

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 I

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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.

INTRODUCTION

Hazardous liquid and natural gas pipeline systems are generally protected from external corrosion using protective coatings as the primary defense mechanism and maintaining adequate levels of cathodic protection (CP). To maintain an effective external corrosion management program, the design, installation, and maintenance of corrosion control strategies should involve a comprehensive list of probable external corrosion threats. The external surface of pipelines is exposed to the atmosphere, fresh or sea water conditions, and soil environments. Additionally, UV radiation accelerates the degradation of protective coatings in pipelines. External corrosion failure mechanisms include uniform corrosion, localized corrosion, atmospheric corrosion, microbiologically influenced corrosion (MIC), stray current corrosion, differential cell corrosion, under deposit corrosion (UDC), corrosion under insulation (CUI), selective seam weld corrosion (SSWC), and stress corrosion cracking (SCC). Contributing factors to external corrosion include moisture, temperature, relative humidity, pollutants, oxygen, soil pH, soil resistivity, soluble salts, nitrogen, phosphorous, sulfates, microorganisms, coating defects, pipe characteristics, construction practices, operational parameters, cathodic protection shielding, and AC and DC interference. Table 1 to Table 4 show the influence of elements in soil characteristics, pipe characteristics, construction practices, and operational parameters respectively.¹⁻³

Table 1
Corrosive effect of soil characteristics

Soil Resistivity (ohm.cm)	Soil Type	Moisture	Corrosivity
<500	Muskeg/sloughs/free water accumulations	Always wet	Very corrosive
500 - 2000	Loams/clays	Mainly wet	Corrosive to moderately corrosive
2000 - 10000	Gravels, sandy	Mainly dry	Mildly corrosive
>10000	Arid, sandy	Always dry	Non-corrosive

Table 2
Influence of pipe characteristics on external corrosion

Element	Influence
Material and grade	Galvanic corrosion where dissimilar metals are joined
	Can create local corrosion cells when exposed to the environment
Diameter	Detection capabilities of indirect inspection tools Allowable defect size and prediction of life span CP monitoring
Wall thickness	Direct impact on allowable defect size and prediction of life span
Year manufactured	Older structures have typically lower toughness levels
Seam type	Older structures have typically lower weld seam toughness
	Pre-1970 electric resistance welded (ERW) or flash-welded seams may be subject to higher corrosion rates than the base metal
Bare pipe	Integrity assessment tools are limited for these segments because many tools rely on coating conditions. Half-cell potential surveys are used on bare pipe to identify "hot spots" where the pipe is corroding, and operators place an anode to mitigate corrosion.

Table 3
Influence of construction practices on external corrosion

Element	Influence
Age and protective coatings	Coating degradation rates Corrosion rate estimates Holiday detection and repairs
Route changes/modifications	May require separate direct assessment methods
Backfill	May involve different soil characteristics
Location of appurtenances	Special consideration to dissimilar metals CP current requirements may vary Dissimilar metals may lead to local corrosion cells Coating degradation rates may be different from adjacent regions
Location of and construction methods used at casings	Additional assessment tools may be required Extrapolation may be required due to future development and/or inaccessible areas. Continued monitoring for casing shorts is required annually
Locations of bends	Coating degradation rates may be different from adjacent regions Localized corrosion may be present on miter and wrinkle bends CP currents may vary
Depth of cover	May impact the flow of current Restricts the use of indirect assessment tools
Underwater sections, river crossings	Impacts the flow of current and interpretation of results Restricts the use of indirect assessment tools
River weights and anchors	Impacts the flow of current and interpretation of results Restricts the use of indirect assessment tools Localized corrosion may be present near weights and anchors
Proximity to other pipelines or structures	Restricts the use of indirect assessment tools Impacts the flow of current and interpretation of results

Table 4
Influence of operational factors on external corrosion

Element	Influence
Temperature	Localized corrosion and acceleration of coating degradation rates
Stress levels and fluctuations	Impacts growth mechanisms and remaining life calculations
Corrosion monitoring programs	May impact repairs and remediation schedules May restrict the use of integrity assessment tools on bare steel pipelines Impacts the interpretation of results
Maintenance and repair history	May change the influence of CP currents Can create local cells May restrict the use of direct assessment tools Impacts the interpretation of results

