Docket:	:	A.11-11-002
Exhibit Number	:	DRA-2
Commissioner	:	Florio
ALJ	:	Long
Witness	:	Phan

DIVISION OF RATEPAYER ADVOCATES
CALIFORNIA PUBLIC UTILITIES COMMISSION

DRA Report on the Pipeline Safety Enhancement Plan of Southern California Gas Company and San Diego Gas & Electric Company

Pipeline Safety Enhancement Plan

San Francisco, California
June 19, 2012

TABLE OF CONTENTS

PIPELINE SAFETY ENHANCEMENT PLAN

I. INTRODUCTION

Commission Decision (D.) 11-06-017, issued on June 16, 2011, ordered "…all California natural gas transmission operators to develop and file for Commission consideration a Natural Gas Transmission Pipeline Comprehensive Pressure Testing Implementation Plan to achieve the goal of orderly and cost effectively replacing or testing all natural gas transmission pipeline that have not been pressure tested. The Implementation Plans may include alternatives that demonstrably achieve the same standard of safety but must include a prioritized schedule based on risk assessment and maintaining service reliability as well as cost estimates with proposed ratemaking."[1]

In response to this directive, Southern California Gas Company ("SoCalGas") and San Diego Gas & Electric Company ("SDG&E") collectively referred to as Sempra, submitted testimony in support of its proposed natural gas pipeline safety enhancement plan ("the Plan"). Sempra's proposal includes plans, in multiple phases, to pressure test or replace all pipeline segments for both SoCalGas and for SDG&E that Sempra says do not have sufficient documentation to validate a post-construction pressure test of at least 1.25*Maximum Allowable Operating Pressure("MAOP").

For the first phase of the Plan, Phase 1A, Sempra seeks Commission authorization to recover a total of $1.7 billion in capital expenditures and Operation & Maintenance ("O&M") expenses to implement its Pipeline Safety Enhancement Plan.[2] Of this total, Sempra seeks $1.4 billion in capital expenditures and $262 million in O&M expenses for the years 2012-2015 for both utilities. Sempra also

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

[2] Amended Testimony, page 5.

seeks $7 million in O&M expenses to implement its interim safety plan scheduled for 2011.[3]

Sempra requests the following:

1. Authorization to recover costs incurred to date, and to be incurred up to the time the Commission issues a decision approving Sempra's Plan, for the review of transmission pipeline transmission pipeline records and for implementation of its interim safety enhancement measures. Sempra forecasts $7 million for the interim safety plan.
2. Approval of Sempra's direct Capital forecasts for implementation of the Plan during the time period of 2012 through 2015 of approximately $1.2 billion for SoCalGas and $229 million for SDG&E, and direct Operation and Maintenance ("O&M") forecasts for implementation of the Plan during the time period of 2012 through 2015 of approximately $255 million for SoCalGas and $7 million for SDG&E.[4]
3. Approval of the revenue requirements resulting from Sempra's Capital and O&M forecasts for the years 2011 through 2015.
4. Authorization to include a request to approve the Capital and O&M forecasts and resulting revenue requirements for subsequent years of the Plan in Sempra's respective General Rate Cases or other appropriate proceedings.
5. Approval to track the costs of implementing Sempra's Plan separately from other pipeline system costs and to allocate those costs to its customers using the Equal Percent of Authorized Margin ("EPAM") method.

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[3] Ibid.

[4] Amended Testimony, p. 5.

6. Approval to identify the costs of implementing its Plan as a separate item, a "PSEP Surcharge," on its customers' bills.
7. Approval to submit an annual status report to the Commission by March 31 of each year, beginning in 2013 that includes (a) information on work completed during the previous year; (b) work planned for the upcoming year; (c) discussion of progress made; and (d) confirmation of the Commission's approved annual budget for the Plan.

Sempra's Plan has minimal if any engineering analysis and contains proposals for system enhancement well beyond the scope of Decision 11-06-017. DRA reviewed Sempra's Plan, and conducted discovery to determine the reasonableness of Sempra's proposed work plans. DRA concludes that Sempra's Plan is overly ambitious and lacks adequate support. DRA recommends that the Commission authorize funding for the hydrostatic testing of the Category 4 pipelines only. DRA's recommendation results in a lower level of funding compared to Sempra's proposal.

II. SUMMARY OF RECOMMENDATIONS

DRA recommends that the Commission:

- address in its decision in this case the pipeline segments Sempra identified for MAOP validation in Phase 1A only. Pipelines Sempra identified to be pressure tested or replaced in Phase 1B and Phase 2 should be addressed in the next Sempra General Rate Case ("GRC"). The Commission will have actual cost data for the pipeline projects after the completion of Phase 1A, and will better be able to assess the reasonableness of pipeline work planned for the later phases.
- reject Sempra's proposal to "enhance" its system beyond the measures required under D.11-06-017. Sempra calls its "enhanced" proposal the Proposed Case, and requests additional ratepayer funding for projects such as fiber optic and

methane detection, which are above and beyond the requirements of D.11-06-017.

- adopt what Sempra calls the Base Case, with some modifications. In its Base Case, Sempra requests funding to pressure test or replace pipelines without MAOP validation.
- authorize the funding necessary for Sempra to perform pressure tests on the Category 4 National Transportation Safety Board ("NTSB") Criteria Miles in Phase 1A only. These are pipeline segments that are located in Class 3 and 4 locations, and Class 1 and 2 High Consequence Areas (HCAs). At this time, Sempra's cost estimates for the Plan are classified as "Class 5". Until Sempra provides a better estimate and additional confirmation of pressure test costs, the Commission should not authorize any funding for Phase 1B or Phase 2 MAOP validation efforts.
- reject Sempra's proposal to include pipeline segments located in Class 1 and 2 non-HCAs, referred to as "Accelerated Miles", in Phase 1A because Sempra has not adequately justified the proposed work.

The Commission should reject Sempra's proposal to replace, instead of pressure test, 260 miles of pipelines in Phase 1A because the criteria Sempra used to identify pipelines for replacement are not adequately supported.

- reduce Sempra's Plan cost by $74 million for pipelines managed as part of the SoCalGas and SDG&E Transmission Integrity Management Program ("TIMP"). Sempra's TIMP is funded through rates set in the General Rate Case process. Pipelines that are pressure tested as part of the Plan will meet the requirements of TIMP.
- reject Sempra's proposal to perform in-line inspections using TFI technology on 607 miles of pipelines *before* pressure testing., Sempra argues that the purpose is to determine if this would be an equivalent method to strength test a pipeline. Sempra requests $8 million for in-line inspections and $54 million for

repairs. Current Federal regulations do not recognize TFI technology as an equivalent means to strength test a pipeline.

- reject the proposal to replace wrinkle bends as part of the Plan. The replacement of wrinkle bends should continue to be managed under the TIMP program and should not be included in the Plan.
- require Sempra to consider the location of pipelines and risk assessments performed based on TIMP and maintenance data collected from O&M activities such as corrosion detection and leak surveys, as part of the sub-prioritization of pipelines for pressure testing. Sempra's current sub-prioritization methodology does not account for pipeline location, risk assessments from TIMP, or maintenance data in ranking pipeline for MAOP validation.

III. EXPLANATION OF DRA RECOMMENDATIONS

A. Sempra's Response to the National Transportation Safety Board's Recommendations and to Commission Resolution L-410

Sempra's Pipeline Safety Enhancement Plan has its roots in the company's response to the National Transportation Safety Board's (NTSB) recommendations, and the Commission's Resolution L-410. On April 15, 2011, Sempra submitted the "Report of Southern California Gas Company and San Diego Gas & Electric Company on Actions Taken in Response to the National Transportation Safety Board Safety Recommendations", ("Report"). In this Report, Sempra states that SoCalGas and SDG&E operate a total of 1,622 Criteria Miles: 1,416 SoCalGas miles and 206 SDG&E miles.[5] Sempra uses the term "Criteria Miles" to refer to pipelines in "Class 3 and Class 4 locations and Class 1 and Class 2 high consequence areas ("HCAs")."[6]

[5] *See* Report of Southern California Gas Company and San Diego Gas and Electric Company on Actions Taken in Response to NTSB Safety Recommendations.

[6] The Report, p. 1.

Of the total 1,622 Criteria Miles, Sempra identified 383 miles for SoCalGas and 64 miles for SDG&E that require, "…additional analysis and action to verify the stability of the long seam at the pipeline segment's MAOP."[7] Sempra also calls the 383 SoCalGas miles and 64 SDG&E miles "Category 4" pipeline segments. Sempra uses the terms "Category 4," "Criteria," and "Category 4 Criteria" interchangeably to refer to pipelines located in Class 3 and 4 locations and Class 1 and 2 HCAs. These Category 4 pipelines essentially become the pipeline segments that Sempra proposes in its Pipeline Enhancement Safety Plan to hydrostatic-test or replace, and to inspect using transverse field inspection (TFI) pigging.[8]

The remaining 1,175 Criteria miles[9] are categorized as Category 1, Category 2, and Category 3 miles. Sempra's definitions of these pipeline miles are as follows: "Category 1 includes only those pipelines and pipeline segments that have documentation of a hydrostatic pressure test to at least 1.25 times the MAOP per NTSB Safety Recommendation P-10-2 (Urgent). Category 2 includes those pipelines and pipeline segments that have documentation of a post-construction strength test to at least 1.25 times the MAOP using a medium other than water. Category 3 includes pipelines and pipeline segments for which documentation validates that the highest in-service operating pressure is at least 1.25 times the current MAOP."[10] Sempra explains that, "Because a pipeline strength test is based upon the pressure at which the pipeline is subjected and is not dependent upon the test media used, the media has no bearing on the outcome of the test. Accordingly, Category 2 pipelines and pipeline segments are equivalent in all relevant respects to Category 1 pipelines and pipeline segments."[11]

[7] The Report, p.11.

[8] Amended Testimony, Chapter IV, see pp. 40-41, 50.

[9] 1,622 Criteria Miles – 383 SoCalGas Miles – 64 SDG&E Miles = 1,175 Remaining Criteria Miles

[10] The Report, pp.7-8.

[11] Ibid.

B. DRA Recommends that Only Category 4 Criteria Miles be Addressed in Phase 1A

1. DRA Takes Issue with the Inclusion of non-HCA Segments and Segments with Demonstrated Safety Margin

Sempra's Plan consists of pipeline segments located in Class 1, Class 2 High Consequence Areas and Class 3 and Class 4, as well as pipeline segments located in Class 1 and Class 2 non-HCA. Sempra calls the non-HCA miles, "Accelerated Miles." Sempra's proposal for hydrostatic testing of SoCalGas' pipelines consists of more non-HCA segments than HCA ones. For Phase 1A, Sempra proposes to test 185 non-HCA miles compared to 176 HCA miles.[12] For replacement, Sempra proposes to replace a total of 136 miles of non-HCA pipelines and 153 miles of HCA pipelines.[13] Sempra has not provided adequate support for including the non-HCA segments in the Plan at the level requested. Sempra's Plan should exclude the Accelerated Miles for several reasons.

First, Sempra is including for pressure testing or replacing pipeline segments identified as "Accelerated," that may have already had the safety margin validated. The Plan includes Criteria segments categorized as Category 1, 2, and 3. The Plan also includes non-HCA segments that may have already had the safety margin validated. According to Sempra, "The Class 1 and 2 non-HCA miles identified… [in the Plan] have undergone a records review and can be characterized per one of the four categories identified in Table IV-4 of the Testimony."[14] In other words, "Accelerated" mileage includes segments that are identified as Category 1, 2, and 3, located in both HCAs and non-HCAs. Category 1, 2, and 3 segments have already demonstrated a safety margin through prior strength testing or with MAOP

[12] Amended Testimony, p. 108.

[13] Amended Workpapers, pp. WP-IX-1-36, 1-29, 1-25.

[14] Sempra's Response to DRA-DAO-21, Q.4 (d).

reductions.[15] These segments do not need to be addressed in the Plan at all because the safety margins have been validated.

Second, Sempra is including mileage for the Plan work without first knowing the scope of work required. Sempra states, "The actual scope of Accelerated Miles to be included in each individual project will be developed during the engineering, design, and execution planning phases of the Plan."[16] Sempra also states, "the assumptions regarding the scope of Accelerated Miles …were for the purpose of developing an overall high level cost estimate for the Plan as a whole."[17]

Sempra has not performed any analyses or assessments to show that it is better to accelerate the testing and replacement of pipelines located in non-populated areas, and are identified for Phase 2, into Phase 1A. DRA asked Sempra to provide a copy of all studies, assessments or evaluations performed to determine that segments in non-populated areas should be included in Phase 1A work as "Category 4 Criteria" or "Accelerated" miles. Sempra responded, "Segments in less populated areas (Class 1 and 2 non-HCAs) that are proposed in the Phase 1A scope are considered "Accelerated" miles. Specific studies, assessments, or evaluations have not yet been performed to determine whether to accelerate segments prioritized for Phase 2 per the Decision Tree into the proposed Phase 1 scope. The high level cost estimate developed for the PSEP assumes that it will be more cost efficient and operationally advantageous for some Phase 2 miles to be accelerated and addressed in Phase 1. Specific studies/analyses will be performed to determine the appropriateness of accelerating specific Phase 2 segments into Phase 1 during the engineering, design, and execution planning phases of the PSEP."[18]

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[15] Amended Testimony, p. 50.

[16] Sempra's Response to DRA-DAO-13, Q. 3.

[17] Ibid.

[18] Sempra's Response to DRA-DAO-15, Q. 1(b).

Sempra is including non-HCA segments in Phase 1A without first completing the records review for these segments and without considering any safety validation results in planning Phase 1A pressure testing or pipeline replacement.[19] Sempra states in Testimony, "The records review of transmission segments in non-High Consequence Area Class 1 and 2 locations is underway and is expected to be completed by July 2012."[20] As of April of 2012, Sempra has not completed its records review of non-HCA Class 1 and 2 pipelines.[21] As of this date, Sempra does not know the number of miles that do not have pressure test records documenting a pressure test to at least 1.25 times MAOP. Sempra states, "This effort is still in progress with 933 remaining at SoCalGas and two miles remaining at SDG&E."[22] The work planned for these segments are scheduled for Phase 2 therefore the records review and safety validation efforts are incomplete. The Accelerated Mileage identified for Phase 1A were included prematurely.

Sempra's current proposal to include non-HCA pipelines in Phase 1A without first completing a search for the records of these segments and validating the safety margin of these segments will inevitably include testing and replacing pipelines unnecessarily. Furthermore, DRA is concerned that Sempra is misinterpreting the Commission's intent in D.11-06-017 by using the wrong criteria for MAOP validation.

According to Sempra, SoCalGas and SDG&E estimate that an additional 2,000 miles of transmission segments will need to be assessed to determine whether they require pressure testing or replacement. Sempra assumes in its filing that, "the CPUC will require pressure testing or replacement of pipeline installed prior to 1970 since

[19] Sempra's Response to DRA-DAO-31, Q.1(d).

[20] Amended Testimony, p. 50.

[21] Sempra's Response to DRA-DAO-21, Q. 4.

[22] Sempra's Response to DRA-DAO-21, Q. 4 (a) (ii).

modern standards were not in place before that time."[23] Sempra is interpreting D.11-06-017 to require all pipeline segments installed prior to 1970 to be tested in accord with 49 CFR 192.619, excluding subsection 192.619 (c).

D.11-06-017 states, "This decision orders all California natural gas transmission operators to develop and file for Commission consideration a Natural Gas Transmission Pipeline Comprehensive Pressure Testing Implementation Plan (Implementation Plans) to achieve the goal or orderly and cost effectively replacing or testing all natural gas transmission pipeline that have not been pressure tested."[24] D.11-06-017 does not require the digging up and testing to Subpart J those pipeline segments that have been previously tested.

Based on Sempra's interpretation of the Decision, SoCalGas and SDG&E are erroneously including segments that have previously been tested, and met the elements required by the regulations in effect, in the scope for Phase 2 and then accelerating these segments into Phase 1A as part of its Accelerated Miles.

Sempra does not have adequate support to accelerate non-HCA segments into Phase 1A. The reasons Sempra provides as support for accelerating pipeline work into Phase 1A are not supported with any analysis or studies: (1) to maximize the cost effectiveness and minimize the impacts to customers of execution of the proposed Plan[25], (2) in light of operational and economic considerations[26] and (3) "…due to operational necessity and project efficiency."[27]

The Decision Tree was not used to identify the Accelerated segments for pressure testing or for replacement as part of Phase 1A.[28] Sempra used the Decision

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[23] Sempra's Response to DRA-DAO-29, Q. 4 (b).

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

[25] Amended Testimony, p. 108.

[26] Amended Testimony, p. 61, footnote 46.

[27] Amended Testimony, p. 52.

[28] Sempra's Response to DRA-DAO-9, Q.1(c).

Tree outcomes of the Criteria segments and then added the non-HCA segments to the scope of work outside of the decision tree. There is no documentation of how this was done.

Sempra used the outcomes of the decision tree to determine and prioritize "accelerated miles" into Phase 1A.[29] Sempra states, "The process shown in Figure IV-1 on page 61 of the Testimony is used to establish the overall phasing for Phases 1A, 1B and Phase 2 work. After these basic phasing requirements were established, estimates for pressure testing in Phase 1A were performed and this included estimates for pressure test boundaries. Phase 1A pressure test boundaries were extended to include adjoining phase 2 pipe segments if those segments were determined through subject matter expert review to be potentially cost effective or reduce customer impacts…"[30]

When asked how pressure test boundaries were determined, Sempra responded that high level judgment by subject matter experts was made to "include adjoining Phase 2 pipe segments" if doing so had the potential to be more cost effective or reduce impacts to customers.[31] When asked for the identification of these subject matter experts, Sempra identified them as "…field services personnel who are most familiar with the pipelines addressed in the PSEP and who are best equipped with the knowledge to make high level judgments regarding which Phase 2 segments could be appropriate to accelerate into the Phase 1 scope in order to be more cost effective or reduce impacts to customers."[32]

No explanation of the review process or copies of the "subject matter expert" reviews were provided because none had been captured.[33] No evaluations, analyses,

[29] Sempra's response to DRA-DAO-9, Q.1.
[30] Sempra's Response to DRA-DAO-14, Q.1.
[31] Sempra's Response to DRA-DAO-12, Q. 1, (b).
[32] Sempra's Response to DRA-DAO-14, Q. 1(c).
[33] Sempra's Response to DRA-DAO-14, Q. 1 (d).

or reviews were performed by these subject matter experts because the "…analysis [will be] performed to determine which Phase 2 segments to actually accelerate into Phase 1 will be documented in the engineering, design, and execution planning phases of the PSEP."[34]

No cost benefit analyses were performed to determine the cost effectiveness of including Accelerated segments in Phase 1A. Sempra states that these analyses will be performed in Phase 2.[35]

No customer impact studies have been performed to accelerate non-HCA segments into Phase 1A. Sempra states, "The assumption that some segments prioritized for Phase 2 per the Decision Tree will be accelerated into the proposed Phase 1 scope to minimize customer impacts was made based on very high level assumptions and judgments by subject matter experts."[36]

Accelerated segments seem to be included primarily to inflate the costs of the Plan. Sempra's mileage in the Plan is dependent on the amount of money it plans to spend per year and not whether the pipelines identified for testing and replacement need to be addressed in the first place. Sempra states, "the number of miles to be pressure tested in each year of Phase 1A is assumed to be proportionate to the cost estimated to be spent each year."[37]

There is no support for the inclusion of these accelerated segments. These segments do not need to be prioritized in Phase 1A because this will delay the testing and replacement of prioritized segments/pipelines located in highly populated, high consequence areas that need to be strength tested first. This is a safety issue that should be considered. This issue is highlighted by the pipelines that are predominantly made up of Accelerated segments. Prioritizing non-HCA segments for

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[34] Sempra's Response to DRA-DAO-14, Q. 1(e).

