Failure Investigation Report

TC Oil Pipeline Operations Inc.

Rupture – Circumferential Girth Weld Failure

Executive Summary

On December 7, 2022, at 9:01 p.m. Central Standard Time (CST)[1], TC Oil Operations (TC) 36-inch diameter Keystone Cushing Extension ruptured in Washington County, Kansas. An estimated 12,937 barrels of crude oil were released, with most of the crude oil flowing down the creek bank and into Mill Creek. The TC Liquids Pipeline Control Center (LPCC) received a leak detection alarm (volume imbalance), then an emergency-line trip alarm, at 9:01 p.m. At 9:07 p.m., the LPCC Controller initiated an emergency shutdown of the Keystone Pipeline system. The pipeline was shut down and fully isolated by 9:20 p.m. Technicians were dispatched to various areas between the Steele City Pump Station in southern Nebraska and 30 miles downstream into Kansas to identify the release location, which was completed by TC technicians on December 8, 2022, at 12:15 a.m.

The Pipeline and Hazardous Materials Safety Administration (PHMSA) has determined the rupture originated in the downstream girth weld on a replacement fabricated assembly between an elbow and a welded pup[2], which was installed in 2010. The cause of the failure was external loading downstream of the girth weld which caused excessive bending stress. Stresses concentrated on the girth weld, which also included a wall thickness transition, with cracks initiating at shallow lack of fusion (LOF) defects in the root bead. The cracks grew through cyclic fatigue due to normal pipeline operations. Under 49 C.F.R. § 195.106, the segment of pipeline where the failure occurred is generally limited to operations at not more than 72% specified minimum yield strength (SMYS) of the pipe. PHMSA notes TC does have a PHMSA Special Permit (SP), initially issued under § 190.341 on April 30, 2007, allowing for operations at up to 80% SMYS on the segment of pipeline where the failure occurred.[3] However, PHMSA's investigation determined that due to the configuration of the pipeline, the pipeline segment has not exceeded 72% SMYS, despite having the allowance for operating at up to 80% SMYS under the SP. Therefore, operations above 72% SMYS were not associated with this failure.

Following post-construction hydrostatic testing of the Cushing Extension in 2010, TC visually identified a manufactured fitting that had exhibited coating damage as a result of the hydrostatic test. Further investigation in 2010 determined that fittings expanded during the hydrostatic test as they did not meet minimum yield strength specifications and required replacement. The area associated with the Mill Creek crossing included three fittings that were included in the warranty replacement program (WRP) in 2010.

In the area of the December 7, 2022, failure, the pipeline flows from north to south. During PHMSA's on site investigation, a bulge[4] on the bottom of the pipe located upstream (north side) of the elbow was identified. The downstream portion of the pipeline, approximately 30-feet south of the ruptured girth weld, was observed to have raised up 6 to 8 inches from its original position while it was being excavated after the rupture. The observed ovality, the bulge, and the pipe rising indicate excessive stress was present on the pipeline as a result of external loading. This stress has been determined sufficient to initiate cracking of the failed girth weld. PHMSA attributes the primary source of external loading, and therefore bending stress, was due to inadequate soil compaction during the backfill process following the fitting replacement in 2010.

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

[2] A pup is typically a short section of pipe, usually 3-5 feet in length, that is welded to a fitting prior to installation.

[3] The U.S. Department of Transportation. (November 17, 2006). Special Permit. (Docket Number: PHMSA-2006-26617). Retrieved from: https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/TC_Keystone_2007-04-30_508compliant.pdf.

[4] See **Figure 5** and discussion below.

As a result of the failure, PHMSA issued TC a Corrective Action Order (CAO)[5], CPF No. 3-2022-074-CAO[6] on December 8, 2022. PHMSA later issued an amended CAO[7] on March 7, 2023. The CAO and amended CAO required TC to take action to ensure the safety of the pipeline and prevent a similar failure from recurring. This included the identification and mitigation of other locations that may have similar attributes to the failure site in Washington, Kansas (*e.g.*, bulges or wrinkles, internal diameter restrictions, ovalities in pipe / elbows, operating stress level, and bending stress due to settlement or inadequate compaction). TC's completed remedial actions included: a review of the WRP, evaluation of in-line inspection (ILI) results for deformations, the analysis of bending strains indicated by ILI results, an evaluation of operating stress levels at elbow assemblies, determination of the girth weld transition ratio joining elbows and pipe, and a review of operational cycling from pressure and temperature changes. PHMSA's Office of Pipeline Safety has overseen TC's execution of the elements of the CAO, including by conducting onsite inspections and observations of the actions required by the CAO and amended CAO.

1. Operator, Location, Consequences

Lead Investigator	Darren Lemmerman
Accident Investigation Director	Chris Ruhl
Date of Report	October 25, 2024
Date of Failure	December 7, 2022
Commodity Released	Crude Oil
City, County, and State	Washington, Washington, Kansas
OpID and Operator Name	32334 – TC Oil Pipeline Operations Inc.
Unit # & Unit Name	72679 – Kansas Cushing Extension
WMS Activity #	22-261792
Milepost / Location	MP 14 / 39.842201, -96.995547
Type of Failure	Rupture – Circumferential Girth Weld Failure
Fatalities	None
Injuries	None
Description of Impacted Area	Mill Creek
Total Costs	$600,793,659

[5] PHMSA, via delegation from the Secretary of Transportation, issues CAOs under the authority of 49 U.S.C. § 60112 and 49 C.F.R. § 190.233. CAOs address the operation of a pipeline facility that is, or would be, hazardous to life, property, or the environment. See § 190.233(a).

[6] The U.S. Department of Transportation. (December 8, 2022). Corrective Action Order (Docket Number: PHMSA: 3-2022-074-CAO).

[7] The U.S. Department of Transportation. (December 8, 2022, amended March 7, 2023). Corrective Action Order (Docket Number: PHMSA: 3-2022-074-CAO)

2. System Description

The Keystone Pipeline originates in Hardisty, Alberta, Canada and transports crude oil to terminals in Patoka, Illinois and Cushing, Oklahoma (**Figure 1**). The U.S. portion of the pipeline is approximately 1,855 miles long and has 23 pump stations along the route through North Dakota, South Dakota, Nebraska, Kansas, Missouri, Illinois, Oklahoma and Texas. The accident occurred at Milepost (MP) 14 within the Cushing Extension, which is a 298-mile section that runs from Steele City, Nebraska to Cushing, Oklahoma. This section was constructed in 2010 and placed into service on February 8, 2011. The pipeline is 36-inch diameter at the failure location, with a maximum operating pressure (MOP) of 1,440 pounds per square inch gauge (psig).

