PREPARED TESTIMONY OF DAVID BERGER ON BEHALF OF THE UTILITY REFORM NETWORK (TURN)

Pacific Gas and Electric Company
2015 Gas Transmission and Storage Rate Case
A.13-12-012

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Testimony of David Berger on Behalf of TURN

Q. Please give your name and business address.

A. I am David Berger; my business address is 31 Buccaneer Lane, East Setauket, NY 11733.

Q. Who are you testifying on behalf of?

A. I am a consultant for The Utility Reform Network, TURN, and am testifying on their behalf.

1. Qualifications

Q. Please describe your qualifications.

A. As both a utility manager and consultant, I have 25 years of experience in pipeline and system integrity management and risk assessment, corrosion control, gas infrastructure asset management, and gas system operation and security. I have recently consulted for this Commission's Safety and Enforcement Division (SED) on two separate cases related to PG&E's gas operations. A copy of my curriculum vita is attached to this testimony as Attachment A.

For approximately the last 10 years, I have been a consultant specializing in pipeline infrastructure and safety issues, including rate cases and pipeline replacement projects. All of my other clients are state and federal regulatory agencies. Currently, I am assisting the Vermont Public Service Department on a gas transmission expansion program, the Connecticut Public Utilities Regulatory Authority on a large gas infrastructure expansion, and the District of Columbia Public Service Commission on a gas infrastructure replacement and repair program. In the recent past, I have assisted New York, New Jersey, Maine, and Washington states on evaluating the safety and prudency of gas infrastructure capital and expense costs in rate cases and on specialized audits on management and capital expenditures. Recently in California, I provided consulting services for SED in the San Bruno explosion investigation (I.12-01-007), helping to write the SED report, particularly with respect to integrity management issues. I was also part of the team of consultants for Cycla Corporation that provided a report for SED regarding PG&E's risk assessment efforts with respect to its gas distribution system in the 2014 general rate case (GRC). I have also been involved in safety and management audits for the New

York, New Jersey, Massachusetts, Illinois and Washington regulatory agencies of their local distribution and transmission companies. I have been involved in accident investigations in Washington and, as noted previously, California.

I am also an associate instructor at the PHMSA Training and Qualifications school in Oklahoma City on the various Direct Assessment (DA) methodologies and consult for the PHMSA Engineering and Technical Services Division on various issues, including integrity management and corrosion control.

Q. Please describe your previous experience as a manager for gas utilities.

A. For the last several years of my approximately 15 years with a gas Local Distribution Company, I served as the Gas Asset Management Manager for the forerunners of National Grid (Keyspan Energy, Brooklyn Union and LILCO) in southern NY (NYC, Long Island) and Boston (Boston Gas, Colonial Gas, Essex Gas). In that capacity, I was the process owner of the gas transmission system. These service territories, while smaller than PG&E, also encompass very urban areas, suburban areas and some near rural areas. While at National Grid, at various times, I was the manager of pipeline integrity, system integrity (distribution integrity), corrosion control, pressure control (regulator stations and gate stations to the transmission system), gas metering and some construction crews. This experience gave me a hands-on appreciation of what it takes to perform maintenance and repairs/replacements on an active gas system.

2. Summary of Testimony

Q. Please summarize the scope and purpose of your testimony.

A. Based on my expertise described above regarding the safe operation and risk management of gas transmission systems, I have reviewed several aspects of PG&E's proposal in this case, including its risk assessment methodology and many of the risk mitigation programs PG&E proposes. My analysis included examining PG&E's justification for the need, scope and timing of its proposed work efforts, as well as the reasonableness of PG&E's funding requests. In my review, I have viewed safety of the general public and employees/contractors of PG&E as being of paramount importance, while also recognizing that PG&E's risk mitigation efforts need to be as cost-effective and efficient as possible in order to keep rates reasonable. My testimony focuses on the concerns I have identified in my review of PG&E's proposal.

Q. How is your testimony organized?

A. I will begin with a discussion of PG&E's risk assessment methodology and present certain concerns about PG&E's approach. I then discuss another general concern with PG&E's proposal -- regarding PG&E's ability to carry out all the work it is proposing in this case within the 2015-2017 period. I then present my comments on the following specific programs:

- In-Line Inspections (ILI)
- Direct Assessment (DA)
- Make Piggable program
- Earthquake Fault Crossings program
- Vintage Pipe Replacement
- Water and Levee program
- Shallow Pipe program
- Work Required by Others
- Measurement and Control Facilities
- Corrosion Control programs (external, internal, and atmospheric)
- Gas Transmission Systems Operations and Maintenance; and
- Gas System Operations

I conclude with a discussion of my concerns regarding PG&E's claims related to best practices.

3. PG&E's Risk Assessment Methodology

Q. Please provide an overview of your discussion of PG&E's risk assessment methodology.

A. I begin with a general discussion of the concept of risk and how it is determined with respect to gas transmission systems. I then proceed to an analysis of the risk assessment and mitigation methodology it used for this case and identify some issues and concerns with PG&E's approach.

3.1 General Risk Principles

Q. What is risk and how is determined?

A. Risk is the product of the likelihood of failure (LOF) times the consequence of that failure (COF).

In order to calculate the LOF, one needs to determine the threats to the pipeline or equipment. ASME B31.8S, for operators who use a prescriptive method of determining risk, breaks those threats into three main categories with three subcategories in each. The first category is time dependent, which includes external corrosion, internal corrosion, and stress corrosion cracking (SCC). These threats change over time and reduce the integrity of the pipeline asset by thinning the wall of the pipe or by reducing the pressure carrying capacity of the asset. The second category is time independent, which includes third party damage (as well as first and second party), incorrect operation, and outside force (including weather). As implied by the name, these threats do not change over time nor can they be easily predicted, as they are often random events. The third and last category is called stable threats, which includes manufacturing related defects, construction defects and equipment threats. These stable threats mean that if there are no changes to the environment or changes in forces on the pipeline or equipment, they should remain stable and not pose a threat to the integrity of the asset. If there is a change, then they may become unstable and thus pose a threat. Each of these threats can affect the integrity of the asset.

In addition, there are interactive threats, where two of more known threats act together, such as third party damage (time independent) interacting with external corrosion (time dependent) because the third party damage to the pipe can included coating damage (also known as a coating holiday, or a holiday) to the corrosion control coating protecting the pipe from external corrosion. Another type of threat is cyclic fatigue, the potential movement (both longitudinally and radially) of the asset from pressure changes or outside forces on the asset must also be reviewed to determine if these forces are accelerating the deterioration of the asset.

Q. What about the consequence side of the risk equation?

A. COF is somewhat easier to determine, and the current regulations and past industry standards for gas assets have used a class system to provide some guidance on consequence. The maximum allowable operating pressure (MAOP) is set as percent of the specified minimum yield strength (SMYS) depending on population density and building density. Thus, an asset in a Class 1 area, rural with little or no human habitation or businesses, is allowed to operate at a higher SMYS than those located in a Class 4 area which is defined as having mainly multistory buildings, typically a city environment. In between are Class 2 and Class 3, country village and suburban, respectively. There are other factors that are included in determining the consequence, such as nearby facilities that are hard to evacuate, such as schools, nursing homes, prisons, hospitals or areas where many people congregate. Thus the consequences of a failure near an elementary school or nursing home would be greater than a location without such a facility, even if the class location were the same.

