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)

COMMENTS OF SOUTHERN CALIFORNIA GAS COMPANY (U 904-G) AND SAN DIEGO GAS & ELECTRIC COMPANY (U 902-M) ON TECHNICAL REPORT OF THE CONSUMER PROTECTION AND SAFETY DIVISION

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Southern California Gas Company (SoCalGas) and San Diego Gas & Electric Company (SDG&E) submit the following comments on the Technical Report of the Consumer Protection and Safety Division (CPSD) on the proposed SoCalGas and SDG&E Pipeline Safety Enhancement Plan (the Report), pursuant to the January 5, 2012 Administrative Law Judge's Ruling Modifying Schedule and Granting Motions for Party Status.

SoCalGas and SDG&E commend CPSD Staff for their thoughtful and thorough review of our proposed Pipeline Safety Enhancement Plan, and look forward to continuing to work closely with Commission Staff to further refine our plan. In the following comments, we offer a few clarifications of our proposed plan and comment on particular findings of the Report.

I. CLARIFICATIONS AND COMMENTS IN RESPONSE TO REPORT FINDINGS AND OBSERVATIONS

A. **CPSD FINDING**: Overall, the PSEP's decision tree for prioritization in Phase 1A, and the sub-prioritization process included therein, appears to result in reasonably prioritized segments. However, CPSD believes the sub-prioritization methodology could be enhanced by having it also consider previous findings (i.e., in-service leaks on seam or girth welds or pressure excursions over MAOP) from routine operations and the presence of combined threats on a segment, as part of the prioritization process. (Report, p. 10)

The sub-prioritization process used the potential impact radius and long seam type to identify which pipeline segments will be planned first, with all segments identified in Phase 1A proposed to be addressed within the first four years. While previous findings, such as incident history, leaks, pressure excursions, etc., may be helpful to fine-tune the preliminary rankings, in practice, as described in our Testimony in Support of the Pipeline Safety Enhancement Plan, the impact of these factors on the final schedule may be muted by other factors such as permits, material availability and customer impacts.[1] In other words, CPSD's proposed enhancement of the sub-prioritization methodology is unlikely to materially affect the completion date of the projects. As a more effective alternative, SoCalGas or SDG&E propose the use of additional interim safety measures, such as pressure reductions and increased leak surveys, for pipeline segments with additional risk factors.

> **B. CPSD FINDING**: The PSEP's decision tree process for Phase 1B needs to evaluate the pressure testability of pre-1946 non-piggable pipe. In particular, the Companies need to evaluate if certain portions of Class 1 or 2, low stress (SMYS less than 30%) pre-1946 non-piggable pipe can be pressure tested rather than replaced. For pipe that is then selected for replacement, the PSEP needs to add sub-priorities to Step F to prioritize the replacement of pre-1946, non-piggable, Class 3 pipe, operating at 30% SMYS or higher, above other replacements. (Report, p. 11)

SoCalGas and SDG&E disagree with this finding and continue to support their proposal to replace rather than pressure test pre-1946 non-piggable pipelines due to the inability of both pressure testing and in-line inspection to validate the integrity of these pre-WWII era girth welds that are now at least 65 years old. We do not believe it is prudent to use ratepayer funds to pressure test pipelines that will subsequently require more ratepayer funds for replacement to address aged girth welds and the inability to use ILI on the pipelines.[2]

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1 *See* Testimony in Support of the Proposed Pipeline Safety Enhancement Plan, Section II.E (starting on p. 23) for a discussion of the permitting, material and labor availability, and environmental challenges. *See* Testimony in Support of the Proposed Pipeline Safety Enhancement Plan, Section II.A.3 (starting on p. 15) for a discussion of the customer impacts.

2 Note that on page 129 of its August 30, 2011 Pipeline Accident Report on the PG&E Natural Gas Transmission Rupture and Fire in San Bruno, California, the National Transportation Safety Board (NTSB) recommends to the Pipeline and Hazardous Materials Safety Administration (PHMSA) that PHMSA, "[r]equire that all natural gas transmission pipelines be configured so as to accommodate in-line inspection tools, with priority given to older pipelines." Note also that the CPUC comments to PHMSA stating that "[i]n-line inspection ("ILI") or hydro-test should be the sole assessment methods permitted by Part 192. January 20, 2012 Comments of the People of the State of California and the California Public Utilities Commission, Docket No. PHMSA—2011—0023.

With respect to the sub-prioritization of this work, the 30% SMYS rupture threshold proposed by CPSD is not ideal for the prioritization of pipeline segments, particularly for the validation of construction or fabrication threats, such as wrinkle bends and girth welds. That is why SoCalGas and SDG&E propose to use the same methodology employed in phase 1A. Potential impact radius overcomes the diminished sensitivity of construction and fabrication threats to hoop stress while still accounting for the consequence of failure, and is therefore better suited to these pipelines. It also provides a consistent and repeatable calculation for the priority regardless of MAOP, operational history and percent of SMYS.

SoCalGas and SDG&E propose that, once some of the work identified in Phase 1A is completed, that experience gained be used to update the decision tree for phases 1B and 2 for Commission consideration in the next General Rate Case, or other appropriate proceeding.

