

California Public
Utilities Commission
Safety and Enforcement
Division
Final Staff Report

Pacific Gas & Electric Company
Proposal for Cost of Service and Rates for
Gas Transmission and Storage for 2015-2017
Application 13-12-012

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EXECUTIVE SUMMARY

The Staff of the California Public Utilities Commission (CPUC) Safety and Enforcement Division (SED) prepared this report on Pacific Gas and Electric's (PG&E) Application for cost of service and rates for Gas Transmission and Storage (GT&S) services for 2015-2017. This report provides a review of the risk identification, risk evaluation and risk ranking methodology used by PG&E in preparing this Application. Additionally, this report evaluates the proposed pipeline integrity management projects against the scope of projects identified in PG&E's Pipeline Safety and Enhancement Plan (PSEP). While critical in the final evaluation of the Application, this Staff report does not opine on funding levels associated with any project.

Staff recognizes that in this Application, PG&E is employing new methods to confront risk trade-offs across different lines of business. PG&E's Application makes strong use of qualitative risk assessments. Staff recommends that PG&E inject additional quantitative rigor into its risk evaluation process. PG&E should improve its risk models to adjust for different scopes and pace of implementation. Additional use of quantitative optimization methods could complement its risk decision-making process. In the future, PG&E should consider integrating techniques that consider both project cost and risk reduction, such as "As Low As Reasonably Practicable" (ALARP), and should provide additional transparency about its enterprise risk tolerance in its overall risk assessment and risk mitigation decision-making process. PG&E shifts its focus from primarily addressing untested segments of pipeline (as targeted by PSEP) to other potential pipeline threats. Overall, the proposals in this Application are more focused and refined. PG&E's proposal views its system more holistically, combining PSEP work with existing "base work."

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INTRODUCTION AND BACKGROUND

As directed by the Assigned Commissioner's Scoping Memo in Application (A.)13-12-012, the California Public Utilities Commission (CPUC) Safety and Enforcement Division Staff (SED) has drafted this report focusing on Pacific Gas and Electric Company's (PG&E) proposal for cost of service and rates for Gas Transmission and Storage (GT&S) services for 2015-2017. The Scoping memo asks SED staff to consider whether "PG&E's proposed risk management approach and asset family categories" are reasonable. As further noted in the Scoping Memo, PG&E's "risk assessment approach is part of the basis upon which PG&E developed its cost for this proceeding." SED staff provides this report with the express aim of providing an evaluation of the risk assessment and risk management methodology used by PG&E in preparing this Application.

Staff's evaluation consists of two main parts. The first part is an objective review of the risk identification, risk evaluation, and risk ranking methodology used by PG&E in the GT&S application. This first part will also make use of the evaluation criteria developed by Cycla Corporation to evaluate the strength of the risk assessment/management program that PG&E has instituted to address transmission and storage related risks. The second part is an evaluation of the proposed integrity management programs against the scope of work identified in PG&E's Pipeline Safety Enhancement Plan (PSEP)¹.

Our report is premised on three critical steps to examine PG&E's application in order to answer the questions posed by the Scoping Memo:

¹ PSEP was approved by the Commission in D.12-12-030, as part of Rulemaking (R.)11-02-019.

- 1) Risk Identification
- 2) Risk Assessment
- 3) Risk Management

In order to properly undertake the evaluation of PG&E's risk management process, it is necessary to have a set of uniform, standardized definitions. The Commission has not yet adopted any specific definition of "risk" as used in this context. In general, it is very possible for there to be an inconsistent usage of the term "threats" and "risks." A threat is a phenomena or an occurrence which alone or in combination have the potential to give rise to or contribute to a risk. Risk is the effect of uncertainty on objectives, expressed in terms of a combination of the likelihood of occurrence of an event and associated event consequences.²

In the context of pipeline safety, a threat is a physical phenomenon or occurrence that can endanger a pipeline, and a risk is a potential effect arising from that threat together with its likelihood of occurrence.

Risk identification is the process of inventorying potential threats and putting them into terms of likelihood and consequence. Risk assessment involves the analysis of data to identify which hazards/threats present the greatest risk in the system. It is in the Risk assessment stage where risks are put into a relative order. Risk management is the process by which the organization responds to the identified risk. We note that risk can never be eliminated, but rather the risk can only be mitigated down to an acceptable level.

Risk identification can either be done subjectively or empirically. As a result, risk identification can have the following attributes:

² Definition from ISO (International Organization for Standardization) Guide 73:2009.

1. For risk calculations based on a subjective risk scoring method, risk is a dimensionless number related to the likelihood of occurrence and the associated event consequences, if both the likelihood and consequences are expressed as dimensionless numbers.
2. For risk calculation based on some physical estimates of frequency and consequence, risk has dimensions expressed as consequence units per unit time, where consequence units can be defined in monetary terms (ex. dollars), number of incidents, number of injuries, number of fatalities, or numbers of buildings damaged, etc.

If a risk value is defined as the product of likelihood and consequence, a risk value is always understood in the context of the associated threat (or combination of threats). Therefore, terms such as “risk ranking” or “top risks” are far more correctly stated respectively as “threat ranking based on the associated risk values”, “top threats based on their risk values.” As applied in this Application, the concept of a “risk register” as used by PG&E is more accurately stated as a “threat register based on the associated risk values” since it is the physical threat phenomena or occurrences (such as corrosion or excavation damage) that are being ranked and addressed by the proposed mitigation programs and projects. However, efforts to make terms precise can quickly lead to expressions that are unwieldy or impractical to use. For this reason, in our evaluation of PG&E’s Application, we use the term “risk” as surrogate for the more precise threat/risk pair concept, with the emphasis understood to be on the physical threat phenomenon based on its associated risk value.

With the standardized set of vocabulary in place, along with the above clarification, we now turn to the particulars of PG&E’s Application.

PURPOSE OF THIS REPORT

In evaluating whether PG&E was complete in its risk assessment and risk management methodology, SED considers whether PG&E included all of the “top” threats based on their risk scores. It is not practical for PG&E to include a mitigation strategy for every potential threat; the value in risk assessment is derived from systematically identifying threats and prioritizing them based on their impact and likelihood of occurrence.

Following identification and ranking of threats and associated risks, the next step is for PG&E to determine the suite of candidate risk mitigation measures. PG&E needs to then select the mitigation measure which best “fits” the assessed risk. Selecting a mitigation strategy should include an evaluation of best practices and available technologies. Selecting between the various different mitigation options should factor in both relative cost and benefits and also the operator’s knowledge and perspective of that particular part of the system. While we encourage prudent spending, this report does not examine the cost effectiveness or affordability of any of PG&E’s proposed risk mitigation programs and projects in this GT&S application. Ideally, a quantification of benefit of reduced risk exposure could be compared to the project’s proposed costs. While SED staff is concerned about affordability, ultimately we did not have sufficient information or resources to provide that type of detailed analysis.

OVERVIEW OF PG&E'S RISK ASSESSMENT & MANAGEMENT FRAMEWORK

This section briefly describes PG&E's threat identification, risk ranking, risk mitigation and, finally, investment³ framework.

PG&E accomplishes the implementation of its asset management and risk mitigation strategies by segregating the gas assets into "asset families," five of which are part of the GT&S application: (1) transmission pipe, (2) gas storage, (3) compression and processing, (4) measurement and control, and (5) liquefied natural gas and compressed natural gas. For each asset family, the responsibility for identifying the threats associated with the asset family, ranking the associated risks, and identifying mitigation measures rests with an asset family owner, who is typically a director-level or senior director-level employee.

During the threat identification process, subject matter experts identify potential threats within each asset family according to one of the three risk categories:

- 1) Loss of containment
- 2) Loss of supply & service
- 3) Inadequate response & recovery

To incorporate the existing Pipeline and Hazardous Materials Safety Administration (PHMSA) Integrity Management framework into the threat classification process, PG&E uses the threat categories developed in American Society of Mechanical Engineers (ASME) B31.8S to classify all threats that can affect pipeline integrity (loss of

³ The terms "investment" and "portfolio" as used by PG&E in this context refer to the mixture of proposed programs and projects and their associated capital expenditures and expenses.

containment) into three buckets: stable threats, time-independent threats, and time-dependent threats. PG&E further classifies the additional threats/risks associated with Loss of Supply and Service (capacity/reliability threats) and inadequate Emergency Response and Recovery. PG&E then ranks the threats according to the relative risk each threat can produce based on its likelihood and consequence of an occurrence. There are 85 identified threats (and threat causes) in the risk register across all asset families. PG&E calculates risk as the product of a likelihood score and a consequence score. For the consequence score, subject matter expert input is used to select a score. For the likelihood score, a combination of a subject matter expert's opinion and actual frequency data is used, depending on the availability of the actual frequency data.

There are two phases to PG&E's risk score calculation and risk ranking process:

- 1) The risk register scoring phase, which focuses on the enterprise level risk;
- 2) The programs and projects scoring phase, which focuses on individual program's ability to mitigate risk.

We go into detail about each phase, below.

Risk Register Scoring

Risk register scoring⁴ is first conducted at the individual asset level. Then, scores are discussed and debated in "calibration" sessions across all Gas Operations asset families, at the Gas Operations senior management level in the Risk and Compliance Committee, and finally at the Enterprise level. Scoring is not complete until Session D, the Enterprise review, is complete.⁵ The main purpose of the Enterprise level review is to identify major threats, i.e. those with the highest risks across all lines of business.