Q. What information is important for determining LOF and COF?

A. For the LOF side of the equation, it is important to have sufficient, accurate and accessible data on the physical characteristics of equipment in question. For a pipeline, this includes the materials, how the pipe was made, when and where it was made, how it was installed, who installed it, when it was installed, and operating data such as past failure, past maintenance, past issues with compliance to the minimum federal and state safety codes, operating pressures, and prior inspections.

For the COF side, important information for a pipeline or other asset includes the exact location, what is around the pipeline or asset, how the pipeline/asset is being operated or was operated in the past, whether there have been any issues with identifying the location of the asset, and the experience of similar pipelines for both this operator and others.

Q. Are there various methods of determining risk for pipeline and other gas assets?

A. Yes, there are several methods that can be used. The simplest is using subject matter experts (SME) to determine the likelihood of failure and using the Class system to determine the consequence of a failure. This system has been used in the past but it can be subjective based on what the SME believes is important.

Another method is called relative risk in which the LOFs and COFs are all rated and weighted. This has the potential to be more objective than pure reliance on SMEs, but the weighting method can introduce subjectivity. A key requirement is that an operator must have accurate information to calculate the LOF and COF ratings and cannot use too many assumptions (all of which should be conservative).[1] When too many assumptions are made, the results of the risk model will become less differentiated and thus many areas, segments, programs and projects will have very similar risk scores, thus negating the value of the risk ranking. As one extreme example, if every pipe segment has the same score, how do you differentiate among segments?

The last and potentially most accurate method is a probabilistic model, which requires the most accurate and detailed asset data of all the methodologies. Instead of ranking risk as in the relative risk model, it can be used to predict when a failure could occur and the consequences of such a failure. As a result, remediation and mitigation can be timed to be performed just before the failure occurs.

3.2 Analysis of PG&E's Methodology

Q. What are your comments relating to the PG&E risk assessment methodology that they are proposing to use to monitor and prioritize risks on the gas transmission system?

A. Although elaborate and complicated, PG&E's methodology ultimately depends heavily on the judgments of its SMEs and may produce results that are no better than an SME methodology. In this respect, PG&E's methodology can be misleading in that the scoring results give the illusion of arithmetic certainty when, in reality, there are significant reasons to question the reliability of the rankings it produces.

Q. To the extent that likelihood of failure influences the results of the analysis, do you have concerns about that part of the equation?

Yes, PG&E's LOF scores are questionable because, in light of PG&E's well-documented recordkeeping problems, some of the information on which the scores rely may be assumed or, worse, inaccurate. For example, throughout the pre-filed testimony, PG&E has made comments that many of the important pipeline characteristics will be determined at a later date.[2]. In fact, since the mid 1980's when PG&E contracted Bechtel to study their gas transmission system,

[1] For example, when calculating design pressure of a pipe, 49 CFR Part 192.113 requires that, if the type of longitudinal seam is not known, the operator must make a conservative assumption that an inferior type of joint is used.

[2] See, e.g., PG&E's response to TURN 1-1, Attachment 11 (Doc. GP-1101), p. 22.

they have had issues with missing records on pipelines that were installed. The Bechtel reports[3] recommended digging up and verifying pipeline records and to date I do not believe that this has been done except where there has been an incident or a failure.[4] Thus, many of the values that PG&E uses for the characteristics of their pipeline may be missing, assumed, or wrong.

In the supplemental testimony (page 2A-3), PG&E states it uses the asset owner, AFO, and subject matter experts, SME, to determine the risks and threats using the available data on the asset. However, for pipelines, developing a reliable database of information is, at best, a work in progress for PG&E, and some key information is missing.[5] Where information is missing, PG&E uses a procedure/policy called PRUPF,[6] to provide what PG&E believes are conservative assumptions. A recent audit by the CPUC's Safety Division, however, showed that a significant number of the supposedly validated conservative pipeline feature values were either erroneous or insufficiently conservative.[7] Even for data that is supposedly "known" and not assumed, significant errors in the data are possible. In some situations in the past, as with Line 132/San Bruno and Line 147/San Carlos, the supposedly "known" GIS data was in error and thus faulty assumptions were made (in San Bruno the GIS data showed the pipe to be 1956 seamless pipe, which it was not, in San Carlos the GIS showed the pipe to be 1947 DSAW pipe which turned out to be 1929 AO Smith pipe).

Q. So, why are these concerns important?

A. Since PG&E has constructed an elaborate method of determining risk, if the data imputed into the initial likelihood of failure part of the equation is wrong, improperly assumed, or not available, then the output is subject to errors or worse, will give the wrong result. For example, PG&E may be not replacing the most failure prone pipelines under the vintage pipeline replacement program since it does not know all locations where re-claimed pipe was installed

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[3] See response to TURN 026-Q01 attachments 01 through 12 for copies of the Bechtel reports.
[4] In the response to TURN 001-Q01 Attachment 11, GP-1101, PG&E states on page 21 that the data confidence has improved based on the MAOP validation work, but in most cases it still has not exposed pipelines to validate that what GIS has listed is actually what was installed.
[5] Procedure for Resolution of Unknown Pipe Features. PG&E Response to TURN 10-1.a. This procedure is only as good as the assumptions and is dependent of knowing when the pipe was manufactured.
[6] PG&E response to TURN 10-1.d.
[7] CPUC SED, Safety Review Report of PG&E's PSEP Update Application, A.13-10-017, April 25, 2014, p.11. This SED report also noted (p. 13) that, for regulator stations, PG&E had not yet developed or validated a list of features.

and thus does not always have accurate information about the age and manufacturer of its pipeline. As shown by the San Bruno explosion, pipeline failures may occur because the information on the condition or the safe pressure of the pipeline may be in error. This could be especially true if re-claimed pipe was used in a pipeline but there are no records showing such use.

Q. Do you have other concerns?

A. Yes, I am concerned that, because of the uncertainty and limited reliability of the scores on the LOF side of the equation, PG&E's ultimate risk rankings rely heavily on the COF side of the equation, in which the scores have low/limited or no uncertainty. By using the population along the pipeline as the main and in some cases a primary driver of its final risk rankings,[8] this system may over-weight the consequence of failure and may undervalue or ignore the likelihood of failure. Because PG&E in some situations has limited data on the physical, chemical and other characteristics of their pipelines, they are using what they call AOL and TOL (which counts population within the impact radius) as the main drivers for calculating risk. Thus a pipeline with known severe corrosion issues in a less populated area may be ranked as having less risk than a pipeline with minor corrosion issues in populated area.

Q. Does this mean that all of the programs that PG&E has suggested to reduce risk are in error?

A. Not necessarily, but many of the risk mitigation efforts that PG&E has proposed may not yield the actual risk reduction expected due to errors in the risk methodology, lack of information, and other factors.

