposed all-in rates lies in allowances for pipe cleaning and hardware replacement and indirect costs. PG&E agrees that its indirect costs are at least 5.24% too high, since the proposed rate erroneously included AFUDC. PG&E's proposed values on 3E-17 should therefore be reduced by 5.24% at a minimum.[330]

Additional adjustments to PG&E's proposed all-in costs result from removing PG&E's proposed allowances for cleaning and hardware replacement. Neither PG&E nor Gulf has provided supporting evidence for these under-defined allowances in Gulf's hydrotest cost estimate. DRA recommends that these potential costs be included as contingency items, and that the Commission consider whether PG&E shareholders should pay for pipe cleaning due to poor maintenance practices. The following

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[327] Ex. 56, PG&E Data Response to DRA-055 Q/A 1. Fixed cost of $25,000 divided by overall cost per mile on the final line of each attachment.

[328] Ex. 9, PG&E Workpapers, p. WP 3-558.

[329] Ex 146, DRA Testimony, Chap. 5, p.2-6.

[330] The AFUDC is applied to all direct and indirect costs, except for one: PG&E Material Burden. This cost is negligible for hydrotest since it is 15% of Material Costs, which are minimal, and the variance produced is smaller than the rounding errors embedded in PG&E's workpapers.

recommended values do however include an adjustment from the values provided in DRA direct testimony to account for certain indirect costs:

| | 12" and under | 14" to 20" | 22" to 28" | 30" to 42" |
|---|---|---|---|---|
| DRA All -in, Exhibit 146 ($/ft) | $ 7 | $ 11 | $ 17 | $ 33 |
| Indirectadders | 12.0% | 12.0% | 12.0% | 12.0% |
| DRA All -in, Adjusted ($/ft) | $ 8 | $ 12 | $ 19 | $ 37 |

These values are based on the following indirect loading rates:[331]

- Engineering and Design 3%
- Land and ROW 6%
- Construction Management and QA/QA 0%
- Regulatory Permits 3%
- PG&E Labor, 0%
- AFUDC 0%

The total indirect rate of 12% accounts for errors in PG&E testimony regarding AFUDC and the engineering and design rate, and the fact the construction management should be covered by either the project level 2.5% program management fee, or in the $415 million request for the PMO. Also, while PG&E has provided no support for Land and ROW, regulatory permits, DRA acknowledges that there will be costs incurred in these categories for every test. DRA's use of the rates proposed by PG&E for these indirect costs should not be construed as support for the specific rates or for the use of ill-defined cost justifications.

### 4. DRA's Proposed Escalation Rate Should Be Adopted

For the Commission to adopt unit costs for Phase 1, the costs should be escalated to account for inflation. PG&E's proposed escalation rate is too high and applied

[331] Percentages greater than 0% from Ex. 56, PG&E Response to DRA-055 Q/A 3, attach. 1-4. The cost for PG&E Material Burden is negligible for hydrotest since it is 15% of Material Costs, which are minimal. The variance produced by this omission is smaller than the rounding error's embedded in PG&E's workpapers.

incorrectly. DRA recommends that the unit cost for 2012-2014 be established based on an escalation rate of 1.1% to 1.5%.

As proposed by PG&E, escalation charges are applied based on the completion date for all PSEP Pipeline Plan costs incurred after 2011 at an annual rate of 3.12%.[332] This adds approximately $70 million to the overall cost of the PSEP Pipeline Plan.[333] PG&E's escalation costs are excessive because:

- PG&E's annual escalation rate of 3.12% is too high given the current state of the economy and the volatility of steel prices.[334]
- Escalation rates are inappropriately applied using the completion date of a project, rather than when engineering and procurement establish actual costs.[335]

DRA recommends using the date of engineering and procurement to apply an escalation rate of approximately 1.1% to 1.5% through Phase 1 of the PSEP.[336]

PG&E maintains that applying escalation rates to the forecasted operative dates is "appropriate for Class 4 level estimates."[337] The AACEI Class 4 level estimates do not discuss the dating application of escalation.[338] PG&E discusses escalation strategy as derived from AACEI tables, and this shows that for Class 4 Level estimates, the escalation strategy is "Preliminary."[339] PG&E's Chapter 7 workpapers also include the "Cost Estimating Guide" by the U.S. Department of Energy (DOE).[340] Under section 6.4.4 Escalation it states: "[C]ost estimating is done in current dollars and then escalated

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[332] Ex. 144, DRA Testimony, Chap. 3, p.108.

[333] Ex. 144, DRA Testimony, Chap. 3, p. 69. Figure 8 shows that escalation contributes approximately 6% to the overall replacement cost of $844 million, or $51 million. Figure 9 on page 70 shows that escalation contributes approximately 4% to the overall hydrotest cost of $405 million, or $16 million.

[334] Ex. 147, DRA Testimony, Chap. 6, pp.16-17.

[335] Ex. 147, DRA Testimony, Chap. 6, p. 16.

[336] Ex. 147, DRA Testimony, Chap. 6, pp. 17-16.

[337] Ex. 21, PG&E Rebuttal Testimony, p. 3-47.

[338] http://www.aacei.org/

[339] Ex. 16, PG&E Workpapers, p. WP 7-29.

[340] Ex. 16, PG&E Workpapers, p. WP 7-38.

to the time when the project will be executed."[341] The section further states: "Most costs are estimated in "current dollars" and then escalated to the time when the work is expected to be performed."[342]

Escalation should be included in an appropriate manner and needs to be justified. "Escalation is the provision in a cost estimate for increases in the cost of equipment, material, labor, etc., due to continuing price changes over time.[343] PG&E believe that its applied escalation rate is consistent with "past forecasts for PG&E rate cases."[344] However, in this case, a lower escalation rate is warranted and unexpected costs that are incurred during project execution are captured in contingency. This is especially true for subcontracted work at a "fixed-price [which] would not need to have escalation applied to the cost of that contract."[345]

### 5. Hydrotesting Experience Should Improve Procedures Going Forward But Should Not Impact Costs

2011 Hydrotest "lessons learned" should be reflected in PG&E's test procedures, but the costs incurred should not impact PSEP cost estimates or cost recovery. PG&E states that 2011 actual hydrotest costs were "66 percent higher than PG&E's estimated PSEP cost for hydrostatically testing 30-inch to 42-inch diameter pipe," but that "PG&E believes that it can drive down costs with more engineering and planning time than was available in 2011, and through competitive bidding for the hydrotest construction."[346] PG&E witness Campbell stated on cross-examination: "[Y]ou have to remember 2011 was an emergency situation as described by the ALJ here recently. Is that we moved significant amount of equipment and time -- on a time-material basis, so I'm not surely

341 Ex. 16, PG&E Workpapers, p. WP 7-87.
342 Ex. 16, PG&E Workpapers, p. WP 7-89.
343 Ex. 16, PG&E Workpapers, p. WP 7-143.
344 Ex. 21, PG&E Rebuttal Testimony, p. 3-47.
345 Ex. 16, PG&E Workpapers, p. WP 7-147.
346 Ex. 21, PG&E Rebuttal Testimony, p.4-2.

the 2011 costs are truly reflective of the [PSEP] estimate."[347] PG&E is not requesting additional funds based on 2011 actual costs, nor should they. Instead, PG&E should act on the lessons learned in 2011 to help bring down future costs, improve safety, and reduce customer disturbances. For example, PG&E's presentation to the Commission indicated that water management was more involved than planned, including the large footprint required for storage tanks.[348] PG&E should consider alternative water treatment systems, such as the CETCO system cited by DRA witness Delfino, and integration of pig launch/receivers within test heads.

### C. If the Commission Authorizes Ratepayer Funding of Pipeline Replacement, It Should Use DRA's Unit Cost Estimates

As discussed in Section II, above, PG&E should bear the replacement cost of any pipeline installed in 1955 or later. However, if the Commission is inclined to grant PG&E ratepayer recovery of replacement costs, the Commission should use the unit costs proposed by DRA, rather than PG&E's proposed unit or aggregate replacement costs. As with hydrotest costs, uncertainty in the composition of projects and in the overall scope of work lead DRA to recommend adopting unit costs rather than aggregate PSEP replacement costs. An accurate total cost estimate for each project will only be available once PG&E has completed final engineering on a project-by project basis.[349] As such, an accurate aggregate cost estimate for the PSEP cannot be determined at this time.[350]

#### 1. DRA's Unit Costs Are True All-in Costs

Four estimates of replacement unit costs have been provided in this proceeding:

- A poorly supported estimate from organizations with a direct financial interest in maximizing the unit costs adopted (PG&E, Gulf and ARB).

[347] 13 RT 1805-06..

[348] PG&E/Ben Campbell presentation at CPUC Hydrotest Symposium, March 7, 2012, slide 20.

[349] Ex. 2, PG&E Rebuttal Testimony, p.3-39.

[350] But this issue impacts application of unit costs and the aggregate cost of replacement projects and the PSEP, not the unit costs themselves or quantification thereof.

- A bottom-up calculation from an industry expert with decades of pipeline experience (DRA consultant Delfino Engineering).
- Costs that apply national average replacement costs to non-congested pipe locations (DRA consultant BEAR/UC Davis Study), and use PG&E data to scale up costs for more congested locations.
- Costs that apply regional average replacement costs to non-congested pipe locations (DRA consultant BEAR/PNNL Study) and use PG&E data to scale up costs for more congested locations.

Each estimate has strengths and weaknesses, but taken together these approaches provide a reasonable basis for the Commission to adopt unit replacement costs.

DRA recommends that the Commission adopt a true all-in cost based on industry data that includes contingency and other adders. The all-in cost developed by DRA consultant BEAR, summarized below, reflects a true all-in cost:[351]

| Diameter | Non-Congested | Semi-Congested | Highly Congested |
|---|---|---|---|
| 10 | $ 214 | $ 370 | $ 598 |
| 16 | $ 278 | $ 494 | $ 784 |
| 24 | $ 398 | $ 648 | $ 978 |
| 36 | $ 704 | $ 1,098 | $ 1,577 |

*Note: These are 2011 dollars.*

These unit costs are based on Oil & Gas Journal (OGJ) data, which is inclusive of overhead costs and contingency, and therefore they are true all-in costs.[352]

These costs conservatively account for the increased cost of replacement in congested locations by treating average industry data as the cost for non-congested locations, and scaling up these costs for semi- and highly congested locations using the same ratios as PG&E used. The fact that these unit costs include overhead and contingency should be considered when adopting a contingency budget.

[351] Ex. 144, DRA Testimony, Chap. 3, p. 78, Table 14.

