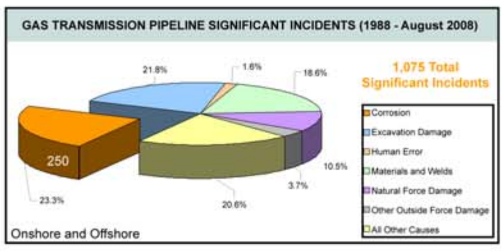
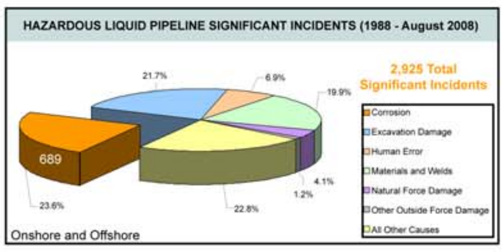
PIPELINE CORROSION

CORROSION IN PERSPECTIVE

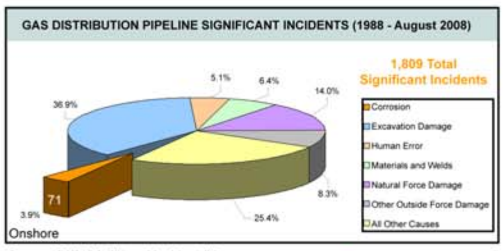
GAS TRANSMISSION PIPELINE SIGNIFICANT INCIDENTS (1988 - August 2008)



HAZARDOUS LIQUID PIPELINE SIGNIFICANT INCIDENTS (1988 - August 2008)



GAS DISTRIBUTION PIPELINE SIGNIFICANT INCIDENTS (1988 - August 2008)

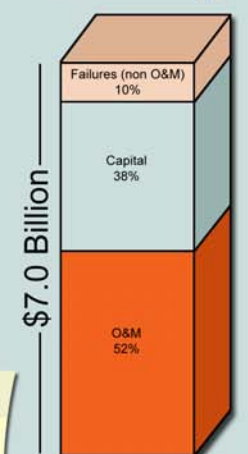


Source: PHMSA Filtered Incident Files

COST OF CORROSION IN PIPELINES

The average annual corrosion-related costs for onshore natural gas and hazardous liquid transmission pipelines is estimated to be $7.0 billion, which can be divided into the cost of capital (38 percent), operation and maintenance (52 percent) and failures (10 percent).

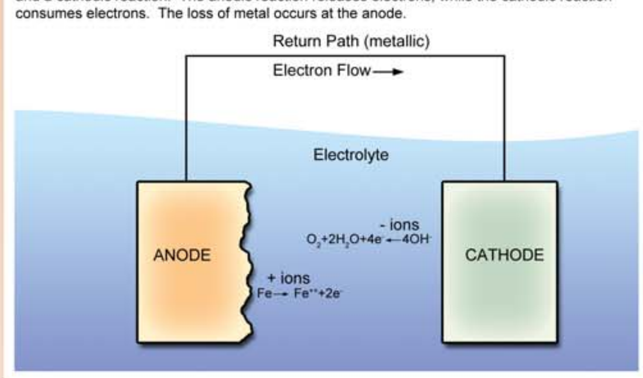
Source: FHWA-RD-01-156, March 2002.



On average, there have been about 52 corrosion-related significant pipeline incidents per year over the past twenty years. Approximately 64 percent of the incidents involved liquid pipelines; 23 percent occurred on gas transmission pipelines, 7 percent on gas gathering pipelines and 6 percent on gas distribution systems.