4. PG&E's Ability to Perform the Proposed Work

Q. Do you have concerns about whether PG&E will have sufficient resources internally and externally to accomplish all of the programs and projects in the time frame that PG&E proposed?

A. Yes. PG&E has proposed a large increase in not only the capital budget but also the expense budget for the gas transmission and storage system in Northern California. Coupled with the increases they have also proposed for the gas distribution and electric system in the 2014 GRC,

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[8] PG&E notes (pp. 2A-3 to 2A-4) that, after it develops its quantitative scores, the scores are "calibrated" by AFOs and SMEs and then "relatively ranked" using SME judgment.

PG&E seems to have stretched the resources of qualified and technically competent personnel to the limit of, or past, what is available both internally and externally. PG&E acknowledges that it pushed its mitigation programs to the limits of its "execution constraints."[9]

My concern is reinforced by PG&E's performance of its 2012-2014 PSEP program. Even though PG&E was originally directed to hydrotest 783 miles and replace 186 miles of pipeline during that time period, PG&E will not be able to complete on time even the significantly scaled back program that it identified in the PSEP Update application (A.13-10-017). In that application, PG&E reduced the miles it will hydrotest to 658 and the miles it will replace to 121.[10] Even so, PG&E will not be able to complete this work by the end of 2014.

In this case, PG&E has requested large increases in funding, in some programs[11] over 600% above current levels and have also proposed large funding for other lines of business that will diminish both internal and external resources available to them. In addition, per their own estimates of new business due to increased economic activity, some of these same resources will be taken up by these projects. Thus the quantity and quality of available contractor assistance will likely be diminished. The consequence of taking on too much work is that either costs will have to increase, or time frames will have to be extended.

5. PG&E's Risk Mitigation Proposals

Q. Please provide an overview of this section of your testimony

A. In this section, I review many of the risk mitigation programs that PG&E proposes in this case. I generally follow the sequence in which the programs are discussed in PG&E's testimony.

Q. Do you have any general observations about PG&E's proposed risk mitigation efforts?

A. One general observation is that parts or all of many of the programs I will discuss are a result of shortcomings in PG&E's regulatory compliance or maintenance over the last decade or

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[9] PG&E responses to TURN 10-7 and 10-13.d, in which PG&E states that increasing the scope of work may not be feasible due to identified constraints.

[10] See PSEP Update Settlement Agreement, Section 4.8, attached to July 25, 2014 Motion to Adopt Settlement in A.13-10-017.

[11] PG&E has requested funding increases for expense and capital expenditures in integrity assessment, automating valves, replacing old pipe, replacing and upgrading measurement and control stations, cathodic protection programs, capacity improvements, and routine maintenance and patrolling.

longer. Numerous external and internal findings point to a long history of deficient operation of PG&E's gas transmission system.[12]

5.1 Integrity Management Assessments – ILI and DA

Q. Please summarize your conclusions regarding PG&E's proposals for ILI and DA.

A. ILI and DA are two key methods of assessing pipelines located in high consequence areas (HCAs) for integrity under the federal integrity management (IM) regulations, 49 CFR Part 192, Subpart O. I conclude that much of the ILI and DA expense that PG&E proposes is for work to address threats that PG&E should have already found, mitigated and remediated in the initial assessments performed between 2002 and 2012.

Q. What were operators supposed to accomplish in their initial assessments?

A. When the Pipeline Safety Act was signed into law on December 17, 2002, it mandated that all gas transmission operators must have assessed all of their existing pipelines by no later than December 17, 2012 and the operator's highest risk pipelines no later than December 17, 2007, which must comprise at least 50% of the total pipeline population. The purpose of doing initial integrity management assessments was to locate all of the immediate and critical defects that could cause a pipeline to fail and to remediate the defects and mitigate the cause of the defects. An operator that performed these initial assessments properly would expect to encounter significantly fewer defects in the re-assessment process.

Q. Is that the case with PG&E?

A. No. Contrary to expectations, it appears that PG&E is finding and expects to continue to find more immediate and critical defects in the re-assessments than in the initial assessments.

[12] In the response to TURN 026-Q04 Attachment 01, PG&E lists the number of self-reported violations it has reported to the CPUC since the San Bruno explosion. Furthermore, the response to TURN 010-Q05 Attachment 01 lists the large number of audit, external (CPUC) and internal (QA, Internal Audit group, outside consultants), findings for both distribution and transmission, which shows a trend of not following appropriate procedures, and other violations. These internal findings are in addition to the well-publicized external findings of the NTSB and this Commission's Independent Review Panel. In addition, three enforcement cases -- relating to the San Bruno explosion (I.12-01-007), recordkeeping violations (I.11-02-016), and class location violations (I.11-11-009) – remain pending (at the time of preparing this testimony) and may be decided by this Commission by the end of this year.

It appears that PG&E's prior assessment programs either were ineffective or did not fully encompass the risks they were supposed to mitigate. An analysis of the response to data request TURN 011-Q02 shows that PG&E has continued to find immediate indications (defects needing immediate attention) at an increasing rate even after some pipelines had reassessments.[13] By virtue of PG&E's heavy reliance on ECDA and its failure to fully follow the requirements of Subpart O, PG&E did not find all of the immediate indications that it should have found. Also, based on my work on SED's San Bruno investigation, I am aware that PG&E reprioritized immediate indications that should have been mitigated during the initial assessments, Now, PG&E proposes in the 2015 rate case to rectify this situation either by using other assessment methods such as in line inspection or by using a more vigorous DA program.

This conclusion is supported by the proposed costs for performing ECDA excavations on re-assessments and the costs for ICDA and SCCDA as shown in Table 4A-7 on page 4A-28 in PG&E's testimony. The proposed expenses in each of these categories are dramatically higher than the recorded costs in 2011.

With respect to ECDA, the methodology used in the ECDA standards (see NACE International SP-0502 2008) implies that all subsequent ECDA assessments should require fewer direct examinations since all of the immediate and many of the scheduled anomalies should have been removed and mitigation should have been performed. In addition, most of the pre-assessment costs (collecting historical data and records) that PG&E mentions (p. 4A-25) should have already been incurred for the initial assessment. With PG&E, it appears just the opposite has transpired and that costs of subsequent assessments are greater than the initial assessments, which would lead to the conclusion that the initial assessments did not find all of the necessary anomalies to protect the pipeline or that assessment and mitigation was not properly performed. PG&E's need to completely revamp its corrosion control program to reduce the number and severity of external corrosion anomalous areas and leaks (discussed below), further suggests that PG&E's prior ECDA work was not as effective as it should have been.

[13] Immediate indications or anomalies are the most severe and ran from a low of 0 per mile assessed in 2003 to a high of 1.29 for ECDA in 2010 and from 0.14 in 2005 to 1.68 in 2002 (before the program started) for in line inspection (ILI).

With respect to ICDA, in past audits of the PG&E integrity management program, SED has noted that PG&E discounted the possibility of internal corrosion (see early versions of RMP-06).[14] As shown in Table 4A-7, PG&E is now ramping up the ICDA work that should have been done in the initial assessments in 2002 through 2012.