[352] Ex. 138, UC Davis Study, Introduction: "Miscellaneous costs are all costs not included in labor, material, or right of way. They generally include surveying, engineering, supervision, contingencies, allowances, overhead, and [permit] filing fees."

### a) DRA's and PG&E's Proposed Unit Costs Can Be Compared "Apples to Apples"

Pipeline replacement costs are dominated by variable costs, which simplifies comparison of unit costs. Pipe replacement involves excavation to fully expose the segments to be replaced, laying the replacement section in the trench, cutting in the new pipe, and returning the site to its original condition. PG&E indicates that the replacement line will generally be installed in the existing right-of-way and existing pipe retired in place.[353] Pursuant to 49 CFR 192, a field hydrotest is required of the new pipe, unless the pipe is "short."[354]

PG&E proposes five separate unit costs, including a variable cost per foot that varies with pipe diameter and estimated level of congestion ("all-in" rate), fixed costs that vary with pipe diameter (Move Around Charge and Mob/Demob), and special excavation costs applied on a per foot basis where PG&E estimates they are needed (HDDs and Road Bores). In addition, PG&E adds an additional variable cost per foot for two lines (Peninsula Adder) and project management and customer outreach at fixed percentages of the estimated project costs. The application and use of these unit costs in Gulf's replacement cost model are described in DRA's prepared testimony.[355] According to PG&E's cost model, pipe replacement costs are dominated by variable "all-in" costs.[356]

An implication of this cost structure is that the cost of replacement per mile is relatively stable and independent on the length of a replacement project. This is illustrated by the range of project per mile costs provided by PG&E, which range "from a low of $780 per foot to a high of $981 per foot, with an average unit cost of $855 per foot."[357] This limited range includes the significant variations in the "all-in" rate based on the diameter of pipe and the location of the pipe (congestion level). As a result,

[353] These and other considerations are provided in Ex. 2, PG&E Direct Testimony, pp. 3-24 to 3-26.
[354] 49 CFR 192.505(e). "Short" is not explicitly defined in the code.
[355] Ex. 144, DRA Testimony, Chap. 3, pp. 64-65.
[356] Ex. 144, DRA Testimony, Chap. 3, p. 70.
[357] Ex. 2, PG&E Direct Testimony, p.3-40.

PG&E's proposed per mile costs can be compared directly to other estimates of per-mile replacement costs, such as those provided by DRA.

### b) DRA's Cost Estimates Are Based On Industry Data Applicable to PG&E

DRA consultant BEAR's cost estimates are based on industry data applicable to PG&E territory, including urban areas. BEAR cites two relevant studies on pipeline replacement costs.[358] The first study was conducted by UC Davis's Institute of Transportation Studies (UC Davis Study), which used information from 893 individual projects that comprise over 20,000 miles of pipeline.[359] The second study was conducted by the Pacific Northwest National Laboratory (PNNL Study), using information gathered for 2,000 pipeline segments from the last 30 years.[360] Both studies used cost data collected by the FERC and published by the Oil & Gas Journal to derive cost algorithms (i.e., equations) to estimate pipeline replacement cost as a function of diameter of pipe and length.[361]

DRA used the cost equations developed by UC Davis and PNNL and the nominal diameter (10", 16", 24" and 36") for each of the four diameter ranges proposed by PG&E to develop variable costs per mile, and escalated the costs to 2011.[362] BEAR then made a critical assumption: "We then assumed that these [costs based on OGJ data] represent pipes into non-congested areas, which is the cheapest. A percent increase for both the semi-congested and highly congested areas was used, equaling the percent increase calculated from PG&E data."[363] Thus, DRA conservatively assumed that costs derived from national averages should be used in locations defined by PG&E as "non-congested," and then scaled up the national average costs for more congested locations. Specifically,

358 Ex. 147, DRA Testimony, p. 9.
359 Ex. 147, DRA Testimony, p. 4.
360 Ex. 59, PNNL Study, p. 108.
361 Ex. 59, PNNL Study, p.111; and Ex, 138, UC Davis Study, beginning at p. 3.
362 Ex. 147, DRA Testimony, p. 4.
363 Ex. 147, DRA Testimony, p. 4.

DRA used the ratios from PG&E's prepared testimony (page 3E-15) to scale up the national average values by approximately 56% to 78% for use in semi-congested locations, and 125% to 182% of these national averages for use in highly congested locations.[364]

PG&E asserts that its PSEP is "unlike any other pipeline replacement program" and proceeds to describe how PG&E has a high percentage of HCA miles, and how pipe replacement is more expensive in dense urban areas compared to rural locations.[365] PG&E witness Hogenson believes the UC Davis Report does not attempt to quantify costs by class location or urban density[366] and concludes, "I see little to no applicability in how FERC-regulated interstate pipeline project scopes, lengths and average cost per mile can be used by DRA as a basis for the PSEP pipeline replacement cost per mile."[367] PG&E's attempt to discredit BEAR's analysis fails on many levels.

First, both studies draw from a large sample of pipeline construction costs in the United States. PG&E attempts to critique this data by implying that interstate pipelines are located in less dense locations, but it fails to provide evidence to support this assertion.[368] In hearings, PG&E acknowledged that it performed only a limited review of the OGJ dataset:

> Q: Do you know for a fact that the data used in the UC Davis and PNNL studies reflect only pipelines in rural or noncongested areas?
> A: No, I do not.[369]

In fact, the PNNL study shows that replacement costs vary significantly by region, and are nearly twice as high on the east coast as the west coast.[370] While interstate pipelines

364 For example, using the All-in costs from Ex. 2, PG&E Direct Testimony, p. 3E-15, 36" pipe replacement in semi-congested areas is 56% higher than in non-congested areas. 36" pipe replacement in highly-congested areas is 125% higher than in non-congested areas.

365 Ex. 21, PG&E Rebuttal Testimony, pp. 3-34 to 3-36.

366 Ex. 21, PG&E Rebuttal Testimony, p. 3-37.

367 Ex. 21, PG&E Rebuttal Testimony, p. 3-38.

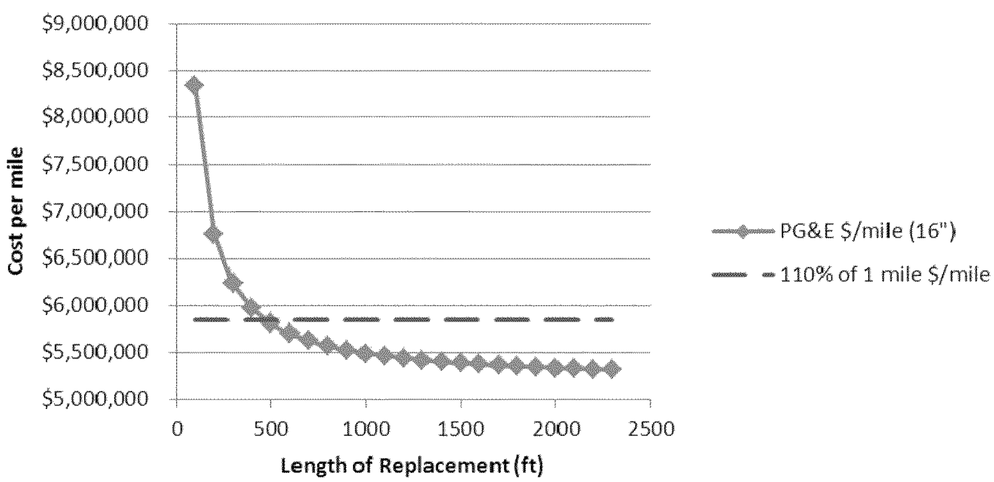
368 Ex. 21, PG&E Rebuttal Testimony, pp. 3-37 to 3-38.

369 11 RT 1410, ll. 19-23, Hogenson/PG&E.

370 Ex. 59, PNNL Study, p.110, Figure 7.

certainly run through some rural areas, the OGJ data captures the higher cost of interstate pipelines in dense areas such as the Northeast U.S.

PG&E also attempts to critique the OGJ data by providing limited statistics for a narrow time period.[371] In contrast, the studies use the full scope of the FERC data over either a 13 or 30 year timeframe, and then analytically develop cost curves based on a large dataset which has been escalated to the year of analysis.[372] This makes the resulting calculations much more robust since they are less biased by a small number of outlying data points. PG&E also states that the average length of pipe in the PSEP is shorter than the OGJ data, and implies that this distorts the use of OGJ data since "the cost-per-mile within a given diameter decreases as the number of miles rises."[373] While the latter point is generally true, the fact that fixed costs of replacement projects is low greatly dilutes the impact of this trend. DRA pointed this out in prepared testimony with a graph showing that all cost models show replacement costs per mile are essentially constant beyond 1mile of length.[374] A more detailed illustration of this concept using PG&E's cost model is provided below:[375]




371 Ex. 21, PG&E Rebuttal Testimony, p. 3-38.

372 Ex. 59, PNNL Study, p. 108. DRA further escalated costs to 2011.

373 Ex. 21, PG&E Rebuttal Testimony, p.3-38.

374 Ex. 147, DRA Testimony, p. 9, Graph 1.

375 All-in and Mob/Demob cost data from Ex. 2, PG&E Direct Testimony, p. 3E-15, for a 16" pipe in a highly congested location.

This graph shows that the cost per mile for 16" pipes in highly congested areas stabilizes within 10% of the constant cost per mile once the replacement length exceeds 500 feet in length. Similar curves are expected for other combinations of pipe size and location.[376]

Finally, DRA explicitly accounted for the higher cost of dense urban areas by allocating average costs from the studies to rural non-congested locations, and applying PG&E's own scale factors for more dense areas. In this way, DRA conservatively accounted for price differences based on whether replacement is in a rural or dense urban area, contrary to the assertions by PG&E.

#### c) DRA's Bottom-Up Costs Are Applicable to PG&E

DRA's "bottom-up" costs are applicable to PG&E territory and comparable to industry sources. DRA witness Delfino provides a bottom-up calculation of pipe replacement costs based on a detailed analysis of the major elements of pipeline replacement, namely the pipe material, welding, trenching, and indirect costs.[377] The following table shows how these costs combine, and the derivation of the Delfino Engineering costs for non-congested areas:

**Table 1: Example of Delfino Engineering Pipeline Replacement Cost Elements**

| Non-Congested Areas | | | | | |
|---|---|---|---|---|---|
| Pipe Size Range | Pipe & Coating | Welding | Trenching | Indirect Costs | Total |
| 10" | $33 | $5 | $47 | $37 | $122 |
| 16" | $73 | $11 | $72 | $54 | $210 |
| 24" | $163 | $25 | $112 | $86 | $386 |
| 36" | $364 | $55 | $180 | $154 | $753 |

376 The 10% threshold is a function of the ratio of fixed to variable costs. It is lowest (shortest length) for highly-congested locations where the variable cost is high.