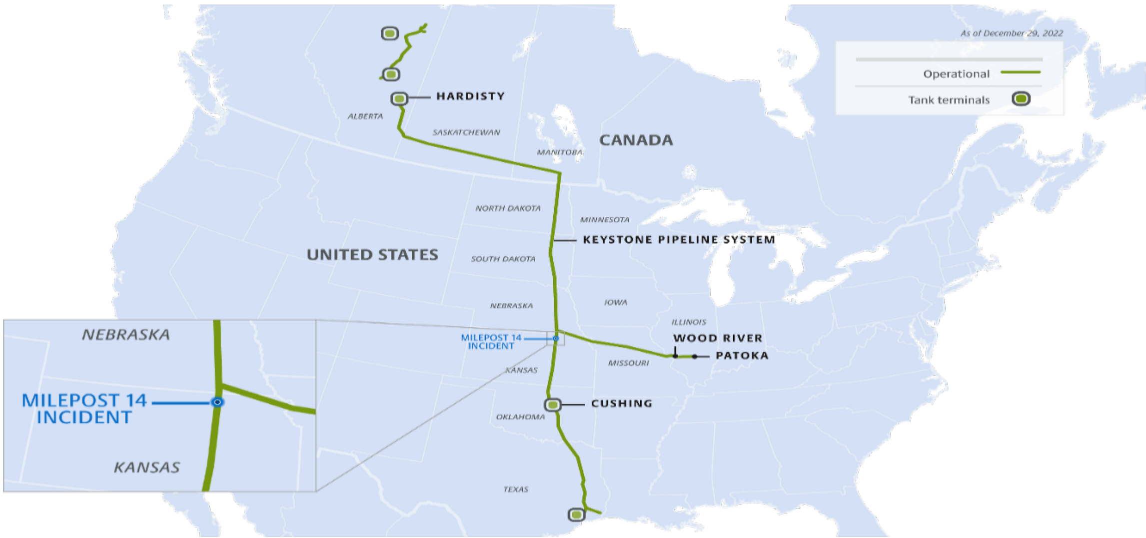

Figure 1. Map of Keystone Pipeline System.

As discussed above, the pipeline was constructed and is operated under a PHMSA SP, which allows operation up to 80% of SMYS. Without the SP, design factors and operating stress levels would otherwise be limited to a maximum of 72% of SMYS under § 195.106. The SP allowed TC to design, construct and operate two new oil pipelines (Keystone Mainline and Keystone Cushing Extension) using a design factor and operating stress level of 80% of the pipe's SMYS, subject to 51 specific conditions. Despite the 80% SMYS allowance, the Cushing Extension has not operated above 72% SMYS. As the system is configured, the 30-inch Keystone pipeline feeds the 36-inch Cushing Extension. During normal operations, a lower pressure is necessary in the 36-inch pipeline to achieve the same capacity at a higher pressure in the smaller diameter 30-inch pipeline. As a result, the 36-inch Cushing Extension does not exceed 72% SMYS despite the 30-inch Keystone Pipeline being permitted to operate at up to 80% SMYS under the SP.

The failure occurred in a girth weld of a fabricated assembly involving a 30° bend with pups in the Cushing Extension (Phase Two) pipeline section. The majority of the Cushing Extension consists of 36-inch diameter, spiral welded, double submerged arcwelded seam pipe, grade X70, with a nominal wall thickness of 0.465 inches and constructed with pipe manufactured in 2010, by Evraz. The pipeline is coated with fusion bonded epoxy.

3. Events Leading up to the Failure

The Keystone Cushing Extension's hydrostatic test in November 2010 identified coating failures in Canadoil Asia elbows that were manufactured in Thailand. Following the hydrostatic test, the elbow fittings were metallurgically examined, and it was determined that these fittings exhibited yield strengths below the design requirements and specifications marked on the fittings. The fittings had a yield strength of 50,000 psi rather than the design requirement of 70,000 psi. There were 70 of these fittings installed on the Cushing Extension which were replaced by TC following the identification of the issue. This replacement project was known as the WRP. Canadoil Forge LTD provided the replacement elbows that were manufactured at their Becancour, Quebec facility. The 36-inch diameter elbows consisted of a two-piece forged shoe manufactured from Grade 70 steel. The two pieces were double submerged arc welded together longitudinally at the inside and outside radius. The forged fitting was manufactured to meet the minimum specification of 0.515-inch wall thickness. The actual wall thickness of the fitting is 0.848-inches thick. Prior to the elbows being installed additional fabrication took place. An 8-foot pup of Grade X70 pipe, 0.515-inch nominal wall thickness was welded on each side of the elbow. This was done to accommodate the wall thickness transition and to improve alignment of the fitting in the field. Welding of these assemblies was performed by offsite fabrication contractors. Boccard USA Corporation, in Houston, Texas assembled 36 fittings, RC Technical in Houston assembled 22 and United Piping Inc., in Duluth, Minnesota assembled 12. Each fitting was radiographed and hydrostatically tested to a minimum of 1,816 psig. Once the WRP was completed the line was placed into service on February 8, 2011.

On December 7, 2022, TC was running a P2D[8] leak detection and a cleaning in-line inspection tool in the pipeline section between the Steele City Pump Station[9] (MP 0) and the Hope Pump Station (MP 95.7) when the failure occurred. The tool approached the Hope station at 8:34 p.m. on that day. The flowrate was reduced on the Cushing extension to allow the tool to by-pass the station. This operation increased the pressure at the Steele City outlet from 1,000 psig to 1,215 psig, which was expected. At 8:59 p.m., the ILI tool had bypassed the Hope Pump Station. The pipeline ruptured at 9:01 p.m. From 8:59 p.m. to 9:08 p.m., the pressure dropped at the Steele City outlet from 1,215 psig to 900 psig.

4. Emergency Response

On December 7, 2022, at 9:01 p.m., the LPCC received an alarm indicating a 2,500 barrel per hour release along with secondary pressure leak triggers.[10] The TC Controller commanded an emergency shutdown of the pipeline, at 9:07 p.m., which stopped all operating pumps from Hardisty, Alberta, Canada to Cushing, Oklahoma. Next, the Steele City Pump Station and the Hope Pump Station were isolated along with three downstream remotely controlled main line valves between the pump stations, at MP 37.1, 49.8 and 68.0, respectively. The 36-inch diameter valves take about 4.6 minutes to close once a command is received. The pipeline was fully isolated at 9:20 p.m.

Around 9:16 p.m., on-call field technicians were dispatched to locate the release. On December 8, at 12:15 a.m., the technicians identified an odor north of US Highway 36 near Washington, Kansas and confirmed the release was two miles north of the highway at the pipeline MP 13.9. TC made notification of the accident to the National Response Center (NRC) at 12:28 a.m. The NRC assigned the accident NRC Report No. 1354442.

PHMSA dispatched two investigators, two inspectors and a Community Liaison (CL) to the accident on December 8, 2022. Other agencies responding to the release included US Environmental Protection Agency (EPA) - Region 7, US Fish and Wildlife Service (USFWS), State of Kansas Department of Health and Environment (KDHE), State of Kansas Department of Wildlife and Parks, Marshall County Emergency Manager, and the Omaha Tribe of Nebraska as an observer as the accident was not on tribal land. TC initially established an incident command post (ICP) at the Steele City Pump Station, 14 miles north of the release. This ICP was moved later to the release site.

TC's Oil Spill Removal Organization (OSRO) began oil recovery operations from Mill Creek on December 9, 2022. Seven clean-up points along the creek were established. Clean-up with vacuum equipment was initially successful with warmer temperatures but

[8] P2D is an in-line inspection tool manufactured by Pipeline 2 Data company designed to clean and detect small leaks through high frequency noise detection.

[9] The Steele City Pump Station can either pump crude oil east to Patoka, Illinois or south to Cushing, Oklahoma.

[10] Pressure leak triggers are operational characteristics of the pipeline that provide the controller with information to confirm a potential release, these include pressure drops, pump throttle changes, a pump falling offline, changes in suction and discharge flow, etc.

became increasingly difficult as temperatures dropped. The oil eventually had to be manually removed as the lighter ends had evaporated and the remaining crude oil became too thick. The impacted area of land was scraped clean and replaced with clean soil.

Figure 2. Drone Photo of Release Site, Provided by TC.

