

Statistical analysis of U.S. reportable onshore hazardous liquid and natural gas pipeline accidents/incidents from January 2010 to January 2021 caused by external corrosion – Part II

Alvaro A. Rodriguez
U.S. Department of Transportation – Pipeline and Hazardous Materials Safety Administration
3700 S. MacArthur Blvd Suite B
Oklahoma City, OK 73179
USA

ABSTRACT

A statistical analysis of reportable hazardous liquid and natural gas pipeline accidents/incidents in the U.S. from January 2010 to January 2021 was conducted by evaluating releases reported to be caused by external corrosion. The US Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) Office of Pipeline Safety (OPS) Accident Investigation Division (AID) collected historical records from Form PHMSA F 7000-1 (Hazardous Liquid/CO₂ Accident Report) and Form PHMSA F 7100.2 (Gas Transmission and Gathering Systems Incident Report) for the 11-year period. Since January 2010, 358 of the 4,332 (8%) hazardous liquid accidents; and 122 of the 1,364 (9%) natural gas incidents involved failures due to external corrosion. These failures were reported as corrosion failures under section G1: Corrosion Failure, and 29 accidents were reported as environmental cracking-related accidents in section G5: Material Failure of Pipe or Weld of PHMSA's accident/incident reports.

The total property damage for these failures accounted for \$1.2 billion and 133,000 barrels of unintentional hazardous liquid released; and \$94 million and 3,000 MMcf of unintentional natural gas released. There were two ignitions, two explosions, one injury, and one fatality associated with hazardous liquid accidents. Likewise, there were 23 ignitions, 14 explosions, three injuries, and no fatalities from natural gas incidents. Soil was contaminated in 236 accidents, wildlife was impacted in 14 accidents, and water was contaminated in 62 accidents. Common causes of external corrosion accidents/incidents involved galvanic corrosion, atmospheric corrosion, stray current, microbiologically influenced corrosion (MIC), selective seam corrosion, stress corrosion cracking (SCC), sulfide stress cracking (SSC), hydrogen stress cracking and other, which can be associated with uniform corrosion, pitting corrosion, crevice corrosion, corrosion under insulation (CUI), metal loss, oxidation, pH, disbonded coating, aqueous corrosion, and corrosion fatigue.

In this paper, several cases will be showcased to highlight the contributing causes and underlying mechanisms of corrosion damage of components that resulted in significant releases of hazardous substances onto operator's property, rights-of-way, and the environment. The objectives of this paper are

to understand the causes of the failures and their consequences, to identify the risk factors involved, to discuss mitigative measures after failure, and to observe trends that may indicate the need for additional preventative and mitigative actions. The over-riding goal is to provide details in areas for potential improvement in pipeline operations to reduce risk and improve integrity management.

Keywords: external corrosion, natural gas, hazardous liquid, pipeline integrity, PHMSA, corrosion mechanisms, contributing factors, environmental cracking, stress corrosion cracking.

DATA ANALYSIS

Root Cause of External Corrosion Failures

AID found that common causes of external corrosion failures included localized corrosion, coating disbondment, CP shielding, unprotected assets (tank floors and bare pipelines), stray current interference, cased crossings, offshore environments, pipeline susceptible to SCC, differential aeration cell, soil characteristics, construction practices, wet/dry cycling, among others. Additional details from the narratives of accident and incident reports grouped by cause type are summarized below.

Localized Corrosion

- A third party notified the operations control center about a leak from a 6-inch pipeline. The spill volume was 1 gallon of refined product due to external corrosion. A metallurgical analysis determined crevice corrosion between the pipeline and the bridge support, which consisted of a partial encirclement bracket fillet welded to the pipe. The line segment is exposed to the atmosphere. A new pre-tested pipe section was installed.
- An oil sheen was reported by platform personnel, where 5 gallons of crude oil reached the water from the interface of a riser support clamp and the 10-in pipeline. The subject pipe clamp is one of eight riser clamps that secure the pipeline riser to the platform and one of two above the water line. The line was shutdown and isolated to stop the leak. The pipe segment was repaired. Metallurgical analysis determined crevice corrosion and atmospheric conditions contributed to localized external corrosion.
- During an aerial patrol, a pilot reported a stain to the damage prevention department near a 20-in pipeline. The control center shutdown the line and sent a field technician to investigate. A spill of approximately 5 barrels of crude oil was confirmed from the underground pipeline. The cause of the spill was due to an external corrosion pinhole. A clamp was installed to repair the segment and soil was remediated.
- A landowner called the control center to report a possible leak from an underground crude oil line. The line was shutdown and contractors were asked to investigate. Emergency response personnel deployed booms in a nearby pond and built emergency dams to recover and remediate the affected area. The cause of the spill was localized pitting. The total volume of commodity spilled was 400 barrels. Repairs and remediation were completed about a month after the leak was discovered.