5.2 Make Piggable Program

Q. What are your comments on PG&E's capital program to make an additional 516 miles of pipeline piggable (able to pass ILI devices to perform integrity assessments) during the 2015-2017 period?

A. PG&E has begun a program to make piggable as much of its gas transmission system and especially high consequence areas (HCAs) as possible, either using what they call traditional ILI or non-traditional ILI. In this rate case period, as part of a 10-year program to make piggable 2,728 additional miles, PG&E proposes to make piggable 516 miles, at a three year capital cost of approximately $300 million.

PG&E has done a poor job of showing that there are any significant risk mitigation benefits from its proposed pacing for this program, as compared to a slower pace, particularly in light of the mandated hydrotesting program and other assessment methods available to the company. Under PG&E's proposed hydrotesting program, all HCA pipe will be hydrotested by the end of 2015 and all non-HCA Class 3 and Class 4 pipe will be hydrotested by the end of 2017 (see Figure 4A-9 on p. 4A-34 of PG&E's testimony). In addition, PG&E proposes to complete hydrotesting of any segments for which cyclic fatigue analysis shows a need for a hydrotest in the 2015-2017 period (Figure 4A-9). The combination of hydrotesting and other available assessment methods, such as ECDA and ICDA, provides significant risk protection. PG&E has not provided any quantification or even a qualitative discussion of the incremental risk reduction in performing ILI versus the combination of hydrostatic testing followed by these other DA assessment methods.

Spreading out the time frame to increase the miles of pipelines that are piggable would be a cost effective method of reducing costs while not materially affecting the relative risk of the pipelines. PG&E rejected a plan to convert 100 miles per year (see page 4A-16 line 19) without

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[14] SED's 2005 and 2010 integrity management audits can be found on the Commission's website at: http://www.cpuc.ca.gov/PUC/events/110208_docs.htm

any useful explanation of the incremental risk impact compared to PG&E's faster program. As long as PG&E properly prioritizes the segments to be made piggable under a 100-mile per year pace, the overall decrease in risk reduction compared to PG&E's proposal, again not quantified or explained by PG&E, would be minimal but the cost impact would be significant.

Finally, as discussed below, PG&E's improvement to its cathodic protection systems is a further risk mitigation measure that limits the incremental risk from extending the time to bring pipelines into the ILI program.

5.3 Earthquake Fault Crossings

Q. What comments do you have about the proposed expenses and capital expenditures for earthquake fault studies and remediation?

A. As with many of PG&E's other programs, it appears that much of this necessary work has been deferred to be included in the 2015-2017 rate case years rather than being done on a continuing basis in the past. Tables 4A-14 and 4A-15 in PG&E's testimony (p. 4A-47) show that expenses and capital costs have been programmed into the rate case years with little spending in prior years. PG&E says that, since it acquired a database of earthquake faults in 2008, it had studied 29 fault crossings before 2013 and expects to study an additional 16 in the 2013 to 2014 period – a total of 45 in that six-year period.[15] Now it proposes to study 98 more crossings in this 3-year rate case period.

PG&E notes that it has known about the problems of crossing earthquake faults since at least 1985 when it began its fault crossing program (p. 4A-43). PG&E's consideration of alternatives beginning on page 4A-48 does not include a longer period of implementation, nor does PG&E quantify or even discuss the risk implications of lengthening the period of work. Based on PG&E's own relatively deliberate approach to this effort in the past and, up to this point, its appropriate concentration on areas with the highest concentrations of pipelines, faults, and HCAs (p. 4A-46), PG&E has not shown that the risk mitigation benefits of an accelerated program to reach a high number of lower priority crossings in this rate case period are significant enough to justify the added cost.

[15] PG&E Testimony, pp. 4A-45 to 4A-46 and Table 4A-13.

5.4 Vintage Pipe Replacement

Q. What are your comments about the vintage pipe replacement capital expenditure program?

A. Replacement of vintage pipelines is the single-biggest program proposed by PG&E, forecast to cost approximately $200 million per year to replace 20 miles of pipeline per year, an average cost of approximately $10 million per mile or $1,900 per foot of pipe replaced. As I indicated earlier, in light of the substantial expansions of many other programs proposed in this case, I believe that PG&E's plan to replace 20 miles of pipeline per year represents the outer limit of its ability to undertake such a large program competently and cost effectively. PG&E's data request responses to TURN indicate that PG&E itself has doubts about its ability to carry out more work than it has proposed in this case.[16]

I also question PG&E's use of its recorded PSEP replacement costs as the basis for its unit cost forecast here.[17] The PSEP program was a fast-tracked and emergency program which, under the circumstances, could not have been performed in the most efficient and coordinated manner. In this rate case period, by better planning, integrating the projects with other work in the area, and having multi-year contracts with suppliers and contractors, considerable costs could and should be saved. Because PG&E has had much more time to plan for this program than PSEP and can learn from its PSEP experience, PG&E should be able to benefit from economies of scale and better efficiencies.

5.5 Water and Levee Program

Q. What are your comments about the Water and Levee Program?

A. This is another program in which PG&E appears to be playing catch-up after having paid minimal attention in the past. PG&E was not able to respond to TURN's request for recorded expenditures (expense and capital) going back to 2005,[18] but the recorded/forecast numbers for

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[16] See PG&E's responses to data requests TURN 010-Q06, TURN 010-Q07 and TURN 010-Q13.
[17] This concern applies to many PG&E programs in which PG&E bases its proposed costs on actual recorded costs during the 2011- 2013 period when many programs were not being run efficiently since they had to be designed ad hoc to respond to orders from the CPUC, NTSB or PHMSA. If proper planning and a ramp up had been performed, there would likely have been efficiency savings from doing the work in a less rushed, more orderly fashion.
[18] PG&E Response to data request TURN 12-5.

2011- 2013 in PG&E's testimony show a huge jump in proposed spending for the rate case period. PG&E forecasts 2015 capital spending of $24.2 million, compared to $7.3 million in 2011-2013. In addition, PG&E has not demonstrated that the risk mitigation benefits of its proposed capital projects necessitate performing all of the proposed work in the rate case period. Since many of these crossings are not in inhabited areas, the amount of risk increase to the general public should not be large if some of the work is postponed. PG&E gives this program one of the lowest risk ranking scores,[19] suggesting that it can be slowed down without significantly affecting the overall risk reduction.

5.6 Shallow Pipe Program

Q. What are your comments regarding the Shallow Pipe Program?

A. Once again, this is a program that appears to have been neglected in the past, as partially shown in Table 4B-7 on page 4B-25 of PG&E's testimony. PG&E was not able to respond to TURN's request for recorded expenditures (expense and capital) going back to 2005,[20] but the recorded/forecast numbers for 2011- 2013 in PG&E's testimony once again show a huge jump in proposed spending for the rate case period. PG&E plans to survey 356 miles of shallow pipe in the rate case period and spend over $3 million per year in expense as compared to $22,000 in 2011 and $528,000 in 2012 (Table 4B-8 on page 4B-25). Similarly, capital expenditures for the rate case period are projected to increase from $2.1 million in 2011 through 2013 to over $73 million in the rate case period (Table 4B-9 on page 4B-25).