377 PG&E's indirect costs were used. See Ex. 146, DRA Testimony, Chap. 5, p. 1-12.

These calculations were performed for the three congestion areas used in Gulf's cost models, as summarized below:

**Table 2: Summary of Delfino Engineering Pipeline Replacement "All-in Per Foot" Unit Costs**

| Pipe Size Range | Non-Congested Areas | Semi-Congested Areas | Highly Congested Areas |
|---|---|---|---|
| 10" | $122 | $242 | $400 |
| 16" | $210 | $383 | $610 |
| 24" | $386 | $650 | $985 |
| 36" | $753 | $1,170 | $1,678 |

It is important to note that Delfino Engineering calculations are self-classified as "conceptual cost estimates" which are consistent with industry practice and represent a conservative estimate that could be as much as 40% higher than actual costs. In other words, they represent an upper bound of costs which includes contingency, based on the analysis of Delfino Engineering.

PG&E criticized this cost estimate, citing various purported omissions and disagreement regarding details such as pipe material and the type of welding equipment used.[378] However, as DRA noted: "Since PG&E did not sufficiently define how their costs were derived, DRA used the Delfino Engineering costs in its illustrative calculations. The burden is on PG&E to specifically define anything Delfino Engineering may have missed, and quantify the impacts."[379] Delfino Engineering provided complete transparency for its cost calculations, and provided workpapers is response to PG&E data requests. PG&E in its rebuttal testimony did not quantify the impacts of any of the perceived shortcomings of Mr. Delfino's analysis.

Two of the omissions alleged by PG&E are costs for permitting and Land/ROW acquisitions.[380] This criticism fails to acknowledge that "all of the indirect costs [used by

[378] Ex. 21, PG&E Rebuttal Testimony, pp. 3-39 to 3-46.

[379] Ex. 144, DRA Testimony, Chap. 3, p. 80.

[380] Ex. 21, PG&E Rebuttal Testimony, p. 3-40.

PG&E] are included"[381] in Mr. Delfino's calculations, and that PG&E's indirect costs include 3% for permitting and a variable rate of 6% to 16% for land and ROW acquisition.[382]

### 2. PG&E's Proposed Unit Costs Are Too High and Unsupported

PG&E's proposed "all-in" variable cost is the highest for all combinations of pipe size and location of the four estimates in the record of this proceeding.[383] PG&E's unit costs are more than 20% higher than other sources when all proposed costs and contingency are considered.

DRA in its prepared testimony explains that PG&E's requested all-in rate is 20 to 21 percent higher than costs derived by DRA consultant BEAR using industry data.[384] In fact, this statement underestimates the margin between these two estimates because PG&E's "all-in rate" is not all inclusive, while the OGJ data is all inclusive. DRA previously showed that PG&E's "all-in" costs account for 80% of the total replacement costs, with fixed costs (Mob/Demob and Move around), special excavation costs (HDD and Road Bores), the peninsula adder, adders for customer outreach and project management, and escalation comprising the remainder of costs.[385] In addition, PG&E is requesting 20% more for contingency. When these other costs are considered, PG&E's requested costs are nearly 75% higher than costs based on the OGJ data, on an "apples-to-apples" basis.[386]

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381 Ex. 146, DRA Testimony, Chap. 5 p. 1-12.4-5.

382 Ex. 2, PG&E Direct Testimony, pp. 3E-8 to 3E-9.

383 PG&E cost estimate from Ex 2, PG&E Direct Testimony, p.3E-13; BEAR cost estimate from Ex. 147, DRA Testimony, Chap. 6, pp. 5-6; Delfino Engineering cost estimate from Ex. 146, DRA Testimony, Chap. 5, p. 1-13.

384 Ex. 147, DRA Testimony, Chap. 6, p. 9.

385 Ex. 144, DRA Testimony, Chap. 3, p. 69, Fig. 8.

386 This 75% figure does not include an adjustment for escalation, which is a reasonable cost component even though DRA disagrees with the escalation rate used by PG&E.

### a) PG&E Provides No Evidence to Support Components of Its Unit Costs

PG&E's proposed PSEP replacement project costs are based exclusively on the unit costs tabulated in its prepared testimony at page 3E-13.[387] DRA asked PG&E to "[p]rovide a narrative description and all workpapers which show how the assumptions on page 3E-12 are used to establish the unit costs on page 3E-13 of the testimony."[388] PG&E's response showed how it derived the "all-in" unit costs shown on 3E-13, but no support for the Road Bore, HDD, Move Around, and Mob/Demob charges that are also included in the table on 3E-13, and used in PG&E's cost estimate.[389] PG&E later provided cost estimates from its contractor ARB that included two quotes with the same date and essentially the same assumptions but which provide dramatically different unit costs.[390]

### b) PG&E's All-In Costs Are Not Based On PG&E-Specific Data

PG&E's all-in costs are based primarily on regional and national data, not PG&E-specific historical data. PG&E claims that its PSEP cost estimating basis "is far superior because project cost estimates were based on a history of actual PG&E gas transmission pipeline projects located within northern California under California project permitting, land rights and environmental regulations."[391] But discovery revealed only a limited and undefined link to PG&E historic costs. PG&E provided workpapers by Gulf in response to a DRA data request for support of the all-in costs used by PG&E in the PSEP.[392] However, these workpapers do not provide the level of detail provided by DRA

[387] This table is duplicated on page 3E-15. This does not include adders for customer outreach, project management, and escalation, which are applied on top of the specific project costs.

[388] Ex. 56, PG&E Data Response to DRA-040, Q/A 1, Dec. 21, 2011.

[389] Ex. 56, PG&E Data Response to DRA-040, Q/A 1, Dec. 21, 2011. Attachment 1 shows the derivation of the all-in cost for 12" and under pipe in non-congested areas.

[390] Ex. 56, PG&E Data Response to DRA-061, Q/A 1, Jan. 25, 2012.

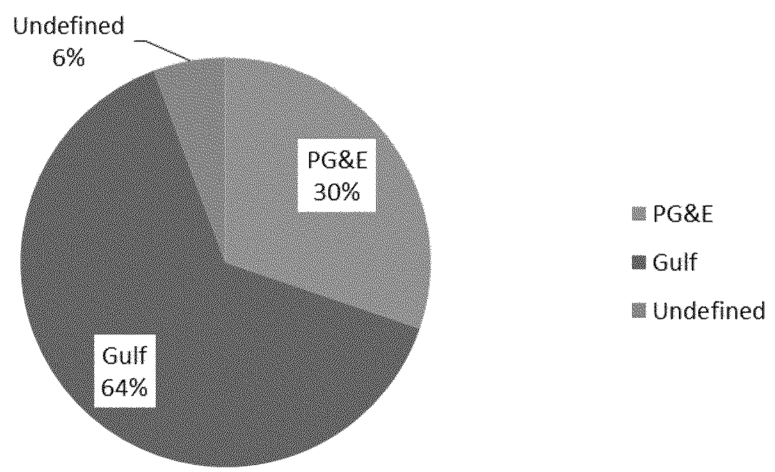
[391] Ex. 21, PG&E Rebuttal Testimony, p. 3-38.

[392] Ex. 56, PG&E Data Response to DRA-040, Q/A 1, Dec. 21, 2011.

consultant Delfino, or the detail described by PG&E witness Hogenson on cross examination:

> [W]hat Gulf did is they generated project cost estimates, and they tried for take pipeline replacement first. They built the projects up estimating the number of personnel that would be on the job, the number of pieces of equipment, the hours that they would work in a given day, what equipment rental costs would be.[393]

If Gulf did indeed undertake this level of analysis, the details were not provided in response to DRA data requests.[394] Gulf did, however, provide both estimated costs per mile for major cost elements, and in most cases a source for the data. The following chart shows the data source for a small pipe in a non-congested location, where 100% is the all-in cost of $282 per foot:[395]




This figure shows that over two-thirds of PG&E's all-in cost was not provided by PG&E, and therefore does not appear to be based on PG&E-specific historic costs. On cross-examination, PG&E confirmed that the bottom-up unit costs derived in Gulf's worksheets are the true source of the all-in costs, which were verified against PG&E's

[393] 11 RT 1406-07, Hogenson/PG&E.

[394] Ex. 56, PG&E Data Response to DRA-040, Q/A 1, Dec. 21, 2011.

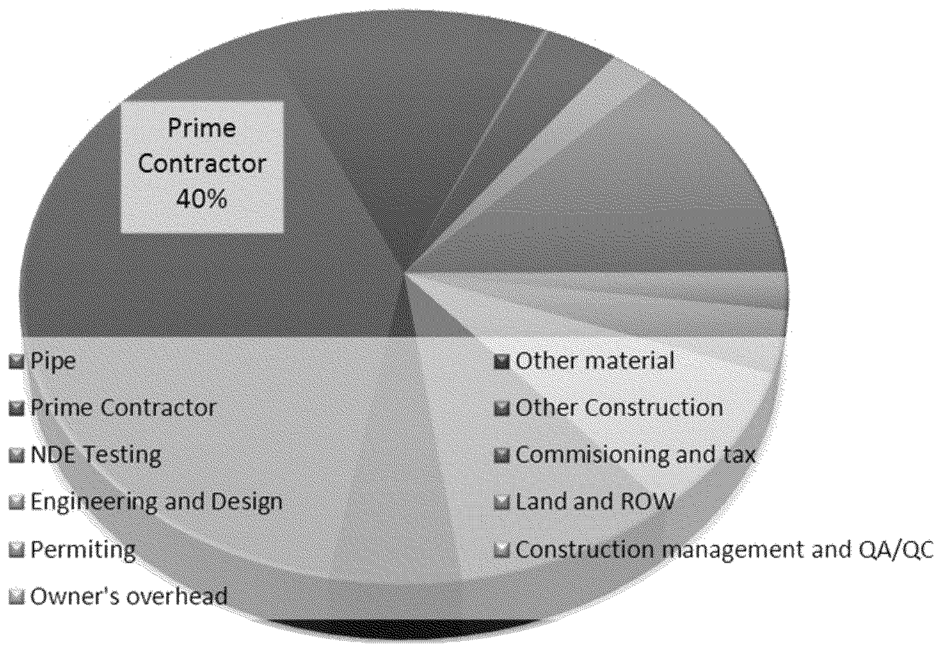
[395] All data from Ex. 56, Data Response to DRA-040, Q/A 1, Dec. 21, 2011, attachment 1, level 3 estimate, where "Client provided" refers to PG&E, and "Prime Pipeline Contractor" is assumed to be ARB.

historic cost database: "[T]hey [Gulf working with ARB] developed an algorithm of a dollar per foot, a dollar per lay, et cetera. They would compare it back to our unit cost database to see does it make sense."[396]

PG&E has not shown how its historic costs compare to the unit costs derived by Gulf and used in the PSEP. PG&E's cost estimate is similar to BEAR's estimates, in that both rely on regional and national cost data.[397]

#### c) PG&E's All-In Costs Are Based On Incorrect Use of ARB Data

PG&E's all-in costs are based on in incorrect application of data provided by its consultant ARB. Gulf's cost estimate for a 10" pipe in a non-congested location can also be used to show the portion of the all-in costs attributed to each cost element:




The figure shows that the cost for the "Prime Contractor" is by far the largest component of the all-in replacement cost.[398] While the record is unclear regarding who this

396 11 RT 1413, ll. 4-7, Hogenson/PG&E.

