Report on Investigation Of Pacific Gas and Electric Company's Gas Transmission Pipeline 147

California Public Utilities Commission
Safety and Enforcement Division
Gas Safety and Reliability Branch

November 14, 2013

Executive Summary

The CPUC first examined the safety of Line 147 in 2011 after PG&E filed an application to lift operating pressure restrictions on the line above the 300 pounds per square inch gage (psig) level at which the line had been operating. PG&E voluntarily reduced the maximum pressure on Line 147 to 300 psig as part of its compliance actions related to the CPUC Executive Director's September 13, 2010 order reducing pressure on Line 132. On October 31, 2011 and November 15, 2011, PG&E served documents supporting its request to increase maximum operating pressure (MOP). [1] The Commission's Consumer Protection and Safety Division (CPSD) reviewed the filing and found no significant issues to prohibit PG&E from increasing the pressure in Line 147, which in 2011 passed a hydrostatic pressure test at levels above minimum requirements per regulations, to 365 psig (below its historical indicated Maximum Allowable Operating Pressure (MAOP) of 400 psig).

Following the formal application review process, an evidentiary hearing was held on November 11, 2011 to review supporting information provided by PG&E. Through Decision (D.) 11-12-048, the Commission formally permitted PG&E to increase the MAOP of Line 147 to 365 psig.

On October 15, 2012, PG&E identified a leak on Line 147. Based on the evidence collected and reviewed by the CPUC, the following took place after discovery of the leak:

- PG&E performed work to repair the leak in October and November of 2012.
- During the repair work, PG&E became aware that the pipeline features in PG&E validated records did not match the characteristics of the pipe observed in the ground.[2]
- PG&E's analysis initially indicated corrosion as the cause of leak found on Segment 109 of Line 147.
- PG&E sent a sample of the pipe to an independent laboratory, Anamet Inc., for analysis. Anamet's analysis attributed the cause of the leak to a very small crack that formed at the root of a fill-repair that added material to the wall. The repair was on the body of the pipe and not on any girth

[1] Maximum Allowable Operating Pressure is defined by 49 CFR, Part 192.3, as "the maximum pressure at which a pipeline or segment of a pipeline may be operated under this part." While establishing MAOP is a regulatory requirement, an operator may establish a Maximum Operating Pressure (MOP) that is lower than the MAOP because some sections of the pipeline or other conditions prevent the operator from operating the entire line up to MAOP. Normally, removal of the sections or condition limiting operations to MOP enables the operator to operate the entire pipeline up to its established MAOP.

[2] The pipeline observed had an A.O. Smith seam, but the validated records from 2011 indicated that the pipeline had a Double Submerged Arc Weld (DSAW) seam.

weld or longitudinal seam. The report also found no evidence of crack growth in the pipe prior to or during the 2011 hydro-test.

- PG&E also had another independent laboratory, Exponent, review samples from Segment 109. Exponent's findings supported those of Anamet.
- PG&E's repair procedures continue to utilize fill-weld as a method to repair metal loss.

On August 19, 2013, in Rulemaking (R.) 11-02-019, the Chief Administrative Law Judge (ALJ) and the Assigned ALJ issued a ruling directing PG&E to show cause why it should not be sanctioned by the Commission for Violation of Rule 1.1 of the Commission's Rules of Practice and Procedure relating to the filing of an "Errata to PG&E Supporting Documentation for Lifting Operating Pressure Restrictions on Line 101, 132A and 147." On the same day the Assigned Commissioner and the Assigned ALJ directed PG&E to appear and show cause why all Commission Decisions authorizing increased operating pressure should not be stayed pending demonstration that records are reliable. On October 8, 2013 the Assigned Commissioner and the Assigned ALJ directed PG&E to file and serve updated safety certification for Line 147. The Commission is actively working to further confirm the ongoing integrity of Line 147.

Safety and Enforcement Division (SED) performed a review of the information contained in PG&E's 2013 Certification for Line 147 to determine the MAOP for the line, as well as what progress PG&E has made to monitor, control, and shutdown pressure on Line 147. SED also investigated PG&E's process to perform a root cause investigation of the cause of the leak. This included investigation of the concerns expressed in a November 17, 2012 e-mail by David Harrison, a former PG&E engineer working as a contractor for PG&E, regarding the potential relationship between the 2011 hydro-tests performed on Line 147 and the leak found on Segment 109.

Based on the results of its findings, SED found no issues at this time that should limit PG&E's operation of Line 147 to a Maximum Operating Pressure (MOP) below 330 psig.[3]

Background

To ensure the safety and reliability of gas pipeline systems in California, the CPUC has adopted several of the most stringent pipeline safety measures in the nation. Driving these measures is the CPUC's commitment to eliminate the

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"grandfathering[4]" of historical pressure levels on transmission pipelines by requiring jurisdictional operators to strength test or replace such lines. Operators must review and validate available records in support of such tests, but the records alone do not serve as a substitute for the strength testing of pipelines missing pressure test documentation. In addition, the Commission is mandating that operators install automated control valves and monitoring equipment in order to more quickly identify safety-related events on transmission lines and take actions to isolate affected sections.

Following the pipeline rupture, explosion and fire of Segment 180 on Line 132, in San Bruno on September 9, 2010, the Executive Director of the CPUC ordered PG&E to reduce pressure on Line 132 by 20% from the operating pressure of 375 pounds per square inch gage (psig) in place prior to September 9, 2010. Because Lines 101, 109 and 132 are all supplied gas through a common header at Milpitas Terminal, the reduction in pressure of Line 132 forced a reduction of the MOP of Lines 101 and 109 to the same level of 300 psig, established for Line 132. Along with Lines 101 and 109, PG&E also voluntarily reduced the MOP of Lines 132A, and 147 to 300 psig on September 13, 2010.

Commission D.11-09-006, issued on September 8, 2011, requires PG&E to provide a filing with the CPUC before increasing or restoring operating pressure on any pipelines for which the CPUC issues an order to reduce operating pressure. As part of its filing, D. 11-09-006 requires PG&E to provide a statement of concurrence from the CPUC's Consumer Protection and Safety Division (CPSD) now known as the Safety and Enforcement Division (SED) with the requested pressure increase.

The requirements of D. 11-09-006 did not apply to Lines 101, 132A, or 147 because no CPUC order directed PG&E to reduce pressure in these lines. Nonetheless, CPSD provided guidance to PG&E that all lines where PG&E reduced pressures, either voluntarily or by CPUC directive, while MAOP validation occurs should be subject to a public review process, and receive CPSD's concurrence with the intended pressure restoration before increasing pressures.