⁴ This procedure is described in full detail in Attachment 2 to PG&E's data response to TURN_001-Q01. Additional details on this procedure can be found in PG&E's Utility Procedure: TD-4011P-01, Rev: 0. SED's report only highlights the major concepts in this methodology.

⁵ Description is based on Comment A10 of PG&E's preliminary comments on Preliminary SED Staff Report.

Through this iterative calibration process, the risk register scoring is adjusted first within asset families and then across different asset families is adjusted for the top 20 threats in order to result in a calibrated set of risk register scores across asset families.

The calibration process involves adjustments of frequency and consequence scores in order to ensure consistency of risk register scores across asset families, but neither the risk calculation model nor the weights are adjusted as a result of calibration. After calibration occurs, similar risks across different asset families should result in similar risk register scores.

Using an Excel spreadsheet model PG&E developed with the assistance of a consultant, the subject matter experts select numeric frequency and consequence scores to each identified threat to produce a risk score associated with the threat. The risk register scoring is a relative, subject matter expert opinion-based measure of what could happen if steps were not taken to mitigate the threat using the program in question. The score reflects the enterprise-level risk, not the ability of any project to mitigate the risk.

During the risk register scoring phase, six categories of consequences (attributes) are considered:

- 1) Health & Safety
- 2) Environment
- 3) Compliance
- 4) Reliability
- 5) Reputation
- 6) Financial

Each consequence attribute initially receives an ordinal score ranging from 1 to 7. The initial ordinal consequence attribute scores are transformed by an increasing exponential function, with the aim of emphasizing high consequence events by

magnifying the events with high consequence attribute scores. This exponential transformation results in what PG&E sometimes refers to as a “logarithmic scale” or “Richter scale” where each succeeding score differs from the previous score by a factor of 10. Different weights are assigned to each of the six consequence attributes. Each transformed consequence attribute score is then multiplied by an adjusted weighting factor. The aim of this adjustment is to ensure that threats with the highest health and safety ordinal scores would produce a higher total consequence score than a threat which otherwise has identical consequence scores due to other non-safety consequence attributes. Finally, for each threat, the values are summed to produce a combined weighted and adjusted, exponentially-transformed consequence score for that threat. This final sum is the consequence of failure (CoF) for that threat.

For each threat, a likelihood of a failure (LoF) value is determined (or selected). The likelihood value is expressed as a frequency value expressed as the expected number of failure events per year due to the threat. The likelihood of failure values are based on actual PG&E failure experience, industry failure experience, or subject matter expert opinion when insufficient failure experience is available.

Finally, for each threat, the risk register score is calculated as the product of the LoF and the CoF. The threats associated with the top 20 risk register scores are forwarded to PG&E’s top leadership at the “Integrated Process Risk and Compliance Session” (known internally at PG&E as “Session D.”) As part of Session D, the asset family owners propose mitigation programs to address some, most, or all identified threats in the combined risk register. At this point, output from Session D, consisting of the complete risk register and proposed mitigation programs, becomes the input for another process referred to as “Session 1.” During Session 1, which involves many iterative steps between top level management and asset family owners, program scope,

program pace, and finally program costs estimates are refined in order to arrive at a selection of final programs to adopt for the rate case cycle.

In addition to programs and projects proposed to mitigate specific threats and associated risks, Session 1 also considers programs and projects that are non-discretionary in nature. These non-discretionary programs and projects are compliance-based, customer-driven, or fixed cost items. PG&E uses the term “strategic” to classify discretionary programs and projects. PG&E indicates⁶ that the “strategic” category also includes multi-year compliance programs; these are programs where PG&E has the discretion to vary the degree of performance from year to year, or to defer performance until the final year, without being out of compliance.

Programs and Projects Risk Scoring

In Session 1, potential programs are risk-scored using an indexing scoring method, where both likelihood and consequence scores are integers ranging from 1 to 7. Each proposed program under the strategic category receives a set of three separate risk scores for safety, environment, and reliability. Risk scores are not calculated for programs and projects that are not classified as strategic. The separate risk scores are integer scores ranging from 1 to 49 shown in a 7x7 matrix, calculated as the product of the likelihood score (1 to 7) and the consequence score (1 to 7). Some of the cells in the 7x7 likelihood/consequence risk score matrix are artificially assigned higher values than would be indicated by a strict application of the likelihood score multiplied by the consequence score, with the apparent aim of assigning higher risk scores to the high consequence events. The program risk score is the maximum of the three separate risk scores. Each strategic program has a final relative risk score. In order to gain further granularity in the mitigation programs, PG&E develops different “tiers” of programs

⁶ Clarification made at a workshop hosted by SED Staff on July 30, 2014.

with each tier addressing a different or escalating level of risk. The program and project risk scores help to inform the Asset Family Owners, subject matter experts, and the Governance and Sanctioning Committee as to the relative importance of the programs on an integer risk scoring, relative risk mitigation effectiveness basis, with emphasis on safety, environmental impact, and reliability. The output from Session 1 is the portfolio of programs and projects, consisting of both capital and expense components, that PG&E proposes to put into an executable investment plan.

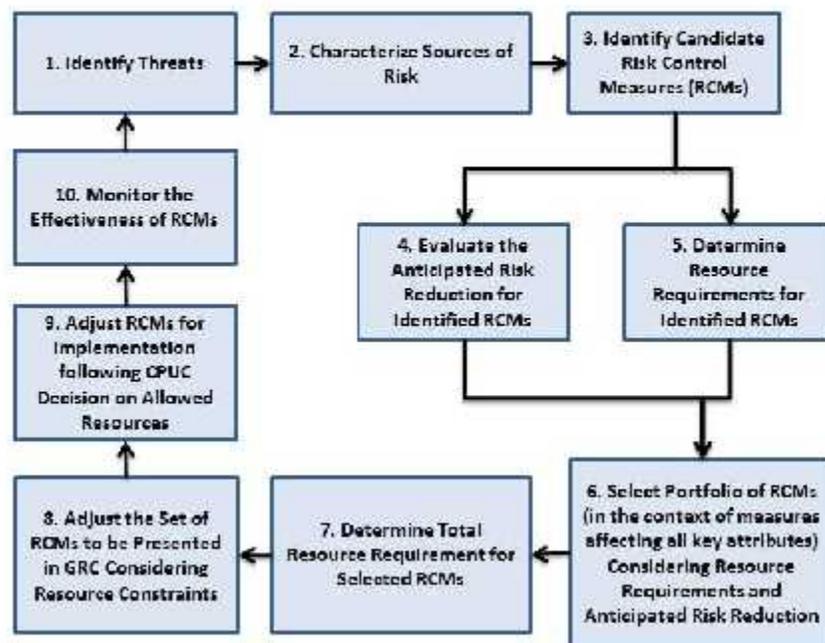
Output from Session 1 is fed into “Session 2”, where risk-based prioritization and constraints across asset families are applied across all the selected programs and projects selected in Session 2 to arrive at the final, executable mix of investment portfolio. PG&E employs the same indexing scoring method in both Session 1 and Session 2.

The foregoing generally describes the threat identification, risk ranking, risk mitigation, and finally investment framework PG&E used to arrive at the list of capital and expense programs and projects in the current GT&S proceeding.

RISK ASSESSMENT AND MANAGEMENT EVALUATION

SED's evaluation of PG&E's GT&S Application relies on the identical criteria developed by Cycla Corporation and used during its evaluation of the PG&E general rate case, A.12-11-009. The evaluation is based on a set of 10-step criteria, which is represented graphically below.

Elements of a Risk-Informed Rate Case Development Process



- 1) Identify the threats having the potential to lead to safety risk;
- 2) Characterize the sources of risk;
- 3) Characterize the candidate measures for controlling risk;
- 4) Characterize the effectiveness of the candidate risk control measures (RCMs);
- 5) Prepare initial estimates of the resources required to implement and maintain candidate RCMs;

- 6) Select RCMs the operator wishes to implement (based on anticipated effectiveness and costs associated with candidate RCMs);
- 7) Determine the total resource requirements for selected RCMs;
- 8) Adjust the set of selected RCMs based on real-world constraints such as availability of qualified people to perform the necessary work;
- 9) Document and submit the General Rate Case filing, on which the CPUC decides the expenditures it will allow, and, based on CPUC decision, adjust the operator's implementation plan;
- 10) Monitor the effectiveness of the implemented RCMs and, based on lessons learned, begin the process again.

We evaluate generally the reasonableness and completeness of PG&E's application and its underlying decision process by examining its documentation using these criteria. As applicable, we apply a series of four maturity levels to evaluate the GT&S filing. The maturity levels are meant to reflect the degree of performance relative to the evaluative criteria, rather than performance relative to an operator's peer utilities. It is therefore possible for PG&E to be industry-leading on a particular criterion and still receive a rating of low maturity.

Maturity Levels

- A. Fully satisfies evaluation criteria
- B. Substantially satisfies the evaluation criteria and provides a good foundation for future satisfaction of the criteria
- C. Partially satisfies the evaluation criteria but requires substantial improvement to fully meet the criteria
- D. Fails to satisfy the evaluation criteria

Evaluation of Criteria Using Maturity Levels

1. **Identify the threats having the potential to lead to safety risk**

Evaluation result: B (substantially satisfies criteria)

The structured threat identification process PG&E relied on to identify threats using subject matter experts' input over an ASME B31.8S threat-categorization inlay has some obvious weaknesses.