397 In PG&E's case, this refers to Gulf's historic database.

398 Gulf data from Ex. 56, PG&E Data Response to DRA-040, Q/A 1, Dec. 21, 2011, all attachments, level 3 estimate, section 2.1 "Construction-Line Pipe Prime Pipeline Contractor."

contractor is, and what the associated cost includes, the following tables suggests that this is the cost was provided by PG&E's contractor ARB.[399] The first table compares the Gulf prime contractor cost to the first ARB estimate:[400]

| All-In Base Lay ($/ft) | Non | Semi | High |
|---|---|---|---|
| 12" and less | 152% | 92% | 115% |
| 14" to 20" | 112% | 105% | 112% |
| 22" to 28" | 106% | 112% | 117% |
| 30" to 42" | 110% | 127% | 109% |
| | Average | | 114% |

This table shows that the Gulf's prime contractor costs, as used to estimate PSEP costs, are higher than ARB's estimates for 11 of 12 combinations of pipe size and location, which average 14% higher. A similar table based on ARB's second estimate yields a similar result, except that Gulf is higher in only 8 of the 12 combinations, for an average of 4% higher:[401]

| All-In Base Lay ($/ft) | Non | Semi | High |
|---|---|---|---|
| 12" and less | 114% | 92% | 106% |
| 14" to 20" | 101% | 105% | 112% |
| 22" to 28" | 93% | 112% | 117% |
| 30" to 42" | 92% | 92% | 109% |
| | Average | | 104% |

As noted previously, PG&E's witness was not familiar with the differences between the two estimates provided by ARB, or how Gulf used them to develop unit

399 Gulf data Ex. 56, PG&E Data Response to DRA-040, Q/A 1, Dec. 21, 2011, all attachments, level 3 estimate, section 2.1 "Construction-Line Pipe Prime Pipeline Contractor."

400 Gulf data Ex. 56, PG&E Data Response to DRA-040, Q/A 1, Dec. 21, 2011, all attachments, level 3 estimate, section 2.1 "Construction-Line Pipe Prime Pipeline Contractor." ARB data from Ex. 56, PG&E Data Response to DRA-061, Q/A 1, attach. 1, Jan. 25, 2012.

401 Gulf data Ex. 56, PG&E Data Response to DRA-040, Q/A 1, Dec. 21, 2011, all attachments, level 3 estimate, section 2.1 "Construction-Line Pipe Prime Pipeline Contractor." ARB data from Ex. 56, PG&E Data Response to DRA-061, Q/A 1, attach. 2, Jan. 25, 2012.

costs.[402] DRA cannot confirm that Gulf's estimate for Prime Contractor costs are derived from the ARB quotes since neither cost estimate, Gulf's or ARB's, provided the level of detail suggested by PG&E in hearings.[403] It is clear from this comparison, however, that PG&E used unit costs based on Prime Contractor costs greater than those provide by ARB, its "California Contractor."

#### d) PG&E's Fixed Costs Are Ill-defined and Incorrect

PG&E's fixed costs for pipeline replacement are ill-defined and do not correctly incorporate input from its contractor ARB. PG&E's most detailed description of its fixed costs was provided in response to a DRA data request:

> The mob/demob costs for the pipe replacement projects represent the movement of excavation, welding, and pipe movement equipment and man power to and from the project site. All the other variables of completing the pipe replacement are including in the construction price per foot, and not in the "mob/demob" line item.[404]

PG&E did not provide a similar narrative description of the Move Around charge for replacement projects. As noted above, PG&E did not provide a derivation for these fixed costs in response to a direct request from DRA, but DRA was able to determine that the fixed costs in 3E-13 are the same as those provided in an ARB cost estimate.[405] However, ARB provided not one, but two cost estimates and the one which was *not* used lists costs which are 50% of the 3E-13 values.[406] The following table compares the two cost estimates provided by ARB.

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402 11 RT 1409, ll. 21-24, Hogenson/PG&E.

403 11 RT 1407, ll. 18-27, Hogenson/PG&E.

404 Ex. 56, PG&E Data Response to DRA-026, Q/A 6, Dec. 5, 2011.

405 Ex. 56, PG&E Data Response to DRA-061 Q/A1, attach. 1, Jan. 25, 2012.

406 Ex. 56, PG&E Data Response to DRA-061, Q/A 1, attach. 2, Jan. 25, 2012.

**Table 3: Comparison of ARB Costs**[407]

| | | Non | Semi | High |
|---|---|---|---|---|
| 12" and less | All-In Base Lay ($/ft) | 133% | 100% | 109% |
| | Move Around Charge (ea) | 50% | 50% | 50% |
| | Mob/Demob Charge (ea) | 50% | 50% | 50% |
| | | | | |
| 14" to 20" | All -In Base Lay ($/ft) | 111% | 100% | 100% |
| | Move Around Charge (ea) | 50% | 50% | 50% |
| | Mob/Demob Charge (ea) | 50% | 50% | 50% |
| | | | | |
| 22" to 28" | All -In Base Lay ($/ft) | 114% | 100% | 100% |
| | Move Around Charge (ea) | 50% | 50% | 50% |
| | Mob/Demob Charge (ea) | 50% | 50% | 50% |
| | | | | |
| 30" to 42" | All -In Base Lay ($/ft) | 120% | 138% | 100% |
| | Move Around Charge (ea) | 50% | 50% | 50% |
| | Mob/Demob Charge (ea) | 50% | 50% | 50% |

Table 3 seems to indicate that the lower fixed costs in Attachment 2 were accompanied by higher all-in rates, but this is not a complete rationale since it is only true for six of the 12 combinations of pipe size and location. PG&E did not provide a witness in hearings who understood the nature and derivation of the ARB cost estimates.[408]

PG&E used the higher fixed charges from Attachment 1 to generate PSEP costs, so based on the ARB cost estimates, they should have also used the lower "all-in costs" from the same attachment. However, the tables above demonstrate that PG&E established all-in costs based on Prime contractor costs that were on average higher than either of ARB's estimates. PG&E's fixed unit replacement costs, as given on 3E-13, therefore are incorrectly based on the highest fixed costs provided by ARB, without capturing the associated reduced variable costs.

407 Ex. 56, PG&E Data Response to DRA-061, Q/A 1, Jan. 25, 2012.

408 As discussed, PG&E witness Hogenson was not familiar with the nuances between the two estimates, or how they were used by Gulf. PG&E witness Campbell was unable to answer questions related to cost estimation.

In rebuttal, PG&E began arguing that its cost estimate was based on its historic costs.[409] However for fixed costs, PG&E has clearly used the estimates provided by ARB, not costs derived from PG&E data.

### 3. PG&E's Proposed Peninsula Adder Should Be Rejected

PG&E's request for replacement costs includes $22.6 million for a so-called "peninsula adder" which is added to six projects.[410] This adder was not discussed in PG&E's testimony or in the narratives for each project in the workpapers. The only indication of this adder is in one line in six of the individual spreadsheets for each project in the workpapers.[411] While DRA specifically asked PG&E to "Provide all workpapers which show and describe how the $200 per foot adder was derived," PG&E provided little more than a brief narrative of why it felt an adder was necessary.[412] PG&E states that "[t]hese increased cost factors are further reinforced by Chapter 4, the rebuttal testimony of Benjamin C. Campbell on 2011 hydrostatic testing costs," but that testimony attributes increased hydrotest costs primarily to managing contaminated water discharged from existing pipes.[413] This is not an issue relevant to the hydrotest of a clean new pipeline following replacement. The Commission should not saddle ratepayers with over $22 million in cost responsibility given the lack of justification by PG&E.

### 4. Acceleration of Segments to Phase 1 Is Not Justified By Economic Efficiency

The cost structure of replacement projects provides much less economic justification for accelerating segments into Phase 1 replacement projects compared to the hydrotest cost structure. DRA in its prepared testimony shows how the relatively low

[409] Ex. 21, PG&E Rebuttal Testimony, pp. 3-36 to 3-38. In PG&E's direct testimony, historical costs are only referenced regarding "pipe, fittings, and valves," which are variable, not fixed costs.

[410] Ex. 144, DRA Testimony, Chap. 3, p. 54.

[411] For example, see Ex. 8, PG&E Workpapers, page WP 3-44, and look for an $18,000 cost. DRA realized the magnitude of this adder by noting a $20+ million variance when calibrating its models.

[412] Ex. 60, PG&E Data Response to DRA-033, Q/A 1c. Dec. 16, 2011; 11 RT 1394-96, Hogenson, PG&E.

[413] Ex. 21, PG&E Rebuttal Testimony, p. 3-32.

level of fixed costs, regardless of the cost model used, results in relatively constant project costs per mile for replacement, beyond 1 mile length.[414] Costs stabilize at even shorter project lengths, closer to 500 feet. As such, there is much less economic incentive to add segments to Phase 1 replacement projects compared to hydrotest projects, where fixed costs are proportionally much higher. For example, it may be efficient to replace rather than hydrotest a 100-foot segment sandwiched between two 200-foot, 10-inch segments, but not a 1,000 ft segment.[415] Therefore, fewer segments should be added to Phase 1 replacement projects based on economic efficiency.

### D. PG&E's Contingency Analysis Is Flawed And Should Be Rejected

PG&E's proposed 20%-21% contingency for the pipeline portion of the PSEP (which constitutes the majority of its contingency request)[416] should be rejected because its Quantitative Risk Assessment (QRA) is inconsistent with the Association for the Advancement of Cost Engineering International (AACEI) estimating range guidelines for a Class 4 Project in at least two ways: (1) PG&E predetermines key contingency amounts before running its QRA; and (2) PG&E considers only the "high side" of AACEI guidelines when analyzing the probability of project costs exceeding its baseline estimate.