On October 31, 2011, Pacific Gas and Electric Company (PG&E) filed documentation to support its request to increase the MOP of its Lines 101, 132A, and 147 and related pipeline facilities - such as supply lines to distribution systems or large customers, blow down vents, etc., which are referred to as "Shorts" within its filing (hereafter referred to as "Request"). Through its Request, PG&E sought to increase the MOP of all pipeline facilities included therein, to a maximum of 365 psig in order to meet winter demand. An MOP of 365 psig was lower than the MOP of 375 psig in place prior to September 9, 2010,

[4] "Grandfathering" is a term used to describe the rule under 49 Code of Federal Regulations (49CFR), Part 192, which exempts certain gas pipelines lines, that were put in service prior to the regulations, from some safety requirements. Specifically, Part 192 permits operators of certain pre-1970 pipe to establish the Maximum Allowable Operating Pressure (MAOP) based on highest actual operating pressure at which the pipeline had been operated during for the five-year period preceding July 1, 1970.

but higher than the 300 psig MOP under which PG&E had been operating since September 13, 2010.

CPSD performed an overall review to determine if PG&E's 2011 Request showed that the company had established and generally applied its MAOP validation processes. However, as CPSD noted in its report on its review of PG&E's filing, the large volume of data did not permit CPSD to confirm each of the thousands of pipeline features included in PG&E's Pipeline Features Lists (PFL) for each of the Lines 101, 132A, 147, and related Shorts on each of the lines.

With some exceptions, the CPSD's review in 2011 noted that all of Line 101, 132A, 147, and related Shorts that, at 365 psig, are considered transmission level facilities, had been subjected to strength testing. CPSD's review also found that PG&E performed spike tests (5-10%) for all pressure testing for the pipeline facilities subject to the Request. CPSD provided PG&E with its concurrence to operate Lines 101, 132A, and 147 at 365 psig. PG&E filed this concurrence as a supplement to its filing. After an Evidentiary Hearing to examine PG&E's filing to increase the MOP on Lines 101, 132A, and 147, held on November 22, 2011, Commission Decision 11-12-048 (D.11-12-048) permitted PG&E to begin operating Lines 101, 132A, and 147 at a maximum of 365 psig.

On October 15, 2012, PG&E found a leak on Segment 109 of Line 147. Based on findings through the process of repairing the leak, PG&E established an MOP of 330 psig on Line 147. As of May 2012, PG&E has not operated Line 147 at a pressure exceeding 300 psig.

Investigation Findings

On October 15, 2012, approximately 10 months after D.11-12-048 permitted the company to begin operating Line 147 at an MOP of 365 psig, a PG&E employee conducting stand-by activities to prevent third-party excavation-related damage to Line 147 noticed bubbles in standing water above the pipeline. PG&E records show that the company began immediate actions to further evaluate and assess the severity of the leak, beyond the surface indication, and by October 18, 2012 had exposed the pipe. At that time, PG&E downgraded the leak from the initially assigned Grade 1 (Hazardous with immediate ongoing action required to repair or mitigate the hazard) to a Grade 2+ (non-hazardous but requiring repair within 90 days), due to the very low leakage rate and because the leak was vented (non-migrating).

On November 13, 2012, the company made permanent repairs to stop the leak, which it initially assessed as being external corrosion-related, by using a 6-inch cap from PLIDCO attached to the pipe through a fillet weld process. SED reviewed records for the last five years for leak surveys and cathodic protection monitoring performed for Segment 109, the section of Line 147 on which the leak was located, and found no deficiencies having been noted through either of these code-required maintenance activities.

In the process of exposing and making repairs to the leaking pipe, PG&E also became aware that the type of the pipe encountered in the field, and which constitutes Segment 109 of Line 147, was different from what its updated records reflected. These updated records were what PG&E had used to validate the characteristics of the segment and determine the MOP of 365 psig noted in its October 2011 filing to increase pressure on Line 147.

On October 8, 2013, a Ruling of Assigned Commissioner and Assigned ALJ in R. 11-02-019, directed PG&E to File and Serve Updated Safety Certification for Line 147. Through its filing, PG&E was expected to provide information supporting its determination of the impact of the discrepancies, between field findings and records for Segment 109 as well as some other segments identified by PG&E through its ensuing investigation, on the ongoing integrity and operability of Line 147. On October 11, 2013, PG&E provided its supporting information for mainline Line 147 and on October 16, 2013, PG&E provided similar information for Line 147 "Shorts," which are smaller diameter pipelines (i.e., gas supply to individual customers, district regulator stations, drips, blowdown lines, stubs, etc.) tapped to Line 147.

SED performed a review of PG&E's certification information for Line 147 to determine the MOP for the line, as well as what progress PG&E had made to monitor, control, and shutdown pressure on Line 147. SED also investigated PG&E's process to perform a root cause investigation of the cause of the leak. This included investigation of the concerns, expressed in a November 17, 2012 e-mail by David Harrison, a former PG&E engineer working as a contractor for PG&E, regarding the potential relationship between the 2011 hydro-tests performed on Line 147 and the leak found on Segment 109.

<u>Line 147</u>

Line 147 is a cross-tie line, composed of 20 and 24-inch diameter pipe, which traverses the City of San Carlos in generally an east-west direction. Line 147 was originally installed in 1947, including Segment 110; however, a portion of the line was relocated in 1957 to accommodate work on a road in San Carlos. The pipeline installed in 1957 includes Segments 108, 108.1, and 109. Records show that Segments 108 and 108.1 were post-construction pressure tested to 750 psig for one hour to establish a 500 psig design pressure in a Class 3 location. In addition to supplying natural gas to four district regulator stations which supply gas to the distribution systems in San Carlos, Line 147 serves the crucial function of re-routing natural gas between Lines 101, 109 and 132 for routine operational needs, during an emergency, or during planned work which requires sections of pipelines to be isolated. Since work began to test or replace pipelines missing or having incomplete pressure test documentation, the intertie function of Line 147 has become that much more important.

CPSD examined PG&E's 2011 pressure records for Line 147 during its first review and found no significant issues with the testing performed. The documentation for the tests included test plans, water volumes, charts, and digitally-recorded information related to the monitoring of temperatures and pressures throughout the test. The hydro-tests themselves were performed by an independent contractor certified by the California Fire Marshal's Office. An engineering firm independent to PG&E, RCP Inc., also performed a review of the quality of the tests, modeling to account for any volume changes throughout the tests, and provided final certification for the validity of the tests towards establishing the final MAOP for the tested section of pipe.

Specifically, CPSD's 2011 review found that PG&E had:

- Hydro-statically or pressure tested gas transmission pipelines and associated components in 2011 in accordance with 49 CFR 192 Subpart J in HCAs (all Class 3 and 4 and HCAs in Class 1 and 2) where a pressure test record could not be located. All hydro tests included a spike test.

- Verified that pressure test records exist for all other pipelines and associated components located in HCAs, including shorts operating greater than or equal to 20% of Specified Minimum Yield Strength (SMYS).

- Conducted excavations in 2010 and 2011, to perform direct inspection of pipeline facilities, in order to obtain missing information or validate questionable data.

- Verified that all leaks found on facilities included in the Request were repaired.

- Verified that PG&E's hydro-tests meet current requirements of 49 CFR Part 192, Subpart J, or those in effect at the time when the pressure test was conducted (OP 4 of D.11-09-006).

