DOT	US Department of Transportation
PHMSA	Pipeline and Hazardous Materials Safety Administration
OPS	Office of Pipeline Safety – Accident Investigation Division

Principal Investigator	Wesley Mathews
Acting Accident Investigation Director	Chris Ruhl
Date of Report	May 26, 2022
Subject	Failure Investigation Report - Denbury Gulf Coast Pipelines, LLC – Pipeline Rupture/ Natural Force Damage

<u>Operator, Location, & Consequences</u>

Date of Failure	February 22, 2020
Commodity Released	Carbon Dioxide
City, County and State	Satartia, Yazoo County, MS
OpID and Operator Name	32545, Denbury Gulf Coast Pipelines, LLC
Unit # and Unit Name	75379 – MS-2
WMS Activity ID	20-176125
Milepost (MP) / Location	MP 6.6 / Pipeline Stationing 348+63
Type of Failure	Natural Force Damage
Fatalities	None
Injuries	None
Description of Area Impacted	Rural, “Could Affect” High Consequence Area (HCA) - Other Populated Area
Total Costs	$ 3,947,009

Key Points

- On February 22, 2020, a carbon dioxide (CO_2) pipeline operated by Denbury Gulf Coast Pipelines LLC (Denbury) ruptured in proximity to the community of Satartia, Mississippi. The rupture followed heavy rains that resulted in a landslide, creating excessive axial strain on a pipeline weld.
- Carbon dioxide is considered minimally toxic by inhalation and is classified as an asphyxiant, displacing the oxygen in air. Symptoms of CO_2 exposure may include headache and drowsiness. Individuals exposed to higher concentrations may experience rapid breathing, confusion, increased cardiac output, elevated blood pressure, and increased arrhythmias. Extreme CO_2 concentrations can lead to death by asphyxiation.
- When CO_2 in a super-critical phase (which is common for CO_2 pipelines) releases into open air, it naturally vaporizes into a heavier than air gas and dissipates. During the February 22 event, atmospheric conditions and unique topographical features of the accident site significantly delayed dissipation of the heavier-than-air vapor cloud. Pipeline operators are required to establish atmospheric models to prepare for emergencies—Denbury's model did not contemplate a release that could affect the Village of Satartia.
- Local emergency responders were not informed by Denbury of the rupture and the nature of the unique safety risks of the CO_2 pipeline. As a result, responders had to guess the nature of the risk, in part making assumptions based on reports of a "green gas" and "rotten egg smell" and had to contemplate appropriate mitigative actions. Fortunately, responders decided to quickly isolate the affected area by shutting down local highways and evacuating people in proximity to the release. Denbury reported on its PHMSA F 7000.1 accident report that 200 residents surrounding the rupture location were evacuated, and forty-five people were taken to the hospital. Denbury also reported that to the company's knowledge, one individual was admitted to the hospital for reasons unrelated to the pipeline failure. No fatalities were reported.
- This event demonstrated the need for:
    - Pipeline company awareness and mitigation efforts directed at addressing integrity threats due to changing climate, geohazards, and soil stability issues.
    - Improved public engagement efforts to ensure public and emergency responder awareness of nearby CO_2 pipeline and pipeline facilities and what to do if a CO_2 release occurs. This is especially important for communities in low-lying areas, with certain topographical features such as rivers and valleys.

Executive Summary

On February 22, 2020, at 7:06 p.m. Central Standard Time (CST[1]), Denbury's 24-inch Delhi (Delhi) Pipeline ruptured, releasing liquid CO_2 that immediately began to vaporize at atmospheric conditions. The site of the rupture was on the northeast side of Highway 433 (HWY 433), approximately one mile southeast of Satartia, Mississippi. Denbury subsequently reported the rupture released an estimated total of 31,405[2] barrels of CO_2. Following the accident, investigators from the Pipeline and Hazardous Material Safety Administration's (PHMSA's) Accident Investigation Division (AID) and Southwest Regional Office, conducted an investigation, including an onsite investigation.

Liquid CO_2 vaporizes when released to the atmosphere. Carbon dioxide vapor is 1.53 times heavier than air, and displaces oxygen, so it can act as an asphyxiant to humans and animals. The National Institute for Occupational Safety and Health has established that concentrations of 40,000 parts per million (ppm) are immediately dangerous to life and health. The Occupational Safety and Health Administration has established 5000 ppm as a permissible exposure limit, which is an 8-hour time-weighted average. The weather conditions and unique topography of the accident site prevented the CO_2 vapor from rapidly dispersing and allowing a plume to form that migrated toward Satartia. Upon learning of the pipeline rupture, Yazoo County Office of Emergency Management (Yazoo County OEM) shut down HWY 433 to all traffic and evacuated the area. Local authorities evacuated approximately 200 people near the rupture, including the entire town of Satartia (around 50 residents), and three homes across the Yazoo River. According to Denbury's PHMSA F 7000.1 accident report, forty-five people sought medical attention at local hospitals, including individuals who were caught in the vapor cloud while driving a vehicle. One individual was admitted to the hospital for reasons unrelated to the pipeline failure. There were no fatalities.

The pipeline failed on a steep embankment adjacent to HWY 433, which had recently subsided. Heavy rains are believed to have led to a landslide, which created axial strain on the pipeline and resulted in a full circumferential girth weld failure. After the accident, Denbury, under PHMSA's oversight, cut out the failed sections of pipe and sent them to Det Norske Veritas' (DNV) Columbus, Ohio laboratory for metallurgical analysis. DNV confirmed the initial onsite observations of a girth weld failure.

PHMSA's investigation also revealed several contributing factors to the accident, including but not limited to, Denbury not addressing the risks of geohazards in its plans and procedures, underestimating the potential affected areas that could be impacted by a release in its CO_2 dispersion model, and not notifying local responders to advise them of a potential failure.

System Details

Denbury's Delhi Pipeline, on which the failure occurred, consists of 77 miles of 24-inch diameter pipeline, the majority of which is located within Mississippi. The entire Delhi Pipeline system flows east to west, beginning at the Jackson Dome in Mississippi and terminating in Delhi, Louisiana. Denbury primarily uses the CO_2 for enhanced oil recovery (EOR) for Denbury Resources Inc. onshore oil wells. The pipeline is controlled from the Denbury control room located in Plano, Texas.

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[1] All times are reported in CST unless otherwise noted.

[2] Denbury reported a total release volume of 31,405 barrels in Form PHMSA F-7000.1, Accident Report – Hazardous Liquid Pipeline Systems, dated November 25, 2020. The actual release volume likely exceeded this amount due to a valve operation error, however, Denbury has not confirmed and reported any new release volume to PHMSA.

Following the Delhi Pipeline rupture, two of Denbury's local oilfields were cut off from its CO_2 supply and assumed non-EOR operation while the pipeline remained out of service. One oilfield returned to full EOR operation before repairs were made to the Delhi Pipeline as the oilfield had an alternate supply of CO_2. The other oilfield conducted non-EOR operations until the pipeline was repaired and returned to service in October 2020.

Stupp Corporation manufactured the pipe in 2007 and Denbury installed it in 2009. The pipe was manufactured to API 5L X80 grade, with an electric resistance welded (ERW) longitudinal weld seam, a 0.469-inch wall thickness on the mainline pipe, 0.540-inch wall thickness on the bored pipe section under roads, which was 240 feet in length and more than 30 feet below HWY 433. The pipe is coated with fusion bonded epoxy (FBE) and was installed by horizontal directional drill. During construction, Denbury welded the pipe joints using an API 1104 qualified welding procedure. The procedure specified using an E6010 electrode root pass, followed by an E9018 electrode hot pass, then E10045 electrode for subsequent passes.

The maximum operating pressure of the Delhi Pipeline is 2160 pounds per square inch gauge (psig). At the time of the rupture, Denbury was operating the Delhi Pipeline at an estimated pressure of 1400 psig, which was above the 1070 psig needed to maintain CO_2 in a supercritical state.

Denbury's control room isolated the failed pipeline section by remotely operating the mainline block valves (MLBVs) at Redwood, Satartia, and Tinsley. There is approximately 9.55 miles of pipe between the Tinsley and Satartia MLBVs, which are the two MLBVs closest to the rupture.

Events Leading up to the Failure

According to the National Weather Service (NWS), accumulated rainfall data between January 1, 2020, through February 29, 2020 (60 days) for each of the cities of Greenville, Greenwood, Vicksburg, and Jackson, Mississippi – which form a relative square (Figure 1) around Satartia and Yazoo County[3] – was 17.43 inches, 19.41 inches, 23.2 inches, and 23.36 inches of rain, respectively. The amount of rain recorded in these four cities was between 7.44 and 13.63 inches above the annual historical average for the same 60-day timespan. Significant variations in environmental/climate conditions such as ambient temperatures and rainfall can impact soil stability and erosion patterns. Landslides are typically associated with periods of heavy rain, particularly in susceptible areas with the right combination of slope and soil-type. On May 26, 2022, PHMSA issued an updated Advisory Bulletin to remind operators of gas and hazardous liquid pipelines of the importance of identifying and mitigating risks caused by changes in environmental and geological conditions on their pipeline facilities.

[3] Neither Yazoo City, Satartia, nor Yazoo County had historic NWS data for the desired date range.

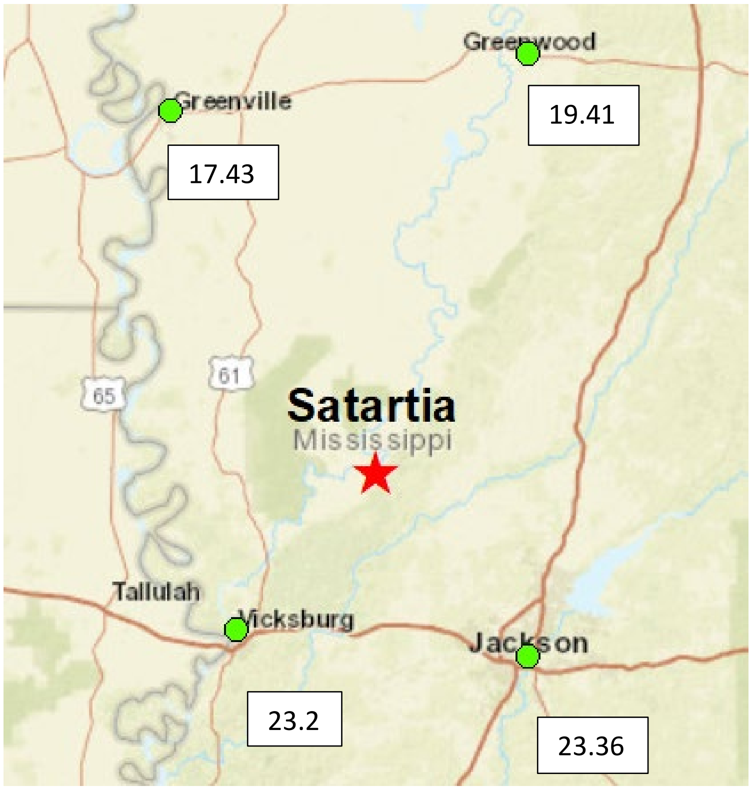

Figure 1: Map of Cities Relative to Satartia and Their Respective Rain Totals Between January 1, 2020, and February 29, 2020

On November 9, 2018, the Delhi Pipeline experienced a girth weld rupture at a valve location during pipeline reloading activities, and not attributed to natural force damage. Laboratory analysis indicated the release was the result of large thermal differential stresses being exerted on the pipeline from CO_2 loading at two different locations at the same time. The pipe between the two loading points shrank due to chilling from the CO_2, causing the girth weld connecting the pipeline to the valve body to rupture. The report found no evidence of inadequate mechanical properties or chemical composition anomalies in the ruptured weld. Denbury updated their procedure to prevent similar occurrences.

Prior to the accident, on November 8, 2019, Yazoo County first responders practiced a full-scale county response during a drill for a rail accident, however Denbury was not a participant in the drill. Local responders believe that the drill prepared them to respond to this event. Denbury had not conducted any drills with local responders since Denbury's modeling had not identified that Satartia would be impacted by a rupture of the pipeline.

Emergency Response

The Delhi Pipeline was operating normally prior to the February 22, 2020 accident.

Approximated Timeline

The following timeline was developed utilizing information provided by the Yazoo County OEM, [4] Denbury, and PHMSA investigator notes.

On February 22, 2020:

- 7:06 p.m. – Denbury's 24-inch pipeline ruptured.
- 7:07 p.m. – Denbury's control room was alerted by its supervisory control and data acquisition (SCADA) system of a pressure drop.
- 7:14 p.m. – Denbury control room remotely closed three MLBVs (one MLBV at Tinsley Station, which is upstream of the rupture site, and two MLBVs at Satartia and Redwood, which are downstream of the rupture).
- 7:15 p.m. – Denbury control room received SCADA confirmation that the MLBVs were closed.
- 7:15 p.m. – Yazoo County OEM dispatcher received an initial report of a "foul smell and green fog across the highway." Based on that information, responders responded under the assumption there was a possible chlorine leak and began contacting people from the local water utility company.
- 7:17 p.m. – Yazoo County OEM dispatcher received a call regarding a person possibly having a seizure. Responders began contacting personnel responsible for a nearby water well as the description of the report indicated chlorine gas.
- 7:19 p.m. – Denbury dispatched personnel to attempt to confirm MLBVs were closed successfully and to identify the location of the release.
- 7:26 p.m. – HWY 433 was ordered closed by local officials due to belief a chlorine leak was occurring.
- 7:30 p.m. – A responder commented that it sounded like a gas line had erupted. It was around this same time that another responder fielded a call from someone in the area who could hear a loud roar. This led the responders to believe that the accident was not chlorine gas related. First responders redirected their efforts to a possible CO_2 and hydrogen sulfide release, based on the initial first-hand reports from community members.
- 7:30 p.m. – First responders accessed a plume model generated by the NWS correlating local meteorological data with product type which indicated the CO_2 would move from the release site directly toward Satartia. Responders then called for the evacuation of Satartia. The scope of the response expanded as the CO_2 cloud dispersed, requiring an Incident Command (IC), commanded by the Chief of the District Three Volunteer Fire Department.
- 7:39 p.m. – Yazoo County OEM closed Highway 3 to traffic (intersection with HWY 433 is about 2/3-mile northwest of the rupture site).
- 7:43 p.m. – IC confirmed Denbury's CO_2 pipeline had ruptured; however, no one could get close to the release site due to the ongoing release of CO_2.
- 7:48 p.m. – Denbury's Tinsley Station Manager was contacted by IC and informed that Denbury's pipeline had ruptured. IC made Denbury aware of the response measures being taken. Denbury informed the IC that the Jackson Dome formation was shut down and that company personnel had been dispatched to check that the MLBVs were closed.

[4] The events entered in the Yazoo County OEM recording system are time stamped upon entry and may be delayed by seconds or minutes from the actual time of the event.

- 7:57 p.m. – Yazoo County OEM blocked off Mechanicsburg Road (around two miles southeast of the rupture site; intersects with HWY 433).
- 7:58 p.m. – According to Yazoo County OEM records, the Mississippi Department of Environmental Quality (MDEQ) contacted the Center for Toxicology & Environmental Health (CTEH) requesting technicians be dispatched to the rupture site with air monitoring equipment.
- 8:06 p.m. – The first Denbury representative arrived near the rupture site after confirming MLBV closures.
- 8:24 p.m. – Yazoo County OEM dispatch confirmed the second Denbury representative arrived near the rupture site.
- 9:06 p.m. – A Denbury representative from the Plano, Texas office called the National Response Center (NRC) to report their Delhi Pipeline had ruptured, releasing an estimated 222 barrels of liquid carbon dioxide (Report No. 1271847).
- 9:25 p.m. – Representatives from the CTEH and Denbury's environmental contractor E3 Environmental (E3) arrived on scene to conduct air monitoring to support the IC.
- 10:25 p.m. – Tinsley MLBV was completely closed.[5]
- 10:30 p.m. – CTEH initiated real-time air monitoring.

On February 23, 2020:

- 1:49 a.m. – The IC established a warming shelter at a local middle school for evacuees.
- 8:00 a.m. – Evacuees were allowed to return home. Air monitoring services were extended to anyone who requested the service. Evacuees were encouraged to vent their homes by opening doors and windows. The closure of HWY 433 was lifted after heavy equipment was used to clear mud that was deposited by the rupture.
- 11:34 a.m. – Real-time air monitoring concluded.

On February 24, 2020:

- 6:56 p.m., Denbury called the NRC and made the PHMSA required 48-hour update (Report No. 1272001). The update stated 21,873 barrels of liquid CO_2 had been released.[5]

Personnel from the Vicksburg Fire Department, including paramedics, District Three Volunteer Fire Department, Pafford EMS, Mississippi Emergency Management Agency, CF Industries, MDEQ, Madison County Fire Department, Warren County Fire Department, NWS, Local Police Departments, Yazoo County OEM, CTEH, E3, and Denbury participated in the emergency response efforts.

Local emergency responders utilized regular media, social media posts, phone calls, and door-to-door checks to notify homeowners and affected individuals of the CO_2 release.

A total of approximately 200 people were evacuated, which included those who were evacuated out of the area and those who were not allowed to pass through the area. During post-accident interviews, PHMSA learned that individuals on HWY 433 and in the area nearest to the migrating CO_2 vapor cloud experienced vehicle engine issues. This included individuals in a vehicle off of HWY 433, who succumbed to the effects of exposure to the released CO_2 and required emergency assistance to be evacuated. PHMSA also learned that one of two residents living in a dwelling in closest proximity to the pipeline rupture

[5] Denbury reported an updated estimate of 31,405 barrels to PHMSA on November 25, 2020.

passed out upon investigating the cloud. She later came-to and was able to evacuate to safety with her partner. Denbury reported a total of forty-five people sought medical attention at local hospitals.

Emergency Response Air Monitoring Plan

CTEH (Denbury's third-party contractor) in consultation with the IC developed an air monitoring plan to ensure the safety of response personnel, the community, and site characterization. CTEH implemented the plan to monitor for concentrations of CO_2, hydrogen-sulfide (H_2S), and oxygen (O_2) using handheld real-time instrumentation throughout the community and within homes of residents who requested monitoring. Air monitoring was conducted from 10:30 p.m. on February 22, 2020, until approximately 11:30 a.m. on February 23, 2020. Monitoring was performed using calibrated RAE Systems instruments made by Honeywell.

Carbon dioxide is considered minimally toxic by inhalation, unless in higher concentrations. CO_2 is classified as an asphyxiant, displacing the oxygen in breathing air. Symptoms of CO_2 exposure may include headache and drowsiness. Those exposed to higher concentrations may experience rapid breathing, confusion, increased cardiac output, elevated blood pressure, and increased arrhythmias. Extreme CO_2 concentrations can lead to death by asphyxiation.

In the hours after the rupture, after outdoor ambient air CO_2 levels continuously measured below 5,000 ppm, responders performed initial indoor assessment monitoring within residences and church buildings potentially impacted by the accident. During initial indoor assessments, CO_2 concentrations ranged from 200 through 28,000 ppm, with six detections exceeding 5,000 ppm. In these instances, occupants of these structures were advised to open doors and windows to allow ventilation to dissipate the concentration of CO_2 and not to enter prior to re-assessment. No subsequent CO_2 readings in the hours after the accident were recorded above 3,500 ppm during re-assessments.

According to firsthand accounts, as well as secondhand accounts from first responders, there was a "rotten eggs" odor associated with the CO_2 release and gas plume. A rotten eggs odor can be attributed to the presence of H_2S, which is naturally occurring in the geologic formation that serves as a source of the CO_2 in the pipeline. PHMSA reviewed the CTEH air monitoring results and did not identify any observed readings of H_2S by monitoring equipment. The monitoring equipment's detection limit for H_2S was 0.1 ppm.

Summary of Return-to-Service

Prior to repairing the pipeline, Denbury contracted an engineering firm to develop plans to cutout the failed section of pipe and to mitigate potential future land movement. Denbury installed soil shoring along HWY 433 to stabilize the area. PHMSA evaluated the repair plan and monitored its execution.

On September 1, 2020, Denbury began replacing the failed pipe section, and on September 26, Denbury welded the new sections of pipe into the pipeline at the accident location. Mannesmann Line Pipe manufactured the newly installed 80-foot section of 24-inch nominal diameter pipe in 2019. The pipe is API 5L X70 grade, has 0.562-inch wall thickness and an ERW longitudinal weld seam, and is coated with FBE.

Denbury restarted the pipeline on October 26, 2020. Prior to the restart of the pipeline, Denbury provided PHMSA with a proposed restart plan for review and approval. Concurrently with Denbury's repair and restart efforts, PHMSA conducted an inspection of Denbury's pipeline operations, which resulted in the issuance of various enforcement actions, including a Notice of Probable Violation in connection with this accident.[6]

Investigation Details

On February 23, 2020, at 10:09 a.m., a PHMSA AID investigator from Oklahoma City arrived at the intersection of HWY 433 and Highway 3 to meet with Denbury representatives and emergency response organizations. The group then proceeded to the site of the rupture (Figure 2). By that time, the IC had demobilized, and roadblocks had been removed. Denbury crews were in the process of setting up caution fencing and slowing traffic on HWY 433 for public and worker safety. The rupture crater was on the northeast side of HWY 433 (Figure 2).

Figure 2: Vehicle is Parked on HWY 433 - The White is Ice Generated by the Release of CO_2 - The Blue Arrow Points North (Aerial Drone Photograph Courtesy of the Mississippi Emergency Management Agency)

[6] CPF 4-2022-017-NOPV, dated May 26, 2022.

The topography along the pipeline right-of-way (ROW) in this area is a steep hill that rises from the valley containing the Big Black River to the east, goes relatively flat across the crest of the hill containing HWY 433, and then slopes downward toward the valley containing the Yazoo River to the west.

Figure 3: Crater Created by the Rupture Containing Fallen Debris (dry ice, and the failed pipe sections)
(Blue Arrow is Pointing at the Pipeline Separation)

The pipeline separated at a girth weld. The pipeline self-excavated due to the discharge of CO_2. The auto refrigeration generated by the CO_2 discharge and accompanying chance in phase covered the area with a thick layer of ice (Figures 2, 3, and 4). The upstream section of pipe was not covered in ice, and a slightly jagged edge was observed on the rupture edge (Figure 4). The crater was an estimated 40-feet-deep on the downstream (HWY 433) side and about four-feet-deep on the upstream side.

Figure 4: The failed pipe sections shown separated by a few inches.

Upon release, the CO_2 transitioned from a liquid to a gaseous phase resulting in a refrigeration effect. Although the pipeline was shut down by 7:15 pm, the remaining contents of the pipe continued to vent to the atmosphere for several hours. The CO_2 was heavier than air[7] and followed a path downhill. CO_2 moved down the slope to the east and remained in the bowl of the crater. As the discharged volume increased, and without significant winds to disperse the CO_2, the CO_2 moved over the crest of the hill then west into the valley, reaching Satartia.

Plume Model

First responders utilized a plume model generated by the NWS to base the decision to evacuate Satartia (Figure 5).

[7] CO_2 has a density approximately 1.53 times that of air in standard atmospheric conditions.

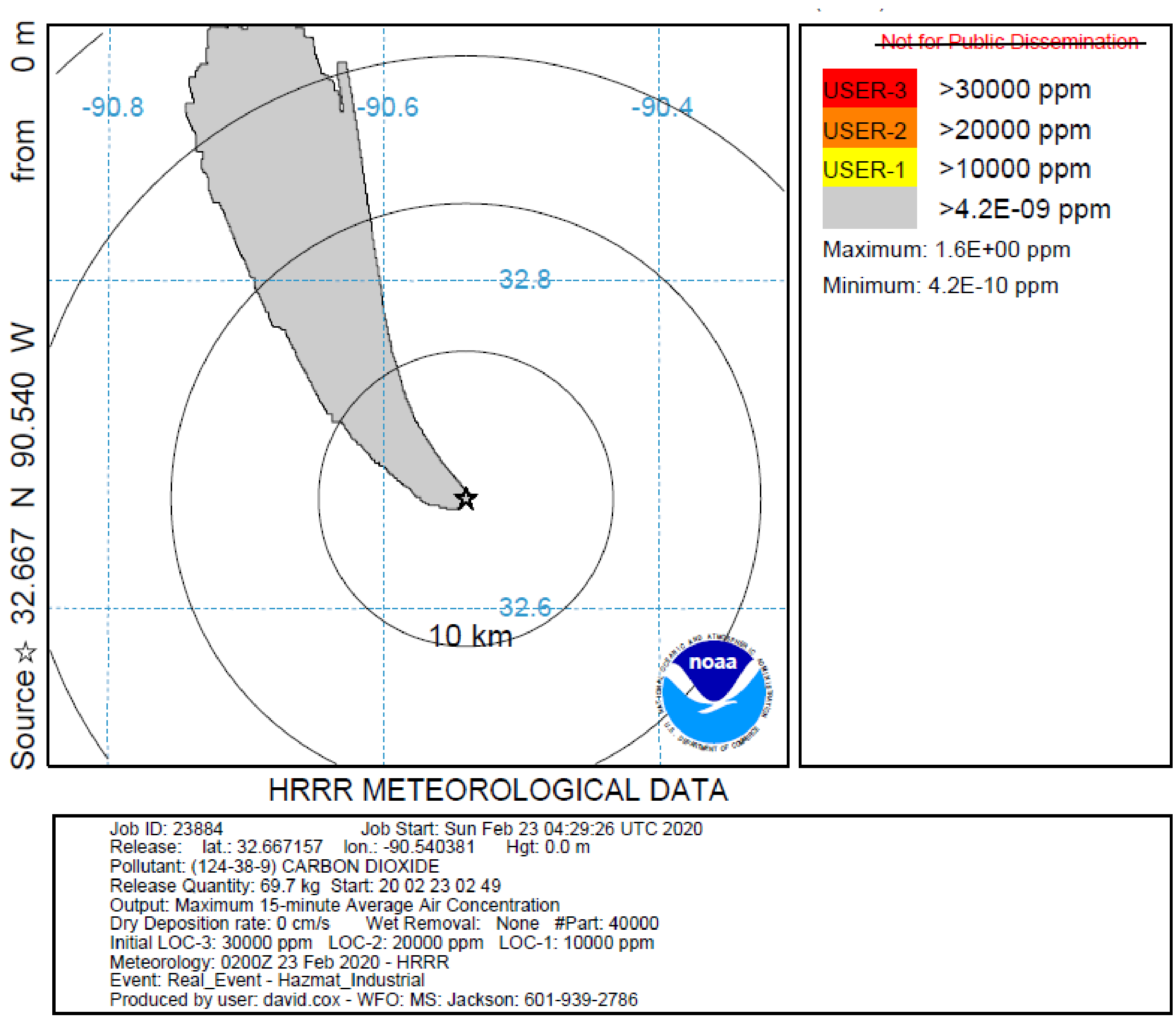

Figure 5: This Chart Shows the Plume Model Data Generated by the National Weather Service/NOAA - The Model Indicates the Direction a Plume or Cloud of CO_2 Would Have Followed from Ground Level While Dissipating, According to Atmospheric Data at the Time of the Release - Each Ring is 10 Kilometers (Satartia is Less Than Two Kilometers Northwest of Release Site, Indicated by the Star)[8]

Prior to the accident in 2011, Denbury had contracted a third-party company to generate an affected radius model for a potential CO_2 release. Denbury used the model to generate a zone along the pipeline ROW to identify pipeline segments which were within or "could affect" an HCA and to develop its Public Awareness Program (PAP).[9] The model established a zone for the Delhi Pipeline (Figure 6) that left Satartia outside of the affected radius, and therefore the pipeline segment was not identified by Denbury as a "could affect" HCA. Additionally, Satartia was not included in Denbury's PAP or considered in any local

[8] The NWS approved inclusion of the chart within this report and clarified that "Not for Public Dissemination" (in the upper right-hand corner) pertains to real-time emergency response utilization, due to inherent uncertainties with several variables.
[9] Required by 49 CFR § 195.440.

emergency response plans. The rupture location was one mile from the center of Satartia, where the entire town was evacuated.

Figure 6: Topographical Map Showing the Delhi Pipeline (Green) and Denbury's Buffer Zone (Red) on Either Side of the Pipeline and the Proximity to Satartia (Blue Star Indicates the Rupture Site)

Soil and Geohazards

The soil at the failure location is identified as a loess soil typical to the area and was relatively saturated due to the recent heavy rainfall. Dry patches of the soil observed later were powdery, confirming the loess to be silty and clayey, indicating the soil would be prone to absorb water as well as collapse or slump under the right conditions.[10] Vertical erosion of the steeply sloped hillside, made heavier by water saturation, produced enough axial loading on the pipeline to cause the girth weld to fail.

On February 23, 2020, representatives from the Mississippi Department of Transportation assessed the condition of the crater's edge along HWY 433. They determined the highway was at risk of further land movement due to current and future soil saturation from rainfall, the weight of the trees at the edge of the crater, and the HWY 433 ROW was impinged upon by the rupture. Crews were dispatched to cut down the trees and mitigate the risk of additional land movement. Soil instability along roads is not unusual in the region. The PHMSA AID investigator observed road damage from unstable soil slumping away from a road along roadways leading to the accident site. Denbury representatives mentioned that, along the Delhi pipeline, they experience two to three issues per year involving land movement. Denbury's Integrity Management Program (IMP)[11] identified "geo-technical hazards" (geohazards) as a potential risk to its pipelines but lacked additional details concerning threat assessment or preventative/mitigative measures for its operational pipelines such as: using in-line inspection tools with inertial measurement unit sensors, conducting bending strain analysis, or conducting geohazard assessments. Denbury's operations and

[10] Loess soil has a relatively high porosity (typically around 50-55%) and often contains vertical capillaries that allow the sediment to fracture and form vertical bluffs. The loess bluffs tend to erode vertically.
[11] Required by 49 CFR § 195.452.

maintenance (O&M) procedures also lacked substantive information regarding geohazard identification, assessment, remediation, and training for employees. Additionally, Denbury's pipeline patrolling program to address federal regulations[12] was commonly performed by aerial patrol. Records indicate that patrols were made at regular intervals, but no geohazards were identified at the rupture location.

In response to this rupture, PHMSA initiated a specialized review of Denbury's IMP and O&M activities. PHMSA's investigation identified that Denbury did not address the risk of geohazards to the pipeline and take adequate preventive and mitigative measures prior to the accident. PHMSA has made specific recommendations for the development of the company's geohazards program, which the company has initiated.

Welding Procedure

Denbury hired DNV prior to the construction of the pipeline to develop its welding procedure. The welding procedure was developed to API 1104, 20th edition and was qualified. The procedure utilized an E6010 electrode root pass, an E9018G electrode hot pass and E10045 electrode filler and cap pass. In 2009, a welding procedure utilizing an E10045 electrode was a pipeline construction industry leading development. Prior industry practice was to utilize cellulosic-type electrodes.

Laboratory and Root Cause Analyses

Once shoring was installed at the rupture site, the upstream pipe was excavated, and two failed pipe sections were cut out. On March 11, 2020, the two failure samples were secured and shipped to DNV's laboratory in Columbus, Ohio for metallurgical analysis. Denbury worked with Mears to provide DNV with a testing protocol to facilitate analysis. Mott MacDonald performed a site-specific soil movement analysis to estimate soil loading on the pipeline and perform a stress analysis. Mears performed a Root Cause Analysis utilizing the above information, coupled with information from original construction documentation, site observations, operating and maintenance records, and related information.

Denbury reported the results of the metallurgical findings and stress evaluations in a written accident report on the PHMSA Form 7000.1 and indicated soil movement upstream of the failure location induced axial stresses sufficient to cause an overload condition, and the soil movement was promoted by unusually heavy rainfall. There were no material defects observed with the pipe or the failed weld which could have contributed to the failure.

PHMSA notes the failed girth weld exhibited both ductile and brittle fracture appearances. A typical overload condition in these circumstances is expected to be ductile, unless the grain structure of the steel is susceptible to brittle failure, or the material has been chilled below its transition temperature from ductile to brittle behavior. A failure scenario whereby a leak initiates, and the refrigeration effect associated with vaporization of the liquid CO_2 results in a brittle failure is plausible, although a distinct failure origin within the girth weld was not identified.

Findings and Contributing Factors

PHMSA has determined that the failure of the Delhi Pipeline was a result of soil movement which caused excessive axial loading leading to failure at the girth weld. Area topography, soil type, and large amounts of rain over the preceding months saturated and vertically eroded the loess soil on the side of the hill above the pipeline. It is unclear whether prevalent warmer temperatures in the two months preceding the heavy rainfall could have contributed to the soil instability as well.

[12] Required by 49 CFR § 195.412.

Contributing factors include:

- Denbury's O&M procedures did not appear to address the potential for pipeline damage due to soil instability despite having prior experience with and knowledge of land movement risks.
- Denbury's IMP did not appear to address integrity threat identification and/or assessment for geohazards or preventative or mitigative measures.
- Denbury's aerial patrols did not identify a geohazard at the failure location prior to the accident.
- Denbury's CO_2 dispersion model underestimated the potential affected area that could be impacted by a release. As a result, the pipeline segment was not identified as a "could affect" HCA, and Satartia was not included in Denbury's PAP.
- Denbury did not notify local responders advising them of a potential failure. Local responders contacted Denbury approximately 40-minutes after the rupture. This led to confusion in understanding circumstances associated with the emergency and hindered the ability of first responders and community members to safely navigate the emergency.

Appendices

Appendix A Map

Appendix B NRC Reports Nos. 1271847 and 1272001

Appendix C PHMSA 7000.1 Final Report

Appendix D Mears Metallurgical and Root Cause Failure Analysis

Appendix E CTEH Air Monitoring Summary Report

Appendix A Map

OPID 32545 - Denbury Gulf Coast Pipelines, LLC - Satartia, MS. 2/22/2020

Figure 7: An ArcGIS-generated Satellite Map with the Site of the Rupture Marked by the Red Star (the Insert Map on the Bottom Right Shows the Rupture Site Location Within the State of Mississippi)

Appendix B NRC Report No. 1271847

Mathews, Wesley (PHMSA)

From: HQS-SMB-NRC@uscg.mil
Sent: Thursday, May 21, 2020 12:28 PM
To: Mathews, Wesley (PHMSA)
Subject: NRC#1271847

NATIONAL RESPONSE CENTER 1-800-424-8802
*** For Public Use ***
Information released to a third party shall comply with any applicable federal and/or state Freedom of Information and Privacy Laws

Incident Report # 1271847

INCIDENT DESCRIPTION

*Report taken by NRC on 22-FEB-20 at 22:06 ET.
Incident Type: PIPELINE
Incident Cause: UNKNOWN
Affected Area:
Incident was discovered on 22-FEB-20 at 19:07 local incident time.
Affected Medium: AIR / ATMOSPHERE

SUSPECTED RESPONSIBLE PARTY

Organization: DENBURY GULF COAST PIPELINE

PLANO, TX 75024

Type of Organization: PRIVATE ENTERPRISE

INCIDENT LOCATION
32.658 County: YAZOO
-90.537
City: SATARTIA State: MS
Distance from City: 1 MILES
Direction from City: SE
OFF HWY 433

RELEASED MATERIAL(S)
CHRIS Code: CDO Official Material Name: CARBON DIOXIDE
Also Known As:
Qty Released: 222 BARREL(S)

DESCRIPTION OF INCIDENT
CARBON DIOXIDE RELEASED FROM A 24 INCH PIPELINE DUE TO AN UNKNOWN CAUSE AT THIS TIME. CALLER STATES THE CONTROL ROOM NOTICED A PRESSURE DROP AT 1907 AND PERSONNEL VERIFIED LEAK AT 2046. CALLER ALSO STATES THERE WERE EMERGENCY RESPONDERS ONSITE AS WELL WHEN THEIR PERSONNEL ARRIVED ONSCENE.

INCIDENT DETAILS

Pipeline Type: TRANSMISSION
DOT Regulated: YES
Pipeline Above/Below Ground: BELOW
Exposed or Under Water: NO
Pipeline Covered: UNKNOWN

IMPACT

Fire Involved: NO Fire Extinguished: UNKNOWN

INJURIES: NO Sent to Hospital: Empl/Crew: Passenger:
FATALITIES: NO Empl/Crew: Passenger: Occupant:
EVACUATIONS:NO Who Evacuated: Radius/Area:

Damages: UNKNOWN

Closure Type	Description of Closure	Hours Closed	Direction of Closure	Major Artery
Air:	NO			
Road:	YES HWY 3; HWY 433; EAGLE BEND RD; PERRY CREEK RD			YES
Waterway:	NO			
Track:	NO			

Passengers Transferred: NO
Environmental Impact: UNKNOWN
Media Interest: NONE

REMEDIAL ACTIONS

VALVES WERE IMMEDIATELY SHUT AFTER IDENTIFICATION OF PRESSURE DROP.
Release Secured: YES
Release Rate:
Estimated Release Duration:

WEATHER

ADDITIONAL AGENCIES NOTIFIED

Federal:
State/Local:
State/Local On Scene:
State Agency Number:

NOTIFICATIONS BY NRC

CENTERS FOR DISEASE CONTROL (GRASP)
22-FEB-20 22:14

DEPT OF HEALTH AND HUMAN SERVICES (SECRETARY'S OPERATION CENTER (SOC))
22-FEB-20 22:14
AZ OFFIC OF INTEL AND ANALYSIS (FIELD INTELLIGENCE AND INTEGRATION DIVISION)
22-FEB-20 22:14
DHS DEFENSE THREAT REDUCTION AGENCY (CHEMICAL AND BIOLOGICAL TECHNOLOGIES DEPARTMENT)
22-FEB-20 22:14
MS DEPT OF HOMELAND SECURITY (I&A FIELD OPS)
22-FEB-20 22:14
DOT CRISIS MANAGEMENT CENTER (MAIN OFFICE)
22-FEB-20 22:14
U.S. EPA IV (MAIN OFFICE)
22-FEB-20 22:17
U.S. EPA IV (EPA RRT4)
22-FEB-20 22:14
GULF STRIKE TEAM (MAIN OFFICE)
22-FEB-20 22:14
JFO-LA (COMMAND CENTER)
22-FEB-20 22:14
MS ANALYSIS AND INFORMATION CENTER (FUSION CENTER)
22-FEB-20 22:14
NATIONAL INFRASTRUCTURE COORD CTR (MAIN OFFICE)
22-FEB-20 22:14
NOAA RPTS FOR MS (MAIN OFFICE)
22-FEB-20 22:14
NTSB PIPELINE (MAIN OFFICE)
22-FEB-20 22:14
PIPELINE & HAZMAT SAFETY ADMIN (OFFICE OF PIPELINE SAFETY (AUTO))
22-FEB-20 22:14
PIPELINE & HAZMAT SAFETY ADMIN (HAZARDOUS MATERIAL ACCIDENT INVESTIGATION)
22-FEB-20 22:14
DOI FOR REGION 4 (MAIN OFFICE)
22-FEB-20 22:14
REPORTING PARTY (RP SUBMITTER)
22-FEB-20 22:14
SECTOR LOWER MISSISSIPPI RIVER (AUTO NRC NOTIFICATIONS)
22-FEB-20 22:14
SHELBY SHERIFF'S OFFICE (CRIMINAL INTELLIGENCE UNIT)
22-FEB-20 22:14
MS EMERGENCY MANAGEMENT AGENCY (MAIN OFFICE)
22-FEB-20 22:14
TEXAS FUSION CENTER (COUNTER TERRORISM)
22-FEB-20 22:14
USCG DISTRICT 8 (MAIN OFFICE)
22-FEB-20 22:14
USCG DISTRICT 8 (PLANNING)
22-FEB-20 22:14

ADDITIONAL INFORMATION

THE ROAD CLOSURES ARE STILL ONGOING.

*** END INCIDENT REPORT #1271847 ***

Report any problems by calling 1-800-424-8802
PLEASE VISIT OUR WEB SITE AT
https://gcc01.safelinks.protection.outlook.com/?url=http%3A%2F%2Fnrc.uscg.mil%2F&data=02%7C01%7Cwesley.mathews%40dot.gov%7Cb811754707c84b89d3e308d7fdabecad%7Cc4cd245b44f04395a1aa3848d258f78b%7C0%7C0%7C637256787161489692&sdata=MzcfYqeN1ZIbmwqa6VXKF9L%2FqieIW0kTmcl30E8JTvk%3D&reserved=0

Appendix B NRC Report No. 1272001

Mathews, Wesley (PHMSA)

From: HQS-SMB-NRC@uscg.mil
Sent: Thursday, May 21, 2020 12:30 PM
To: Mathews, Wesley (PHMSA)
Subject: NRC#1272001

NATIONAL RESPONSE CENTER 1-800-424-8802
*** For Public Use ***
Information released to a third party shall comply with any
applicable federal and/or state Freedom of Information and Privacy Laws

Incident Report # 1272001

INCIDENT DESCRIPTION

*Report taken by NRC on 24-FEB-20 at 19:56 ET.
Incident Type: PIPELINE
Incident Cause: UNKNOWN
Affected Area:
Incident was discovered on 22-FEB-20 at 22:06 local incident time.
Affected Medium: AIR / ATMOSPHERE

SUSPECTED RESPONSIBLE PARTY

Organization: DENBURY GULF COAST PIPELINE

PLANO, TX 75024

Type of Organization: PRIVATE ENTERPRISE

INCIDENT LOCATION
OFF HWY 433 County: YAZOO
City: SATARTIA State: MS
Distance from City: 1 MILES
Direction from City: Latitude: 32° 39' 28" N

Longitude: 090° 32' 13" W

RELEASED MATERIAL(S)
CHRIS Code: CDO Official Material Name: CARBON DIOXIDE
Also Known As:
Qty Released: 21873 BARREL(S)

DESCRIPTION OF INCIDENT
///THIS IS A PHMSA 48HR UPDATE TO NRC REPORT 1271847///

UPDATE: THE CORRECT LAT/LONG FOR THE INCIDENT IS 32.65785 NORTH AND
-90.53695 WEST.
TWO HUNDRED PRIVATE CITIZENS WERE EVACUATED FROM THEIR HOMES IN THE

AREA OF THE RELEASE.
FORTY FIVE PEOPLE WERE TAKEN TO A HOSPITAL. THE NUMBER OF PEOPLE TAKEN TO A HOSPITAL DUE TO INJURIES IS UNKNOWN
TWO PEOPLE ARE STILL AT THE HOSPITAL AS OF 24-FEB-20. THE RELEASE WAS COMPLETELY SECURED AT 23:08HRS ON SATURDAY THE 22-FEB-20. ROAD CLOSURES AND EVACUATION ORDER WAS LIFTED AT 08:00AM ON SUNDAY FEBRUARY 23RD. THE TOTAL AMOUNT OF THE RELEASE WAS DETERMINED TO BE 21,873 BARRELS OF CARBON DIOXIDE GAS. THE EVACUATION RADIUS WAS .25 MILES. TV NEWS AND POSSIBLY NEWSPAPERS IN THE LOCAL AREA AS WELL AS NATIONAL NEWS REPORTED THE INCIDENT. RELEASE DURATION WAS 4 HOURS. PHMSA, MS OIL AND GAS, MS DEQ WERE NOTIFIED. MS DEQ, STATE POLICE, LOCAL FD, LOCAL PD, EMS AND HWY PATROL WERE ALL ON SCENE.

ORIGINAL REPORT: CARBON DIOXIDE RELEASED FROM A 24 INCH PIPELINE DUE TO AN UNKNOWN CAUSE AT THIS TIME. CALLER STATES THE CONTROL ROOM NOTICED A PRESSURE DROP AT 1907 AND PERSONNEL VERIFIED LEAK AT 2046. CALLER ALSO STATES THERE WERE EMERGENCY RESPONDERS ONSITE AS WELL WHEN THEIR PERSONNEL ARRIVED ONSCENE.

INCIDENT DETAILS

Pipeline Type: TRANSMISSION
DOT Regulated: YES
Pipeline Above/Below Ground: BELOW
Exposed or Under Water: NO
Pipeline Covered: UNKNOWN

IMPACT

Fire Involved: NO   Fire Extinguished: UNKNOWN

INJURIES: YES 45 Sent to Hospital:45 Empl/Crew: Passenger:
FATALITIES: NO Empl/Crew: Passenger: Occupant:
EVACUATIONS:YES 200 Who Evacuated: EVERYONE Radius/Area:.25 Mile(s)

Damages: NO

Closure Type	Description of Closure	Hours Closed	Direction of Closure	
Air: NO				
Road: YES	HWY 3; HWY 433; EAGLE BEND RD; PERRY CREEK RD			Major Artery:YES
Waterway:NO				
Track: NO				

Passengers Transferred: NO
Environmental Impact: UNKNOWN
Media Interest: HIGH

REMEDIAL ACTIONS

VALVES WERE IMMEDIATELY SHUT AFTER IDENTIFICATION OF PRESSURE DROP
Release Secured: YES
Release Rate:
Estimated Release Duration:

WEATHER

ADDITIONAL AGENCIES NOTIFIED
Federal: PHMSA
State/Local: MS DEQ, MS OIL AND GAS, SATATE POLICE
State/Local On Scene: MS DEQ, STATE POLICE, PD, FD, EMS
State Agency Number:

NOTIFICATIONS BY NRC
AGCY TOXIC SUBST & DISEASE REGISTRY (HHS)
24-FEB-20 20:22
CENTERS FOR DISEASE CONTROL (GRASP)
24-FEB-20 20:22
DEPT OF HEALTH AND HUMAN SERVICES (SECRETARY'S OPERATION CENTER (SOC))
24-FEB-20 20:22
AZ OFFIC OF INTEL AND ANALYSIS (FIELD INTELLIGENCE AND INTEGRATION DIVISION)
24-FEB-20 20:22
DHS DEFENSE THREAT REDUCTION AGENCY (CHEMICAL AND BIOLOGICAL TECHNOLOGIES DEPARTMENT)
24-FEB-20 20:22
MS DEPT OF HOMELAND SECURITY (I&A FIELD OPS)
24-FEB-20 20:22
DOT CRISIS MANAGEMENT CENTER (MAIN OFFICE)
24-FEB-20 20:22
EPA HQ EMERGENCY OPERATIONS CENTER (MAIN OFFICE (AUTO))
24-FEB-20 20:22
EPA HQ EMERGENCY OPERATIONS CENTER (AFTER HOURS SECONDARY)
24-FEB-20 20:36
U.S. EPA IV (MAIN OFFICE)
24-FEB-20 20:32
U.S. EPA IV (EPA RRT4)
24-FEB-20 20:22
GULF STRIKE TEAM (MAIN OFFICE)
24-FEB-20 20:22
INFO ANALYSIS AND INFRA PROTECTION (MAIN OFFICE)
24-FEB-20 20:22
JFO-LA (COMMAND CENTER)
24-FEB-20 20:22
MS ANALYSIS AND INFORMATION CENTER (FUSION CENTER)
24-FEB-20 20:22
NATIONAL INFRASTRUCTURE COORD CTR (MAIN OFFICE)
24-FEB-20 20:22
NOAA RPTS FOR MS (MAIN OFFICE)
24-FEB-20 20:22
NRC COMMAND DUTY OFFICER (MAIN OFFICE)

24-FEB-20 20:50
NTSB PIPELINE (MAIN OFFICE)
24-FEB-20 20:22
OCCUPATIONAL SAFETY & HEALTH ADMIN (MAIN OFFICE)
24-FEB-20 20:22
PIPELINE & HAZMAT SAFETY ADMIN (OFFICE OF PIPELINE SAFETY (AUTO))
24-FEB-20 20:22
PIPELINE & HAZMAT SAFETY ADMIN (OFFICE OF PIPELINE SAFETY WEEKDAYS (VERBAL))
24-FEB-20 20:34
PIPELINE & HAZMAT SAFETY ADMIN (HAZARDOUS MATERIAL ACCIDENT INVESTIGATION)
24-FEB-20 20:22
DOI FOR REGION 4 (MAIN OFFICE)
24-FEB-20 20:22
REPORTING PARTY (RP SUBMITTER)
24-FEB-20 20:22
SECTOR LOWER MISSISSIPPI RIVER (AUTO NRC NOTIFICATIONS)
24-FEB-20 20:22
SHELBY SHERIFF'S OFFICE (CRIMINAL INTELLIGENCE UNIT)
24-FEB-20 20:22
MS EMERGENCY MANAGEMENT AGENCY (MAIN OFFICE)
24-FEB-20 20:22
TEXAS FUSION CENTER (COUNTER TERRORISM)
24-FEB-20 20:22
USCG DISTRICT 8 (MAIN OFFICE)
24-FEB-20 20:22
USCG DISTRICT 8 (PLANNING)
24-FEB-20 20:22

ADDITIONAL INFORMATION
///THIS IS A PHMSA 48HR UPDATE TO NRC REPORT 1271847///

*** END INCIDENT REPORT #1272001 ***
Report any problems by calling 1-800-424-8802
PLEASE VISIT OUR WEB SITE AT
https://gcc01.safelinks.protection.outlook.com/?url=http%3A%2F%2Fnrc.uscg.mil%2F&data=02%7C01%7Cwesley.mathews%40dot.gov%7Cb126276307c640ca447f08d7fdab7b17%7Cc4cd245b44f04395a1aa3848d258f78b%7C0%7C0%7C637256785273758601&sdata=wEB2Wbm6RWfQw9nm5l8g20CXFahn0HprioWivv3i1Uo%3D&reserved=0

Appendix C PHMSA 7000.1 Final Report

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: 8/31/2020

U.S Department of Transportation Pipeline and Hazardous Materials Safety Administration	**Original Report Date:**	03/21/2020
	No.	20200087 - 34574 ------------------------- (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	**Yes**

Last Revision Date:	11/25/2020
1. Operator's OPS-issued Operator Identification Number (OPID):	32545
2. Name of Operator	DENBURY GULF COAST PIPELINES, LLC
3. Address of Operator:	
3a. Street Address	5851 LEGACY CIRCLE SUITE 1200
3b. City	PLANO
3c. State	Texas
3d. Zip Code	75024
4. Local time *(24-hr clock)* and date of the Accident:	02/22/2020 19:07
5. Location of Accident:	
Latitude / Longitude	32.65785, -90.53695
6. National Response Center Report Number (if applicable):	1271847
7. Local time *(24-hr clock)* and date of initial telephonic report to the National Response Center (if applicable):	02/22/2020 20:51
8. Commodity released: *(select only one, based on predominant volume released)*	CO2 (Carbon Dioxide)
- 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):	9,532.00
10. Estimated volume of intentional and/or controlled release/blowdown (Barrels):	21,873.00
11. Estimated volume of commodity recovered (Barrels):	
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:	02/22/2020 19:15
14b. Local time pipeline/facility restarted:	10/26/2020 12:30
- Still shut down? (* Supplemental Report Required)	
15. Did the commodity ignite?	No
16. Did the commodity explode?	No
17. Number of general public evacuated:	200
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":	02/22/2020 20:20
18b. Local time Operator resources arrived on site:	02/22/2020 20:20

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:	Mississippi
3. Zip Code:	39194
4. City	Not Within a Municipality
5. County or Parish	Yazoo County
6. Operator-designated location:	Milepost/Valve Station
Specify:	6.6
7. Pipeline/Facility name:	Delhi
8. Segment name/ID:	Delhi
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):	360
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:	Weld, including heat-affected zone
- If Pipe, specify:	
3a. Nominal diameter of pipe (in):	24
3b. Wall thickness (in):	.540

3c. SMYS (Specified Minimum Yield Strength) of pipe (psi):	80,000
3d. Pipe specification:	API 5L
3e. Pipe Seam , specify:	Longitudinal ERW - High Frequency
- If Other, Describe:	
3f. Pipe manufacturer:	Stupp Corporation
3g. Year of manufacture:	2007
3h. Pipeline coating type at point of Accident, specify:	Field Applied Epoxy
- If Other, Describe:	
- If Weld, including heat-affected zone, specify. If Pipe Girth Weld, 3a through 3h above are required:	Pipe Girth Weld
- 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:	2009
5. Material involved in Accident:	Carbon Steel
- If Material other than Carbon Steel, specify:	
6. Type of Accident Involved:	Other
- If Mechanical Puncture – Specify Approx. size:	
in. (axial) by	
in. (circumferential)	
- If Leak - Select Type:	
- If Other, Describe:	
- If Rupture - Select Orientation:	
- If Other, Describe:	
Approx. size: in. (widest opening) by	
in. (length circumferentially or axially)	
- If Other – Describe:	Guillotine Type Failure

PART D - ADDITIONAL CONSEQUENCE INFORMATION

1. Wildlife impact:	No
1a. If Yes, specify all that apply:	
- Fish/aquatic	
- Birds	
- Terrestrial	
2. Soil contamination:	No
3. Long term impact assessment performed or planned:	No
4. Anticipated remediation:	No
4a. If Yes, specify all that apply:	
- Surface water	
- Groundwater	
- Soil	
- Vegetation	
- Wildlife	
5. Water contamination:	No
5a. If Yes, specify all that apply:	
- Ocean/Seawater	
- Surface	
- Groundwater	
- Drinking water: *(Select one or both)*	
- Private Well	
- Public Water Intake	
5b. Estimated amount released in or reaching water (Barrels):	
5c. Name of body of water, if commonly known:	
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?	No
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:	
Was this HCA identified in the "could affect" determination for this Accident site in the Operator's 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	Yes
Was this HCA identified in the "could affect" determination for this Accident site in the Operator's Integrity Management Program?	No
- 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	
Was this HCA identified in the "could affect" determination for this Accident site in the Operator's Integrity Management Program?	
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	$ 225,899
8b. Estimated cost of commodity lost	$ 11,130
8c. Estimated cost of Operator's property damage & repairs	$ 3,504,518
8d. Estimated cost of Operator's emergency response	$ 205,462
8e. Estimated cost of Operator's environmental remediation	$ 0
8f. Estimated other costs	$ 0
Describe:	
8g. Estimated total costs (sum of above) – effective 12-2012, changed to "Total estimated property damage (sum of above)"	$ 3,947,009

PART E - ADDITIONAL OPERATING INFORMATION

1. Estimated pressure at the point and time of the Accident (psig):	1,402.00
2. Maximum Operating Pressure (MOP) at the point and time of the Accident (psig):	2,160.00
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:	Remotely Controlled
5c. Length of segment isolated between valves (ft):	50,406
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?	Yes
- 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	Yes
- 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?	No
- If Yes:	
7a. Was it operating at the time of the Accident?	
7b. Was it fully functional at the time of the Accident?	
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?	
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?	
8. How was the Accident initially identified for the Operator?	CPM leak detection system or SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume calculations)
- 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:	
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	
- Investigation identified areas other than those above:	
Describe:	
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?	No
- If Yes:	
1a. Specify how many were tested:	

1b. Specify how many failed:	
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:	G2 - Natural Force Damage

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

Corrosion Failure – Sub-Cause:	
- If External Corrosion:	
1. Results of visual examination:	
- If Other, Describe:	
2. Type of corrosion: *(select all that apply)*	
- Galvanic	
- Atmospheric	
- Stray Current	
- Microbiological	
- Selective Seam	
- Other:	
- If Other, Describe:	
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	
- Other:	
- If Other, Describe:	
4. Was the failed item buried under the ground?	
- If Yes :	
4a. Was failed item considered to be under cathodic protection at the time of the Accident?	
If Yes - Year protection started:	
4b. Was shielding, tenting, or disbonding of coating evident at the point of the Accident?	
4c. Has one or more Cathodic Protection Survey been conducted at the point of the Accident?	
If "Yes, CP Annual Survey" – Most recent year conducted:	
If "Yes, Close Interval Survey" – Most recent year conducted:	
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?	
- 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?	
15a. If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run: -	
- Magnetic Flux Leakage Tool	
Most recent year:	
- Ultrasonic	
Most recent year:	
- Geometry	
Most recent year:	
- Caliper	
Most recent year:	
- Crack	
Most recent year:	
- Hard Spot	
Most recent year:	
- Combination Tool	
Most recent year:	
- 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?	
If Yes -	
Most recent year tested:	
Test pressure:	
17. Has one or more Direct Assessment been conducted on this 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:	
18. Has one or more non-destructive examination been conducted at the point of the Accident since January 1, 2002?	
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:	Heavy Rains/Floods
- If Earth Movement, NOT due to Heavy Rains/Floods:	
1. Specify:	

- If Other, Describe:	
- If Heavy Rains/Floods:	
2. Specify:	Other
- If Other, Describe:	,Soil movement, promoted by unusually high rainfall averages and not a singular event, induced axial stresses sufficient to cause an overload condition.,,
- 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?	No
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:	
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

On 2/22/2020 at 19:07, the Denbury Control Center (DCC) observed a low-pressure alarm at the Satartia motor operated valve (MOV) location on the Delhi segment. The Control Center Supervisor was notified and at 19:15 the upstream MOV, downstream MOV, and the Satartia MOV were closed by the DCC. Denbury operations personnel were immediately notified by the DCC of low-pressure alarms and valve closures and were mobilized to the area in addition to emergency response contractors. While mobilization of personnel occurred, the DCC closed all CO2 sources to Delhi segment between 19:26 and 19:28. At 19:54, a Denbury representative contacted the Tri-Community Fire Chief, who was on-site and identified himself as the Incident Commander on location acknowledging the incident was being managed in the Unified Command. Denbury personnel arrived on-site at 20:20 to confirm the Delhi segment had experienced a pipeline failure upstream of the Hwy 433 road crossing. At 20:21, a Denbury representative contacted the Yazoo County EMA, who was directing the Yazoo County Sheriffs Department, MS Highway Patrol, and MDOT. The Yazoo County EMA confirmed that they began facilitating the evacuation of residence near Satartia, MS at approximately 19:20. MSDEQ was notified at 19:58. Both MSDEQ and MEMA were on-scene and performing supporting agency roles during the emergency phase of the response (4 hours). At 20:51, the NRC was notified, and the CO2 leak was reported (NRC #1271847). At 21:36 emergency response contractors arrived on-site and began conducting preliminary air-monitoring for response personnel. At 21:55 additional emergency response contractors arrived on-site and began conducting community air monitoring and atmospheric testing in and around the failure site and the City of Satartia and the surrounding area. Air monitoring and atmospheric testing continued throughout the night. At 23:06, Denbury personnel observed no product coming from the failure location. At 0:00 on 2/23/2020, an Operation Period Briefing was conducted by the Unified Command. During the briefing, the incident command team instructed responders to continue air monitoring, conduct reconnaissance within the evacuated areas to ensure no people were left behind, clear the debris and soil off of HWY 433, and begin developing a plan to lift the evacuation. At 06:00 a planning meeting was conducted by the Unified Command. The recon team confirmed all personnel had been evacuated and reported seeing live cows, dogs, and cats throughout the evacuated area. The air monitoring team also reported that CO2 levels were down to ambient levels and the evacuation could be lifted. At 08:00 the Unified Command gave the All Clear, and the roads were opened and residents in the surrounding area were allowed to return to their homes. Personnel and a toxicologist from CTEH were made available to inspect homes prior to the residence re-entry. At 18:39 on 2/24/2020, the NRC was contacted and given a 48-hour update report (NRC #1272001). A total of 200 residents were evacuated and 45 residents were taken to the hospital. To Denburys knowledge, one individual was admitted to the hospital for reasons unrelated to the pipeline failure.

On 3/9/2020 pipeline samples of the failure location were removed, prepared for shipment, and sent to a testing laboratory on 3/11/2020. The results from the laboratory testing were received and shared with PHMSA on 6/26/2020.

Based on the findings of metallurgical and stress evaluations and the evidence of a code compliant pipeline, it is concluded that soil movement upstream of the failure location induced axial stresses sufficient to cause an overload condition and resulted in the pipeline rupture. Soil movement was promoted by unusually high rainfall averages and not a singular rainfall event.

The pipeline segment was repaired and on 10/26/2020 at 12:30 the pipeline was restarted with no issues.

PART I - PREPARER AND AUTHORIZED SIGNATURE

Preparer's Name	Chad Docekal
Preparer's Title	Regulatory Compliance Specialist
Preparer's Telephone Number	9726732734
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Preparer's Facsimile Number	
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Authorized Signer Email	david.sheppard@denbury.com
Date	11/24/2020

Appendix D Mears Metallurgical and Root Cause Failure Analysis

A QUANTA SERVICES COMPANY

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Study of Root Cause and Contributing Factors

Denbury – Yazoo County

Failure Investigation

Final Report

Revised 9/02/2021

Prepared for:

Denbury Resources Inc.

Prepared by:

Mears Group, Inc.

September 2, 2021

Denbury Resources Inc.

5320 Legacy Drive

Plano, TX 75024

(214) 662-2536

chad.docekal@denbury.com

Attention: Chad Docekal

Subject: Denbury Delhi 24-inch Transmission Line failure Root Cause Analysis – Final Report, Revised 9/02/2021

Thank you for the opportunity to provide Denbury Resources with root cause investigation and analysis for the Denbury Delhi 24-inch transmission line near Satartia, Mississippi. This revision includes additional appendices providing supporting information and responses to questions provided to Mears 4/7/2021. If you have any questions or comments, please call me at (614) 832-3896.

Sincerely,

Kevin Garrity

Executive Vice President

Cc: Dan Wagner

Aida Lopez-Garrity

Kurt Lawson

mears
A QUANTA SERVICES COMPANY

SIGNATURE FORM

Study of Root Cause and Contributing Factors

Denbury – Yazoo County

Failure Investigation

Final Report

Prepared by:

Dan Wagner – Principal Technical Advisor — 9/02/2021 Date

Aida Lopez-Garrity – Executive Director – Special Projects — 9/2/2021 Date

Kevin C. Garrity, P.E., FNACE – Executive Vice President — 9/2/2021

Executive Summary

Mears Group, Inc. (Mears) was retained by Denbury Resources (Denbury) to support investigation efforts and provide a Root Cause Analysis (RCA) in coordination with their response to a pipeline failure on the Delhi 24-inch Transmission Line near Satartia, Mississippi. The failure is reported to have occurred February 22, 2020, with a rupture approximately 6.59 miles (stationing 348+26) downstream of the Tinsley, MS station.

The investigation into the cause and contributing factors to the Delhi 24-inch failure has been undertaken through the following activities:

- In-Situ investigations at the incident location,
- Corrosion and coating related assessments,
- A review of available documents and information associated with the design, specification, construction, operation and maintenance of the pipeline infrastructure, and
- Laboratory Analysis of the Failure.

Metallurgical Testing and Failure Analysis was performed on three samples of pipe from the failure site. The metallurgical testing laboratory completed the following tests and examinations:

- Physical examination,
- Photographic documentation and videography,
- Magnetic Particle Inspection,
- Scanning electron microscopy,
- Metallographic analysis,
- Hardness testing,
- Mechanical testing, and
- Chemical analysis.

The results of the metallurgical testing have been analyzed for the purposes of this report and are relied upon in the formulation of the opinions and conclusions expressed in this report.

Based on the findings presented, the pipeline failure occurred at the girth weld due to an overload of axial stress on the weld. A possible contributing factor to the failure may have been axial stresses introduced by movement. These findings are supported by the following:

1. The brittle failure originated at a girth weld. The presence of soft regions with dimples (ductile mode) and cleavage facets (brittle mode) are characteristics typical of a failure from overload conditions.
2. The failure occurred due to axial stresses. There was no indication of a pre-existing defect and a specific failure initiation site was not apparent.
3. The weld metal for both the failed girth weld and the intact weld was found to have lower hardness values than the surrounding pipe materials indicating the weld metal was weaker than the pipe material and thus, more susceptible to overload under axial stress conditions. The findings do not suggest the failure resulted from a welding quality issue.
4. There was no evidence of internal or external corrosion that may have contributed to the failure mode.
5. The mechanical and chemical testing results were in accordance with the requirements for API 5L X-80M PSL 2 line pipe.
6. The microstructure of the pipe material U/S and D/S of the failed girth weld are consistent with modern X-80M PSL 2 line pipe steel.

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Acronyms and Abbreviations

API	American Petroleum Institute
ARO	Abrasion Resistant Overlay
CP	Cathodic Protection
CVN	Charpy V-Notch
D/S	Downstream
EDS	Energy-Dispersive Spectroscopy
ERW	Electric Resistance Welding
FATT	Fracture Appearance Transition Temperature
FBE	Fusion Bonded Epoxy
GW	Girth Weld
HAZ	Heat Affected Zone
HDD	Horizontal Directional Drilling
HF-ERW	High Frequency Electric Resistance Welding
HV	Hardness Value
ID	Inside Diameter
MAOP	Maximum Allowable Operating Pressure
MPI	Magnetic Particle Inspection
NWT	Nominal Wall Thickness
OD	Outside Diameter
PS	Pipe Sample
PSIG	Pounds per Square Inch Gauge
PSL	Product Specification Levels
RCA	Root Cause Analysis
SEM	Scanning Electron Microscope
SMYS	Specified Minimum Yield Strength
TS	Tensile Strength
U/S	Upstream
UTS	Ultimate Tensile Strength

WT	Wall Thickness
YS	Yield Strength

1.0 INTRODUCTION

Mears Group, Inc. (Mears) was retained by Denbury Resources (Denbury) to support investigation efforts and provide a Root Cause Analysis (RCA) in coordination with their response to a pipeline failure on the Delhi 24-inch Transmission Line near Satartia, Mississippi. The incident is reported to have occurred on February 22, 2020, when a failure occurred on the 24-inch Delhi Transmission Line, resulting a rupture of the pipeline.

The information, material and documentation reviewed and relied upon in the formation of the findings expressed include:

- Pipe and coating data,
- Alignment Sheets,
- Indirect inspection results,
- Google Earth™ imagery,
- As-built drawings and sketches,
- Onsite inspections,
- Field and laboratory test results,
- Metallurgical examination reports,
- Welding Procedures,
- Stress Analysis Report, and
- Personnel interviews.

