U.S. Department of Transportation

Pipeline and Hazardous Materials Safety Administration

Failure Investigation Report

Plains Pipeline, LP, Line 901 Crude Oil Release, May 19, 2015 Santa Barbara County, California

May 2016

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Executive Summary

At approximately 10:55 a.m. Pacific Daylight Time (PDT) on May 19, 2015, the Plains Pipeline, LP (Plains), Line 901 pipeline in Santa Barbara County, CA, ruptured, resulting in the release of approximately 2,934 barrels (bbl) of heavy crude oil.[i] An estimated 500 bbl of crude oil entered the Pacific Ocean. Line 901 is a 24-inch diameter buried, insulated pipeline which extends approximately 10.7 miles in length and transports heated crude oil from Exxon Mobil's storage tanks in Las Flores Canyon westward to Plains' Gaviota Pumping Station. On May 21, 2015, the Pipeline and Hazardous Materials Safety Administration (PHMSA), a regulatory agency within the U.S. Department of Transportation, issued a Corrective Action Order (CAO) that required the operator to shut down Line 901. Concurrent with the issuance and implementation of the CAO, PHMSA conducted an investigation to identify causal factors that contributed to the occurrence and size of the crude oil release. As the failure investigation progressed, the CAO was amended to address additional safety concerns that were identified. On June 18, 2015, Line 901 was purged and filled with inert nitrogen to enhance safety during the investigation and development of a remedial action plan.[ii] No fatalities or injuries occurred as a result of this rupture and release. The spill resulted in substantial damage to natural habitats and wildlife.

PHMSA's findings indicate that the proximate or direct cause of the Line 901 failure was external corrosion that thinned the pipe wall to a level where it ruptured suddenly and released heavy crude oil. PHMSA's investigation identified numerous contributory causes of the rupture, including:

1) Ineffective protection against external corrosion of the pipeline
    - The condition of the pipeline's coating and insulation system fostered an environment that led to the external corrosion.
    - The pipeline's cathodic protection (CP) system was not effective in preventing corrosion from occurring beneath the pipeline's coating/insulation system.
2) Failure by Plains to detect and mitigate the corrosion
    - The in-line inspection (ILI) tool and subsequent analysis of ILI data did not characterize the extent and depth of the external corrosion accurately.
3) Lack of timely detection of and response to the rupture
    - The pipeline supervisory control and data acquisition (SCADA) system did not have safety-related alarms established at values sufficient to alert the control room staff to the release at this location.
    - Control room staff did not detect the abnormal conditions in regards to the release as they occurred. This resulted in a delayed shutdown of the pipeline.
    - The pipeline controller restarted the Line 901 pipeline after the release occurred.
    - The pipeline's leak detection system lacked instrumentation and associated calculations to monitor line pack (the total volume of liquid present in a pipeline section) along all portions of the pipeline when it was operating or shut down.
    - Control room staff training lacked formalized and succinct requirements, including emergency shutdown and leak detection system functions such as

alarms.

The consequences of the spill were additionally aggravated by an oil spill response plan that did not identify the culvert near the release site as a spill pathway to the Pacific Ocean.

This report contains factual information and analysis regarding the events leading up to the release, information collected during PHMSA's failure investigation to date, and the technical analysis of that information known at the time of the completion of this report. PHMSA used this information to mandate remedial measures on Line 901, Line 903, and associated stations and tankage. PHMSA will also use the information to determine whether violations of the federal pipeline safety regulations occurred.

Final Report Methodology

PHMSA conducted relevant interviews, gathered and reviewed numerous historical documents and available records, and performed a thorough review of the Plains Control Room in Midland, TX. An ILI subject matter expert (SME) was hired to review the raw magnetic flux leakage (MFL) data and final vendor reports from the MFL surveys, and evaluated Plains actions as a result of their review of the vendor reports. PHMSA issued a CAO which in part instructed Plains to have the failed pipe examined by a PHMSA-approved metallurgical laboratory and to have a root cause failure analysis (RCFA) performed by a third party independent consultant.

The factual evidence reviewed includes: the Plains Integrity Management Plan (IMP), CP records, ILI reports, anomaly dig information, SCADA event and alarm logs, pressure and flow trends, procedures and reports obtained from the pipeline operator and PHMSA SMEs.

The arrangement of this report provides a general description of the pipeline system, the events that occurred on the day of the release, and acts or omissions of the operator that led to this failure and release of crude oil. Specific evidence is supplied and pertinent statements from each report are excerpted where appropriate.

Facility Background

Plains transports crude oil produced in federal and state waters off the coast of Santa Barbara, CA to inland refineries. Plains' pipeline is composed of two major pipeline sections: (1) Line 901, and (2) Line 903. Lines 901 and 903 were constructed in the late 1980s, hydrostatically tested in 1990, and went into crude oil service in 1992 and 1991, respectively. The pipelines are coated with coal tar urethane and covered with foam insulation which in turn is covered by a tape wrap over the insulation. Shrink wrap sleeves, which provide a barrier between the steel pipeline and soil for corrosion prevention, are present at all of the pipeline joints on Line 901 and multiple locations on Line 903. The pipelines carry high viscosity crude oil at a temperature of approximately 135 degrees Fahrenheit to facilitate transport. Lines 901 and 903 are controlled from the Plains Control Room's (PCR) California console in Midland, TX.

(1) Line 901 is a 24-inch diameter pipeline that extends approximately 10.7 miles in length from the Las Flores Pump Station to the Gaviota Pump Station; and (2) Line 903 is a 30-inch diameter pipeline that extends approximately 128 miles in length from the Gaviota Pump Station to the Emidio Pump Station, with intermediate stations at Sisquoc Mile Post (MP) 38.5 and Pentland (MP 114.57). There is a delivery point into Line 901 from Venoco's Line 96 located approximately 2 miles downstream of the Las Flores Station. All of Line 901 crude oil throughput enters Line 903. Line 901 was manufactured of low carbon steel by Nippon Steel

in Japan in 1986. Line 901's pipe specifications are API 5L, Grade X-65 pipe, 0.344-inch wall thickness, with a high frequency-electric resistance welded (HF-ERW) long seam. The line was hydrotested to 1,686 pounds per square inch gauge (psig) on November 25, 1990.

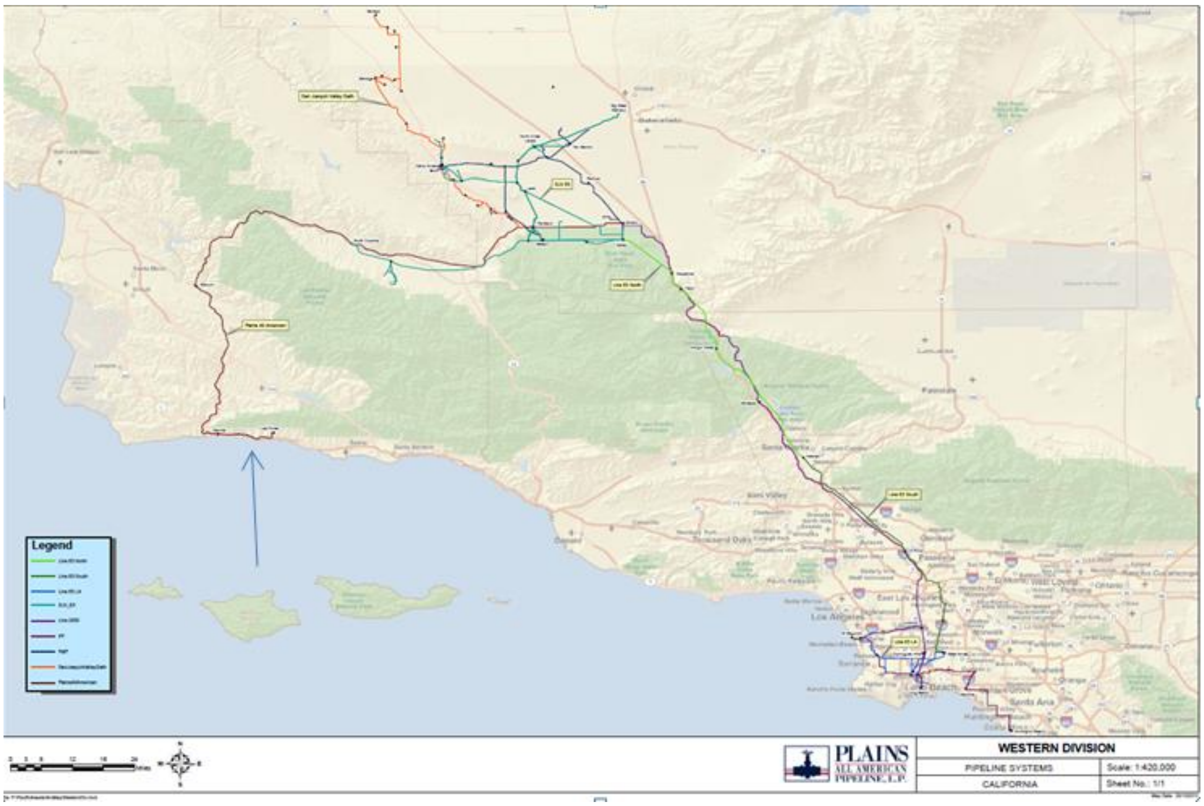

Figure 1. Map of Plains' Western Division Pipelines. The arrow points to the approximate release site on Line 901.

At Sisquoc Station, crude oil can be pumped to one of two locations: a nearby refinery via a 12-inch diameter pipeline operated by Phillips 66, or continue down Line 903 to Pentland Station. There are additional crude oil lines coming in and out of Pentland Station with numerous tanks at that station used to blend different crude oils for delivery further downstream. At Emidio Station crude oil is delivered to above-ground storage tanks for future delivery to Los Angeles refineries in a separate pipeline system.

Prior to the May 19, 2015 release, there had been four small releases meeting PHMSA reportable criteria at pump stations on Lines 901 and 903. No releases were reported to PHMSA on the pipelines outside of pump stations prior to 2015. The operator reported maximum operating pressure (MOP) of Line 901 is 1,341 psig.

At the time of the spill, Plains All American Pipeline (PAAPL) operated Line 901 and Line 903 under a Federal Energy Regulatory Commission (FERC) certificate of economic regulatory jurisdiction that was issued in 1987. Plains Pipeline, LP, is a subsidiary of PAAPL. Based on the FERC filing, Lines 901 and 903 were classified as interstate pipelines, pursuant to 49 U.S.C. § 60101(7), as facilities used to transport hazardous liquid in interstate or foreign commerce, and as such, were regulated by PHMSA as interstate pipelines. Plains cancelled the FERC certificates for Lines 901 and 903 on February 12, 2016 and April 29, 2016, respectively, stating that the transportation service was no longer available in interstate commerce. Line 903 from Gaviota to Sisquoc to Pentland Stations was purged with nitrogen in accordance with Amendment No. 2 to the CAO, and remains shut down between these stations. The Pentland to Emidio segment of Line 903 is active and operating intermittently at low pressures. This section of pipe between Pentland and Emidio is not directly connected to the Gaviota to Pentland segment and is used to transport crude product from breakout tanks in Pentland Station.

Events Immediately Prior to and During the Crude Oil Release

On the morning of May 19, 2015, Lines 901 and 903 were transporting crude oil with a flow rate setpoint of 1,240 bbl per hour (BPH) leaving the Las Flores Station, and the discharge pressure was approximately 575 psig. Pumps were operating at the Las Flores Station on Line 901 and Sisquoc Station on Line 903. A Plains instrumentation and electrical technician was dispatched that morning to disconnect and remove a motor from a non-operational pump at the Sisquoc Station. While the technician was performing his work, the operational pump (Pump 401) at the Sisquoc Station was shut down unintentionally (i.e., “uncommanded”). When Pump 401 on Line 903 stopped operating, the pressure in Line 901 increased. The pressure rose to a maximum of 696 psig at the Las Flores Station discharge. The controller shut down the pump at Las Flores Station and the pressure remained at 677 psig. Approximately four minutes later, the pump at Las Flores Station was restarted. At approximately 10:55 a.m. PDT, the flow rate at Las Flores Station climbed from zero to 2,042 BPH. Concurrently, the line pressure rose to a high of 721 psig, then dropped to 199 psig, and then slightly increased to approximately 210 psig until the Las Flores pump was shut down a second and final time. Generally, a sudden increase in flow rate accompanied by a decrease in pressure is indicative of a release. PHMSA has determined that Pump 401 going offline in an “uncommanded” manner on the morning of May 19, 2015, was an abnormal event, but that this in itself should not have caused Line 901 to rupture.

PHMSA performed a detailed review of the SCADA event and alarm logs, and pressure and flow records. The review indicated that there was information reported by the SCADA system that indicated a release had occurred by approximately 10:58 a.m., and an alarm was generated on low pressure. The alarm was not set at an appropriate value. The alarm also did not have a major priority/severity or safety-related alarm status. The controller did not recognize the information he received as indicative of an abnormal operation. Evidence indicates that the controller was focused on the events at Sisquoc Station (i.e., restarting the Sisquoc pump that had gone down once uncommanded, and a second time on high case temperature along with other duties).[iii]

Due to the Sisquoc Station maintenance activity resulting in an unplanned pump shutdown, the controller anticipated alarms would be activated from the pipeline leak monitoring (PLM) system. According to interviews and a review of the alarm log, the PLM inhibit was requested by the controller to the step-up shift supervisor between 11:15 and 11:22 a.m.[iv] The step-up shift supervisor then inhibited (shut off) the PLM system alarms.[v] Also, during this time, the controller started an investigation of the SCADA data in an attempt to understand the operational abnormalities that were occurring. After attempting to restart the Sisquoc pump twice, the controller shut down the pipeline. PHMSA requested the operator review the flow imbalance calculations and provide a time when the PLM system would have generated an alarm if not inhibited, and it was determined that alarms would have been generated approximately two minutes before the controller shut down the pipeline.[vi]

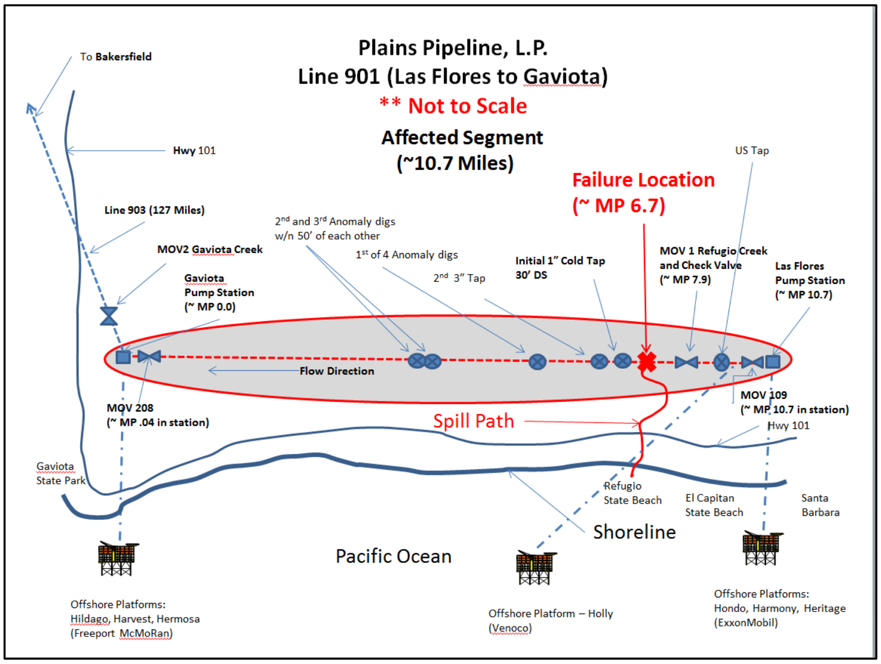

Figure 2. Schematic of Plains Pipeline, LP, Line 901 and spill path.

Plains' Field Response and National Response Center Notifications

The following is a timeline of Plains and emergency responder activities conducted immediately prior to locating the leak site:[vii]

- At 11:42 a.m. a call reporting a petroleum smell was received at Santa Barbara Fire Department (SBFD) Station 18. Engine 18 left the station to investigate the odor complaint near Refugio State Beach.
- At approximately 12:15 p.m., prior to a scheduled tabletop spill drill required by federal regulations 49 C.F.R. §194, the pre-drill meeting was completed and adjourned. A representative from the Santa Barbara Office of Emergency Management (SB-OEM) received a call from the SBFD reporting that there was oil on Refugio Beach. The SB-OEM representative and the Plains representatives left the spill drill and drove separately to Highway 101 at Refugio Beach.
- The Santa Barbara Dispatch notified the National Response Center (NRC #1116950) at 12:43 p.m. PDT of an unknown sheen in the ocean at Highway 101 and Refugio Beach.[viii]
- At approximately 12:55 p.m., the two Plains representatives arrived at the south side of Highway 101 where the SBFD personnel were. They noted oil in the ocean but could not determine the source of the oil. One of the Plains representatives told the assembled group that he did not think the oil was coming from Line 901 because the pipeline is located on the other side of Highway 101, and there would be oil flowing across Highway 101 if Line 901 was leaking.

- The Plains representatives drove to the company's pipeline right-of-way (ROW). At approximately 1:27 p.m., the Plains representatives located the leak site on the Plains ROW. They called the controller to report the leak and to tell the controller to leave Line 901 shut down and to close the Refugio gate valve. The Plains representatives used their cell phones to contact other Plains personnel, the landowner where the leak occurred, Plains' oil spill response contractors, and others. The Plains representatives noted that crude oil from the release site had entered a culvert that crosses under the Highway 101 and railroad tracks and discharges to Refugio Beach. The Plains representatives, along with Fire Department personnel, attempted to stop the flow of oil into the culvert. However, the culvert was too large to stop the flow with shovels, and sand bags were not readily available, so their immediate efforts were unsuccessful. At approximately 3:00 p.m., additional equipment and personnel arrived, the culvert was dammed and oil was prevented from entering the culvert.
- At 2:56 p.m., a representative from Plains called the NRC to report (NRC #1116972) the release of crude oil at 2:56 p.m. PDT. This report indicated that the release was at Latitude: 34° 27' 43" N; and Longitude: 120° 05' 24" W. This NRC report was made 89 minutes after the release site was found by Plains field personnel.[ix]

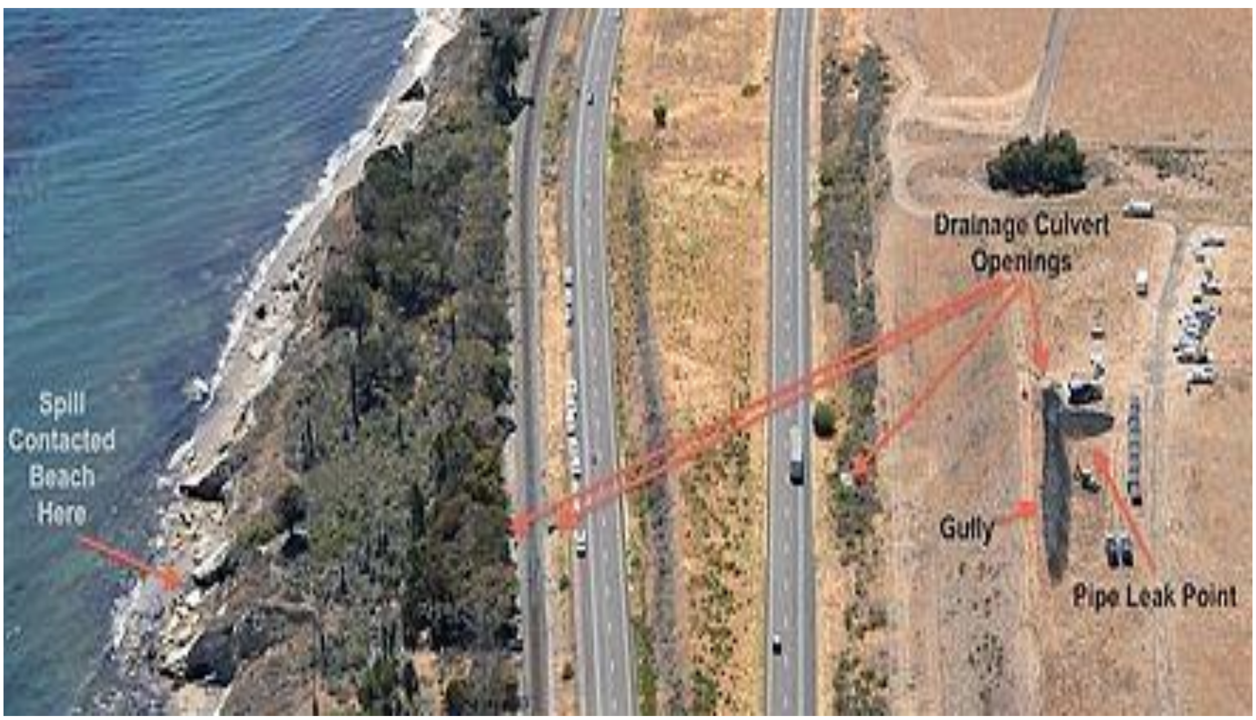

Figure 3. Spill location relative to Refugio Beach in Santa Barbara County, CA. Photo: John L. Wiley http://flickr.com/jw4pix

Federal pipeline safety regulations, (49 C.F.R. § 195.52), require that the NRC be notified at the earliest practicable moment following discovery of a release of a hazardous liquid, including "[a]ny failure that resulted in pollution of any stream, river, lake, reservoir, or other similar body of water that violated applicable water quality stands, caused a discoloration of the surface of the water or adjoining shoreline, or deposited a sludge or emulsion beneath the surface of the water or upon adjoining shorelines." On January 30, 2013, PHMSA issued an

Advisory Bulletin clarifying that this was to be interpreted as within one hour of discovery. Plains reported the rupture to the NRC approximately 89 minutes after discovery, thus notifying the NRC 29 minutes late.

The estimated costs reported by the operator as of December 23, 2015, were $142,931,884. This figure includes all costs the operator spent as a result of this release through the date reported, including commodity lost, the operator's property damage and repairs, operator's emergency response, environmental remediation, and estimated other costs spent including government agency costs and media relations expenses.[x]

PHMSA's Corrective Action Order

On May 21, 2015, PHMSA issued a CAO, CPF No. 5-2015-5011H, to Plains. The CAO required Plains to purge Line 901; review the pipeline's construction, operating, maintenance, and integrity management history; expedite the review of data from the May 5, 2015, ILI tool run; conduct metallurgical evaluation of the failed pipe; repair any integrity-threatening anomalies identified by the ILI survey; and conduct a root cause failure analysis. The CAO requires Plains to purge Line 901 and to keep Line 901 shut down until PHMSA approves the restart of the pipeline. Plains' Line 901 was purged and filled with an inert nitrogen gas on June 18, 2015.

On June 3, 2015, PHMSA issued Amendment No. 1 to the CAO. The amendment was issued to address preliminary findings from the early stages of PHMSA's investigation, and the possibility that the conditions on Line 901 also existed on Plains Line 903. The amendment to the CAO required Plains to conduct additional non-destructive testing of ILI anomalies on Lines 901 and 903; review the construction, operating, maintenance, integrity management, and ILI history of Line 903; and reduce the operating pressure of Line 903 to 80% of the highest pressure sustained for a continuous 8-hour period during the month before the May 19 failure. This pressure reduction was intended to enhance safety until all facets of the line's integrity could be evaluated.

On November 12, 2015, PHMSA issued Amendment No. 2 to the CAO. The amendment required Plains to empty and purge Line 903 between Gaviota and Pentland Stations and fill it with an inert gas. Line 903 was purged between Gaviota and Pentland Stations and filled with inert nitrogen. The complex purging operations began in December 2015, and were completed on April 18, 2016. Both Line 901 and the purged sections of Line 903 will remain shut down until all actions required by PHMSA's CAO and subsequent amendments have been completed. PHMSA may continue to issue additional amendments to the CAO as necessary.

Pipeline Alignment

Las Flores Station to Gaviota Station Line 901 Elevation Description

To fully understand the Line 901 release, it is vital to understand the elevation profile of Line 901 and Line 903 from the Las Flores Canyon to Pentland Station. Line 901 starts at the Las Flores Station at an elevation of approximately 180 feet. There are two large hills downstream of the originating pump station. The first hill has a peak elevation of approximately 740 feet and the second hill has an elevation of approximately 600 feet. The release occurred downstream of the second hill at an elevation of approximately 80 feet. Immediately downstream of the release point, the pipeline rises slightly and then runs relatively level approaching the Gaviota station. This fact is important because as soon as the pump at Las

Flores Pump Station was turned off the second time, the only crude oil that could be released was the height of oil in the pipeline above the release site and not the amount located between the two aforementioned hills.

Gaviota to Pentland Station Line 903 Elevation Description

Line 903 receives all of the crude oil delivered by Line 901. The line elevation at Gaviota is approximately 150 feet. The elevation at Sisquoc is approximately 880 feet. Downstream of Sisquoc, Line 903 rises to 2,420 feet and then to a height of approximately 2,750 feet and ultimately to an elevation of close to 3,000 feet before dropping into Pentland Station at an elevation of approximately 690 feet. Line 903 exhibits many of the same construction and operation conditions as Line 901 and was addressed by the amendments to the CAO. Pump 401 at Sisquoc Station has adequate capacity to push the oil up and over the downstream hills and into Pentland Station but only if it has full suction pressure and full flow coming into the pump. Because of the release, the pump could not push the oil over the downstream hills, and so the oil in the pump became hot and the pump shut down to prevent overheating.

Post-Incident Investigation Results

Metallurgical Evaluation of Failed Pipe

The failed pipe segment has been analyzed by third-party metallurgical experts, Det Norske Veritas (U.S.A.), Inc.'s (DNV-GL) in Dublin, OH. The failed pipe assessment and testing was witnessed by PHMSA, the California Department of Fish and Wildlife, and the U.S. Department of Justice.

Figure 4. The failed pipe and surrounding insulation and coating.

Figure 5. Pipe External Surface at the Line 901 failure site after cleaning.

DNV-GL's draft report was completed and disseminated to Plains and PHMSA on August 6, 2015. The draft report was reviewed by PHMSA engineers, and a number of comments and clarification requests were made. DNV-GL reviewed the comments and revised the report. The Final Report was issued on September 18, 2015.

The Final Report provides a summary of findings, including the following excerpt:

"The results of the metallurgical analysis indicate that the leak occurred at an area of external corrosion that ultimately failed in ductile overload under the imposed operating pressure. The morphology of the external corrosion observed on the pipe section is consistent with corrosion under insulation facilitated by wet-dry cycling."[xi]

In-Line Inspection Survey Review

Plains conducted ILI surveys on Line 901 (10.7 miles in length) to assess the integrity of the pipeline in accordance with PHMSA regulations in 2007, 2012, and 2015. According to 49 C.F.R. § 195.452(j)(3), the pipeline is required to be surveyed at intervals commensurate with the pipeline's risk of integrity threats, but at least every 5 years. Plains changed Line 901 from a 5-year assessment cycle to a 3-year assessment cycle after the 2012 ILI survey.

The data collected during these surveys must be fully evaluated within 180 days of the ILI, and an operator must take action upon discovery of any "immediate repair conditions" as defined in 49 C.F.R. § 195.452(h) unless the operator can demonstrate that the 180-day period is impracticable.

The most recent ILI survey for Line 901 was completed on May 6, 2015. The 2015 ILI survey data for the first 2 miles of Line 901, as measured from the Las Flores Station, was found to be incomplete and not useable for ILI analysis. For the rest of the ILI survey, the correlation digs, which are used to gauge survey data accuracy in the ILI vendor's preliminary report, had not been finished at the time of the May 19, 2015 failure.

PHMSA's independent third-party ILI SME also performed an analysis of the data from past ILI surveys of Line 901. Preliminary data from the results of each of the ILI surveys are summarized below and show a growing number of corrosion anomalies on Line 901.

Number of Anomalies

Metal loss	June 19, 2007	July 3, 2012	May 6, 2015
Greater than 80%	0	0	2
60-79%	2	5	12
40-59%	12	54	80

The May 6, 2015 ILI survey data and subsequent analysis by the ILI vendor predicted external corrosion at the failure site with an area of 5.38 inches by 5.45 inches, and a maximum depth of 47% of the original pipe wall thickness. After the failure, the DNV-GL metallurgical investigators physically measured external corrosion at the failure site to have a maximum depth of 89%.[xii] The dimensions of the corrosion feature were 12.1 inches axially by 7.4 inches in circumference. The maximum depth, as measured using laser scan data, was 0.318 inches or 89% of the measured wall thickness (0.359 inches).

The ILI summary report prepared by PHMSA's SME also examined the "as-called" (ILI-predicted) versus as-found (field measured) lengths, widths and area for the excavated anomalies on Line 901. The report demonstrates that the lengths and widths of the anomalies were under-called (underestimated) in many cases, however many were also over-called. Plains submitted little documentation concerning their analysis of how the field measured anomalies compared to the ILI vendor analysis. Furthermore, Plains did not provide documentation showing that discrepancies between the originally reported anomaly sizes predicted by the ILI vendor and Plain's actual field-measured sizing of the corrosion anomalies were subsequently discussed with the ILI vendor, as required by Plains' IMP.[xiii]

Cathodic Protection Findings

According to 49 C.F.R. § 195.563, CP is required under the federal Pipeline Safety Regulations to prevent external corrosion of buried pipelines. Historical CP records for line 901 have been reviewed and reveal protection levels that typically are sufficient to protect non-insulated, coated steel pipe. Line 901 and Line 903, however, are insulated. An increasing frequency and extent of corrosion anomalies were noted on both Lines 901 and 903 in ILI survey results, anomaly excavations, and repairs. PHMSA inspectors noted moisture entrained in the insulation at four excavations performed by Plains on Line 901 after the May 19 spill and prior to the PHMSA-mandated purging of the pipelines.

Spill Volume Estimate from Plains' Third-Party Consultant

Plains initially estimated the volume of spilled crude oil to be approximately 2,400 bbl, of which 500 bbl was estimated to have reached the ocean. On August 4, 2015, Plains reported to the Unified Command that the 2,400 bbl release estimate was still accurate. However, after Plains completed the PHMSA-mandated purge, the company's calculations indicated that up to 3,400 bbl had possibly been released from the pipeline. Plains notified the Unified Command that RPS Knowledge Reservoir (RPS), a third-party investigator hired by Plains, was still trying to reconcile the difference.

On November 24, 2015, Plains informed PHMSA that RPS had completed their analysis regarding the release volume and produced a report of findings. RPS used the OLGA simulation software tool to model the behavioral dynamics of the pipeline prior to, during, and immediately after the May 19, 2015 leak. The report concluded that the discharge leak volume was 2,934 bbl. The RPS report was dated November 11, 2015. Plains has reported 1,100 bbl of crude oil have been recovered.

Investigation Findings and Conclusions

Line 901 pipeline ruptured at approximately 56% of the MOP. Although the operational events that occurred on the morning of the release were abnormal, this should not have caused the release if the pipeline's integrity had been maintained to federal standards.

Proximate or Direct Cause

PHMSA determined that the proximate or direct cause of the release was progressive external corrosion of the insulated, 24-inch diameter steel pipeline. The corrosion occurred under the pipeline's coating system, which consisted of a urethane coal tar coating applied directly to the bare pipe, covered by foam thermal insulation with an overlying Polyken tape wrap. Water has been noted in the foam insulation at a number of digs, indicating that the integrity of the coating system had been compromised. The external corrosion was facilitated by the environment's wet/dry cycling, as determined by the PHMSA-approved, third-party metallurgical laboratory. The release was a single event caused at an area where external corrosion had thinned the pipeline wall. There is no evidence that the pipeline leaked before the rupture. There was a telltale "fish mouth" (a split due to over-pressurization) at the release site indicating the line failed in a single event.

PHMSA's investigation identified numerous contributory causes of the rupture. The contributory causes can be grouped into three categories: 1) ineffective protection against external corrosion of the pipeline; 2) failure by Plains to detect and mitigate the corrosion;, and 3) lack of timely detection of the rupture. Below is a summary of the key contributory causes:

Contributory Causes

1) Ineffective protection against external corrosion of the pipeline

    - Plains' CP system was ineffective in protecting thermally insulated underground pipeline systems from external corrosion. Industry practices recognize that an impressed current system like the one utilized on Line 901 cannot protect an insulated steel pipeline should the coating (tape wrap over insulation) become compromised. The external coating in the area of the rupture had allowed moisture to enter the insulation adjacent to the steel pipe.[xiv] Corrosion under insulation (CUI) cannot be prevented on insulated lines where the coating system has been compromised.[xv]

2) Failure by Plains to detect and mitigate external corrosion

    - Plains did not identify CUI as a risk-driving threat in their federally-mandated integrity management program (IMP).

- Plains' did not fully implement their IMP.
    - Plains did not perform suitable analysis of the field measurements of the excavated corrosion anomalies that occurred after ILI surveys were completed in 2007 and 2012.
    - The data reported by the ILI vendor were inconsistent (and did not meet the published accuracy of the ILI tools of +/- 10%, 80% of the time for depth) when compared to the results of the field-measured corrosion anomalies.
    - Plains' as-found field measurements of corrosion anomalies were inconsistent with the as-called vendor-provided ILI data and analytical reports. ILI surveys conducted in 2007 and 2012 revealed inconsistencies in the character of the anomalies. In both of these cases, Plains did not consult the ILI vendor to help resolve the inconsistency.
    - Plains failed to follow written procedures directing the IMP group to perform appropriate statistical analysis after the anomaly dig reports were received from the field, and to discuss any inconsistencies with the ILI vendor.[xvi]
        - Plains' Pipeline Integrity group created a unity plot for depth after the 2012 ILI survey and anomaly digs. There is no documentation detailing what was done with the information from the unity plot.
    - Plains incorrectly added the over-called anomalies in the close-out reports.
        - The close-out reports should have only reported the anomalies that were within the reported accuracy of the ILI tool. The reported tool accuracy is +/- 10 %, 80 % of the time. Adding the overcalled anomalies outside of the tool accuracy skews the data.
- Plains' Pipeline Integrity group was historically focused on pitting corrosion under "shrink sleeves" at the pipeline girth welds (circumferential welds to join pipe segments).
    - The release location was within 6 feet of a corrosion anomaly that was exposed and repaired after the 2012 ILI survey. There was evidence of corrosion and degraded coating systems between the 2012 repair site and the 2015 rupture site.
    - The anomaly that ruptured was called out by the ILI tool at 45% depth in 2012. Plains' IMP specified adding 10% to all anomalies (55% depth in this case) then "growing them" to predicted failure using an anticipated corrosion growth rate. This analysis would provide a predicted failure time. Plains did not excavate the anomaly that failed.

3) Lack of timely detection of and response to the rupture

- The controller did not have information communicated from the SCADA system in such a manner to be successful in detecting abnormal operations. The pipeline SCADA system did not have safety-related alarms on low pressure configured at the correct value or priority to alert the control room staff of the rupture. When this alarm was provided to the controller, the discharge pressure at Las Flores was 199 psig but, within a minute, pressure elevated above 210 psig, the alarm status cleared, and the discharge pressure remained above 200 psig (approximately 210-211 psig) until the pipeline was purged. The pipeline was still leaking when the discharge pressure at Las Flores was above 200 psig, and continued to do so without additional alarm indications. When the pipeline was down, isolated but still leaking, the minimum pipeline discharge pressure at Las Flores remained at 210-211 psig. The low discharge pressure alarm setpoint value was not set properly as it should have been above 211 psig. This type of alarm should be identified as a high priority safety related alarm. While the controllers and shift supervisors can access historical trend data or continue to monitor a given pressure or flow, when the pipeline was ultimately shut down at 11:30 a.m., neither the controller nor step-up shift supervisor detected any drop of pressure at the specific failure location that would indicate that oil was being released.

- Neither the pipeline controller nor step-up shift supervisor detected the initial abnormal conditions as the release occurred. There was an indication of decreased pressure and increased flow between 10:53 and 10:58 a.m., which is consistent with a pipeline release. This resulted in a delayed shutdown of the pipeline. Adequate alarm setpoint values with correct priorities are essential to controller and shift supervisor recognition of abnormal operations, especially when many pipeline systems are operated from the same console.

- The pipeline controller restarted Line 901 after the release occurred.

- The pipeline leak detection system lacked instrumentation and associated calculations to monitor line pack.
  - The function of the PLM system was a simple line balance calculation based on flow meter values without line pack considerations. The PLM relies on comparing “meter in – meter out” calculations over time. This type of leak detection system without the use of safety-related, high-priority, low-pressure alarms does not provide the controller or shift supervisors with adequate information when the pipeline is down.
  - When the pipeline is not running, even if only due to scheduling and not required maintenance activities, flows will be close to zero and the imbalance calculation will provide little if any value as currently configured. Leak detection on a down pipeline requires a robust system of planned and accurate high-priority alarm types and alarm setpoint values in order for response to occur on critical low pressures.
  - The leak detection system for Lines 901 and 903 consists of two leak detection segments. Additional instrumentation such as pressure and temperature transmitters located at Refugio Gate and Cuyama valve settings (both transmitter types on each side of the valves) would allow additional information about the operating status of the pipeline to be presented and pack calculations pursued.
  - Plains utilizes the SimSuite application for other pipelines in the control

center. This application does allow for pack calculations to be utilized in the leak detection system. According to information obtained during meetings with Plains hydraulic specialists, Lines 901 and 903 were pipeline systems with a low to medium priority defined for future modeling efforts compared to other assets in the Plains operations. The approach utilized by Plains for prioritizing which systems should be modeled first did not appear to take into account all appropriate consequence-based asset impacts (such as culverts providing a pathway to the ocean) associated with these two systems. Existing instrumentation and the need for added instrumentation would factor into this prioritization decision.

- Control room staff training lacked formalized and succinct requirements, including emergency shutdown and leak detection system functions such as alarms.
  - Interviews determined that the step-up shift supervisor and shift supervisor training lacked formalized and succinct requirements, including that for leak detection system functions such as "inhibit" options. The interviews determined that different shift supervisors performed PLM inhibit functions without contacting the console supervisor first as required by procedure.
  - Step-up and shift supervisor responsibilities include emergency shutdown of any pipeline. However, training does not cover a means by which to accomplish this for all relevant pipelines. A general emergency shutdown provision has not been programed for supervisory use on all systems.
- The oil spill response plan required by 49 C.F.R. §194 did not account for a culvert near the release site that traversed the Pacific Coast Highway and Amtrak railroad tracks. This culvert provided a quick flow path between the pipeline ROW and the Pacific Ocean, thereby allowing crude oil to flow easily towards Refugio State Beach and the ocean. The response plan did not have a response strategy that considered the presence of the culverts.

PHMSA Post-Incident Action Chronology

Following the May 19, 2015 Plains Pipeline, LP, Line 901 rupture in Santa Barbara County, CA, PHMSA took the following actions:

- On May 19, 2015, PHMSA deployed inspectors to investigate the Plains Pipeline LP Line 901 pipeline failure in Santa Barbara County, CA. PHMSA also provided information updates to the Unified Command (UC), US Coast Guard, the Federal on Scene Coordinator (FOSC), State Fish and Wildlife, and other agencies on site.
- On May 21, 2015:
    - PHMSA issued a Corrective Action Order (CAO), CPF No. 5-2015-5011H, to Plains Pipeline LP ordering it to suspend operations and to specific safety actions to further protect the public, property, and the environment from potential hazards associated with the recent failure. PHMSA staff reviewed the CAO with the operator and briefed the California State Attorney on the CAO and provided an overview of PHMSA's regulations.
    - PHMSA sent an inspector to Plains' control room in Midland, Texas to collect operational data and interview the control room operators on duty at the time of the incident and their supervisors. The inspector gathered any pertinent logs and information, including electronic copies of relevant data from the Supervisory Control and Data Acquisition (SCADA) system.
    - PHMSA staff worked with the operator to review their plan to expose the pipe and to cold tap it to ensure there was no pressure or crude left in the line at a low spot immediately downstream of the release point. The plan was signed off by the UC at approximately 5 pm PDT.
- On May 22, 2015:
    - PHMSA staff met with representatives from the Assistant U.S. Attorney, DOT Inspector General, EPA Criminal Investigation Division, California Attorney General, and others to brief them on PHMSA's process for securing and transporting the failed pipe to a metallurgical lab for evaluation.
    - PHMSA staff remained on the scene as the operator exposed, tapped, removed any remaining product, and excavated the pipeline downstream of the release site.
- On May 25, 2015:
    - PHMSA issued an approval letter for Plains to excavate, remove and secure the failed joint of pipe under the supervision of two DNV metallurgists (third party contractor) but requested that the coating and insulation not be touched until the failed pipe has been removed because the DNV personnel were interested in in gathering available samples there as well.
    - A PHMSA inspector returned to Midland, TX to interview the controller and the Operations Control Center supervisor and to obtain any handwritten logs created by the controller on the morning of the release.
- On May 28, 2015:
    - A PHMSA investigator was on site when affected pipeline was removed, crated, and transported to secure location for metallurgical evaluation. PHMSA retained a third-party ILI expert to examine the 2012 and 2015 ILI runs. DNV personnel took soil and insulation samples.
- On June 3, 2015, PHMSA amended the CAO to address preliminary findings from the early stages of the investigation (Amendment No. 1). The amended CAO mandated

additional safety requirements on Line 901 and expanded the scope of the CAO to include the 128-mile long Line 903, which is located downstream of Line 901. The amendment reduced the operating pressure of the Lone 903 by 80% of the highest 8 hour continuous pressure between April 19, 2015 and May 19, 2015. On May 30, 2015, Plains voluntarily shutdown Line 903.

- On June 18, 2015, PHMSA staff monitored the Line 901 purge to ensure safety during the purging process. Plains completed the purge and injected inert gas in Line 901.
- On September 18, 2015, PHMSA received the DNV Final Mechanical and Metallurgical Report. PHMSA staff reviewed the document and provided comments.
- On November 12, 2015, PHMSA issued Amendment No. 2 to the CAO, which ordered Plains to purge and shutdown Line 903 from Gaviota to Pentland.
- On December 1, 2015, PHMSA staff monitored Plains moving Freeport McMoRan crude oil from their offshore platforms into Line 903 from Gaviota Station to Sisquoc Station. Movement of the Freeport McMoRan oil was completed on December 10, 2015.
- On December 4, 2015, PHMSA staff received the DNV Root Cause Failure Analysis Report. PHMSA reviewed and commented on the report.
- On December 14, 2015, PHMSA staff monitored the purge process on Line 903 from Gaviota Station to Sisquoc Station. The purge was completed on December 18, 2015 and the line was filled with inert gas.
- On February 17, 2016, PHMSA issued a Preliminary Factual Final Report.
- On April 2, 2016, PHMSA staff monitored the Line 903 Sisquoc to Pentland portion purge that was completed on April 18, 2016. Line 901 and 903 are shutdown, except for the Pentland to Emidio section of Line 903, which is not connected to 903 any longer.

APPENDICES

A. Investigation Summary Detail
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J. National Response Center Report #1
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M. Det Norske Veritas (U.S.A.), Inc. (DNV GL): Line 901 Release (5/19/15) Mechanical and Metallurgical Testing
N. Det Norske Veritas (U.S.A.), Inc. (DNV GL): Line 901 Release (5/19/15) Technical Root Cause Analysis
O. NACE International: Effectiveness of Cathodic Protection on Thermally Insulated Underground Metallic Structures

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[i] According to the *FRACTURE CONTROL TECHNOLOGY FOR NATURAL GAS PIPELINES CIRCA 2001* (the PRCI report superseding NG-18 Report 208): "The distinction between leak and rupture for the pipeline community is based on the size and configuration of the breach, not how it develops." Based on these calculations and visual observations, the length of the feature is consistent with a leak, arresting within the corrosion feature, and did not propagate outside of the feature into nominal wall-thickness pipe. According to the instructions for completing PHMSA Accident Form 7000-1, this type of accident would be classified as a rupture since PHMSA defines a "rupture" as a "loss of containment that immediate impairs the operation of the pipeline".

[ii] The remedial action plan requires: a) investigation and remediation of anomalies on Line 901 (including anomalies requiring repair per 49 C.F.R. § 195.452(h) and similar anomalies); b) analysis of field measurements taken from anomaly investigations; c) re-grade of previous in-line inspection (ILI) data from 2012 and 2015 ILI surveys using an expanded set of interaction criteria; d) additional integrity assessments using a circumferential magnetic flux leakage (MFL-C) ILI tool and integration of MFL-C ILI data with previous ILI survey results; e) investigation and remediation of anomalies that are identified in the MFL-C tool run (if any); f) based on information collected from remedial work plan and root cause analysis report released by Det Norske Veritas (U.S.A.), Inc., improving the integrity management program; and g) integrity studies to reduce spill volumes, including an emergency flow restriction device evaluation and a surge study. Completion of the remedial work plan is required prior to the PHMSA Western Region Director approving a restart plan and return to service for Line 901.

[iii] High case temperature refers to the oil temperature inside the pump cavity. The case holds the pump impeller

where oil passes through. This was a centrifugal pump that continues spinning whether there is product in the pump or not. When the rupture occurred, there was not enough pressure or flow rate to allow the pump to continue pumping the oil over the hills and into Pentland Station. Therefore, the oil that was in the pump remained in place and as the pump continued to spin, and temperature was reported to the SCADA system. If the pump reaches the high temperature setpoint, the pump shuts itself off to protect itself from burning up.

[iv] The PCR utilizes two shift supervisors to cover the entire set of 22 consoles. The California Console is handled by shift supervisor B. The shift supervisor B position at the time of the failure was filled by a step-up shift supervisor. A step-up shift supervisor is a controller who is currently qualified on a specific console in the PCR and has received some informal training by working on shift with other shift supervisors. Step-up shift supervisors are used to cover the shift supervisor positions when additional personnel are needed due to illness, vacation, training, etc. Plains has indicated that two step-up shift supervisors are not allowed to be on duty at the same time so one shift supervisor is paired with a step-up shift supervisor when additional personnel is needed.

[v] PLM is the SCADA vendor software tool that serves as the leak detection system for PCR.

[vi] *See* Appendix B.

[vii] SCADA Data/Plains Control Room time is local to the Central Time Zone. A two-hour time difference separates Central Time from Pacific Time, with Central Time falling two hours ahead. The release occurred in the Pacific Time Zone which is two (2) hours earlier. All times in this report have been adjusted to Pacific Time.

[viii] *See* Appendix J.

[ix] *See* Appendix K.

[x] *See* Appendix L.

[xi] *See* Appendix M.

[xii] PHMSA has access to this data through a view-only web portal.

[xiii] *See* Appendix G.

[xiv] The inability of an impressed cathodic protection system to protect insulated pipelines was most recently reaffirmed in the National Association of Corrosion Engineers (NACE) Publication 10A392 (2006 Edition) – "Effectiveness of Cathodic Protection (CP) on Thermally Insulated Underground Metallic Structures."

[xv] *See* NACE Report at Appendix O, Background section stating that "[o] n most thermally insulated oil and gas transmission pipelines installed prior to 1980 to 1981, a shop mold-formed thermal insulation was placed directly over the bare steel pipe, with an outer jacket applied to moisture-proof the system. At the field joint, preformed insulation half shells were applied over the joint area to fit between the ends of the shop-applied insulation. After the insulation was fitted, a heat shrink sleeve or a tape wrap was applied over the insulation. When the integrity of the outer moisture barrier was compromised, the space, gap, or void between the edges of the preformed half shells and the shop-applied insulation allowed oxygenated water to diffuse to the bare steel beneath. Damage to the outer moisture barrier has also occurred remote from the joint, allowing oxygenated ground water ingress.

"Thermally insulated pipelines have experienced relatively aggressive corrosion, with some failures occurring within three years of service, although acceptable industry standards of CP had been applied and maintained shortly after line construction. The most predominant failures have been those occurring at joints; however, moisture has migrated along the pipeline steel surface to create electrochemical corrosion cells remote from the field joint, culminating in extensive replacements of substantial lengths of line. An article titled 'Corrosion of Underground Insulated Pipelines' supports this committee's conclusions that sufficient CP current from an external source may not reach the insulated metallic surface in sufficient quantity to establish adequate corrosion control."

[xvi] *See* Appendix D.

Appendix A

Investigation Summary Detail

Appendix A: Investigation Summary Detail

DOT	US Department of Transportation
PHMSA	Pipelines and Hazardous Materials Safety Administration
OPS	Office of Pipeline Safety
	Western Region

Principal Investigator	Peter J. Katchmar
Regional Accident Coordinator	Peter J. Katchmar
Region Director	Chris Hoidal
Date of Report	5/5/2016
Subject	Failure Investigation Report – HL Santa Barbara County CA Crude Oil Release

Operator, Location, & Consequences

Date of Failure	5/19/2015
Commodity Released	Crude Oil
City/County & State	Refugio State Beach, Santa Barbara County, CA
OpID & Operator Name	300 – Plains Pipeline, LP
Unit # & Unit Name	33175 - CSFM #1050A
SMART Activity #	150537
Milepost / Location	MP 4.16
Type of Failure	External Corrosion
Fatalities	0
Injuries	0
Description of area impacted	Ranch land ¼ mile east of the Pacific Ocean, Refugio State Beach and the Pacific Ocean. Oil flowed to a water drainage culvert that ran under California State Highway 101 (Pacific Coast Highway) and the Amtrak Railroad embankment and into the Pacific Ocean.
Property Damage and Cleanup Cost	$ 142,931,884 (through December 23, 2015)

Appendix B

Supervisory Control and Data Acquisition (SCADA) Log Excerpts

Appendix B: Supervisory Control and Data Acquisition (SCADA) Log Excerpts

Listed below is a chronology of events, as obtained from the Plains Control Room (PCR) Supervisory Control and Data Acquisition (SCADA)[1] logs. The SCADA log records alarms and events that occur per pipeline system for each line operated from the console. Due to the significant volume of entries and information occurring at the time of this release, only those data points relevant to the CA30 system (901 and portions of 903) have been included

- At 10:42:06, Pump 401 at the Sisquoc Station shut down uncommanded due to maintenance activities.
- At 10:48:44, the Plains controller at the PCR issued a command to shut down Pump 102 at the Las Flores Station as the result of pump problems at Sisquoc.
- At 10:48:52, the SCADA system reported that the Pump 102 at Las Flores had successfully shut down.
- The discharge pressure at the Las Flores Station immediately prior to shutdown was recorded by the SCADA to have reached ~677 psig at a flow setpoint of ~1220 Barrels per Hour (BPH).
- At 10:49, Tech 2 called the controller and notified him that he could restart Pump 401 at Sisquoc Station.
- At 10:52:52, the controller issued a command to restart Pump102 at Las Flores PS.
- At 10:53:01, the SCADA system reported Pump 102 successfully started.
- Between 10:53 and 10:56 the Pressure and Flow Data from the SCADA indicated the discharge pressure at the Las Flores PS reached ~721 psig and the flow rate reached as high as ~2042 barrels per hour (BPH). Pressure and Flow Trends confirm that 10:55 is approximately when the release occurred.
- At 10:55:52, the controller commanded the Pump 401 at the Sisquoc Station to start.
- At 10:56:52, the SCADA system reported that Pump 401 at Sisquoc Station was running.
- At 10:57:59, the SCADA system reported the discharge pressure at the Las Flores Station dropped to 199 psig and the SCADA system reported a low pressure alarm to the controller.
- At 10:58:48 the discharge pressure rises to 210 psig. This automatically resets the low pressure alarm.
- At 10:58:58 the controller acknowledges the 210 psig discharge pressure notification.