> **C. CPSD FINDING:** The projects sampled by CPSD raise a concern that some of the Companies' prioritized projects, especially the large project related to Line 1600 included in the PSEP for Phase 1, may not be targeting the highest priority pipe segments. CPSD believes that a significant portion of the estimated costs for these projects appear to be inappropriately targeted towards testing or replacing low priority pipe. In the case of Line 1600 alone, of the approximately $325 million to replace Line 1600 and $14.4 million to make the line piggable, pig it, and then hydro-test it, considerable portions of these estimated costs are attributable to addressing lower priority sections of pipe and to increasing pipeline capacity. (Report, p. 13)

SoCalGas and SDG&E organized transmission pipeline segments into four categories based on our review of post-construction pressure test documentation following the NTSB's issuance of four Safety Recommendations to Pacific Gas and Electric Company on January 3, 2011. Those NTSB recommendations focused on pipeline segments located in more populated areas, specifically Class 3 and 4 locations and High Consequence Areas, and SoCalGas and SDG&E refer to these pipeline segments as "Criteria Miles." The four category descriptions developed by SoCalGas and SDG&E in response to the NTSB Safety Recommendations are as follows:

- Category 1 – Documented hydrotest to 1.25 x MAOP
- Category 2 – Documented strength test with a medium other than water to 1.25 x MAOP
- Category 3 – In-service strength test with MAOP reduction

- Category 4 – Lacking complete, accurate, and/or verifiable documentation to validate a post construction pressure test to 1.25 x MAOP

Category 4 segments represent the highest priority Criteria Mileage in the proposed Pipeline Safety Enhancement Plan and, per our proposed decision-making process, are to be addressed in Phase 1. SoCalGas and SDG&E propose to address non-Criteria Mile segments (i.e. those located in Class 1 and 2 non-High Consequence Area locations), in Phase 2, along with any Category 1 or 2 pipeline segments for which the existing documentation, though satisfactory to validate a 1.25 x MAOP strength test, does not meet the Commission's objective of ensuring that all California pipelines have been tested to the current requirements of 49 CFR 192.619, excluding subsection 49 CFR 192.619(c).[3]

The mileage of Category 4 pipeline proposed to be addressed in Phase 1 of the Pipeline Safety Enhancement Plan is actually greater than CPSD suggests in the Report. The proposed pressure test or replacement mileage breakdown of the four pipelines sampled by CPSD should be as follows:

Line #	Category 4 *Criteria* miles	Category 4 *non-Criteria* miles	Category 1 & 2 miles
49-15	1.98	1.26	3.36
49-16	0.72	0	8.87
49-28	1.80	0.91	2.19
1600	29.7	14.9	0.08

Category 4 non-Criteria miles are lower in priority than Category 4 Criteria Miles and are the focus of PSEP efforts in Phase 2. In our development of a high level pressure test and replacement scope, however, SoCalGas and SDG&E shifted, or "accelerated," to Phase 1 some Category 4 mileage that under our decision tree would have been addressed in Phase 2, where it is more efficient or where operational requirements necessitate the replacement or pressure testing of all Category 4 miles at one time. This was explained on page 52 of our Testimony:

> In many cases…the length of the segment to be tested or replaced will be increased to include adjoining pipeline that is in more sparsely populated areas due to operational necessity and project efficiency. These adjoining segments are, in essence, accelerated into phase [1] even though they are identified to be addressed in a later phase, and are referred to as "accelerated" segments.

[3] See D.11-06-017 Ordering ¶ 4.

In the cases of Lines 49-15, 49-28, and 1600, all sampled by CPSD in their review, the high level project scope developed for the PSEP filing accelerates approximately 1.26 miles, 0.91 miles, and 14.9 miles, respectively, of Category 4 pipe that is located in Class 1 and 2 non-HCAs into Phase 1 in order to avoid possible duplication of permitting efforts, customer and community impacts, contractor mobilization, pipeline outage, evacuation of gas, etc., that could occur if two separate replacement or pressure test efforts are planned on each line for two different time periods.

For pipelines 49-15, 49-16, and 49-28, initial assessment indicates that it may be infeasible to replace the Category 4 Criteria segments in their current location and would require realignment from the existing route. Preliminary evaluation also indicates that it may be impractical to tie the newly aligned pipe back over to the existing Category 1 and 2 segments. Therefore, these miles are also included in the Phase 1 scope.

As is stated in the CPSD report:

> Firm criterion for the determination of miles to be accelerated in Phase [1], including cost/benefit analyses, will be performed during the engineering, design, and execution planning phase of the project.

Using this criterion, and considering that each line and segment has unique characteristics, the entire replacement and pressure test scope for each pipeline will be re-evaluated to determine which Category 4 non-Criteria segments and Category 1 and 2 segments should be included in the Phase 1 scope.

SoCalGas and SDG&E are in agreement with the CPSD assessment that hydrotesting Line 1600 is not a viable option considering the significant service and customer impacts that would be required.[4] SoCalGas and SDG&E do not agree, however, with CPSD's suggestion that "it may be possible to replace the remainder of Line 1600 (i.e., the 29.73 Category 4 miles estimated for replacement in the PSEP) as has been done when sections were replaced on this line in the past, but perhaps on a more accelerated schedule." SoCalGas and SDG&E believe the replacement of Line 1600 in its entirety in a new location is the best option to minimize community and cost impacts and complete the work in a reasonable timeframe. The narrow easements, and adjacent development, will not allow for the construction of the replacement pipe in the existing easement. Moreover, contrary to the CPSD Finding with respect to Line 1600, the proposed Pipeline Safety Enhancement Plan does not include estimated

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[4] *See* Report, p. 5.

costs to make Line 1600 piggable. Line 1600 is currently in the process of being made piggable as part of our ongoing Integrity Management Program and this retrofitting work (as well as an in-line assessment) is expected to be completed for Line 1600 by the end of this year.