The findings expressed are based upon the information reviewed to date and analyses performed to date and may be modified as new or additional information/analysis are considered.

2.0 BACKGROUND

The Delhi 24-inch Transmission Line serves as a carrier of carbon dioxide and is approximately 77.4 miles in length. The pipeline segment begins at the Denbury Tinsley Station in Yazoo County, Mississippi and continues to a meter station near Delhi, Louisiana. An overview of the pipeline segment is provided in Figure 1.

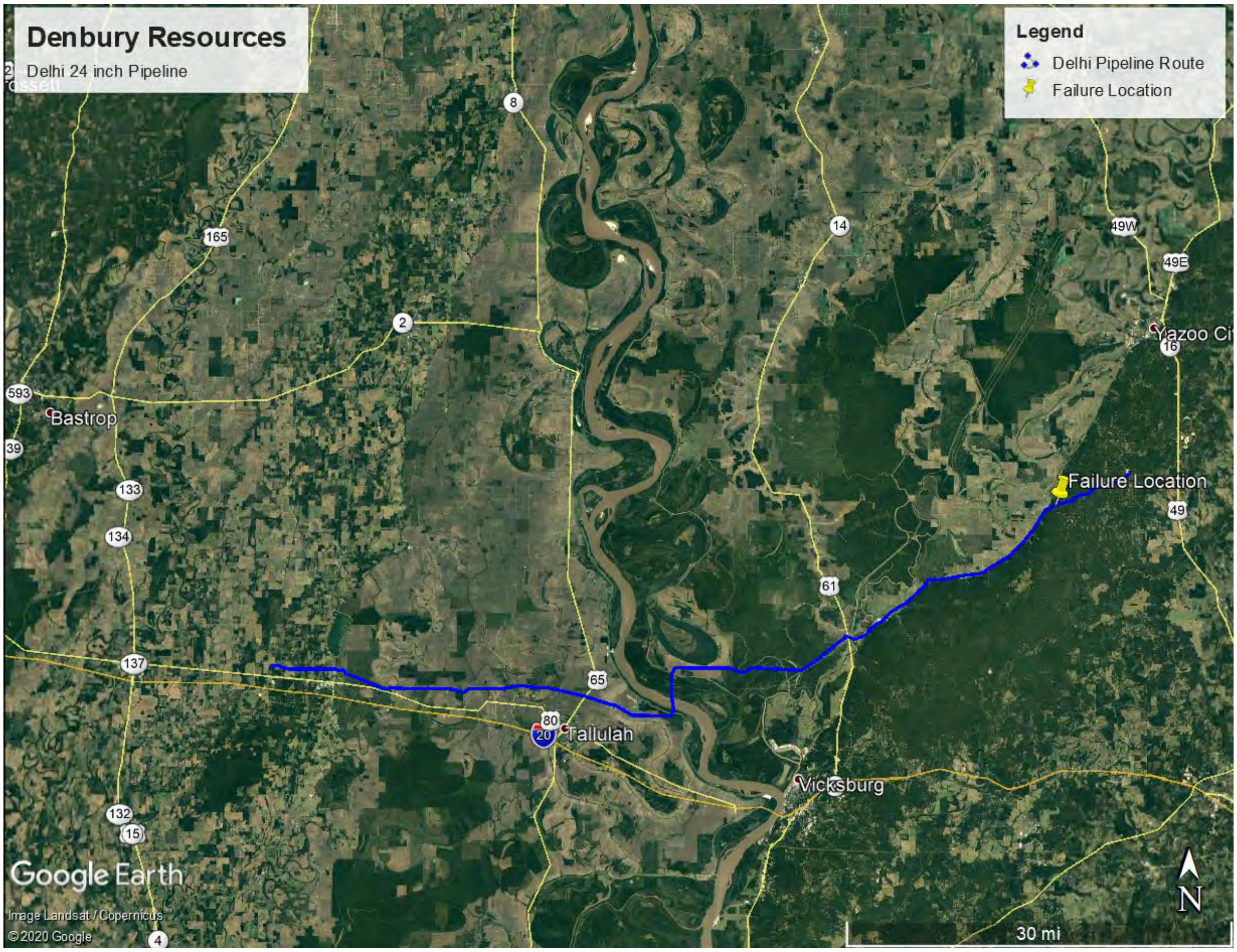

Figure 1. Delhi 24-inch Transmission Pipeline Route

2.1 Pipeline Construction Data

The Delhi 24-inch Transmission Line is documented as installed in 2009, primarily of 0.469-inch wall thickness, API 5L Grade X-80M PSL 2 piping, with a high frequency electric resistance welded (HF-ERW) seam, coated with fusion-bonded epoxy (FBE). Sections of piping installed using slick bore were constructed of 0.540-inch X-80 coated with FBE and an additional layer of abrasion-resistant overcoat (ARO). The pipeline has a diameter of 24 inches. A simplified overview of the pipeline segment is provided in Figure 2.

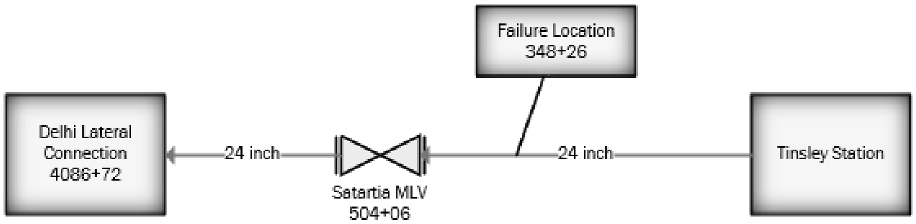

Figure 2. Simplified Delhi 24-inch Transmission Line Diagram

A summary of pipeline information for the Delhi 24-inch Transmission Line in included in Table 1.

Table 1. Pipeline Data

Pipeline Information	Delhi 24-inch Transmission Line
Line Length (miles)	77.4
Pipe Outside Diameter (inches)	24
Pipe Wall Thickness (inches)	0.469, 0.540
Pipe Grade	X-80
Maximum Allowable Operating Pressure (MAOP, psi)	2,160
Normal Operating Stress Level (psi)	1,200-1,450
Pressure at Time of Failure (psi)	1,336
Pipe Seam Type	ERW
Product Carried	Carbon Dioxide (dry)
Pipe Construction Date	2009
Pipe Coatings (type/thickness)	FBE 14-16 mils and ARO 40 mils
Girth Weld Coatings	Liquid Epoxy – SPC-2888

A post-construction hydrostatic pressure test was reported to have been conducted on the piping in January 2009 to a minimum test pressure of 2,908 psig at the Dead Weight Location for 8 hours.

The pipeline is reported to have had impressed current cathodic protection applied since the date of construction with no interference bonds and two continuity bonds at the start and end of the pipeline section.

2.2 Incident Summary

The incident is reported to have occurred after 7:00 p.m. local time, based on resident reports and an evacuation order, on February 22, 2020 near Satartia Mississippi, when a failure occurred at a girth weld, resulting in a rupture of the pipe near a crossing of Mississippi Highway 433 approximately 1 mile southeast of Satartia. The line was shut down and valves closed at approximately 7:17 p.m. as reported by Denbury.

The failure occurred on a pipe section consisting of 24-inch diameter by 0.540-inch wall thickness API 5L Grade X-80M PSL 2 line pipe with a high frequency electric resistance welded (HF ERW) seam. The pipe at the site of the failure was installed using slick bore, coated with FBE/ARO on the pipe and liquid epoxy coating applied on the girth welds. The failure occurred at approximate stationing 348+26, about 6.59 miles downstream of the Tinsley Station at the base of a hill, significantly lower in elevation than the surface of Highway 433. The pipeline normally operates between 1,200 psig and 1,450 psig. At the time of the failure, the pressure at the Tinsley Meter Station (0+00) was 1,336 psig.
A Google Earth™ overview of the failure location is provided in Figure 3.

Figure 3. Delhi 24-inch Transmission Failure Location

A photo of the failure location post-incident is included in Figure 4.

Figure 4. Post-Incident Photo of Failure Location (Downstream to Upstream)

3.0 ROOT CAUSE ANALYSIS PROCESS

A failure action sequence was used for the purposes of performing the Root Cause Analysis. The basic role of a root cause analysis is as follows:

- Collect information.
- Understand what happened.
- Identify the problems that caused the incident.
- Analyze each problem's root causes.
- Look beyond root causes for systemic, cultural, and organizational factors.
- Develop recommendations for remediation to improve performance and prevent repeat incidents.

Since root cause analyses are normally associated with incidents or accidents, much of the existing terminology in use refers to "incidents".

A typical Failure Action Response Sequence adapted from Guidance for Plant Personnel on Gathering Data and Samples for Materials Failure Analysis MTI catalog MTI 9539 is shown in Figure 5.

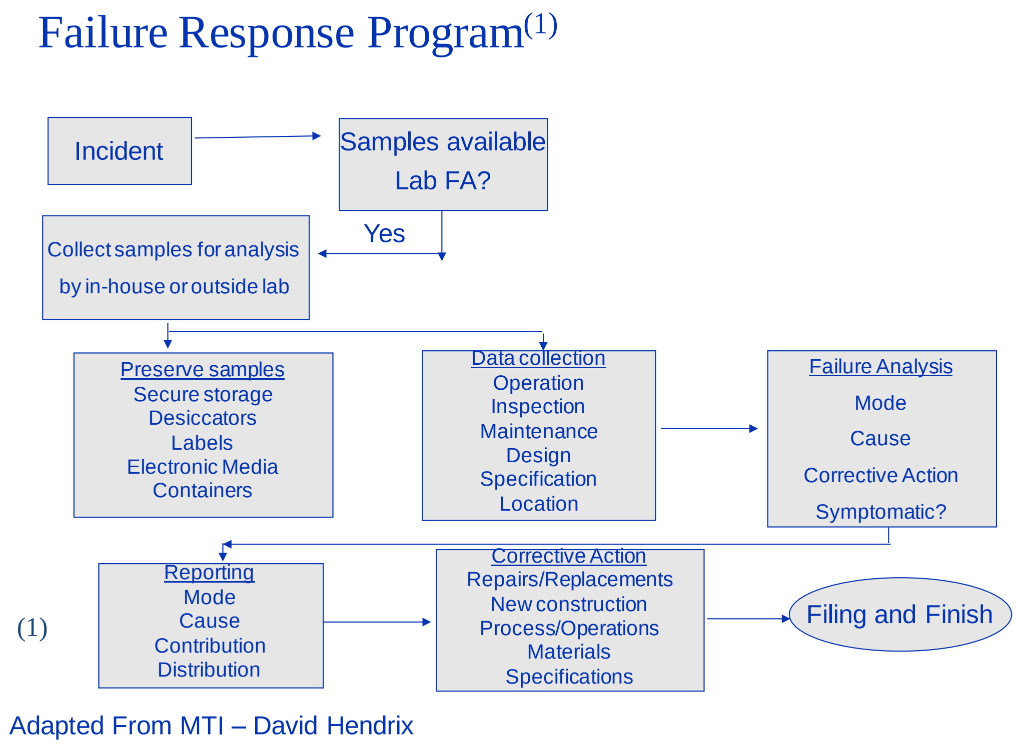

Figure 5. Failure Response Sequence

The root cause analysis focused on identifying the root cause(s) of the pipeline failure and contributing factors.

4.0 DESCRIPTION OF INVESTIGATIVE PROCESS

The investigation into the cause and contributing factors to the Delhi 24-inch Transmission line failure has been undertaken through the following activities:

1. In-Situ investigations at the release location,
2. Corrosion and coating related assessments,
3. A review of available documents and information associated with the design, specification, construction, operation and maintenance of the pipeline infrastructure, and
4. Laboratory failure analysis of the failure.

Metallurgical testing and a failure analysis were performed on three samples of pipe from the release site. The metallurgical testing lab completed the following tests and examinations:

- Physical examination,
- Photographic documentation and videography,
- Magnetic Particle Inspection,
- Scanning electron microscopy,
- Metallographic analysis,
- Hardness testing,
- Mechanical testing, and
- Chemical analysis.

The results of the metallurgical testing have been analyzed for the purposes of this report and are relied upon in the formulation of the opinions and conclusions expressed in this report.
The available information related to construction, prior integrity assessments and cathodic protection was analyzed to assist in establishing the root cause and contributing factors of the failure.

4.1 In-Situ Investigation Findings

On February 27, Mears mobilized to the release location to secure the failed pipe sections for laboratory investigation, perform initial site investigations, and collect information to support the root cause analysis.

Upon arrival, significant response and operational activities had been undertaken to secure the site and prepare for excavation and removal of the pipe section.

From initial visual examination, the failure appeared to have occurred at least 40 feet in elevation below the roadway, with indications of soil subsidence in the vicinity of the failure. The release crater included trees and root debris, but based on the pipeline alignment sheet elevation profile, a significant volume of soil in the slick bore section between the failure and MS Highway 433 had collapsed. The soil in the vicinity of the failure appeared to be extremely wet.

Figure 6 and Figure 7 show the view of the release location as-found on February 27, 2020.

Figure 6. Failure Location (Upstream to Downstream)

Figure 7. Failure Location (Upstream to Downstream)

Personnel were unable to access the pipe at the failure location due to the depth of the crater and instability of the soil on the downstream side of the crater.

In-situ visual inspection of the exterior surface of the pipe identified a separation of the piping at a girth weld of approximately 8 inches, with slight misalignment between the upstream and downstream joints. Figure 8 provides a close-up of the as-found pipe and coating condition at the separation.

Figure 8. Delhi 24-inch Transmission Line Failure - As-Found Condition at Girth Weld

A protocol was developed for removal of pipe samples in the vicinity of the failure, to include the upstream and downstream sections of the failure and an intact girth weld near the failure location. A copy of the Pipe Collection Protocol is provided in Appendix A.

Removal of the samples began on March 9, 2020. Excavation and removal of an upstream section of piping included the upstream half of the failure and the intact girth weld noted above. This section was approximately 68 feet 5 ½ inches in length.

Figure 9 shows the upstream pipe section being removed from the site.

Figure 9. Upstream Pipe Section During Removal

Following removal of the upstream section, limited excavation and backfill was conducted to allow access to the downstream side of the failure. A section of pipe containing the downstream section of the failure was then removed using a magnesium torch attached to the bucket of an excavator.

Once moved to an accessible location, the pipe sections were documented, samples were cut and prepared for shipment to the laboratory. Figure 10 provides an overview of the pipe sections as removed and prepared for shipment.

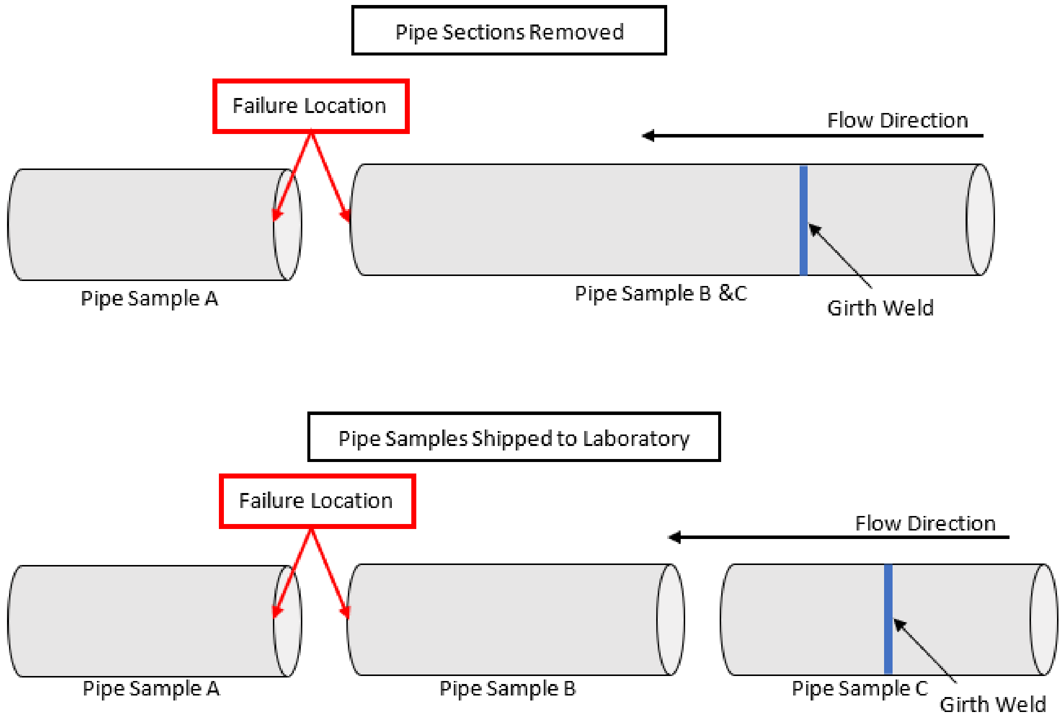

Figure 10. Overview of Pipe Sections and Samples

Visual inspection of the external surface of the pipe sections identified an area of coating damage near the failure, which appeared to have occurred as a result of the failure (no pitting, attached solids, and apparent adhesive failure). No external corrosion was observed and the pipe coating on the remainder of the section appeared to be in excellent condition.

Initial visual inspection of the internal surface of the piping showed no accumulated solids or liquids in the pipe sample and no indications of pitting or corrosion. A view of the internal condition of the pipe section containing samples B & C after removal is provided in Figure 11.

Figure 11. Internal Condition of Pipe Sample During Removal

Soil samples were collected from the area around the pipe for chemical and microbiological analysis, the failure surfaces were protected with foam insulation, then the pipe samples were wrapped, crated and shipped to the laboratory for metallurgical testing on March 10, 2020. The approximate lengths of the pipe samples were PS A – 6 feet, PS B – 6 feet and PS C – 8 feet.

5.0 LABORATORY INVESTIGATION FINDINGS

Metallurgical Testing and a Failure Analysis was performed on a multiple pipe samples from the release site. The work was conducted under Mears direction by a third-party independent laboratory (DNV GL). The metallurgical testing consisted of the following tests and examinations:

- Physical Examination,
- Photographic documentation and videography,
- Scanning electron microscopy
- Metallographic Analysis,

- Hardness testing, and
- Chemical analysis.

The metallurgical sampling and testing protocol utilized for the laboratory investigations is included in Appendix B.

5.1 Visual and Nondestructive Examination

The pipe sections were removed from the shipping crates, visually inspected and photographed. As noted above, some of the pipe coating adjacent to the failed girth weld was missing on PS A and PS B. This may be due to the fact that CO2 is in a supercritical state at about 1,000 psig and about 60°F during the transportation before the rupture. The release of CO2 after the rupture from the actual operating conditions to the atmospheric conditions commonly results in an accumulation and flow of dry ice (i.e. -70°F or colder) which may have impacted adhesion to the pipe.

The mill-applied pipe coating (FBE/ARO) was brown in color, with a light blue liquid epoxy applied to the girth welds. Black residue was found adjacent to ends of the pipe samples cut in the field using an acetylene torch. Figure 12, Figure 13 and Figure 14 show the as-received pipe samples after removal from the crates and protective wrappings.

The pipe adjacent to the fracture surfaces and failed girth weld were visually inspected. The fractured surface was flat and generally at a 180-degree angle with no thinning and/or reduction of the affected area. The fracture path traversed or crossed over the weld at various locations.

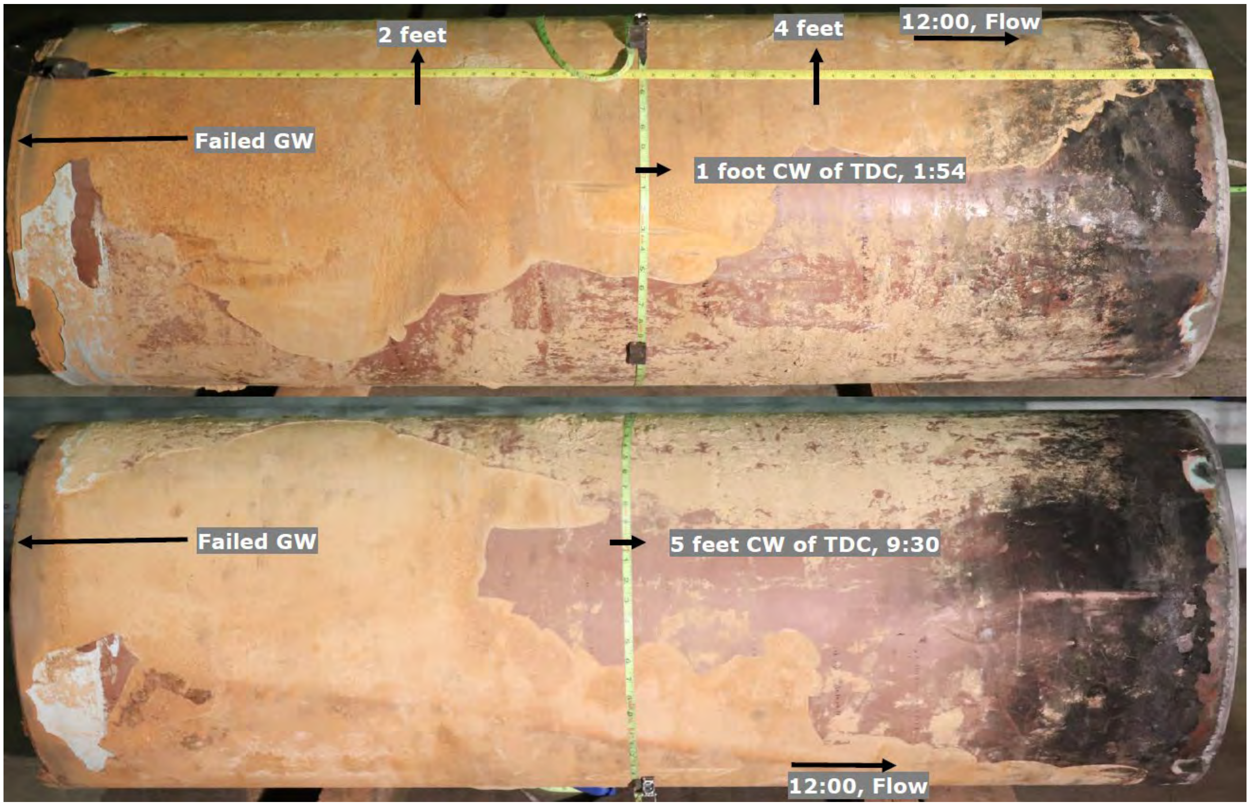

Figure 12. Pipe Sample A (PS A)

Figure 13. Pipe Sample B (PS B)

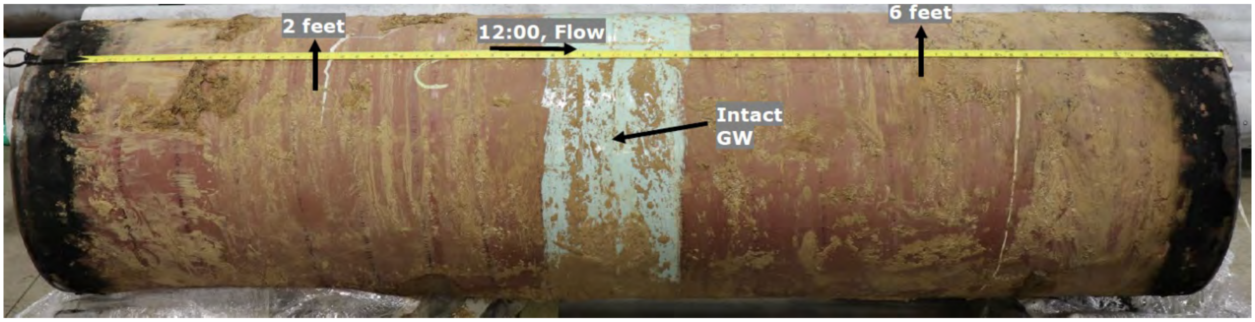

Figure 14. Pipe Sample C (PS C)

A photograph of the fracture surface of PS A is provided in Figure 15.

Figure 15. PS A Fracture Surface (Upstream to Downstream)

Pipe circumferences and diameters were measured at the field-cut ends of the pipe sections, finding no measurable ovality and diameters meeting API 5L tolerances for the 24-inch diameter pipe. Wall thicknesses were between 0.530 inches and 0.540 inches, which meet API 5L tolerances for pipe with a nominal wall thickness (NWT) of 0.540 inches.

The intact girth weld (PS C) was grit blasted and MPI was conducted on the external and internal surfaces. No crack-like indications were identified.

After detailed visual inspection and measurements were collected, the pipe samples were aligned and evaluated to identify locations for further sampling and metallurgical analyses. An overview of the locations selected for metallography (M, MU), fractography (S), mechanical and chemical analyses is provided in Figure 16.

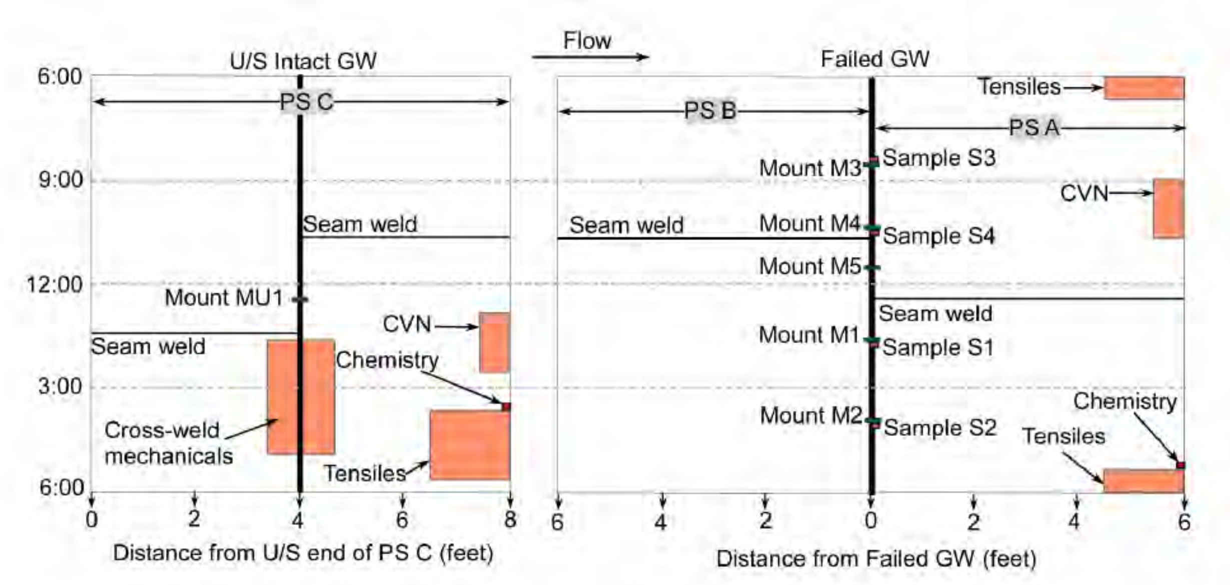

Figure 16. Laboratory Testing and Sample Schematic

5.2 Defect Examination

The internal and external surfaces of the failed girth weld were cleaned with a soft bristle brush to for more detailed examination. Five areas were selected for metallurgical analyses of the failed girth weld (PS A, PS B) and one area from the intact girth weld in PS C. The fracture surface consisted of smooth regions and rougher surfaces that varied in thickness throughout the rupture face. An example of these regions is provided in Figure 17. There was no evidence of pre-existing manufacturing flaws. It was not possible to determine the exact location of the failure initiation process due to the lack of chevrons on the fracture surface.

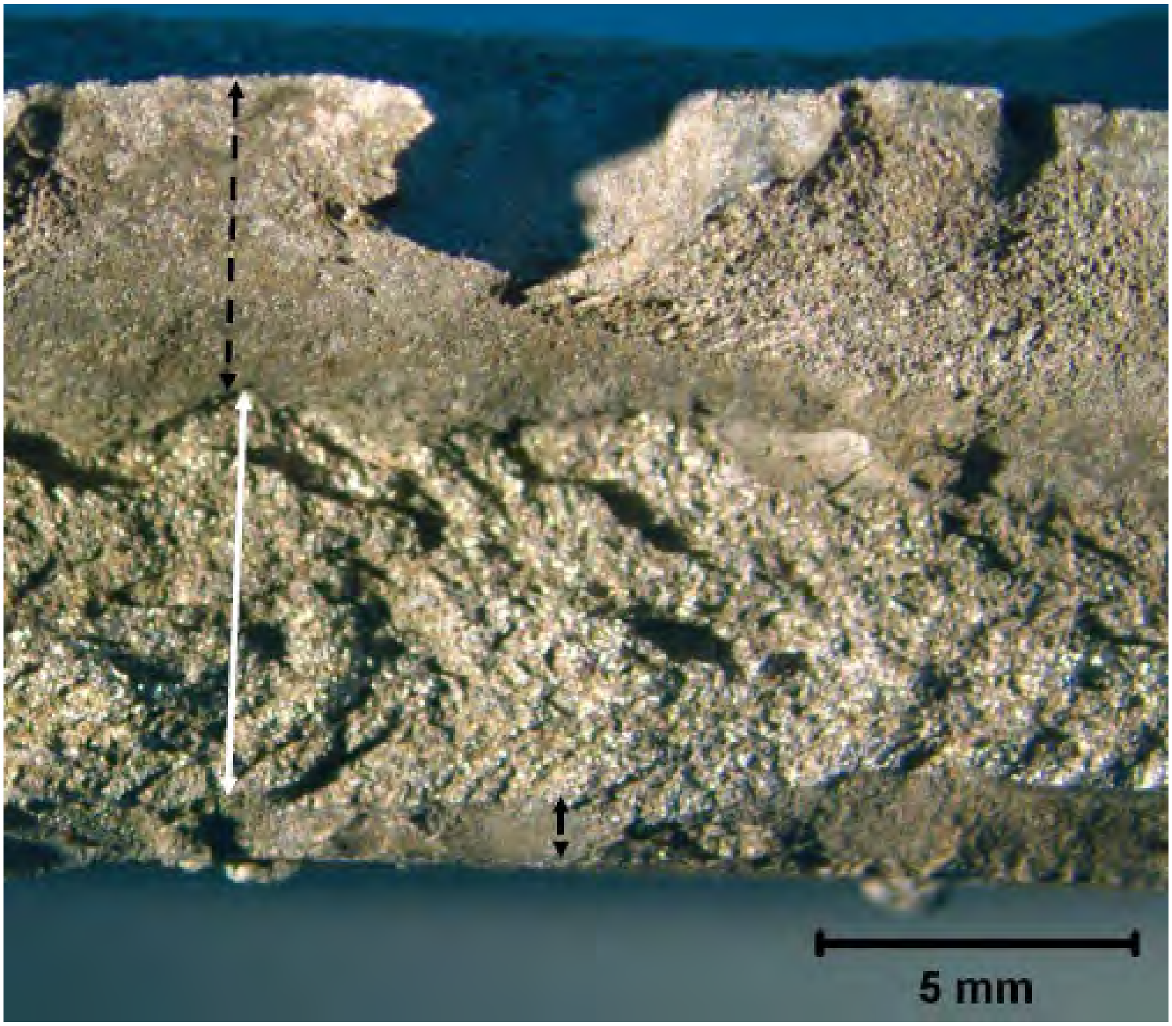

Figure 17. Image of Sample S2 - Smooth (Black Arrow) and Rough (White Arrow) Regions

5.3 Metallography and Fractographic Examination

Upon removal of the samples discussed above, the samples were evaluated utilizing standard microscopy techniques including stereographic evaluations, microscopic evaluation and scanning electron microscopy. Five (5) axial and cross-sections were removed from the failed girth weld and one (1) from the intact weld for metallographic analysis. Some of the samples contain fracture paths at a shear angle (fracture path through the smooth surfaces) and other show the fracture path perpendicular to the free surface and regions of shear failure (fracture surface is rough).

These samples are shown in Figure 18.

Figure 18. Metallurgical samples M1 through M5

5.3.1 Metallurgical Sample 1

Sample M1 contains a fracture path at a shear angle. This sample was removed from the girth weld at the 1:35 o'clock orientation (see Figure 19).

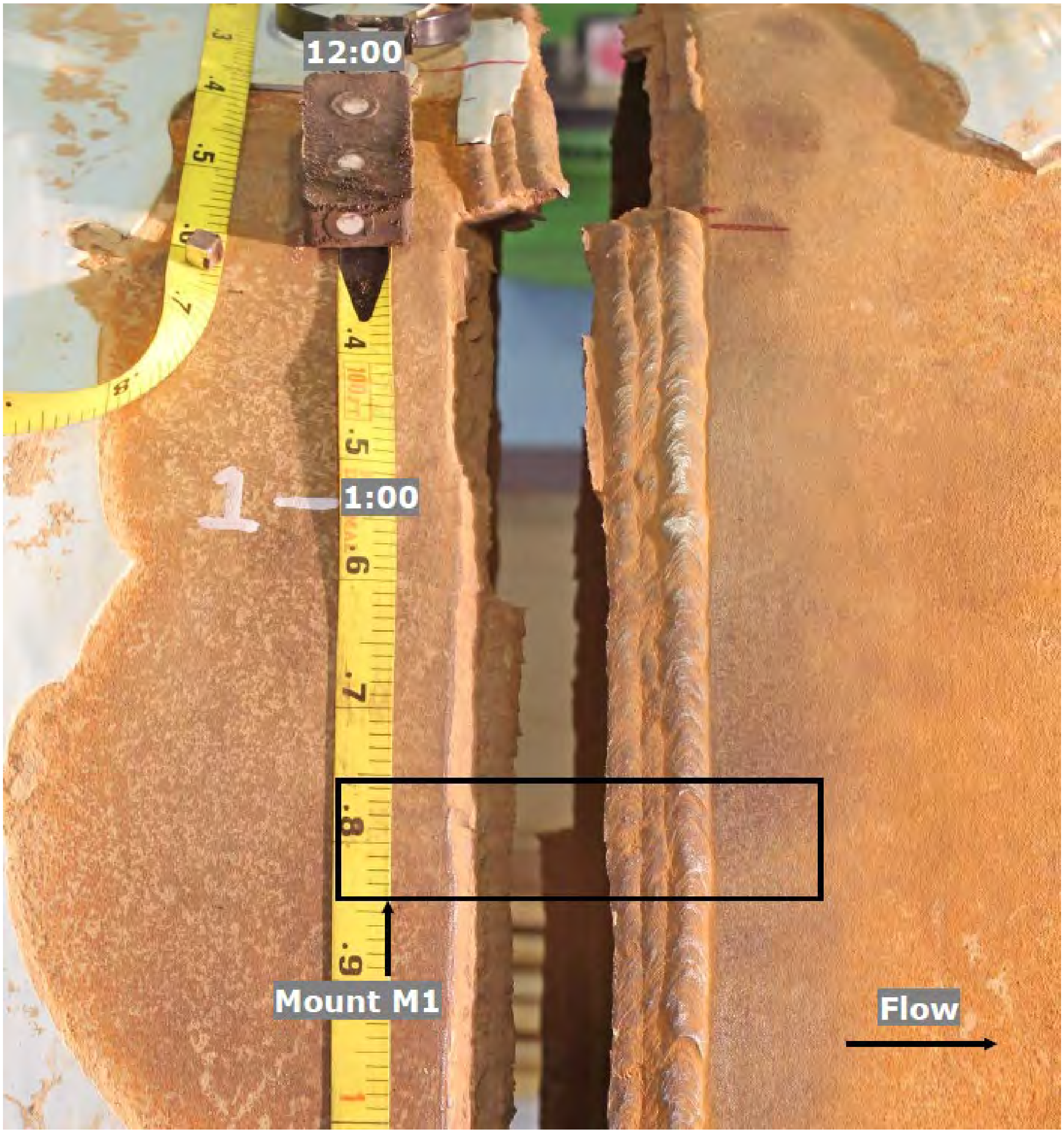

Figure 19. Overview of Mount M1

The fracture path of this sample is located in the HAZ near the toe of the weld at the OD surface. An image of the cross section of sample M1 is provided in Figure 20.

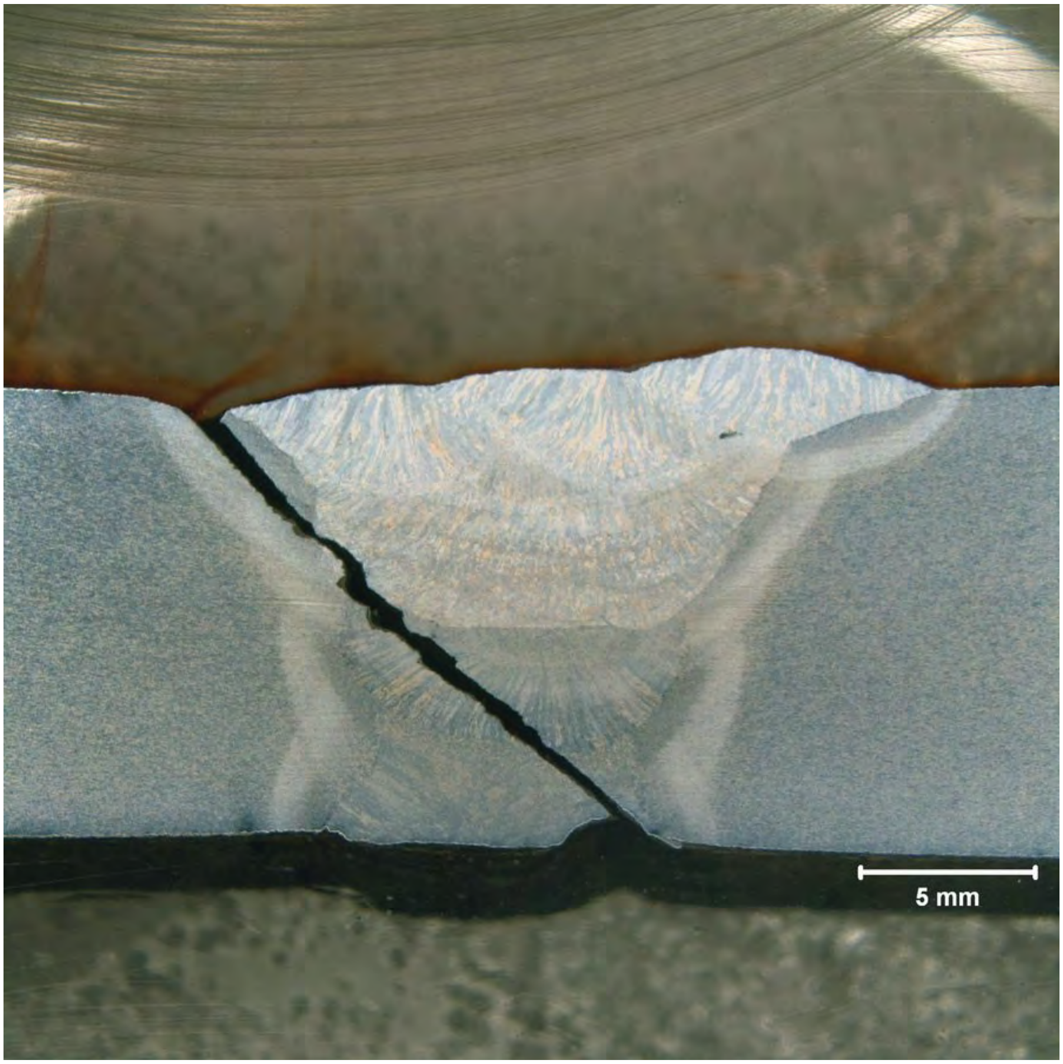

Figure 20. Representative Cross-Section from Sample M1

There is no indication of excessive porosity and/or inclusions. It shows a slight misalignment of the high-low weld of approximately 4.3% of the NWT. Higher magnifications are provided in the laboratory report which show grain elongation due to the cold work that took place during the rupture process. This is consistent with ductile overloading. The microstructure is typical of modern X80 line pipe. A close-up of sample M1 is provided in Figure 21.

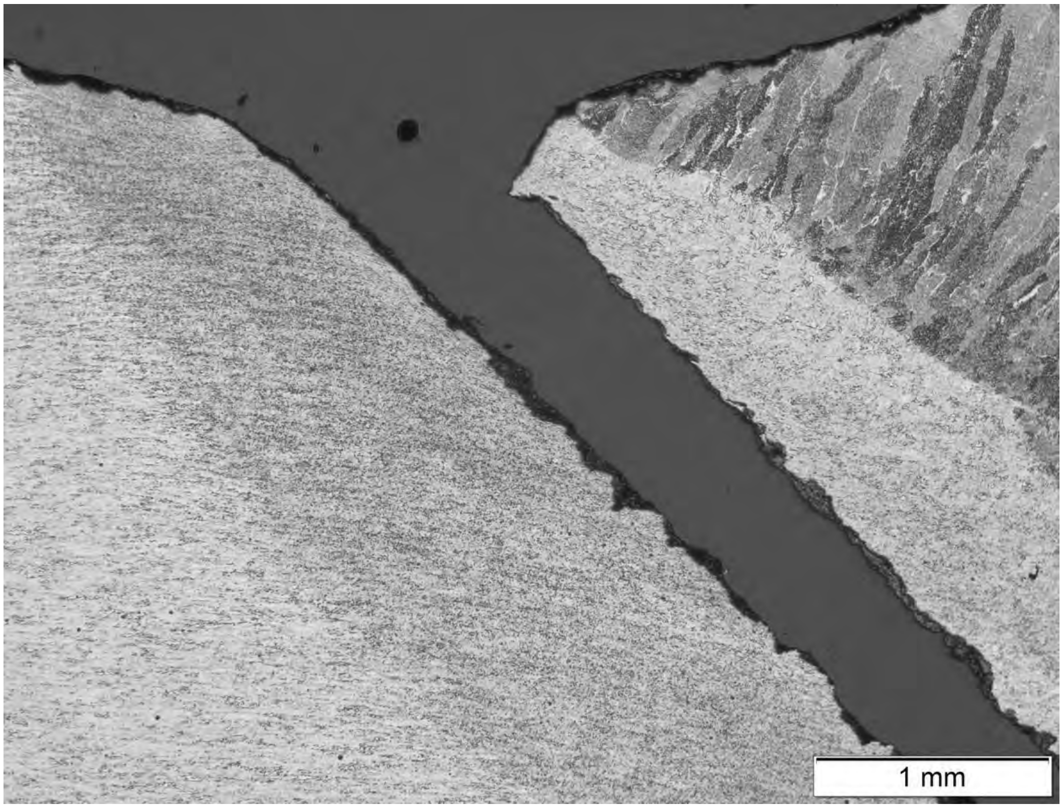

Figure 21. Close-Up of Sample M1

5.3.2 Metallurgical Sample 2

Sample 2 contains regions where the fracture path is perpendicular to the free surface and regions of shear failure. This sample was taken from the GW at the 3:55 o'clock orientation (see Figure 22).

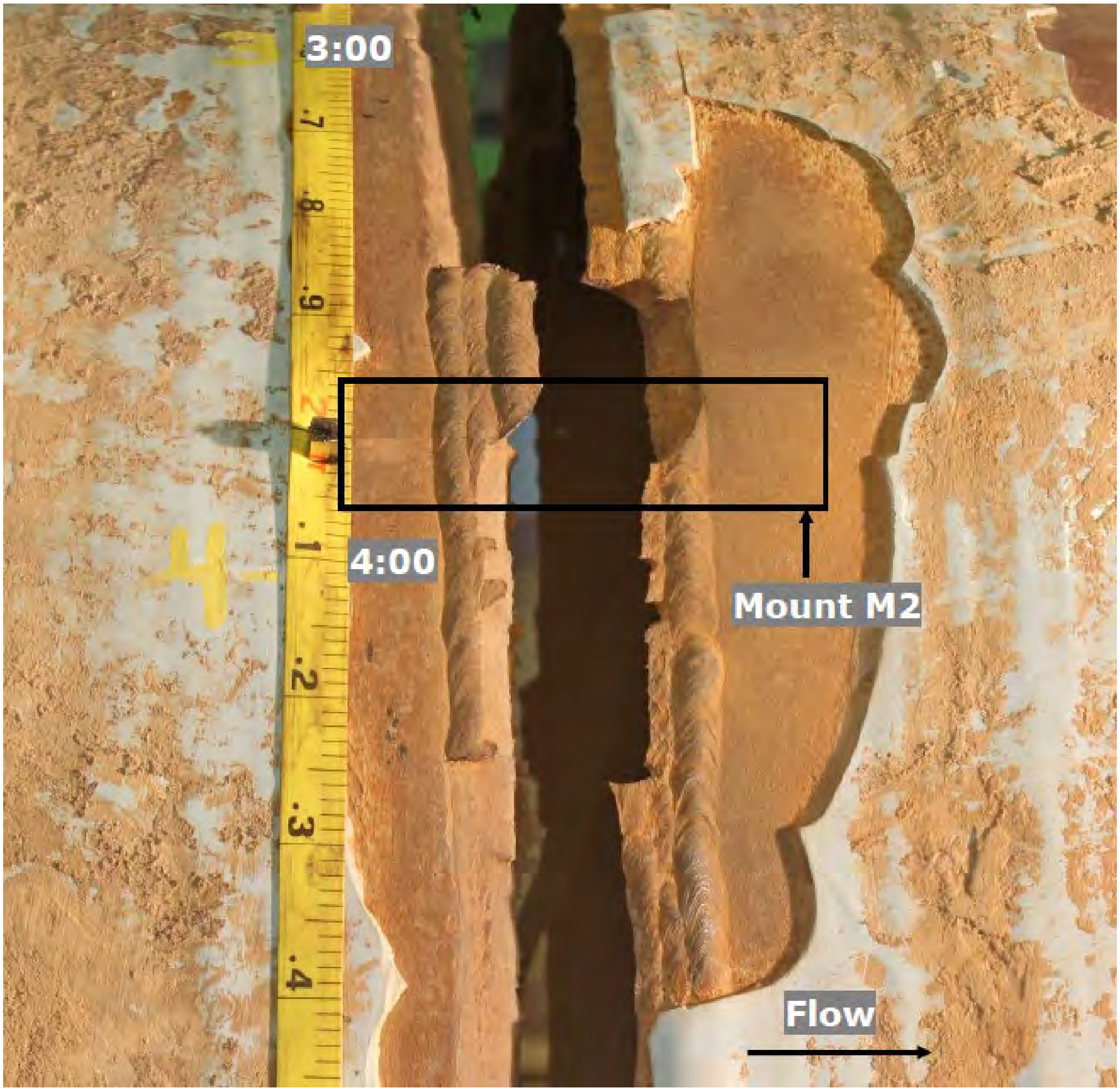

Figure 22. Overview of Mount M2

The cross section of M2 includes both the weld metal and HAZ. The cross section of sample M2 is provided in Figure 23.

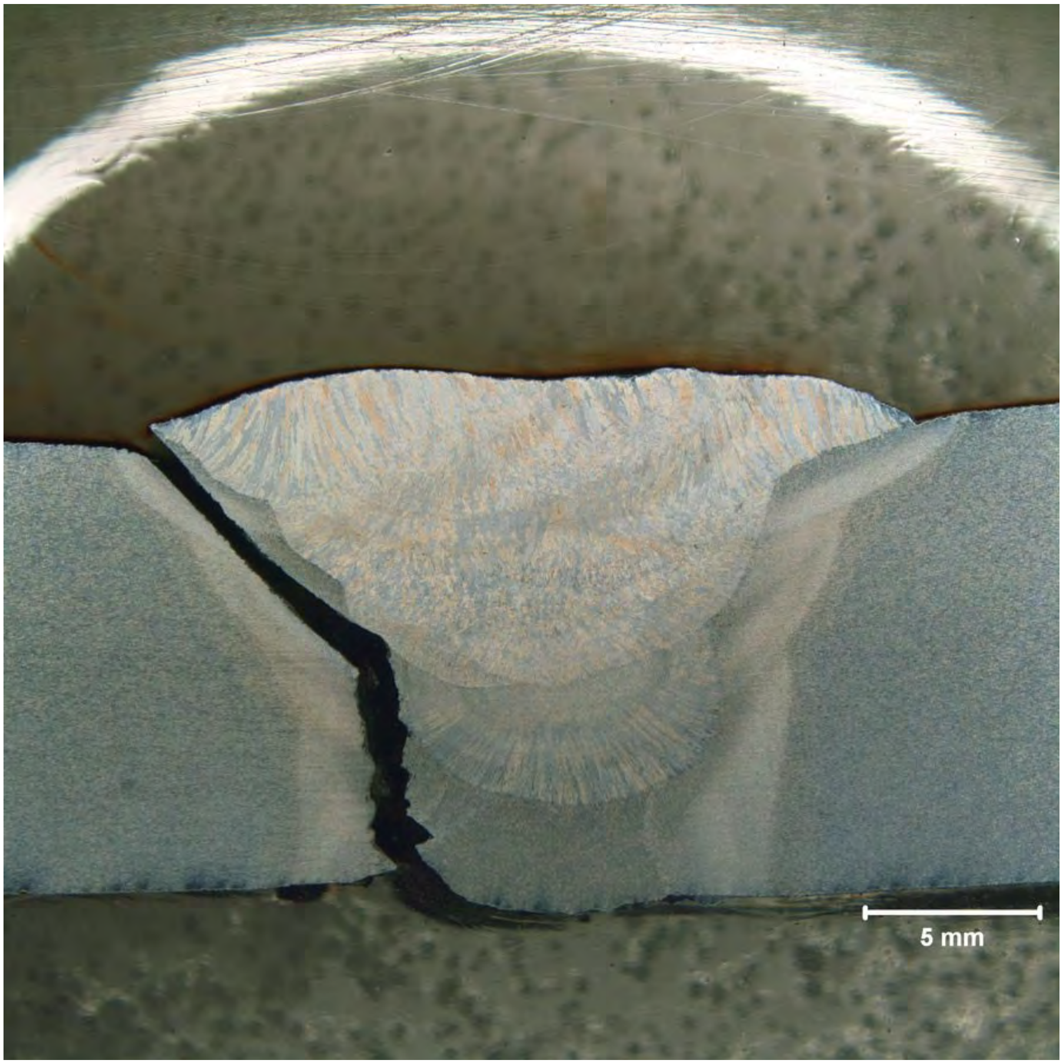

Figure 23. Representative Cross-Section from Sample M2

There are both smooth and rough regions in this sample. The high-low weld misalignment at this location is approximately 6.9% of the NWT. The fracture path at this location was mainly located at the HAZ. Fractography in the SEM shows the presence of a smooth region containing dimples (typical of ductile behavior) and cleavage facets (typical of brittle behavior) in the rough region. Some fissures were also found in the area where cleavage facets were located. These fissures are usually seen in girth weld overload areas (see Figure 24).

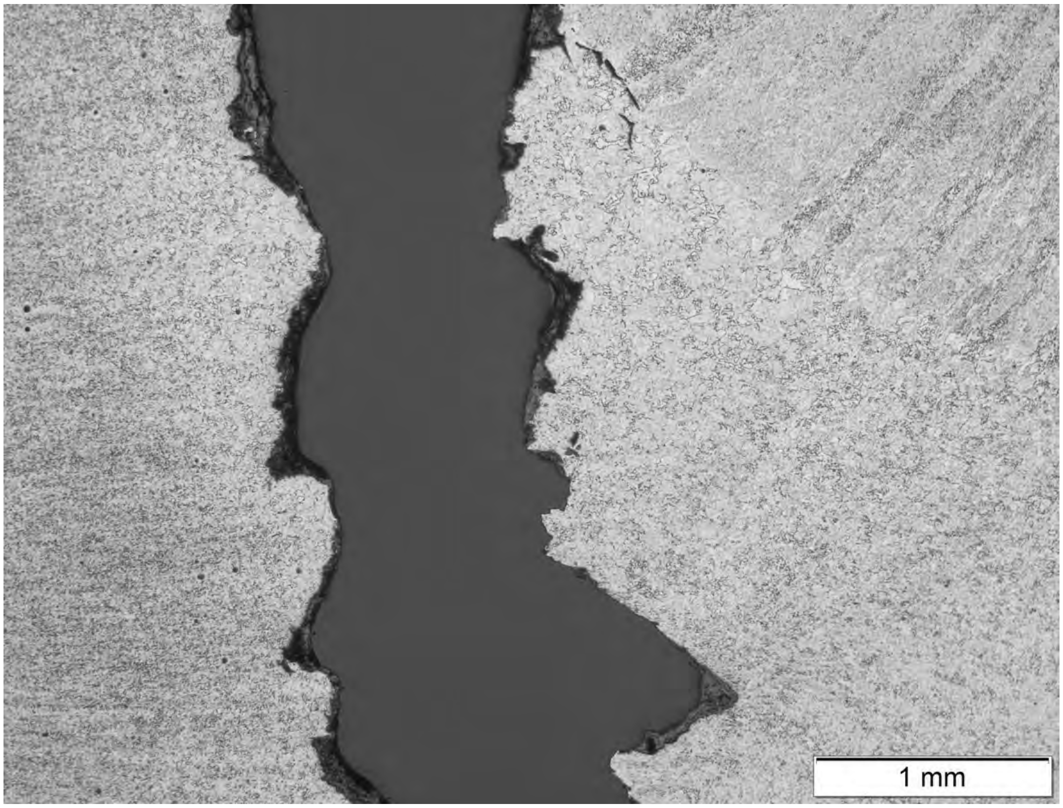

Figure 24. Close-Up of Sample M2

5.3.3 Metallurgical Sample 3

This sample was removed from the failed GW at the 8:35 o'clock orientation (Figure 25).

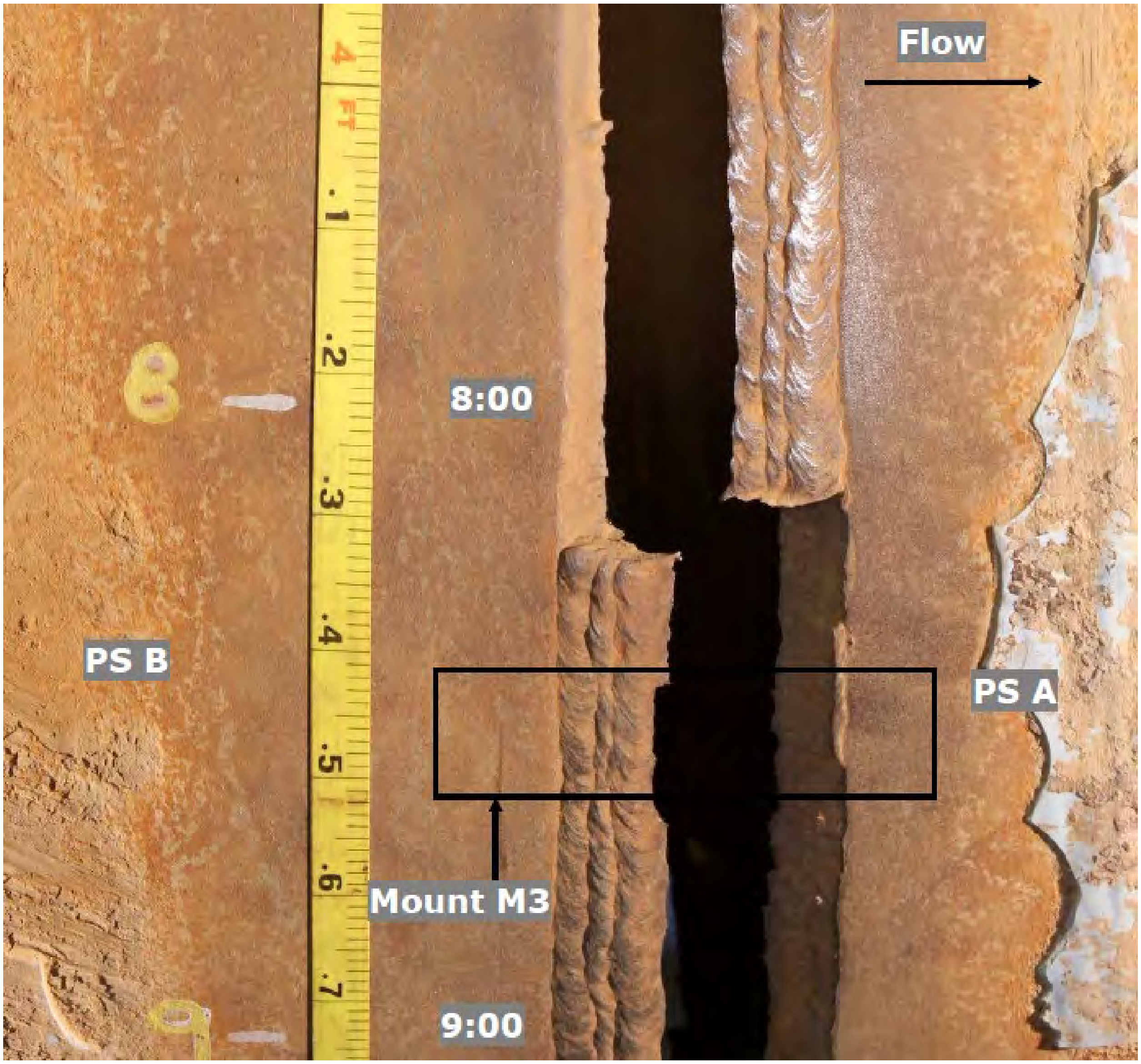

Figure 25. Overview of Mount M3

The fracture path is at a shear angle and mainly located in the weld metal. The morphology of the weld is similar to samples M1 and M2. The high-low weld misalignment at this location was approximately 2.6% of the NWT. The microstructure is consistent with the findings in samples M1 and M2 (see Figure 26 and Figure 27).

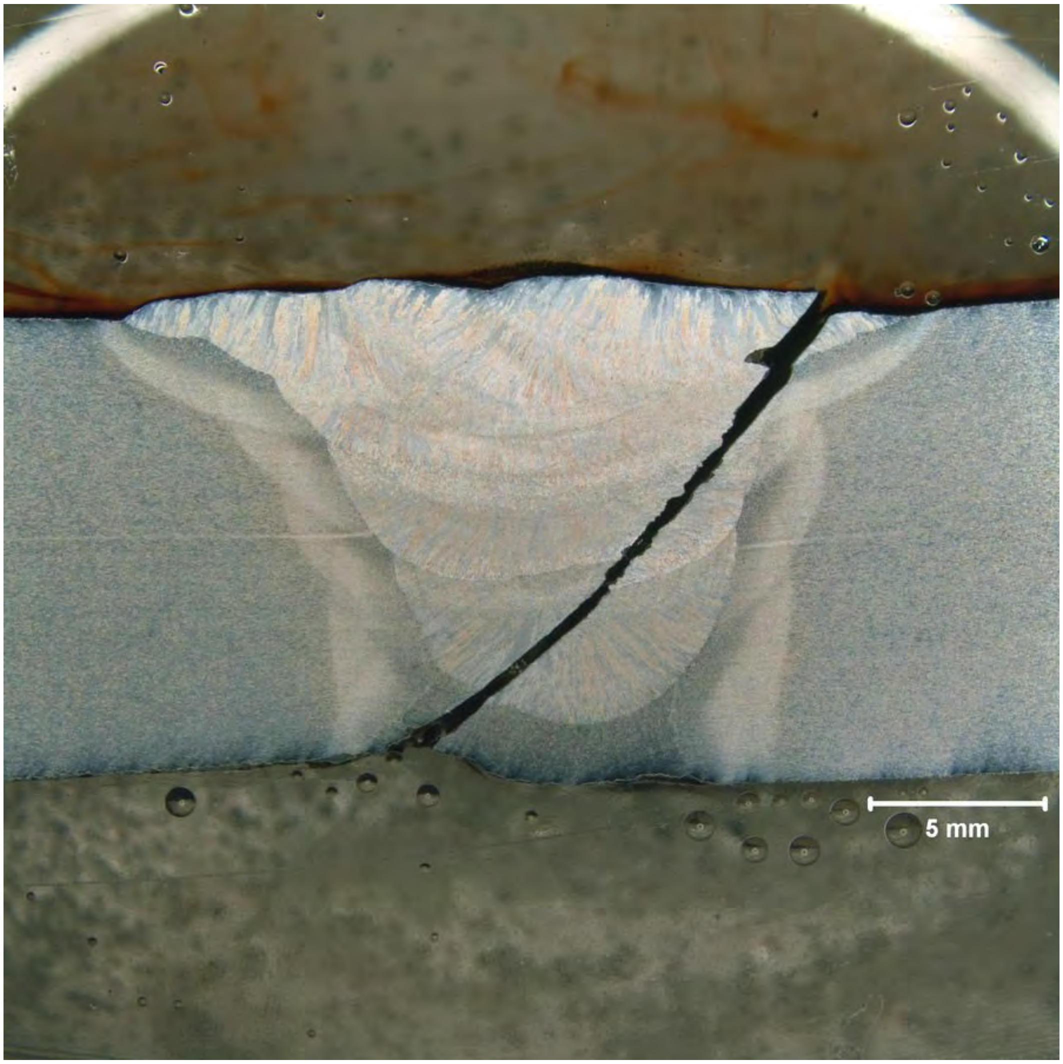

Figure 26. Location of Mount M3

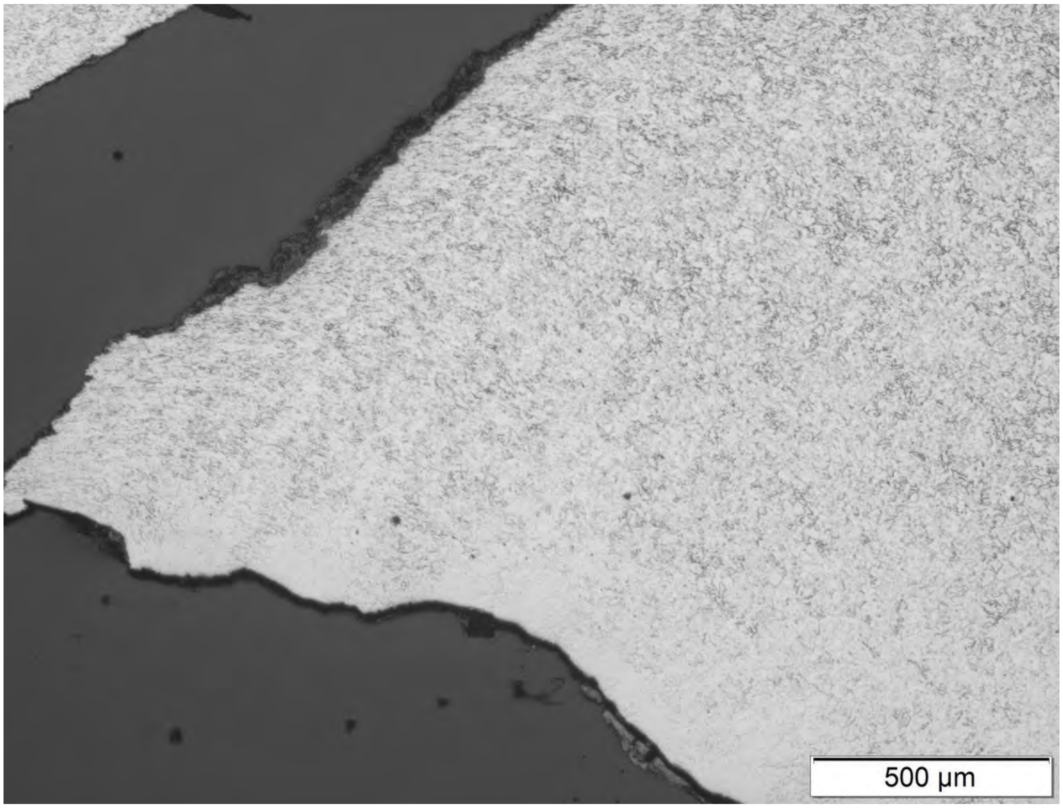

Figure 27. Close-Up of Sample M3

5.3.4 Metallurgical Sample 4

Sample M4 was removed from the failed GW at the 10:24 o'clock orientation. An overview of sample M4 is provided in Figure 28.

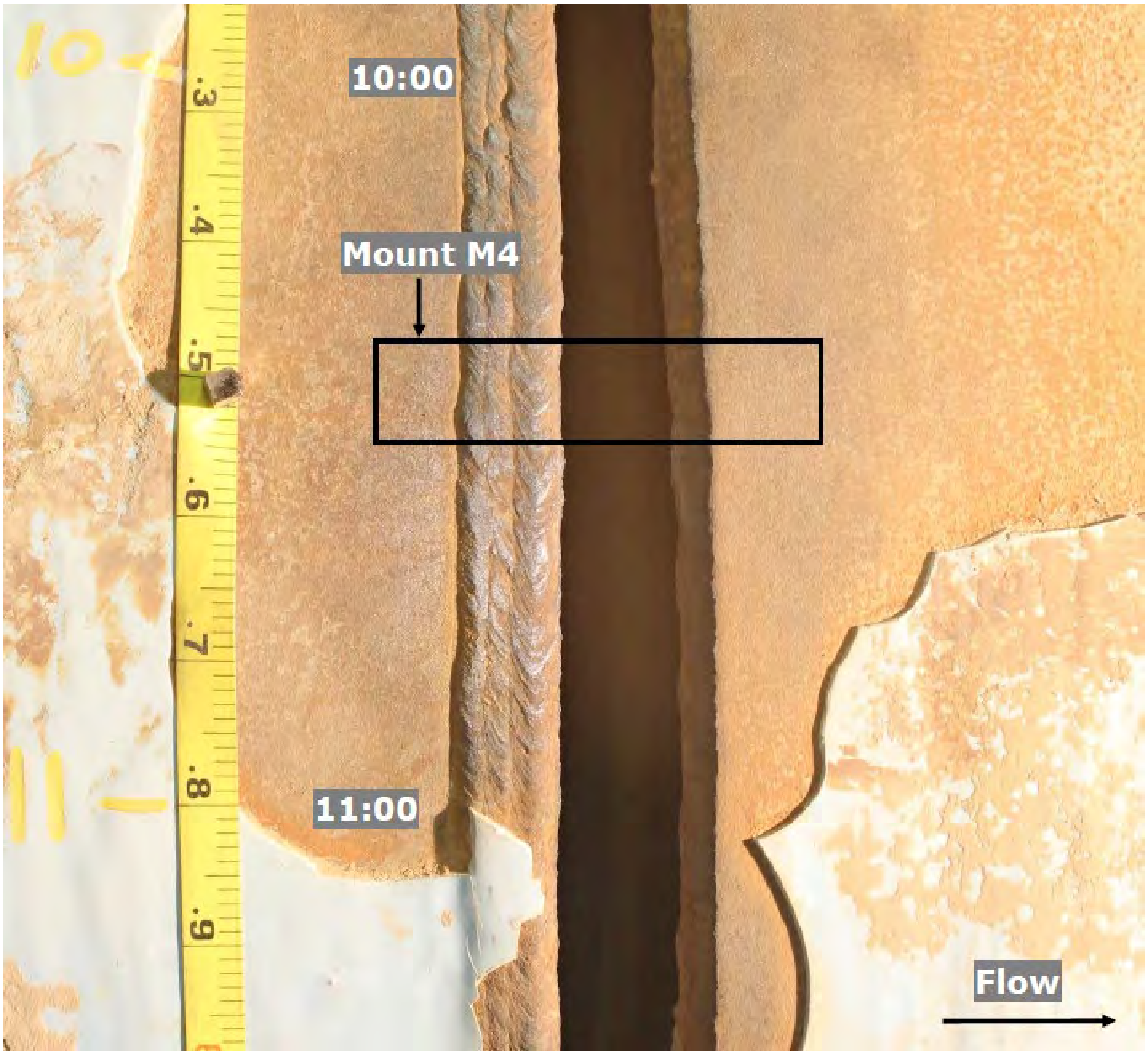

Figure 28. Overview of Mount M4

There is a smooth shear angle region and a rough region. The fracture path at this location is mainly in the HAZ. (see Figure 29).

