BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

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	R.11-02-019 (Filed February 24, 2011)

DIRECT TESTIMONY OF

THE CITY AND COUNTY OF SAN FRANCISCO IN RESPONSE TO

PACIFIC GAS & ELECTRIC COMPANY'S PIPELINE SAFETY ENHANCEMENT PLAN

(IMPLEMENTATION PLAN)

RULEMAKING 11-02-019,

CALIFORNIA PUBLIC UTILITIES COMMISSION

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OVERVIEW

Phillip S. Tuemim

PG&E's Implementation Plan should not be approved as proposed. In terms of both safety and costs, PG&E fails to provide sufficient analytical support for the Commission to determine that this proposal is reasonable.

Scope

PG&E's proposal is inconsistent with the Commission's order in that it expands the scope of the immediate work. The results are that work in high risk locations is not prioritized as it should be and the completion of the high priority work ordered by the Commission will take longer and cost more. PG&E did not provide any safety analysis for this modification of the scope. PG&E's addition of a Phase 2 (2015 and beyond) contains no estimate of costs and further complicates review of this proposal.

The complexity, schedule, and project management approach proposed by PG&E raise questions about the utility's ability to do the work it has outlined, especially given the systemic problems with PG&E's management, corporate culture, and technical ability that have been identified in a number of published reports.

Safety

In addition to delaying testing on the pipelines in the most populous locations, PG&E's proposal fails to provide analytical support for other key safety proposals. For example, PG&E proposes a valve automation program but fails to support it with the analysis required by federal law. Similarly, PG&E continues to ignore the findings of the Commission’s Independent Panel and the National Transportation Safety Board by failing to revise its Integrity Management Program to comply with the requirements of federal law.

Costs

PG&E has not justified the costs it proposes and should not get approval for rate recovery. The City's testimony shows that much of the work proposed here by PG&E should have been done previously by PG&E under federal regulations and prudent industry practices to ensure pipeline safety. For the main gas pipelines serving San Francisco (Lines 101, 109, and 132), the City's analysis indicates that approximately 86% of the project costs for proposed pressure tests are only necessary because PG&E did not perform the work it should have performed for many years. PG&E has not made any effort to show that the work it proposes here is "incremental" to requirements that were already in place. Absent such a showing, ratepayers should not pay for this work. Similarly, PG&E proposes to cap PG&E shareholder liability for costs, but this should be rejected because it is arbitrary and premature.

The Commission should not approve any of the proposed costs, absent a reasonableness review of the projects and expenditures. The Commission could allow PG&E to record these costs as a regulatory asset. This will provide PG&E with the opportunity to recover the reasonable costs, without a guarantee of full recovery. If the Commission insists on giving a rate increase now to fund necessary safety work, it should do so subject to refund and cap the increase at 1.5% per year pending further review.

DIRECT TESTIMONY OF
JOHN GAWRONSKI
ON BEHALF OF THE
CITY AND COUNTY OF SAN FRANCISCO

RESPONSE TO CHAPTER 3 OF PG&E'S IMPLEMENTATION PLAN:

PIPELINE MODERNIZATION OR IMPLEMENTATION PLAN

Q.1 PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A.1 My name is John Gawronski. I am a consultant affiliated with Hudson River Energy Group. My business address is 2079 County Route 47, Salem NY 12865.

Q.2 PLEASE SUMMARIZE YOUR EDUCATION AND BUSINESS EXPERIENCE?

A.2 I have over 40 years of natural gas pipeline industry expertise in the areas of transmission and distribution pipeline integrity management, pipeline codes and standards, as well as, monitoring and regulatory compliance reviews. I hold a BS (Mechanical Engineering) and MME (Engineering Management) degrees from City College of NY. For the period 1977 – 2003 I was Chief of Investigations for the Gas Division, Chief of Safety and Reliability for the Office of Energy & Water, and later Gas & Water for the New York Public Service Commission, supervising a staff of up to 30 employees and serving as a senior technical advisor to the Commission primarily on gas matters. I have reviewed the engineering, asset planning and operations of all major New York combination companies and gas utilities, including senior supervisory responsibility for staff investigations of significant incidents and accidents, and other unusual events. I have evaluated cast iron and steel pipe replacement programs of utility operators and have participated in Transmission Integrity Management Plan reviews and inspections with the USDOT of transmission pipeline operators.

My resume is included as Exhibit 1.

Q.3 ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A.3 I am testifying on behalf of the City and County of San Francisco (the City), which hired Hudson River Energy Group (HREG) to assist in its review of the Pacific Gas & Electric's (PG&E or the company) Pipeline Safety Enhancement Plan (the Implementation Plan or the Plan), filed on August 26, 2011, in response to California Public Utilities Commission (Commission) Decision (D).11-06-017

Q.4 WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A.4 This testimony addresses three general issues:

(1) ***Scope of the Implementation Plan*** - PG&E's gas transmission pipeline Implementation Plan[1] significantly exceeds the scope of work ordered by Commission Decision 11-06-017. Even though it exceeds what was ordered by the Commission, it provides no analysis demonstrating that it will provide any greater or equivalent safety benefits, while at the same time, the increased scope of work delays important safety activities in highly populated areas.

(2) ***Incremental Activities*** - PG&E's proposal clouds the issue of what is truly "incremental." Using the proposed safety activities on Lines 101, 109 and 132 as a representative sample of the transmission lines in PG&E's service territory, I found that many of the actions in its Implementation Plan are duplicative of actions that PG&E should have performed years ago if PG&E had been faithfully complying with federal and state pipeline safety regulations. These safety requirements have existed for many years and the fact that PG&E considers these actions to be incremental demonstrates that PG&E has misunderstood and continues to ignore relevant safety regulations. I will also cite specific examples of costs PG&E seeks to recover from ratepayers that are either already included within the existing rates under the Gas Accord V agreement, or are due to PG&E's negligence in recordkeeping and pressure testing following construction, pressure testing that should have been accomplished at the time of construction or during the first two assessments under its existing IMP plan.

(3) ***Risk Reduction Cost Analysis*** - PG&E did not include a risk reduction versus cost benefit component in its proposed Implementation Plan. PG&E's failure to provide this makes it difficult to adequately review its decision making process regarding replacement over testing of pipelines.

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[1] PG&E filing with CPUC dated 8-26-2011 PACIFIC GAS AND ELECTRIC COMPANY'S NATURAL GAS TRANSMISSION PIPELINE REPLACEMENT OR TESTING IMPLEMENTATION PLAN

Q.5 PLEASE IDENTIFY THE PRIMARY REPORTS WHICH INFORMED YOUR ASSESSMENT.

A.5 In addition to Chapter 3 Pipeline Modernization of PG&E's Implementation Plan, reports reviewed included the National Transportation Safety Board Report (NTSB) Accident Report dated September 9, 2010, the Independent Review Panel report dated June 24, 2011, the Consumer Protection and Safety Division (CPSD) Technical Report dated December 23, 2011, the CPUC Decision Regarding the Gas Accord V Settlement dated April 18, 2011, PG&E's Annual Transmission reports to USDOT for 2008 and 2009, and PG&E's response to the City and County of San Francisco's Data Request 001-Q06.

Scope of the Implementation Plan

Q.6 WHAT DID COMMISSION DECISION 11-06-017 REQUIRE PG&E TO ADDRESS IN ITS IMPLEMENTATION PLAN FILING?

A. 6 D.11-06-017 requires PG&E to file a Natural Gas Transmission Pipeline Replacement or Testing Implementation Plan (Pipeline Safety Enhancement Plan, Implementation Plan or Pipeline Modernization Program) to:

- Pressure test or replace all in-service natural gas transmission pipelines that do not have verifiable records of a pressure test in accordance with 49 CFR §192.619, excluding subsection 49 CFR §192.619(c).[2]
- Start with pipeline segments in Class 3 and 4 locations and Class1 and 2 High Consequence Areas (HCAs)
- Set forth criteria by which pipeline segments are identified for replacement instead of strength testing.
- Provide a priority-ranked schedule for strength testing and pipeline replacement of pipe not previously strength tested,

[2] Decision 11-06-017 requires minimum test pressure of 1.25 times Maximum Allowable Operating Pressure (MAOP) in Class 1 and 2 areas and 1.5 times MAOP in Class 3 and 4 areas.

- Consider improved safety effects relative to the amount expended in establishing projects' priorities, after allowing for testing or replacing segments with the highest risk, and
- Consider retrofitting pipeline to allow for In-Line Inspection (ILI) tools (i.e., to make the pipeline "piggable").

Q.7 DID THE COMMISSION IDENTIFY CERTAIN PRIORITIES FOR ACCOMPLISHING THESE ACTIONS?

A.7 Yes. The Commission stated that the Implementation Plan should start with pipeline segments located in Class 3 and 4 locations and Class 1 and 2 high consequence areas (HCA). For these segments, the Commission ordered PG&E to:

1. Develop a timeline in the plan that was as soon as practicable.
2. Include a priority to pressure test pipelines operating at over 30% SMYS, and for those pipelines that have not previously been tested to subpart J requirements.
3. Segments with the highest risk must be tested or replaced first and
4. Improved safety effects for dollars expended must be considered in prioritizing projects.

Q.8 WHY DO YOU BELIEVE THE COMMISSION CHOSE THESE PRIORITIES?

A.8 The U.S.D.O.T. defines class locations[3] as follows.

Class Location Designation	**# of Buildings or Dwelling Units**
1	10 or fewer
2	> 10 and less than 46

[3] USDOT defines class locations as one continuous mile and a width of 220 yards on either side of the pipeline's centerline containing dwelling units.

3	46 or more
4	4 story or higher buildings are prevalent

From the table above, I believe that the Commission intended that remedial work be accomplished as soon as practicable for those pipelines nearest and most affecting the highest population or affecting HCAs. In addition to class 3 and 4 locations, an HCA also includes locations where a potential impact circle contains 20 or more buildings intended for human occupancy, and other areas where people congregate as defined under §192.903

Q.9 HOW IS RISK DEFINED WHEN ADDRESSING GAS PIPELINE SAFETY?

A.9 Risk can be defined as the probability of an adverse event occurring multiplied by the consequence of that event.

Q.10 DOES PG&E'S IMPLEMENTATION PLAN ADHERE TO COMMISSION'S DECISION ORDERING PRIORITY BASED ON CLASS LOCATION?

A.10 No. The Commission's Decision required PG&E to prioritize segments lacking pressure test records in Class 3 and 4 locations and Class 1 and 2 HCAs. Using these parameters, there are 1805 miles of transmission pipelines in PG&E's service territory that should be evaluated for pressure test records and prioritized for strength testing or replacement. PG&E's Implementation Plan does not comply with this prioritization requirement. Instead, PG&E's[4] Implementation Plan proposes to include and assess all 5,786 miles of its natural gas transmission pipelines whether or not they were previously pressure tested. To test, replace, or upgrade and perform an in-line inspection of all of its pipelines, the Implementation Plan proposes a two phase approach which fails to give priority to testing and replacing pipelines consonant with the Commission's decision. In the first phase, in addition to pipelines located

[4] Page 1 of its 8-26-2011 Implementation Plan filing in response to Rulemaking 11-02-019.

in the higher populated class 3 and 4 locations as required by the Commission Decision, PG&E's plan includes additional pipeline segments in the lower populated Class 2 locations which are not required by D.11-06-017to be priority tested and replaced. At the same time, the Plan delays to the second phase work on pipeline segments in Class 3 and 4 locations and Class 1 HCAs operating between 20 percent SMYS and 30 percent SMYS with manufacturing and construction defects, corrosion and latent mechanical damage threats that the Commission Decision requires be made a priority. Summarized below is a breakout of the miles of pipe PGE proposed to be replaced, strength tested and ILI retrofitted by Class Location and HCA within Phase 1 (2011-2014) of PG&E's Pipeline Safety Enhancement Plan. Note PG&E proposes work for non-HCAs in Class 1 and 2 locations in Phase 1.[5]

Summary of Phase 1 work per HCA and Class Location

Pipeline Replacement					
	Total Length	Class 4	Class 3	Class 1 & 2 HCA	Class 1 & 2 non HCA
feet	980,753	0	728,020	23,869	228,864
miles	185.7	0.0	137.9	4.5	43.3

Pipeline Pressure Test					
	Total Length	Class 4	Class 3	Class 1 & 2 HCA	Class 1 & 2 non HCA
feet	4,134,487	0	2,499,775	185,967	1,448,745
miles	783.0	0.0	473.4	35.2	274.4

ILI Projects (Retrofit / Inspections)					
	Total Length	Class 4	Class 3	Class 1 & 2 HCA	Class 1 & 2 non HCA
feet	1,241,067	5,449	240,457	33,455	961,706
miles	235.1	1.0	45.5	6.3	182.1

Q.11 DID PG&E PROVIDE AN EXPLANATION FOR WHY IT MODIFIED THE SCOPE OF WORK?

A.11 Having expanded the planned work beyond that required by the Commission Decision to include the entirety of its 5,786 miles of transmission pipelines, PG&E claims that this imposes "far too large of a work scope" to complete in four years.

[5] Table is from CCSF Data Request 001-Q006, attached as Exhibit 5.

Q.12 WHAT EFFECT DOES THIS HAVE ON THE GOAL OF REDUCING THE RISK OF ITS PIPELINES AS SOON AS PRACTICABLE?

A.12 By including class 2 locations as a criterion for its highest priorities for accomplishing remedial actions, PG&E's plan will delay testing pipelines with the highest risk in class 3 and 4 locations and will have their remedial actions delayed until pipelines with lower risk class 2 locations are worked on. For this reason we recommend that PG&E's Implementation Plan be revised to remove the class 2 location criterion for consideration at this time, and reorder its priorities first concentrating on class locations 3 and 4 as well as HCAs in class 1 and 2 locations, as ordered by the Commission.

