BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

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

PIPELINE SAFETY ENHANCEMENT PLAN OF SOUTHERN CALIFORNIA GAS COMPANY (U 904-G) AND SAN DIEGO GAS & ELECTRIC COMPANY (U 902-M) PURSUANT TO D.11-06-017, REQUIRING ALL CALIFORNIA NATURAL GAS TRANSMISSION OPERATORS TO FILE A NATURAL GAS TRANSMISSION PIPELINE COMPREHENSIVE PRESSURE TESTING IMPLEMENTATION PLAN

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On June 9, 2011, the California Public Utilities Commission (Commission) issued *Decision Determining Maximum Allowable Operating Pressure Methodology and Requiring Filing of Natural Gas Transmission Pipeline Replacement or Testing Implementation Plans* (June 9 Decision). In that the Decision, the Commission "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 Plan) to achieve the goal of orderly and cost effectively replacing or testing all natural gas transmission pipeline that have not been pressure tested."[1] These plans, as the Commission has directed, will move California natural gas transmission operators beyond existing regulations that allow operators to base the maximum allowable operating pressure (MAOP) on historical operating pressures for pipelines that were installed prior to 1970.

1 D.11-06-017, p. 1; *see also Id.*, Ordering Paragraphs 4-10.

Southern California Gas Company (SoCalGas) and San Diego Gas & Electric Company (SDG&E) submit this Pipeline Safety Enhancement Plan (PSEP) in compliance with that order.[2] As described below and in the Supporting Testimony, their plan includes elements beyond those required by the Commission's Order that are consistent with the goals set out by the Commission to enhance public safety. It also includes proposed alternatives to pressure testing or replacing that "demonstrably achieve the same standard of safety" as pressure testing or replacement. SoCalGas and SDG&E seek the following specific Commission approvals in connection with their Pipeline Safety Enhancement Plan:

- Approval of the scope and methodology of their proposed Pipeline Safety Enhancement Plan, including:
  - Replacing or pressure testing pipeline segments that meet the Commission's criteria for replacement or pressure testing;
  - Use of non-destructive examination methods, such as radiography, ultrasonic inspection, and magnetic particle testing, as an appropriate alternative to pressure testing or replacement for those pipeline segments meeting the Commission's criteria for replacement or pressure testing;
  - Use of in-line inspections, using transverse field inspection (TFI) tools, in parallel with the pressure test;
  - Continued use of their proposed interim safety measures;
  - Enhancement of SoCalGas and SDG&E's existing valve infrastructure by installing additional remote control and automated shutoff valves or retrofitting existing valves to make them automatic or remote control capable;
  - Equipping replacement pipelines with advanced fiber optic technology and strategically installing methane detection technology; and

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2 This plan is supported by testimony. *See Testimony of SoCalGas and SDG&E in Support of Natural Gas Pipeline Safety Enhancement Implementation Plan* (Supporting Testimony). Corporate affiliates of SoCalGas and SDG&E may be affected by this filing to the extent they take service from either SoCalGas or SDG&E. Such affiliates would not be affected any differently from other similarly situated customers receiving service under the same rate schedules. SoCalGas and SDG&E management considered the following alternatives to the proposals in this application: (1) using current cost allocation methodology or allocating costs based on customer count rather than using EPAM cost allocation methodology; (2) having a different scope and size for the Pipeline Safety Enhancement Plan (PSEP); and (3) using possible alternatives to pressure testing. Management determined that the EPAM cost allocation methodology was most appropriate in these circumstances, and included within the scope of the PSEP those elements that meet the Commission's goals and enhance the safety of SoCalGas and SDG&E's systems in a cost effective manner that minimizes customer impacts.

- Developing the architecture and design for a comprehensive Enterprise Asset Management System.

- Approval of their phasing approach (*i.e.*, Phase 1(A) and (B) and Phase 2) and prioritization process for pipeline segments meeting the Commission's criteria for replacement or pressure testing.
- Approval of their Capital forecasts for Phase 1(A) of $1.2 billion for SoCalGas and $229 million for SDG&E and Operation & Maintenance (O&M) forecasts for Phase 1(A) of $256 million for SoCalGas and $7 million for SDG&E.[3]
- Approval of the revenue requirements resulting from the Capital and O&M forecasts for the years 2011 through 2015.
- Approval to include the Capital and O&M forecasts and resulting revenue requirements for the remaining years of their Pipeline Safety Enhancement Plan in their next General Rate Cases (GRCs), subsequent rate case cycles or other applicable proceedings, as needed.
- Approval to track the costs of their Pipeline Safety Enhancement Plan separately from other pipeline system costs and allocate these costs to customers on an Equal Percent of Authorized Margin (EPAM).
- Approval to have the allocated costs appear as a separate line item on customers' bills as the "PSEP Surcharge."
- Approval to allocate costs attributable to the residential market on an equal cost per customer basis and to non-residential customers on a volumetric basis (CARE customers would receive the established 20% discount).
- Approval of their proposal to submit an annual status report to the Commission by March 31st 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 PSEP budget.
- Authorize the recovery of the costs incurred to date and to be incurred until the Commission issues a decision approving the Pipeline Safety Enhancement Plan. To date, SoCalGas and SDG&E have incurred costs of approximately $3 million and forecast an additional $4 million for the rest of the year, for a total of $7 million by year end.

SoCalGas and SDG&E also request that the Commission expressly state in its decision approving SoCalGas and SDG&E's Pipeline Safety Enhancement Plan that execution of the approved Implementation Plan is a matter of statewide concern, and as such, the Commission has

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3 If the Commission approves SoCalGas and SDG&E's request to use non-destructive testing as an appropriate alternative to pressure testing or replacing pipeline segments less than 1,000 feet in length (item 1(b) above), this forecasted amount would be reduced by $5 to 15 million.

preemptory authority over conflicting local zoning regulations, ordinances, codes or requirements to the extent that such local authority would deny, or significantly delay execution of the Implementation Plan.

Finally, SoCalGas and SDG&E propose to work with Commission Staff and other stakeholders to develop a standard for determining when a pressure reduction may be used as an alternative to pressure testing or replacement. Because such a standard could potentially reduce Pipeline Safety Enhancement Plan implementation costs for customers, while providing equivalent safety benefits, SoCalGas and SDG&E request that the Commission consider this issue in the next phase of this proceeding.

I. INTRODUCTION AND BACKGROUND

On September 9, 2010, a 30-inch diameter natural gas transmission pipeline owned and operated by Pacific Gas and Electric Company (PG&E) ruptured in the city of San Bruno, California, causing significant property damage, killing eight people, and injuring others. The information gathered in connection with the National Transportation Safety Board's (NTSB) investigation of that rupture suggests that it initiated at the long seam of one of the pipeline segments.[4]

This incident along with a number of other pipeline incidents this past year has caused the natural gas pipeline industry and those who regulate it, including the Commission, to reassess existing pipeline safety standards and best practices. Specifically, the Commission opened this

4 *Materials Laboratory Factual Report*, National Transportation Safety Board Report No. 10-119, dated January 21, 2011. A long seam is the joining of two edges of a steel plate that has been rolled to form a cylinder.

Rulemaking "to establish a new model of natural gas pipeline safety regulation" in California.[5] SoCalGas and SDG&E fully support these efforts.

As part of its efforts, the Commission required California natural gas operators to perform a comprehensive records review of their transmission pipelines in Populated Areas (i.e., transmission pipelines located in Class 3 and 4 and Class 1 and 2 High Consequence Areas (HCA) as defined in 49 CFR §§192.5 and 192.903)[6] as a result of several NTSB safety recommendations directed at PG&E. The NTSB recommendations focus on identifying transmission pipeline segments in Populated Areas that have not been pressure tested. A pressure test (also known as a strength test) is one method to assess the integrity of the long seam of a pipeline.

This Commission ordered PG&E, SoCalGas, SDG&E and Southwest Gas Corporation (Southwest Gas) to submit the findings of their records research to the Commission in this proceeding. PG&E and Southwest Gas submitted their reports on March 15, and SoCalGas and SDG&E submitted theirs on April 15, 2011. SoCalGas and SDG&E were, in their records research, specifically searching for documentation of a performed strength test to at least 1.25 times MAOP. SoCalGas and SDG&E used a 1.25 times MAOP threshold because a United States Department of Transportation Office of Pipeline Safety publication found that "[a]ny

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5 Order Instituting Rulemaking on the Commission's Own Motion to Adopt New Safety and Reliability Regulations for Natural Gas Transmission and Distribution Pipelines and Related Ratemaking Mechanisms, issued February 24, 2011, p. 1.

6 Throughout this Plan, SoCalGas and SDG&E use the term "Populated Areas" to refer to transmission pipelines located in Class 3 and 4 and Class 1 and 2 HCAs as defined in the Federal code. They use the term "Non-populated Areas" to refer to transmission pipelines located in Class 1 and 2 non-HCAs as defined in the Federal Code.

manufacturing defect or imperfection that survives a pre-service pressure test to 1.25 times the maximum allowable operating pressure (MAOP) is stable immediately after the test."[7]

As part of their records research, SoCalGas and SDG&E reviewed many types of pre-construction documents that provide confidence that their pipelines were manufactured, designed and constructed to operate safely and are operating at a safe pressure. All of the pipelines reviewed for the April 15 Report have construction and/or operations records to support their current MAOP. Such records include design and construction specifications and drawings, material specifications, pipe mill inspections and test records as well as other pre-construction documentation. Post-construction documents, such as as-built drawings and strength test records, were also reviewed.[8]

In their April 15 Report, SoCalGas and SDG&E identified 447 "Criteria Miles"[9] (383 miles for SoCalGas and 64 miles for SDG&E) that did not have sufficient documentation of a strength test of at least 1.25 times MAOP.[10] SoCalGas and SDG&E referred to these pipelines as Category 4. Further records research reduced the number of miles in Category 4 to 385 miles

7 *Final Report of Evaluating the Stability of Manufacturing and Construction Defects in Natural Gas Pipelines*, April 16, 2007, prepared for the United States Department of Transportation Office of Pipeline Safety by John F. Kiefner of Kiefner and Associates, with the Assistance of the Natural Gas Association of America, pp. 17-18.

8 April 19, 2011, Letter to Executive Director Paul Clanon from Richard M. Morrow.

9 "Criteria Miles" are defined in SoCalGas and SDG&E's April 15 Report as transmission pipelines located in Populated Areas. Report of SoCalGas and SDG&E on Actions Taken in Response to the NTSB Safety Recommendations, p. 5.

10 SoCalGas also identified 27 Criteria Miles that, although did not have sufficient documentation of a strength test, had a documented highest historical operating pressure that is at least 1.25 times the current MAOP. Pipeline segments fitting this description were identified as Category 3. SoCalGas' Category 3 miles now total 23 miles. June 24, 2011, Status Report of SoCalGas and SDG&E on Actions Taken in Response to NTSB Safety Recommendations (April 15 Report), p. 3. For purposes of their Pipeline Safety Enhancement Plan, Category 3 pipeline miles are to be addressed in Phase 1(B) and Phase II.

(322 miles for SoCalGas and 64 miles for SDG&E).[11] All but 8 miles of the Category 4 miles were installed prior to 1970.[12]

1970 is an important date for purposes of pipeline regulations. In 1970, Federal Regulation 49 CFR §192 (Part 192) went into effect. This regulation prescribes the minimum safety requirements for pipeline facilities and the transportation of gas.[13] It also prescribes the pressure test records that are to be maintained for pipelines installed after 1970.

Under Part 192, a transmission pipeline's MAOP may be governed by several factors, including the highest actual operating pressure to which the segment was subjected during the five-year period preceding November 12, 1970.[14] The effect of this clause – which is commonly referred to as the "Grandfather Clause" – is to allow operators to maintain the MAOP of pipelines that were installed prior to 1970 without having to pressure test or de-rate them.[15] It is thus not surprising (and would be expected) that a pipeline operator would not have documentation of a strength test for pipelines installed before regulations requiring these tests were adopted.

Shortly after SoCalGas and SDG&E filed their April 15 Report, PG&E filed a Motion for Adoption of a Maximum Allowable Operating Pressure Validation Methodology. In that motion, PG&E sought approval of its MAOP validation methodology for pipelines in Populated Areas that had not previously been pressure tested. It stated in its motion that it intended to

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11 *Id.*

12 *Id.* Six miles for SoCalGas and two miles for SDG&E. With respect to these miles, SoCalGas and SDG&E are confident all test requirements of 49 CFR §192(J) were performed indicating they were pressure tested, but these pipeline files were not 100% complete when they conducted their records review. SoCalGas and SDG&E are not seeking cost recovery for any remediation work associated with these miles.

13 Supporting Testimony, p. 38.

14 49 CFR §192.619(c).

15 Supporting Testimony, p. 45.

define "traceable, verifiable and complete records" as used in NTSB Safety Recommendation P-10-3 (Urgent) in a certain manner for purpose of its validation methodology. SoCalGas and SDG&E supported PG&E's motion to the extent that it sought guidance regarding the meaning of the phrase "traceable, verifiable, and complete records," which the NTSB did not define in its safety recommendation.

The Commission responded to PG&E's motion in its June 9 Decision. In that decision, the Commission told PG&E that it "should continue to work on its determination of Maximum Allowable Operating Pressure through pipeline features analysis and should use the result of that analysis to impose further pressure reductions as necessary pending replacement or testing."[16] In addition, the Commission ordered "all California natural gas transmission operators to develop and file for Commission consideration" an 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." These Implementation Plans, the Commission stated, "must include a prioritized schedule based on risk assessment and maintaining service reliability, as well as cost estimates with proposed ratemaking."[17]

The rationale behind this requirement, the Commission explains is to do away with reliance on historic exemptions, such as the Grandfather Clause:

> [T]he untested pipelines are . . . some of the oldest in the natural gas transmission system and the more likely to lack a complete set of documents allowing pipeline feature documents to be established without the use of assumptions. We find that this circumstance is not consistent with this Commission's obligations to promote the safety, health, comfort, and convenience of utility patrons, employees, and the public. We conclude, therefore, that all natural gas transmission pipelines in service in California must be brought into compliance with modern standards for safety.

16 June 9 Decision, p. 1; *see also* Ordering Paragraph 1. The Implementation Plans "may [also] include alternatives that demonstrably achieve the same standard of safety."

17 *Id.*, p. 1; *see also* Ordering Paragraphs 4-10.

> Historic exemptions must come to an end with an orderly and cost-conscience implementation plan.[18]

SoCalGas and SDG&E agree that reliance on the "Grandfather Clause" should come to an end but must be done in an orderly fashion. The Implementation Plans contemplated by the Commission's June 9 Decision will do that and are a significant step toward accomplishing the goals set forth in this rulemaking.

In the sections that follow, SoCalGas and SDG&E describe (1) the unique features of their natural gas systems as they relate to their Implementation Plan, (2) current pipeline integrity management regulations and SoCalGas and SDG&E's compliance with them, (3) their proposed Implementation Plan, which they refer to as their Pipeline Safety Enhancement Plan, and (4) the cost estimates for that plan. Also discussed is how SoCalGas and SDG&E intend to execute on their plan and some of the challenges they anticipate may arise when executing on that plan. Finally, SoCalGas and SDG&E discuss their proposed ratemaking and regulatory accounting treatment.