Proper application of AACEI guidelines for a Class 4 project results in, at most, a 15% contingency for PG&E's PSEP. Alternatively, if PG&E were to use its narrowed range of uncertainty between +0% to +17.5%, the contingency amount would be about 12% instead of the 20% requested by PG&E.[417]

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[414] Ex. 147, DRA Testimony, Chap. 6, p. 9, Graph 1.

[415] In a non-congested location, PG&E estimates the fixed Mob/Demob cost to be $45,000, and the variable cost per foot to be $282 per foot (Ex. 2, PG&E Direct Testimony, p. 3E-15). Adding 100 feet of pipe adds $28,200, which is less than the fixed cost of the replacement project, and much less than the fixed cost of a hydrotest. However, adding a 1,000-foot segment increases the cost by $282,000, which is over six times the fixed cost of a replacement project, and more than fixed hydrotest costs estimated by DRA. This is an example where the middle 1,000-foot section along with the two new sections should be pressure tested together as part of the required post-replacement hydrotest.

[416] See, e.g. Ex. 2, PG&E Direct Testimony, p. 7-21, Table 7-3. The pipeline portion of the PSEP is comprised of four MAT codes on Table 7-3: 2H1, 44A, KE1, and 34A.

[417] Ex. 21, PG&E Rebuttal Testimony, p. 16-10, Table 16-1, Sensitivity Scenario Column "SS1" lines 1 and 12.

To conform PG&E's contingency analysis to AACEI guidelines, the Commission should require PG&E provide an updated baseline cost estimate and an updated contingency estimate supported by a proper QRA that reflects actual experience with the PSEP to date. The contingency amounts should be approved for each cost category shown in Table 7-6 of PG&E's Direct Testimony,[418] and in silos as described in Section IV.D.4 below.

In the absence of a proper contingency analysis based on an updated baseline cost estimate, the Commission should approve a contingency amount of no more than 8%, which is comparable to amounts the Commission has approved for more complicated projects such as PG&E's Advanced Metering Infrastructure (AMI) projects.

### 1. PG&E's Pre-Determined Contingency Amounts Render its Monte Carlo Analysis Meaningless

While PG&E's use of a Monte Carlo analysis to quantify the risk in PG&E's PSEP cost estimates seems impressive, PG&E's use of predetermined contingency amounts embedded in the model render PG&E's QRA analysis self-serving and meaningless.

PG&E developed a QRA model using the Monte Carlo simulation technique, where both risk and uncertainty values are recalculated over many iterations. This analysis provides confidence level curves for the potential final costs of the PSEP and each component project. PG&E asserts that its contingency recommendation is based on 1,000 iterations corresponding to 1,000 potential outcomes.[419]

Although this sounds like a very thorough and impressive effort to capture all possible cost outcomes for its PSEP, PG&E's analysis is a mirage. PG&E assigns a fixed point estimate of +17.5% out of its 20% contingency request to reflect cost uncertainty for the Pipeline Replacement project, and a fixed point estimate of +20% out of its 21% contingency request to reflect cost uncertainty for the Strength Testing project.[420] Thus,

[418] Ex. 2, PG&E Direct Testimony, p. 7-39, Table 7-6.

[419] Ex. 2, PG&E Direct Testimony, p. 7-39.

[420] Compare Ex. 2, PG&E Direct Testimony, p. 7-46, Table 7-10, lines 2 and 16 with Ex. 21, PG&E

for the Pipeline Replacement project, PG&E predetermined almost 88 %[421] of its total contingency request before it ever ran its QRA model. Similarly, for the Strength Testing expense PG&E determined almost 95%[422] of its total contingency request before it ever ran its QRA model. As a result, PG&E only varies a very small portion of its requested contingency costs in its simulation model. Thus, debate about whether to seek an 80 or 90% level of certainty (P80 or P90) from the QRA analysis is meaningless,[423] as there is little difference between the two values.[424]

The only "analysis" PG&E offers to support these high contingency requests for estimating uncertainty is a judgment call. When DRA asked whether any of PG&E's work papers supported the 17.5 % contingency for estimating uncertainty for the Pipeline Replacement project, PG&E's witness explained that it was a matter of "professional judgment":

> There is no calculation. It was a professional judgment based on the meetings that we had, and reducing the range. Remember, this was a Class 4 estimate, and the recommendation for a Class 4 estimate is that you could apply a range as wide as negative 30 to plus 50. And in running a model in this scenario, when we had input from all the engineers, people who did the design, to go with the wide off-the-shelf range wouldn't be professionally correct. So we narrowed that range down to a point where intuitively our judgment was comfortable for that program specifically.[425]

PG&E provided more than 800 pages of work papers to support its testimony on contingency, including the AACEI and the U.S. Government Accountability Office (GAO) guidelines on cost estimating, but none of these guidelines provide any support

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Rebuttal Testimony, p. 16A-2, lines 1 and 14.

[421] PG&E uses a fixed point estimate of 17.5% contingency out of a total contingency request of 20%. 88% = 17.5% / 20%

[422] PG&E uses a fixed point estimate of 20% contingency out of a total contingency request of 21%. 95%= 20%/21%.

[423] 15 RT 2127-2128, Caletka/PG&E.

[424] Ex. 2, PG&E Direct Testimony, p. 7-41, Table 7-7.

[425] 15 RT 2097, Caletka/PG&E.

for PG&E's suggestion that it is appropriate to rely on "judgment" to predetermine 90 percent of contingency costs *before* running a QRA model.[426]

PG&E's own analysis shows that if PG&E used the AACEI recommended range of uncertainty for a Class 4 project, the contingency amount for the Pipeline Replacement and Strength Testing projects would be about 15% each, instead of the 17.5% and 20% requested by PG&E.[427]

PG&E's QRA model results give a false sense of thoroughness because the bulk of the model outcomes were predetermined by "judgment" "intuition." PG&E might as well have proposed its contingency request only on its intuition; instead it performed an extremely limited and misleading Monte Carlo simulation to give its contingency request a pretense of thoroughness. The Commission should reject PG&E's self serving contingency analysis.

Alternatively, if PG&E's intent was to justify most of its contingency request based on a fixed point estimate, it should be required, at a minimum, to perform a sensitivity analysis using the "Best Practices Checklist," which PG&E itself claims is a key component of any QRA.[428] While PG&E included this checklist in its prepared testimony,[429] DRA found that PG&E did not follow many key aspects of the checklist.[430] The Commission should also require PG&E to describe its process and results in detail, rather than permit PG&E to ascribe all of its conclusions to "judgment" or "intuition."

[426] Exs. 16 and 17, PG&E Work Papers Supporting Chapter 7, Volumes 1 and 2.

[427] Ex. 21, PG&E Rebuttal Testimony, p. 16-10, Table 16-1, Sensitivity Scenario Column "SS2" lines 1 and 12.

[428] Ex. 2, PG&E Direct Testimony, p. 7-28.

[429] Ex. 2, PG&E Direct Testimony, p. 7-29, Figure 7-4.

[430] Ex. 144, DRA Testimony, Chap. 3, § 7.3.

### 2. PG&E's QRA Only Considers The "High Side" of AACEI Guidelines Regarding The Range of Accuracy of Project Estimates

PG&E's QRA improperly considers only the "high side" of AACEI guidelines regarding the range of accuracy of Class 4 project estimates,[431] and should therefore be rejected.

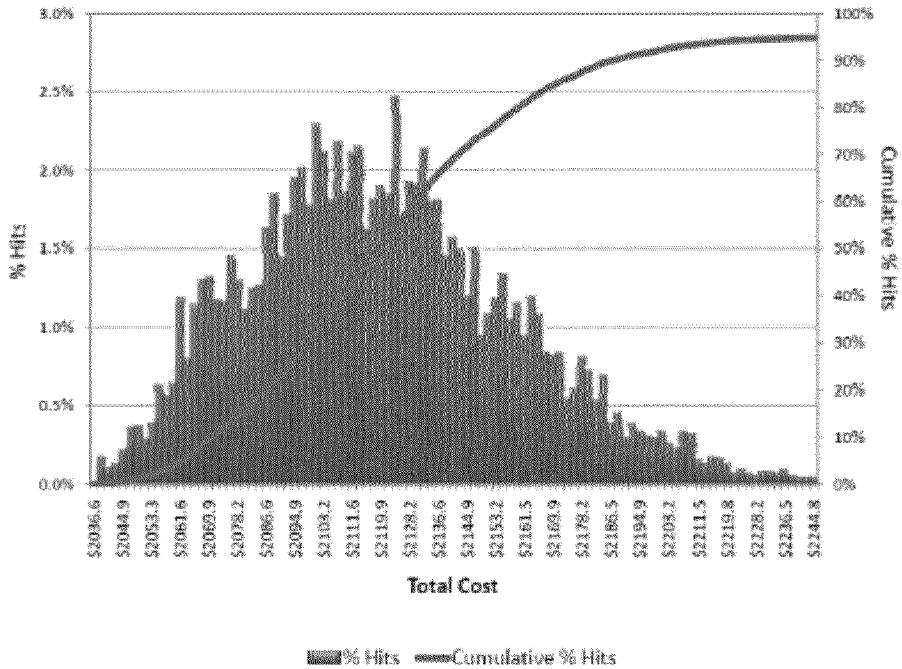
PG&E explains that AACEI guidelines for Class 4 projects provide that the accuracy of PG&E's estimates will range from 30% below PG&E's baseline estimates to 50% over its baseline estimates.[432] Notwithstanding this guideline, PG&E analyzes *only* the probability of costs coming in *well above* its baseline estimate, and it uses that analysis to justify its contingency request. PG&E's faulty analysis is reflected in its S curve for the PSEP at Figure 7-5, reproduced here:[433]

[431] PG&E considers the PSEP a Class 4 project. PG&E explains that when it developed its PSEP for filing with the Commission that the "project definition was at or below 15 percent, meaning that estimates included in the [PSEP] are at a level of a 'Class 4' estimate according to the AACEI." Ex. 21, PG&E Rebuttal Testimony, p. 16-4. This low level of project definition was because "PG&E had less than three months to develop a comprehensive plan to modernize its pipeline infrastructure and propose an expansion of the use of automated valves, among other things. Therefore, PG&E did not have the luxury of evaluating the project's definition, design intent or business case." *Id.* On this basis, PG&E defined most of its estimates as Class 4, including both its Pipeline Replacement and Strength Testing projects. Ex. 2, PG&E Direct Testimony, pp. 7-30 and 7-31.

[432] Ex. 2, PG&E Direct Testimony, pp. 7-31. See also Figure 7-3 at Ex. 2, p. 7-25 which shows the AACEI "expected accuracy range" for various classes of estimates.