Q.13 HOW MANY MILES OF PIPELINE WOULD PG&E PRESSURE TEST, REPLACE OR IN-LINE INSPECT IF PG&E FOCUSED ITS PRIORITY ACCORDING TO D.11-06-017?

A.13 Using the segments already included in Phase I, if PG&E focused its priority on assessing "pipeline segments located in Class 3 and Class 4 locations and Class 1 and Class 2 high consequence areas," it would pressure test, replace or upgrade for ILI assessment 703.8 miles of pipeline.[6] In addition, 176 miles of pipeline in Class 3 and 4 locations and Class 1 HCAs operating between 20 percent SMYS and 30 percent SMYS with manufacturing and construction defects, corrosion and latent mechanical damage threats that should be included in Phase I are currently delayed to Phase II.

Q.14 HOW MANY ADDITIONAL MILES OF PIPELINE DOES PG&E PROPOSE TO INCLUDE IN PHASE I THAT ARE NOT LOCATED IN CLASS 3 AND 4 LOCATIONS OR CLASS 1 AND 2 HCAS?

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[6] Answer 6 - OIR_DR_CCSF_001_Q06

A.14 PG&E proposes to pressure test, replace and in-line inspect 499.8 miles of pipeline that are not in Class 3 and 4 locations or Class 1 and 2 HCAs.

Q.15 WHAT IS YOUR CONCLUSION WITH RESPECT TO THE SIZE AND SCOPE OF PG&E'S PROPOSED IMPLEMENTATION PLAN?

A.15 PG&E's Implementation Plan does not comply with the priorities set forth in the Commission Decision, and does not focus on those gas transmission pipelines having the highest risk and has not demonstrated the safety benefits of its proposal. In addition, this is a problem of PG&E's own making.

First, PG&E's Implementation Plan does not adhere to the prioritization ordered by D. 11-06-017. PG&E proposes to analyze whether to test or replace pipeline segments lacking prior test records for all 5,786 miles of its transmission pipelines, but then chooses its own priorities instead of performing pressure tests and replacements for pipelines in Class 3 and 4 locations and Class 1 and 2 HCAs. In addition, based on PG&E's proposed modified implementation scope, PG&E asserts that the work project became too large, which required it to develop a two phase approach. However, Phase I of PG&E's proposal actually covers more miles of pipeline segments than would have been included if PG&E had developed a plan responsive to D.11-06-017.

With respect to each of the 3 categories of remediation, I conclude:

Replacements: PG&E proposes to replace 43 miles in the least populous class locations and non-HCAs in the first years of the program. That is 23% (43 of 185.7 miles) of the total miles of proposed pipe replacement in the lowest populated areas.

Pressure Tests: PG&E proposes to pressure test 274.4 miles in the lowest populated areas. This equals 31.6% (274.4 of 783 miles) of the proposed miles to be pressure tested.

> ***Retrofits for ILI:*** PG&E proposes to retrofit 182.1 miles of its pipelines for ILI in the least populous areas. This is over 77% of the proposed ILI projects (182.1 of 235.1 miles).

By widening the scope of this pipeline project to less populated locations, PG&E is proposing a Phase 1 Implementation Plan that does not focus on those pipelines presenting the highest risk reduction to populated areas. In sum, PG&E proposes to pressure test, replace and in-line inspect 499.8 miles of pipeline in the least populous locations at the expense of performing the same activities for 176 miles of pipeline in more densely populated areas.

Q.16 WHAT DO YOU RECOMMEND?

A.16 I recommend that PG&E limit the size and scope of projects proposed at this time to those the Commission identified as requiring priority, namely those pipeline projects located in class 3 and 4 locations and affecting HCAs in class 1 and 2 locations. The remaining projects, i.e., those that lack a documented pressure test and do not meet 49 CFR Part 192 subpart J requirements, or for which PG&E can clearly document the highest risk reduction to cost benefit that contain threats it cannot address with other methods-- should be identified with lower priority and addressed at a later time.

<u>Incremental Activities</u>

Q.17 IS THE WORK PROPOSED UNDER PG&E'S IMPLEMENTATION PLAN INCREMENTAL TO THE EXISTING PG&E IMP PLAN AS REQUIRED BY 49 CFR PART 192 SUBPART O?

A.17 PG&E's use of the term incremental should be defined as those actions, activities or proposed projects not currently required under existing safety regulations (49CFR Part 192), or those that PG&E should have accomplished as a prudent gas pipeline operator under industry consensus standards ASA B 31.1.8- 1955. PG&E claims the proposed Implementation Plan is incremental to work PG&E performs today to ensure the safety of its gas transmission pipeline system. However as discussed above, the numbers do not agree. There is only a fixed amount of gas transmission pipe PG&E has in class 3 and 4 locations and Class 1 and 2 HCAs. The pipe should not be counted as being under both the existing IMP plan and under the proposed Implementation Plan.

Q.18 DOES PG&E CURRENTLY HAVE AN INTEGRITY MANAGEMENT PROGRAM PLAN (IMP)?

A.18 Yes. PG&E developed an IMP plan by December 17, 2004 and began integrity assessments of its pipelines.

Q.19 ARE ANY OF THE ACTIONS PROPOSED IN PG&E'S IMPLEMENTATION PLAN REDUNDANT OF ACTIONS PG&E SHOULD BE TAKING IN ITS IMP?

A.19 Yes. The Commission decision requires many of the same actions of PG&E that the federal safety regulations required PG&E to have taken years ago, that is, the regulations required PG&E identify and assess its most risky pipeline segments operating in as of the start of its integrity management program, December 17, 2004.

Q.20 IS THE STANDARD FOR PRESSURE TEST REQUIRED BY THE COMMISSION'S DECISION THE SAME STANDARD REQUIRED FOR PRESSURES TESTS UNDER TIMP?

A.20 Yes. Both D. 11-06-017, and TIMP require that assessments for manufacturing and construction defect be performed pursuant to 49 C.F.R. Part 192 Subpart J requirements.

Q.21 HOW MANY MILES OF GAS TRANSMISSION LINES DOES PG&E INCLUDE WITHIN ITS CURRENT GAS TRANSMISSION IMP PLAN (TIMP)?

A.21 The USDOT federal regulations for Integrity Management Programs under Subpart O, primarily applies to class 3 and 4 locations. However the regulations allow operators two options for identifying HCAs. Method 1 calculates HCAs by including pipe segments within Class locations 3 and 4 and pipe segments affecting HCAs in Class 1 and 2 locations. Method 2 identifies HCAs by applying a formula that calculates a potential impact radius (PIR) to determine those of its pipe segments which may affect 20 or more buildings or other areas where people may normally congregate. If PG&E applied method 1, the Class location method, to calculate the number of pipeline segments in HCAs, its TIMP would cover 1805 miles of gas transmission pipelines. However PG&E has elected to apply method 2[7] to identify transmission pipe requiring integrity assessments. This method yields a much lower number of pipeline miles requiring assessments within the TIMP. Using method 2, PG&E states its TIMP includes[8] 1,059 miles of gas transmission pipe within HCAs.

Q.22 HAS PG&E CLEARLY IDENTIFIED THOSE PROJECTS WITHIN ITS PROPOSED IMPLEMENTATION PLAN THAT IT IS ALREADY REQUIRED TO ADDRESS UNDER ITS EXISTING TIMP PLAN AND INCLUDED UNDER THE GAS ACCORD V SETTLEMENT AGREEMENT FOR RATES EFFECTIVE 2011-2014?

A.22 No. PG&E states that the existing pipeline safety and risk management program will continue in place as currently funded through the GT&S rate case, Decision 11-04-031. However, PG&E's Implementation Plan does not clearly separate out or identify those projects already funded that it plans to assess under the current IMP plan. PG&E includes pipeline segments in its proposed modernization plan that overlaps with those in the TIMP.

Q.23 WHAT DO THE FEDERAL SAFETY REGULATIONS REQUIRE PG&E TO DO?

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[7] An area within a potential impact radius (PIR) containing 20 or more buildings. PIR is determined by the formula (from any segment of pipeline): PIR=.69 D $\sqrt{P}$ in feet, P=MAOP in psig, and d is the diameter in inches, [§192.903.]

[8] Page 3-32 Chapter 3 of PG&E's modernization program

A.23 In carrying out the requirements of the federal law, PG&E must address the following pipeline safety code requirements:

- § 192.613(b) re-conditioning or phasing out pipeline segments in unsatisfactory condition
- §192.917 (b) data gathering and integration,
- §192.917 (e)(3)&(4) actions to address particular threats, manufacturing and construction defects, and ERW pipe,
- §192.921 (a)&(c) applying assessment methods best suited to address the threats,
- §192.935 (a)&(c) automatic and remotely controlled shut-off valves, and
- §192.937 continual evaluation and assessment of integrity.

These provisions require PGE to replace pipeline segments in unsatisfactory condition or more prone to failure, and under PGE's existing integrity management program's plan (IMP plan), identify pipelines that have similar attributes to those that were involved in the San Bruno pipeline failure and appropriately assess those threats as well as install automatic or remotely operated shut-off valves. Since these actions are already required under the currently approved and rate funded gas operations, and many of those same actions are identified as projects to be included in the Implementation Plan, it appears that PGE is double counting its pipeline miles and projects under both its Integrity Management Program plan and its proposed Implementation Plan.

Q.24 WHY WOULD PG&E CONSIDER THE TESTING AND REPLACEMENT OF PIPE ORDERED BY THE COMMISSION TO BE INCREMENTAL TO ITS NORMAL PIPELINE OPERATIONS?

A.24 In its investigation of PG&E's programs following San Bruno, the NTSB found that PG&E's gas transmission integrity management program (TIMP) was deficient and ineffective. The Commission 's Independent Review Panel also found problems with PG&E's data management practices which impacted the company's ability to properly identify threats, and a recent report by the Commission's Consumer Protection and Safety Division (CPSD) similarly alleges that

PG&E violated various Commission and federal safety regulations, and that the San Bruno incident was caused by PG&E's failure to follow accepted industry practices when installing the pipe. If PG&E was not following the safety regulations prior to the Commission's Decision, then these testing and replacement activities could be seen as incremental. In essence, PG&E's current TIMP is deficient and PG&E has not been taking the necessary actions required by federal safety regulations. PG&E's plan to test or replace pipeline segments without prior pressure test records in the most densely populated areas is, therefore, not incremental, but merely belated compliance with federal and state safety standards.

Q.25 HOW SHOULD THE COMMISSION DETERMINE WHICH PROJECTS ARE TRULY INCREMENTAL TO PG&E OBLIGATIONS UNDER FEDERAL LAW?

A.25 As stated earlier, incremental should apply only to those actions, activities or proposed projects not currently required under existing safety regulations (49 C.F.R. Part 192), or those that PG&E should have accomplished as a prudent gas pipeline operator under industry consensus standards ASA B 31.1.8- 1955. Before PGE's proposed projects are approved for additional funding beyond the existing rate case agreement, I recommend that the Commission audit PG&E's TIMP to determine which actions and projects should have been performed as a prudent operator or pursuant to federal law. Only those projects that are truly incremental should be included within the new proposed Implementation Plan.

The current Implementation Plan serves to confuse this issue and does not provide this clear identification and demarcation of the integrity management program versus the proposed incremental testing/replacement plan.

Q.26 WAS PG&E SUPPOSED TO BE FOLLOWING STANDARDS CONCERNING PIPELINE DESIGN CONSTRUCTION, PRESSURE TESTING, RECORD KEEPING AND MAXIMUM ALLOWABLE OPERATING PRESSURES FOR SAFE OPERATION OF PIPELINES EVEN BEFORE TIMP WAS ADOPTED?

A.26 Yes. The first edition of industry consensus pipeline safety standards was published in 1952. This was an integrated document known as American Standard Code for Pressure Piping, Section 8, Gas Transmission and Distribution Piping Systems. A second edition of the American Standard Code for Pressure Piping, Section 8, Gas Transmission and Distribution Piping Systems was published in 1955 (ASA B31.1.8-1955). ASA B31.1.8-1955 was the pipeline industry standard during the construction of Segment 180 of Line 132 in San Bruno in 1956. ASA B31.1.8-1955 established detailed requirements for pipe materials, welding, fabrication, installation, testing, operation and maintenance. It also adopted API standards for pipe material specifications. Refer to Attachment at the end of my testimony for further details concerning industry standard ASA B31.1.8 – 1955.

Q.27 COULD MUCH OF THE WORK THAT PG&E PROPOSES UNDER THE IMPLEMENTATION PLAN HAVE BEEN AVOIDED IF PG&E HAD KEPT BETTER RECORDS?

A.27 Yes, much of the work that PG&E identifies as incremental and has included under its proposed Implementation Plan is a result of PG&E not maintaining or establishing records for its transmission lines, or not previously pressure testing the pipelines as was required under existing industry consensus standards.[9] The requirements for pressure testing and record keeping were first established by ASA B31.1.8 in 1955, further confirmed by the California Decision and General Order 112 in 1960, and again confirmed by federal regulations 49 CFR Part 192 Subpart J. Ratepayers should not be required to bear the cost of re-establishing pipeline records and pressure testing records as a result of PG&E's poor design, quality control, construction, pressure testing and oversight practices of the past, or deficiencies in carrying out its current IMP plan.

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[9] The CPUC instituted Case I. 11-02-016, on February 24, 2011 to determine whether PG&E violated any order, rule or applicable rules pertaining to safety record keeping for its gas facilities. The investigation will examine such practices related to the facilities at San Bruno and PG&E's entire transmission system. The CPUC put PG&E on notice that it will decide in a separate rulemaking the extent to which PG&E shareholders, ratepayers, or both will be responsible for testing, pipe replacement and other costs.