The risk register of threats is comprised of fairly high level entries which do not show sufficient granularity. PG&E's Risk Register contains 85 identified threats (and threat causes) across all asset families in the entire risk register.⁷ An example is the conglomeration of vintage construction in one large threat category, which is comprised of pre-1962 girth welds, wrinkle bends, dresser couplings, miter bands, etc. To the extent that more granular threat data exist, it would be beneficial to have more granular data to drive more specific mitigation measures. Clearly this coarse granularity results from the broad application of the risk register across all PG&E asset families and business areas. We encourage PG&E to continue the path of improving data collection to improve granularity. In the absence of this granularity, it is difficult (later in this process) to determine how much resource should be devoted to each sub-threat.

2. Characterize the sources of risk

Evaluation result: C (partially satisfies criteria)

For each threat, PG&E defines risk as the product of a frequency value and a consequence value. We evaluate the strength of PG&E's risk ranking methodology separately for its frequency estimation methodology and its consequence estimation methodology.

For each threat category, the frequency value is based on actual PG&E failure experience, industry failure experience, or subject matter expert opinion when insufficient failure experience is available. Frequency value based on subject matter experts' opinion is just that, a subjective estimation based on judgment. The majority of the frequency values in the risk register appears to be based on subject matter experts' opinions rather than actual event experience, as evidenced by their order of magnitude, round number values.

⁷ PG&E's usage of "threat causes" is consistent with the definition of threats as defined in this report.

The calibration sessions conducted by PG&E is fundamentally a subjective evaluation of consequence based on subject matter expert opinion. In spite of the subsequent exponential transformation, the scoring process began as an ordinal scoring process, which has well known drawbacks.

The current risk ranking methodology does not explicitly or rigorously take into account the potential effect of a pipeline failure according to either population or building density (or some surrogate of population or building density, such as class location) in calculating potential consequence, other than some subjective estimation by subject matter experts. This is a fundamental flaw with PG&E's methodology, which is inherent in this scoring method. This flaw could be corrected by considering risk for individual well-defined pipe segments having comparable adjacent populations.

Given the transmission integrity management program (TIMP) and pipeline segmentation framework PG&E already has in place, it would be a logical progression to leverage this existing framework and the data already available (such as potential impact radius, population or building density, class location, etc.) to evaluate the potential consequence for each threat across all segments to arrive at a total potential consequence value for each threat. This would be a much more meaningful measure of potential consequence than one based on subject matter expert estimates. Although TIMP and its pipeline segmentation concept are meant to be location specific, the concept could be scaled up to measure system risk for each threat to allow for identification of the threats with the highest risks to the system as a whole.

Although PG&E's current risk ranking process is still substantially qualitative in nature, we expect tangible substantial improvements in the future as data quality improves to further improve on the characterization of the risks in a more quantitative fashion.

3. Identify candidate risk control measures (RCMs)

Evaluation result: B (substantially satisfies criteria)

This step requires the operator to document its process so that it includes a description of the sources included in identifying risk control measures and a description of the breadth of application of identified risk control measures. While PG&E has identified a variety of risk control measures, there should be more analysis about how PG&E analyzed and examined these risk control measures and their effectiveness in mitigating risks similar to those confronted by PG&E.

For example, with respect to the Well Integrity Management Program, there is a lack of supporting information or detail to show how this program will be effective in addressing the associated or identification of risks. For the Gas Transmission System Operations and Maintenance Program, PG&E states its surveillance program surrounding maintenance and operations activities consists of both aerial and ground patrols among other things. PG&E also states this program consists of “[a]ll other activities that include observations of the pipeline facilities”. However, PG&E does not provide further detail as to what these “other” activities consist of, how effective they are in addressing threats, etc. Similarly, PG&E proposes the use of more aerial leak survey equipment in its Leak Management Program, but there is a lack of supporting information about the effectiveness of aerial activities, projected benefits versus cost of these activities, etc. The same lack of information exists with respect to PG&E’s proposed increase in use of aerial patrols for pipeline patrols. PG&E does not provide a robust analysis of the effectiveness of these risk control measures in relation to the identified threat, industry practices, or proposed costs.

PG&E should also demonstrate that it has evaluated how these risk control measures performed in other similar circumstances, as much as feasible.

4. Characterize the effectiveness of the candidate risk control measures (RCMs)

Evaluation result: C (partially satisfies criteria but needs substantial improvement)

PG&E has characterized the list of risk control measures aimed at addressing the identified threats and associated risks to some degree. In evaluating the anticipated risk reduction for identified risk control measures, PG&E has documented the basis for key decisions it has made. However, it is significant to note that PG&E has not made a showing of the incremental risk reduction achieved by the RCMs to justify the proposed scope and pace of implementation. The current risk scoring methods reflect that the programs are either fully adopted or not adopted at all. PG&E's model provides no evaluation of the incremental reduction in risk that would result from partial implementation of candidate risk control measures. PG&E has not identified its approach to considering uncertainty in assessing the effectiveness of selected risk control measures.

5. Determine resource requirements for identified RCMs

Evaluation result: B (substantially satisfies criteria)

The structured investment planning approach involving top level corporate leadership in Sessions 1 and 2 is indicative of a generally effective approach to investment planning. In program/project scoring sheets and other budget planning worksheets, PG&E generally demonstrated that mix, pace, and scope of programs and projects were considered and modified as needed to accommodate resource and operational constraints. However, SED staff saw no evidence of a structured approach to optimize mix, pace, and scope of projects subject to those constraints. It appears that decisions were based largely on informed judgment rather than a formal, structured optimization methodology. PG&E should provide more analysis and documentation to support its basis for determining resources required to implement selected risk control measures.

For example, it appears that the proposed Earthquake Fault Crossings Program and the Geo-Hazard Threat Identification and Mitigation Program overlap somewhat in terms of resource requirements. In this case, PG&E should seek out and estimate economies of scale to reduce resource requirements. The Geo-Hazard Threat identification and Mitigation Program also overlaps with the Vintage Pipeline Replacement program⁸, in that both deal with land movement.

PG&E acknowledges⁹ that the Geo-Hazard Threat Identification and Mitigation Program and the Vintage Pipeline Replacement Program are “different and complementary.” PG&E also implies that one program is almost a subset of the other. Although PG&E states¹⁰ there is no “measurable” overlap of resources between these programs, SED determines that more information is necessary to explain the resource requirements for these programs, whether that overlap is measurable or not.

PG&E could also strive to obtain more information from peer utilities on resources required for similar projects as a basis upon which to evaluate PG&E’s resource requirements. It is unclear whether resource requirements for some of PG&E’s programs (Hydrostatic Testing, Vintage Pipe Replacement) have been scaled for activities that would actually represent an increase in the use of existing practices.

6. Select RCMs the operator wishes to implement (based on anticipated effectiveness and costs associated with candidate RCMs)

Evaluation result: C (partially satisfies criteria but needs substantial improvement)

PG&E has generally provided a basis for selecting risk control measures but has not always provided enough analysis and documentation supporting its decisions.

⁸ See PG&E Testimony, page 4A-59.

⁹ See PG&E Comments on SED Preliminary Report, p. 13, Comment A36.

¹⁰ See PG&E Comments on SED Preliminary Report, p. 13, Comment A35.

In considering alternatives to decisions made on pace and scope, PG&E rejects alternatives with a rather cursory explanation. PG&E does not provide a detailed, substantive analysis which supports PG&E's selection of the candidate RCM over the alternatives. For example, in deciding between an 8-year, 10-year, and 12-year plan to make a system piggable, PG&E rejects the 12-year plan. PG&E states that the "risk reduction benefit of the increase in make piggable under the 10-year plan is more important than the cost impact". However, PG&E does not quantify, explain, or discuss what the risk reduction benefit is and PG&E does not compare it to the cost differential between the alternatives. PG&E does state that the delay between the 10-year and 12-year plans would hinder its ability to collect more data about the system; PG&E does not discuss how it plans to use this data or justify why the same delay in data collection between the 8-year and 10-year plan is tolerable.

PG&E states that alternatives were considered and that "an 8-year plan was not feasible due to system constraints."¹¹ It is unclear, however, how these system constraints were assessed, qualified and quantified in comparison to the other alternatives. PG&E provides *some* explanation as to why it rejected an alternative, but insufficient detail and analysis to clearly support the selection or rejection of an RCM. PG&E should provide more detailed analysis of the basis for the risk control measures that were selected and how the resources required for those risk control measures were estimated.

With respect to Hydrostatic Testing, PG&E summarily states that its forecast "provides the most appropriate risk reduction associated with previously untested pipe" but does not provide detail or quantification of said risk reduction. In the Earthquake Fault Crossings Program, PG&E provides a little detail as to why three

¹¹ Comments on the Preliminary SED Report, p. 14, Comment A40.

alternatives were rejected, but then summarily states that the chosen program was selected because it incorporated the:

Best aspects of the transmission integrity management program algorithms along with additional geotechnical site specific data to understand and prioritize the specific risk presented by each earthquake fault crossing. It is the right amount of work because it does not constrain the system with too many outages and it is supported by the limited engineering resources available for this type of specialized work.

PG&E has not provided sufficient detail or quantification as to why the selected program provides “the right amount of work” or what “too many outages” means. In the Vintage Pipe Replacement Program, PG&E concludes that “20 miles of pipeline replacement per year is the right pace for reducing risk for these interacting threats... because we are able to reduce risk to 90 percent of the population in the vicinity of our pipelines¹².” However, there is no basis by which to compare PG&E’s determination of the right pace or sufficient substantive analysis to support its conclusion as to the pace chosen and the determination of the level of risk reduction.