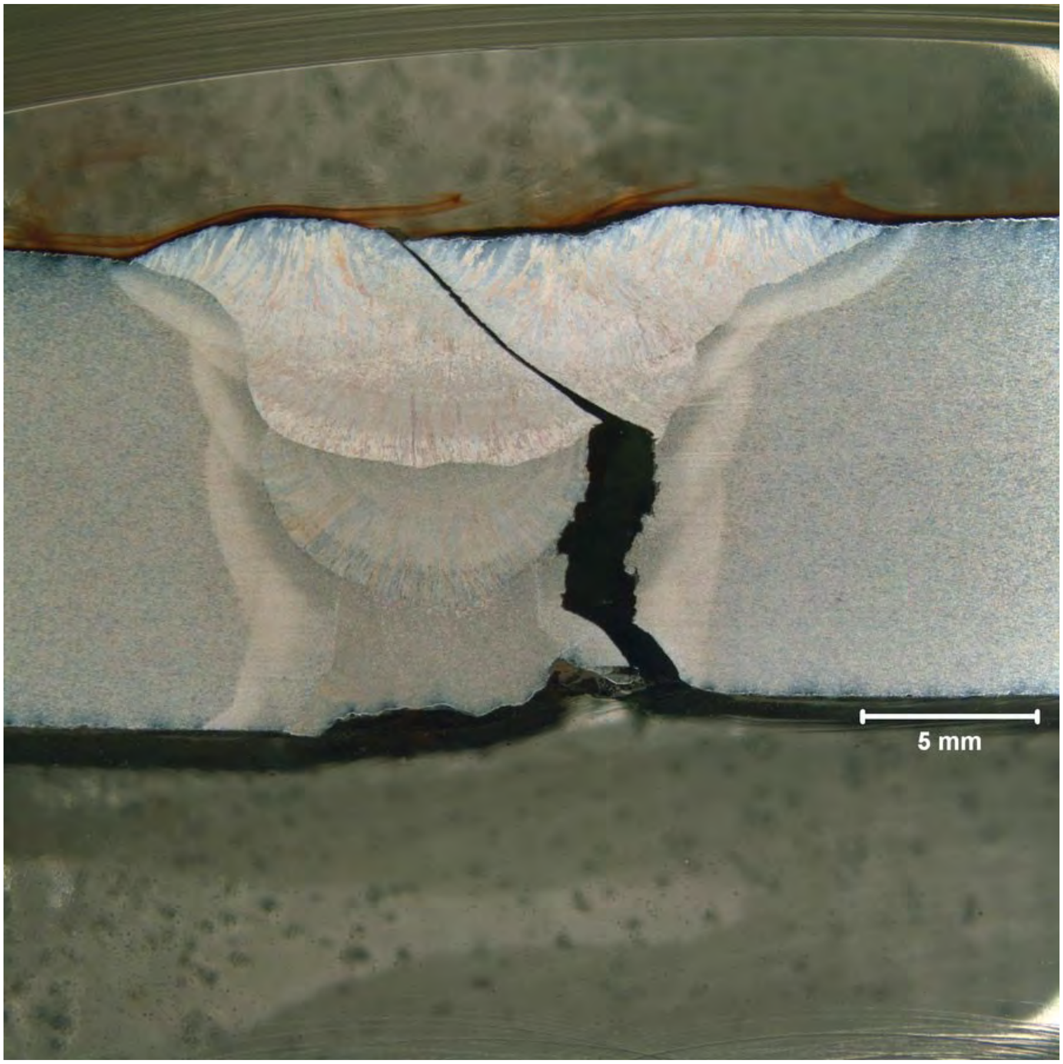

Figure 29. Representative Cross-Section from Sample M4

The sample shows grain elongation and an inclusion orientated parallel to the fracture surface which is consistent with ductile overload. There are also fissures in this sample that have the same morphology shown in M2 sample. A close-up of the M4 sample is provided in Figure 30.

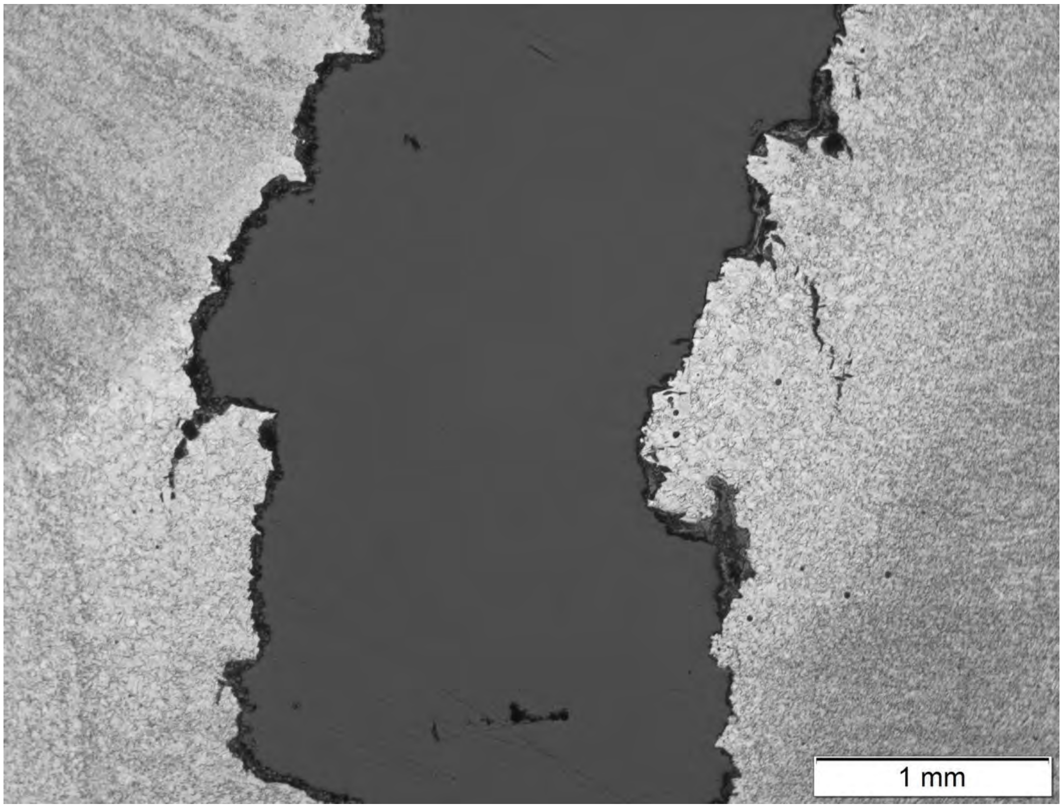

Figure 30. Close-Up of Sample M4

5.3.5 Metallurgical Sample 5

Sample 5 was removed from the failed GW at the 11:37 o'clock orientation (see Figure 31).

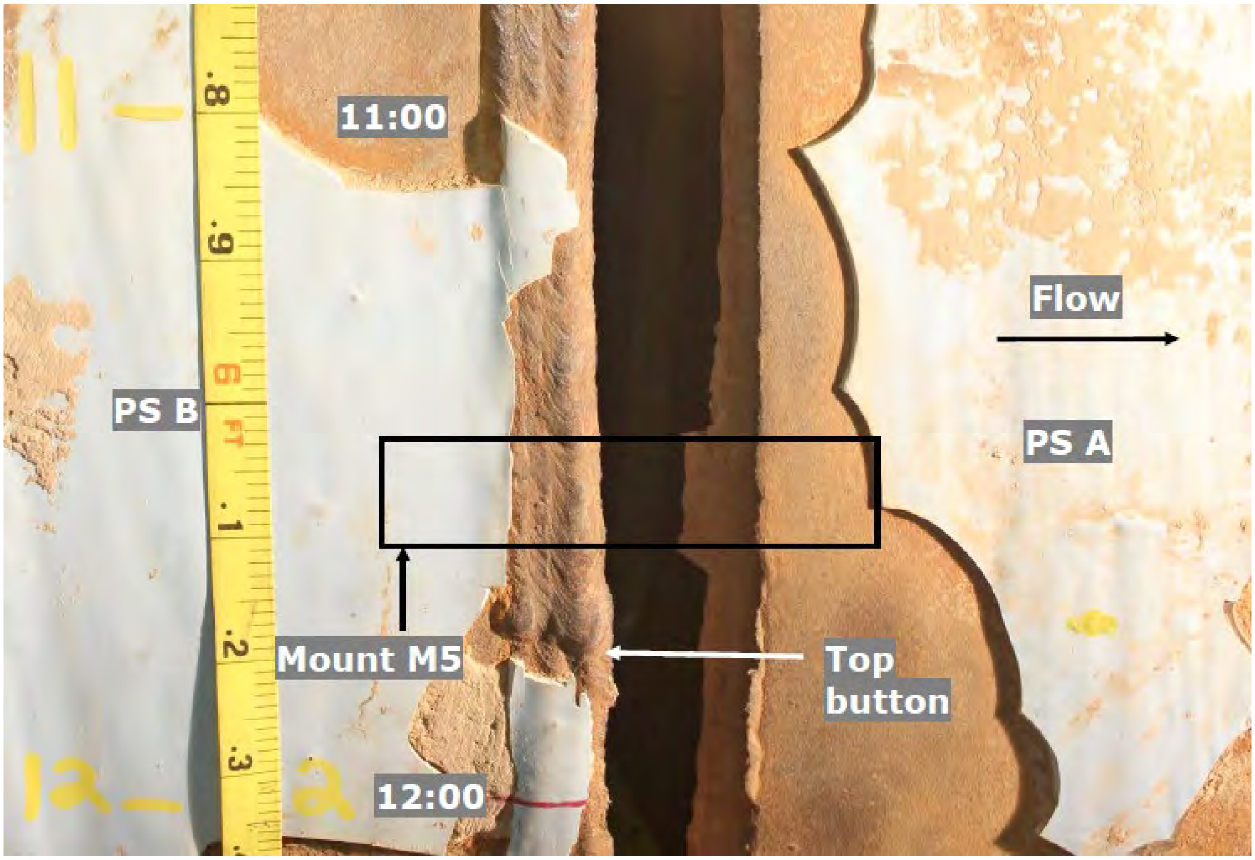

Figure 31. Overview of Mount M5

This sample has a smooth shear region on most of the fracture surface, located in both the weld metal and base metal. There is a shallow flaw between the weld metal and HAZ which is consistent with incomplete fusion. The high-low weld misalignment at this location was approximately 4.6% of the NWT. There is no evidence of crack extension at the flaw in this sample. A view of the cross section of sample M5 is provided in Figure 32.

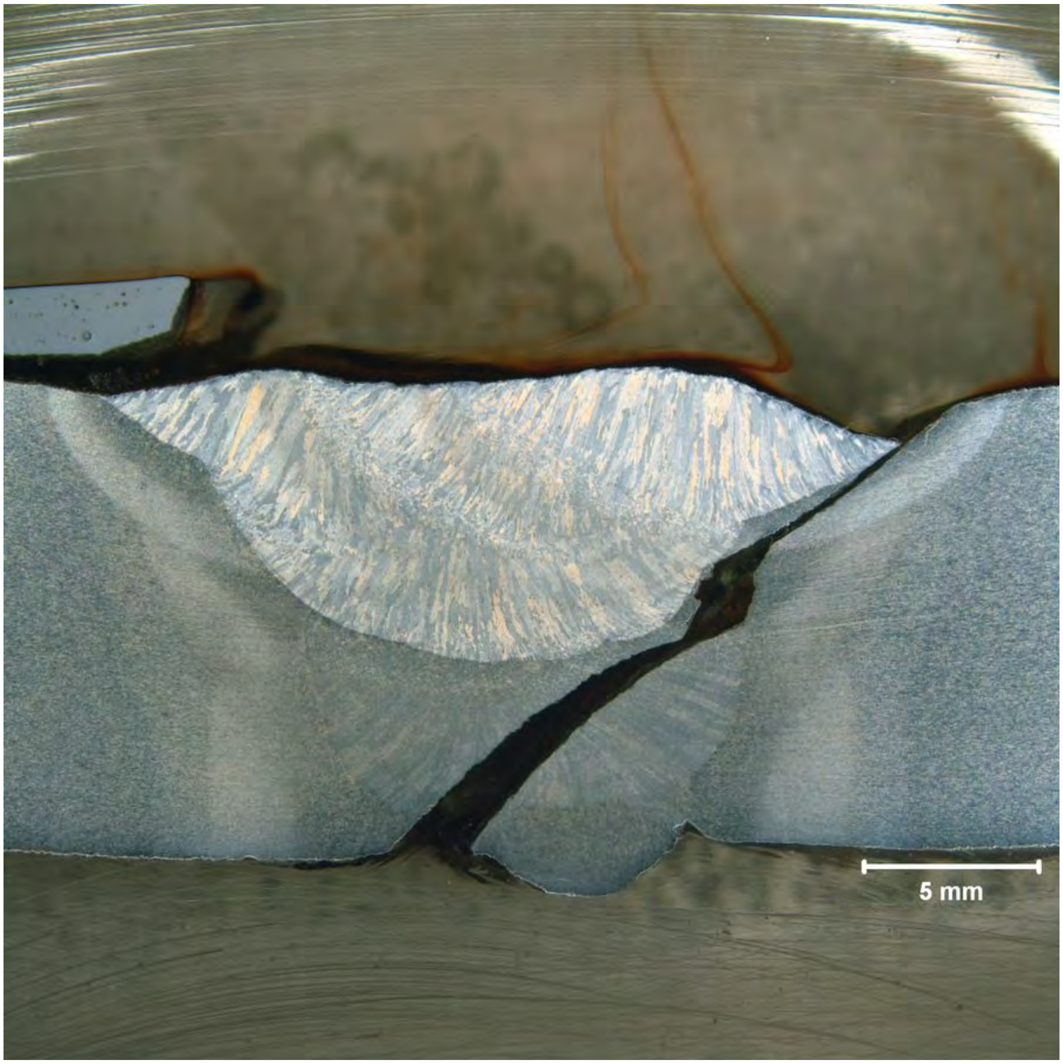

Figure 32. Representative Cross-Section from Sample M5

5.3.6 Metallurgical Sample MU1

Sample MU1 was removed from the intact girth weld. An overview of this sample is provided in Figure 33.

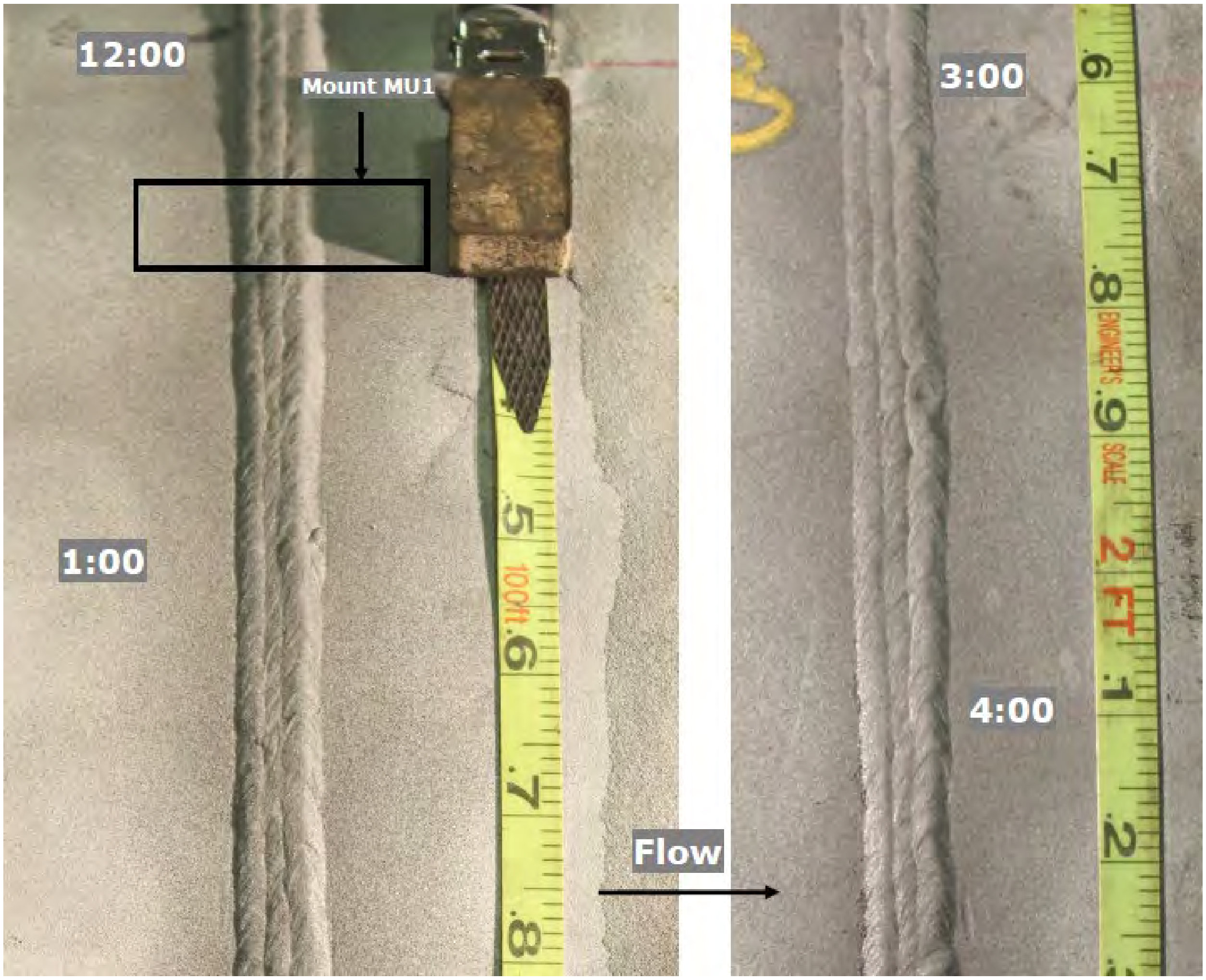

Figure 33. Overview of Mount MU1

This sample was removed from the intact GW at the 12:24 o'clock position. The morphology is similar to the previous mounts. The high-low weld misalignment at this location is approximately 4.6% of the NWT. The figure shows a shallow incomplete fusion flaw (1.9% of the NWT) between the weld metal and the HAZ. An image of the cross section of sample MU1 is provided in Figure 34.

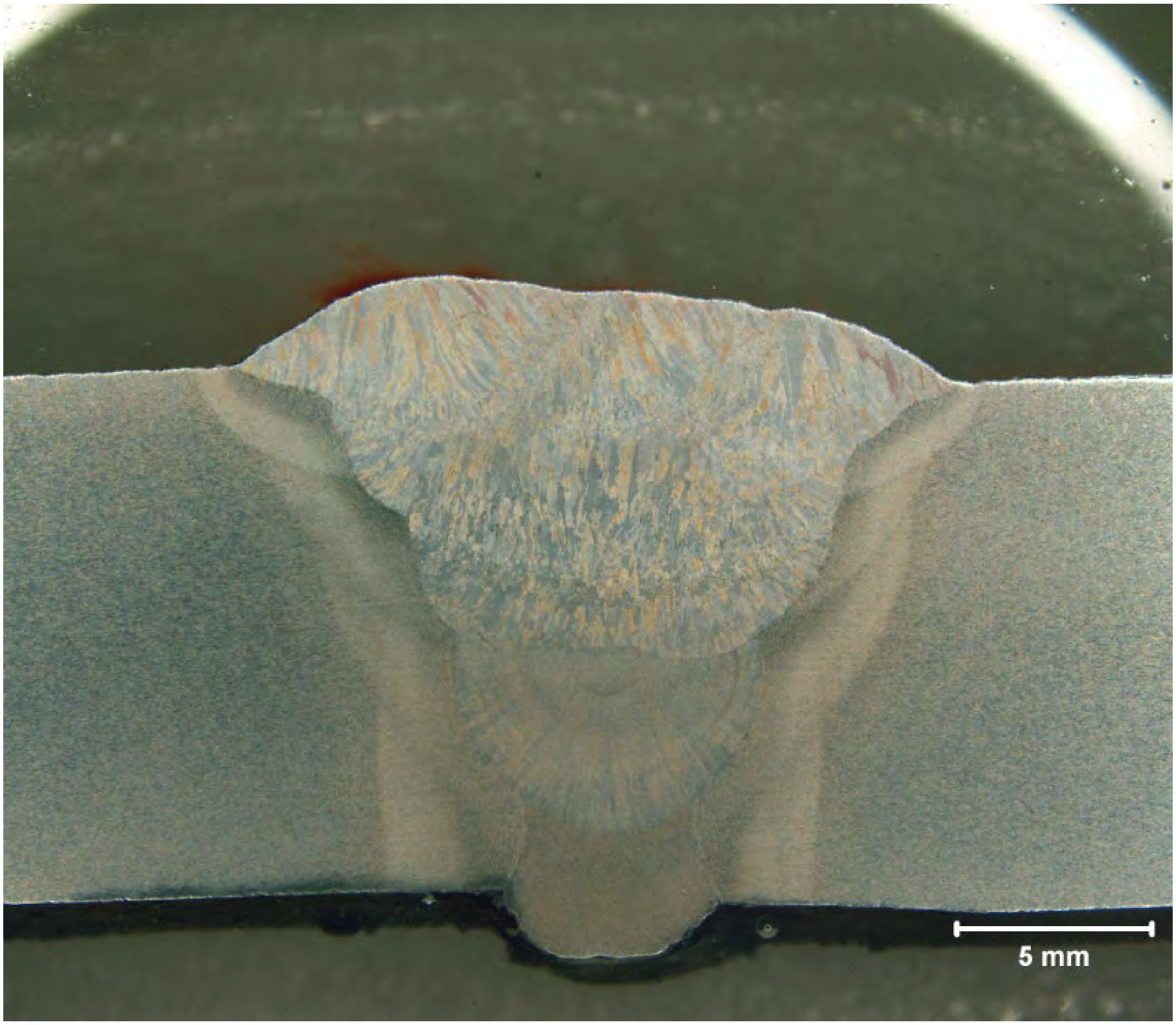

Figure 34. Cross Section of Mount MU1

A shallow flaw was identified between the weld metal and HAZ, with no evidence of cracking or extension of the flaw. A close up view of the flaw is provided in Figure 35.

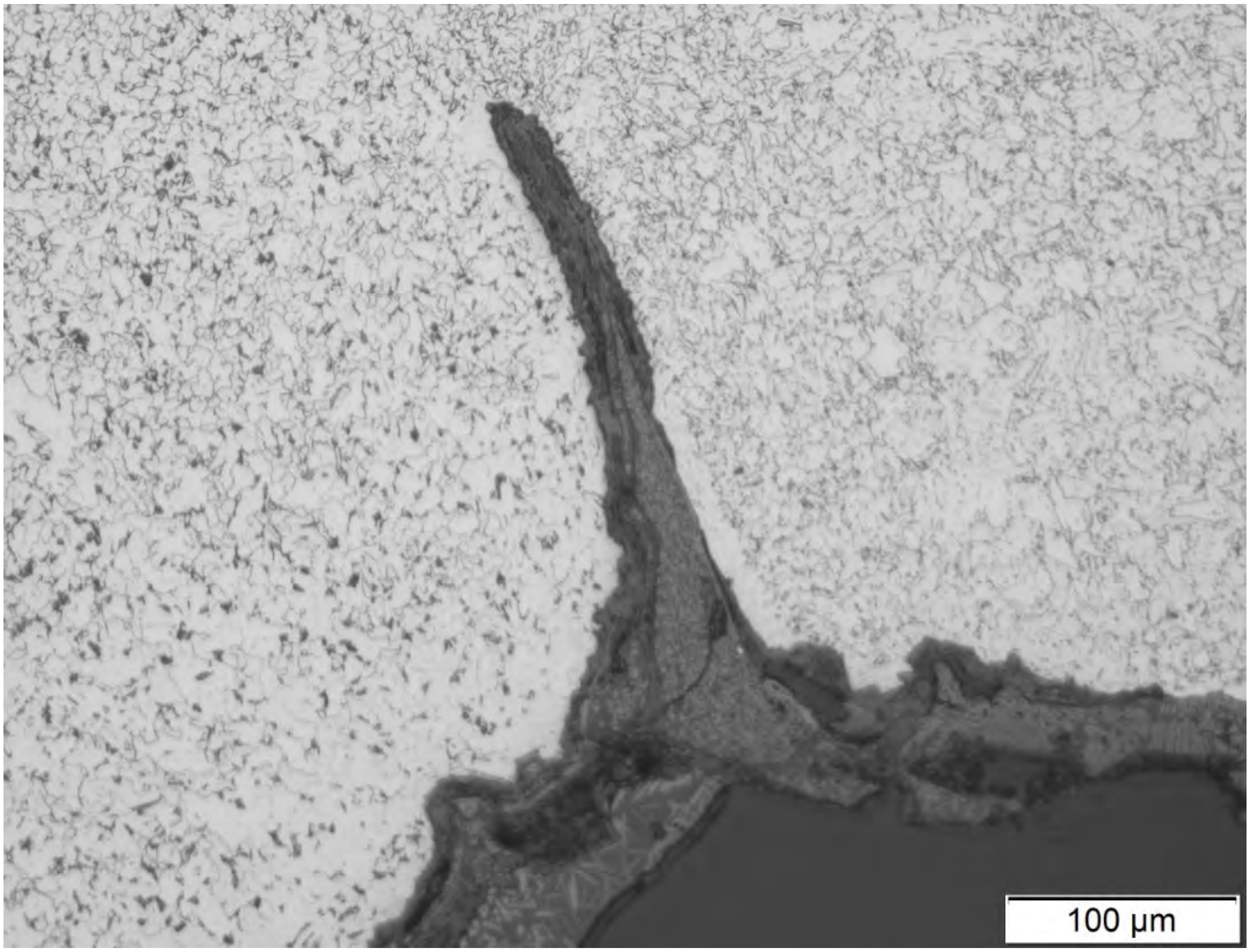

Figure 35. Close Up View of Sample MU1 Flaw

5.4 Scanning Electron Microscopy

As noted above, 4 samples were removed from PS A adjacent to the metallographic samples. No evidence of pre-existing flaws or fatigue were identified. SEM images (Figure 36, Figure 37, Figure 38) provide examples of dimples and mid-wall tears associated with ductile fracture, and cleavage facets associated with brittle fracture.

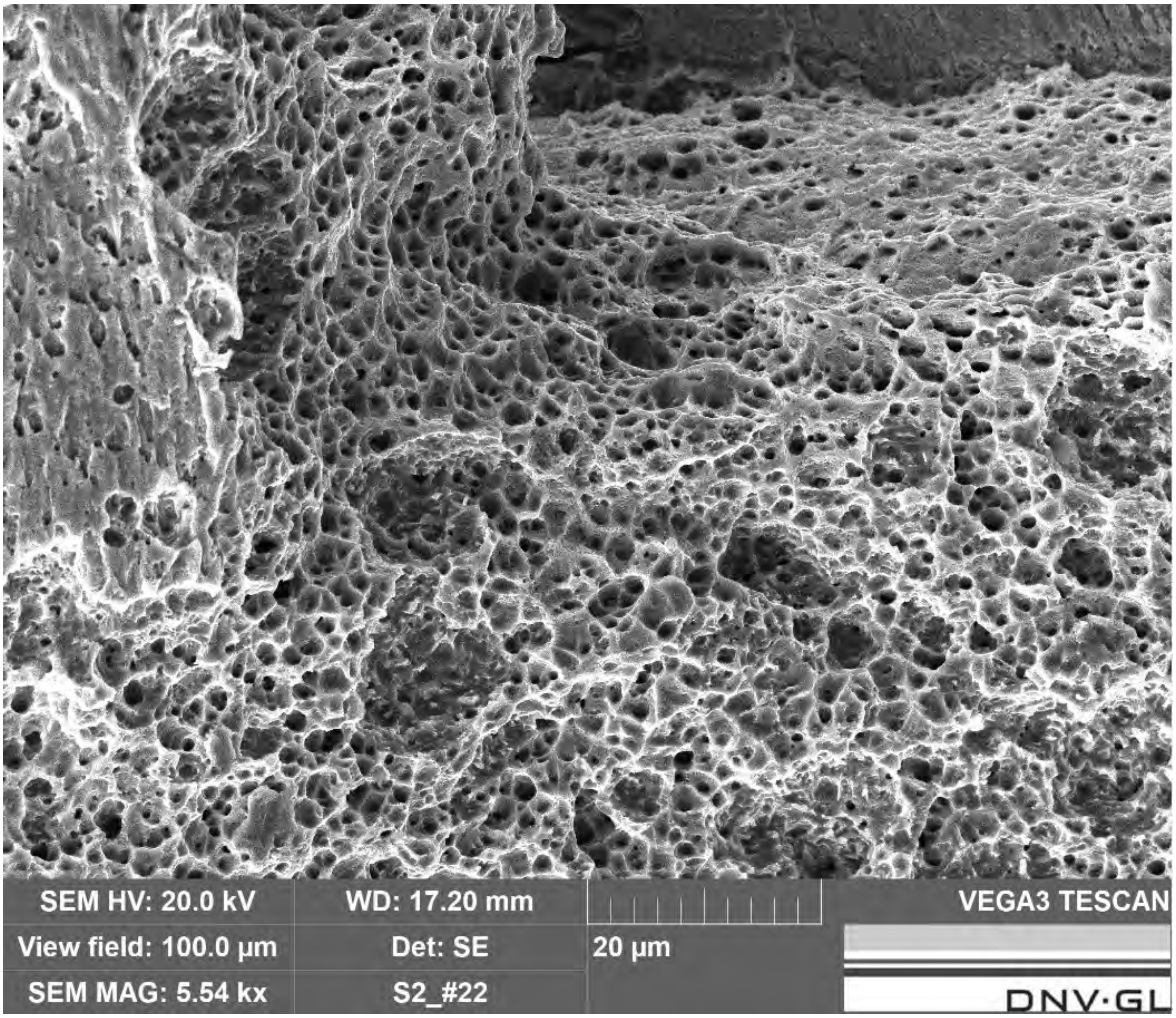

Figure 36. Sample S2 – Dimples Associated with Ductile Fracture

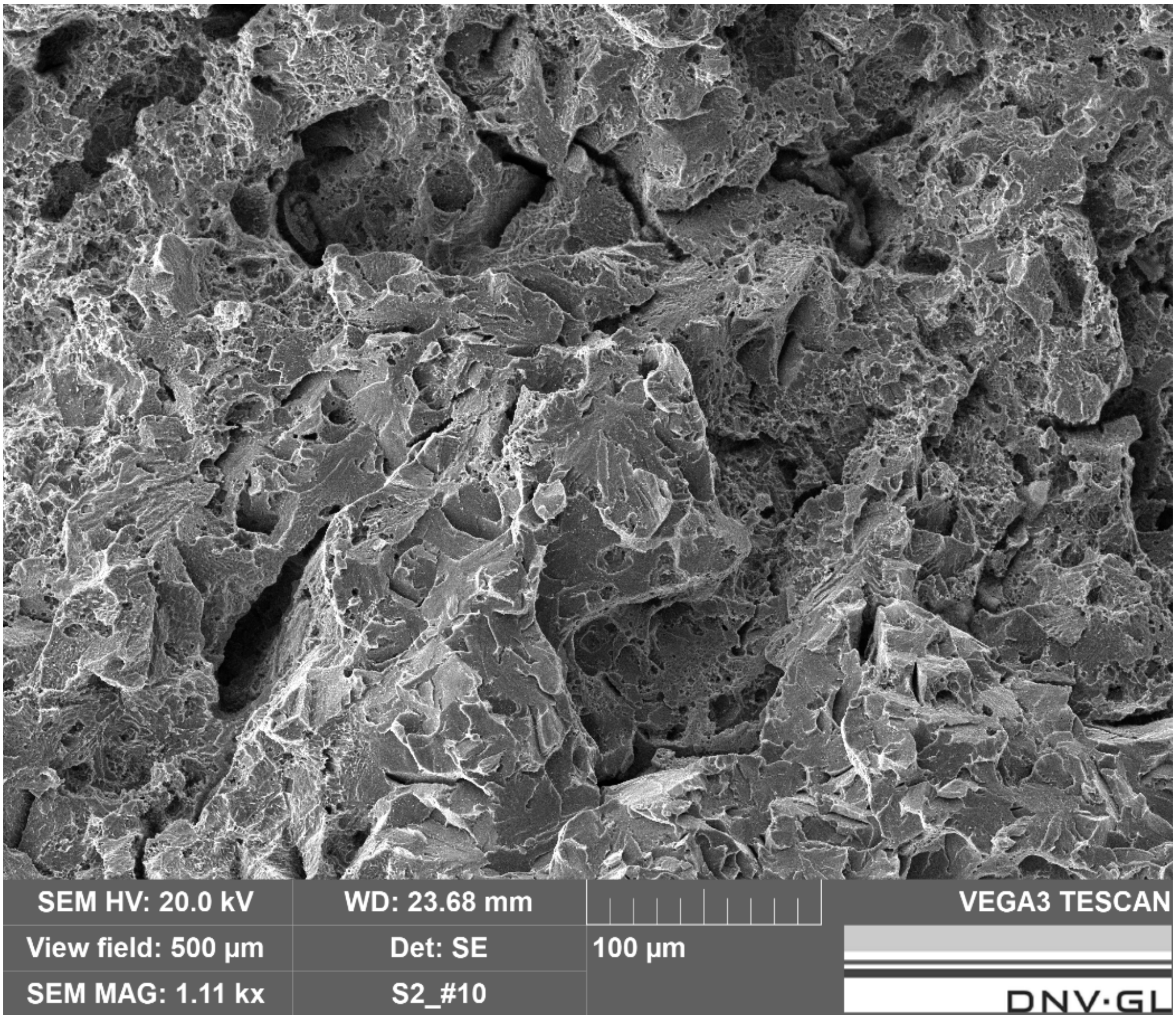

Figure 37. Sample S2 – Facets Associated with Brittle Fracture

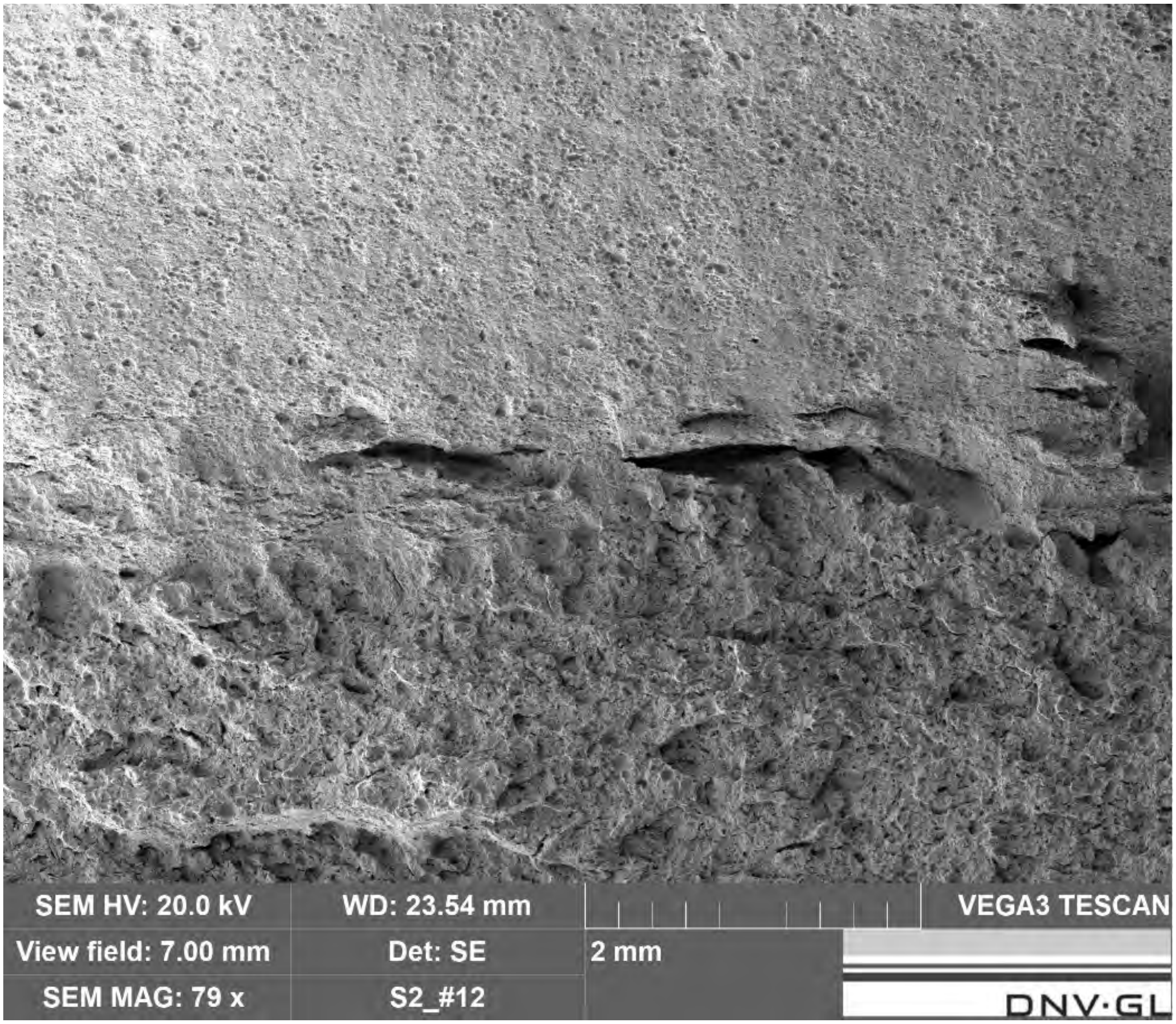

Figure 38. Sample S2 – Tears Mid-Wall (Smooth Region)

5.5 Hardness Testing

Vickers hardness testing was conducted on all six metallographic cross sections. No areas of unusually high hardness were identified. Hardness testing of the failed girth weld exhibit variability that is likely associated with cold work sustained during the failure. The hardness testing of the intact weld are the best representation of the base hardness of the welds preceding the failure. The results indicate a lower hardness of the weld metal compared to the pipe metal, which indicating that the weld metal is softer than the parent metal. Typically, the parent metal is harder than the weld metal. The axial tensile tests on the intact girth weld show similar failure to the actual fracture, further indicating that the lower hardness typical of the weld was the preferred location for the overload failure under applied axial stress. Hardness levels at varying points on sample M2 from the failed girth weld are shown in Figure 39.

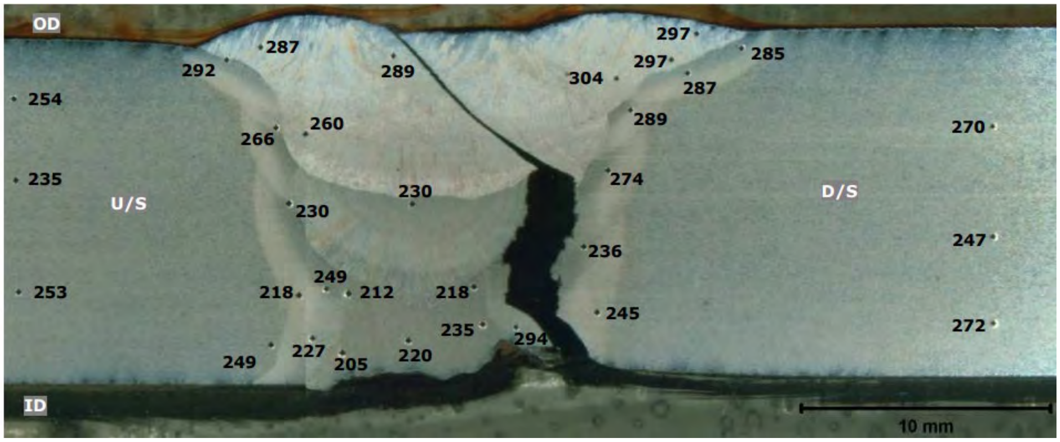

Figure 39: Light Photomicrograph of M2 Axial Cross-Section Showing Hardness Levels in HV

5.6 Mechanical Testing

A summary of mechanical testing results for the Delhi 24-inch pipeline samples is provided below. Additional detail is included in Appendix C.

5.6.1 Tensile Testing

Tensile testing of duplicate circumferential base metal specimens indicates the average yield strength (YS) and ultimate tensile strength (UTS) meet the requirements for API 5L X80M PSL 2 line pipe at the time of construction. The average UTS of duplicate axial specimens taken from the intact girth weld was 103.3 ksi. Both specimens failed in the girth weld, similar to the in-service pipeline failure. The average axial YS and UTS value across the weld meets the tensile requirements for API 5L X80M PSL 2 line pipe at the time of construction.

5.6.2 Charpy V-Notch Testing

The results of CVN testing of the base metal samples indicate impact values all exceeding the specified values for the specified minimum value for API 5L X80M PSL 2 line pipe at the time of construction. Test results of the girth weld samples taken from PS C indicate acceptable values, with the 85% Fracture Appearance Transition Temperature (FATT) 59.9ºF.

5.6.3 Chemical Analyses

The results of the chemical analysis indicate that the steels meet the compositional requirements of API 5L Grade X80M PSL 2 line pipe. The carbon equivalent (CE) values were calculated for the base metal samples PS A and PS C and are 0.17 and 0.16 respectively. These values compare favorably to the maximum allowable 0.25 according to API 5L specification at the time of construction.

6.0 CONCLUSIONS

The combined results of this investigation indicate that the root cause of the 24-inch Delhi pipeline failure was overload at a field girth weld due to axial stresses sufficient to cause an overload condition. Movement is considered to be a possible contributing factor. Based on the results of this investigation, we provide the following conclusions:

1. The brittle failure originated at a girth weld. The presence of soft regions with dimples (ductile mode) and cleavage facets (brittle mode) are characteristics typical of a failure from overload conditions.
2. The failure occurred due to axial stresses. There was no indication of a pre-existing defect and a specific failure initiation site was not apparent.
3. The weld metal for both the failed girth weld and the intact weld was found to have lower hardness values than the surrounding pipe materials indicating the weld metal was weaker than the pipe material and thus, more susceptible to overload under axial stress conditions. The findings do not suggest the failure resulted from a welding quality issue.

4. There was no evidence of internal or external corrosion that may have contributed to the failure mode.
5. The mechanical and chemical testing results were in accordance with the requirements for API 5L X80M PSL 2 line pipe.
6. The microstructure of the pipe material U/S and D/S of the failed girth weld are consistent with modern X-80M PSL 2 line pipe steel.

7.0 APPENDICES

Appendix A – Denbury Yazoo County Pipe Sample Collection Protocol

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Appendix A

Denbury Yazoo County Pipe Sample Collection Protocol

Pipe Sample Collection Protocol

Denbury Yazoo County Pipeline

1. Each pipe sample location will be identified and documented according to Mears procedures.

2. The as-found condition of the site will be documented and photographed, and the areas previously identified will be excavated to uncover the pipeline.

3. Any welded sleeves or temporary repair clamps covering the area of interest are to be left in place for removal after delivery of the sample to the laboratory.

4. If any bolted connections are disconnected or removed, fasteners and gaskets will be marked for identification purposes, photographed and retained for further analysis (if applicable).

5. If the pipeline is encased at the area of interest:

    a. The exterior of the casing will be visually inspected, condition documented, and a section of the casing will be selected and marked for identification purposes.
    b. The identified casing section will then be removed in a manner that preserves the condition of the pipeline and casing in the area of interest to provide access for inspection of the pipeline in the area of interest.
    c. The interior surface of the casing will be visually inspected, documented and photographed.
    d. If applicable, samples of the casing or materials inside the casing will be selected and collected for detailed analysis.

6. The as-found condition of the carrier pipe will be documented and photographed. Labeling will include the 12:00 position of the pipe and direction of flow, prior to coating removal and pipe inspection.

7. Prior to disturbing or removing the pipe coating, samples of any liquids or solids deposits located between the carrier pipe and coating or adhered to the pipe surface located in the area of interest will be collected in duplicate. Liquid samples will be retrieved using a syringe. Solids samples will be collected using a wooden spatula/tongue depressor. All samples will be placed in sealed enclosures (test tubes or sample bags). Samples will then be labeled and photographed. Duplicate samples will be transferred to designated representatives of IPL or shall be retained for future transfer.

8. If no liquids are present, pH paper may be used to evaluate any moisture present on the pipe section.

9. The pipeline in the area of interest will then be evaluated to determine if pipe samples are required for further detailed analysis.

10. If temporary repairs are required at the area of interest in order to allow future removal of a pipe sample, the repair will be installed preserving the condition of the area of interest and will be left in place for removal after delivery to the laboratory.

11. Sample(s) to be removed for detailed analysis and testing from the pipe section cut out of the pipeline will be identified:

    a. The sample(s) will be marked for identification, including the 12:00 position of the pipe and direction of flow.
    b. The identified sample(s) will be photographed prior to removal from the pipeline.
    c. Coating removal and cuts will be made at least 12" from the identified defect/damage location, with care taken not to disturb the area of interest.
    d. If welded sleeves or temporary repair clamps cover the area of interest, cuts will be performed at least six inches from the edges of the sleeve or clamp.

12. After removal, the pipe sample(s) will be photographed prior to packaging for shipment:

    a. The pipe sample(s) will be wrapped in hydrophobic material like polyethylene to prevent contamination.
    b. The pipe sample(s) will then be crated for shipment, along with any other portable evidence identified for further testing.
    c. The pipe sample(s) will be immobilized within the container.

13. Transport documentation and chain of custody will then be initiated.

14. The pipe sample will then be shipped to DNV GL, Columbus, OH or Plain City, OH receiving yard.

Appendix B

Denbury Yazoo County Metallurgical Sampling & Testing Protocol

METALLURGICAL FAILURE INVESTIGATION PROTOCOL

Denbury Delhi 24 inch Transmission Pipeline

1. INTRODUCTION

The purpose of the failure analysis is to assign one or more probable causes to the failure. This failure analysis protocol specifically addresses the failure analysis of line pipe.

The protocol was written in accordance with the March 21, 2019 Metallurgical Laboratory Failure Examination Protocol by PHMSA.

2. VISUAL AND NONDESTRUCTIVE EXAMINATION

2.1 Open the crate to visually inspect the failed pipe sections. The crates should contain the failed pipe section, including one intact girth weld.

2.2 Photographically document each pipe section in the "as-received" condition before initiating the metallurgical evaluation.

2.3 Remove the protective wrapping from the failed pipe sections and perform visual examination of the external and internal pipe surfaces in the "as received" condition. Measure the length of the failed pipe sections and document the position and orientation of anomalies that may be present in the failed pipe sections. This step shall include:

- Fracture area and surface
- Seams
- Girth welds
- Coating condition
- Anomalies
- Manufacturing flaws and defects
- Presence of External or internal corrosion

2.4 Collect coating samples, solid and liquid samples (if present). All samples will be collected with companion samples or retained. If a sample is determined to be of insufficient volume for a companion sample to be collected, the sample will be retained for evaluation at a later date. Solid deposits and liquid samples, if present, from the internal and external pipe surfaces will be submitted for energy dispersive spectroscopy (EDS) elemental analysis, X-ray diffraction (XRD) and microbial tests. If not enough liquid is present for collection, consider using pH paper to characterize pH. Use a soft clean/uncontaminated knife or spatula to collect samples and re-inspect the pipe section after collecting samples. Knives/Tools should be cleaned with alcohol wipes before each use. The films or deposits may be from the steel surface, coating surface, interior of a corrosion pit, or the backside of the coating. The color and type of sample should be recorded. Carefully transfer the sample to the test kit vial for testing and carefully follow the instruction given in the kit manual.

2.5 Carefully remove and retain samples of the coating around the suspected area of damage using a knife or similar instrument. Knives/Tools should be cleaned with alcohol wipes before each use. Avoid touching the soil, pipe surface deposits or product, or film with hands or tools other than those to be used in sample collection and/or provided with the test kits. Any liquid under the coating should be sampled if sufficient quantities are available. If insufficient quantities are found, the pH shall be tested with litmus paper.

2.6 After the coating sample is collected, visually inspect the internal and external surfaces of the failed section. Identify areas that may contain other types of anomalies such as cracking, stress corrosion cracking, or any other condition that could affect the long-term integrity of the pipeline. Clean and examine the external pipe surfaces adjacent to the failure using nondestructive testing techniques, such as magnetic particle inspection (MPI) such as wet fluorescent magnetic particle (WFMT). The surfaces of the pipe surrounding the corrosion or cracks must be clean, dry, and free of surface contaminants such as dirt, oil, grease, corrosion products and coating remnants.

2.7 The physical location of all samples that are removed from the pipe section for examination and metallurgical analysis will be documented such that all relevant features are visible (graphically and/or photographically). A pipe section schematic detailing the location and orientation of any samples will be prepared.

2.8 Determine the appropriate failure analysis processes to complete based on the initial observations and testing.

3. PHYSICAL MEASUREMENTS

3.1 Measure the diameter and wall thickness at the 12, 3, 6 and 9 o'clock orientations on undisturbed areas of the pipe.

3.2 Measure and record the length of each sample.

3.3 Examine the details of the failed area. Measure and record any additional defects identified.

3.4 Measure the diameter and wall thickness at selected locations of anomalies.

3.5 Verify roundness and geometry of pipe at the extremities and near the failed surface.

3.6 Measure the wall thickness around the failure and any damaged areas. Provide a schematic detailing the extent of the damage on the pipe surface and the pipe wall thickness on those areas. Supplement with photographic records. Supplement these measurements with laser scanning.

3.7 Determine and mark the locations of the long seam weld at each end of the sample.

3.8 Measure and record the size and location of anomalies and confirm the dimensions of the failed pipe section. Measure crack depths (if present) using direct exploration (grinding), shear wave ultrasonic testing, or other suitable method.

3.9 Measure the shortest axial distance from the failure to the nearest long seam weld (if applicable). Measure the shortest longitudinal distance from the failure to the nearest girth weld (if applicable).

4. CORROSION EXAMINATION

4.1 Examine the pipe external surface near the failure location to determine if anomalies exist.

4.2 Examine the pipe internal surface at the failure location to determine if anomalies exist.

4.3 If not already performed as described in Section 2, collect surface deposits and residues associated with the external pipe surface at the failure area and adjacent areas and analyze using MIC IV kits (or equivalent) and energy dispersive spectrometry (EDS) and microbial analysis. Knives/Tools should be cleaned with alcohol wipes before each use.

4.4 Photographically document the pipe internal surface conditions and any anomalies present.

4.5 Evaluate and document processes that potentially contributed to the failure to support selection of samples within the failed pipe section.

4.6 If internal anomalies are found, proceed with collection of surface deposits and residues associated with the failure area and analyze using MIC IV and MIC V kits (or equivalent) and energy dispersive spectrometry (EDS) and microbial analysis.

4.7 Determine specific locations of the failed pipe section for further investigation.

4.8 Cut and clean the selected locations for selection of initial metallographic sections, taking additional solids and liquid samples as necessary.

4.9 Perform hardness measurements in areas near the anomalies and also remote from the failure site.

4.10 Take initial metallographic sections at appropriate locations within the failure area.

4.11 Anomaly depths may be determined using pit depth gauge, ultrasonic thickness probe, profile gauges, 3D laser scanning, etc.

5. FRACTOGRAPHIC EXAMINATION

5.1 Visually examine the fracture surface in detail to identify specific characteristics, the nature of the original defect, and the failure initiation point (s). If it becomes necessary, a metallographic section will be made through the sample to open the failure for further examination.

5.2 Clean samples in an appropriate manner to remove loose rust, scale, etc. as necessary.

5.3 Remove selected fractographic samples as necessary for detailed microscopic examination using a scanning electron microscope equipped with EDS. Examine and document the fracture surface morphology.

5.4 Thoroughly document the location of the samples taken from the pipe section at or near the failure.

6. METALLOGRAPHIC EXAMINATION

6.1 Identify metallographic sample origin (sample identification, location, orientation, etc.), perform metallographic evaluation, and take representative photomicrographs.

6.2 Perform micro-hardness profiles at appropriate locations.

6.3 Document microstructural appearance of samples.

6.4 Document the extent of the wall loss, if any, of the cross section.

6.5 Based on the results of the visual, non-destructive, and metallographic examinations, the presence of corrosion will be documented, and the type and characteristics of any corrosion present should be evaluated.

NOTE:

- This protocol is subject to change.
- Additional tests may be added and/or changes made as necessary to accomplish the purpose of this failure analysis and complete this process.

Appendix C

DNV GL Metallurgical Analysis Report

Draft Report

Metallurgical Analysis of 24-Inch Diameter Delhi Pipeline Failure (02/22/20)

Mears Group, Inc.
Plain City, Ohio

Report No.: O-AP-FINV / GTQU (10206282)
June 4, 2020

Project Name:	Metallurgical Analysis of 24-Inch Diameter Delhi Pipeline Failure (2/22/20)
Customer:	Mears Group, Inc.
Contact Person:	Aida Garrity
Date of Issue:	June 4, 2020
Project No.:	10206282
Organization Unit:	Incident Investigation
Report No.:	O-AP-FINV / GTQU

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Task and Objective:

Please see Executive Summary.

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☐ Unrestricted Distribution (internal and external)
☐ Unrestricted Distribution within DNV GL
☐ Limited Distribution within DNV GL after 3 years
☒ No Distribution (confidential)
☐ Secret

Keywords

Rev. No.	Date	Reason for Issue:	Prepared by:	Verified by:	Approved by:
0	2020-05-27	Draft			
1	2020-06-04	Revised Draft			

Executive Summary

Mears Groups, Inc. (Mears) retained DNV GL USA, Inc. (*DNV·GL*) to perform a metallurgical analysis on a portion of the Delhi 24-inch diameter carbon dioxide (CO_2, dry) transmission pipeline, that failed at a girth weld while in service, resulting in full separation. The failure occurred on February 22, 2020 in Satartia, Mississippi at Stationing 348+26, 6.59 miles from the nearest upstream (U/S) pump station.

The segment of the pipeline that failed is comprised of 24-inch diameter by 0.540-inch wall, API 5L Grade X80M PSL 2 line pipe steel that contains a high frequency electric resistance welded (HF ERW) seam. The maximum allowable operating pressure (MAOP) is 2,160-psig, which corresponds to 59.6% of the specified minimum yield strength (SMYS). The pressure at the Tinsley Meter Station (Stationing 0+00) at the time of the failure was 1,336-psig (36.9% of SMYS). The pipeline normally operates between 1,200 and 1,450-psig (33.1 and 40.0% of SMYS, respectively).

The pipeline was installed in 2009 and is externally coated with a factory applied fusion bonded epoxy (FBE) and abrasion resistant overlay (ARO) coating. A liquid epoxy coating was applied to the pipeline at the girth welds in the field. Following construction, a hydrostatic pressure test was performed on January 14, 2009 to a minimum pressure at the dead weight gage of 2,908 psig (80.3% of SMYS). The pipeline has an impressed current cathodic protection (CP) system that was commissioned in 2009, directly following pipeline installation.

Three pipe sections (Pipe Sections [PSs] A, B, and C) were delivered to DNV GL for analysis. Pipe Section A was 5.99 feet long and contained the downstream (D/S) portion of the failed girth weld. Pipe Section B was 6.08 feet long and contained U/S portion of the failed girth weld. Pipe Section C was 8.00 feet long and contained an adjacent U/S intact girth weld. The objectives of the analysis were to determine the metallurgical cause of the failure and identify any contributing factors.

The results of the metallurgical analysis indicate that the failure initiated at a field girth weld, due to axial stresses sufficient to produce overload failure. No pre-existing flaws were present on the fracture surface. A contributing factor to the failure was that the pipe steel was stronger than the girth weld.

The scope of the work consisted of:

- Visual inspection and photography
- Magnetic particle inspection
- Fractography
- Scanning electron microscopy
- Metallography
- Energy dispersive spectroscopy

- Hardness testing
- Mechanical testing
- Chemical analysis

The results of the metallurgical analysis indicate that the failure initiated at a field girth weld, completely separating the girth weld. The exact location of the initiation could not be determined due to a lack of chevrons on the fracture surfaces and the fact that no significant pre-existing (prior to failure) cracks were identified. Microscopically, the fracture surface contained regions with dimples (ductile fracture) and cleavage facets (brittle fracture). The dimples were located where the fracture surface was at a shear angle and macroscopically smooth, and the cleavage facets were located where the fracture surface was perpendicular to the free surfaces and macroscopically rough. Both fractographic features are an indication of the overload nature on the fracture surface.

The failure occurred due to axial stresses sufficient to produce an overload failure. Supporting evidence for the presence of large axial stresses include 1) a relatively large opening between the failed ends and 2) cracked and missing epoxy coating U/S of the failed girth weld indicating a high strain prior/during fracture. A possible contributing factor to relatively large axial stresses includes stresses associated with movement.

No excessively high hardness areas were identified in the girth weld cross-sections. The weld metal of the intact girth weld had a lower hardness than the surrounding pipe material, indicating that the weld metal is weaker than the surrounding pipe material. This trend was somewhat followed for the failed girth weld, although cold work from the failure likely skewed some of the data. The softest regions in all the mounts was the weld metal root pass. The lower overall hardness values of the weld metal compared to the surrounding pipe material is consistent with the axial tensile results. The ultimate tensile strength for the girth weld of 103.3 ksi is less than the axial tensile strength of 109.7 ksi and 106 ksi for the joint's D/S and U/S, respectively, of the failed girth weld. The axial tensile tests across the intact GW failed in the GW, similar to the actual failure. Therefore, a contributing factor to the failure was that the pipe steel was stronger than the girth weld.

Below is a summary of additional conclusions:

- There was no evidence of notable internal or external corrosion.

- The tensile and toughness properties of the joint's U/S and D/S of the failed girth weld meet requirements for API 5L X80M PSL 2 line pipe at the time of construction.

- The chemical compositions of the joint's U/S and D/S of the failed girth weld meet the requirements for API 5L X80M PSL 2 line pipe at the time of construction.

- The microstructures of the joint's U/S and D/S of the failed girth are consistent with modern API 5L X80 line pipe steel.
- An analysis of the Charpy V-notch impact testing data for the intact girth weld indicates that the 85% fracture appearance transition temperature (FATT) is 59.9°F and upper shelf Charpy energy is 114 ft lbs.

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1.0 BACKGROUND

Mears Groups, Inc. (Mears) retained DNV GL USA, Inc. (*DNV·GL*) to perform a metallurgical analysis on a portion of the Delhi 24-inch diameter carbon dioxide (CO_2, dry) transmission pipeline, that failed at a girth weld while in service, resulting in full separation. The failure occurred on February 22, 2020 in Satartia, Mississippi at Stationing 348+26, 6.59 miles from the nearest upstream (U/S) pump station.

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The pipeline was installed in 2009 and is externally coated with a factory applied fusion bonded epoxy (FBE) and abrasion resistant overlay (ARO) coating. A liquid epoxy coating was applied to the pipeline at the girth welds in the field. Following construction, a hydrostatic pressure test was performed on January 14, 2009 to a minimum pressure at the dead weight gage of 2,908 psig (80.3% of SMYS). The pipeline has an impressed current cathodic protection (CP) system that was commissioned in 2009, directly following pipeline installation.

Three pipe sections (Pipe Sections [PSs] A, B, and C) were delivered to DNV GL for analysis. Pipe Section A was 5.99 feet long and contained the downstream (D/S) portion of the failed girth weld. Pipe Section B was 6.08 feet long and contained U/S portion of the failed girth weld. Pipe Section C was 8.00 feet long and contained an adjacent U/S intact girth weld. The objectives of the analysis were to determine the metallurgical cause of the failure and identify any contributing factors.

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 the analysis. The pipe sections were removed from the wooden shipping crates and visually inspected and photographed. Wall thicknesses, outside diameters (ODs), and circumferences were measured at the field cut ends of the pipe sections. The external and internal surfaces of the pipe sections at the failed girth weld were cleaned with a Scotch-Brite™ pad, followed by photography of the surfaces. The fracture surfaces were then cleaned with a soft bristle brush, followed by photography at one hour o’clock increments. The external surface of PS C was grit blasted at the intact girth weld, followed by magnetic particle inspection (MPI) of the grit blasted surface. Samples were removed from PS A and C for mechanical testing and steel chemical analysis.

Axial (cross girth weld) cross-sections were removed from the failed girth weld (five total) and intact girth weld (one total) for metallographic analysis. The cross-sections were mounted, polished, and etched. Light photomicrographs were taken to document the morphology of any flaws and the microstructures of the pipe steel and welds. Hardness testing was performed on the six mounted cross-sections to document the hardness values at and away from the girth welds. Fracture surface samples (four total) were removed from PS A, cleaned in ENPREP® 214, examined optically at low magnification with a stereomicroscope, and imaged at high magnification in a scanning electron microscope (SEM) to document the fracture morphologies.

Magnetic particle inspection was performed on the internal surfaces of the intact and failed girth welds. Chemical analyses were performed on the steel samples removed from the joints U/S and D/S of the failed girth weld to determine the compositions. Tensile (duplicates) testing was performed on transverse and axial specimens removed from the joints U/S and D/S of the failed girth weld, and on axial (cross-girth weld) specimens removed from the intact girth weld, to document the tensile properties. Charpy V-notch (CVN, triplicates) testing was performed on transverse specimens removed from the joints U/S and D/S of the failed girth weld to document the base metal toughness. Charpy V-notch (CVN) impact testing (full curve, 10 specimens per curve) was performed on axial (cross-girth weld, heat affected zone [HAZ] notch) specimens removed from the intact girth weld and an upper shelf impact energy and 85% fracture appearance transition temperature (FATT) was determined.

Figure 1 is a schematic of PSs A, B, and C showing the locations of the girth welds and seam welds, and where samples for metallography (Mount M1, M2, M3, M4, M5, and MU1), fractography (Sample S1, S2, S3, and S4), mechanical testing, and chemical analysis were removed.

3.0 RESULTS AND DISCUSSION

3.1 Optical Examination

Figure 2 is a photograph of the wooden shipping crate that contained PS A as received at DNV GL. The crate is approximately 10 feet long and was in good condition. Figure 3 is a photograph of PS A after removal from the wooden crate. The figure shows that the ends of the pipe were wrapped in clear plastic that was secured with duct tape. Foam insulation was secured to the U/S end of the pipe to cover the fracture surface of the failed girth weld. Figure 4 are photographs of PS A after removal of the clear plastic and foam insulation. Flow direction and o'clock orientation were marked (prior to shipment to DNV GL) on the pipe section. The pipe section is 5.99 feet long, contains a longitudinal seam weld at the 12:26 orientation, has portions of a field applied liquid epoxy coating (light blue appearance) at the girth weld, and portions of a factory applied FBE coating (reddish brown appearance) on the remainder of the pipe section. The figure shows a large portion of the coating is not present. The coating is not present between approximately 0 and 5.70 feet D/S of the girth weld, from the 8:00 to 4:00 orientations. Field personnel indicated that following failure the product flow was toward PS A, which may have contributed to the lack of coating. Additionally, the figure shows some residual soil is present on the pipe section.

Figure 5 is a photograph of the wooden shipping crate that contained PS B as received at DNV GL. The crate also is approximately 10 feet long and was in good condition. Figure 6 is a photograph of PS B after removal from the wooden crate. The figure shows that the ends of this pipe also were wrapped in clear plastic that was secured with duct tape. Foam insulation was secured to the D/S end of the pipe to cover the fracture surface of the failed girth weld. Figure 7 is a photograph of PS B after removal of the clear plastic and foam insulation. Flow direction and o'clock orientation were marked (prior to shipment to DNV GL) on the pipe section. The pipe section is 6.08 feet long, contains a longitudinal seam weld at the 10:37 orientation, has portions of a field applied liquid epoxy coating (light blue appearance) at the girth weld, and a factory applied FBE coating (reddish brown appearance) on the remainder of the pipe section. Some of the field applied coating was not present adjacent to the girth weld, for the entire circumference. Additionally, the figure shows some residual soil is present on the pipe section.