Attached is an analysis of projects PG&E proposes within its Implementation Plan and identified as "incremental" for pressure testing of Lines 101, 109, 132, and 132A (transmission pipelines that are located on the Peninsula).[10] In this document, I identify pipeline segments on which pressure testing should have been performed previously.[11] Using PG&E's estimates for costs and identifying whether pressure testing should have previously been performed and documented in accordance with industry consensus standards or Commission Order or federal safety code requirements, we identify the reasons and justification for recommending that PG&E only recover 14% of the $30.813 million PG&E estimates is necessary to test these lines, or $4,420,568.

Q.28 WHAT IS THE BASIS FOR YOUR DETERMINATION?

A.28 The attached analysis consisted of reviewing PG&E work papers supporting Chapter 3, Pipeline Modernization and PG&E's Program Project Summary Exhibit A Tables 2 & 3, in determining whether PG&E should have:

- Pressure tested the proposed segments as part of its IMP
- Whether industry standards, California law, or federal law required PG&E to test a segment when it was installed and maintain the record of the pressure test for the useful life of the pipeline.
- If the IMP plan, industry standards, Commission Order or safety code required pressure testing in the past, then the current "incremental" costs contained in the PG&E proposed plan for re-testing should be disallowed from recovery.

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[10] See analysis developed using PG&E's Baseline Assessment Plan (Exhibit 6) and PG&E's 2010 Baseline Assessment Plan (Exhibits 8A and 8B).

[11] Attached as Exhibit 7.

Q.29 WHAT HAVE YOU CONCLUDED WITH RESPECT TO THE DETERMINATION OF WHICH ACTIVITIES PROPOSED BY PG&E ARE INCREMENTAL, AND THEREFORE ELIGIBLE FOR COST RECOVERY?

A.29 We have concluded that PG&E has incorrectly:

- Included much of its transmission line IMP activities within this modernization program.
- Included the costs of retesting pipelines to re-establish pressure testing documentation of those pipelines installed during the period 1955 thru 1970.
- Included the costs of replacing pipelines where PG&E did not comply with industry consensus standards at the time of original construction during the period 1955 and later.

Q.30 WHAT DO YOU RECOMMEND?

A.30 We recommend PG&E be required to:

- Limit its modernization program proposed to be funded by ratepayers to those new criteria in the Commission decision 11-06-017,
- Exclude its gas transmission line IMP activities from the scope of this modernization program,
- Exclude the costs of retesting pipelines to re-establish pressure testing documentation of those pipelines installed during the period 1955 thru 1970,
- Exclude the costs of replacing pipelines where PG&E did not comply with industry consensus standards at the time of original construction during the period 1955 and later.

Further we recommend PG&E be required to identify each project that includes an increase in capacity due to increased diameter in its replacement projects, to identify whether this is part of an approved Commission long term gas supply transmission pipeline delivery system. If the proposed increased capacity is not part of an approved plan, the increased costs related to the need for such projects should be the subject of a separate evaluation as to the prudency of those costs.

Risk Reduction Cost Analysis

Q.31 WHAT HAVE YOU CONCLUDED WITH RESPECT TO PG&E'S COMPLIANCE WITH THE COMMISSION DIRECTIVE THAT ITS PLAN INCLUDE A RISK REDUCTION VERSUS COST ANALYSIS COMPONENT ASSOCIATED WITH EACH PROJECT'S PRIORITY?

A.31 PG&E has simply not provided that analysis in its proposed Implementation Plan.

Q.32 WHAT DO YOU RECOMMEND?

A.32 PG&E must be required to include in the evaluation of each project a process that considers the risk reduction and cost in its projects' priorities.

Q.33 DOES THAT CONCLUDE YOUR TESTIMONY?

A.33 Yes, it does.

Attachment – Excerpts from CPUC's Consumer Protection and Safety Division (CPSD)

San Bruno Incident Investigation Report released January 12, 2012

Regulations and Industry Standards Applicable in 1956[12]

At the time Segment 180 was constructed in 1956, the Commission had jurisdiction over the safety of PG&E natural gas facilities but there were no specific federal or state safety regulations applicable to transmission line construction. However, there were standards established by ASME which the industry developed and followed.

1. ASA B31.1.8-1955 Background

In March 1926, under the sole sponsorship of the American Society of Mechanical Engineers, the American Standards Association (ASA) initiated Project B31 to address the need for a national code for pressure piping during that period. After several years of work by the sectional committees and subcommittees, a first edition was published in 1935 as an American Tentative Standard Code for Pressure Piping.

A revision of the tentative standard began in 1937 to secure uniformity between sections and eliminate divergent requirements and discrepancies. This revision also moved the code abreast of current developments in welding technique and stress computations, and added references to new dimensional and material standards. This resulted in the 1942 American Standard Code for Pressure Piping.

Because of the wide fields involved, various engineering societies, trade associations, government bureaus, institutes and the like were actively involved and had

[12] . page 18 of the CPUC staff report on San Bruno Explosion – Jan 12, 2012

one or more representatives on the sectional committees to represent general interests. As a result, code activities had been subdivided according to scope. In 1948, a review of the 1942 standard resulted in a general revision and extension of requirements to meet present day practice and to clarify ambiguous or conflicting requirements. In February of 1951, the project was designated as an American Standard referred to as B31.1-1951. On November 29, 1951, a separate publication of a section of the Code for Pressure Piping dealing with gas transmission and distribution was approved which combined applicable parts of different sections of the 1951 edition. The purpose was to provide an integrated document for gas transmission and distribution piping that would not require cross-referencing to other sections of the Code. The first edition of this integrated document known as American Standard Code for Pressure Piping, Section 8, Gas Transmission and Distribution Piping Systems, was published in 1952. A new subcommittee was formed to take over responsibility for this section of code. A second edition of the American Standard Code for Pressure Piping, Section 8, Gas Transmission and Distribution Piping Systems was published in 1955 (ASA B31.1.8-1955). ASA B31.1.8-1955 was the pipeline industry standard during the construction of Segment 180 of Line 132 in San Bruno in 1956.

2. ASA B31.1.8-1955 Applicable Requirements

ASA B31.1.8-1955 established detailed requirements for pipe materials, welding, fabrication, installation, testing, operation and maintenance. It also adopted API standards for pipe material specifications. ASA B31.1.8-1955 contained requirements covering:

- Determination of wall thickness

- Determination of yield strength based on American Petroleum Institute (API) standards
- Hydrostatic testing for new and used pipe and recordkeeping associated with the testing
- Cleaning pipe from inside and outside and visually inspecting it to discover defects
- Welder qualifications and testing of welds

DIRECT TESTIMONY OF
MICHAEL J. SCOTT
ON BEHALF OF THE
CITY AND COUNTY OF SAN FRANCISCO

RESPONSE TO CHAPTERS 4, 5 AND 6 OF PG&E'S IMPLEMENTATION PLAN: VALVE AUTOMATION PROGRAM, PIPELINE RECORDS INTEGRATION PROGRAM, AND INTERIM SAFETY ENHANCEMENT MEASURES

Q.1. PLEASE STATE YOUR NAMES AND BUSINESS ADDRESSES.

A. 1. My name is Michael J. Scott. I am a consultant affiliated with Hudson River Energy Group. My business address is 1220 Best Road, East Greenbush, New York 12061.

Q.2. PLEASE SUMMARIZE YOUR EDUCATION AND BUSINESS EXPERIENCE?

A.2. I have thirty-eight (38) years of experience in various aspects of utility regulation and long term energy planning, both primarily focused on natural gas. I hold a BS in Mechanical Engineering from Manhattan College, and a New York State Professional Engineer License. I retired from the staff of the New York State Public Service Commission (NYPSC) in August, 2011. Prior to leaving state service, I served as Deputy Director for Gas, Water, Safety and Security, in the NYPSC's Office of Electric, Gas and Water. In that position I was a senior policy and technical advisor to the NYPSC on all natural gas, water, safety, and security issues. I also had technical, administrative and supervisory responsibility for the activities of approximately 70 engineers and analysts organized in five units: Natural Gas Rates Section, Natural Gas Policy and Supply Section, Water Rates Section, Safety Section (natural gas and liquid petroleum pipelines and electric stray voltage mitigation), and Security Section (physical and cyber security).

I have experience in all facets of the natural gas business from senior level policy issues to technical matters – such as rate-making and rate case proceedings, annual reviews of utility gas supply and capacity portfolios, annual reviews of utility commodity purchasing strategies and efforts to limit price volatility, and enforcement of gas safety requirements for utilities and interstate pipelines. I had primary responsibility for the preparation of the natural gas element of all New York State Energy Plans since 1980.

My resume is included as Exhibit 2.

Q.3. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of the City and County of San Francisco (City), which hired Hudson River Energy Group (HREG) to assist in its review of the Pacific Gas & Electric's (PG&E or the company) Pipeline Safety Enhancement Plan (the Implementation Plan or the Plan), filed on August 26, 2011, in response to California Public Utilities Commission (he Commission) Decision (D).11-06-017.

Q.4 WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A.4 I have been asked to review the reasonableness of Chapters 4, 5 and 6 of the Company's Implementation Plan which contain its proposed Valve Automation Program, Pipeline Records Integration Programs, and Interim Safety Enhancement Measures. I will address each of those Chapters in turn below.

Q.5 WHAT DID YOU REVIEW WHEN PREPARING FOR YOUR TESTIMONY?

A.5 I reviewed D.11-06-017, the relevant portions of the company's Implementation Plan, the National Transportation Safety Board (NTSB) report on the San Bruno incident, the Independent Panel's report, the Jacobs Consultancy report, and applicable federal law and regulations. I also briefly examined other relevant documents on the CPUC website.

Q.6 CAN YOU PROVIDE A BROAD OVERVIEW OF YOUR CONCLUSIONS?

A.6 Yes, I find that while PG&E is proposing a very aggressive Valve Automation Program, the company has not provided the Commission with an analysis in support of this program that complies with the CPUC order. Without such analysis, it is difficult to reach an informed opinion on the reasonableness of the PG&E's proposal. I also find that PG&E's Maximum Allowable Operating Pressure (MAOP) Validation program goes far beyond what the CPUC required and this expansion likewise is not properly supported. The proposed Gas Transmission Asset Management (GTAM) was not included in the scope of the CPUC order and should therefore be considered in a separate proceeding. Finally, I find that in some situations the company's proposed pressure reductions, which the company has used as an

Interim Safety Enhancement Measure, are unnecessarily limited to modest pressure reductions and that greater pressure reductions could be achieved if safety concerns warranted. These findings are explained more fully below.

Chapter 4 - Valve Automation Program

Q.7 WHAT ARE THE ISSUES THAT PG&E IS ADDRESSING IN CHAPTER 4?

A.7 PG&E is proposing a Valve Automation Program and an associated upgrade of its Supervisory Control and Data Acquisition (SCADA) system as a part of its Implementation Plan. The objective of this program is to enable PG&E to quickly isolate any problems with its transmission lines in highly populated areas. This Valve Automation Program is intended to work in tandem with the company's Pipeline Modernization program.

Q.8 HOW DID THESE PROBLEMS/ISSUES ARISE?

A.8 The NTSB criticized PG&E for taking an "excessive" amount of time – 95 minutes – to stop the flow of gas following the San Bruno pipeline rupture. The NTSB found that the limitations of PG&E's SCADA system contributed to PG&E's delay in recognizing that there had been a transmission line break and its ability to pinpoint quickly its location. The NTSB also found that the lack of automatic shut-off valves contributed to PG&E's inability to stop quickly the flow of gas. The NTSB states that use of automatic shutoff valves (ASVs) or remote control valves (RCVs) along the entire length of line 132 would have significantly reduced the amount of time taken to stop the flow of gas. The NTSB recommends that PG&E expedite the installation of automatic shutoff valves and remote control valves on transmission lines in high consequence areas and in Class 3 and 4 locations, and space them at intervals that consider the factors listed in Title 49 CFR 192.935(c).

In addition, the NTSB found that management issues – specifically the lack of detailed and comprehensive procedures for responding to a large-scale emergency, including lack of a defined command structure, - contributed to the excessive time PG&E took to shut the flow of gas.

Q.9 WHAT DID THE COMMISSION ORDER IN D.11-06-017?

A.9 The Commission ordered PG&E to consider the use of automatic shutoff valves where appropriate, and to consider an analysis of improved safety effects for amount expended when prioritizing projects.[13]

Q.10 DOES PG&E'S PROPOSAL ADEQUATELY RESPOND TO THE COMMISSION'S ORDER?

A.10 No. PG&E's valve proposal does not consider any of the factors listed in 49 C.F.R. 192.935(c). Instead, since there are no specific code requirements or regulatory guidance for the installation of automatic valves at certain intervals, PG&E proposes to install automatic valves at intervals that track the minimum code required spacing for isolation or sectionalizing valves. The valve spacing intervals for "isolation" or "sectionalizing" valves are 8 miles in Class 3 locations, 5 miles in Class 4 locations. PG&E states that these intervals will be adjusted as needed so that the valves are installed in the most suitable locations and so that no more than 50,000 customers would be affected by a valve closure.

Q.11 WHAT FACTORS SHOULD PG&E HAVE CONSIDERED?

A.11 The factors listed in Title 49 CFR 192.935(c) are: (i) swiftness of leak detection and pipe shut-down capabilities, (ii) the type of gas being transported, (iii) operating pressure, (iv) the rate of potential release, (v) pipeline profile, (vi) the potential ignition, and (vii) the location of nearest response personnel. PG&E's filing contains no explicit, rigorous discussion of any of these factors.

[13] D.11-06-017, Order Paragraphs 8 and 9.

Although PG&E proposes to use the spacing requirements for sectionalizing valves, PG&E's testimony contains no analysis that supports that valve spacing proposal. Its discussion is limited to this statement "49 CFR 192.179(a) .... Although this is not applicable specifically to automated valves, it is a good starting point for a maximum spacing guideline since it was developed taking into account typical operational impacts of pipeline in various class locations."