As part its October 2013 recertification filing, PG&E provided updated test pressure reports for two of the tests, T42 and T43B. Documentation for T43A remained the same as that provided in October 2011. SED reviewed the two reports updated in March 2012 and noted that there were only minor differences in the data from the 2011 reports. However, SED noted that the March 2012 reports included data related to 192.619 (a)(1)(i) , which references section N5 of Appendix N, of ASME B31.8-2007, in determining a possible MAOP value based on the yield point determined from data gathered during a strength test.

According to the March 2012 reports, the MAOP values established by tests 42 and 43B, based on Appendix N would be 220 and 236 psig for tests 42 and 43B, respectively. However, the test certifications from RCP Inc. and the pressure test documentation itself, including pressure-volume plots, showed that no yielding of the pipe section occurred throughout any of the tests, including the spike pressure. Since no yielding in any tested pipe section occurred at pressures well above the Appendix N values shown in the March 2012 reports, SED determined these low values could not be correct when all the data included in the report, as well as information shown on the pressure charts, is considered.

Discussion with PG&E regarding the suspect data and updated information provided by PG&E's vendor certifying the test confirmed SED's suspicions regarding the 2012 data being incorrect. SED accepted the updated data provided by the vendor. SED finds that the data PG&E has presented for the three mainline tests, and the test for the mainline valve performed for Line 147, can support an MOP of 330 psig established by the tests.

<u>Line 147 Segments Updated in PG&E's 2013 Line 147 Certification Filing:</u>

As part of its 2013 Certification filing, and other information which it has learned following its filing, PG&E changed specifications for seam type, and the safety factor for class location, for several segments of Line 147. SED reviewed the changes to these segments, as well performed an overall review of other pipeline features contained in PG&E's filing. As it noted before, the number of pipeline features, even for Line 147 alone is extensive; therefore, it is not possible for SED to confirm every feature listed in the filing. However, SED did examine five randomly selected features in detail to review documents supporting the listed feature. This review found no issues with the supporting materials. In addition, on October 25, 2013 SED conducted a field review of the work at Edgewood Cross-tie station, Commercial Way, and inspected parts of the right-of-way for Line 147. SED found three issues, that PG&E has addressed, which are discussed later in this report. Details related to the changes for the specific segments are as follows:

<u>Segment 100.3</u> – PG&E indicated that this is a 2-foot section of pipe upstream of Valve V-0.00 designated as segment 100.3 which PG&E indicated was historically associated with Line 147, but was not part of the pressure restoration filing as this pipe was connected to L-109 and L-132 and isolated from L-147 at the closed valve, V-0.00. Moreover, SED observed during its field inspection that this section of pipe has been replaced as part of the construction being performed at Edgewood Cross-tie Station. Nonetheless, SED reviewed the operating diagrams, operating map and MAOP Validation Report associated with Segment 100.3 and determined they were upstream of Valve-0.00, and based on pipe specifications that would enable the pipe to operate at pressure of 1,260 psig in its Class 1 location. This is well above the historical MAOP of 400 psig of the lines to which the segment was cross-tied.

<u>Segments 103, 103.1, and 103.6</u> – A discrepancy was noted by the engineer validating records in 2011 that indicated that a transmission plat noted both

seamless and butt-welded pipe for these segments while a purchase order noted "seamless only" for the segments. However, the PFL continued to reflect the segments being seamless until noted during the review of Line 147 pipeline features PG&E conducted in 2012. PG&E conducted a field examination at an above ground span at M.P. 0.52 and found the seam to be single submerged arc-welded (SSAW) and not DSAW. Applying a joint fact (JF) of 0.8 JF per PG&E's standards for an SSAW seam determined for these segments resulted in:

- Segment 103 decreasing from an MAOP of 590 to 495 psig
- Segments 103.1 and 103.6 decreasing from an MAOP of 409 to 343 psig

<u>Segments 108 and 108.7</u> – The installation of Segment 109 occurred along with the same job that installed Segments 108 and 108.7. PG&E states that records for Segments 108 and 108.7 correctly reflected a 0.8 JF due to the seam type being indicated in the original validation as "unknown greater than 4-inch" which defaults to 0.8 JF. However, after destructive tests showed a SMYS for the pipe as being 42,000 psi, PG&E chose to apply a conservative value of 33,000 psi to segment. As a result, this caused PG&E to reduce the MAOP of Segments 108 and 108.7 from 525 to 412 psig. However, through its October 18, 2013 supplement, PG&E further reduced the MAOP to 330 psig based on an August, 29, 2013 report, on testing performed by PG&E's Applied Technology Services (ATS) (ATS Report# 413.61-13.327), which confirmed the wall thickness to be .250-inches.

PG&E also determined that an error in mile-point designation on a December 2, 2011 H-form for an October 21, 2011 excavation (T43A, Location B/T-43B Loc. B) associated M.P. 1.89 with Segment 107.7. The H-form also indicated the pipe as being 20" diameter DSAW, .261-.275 wall. However, PG&E records reflected pipe at M.P. 1.89 as being 24-inch diameter pipe and not 20-inch pipe. PG&E continued to rely on a 1957 pressure test to apply a .3125 wall thickness value for Segments 108 and 108.7, but discounted other considerations from the December 2011 H-form until the August 29, 2013 confirmation from ATS.

However, SED reviewed documents that showed ATS, in its May 31, 2012 report (Report# 413.62-12-55), the same report that provided the SMYS value of 42,000 psi for the Line 147 sample submitted for destructive testing, denoted the section of pipe sent to ATS for the analysis as being 20-inch diameter and having a wall thickness of .256-inches. In addition, the GPS data shown on the spool in the photograph provided with the August 29, 2013 ATS Report (Report#413.61-13.327), is the same as the GPS data in the December 2011 H-form, and the GPS data in ATS Report# 413.62-12-55. Moreover, the May 31, 2012 ATS Report# 413.62-12.55 shows the mile-point for the tested section as being "M.P. 1.951" the same mile-point to the December 2, 2011 H-form was changed to reflect (i.e., changed from M.P. 1.89 to M.P. 1.951) on August 27, 2013.

SED's review of the December 2, 2011 H-form shows, in the photograph of the feature long joint seam @ 8:55, on page 22, what appears to be an A.O. Smith seam on the cut-out section of pipe. However, PG&E's vendor, G.E. Inspection Services, incorrectly indicated the seam as being DSAW on the December 2, 2011 H-form, for the October 07, 2011 excavation. PG&E has stated it believes the seam is not A.O. Smith, but an SSAW seam. In addition, SED found that the chain of custody form, used to document the cutout section removed from the jobsite, also continued to reflect, incorrectly, the wall thickness of the section as being .3125-inches.

Based on the above information, it is apparent to SED that by December 2, 2011 PG&E had information available showing that the wall thickness of pipe installed in Segments 108 and 108.7 was of .256-inches and not .3125-inches as reflected in its validated records. Another opportunity to become aware of this would have occurred through review of the May 31, 2012 ATS Report #413.62-12.55, which also conveyed the correct information regarding the wall thickness of pipe installed in Segments 108 and 108.7 being .256-inches and not .3125-inches. It is not known if or when the wall thickness information from the ATS report was communicated to the MAOP validation group, or why the information did not result in this value being applied to Segments 108 and 108.7 earlier than August 29, 2013. It is also apparent that the chain of custody process is not providing for a "checks and balances" which enables discrepancies in pipeline specifications to be identified early in the transfer process and communicated to those who could make use of the information towards making operations and maintenance decisions.