[1] SCADA systems are used to remotely control and monitor pipeline operations.

- At 11:00:00 the SCADA system reported the flow rate was at 1458 BPH – (a soft high state)
- At 11:00:05 controller acknowledges the soft high flow rate.
- At 11:00:14 the SCADA system reported flow rate at Las Flores was 1254 BPH = Normal State.
- At 11:09:20, the SCADA System recorded that Sisquoc Pump 402 had a high case temperature. However, Sisquoc Pump 402 was not running.
- At 11:12, Venoco personnel called the controller and notified him they wanted to start a delivery into line 901 through their line 96. Venoco's line 96 ties into line 901 about 2.83 miles downstream of the Las Flores Station between the two hills.
- At 11:14, controller called the I&E Tech at Sisquoc Station to tell him of the high temperature on Pump 402.
- At 11:15:14, the SCADA System recorded that Sisquoc Pump 401 shut down on High Temperature.
- At 11:15:48, Venoco started their pump to start a delivery into line 901.
- At 11:20, Venoco personnel called the Plains controller and told him the pressure in line 901 was too low to run their line 96 pump.
- At 11:20:12, Venoco turned off their pump and closed their valve.
- At 11:22:58, the SCADA log states "PLM inhibited." The Pipeline Leak Monitoring System, or PLM, calculates the imbalance between volumetric meters along the pipeline.
- At 11:26:43, the controller issued a command to start Pump 401 at Sisquoc PS.
- At 11:27:50, the pump start command timed out. Pump 401 did not start.
- At 11:28:12 the controller again issued a command to start Pump 401 at Sisquoc PS.
- At 11:29:20, the pump start command timed out. Pump 401 did not start.
- At 11:29:56, the controller issued a stop command to the Pump 102 at Las Flores PS. **[2 minutes after the PLM would have alarmed according to the calculation presented in Appendix C.]**
- At 11:30:05, the SCADA system reports that Pump 102 at Las Flores PS is stopped. Mainline Valve 102B at Las Flores closes automatically upon Las Flores Pump 102 shutdown. The pressure at Las Flores is recorded by the SCADA to be between 211 and 213 psig.
- At 1:27, the PCR was notified of the line 901 release near Refugio Beach, approximately 4.16 miles from the Las Flores PS. The static pressure immediately downstream of the Las Flores PS is recorded by SCADA to be 211 psig.
- At 1:27:23, the controller at the PCR issues a command to close the Refugio Creek mainline valve. **[This and the following actions were in response to the controller being informed of oil on the ground at MP 4.16.]**

- At 1:28:31, the controller Issues Command to close Valve 108 at Las Flores PS.
- At 1:29:34, SCADA reports the mainline valve at Refugio Creek, approximately 2.83 miles downstream of the Las Flores PS and 1.2 miles upstream of the release site, had successfully closed.
- At 1:30:34, SCADA reports Las Flores PS Valve 108 successfully closed.
- Between 3:47:14 and 3:48:13, the controller issues commands to close valves 208A, 208 C, and 209A at Gaviota Station.
- Between 3:49:51 and 3:51:11, SCADA reports successful closure of valves 208A, 208C, and 209A at Gaviota PS.
- At 3:57:48, controller issues command to close valve 209B at Gaviota PS.

At 4:00:49, SCADA reports successful closure of Valve 209B at Gaviota PS and the pipeline remained down.

Appendix C

Pipeline Leak Monitoring Details

Appendix C: Pipeline Leak Monitoring Details

Plains submitted documentation showing the parameters of the PLM and extrapolated what would have occurred if the PLM system had not been inhibited. The submitted documentation shows that the PLM would have alarmed at approximately two minutes before the controller issued the command to shut down the pump at Las Flores PS at approximately 11:30am PDT. The graphical representation is shown on this page.

Graphical Representation of when the PLM System would have alarmed had it not been "inhibited". Times in the graph and explanation are in Central Time. Pacific Time is two hours earlier.

Plains provided the following explanation along with the graphical representation above. It is quoted as all content is there. [A few changes were made for emphasis and readability that do not compromise the integrity of the explanation.]

<u>"This is an explanation of how the program calculated the time when the PLM would have alarmed.</u>

- There are 5 meters that receive oil into the line 901/903 PLM. The SCADA tags are:
  - [redacted]

- There are 6 meters that deliver oil out of the PLM. The SCADA tags are:
  - [redacted]

- [redacted]

- Each of these meters are running accumulators, like the odometer on your car, that count barrels (BBLs) through them. The BBLs through them in the last hour is the current value of the accumulator minus the value of the accumulator from 1 hour ago. If we designate the specific value of the accumulator by appending the time parenthetically, the volume of oil through the first Las Flores meter in the hour before 5/19/15 13:27 would be:

  - [redacted](5/19/15 13:27) - [redacted] 5/19/15 12:27)

- The one hour over/short is the sum of all the oil through the out meters for the past hour minus the sum through the in meters for the same time period

- [redacted](5/19/15 13:27) =
  - [redacted] 5/19/15 13:27) [redacted](5/19/15 12:27) +
  - [redacted] 5/19/15 13:27) [redacted](5/19/15 12:27) +
  - [redacted](5/19/15 13:27) [redacted](5/19/15 12:27) +
  - [redacted](5/19/15 13:27) [redacted](5/19/15 12:27) +
  - [redacted](5/19/15 13:27) [redacted](5/19/15 12:27) +
  - [redacted](5/19/15 13:27) [redacted](5/19/15 12:27) -
  - [redacted](5/19/15 13:27) [redacted] 5/19/15 12:27) +
  - [redacted] /19/15 13:27) - [redacted] /19/15 12:27) +
  - [redacted](5/19/15 13:27) [redacted] 5/19/15 12:27) +
  - [redacted](5/19/15 13:27) [redacted] (5/19/15 12:27) +
  - [redacted](5/19/15 13:27) [redacted] (5/19/15 12:27))

- The estimated value o[redacted]5/19/15 13:26) was -585.6 BBLs. The value of[redacted] (5/19/15 13:27) was -607.5 BBLs. The alarm limit was at -600 BBLs so the alarm would have been issued at 13:27. <u>[This equals 11:27am Pacific Time]</u>

Appendix D

Excerpts and Discussion of Plains Integrity Management Plan (IMP) Requirements

Appendix D: Excerpts and Discussion of Plains Integrity Management Plan (IMP) Requirements

Plains submitted a copy of their IMP dated, December 18, 2003. Applicable sections from that IMP are copied below.

"Section 6.0 Procedures for Conducting Assessments and Processing Results

Rule 49 CFR §195.452 (f)(8) and (f)(4) requirements:

(f)(8) - A process for review of integrity assessment results and information analysis by a person qualified to evaluate the results and information.

(f)(4) Criteria for remedial actions to address integrity issues raised by the assessment methods and information analysis."

On page 6-4 of the Plains' IMP, there is a flowchart, "Figure 6-1 Pipeline In-Line Inspection (ILI) Assessment and Repair – Sequencing of Tasks."

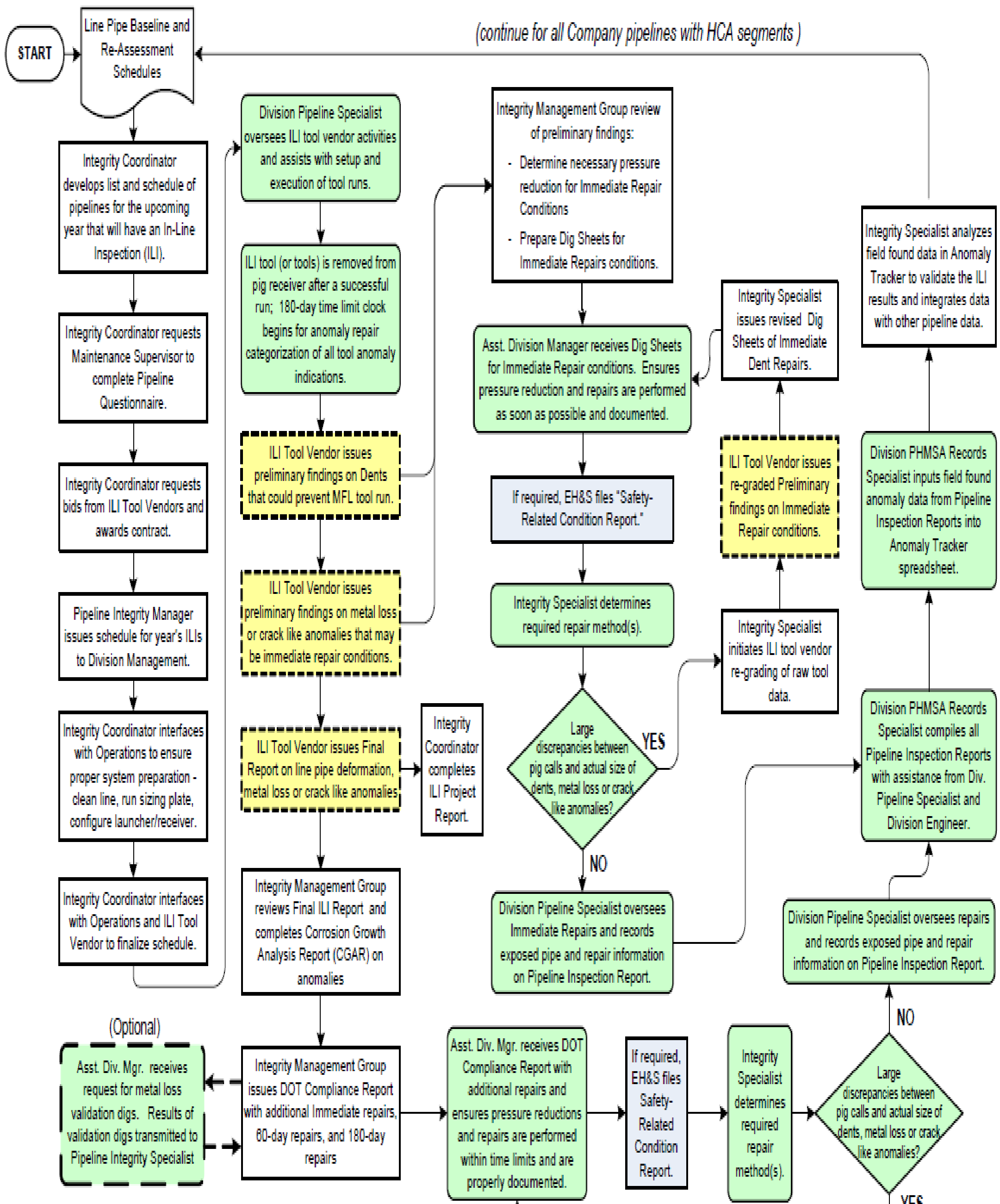
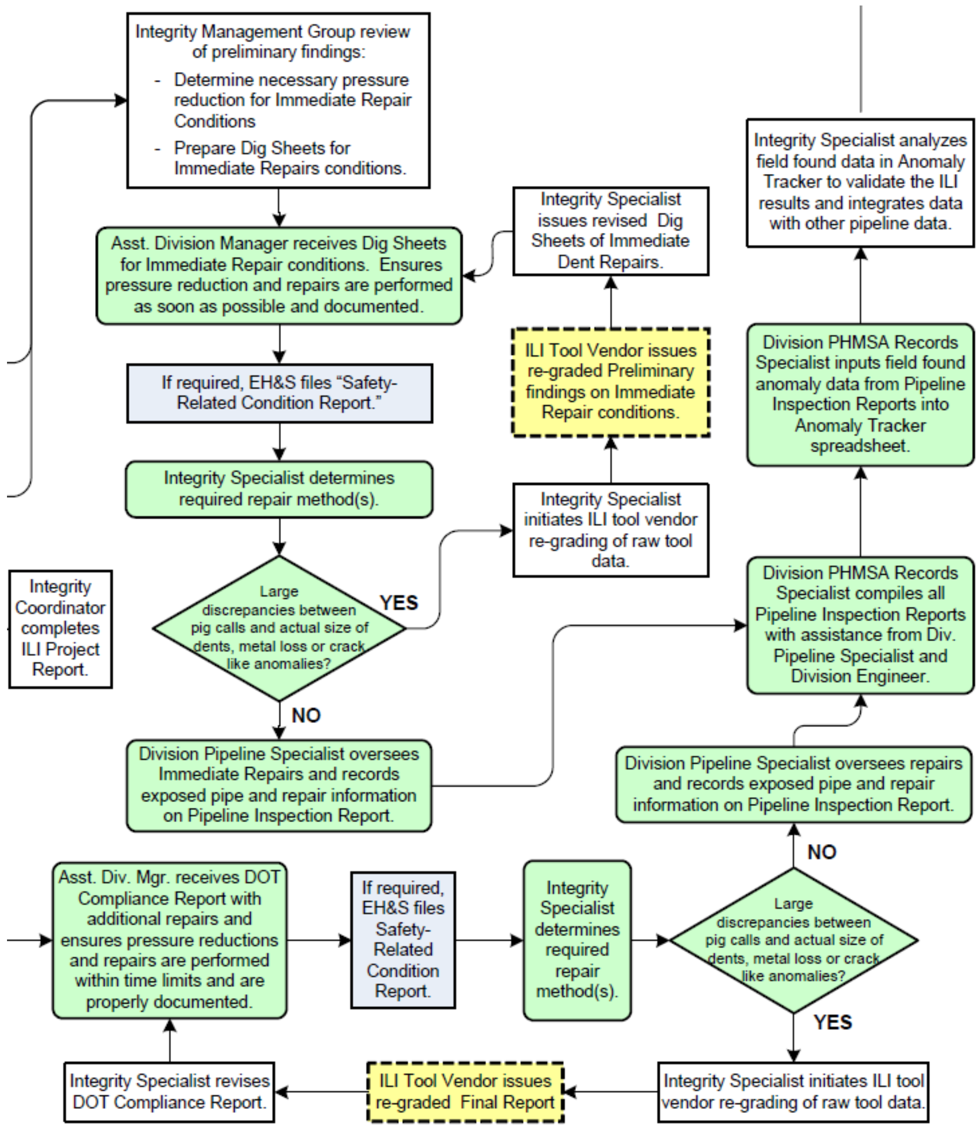


FIGURE 6 – 1
Pipeline In-Line Inspection (ILI) Assessment and Repair - Sequencing of Tasks

An enlarged portion of Figure 6-1, from the bottom right quadrant is copied below.



The two diamond shapes in the flowchart state the same decision point:

"Large discrepancy between pig calls and actual size of dents, metal loss or crack like anomalies?"

If "yes" the next box in both cases is:

"Integrity Specialist initiates ILI tool vendor re-grading of raw tool data."

PHMSA requested all documentation between the Plains IMP Group and their ILI vendor with respect to their line 901 and 903 before March 19, 2015. PHMSA was provided access to three email strings between the vendor and Plains IMP Group. The first email string had to do with discrepancies noted by Plains IMP group for "clustering" on the Pentland to Emidio segment on line 903.

The second and third email strings discuss an anomaly called out as a 66% wall loss by the vendor which was found to be 95% wall loss when excavated and measured in the field. This anomaly was on line 903 between the Gaviota PS and Sisquoc PS and was excavated after the 2013 ILI survey on that line segment. This event was described as a “close call” by the Plains representative. He asked the vendor what the cause of this under reporting might be. The ILI vendor responded:

> “The anomaly in the 2008 run had a lower calculated wall loss of 28% (A neighboring anomaly had a wall loss of 32%, which ended up being assigned to the cluster) because the lower resolution DHD sensors capturing the signal as one anomaly with a wide profile, which resulted in a low wall loss calculation. For the 2013 run, although the tool captured a better profile, with two peaks at that same spot, the anomaly sized a bit wider, encompassing part of the neighboring peak (which had the lower amplitude), which resulted in the 66% wall loss. After adjusting the width to only account for the higher peak, the resulting wall loss was 76%.”

The vendor also requested additional dig results from this Gaviota to Sisquoc survey via email. Plains apparently sent them additional digs results at a later date via email attachment.

This interaction demonstrates that the ILI vendor is able to reanalyze data and did come closer to the actual anomaly depth. Even after re-analyzing the anomaly, the vendor still under-called the anomaly by 19%. This should have led to increased conversation.

When provided additional information from the operator, the vendor uses the “new” information to reanalyze the specific anomaly to better provide a more accurate characterization of the anomaly. Also, the vendor analyst requested additional data from the digs that were being performed.

Appendix E

Corrosion Control and Pipeline Conditions

Appendix E: Corrosion Control and Pipeline Conditions

Corrosion Control

All interstate pipelines regulated by PHMSA on which construction was begun after March 31, 1970 are required to be coated and cathodically protected. Cathodic protection (CP) is a process by which bare steel is protected from corrosion by introducing a small electric current from a rectifier through an anode bed into the earth and back to the rectifier through the pipe (the cathode). A pipe will corrode if steel is allowed to leave the pipe at bare spots called "holidays" in the coating. CP forces electricity toward the pipe at holidays which counters the corrosion process.

Pipeline Coatings

The first line of protection from pipeline corrosion is a good coating. Line 901 was installed with a coal tar urethane coating in intimate contact with the bare steel 24-inch pipe. Approximately 1.5-inches of urethane foam insulation were then sprayed onto the pipe over the coal tar urethane coating. The pipe was then finally wrapped with a polyethylene tape as a moisture barrier and to hold and protect the insulation on the pipe. The girth welds, where each joint of pipe is welded to the next joint, were coated with shrink sleeves which are made of a thermoplastic that shrinks when heat is applied with a torch which then adheres the sleeve tightly to the pipe.

CP on Line 901

Operators are required to install and monitor a CP system within a year of constructing a pipeline. This was done for Line 901. Periodic testing and evaluations are required to ensure the CP system is functioning properly. Bimonthly inspections of rectifiers and annual inspections of pipe-to-soil potentials at each test station along the pipeline are required and reports are kept. PHMSA reviewed CP reports for Line 901 with a focus on 2003 to the present. The operator conducted a close-interval-survey (CIS) in December 2008 and again in April 2015 on Line 901. A CIS is an effort where the operator reports an "on" potential and an "off" potential at approximate three-foot intervals. These reports showed that the CP system appeared to be working well and that the pipe-to-soil potentials were within accepted criteria. The CIS in 2008 showed that the polarized potential of the pipeline was generally around a volt (-1,000mV). In 2015, the polarized potential had moved in the more negative direction towards the maximum polarized potential of steel or ~1,200mV. The off readings in 2015 were generally more negative than -1,100mV.

There are two explanations for the movement of the polarized potential on Line 901. One would be that the operator turned up the output on the rectifiers that supply the current to the pipe or they installed additional rectifiers. The second would be that the operator removed some of the protected steel from the CP circuit.

PHMSA reviewed the rectifier inspections and found that they were not "turned up" during this time period. The rectifiers had generally consistent output. This meant that the only other possibility would be the removal of a significant amount of steel from the protected pipeline system.

PHMSA requested that the operator provide documentation of the amount of pipe removed from the system between 2008 and 2015. Plains provided a statement to PHMSA indicating that between 2008 and 2015, approximately 2120 feet of 20-inch and 24-inch piping was disconnected from or removed from the cathodically protected pipeline system.

CP is Ineffective on Buried Insulated Pipelines

After the release, PHMSA personnel visited Plains offices in Houston, TX, to continue the investigation. During this first visit, one of the first questions concerned external corrosion and cathodic protection because this appeared to be the apparent cause of the release. Plains personnel showed PHMSA a Technical Committee Report from the National Association of Corrosion Engineers (NACE International), titled, "Effectiveness of Cathodic Protection (CP) on Thermally Insulated Underground Metallic Structures" - NACE International Publication 10A392 (2006 Edition) – originally prepared in 1992 by NACE Task Group (TG) T-10A-19, a component of Unit Committee T-10A on Cathodic Protection and was reaffirmed with editorial changes in 2006 by Specific Technology Group (STG) 35 on Pipelines, Tanks, and Well Casings. It is published by NACE under the auspices of STG 35."

This report details the reasons that CP is not effective on buried insulated underground structures. In the "Background" section the report states,

> "Thermally insulated pipelines have experienced relatively aggressive corrosion, with some failures occurring within three years of service, although acceptable industry standards of CP had been applied and maintained shortly after line construction. The most predominant failures have been those occurring at joints; however, moisture has migrated along the pipeline steel surface to create electrochemical corrosion cells remote from the field joint, culminating in extensive replacements of substantial lengths of line."

Ultimately, it appears that moisture migrated along Line 901 to the lowest local elevation point and created an electrochemical corrosion cell approximately six (6) feet from the nearest girth weld.

Discussion of Corrosion Under Insulation (CUI)

On non-insulated buried pipelines, external corrosion is normally able to be mitigated by Cathodic Protection (CP). Generally, external corrosion cannot occur as long as CP current is getting onto the pipe. CP current creates an oxygen-free environment around the pipe which will stop the electrochemical process of corrosion, barring additional circumstances.

Where external corrosion does occur, current is allowed to get off the pipe and migrate into the surrounding soil. When this occurs, the current takes metal ions with it causing the wall loss or external corrosion. There is little to no "corrosion product" that remains at the pipe surface.

In a buried insulated line, the coatings and insulation do not allow the metal ions that result from the electrochemical process of corrosion to migrate away from the pipe surface. Thus, the "corrosion product" will remain close to the pipe and it will become dormant when the electrochemical process depletes all of the oxygen in the moisture. This is known as the dry cycle. When fresh "oxygenated" moisture infiltrates the coating and reaches the area of external corrosion on the pipe, the corrosion process reactivates and again continues until the oxygen is depleted. This is known as the wet cycle. This process is described in detail in the attached metallurgical report as Corrosion Under Insulation (CUI) facilitated by wet/dry cycling which was determined to be the actual cause of the wall thinning at the release site.

The metallurgical report contained descriptions of the "corrosion product" as being dense and tightly adhered to the pipe. The structure of the “corrosion product” was alternating layers of magnetite and goethite; both have magnetic properties. Due to the composition and density, PHMSA requested additional testing to better quantify the parameters of density and magnetic permeability of the “corrosion product”. This was done and the results were presented in the final root cause failure analysis (RCFA) report also attached to this report. The results came back that the density of the “corrosion product” was 25% of steel and the magnetic permeability was 5% that of steel. While 5% magnetic permeability is small, the large volume of the corrosion product compared with that of the remaining pipe wall led, in part to the MFL tool’s inconsistent reporting. This phenomenon is discussed below and in more detail in the ILI SME Report.

Magnetic Flux Leakage (MFL) Technology and Under-Calling the Failed Anomaly

In simple terms, the MFL tools used are comprised of magnets that apply a magnetic flux into the pipe steel in the longitudinal direction. The amount of magnetic flux put into the pipe is calibrated to saturate the full wall thickness. There are numerous sensors placed circumferentially around the tool and central to the induced flux field so as to measure and record variances in the magnetic flux that remains in the pipe wall. Any volumetric metal loss that the magnetic field encounters will cause the magnetic flux to “leak” from the pipe wall. The amount of this leakage is then recorded by any number of the sensors in its proximity. When this data is processed, the leakage can be measured to infer the depth, length and width of the metal loss in the pipe wall. As discussed above, when external corrosion is allowed to leave the pipe and migrate into the surrounding soil, the anomaly that is left is usually only the remaining steel. Slight corrosion product might be discovered but not to the extent encountered under insulated coated buried pipe.

On coated, insulated and buried pipe, the “corrosion product” grows and remains in close proximity to the pipe steel. This is similar to the type of corrosion on vehicles, in which the corrosion under bubbled paint can be easily flaked off. The corrosion-related paint bubbling on vehicles is similar to what occurred on Line 901. There is a pinhole in the paint where oxygenated moisture can get in and allow the corrosion to occur. The remaining paint has enough integrity to keep the moisture in, which allows the corrosion to occur and corrosion product to grow. The corrosion product gets thicker and thicker until the paint fails entirely.

This is similar to the mechanism of CUI that occurred on Line 901. The following picture is excerpted from the metallurgical report.

This picture is excerpted from the final metallurgical report. “Figure 16. Photograph showing a piece of insulation removed from adjacent to the failure location; near 4:30 orientation.”

Appendix F

Industry Standards and General Requirements for In-Line Inspection

Appendix F: Industry Standards and General Requirements for In-Line Inspections

49 CFR Part 195.452(b)(6) requires that operators, “Follow recognized industry practices in carrying out this section, unless – (i) This section specifies otherwise; or (ii) The operator demonstrates that an alternative practice is supported by a reliable engineering evaluation and provides an equivalent level of public safety and environmental protection.” The following discusses the three current accepted industry standards for In-Line Inspections (ILI).

The American Petroleum Institute (API) developed “API Standard 1163, “In-line Inspection Systems Qualification Standard” in 2005. A portion of the forward states that this document, “…serves as an umbrella document to be used with and complement companion standards. NACE RP 0102 Standard Recommended Practice, In-Line Inspection of Pipelines; and ASNT ILI-PQ In-Line Inspection Personnel Qualification & Certification all have been developed enabling service providers and pipeline operators to provide rigorous processes that will consistently qualify the equipment, people, processes and software utilized in the in-line inspection industry.”

Section 1.2 Guiding Principles of API 1163 goes on to state, “Personnel and equipment used to perform in-line inspections and analyze the results shall be qualified according to this Standard and its companions, ASNT In-Line Personnel Qualification and Certification Standard No. ILL-PQ, and NACE Standard Recommended Practice In-Line Inspection of Pipelines RP0102. Combined, these three standards provide requirements and processes for the qualification of inline inspection systems, including the in-line inspection tools, their software, and the personnel to operate the systems and analyze the results. This Standard is an umbrella document covering all aspects of in-line inspection systems, incorporating the requirements of ASNT ILI-PQ and NACE RP 0102 by reference.

Section 9 System Results Verification and Section 9.2.4 – Verification Measurements requires in part, “When verification digs are performed, information from the measurements shall be given to the service provider to confirm and continuously refine the data analysis processes. The information to be collected from the verification measurements and given to the service provider shall be agreed upon by both the operator and the service provider and shall include the measurement techniques used and their accuracies. Information to be provided by the service provider to the operator should include the measurement threshold, reporting threshold, and interaction criteria, if any. Appendix D lists types of information that should be provided to the service provider. Any discrepancies between the reported inspection results and verification measurements that are outside of performance specifications shall be documented. The source of the discrepancies should be identified through discussions between the service provider and the operator and through analyses of essential variables, the dig verification process, and data analysis process. Based on the source and extent of the identified and analyzed discrepancies, one of the following courses of action may be taken: a. The inspection data may be reanalyzed taking into account the detailed correlations between anomaly characteristics and the inspection data. b. All or part of the inspection results may be invalidated. c. The performance specification may be revised for all or part of the inspection results.”

Generally, the pipeline operator will contract with an ILI vendor to provide an assessment of their pipeline. It must be stated that even though MFL ILI devices are known as “Smart Pigs” they only report what they record. It is up to the pipeline operator to establish defined parameters for what they want the ILI vendor to do with the raw data. The operator, by contract, establishes operational parameters, sets interaction criteria, and must work intimately with the ILI vendor to obtain useable information about their pipeline system.

After a tool is removed from the pipeline, the vendor converts the raw data into useable, measurable data. They provide a final report to the operator that provides their best analysis of the data obtained from the tool within the operator’s defined parameters. It is then the operator’s responsibility to review the final report and create a dig list and perform the excavations. A vital step in the overall process is feedback to the vendor with respect to the accuracy of their tool calls.

Section “8.7 Correlation of ILI Reported Results with Field Measurements from Section 8: Data Analysis in the NACE Standard RP0102 – “In-Line Inspection of Pipelines” is excerpted below:

> “8.7.1 An important part of “closing the loop” is the feedback of the field inspection results to the ILI service provider. Using this information, the ILI vendor can continuously improve the validity and accuracy of the data analysis.”

Appendix G

In-Line Inspection Report

In Line Inspection Review

For

NPS 24 Pipeline

Plains All American Pipeline;

Line 901 – Las Flores to Gaviota

Last Surveyed

May 6, 2015

Final Report March 4, 2016

Contains Confidential Information Provided By Plains All American Pipeline LP

121 Lippincott St
Toronto, ON M5S 2P2
Canada

Cell: 289.259.6277
email: mlamontagne@pipe-life.com

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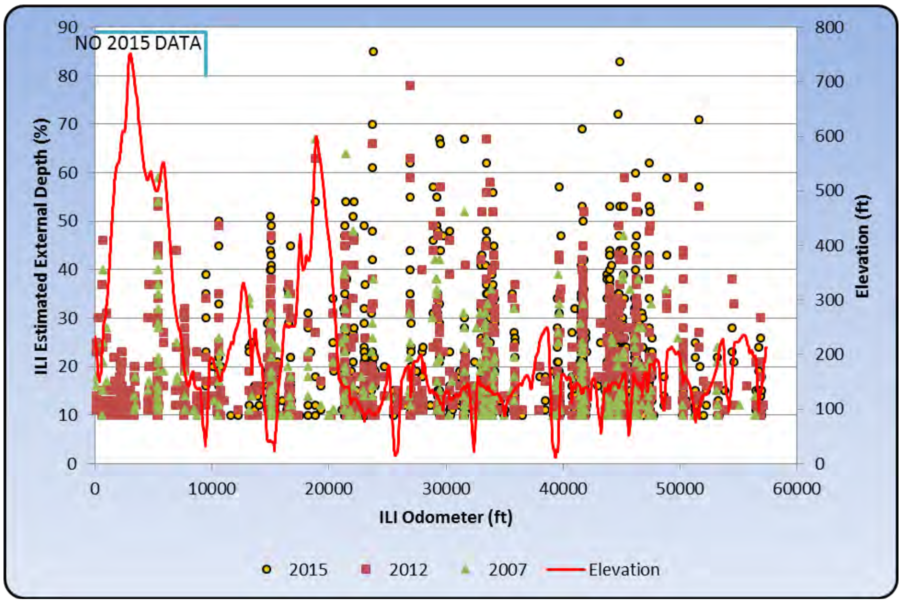
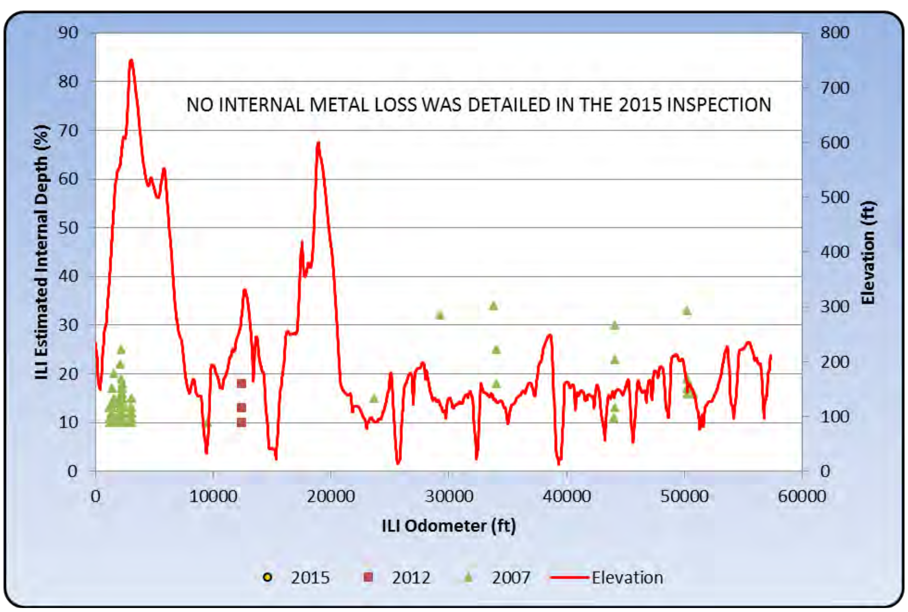
Executive Summary

An ILI review has been completed on the Plains All American Pipeline, 10.87 mile, 24" OD Line 901 - Las Flores to Gaviota based on the comparison of the June 19, 2007, July 3, 2012 and May 6, 2015 magnetic flux leakage (MFL) and associated deformation inspections. The focus of this report was to examine the veracity of the inspections and to estimate appropriate growth rates within the segment then apply those rates to the metal loss anomalies as delineated in the most recent 2015 MFL inspection. An excavation prioritization for the segment was then investigated. A discussion on the MFL characterization of the failed anomaly is also presented.





The in-line inspection results from the 2007, 2012, and 2015 MFL runs were examined. The vast majority of the corrosion is external and distributed throughout the length of the segment. The distribution of the external metal loss, in general terms, can be said to predominate in localized low elevations. Previous to the 2015 inspection, the majority of the internal anomalies were found in the first 3000'. This data was not collected in 2015. All three inspections were completed by Rosen USA with different tool designations and modifications employed for each run, either in hardware or software.

Inspection	# Ext. Metal Loss	# Int. Metal Loss	# Mill Metal Loss	Total Metal Loss	Metal Loss in First 9450'	# Dents	# Dents with Metal Loss or on Weld
2007 MFL (≥10%)	386	237	88	711	277	0	0
2012 MFL (≥10%)	1578	6	2	1586	469	22	2 (repaired)
2015 MFL* (≥10%)	1747	0	21	1768	N/A	6	1 (repaired)

***First 9450' of 2015 data did not record metal loss**

There is a trend indicating an increase in the number of metal loss anomalies greater than 10% depth. The 2007 inspection had an ID/OD discrimination fault defining many external anomalies as internal. This discrimination error would not compromise excavation prioritization.

An anomaly matching analysis was conducted between the 2007, 2012, and 2015 MFL inspections by aligning each of the runs by distance and orientation. The following table describes the number of metal loss anomalies that were aligned (considered the same anomaly) between particular inspections. The "percent possible" noted represents the percentage aligned of the maximum possible. It is intuitive that the greater the number of matches, the more informed is the determination of growth.

ILI Runs Compared	# of Matches for External Metal Loss	# of Matches for Internal Metal Loss	# of Matches for Mill Metal Loss	Total # Anomaly Matches (% of possible matches)
2007-2012	488	1	2	491 (70%)
2007-2015*	306	0	12	318 (73%)
2012-2015*	802	0	18	820 (73%)

***Consideration given to missing data area**

Corrosion growth rates were investigated by analyzing the growth of matched metal loss anomalies between the 2007, 2012, and 2015 MFL inspections. The best statistical fit came from the 2007 to 2015 comparison. A growth rate could only be established for external corrosion as no internal anomalies were delineated in the 2015 inspection and very few in 2012 as well. The corrosion rate for the external anomalies was calculated as the 99th percentile with a 95% confidence interval and was determined to be 0.0166 in/yr.

By applying this estimated growth rate to the anomalies delineated in the first 9450' of the 2012 inspection and the 2015 data, a suggested excavation timeline based on a 50% depth limit and 139% MOP pressure limit was investigated. This is a conservative approach but is considered necessary as a result of the errant depth reported by the ILI at the failed defect.

Based on the above limits, and taking into account excavations already completed, the following excavation timeline for metal loss was delineated;

Dig Date	Anomalies 'Failing' 50% Depth Criteria	Number of Excavations
Jan-15	3	3
May-15	18	17
Nov-15	7	5
Jan-16	3	2
May-16	12	6
Jul-16	2	1
Nov-16	8	5
Jan-17	5	2
May-17	11	5
Jul-17	4	2
Nov-17	7	3
Jan-18	10	6
May-18	20	10
Jul-18	20	8
Nov-18	34	9

Based on the ILI sizing and these growth estimates, all of the anomalies will fail by the 50% depth criterion prior to being concerned with the burst pressure approaching 139% MOP.

The locations with the 2015 excavation timeline are,

GW	Dig Start	Dig End	Length	Dig Date
260	[redacted]	[redacted]	0.03	Jan-15
1370	[redacted]	[redacted]	2.3	Jan-15
1570	[redacted]	[redacted]	0.81	Jan-15
4150/4160/ 4160.01/4160.02	[redacted]	[redacted]	23.4	May-15
4210/4220	[redacted]	[redacted]	26.49	Nov-15
4220/4230	[redacted]	[redacted]	20.19	May-15
6100/6110	[redacted]	[redacted]	1.69	May-15
6350/6360	[redacted]	[redacted]	25.71	May-15
7990	[redacted]	[redacted]	0.02	May-15
8060	[redacted]	[redacted]	17.44	May-15
8140	[redacted]	[redacted]		Nov-15
8280/8290	[redacted]	[redacted]	25.97	May-15
8640/8650	[redacted]	[redacted]	2.72	May-15

GW	Dig Start	Dig End	Length	Dig Date
9270/9280	[redacted]	[redacted]	29.23	May-15
9280/9290	[redacted]	[redacted]	12.89	May-15
9420	[redacted]	[redacted]	27.28	May-15
11060	[redacted]	[redacted]		Nov-15
12410/12420	[redacted]	[redacted]	17.5	May-15
12420/12430	[redacted]	[redacted]	29.4	Nov-15
12820/12830	[redacted]	[redacted]	25.33	May-15
12880	[redacted]	[redacted]	8.85	May-15
13200/13210	[redacted]	[redacted]	29.07	May-15
13210	[redacted]	[redacted]	0.49	May-15
13700	[redacted]	[redacted]	0.2	May-15

The growth rates, excavations required and re-inspection frequency should be re-examined after every future in line inspection.

The depth sizing accuracy stated by Rosen is ±10% with 80% certainty for pitting and general corrosion. With respect to depth measured during excavations, the 2015 inspection was within ±10%, 57% of the time, the 2012 inspection was within ±10%, 58% of the time, and the 2007 inspection was within ±10%, 33% of the time. If overcalled anomalies were considered (i.e. ILI depth>10% over actual) then in all years the unities would be ±10%, >70% of the time. Likewise, employing API 1163, the tool performance was not within stated specifications.

The length and width dimensions of metal loss anomalies also play a key part in the sentencing of metal loss with respect to the remaining strength. The depth and axial length of metal loss are primary factors in the remaining strength evaluations, whilst the width estimates can affect the estimated depth of an anomaly during grading by the ILI vendor. Parameters that may affect the accuracy of the sizing estimate are the aspect ratio of the corrosion, corrosion geometry, corrosion complexity, defect spacing, tool velocity, and pipe line magnetic permeability amongst others. The length and width sizing specification given by Rosen is ±0.59" for general corrosion and better for pitting.

The importance of interacting "boxes" appropriately to form "clusters" of an area as closely approximating the actual corrosion area dimensions cannot be emphasized enough. Plains specifies an interaction rule that is one of the most commonly employed throughout industry. But Plains requires that only metal loss with depths 15% or greater, are to be included for "clustering". This differs from the usual. Typically all ILI delineated corrosion is interacted to define "clusters". The vast majority of all excavated anomalies have been undercalled in length and to a lesser extent in width. A recommendation is provided to review and possibly alter the present interaction criteria for both the in-line inspection analysis and the field measurement process.

Deformation or dents were examined with consideration to depth, location to welds and their association to corrosion. The 2012 inspection delineated 1 dent on a weld that was subsequently repaired and the 2015 ILI reported 6 dents. In order to expedite the May 2015 deformation report after the rupture, Plains asked for the report with graded metal loss only. As a result, the report did not provide sizing of the dents. Consideration should be given to reviewing this further. For further delineation of possible dents with metal loss, ILI anomaly alignment was also completed between the 2007, 2012, and 2015 MFL and deformation runs. To which, no locations of a dent with metal loss were found.

The documented procedure used by Plains entitled "Procedure for the Assessment of In-Line Inspection Results; DOC NO: PAALP-INT-PRC-NJP- 001" was provided as part of the review process. The document outlines the steps Plains personnel are required to take following the receipt of preliminary and final ILI reports. According to this document they comply with the requirements of the Code of Federal Regulations 49 Part 195.452 with respect to addressing MFL detectable anomalies.

Besides the complex shape of the corrosion, it is surmised that the tightly adhered magnetically susceptible corrosion product may have had some influence in the MFL sizing of the failed anomaly. This segment should be re-inspected with an ultrasonic wall loss tool. The ultrasonic inspection will provide a measure of the remaining wall thickness and length without being influenced by the corrosion product and less by shape. A circumferential MFL may delineate the corrosion lengths more accurately but there is still the issue of depth determination by that magnetic tool.

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Introduction

Data was provided by Plains All American Pipelines (Plains) for three magnetic flux leakage (MFL) and deformation in-line inspections (ILI) that have been conducted on the 10.87 mile, 24” OD Line 901 - Las Flores to Gaviota segment. This line is reported to transport crude oil at high temperatures (135°F+) and is comprised of 0.344” API5L X-65 HF-ERW and 0.500” API5L X-60 HF-ERW pipe. The inspection runs reviewed were all axially oriented magnetic flux leakage tools by ROSEN USA (Rosen). The inspections were conducted on June 19, 2007, July 3, 2012 and May 6, 2015. The 2007 inspection employed the CDG (corrosion detection and mapping tool) and EGP (Electronic Geometry Pig) in two separate runs. The 2012 and 2015 inspections used tools having both metal loss and geometry capabilities. The 2012 inspection utilized the CXG (corrosion detection and extended geometry) tool and the 2015 inspection was made using the A/XT (Axial extended geometry) tool.

The aim of this report is to review the findings of the in-line inspections with the focus on anomalies requiring excavation and further evaluation that may lead to repair. This report will review the caliper and corrosion inspections and recommended excavation evaluation for those anomalies to be examined in short order and based on an estimated growth rate applied to the 2012/2015 inspection to determine future excavation dates. The growth rates will be estimated based on the differences found by comparing the 2007 MFL inspection to the most recent 2012 and 2015 MFL inspections. There are also brief discussions on the Plains mitigation strategy and details surrounding the MFL interpretation of the failed anomaly.

Results and Discussion

Review of the Inspection Metal Loss Data

The service provider, Rosen, has stated within the 2007 and 2012 reports received by Plains that all data was accepted and used for evaluation purposes. The 2015 inspection data from ~ 9450’ to the end of the inspection was accepted. At the time of the release Plains and Rosen were in discussions around scheduling a re-inspection of this segment to capture the initial 9450’.

The distribution of the metal loss anomalies is detailed in Figures 1 and 2. The vast majority of the corrosion is external and distributed throughout the length of the segment. The distribution of the external metal loss, in general terms, can be said to predominate in localized low elevations. The internal anomalies are seen primarily in the first 3000’ and are most likely the result of the incline of the pipeline. There was no internal metal loss delineated in the 2015 inspection, which may be due to the data quality or classification, it also did not have any information on the first 9450’ of pipe.

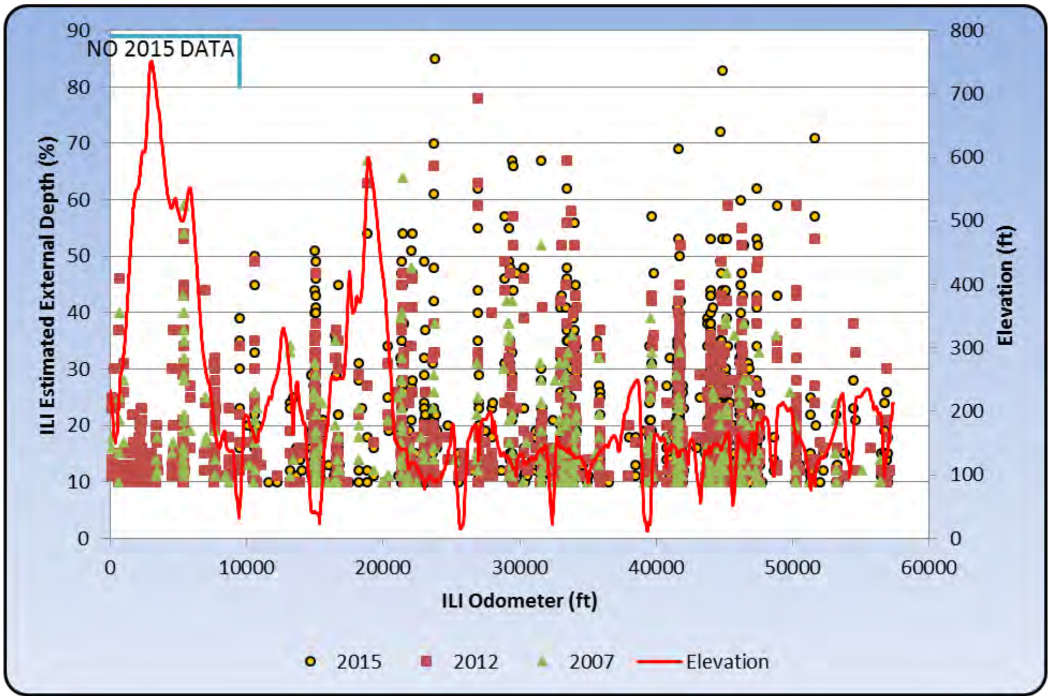


Figure 1. Distribution of external metal loss anomalies.

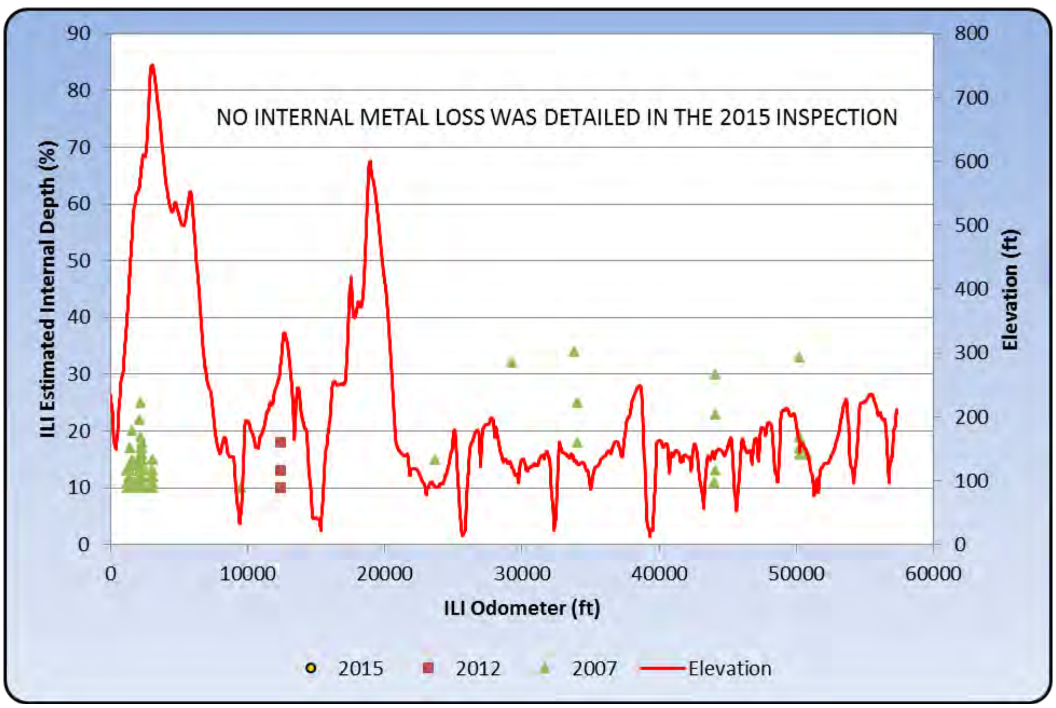


Figure 2. Distribution of internal metal loss anomalies.

A check of the distribution of the corrosion anomalies by clock position in Figures 3 and 4 showed some preference for external metal loss around 4:00 to 8:00 (bottom of pipe) but may be found in all orientations. The internal metal loss in the first 3000' can be found at any orientation. The remainder of the internal metal loss is shown to be between the 4:00 to 8:00 (bottom of pipe) o'clock orientations. The internal anomalies identified in 2007 in the first 3000' may be external due to an ID/OD discrimination error.

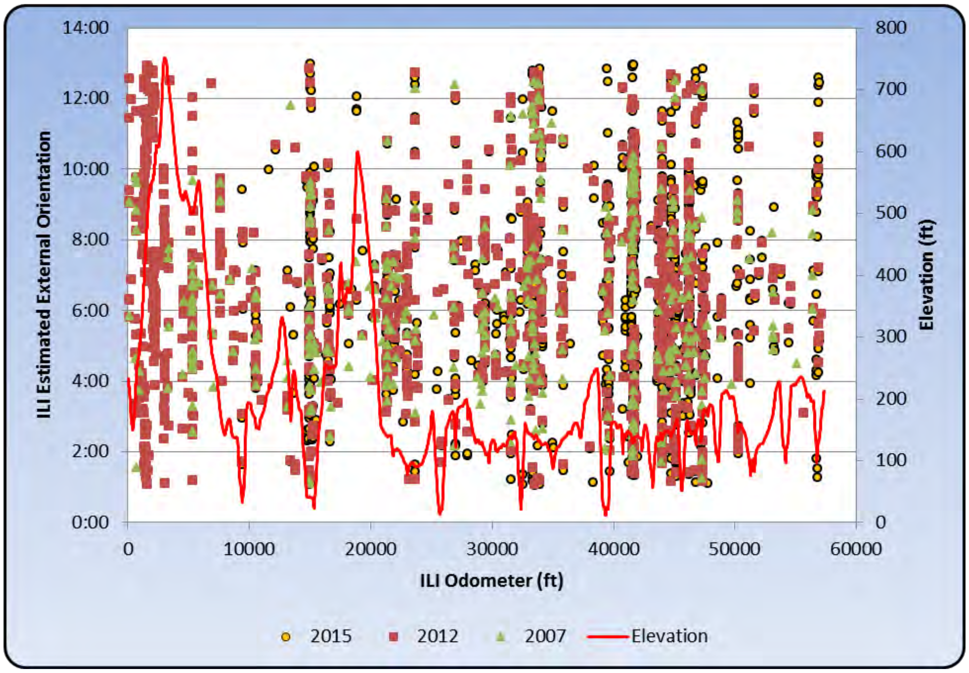


Figure 3. Distribution of external metal loss anomalies by clock position.