[433] Ex. 7, Errata to PG&E Direct Testimony, January 20, 2012, p. 7-42.

FIGURE 7-5
PACIFIC GAS AND ELECTRIC COMPANY
CONTINGENCY MODEL CONFIDENCE LEVEL CURVE




An S curve, like the one above, should represent the probability of project costs being met at various levels of assumed costs, including the probability that costs will meet, exceed, *or be less than*, the baseline estimate. As discussed above, under AACEI guidelines, the actual costs of the PSEP, as a Class 4 project, could come anywhere in the range of -30% to +50% of the baseline cost. The purpose of developing an S curve is to show various costs in this range and their associated probabilities. The S curve is a tool for project owners and the Commission to make an informed decision about how much over and above the baseline budget should be approved in contingency to provide the needed level of confidence that the project will be fully funded. For this to happen, the S curve should represent all reasonable scenarios of actual costs within the -30% to +50% AACEI range. Simply put, PG&E should have first developed an S curve considering the *full* ACEE International range of costs for the project. Only then can the S curve be used to identify a proper contingency amount corresponding to the desired level of confidence identified by the curve.

Instead, PG&E's S curve shows there is zero probability that the actual PSEP costs will come in under its base estimate of $1,803.4 million.[434] In fact, PG&E's starting cost projection is $2,036.6 million, $233.2 million *more than* PG&E's baseline estimate.

PG&E's explanations for why it only considered the "high side" of the AACEI guidelines are unsatisfactory. In Rebuttal Testimony, PG&E explained: "When used to set contingency, it is advised to rely on the "+' values of the uncertainty, which for Class 4 estimates range from "+20 percent to +50 % on the high side."[435] Neither the AACEI nor GAO guidelines provided in PG&E's contingency work papers provide any support for the above statement.[436] When DRA asked PG&E's witness why it relied only on the "+" values of the uncertainty analysis, PG&E's witness admitted: "None of the workpapers give specific definition on how to run a quantitative risk model using the AACE guidelines. So that's my experience and my advice."[437] When asked why PG&E's S curve in Figure 7-5 of its Direct Testimony did not consider costs *under* PG&E's baseline estimate of $1.8 billion, PG&E's witness explained that "there is zero confidence level" that costs will come in at $1.8 billion.[438] This contradicts an earlier PG&E witness's testimony that PG&E directed its consultants to use "basically the AACE cost estimating system specification" and that it did not "give them specific direction to estimate high or low." That witness testified that "We said follow the cost estimating principles and standards."[439]

Thus, one PG&E witness says PG&E intended to follow AACEI standards, which required PG&E to analyze the full range of possible project costs from -30 to +50, while the other asks us to rely on his "experience" and "advice" to conclude that eliminating the negative portion of the AACEI cost range was appropriate.

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434 Ex. 7, Errata to PG&E Direct Testimony, January 20, 2012, p. 7-42.

435 Ex. 21, PG&E Rebuttal Testimony, p. 16-7.

436 Exs. 16 and 17, PG&E Work Papers supporting Chapter 7, Volumes 1 and 2.

437 15 RT 2085, Caletka/PG&E.

438 15 RT 2089-2090, Caletka/PG&E.

439 11 RT 1404, Hogenson/PG&E.

But PG&E does not even heed its own advice. PG&E's contingency analysis not only ignores *all* of the negative values of the AACEI cost range to run its Monte Carlo simulation model, but PG&E, inexplicably, ignores all of the *positive* values between 0 % and 17.5% of the cost range also.

PG&E explains that it "'tightened-up' the uncertainty range recommended by AACEI (i.e., lowered the 'high side') and prevented 'negative' contingency calculations (i.e., outcomes lower than the base estimate) due to expressed exclusions in the base estimates."[440] However, PG&E's explanation fails to explain why PG&E's QRA analysis ignored any outcomes between the base estimate of $1,803.4 million and the starting point on its S curve at approximately $2,036.6 million.

Instead of providing a proper QRA analysis supported with a proper S curve that conforms to AACEI guidelines, PG&E asks the Commission to accept its approach at face value. The Commission should reject PG&E's request and require a proper QRA analysis to determine contingency for the PSEP.

### 3. PG&E's Contingency Should Be Based on An Updated Baseline Estimate and Contingency Analysis

PG&E's PSEP contingency should be based on an update baseline cost estimate and contingency analysis. PG&E now has more than a year's actual experience with its PSEP, including the costs to perform the various tasks in the plan. Since there is no recourse for ratepayers if PG&E's contingency request is excessive, it is critical that both PG&E's baseline cost estimate and its contingency request are as accurate as possible.

PG&E has already committed to update its PSEP cost estimate annually. In response to CPSD's report on its PSEP, PG&E agreed that: "PG&E should revisit its cost estimates at least annually and recalculate balance of project capital and expense requirements based on project progress and new knowledge gained through the data

[440] Ex. 21, PG&E Rebuttal Testimony, p. 16-7

examination. The CPUC should be provided with a report in a format that it specifies."[441]

DRA recommends that the Commission require that, coinciding with the due date of the first annual report, PG&E provide an updated baseline cost estimate and contingency estimate supported by a proper QRA analysis. The Commission has not yet approved a budget for the PSEP. The Commission should require PG&E to incorporate the actual experience gained so far to develop its contingency request.

#### 4. Contingency Amounts Should Apply to Specific Cost Categories

Based on the same concerns expressed in the section above, DRA recommends that the Commission restrict the use of a contingency budget for a category item to performing work under that category item only. DRA is concerned that if the Commission authorizes the entire contingency budget PG&E requests - $380.5 million - as a lump sum, the Commission cannot properly ensure that contingency funds are used only for uncertainties and risks not already captured in the baseline estimate. The costs of various categories in Table 7-7 of PG&E's Direct Testimony vary from a relatively small amount of $0.1 million (capital item 44A at line 3) to as high as $167.7 million (capital item 2H1at line 2).[442] Absent siloing contingency amounts in this way, PG&E would be able to use contingency budgets from larger and/or unused categories to cover improper or inefficient spending in smaller categories. For scale, consider that the contingency for pipe replacement ($165.3 million)[443] is more than the baseline *capital* request for valve automation ($132.5 million) and PMO ($22.9 million) combined.[444]

Fund shifting between various items within a silo could be allowed through a Tier 2 Advice Letter process, provided staff are given adequate guidelines in approving a

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[441] Pacific Gas and Electric Company's Response to Technical Report of the Consumer Protection and Safety Division Regarding PG&E's Pipeline Safety Enhancement Plan, R.11-02-019, January 13, 2012, Appendix A, p.4.

[442] Ex. 2, PG&E Direct Testimony, p. 7-41, Table 7-7.

[443] Ex. 2, PG&E Direct Testimony, p. 7-41, Table 7-7.

[444] Ex.2, PG&E Direct Testimony, p.1-16, Table 1-3.

PG&E proposal. DRA recommends the following fund shifting guidelines for staff to apply:

- Require separation of contingency amounts for "capital" and "expense" items.
- If having a contingency silo for each item shown in Table 7-6 of PG&E's Direct Testimony[445] is not practical, silo the contingency amounts for a group of items in a way that makes sense, e.g., all "Valve" items could be grouped together to have their own contingency amount.
- Contingency funds may be shifted between any two silos if required to meet cost overruns for events and conditions specifically excluded from base estimate and contingency.

### 5. Absent A Proper Analysis, A Contingency of No More Than 8% Is Appropriate

In the absence of a proper contingency analysis based on an updated baseline cost estimate, the Commission should approve a contingency amount of no more than 8%, which is comparable to amounts the Commission has approved for more complicated projects such as PG&E's Advanced Metering Infrastructure (AMI) projects.

One of PG&E's contingency witnesses in its original AMI application, A.05-06-028, was Mr. Stephen Lechner, who also addressed certain contingency issues in this proceeding.[446] In PG&E's original AMI proceeding, Mr. Lechner testified that a contingency of 5-7% "reflects typical contingency values for standard construction projects (e.g., road and highway construction) that do not have the additional complexities of a project like PG&E's AMI Project."[447] In that case, the Commission adopted a 8.0% contingency for PG&E's original AMI project.[448]

PG&E's original AMI application was the first one filed by a California utility, and it proposed implementation of state-of-the-art metering technology and major upgrades and enhancements to PG&E's information technology systems. In contrast, the

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[445] Ex. 2, PG&E Direct Testimony, p. 7-39, Table 7-6.

[446] Exhibit 21, PG&E Rebuttal Testimony, p.14-3, lines 31-32.

[447] Exhibit 114, Rebuttal Testimony of Stephen P. Lechner in Application 05-06-028, p. 13-5.

[448] D.06-07-027, Conclusion of Law 3 ("There is sufficient credible evidence to adopt as reasonable a project budget of $1.7394 billion, inclusive of a Risk Based Allowance, or contingency, of $128.8 million …) 1739.4-128.8)/1739.4 = 8.0%.

technology associated with pipeline installation, replacement, and hydrotesting is largely decades-old. PG&E argued in the AMI case that "it is necessary for PG&E to consider a significantly higher contingency value associated with IT elements of the AMI Project than for a typical construction project."[449] While Mr. Lechner did not know if the "pipeline replacement and hydrotest portions of PG&E's PSEP require[d] the use of any new or innovative technologies,"[450] he confirmed that the only significant information technology request in the PSEP is for the GTAM database upgrade, not for pipe replacement.[451]

DRA believes that pipeline replacement and hydrotesting has more in common with road and highway projects than a state-of-the-art metering and data management system, and should thus have a contingency consistent with a "standard construction project." In no event should the PSEP have a *higher* contingency than established in the original AMI application. On this basis, absent a proper contingency analysis, DRA recommends that the contingency for the PSEP be no more than 8%.

### E. Other Issues

#### 1. PG&E Shareholders Should Pay for Public Relations Efforts

PG&E applies a 2.9% adder for "customer outreach" costs which adds over $31 million to replacement and hydrotest project costs.[452] DRA consultant BEAR reviewed information provided by PG&E in response to DRA discovery requests and found that customer outreach includes approximately $5 million for new databases and $3 million for government relations.[453] PG&E justifies these activities as new work, stating that

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[449] Ex. 114, Rebuttal Testimony of Stephen P. Lechner in Application 05-06-028, p.13-6, lines 19-21.

[450] 14 RT 1932, lines 1-5, Lechner/PG&E.

[451] 14 RT 1930, lines 9-22, Lechner/PG&E.