II. SOCALGAS AND SDG&E TOOK INTO ACCCOUNT THE UNIQUE ATTRIBUTES OF THEIR NATURAL GAS TRANSMISSION SYSTEMS WHEN DESIGNING THEIR PIPELINE SAFETY ENHANCMENT PLAN[19]

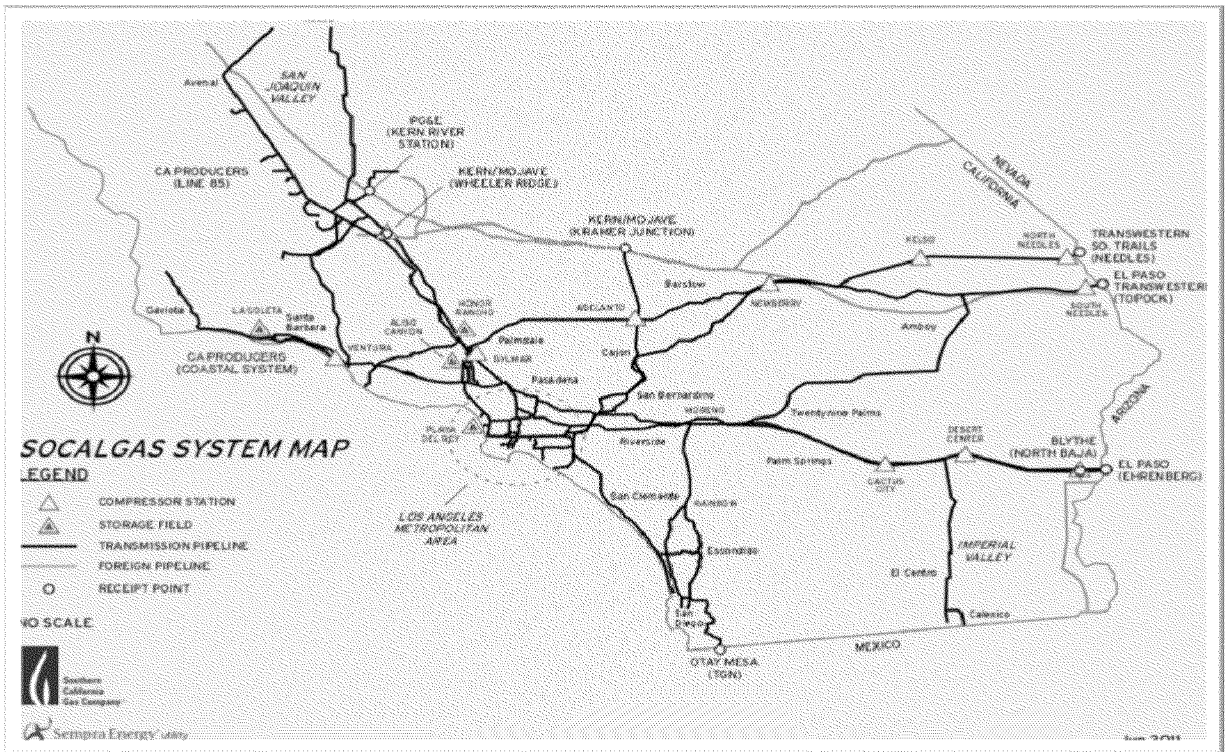
As the commission knows, SoCalGas is the largest natural gas distribution company in the nation, delivering natural gas to over five million residential and business customers. SDG&E provides natural gas distribution service to San Diego County and delivers natural gas to over 845,000 residential and business customers. SoCalGas and SDG&E have been providing

18 *Id.*, p. 18. SoCalGas and SDG&E believe the Commission's directives in the June 9 Decision are intended to require California's natural gas transmission pipeline operators to eliminate the reliance in California on the Grandfather Clause of Part 192. The decision, however, would appear to exclude subsection 192.619(c) entirely, eliminating other provisions of the Federal regulations that are essential because they cross-reference and incorporate other subparts of 49 CFR 192.619.

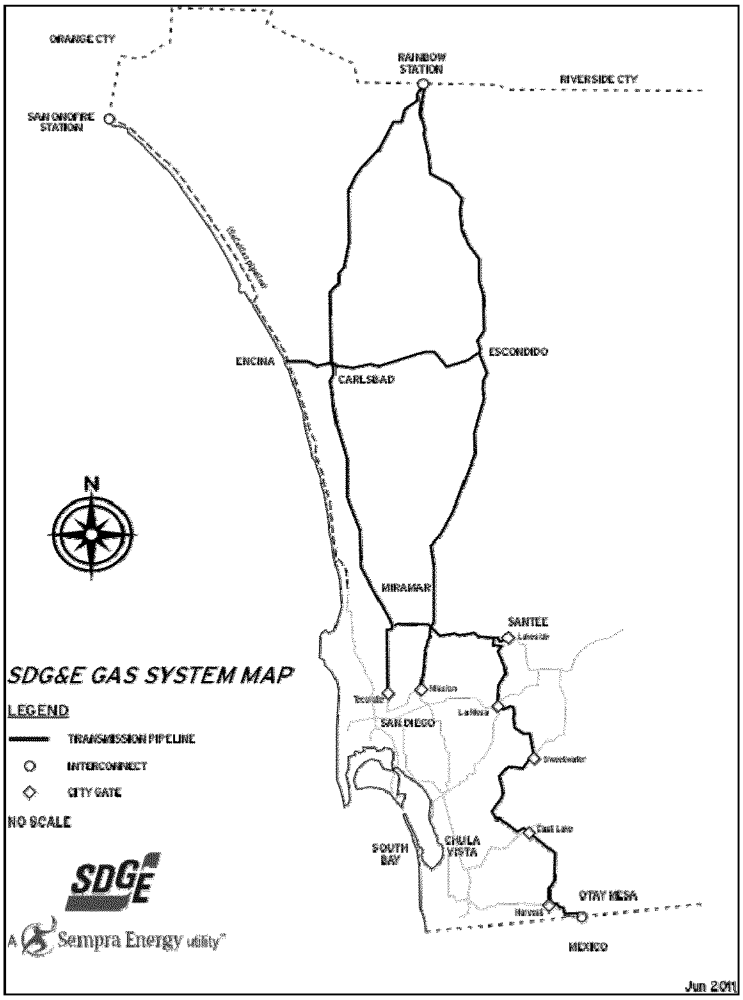
19 This discussion in this section is supported by the testimony of Mr. David Bisi at pages 29 to 36 of the Supporting Testimony.

safe and reliable gas delivery service for over 100 years and are committed to continuing to do so. Both have diverse customer bases and diverse customer needs. Their transmission systems are integrated and designed to provide reliable service to their customers.

SoCalGas' transmission system consists of an integrated pipeline system and four storage facilities. It extends from the Colorado River on the eastern end to the Pacific Coast on the western end and from Tulare County in the north to the United States/Mexico border in the south (excluding parts of San Diego County and Orange County). The SoCalGas transmission and storage system currently has sufficient capacity to serve a demand of 6.0 Bcfd per day through a combination of flowing supply and stored gas. Below is a map of SoCalGas' transmission system:



The SDG&E gas transmission system consists primarily of two high-pressure large diameter pipelines that extend south from Rainbow Station, located at the Riverside/San Diego County border. Both pipelines terminate at the San Diego metropolitan area. At Santee, another large diameter pipeline extends to the Otay Mesa metering station at the U.S./Mexico border. At Otay Mesa, the SDG&E system interconnects with the Transportadora de Gas Natural, S.R.L. (TGN) pipeline, providing another receipt point for supplies into the SoCalGas/SDG&E systems. A small diameter, lower pressure pipeline owned by SoCalGas also extends south from Orange County down to San Diego. Based on the current winter demand forecast, the SDG&E transmission system currently has sufficient capacity to serve 630 MMcfd of customer demand during the winter season. Below is a map of SDG&E's gas transmission system:



Since 1998, SoCalGas' Gas Control department has operated both gas transmission systems as an integrated, common system. By operating the two systems as a common system, SoCalGas and SDG&E have been able to provide higher pressures to the SDG&E system and have been able to maximize system capacity to the benefit of customers and shippers.

SoCalGas and SDG&E's natural gas transmission systems are designed to transport supplies received at the edges of their service territories to load centers, with the largest load center for SoCalGas being the Los Angeles metropolitan area and the city of San Diego for the SDG&E system. As a result, the gas transmission systems of both utilities consist of pipelines with "telescoping" operating pressures. That is the MAOPs are higher at the receipt points and lower near the load centers. As gas supply is transported in the pipelines, pressure declines as a function of volume transported and distance traveled. It is this pressure differential that allows gas supplies to flow in a pipeline to the load centers. Mainline compressor stations are then used to boost the pressure in the transmission lines as necessary so that the gas supply arrives at the load centers with sufficient pressure for delivery to customers.

Highly interconnected pipeline networks serve the metropolitan load centers of Los Angeles and San Diego. These networks are referred to as a "Loop System" by each utility. The pipelines within both the Los Angeles and San Diego Loop Systems operate at a common pressure. Major regulator stations supply these Loop Systems. The operating pressure of the Loop Systems can only be controlled at these regulator stations; neither SoCalGas nor SDG&E have the ability to isolate a pipeline that is part of a Loop System to operate it at a different pressure.[20] Absent the installation of new facilities, lowering the pressure of a single pipeline within the Loop System requires lowering the pressure of the entire Loop System at these regulator stations. Outside these Loop Systems, isolating and lowering the pressure of a

20 Both SoCalGas and SDG&E operate pipelines within the Loop Systems that serve a specific customer or area and operate at a different pressure. From a system perspective, however, these pipelines can be viewed as a sub-set of the Loop Systems and do not contribute to the interconnectivity or flexibility of the Loop Systems.

transmission pipeline could impact shippers and the market. For example, when SoCalGas removed Transmission Line 235-2 from service in 2009 for repairs, receipt capacity at its North Needles and Topock receipt points was cut for an extended period.

These features, as well as others, were taken into account when SoCalGas and SDG&E developed their Pipeline Safety Enhancement Plan.

III. PIPELINE SAFETY AND THE REGULATIONS THAT GOVERN THEM HAVE EVOLVED OVER TIME[21]

As stated, SoCalGas and SDG&E's commitment to the safe and reliable delivery of natural gas goes back more than 100 years, and throughout their history they have been and continue to be proactive in developing industry standards. Both strive to meet or exceed existing regulations and take a conservative approach to maintaining their systems in a safe manner.

Current regulations – which have been developed and improved over time – got their start in 1926 when the American Engineering Standards Committee (currently American Society of Mechanical Engineers) initiated a project to develop a safety code for pressure piping, and in November 1951 the Committee authorized a separate publication dealing with gas transmission and distribution piping. The purpose of this publication, known as B31.8, was to provide a document for gas transmission and distribution piping that would be complete and not require cross referencing to other sections of the code. The first edition was published in 1952 and since then has been revised many times to reflect changes in materials, methods of construction and operations.

In 1960, the Commission adopted General Order 112 and the requirement that transmission pipelines be strength tested in California took effect on July 1, 1961. Federal

21 The discussion in this section comes from the testimony of Mr. Douglas Schneider at pages 37 to 66 of the Supporting Testimony.

regulations were adopted in 1970, with Part 192. As discussed above, Part 192 prescribes the minimum safety requirements for pipeline facilities and the transportation of gas. It includes a pressure testing requirement and prescribes the pressure test records that are to be maintained for pipelines installed after 1970.

Since 1970, the Federal Code has changed over time to reflect changes in materials, methods of construction and operations, and General Order 112, which incorporates Part 192, has been updated accordingly. In 2003, Subpart O "Gas Transmission Integrity Management" was added to Part 192. Under this subpart, natural gas transmission operators are required "to develop and follow a written integrity management program . . . that addresses the risks on each . . . transmission pipeline segment" covered by the regulations.[22] Subpart O requires natural gas transmission pipeline operators to perform, as part of their pipeline integrity management programs, additional inspections on transmission pipelines that pass through areas known as High Consequence Areas (HCA).[23]

Current regulations require that HCA segments receive a baseline assessment by December 17, 2012, followed by a reassessment at least every seven years. These assessments can be completed using in-line inspection, direct assessment and/or pressure testing and are designed to identify threats to the safe operation of a pipeline. These threats have been grouped by three time factors: (1) Time Dependent; (2) Time Independent; and (3) Stable. Time Dependent threats are generally those related to corrosion and include external corrosion, internal corrosion and stress corrosion cracking. Time Independent threats include third party/mechanical damage, incorrect operational procedure, and weather-related and outside

22 49 CFR §192.907.

23 The technical definition of HCA can be found at 49 CFR §192.903.

forces. Stable threats are manufacturing-related, welding/fabrication-related or equipment-related (these are often referred to as construction and fabrication threats).

IV. SOCALGAS AND SDG&E HAVE A RIGOROUS PIPELINE INTEGRITY MANAGEMENT PROGRAM[24]

SoCalGas and SDG&E have strong transmission pipeline integrity management programs and are on target to complete their baseline assessments by the end of next year. In addition to completing these inspections and assessments, SoCalGas and SDG&E perform numerous maintenance activities to validate the integrity of their transmission pipelines, including leak surveys, pipeline patrols, damage prevention programs and corrosion control measures.

SoCalGas and SDG&E's preferred assessment method is in-line inspection (often referred to as smart pigging), and they have and continue to make significant investments to retrofit their transmission pipelines to allow for in-line inspection (commonly referred to as "piggable lines"). Combined SoCalGas and SDG&E have completed a baseline assessment on over 1,079 miles of transmission lines located in HCAs. A summary of the baseline assessment of HCA miles is provided in the Table A below.[25]

Table A
Summary of Baseline Assessment of HCA Miles

	In-Line Inspection	External Corrosion DirectAssessment	Pressure Test	Total HCA Miles Baseline Assessed	Total HCA Miles	% HCA Baseline Assessed
SoCalGas	807	143	19	969	1,178	82%
SDG&E	26	84	0	110	178	62%
Total	833	227	19	1,079	1,356	80%

24 The discussion in this section comes from the testimony Mr. Schneider at pages 37 to 66 of the Supporting Testimony.

25 Table A corresponds to Table IV-2 in the Supporting Testimony.

SoCalGas and SDG&E have also performed baseline assessments beyond those required by current regulations because they believe it is neither practical nor prudent to limit the baseline assessment solely to the segment of pipeline in the HCA. A summary of the inspection of non-HCA transmission miles is summarized in Table B below.[26]

Table B
Summary of Baseline Assessment of Non-HCA Miles

	In-Line Inspection	External Corrosion Direct Assessment	Pressure Test	Total non-HCA Assessed	Total non-HCA	% non-HCA Baseline Assessed
SoCalGas	1,059	25	1	1,085	2,579	42%
SDG&E	4	0	0	4	73	5%
Total	1,063	25	1	1,089	2,652	41%

V. SOCALGAS AND SDG&E'S PIPELINE SAFETY ENHANCEMENT PLAN IS FOUNDED UPON FOUR OVERARCHING OBJECTIVES[27]

In response to the Commission's June 9 Decision, SoCalGas and SDG&E propose to implement a comprehensive Pipeline Safety Enhancement Plan that is designed to meet the following four objectives: enhancement to public safety, compliance with the Commission's directives, minimization of customer impacts, and maximization of cost effectiveness. That plan is divided into two phases. The first phase (Phase 1) primarily covers pipeline segments in Populated Areas that, based on the June 9 Decision, need to be pressure tested or replaced as well as the replacement of pipeline segments installed prior to 1946 that are not piggable.[28] Phase 1 will also include upgrades to SoCalGas and SDG&E's valve systems, some technological enhancements for better detection of incidents on transmission pipeline, and the development of a comprehensive Enterprise Asset Management System.