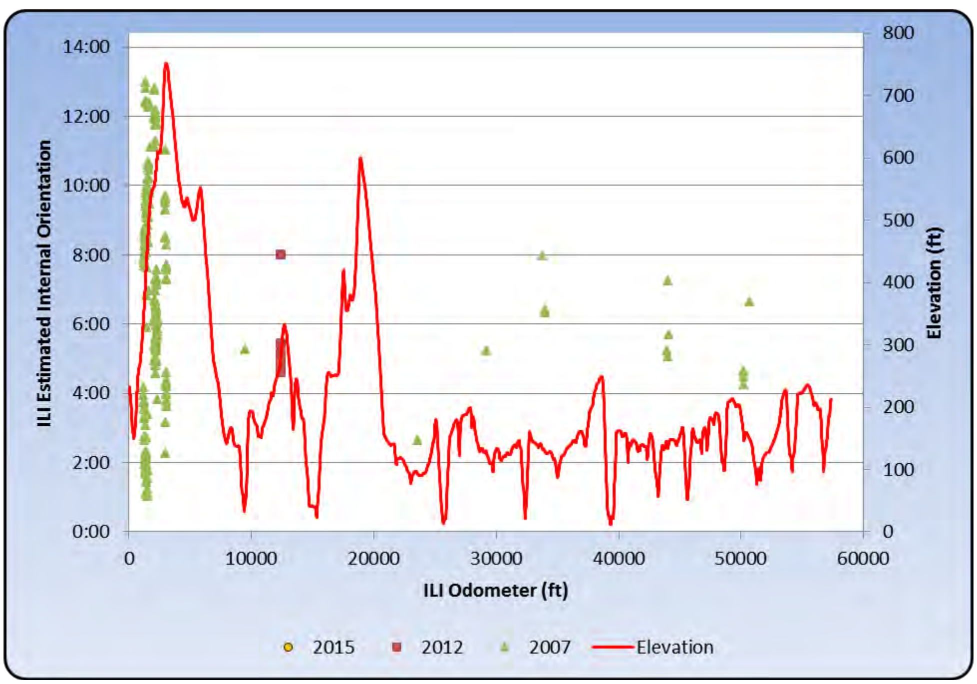


Figure 4. Distribution of internal metal loss anomalies by clock position.

Plains had previously identified the shrink sleeve coating applied over the girth welds as a priority corrosion issue. Figure 5 shows the distance of each metal loss >20% depth in relation to the nearest girth weld as identified in the 2012 inspection.

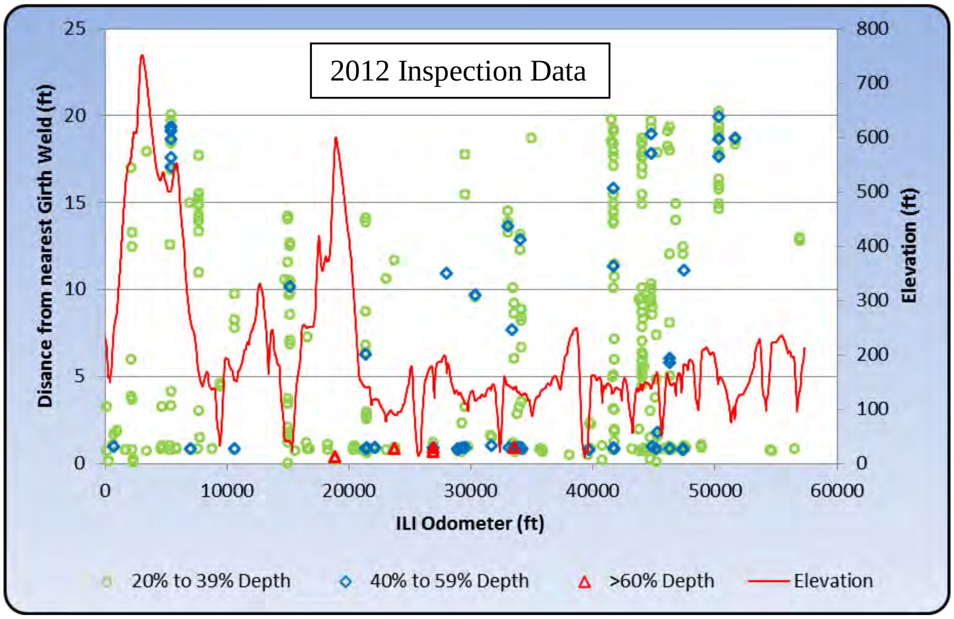


Figure 5. Distance of metal loss to the nearest girth weld in 2012.

The percentage of anomalies by depth within 18" of the nearest girth weld is presented in Table 1. This distance was examined in consideration of the 34" length of shrink sleeve employed (1" greater due to coating interface). The depths were found to have greater criticality nearer the girth welds in the 2012 data than in either of the 2007 or 2015 data. The 2007 and 2015 data approximate an even spread of depth whether under a shrink sleeve or not.

Table 1. Percentage of metal loss by depth under shrink sleeves.

	Percentage of Anomalies Within 18" of Girth Weld		
Anomaly Depth	**2007**	**2012**	**2015**
20% to 39%	53%	36%	35%
40% to 59%	50%	56%	50%
>60%	50%	100%	57%

In-Line Inspection Comparison and Growth Rate Estimation

The in-line inspection results from the 2007, 2012, and 2015 MFL runs were examined. All three inspections were completed by Rosen USA with different tool designations and modifications employed for each run, either in hardware or software. Table 2 details the inspection results. There is a trend indicating an increase in the number of metal loss anomalies greater than 10% depth and therefore active corrosion.

Table 2. In line inspection results.

Inspection	*# Ext. Metal Loss*	*# Int. Metal Loss*	*# Mill Metal Loss*	*Total Metal Loss*	*Metal Loss in First 9450'*	*# Dents*	*# Dents with Metal Loss or on Weld*
2007 MFL (≥10%)	386	237	88	711	277	0	0
2012 MFL (≥10%)	1578	6	2	1586	469	22	1
2015 MFL* (≥10%)	1747	0	21	1768	N/A	6	1 (sleeved)

**First 9450' of 2015 data did not record metal loss*

An anomaly matching analysis was conducted between the 2007, 2012, and 2015 MFL inspections by aligning each of the runs. Table 3 summarizes the number of metal loss anomalies that have been matched between inspections (considered the same anomaly). The "percent possible" noted represents the percentage aligned of the maximum possible. It is intuitive that the greater the number of matches, the more informed is the determination of growth.

Table 3. Anomaly matches between inspections.

ILI Runs Compared	*# of Matches for External Metal Loss*	*# of Matches for Internal Metal Loss*	*# of Matches for Mill Metal Loss*	*Total # Anomaly Matches (% of possible matches)*
2007-2012	488	1	2	491 (70%)
2007-2015*	306	0	12	318 (73%)
2012-2015*	802	0	18	820 (73%)

***Consideration given to missing data area**

Corrosion growth rates were investigated by analyzing the growth of matched metal loss anomalies between the 2007, 2012, and 2015 MFL inspections. The best statistical fit came from the 2007 to 2015 comparison. A growth rate could only be established for external corrosion as no internal anomalies were delineated in the 2015 inspection and very few in 2012. Figure 6 displays the frequency of growth by percentage from 2007 to 2015. Figure 7 provides a probability plot of the absolute percentage growth. The corrosion rate for the external anomalies was determined to be 0.0166 in/yr by the 99th percentile having a 95% confidence interval. In some instances the growth rate of pitting may be higher than the growth rate of general corrosion. Unfortunately this cannot be delineated as the interaction rules applied to cluster metal loss in the MFL analysis do not appear appropriate as will be discussed later.

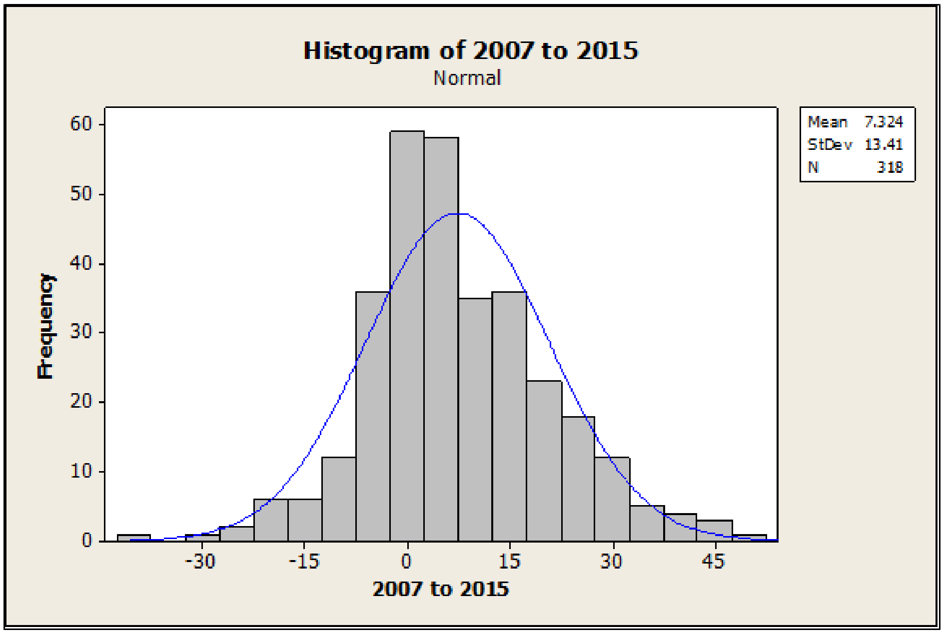


Figure 6. Distribution of growth rates for matching metal loss.

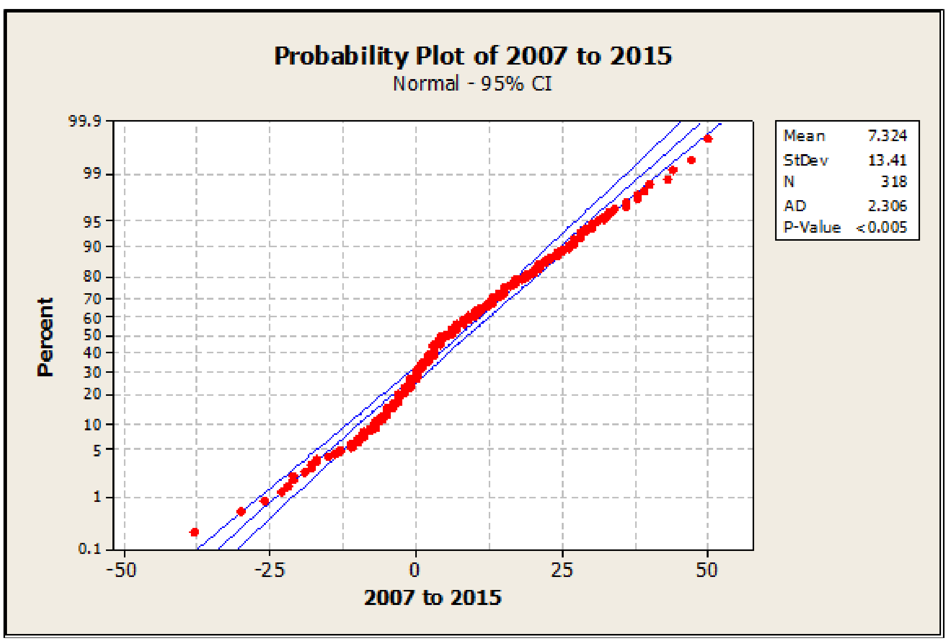


Figure 7. Probability plot of growth rates for a linear rate assumption.

Figure 8 details the 99th percentile growth rate with respect the absolute variance in the estimated depths from the 2007 and 2015 inspections.

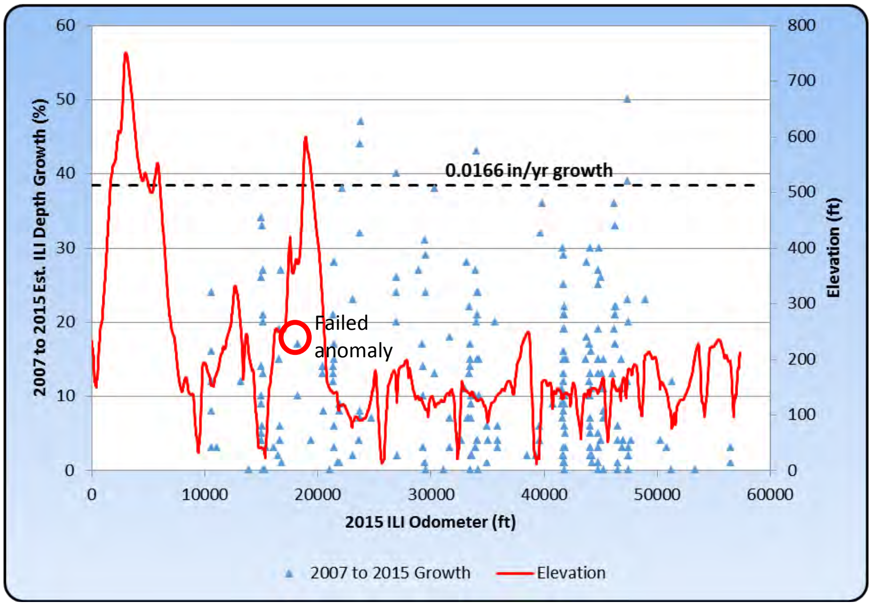


Figure 8. Distribution of external growth by ILI depth variance.

Appendix A examines the ILI growth variance in depth between all inspections similar to Figure 8, except with a finer odometer. It clearly illustrates the greater potential for corrosion and corrosion growth within localized low elevations.

In-Line Inspection Tool Accuracy

The Rosen stated depth sizing accuracy is ±10% with 80 % certainty for pitting and general corrosion. The unity plot in Figure 9 examines the 2015 MFL inspection tool accuracy. The 2015 ILI estimated depths are compared to field measured depths either from the 4 excavations following the failure or the areas recoated after the 2007 and 2012 inspections. The unity plot shows that the 2015 Rosen inspection is within ±10%, 57% of the time. It may be seen that the failure location has an uncharacteristically high deviation from the ILI estimate.

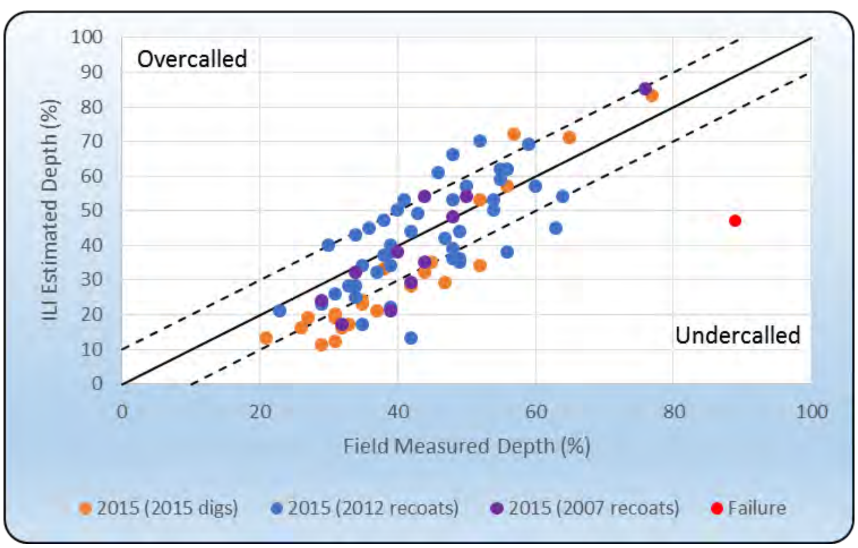


Figure 9. Unity plot for the 2015 MFL inspection.

The unity plot for the 2012 inspection is provided in Figure 10. The 2012 Rosen inspection is within ±10%, 58% of the time with respect to the 2012 excavations (blue) and 2007 excavation recoats (violet). When comparing to the 2015 field excavated results based on the 2012 ILI data, growth may have occurred, causing the comparisons between field and ILI to be undercalled (orange). The 2015 digs were not considered in the above stated accuracy.

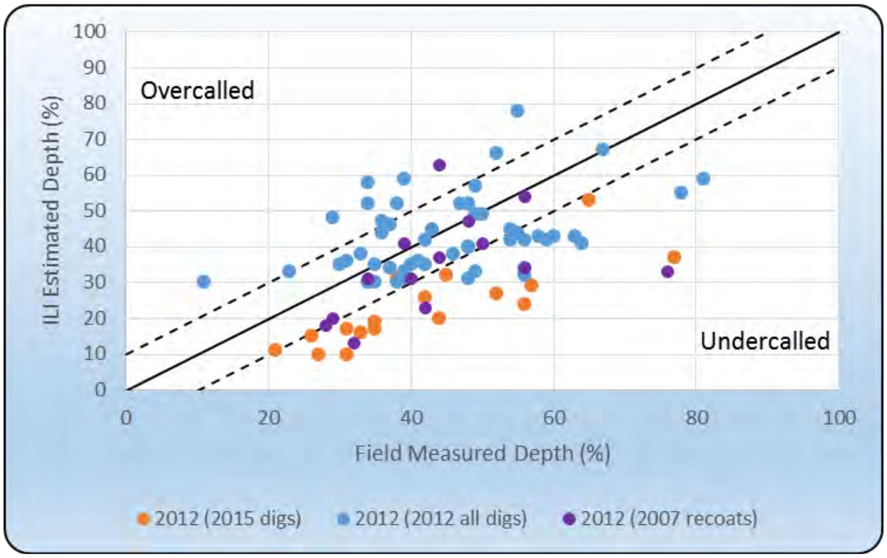


Figure 10. Unity plot for the 2012 MFL inspection.

The unity plot for the 2007 inspection is provided in Figure 11. The 2007 Rosen inspection is within ±10%, 33% of the time with respect to the 2007 excavations.

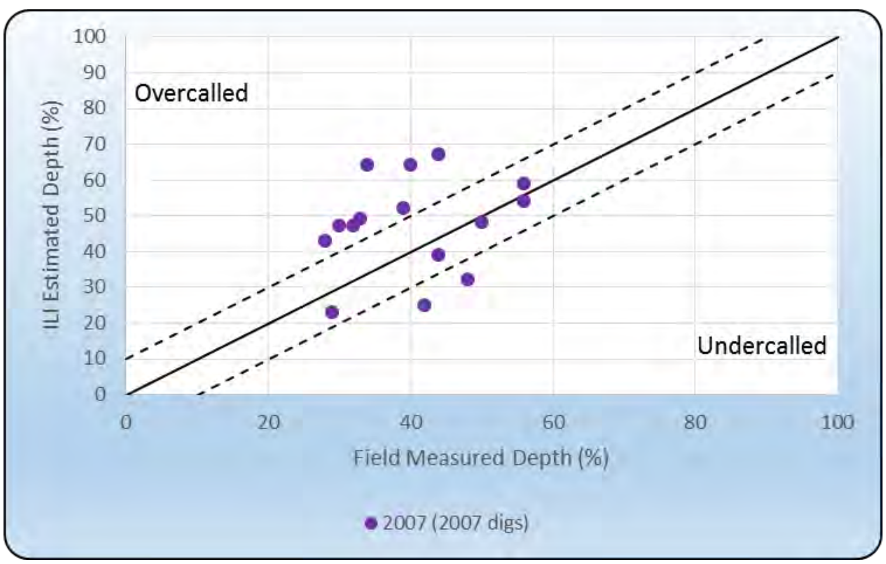


Figure 11. Unity plot for the 2007 MFL inspection.

Likewise, employing API 1163, the tool performance was not within stated specifications. If overcalled anomalies were considered (i.e. >10% over actual) then in all years the unities would be ±10%, >70% of the time.

The length and width dimensions of metal loss anomalies also play a key part in the sentencing of metal loss with respect to the remaining strength. The depth and axial length of metal loss are primary factors in the remaining strength evaluations, whilst the width estimates can affect the estimated depth of an anomaly during grading by the ILI vendor. Parameters that affect the accuracy of the sizing estimate are the aspect ratio of the corrosion, corrosion geometry, corrosion complexity, defect spacing, tool velocity, and pipe line magnetic permeability amongst others.

All ILI vendors employ software that examine the flux leakage characteristics and amplitude then automatically “box” the metal loss anomalies. The automated boxing determines the depth, length and width for each anomaly based on proprietary algorithms developed by each vendor. These algorithms are created for each model and diameter of inspection tool by pulling (i.e. pull test) the instrument through many known metal loss sizes under controlled conditions. From the signal response the algorithms are created or calibrated. Vendors may create algorithms specifically for particular metal loss characteristics such as general metal loss (large area) or pitting (small and isolated). This is done to more accurately size anomalies as the signal strength and characteristics can and do vary. During the process of characterization the vendor’s proprietary software extracts specific signals from the inspection by an automated algorithm, then classifies the “metal loss”, then quantifies the depth, length and width by the algorithm. The proprietary algorithms must take into account the signal dimensions and typically follow the generic relationship

$$dep_{predict} = \left(\frac{width}{length}\right)^{a} \frac{amplitude^{b}}{background^{c}}$$

(K. Reber, A. Belanger, **Reliability of Flaw Size Calculation based on Magnetic Flux Leakage Inspection of Pipelines**, ECNDT 2006 - Tu.3.1.1, pp 1-11)

This characterization “boxes” individual metal loss anomalies. Once the metal loss is individually “boxed”, interaction routines are applied to “cluster” individual indications into a more realistic representation of the corrosion area. Clusters can also be grouped; however, Plains did not request that Rosen do any grouping. Generally, the interaction criteria are specified by the operator (Plains) as part of the inspection contract. Internal and external corrosion must be considered at the same time. If they are at a coincident location, they should be considered additive. There are five general categories of interaction criteria to “cluster” and/or “group” the “boxed” anomalies

1) Length and/or width dependence
2) Absolute value
3) Wall thickness dependent
4) Combinations
5) Sector defined

The choice of interaction criteria is important as it may need to be varied depending on the characteristics of the metal loss in the segment being inspected. Plains specifies an interaction criteria to be a combination of absolute value for the length component (1”) and wall thickness dependence for the width component (6t). The 1” x 6t interaction rule is one of the most commonly employed throughout industry and is the example given in ASME B31.4.

To form a metal loss "cluster" from "boxes", two or more "boxes" must be within 1" of axial separation or within 6 wall thicknesses circumferentially. An example of this process may be seen in Figure 12 which shows the boxes and clusters delineated at the failed anomaly in the 2015 inspection. Solid yellow boxes are metal loss with depths 10%-20%. Solid green boxes are 20-40% depth and solid blue boxes have depths greater than 40%. As requested by Plains, only 15%, and greater metal loss, are to be included for "clustering". The dashed boxes represent the metal loss "cluster" formed by employing the above interaction rule to the boxes (>15%). The resulting size of a clustered anomaly is the length and width extent with a depth represented by the deepest metal loss box within the cluster.

The clusters formed by Rosen (green and blue dashed) in Figure 12 by the interaction process overlap and do not accurately represent the extent of the actual corrosion area. The two clusters identified overlap due to clustering of metal loss ≥15% depth only, as per Plains. If all "boxes" down to 10% depth were included in the interaction parameter then the cluster would have been represented as per the orange dashed box in Figure 12. Consideration of all metal loss would have defined the actual area much more accurately or alternatively, grouping of clusters could be considered.

The importance of interacting "boxes" appropriately to form "clusters" of an area as closely approximating the actual corrosion area cannot be emphasized enough. The importance of the depth and length measurement will be explored in more detail in the discussion to follow.

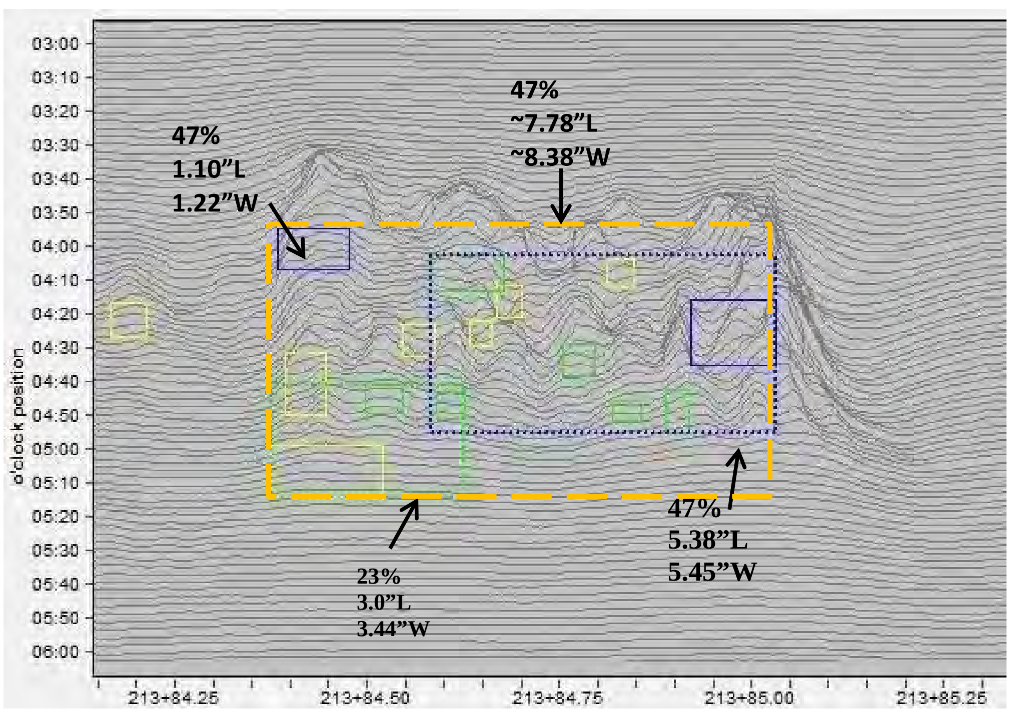


Figure 12. Interacted MFL metal loss in failed anomaly.

During this review process a variance was seen in the length and width sizing of anomalies between inspections as detailed in Tables 4 and 5. The 2007 inspection delineated generally larger metal loss features in length and width dimensions. The 2012 inspection defined the smallest anomalies. The 2012 inspection greatly undercalled the length and width of the failed defect. All 3 inspections were to have used the 1" x 6t interaction of the boxes although it is unknown if there were changes in the minimum depth requirements. All three inspections were carried out using different MFL tool generations. There have been no details provided as to what changes were made in the proprietary sizing algorithms between tool generations or analysis processes.

Table 4. Distribution of metal loss lengths for boxes and clusters.

Length (in)	2007 Boxes	2012 Boxes	2015 Boxes
0-0.5	16	379	166
0.5-1	151	683	907
1-1.5	59	238	304
1.5-2	21	154	206
2-2.5	13	49	63
2.5-3	9	0	0
3-3.5	20	0	0
3.5-4	19	0	0
4-4.5	10	0	0
4.5-5	1	0	0
5-5.5	3	0	0
5.5-6	1	0	0
6-6.5	1	0	0

Length (in)	2007 Clusters	2012 Clusters	2015 Clusters
0-5	263	83	121
5-10	90	0	1
10-15	20	0	0
15-20	4	0	0
20-25	3	0	0
25-30	3	0	0
30-35	2	0	0
35-40	1	0	0
40-45	1	0	0

Table 5. Distribution of metal loss widths for boxes and clusters.

Width (in)	2007 Boxes	2012 Boxes	2015 Boxes
0-1	192	632	357
1-2	84	683	976
2-3	19	113	198
3-4	7	40	50
4-5	5	19	29
5-6	3	9	18
6-7	5	5	8
7-8	3	1	6
8-9	4	1	2
9-10	2	0	0
10-11	0	0	1
11-12	0	0	1

Width (in)	2007 Clusters	2012 Clusters	2015 Clusters
0-5	168	58	90
5-10	117	21	29
10-15	68	3	2
15-20	19	1	1
20-25	8	0	0
25-30	3	0	0
30-35	2	0	0
35-40	1	0	0
40-45	1	0	0

Now consider the length and width sizing with respect to that measured in excavations. Figures 13 and 14 compare the tool estimates of length and width to measurements taken during a few field excavations and repair. There are only a few as these were all of the length and width measurements from the field that were provided. In both figures the solid line represents the ideal where the estimated tool sizing is equal to the field measurement and the dashed lines represent ± 0.59", the tool sizing error for length and width specified by the vendor. Figure 13 shows the data to have a couple length estimates within specification but the remainder of length and width estimates were all under estimated. The excavations shown were done after the 2012 inspection and only the locations that were called by all three tool runs are included. The red markers representing the failure lengths and widths will most assuredly not be the same field measurement in 2007 or 2012, this only represents the dimensions as called by the ILI in that year.

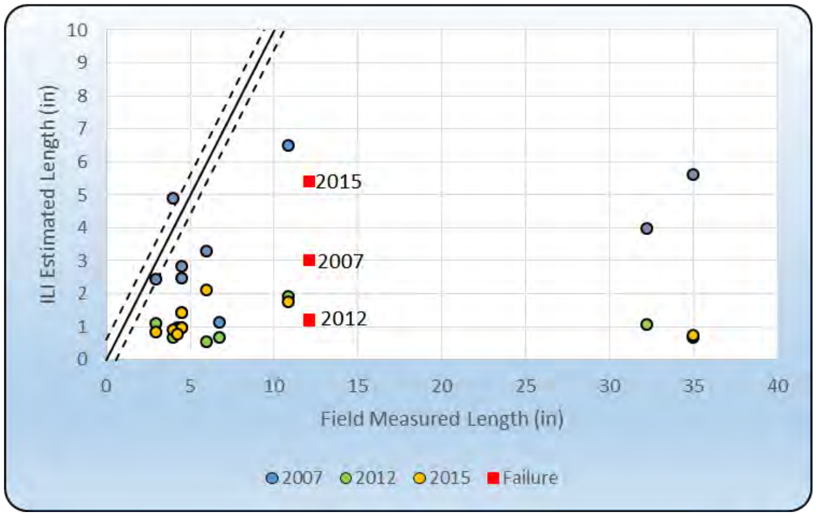


Figure 13. ILI estimated length compared to field measured.

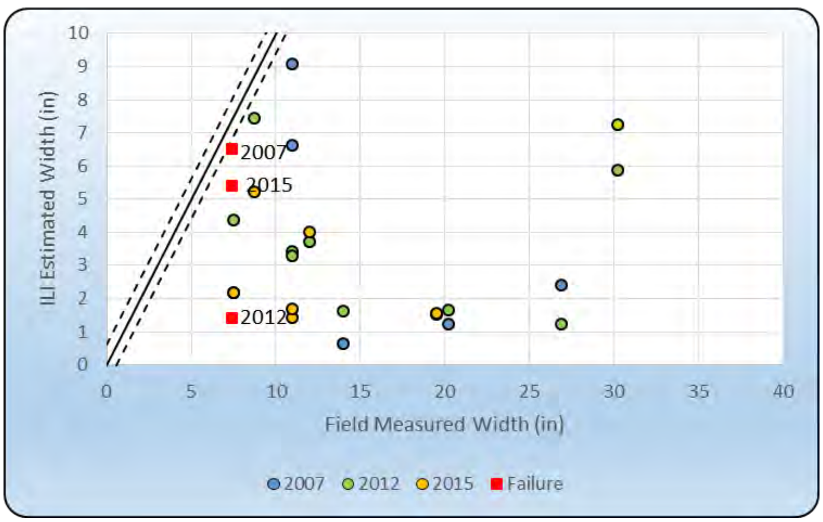


Figure 14. ILI estimated width compared to field measured.

Figure 15 details the depth comparison of the same anomalies. The 2007 depths are primarily undercalled but this could be a result of the 5 years growth from the time of inspection to excavation. The 2012 and 2015 inspections had 56% and 63% of the anomalies overcalled or within specification, respectively. The red markers representing the failure depths will most assuredly not be 89% in 2007 or 2012, this only represents the depth as called by the ILI in that year.

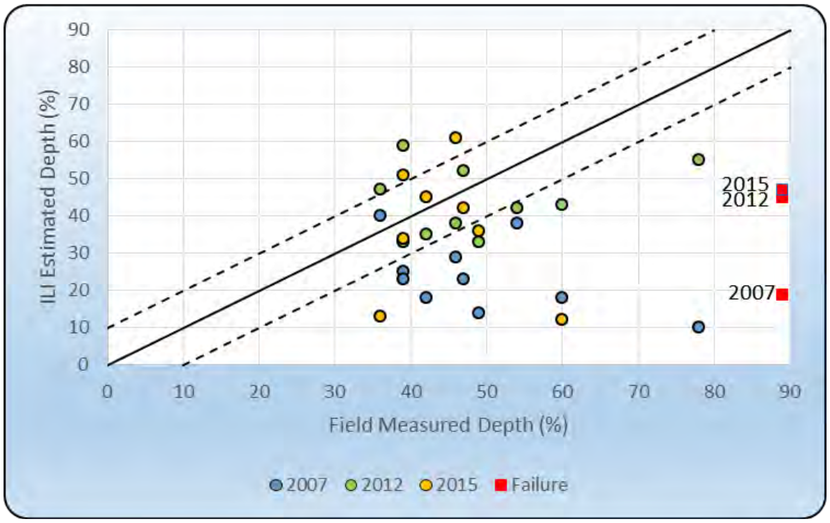


Figure 15. ILI estimated depth compared to field measured.

The issue of underestimating the length and width of a corrosion anomaly will lead to gross underestimations of the corrosion area. Figure 16 delineates all of the Line 901 anomalies with width and length reported from ILI estimates versus excavations made, on a logarithmic scale. As an example, it is showing that 38% of the anomalies had an area stated by the ILI of ≤ 1.5 in^2 when in fact the corrosion areas were between 2.5 in^2 and 7300 in^2. This being said, there may be a difference in the field measurement technique to consider. It is important that the techniques used in the field be comparable to that required by the ILI analysis to enable a proper assessment of the ILI performance.

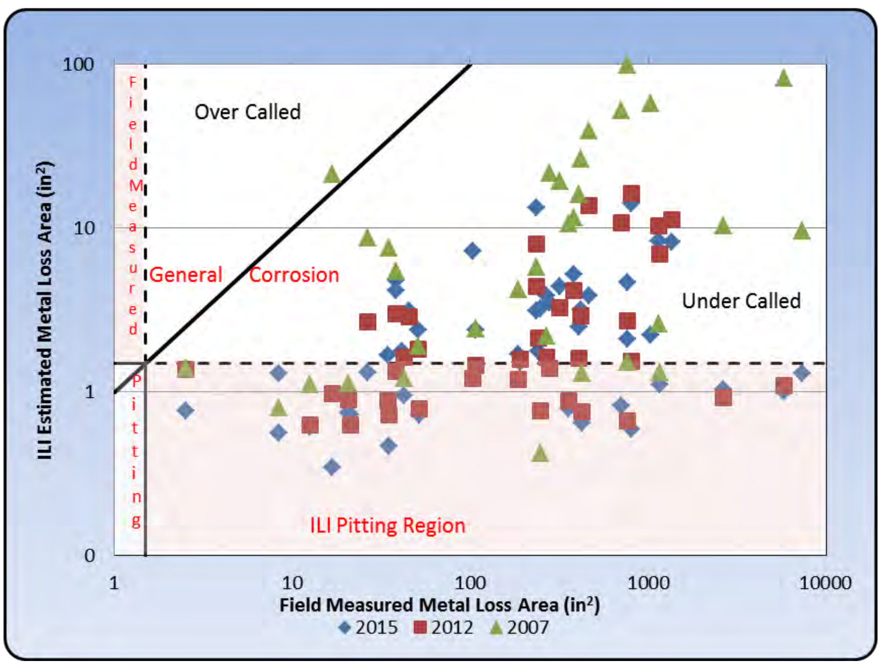


Figure 16. Metal loss area; ILI vs field measurement.

Plains Anomaly Mitigation Strategy

The documented procedure used by Plains entitled "Procedure for the Assessment of In-Line Inspection Results; DOC NO: PAALP-INT-PRC-NJP- 001" was provided as part of the review process. The document outlines the steps Plains personnel are required to take following the receipt of preliminary and final ILI reports. According to this document they comply to the requirements of Code of Federal Regulations 49 Part 195.452 with respect to addressing MFL detectable anomalies.

Part of the Plains document process is a "Close-Out" report that is created following the reception and repair of anomalies related to any ILI Final Report. The most recent "Close-Out" report for the segment in question relates to the 2012 inspection as the 2015 inspection was run only 13 days before the failure. Table 6 is the summary that was provided within the 2012 Las Flores to Gaviota Close-Out report. The table shows that this segment had 382 anomalies addressed. The worst anomalies remaining after repairs, based on the ILI estimated sizing was a 52% deep anomaly and one with an estimated failure pressure of 1608 psi (1.57 factor of safety). It is not clear in the document whether these are one in the same anomaly. It is also unclear as to why an anomaly greater than 50% depth was left as Plains repairs to a minimum of 50% and try to repair to 40% depth (i.e. To attain 50% with the 10% tool tolerance). But the regulations state a ≥50% deep area of general corrosion need be repaired, this does not included pitting.

Assuming the remaining >50% deep anomaly was considered to be pitting then Plains by all accounts met 49 CFR 192.452 requirements as per the 2012 ILI information. Note: the close out report for the 2012 inspection has a later date than the May 19, 2015 release.

Plains has noted in their response to PHMSA on November 23, 2015 with respect to CPF 5-2015-5011H Correction Action Order Amendment 2, page 3, that

> "…Furthermore, Plains' focus on the depth of anomalies, rather than length and width, is supported by the industry standard API 1160, Annex D, *Managing System Integrity for Hazardous Liquid Pipelines*, which states on p. 87: "Growth of an anomaly in depth has a much greater deleterious effect on failure pressure than growth in length, so much so that growth in length can be safely ignored." "

Although this response is with respect to Line 903, it is misleading and incorrect. The comment quoted above from API 1160 is out of context. Having the most accurate length is very important to the calculation of the remaining strength of every type of anomaly. The length must be defined as accurately as possible. The comment quoted from API 1160 above refers only to the known fact that when corrosion is growing, the depth aspect will be much more influential than the length. This occurs because the percentage depth increases much more rapidly due to the thin wall of the pipe.

Table 6. Close-Out summary for the 2012 inspection of Las Flores to Gaviota.

CLOSE-OUT REPORT

Line Name:	L901 - Las Flores - Gaviota - 24"	**ILI run date:**	7/3/2012	**Date:**	6/22/2015

Summary of In-Line Inspection Indications

Metal Loss Anomalies	**Ext**		**Int**		**Mfg**		**Total**	
	ILI	**After**	**ILI**	**After**	**ILI**	**After**	**ILI**	**After**
d/t < 20% WT	1,241	992	6	6	0	0	1,247	998
20% WT $\leq$ d/t < 30% WT	182	137	0	0	2	2	184	139
30% WT $\leq$ d/t < 40% WT	99	57	0	0	0	0	99	57
40% WT $\leq$ d/t < 50% WT	36	9	0	0	0	0	36	9
50% WT $\leq$ d/t < 60% WT	15	1	0	0	0	0	15	1
60% WT $\leq$ d/t < 70% WT	4	0	0	0	0	0	4	0
70% WT $\leq$ d/t < 80% WT	1	0	0	0	0	0	1	0
d/t $\geq$ 80% WT	0	0	0	0	0	0	0	0
Internal ML consistent with internal corrosion	0	0	0	0	0	0	0	0
Selective Seam Corrosion	0	0	0	0	0	0	0	0
Total	1,578	1,196	6	6	2	2	1,586	1,204

Failure Pressures and Deepest Pits	**ILI**	**After**
Reported deepest external metal loss (%WT)	78%	52%
Reported deepest internal metal loss (%WT)	18%	18%
Calculated lowest Safe_ pressure (based on CGAR)	1,090	1,158
Calculated lowest P_Burst (based on CGAR)	1,515	1,608

Seam Weld Anomalies	**Total**	**After**
SWA-A	0	0
SWA-B	0	0
[redacted]	0	0

Deformation Anomalies	**Total**	**After**
Dent Depth > 6% OD	0	0
Dent Depth $\leq$ 6% OD	22	5
Dent Depth $\geq$ 2% OD with metal loss/crack	0	0
Dent Depth < 2% OD with metal loss/crack	0	0
Dent Depth $\geq$ 2% OD affecting weld	0	0
Dent Depth < 2% OD affecting weld	2	0
Girth weld anomalies	0	0
Wrinkle bends	16	0

Crack Anomalies (Depth)	**Crack-Like**		**Crack Field**		**Notch-Like**		**Mid Wall (Lamination/ inclusion)**		**Total**	
	ILI	**After**	**ILI**	**After**	**ILI**	**After**	**ILI**	**After**	**ILI**	**After**
0.040" - 0.079"	0	0	0	0	0	0	0	0	0	0
0.08" - 0.119"	0	0	0	0	0	0	0	0	0	0
0.12" - 0.159"	0	0	0	0	0	0	0	0	0	0
$\geq$ 0.16"	0	0	0	0	0	0	0	0	0	0
No depth	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0	0	0	0

Results/Comment/Recommendation:

1. 2012 ILI - 49 anomalies repaired using Type B, 37 anomalies using composite sleeves, 211 anomalies using recoat, and 0 anomaly using pipe replacement.
2. The result shows that the ILI tool is within the tool's tolerance specification. No further anomalies need to be investigated.
3. The result shows that 73 % of the excavated anomalies were within tool tolerance or overcalled by the ILI tool and no anomalies meet conditions for further evaluations.
4. The earliest the remaining ML anomalies to have predicted depth >80%WT or calculated burst pressure < MOP (based on CGAR) is 3/19/2016.

ILI Details for the Failed Anomaly

All three in-line inspections sized the eventual failure site. Table 7 details the failed anomaly as it was reported by the various inspections.

Table 7. ILI reported dimensions of the failed area.

	Distance (ft)	Length (in)	width (in)	Depth (%)	Clock	Comments
2007	[redacted]	3	6.5	19	4:01	Ext Cluster
2012	[redacted]	1.2	1.4	45	4:23	Ext metal loss
2015	[redacted]	5.38	5.45	47	3:57	External cluster

The anomaly as detailed by the C-Scan (color scan) for each inspection is given in Figure 17.

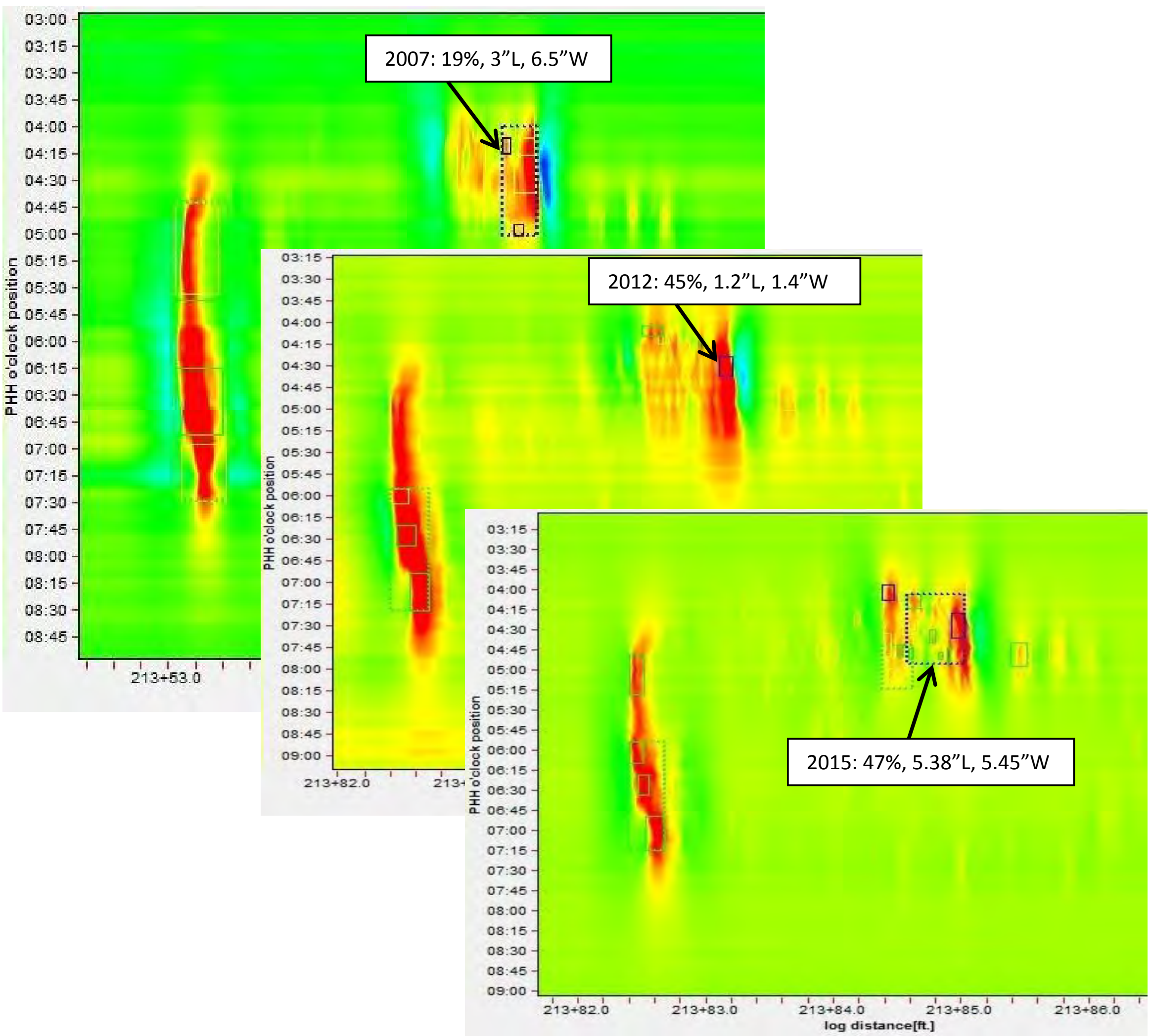


Figure 17. C-Scans with boxes of the failed location as detailed by the 2007, 2012 and 2015 inspections

Figure 18 provides the in-line inspection A-scan in comparison to the in-the-lab laser scan as described in the "**Draft Mechanical and Metallurgical Testing Report, Report OAPUS309DNOR (PP136049)**, DNV, August 6, 2015".

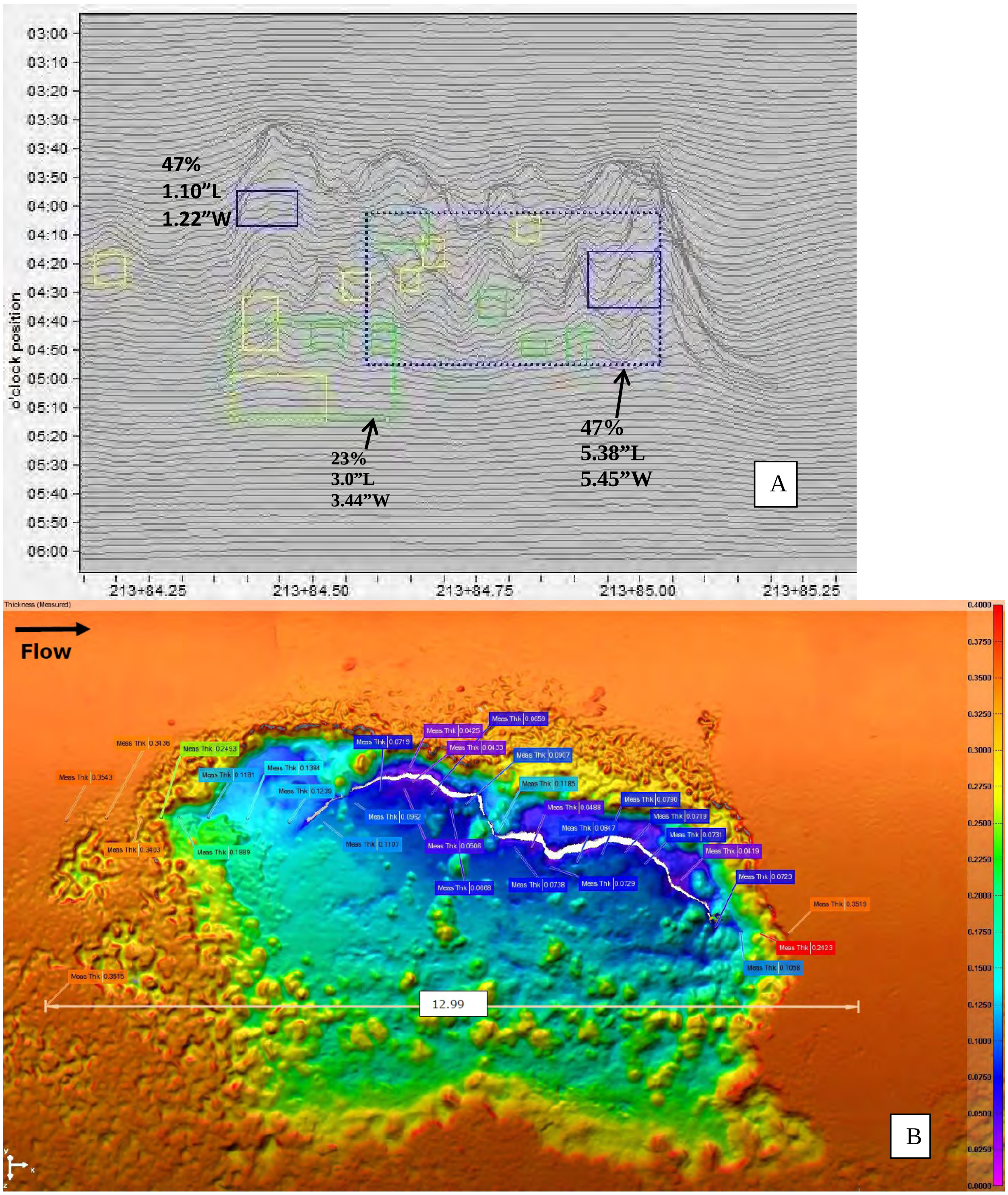


Figure 18. The failed area, A) the Rosen 2015 A-Scan, B) the Laser Scan.