Ninety percent of the current easements for Line 1600 are twenty feet in width, with some locations narrowing to ten feet in width. The existing easements allow for buildings to be sited as close as fifteen feet from the pipeline. The area surrounding the current pipeline route and existing easement has been heavily developed and urbanized since the original installation of the pipeline. In many areas, homes, apartment buildings and businesses lie immediately adjacent to this existing pipeline. Standard pipeline construction equipment, spoil management and installation practices cannot be employed in these narrow easements. Managing spoils (dirt and trench materials) would, at a minimum, require extensive trucking efforts and local traffic impacts to haul the trench spoil to a temporary storage location. Because there is no room in the existing easements for spoils to be placed alongside the open trench while the new pipe is safely constructed in place, trench backfill materials from the excavation would need to be trucked back again to these narrow easements to fill and compact the material back into the trench once the new pipe is installed. The compaction equipment may also cause significant vibration, disruption, and impact to the physical structures that are located in close proximity to the trench location directly adjacent to the pipeline route. Normal pipe installation equipment and practices would need to be significantly modified for working in such narrow easements.

The Report raises an additional concern that SDG&E may not be targeting the highest priority segments with respect to Line 1600 in Phase 1. Strictly speaking, the Pipeline Safety Enhancement Plan Test/Replace Decision Tree analysis of the segments would place the 29.73 miles in Phase 1A and the 15.00 miles in Phase 2. However, the 29.73 miles of Phase 1 replacement is expected to trigger extensive local, state and federal permitting requirements as well as CEQA review, which will likely require an environmental impact assessment of the 15.00 Category 4 miles in Class 1 and 2 locations during the CEQA process. SoCalGas and SDG&E anticipate the time for design, CEQA compliance and permitting to take up to three years. For this reason, the actual construction would not begin until Phase 1B.

SoCalGas and SDG&E appreciate CPSD's concerns regarding the planned diameter of the Line 1600 replacement pipeline. A 36-inch diameter pipeline does indeed provide a substantial amount of capacity to the SDG&E system relative to that provided by Line 1600. However, as CPSD alludes to in their finding, the cost of engineering, planning, permitting, and construction of such a large project obligates SoCalGas and SDG&E to examine whether a larger diameter pipeline is warranted. In the case of Line 1600, SoCalGas and SDG&E examined the state of the SDG&E system and determined that investment in a 36-inch diameter pipeline would support the safety goals set forth in the Pipeline Safety Enhancement Plan filing, while also addressing the long-term reliability and capacity needs of San Diego.

As described in our testimony, the SDG&E system consists of two high-pressure large diameter pipelines, one of which is 16-inch Line 1600. Not surprisingly, the other pipeline, 30-inch diameter Line 3010, provides the vast majority of the SDG&E system supply. Should there be an outage on Line 3010, either planned (such as that required for pipeline inspection) or unplanned (third-party damage or a natural disaster), Line 1600 cannot provide sufficient capacity to support anything but a nominal level of demand in San Diego. Noncore curtailment and core outages are a certainty. This was demonstrated in October and November of 2011, when curtailment was required on the SDG&E system for a total of nine weekend days due to pipeline integrity construction on Line 3010. While supply delivered at Otay Mesa can partially mitigate the capacity loss and impact to customers, the availability of supply is not assured at that location. Moreover, since the route through Mexico is generally more expensive for shippers, Otay Mesa does not normally receive gas supplies.

Additionally, as the Commission is aware, the SDG&E system has been capacity-constrained for a number of years, requiring customers to bid, on an hourly basis, for the level of firm transportation capacity they need for a two-to-five-year term. Any firm capacity awarded is also subject to a use-or-pay requirement. This is not a desirable long-term situation for SDG&E customers.

Further, initial research by SoCalGas and SDG&E has found that potential routes for a new pipeline of this length in San Diego may be limited. Therefore, it would be poor planning to install a pipeline replacement for Line 1600 that does not also provide sufficient capacity or reliability for the long term.

Finally, as SoCalGas and SDG&E stated in its data request response to CPSD, we have not yet finalized our plan for Line 1600 following the completion of its replacement pipeline in a new location. It is possible that Line 1600 operating as a transmission pipeline at its historical pressures provides sufficient benefit to customers even with a replacement pipeline, but it is also possible that SoCalGas and SDG&E may simply reduce the pressure of Line 1600 and operate it as part of the San Diego distribution system. If, after further study, it is determined that there is no benefit to keeping Line 1600 in service, abandonment could also be considered. The need to pressure test Line 1600 after the installation of the replacement line may be dependent upon Commission approval of the use of an in-service pressure test.

For these reasons, SoCalGas and SDG&E believe that it is in the long-term interest of our ratepayers to apply resources required to be spent on Line 1600 towards the cost of a new pipeline that provides solutions to enhance the safety of our system, while simultaneously dealing with capacity, and reliability issues that are facing San Diego's gas infrastructure. Due to the significant constructability risks, cost and schedule uncertainty, customer, and community impacts that would be involved in working in the existing Line 1600 easements, SoCalGas and SDG&E propose to install a replacement line for Line 1600 in a new location.

D. **CPSD FINDING**: If the CPUC is willing to accept some risk of false closure, the number of automated valves proposed in the PSEP could be reduced with the installation of ASVs, at intervals longer than those being proposed by the Companies for RCV installations, and still ensure that gas flow is stopped within 30 minutes of a full breach of the pipeline. If the CPUC decides that the risk of false closure is too high, CPSD believes the Companies' PSEP valve program will allow gas flow from a full breach to be extinguished within 30 minutes from the time of the breach, provided that the Companies close all RCVs necessary to isolate the affected section of pipe, within 15 minutes of the breach. (Report, p. 16)

SoCalGas and SDG&E agree that extending the spacing interval from eight miles to up to sixteen miles would provide acceptable depressurization timelines for a pipeline when valves are closed following a rupture. This is precisely the strategy we have employed in prior and current ASV implementations. SoCalGas and SDG&E currently operate ASVs at over 200 locations, along specific pipeline intervals where we have determined through both engineering evaluation and, in some instances experience, that an accidental closure is less likely to be accompanied by a greatly-elevated risk of wide-scale customer loss.