Q.12 DO YOU HAVE OTHER CONCERNS WITH PG&E'S ANALYSIS?

A.12 Yes, Ordering Paragraph 9 of Decision 11-06-017 states that "…Although not the determinative factor, improved safety effects for the amount expended must be considered in prioritizing projects". In my view, the Commission was properly seeking a response from the company that would both demonstrate that the company conducted a risk assessment that carefully weighed the safety benefits that could be achieved at various alternative program levels and costs. Such a response would serve as a basis to demonstrate that the company has put forth a balanced proposal. That type of analysis is fundamental for both the company and the Commission to determine the reasonableness of the company's proposal. Yet, PG&E did not provide the Commission with a cost-benefit or other risk assessment analysis to support its proposed valve spacing intervals. Instead, PG&E simply adopted the spacing interval for "isolation" or "sectionalizing" valves.

Q.13 DID PG&E PREVIOUSLY CONSIDER WHETHER TO USE ASV/RCVS?

A.13 No, not adequately. In a 2005 audit of PG&E's Integrity Management Program, the Commission found that PG&E had failed to properly consider the factors listed in 49 C.F.R. 192.935(c). In response, PG&E issued a memorandum on June 14, 2006 that concluded that most of the damage from a pipeline rupture occurs in the first 30 seconds, and that installation of automatic shutoff valves (ASVs) or remote shutoff valves (RCVs) would have "little or no effect on increasing human safety or protecting properties."[14] PG&E's June 14, 2006 memorandum relied solely on one-sided industry studies and did not address of any of the seven factors specified by 49 C.F.R. § 192.935(c).

As the NTSB stated: "According to Federal pipeline integrity management regulations ….an operator must take additional measures …to prevent a pipeline failure and to mitigate the consequences of a pipeline failure in HCAs. The additional measures must be based on the threats the operator has identified to each pipeline segment, and the operator must conduct a risk analysis of its pipeline to identify additional measures, including but not limited to, installing automatic shutoff valves (ASVs) or remote control valves (RCVs)"[15]

Q.14 IS PG&E'S PROPOSAL REASONABLE?

A.14 No. While I believe that RCVs and ASVs can be useful and appropriate components of pipeline transmission systems, as discussed above I have an overriding concern with PG&E's failure to provide a rigorous analysis to support its planned spacing intervals for these valves in light of their expected costs. Without any detailed consideration of the factors listed in the federal regulations, or at least a consideration of cost versus safety benefit, PG&E's proposal is unreasonable.

Q.15 HOW DOES PG&E PROPOSE TO INSTALL AUTOMATIC VALVES?

A.15 Under PG&E's proposal, automatic valves will be installed in two phases. Under Phase 1 of the proposal, which began in 2011 and will extend through 2014, some 228 valves will be replaced, automated, and upgraded in Class 4 locations and in Class 3 locations that contain larger diameter, higher-pressure pipe. Under Phase 2, starting in 2015, an additional 330 valves will be installed.

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[14] NTSB Docket No. SA-534, Exhibit No. 2-Q.

[15] NTSB Report at p. 56.

PG&E states that the key safety benefits of installing the valves will be the reduction in the time that it takes to isolate and blow-down a pipeline segment, thereby enabling first responders to mobilize quickly and take action to address the pipeline rupture.

PG&E also proposes SCADA system improvements, to include additional monitoring points, detailed viewing tools, specific pipeline segment shutdown protocols, situational awareness tools, interactive tools, and training.

PG&E estimates that the total program costs for Phase 1 is $143.8 million, of which PG&E proposes to absorb $15.3 million (the cost incurred in 2011). Of the $143.8 million total costs, $132.5 million is capital, and $11.1 million is expense (consisting of SCADA system enhancements and recurring O&M associated with the new valves). Estimated program costs for Phase 2 are not provided, but PG&E states that such costs will be included in a subsequent filing. PG&E is seeking conceptual approval for the overall program, but only approval for recovery of Phase 1 costs in this filing.

Q.16 DO YOU HAVE ANY ADDITIONAL CONCERNS REGARDING PG&E'S VALVE AUTOMATION PROGRAM?

A.16 Yes. PG&E and its consultant, EN Engineering (ENN), state that implementation of this proposal will make PG&E the leader in the use of automatic valves. A company facing the challenges that PG&E faces should not be focusing on becoming the industry leader given the learning curve that entails, rather PG&E should be deriving benefits from what others have learned (see the portion of the HREG's testimony addressing PG&E management and operational problems, and management challenges).

While becoming an industry leader is a worthy goal, it should not be PG&E's primary objective nor should it excuse the lack of appropriate analysis supporting the program. In addition, becoming an industry leader is costly, and PG&E has not justified these costs. PG&E only provided estimated costs for Phase 1, but is requesting conceptual approval for the overall program. If costs for Phase 2 are proportional to the per valve costs for Phase 1, total program costs would be roughly $360 million plus contingencies and the impact of inflation on Phase 2 costs. Because the benefits of automatic valves are difficult to quantify, and ratepayer funds are not unlimited, PG&E must carefully consider what safety enhancement could be achieved by various levels of incremental spending, and craft a plan that is well reasoned and cost justified.

If the chief benefit of installing RCVs and ASVs is to quickly isolate transmission line segments in the event of a break and minimize risk to the public and property damage, an examination of the time to isolate a transmission line segment with various valve spacing intervals vs. the costs associated with those valve spacing intervals is essential. While PG&E does provide a chart showing blow-down times for several different spacing intervals, it fails to provide any analysis of that information in support of its proposed valve spacing.

To put the discussion of valve spacing in perspective, the chart included in PG&E's plan shows the blow-down time with valve spacing of 8 miles to be about 4 minutes vs. about 10 minutes or so for a spacing of 20 miles. The average time between rupture and initiation of RCV valve closure is about 10 minutes, if no on-the-ground confirmation of the rupture by operator personnel is required. Therefore, the total time it will take to initiate valve closure and clear the flow of gas in that situation would be about 14 vs. 20 minutes for valve spacing intervals of 8 and 20 miles, respectively. However, there is no indication, discussion or analysis to support PG&E's decision to incur 2 ½ times the cost for valves spaced at 8 miles vs. 20 miles to achieve about a 6-minute reduction in total time to stop and clear the flow of gas.

An analysis that would be useful for comparing the safety benefit that can be achieved at various alternative program costs, for example would start with a "base plan" that includes replacing existing valves with automatic valves in locations needed to make the line "piggable" and where valves need to be replaced to achieve an established MAOP for a pipeline segment.

Using that starting point, PG&E could provide an analysis of the costs and benefits of installing additional automatic valves at strategic locations based on a risk analysis (as required by code) along that line segment. As noted, no such analysis was provided by PG&E.

In addition, in determining the proposed spacing for the automatic valves, PG&E included no discussion or indication that it has accounted for the reduced likelihood that its pipeline will rupture because of its Pipeline Modernization Program combined with the improved operational information that will result from its proposed SCADA system improvement.

Finally, while the NTSB identified the lack of detailed and comprehensive procedures for responding to a large-scale emergency, including lack of a defined command structure, as contributing to this excessive time to shut the flow of gas, PG&E did not elaborate in Chapter 4 on how it is addressing those management problems (or even include a reference to how or where information can be found as to how it is addressing those management problems).

Q.17 IS PG&E'S VALVE AUTOMATION PROGRAM RIPE FOR CONSIDERATION?

A.17 No. Considering the lack of analysis in support of the program, and ongoing proceedings into whether PG&E's compliance with regulations, including whether the company had an effective Integrity Management Plan and took appropriate actions under that plan, I believe that the issue of the appropriate level of cost recovery is not yet ripe for consideration. Further, without further analysis, it is not reasonable to provide conceptual approval of the entire program (Phases 1 and 2), especially since no cost information has been provided for Phase 2.

Q.18 WHAT ARE YOUR CONCLUSIONS WITH RESPECT TO PG&E'S VALVE AUTOMATION PROGRAM?

A.18 I find that:

(1) PG&E did not provide an analysis in support of its valve spacing proposal that complies with the Commission order and that is necessary to reach an informed opinion on the reasonableness of the company's proposal.

(2) PG&Es filing contains no explicit, rigorous discussion of all of the factors listed in Title 49 CFR 192.935(c) for the spacing of valves as recommended by the NTSB.

(3) In determining the proposed spacing for automatic valves, PG&E included no discussion or indication that it has accounted for the reduced likelihood that its pipeline will rupture because of its Pipeline Modernization Program combined with the improved operational information that will result from its proposed SCADA system improvement.

(4) PG&E did not elaborate on how it is addressing the NTSB finding that the company lacked detailed and comprehensive procedures for responding to a large-scale emergency, including lack of a defined command structure, as contributing to this excessive time to shut the flow of gas.

(5) With respect to the costs of PG&E's proposed Valve Automation Program, considering the lack of analysis in support of the program, and ongoing proceedings into whether PG&E's compliance with regulations, I believe that the issue of the appropriate level of cost recovery is not yet ripe for consideration. Further, I do not support conceptual approval of the entire program (Phases 1 and 2) for the same reasons, and because no cost information has been provided for Phase 2.

Q.19 WHAT DO YOU RECOMMEND?

A.19 I recommend that the Commission:

(1) Require PG&E to reconsider and revise its program to consider the above factors and support its selection of valve spacing by comparing the costs and benefits of several different approaches to valve spacing.

(2) Only consider cost recovery for a fully developed and well-supported proposal, for which credible cost information has been provided. Please see the portion of the HREG testimony that addresses cost deferral and recovery.

(3) Require PG&E to provide its detailed and comprehensive procedures for responding to a large-scale emergency and including a defined command structure, the lack of which were also identified by the NTSB as problems.

Chapter 5 - Pipeline Records Integration Program

Q.20 WHAT ARE THE PROBLEMS OR ISSUES THAT PG&E IS ADDRESSING IN CHAPTER 5?

A.20 PG&E is proposing a Pipeline Records Integration Program with two elements: (1) a maximum allowable operating pressure (MAOP) Validation Project to confirm the MAOP of pipeline segments based on pipeline features, or if complete and reliable pipeline features records do not exist, based on engineering assumptions; and, (2) a Gas Transmission Asset Management Project (GTAM) to upgrade the company's gas transmission processes and record management infrastructure, to transition away from reliance on paper records and consolidate data into integrated core data management systems.

Q.21 HOW DID THE NEED FOR THE MAOP VALIDATION PROJECT ARISE?

A.21 This MAOP Validation Project responds to a January 3, 2011 NTSB urgent recommendation that all pipeline operators validate, through records, the MAOP of all transmission lines in Class 3 and 4 locations and Class 1 and 2 High Consequence Areas (HCAs) that have not had an MAOP established through a pressure test, and that all information used to calculate a pipeline's MAOP should be "traceable, verifiable, and complete". On the same day, the Commission's Executive Director issued a letter directing PG&E to comply with the NTSB recommendations; on January 14, 2011, the CPUC ratified that letter.

Q.22 HAS PG&E APPROPRIATELY RESPONDED TO THESE REQUIREMENTS?

A.22 No. The company's proposed MAOP Validation Project goes far beyond the pipeline segments in HCAs without prior pressure tests that the Commission directed the company to address. PG&E's MAOP Records Validation Project involves collecting and verifying the pipe strength and pipe features data necessary to validate and re-calculate the MAOP for ***all*** of

PG&E's gas transmission lines ***and*** its distribution lines operating above 60 psig. According to PG&E, this covers a total of 6,741 miles of pipelines, including 975 miles of distribution pipelines operating at pressures greater than 60 psig. Of that total, 5,786 miles meet the federal code definition of transmission pipeline, and of that, 1,805 miles are located in Class 3 and 4 locations and Class 1 and 2 HCAs.

Q.23 WHAT DOES PG&E's MAOP VALIDATION PROJECT ENTAIL AND WHAT ARE THE PROJECTED COSTS?

A.23 The MAOP Validation Project will consist of three parts: (1) a comprehensive search for strength test records (limited to pipeline segments in Class 3 and 4 locations and HCAs in Class 1 and 2 locations); (2) MAOP validation for pipeline segments in HCAs without prior strength tests by gathering information on pipeline features; and (3) MAOP validation for all remaining transmission system pipeline segments using the same process used for MAOP validation of HCAs pipeline segments without prior strength tests.

With respect to costs, PG&E is generally seeking recovery of MAOP validation costs related to pipelines installed prior to 1970, except for such costs incurred in 2011. Specifically PG&E seeks recovery of $107.1 million in expenses for 2012 and 2013.

Of the $162.3 million in expenses that PG&E expects to incur through 2013, $54.9 million is for document preparation, $66.0 million is for MAOP calculations, $20.6 million is for project management, $7.5 million for excavations, $6.9 million for information system technology service (ISTS) applications support, $3.3 million for overheads, and $3.1 million for ISTS infrastructure support.

Q.24 DO YOU HAVE ANY CONCERNS REGARDING PG&E'S MAOP VALIDATION PROJECT?

A.24 Yes. My overriding concern is that the company's plan goes far beyond what was required by the CPUC in that its covers its entire transmission system and some distribution pipelines, not just those portions of its transmission system in HCAs for which pressure test records do not exist.

While PG&E did not provide in Chapter 5 an explicit justification for going beyond what the CPUC ordered, in a letter dated March 21, 2011 the company explained that a benefit of covering its entire system, would be the possibility that in some circumstances the MAOP Validation Project could result in the pressure being lowered from the current MOP to a calculated MAOP on some pipeline segments. However, the company did not provide any cost-benefit or other information that addresses the CPUCs requirement contained in clause 9 of its order (D 11-06-017) that " …improved safety effects for amount expended must be considered in prioritizing projects", to support its proposal to go beyond HCAs.