Noted in Table 7 and Figure 17, the last known depth prior to failure was 45% in 2012. The verification of the depth estimate at that time is not available. It is highly likely that there was continued corrosion growth of the anomaly from that time to failure.

The metallurgical report by DNV provided the following information for the depth profile of the failed anomaly in Figure 19. The remaining strength of the anomaly was determined using industry accepted and publicly available software (KAPA, Kiefner and Associates) and is provided in Table 8.

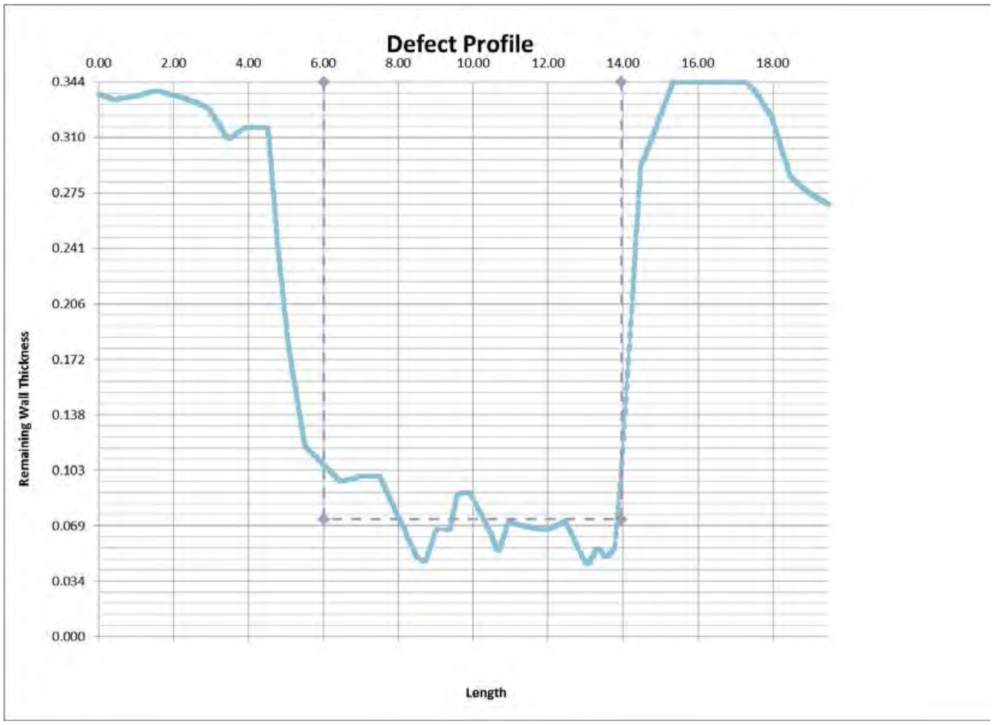


Figure 19. Depth profile of failed anomaly (DNV).

Table 8. Estimated failure pressure from profile in Figure 18.

	Predicted Failure Pressure (Pf, psi)	Factor of Safety (P_f/MOP)	Effective Length (in)
Effective Area Method	684	0.67	7.94
Modified B31G	665	0.65	

The estimated operating pressure at the time and location of failure was 737 psi, the estimated failure pressure as determined by the profile is 685 psi with an effective length of 7.94”. This effective length illustrates the difference between the ILI determined cluster length (5.38”) and actual. Albeit there was a depth prediction error, an appropriate representation of the corrosion area should be determined through appropriate interaction rules.

Rosen stated in their final report (**RoCombo Inspection Service, Line 901 Las Flores to Gaviota, May 2015, Project # 0-1000-12834**, Rosen Group, June 4, 2015) presented to Plains,

> "The data recorded during the RoCombo MFL-A/XT inspection survey, performed on May 6. 2015, was accepted and used for evaluation purposes. During the RoCombo MFL-A/XT inspection survey, there was an area of incomplete data due to odometer slippage. The area starts at ROSEN log distance 111.52 ft and continues to 9412.95 ft totaling 9301.43 ft. The resulting data recorded is 83.79% of the total line length. The survey was correlated to the ROSEN 2012 inspection survey to aid in the evaluation process. During the survey, all sensors were operational in areas outside of the odometer slippage. An additional inspection for this line segment will be performed for coverage in the areas of odometer slippage. The tool velocity during RoCombo MFL-A/XT inspection survey was within the pre-agreed range. Generally, in all areas where the velocity is outside of the optimum range, the ROSEN standard accuracy might not be achieved. Over the complete line length of the RoCombo MFL-A/XT inspection survey, the magnetization level was within the pre-agreed specification of 10 - 30 kA/m. Generally, in all areas where the magnetization level is outside of the optimum range, the ROSEN standard accuracy might not be achieved."

Further, with respect to the tool velocity,

> "The RoCombo MFL-A/XT tool used during this survey was programmed to operate within a velocity range of 0.33 feet per second to 16.41 feet per second."

The velocity of the 2015 tool in the failed joint was reported to be 0.7 ft/s, which is within the accepted velocity range.

Further, with respect to the magnetization level,

> "The magnetization level achieved during the RoCombo MFL-A/XT survey is typically between 10kA/m and 30kA/m in order to meet the Metal Loss Inspection Performance Specifications."

The magnetization level of the 2015 tool in the failed joint was reported to be approximately 23 kA/m at the failure location, which is within the accepted magnetization range.

The reported maximum depth of the failed anomaly in the 2015 inspection was 47% of the wall thickness ±10%. The actual maximum depth was determined by the metallurgical examination to be 89%.

The axial and circumferential (length and width) sizing in the 2015 MFL report, though not fully interacting throughout, provides a respectable representation of the actual anomaly. This feature does have complexity in the feature geometry that should be considered as well.

The depth variance mentioned above raises some question.

Since the inspection tool at the failure location was responding normally and the velocity and magnetization levels were within specification, the tool response is said to be acceptable and within optimal conditions.

When the pipe wall is saturated with magnetic flux there is a specific background signal attained by the MFL sensors. When there is a corrosion area that is free from ferromagnetic material, there will be a flux leakage that is attained and is relative to the length, width and depth of the missing metal. With a tightly adhered magnetic corrosion product such as described in the metallurgical report, the level of flux that "leaks" from the metal loss may have been reduced. This may in turn be partially responsible for the undercalling of the depth based on the observed length and width dimensions. The metallurgical report states that the thickness of the said corrosion product adjacent to the failure area was approximately 0.55" thick.

The corrosion product as detailed in the metallurgical study, Figures 20 and 21, describe a layered strata of Magnetite (Fe_3O_4) and Goethite ($FeO(OH)$). Magnetite (aka. Lodestone) is highly magnetic, whereas Geothite has low magnetic properties but nonetheless is still magnetically susceptible. This magnetic acceptance of the corrosion products provides for the potential retarding of flux leakage. Further study into the actual magnetic properties of the corrosion product has determined that the corrosion product has a slightly increasing magnetic permeability as the magnetic field increases, Figure 22. In the region of the release the magnetization was noted by Rosen to be ~23 kA/m = ~288 Oe. At this level the amplitude permeability of the corrosion product is approximately 5% that of the steel pipe. Intuitively, the greater the permeability the greater the flux density allowed into a material. That being said, the maximum flux densities derived from testing, given in Table 9, show that the corrosion product will carry, at a maximum, ~5% of the flux density of the steel pipe. Consideration must also be given to the volume of the corrosion product with respect to the flux carrying capacity. A greater volume of corrosion product will carry a greater flux density. Therefore, intrinsically, there will be some "masking" of the flux leakage thereby interfering with an accurate determination of the corrosion depth (less flux leakage=shallower depth). To what degree is beyond the scope of this review. The magnetic study was performed by the Edison Welding Institute, **EWI Project No. 56251CSP** Final Report October 16, 2015.

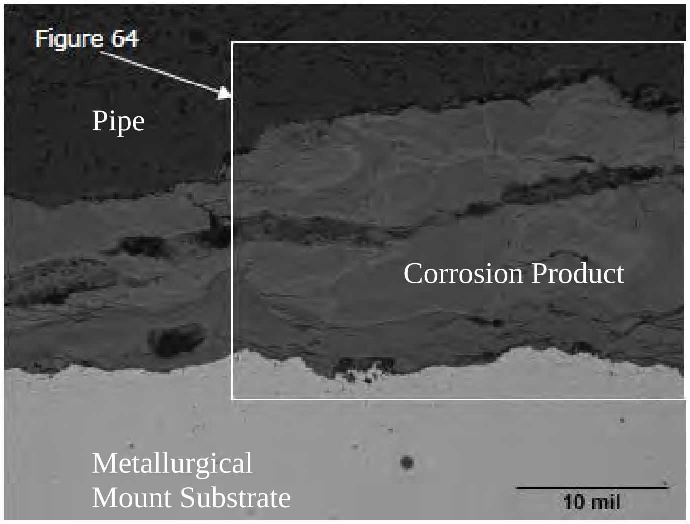


Figure 20. Tightly adhered corrosion product (Fig. 58 from metallurgical report).

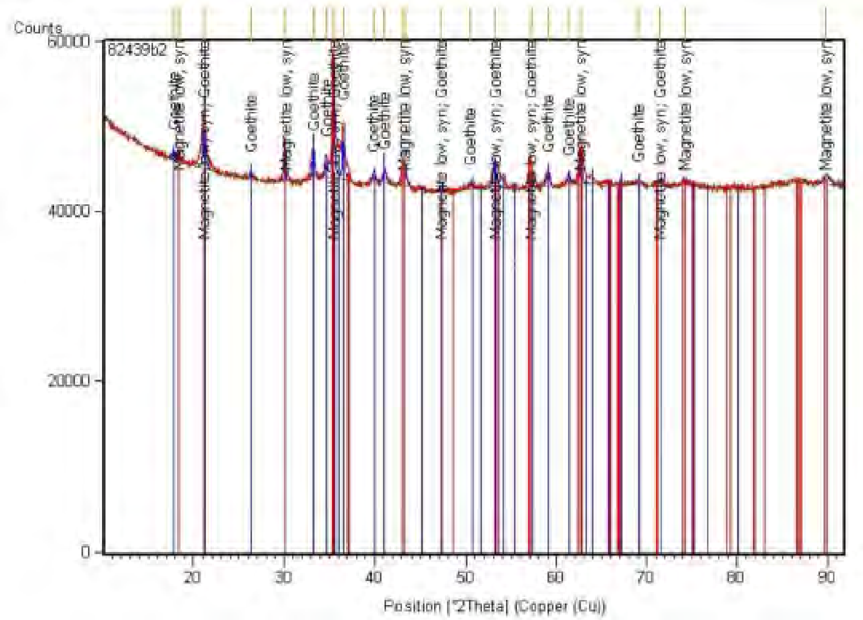


Figure 21. X-Ray Diffraction (XRD) of the corrosion product indicating layering of Magnetite and Goethite (Fig. 62 from metallurgical report).

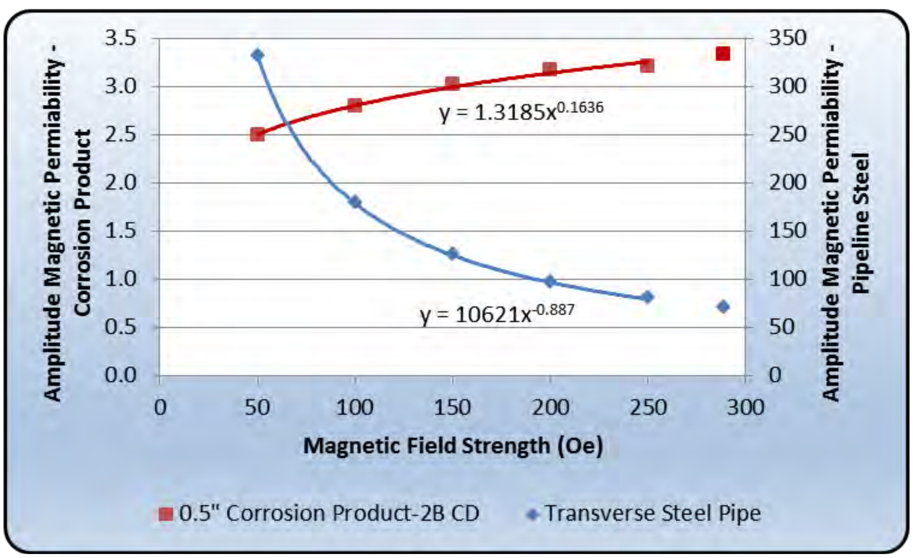


Figure 22. Amplitude magnetic permeability of the pipeline steel and corrosion product (EWI).

Table 9. Magnetic properties of the pipeline steel and corrosion product (EWI).

Specimen	μ_{in}	μ_{max}	H_c	B_r	H_{max}	B_{max}
	-	-	Oe	G	Oe	G
Longitudinal Steel Pipe	149	1467	6.66	12750	1018.2	22193
Transverse Steel Pipe	177.3	1863	6.50	14147	1011.5	22337
0.5" Corrosion Product-2A AB	1.87	2.545	95.16	280	1008.0	1802
0.5" Corrosion Product-2B CD	2.475	3.598	104.40	426	998.3	1987
0.3" Corrosion Product-3A AB	2.229	2.89	86.27	278	1020.6	1680
0.3" Corrosion Product-3B CD	2.511	3.325	92.31	352	1009.9	2050

It should be noted as well that each inspection was carried out by a different model of Rosen MFL inspection tool. The June 2007 inspection employed the Corrosion Detection and Mapping (CDG) tool. The July 2012 inspection utilized the Corrosion Detection and eXtended Geometry tool (CXG). The May 2015 inspection utilized the Axial/eXtended Geometry tool (A/XT). It is unclear by their publicly released specifications the exact differences in the technologies.

It is also unclear what the differences in the sizing algorithms used through the years and on various tools may be. It is conjectured that there was a change in sizing algorithms as the length and width dimensions for the 2012 inspection were typically smaller than that for the 2007 and 2015 inspections. Rosen states that all reports used the 1" by 6t interaction rule, but as stated earlier this may have changed by the minimum depth required for interaction as specified by Plains.

Future Anomaly Mitigation

By using the above determined maximum rate of growth (0.0166 in/yr) and applying this rate to both the length and depth of the corrosion anomalies delineated in the 2012 (first 9450') and 2015 inspection, an anomaly mitigation program can be developed. Two variables were examined with respect to the corrosion growth, the first being the depth and the second being the estimated burst pressure. To examine the effect of growth the rate was applied on a six month interval over a span of ten years.

Depth and remaining strength (estimated burst pressure) limits were set to determine when an anomaly should be excavated. The depth criterion was set at 50% and the burst pressure criterion was set at 139% of the MOP of 1025 psi or 1425 psi. To determine the effects of growth on the estimated burst pressures of each anomaly the 0.85 dL technique, otherwise known as the modified B31G equation, was applied to the growing depth and length estimates.

To be even more aggressive, anomalies were deemed to require excavation six months prior to their estimated burst pressures becoming less than or equal to 139% MOP or having an estimated depth greater than or equal to 50%. *Employing these conservative limits, conservative growth rate and the six month buffer, allows for ILI sizing prediction error.*

The determination of excavation locations and their suggested date were made considering the 2012 inspection data for the first 9450' (no 2015 data collected) and the 2015 data for the remainder. The results were combined and the suggested excavation timeline to the end of 2018 is given in Table 10. Table 11 lists the chainage of the recommended locations for 2015. Some of the locations listed in Table 11 and also in Appendix C may be combined into a single excavation. For a listing of all excavations to 2025 refer to Appendix B and C.

The growth rates, excavations required and re-inspection frequency should be re-examined after every future in line inspection.

Table 10. Suggested excavation timeline.

Dig Date	Anomalies 'Failing' Criteria	Number of Excavations
Jan-15	3	3
May-15	18	17
Nov-15	7	5
Jan-16	3	2
May-16	12	6
Jul-16	2	1
Nov-16	8	5
Jan-17	5	2
May-17	11	5
Jul-17	4	2
Nov-17	7	3
Jan-18	10	6
May-18	20	10
Jul-18	20	8
Nov-18	34	9

Table 11. Suggested excavation locations.

GW	Dig Start	Dig End	Length	Dig Date
260	[redacted]	[redacted]	0.03	Jan-15
1370	[redacted]	[redacted]	2.3	Jan-15
1570	[redacted]	[redacted]	0.81	Jan-15
4150/4160/ 4160.01/4160.02	[redacted]	[redacted]	23.4	May-15
4210/4220	[redacted]	[redacted]	26.49	Nov-15
4220/4230	[redacted]	[redacted]	20.19	May-15
6100/6110	[redacted]	[redacted]	1.69	May-15
6350/6360	[redacted]	[redacted]	25.71	May-15
7990	[redacted]	[redacted]	0.02	May-15
8060	[redacted]	[redacted]	17.44	May-15
8140	[redacted]	[redacted]		Nov-15
8280/8290	[redacted]	[redacted]	25.97	May-15
8640/8650	[redacted]	[redacted]	2.72	May-15
9270/9280	[redacted]	[redacted]	29.23	May-15
9280/9290	[redacted]	[redacted]	12.89	May-15
9420	[redacted]	[redacted]	27.28	May-15
11060	[redacted]	[redacted]		Nov-15
12410/12420	[redacted]	[redacted]	17.5	May-15
12420/12430	[redacted]	[redacted]	29.4	Nov-15
12820/12830	[redacted]	[redacted]	25.33	May-15
12880	[redacted]	[redacted]	8.85	May-15
13200/13210	[redacted]	[redacted]	29.07	May-15
13210	[redacted]	[redacted]	0.49	May-15
13700	[redacted]	[redacted]	0.2	May-15

Deformation Discussion

Deformation or dents were examined with consideration to depth, location to welds and their association to corrosion and/or cracking. Table 12 summarizes the details of the three previous deformation inspections. For further delineation of possible dents with metal loss, ILI anomaly alignment was also completed between the 2007, 2012, and 2015 MFL and deformation runs. To which, no locations of a dent with metal loss were found. In order to expedite the May 2015 deformation report after the rupture, Plains asked for the report with metal loss only. As a result, the report did not provide dent sizing. Consideration should be given to reviewing this further.

Table 12. Dent summary from previous deformation inspections.

Inspection	# Dents	# Geometric Magnetic Anomalies	# Dents with Metal Loss	# Dents on Girth Welds	# Dents on or adjacent to Long Seam
2007 Def (≥2%)	0	0	0	0	0
2012 Def (≥1.0%)	1	22	0	2 (repaired)	0
2015 Def (≥n/a)	6	0	0	1 (repaired)	0

Discussion to Note

The following points should be considered:

1. This segment should be re-inspected with an ultrasonic wall loss tool. The ultrasonic inspection will provide a measure of the remaining wall thickness without being influenced by the corrosion product. A circumferential MFL may delineate the corrosion lengths more accurately but there is still the issue of depth determination.

2. Interaction rules should be reviewed and changed to provide for adequate sizing of the corrosion anomalies.

3. The field measurements should be comparable to the ILI interaction rules (i.e. the extent of the anomaly is to a depth of 10% with no other metal loss within the specified interaction distance).

4. The dent review found inadequate information from the 2015 inspection.

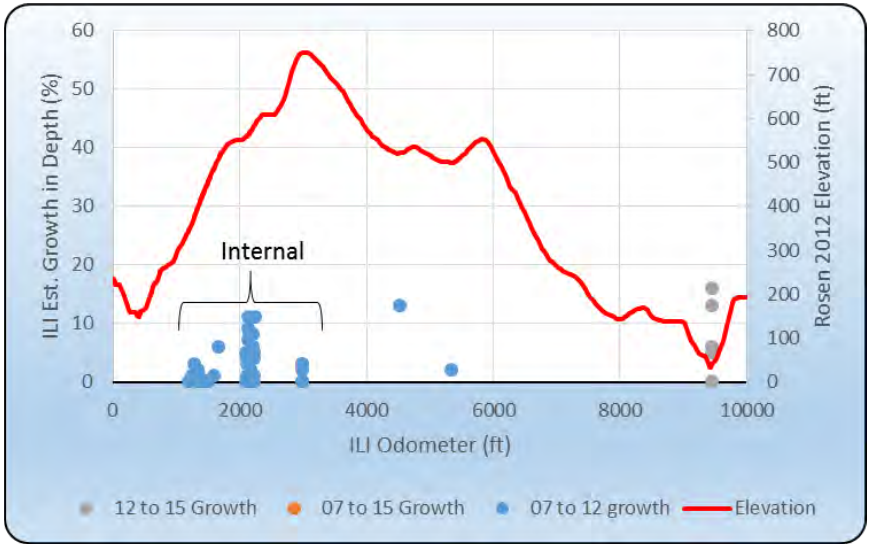
Other details to consider with respect to this report:

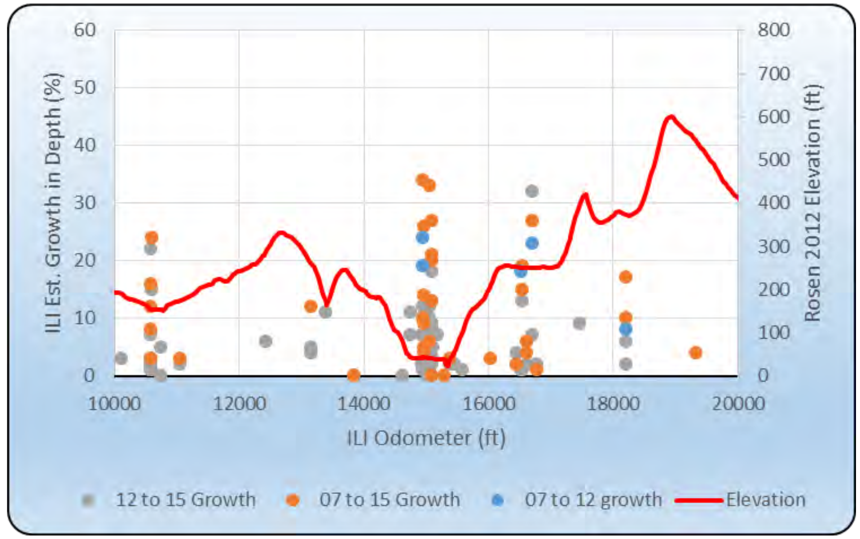
1. Correlations were not made with respect to the agreement in location concerning tees and/or pipe supports or other appurtences.

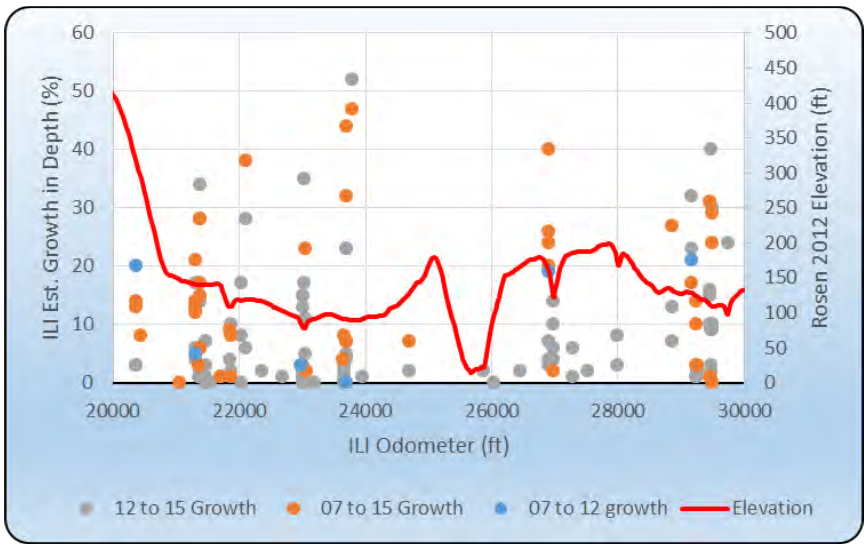
2. The defects during the growth stage of this report are not examined for further interaction.

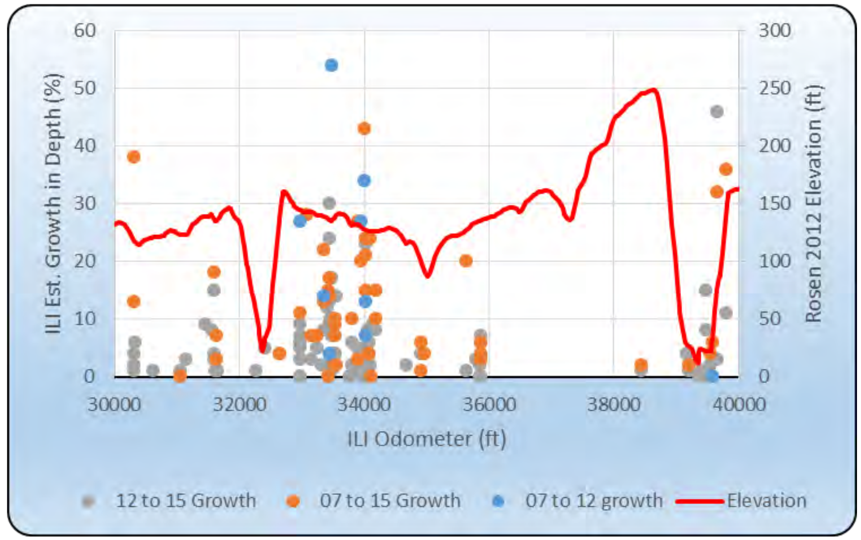
3. This report considers metal loss as delineated by the MFL and deformation tool; no other threats or areas of possible concern were considered.

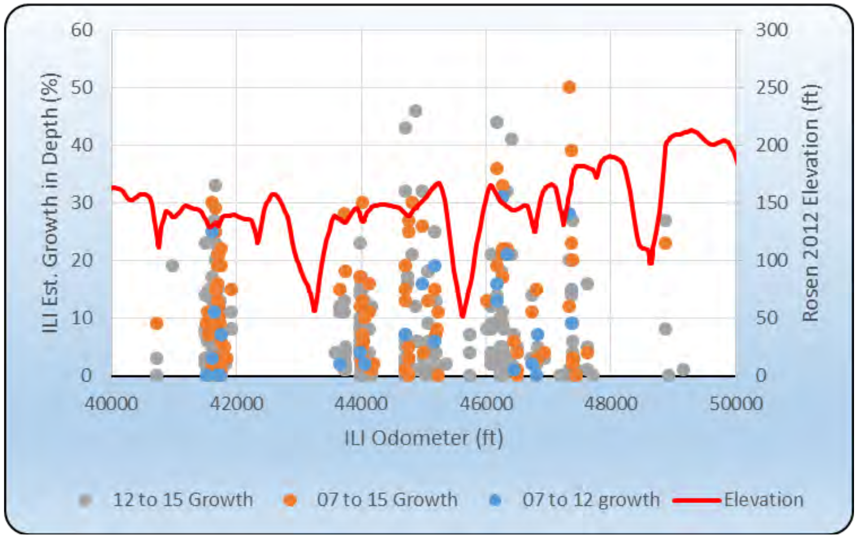
Appendix A – ILI growth variance in depth between all inspections

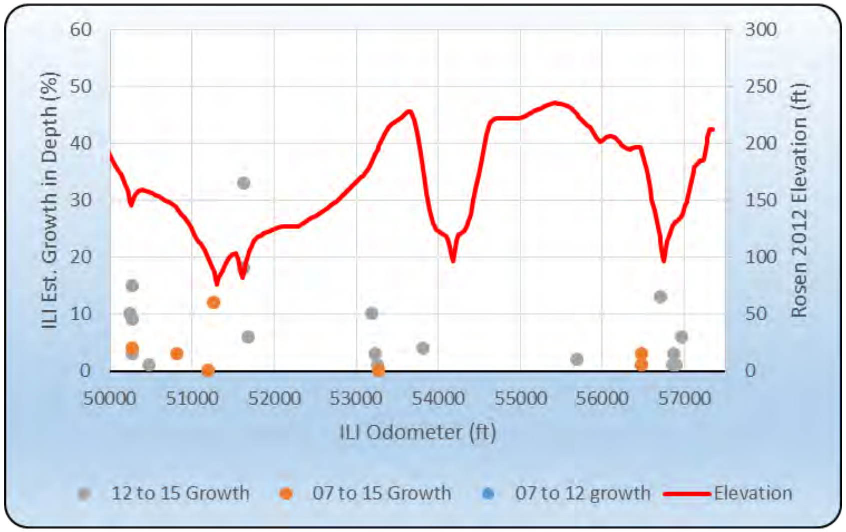









ILI Est. Growth in Depth (%)
Rosen 2012 Elevation (ft)
ILI Odometer (ft)
12 to 15 Growth
07 to 15 Growth
07 to 12 growth
Elevation


ILI Est. Growth in Depth (%)
Rosen 2012 Elevation (ft)
ILI Odometer (ft)
12 to 15 Growth
07 to 15 Growth
07 to 12 growth
Elevation

Appendix B – Individual Anomaly Excavation Timeline

GW	Distance (ft)	Jan-15	May - 15	Nov - 15	Jan-16	May - 16	Jul-16	Nov - 16	Jan-17	May - 17	Jul - 17	Nov - 17	Jan-18	May - 18	Jul-18	Nov-18	Jan-19	May-19	Jul-19	Nov-19	Jan-20	May-20	Jul-20	Nov-20	May-21	Nov-21	May-22	Nov-22	May-23	May-24
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GW	Distance (ft)	Jan-15	May - 15	Nov - 15	Jan-16	May - 16	Jul-16	Nov - 16	Jan-17	May - 17	Jul - 17	Nov - 17	Jan-18	May - 18	Jul-18	Nov-18	Jan-19	May-19	Jul-19	Nov-19	Jan-20	May-20	Jul-20	Nov-20	May-21	Nov-21	May-22	Nov-22	May-23	May-24
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GW	Distance (ft)	Jan-15	May - 15	Nov - 15	Jan-16	May - 16	Jul-16	Nov - 16	Jan-17	May - 17	Jul - 17	Nov - 17	Jan-18	May - 18	Jul-18	Nov-18	Jan-19	May-19	Jul-19	Nov-19	Jan-20	May-20	Jul-20	Nov-20	May-21	Nov-21	May-22	Nov-22	May-23	May-24
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GW	Distance (ft)	Jan-15	May-15	Nov-15	Jan-16	May-16	Jul-16	Nov-16	Jan-17	May-17	Jul-17	Nov-17	Jan-18	May-18	Jul-18	Nov-18	Jan-19	May-19	Jul-19	Nov-19	Jan-20	May-20	Jul-20	Nov-20	May-21	Nov-21	May-22	Nov-22	May-23	May-24
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GW	Distance (ft)	Jan-15	May-15	Nov-15	Jan-16	May-16	Jul-16	Nov-16	Jan-17	May-17	Jul-17	Nov-17	Jan-18	May-18	Jul-18	Nov-18	Jan-19	May-19	Jul-19	Nov-19	Jan-20	May-20	Jul-20	Nov-20	May-21	Nov-21	May-22	Nov-22	May-23	May-24
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GW	Distance (ft)	Jan-15	May-15	Nov-15	Jan-16	May-16	Jul-16	Nov-16	Jan-17	May-17	Jul-17	Nov-17	Jan-18	May-18	Jul-18	Nov-18	Jan-19	May-19	Jul-19	Nov-19	Jan-20	May-20	Jul-20	Nov-20	May-21	Nov-21	May-22	Nov-22	May-23	May-24
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GW	Distance (ft)	Jan-15	May - 15	Nov - 15	Jan-16	May - 16	Jul-16	Nov - 16	Jan-17	May - 17	Jul - 17	Nov - 17	Jan-18	May - 18	Jul-18	Nov-18	Jan-19	May-19	Jul-19	Nov-19	Jan-20	May-20	Jul-20	Nov-20	May-21	Nov-21	May-22	Nov-22	May-23	May-24
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GW	Distance (ft)	Jan-15	May - 15	Nov - 15	Jan-16	May - 16	Jul-16	Nov - 16	Jan-17	May - 17	Jul - 17	Nov - 17	Jan-18	May - 18	Jul-18	Nov-18	Jan-19	May-19	Jul-19	Nov-19	Jan-20	May-20	Jul-20	Nov-20	May-21	Nov-21	May-22	Nov-22	May-23	May-24
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GW	Distance (ft)	Jan-15	May - 15	Nov - 15	Jan-16	May - 16	Jul-16	Nov - 16	Jan-17	May - 17	Jul - 17	Nov - 17	Jan-18	May - 18	Jul-18	Nov-18	Jan-19	May-19	Jul-19	Nov-19	Jan-20	May-20	Jul-20	Nov-20	May-21	Nov-21	May-22	Nov-22	May-23	May-24
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GW	Distance (ft)	Jan-15	May - 15	Nov - 15	Jan-16	May - 16	Jul-16	Nov - 16	Jan-17	May - 17	Jul - 17	Nov - 17	Jan-18	May - 18	Jul-18	Nov-18	Jan-19	May-19	Jul-19	Nov-19	Jan-20	May-20	Jul-20	Nov-20	May-21	Nov-21	May-22	Nov-22	May-23	May-24
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GW	Distance (ft)	Jan-15	May - 15	Nov - 15	Jan-16	May - 16	Jul-16	Nov - 16	Jan-17	May - 17	Jul - 17	Nov - 17	Jan-18	May - 18	Jul-18	Nov-18	Jan-19	May-19	Jul-19	Nov-19	Jan-20	May-20	Jul-20	Nov-20	May-21	Nov-21	May-22	Nov-22	May-23	May-24
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14110	[redacted]																											x		
14200	[redacted]																											x		
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14470	[redacted]																												x	
14500	[redacted]																								x					
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GW	Distance (ft)	Jan-15	May - 15	Nov - 15	Jan-16	May - 16	Jul-16	Nov - 16	Jan-17	May - 17	Jul - 17	Nov - 17	Jan-18	May - 18	Jul-18	Nov-18	Jan-19	May-19	Jul-19	Nov-19	Jan-20	May-20	Jul-20	Nov-20	May-21	Nov-21	May-22	Nov-22	May-23	May-24
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GW	Distance (ft)	Jan-15	May - 15	Nov - 15	Jan-16	May - 16	Jul-16	Nov - 16	Jan-17	May - 17	Jul - 17	Nov - 17	Jan-18	May - 18	Jul-18	Nov-18	Jan-19	May-19	Jul-19	Nov-19	Jan-20	May-20	Jul-20	Nov-20	May-21	Nov-21	May-22	Nov-22	May-23	May-24
15900	[redacted]																											x	
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Appendix C – Full Excavation Timeline (30' limit)

GW	Dig Start (ft)	Dig End (ft)	Length (ft)	Dig Date
70.01/80	[redacted]	[redacted]	17.23	Jul-17
250/260	[redacted]	[redacted]	10.33	Jan-20
260	[redacted]	[redacted]	0.03	Jan-15
290/310	[redacted]	[redacted]	10.51	Jul-17
420	[redacted]	[redacted]	0.06	Jan-16
470	[redacted]	[redacted]		Jul-20
480	[redacted]	[redacted]	21.44	Jan-20
480/490	[redacted]	[redacted]	26.93	Jul-20
500	[redacted]	[redacted]	22.15	Jul-20
500/510	[redacted]	[redacted]	26.18	Jul-19
520	[redacted]	[redacted]	28.35	Jan-20
530	[redacted]	[redacted]	25.61	Jul-19
530/540	[redacted]	[redacted]	25.24	Jul-20
540	[redacted]	[redacted]	24.55	Jul-20
550	[redacted]	[redacted]	26.57	Jul-20
560	[redacted]	[redacted]	27.56	Jan-20
560/570	[redacted]	[redacted]	28.93	Jul-20
570/580	[redacted]	[redacted]	23.04	Jul-20
580/590	[redacted]	[redacted]	32.1	Jan-18
600/610	[redacted]	[redacted]	26.94	Jan-18
610	[redacted]	[redacted]		Jul-20
620	[redacted]	[redacted]	0.97	Jul-20
640/650	[redacted]	[redacted]	12.42	Jan-20
710/720	[redacted]	[redacted]	29.36	Jan-19
720/730	[redacted]	[redacted]	26.4	Jul-18
730/740	[redacted]	[redacted]	26.79	Jul-18
740/750	[redacted]	[redacted]	29.86	Jul-18

GW	Dig Start (ft)	Dig End (ft)	Length (ft)	Dig Date
750	[redacted]	[redacted]	27.37	Jan-18
750/760	[redacted]	[redacted]	22.21	Jul-18
760/770/780	[redacted]	[redacted]	27.64	Jan-18
800	[redacted]	[redacted]	0.38	Jul-19
970	[redacted]	[redacted]	29.48	Jul-19
970/980	[redacted]	[redacted]	28.96	Jul-20
980/990	[redacted]	[redacted]	19.14	Jul-19
1050	[redacted]	[redacted]	0.11	Jul-18
1070	[redacted]	[redacted]	21.35	Jul-18
1090	[redacted]	[redacted]		Jan-20
1350/1360	[redacted]	[redacted]	1.72	Jul-16
1370	[redacted]	[redacted]	2.3	Jan-15
1480	[redacted]	[redacted]		Jul-19
1520	[redacted]	[redacted]		Jan-20
1550/1560	[redacted]	[redacted]	24.84	Jul-18
1570	[redacted]	[redacted]	0.81	Jan-15
1580/1590/1600	[redacted]	[redacted]	24.88	Jan-20
1700	[redacted]	[redacted]	0.06	Jan-17
1980/1990	[redacted]	[redacted]	25.87	Jul-18
2170	[redacted]	[redacted]	29.93	Jan-16
2170	[redacted]	[redacted]	0.31	Jan-17
2210	[redacted]	[redacted]	0.21	Jan-18
2370	[redacted]	[redacted]		Jul-20
2430	[redacted]	[redacted]		Jul-20
2450	[redacted]	[redacted]	0.1	Jan-18
2500	[redacted]	[redacted]		Jul-20
2640	[redacted]	[redacted]	7.88	May-17

GW	Dig Start (ft)	Dig End (ft)	Length (ft)	Dig Date
2830	[redacted]	[redacted]		May-21
2940	[redacted]	[redacted]		May-23
2960	[redacted]	[redacted]	5.31	May-16
3010	[redacted]	[redacted]	0.43	May-21
3090	[redacted]	[redacted]		May-22
3220	[redacted]	[redacted]		May-23
3370	[redacted]	[redacted]		May-23
3430	[redacted]	[redacted]		May-22
3630	[redacted]	[redacted]	0.27	May-20
3680	[redacted]	[redacted]		May-20
3750	[redacted]	[redacted]	0.19	May-22
3810	[redacted]	[redacted]	1.39	May-22
3850	[redacted]	[redacted]		Nov-22
4080	[redacted]	[redacted]	5.95	May-19
4140/4150	[redacted]	[redacted]	25.26	Nov-19
4150/4160/4160.01/4160.02	[redacted]	[redacted]	23.4	May-15
4200/4210	[redacted]	[redacted]	10.34	May-22
4210/4220	[redacted]	[redacted]	26.49	Nov-15
4220/4230	[redacted]	[redacted]	20.19	May-15
4240/4250	[redacted]	[redacted]	1.7	May-20
4260/4270	[redacted]	[redacted]	11.66	Nov-21
4300	[redacted]	[redacted]		May-23
4340/4360	[redacted]	[redacted]	11.51	May-21
4390	[redacted]	[redacted]		May-21
4410	[redacted]	[redacted]		Nov-22
4430	[redacted]	[redacted]		May-21
4540	[redacted]	[redacted]		Nov-22
4620	[redacted]	[redacted]		May-23
4640/4650	[redacted]	[redacted]	2.13	Nov-17
4660	[redacted]	[redacted]	6.55	May-18

GW	Dig Start (ft)	Dig End (ft)	Length (ft)	Dig Date
4680/4690	[redacted]	[redacted]	1.87	May-22
4730	[redacted]	[redacted]	0.32	Nov-22
4900	[redacted]	[redacted]		May-23
5100/5120	[redacted]	[redacted]	10.11	Nov-18
5180	[redacted]	[redacted]		Nov-20
5400	[redacted]	[redacted]	0.72	May-22
5620	[redacted]	[redacted]		May-23
5660	[redacted]	[redacted]	0.19	May-18
5680	[redacted]	[redacted]		May-21
5840	[redacted]	[redacted]		May-20
5870	[redacted]	[redacted]		May-23
5930	[redacted]	[redacted]	18.58	Nov-15
5980	[redacted]	[redacted]		May-23
6010	[redacted]	[redacted]		May-22
6060/6070	[redacted]	[redacted]	29.83	May-18
6090	[redacted]	[redacted]		May-23
6100/6110	[redacted]	[redacted]	1.69	May-15
6180	[redacted]	[redacted]		May-22
6270	[redacted]	[redacted]	0.33	May-22
6310	[redacted]	[redacted]		May-23
6350/6360	[redacted]	[redacted]	25.71	May-15
6360/6370	[redacted]	[redacted]	23.23	Nov-17
6370	[redacted]	[redacted]		May-23
6400	[redacted]	[redacted]		May-23
6520	[redacted]	[redacted]	29.25	Nov-18
6580	[redacted]	[redacted]		Nov-20
6590/6600	[redacted]	[redacted]	1.94	May-21
6790	[redacted]	[redacted]		May-21
6990	[redacted]	[redacted]		May-22
6990	[redacted]	[redacted]		May-23

GW	Dig Start (ft)	Dig End (ft)	Length (ft)	Dig Date
7010	[redacted]	[redacted]		Nov-22
7120	[redacted]	[redacted]		May-22
7120	[redacted]	[redacted]		May-23
7160	[redacted]	[redacted]		Nov-22
7260	[redacted]	[redacted]	10.01	May-22
7400/7420	[redacted]	[redacted]	15.49	May-19
7490	[redacted]	[redacted]	0.39	Nov-21
7520	[redacted]	[redacted]		May-23
7550	[redacted]	[redacted]	0.23	May-21
7670	[redacted]	[redacted]	6.72	May-20
7760	[redacted]	[redacted]		Nov-22
7860	[redacted]	[redacted]	0.15	Nov-22
7990	[redacted]	[redacted]	0.02	May-15
8060	[redacted]	[redacted]	17.44	May-15
8060/8070	[redacted]	[redacted]	11.34	Nov-20
8140	[redacted]	[redacted]		Nov-15
8280/8290	[redacted]	[redacted]	25.97	May-15
8300	[redacted]	[redacted]		May-23
8300	[redacted]	[redacted]	0.37	Nov-22
8340	[redacted]	[redacted]		May-23
8360	[redacted]	[redacted]	2.52	Nov-22
8460	[redacted]	[redacted]	0.09	Nov-21
8500	[redacted]	[redacted]		May-22
8520	[redacted]	[redacted]	1.45	May-21
8590	[redacted]	[redacted]	0.08	May-21
8640/8650	[redacted]	[redacted]	2.72	May-15
8660	[redacted]	[redacted]	15.02	May-19
8680/8690/8700	[redacted]	[redacted]	24.22	Nov-20
8700	[redacted]	[redacted]		May-22
8910	[redacted]	[redacted]	0.11	May-22
8960/8980	[redacted]	[redacted]	10.29	May-21
9030/9040	[redacted]	[redacted]	0.9	Nov-22
9060	[redacted]	[redacted]	0.04	May-22
9160	[redacted]	[redacted]	16.13	Nov-16
9200/9210	[redacted]	[redacted]	1.77	May-21
9220/9230	[redacted]	[redacted]	1.3	Nov-21
9250	[redacted]	[redacted]		May-22
9250/9260	[redacted]	[redacted]	17.55	Nov-16
9260/9270	[redacted]	[redacted]	24.51	Nov-18
9270/9280	[redacted]	[redacted]	29.23	May-15
9280/9290	[redacted]	[redacted]	12.89	May-15
9300	[redacted]	[redacted]	3.5	May-18
9310	[redacted]	[redacted]	0.24	May-18
9360	[redacted]	[redacted]	25.33	May-19
9390	[redacted]	[redacted]		May-18
9390	[redacted]	[redacted]	0.99	May-17
9420	[redacted]	[redacted]	27.28	May-15
9430	[redacted]	[redacted]	4.93	May-16
9450/9460	[redacted]	[redacted]	18.32	Nov-16
9470	[redacted]	[redacted]	0.04	May-18
9590	[redacted]	[redacted]		Nov-22
9650	[redacted]	[redacted]	1.52	May-21
9660/9670	[redacted]	[redacted]	9.4	May-22
9690	[redacted]	[redacted]		May-23
9860	[redacted]	[redacted]		May-18
9890	[redacted]	[redacted]	0.03	Nov-19
9910/9920	[redacted]	[redacted]	22.54	Nov-19
10070	[redacted]	[redacted]		May-23
10510	[redacted]	[redacted]		May-23
10540	[redacted]	[redacted]		Nov-21

GW	Dig Start (ft)	Dig End (ft)	Length (ft)	Dig Date
10620	[redacted]	[redacted]		May-23
10640	[redacted]	[redacted]	0.02	Nov-21
10830	[redacted]	[redacted]	16.7	May-21
10840	[redacted]	[redacted]		Nov-22
10920	[redacted]	[redacted]	20.86	May-22
10930	[redacted]	[redacted]		May-22
10950	[redacted]	[redacted]	26.07	May-18
10960	[redacted]	[redacted]		May-23
10960/10980	[redacted]	[redacted]	13.47	May-21
10990/11000	[redacted]	[redacted]	23.3	May-21
11030	[redacted]	[redacted]	0.32	May-22
11050	[redacted]	[redacted]		Nov-22
11060	[redacted]	[redacted]		Nov-15
11310/11330	[redacted]	[redacted]	19.6	Nov-19
11410	[redacted]	[redacted]	8.02	Nov-18
11460/11470	[redacted]	[redacted]	29.74	Nov-21
11540/11550	[redacted]	[redacted]	24.93	Nov-16
11550	[redacted]	[redacted]	27.69	Nov-19
11550/11560	[redacted]	[redacted]	2.46	May-19
11570	[redacted]	[redacted]	4.88	May-20
11580/11590	[redacted]	[redacted]	29.39	May-17
11590	[redacted]	[redacted]	16.96	Nov-17
11600/11610	[redacted]	[redacted]	6.18	Nov-18
11620/11630	[redacted]	[redacted]	9.03	May-21
11630/11640	[redacted]	[redacted]	12.51	May-22
11650/11660	[redacted]	[redacted]	1.69	Nov-19
11670	[redacted]	[redacted]	24.96	Nov-20
11930	[redacted]	[redacted]		May-22
11990	[redacted]	[redacted]		May-20
12120/12130	[redacted]	[redacted]	23.42	Nov-21

GW	Dig Start (ft)	Dig End (ft)	Length (ft)	Dig Date
12150	[redacted]	[redacted]	0.07	May-19
12160/12170	[redacted]	[redacted]	29.8	May-17
12170	[redacted]	[redacted]	8.81	May-20
12190	[redacted]	[redacted]		May-22
12230/12240	[redacted]	[redacted]	29.13	May-16
12240/12250	[redacted]	[redacted]	8.52	Nov-19
12270	[redacted]	[redacted]	0.02	Nov-16
12280	[redacted]	[redacted]	2.7	May-20
12280	[redacted]	[redacted]	0.05	Nov-19
12310	[redacted]	[redacted]		May-23
12410/12420	[redacted]	[redacted]	17.5	May-15
12420/12430	[redacted]	[redacted]	29.4	Nov-15
12430	[redacted]	[redacted]	4.64	May-21
12460/12470	[redacted]	[redacted]	1.69	May-21
12480/12490	[redacted]	[redacted]	22.95	May-16
12500	[redacted]	[redacted]	10.33	May-22
12510	[redacted]	[redacted]	22.54	May-16
12530	[redacted]	[redacted]	28.4	May-21
12540/12550	[redacted]	[redacted]	25.3	May-17
12550	[redacted]	[redacted]		May-23
12590	[redacted]	[redacted]	0.64	May-20
12710	[redacted]	[redacted]	0.1	Nov-19
12720/12730	[redacted]	[redacted]	1.34	Nov-22
12780/12790	[redacted]	[redacted]	21.7	Nov-19
12800	[redacted]	[redacted]	20.7	May-18
12820/12830	[redacted]	[redacted]	25.33	May-15
12840	[redacted]	[redacted]	26.86	Nov-18
12840/12850	[redacted]	[redacted]	29.8	Nov-18
12850	[redacted]	[redacted]	8.69	Nov-18
12860/12870	[redacted]	[redacted]	3.04	May-16

GW	Dig Start (ft)	Dig End (ft)	Length (ft)	Dig Date
12880	[redacted]	[redacted]	8.85	May-15
12890	[redacted]	[redacted]	2.23	May-21
12900/12910	[redacted]	[redacted]	6.91	May-19
12970/12980	[redacted]	[redacted]	17.6	Nov-18
13000	[redacted]	[redacted]	11.33	May-19
13010/13020	[redacted]	[redacted]	1.18	May-20
13040	[redacted]	[redacted]		May-22
13110	[redacted]	[redacted]	3.66	May-22
13140	[redacted]	[redacted]		Nov-21
13170/13180	[redacted]	[redacted]	11.53	May-21
13200/13210	[redacted]	[redacted]	29.07	May-15
13210	[redacted]	[redacted]	0.49	May-15
13220	[redacted]	[redacted]		May-23
13220/13230	[redacted]	[redacted]	1.72	May-22
13260	[redacted]	[redacted]	0.18	Nov-19
13320	[redacted]	[redacted]		May-23
13570	[redacted]	[redacted]	0.62	Nov-21
13700	[redacted]	[redacted]	0.2	May-15
14020	[redacted]	[redacted]		Nov-20
14040/14060	[redacted]	[redacted]	26.62	May-20
14110	[redacted]	[redacted]		Nov-22

GW	Dig Start (ft)	Dig End (ft)	Length (ft)	Dig Date
14200	[redacted]	[redacted]	0.18	May-21
14300	[redacted]	[redacted]		May-22
14310	[redacted]	[redacted]	0.74	May-20
14470	[redacted]	[redacted]		May-23
14500	[redacted]	[redacted]		May-21
14590	[redacted]	[redacted]		May-23
14650	[redacted]	[redacted]	0.01	May-22
14890/14900	[redacted]	[redacted]	1.74	Nov-20
14910	[redacted]	[redacted]		Nov-22
14920	[redacted]	[redacted]	0.3	Nov-22
14920	[redacted]	[redacted]		May-23
15050	[redacted]	[redacted]		May-22
15530	[redacted]	[redacted]		May-23
15540	[redacted]	[redacted]		Nov-21
15770/15780	[redacted]	[redacted]	1.68	May-22
15850	[redacted]	[redacted]	5.81	May-20
15880	[redacted]	[redacted]	0.01	May-23
15900	[redacted]	[redacted]	28.05	May-22
15900/15910	[redacted]	[redacted]	21.27	Nov-19
15910	[redacted]	[redacted]	7.89	May-22
15950	[redacted]	[redacted]	1.73	Nov-21

Appendix H

PHMSA's Independent Analysis of In-Line Inspection Data

Appendix H: PHMSA's Independent Analysis of ILI Data

Plains' IMP provides written procedures for reviewing an ILI vendor's final report and describes how they are to analyze the data provided to create a dig list. The corrosion growth rate is assumed to be a linear growth that has taken place over 75% of the time since construction. This is considered similarly for both the depth and length growth. Plains' IMP Group then considers two failure modes, leak (80% depth limit) and rupture at maximum operating pressure (MOP). The rupture date is set to the date that is 70% of the estimated time taken to reach failure at the MOP. An anomaly is scheduled for excavation when the nearest date from either mode occurs prior to the next proposed ILI assessment survey date.