[35] Sempra's Response to DRA-DAO-14, Q. 1(f).

[36] Sempra's Response toDRA-DAO-14, Q.1(g).

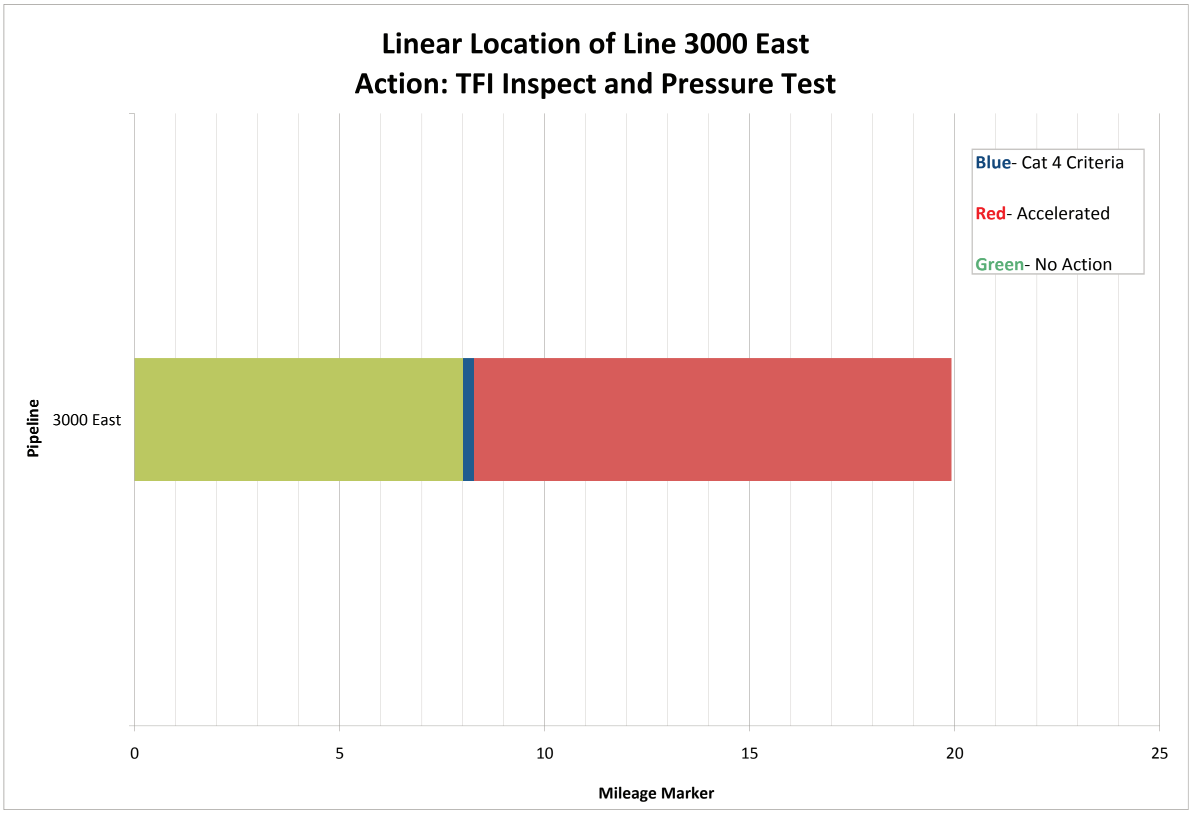
[37] Sempra's Response to DRA-DAO-2, Q. 8.

testing or replacing as part of Category 4 Criteria mileage means that segments located in more populated areas or in high consequence areas will be delayed when these segments should be addressed first. Sempra's workpapers demonstrate this. In the workpapers, the pipeline, and not the individual segments, is ranked in order to be addressed. In the current priority process, an Accelerated segment located in a non-populous area would be pressure tested or replaced as part of a line with a higher priority, before a Criteria Category 4 segment of a lower priority line would be addressed. For SoCalGas, 299 miles of non-HCA miles are ranked with the same criteria for priority as the 321 Criteria miles.[38]

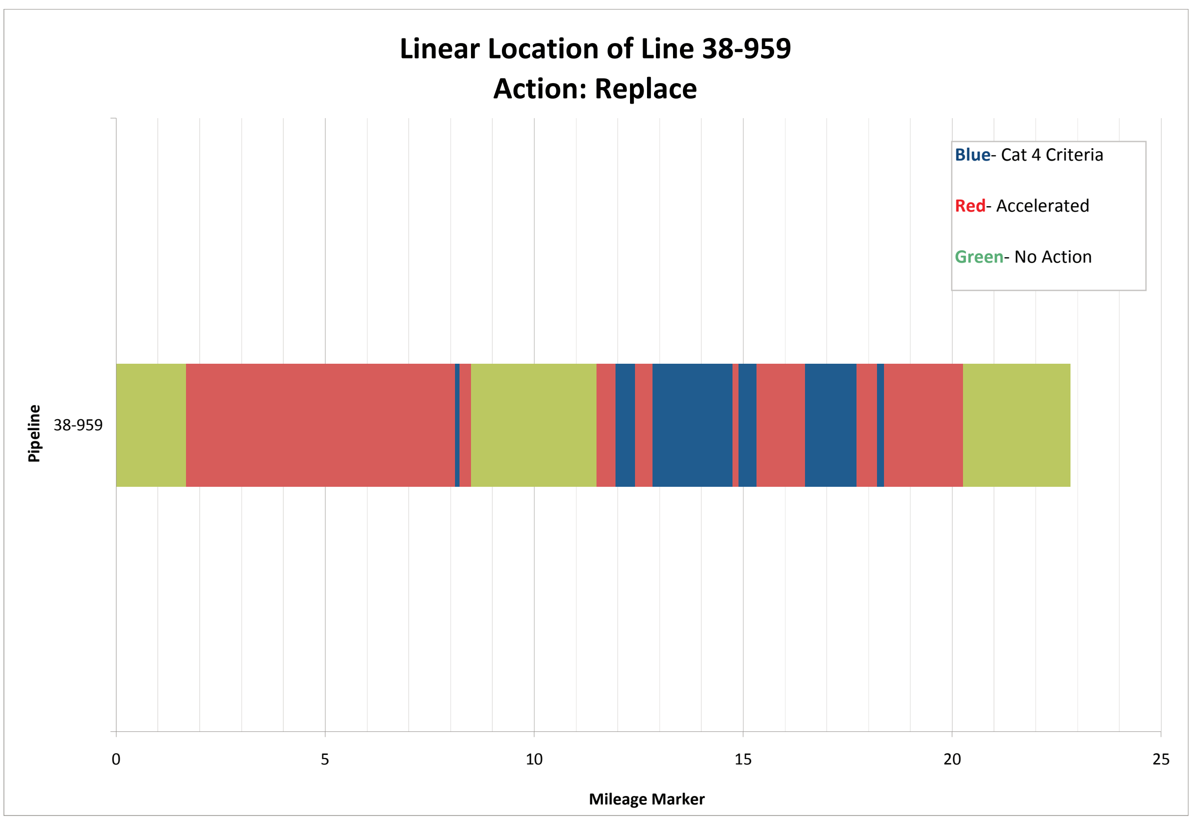
In the Plan's workpapers, there are several lines that include more Accelerated than Criteria segments. A small sample of those lines are: (1) Line 41-6000-2—36 miles with 70% Accelerated to 30% Criteria segments,[39] (2) Line 4000—4 miles with 84% Accelerated to 16% Criteria[40], (3) Line 3000 East—12 miles with 97% Accelerated to 3% Criteria[41], (4) Line 2001West—6 4 miles with 75% Accelerated to 16% Criteria[42], and (5) Line 30-32—3 miles with 68% Accelerated to 32% Criteria[43].

Some examples of pipelines where there is a significant number of Accelerated miles compared to Criteria miles are presented in linear charts below.

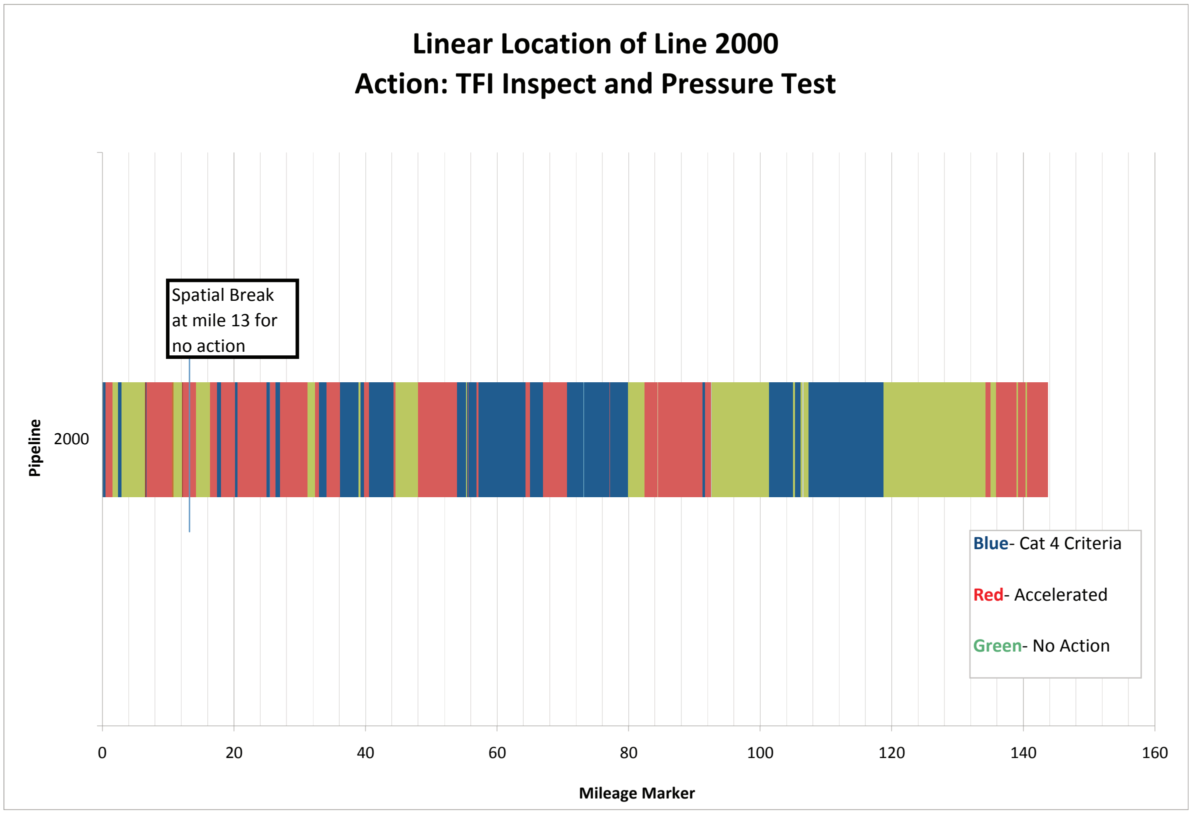
[38] Amended Workpapers, pp. WP-IV- 3 of 12 to 9 of 12.
[39] Amended Workpapers, p. WP-IX-B170.
[40] Amended Workpapers, p. WP-IX-1-A85.
[41] Amended Workpapers, p. WP-IX-1-A82.
[42] Amended Workpapers, p. WP-IX-1-A71.
[43] Amended Workpapers, p. WP-IX-B7.

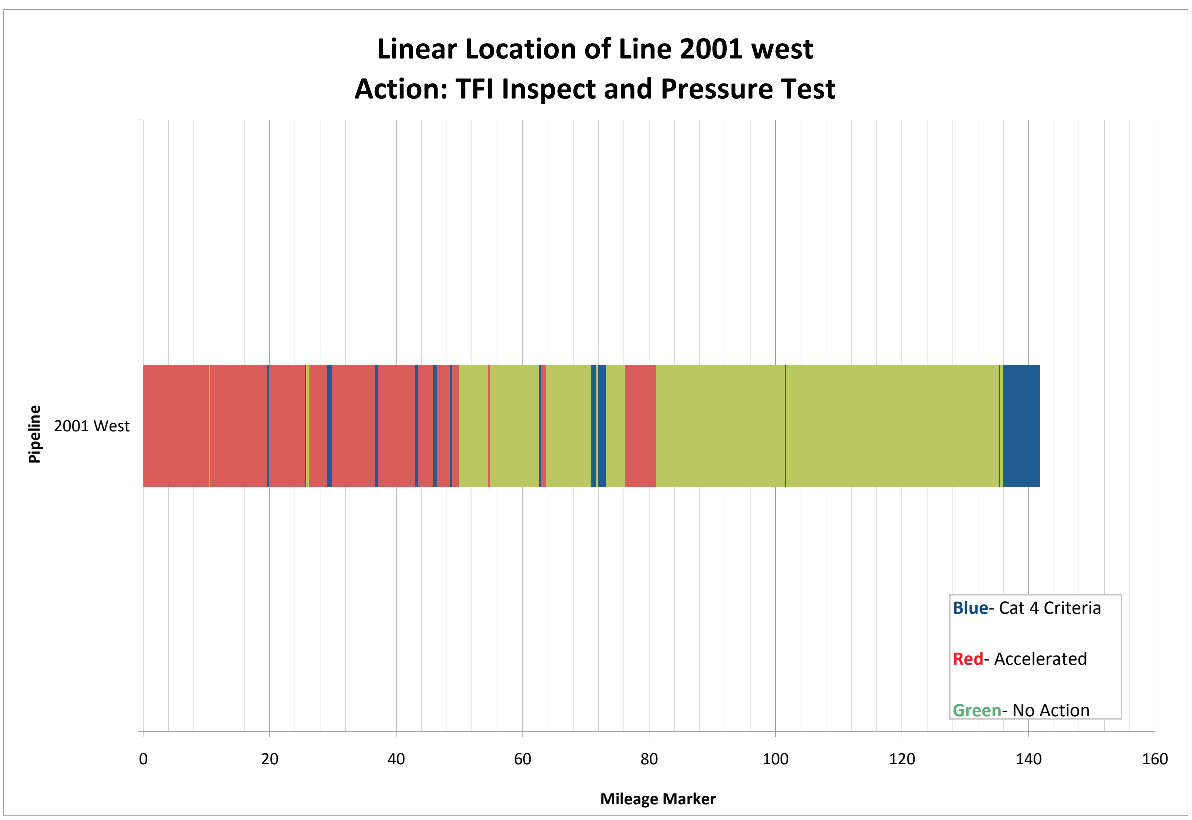

Linear Location of Line 3000 East
Action: TFI Inspect and Pressure Test
Blue- Cat 4 Criteria
Red- Accelerated
Green- No Action
Pipeline
3000 East
0
5
10
15
20
25
Mileage Marker

1


Linear Location of Line 38-959
Action: Replace
Blue- Cat 4 Criteria
Red- Accelerated
Green- No Action
Pipeline
38-959
0
5
10
15
20
25
Mileage Marker

2


Linear Location of Line 2000
Action: TFI Inspect and Pressure Test
Spatial Break at mile 13 for no action
Pipeline
2000
Blue- Cat 4 Criteria
Red- Accelerated
Green- No Action
0
20
40
60
80
100
120
140
160
Mileage Marker


Linear Location of Line 2001 west
Action: TFI Inspect and Pressure Test
Pipeline
2001 West
Blue- Cat 4 Criteria
Red- Accelerated
Green- No Action
0
20
40
60
80
100
120
140
160
Mileage Marker

For all the reasons discussed above, DRA recommends that the Commission reject Sempra's proposal to include the non-HCA, "Accelerated" segments in the Plan. For Phase 1A, DRA recommends that only Criteria miles, those that are located in Class 3, Class 4, and Class 1 and 2 High Consequence Areas, be addressed.

C. The Commission Should Exclude Non-Transmission Pipelines

In the Plan, Sempra has segregated its plan into separate proposals for SoCalGas, for SDG&E, and for Transmission and Distribution pipelines for both utilities. Sempra states that the pipelines identified as "Distribution" meet the definition of the 49 CFR 192 for a transmission pipeline but is designated as such in the Plan because these pipelines meet the definition of what is used to identify these pipelines functionally and in alignment with 18 CFR 201 definitions.[44]

DRA does not take issue with the inclusion of pipelines identified functionally as Distribution but meet the definition of the 49 CFR 192 for a transmission line in the Plan. However, DRA takes issue with the inclusion of pipelines that operate at less than 20% Specified Minimum Yield Strength or DOT defined as distribution. The segments that make up these pipelines do not meet the definition of a transmission pipeline according to Commission General Order 112, which identifies transmission pipelines as operating at 20% or more of SMYS.[45] These segments also do not meet the definition of a transmission line per Title 49 of Part 192:

<u>§ 192.3 Definitions.</u>

> Transmission line means a pipeline, other than a gathering line, that: (1) Transports gas from a gathering line or storage facility to a distribution center, storage facility, or large volume customer that is not down-stream from a distribution center; (2) operates at a hoop stress of 20 percent or more of SMYS; or (3) transports gas within a storage field.

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[44] Sempra's Response to DRA-DAO-17, Q. 1.

[45] D.11-06-017, footnote 3.