Coating Disbondment

- A patrolling crew discovered a small amount of gas blowing through the soil by the right-of-way of an underground 26-inch pipeline. Once the leak was confirmed, the pipeline valve section was isolated, blown down and secured. During excavation, disbondment of coal tar coating was discovered on a pipeline installed in 1947. Localized pitting corrosion was developed under the disbonded coating. The pipe segment was replaced, and the valve section was returned to service. The total release of gas was 1,488 Mcf.
- The control room observed a drop in pressure and dispatched a crew to investigate the source of a potential leak. Field operations personnel confirmed gas venting to atmosphere from an 8-inch coal tar coated pipe in a low wet area covered by ground water. During the inspection of the failure site, a

4-inch long corroded section was discovered on a carbon steel pipe, which was installed in 1930. The incident was caused by coating disbondment. The pipe was replaced with a new pre-tested segment. The total release of gas was 3,624 Mcf.

- An operator's contractor discovered gasoline leaking from a nearby pipe section on a 24-inch line to a breakout tank. The line was isolated, free product was recovered, and contaminated soil and stone were properly remediated. A visual inspection of the pipe was completed, concluding that the above ground pipe segment showed small areas of localized pitting under the damaged coating, which contributed to the spill. The repair plan included replacing 60 ft of pipe and fittings. The total spill amount was 2.5 barrels of gasoline and \$40,000 in damages.

CP Shielding

- The control center received a notification from a landowner of a leak on a gas system. The operating pressure was lowered, and a crew was dispatched to investigate. Results from the metallurgical analysis revealed that an area of coating was disbonded, which caused cathodic shielding of the pipe material, enabling the corrosion process. The leak developed when the remaining ligament was unable to support the hoop stress induced by the internal pressure. The total release of gas was 2,186 Mcf. The repair involved the replacement of a section of 6 ft of pipe.
- Local operating personnel were notified by gas control of a pressure loss on a 16-inch pipeline. In addition, gas control received a call from the local police department indicating a pipeline rupture in a rural area. The line was pressurized at 783 psig at static conditions without gas flow at the time of the incident. The line was immediately isolated with an estimated volume of gas released of 4,000 Mcf. Pipe specimens were sent for metallurgical analysis. The rupture of the pipeline was caused by external corrosion due to coating disbondment, which shielded CP current. Total damages due to the incident were greater than \$550,000.

Uncoated Assets

- During filling operations of a breakout tank with light crude oil, personnel on-site noticed crude oil at the ring wall in the soil/rock tank dike after reaching 10 ft in volume. The controller was contacted to reroute the crude oil to an alternate tank. The tank was emptied, degassed, and cleaned to inspect the bottom. The inspection team found two pinholes in the tank floor caused by external corrosion localized pitting. Approximately 6 gallons were released, and total costs were \$1,000,000.
- The operator received a call from a third party on the discovery of a crude oil spill. Personnel responding to the accident determined that the underground 12-inch pipe, which was installed in 1944 failed due to external corrosion pitting. This line was found to be uncoated, however the CP readings taken after the incident occurred indicated the line was properly protected by CP which was well above the requirements. The CP records from previous ownership also indicated adequate CP on this line. The total amount of crude oil spilled was 5 barrels with \$35,000 in total damages.
- Field personnel discovered 75 gallons of free-phase jet fuel next to a storage tank. The release was completely contained inside the tank dike. The tank was emptied and cleaned for inspection. A metallurgical report concluded that the cause was corrosion fatigue on the underside of the tank floor surface inside the heat affected zone of the corner weld. Total costs reached \$575,000 including cleaning, testing of the tank and lines, and replacement of the sketch plate on the entire circumference of the tank.
- A maintenance technician discovered approximately 10 gallons of crude oil leaking around a storage tank at the terminal. After the tank was cleaned, visual inspection did not identify the origin of the leak. A helium test was performed and a pinhole in the tank floor bottom was found, which was caused by soil side corrosion (electrolytic contact with soil for the tank bottom). The location had been previously identified and repaired with a 12-inch by 14-inch patch that was necessary to cover the leak area. However, the contractor orientated the patch in the wrong direction, resulting in part of the corroded area not properly repaired. That patch was removed, the proper size patch installed, and the tank returned to service. Total damages for the failure reached \$80,000.

