IN THE MATTER OF
CALIFORNIA PUBLIC UTILITIES COMMISSION
RULEMAKING 11-02-019

PREPARED DIRECT TESTIMONY
OF
LYNN A. MALLOY

ON BEHALF OF
SOUTHWEST GAS CORPORATION

August 26, 2011

BEFORE THE CALIFORNIA PUBLIC UTILITIES COMMISSION

Prepared Direct Testimony
of
LYNN A. MALLOY

Q. 1 Please state your name and business address.

A. 1 My name is Lynn A. Malloy. My business address is 5241 Spring Mountain Road; Las Vegas, Nevada 89150-0002.

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

A. 2 I am employed by Southwest Gas Corporation (Southwest Gas or the Company) in the Corporate Engineering Staff department. My title is Director/Engineering Staff.

Q. 3 Please summarize your educational background and relevant business experience.

A. 3 My educational background and relevant business experience are summarized in Appendix A to this testimony.

Q. 4 Have you previously testified before any regulatory commission?

A. 4 No.

Q. 5 What is the purpose of your direct testimony in this proceeding?

A. 5 I sponsor testimony supporting the Company's Natural Gas Transmission Pipeline Comprehensive Pressure Testing Implementation Plan (Implementation Plan) pursuant to the California Public Utilities Commission (CPUC) Order Instituting Rulemaking 11-02-019 (Rulemaking).

Q. 6 Please summarize your prepared direct testimony.

A. 6 My prepared testimony summarizes:

- Southwest Gas' transmission systems including those facilities which do not have pressure testing records.
- The Company's analysis, prioritization, and decision-making to propose replacing approximately 7.1 miles of transmission pipeline.
- The interim safety enhancement measures being implemented until such replacement can be completed.
- Whether any transmission facilities require retrofitting to accommodate in-line inspection tools and where appropriate, whether automated or remote controlled shut off valves need to be installed to meet all the requirements set forth in the Rulemaking.

Q. 7 Please briefly describe Southwest Gas' California transmission systems.

A. 7 Southwest Gas maintains approximately 15.4 miles of pipeline classified as transmission in California under the CPUC's jurisdiction. The 15.4 miles of pipeline is located within two systems: The Harper Lake Transmission System and the Victor Valley Transmission System.

Q. 8 Please describe the Harper Lake Transmission system and whether any portion of the system has had a pressure test in accordance with General Order 112.

A. 8 The Harper Lake Transmission System contains approximately 8.30 miles of 10-inch, 12-inch, and 16-inch original steel pipe installed in 1989 that has been pressure tested consistent with the requirements of 49 CFR 192 Subpart J and has readily available test records to establish its MAOP. The Harper Lake Transmission System, which resides in areas of both Class 1 and Class 3 locations, with no High Consequence Areas, has a Maximum Allowable Operating Pressure (MAOP) of 720 psig and a Maximum Operating Pressure (MOP) of 550 psig which corresponds to a hoop stress of 39% as a percentage of Specified Minimum Yield Strength (SMYS).

Because the Harper Lake Transmission System complies with the pressure test requirements identified in the Rulemaking, the focus of this system in the Implementation Plan is the ability to accept in-line inspection tools, as well as to consider placement of automated or remote controlled shut off valves. These issues are discussed later in this testimony.

Q. 9 Please describe the Victor Valley Transmission system and whether any portion of the system has a pressure test in accordance with General Order 112.

A. 9 The Victor Valley Transmission System is comprised of 7.1 miles of 6-inch and 8-inch steel pipeline. The pipeline was installed in 1957 and 1965 and has no original, readily available test records. The pipeline is located primarily within a Class 3 location and contains 1.33 miles of High Consequence Areas (HCA). The pipe specifications such as wall thickness and pipe grade are unknown. Southwest Gas has assumed the minimum SMYS value and longitudinal joint factor allowed by 49 CFR Part 192 and a minimum wall thickness based upon commercially available pipe, as specified in the Company's Operations Manual. The pipeline's MAOP of 250 psig is based upon an uprating conducted in 1973 in accordance with 49 CFR 192 Subpart K in effect at that time. The MAOP and MOP produce a hoop stress of approximately 24% and 23%, respectively.