[452] Ex. 144, DRA Testimony, Chap. 3, p. 107, n. 198: "$31 million was calculated by DRA by summing the customer outreach cost included in each replacement and hydrotest project. BEAR found that PG&E reported the total budget for customer outreach to be $28.5 million."

[453] Ex. 147, DRA Testimony, Chap. 6, pp. 17-19.

"the outreach to local governments helped expedite the permit process…."[454] But costs associated with permitting should be part of the 3% permitting cost included for all projects.[455]

BEAR appropriately questions the need for "government relations" as a component of customer outreach, and for customer outreach generally for an issue with so much public interest and media attention. PG&E should not receive ratepayer funding to walk neighborhoods or meet with local officials in efforts to show off its corrective efforts to make its gas system is safe. Such tasks would constitute a public relations effort to polish PG&E's tarnished reputation, and is solely the responsibility of PG&E shareholders.

### 2. PG&E Has Not Justified the Need and Costs of Its Proposed In-Line Inspection (ILI) Projects

#### a) ILI Projects Should Not Be Included in Phase 1

PG&E requests $9.6 million in expenses and $30.3 million in capital to perform ILI in Phase 1.[456] This request is to fund eight discrete ILI runs,[457] and six discrete upgrade projects to accommodate these ILI runs.[458] However, PG&E's decision tree does not produce any outcomes directing ILI to be performed as a high priority in Phase 1, and the vast majority of segments included in these ILI projects require no Phase 1 action.[459] As discussed above, PG&E also stated in hearings that it does not believe ILI can currently be used in lieu of hydrotesting or replacement.[460]

PG&E provides the following justification for these activities:

[454] Ex. 21, PG&E Rebuttal Testimony, p. 4-5; Ex. 147, DRA Testimony, Chap. 6, p. 19.

[455] Ex. 2, PG&E Direct Testimony, p.3E-9.

[456] Ex. 2, PG&E Direct Testimony, p.3-6, Table 3-1.

[457] Ex. 9, PG&E Workpapers, p. WP 3-757.

[458] Ex. 8, PG&E Workpapers, p. WP 3-6.

[459] Ex. 10, PG&E Workpapers, pp. WP 3-1280 to 1307.

[460] 11 RT 1418, ll.17-23, Hogenson/PG&E.

> PG&E has identified 199 miles of ILI retrofit work and 234 miles of ILI runs in Phase 1. This work is located on the L-300 Backbone system and on three pipelines within the South Bay and San Francisco Peninsula. Phase 1 ILI work will provide valuable input into the ECA process PG&E will use to identify, locate and remove excessive pups, miter bends, and wrinkle bends.[461]

This is a curious justification considering that PG&E does not currently have a plan for ECA,[462] and is requesting funds to develop the capability to perform ECA.[463] No justification has been provided to support including these projects in Phase 1. More definition of the ILI runs PG&E plans to perform, the data it hopes to acquire, and how this data will be used, should be provided before the Commission considers authorizing PG&E to proceed with these projects.

#### b) PG&E Has Not Provided Adequate Support for ILI Unit Costs

Not only has PG&E failed to demonstrate the need for including ILI projects in Phase 1, PG&E has also not justified the requested costs. For ILI expenses, unit costs are provided in PG&E's prepared testimony and described by Gulf as "[t]hese estimated unit rates used for In-Line Inspection orders have been developed in conjunction with PG&E, based on PG&E's past project experience."[464]

DRA requested that PG&E "[p]rovide workpapers in excel format supporting each unit cost for Test and ILI projects, as shown on page 3E-17 of the testimony."[465] PG&E responded not with workpapers showing how the costs were derived, but with a statement that describes how the unit costs were used:

> For the ILI projects, a simple manual calculation using the length of the proposed ILI run, number of main line valves between ending points, and one launcher and one receiver

[461] Ex. 2, PG&E Direct Testimony, p.3-27. PG&E's workpapers also state that "[t]he work is being performed to inspect the pipeline with a MFL tool." Ex. 10, PG&E Workpapers, p. WP 3-1295.

[462] Ex. 21, PG&E Rebuttal Testimony, p.3-6.

[463] Ex. 10, PG&E Workpapers, p. WP-1308.

[464] Ex. 2, PG&E Direct Testimony, pp. 3E-8, 3E-17.

[465] Ex. 56, PG&E Data Response to DRA-055, Q/A 3, Jan. 6, 2012.

> were respectively multiplied by the cost figures used in the Unit Cost Summary Matrix, shown on page 3E-17, to derive the project cost for the workpapers.[466]

DRA independently determined that the figures on page 3E-17 do not agree with the ARB quotes, both of which indicate the "Smart Pig" costs are $40 to $60 thousand per 5,000ft, depending on the pipe diameter.[467] The ARB quotes provide no support for the capital unit costs, or the "direct examine and repair" unit expense cost.[468]

## V. PG&E'S VALVE REPLACEMENT PROGRAM MUST BE CONSIDERED IN LIGHT OF ITS VALUE TO CUSTOMERS

The order opening this proceeding recognized the "extraordinary safety investments required for PG&E's gas pipeline system" in light of the revelations from the San Bruno explosion. It emphasized the need for cost-conscious safety investments:

> Given the economic challenges confronting California's families and businesses, we must be certain that each investment in safety that we order provides value to customers.[469]

The Assigned Commissioner's Amended Scoping Memo and Ruling dated November 2, 2011 reiterated this point and specifically asked parties to address the issue of whether proposed safety investments provide value to customers.[470]

Among the "safety investments" proposed in its PSEP PG&E seeks over $128 million from ratepayers to install automated valves on its gas transmission system before its next rate case. This proposal is presumably consistent with § 957, which requires California's gas utilities to submit a "valve location plan" so that the Commission can

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[466] Ex. 56, PG&E Data Response to DRA-055, Q/A 3, Jan. 6, 2012.

[467] Ex. 56, PG&E Data Response to DRA-061, Q/A 1, attach. 1 and 2, Jan 25, 2012..

[468] Ex. 56, PG&E Data Response to DRA-061, Q/A 1, Jan 25, 2012. Capital unit costs are upgrade and pre-assess, MLV modification, and launcher/receiver installation.

[469] Order Instituting Rulemaking 11-02-019, p. 12.

[470] Amended Scoping Memo and Ruling of the Assigned Commissioner, R.11-02-019, November 2, 2011, p. 3.

require the installation of automatic shutoff or remote controlled valves "*if it determines those valves are necessary for the protection of the public.*"[471]

The problem is that PG&E has not demonstrated that its valve automation program is "necessary for the protection of the public" or that it provides "value to its customers," justifying rate recovery between rate case cycles.

### A. PG&E's Cost Recovery Proposal Should Be Rejected

PG&E estimates capital expenditures and expenses of $143.6 million between 2011 and 2014 for its valve automation program. Under PG&E's proposal, PG&E shareholders would pay for those costs incurred in 2011; ratepayers would be responsible for costs incurred after that.

DRA's position regarding this program and PG&E's other proposals set forth in Chapter 4 of its Direct Testimony (Exhibit 2) is consistent with the policy set forth in Section 2 above, and in DRA's Testimony (Exhibit 143). The Commission should deny PG&E's request for any rate recovery outside of its rate case cycles.

In the alternative, DRA recommends that the Commission limit the scope of PG&E's valve automation program to automating existing valves and installing new automatic shut-off valves on pipelines in populated areas that cross active earthquake faults where the fault poses a significant threat to the pipeline.[472] This proposal goes beyond what is required under existing laws and regulations, and allows the Commission time to consider PG&E's proposal in light of the statutory guidance discussed below.

The remaining projects recommended by PG&E, which include: (1) installation of new automated valves where there is currently no valve or where an existing valve cannot be automated; (2) upgrades to hardware on existing automated valves; and (3) automation or replacement of existing valves in vaults,[473] should be postponed to PG&E's next rate

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[471] Pub. Utils. Code § 957(a)(1) (emphases added).

[472] Ex. 2, PG&E Direct Testimony, p. 4-1.

[473] Ex. 2, PG&E Direct Testimony, pp. 4-51 to 4-52.

case because these proposals exceed the requirements of D.11-06-017, and the cost estimates for this work are highly speculative.

Under DRA's proposal, set forth in the table below, the estimate for Phase 1 of PG&E's valve automation program would be reduced and ratepayer responsibility would be capped at $45.8 million. PG&E shareholders would be responsible for all costs incurred in 2011, consistent with PG&E's cost sharing proposal.

Ratepayer Responsibility For Valve Automation Program - PG&E vs DRA
(in millions of dollars)

| | 2012 | 2013 | 2014 | Total |
|---|---|---|---|---|
| PG&E Request | 42.1 | 56.4 | 29.8 | 128.3 |
| DRA Recommended | 11.0 | 22.4 | 12.4 | 45.8 |

DRA also recommends that PG&E's proposal to establish four gas engineer positions associated with the interim safety enhancement measures be rejected. PG&E has not shown that these positions are necessary, as PG&E is already meeting its pressure reduction requirements with its current number of engineering staff.

In making its proposal to disallow all of the costs, or delay PG&E's installation of automated valves, DRA is aware of the public interest in automated valves. This interest has justifiably arisen because it took PG&E *95 minutes* to identify the location of the San Bruno rupture, stop the flow of gas, and isolate the rupture site so that emergency responders could enter the area.[474] In considering PG&E's valve automation proposal, it is fair to ask how PG&E's proposal might have changed the San Bruno situation, and whether remote controlled valves, which is what PG&E proposes to install,[475] would have worked.

Significantly, the Administrative Law Judge asked PG&E these types of questions. She asked if PG&E had "looked at the San Bruno incident to study it to see where automatic shut-off valves might have been placed, where they – what affect they might

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[474] NTSB Report, p. x.

[475] Ex. 2, PG&E Direct Testimony, p. 4-1. PG&E proposes to only install automatic shut-off valves in lines along earthquake faults.

have had on that sequence of events?" PG&E admitted that it did not do a specific analysis of the San Bruno event. And it did not address the Judge's specific question regarding automatic shut-off valves. Rather, PG&E admitted that it had only considered the San Bruno event in a "general" manner, but clarified: "It's the same, though."