Current Interference

- Operator's control center shut down the 8-inch crude oil pipeline due to a leak alarm indication. Field personnel investigated and confirmed the release in the right-of-way, 13 miles downstream from the nearest pump station. The line was isolated, and the total commodity released was 15 barrels. Results of the in-field visual analysis indicated that the failure occurred at the 12:00 orientation in an externally corroded area with a size that was approximately 10-inch by 1.5-inch. Coating damage and possible mechanical damage were also visible in the failed area. The operator had previously installed a high-density polyethylene (HDPE) liner to prevent degradation of the internal surface. External corrosion and coating damage caused the liner underneath to be pierced by the sharp edges of the corroded steel pipe. Metallurgical analysis determined that the leak occurred in an area of through wall, external corrosion pits which were aligned with an area of top side mechanical damage, in the form of a gouge. Analysis of cathodic protection data confirmed this area was subject to local stray current interference which caused an accelerated corrosion growth rate at the failure point. The repair included the replacement of approximately 2,000 ft of pipe and internal liner. Total damages surpassed \$4.5 million.

Cased Crossings

- An operator's contractor working on a nearby project detected the odor of natural gas. Upon further investigation, the source of the leak was a casing vent. The segment was isolated, and the line was blown down. Upon removal of the casing and the pipe, a through wall external corrosion pit was determined to be the cause of the leak. The pit was at the 5:00 position where coating was damaged. The damaged coating was located under the rubber casing end seal. Both rubber casing end seals and wooden centralizers were observed during the casing removal. However, the carrier pipe was not centered through the casing. Water marks were observed on both the carrier pipe and casing, indicating that the casing seals had been compromised and, at times, water had been present in the annular space. The coating damage likely occurred during installation of the casing or during a subsequent excavation of the casing ends. The wooden centralizers caused and/or exacerbated the coating damage. The placement of the casing end seal over the area of damaged coating did not isolate the exposed steel from groundwater intrusion. With water being present between the casing seal and the pipe, the external surface of the pipe was corroded by atmospheric and crevice corrosion, which caused the leak. The introduction of water as an electrolyte to the exposed steel created a localized corrosion cell under the rubber casing end seal. During the time when the casing was filled with water, the rubber casing end seal shielded the exposed steel from CP current that could have mitigated the corrosion. The 24-inch pipeline was installed in 1968, and the operating pressure of the pipeline was 454 psig. The failure resulted in the release of more than 3,000 Mcf natural gas with total costs surpassing \$300,000.

Offshore Environments

- During a helicopter overflight, bubbling was observed in the Gulf of Mexico with a sheen measuring approximately 500 ft by 20 ft. The line was shut down and isolated, and a diving crew was sent to investigate. The investigation team confirmed the leak of natural gas from a 30-inch pipeline installed in 1977. The leak area had a pinhole of approximately 1/8 inch in diameter. The pipeline was operating at 745 psig at the time of the incident and coated with asphalt enamel. The coating was damaged at the area where the pipe is in contact with the seabed surface. Localized corrosion occurred at the coating damage area. The pipeline was repaired with a PLIDCO clamp and passed the pressure tests without any issues. The total volume of natural gas released was greater than 5,000 Mcf and total cost of damages surpassed \$1,000,000.
- Gas control received a phone call from another operator's control center regarding a leak underneath a platform in the Gulf of Mexico, which was venting natural gas to the atmosphere. Field personnel were dispatched and confirmed the leak on the 2-inch bypass line around the 16-inch ESD valve on