Similarly, there is a lack of surrounding explanation or supporting documentation as to the proposed scope of Direct Assessment. It is unclear from PG&E’s testimony what factors and considerations led to the determination of scope PG&E selected for this program.

Within the Programs to Enhance Integrity Management, PG&E again makes summary statements without providing sufficient supporting detail or analysis. PG&E states “the current RCA [(Root Cause Analysis)] process is not robust enough to achieve our desired risk reduction and continuous improvement levels.¹³” However, there is no explanation of what that “desired risk reduction” level or amount is and how the

¹² PG&E Testimony, Page 4A-55

¹³ PG&E Testimony, Page 4A-64

corresponding funding request will reduce risk per dollar spent. Similarly, with respect to the Risk Analysis Process Improvements, PG&E simply states “[t]he scope and volume of integrity assessments that is required... requires this level of funding¹⁴” yet does not provide any explanation or analysis as to why.

In general, there is a lack of detailed analysis surrounding the proposed risk-mitigation activity and its cost as compared to the alternatives that were rejected. In many cases PG&E states its conclusion but fails to “show its work” and supporting, detailed analyses as to how it arrived at that conclusion

7. Determine the total resource requirements for selected RCMs

Evaluation result: B (substantially satisfies criteria)

Overall, the process PG&E used to arrive at the final portfolio of programs and projects lacks some transparency. The process is transparent as to the identification of threats and associated risks but lacks details pertaining to the decision-making process that led to the evolution of different cost estimates and different scopes and paces of implementation. PG&E explains that the decision making process occurs during Sessions 1 and 2, but the precise methodology and guiding criteria behind the evolution of the different estimates are not provided. Although the testimony alludes to the concept of risk tolerance, there is no showing of risk tolerance at the corporate level to adequately justify the scope and pace of the proposed programs.

8. Adjust the set of RCMs to be presented in the rate case considering resource constraints

Evaluation result: B (substantially satisfies criteria)

In general, PG&E has taken resource constraints into account when selecting its risk control measures. However, the decision-making process incorporating resource

¹⁴ PG&E Testimony, Page 4A-66.

constraints seems reliant on judgment, with no evidence showing the mix, pace, and scope of mitigation measures are optimum based on the constraints. SED believes an appropriate application of quantitative optimization methods that take into account resource constraints, incremental risk reductions at different incremental paces and project scopes, lowest total cost, lowest rate shock, and risk tolerance would be conducive to improved decision making on overall portfolio selection.

Additionally, as mentioned above, PG&E should provide more explanation or analysis to support its decision to select certain risk control measures while rejecting alternatives.

Steps 9 and 10 are not applicable at this stage of the rate case process; both steps are how PG&E performs post-CPUC decision.

Findings and Observations

Based on our preliminary review of PG&E's GT&S application, SED staff makes the following evaluation findings and observations about PG&E's risk assessment and risk management methodology.

1. **No determination of incremental risk reduction values for various risk mitigation programs.** The programs are either "on or off" and the risk scores reflect this dynamic. The risk scores, whether at the risk register level or at the program and project level, reflect what could happen if a threat developed in the absence of a mitigation program. There is no provision in the scoring process to address partial reductions in risk. Even with a relative risk ranking model, such incremental risk evaluations would help decision makers balance affordability and risk reduction.
2. **Allocation of funding to different programs is subjective.** Although the funding is generally followed a reasoned and deliberative approach taking into

account resource and operational constraints, no evidence exists to demonstrate that the allocation of funding, the portfolio mix, and the implementation pace for the various programs are optimal based on any metrics, such as quantifiable maximum risk reduction, quickest risk reduction, lowest total cost, maximum cost benefit ratio, lowest rate shock. Other than some documents showing the evolution of portfolio size and mix, with documentation of the thought process for changes, SED could not find documentation (or other apparent evidence) showing any effort to optimize the portfolio mix taking into account any of the metrics or other metrics. It appears that there is a large degree of subjectivity involved in the planning process in both portfolio size and allocation of funding (or partial funding) to the portfolios. Additional quantification of risk reductions subject to constraints would help in deciding the best pace and best mix of strategies. This may mean exploring the use of some formalized decision making or optimization algorithms to help inform best allocation of resources subject to constraints. This observation is not meant to force PG&E to blindly use a “press a button” approach to dispense with or override human knowledge-based decision making; rather, SED suggests this more structured approach as a tool to enhance decision making.

3. **The use of an indexing scoring method to inform decision making at the programs and projects level in Sessions 1 and 2 has several known limitations.** Despite the apparent level of sophistication displayed at the risk register scoring level, the method PG&E employs to calculate and rank risks at both the Risk Register level and the program and projects level is fundamentally a relative risk scoring method that has well known limitations.¹⁵ We caveat our statement with the acknowledgement that PG&E is relying on this relative risk scoring method

¹⁵ Problems with scoring methods and ordinal scales in risk assessment by Douglas Hubbard and Dylan Evans, IBM Journal of Research and Development, Vol. 54 No. 3 Paper 2 May/June 2010.

due to the lack of reliable frequency of failure data for many of the identified threats. We also fully recognize that PG&E is embarking on a journey to apply risk-based decision making techniques to managing its gas assets and that progress made to-date is commendable.

4. **PG&E should continue the path to develop a more robust quantitative approach to threat/risk ranking.** In order to avoid more of the pitfalls associated with an indexing risk scoring method, PG&E should continue to refine the risk ranking models by driving toward a more probabilistic model. To alleviate the constraint imposed by the lack of meaningful frequency data, PG&E could consider pooling information with other utilities to obtain more credible frequency data.
5. **Inadequate rigorous consideration of interacting threats other than earth movement with construction defects.** Current methodology to consider interacting threats is very qualitative at best and not conducive to adequate consideration of interactions. PG&E demonstrated to SED staff a fairly sophisticated mathematical model under development to incorporate interacting threats using quantitative means, but the current indexing method of risk ranking does not seem to lend itself to a ready application of such a mathematical model. In general, PG&E did not examine effects of interacting threats or their effects on the mitigation efforts of those risks. We note at least one exception to this observation: PG&E did consider the danger of earth movement interacting with construction vulnerabilities (such as wrinkle bends and mitered bends). Besides this example, PG&E has not furnished any evidence that interactive threats were considered beyond cursory display of the matrix in Risk Management Procedure (RMP)-16¹⁶. PG&E has not demonstrated whether

¹⁶ GTS_RateCase 2015_DR_ORA_077Q4Atch01CONF.

its risk registers and the associated scoring mechanism properly took into account other interactive threats.

6. No quantification of risk tolerance. PG&E mentions the need to establish the appropriate level of risk tolerance, but no evidence of a corporate level risk tolerance was shown to SED.¹⁷ PG&E personnel has stated to SED that it has not yet reached a level of risk reduction where the concept of risk tolerance becomes relevant. As noted above, risks can never be completely eliminated, but rather mitigated down to an acceptable level. Quantifying risk tolerance is critical to determining this “acceptable level” depending on the context. The willingness to accept an established level of risk (risk tolerance) and risk tradeoff are foundational to risk management, whether from a theoretical viewpoint or from a practical viewpoint. PG&E should explore the concept of risk tolerance in an As Low As Reasonably Practicable (ALARP)¹⁸ framework potentially including in this framework the prudent application of industry best practices. We encourage PG&E to explore this concept in future rate cases. In the absence of an ALARP standard formally adopted by the Commission, PG&E can still select a level based on its own judgment. It is our expectation that incorporation of an ALARP approach to utility risk management could improve decision making with respect to the question of scope and implementation pace of the proposed programs and projects. A possible approach is to combine the concept of ALARP, best practices, and compliance requirements by utilizing a “safety budget.” A possible algorithm is to first consider what level of spending (and activity) is necessary to bring about compliance requirements and then compare this level with the level of activity recommended by best practices. The operator

¹⁷ Prepared Testimony, P.1-9.

¹⁸ See Attachment to this report for additional detail on ALARP.

can then select a level of activity that is based either on compliance, best practices, or a combination of the two.¹⁹ The operator then calculates the level of activity needed in accordance with an ALARP approach consistent with its selected risk tolerance. Finally, the operator selects the final level of activity that is the higher of the estimates based on compliance/best practices and risk tolerance/ALARP.

7. Insufficient documentation of basis for selecting alternative mitigation approaches. PG&E has selected more than one method to control similar risks without clearly documenting the basis for these selections. While such variation may well be appropriate, additional documentation on why PG&E made its selections should be provided in the future. This type of additional documentation will provide additional context into how the selection process works.

¹⁹ For the purposes of this illustrative example, we assume that best practices produce a level of activity that is at least as high as that dictated by regulatory compliance.