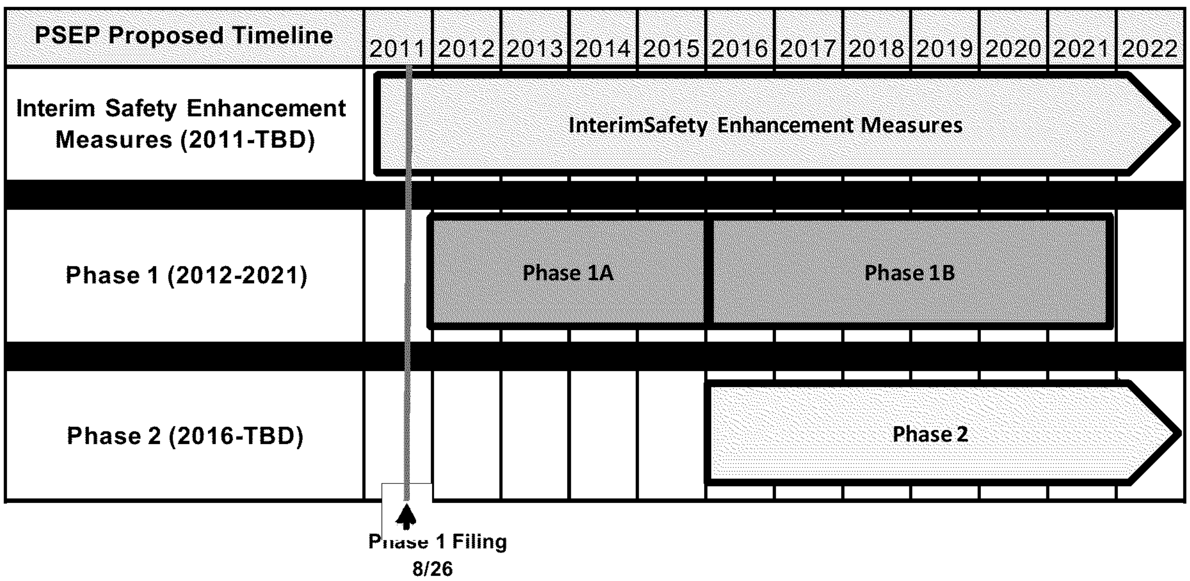
26 Table B corresponds to Table IV-3 in the Supporting Testimony.

27 The introduction to this section comes from the testimony of Mr. Michael Allman at pages 1 to 9 and Mr. Richard Morrow at pages 10 to 28; the discussion in Subsection A comes from the testimony of Mr. Schneider at pages 37 to 66 of the Supporting Testimony.

28 Phase 1 will include some pipeline segments in Non-populated Areas because it is more economical and practical to pressure test or replace them in Phase 1.

Phase 1 is divided into two parts (Phase 1(A) and Phase 1(B)). Phase 1(A) includes the higher priority pipelines, which SoCalGas and SDG&E propose to address over the next four years. Phase 1(B) covers pipeline segments that were installed before 1946 that are not piggable and pipeline segments that based on SoCalGas and SDG&E's prioritization methodology would be included in Phase 1(A) but due to the lead time necessary to design and obtain the necessary permits for the projects will not have construction begin until after 2015.

Phase 2 covers the remaining pipeline segments in SoCalGas and SDG&E's service territories. Pipeline segments to be addressed in Phase 2 will be scheduled after Phase 1(A) in order to prioritize pipeline segments located in more Populated Areas that have either not been pressure tested or lack sufficient details related to the completion of a pressure test. Phase 2 will likely extend well beyond 2021 (the year Phase 1 is anticipated to end). The interim safety measures, discussed below, have been ongoing since SoCalGas and SDG&E submitted their April 15 Report. The following timeline provides an overview of this phasing plan.



SoCalGas and SDG&E seek cost recovery at this time for Phase 1(A) only. Cost recovery for Phase 1(B) and Phase 2 will be sought in the next GRCs and subsequent rate case cycles and in other applicable proceedings, as needed. Each of the components of SoCalGas and SDG&E's Pipeline Safety Enhancement Plan is discussed further in sections (A) through (D) below.

A. **SoCalGas and SDG&E Propose to Implement the Pipeline Portion of PSEP in Phases.**

SoCalGas and SDG&E, will implement the pipeline portion of their Pipeline Safety Enhancement Plan in phases, and have, within each phase a prioritization and sub-prioritization process for determining whether and when to pressure test or replace a pipeline segment. Figure 1[29] below illustrates SoCalGas and SDG&E's proposed Pipeline Safety Enhancement Plan prioritization and decision-making process for testing or replacing pipeline segments. After priorities have been broadly established using this decision tree, the pipeline segments are sub-ranked for scheduling purposes primarily based on the consequence of failure of each segment.[30] This approach is consistent with pipeline risk principles.[31]

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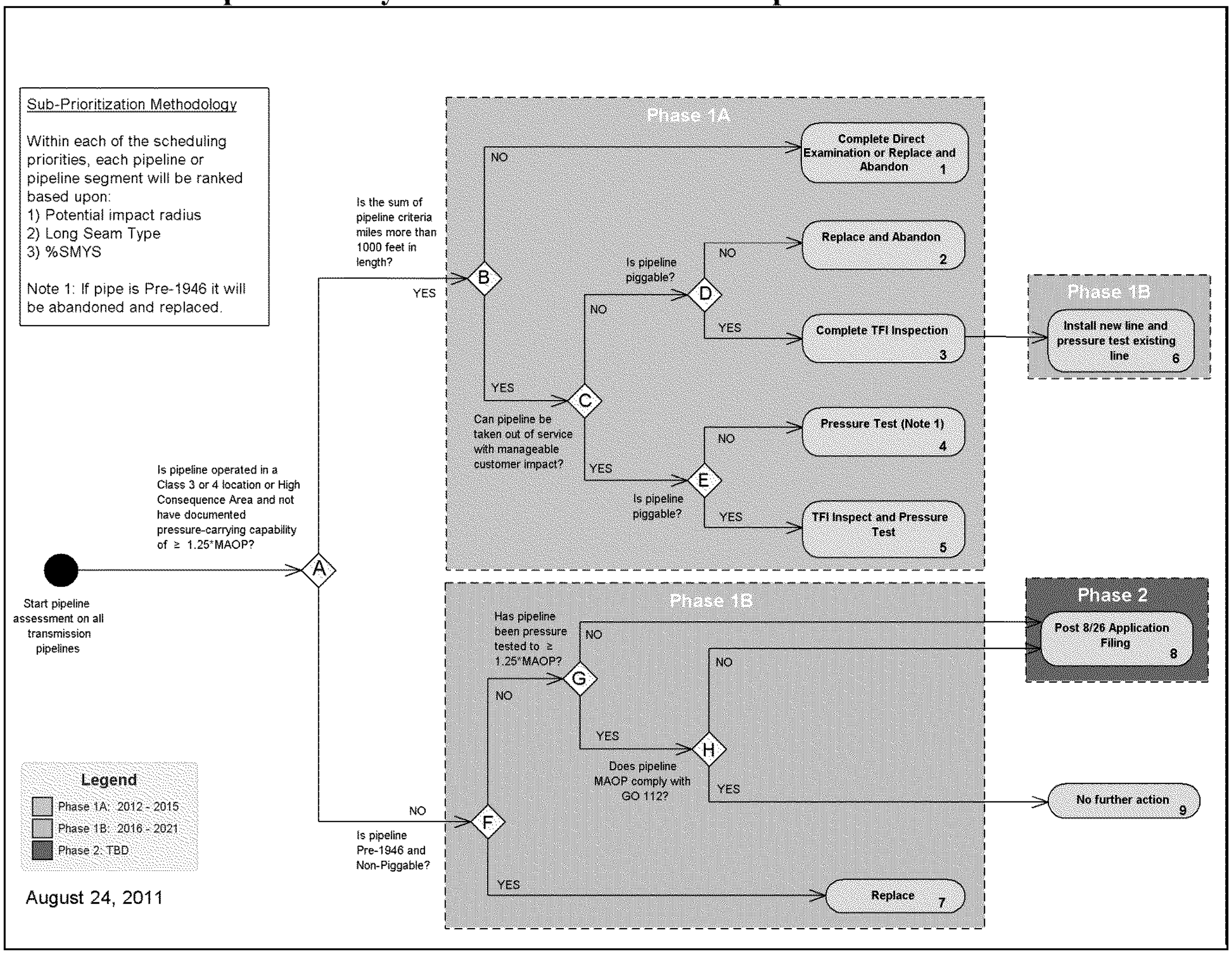
29 Figure 1 corresponds to Figure IV-1 in the Supporting Testimony.

30 Pipeline risk is commonly defined as the product of the likelihood of failure (LOF) and the consequence of failure (COF), or Risk = LOF x COF. LOF is closely related to the specific characteristics and anticipated threats of each pipeline segment. COF is related to the energy in each pipeline and the population density potentially affected by a failure.

31 Although SoCalGas and SDG&E intend to use this prioritization and sub-prioritization processes, the final implementation schedule may change as a result of system conflicts, logistical coordination, and incorporation of information obtained through interim inspections and assessments.

Figure 1
Pipeline Safety Enhancement Plan Test/Replace Decision Tree



1. Phase 1(A) Pipeline Segments Represent the Higher Priority Work.

Phase 1(A) pipeline segments include all transmission pipelines in Populated Areas that do not have sufficient documentation to validate a post-construction pressure test of at least 1.25 times MAOP. These segments represent the higher priority work. In determining the appropriate action with respect to each Phase 1(A) pipeline segment, SoCalGas and SDG&E have divided the segments into three categories: (1) pipeline segments that are 1,000 feet in length or less; (2) pipeline segments greater than 1,000 feet in length that can be removed from service for pressure testing; and (3) pipeline segments greater than 1,000 feet in length that cannot be removed from service for pressure testing. Each is discussed below.

a. *Proposal for Pipeline Segments That Are 1,000 Feet or Less*

SoCalGas and SDG&E propose to perform a complete inspection of a pipeline segment using non-destructive examination methods on segments of pipe that are 1,000 feet in length or less as an alternative to pressure testing or replacement. Non-destructive examination is an equivalent means to validate the strength of the pipeline segment. Non-destructive examination methods such as radiography, ultrasonic inspection, and magnetic particle testing have been used for years and are typically more direct and reliable, and they provide a higher level of anomaly discrimination when compared to pressure testing or in-line inspection. As a result they are commonly used to investigate pressure test failures or validate in-line inspection data.

Cost is usually the limitation of non-destructive examination methods for buried pipelines because they require direct access to the pipe surface. For short segments, however, these non-destructive examination techniques are likely to be more practical and less costly for long seam and weld validation for short segments of pipe when compared with pressure testing or replacement. And direct examination has the added benefit of providing additional information that pressure testing cannot, such as coating condition, corrosion, and other sub-critical defects. Additionally, the disadvantages of pressure testing – namely the introduction of water, disposal of the water and service disruptions – can be avoided. All of these factors combine to make direct examination of short segments a reliable and cost-effective alternative to pressure testing.

If this alternative method is not accepted, SoCalGas and SDG&E propose to replace these short segments because it is typically more cost effective to replace them rather than perform a pressure test in these situations.

b. *Pipeline Segments Greater Than 1,000 Feet That Can Be Taken Out of Service Will Be Pressure Tested*

For pipeline segments that are longer than 1,000 feet in length, SoCalGas and SDG&E completed a preliminary review to determine if the pipeline segment can be taken out of service for a period of two to six weeks to complete pressure testing. Where removal from service is feasible, the Pipeline Safety Enhancement Plan identifies these pipeline segments for pressure testing.[32]

At the time of pressure testing, SoCalGas and SDG&E also propose to remove any oxy-acetylene girth welds or wrinkle bends on these pipeline segments because the pipeline will have already been removed from service, making it an ideal time to mitigate these historic features.[33] Although SoCalGas and SDG&E believe oxy-acetylene girth welds and wrinkle bends on their systems are stable and do not pose significant risk, their removal will provide for more reliable service and a lower likelihood of disruption from pressure test failures. Once the oxy-acetylene girth welds and wrinkle bends have been removed and replaced, the remaining pipeline segments will be pressure tested to finalize the validation of the entire segment.

For pipeline segments greater than 1,000 feet in length that have already been retrofitted for smart pigging, SoCalGas and SDG&E also request that the Commission approve the use of in-line inspections, using transverse field inspection (TFI) tools, in parallel with the pressure test. While SoCalGas and SDG&E are confident in the safety of their pipeline system, pressure testing will expose pipelines to pressure levels well in excess of pressures experienced in-service.

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32 For non-piggable pipeline segments that are to be addressed in Phase 1(A), SoCalGas and SDG&E may consider replacing a line rather than testing it if the pipeline contains pre-1946 construction and fabrication threats and can be replaced within the Phase 1(A) four-year timeframe.

33 A girth weld is the physical point at which two segments of pipe are fused together at the ends to form a single, larger section of continuous pipe. Oxy-acetylene girth welds were not used to construct high-pressure pipelines after World War II.

Knowledge obtained though in-line inspection runs using the TFI tool will allow SoCalGas and SDG&E to proactively mitigate pipeline anomalies that could lead to a potential pipeline failure at higher pressure test levels. By mitigating potential sources of pressure test failures before conducting the pressure test, planners can avoid the pitfalls associated with entering into a cycle of pressure test failures.

The use of the TFI tool may also significantly reduce the costs of Phase 2. SoCalGas and SDG&E propose that, as part of PSEP, they analyze the data obtained during the in-line inspections and compare those results to the pressure test results to validate that an in-line inspection using the TFI tool is an equivalent means of assessing the strength of in-service pipelines. SoCalGas and SDG&E hope that the data they gather from the TFI tool aligns with the information they gather from the pressure test so that they will be able to demonstrate at a future time (*e.g.*, at their next GRCs) that they can use in-line inspections using the TFI tool in lieu of pressure testing Phase 2 pipelines where appropriate. Although, as discussed in Section VIII below, this adds to the estimated costs for Phase 1(A), SoCalGas and SDG&E believe that, if the TFI data proves out, they will be able to dramatically reduce the overall costs of their ipeline Safety Enhancement Plan in Phase 2.

c. *Proposal for Pipeline Segments Greater Than 1,000 Feet That Cannot Be Taken Out of Service*

All non-piggable pipeline segments that cannot be taken out of service for pressure testing with manageable customer impacts will be replaced. Construction and installation of the new replacement segment can take place while service is maintained to customers on the existing pipeline segment, thereby avoiding the service disruptions that would otherwise occur if the pipeline segment were removed from service for pressure testing. The newly installed systems will be constructed using state-of-the-art methods and to modern standards.