Figure 8 is a photograph of the wooden shipping crate that contained PS C. The crate also is approximately 10 feet long and was in good condition. Figure 9 is a photograph of PS C after removal from the wooden crate. The figure shows that the ends of the pipe also were wrapped in clear plastic that was secured with duct tape. Figure 10 is a photograph of PS C after removal of the clear plastic. Flow direction and o'clock orientation were marked (prior to shipment to DNV GL) on the pipe section. The pipe section is 8.00 feet long and contains longitudinal seam welds at the 1:24 orientation (U/S joint) and at the 10:37 orientation (D/S joint). An intact girth weld, that is the girth weld just U/S of the failed girth weld, is indicated in the figure. A field applied liquid epoxy coating (light blue appearance) is located at the girth weld and a factory applied FBE coating (reddish brown appearance) on the remainder of the pipe section. The field and factory applied coatings were intact. Additionally, the figure shows some residual soil is present on the pipe section. There was no evidence of notable internal or external corrosion of the three pipe sections.

Figure 11 through Figure 14 are photographs of the external surface of PSs A and B adjacent to the fracture surfaces/failed girth weld. The figures are sequential photographs taken around the circumference of the girth weld and show the morphology of the weld pattern and where coating is present. The lack of coating adjacent to the girth weld on the PS B side (U/S of the failed girth weld) suggests that large strains were present prior to/during the failure. The figures shows that the fracture path traversed (crossed over) the weld at various locations. The external appearance of the weld ripple pattern is indicative of low hydrogen electrodes deposited in the vertical-down direction, with a triple pass wide weave cap pass. Even though downhill welding progression with low-hydrogen electrodes is not common in the pipeline industry, electrode manufactures do provide low-hydrogen electrodes specifically designed to weld down, which are classified as EXX45 type electrodes. The morphology of the weld ripple pattern also indicates that the top button (start of welding) is located near the marked 12:00 orientation; see Figure 14.

Figure 15 and Figure 16 contain photographs of the internal pipe surface adjacent to the fracture surface of PS B. Each photograph shows approximately 3 o'clock hours of the internal surface at the girth weld adjacent to the fracture surface. The figures show that the root pass is located on the PS A side of the failure opening between approximately the 6 and 9 o'clock orientations and a majority of the root pass is located on the PS B side of the failure opening elsewhere. The top button is indicated in Figure 16, near the marked 12:00 orientation.

Circumferences and ODs were measured at the four field cut ends of the pipe sections. Table 1 summarizes the results of the measurements. The ODs calculated from the circumference measurement were between 24.1 and 24.2 inches at the field cut ends. The diameters meet API 5L tolerance requirements for 24-inch diameter pipe. The ODs were measured with a tape measure from the 3 to 9 o'clock and 12 to 6 o'clock orientations to check for ovality. The ODs at the ends of PSs B and C, and both orientations, were 24.0 inches, indicating no measurable ovality. The ODs at the end of PSs A, and both orientations, were 24.1 inches, indicating no measurable ovality.

Wall thicknesses were measured at the 12, 3, 6, and 9 o'clock orientations at the four field cut ends. The external coating was ground prior to the measurements. The wall thickness values were between 0.530 and 0.540 inches, as shown in Table 2, and meet API 5L tolerance requirements for pipe with a nominal wall thickness (NWT) of 0.540 inches.

3.2 Magnetic Particle Inspection

The intact girth weld on PS C was grit blasted and MPI was performed. Figure 17 and Figure 18 contain photographs of the external surface at the girth weld following MPI. No crack-like indications were identified. A metallographic cross-section (Mount MU1) was removed from the 12:24 orientation. The weld ripple pattern of the weld is consistent with PS A and PS B and with the use of a low hydrogen electrode and a vertical-down progression. The top button (Figure 18) is just above (counter-clockwise of) the 12:00 orientation.

Note that MPI of the internal surface of the intact weld also was performed following mechanical testing, as was MPI of the internal surface of at the failed GW, following metallography. No crack-like indications were identified.

3.3 Fractography

3.3.1 Optical

Figure 19 is a photograph of the fracture surface and internal surface of PS A following cleaning with a soft bristle brush. Each o'clock hour is indicated and located at the twelve grey magnets. Figure 20 through Figure 31 are sequential photographs of the PS A side of the fracture surface of the failed girth weld, in 1 hour o'clock increments, starting at the 12:00 orientation. The fracture surface mainly consists of fairly smooth surfaces (*smooth regions*) at a shear (~45°) angle with respect to the free surfaces, and rougher surfaces (*rough* surfaces) that are perpendicular to the free surfaces. Some examples of the smooth surfaces are in Figure 21 through Figure 23, between the 1:00 and 3:45 orientations. The fracture surface between the 3:45 and 4:15 orientations contains smooth and rough regions. Some other examples of the rough regions are in Figure 29 through Figure 31, between the 9:15 and 12:00 orientations, where the rough regions are mainly ID surface breaking, with some midwall portions. The differences in these appearances is related to the fracture mode (ductile vs brittle), as described in Section 3.3.2, and both regions formed as a result of overload. There was no evidence of gross pre-existing flaws on the fracture surface that would have been rejected if detected by radiographic inspection. The exact location of the initiation could not be determined due to a lack of chevrons on the fracture surfaces and the fact that no significant pre-existing (prior to failure) cracks were identified.

3.3.2 Optical and Scanning Electron Microscopy

Four fracture surface samples (Samples S1, S2, S3, and S4) were removed from the PS A side of the failed girth weld, adjacent to the metallographic cross-sections. The results of examinations of Samples S2 and S3 are below.

Figure 32 is a light photomicrograph of the fracture surface of Sample S2, following cleaning in ENPREP® 214. Sample S2 was removed near the 4:00 orientation. The figure shows smooth regions (black dashed double arrows) adjacent to the OD and ID surfaces, and a rougher region (white double arrow) midwall. There is no evidence of any pre-existing (present prior to the failure) flaws on the facture surface. Figure 33 is an SEM image of Sample S2 adjacent to the ID surface. The figure shows a smooth region (adjacent to the ID surface) and a rough region of the fracture surface. Figure 34 is an SEM image of Sample S2 at the interface of a smooth and rough region. The black box in the figure is just below the interface and the figure shows dimples in the smooth region. Dimples indicate ductile (overload) fracture, which occurred during the failure. Figure 35 is a high magnification SEM image of Sample S2 in the smooth region. The figure clearly shows the dimples. Figure 36 and Figure 37 are SEM images of Sample S2 in a rough region. The fracture surface contains cleavage facets, which indicates brittle (overload) fracture, which occurred during the failure.

Figure 38 is an SEM image of Sample S2, midwall at a second interface of the smooth and rough regions. The figure shows what appear to be some tears in the smooth region, above the rough region. Figure 39 and Figure 40 are SEM images in the smooth region. The figures shows dimples, consistent with ductile (overload) fracture.

Figure 41 and Figure 42 are SEM images of Sample S2 in a smooth region adjacent to the OD surface. The figures show dimples, which is very clear in the high magnification SEM image. Again, the dimples indicate ductile (overload) fracture and are consistent with ductile fracture in the smooth region.

Figure 43 is a light photomicrograph of the fracture surface of Sample S3, following cleaning in ENPREP® 214. Sample S3 was removed near the 8:30 orientation. Figure 44 is an SEM image of Sample S3. The fracture surface is macroscopically smooth and at a shear angle to the free surfaces, and consists of mainly, if not entirely, smooth regions. Figure 45 is an SEM image of Sample S3 midwall. The figure shows small and larger dimples. Figure 46 is a high magnification SEM image of Sample S3 in the smooth region. The figure clearly shows the dimples.

Examination of Samples S1 and S4 showed similar fractographic features that formed as a result of overload failure. There was no evidence of obvious pre-existing flaws or fatigue growth on the fracture surfaces examined.

3.4 Metallography

Axial (cross girth weld) cross-sections were removed from the failed girth weld (five total) and the intact girth weld (one total) for metallographic analysis. Figure 47 is a photograph of the mounts that were removed from across the failed girth weld. The figure shows that Mounts M1 and M3 contain fracture paths at a shear angle, which is indicative of ductile overload failure. Mounts M2 and M4 (and a small portion of M5) contain regions where the fracture path is perpendicular to the free surface and regions of shear failure. The perpendicular portions are where the fracture surfaces are rough and the shear angle portions are where the fracture surfaces are smooth.

Figure 48 is a light photomicrograph of the axial metallographic cross-section (Mount M1), which was removed from the failed GW at the 1:35 o'clock orientation; refer to Figure 1 and Figure 11 for the location. The sequence of the welding is typical of a pipeline girth weld consisting of a root pass, a hot pass, several fill passes (depending on o'clock orientation), and cap passes. There is no evidence of excessive porosity or slag inclusions in the weld. The fracture path is at a shear angle and mainly located in the weld metal. The high-low weld misalignment at this location is approximately 0.023 inches (4.3% of NWT); note the misalignment is difficult to measure on the fracture cross-section and is an approximation.

Figure 49 is light photomicrograph of Mount M1 adjacent to the OD surface. The figure shows the fracture path is located in the HAZ, near the toe of the weld at the OD surface. Figure 50 is a light photomicrograph of Mount M1 adjacent to the fracture surface, near the OD surface. The figure shows inclusions aligned at an oblique angle with the fracture surface. The orientation of the inclusions is a result of cold work from the failure. Figure 51 is a high magnification light photomicrograph of Mount M1 adjacent to the fracture surface. The figure shows some grain elongation adjacent to the fracture surface and inclusions. The presence of the grain elongation from cold work and orientation of the inclusions is consistent with ductile overload. Figure 52 is a high magnification light photomicrograph of Mount M1 midwall adjacent to the fracture surface. The figure clearly shows the change in the grain orientation and thus more grain elongation adjacent to the fracture surface.

Figure 53 and Figure 54 are light photomicrographs showing the microstructures of the U/S and D/S Joints, respectively. The microstructures of the joints consist mainly of ferrite (white areas), which is consistent with modern X80 line pipe.

Figure 55 is a light photomicrograph of the axial metallographic cross-section (Mount M2), which was removed from the failed GW at the 3:55 o'clock orientation; refer to Figure 1 and Figure 12 for the location. The morphology of the weld similar to Mount M1. The high-low weld misalignment at this location is approximately 0.037 inches (6.9% of the NWT). The figure clearly illustrates the smooth and rough regions examined near SEM Sample S2, such that the smooth regions are surface breaking and the rough region is midwall. The fracture path at this location is in both the weld metal and HAZ, such that smooth region near the OD surface is in the weld metal, and the rough region midwall and smooth region near the ID surface are in the HAZ. Fractography in the SEM demonstrated that the smooth region contains dimples and the rough region contains cleavage facets.

Figure 56 is a light photomicrograph of Mount M2 adjacent to the ID surface. The figure shows that the fracture surface is relatively smooth. Figure 57 is a high magnification light photomicrograph of Mount M2 adjacent to the ID surface. The figure shows grain elongation adjacent to the fracture surface. The presence of the grain elongation from cold work is consistent with ductile overload. Figure 58 is a light photomicrograph of Mount M2 midwall, in a rough region. The fracture surface is clearly rougher here than the previous figure, and the fracture path is mainly located in the HAZ, if not entirely. Figure 59 is a light photomicrograph of Mount M2 adjacent to the fracture, midwall. The figure shows some fissures. Figure 60 is a high magnification light photomicrograph of Mount M2 at fissures. The fissures are located where cleavage facets (brittle fracture) were present on the fracture surface. These fissures are commonly seen in girth weld overload failures, adjacent to fractures surfaces, or pipe (body or seam weld) failures that involve axially running fracture.

Figure 61 is a light photomicrograph of the axial metallographic cross-section (Mount M3), which was removed from the failed GW at the 8:35 o'clock orientation; refer to Figure 1 and Figure 13 for the location. The morphology of the weld is similar to Mounts M1 and M2. The fracture path is at a shear angle and mainly located in the weld metal. The high-low weld misalignment at this location is approximately 0.014 inches (2.6% of the NWT). The figure clearly illustrates the smooth region examined near SEM Sample S3.

Figure 62 is light photomicrograph of Mount M3 adjacent to the fracture surface, near the ID surface. The figure shows grain elongation adjacent to the fracture surface that is consistent with ductile overload.

Figure 63 is a light photomicrograph of the axial metallographic cross-section (Mount M4), which was removed from the failed GW at the 10:24 o'clock orientation; refer to Figure 1 and Figure 14 for the location. The morphology of the weld is similar to the previous mounts. The high-low weld misalignment at this location is minimal. The figure shows both a smooth shear angle region and a rough region oriented perpendicular to the free surfaces. The fracture path at this location is mainly in the HAZ.

Figure 64 is light photomicrograph of Mount M4 adjacent to the OD surface. The figure clearly shows the fracture path is located in the HAZ. Figure 65 is a high magnification light photomicrograph of Mount M4 adjacent to the OD surface. The figure shows grain elongation, and an inclusion orientated parallel to the fracture surface, both observations consistent with ductile overload. Figure 66 is a light photomicrograph of Mount M4 midwall, mainly in a rough region. The figure shows some fissures. Figure 67 is a high magnification light photomicrograph of Mount M4 at some fissures. The fissure have the same morphology as shown in Mount M2. Figure 68 is a high magnification light photomicrograph of Mount M4 near the ID surface. The figure shows grain elongation adjacent to the fracture surface.

Figure 69 is a light photomicrograph of the axial metallographic cross-section (Mount M5), which was removed from the failed GW at the 11:37 o'clock orientation; refer to Figure 1 and Figure 14 for the location. The morphology of the weld is similar to the previous mounts. The high-low weld misalignment at this location is approximately 0.025 inches (4.6% of the NWT). The figure shows a smooth shear angle region for a majority of the fracture surface, and a rough region oriented perpendicular to the free surfaces midwall. The fracture path at this location is located in both the weld metal and base metal.

Figure 70 is a light photomicrograph of the axial metallographic cross-section (Mount MU1), which was removed from the intact GW at the 12:24 o'clock orientation; refer to Figure 1 and Figure 17 for the location. The morphology of the weld is similar to the previous mounts. The high-low weld misalignment at this location is approximately 0.011 inches (2.0% of the NWT). Figure 71 is a light photomicrograph of Mount MU1 adjacent to the ID surface. The figure shows a shallow (0.01 inches [1.9% of NWT] deep) flaw between the weld metal and HAZ. The location of the flaw is consistent with incomplete fusion (IF). Figure 72 is a high magnification light photomicrograph of Mount MU1 at the tip of the shallow IP flaw. The figure shows there is no evidence of crack extension at the flaw.

3.5 Hardness Testing

Vickers hardness testing was performed on all six mounts in the base metal, HAZ, and weld metal. A 1 kg load was used on Mounts M1, M4, and MU1 and approximately 1500 indents with approximately 0.5 mm spacing were performed. Figure 73, Figure 76, and Figure 78 are hardness map overlays showing the locations of the indents and color coded maps indicating the hardness values. The hardness values for the two mounts from the failed girth weld are between 208 and 317 HV, and the values for the mount from the intact girth weld are between 167 and 268 HV. The average hardness for Mount M1, M4, and MU1 are 266, 253, and 228 HV, respectively. There was a larger variation in the hardness values, and less of a consistent pattern of hardness values, for the mounts from the failed GW compared to the intact girth weld. Overall for the mounts from the failed girth weld, the weld metal in the root pass was the softest, the weld metal in the cap pass was higher than the fill passes, and the base metal was somewhere in between. The highest values for the mounts from the failed girth weld was adjacent to the shear fracture surface, between midwall and the OD surface.

The hardness of the intact girth weld (Figure 78) is a better representation of the hardness of all the welds prior to the failure. For the intact girth weld, the values appeared to follow a more consistent pattern. Figure 78 clearly shows that the root pass of the weld metal is the softest and the surrounding base metal (adjacent to the HAZ) is harder than the weld metal. Hardness typically correlates with ultimate tensile strength (UTS) fairly well, thus the data indicates that the weld metal is weaker than the surrounding pipe material. The higher hardnesses measured in the failed welds, and the large variation and lack of a consistent pattern, is a byproduct of the cold work the material experienced during the failure.

A 10 kg load was used on Mounts M2, M3, and M5 (all from the failed girth weld) and indents were performed at approximately 20 to 30 locations. Figure 74, Figure 75, and Figure 77 are light photomicrographs of the mounts showing the indents and hardness values. The hardness values are between 205 and 304HV. The lowest values are at the ID weld metal (root pass, similar to the hardness maps), and the highest values are in the weld metal cap pass. The base metal is generally harder than the root and fill passes, and similar to or sometimes less than the cap pass.

Overall no areas of unusually high hardness area were found. The hardness results show that the softest region is located in the weld metal root pass, suggesting a lower grade electrode was used for the root pass compared to the other passes.

3.6 Mechanical Testing

3.6.1 Tensile Testing

The results of tensile testing of duplicate circumferential base metal specimens removed from PS A (Joint D/S of failed GW) are shown in Table 3. The average yield strength (YS) and ultimate tensile strength (UTS) of the circumferential specimens were 93.5 ksi and 112.4 ksi, respectively. The results of tensile testing of axial base metal specimens also are shown in the table and YS values for the axial specimens are quite a bit higher than those of the circumferential specimens (by 8 ksi). The YS and UTS of the circumferential base metal specimens meet the requirements for API 5L X80M PSL 2 line pipe at the time of construction.

The results of tensile testing of duplicate circumferential base metal specimens removed from PS C (Joint U/S of failed GW) are shown in Table 4. The average YS and UTS of the circumferential specimens were 91.0 ksi and 104.8 ksi, respectively, which is slightly less than the values for PS A. The results of tensile testing of axial base metal specimens also are shown in the table and the YS values for the axial specimens also are higher than those of the circumferential specimens (by 6.7 ksi). The YS and UTS of the circumferential base metal specimens meet the requirements for API 5L X80M PSL 2 line pipe at the time of construction.

The average UTS of duplicate axial specimens removed across the intact girth weld was 103.3 ksi. Both cross-girth weld specimens failed in the girth weld, similar to the actual failure. YS values across the girth weld are not reliable and not specified in API 1104. The average UTS value across the weld meets the tensile requirements API 5L X80M PSL 2 line pipe at the time of construction. Note that the value of 103.3 ksi is less than the axial tensile strength of 109.7 ksi and 106 ksi for the joints D/S and U/S, respectively, of the failed girth weld.

3.6.2 CVN Testing of Base Metal Specimens

The results of CVN testing of triplicate transverse base metal specimens removed from PSs A (Joint D/S of failed GW) and C (Joint U/S of failed GW) are shown in Table 5. The specimens were tested at 32°F. The impact values are relatively high, i.e. full-size values all above 93 ft·lbs for PS A and above 148 ft·lbs for PS C. The shear % values are all 100% (indicating fully ductile behavior). The impact values all exceed the specified minimum value of 30 ft·lbs (at 32°F) for API 5L X80 PSL 2 line pipe, and the average of shear % values are greater than 85 %.

3.6.3 CVN Testing of Girth Weld Specimens

Table 6 shows the results of CVN testing for axial specimens removed from the intact girth weld (notch in the HAZ from PS C), while Figure 79 and Figure 80 show the Charpy percent shear and impact energy curves. An analysis of the data for the girth weld specimens indicates that the 85% FATT is 59.9°F and upper shelf Charpy energy is 114 ft lbs, as shown in Table 7. Both values are good for line pipe steel.

3.7 Chemical Analysis

The results of the chemical analyses conducted on steel samples removed from PSs A (Joint D/S of failed GW) and C (Joint U/S of failed GW) are summarized in Table 8. The results of the chemical analyses indicate that the steels meet the chemical composition requirements for API 5L Grade X80M PSL 2 line pipe steel at the time of construction. Carbon equivalent (CE) values were calculated for the base metal samples. The calculated CE_{Pcm} values for the PSs A and C are 0.17 and 0.16, respectively, compared to a maximum allowed CE_{Pcm} of 0.25 per the API 5L spec at the time of construction. These values for the joints are relatively low and indicate a very good resistance to HACC in the HAZ.

4.0 CONCLUSIONS

The results of the metallurgical analysis indicate that the failure initiated at a field girth weld, completely separating the girth weld. The exact location of the initiation could not be determined due to a lack of chevrons on the fracture surfaces and the fact that no significant pre-existing (prior to failure) cracks were identified. Microscopically, the fracture surface contained regions with dimples (ductile fracture) and cleavage facets (brittle fracture). The dimples were located where the fracture surface was at a shear angle and macroscopically smooth, and the cleavage facets were located where the fracture surface was perpendicular to the free surfaces and macroscopically rough. Both fractographic features are an indication of the overload nature on the fracture surface.

The failure occurred due to axial stresses sufficient to produce an overload failure. Supporting evidence for the presence of large axial stresses include 1) a relatively large opening between the failed ends and 2) cracked and missing epoxy coating U/S of the failed girth weld indicating a high strain prior/during fracture. A possible contributing factor to relatively large axial stresses include stresses associated with movement.

No excessively high hardness areas were identified in the girth weld cross-sections. The weld metal of the intact girth weld had a lower hardness than the surrounding pipe material, indicating that the weld metal is weaker than the surrounding pipe material. This trend was somewhat followed for the failed girth weld, although cold work from the failure likely skewed some of the data. The softest regions in all the mounts was the weld metal root pass. The lower overall hardness values of the weld metal compared to the surrounding pipe material is consistent with the axial tensile results. The ultimate tensile strength for the girth weld of 103.3 ksi is less than the axial tensile strength of 109.7 ksi and 106 ksi for the joints D/S and U/S, respectively, of the failed girth weld. The axial tensile tests across the intact GW failed in the GW, similar to the actual failure. Therefore, a contributing factor to the failure was that the pipe steel was stronger than the girth weld.

Below is a summary of additional conclusions:

- There was no evidence of notable internal or external corrosion.
- The tensile and toughness properties of the joints U/S and D/S of the failed girth weld meet requirements for API 5L X80M PSL 2 line pipe at the time of construction.
- The chemical compositions of the joints U/S and D/S of the failed girth weld meet the requirements for API 5L X80M PSL 2 line pipe at the time of construction.
- The microstructures of the joints U/S and D/S of the failed girth are consistent with modern API 5L X80 line pipe steel.

- An analysis of the Charpy V-notch impact testing data for the intact girth weld indicates that the 85% FATT is 59.9°F and upper shelf Charpy energy is 114 ft lbs.

Table 1. Results of circumference and diameter measurements performed at the field cut ends of Pipe Sections (PS) A, B, and C.

Pipe Section	Pipe Section End	Circumference (feet)	Diameter (inches)		
			From Circumference Measurement	3 to 9 o'clock	6 to 12 o'clock
A	D/S	6.31	24.1	24.1	24.1
B	U/S	6.31	24.1	24.0	24.0
C	D/S	6.32	24.2	24.0	24.0
C	U/S	6.31	24.1	24.0	24.0

Table 2. Results of wall thickness measurements performed at the field cut ends of PS A, B, and C.

O'clock Orientation	Wall Thickness (inches)			
	PS A, D/S End	PS B, U/S End	PS C, D/S End	PS C, U/S End
12	0.539	0.536	0.537	0.531
3	0.533	0.538	0.536	0.530
6	0.536	0.535	0.534	0.530
9	0.533	0.540	0.537	0.530
Average	0.535	0.537	0.536	0.530

Table 3. Results of tensile tests performed on circumferential specimens from PS A (Joint D/S of failed GW) compared with requirements for API 5L X80M PSL 2 line pipe steel, and axial base metal specimens from Pipe Section A.

	Circumferential	API 5L X80M Line Pipe Steel [2]	Axial
Yield Strength, ksi [1]	93.5	80.5 – 102.3	101.5
Tensile Strength, ksi [1]	112.4	90.6 – 119.7	109.7
Elongation in 2 inches, % [1]	29.5	20.7 (min)	31.1
Reduction of Area, % [1]	61.6	–	67.1

1 – Average of duplicate tests.
2 – API 5L 44th Edition, October 1, 2007.

Table 4. Results of tensile tests performed on circumferential specimens from PS C (Joint U/S of failed GW) compared with requirements for API 5L X80M PSL 2 line pipe steel and axial base metal specimens and axial/cross-girth weld specimens from Pipe Section C.

	Circumferential	API 5L X80M Line Pipe Steel [2]	Axial	Cross Girth Weld
Yield Strength, ksi [1]	91.0	80.5 – 102.3	97.7	–
Tensile Strength, ksi [1]	104.8	90.6 – 119.7	106.0	103.3
Elongation in 2 inches, % [1]	29.0	20.7 (min)	31.8	–
Reduction of Area, % [1]	62.1	–	70.9	–

1 – Average of duplicate tests.
2 – API 5L 44th Edition, October 1, 2007.

Table 5. Results of Charpy V-notch impact tests for circumferential base metal specimens removed from the PS A (Joint D/S of failed GW) and PS C (Joint U/S of failed GW). Specimens were tested at 32F.

Sample ID	Sub Size Impact Energy, ft-lbs	Full Size Impact Energy, ft-lbs	Shear, %	Lateral Expansion, mils
Pipe Section A				
PSA1	93	93	100	56
PSA2	109	109	100	71
PSA3	105	105	100	68
Avg.	102	102	100	65
Pipe Section C				
PSC1	164	164	100	71
PSC2	148	148	100	81
PSC3	155	155	100	73
Avg.	156	156	100	75
API 5L [1]	-	30	$\geq$ 85	-

1 – API 5L 44th Edition, October 1, 2007.

Table 6. Results of Charpy V-notch impact tests performed on axial/cross-girth weld (heat affected zone [HAZ] notch) specimens removed from PS C.

Sample ID	Temperature, °F	Sub Size Impact Energy, ft-lbs	Full Size Impact Energy, ft-lbs	Shear, %	Lateral Expansion, mils
1	-184	4	4	5	0
2	-112	7	7	16	6
3	-76	32	32	44	22
4	-40	59	59	51	41
5	32	69	69	69	48
6	73	116	116	97	81
7	104	117	117	87	65
8	140	122	122	100	86
9	176	95	95	92	64
10	194	118	118	100	87

Table 7. Results of analyses of Charpy V-notch impact energy and percent shear plots for axial/cross-girth weld (HAZ notch) specimens removed from PS C (Joint U/S of failed GW).

	Girth Weld
Upper Shelf Impact Energy (Full Size), Ft-lbs	114
85% FATT, °F	59.9

Table 8. Results of chemical analyses of base metal samples removed from PS A (Joint D/S of failed GW) and PS C (Joint U/S of failed GW), compared with composition requirements for API 5L X80M PSL 2 line pipe steel. The highlighted CE values are the ones that are applicable based on carbon wt%.

Element	Composition (Wt. %)		
	PS A (Joint D/S of failed GW)	**PS C (Joint U/S of failed GW)**	**API 5L X80M [1] Req.**
C (Carbon)	0.059	0.053	0.12 (max)
Mn (Manganese)	1.62	1.65	1.85 (max)
P (Phosphorus)	0.012	0.009	0.025 (max)
S (Sulfur)	0.003	0.005	0.015 (max)
Si (Silicon)	0.202	0.219	0.45 (max)
Cu (Copper)	0.016	0.023	$\leq$ 0.50
Sn (Tin)	0.006	0.002	–
Ni (Nickel)	0.006	0.009	$\leq$ 1.00
Cr (Chromium)	0.047	0.038	$\leq$ 0.50
Mo (Molybdenum)	0.260	0.249	$\leq$ 0.50
Al (Aluminum)	0.042	0.039	–
V (Vanadium)	0.006	0.007	–
Nb (Niobium)	0.082	0.081	–
Zr (Zirconium)	0.002	0.002	–
Ti (Titanium)	0.020	0.019	–
B (Boron)	0.0003	0.0003	–
Ca (Calcium)	0.0034	0.0025	–
Co (Cobalt)	0.002	0.004	–
Fe (Iron)	Balance	Balance	Balance
Nb + V + Ti	0.108	0.107	$\leq$ 0.15
CE_{IIW} [2]	0.39	0.39	0.43 (max)
CE_{Pcm} [3]	0.17	0.16	0.25 (max)

1 – API 5L 44th Edition, October 1, 2007.

2 – $CE_{IIW} = C + Mn/6 + (Cu + Ni)/15 + (Cr + Mo + V)/5$

3 – $CE_{Pcm} = C + Si/30 + Mn/20 + Cu/20 + Ni/60 + Cr/20 + Mo/15 + V/10 + 5B$.

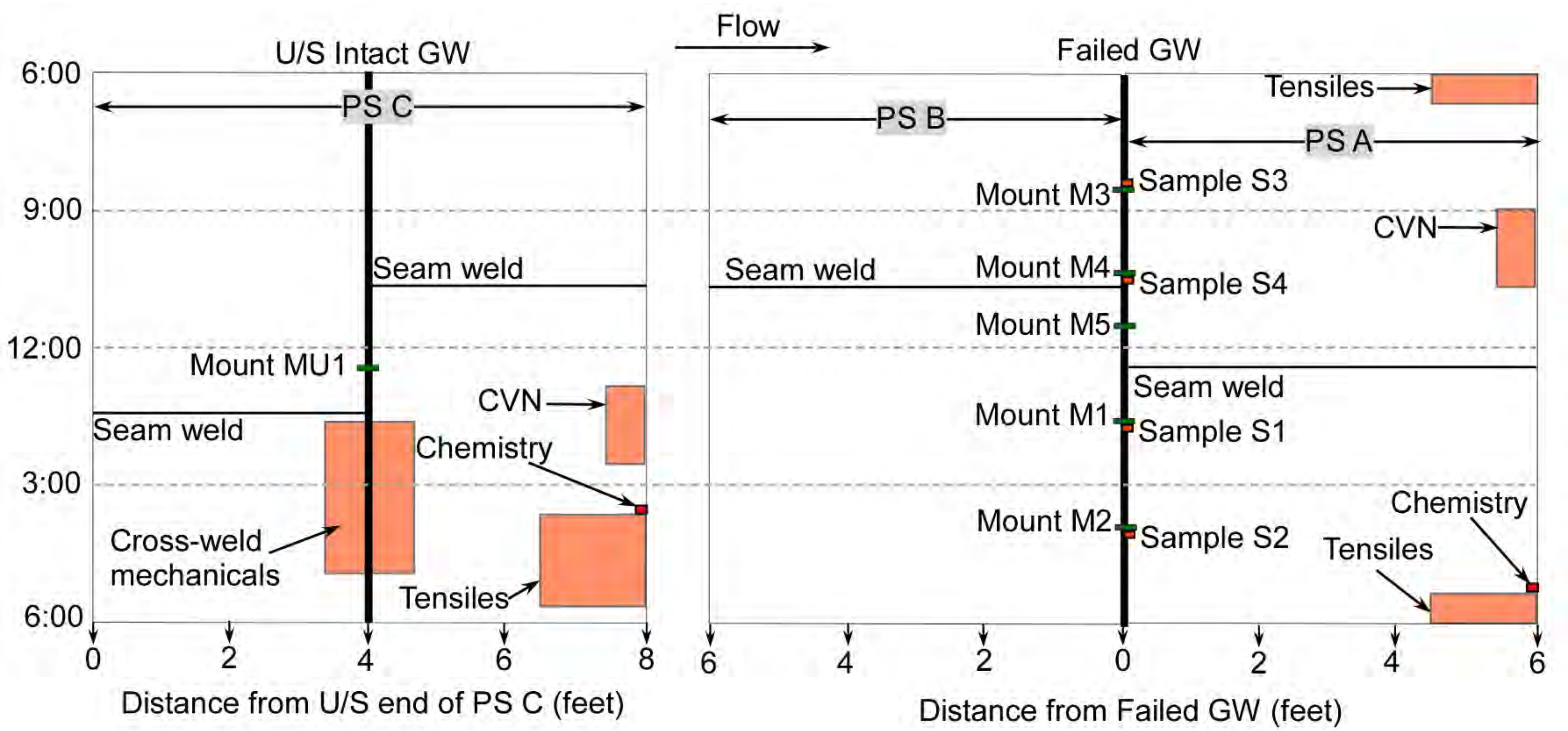

Figure 1. Schematic of Pipe Sections (PSs) A, B, and C showing the locations of the girth welds and seam welds, and where samples for metallography (Mounts M1, M2, M3, M4, M5, and MU1), fractography (Sample S1, S2, S3, and S4), mechanical testing (CVN, cross-weld mechanicals, and tensiles), and chemical analyses (chemistry) were removed.

Figure 2. Photograph of the wooden crate that contained PS A, as received at DNV GL.

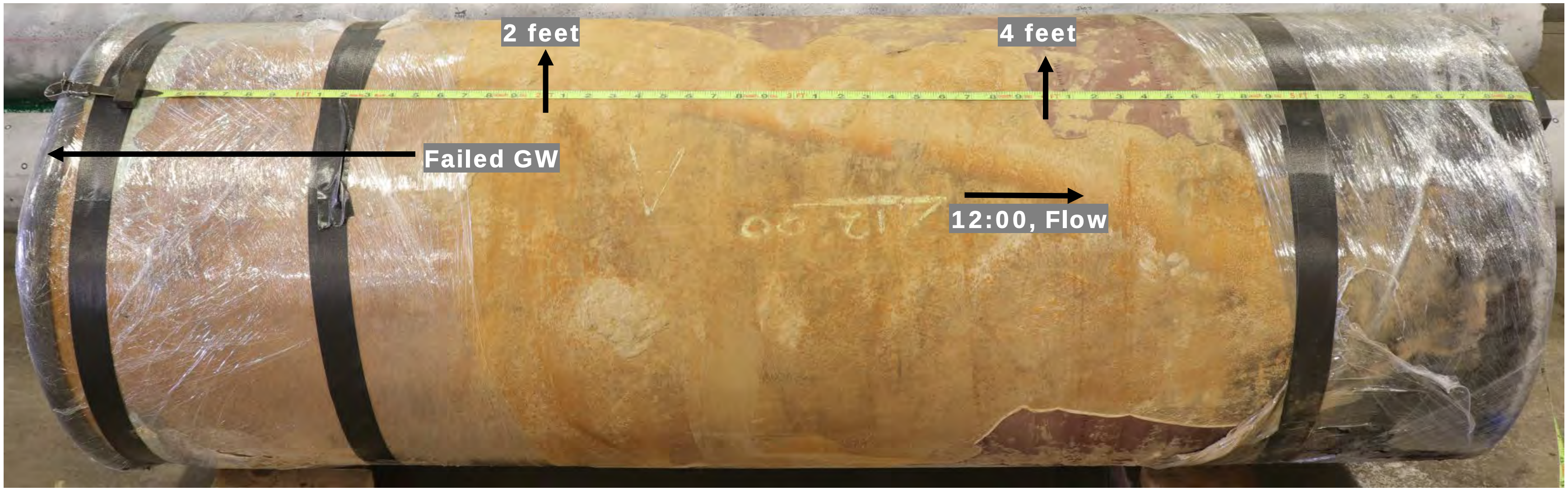

Figure 3. Photograph of PS A after removal from the wooden crate. The tape measure indicates the distance from the U/S end of PS A.

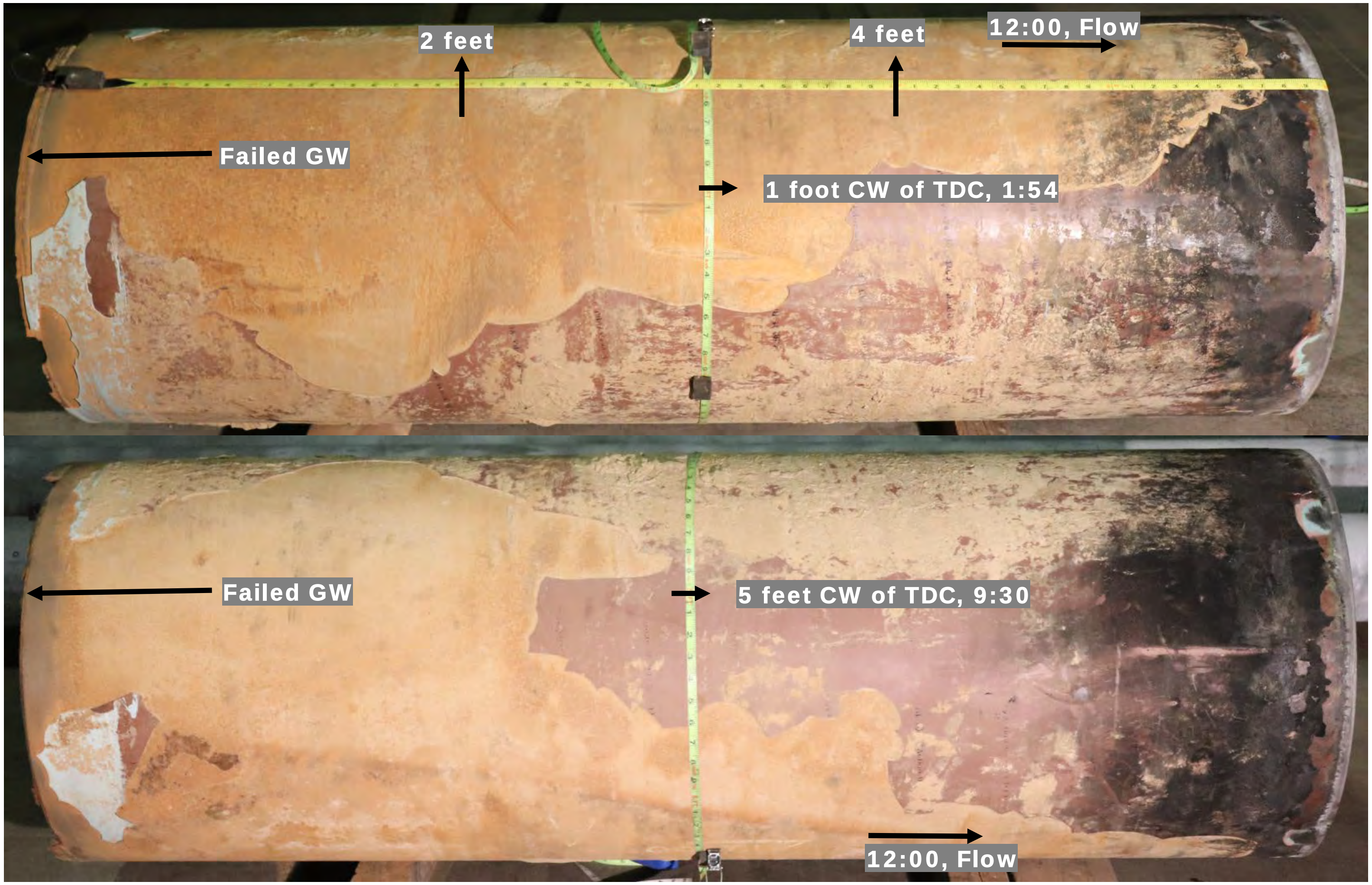

Figure 4. Photographs of PS A after removal of the protective wrappings. The horizontal tape measure indicates the distance from the U/S end of PS A, and circumferential tape measure indicates the distance clockwise (CW) of top-dead-center (TDC) looking downstream (D/S).

Figure 5. Photograph of the wooden crate that contained PS B, as received at DNV GL.

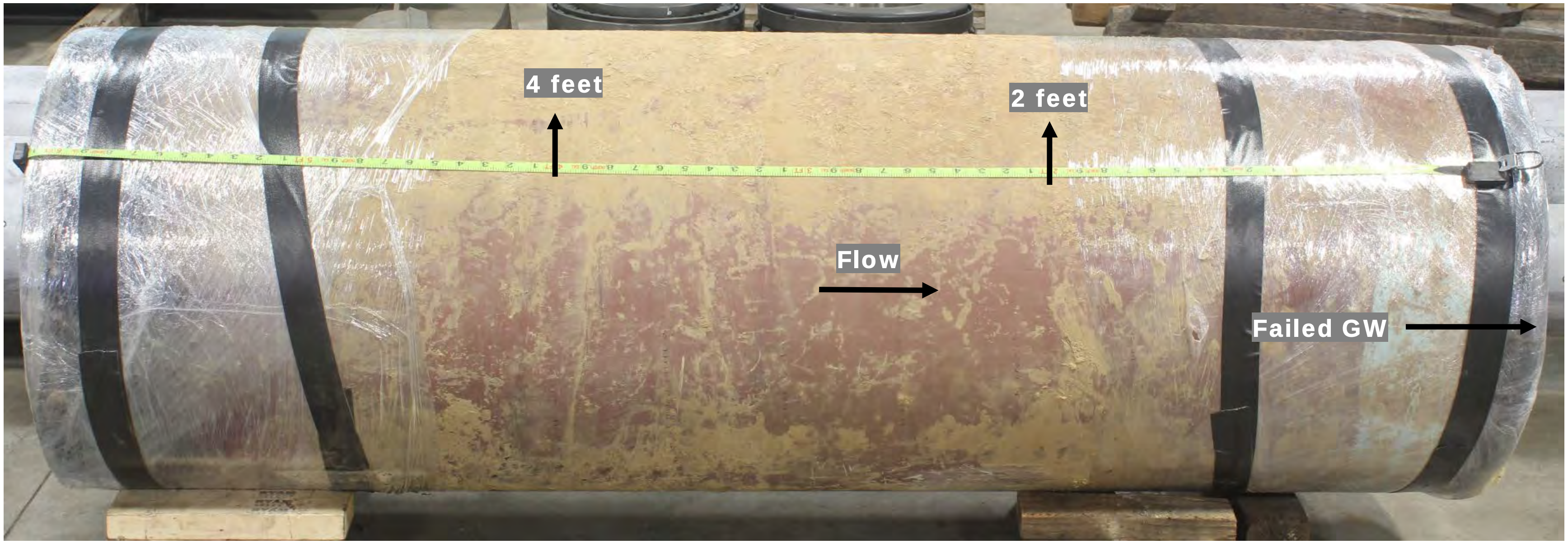

Figure 6. Photograph of PS B after removal from the wooden crate. The tape measure indicates the distance from the D/S end of PS B.

Figure 7. Photograph of PS B after removal of the protective wrappings. The tape measure indicates the distance from the D/S end of PS B.

Figure 8.   Photograph of the wooden crate that contained PS C, as received at DNV GL.

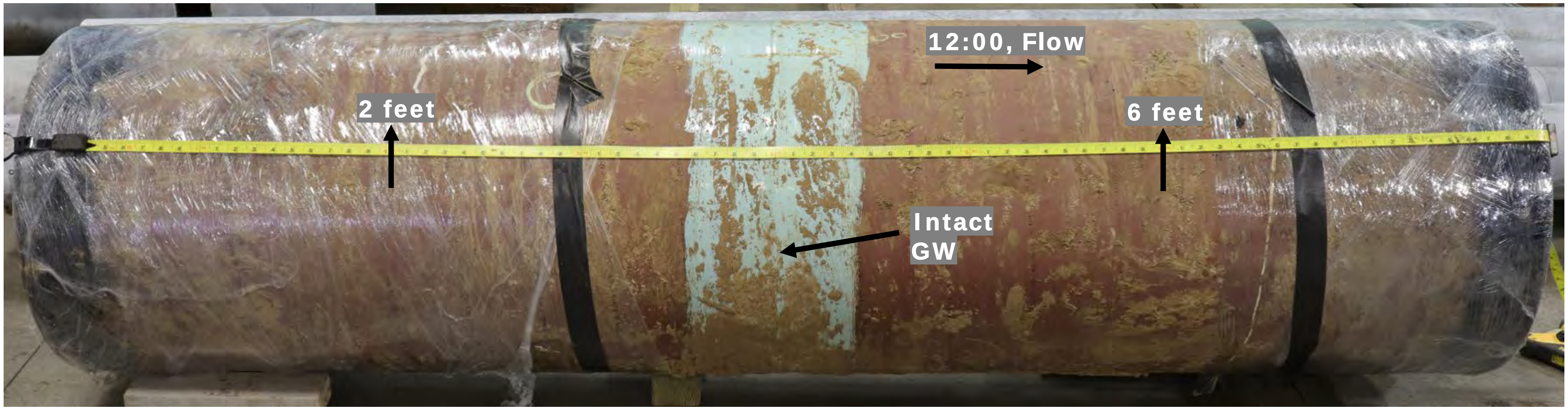

Figure 9. Photograph of PS C after removal from the wooden crate. The tape measure indicates the distance from the U/S end of PS C.

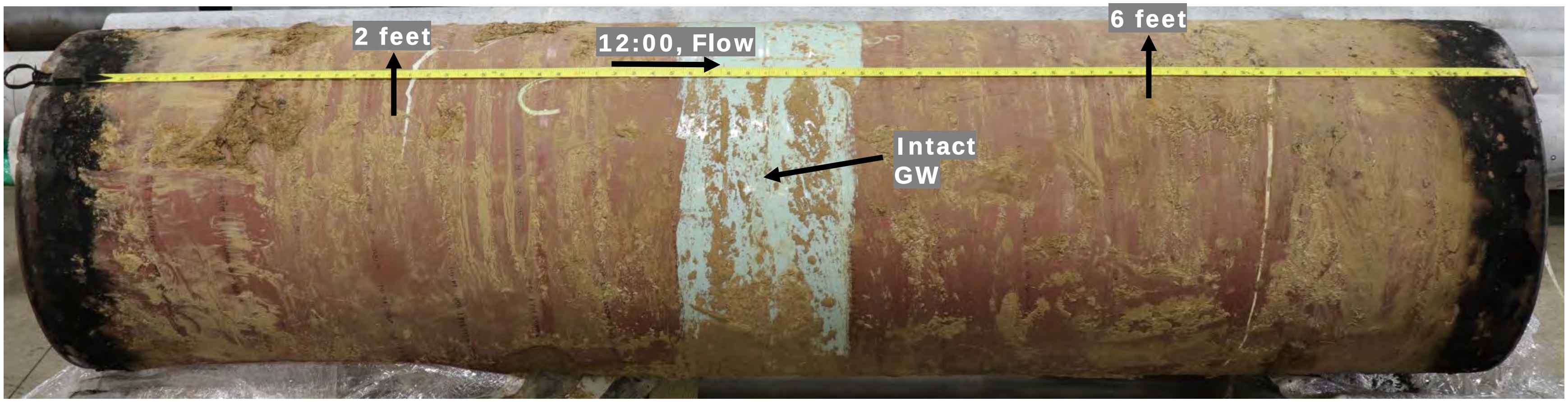

Figure 10. Photograph of PS C after removal of the protective wrappings. The tape measure indicates the distance from the U/S end of PS C.

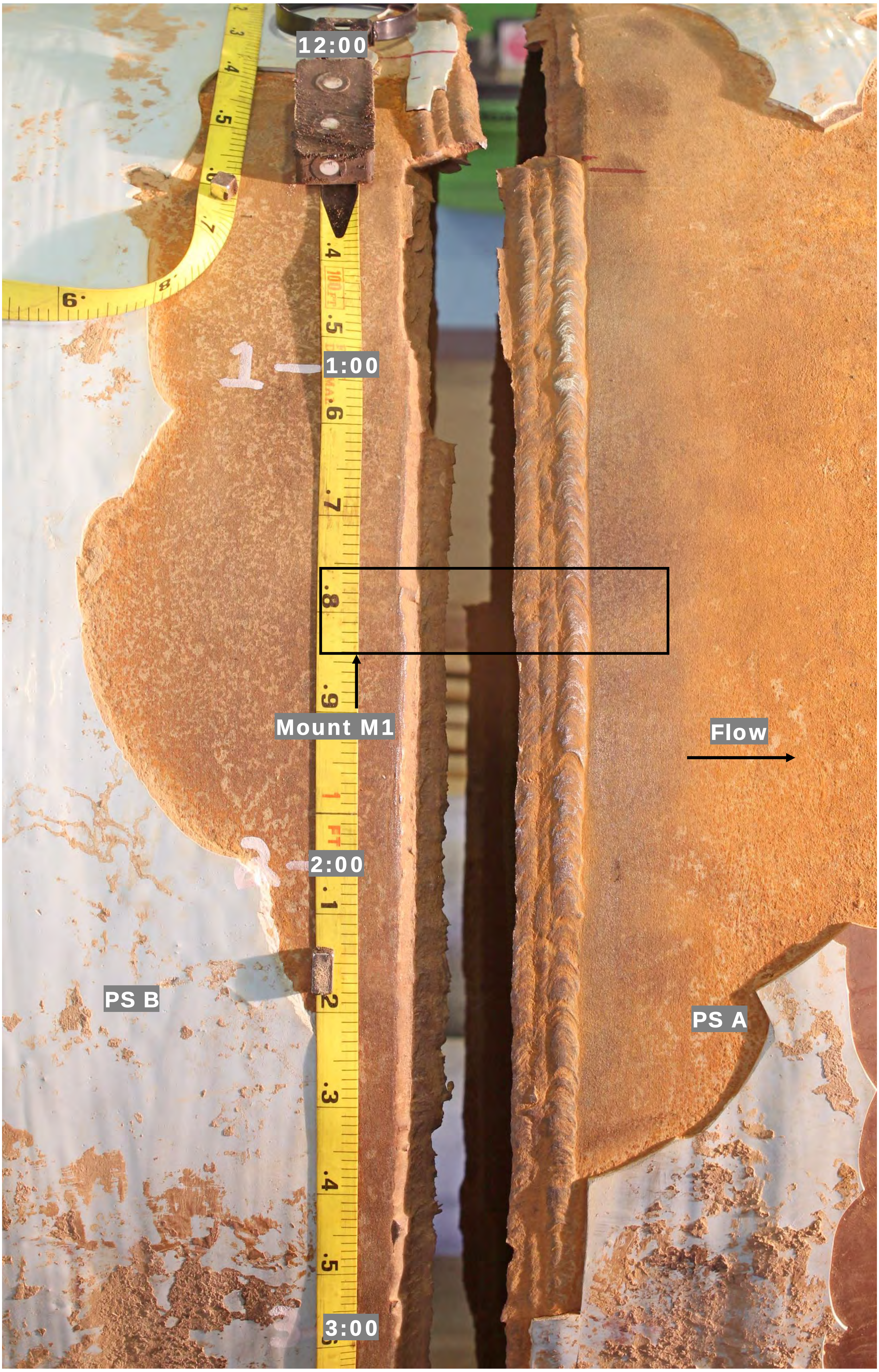

Figure 11. Photograph of the external of surfaces of PSs A and B adjacent to the fracture surfaces, between the 12 and 3 o'clock orientations, showing the failed girth weld and the morphology of the coating. The tape measure indicates the approximate distance CW of TDC (looking D/S convention).

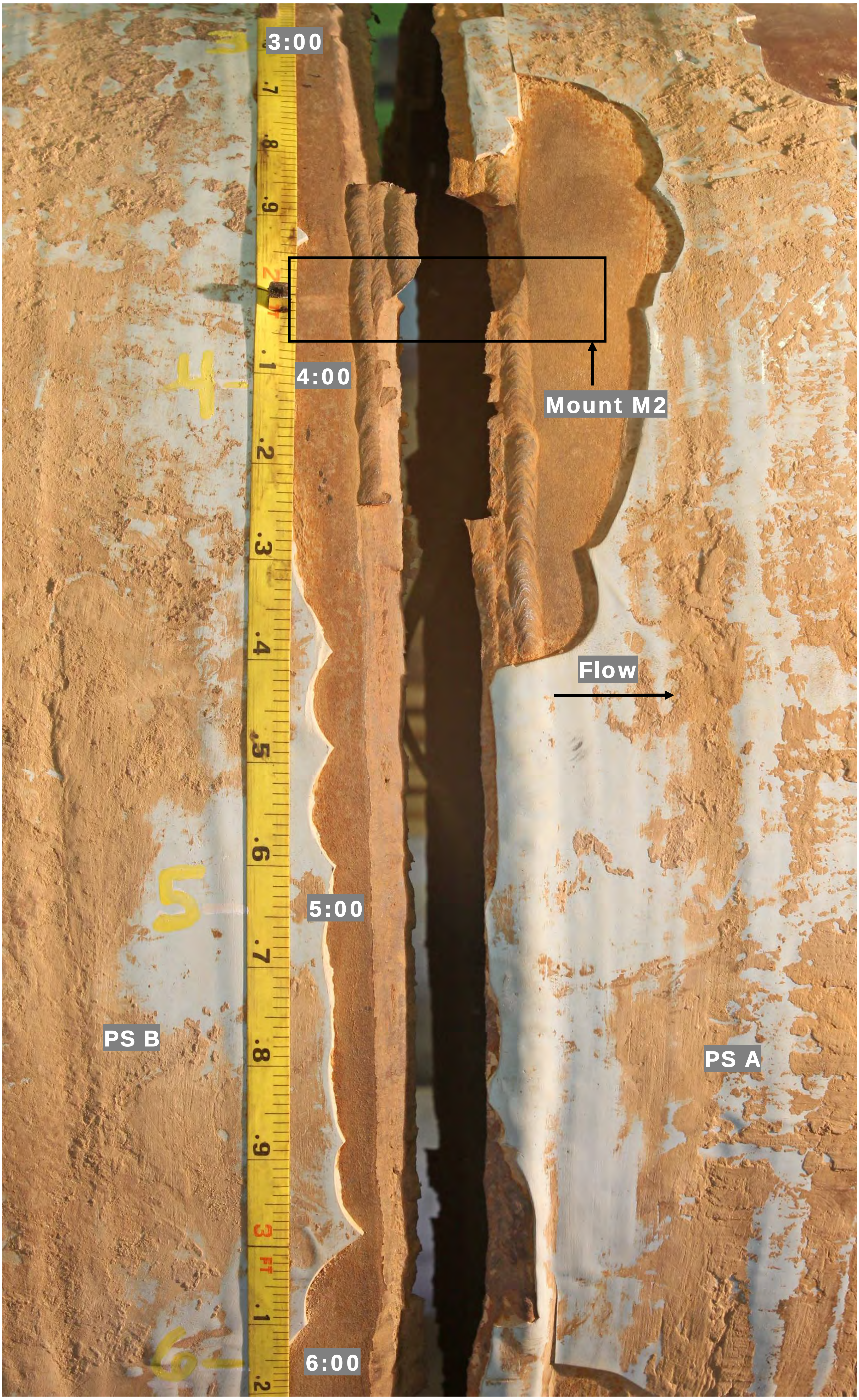

Figure 12. Photograph of the external of surfaces of PSs A and B adjacent to the fracture surfaces, between the 3 and 6 o'clock orientations, showing the failed girth weld and the morphology of the coating. The tape measure indicates the approximate distance CW of TDC (looking D/S convention).

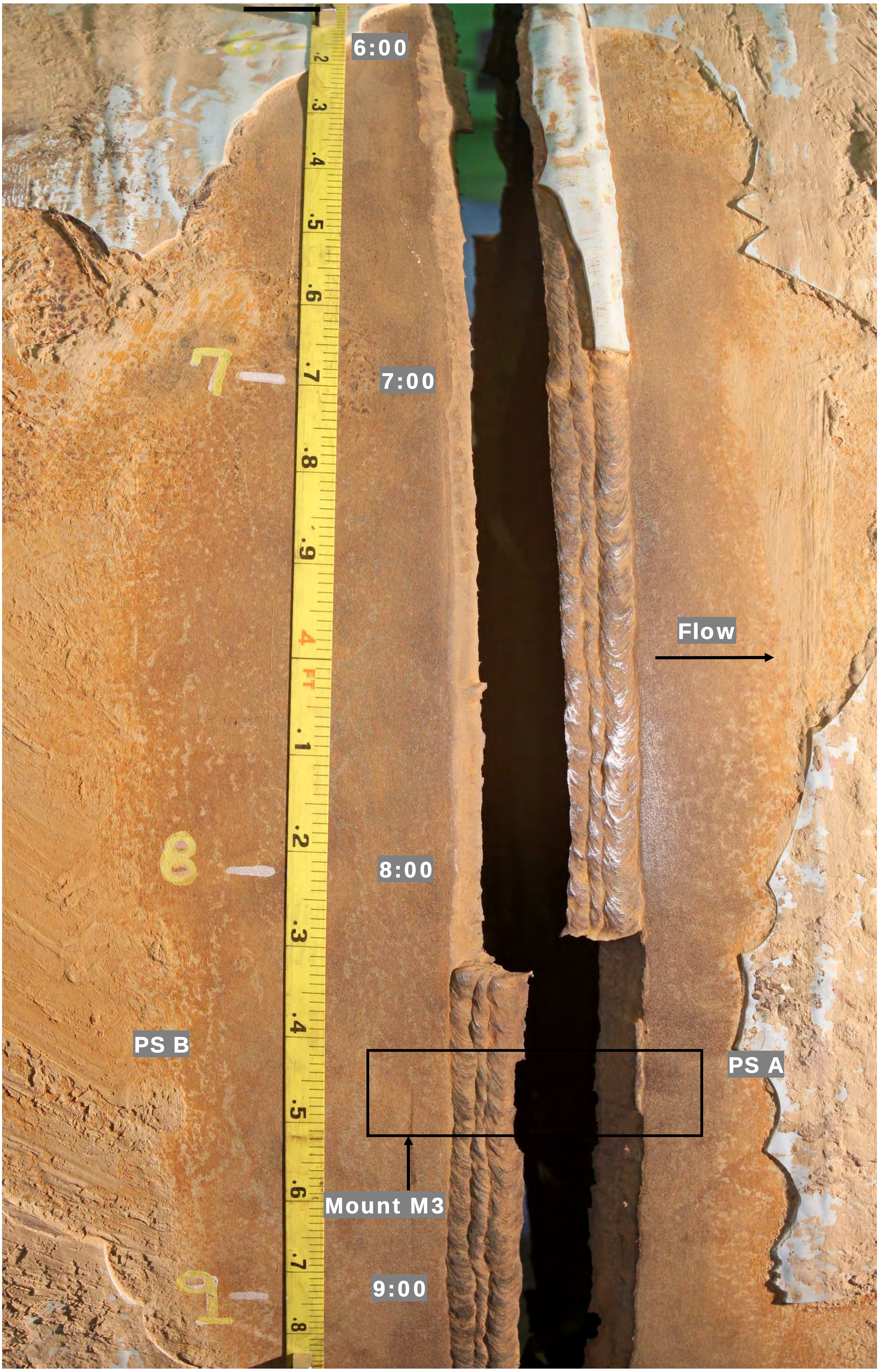

Figure 13. Photograph of the external of surfaces of PSs A and B adjacent to the fracture surfaces, between the 6 and 9 o'clock orientations, showing the failed girth weld and the morphology of the coating. The tape measure indicates the approximate distance CW of TDC (looking D/S convention).

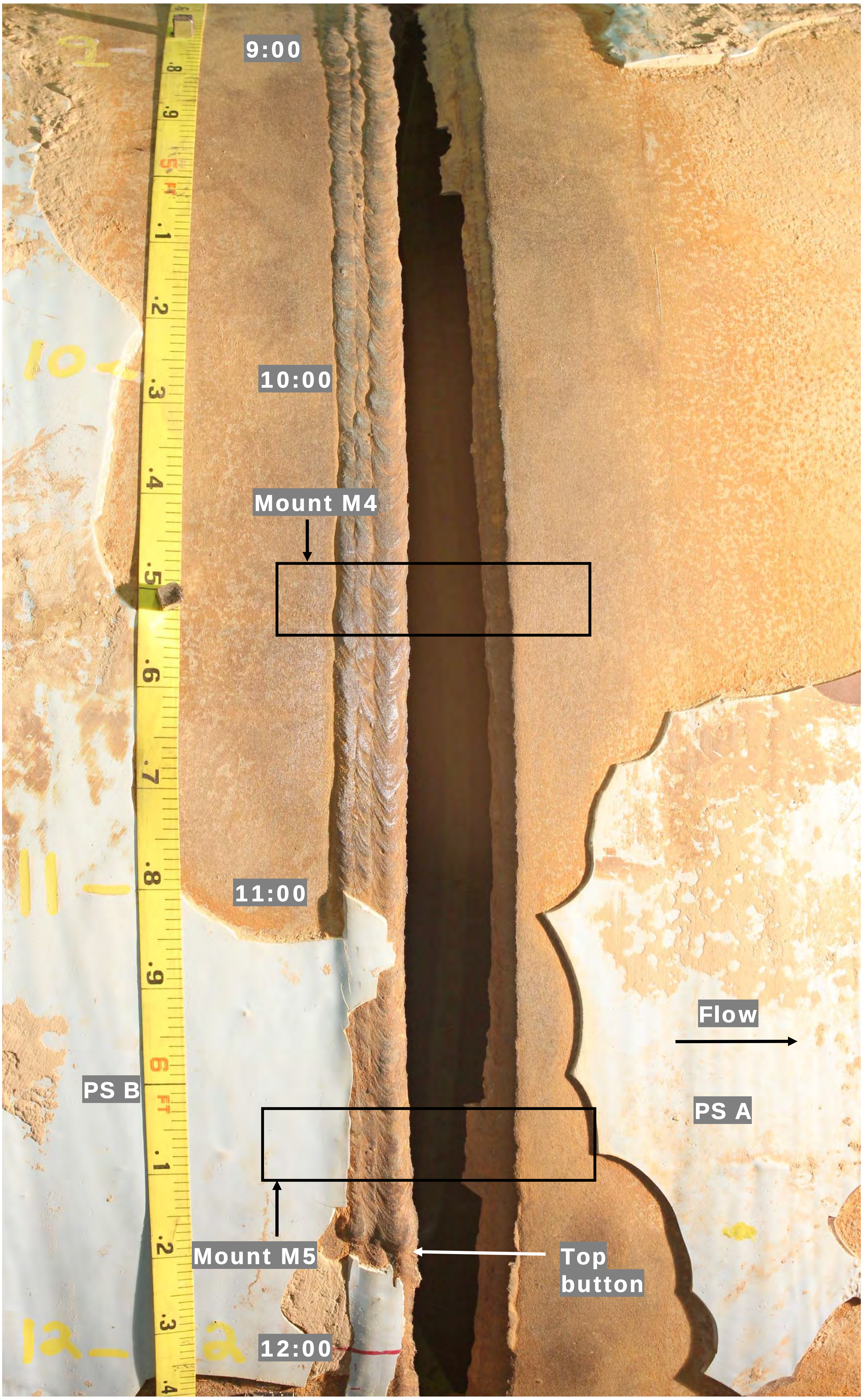

Figure 14. Photograph of the external of surfaces of PSs A and B adjacent to the fracture surfaces, between the 9 and 12 o'clock orientations, showing the failed girth weld and the morphology of the coating. The tape measure indicates the approximate distance CW of TDC (looking D/S convention).

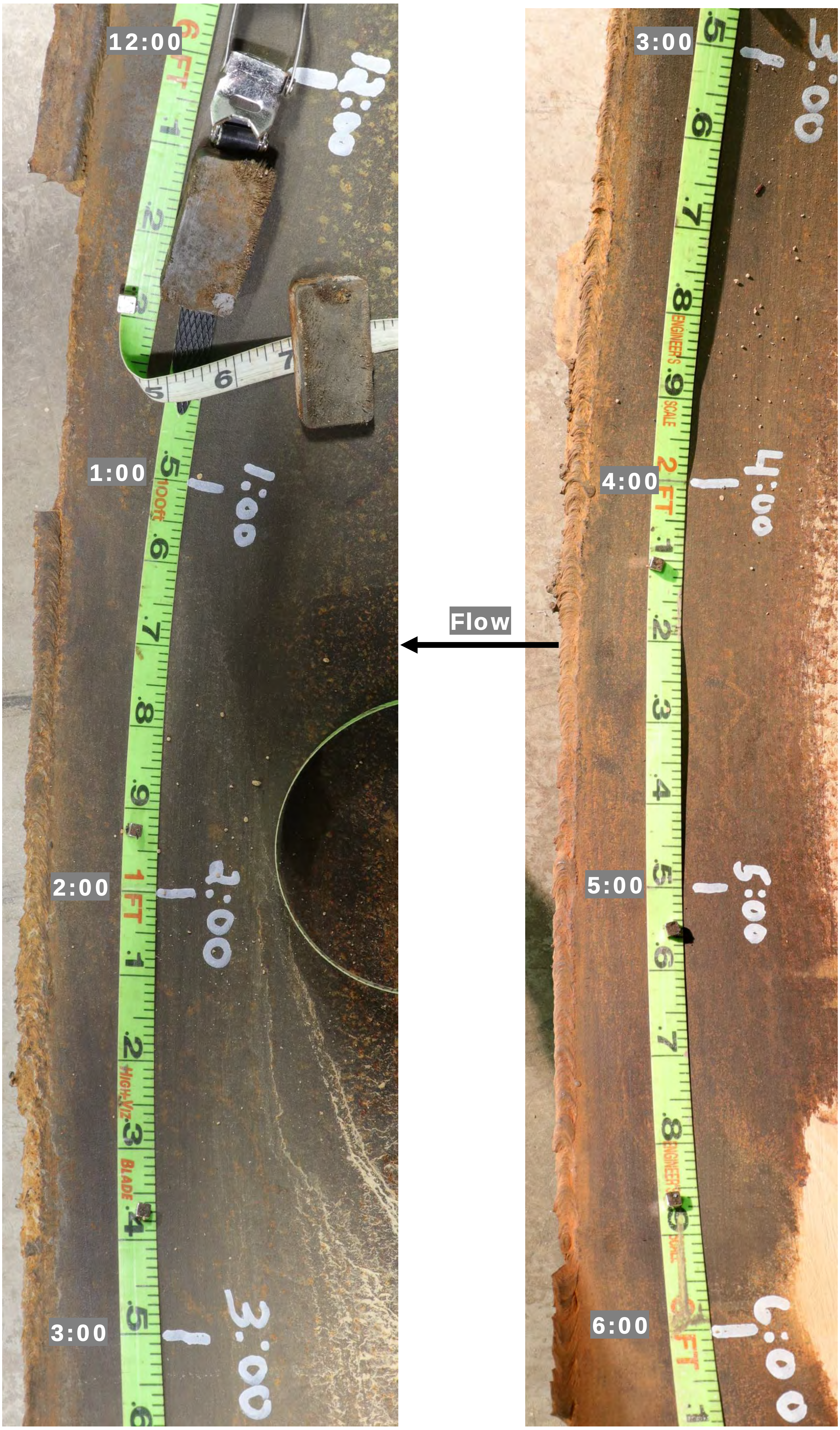

Figure 15. Photograph of the internal pipe surface adjacent to the fracture surface of PS B, between the 12 and 6 o'clock orientations. The tape measure indicates the approximate distance CW of TDC (looking D/S convention).