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Based both on our knowledge of the design of our pipeline system and past experience, SoCalGas and SDG&E do not believe it is appropriate to analogize a successful longer-interval strategy that manages risk in outlying areas, to complex piping networks and looped pipelines. Therefore, SoCalGas and SDG&E do not share the CPSD's technical interpretation or anecdotally-based level of risk-tolerance associated with the potential shut-off of 200,000 or more customers due to a false closure or even valid closure of an ASV, when such can be mitigated. Through their proposed Valve Enhancement Plan, SoCalGas and SDG&E strive to avoid the potential risk of large-scale losses in the event of a rupture. Extending pipeline space intervals for isolation in areas of complex pipeline networks may result in shutting not only the primary supply, but might also result in shut down of the secondary and sometimes tertiary supplies into a distribution area when valves are closed. Such an approach, if implemented in Class 3, Class 4 and high consequence areas, and without the flexibility provided by additional shorter-interval RCVs. Such an approach, if implemented in Class 3, Class 4 and high consequence areas, would greatly elevate the potential for large-scale customer losses in the event of a rupture. Accordingly, our proposed plan is designed to avoid this risk by converting most valves to support both ASV and RCV operation, and to provide this capability at shorter intervals. This will support maximum flexibility in operations, and allow us to update our control strategy over time as our system requirements change.

SoCalGas and SDG&E intend to ultimately operate many (perhaps 50%) of the valves to be installed as part of our proposed Valve Enhancement Plan as ASVs (some even at longer intervals), after sufficient operating history is collected and carefully analyzed for each valve location. This includes information gathered from expanded SCADA system monitoring points. The initial approach would be to use the remote-control functionality of the valve. With further analysis and confirmation through operating experience, SoCalGas and SDG&E would then change, if and where appropriate, the valve functionality to enable automatic control. In some instances, this approach may achieve exactly what CPSD is promoting for consideration in its Finding. However, any approach of this nature also requires the flexibility of shorter-interval RCV capability at many locations in support of longer interval ASVs. Simple ASV operation at longer spacing intervals will not singularly serve this measured and dynamic strategy for managing risks.

SoCalGas and SDG&E recognize that the Commission may decide to reduce the valve count with some extension of spacing intervals, and would welcome the opportunity to work with CPSD to ensure this reduction takes place as a result of detailed system engineering review for each major stretch of pipeline scheduled for ASV/RCV installation.

E. CPSD FINDING: As described below, the proposed alternatives to pressure testing or replacement are not functionally equivalent to pressure testing or replacement and may ultimately delay the implementation of the CPUC's pressure test or replace policy. (Report, p. 18)

As authorized in Decision 11-06-017, the SoCalGas and SDG&E Pipeline Safety Enhancement Plan proposes alternatives to pressure testing or replacement that "demonstrably achieve the same standard of safety" as pressure testing or replacement.[5] We interpret the Commission's authorization to include such alternatives as supporting the use of technically-sound equivalent methods, where appropriate, to minimize costs and/or customer impacts. Accordingly, in our proposed Pipeline Safety Enhancement Plan, we propose the following alternatives:

- The use of non-destructive examination methods, such as radiography, ultrasonic inspection, and magnetic particle testing as an appropriate alternative to pressure testing or replacement; and
- Use of transverse field (TFI) in-line inspection tools, in parallel with pressure tests, to validate the ability of TFI tools to provide equivalent standards of safety.

SoCalGas and SDG&E disagree with the CPSD finding that these "proposed alternatives to pressure testing or replacement are not functionally equivalent to pressure testing or replacement and may ultimately delay the implementation of the CPUC's pressure test or replace policy."[6] This finding does not acknowledge that for applicable threats, these methods are included as independent and equivalent assessment methods under 49 CFR 192, Subpart O.[7] These proposed methods are recognized as reliable assessment methods and are often used in preference to pressure testing. The equivalency of an assessment method is dependent upon the detection of critically sized flaws, and the detection capabilities of in-line inspection using TFI technology and non-destructive evaluation often exceed that of pressure testing. The equivalency of non-destructive examination has a well-established record, as

5 D.11-06-017, p. 1.
6 Report, p. 18.
7 *See* 49 CFR 192.921(a).

evidenced by the fact that non-destructive examination is used as a "prove-up" method to both ILI and pressure testing. Through the use of these alternative methods, flaws that would otherwise remain unknown as the result of a pressure test alone can be fully evaluated to demonstrate the required margins of safety.

Additionally, these alternatives provide the benefit of greatly enhanced information about the character, size, and distribution of flaws to enable the future management of both the subject pipelines, and like-size-and-kind pipelines that are not necessarily included in the scope of the proposed Pipeline Safety Enhancement Plan. In this manner, the objectives of the Pipeline Safety Enhancement Plan could be met and the benefits of the Pipeline Safety Enhancement Plan can extend beyond the scope of the Pipeline Safety Enhancement Plan alone. For these reasons, SoCalGas and SDG&E seek the flexibility to apply these methods to the extent possible.

F. **CPSD FINDING**: Adopting the change proposed by the Companies to GO 112-E would allow pipelines that have not been pressure tested to have their MAOP validated without a pressure test. (Report, p. 18)

SoCalGas and SDG&E's proposed changes to General Order 112-E are to be applied to pipelines that currently have their MAOPs established under 49 CFR 192.619(c) (i.e. the Federal "Grandfather Clause").[8] By applying these additional requirements to grandfathered pipelines as an alternative to pressure testing or replacement, the Commission could adopt requirements that exceed those currently set forth in the Federal Code, while achieving the same level of safety at a lower cost and/or with less customer impacts as compared to pressure testing.