EPA provided the Federal On-Scene Coordinator (FOSC) that was responsible for federal oversight of the oil spill response. Summaries of their activities were provided with their issuance of Pollution Reports (POLREP). The POLREPS show the response resources dedicated to the spill response and restoration effort. On December 11, 2022, the response had 119 contract personnel and 41 company representatives with 17 vacuum trucks and 1,800 feet of boom. On December 18, 2022, resources had grown to 368 contract personnel, 48 company representatives with 27 vacuum trucks and 7,300 feet of boom. By January 21, 2023, the response resources peaked at 785 contract personnel and 53 company representatives with 36 vacuum trucks, 72 skimmers, and 10,650 feet of boom.

Most of the crude oil flowed about 75-feet downhill into Mill Creek.[11] Crude oil also sprayed south of the rupture, impacting an agricultural area approximately 1/4-mile in length and 600-feet wide (**Figure 2**). Containment booms were installed at several locations on Mill Creek and an underflow dam was installed about 3.5-miles downstream from the pipeline crossing to contain the

[11] Mill Creek is a tributary of the Little Ble River, which contributes its flow to the Blue River and subsequently the Kansas River, which finds its terminus at the Missouri River in Kansas City. It is considered a "Water of the United States" by EPA.

oil and prevent it from migrating further. The underflow dam was effective in containing the oil, however water testing confirmed benzene did adsorb into the water column in Mill Creek and went beyond the underflow dam. This affected clams downstream of the underflow dam. Some clams were found dead as far as five miles downstream of the underflow dam.

Clean-up of the oil contaminated sediment and debris within Mill Creek began on January 30, 2023, and was completed on May 9, 2023. A dam was installed upstream of the pipeline crossing and the creek was diverted to the downstream side of the underflow dam (**Figure 3**). All contaminated soil and woody debris within Mill Creek were excavated and replaced with clean soil. The creek bed was then reflooded above the creek's water level at the time of the failure to assess for the presence of any oil sheen. No oil sheen was identified, which concluded the clean-up of Mill Creek. All waste was disposed of at the Pheasant Point Landfill in Bennington, Nebraska. A total of 12,973 barrels of crude oil were either recovered, disposed of, or evaporated.

Figure 3. Keystone Cushing Extension Pipeline Crossing of Mill Creek Near the Failure. Dry Creek Bed and Clean-up After River Diversion (South is to the Left), Provided by TC.

<u>Community Liaison (CL) Outreach</u>

On December 13, 2022, a PHMSA CL contacted and met with landowners of the properties impacted by the spill. The purpose of the CL's outreach was to make sure landowners were informed about the ongoing response activities on their property along with identifying any concerns they had to share with incident command. They also conveyed PHMSA's role and answered questions. As a result of the conversation with landowners, landowners requested a public meeting be held in Washington, Kansas.

On December 19, 2022, there was a stakeholder meeting held at the First National Bank, in Washington, Kansas. During the meeting the spill response, clean-up plan, and restart of the pipeline were discussed. EPA, PHMSA, and the State of Kansas participated along with TC.

On February 2, 2023, CLs held another landowner meeting in Washington, Kansas to update them on clean-up efforts, and to answer pipeline safety concerns of the affected landowners.

5. Summary of Corrective Actions Taken

As discussed above, PHMSA issued to TC a CAO on December 8, 2022. The CAO required written approval from the PHMSA Central Region Director for TC's investigative process actions, pipeline repair work, and the pipeline's return to service. It directed specific corrective actions to be taken by TC to verify the integrity of the pipeline. The order limited the Keystone Cushing Extension pipeline between the Steele City and the Hope Pump Stations to be operated at no more than 80% of the operating pressure at the time of the failure. The CAO required TC to conduct a metallurgical examination of the failed specimen and document the findings of that analysis within a report. TC was required to conduct a Root Cause Failure Analysis (RCFA) and address whether the RCFA findings were applicable to other portions of the TC Oil pipeline system. TC was required to review prior ILI results to identify any other potentially similar anomalies on the pipeline and correct any anomalies that were identified. The CAO also required the submission of a remedial work plan specifying tests, inspections, and evaluations to verify the integrity of the Steele City Pump Station to the Hope Pump Station segment of the Cushing Extension.

On March 7, 2023, an amended CAO was issued, extending the scope of the required corrective measures. In addition to the pressure restriction on the Steele City to the Hope Pump Stations segment, the amended CAO required that the operating pressure on the 30-inch Keystone Mainline and 36-inch Keystone Cushing Extension not exceed 72% SMYS, consistent with § 195.106. TC was required to complete an independent evaluation of their geohazard program and determine whether land movement may have contributed to the December 7, 2022, failure. The scope of the remedial work plan was extended to cover the Keystone Mainline and the Keystone Cushing Extension to determine whether and to what extent conditions associated with girth weld failure were present elsewhere. TC was also required to evaluate the Keystone system for all integrity threats identified, or suspected, in previous failures. The amended CAO also required the submission of operational reliability assessments for girth welds on the Keystone Mainline and Cushing Extension. To lessen the consequences of pipeline failures, a mitigation plan was also required to reduce pressure cycling, improve spill response, and employ measures to limit spill volumes.

PHMSA personnel have provided oversight of the following activities required by TC Oil within the amended CAO. These activities included the onsite investigation of the accident, the replacement of the failed segment and the restart of the pipeline. PHMSA personnel observed the metallurgical testing discussed below conducted at third party laboratory. As a result of the CAO, TC Oil has implemented a pressure reduction for the operation of Keystone Phase 1 and Phase 2 reducing the number and amplitude of pressure cycles. TC is implementing a remedial work plan with PHMSA oversight to evaluate WRP fittings and repair girth welds when necessary. This includes a modification of TC's backfill procedures to be used when the pipeline is exposed for inspection or repair. PHMSA witnessed onsite assessments, repairs of WRP fittings and TC backfill practices.

6. Investigation Details

On December 13, 2022, the failure was excavated and exposed (**Figure 4**). A circumferential crack was identified in the girth weld. The crack was open about a 1.5-inches wide at the widest point. The crack spanned 26.5 inches from 333° to 54° along the girth welds circumference. A bulge (**Figure 5**) was observed at the 6:00 position upstream of the failed girth weld. TC's geotechnical expert was on site to determine if soil slippage contributed to the failure. The expert concluded that there was evidence of shallow surface soil slippage on the south creek slope over the pipeline, however the slippage was determined to be not deep enough to affect the pipeline and did not contribute to the failure. Furthermore, the soil slippage was on the upstream side (north) of the fitting. (**Figure 6**).

Figure 4. Initial View of Failed Girth Weld Exposed.

Figure 5. The Compression Stress Bulge in the 6:00 Position. This Single Compression Point Caused the Pipeline to Bulge out About 1/2-Inch from the Normal Plane of the Pipeline. This Photo Was Taken After the Failure in December 2022 Looking Up.

Figure 6. South Creek Bank Showing Shallow Soil Slippage, Pipeline Runs from Creek Uphill to Orange Fencing.

On December 14, 2022, PHMSA observed the that the pipeline rose 6 to 8 inches, 30 feet downstream of the failed girth weld as the soil overburden was removed. This observation indicates that stress existed on the pipeline prior to the failure and the stress was relieved when the overburden was removed. On December 16, 2022, a stopple fitting was installed to prevent additional oil from releasing from the pipeline while the failed specimen was removed and for the pipeline to be repaired. This stopple installation was placed on the north side of Mill Creek. A hill immediately south of the failure provided an adequate change in elevation that prevented crude oil from flowing back to the rupture and no stopple fitting was necessary.