<u>Segment 109</u> – PG&E indicates that due to an engineer not applying its procedures correctly, Segment 109, based on an assumption, was designated as being DSAW and, as a result, a JF of 1.0 was assigned to the seam and the segment. Failures in quality control that did not confirm the first engineer's work was peer-reviewed to confirm that assumptions were applied per procedures, further contributed to the error passing through into the validated data for the MAOP. After the finding in October 2012 that Segment 109 contained A.O. Smith pipe and the application of a 0.5 Class 3 factor to eliminate the possibility of the segment being one-class-out in a Class 3 location, PG&E reduced the MAOP for Segment 109 437 to 330 psig.

<u>Segment 110</u> – An H-Form for a 2004 ECDA dig indicated the pipe observed at Segment 110 to be 22-inch diameter, .281 wall, A.O. Smith pipe. However, the MAOP validation performed in 2011 determined the segment as being 20-inch seamless pipe based on plat sheets and other company records that showed the installed pipe to be 20-inch seamless. Although purchase records indicating that seamless pipe, only in 20 and 24-inch diameters, was delivered to the project and certified by the project to have been installed on site. On November 4, 2013, PG&E examined the pipe at the same location as in 2004 and confirmed the determinations regarding Segment 110 made during the MAOP validation process. The results of the excavation confirmed the pipe to be 20-inch, .281 wall

thickness, seamless pipe, which is consistent with PG&E's validated data for Segment 110.

In addition to the above, PG&E has performed the following actions for Line 147:

- PG&E has installed automated valves on both ends of Line 147, at its Edgewood Cross-tie Station and its connection to Line 101. However, in order for these valves to be made functional, PG&E will have to calibrate and set the valves after flow is restored through the valves;

- PG&E currently has an ERX or interim electronic pressure recorder installed on Line 147 to record pressure conditions on Line 147. This data is not obtainable in real time, but must be downloaded and taken back for processing. PG&E has also installed supervisory control and data acquisition (SCADA) equipment on Line 147 to allow for the monitoring of pressure conditions within the pipeline in real time. However, this equipment requires calibration, which in turn requires there to be flow in the pipeline, before being placed into service.

- PG&E has ongoing mainline valve work at its Edgewood Cross-tie Station is that is expected to be completed by December 2013.

- Supervisory control and data acquisition (SCADA equipment has been installed on Line 147 so that pressure conditions in the pipeline can be monitored. However, this equipment must be calibrated under flow conditions before it is operational;

- PG&E is in the process of installing a launcher and receiver on Line 147, and has eliminated pipeline restrictions, with the exception of a miter bend which it is working to examine, that would enable the company to perform future inspections of the line using inline inspection (ILI) tools. However, the use of such tools will be contingent on pressure and flow conditions which enable pressure differentials required for proper testing (i.e., tool speed) to be obtained such that a varying diameter ILI tool can be used;

- PG&E performed an ultrasound inspection of the drip at mile-point 0.52 and at SED's direction from its field inspection, the drip at M.P. 0.77, which are both low points within the pipeline. Both inspections found no internal corrosion within the pipeline, confirming the absence of corrosive elements within the section of pipeline, and confirmed the wall strength of the pipeline and the drip at that location to operate at 330 psig;

- PG&E performed a centerline survey of Line 147 to accurately determine its true location and to confirm that no dwellings are located in the right-of-way of the line;

- At the direction of SED's field inspection, PG&E placed locks on distribution valves within an above ground regulator station and installed temporary fencing to improve the security of the station. A project has been initiated to install a permanent fence;

- At the direction of SED's field inspection, PG&E reviewed its records and provided confirmation that an inlet cover for a fire valve tapped to Line 147 is designed for exposure to full traffic at a location that appears to have potential for occasionally experiencing heavy vehicle traffic from a makeshift driveway at a nearby residence.

Concerns expressed by David Harrison

In the process of PG&E providing data responses in connection with the ongoing Order to Show Cause hearing related to the company's July 3, 2013 filing, certain PG&E e-mails surfaced and raised public concerns. The e-mails sent between PG&E engineers and managers following the October 2012 leak finding and identification of the discrepancies between the pipe seam type reflected in PG&E's then current MAOP validation records and the seam type actually observed for Segment 109 in the field during the leak repair process.

The public's concerns focused on a November 17, 2012 e-mail from David Harrison, an engineer employed by PG&E until year 2000, but working as a contractor for the company in 2012. In his e-mail, Mr. Harrison appeared to express concerns related to the cause of the leak, the finding of external corrosion on the "thin-walled pipe" at the location of the leak, the adequacy of the 2011 hydro-tests on Line 147 towards confirming the on-going integrity of the pipeline, and the contribution of the hydro-tests to the leak in some way. Specifically, in his e-mails, Mr. Harrison stated:

"...I'm guessing that you did not x-ray anything on this pipe? Did you look for cracks in any way other than visual? Is this hole backfilled?

After thinking about this some more, I have concerns about this pipe. My thought pattern is like this: We are still searching records, but we now believe this is 1929 pipe that was recently tested to just 1.5 times the MAOP in 2011. It is thin wall pipe and now we have found external corrosion on it. Could the recent hydro test contributed to additional cracking in this pipe and essentially activated a threat? Are we sitting on a San Bruno situation? With fatigue crack growth over many years? Is the pipe cracked and near failure? I don't want to panic people but seems like we should consider this and probably move this pipe up the PSEP priority for replacement.

I know there is industry evidence and discussion of how the hydro testing can activate the cracks and cause failures soon after the hydro testing. I know in theory the 1.5 times the MAOP test pressure should be sufficient, but I believe there is industry evidence that this is not always true. Let me know your thoughts on this…"

Mr. Harrison's November 17, 2012 e-mail followed his November 16, 2012 e-mail to his upper manager, Sumeet Singh, in which he conveyed the results of his analysis supporting the operability of Line 147 at the then currently allowed 365 psig. SED interviewed Mr. Harrison and four other PG&E engineers under oath, to learn what prompted Mr. Harrison's concerns expressed in his November 17, 2013 e-mail, with whom did he share those concerns and what responses he received, and, most importantly, did he continue to maintain those concerns today.

Mr. Harrison's interview, as well as the interviews of the other four engineers began by having the interviewees read and become aware of the Commission's Whistleblower Protections as provided in D.12-12-009. All interviewees were also asked if they felt any threats of retaliation in connection with their being interviewed or with their statements made in e-mails that became the subject of recent public attention. All interviewees stated they did not feel any threats of retaliation in connection with neither the interview nor the e-mails. In particular, Mr. Harrison stated, *"No. No, I feel bad because I think I've generated a lot of work that is not necessary."* All engineers were also asked how they felt about the ability historically in their careers with PG&E and within the past three years of PG&E employees to be able to bring safety concerns to their management. All engineers stated their belief the process has dramatically improved within the last three years in a way that encourages reporting without punishment. One engineer also commented that there is a lot more interest and awareness of issues from levels of management that did not exist in prior years.