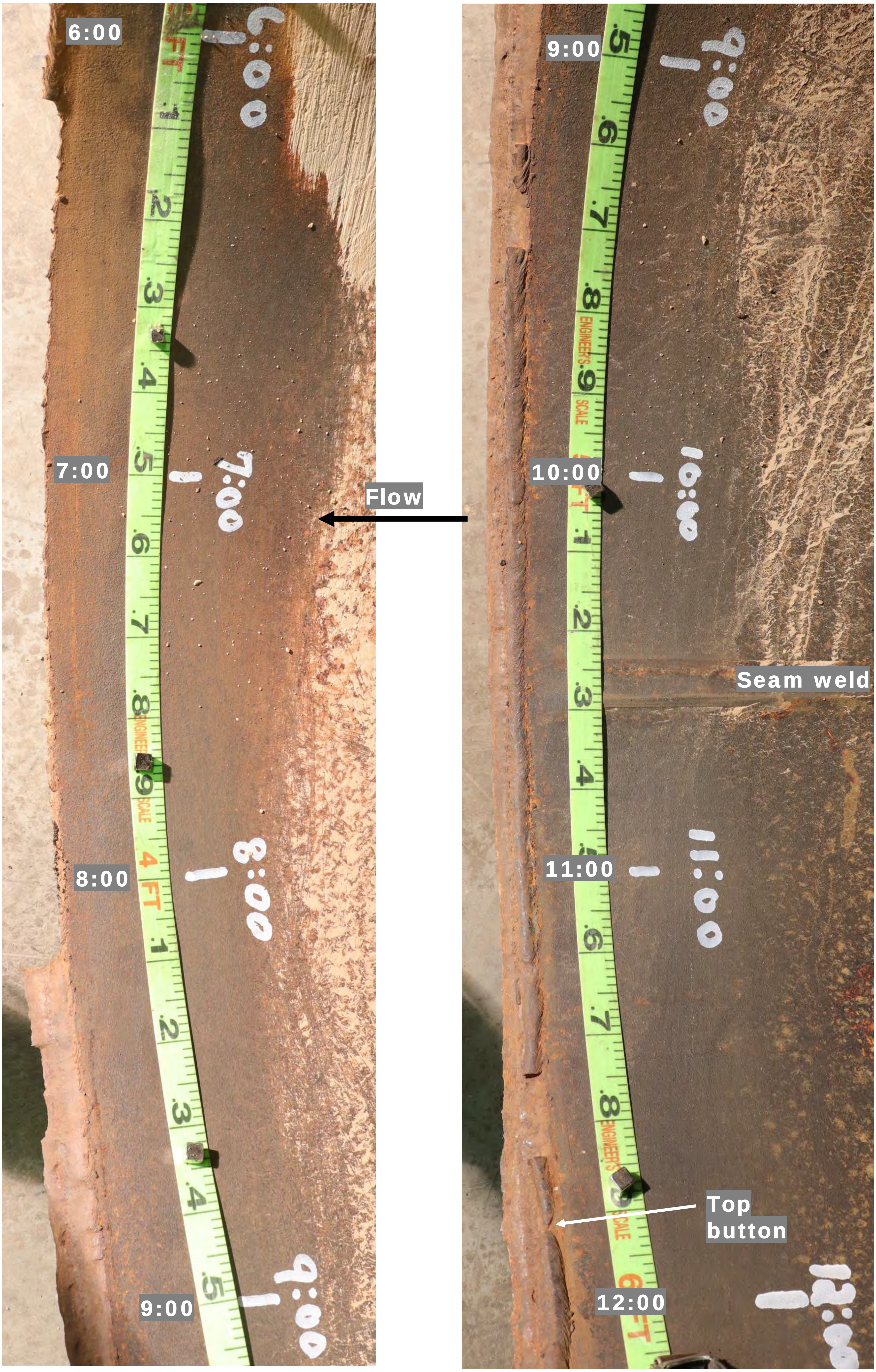

Figure 16. Photographs of the internal pipe surface adjacent to the fracture surface of PS B, between the 6 and 12 o'clock orientations. The tape measure indicates the approximate distance CW of TDC (looking D/S convention).

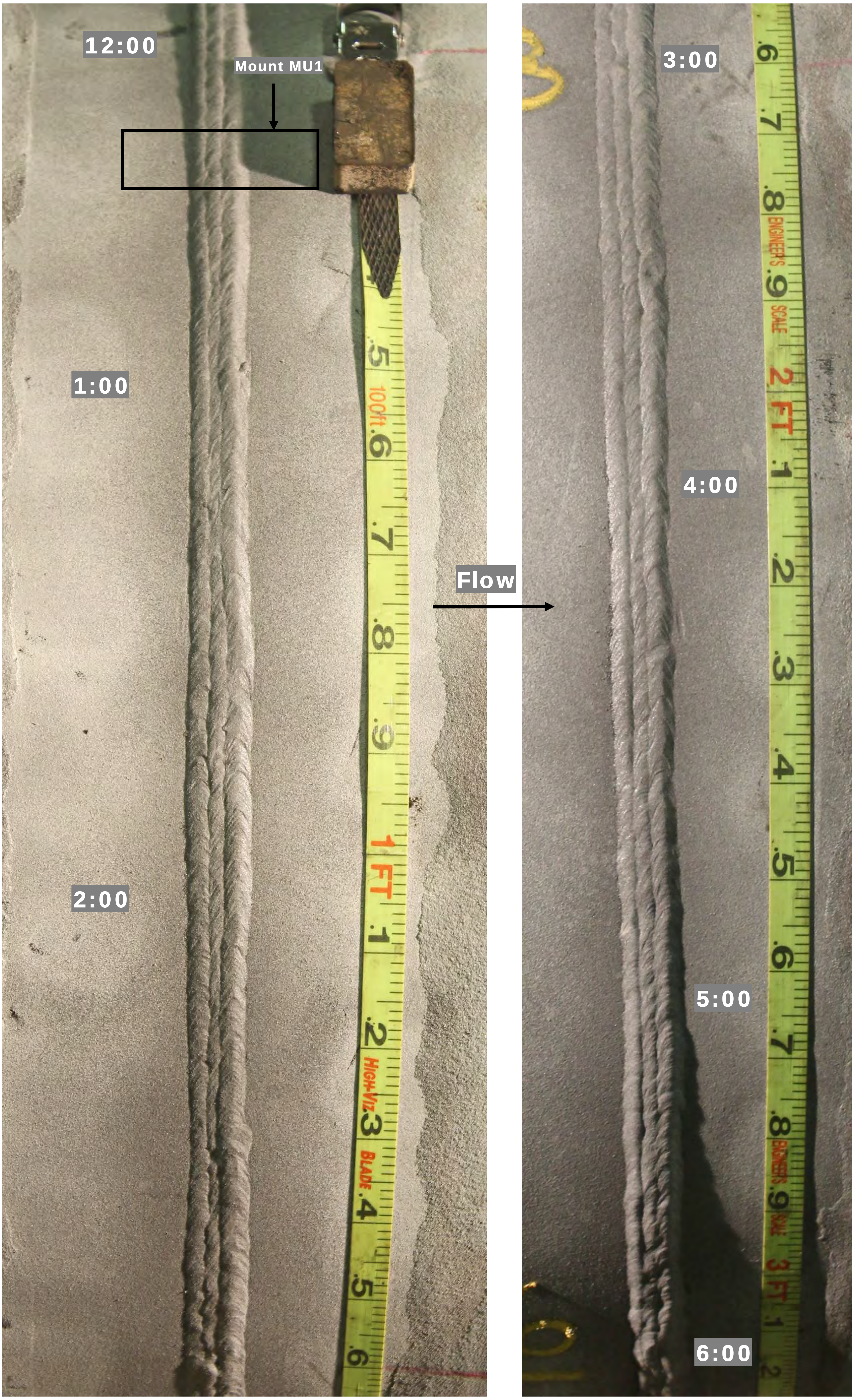

Figure 17. Photograph of the external pipe surface at the intact girth weld following grit blasting and MPI, between the 12:00 and 6:00 orientations. The tape measure indicates the approximate distance CW of TDC (looking D/S convention).

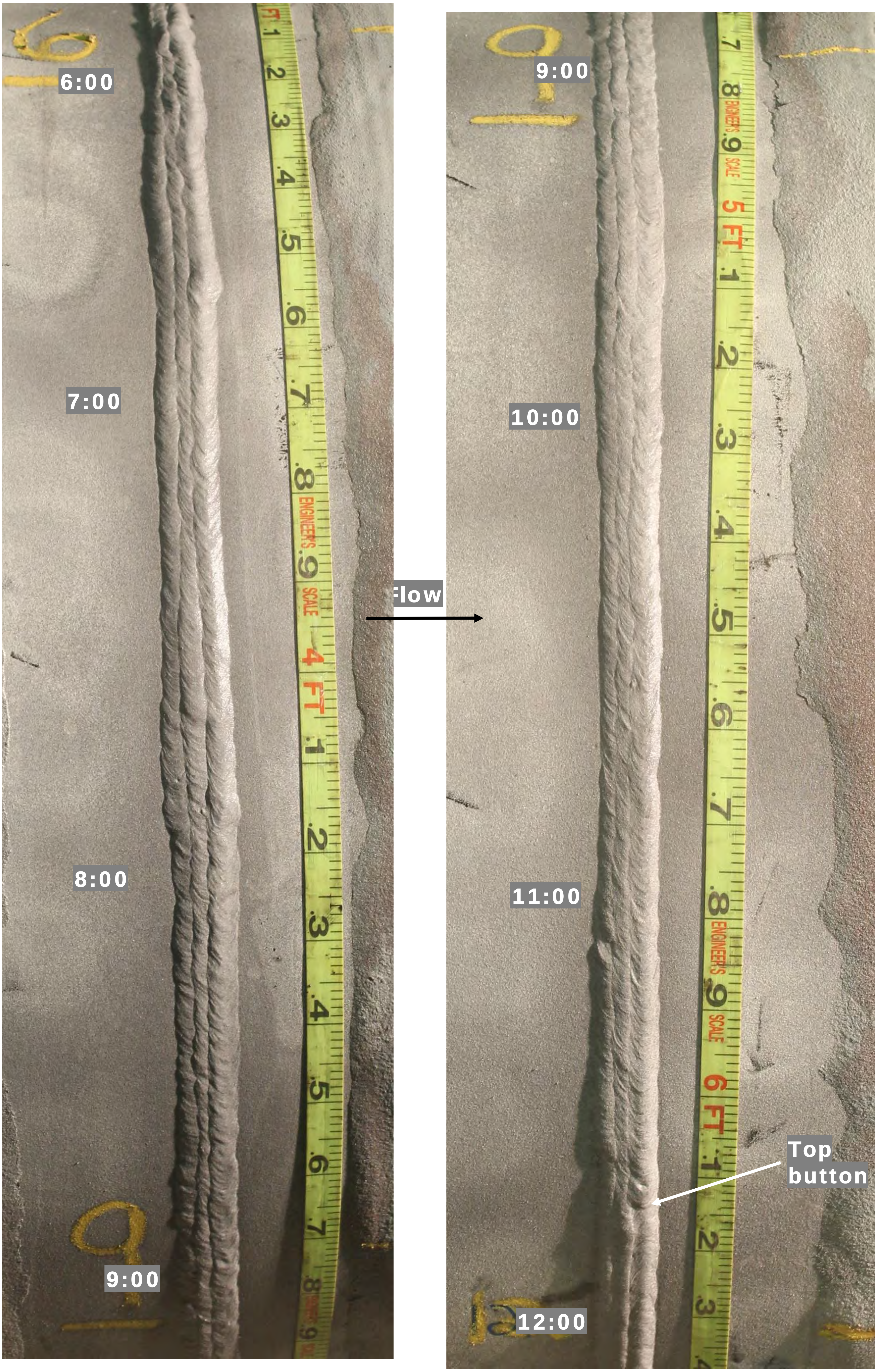

Figure 18. Photograph of the external pipe surface at the intact girth weld following grit blasting and MPI, between the 6:00 and 12:00 orientations. The tape measure indicates the approximate distance CW of TDC (looking D/S convention).

Figure 19. Photograph of the fracture surface and internal pipe surface of PS A. Flow direction is into the photograph. Labels on magnets indicate o'clock orientations.

Figure 20. Photograph of the fracture surface of PS A between the 12 and 1 o'clock orientations. Units of ruler are in cm. Flow direction is into the photograph.

Figure 21. Photograph of the fracture surface of PS A between the 1 and 2 o'clock orientations. Units of ruler are in cm. Flow direction is into the photograph.

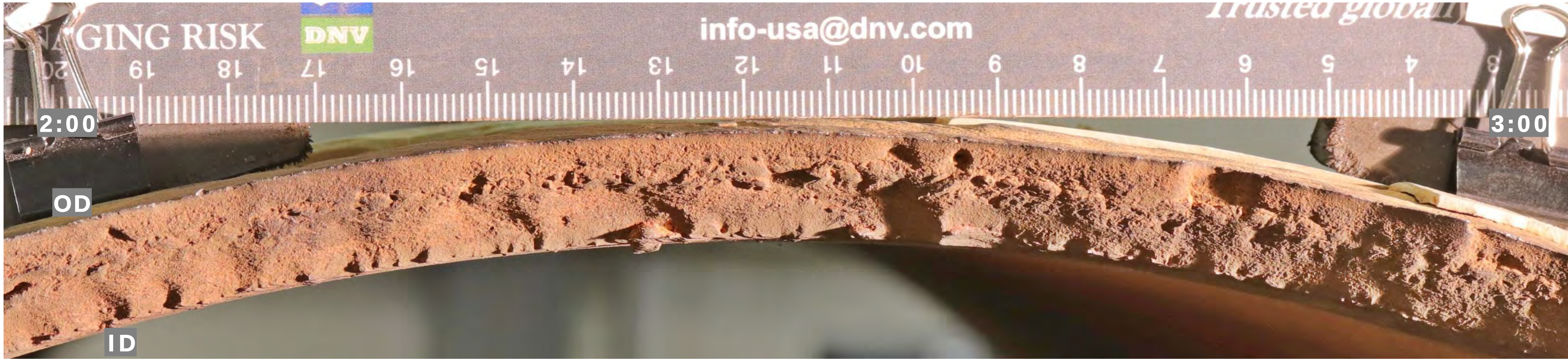

Figure 22. Photograph of the fracture surface of PS A between the 2 and 3 o'clock orientations. Units of ruler are in cm. Flow direction is into the photograph.

Figure 23. Photograph of the fracture surface of PS A between the 3 and 4 o'clock orientations. Units of ruler are in cm. Flow direction is into the photograph.

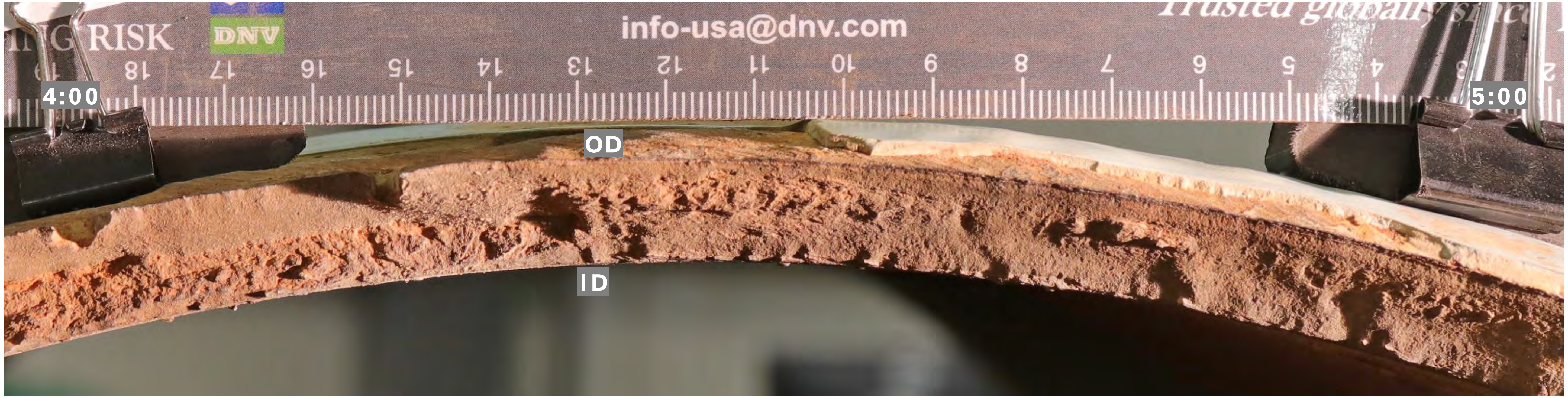

Figure 24. Photograph of the fracture surface of PS A between the 4 and 5 o'clock orientations. Units of ruler are in cm. Flow direction is into the photograph.

Figure 25. Photograph of the fracture surface of PS A between the 5 and 6 o'clock orientations. Units of ruler are in cm. Flow direction is into the photograph.

Figure 26. Photograph of the fracture surface of PS A between the 6 and 7 o'clock orientations. Units of ruler are in cm. Flow direction is into the photograph.

Figure 27. Photograph of the fracture surface of PS A between the 7 and 8 o'clock orientations. Units of ruler are in cm. Flow direction is into the photograph.

Figure 28. Photograph of the fracture surface of PS A between the 8 and 9 o'clock orientations. Units of ruler are in cm. Flow direction is into the photograph.

Figure 29. Photograph of the fracture surface of PS A between the 9 and 10 o'clock orientations. Units of ruler are in cm. Flow direction is into the photograph.

Figure 30. Photograph of the fracture surface of PS A between the 10 and 11 o'clock orientations. Units of ruler are in cm. Flow direction is into the photograph.

Figure 31. Photograph of the fracture surface of PS A between the 11 and 12 o'clock orientations. Units of ruler are in cm. Flow direction is into the photograph.

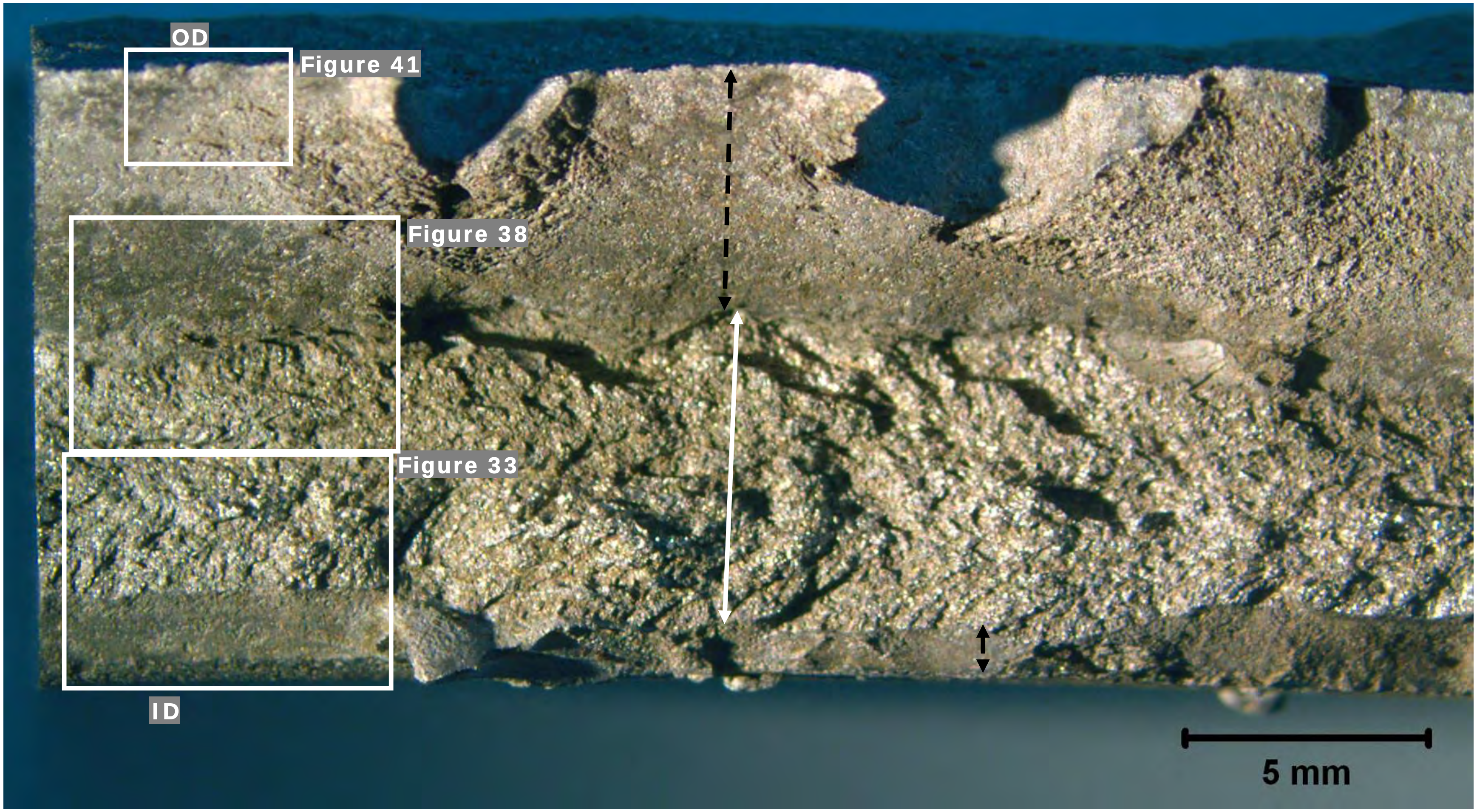

Figure 32. Light photomicrograph of the fracture surface of Sample S2, following cleaning in ENPREP® 214. The sample was removed near the 4:00 orientation from PSA; area indicated in Figure 23. The black, dashed double arrows indicate smooth regions and the white double arrow indicates a rough region.

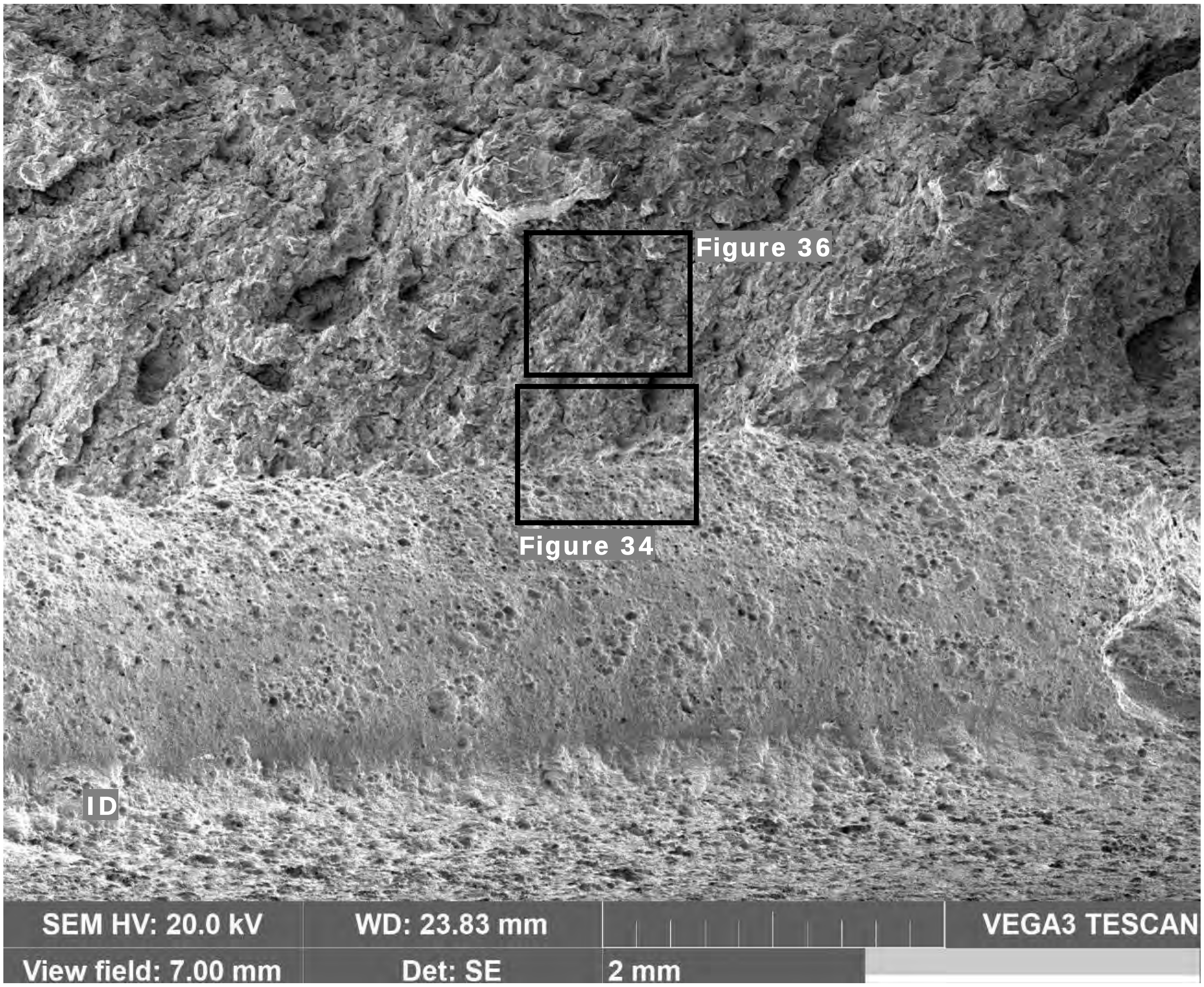

Figure 33. SEM image of Sample S2 adjacent to the ID surface; area indicated in Figure 32.

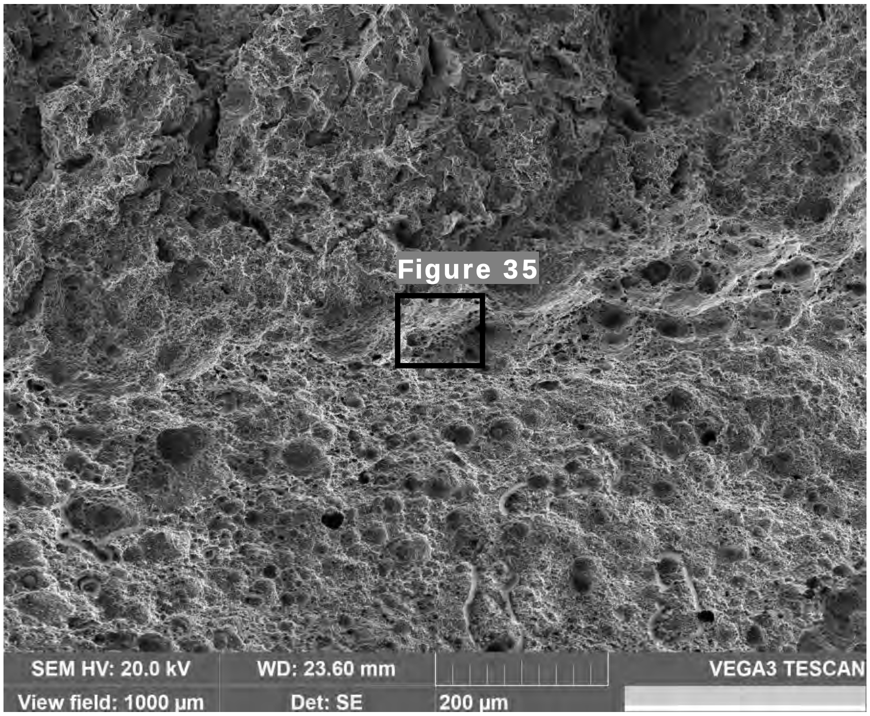

Figure 34. SEM image of Sample S2 at the interface of a macroscopically smooth and rough region; area indicated in Figure 33.

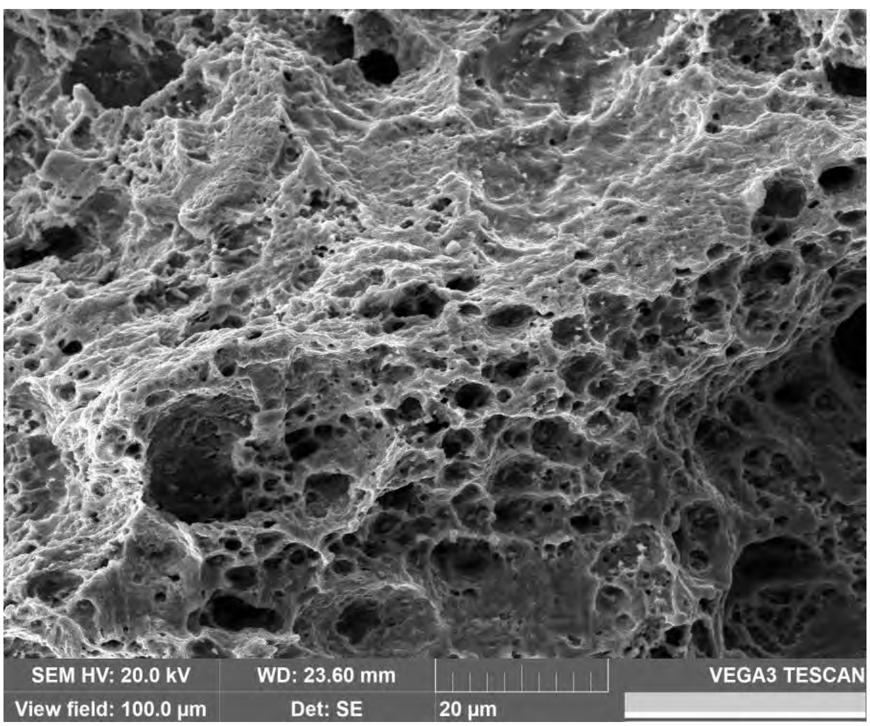

Figure 35. High magnification SEM image of Sample S2 in the macroscopically smooth region; area indicated in Figure 34.

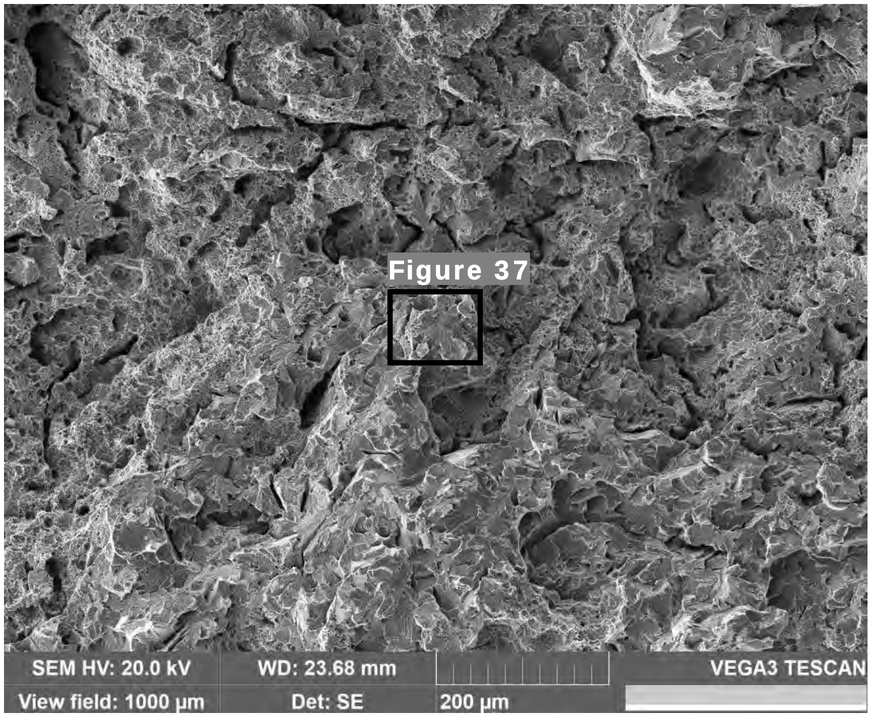

Figure 36. SEM image of Sample S2 in a macroscopically rough region; area indicated in Figure 33.

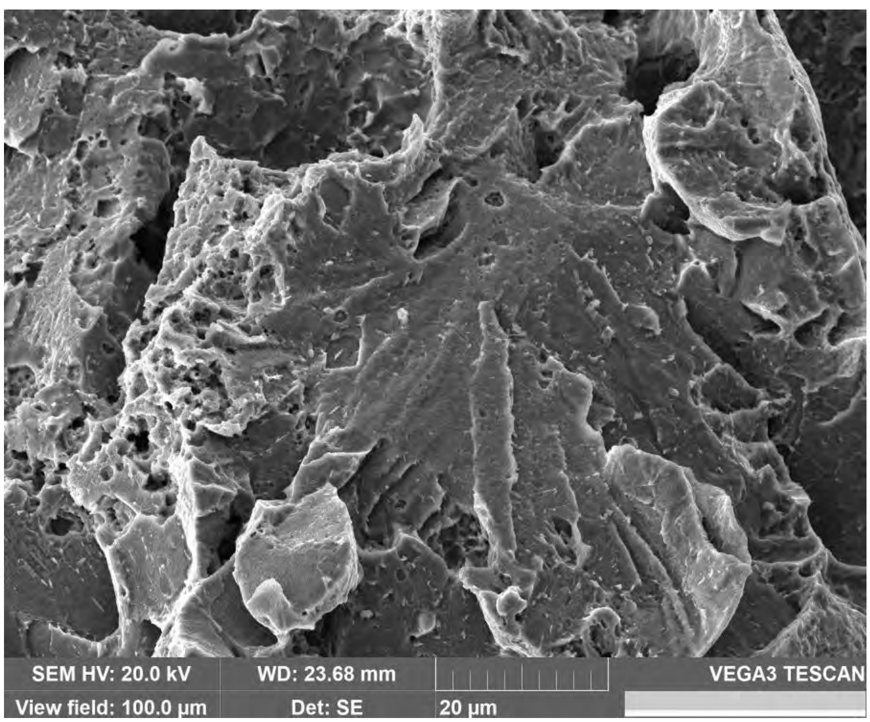

Figure 37. High magnification SEM image of Sample S2 in a macroscopically rough region; area indicated in Figure 36.

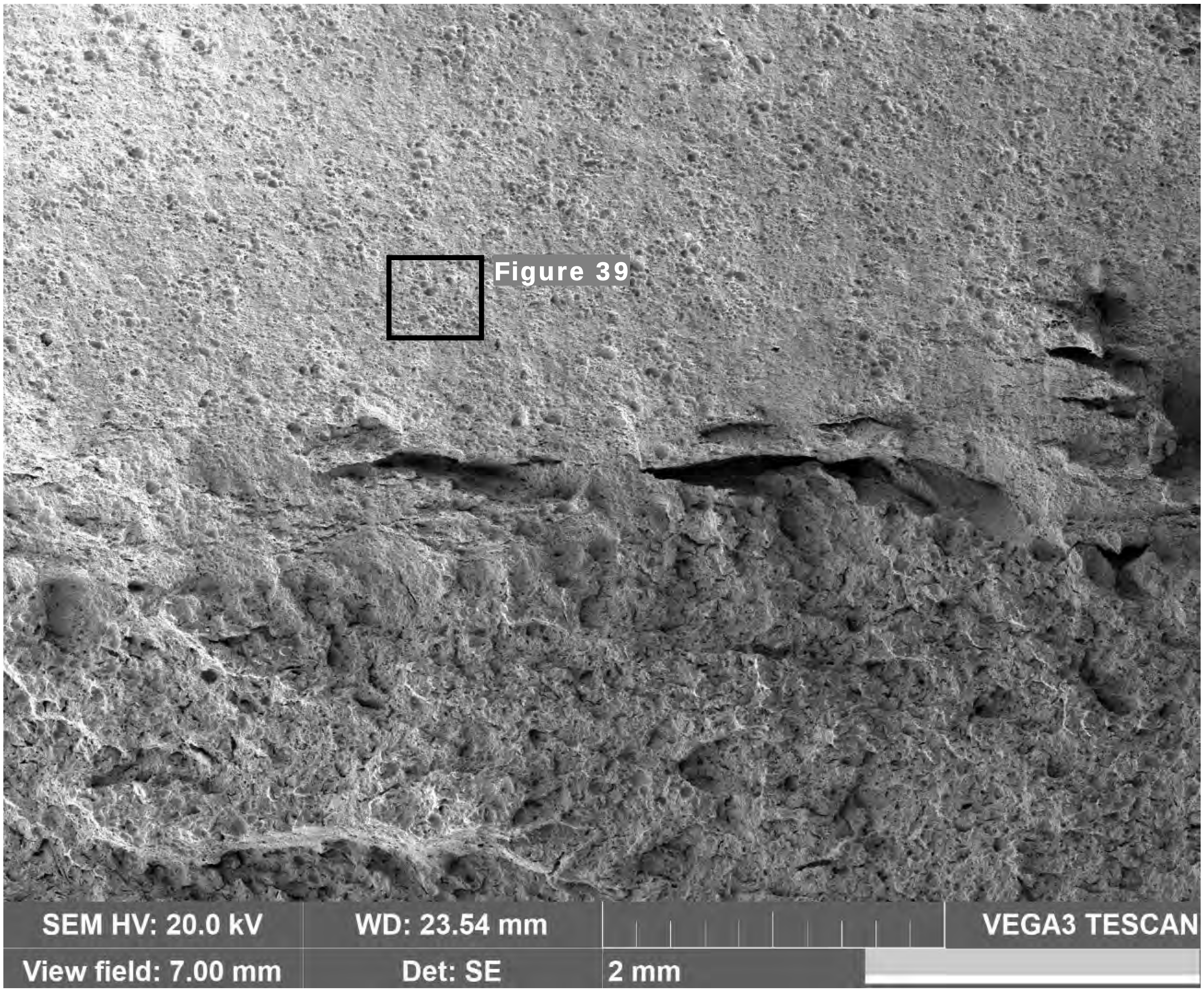

Figure 38. SEM image of Sample S2 midwall, showing macroscopically rough and smooth regions; area indicated in Figure 32.

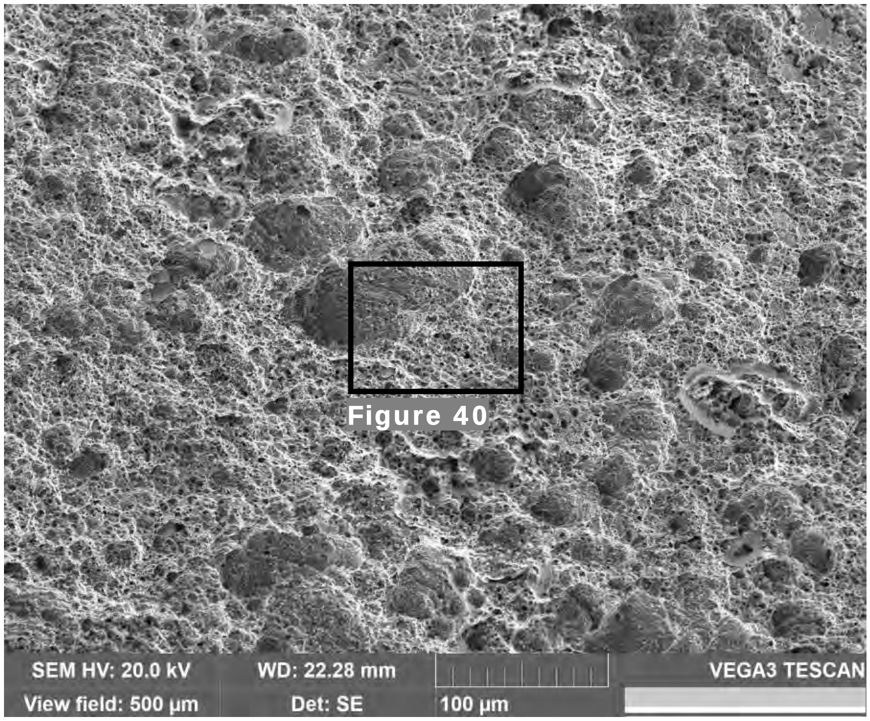

Figure 39. SEM image of Sample S2 in a macroscopically smooth region, near the OD surface; area indicated in Figure 38.

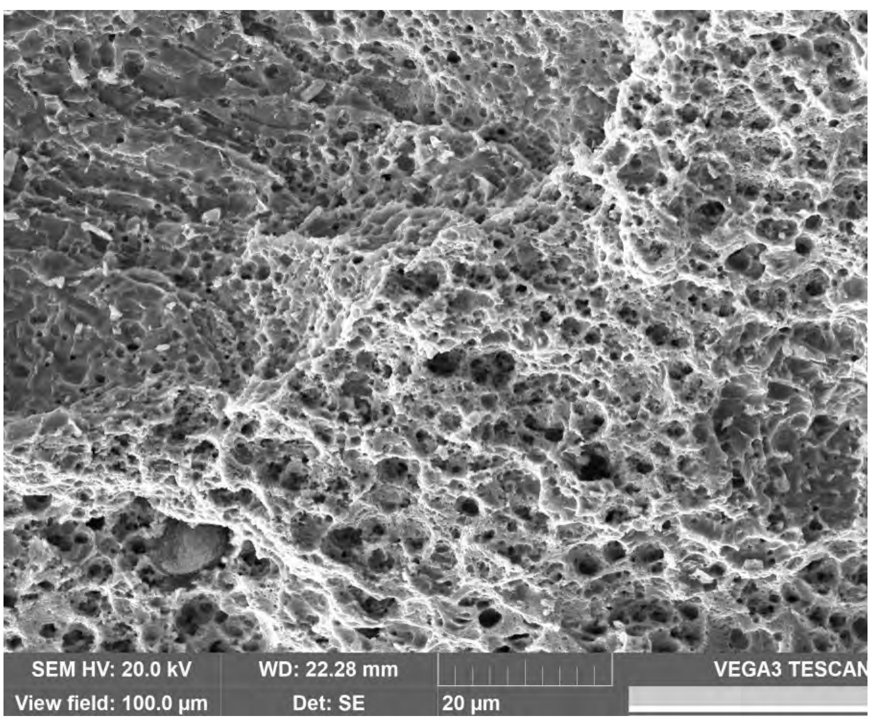

Figure 40. High magnification SEM image of Sample S2 in a macroscopically smooth region, near the OD surface; area indicated in Figure 39.

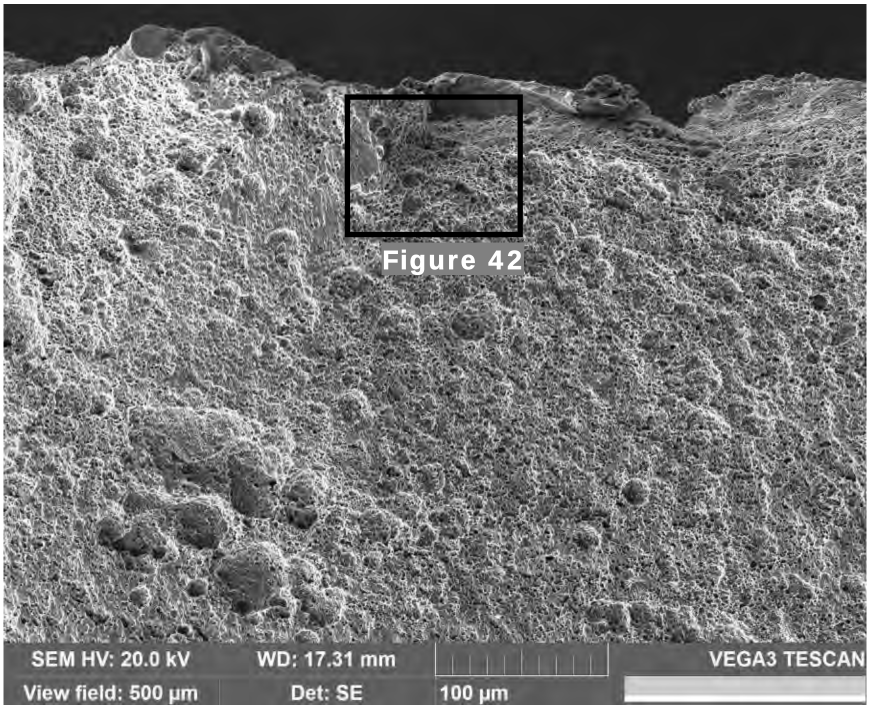

Figure 41. SEM image of Sample S2 adjacent to the OD surface; area indicated in Figure 32.

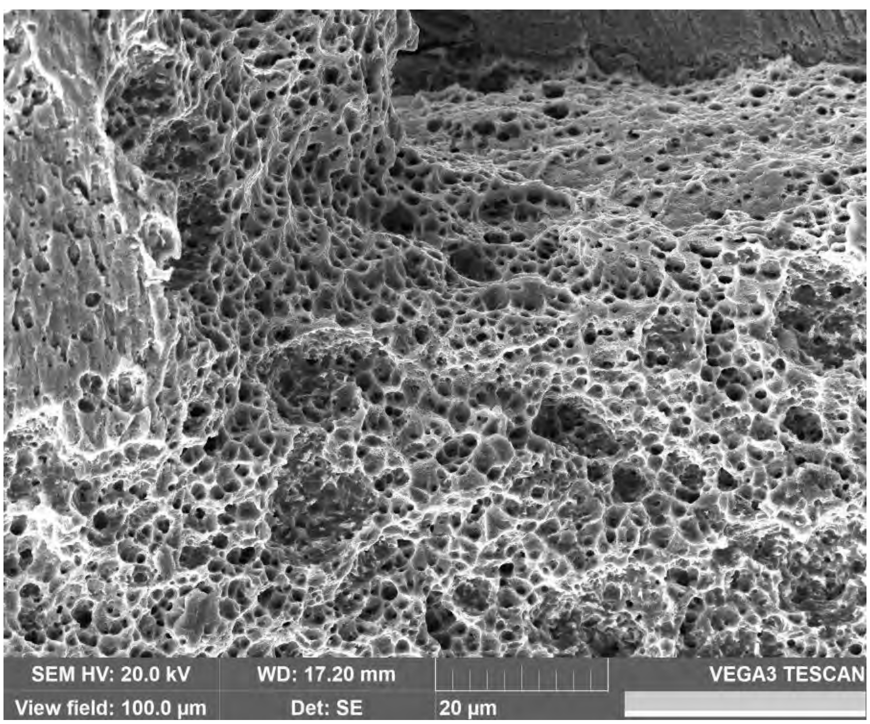

Figure 42. High magnification SEM image of Sample S2 adjacent to the OD surface; area indicated in Figure 41.

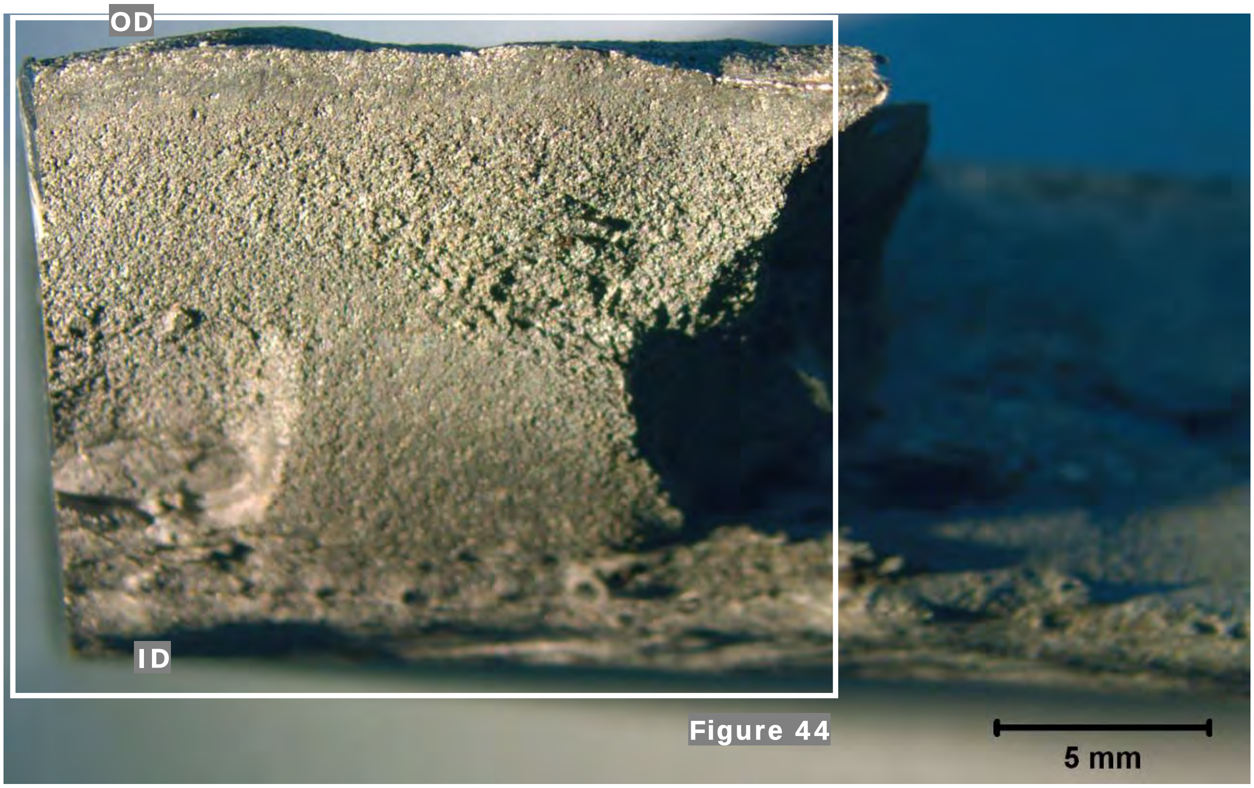

Figure 43. Light photomicrograph of the fracture surface of Sample S3, following cleaning in ENPREP® 214. The sample was removed near the 8:00 orientation; area indicated in Figure 28.

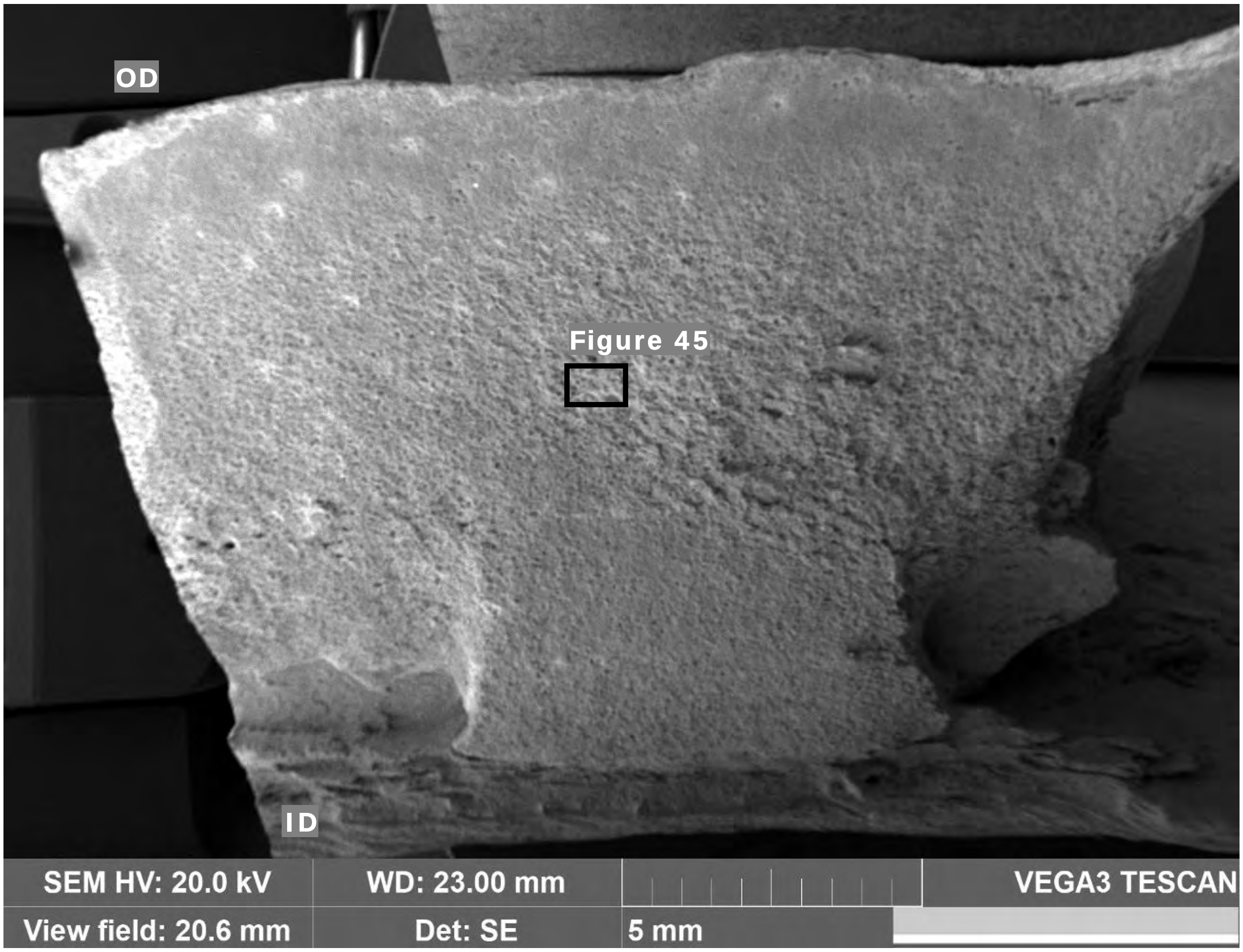

Figure 44. SEM image of Sample S3; area indicated in Figure 43.

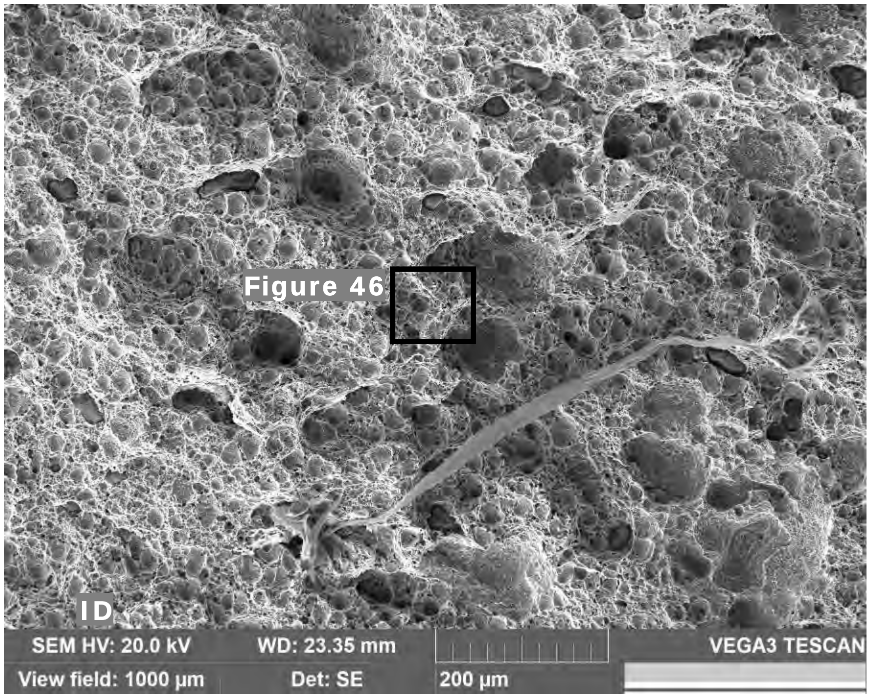

Figure 45. SEM image of Sample S3 midwall; area indicated in Figure 44.

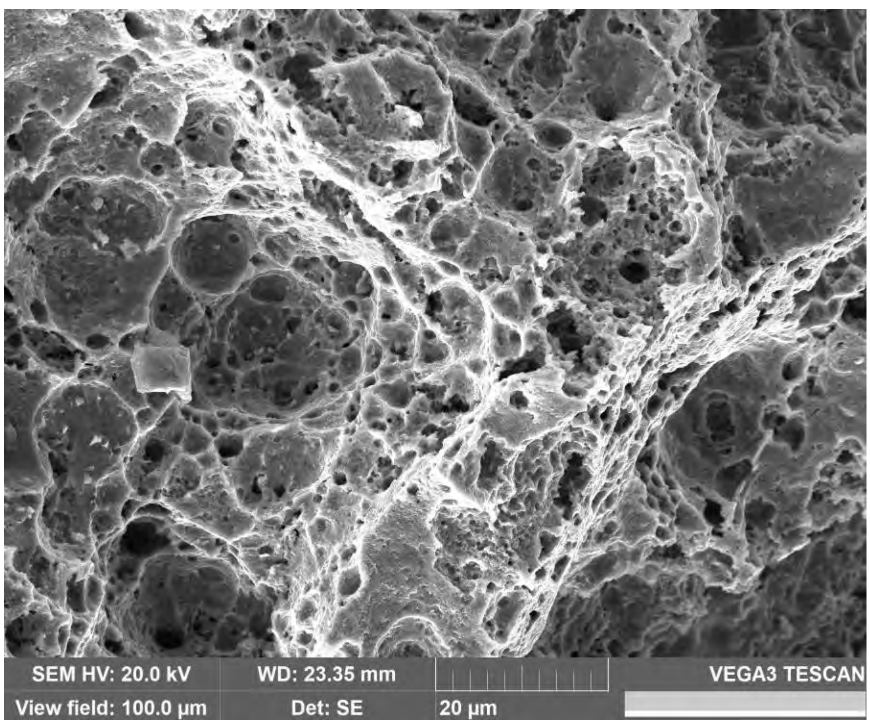

Figure 46. High magnification SEM image of Sample S3 midwall; area indicated in Figure 45.

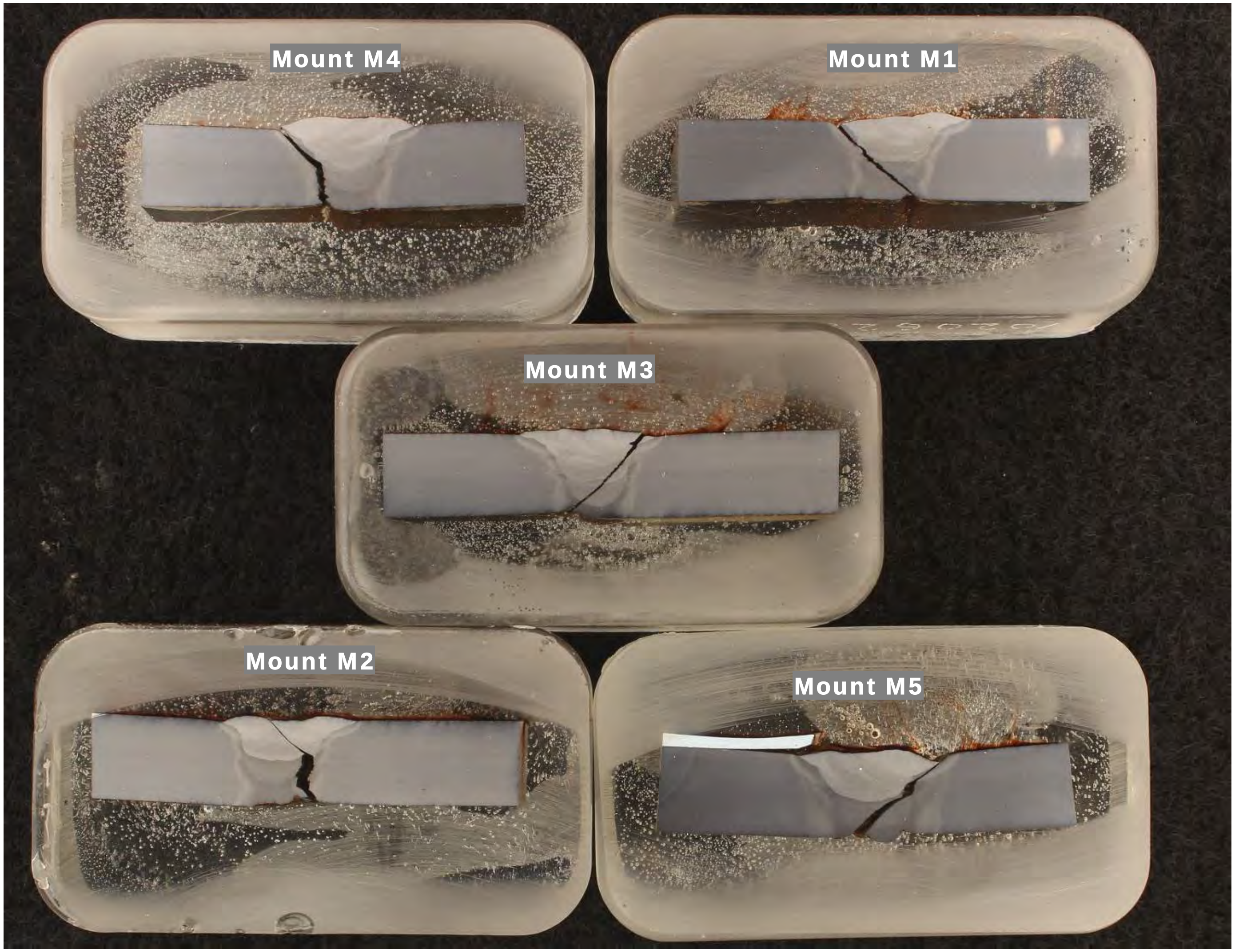

Figure 47. Photograph of the mounts (M1, M2, M3, M4, and M5) that were removed across the failure opening (2% Nital Etchant).

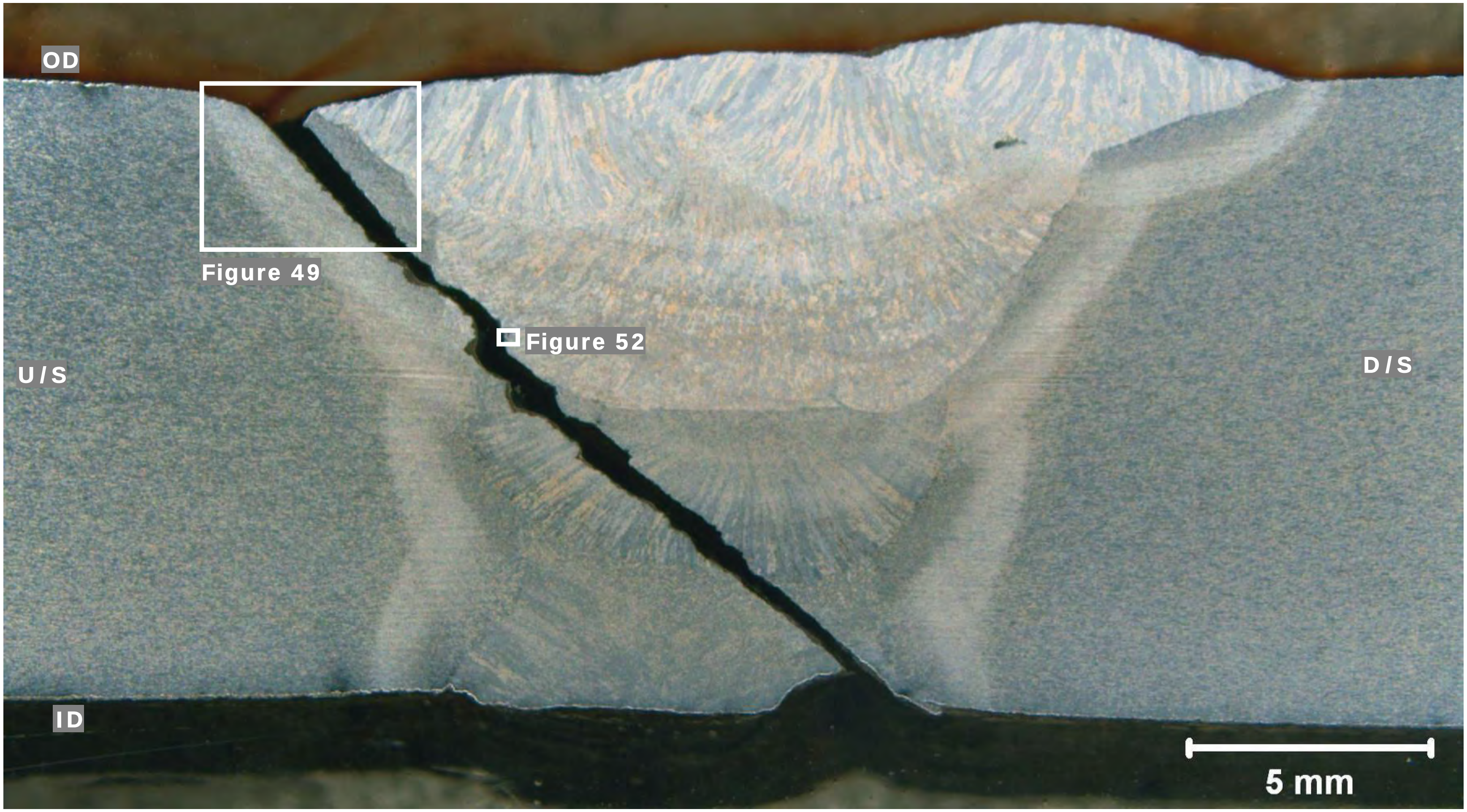

Figure 48. Light photomicrograph of Mount M1 (axial cross-section), which was removed from the failed GW at the 1:35 orientation; refer to Figure 1, Figure 11, and Figure 21 for location (2% Nital Etchant).