On December 17, 2022, a 13-foot 11.25-inch joint of pipe containing the failed girth weld was cut out and temporarily stored near the ditch. It was prepared and crated for shipping to Anderson and Associates (AA), in Houston, Texas for metallurgical evaluation utilizing a documented chain of custody.

The Fitting Assembly Fabrication

The failed fitting assembly, known as TAG 98, (**Figure 7**) was fabricated in 2010. It had the 30° elbow manufactured by Canadoil in Becancour, Quebec and was then sent to Texas, where RC Fabrication attached an 8-foot-long pup to each end of the elbow. The pipe pups were 0.515-inches thickness thick and were welded to the 30° elbow. The elbow was specified to have a minimum wall thickness of 0.515 inches, and was stamped 0.515 inches, however it had an actual wall thickness of 0.890 inches. The two girth welds were welded in the shop following the TransCanada qualified welding procedure (QWP) TES-WELD-AS-US and RC Fabrication's welding procedure. RC Fabrication's procedure complement the QWP. The QWP used GMAW with 100% CO_2 and ER80S-NI wire for the first pass and E81T1-Ni Flux core on the following passes.

The weld was radiographed on November 19, 2010, and passed. The metallurgical examination of the failed weld (GWD 13530) identified several internal root pass repair locations that showed grind marks and additional weld metal deposits. There was no documentation showing that these welds failed the original nondestructive radiographed examination, suggesting that the repairs occurred prior to the nondestructive examination. Other locations on the girth weld where repairs were not made contained large areas of LOF. Radiographic technology is known to be unable to pick-up up LOF defects when they are parallel to the pipe wall. This fitting was also radiographed at the lab after the accident, and that examination also did not identify the LOF defect. The defects were identified with ultrasonic phased-array examination during the metallurgical examination.

The weld joint design of TAG 98 consisted of a 30° bevel and a 30° taper transition. The length of the taper transition was measured at 0.78 inches (**Figure 7**). The minimum taper transition according to MSS SP-75-2008 is 1 inch. The shorter taper transition increased the stress at the weld. In the welding procedure TES-WELD-AS-US section 8.20 it states that the preferred transition when the wall thicknesses exceed 0.100 inches is a counterbore and taper transition.

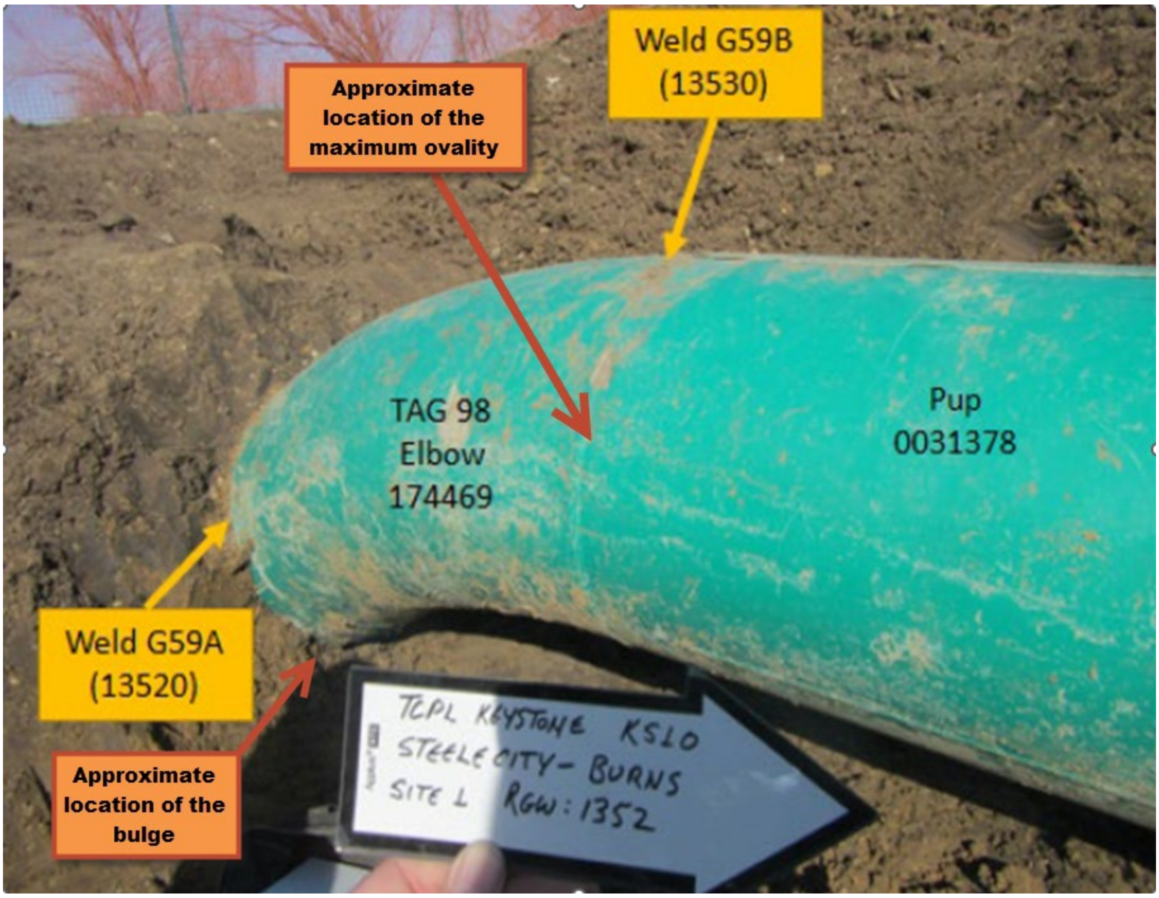

Figure 7. Photo of TAG 98 Fitting Assembly During 2013 Ovality Investigation, Weld G59B (13530) (GWD 13530) Contained the Failure, the White Arrow Represents the Flow Direction of The Crude Oil. AID Added the Approximate Location ff the Bulge and the Ovality to the Photo Provided by TC.

The failed fitting assembly was received by AA on December 19, 2022 (**Figure 8**).

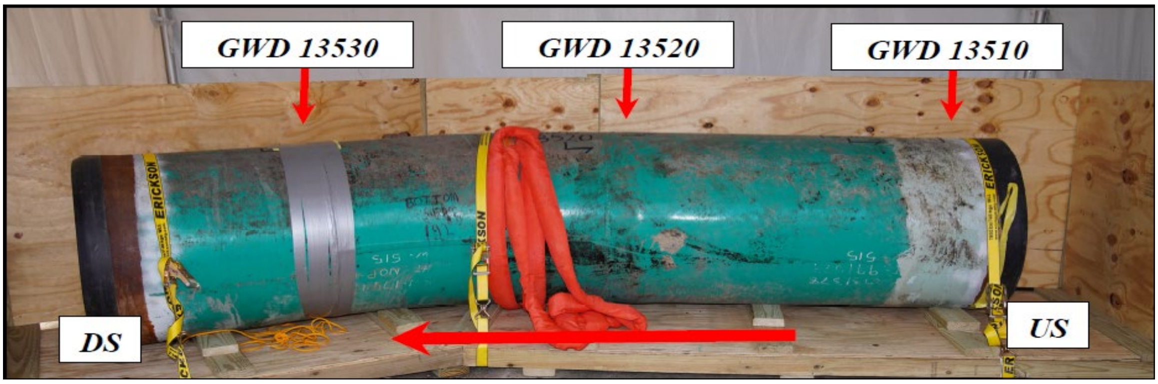

Figure 8. Failed TAG 98 Fitting Assembly Received at Anderson Lan, Duct Tape is Covering the Failed Girth Weld GWD 13530, Photo from AA.