Mr. Harrison stated that in his November 16, 2012 e-mail, his opinion that Line 147 could continue to operate at 365 psig was *"…only based on the evaluation of the one class out."* Regarding his November 17, 2012 e-mail, Mr. Harrison stated: *"The purpose of this e-mail was just that people were thinking about everything as routine. And we knew this pipe, we discovered it was AO Smith. They felt it was just routine…so the point of the e-mail was to make people think about that…"* Mr. Harrison stated, *"…My reference to San Bruno in here was not about a rupture, a failure, in that sense," but "…what have we learned from San Bruno…and could something else be going on… It is sort of like due diligence"*

Mr. Harrison stated that the discrepancy with seam noted for Segment 109 occurred soon after he *"…testified in the records OII"* and that he knew *"…everybody would be coming after us for this information and would be concerned about it. So I wanted to make sure that we did as much as possible. It wasn't that I thought there was an immediate rupture threat or safety threat* *right there on the pipeline. It was that I wanted to make sure we were very clear and gathered all the information we needed to show there wasn't a threat to it."*

As one reason behind the discrepancies between field findings and validated records, Mr. Harrison stated that the Phase 3 revaluation process, *"which has the improved validation, improved assumptions, automated engineering..."* had not been applied to Line 147 in order to confirm the quality of validation data that had been assembled in preparation for the 2011 pressure restoration filing. Mr. Harrison stated that he believes the automated processes installed to *"...force use and automatic use of what we call our PRUPF macro, which PRUPF is basically the document that describes how we would make engineering judgments and decisions..."* along with *"...making sure we have quality control steps...so the engineer does that evaluation and then has to get a peer review by it, and then there is quality assurance process after that"* are significant changes to address the failings encountered with the quality failings of the earlier validation performed on Line 147. Regarding peer review for Line 147, Mr. Harrison stated, *"in this case, at this time it wasn't very clear whether we actually did the peer review or not. It doesn't appear that we did."*

In his November 17, 2012 e-mail, Mr. Harrison inquired of the engineer in charge of the repair if *"he x-rayed anything."* At the time when he made this inquiry, Mr. Harrison stated he *"was under the impression that it was a leak or a weld on the side of the pipe, and people had talked about it being a prior repair...and if it was a prior repair then why did we repair it?"* Mr. Harrison stated, *"...an x-ray probably shows nothing, but it felt like this pipe was unknown to us. It was not what we expected. We should do due diligence to make sure that there is nothing possibly wrong with this pipe."* When asked about the operational safety of Line 147 and the repairs performed on the line prior to his November 17, 2012 e-mail, Mr. Harrison stated, *"...They did the appropriate things with the repair,"* and that *"...from an operation of the pipeline...I knew it was operating at 300 pounds. So I didn't consider the pipeline to be unsafe, or anything, have any problems at this point. At 300 pounds the pipeline is definitely fine."*

Mr. Harrison was asked questions to help clarify some of the terms he used in his November 17, 2012 e-mail. The following are the terms and his responses:

<u>Vintage (1929 pipe)</u> – *"Well, just that the 1929 pipe was typically the AO Smith pipe that we reconditioned was supplied basically from 1929 through like '32."* Mr. Harrison stated, *"There is no particular concern about the age. I mean we have evaluated AO Smith pipe over the years. It is older pipe. But again, we do not have a history at all of problems with AO Smith pipe."*

<u>Thin walled pipe</u> – *"Well, thin wall pipe is just thinner walls. So it doesn't have overall strength ...It is less than thicker pipe. So this is .250 wall pipe which is just quarter inch wall thickness. It is not unusual to do that...So if you do have corrosion or other problems with it, you know, it is more sensitive to that. There is less material there."* Mr. Harrison went on to add, *"So that is the only*

reference or the significance of the thin wall pipe. It wasn't that this is particularly thinner compared to all the other pipe in the system or anything like that…I'm just really trying to point out that it is .250, it is not .281, it is not .312 wall. The surrounding pipe was greater wall thickness."

San Bruno situation – *"Well, the fact, the key one being this pipe is not what we expected. You know, we discovered something. Our records don't illustrate it. It is definitely different. And so I feel in those kinds of situations that we should be doing due diligence. We should swiftly review the pipeline and, you know, look at all the threats to the pipeline and evaluate them all, and consider the fact that could there be something here that we don't know about."*

Pipe cracked and near failure – Mr. Harrison was asked if by this statement he had concerns at that time that the line was in any imminent danger of failure. Mr. Harrison stated, *"No. Again, with the pressure test ratio on there, I felt the pipe was fine. But the near failure is just, you know, the pipe being damaged internally and near failure during the Hydrotest is really what I was thinking of. And we needed to do due diligence."*

I don't want to panic people – Mr. Harrison was asked which people he was referring to in this statement. Mr. Harrison stated, *"Well, it is sort of like what has actually happened here…And so yeah, it was trying to not cause everybody to get all excited that it was ready to rupture or anything like that."* When asked if this meant people at PG&E, the public, or both, Mr. Harrison stated, *"Well, mostly the people at PG&E. I mean, again, I wrote it to just a couple of people."*

We should consider this and probably move this pipe up the PSEP priority for replacement – Mr. Harrison was asked if it was his suggestion that Line 147 or the Segment 109 needed to be replaced ahead of other PSEP work or other prioritized work. Mr. Harrison stated, *"…I guess I'm not saying that – I don't know their priorities, so I'm not the person to judge. That is why I'm asking them how would it fit in the priority listing…And so my thinking was is that, well, now that we know it is AO Smith, it is pressure tested, but does that change the replacement criteria such that it would move up the list or switch around the list."*

Some significant concerns expressed in Mr. Harrison's November 17, 2012 e-mail centered on the adequacy of the 2011 hydro-testing being high enough to confirm the integrity of Line 147 and/or if the hydro-test could have contributed to the leak found on Segment 109.

When asked about his belief regarding the applicability of the 1.5xMAOP towards strength testing and integrity confirmation of pipeline in general, and in particular for Line 147, Mr. Harrison stated, *"Well, 1.5 is in the federal code. There is a lot of smart people that have looked at it and evaluated it and come up with 1.5 as an adequate test pressure ratio. And so, again, I'm not the world's expert or anything on this stuff. So obviously they feel it is adequate to test to*

1.5. So I'm fine with that." Asked if particular to Line 147 the MAOP that had been established versus the test pressure provided for an inadequate differential, Mr. Harrison stated, *"No, I felt that was adequate."* Mr. Harrison went on to add, *"As far as Line 147 goes, it is pretty much, given the material that we have, it was pretty much tested as high as they can test the line due to the differences in elevation..."*

Mr. Harrison's concerns regarding the 2011 strength test contributing to a failure of the pipeline after the strength test, and at a value below the test pressure, were in relation to a phenomenon known as pressure reversal. Mr. Harrison stated he was *"definitely not an expert"* on the issue; however, he had *"read about it, and I just wanted to make sure that we got that under control and understand how it would impact this kind of a situation."*

As an example of a documented worst case pressure reversal he was familiar with, Mr. Harrison stated, *"...The worst case that is documented is the one that is like 1.67. Again, it is after testing five times. I think that is the only one that goes over 1.5, and it after testing five times. I think it is on a liquid line."* In an apparent reference to the recent report from Mike Rosenfeld which PG&E submitted as testimony in R.11-02-019, Mr. Harrison went on to add, *"I mean essentially what Rosenfeld has written would be exactly what I would have written at the same time. But I'm not the expert at it, he is the expert."*

Other engineers at PG&E, with whom Mr. Harrison shared the concerns expressed in his November 17, 2012 e-mail, were interviewed by SED. It appears that although these engineers understood Mr. Harrison's concerns, they did not share them in the same capacity.

