Pipeline Corrosion

FINAL REPORT

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Submitted by

Baker

Michael Baker Jr., Inc.

Contributing Author
Raymond R. Fessler, Ph.D.
BIZTEK Consulting, Inc.

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List of Abbreviations

AC	Alternating Current
AGA	American Gas Association
AGM	Aboveground Marker
ANB	Anaerobic Bacteria
ANSI	American National Standards Institute
AOPL	Association of Oil Pipelines
APB	Acid-Producing Bacteria
API	American Petroleum Institute
ASME	American Society of Mechanical Engineers
ASNT	American Society for Nondestructive Testing
ASTM	ASTM International (formerly the American Society for Testing and Materials)
AWWA	American Water Works Association
BSI	British Standards Institute
CEPA	Canadian Energy Pipeline Association
CFR	Code of Federal Regulations
CP	Cathodic Protection
CSE	Copper/Copper Sulfate Electrode
DA	Direct Assessment
DC	Direct Current
DNV	Det Norske Veritas
DOE	(U.S.) Department of Energy
DOI	(U.S.) Department of the Interior
DOT	(U.S.) Department of Transportation
DSAW	Double Submerged Arc Weld
EAC	Environmentally Assisted Cracking
EC	External Corrosion
ECDA	External Corrosion Direct Assessment
EGIG	European Gas pipeline Incident data Group
EMAT	Electromagnetic Acoustic Transducer
ERCB	Energy Resources Conservation Board (formerly EUB)
ERW	Electric-Resistance Welded
EUB	Energy and Utilities Board (Alberta)
FBE	Fusion-Bonded Epoxy
FFS	Fitness-For-Service
FTE	Full-Time Equivalent
GPS	Global Positioning System
GRI	Gas Research Institute
GTI	Gas Technology Institute
GUL	Guided Ultrasonic
GWUT	Guided-Wave Ultrasonic Testing
HAZ	Heat-Affected Zone
HCA	High-Consequence Area
HDD	Horizontally Directionally Drilled
HIC	Hydrogen-Induced Cracking
IC	Internal Corrosion
ICDA	Internal Corrosion Direct Assessment
IDX	Integrity Data Exchange

ILI	In-Line Inspection
INGAA	Interstate Natural Gas Association of America
ISO	International Organization for Standardization
LDC	Local Distribution Company
LRGWUT	Long-Range Guided-Wave Ultrasonic Testing
MAOP	Maximum Allowable Operating Pressure
MFL	Magnetic-Flux Leakage
MIC	Microbiologically Influenced Corrosion
MOP	Maximum Operating Pressure
MPI	Magnetic Particle Inspection
NACE	NACE International
NDE	Non-Destructive Evaluation
NDT	Non-Destructive Testing
NEB	National Energy Board (Canada)
NETL	National Energy Technology Laboratory
NGA	Northeast Gas Association
O&M	Operations and Maintenance
OPS	(U.S. Department of Transportation) Office of Pipeline Safety
OTD	Operations Technology Development Company
PAMP	Portable Acoustic Monitoring Packages
P&M	Preventative and Mitigative Measures
PHMSA	(U.S. Department of Transportation) Pipeline and Hazardous Materials Safety Administration
PRCI	Pipeline Research Council International
R&D	Research and Development
RAPID	Real-Time Active Pipeline Integrity Detection
RFEC	Remote Field Eddy Current
RFET	Remote Field Electromagnetic Technique
RFT	Remote Field Testing
RP	Recommended Practice
RSTRENG	Remaining Strength of Corroded Pipe
SATT	Shear Appearance Transition Temperature
SCC	Stress Corrosion Cracking
SCC DA	Stress Corrosion Cracking Direct Assessment
SGA	Southern Gas Association
SME	Subject Matter Expert
SMYS	Specified Minimum Yield Strength
SP	Standard Practice
SRB	Sulfate-Reducing Bacteria
SSAW	Single Submerged Arc Weld
SSC	Sulfide Stress Cracking
UT	Ultrasonic Testing

1 Introduction

This study was developed at the request of the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) to provide a non-technical, high-level common understanding of issues related to pipeline corrosion. This study follows similar efforts by PHMSA to provide information on topics regarding pipeline integrity issues in report format. The intent is that the report be used to facilitate effective communication on issues with all stakeholders (public officials, industry representatives, trade associations, pipeline companies, and the general public). Readers who desire more technical depth are encouraged to refer to books such as Peabody's Control of Pipeline Corrosion or the many technical papers published by NACE International (NACE), American Society of Mechanical Engineers (ASME), and other technical societies and research organizations.