G. CPSD FINDING: The Companies have not justified running a TFI tool on all piggable lines prior to pressure testing unless such a run allows them to supplant IMP activities for that segment. (Report, p. 19)

Accordingly, the proposed use of TFI technology in the Pipeline Safety Enhancement Plan is for the purposes of satisfying the Commission's directives in Decision 11-06-017 and achieving our

[8] As explained in our proposed Pipeline Safety Enhancement Plan, the term "Grandfather Clause" refers to the provision of 49 CFR Section 192.619(c) that allows a transmission pipeline's MAOP to be set based on the highest actual operating pressure to which the segment was subjected during the five-year period that preceded the date that Federal Regulation 49 CFR Section 192 went into effect. The effect of this provision 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.

overarching objectives to enhance public safety while minimizing customer impacts and maximizing the cost effectiveness of investments in the SoCalGas/SDG&E transmission system.[9] The use of TFI as part of the Pipeline Safety Enhancement Plan accomplishes these objectives by:

1. Utilizing the pressure testing opportunities presented in Phase 1 to develop sufficient data to analyze the potential use of TFI as an equivalent alternative to pressure testing in Phase 2, thereby avoiding costly testing that may otherwise result; and
2. Minimizing the impact of unpredicted and avoidable pressure test failures as part of our responsibility to minimize customer impacts and outages.

While SoCalGas and SDG&E currently have primarily axial tool data, there are no TFI runs planned as part of their normal Integrity Management Program-related efforts. In the Report, CPSD observes that existing axial tool data "could be used by the Companies for their intended purpose – to identify and remove some of the potential weaknesses from the pipeline before it is pressure tested." However, SoCalGas and SDG&E propose the use of the TFI tool because existing axial MFL data provides little benefit with regard to effective identification of tightly spaced long seam anomalies of the kind that the Pipeline Safety Enhancement Plan is intended to address. These same anomalies, if subject to pressure tests in excess of the pressures experienced historically during normal operation, have the potential to extend and prolong the testing efforts in a manner far less controlled than would otherwise be encountered.

While SoCalGas and SDG&E are aware that PG&E has successfully tested approximately 160 miles of pipeline, we are also aware that some of those tests led to unplanned test failures.[10] The impact of these test failures was largely mitigated by their locations relative to people and property. These failures could have had a much greater impact on customers, both with respect to disruption of service and cost, had they occurred in more populated areas.

Moreover, the pressure testing schedule is not expected to be heavily impacted by the use of TFI. The testing of pipelines within the Pipeline Safety Enhancement Plan needs to be phased to

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9 *See* the full discussion of our four overarching objectives on pages 10-17 of our Testimony in Support of Pipeline Safety Enhancement Plan.

10 On October 24, 2011, a 34-inch diameter PG&E pipeline burst during a hydrostatic pressure test in Bakersfield farmland. On November 6, 2011, a 24-inch diameter PG&E pipeline in Woodside burst during a hydrostatic pressure test, flooding, and partially closing, Interstate 280.

accommodate the logistics of testing. The phased schedule can also be made to accommodate the use of TFI, with minimal delay, particularly because TFI does not require a system outage. In this manner, all follow-on work required to remove critically-sized anomalies can be accomplished during the outage required for pressure test work. This would ensure that system outage time, and the related impacts to our customers, are minimized.

Additionally, our recent experience has shown that the availability of TFI tools and TFI adaptability to our system is limited. We do not propose in our Pipeline Safety Enhancement Plan to retrofit our system for the purpose of accommodating TFI tools prior to pressure testing. Nor do we propose to delay or postpone pressure test work in cases where the TFI tool may not be readily available. Therefore, the actual scope of pipeline mileage that is likely to be assessed using the TFI tool is anticipated to be limited to a small subset of pipeline segments that can accommodate the tool and for which the tool is readily available prior to pressure testing. Even such limited implementation, however, would provide benefits through increased flexibility and preventative action, as well as serving as a pilot for purposes of assessing the potential use of the TFI tool as an alternative to pressure testing in Phase 2.

The goal of pressure testing is successful demonstration of a sufficient margin of safety. This can be accomplished in a controlled and confident manner through the use of TFI prior to testing. There is a longer-term potential for significant cost savings and minimization of customer impacts during Phase 2, if in-line inspection using TFI technology can be demonstrated as an equivalent alternative to pressure testing or replacement. Accordingly, SoCalGas and SDG&E urge the Commission to approve their forward-looking request to utilize the opportunities presented in Phase 1 of the Pipeline Safety Enhancement Plan to validate the effectiveness of in-line inspection using a TFI tool as an alternative to pressure testing.

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H. **CPSD FINDING**: The CPUC should require static pressure tests as a validation method consistent with the federal pipeline safety regulations. If the CPUC allows in-service pressure levels to substitute for static pressure testing, then the minimum in-service pressure equivalency of no less than 1.7xMAOP should be considered adequate by the CPUC. This would result in a 1.5xMAOP test for Class 3 locations with an equivalent safety margin as proposed by the Companies in their proposal for a 1.39xMAOP historical pressure functional equivalency. (Report, p. 20)

Consistent with Decision 11-06-017, SoCalGas and SDG&E propose the use of an "in-service" pressure test to achieve the same standard of safety as pressure testing, where feasible, thereby eliminating the need for additional pressure testing and avoiding the associated costs and impact to customers. [11]

An in-service strength test is a reasonable and technically viable alternative consistent with the concept of being functionally equivalent to a static pressure test to validate the stability of manufacturing flaws that may exist in the system. In their Technical Report Regarding Southwest Gas Corporation's Pipeline Safety Implementation Plan, CPSD notes that existing regulations allow for pressure tests to be conducted using air or an inert gas as the test medium and issued a finding that "[t]he use of air, inert gas, or some combination would avoid any damage to pipeline facilities or equipment that could occur from any water not removed from the pipeline after pressure testing and avert potential permitting difficulties related to the disposal of water after testing."[12] The use of in-service natural gas is consistent with this approach. Lowering the MAOP to 72% of the highest recorded pressures over the past five years (1.39 times the new MAOP) will establish a safety margin equivalent to a pressure test needed to demonstrate the stability of the long seams and similar manufacturing flaws. The new, reduced MAOP would serve to provide adequate and defensible validation of the safety of these segments. As a result, additional static pressure testing would be unnecessary, and the risks, limitations, costs, and disruptions associated with pressure testing can be avoided.