2. SoCalGas and SDG&E Propose to Replace Non-Piggable Transmission Pipeline Segments in Phase 1(B).

SoCalGas and SDG&E have identified, as part of their existing pipeline integrity management programs, those pre-1946 transmission pipelines that are operationally suited to in-line inspection and have converted them to be piggable. The remaining pre-1946 segments in the SoCalGas/SDG&E systems are not well suited for in-line inspection and likely have non-state-of-the-art welds. Rather than expend significant resources to make them piggable, SoCalGas and SDG&E propose to replace all remaining pre-1946 non-piggable pipelines as part of Phase 1(B). This is consistent with the Commission's directive in its June 9 Decision to "consider retrofitting pipeline to allow for inline inspection tools," and it is consistent with SoCalGas and SDG&E's overarching objectives to enhance the safety of their pipeline systems in a proactive, cost effective manner.

There are also some pipeline segments that, based on their decision tree (Figure 1 above), fall within Phase 1(A) but that SoCalGas and SDG&E anticipate will not have construction begin within the Phase 1(A) time period because of the time it will take to plan, obtain the necessary permits and build the new infrastructure for these pipeline segments. Accordingly, these lines are included as a parallel effort within Phase 1(B) to account for the estimated lead times required for the design and permitting of the new infrastructure. For pipeline segments that fall within this category, SoCalGas and SDG&E propose as an interim measure that they perform an in-line inspection on these pipeline segments using TFI technology to the extent the pipeline has already been made piggable or can be readily converted to accommodate in-line inspection.

3. Remaining Pipeline Segments in Non-Populated Areas Will Be Tested in Phase 2.

In Phase 2, which, as stated, is expected to run in parallel with and may extend past the completion of Phase 1(B), SoCalGas and SDG&E will address remaining transmission pipeline segments that meet the Commission's criteria in its June 9 Decision. These pipeline segments are scheduled to be addressed after Phase 1(A) pipeline segments.

SoCalGas and SDG&E are currently conducting a records review similar to the review for their April 15th Report for the transmission pipelines located in Non-populated Areas. They expect to complete their review by July 2012.

B. SoCalGas and SDG&E's Proposed Valve Enhancement Plan Will Result in the Installation or Modification of an Additional 367 Remote Control Capable and Automatic Shutoff Valves on Their Systems.[34]

The San Bruno pipeline rupture and fire has focused considerable attention at both the State and Federal level on protocols for pipeline isolation in the event of a pipeline rupture, and as part of its June 9 Decision, the Commission orders all California natural gas pipeline operators to consider retrofitting pipelines to allow for improved shut-off valves. In response to this directive, and in light of concerns raised by the pipeline rupture in San Bruno, SoCalGas and SDG&E offer a proposed Valve Enhancement Plan as part of their overall Pipeline Safety Enhancement Plan.

SoCalGas and SDG&E currently employ over 800 mainline valves to isolate and sectionalize transmission pipelines for operational and emergency conditions in the areas discussed in their Valve Enhancement Plan. The current valve infrastructure consists of about

34 The discussion in this section comes from the testimony of Mr. Joseph Rivera at pages 67 to 84 of the Supporting Testimony.

600 manually-operated valves and more than 200 automatic shut-off valves (ASVs) and remote control valves (RCVs) to meet and/or exceed the current regulations.[35] For over forty years (and prior to the adoption of existing regulations) SoCalGas and SDG&E have incorporated ASVs and RCVs into their systems. In their experience, ASVs and RCVs can reduce response time and enhance their ability to contend with a significant pipeline rupture. They can also help an operator deal with simultaneous ruptures triggered in an event, such as a major earthquake.

Approximately 50% (2,000 miles) of SoCalGas and SDG&E's high-pressure transmission lines are currently covered by 208 active ASVs, which are installed at intervals averaging ten miles in length, but which range between five and twenty miles in spacing. This ASV control closure scheme is augmented by over thirty mainline valves, pressure limiting stations, and/or compressor shutdown controls that can be operated remotely by Gas Control personnel in a matter of five to fifteen minutes (or less) to restrict gas flow to a ruptured pipeline section.

SoCalGas and SDG&E's Valve Enhancement Plan focuses on the Populated Areas and augments SoCalGas and SDG&E's existing ASVs and RCVs. Their plan will include the (1) retrofitting manually operated valves to provide ASV/RCV capability; (2) modifying the existing ASV network to support RCV operation, and (3) limiting ASV/RCV pipeline isolation length to existing DOT class location requirements. The valve work being proposed would be done over a ten-year timeframe, commencing in 2012 (*i.e.*, Phase 1).

By installing the additional ASVs/RCVs, SoCalGas and SDG&E will reduce the time required to identify and characterize a pressure drop as a result of a pipeline rupture and to provide for automatic closure locally thus eliminating the time for operators to determine and

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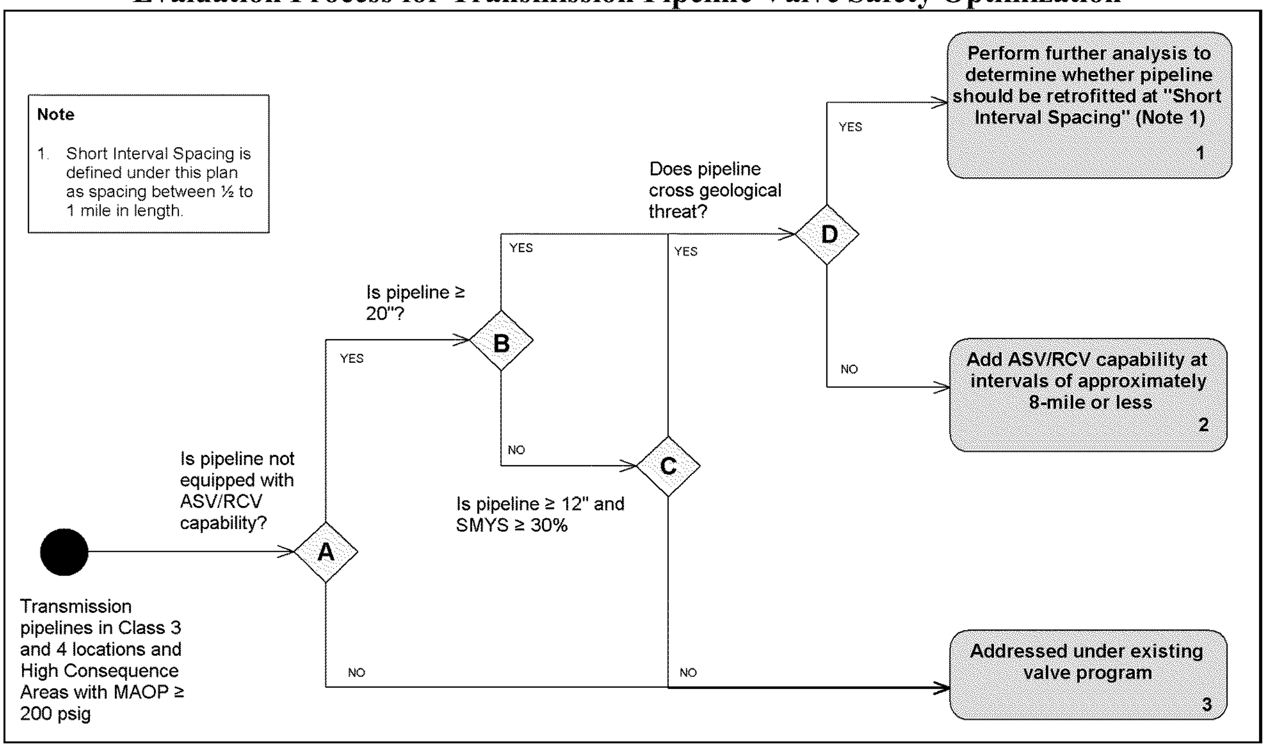
35 *See* 49 CFR §192.179.

close the valve (either manually or remotely). The additional RCVs (and the additional pipeline pressure monitoring to be installed with each ASV/RCV upgrade as proposed) will reduce the time required to identify and characterize a pressure drop as a result of a pipeline rupture for those areas in SoCalGas and SDG&E's service territories where ASVs are not appropriate.

To determine where to locate the additional ASVs and RCVs, SoCalGas and SDG&E developed a decision-making process. This decision-making process distinguishes between those pipelines that are greater than or equal to twenty inches in diameter and those that are less than that diameter. Figure 2[36] illustrates the proposed evaluation process and installation criteria for SoCalGas and SDG&E's proposed Valve Enhancement Plan.

Figure 2
Evaluation Process for Transmission Pipeline Valve Safety Optimization



36 Figure 2 corresponds to Figure V-4 in the Supporting Testimony.

Based on this decision tree, SoCalGas and SDG&E propose to install ASV/RCV capability on all transmission pipeline segments greater than or equal to twenty inches in diameter that are located in Populated Areas at intervals of approximately eight miles or less. Pipelines meeting this criterion that also cross a known geological threat, such as an earthquake fault, landslide area or washout area, have been identified for further analysis to determine whether the pipeline segment should be retrofitted at "Short Internal Spacing" (*i.e.*, spacing between half a mile and one mile in length).[37] For pipeline segments less than twenty inches in diameter, SoCalGas and SDG&E propose to install ASV/RCV capability at approximately eight mile intervals if a pipeline is equal to or larger than twelve inches in diameter and operates at 30% or more of SMYS. This stress level is widely recognized as the lower threshold at which a pipeline can rupture rather than leak.

The eight-mile spacing SoCalGas and SDG&E used in their Valve Enhancement Plan is based on current regulations that require valves to be placed at increments of eight miles or less in Populated Areas. In developing their Valve Enhancement Plan, SoCalGas and SDG&E reviewed the effective time difference between isolating an eight-mile pipeline segment and five-mile pipeline segment as contemplated in certain proposed legislation. SoCalGas and SDG&E found little time difference in the depressurization associated with a reduction in valve spacing from eight to five miles. Accordingly, SoCalGas and SDG&E determined that reduction in valve spacing beyond existing requirements would not yield incremental benefits and would be inconsistent with their objective of maximizing cost effectiveness.

SoCalGas and SDG&E also took into account in developing their Valve Enhancement Plan some of the challenges associated with the deployment of ASVs and RCVs, including errant

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37 Based on their current analysis, SoCalGas and SDG&E propose to install ASV/RCV capability at Short Interval Spacing on no more than 20 pipeline segments.

closures for a variety of reasons. Such closures can occur due to equipment failure or spurious pressure waves. SoCalGas and SDG&E experience three to four such errant valve closures each year on their current valve system. If an errant closure occurs in complex pipeline networks, where flow patterns are bi-directional and/or pipelines are operating at near-full capacity, it can compromise the ability to serve customers reliably and potentially result in wide-spread outages. Thus, to properly manage the 367 added ASVs and RCVs, operations personnel need added visibility of transmission flow at the locations where these valves are to be installed. Accordingly, SoCalGas and SDG&E include in their Valve Enhancement Plan the co-deployment of significant gas-pipeline monitoring technologies that will provide operators with twenty additional real-time flow measurement reference points along transmission pipelines to support pipeline system management.

The Valve Enhancement Plan also incorporates measures to address potential backflow, which occurs when a ruptured pipeline section has more than one supply point and/or receipt point within the section to be isolated. Backflow concerns are addressed by retrofitting 160 pipeline locations with one of three control features to prevent backflow in the event of a pipeline rupture.

C. PSEP Presents the Ideal Opportunity to Retrofit Pipelines with Advanced Fiber Optic and Methane Detection Technology.[38]

Although not required by the June 9 Decision, SoCalGas and SDG&E believe the work that will be performed in compliance with that order provides an ideal opportunity to retrofit pipelines with existing and emerging technologies to provide advance warning of a potential pipeline failure and decrease the time to identify, investigate, prevent and remedy or manage the

38 The discussion in this section comes from the testimony of Mr. Rivera at pages 85 to 89 of the Supporting Testimony.

effects of such an event. Accordingly, SoCalGas and SDG&E propose to install fiber optic cabling and methane detection instruments as part of their Pipeline Safety Enhancement Plan. This work would be performed during pipeline replacements in Phase 1.

1. Fiber Optic Right-of-Way Monitors.

Fiber optic right-of-way (ROW) monitors can help a pipeline operator identify when intrusions into a pipeline have occurred or when a pipeline (or ROW) has experienced movement that might pose a threat to pipeline structural integrity. Advances in fiber optic signature analysis now allow an operator to pinpoint, to within several feet, where a direct buried (12 to 18 inches above the pipeline) fiber cable has been disturbed, is severed, or otherwise has picked up abnormal vibrations. This signature interpretation can be used to monitor pipeline ROW activity in real-time and help drive decisions to send operational crews to investigate when a suspected incident has occurred that might, acutely or with some latency, pose a risk to a pipeline's structural integrity.

Typically, fiber optic technology is not cost effective to install on pipelines that are buried and in service. But it does become cost effective to install when a pipeline is already exposed. SoCalGas and SDG&E plan to take advantage of the fact that existing pipelines will be exposed during pressure testing or replacement and include as part of their Pipeline Safety Enhancement Plan the installation of 280 miles of fiber optic cable during the pipeline work being undertaken during Phases I.[39] SoCalGas and SDG&E will install permanent monitoring stations at each contiguous pipeline section equipped with fiber optics reaches five miles in length.

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39 Fiber optic technology will be installed generally on pipelines twelve inches in diameter and larger.

2. Methane Detection Monitors.

The safety of the SoCalGas and SDG&E system may be further enhanced through the addition of real-time pipeline ROW gas detection 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.[40] SoCalGas and SDG&E have identified approximately 2,100 general locations that fit this proposed criterion for installing methane detection devices.

The installation of these methane detectors will allow SoCalGas and SDG&E to identify gas leaks sooner so that they can dispatch operations personnel to specific locations more quickly. The methane sensors proposed to be deployed will be capable of reliably detecting gas/air concentration levels approximately 25% or less of what is typically detected by the human sense of smell of the odorant.

3. Pipeline Infrastructure Monitoring Data Collection and Management System.

SoCalGas and SDG&E propose to develop a new data collection, storage, alarm-processing and data management system to collect information from the field monitoring sensors described above. SoCalGas and SDG&E envision using the Advanced Metering Infrastructure and Smart Metering Radio System expansions to support data gathering from the fiber optic cable and methane detection sensors.[41]

The data collection and management system will serve several functions. It will provide periodic (at minimum daily) health/status monitoring of all fiber optic and methane detection

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40 SoCalGas and SDG&E have identified approximately 2,100 general locations that fit this proposed criterion for installing methane detection devices.