In the Sempra Decision Tree database, which contains all pipeline segments identified as Category 4 Criteria, there are 15 miles that operate below 20% SMYS[46]. DRA requested that Sempra confirm that these pipelines are transmission and not distribution pipelines. Sempra responded, "In some instances a pipeline will have segments that operate below 20% SMYS and above 20% SMYS, however the data collection was performed by line number to maintain continuity. SoCalGas and SDG&E plan to serve supplemental testimony in this proceeding to explain the inclusion of some small distribution segments within the scope of Phase 1 of the proposed PSEP."[47] Sempra further states, "As will be explained in our forthcoming Supplemental Testimony, these segments were identified as transmission during the population of the database."[48]

In the Supplemental Testimony filed on June 4, 2012, Sempra identified a total of 28 miles of distribution pipelines—13 more miles than shown in the Plan database provided to DRA which shows a total of 15 miles that are operating below 20% SMYS.[49] Sempra states, "The length of the distribution pipe included in our proposed Plan accounts for approximately 4.3% of the Phase 1A scope for pressure test and replacement, totals approximately 28 miles, and is generally interspersed among the transmission lines included in the Plan."[50]

Sempra has not identified the criteria that qualify these pipelines as meeting the requirements of the Plan. Sempra states in its Supplemental Testimony that these pipelines technically do not fall within the Commission's directive in D.11-06-017 to propose an implementation plan to address transmission lines.[51] Sempra also has not

[46] Sempra's Response to DRA-DAO-16, Q.6.
[47] Sempra's Response to DRA-TCAP-PSEP-33, Q.1.(a).
[48] Sempra's Response to DRA-TCAP-PSEP-33, Q. 1(b).
[49] Sempra's Supplemental Testimony, Dated June 4, 2012, pp. 1-2.
[50] Sempra's Supplemental Testimony, Dated June 4, 2012, pp. 1-2.
[51] Ibid., p. 1.

provided any support as to why these pipelines should be included as part of the work activities identified for transmission lines in the Plan.

Although Sempra claims that it is more practical to include these distribution segments within the scope of Phase 1A work, no engineering analysis or cost benefit studies have been provided as support for its claim. Sempra states that the utilities won't be able to determine whether or not the inclusion of distribution pipe is cost effective or more practical until a later phase.[52]

Sempra has not asserted in its testimony or application that it needs to validate the MAOP of its distribution lines. The Commission should reject the inclusion of these 28 miles of distribution pipelines from the Plan because these pipelines would be more appropriately addressed as part of SoCalGas' and SDG&E's Distribution Integrity Management Program (DIMP) or with its next GRC. If these distribution pipelines are included in Phase 1A of the Plan, then ratepayers should not be responsible for the cost of testing or replacing these lines.

Sempra is currently receiving ratepayer funding to manage its DIMP and will receive additional funding in its Test Year 2012 GRC. DIMP is a broad program that encompasses SoCalGas' and SDG&E's entire systems including HCAs.[53] Sempra's DIMP must address seven specific elements required by PHMSA: (1) knowledge of system; (2) identify threats; (3) evaluate and rank risk; (4) identify and implement appropriate measures to mitigate risks; (5) measure performance, monitor results, and evaluate effectiveness; (6) periodic evaluation and improvement; and (7) report results.

Sempra should address these 28 miles of distribution pipelines as part of the DIMP by evaluating the threats pose by these segments, risk rank these threats, and mitigate them accordingly. If not addressed in the 2012 Test Year GRC cycle, then

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[52] Sempra's Supplemental Testimony, pp. 2- 4.

[53] A.10-12-006, Exhibit SCG-5R, Testimony of Raymond Stanford, p. RKS-34.

Sempra should request funding in its next GRC. Additional funding to test or replace these distribution lines should not have to be paid for by ratepayers again.

Sempra has not provided any engineering or cost benefit analyses in the Plan to justify that it is necessary or more beneficial to include the distribution segments as part of the Plan, the purpose of which is to validate the MAOP of transmission pipelines.

DRA recommends the removal of these segments from the work identified for the Plan and a reduction of costs associated with these segments. The Supplemental Testimony shows a total number of 38 distribution lines identified to be addressed in the Plan. Of these 38 lines, only 3 lines with a total mileage of 0.3 miles are scheduled for hydrostatic testing. The remaining 35 lines totaling 27.4 miles are scheduled for replacement. Sempra's estimated cost associated with these pipelines is approximately $72 million.[54] These distribution lines are more appropriately addressed in the context of a GRC request for distribution mains and/or a different pipeline replacement program.

Additionally, DRA recommends the removal of $1 million for 0.08 miles of non-transmission mileage identified in Table 2 of the Supplemental Testimony.[55] Sempra states that it is reasonable to continue to include the 0.08 miles of distribution segments in Phase 1A although it admits that these segments are not adjacent or sandwiched between transmission segments. Sempra provides no support in its Plan showing or in its Supplemental Testimony to demonstrate that pipelines outside the scope of the Commission's directives should be addressed as part of Phase 1A.

If Sempra believes that it is necessary to also strength test or replace non-transmission pipelines, then ratepayers should not be responsible for the $73 million total estimated cost to address non-transmission pipelines in the Plan.

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[54] Using Sempra's numbers: 28 miles out of 200 total miles is equal to 14% of the work planned and at $72 million is 14% of the total $514 million. Sempra's response to provide DRA with numbers associated with the Supplemental Testimony, dated June 8, 2012.

D. Phases 1A (2012-2015), 1B (2016-2021), and Phase 2 (also to begin in 2016)

Sempra proposes to implement its Plan in multiple phases, Phase 1A, Phase 1B, and Phase 2. Phase 1A is expected to span from 2012-2015 and Phase 1B is proposed to span from 2016-2021. Phase 2 is expected to be implemented in parallel with Phase 1B, which begins in 2016.

For Phase 1A, Sempra proposes to replace 246 miles of SoCalGas pipelines and 49 miles of SDG&E and to pressure test 361 miles of SoCalGas and 1 mile of SDG&E pipelines.[56] The combined total mileage of 657 miles proposed for both utilities include pipelines that were identified as NTSB Criteria Miles or Category 4 Miles in the Report in Response to the NTSB Recommendations above. In the Plan testimony, the number of NTSB Criteria Miles changed from 383 to 322 for SoCalGas and from 64 to 63 for SDG&E.[57]

A summary of Sempra's proposal for Phase 1A pipeline MAOP validation work, in-line inspection, and valve retrofit is presented in the Table below.

Table 1

Sempra's Base Case—Phase 1A Pipeline and Valve Work

SoCalGas	2012	2013	2014	2015	Total Miles
Replacement (miles)	25	73	74	74	246
Pressure Test(miles)	73	96	96	96	361
In-Line Inspection (miles)	133	178	178	178	667
Valve Retrofit (valves)	30	40	51	52	173
SDG&E	**2012**	**2013**	**2014**	**2015**	**Total Miles**
Replacement (miles)	5	14	15	15	49
Pressure Test(miles)	<1	<1	<1	<1	1
In-Line Inspection (miles)	-	-	54	-	54
Valve Retrofit (valves)	7	7	8	8	30

Source: Amended Testimony, p. 5

(continued from previous page)
55 Sempra's Supplemental Testimony, p. 5.
56 Amended Testimony, p. 5.
57 Amended Testimony, p. 50.

For Phase 1B, Sempra proposes to replace all pre-1946 pipeline segments for SoCalGas at a cost of $884 million.[58] There is no pipeline pressure test or pipeline replacement in lieu of a pressure test, proposed for any other SoCalGas pipelines. Sempra proposes to pressure test 45 miles of SDG&E's Line 1600 at a cost of $10 million, and to replace 54 miles of the same line at a cost of $318 million.[59] Sempra does not propose any additional pressure tests or pipeline replacement in lieu of a pressure test for any other lines, or to replace pre-1946 pipelines for SDG&E. A summary of Sempra's proposal for Phase 1B is presented in Table 2 below.

<u>Table 2</u>

Sempra's Base Case—Phase 1B Pipeline and Valve Work

SoCalGas	2016	2017	2018	2019	2020	2021	Total Miles
Replacement (miles)	-	-	-	-	-	-	-
Pressure Test(miles)	-	-	-	-	-	-	-
In-Line Inspection (miles)	-	-	-	-	-	-	-
Valve Retrofit (valves)	$36	$36	$36	$36	$37	$39	220
SDG&E	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**Total Miles**
Replacement (miles)	-	-	54	-	-	-	54
Pressure Test(miles)	-	-	-	45	-	-	45
In-Line Inspection (miles)	-	-	-	-	-	-	-
Valve Retrofit (valves)	7	7	7	7	7	7	42

Source: Workpapers, pp. WP-IX-1-17, 1-34 for pipelines. For SoCalGas valves, Workpapers, p. WP-IX-2-75 of 116 and SDG&E valves, WP-IX-2-62 of 116.

For Phase 2, Sempra proposes a total estimate of $1.7 billion—$1.6 billion for SoCalGas and $100 million for SDG&E to pressure test 478 miles, replace 362 miles, and ILI inspect 1,260 miles.[60] A summary of the planned work for Phase 2 is presented in the table below.

[58] Amended Workpapers, pp. WP-IX-1-44 to 1-45

[59] Amended Workpapers, pp. WP-IX-1-17 and WP-IX-1-34.

[60] Amended Workpapers, p. WP-IX-1-58.

Table 3

Sempra's Plan—Phase 2 Pipeline Work

	Miles			Cost (Millions of 2011$)			
	ILI Mileage	Pressure Test Mileage	Pipe Replacement Mileage	ILI O&M	Pressure Test O&M	Pipe Replacement Capital	Total Phase 2 (Rounded)
	(60%)	(57%)	(43%)	($86,000 / mile)	($479,000 / mile)	($3.58 Million / mile)	
SoCalGas	1200	455	345	$ 103.2	$ 218.1	$ 1,235.3	**$1.6 Billion**
SDG&E	60	23	17	$ 5.2	$ 10.9	$ 61.8	**$100 Million**
Total	1260	478	362	$ 108.3	$ 229.0	$ 1,297.0	**$1.7 Billion**

Source: Sempra's Workpapers, p. 1-58.

1. The Commission Should Address and Authorize Funding for Phase 1A at This Time and Consider Phase 1B and Phase 2 in the Next Sempra GRC

Sempra requests $1.7 billion to address pipeline MAOP validation for the years 2012-2015 as part of the proposal for Phase 1A.[61] Of this total, $1.4 billion is allocated to SoCalGas and $237 million is allocated to SDG&E.[62]

DRA recommends the Commission only address the pipeline segments identified for MAOP validation in Phase 1A in this proceeding. DRA recommends that the pipelines Sempra identified to be pressure tested or replaced in Phase 1B and Phase 2 be addressed in the next Sempra GRC. By the time Sempra completes the Phase 1A pipeline work, the Commission will have actual cost data for pipeline MAOP validation and will be better able to assess the reasonableness of the pipeline work and the related cost estimates for the later phases.

Sempra's cost estimates for pipeline replacement and pressure tests were developed by its consulting firm, SPEC Services. Sempra did not compare SPEC's

[61] Amended Testimony, p. 5.

[62] Amended Testimony, p. 5.

cost estimates for pipeline replacement and pressure test with industry cost for materials, construction, or engineering analysis.[63] Sempra also did not perform a comparison of SPEC's cost estimates with SoCalGas' or SDG&E's historical costs for materials, construction, and engineering analysis for replacement and hydrostatic test projects.[64]

In its Application, Sempra says its "Cost estimates are preliminary and were developed based on minimal engineering, operational planning, and project execution planning."[65] Sempra describes the cost estimates used in this Application as "Class 5 or slightly better."[66] Sempra defines a Class 5 estimate as follows:

> "This classification system was developed by the Association for the Advancement of Cost Engineering (AACE International). It separates cost estimates into the various classes based on the level of project definition and also assigns expected accuracy ranges.
>
> Per AACE, a Class 5 estimate has 0% to 2% project definition, can be considered a "conceptual" estimate, is typically used for such purposes as project screening or assessment of initial viability, and has an expected accuracy range of -20% to -50% on the low side and +30% to +100% on the high side."[67]

A Class 5 estimate is not a very good indicator of how much a pressure test will ultimately cost. An accuracy range of -20% to -50% on the low side and +30% to +100% on the high side does not signify a very reliable cost estimate.

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[63] Sempra's Response to DRA-DAO-07, Q. 2(b).
[64] Sempra's Response to DRA-DAO-07, Q. 2(c).
[65] Amended Testimony, p. 103.
[66] Sempra's Response to DRA-DAO-19, Q.2 (a).
[67] Sempra's Response to DRA-DAO-19, Q. 2(a).

When asked why Sempra had presented "Level 5" cost estimates, Sempra responded that, "[d]ue to the large number of projects proposed in the PSEP, and the expedited timeframe given to develop and file the plan, it was not feasible to prepare a more precise estimate."[68] DRA recognizes that Sempra had a limited amount of time to prepare the Plan estimates, but since the filing of this application, there has been no cost update.

Sempra is requesting $1.7 billion for SoCalGas and SDG&E to test or replace pipelines in the next 4 years.[69] Instead of supporting this request with engineering analysis or cost benefit studies, Sempra's proposals are based on "engineering judgment... based on the collective experience and knowledge of those involved."[70]

There is no assurance from Sempra that the work proposed for Phase 1A will be completed in the timeframe identified. According to Sempra, "Development of a detailed and accurate schedule for a project of this size requires sufficient completion of engineering and design work, operational planning, permitting studies, community impact studies, and other aspects of project execution and planning. Until this engineering and execution planning is completed, and the extent that the execution challenges and risks…can be mitigated, the certainty of the schedule cannot be predicted with certainty."[71] Sempra further states, "In the absence of any detailed planning, the cost estimates assumed construction and engineering activities to be carried out by third-party contract labor. The specific roles of company and contractor labor will be determined after detailed engineering and execution planning has been completed."[72]

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[68] Sempra's Response to DRA-DAO-19, Q. 2(b).

[69] Amended Testimony, p. 5.

[70] See the discussion of Sempra's hydrostatic test and pipeline replacement costs in Section E (3) (b) of this Report.

[71] Sempra's Response to DRA-DAO-9, Q. 4(b).

[72] Sempra's Response to DRA-DAO-9, Q. 4(e).

In this Application, Sempra proposes a plan for Phase 1A that is at a very high level and contains many unknowns. Sempra acknowledges that there are no engineering analyses, no cost benefit analyses, no studies of any kind to support the level of worked its plan sets out for Phase 1A. Based on the limitations associated with Sempra's plan, DRA recommends that the Commission address Phase 1B and Phase 2 work when Sempra has undertaken the execution of the work activities planned for Phase 1A. After such experience, Sempra can demonstrate the level of work completed and will have actual cost data that can be used to forecast the next level of testing and replacement work with more accuracy than its current Class 5 estimate.

2. The Commission Should Adopt a One-Way Balancing Account Based on Uncertainties Associated with Class 5 Cost Estimates

DRA recommends adopting a one-way balancing account treatment of the cost to pressure test pipelines. Due to the lack of engineering design and analyses in the level of work and Class 5 cost estimates proposed in the Plan by Sempra, DRA recommends that ratepayers be protected from the uncertainties of Sempra's proposal.

The one-way balancing account will provide Sempra with a spending target but also ensure that money is spent prudently. If expenditures do not meet the spending target, the unspent funds are returned to the ratepayers. If the expenditures exceed the target, that amount over the target is not recoverable through rates and is absorbed by shareholders.

E. The Commission Should Adopt the Base Case, with Some Modifications, and Reject the Proposed Case

1. Sempra's Base Case versus Proposed Case

Within the Phase 1 proposal, Sempra has presented 2 plans to address D. 11-02-019 requirements: one Sempra identifies as the Proposed Case and the other it refers to as the Base Case. The Base Case addresses the requirements of D.11-06-017 and the Proposed Case requests approval of additional measures beyond the Commission's orders. According to Sempra:

> SoCalGas and SDG&E strive to be proactive and innovative in our approach to pipeline safety and reliability. Therefore, our proposed plan also offers proposals to enhance our system beyond the measures strictly required under D.11-06-017, and includes alternatives that can be adopted by the Commission…[73]

The Base Cases for SoCalGas and SDG&E include pipeline replacement, pressure testing, inline inspection, Remote Control and Automatic Shutoff Valves, and Interim safety enhancement measures. The Proposed Cases for SoCalGas and SDG&E include expenses in addition to the Base Case, plus expenses for the following categories: (a) Mitigation of Pre-1946 Construction Methods, (b) Technology Enhancements, and (c) Enterprise Asset Management System.[74]

For ease of reference, DRA describes the primary differences between the Proposed Case and the Base Case for both Phases 1A and Phase 1B below. Although the cost differences between the Proposed Case and the Base Case identified for Phase 1A are relatively small, the costs increase significantly in the Proposed Case in Phase 1B. The Proposed Case projects start small in Phase 1A but begin to accumulate substantial costs in Phase 1B if the Commission approves Sempra's enhancement measures. This is especially apparent with the proposal to replace Pre-1946 pipelines in SoCalGas' plan for $1.1 billion.[75]

For SoCalGas, the Base Case proposal is $1.4 billion for years 2011-2021, which includes $817 million for pipeline replacement, $181 million for pressure testing, $58 million for In-Line Inspection, $315 million for Remote Control and Automatic Shutoff Valves, $11 million for Interim Safety Enhancement Measures,

[73] Amended Testimony, p. 2.

[74] Amended Testimony, Appendix B.

and $1 million for Implementation costs.[76] The SoCalGas Proposed Case for years 2011-2021 costs $2.5 billion and exceeds the Base Case by $1.2 billion.[77] The Proposed Case includes an additional $1 billion for Mitigation of Pre-1946 Construction Methods, an additional $64 million for Technology Enhancements and an additional $6 million for Enterprise Asset Management System.[78]

For SDG&E, the Base Case proposes $594 million in costs, which includes $515 million for pipeline replacement, $11 million for Pressure Testing, $4 million for In-Line Inspection, $64 million for Remote Control and Automatic Shutoff Valves, $2 million for Interim Safety Enhancement Measures, and $1 million for Implementation Costs.[79] The SDG&E Proposed Case exceeds the Base Case by $9 million and includes $9 million in additional expenses for Technology Enhancements ($9 million) and Enterprise Asset Management System ($1 million).[80]

A summary of the differences between the Proposed Case and the Base Case for SoCalGas and for SDG&E is presented in the tables below.

(continued from previous page)

[75] Amended Testimony, Appendix B.

[76] Amended Testimony, Appendix C, p. C-1.

[77] Amended Testimony, Appendix B.

[78] Ibid.

[79] Amended Testimony, Appendix, p. C-2.

[80] Amended Testimony, Appendix, p. B-2.