Mechanisms of External Corrosion

The mechanisms of external corrosion in a pipeline system can be characterized in two different areas: aboveground and underground. Protective coatings act as the first mechanism of defense, while CP systems are employed for underground pipelines. Figure 1 shows the mechanisms of corrosion encountered on aboveground pipelines accompanied with contributing factors. The types of atmospheric corrosion under these conditions include uniform corrosion, localized corrosion, UDC, CUI, and MIC under special conditions. The main contributing factors are moisture, temperature, pollutants, coating degradation by UV radiation, oxygen, soluble salts, microorganisms, coating defects, and pipe and coating characteristics.⁴

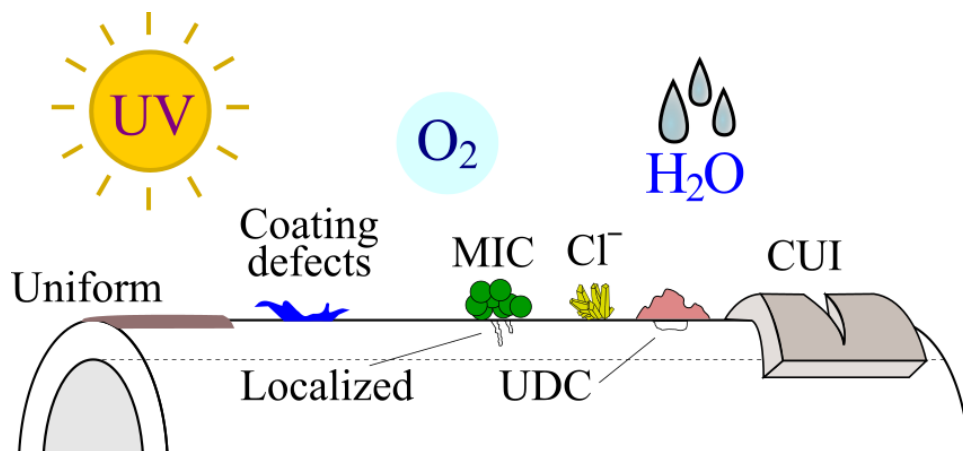


Figure 1: Mechanisms of external corrosion and contributing factors in an aboveground pipeline system.

Figure 2 depicts the most common mechanisms of corrosion in underground pipelines accompanied with contributing factors. The types of corrosion encountered under this environment include uniform corrosion, localized corrosion, and SCC. Localized corrosion includes MIC, stray current corrosion, differential cell corrosion, UDC, CUI, and SSWC. The main contributing factors in underground external corrosion are moisture, soil pH, soil resistivity, soluble salts, oxygen, nitrogen, phosphorous, sulfates, microorganisms, coating defects, and disbonded coatings, pipe characteristics, and AC and DC stray currents.

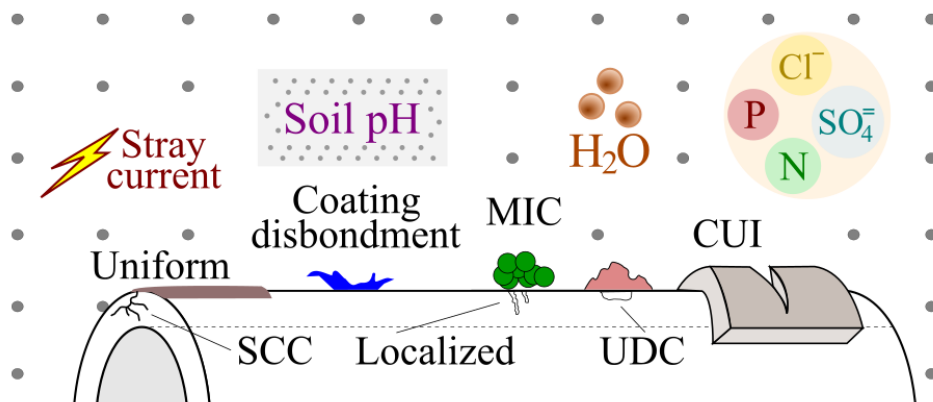


Figure 2: Mechanisms of external corrosion and contributing factors in an underground pipeline system.