41 The system SoCalGas and SDG&E propose can accommodate future expansion to 10,000 monitoring points and multiple sensor types, including remote Cathodic Protection, acoustic monitoring and pressure alarm.

monitors and receive alarm information from a fiber optic or methane detection monitor in less than two minutes. It will also report alarms to appropriate dispatch personnel for review, call-out and resolution, as required, and it will track alarm acknowledgment and status and permanently store all events with appropriate time and date stamping of those events. Finally, the system will provide system-wide viewing of current alarm information to help field and operations personnel reconcile fiber optic and methane detection monitor information with SCADA and other field observations during an emergency situation and will export/route information to support near real-time graphical viewing presentation of alarms on SoCalGas/SDG&E mapping products and provide connectivity with automated customer notification systems.

D. SoCalGas and SDG&E Propose to Design a Comprehensive Enterprise Asset Management System That Will Allow New and Existing Pipeline Infrastructure Documentation to be "Readily Available."[42]

Finally, SoCalGas and SDG&E have included in their Pipeline Safety Enhancement Plan a proposal to develop over the next 6 to 12 months the detailed architecture and design of a comprehensive Enterprise Asset Management System to facilitate ready access to pipeline infrastructure data.[43] In its June 9 Decision, the Commission states that at the end of the implementation period, each pipeline operator will have their transmission pipeline records "readily available."[44] SoCalGas and SDG&E support this goal. While the data required to operate and maintain their natural gas transmission pipeline systems are currently readily available, supporting data and documents, which are often paper records, are more difficult to access. And SoCalGas and SDG&E's existing systems for storing and accessing data, which

42 The discussion in this section comes from the testimony of Mr. Rivera at pages 90 to 94 of the Supporting Testimony.

43 Once the Enterprise Asset Management System has been fully designed, SoCalGas and SDG&E will seek authorization to request funding in a subsequent filing.

44 June 9 Decision, p. 9.

have evolved over time, are not integrated and are often in different formats. To have all such data, and supporting data, integrated and readily available, various data repositories, including maintenance and inspection systems, geographical information systems, purchasing systems, and paper records must be connected and interrelated. The Enterprise Asset Management System that SoCalGas and SDG&E propose to design will do that and will focus on applying industry leading records management practices and information technology solutions to govern, record, store, secure, maintain, access, search and analyze transmission pipeline system data. Once developed it will support leading records and data governance practices and controls; ensure the validity, traceability and completeness of pipeline data; and provide SoCalGas and SDG&E personnel with secure anytime, anywhere access to necessary pipeline system data.

VI. SOCALGAS AND SDG&E'S PIPELINE SAFETY ENHANCEMENT PLAN INCLUDES A NUMBER OF INTERIM SAFETY MEASURES THAT THEY BEGAN IN CONNECTION WITH THEIR APRIL 15 REPORT[45]

In addition to their existing pipeline integrity management program, SoCalGas and SDG&E propose the following interim safety measures as part of their Pipeline Safety Enhancement Plan. These measures include continuing the increased frequency of ground patrols and leakage surveys that SoCalGas and SDG&E began in connection with their April 15 Report.[46]

In addition, SoCalGas and SDG&E have had and continue to have a practice of reducing the MAOP of pipelines when system changes allow for a lower maximum pressure to minimize the stress in the pipeline and provide an enhanced safety margin. SoCalGas and SDG&E have already implemented pressure reductions where operational constraints permitted SoCalGas and

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45 The discussion in this section comes from the testimony of Mr. Schneider at pages 37 to 66 of the Supporting Testimony.

46 As indicated by SoCalGas and SDG&E in their June 24, 2011 update to their April 15, 2011 Report, the first round of bi-monthly inspections had been completed.

SDG&E to take immediate action. Work continues to review pipelines to determine where other pressure reductions are possible while meeting capacity requirements and service reliability. Additionally, as discussed, for those pipeline segments that would, based on SoCalGas and SDG&E's prioritization process, be replaced in Phase 1(A) but can't be completed by the end of Phase 1(A), SoCalGas and SDG&E propose to run the TFI tool during Phase 1(A) to perform a more complete evaluation of the pipe integrity.

VII. SOCALGAS AND SDG&E PLAN TO EXECUTE PSEP AS EXPEDITIOUSLY AS POSSIBLE WHILE MAINTAINING ITS HIGH STANDARD OF QUALITY CONTROL AND SERVICE TO CUSTOMERS, BUT TO DO SO WILL NOT BE WITHOUT SIGNIFICANT CHALLENGES[47]

Successfully implementing Pipeline Safety Enhancement Plan in an expeditious manner will be challenging. SoCalGas and SDG&E have set an aggressive schedule for completing Phase 1 of PSEP. Below SoCalGas and SDG&E discuss how they intend to execute on PSEP while maintaining their high standards for quality control and service to customers. They also describe some of the challenges they anticipate encountering along the way and how a strong partnership with the Commission is essential to successfully overcoming these challenges.

A. Project Planning and Scheduling.

Due to the size, scale, and complexity of the Pipeline Safety Enhancement Plan, SoCalGas and SDG&E plan to execute the plan under the framework of a Project Management Organization (the PSEP PMO), which will be a separate organization comprised of a group of staff dedicated solely to the execution of the Plan. The primary objective of the PSEP PMO will be to assure compliance with Commission requirements and to develop and implement

47 With the exception of Sub-Section H, the discussion in this section comes from the testimony of Mr. Rivera at pages 95 to 102 of the Supporting Testimony. The discussion in Sub-Section H comes from the testimony of Mr. Morrow at pages 23 to 28 of the Supporting Testimony.

procedures to ensure that the Plan is executed safely and to the required level of quality that SoCalGas and SDG&E expect in engineering, supply of materials, and in construction.

The planning and scheduling of these projects, which consist of a mixture of small, intermediate, and large scale projects, will take varying lengths of time to complete. Each individual project can be impacted significantly by outside issues such as permits, material availability and public resistance. And each project will be subject to specific individual circumstances, stake holder concerns and logistical constraints no matter the "size," making even an apparent "small and simple" project, considerably more complex to execute.

1. The "Small" Scale Project

In their PSEP, SoCalGas and SDG&E define small scale projects to generally include those projects involving smaller diameter pipes of short distance (less than 1,000 linear feet) with limited or no customer/stakeholder impacts, a valve retrofit, or a short section of pipe to be pressure tested. Under a "best case" scenario, the project management schedule for these projects is anticipated to be three to six months. During this time, SoCalGas and SDG&E will identify the materials and permits required to complete the project as well as any logistical concerns, such as the water fill source, storage tank needs and de-water locations. SoCalGas and SDG&E will also submit any required permit drawing package to the appropriate agency for review and approvals. During the permitting approval process, they will procure any necessary materials and address any specific traffic control plans. Once SoCalGas and SDG&E have received the necessary permits and work conditions, they will submit a "Request for Proposal" to pre-qualified contractors for bid. After the bids have been reviewed and a contractor selected, SoCalGas and SDG&E anticipate a one to four week construction schedule.

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2. The "Intermediate" Scale Project

SoCalGas and SDG&E define intermediate scale projects to include those pressure test or replacement projects that involve larger diameter pipe, ranging in length from 1,000 linear feet to five linear miles that have more significant customer or stakeholder impacts. For these projects, SoCalGas and SDG&E anticipate a 6 to 36 month project life cycle. The detailed planning, design and execution will follow the same general path as that of small projects with additional time needed for coordination activities. These projects will also require longer lead times to develop detailed design, routing and project logistics. There will also be a longer lead time to procure materials. SoCalGas and SDG&E also anticipate that these intermediate projects will require more time to coordinate and resolve permitting issues, stakeholder concerns, and customer and gas delivery system impacts. Construction times for intermediate projects are anticipated to range between one and six months in length.

3. The "Large" Scale Project

In general, large scale projects will be the most complex, involving larger diameter pipe, ranging in length from 5 to 50 linear miles. As would be expected, these projects will have the longest project management life cycle, which SoCalGas and SDG&E anticipate will run 3 to 5 or more years and may be completed in multiple "phases" or "segments." The size of these projects will also increase the expected risks associated with permit delays, stakeholder opposition and community impacts.

B. Material and Construction Quality Assurance and Control.

SoCalGas and SDG&E currently employ a rigorous material specification and quality control process that they intend to use for PSEP activities. Their material specifications and quality control process requires that all critical materials on a project meet Department of Transportation (DOT), Commission and ANSI requirements and guidelines. And they require that SoCalGas and SDG&E only buy critical material components from approved manufacturers, suppliers and vendors, who are pre-screened and approved through our quality assurance assessment process that includes physical on-site, raw material selection, manufacturing process and quality control evaluation. Once a vendor has been approved, SoCalGas and SDG&E give that vendor the necessary requirements and guidelines and require that these manufacturers, suppliers and vendors certify that the material components they supply meet SoCalGas and SDG&E's strict material specifications.

SoCalGas and SDG&E have an aggressive material and component inspection process. Critical materials and components are physically inspected at critical points during the manufacture and delivery process to visually verify that they strictly meet specifications. Such inspections will be a part of the Pipeline Safety Enhancement Plan.

Finally, SoCalGas and SDG& plan to use their existing policies and procedures to address and maintain the quality in the construction and fitness for services of the activities and facilities proposed in their Pipeline Safety Enhancement Plan. These projects will receive full time construction inspection and oversight to ensure these facility enhancements are constructed and tested in compliance with our rigorous standards, policies and procedures and meet regulatory requirements. Existing and proven construction management techniques will be used, along with on-site Company representatives that have the demonstrated the ability to effectively and safely provide construction oversight.

C. Contractor Approval and Selection.

SoCalGas and SDG&E intend to contract some of the pipeline project work that stems from their Pipeline Safety Enhancement Plan. Contractors for this work will be selected according to existing company policies and procedures. These policies and procedures require that only pre-approved contractors who have demonstrated the ability to successfully complete like and kind projects can be used. SoCalGas and SDG&E's policies also require a complete review of a contractor's ability, expertise, equipment, facilities and financial backing to complete and appropriately warranty the types of construction projects the contractor has been approved to perform. SoCalGas and SDG&E also have an ongoing contractor performance review process to document, address and correct any contractor performance deficiencies experienced over time.

D. <u>Company Labor Qualifications</u>.

SoCalGas and SDG&E employees will be actively engaged and integral to the Pipeline Safety Enhancement Plan activities and facility improvements. The employees SoCalGas and SDG&E will use on PSEP activities will be subject to SoCalGas and SDG&E's extensive policies, training requirements and operator qualifications so that Pipeline Safety Enhancement Plan work is completed with the high level of skill, quality and compliance that is expected on all projects.

E. <u>Supplier Diversity</u>.

SoCalGas and SDG&E have an ongoing, successful and active commitment to engage, cultivate and ensure supplier diversity throughout our procurement activities. Accordingly, they intend to follow existing and proven company guidelines and goals for supplier diversity on the Pipeline Safety Enhancement Plan activities.

F. <u>Managing Customer Impacts.</u>

It is SoCalGas and SDG&E's practice to minimize where possible the impact to customers when a line is taken out of service, and they intend to continue that practice for projects that stem from their Pipeline Safety Enhancement Plan. Under their current practice, SoCalGas and SDG&E's Gas Transmission pipeline project managers work internally with the

Public Affairs Department to apprise them of potential customer impact issues. Public Affairs personnel then act as a liaison with government agencies that need to be informed. SoCalGas and SDG&E also work with customers to manage customer impacts, and they undertake a number of outreach activities, including meeting with city officials and holding "Town-Hall" type meetings to inform the public of pending projects.

SoCalGas and SDG&E also make every attempt to work around customer schedules as much as possible. When appropriate, they coordinate with the CAISO in advance for planned outages and make every attempt to schedule the outage during the low demand shoulder months. For large customers, it is SoCalGas and SDG&E's practice to keep in regular communication up to, during and after a shutdown, and try to provide alternate feeds where they can if an outage creates too significant a customer impact.

It is SoCalGas and SDG&E's expectation that they will provide at least 30 days' notice to firm noncore customers, and any affected core customers of any scheduled service outages necessary to implement a project stemming from the Pipeline Safety Enhancement Plan. And notice for suspension of service to interruptible noncore customers will be provided at least 96 hours in advance of any scheduled service outages to accommodate electric generators' CAISO noticing requirements.

G. <u>Customer and Stakeholder Outreach.</u>

SoCalGas and SDG&E anticipate that their customers and the community in general will see more work being performed on pipelines as a result of the Pipeline Safety Enhancement Plan. This construction activity may raise questions and concerns about pipeline safety. Accordingly, SoCalGas and SDG&E include as part of their Plan a comprehensive customer and public outreach effort. This effort will include basic information on pipeline safety, the importance and benefits of the work being done, how the project will impact nearby residents and businesses, and how the cost of the program is distributed across customers.

To do this, SoCalGas and SDG&E plan to use a blend of communications channels to reach as many customer groups and stakeholders as possible. The channels that they intend to use include in-person customer meetings, news releases, community print ads, special events, e-mails and e-newsletters, social, interactive and mobile media, direct mail, bill messages and newsletters, as well as a dedicated microsite on both www.socalgas.com and www.sdge.com.

Specific outreach efforts are planned for areas where there will be significant work. The plans for those efforts include local and community meetings, letters mailed to residents and businesses prior to the start of a project, door hangers, email blasts, and news releases directing the customer to view SoCalGas and SDG&E's dedicated microsite where they plan to have interactive maps indicating project locations and timing. Messages will be delivered in English and Spanish, and other in-language messages will be developed based on the geographic area of the projects.

H. Execution Plan Challenges and Risks.

SoCalGas and SDG&E anticipate that they will face a number of challenges as they implement the Pipeline Safety Enhancement Plan, the most significant of which will be permitting challenges. A strong partnership with the Commission is essential to successfully overcoming these challenges. Accordingly, SoCalGas and SDG&E include as part of PSEP some suggestions for actions that the Commission can take to alleviate some of the anticipated challenges.

One thing the Commission can do is help communicate to all agencies responsible for issuing environmental permits the importance of Implementation Plan projects because these projects will enhance the safety and reliability of an essential public service. This simple request to all applicable agencies should provide the necessary direction and guidance to resource constrained agencies that must balance the demands of various competing project applicants. The Commission can also request that applicable permitting agencies set aside personnel and consultant resources that can be funded by the natural gas utilities to focus on these infrastructure projects. And the Commission can request that environmental agencies develop, or expeditiously approve, pending applications for programmatic permits that will ensure consistent permit conditions and mitigation requirements for these projects to create certainty for planning purposes.