Q. 10 Does Southwest Gas' uprating procedure conducted in 1973 comply with the criteria of this Rulemaking?

A. 10 No. In 1973, Southwest Gas' uprating procedure did not subject the pipeline to a pressure test 1.5 times its MAOP, as is currently required by this Rulemaking. As a result, three options were considered for the Victor Valley Transmission System in the Implementation Plan to meet the standards of the Rulemaking: (1) pressure testing, (2) a pressure reduction, or (3) replacement.

Q. 11 Please briefly describe the analysis performed by the Company that supports its recommendation to replace the Victor Valley Transmission System.

A. 11 The first step was to perform an analysis to determine whether pressure testing of the system would be prudent. As previously mentioned, Southwest Gas does not know the pipeline specifications, and therefore assumes the minimum wall thickness, pipe grade and longitudinal joint factor. Furthermore, the installation practices are unknown including whether any radiographic examinations of butt welds were conducted. The pipeline also contains laterals to both existing and abandoned pressure limiting stations as well as components such as fitting caps that will require replacement prior to any pressure test. Though the 54 year old pipeline has been safely operating at or near its MAOP of 250 psig for nearly 38 years, the Company does not believe it would be prudent to subject the pipeline to a hydrostatic strength test of 1.575 times its MAOP without the knowledge of these pipeline specifications. It is best to identify, if possible, any potential manufacturing or construction defects prior to subjecting the pipeline to higher stress levels. The defects would be repaired prior to the pressure testing and thereby potentially avoiding negative issues including extensive customer outages. The Company would need to engage in a costly sampling program to test the wall thickness, SMYS and joint factor in accordance with the requirements set forth in 49 CFR Part 192. It is unknown whether these tests would result in a positive conclusion to hydrostatically test the pipeline. The cost of all the above work including the hydrostatic test is estimated at approximately $3,750,000. Furthermore, should leaks or other issues be discovered during the testing, additional customer outages could occur to perform immediate repairs or replacement resulting in additional costs. Next, Southwest Gas analyzed whether the pressure could be reduced from 240 psig to 151 psig, thereby using its current operating pressure as its test pressure. Specifically, this pressure was derived by using the NTSB Safety Recommendation of a pressure test plus a spike. Implementation of this recommendation would require a peak pressure of 1.575 times the proposed MAOP, thus making the new MAOP of the pipeline 63% of its current MOP, or 151 psig. Southwest Gas' analysis showed that it was not possible to meet current design day load requirements with such a pressure reduction.

After careful consideration of the pressure testing and pressure reduction alternatives, Southwest Gas concluded that replacement of the entire 7.1 miles of pipeline was the most prudent alternative. The estimated cost of replacement is $7,150,000. The pipeline will be replaced over an 18-24 month period and will be designed to operate at less than 20% of SMYS, thereby classifying it as a distribution system.

Q. 12 Why is Southwest Gas recommending replacement of the pipeline as opposed to pressure testing?

A. 12 Based on the evaluation of the alternatives, replacing the existing transmission pipe with new pipe operated at distribution stress levels was determined to be the best option. Though the pressure testing may be less costly than replacing pipe, potential leaks by subjecting the pipe to a 1.575 times pressure test could increase the overall costs and customer constraints substantially. Furthermore, the pressure testing alternative will not accommodate the future use of in-line inspection (ILI) tools. Replacement of the pipeline will enhance the overall integrity of the pipeline system to the greatest extent of the three identified alternatives, thereby further mitigating risk within the HCA's while meeting the overall goal of improving public safety.

Q. 13 How does Southwest Gas' implementation plan prioritize its schedule for replacing the pipeline over an 18-24 month period?