Similar to my concerns stated above with respect to the Valve Automation Program, PG&E has not provided analytical support for this proposal. I think that a useful analysis that PG&E should have provided would start with a "base plan" consisting of what the CPUC directly required the company to do, together with an assessment of the benefits and costs of adding to that base plan in increments (e.g. including pipeline segments within HCAs with prior pressure tests, then extending beyond HCAs both with and without prior pressure test records, and the distribution pipeline segments). The company provided no such analysis.

I am also concerned that within the MAOP Validation Project the amount of funds allocated to excavations – $7.5 million – appears to be relatively small, approximately 5 percent of the total budget for this Project, as compared to a total of $120.9 million for document preparation and MAOP calculations. Considering that PG&E did not have accurate information on the physical pipe and construction method employed at the San Bruno site, the company needs to ensure that sufficient resources are allocated for field verification, as a part of its MAOP

Validation Project. PG&E should verify the accuracy of the pipeline features that it either has records for or makes engineering assumption for, through excavations of an adequate random sample of its facilities in populated areas. I am concerned that this effort appears to be dominated by a paperwork exercise, and may not be providing enough resources for fieldwork.

Q.25 WHAT MANDATE DOES THE GTAM PROJECT ARISE?

A.25 There was no mandate for such a project; the GTAM Project was volunteered by PG&E.

Q.26 WHAT HAS PG&E PROPOSED?

A.26 According to PG&E, GTAM is a multi-faceted effort to enhance the amount, quality, and type of information collected, stored, and managed by the company. GTAM involves upgrading the company's Geographic Information System (GIS) to reflect improved linear referencing, developing a comprehensive system to track and trace all materials from receipt through installation and through the life of the component. It also includes enhancements to work management and data capture processes and tools relating to maintenance and inspection processes by eliminating paper-based work processes and developing tools to support integration of all pipeline asset data.

GTAM will be implemented in four phases, over 3 ½ years, from the fourth quarter 2011 through the first quarter 2015. The first phase involves Planning and System Architecture Design (through 2nd Q 2012); the next three phases involve the implementation of technology to support the records management systems and the processes, tools, and systems to implement enhanced work, asset, and Integrity Management for pipeline assets, corrosion and line equipment assets, and station assets, respectively.

GTAM costs are estimated to be $136.0 million, of which the company expects to expend $12.4 million in 2015 that will be included for recovery in a future rate filing. PG&E here seeks recovery of $115.7 million in GTAM costs for the years 2012 through 2014 ($95.2 million in capital costs and $20.5 million in expenses).

Q.27 WHAT ARE YOUR CONCERNS REGARDING THE PROPOSED GTAM?

A.27 My basic concern is that the proposed GTAM is beyond the scope of the CPUC order and as such should not be considered in this proceeding. Moreover, PG&E has not presented an analysis that is sufficient to justify these extra expenses and, indeed, questions remain about whether PG&E should have been collecting and maintaining the data all along.

An additional concern is that the GTAM element of PG&E's proposal refers to implementing "Integrity Management Program" elements, but these elements are not provided or discussed, even though the NTSB found that the company's Integrity Management Program was deficient and ineffective. While the company may view its Integrity Management Program as outside the scope of the Implementation Plan, if PG&E expects the Commission to approve a plan and related expenses to implement something, it should provide a detailed explanation of what it is planning to implement.

Q.28 WHAT ARE YOUR CONCERNS REGARDING WHETHER THE COSTS OF THE RECORDS INTEGRATION PROGRAM ARE INCREMENTAL?

A.28 PG&E argues that the NTSB established a new standard that records must be "traceable, verifiable, and complete" and therefore the costs of this program are incremental. I disagree with this statement for the simple reason that the NTSB recommendation does not imply that earlier recordkeeping practices that were inadequate are acceptable. To the contrary, the NTSB explicitly described the types of records that are necessary in response to PG&E's failure to produce the type of records necessary for safe pipeline operations.

At the time that the San Bruno pipeline was constructed, the American Standards Association (ASA) standard B31.1.8 – 1955 was the pipeline industry standard for detailed requirements for pipe materials, welding, fabrication, installation, operation and maintenance. ASA B31.1.8-1955 also adopted American Petroleum Institute (API) standards for pipe material specifications. ASA B31.1.8-1955 contained requirements covering hydrostatic testing for new and used pipe and recordkeeping associated with the testing. While this was a voluntary industry standard, not mandated under regulation at that time, it established what the standard industry practice should be.

Moreover, since 2004 the company has been required to improve data collection, integration, and analysis as a part of its Integrity Management Program. Under 49 CFR 192.947 (c) an operator is required to document everything that supports any decision, analysis and process developed and used to implement and evaluate each element of the Base Line Assessment and its Integrity Management Program. Ratepayers have been paying for this required documentation and should not have to pay twice.

Further, it appears that some data in the company's existing databases that ratepayers have already funded may prove to be unreliable, and correcting those deficiencies through this proposed program would result in duplicative expenses. In addition, the company needs to provide a mechanism to ensure that any decisions made based on existing data that later proves to be faulty, are revisited.

Q.29 ARE THERE OTHER PROCEEDINGS THAT MAY AFFECT THE REASONABLENESS OF PG&E'S PROPOSED COST RECOVERY FOR ITS RECORDS INTEGRATION?

A.29 The Commission has an ongoing investigation into the company's record keeping that may determine the extent to which such costs are truly incremental. To the extent that the Commission finds that PG&E did not properly perform its record keeping responsibilities in the past, concessions in the cost of this program would be warranted. Therefore, the issue of cost recovery for PG&E's proposed Records Integration Program is not yet ripe for Commission action, as discussed further in the cost recovery testimony of Mr. Radigan.

Q.30 WHAT ARE YOUR CONCLUSIONS WITH RESPECT TO THE PROPOSED PIPELINE RECORDS INTEGRATION PROGRAM?

A.30 I conclude that:

(1) PG&E's plan goes beyond what was required by the CPUC because its covers PG&E's entire transmission system and some distribution pipelines, not just transmission line segments. Yet, the Company has not provided the Commission with any cost-benefit or other information in support of including pipeline segments beyond the scope of what the CPUC required.

(2) The proposed GTAM is beyond the scope of what the CPUC required and should be considered in a separate proceeding, such as the company's next rate case.

(3) The proposed records integration is not incremental to PG&E's ongoing obligation under state and federal law or industry standards.

(4) The issue of cost recovery for PG&E's proposed MAOP Validation Project is not yet ripe for Commission action.

(5) A mechanism is needed to ensure that any decisions made based on existing data that later proves to be faulty are revisited.

(6) (PG&E needs to ensure that sufficient attention and program resources are dedicated to excavations and direct physical examination of the pipes.

(7) PG&E is proposing to implement parts of its Integrity Management Program through the GTAM, but has not provided sufficient information to explain and provide context for that proposal.

Q.31 WHAT DO YOU RECOMMEND?

A.31 I recommend that the Commission require that PG&E to:

(1) Provide a justification and cost-benefit analysis for aspects of the MAOP project that go beyond HCAs that do not have pressure test records.

(2) Make cost concessions to the extent that existing PG&Es data is found to be unreliable, resulting in the need to duplicate work already funded by ratepayers.

(3) Provide a mechanism to ensure that any decisions made based on existing data that later proves to be faulty, are revisited.

(4) Propose its GTAM in a separate proceeding, such as the company's next rate case.

(5) Ensure that sufficient attention and program resources are dedicated to excavations and direct physical examination of the pipes.

Chapter 6 - Interim Safety Enhancement Measures

Q.32 WHAT ARE THE PROBLEMS OR ISSUES THAT PG&E IS ADDRESSING IN CHAPTER 6?

A.32 PG&E proposes an Interim Safety Enhancement Program as a part of its Implementation Plan as required by the Commission. PG&E also proposes to implement enhancements to its Emergency Planning and Response Program.

Q.33 WHAT DID THE COMMISSION REQUIRE?

A.33 The Commission required that the Implementation Plan be completed as soon as practicable, and contain interim safety enhancement measures. The Commission specified that increased patrols and leak surveys, pressure reductions, and prioritization of pressure testing for critical pipelines that must run at or near a pressure which result in hoop stress levels at or above 30 percent of the specified minimum yield strength (SMYS) of the pipe, be considered, along with other such measures that will enhance public safety during the implementation period. The NTSB also found that PG&E lacked detailed procedures for responding to a large-scale emergency, including a defined chain of command, and concluded that PG&E's flawed emergency response procedures contributed to the severity of the accident.

Q.34 HOW DOES PG&E PROPOSE TO ADDRESS THESE PROBLEMS/ISSUES?

A.34 PG&E proposes to enhance safety through three interim measures: (1) a MAOP Records Validation Project; (2) Interim Pressure Reductions until PG&E can replace or pressure test those pipeline segments; and, (3) Increased Leak Surveys and Patrols.

Q.35 WHAT DOES PG&E PROPOSE FOR ITS MAOP RECORDS VALIDATION PROJECT?

A.35 The MAOP validation process will identify situations where the calculated MAOP for a pipeline segment or one of its components is lower than the current maximum operating pressure (MOP) and where on an interim basis, pressure reduction is warranted. The validation process is to be conducted first on pipeline segments with the highest risk.

Q.36 WHAT DOES PG&E PROPOSE WITH RESPECT TO PRESSURE REDUCTIONS?

A.36 PG&E states that interim pressure reductions may be called for on a pipeline segment under two circumstances, as follows:

(1) the MAOP Validation process identifies a pipeline segment where the calculated MAOP is lower than the current MOP, in which case pressure should be reduced to the calculated MAOP on an interim basis; or

(2) the Pipeline Program Decision Tree (Chapter 3) identifies an interim pressure reduction as a recommended mitigation measure. If a pressure reduction is indicated for a pipeline segment under the Pipeline Program Decision Tree, PG&E will operate the pipeline segment at a pressure that is 20 psig below the segment MAOP, provided that PG&E can still meet its Cold Winter Day (CWD) and Abnormal Peak Day (APD) design criteria[16] and pressure will still be sufficient to prevent customer outages. If not, PG&E will reduce the pressure by something less than 20 psig, while meeting the mentioned criteria.

Q.37 DO YOU HAVE ANY CONCERNS REGARDING PG&E'S PROPOSED PRESSURE REDUCTIONS?

A.37 Yes. The proposed pressure reductions of up to 20 psig when a pressure reduction is called for under the Pipeline Program Decision Tree appears modest compared to the initial pressure reductions of 20 percent that the Commission required for the San Bruno line. PG&E provided

[16] CWD design conditions consist of meeting all core and non-core customer requirements during a cold day that is expected to occur once every 2 years; APD design conditions consist of meeting only core customer requirements during a peak day expected to occur once every 90 years.

no discussion of why it decided to limit pressure reductions as proposed, and does not address the possibility of greater pressure reductions in situations where safety concerns may warrant a greater pressure reduction. For example, it appears that there is an opportunity for PG&E to modify its CWD design criteria temporarily to permit greater pressure reductions until the company has completed validation or testing for a pipeline segment. This could result in the interruption of some non-core load during colder weather. I am not suggesting that non-core load be interrupted unnecessarily, only that safety should have the priority. The CPUC requirement for a 20 percent pressure reduction for the San Bruno pipe was not constrained by whether non-core load could be met, nor should it have been.

Q.38 WHAT DOES PG&E PROPOSE WITH RESPECT TO LEAK SURVEYS AND PATROLS?

A.38 With respect to leak surveys and patrols, PG&E's practice has been to conduct leak surveys at intervals of two times, four times and once per year for Class 3, Class 4 and Class 1 and 2 areas, respectively. PG&E proposal is to increase that to six times per year for Class 3, Class 4, and, Class 1 and 2 in high consequence areas (HCAs). Similarly, PG&E's practice has been to conduct patrols four times per year in Class 3, Class 4 and, Class 1 and 2 areas. PG&E's proposal is to increase that to six times per year in Class 3, 4 and Class 1 and 2 HCAs. PG&E will also continue its monthly aerial patrols.

Q.39 WHAT ARE THE PROJECTED COSTS FOR THESE MEASURES?

A.39 PG&E estimates the costs of these measures at $1.071 million per year for the years 2012 through 2014. Of this amount, $700,000 per year is allocated for the MAOP validation project, to cover the cost of four full-time Senior Gas Engineers (including benefits and payroll taxes). PG&E claims that these costs are incremental because these positions reflect either new hires or existing positions that will be back-filled. The cost of the increased leak surveys is estimated at $351,000 per year and increased patrols at $20,000 per year.

Q.40 DO YOU HAVE ANY CONCERNS REGARDING THESE PROJECTED COSTS?

A.40 Yes. While the overall costs for these measures are not large compared to other elements of PG&E's Implementation Plan, most of the costs are attributable to the MAOP validation project. PG&E claims that it needs four full-time Senior Gas Engineers at a fully loaded cost of $175,000 per year each to perform these calculations, and that these costs are incremental because these positions reflect either new hires or existing positions that will be back-filled. However, PG&E has not explained why these costs are not covered by the $66 million in pipeline features list and MAOP calculation costs identified in Chapter 5. The Chapter 5 work-papers do not provide enough detail to determine what is covered, but MAOP validation expenses are included there. Further, in the event that PG&E can show that these expenses are not covered by the costs contained in Chapter 5, and the Commission approves these four positions, a mechanism should be established to ensure that if actual incremental hiring does not materialize the funds are credited back to ratepayers.

Q.41 WHAT DOES PG&E'S PLAN SAY WITH RESPECT TO EMERGENCY PREVENTION, PREPAREDNESS, AND RESPONSE?

A.41 According to PG&E, while the company's Emergency Prevention, Preparedness and Response Program is outside the scope of the Implementation Plan it is related to the goal of enhancing safety. PG&E states that its enhanced Emergency Prevention, Preparedness, and Response Program consist of education programs for first responders, contractors, infrastructure departments, community members, schoolchildren and other stakeholders. PG&E states that education activities include damage prevention, recognizing safety hazards, and securing a site once an incident has occurred. PG&E states that preparedness activities include developing plans, training to the plan, and exercising the plan.