SoCalGas and SDG&E's proposed use of an "in-service" test is solely to address "grandfathered" pipelines, and would therefore exceed the requirements that currently exist under the Federal Code.[13]

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11 D.11-06-017, p. 1 (authorizing California's pipeline operators to include alternatives to pressure testing or replacement that "demonstrably achieve the same standard of safety" as pressure testing or replacement).

12 Technical Report of CPSD Regarding Southwest Gas Corporation's Pipeline Safety Implementation Plan, January 3, 2012, p. 12.

13 *See* discussion of the eliminating reliance on the Grandfather Clause in our Testimony in Support of the Proposed Pipeline Safety Enhancement Plan, p. 44.

SoCalGas and SDG&E suggest that an appropriate threshold for such in-service pressure tests should be developed through a collaborative process and reviewed for consistency in approach and technical merit across all class locations.

> **I. CPSD FINDING**: Because the PSEP utilizes "pressure carrying" capability of 1.25xMAOP rather than a documented pressure test to the same level as its first screen, the decision tree excludes 23 miles of Category 3 pipeline segments from SoCalGas' Line 1026 from consideration in Phase 1A, even though these segments do not have a documented pressure test to a level of 1.25 times the segments' current MAOP. If the CPUC requires static pressure tests as recommended above, the Category 3 miles in the PSEP should be rescreened for placement into the correct phase of the PSEP. If the CPUC allows an in-service functional equivalency test, the Category 3 miles should be rescreened to ensure that the functional equivalency is to 1.7 x MAOP. (Report, p. 20)

In a letter issued on May 3, 2011, CPSD provided the following comment concerning pipelines that had proven pressure carrying capability more than 1.25 times MAOP through an "in service test":

> CPSD believes that the pressure reductions Sempra has taken on the Category 3 segments are an important factor in its consideration of the relative priority of hydrotesting these segments, but we do not believe that such permanent pressures reductions serve as a substitute for performing a static pressure strength test (hydrotest) to establish the MAOP for these segments.[14]

Consistent with this comment, in their proposed Pipeline Safety Enhancement Plan, SoCalGas and SDG&E propose to address Category 3 pipeline in Phase 1B or Phase 2, rather than Phase 1A. Given that Commission Staff previously supported using pressure reductions for prioritization, and in light of the authorization in Decision 11-06-017 to propose alternatives to pressure testing, SoCalGas and SDG&E also offered the "in-service functional equivalency" approach as a potentially cost-saving alternative to pressure testing or replacement. As explained in our proposed Pipeline Safety Enhancement Plan, we believe such an approach should be developed through a collaborative process that incorporates the input of technical experts and stakeholders.[15]

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[14] May 3, 2011 letter from Richard Clark, Deputy Director, CPSD to Richard Morrow, Vice President, Southern California Gas Company.

[15] See Proposed Pipeline Safety Enhancement Plan, pp. 59, *et seq*.

Absent formal Commission approval of this alternative, SoCalGas will continue to schedule such segments for pressure testing or replacement, consistent with the prioritization process ultimately approved by the Commission.

> **J. CPSD FINDING:** Segments less than 1000-feet in length should be pressure tested or replaced rather than directly examined in light of the limited cost savings associated with direct examination for these shorts. (Report, p. 21)

SoCalGas and SDG&E also propose to use non-destructive direct examination methods (such as ultrasonic, radiographic, and magnetic particle inspection techniques) for short segments in accordance with the Commission's authorization that "Implementation Plans may include alternatives that demonstrably achieve the same standard of safety"[16] and our overarching objectives to enhance public safety while minimizing customer impacts and maximizing the cost effectiveness of investments in the SoCalGas/SDG&E transmission system.[17] The primary benefit of using non-destructive examination on short segments is eliminating or minimizing the impact to the customer since the line will not be taken out of service. As noted in our Testimony, the benefit of applying direct examination to short segments using proven non-destructive methods is the reduction of time, costs, customer impacts, and hazards associated with pressure testing or replacement.[18]

As further explained in our Testimony:

> Non-destructive examination methods have been used for years as a proven means to inspect pipelines for injurious anomalies. These non-destructive examination methods are typically more direct, reliable, and provide a higher level of anomaly discrimination when compared to pressure testing or in-line inspection. As a result they are commonly employed as part of the overall process to investigate pressure test failures and are also used to validate in-line inspection data. It follows that if these methods provide the reference for validation of other inspection methods, they are viable alternatives for providing the same level of reliable fitness for-service evaluations. Direct examination of the pipeline also has the added benefit of providing additional information that pressure testing cannot, such as coating condition, corrosion, and other sub-critical defects that would not be detected through a pressure test. Additionally, the disadvantages of

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

[17] *See* the full discussion of our four overarching objectives on pages 10-17 of our Testimony in Support of Pipeline Safety Enhancement Plan.

[18] Testimony in Support of Proposed Pipeline Safety Enhancement Plan, pp. 41-42.