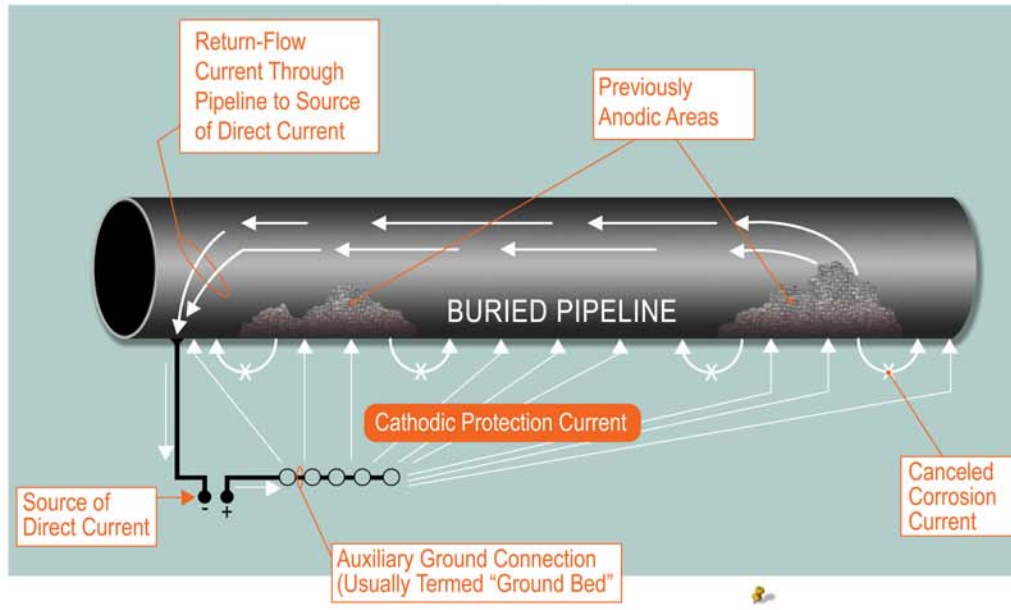
BASIC CORROSION THEORY

Corrosion is an electrochemical reaction composed of two half cell reactions, an anodic reaction and a cathodic reaction. The anodic reaction releases electrons, while the cathodic reaction consumes electrons. The loss of metal occurs at the anode.



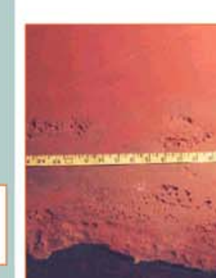
EXTERNAL CORROSION

The primary method of preventing and mitigating external corrosion on buried pipelines involves a combination of cathodic protection and coatings. Cathodic protection involves applying a current to the pipeline through the soil from external sources (sacrificial anodes and/or induced current) sufficient enough to nullify any outgoing currents from the anodic areas of the pipeline, rendering exposed portions of the pipeline surface cathodic. Coatings are intended to reduce the surface area of exposed metal on the pipeline, thereby reducing the current necessary (and cost) to cathodically protect the metal. The most widely used pipe coating is Fusion Bonded Epoxy (FBE) which is applied to hot rotating pipe that is electrically charged. FBE is resistant to high temperatures, can withstand high stresses, and provides good protection against corrosion.



Localized corrosion - typically manifests as pitting on a small area of the metal and is not uniform across the surface.

Uniform/general corrosion - General, but irregular, thinning of the pipe wall which proceeds at approximately the same rate over the whole surface being corroded.


localized pitting

INTERNAL CORROSION

Internal corrosion generally cannot occur in a pipeline unless there is an electrolyte to complete the corrosion cell. Water or other aqueous materials are needed to form the electrolyte. Also, other chemicals usually must be present: for example, carbon dioxide (CO_2) for the formation of dilute organic and inorganic acids or sulfur for the formation of acid or growth of bacteria. Once introduced, the corrosive materials may continue to damage the pipeline until they are removed, or until they are consumed in corrosion reactions.