I am also concerned that PG&E provided only a vague, broad outline of its Emergency Prevention, Preparedness and Response Procedures update with no detailed information. This is insufficient considering that the NTSB identified those procedures as flawed and contributing to the severity of the accident.

Q.42 WHAT ARE YOUR CONCLUSIONS WITH RESPECT TO PG&E'S PROPOSED INTERIM SAFETY ENHANCEMENT MEASURES?

A.42 I conclude that:

(1) The proposed pressure reductions of up to 20 psig, when the Pipeline Program Decision Tree indicates that a pressure reduction is warranted, appear modest compared to the initial pressure reductions of 20 percent that the Commission required for the San Bruno line. PG&E provided no discussion of the possibility of greater pressure reductions in situations where safety concerns may be warranted.

(2) PG&E has not explained why the costs of the four full-time Senior Gas Engineers are not covered by the $66 million in pipeline features list and MAOP calculation costs identified in Chapter 5.

(3) PG&E provided only a vague, broad outline of its Emergency Prevention, Preparedness and Response Procedures update with no detailed information.

Q.43 WHAT DO YOU RECOMMEND?

A.43 I recommend that the Commission:

(1) Require PG&E to explain why pressure reductions greater than 20 psig are not considered an appropriate safety enhancement measure under the Pipeline Program Decision Tree, and why the company's Interim Safety Enhancement Measures should not be modified to allow pressure reductions greater than 20 psig.

(2) Require PG&E to better support its costs for the MAOP validation project and explain why those costs are not covered by the costs identified in Chapter 5. In the event that PG&E can show that these expenses are not covered by the costs contained in Chapter 5, and the Commission approves these four positions, a mechanism should

be established to ensure that if actual incremental hiring does not materialize the funds are credited back to ratepayers.

(3) Require PG&E to provide it's a more detailed explanation of its updated Emergency Response Procedure.

Q.44 DOES THAT CONCLUDE YOUR TESTIMONY?

A.44 Yes, it does.

DIRECT TESTIMONY OF PHILLIP S. TEUMIM,

ON BEHALF OF THE

CITY AND COUNTY OF SAN FRANCISCO

Response to Chapter 7 of PG&E's Implementation Plan:
Implementation Plan Management and Estimate Risk Quantification

Q.1 PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A.1 My name is Phillip S. Teumim. I am a consultant affiliated with Hudson River Energy Group. My business address is 37 Ruxton Road, Delmar NY 12054.

Q.2 PLEASE SUMMARIZE YOUR EDUCATION AND BUSINESS EXPERIENCE?

A.2 I hold a Bachelor of Science degree in Electrical Engineering and a Master's Degree in Business Administration from Rensselaer Polytechnic Institute in Troy NY. I was employed by the New York State PSC from 1970 to 1988, and again from 1992 to 2002. During the period 1988 to 1992, I worked for the consulting firm of Theodore Barry & Associates, and later Resource Management International. During my initial tenure with the PSC, I worked extensively on telecommunications, electric, gas, and water matters. During my second tenure with the PSC, I was the Director of the Energy and Water Division, and later the Gas and Water Division, at various times responsible for all electric, gas and water technical and policy analysis, evaluations recommendations coming before the New York Public Service Commission. In 2002 I became a consultant, and have worked on gas, electric and water matters for a variety of clients in various jurisdictions since that time. I have appeared before a number of regulatory commissions, the FERC, and several legislative committees. I have also been an instructor at Camp NARUC and other regulatory training workshops and have been an invited speaker at a number of regulatory, trade and industry conferences nationally.

My resume is included as Exhibit 3.

Q.3 ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A.3 I am testifying on behalf of the City and County of San Francisco (the City), which hired Hudson River Energy Group (HREG) to assist in its review of the Pacific Gas & Electric's (PG&E) Pipeline Safety Enhancement Plan (the Implementation Plan or the Plan), filed on August 26, 2011, in response to California Public Utilities Commission (Commission) Decision (D).11-06-017.

Q.4 WHAT IS THE PURPOSE OF THIS TESTIMONY?

A.4 I will address PG&E's corporate and project management as they pertain to the Plan, and the risks to cost, schedule and operational performance associated with the Plan as proposed by PG&E.

Q.5 PLEASE DESCRIBE THE CONTEXT OF YOUR REVIEW.

A.5 In order to assess PG&E's corporate and project management ability to implement the proposed Plan, it is necessary to understand how PG&E is positioned – i.e., to understand its capabilities and limitations – and to assess its potential for success.

Q.6 PLEASE IDENTIFY THE PRIMARY STUDIES AND REPORTS WHICH INFORMED YOUR ASSESSMENT.

A.6 Those reports include the National Transportation Safety Board Report (NTSB) Accident Report dated September 9, 2010, the Independent Review Panel report dated June 24, 2011, the Consumer Protection and Safety Division (CPSD) Technical Report dated December 23, 2011, the Jacobs Consultancy report dated December 23, 2011, and the relevant chapters of PG&E's testimony.

Q.7 WHAT ASPECTS OF THOSE REPORTS DO YOU FIND SIGNIFICANT IN EVALUATING PG&E'S IMPLEMENTATION PLAN?

A.7 The NTSB found that the information initially reported by PG&E regarding the characteristics of the pipe involved and how it was constructed was inaccurate. Specifically, the NTSB found that the pipe that ruptured was constructed by PG&E using short sections of pipe, known as "pups," that did not conform to known specifications and was fabricated to no known specifications, demonstrating PG&E's lack of quality control at the time of construction. The NTSB also found that PG&E's gas transmission integrity management program (TIMP) was deficient and ineffective, that PG&E lacked detailed and comprehensive procedures for responding to a large-scale emergency, that PG&E's response was excessively slow, that PG&E's supervisory control and data acquisition (SCADA) system limitations contributed to the slow response, that multiple and recurring deficiencies in PG&E operational practices indicate a systemic problem, and that the deficiencies identified are indicative of an organizational accident.

The Independent Review Panel questioned the role of PG&E's organizational culture in the incident, noting that management's focus in recent times has been on occupational worker safety and lacking an equivalent focus on public safety. The Panel found problems with PG&E's data management practices which impacted the company's ability to properly identify threats, PG&E's shortcomings with respect to complying with the spirit of regulations and management compensation incentives that do not suggest a focus on achieving industry leading safety performance, as well as issues related to the company's organizational effectiveness, resource allocation and quality control processes, and strategic integrity plan.

The CPSD similarly concluded that PG&E violated various Commission and federal safety regulations, that the San Bruno incident was caused by PG&E's failure to follow accepted industry practices when installing the pipe, and failure to comply with federal Integrity Management Practices. The CPSD also noted PG&E's inadequate record keeping, deficiencies in PG&E's SCADA system, inadequate procedures to handle emergencies and abnormal conditions, and the systemic failure of PG&E's corporate culture that emphasized profits over safety.

Q.8 WHAT OVERALL CONCLUSIONS HAVE YOU DRAWN FROM THESE REPORTS?

A.8 The San Bruno explosion and resulting investigations and examinations have identified a range of systemic deficiencies pervading PG&E's management and operations of its gas business. Some of those deficiencies have existed for a very long time.

The way of operating that produced or accommodated those deficiencies is deeply rooted in the corporate culture. Among other things, this appears to have resulted in a *money-first* rather than a *safety-first* culture. PG&E has not identified and addressed the root causes of its deficiencies and has not addressed its corporate culture issues.

Q.9 WHY ARE THESE CONCLUSIONS RELEVANT TO THE COMMISSION'S REVIEW OF PG&E'S IMPLEMENTATION PLAN?

A.9 The Plan is not simply a document to be prepared, reviewed and put on a shelf. Ultimately, PG&E must be able to execute the plan. That is, it must ensure timely performance, assure quality, and provide safe operations. Even the best possible plan will be severely impaired if PG&E is unable to execute it efficiently and effectively. The Plan is the first step in demonstrating the reasonableness of the actions to be undertaken by PG&E and the reasonableness of the cost of those actions.

Q.10 WHAT ARE YOUR OVERALL CONCERNS WITH RESPECT TO THE PROPOSED MANAGEMENT OF THE IMPLEMENTATION PLAN?

A.10 The primary concerns are that poor corporate and project management will result in significant cost increases, significant schedule slippages, while not addressing pressing safety issues in a timely fashion, and may result in the installation of unsafe facilities.

Based on my review of PG&E's management approach, I have concerns that it will not be able to perform as promised while ensuring that quality and safety are not compromised. Specifically, PG&E has not adequately considered:

Corporate and Project Management: Corporate and Project Management were identified as weaknesses by the Independent Panel. In addition, PG&E has recently made several changes to its corporate structure which will create greater uncertainty regarding specific roles and functions within the company.

Program Risk: Although PG&E has self-identified a number of potential risks to the Implementation Plan, it has not adequately considered PG&E's own management ability as a potential risk.

Corporate Culture: Part and parcel of PG&E's Corporate and Project Management and consideration of whether PG&E itself is equipped to deliver on such an ambitious project is the fact that, intentionally or not, PG&E has developed a corporate culture that prioritizes financial goals over safety goals. The fact that PG&E characterizes the projects in its Implementation Plan as incremental to existing federal requirements when many of the proposed activities are already required by law demonstrates that PG&E continues to prioritize dollars over safety.

Corporate and Project Management

Q.11 WHAT IS YOUR VIEW OF THE CHANGES PG&E HAS MADE TO ITS CORPORATE ORGANIZATION SINCE THE SAN BRUNO INCIDENT?

A.11 PG&E's organization is in a state of flux. According to its filing, PG&E is in the midst of or has recently made significant changes to its organization. It has:

- Created a gas business unit,
- Made several new officer and senior management appointments,
- Substantially increased its engineering and field forces,
- Created a project management organization, and
- Hired a number of consulting organizations to assist it with various aspects of its corporate and/or project management.

These proposed changes inevitably bring a level of uncertainty to the organization as roles, reporting relationships, and job duties and responsibilities are changed and redefined, communications channels are disrupted and new ones developed. Old loyalties tend to conflict with new, and existing and new employees must acclimate to the organization. Consulting organizations must be integrated with the corporate and project organizations while they are evolving. It is a time of great uncertainty within the organization.

PG&E also intends to make additional, unspecified changes to its organization, further exacerbating its organizational flux and uncertainty. In addition to the changes identified above, PG&E states qualitatively that it will actively and consistently engage senior PG&E management, and will have dedicated resources to work with the management team for each component project, including engineering, land, permitting and environmental efforts, procurement, and construction, including field services and quality and safety management, all of which will be audited by the internal audit group.

Q.12. IS THE STATE OF ORGANIZATIONAL FLUX A NEW PHENOMENON AT PG&E?

A.12. No. According to the Independent Review Panel, this has existed for over a decade. However, the additional changes ensure that the uncertainty that comes with such change will continue.

Q. 13. HAVE YOU IDENTIFIED ANY SAFETY CONCERNS ASSOCIATED WITH ORGANIZATIONAL FLUX?

A.13. Yes, the Independent Panel specifically found that PG&E has been in a state of organizational instability for over a decade and that as a result PG&E's pipeline integrity management operations suffered. [17]

Q.14. HAVE YOU IDENTIFIED ANY PROBLEMS WITH THE PROPOSED PROJECT MANAGEMENT ORGANIZATION?

A.14. Yes. The proposed project management organization is a very complex organization involving many disparate parties. It will continue the organizational flux and will add even more layers of management, which has already been identified by the Independent Review Panel as a source of "...*dysfunction from excessive layers of management...*[18]. And yet, the proposed project management organization will add many more layers. These proposed additional layers

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[17] Independent review Panel Report, p. 52

[18] Id., p. 48

are: a Project Controls Group, a Project Support Team, a QA/QC team, and a Business Planning and Coordination, and will be composed of employees from PG&E, Parsons Commercial Technology Group (Parsons) and others, with integrated project management sub-teams and supported by a pool of subcontractors and a specialist information technology vendor.

PG&E has also retained or intends to retain several firms to assist with project management, including Price Waterhouse Coopers, and Parsons. PG&E estimates project management contractor labor to include 20-25 full-time equivalent employees in addition to the Parsons resources dedicated to the team. Finally, PG&E also proposes what it refers to as an External Advisory Board as part of the Project Management organization.

Against the background of the organizational issues identified by the various reports, PG&E should develop a simple, straightforward project management organization, with clear lines of responsibility and authority. The complexity of this organization is ripe for confusion of roles and responsibilities. PG&E has not demonstrated an ability to manage itself, let alone a number of contractors and subcontractors. In addition, the process will be also be complicated by growing pains. It is, or will be, in startup mode for some time, and will be assembling the organization while work is supposedly going full bore.

Q.15. WHAT IS YOUR OPINION OF THE EXTERNAL ADVISORY BOARD PROPOSED BY PG&E?

A.15. The proposed board is neither external nor advisory. The concept of an external review board has merit, but not as proposed by PG&E. As proposed, it will be made up of individuals employed by and reporting to PG&E, and its list of responsibilities indicate it is as an operations review board. According to PG&E, its objectives are to:

- Confirm project and program participants are properly implementing established procedures and processes for their respective areas of responsibility.
- Confirm compliance with applicable Sarbanes-Oxley, and other government and regulatory requirements associated with the Program.
- Determine whether contractors are fully complying with applicable terms and conditions of their contracts.
- Provide observations and recommendations for process improvements and enhanced performance.[19]

Since the Advisory Board members will be employed by and will report to PG&E, they will not be independent. To be truly independent the External Advisory Board members should report to a body outside of PG&E. In the same way that PG&E shareholders bore the costs of the Independent Panel Report, the Commission should require PG&E to pay for an independent analyst to assess PG&E's execution of the Implementation Plan.