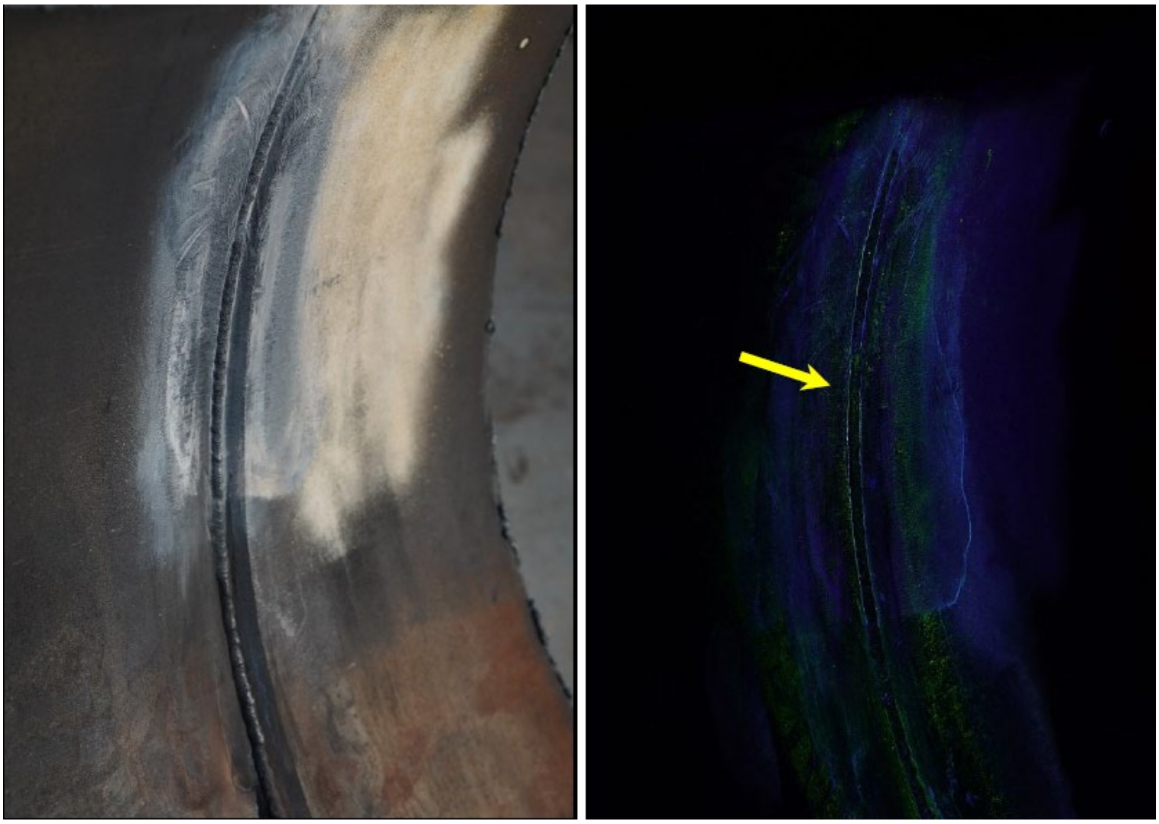

Figure 9. GWD 13520 Internal Girth Weld Showing LOF Defects in the Root Pass, Photo from AA.

Visual observation identified a bulge, on the upstream side of the upstream pup to fitting girth weld (GWD 13520) and the girth weld crack that spanned from 333° to 54°, approximately 26.5 inches in circumference and 0.638-inches wide. The pipe was sandblasted to perform nondestructive testing of the pipe sample. This testing included radiographic, phased array ultrasonic testing, ultrasonic thickness, magnetic particle, time of flight diffraction and inverse wave field extrapolation. The pipe was also 3-D laser scanned inside and outside.

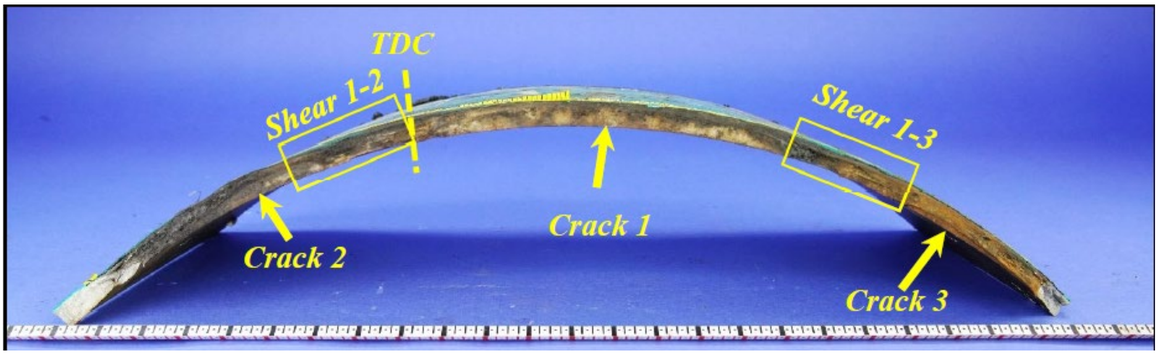

Figure 10. GWD 13520 Failed Girth Weld Show 3 Elliptical Crack Regions, Photo from AA.

NDT of the intact portion of the pup-to-fitting girth weld identified lengthy crack-like indications in the hot pass weld deposit and the base metal. The metallurgical testing identified these indications LOF of the filler metal and the initiation point of the failure (**Figure 9**).

The fracture consisted of five distinct regions (**Figure 10**). There were three elliptical fatigue cracks that initiated from the inside diameter (ID) of the pipe, separated by two shear areas. The shear areas are locations where the root pass was repaired from the inside. The repairs interrupted the LOF defects which eliminated the crack initiation stress riser. There existed three elliptical crack regions. Each showed initiation points at the LOF between the pup and the girth weld. A straight edge was placed at the apex of the bulge (**Figure 11**). Within the three elliptical crack regions, beach marks are illustrated with the yellow arrows (**Figure 12**). The beach marks align with the weld passes that exist in the girth weld. The red arrow in **Figure 12** points to a dark ledge that is the crack initiating stress riser. This was created during the welding process. The darkness of the ledge is a result of a dense, tightly adhered oxide scale consistent with magnetite, which can only be created at temps during welding. This material is formed at temperatures higher than 600°C.

Figure 11. Sandblasted Pipe with Mag Particle Contrast Paint Applied. The Bulge is Located at the 6:00 Position.

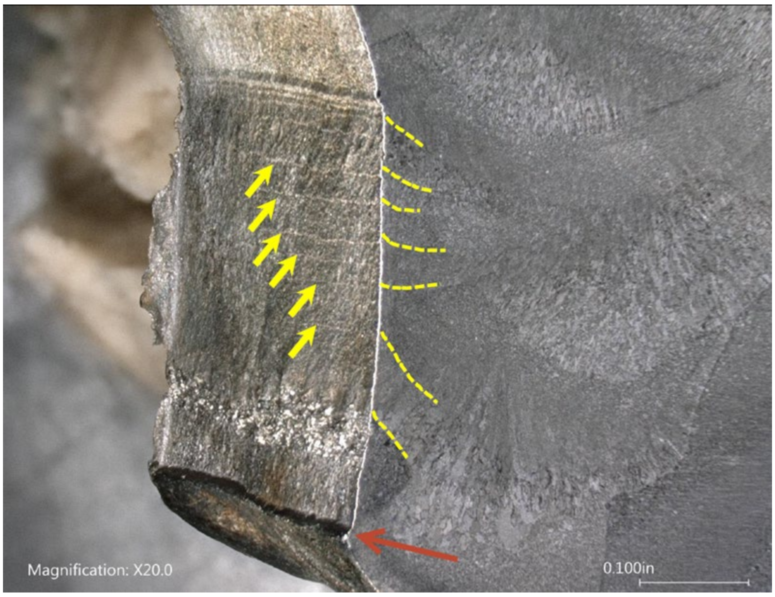

Figure 12. GWD 13520, Beach Marks on the Crack Origin, Showing the Sequential Crack Growth Over Time, Photo from AA.