Prevention/Mitigation Methods for Internal Corrosion include:

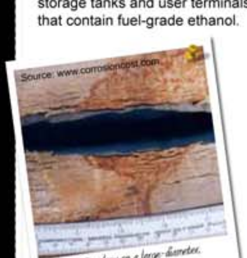
- **Dehydration/Separation** – removal of condensation and free water from gas streams and liquids
- **Coatings/plastic liners** - Not very effective as sole measure, but can be used with other methods
- **Inhibitors** - Chemicals added to the pipeline to reduce the rate of corrosion, can be absorbed onto the metal surface or react with it to form a protective film, or can react with the corrodent to make it less corrosive
- **Cleaning Pigs** – removal of liquids and contaminates that buildup in pipelines
- **Biocides** – Injected into the product stream to kill microbes that cause microbiologically influenced corrosion (MIC)
- **Buffering** – Introduction of a buffering agent to reduce corrosivity of any standing liquid (not widely used)


Internal corrosion of crude oil pipeline.
Source: www.corrosioncost.com

ENVIRONMENTALLY ASSISTED CRACKING

Stress Corrosion Cracking (SCC) is a form of Environmentally Assisted Cracking (EAC), in which a combination of tensile stress and a corrosive environment causes cracks to form in the metal. SCC was discovered in 1965 to be a possible cause of pipeline failure, resulting in one or two failures per year in the US.

The two types of external SCC are High-pH SCC and Near-neutral-pH SCC. Most instances of high-pH SCC, whose crack growth rate increases with increasing temperature, have been found downstream of gas compressor stations and rarely on liquid lines. External SCC has been observed only under field-applied coating; neither form of SCC has been detected on offshore pipelines. There have been no reports of internal SCC in pipelines in North America; however, SCC has been observed inside storage tanks and user terminals that contain fuel-grade ethanol.



SCC colony on a large-diameter, high-pressure, gas transmission pipeline

Hydrogen Embrittlement, another form of EAC, refers to one of three forms of hydrogen degradation to the properties of a metal: Hydrogen-stress cracking, hydrogen-induced cracking, and loss of ductility (less of a concern to operating pipelines). Common features are an applied tensile stress and hydrogen dissolved in the metal (due to corrosion or cathodic protection), which can seriously reduce the ductility and load-bearing capacity of the metal, causing cracking and catastrophic brittle failures at stresses below the yield stress of susceptible materials. Hydrogen embrittlement is typically found in high-strength steels and at "hard spots" of lower strength pipe (i.e., X52).

Sulfide-Stress Cracking (SSC) can occur from two sources: internally, from transporting wet, sour products, or from water containing sulfate-reducing bacteria (SRB); and externally, from SRB in soil or water in contact with the pipe. Reported failures due to SSC are relatively few, with internal SSC far more common than external SSC. Steels with high strength or hardness and those under tensile stress are more susceptible to SSC. Prevention of SSC failures in pipelines that could be exposed to wet hydrogen sulfide environments includes uses of steel with maximum strength level of 80,000 psi and control of welding processes to avoid inducement of regions of high hardness and high residual stress.

CORROSION DAMAGE ASSESSMENT METHODS

To assess the structural integrity of a pipeline that may contain corrosion defects, 49 CFR Part 192 (gas) and 49 CFR Part 195 (liquid) recognize three acceptable approaches:

In-Line Inspection (ILI)

- Referred to as "smart pigging"
- Provides very good coverage and ability to locate corrosion defects
- The location ad size of all internal and external wall loss features are recorded
- Pipelines may require modifications for "pigs" to pass through the line - not all lines are piggable


MFL inspection pig (BJ Pipeline Inspection)

Hydrostatic Testing

- Requires filling a section of the pipeline with water and pressuring it significantly above normal operating pressure
- Detects defects, such as corrosion pits or cracks, by causing them to leak or rupture
- Finding source of water and disposal of water could be a problem in some cases
- Requires that the pipeline be removed from service when tested

Direct Assessment

- Typically used where hydrostatic or ILI testing is impractical
- Involves a 4 step process using a combination of corrosion technologies accompanied by physical inspections to assess a pipeline segment: 1) Pre-assessment; 2) Indirect inspections; 3) Direct examinations; 4) Post assessment
- ECDA, ICDA and SCCDA processes are meant to insure that the pipeline does not have external corrosion, internal corrosion or SCC that is severe enough to cause a failure before the next inspection.