1. Environmental Permitting Issues

As stated, one of the most significant challenges SoCalGas and SDG&E will face in executing their Pipeline Safety Enhancement Plan under their proposed timeline involves environmental permitting issues. While the Pipeline Safety Enhancement Plan itself and many of the projects that will stem from the plan are not subject to the California Environmental Quality Act (CEQA),[48] SoCalGas and SDG&E recognize that some activities described in the

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48 CEQA requires agencies approving activities that constitute projects to consider the environmental implications of their actions prior to approving such projects. The first step in determining whether CEQA applies to an activity is to determine whether that activity is a "project." *See, e.g., Muzzy Ranch Co. v. Solano County Airport Land Use Commission*, 41 Cal. 4th 372, 380 (2007) (an activity that is not a "project" as defined in Public Resources Code (see § 21065) and the CEQA Guidelines (See, 14 Cal. Code Regs. § 15378) is not subject to CEQA"). If an activity is not a project, as defined under CEQA, then no further environmental review is necessary. The Commission's approval of the PSEP itself is not an activity that will cause a direct physical change in the environment. (CEQA guidelines § 15352(a) defines "approval" as the decision by a public agency "which commits the agency to a definite course of action in regard to a project intended to be carried out by any person"). In effect, these potential projects are in an embryonic stage of planning. As a consequence, there are no "reasonably foreseeable" impacts yet associated with the activities contemplated under the PSEP. *See, e.g., Friends of the Sierra Railroad v. Tuolumne Park and Recreation Dist.*, 147 Cal.App.4th 643, 663 (2007)(Some activities are not projects because no identifiable environmental change is reasonably foreseeable, even though it cannot be said with certainty that no significant environmental change is possible.). Therefore, a detailed CEQA review of those activities under the PSEP would be premature and wholly speculative. *See, e.g., Id.*, at 654-655 (CEQA review is premature if the agency action in question occurs too early in the planning process to allow meaningful analysis of potential impacts). Even if the PSEP could meet the definition of a "project" under CEQA, Commission consideration and approval of the PSEP as part of the ratemaking process would nonetheless be exempt from CEQA review. It is long established that the

Pipeline Safety Enhancement Plan may eventually ripen into projects as defined by CEQA and thereafter require environmental review. To this end, each utility will submit those projects to the appropriate agencies for review once project scopes and descriptions have been developed.

Unless Federal, State and local jurisdictions make each project's particular environmental permitting a matter of utmost priority, then environmental permitting has the potential to significantly delay and incrementally increase the cost of implementing many of the larger projects contemplated under the plan. For example, a pipeline replacement project within the coastal zone that has the potential to impact sensitive coastal resources would likely trigger multiple Federal, State, and local permits/approvals. This complex regulatory environment requires project proponents to overcome significant agency coordination challenges and navigate a process that may include conflicting policies and procedures. Within individual agencies there are often multiple departments with conflicting regulatory objectives.

Projects crossing lands under Federal jurisdiction provide another example of environmental and land use permitting challenges that may affect the timely execution of the Implementation Plan. Projects in these geographical areas must comply with a host of additional laws and regulations including the National Environmental Policy Act, Federal Mineral Leasing Act and the Federal Land Policy and Management Act. These laws and regulations are administered by an additional suite of regulatory agencies, including the Bureau of Land Management, National Park Service and USDA Forest Service.

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act of ratemaking by the Commission is exempt from CEQA review. The "establishment, modification, structuring, restructuring, or approval of rates, tolls, fares, or other charges by public agencies" including "obtaining funds for capital projects necessary to maintain service within existing service areas" is exempt from CEQA. Cal. Pub. Resources Code §21080 (b)(8); *Accord* 14 Ca. Code Regs. § 15273. In their proposed PSEP, SoCalGas and SDG&E seek Commission approval for rates and regulatory accounting treatment for all of the activities laid out herein. These Commission activities fall squarely within this CEQA exemption. As a result, the Commission's activities contemplated herein are likewise exempt from CEQA.

2. General Construction Permitting Challenges

Because SoCalGas and SDG&E operate transmission and distribution pipelines in 242 cities and 13 counties, execution of the Implementation Plan will involve or lead to a substantial amount of construction activity within numerous cities and counties that will have permitting authority over various aspects of the projects that will stem from the Plan. Applying for and obtaining these local ministerial permits can often take considerable time and effort. The timing associated with the review and approval process form these permits is beyond the control of the utilities, and is likely to significantly impact the planning and scheduling projects. Continuing budget constraints and resource issues are making the review and approval of these permits in a timely manner even more difficult.

Permit conditions and requirements are also likely to have significant impacts on construction costs and project scheduling. Generally, the more restrictive the permit conditions, the more time consuming and costly a project is likely to be. Examples of common local jurisdiction construction permit requirements that may significantly impact construction costs and project scheduling include paving requirements that go beyond the actual trench limits and the imposition of restrictive work hour limitations that significantly limit construction progress each day. In addition, there is the potential for significant local public resistance to the issuance of permit approvals needed to complete projects.

Local permitting agencies often attempt to regulate the utilities beyond the ministerial permitting level, and in turn, subject SoCalGas and SDG&E to various discretionary approval processes as part of various construction activities. To minimize the potential for such delays and challenges, SoCalGas and SDG&E request that the Commission expressly state in its decision approving SoCalGas and SDG&E's Pipeline Safety Enhancement Plant that execution of the approved Implementation Plan is a matter of statewide concern, and as such, the

Commission has preemptory authority over conflicting local zoning regulations, ordinances, codes or requirements to the extent that such local authority would deny, or significantly delay execution of the Implementation Plan, while affirming that SoCalGas and SDG&E are required to obtain all necessary non-preempted permits prior to commencing construction.

3. Availability of Materials, Contractors and Additional Workers

The availability of contractors and materials may also delay the completion of Implementation Plan projects and could present additional challenges. This is especially true where, as here, multiple utilities will be striving to complete similar work simultaneously, and on an aggressive schedule. Critical material components, such as pipe, valves and fittings, may be in short supply due to increased demand. SoCalGas and SDG&E also anticipate that they will need to hire over 200 additional full-time employees during a relatively short time period. This may prove difficult, especially since other natural gas operators may be seeking to hire additional employees with similar qualifications at the same time. Shortages in availability of contractors, materials and workers could not only delay completion of the plan, but also increase costs beyond those initially contemplated.

VIII. THE PIPELINE SAFETY ENHANCEMENT PLAN'S ESTIMATED CAPITAL AND OPERATIONS AND MAINTENANCE (O&M) COSTS ARE INCREMENTAL TO SOCALGAS AND SDG&E'S 2012 GENERAL RATE CASE REQUESTS[49]

SoCalGas and SDG&E seek approval of their Pipeline Safety Enhancement Plan or "Proposed Case," which as outlined above, includes elements not required under the Commission's June 9 Decision (what is referred to in this chapter as the Base Case). For comparison purposes, SoCalGas and SDG&E set out the estimated costs for both cases. The

49 The discussion in this section comes from the testimony of Mr. Rivera at pages 103 to 120 of the Supporting Testimony.

Base Case does not include any cost estimates associated with (1) the replacement of pipeline segments to mitigate construction and manufacturing threats, (2) the proposed technology enhancements, or (3) the development and design of a comprehensive Enterprise Asset Management system. SoCalGas and SDG&E have based their cost estimates on an aggressive schedule, and as discussed in the preceding section could be impacted by a number of execution challenges.

The cost estimates presented are direct costs, that is, unloaded and without escalation and are incremental to SoCalGas and SDG&E's 2012 General Rate Case requests. They are based on full approval of the Phase 1 scope to begin in the first quarter of 2012. They are also are based on minimal engineering, operational planning and project execution planning and are "all-inclusive," that is they include construction labor and materials, third-party engineering, procurement, and construction management and consultant costs, and other internal company costs. As discussed above, the Phase 1(A) schedule is aggressive, and as result, subject to potential execution challenges that could impact costs, and a delay in a decision on SoCalGas and SDG&E's Pipeline Safety Enhancement Plan could have an impact on cost as well.

SoCalGas and SDG&E's cost estimates are broken down according to their phasing approach, and as discussed in the next chapter, SoCalGas and SDG&E are only requesting approval of the revenue requirements resulting from Phase 1(A) Capital and O&M cost estimates.

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The Capital cost estimates for SoCalGas' Proposed Case is $1.2 billion for Phase 1(A). The O&M cost estimate is $256 million for Phase 1(A). An overall cost estimate summary of the proposed cost for Phase 1 for SoCalGas is shown in Table C[50] below.

Table C
SoCalGas Estimated Phase 1 Pipeline Safety Enhancement Plan
Proposed Case Costs
(In Millions of Dollars)

	2011	Phase 1A (2012-2015)		Phase 1B (2016-2021)	
	O&M	Capital	O&M	Capital	O&M
Pressure Testing	-	-	183	-	-
Pipe Replacemen t	-	818	-	-	-
In-Line Inspection	-	-	58	-	-
Interim Safety Enhancements	6	-	5	-	-
Remote Control & Automatic Shutoff Valves	-	121	2	180	12
Implementation Costs	-	-	< 1	-	-
Mitigation of Pre-1946 Construction Methods	-	200	-	884	-
Technology Enhancements	-	45	2	12	5
EnterpriseAsset Management System	-	-	6	-	-
Total	$6	$1,184	$256	$1,076	$17

50 Table C corresponds to Table IX-1 in the Supporting Testimony.

For SDG&E, the Capital costs estimates for the Proposed Case are $229 million for Phase 1(A). The O&M cost estimates for SDG&E are $7 million for Phase 1(A). An overall cost estimate summary of the proposed cost for Phase 1 for SoCalGas is shown in Table D[51] below.

Table D
SDG&E Estimated Phase 1 Pipeline Safety Enhancement Plan
Proposed Case Costs
(In Millions of Dollars)

	2011	Phase 1A (2012-2015)		Phase 1B (2016-2021)	
	O&M	Capital	O&M	Capital	O&M
Pressure Testing	-	-	< 1	-	10
Pipe Replacement	-	197	-	318	-
In-Line Inspection	-	-	4	-	-
Interim Safety Enhancements	1	-	< 1	-	-
Remote Control & Automatic Shutoff Valves	-	26	1	35	2
Implementation Costs	-	-	< 1	-	-
Mitigation of Pre-1946 Construction Methods	-	-	-	-	-
Technology Enhancements	-	6	< 1	2	1
EnterpriseAsset Management System	-	-	< 1	-	-
Total	$1	$229	$7	$354	$13

51 Table D corresponds to Table IX-2 in the Supporting Testimony. Numbers may not add due to rounding.

The Capital cost estimates for the Base Case Phase I(A) are $939 million for SoCalGas and $223 million for SDG&E. The O&M cost estimates for the Base Case Phase I(A) are $247 million for SoCalGas and $6 million for SDG&E. The total estimated investment required to complete Phase I for the Base Case is summarized in Table E[52] below for SoCalGas and Table F[53] for SDG&E.

Table E
SoCalGas Estimated Phase 1 Pipeline Safety Enhancement Plan
Base Case Costs
(In Millions of Dollars)

	2011	Phase 1A (2012-2015)		Phase 1B (2016-2021)	
	O&M	Capital	O&M	Capital	O&M
Pressure Testing	-	-	183	-	-
Pipe Replacements	-	818	-	-	-
In-Line Inspections	-	-	58	-	-
Interim Safety Enhancements	6	-	5	-	-
Remote Control & Automatic Shutoff Valves	-	121	2	180	12
Implementation Costs	-	-	< 1	-	-
Total	$6	$939	$247	$180	$12

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52 Table E corresponds to Table IX-3 in the Supporting Testimony. Numbers may not add due to rounding.

53 Table F corresponds to Table IX-4 in the Supporting Testimony.

Table F
SDG&E Estimated Phase 1 Pipeline Safety Enhancement Plan
Base Case Costs
(In Millions of Dollars)

	2011	Phase 1A (2012-2015)		Phase 1B (2016-2021)	
	O&M	Capital	O&M	Capital	O&M
Pressure Testing	-	-	< 1	-	10
Pipe Replacements	-	197	-	318	-
In-Line Inspections	-	-	4	-	-
Interim Safety Enhancements	1	-	<1	-	-
Remote Control & Automatic Shutoff Valves	-	26	1	35	2
Implementation Costs	-	-	< 1	-	-
Total	$1	$223	$6	$353	$12

Each cost element of SoCalGas and SDG&E's proposed Pipeline Safety Enhancement Plan are discussed further in Sections A through I below.

A. <u>Pressure Testing</u>.

Both the Proposed Case and the Base Case include the same estimated costs for SoCalGas and SDG&E to pressure test 206 miles of transmission pipeline segments located in Populated Areas. These estimates include the costs for pressure testing the 206 miles of pipe, as well as mileage connected to those segments that similarly lack sufficient documentation of pressure testing, but are located in Non-populated Areas (Accelerated Miles). These Accelerated Miles, which would otherwise be addressed in Phase 2, were included within the scope of Phase 1 to maximize the cost effectiveness and minimize the impacts to customers. Also included is a small number of other segments, as necessary, to facilitate continuity of the testing. In total, 407 miles of transmission pipeline will be pressure tested in Phase 1 at a cost of $194 million.

Table G below summarize the scope of pressure testing work to be completed in Phase 1.[54] Table H[55] summarizes the O&M costs associated with this pressure testing work.

Table G
Phase 1 Pressure Test Mileage

	Criteria Miles	Accelerated Miles	Total
SoCalGas	176	185	361
SDG&E	30	16	46
Total	206	201	407

Table H
Phase 1 Pressure Test O&M Cost Estimates
(In Millions of Dollars)

	Phase 1A				Phase 1B						
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Total
SoCalGas	37	49	49	49	-	-	-	-	-	-	$183
SDG&E	0	0	0	0	-	-	-	10	-	-	$11
Total	37	49	49	49	-	-	-	10	-	-	$194

SoCalGas and SDG&E developed their pressure testing cost estimates based on proposed pressure test mileage and certain pipeline system data, such as pipeline diameter, and estimating factors including segment size, pipeline profile, water supply, equipment, personnel, materials, etc.

B. Pipeline Replacement.

Both the Base Case and the Proposed Case require SoCalGas and SDG&E to replace approximately 156 miles of pipeline segments located in Populated Areas, Accelerated Miles, and a small number of other segments, as necessary, to facilitate continuity in construction. In total, 348 miles of transmission pipeline will be replaced in Phase 1 at a cost of $1,333 million. Table I[56] below summarizes the scope of pipeline replacement construction to be completed in

54 Table G corresponds to Table IX-5 in the Supporting Testimony.

55 Table H corresponds to Table IX-6 in the Supporting Testimony. Numbers may not add due to rounding.

56 Table I corresponds to Table IX-7 in the Supporting Testimony. Numbers may not add due to rounding.

Phase 1. Table J[57]summaries the Capital costs associated with the execution of this pipeline replacement work.

Table I
Phase 1 Transmission Pipeline New Construction Summary

	Criteria Miles	Accelerated Miles	Total Cost
SoCalGas	128	118	$818 million
SDG&E	28	74	$515 million
Total	156	192	$1,333 million

Table J
Phase 1 Transmission Pipeline New Construction Capital Cost Estimates
(In Millions of Dollars)

	Phase 1A				Phase 1B						
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Total
SoCalGas	90	243	243	243	-	-	-	-	-	-	$818
SDG&E	23	58	58	58	106	106	106	-	-	-	$515
Total	113	301	301	301	106	106	106	-	-	-	$1,333

SoCalGas and SDG&E developed their replacement cost estimates based on proposed replacement mileage and certain pipeline system data, such as operating pressure and diameter. GIS Maps of each pipeline were studied to identify the location and type of construction applicable for each relocation area.