Figure 13 shows a cross section of the failed girth weld where it did not fail, at 500X magnification, that shows the area of the LOF. The welding process was gas metal arc welding (GMAW).

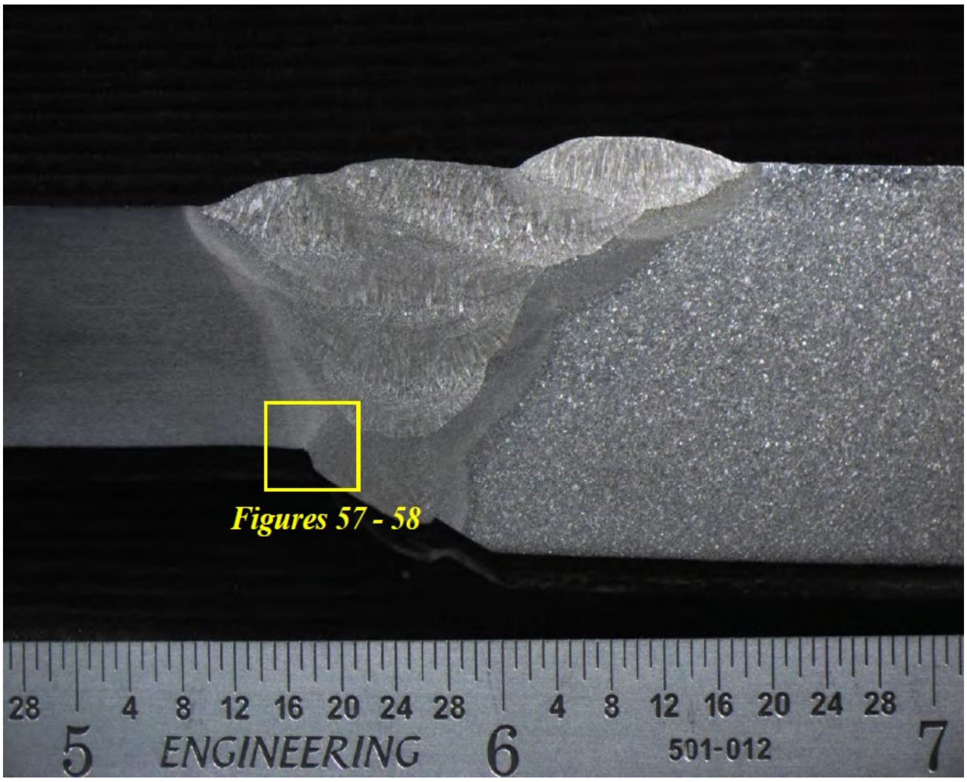

Figure 13. GWD 13520 Location of the LOF, Photo from AA.

Metallurgical testing of the metal and weld for GWD 13520 confirmed their properties met the API Specification 5L, 43rd Edition. The metallurgical analysis and PHMSA's observation of the metallurgy testing conclude the girth weld failed as a result of cyclic fatigue of the cracks which initiated at points of LOF in the root pass (**Figure 14** and **Figure 15**). The cracks grew to the point that they could no longer withstand the external loading of the pipeline. The girth weld in the fabricated assembly that failed was part of the WRP and was fabricated in Houston, Texas by RC Technologies.

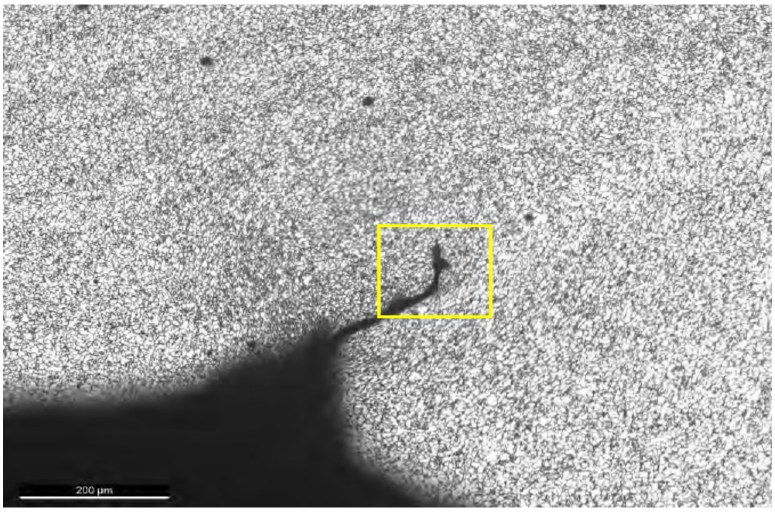

Figure 14. GWD 13520 LOF in Root Pass, Photo from AA.

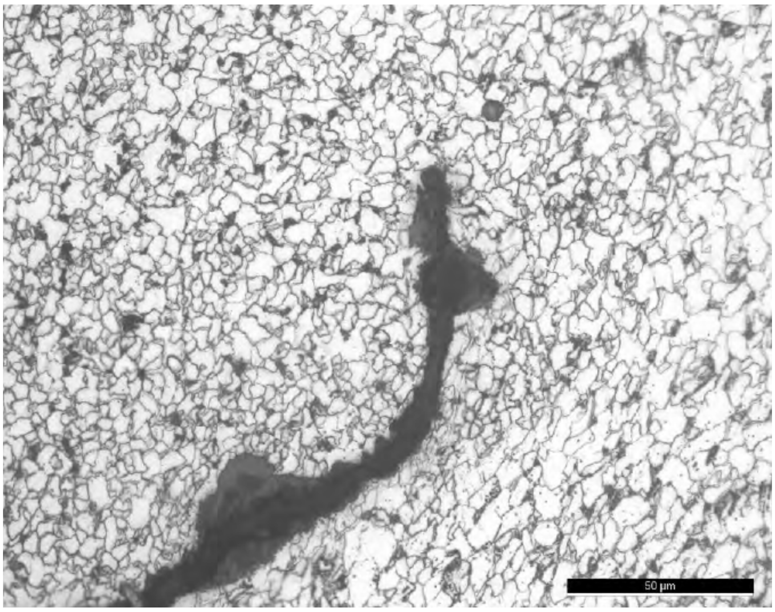

Figure 15. Zoomed-in View of GWD 13520 LOF, Photo from AA.

2010 Excavation for the Warranty Replacement Program

There were three fitting assemblies at the Mill Creek crossing that were replaced as part of the WRP in December 2010 (**Figure 16**). The Mill Creek crossing was an open-trench crossing, (**Figure 16**), as the rising elevation to the south and the depth of the creek crossing exceeded the bending radius of the 36-inch pipe required for a directional bore installation.