Regarding the adequacy of 1.5xMAOP and pressure reversal, they did not share them in the same capacity. One engineer stated in a November 28, 2012 e-mail, *"The papers written by Kiefner that I'm familiar with seem to indicate an almost zero chance of such a failure when the pipe has been tested to 1.5 times the MAOP."* Another engineer stated, *"I did not share his concerns. My limited knowledge, not having extensive experience in the pipeline industry, was that the spike test performed in 2011 basically alleviated and addressed the concerns that he mentioned."* Mr. Harrison's boss, Sumeet Singh, stated that based on his *"...technical and professional engineering experience and what I know about strength testing...This information was speculation. It was not based on any evidence."* Mr. Singh cited a 2007 Kiefner and Associates study, done for US Department of Transportation **Pipeline and Hazardous Materials Safety Administration** (PHMSA), as *"the reference I used from an engineering perspective where did not deem the claims and the speculations being made by Mr. Harrison."*

Regarding whether or not Segment 109 would have been a candidate for replacement as part of PG&E's PSEP program, an engineer stated that, as he understood it: *"...the line was operating at over 30 percent SMYS. It was in a*

Class 3 area, and had a joint efficiency factor of .8. in our decision tree, that would have resulted in an outcome of M-2, which would normally call for replacement." However, this engineer also stated that once Segment 109, Line 147 had been through the hydro-test process, *"it was outside the scope... of PSEP."* Moreover, the engineer stated, *"It was not my opinion it should be replaced. Having successfully passed the hydro test, I felt it was safe to operate."*

Mr. Harrison was asked if he believed his concerns had been or were being resolved or at least addressed by PG&E. Mr. Harrison stated, *"When l wrote the e-mail I was probably not feeling so good about that that they were being addressed. But then by the conference call within a week I felt they had been addressed. And that everybody had evaluated it and looked at it and made a reasonable decision. So, yeah."* It is notable that Mr. Harrison's signature is included, within PG&E's October 11, 2013 Line 147 Certification filing, as the reviewer of the MAOP documentation included therein.

<u>PG&E's Root Cause Investigation of the Leak on Segment 109</u>

SED reviewed the actions PG&E initiated, after finding the leak on Segment 109, to excavate and remove the leaking section of Segment 109 for further analysis.

Review of company e-mails following the October 15, 2012 finding of the leak on Segment 109, indicates that PG&E initiated plans to first repair the leak, and then excavate the leaking section for a more detailed root cause investigation at a future date when operations and load conditions permitted. An October 22, 2012 e-mail from PG&E's Principal Corrosion Engineer states: *"Also pls note that per our discussion this pipe will be cut out at a convenient later date to for the purpose of performing a full root-cause investigation."* A November 21, 2012 e-mail from David Harrison indicates efforts to preserve the leaking area when it states: *"...They used the 6 inch cap to cover the leak so that the rest of the pipe remained exposed so that Integrity Mgmt could eventually evaluate it closely when it is cut out. This is why they did not sleeve it...."* A December 4, 2012 exchange of e-mails between these two engineers, and the pipeline engineer responsible for the repair of the initial leak, indicates there was thought being given to *"...material testing of base material and across the long seam..."* and *"...currently planning the cut-out for April."*

An e-mail from January 3, 2013 shows a work schedule for May 2013 to remove the section of Segment 109 for testing. On February 19, 2013 e-mail, PG&E submitted a request for permit and traffic plans to the City of San Carlos to excavate a 10-foot section of pipe between March 1 and June 30, 2013. An e-mail from May 14, 2013 shows the removal of the section being moved to July 2013 to coincide with a July 16, 2013 planned clearance. Finally, a June 26, 2013 e-mail shows removal of the section moved to July and August 2013 timeframe. PG&E

delivered the section of pipe containing the repaired leak to Anamet for analysis in August 2013.

As part of its analysis of the leak finding, PG&E sent a sample of the pipe from Segment 109 to an independent laboratory, Anamet Inc., for analysis. This analysis concluded that the leak was attributable to a weld crack that formed at the root of a fill-weld repair when the repair occurred. This would have occurred when the pipe was re-conditioned prior to installation in the ground and being placed in service. Anamet's analysis noted that the repair performed was on the body of the pipe and not on any girth weld or longitudinal seam. Anamet's report also noted that there is *"No evidence of crack growth during service or hydrotesting was detected."* Anamet's testing also found the SMYS of the tested sample to be approximately 39,000 psi.

PG&E also had another independent laboratory, Exponent, review samples from Segment 109. Exponent's findings supported those of Anamet. Exponent's report noted that the leak on Segment 109 occurred in a weld repair on the body of the pipe when the repair occurred. Exponent further concluded that, *"No evidence of progressive crack growth during service was observed at the leak site. Thus, the subject leak did not grow during service."* Exponent also concluded that the *"cracks associated with the subject leak were present during the 2011 hydrotest. However, the hydrotest did not result in any ductile tearing or crack extension (a pressure reversal) at the leak site."*

SED reviewed a letter from July 1965 that indicates that the Commission accepted the use of salvaged or reconditioned pipe. Moreover, SED notes that PG&E's repair procedures continue to utilize fill-weld as a method to repair metal loss on the body of pipe.

It is notable that the leak on Segment 109, Line 147 that occurred approximately one year after the segment had been strength tested, is not unique. Leaks have been experienced either during ramp up to the maximum pressure test values, for some of the hydro-tests completed to date. Any known leaks that prevented the test from reaching the required test pressure values from being reached, or maintained throughout the test, are expected to be repaired and the section to be retested. Routine leak surveys of the pipeline are expected to find any small leaks that may develop on the tested section after the test. Because the pipeline is in a buried environment, many factors can influence if, and when, a leak may develop; however, as far as SED is aware, subsurface leaks on pipe that kept test pressures from being reached have been pinhole leaks.