> replacement of these short segments, namely the construction of temporary by-pass piping 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.[19]

Although the high level estimates provided in our plan are conservative in nature, it is apparent that the flexibility afforded by this option will provide millions of dollars in savings in Phase 1 and potentially greater savings in Phase 2. Once detailed project planning is completed, the full scope of savings can be determined. Additional flexibility will almost certainly provide benefits in terms of both time and cost, even if the flexibility is only feasible for particular or extenuating circumstances where service disruption or the logistics of testing become onerous.

> K. **CPSD OBSERVATION:** CPSD believes that work and materials related to the installation of fiber-optic sensors and the DCMS may have value. The greatest cost of placement of fiber-optic cable, which must be buried slightly above the pipeline, is the cost of the excavation itself. The costs for material and installation justify placing the cable in the ground even if it is not connected to monitors right away. However, even if the Companies place the fiber-optic cable in all the locations where pipe is replaced, and install the required monitors, it appears to CPSD that the additional protection will be functional in only a very small part of the Companies' system. (Report, p. 21)

CPSD accurately interprets that the fiber installation component is a dominant cost driver of pipeline right-of-way monitoring, and that the scope of pipelines to be up-fitted with such under the Pipeline Safety Enhancement Plan is small in comparison to the total length of the companies' pipeline system(s). What may not be evident from this observation in the Report, however, is that fiber monitoring, as proposed for pipeline replacements to be completed under the Pipeline Safety Enhancement Plan, will also be a technical standard for all pipeline work performed by SoCalGas and SDG&E outside of the Pipeline Safety Enhancement Plan.[20] This means newly-installed pipelines and/or replacements of pipelines twelve inches or greater in diameter covered through the ongoing General Rate Case (GRC) and third-party activity will also be considered for such monitoring, assuming the system is placed in-service.[21] Therefore, the total protected length of pipelines over time will not be limited to the scope of the Pipeline Safety Enhancement Plan mileage. In addition, SoCalGas and SDG&E may find

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19 *Id.*, p. 54.

20 *See* Testimony in Support of the Proposed Pipeline Safety Enhancement Plan, p. 86.

21 Funding for such pipeline/fiber work is not included within the proposed Pipeline Safety Enhancement Plan.

that some existing pipelines may be retrofitted with fiber optic monitoring in an economic manner.[22]

> **L. CPSD FINDING**: The Companies should continue evaluating next generation methane detection technologies. Any technology that shows promise in regard to accuracy, reliability, maintenance needs, and cost should be tested through a pilot program through which the units are evaluated in actual, varying, field conditions, to support wide scale deployment throughout the system. (Report, p. 22)

This finding appears to be based upon the following observation in the Report:

> [T]he benefits of the 2,100 proposed methane leak detection monitors may not justify the costs at this time. Additional leak surveys being performed as interim measures are already providing increased assurance of pipeline safety and will continue to do so until pressure testing and replacement are completed. The Companies have indicated that the installation of the methane detectors will not result in the reduction of current leak detection work or any accompanying savings that might have accrued from normally scheduled leak survey activity being displaced by the installation of the methane detectors. There are no indications that the Companies' current processes and procedures related to leak surveys, odorization, and emergency response are not adequate to enable the Companies' personnel or the public to detect gas leaks, or the Companies' personnel being unable to respond to a gas smell call in a timely manner. Finally, maintaining the calibration of methane detection devices currently in use by SoCalGas has proven to be labor intensive. This is so even though units are installed in a relatively well controlled environment. In the open environment, as proposed in the PSEP, the units would be exposed to all kinds of hydrocarbon, such as gasoline and even car exhaust. The very low sensitivity to which the methane detectors are intended to be calibrated, 1/20 of the normal human sense of smell, will likely result in numerous false alarms requiring a response and unit maintenance.[23]

The approach proposed in the Pipeline Safety Enhancement Plan allows sufficient time and technical latitude to pilot test and evaluate alternative sensing technologies to provide for more robust sensors; and to reconcile existing sensor technology performance with deployment in field applications along pipeline rights-of-way. Table 1 in our supporting Workpaper (WP)-IX-3-32, shows that even under the proposed schedule, only 200 units would be installed by the end of year 2013. This was to leave a year for testing of various units and refinement of application specifications. This measured approach did assume, however, that significant work and capital would be expended in 2013-14 on the Data Collection and Management System (DCMS) to ultimately collect and manage sensor information

22 While the potential costs for retrofitting such pipelines are not included in the proposed Pipeline Safety Enhancement Plan, SoCalGas and SDG&E intend to include requests to fund such projects through future GRC applications, if and when the technical assessments are completed and a monitoring system is approved and in place.

23 Report, p. 21.

from methane detectors via the fiber optic system.

While SoCalGas and SDG&E agree that our leak survey activity provides acceptable and reliable information based on periodic patrols and customer or employee reports of gas odor, the methane detection monitors proposed in the Pipeline Safety Enhancement Plan would provide this information in real-time at a location closer to the pipeline than the public would generally venture. As CPSD rightfully points out, the proposed monitors are able to detect the presence of gas well before the normal limits of human olfactory sensing. Accordingly, in contemplating what SoCalGas and SDG&E might do to improve system safety in a post San-Bruno operations frontier, we believe, and have proposed in our Pipeline Safety Enhancement Plan, that remote methane detection for selected categories of pipeline offers potential enhancement to the current leak detection process.

> **M. CPSD FINDING:** Discretionary activities, such as removal of wrinkle bends or Oxy-Acetylene Girth welds, may be drivers of the extensive clearance times the Companies have identified for pressure tests which are then used as the basis for replacing a segment rather than performing a pressure test on it. (Report, p. 23)

Contrary to statements made in the Report, the proposed decision tree process set forth in the Pipeline Safety Enhancement Plan considers whether a pipeline can be taken out of service with manageable customer impacts in order to determine the assignment of that pipeline to the replacement or pressure test scope. Removal of wrinkle bends did not drive the estimated time required to complete pressure testing. Rather, the planned service outage for pressure testing provides an opportunity to remove wrinkle bends at a reduced cost when compared to removing the line from service solely for wrinkle bend removal.