<u>Table 4</u>

SoCalGas
Base Case and Proposed Case for <u>Phase 1A</u>
(In Millions of Dollars)

	Direct Costs	2012	2013	2014	2015	Total
BASE CASE	Pipeline Replacement (Capital) ($132 M for Transmission +$686 M for Distribution)	$90	$243	$243	$243	$818
	Pressure Testing (O&M)	$36	$49	$48	$48	$182
	In-Line Inspection (O&M)	$12	$15	$15	$15	$58
	Remote Control &Auto Shutoff Valves	$26	$28	$34	$34	$120
	Interim Safety Enhancement Measures	$4	$0	$0	$0	$4
	Implementation Costs	$1	0	0	0	$1
	Annual Base Case Total	**$169**	**$335**	**$340**	**$340**	**$1,184**
PROPOSED CASE	**Base Case Total + the Following:**					
	Mitigate Construction/Fabrication Methods (Replace 3996 Wrinkle Bends)	$29	$57	$57	$57	$200
	Technology Enhancements	$15	$17	$8[81]	$7[82]	$47
	Enterprise Asset Management	$6	$0	0	0	$6
	Proposed Case Annual Total	**$219**	**$410**	**$405**	**$405**	**$1,439**

Source: Direct Costs from Appendix C of the Amended Testimony, p. C-1.

[81] $7 million is for Capital and $1 million is for O&M.

[82] $6 million is for Capital and $1 million is for O&M.

Table 5

SDG&E
Base Case and Proposed Case for Phase 1A
(In Millions of Dollars)

BASE CASE	Direct Costs	2012	2013	2014	2015	Total
	Pipeline Replacement (Capital) ($14 M for Transmission + $182 M for Distribution)	$23	$58	$58	$58	$197
	Pressure Testing (O&M)	-	-	-	-	-
	In-Line Inspection (O&M)	-	-	$4	-	$4
	Remote Control & Auto Shutoff Valves	$5	$6	$7	$7	$25
	Interim Safety Measures	$1	$0	$0	$0	$0
	Implementation Costs	$1	$0	$0	$0	$1
	Annual Base Case Total	**$29**	**$64**	**$70**	**$65**	**$228**
PROPOSED CASE	**Base Case Total +The Following:**					
	Technology Enhancements	$2	$2	$1	$1	$6
	Interim Safety Measures	$1	$0	$0	$0	$1
	Proposed Case Total	**$32**	**$67**	**$71**	**$66**	**$236**

Source: Pipeline miles from the Amended Testimony, p. 5. Direct Costs from Appendix C of the Amended Testimony, p. C-2.

2. Why the Commission Should Adopt the Base Case, with Some Modifications, and Reject the Proposed Case

Sempra requests funding to perform the work activities identified in the Proposed Case, and not the Base Case. DRA recommends that the Commission reject the Proposed Case and adopt the Base Case, with modifications, instead. Sempra's Proposed Case has added activities and projects that are costly and unnecessary to achieve the safety directives of D.11-06-017.

D.11-06-017 directed California utilities to replace or test transmission pipeline that have not been pressure tested. The Decision should not be used as an opportunity to "enhance" their systems by accelerating certain replacements or to improve the way they manage their technology. Funding for these proposed investments should be requested in the utilities' GRCs. DRA recommends that all of the funding for additional activities Sempra requests in the Proposed Case be denied. DRA recommends that Sempra's proposal in its Base Case to conduct in-line inspections of pipelines prior to pressure testing be rejected. DRA's analysis is presented below.

a. The Commission Should Reject Sempra's Proposal To Replace Wrinkle Bends (as Part of the Proposed Case)

Sempra requests $199.8 million to replace 3,996 wrinkle bends as part of its proposal to Mitigate Construction/Fabrication Methods.[83] Sempra says its proposal is to replace wrinkle bends on lines scheduled to be pressure tested first so that the construction threats are removed before the pressure tests.[84] Sempra states that these wrinkle bend replacements are scheduled to start in the second half of 2012 and be completed by the end of 2015.[85] The wrinkle bend replacement plan in Phase 1A and Phase 1B is part of Sempra's proposal to mitigate construction/fabrication threats that include the replacement of all pre-1946 pipelines in Phase 1B.

Sempra has not demonstrated that this proposal is just and reasonable, and it therefore should be rejected. First, Sempra acknowledges that its proposal to replace wrinkle bends goes beyond the requirements of D.11-06-017.[86] Nor has Sempra demonstrated that including these costs in this proceeding will actually be beneficial to customers. Sempra's Base Case proposal to pressure test and replace its pipelines in the next four years will significantly increase rates; Sempra has not justified the additional costs to accelerate the replacement of 3,996 wrinkle bends in the Proposed Case. Sempra is currently managing wrinkle bends as part of its Transmission Integrity Management Program.

Second, Sempra has not supported the cost estimate of the 3,996 wrinkle bend replacement. In its workpapers, Sempra estimated that the unit cost of replacing a

[83] Amended Workpapers, WP-IX-1-48.
[84] Amended Workpapers, WP-IX-1-46.
[85] Ibid.
[86] Amended Testimony, pp. 42, 51, 55 and Response to PZS2-5.

wrinkle bend would be $75,000 "based on historical projects."[87] In the same workpaper, Sempra reduced the unit cost to $50,000 each on the lines scheduled to be pressure tested "due to efficiency gains."[88] To attempt to verify Sempra's cost estimates, DRA requested a copy of all historical projects and calculations used to determine the unit cost of wrinkle bend replacement. SoCalGas/SDG&E did not provide any copies, stating instead that "The cost estimate of $50,000 per Phase 1A wrinkle bend is a high-level allowance for replacement of these pipe features."[89] At a later date, Sempra provided a response which states, "This cost figure represents a high level allowance for the replacement of these pipe features. Question 1(g) of TY2012 GRC data request DRA-SCG-022-DAO identifies an average repair cost per foot of $1,343 based on data from the 2005 to 2009 timeframe. Assuming that a 25-foot section of pipe would be replaced for each wrinkle bend repair yields approximately $33,575 per repair. From the same TY2012 data response, Question 6(e), the average expense per excavation dig was approximately $40,000. Combining these two values and rounding up slightly equals $75,000, thus giving validation that the assumption used in the PSEP filing for wrinkle bend replacements is reasonable. Each project may have unique circumstances that could result in actual costs being above or below this assumed unit cost."[90] No actual cost of any wrinkle bend replacements was identified; only averages of pipeline repairs from the 2005-2009 timeframe were provided.

Finally, wrinkle bend replacement is an issue currently addressed in Sempra's TIMP. This issue should continue to be addressed there. SoCalGas currently receives funding for and performs wrinkle bend replacement through its Baseline Assessment within the TIMP. In the course of assessing its pipelines for threats, wrinkle bends

[87] Amended Workpapers, p. WP-IX-1-48. Footnote 1.
[88] Ibid, at Footnote 2.
[89] Sempra's Response to DRA-DAO-21, Q. 2(b).
[90] Sempra's Response to DRA-DAO-24-Q.3(a).

are replaced if deemed “not stable.” Wrinkle bends deemed “stable” are allowed to remain in service per federal regulations [CFR 49, 192, Subpart O, and B31.8S].[91] According to Sempra, “Within the TIMP, the wrinkle bends identified as part of the PSEP are currently considered as stable in the absence of other factors that may exacerbate their condition (such as external forces that may subject the wrinkle bends to movement).”[92] These wrinkle bends have been assessed by Sempra recently as part of TIMP and will continue to be monitored and reassessed at least once every seven years as part of federal requirements regulating TIMP. Additional funding to replace wrinkle bends should be requested by Sempra in its next GRC in conjunction with its TIMP.

In the 2012 GRC, Sempra requested $25 million in expenses to manage its TIMP program[93], which is an increase of $14 million above the base year 2009 level. Since its baseline assessment is scheduled to be completed by the end of 2012, Sempra should evaluate and identify threats associated with its transmission pipelines and manage them accordingly.

Wrinkle bends identified as “unstable” should have been replaced by Sempra as part of TIMP. In its Test Year 2012 GRC, Sempra did not identify the issue of wrinkle bends as a threat to its system and failed to propose a system-wide accelerated replacement of wrinkle bends in that proceeding. Sempra has not provided any showing that these 3,996 wrinkle bends need to be addressed to meet the requirements of D.11-06-017, or that they need to be replaced during the next 4 years.

For all the reasons stated above, DRA recommends rejecting this proposal as part of this Pipeline Safety Enhancement proceeding. Sempra should continue to address wrinkle bends as part of its management of TIMP.

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[91] Sempra’s statement to DRA during April 25, 2012 Conference Call.

[92] Sempra’s Response to DRA-24, Q. 3 (f).

[93] A.10-12-006, Exhibit-SCG-05-R, Revised Prepared Testimony of Raymond K. Stanford, p. RKS-25.

As for the Pre-1946 pipelines, Sempra is currently managing these lines as part of the requirements of Subpart O. According to Sempra, SoCalGas and SDG&E have already identified and retrofitted, and in-line inspected all pre-1946 transmission pipelines that were constructed using acceptable welding techniques and are operationally suited to in-line inspection.[94] The Pre-1946 pipelines identified for replacement in Phase 1B are the remaining non-piggable pipelines located in non-populated areas and are not planned to be retrofitted to allow for in-line inspection.[95]

SoCalGas has been assessing the risks and managing the risks of these pipelines as part of the on-going management of the transmission pipeline system. SoCalGas should continue to manage the Pre-1946 pipelines and address the issues associated with these pipelines accordingly. The management of these pipelines should not be included for ratepayer funding as part of the Pipeline Safety Enhancement proceeding. This is above and beyond the scope of D.11-06-017.

b. The Commission Should Reject Sempra's Proposal To Include Expenses For Technology Enhancements (As Part Of The Proposed Case)

i. Sempra Has Not Justified Its Proposal To Enhance A System It Testifies Is Safe

Sempra requests $53 million ($47 million for SoCalGas and $6 million for SDG&E) to install fiber optic cabling and methane detection instruments as a safety enhancement.[96] Sempra proposes to install about 280 miles of fiber optic technology in association with pipeline replacements during phase 1.[97] Sempra states, "Fiber optic right-of-way monitors will help SoCalGas and SDG&E identify when intrusions

[94] Sempra's Response to DRA-DAO-9, 2(c).
[95] Sempra's Response to DRA-DAO-9, 2(a).
[96] Amended Testimony, Appendix B.
[97] Amended Testimony, pp.85-86.

into their pipeline rights-of-way have occurred or when a pipeline (or right-of-way) has experienced movement that might pose a threat to pipeline structural integrity."[98] Sempra proposes to "further enhance" its system through the addition of real-time pipeline right-of-way gas detection monitors near facilities that are high-occupancy and pose evacuation challenges, particularly where those facilities are located within 220 yards of a high-pressure, large-diameter gas transmission pipeline.[99]

Sempra proposes to develop a new data collection, storage, alarm processing and data management system to collect information from the methane detection and fiber optic monitors. Sempra states that the data collection and management system (DCMS) will provide the health/status of all fiber optic and methane detection monitors by way of daily status reporting and remote data collection.[100] Also, the DCMS will receive alarm information initiated by any fiber optic or methane detection monitor with a latency of less than 2 minutes.[101] Sempra states that DCMS will also provide permanent storage of all events with appropriate time and date stamping of events. Sempra says DCMS will accommodate future expansion to 10,000 monitoring points and multiple sensor types, as well as support near real-time graphical viewing presentation of alarms on SoCalGas/SDG&E mapping products and provide connectivity with automated customer notification system.[102]

Sempra's proposal for additional technology enhancements is above and beyond the scope of the Commission's directives. Sempra has repeatedly claimed that it is confident in the safety of its system as in its Report to the NTSB as well as in its Testimony in this proceeding. Even if it proposes to address certain pipelines in the Plan, Sempra believes that these pipelines are operating safely today. In the

[98] Amended Testimony, p. 85.
[99] Amended Testimony, pp. 86-87.
[100] Amended Testimony, p. 87.
[101] Amended Testimony, p.87.
[102] Amended Testimony, pp. 87-88.

Report on Actions Taken in Response to the NTSB Recommendations, Sempra states, "During the course of their records review, SoCalGas and SDG&E did not discover any documented inconsistencies that would call into question the standard engineering practices used throughout the years, nor cause concern regarding the current pressure-carrying capacity of in-service pipelines…"[103] Although SoCalGas and SDG&E have identified pipelines that need to be pressure tested or replaced— Category 4 miles that are the focus of this proceeding and the Commission's objective to ensure that California pipelines are operating safely, the utilities testify, "Nothing in our records review process revealed any significant concerns with the currently-established MAOPs for Category 4 pipelines. Accordingly, we remain confident that these pipelines are operating safely."[104]

Sempra's Annual Reports to PHMSA regarding its transmission integrity program continue to show a system that is operating safely. A summary of the number of leaks, failures, and incidents from 2003-2010 is presented below.

Table 6

SoCalGas and SDG&E

Year	Failures	Incidents	Leaks
2003-2004	1	0	10
2005	2	0	2
2006	1	0	1
2007	5	0	6
2008	0	0	0
2009	0	1	0
2010	0	0	2

Source: Response to DRA-PZS-02-Q.1(f)

According to Sempra, the metrics used for evaluation of each utility's safety record for the transmission pipeline integrity program are leaks, failures, and

[103] The Report, p. 10.
[104] The Report, p. 3.

incidents as required by 49 CFR 192.945(a) and are defined as follows[105]:

> **Leaks** are unintentional escapes of gas from a pipeline that are not reportable as Incidents under 49 CFR 191.3. A non-hazardous release that can be eliminated by lubrication, adjustment, or tightening is not a leak.
>
> **Failure** is defined in ASME/ANSI B31.8S as the "general term used to imply that a part in service has become completely inoperable; is still operable but is incapable of satisfactorily performing its intended function; or has deteriorated seriously, to the point that it has become unreliable or unsafe for continued use." Failures that result in an unintentional release of gas are reported as leaks.
>
> **Incident**, as defined in 49 CFR 191.3, "means any of the following events: (1) An event that involves a release of gas from a pipeline, or of liquefied natural gas, liquefied petroleum gas, refrigerant gas, or gas from an LNG facility, and that results in one or more of the following consequences: (i) A death, or personal injury necessitating in-patient hospitalization; (ii) Estimated property damage of $50,000 or more, including loss to the operator and others, or both, but excluding cost of gas lost;(iii) Unintentional estimated gas loss of three million cubic feet or more; (2) An event that results in an emergency shutdown of an LNG facility. Activation of an emergency shutdown system for reasons other than an actual emergency does not constitute an incident. (3) An event that is significant in the judgment of the operator, even though it did not meet the criteria of paragraphs (1) or (2) of this definition."

ii. Sempra's Proposal is Beyond the Directives of D.11-06-017

Sempra is proposing enhancements to its operations that are above and beyond the requirements of the Decision. Nothing in D.11-06-017 requires Sempra or any utility to find ways to monitor disturbances on its system as part of the Pipeline Safety Enhancement proceeding. The Decision directed California gas operators to test or replace transmission pipelines that have not been pressure tested. Sempra has not shown why its proposal for fiber optic and methane detection monitors, or DCMS, should be included as part of the Plan.

Sempra's references to facilities that are high-occupancy and pose evacuation challenges do not justify including the costs of this proposal in this proceeding.

[105] Sempra's Response to DRA-PZS-02, Q. 1(f).

Sempra already treats high-occupancy areas differently. These areas are defined as High Consequence Areas and Sempra receives additional funding to manage the transmission pipelines located in these areas as part of its TIMP program.

As part of TIMP, Sempra is required to identify the threats to its pipelines in HCAs, analyze the risk posed by these threats, collect information about the physical condition of its pipelines, and take actions to minimize applicable threats and integrity concerns before pipeline failures occur. If methane detection monitors will enhance the safety and integrity of the lines in high-occupancy, high consequence areas, then the company should leverage the installation of these monitors in the TIMP program.

Leaks that the fiber optic monitors are designed to pick up are normal day to day risks that Sempra has to manage. Sempra performs leak surveys on a regular basis. Abnormal vibrations from right-of-way activity, such as by construction crews working in an area are also risks Sempra must manage, and Sempra is part of the Underground Service Alert that manages the third party constructions and dig-ins.

If Sempra wants to pursue ratepayer funding of system enhancements, it should do so in its General Rate Case. By that time, Sempra will have prepared a cost benefit analysis to determine if the benefits of these projects outweigh the costs and if this is a prudent use of ratepayer funding. Sempra's request in this proceeding to saddle ratepayers with additional costs for fiber optic and methane detection should be rejected.

c. The Commission Should Reject Sempra's Proposal to Include Costs Associated with Enterprise Asset Management (as Part of the Proposed Case)

Sempra seeks $7 million ($6 million for SoCalGas and $1 million for SDG&E) to design a comprehensive Enterprise Asset Management System (EAMS) as part of its Plan.[106] Sempra states that the EAMS will focus on applying industry record management practices and information technology solutions to govern, record, store,

[106] Amended Testimony, Appendix B.

secure, maintain, assess, search and analyze transmission pipeline system data.[107] According to Sempra, the EAMS will support leading records and data governance practices and controls; ensure the validity, traceability and completeness of pipeline data; and provide Sempra personnel with secure, anytime, anywhere access to critical system data.[108]

DRA recommends rejection of the requested $7 million for the EAMS because Sempra acknowledges that this proposal goes well beyond the directives of the Commission to pressure test or replace pipelines located in Class 3, 4 and Class 1, 2 High Consequence Areas.[109]

Sempra responded to the NTSB recommendations and prepared its Plan as required by D.11-06-017 using its current records and data management system. Sempra reviewed pipeline records and determined whether or not specific lines should be identified for pressure testing or replacement using its current system. If the current records and data management systems are inadequate, SoCalGas and SDG&E should raise this issue in their next General Rate Case applications. Moreover, the cost of record keeping is already embedded in rates: Sempra's ratepayers are already paying for accurate and orderly record keeping of pipeline information. Sempra acknowledges that:

> Record keeping is part of SoCalGas' and SDG&E's existing pipeline integrity program. Transmission pipeline data is stored and organized in a manner that supports the analysis and decision making required for pipeline integrity work.[110]

[107] Amended Testimony. p. 92.
[108] Ibid.
[109] Sempra Response to PZS-2, Q.5, (b).
[110] Response to PZS-2, Q.4 (c).