This study presents an overview of the corrosion threat to gas and liquid pipelines, focusing on the prevention, detection, characterization, and management of internal and external corrosion, primarily on onshore pipelines. The report provides concise information on the state of pipeline corrosion control, the gaps in current knowledge, and the direction of current research and development. While not formally or comprehensively addressing corrosion of offshore pipelines, this study does highlight aspects of corrosion in offshore pipelines in various sections and is specific in reference when discussed.

1.1 Corrosion Overview

Corrosion is one of the leading causes of failures in onshore transmission pipelines (both gas and hazardous liquids) in the United States. It also is a threat to gas distribution mains and services, as well as oil and gas gathering systems.

PHMSA uses specific criteria to identify the incidents that are significant from a pipeline safety viewpoint. An incident is defined as significant if it meets any of the following conditions:

- Fatality, or injury requiring in-patient hospitalization
- $50,000 or more in total costs, measured in 1984 dollars
- Highly volatile liquid releases of five barrels or more, or other liquid releases of 50 barrels or more
- Liquid releases resulting in an unintentional fire or explosion.

As shown in Figure 1-1, corrosion has been responsible for 18 percent of the significant incidents (both onshore and offshore) in the 20-year period from 1988 through 2008. By comparison, during this same period, excavation damage accounted for 26 percent of significant incidents. By contrast, corrosion accounted for only 5.8 percent of all serious incidents (onshore and offshore), defined as those resulting in fatality or injury requiring in-patient hospitalization, during this same period, while excavation damage was responsible for 34.5 percent of all serious incidents.

NACE currently estimates the total costs attributed to all types of corrosion at $276 billion. Corrosion of onshore gas and liquid transmission pipelines represents $7 billion of this total. Table 1-1 shows the estimated corrosion costs in the 1990s for onshore transmission pipelines. The costs are broken down by the cost of capital, operations and maintenance (O&M), and the cost of failures (non-related O&M costs). The pipeline rehabilitation and replacement costs are included in the capital costs. O&M costs comprise approximately half of the total costs associated with corrosion.

All Pipeline Significant Incidents (1988 – August 2008)

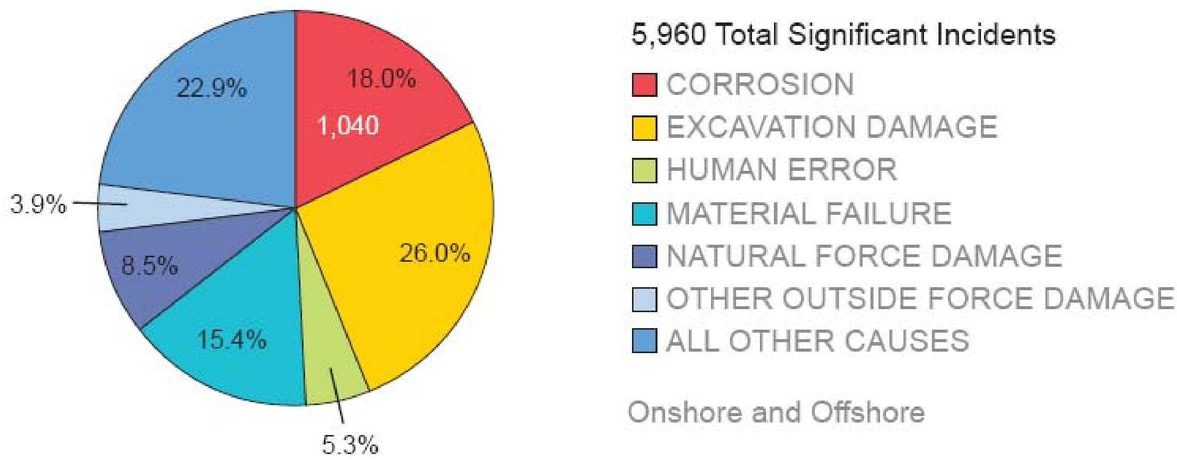

Figure 1.1 – Causes of significant incidents in onshore and offshore pipelines (Source: PHMSA Filtered Incident Files)

Table 1.1 – Cost of Corrosion in U. S. Transmission Onshore Pipelines

	Low Estimate (Millions of US $)	High Estimate (Millions of US $)	Average	
			(Millions of US $)	Percent
Cost of Capital	2,500	2,840	2,670	38
Operations and Maintenance (O&M)	2,420	4,840	3,630	52
Cost of Failures (Non-Related O&M)	471	875	673	10
Total Cost Due To Corrosion	5,391	8,555	6,973	100
(Source: http://www.corrosioncost.com/pdf/gasliquid.pdf) FHWA-RD-01-156, March 2002.				