RECOMMENDATIONS ON RISK ASSESSMENT AND RISK MANAGEMENT

1. PG&E should continue the path of injecting quantitative rigor into the risk evaluation process by improving data collection to enhance knowledge on failure frequencies. Along this line, PG&E should consider sharing failure data with other utilities to help expand the knowledge on rates of pipeline failure due to different threats and mechanisms.
2. PG&E should improve the risk calculation and ranking models to demonstrate the incremental value of risk control measures at different scopes and paces of implementation. PG&E should provide more detailed analysis, including incremental values, of not only the proposed risk-mitigation activity and its cost, but also the alternatives that were rejected to support its selection of the activity.
3. PG&E should explore the use of structured optimization methods to enhance decision making to incorporate resource constraints, risk tolerance, incremental risk reduction, cost minimization, and lowest rate shock. This should not be misconstrued to be a recommendation to forgo professional judgment in favor of a blind application of quantitative approach to decision making. Rather, we believe there is value in having output from a quantitative approach to act as one of many input ingredients in a structured decision making process.
4. PG&E should explore the concepts of risk tolerance and “As Low As Reasonably Practicable” to future rate cases decision making. PG&E should balance this approach with prudent application of industry best practices.
5. PG&E should provide additional information on the methodology and guiding criteria used in its Session D, Session 1 and Session 2 steps to show the reasoning behind the evolution of final programs and projects selected, as well as their

respective scopes and paces of implementation. Additional information on how the assumptions from the Session D process feed into Sessions 1 and 2 should also be provided.

6. PG&E should consider interactive threats in its threat identification and risk ranking steps in a more mathematically rigorous manner than the current subjective qualitative approach.
7. PG&E should report progress on mitigation of identified threats and risks to SED staff, including emerging priorities which may shift funding away from approved projects.

RELATIONSHIP BETWEEN GT&S REQUEST AND PSEP

In response to the tragic failure of PG&E's transmission pipeline in the city of San Bruno, the CPUC and the California Legislature instituted several pipeline safety requirements beyond those contained in the Federal pipeline safety regulations listed under the Code of Federal Regulations (CFR), Title 49, Parts 190 to 199. Among the most significant of these requirements was the mandate ending historic exemptions from pressure testing. This mandate requires natural gas pipeline operators to pressure test or replace all previously untested transmission pipeline and has resulted in an unprecedented undertaking for PG&E. SED identifies how in this Application PG&E addresses these new mandates to pressure test or replace previously untested pipeline.²⁰

As discussed in its testimony²¹ and noted in SED's Safety Review Report of the Pipeline Safety Enhancement Plan Update Application (PSEP Update)²², PG&E's GT&S Application proposes a new decision-making framework to determine pressure testing and replacement activity priorities for untested pipeline segments that differs from the one previously approved under PSEP in 2012. PG&E asserts these changes result in a more holistic risk assessment approach to prioritizing, i.e. PG&E will not plan PSEP work separately from base work.²³ PG&E indicates the changes incorporate the lessons learned from PSEP work so far.

²⁰ Required under CA Public Utilities Code Section 958 and D.11-06-017.

²¹ Testimony p. 1-12, p. 2-25, and Chapter 4A.

²² A.13-10-017 - Pipeline Safety Enhancement Plan (PSEP) Update filed on October 29, 2013. SED's Report was issued to that service list on April 25, 2014.

²³ Capital and O&M Expenditures included in the Gas Transmission and Storage Rate Case.

As mandated by Decision (D.) 11-06-017 and approved by D.12-12-030, the original²⁴ PSEP contained PG&E's comprehensive plan for implementing the CPUC's order that all California gas operators either pressure test or replace every untested segment of natural gas transmission pipeline.

In order to ensure PG&E's continued progress towards complying with the CPUC's and the State of California's²⁵ orders ending historic exemptions from pressure testing, SED reviewed the Hydrostatic Testing and Vintage Pipeline Replacement Programs²⁶ proposed in this GT&S application and evaluated PG&E's modifications against the previously approved PSEP. Although other PSEP components include in-line inspection and valve automation activities, this review focuses its attention on the aforementioned programs: their activities are fundamental to meeting the CPUC's and State of California's goal of ensuring a safe and reliable natural gas pipeline system. In formulating its observations, SED primarily relies on the approved PSEP, the applicable CPUC orders, its experience with oversight of the PSEP program activities, previous review of PSEP, interviews with testimony witnesses, and the corresponding application testimony and workpapers. It is important to note that this review is by no means an exhaustive assessment of the PSEP transition. Rather, our review is comprised of observations intended to assist in determining the reasonableness of the modifications to the approach.

Background

California Public Utilities Code (PU Code) Section 958 requires a "comprehensive pressure testing implementation plan" to replace or test "all intrastate

²⁴ Filed on August 26, 2011,

²⁵ Following D.11-06-017 mandated filing of the implementation plan the California Legislature codified this requirement under Section 958 of the Public Utilities Code.

²⁶ Chapter 4A of the Testimony. This value does not include the results from the records integration program completed mid-2013.

transmission lines that were not previously pressure tested or that lack sufficient details related to performance of pressure testing.” At the end of the implementation period, “all California natural gas intrastate transmission line segments shall ...1) have been pressure tested ; 2) have traceable, verifiable and complete records...”

In D.11-06-017, the CPUC required the implementation plan to:

- Comply with the requirement that all in-service transmission pipelines have been pressure tested in accordance with 49 Code of Federal Regulations (CFR) 192.619, excluding 49 CFR 192.619 (c).
- Include a timetable for completion and interim safety enhancement measures for pipelines that must run at or near Maximum Allowable Operating Pressure, or above 30% System Minimum Yield Stress.
- State the criteria on which pipeline segments are identified for replacement rather than pressure testing.
- Contain a priority-ranked schedule for pressure testing pipeline not previously tested and for certain Maximum Allowable Operating Pressure reductions.
- Consider retrofitting pipeline to allow for in-line inspection tools and shutoff valves.
- Include expense and capital cost projections by component for each Plan year.
- Recommend a rate proposal with cost sharing between shareholder and ratepayer.

To generate a prioritized schedule based on risk assessment, PG&E developed an analytical framework in the form of a decision tree to evaluate every transmission pipeline segment in its system. PG&E’s decision tree focuses on five of the nine potential threats to pipeline integrity specified in ASME B31.8S and groups into three categories:

- 1) Manufacturing threats
- 2) Fabrication and construction threats
- 3) Corrosion and latent mechanical damage threats

The PSEP “Pipeline Modernization Decision Tree”²⁷ (PSEP Decision Tree) groups work into two phases, prioritizing based on pipe vintage, population density surrounding the pipeline segment, and the operating pressure. PG&E requested that the CPUC approve the work scope proposed for both Phase 1 and Phase 2 of the PSEP but only cost recovery for Phase 1, explaining that “Phase 2 timing and cost recovery will be addressed in a subsequent filing for rates effective January 1, 2015,” consistent with the timing of this Application. The CPUC approved the PSEP plan with some modifications in D.12-12-030 and required PG&E to file an update upon completion of its records integration program. As referenced above, A.13-10-017 is the PSEP update.

Although PSEP was approved late in 2012, Phase 1 has been underway since 2011 and is set to conclude at the end of 2014. During that time PG&E targeted two untested pipeline profiles:

- 1) Segments in highly populated areas (Class 3, 4 locations and High Consequence Areas (HCA)), operating at or above a Specified Minimum Yield Strength (SMYS) of 30 percent or greater, and characterized with a construction/fabrication and/or corrosion/mechanical damage threat; and/or
- 2) Segments located in highly populated areas and characterized with a manufacturing threat.

As of June 30, 2014, PG&E reports having replaced 87.6 miles²⁸ of transmission pipeline and pressure tested another 566 miles as part of PSEP. However, SED learned upon review of the PSEP Update, there still exist pipeline segments that meet the criteria for Phase 1 mitigation which were not and will not be addressed by Phase 1. These have been deferred beyond Phase 1.

PG&E explains that work related to pipeline replacement and strength testing outside of the PSEP Phase 1 period of 2011-2014 is reflected in this 2015 GT&S

²⁷ Attachment C, D.12-12-030

²⁸ This number excludes 11.6 miles of pipeline downrates and 8.7 miles of pipeline retirements performed under PSEP.

proceeding. Work should include the deferred segments and Phase 2 segments. PG&E estimates that approximately 1,500 miles of untested pipeline still remain to be addressed. This is discussed in Chapter 4A of its testimony.

GT&S modifications to PSEP

Despite PG&E's assertions that the logic and approach in GT&S are only an extension of PSEP by adding context to an otherwise unspecified approach to Phase 2 of PSEP, PG&E's proposal does represent a noticeable change to the approach and logic used in the previously approved PSEP. We detail further our observations, below.

Integrated PSEP and Base Work Planning. The most evident change to the transition of PSEP is PG&E's approach to no longer plan PSEP work separately from base work. From its discussions with the PG&E witnesses, SED understands that, prior to this proceeding, PG&E designated resources to focus solely on PSEP related work, even though other resources may have performed the same type of activities for base work. PG&E now plans to integrate those groups responsible for the same workstream.²⁹ PG&E contends this should result in improved collaboration and information flow, as well as a reduction in duplication of efforts, and increase in other process efficiencies. SED believes that it is important that PG&E be able to track and readily identify the specific drivers for any given project within a workstream. Several drivers can exist within a single workstream, even co-mingled drivers for a specific project within the workstream. For example, the hydrotesting program can encompass work required by compliance with 49 CFR Part 192, Subpart O, compliance with state-only mandates (California pressure testing mandates), or for integrity assessment of non-HCA segments (expansion of integrity management principles beyond required HCA's). In some circumstances a single project could have more than one of those

²⁹ Testimony p.9-10 Workstreams are a grouping of projects aligned with particular skills, industry disciplines, and expertise.

drivers. PG&E should also be mindful of how prioritization takes into account regulatory compliance and non-compliance integrity management drivers in its work prioritization process.