In its Test Year 2012 GRC, SoCalGas and SDG&E provided testimony describing a set of enterprise, technology-based initiatives intended to make the utilities more efficient. The program is called Operational Excellence.[111] In the last GRC, Sempra requested $545 million to implement the Operational Excellence Program or OpEx 20/20.[112] According to SoCalGas' testimony in that case, "the non-financial benefits [of OpEx 20/20] include…more accurate and timely asset information and ready access to information in the field for front line supervisors, technicians and crews."[113]

The OpEx 20/20 is an enterprise program composed of three major work streams containing 12 projects.[114] One of these projects is the Geographic Information System (GIS). In its Test Year 2012 GRC testimony, SoCalGas states that, "the GIS project implements an industry standard, enterprise-wide geographic information system that supports SoCalGas and SDG&E gas transmission and distribution, electric transmission, substation, distribution, and vegetation management, and Sempra Utilities land services, environmental, and telecommunication. Critical to this GIS is a centralized asset register with validated asset attribute data, integration to other key asset management systems and applications such as outage management, network modeling, work management, graphical work design, and mobile data devices."[115]

In addition to the data management and integration through OpEx 20/20, SoCalGas and SDG&E currently use several databases for record and data management of transmission and distribution pipelines. These data bases record, store, secure, maintain, search and analyze and provide access to the transmission and

[111] A. 10-12-006 (TY 2012 GRC) Prepared Direct Testimony of Rick Phillips, Ex. SCG-13, p. RP-1.
[112] A. 10-12-006 (TY 2012 GRC) Prepared Direct Testimony of Rick Phillips, Ex. SCG-13, p. RP-1.
[113] A. 10-12-006 (TY 2012 GRC) Prepared Direct Testimony of Rick Phillips, Ex. SCG-13, p. RP-3.
[114] A. 10-12-006 (TY 2012 GRC) Prepared Direct Testimony of Rick Phillips, Ex. SCG-13, p. RP-3.
[115] Ibid., p. RP-2A.

distribution pipeline system data. For SoCalGas, the databases and applications currently in use are[116]: (1) Maximo, (2) SAP, (3) Enterprise GIS, (4) High Pressure Pipeline Database, (5) NTSB Access Database, (6) PDMS, (7) Bell Hole Inspections, (8) Casings, (9) DREAMS, and (10) Falcon/DDB. For SDG&E, the utility currently uses the same databases and applications as SoCalGas with the exception of the Falcon/DDB. Instead, SDG&E uses Gport.

The primary functions of each database are described below:

a. Maximo---Oracle database of all maintenance work performed by Transmission and Storage Operations personnel on pipelines, equipment and facilities.
b. SAP—SAP plan Maintenance (PM) is used to record and manage preventative maintenance and inspection activities for distribution operated pipelines.
c. Enterprise GIS—Spatial data repository for Transmission and Distribution assets. Network Model and spatial analysis tools to support system modeling.
d. High Pressure Pipeline Database—Spatial data repository for High Pressure Pipelines. Spatial analysis tools that primarily support Pipeline Integrity.
e. NTSB Access Database—MAOP records collection and segment categorization.
f. PDMS— Pipeline Document Management System (PDMS) contains construction records.
g. Bell Hole Inspections—Access database of excavation inspections and locations conducted as part of the Pipeline Integrity Management Program.

[116] Sempra's Response to DRA-DAO-34, Q. 2.

h. Casings—Access database used to inventory casing locations and extents.

i. DREAMS—the Distribution Risk Evaluation and Monitoring (DREAMS), an Oracle database used by Pipeline Integrity as a repository for leak records on medium pressure distribution pipelines.

j. Falcon/DDB—Transmission and storage construction drawing Oracle database and viewer.

k. GPort—Plant maintenance information for valve and historic regulator station maintenance records.

Sempra has not demonstrated that the eleven existing databases and applications currently in use are inadequate for the management of data and records for purposes of meeting the requirements of D.11-06-017. Sempra says that the EAMS will provide personnel with "...secure, remote, anytime, anywhere access to critical pipeline information through a web portal using a variety of mobile computing devices,[117] but has not shown the need for this level of access and availability to information in this proceeding.

Sempra's ratepayers are already paying for eleven databases and applications, in addition to OpEx 20/20, for data and record management. Sempra has not demonstrated that ratepayer funding for Enterprise Asset Management is necessary for Sempra to meet the requirements of D.11-06-017. DRA, therefore, recommends the Commission reject Sempra's request for additional ratepayer funding of $7 million for the program.

[117] Amended Testimony, p. 93; comments at May 30, 2012 Workshop.

3. Flaws in the Sempra Decision Tree Outcomes

a. Sempra's Decision Tree

Sempra says its proposal to pressure test or replace a pipeline segment is determined by the outcomes of its Decision Tree. The Decision Tree prioritizes work for one of three phases, Phase 1A, Phase 1B, and Phase 2.[118]

Sempra's Decision Tree starts with all pipeline operated in a Class 3 or 4 locations or High Consequence Area (Criteria Segments) for which Sempra does not have documented pressure carrying capability of ≥ 1.25*MAOP or Maximum Allowable Operating Pressure. Applying the Decision Tree, Criteria Segments with no safety validation or validated at less than 1.25*MAOP would be addressed in Phase 1A and all other Criteria segments that have ≥ 1.25*MAOP would be addressed in Phase 1B or Phase 2.

The starting point of the Decision Tree is also the 1,622 miles of NTSB Criteria Miles identified in the Report of Southern California Gas Company and San Diego Gas & Electric Company on Actions Taken in Response to the National Transportation Safety Board Safety Recommendations.[119]

There are 5 outcomes for pipeline segments that go through Phase 1A of the Decision Tree. Outcome #1 is Complete Direct Examination or Replace and Abandon. Outcome #2 is Replace and Abandon. Outcome #3 is Complete TFI in-line inspection. Outcome #4 is Pressure Test. Outcome #5 is TFI inspect and Pressure Test.

For Phase 1B, there are 4 outcomes. Outcome # 6, which is directly linked to Outcome #3, is Install New Line and Pressure Test Existing Line. Outcome # 7 is Replace. Outcome #8 is to move pipeline into Phase 2. Lastly, Outcome #9 is No Further Action.

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[118] Amended Testimony, p. 61.

[119] The Report, p. 11.

A summary of the number of miles of Category 4 pipelines identified in the Decision Tree and used to develop the Plan's scope is presented below.

Table 7

Sempra Testimony, Decision Tree Outcome for Phase 1A

Category 4 Criteria Miles

	SoCalGas	SDG&E	Total
Outcome #1, NDE or Replace	2 miles	0 miles	2 miles
Outcome #2, Replace and Abandon	126 miles[120]	28 miles[121]	154 miles
Outcome #3, TFI inspection	0 miles	0 miles[122]	0 miles
Outcome #4, Pressure Test	11 miles	1 mile	12 miles
Outcome #5, TFI inspection & Pressure Test	165 miles	0 miles	165 miles
TOTAL CATEGORY 4 Miles	**304 miles**	**29 miles**	**333 miles**

Source: Sempra's Response to DRA-DAO-5, Q. 1, the Plan workpapers, Chapter IV.

b. DRA Takes Issue with Sempra's Decision Tree Outcomes

In general, Sempra's Decision Tree is efficient at addressing the Commission's order of identifying and prioritizing the testing of pipelines that lack records of having had a pressure test. However, there are several decision outcomes that DRA opposes.

DRA disagrees with Outcome #1 which identifies pipelines to replace and abandon if the pipeline segments are less than 1000 feet in length. DRA disagrees with Outcome #2, which identifies pipelines to replace and abandon if the pipeline segments are non-piggable and cannot be taken out of service with manageable customer impact. DRA disagrees with Outcome #5, which identifies pipelines to

[120] For SoCalGas, a total of 145 miles are scheduled for replacement with 128 miles of new construction (2 miles from Outcome #1 and 126 miles from Outcome #2) and 16 miles of abandonment. Response to DRA-DAO-5, Q.1.

[121] For SDG&E, a total of 32 miles are scheduled for replacement with 28 miles of new construction and 5 miles of abandonment. Response to DRA-DAO-5-Q.1.

[122] SDG&E proposes to TFI inspect and repair 54 Accelerated miles in 2014 for a total of $4 million.

perform TFI inspection and Pressure Test. DRA also disagrees with Sempra's sub-prioritization methodology. DRA recommends that Sempra incorporate the Class location of individual segments in the sub-prioritization methodology. Finally, DRA disagrees with the inclusion of pipeline segments located in non-populated areas, outside of the Decision Tree as Phase 1A work instead of a later phase.

DRA's analyses and recommendations for pipelines specific to these Decision Tree outcomes are addressed in the sections below.

1. Pipeline Replacements

Sempra uses two criteria from the Decision Tree to determine pipeline replacements: (1) all segments that are 1,000 feet or less in length, and (2) pipeline segments greater than 1,000 feet in length that cannot be removed from service for pressure testing and that are not piggable.

i. Pipeline Segments ≤1,000 Feet

Sempra has identified two miles of SoCalGas transmission pipelines with segments less than 1,000 feet that need to be addressed in Phase 1A.[123] Sempra states, "For short segments of pipe, the logistical costs associated with pressure testing (permitting, construction, water handling, service disruptions for non-looped system) can approach or exceed the cost of replacement.[124] Sempra's proposal to replace instead of hydrostatic test segments less than 1,000 feet should be rejected. Sempra did not adequately support this proposal.

Alternatively, Sempra requests the option to perform a complete inspection of the pipeline segment using non-destructive examination (NDE) methods, such as ultrasonic, radiographic and magnetic particle inspection techniques. Sempra states that non-destructive examination offers an equivalent means to validate the strength

[123] Amended Testimony, p. 53.
[124] Amended Testimony, p.53.

of the pipeline segment.[125] Also, Sempra states that the use of these techniques will reduce the time, costs, customer impacts and construction hazards associated with replacement.[126]

DRA takes issue with the alternative proposal to use NDE methods on these short segments because at this time NDE methods have not been officially recognized as achieving the same standard of safety as hydrostatic testing. Instead, DRA recommends that these short segments be pressure tested. Pressure testing a pipeline segment continues to be the recommended method to strength test a pipeline segment according to the 2010 ASME code. Pressure testing a pipeline segment continues to be required by Title 49 CFR, Subpart J.

Sempra has no basis for its proposal of automatically replacing segments less than 1,000 feet. Sempra's statement that the cost of pressure testing these short segments can approach or exceed the cost of replacement is unsupported. Although Sempra claims in testimony that it is more cost effective to replace these segments, Sempra did not perform any cost benefit analyses to support this claim. Sempra states, "…SoCalGas and SDG&E did not conduct a formal cost/benefit analyses to determine that pressure testing of short pipeline segments less than 1,000 feet in length would exceed the cost of replacement. This determination was based on engineering judgment."[127] Sempra further states, "Once detailed planning and engineering/design is completed, there may be cases where it is determined that a pressure test is more cost effective than a replacement."[128]

In the past, SoCalGas has performed several pressure tests on segments that are shorter than 1,000 feet as part of its Transmission Integrity Management Program. Between 2005 and 2011, SoCalGas performed pressure tests on multiple segments

[125] Amended Testimony, p. 54.
[126] Amended Testimony, p.54.
[127] Sempra's Response to DRA-DAO-3, Q. 1.
[128] Ibid.

ranging from as short as 52.8 feet to as long as 17.85 miles.[129] When asked if in the past SoCalGas had replaced instead of pressure test pipeline segments less than 1,000 feet because it was more cost effective to do so, Sempra was non-responsive.[130]

DRA recommends that the Commission reject the proposal to replace the segments that make up the 2 SoCalGas miles. Instead, DRA recommends that Sempra pressure test these segments. Without adequate justification to replace instead of test, it is unreasonable for Sempra to request the more costly option. If the Commission finds NDE methods achieve the same standard of safety as hydrostatic testing, DRA would not take issue with the use of NDE methods.

ii. Pipeline Segments >1000 Feet that Sempra Says Cannot Be Taken Out of Service with Manageable Customer Impact, and not Piggable (Outcome #2)

Sempra's Decision Tree also identifies a pipeline segment for replacement if it meets the following criteria: (1) the pipeline segment is located in a Class 3 or 4 location of High Consequence Area and does not have documented pressure carrying capability of $\geq$ 1.25 MAOP and (2) the pipeline cannot be taken out of service with manageable customer impact, and (3) the pipeline has not been retrofitted to accommodate an in-line inspection tool (non-piggable).

Sempra requests a total of $818 million in capital expenditures to replace a total of 260 miles of Criteria and Accelerated pipelines.[131] 2.14 miles were based on Outcome #1[132] and 257 miles were based on Outcome #2.[133] Of the total 260 miles, 42 miles will be abandoned and 28 new segments will be added.[134] The net total of

[129] Sempra's Response to DRA-DAO-2, Q. 14.
[130] Sempra's Response to DRA-DAO-3-3.
[131] Amended Workpapers, p. WP-IX-1-22.
[132] Amended Workpapers, p. WP-IV-5 of 12.
[133] Amended Workpapers, p. WP-IV-7 of 12.
[134] Amended Sempra Response to DRA-DAO-5, Q.1.

new pipeline construction is 246 miles.[135] Of this total, 128 miles, or 52 percent, are identified as Criteria Miles and 118 miles, or 48 percent, are identified as Accelerated Miles.[136]

Sempra requests a total of $197 million in capital expenditures to address 102 miles of SDG&E pipelines.[137] Of this total, $14.3 million is allocated to address the design and engineering work for 54 miles of Line 1600.[138] One hundred percent of the 54 miles of Line 1600 is designated as Accelerated. The remaining $182.2 million is for the replacement of 48.5 miles of SDG&E Distribution pipelines.[139] The Accelerated segments make up 42 percent of the total planned replacement of the Distribution pipelines.[140]

2. The Commission Should Reject Sempra's Proposal To Replace Instead of Pressure Test Pipeline Segments >1,000 Feet Based on Unsupported Assumptions about "Manageable Customer Impact"

Sempra's main criterion to identify pipelines for replacement is whether or not they can be taken out of service with manageable customer impact. Conceptually, this sounds reasonable, but Sempra's explanation of how the company determines a "manageable customer impact" is inadequate and unsubstantiated.

Sempra says "Manageable Customer Impact" means: "…an acceptable level of negative effects to our customers as a result of the PSEP."[141] The criteria Sempra used to determine whether a segment can be taken out of service are "…based upon

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[135] Sempra's Response to DRA-5, Q. 1.

[136] Ibid.

[137] Amended Workpapers, pp. WP-IX-1-33 and WP-IX-1-35.

[138] Amended Workpapers, p. WP-IX-1-34.

[139] Amended Workpapers, p. WP-IX-1-36.

[140] Amended Workpapers, p. WP-IX-1-36.

[141] Sempra's Response to DRA-DAO-7, Q.1.

specific pipeline and local system characteristics that may include, but are not limited to system looping and flexibility; impact to capacity; curtailment to non-core customers; impact to shippers, customers, and the gas market; availability of alternative sources of gas; anticipated outage duration; and the ability to mitigate these negative impacts through construction of parallel systems."[142]

This "criteria" is too vague and subjective to be relied on by the Commission as the basis of ordering ratepayer funding of hundreds of millions of dollars.

iii. The Criteria Used To Determine Manageable Customer Impact Were Based on Judgment and Not Engineering Analyses

Sempra performed no specific analyses on any actual segments or pipelines to determine possible impacts on customers if a line were tested instead of replaced. Sempra provided no data regarding system looping and flexibility; impact to capacity; curtailment to non-core customers; impact to shippers, customers, and the gas market; availability of alternative sources of gas; anticipated outage duration; and the ability to mitigate these negative impacts through construction of parallel systems. Sempra provided no support for any of the criteria identified as influencing factors in determining whether to replace instead of test a segment of pipeline.

Sempra states the following: "Specific studies or analyses have not yet been performed to identify all customer impacts, and the economic consequences of those impacts, that would be incurred as a result of each specific PSEP pipeline segment being removed from service for the assumed two to six weeks necessary to perform a pressure test. Evaluation of the customer impacts and the cost effectiveness of pressure testing as compared to replacement on a segment-by-segment basis will be conducted during the engineering, design, and execution planning phases of the PSEP."[143]

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[142] Sempra's Response to DRA-DAO-7-1.

[143] Sempra's Response to DRA-DAO-20-Q.4.

DRA asked if Sempra explored alternatives to serving customers in the areas where lines and segments have been identified for replacement because Sempra determined that they cannot be taken out of service with manageable customer impact. Sempra states, "The development of the pressure test and replacement scope for the PSEP was done at a high level and all options to manage customer impacts have not yet been evaluated. Such evaluation, including an analysis regarding the viability of alternatives to serve customers while pipelines are out of service for pressure testing, will occur during the engineering/design phase of each project."[144]

As with so much else in Sempra's Plan, there is scant, if any, verifiable support; rather, there are only unverified assertions that everything will be designed and engineered at some point in the future.

iv. The Commission Should Reject Sempra's Unsupported Assertion that Un-piggable Pipelines Should Be Replaced

Sempra's other proposal that pipelines that are not-piggable must be replaced is similarly unsupported. Sempra has not identified any explanation as to why non-piggable pipelines cannot be pressure tested and why, consequently, the Commission must adopt the more expensive alternative of replacement.

Given the Sempra estimate for replacement at seven times higher than for pressure testing[145], there is a disincentive for Sempra to pursue an action that is lower in costs.   Absent clear evidence that it is absolutely necessary to replace these particular pipeline segments, Sempra should not be allowed funding for any pipeline replacement in the current proceeding.

v. Pipeline Replacement Projects Should Be Rejected Because Sempra Is Trying To Use the Plan To Increase Capacity Without Justification

[144] Sempra's Response to DRA-DAO-20, Q. 5.

[145] The average cost of pipeline replacement in the Plan is $3.5 million per mile and the average cost of a hydrostatic test is $500,000 per mile.

Sempra proposes to increase the size of its pipelines for many replacement projects proposed in the Plan. DRA reviewed the Sempra proposal for SoCalGas Distribution Replacement and found that 21of the 54 individual projects (or 40%) that had its own workpapers, show an increase in pipeline diameter for the proposed new replacement.[146] The increase in diameter ranges from 1" to several inches in size.

There are several examples that warrant concern due to significant increases in pipeline diameter.

a. Line 41-6000-2 and L-6914 Should be Removed from the Plan

The proposal to abandon Line 41-6000-2 and extend Line 6914 appears to be a project designed to address issues above and beyond the scope of D.11-06-017. Sempra proposes to abandon 36 miles of Line 41-6000-2, with segment diameter range from 6"-16" and install 14 miles of new segments with smaller diameter ranging from 2" to 6". These segments are then used to tie L-6914 in to the existing pipeline system with an additional 14 miles of pipelines with a diameter of 10" and 24".[147] The total cost of this project is $77.8 million with $24.8 million for the abandonment and replacement of Line 41-6000-2 [148] and $53 million for the extension of Line 6914.[149]

This project does not appear to have been planned based on the criteria used in the Decision Tree. While the 36 miles of pipelines proposed for abandonment are identified as having come from Box 2 of the Decision Tree, no action plan was identified for L-6914. DRA asked Sempra about this project and Sempra stated that it was a "capacity planning" project. The one sentence statement in Sempra's

[146] DRA did not look at any small projects that Sempra grouped together and that did not have its own workpapers.