The project began on December 6, 2010, when the Mill Creek crossing was excavated. The creek crossing was completed first. The hydrotesting and backfill were completed on December 10, 2010, for the Mill Creek crossing (**Figure 16** – Creek Section). The failed fitting assembly (TAG 98) and piping downstream of the creek crossing was the next fitting assembly that was replaced (**Figure 16** – Overbend Section). In total, 158 feet of pipe plus the fitting assembly were pre-welded and prepared for burial. The trench was excavated on December 11, 2010. The pre-welded piping was then lowered into the ditch for line-up. The first tie-in weld was completed on the upstream side (north) of the fitting assembly on December 10, 2010. On December 11, 2010, the creek crossing (**Figure 16** – Creek Section) was again hydrotested along with the fitting assembly and 158 feet of pipe (**Figure 16** – Overbend Section). The hydrotest water removal began the evening of December 11, 2010, and was completed the following evening. On December 13, 2010, the final tie-in weld was completed. On December 14, 2010, the overbend section was back filled with 8.5 feet of cover.

Historical weather records provided by the National Oceanic and Atmospheric Administration (Appendix I) indicate that the spoil pile from the excavation was exposed to freezing temperatures between December 11 and December 14. PHMSA believes the bending stress that contributed to the failure originated when inadequately compacted soil underneath the pipeline allowed the unsupported pipe to bend from the 8.5 feet of overburden. The inadequate soil compaction may have occurred from the lack of mechanical compaction and frozen soil used in the backfill.

A review of TC procedures identified that there were backfill procedures in place at the time the work was completed. The procedures provided instruction on actions to be taken to minimize soil settlement beneath the pipe, that frozen soil should not be used as padding beneath the pipe and that the Contractor would not be compensated for any imported soil for use in padding of the pipe should the backfill spoil piles freeze.

Figure 16. December 2010 WRP Work at the Failure Location Looking South in the Downstream Direction (TAG 98 Label Added by PHMSA), Photo from TC.

Procedures required that any frozen spoil used as backfill had to be broken up and pulverized and receive the approval of the Company Representative (CR) before it could be placed in the trench as backfill. During PHMSA's investigation, TC was unable to provide any site-specific records of how the backfill was performed or inspection records of the CR.

As mentioned above, during excavation of the pipeline after the failure, it was observed by PHMSA that the pipeline rose 6 to 8 inches, 30 feet downstream of the failed girth weld as the soil overburden was removed. Post failure, the Finite Element Analysis (FEA) conducted by RSI Pipeline Solutions concluded that one foot of settlement would have been enough to cause the 2013 observed ovality in the pipe. The stress applied at the girth weld would be adequate to initiate the failure according to the FEA.

2013 Excavation

In December 2012, TC inspected the pipeline using a BHI Profile, low resolution ILI caliper tool. This tool was used in preparation for sending the Gemini ILI tool used in September 2013. This low-profile tool was intended to assure that the Gemini could pass through the pipeline without issue. The tools identified a 9% ID restriction at the failed girth weld fitting assembly. An ovality was identified in both the fitting and the pup. On March 2, 2013, the fitting was excavated to expose the fitting and a portion of the pup on the upstream side of the fitting and the whole pup on the downstream side along with a portion of the main pipeline. Three girth welds in total were exposed. Wall thicknesses testing was completed on the pups and the fitting. The upstream pup was tested at the 3:00, 6:00, 9:00 and 12:00 positions. Inspection records and photos show that the location of the bulge was not excavated. Measurements were taken to determine the exact out-of-roundness that existed on the pipe sections near the girth weld of the fitting on the downstream side. The fitting was measured in ½-inch increments from 5 inches upstream for the girth weld of the fitting to 6.5 inches downstream of the girth weld for the pup. The maximum ovality of the fitting was 7.612% at the girth weld and the ovality of the pup was 3.460% at the girth weld. Post failure, the metallurgy laboratory performed a 3-D laser scan of the pipe and a maximum ovality was measured at 4.7% near the girth weld. This shows that the ovality identified in 2013 was caused by stresses exerted on the pipeline prior to the excavation. The 2.912% difference in ovality is credited to elastic deformation as it was not permanent and relaxed after the soil stresses were removed.

Figure 17. Photo of TAG 98 Fitting Assembly During the 2013 Ovality Inspection Showing the Extent of Excavation. The Excavation Did Not Add or Decrease Any Stress on the Pipeline, Photo from TC.

While the excavation was still open in March 2013, (**Figure 17**), the integrity team worked with the ILI vendor on options to address the restriction in the pipeline. Three options were identified; 1) modify the tool to pass through the restriction, 2) use a dual diameter tool, or 3) cut out a segment of pipe containing the ovality. The options were provided to TC senior leadership, who chose not to cutout and replace the ovality but instead opted for tool modification option. Post incident, during PHMSA interviews with TC integrity personnel, it was stated that the cause of the ovality was not considered a stress-related integrity threat.

In September 2013, TC conducted an ILI of the pipeline using a Baker Hughes Gemini high-resolution magnetic flux leakage (MFL), caliper and inertial measurement unit (IMU). The tool identified 38 dents and 25 ovalities. The largest restriction was measured at 9% of the ID at the failed girth weld. Since this site had been previously exposed and examined, it was not re-evaluated.

The stresses are believed to have remained constant as the ovality of the elbow and pipe did not change as demonstrated by the 2012 ILI, the field inspection conducted in March of 2013, and the September 2013 ILI. After the failed elbow was cutout, the ovality was measured during the metallurgical analysis. The measured ovality showed that with no overburden on the pipeline, the ovality elastically sprung back to less than 3% near the failed girth weld location. This further demonstrates that the failed elbow and pipe were under stress prior to their cutout.

Operating Pressures and Cycling Threat

Since February 2011, the segment of the pipeline where the failure occurred never exceeded 72% of SMYS (1,300 psig). The pipeline was operating at 1,210 psig (67 % of SMYS) when it ruptured. The pressure throughout 2022 rarely exceeded 1,250 psig. The pipeline is operated with significant pressure cycling. When crude oil is transported to Patoka the Cushing Extension static pressure drops below 100 psig and when active it operates at full operating pressure.

TC was running a leak detection tool on the day of the failure. As the tool approached the Hope Pump Station, the station was placed on bypass to allow the tool to pass. As a result, pressure at Steele City was increased from around 1,000 psig to 1,215 psig to make up for the pressure loss when the Hope Pump Station was bypassed. This pressure increase was anticipated and never exceeded the MOP. The pipeline failed two minutes after this pressure increase occurred.

The Steele City Pump Station had discharge pressures above 1,215 psig 43 times in 2022. The highest pressure the line operated in 2022 was 1,264 psig on June 3. The most recent operation with a pressure over 1,215 psig occurred on November 24, 2022, at 1,218 psig.

Temperature cycling also occurs on this pipeline according to an Integrity Threat Assessment (ITA) report dated September 25, 2023, required by the 2022 PHMSA-issued-CAO. The relative contribution of pressure cycling is approximately 70 times greater at the Steele City Pump Station compared to temperature cycling. Pressure and temperature cycling occur concurrently, however, with the pressure cycle being fairly immediate, and the temperature cycle being much more gradual.

Flow Capacity Increases

In 2016, TC initiated a flow capacity increase on the Keystone pipeline from 4,350 to 4,500 m^3/hour, then on December 5, 2022, to 4,750 m^3/hour. This occurred two days prior to the failure. The increase in flow rates also increases the relative cyclic stresses at the elbows. The pre-failure stress analysis for increased flow rates did not consider the effect of these combined increased cyclic stresses could have on girth weld flaws already being subjected to excessive bending stress.