Such a large increase is not the result of regular surveying but rather the result of not performing this surveying and mitigation work in the recent past. PG&E states that the shallow pipe was discovered via ECDA, patrolling and pipeline centerline surveys. ECDA surveys were performed between 2002 and 2012, and under the federal regulations, patrolling should have been performed since 1970. Since ECDA and patrolling have been ongoing for many years PG&E should have been aware of and mitigated its shallow pipe problems earlier than this rate case. In a data request response seeking miles of shallow pipe PG&E has mitigated since 2002, PG&E acknowledged that it "did not have a programmatic approach" for addressing shallow pipe

[19] PG&E Response to data request TURN 010-Q03.
[20] PG&E Response to data request TURN 12-5.

locations and that PG&E does not have a comprehensive list of total miles of shallow pipe mitigated during this time period.[21] This deficiency was a compliance issue as the federal regulations specify depth of cover and regular patrolling and surveillance to look for changes that affect safety and operation.[22]

5.7 Work Required By Others

Q. What are your comments on the Work Required by Others (WRO) program?

A. This program is driven by the requirements of municipalities and other entities that require the removal or movement of PG&E gas facilities. Table 4B-12 shows that PG&E is projecting that the increase in capital spending for WRO in the rate case years as compared with 2011 through 2013 will be close to 180% ($79 million vs. $29 million respectively). PG&E claims that the increase is attributable to more transportation projects based on the improvement in municipal and state budgets. However, PG&E has not made a credible showing that the large increase in activity that PG&E is projecting is a reasonable forecast.

5.8 Measurement and Control Facilities

Q. What are your comments about M&C (Measurement and Control)?

A. Besides doing upgrades of the M&C equipment and rebuilds, PG&E has proposed to study the piping, valves and other equipment in the stations to determine what if any additional threats, such as manufacturing related or construction related defects, exist in the stations. For stations that are located in HCAs (High Consequence Areas), under Subpart O, this should have been completed no later than 2012.

PG&E is proposing a two phase approach to this issue, an ECA (Engineering Critical Assessment) Phase 1 to identify the issues and ECA Phase 2 to mitigate the issues which may include hydrostatic testing of station piping. Other threats to the stations may also be uncovered such as corrosion, outside force and possible third party damage. The ECA Phase 1 and Phase 2 expenses projected for the rate case period are estimated at $10.3 million[23] and $4.8 million,[24]

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[21] PG&E Response to data request TURN 012-4.
[22] 49 CFR Parts 192.327, 192.705, and 192.613.
[23] See Table 6-10 in the testimony at page 6-29.

respectively, with no spending prior to the rate case. The hydrotesting expenses are forecast to total $40 million during the rate case period.[25] Since most of these stations were installed after 1955, per Figures 6-3 and 6-4, under industry standard ASA B31.1.8–1955, CPUC GO 112 and 49 CFR Part 192, records should have been kept of these facilities and the testing and certification of their components. Since 1955, PG&E has either modified or upgraded these stations and thus there should be records of all of the tests that should have been performed.[26] If PG&E had followed these standards and requirements, ECA and hydrotesting would only be necessary for stations that are older than 58 years (2013 less 1955) that were not modified since installation.[27]

5.9 Corrosion Control - Overview

Q. Please provide an overview of PG&E's proposed corrosion control activities.

A. PG&E seeks a major expansion of its past corrosion control efforts in each of the areas of external corrosion, internal corrosion, and atmospheric corrosion. This expansion is reflected in a dramatic increase in PG&E's funding request compared to recorded levels. PG&E proposes 2015 forecast expenses of nearly $99 million, as compared to recorded expenses of $2.8 million in 2011 and $8.4 million in 2012. (Expenses related to some corrosion control activities may have been included in other cost categories, but PG&E is not able to identify these amounts.)[28] Similarly for capital expenditures, PG&E proposes $155 million of spending, as compared to $17.5 million of recorded costs from 2011 to 2013. These proposed expenses and capital expenditures do not include an additional $23 million of expenses and $21 million of capital costs that PG&E forecasts but will be paid by shareholders.[29]

In Figure 7-4 on page 7-13 of the testimony, PG&E relates that over 25% of the leaks on its gas system in the past 20 years were caused by the various types of corrosion. PG&E states that its

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[24] See Table 6-11, p. 6-30.
[25] See Table 6-12, p. 6-31.
[26] If PG&E did not perform tests when they made changes to the piping and the configuration of these stations, then they did not meet the requirements of ASA B31.1.8, CA GO 112, ASME B31.8, B31.8S or 49 CFR Part 192.
[27] Based on Figures 6-3 and 6-4, this would appear to mean approximately 24 complex stations and 83 simple stations out of the significantly larger population of these stations.
[28] PG&E Testimony, pp. 7-15 to 7-16.
[29] PG&E Testimony, pp. 7-1 to 7-2.

”decentralized” corrosion control program resulted in many adverse audit findings and “non-compliance issues”, and a new centralized program is being instituted to better align with industry best practices (page 7-13).

Most of PG&E’s proposed expenses, and almost all of its proposed capital costs, relate to external corrosion control. With respect to external corrosion, PG&E intends, among other things, to improve its cathodic protection, improve its maintenance of cathodic protection, use close interval surveys on gas transmission mains, improve its mitigation of electrical interference, and improve its casing mitigation and remediation. Even with PG&E not adding much additional new piping on their system, they are planning to add 35 more rectifier systems to provide sufficient cathodic protection to existing assets.

With respect to internal corrosion control, PG&E proposes to adopt “more prescriptive” standards and procedures, including site specific plans (p. 7-40). For atmospheric corrosion, PG&E proposes a significant expansion of the scope and quality of its current inspection procedures (pp. 7-42 to 7-43).

5.9.1 External Corrosion Control

Q. What are your comments regarding PG&E’s proposal to install new cathodic protection (CP) systems?

A. PG&E plans to install new CP systems where CP levels are inadequate (p. 7-21). This work is necessary to rectify PG&E’s failure to meet code requirements. Subpart I in 49 CFR Part 192 requires that all gas operators meet minimum cathodic protection criteria. In many situations PG&E has not met these criterion and failed to take prompt remedial action to correct the situation.[30] In addition, 49 CFR 192.613, required PG&E to engage in continuing surveillance, from which PG&E should have determined that its cathodic protection criteria were not effective in stopping external corrosion. Although I believe the new systems are needed to improve the cathodic protection and reduce the risk of unwanted and unplanned gas releases, a high proportion of these costs are necessary to bring PG&E’s cathodic protection into compliance

[30] See audit findings in the response to TURN 10-5, Attachment 1 and corrosion leak data in PHMSA annual reports per TURN 008-Q07, Attachments 1 through 4.

with code requirements and, furthermore, are necessary because of past inaction prior to the rate case period in addressing inadequate cathodic protection.