Further, given the types of responsibilities described by PG&E, it appears that PG&E will create the External Advisory Board as part of the project management organization, with line and staff responsibilities, as opposed to actually providing independent assessments of program execution.

By providing periodic assessment of PG&E's performance, a truly independent External Advisory Board, could provide feedback to the Commission to help evaluate the reasonableness of PG&E's performance and the reasonableness of the costs being requested by PG&E. This could be a feedback mechanism similar to that contemplated by the Assigned Commissioner in his November 2, 2011 ruling.

[19] PG&E Testimony Volume 7, p. 7 - 12

Q.16. IN VIEW OF THESE WEAKNESSES, HOW COULD PG&E MAXIMIZE ITS EFFECTIVENESS?

A.16. Ideally, PG&E should address its cultural, organizational and management problems prior to undertaking any substantial project. However, given the pressing safety issues, PG&E could maximize its chances for success by implementing a much simpler, streamlined plan which addresses the issues identified by the Commission in D.11-06-017.

Program Risk

Q.17. HAS PG&E IDENTIFIED RISKS TO THE PLAN?

A.17. PG&E has identified general risks to the Plan to include the following:

- It will be engaged in several large and complex component projects that individually require focused project management and structured control tools and procedures.
- Work streams are being performed under very aggressive schedules.
- PG&E will be subjected to increased regulatory oversight and public review.
- The projects must be managed as part of an overall capital program to achieve objectives and manage risks.

PG&E notes that its estimates are based on limited information: It characterizes those estimates as conceptual in nature, given the limitations of knowledge at this time. For example, PG&E states it only had less than 15% of the "project definition" available at the time it prepared the estimates for Valve Automation and Pipeline Replacement.[20] As a result, PG&E calculates that the expected range of accuracy of those estimates to be between -30% and +50%. In addition, PG&E identifies additional risk associated with its estimates, not included in the above, associated with:

- escalation higher than 3.12% per year

[20] PG&E Testimony, Chapter 7, p. 7-29 – 7-31.

- design, engineering, and survey cost increases
- unusual weather
- inaccurate schedule duration estimates
- unforeseeable field conditions
- unforeseeable community or permitting requirements

PG&E has also identified a number of risk elements associated with the Plan, which it states may affect the accuracy of its cost estimates, even beyond the limitations included in the above range of accuracy, including:

- Current business and regulatory environment
- Maintaining reliability
- Program and project scope and change control
- Schedule controls
- Quality and inspections
- Cost management
- Resource management
- Communications and reporting
- Procurement and contract administration
- Issue and risk management
- Information technology management
- Safety and environmental compliance
- Customer relations and stakeholder management.

Q.18. DO THE ABOVE RISKS IDENTIFIED BY PG&E CAPTURE ALL THE RISKS TO THE PLAN?

A.18. No. PG&E has not assessed the risks associated with its ability, or lack thereof, to effectively manage the Plan from a corporate and project management perspective.

It is starting from a position of significant corporate and managerial weakness, which it has addressed only superficially. The company's response is best characterized as knee-jerk. There is no basis for concluding it can perform as proposed, and there are no incentives or penalties included in its proposals. It marks a continuation of the culture of profits over safety – the primary objective here appears be to grow rate base, thereby growing returns to shareholders. PG&E has not performed a serious self-assessment and has not identified the root causes of its problems, which would be a necessary first step in addressing its organizational and cultural deficiencies. The company has performed very poorly without all of the risks and complexities it has identified here. We have seen no evidence that it is capable of effectively managing a program with the addition of those risks and complexities, and substantial evidence that it will be unable to do so successfully.

Q.19. WHAT IS THE LIKELY EFFECT OF THE RISKS AND UNCERTAINTIES THAT YOU HAVE IDENTIFIED?

A.19. As proposed, the Plan is a difficult, complex and expensive undertaking, with significant uncertainty and risk, for any organization. Given the concerns I have expressed above, there is a very high likelihood that costs will increase substantially, possibly dramatically, that schedules will slip, possibly dramatically, and that the safety requirements will not be met.

Corporate Culture

Q.20. DO YOU HAVE ANY CONCERNS WITH RESPECT TO THE EFFECT PG&E'S CORPORATE CULTURE WILL HAVE ON THE PROPOSED PROJECT?

Q.20. Yes, I have very significant concerns. Corporate culture plays a major role in the ability of an organization's performance. As described by the Independent Review Panel:

It is difficult to capture the full spectrum of factors that make an organization unique, such as history, hierarchy, mission, leadership, experiences, attitudes and values. Nevertheless, these intangible factors can often play as much a role in an organization's success as its processes and procedures, its technology and its people. The character of an organization very much affects its performance.[21]

PG&E's corporate culture is the antithesis of what is needed here, and PG&E has also woefully underestimated the difficulties of changing that culture. Changing a corporate culture takes years, absent a series of extraordinary events, e.g., a bankruptcy, complete turnover of management, or technological upheaval. None of that has happened here. Cultural change begins with an identification of root causes. That has not happened here.

Q.21. IS THERE A RELATIONSHIP BETWEEN THE CORPORATE CULTURE IDENTIFIED AND PG&E'S SAFETY PERFORMANCE?

A.21. According to the NTSB Report, the deficiencies identified in its investigation are indicative of an organizational accident, and the multiple and recurring deficiencies in the company's operational practices indicated a systemic problem.[22] The changes described by PG&E simply continue the organizational flux.

Q.22. CAN YOU CITE ANY EXAMPLES OF THE DIFFICULTIES OF CORPORATE CULTURE CHANGE?

A.22. Yes. A good example, which we have encountered in a large combination utility roughly comparable to PG&E, involves Consolidated Edison Company of New York, Inc. (Con Edison). In the 1990s, Con Edison committed several violations of environmental law,

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[21] Independent Review Panel Report, p. 48.

[22] NTSB Report, p. 125

including the release of asbestos from a steam explosion in the Gramercy Park area of Manhattan in 1989 and a spill of PCB-contaminated oil into surface water from the Arthur Kill Generating Station on Staten Island in 1998.

After the Gramercy Park incident, Con Edison was indicted, fined, and placed on probation for 3 years, under the supervision of a court-appointed environmental monitor. At about the time the three year period was ending, Con Edison experienced the oil spill at the Arthur Kill plant and the subsequent return of the environmental monitor.

Following is an excerpt from a management audit report of Con Edison on that subject:

> *The difficulty of culture change should not be underestimated. An example, perhaps the only example in the last 20 years that could be characterized as a massive cultural change [at Con Edison], was the environmental awareness movement. CECONY [Con Edison] senior managers trace the beginnings of that movement to the steam main explosion in Gramercy Park in 1989. There is no question that CECONY devoted significant efforts, from top to bottom of the Company, to make those changes. Eleven years later, however, the March 30, 2001 report of the court appointed environmental monitor found that …pockets of resistance persist, if not in the whole organizations then in parts of them. ….*[23]

PG&E does not have a safety culture, and the lesson from Con Edison is clear. It will take many years and extraordinary effort to develop such a culture.

Q.23. ARE THERE ANY OTHER FACTORS WHICH YOU BELIEVE WILL AFFECT PG&E'S PERFORMANCE IF IT GOES FORWARD WITH THE PLAN AS PROPOSED?

[23] *Management Audit of Consolidated Edison Company of New York, Inc*, The Liberty Consulting Group, June 16, 2009 for the New York Public Service Commission, p. III-21

A.23. Yes. PG&E is involved in a number of regulatory proceedings which require a significant technical, legal and administrative effort by the company, as major programs and hundreds of millions, perhaps billions of dollars are at stake. The proceedings will take years, and the uncertainties associated with the potential outcomes would weigh heavily on the best-managed projects. In addition to the direct burdens of participating in the proceedings, PG&E may be subject to additional state and federal requirements. This will be a significant drain on management resources, adding another level of complexity to corporate and project management.

Q.24. WHAT ARE YOUR OVERALL CONCLUSIONS ABOUT THE PROGRAM MANAGEMENT PROPOSED BY PG&E?

A.24. The management organization and process as proposed is very complex. Roles and responsibilities have not been defined. PG&E has no experience managing this type of organization and project. As proposed, this is a highly complex project with an aggressive schedule, as stated repeatedly by PG&E. It has a high risk of cost and schedule overruns, and poor performance. The program has maximized the potential for failure.

This proposal bears remarkable similarities to the nuclear plant construction projects of the 1970s and 1980, which were plagued by cost overruns and schedule slippages. Some of the lessons learned from those experiences, obviously not applied here, include the need for:

- Clear definitions of roles and responsibilities of the key players, in this case, PG&E corporate management, PG&E project management, and Parsons. They are not clearly defined here.
- Competent project leadership and personnel.

- Engineering complete well in advance of construction.
- A well-defined scope.
- Close working relationship with the regulators.
- As much regulatory certainty as possible.

Q.25. WHAT HAVE YOU CONCLUDED WITH RESPECT TO OVERALL RISK TO PROGRAM PERFORMANCE?

A.25. The chances of this project being completed effectively, on budget and on schedule are very low. In simple terms, PG&E is biting off far more than it can chew. There exists an uncertain and poorly defined scope, an inappropriate corporate culture, a weak corporate organization, significant corporate organizational changes, and a new and complex project management and project team made up of a number of organizations. Coupled with that are a cost-plus environment with no price caps, no incentives for good performance or penalties for poor performance, and no performance metrics. This program has a very high risk of failure.

Not identified by PG&E, but a very significant risk element, is the performance risk, i.e., the risk associated with PG&E's ability or inability to manage the job.

Also not recognized by PG&E is the regulatory risk. There are several regulatory processes at the state and federal level that could have a profound impact on project scope and schedule. In addition, participation in those proceedings will place a heavy burden on PG&E.

As proposed by PG&E, all program costs and risk is on ratepayers, except for certain limited costs that PG&E indicates shareholders will bear, which are identified in Mr. Radigan's testimony.

Q.26. HOW MIGHT THE COMMISSION MOTIVATE BETTER PERFORMANCE ON THE PART OF THE COMPANY?

A.26. Rather than placing all risk on ratepayers, the Commission might impose price caps on segments of the Plan, and it might set up incentives for good cost and schedule performance and penalties for poor cost and schedule performance. Both management and shareholders should be at substantial financial risk.

Q.27. EARLIER, YOU STATED THAT PG&E HAS ASSUMED THAT ALL PROGRAM COSTS ARE INCREMENTAL AND THAT THEY SHOULD BE RECOVERED FROM RATEPAYERS. DO YOU AGREE WITH THOSE ASSUMPTIONS?

A.28. No. As discussed in Mr. Radigan's testimony, the extent to which PG&E's Implementation Plan costs are actually incremental is far from decided, and it appears that a substantial portion of the funds to support some programs have been provided previously by ratepayers. A recent audit by Overland Consulting covering the period 1997 – 2010, found that PG&E underspent both the expense and capital monies approved in past rate cases and provided by ratepayers. At the same time, Overland Consulting found that the company's operations were very profitable, with revenues exceeding the amount needed to achieve the authorized rate-of-return by $430 million. To the extent that the Commission finds that the company was not using funds that ratepayers provided for their intended purpose, incremental funds for the same functions would not be necessary or appropriate.

Q.29. PLEASE SUMMARIZE YOUR CONCLUSIONS WITH RESPECT TO PG&E'S PROPOSED PLAN.

A.29. After exhibiting numerous organizational and technical failings over a long period of time, PG&E has proposed a complex, expensive, ambitious and challenging program on a cost-plus, pass-through basis.

PG&E's approach to successfully implementing the program it has proposed can be summed up as pie-in-the-sky optimism.

Q.30. WHAT ARE YOUR RECOMMENDATIONS TO THE COMMISSION?

A.30. I recommend the Commission take the following actions:

1. With respect to PG&E's filing in this proceeding, at this time the Commission should consider only the portion of PG&E's filing which is responsive to the Commission's June 9, 2011 order. All other portions of PG&E's filing should be deferred to a later date, to be determined at a later time.
2. With respect to costs associated with Item 1 above, direct PG&E to submit a downsized and streamlined management structure for the projects.
3. The Commission should direct PG&E to submit a detailed report addressing the corporate culture and management issues identified in the Independent Panel Report as this is necessary for PG&E to develop good corporate and project management.
4. To provide a feedback loop to the Commission, the Commission should:
    - Hire an independent third party individual or board, the cost of which is to be borne by PG&E shareholders, to monitor and report to the Commission on PG&E's progress on this program. The Con Edison example may be a useful guide in this regard.
    - Hire an independent third party individual or board, the cost of which is to borne by PG&E shareholders, to monitor and report on PG&E's progress in developing a safety culture.

DIRECT TESTIMONY OF

FRANK W. RADIGAN

ON BEHALF OF THE

CITY AND COUNTY OF SAN FRANCISCO

RESPONSE TO CHAPTERS 8 AND 10 PG&E'S IMPLEMENTATION PLAN: COST RECOVERY AND COST ALLOCATION

Q. PLEASE STATE YOUR NAMES AND BUSINESS ADDRESSES.

A. My name is Frank W. Radigan. I am a principal in the Hudson River Energy Group, a consulting firm providing services regarding the electric utility industry and specializing in the fields of rates, planning and utility economics. My office address is 120 Washington Avenue, Albany, New York 12210.

Q. PLEASE DESCRIBE THE HUDSON RIVER ENERGY GROUP.

A. The Hudson River Energy Group (HREG) is an engineering consulting firm specializing in the fields of rates, planning, economics and utility operations for the electric, natural gas, steam and water utility industries. HREG was founded in 1998 and has served a wide variety of clients including municipal utilities, government agencies, state commissions, consumer advocates, law firms, industrial companies, power companies, and environmental organizations. HREG conducts rate design and cost of service studies, designs performance based rate plans. HREG also assists clients in dealing with the complexities of deregulation and restructuring, including OATT pricing, unbundling of rates, resource adequacy, and transmission planning policies and power supply. Our experience in these areas has brought us to testify before the federal energy regulatory commission and a large number of utility commissions across the country.