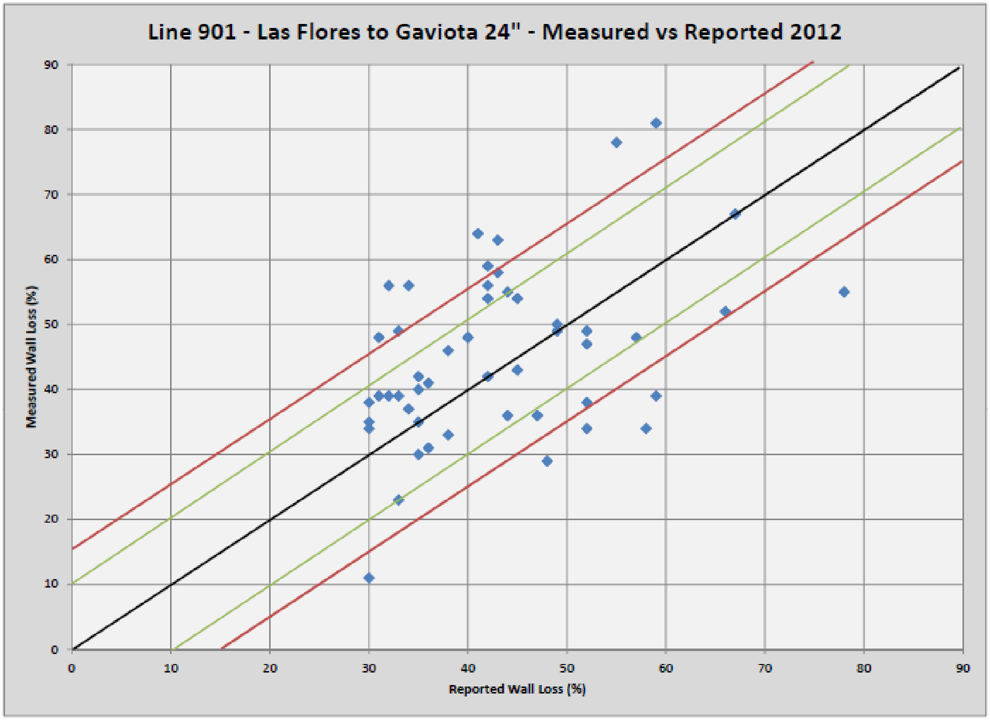
Anomaly dig sheets are then created in Houston and they are sent to the field for execution. The field obtains appropriate permits, conducts the digs and hires a company to come in and perform the NDE on each anomaly. A dig package is then created for each anomaly and includes pictures, data forms, NDE measurements, etc. Once an anomaly dig is completed, the dig package is sent back to the IMP Group in Houston, TX.

Plains' IMP has procedures directing the IMP Group how to analyze the data once the dig information arrives back in Houston from the field. Their procedures are contained in Section 6 and Appendix E1 Magnetic Flux Leakage In-Line Inspection Tool Specification of Plains' IMP.

A short section from page 6-17 and 6-18 of Section 6 of the Plains IMP [Date of Revision: 10 July 2008] are excerpted below.

> *"Validation of ILI Results* To validate the ILI results, Plains will record field found anomaly data on the Anomaly Tracker spreadsheet for the anomalies selected for investigation from the PHMSA Compliance Report. A list of data columns of the Anomaly Tracker spreadsheet is included at the end of this Section. The PHMSA Records Specialists will be responsible for inputting the data into this spreadsheet using data from the Form 501 Pipeline Inspection Reports. Once the data on a pipeline segment is compiled, it will be analyzed by various methods, such as, plotting unity graphs and performing statistical analysis. The field found anomaly data will also be entered into a database, where it can be integrated with other pipeline data for additional analysis."

PHMSA requested all records and analysis performed after each of the ILI Surveys on line 901. Plains' submitted a Unity Plot for as-found versus as-called depth that was created in 2013 – after the 2012 survey and the ILI digs. The plot is shown here.



The black line is the one to one line where any "as-called equal as-found" anomalies would be plotted. The green lines are +/- 10% lines and the red lines are +/- 15% lines. ~57% of the plotted anomalies are within the +/- 10% lines. Reported tool accuracy is +/- 10% 80% of the time. There is no documentation regarding any further analysis or discussion which may have ensued after the creation of this Unity Plot for wall loss (depth).

Appendix E-1 has more specific written procedures concerning contracting with an MFL Tool vendor. This information is excerpted from the Plains IMP with a Date of Revision: "20 December, 2005 APPENDIX E Integrity Management Plan".

On page E1-7 and E1-8 it states:

> ***"6.2 Detection and Anomaly Sizing Specification***
>
> The MFL tool shall meet the minimum detection and anomaly sizing specifications listed in Table E1-1. The Tool Vendor will submit their MFL tool's actual specifications with their bid. The Company may modify these specifications.

Table E1-1 Detection and Sizing Accuracy at 80% Confidence Level

	Seam Welded		Seamless	
	Isolated Corrosion < 3t x 3t	Generalized Corrosion > 3t x 3t	Isolated Corrosion < 3t x 3t	Generalized Corrosion > 3t x 3t
Minimum Detectable Depth	0.2 t	0.1 t	0.3 t	0.15 t
Depth Accuracy	± 0.15 t	± 0.15 t	± 0.15 t	± 0.15 t
Length Accuracy	± 1.0"	± 1.0"	± 1.0"	± 1.0"
Width Accuracy	± 1.4"	± 1.4"	± 1.4"	± 1.4"
Axial Location Accuracy	± 1 %	± 1 %	± 1 %	± 1 %
Orientation	± 15 °	± 15 °	± 15 °	± 15 °
Probability of Detection (POD)	90 %	90 %	90 %	90 %

Where t = the nominal wall thickness
Depth = maximum metal loss anomaly depth
Length = metal loss in the axial direction
Width = metal loss in the circumferential direction

6.3 Interaction Criteria

The Tool Vendor shall use the 1"x 6t interaction criteria in data analysis. For the 1"x 6t interaction criteria, two anomalies will interact if the distance between them is less than or equal to 1" in the axial direction and the circumferential distance between them is less than or equal to 6 times the nominal wall thickness."

The Plains' IMP also includes a section on verification of tool data as follows:

"***8.0 Verification of the Inspection Data***

8.1 Selection of Verification Digs

The investigation of selected anomalies that the Company and Tool Vendor agree upon will be used to compare actual vs. predicted dimensions to provide anomaly verification data to the Tool Vendor. The Tool Vendor's bid must contain a provision for adjusting the anomaly grading based on the verification data at no cost to Company.

8.2 Verification of External Anomalies

External anomalies will be measured by Company field personnel who are qualified to perform API Covered Tasks 8.1 and 8.3. Measurements will be made and recorded for the depth, length and width of the anomaly, as well as the location of the anomaly relative to the reference girth weld. Digital photographs and a sketch or etchings of the anomalies will be made and included in the record. Length of the affected joint and its location relative to the reference marker will be included for comparison to information provided by Tool Vendor. The Company will provide copies of all information obtained from the selected anomalies to the Tool Vendor as soon as possible. The Tool Vendor will review the field data for any corrections to the data analysis for the Final Report."

Independent Review of Smart Pig Data and Field Found Data

PHMSA contracted with Oak Ridge National Laboratories (ORNL) to provide a Subject Matter Expert (SME) to assist in the investigation by performing an analysis of the MFL smart pig in-line-inspection (ILI) data and by comparing that data with the digs made and the information gathered by the non-destructive-examination (NDE) of the anomalies in the field. The analysis included a review of the raw ILI data from the 2007, 2012 and 2015 ILI surveys and comparing that data to the as found data when each anomaly was excavated and measured in the field. All of the data used in the ILI-SME report was provided by the Plains' IMP Group.

Unity plots (as-found versus as-called) were made for length, width and depth. Generally, if a point is called a certain value and the field measured value is the same value, the point will fall on a line that runs at a 45 degree angle from zero up and to the right on a Cartesian coordinate graph. Dotted lines are added parallel to the unity line, placed at +/- 10% which is the reported tool tolerance. The smart pigs utilized for each of the surveys in 2007, 2012, and 2015 were from the same vendor and were high resolution magnetic flux leakage (MFL) smart pigs.

> **Note:** The tools differed slightly but utilized the same MFL technology. See the full report for the full discussion.

The first item of note in the ILI-SME Report is that external corrosion was active on line 901. "Table 2. In line inspection results" from that report is copied below. The table shows that from survey to survey (5 years then 3 years), the number of external corrosion anomalies greater than or equal to 10% increased by 1192 and 169 from 2007 to 2012 and 2012 to 2015 respectively.

Table 2. In line inspection results.

Inspection	*# Ext. Metal Loss*	*# Int. Metal Loss*	*# Mill Metal Loss*	*Total Metal Loss*	*Metal Loss in First 9450'*	*# Dents*	*# Dents with Metal Loss or on Weld*
2007 MFL (≥10%)	386	237	88	711	277	0	0
2012 MFL (≥10%)	1578	6	2	1586	469	22	1
2015 MFL* (≥10%)	1747	0	21	1768	N/A	6	1 (sleeved)

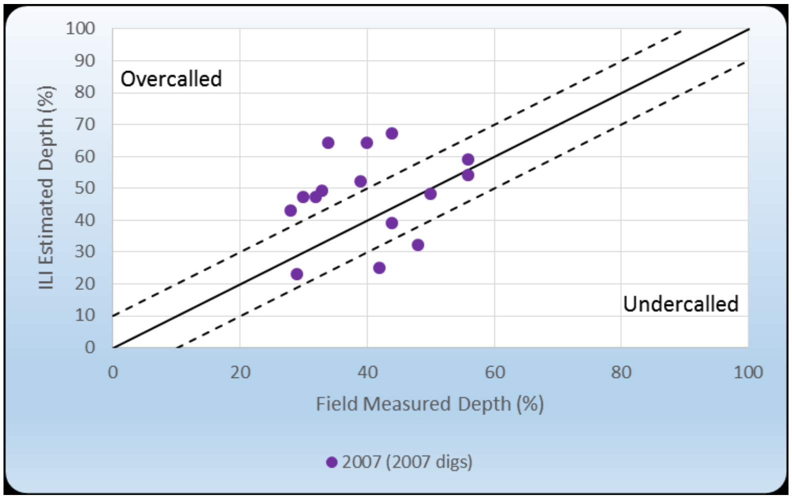
*__First 9450' of 2015 data did not record metal loss__

The ILI-SME report goes on to describe the accuracy of the data presented by the ILI tool vendor compared with the actual measurements found when excavated and measured. The stated accuracy of the tool in the vendor-operator contract was not met for any of the ILI surveys. Also, the tool accuracy using the accepted industry standard, API 1163, was not within stated specifications either.

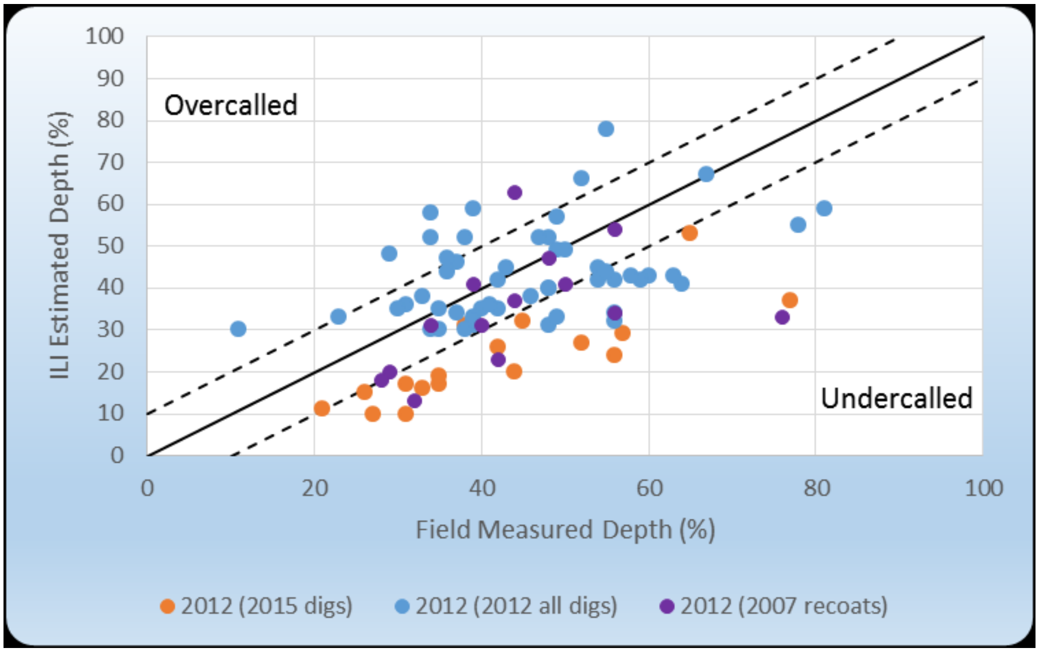
Note: The report does conclude that: “If overcalled anomalies were considered (i.e. >10% over actual) then in all years the unities would be ±10%, >70% of the time for depth.”

The report concludes the following with respect to the accuracies reported by the ILI Tool vendor after the field reported measurements for the same anomalies.

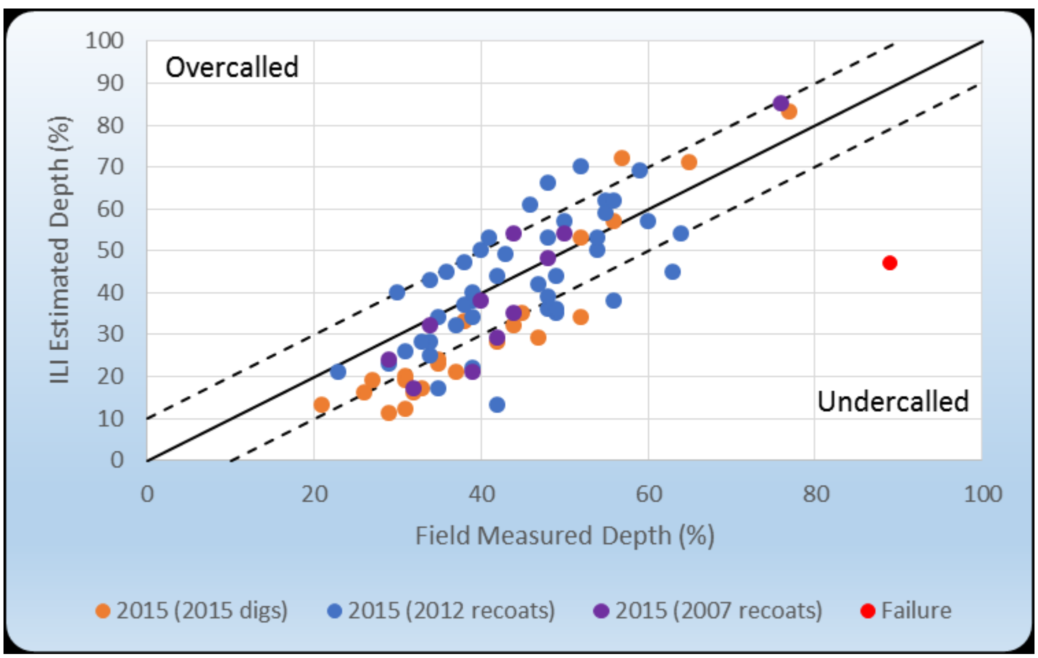
“The unity plot for the 2007 inspection is within ±10%, 33% of the time with respect to the 2007 excavations.”



“The unity plot for the 2012 inspection is within ±10%, 58% of the time with respect to the 2012 excavations (blue) and 2007 excavation recoats (violet). When comparing to the 2015 field excavated results based on the 2012 ILI data, growth may have occurred, causing the comparisons between field and ILI to be under-called (orange). The 2015 digs were not considered in the above stated accuracy.”



"The 2015 ILI estimated depths are compared to field measured depths either from the 4 excavations following the failure or the areas recoated after the 2007 and 2012 inspections. The unity plot shows that the 2015 Rosen inspection is within ±10%, 57% of the time. It may be seen that the failure location has an uncharacteristically high deviation from the ILI estimate."



The ILI-SME describes the process for calculating the remaining strength of a pipe based on the length, width and depth of an anomaly. He also describes the manner in which ILI vendors' interact individual pits into boxes and then how the boxes interact to form clusters and how clusters can be grouped. Suffice it to say that there is a defined process for interacting metal loss anomalies. The only interaction criterion requested by Plains IMP Group was the industry standard one inch by 6 wall thicknesses (1" X 6t) which is normally used for isolated pitting.

> **From the ILI-SME report:** "Plains specifies an interaction criteria to be a combination of absolute value for the length component (1") and wall thickness dependence for the width component (6t). The 1" x 6t interaction rule is one of the most commonly employed throughout industry and is the example given in ASME B31.4."

The ILI-SME report goes on to describe why accurate length and width measurements are important when analyzing external corrosion anomalies.

> **From the ILI-SME report:** "The issue of underestimating the length and width of a corrosion anomaly will lead to gross underestimations of the corrosion area. Figure 16 delineates all of the line 901 anomalies with width and length reported from ILI estimates versus excavations made, on a logarithmic scale. As an example, it is showing that 38% of the anomalies had an area stated by the ILI of ≤ 1.5 in^2 when in fact the corrosion areas were between 2.5 in^2 and 7300 in^2. This being said, there may be a difference in the field measurement technique to consider. It is important that the techniques used in the field be comparable to that required by the ILI analysis to enable a proper assessment of the ILI performance."

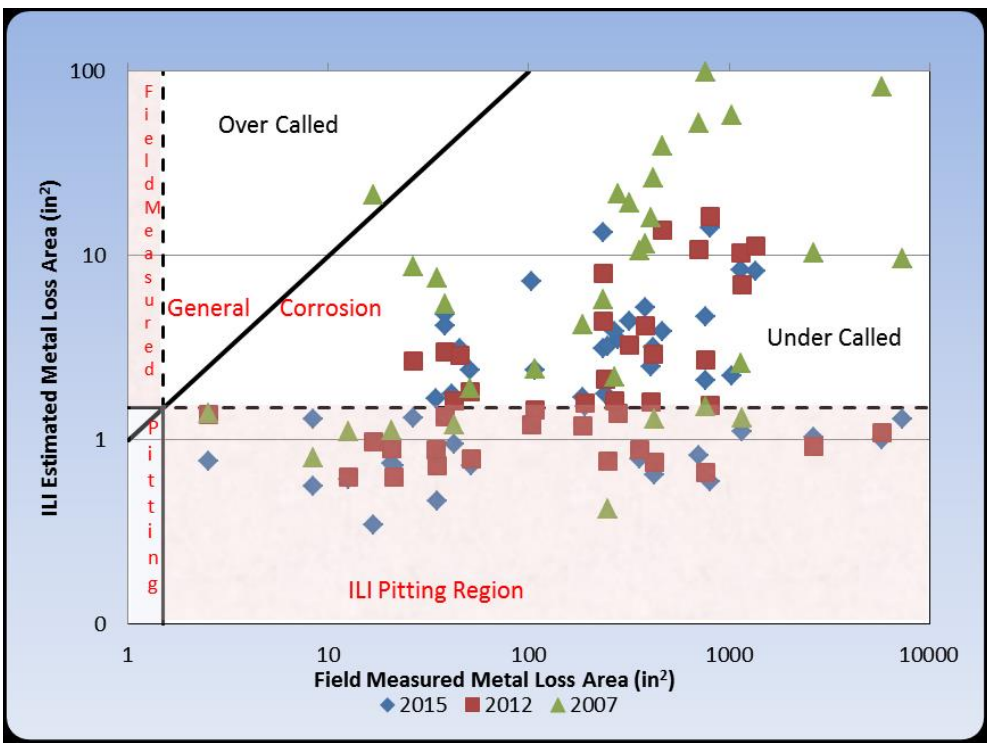


Figure 16. Metal loss area; ILI vs field measurement.

The following are two "Close-Out Reports" provided by the Plains IMP Group. The first one is for the 2007 ILI survey and anomaly digs and the second is for the 2012 ILI survey and anomaly digs. The 2007 Close-Out Report states in the, "Results/Comments/Recommendations", at the bottom of the form, "2. The results show that 86% of the excavated anomalies were within tool tolerance or over-called by the ILI tool and no anomalies meet conditions for further evaluations." This report was completed on 6/21/2015.

The 2012 Close-Out Report states in the "Results/Comments/Recommendations", at the bottom of the form:

"2. The results show that the ILI tool is within the tool's tolerance specification.

3. The results show that 73% of the excavated anomalies were within tool tolerance or over-called by the ILI tool and no anomalies meet conditions for further evaluations."

CLOSE-OUT REPORT

Line Name: L901 - Las Flores - Gaviota - 24" **ILI tool run date:** 6/19/2007 **Date:** 6/21/2015

Summary of In-Line Inspection Indications

Metal Loss Anomalies	Ext		Int		Mfg		Total	
	ILI	After	ILI	After	ILI	After	ILI	After
d/t < 20% WT	257	246	228	228	71	71	556	545
20% WT ≤ d/t < 30% WT	82	76	5	5	16	16	103	97
30% WT ≤ d/t < 40% WT	33	27	4	4	1	1	38	32
40% WT ≤ d/t < 50% WT	9	3	0	0	0	0	9	3
50% WT ≤ d/t < 60% WT	3	0	0	0	0	0	3	0
60% WT ≤ d/t < 70% WT	2	0	0	0	0	0	2	0
70% WT ≤ d/t < 80% WT	0	0	0	0	0	0	0	0
d/t ≥ 80% WT	0	0	0	0	0	0	0	0
Internal ML consistent with internal corrosion	0	0	0	0	0	0	0	0
Selective Seam Corrosion	0	0	0	0	0	0	0	0
Total	386	352	237	237	88	88	711	677

Failure Pressures and Deepest Pits	ILI	After
Reported deepest external metal loss (%WT)	67%	42%
Reported deepest internal metal loss (%WT)	34%	34%
Calculated lowest Safe_pressure (based on CGAR)	885	1,201
Calculated lowest P_Burst (based on CGAR)	1,230	1,669

Deformation Anomalies	Total	After
Dent Depth > 6% OD	0	0
Dent Depth ≤ 6% OD	0	0
Dent Depth ≥ 2% OD with metal	0	0
Dent Depth < 2% OD with metal	0	0
Dent Depth ≥ 2% OD affecting weld	0	0
Dent Depth < 2% OD affecting weld	0	0
Girth weld anomalies	0	0
Wrinkle bends	0	0

Seam Weld Anomalies	Total	After
SWA-A	0	0
SWA-B	0	0
SWA	0	0

Crack Anomalies (Depth)	Crack-Like		Crack Field		Notch-Like		Mid Wall		Total	
	ILI	After	ILI	After	ILI	After	ILI	After	ILI	After
0.040" - 0.079"	0	0	0	0	0	0	0	0	0	0
0.08" - 0.119"	0	0	0	0	0	0	0	0	0	0
0.12" - 0.159"	0	0	0	0	0	0	0	0	0	0
≥ 0.16"	0	0	0	0	0	0	0	0	0	0
No depth	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0	0	0	0

Results/Comment/Recommendation:

1. 1 anomaly (cluster) repaired using type B sleeve, 11 anomalies/clusters using composite sleeves, 26 anomalies/clusters using recoat, and 0 anomaly using pipe replacement.
2. The results show that 86% of the excavated anomalies were within tool tolerance or overcalled by the ILI tool and no anomalies meet conditions for further evaluations.
3. The earliest the remaining ML anomalies to have predicted depth >80%WT or calculated burst pressure < MOP (based on CGAR) is > 2012.

CLOSE-OUT REPORT

Line Name L901 - Las Flores - Gaviota - 24" **ILI tool run date:** 7/3/2012 **Date:** 6/22/2015

Summary of In-Line Inspection Indications

Metal Loss Anomalies	Ext		Int		Mfg		Total	
	ILI	After	ILI	After	ILI	After	ILI	After
d/t < 20% WT	1,241	992	6	6	0	0	1,247	998
20% WT ≤ d/t < 30% WT	182	137	0	0	2	2	184	139
30% WT ≤ d/t < 40% WT	99	57	0	0	0	0	99	57
40% WT ≤ d/t < 50% WT	36	9	0	0	0	0	36	9
50% WT ≤ d/t < 60% WT	15	1	0	0	0	0	15	1
60% WT ≤ d/t < 70% WT	4	0	0	0	0	0	4	0
70% WT ≤ d/t < 80% WT	1	0	0	0	0	0	1	0
d/t ≥ 80% WT	0	0	0	0	0	0	0	0
Internal ML consistent with internal corrosion	0	0	0	0	0	0	0	0
Selective Seam Corrosion	0	0	0	0	0	0	0	0
Total	1,578	1,196	6	6	2	2	1,586	1,204

Failure Pressures and Deepest Pits	ILI	After
Reported deepest external metal loss (%WT)	78%	52%
Reported deepest internal metal loss (%WT)	18%	18%
Calculated lowest Safe_pressure (based on	1,090	1,158
Calculated lowest P_Burst (based on CGAR)	1,515	1,608

Deformation Anomalies	Total	After
Dent Depth > 6% OD	0	0
Dent Depth ≤ 6% OD	22	5
Dent Depth ≥ 2% OD with metal	0	0
Dent Depth < 2% OD with metal	0	0
Dent Depth ≥ 2% OD affecting weld	0	0
Dent Depth < 2% OD affecting weld	2	0
Girth weld anomalies	0	0
Wrinkle bends	16	0

Seam Weld Anomalies	Total	After
SWA-A	0	0
SWA-B	0	0
SWA	0	0

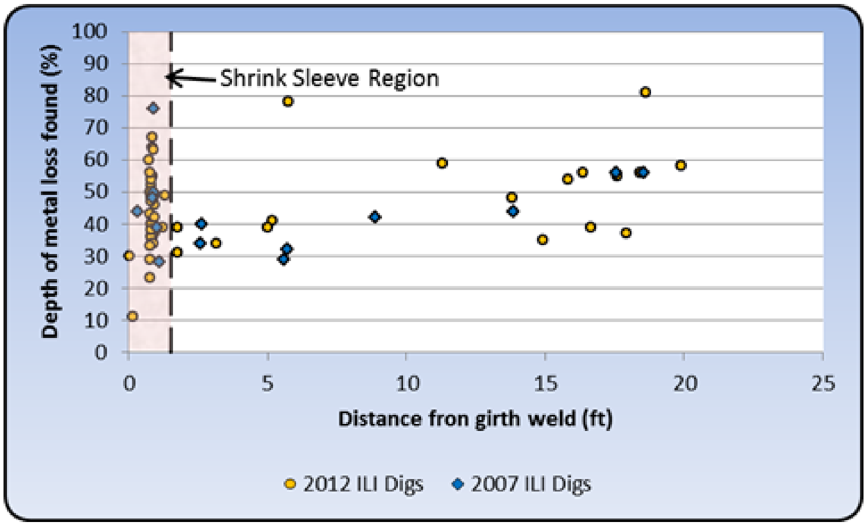
Crack Anomalies (Depth)	Crack-Like		Crack Field		Notch-Like		Mid Wall		Total	
	ILI	After	ILI	After	ILI	After	ILI	After	ILI	After
0.040" - 0.079"	0	0	0	0	0	0	0	0	0	0
0.08" - 0.119"	0	0	0	0	0	0	0	0	0	0
0.12" - 0.159"	0	0	0	0	0	0	0	0	0	0
≥ 0.16"	0	0	0	0	0	0	0	0	0	0
No depth	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0	0	0	0

Results/Comment/Recommendation:

1. 2012 ILI - 49 anomalies repaired using Type B, 37 anomalies using composite sleeves, 211 anomalies using recoat, and 0 anomaly using pipe replacement.
2. The result shows that the ILI tool is within the tool's tolerance specification. No further anomalies need to be investigated.
3. The result shows that 73 % of the excavated anomalies were within tool tolerance or overcalled by the ILI tool and no anomalies meet conditions for further evaluations.
4. The earliest the remaining ML anomalies to have predicted depth >80%WT or calculated burst pressure < MOP (based on CGAR) is 3/19/2016.

Two additional analyses were performed by the ILI-SME which was not included in the final filed report. One data set was the number of anomaly digs that were within one and a half feet of a girth weld. Below is the analysis stated and presented graphically.

> "Within the 2007 excavation locations approximately 50% were within 1.5' of a GW (blue diamonds). Within the 2012 excavation locations approximately 76% were within 1.5' of a GW (yellow circles). (The shrink sleeve utilized was 34" total, therefore the length from each side of the GW is app 1.5'). The depth of metal loss found within these excavations relative to distance from the girth weld is shown below."



The second analysis had to do with the estimated cubic yards of dirt excavated during each anomaly dig. Plains' personnel explained to PHMSA that they were required to keep their excavations below 100 cubic feet. This is important because PHMSA was told by the Plains' IMP Group that Santa Barbara County has strict requirements for excavators and that obtaining a permit for larger excavations would take from six months or more to obtain a permit. However, Plains' IMP Group reported that there is an exception for excavations made that are less than 100 cubic yards of dirt. Below is an excerpt from the "Santa Barbara County, Planning and Development, Building and Safety Division Grading Plan Submittal Requirements for Projects (Other than Subdivisions)" delineating exception #4.

(b) Aside from areas designated as open space on the Orcutt Community Plan Open Space Areas Map, these regulations shall not apply to the following exceptions:

(4) The initial excavation and fill necessary to effect such temporary repair or maintenance of oil and gas and utility lines (located outside of an existing oil producing area) as can be completed within seven days of commencement where such excavation or fill does not exceed a total of one hundred cubic yards of material and where all work is protected, as may be required, by a safety fence or other similar protective device;

The following spreadsheet is a calculated estimate of the amount of dirt excavated during a number of the anomaly digs in 2007 and 2012. On the right of the figure there are some noted assumptions including:

"* Assuming 10' width and 8' depth
** Does not include side or end wall terracing
Lengths taken from individual "Pipeline Inspection and Repair Reports"
*** Lengths in Repair Reports are inconsistent
-Some refer to the full dig opening and others refer to the repaired/recoat length only."

2007 Excavations

Dig #	Length	App. Volume*
3	4.8	14.2
3A	10.3	30.5
4	13.5	40.0
5	3.0	8.9
6	8.0	23.7
7	7.1	21.0
8	11.3	33.5
9	4.4	13.0
10	11.1	32.9
11	2.5	7.4
11B	3.0	8.9
12	2.7	8.0
13	3.0	8.9

2012 Excavations

Dig#	Length	App. Volume*	
1	11.2	33.2	
2	9.6	28.4	
3	14.6	43.3	
4	16.8	49.8	
5	13.5	40.0	
6	9.3	27.6	
7	12.1	35.9	
8	7.8	23.1	
9	2.1	6.2	
10	12.0	35.6	
11	11.3	33.5	
12	6.6	19.6	
13	8.0	23.7	6' d/s of failure
14	6.7	19.9	
15	8.3	24.6	
16	6.5	19.3	
17	7.1	21.0	
18	6.0	17.8	
19	9.6	28.4	
20	7.7	22.8	
20A	8.7	25.8	
21	5.8	17.2	
21A	5.5	16.3	
22	6.3	18.7	
23	5.8	17.2	
24	7.1	21.0	
25	7.3	21.6	
26	5.0	14.8	
27	7.9	23.4	
28	9.0	26.7	
29	6.9	20.4	
30	6.6	19.6	
31	5.8	17.2	
32	12.2	36.1	
33	6.2	18.4	
33A	6.7	19.9	
34	5.6	16.6	
35	8.6	25.5	
36	16.0	47.4	
37	4.0	11.9	
38	12.1	35.9	
39	6.1	18.1	
40	8.8	26.1	
41	4.8	14.2	

NOTES

*Assuming 10' width and 8' depth

**does not include side or end wall terracing

Lengths taken from individual "Pipeline Inspection and Repair Reports"

***Lengths in Repair Reports are inconsistent
- Some refer to the full dig opening and others refer to the repaired/recoat length only

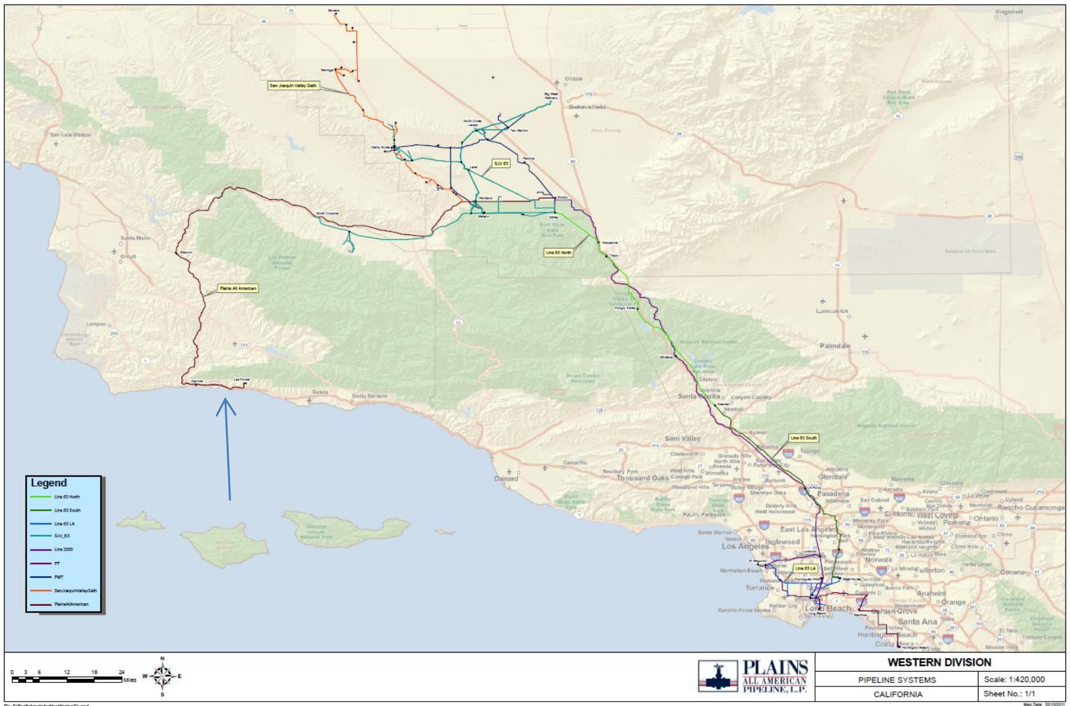
This spreadsheet was created to estimate excavated soil volumes for each anomaly dig. Dig numbers are provided as well as volume estimates and assumptions used. Volume was calculated in Cubic Feet and converted to Cubic Yards.

If the volume estimates are doubled, they all still come in under the 100 cubic yard threshold. Dig #13 in 2012, was located only six feet downstream of the failure location.

Appendix I

Maps and Photographs

Appendix I: Maps and Photographs

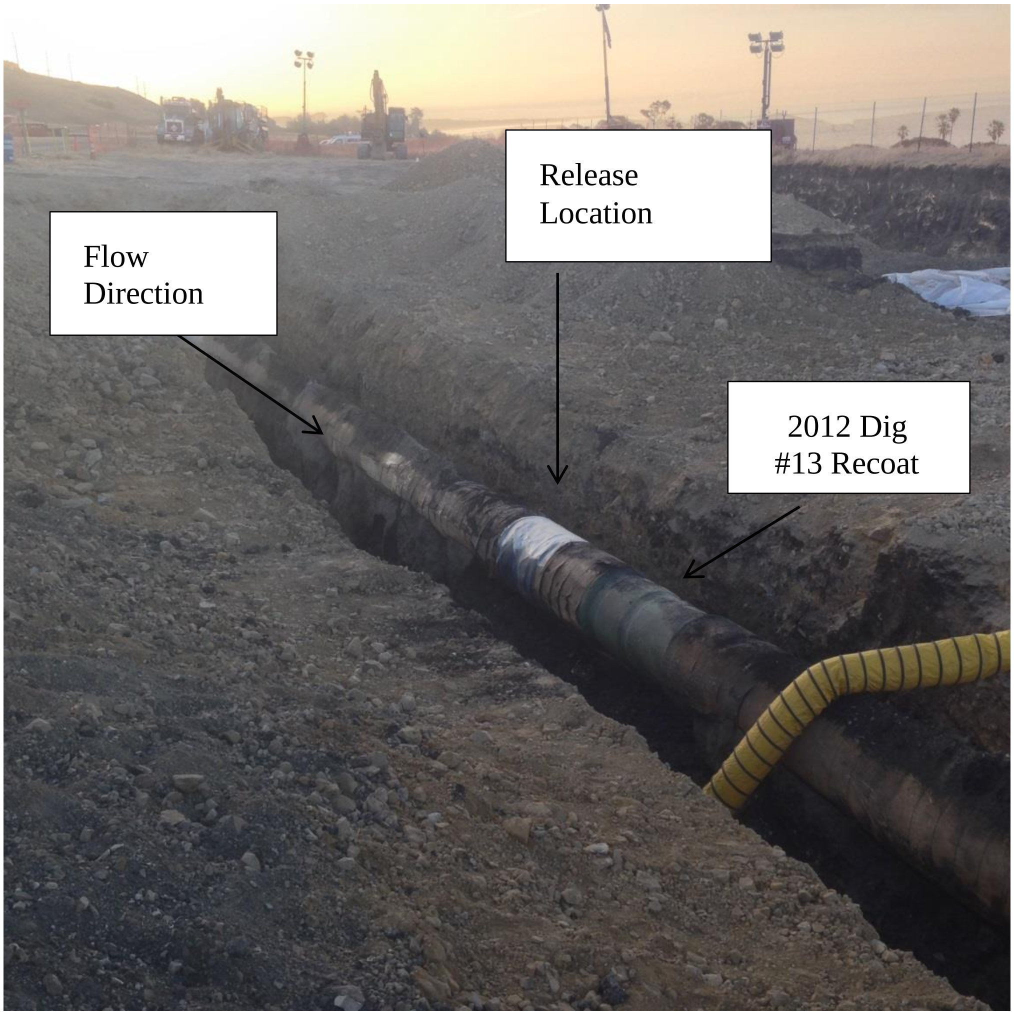


Map of Plains' Western Division Pipelines. The arrow in the ocean is pointing to the approximate release site on line 901.

Overview from Santa Barbara Spill Web Site

Release Site with Culvert in the foreground. Vacuum Truck sucking up pooled oil in the background.

Culvert Under Highway and RR Tracks to Ocean



This picture shows the release site wrapped in plastic 6 feet upstream from girth weld 5940 where the coating repair is visible. The repair was identified as Dig #13 from the Post 2012 ILI Survey Anomaly Digs.

This is one of the first pictures of the release location after removal from the ditch.

Plains All American Pipeline, L.P.
Line 901 Release (05-19-15): Mechanical and Metallurgical Testing

Figure 2. Photograph showing Pipe Section 1 following removal from the ditch.

This picture was copied from the Final Metallurgical Report. One can see the bare pipe where the insulation and other coatings were removed to allow the pipe to be cut.

Appendix J

National Response Center Report #1

PHMSA Pipeline & Hazardous Materials Safety Administration (Version 4.0.0 PROD)

HMIS->INCIDENTS->TELEPHONICS

Rules of Behavior Home Logout Menu

[Return to Search]

NRC Number: 1116950

Call Date: 05/19/2015 **Call Time:** 15:43:00

Caller Information

First Name: Last Name: 2457
Company Name: SANTA BARBARA DISPATCH
Address: MSD SANTA BARBARA
City: SANTA BARBARA State: CA
Country: USA Zip: 93019
Phone 1: 8056832724 Phone 2:
Organization Type: PRIVATE I Is caller the spiller? Yes No No Response
Confidential: Yes No No Response

Discharger Information

First Name: Last Name: UNKNOWN
Company Name:
Address:
City: State: XX
Country: USA Zip:
Phone 1: Phone 2:
Organization Type: UNKNOWI

Spill Information

State: CA County: SANTA BARBARA
Nearest City: Zip Code:
Location
HWY 101 AT REFUGIO BEACH

Spill Date: 05/19/2015 (mm/dd/yyyy) Spill Time: 12:39:00 (24hh:mm:ss)
DTG Type: <- Select DTG Type ->
Incident Type ALL Reported Incident Type UNKNOWN SHEEN
Description
CALLER REPORTED AND UNKNOWN SHEEN COMING FROM AN UNKNOWN SOURCE.

Materials Involved

Material / Chris Name	Chris Code	Total Qty.	Water Qty.
UNKNOWN OIL	OUN	0 UNKNOWN AMOUNT	0 UNKNOWN AMOUNT

Medium Type: <- Select Medium Type ->
Additional Medium Information:
PACIFIC OCEAN

Injuries: Fatalites:
Evacuations: Yes No Unknown No. of Evacuations:
Damages: Yes No Unknown Damage Amount:

Federal Agency Notified: Yes No Unknown State Agency Notified: Yes No Unknown
Other Agency Notified: Yes No Unknown

Remedial Actions

Additional Info

VERY LIMITED INFORMATION.

Latitude

Degrees: Minutes: Seconds: Quadrant:

Longitude

Degrees: Minutes: Seconds: Quadrant:

Distance from City: Direction:

Section: Township:

Range: Milepost:

Rescinded **Comments** (max 250 characters)

<< Previous 11..11 of 26 Next >>

Appendix K

National Response Center Report #2

PHMSA Pipeline & Hazardous Materials Safety Administration (Version 4.0.0 PROD)

HMIS->INCIDENTS->TELEPHONICS

Rules of Behavior | Home | Logout | Menu

[Return to Search]

NRC Number: 1116972

Call Date: 05/19/2015 **Call Time:** 17:56:00

Caller Information

First Name:	JAMES	Last Name:	BUCHANAN
Company Name:	PLAINS ALL AMERICAN PIPELINE		
Address:	3600 BOWMAN CT		
City:	BAKERSFIELD	State:	CA
Country:	USA	Zip:	93308
Phone 1:	6613367906	Phone 2:	6614371459
Organization Type:	PRIVATE I	Is caller the spiller?	Yes No No Response
Confidential:	Yes No No Response		

Discharger Information

First Name:	JAMES	Last Name:	BUCHANAN
Company Name:	PLAINS ALL AMERICAN PIPELINE		
Address:	3600 BOWMAN CT		
City:	BAKERSFIELD	State:	CA
Country:	USA	Zip:	93308
Phone 1:	6613367906	Phone 2:	6614371459
Organization Type:	PRIVATE I		

Spill Information

State:	CA	County:	SANTA BARBARA
Nearest City:	GOLETA	Zip Code:	

Location

SEE LAT/LONG

Spill Date:	05/19/2015 (mm/dd/yyyy)	Spill Time:	13:30:00 (24hh:mm:ss)
DTG Type:	<- Select DTG Type ->		
Incident Type	ALL	Reported Incident Type	PIPELINE

Description

CALLER STATED THAT CRUDE OIL WAS DISCOVERED TO BE COMING OUT OF A TRANSMISSION PIPELINE AT A CULVERT UNDER HWY 1 BY THE PACIFIC OCEAN. THE SPILL DID IMPACT AN UNNAMED BEACH AS WELL AS THE OCEAN. CALLER IS ESTIMATING THE AMOUNT SPILLED IS GREATER THAN 500 BARRELS BUT THERE IS LIMITED INFORMATION AT THIS TIME.

Materials Involved

Material / Chris Name	Chris Code	Total Qty.	Water Qty.
OIL: CRUDE	OIL	500 BARREL(S)	0 UNKNOWN AMOUNT

Medium Type: <- Select Medium Type ->

Additional Medium Information:

PACIFIC OCEAN

Injuries:		Fatalites:	
Evacuations:	Yes No Unknown	No. of Evacuations:	
Damages:	Yes No Unknown	Damage Amount:	
Federal Agency Notified:	Yes No Unknown	State Agency Notified:	Yes No Unknown
Other Agency Notified:	Yes No Unknown		

Remedial Actions

LINE HAS BEEN SHUT IN. CONTRACTORS ARE ONSCENE.

Additional Info

Latitude

Degrees: 34 Minutes: 27 Seconds: 43 Quadrant: N

Longitude

Degrees: 120 Minutes: 5 Seconds: 24 Quadrant: W

Distance from City: Direction:

Section: Township:

Range: Milepost:

Rescinded **Comments** (max 250 characters)

<< Previous 1..1 of 1 << Save >>

Appendix L

Form PHMSA F 7000.1: Accident Report for Hazardous Liquid Pipeline Systems

NOTICE: This report is required by 49 CFR Part 195. Failure to report can result in a civil penalty not to exceed $100,000 for each violation for each day that such violation persists except that the maximum civil penalty shall not exceed $1,000,000 as provided in 49 USC 60122.	OMB NO: 2137-0047 EXPIRATION DATE: 12/31/2016

U.S Department of Transportation Pipeline and Hazardous Materials Safety Administration	**Original Report Date:**	06/17/2015
	No.	20150224 - 21010 -------------------------- (DOT Use Only)

ACCIDENT REPORT - HAZARDOUS LIQUID PIPELINE SYSTEMS

A federal agency may not conduct or sponsor, and a person is not required to respond to, nor shall a person be subject to a penalty for failure to comply with a collection of information subject to the requirements of the Paperwork Reduction Act unless that collection of information displays a current valid OMB Control Number. The OMB Control Number for this information collection is 2137-0047. All responses to the collection of information are mandatory. Send comments regarding this burden or any other aspect of this collection of information, including suggestions for reducing the burden to: Information Collection Clearance Officer, PHMSA, Office of Pipeline Safety (PHP-30) 1200 New Jersey Avenue, SE, Washington, D.C. 20590.