In general, the lines that were identified for replacement in Phase 1A of the Pipeline Safety Enhancement Plan were identified as such due to the number of customer taps on the lines, the absence of secondary feeds, and the inability to take out of service a line without adversely impacting our customers. The majority of the hydrotest scope in Phase 1A of the Pipeline Safety Enhancement Plan is on major transmission lines that do have parallel lines and, when properly scheduled, can be taken out of service in phases. As indicated in our Testimony and above, we propose to take advantage of this opportunity to remove construction and fabrication threats while the line is out of service.

Manageable customer impact means an acceptable level of negative effects to our customers during implementation of the Pipeline Safety Enhancement Plan.[24] The criteria used to determine whether a segment can be taken out of service varies based upon specific pipeline and local system characteristics that may include, but are not limited to, system looping and flexibility; impact to capacity; curtailment to non-core customers; impact to shippers, customers, and the gas market; availability of alternate sources of gas; and anticipated outage duration.

In order to address the anticipated outage duration, a time period of two-to-six weeks to complete pressure testing was used as a general guideline to assist in the high-level development of the Pipeline Safety Enhancement Plan replacement and pressure test scope. Considering the activities and logistics involved in a pressure test, such as installation of necessary valves/test heads, isolation of taps, gas handling, purging, pressure testing, minor leak detection and repair, de-watering after the test and tying facilities back into existing piping system infrastructure, two-to-six weeks is a reasonable general assumption for project duration. Although the removal of oxy-acetylene girth welds or wrinkle bends is not a driver for the time required to conduct the test, if the wrinkle bends are not addressed prior to a test and a failure occurs during the pressure test, it can prolong the test duration.

As discussed in Section IV of our Testimony, SoCalGas and SDG&E believe construction and fabrication threats should be addressed as part of our proposed Pipeline Safety Enhancement Plan. The stability of oxy-acetylene girth welds and wrinkle bends cannot be fully assessed with pressure testing and in-line inspection tools. The removal from service for pressure testing, combined with the logistics already committed to preparing for pressure testing, provide a window of opportunity for SoCalGas and SDG&E to mitigate these features. Execution of the Pipeline Safety Enhancement Plan provides a particularly opportune time for this type of mitigation in High Consequence Areas and urbanized environments where access and logistics continue to narrow such windows of opportunity. The cost of this effort will be minimized through synergies with the mobilization that will already take place to support the pressure test. The removal of these historic features will also provide for more reliable service and a lower likelihood of disruption to customers that may have otherwise resulted from pressure test failures.

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[24] *See* discussion of reliability of service to customers on pages 35 and 36 of our Testimony in Support of the Pipeline Safety Enhancement Plan.

As each line and segment has unique characteristics, further definition and substantiation of pressure testing scope and schedule will be determined after development of engineering, design, and execution planning.

> **N. CPSD FINDING**: If the Companies cannot provide records showing that the 20 miles of pipeline segments installed between July 1, 1961 and 1970 were tested and documented per GO 112 requirements, the segments lacking documentation must be tested or replaced at the Companies' expense. (Report, p. 24)

In the Report, CPSD correctly observe that SoCalGas and SDG&E propose "to absorb costs related to pipeline segments installed after 1970 that do have insufficient pressure test documentation, but [do] not propose similar segments installed between July 1, 1961 and 1970 with similar deficiencies." As noted in the Report, segments installed between July 1, 1961 and 1970 were subject to the provisions of General Order 112, which codified safety requirements for transmission pipelines in California at that time. The safety requirements of General Order 112, however, are not sufficient to satisfy the Commission's directives in Decision 11-06-017, which directs California's pipeline operators to "file and serve a proposed Natural Gas Transmission Pipeline Comprehensive Pressure Testing Implementation Plan (Implementation Plan) to comply with the requirement that all in-service natural gas transmission pipeline in California has been pressure tested in accord with 49 CFR 192.619, excluding subsection 49 CFR 192.619 (c)." This requirement to either test or replace all pipeline segments that lack documentation sufficient to exceed current Federal regulations requires the testing or replacement of all pipeline segments installed between July 1961 and 1970, regardless of documentation. Thus, the question of whether existing documentation satisfies the requirements that existed between July 1961 and 1970 irrelevant. The requirement to test or replace these segments is driven entirely by the Commission's desire to exceed current Federal regulations, and therefore, the costs of such testing or replacement should be borne by our customers.

Moreover, CPSD's finding appears to be premised on the assumption that if a pipeline operator lacks documentation today sufficient to show compliance with regulations that were superseded by subsequent regulations more than forty years ago, that pipeline operator should be penalized regardless of whether that pipeline operator has documentation sufficient to satisfy current regulatory requirements under the Grandfather Clause. As this assumption is not consistent with current legal requirements or equity, the ratemaking recommendation based on this assumption would constitute retroactive ratemaking and should not be adopted by the Commission.

II. CONCLUSION

SoCalGas and SDG&E would like to once again reiterate their appreciation for CPSD's efforts in thoroughly reviewing our proposed Pipeline Safety Enhancement Plan. SoCalGas and SDG&E share the Commission's commitment to enhance the public safety and reliability of California's natural gas transmission infrastructure and look forward to continuing to work closely with Commission Staff to further refine and improve our plan to achieve the Commission's goals in the most cost effective and efficient manner possible, while maintaining our commitment to providing our customers with reliable service.

Respectfully submitted,

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