Reduced Scope of Pipeline Replacement. Another significant change in PG&E's approach is the reduced scope of the replacement activities to address the State's pressure testing requirements. PG&E will primarily rely only on hydrotesting activities exclusively to comply with the pressure testing mandate. At the proposed implementation rate PG&E estimates compliance will be completed by 2024.

Overall Reduction in Scope Targets at Addressing Pressure Testing Requirements. The Hydrostatic Testing Program will not just address most pressure testing of untested pipeline but will also cover testing of segments as necessary for other integrity management purposes. The proposed pace of 170 miles is reported to be close to the average of that tested in PSEP but in GT&S the total mileage to be tested will cover not just PSEP but also other hydrostatic testing priorities necessary for integrity management. This program integration will result in a reduction in the current pace of pressure testing targeted at meeting the State's pressure testing goal.

Average Occupancy Count/Total Occupancy Count. PG&E will be using the concept of Average Occupancy Count/Total Occupancy Count (AOC/TOC) to further prioritize work. This concept consists of using the potential impact radius (PIR) to evaluate the population that would be impacted by a failure and prioritize based on people. PG&E should provide additional details, including any white papers, supporting the development of the AOC/TOC concept.³⁰

Valid Pressure tests to meet code at the time only. PG&E will prioritize pressure testing of segments based on whether a valid pressure test that *met code at the time* exists.

³⁰ SED staff was unable to review this whitepaper since it was not furnished on a timely fashion.

These segments will be deprioritized in order to raise priority to segments that remain untested. Although this approach was introduced and at times applied in the PSEP Update, the original PSEP and Decision Tree still specified prioritization based on whether a pressure test met 49 CFR Part 192, Subpart J requirements. Today's Subpart J requirements are more demanding. PG&E has expressed that, as with the PSEP program, its long term goal still remains to have its entire transmission pipeline tested based on Subpart J requirements. At least 47 percent of PG&E's natural gas transmission system was installed before the Subpart J requirements were in place.

SED's observations on the PSEP transition changes and how they affect the remaining untested segments are discussed in more detail below.

Hydrostatic Testing Program

As of March 31, 2014, PG&E has pressure tested, to 49 CFR 192 Subpart J standards, approximately 541 miles of transmission pipeline as part of PSEP. It estimates that, by January 1, 2015, approximately 2,700 miles of transmission pipeline in its system will not have been tested to Subpart J standards³¹. However, PG&E's testimony states that 1,500 miles³² of transmission pipeline operating at 20 percent or more of SMYS remains to be addressed.

PG&E developed what it describes as an extension of the PSEP decision tree as it moves from Phase 1 into the pressure testing program proposed in GT&S. Figure 4A-9 of the testimony depicts the proposed hydrostatic testing program's decision tree which uses a similar deterministic threat model to PSEP. That decision tree contains new prioritization criteria that will be used to not only comply with the State's pressure testing mandate, as was done in PSEP, but also to assess the integrity of its already

³¹ GTS-RateCase2015_DR_ORA_007-Q07

³² It is unclear to SED whether the 1,200 mile difference between mileage without Subpart J pressure test and remaining to be addressed represents pipeline operating below twenty percent SMYS.

pressure tested transmission pipeline. For the 2015-2017 cycle, the program will first address untested pipeline in HCAs followed by non-HCA class 3 and 4 segments operating at greater than 20 percent SMYS. All remaining pipeline (tested or untested) which is identified by either integrity management or via cyclic fatigue analyses to require a test to assess immediate threats will also be addressed in this cycle. All remaining untested pipeline, i.e. untested non-HCA segments located in class 1 and 2 (rural) areas or non-HCA segments operating under 20 percent SMYS will be addressed at some point beyond 2017.

Test to meet code only. The first filter determining pressure testing priorities under the program is now whether a pipeline segment has pressure test records that at least met the code at the time as opposed to Subpart J Standard.

PG&E has expressed that, although its long term intent remains to test all pipeline to today's Subpart J standards, it is using the condition of whether the test has met code at the time as a means of prioritizing to focus on pipeline that has no record of a pressure test.

While this approach may be a reasonable means of *prioritizing* work, e.g. some testing as opposed to no test, there are a few considerations that must be kept in mind when implementing this approach. Although the PSEP Decision Tree shows filtering of segments to be addressed based on whether a Subpart J test has been conducted, actual implementation was based on evaluation of two criteria for each segment: whether 1) Test met PSEP criteria and 2) Test met Code at the time. The "Test met PSEP" criterion stipulates that some Subpart J requirements be met by pre-1970's tests, specifically test pressure factor and witness requirements. For a test to meet code only, the criterion is based on whichever code or best practice was in effect at the time, resulting in tests conducted pre-regulation with no minimum requirements, including no minimum pressure factor or duration requirement, depending on operating pressure and class

location properties. PG&E should very clearly define what criteria it will apply to determine if test met the code, especially considering Ordering Paragraph 3 of D.11-06-013:

A pressure test record must include all elements required by the regulations in effect when the test was conducted. For pressure tests conducted prior to the effective date of General Order 112, one hour is the minimum acceptable duration for a pressure test.

PSEP pressure test record evaluation also failed to consider whether the record was traceable, verifiable, and complete (TVC), and validated records that did not meet these documentation criteria. TVC record criteria must be considered. If PG&E expects to further prioritize work based on the level of TVC of records, it must develop and document the prioritization policy. However, in no circumstance should a pipeline with a record of intent to conduct a test, such as design documents, be considered for de-prioritization.

PG&E must clearly define what it means by “verified records”³³ as it relates to its segment development for the hydrotesting database. A data validation effort should be performed to verify these records and the database development and data validation procedure should be provided to SED. This proceeding’s time frame of 2015-2017 will target all HCA’s without pressure testing records that met code at the time for testing in 2015, followed by non-HCA segments operating at or above 20 percent in class 3 and 4 locations and or class 1 and 2 locations with identified Integrity Management threats that require hydrotesting.

Cyclic Fatigue Analysis. A cyclic fatigue analysis is adequately proposed as an assessment tool for segments that have been tested to code at the time. If the analysis results in a re-test examination for an HCA segment, then it will be eligible for testing in

³³ PG&E Testimony p.4A-38.

this rate cycle. However, it is unclear whether all transmission pipeline meeting the “test met code” condition will be evaluated for cyclic fatigue, what the timeline is to perform all these analyses, and how PG&E will prioritize segments for evaluation. Details about the cyclic fatigue analysis components, results evaluation criteria, and procedures are also insufficient. PG&E must submit all evaluation, procedure, and implementation details, as mentioned above, to the CPUC for review.

Vintage Pipeline Replacement Program

This Vintage Pipeline Replacement Program, described under Chapter 4A of the testimony, is an integrity management program which seeks to replace transmission pipeline at a rate of 20 miles per year to mitigate the threat posed by fabrication/construction defects interacting with land movement. The historic fabrication and construction methods targeted by the program include:

- Wrinkle bends
- Mechanical/Compression couplings
- Miter bends
- Other non-standard fittings like orange peel reducers
- Chil ring welds
- Bell and spigot
- Acetylene girth welding process

As with PSEP, this program proposes to utilize a deterministic threat model in the form of a high-level decision tree. Prioritization of work within the program is proposed to be based on applying the concept of Average Occupancy Count (AOC) which PG&E developed. SED did not evaluate this method.

Below are some of SED’s observations as they relate to this program’s continuation of PSEP.

Focuses on a new threat not specifically targeted in PSEP

Although these fabrication/construction threats are two of the five threat categories it considered, PSEP did not specifically address land movement as a threat to be mitigated. At that time, PG&E considered other programs were addressing that threat³⁴. However, these interactive threats ranked as the number one³⁵ risk coming out of PG&E's first Risk and Compliance Session or "Session D"³⁶. Session D was first added by PG&E to its integrative planning process in 2013 and is the vehicle by which Asset Family Owners communicate to PG&E leadership the largest risks to their assets through the enhanced risk management framework reviewed above.

Earth movement is recognized as a type of weather related/outside force (WROF) pipeline integrity threat under in ASME B31.8S, which is incorporated by reference in 49 CFR Part 192, Subpart O, as fabrication/construction threats. Consideration of these as interactive threats was driven by qualified subject-matter expert (SME) experience and what PG&E now qualifies as industry recognition of the significance of this threat. Spurred by the 2011 failure of a 36" transmission pipeline operated by Tennessee Gas Pipeline, LLC (TGP) in Morgan County, Ohio caused by and other incidents suspected to have been caused by this interactive threat. PG&E believes that industry recognition is relatively new; as a result, the industry lacks reliable data to analyze past incidents based on this interactive threat. PG&E is relying on its participation in the Joint Industry Project (JIP), which is evaluating and developing best practices for mitigation of this threat, and states this program was developed to be consistent with the JIP Committee's work. JIP recommendations and work were not made available to SED; SED staff was unable to confirm and evaluate the scope of the program in alignment

³⁴ R.11-02-019, PSEP Implementation Plan, Testimony p. 3-8

³⁵ GTS-RateCase2015_DR_TURN_001-Q01Atch04, p. 9 Session D analysis, April 2013.

³⁶ PG&E Testimony p. 2-15.

with the JIP recommendations. Absent this confirmation, the implementation details of the proposed mitigation program remain unsupported.