INSTRUCTIONS

Important: *Please read the separate instructions for completing this form before you begin. They clarify the information requested and provide specific examples. If you do not have a copy of the instructions, you can obtain one from the PHMSA Pipeline Safety Community Web Page at http://www.phmsa.dot.gov/pipeline/library/forms.*

PART A - KEY REPORT INFORMATION

Report Type: *(select all that apply)*	**Original:**	**Supplemental:**	**Final:**
		Yes	

Last Revision Date:	12/23/2015
1. Operator's OPS-issued Operator Identification Number (OPID):	300
2. Name of Operator	PLAINS PIPELINE, L.P.
3. Address of Operator:	
3a. Street Address	333 CLAY STREET, SUITE 1600
3b. City	HOUSTON
3c. State	Texas
3d. Zip Code	77002
4. Local time *(24-hr clock)* and date of the Accident:	05/19/2015 10:57
5. Location of Accident:	
Latitude:	34.462434
Longitude:	-120.086714
6. National Response Center Report Number (if applicable):	1116972
7. Local time *(24-hr clock)* and date of initial telephonic report to the National Response Center (if applicable):	05/19/2015 14:56
8. Commodity released: *(select only one, based on predominant volume released)*	Crude Oil
- Specify Commodity Subtype:	
- If "Other" Subtype, Describe:	
- If Biofuel/Alternative Fuel and Commodity Subtype is Ethanol Blend, then % Ethanol Blend:	
- If Biofuel/Alternative Fuel and Commodity Subtype is Biodiesel, then Biodiesel Blend e.g. B2, B20, B100	
9. Estimated volume of commodity released unintentionally (Barrels):	2,934.00
10. Estimated volume of intentional and/or controlled release/blowdown (Barrels):	
11. Estimated volume of commodity recovered (Barrels):	1,100.00
12. Were there fatalities?	No
- If Yes, specify the number in each category:	
12a. Operator employees	
12b. Contractor employees working for the Operator	
12c. Non-Operator emergency responders	
12d. Workers working on the right-of-way, but NOT associated with this Operator	
12e. General public	
12f. Total fatalities (sum of above)	
13. Were there injuries requiring inpatient hospitalization?	No
- If Yes, specify the number in each category:	
13a. Operator employees	
13b. Contractor employees working for the Operator	
13c. Non-Operator emergency responders	
13d. Workers working on the right-of-way, but NOT associated with this Operator	
13e. General public	

13f. Total injuries (sum of above)	
14. Was the pipeline/facility shut down due to the Accident?	Yes
- If No, Explain:	
- If Yes, complete Questions 14a and 14b: *(use local time, 24-hr clock)*	
14a. Local time and date of shutdown:	05/19/2015 11:30
14b. Local time pipeline/facility restarted:	
- Still shut down? (* Supplemental Report Required)	Yes
15. Did the commodity ignite?	No
16. Did the commodity explode?	No
17. Number of general public evacuated:	1
18. Time sequence *(use local time, 24-hour clock)*:	
18a. Local time Operator identified Accident - effective 7- 2014 changed to "Local time Operator identified failure":	05/19/2015 13:27
18b. Local time Operator resources arrived on site:	05/19/2015 13:27

PART B - ADDITIONAL LOCATION INFORMATION

1. Was the origin of the Accident onshore?	Yes
If Yes, Complete Questions (2-12)	
If No, Complete Questions (13-15)	
- If Onshore:	
2. State:	California
3. Zip Code:	93117
4. City	Goleta
5. County or Parish	Santa Barbara
6. Operator-designated location:	Milepost/Valve Station
Specify:	4
7. Pipeline/Facility name:	Las Flores to Gaviota 24"
8. Segment name/ID:	Line 901
9. Was Accident on Federal land, other than the Outer Continental Shelf (OCS)?	No
10. Location of Accident:	Pipeline Right-of-way
11. Area of Accident (as found):	Underground
Specify:	Under soil
- If Other, Describe:	
Depth-of-Cover (in):	56
12. Did Accident occur in a crossing?	No
- If Yes, specify type below:	
- If Bridge crossing –	
Cased/ Uncased:	
- If Railroad crossing –	
Cased/ Uncased/ Bored/drilled	
- If Road crossing –	
Cased/ Uncased/ Bored/drilled	
- If Water crossing –	
Cased/ Uncased	
- Name of body of water, if commonly known:	
- Approx. water depth (ft) at the point of the Accident:	
- Select:	
- If Offshore:	
13. Approximate water depth (ft) at the point of the Accident:	
14. Origin of Accident:	
- In State waters - Specify:	
- State:	
- Area:	
- Block/Tract #:	
- Nearest County/Parish:	
- On the Outer Continental Shelf (OCS) - Specify:	
- Area:	
- Block #:	
15. Area of Accident:	

PART C - ADDITIONAL FACILITY INFORMATION

1. Is the pipeline or facility:	Interstate
2. Part of system involved in Accident:	Onshore Pipeline, Including Valve Sites
- If Onshore Breakout Tank or Storage Vessel, Including Attached Appurtenances, specify:	
3. Item involved in Accident:	Pipe
- If Pipe, specify:	Pipe Body
3a. Nominal diameter of pipe (in):	24

3b. Wall thickness (in):	.344
3c. SMYS (Specified Minimum Yield Strength) of pipe (psi):	65,000
3d. Pipe specification:	X-65
3e. Pipe Seam , specify:	Longitudinal ERW - High Frequency
- If Other, Describe:	
3f. Pipe manufacturer:	Nippon Steel
3g. Year of manufacture:	1986
3h. Pipeline coating type at point of Accident, specify:	Coal Tar
- If Other, Describe:	
- If Weld, including heat-affected zone, specify. If Pipe Girth Weld, 3a through 3h above are required:	
- If Other, Describe:	
- If Valve, specify:	
- If Mainline, specify:	
- If Other, Describe:	
3i. Manufactured by:	
3j. Year of manufacture:	
- If Tank/Vessel, specify:	
- If Other - Describe:	
- If Other, describe:	
4. Year item involved in Accident was installed:	1990
5. Material involved in Accident:	Carbon Steel
- If Material other than Carbon Steel, specify:	
6. Type of Accident Involved:	Leak
- If Mechanical Puncture – Specify Approx. size:	
in. (axial) by	
in. (circumferential)	
- If Leak - Select Type:	Other
- If Other, Describe:	Narrow slit opening.
- If Rupture - Select Orientation:	
- If Other, Describe:	
Approx. size: in. (widest opening) by	
in. (length circumferentially or axially)	
- If Other – Describe:	

PART D - ADDITIONAL CONSEQUENCE INFORMATION

1. Wildlife impact:	Yes
1a. If Yes, specify all that apply:	
- Fish/aquatic	Yes
- Birds	Yes
- Terrestrial	Yes
2. Soil contamination:	Yes
3. Long term impact assessment performed or planned:	Yes
4. Anticipated remediation:	Yes
4a. If Yes, specify all that apply:	
- Surface water	Yes
- Groundwater	
- Soil	Yes
- Vegetation	Yes
- Wildlife	Yes
5. Water contamination:	Yes
5a. If Yes, specify all that apply:	
- Ocean/Seawater	Yes
- Surface	Yes
- Groundwater	
- Drinking water: *(Select one or both)*	
- Private Well	
- Public Water Intake	
5b. Estimated amount released in or reaching water (Barrels):	500.00
5c. Name of body of water, if commonly known:	Pacific Ocean.
6. At the location of this Accident, had the pipeline segment or facility been identified as one that "could affect" a High Consequence Area (HCA) as determined in the Operator's Integrity Management Program?	Yes
7. Did the released commodity reach or occur in one or more High Consequence Area (HCA)?	Yes
7a. If Yes, specify HCA type(s): *(Select all that apply)*	
- Commercially Navigable Waterway:	Yes
Was this HCA identified in the "could affect" determination for this Accident site in the Operator's	Yes

Integrity Management Program?	
- High Population Area:	
Was this HCA identified in the "could affect" determination for this Accident site in the Operator's Integrity Management Program?	
- Other Populated Area	
Was this HCA identified in the "could affect" determination for this Accident site in the Operator's Integrity Management Program?	
- Unusually Sensitive Area (USA) - Drinking Water	
Was this HCA identified in the "could affect" determination for this Accident site in the Operator's Integrity Management Program?	
- Unusually Sensitive Area (USA) - Ecological	Yes
Was this HCA identified in the "could affect" determination for this Accident site in the Operator's Integrity Management Program?	Yes
8. Estimated cost to Operator – effective 12-2012, changed to "Estimated Property Damage":	
8a. Estimated cost of public and non-Operator private property damage paid/reimbursed by the Operator – effective 12-2012, "paid/reimbursed by the Operator" removed	$ 0
8b. Estimated cost of commodity lost	$ 144,000
8c. Estimated cost of Operator's property damage & repairs	$ 9,868,173
8d. Estimated cost of Operator's emergency response	$ 90,701,042
8e. Estimated cost of Operator's environmental remediation	$ 22,421,933
8f. Estimated other costs	$ 19,796,736
Describe:	Goverment Agency Costs and Media Relations.
8g. Estimated total costs (sum of above) – effective 12-2012, changed to "Total estimated property damage (sum of above)"	$ 142,931,884

PART E - ADDITIONAL OPERATING INFORMATION

1. Estimated pressure at the point and time of the Accident (psig):	750.00
2. Maximum Operating Pressure (MOP) at the point and time of the Accident (psig):	1,056.00
3. Describe the pressure on the system or facility relating to the Accident (psig):	Pressure did not exceed MOP
4. Not including pressure reductions required by PHMSA regulations (such as for repairs and pipe movement), was the system or facility relating to the Accident operating under an established pressure restriction with pressure limits below those normally allowed by the MOP?	No
- If Yes, Complete 4.a and 4.b below:	
4a. Did the pressure exceed this established pressure restriction?	
4b. Was this pressure restriction mandated by PHMSA or the State?	
5. Was "Onshore Pipeline, Including Valve Sites" OR "Offshore Pipeline, Including Riser and Riser Bend" selected in PART C, Question 2?	Yes
- If Yes - (*Complete 5a. – 5f below*) effective 12-2012, changed to *"(Complete 5.a – 5.e below)"*	
5a. Type of upstream valve used to initially isolate release source:	Remotely Controlled
5b. Type of downstream valve used to initially isolate release source:	Check Valve
5c. Length of segment isolated between valves (ft):	56,752
5d. Is the pipeline configured to accommodate internal inspection tools?	Yes
- If No, Which physical features limit tool accommodation? (*select all that apply)*	
- Changes in line pipe diameter	
- Presence of unsuitable mainline valves	
- Tight or mitered pipe bends	
- Other passage restrictions (i.e. unbarred tee's, projecting instrumentation, etc.)	
- Extra thick pipe wall (applicable only for magnetic flux leakage internal inspection tools)	
- Other -	
- If Other, Describe:	
5e. For this pipeline, are there operational factors which significantly complicate the execution of an internal inspection tool run?	No
- If Yes, Which operational factors complicate execution? (*select all that apply*)	

- Excessive debris or scale, wax, or other wall buildup	
- Low operating pressure(s)	
- Low flow or absence of flow	
- Incompatible commodity	
- Other -	
- If Other, Describe:	
5f. Function of pipeline system:	> 20% SMYS Regulated Trunkline/Transmission
6. Was a Supervisory Control and Data Acquisition (SCADA)-based system in place on the pipeline or facility involved in the Accident?	Yes
If Yes -	
6a. Was it operating at the time of the Accident?	Yes
6b. Was it fully functional at the time of the Accident?	Yes
6c. Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the detection of the Accident?	Yes
6d. Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the confirmation of the Accident?	Yes
7. Was a CPM leak detection system in place on the pipeline or facility involved in the Accident?	Yes
- If Yes:	
7a. Was it operating at the time of the Accident?	Yes
7b. Was it fully functional at the time of the Accident?	Yes
7c. Did CPM leak detection system information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the detection of the Accident?	No
7d. Did CPM leak detection system information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the confirmation of the Accident?	No
8. How was the Accident initially identified for the Operator?	Local Operating Personnel, including contractors
- If Other, Specify:	
8a. If "Controller", "Local Operating Personnel", including contractors", "Air Patrol", or "Ground Patrol by Operator or its contractor" is selected in Question 8, specify:	Operator employee
9. Was an investigation initiated into whether or not the controller(s) or control room issues were the cause of or a contributing factor to the Accident?	Yes, specify investigation result(s): (select all that apply)
- If No, the Operator did not find that an investigation of the controller(s) actions or control room issues was necessary due to: *(provide an explanation for why the operator did not investigate)*	
- If Yes, specify investigation result(s): *(select all that apply)*	
- Investigation reviewed work schedule rotations, continuous hours of service (while working for the Operator), and other factors associated with fatigue	Yes
- Investigation did NOT review work schedule rotations, continuous hours of service (while working for the Operator), and other factors associated with fatigue	
Provide an explanation for why not:	
- Investigation identified no control room issues	Yes
- Investigation identified no controller issues	Yes
- Investigation identified incorrect controller action or controller error	
- Investigation identified that fatigue may have affected the controller(s) involved or impacted the involved controller(s) response	
- Investigation identified incorrect procedures	
- Investigation identified incorrect control room equipment operation	
- Investigation identified maintenance activities that affected control room operations, procedures, and/or controller response	Yes
- Investigation identified areas other than those above:	Yes
Describe:	Investigation identified that a minor procedure was not followed. This failure was not a cause of or contributing factor to the Accident. Additional training on this procedure has been provided.

PART F - DRUG & ALCOHOL TESTING INFORMATION

1. As a result of this Accident, were any Operator employees tested under the post-accident drug and alcohol testing requirements of DOT's Drug & Alcohol Testing regulations?	Yes
- If Yes:	
1a. Specify how many were tested:	1
1b. Specify how many failed:	0
2. As a result of this Accident, were any Operator contractor employees tested under the post-accident drug and alcohol testing requirements of DOT's Drug & Alcohol Testing regulations?	No
- If Yes:	
2a. Specify how many were tested:	
2b. Specify how many failed:	

PART G – APPARENT CAUSE

Select only one box from PART G in shaded column on left representing the APPARENT Cause of the Accident, and answer the questions on the right. Describe secondary, contributing or root causes of the Accident in the narrative (PART H).

Apparent Cause:	G1 - Corrosion Failure

G1 - Corrosion Failure - only one **sub-cause** can be picked from shaded left-hand column

Corrosion Failure – Sub-Cause:	External Corrosion
- If External Corrosion:	
1. Results of visual examination:	Other
- If Other, Describe:	Corrosion under insulation.
2. Type of corrosion: *(select all that apply)*	
- Galvanic	
- Atmospheric	
- Stray Current	
- Microbiological	
- Selective Seam	
- Other:	Yes
- If Other, Describe:	Corrosion under insulation.
3. The type(s) of corrosion selected in Question 2 is based on the following: *(select all that apply)*	
- Field examination	
- Determined by metallurgical analysis	Yes
- Other:	
- If Other, Describe:	
4. Was the failed item buried under the ground?	Yes
- If Yes :	
4a. Was failed item considered to be under cathodic protection at the time of the Accident?	Yes
If Yes - Year protection started:	1990
4b. Was shielding, tenting, or disbonding of coating evident at the point of the Accident?	Yes
4c. Has one or more Cathodic Protection Survey been conducted at the point of the Accident?	Yes
If "Yes, CP Annual Survey" – Most recent year conducted:	2015
If "Yes, Close Interval Survey" – Most recent year conducted:	2015
If "Yes, Other CP Survey" – Most recent year conducted:	
- If No:	
4d. Was the failed item externally coated or painted?	
5. Was there observable damage to the coating or paint in the vicinity of the corrosion?	Yes
- If Internal Corrosion:	
6. Results of visual examination:	
- Other:	
7. Type of corrosion *(select all that apply)*: -	
- Corrosive Commodity	
- Water drop-out/Acid	
- Microbiological	
- Erosion	
- Other:	
- If Other, Describe:	
8. The cause(s) of corrosion selected in Question 7 is based on the following *(select all that apply)*: -	
- Field examination	
- Determined by metallurgical analysis	
- Other:	

- If Other, Describe:	
9. Location of corrosion *(select all that apply)*: -	
- Low point in pipe	
- Elbow	
- Other:	
- If Other, Describe:	
10. Was the commodity treated with corrosion inhibitors or biocides?	
11. Was the interior coated or lined with protective coating?	
12. Were cleaning/dewatering pigs (or other operations) routinely utilized?	
13. Were corrosion coupons routinely utilized?	
Complete the following if any Corrosion Failure sub-cause is selected AND the "Item Involved in Accident" (from PART C, Question 3) is Tank/Vessel.	
14. List the year of the most recent inspections:	
14a. API Std 653 Out-of-Service Inspection	
- No Out-of-Service Inspection completed	
14b. API Std 653 In-Service Inspection	
- No In-Service Inspection completed	
Complete the following if any Corrosion Failure sub-cause is selected AND the "Item Involved in Accident" (from PART C, Question 3) is Pipe or Weld.	
15. Has one or more internal inspection tool collected data at the point of the Accident?	Yes
15a. If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run: -	
- Magnetic Flux Leakage Tool	Yes
Most recent year:	2015
- Ultrasonic	
Most recent year:	
- Geometry	
Most recent year:	
- Caliper	Yes
Most recent year:	2015
- Crack	
Most recent year:	
- Hard Spot	
Most recent year:	
- Combination Tool	Yes
Most recent year:	2015
- Transverse Field/Triaxial	
Most recent year:	
- Other	
Most recent year:	
Describe:	
16. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Accident?	No
If Yes -	
Most recent year tested:	
Test pressure:	
17. Has one or more Direct Assessment been conducted on this segment?	No
- If Yes, and an investigative dig was conducted at the point of the Accident::	
Most recent year conducted:	
- If Yes, but the point of the Accident was not identified as a dig site:	
Most recent year conducted:	
18. Has one or more non-destructive examination been conducted at the point of the Accident since January 1, 2002?	No
18a. If Yes, for each examination conducted since January 1, 2002, select type of non-destructive examination and indicate most recent year the examination was conducted:	
- Radiography	
Most recent year conducted:	
- Guided Wave Ultrasonic	
Most recent year conducted:	
- Handheld Ultrasonic Tool	
Most recent year conducted:	
- Wet Magnetic Particle Test	
Most recent year conducted:	
- Dry Magnetic Particle Test	
Most recent year conducted:	
- Other	
Most recent year conducted:	
Describe:	

G2 - Natural Force Damage - only one **sub-cause** can be picked from shaded left-handed column	
Natural Force Damage – Sub-Cause:	
- If Earth Movement, NOT due to Heavy Rains/Floods:	
1. Specify:	
- If Other, Describe:	
- If Heavy Rains/Floods:	
2. Specify:	
- If Other, Describe:	
- If Lightning:	
3. Specify:	
- If Temperature:	
4. Specify:	
- If Other, Describe:	
- If Other Natural Force Damage:	
5. Describe:	
Complete the following if any Natural Force Damage sub-cause is selected.	
6. Were the natural forces causing the Accident generated in conjunction with an extreme weather event?	
6a. If Yes, specify: *(select all that apply)*	
- Hurricane	
- Tropical Storm	
- Tornado	
- Other	
- If Other, Describe:	
G3 - Excavation Damage - only one **sub-cause** can be picked from shaded left-hand column	
Excavation Damage – Sub-Cause:	
- If Previous Damage due to Excavation Activity: Complete Questions 1-5 ONLY IF the "Item Involved in Accident" (from PART C, Question 3) is Pipe or Weld.	
1. Has one or more internal inspection tool collected data at the point of the Accident?	
1a. If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run: -	
- Magnetic Flux Leakage	
Most recent year conducted:	
- Ultrasonic	
Most recent year conducted:	
- Geometry	
Most recent year conducted:	
- Caliper	
Most recent year conducted:	
- Crack	
Most recent year conducted:	
- Hard Spot	
Most recent year conducted:	
- Combination Tool	
Most recent year conducted:	
- Transverse Field/Triaxial	
Most recent year conducted:	
- Other	
Most recent year conducted:	
Describe:	
2. Do you have reason to believe that the internal inspection was completed BEFORE the damage was sustained?	
3. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Accident?	
- If Yes:	
Most recent year tested:	
Test pressure (psig):	
4. Has one or more Direct Assessment been conducted on the pipeline segment?	
- If Yes, and an investigative dig was conducted at the point of the Accident:	
Most recent year conducted:	
- If Yes, but the point of the Accident was not identified as a dig site:	
Most recent year conducted:	
5. Has one or more non-destructive examination been conducted at the point of the Accident since January 1, 2002?	

5a. If Yes, for each examination, conducted since January 1, 2002, select type of non-destructive examination and indicate most recent year the examination was conducted:	
- Radiography	
Most recent year conducted:	
- Guided Wave Ultrasonic	
Most recent year conducted:	
- Handheld Ultrasonic Tool	
Most recent year conducted:	
- Wet Magnetic Particle Test	
Most recent year conducted:	
- Dry Magnetic Particle Test	
Most recent year conducted:	
- Other	
Most recent year conducted:	
Describe:	
Complete the following if Excavation Damage by Third Party is selected as the sub-cause.	
6. Did the operator get prior notification of the excavation activity?	
6a. If Yes, Notification received from: *(select all that apply)* -	
- One-Call System	
- Excavator	
- Contractor	
- Landowner	
Complete the following mandatory CGA-DIRT Program questions if any Excavation Damage sub-cause is selected.	
7. Do you want PHMSA to upload the following information to CGA-DIRT (www.cga-dirt.com)?	
8. Right-of-Way where event occurred: *(select all that apply)* -	
- Public	
- If "Public", Specify:	
- Private	
- If "Private", Specify:	
- Pipeline Property/Easement	
- Power/Transmission Line	
- Railroad	
- Dedicated Public Utility Easement	
- Federal Land	
- Data not collected	
- Unknown/Other	
9. Type of excavator:	
10. Type of excavation equipment:	
11. Type of work performed:	
12. Was the One-Call Center notified?	
12a. If Yes, specify ticket number:	
12b. If this is a State where more than a single One-Call Center exists, list the name of the One-Call Center notified:	
13. Type of Locator:	
14. Were facility locate marks visible in the area of excavation?	
15. Were facilities marked correctly?	
16. Did the damage cause an interruption in service?	
16a. If Yes, specify duration of the interruption (hours)	
17. Description of the CGA-DIRT Root Cause *(select only the one predominant first level CGA-DIRT Root Cause and then, where available as a choice, the one predominant second level CGA-DIRT Root Cause as well):*	
Root Cause:	
- If One-Call Notification Practices Not Sufficient, specify:	
- If Locating Practices Not Sufficient, specify:	
- If Excavation Practices Not Sufficient, specify:	
- If Other/None of the Above, explain:	
G4 - Other Outside Force Damage - *only one **sub-cause** can be selected from the shaded left-hand column*	
Other Outside Force Damage – Sub-Cause:	
- If Damage by Car, Truck, or Other Motorized Vehicle/Equipment NOT Engaged in Excavation:	
1. Vehicle/Equipment operated by:	
- If Damage by Boats, Barges, Drilling Rigs, or Other Maritime Equipment or Vessels Set Adrift or Which Have Otherwise Lost Their Mooring:	
2. Select one or more of the following IF an extreme weather event was a factor:	
- Hurricane	
- Tropical Storm	
- Tornado	

- Heavy Rains/Flood	
- Other	
- If Other, Describe:	
- If Previous Mechanical Damage NOT Related to Excavation: Complete Questions 3-7 ONLY IF the "Item Involved in Accident" (from PART C, Question 3) is Pipe or Weld.	
3. Has one or more internal inspection tool collected data at the point of the Accident?	
3a. If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run:	
- Magnetic Flux Leakage	
Most recent year conducted:	
- Ultrasonic	
Most recent year conducted:	
- Geometry	
Most recent year conducted:	
- Caliper	
Most recent year conducted:	
- Crack	
Most recent year conducted:	
- Hard Spot	
Most recent year conducted:	
- Combination Tool	
Most recent year conducted:	
- Transverse Field/Triaxial	
Most recent year conducted:	
- Other	
Most recent year conducted:	
Describe:	
4. Do you have reason to believe that the internal inspection was completed BEFORE the damage was sustained?	
5. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Accident?	
- If Yes:	
Most recent year tested:	
Test pressure (psig):	
6. Has one or more Direct Assessment been conducted on the pipeline segment?	
- If Yes, and an investigative dig was conducted at the point of the Accident:	
Most recent year conducted:	
- If Yes, but the point of the Accident was not identified as a dig site:	
Most recent year conducted:	
7. Has one or more non-destructive examination been conducted at the point of the Accident since January 1, 2002?	
7a. If Yes, for each examination conducted since January 1, 2002, select type of non-destructive examination and indicate most recent year the examination was conducted:	
- Radiography	
Most recent year conducted:	
- Guided Wave Ultrasonic	
Most recent year conducted:	
- Handheld Ultrasonic Tool	
Most recent year conducted:	
- Wet Magnetic Particle Test	
Most recent year conducted:	
- Dry Magnetic Particle Test	
Most recent year conducted:	
- Other	
Most recent year conducted:	
Describe:	
- If Intentional Damage:	
8. Specify:	
- If Other, Describe:	
- If Other Outside Force Damage:	
9. Describe:	
G5 - Material Failure of Pipe or Weld - only one **sub-cause** can be selected from the shaded left-hand column	
Use this section to report material failures ONLY IF the "Item Involved in Accident" (from PART C, Question 3) is "Pipe" or "Weld."	
Material Failure of Pipe or Weld – Sub-Cause:	
1. The sub-cause shown above is based on the following: *(select all that apply)*	

- Field Examination	
- Determined by Metallurgical Analysis	
- Other Analysis	
- If "Other Analysis", Describe:	
- Sub-cause is Tentative or Suspected; Still Under Investigation (Supplemental Report required)	
- If Construction, Installation, or Fabrication-related Or If Original Manufacturing-related:	
2. List contributing factors: *(select all that apply)*	
- Fatigue or Vibration-related	
Specify:	
- If Other, Describe:	
- Mechanical Stress:	
- Other	
- If Other, Describe:	
- If Environmental Cracking-related:	
3. Specify:	
- If Other - Describe:	
Complete the following if any Material Failure of Pipe or Weld sub-cause is selected.	
4. Additional factors: (*select all that apply*):	
- Dent	
- Gouge	
- Pipe Bend	
- Arc Burn	
- Crack	
- Lack of Fusion	
- Lamination	
- Buckle	
- Wrinkle	
- Misalignment	
- Burnt Steel	
- Other:	
- If Other, Describe:	
5. Has one or more internal inspection tool collected data at the point of the Accident?	
5a. If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run:	
- Magnetic Flux Leakage	
Most recent year run:	
- Ultrasonic	
Most recent year run:	
- Geometry	
Most recent year run:	
- Caliper	
Most recent year run:	
- Crack	
Most recent year run:	
- Hard Spot	
Most recent year run:	
- Combination Tool	
Most recent year run:	
- Transverse Field/Triaxial	
Most recent year run:	
- Other	
Most recent year run:	
Describe:	
6. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Accident?	
- If Yes:	
Most recent year tested:	
Test pressure (psig):	
7. Has one or more Direct Assessment been conducted on the pipeline segment?	
- If Yes, and an investigative dig was conducted at the point of the Accident -	
Most recent year conducted:	
- If Yes, but the point of the Accident was not identified as a dig site -	
Most recent year conducted:	
8. Has one or more non-destructive examination(s) been conducted at the point of the Accident since January 1, 2002?	
8a. If Yes, for each examination conducted since January 1, 2002, select type of non-destructive examination and indicate most recent year the examination was conducted: -	

- Radiography	
Most recent year conducted:	
- Guided Wave Ultrasonic	
Most recent year conducted:	
- Handheld Ultrasonic Tool	
Most recent year conducted:	
- Wet Magnetic Particle Test	
Most recent year conducted:	
- Dry Magnetic Particle Test	
Most recent year conducted:	
- Other	
Most recent year conducted:	
Describe:	
G6 – Equipment Failure - only one **sub-cause** can be selected from the shaded left-hand column	
Equipment Failure – Sub-Cause:	
- If Malfunction of Control/Relief Equipment:	
1. Specify: *(select all that apply)* -	
- Control Valve	
- Instrumentation	
- SCADA	
- Communications	
- Block Valve	
- Check Valve	
- Relief Valve	
- Power Failure	
- Stopple/Control Fitting	
- ESD System Failure	
- Other	
- If Other – Describe:	
- If Pump or Pump-related Equipment:	
2. Specify:	
- If Other – Describe:	
- If Threaded Connection/Coupling Failure:	
3. Specify:	
- If Other – Describe:	
- If Non-threaded Connection Failure:	
4. Specify:	
- If Other – Describe:	
- If Other Equipment Failure:	
5. Describe:	
Complete the following if any Equipment Failure sub-cause is selected.	
6. Additional factors that contributed to the equipment failure: *(select all that apply)*	
- Excessive vibration	
- Overpressurization	
- No support or loss of support	
- Manufacturing defect	
- Loss of electricity	
- Improper installation	
- Mismatched items (different manufacturer for tubing and tubing fittings)	
- Dissimilar metals	
- Breakdown of soft goods due to compatibility issues with transported commodity	
- Valve vault or valve can contributed to the release	
- Alarm/status failure	
- Misalignment	
- Thermal stress	
- Other	
- If Other, Describe:	
G7 - Incorrect Operation - only one **sub-cause** can be selected from the shaded left-hand column	
Incorrect Operation – Sub-Cause:	

- If Tank, Vessel, or Sump/Separator Allowed or Caused to Overfill or Overflow	
1. Specify:	
- If Other, Describe:	
- If Other Incorrect Operation	
2. Describe:	
Complete the following if any Incorrect Operation sub-cause is selected.	
3. Was this Accident related to *(select all that apply)*: -	
- Inadequate procedure	
- No procedure established	
- Failure to follow procedure	
- Other:	
- If Other, Describe:	
4. What category type was the activity that caused the Accident?	
5. Was the task(s) that led to the Accident identified as a covered task in your Operator Qualification Program?	
5a. If Yes, were the individuals performing the task(s) qualified for the task(s)?	

G8 - Other Accident Cause - only one **sub-cause** can be selected from the shaded left-hand column	
Other Accident Cause – Sub-Cause:	
- If Miscellaneous:	
1. Describe:	
- If Unknown:	
2. Specify:	

PART H - NARRATIVE DESCRIPTION OF THE ACCIDENT

Crude oil was released from a 24-inch pipeline, located along Highway 101 in Santa Barbara County, California. The released crude reached a culvert which leads to the Pacific Ocean and, as a result, impacted the shoreline and ocean water. The cause of the release is currently under investigation. The pipe has been excavated. The affected portion of pipe was securely packaged to preserve its condition and has been transported to a secure, independent facility for an independent third-party analysis and investigation. A supplemental report will be submitted upon receipt of the third party, metallurgical analysis. In the meantime, Plains personnel are actively engaged in cleanup and environmental remediation efforts.

Part A. Question 7. - 14:56 is the time Operator notified the National Response Center (NRC). The NRC was first notified at 12:43 by an unrelated third party.
Part A. Question 9. - Answer is a best-estimate as of 6/17/2015.
Part A. Question 11.- Response reflects current estimate as of 6/17/2015. The volume of recovered commodity will be revised upward in the supplemental report as more information becomes available.
Part A. Question 17. -The number of people evacuated from local State Park campsites is currently undetermined as no estimates are included in the initial first responder reports we have received. We are investigating this further and will revise the Supplemental report as more information becomes available.

Part D. Question 8. - Answer reflects estimated costs incurred through 6/16/2015.

Supplemental Narratives:

Part A, Number 11 and Part D, Number 8 have also been updated to reflect new information as of 7/10/2015.

As of 8/4/15 the current estimated release volume remains approx. 2,400 bbls. Preliminary data from the purge activity estimates the release could be potentially 3,400 bbls. While Plains believes the volume estimate listed in Part A, Question 9 best represents the potential discharge volume, we are working with an outside expert to reconcile the differences and will provide additional updates as appropriate.

As of 11/24/2015, based on the work performed by our independent third party consultant (i.e. the 'outside expert' mentioned above), our best estimate of the spill volume is 2,934 barrels.

The results of the metallurgical analysis of the pipeline segment indicate that the failure occurred at an area of wall thinning from external corrosion that ultimately failed by ductile overload under the imposed operating pressure. The morphology of the external corrosion observed on the pipe section is consistent with corrosion under insulation facilitated by wet-dry cycling.
Line 901 remains shut down and subject to Corrective Action Order CPF No. 5-2015-5011H and Amendments. Updated costs for the repair and restart of this line, remains the only outstanding item in order to finalize this 7000-1 form.

PART I - PREPARER AND AUTHORIZED SIGNATURE

Preparer's Name	Chrystah Carter
Preparer's Title	Compliance Specialist
Preparer's Telephone Number	713-993-5080
Preparer's E-mail Address	crcarter@paalp.com
Preparer's Facsimile Number	713-646-4310
Authorized Signer Name	Troy E Valenzuela

Authorized Signer Title	VP of Environmental Health and Safety
Authorized Signer Telephone Number	713-646-4614
Authorized Signer Email	tevalenzuela@paalp.com
Date	12/23/2015

Appendix M

Det Norske Veritas (U.S.A.), Inc. (DNV GL): Line 901 Release (5/19/15) Mechanical and Metallurgical Testing

DNV·GL

Final Report

Line 901 Release (5/19/15): Mechanical and Metallurgical Testing

Plains All American Pipeline, L.P.
Houston, Texas

Report No.: OAPUS309DNOR (PP136049)
September 18, 2015

Project Name:	Line 901 Release (05-19-15): Mechanical and Metallurgical Testing	
Customer:	Plains All American Pipeline, P.L.	
Contact Person:		
Date of Issue:	September 18, 2015	
Project No.:	PP136049	
Organization Unit:	Incident Investigation	
Report No.:	OAPUS309DNOR	

DET NORSKE VERITAS (U.S.A.), INC. (DNV GL)
Materials & Corrosion Technology Center
Incident Investigation
5777 Frantz Road
Dublin, OH 43017-1886
United States
Tel: (614) 761-1214
Fax: (614) 761-1633
www.dnvgl.com

Task and Objective:

Please see Executive Summary.

Prepared by	Verified by	Approved by
David M. Norfleet, Ph.D., P.E. Principal Engineer	John A. Beavers, Ph.D., FNACE Director – Incident Investigation	Neil G. Thompson, Ph.D., FNACE Senior VP, Pipeline Services

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Executive Summary

Plains All American Pipeline, L.P. (Plains) retained Det Norske Veritas (U.S.A.), Inc. (DNV GL) to perform a metallurgical analysis and mechanical testing on a section of pipe from Line 901 - Las Flores to Gaviota (L901), 24-inch nominal diameter crude oil pipeline that failed while in service. The failure occurred on May 19, 2015 in Goleta (Santa Barbara County), California at milepost (MP) 4, 33.5 feet downstream (D/S) of the nearest upstream (U/S) girth weld and 4.05 miles D/S of the nearest U/S pump station. A failure of a pipe segment can be characterized either as a leak or a rupture; the failure on L901 is characterized as a leak.[1]

The section of the pipeline that failed is comprised of 24-inch diameter by 0.344-inch wall thickness, API 5L Grade X65 line pipe steel that contains a high frequency electric resistance welded (ERW) longitudinal seam and was manufactured by Nippon Steel in 1986. The maximum operating pressure (MOP) is 1,341[2] pounds per square inch gauge (psig) (72% of the specified minimum yield strength [SMYS]). The pressure at the time of failure was reported by Plains to be 737 psig (39.6% of SMYS) at the failure location and time of failure.

The pipeline was installed in 1990 and constructed using pipe that was externally coated with a coal tar urethane coating on the steel substrate, 1.5-inch thick rigid polyurethane foam, and an external polyethylene tape. The pipeline has an impressed current cathodic protection (CP) system with the nearest rectifier located 4.05 miles U/S of the failure location, at the Las Flores Pump Station. A hydrostatic test was performed at the time of commissioning for 8 hours at 1719 psi (Gaviota Station) on November 25th, 1990. In-line inspection (ILI) runs, consisting of deformation and magnetic flux leakage (MFL) tools, were performed in 2007, 2012, and 2015.

The failed pipe joint and 5 feet of the U/S and D/S joints were removed from the failure location and delivered to DNV GL in two pipe sections for analysis. Pipe Section 1 (PS 1) was 19.05 feet in length and contained 5.05 feet of the U/S joint, the U/S girth weld, and

1 According to the *FRACTURE CONTROL TECHNOLOGY FOR NATURAL GAS PIPELINES CIRCA 2001* (the PRCI report superseding NG-18 Report 208), "The distinction between leak and rupture for the pipeline community is based on the size and configuration of the breach, not how it develops. A "leak" is characterized by a narrow slit-like hole with length less than the diameter, which limits the fluid volume that escapes through the breach. In contrast, a "rupture" involves a longer, open hole that can be bulged over its length, which is on the order of a diameter or longer and can permit escape of a significant fluid volume." Similarly, the research performed as part of the historical NG-18 work identified empirical equations to predict the length at which a feature will propagate versus pop through and arrest; the leak/rupture length. Based on these calculations and visual observations, the length of the feature is consistent with a leak, arresting within the corrosion feature, and did not propagate outside of the feature into nominal wall-thickness pipe.

2 Theoretical maximum operating pressure at the lowest elevation using the lowest pressure of either 80% of the commissioning hydro-test pressure, the 72% of SMYS, or the lowest component rating along the line segment.

15 feet of the failure joint located U/S of the failure. Pipe Section 2 (PS 2) was 31.06 feet in length and contained the failure location, the D/S girth weld, a 2013 composite repair sleeve, and 5 feet of the D/S joint. The objective of the analysis was to determine the metallurgical (or immediate) cause of the failure.

***<u>Metallurgical Cause:</u>* The results of the metallurgical analysis indicate that the failure occurred at an area of wall thinning from external corrosion that ultimately failed by ductile overload under the imposed operating pressure. The morphology of the external corrosion observed on the pipe section is consistent with corrosion under insulation facilitated by wet-dry cycling.**

The following steps were performed for this analysis. The pipe sections were visually inspected and photographed. The external polyethylene (PE) tape was removed from PS 1 and PS 2 and visually inspected and photographed. The external pipe surfaces (with insulation) were laser scanned using a FaroArm™ to produce digital maps. The insulation from PS 2 was then removed and the pipe was visually inspected and photographed. The coal tar coating was then removed around the failure location, areas of corrosion, and at the ends of each pipe section.

Wall thicknesses, diameters, and circumferences were measured at various locations on PS 1 and PS 2 where coating was removed and there was no measurable corrosion. Corrosion products were collected from PS 2 for characterization. Analyses performed on these products included: (1) pH testing using litmus paper, (2) spot tests for carbonates and sulfides using 2-normal hydrochloric acid (2N HCl), (3) elemental analyses using energy dispersive spectroscopy (EDS) with a scanning electron microscope (SEM) and (4) compound identification using x-ray diffraction (XRD).

Swab samples were also obtained for bacteria analyses at two locations; an area of external corrosion and an area where the coating was disbonded but there was negligible external corrosion. Separate swab samples were taken for serial dilution and microscopic analysis. Liquid culture media for acid-producing bacteria (APB), sulfate-reducing bacteria (SRB), nitrate-reducing bacteria (NRB), aerobic bacteria (AERO), anaerobic bacteria (ANA), and iron-related bacteria (IRB) was used for the serial dilutions to evaluate growth of various types of bacteria. A five vial serial dilution (1:10,000) was performed using each type of media.

Coupons containing the failure location and areas of corrosion were cut from PS 2 using cold-cutting techniques. Coupon 1 contained the failure location and was a full ring section removed between 30.66 and 35.95 feet from the U/S GW. Coupon 2 contained external corrosion features further U/S from the failure location and was removed between 14.00 and 20.60 feet from the U/S GW; between the 4- and 8-o'clock orientations. The internal and external surfaces were visually inspected and photographed. Where necessary, the samples were cleaned using a degreaser (LPS Presolve®) and acetone. Ultrasonic testing (UT) was performed on the samples removed from PS 2, using a 1-inch by 1-inch grid spacing, to produce a thickness map. The external and internal pipe surfaces of these coupons were laser scanned to produce a thickness contour dataset. Magnetic particle inspection (MPI) was performed on the external and internal pipe surfaces of the coupon containing the failure location.

The fracture surfaces were cleaned with methanol and acetone, optically examined, and photographed. Samples were then removed from one of the mating fracture surfaces, cleaned with Rhodine inhibited HCl solution and ENPREP® 214 to remove corrosion products, and examined at high magnifications in an SEM to document the fracture morphology. Transverse cross sections were removed from the suspected failure origin, an area of corrosion further U/S, and across the longitudinal seam weld of the failure joint. The transverse cross sections were mounted, polished, and etched. Light photomicrographs were taken to document the fracture and corrosion morphologies and steel microstructure. In addition, corrosion products collected from an area adjacent to the failure location and from areas of corrosion further U/S of the failure were mounted in cross-section and polished. Light photomicrographs were taken to document the corrosion product morphologies. Elemental analysis using EDS was performed to identify the elemental constituents of each.

Soil analyses were conducted on a sample removed (in the field) approximately 8 feet U/S of the U/S girth weld (GW). The soil was tested for resistivity, moisture content, pH, total acidity, total alkalinity, concentration of soluble anions and cations, total dissolved solids, and linear polarization resistance.

Mechanical (duplicate tensile tests and full Charpy V-notch [CVN]) curves) testing was performed on specimens removed from the failed pipe joint and U/S and D/S joints to determine the tensile and fracture toughness properties. Chemical analyses were performed on a steel sample removed from the failed pipe joint and U/S and D/S joints to determine the compositions.

CorLAS™ calculations were performed to estimate the failure pressure based on the pipe geometry, base metal mechanical properties, and the measured flaw profile. This value was compared with the estimated pressure at the failure location.

External corrosion was identified at several locations along the bottom of the failed pipe section, including the corrosion feature that ultimately failed on May 19, 2015. The corrosion features were associated with thick layered deposits and areas of compression and water saturation of the thermal insulation. The characteristics of the failure are consistent with corrosion under insulation in the presence of wet-dry cycling.

Summary of Observations

- The failure was associated with an external corrosion feature located 33.50 feet from the upstream girth weld, at the 4:24 orientation (center of corrosion feature).
- The dimensions of the corrosion feature were 12.1 inches axially by 7.4 inches circumferentially. The maximum depth, as measured using laser scan data, was 0.318 inches or 89% of the measured wall thickness (0.359 inches).
- The failure opening was 6.6 inches in axial length, with the upstream and downstream ends located 33.35 and 33.9 feet from the upstream girth weld.
- The maximum circumferential dimension of the failure opening was 1.14 inches, approximately 33.45 feet from the upstream girth weld, at the 4:15 orientation.
- The fracture surfaces exhibited ductile overload.
- Cracking and wrinkling were observed within the polyethylene tape.
- Compression was observed within the polyurethane insulation at areas on the bottom of the pipe. These areas were saturated with moisture.
- Disbondment of the coal tar coating was observed on the bottom of the pipe along the length of Pipe Section 2.
- External corrosion features, including the feature associated with the failure, were identified at or adjacent to areas of saturated, compressed insulation.
- The corrosion products were rigid, non-friable, and, at some locations, well adhered to the pipe section. The products consist of alternating layers of goethite and magnetite.
- There is no strong evidence to indicate that microbiological influenced corrosion (MIC) contributed to the observed corrosion.
- No evidence of internal corrosion was observed along the length of the pipe sections inspected.
- The average yield strength (YS) for the failure joint is marginally lower than the minimum YS requirements for API 5L X65 line pipe steel of 65.0 ksi. The average is based on two tests values; one slightly higher (65.2 ksi) and one slightly lower (64.4 ksi) than the requirement. The average ultimate tensile strength (UTS) of the failure joint meets the minimum UTS requirements for API 5L X65 line pipe steel of 80 ksi.
- The Charpy V-notch (CVN) properties of the base metal are typical for the vintage and grade of line pipe steel.

- The chemical composition of the base metal meets requirements for the vintage and grade of line pipe steel.
- The microstructure of the base metal is typical for the vintage and grade of line pipe steel.
- The CorLAS™ predicted failure pressure for the failed joint was calculated to be approximately 760 psig, which is in very good agreement with reported pressure at the failure location and time of failure (737 psig).

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Appendix A – CorLAS™

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1.0 BACKGROUND

Plains All American Pipeline, L.P. (*Plains*) retained Det Norske Veritas (U.S.A.), Inc. (*DNV GL*) to perform a metallurgical analysis and mechanical testing on a section of pipe from Line 901 - Las Flores to Gaviota (L901), 24-inch nominal diameter crude oil pipeline that failed while in service. The failure occurred on May 19, 2015 in Goleta (Santa Barbara County), California at milepost (MP) 4, 33.5 feet downstream (D/S) of the nearest upstream (U/S) girth weld and 4.05 miles D/S of the nearest U/S pump station. A failure of a pipe segment can be characterized either as a leak or a rupture; the failure on L901 is characterized as a leak.[1]

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The failed pipe joint and 5 feet of the U/S and D/S joints were removed from the failure location and delivered to DNV GL in two pipe sections for analysis. Figure 1 is a photograph showing the failed pipe section at the failure site, while Figure 2 and Figure 3 are

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photographs showing the pipe sections after removal from the ditch. Pipe Section 1 (PS 1) was 19.05 feet in length and contained 5.05 feet of the U/S joint, the U/S girth weld, and 15 feet of the failure joint located U/S of the failure. Pipe Section 2 (PS 2) was 31.06 feet in length and contained the failure location, the D/S girth weld, a 2013 composite repair sleeve, and 5 feet of the D/S joint. The objective of the analysis was to determine the metallurgical (or immediate) cause of the failure.

2.0 TECHNICAL APPROACH

The procedures used in the analysis were in accordance with industry-accepted standards. Five of the general standards governing terminology, specific metallographic procedures, mechanical testing, and chemical analysis used are as follows:

- ASTM E7, "Standard Terminology Relating to Metallography."
- ASTM E3, "Standard Methods of Preparation of Metallographic Specimens."
- ASTM E8, "Test Methods for Tension Testing of Metallic Materials."
- ASTM E23, "Standard Test Methods for Notched Bar Impact Testing of Metallic Materials."
- ASTM A751, "Standard Test Methods, Practices, and Terminology for Chemical Analysis of Steel Products."

The following steps were performed for this analysis. The protective shipping wrap was removed and the pipe sections were visually inspected and photographed. The external polyethylene (PE) tape was removed from PS 1(PS 1-ID 10000152251[3]) and PS 2 (PS 2-ID 10000152251) and visually inspected and photographed. The external pipe surfaces (with insulation) were laser scanned using a FaroArm™ to produce digital maps. Laser scanning is a non-destructive technique that uses light, in the form of a laser, to make very accurate three-dimensional (3D) data sets, which capture the x, y, and z coordinates from millions of measurements along the scanned surface. The datasets can then be used to generate 3D renderings of the scanned object(s) that can be rotated, manipulated, and measured.

The insulation from PS 2 was then removed and the pipe was visually inspected and photographed. The coal tar coating was then removed around the failure location, areas of corrosion, and at the ends of each pipe section using brass mallets, putty knives, and methyl ethyl ketone (MEK) and/or acetone.

3 Unique DNV GL barcode assigned to each piece of evidence.

Wall thicknesses, diameters, and circumferences were measured at various locations on PS 1 and PS 2 where coating was removed and there was no measurable corrosion. Corrosion products were collected from PS 2 for characterization. Analyses performed on these products included: (1) pH testing using litmus paper, (2) spot tests for carbonates and sulfides using 2-normal hydrochloric acid (2N HCl), (3) elemental analyses using energy dispersive spectroscopy (EDS) with a scanning electron microscope (SEM) and (4) compound identification using x-ray diffraction (XRD). The pH measurements were obtained by placing a few drops of deionized (DI) water on the pH test paper and then the wetted paper was placed in contact with the surface. The pH test paper was examined for color changes and compared to pH color charts.

Swab samples were also obtained for bacteria analyses, over a standard area of 1 cm^2, at the two locations; at an area of corrosion and area where the coating was disbonded but there was negligible external corrosion. Separate swab samples were taken for serial dilution and microscopic analysis. Liquid culture media for acid-producing bacteria (APB), sulfate-reducing bacteria (SRB), nitrate-reducing bacteria (NRB), aerobic bacteria (AERO), anaerobic bacteria (ANA), and iron-related bacteria (IRB) was used for the serial dilutions to evaluate growth of various types of bacteria. A five vial serial dilution (1:10,000) was performed using each type of media. The swab obtained for the microscopic analysis was fixed in 1% glutaraldehyde. A five microliter spot was removed from the fixed sample and prepared for examination by drying on a microscope slide and staining with 0.1% fluorescein isothiocyanate (FITC). The sample was examined using a CFI PLAN FLUOR 100X oil immersion objective on a Nikon Eclipse 50i epifluorescent microscope equipped with a FITC filter set to determine bacteria cell counts and morphology.

Coupons containing the failure location and areas of corrosion were cut from PS 2 using cold-cutting techniques. Coupon 1 contained the failure location and was full ring section removed between 30.66 and 35.95 feet from the U/S GW. Coupon 2 contained external corrosion features further U/S from the failure location and was removed between 14.00 and 20.60 feet from the U/S GW; between the 4- and 8-o'clock orientations. The internal and external surfaces were visually inspected and photographed. Where necessary, the samples were cleaned using a degreaser (LPS Presolve®) and acetone. Ultrasonic testing (UT) was performed on the samples removed from PS 2, using a 1-inch by 1-inch grid spacing, to produce a thickness map. The external and internal pipe surfaces of these coupons were laser scanned to produce a thickness contour dataset. Magnetic particle inspection (MPI) was performed on the external and internal pipe surfaces of the coupon containing the failure location.

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CorLAS™ calculations were performed to estimate the failure pressure based on the pipe geometry, base metal mechanical properties, and the measured flaw profile. This value was compared with the estimated pressure at the failure location.

3.0 RESULTS AND DISCUSSION

3.1 Visual Examination

The pipe sections were transported to DNV GL's facility near Columbus, Ohio in a sealed cargo container on a flatbed semi-truck. The cargo container was locked and secured with three keyed padlocks, a serialized cargo lock, and evidence tape prior to transport. The corresponding keys for the locks were distributed amongst the interested parties, such that no one person had access to all of the keys. The container was then driven non-stop to a DNV GL storage facility. Upon receipt, the locks and evidence tape were inspected. Figure 5 is a photograph showing the container being loaded into a DNV GL storage facility; the four locks are identified in the figure with yellow circles.

Figure 6 contains photographs showing the two pipe sections in the as-received condition. The pipe sections were wrapped in opaque plastic wrap and boxed. Evidence tape was applied in the field on top of the plastic wrap approximately 1 foot U/S and D/S of the failure on PS 2. Figure 7 contains photographs showing the failure location before and after removal of the evidence tape and protective plastic wrap at DNV GL's facility. The fracture surfaces were protected with foam insulation that was place around the clockwise (CW) fracture surface; shown in Figure 7b. Figure 8 contains photographs showing the failure location while on site (Figure 8a - May 28, 2015) and at DNV GL's facility (Figure 8b – June 15, 2015). Some red corrosion products were observed near the failure location, as shown in Figure 8b. The failure opening was 6.6 inches in length and located at the 4:15 orientation, consisting of an irregular fracture path that opened in the clockwise (CW) direction looking D/S. The U/S and D/S ends of the fracture path were located at 33.35 and 33.9 feet, respectively, from the U/S GW. The maximum opening measured 1.14 inches, approximately 33.45 feet from the U/S GW. The failure is associated with a corrosion feature that measured approximately 12.1 inches axially in length by 7.4 inches circumferentially in width. Additional data are presented in Section 3.1.4.

PS 1 was 19.05 feet in length and contained 5.05 feet of the U/S joint, the U/S girth weld (GW) and 14 feet of the failure joint U/S of the failure. Pipe Section 2 was 31.06 feet in length and contained 26.06 feet of the failure joint, including the failure location, the D/S GW, a 2013 composite repair sleeve, and 5 feet of the D/S joint. PS 2 was 31.06 feet in length and contained the failure location, the D/S GW, a composite repair sleeve, and 5 feet of the D/S joint. Reference markings were identified on each pipe section noting the top-dead-center (TDC) and the location of each girth weld. A stamp was identified on the internal surface of the failure joint towards the D/S end, adjacent to GW 5940. Figure 9 is a photograph showing the stamp; "NIPPON", "24", and other indiscernible characters were observed.

3.1.1 External Polyethylene Tape

An external polyethylene tape (external surface of the rigid polyurethane insulation) was present on PS 1 and PS 2, Figure 2 and Figure 10 respectively. The tape is installed in a white condition; however, exposure to the soil and released product discolored the tape to varying shades of brown. Areas of decohesion from the insulation substrate were observed in varying degrees along the length of the two pipe sections. The most pronounced areas were located near the failure location, as shown in the photographs presented at the bottom of Figure 10. Cracks were also observed in the PE tape, primarily at the 12- and 6-o'clock orientations; some of the cracks are identified in Figure 10. Wrinkles in the tape were observed along the entire length of both pipe sections on the bottom half of the pipe (2:00 to 10:00 orientation).

The PE tape was removed from each pipe section, aligned as it was on the pipe, and visually inspected and photographed. Figure 11 is a photograph of the internal surface of the tape looking D/S. The original white coloration of the PE tape is apparent in the figure along with bands of product at the 4:00 and 7:00 orientations, which appear to correlate with the wrinkle bands in the tape along the pipe section. In general, the areas exhibiting wrinkles were disbonded or partially disbonded from the insulation and were much easier to remove from the pipe section. Figure 12 and Figure 13 are photographs showing the internal and external surfaces of the PE tape at the failure location, respectively. Similar to other areas along the pipeline, cracking and wrinkles in the PE tape were observed near the failure location. The cracks in the tape were located at the 6:00 orientation, while the wrinkles were located at the 4:00 and 7:00 orientations.

3.1.2 Rigid Polyurethane Insulation

The polyurethane (PU) insulation was visually inspected after the PE tape was removed. Figure 14 contains photographs from two location along PS 2; the U/S end and the failure location. The insulation exhibited impressions corresponding to the wrinkles observed in the PE tape and, at one location a small crack in the insulation was identified within a wrinkle impression, refer to Figure 15. The white contrast paint evident in the figure was applied to the insulation to facilitate laser scanning and visual inspection. Compression of the insulation was also observed at locations along the 6:00 orientation; two locations are identified Figure 14. Additional detail is provided in Section 3.2.