[147] Amended Workpapers, pp. WP-IX-1-B170-B172, and WP-IX-1-A89-A91.

[148] Amended Workpapers, p. WP-IX-1-B170.

[149] Amended Workpapers, p. WP-IX-1-A89.

workpapers, "The extension of existing L-6914 will allow for the abandonment of 41-6000-2" does not provide adequate support for this project.[150] In fact, L-6914 was installed in 2009 and is not a pipeline that should be included in the group of pipelines affected by the Decision to test or replace.[151]

<u>Table 8</u>

Line 6914/Line 41-6000-2

Abandoned					New Construction				
Accelerated	Criteria Category 4								
6.625"-16"	6.625"	8.625"	10.625"	16"	2"	4"	6"	10"	24"
25 miles	6 miles	2 miles	3 miles	.15 miles	2 miles	211 ft	10 miles	3 miles	11 miles
36 miles to be abandoned					Install new 28 Miles* (rounding)				

b. SoCalGas Distribution--Line 38-959 (From 6.25" to 12.75")

SoCalGas proposes to replace 15.6 miles of Line 38-959 at a cost of $28.3 million.[152] Sempra states, "This system needs pressure betterment due to low pressure problems."[153] If this is a system planning issue, Sempra should have addressed this as part of the 2012 GRC application or plan to request it in its next GRC, and not in the Plan.

Sempra has not explained why doubling of pipeline diameter for this line is required by D.11-06-017.

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[150] Amended Workpapers, p. WP-IX-1-A89.

[151] Sempra's Response to DRA-16, Q. 6, Decision Tree Database.

[152] Amended Workpapers pp. WP-IX-1-B136 to B138

[153] Amended Workpapers, p. WP-IX-1-B138.

<u>Table 9</u>

Line 38-959

Abandoned			New Construction
Accelerated	Criteria Category 4		
6.625”	4.5”	6.25”	12.75”
11.3 miles	0 miles	4.3 miles	15.6 miles
Replace 15.6 miles			Install new 15.6 miles

c. Line 38-539 (SoCalGas Dist.)

Sempra requests a total of $31 million to replace 12 miles of Distribution pipelines of Line 38-539.[154] 2.3 miles of the total are identified as “Criteria” and 9.7 miles are identified as “Accelerated.” It appears that Sempra is proposing a capacity upsizing project. Sempra proposes to replace pipeline segments with 6.625” and 8.625” in diameter with 10.75” in new construction. The notes in the workpapers show: (1) “Include non-criteria Cat 4 segments” and (2) Upsize to 10” per Master Planning.

<u>Table 10</u>

Line 38-539 (SoCalGas Dist.)

Abandoned			New Construction
Accelerated	Criteria Category 4		
6.625” and 8.625”	6.625”	8.625”	10.75”
9.7 miles	2.1 miles	.22 miles	12 miles
Replace 12 miles			Install new 12 miles

The proposal to replace existing pipelines with new segments to increase capacity does not meet the objective of Commission Decision 11-06-017. Sempra’s proposal is above and beyond the requirements of the Commission. The objective of the Decision is to validate the MAOP of the pipelines that were not pressure tested. Sempra is using the opportunity of the Plan to increase the capacity of its system without any support. Sempra has not performed or presented any cost benefit

[154] Amended Workpapers, pp. WP-IX-1-B129 to B130

analyses or justification as to why the capacity of these lines needs to increase. Sempra's proposal to replace pipelines should be rejected.

vi. Absent Adequate Support for Pipeline Replacement, DRA Recommends Testing All Sempra Identified Category- 4 Lines.

D.11-06-017 states, "…the Implementation Plan must set forth criteria on which pipeline segments were identified for replacement instead of pressure testing."[155] The Commission requires California utilities to pressure test its transmission pipelines that do not have records to verify that a pressure test has been performed. For those instances where a pipeline segment must be replaced instead of test, criteria must be developed and used to support the replacement work. Sempra's Plan does not provide support for the criteria used to replace pipeline instead of performing a hydrostatic test.

Absent thorough engineering analysis, customer impacts studies, and the economic consequences of those impacts in the Plan, the current pipeline replacement proposals are not adequately supported. DRA recommends funding to perform the hydrostatic tests on the Category 4 pipelines that Sempra has identified for replacement.

3. Absent any Support for the Acceleration of non-HCA Pipelines into Phase 1A, The Commission Should Authorize Funding To Pressure Category 4 Pipelines Only

Sempra requests a total of $182 million in O&M expenses to pressure test 355 miles of SoCalGas pipelines in Phase 1A.[156] Sempra does not propose to pressure test any SDG&E pipelines in Phase 1A.

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[155] D.11-06-017, p. 31.

[156] Amended Workpapers, pp.WP-IX-1-5, WP-IX-1-9, and WP-IX-1-13.

The pipeline is pressure tested if it meets the following criteria: (1) the pipeline segment is located in a Class 3 or 4 location of High Consequence Area and not has documented pressure carrying capability of ≥ 1.25 MAOP, (2) the sum of the pipeline Criteria Miles is more than 1,000 feet in length, (3) pipeline can be taken out of service with manageable customer impact; and (4) the pipeline has not been retrofitted to accommodate an in-line inspection tool. If the pipeline meets all of these requirements then it will be assigned Outcome #4, "Pressure Test". If any of the pipelines is Pre-1946, it will be abandoned and replaced instead.[157] Sempra's Workpapers show a total of 25 miles identified for pressure testing. Of this total, 11 miles are categorized as Criteria Miles and 14 are categorized as Accelerated Miles.[158]

The pipeline is identified for TFI inspection and pressure testing if: (1) the pipeline segment is located in a Class 3 or 4 location of High Consequence Area and not has documented pressure carrying capability of ≥ 1.25 MAOP and (2) the sum of the pipeline Criteria Miles is more than 1,000 feet in length, and (3) pipeline can be taken out of service with manageable customer impact and (4) the pipeline has been retrofitted to accommodate an in-line inspection tool. If the pipeline meets all of these requirements then it will be assigned Outcome #5, "TFI Inspect and Pressure Test". Sempra's Workpapers identified a total of 335 miles for TFI inspection and pressure testing. Of this total, 165 miles are Criteria Miles and 170 miles are Accelerated Miles.[159] Although the Decision Tree identified 335 miles for TFI inspection, Sempra is proposing to TFI inspect a total of 667 miles of pipelines, which is an additional 332 miles of pipelines above the Decision Tree figure.[160]

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[157] Amended Testimony, p. 61, Decision Tree, Note 1.
[158] Amended Workpapers, p. WP-IV-8 of 12.
[159] Amended Workpapers, p. WP-IV-9 of 12.
[160] Amended Workpapers, p. WP-IX-1-40.

Sempra's proposal for pressure testing and for ILI and pressure testing, as proposed in its workpapers, is summarized below.

Table 11

	Costs	Total Miles	Accelerate Miles	Criteria Miles
Pressure Tests				
SoCalGas				
Distribution	$3,500,000	17	10	7
Transmission	$177,100,000	335	170	165
Storage	$1,200,000	3	3	0
SDG&E	$300	0	0	0
TOTAL	**$182,100,000**	**355**	**183**	**172**
ILI				
		Total Miles		
SoCalGas	$58,000,000	667	-	-
SDG&E	$4,300,000	52	-	-
TOTAL	$62,300,000	719	-	-

Source: Sempra's Amended workpapers, WP-IX-1- 5 and WP-IX-1-9.

For SoCalGas, Sempra proposes to test a total of 355 miles of Category 4 and Accelerated pipelines.[161] Of this total, 172 miles, or 48%, are categorized as Criteria Miles and 183 miles, or 52%, are categorized as Accelerated Miles. Sempra is proposing to test more Accelerated miles than Criteria miles. The average unit cost per mile is $513,000 per mile.[162]

i. Historical Hydrostatic Tests

DRA attempted to provide a comparison of Sempra's consultant's, (SPEC), estimate to Sempra's hydrostatic test cost estimate for transmission pipelines assessed as part of the utilities' day-to-day maintenance and as part of the management of TIMP. However, Sempra did not provide the historical data in a format that would provide a meaningful comparison to the SPEC estimates.[163]

[161] Amended Workpapers, p. Wp-IX-1-5 and 1-9.

[162] Total hydrostatic test cost estimate of $182 million divided by 355 miles.

[163] Sempra's Response to DRA-DAO-2, Q. 14.

Sempra did not provide a breakdown of the cost elements of the historical testing projects so that these cost elements could be compared with what SPEC had estimated.

According to Sempra, the historical costs associated with the hydrostatic tests performed on transmission pipelines under TIMP are co-mingled with other project costs or these costs are not representative of hydrostatic testing of an in-service pipeline.[164] Sempra did not identify the recorded costs of hydrostatic testing in the same format that it developed the Plan forecasts. In the SPEC's hydrostatic test estimates, costs for Materials, Construction, SCG Labor/Inspection, Design, Engineering, Construction, and Environmental elements are identified for each line.

DRA requested historical costs to perform hydrostatic tests on lines that are "new", "relocated," "repaired", or "related situation" from 2001 to 2011, and asked that Sempra identify cost variances, if any exists between the different categories. Sempra did not provide the data which DRA requested. Sempra states, "This test is an integral part of the project, but typically only a small part of the entire job scope and cost. The costs specific to the hydrostatic test are embedded with other project planning and execution costs and cannot be separated from the total construction costs."[165]

Sempra explained that SoCalGas has not performed many pressure tests on in-service existing pipeline segments. Sempra states, "Although infrequent, there have been additional projects that were more hydrostatic testing-specific and not part of our TIMP assessment activities. The Table below shows recent examples of these types of projects, along with the miles tested and the total project costs."[166]

[164] Sempra's Response to DRA-DAO-30, Q.1, Sempra's Response to DRA-DAO-2, Q. 14.
[165] Sempra's Response to DRA-DAO-30, Q.1.
[166] Ibid.

Table 12
Hydrostatic Testing Projects
Pipelines and Cost of Inspection
(Thousands, fully loaded, nominal dollars)

Line #	Miles Hydrostatic Tested	Pressure Test Year	Total Expense
Line 4000	0.6	2007	$ 484
Line 6916 S	8.9	2010	$ 2,908
Line 1022	0.4	2011	$ 1,001

Source: Sempra Response DRA-DAO-30, Q.1.

The data provided by Sempra shows an average cost of $439,000 per mile for 10 miles of hydrostatic tests. The average cost for the 8.9 miles tested in 2010 was $327,000 per mile.

As for the TIMP projects, Sempra identified the following and distinguished the difference in costs to perform hydrostatic testing of an in-service line versus a newly constructed line:

Table 13

Pipeline	Length	Comments
1229	0.51	Long line example provided below
PGR6 (multiple Segments)	0.49	Short segment example provided below
PGR6-D	0.02	Short segment example provided below
PGR6-E	0.06	Short segment example provided below
PGR6-F	0.02	Short segment example provided below
PGR6-F1	0.02	Short segment example provided below
PGR6-F2	0.02	Short segment example provided below
PGR6-G	0.04	Short segment example provided below
80	0.06	Mixed costs provided below – see note 1
G80.01	0.08	Mixed costs provided below – see note 1
G80.02	0.07	Mixed costs provided below – see note 1
G80.03	0.05	Mixed costs provided below – see note 1
324	0.48	N/A – new construction, see note 2
6906	17.85	N/A – new construction, see note 2
6906XO1	0.05	N/A – new construction, see note 2
44-137	0.01	N/A – misc. segments, see note 3
44-137BO1	0.01	N/A – misc. segments, see note 3

Pressure Testing Costs for In-service Piping

Line 1229 - Long Line Example

Total Pressure Test Miles: 0.5

Pressure Test Year	Labor	Non-Labor	Totals
2006	**$32,791**	**$471,609**	**$504,400**

PGR-6 – Short Segment Example

Total Pressure Test Miles: 0.7

No. of Pressure Test Segments: 7

Avg. Pressure Test Length: 0.1

Pressure Test Year	Labor	Non-Labor	Totals
2010	**$22,623**	**$209,095**	**$231,718**

Pressure Testing Costs for Mixed Assessment & New Construction Projects

LINE 80 - Mixed Assessment Costs (see note 1)

Total Pressure Test Miles: 0.3

No. of Pressure Test Segments: 4

Avg. Pressure Test Length: 0.08

Date	Labor	Non-Labor	Totals
2010	**$42,467**	**$949,983**	**$992,450**

Line 324 Relocation and Pressure Test (see note 2)

Total Miles: 0.5

Date	Labor	Non-Labor	Totals
2009	**$43,090**	**$1,961,219**	**$2,004,309**

Line 6906 Construction and Pressure Test (see note 2)

Total Miles: 17.9

Line 6906 was completed under a collectable work agreement. The total cost of this project was approximately $44M.

Sempra explains the testing of the above lines:

"L80 pipeline was assessed using a combination of both in-line inspection and pressure testing. These combined costs were an integral part of the job planning, and shared many of the same resources for planning and execution. As a result these combined costs cannot be separated.

Lines 6906 and 324 were new construction projects, and the costs for pressure testing are not representative of a pressure test for in-service piping.

Commissioning pressure tests are inherently part of the total commissioning effort; these embedded costs are an integral part of project planning and execution and cannot be separated from the total construction costs.

Additionally, new construction projects do not incur the water handling and disposal issues associated with in-service pipelines. These water management costs can be significant, and are not reflected in new construction projects. These small segments of pipeline represent miscellaneous pressure tests required as part of the installation of new components (for example, the testing of fittings, tees, taps, etc.) needed to support larger projects. These costs are commingled with the larger project costs and do not represent typical pressure test costs. These costs are negligible and unrepresentative of pressure testing costs for existing segments and have not been provided. Costs are not available in the workpaper format used by SPEC Services, therefore the costs provided below reflect the total costs associated with these projects."[167]

In the explanation of the costs for the TIMP lines provided above, Sempra implied that the cost of testing an in service line is more expensive than the cost of testing a brand new line because of water management costs.

Although the average cost per mile gives some indication of how much it would cost to perform hydrostatic testing, the cost of testing a segment is a better indicator of testing costs. Sempra's proposal to test SoCalGas' transmission lines in the Plan shows a much higher estimate per test segment when compared to both in-service testing and to new construction testing. In the Plan, Sempra proposes an average unit cost of $1,402,000 per test segment for 122 segments, for the SoCalGas Transmission pressure testing projects. For the Distribution lines, Sempra proposes an average unit cost of $298,000 per segment for 10 segments. There is no pressure testing proposed for SDG&E.

Sempra's average unit cost per segment of $1.4 million for SoCalGas Transmission pressure testing projects is excessive and without justification. DRA concludes that Sempra's variable costs per test project, which accounts for the volume of each test segment and the amount of water required, are too high.

DRA developed its own cost model which uses a different water cost than Sempra's estimate for each of the lines proposed for Phase 1A. The detailed analyses used to develop DRA's hydrostatic test costs are presented in Witness Tom Roberts' testimony, Exhibit DRA-2A.

ii. Repairs estimated per Test Segment.

Sempra estimates a total of 1 repair per pressure test segment for SoCalGas and SDG&E transmission and distribution pipelines in its workpapers.[168] Sempra states the following as the basis of this estimate, "Based on historical projects, it was estimated that an average of one repair would be needed for each pressure test segment, and the repairs would cost an average of $50,000 (10% labor and 90% non-labor) each."[169] The table below provides a summary of the number of repairs estimated for each pipeline category.

Table 14

Sempra Pressure Test & Repair Estimates

(In 000's of Dollars)

	Pressure test Miles	Number of Repairs	Repair Costs	Pressure Test Costs	Total Costs
SOCALGAS					
Transmission	335 miles	122	$6,100	$171,000	$177,100
Distribution	17 miles	10	$500	$2,982	$3,500
SDG&E					
Transmission	-	-	-	-	-
Distribution	.3 miles	1	$50	$210	$300
TOTAL	352.3 miles	133			$180,900
Cost per Mile with Proposed Repairs					$513 per mile
Cost per Mile without Repairs					$494 per mile

(continued from previous page)

167 Sempra's Response to DRA-DAO-2, Q. 14.

168 Amended Workpapers, pp. WP-IX-1-6, WP-IX-1-10, WPWP-IX-1-17, and WP-IX-1-19.

169 Ibid.

DRA requested that Sempra identify the "historical projects" used to determine the number of repairs necessary and the repair cost. DRA requested that Sempra provide a copy of the work orders for testing and/or for repairing, including the project scope if available, which shows the project start and end dates, the details of the hydrostatic test and/or repair, along with the expenses incurred for the test and/or repair, for all the identified "historical projects". Sempra did not provide this data.[170] Sempra states, "Given the short timeframe allotted for preparation of the PSEP, subject matter expertise was relied upon to determine the scope and estimated cost associated with post-pressure test repair work. A specific set of projects was not consulted, but rather institutional knowledge of previous repair work was applied to determine a reasonable, high level allowance to include as part of the total cost of the pressure testing effort. Every project contains unique circumstances that can affect both scope and cost."[171]

Sempra's proposal to perform 133 repairs on 352 miles of SoCalGas pipelines is without support. The rate of 0.4 repairs per mile has no factual basis. As discussed above in Section E (2)(b)(i), Sempra's current transmission system does not require this level of repair.

For comparison purposes, in 2011 PG&E tested approximately 164 miles of transmission pipeline. PG&E experienced 2 ruptures, and 1 small leak.[172] A total of 3 repairs were needed. Sempra's estimate of 133 repairs needed for 352 miles of pipelines tested is excessive.

Sempra stresses in its Report to the NTSB and testifies in its Plan that its systems are safe.[173] Sempra specifically stated in the Report, "Nothing in our records review process revealed any significant concerns with the currently-established

[170] Sempra's Response to DRA-DAO-6, Q. 3.
[171] Sempra's Response to DRA-DAO-6, Q. 3.
[172] PG&E's Presentation to the CPUC on Hydrostatic Testing Process and Lessons Learned, p. 12.
[173] Amended Testimony, p. 1.

MAOPs for Category 4 pipelines. Accordingly, we remain confident that these pipelines are operating safely."[174] Sempra further states that the majority of the Category 4 pipelines (207 miles out of 385 miles of Category 4 pipelines) has been assessed as part of its ongoing pipeline integrity program using smart pigs, and that these assessments give the utilities additional confidence in the integrity of the pipeline.[175]

Sempra's proposal for the number of hydrostatic test repairs and costs should be disregarded because there is no support for the estimates. Sempra has not provided any analysis or factual evidence demonstrating that its system will leak or rupture following the performance of a hydrostatic test. Sempra has not justified the level of repairs estimated for the proposed hydrostatic tests.