In contrast with internal corrosion, the commodity being transported in a pipeline system has no effect on the corrosive behavior of metal surfaces due to external factors. Hazardous liquid and natural gas underground and aboveground pipelines are exposed to two different environments as shown above in Figure 1 and 2. The most common external corrosion mechanisms in a pipeline system are described below.

Uniform corrosion, also referred to as general corrosion, is the oxidation of the external bare surface of the pipe and a reduction of the wall thickness caused by a corrosive environment. The most susceptible areas impacted by uniform corrosion in a pipeline are areas with constant exposure to water, homogeneous soils, and bare pipe or inadequately coated pipelines that are not properly protected by CP. This type of corrosion is uniform over the entire pipe surface.

Pitting corrosion is a localized form of corrosion, in which cavities or pits of micron or millimeter size initiate in an anodic area in the metal and grow as time progresses. Pitting can be difficult to identify

because isolated pits can be small in diameter, deep, and are sometimes underneath coatings, insulation, or covered with deposits or corrosion products that have some magnetic permeability which can mask the wall loss to a magnetic flux leakage (MFL) signal. This type of corrosion is more common than general corrosion and occurs more rapidly at some locations than others. Transition areas between the atmosphere and the soil are susceptible to this type of corrosion.

Atmospheric corrosion is the degradation of the external surface of the pipe due to direct exposure to the atmosphere. The factors that influence the rate of corrosion include moisture, contamination, temperature, relative humidity, condensation, high chloride concentrations, oxygen, microorganisms, and UV radiation degrades coatings. Localized corrosion and scale on the steel surface are the most common forms of corrosion encountered. This type of corrosion is predominant in aboveground pipes, storage tanks, valves, splash zones, soil-to-air and water-to-air transition areas, exposed pipe, under insulation, through walls, cased pipelines, pipe supports, and brackets.

MIC refers to corrosion caused by the presence and activity of microorganisms on metal surfaces by adhering biofilms. Underneath these colonies, localized corrosion is initiated. The presence of microorganisms does not translate into the development or occurrence of corrosion but must be considered as a factor along with chemical and physical conditions. The main types are sulfate-reducing bacteria (SRB) and acid-producing bacteria (APB).

Microorganisms find essential nutrient conditions to thrive in around carbon, nitrogen, sulfates, and phosphate sources. Although these conditions are more frequently found around underground pipelines, aboveground pipelines can also see favorable atmospheric conditions such as temperature, oxygen, and relative humidity. Microorganisms with conducting characteristics may use iron as their source of energy under starving conditions.³ Once a biofilm is established, a localized chemical environment develops, which is very different from the bulk chemistry where the pipe surface is exposed to, thereby the CP system may not be suitable to provide sufficient protection to prevent MIC.

Stray current corrosion results from underground electrical currents from external sources causing interference with a CP system. Stray currents are classified as direct, alternating, and telluric currents. Direct stray currents originate from foreign cathodic protection systems, transit systems, electrified railways, subway systems, streetcars, and high-voltage DC power lines. Stray alternating currents are associated with electrical power transmission systems. Corrosion will occur at the point of high current density discharges from the structure and is independent from environmental factors such as oxygen, chloride concentrations, or pH.

Differential cell corrosion is the result of oxidation and reduction reactions occurring at or very near the same location on a metal. These sites can be exposed to different soil characteristics, chemistry, or dissimilar metals. A differential aeration cell is influenced by the oxygen content in the soil. The rate of corrosion is affected by pH and the concentration of aggressive ions such as chlorides in the soil. Galvanic corrosion is another example of a differential corrosion cell and can be detrimental to a system when the pipeline becomes the anode.^{4,5}

UDC is localized corrosion formed beneath or around deposits present on a metal surface due to disbonded coatings and consequently shielding. Tape coating systems in pipelines are more susceptible to UDC on disbondment areas, typically at 3 and 9 o'clock position. UDC may also be present beneath coating wrinkles, layers of debris, scale, biofilm, or corrosion products. In this corrosion cell, the environment is favorable for many types of corrosion to occur including galvanic, localized, and MIC. Soil stresses may contribute to the coating degradation to UDC, and can be more predominant on large diameter pipes.

CUI occurs when penetration of water, moisture, and/or contaminants are trapped under insulation and are under continuous contact with the external surface of the pipe. It is caused by condensation, rain, and pollutants such as high concentration of oxides in the atmosphere. The corrosion process is generally