By considering land movement, the proposed Vintage Pipeline Replacement program is targeting pipeline locations where potential longitudinal stress can result in circumferential pipeline failure. Land movement imparts longitudinal stress on pipelines and fabrication/construction threats are particularly susceptible to circumferential defects that may fail under longitudinal stress. Hydrotesting is not considered a suitable assessment methodology for this type of threat as it does not impart sufficiently high longitudinal stress on the pipeline to assess anomalous girth welds. This may result in defects not being detected through a hydrotest that would otherwise fail when outside forces such as land movement are applied to the pipeline.

In 2013, SED Staff became aware of an issue with PG&E girth weld Non-Destructive Examination (NDE) program. Specifically, one of the PG&E contractors was not performing NDE in accordance with the applicable codes and standards. As a result, SED issued a citation to PG&E for \$8.1 million and directed PG&E to develop and execute a comprehensive corrective action plan to systematically address the full extent of non-compliance of radiographic testing. PG&E has taken significant steps to address this issue, but the historical deficiencies in PG&E's NDE program potentially increase the risk of girth weld issues. PG&E should incorporate the findings from the NDE program evaluation into the Vintage Pipeline Replacement program, as practical.

Pipeline Replacement Not Targeted to Mitigate the Pressure Testing Mandate for Untested Pipeline

Replacement of pipeline³⁷ under the PSEP program was primarily carried out to address the state's pressure testing goals for untested segments. The PSEP Decision Tree further prioritized pipeline replacement based on specific integrity threats and prioritization criteria³⁸. As of March 31, 2014, PG&E had replaced about 105 miles³⁹ as part of PSEP by targeting untested pipeline segments with manufacturing threats⁴⁰.

Unlike PSEP, the proposed Vintage Pipeline Replacement Program is no longer intended to address the mandate to replace or pressure test all untested transmission pipeline. The program is instead focused at mitigating risk posed by vintage pipeline fabrication/construction defects interacting with land movement; very little weight, if at all, will be placed on whether a pressure test has been performed in order to prioritize pipeline replacement. This also means it is possible that pipeline that was hydrotested in PSEP Phase 1 may now be replaced under this program.

The new replacement decision tree does, however, provide a decision point applicable to pipeline without the presence of vintage/construction or land movement threats, in the event PG&E determines it is "impractical" to hydrotest a segment, and prioritizes for replacement instead of pressure testing. PG&E expects these changes to include circumstances when additional engineering analysis at the time of planning a hydrotest determines hydrotest failure is likely, among other scenarios. Although SED agrees with maintaining the ability to replace certain segments instead of testing, from

³⁷ 49 CFR Part 192, Subpart J requires all new pipeline to be pressure tested before being placed into service.

³⁸ Action Boxes M2, M3, F2, F3, and C2 of the PSEP Decision Tree.

³⁹ PSEP Compliance Report No. 2014-01, Table 22-1. Mileage includes pipeline that was retired and downgraded.

⁴⁰ Although the PEP Decision Tree reflects that PG&E would also be replacing pipeline characterized with specific fabrication/construction threats, operating at or greater than 30 percent SMYS, and located in high population areas, PG&E did fully develop and implement that process in Phase 1.

both a safety and efficiency standpoint, all analyses and decision rationales should be complete, well documented, and determinations must follow a robust management of change controls. PG&E's proposal fails to provide sufficient detail on the safety and efficiency criteria that would be considered in the engineering analyses that could result in a replacement instead of testing determination. These analyses should be developed, if not done already, and provided to SED for review.

PSEP mitigation of Fabrication and Construction threats not addressed in Phase 1 will be partially addressed by the Vintage Pipeline Replacement Program

In its review of the PSEP Update,⁴¹ SED learned that with the exception of some targeted removal of dresser couplings, PG&E did not develop and implement PSEP projects targeted at mitigating threats posed by unique pipe joining features⁴² on pre-1960's pipeline as was indicated would be done by the fabrication/construction threat process contained in the approved PSEP decision tree. That process shows mitigation projects would be undertaken in Phase 1 and 2.

PG&E explains that it did not have sufficient information to identify the locations of these fittings at time of filing the PSEP⁴³, but that with the completion of the MAOP Validation Project last year, it has gathered the information necessary to identify the locations.

The Vintage Pipeline Replacement Program proposed in the GT&S proceeding addresses most of the same PSEP fabrication/construction threats by replacing pipeline characterized for vintage fabrication threats in areas prone land movement threats. The proposed program is essentially replacing the fabrication/construction threat process that was minimally implemented in PSEP Phase 1, with the following exceptions:

⁴¹ SED Safety Review Report of PG&E's PSEP Update Application, A.13-10-017, p.30.

⁴² Wrinkle Bends, Miter > 3 degrees, Dresser Couplings, Expansion Joints, Non-Standard Fittings, Excessive Pups.

⁴³ PG&E response to SED's Safety Review of PG&E's PSEP Update Application.

- 1) The program targets areas susceptible to outside forces such as land movement.
- 2) Pipeline conditions with excessive pups⁴⁴ do not appear to be considered for mitigation under fabrication/construction threats for the program, unlike the approved PSEP decision tree.
- 3) The new decision tree does not specify whether an “engineering condition assessment” will be performed.

SED contends that PG&E’s application and testimony lacks supporting justification to warrant the exclusion of excessive pups under this program. PG&E should explain why the program excludes that fabrication condition, demonstrate how its GT&S proposal would address it, if at all, and justify why its intended approach is reasonable considering the potential risks posed by the condition.

Vintage Pipeline Replacement Program Lacks Sufficient Prioritization Details

The decision tree presented under Fig 4A-11 depicts a very high level approach to the determinations that will be made in the program. However, the prioritization of work is insufficiently specified for evaluation.

The decision tree abruptly ends with an action box called out as “prioritize to replace” after it is determined that a segment either 1) contains vintage fabrication/construction interacting with land movement threat, or 2) is “infeasible” to pressure test. The testimony emphasized use of the AOC/TOC concept to prioritize the work. However, use of AOC/TOCs concept by itself is an insufficient means of prioritizing absent a complementary risk evaluation. Actual implementation requires further prioritization that should be based, if possible, on a full-scale risk analysis. PG&E states that it will replace the “riskiest” locations first⁴⁵, but there is no indication of what methodology or criteria will be used to evaluate the relative risk and establish work priorities beyond use of the AOC/TOC. In order to provide the needed level of

⁴⁴ “A short piece of pipe can be called a pup or a can; these are often used in fabricated pipe assemblies for wall thickness transitions, tie-in pieces, and pipe fitting.”

⁴⁵ Testimony p.4A-59.

transparency, PG&E should explain the risk methodology and address questions such as:

- How will the difference between replacement based on fabrication/land movement threat interaction be weighed against replacement based on infeasibility of a pressure test?
- How will additional interactive threats be considered?
- Does one type of fitting or type of land movement ⁴⁶present a higher risk than others?
- Will there be sufficient information available to adequately evaluate the severity of the threat at a particular location and determine the risk?

PG&E will focus the program on wrinkle bends, miter bends, and mechanical/compression couplings. These are potentially riskier fittings as they are less conducive to earth movement than the others, and PG&E is also able to more readily identify these than the remaining non-standard fittings.

Although the program's infancy and possible lack of data could be responsible for the absence of adequate implementation prioritization criteria, this deficiency must be properly addressed before the program can be adequately implemented.

Replace to Test and Acceptance Criteria

With respect to PG&E's proposed vintage pipeline program in the GT&S application, it does not appear that PG&E is proposing or building any flexibility into the program for circumstances where pipeline that meets the decision tree conditions for replacement may not actually be replaced but instead hydrotested or mitigated otherwise. However, PG&E does describe under its hydrostatic testing program that it may add "higher priority strength tests" to the program such as when "circumstances or new information determine that a strength test is a better alternative than potential

⁴⁶Testimony p-4A-54 lists as "landslides, soil creep, subsidence, and ground movement generated by earthquakes or large rainfalls".

planned replacement.⁴⁷ It is unclear if PG&E expects that these circumstances would include vintage pipeline replacements, which could be problematic due to hydrostatic testing not being the most appropriate assessment tool for that program's threats.

Additionally, SED could not find details about the characterization of the conditions to be addressed by the program, nor evidence of any acceptance/rejection criteria that has been developed or applied. PG&E should clarify if this means that every pipeline with a wrinkle bend or miter bend in an area susceptible to any land movement will be replaced.

SED recommends that implementation details for this program must be further developed and shared.

PSEP Deferrals

Approximately 30 miles⁴⁸ of transmission pipeline qualified for PSEP Phase 1 action but was not addressed and deferred to beyond Phase 1. This mileage includes:

- Non-PSEP Phase 1: Pipeline segments not filed by PG&E as part of the original PSEP. These segments were found to have met Phase 1 criteria after the records integration effort was conducted.
- PSEP Deferred Beyond Phase 1: Pipeline segments that were part of the original PSEP filing, met Phase 1 Criteria, but were intentionally deferred beyond Phase 1 based on engineering judgment.

PG&E explains these will be addressed, from a risk-based perspective, in this Application. This could make the priority higher or lower than it would have been in PSEP. Some may be addressed in this Application while others may be deprioritized for future mitigation. Both of these deferral types will be included in the data set to be run through the decision trees to analyze what action to take.

⁴⁷ Testimony p.4A-34.

⁴⁸ PG&E data response to SED March 31, 2014.

About 20 miles⁴⁹ or two thirds of the deferred mileage would have qualified for replacement⁵⁰ in Phase 1. Based on the new approach in this Application, these would be pressure tested in 2015-17 instead if untested or test failed to meet code at the time. The remaining 10 miles would have been hydrottested in Phase 1, and would also be tested in 2015-17 if untested or test failed to meet code at the time. However, these segments may be further prioritized or deprioritized based on AOC or pushed to future rate case periods if tested to code at the time.