Based on the fact that Sempra testifies its system is safe and PG&E had only 3 repairs following one year's worth of testing 164 miles of transmission pipeline, Sempra's estimate of 133 repairs is unlikely and excessive. DRA recommends the Commission reject Sempra's request for repair costs associated with Sempra's hydrostatic tests. If there are any repairs needed, the cost will be de minimis based on Sempra's safety record.

iii. DRA Recommends Pressure Testing of Category 4 Pipelines

DRA recommends pressure testing of all pipelines located in Class 3 and 4 and Class 1 and 2 HCAs that have not been pressure tested. In the Plan, Sempra has identified these pipelines as Category 4 pipelines. As discussed above, Sempra has not provided adequate support for including the number of Accelerated pipelines with the Category 4 pipelines in the first phase of its Plan. Sempra's reasoning that including the Accelerated pipelines as part of Phase 1A work would be more operationally efficient and economical is not supported. DRA recommends that the

[174] The Report, p. 3.
[175] Ibid.

Commission exclude the number of Accelerated pipelines as part of Phase 1A work until Sempra can demonstrate that by including Accelerated pipelines, the utility would gain efficiency and ratepayers would benefit from the cost savings of including this work in Phase 1A.

4. The Commission Should Reject the Contingency Percentages and Amounts Proposed by Sempra

Sempra proposes an overall contingency amount of $162 million[176] for the pipeline replacement projects and $30 million[177] for hydrostatic test projects.

The contingency percentages that SPECs applied, 20 percent for projects costing more than $2 million and 30 percent for projects less than $2 million, seem arbitrarily high. Sempra explains, "We typically assign a contingency cost of 30% to all of our ROM [rough-order of magnitude] cost estimates to account for uncertainty associated with a true understanding of the project scope."[178] Sempra further states, "For typical pipeline projects most costs are tied directly to the pipeline footage (ie materials and construction labor). However there are some costs including environmental permitting and right-of-way acquisition that tend to decrease on a per foot basis as the size of the project increases. There is also an indication that material and construction labor costs will tend to decrease as the size of the project increases due to competitive pricing and the desire of suppliers to reduce profit for volume. Considering these factors, the estimates generated for SCG identified a threshold of $2 million at which the contingency amount could logically be reduced from 30% to 20%"[179]

Sempra did not provide adequate support for the contingency percentages used in the Plan. Sempra identifies the following "uncertainties" that the contingency

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[176] Sempra's Response to DRA-DAO-32, Q. 2(a).
[177] Sempra's Response to DRA-DAO-32, Q. 1(a).
[178] Sempra's Response to DRA-DAO-1-5.
[179] Ibid.

amounts were applied to: "…definitive designs and material takeoffs, labor market, cost of materials, availability of right-of-way, public relations issues, environmental/permit restrictions on the construction effort, soil conditions, etc..."[180] Although specific percentages were applied to address "uncertainties", Sempra could not quantify these "uncertainties" and did not explain how the percentages were derived. Sempra also did not identify project "unknowns" and "risks" that the contingency amounts would cover or how these "unknowns" and "risks" are quantified as 20% or 30%.

Sempra stated that individual costs were based on a reliance on past project experience. Yet Sempra could not identify or provide any details about these past projects wherein cost estimates were derived.[181] Sempra simply stated that it was for projects that SPEC Services were involved for various clients.[182]

The 20% and 30% contingency percentages Sempra proposes are unreasonably high and without support. DRA recognizes that a contingency amount is necessary to address the uncertainties in the current forecasts. In the absence of a proper contingency analysis, the Commission should approve a contingency amount of no more than 8%, which is comparable to amounts the Commission has approved for more complicated projects such as PG&E's, SoCalGas', and SDG&E's Advanced Metering Infrastructure (AMI) projects.

A review of all Commission authorized contingency amounts for all AMI-related applications show an average of 8.1%:

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[180] Sempra's Response to DRA-DAO-19, Q. 3(f).
[181] Response to DRA-DAO-19-Q.3(b).
[182] Response to DRA-DAO-19, Q.3(a).

Table 15

Commission Authorized Contingency Percentages for CA Utilities

(in Millions of Dollars)

Project	Cost Adopted	Contingency Adopted	Contingency % Adopted	Citation
SoCalGas	$1,051	$68.7	7.0%	D.10-04-027 in A.08-09-023, pp.2-37.
SDG&E	$572	$33.8	6.3%	D.07-04-043 in A.05-03-015, p. 38.
PG&E Original	$1,739	$128.8	8.0%	D.09-03-026 in A.07-12-009, p. 87
PG&E Upgrade	$467	$49	11.7%	D.09-03-026 in A.07-12-009
SCE	$1,634	$130.1	8.7%	D.08-09-039 in A.07-07-027; Dec. 5, 2007 errata Testimony, SCE-2, p. 14
ALL AMI	$5,463.4	$410.4	8.1%	Avg. for All Projects

In no event should the Plan have a *higher* contingency than the average AMI contingency for all projects. On this basis, absent a proper contingency analysis, DRA recommends that the contingency for the Plan be no more than 8%.

Based on the past three General Rate Cases, Sempra has used contingency percentages that ranged between 7% and -15% of project costs.[183] Sempra states, "Contingencies were most often used on projects in locations where various construction, permitting and environmental fees are not well defined in the early project development phases."[184] Although the scale of work is much larger for the Plan, the type of activity is quite limited in nature to test or replace pipelines. Testing and replacing pipelines are activities that SoCalGas and SDG&E perform on a regular basis. With the Plan, Sempra is proposing work activities that are not any different

[183] Sempra's Response to DRA-DAO-27, Q. 2.

[184] Ibid.

than, and with a similar time frame as, the work activities proposed in a general rate case.

DRA recommends using an 8% contingency for the Plan estimates based on the reasons discussed. The 8 percent is within the contingency percentage range used in the past 3 general rate cases by Sempra. Since the projects proposed in the Plan are similar in nature to pipeline projects proposed in the GRC, where various construction, permitting and environmental fees are not well defined and these projects are also in the early stages of planning, the 8 percent contingency is appropriate.

5. The Commission Should Reject Sempra's Proposal To Perform In-Line Inspection Prior to Performing Pressure Tests as Part of the Base Case Proposal

Sempra requests a total of $62 million ($58 million for SoCalGas and $4 million for SDG&E) to in-line inspect using transverse field inspection (TFI) tools, *and for estimated repairs*, prior to pressure testing the Criteria segments identified for pressure testing.[185] Of the $62 million proposed, $8 million is for the inspection of 667 miles in SoCalGas' territory and 54 miles in SDG&E's territory. The remaining $54 million is for the repairs of potential problems identified by the inspections. Sempra's repair estimate is based on an average of one repair per mile of pipe inspected at a unit cost of $75,000 per repair.[186]

According to Sempra, "…TFI tools can be used to facilitate proactive mitigation of any pipeline anomalies that may lead to a potential pipeline failure at high pressure test levels."[187] Sempra states that by mitigating potential sources of

[185] Amended Workpapers, pp. WP-IX-1-39 through WP-IX-1-43.
[186] Amended Workpapers, pp. WP-IX-1-39 through WP-IX-1-43.
[187] Amended Testimony, p. 57.

pressure test failures before conducting the pressure test, the company can avoid the pitfalls associated with entering into a cycle of pressure test failures.[188]

Sempra also seeks authorization to analyze the data obtained through the inspection process to validate TFI as an equivalent means of validating the long seam stability of in-service pipelines. Sempra states, "SoCalGas and SDG&E seek to analyze and compare the results of pressure testing with the results of in-line inspections in Phase 1, in order to demonstrate that TFI provides an equivalent alternative to pressure testing for Phase 2 pipelines."[189]

DRA asked Sempra to provide a copy of the research/study's scope, objectives, details on how data will be collected and analyzed, and how results will be interpreted to validate TFI. SoCalGas and SDG&E have indicated that they have yet to develop a research scope or proposal for the TFI validation study.[190]

DRA recommends rejecting the entire proposal of $62 million to inspect 721 miles of pipelines prior to pressure testing and to perform 721 repairs to these lines for several reasons. DRA's recommendation is based on the fact that these lines have been recently inspected and any problems identified as a result of these inspections should have been corrected. According to Sempra, "These pipelines have already been inspected with a magnetic flux leakage (MFL) in-line inspection tool as part of our existing pipeline integrity management program, with re-assessments scheduled to occur over the next five years."[191] Sempra further states, "During the re-assessment, in addition to running the MFL tool, a transverse flux in-line inspection (TFI) tool will also be utilized to allow for evaluation of the condition of the long seam as well."[192]

[188] Ibid.
[189] Amended Testimony, p. 57.
[190] Sempra's Response to DRA-31, Q.3
[191] Amended Workpapers, pp. WP-IX-1-38 and WP-IX-1-42.
[192] Ibid.

These statements show that the Criteria segments planned to be inspected using the TFI tool have already been inspected, with the MFL tool, as part of SoCalGas' and SDG&E's transmission integrity management program and that these same segments are scheduled to be re-assessed using the TFI tool in the next five years. These re-assessments will also be performed as part of the TIMP program.[193]

If SoCalGas or SDG&E wants to supplement the assessment tools and methods used to re-assess transmission pipelines as part of the TIMP, then the utilities can manage this as part of the TIMP program.

Sempra has not demonstrated why performing another round of inspection to search for potential problems for repair is prudent when there is no indication that the system is in need of additional mitigation. Its workpapers show that the segments proposed for TFI had recently been in-line inspected in the past 2 years because the re-assessments are scheduled to occur over the next five years.[194] TIMP regulations require operators to reassess a segment that has completed a baseline assessment within seven years of the completion of the last assessment.[195] Moreover, Sempra states repeatedly in the Report and in the Plan that it remains confident in its existing transmission pipeline integrity program and that it has an excellent safety record.[196]

DRA recommends that the proposal be rejected because the 721 miles of inspection and 721 repairs are unsupported. DRA asked Sempra to provide a copy of all supporting analyses, assessments, and calculations performed, to determine the 667 miles for inspection when only 170 miles are identified as Criteria miles located in Class 3 and 4 and High Consequence Areas, Sempra responded with the following statement:

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[193] Sempra's Response to DRA-DAO-24, Q.1.

[194] Amended Workpapers, p. WP-IX-1-38.

[195] TIMP requirements as identified by Sempra in the 2012 GRC Application, Testimony of SoCalGas witness, Raymond Stanford, p. RKS-30.

[196] Amended Testimony, p. 1.

"The boundaries of the in-line inspections proposed as part of the PSEP will be determined by the locations of existing launcher and receiver facilities. This approach aligns with one of the overarching objectives of the PSEP, to maximize the cost effectiveness of investments in the SoCalGas transmission system….Please refer to pages WP-IX-39 and WP-IX-1-43 of the workpapers supporting Chapter IX of the Testimony for the number of in-line inspections and the total in-line inspection mileage per pipeline proposed in the PSEP."[197]

This response does not adequately support the excessive level of inspection mileage proposed in the Plan.

The explanation Sempra provided for the 667 miles of inspection does not adequately justify the level of miles planned for inspection:

"The placement of in-line inspection launcher and receiver facilities is typically based on the configuration and operation of the pipeline and it is customary to space them as far apart as practical to maximize the inspection length. As a result, the launcher receiver facilities are commonly located in less populated areas, and a single inspection can include a range of Location Class types and both HCA and non-HCA."[198]

Sempra's proposal of one repair per mile, resulting in a total of 721 repairs for the 721 miles of inspection, is not adequately supported as well. The only support provided for the repair estimate is Sempra's statement, "the assumption that one repair would be required per mile of pipe inspected with a TFI tool constitutes a high-level allowance for post-inspection repair work. Actual inspection data may dictate the need for more than one repair per mile in some cases or fewer than one repair per

[197] Sempra's Response to DRA-24, Q. 1(b).

mile in others."[199] No studies, assessments, or analyses were performed to determine the repair estimates.

The number of repairs estimated is excessive and has no factual basis. Its transmission system does not require this level of repair. According to the Annual Report for Calendar Year 2010 Natural or Other Gas Transmission and Gathering Systems that Sempra filed with the Department of Transportation, Pipeline and Hazardous Material Safety Administration, SoCalGas inspected 1,502 miles of transmission pipelines and repaired 148 anomalies both within an HCA segment and outside of an HCA segment. This is equivalent to a rate of repair of less than 0.1 repairs per mile of pipeline inspected. As for SDG&E, in 2010, the utility in-line inspected a total of 90 miles and recorded zero repairs.

As for the repair cost of $75,000 per repair, Sempra has not adequately supported this estimate either. The only support provided was the statement from Sempra: "The cost of $75,000 per repair represents a high-level estimate for post-inspection repair work."[200] No cost estimates, studies, assessments, or analyses performed to determine the cost of TFI runs were provided.

This request is above and beyond the directives of the Commission to pressure test or replace pipelines that have not been pressure tested. Although the Commission states in D.11-06-017 that, "The Implementation Plans may include alternatives that demonstrably achieve the same standard of safety…" DRA asserts that Sempra's proposal to perform ILI studies in the Plan is not on par with the directives of the Commission.

At this time, the TFI technology has not been confirmed or validated by any regulation agency to provide an equivalent means to strength test a pipeline. The

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(continued from previous page)
198 Sempra's Response to DRA-DAO-24, Q. 1(c).
199 Sempra's Response to DRA-DAO-21, Q. 3(b).
200 Sempra's Response to DRA-DAO-21, Q. 3 (d).

latest 2010 ASME Code for Pressure Piping continues to advise that "…Pressure testing with water is recommended whenever possible."[201] For transmission pipelines operating at high pressure, the ASME Code specifies the following:

> Section 841.3.2 states, "Pressure Test Requirements to prove strength of pipelines and mains to operate at hoop stresses of 30% or more of the Specified Minimum Yield Strength of the pipe…the recommended test medium is water."[202]

Federal regulations currently do not recognize TFI as an equivalent means to validate the safety margin of a pipeline. Title 49 CFR, Part 192, Subpart J, Section 192.503 requires that all new segments of pipe or a new segment that has been relocated or replaced be strength tested using liquid, air, natural gas, or inert gas.

The TFI tool has been in existence since 1999, but Sempra has used it to inspect only 2 miles in its territory.[203] Sempra has stated that the preferred assessment method for both SoCalGas and SDG&E is in-line inspection using MFL technology.[204] TFI does not appear to be favored as an assessment tool by Sempra. According to Sempra, "In general, the ILI [MFL] is the preferred choice for assessment at SoCalGas due to the fact that the pipeline systems are conducive to accommodating ILI tools (gas flow, pipeline pressure, diameter, etc), measurements are collected along the entire length of the line, and in general, service impacts to customers are usually manageable. Lastly, the execution of reassessments every seven years as required by regulations is more practical using ILI compared to other assessment methods."[205] TFI is not currently an equivalent strength validation tool

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[201] ASME, ASA B 31 8 2010, Section 841.3, Testing after Construction, p. 45.
[202] ASME Code for Pressure Piping, 2010, p. 46.
[203] Sempra's Response to DRA-DAO-15, Q. 3 (c).
[204] Sempra's Response to DRA-DAO-18-Q.1
[205] Sempra's Response to DRA-DAO-18-Q. 1(a).

compared to hydrostatic-testing. Sempra has not demonstrated that it is an equivalent validation tool in its Plan. Sempra is not requesting to perform TFI inspections in lieu of hydrostatic testing anywhere in the Plan. DRA is not convinced that ratepayers should fund a technology that Sempra has not embraced.

Sempra's current system design is not capable of accommodating in-line inspections using the TFI tool. Sempra could not identify how much of the SoCalGas or SDG&E system has been retrofitted to accommodate the TFI tool.[206] There is also an issue with the lack of vendors and tool options at this time. Sempra states, "We have found that the number of vendors and tool options for this technology is limited. This results in restricted tool availability due to scheduling conflicts as well as the need to complete a detailed analysis to verify that each of the identified pipelines is has a configuration that is compatible with the TFI tools that are available."[207]

Sempra has not developed the TFI aspect part of its Plan. Sempra states, "SoCalGas and SDG&E have not yet developed a research scope or proposal to fund a TFI validation study."[208] Since the TFI proposal is not yet developed, DRA cannot ascertain how the TFI validation study can be used to compare to the hydrostatic tests so that results can be compared. According to Sempra, the TFI study will be a validation study in which the pipeline would be pigged using TFI technology and then exposed and directly examined so that a comparison of reported anomalies from the inspection could be compared to actual anomalies. It does not appear that the anomalies reported from the inspection would be compared to the anomalies experienced from the hydrostatic tests because Sempra would repair any anomalies detected from the inspection prior to performing a hydrostatic test. It is not clear how the TFI study will be used to demonstrate that it would be an equivalent tool as the

[206] Sempra's Response to DRA-DAO-27, Q.9.
[207] Sempra's Response to DRA-DAO-27, Q.9.
[208] Sempra's Response to DRA-DAO-31, Q.3.

hydrostatic test for strength testing if the repairs are made. If a pipe leaks or ruptures based on a pressure test, it would unlikely be from the same anomalies detected from the inspection because these anomalies would have been repaired.

For all the reasons stated above, DRA opposes ratepayer funding of Sempra's proposal to perform TFI inspection on all lines prior to hydrostatic testing, and in particular, the $54 million in repair costs.

DRA is open to the use of efficient or effective alternatives to hydrostatic testing such as TFI. The possibility of alternatives can be explored through a different forum dedicated to studying alternative approaches, methodologies, tools, etc., that can achieve the same standard of safety as hydrostatic testing. Involved participants could include representatives from the utilities, experts in the ILI field who specialize in TFI tools, and safety regulators from the federal and state safety regulators. If it turns out that TFI could be a true equivalent method to hydrostatic testing, then it could be funded in the future as an alternative to funding hydrostatic testing.

F. DRA Recommends Sempra Perform Hydrostatic Testing of 324 Miles of Category 4 Pipelines.

Sempra has identified several different sets of numbers for the Criteria/Category 4 pipelines and Accelerated pipelines in its testimony, in its workpapers, and in the Decision Tree database. DRA has not been able to validate the data that Sempra used to generate the results of the Decision Tree. DRA has not been able to validate the scope of the Plan based on the Decision Tree database Sempra provided.[209]

Although Sempra identifies the total DOT defined transmission mileage for SoCalGas as 3,757 miles and for SDG&E as 251 miles,[210] the Decision Tree database shows 3,131 for SoCalGas and 251 for SDG&E. In its Testimony, Sempra identifies

[209] Sempra's response to DRA-DAO-16, Q. 6

[210] Sempra's response to DRA-DAO-16, Q. 2.