A. 13 Southwest Gas' first priority is to replace a total of 3.1 miles of pipeline which is primarily within a Class 3 location and includes all of the 1.33 miles of HCA's. The second and final priority will be to replace the remaining 4.0 miles of pipeline. Our goal is to complete the work as soon as practical. To enhance public safety, additional interim safety measures will be implemented until replacement is completed.

Q. 14 What interim safety measures does the Company propose?

A. 14 Southwest Gas first evaluated whether it could reduce the pipeline pressure to 80% of the recorded MOP, or 192 psig. The analysis concluded that peak day customer load requirements would not be able to be met with this pressure reduction. Southwest Gas therefore will double the amount of leak surveys and patrols required by 49 CFR Part 192 until the pipeline is replaced.

Q. 15 What conclusion did the Company derive from its evaluation to retrofit its transmission facilities to allow for ILI tools?

A. 15 The existing Victor Valley Transmission System is not capable of accommodating ILI tools. However, the replacement of the Victor Valley Transmission System will be designed to accommodate ILI tools with the exception of launchers and receivers. The Harper Lake Transmission System in its current configuration is capable of accommodating ILI tools with the exception of launchers and receivers. Launchers and receivers are not planned for installation on either system at this time.

Q. 16 What was the Company's conclusion regarding the installation of automated or remote controlled shut off valves?

A. 16 The enhanced safety of replacing the Victor Valley Transmission system with a distribution system combined with the accessibility to manually operate valves in less than 25 minutes along any part of the pipeline, has led Southwest Gas to conclude that the installation of such valves is not warranted.

The time to access manually operated valves within the Harper Lake Transmission System could take up to 60 minutes. Southwest Gas has decided to install a remote-controlled shut off valve on this pipeline for enhanced safety and response time to secure the pipeline from an unintentional release of gas.

Q. 17 What is the Company's estimate and schedule for the installation of the remote-controlled shut off valve?

A. 17 The Company estimates the cost to be approximately $250,000 and its installation will be completed within the same 18-24 month period of the proposed pipeline replacement.

Q. 18 What is the Company's rate proposal regarding the costs of the pipeline replacement and remote-control shut off valve?

A. 18 Please refer to Company witness Edward Gieseking's testimony concerning the rate proposal.

Q. 19 Does this conclude your prepared direct testimony?

A. 19 Yes.

Appendix A

SUMMARY OF QUALIFICATIONS
LYNN A. MALLOY, P.E.

Lynn A. Malloy is the director/Engineering Staff for Southwest Gas Corporation (Southwest Gas). She directs and coordinates support to five operating divisions for pipeline safety code compliance; distribution integrity management; material specifications and approval; environmental compliance; proper energy measurement; pipeline cathodic protection; SCADA support; project design; and the training and qualification of technical services personnel.

Ms. Malloy joined Southwest Gas in 1988 as an engineer in Las Vegas, Nevada. She was subsequently promoted to distribution engineer in 1989 and supervisor/Engineering in 1991. During this period, Ms. Malloy oversaw the design of transmission and distribution facilities for new business, franchise and system reinforcements; safety code compliance; Gas Control and compressor station operations; MAOP studies and requalification programs; and preparation of short and long-term capital budgets.

She was promoted to manager/Engineering Planning in 1998 where she directed project management services of transmission projects to Southwest Gas' five operating divisions and Paiute Pipeline. Project management services included hydraulic modeling, preliminary design, cost estimates, major equipment/material selection, environmental surveys/reports, and Federal and State permit/easement acquisition. Other responsibilities included the liaison with interstate companies for new and modification of upstream facilities. Ms. Malloy was subsequently promoted to director/Engineering Staff in March of 2011.

She holds a Bachelor of Science degree in Civil and Environmental Engineering from Michigan State University. She is a registered Professional Engineer in the State of Nevada with a proficiency in Civil Engineering. Ms. Malloy currently serves on AGA's Operations Safety Regulatory Action Committee.