Final Observations on GT&S and PSEP

From SED's limited review, PG&E's modified approach in this GT&S application is not exactly "improved" or more "conservative" as it relates to continuation of the PSEP-specific pressure testing mandates. The approach is more focused and refined from what was presented in PSEP. The result is a reduction of PSEP specific scope targeted at complying with the State's pressure testing mandates, while simultaneously expanding the scope of programs previously targeted only for PSEP purposes to now address the integrity of the entire transmission system as a whole. This shifts the focus from just addressing untested segments of pipeline targeted by PSEP to mitigating other potential pipeline threats.

This means that the appropriate balance between regulatory compliance activities and the need for enhanced integrity management must be achieved. This is particularly significant when considering that some safety regulatory compliance activities, such as California's pressure testing mandates, have established a completion date that is "as soon as practicable". Such balance demands thorough consideration of a

⁴⁹ GTS-RateCase2015_DR_ORA_089-Q01_308014Atch02_308016.

⁵⁰ PSEP decision tree action box M2 "Reduce Pressure and Replace Phase 1" and F2.

multitude of factors, and a robust risk-based assessment should be one such tool used to help determine that balance.

CONCLUSION AND NEXT STEPS

In this report, SED Staff provides a review of the risk identification, risk evaluation and risk ranking methodology used by PG&E in preparing its GT&S Application. Additionally, this report evaluates the proposed pipeline integrity management projects against the scope of projects identified in PG&E's PSEP.

Staff recognizes that in its Application, PG&E is employing new methods to confront risk trade-offs across different lines of business. PG&E's Application makes strong use of qualitative risk assessments. Staff recommends that PG&E inject additional quantitative rigor into its risk evaluation process. PG&E should improve its risk models to adjust for different scopes and pace of implementation. Additional use of formal quantitative optimization techniques could complement its risk decision-making process. In the future, PG&E should consider integrating techniques such as "As Low As Reasonably Practicable" (ALARP), and should provide additional transparency about its enterprise risk tolerance in its overall risk assessment and risk mitigation decision-making process.

PG&E shifts its focus from primarily addressing untested segments of pipeline (as targeted by PSEP) to other potential pipeline threats. Overall, the proposals in this Application are more focused and refined. PG&E's proposal views its system more holistically, combining PSEP work with existing "base work."

After the preliminary issuance of this report, SED staff hosted a workshop on July 30, 2014. At the workshop, parties discussed technical questions, corrections and clarifications. As a result of this feedback, SED staff implemented several changes and clarifications. SED staff intends to submit this final report into the record of A.13-12-012.

ATTACHMENT 1: DEFINITIONS AND TERMS

Terms Used in the Report

- Effectiveness – In the evaluation criteria the term “effectiveness” as applied to a risk control measure (RCM) is used to mean the extent to which use of the RCM contributes to reducing pipeline risk.
- Industry Best Practices - Industry Best Practices can be defined as that set of practices, beyond minimal safety regulations, that have been demonstrated in practice to produce superior safety results.
- Risk characterization – A process involving development of sufficient information at the segment level on the sources contributing to the probability and potential consequences of events affecting risk to inform risk management decisions.
- Threats – Phenomena (e.g., corrosion, embrittlement) or occurrences (e.g., excavation damage, seismic events, auto collision with meter sets, operator error) which alone or in combination have the potential to give rise to or contribute to risk.

Terms in General Use

- Risk: The effect of uncertainty on objectives; often expressed in terms of a combination of the likelihood of occurrence of an event and associated event consequences (Definition from ISO Guide 73:2009)
- Likelihood: The frequency of an event leading to adverse consequences (Definition derived from ISO Guide 73:2009)
- Consequence: The impact or outcome of an event affecting objectives; often expressed in terms of human health and safety impacts, economic damage, and/or environmental damage (Definition derived from ISO Guide 73:2009)
- Risk Assessment: The overall process of risk identification, risk analysis, and risk evaluation (Definition from ISO Guide 73:2009)
- Risk Identification: The process of finding, recognizing and describing risks (Definition from ISO Guide 73:2009)
- Risk Analysis: Process to comprehend the nature of risk and to determine the level of risk (Definition from ISO Guide 73:2009)
- Risk Evaluation: Process of examining the results of risk analysis to determine whether the risk and/or its magnitude is acceptable or tolerable (Definition derived from ISO Guide 73:2009)
- Risk Management: Coordinated activities, beginning with risk assessment, to inform and implement decisions designed to direct and control an organization with regard to risk (Definition derived from ISO Guide 73:2009)

- *Risk Management Process*: Systematic application of management policies, procedures and practices to the activities of communicating, consulting, establishing the context, and identifying, analyzing, evaluating, treating, monitoring and reviewing risk (Definition from ISO Guide 73:2009)
- *Risk Treatment*: Process to modify risk; can involve removing the risk source, changing the likelihood, or changing the consequences (Definition derived from ISO Guide 73:2009)
- *Monitoring and Review*: Process of continually observing risk status to identify change from the expected performance level, and to determine the effectiveness of the treatment of risk (Definition derived from ISO Guide 73:2009)
- *Risk Register*: Record of information about identified risks (Definition from ISO Guide 73:2009)
- *Residual Risk*: Risk remaining after risk treatment (Definition from ISO Guide 73:2009)

ATTACHMENT 2: THE PRINCIPLE OF “ALARP” AND ITS APPLICATION

One way operators and regulators outside the US have agreed upon to determine the right balance between safety improvement and resource expenditure is the “As Low as Reasonably Practicable” (ALARP) principle. This principle is fundamental to the regulation of hazardous facilities in the UK and other European countries. In essence, it involves weighing a change in level of risk against the trouble, expressed in time and money, needed to control it.

At the core of ALARP is the concept of “reasonably practicable” which, once defined, allows regulators to establish the basis for operator decisions without the need for excessively prescriptive regulation. One principle means in Europe for evaluating whether a safety improvement is “reasonably practicable” has been cost-benefit analysis, supported by a quantitative risk assessment (QRA) to evaluate the benefits. In practice, application of the cost-benefit analysis has evolved to be based on the premise that a safety improvement is reasonably practicable unless its costs are *grossly disproportionate* to the benefits realized. Formalized risk-based cost benefit analysis requires not only performance of a QRA, but also that benefits expected from a safety improvement be monetized (i.e., expressed in terms of dollars or euros). Monetizing benefits usually requires expressing the value of a human life in monetary terms, then deciding what multiple on the value of a human life is judged to be *grossly disproportionate* to the costs incurred. In the offshore petroleum drilling and production industry in the North Sea, the value of a human life has been set at one million pounds, and decision making on whether the cost of a safety improvement is *grossly*

disproportionate is typically based on a value of human life of six million pounds (i.e., a factor of six greater).

Even if it were possible to rigorously quantify risk in support of cost-benefit analysis, the resultant answer on how much is enough to spend on safety risk reduction may not be acceptable to safety regulators, to the public, or even to utilities. As an example, over the past 26½ years PG&E has experienced 51 incidents on its gas distribution system with injuries or fatalities leading to a total of 60 injuries (2.26/yr.) and 17 fatalities (0.64/yr.). These consequences exclude the San Bruno tragedy since that incident resulted from the rupture of a gas transmission line. The monetized cost of these fatalities and injuries (assuming injuries ~ 20% of monetized fatality cost; 1.6 \$/£ x £6 million per fatality⁵¹) is \$278.4 million or \$10.5 million per year. The ratio of property damage costs reported for gas distribution incidents over the past five years (2008-2012) to total monetized fatality and injury costs is 0.0414. Using this figure to adjust the monetized fatality and injury costs from PG&E experience yields a justifiable annual expenditure on an ALARP cost-benefit basis of \$10.9 million. So analyses based purely on the monetization of past public safety and economic consequences often seriously underestimate the social and economic consequences of pipeline accidents, and therefore lead to a grossly inadequate safety budget. The other indirect consequences (e.g., loss of shareholder value, fines, liability settlements, loss of near-by property value), and intangible societal consequences (e.g., loss of confidence, degraded customer relations, regulatory uncertainty) of accidents, as well as all of the other economic consequences to the pipeline operator, are very difficult to identify, much less to accurately quantify, with any confidence.

⁵¹ This value of a life of £6 million is the figure typically used in the UK in making ALARP cost-benefit decisions.

Since deciding whether a risk control measure is ALARP based on cost-benefit analysis can be challenging, requiring operators and regulators alike to exercise judgment, the British regulator (The Health and Safety Executive - HSE) often decides by referring to industry best practices, which are established by a process of discussion with stakeholders to arrive at a consensus on what is ALARP. An alternate way to establish a total budget is to look to the risk control practices currently used by the top industry performers as a proxy for "acceptable level of risk" and "reasonably practicable". The rationale for this approach is that the current best industry practices represent the outcome of a well-accepted legal and technical process that is based on a foundation of safety practices established in existing regulation, supported by national consensus technical standards, and then strengthened by operators making deliberate decisions, considering costs and benefits, to exceed these minimum requirements and standards. By the mere fact that they have been selected, funded, and implemented at public-regulated facilities, industry best practices are *de facto* judgments made by both regulators and industry that these activities are reasonable and practicable. As discussed above, in many European countries the level of risk that results from implementation of the best industry practices is considered to be as low as reasonably practicable.