Discussion

The 2012 leak investigation of Segment 109, Line 147 revealed the pipe in the ground to be different from what even the more recently validated records expected. This, in turn, led some to make comparisons between the records discrepancy found on Segment 109 to the records discrepancy on Segment 180 of Line 132 that failed in San Bruno with tragic consequences and the loss of eight lives. While both cases involve records discrepancies, there exists one large and important distinction between the two cases. While Segment 109 has been very recently, in 2011, strength tested thorough a modern pressure strength test to confirm its current integrity and fitness to operate at 330 psig with safety factors applied, and possibly higher under certain conditions or replacements, Segment 180, of Line 132, was never subjected to such tests. The hydro-tests performed on Line 147 in 2011, which included Segment 109, assessed for the effects of exposure to decades of time dependent threats such as cracking due to fatigue or stress corrosion cracking (SCC) and internal or external corrosion, as well as non-time dependent threats, such as third-party damage, and confirmed the ongoing integrity of Line 147.

It would be impractical, extremely disruptive to the public's general convenience and need for gas service, and come at great cost, without any quantifiable increase in safety, to excavate every inch of every transmission pipe undergoing examinations to validate records, before determining what needs to be done in regards to the pipe. Therefore, in light of these facts, any expectations of pristine records for 50+ year old facilities need to be tempered and should expect that even after records for facilities, especially much older facilities have been validated, there could well be something different in the ground than expected by records review or validation, no matter how well it is done.

Record keeping has generally improved through the decades such that more recent the records, the more accurate, detailed, and complete the records can expected to be. However, it is not reasonable to believe that any records review or validation, especially those of records predating code requirements, can enable someone to "know what you don't know." It is for this very important reason, that records review alone, whether based on actual construction records or any records supplemented with conservative assumptions, is currently not permitted by the Commission to be used towards the determination to NOT strength test pipeline facilities that have never been strength tested or where records for testing are incomplete or missing needed data. CPSD, the predecessor to SED, recognized and conveyed this to PG&E in its April 26, 2011 letter to PG&E.

In its April 26, 2011 letter, CPSD stated, *"CPSD believes that the Pipeline Features list that PG&E has described in its filings is useful for PG&E's on-going operations and will provide crucial data that will prove valuable in making future decisions related to its pipelines. The PFL will also allow PG&E to confirm that any pressure reductions, taken as mitigative steps for pipeline segments where necessary hydro-test or replacement is delayed due to operational considerations, is an adequate pressure reduction. For these reasons, CPSD supports PG&E's efforts to gather the data and create PFLs...."* CPSD's letter also stated that, *"CPSD believes that although PG&E's MAOP validation process and field activities such as x-ray, camera inspection, or Automated Ball Indentation can aid in establishing an MAOP or help in*

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prioritizing pipeline segments for hydro-testing, these measures should not serve as a substitute for the hydro-testing or replacement of pipeline segments which have never been hydro-tested."

<u>Discrepancies with Field Documents</u>

SED's review of PG&E's 2011 Certification filing for Line 147 suggested that PG&E endeavor to perform inspections that captured more detail, not less, through its excavations and use its H-form to document the findings. As SED also noted, although there can be instances in which such reductions in inspections may be warranted, the highest cost component of any excavation to perform an inspection or verification is the cost of the excavation itself. Therefore, SED suggested that all excavations where practicable, should attempt to gather all of the information included on PG&E's H-Form because such information, especially for vintage pipes, can provide invaluable data related to pipeline conditions.

PG&E has attributed the specifications of Segment 109 being wrong in its MAOP validation data to human error and issues of quality control in the MAOP validation process that resulted in other segments also wrongly classified in its validated data. However, SED's review finds that there also appear to be quality control issues with information collected in the documents used to track pipeline specifications found during field inspections. More importantly, it appears the gathered information is not being integrated into PG&E's overall operations and timely made available to all groups who would appear to need the information to make operations decisions. Examples of this include the documents deficiencies related to Segments 108, 108.7, and 110 discussed earlier in this report.

SED believes that review of field H-Forms needs to be included into PG&E's quality control/quality assurance steps. Moreover, a "checks and balances" step to confirm critical data within H-Forms needs to be initiated and needs to include clearly identified data points which must be independently gathered during the completion of the H-Form and the Chain-Of-Custody Process. This also needs to include training of personnel on the need to independently collect the data and not just copy it over from other documents. Finally, steps need to be implemented which allow entries for critical pipeline features (i.e., stationing, pipe diameter, wall thickness, seam type, coating, yield data, etc.) from different source documents to be electronically, and automatically compared, flagged, and communicated to appropriate staff.

<u>Maximum Operating Pressure of 330 psig for Line 147</u>

SED's review has determined that:

- PG&E has correctly, and conservatively, applied the de-rating factors resulting from changes it has identified for Segments 103, 103.1, 103.6, 108, 108.7 and 109. These de-rating factors are the same as what would be required for a new pipeline built in the same locations, and, at this time, without the application of any provisions of one-class-out. Moreover, PG&E's application of 0.8 as a JF for its SSAW seams is more conservative than the 1.0 JF which 49 CFR, Part 192 allows;

- PG&E successfully strength tested, using hydro-testing conforming to 49 CFR, Part 192 Subpart J requirements, and with a minimum spike pressure of 5% and no more than 10% above the minimum test pressure held for no more than 30 minutes, Line 147 to establish its integrity to operate at pressures in excess of 330 psig. Moreover, none of the pressure tests performed by PG&E resulted in any yielding of the pipe within the tested sections. This would mean that the pipe sections had sufficient strength to remain within their elastic range. SED notes that federal regulations do not limit strength tests to 100% of SMYS. In fact, some pipeline experts, including John Kiefner, support strength tests above 100% of SMYS and believe that even up to 110% of SMYS very little yielding actually occurs on the pipe and what does occur on some joints does not affect the integrity of the pipe.[5]

- PG&E took appropriate actions to repair the leak found on October 15, 2012 on Segment 109 and also took actions to preserve the pipe for further evaluation to determine the root cause of the leak;

- PG&E initiated actions, soon after finding the leak on Segment 109, to repair the leak and initiate plans to excavate and remove the section of Segment 109 for further analysis.

- PG&E's root cause analysis of the leaking section of Segment 109, performed by two independent laboratories, Anamet and Exponent, found that the cause of the leak to be a small crack formed when the original repair was made on the body of the pipe. SED's review of PG&E records back to 2008 found that PG&E found no leaks at this location. The analysis by Anamet and Exponent indicates there is no evidence indicating the crack was growing prior to or subsequent to the hydro-test.

- Based on SED's findings related to the reductions in pressure resulting from the changes identified by PG&E for Segments 103, 103.1, 103.6, 108, 108.7 and 109, SED finds no issues which would limit PG&E's operation of Line 147 at an MOP of 330 psig.

[5] THE BENEFITS AND LIMITATIONS OF HYDROSTATIC TESTING – John F. Kiefner and Willard A. Maxey

Hydro-testing

Concerns about the safety and integrity of grandfathered pipelines, which had never been strength tested or tested to lesser standards than today, became apparent in the early stages of the National Transportation Safety Board's investigation of Line 132. The Commission made the decision to eliminate grandfathering of transmission pipelines by requiring strength testing of such lines. At that time, many others had the same concerns about hydro-testing and pressure reversals expressed by David Harrison in his November 17, 2012 e-mail. That is why before proceeding with strength testing, the Commission took steps to allay public concerns regarding strength testing.