C. <u>In-Line Inspection</u>.

As discussed above, SoCalGas and SDG&E propose to run the TFI tool on piggable lines in addition to pressure testing the lines. The TFI tool will allow SoCalGas and SDG&E to proactively mitigate pipeline anomalies that could lead to a potential pipeline failure at higher pressure test levels and may also significantly reduce the costs of Phase 2. The incremental cost to run a TFI tool through the pipeline is estimated at $200,000 per run. In addition, costs for two validation digs per run (at $50,000/dig) and one excavation and repair ($75,000) per mile were

57 Table J corresponds to Table IX-8 in the Supporting Testimony. Numbers may not add due to rounding.

added to the total cost. These values are based on historical costs that SoCalGas and SDG&E have observed on prior company projects. Table K[58] summarizes these Phase 1 in-line inspection costs.

Table K
Phase 1 Incremental In-Line Inspection O&M Cost Estimates

Cost Element	Unit Cost (in thousands)	Quantity	O&M Costs
TFI Runs	$200/run	27	$5 million
Validation Digs	$50/dig	54	$3 million
Repairs	$75/repair	721	$54 million
		Total	$62 million

D. <u>Remote Control & Automatic Shutoff Valves</u>.

This Section covers estimated Phase 1 costs to implement the proposed Valve Enhancement Plan. In total, SoCalGas and SDG&E propose to enhance 561 valve sites pursuant to the Valve Enhancement Plan: (1) 367 valves in sizes ranging from 12 to 36 inches in diameter will be modified, replaced, or newly added; (2) 94 valves will be equipped with enhanced electronic monitoring and controls; and (3) monitoring capabilities at the 100 ASV locations on the SoCalGas pipeline system that currently do not have remote communications installed to allow operators to determine if the valves are opened or closed.

58 Table K corresponds to Table IX-9 in the Supporting Testimony.

In addition, SoCalGas and SDG&E, as discussed, propose to install companion equipment to allow their operators to better view system operations and better manage valve closures, ruptures and other extraordinary events. Table L[59] below provides a summary of the scope of work proposed under the Valve Enhancement Plan.

Table L
Summary of Proposed Phase 1 Control Valve Work

Installation Type	SoCalGas	SDG&E	Total
Upgrade Existing Manual Control Valves to ASV/RCV	273	74	347
Upgrade Existing ASV with RCV Functionality	94	0	94
Upgrade Existing ASV with Communications only	100	0	100
Add New ASVs/RCVs to Pipeline System	20	0	20
Total Valve Sites Addressed	487	74	561

A summary of the Capital and O&M expenditures required to implement Phase 1 of the Valve Enhancement Plan is presented in Table M[60] below.

Table M
Phase 1 Valve Enhancement Plan Cost Summary
(In Thousands of Dollars)

SoCalGas	Phase 1A				Phase 1B						Total
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	
Capital	$ 26,254	$ 28,474	$ 32,719	$ 33,321	$ 32,323	$ 31,653	$ 29,353	$ 28,661	$ 28,883	$ 29,327	$ 300,967
O&M	$ 64	$ 192	$ 730	$ 945	$ 1,269	$ 1,958	$ 2,054	$ 2,060	$ 2,152	$ 2,247	$ 13,671
Total	$ 26,318	$ 28,666	$ 33,449	$ 34,266	$ 33,593	$ 33,611	$ 31,407	$ 30,721	$ 31,035	$ 31,574	$ 314,639
SDG&E	Phase 1A				Phase 1B						Total
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	
Capital	$ 5,342	$ 6,367	$ 7,120	$ 7,120	$ 5,821	$ 5,821	$ 5,821	$ 5,702	$ 5,702	$ 5,702	$ 60,519
O&M	$ 17	$ 102	$ 253	$ 267	$ 262	$ 277	$ 293	$ 308	$ 324	$ 339	$ 2,443
Total	$ 5,360	$ 6,469	$ 7,373	$ 7,387	$ 6,082	$ 6,098	$ 6,114	$ 6,011	$ 6,026	$ 6,041	$ 62,962

59 Table L corresponds to Table IX-11 in the Supporting Testimony.

60 Table M corresponds to Table IX-12 in the Supporting Testimony. Numbers may not add due to rounding.

SoCalGas and SDG&E developed their estimated Capital and O&M costs for proposed valve installations and upgrades from a review of recorded costs (where available and applicable) for historical valve and control system installation and replacements of similar size and complexity and estimates from contractor(s) providing consulting estimates for planned valve work. Where historical costs were considered, a reduction in costs was factored in to account for expected economies-of-scale on a managed program of this size, as opposed to individual valve installations. The O&M costs include labor and non-labor incidentals for technicians to perform scheduled and unscheduled maintenance on installed control valve assets. Estimated Capital and O&M costs for supporting valve system enhancements were developed from a review of recorded costs (where available and applicable) for historical system installation and replacements of similar size and complexity and estimates from contractor(s) and equipment vendors.

E. **Interim Safety Enhancement Measures.**

SoCalGas and SDG&E – as part of its records research efforts in connection with the NTSB's safety recommendations – implemented temporary remediation measure, such as bi-monthly leak surveys and pipeline patrols. As previously discussed, SoCalGas and SDG&E propose to continue these interim measures as part of their Pipeline Safety Enhancement Plan.

Incremental costs that have been and will be incurred as a result of these increased efforts include employee overtime pay to implement the additional leak surveys and pipeline patrols, costs for contractors to assist in the data mining and document scanning efforts and incremental costs associated with the installation of pressure control equipment to facilitate pressure lowering of some segments. These costs are shown in Table N[61] below.

Table N
Phase 1 Safety Interim Enhancement Measures
O& M Estimated Costs
(In Thousands of Dollars)

	2011	2012	2013	2014	2015
SoCalGas	5,900	4,200	200	150	100
SDG&E	900	500	8	8	8

F. Cost Estimates to Replace Non-Piggable Pipelines That Were Constructed Before 1946.

SoCalGas and SDG&E propose to replace all pre-1946 pipeline segments that are not piggable. To the extent these pipeline segments have not already been identified for replacement under the Base Case, their costs have been included in Table O[62] below. Costs for replacement of wrinkle bends located on pipelines are also included.

Table O
Phase 1 Pipeline Replacement Estimated Costs
To Mitigate Pre-1946 Construction/Fabrication Methods
(In Millions of Dollars)

SoCalGas	Phase 1A				Phase 1B					
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Capital Cost	29	57	57	57	167	167	167	128	128	128
Miles	-	-	-	-	38	38	38	27	27	27
Wrinkle Bends (#)	580	1140	1140	1140	200	200	200	200	200	200

Replacement costs for pre-1946 pipeline segments were estimated using a cost matrix. This matrix combines pipeline diameter with replacement length to arrive at a replacement cost per foot. The cost estimates will require refinement during Phase 1(A) and prior to execution in

61 Table N corresponds to Table IX-10 in the Supporting Testimony.

62 Table O corresponds to Table IX-14 in the Supporting Testimony.

Phase 1(B). Wrinkle bend replacement costs are consistent with historically-observed pipeline repair costs.

G. Technology Enhancements.

As discussed, SoCalGas and SDG&E propose to install fiber optic cabling, methane detection monitors and a computer-based remote monitoring system to collect and manage information and alarms from these sensor technologies. The costs presented in this section are for the Capital and O&M requirements to install, operate and manage these assets. Table P[63] provides a summary of the Phase 1 Capital and O&M cost estimates for the installation and maintenance of these technologic enhancements.

Table P
Phase 1 Technology Enhancement Cost Estimate Summary
(In Thousands of Dollars)

	SoCalGas		SDG&E		Total	
	Capital	O&M	Capital	O&M	Capital	O&M
Fiber Optic Monitors	23,526	1,194	3,229	164	26,755	1,358
Methane Detectors	8,462	791	1,161	109	9,624	900
Monitoring System	24,826	5,342	3,407	733	28,233	6,075
Totals	56,815	7,327	7,797	1,006	64,612	8,333

Estimated Capital costs for Fiber Optic Right-of-Way Monitoring were developed based on (1) unit cost information provided by fiber system vendors for fiber optic cabling and field instrumentation, (2) historic utility costs for communication systems of similar size, and (3) complexity and construction cost based on vendor installation requirements. The O&M cost estimates include labor and non-labor incidentals for technicians to perform maintenance on installed field monitoring equipment and communications equipment.

63 Table P corresponds to Table IX-15 in the Supporting Testimony. Numbers may not add due to rounding.

Estimated Capital costs for Methane Detection Monitors were similarly developed using unit cost information provided by methane detection system vendors, historical utility costs for communication systems of similar size and complexity and construction cost based on vendor installation requirements and experience. The O&M cost estimates include labor and non-labor incidentals for technicians to perform annual inspections and calibration of equipment and maintenance on detector and communications equipment.

H. **Enterprise Asset Management System.**

SoCalGas and SDG&E estimate approximately $6.5 million in O&M costs in 2012 to design a comprehensive Enterprise Asset Management System. High-level Enterprise Asset Management System requirements and the cost and scale of similar projects were considered when developing this cost estimate. Costs are allocated to SoCalGas and SDG&E based on miles of transmission pipeline to be addressed in Phase 1, 93.7% and 6.3% respectively.

I. **Projected Cost Savings if Direct Examination if the Commission Approves Non-Destructive Testing for Short Segments as an Alternative to Pressure Testing or Replacement.**

As discussed, SoCalGas and SDG&E propose as part of their Pipeline Safety Enhancement Plan to conduct non-destructive testing on pipeline segments 1,000 feet or less instead of pressure testing or replacing them. SoCalGas and SDG&E estimate that the integrity of approximately 1.64 miles of pipelines for SoCalGas and 0.05 miles for SDG&E covered in Phase 1 could be validated through Direct Examination more economically and with less system and customer impacts as compared to pressure testing or replacement. SoCalGas and SDG&E estimate that using direct examination methods in lieu of replacement or pressure testing could reduce the Pipeline Safety Enhancement Plan costs by approximately $5-15 million. Items covered in these estimates include the cost of excavation, coating removal, non-destructive evaluation of pipe wall, girth welds, and long seams, re-coating, and backfill/site restoration.

Because this alternative has not yet been approved, these cost reductions are not reflected in either the Base Case or Proposed Case cost estimates shown above. If this method is approved, SoCalGas and SDG&E would study additional areas to apply this method with the potential for additional savings.

J. Phase 2 Cost Estimates.

SoCalGas and SDG&E propose that Phase 2 of their Pipeline Safety Enhancement Plan run in parallel with and extend past the completion of Phase 1(B) and address mileage not addressed in Phase 1. An assessment of these lines is underway and will not be completed until July 2012. Based on a preliminary review, SoCalGas and SDG&E anticipate that some of these pipeline segments will require pressure testing or replacement.

The cost to pressure test or replace pipelines in Phase 2 will vary based on pipeline size, location, and operational requirements. If the Phase 2 costs are similar to Phase 1, SoCalGas and SDG&E would expect the following average testing and replacement costs: (1) $3.5 to $4 million per mile (Capital) for new construction or pipe replacement; (2) $500,000 t0 $600,000 per mile (O&M) to pressure test; and (3) $86,000 per mile (O&M) to in-line inspect using the TFI tool.

SoCalGas and SDG&E are unable to provide Phase 2 cost estimates to any level of certainty because they have not yet finished their records review on Phase 2 pipeline segments. If one were to assume that 40% of Phase 2 transmission pipelines will be addressed using either pressure testing or replacement and apply the same pressure testing versus replacement ratio as Phase 1 pipeline segments, the total estimated costs would be in the range of $1.5 to $3 billion or more for SoCalGas and about $100 million for SDG&E. These speculative cost estimates – which are provide not only before the completion of the records review but also before the

Commission has clarified the scope of required testing[64] and replacement in Phase 2 – are provided for illustrative purposes only.

These Phase 2 cost estimates are also based on the assumption that approximately 200 miles of pipelines installed before 1946 that are not piggable will be replaced in Phase 1(B). If that is not the case, these pipeline segments will need to be carried over to Phase 2, increasing the Phase 2 cost estimates by approximately $700 million.

Cost estimates for Phase 2 could potentially be reduced by hundreds of millions of dollars if (1) the Commission approves the use of the TFI tool in parallel with pressure testing in Phase 1, (2) the data gathered from these TFI tool runs demonstrates that it is an equivalent means to test the strength of a pipeline when compared to pressure testing; and (3) the Commission subsequently approves the use of the TFI tool as an appropriate alternative to pressure testing. In addition, adoption of SoCalGas and SDG&E's proposal to modify General Order 112-E to eliminate reliance on the Grandfather Clause rather than precluding California pipeline operators from utilizing 49 CFR §192.619(c) would further reduce the scope and costs of Phase 2.[65]

IX. RATEMAKING AND REGULATORY ACCOUNT TREATMENT FOR PSEP

SoCalGas and SDG&E request approval and recovery of the revenue requirements resulting from the Capital and O&M forecasts of the Pipeline Safety Enhancement Plan for the years 2011 through 2015, to coincide with our anticipated General Rate Case cycles.[66] The Phase 1(A) Proposed Case interim revenue requirements for the years 2011 through 2015 totals

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64 It is unclear in the June 9 decision whether natural gas pipeline operators are required to retest pipeline segments that were not previously tested to a standard that would satisfy current provisions of 49 CFR §192.619. *See* Footnote 70 at page 119 in the Supporting Testimony.

65 *See* starting at page 44 of Supporting Testimony.

66 References to the next rate case cycles with 2016 test years are based on a proposal in SoCalGas and SDG&E's 2012 General Rate Case applications that are pending before the Commission and are subject to Commission approval.

$594 million for SoCalGas and $62 million for SDG&E. Pipeline Safety Enhancement Plan funding requests for the remaining years will be reassessed and approved in SoCalGas and SDG&E's next General Rate Cases, subsequent rate case cycles, or in other applicable proceedings, as needed.

SoCalGas and SDG&E propose that the authorized Pipeline Safety Enhancement Plan revenue requirement and post-test year spending requests have a separate attrition mechanism and that the regulatory accounting treatment be handled as described below. This is similar to how generation revenue requirement is authorized for SDG&E in its GRC proceeding and recovered and tracked through SDG&E's Non-Fuel Generation Balancing Account through its commodity rates.

SoCalGas and SDG&E propose to recover PSEP costs through a separate line-item "PSEP Surcharge" to be reflected on customers' bills on a monthly basis. Even though approval of Pipeline Safety Enhancement Plan costs for 2016 and beyond will be rolled into other proceedings, SoCalGas and SDG&E propose to continue to recover those costs through the PSEP Surcharge. Should there be a delay in the 2016 General Rate Cases, they request approval to continue recovering the Pipeline Safety Enhancement Plan revenue requirements consistent with the proposal laid out for the time period not addressed due to a delay in the GRCs.

A. Revenue Requirement.[67]

SoCalGas and SDG&E derive the Pipeline Safety Enhancement Plan revenue requirements from the forecasted incremental Capital costs related to the Plan as well as estimates of incremental O&M costs. The incremental Capital and O&M costs for the Proposed Case and Base Case are adjusted to include applicable overhead rates, escalation rates, and other

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67 The discussion in this section comes from the testimony of Ms. Cheryl Shepherd at pages 121 to 128 in the Supporting Testimony.

costs to support the investment. Overhead rates are applied to each direct cost input, according to its classification as company labor, contract labor, purchased services and materials. Overhead rates are estimated using Year 2010 actual expenditures, but are only intended to be indicative for forecasting purposes; actual overhead rates each year will be used in the calculation of the actual revenue requirement. Only overheads that are considered incremental to each Pipeline Safety Enhancement Plan Case are included. For example, overheads associated with incremental labor and additional procurement activities are included.[68] Table R[69] shows the overhead rates that SoCalGas and SDG&E applied.