Part of PG&E's rationale for adding new cathodic protection systems is that PG&E plans to adopt the level of protection described in industry standard NACE SP0169-2007 which has an off potential requirement much more stringent than the one currently in use by PG&E (p. 7-21). Adopting this standard may help PG&E comply with code requirements. Whether or not PG&E followed this standard in the past, it still had an obligation to provide adequate cathodic protection, and PG&E's choice not to employ this standard previously does not excuse its past shortcomings.

Q. What are your comments regarding PG&E's proposal to add new coupon test stations along their pipelines at intervals of no greater than 1 mile (page 7-23)?

A. PG&E intends to start this program by installing almost 1,000 new test stations in the rate case period at a three-year capital cost of $18.5 million, and to complete the program within 5 years. PG&E claims that it should adopt a more prescriptive standard to have test stations no more than 1 mile apart (p. 7-23).

Nothing in federal or state regulations require having test stations located at no more than 1 mile intervals. There are much less expensive alternatives that would provide virtually the same risk benefit such as using trailing wires between test points and/or spreading out the program to 10 years or more. Increasing the implementation period to 10 years should reduce the rate case period capital costs by one-half. Slowing implementation or cancelling this program altogether would pose a minimum of additional risk since many of the existing test stations can be used to take readings by attaching a wire to the existing test station and moving the wire over the pipe at other locations. Having coupon test stations every mile is not necessary and will not noticeably reduce risk especially since PG&E is proposing to perform CIS over all of its pipelines on a periodic basis.

Q. What are your comments regarding PG&E's proposed corrosion investigations (expense)?

A. PG&E forecasts $5.5 million for corrosion investigations in 2015 as compared with slightly over $1 million of recorded costs in 2011 and $1.8 million of forecast costs in 2014. As stated in the testimony (page 7-25), PG&E has been plagued with low cathodic protection readings, evidence of inadequate cathodic protection, and forecasts that it will spend $16 million in shareholder funds to perform corrective action. PG&E has not shown that the high ramp-up in investigation costs for 2015 as compared to previous years is not also part of the historic problem of low readings and thus a consequence of its failure to meet code requirements.

Q. What are your comments about PG&E's proposed programs to address electrical interference?

A. Under the regulations in 49 CFR Part 192, Subpart I, operators are required to check for and mitigate any electrical interference from AC (alternating current) and DC (direct current) sources. It appears from the historic recorded low level of spending for AC interference expense and capital that only recently has PG&E proposed to survey for AC interference and mitigate areas of interference (see Tables 7-9 and 7-10 on page 7-32). Capital spending on mitigation was $485,000 in the 2011 through 2013 period, and PG&E now proposes almost $42 million for the rate case period. Clearly PG&E has had problems complying with its obligations under 49 C.F.R. Section 192.473, and only recently has PG&E decided to address the issue even though this requirement has been part of federal and state pipeline safety regulations since 1970. PG&E appears to be asking ratepayers to pay for costs to mitigate problems that it should have addressed previously.[31]

With respect to DC interference, although Part 192.473 requires an operator to have a continuing program to minimize the detrimental effects of stray currents, PG&E has not shown that it historically had any such program and acknowledges as much when it admits that it needs to "formalize" its program. In fact, PG&E's expense history is not able to show any recorded costs in 2011 and 2012 (Table 7-11, p. 7-35). The recorded capital spending for mitigation efforts (Table 7-12, p. 7-35) is most likely the result of test station readings taken for other purposes rather than a program that satisfies Part 192.473. Here, PG&E proposes to ramp up survey expenses, from zero in 2011 to $2.5 million in 2015 (Table 7-11). This sudden spike in spending appears to be an effort to make up for its past non-compliance with code requirements.

[31] In the response to TURN 014-Q017, PG&E states the data for this element of corrosion control is "not readily" available prior to 2009 and spending between 2009 and 2012 was between $0MM and $0.01MM for expense and $0MM and $0.268MM for capital.

Q. What are your comments regarding PG&E's proposed expenses and capital expenditures for casings?

A. Since 1970, Part 192.467 has required that pipelines be electrically isolated from metallic casings. PG&E reports that of its over 3200 casings, it has identified 335 that need to be remediated to remove shorts or electrolytic contacts (contacts that allow electric current to pass from the carrier pipe to the metallic casing).[32] These problems have not just suddenly occurred, but constitute a backlog that PG&E has failed to effectively correct.

Most of the proposed expenses and capital expenditures constitute costs for mitigation work that PG&E should have already performed to comply with the federal regulations. PG&E states that only 4 of the 98 capital mitigation projects it proposes for the rate case period are for expected mitigations required by annual casing surveys, which means the remaining 94 are to help address the backlog.[33] Similarly, 111 of the 117 expense mitigations are for backlogged casings that need correcting.[34] Thus, the overwhelming majority of PG&E's proposed funding request in this area is for costs that are needed to remediate PG&E's past failure to comply with Part 192.467.

5.9.2 Internal Corrosion

Q. What are your comments regarding PG&E's internal corrosion program?

A. As noted in the PG&E testimony on page 7-39, since 1970, 49 CFR 192.475 to 192.477 prohibited operators such as PG&E from transporting corrosive gas unless the corrosivity of the gas is investigated and steps are taken to minimize internal corrosion. PG&E claims that it has a current program that ensures compliance with these requirements, yet is not able to show that it has any such program. In fact, PG&E shows no recorded expenses for internal corrosion control in 2011 and 2012 and near-zero capital expenditures for the 2011-2103 period. In this case, PG&E now proposes 2015 expenses of $8.7 million to develop site specific plans targeting key points where liquids are most likely to accumulate and that will contain internal corrosion monitoring, testing and inspection requirements.[35] This is another example of a corrosion

[32] PG&E Testimony, p. 7-36.
[33] PG&E Testimony, p. 7-37.
[34] PG&E Testimony, p. 7-38.
[35] PG&E Testimony, p. 7-40 and p. 7-41, Table 7-15.

control program in which most of the costs are to remediate PG&E's past failure to have a code-compliant program, not to address ongoing requirements.

Regarding capital spending, PG&E proposes to purchase electron microscopy coupon devices along with permanent ultrasonic thickness sensors (page 7-41) which are not necessary since old fashion test coupons would do the same thing at considerably less cost.

5.9.3 Atmospheric Corrosion

Q. What are your comments regarding PG&E's atmospheric corrosion program?

A. Atmospheric corrosion is a form of external corrosion when steel is exposed to wet conditions above ground and starts to corrode. Since the advent of federal pipeline safety regulations in 1970, operators such as PG&E were supposed to have programs to inspect and mitigate the effects of atmospheric corrosion.[36] Although PG&E claims that its current efforts meet "minimum requirements," it acknowledges that its atmospheric corrosion activities are performed as a secondary activity by field personnel who are not specifically trained to inspect for atmospheric corrosion (pp. 7-42 to 7-43). It goes on to say that currently such inspections have a very limited scope and do not require much time (p. 7-43). Clearly, PG&E has been neglecting its obligation to effectively inspect for atmospheric corrosion. As a result, PG&E likely has failed to identify and mitigate atmospheric corrosion that a compliant program would have found.