The Commission held a Hydrostatic Testing Symposium (Symposium) on May 6, 2011, and a second Symposium on March 7, 2012. The May 6th Symposium served to allow the public to "[h]ear from industry experts about what can be learned from hydrostatic testing, receive an overview of PG&E's testing program, and learn what the public can expect when hydrostatic testing occurs in their neighborhood," while the March 7th Symposium served to provide an update on testing conducted during 2011.

During the May 6, 2011 Symposium, information related to strength testing regulations and the benefits and shortcomings related to strength testing in general, and hydro-testing in particular, were discussed. Specifically, the May 6th Symposium provided information on the issue of pressure reversals – a phenomena under which the pressure test results in lowering the failure pressure of defect that survives the test pressure, but fails at a pressure below the test pressure, but above the MAOP. Industry experts, including John Kiefner (Ph.D, P.E.), whose studies and reports related to the testing and integrity of steel transmission pipelines are referenced within federal pipeline safety regulations, Bob Gorham, from the California State Fire Marshal's Office of Pipeline Safety and representatives from PG&E and CPSD, predecessor to SED, presented information at this Symposium.

Based on information presented at the May 6, 2011 Symposium, the Commission determined that a strength test, performed in conformance with specified requirements, is an industry recognized and accepted method which can safely establish the MAOP of a pipeline and confirm its on-going operational integrity. Moreover, the Commission learned that a pressure test to a minimum level of 1.5 x MAOP, provides an assurance of pipeline safety while providing enough margin to minimize the likelihood of post-test failure due to pressure reversal. As noted at the Symposium by John Kiefner, "[t]he likelihood of a pressure revers essentially nil if a pipeline segment has no failures during its hydrostatic pressure test." It is notable that Line 147 experienced no test failures during any of the hydro-tests performed on the line in 2011.

Due to the more severe pressure cycles experienced by hazardous liquid pipelines, as compared to gas transmission pipelines, the use of hydro-testing to confirm the integrity of hazardous liquid pipelines has been a requirement in California since 1984. California's law requires hazardous liquid pipelines to be strength tested to 1.25 x MOP, at intervals not to exceed 60 months to confirm the ongoing integrity of the pipelines. Under this testing requirement, which provides for a maximum pressure reversal value of 20%, tested pipelines have operated without significant incidents or failures (i.e., other than minor leaks) due to pressure reversals.

In contrast to the 1.25xMAOP testing requirement for hazardous liquids lines in California, the spike pressure of 669 psig (1.67xMAOP of 400 psig) for Line 147 in 2011 provides for a pressure reversal value of approximately 40%. For an MAOP of 365 psig, the 2011 test pressure provides for a 45% pressure reversal, while for 2xMAOP of 330 psig, the test provides for a pressure reversal value of approximately 50%. This level of pressure reversal places Line 147 in an extremely low probability of failure due to defect growth resulting from pressure reversal, and in comparison to other threats to the pipeline. According to Kiefner: *"A pressure reversal of 20% has a probability of about 1 in 800 million – and even this would require operating the pipeline above MAOP."* Pressure reversals greater than 20%, as would be the case with Line 147 even at 400 psig, would have even lower probability of occurring. The results of the analysis from Anamet and Exponent, which found that the weld crack that was the source of the leak on Segment 109 existed before the hydro-test and did not grow or extend during the hydro-test in 2011, further validates the low probability of pressure reversals associated with high pressure test to MOP ratios.

External Corrosion

Although PG&E engineers initially believed external corrosion to be the cause of the leak on Segment 109, closer examination by Anamet and Exponent determined that not to be the case. However, external corrosion continues to be a threat to Line 147, like all other steel pipelines, that requires routine monitoring, as well as closer monitoring through threat assessments by PG&E's integrity management program, to enable for the making of concrete decisions regarding the adequacy of cathodic protection applied to the pipeline to prevent corrosion.

Based on its experience overseeing PG&E's hydro-test program and other inspection activities in which the pipe is exposed allowing for an inspection of coating or base metal, GSRB has observed minor corrosion or cracked asphalt coating on pipelines. Although not common, this is also not unusual, nor unexpected, since, after all, the pipelines are located in a subsurface environment where rocks, tree roots, and other features work to initiate such damage. These same features can hinder proper cathodic protection monitoring and/or make it difficult to protect the pipeline.

Since the coating on the pipeline is the first barrier to help prevent external corrosion on the pipeline, it is the job of the cathodic protection to help mitigate breaches in this barrier. Cathodic protection, however, has limitations. While it can help in significantly reducing the rate of external corrosion on pipelines to extremely low levels, it may not be able to prevent all corrosion from ever occurring.

Conclusions and Recommendations

SED did not review all of the large number of pipeline features contained in PG&E's 2013 Certification for Line 147; however, SED did examine five randomly selected features in detail to review documents supporting the listed feature. This review found no issues with the supporting materials. In addition, on October 25, 2013 SED conducted a field review of the work at Edgewood Cross-tie station, Commercial Way, and inspected parts of the right-of-way for Line 147. This review found three issues that PG&E has resolved to SED's acceptance.

Strength testing of pipelines has been recognized and used for decades as a safe method for the testing of pipelines. In fact, state and federal regulations require strength testing be used under specific circumstances included in the regulations. However, before proceeding with strength testing of pipelines lacking strength testing, the Commission took actions to address public concern about such testing and to confirm its effectiveness in validating the integrity of pipelines and revealing critical conditions existing on the lines unbeknownst to the operator.

Analysis of the leaking section of Segment 109 by Anamet and Exponent that found that the 2011 hydro-test did not result in causing or worsening a weld crack defect determined to be the cause of the 2012 leak. Also, information the Commission received at the May 6, 2011 Symposium on hydro-testing which indicated that the probability of failures due to pressure reversal is extremely remote at the level of testing (1.5xMAOP + spike test of 5-10%) being mandated by the Commission in Class 3 and 4 and all HCA locations. Based on this, SED finds that hydro-testing continues to be a safe and reasonable method to test for the integrity of gas pipelines in California.

Records reviewed by CPSD showed that Line 147, including the segments containing the A.O. Smith pipe, and subject to the records discrepancy which contain SSAW pipe, passed a hydro-test at levels approximately two times the 330 psig MOP PG&E is seeking through its 2013 Certification filing. Moreover, there are no other indications at this stage that indicate any adverse impacts from the hydro-testing performed on Line 147 in 2011. Therefore, SED finds no issues at this time that should limit PG&E's operation of Line 147 to an MOP below 330 psig.

SED believes that review of field H-Forms needs to be included into PG&E's quality control/quality assurance steps. Moreover, a "checks and balances" step to confirm critical data within H-Forms needs to be initiated and needs to include clearly identified data points which must be independently gathered during the completion of the H-Form and the Chain-Of-Custody Process. This also needs to include training of personnel on the need to independently collect the data and not just copy it over from other documents. Finally, steps need to be implemented which allow entries for critical pipeline features (i.e., stationing, pipe diameter, wall thickness, seam type, coating, yield data, etc.) from different source documents to be electronically, and automatically compared, flagged, and communicated to appropriate staff.