206 miles of Category 4 pipelines for hydrostatic testing.[211] In its workpapers, Sempra identifies a lower number, 171.5 miles, for hydrostatic testing.[212] In the Decision Tree database, Sempra identifies an even lower number, 168 miles, of Category 4 pipelines for hydrostatic testing.[213]

For pipeline replacements, Sempra's Testimony identifies 156 miles of Category 4 pipelines.[214] Sempra's Decision Tree database also identifies 156 miles of Category 4 pipelines for replacement.[215] However, Sempra's workpapers identifies only 152.5 miles for replacement.[216]

DRA recommends the Commission require Sempra to explain the differences in the number of pipelines identified in its testimony and workpapers, and the number of miles of pipelines identified in the Decision Tree database, and to provide additional assurance that the Plan's scope is accurate, reliable, and can be validated. DRA also recommend that the commission require Sempra do the following with regard to any changes made to the Plan's data which ultimately drive the scope and cost of mitigation: (1) justify any deviations from the decision tree outcome/mitigation due to new data, (2) justify any deviations from the decision tree outcome/mitigation due to engineering judgment, (3) Sempra's implementation of the "ors" in the decision tree, (4) justify any acceleration of Phase 2 segments into Phase 1, (5) justification for any diameter increases, (6) justification for any line relocations, and (7) justification of any engineering condition assessment.

The original 385 miles of Category 4 pipelines cannot be confirmed at this time. The Decision Tree database only shows a total of 324 miles of Category 4

[211] Sempra's Amended Testimony, p. 108.
[212] Sempra's workpapers, p. WP-IX-1-5, WP-IX-1-9, and WP-IX-1-13.
[213] Sempra's Testimony, p. 108. Sempra's Response to DRA-16, Q. 6.
[214] Sempra's Amended Testimony, p. 110.
[215] Amended Testimony, p. 110. Sempra's Response to DRA-16, Q. 6.
[216] Amended Workpapers, p. WP-IX-1-25, WP-IX-1-29, WP-IX-1-36.

pipelines. Until Sempra can substantiate that additional pipelines need to be addressed, DRA recommends that 324 miles of Category 4 pipelines be hydrostatic tested. DRA used this group of 324 miles of Category 4 pipelines to determine the ratepayer/shareholder cost sharing proposal in Exhibit 1.

DRA recommends the Commission reject Sempra's cost estimate for hydrostatic testing because it is excessive and not adequately supported. DRA recommends the Commission adopt the DRA cost estimates presented in Exhibit DRA-2A.

DRA used 327 miles for project scope instead of 324 miles of Category 4 pipelines. This number comes from a total of 171.5 miles of Category 4 pipelines identified by Sempra in its' workpapers and [217] a total of 155.8 miles of Category 4 pipelines identified by Sempra for replacement in the Decision Tree database. It was necessary for DRA to rely on two different sources, Sempra's workpapers and the Sempra Decision Tree database, in order to come up with the hydrostatic testing cost calculations for the 327 miles because this was the most efficient way to develop the cost model and to apply it to the numerous projects Sempra proposed in the Plan.

To determine DRA's hydrostatic test cost estimate, DRA analyzed all the cost elements that make up Sempra's proposed hydrostatic test, which were only identified in its workpapers. DRA then applied its hydrostatic test assumptions to the group of pipelines Sempra proposed for replacement. Due to the numerous pipelines Sempra proposed for replacement, the most efficient way for DRA to apply our cost model was to use the Decision Tree database to estimate the hydrostatic test costs. A more detailed description of DRA's cost method and explanation of DRA's cost model can be seen in Exhibit DRA-2A.

DRA's cost model shows a total of $78.2 million for the hydrostatic testing of 327 miles of Category 4 pipelines. A breakdown of the DRA cost estimates for the "Sempra proposed hydrostatic test" lines and for the "Sempra proposed replacement" lines for SoCalGas and SDG&E, and for Distribution versus Transmission, are presented in the two tables below.

<u>Table 16</u>

DRA Proposed Cost of Hydrostatic Testing for Sempra's Proposed Hydrostatic Testing Pipelines. (In Millions of Dollars)

Sempra Designated Hydrostatic test					
	Total	2012	2013	2014	2015
SoCalGas-Distribution, Company Labor	0.03	0.01	0.01	0.01	0.01
SoCalGas-Distribution, Non-Company Labor	0.94	0.19	0.25	0.25	0.25
SoCalGas-Transmission, Company Labor	0.90	0.18	0.24	0.24	0.24
SoCalGas-Transmission, Non-Company Labor	32.82	6.56	8.75	8.75	8.75
SDG&E-Distribution, Company Labor	$ -	$ -	$ -	$ -	$ -
SDG&E-Distribution, Non-Company Labor	$ -	$ -	$ -	$ -	$ -
SDG&E-Transmission, Company Labor	$ -	$ -	$ -	$ -	$ -
SDG&E-Transmission, Non-Company Labor	$ -	$ -	$ -	$ -	$ -
TOTAL	$ 34.7	$ 6.9	$ 9.2	$ 9.2	$ 9.2

(continued from previous page)

[217] Amended Workpapers, p. WP-IX-1-5, WP-IX-1-9, and WP-IX-1-13.

Table 17

DRA Proposed Cost of Hydrostatic Testing for Sempra's Proposed Replacement Pipelines (In Millions of Dollars)

Sempra Designated Replacement					
	Total	2012	2013	2014	2015
SoCalGas-Distribution, Company Labor	0.84	0.17	0.22	0.22	0.22
SoCalGas-Distribution, Non-Company Labor	29.85	5.97	7.96	7.96	7.96
SoCalGas-Transmission, Company Labor	0.21	0.04	0.05	0.05	0.05
SoCalGas-Transmission, Non-Company Labor	7.30	1.46	1.95	1.95	1.95
SDG&E-Distribution, Company Labor	0.14	0.03	0.04	0.04	0.04
SDG&E-Distribution, Non-Company Labor	5.11	1.02	1.36	1.36	1.36
SDG&E-Transmission, Company Labor	0.00	0.00	0.00	0.00	0.00
SDG&E-Transmission, Non-Company Labor	0.00	0.00	0.00	0.00	0.00
TOTAL	$43.5	$8.7	$11.6	$11.6	$11.6

G. DRA Recommends No Ratepayer Funding for Pipelines Installed After 1935

Sempra provided an Excel file containing the installation date of all pipeline segments identified for hydrostatic test or replacement in its Plan.[218] The data contained in this file shows a total of 324 miles of pipelines categorized by Sempra as Category 4 Criteria Miles. These specific pipelines need to be addressed immediately because they are located in more populated areas or are in High Consequence Areas. DRA recommends that only these Category 4 Criteria miles be addressed in Phase 1A for the reasons discussed above.

[218] Sempra's Response to DRA-DAO-16, Q.6.

DRA recommends that shareholders, and not ratepayers, fund the cost of hydrostatic testing of 312 miles of pipelines installed in 1935 to the present. DRA's recommendations are based on the discussion in DRA Witness David Peck's testimony. See Exhibit DRA-1.

Table 18 below provides a summary of the mileage proposed for hydrostatic-testing and pipeline replacement in the Plan.

Table 18

Decision Tree Database—
Number of Category 4 Criteria Miles (without L1600, without Storage)

Total Mileage in the Plan's Database: **324 Category 4 Criteria Miles**		
	Hydrostatic-testing	**Pipeline Replacement**
Year Installed	Mileage	Mileage
1900-1934		
1935-1954		
1955-1960		
1961-Present		
Total Hydrostatic Test Miles		

Source: Sempra's Response to DRA-DAO-16, Q.6

H. The Plan Cost Estimates Should Be Reduced for Pipelines Managed By the TIMP

Sempra identified a total of 383 Category 4 miles in the Plan currently managed under the Transmission Integrity Management Program (TIMP). See Table 19 below. Of this total 206 miles are planned for pressure testing and 156 miles are planned for replacement.[219]

[219] Sempra's Response to DRA-DAO-7, Q.3(b) and (c).

Table 19

PSEP Criteria Miles Currently Managed Under TIMP			
Abandon	**Replace**	**Hydrostatic-test**	**Total Criteria**
21 miles	**156 miles**	**206 miles**	**383 miles**

Source: Sempra's Response to DRA-DAO-7, Q.3(b) and (c).

TIMP regulations require assessments to be performed in compliance with the requirements of CFR 49, Subpart O Section 192.921. The assessment methods prescribed by 49 C.F.R., Subpart O and used by SoCalGas and SDG&E include direct assessment, pressure testing, and in-line inspection. The TIMP rules specify how pipeline operators must identify, assess, prioritize, evaluate, repair and validate the integrity of gas transmission pipelines. The rules focus on the potential impacts of pipeline failures or leaks on heavily populated or occupied areas, referred to as High Consequence Areas ("HCAs"). Under TIMP regulations Sempra will have completed assessing all of its HCA transmission pipelines as part of the Baseline Assessment by December of 2012. Thereafter, Sempra will need to reassess the lines on a periodic cycle within the next seven years.

The abandonment, replacement and hydrostatic testing of these 383 miles as part of the Plan will also enable Sempra to meet the TIMP requirements of reassessing these pipelines in the next seven years. The abandonment of 21 miles will remove these pipelines from the TIMP and Sempra will not need to assess these pipelines again. The replacement and hydrostatic testing of the remaining 362 miles will meet the assessment methods required by TIMP.

Sempra requests funding for the assessments and reassessments of TIMP pipelines in its General Rate Case applications. In the most recent GRC filed in December 2010, Sempra requested $25 million each year, starting in 2012, for the assessment and reassessment of pipelines as part of the TIMP.[220] Since Sempra is

[220] A.10-12-006, Witness Raymond Stanford Testimony, p. RKS-25 and RKS-31.

managing the assessment work of these specific lines under TIMP, DRA recommends an adjustment to the Plan cost estimates to reflect the accounting of these 383 miles in that program. If the Plan cost estimates for these 383 miles are not adjusted, then Sempra would receive funding for the assessment/management of the same pipelines twice, as part of the GRC and as part of the Plan.

DRA recommends adjusting the cost of the 383 miles of the Plan by the same amount of funding that Sempra would otherwise be receiving from the GRC process. Using Sempra's 2012 GRC proposed estimate unit cost of $192,000 per mile[221] for pipeline assessments under TIMP, the total adjustment amount for 383 miles is $74 million.

I. The Costs for Line 1600 Should Be Addressed in Phase 1B

Sempra requests $14.3 million in Phase 1A for work associated with the planned replacement of Line 1600 in Phase 1B. The total project is estimated at $332.5 million. Sempra estimated that approximately 4% of the total costs, or $14.3 million, will occur in Phase 1A.[222]

DRA recommends the removal of $14.3 million from Phase 1A. DRA recommends that all costs associated with the replacement of Line 1600 be rejected. Sempra has allocated 4% of the total cost of replacing Line 1600 to Phase 1A. This amount is for the design and engineering work of Line 1600.

In Phase 1A, Sempra plans to perform TFI inspections and perform repairs on 53.6 miles of Line 1600 at a cost of $4.3 million. In Phase 1B, Sempra will pressure test and repair this same at a cost of $10.2 million, and then Sempra will replace this line and change its capacity by increasing the pipeline diameter from 16" to 36" at a total cost of $332.5 million.

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[221] Sempra 2012 GRC Testimony, A.10-12-006, Witness Raymond Stanford, Exhibit SCG-5, pp. RKS-25 and RKS-31.

[222] Amended Workpapers, p. WP-IX-1-34.

The entire 53.6 miles of Line 1600 scheduled for TFI inspections during phase 1A are identified as "Accelerated" miles[223] and therefore should be excluded from Phase 1A. Sempra has not presented any evidence as to why Line 1600 needs to be addressed in Phase 1A or why the cost to perform the work associated with increasing the capacity of Line 1600 should be addressed in Phase 1A.

If Sempra wants to increase the capacity of Line 1600, as demonstrated in the proposal to increase the pipeline diameter from 16" to 36", Sempra should address this project in a separate application.

J. Sempra Should Modify the Sub-Prioritization Process of the Decision Tree

According to Sempra, after a pipeline segment is assigned a numbered box from the Decision Tree, it has the same outcome as all other segments. It is within each numbered box that Sempra will perform the detailed planning and rank the order of work based upon segment-specific characteristics that appropriately reflect the risk factors for that segment.[224] For presentation purposes in the Plan, Sempra ranks the order of work based on the potential impact radius for each pipeline segment divided by its long seam factor. Sempra states, "…the pipeline segments are sub-ranked for scheduling purposes primarily based on the consequence failure of each segment."[225]

For the sub-prioritization methodology, Sempra ranks and schedules the pipeline for hydrostatic test or replacement based on (1) Potential Impact Radius (PIR), (2) Long Seam Type, and (3) %SMYS.

Although DRA generally agrees with the sub-prioritization process proposed by Sempra, DRA believes that the sub-prioritization process could be enhanced by including the class locations of the pipeline segments. The PIR, as defined by Sempra, only measures the distance of impact from outside the vicinity of a pipeline

[223] Amended Workpapers p. WP-IX-1-34.
[224] Amended Testimony, page 62.
[225] Amended Testimony, p. 63.

rupture. Sempra defines PIR as, "the radius of a circle within which the potential failure of a pipeline could have significant impact on people or property and is dependent upon the pipeline's diameter and MAOP. A larger potential impact radius typically affects proportionally larger numbers of people, and in this manner, calculation of the segment specific potential impact radius provides an effective means to rank segments by their potential energy and possible effect on population density."[226]

The PIR increases as the diameter of the pipeline increases and as the pressure in the pipeline increases. The PIR measures the distance and not the population density. The impact will be greater in a more populated Class 3 than in a less populated Class 1. Sempra should consider Class location in addition to the PIR in ranking the work proposed.

The definition of Class Locations based on 49 CFR 192.5 is summarized as follows:

A "class location unit" is an onshore area that extends 220 yards on either side of the centerline of any continuous 1 mile length of pipeline.

Class 1—A Class location unit has 10 or fewer buildings intended for human occupancy.

Class 2— A Class location unit has more than 10 but fewer than 46 buildings intended for human occupancy.

Class 3—A Class location unit has 46 or more buildings intended for human occupancy; or pipeline lies within 100 yards of either a building or place of public assembly that is occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period.

Class 4—A Class location unit where buildings with four or more stories above ground are prevalent.

[226] Amended Testimony, p. 63.

In the sub-prioritization process, if appropriate Sempra should consider ranking pipeline segments in descending order of class location from Class 3[227] to Class 1, decreasing PIR's and percentage of high consequence area (HCA) pipe within each project.

Sempra should consider the date of the last assessment in sub-prioritization as well. All other factors being equal, a pipeline that is more problematic or shows a higher level of risks, based on the TIMP risk assessments, should be given higher priority than a pipeline that was assessed and was ranked with a lower level of risks.

IV. CONCLUSIONS

DRA recommends that the Commission adopt DRA's proposal for Sempra to focus on the group of pipelines that SoCalGas and SDG&E have identified as Category 4/NTSB Criteria Miles. These pipelines are presumably the highest priority from a safety standpoint. At issue in the Sempra Plan is an extension of project scope that is above and beyond the directives of D.11-06-017, which was aimed at high-priority safety measures. It is evident from this filing that Sempra is trying to use this opportunity to enhance its system—a system that it claims is operating safely. Sempra's safety record demonstrates that it is a safe system, with 1 incident from 2003-2010 and declining leak levels.[228] Sempra states repeatedly in its Report to the NTSB as well as in its filing in this proceeding that it is operating a safe system. Sempra believes that the Category 4 pipelines it has identified as needing MAOP validating are operating safely and that nothing in its records review process indicated otherwise.

The Plan was developed at a high level and without any engineering analysis or cost benefit studies to support it. As a result, the Sempra proposed actions are

[227] Sempra does not operate any transmission pipeline segments in a Class 4 location.

[228] Sempra's Response to DRA-PZS-02, Q. 1(f).

unsupported. The cost estimates have no support and range between -50% to upwards of +100%. The Plan proposes to accelerate Phase 2 pipelines that make up 48% of the planned work for SoCalGas and 40% of the planned work for SDG&E into Phase 1A. In the face of so many uncertainties, DRA recommends that the Commission focus only on the highest priority pipelines—the Category 4 pipelines. DRA recommends that the Commission only authorize funding to test these pipelines as well because Sempra has not adequately supported the alternative proposal to replace. The Commission should also reject all requests to enhance the utilities' systems above and beyond the requirements of D.11-06-017.

ATTACHMENT A

Statement of Qualifications

Q.1 Please state your name and address.

A.1 My name is Dao A. Phan. My business address is 505 Van Ness Avenue, San Francisco, California.

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

A.2 I am employed by the California Public Utilities Commission as a Public Utilities Regulatory Analyst in the Division of Ratepayer Advocates Energy Cost of Service and Natural Gas Branch.

Q.3 Briefly describe your educational background and work experience.

A.3 I have a Master of Arts Degree in Political Science from San Francisco State University and a Bachelor of Arts Degree in Political Science from California State University, Hayward. I have testified before the Commission as an expert witness in numerous Commission enforcement and regulatory proceedings. The areas and proceedings that I have been an expert witness in are as follows: (1) gas distribution operations and maintenance in the Pacific Gas and Electric Company 2003 General Rate Case (A.02-11-017), (2) gas transmission and storage operations and maintenance and capital expenditures in the Pacific Gas and Electric Company transmission and storage 2005 General Rate Case (A.04-03-021), (3) gas distribution capital expenditures in the Southern California Gas Company's 2004 cost of service application (A.02-12-027), (4) PG&E long-term electric procurement RFO application (A.06-04-012) (5) gas distribution O&M, customer service issues, and customer accounts in PG&E's 2007 GRC Application (A.05-12-002), (6) PG&E's long term electric procurement RFO application (A.06-04-012), (7) O&M expenses for Gas Distribution, Transmission, Underground Storage, Engineering, and Procurement in the Southern California Gas Company's TY 2008 GRC Application (A. 06-12-010), and (8) Gas Distribution operation and maintenance expenses, plus Technical Training and Applied Technology Services costs for the PG&E 2011 GRC Application (A.09-12-020). Most recently, I was the DRA witness for Compensation and Incentives, Shared Services Billing Policy and Process, SoCalGas O&M expenses for Gas Distribution, Transmission, Engineering, and Underground Storage, and SoCalGas Procurement expenses in the Southern California Gas Company's TY 2012 GRC Application (A.10-12-006).

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

A.4 I am responsible for Exhibit DRA-2, which addresses Sempra's Pipeline Safety Enhancement Plan.

Q.5 Does that complete your prepared testimony?

A.5 Yes, it does.