Now, PG&E proposes $20.4 million of expenses for inspection and mitigation of atmospheric corrosion in 2015. In comparison, PG&E recorded a total of $1.4 million for mitigation in 2011-2012 and only $720,000 for 2013.[37] The huge jump in mitigation costs is the result of mitigating corrosion that should have previously been detected and mitigated under an effective inspection program. PG&E states that it does not include in its forecast 2015 mitigation costs expenses for locations identified more than three years earlier (p. 7-45),[38] but this exclusion does not

[36] See 49 CFR 192.479 and 192.481

[37] See PG&E response to TURN 14-2 for 2013 recorded costs. PG&E says it did not separately record all costs for atmospheric corrosion in 2011-2013 (p. 7-43).

[38] PG&E notes that it is excluding from its 2015 forecast $29 million that it expects to spend in 2014-2017 to remediate corrosion identified more than three years earlier (p. 7-44).

adequately address the fact that PG&E will only just now identify corrosion that it should have found more than three years ago.

5.10 Gas System Operations and Maintenance

Q. What are your comments regarding PG&E's proposed expenses for locate and mark work?

A. PG&E forecasts $9 million in 2015 expenses for this work even though recorded expenses in 2011 and 2012 were much lower, $5.5 million and $7.2 million, respectively. PG&E asserts without much support that the volume of locate and mark activities and the length of stand-by time are increasing (p. 8-12). PG&E has not justified its forecast, and a forecast based on the average of recorded costs for 2011-2013 would be more reasonable.

Q. What are your comments regarding Pipeline Patrol costs, an element of the Pipeline Maintenance area?

A. PG&E forecasts $2.0 million for 2015 ground patrol costs, compared to an average of $630,000 for such costs in 2011-2013 (Table 8-7 on p. 8-17). PG&E does not provide any explanation for this increase in cost and should be limited to a labor cost escalation over its historic 2011-2013 average costs.

PG&E forecasts $6.6 million for aerial patrol costs in 2015 compared to an average of $900,000 per year for 2011-2013 (Table 8-7, p. 8-17), The justification in the testimony (p. 8-16) states that the additional costs are due to using a helicopter to patrol the 1070 miles of HCAs a second time each month. However, using the existing method would only double the prior costs of less than $1 million to slightly less than $2 million. PG&E did not justify why using a helicopter would improve the survey and assist in finding areas of leaks, encroachment, and shallow cover any more effectively than the existing method.

Q. What are your comments regarding Pipeline Maintenance and Repair Expenses, another component of the Pipeline Maintenance category?

A. The significant jump in PG&E's 2015 forecast of $11.2 million from recorded levels of $4.1 million and $5.3 million in 2011 and 2012 (Table 8-8, p. 8-18) does not seem to take into account reductions in preventive and corrective maintenance that should result from the other extensive capital improvements PG&E proposes, such as corrosion control repairs and improvements, improved response to low cathodic protection readings, replacement of old valves, and overhauling measurement and control stations. Although some increase in this category may be warranted, particularly in light of twice per year maintenance of automated valves (compared to once per year for manual valves), PG&E's forecast that is more than double the 2012 recorded costs seems excessive.

Q. What are your comments regarding Transmission Expense Projects, another element of the Pipeline Maintenance category?

A. As PG&E shows in Table 8-13, Pipeline Projects (the biggest category of Transmission Expense Projects) consists of work to repair pipeline – including leak, corrosion and weld repairs – vegetation management, and addressing right-of-way encroachments. PG&E forecasts $30.6 million for this work in 2015, compared to an average of $11 million for 2011-2013. Much of this increase is attributable to deferred maintenance that should have been done during previous rate cases that PG&E is finally getting around to addressing in the current case. For example, some of these costs are for leak repairs due to not responding properly to cathodic protection issues and not taking the correct measurements for cathodic protection, not having individuals witness contractors who may be encroaching on the pipeline, and other actions contrary to code requirements and prudent practices.

5.11 Gas System Operations

Q. What are your comments regarding the programs PG&E is proposing in the Gas Systems Operations category?

A. I will comment on two aspects of PG&E's Capacity Projects capital expenditure forecasts for the 2015-2017 period -- the Normal Operating Pressure (NOP) reductions and PG&E's Customer Demand Growth estimate.

Using NOP reductions to overcome historic overpressure events is an extremely costly method of correcting operational issues based on poor maintenance of equipment, training issues, and bad record keeping. PG&E estimates that NOP reductions will cause the need for capacity projects costing a total of $80 million over the rate case period. At the same time, PG&E is reducing NOP, it is also proposing to address its operational deficiencies with many new and expanded programs at great cost. Lowering the set points of regulators to give a greater safety margin to compensate for operational errors should not be necessary. PG&E claims that lowering these set points has reduced unwanted over pressure events. But PG&E has also requested funding to increase the number of pressure sensing devices, improving the SCADA system, adding artificial intelligence, installing remote control valves, plus improving the maintenance and reliability of the station infrastructure, all at significant expense to ratepayers. By reducing the pressures, and thus the capacity, of lines to protect from over pressure events is treating the symptom, but not the cause. In effect, PG&E is asking ratepayers to pay twice to address its past operational shortcomings.

PG&E's capacity need projection for customer demand growth seems extremely optimistic and, at best, speculative. Although the economy is growing again, growth is still somewhat constrained by other factors such as lack of wage growth, increased conservation, and improvements in gas appliance efficiency. PG&E's projection that added demand will require a 35% increase in pipeline spending (from $85.4 million for 2011 to 2013 vs. $115.6 million for the rate case period) is more guesswork than reasonable forecast.

6. Best Practices

Q. What are your concerns about PG&E's reliance on the concept of "best practices"?

A. PG&E frequently states that it is instituting "best practices" or "industry best practices" to justify many of the tasks and programs for which it seeks large increases for both expense and capital costs.[39] In my view, many of these "best practices" are actually requirements of current regulations. And many of the others are practices that PG&E should have been doing to improve integrity and reduce risk on their pipelines in the past, in order to operate their system prudently and to comply with the spirit, if not the letter, of existing regulations.

Below is a listing of some of these "best practices" and comments regarding them.

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[39] See PG&E Supplemental Testimony, Chapter 2B, and Appendix 1 entitled "INDUSTRY BEST PRACTICES INCORPORATED INTO 2015 GAS TRANSMISSION AND STORAGE TESTIMONY" for a complete listing of claimed best practices.