CORROSION DAMAGE ASSESSMENT

Costs for Corrosion Damage Assessment Methods
(Includes costs of cleaning, preparation, inspection, operator oversight, loss of throughput)

Activity	Natural Gas Pipelines		Liquid Pipelines	
	Low Estimate ($ per mi)	High Estimate ($ per mi)	Low Estimate ($ per mi)	High Estimate ($ per mi)
In-Line Inspection	$3,200	$5,300	$4,600	$6,100
Hydrostatic Testing	$10,140	$29,960	$30,900	$99,160
Direct Assessment	$2,720	$9,600	$2,000	$6,000

Summary of Assessment Methods

METHOD	STRENGTH	WEAKNESS
In-Line Inspection	Measures and maps remaining wall thickness	Single run does not identify active corrosion and the accuracy of multiple run predictions is uncertain. Resolution of tools varies.
Hydrostatic Testing	Causes a controlled hydrostatic rupture of near-critical flaws.	Does not identify the presence or severity of flaws other than critical axial flaws that fail at the pressure tested.
Direct Assessment	Identifies areas of high probability of active corrosion.	Verifies accuracy through excavation program; does not permit 100% direct assessment of pipeline.

Source: FHWA-RD-01-156, March 2002

REGULATIONS AND STANDARDS

The Department of Transportation's (DOT) Pipeline and Hazardous Material Safety Administration (PHMSA), acting through the Office of Pipeline Safety (OPS), administers DOT's national regulatory program to assure the safe transportation of natural gas, petroleum, and other hazardous materials by pipeline.

For natural gas pipelines, 49 CFR Part 192, Subpart I, §§192.451 to 192.491 entitled "Requirements for Corrosion Control" prescribes minimum requirements for the protection of metallic pipelines from external, internal, and atmospheric corrosion.

For hazardous liquid pipelines, 49 CFR Part 195, Subpart H §§192.551 to 192.589 entitled "Corrosion Control" prescribes minimum requirements for protecting steel pipelines against corrosion.

These regulations incorporate standards that are developed by various industry consensus organizations.

NACE International (NACE) is the principal professional organization for the development of corrosion control standards and test methods. Among the most important NACE standards are those addressing control of external corrosion on underground or submerged metallic piping systems; control of internal corrosion in steel pipelines and piping systems; cathodic protection; pipeline coatings; field monitoring techniques; and procedures for direct assessment (external corrosion, internal corrosion for pipelines that carry normally dry gas, and SCC).

Other relevant SDOs include the American Society of Mechanical Engineers (ASME), American Petroleum Institute (API), ASTM International (ASTM), American Society for Nondestructive Testing (ASNT), American National Standards Institute (ANSI), and Det Norske Veritas (DNV).

Integrity Management

On November 15, 2002, Congress passed the Pipeline Safety Improvement Act of 2002. This law requires PHMSA/OPS to issue regulations prescribing standards to direct a natural gas system operator to conduct a risk analysis and adopt and implement an integrity management program (IMP). The statute sets forth minimum requirements for IMPs for gas transmission pipelines located in High Consequence Areas (HCAs). These requirements have been incorporated into 49 CFR Part 192, Subpart "O". Part 192.917 specifically mentions internal corrosion, external corrosion and SCC as threats that must be considered for gas pipelines.

Similarly, IMP requirements for hazardous liquid pipelines effective May 29, 2001, and February 15, 2002, specify regulations to assess, evaluate, repair and validate through comprehensive analysis the integrity of hazardous liquid pipeline segments that, in the event of a leak or failure, could affect populated areas, areas unusually sensitive to environmental damage and commercially navigable waterways. 49 CFR Part 195.452 addresses IMP requirements for hazardous liquid pipelines, including the need to assess for corrosion.

Prepared for DOT/PHMSA/OPS by Michael Baker Jr., Inc. 2008