The insulation adjacent to the failure location was removed at the 6:00 orientation, refer to Figure 16. Wedged between the insulation and the pipe surface was a piece of corrosion product, which was collected and bagged. Figure 17 is a photograph showing the corrosion product. The corrosion product is dark, saturated with oil, and rigid. The insulation was partially saturated with a clear liquid. Figure 18 contains photographs showing the insulation in cross-section. The liquid line is evident in the lower-left photograph. At this location, the insulation is saturated near the external surface, while the middle photograph shows saturation that is through the full thickness of the insulation. In addition, signification compression of the insulation was observed at this location (center photo). The compressed thickness measured 0.276 inches as compared to the nominal thickness of 1.5 inches, which corresponds to over 80% compression. In general, the compressed insulation was located on the bottom of the pipe and areas of saturation were within the compressed areas. A pH measurement was also made at a saturated location along the insulation using pH paper; location identified in Figure 17. The pH was between 6 and 7.

3.1.3 Coal Tar Urethane Coating

The thickness of the coal tar coating was measured using micrometers on a piece that disbonded near the failure location; area shown in Figure 16. The average of four measurements was 0.043 inches, which corresponds closely with measurements performed further U/S (~20 feet U/S from failure location) that averaged 0.040 inches. Figure 19 is a photograph showing the removal of the PU insulation and coal tar coating. Along the underside of the pipe, the insulation and coal tar coating came off together, such that the coal tar coating had disbonded from the pipe surface. At this location, released product can be seen along the mating surfaces of the pipe and coating.

Disbondment of the coal tar coating was also observed further U/S on PS 2 at areas where released product did not reach, refer to Figure 20. Disbondment was associated with large corrosion cells, evident in the figure, and in areas where no deep corrosion was observed, but exhibited a layer of fine corrosion products on the pipe surface. Approximately 28 feet from the U/S GW on PS 2 an area of blistered coal tar coating was observed; refer to Figure 21. The insulation against this area was moist, but there was no significant corrosion associated with this location. A syringe was used to extract fluid contained within one of the blisters from which a pH measurement was made using pH paper. The pH was between 6 and 7, consistent with the pH measurement performed on a piece of saturated insulation adjacent to the failure location described above.

3.1.4 Carbon Steel Line Pipe

Following removal of the PE tape, PU insulation, and areas of coal tar coating that had disbonded from PS 2, the pipe section was visually inspected. Areas of corrosion were observed on the external surface surrounding the failure location and approximately 14 to 20 feet U/S of the failure location on the bottom of the pipe. The larger features are identified in Figure 22 through Figure 25; a summary of the feature dimensions and locations is presented in Table 1. The corrosion features were located on the bottom of the pipe section in or adjacent to areas that exhibited disbondment of the coal tar coating and compression in the adjacent PU insulation. The corrosion products were dry, rigid, and magnetic. At some locations, a putty knife was required to separate the corrosion products from the pipe body. For the most part, the products associated with each corroded area came off in one piece that was non-friable in nature. The products were dark brown to black or charcoal in appearance and could be handled while remaining intact. The products also appeared to be layered. A Dremel® rotary tool was ultimately used to cut through some of the products for the metallography presented in Section 3.6. The corrosion products from each of the features identified in Table 1 were collected for subsequent analyses.

A 5.3-foot ring coupon (Coupon 1) containing the failure location and Features 3 through 6 was cut from PS 2. The cuts were made at 30.66 and 35.95 feet from the U/S GW. Similarly, a 6.6-foot coupon (Coupon 2) was cut from U/S end of PS 2 capturing Feature 1 and Feature 2. The longitudinal cuts were made at approximately the 4:00 and 8:00 o'clock orientations.

Circumferences/diameters and wall thicknesses were measured on the U/S end of PS 1 (U/S Joint), D/S end of PS 2 (D/S Joint), and on the U/S and D/S ends of the ring section containing the failure location. The measurements were made in areas with no coating or measurable corrosion. The diameters were measured using a Pi tape and are shown in Table 2. The diameter meets API 5L tolerances for 24-inch nominal diameter pipe. The diameters were measured with a tape measure from the 3 to 9 o'clock and 12 to 6 o'clock orientations. The diameters varied from 24.0 to 24.1 inches, indicating no significant ovality, as shown in Table 2 . The wall thickness was measured at the 12, 3, 6, and 9 o'clock orientations at the same locations described above; see Table 3 for details. The wall thickness values ranged from 0.356 to 0.362 inches. These wall thickness values meet API 5L tolerances for a nominal wall thickness of 0.344 inches.[4]

The 5.3-foot long ring coupon was cut longitudinally at the 3:00 and 9:00 o'clock orientations to facilitate examination of the internal surface. Figure 26 contains photographs showing the external and internal surfaces of the bottom-half of the ring coupon. There was no observable corrosion on the internal surface. A small, superficial, mill anomaly was identified approximately 6 inches D/S from the failure opening.

3.1.5 Composite "Armor Plate" Sleeve

The composite repair sleeve installed on May 13, 2013, was comprised of composite Armor Fiber® and cured resin, overlaid with a green two-part epoxy. There were no indications of water ingress or disbondment of the two-part epoxy. The repair was removed by cutting, chiseling, and ultimately sand blasting. Figure 27 contains photographs showing the pipe before and after removal of the repair sleeve. Throughout the removal process, the pipe section was visually inspected for indications of discoloration and corrosion to determine if additional corrosion had occurred following installation of the sleeve in 2013. Figure 28 is a photograph showing the primary feature that was repaired in 2013 after the composite sleeve was removed. There was no evidence of discoloration or additional corrosion associated with the feature; additional discussion and depth measurements are presented in Section 3.2.

4 API 5LX, 35th Edition, May 1986.

The two-part epoxy and resin were well-adhered, precluding electrolyte from reaching the pipe surface and thus, eliminating additional corrosion of the feature. Similarly, there is no evidence that the repair influenced corrosion of the feature that ultimately failed, i.e. galvanic couple. Without an ionic pathway through the electrolyte there is no means by which to setup such a cell.

3.2 3D Laser Scanning

The external surfaces of PS 1 and PS 2 were laser scanned, using a FaroArm™, following removal of the external polyethylene tape. Similarly, the failure opening and corrosion features along the external surfaces of the pipe section (and the corresponding internal surfaces) were also laser scanned once the polyurethane insulation was removed. The datasets were aligned using reference magnets placed along the pipe sections prior to scanning. With the exception of Feature 1, the features were cleaned with a soft-bristled brush, brass-bristles brush, and methanol and/or acetone. The corrosion products within Feature 1 were left intact for metallographic examination (Section 3.6). As a result of scanning the internal and external surfaces of the pipe at and around the corrosion features, a remaining wall thickness profile was generated to show the extent of corrosion for each feature.

Figure 29 contains renderings of the aligned dataset, highlighting the areas of corrosion on the U/S end of PS 2 (Feature 1 and Feature 2). The pipe was rotated such that the viewing direction is normal to the 6:00 orientation. From this perspective, areas of corrosion are clearly visible along the 6:00 orientation. The transparency of the polyurethane dataset on PS 2 was set to 30% providing an opportunity to identify any correlation between features on the insulation and areas of corrosion. It is clear from these data that the corrosion features are located at or adjacent to areas of compressed insulation.

Similarly, Figure 30 contains renderings highlighting the areas of corrosion at or near the failure location (Features 3-6). Consistent with the observations above, the corrosion features are located at or adjacent to areas of compressed insulation. Figure 31 is a rendering showing Feature 4; the failure location. The maximum depth of each feature was determined, based on a measured nominal wall thickness of 0.359 inches, from the laser scan data and are presented in Table 1. Various thickness measurements were made slightly offset (~0.100 inches circumferentially) from the fracture path to provide data that would not contain necking, providing a better representation of the wall thickness just prior to the failure. A rendering showing the measurement locations is provided in Figure 32, while the data is given in Table 4. Based on this, the maximum depth of Feature 4 was 0.318 inches or 89% of the measured wall thickness. The failure opening measured 6.55

inches in length with a maximum opening of 1.10 inches, which are consistent with the measurements made during the visual examination.

The corrosion areas associated with the 2013 repair were also laser scanned. Figure 33 is a rendering showing the thickness profile of the deepest feature. The maximum corrosion depth was 0.220 inches, which corresponds closely to the maximum depth (0.228 inches) and location within the feature identified in 2013 prior to sleeving the pipe section. It's possible that the discrepancy is due to remnant resin still present within the feature prior to laser scanning.

3.3 Ultrasonic Testing

Ultrasonic testing was performed on the coupons identified in Figure 29 and Figure 30. Thickness measurements were made at 1-inch intervals along a 1 × 1-inch grid that was applied to the internal surfaces of each coupon. Figure 34 is a photograph of the grid applied to the coupon containing the failure location. The corresponding measurements are provided in Figure 35; however, the data or the photograph in Figure 34 would need to be mirrored to match one another, as the data is provided as observed from the external surface. Similar measurements were made on the coupon containing Feature 1 and Feature 2. These data are presented in Figure 35 and Figure 36, respectively. The data are provide with a color overlay; dark red being the thinnest remaining wall thickness. Similar measurements were made on the coupon containing Feature 1 and Feature 2. The results from Feature 2 are provided in Figure 37. The UT data agreed very well with the laser scan data, and given the increased lateral resolution of the laser scan data, subsequent discussions and depth data presented in this report are based on the laser scan datasets.

3.4 Magnetic Particle Inspection

Magnetic particle inspection was performed on the internal and external surfaces surrounding the failure location. There were no features or anomalies identified.

3.5 Fractographic Examination

3.5.1 Optical

Figure 38 contains photographs of the clockwise (CW) and counterclockwise (CCW) fracture surfaces, Figure 38a and Figure 38b, respectively following cleaning with a degreaser and methanol and/or acetone. The fracture surfaces are brown in color and slanted with respect to the radial direction.

Figure 39 contains stereo light photomicrographs of representative locations along the CW fracture surface following cleaning with a degreaser and methanol and/or acetone [(a), (b), (c)] and one location following cleaning with Rhodine inhibited HCl acid and ENPREP® 214 [(d), (e)]. As shown in Figure 39a and Figure 39c, the fracture surface is tapered or slanted through the thickness. This is a typical characteristic of ductile overload. Similarly, the fracture surface along its length is wavy and has characteristics of ductile tearing and overload. Figure 39d and Figure 39e are micrographs of the regions shown in Figure 39b following cleaning with Rhodine inhibited hydrochloric (HCl) acid and ENPREP® 214. At this location, two unique morphologies are present; Region 1, which has a dull/matte finish and is associated with the areas along the slanted fracture surface, and Region 2, which is more reflective and at a shallower angle with respect to the outer or inner surfaces. These areas are identified in Figure 39e. Region 2 extended the deepest at this location, approximately 33.76 feet from the U/S GW, along the fracture surface.

3.5.2 Scanning Electron Microscopy

Figure 40 is an SEM image of the area identified in Figure 39e along the CW fracture surface (Sample 195367-1; 33.76' from the U/S GW). The white dashed line indicates the interface between Region 1 and Region 2. Figure 41 is a higher magnification SEM image showing the transition between Region 1 and Region 2. Region 2 is relatively smooth with spherical-shaped impressions, while Region 1 appears rough with smaller topographical features. Figure 42 contains a high magnification SEM image in Region 1, near the ID. The fracture surface at this location exhibits dimples, which are characteristic of ductile overload. Figure 43 contains a high magnification SEM image in Region 2, near the ID surface. The fracture surface is nondescript having a corroded appearance and is inconsistent with a typical fracture morphology, indicating that this region was present prior to the failure. This observation coupled with the oblique angle of the surface and visual appearance indicates that Region 2 is associated with external corrosion.

Figure 44 is an SEM image from a representative location along the fracture surface exhibiting a shear or slanted fracture surface (Sample 195367-2, 33.55' from the U/S GW). At higher magnification (Figure 45), a rough-dimpled appearance, consistent with ductile overload, was observed. The dimples are elongated in the vertical direction as shown in the figure, which is consistent with the orientation of the sheared fracture plane.

3.5.3 Fracture/Corrosion Profile

Using the observations of the optical and SEM fractographic examinations, a fracture profile was generated showing the boundary of Region 1. Measurements were made along the fracture surface at 5 mm intervals, refer to Figure 46. The resulting data are plotted in Figure 47 as measured (remaining) wall thickness versus distance to U/S GW. Given that plasticity/ductility was observed along the fracture surface, the measured thickness of Region 1 is not necessarily representative of the remaining wall thickness prior to failure. This is due to necking of the material, a process governed by the Poisson effect, whereby tensile strain on one direction (i.e. circumferential) results in compressive strain in the other two perpendicular directions (i.e. radial and longitudinal) for isotropic materials; such as steel. Therefore, the thickness of Region 1 was larger than the measured values prior to failure. For this reason, two additional profiles are presented in the figure using the laser scan data; one based on a ½-inch by ½-inch grid, which will be discussed in Section 3.12 and one based on the measurements made adjacent to the fracture surface (Figure 32), approximately 0.100 inches circumferentially, presumably at locations not heavily influenced by necking.

3.6 Metallographic Examination

Figure 48 is a photograph of the transverse metallographic cross-section (Mount 195367-1b) removed from across the fracture surface at approximately 33.76 feet D/S of the U/S GW; same location identified in Figure 41. The corrosion profile near the failure opening is relatively uniform; however, transitions sharply with a steep side wall approximately 15 mm CCW from the opening. Figure 49 is a photomicrograph showing the two mating fracture surface in the etched condition. Figure 50 is a photomicrograph showing the mating CW fracture surface. With the exception of a small ligament at the internal surface, there were no obvious indications of plasticity corresponding to Region 1. This suggests that the preexisting corrosion feature was almost through-wall at this location just prior to failure. In comparison, the mating CCW fracture surface, presented in Figure 51, exhibited grain elongation and deformation, consistent with plasticity and the results obtained from the SEM examination showing dimpled failure in Region 1. The discrepancy between microstructural characteristics of the CW and CCW surfaces at this location is due to a small misalignment between the two mating fracture surfaces when the transverse cuts were made to produce the metallographic cross-section.

Figure 52 and Figure 53 are representative photomicrographs showing the corrosion morphology along the external surfaces of Mount 195367-1b. The corrosion is scalloped in most cases (Figure 52), and the remaining corrosion products exhibit a layered texture with alternating light and dark bands. However, at the base of some of these scallops, some undercutting was also observed, as shown in Figure 53. Figure 54 is a photomicrograph showing the typical microstructure of the base metal. The microstructure consists of ferrite (white areas) and fine pearlite (gray areas). This microstructure is consistent with the vintage and grade of the steel.

Figure 55 is a photograph of the transverse metallographic cross-section (Mount 195331-1) removed from the corrosion products associated with Feature 4; collected adjacent to the failure location. At this location, the thickness of the product is approximately 0.55 inches. Droplets of oil can be seen on the surface of the mount, as the photograph was taken following the SEM examination in which the mount was pumped down to low pressures to facilitate observation in the SEM. Figure 56 contains photomicrographs through the thickness of the corrosion product. The morphology of the corrosion products are similar throughout, consisting of alternating light and dark layers.

Figure 57 is a photograph of the transverse metallographic cross-section (Mount 195370-1) removed through Feature 1, at approximately 16.65 feet D/S of the U/S GW; feature identified in Figure 22. The corrosion depth is much less severe at this location and the profile is relatively uniform. At higher magnification (Figure 58), the corrosion products exhibit a similar layered morphology as those observed near the failure location; Figure 52. Figure 59 is a photograph showing the transverse metallographic cross-section (Mount 195322-1) removed from the corrosion products associated with Feature 1. At this location, the thickness of the product is approximately 0.40 inches. Consistent with the other corrosion products, the morphology contains alternating dark and light layers; refer to Figure 60.

Figure 61 is a photograph showing the transverse metallographic cross-section remove from the longitudinal seam weld of the failure joint. At higher magnification, an hourglass shape (associated with a heat affected zone) can be observed, characteristic of a high-frequency electric resistance weld (ERW).

3.7 Solid Sampling of Corrosion Products

3.7.1 pH Testing and Qualitative Spot Testing

The pH of the external corrosion products collected from Feature 5 was determined using deionized (DI) water and pH test paper. The pH of the deposits was 5 to 6 and the pH of the DI water used in the analysis was also 5 to 6.

Qualitative spot testing, using 2N HCl, was performed on three external corrosion products collected from Feature 1, Feature 2, and Feature 5. Portions of the samples were placed in vials with lead acetate tape and a few drops of the HCl were placed on the products. Vigorous bubbling is a positive indication for the presence of carbonates. A rotten egg odor and/or discoloration of lead acetate tape are positive indications for the presence of sulfides. All samples tested negative for both carbonates and sulfides.

3.7.2 X-ray Diffraction

X-ray diffraction was performed on corrosion products collected from Feature 1 and Feature 2. The resulting spectrum for each is presented in Figure 62 and Figure 63, respectively. The compounds identified for each were goethite (FeOOH) and magnetite (Fe_3O_4). Goethite is one of the most thermodynamically stable iron oxides under aerobic (high oxygen) conditions. Conversely, magnetite is metastable phase formed under low oxygen conditions.

3.7.3 Energy Dispersive Spectroscopy

Energy dispersive spectroscopy was performed on the corrosion products captured in the metallographic cross-sections. Figure 64 contains the results of EDS scans performed on the corrosion products in Mount 195370-1, associated with Feature 1. EDS scans were performed within the layered regions identified in the metallographic examination. The results are summarized in Table 5. The two primary constituents are iron (Fe) and oxygen (O), which are characteristic of iron oxides. Small quantities of chlorine (Cl) were identified, likely associated with chlorides, while most of the other constituents are elements common to line pipe steels. A relatively high concentration of copper (Cu) was identified in Scan 1 (8 wt.%), which is atypical of line pipe steel and may be associated with deposits from groundwater. The other three scans identified typical concentrations of Cu. The light area, Scan 3, has an O content of 29.24 wt.%, while the darker bands, Scan 2 and Scan 4, have an average oxygen content of 36.88 wt.%. Given that the XRD analyses identified goethite and magnetite as the two compounds associated with the corrosion products, these values were compared to the calculated oxygen content for goethite (36 wt.%) and magnetite (28 wt.%). These values correlate very closely, indicating that the light areas are likely magnetite and the darker areas are likely goethite.

Figure 65 contains the results of EDS scans performed on the corrosion products on Mount 195331-1, associated with Feature 4. Similar results were obtained for the layers identified in the cross-section. The results are summarized in Table 5, which again shows that the compositions of the light layers correspond to magnetite and the compositions of the darker layers correspond to goethite. The variation in oxygen content is apparent in the line scan presented in Figure 66, which illustrated the decreased oxygen content of the lighter layer.

3.8 Microbiological Analyses

The external surface of the pipe section was swabbed (at DNV GL) over a standard area of approximately 1 cm^2 for bacterial analysis. The swabs were taken from the bottom of Feature 1, 16.65 feet D/S from the U/S GW and from an area beneath disbonded coal tar coating with no significant corrosion; approximately 5 inches CCW from Feature 1. Separate swab samples were taken from each location for the serial dilution and microscopic examination analyses. The results of the microbiological analyses are discussed below.

3.8.1 Serial Dilution – Liquid Culture Media

Table 6 shows the results of the bacteria serial dilution testing for the swab samples collected from the pipe section. The results reveal a positive indication for five types of bacteria (APB, AERO, ANA, IRB, and NRB) at the corrosion feature, while there were no positive indications for bacteria at the area away with no significant corrosion. As seen in the table, the highest concentration of bacteria detected was 100 bacteria per cm^2, which is a relatively low value.

3.8.2 Microscopic Examination for Total Bacteria

The swabs collected from Feature 4 and from the area away were fixed in 1% glutaraldehyde and examined using epifluorescent microscopy. The practical minimum detection limit for this method is approximately 10^3 cells/ml of fixed sample. The results of the analysis are provided in Table 7. As seen in the table, rod-shaped cells were detected for the swab samples removed at Feature 1 and an area of no apparent corrosion. The calculated concentration of cells for the swab samples were 1.70×10^4 cells/mL and 2.8×10^4 cells/mL. This type of microscopic examination does not differentiate between living and non-living organisms.

3.9 Soil Testing

DNV GL collected six (6) soil samples from the dig site at the failure location. Two samples were collected from under the pipe at each of the three locations: 8 feet U/S of GW 5930 (IDs 10000151761 & 10000151762), 2 feet D/S of failure location (IDs 10000151753 & 1000151759), and 12.5 feet D/S of GW 5940 (IDs 10000151754 & 10000151755). The only samples not contaminated with product were the samples collected 8 feet U/S of GW 5930. Figure 67 is a photograph showing the soil samples collected 8 feet US of GW 5930. The samples were placed in a cooler with ice packs and shipped to DNV GL's laboratory for testing. One of the uncontaminated samples (Sample 10000151761) was sieved in order to conduct the testing.

Testing was conducted to determine the physical and chemical properties of the sample, including: (1) resistivity, (2) moisture content, (3) pH, (4) soluble anions [Cl-, SO_4^{2-}, S_2^-, NO_2^-, NO_3^-, CO_3^{2-}, HCO_3^-], (5) soluble cations [K+, Ca^{2+}, Mg^{2+}, Na^+], (6) total alkalinity, (7) total acidity, (8) linear polarization resistance, and (9) total dissolved solids (TDS). The results of the analyses are provided in Table 8 through Table 10.

The sample exhibited relatively low levels of nitrate (NO_3^-), chloride (Cl^-) and carbonate (HCO_3^-) and high levels of sulfate (SO_4^{2-}) anions; 115, 117, 204, and 3600 mg/L, respectively. The soil resistivity decreased from 3,800 ohm-cm in the as-received condition to 400 ohm-cm when saturated. Based on these data, the soil is considered corrosive.[5] Corrosion rates were determined for the soil sample in the as-received and saturated condition using linear polarization resistance (LPR). The resulting corrosion rates were 2.5 and 2.7 mils per year (mpy), respectively.

3.10 Mechanical Testing

The results of tensile testing of duplicate, transverse base metal specimens removed from the pipe joint that failed and the U/S and D/S joints are shown in Table 11. The average yield strength (YS) and ultimate tensile strength (UTS) of Joint 5930 were 64.8 ksi and 84.0 ksi, respectively. The average YS of the base-metal samples is marginally lower than the minimum YS requirements for API 5L X65 line pipe steel of 65.0 ksi. The average is based on two tests values of 65.2 and 64.4 ksi. The average UTS of the base-metal samples meets the minimum UTS requirements for API 5L X65 line pipe steel of 80 ksi. The tensile properties of the U/S and D/S joints meet the requirements for API 5L X65 line pipe steel, as shown in Table 11.

Table 12 - Table 14 summarize the results of the Charpy testing for the transverse base metal samples while Figure 68 through Figure 73 show the corresponding Charpy percent shear and impact energy curves. An analysis of the data for the base metal specimens from the failure joint, Joint 5930, indicates that the 85% fracture appearance transition temperature (FATT) is -58.5°F and the upper shelf Charpy energy is 164.8-ft·lbs, full size. These are very good values and typical for modern line pipe steels. The CVN test results can be adjusted to determine the 85% FATT that would be expected for full-scale pipe by applying temperature shifts to the data. This method (full-scale) adjusts the 85% FATT obtained from the Charpy tests to a predicted FATT from the Battelle Drop-Weight Tear Test (BDWTT). The predicted 85% FATT from the BDWTT test most closely represents the

5 *Peabody's Control of Pipeline Corrosion*, 2nd Edition, Table 5.5 and Table 5.7.

expected FATT for full-scale pipe wall material.[6] The full-scale brittle to ductile transition temperature for the failure joint, based on a pipe wall thickness of 0.359 inches, is shown in Table 15. The pipe joint is expected to exhibit ductile fracture behavior above -78.4°F.[7] The values for the U/S and D/S joints are also provided in Table 15. The toughness properties of these joints also are very good but not quite as good as the failure joint.

3.11 Chemical Analysis

The results of the chemical analyses performed on samples removed from the failure joint and the U/S and D/S pipe joints are shown in Table 16. The results show that the pipe joints meet the composition specifications for API 5L X65 line pipe steel at the time of manufacture.

3.12 Failure Pressure Analysis

CorLAS™ (Version 3.02) was used to perform Remaining Strength (RSTRENG) calculations to estimate the failure pressure incorporating the effective-area methodology. The calculations were based on the measured mechanical properties and dimensions of the failure joint, and the measured flaw profile. Three flaw profiles were considered for the analysis:

- Case 1: Measurements made along the fracture surface combined with laser scan data on either end of the failure opening, within Feature 4; the black profile presented in Figure 47.
- Case 2: The laser scan data and measurements made adjacent to the fracture surfaces, presumably in areas where necking/plasticity was minimized; the blue profile presented in Figure 47.
- Case 3: The laser scan data and discretizing corrosion Feature 4 into ½-inch cells; columns running axial and rows running circumferential. The average depth for each cell was determined and the lowest values identified within each column were then used to generate the flaw profile; refer to Figure 74 and Figure 47 (green profile).[8]

The measured flaw profiles, presented in Figure 47, were fed into CorLAS™ whereby an algorithm converted each profile into an equivalent semi-elliptical flaw. These effective (or

6 W. A. Maxey, J. F. Kiefner, R. J. Eiber, *Brittle Fracture Arrest in Gas Pipelines,"* NG-18 Report No. 135, A.G.A. Catalog No. L51436, April 1983, Battelle Columbus Laboratories.

7 Rosenfeld, M.J., *"A Simple Procedure for Synthesizing Charpy Impact Energy Transition Curves from Limited Test Data,"* International Pipeline Conference, Volume 1, ASME, 1996, Equation 1.

8 The average thickness for each cell was used (instead of minimum values) due to meshing effects along the fracture surface that provided unrealistic minimum wall thickness values as a result of the slanted fracture surfaces.

equivalent) flaws were used to estimate the failure pressure. The results of the analysis are presented in Table 17. The calculated failure pressure for Case 1, Case 2, and Case 3 are 474 psig, 759 psig, and 763 psig, respectively.

The estimated pressure at the failure location at the time of the failure was reportedly 737 psig, which is in very good agreement with the estimated failure pressures for Case 2 and Case 3. As discussed previously, the estimated failure pressure for Case 1 is underestimated due to the presence of necking that resulted from the overload event. Additional results of the analysis, and a description of CorLAS™, are summarized in Appendix A.

4.0 DISCUSSION AND CONCLUSIONS

External corrosion was identified at several locations along the failed pipe section, including the corrosion feature that ultimately failed on May 19, 2015. The corrosion features are located in areas where the external polyethylene tape, thermal polyurethane insulation, and coal tar enamel were compromised, allowing the ingress of moisture to facilitate aqueous corrosion. Cracking in the polyethylene tape, as well as wrinkles, provided pathways for water to collect against the bottom of the pipe section. This in turn may have initiated and/or accelerated the breakdown of the thermal insulation that resulted in compression of the insulation and breakdown of the cellular structure, causing water absorption and retention. The presence of goethite and magnetite in a layered morphology is consistent with aqueous corrosion under wet-dry cycling.[9] When oxygen transport is high, such as during the drying stages when the electrolyte is relatively thin, goethite is the stable oxide. However, during saturated conditions or when oxygen is limited (i.e. thick products), magnetite is predominant. The alternating nature of the layers suggests that external variables, such as rain, drainage, and operating temperature contributed to the corrosion process.

The term corrosion under insulation (CUI) may be defined as external corrosion of carbon steel piping, pressure vessels, and structural components resulting from water trapped under insulation.[10] Although typically associated with above-ground piping, CUI is the appropriate corrosion mechanism for this particular failure given the contributing role of the thermal insulation to the corrosion process. Thus, the results of the analyses indicate that CUI was the primary corrosion mechanism, facilitated by wet-dry cycling. Although bacteria were identified at a corrosion feature sampled U/S of the failure location, the quantities were low and the layered morphology within the corrosion products is not necessarily

9 Nasrazadani, S. and Raman, A., *Formation and Transformation of Magnetite (Fe3O4) on steel surfaces under Continuous and Cyclic Water Fog Testing*, Corrosion, 1993.
10 API Recommended Practice 583, Corrosion Under Insulation and Fireproofing, May 2014.

consistent with MIC, particularly given that the corrosion products are extremely rigid. Therefore, there is no strong evidence to indicate that MIC contributed to the observed corrosion. A summary of our observations are provided below.

Summary of Observations

- The failure was associated with an external corrosion feature located 33.50 feet from the upstream girth weld, at the 4:24 orientation (center of corrosion feature).
- The dimensions of the corrosion feature were 12.1 inches axially by 7.4 inches circumferentially. The maximum depth, as measured using laser scan data, was 0.318 inches or 89% of the measured wall thickness (0.359 inches).
- The failure opening was 6.6 inches in axial length, with the upstream and downstream ends located 33.35 and 33.9 feet from the upstream girth weld.
- The maximum circumferential dimension of the failure opening was 1.14 inches, approximately 33.45 feet from the upstream girth weld, at the 4:15 orientation.
- The fracture surfaces exhibited ductile overload.
- Cracking and wrinkling were observed within the polyethylene tape.
- Compression was observed within the polyurethane insulation at areas on the bottom of the pipe. These areas were saturated with moisture.
- Disbondment of the coal tar coating was observed on the bottom of the pipe along the length of Pipe Section 2.
- External corrosion features, including the feature associated with the failure, were identified at or adjacent to areas of saturated, compressed insulation.
- The corrosion products were rigid, non-friable, and, at some locations, well adhered to the pipe section. The products consist of alternating layers of goethite and magnetite.
- No evidence of internal corrosion was observed along the length of the pipe sections inspected.
- The average yield strength (YS) for the failure joint is marginally lower than the minimum YS requirements for API 5L X65 line pipe steel of 65.0 ksi. The average is based on two tests values; one slightly higher (65.2 ksi) and one slightly lower (64.4 ksi) than the requirement. The average ultimate tensile strength (UTS) of the failure joint meets the minimum UTS requirements for API 5L X65 line pipe steel of 80 ksi.
- The Charpy V-notch (CVN) properties of the base metal are typical for the vintage and grade of line pipe steel.

- The chemical composition of the base metal meets requirements for the vintage and grade of line pipe steel.
- The microstructure of the base metal is typical for the vintage and grade of line pipe steel.
- The CorLAS™ predicted failure pressure for the failed joint was calculated to be approximately 760 psig, which is in very good agreement with reported pressure at the failure location and time of failure (737 psig).

Table 1. Summary of the locations and dimensions of corrosion features identified during the laboratory examination on the external surface of PS 2.

Corrosion Feature (2015 ILI "Log Dist.")	Distance from U/S GW to Center of Feature (feet)	Axial Length (inches)	Distance from TDC to Center of Feature, Clockwise (inches)	Circumferential Length (inches)	O'clock Orientation (TDC to Center of Feature)	Maximum Depth from Laser Scan Data[11] (inches)
Feature 1 [redacted]	16.55	8.3	43.00	7.7	6:50	0.112 (31%)
Feature 2 [redacted]	18.61	21.9	40.30	9.8	6:24	0.199 (55%)
Feature 3 [redacted]	31.52	7.7	35.60	17.2	5:40	0.208 (58%)
Feature 4 [redacted]	33.50	12.1	27.75	7.4	4:24	0.318 (89%)
Feature 5	33.83	1.8	44.80	2.2	7:00	0.025 (7%)
Feature 6 [redacted]	34.32	2.8	30.10	2.8	4:48	0.122 (34%)

11 Based on measured nominal wall thickness of 0.359 inches.

Table 2. Results of diameter measurements performed on PS 1 and PS 2 using Pi tape and a tape measure.

Location	Diameter Using Pi Tape (inches)	Diameter 3 to 9 o'clock (inches)	Diameter 6 to 12 o'clock (inches)
PS 1 - U/S end; Joint 5920	24.059	24.0	24.0
PS 2 - 30.7' from U/S GW; Joint 5930	24.059	24.0	24.0
PS 2 - 36' from U/S GW; Joint 5930	24.055	24.1	24.0
PS 2 - D/S end; Joint 5940	24.048	24.1	24.0

Table 3. Results of wall thickness measurements performed on PS 1 and PS 2.

O'clock Orientations	Wall Thickness, PS 1 U/S End Joint 5920 (inches)	Wall Thickness, PS 2 30.7' from U/S GW Joint 5930 (inches)	Wall Thickness, PS 2 36' from U/S GW Joint 5930 (inches)	Wall Thickness, PS 2 D/S End Joint 5940 (inches)
12:00	0.356	0.359	0.359	0.358
3:00	0.360	0.362	0.362	0.359
6:00	0.356	0.359	0.358	0.359
9:00	0.357	0.359	0.357	0.358
Average	0.357	0.360	0.359	0.359

Table 4. Results of thickness measurements performed adjacent (~0.100 inches circumferentially) to the failure opening using the laser scan dataset. See Figure 32.

Distance to U/S GW (feet)	Measured Wall Thickness (inches)
33.02	0.354
33.07	0.344
33.12	0.340
33.15	0.249
33.17	0.189
33.21	0.118
33.26	0.138
33.32	0.124
33.36	0.111
33.41	0.096
33.44	0.072
33.47	0.051
33.48	0.043
33.48	0.043
33.51	0.066
33.53	0.067
33.55	0.091
33.60	0.119
33.62	0.074
33.64	0.049
33.67	0.073
33.70	0.085
33.73	0.079
33.76	0.072
33.79	0.073
33.84	0.042
33.89	0.072
33.92	0.106
33.95	0.242
33.98	0.352

Table 5. Results of elemental analyses, using EDS, performed on corrosion products from Feature 1 and Feature 4 compared to ideal chemistry compositions of goethite and magnetite; values presented in mass percent (wt.%).

Element	Mount 195370-1 (Feature 1 Products)				Mount 195331-1 (Feature 4 Products)			Goethite (FeOOH)	Magnetite (Fe_3O_4)
	Scan 1 (Mixed Layers)	Scan 2 (Dark Layer)	Scan 3 (Light Layer)	Scan 4 (Light Layer)	Scan 1 (Light Layer)	Scan 2 (Light Layer)	Scan 3 (Dark Layer)		
Oxygen (O)	33.52	35.78	29.24	37.97	27.85	29.45	37.83	36.01	27.64
Silicon (Si)	0.19	0.40	0.41	0.26	0.21	0.20	0.22	–	–
Chlorine (Cl)	0.19	0.06	0.07	0.15	–	–	–	–	–
Sulfur (S)	–	–	–	–	–	–	0.18	–	–
Manganese (Mn)	0.79	0.80	0.68	0.73	0.59	0.93	0.98	–	–
Magnesium (Mg)	–	–	–	–	–	–	0.48	–	–
Iron (Fe)	56.87	62.46	69.60	60.71	71.35	69.41	60.30	62.85	72.36
Copper (Cu)	8.44	0.49	–	0.18	–	–	–	–	–

Table 6. Results of bacteria analyses performed on swabs taken, over an ~1 cm^2 area, from the external surface of Pipe Section 2 at Feature 1 on the failure joint and at an area of disbonded coating away from significant corrosion.

Bacteria Type	**Feature 1** (16.65 ft D/S from U/S GW)		**Area of No Significant Corrosion** (Outside of Feature 1; ~ 5 inches CCW)	
	Test Result	**Number of Positive Vials**	**Test Result**	**Number of Positive Vials**
Aerobic (AERO)	Positive	2	Not detected	–
Anaerobic (ANA)	Positive	2	Not detected	–
Acid-Producing (APB)	Positive	2	Not detected	–
Sulfate-Reducing (SRB)	Not detected	–	Not detected	–
Iron-Related (IRB)	Positive	2	Not detected	–
Nitrate-Reducing (NRB)	Positive	2	Not detected	–

Bacteria Concentration Key:

1 10 bacteria per cm^2
2 100 bacteria per cm^2,
3 1,000 bacteria per cm^2,
4 10,000 bacteria per cm^2,
5 100,000 bacteria per cm^2

Table 7. Results of optical microscopy examination for fixed internal swab samples taken, over a ~1 cm^2 area, from the external surface of the pipe section at Feature 1 and at an area away from significant corrosion.

Sample Identification	Aliquot Volume, uL	Total Cells Observed	Calculated № cells/mL	Morphology
Feature 1 (16.65 ft D/S from U/S GW)	5	12	1.70×10^4	Rod
Area of No Apparent Corrosion (Outside of Feature 1; ~ 5 inches CCW)	5	>20	2.80×10^4	Rod

Table 8. Summary of soluble cation and anion concentrations for soil sample 10000151761.

Sample ID	Soluble cations mg/L				Soluble anions mg/L						
	Na^+	K^+	Ca^{2+}	Mg^{2+}	NO_2^-	NO_3^-	Cl^-	SO_4^-	S_2^-	CO_3^{2-}	HCO_3^-
10000151761 (8' U/S of GW 5930; below pipe)	898	320.	495	9.64	< 2.1	115	117	3600	< 0.67	< 13.3	204

Table 9. Summary of various chemical properties for soil sample 10000151761.

Sample ID	pH soil	Total Acidity mg $CaCO_3$/kg	Total Alkalinity mg $CaCO_3$/kg	As-Received Moisture Content %	Total Dissolved Solids (mg/L)
10000151761 (8' U/S of GW 5930; below pipe)	7.95	< 66.5	204	(a) 27.59% (b) 21.62%	6350

a – Percent moisture per AASHTO T265 & ASTM D2216
b – Percent moisture per EPA Method 1684, Eq. 2.

Table 10. Summary of various electrochemical properties for soil sample 10000151761.

Sample ID	Resistivity Ohm-cm (as-received)	Resistivity Ohm-cm (saturated)	LPR mpy (as-received)	LPR mpy (saturated)
10000151761 (8' U/S of GW 5930; below pipe)	3,800	400	2.5	2.7

Table 11. Results of tensile tests performed on transverse base metal specimens from the failure and the U/S and D/S joints compared with requirements for API 5L Grade X65 line pipe steel.

	Failure Joint (10000151970)	U/S Joint (10000151968)	D/S Joint (10000151969)	API 5L Grade X52 (Minimum Values) [3]
Yield Strength, ksi [1]	64.8[2]	65.9	68.4	65
Tensile Strength, ksi [1]	84.0	84.6	87.7	80
Elongation in 2 inches, % [1]	35.0	33.6	32.8	21.25
Reduction of Area, % [1]	60.1	62.8	57.6	–

1 – Average of duplicate tests.

2 – Average of 65.2 ksi (extensometer on OD) and 64.4 ksi (extensometer on ID)

3 – API 5LX, 35th Edition, May 1986.

Table 12. Results of Charpy V-notch impact tests for transverse base metal specimens removed from the joint that failed (Joint 5930).

Sample ID	Temperature, °F	Sub-size Impact Energy, ft-lbs	Full Size Impact Energy, ft-lbs	Shear, %	Lateral Expansion, mils
15446-1-6	-238	2	2	0	0.006
15446-1-10	-189	4	5	1	0.006
15446-1-4	-148	24	28	8	0.017
15446-1-2	-103	33	38	29	0.022
15446-1-8	-65	103	120	83	0.076
15446-1-7	-29	124	144	91	0.084
15446-1-1	-4	119	138	99	0.081
15446-1-3	32	130	151	100	0.082
15446-1-5	68	158	184	100	0.083
15446-1-9	100	142	165	100	0.080

Table 13. Results of Charpy V-notch impact tests for transverse base metal specimens removed from the U/S joint (Joint 5920).

Sample ID	Temperature, °F	Sub-size Impact Energy, ft-lbs	Full Size Impact Energy, ft-lbs	Shear, %	Lateral Expansion, mils
15446-2-9	-312	1	1	0	0.001
15446-2-3	-238	2	2	0	0.001
15446-2-2	-193	4	5	3	0.001
15446-2-5	-148	5	6	15	0.002
15446-2-1	-103	18	22	20	0.012
15446-2-10	-51	48	58	41	0.045
15446-2-4	-4	101	122	92	0.075
15446-2-6	32	104	126	100	0.073
15446-2-7	75	111	135	100	0.078
15446-2-8	100	117	142	100	0.079

Table 14. Results of Charpy V-notch impact tests for transverse base metal specimens removed from the D/S joint (Joint 5940).

Sample ID	Temperature, °F	Sub-size Impact Energy, ft-lbs	Full Size Impact Energy, ft-lbs	Shear, %	Lateral Expansion, mils
15446-3-9	-312	1	1	0	0.000
15446-3-3	-238	2	2	1	0.002
15446-3-2	-193	3	4	3	0.002
15446-3-5	-148	5	6	15	0.003
15446-3-1	-103	12	15	15	0.007
15446-3-10	-51	40	48	36	0.040
15446-3-4	-4	83	101	83	0.068
15446-3-6	32	92	112	100	0.077
15446-3-7	75	96	116	100	0.079
15446-3-8	100	103	125	100	0.080

Table 15. Results of analyses of the Charpy V-notch impact energy and percent shear plots for base metal specimens removed from the three pipe joints.

	Failure Joint; Joint 5930 (10000151970)	**U/S Joint; Joint 5920 (10000151968)**	**D/S Joint; Joint 5940 (10000151969)**
Upper Shelf Impact Energy (Full Size), Ft-lbs	164.8	138.9	121.3
85% FATT, °F	-58.5	-1.6	4.8
85% FATT, °F (Full Scale Pipe) [1]	-78.4	-19.4	-12.7

1 – Full Scale Pipe FATT = 85% FATT + $((66*(t_w^{0.55}/t_c^{0.7})-100)$ where t_w = pipe wall thickness and t_c = width of the CVN specimen.

Table 16. Results of chemical analyses of samples removed from the joint that failed and the U/S and D/S joints compared with composition requirements (product analysis) for API 5L Grade X65 line pipe steel.[1]

Element		Failure Joint; 5930 (10000151970) (Wt. %)	U/S Joint; 5920 (10000151968) (Wt. %)	D/S Joint; 5940 (10000151969) (Wt. %)	API 5L Grade X65 Spec (Wt. %) [1]
C	(Carbon)	0.082	0.083	0.078	0.30 (max)
Mn	(Manganese)	1.110	1.160	1.120	1.50 (max)
P	(Phosphorus)	0.011	0.010	0.010	0.050 (max)
S	(Sulfur)	0.007	0.007	0.007	0.060 (max)
Si	(Silicon)	0.170	0.190	0.160	–
Cu	(Copper)	0.268	0.270	0.274	–
Sn	(Tin)	0.000	0.000	0.000	–
Ni	(Nickel)	0.008	0.008	0.006	–
Cr	(Chromium)	0.035	0.027	0.028	–
Mo	(Molybdenum)	0.000	0.000	0.000	–
Al	(Aluminum)	0.010	0.016	0.012	–
V	(Vanadium)	0.022	0.024	0.028	0.010 (min)
Nb	(Niobium)	0.063	0.065	0.062	0.005 (min)
Zr	(Zirconium)	0.000	0.000	0.000	–
Ti	(Titanium)	0.011	0.016	0.015	–
B	(Boron)	0.0006	0.0005	0.0005	–
W	(Tungsten)	0.000	0.000	0.000	–
Co	(Cobalt)	0.000	0.000	0.000	–
Fe	(Iron)	98.200	98.100	98.200	Balance

1 – API 5L, 35th Edition, May 1986.

Table 17. Results of failure pressure analyses using CorLAS™. The pressure at the failure site was estimated at 737 psig.

Case №	Equivalent Flaw Profile	Properties	Estimated Failure Pressure (psig)
1	As-measured along fracture surface (includes necking)	Measured	474
2	Laser scan data adjacent to fracture surface	Measured	759
3	Laser scan data ½ × ½ inch grid (average)	Measured	763

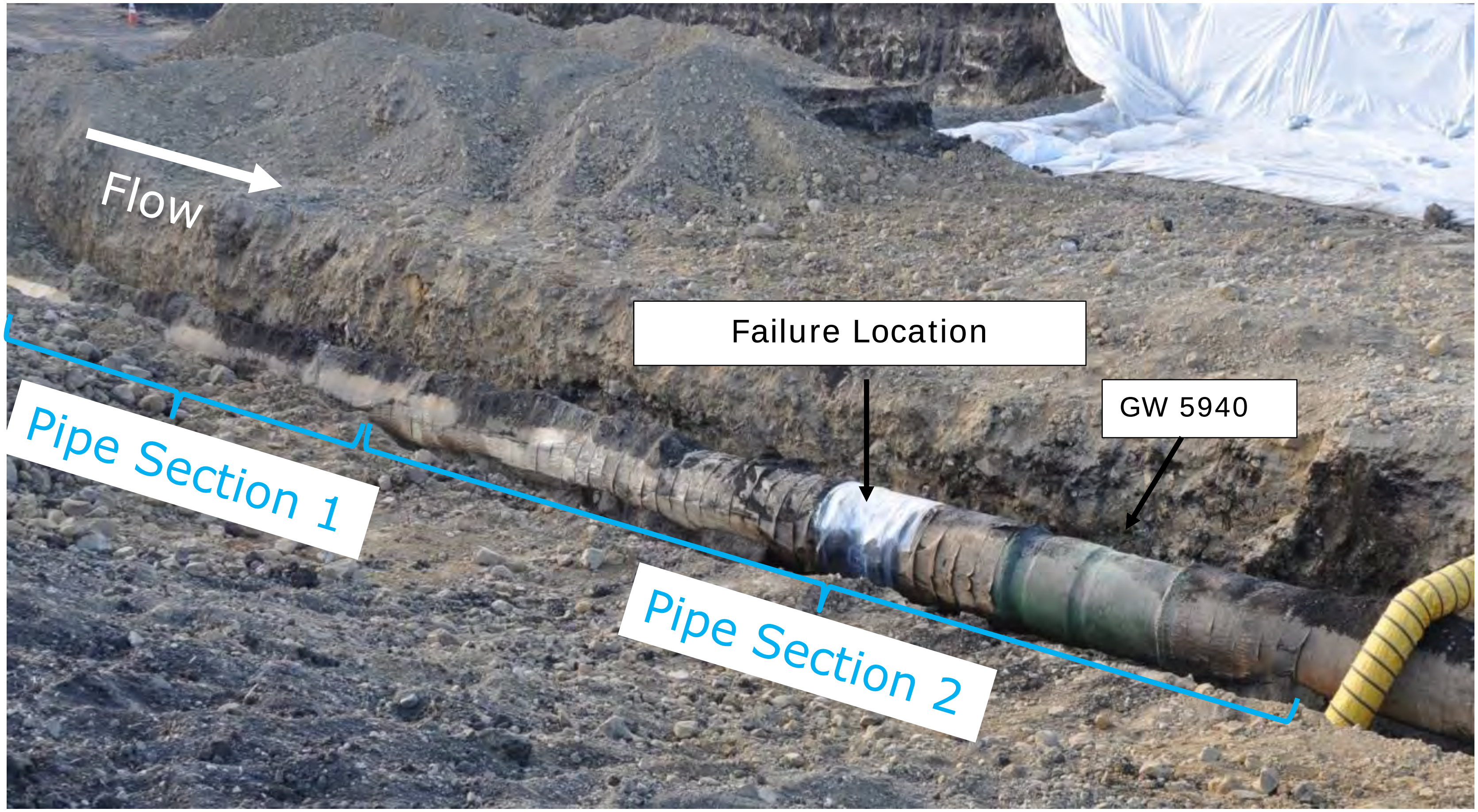


Figure 1. Photograph showing the failure location and the locations of the two pipe sections, during excavation.

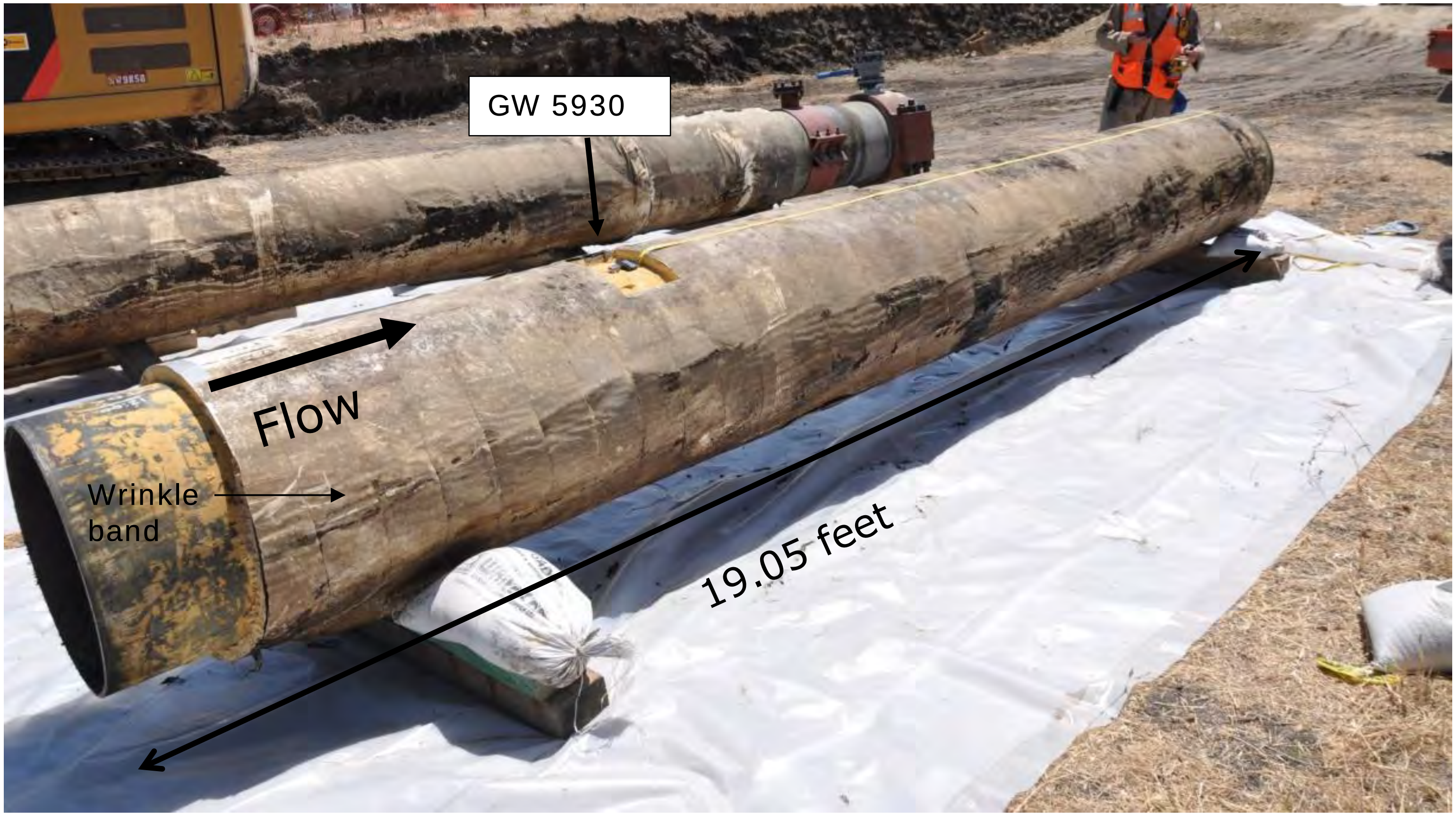


Figure 2. Photograph showing Pipe Section 1 following removal from the ditch.