In-line Inspections

A TDW construction caliper tool was conducted on the pipeline in October 2010 following completion of construction. This ILI was a quality assurance assessment of the construction intended to identify any deformations of the pipeline during original pipeline construction. The assessment did not identify any defects in the area near the failure location. As part of the WRP, TC replaced the original fitting assembly and pipe in this area after the tool run. TC did not conduct an additional ILI to assess if any deformation existed after the completion of the WRP in December 2010.

A Baker Hughes General Electric MFL4 ILI high-resolution MFL, caliper and IMU tool with technology specifically configured to identify girth weld anomalies at transition welds was performed in November 2018. This tool was used based on findings associated with the Freeman failure in Hutchinson County, South Dakota on April 2, 2016. The metallurgical report for that Freeman failure identified crack initiation from a LOF defect in the internal girth weld of a road crossing transition, unrelated to the WRP fittings. The November 2018 ILI revealed no reportable girth weld anomalies in the elbow welds. The tool did not identify any girth weld cracks although it is likely that the crack existed but fell below the tool's capability to identify the crack. The tool is not capable of identifying cracks less than 0.01 inches in width or less than 30% through wall. The 2018 ILI data was re-evaluated for signs of a bulge on the upstream side of the fitting after the accident and there was no indication of the deformation. The 2012 and 2013 ILI's also had not identified a bulge in the pipeline.

The capability of ILI tools is degraded when the sensors pass into wall thickness transitions and when passing into and out of a bend causing the sensors to lift from the pipe wall. In this case, the tools were passing through both degradation configurations which prevented the indication of a bulge or girth weld cracking.

In September 2020, an NDT Eclipse ultrasonic axial crack detection tool was performed. No crack-like features were identified. The tool is not designed to identify girth weld cracks, nor was it intended to identify bulges in the pipe.

On December 7, 2022, a leak detection tool was launched from the Steele City Pump Station and was planned to bypass the Hope Pump Station when the pipeline failed. The leak detection tool did not identify a leak at the fitting when it passed by the fitting that failed. Leak detection and cleaning tool assessments are performed annually.

The IMU data collected during the 2013 and 2018 ILIs was reviewed by the tool vender for movement and strain. There was no movement between the two sets of IMU data at the failure location. IMU data was not collected post construction in 2010 to establish a baseline for the pipeline.

Control Room

The Hope Pump Station was placed on bypass at 8:34 p.m. on December 7, 2022, to allow the leak detection tool to pass the station. This required a pressure increase at the Steele City Pump Station from 1,000 to 1,212 psig. The tool passed Hope at 8:59 p.m. At 9:01 p.m., an alarm indicating that a leak meeting the two-minute threshold along with leak triggers were received in the LPCC. At 9:07 p.m., the LPCC initiated an emergency shutdown of the Keystone Pipeline system, along with the isolation of the segment between Steele City to Hope. Isolation was complete by 9:20 p.m.

Geotechnical

TC performed the initial geological hazard assessment in 2012 on the Keystone Pipeline. Mill Creek was not identified as a geotechnical threat for soil slippage. The report indicates that the majority of the pipeline is in collapsible and expansive soils. In March 2017, TC hired DoC Mapping to map the pipeline's position and determine the depth of cover at water crossings and banks. During that process, several photos were taken in the area where the failure would occur. The report provided photos of the creek crossing and bank that look similar to those taken in 2012, and also at the time of failure in 2022. This demonstrates the south bank was stable. In January of 2022, a new review was completed on the Keystone Pipeline to determine where geotechnical hazards may exist. TC's geotechnical expert review was focused on the terrain associated with the potential for landslides, seismic and subsidence on the Keystone Pipeline. The 2022 report was compared to the 2012 report to determine if any new geohazards existed. The geotechnical review did not include backfill settling due to construction practices or the effects of how soil surrounding the pipeline that may encounter dry to saturated conditions within the open trenched creek crossing. The geotechnical review addressed soil slippage, seismic hazards, and ground subsidence. The report concluded that the failure location is of a low concern. Even though there was some surface soil slippage in the area, the burial depth of the pipeline was deeper than the slips. The pipeline was not affected by any soil slips in this area. The pipeline in the area was rated low for the possibility of soil movement. After the December 2022 accident, there was also no visual evidence of soil slippage that would have affected the pipeline. The creek crossing was stable. The lack of evidence of movement that could have impacted the pipeline at this location supports PHMSA's position that settling occurred during the December 2010 construction period.

TC had their geotechnical expert review the area for ground movement immediately after the accident. There were no visual signs of ground movement that could affect the pipeline. The slope to the creek was 10%. This slope and the area soil type are not prone to soil slippage. IMU data from 2013 and 2018 showed no signs of pipe movement.

In addition, PHMSA's CAO discussed above ordered TC to perform an additional geohazard study by an independent third party. TC engaged Geosyntec Consultants to perform that study. The review was performed on TC's Geohazard Program and the MP14 failure to determine if a geohazard played a role in the failure. The Geosyntec Consultants' report concluded the MP 14 leak was unlikely caused by ground movement, consistent with PHMSA field observations and TC's prior geohazard review.

7. Findings and Contributing Factors

PHMSA has determined the failure was caused by bending stress from soil loading on the pipeline which concentrated at the girth weld containing LOF defects on the fitting assembly TAG 98. Cracks initiated due to the applied bending stress, and they grew in service due to cyclic fatigue.

The following factors contributed to the failure:

- Inadequate quality control of original fitting manufacture resulted in a fitting replacement program prior to the pipeline being placed in service.
- At the location of the failure, the fitting replacement program was executed in a manner which allowed excessive bending stress to be applied to TAG 98 fitting assembly and caused excessive ovality of the assembly.
- The back fill process during the TAG 98 replacement was not adequately inspected to assure proper compaction.
- The replacement fitting assembly TAG 98 contained welding defects which were exacerbated by an inadequate wall thickness taper transition design that concentrated applied stress at the girth weld.
- Counterboring with tapers is preferred in TC's welding procedure for transition welds exceeding 0.100 inches but was not used.
- The TAG 98 ovality investigation in 2013 did not consider the integrity threat associated with the bending stress that caused it.
- Removal of the TAG 98 fitting assembly to mitigate the ovality present in 2013 was declined in favor of ILI tool modification.
- The fitting assembly TAG 98 design, wall thickness taper transition and ovality decreased the probability that girth weld defects in the assembly could be reliably identified through ILI.
- IMU data post construction was not gathered to establish a baseline pipeline position to be compared to future IMU data collections.
- Bends and wall thickness transitions affect the accuracy of in-line inspections.

Appendices

A. NRC Report Nos. 1354442, 1354446, 1354625.
B. Operator Accident Report – Hazardous Liquid Pipeline Systems No. 20230004.
C. Metallurgical Analysis of NPS-36 KS10 MP-14 Pipeline (Anderson & Associates, Inc.).
D. Root Cause Failure Analysis for the Keystone Milepost 14 Release (RSI Pipeline Solutions).
E. Phase I Geologic and Hydrotechnical Hazards Assessment Keystone Mainline and Cushing Extension Pipelines Midwestern United States (Golder Associates USA Inc. - 2012).
F. Mill Creek (64029) - Keystone - Cushing Extension - MP 13.9 (36in) - Positional & Depth of Cover Study Near Washington, KS (DoC Mapping, LLC. - 2017).
G. Phase I Geologic Hazards Assessment Update (Golder Associates USA Inc. - 2022).
H. Integrity Threat Assessment (TC Energy).
I. NOAA weather records December 2010 for Washington, Kansas