Q. PLEASE SUMMARIZE YOUR EDUCATION AND BUSINESS EXPERIENCE?

A. I received a Bachelor of Science degree in Chemical Engineering from Clarkson College of Technology in Potsdam, New York (now Clarkson University) in 1981. I received a Certificate in Regulatory Economics from the State University of New York at Albany in 1990. From 1981 through February 1997, I served on the Staff of the New York State Public Service

Commission (PSC) in the Rates and System Planning sections of the Power Division. My responsibilities included resource planning and the analysis of rates, depreciation rates and tariffs of electric, gas, water and steam utilities in the State and encompassed rate design and performing embedded and marginal cost of service studies as well as depreciation studies.

Before leaving the Commission, I was responsible for directing all engineering staff during major proceedings including those relating to rates, integrated resource planning, and environmental impact studies. In February 1997, I left the Commission and joined the firm of Louis Berger & Associates as a Senior Energy Consultant. In December 1998, I formed my own Company.

In my 30 years of experience, I have testified as an expert witness in utility rate proceedings on more than 100 occasions before various utility regulatory bodies including the Arizona Corporation Commission, the Connecticut Department of Public Utility Control (DPUC or Department), the Delaware Public Service Commission, the Illinois Commerce Commission, the Maryland Public Service Commission, the Massachusetts Department of Telecommunications and Energy, the Michigan Public Service Commission, the New York State Public Service Commission, the New York State Department of Taxation and Finance, the Nevada Public Utilities Commission, the North Carolina Utilities Commission, the Public Service Commission of the District of Columbia, the Public Utilities Commission of Ohio, the Rhode Island Public Utilities Commission, the Vermont Public Service Board, and the Federal Energy Regulatory Commission (FERC). I currently advise a variety of regulatory commissions, consumer advocates, municipal utilities, and industrial customers concerning rate matters, including wholesale electricity rates and electric transmission rates.

My resume is attached as Exhibit 4.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

B. I am testifying on behalf of the City and County of San Francisco (the City), which hired Hudson River Energy Group (HREG) to assist in its review of the Pacific Gas & Electric's (PG&E or the Company) Pipeline Safety Enhancement Plan (the Implementation Plan or the Plan), filed on August 26, 2011, in response to California Public Utilities Commission (Commission) Decision (D).11-06-017 (the Rulemaking).

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I have been asked to review the reasonableness of the Company's proposed cost recovery and proposed rate impact that are addressed in Chapters 8 and 10 of the Plan respectively.

Q. WHAT ARE THE ISSUES THAT PG&E IS ADDRESSING WITH RESPECT TO COST RECOVERY?

A. PG&E is proposing cost recovery criteria and a methodology to recover costs required to implement Phase 1 of the Pipeline Safety Enhancement Plan. PG&E requests that the Commission adopt its forecast capital expenditures and expenses and deem that these costs are reasonable.

Q. HAS PG&E PROPOSED AND APPLIED REASONABLE COST RECOVERY CRITERIA?

A. No. PG&E asserts that it is seeking recovery in rates for the costs of new safety programs and investments that go above and beyond preexisting regulatory requirements and were not contemplated when PG&E's existing rates for gas transmission service were established (Plan at 8-5). PG&E explains its cost recovery plan as follows:

> 1) It is not seeking recovery of costs in the Plan that is a direct result of the San Bruno accident (including the costs of personal injuries, property damage, emergency response, or civil litigation),
>
> 2) It is not seeking recovery of incremental utility expenses for unanticipated gas business activities, such as gathering gas system records and documents, responding to requests for information and documentation, and supporting the NTSB, CPUC, and IRP investigations.
>
> 3) To the extent PG&E must undertake tasks to comply with preexisting regulatory requirements, PG&E will not seek cost recovery'
>
> 4) It is only seeking rate recovery only for incremental Implementation Plan costs that would not otherwise be incurred were it not for the work described in Chapters 3 through 7 and were not included in PG&E's most recent GRC (A.09-12-020) or GT&S Rate Case (A.09-09-013).

While this may be sound in theory, as discussed below, PG&E's contention that all of the work proposed in the Implementation Plan is incremental is not reasonable.

Q. DO YOU BELIEVE THAT PG&E'S COST RECOVERY PROPOSAL IS REASONABLE?

A. No, for several reasons. First, as explained in the testimony of Messrs. Gawronski and Scott, much of the work that the Company proposes exceeds the scope of work ordered by the Commission. In addition, PG&E has not supported this increase in the scope of work with any analysis demonstrating improved safety effects for the amount expended.

Second,, by breaking the proposed work into two phases, PG&E has de-prioritized safety activities for pipeline segments in highly populous locations without showing that it is reasonable to do so.

Third, Mr. Gawronski also explains that many of the proposed safety activities should be included in PG&E's TIMP if PG&E were in fact faithfully following federal law, and that many of the proposed pressure tests could have been avoided if PG&E had record keeping practices that historically complied with state and federal law. Thus, PG&E should have already performed much of the pipeline modernization work and therefore this work should not be considered incremental.

Fourth, as explained by Mr. Scott, PG&E's valve spacing proposal fails to provide any analysis that complies with the Commission order or considers all of the factors listed in Title 49 CFR 192.935(c) for the spacing of remote control and automatic valves as required by federal law and recommended by the NTSB. Instead, PG&E proposes to use the spacing requirements for isolation or sectionalizing flow valves, again without any supporting analysis. Therefore, these costs have not been shown to be reasonable.

Fifth, as explained in the testimony of Mr. Scott, the costs claimed by the company for record keeping are not incremental since federal law already requires substantial record keeping as a key component to pipeline safety. In addition, the costs associated with the GTAM are beyond the scope of the Commission's order, have not been demonstrated to be necessary or reasonable, and should not be considered by the Commission in this proceeding.

Finally, PG&E's cost recovery proposal is unreasonable in view of the likelihood that the company will be unable to deliver on this audacious proposal. As explained in Mr. Teumim's testimony it is unclear that the Company currently is competent to implement a successful plan of such massive scope and complexity.

Q. CAN YOU PROVIDE AN EXAMPLE THAT ILLUSTRATES THE UNREASONABLENESS OF PG&E'S COST PROPOSAL?

A. Yes. One particular example is the proposed replacement of L108. In its work papers, PGE proposed to replace 92 feet of pipe installed prior to 1970 operating above 30% SMYS with the potential for pipe manufacturing threats, located within a Class Location 2-4 or HCA. In addition, 17 segment(s) totaling 13,509 feet of pipe that has a documented strength test is included in this project for construction efficiency."[24] PG&E proposes to recover the costs of all of this work when only 92 feet of the 13,601 feet proposed to be replaced are actually within the scope of D. 11-06-017. That is, only 92 feet of the proposed project were ordered by the Commission, but PG&E is asserting that over 13,000 feet must be replaced as part of construction efficiency. Therefore, it is unreasonable for PG&E to seek recovery for this project under the auspices of replacing pipeline segment without documented prior pressure tests.

Q. DO YOU BELIEVE THAT PG&E'S PROPOSAL FOR TRACKING COSTS IS REASONABLE?

[24] Work Papers supporting Chapter 3 Pipeline Modernization November 4, 2011, WP 3-61. Order No. 30842211.

A. No. PG&E requests that the Commission find the forecast costs and associated revenue requirements to be reasonable so long as the Phase 1 recorded costs are equal to or less than the forecast cost estimates for expense and capital proposed in the Plan (Plan at 8-13). This is statement is misleading because PG&E is also seeking the ability to submit advice letters so that it can request recovery of costs spent above the approved forecasts (See Plan at 8-14).

Q. DO YOU HAVE ANY ADDITIONAL CONCERNS REGARDING PG&E'S COST RECOVERY?

A. Yes. PG&E requests that the Commission adopt the Implementation Plan cost estimate and find that if costs come in at or below the cost estimate, all expenditures will be found reasonable and therefore recoverable from ratepayers. This is essentially a request for pre-approval based on admittedly unreliable cost estimates. PG&E has stated the cost estimates may be 30% lower or 50% higher than its estimated costs. The riskiness of this proposal is increased by the Company's demonstrated negligence in carrying out its duties to adequately operate and maintain its system.

In addition to pre-approval of cost estimates, the Company is also asking for pre-approval of the amount of company liability for the pipeline safety enhancement plan. PG&E proposes to absorb $221 million of $2,184 million or approximately 10% of the Phase I costs. This is based on the costs PG&E states it incurred in 2011. This is an arbitrary cut-off date with no support in fact. In addition, it is inappropriate for the Commission to limit the cost responsibility of shareholders before PG&E's Phase II proposal has even been submitted. The total cost to PG&E's shareholders, like the total cost to ratepayers, can only be determined once the total costs are known. The company states it will also absorb incremental non-implementation plan expenses of $215 million, and $98 million of costs related to pressure testing and strength testing of post-1970s pipe. Using PG&E's cost estimates, these costs add up to approximately $444 million.

I am concerned that there is insufficient information available at this time to: 1) establish which costs are actually incremental, and 2) to establish any ceiling on the Company's share of cost liability for this multi-billion dollar project. PG&E has assumed that its cost proposal will be fully adopted by the Commission without any further review and its proposed cost allocation reflects that belief. The Commission is conducting several other proceedings that should result in additional information that is relevant to the appropriate allocation of costs between ratepayers and the company, including the penalty consideration case (**I.12-01-007**), the recordkeeping case (I.11-02-016), and the HCA investigation (I.11-11-009) As such, the City believes that it is premature to make the determination which costs are truly incremental and what the cost sharing responsibility should be.

Q. WHAT IS THE RATE IMPACT OF PG&E'S IMPLEMENTATION PLAN ON THE CITY?

A. The City has a number of accounts, including both core and non-core customers. The rate impacts vary by Department and range between 1.9% and 4.8% and average 3.9%. The increase proposed by PG&E would result in an annual bill increase of over $500,000. Given the last several years of large budget deficits for local governments including San Francisco and forecasts of larger budget deficits in the future, any rate increase is unwelcome. In this financial environment, City departments are trying to minimize every expense. There is no reason to increase rates as PG&E has proposed to overcome PG&E's past management missteps. Given that there are other rate recovery methods (such as phasing in or amortizing over a longer period), the Company's proposed surcharge level is unreasonable.

Q. WHAT ARE YOUR CONCLUSIONS WITH RESPECT TO THE PROPOSED COST RECOVERY?

A. The company seeks to increase rates and get cash flow immediately to pay for the Plan on an ongoing basis. Implicit in the Company's proposal is the pre-approval of all of its estimates and proposed projects. As noted above the Commission has ample reason for serious misgivings regarding the Company's proposal and its management ability and work plan. In my opinion, deferral of a decision on cost recovery rather than an immediate approval of costs is a much better ratemaking approach. One way for the Commission to accomplish this is through creation of a regulatory asset; this is a very useful tool for both shareholders and ratepayers that is generally used for rare or onetime events. The Commission would authorize the expenditures to be tracked as a regulatory asset, and the expenditures would appear on a balance sheet account rather than the income statement account. Recovery of the costs would not be guaranteed but PG&E would have the ability to recover all of its reasonably incurred costs.

One good example of the use of a regulatory asset is for costs incurred during major storms. One cannot predict when a major storm will occur in a utility's service territory or how bad the storm will be. For shareholders, the regulatory asset protects current operating profits, as the large expense of repairing facilities after a storm does not appear on the income statement in the year that occurs. Revenue recovery of the cost of storm repair is adjudicated in a separate proceeding or rate case and the utility has the opportunity to recover its costs at some future time. For the ratepayer, the deferral gives the regulator and customers the ability to examine whether the costs incurred are reasonable, and to determine for any costs that should be recovered over what period. This is an effective way of cost recovery as it allows the Commission to make a decision about cost recovery once it has been presented with full information, rather than a mechanism such as PG&E proposes here where the Commission is being asked to approve large, uncertain, and questionable costs in advance.

In sum, PG&E should track its costs and be responsible for showing that the expenditures are reasonable. As to the amount of up front cost recovery, if the Commission intends to grant a rate increase at this time, the City recommends an increase of no more than an average 1.5% , subject to refund. This proposal recognizes that the utility may not spend all that it forecasts due to timing delays or findings by the Commission that not all projects are necessary at this time. This also allows the Commission the opportunity to complete the other proceedings it has initiated that will provide substantial information about how much of the expenditures the ratepayers should pay for.

Q. WHAT DO YOU RECOMMEND?

A. We recommend that the Commission:

1) In lieu of the accounts proposed by PG&E, direct the utility to establish a regulatory asset to track Implementation Plan costs but not guarantee recovery. While the establishment of regulatory assets is done in expectation of future cost recovery through rates, it is not a guarantee of recovery. That determination will be made in a rate case based upon the evidence presented in a future proceeding.

2) Based on recommendation 1) above, reject the PG&E request to establish an Account (the NGTPSRMA) that would authorize PG&E to track and record its actual revenue requirements

for its 2011 and subsequent Implementation Plan. The establishment of a NGTPSRMA implies that the utility would automatically recover any costs incurred. Also, reject the PG&E request for balancing accounts (GPEBA and GPSBA) to track expenditures related to the implementation plan as they provide for a guaranteed cost recovery mechanism for the utility.

4) If the Commission intends to increase rates immediately, in order to help fund the Implementation Plan, it should limit the rate increase to 1.5% per year, subject to refund, until PG&E's next rate case.

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Q. DOES THAT CONCLUDE YOUR TESTIMONY?

A. Yes, it does.