Figure 3. Photograph showing Pipe Section 2 being removed from the ditch.

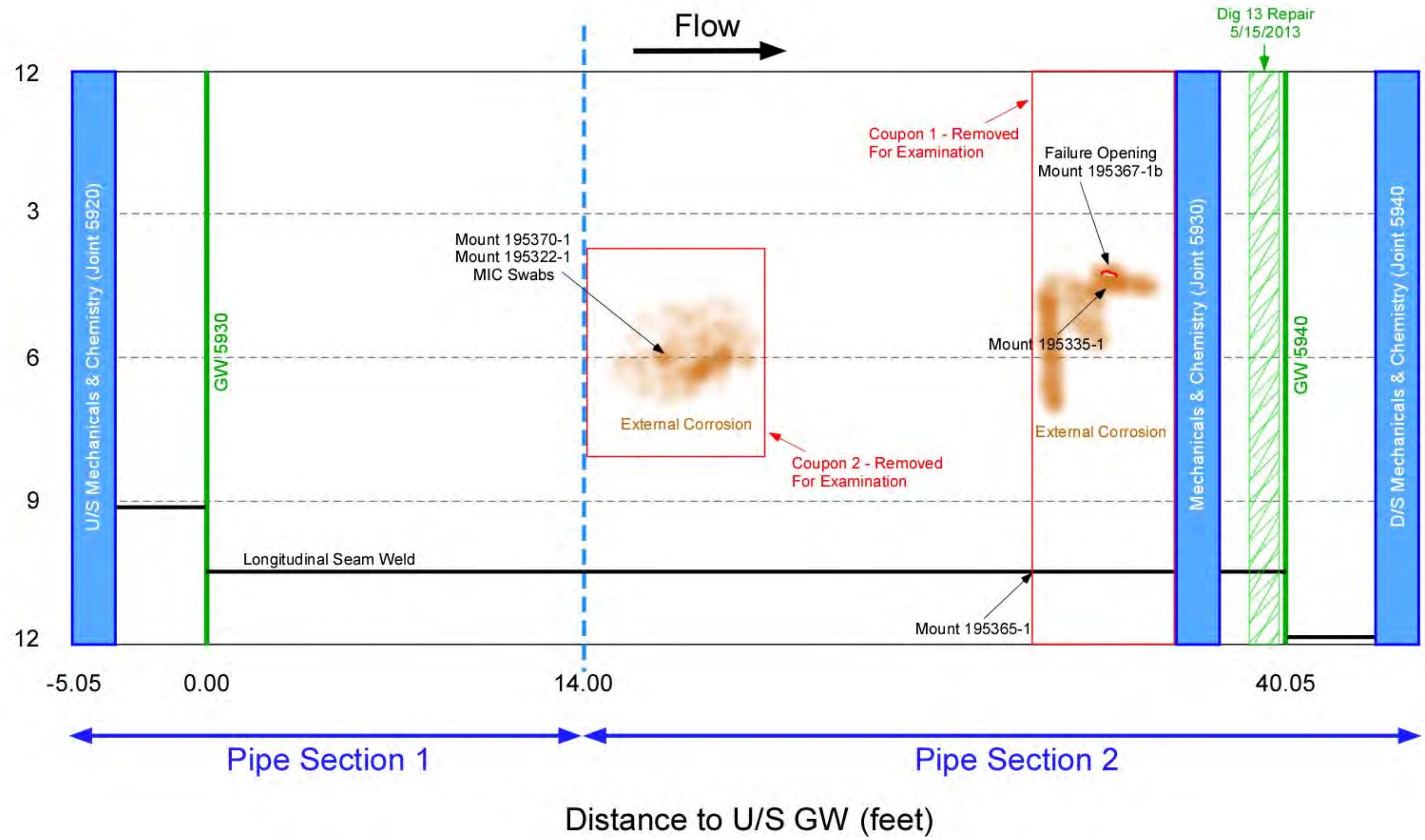


Figure 4. Schematic showing the location of the failure and where samples were removed for various analyses.

Figure 5. Photograph showing the cargo container in the as-received condition.

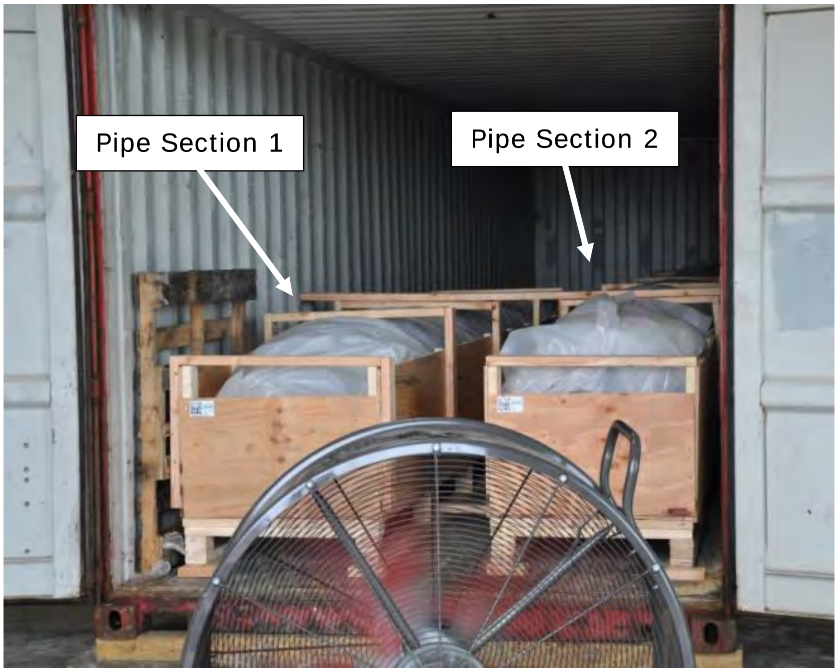
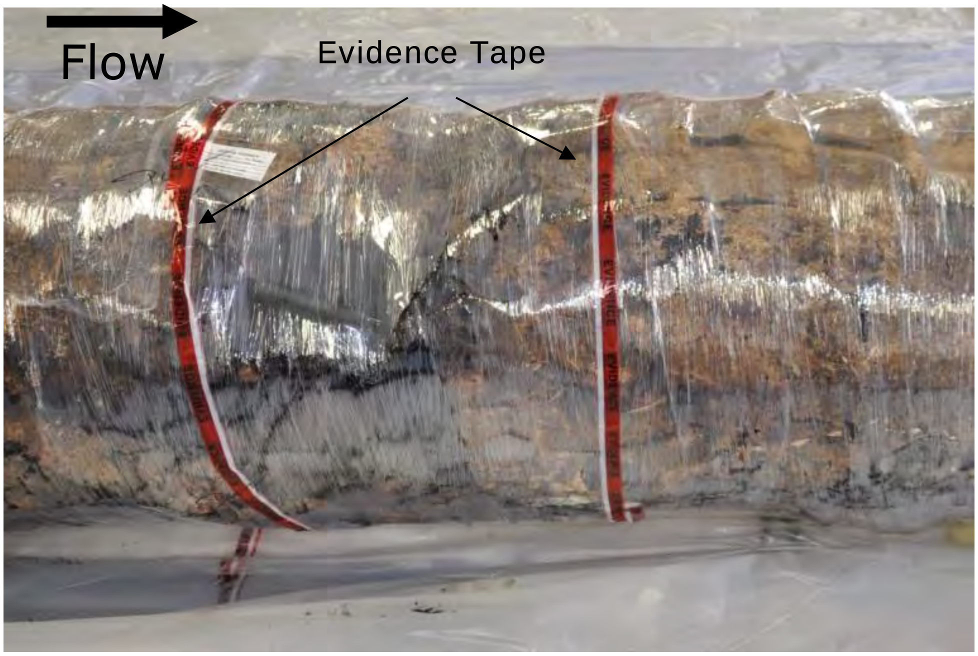


Figure 6. Photographs showing the pipe sections in the as-received condition, within the cargo container.



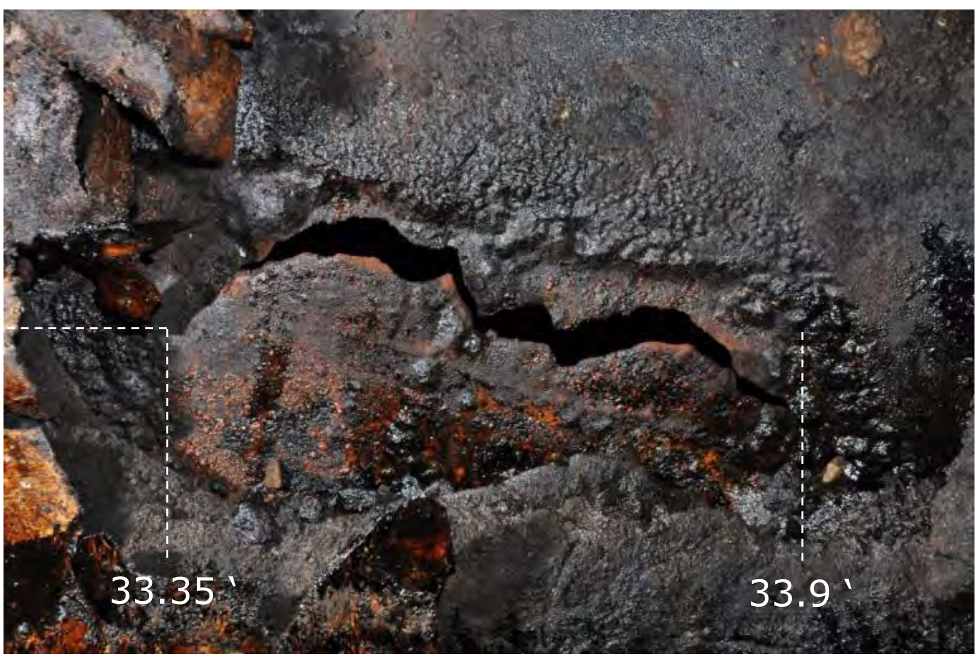
(a)

(b)

Figure 7. Photographs showing failure location on PS 2 a) before and b) after evidence tape and a clear protective wrapping was removed.

(a)

4:22



(b)

Figure 8. Photographs showing the failure location a) while on site (May 28, 2015) and b) after transit to DNV GL's facility (June 15, 2015).

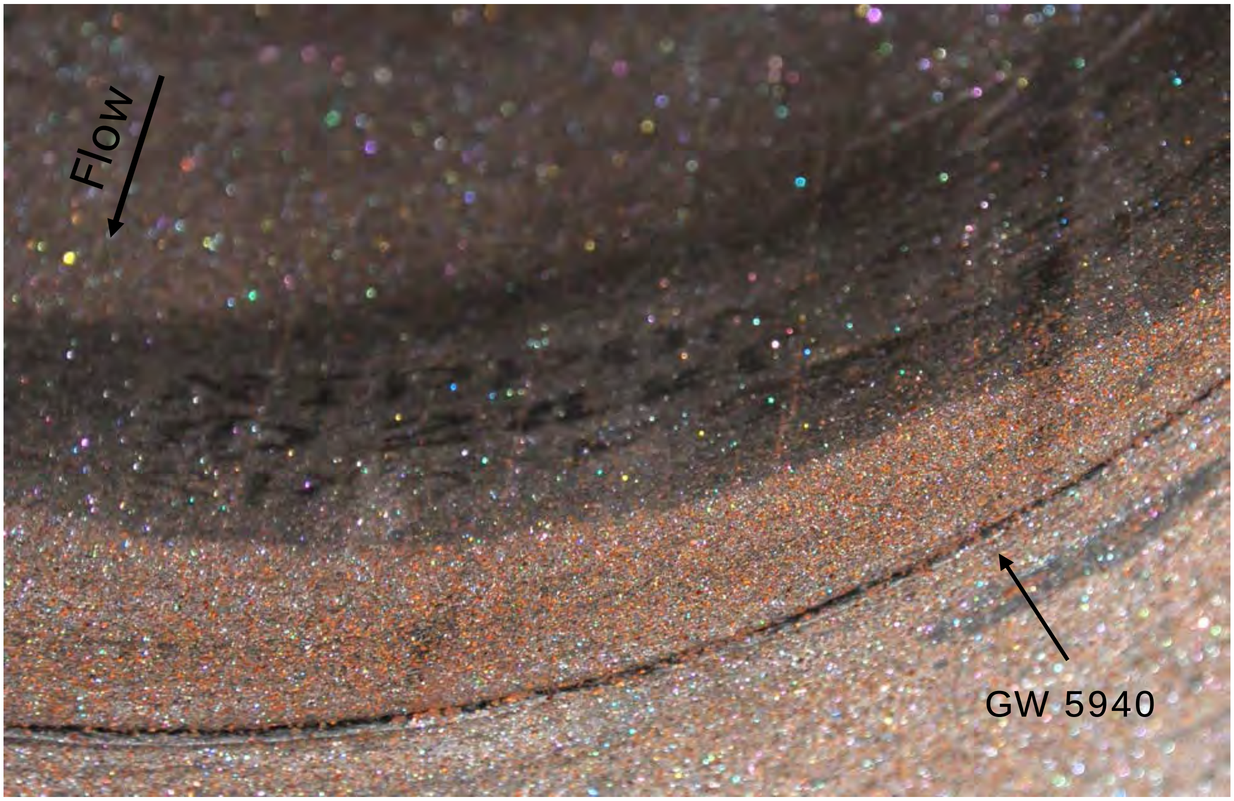


Figure 9. Photograph showing a stamp on the internal surface of the failure joint, near the D/S GW (GW 5940). “NIPPON” and “24” are legible.

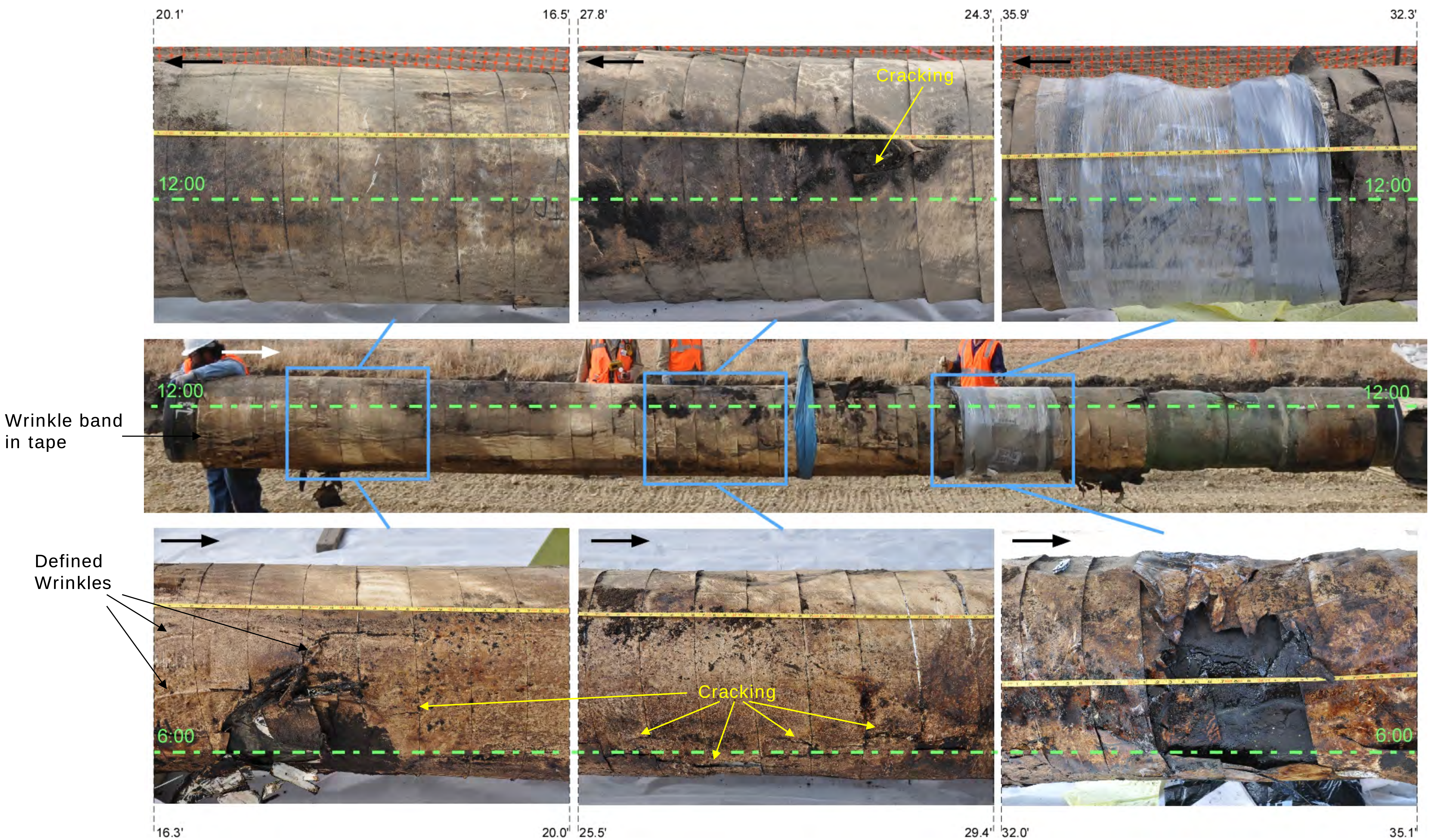


Figure 10. Photographs showing the condition of the external tape on the failure joint. Tape measure indicates distance to upstream girth weld.

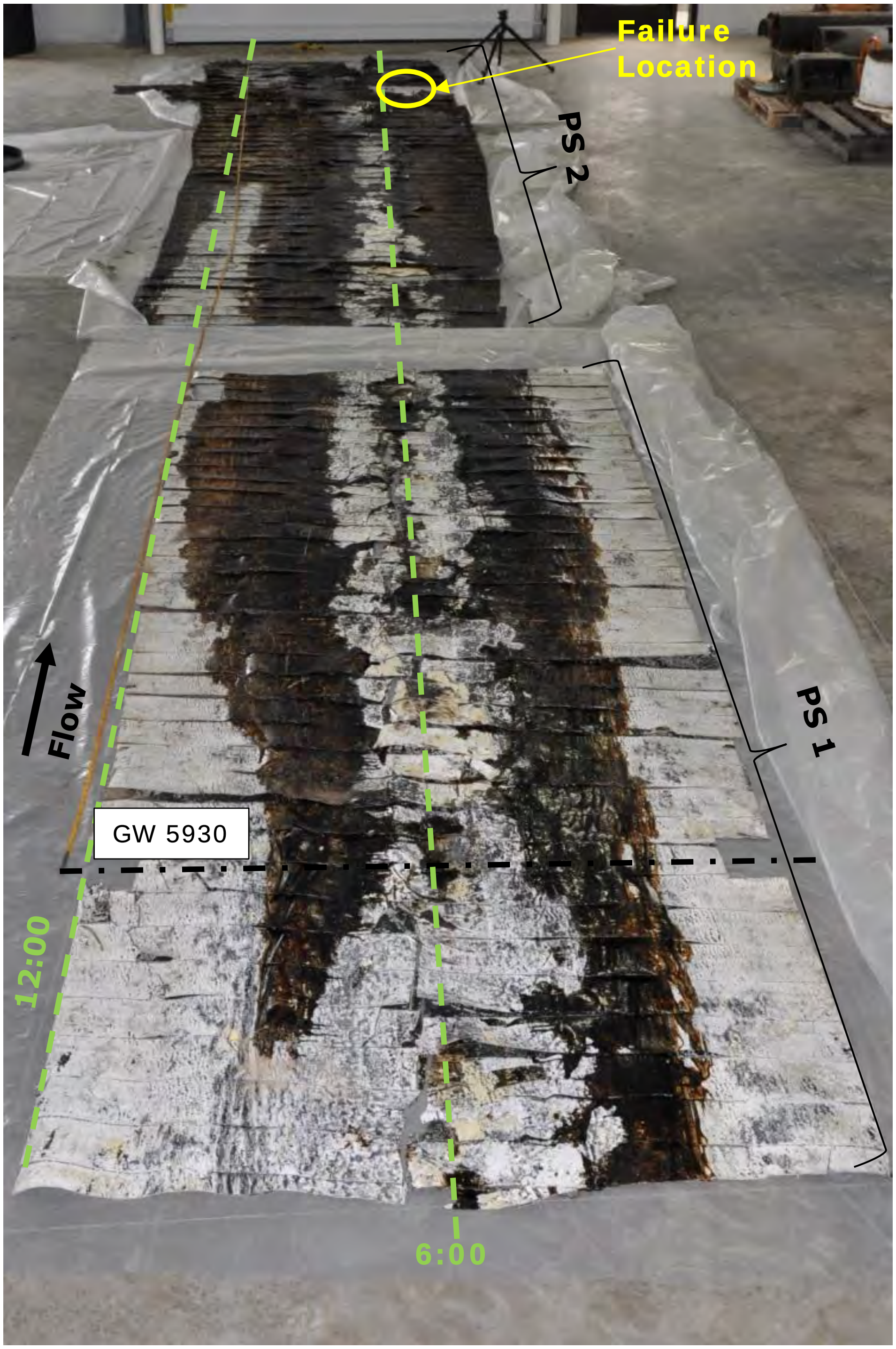


Figure 11. Photograph showing the internal surface of the external tape from the failure joint.

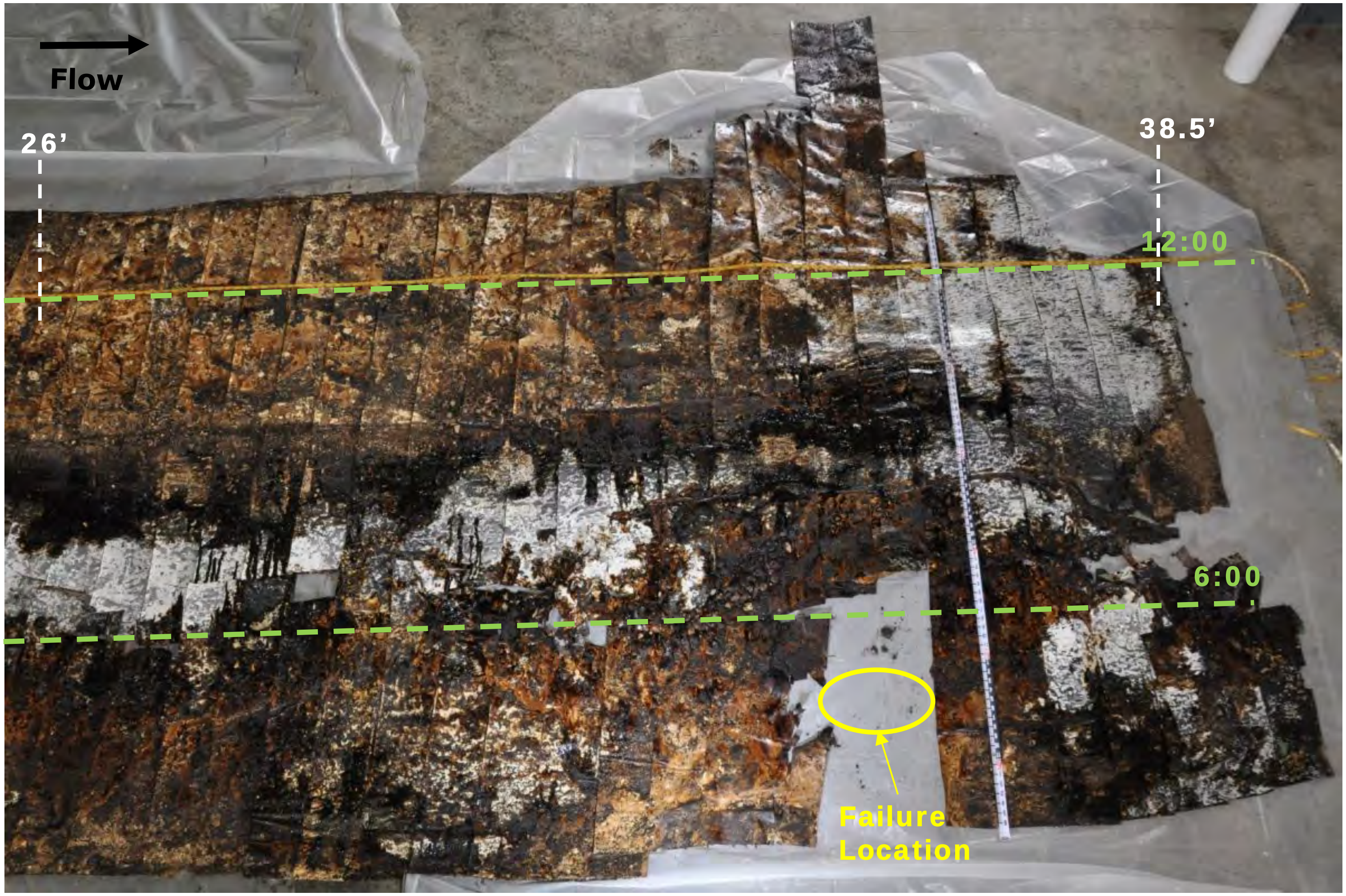


Figure 12. Photograph showing the internal surface of the external tape at the failure location. Tape measure indicates distance to upstream girth weld.

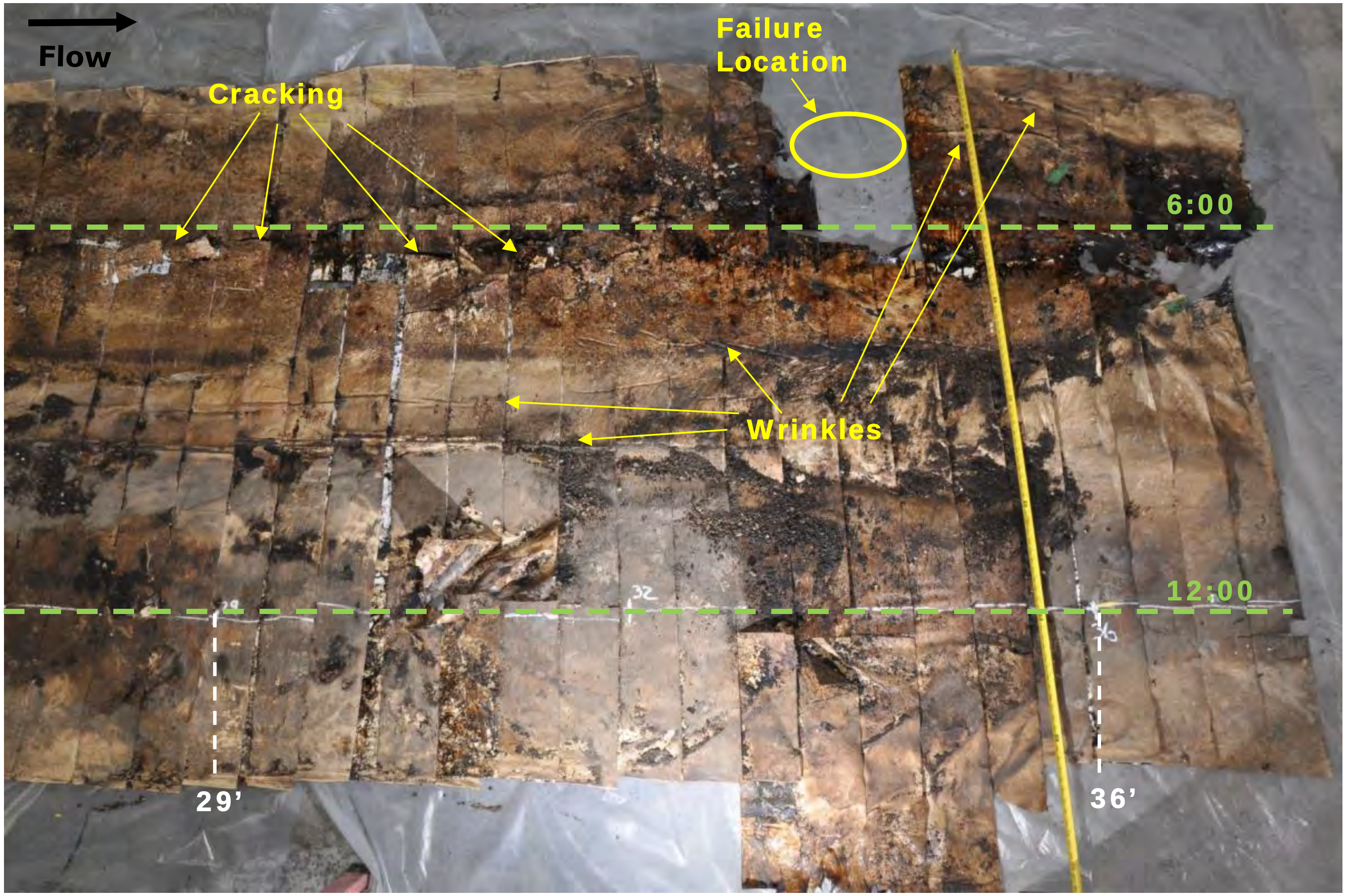
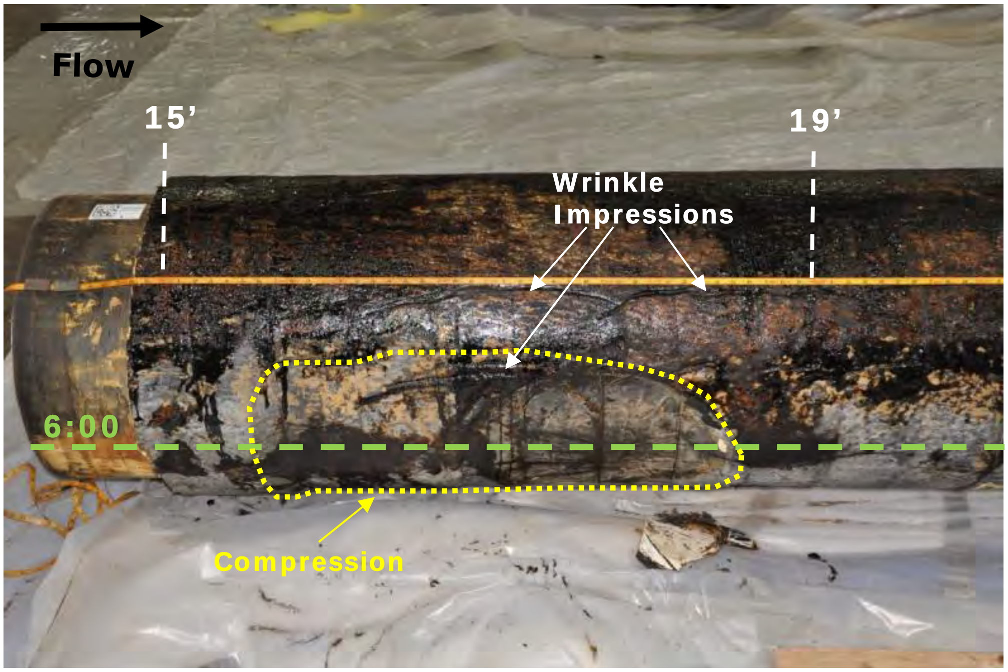
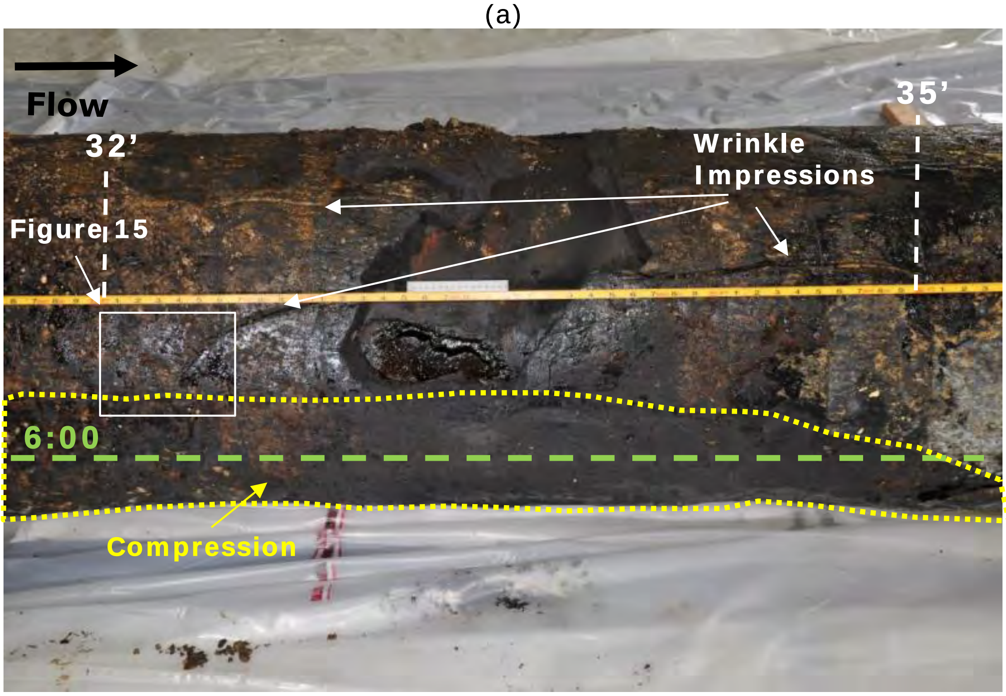


Figure 13. Photograph showing the external surface of the external tape at the failure location.



(a)



(b)

Figure 14. Photographs showing the external surface of the PU insulation at a) the U/S end of PS 2 (14' to 20' from U/S GW) and b) the failure location (31.5' to 36.4' from U/S GW). Tape measure indicates distance to upstream girth weld.

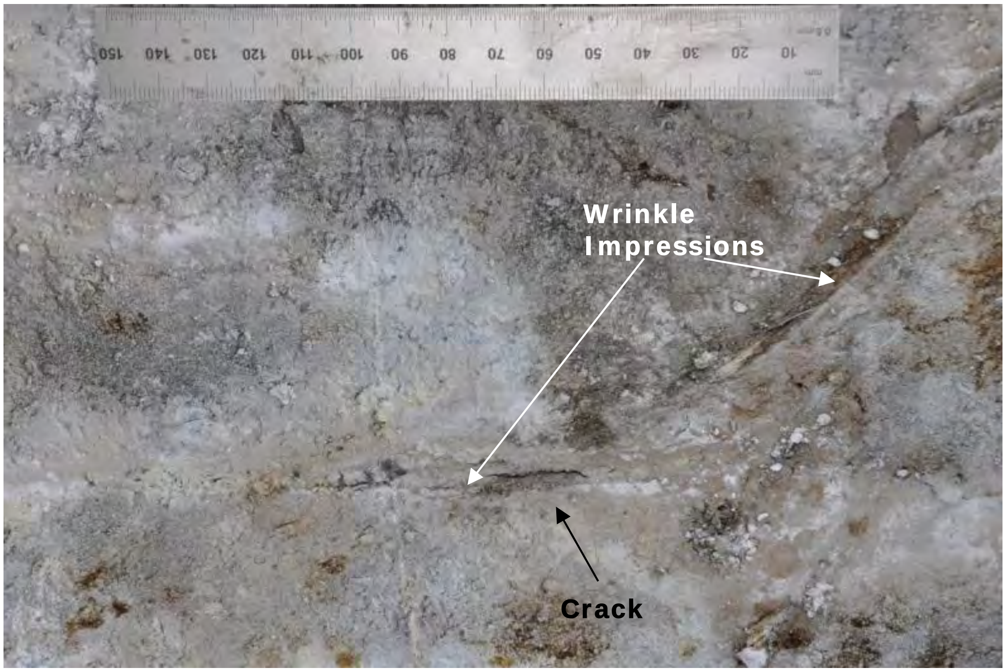


Figure 15. Photograph showing a crack in the PU insulation within a wrinkle. White contrast paint was applied to the surface to facilitate laser scanning and visual inspection. Area shown in Figure 14; scale in mm.

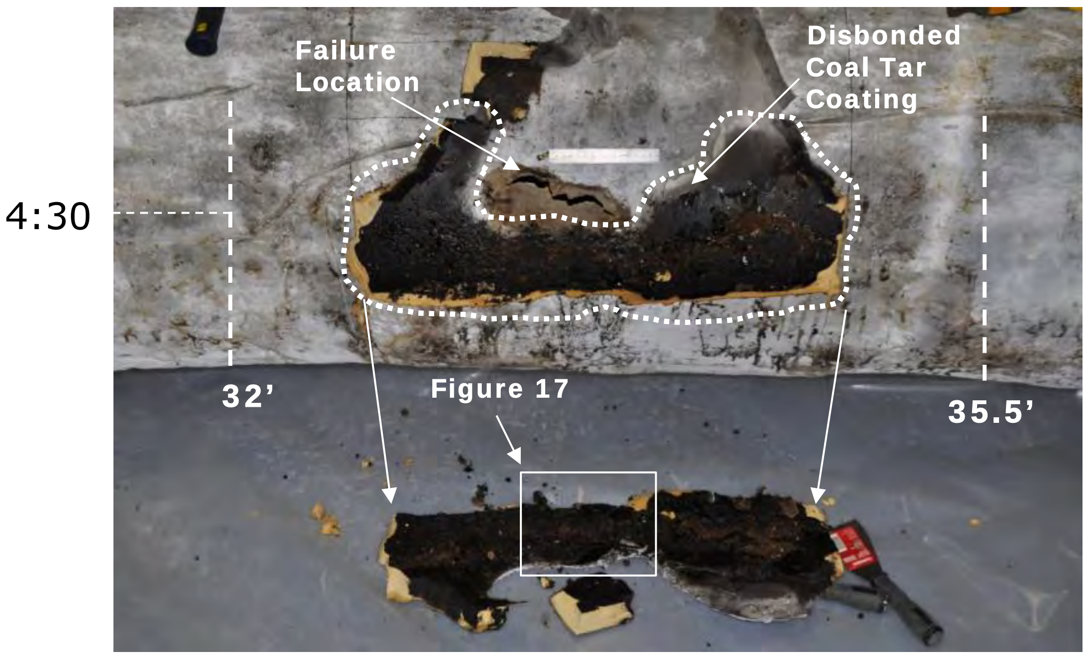


Figure 16. Photograph showing a piece of insulation removed from adjacent to the failure location; near 4:30 orientation.

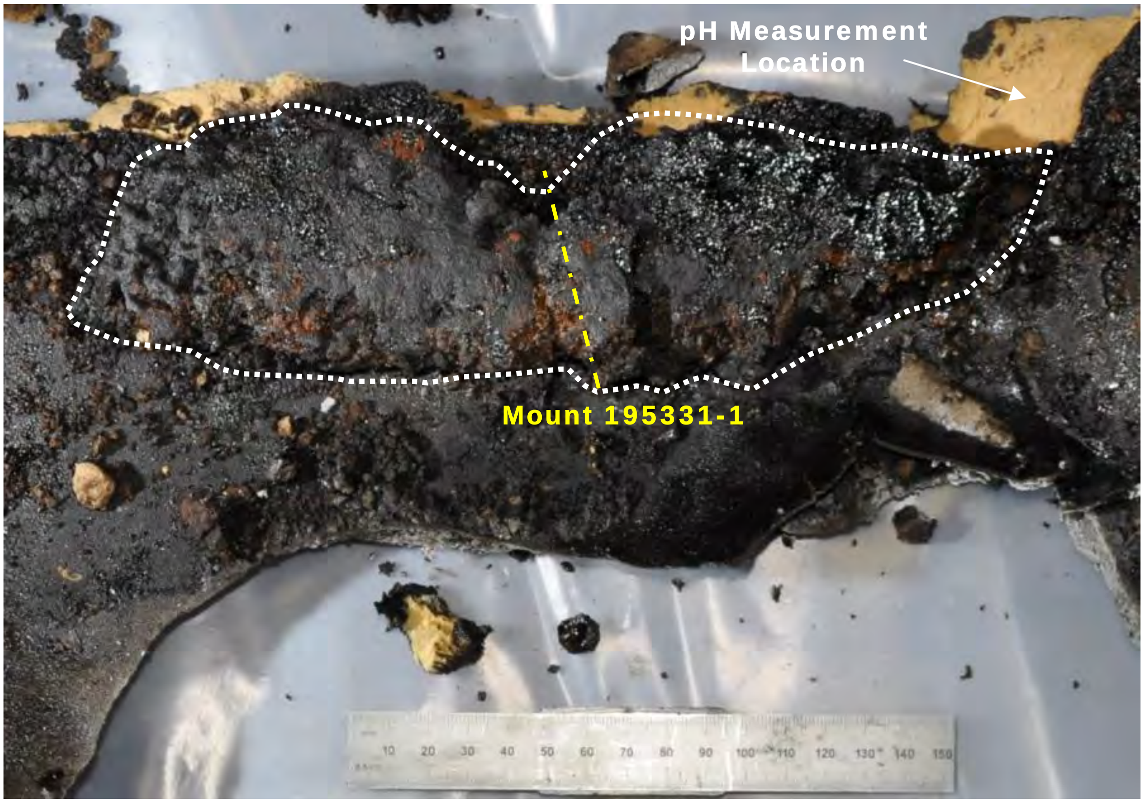


Figure 17. Photograph showing corrosion product that was wedged between the pipe surface and polyurethane insulation. Location indicated in Figure 16; scale in mm.

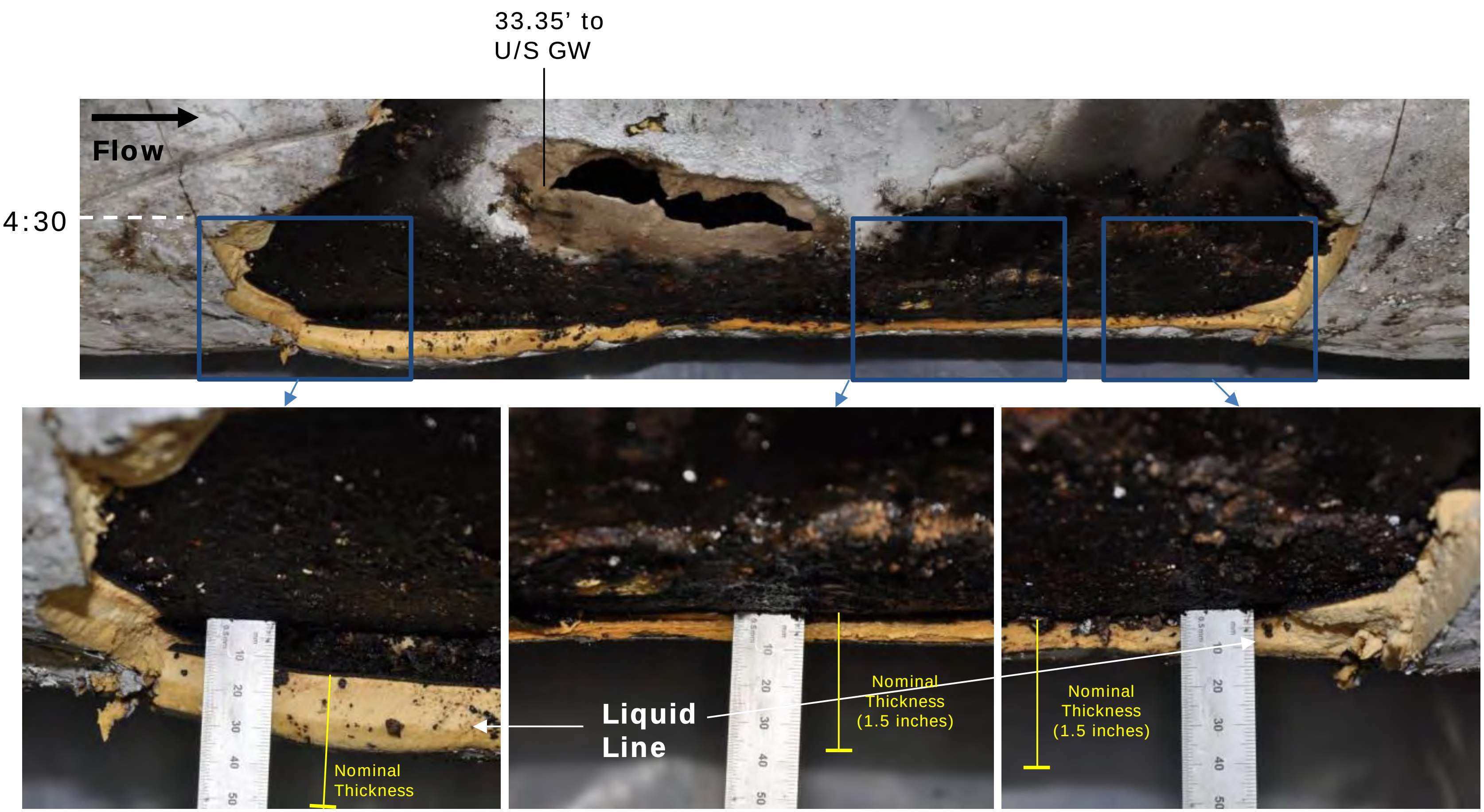


Figure 18. Photographs showing the amount of compression in the insulation adjacent to the failure location; near 6:00 orientation. Scale in mm.

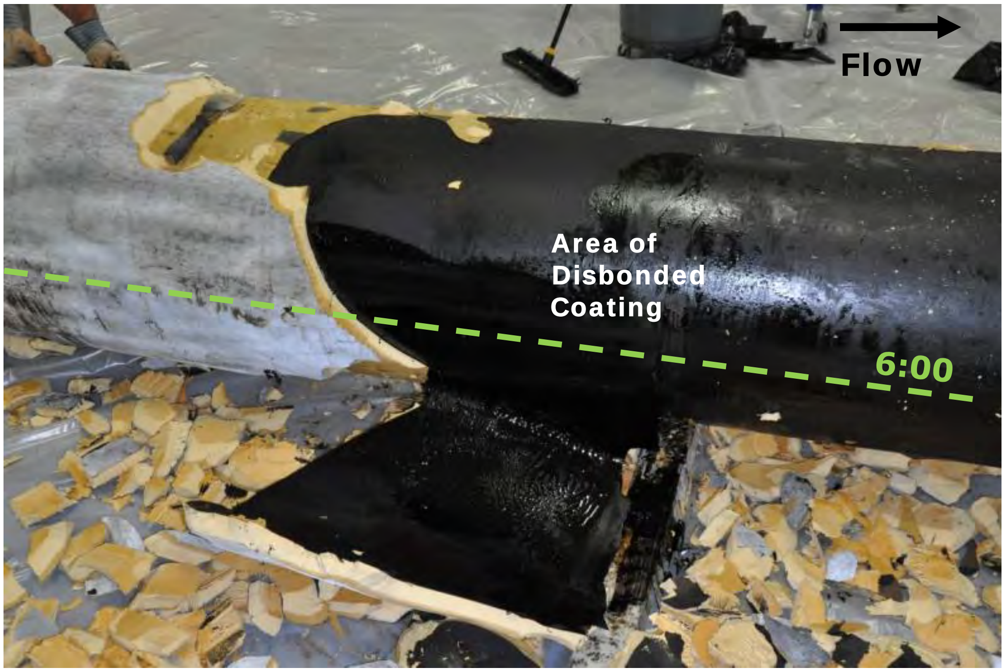


Figure 19. Photograph showing the insulation and coal tar coating separating from the pipe in large sheets on the underside of the pipe; approximately 29' from U/S GW.

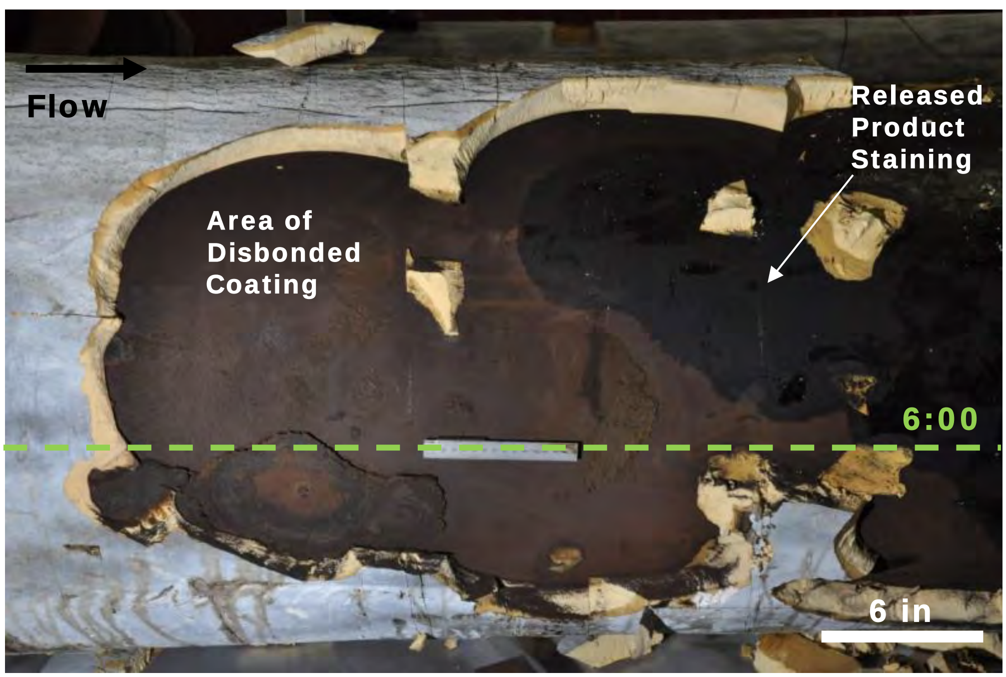


Figure 20. Photograph showing the insulation and coal tar coating separating from the pipe in large sheets on the underside of the pipe; approximately 17' from U/S GW.