Table R
SoCalGas and SDG&E Pipeline Enhancement Plan
Overhead Loaders

Overhead Category	SoCalGas	SDG&E	LoadingBase
Payroll Taxes	7.73%	7.27%	Direct Labor
Vacation and Sick Time	17.44%	15.67%	Direct Labor
Benefits (non-balanced only)	19.74%	18.85%	Direct Labor
Workers' Compensation	5.74%	1.46%	Direct Labor
Public Liability/ Property Damage	2.80%	3.33%	Direct Labor
IncentiveCompensation Plan	18.17%	17.79%	Managementand Associate Direct Labor
Purchased Services and Materials	1.28%	0.40%	ContractLabor, Services and Purchased Materials
Administrative and General	4.27%	2.05%	Capital Direct Costs

68 Pension and Post-Retirement Benefits Other Than Pensions overhead costs are excluded, as these costs are subject to a separate balancing account mechanism and addressed in connection with the General Rate Cases for the respective utilities.

69 Table R corresponds to Table X-1 in the Supporting Testimony.

SoCalGas and SDG&E escalated the overhead-loaded constant-dollar values for the Proposed Case and Base Case incremental costs for inflation using the following escalation factors for Years 2012 through 2021.[70] These factors vary over the ten-year horizon. Table S[71] shows the range of annual escalation rates applied to each cost type.

Table S
SoCalGas and SDG&E Enhancement Plan Escalation Rates

Cost Category	EscalationFactor	Range of Annual % Change		
Capital (Labor & Non- Labor)	Gas Plant (Various)	-0.1%	-	3.9%
O&M (Labor)	Gas UtilityLaborO&M	2.3%	-	2.7%
O&M (Non-Labor)	Gas Utility O&M Non-Labor	2.3%	-	2.9%

The revenue requirement evaluation assumes all Capital costs, including Allowance For Funds Used During Construction, are recovered through depreciation[72] over the book-life of the assets and assumes that O&M is recovered in the period it is spent. In addition to the actual expenditure amounts, the revenue requirements include all other expenses required to support the investment, including authorized return on investment, income and property taxes, franchise fees, uncollectibles, and working cash associated with O&M. The SoCalGas revenue requirement calculation reflects the current authorized rate of return of 8.68% based on 10.82% return on equity. The SDG&E revenue requirement calculation reflects the current authorized rate of return of 8.40% based on 11.10% return on equity. Tables T[73] summarize the necessary revenue requirements for SoCalGas and SDG&E to implement the projects for the Proposed

70 *See* IHS Global Insight's First Quarter 2011 Utility Cost Forecast.

71 Table S corresponds to Table X-2 in the Supporting Testimony. The factors shown are escalation indices published in HIS Global Insight's First Quarter 2011 Utility Cost Forecast.

72 The revenue requirements reflect the incorporation of the bonus depreciation provisions recently enacted as part of the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 ("Tax Relief Act of 2010"). The Tax Relief Act of 2010 is an economic stimulus tool that President Obama called on Congress to enact in 2010. The Tax Relief Act 2010 was signed on December 17, 2010.

73 Table T corresponds to Table X-5 in the Supporting Testimony.

Case. Table U[74] summarizes the necessary revenue requirement for each utility to implement the projects for the Base Case.

Table T
Revenue Requirement Summary for Proposed Case
(In Millions of Dollars, nominal)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023+	Total
SoCalGas	6.37	57.91	100.49	182.58	247.01	233.95	266.30	296.51	325.83	350.43	375.87	396.61	6,581.51	9,421
SDG&E	0.92	0.35	5.19	24.53	30.73	44.15	64.43	83.69	116.82	100.32	98.77	96.04	1,762.75	2,429

Table U
Revenue Requirement Summary for Base Case
(In Millions of Dollars, nominal)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023+	Total
TotalSoCalGas	6.37	58.86	95.82	150.97	205.75	182.57	181.93	183.54	183.93	184.48	185.25	182.44	2,731.89	4,534
Total SDG&E	0.92	0.98	5.27	22.32	28.56	41.92	62.38	82.17	115.84	99.33	97.75	95.22	1,749.47	2,402

B. Regulatory Accounting Treatment.[75]

SoCalGas and SDG&E propose that the costs to be recovered through the PSEP Surcharge be incorporated into rates on January 1st of each year and continue until Pipeline Safety Enhancement Plan investments are fully recovered. They propose to establish a "Pipeline Safety Enhancement Plan Cost Recovery Account"[76] for each utility to recover costs associated with the PSEP. In connection with their annual regulatory account balance update filings, SoCalGas and SDG&E propose that the current-year forecasted year-end balance in the proposed regulatory account, combined with the revenue requirement for the coming year, be incorporated into rates, as necessary, to ensure appropriate recovery of the revenue requirement in between

74 Table U corresponds to Table X-8 in the Supporting Testimony.

75 The discussion in this section comes from the testimony of Ms. Cheryl Shepherd at pages 121 to 127 in the Supporting Testimony.

76 These will be interest bearing accounts that are recorded on SoCalGas and SDG&E's respective financial statements. These accounts will record the difference between the authorized revenue requirements collected through the PSEP Surcharge and actual O&M and capital-related costs associated with implementation of the Pipeline Safety Enhancement Plan.

rate case cycles. Any residual balance would be amortized in rates at the completion of the Pipeline Safety Enhancement Plan. Upon approval of their Plan, SoCalGas and SDG&E each propose to file an advice letter to implement the Commission's decision. These advice letters would include updated revenue requirements and timing to reflect any decision-ordered changes to the Pipeline Safety Enhancement Plan. This will allow SoCalGas and SDG&E to reflect any delays and incorporate the surcharge into rates, should approval of the Pipeline Safety Enhancement Plan occur after January 1, 2012. This would also include the costs recorded in the Pipeline Safety and Reliability Memorandum Accounts, proposed in our joint motion filed May 4, 2011, if approved in sufficient time; and, any costs that would have been recorded in these memo accounts, if they had been approved in sufficient time.

In connection with their annual regulatory account balance update filings in October of each year, the current-year forecasted year-end balances in the Pipeline Safety and Enhancement Plan Cost Recovery Accounts, combined with the revenue requirements for the coming year, will be incorporated into rates, as appropriate. Any residual balance will be amortized in rates at the completion of the Pipeline Safety Enhancement Plan. SoCalGas and SDG&E propose to file expedited advice letters requesting approval for any adjustments to the overall level of Pipeline Safety Enhancement Plan funding requirements previously approved. These advice letters will include an explanation for changes from the original revenue requirements, as previously proposed and approved. They also propose to use this advice letter process to request any additional revenue requirement associated with the Enterprise Asset Management System or the expansion of the Pipeline Safety Enhancement Plan for pipeline safety enhancement activities not covered by this filing but subsequently adopted by the Commission.

Finally, SoCalGas and SDG&E propose that, beginning in 2013, they provide an annual status report to the Commission on or before March 31st of each year that will include the following: (1) Information on any work completed during the previous year (scope and cost); (2) Work planned for the upcoming year (scope and cost); (3) Discussion of progress made to date in order to keep the Commission informed and provide transparency to the public regarding our progress; and (4) Confirmation of our Commission-approved annual Pipeline Safety Enhancement Plan budget.

C. **Rates.**[77]

SoCalGas and SDG&E propose to recover all Pipeline Safety Enhancement Plan costs through a PSEP Surcharge. The surcharge will be comprised of the estimated revenue requirements for that year, which in the initial year will include costs being incurred in 2011, combined with the balance in the Pipeline Safety Enhancement Plan Cost Recovery Account to be incorporated into rates, as appropriate. The Surcharge will be implemented upon Commission approval and updated on January 1st of each year as part of SoCalGas and SDG&E's respective Annual Consolidated Rate Update Filings.

The costs are to be recovered each year through the PSEP Surcharge. The PSEP Surcharge would include PSEP costs based on: (1) The Pipeline Safety Enhancement Plan revenue requirements, which include costs to be tracked in the Pipeline Safety and Reliability Memorandum Account proposed in SoCalGas and SDG&E's joint motion filed May 4, 2011 and (2) any balance in the Pipeline Safety Enhancement Plan Cost Recovery Account to be incorporated into rates, as appropriate.

77 The discussion in this section comes from the testimony of Mr. Gary Lenart at pages 128 to 136 in the Supporting Testimony.

These Pipeline Safety Enhancement Plan costs will be incorporated into rates upon implementation of the Commission's decision; and on January 1st of each subsequent year, as part of the Annual Consolidated Update Filing. Costs will be allocated among customer classes via the Equal Percent Authorized Margin method.[78]

SoCalGas and SDG&E believe that this cost allocation methodology is appropriate since the new safety enhancements being proposed benefit all customers. As a result, the costs of the Pipeline Safety Enhancement Plan should be allocated in a manner that, on a percentage rate impact basis, is relatively equitable across our different customer classes.[79]

SoCalGas and SDG&E propose to charge a flat monthly surcharge for residential customers and a volumetric surcharge for non-residential customers. It is not practical to develop a single flat-monthly or volumetric surcharge that would apply to all customers in all rate classes using an Equal Percent Authorized Margin allocation. Accordingly, a different surcharge is required to be calculated for each customer class. The surcharges for customers within each customer class may be flat monthly surcharges, volumetric surcharges, or a combination. Since the residential market is a relatively homogeneous market in terms of natural gas demand, SoCalGas and SDG&E determined that a fixed monthly PSEP Surcharge is reasonable and works well for this class. Due to the wide range of demand profiles among the non-residential customer classes, a volumetric surcharge is more appropriate. Wholesale customers, along with others on the transmission-level service rate, will be charged the PSEP Surcharge, however, SDG&E will not be charged the PSEP Surcharge as part of wholesale

78 Pursuant to D.09-11-006, Equal Percent Authorized Margin (EPAM) is defined as the percent of base margin, on a post-system integration and post-Firm Access Rights unbundled basis, allocated to each class.

79 The discussion in this paragraph comes from Mr. Morrow starting at page 22 of the Supporting Testimony.

service. This is due to the integration of the Pipeline Safety Enhancement Plan between the two utilities, with the Surcharge being determined on a combined cost and demand basis.

The PSEP Surcharge will be a separate line item on customers' bills. The illustrative surcharges at the end of Phase 1A (*i.e.,* 2015) are summarized in Table V.[80]

Table V
SoCalGas and SDG&E PSEP Surcharges for Phase 1(A)

	Proposed Case	Base Case
SoCalGas		
Monthly PSEP Surcharge ($/mo)		
Residential	$2.82	$2.38
Volumetric PSEP Surcharges ($/th)		
Core Commercial & Industrial	$0.03484	$0.02939
Gas Air-Conditioning	$0.00987	$0.00832
Gas Engine	$0.01270	$0.01071
Natural Gas Vehicle	$0.01030	$0.00869
Noncore C&I - Distribution Level Service	$0.00973	$0.00821
Electric Generation Distribution Level Service	$0.00435	$0.00367
EOR - Distribution Level Service	$0.00435	$0.00367
Transmission Level Service	$0.00284	$0.00240
SDG&E Gas		
Monthly PSEP Surcharge ($/mo)		
Residential	$2.83	$2.38
Volumetric PSEP Surcharges ($/th)		
Core C&I	$0.03484	$0.02939
Natural Gas Vehicle	$0.01031	$0.00870
Noncore C&I - Distribution Level Service	$0.00978	$0.00825
Electric Generation-Distribution Level Service	$0.00437	$0.00369
Transmission Level Service	$0.00286	$0.00241

SoCalGas and SDG&E propose to apply the 20% rate discount to the PSEP Surcharge for those customers on the California Alternate Rate for Energy (CARE) rate schedule. The discounted amounts would be included in the CARE program costs and recovered through the Public Purpose Program Surcharge rate.

80 Table V corresponds to Table X-10 in the Supporting Testimony.

Combining the charges described above for the PSEP Surcharge with the Public Purpose Program Surcharge rate impact will result in the illustrative Residential monthly bills and Non-Residential class average volumetric rates shown in Table W.[81] Table W shows both the residential and non-residential customer rate impacts.

Table W
Consolidated Rate Impacts for Phase 1(A)

	Current	Proposed Case		Base Case	
SoCalGas			% Change		% Change
Residential Avg Monthly Bill - $/mo	$39.08	$42.00	7.5%	$41.54	6.3%
Avg Monthly Bill w/out G-CP - $/mo	$21.98	$24.91	13.3%	$24.45	11.2%
Non-res Rates ($/th)					
Core C&I	$0.38341	$0.42097	9.8%	$0.41510	8.3%
NGV	$0.11969	$0.13272	10.9%	$0.13068	9.2%
Noncore C&I – Distribution	$0.10884	$0.12129	11.4%	$0.11934	9.7%
EG – Distribution	$0.03874	$0.04309	11.2%	$0.04241	9.5%
Transmission Level Service	$0.02517	$0.02801	11.3%	$0.02757	9.5%
SDG&E					
Residential Avg Monthly Bill - $/mo	$38.76	$41.68	7.5%	$41.23	6.4%
Avg Monthly Bill w/out G-CP - $/mo	$23.91	$26.84	12.2%	$26.38	10.3%
Non-res Rates ($/th)					
Core C&I	$0.36970	$0.40749	10.2%	$0.40158	8.6%
NGV	$0.11915	$0.13240	11.1%	$0.13033	9.4%
Noncore C&I – Distribution	$0.25462	$0.26735	5.0%	$0.26536	4.2%
EG – Distribution	$0.04229	$0.04667	10.3%	$0.04598	8.7%
Transmission Level Service	$0.02517	$0.02803	11.4%	$0.02758	9.6%

The Residential bills are based on system-wide average monthly usage for SoCalGas of 38 therms/month and SDG&E of 33 therms/month, using current transportation rates and core procurement rates. The Non-Residential rates are based on current class-average transportation rates, excluding Firm Access Rights charges and gas commodity.

81 Table W corresponds to Table X-13 in the Supporting Testimony.

X. CONCLUSION

As shown in the preceding sections, SoCalGas and SDG&E have developed an Implementation Plan that meets the Commission's directives, enhances public safety, minimizes customer impacts and maximize cost effectives. If approved, SoCalGas and SDG&E's Pipeline Safety Enhancement Plan will result in (1) the replacement, pressure testing or direct examination of all transmission pipelines that meet the Commission's criteria for replacement or pressure testing; (2) the replacement of all non-piggable pipeline segments installed prior to 1946; (3) the enhancement of SoCalGas and SDG&E's existing valve infrastructure through the installation or modification of remote control and automated shutoff valves, (4) equipping replacement pipelines with advanced fiber optic and methane detection technology, and (5) the development of a fully integrated Enterprise Asset Management System.

Respectfully submitted,

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