- Taking into account interactive threats -- this is a current requirement of Subpart O of the federal regulations
- Using DA when a pipeline cannot be assessed via ILI devices -- using the right assessment methodology is a requirement of Subpart O; only using DA is not necessarily a best practice since performing pressure testing may be appropriate for some pipelines
- Implementing root cause analysis beyond the direct cause -- something that should have been ongoing especially for a company the size of PG&E and one that is having so many integrity issues
- Assessing threats on pipelines that cross levees -- this should have been done previously, especially if the levee is in an HCA
- Developing performance metrics for risk analysis and decision making -- this should have been part of the risk assessment program
- Managing assets to ensure highest risk assets receive resources - this should have been done in the past
- Controlling gas quality by monitoring -- required under current regulations, 49 CFR Part 192.475-477
- Creating a corrosion control discipline -- should have been undertaken previously based on root cause analysis of corrosion issues
- Use of more stringent off potential -- should have been implemented in the past due to documented corrosion control failures
- Use of site specific plans to mitigate internal corrosion -- a requirement of current regulation, 49 CFR Part 192.475
- Expanded scope and frequency of atmospheric corrosion inspection -- based on known failures and issues, this is not a best practice but a regulatory requirement
- Installation of AC coupons -- a regulatory requirement due to interference and safety concerns
- Reducing operator re-qualification testing from 5 years to 3 years -- most industry and states have implemented this from the onset of the OQ regulations
- Reducing NOP -- not a best practice but rather a work around to make up for other shortcomings such as poor, maintenance, records and training

- Discontinue use of manual throttling of valves -- a work around to compensate for poor training and operating errors
- Consultant review of control room management -- a probable requirement of the control room operation regulation
- Consultant review of human factors in the control room -- a requirement of control room management regulation
- Fatigue management program for the control room -- a requirement of control room management regulation
- Alarm management program -- a requirement of control room management regulation

Thus, it is evident that many of the "best practices" are really regulatory requirements or responses to problems that PG&E has ignored in the past.

Q. Does this conclude your testimony?

A. Yes, it does.

ATTACHMENT A

CURRICULUM VITA OF DAVID BERGER

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Areas of Specialization

Mr. Berger specializes in pipeline and system integrity management and risk assessment, corrosion control, gas-infrastructure asset management, and gas system operation and security.

Relevant Experience

Mr. Berger has been involved in rate making cases for gas distribution companies for many years from both the operator and regulatory perspective. Most recently he advised the Maine PUC on a rate case for the largest gas distribution company in the state and in particular on their proposed infrastructure replacement program. Previously he had performed a safety and management audit on this company for the commission staff as part of settlement agreement. When Mr. Berger was with KeySpan Energy (now part of National Grid) he was involved in several rate cases with regard to gas metering and corrosion control issues along with infrastructure improvements (system integrity aka DIMP).

Mr. Berger performed two management audits for the New York PSC on three gas distribution companies on their recently approved rate cases with regard to safety programs and main and service capital replacement programs. These audits included the state's largest utility and also a more rural utility.

Mr. Berger was the task area leader for the areas of corrosion control and emergency plans in an investigation of operational safety for the Illinois Commerce Commission. The audit reviewed and evaluated an LDC's overall operations and maintenance activities and its gas safety programs to determine the degree to which they are in compliance with federal and state regulations and conformance of those activities and program with industry best practices and the best practices determined by the ICC Staff in consultation with the LDC.

He is consulting for the Vermont Public Service Department on evaluating the safety, construction and operating issues on proposed expansion which requires a certificate of public good. This expansion will involve both transmission and distribution pipelines and mains.

He was the task area leader for gas operations in an investigation of operational safety and management practices of a small gas operator for the New Jersey Board of Public Utilities.

He provided expert review and possible testimony regarding a safety issue on mechanical couplings for the District of Columbia Public Service Commission.

Mr. Berger is under contract to United States Department of Transportation (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) to assist in developing and implementing a gas and liquid pipeline integrity management program and to assist in inspecting operators of pipelines through Cycla Corporation. He is the author and instructor at PHMSA's Training and Qualifications Section (T & Q) on direct assessment training modules for External Corrosion Direct Assessment (ECDA) (including a course on ECDA indirect inspection techniques) Internal Corrosion Direct Assessment (ICDA), Stress Corrosion Cracking Direct Assessment (SCCDA), and Confirmatory Direct Assessment (CDA). In addition, he is a consultant to PHMSA on integrity management notifications, special permits (such as alternate MAOP and class location changes) and corrosion control issues for both gas and liquid pipelines.

He consults with the Washington Utilities and Transportation Commission for corrosion control and integrity issues and provides expert advice regarding commission investigations and consent orders pertaining to gas infrastructure issues. He is a technical consultant for a risk model regarding distribution integrity issues. He completed a validation audit on the implementation of audit recommendations as the outcome of consent order.

Most recently Mr. Berger has been retained by the California PUC to assist in an investigation of an incident on a transmission pipeline in Northern California. He has assisted commission staff with preparing relevant documents and reviewed and commented on documents provide by the utility. Mr. Berger also performed a risk review for a recent rate case on gas distribution for the staff of the CPUC. Currently Mr. Berger is working with TURN in reviewing and providing testimony on a gas transmission rate case.

Mr. Berger is also under contract as a technical expert and possible expert witness for the US Department of Justice. He is currently working on a case that has been proposed for trial involving fatalities and significant property losses.

He has worked for the Florida Department of Transportation as an expert witness in a litigation concerning a right of way issue with gas pipeline along the Florida Turnpike.

Until July 2004, Mr. Berger was the Division Manager, Asset Management, for KeySpan Energy (now part of National Grid). In this capacity, he managed a group of engineers, clerks, technician assistants, supervisors, and field labor to assess, maintain and improve the assets of the gas infrastructure (both distribution and transmission facilities) and the cathodic protection systems on all KeySpan Energy gas and electric facilities (Long Island, New York City, New England). He was the process owner of KeySpan Energy's gas transmission system and directed the overall corrosion control programs for all KeySpan Energy's assets (gas, electric, electric generation). Many of the issues he provided guidance on related to implementation of improvements in the gas distribution assets one of which included work on a mechanical coupling issue relating to change in gas quality. He provided guidance to corporate security on gas operational security issues and implemented security plans for the gas infrastructure in all service areas. He was a developer of the direct assessment method of determining gas pipeline integrity.

In the position of section head of the Environmental Engineering Department for KeySpan, Mr. Berger managed a group of engineers that was responsible for all of the hazardous waste, industrial waste and petroleum storage facilities for the company. He negotiated permits and compliance schedules with all levels of regulatory officials (local, county, state and federal). He prepared and submitted all superfund and other legal notifications. He provided support to operating organizations, legal department, and fuel management personnel for environmental matters.

Prior to his employment at KeySpan, Mr. Berger was the Director of Operations for Russell Plastics Technology Inc. and a Plant Manager for ICI Americas, Inc. - Aerospace and Chemical Divisions

Education

University of Delaware, course work (32+ credits) for M.S. in Environmental Engineering

New York University, B. Ch.E. (Chemical Engineering)

Other Honors, Societies, and Papers

Member A.I. Ch. E.

Member NACE

Author and co-author of papers in WPCF, AGA, NACE

AGA Corrosion Control Committee Chairperson 2000 to 2004

AGA Distribution Engineer of the Year, 2002

CIS, PCM and ACVG Corrosion Tools

AGA Achievement Awards, 2003, 2004

Bass Trigon Corrosion Control Data Base

Numerous papers in various pipeline technical journals and NACE publications

New York State Regents Scholarship (College) and Incentive Award