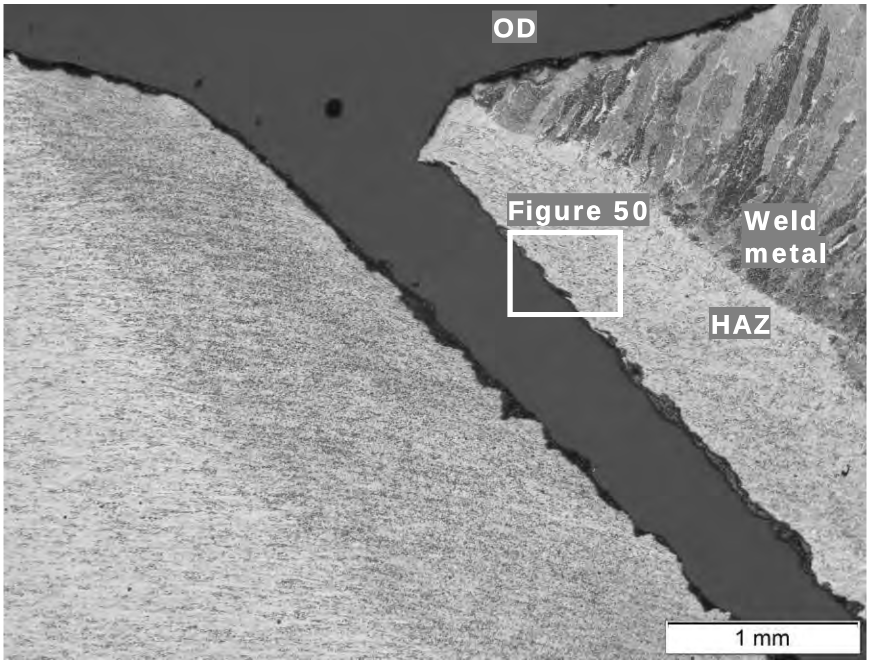

Figure 49. Light photomicrograph of Mount M1 adjacent to the OD surface (2% Nital Etchant); area indicated in Figure 48.

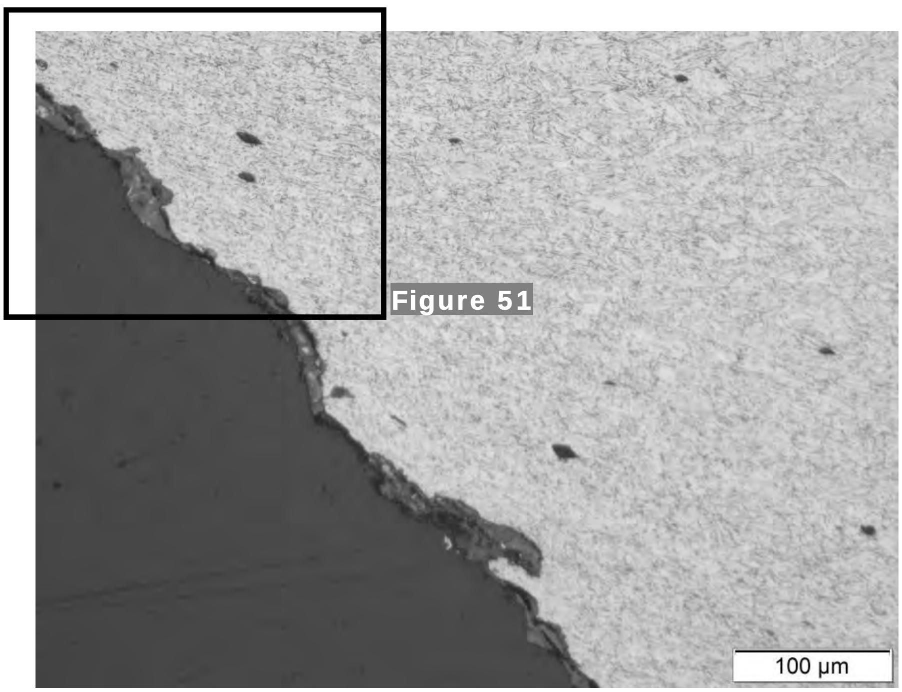

Figure 50. Light photomicrograph of Mount M1 showing inclusions in HAZ adjacent to the fracture surface; area indicated in Figure 49.

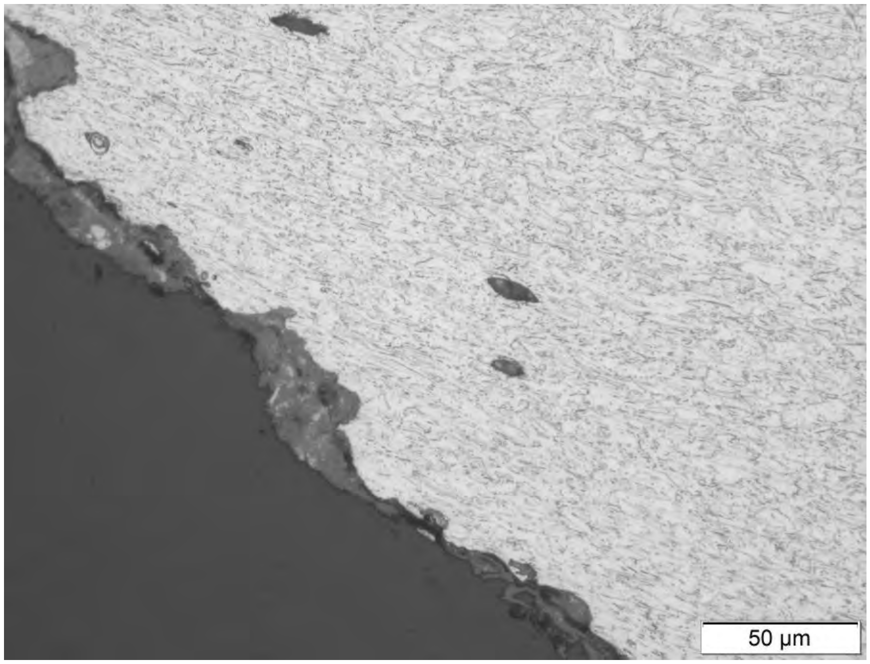

Figure 51. High magnification light photomicrograph of Mount M1 showing grain elongation adjacent to the fracture surface; area indicated in Figure 50.

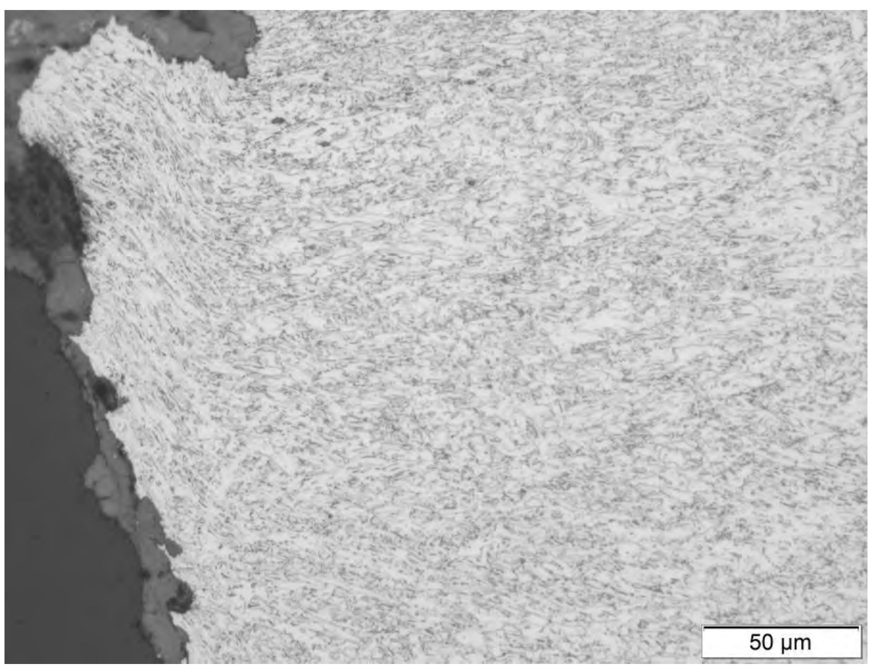

Figure 52. High magnification light photomicrograph of Mount M1 midwall adjacent to the fracture surface (2% Nital Etchant); area indicated in Figure 48.

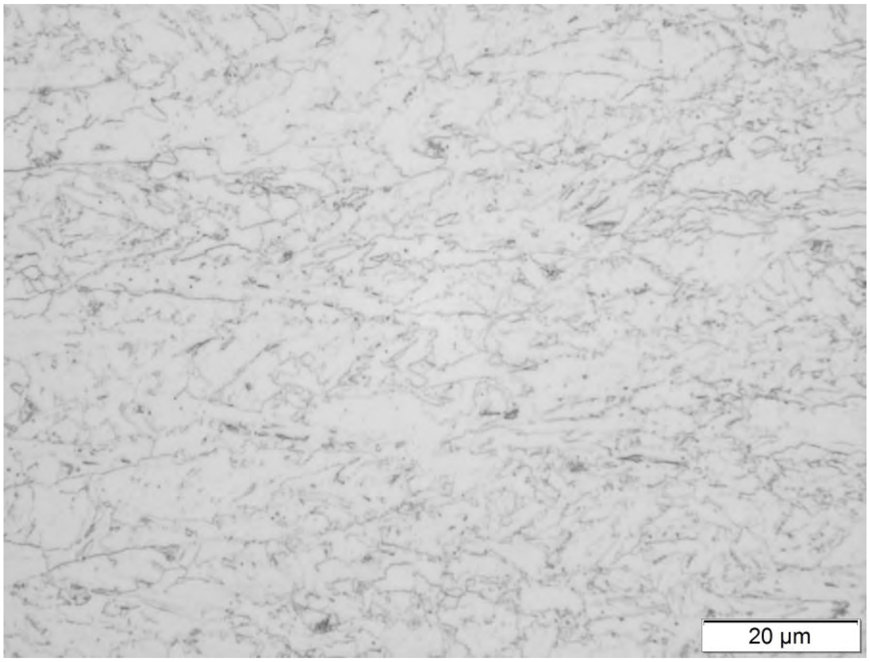

Figure 53. High magnification light photomicrograph of Mount M1 showing the typical base metal microstructure of the U/S Joint (PS B, 2% Nital Etchant).

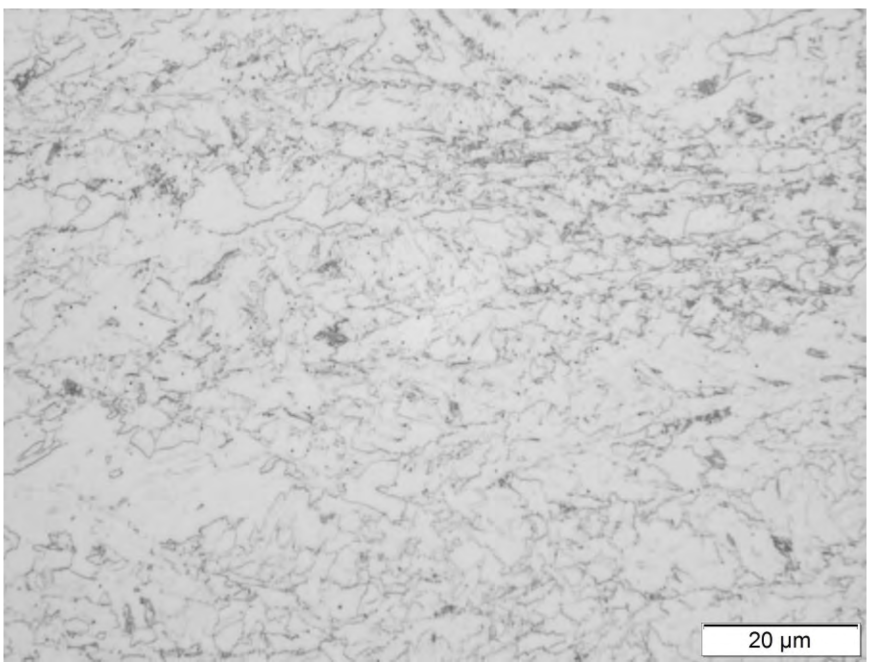

Figure 54. High magnification light photomicrograph of Mount M1 showing the typical base metal microstructure of the D/S Joint (PS A, 2% Nital Etchant).

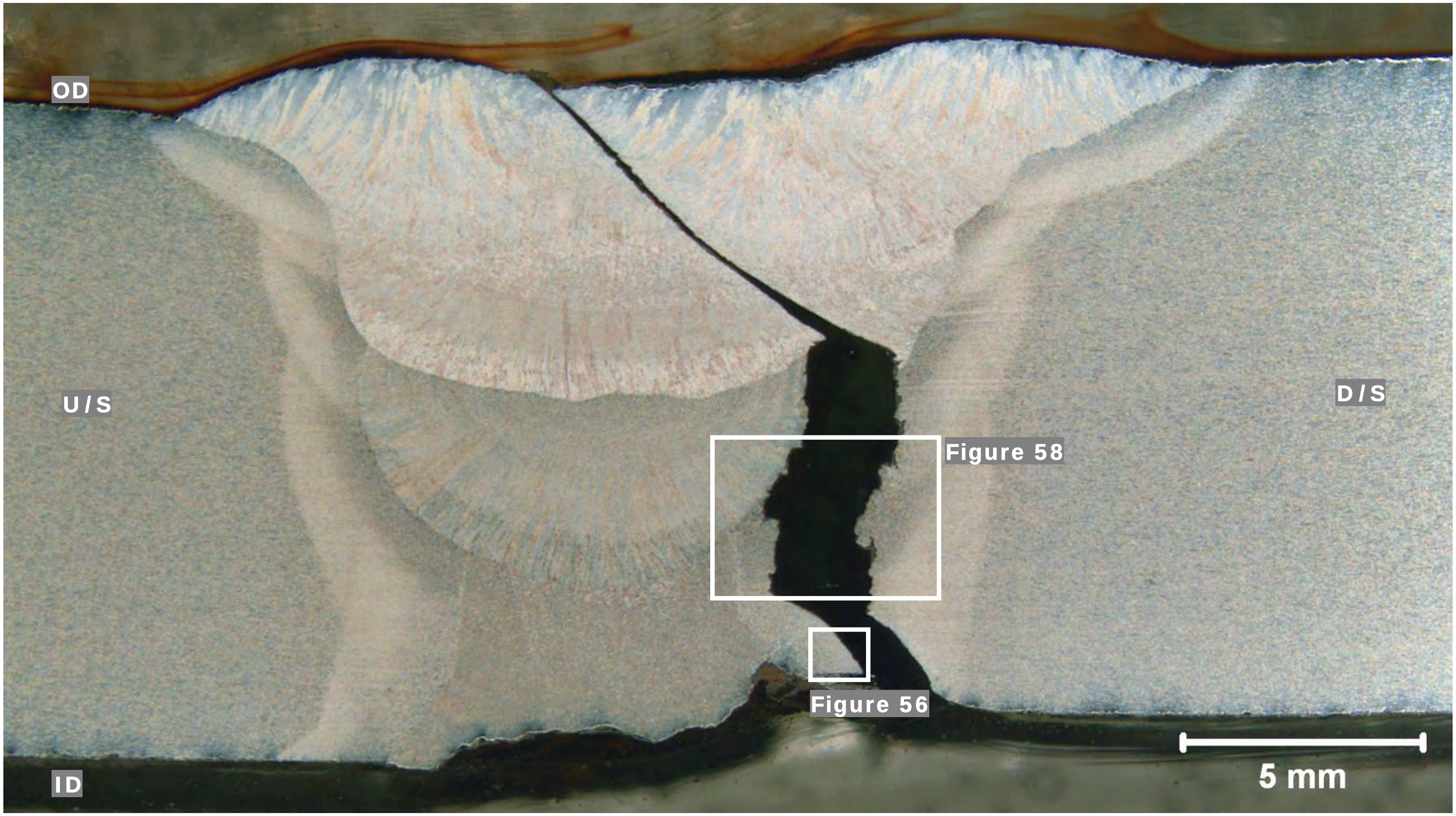

Figure 55. Light photomicrograph of Mount M2 (axial cross-section), which was removed from the GW at the 3:55 orientation; refer to Figure 1, Figure 12, and Figure 23 for location (2% Nital Etchant).

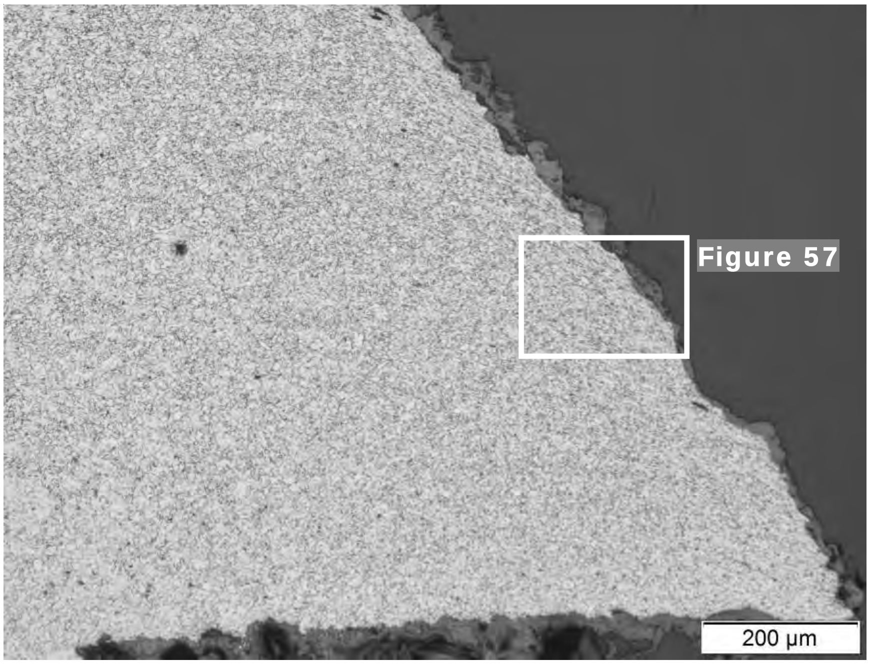

Figure 56. Light photomicrograph of Mount M2 adjacent to the ID surface (2% Nital Etchant); area indicated in Figure 55.

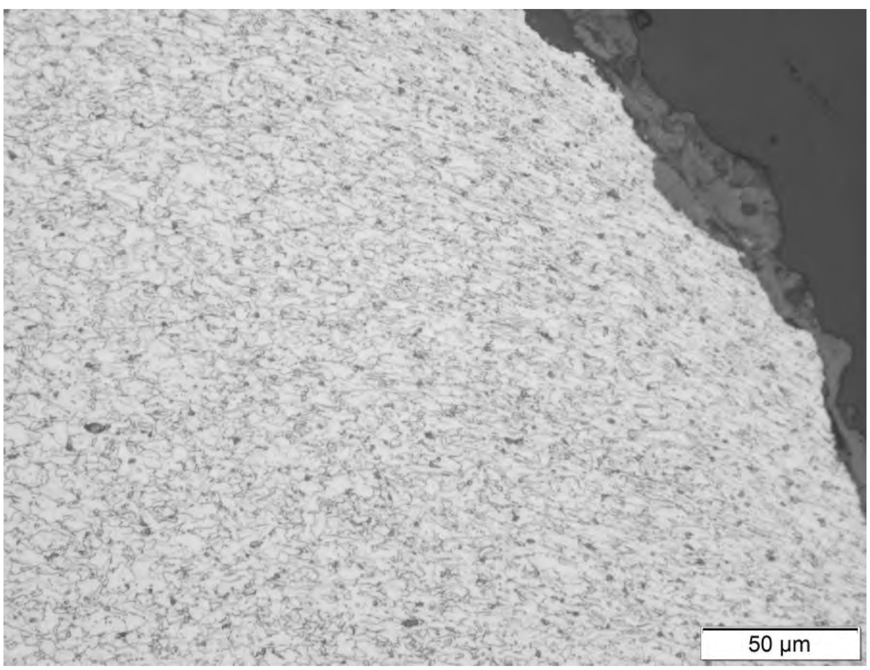

Figure 57. High magnification light photomicrograph of Mount M2 near the ID surface, adjacent to the fracture surface (2% Nital Etchant); area indicated in Figure 56.

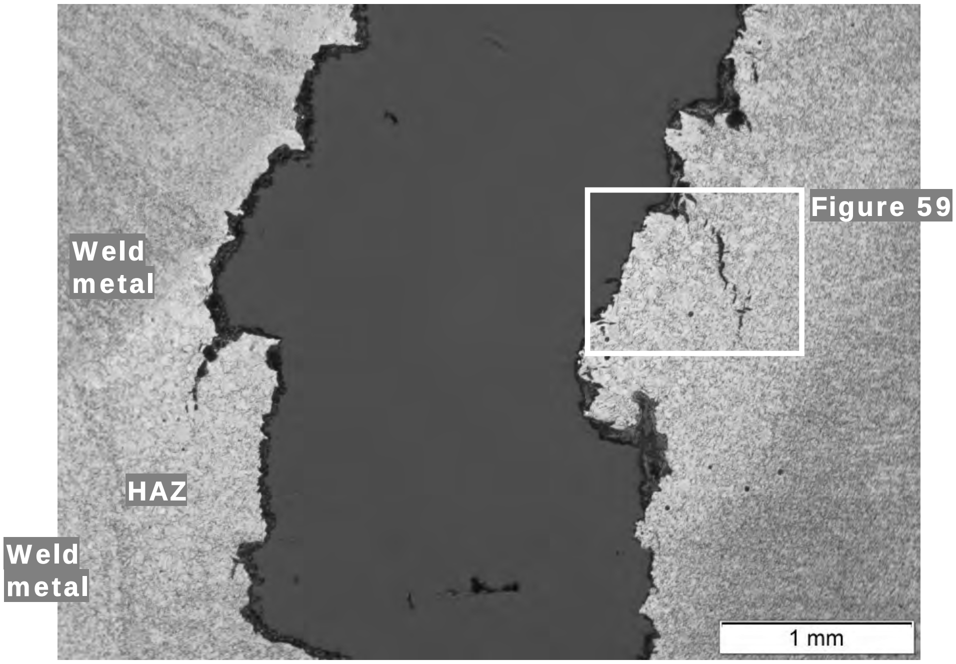

Figure 58. Light photomicrograph of Mount M2 midwall (2% Nital Etchant); area indicated in Figure 55.

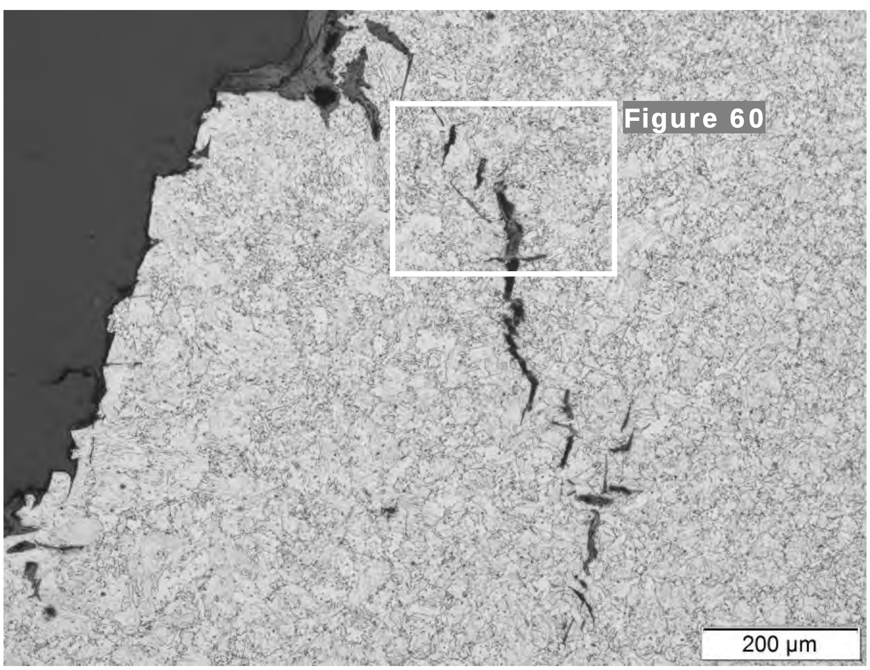

Figure 59. Light photomicrograph of Mount M2 adjacent to the fracture surface showing fissures (2% Nital Etchant); area indicated in Figure 58.

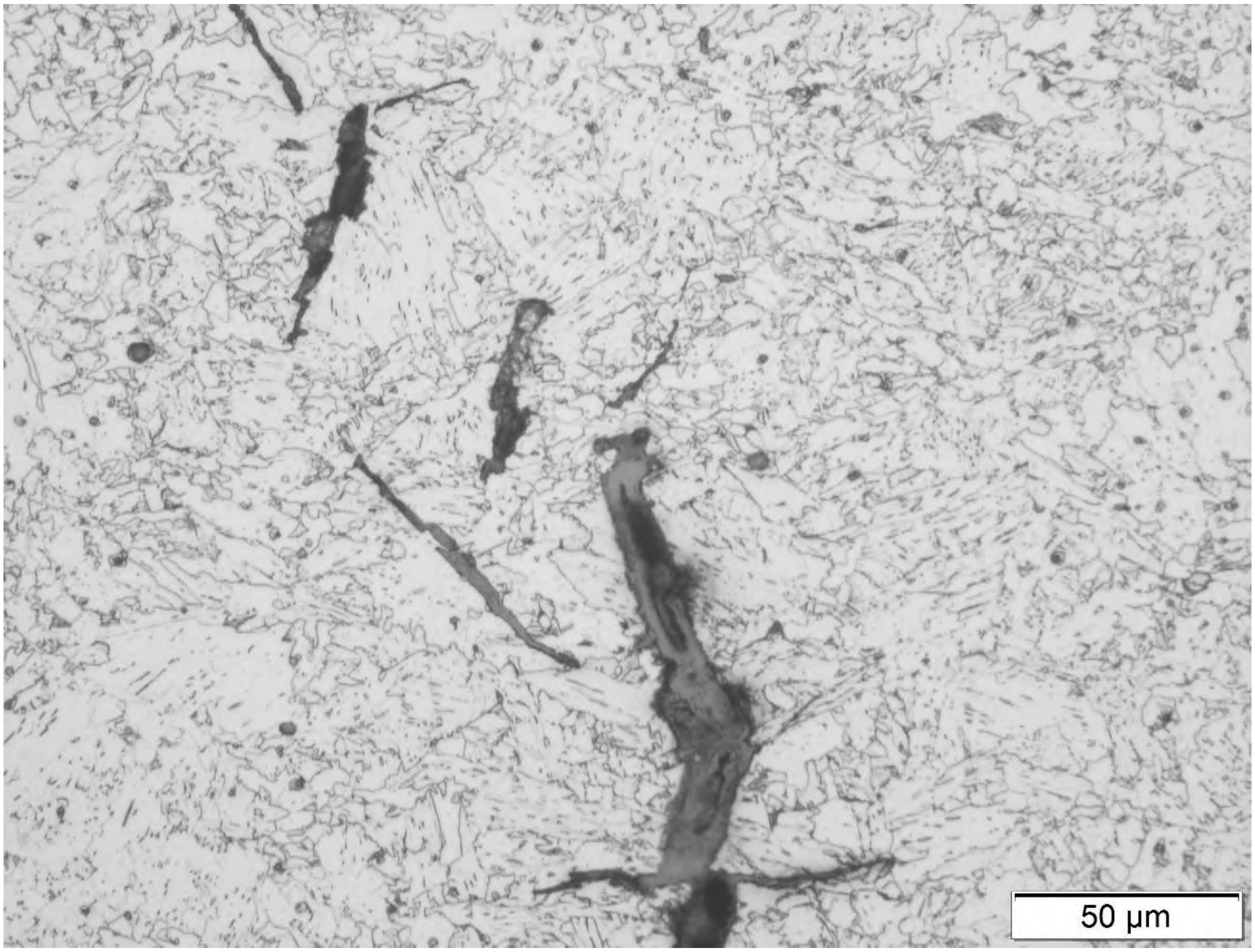

Figure 60. High magnification light photomicrograph of Mount M2 at fissures (2% Nital Etchant); area indicated in Figure 59.

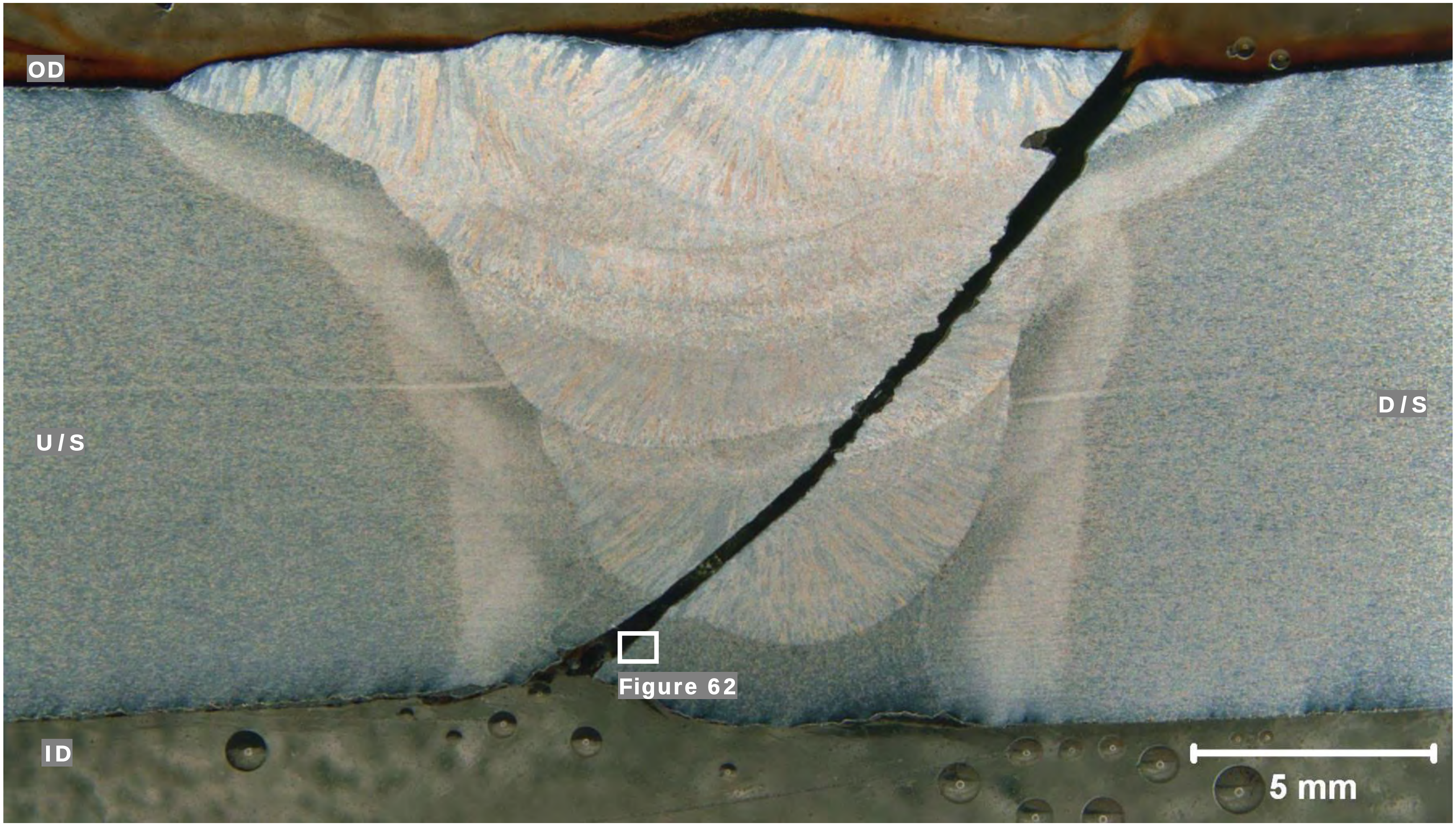

Figure 61. Light photomicrograph of Mount M3 (axial cross-section), which was removed from the GW at the 8:35 orientation; refer to Figure 1, Figure 13, and Figure 28 for location (2% Nital Etchant).

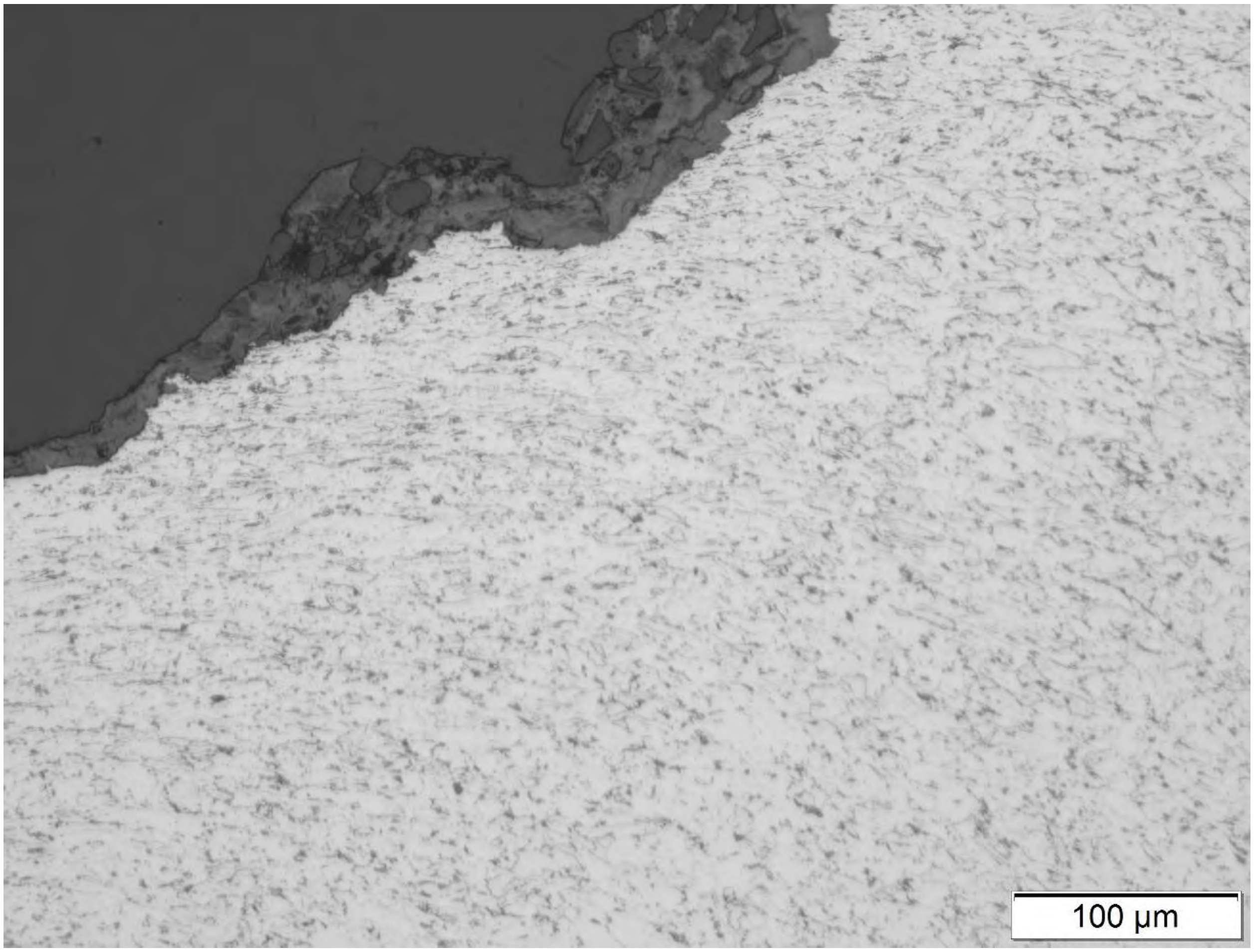

Figure 62. Light photomicrograph of Mount M3 adjacent to the fracture surface, near the ID surface (2% Nital Etchant); area indicated in Figure 61.

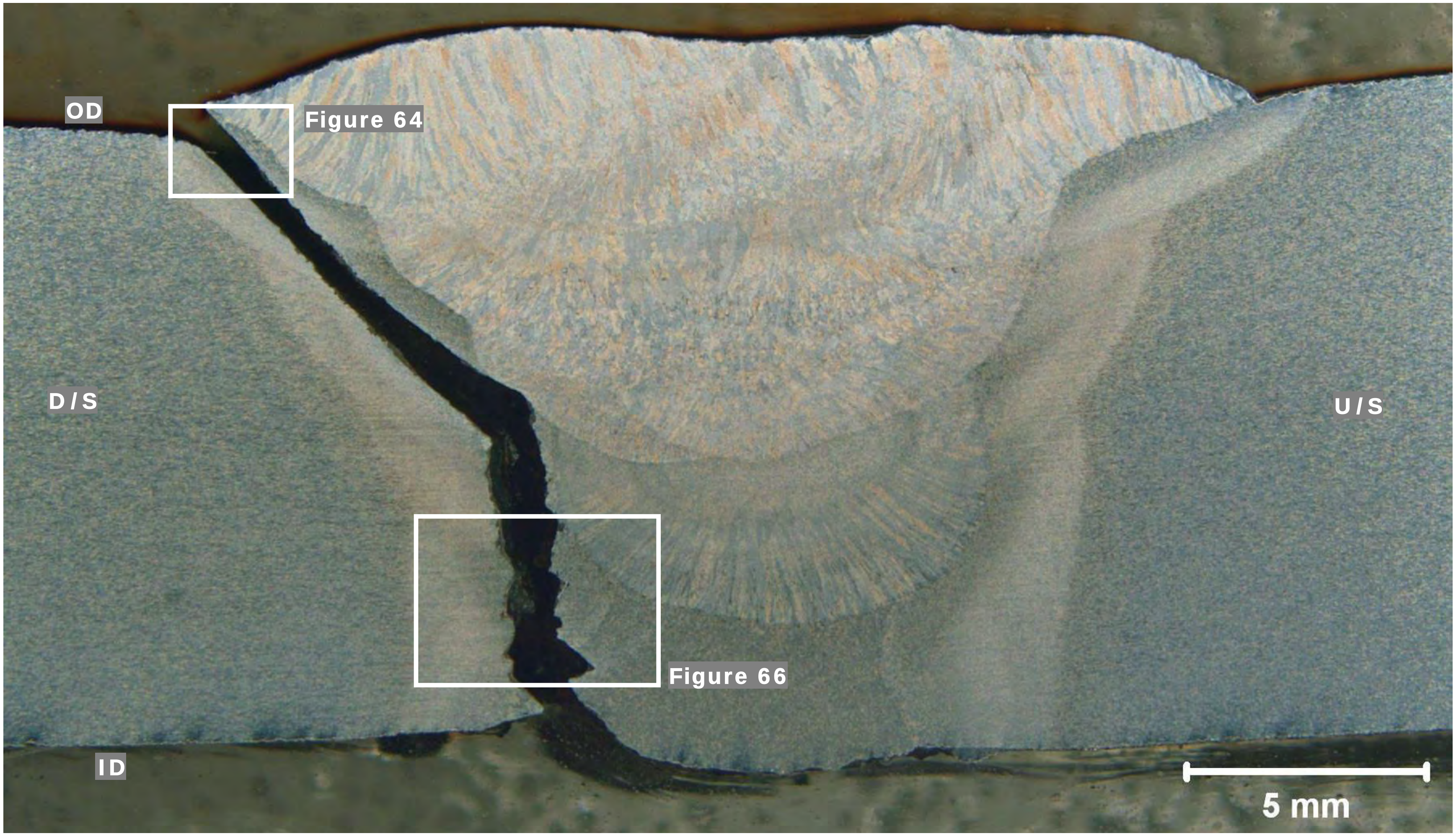

Figure 63. Light photomicrograph of Mount M4 (axial cross-section), which was removed from the GW at the 10:24 orientation; refer to Figure 1, Figure 14, and Figure 30 for location (2% Nital Etchant).

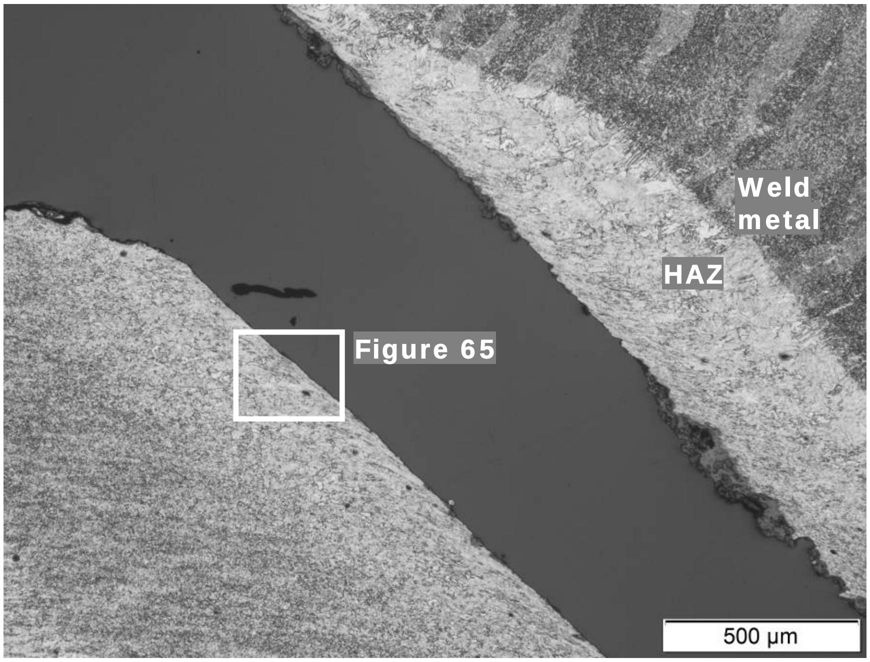

Figure 64. Light photomicrograph of Mount M4 near the OD surface (2% Nital Etchant); area indicated in Figure 63.

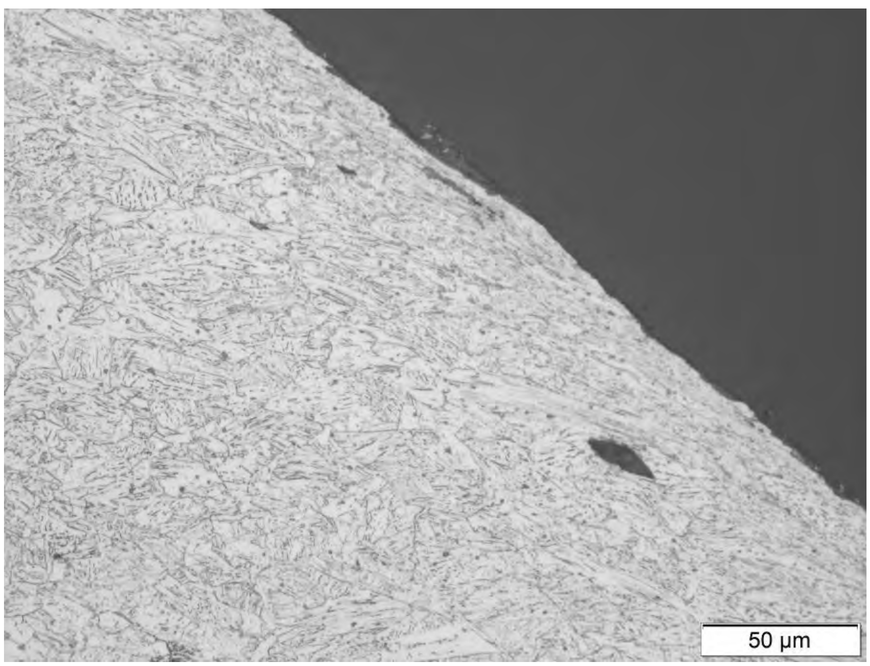

Figure 65. High magnification light photomicrograph of Mount M4 showing grain elongation adjacent to the fracture surface (2% Nital Etchant); area indicated in Figure 64.

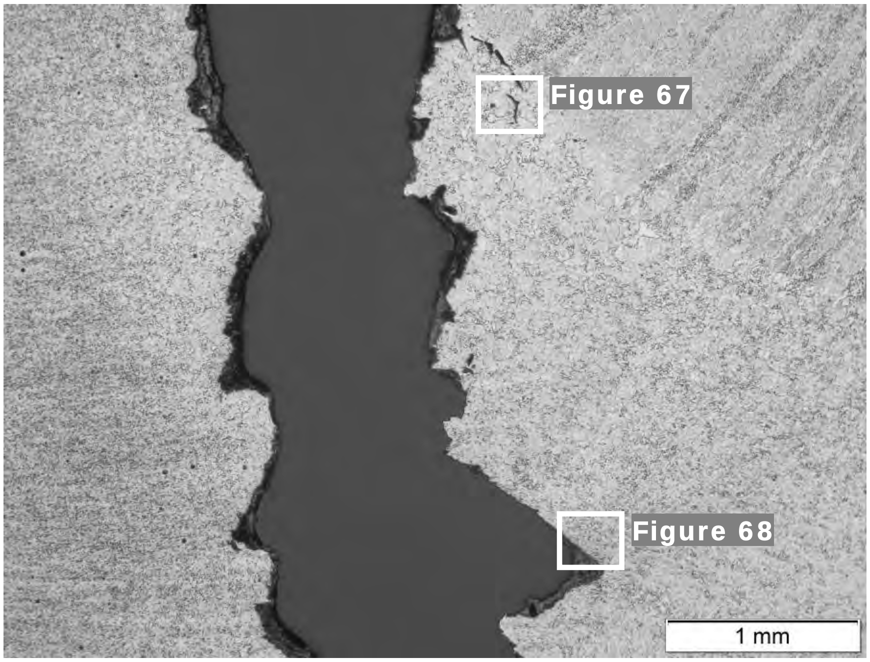

Figure 66. Light photomicrograph of Mount M4 near the ID surface (2% Nital Etchant); area indicated in Figure 63.

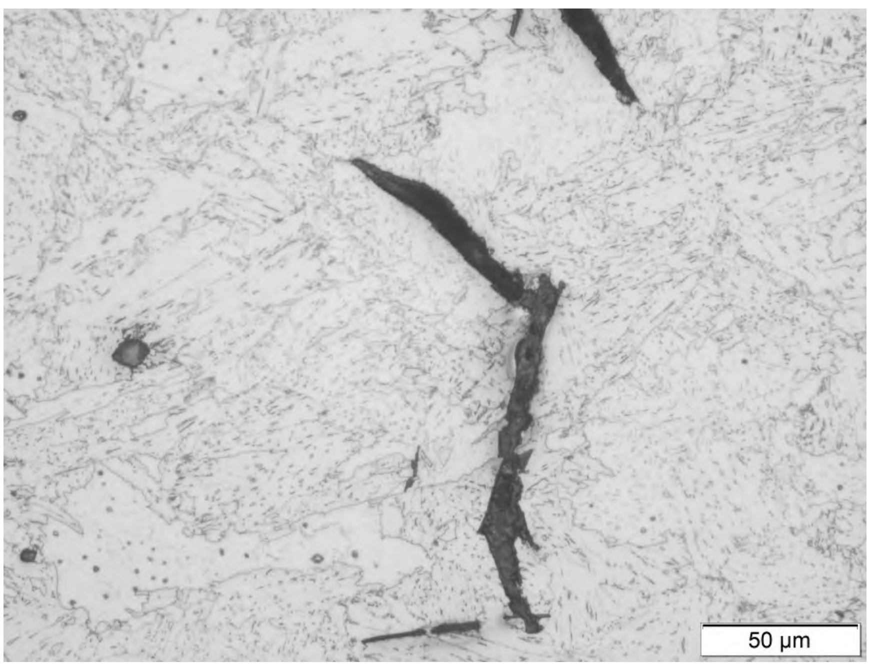

Figure 67. High magnification light photomicrograph of Mount M4 showing fissures (2% Nital Etchant); area indicated in Figure 66.

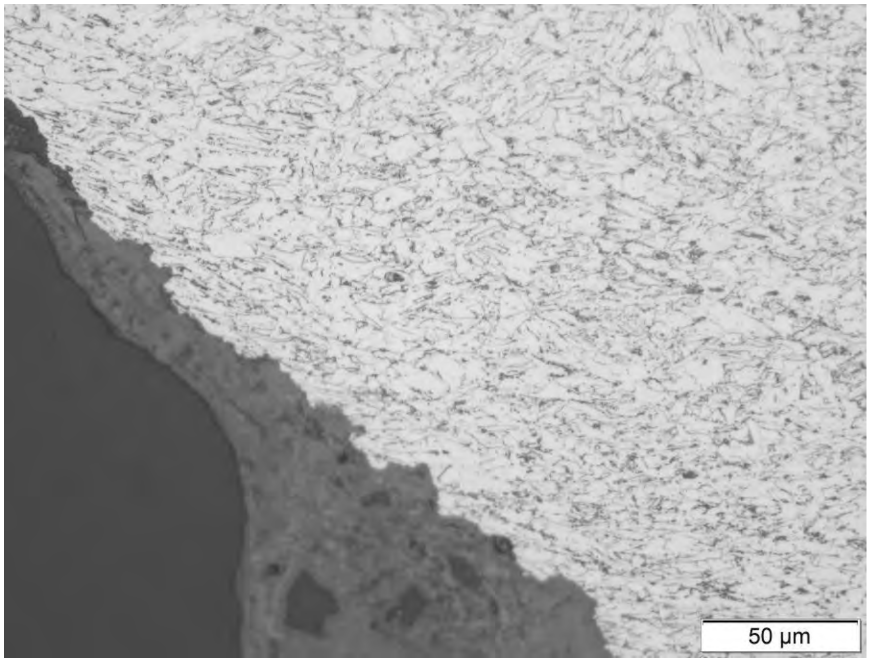

Figure 68. High magnification light photomicrograph of Mount M4 showing grain elongation adjacent to the fracture surface, near the ID surface (2% Nital Etchant); area indicated in Figure 66.

Figure 69. Light photomicrograph of Mount M5 (axial cross-section), which was removed from the GW at the 11:37 orientation; refer to Figure 1, Figure 14, and Figure 31 for location (2% Nital Etchant).

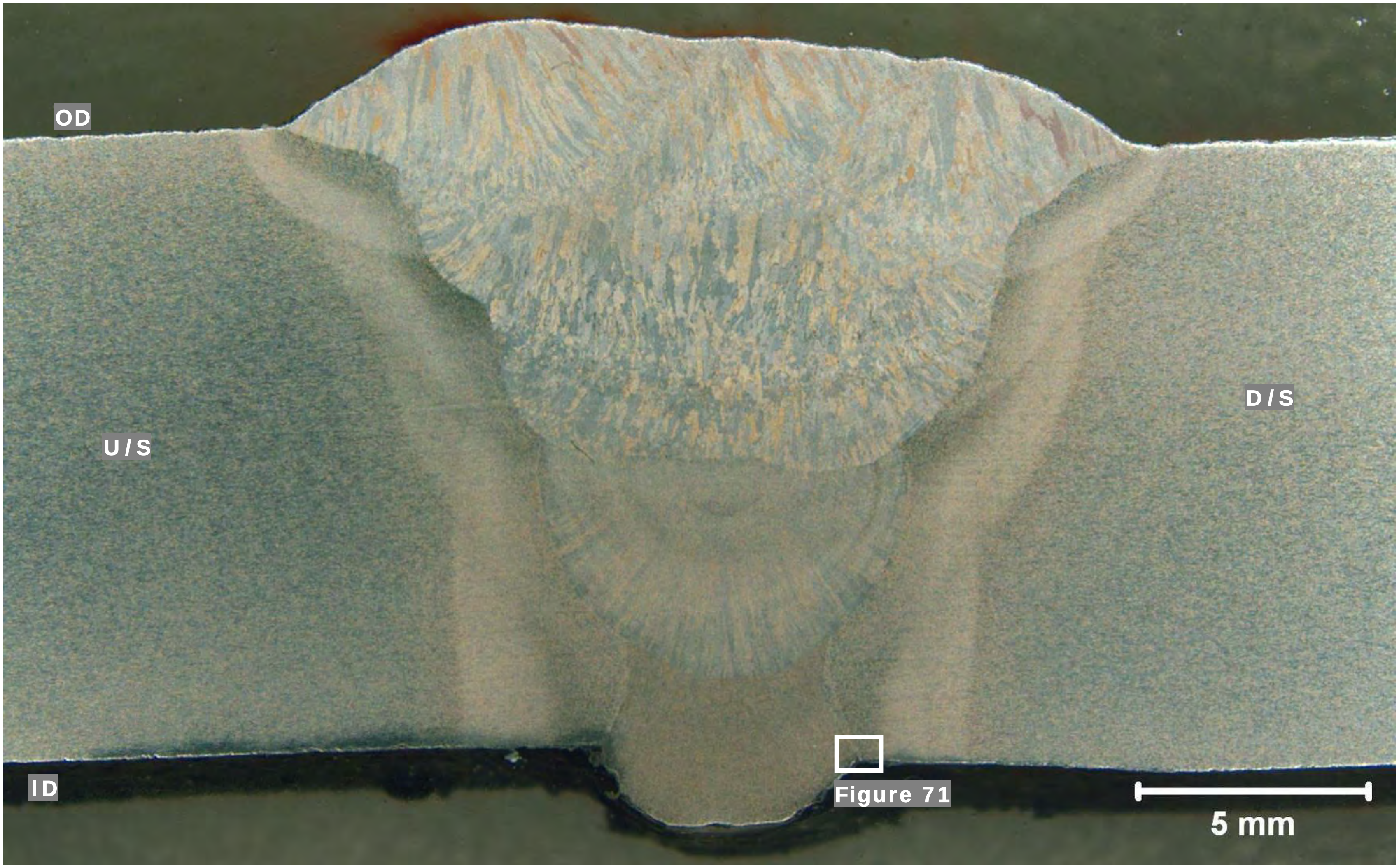

Figure 70. Light photomicrograph of Mount MU1 (axial cross-section), which was removed from the intact GW at the 12:27 orientation; refer to Figure 1 and Figure 17 for location (2% Nital Etchant).

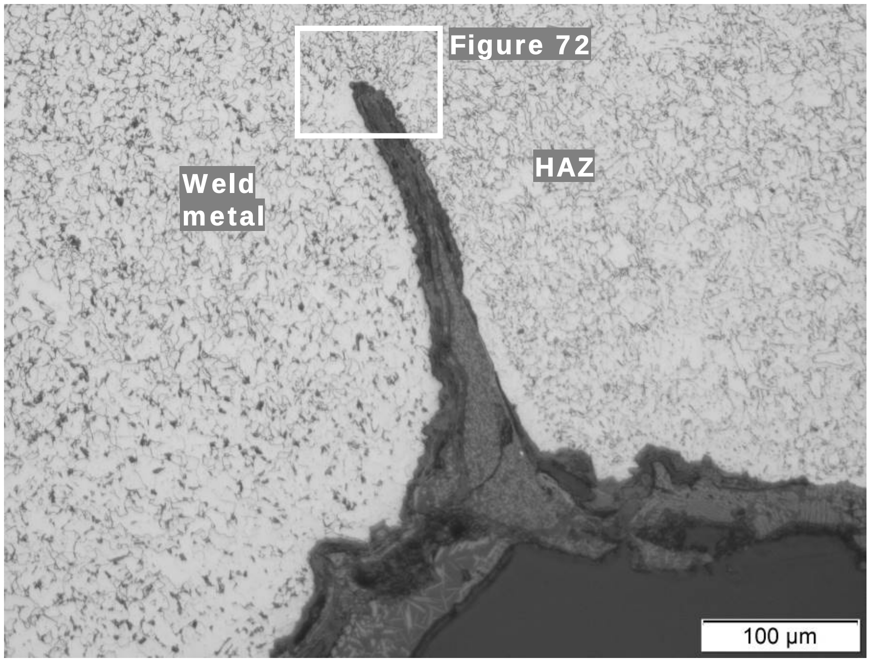

Figure 71. Light photomicrograph of Mount MU1 adjacent to the ID surface (2% Nital Etchant); area indicated in Figure 70.

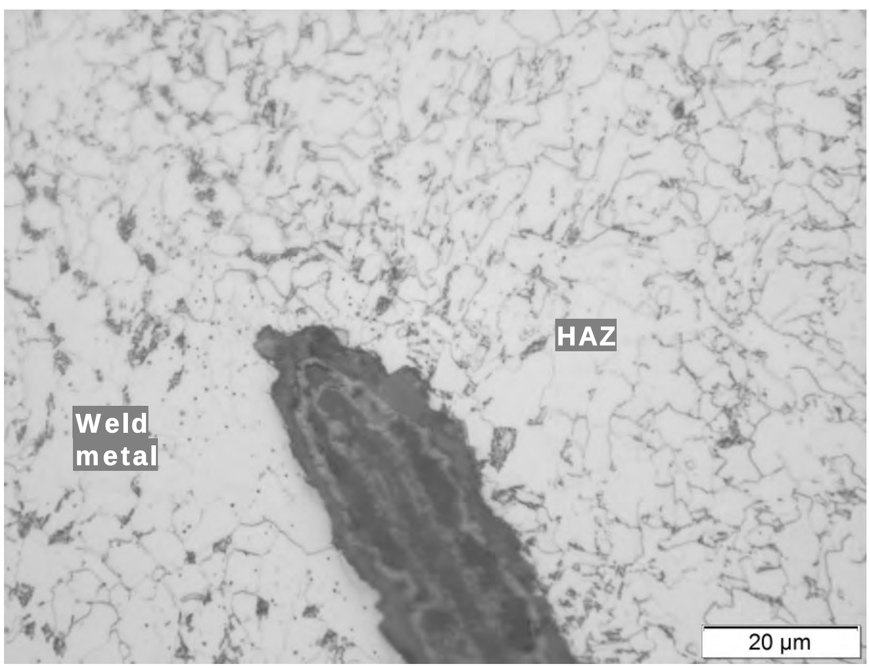

Figure 72. High magnification light photomicrograph of Mount MU1 at the tip of a shallow incomplete fusion (IF) flaw (2% Nital Etchant); area indicated in Figure 71.

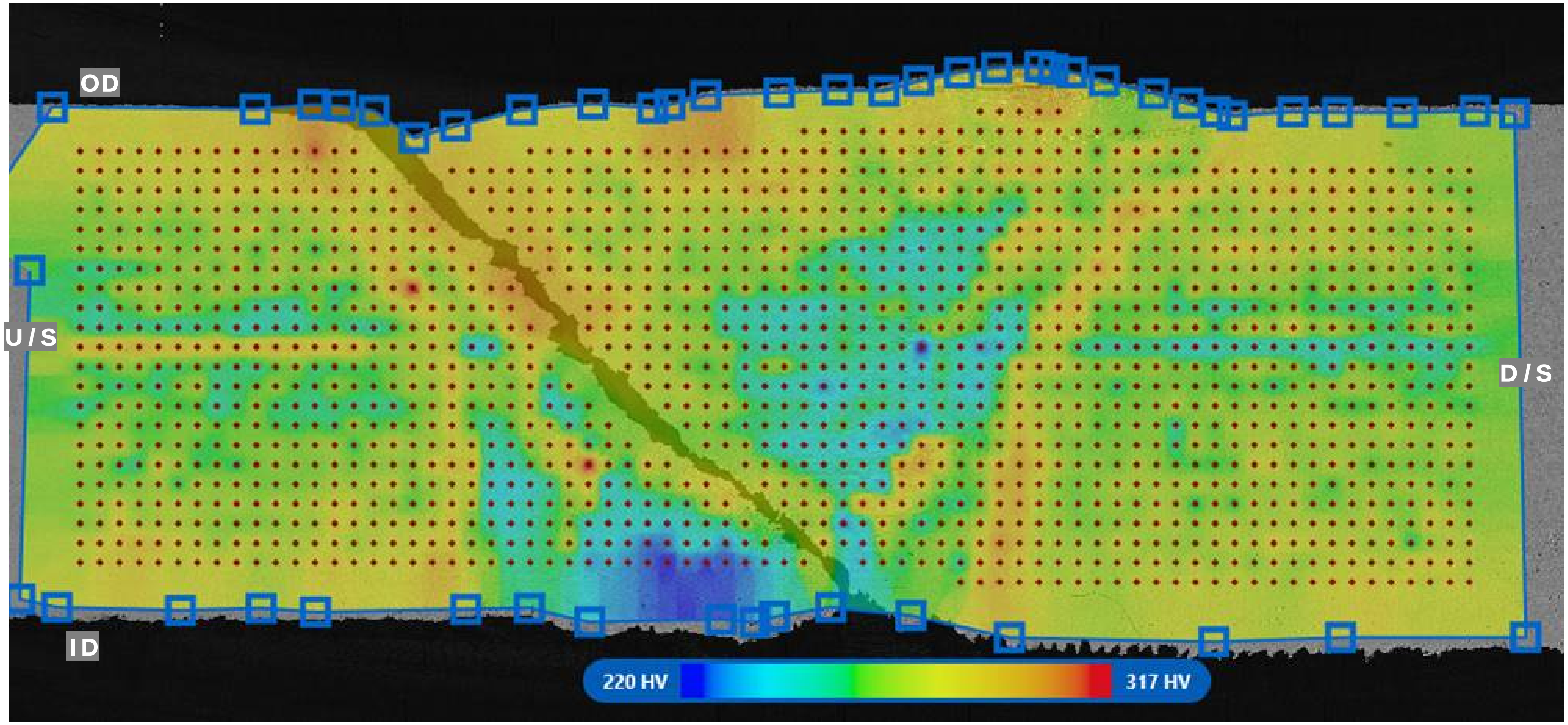

Figure 73. Hardness map overlay following hardness testing (Vickers 1 kg load) performed on Mount M1.

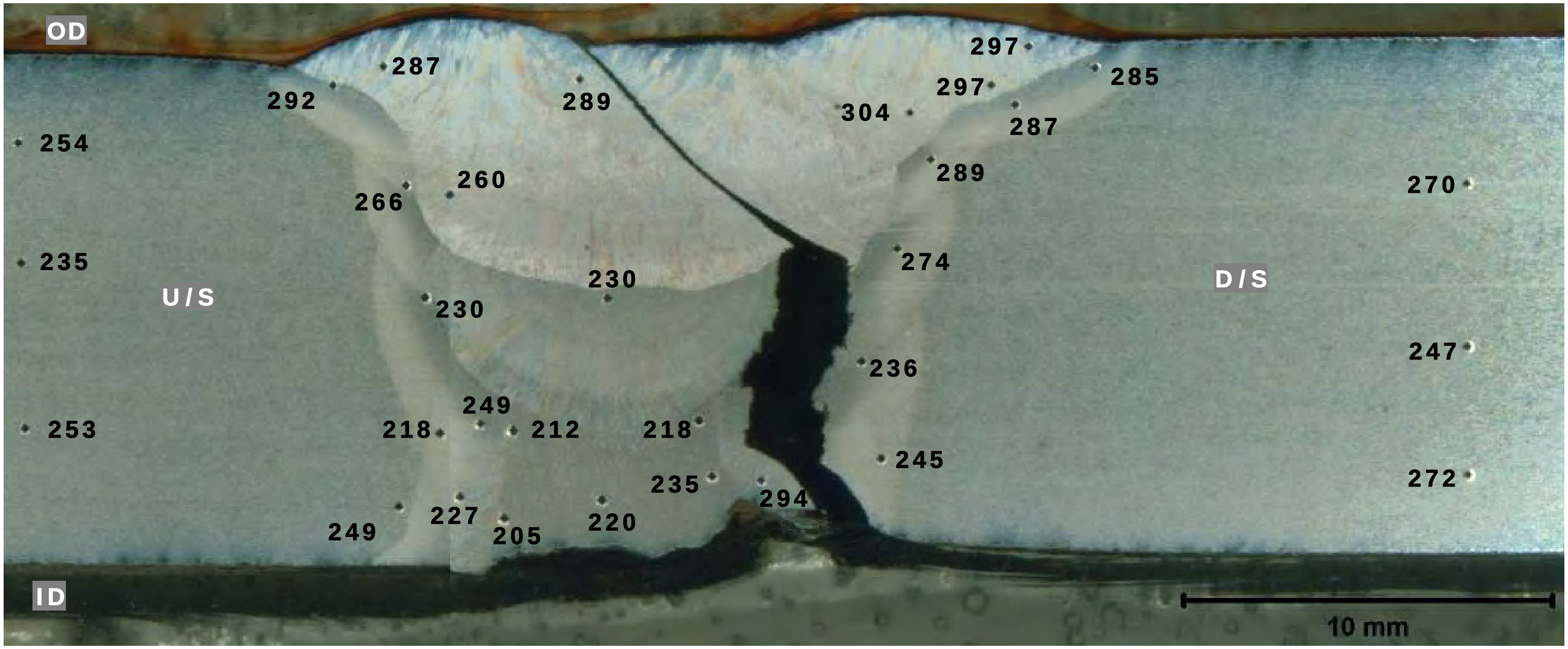

Figure 74. Light photomicrograph montage of Mount M2 (axial cross-section), showing the hardness indentations and the hardness values in HV (2% Nital Etchant).