> A We looked at that section of pipe and determined where we were going to put automated valves to be able to isolate that pipe segment.
>
> Q Okay. But that's all you did, you didn't look at the sequence of events and see in a sort of real-time emergency rupture situation how it would have worked?
>
> A We looked at in general how they would have responded to any event for a pipe segment of certain length. So you could apply that to San Bruno.
>
> Q Okay. But you just looked in general, you did not do a specific analysis of that specific event?
>
> A No.
>
> Q Okay.
>
> A It's the same, though.[476]

Thus, even PG&E cannot explain how its automated valve program would have changed what happened in San Bruno. Later, and related, PG&E's own engineer suggested that where parallel lines have cross connections, PG&E may not be able to tell which line has ruptured and should be shut down.[477] Finally, PG&E has admitted that it has no documented plan of action/safety plan for when an automated valve fails during a real emergency: "There is [sic] no specific documented action plans outlining the response of Gas Control operators in the event an Automatic Shut-off Valve (ASV) or Remote Control Valve (RCV) fails to perform during a real emergency."[478]

[476] 11 RT 1352, Menegus/PG&E.

[477] 11 RT 1356-1357, Menegus/PG&E.

[478] Ex. 65, PG&E Data Response to DRA-073, Q/A 6, March 16, 2012.

Given these factors, and the requirements of § 957 described below, it is not clear that PG&E's automated valve program will increase public safety sufficient to justify its cost.

### B. PG&E Has Not Demonstrated That The Safety Value Justifies The Cost Of Its Valve Automation Program

In the wake of revelations from the San Bruno explosion, the California Legislature adopted the Natural Gas Pipeline Safety Act of 2011 (Act). The Act directed the Commission to undertake several gas pipeline safety activities, including consideration of automated valves. The Act added § 957 to the California Public Utilities Code. Pursuant to § 957, the Commission "shall require the installation of automatic shutoff or remote controlled … valves … *if it determines those valves are necessary for the protection of the public.*"[479]

Section 957 is prescriptive and anticipates quick action by the Commission. It requires gas utilities to file a "valve location plan" with the Commission, which the Commission may modify "consistent with the protection of the public." It requires the Commission to "establish action timelines, adopt standards for how to prioritize installation" of the valves, ensure that the valves are "installed as quickly as is reasonably possible, and establish ongoing procedures for monitoring progress in achieving the requirements" of the section.[480] Finally, the Commission is required to authorize rate recovery for all reasonably incurred costs.[481]

Commission consideration of PG&E's currently proposed "valve location plan" submitted in this proceeding will not produce the type of review contemplated under the statute. First, the Commission may only require the installation of automated valves "*if it determines those valves are necessary for the protection of the public.*"[482] PG&E has failed to provide any cost/benefit analysis that will permit such a finding consistent with

[479] Pub. Utils. Code § 957(a)(1) (emphases added).

[480] Pub. Utils. Code § 957(a).

[481] Pub. Utils. Code § 957(b).

[482] Pub. Utils. Code § 957(a)(1) (emphases added).

the Commission's stated intent to "be certain that each investment in safety that [it] order[s] provides value to customers."[483] In fact, PG&E has declined to provide any kind of cost/benefit assessment claiming that it "would require PG&E to place a dollar value on the potential loss of life and property."[484] Second, the Commission has not retained anyone with valve expertise to assist in analyzing and potentially modifying PG&E's plan to make it safer and/or more cost effective. Thus, the Commission is unable to modify PG&E's plan "consistent with the protection of the public" or to propose or adopt "standards for how to prioritize installation" of the valves.[485]

The findings required by § 957 cannot be made in a vacuum. The statutory framework of § 957, combined with the competing technical testimony in this proceeding, and the Commission's lack of established valve automation standards, all reflect that the issue of how to design a cost-effective automated valve program which will protect the public is a complicated one. Because PG&E's system currently meets all regulatory standards in this area,[486] there is no need for potentially wasteful haste. DRA recommends that the valve automation issue be scoped for further development, consistent with the statute, and with the participation of *all* of the implicated natural gas utilities.

[483] Order Instituting Rulemaking 11-02-019, p. 12.

[484] Ex. 21, PG&E Rebuttal Testimony, p. 6-15.

[485] Pub. Utils. Code § 957(a)(2) and (3).

[486] 10 RT 1250-1251, Menegus/PG&E. See also Ex. 63, PG&E Data Response to DRA-042, Q/A 1, Dec. 22, 2011 ("PG&E is in compliance with valve spacing requirements specified in 49 CFR Section 192.179(a). All new and replacement pipeline and station work evaluates valve spacing to ensure properly spaced valves are provided as part of the preliminary engineering process."); Ex. 2, p. 4-32 ("Currently, there are no prescriptive requirements in the prevailing pipeline code, Title 49 CFR Part 192, that require operators to install automated valves.")

## VI. IF COST RECOVERY IS AUTHORIZED, THE COMMISSION SHOULD REQUIRE PG&E TO SUBMIT NEW ESTIMATES AND TO BE ACCOUNTABLE FOR ALL EXPENDITURES

### A. PG&E's Estimates Should Be Revised To Reflect Its Changed Position On Shareholder Cost Responsibility

As described in Section III.B above, PG&E originally proposed that ratepayers pay to pressure test all of PG&E's gas transmission lines installed before 1970 for which it does not have pressure test records. It based its PSEP estimates on this proposal.

In its Rebuttal Testimony PG&E acknowledged that General Order 112 required PG&E to pressure test all pipeline segments installed since July 1, 1961. On this basis, PG&E agreed that it would be responsible for the costs of testing all lines installed after that date.[487]

PG&E has not updated any of its PSEP estimates to reflect this change. If the Commission authorizes any cost recovery under PG&E's PSEP, it should require PG&E to first update its estimates.

### B. The Commission Should Consider Mechanisms Consistent With D.12-04-021

Consistent with DRA's recommendation to disallow all PSEP costs between rate cases, DRA has recommended that the Commission deny PG&E's request for balancing and memorandum accounts for Phase 1 of its PSEP.[488] However, in the event the Commission wants to consider some level of cost recovery, it should do so consistent with the mechanisms adopted in D.12-04-021, which addresses the pipeline testing and replacement implementation plans for San Diego Gas & Electric Company (SDG&E) and Southern California Gas Company (SoCal Gas).

Decision 12-04-021 "authorizes a memorandum account for both companies, but does not change rates."[489] It authorizes the two utilities to file Tier 2 Advice Letters to

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[487] Ex. 21, PG&E Rebuttal Testimony, p. 10-13 ("In the case of transmission pipe installed in California after July 1961, I agree that if no pressure test records can be found then PG&E should be bear [sic] the expense of pressure testing.")

[488] Ex. 149, DRA Testimony, Chap. 9, p. 57.

[489] D.12-04-021, p. 1.

create memorandum accounts to record, for later Commission ratemaking consideration, the costs of their PSEPs. "Authorization of the memorandum account does not ensure any recovery from ratepayers."[490]

Consistent with D.12-04-021, if the Commission seeks to consider cost recovery for PG&E, it should not grant it now. Instead, it should require PG&E to file a Tier 2 Advice Letter to create a memorandum account for the 12 months following a decision in this proceeding, and include supporting documentation similar to what was provided by SDG&E and SoCal Gas, including a scope of work and cost estimates. The memorandum account would only be for a 12 month increment. To the extent PG&E seeks additional ratepayer funding in later years of Phase I -and before its next rate case – PG&E would file another Tier 2 Advice Letter to create another 12 month memorandum account, with supporting documentation. The Commission would look at each 12 month increment at a later date to determine whether "properly recorded costs are reasonable and incremental as well as which costs, if any, may be recovered from ratepayers in revenue requirement."[491] Consistent with D.12-04-021, PG&E would also be required to file a Tier 1 Advice Letter to advise the Commission and parties if its cost forecasts increase by more than 10%. Such an Advice Letter "would simply document a change in cost estimates and not [constitute] approval of any costs recorded in the memorandum account."[492]

### C. The Commission Should Place Specific Requirements On PG&E's Records Correction Program

If the Commission does not deny PG&E's $222.8 million Records Correction Program request in full, then prior to authorizing any ratepayer funding for the program, it should:

- Recognize that PG&E's program estimates are unreliable and require PG&E to update its estimates, including, among other things:

[490] D.12-04-021, p. 11.
[491] D.12-04-021, p. 7.
[492] D.12-04-021, p. 7.

- Identification of all historical embedded costs available to fund the program;
- Identification of projected savings available to fund the program; and
- Recognition of PG&E's revised position that it is responsible for validation and testing costs associated with pipelines installed after July 1961.

- Require PG&E to identify all savings associated with implementation of the Records Correction program in its next GRC, including reduced staff time to perform gas transmission record keeping;
- Require PG&E to provide all documentation regarding program costs sufficient to verify the accuracy of the costs in its next GRC; and
- Require PG&E to provide a report in its next GRC regarding the progress of the program in correcting all deficiencies in its gas transmission records.

### D. The Commission Should Reject PG&E's Proposal To Seek Recovery Of Additional Costs Through Tier 3 Advice Letter Filings

Whether or not the Commission authorizes cost recovery for PG&E's PSEP, it should reject PG&E's proposal to seek recovery of additional costs through a Tier 3 Advice Letter process.

PG&E proposes that the Commission authorize additional recovery for increased PSEP expenses through a Tier 3 Advice Letter.[493] PG&E does not suggest a limit to the amount that may be authorized through the Tier 3 Advice Letter.[494] That means PG&E could ask for any amount in a Tier 3 Advice letter filing. PG&E admits that if adopted, fund authorized through the Tier 3 Advice letter process could increase Phase 1 PSEP costs. PG&E states: "The amounts PG&E contemplates under the Tier 3 Advice letter could increase (if authorized) the original PSEP authorized forecast."[495]

DRA opposes PG&E's request to authorize PSEP cost recovery through a Tier 3 Advice Letter Process. This will only serve to drive up the costs of PG&E's PSEP

[493] Ex. 2, PG&E Direct Testimony, p. 8-14.

[494] Ex. 149, DRA Testimony, Chap. 9, pp. 46-47 and note 204.

[495] Ex. 149, DRA Testimony, Chap. 9, p. 47 and note 205.

further, after initial approval. Further increases to PSEP costs will in turn increase the PG&E rate base for any capital expenditures that become capital additions. An increase in the PG&E rate base means more opportunity for profits since the PG&E authorized rate of return will have a higher amount of used and useful operating assets against which to multiply in order to generate PG&E's net return.

On these bases, the Commission should reject PG&E's proposal for a Tier 3 Advice Letter process that would allow increases to any authorized PSEP costs.

### E. The Commission Should Adopt DRA's Unit Costs for Pipe Testing and Replacement

As discussed in Section IV above, if the Commission authorizes PG&E to recover from ratepayers the costs of hydrostatic testing and pipe replacement, DRA recommends that the unit costs developed by DRA be used instead of PG&E's proposed costs.

## VII. CONCLUSION

For all the foregoing reasons, and the reasons set forth in its testimony, DRA asks that its recommendations be adopted.

Respectfully submitted,

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/s/ MARION PELEO

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