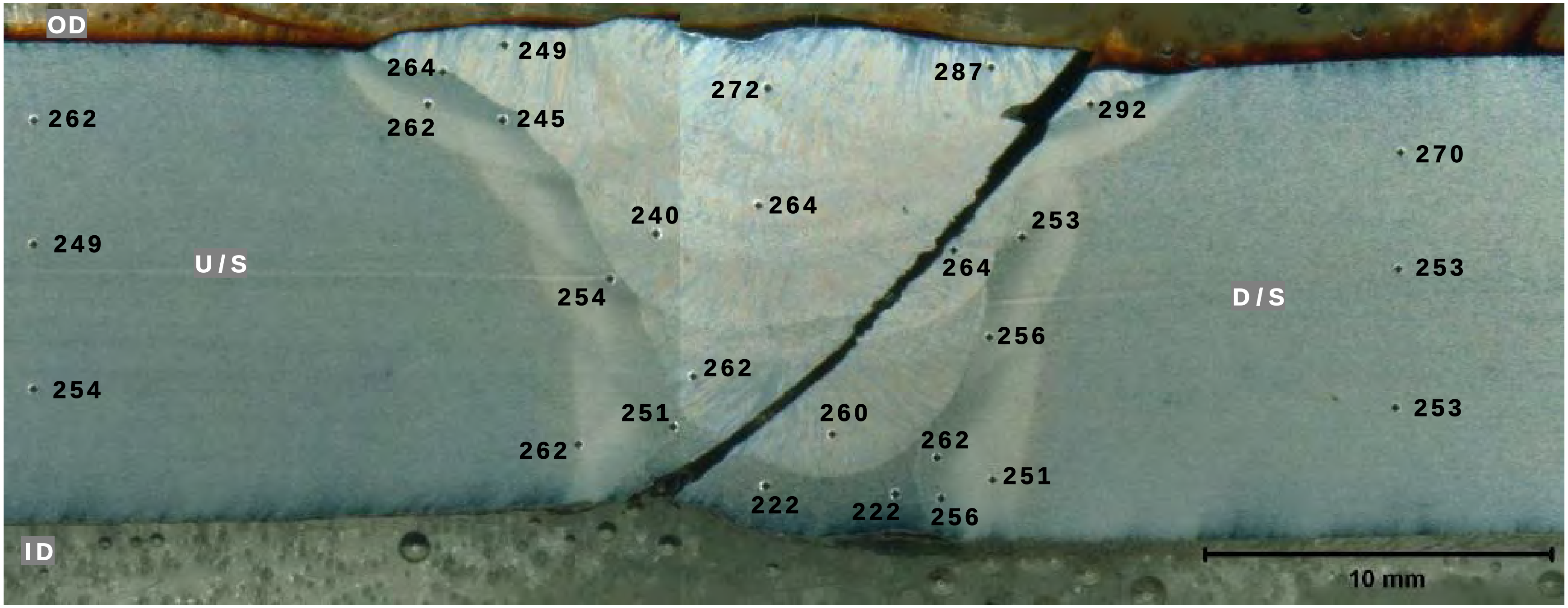

Figure 75. Light photomicrograph montage of Mount M3 (axial cross-section), showing the hardness indentations and the hardness values in HV (2% Nital Etchant).

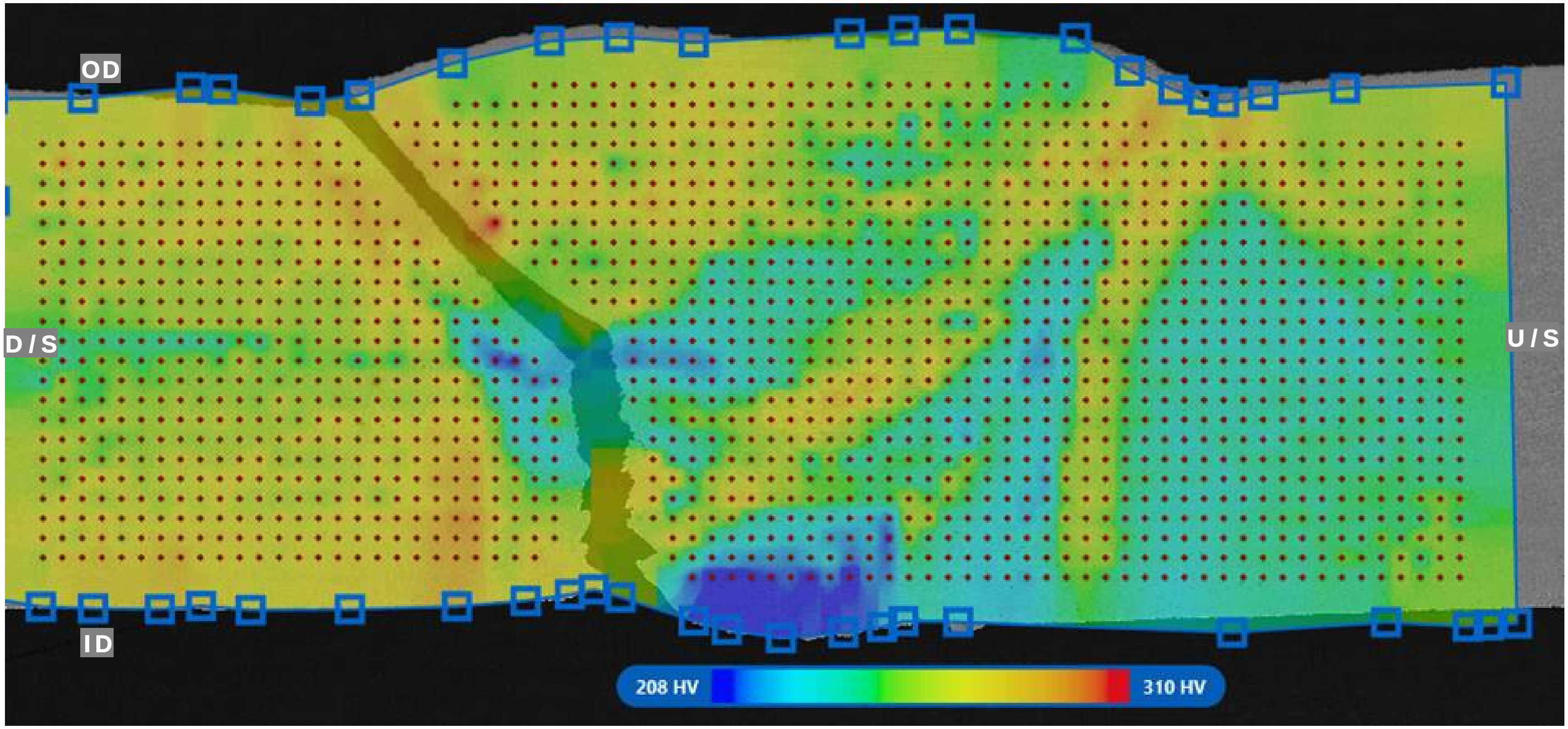

Figure 76. Hardness map overlay following hardness testing (Vickers 1 kg load) performed on Mount M4.

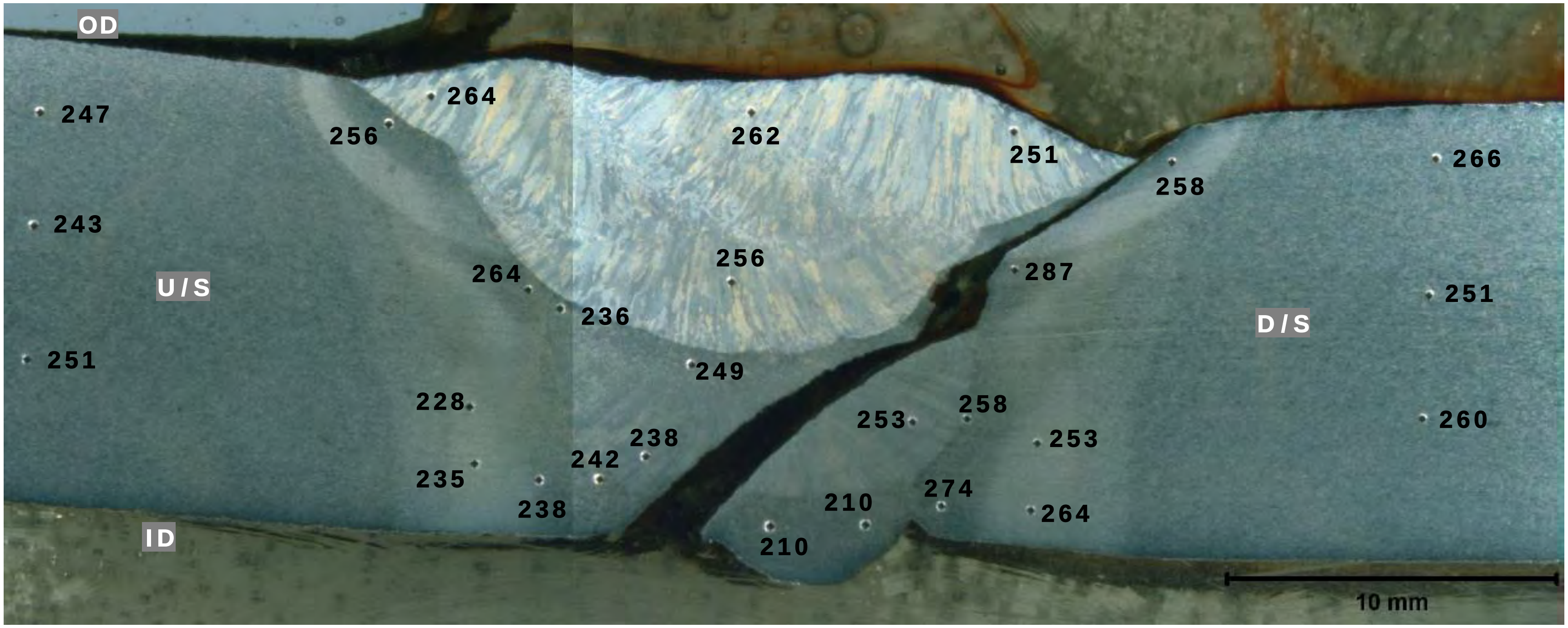

Figure 77. Light photomicrograph montage of Mount M5 (axial cross-section), showing the hardness indentations and the hardness values in HV (2% Nital Etchant).

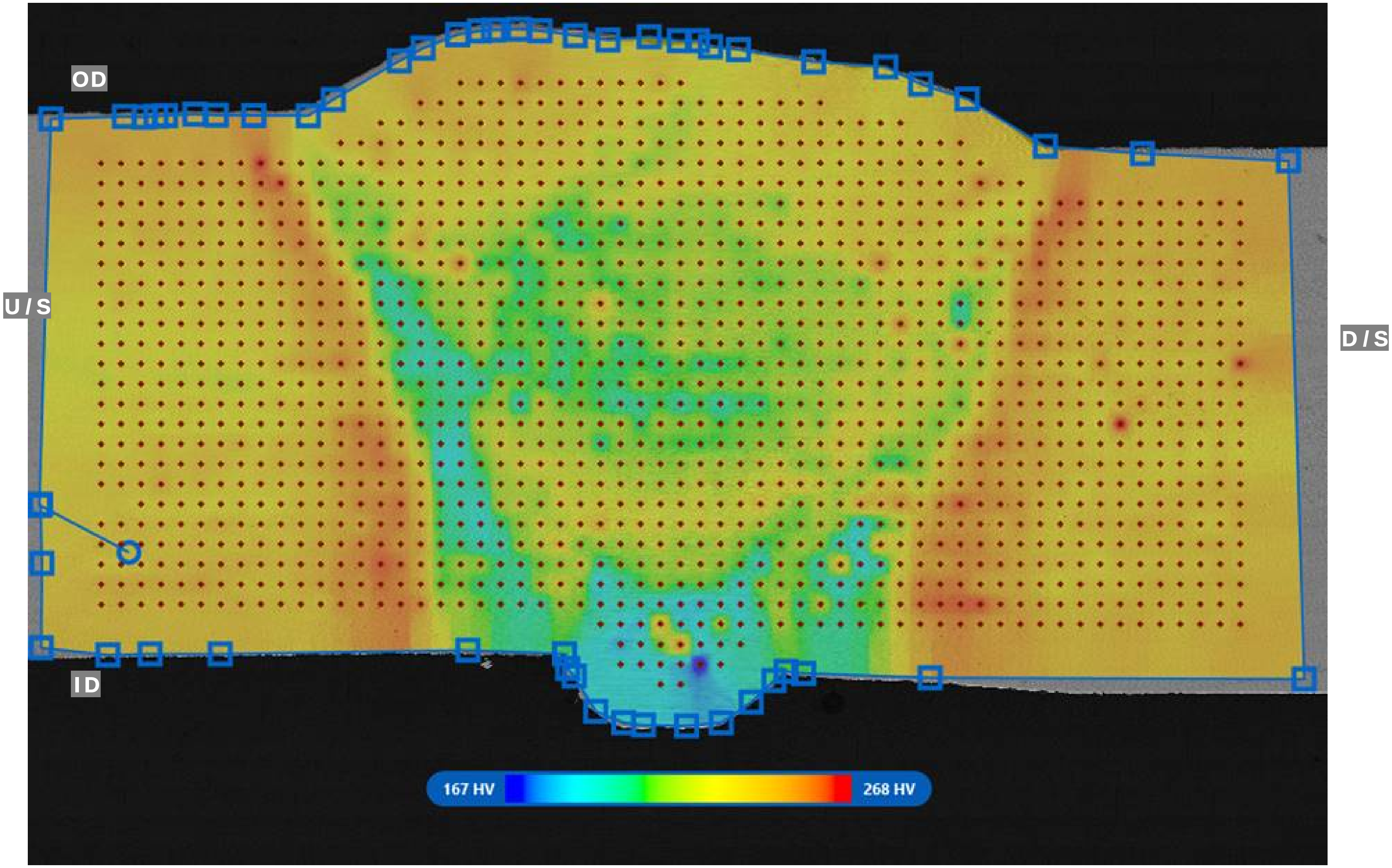

Figure 78. Hardness map overlay following hardness testing (Vickers 1 kg load) performed on Mount MU1.

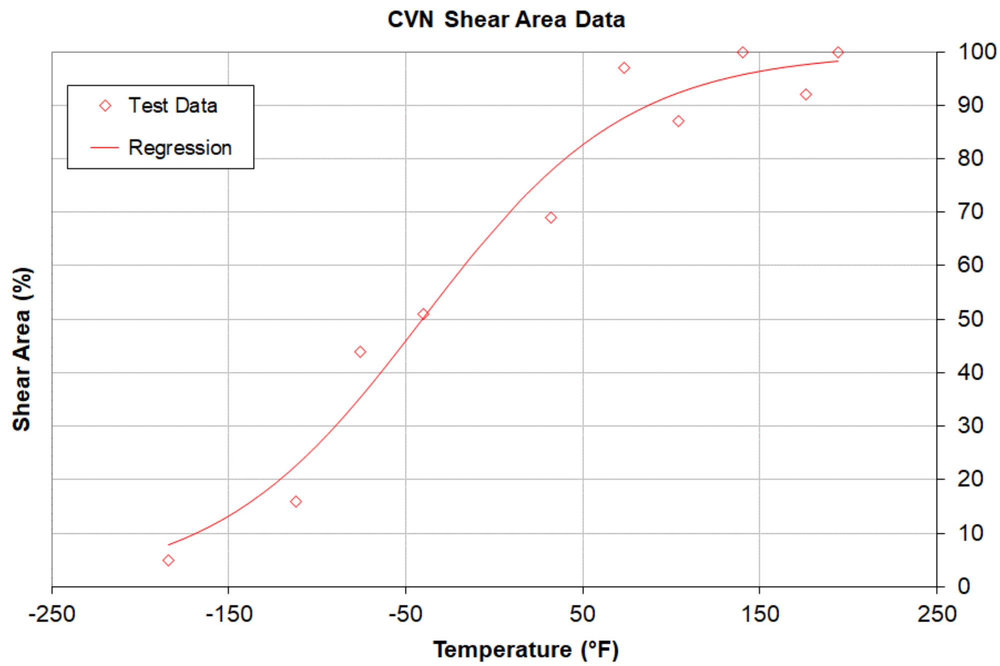

Figure 79. Percent shear from Charpy V-notch tests as a function of temperature for axial/cross-girth weld (HAZ notch) specimens removed from Pipe Section C.

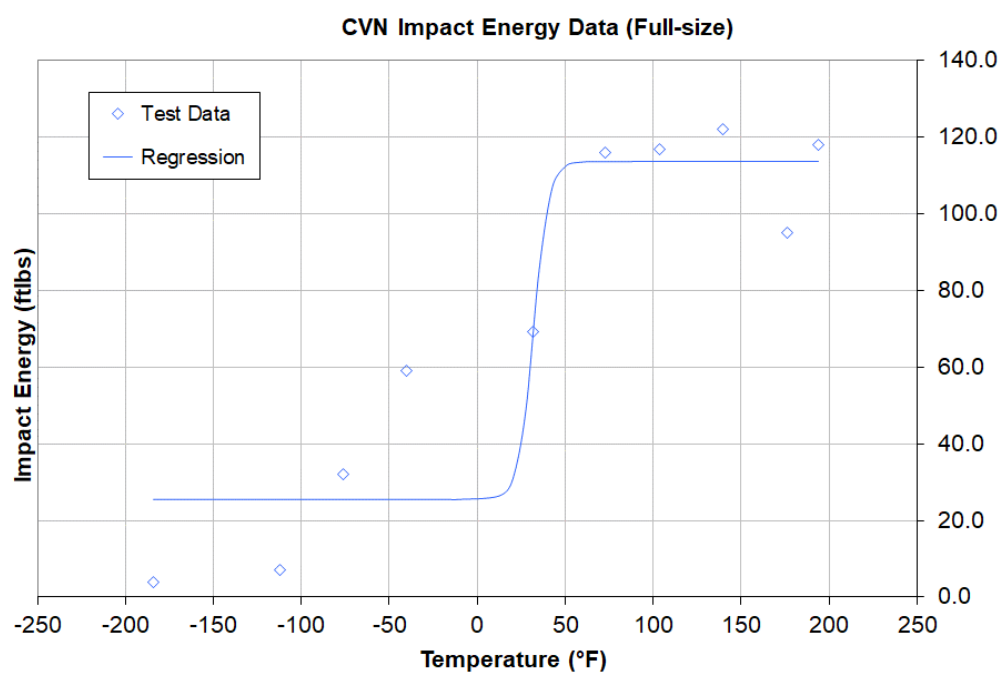

Figure 80. Charpy V-notch impact energy as a function of temperature for axial/cross-girth weld (HAZ notch) specimens removed from Pipe Section C.

ABOUT DNV GL

Driven by our purpose of safeguarding life, property, and the environment, DNV GL enables organizations to advance the safety and sustainability of their business. We provide classification and technical assurance along with software and independent expert advisory services to the maritime, oil and gas, and energy industries. We also provide certification services to customers across a wide range of industries. Operating in more than 100 countries, our professionals are dedicated to helping our customers make the world safer, smarter, and greener.

Appendix D

Responses to Questions Provided by PHMSA 4/7/2021

Questions and responses related to the Denbury Yazoo County RCA Final Report dated 8/7/2020:

1. **The metallurgy report does not reference chain-of-custody. Were chain-of-custody procedures used**

   Chain of custody procedures were used for collection and transport of the failed pipe section and samples. Copies of the chain-of-custody documentation have been provided to PHMSA and have been added to the appendices of this report.

2. **Copy and discussion of welding procedure used needed**

   A summary of the review of Denbury's welding procedure for the Delhi 24-inch Transmission Line utilized for original construction is provided below:

   Material: In this case the pipe material was high strength API 5L-X80-PSL2, 24-inch diameter, and 0.54-inch wall thickness.
   It is a requirement of the welding procedure that it produce a completed girth weld with similar strength properties of the pipe's base metal. This helps to ensure that the strains caused by loads imposed on the completed pipeline structure, do not concentrate in the vicinity of the weld. Another important aspect of the welding procedure is that it mitigates the risk of hydrogen embrittlement, which could lead to hydrogen cracking at the weld.

   There are 3 requirements for hydrogen cracking:
   a) Hydrogen in the weld,
   b) A crack susceptible microstructure, and
   c) Tensile stresses acting on the weld

   Weld Material: The Welding Procedure Specification WPS 14 indicates the use of the following electrodes:
   a) Root Bead: E6010
   b) Hot: E9010-G
   c) 1st Fill: E10045 P2 H4R
   d) Fill (s): E10045 P2 H4R
   e) Cap (s): E10045 P2 H4R

   Post Weld Heat Treatment: Not recommended

   Comments:

   1) Cellulosic-coated electrodes (AWS EXX10-type) contain moisture and organic compounds in the electrode coatings and result in a considerable amount of hydrogen in the weld. In the Denbury procedure electrode AWS E6010 and E9010-G were used for the root and hot pass in conjunction with low-hydrogen electrodes for the fill and cap passes. The Welding Procedure indicated that this is permissible because the heat from the fill and cap passes allows the hydrogen from the first 2 passes to diffuse out of the weld.

2) Electrode E10045 P2 H4R was used as a strength level low hydrogen downhill electrode. Only consumables with a maximum diffusible hydrogen content of 4ml/100g of deposited weld metal were selected for this case. “H” stands for hydrogen, the “4” stands for a maximum of 4ml of hydrogen per 100 grams of deposited weld metal, and “R” means the consumable is resistant to absorbing moisture from atmospheric conditions. During the qualification procedure, this electrode was found to be the most suitable electrode for this project. After the destructive testing, it was determined that the 100 ksi electrodes were a better match for use on this particular X80 line material which has a yield strength approaching 100 ksi.
3) Samples obtained during the failure analysis were evaluated using standard microscopy techniques including stereographic evaluations, microscopic evaluation, and scanning electron microscopy. Five axial and cross-sections were removed from the failed girth weld and one from an intact weld for metallographic analysis.

Actual findings during the failure analysis process:

a) There was no evidence of pre-existing manufacturing or welding flaws,
b) No indications of excessive porosity and/or inclusions,
c) Slight misalignment of high-low weld in the failed girth weld between 2.6% and 6.9% of the NWT,
d) Grain elongations due to the cold work that took place during the rupture process which is consistent with ductile overloading (see fig. 21 of the Mears report),
e) The sample obtained from the intact GW presented a similar morphology to the previous mounts. The high-low weld misalignment at this location was 4.6% of the NWT. The metallography of the section does not indicate a presence of a martensitic phase.
f) Hardness measurements were conducted on all metallographic cross sections. The values ranged between 205 and 304 HV. All the values were found to be in accordance with the applicable standards. Hardness testing of the failed weld presented variability that is likely associated with cold work sustained during the failure. The intact weld was the best representation of the base hardness of the pipe metal. The results indicate lower hardness of the weld metal compared to the pipe metal, which indicates that the weld metal is softer than the parent metal, however tests results were consistent with specifications for pipe of this vintage and yield strength in both the base metal and weld metal. Typically, the parent metal is harder than the weld metal. The axial tensile tests on the intact GW show similar failure to the actual failed pipe sample, further indicating that the lower hardness typical of the weld was the preferred location for the overload failure under applied axial stress. (See fig. 39 of the Mears report).
g) The mechanical testing indicated the average yield (YS) and ultimate tensile strength (UTS) meet the requirements for API X80M PSL 2 Line pipe. The average UTS of duplicate axial specimens taken from the intact girth weld was 103.3 ksi. The same applies to the Charpy V-Notch Testing.

Based upon review of the welding procedure, we conclude that:

1) The Welding Procedure Specification WPS 14 was appropriate to be use as a welding process for the material involved in this project.

2) The testing performed on the samples obtained during the failure investigation indicate that the welds showed that the microstructure and the mechanical properties of the base material and girth weld were in accordance with industry accepted standards.

3. **Report states on page iv: "The exact location of the initiation could not be determined due to a lack of chevrons on the fracture surfaces and the fact that no significant pre-existing (prior to failure) cracks were identified." "no significant" how was this determined?**

   The failure surfaces were inspected visually and optically for indications of surface oxides associated with development and deepening of cracks over an extended period. The lack of oxides precludes the possibility of pre-existing cracks and supports the determination that the failure occurred due to a sudden axial stress. In addition, the visual and optical inspections did not identify any marks or indications on the surface of the fracture that indicated an initiation point of the failure.

4. **The section on page 7 describes figures 53 and 54 and describes the area as "mainly ferrite". Specifically characterize the complete microstructure of the pipe and the weld metal.**

   Figures 53 and 54 of the DNV Metallurgical Analysis Report (Section 3.4) characterize the microstructure of the upstream and downstream pipe. Analysis of these photomicrographs indicate a significantly larger amount of ferrite than pearlite, which is consistent with the expected microstructure for pipe with the specified minimum yield strength and vintage of the Delhi 24-inch pipeline. Compared with photomicrographs of metal samples provided through industry literature, the microstructure of the 24-inch pipeline has a low carbon content, consistent with other X-80 pipelines. The microstructure of the failed girth shows similar characteristics (see Figure 62 of the DNV Metallurgical Analysis Report.

5. **Provide the hardness montage for MU1**.

   The hardness montage for mount MU1 is provided in Figure 78 of the DNV Metallurgical Analysis Report (Appendix C).

6. **Section 3.5 on hardness testing indicates various areas related to the weld area, include a discussion of the welding procedure utilized to produce the weld.**

   Discussion of the welding procedure is provided in the response to question #2 above.

7. **Typically, there is narrowing of a tensile specimen due to the area reduction during tensile overload. In this case was there a measurable necking down of the wall thickness adjacent to the fracture surface**

Evaluation of the metallurgical samples indicated slight reduction in wall thickness in each sample, ranging from 1.44% to 6.46%. Photos and measurements are provided in in figures 1 through 5 below:

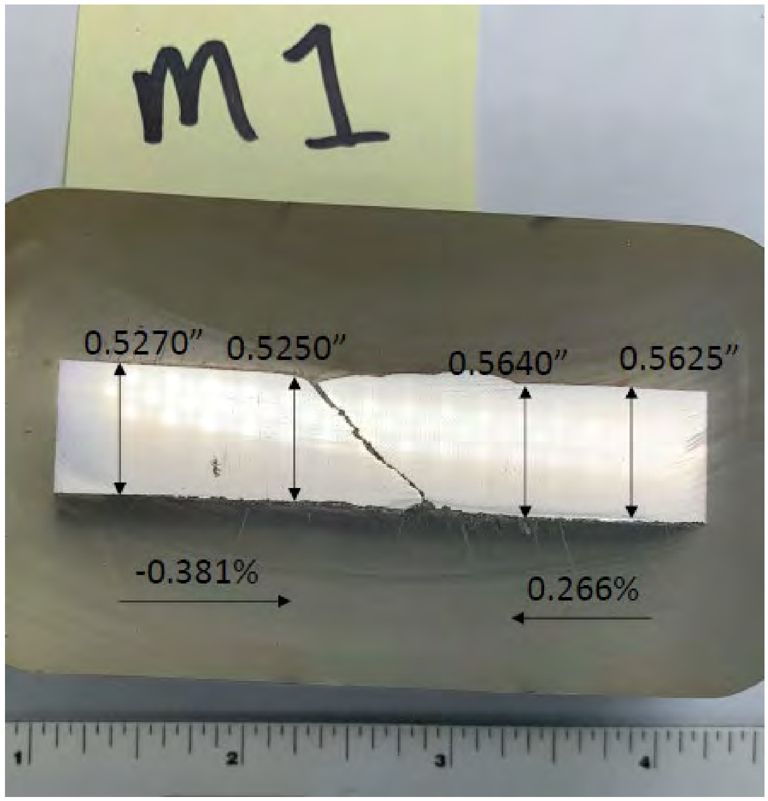

Figure 1: Cross-Sectional Measurements, Mount M1

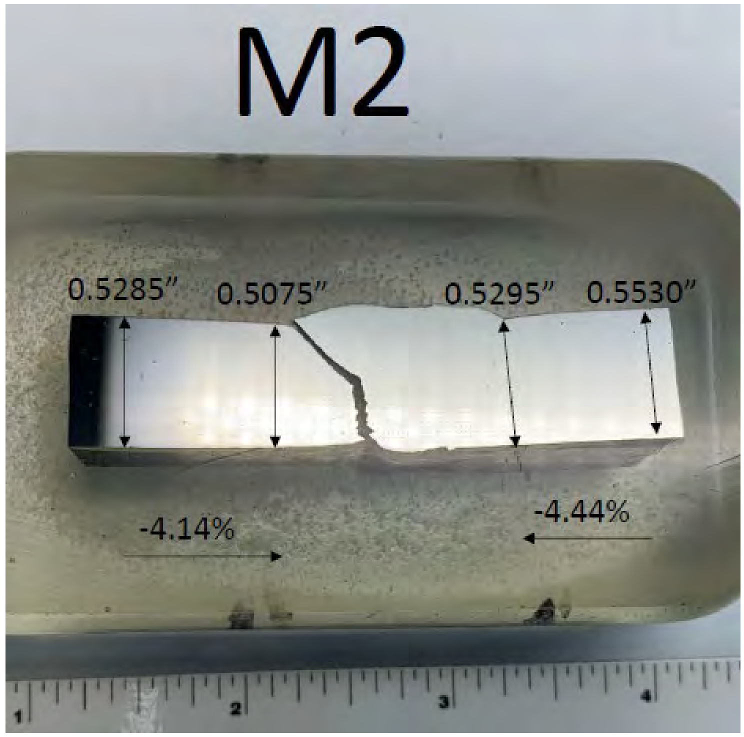

Figure 2: Cross-Sectional Measurements, Mount M2

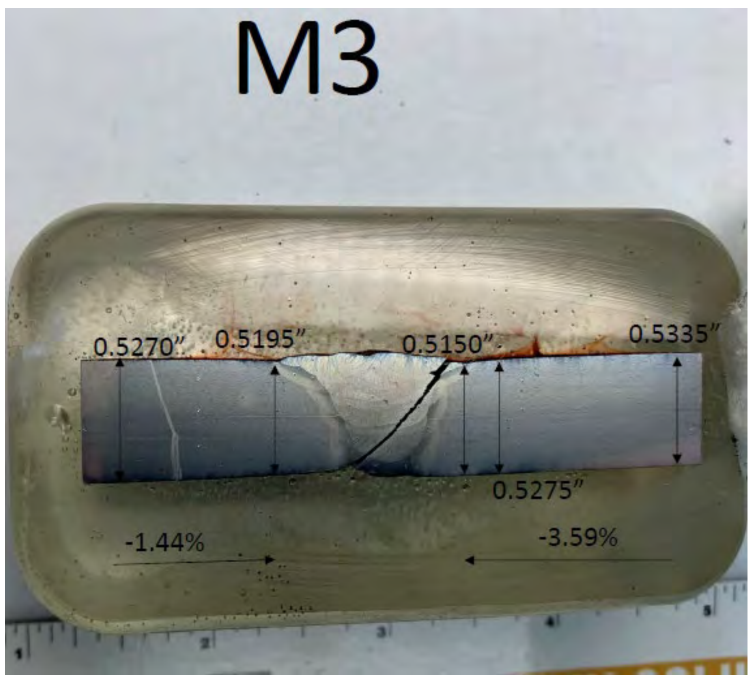

Figure 3: Cross-Sectional Measurements, Mount M3

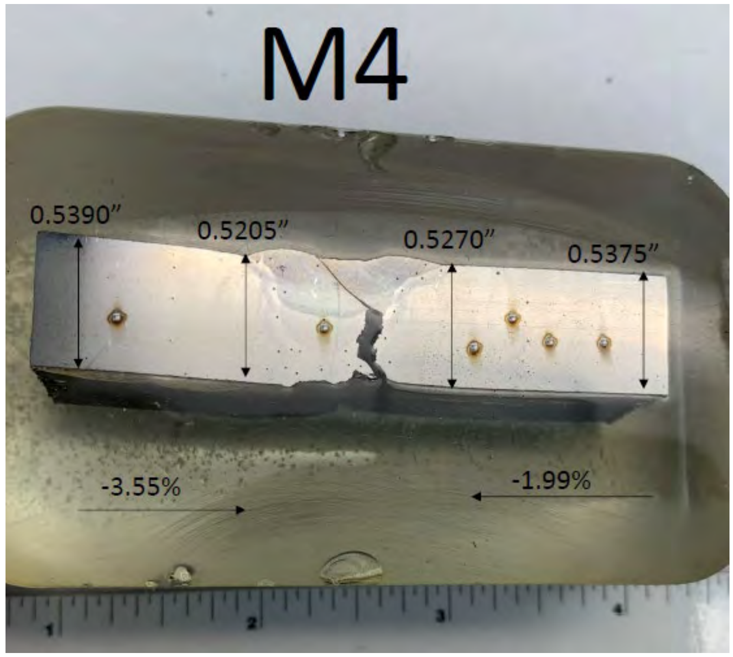

Figure 4: Cross-Sectional Measurements, Mount M4

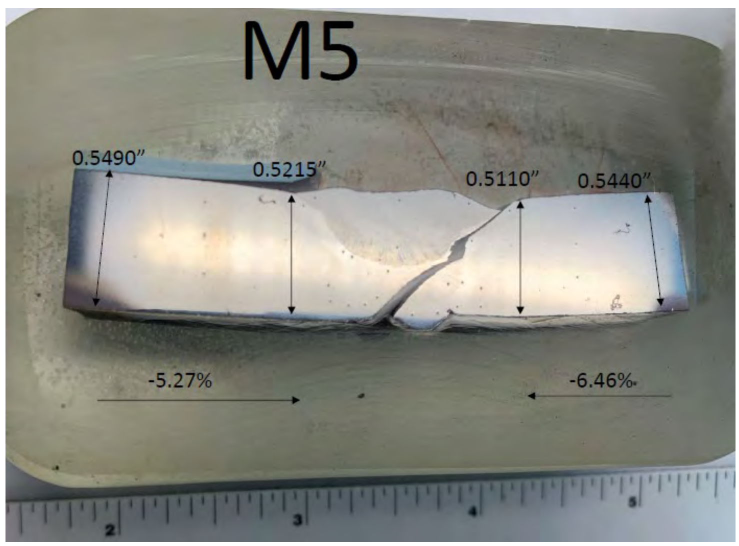

Figure 5: Cross-Sectional Measurements, Mount M5

These results are consistent with the characteristics of API X80M PSL 2 Line pipe.

8. Intact girth weld was tensile tested – compare and contrast fracture appearance of tested intact weld to failed girth weld

The average UTS of the axial specimens taken from the intact girth weld was 103.3 ksi, and both samples failed in the girth weld (DNV Metallurgical Analysis Report, section 3.6). While visual examination of the tensile sample fractures will confirm the location of each fracture, a comparison of the samples would only provide confirmation of the location of each fracture and not provide additional insight as to the reason for the failure, as the applied stresses would not be similar. The Pipeline Stress Analysis Report provided by Mott MacDonald provides information related to the stress analysis associated with this failure.

9. Was leak before fracture mode of failure considered

Occurrence of a leak prior to the failure was considered, however the available information supports a rupture of the pipeline, including the following:

1) There was no indication of a pre-existing defect that would have contributed to a leak and a specific failure initiation site was not apparent.
2) Based upon a witnessed examination of the pipe, there was no evidence of internal or external corrosion that may have contributed to the failure mode.
3) No indication of a leak prior to the failure was identified in operating pressure trends.

10. Failure mode and influence of CO2 on ductile/brittle transition considering leak before rupture

Based upon the metallurgical examination, there is no evidence a leak occurred prior to the failure, therefore brittle failure mode is not feasible.

11. Chemistry of weld needed as this was a girth weld failure

Chemical analysis of the GW was not performed during the investigation. The mechanical testing results were within the accepted criteria during the preparation of the Welding Procedure Specification WPS 14. No additional testing of the chemistry of the girth weld was considered necessary based upon the results of the testing conducted.

12. Report states failure caused by large axial stress but fails to quantify strain

The Pipeline Stress Analysis Report provided by Mott MacDonald identified a stress ratio approximately 43% greater than allowable stresses per ASME B31.4 (2016).

13. Strain analysis would be an input for a geohazard management plan

The Pipeline Stress Analysis Report provided by Mott MacDonald provides information related to the strain analysis associated with this failure.

14. Brittle (cleavage facets) mode of failure noted, but no chevrons – significance

V-shaped chevron markings are characteristic of brittle fracture. These markings may indicate the origin of the fracture, however in this case no chevrons were identified.

15. Explanation of ductile/brittle appearance of the failed girth weld

As described in section 5.3 of the Mears report, the samples were evaluated utilizing standard microscopy techniques including stereographic evaluations, microscopic evaluation and scanning electron microscopy. Five (5) axial and cross-sections were removed from the failed girth weld and one (1) from the intact weld for metallographic analysis. Some of the samples contain fracture paths at a shear angle (fracture path through the smooth surfaces) and other show the fracture path perpendicular to the free surface and regions of shear failure (fracture surface is rough). The appearance of these surfaces further support the mode of failure as described in the executive summary of the DNV Metallurgical Analysis Report "The results of the metallurgical analysis indicate that the failure initiated at a field girth weld, due to axial stresses sufficient to produce overload failure. No pre-existing flaws were present on the fracture surface. A contributing factor was that the pipe steel was stronger than the girth weld."

16. Correlation of hardness areas and welding procedure

Hardness measurements were conducted on all metallographic cross sections. The values ranged between 205 and 304 HV. All the values were found to be in accordance with the applicable standards. Hardness testing of the failed weld presented variability that is likely associated with cold work sustained during the failure. The intact weld was the best representation of the base hardness of the pipe metal. The results indicate lower hardness of the weld metal compared to the pipe metal. Which indicates that the weld metal is softer than the parent metal, which was in accordance with the results of the welding qualification. Typically, the parent metal is harder than the weld metal. The axial tensile tests on the intact GW show similar failure to the actual fracture to the actual fracture, further indicating that the lower hardness typical of the weld was the preferred location for the overload failure under applied axial stress. (See fig. 39 of the Mears report).

17. How does the welding procedure tensile tests compare to the intact weld tensile tests

The mechanical testing indicated the average yield (YS) and ultimate tensile strength (UTS) meet the requirements for API X80M PSL 2 Line pipe. The average UTS of duplicate axial specimens taken from the intact girth weld was 103.3 ksi. The same applies to the Charpy V-Notch Testing (see section 5.6.2 of the Mears RCA Final Report).

The results of the Procedure Qualification Record (PQR 14a) indicated cross weld UTS of 115.6 ksi to 117.3 ksi. Per the Welding Procedure Development and Qualification for X80 Line Pipe, dated 8/13/2008, section 3.1, "After destructive testing it was determined that the 100 ksi electrodes were a better match for use on this particular X80 line pipe material, which has a yield strength approaching 100 ksi." Therefore test results from the mechanical testing of the intact girth weld are consistent with the pipeline's specifications.

Appendix E

Chain of Custody Documentation

mears
A QUANTA SERVICES COMPANY

STEP 2 – CHAIN OF CUSTODY

1. ORIGINATING LOCATION – Denbury Delhi 24 inch Transmission	
Contact Person: Seth Bayham	Phone Number: (225) 202-1402
Title: Corrosion Foreman	Date: 3/10/2020
Contact Address: 31589 Netterville Rd, Denham Springs, LA 70726	
Material Location, City, State: 688 MS 433, Sartitia, MS	
Signature: Seth Bayham	Date: 3/10/2020

2. AUTHORIZATION FOR RELEASE	
Authorized by: Seth Bayham	Phone Number: (225) 202-1402
Title: Corrosion Foreman	Date: 3-10-20
Department:	
Authorization provided (check one):________by Telephone ✓ in Person______in Writing	

SHIPPING INSTRUCTIONS

Samples should be shipped to DNV GL 9037 Heritage Drive, Plain City, OH 43064. Please contact Greg Quickel. Phone: (614) 378-4083.

3. ITEMS TRANSFERED	
Reference Number: Delhi 24-3 *Sample Identifier: Sample A* *Date Collected: 3/09/2020*	*Description: 24" diameter by 6' long pipe sample (D/S failure section)*
Reference Number: Delhi 24-4 *Sample Identifier: Sample B* *Date Collected: 3/09/2020*	*Description: 24" diameter by 6 ' long pipe sample (U/S failure section)*
Reference Number: Delhi 24-5 *Sample Identifier: Sample C* *Date Collected: 3/09/2020*	*Description: 24" diameter by 8' long pipe sample (U/S pipe section containing exemplar weld)*
Reference Number: *Sample Identifier:* *Date Collected:*	*Description:*
Reference Number: *Sample Identifier:* *Date Collected:*	*Description:*

CHAIN OF CUSTODY RECORD FOR SAMPLE A, B, C

☒ Received from Denbury Resources Date: 3/10/hr 1:30P Received by P. Jo Reid
Reason for transfer

From: Company: Denbury Resources Signature [signature]
To: Company: Reid's Dozer service Signature P-JOE REID

Until the time you transferred custody of sample
To recipient listed above, has (have) this (these) item (s) left your custody, control at any time:
YES
NO

If YES, please explain:

Signature

CHAIN OF CUSTODY RECORD FOR SAMPLE A, B, C

☐ Received from Reid's Dozer Service Date: 3/12/hr 8:10 Received by Greg Quickel

Reason for transfer Testing at DNVGL

From: Company: Reid's Dozer Sevice Signature P-JOE REID
To: Company: DNV GL Signature Greg Quickel

Until the time you transferred custody of sample A, B, C
To recipient listed above, has (have) this (these) item (s) left your custody, control at any time:
YES
✓ NO

If YES, please explain:

Signature P-JOE REID

DNV GL USA, Inc.
Materials & Corrosion Technology Center
Incident Investigation
5777 Frantz Road
Dublin, OH 43017-1886
Tel: (614) 761-1214
Fax: (614) 761-1633
www.dnvgl.com

DNV·GL

CHAIN OF CUSTODY FORM

Project No.: 10206282 Sample: 24" Q Denbury

1. ORIGINATING LOCATION	
Contact Person: Greg Quickel	*Phone No.:* 614 378 4083
Title: Principal Eng	*Date:* 9/30/2020
Contact Address: See above	
Material Location, City, State:	
Signature: Greg Quickel	*Date:* 9/30/2020

Description of Evidence	Date Evidence Placed into Controlled Custody:
24" Q Denbury Failure	
Four pipe sections	
One box of samples (met/FS.)	Date Evidence Released from Controlled Custody: 9/30/2020
Two bags of soil from pipe	
Five steel coupons for mech testing	
Two bags of mech specimens	
	Release of Evidence Authorized by: [signature]

Received by:	**Date**	**Time**
Signature: [signature] Reason: TRANSFER	9/30/20	
Signature: Reason:		
Signature: Reason:		

Appendix F

Welding Procedure Development and Qualification for X80 Line Pipe

8/13/2008

FINAL REPORT

PROJECT CONSULTING SERVICES, INC.

WELDING PROCEDURE DEVELOPMENT AND QUALIFICATION FOR X80 LINE PIPE

PROJECT NO. 82681591
AUGUST 13, 2008

DET NORSKE VERITAS

CC Technologies
a DNV company

DET NORSKE VERITAS

FINAL REPORT

CC TECHNOLOGIES, INC.
Integrity & Materials

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Date of Issue:

August 13, 2008

Project No.:

82681591

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Director
Welding Technology

Approved By:

Patrick H. Vieth
Senior Vice President
Integrity & Materials

Client:

Project Consulting Services, Inc.

Summary:

CC Technologies, Inc. (CCT) was retained by Project Consulting Services, Inc. to develop and qualify welding procedures for 24 inch by 0.54 inch grade X80 line pipe. Several different production, repair, and in-service procedures were developed. These procedures were run at a Progressive Pipeline Inc. facility in Meridian, Missipppi under the supervision of a representative from CCT. The welds were sent to an independent laboratory for destructive testing. CCT then created welding procedure specifications and procedure qualification records for welds that passed all testing.

Project No:	Subject Group:	Date :	Number of Pages:
82681591	Welding Technology	August 13, 2008	6

Report Title:

Welding Procedure Development and Qualification for X80 Line Pipe

Final Report

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FINAL REPORT

1. PROJECT SCOPE

CC Technologies, Inc. (CCT) was contracted by Project Consulting Services Inc. (PCS) to create and qualify welding procedure specifications (WPS) and procedure qualification records (PQR) for the construction of two 24-inch diameter x 0.54 inch wall thickness, API 5L-X80-PSL2 pipelines as per the requirements of the 19^{th} and 20^{th} editions of API 1104. A variety of procedure qualifications were performed so as to give PCS's client, Denbury Resources Inc. (DRI), options when selecting welding processes and consumables for construction. CCT was also asked to use their welding experience and expertise to identify the most appropriate welding procedures for the construction, maintenance, and repair of these pipelines. Procedure qualifications were performed using welding consumables and process that were suggested by PCS/DRI and using welding consumables and process that were determined by CCT to be acceptable alternatives to those suggested by PSC/DRI.

2. WORK PERFORMED

CCT attended a project kick off meeting in Birmingham, Alabama on April 2, 2008 at the PCS office. The goal of this meeting was to discuss what consumables to use for the construction of two new X80 pipelines that will operate in carbon dioxide service. When welding higher strength line pipe material such as X80, several concerns need to be addressed including weld strength level and the risk of weld metal hydrogen cracking.

In most welding applications, including pipeline girth welding, it is desirable for the weld to overmatch the strength of the base material. This ensures that the strains caused by loads imposed on the completed structure do not concentrate in the vicinity of the weld. Welds are more likely to contain discontinuities than base materials, so it is desirable to avoid the concentration of strains in the vicinity of welds. A letter report pertaining to the use of welding consumables and process that were suggested by DRI for construction of these pipelines, from the prospective of weld strength level, is shown in Appendix A.

There are three requirements for hydrogen cracking; hydrogen in the weld, a crack-susceptible weld microstructure, and tensile stresses acting on the weld. Cellulosic-coated electrodes (AWS EXX10-type) contain moisture and organic compounds in the electrode coatings and result in a considerable amount of hydrogen in the weld. Traditionally, heat-affected zone (HAZ) microstructures have been considered to be the most susceptible to hydrogen cracking. With the introduction of higher strength line pipe steels with good weldability, and the higher strength welding consumables required to weld them, weld metal microstructures are now as susceptible (if not more so) than HAZ microstructures. A letter report pertaining to the use of cellulosic-coated electrodes for construction of these pipelines, from the prospective of hydrogen cracking risk, is shown in Appendix B.

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CCT was asked to provide alternatives to traditional cellulosic-coated electrodes in the form of low-hydrogen consumables and processes. CCT provided several low-hydrogen alternatives to be qualified along with cellulosic-coated electrode procedures requested by DRI. These procedures were qualified, documented, and the completed WPS's and PQR's delivered to PCS.

The procedure qualifications were performed at a Progressive Pipeline Inc. facility in Meridian, Mississippi. A CCT employee was onsite during procedure qualification to provide support and record relevant welding parameters. The first round of welding procedure qualifications took place April 14 through 18, 2008. WPS 4 through WPS 11 (Table 1) were conducted during this first round of welding. A typical setup for these procedures is shown in Figure 1. A 2 foot long length of pipe was welded onto a longer piece of pipe using an external lineup clamp. The preheat was applied using propane with rosebud torches. These welds were inspected by radiography before being sent for destructive testing to prevent incurring the cost of performing destructive testing on welds that may contain unacceptable discontinuities. A second round of procedures was performed at the same location May 12 through 17, 2008. The procedures performed in May were WPS 14 through WPS 20 (Table 1) and included two in-service repair procedures for the installation of a tight fitting Type B repair sleeve, as shown in Figure 3.

3. RESULTS

3.1 Pipeline Girth Welding

A total of 12 procedures were qualified, a complete list of the procedures can be found in Table 1. The low-hydrogen procedures are WPS 7 through WPS 11 and WPS 17 through WPS 20. All of the other procedures involve the use of cellulosic-coated electrodes exclusively. Except for the in-service procedures (WPS 19 and 20), all of the procedures use cellulosic-coated electrodes for the root pass and the hot pass. For pipeline girth welding on thicker-wall X80 line pipe material, it is typically acceptable to use cellulosic-coated electrodes for the root and hot pass in conjunction with low-hydrogen consumables for the fill and cap passes. This is permissible because the heat from the fill and cap passes allows the hydrogen from the first two passes to diffuse out of the weld.

Three different types of low hydrogen consumables were used; low hydrogen down-hill stick electrodes (AWS EXX45-type), traditional up-hill low-hydrogen stick electrodes (AWS EXX18-type) and gas-shielded flux-cored arc welding wire (AWS E101T1-type). These consumables were used with the manual shielded metal arc welding (SMAW) process and the semi-automatic flux-core arc welding (FCAW) processes, respectively. Traditional vertical up low-hydrogen electrodes (E10018-G H4R) were used for a single repair procedure, WPS 11. Two different strength levels of the low hydrogen down-hill electrode (E9045 P2 H4R and E10045 P2 H4R) were used during the first set of welding trials. These strength levels represent the minimum ultimate tensile strength of the consumable. After destructive testing it was determined that the 100 ksi electrodes were a better match for use on this particular X80 line

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pipe material, which has a yield strength approaching 100 ksi. During the second round of procedure qualifications the E10045 P2 H4R electrodes were the only low hydrogen down-hill electrodes used.

3.2 In-Service Welding

When qualifying welding procedures to be used on pipelines that are in-service, it is good practice to simulate in-service operating conditions. This is important because of the effect that the flowing contents in the pipeline has on the weld cooling rate. The flowing contents act as a heat sink when welding onto the carrier pipe, which causes the weld to solidify and cool extremely quickly. This in turn can promote the formation of crack-susceptible weld microstructures and cause large amounts of hydrogen to become trapped in the weld, if good low hydrogen welding techniques are not used. It is therefore critical to use welding processes and consumables that produce welds with a low amount of diffusible hydrogen.

For this reason, only consumables with a maximum diffusible hydrogen content of 4ml/100g of deposited weld metal were used. Notice the "H4R" designation at the end of the consumable specification in column 5 of Table 1. The "H" stands for hydrogen, the "4" stands for a maximum of 4 ml of hydrogen per 100 grams of deposited weld metal, and the "R" means the consumable is resistant to absorbing moisture from atmospheric conditions.

The setup used for the in-service welding procedure qualification can be seen in Figure 4. To create this testing rig, a section of pipe is enclosed by welding end caps to the open ends. A nozzle for an ordinary garden hose is installed on both ends of the vessel. This allows water from the faucet to flow through the pipe section while welding is performed. A valve was installed on the top of the pipe close to the end where the water exits to allow for air to be vented, ensuring the pipe is completely full of water. That end of the pipe was slightly elevated, which ensures that no air bubbles become trapped along the top of the pipe. Water flow was maintained during welding and continued until the welds cooled to room temperature.

3.3 Documentation

WPS and PQR combinations for each of the procedures that passed destructive testing were provided to PCS.

Table 1. Qualified Welding Procedures Specifications.

Procedure	Type	Root Pass Consumable Specification	Hot Pass Consumable Specification	Fill and Cap Pass Consumable Specification
WPS 4	Production	E6010	E9010-G	E9010-G
WPS 7	Production	E6010	E9010-G	E9045 P2 H4R
WPS 8	Repair	E6010	E9010-G	E9045 P2 H4R
WPS 9	Production	E6010	E9010-G	E10045 P2 H4R
WPS 10	Repair	E6010	E9010-G	E10045 P2 H4R
WPS 11	Repair	E6010	E9010-G	E10018-G H4R
WPS 14	Production	E6010	E9010-G	E10045 P2 H4R
WPS 15	Repair	E6010	E9010-G	E10045 P2 H4R
WPS 16	Repair	E6010	E9010-G	E9010-G
WPS 17	Production	E6010	E9010-G	E101T1-GM-H8
*WPS 19	Sleeve	E10045 P2 H4R	E10045 P2 H4R	E10045 P2 H4R
*WPS 20	Sleeve	E101T1-GM-H4R	E101T1-GM-H4R	E101T1-GM-H4R

*In-service weld.

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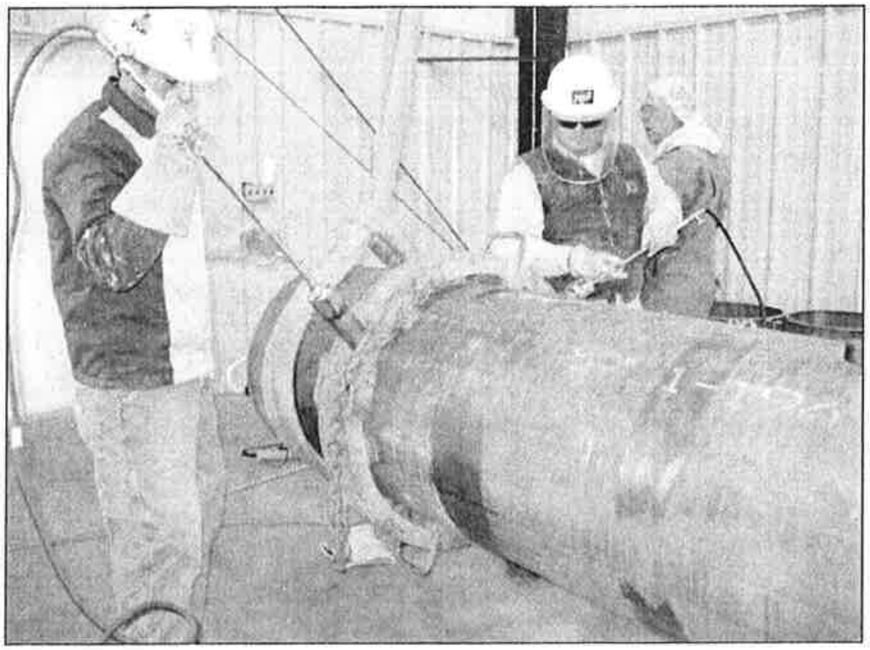


Figure 1. Typical setup for girth weld procedure qualification.

Figure 2. Typical completed girth weld coupon after cutting.

FINAL REPORT

Figure 3. In-service tight-fitting repair sleeve.

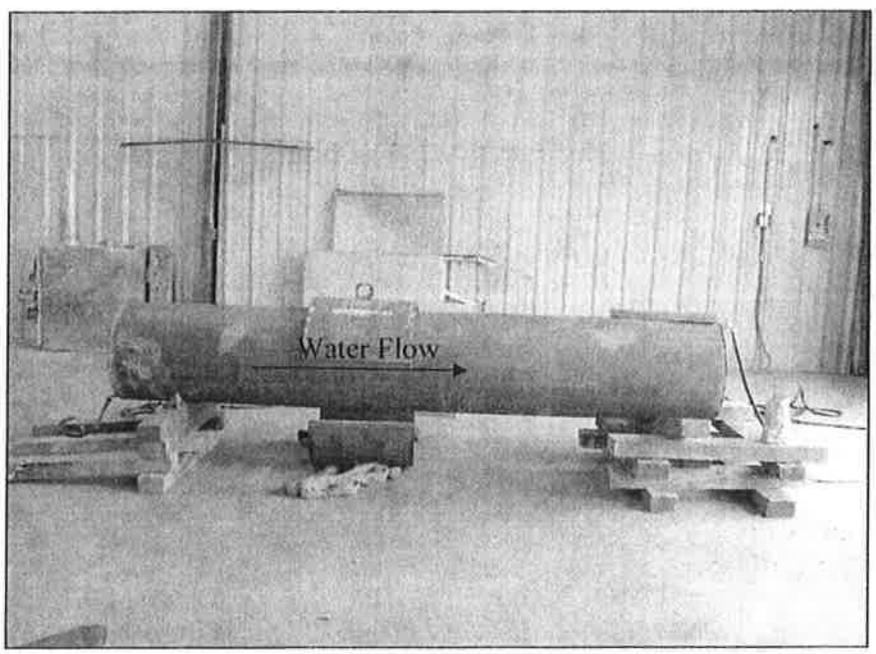
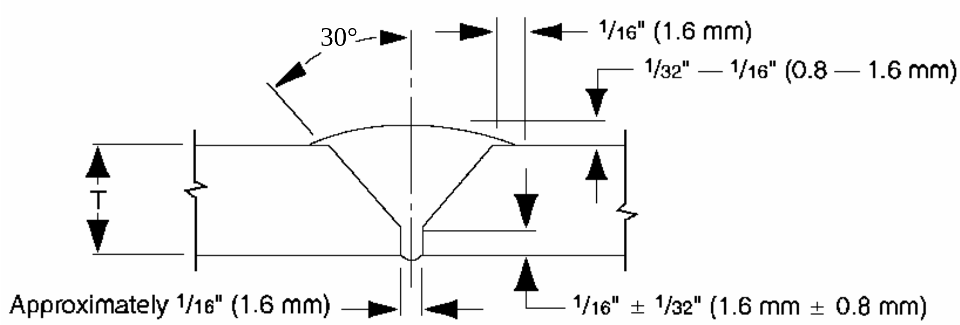
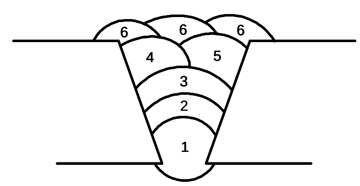


Figure 4. Setup for in-service welding procedure qualification.

Appendix G

Welding Procedure Specification WPS 14

6/18/2008

Scope of Procedure	This welding procedure specification details the procedure to be followed for the production of field butt welds in line pipe as required by the 19th and 20th editions of API 1104, Welding of Pipelines and Related Facilities
Applicable Codes and Specifications	■ 19th & 20th Editions of API 1104 ☐ ASME B 31.3 ☐ ASME B 31.8 ☐ DOT 49 CFR Part 195 ☐ ASME B 31.4 ☐ DOT 49 CFR Part 192 ☐ ASME BPVC Section IX
Supporting PQR	PQR: PQR-14a — Date Qualified: 5/14/08 Witnessed By: Brad Etheridge — Location: Meridian, Mississippi
Materials	Grades Qualified: X80 — PQR Material: API 5L – X80 - PSL2 Qualified Diameter Range: All — Diameter of PQR: 24 inches Qualified Wall Thickness Range: from 0.188" through 0.750" — Wall Thickness of PQR: 0.54 inches
API 1104 Material Groupings Qualified	Diameter (inch): ☐ OD < 2.75 ☐ 2.75 < OD ≤ 12.750 ■ OD ≥ 12.750 Wall Thickness (inch): ☐ WT < 0.188 ■ 0.188 ≤ WT ≤ 0.750 ☐ WT > 0.750 SMYS (psi): ☐ ≤ 42,000 ☐ 42,000 < SMYS < 65,000 ■ ≥ 65,000
Joint Design	
Position of Pipe Axis	■ Horizontal (1G or 5G) ■ Fixed ☐ Vertical (2G) ☐ Rolled ☐ Inclined (6G) Generic Bead Sequence 
Minimum Number of Welders	☐ One ■ Two ☐ Other
Line Up Clamp	Type: External or Internal — A minimum of 50% the root bead must be completed before removal of the clamp.
Preheating	Gas torch, electric induction coils, or any other company approved method. Verify temperature using company approved method Preheat Temp. Min.: 200℉ Interpass Temp. Max.: N/A Interpass Temp. Min.: 200℉

Time Between Passes	Root and Hot	5 minutes	Hot and First Fill	24 hours
Cleaning	The use of both hand and power tools is acceptable. The base material should be free of scale or anything else that may impede welding before the start of any welding. Each pass should be thoroughly cleaned and free from slag and spatter before the next pass is made.			
Defect Removal	The only area that may be repaired is the weld cap. Other repairs are to be addressed by qualified repair welding procedures. Defects in the cap should be removed by grinding and welding shall follow the guidelines set forth in this procedure.			
Post Weld Heat Treatment	☐ Yes ■ No			

Welding Pass	Root Bead	Hot	1^{st} Fill	Fill(s)	Cap(s)
Welding Process	SMAW	SMAW	SMAW	SMAW	SMAW
Manual or Automatic	Manual	Manual	Manual	Manual	Manual
Direction of Welding	Vert. Down	Vert. Down	Vert. Down	Vert. Down	Vert. Down
Shielding Gas	N/A	N/A	N/A	N/A	N/A
Flow Rate	N/A	N/A	N/A	N/A	N/A
Wire Feed Speed	N/A	N/A	N/A	N/A	N/A
Deposition Type	Stringer	Stringer/Weave	Weave	Weave	Weave
Technique	Backhand	Backhand	Backhand	Backhand	Backhand
Filler Manufacturer	Lincoln	Lincoln	Lincoln	Lincoln	Lincoln
Filler Trade Name	Fleetweld 5P+	Shield-Arc 90	LH-D100	LH-D100	LH-D100
AWS Group	1	2	3	3	3
AWS Specification	A5.1	A5.5	A5.5	A5.5	A5.5
AWS Classification	E6010	E9010-G	E10045 P2 H4R	E10045 P2 H4R	E10045 P2 H4R
Polarity	DCEP	DCEP	DCEP	DCEP	DCEP
Electrode Diameter(s)	1/8”* or 5/32”	5/32”	5/32”	5/32”	5/32”
Arc Voltage (V)	20 - 32	20 - 30	18 - 26	18 - 26	18 - 26
Current Range (Amp)	100 – 150* 110 - 170	110 - 170	150 - 230	150 - 230	150 - 230
Travel Speed Range (inch/min)	5 – 15	5 – 15	5 – 20	5 – 20	5 – 20

Minimum number of Passes	Wall Thickness Range (in)	Number of passes	Minimum does not include stripper passes or split caps.
	≤ 0.188	3	
	> 0.188 to 0.25	4	
	> 0.25 to 0.50	5	
	> 0.50 to 0.750	7	

Notes	Weave the hot pass as necessary to prevent wagon tracks. Stripper passes are optional. Either a two or three bead cap is acceptable.	
Submittal	Author: Brad Etheridge	Title: Welding Engineer
	Company: CC Technologies Inc. A DNV Company	Date: 5/30/08

Owner Approvals	Title	Name	Signature	Date

Company Name: Progressive Pipeline	Date: 5/14/08	Notes: Welding machine used was a Lincoln Red-D-ARC, D300K 3+3 Diesel
Project Number:	Location: Meridian, MS @ Progressive Pipeline facility	
PQR #: 14a	Inside/Outside: Inside, with open bay doors	
WPS #: 14	Temperature: 78 inside shop	
Coupon #:	Recorded by: Brad Etheridge	

#	Material	OD	WT	Length	Joint ID #	Heat #	Test Position	Horizontal	Time between root and hot		2:55
1	API 5L - X80 - PSL2	24	0.54	2 feet	L	8791-1940-06	Preheat Temp	200	Time between hot and first		
2	API 5L - X80 - PSL2	24	0.54	N/A	R	8791-1943-06	Clamp Type	EXT	Start	9:41 AM Stop	11:00 PM

Filler Metal #	Manufacturer	Trade name	Classification	Specification	Diameter	Batch/Lot #	Welder Information	
1	Lincoln	Fleetweld 5P+	E6010		5/32	11558962	Side A Welder	Randall Nunez
2	Lincoln	Shield-Arc 90	E9010	G	5/32	11558966	Welder Stamp	
3	Lincoln	LH-D100	E10045	P2 H4R	5/32	Lot Q2 863C	Side B Welder	Ken Abernathy
4							Welder Stamp	

Notes	External linup clamp used to tack 2 foot coupon onto long joint. The short side of the coupon is "R" and the long side is "L". Pass 2 and 3 were split passes; they were placed side by si

Pass Type/ Number / Welder ID	Filler #	Process	Travel Direction	Amps	Volts	Distance (in)	Arc Time (Sec)	Travel Speed (IPM)	WFS (IPM)	Heat Input (KJ/in)	Oscillation Freq cycle/sec	Oscillation Width ( )	Method Stringer or Weave	Welding Gas Type	Welding Gas Flow ( )	Interpass Temp ( )
Root A	1	SMAW	VD	116	22	6	33	10.91		13.7			S			
Root A	1	SMAW	VD	118	23	2.25	14	9.64		16.5			S			
Root A	1	SMAW	VD	107	24	8	45	10.67		14.1			S			
Root B	1	SMAW	VD	128	23	9	54	10.00		17.3			S			
Root B	1	SMAW	VD	137	24	2.5	16	9.38		21.0			S			
Hot A	2	SMAW	VD	141	29	8	32	15.00		16.0			S/W			
Hot B	2	SMAW	VD	138	30	6	36	10.00		24.3			S/W			
Hot B	2	SMAW	VD	136	30	6	36	10.00		24.1			S/W			
Fill 1-1 A	3	SMAW	VD	194	22	7	50	8.40		30.4			S/W			
Fill 1-2 A	3	SMAW	VD	218	21	8.5	46	11.09		24.8			S/W			
Fill 1 A	3	SMAW	VD	208	24	13	51	15.29		19.2			S/W			

Pass Type/ Number / Welder ID	Filler #	Process	Travel Direction	Amps	Volts	Distance (in)	Arc Time (Sec)	Travel Speed (IPM)	WFS (IPM)	Heat Input (KJ/in)	Oscillation Freq cycle/sec	Oscillation Width ( )	Method Stringer or Weave	Welding Gas Type	Welding Gas Flow ( )	Interpass Temp ( )
Fill 1-1 B	3	SMAW	VD	198	20	6.5	48	8.13		28.4			S/W			
Fill 1-3 B	3	SMAW	VD	216	20	8.5	48	10.63		24.4			S/W			
Fill 2-1 A	3	SMAW	VD	199	22	8.5	48	10.63		24.1			S/W			
Fill 2-3 A	3	SMAW	VD	215	20	8	43	11.16		23.1			S/W			
Fill 2-1 B	3	SMAW	VD	205	21	8.75	55	9.55		26.4			S/W			
Fill 2-2 B	3	SMAW	VD	199	20	12	55	13.09		17.8			S/W			
Fill 3-1 A	3	SMAW	VD	197	22	8.5	51	10.00		25.4			S/W			
Fill 3-3 A	3	SMAW	VD	176	21	8	35	13.71		16.1			S/W			
Fill 3-1 B	3	SMAW	VD	196	20	7.5	49	9.18		25.6			S/W			
Fill 3 B	3	SMAW	VD	201	20	8.75	49	10.71		21.9			S/W			
Fill 4-1 A	3	SMAW	VD	195	20	8	46	10.43		22.4			S/W			
Fill 4-3 A	3	SMAW	VD	215	20	9	36	15.00		17.2			S/W			
Fill 4-1 B	3	SMAW	VD	184	21	8.5	45	11.33		20.4			S/W			
Fill 5-1 A	3	SMAW	VD	195	21	8	42	11.43		21.4			S/W			
Fill 5 A	3	SMAW	VD	212	20	9	34	15.88		16.0			S/W			
Fill 5-1 B	3	SMAW	VD	205	20	13.5	53	15.28		16.1			S/W			
Fill 5 B	3	SMAW	VD	198	20	9.5	49	11.63		20.4			S/W			
Cap 1 A	3	SMAW	VD	205	20	7	42	10.00		24.6			W			

Pass Type/ Number / Welder ID	Filler #	Process	Travel Direction	Amps	Volts	Distance (in)	Arc Time (Sec)	Travel Speed (IPM)	WFS (IPM)	Heat Input (KJ/in)	Oscillation		Method	Welding Gas		Interpass Temp
											Freq cycle/sec	Width ( )	Stringer or Weave	Type	Flow ( )	( )
Cap 1 A	3	SMAW	VD	208	20	9.5	58	9.83		24.8			W			
Cap 1 B	3	SMAW	VD	198	20	9	37	14.59		16.3			W			
Cap 1 B	3	SMAW	VD	214	20	8	33	14.55		17.6			W			
Cap 2 A	3	SMAW	VD	201	20	7.5	44	10.23		23.6			W			
Cap 2 B	3	SMAW	VD	207	20	10	46	13.04		19.0			W			
Cap 2 B	3	SMAW	VD	212	20	7	27	15.56		15.9			W			

Bodycote

Bodycote Testing Group, Houston North Laboratory, 9925 Regal Row, Houston, Texas, 77040
Tel: 281-848-0270, Fax: 281-848-0275

ACCREDITED CERTIFICATE 1283.01

CC Technologies, Inc.
5777 Frantz Road
Dublin, OH
43017-1386

REF No O802887 : Issue 1
Ord No 82681591

Date Tested 06/02/08
Date Reported 06/02/08

Attn: Brad Etheridge

Item - 24" OD x 1/2" Wall girth welded pipe sample
WPS 14

Specification - API 1104 & Client Requirement

Cross Weld Tensile - API 1104

	Dimensions [in]	Area [in^2]	UTL [lbs]	UTS [psi]	Fracture Location	Fracture Type
001:Cross Weld	0.9770x 0.5440	0.5315	61872.0	116400	Base	Ductile
002:Cross Weld	0.9720x 0.5400	0.5249	61559.0	117300	Base	Ductile
003:Cross Weld	0.9810x 0.5330	0.5229	60659.0	116000	Base	Ductile
004:Cross Weld	1.0170x 0.5400	0.5492	63462.0	115600	Base	Ductile

Item 01: Quad 1
Item 02: Quad 2
Item 03: Quad 3
Item 04: Quad 4

Charpy Test - ASTM E 23

	Position	Dimensions [mm]	Denomination	Test Temp [^oF]	Energy Absorbed [ft.lbf]	Average [ft.lbf]	Comments
005:Weld Centre Line	N/A	10x10x2V	N/A	32.0	79, 69, 70	72.7	See Below
006:Weld Centre Line	N/A	10x10x2V	N/A	-50.0	45, 39, 29	37.7	See Below
007:Weld Centre Line	N/A	10x10x2V	N/A	-80.0	15, 31, 14	20.0	See Below

Item 05: Percent Shear: 85, 80, 75 / Mils Lat Exp: 58, 53, 46
Item 06: Percent Shear: 25, 35, 10 / Mils Lat Exp: 33, 25, 21
Item 07: Percent Shear: 10, 20, 10 / Mils Lat Exp: 12, 24, 14

Bend Test - API 1104

	Position	Dimension [in]	Bend Angle [^{o}]	Former Dia	Result	Comments
008:Face Bend	Quad 1	.500	180	3.5"	Acceptable	Nil

Page 1 of 2

Bodycote

Bodycote Testing Group, Houston North Laboratory, 9925 Regal Row, Houston, Texas, 77040
Tel: 281-848-0270, Fax: 281-848-0275

ACCREDITED CERTIFICATE 1283.01

CC Technologies, Inc.
24" OD x 1/2" Wall girth welded pipe sample
WPS 14

REF No O802887 : Issue 1

Bend Test - API 1104

	Position	Dimension [in]	Bend Angle [°]	Former Dia	Result	Comments
009:Face Bend	Quad 2	.500	180	3.5"	Acceptable	Nil
010:Face Bend	Quad 3	.500	180	3.5"	Acceptable	Nil
011:Face Bend	Quad 4	.500	180	3.5"	Acceptable	Nil
012:Root Bend	Quad 1	.500	180	3.5"	Acceptable	Nil
013:Root Bend	Quad 2	.500	180	3.5"	Acceptable	Nil
014:Root Bend	Quad 3	.500	180	3.5"	Acceptable	Nil
015:Root Bend	Quad 4	.500	180	3.5"	Acceptable	Nil

Nick Break Test - API 1104

	Result	Comments
016:Weld	Unacceptable	Quad 1
017:Weld	Acceptable	Quad 2
018:Weld	Acceptable	Quad 3
019:Weld	Unacceptable	Quad 4

Approved By **Jim Blevins**

Jim Blevins
For and on authority of
Bodycote Testing Group

The failed two nick break tests were replaced by four acceptable retests of adjacent specimens. This is common practice in welding procedure qualification testing. The retest results can be found on the next page.

Bodycote MATERIALS TESTING
METAL TECHNOLOGY
Bodycote Testing Group, Houston North Laboratory, 9925 Regal Row, Houston, Texas, 77040
Tel: 281-848-0270, Fax: 281-848-0275

ACCREDITED CERTIFICATE 1283.01

Test Certificate

CC Technologies, Inc.
5777 Frantz Road
Dublin, OH
43017-1386

REF No 0803170 : Issue 1
Ord No 82681591

Date Tested 06/09/08
Date Reported 06/09/08

Attn: Brad Etheridge

Item - 24" OD x 1/2" Wall girth welded pipe sample
WPS 14

Specification - API 1104 & Client Requirement

Nick Break Test - API 1104

	Result	Comments
001:Weld	Acceptable	Quad 1
002:Weld	Acceptable	Quad 1
003:Weld	Acceptable	Quad 4
004:Weld	Acceptable	Quad 4

Certificate Comments

This is an electronic copy. See original certificate for photographs and figures where referenced.

Approved By Jim Blevins

Kevin J. Elliott
For and on authority of
Bodycote Testing Group

Page 1 of 1

Appendix H

Stress Analysis Report

Denbury Delta Pipeline Repair

7/28/2020

Denbury

MOTT MACDONALD

Document No. 20200724_MM_507102444_Pipeline Stress Analysis Report_EN_0015

PIPELINE STRESS ANALYSIS REPORT
DENBURY GULF COAST PIPELINES, LLC

DELHI PIPELINE REPAIR PROJECT

SATARTIA, MISSISSIPPI

Issue and Revision Record					
Rev	**Date**	**Originator**	**Checker**	**Approver**	**Description**
A	06/12/20	D. Dowling, PE	R. Sprague	R. Spence, PE	Draft
B	07/27/20	D. Dowling, PE	R. Sprague	R. Spence, PE	For Review
C	07/28/20	D. Dowling, PE	R. Sprague	R. Spence, PE	Final

DANON C. DOWLING
LICENSED PROFESSIONAL
ENGINEER
31029
STATE OF MISSISSIPPI

Danon Dowling
7/28/2020

TABLE OF CONTENTS

1 EXECUTIVE SUMMARY

Mott MacDonald (MM) has performed a stress analysis on the piping associated with the Delhi Pipeline incident/release on February 22, 2020. The piping was modeled using dimensions from Denbury supplied as-built records and Mott MacDonald survey data using AutoPIPE CONNECT Advanced Edition 12.02.00.14. The model was analyzed utilizing a combination of stress engineering methodologies and computational stress analysis.

Mott MacDonald performed a site-specific soil movement analysis that was used to establish soil loading on the pipeline for the stress analysis Utilizing guidance presented in the American Lifelines Alliance (guidance for the design of buried steel pipe July 2001) the Peak lateral earth pressure was calculated by utilizing Horizontal Bearing Capacity factors.

The mitigation procedure involved the identification and evaluation of critical areas against code allowable stress combinations. The results were compared using the stress ratio experienced by the component. A stress ratio greater than 1.0 represents components exhibiting stresses greater than the allowable stresses per ASME B31.4 (2016).

The following stress conditions were evaluated in the stress analysis:

- Load Cases
- Code Combinations
- Non-Code Combinations
- Thermal Analysis
- Soil Spring Analysis
- Soil Settlement Analysis
- Thermal Displacement

The geotechnical properties simulated within the models were reflective of the soil spring results presented in Section 7.2. Based on the models developed for this analysis, it is apparent that the soil movement present at the incident location was capable of exerting forces on the pipeline that exceed allowable limits. Mott MacDonald has reviewed the stress results with Denbury and developed solutions for the repair of the pipeline.

2 Project Description

On February 22, 2020 the 24" CO_2 Delhi Pipeline ruptured near a crossing of Mississippi Highway 433 approximately 1 (one) mile southeast of Satartia, MS. To help evaluate the cause of the release, Denbury contracted Mott MacDonald to gather information to support a thorough investigation. Mott MacDonald collected drone photogrammetry, terrestrial LIDAR and contracted PSI to perform a geotechnical investigation. Using this information Mott MacDonald performed a nodal evaluation using Bentley AutoPIPE CONNECT Advanced Edition Version 12.02.00.14 to determine stresses from external loading near the release of the Delhi Pipeline.

3 Scope

The stress model reflects the design of the project drawings and as-built information. The models were further analyzed using the various code and non-code guidelines listed in this section. These load combination guidelines can be generally categorized as follows:

- Hoop
- Sustained
- Occasional
- Expansion
- Combined Stress
- Unrestrained
- Support Loads

3.1 Load Combinations

Mott MacDonald analyzed the following code combinations as required by ASME B31.4. The loads are listed in Table 1 and 2 shown below. For allowable stress limits definition, see Appendix A.

Table 1 – Code Combinations

Case No.	Load Case Combinations	Category	Load Description
1	Max P	Hoop	Hoop Stress; ASME B31.4 Para. 402.3.5
2	GR + Max P	Sustained	Stress due to Sustained Loads; ASME B31.4 Para 402.6
3	Amb to T1	Expansion	Thermal stress range from restraint temp to the maximum temperature; ASME B31.4, Para. 402.5
7	Max Range	Expansion	Thermal stress range from the minimum temp to the maximum temperature (refer to all combinations); ASME B31.4, Para. 402.5
8	SUS + U1	Sustained	Stress due to Sustained Load and Soil Settlement; Sustained ASME B31.4, Para. 402.6

4 DESIGN INPUTS AND RESOURCES

The following resources and reports were utilized to provide design information and engineering inputs to various portions of the stress calculations and analysis:

Codes, Standards and Regulations - Applicable Federal, Provincial and Territorial Regulations, Codes and Bylaws – Latest Edition

1. ASME B31.4, Pipeline Transportation Systems for Liquids and Slurries
2. Federal Energy Regulatory Commission (FERC), Onshore Pipeline Regulations

External References

1. 49 CFR Part 195, Transportation of Hazardous Liquids by Pipeline
2. American Lifelines Alliance, Guidelines for the Design of Buried Steel Pipe, 2001
3. Peng, L.-C., & Peng, T.-L. (2009). Pipe Stress Engineering. New York, NY: The American Society of Mechanical Engineers.

The Project Data Sheet (Table 3) and additional variables (Table 4) defined below contain the design information and engineering inputs that were used for the stress calculations and analysis:

Table 3 – Project Data Sheet Variables			
General Project Information			
Project Name:	Delhi Pipeline Repair Project	**Project No:**	507102444
Description:	Pipeline Repair Project		
Pipeline Data			
General Location	Satartia, MS		
MOP [psig]	2160		
Maximum Operating Temperature [˚F]	Maximum: +120˚F		
Pipe Data	API 5L 24” – 0.469” W.T., X80		
	API 5L 24” – 0.540” W.T., X80		
Pipeline Data			
Minimum Operational Design Temperature [˚F]	Above grade:	32˚F	
	Below grade:	70˚F	
Design Temperature [˚F]	Minimum:	-20˚F	
	Maximum:	120˚F	
Pipe Installation Temperature [˚F]*	60˚F		

* Based on average low temperature for this region during the month of construction.

5 ANALYSIS ASSUMPTION SUMMARY

The facility stress analysis was carried out using the following assumptions.

- Minimum Installation temperature of 60˚F.
- All welds connecting assembly piping are defect free
- Pipe is homogeneous and does not contain defects.
- Strains due to welding were ignored for this analysis.
- Bolt up strains are negligible.
- Small bore attachments do not govern the design.
- Dynamic Fluid loads were ignored for this analysis.
- Pressure and viscous drag effects were ignored for this analysis.
- All dynamic loads applied internally/externally were minimal.
- All material properties were assumed to be linear and elastic.
- Soil is represented by discrete linear elastic perfectly plastic springs.
- Welded branch connections consist of an ASME B31.4 listed fitting and is constructed with adequate strength.

6 PROJECT ANALYSIS

6.1 SOILS

Soil data used for the analysis was taken from soil bore samples provided by Intertek-PSI USA. For each USCS soil type, average values were developed for the peak and remolded undrained shear strengths and typical values were used for the soil densities. This data was applied to all below grade piping by centering the soil blocks at each of the shear vane locations. American Lifelines Alliance (ALA) soil spring calculations were generated manually using the ALA formulas at a depth appropriate for the location and spacing appropriate for the pipe size. The soil spring summary is included in Table 4.

Table 4 – Soil Spring Summary			
Stiff Clay – Under Road (SCUR)			
Total Unit Weight below pipe (lb/ft^3)	**100**		
Dry Unit Weight above pipe (lb/ft^3)	**97**		
Effective Unit Weight above pipe (lb/ft^3)	**100**		
Soil Cohesion (psf)	**1000**		
Friction Angle (deg)	**0**		
Direction Specific Soil Spring Values			
	K1 (lbf/in/ft)	P1 (lbf/ft)	Yield Disp. (in)
Trans. Horizontal	5780.82	13873.96	2.4
Longitudinal	14566.52	4369.96	0.3
Trans. Vertical Up	4166.67	20000	4.8
Trans. Vertical Dn	2643.55	12689.02	4.8
Soft Clay – Embankment (SOE)			
Total Unit Weight below pipe (lb/ft^3)	**100**		
Dry Unit Weight above pipe (lb/ft^3)	**97**		
Effective Unit Weight above pipe (lb/ft^3)	**100**		
Soil Cohesion (psf)	**250**		
Friction Angle (deg)	**0**		
Direction Specific Soil Spring Values			
	K1 (lbf/in/ft)	P1 (lbf/ft)	Yield Disp. (in)
Trans. Horizontal	920.34	3313.22	3.60
Longitudinal	3941.42	1576.57	0.40
Trans. Vertical Up	833.33	4000	4.80
Trans. Vertical Dn	871.78	4184.57	4.80
Soft Clay – Landside Edge (LSE)			
Total Unit Weight below pipe (lb/ft^3)	**100**		
Dry Unit Weight above pipe (lb/ft^3)	**97**		
Effective Unit Weight above pipe (lb/ft^3)	**100**		
Soil Cohesion (psf)	**200**		
Friction Angle (deg)	**0**		
Direction Specific Soil Spring Values			
	K1 (lbf/in/ft)	P1 (lbf/ft)	Yield Disp. (in)

Trans. Horizontal	657.98	2470.98	3.76
Longitudinal	3171.19	1268.48	0.40
Trans. Vertical Up	416.67	2000.00	4.8
Trans. Vertical Dn	639.78	3070.94	4.8
Stiff Clay – Outside Landslide (OLS)			
Total Unit Weight below pipe (lb/ft^3)	**100**		
Dry Unit Weight above pipe (lb/ft^3)	**97**		
Effective Unit Weight above pipe (lb/ft^3)	**100**		
Soil Cohesion (psf)	**250**		
Friction Angle (deg)	**0**		
Direction Specific Soil Spring Values			
	K1 (lbf/in/ft)	P1 (lbf/ft)	Yield Disp. (in)
Trans. Horizontal	1072.47	3088.72	2.88
Longitudinal	3941.42	1576.57	0.40
Trans. Vertical Up	520.83	2500.00	4.80
Trans. Vertical Dn	746.79	3584.57	4.80

6.2 ENVIRONMENTAL LOADING

During the initial site visit, Mott MacDonald noticed evidence of soil movement along the ROW. The soil failure planes in the ROW extended approximately 900 ft at varying angles from 45° to 90°. Figure 1 and Figure 2 below show 3D photogrammetry scans taken of the ROW and displays the long linear failures.

FIGURE 1: SOIL MOVEMENT PLAN VIEW

FIGURE 2: SOIL MOVEMENT ROW VIEW

The depth of the soil failures varied throughout the ROW, but as shown in Figure 3, the high level of detail captured with the 3D photogrammetry allowed for accurate measurements.

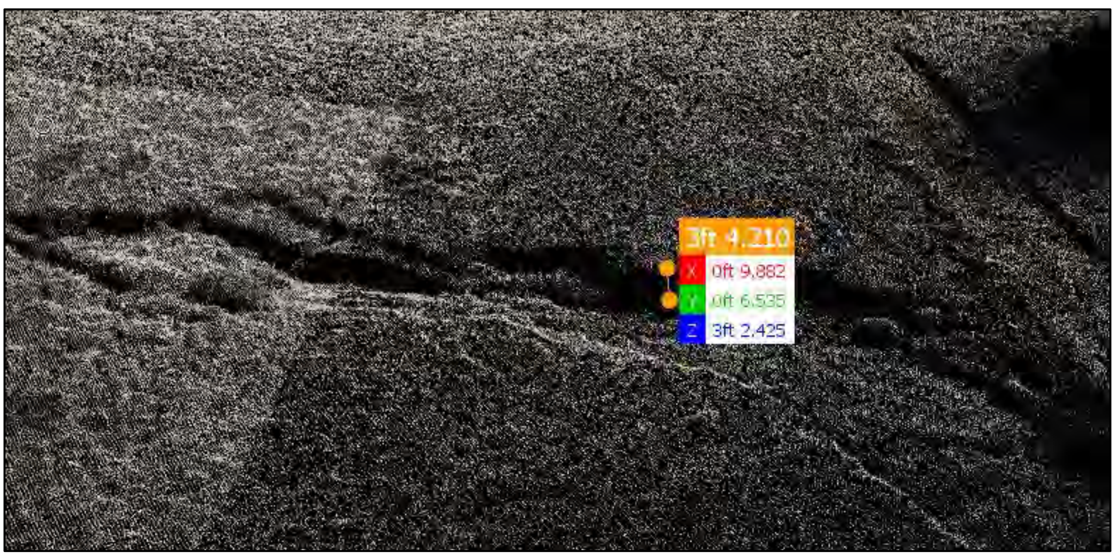


FIGURE 3: SOIL FAILURE DEPTH

To model the external force due to soil movement appropriately, Mott MacDonald's geotechnical team performed a soil movement analysis. Based upon information of the soil properties, pipeline burial depth and relative slope movement a calculation of the maximum earth pressure which could be applied to the pipe was developed. This value represents the maximum force per unit length which the soil could apply to the pipeline.

Note that this calculation method is applicable to small strain (pipe-soil localized strain) situations. Utilizing guidance presented in the American Lifelines Alliance (guidance for the design of buried steel pipe July 2001) the Peak lateral earth pressure was calculated by utilizing Horizontal Bearing Capacity factors. This calculation resulted in a value of **2,800lb/ft** (force per foot length of pipe) being the maximum force the moving soil could apply to the pipeline at small strain. For this calculation, the following assumptions were made:

- Ground surface to spring line = 5ft
- Soil cohesion = 200 psf
- Soil angle of internal friction = zero
- Applied distributed load value = the maximum force per unit length of pipe that the soil could transmit to the pipe. This force may not have fully mobilized if pipe failed before sufficient earth strain occurred to reach this maximum force.
- Calculations follow American lifeline alliance, guideline for the design of buried steel pipe 2001 (B-2).

Utilizing the as-built data in conjunction with the photogrammetry, the Mott MacDonald team was able to provide varying environmental loading conditions for the pipeline. Table 6 below presents the soil classification (from geotechnical investigations performed by PSI), applied environmental loads and general soil description.

Table 6 – Environmental Loading

Station	Soil Classification	Applied Distributed Loads	General Description
361+00 -> 349+80	[A] Stiff Clay		Stronger soils restraining movements at boundary
349+80 -> 348+50	[B] Stiff Clay		Stronger soils with deep burial from highway embankment causing strong pipe restraint
348+50 -> 347+00	[C] Soft Clay		Softer soils down from highway embankment.
347+00 -> 346+50	[D] Soft Clay	2,800 lb/ft	Moving landslide body edge
346+50 -> 340+00	[E] Soft Clay [Horiz. Strength = 0]	2,800 lb/ft	Moving landslide body middle

340+00 -> 339+00	[D] Soft Clay	2,800 lb/ft	Moving landslide body edge
339+00 -> 338+50	[C] Soft Clay		Softer materials outside landslide body
339+00 -> 325+00	[A] Stiff Clay		Stronger soils restraining movements at boundary

The distributed loads were applied in the model based on understanding of the topography in the area as shown in the Figure 4 below.

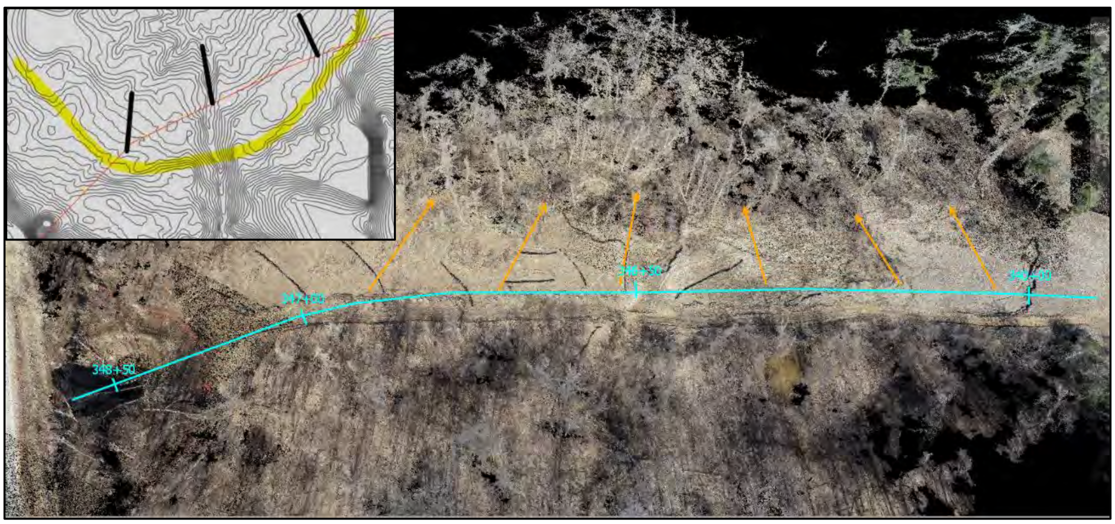


FIGURE 4: SOIL MOVEMENT DIRECTION

The external loads due to soil movement were applied per the list below.

- 347+00 -> 346+50 Azimuth 005 (5° east of north)
- 346+50 -> 340+00 Azimuth 350 (10° west of north)
- 340+00 -> 339+00 Azimuth 335 (25° west of north)

7 ANALYSIS RESULTS

7.1 PIPELINE ANALYSIS

The pipeline was modeled as per the above listed design information. Though not all of the model is shown the below Figure 5, Figure 6 and Figure 7 display the area of concern.

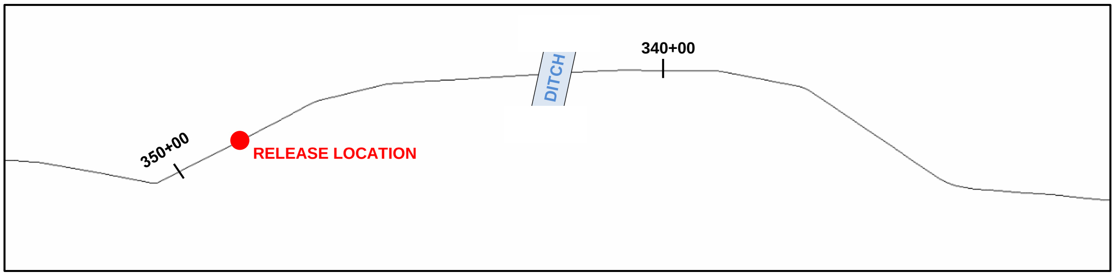


FIGURE 5: AUTOPIPE MODEL

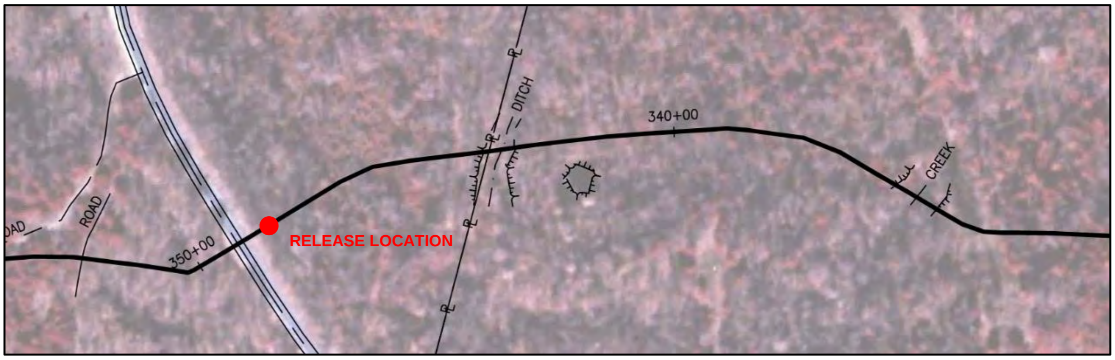


FIGURE 6: AS-BUILT ALIGNMENT SHEET

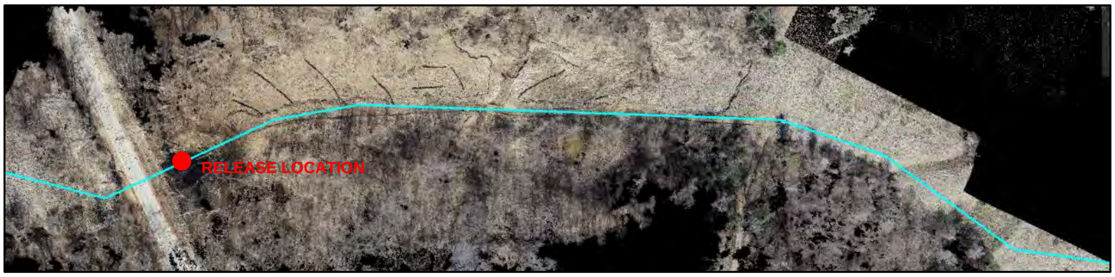


FIGURE 7: MODEL OVERVIEW

The road crossing utilized thicker pipe and was modeled as per the as-built alignment sheet, as shown in Figure 8.1.3.

- 24”-0.540 in - API 5LX-X80 - Cyan
- 24”-0.469 in - API 5LX-X80 - Red

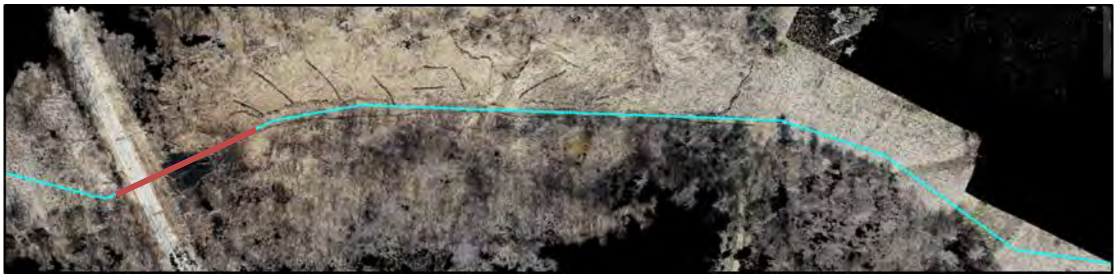


FIGURE 8: PIPE IDENTIFIER

Below shows the soil modeling based on the guidelines set forth in Section 7.1. The colors shown below denote the division in the soil as defined in Table 6.

FIGURE 9: SOIL IDENTIFIERS

The piping model was analyzed at low temperature limits defined by the project data sheet. At this location, the entire design was modelled at installation temperature, 60ºF. The effects of thermal expansion due to temperature within the pipeline as well as environmental changes are negligible.

The most significant stress values came from the external loading from soil movement. To establish a baseline, the stress team determined the maximum horizontal distributed load the pipe could withstand without rupture. Once the geotechnical team determined the estimated distributed loads, these numbers were compared. The comparison showed that the geotechnically determined loads exceeded the allowable horizontal distributed loads by more than 300 lbs/ft (2,800 lbs/ft vs. 2,475 lbs/ft).

As shown in Figure 10 below, the pipeline release location experienced excessive stress. The focal point of the stress at this location shows a maximum stress ratio of 1.43.

FIGURE 10: FAILURE LOCATION

At the release location, the pipe was calculated to have experienced load given in Table 7 below.

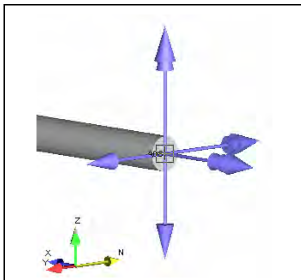
	**Table 7: Loads Experienced at Pipeline Release Location**		
	X-Direction	Y-Direction	Z-Direction
	-848,020 lbf	7,229 lbf	-46483 lbf
	-54,921 ft-lb	-706,996 ft-lb	36,274 ft-lb

Figure 11 below shows an exaggerated deflection curve of the pipeline.

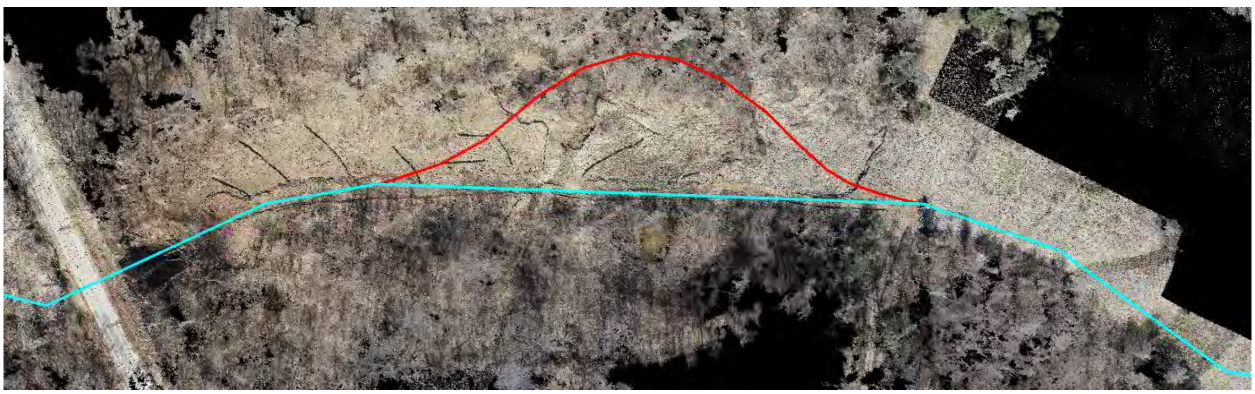


FIGURE 11: DEFLECTION CURVE

Mott MacDonald examined results as full design group to analyze the failure types and deflection curves. It was established that forces applied to the pipeline from the soil movement were significant enough to exceed the allowable stress limit of the Delhi Pipeline and likely was a contributing factor to the rupture.

8 CONCLUSION

Mott MacDonald performed a nodal analysis to analyze the Denbury Delhi Pipeline for stress concerns surrounding the rupture area. Key information (i.e. soil bores, topography, LIDAR scans) was gathered, interpreted and used in the evaluation.

The initial task performed by the stress team was to determine the maximum distributed load due to soil movement the pipeline could withstand under the given environmental conditions without exceeding the allowable stress. The results of this study found that at 2475 lb/ft certain areas began to exceed the allowable stress.

Utilizing the geotechnical investigation results and drone topography, the geotechnical team performed a soil movement analysis. The analysis concluded that the soil movement could project a load of 2800 lb/ft on the pipeline.

Under the provided 2800 lb/ft condition, the stress analysis showed the area of rupture on the Delhi Pipeline could have experienced stress ratios up to 1.43 or 43% greater than the allowable stresses under ASME B31.4 code.

The results of the analysis concluded that the soil movement found on the Delhi Pipeline Right-of-Way could induce axial stresses sufficient to cause an overload condition in the pipeline near the incident location.

9 RECOMMENDATION

Based on the results of the evaluation, Mott MacDonald recommends to stress relieve the pipeline by exposing approximately 135 feet of pipe near the opposing soil failure plane(at 339+00) then cut and replace a length of pipe.

The length of stress relieving area was determined by evaluating the over stressed model from the previous analysis. Using the deflection curve and stress ratio visuals in conjunction, the stress team identified a length of pipeline that exhibited a peak in stress values near the soil failure plane or at approximately 339+00.

On the upstream side of 339+00, the stress values decrease from 1.51 to 1.2 where they remained as it progressed upstream. These values are acceptable given these forces were due to axial stress and therefore were relieved when the pipeline failed.

The stress on the downstream side of 339+00 was caused by the restrained/unrestrained boundary condition created by the soil movement. This bending stress is the target of the relief exercise. The area shown in Figure 12 below, show a sharp rise in stress from a ratio of 0.70 to 1.51 in less than 50 ft. This boundary condition at the soil failure plane did not relieve after the pipeline failure and will have to be repaired.

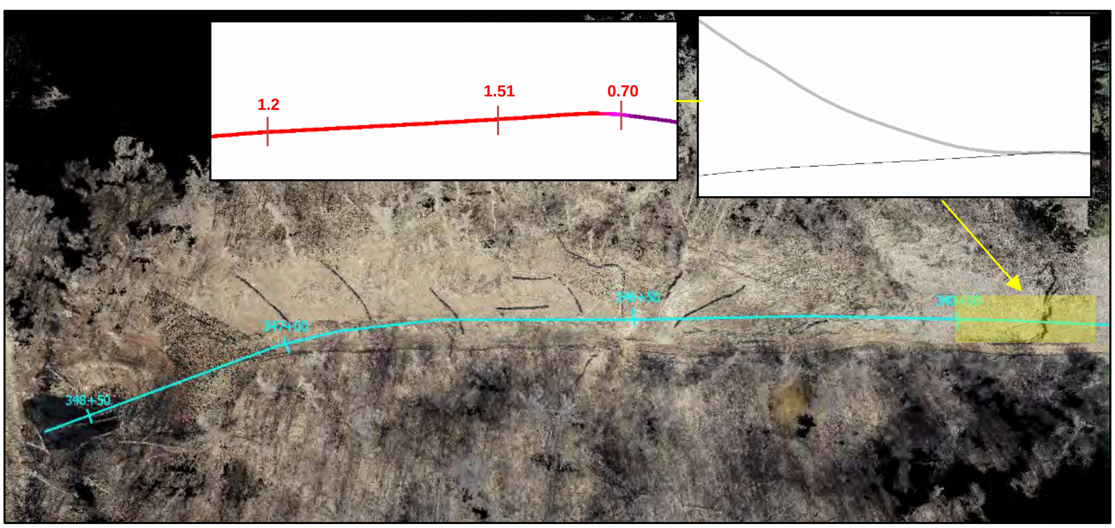


FIGURE 12: RECOMMENDED

Exposing at least 135 ft and removing and replacing as least a 10 ft section of pipe as recommended in the repair alleviates the overstressed boundary condition left by the soil movement and allows for safe transition between the two soil conditions. This recommendation is with the understanding that the remainder of the area of concern will be hydrotested as per ASME B31.4 to ensure the integrity of the pipe that experienced high tensile loads.

APPENDIX A: SUPPORTING INFORMATION

TEMPERATURE FOR SATARTIA, MS

History

September Data	Choose another month September Submit		
Averages			
Average High Temperature	31 °C	Average Morning Relative Humidity	94%
Average Low Temperature	18 °C	Average Afternoon Relative Humidity	55%
Average Mean Temp	24 °C	Typical Sky Cover	CLR
Average Dew Point	19 °C	Average Precipitation (US Only)	91 mm
Average Windspeed	13 km/h	Average Snowfall (US Only)	0.00 cm
Average Wind Direction	SE		
Daily Counts			
Days With Precipitation	8	Days With Snow	0
Days With Thunderstorms	5	Days With Lows Below Freezing	0
Days With Fog	20	Days above 90° F (32.2° C)	12
Records			
Record High	40 °C	Record 24-hour Snowfall	0.00 cm
Record Low	2 °C	Record Monthly Rainfall	244 mm
Record Wind Speed	83 km/h	Record 24-hour Rainfall	117 mm
Record Monthly Snowfall	0.00 cm	Record Minimum Monthly Precipitation	15 mm

http://myforecast.co/bin/climate.m?city=21275&zip_code=39162&metric=true

ALLOWABLE STRESS LIMITS

HOOP STRESS

Hoop Stress (ASME B31.4 - 2016)

The hoop stress (shoop) is calculated per A402.3.5

$$S_h = (P_i - P_e) \cdot \frac{D}{2t} \leq F_1 ST \quad (1)$$

$$\left[S_h = (P_i - P_e) \cdot \frac{D}{2000t}\right] \leq F_1 ST \quad (2)$$

$$S_h = (P_i - P_e) \cdot \frac{D-t}{2t} \leq F_1 ST \quad (3)$$

$$\left[S_h = (P_i - P_e) \cdot \frac{D-t}{2000t}\right] \leq F_1 ST \quad (4)$$

Where,

D is the nominal outside diameter of pipe, in. (mm)

F1 is the hoop stress design factor from Table A402.3.5-1

Pe is the external pressure, psi (kPa)

Pi is the internal pressure, psi (kPa)

S is the yield strength, psi (MPa)

Sh is the hoop stress, psi (MPa)

T is the temperature derating factor, found in the Results Model Options dialog

t is the nominal wall thickness, in. (mm)

Notes:
1. Equation 1 should be used if D/t is greater than or equal to 30. Equation 3 should be used if D/t is less than 30.
2. Equations 2 and 4 are the SI equivalents of equations 1 and 3, respectively.
3. In AutoPIPE, pressure data is gage pressure. In other words, $P_{AutoPIPE} = P_i - P_e$

SUSTAINED LOADS

Restrained

Calculations for restrained piping take into account flexibility and stress intensification factors of piping components. Longitudinal stress in restrained piping is calculated as:

$$S_L = S_E + vS_H \pm \frac{M}{Z} + \frac{F_a}{A}$$

Where sE is the restrained **thermal expansion stress**, sH is the **hoop stress** and A is the cross sectional area of steel.

When the "Use rest. long. code eq" option is not taken into account, AutoPIPE considers the actual restraint condition from supports and soil stiffness for longitudinal stress calculation.

$$S_L = MAX(\sigma_a + \sigma_b; \sigma_a - \sigma_b)$$

Where

$$\sigma_a = \frac{P_i D}{4t} - \frac{F_a}{A}$$

$$\sigma_b = \frac{\sqrt{M_i^2 + M_o^2}}{Z}$$

AutoPIPE reports sL and the allowable stress (0.90 Sy), where Sy is the specified minimum yield strength. If more than one operating load condition exists there may be more than one P value. Results are output for the operating load condition which produces the smallest margin (i.e., smallest value of 0.90· Sy, sL) at each point.

Note: AutoPIPE does not use the exact code equation for the longitudinal pressure stress. The code requires the use of vSH, whereas AutoPIPE uses PD/4t, which is approximately equal to 0.5SH.

THERMAL EXPANSION

Thermal Expansion Stress Range (ASME B31.4 - 2016)

Unrestrained

The stress due to defined thermal expansion ranges (s_E) is calculated per the equation listed in para. 419.6.4(c) of the code, and as shown in Equation I.5-5:

$$s_E = \sqrt{s_b^2 + 4 \cdot s_t^2} \quad \text{(I.5 5)}$$

where:

$$s_b = \frac{\sqrt{(i_i \cdot M_{it})^2 + (i_o \cdot M_{ot})^2}}{Z_{cor}} \quad \text{(I.5 6)}$$

and:

$$s_t = \frac{M_{tt}}{2 \cdot Z_{cor}} \quad \text{(I.5 7)}$$

AutoPIPE reports s_E, and the allowable stress (S_A).

Restrained

The thermal expansion stress in restrained pipe is calculated as shown in Equation I.5-8:

$$S_E = E\alpha(T_1 - T_2) \quad \text{(I.5 8)}$$

Where E is the cold modulus of elasticity, a is coefficient of thermal expansion, in./in./F (mm/mm/C), T1 is the temperature of the pipe at installation or completion of final tie-in, F(C), and T2 is the operating temperature, F(C).

AutoPIPE reports sE and the allowable stress (0.90 Sy), where Sy is the specified minimum yield strength of the pipe material, in psi (MPa).

Appendix E CTEH Air Monitoring Summary Report

THE SCIENCE OF READY℠

Denbury Resources

Air Monitoring Report

Satartia, Mississippi

Carbon Dioxide Pipeline Release

February 22-23, 2020

Project #112628

Report Submitted on June 05, 2020

1.0 INTRODUCTION

On February 22, 2020, CTEH®, LLC (CTEH) responded to a request from Denbury Resources (Denbury) to provide toxicology and air monitoring support following a carbon dioxide (CO_2) pipeline release near the town of Satartia, Mississippi. The village of Satartia was evacuated at approximately 2100 Central Standard Time (CST)[1] by local emergency management personnel and first responders. At 2230 on February 22, a CTEH consultant arrived onsite with air monitoring instrumentation and began monitoring areas in and around the village of Satartia for the presence of CO_2. As the potential for residual hydrogen sulfide (H_2S) resided in the line and complaints of an odor were received, monitoring was also conducted for the presence of H_2S. Additional CTEH personnel arrived and conducted air monitoring throughout the community. Once CO_2 levels returned to near ambient within the community, CTEH personnel conducted clearance monitoring within eighteen homes and three churches and their associated buildings. Denbury demobilized CTEH once ambient CO_2 concentrations within those structures were sustained below 5,000 parts per million (ppm) and residents had returned to their homes. This report summarizes data collected from February 22 through February 23.

2.0 METHODS

2.1 Handheld Real-Time Air Monitoring

Prior to CTEH's arrival, an air Sampling and Analysis Plan (SAP, Attachment A) was developed for worker monitoring, community monitoring, and site characterization. Based on site characteristics and associated scope of work, no worker monitoring or site characterization readings were recorded. In accordance with the SAP, CO_2, H_2S, and oxygen (O_2) concentrations were monitored using handheld real-time instrumentation throughout the community as well as within homes of residents who requested monitoring prior to re-occupancy. Monitoring was performed using RAE Systems by Honeywell MultiRAE Pro instruments. All instrumentation was calibrated prior to use.

Community monitoring was delineated into two subcategories: community real-time monitoring and indoor assessment real-time monitoring. Community real-time monitoring consisted of roaming handheld monitoring performed outdoors and downhill from the incident site, including checkpoints and church parking lots. Indoor assessments consisted of real-time monitoring within residences and church buildings potentially affected by the incident at the request of community members. If the initial indoor assessment resulted in CO_2 levels above the CTEH project-specific action level, another indoor assessment was performed after allowing the building to air out. For example, if real-time monitoring during the initial indoor assessment detected CO_2 levels above the CTEH project-specific action level, the windows and doors were opened and the occupant was advised not to re-enter until CO_2 concentrations returned to ambient levels, as determined by another indoor assessment. The ambient levels CO_2 in the non-industrial

[1] All other times referenced in the report will be CST unless otherwise delineated.

indoor environments may have a variety of sources, including human metabolism, and CO_2 levels can vary based on the number of people present, how long the area has been occupied, and the amount of outdoor fresh air entering the area.

2.2 Protective Action Criteria and CTEH Project-Specific Action Levels

The U.S. Department of Energy's Subcommittee on Consequence Assessment and Protective Actions (SCAPA) has established Protective Action Criteria (PACs) for over 3,300 chemicals for planning and response to uncontrolled releases of hazardous chemicals (DOE/SCAPA 2018). These criteria, combined with estimates of actual exposure, provide information necessary to evaluate chemical release events for the purpose of taking appropriate protective actions. During an emergency response, these criteria may be used to evaluate the severity of the event and to inform decisions regarding what protective actions may be taken. The PAC values for the chemicals of concern for this response are provided in Attachment B. The PAC-1, -2, and -3 for CO_2 are 30000, 40000, and 50000 ppm, respectively. For comparison, the American Conference of Governmental Industrial Hygienists (ACGIH) threshold limit values (TLVs) are also included in Attachment B. Although the TLVs are intended for occupational daily work shift exposures over an entire working lifetime, the literature regarding reviewed human studies involving CO_2 within the TLV documentation were referred to and will be discussed in Section 4.0. The current ACGIH TLV-Time Weighted Average (TLV-TWA) for CO_2 (5,000 ppm) is based on the lack of inhalation toxicity data in humans at this level and the ACGIH TLV-Short Term Exposure Limit (STEL) for CO_2 is 30,000 ppm. The TLV documentation cites data indicating elevated concentrations (above 50,000 ppm) of CO_2 can produce '*mild narcotic effects, stimulation of the respiratory center, and asphyxiation*', depending on exposure duration and conditions (ACGIH 2001). CTEH project-specific action levels for both monitoring plans were set at 5,000 ppm (sustained for 15 minutes) for CO_2 based on the ACGIH TLV-TWA (well below PAC-1 and ACGIH TLV-STEL), and the action level for H_2S was set at 1 ppm, which was also based on the ACGIH TLV-TWA.

In accordance with the SAP, CTEH project-specific action levels were used to provide information for assessing need to take corrective action to limit the potential of exposure. These values do not replace community exposure standards or guidelines but are intended to be a concentration limit that triggers a course of action to better address public safety.

3.0 RESULTS

Handheld real-time air monitoring results are summarized by subcategory in Tables 1 and 2: community real-time air monitoring and indoor assessment real-time air monitoring. Maps of the site location, community real-time monitoring locations, and indoor assessment real-time air monitoring locations are provided in Attachment C.

Table 1 Community Real-Time Air Monitoring Results

Analyte	Instrument	Number of Readings	Number of Detections	Concentration Range[1]
CO_2	MultiRAE Pro	108	108	100 – 26,000 ppm
H_2S	MultiRAE Pro	85	0	< 0.1 ppm
O_2	MultiRAE Pro	84	84	20.9 - 21.1 %

[1]A value preceded by the "<" symbol is considered below the instruments limit of detection and the value to the right is the instrument detection limit. ppm = parts per million.

Table 2 Indoor Assessment Real-Time Air Monitoring Results

Analyte	Instrument	Number of Readings	Number of Detections	Concentration Range[1]
CO_2	MultiRAE Pro	30	30	200 – 28,000 ppm
H_2S	MultiRAE Pro	18	0	< 0.1 ppm
O_2	MultiRAE Pro	8	8	20.9 %

[1]A value preceded by the "<" symbol is considered below the instruments limit of detection and the value to the right is the instrument detection limit. ppm = parts per million.

4.0 DISCUSSION

CTEH performed real-time air monitoring using handheld real-time instrumentation. Results of handheld real-time air monitoring are discussed below.

No H_2S detections were observed during handheld real-time air monitoring in the community or indoor assessment real-time monitoring. O_2 concentrations were not observed below 20.9%. Outdoor CO_2 concentrations ranged from 100 through 26,000 ppm in the community. Five detections of CO_2 exceeded 5,000 ppm. Residents of the community were already evacuated when these detections were observed.

After outdoor community CO_2 levels were sustained continually measured below 5,000 ppm, initial indoor assessment real-time monitoring was performed inside residences and church buildings potentially impacted by the incident, at owners'/occupants' request. During initial indoor assessment real-time monitoring, CO_2 concentrations ranged from 200 through 28,000 ppm, with six detections exceeding 5,000 ppm. In these instances, occupants of these structures were advised to open doors and windows and not to occupy those structures prior to re-assessment.

Indoor assessment real-time monitoring was performed for six structures to further assess homes and church buildings in which CO_2 concentrations above 5,000 ppm were observed during initial indoor assessment real-time monitoring. No readings of CO_2 greater than 3,500 ppm were recorded following any of these re-assessments.

While CTEH personnel were onsite, values of CO_2 were recorded up to 28,000 ppm. A notice issued by the Satartia Fire Department advising residents and members of the general public to evacuate the area was active during the period in which elevated CO_2 concentrations were observed. The ACGIH TLV documentation reports several effects resulting from inhalation of elevated CO_2 concentrations, including mild narcotic effects (30,000 ppm) and unconsciousness (> 50,000 ppm). Additional reports of human exposure to CO_2 indicate 20,000 ppm for several hours may cause transient effects, such as headaches, and exposure to up to 5,500 ppm for six hours may cause *no noticeable symptoms* (ACGIH 2001). To the best of CTEH's knowledge, including several interactions with community members during this response, there were no reports of hospitalization due to loss of consciousness within the community.

In conclusion, during the time period CTEH was present, the CO_2 concentrations observed were below the ACGIH TWA-STEL and PAC values and thus were not detected at levels that would be expected to cause anything other than transient effects, if any, or pose a chronic health risk to members of the community.

5.0 REFERENCES

ACGIH (2001) Carbon dioxide: TLV® Chemical Substances 7th Edition Documentation. Cincinnati, Ohio: American Conference of Governmental Industrial Hygienists.

ACGIH (2019) Guide to Occupational Exposure Values. Cincinnati, Ohio: American Conference of Governmental Industrial Hygienists.

DOE/SCAPA (2018) Protective Action Criteria (PAC): Chemicals with AEGLs, ERPGs, & TEELS: Rev. 29A. Washington, DC: U. S. Department of Energy. Available at:https://www.energy.gov/ehss/protective-action-criteria-pac-aegls-erpgs-teels-rev-29-chemicals-concern-may-2016.

Attachment A

Sampling and Analysis Plan

THE SCIENCE OF READY™

Carbon Dioxide Pipeline Release

Satartia, MS

Air Sampling and Analysis Plan (SAP)

Version 1.0

Prepared on Behalf of:

Denbury Resources

Prepared By:

CTEH, LLC

5120 Northshore Drive

Little Rock, AR 72118

501-801-8500

February 22, 2020

	Name/Organization	Signature	Date Signed
Prepared by:	Pamella Tijerina, Ph.D.	PBT	02-22-2020
Reviewed by:	Eric Allaby		02-22-2020
Approved by:			
Approved by:			

Air Monitoring Strategy

CTEH® is focusing on the chemicals below chosen below because they are among the most important and readily monitored hazards of a carbon dioxide (CO_2) release. It is notable, however, that some chemicals may also be included within the SAP on the basis that some uncertainty exists during incidents and monitoring for these chemicals is necessary to ensure that a hazard does not exist. Monitoring for some chemicals or indicators of the presence of CO_2 may be conducted less frequently or even discontinued as product-specific information becomes available or as initial air monitoring results indicate that these chemicals and indicators do not pose a health concern.

The strategy is to utilize three broadly defined monitoring plans: **1)** Work Area Monitoring; **2)** Community Monitoring; and **3)** Site Assessment. Work Area monitoring will generally take place in those areas where workers are actively performing/supporting remediation operations. The readings will generally be taken at a height consistent with that of the workers breathing zone and in close proximity to workers without interfering or obstructing their remediation tasks. Community Monitoring may take place in those residential and/or commercial locations immediately surrounding the incident site, not necessarily currently occupied by members of the community. Unlike Work Area and Community monitoring, Site Assessment does not necessarily represent ambient air monitoring near breathing zone level. Site Assessment may involve a variety of different monitoring tasks intended to provide information that may help to delineate the nature and extent of the release (e.g. fence line monitoring, worst case determination, container head space, ground level, etc.).

Free-roaming handheld real-time air monitoring may be conducted in a variety of areas based on levels of activity, proximity to the release, and site conditions. Fixed-location handheld real-time locations may be established in the Community in order to provide concentration averages that may be observed and analyzed over time in distinct geographic locations in the community. AreaRAEs may be utilized to monitor the scene from remote location, if necessary.

CTEH® has the capabilities on site to collect ambient air samples, if necessary. These sampling methodologies may be utilized if the results from real-time air monitoring efforts indicate the potential for exposure above acceptable occupational or community exposure levels. CTEH® will discuss these methodologies with Denbury staff prior to implementation.

CTEH Site-Specific Action Levels

CTEH® site-specific action levels may be employed in all air monitoring plans to provide information for corrective action to limit potential exposures. These values do not replace occupational or community exposure standards or guidelines, but are intended to represent a concentration limit that triggers a course of action to better address worker and public safety. Action level exceedances will be communicated to Site Management and the CTEH Project Technical Director by the CTEH Project Manager (PM). Work practice may be assessed and then altered if necessary. Site-Specific Action Levels are not utilized for Site Assessment monitoring.

Plan 1: Work Area Monitoring

Objective: Report air levels before they reach those requiring respiratory protection

Analyte	Action Level	Action to be Taken	Basis	Instrument	Detection Limit	Notes	Correction Factor
CO_2	5,000 ppm 15 min.	Egress & Notify PM	OSHA PEL & ACGIH TLV	MultiRAE Sensor	100 ppm	Measuring Range: 0 – 50,000 ppm	N/A
	30,000 ppm* 1 min.	Egress & Notify PM	ACGIH STEL				
O_2	< 20.3 %	Egress and Notify PM	ACGIH STEL for CO_2	MultiRAE Sensor	0.1 %	Range: 0 – 30 %	N/A
Hydrogen Sulfide	1 ppm	Egress and Notify PM	ACGIH TLV-TWA; Precautionary Monitoring to Rule Out	MultiRAE Sensor	0.1 ppm	Range: 0 – 100 ppm	N/A

* Note small margin between STEL and NIOSH IDLH (40,000 ppm)

Plan 2: Community Assessment

Objective: Report air levels before they reach those causing nuisance or health issues

Analyte	Action Level	Action to be Taken	Basis	Instrument	Detection Limit	Notes	Correction Factor
CO_2	5,000 PPM* 15 min.	Notify PM	Warning prior to reaching PAC-1	MultiRAE Sensor	100 ppm	Measuring Range: 0 – 50,000 ppm	N/A
O_2	< 20.3 %	Notify PM	Precautionary	MultiRAE Sensor	0.1 %	Range: 0 – 30 %	N/A
Hydrogen Sulfide	Detection	Notify PM	Precautionary	MultiRAE Sensor	0.1 ppm	Range: 0 – 100 ppm	N/A

* Note: PAC-1 is 30,000 ppm, PAC-2 is 40,000 ppm, PAC-3 is 50,000 ppm

Plan 3: Site Assessment							
Objective: Characterize nature and extent of release							
Analyte	Action Level	Action to be Taken	Basis	Instrument	Detection Limit	Notes	Correction Factor
CO_2	NA	Report reading to PM	NA	MultiRAE PID	0.1 ppm	Measuring range: 1 – 5,000 ppm	NA

All Plans (1-3): Flammability								
Analyte	Action Level	Corrected Value/ Instrument Reading	Action to be Taken	Basis	Instrument	Detection Limit	Notes	Correction Factor
LEL	CO_2 is non-flammable; Notify PM & PTD if LEL detected.							

General Information on Procedures (Assessment Techniques) Used

Procedure	Description
Real-Time Handheld Survey	CTEH staff members may utilize handheld instruments (e.g. MultiRAE Plus; ppbRAE, Gastec colorimetric detector tubes, etc.) to measure airborne chemical concentrations. CTEH will use these handheld instruments primarily to monitor the ambient air quality at breathing zone level. Additionally, measurements may be made at grade level, as well as in elevated workspaces, as indicated by chemical properties or site conditions. CTEH may also use these techniques to verify detections observed by the AreaRAE network.
Radio-Telemetering Network	CTEH may deploy a radio-telemetering network of AreaRAEs in locations where monitoring from a remote location would be beneficial. These instruments will relay readings back to a centralization location that is monitored by CTEH.
Fixed Real-Time Monitoring locations	Multiple Community locations may be identified and monitored at the same location approximately once per hour using handheld instruments. This allows the use of statistical analysis more effectively than with a random approach.

Quality Assurance/Quality Control Procedures

Method	Procedure
Real-Time	Real-time instruments may be calibrated in excess of the manufacturer’s recommendations.

Method	Procedure
	At a minimum whenever indicated by site conditions or instrument readings. Co-located sampling for analytical analysis may be conducted, if necessary, to assess accuracy and precision in the field. Lot numbers and expiration dates may be recorded with use of Gastec colorimetric tubes.
Reporting	Daily data summaries may be provided for informational purposes using data that have not undergone complete QA/QC. Comprehensive reports of real-time and/or analytical data may be generated following QA/QC and may be delivered 60 days following receipt of validated results, if applicable.

Glossary

Term	Definition
Sustained	Instrument reading above the action level continuously for the listed time period.
Breathing zone	The area within an approximate 10-inch radius of an individual's nose and mouth.
Ambient Air	That portion of the atmosphere (indoor or outdoor) to which workers and the general public have access.

Attachment B

SCAPA PACs and ACGIH TLVs

No.	Chemical Name	CASRN	PACs based on AEGLs, ERPGs, or TEELs			Units
			PAC-1	PAC-2	PAC-3	
570	Carbon dioxide	124-38-9	30,000	40,000	50,000	ppm
1426	Hydrogen sulfide	7783-06-4	0.51	27	50	ppm

Chemical Name	CASRN	ACGIH TLVs		Units
		TWA	STEL	
Carbon dioxide	124-38-9	5,000	30,000	ppm
Hydrogen sulfide	7783-06-4	1.0	5.0	ppm

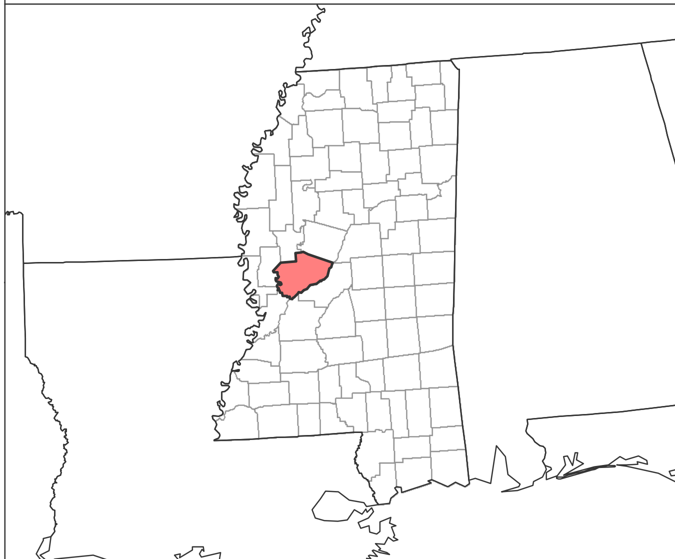
Attachment C

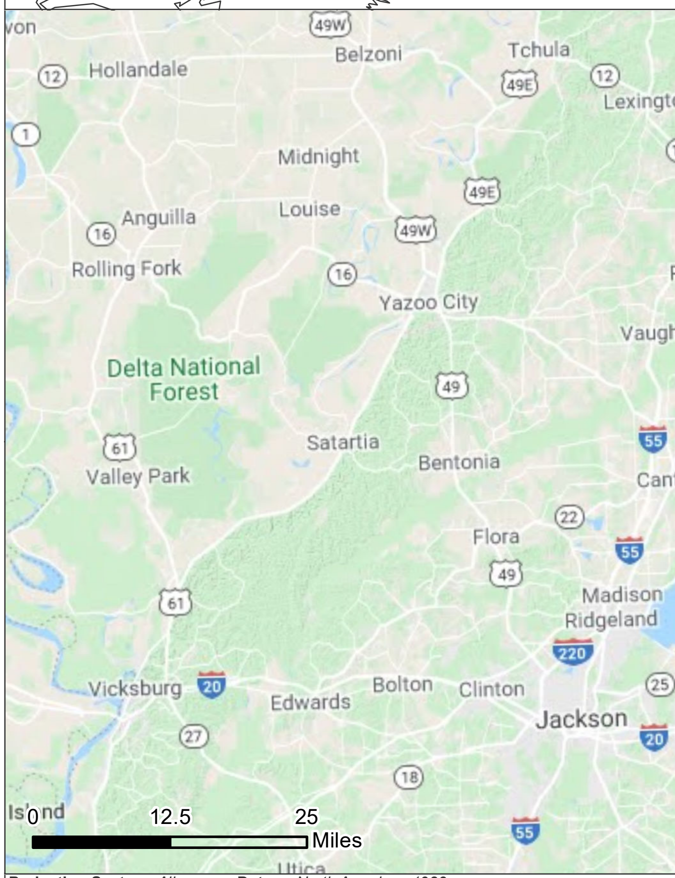
Site Maps

Site Location

CO_2 Pipeline Release

Project: 112628
Client: Denbury
City: Satartia, MS
County: Yazoo





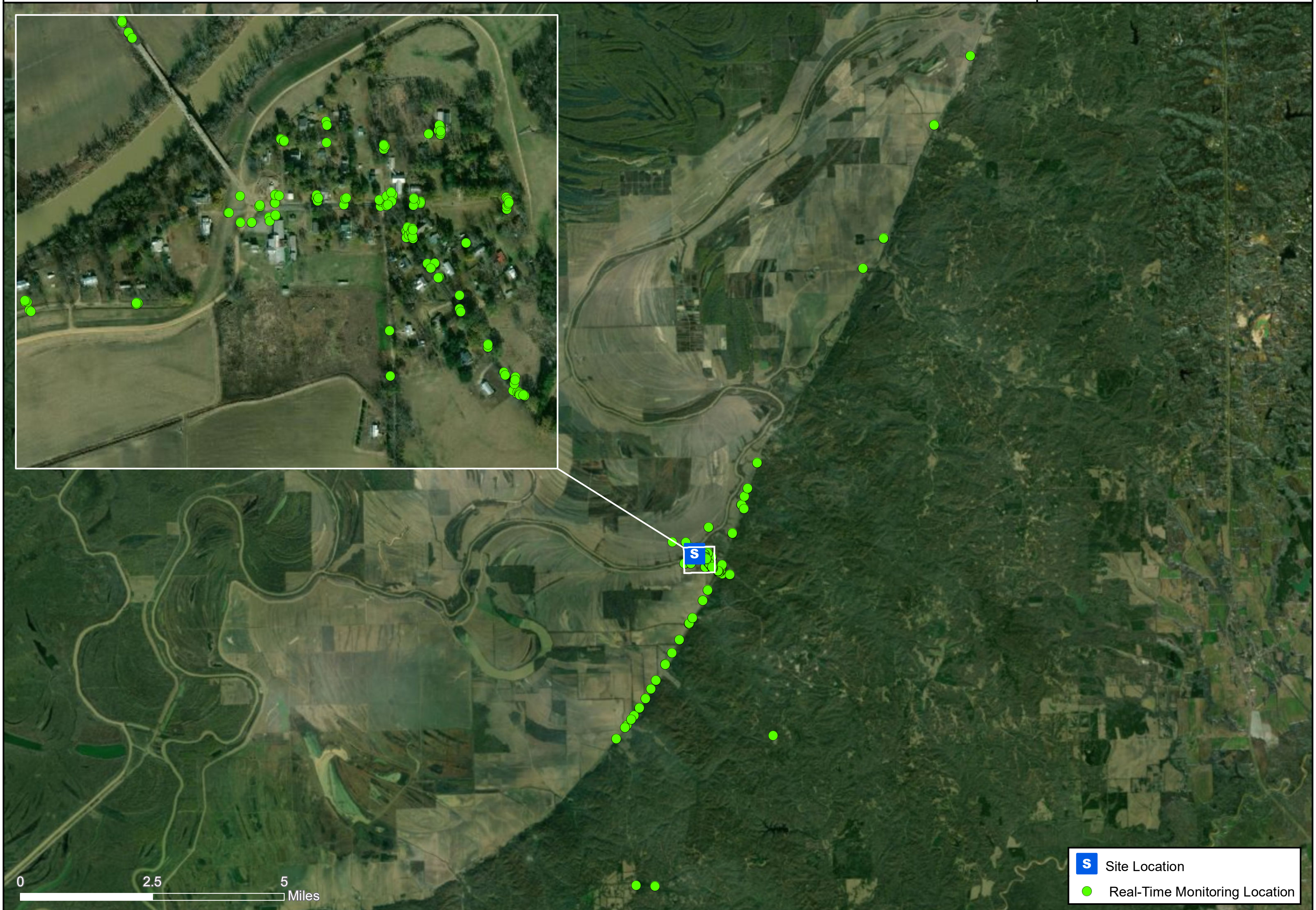
Projection System: *Albers* **Datum:** *North American 1983* *Document Name: 112628_site_location* **Last Updated:** *3/19/2020 1:44:18 PM*

CTEH

Community Real-Time Air Monitoring Locations

CO_2 Pipeline Release l Satartia, MS | 2/22/2020 2230 - 2/23/2020 1134 CST

Project:112628
Client: Denbury
City: Satartia, MS
County: Yazoo



COORDINATE SYSTEM: *NAD 1983 UTM Zone 15N* **DATUM:** *North American 1983* **LAST UPDATED:** *4/24/2020 12:20:55 PM*

Indoor Assessment Real-Time Monitoring Locations

CO_2 Pipeline Release l Satartia, MS | 2/23/2020 0636 - 2/23/2020 1805 CST

Project:112628
Client: Denbury
City: Satartia, MS
County: Yazoo

COORDINATE SYSTEM: *NAD 1983 UTM Zone 15N* **DATUM:** *North American 1983* **LAST UPDATED:** *4/24/2020 12:10:31 PM*