1.2 Corrosion in Perspective

1.2.1 Frequency and Consequences in the United States

As is shown in Figure 1-2, there have been 40 to 65 significant corrosion incidents per year on pipelines during the past 20 years, which averages to 52 such incidents per year. Typically, half or more involve onshore liquid pipelines; the next highest frequency involves onshore gas transmission pipelines. The pattern has been relatively consistent over time and, rather surprisingly, has not been influenced by the aging of the infrastructure. The fact that the pipeline failure rate has not increased significantly over a 20-year interval attests to the effectiveness of industry efforts at corrosion control.

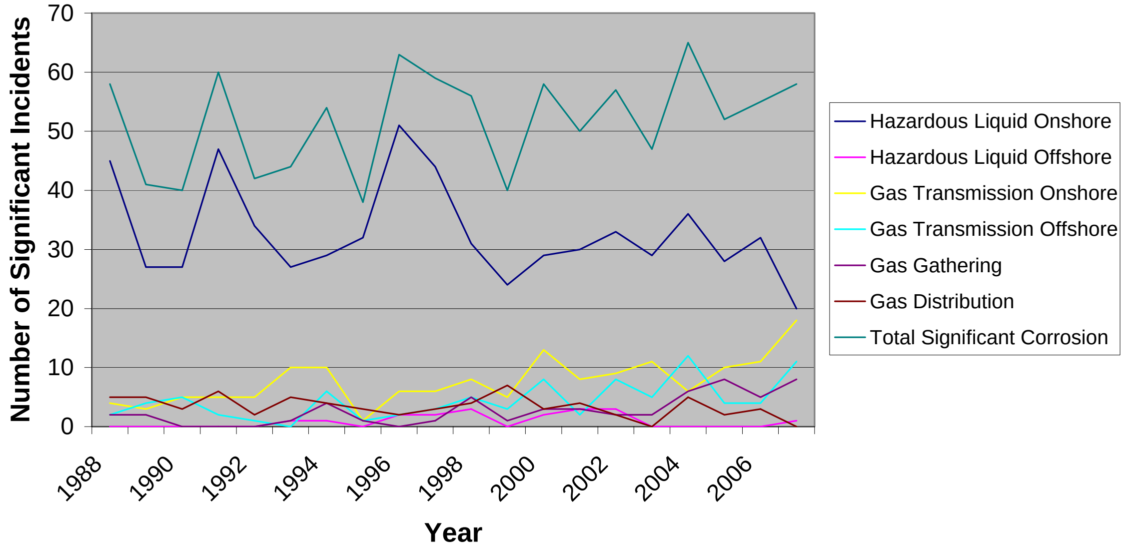

Figure 1.2– History of significant corrosion incidents in the U.S.
(Source: PHMSA Filtered Incident Files)

The 1,074 significant incidents during that 20-year period resulted in 30 fatalities, 100 injuries, and $551 million in property damage. This contrasts with 1,552 significant excavation damage incidents which resulted in 147 fatalities, 619 injuries, and $518 million in property damage. Table 1-2 presents comparable data on significant corrosion incident consequences.

Table 1.2 – Average Annual Consequences of Significant Corrosion Incidents Between 1988 and 2007

Type of Pipeline	Mileage		Number	Fatalities	Injuries	Property Damage
	1988	2007				
Hazardous Liquid	153K	166K				
Onshore			33	0.05	0.8	$14M
Offshore			0.9	0	0	$1.7M
Gas Transmission						
Onshore	284K	294K	7.7	0.6	0.2	$8.2M
Offshore	7K	7K	4.4	0	0	$1.2M
Gas Gathering	32K	20K	2.7	0	0.2	$1.2M
Gas Distribution	802K	1172K	3.4	0.8	3.9	$0.6M
Total	1278K	1659K	51.9	1.4	5.2	$25M

(Source: PHMSA Filtered Incident Files)

1.2.2 Transmission Pipelines

As is shown in Figures 1-3 and 1-4, corrosion accounts for about 23 percent of the significant failures in both hazardous liquid and gas transmission pipelines. In terms of absolute numbers, there were more significant failures and more property damage associated with liquid pipelines than with gas pipelines during the twenty year period.

Hazardous Liquid Pipeline Significant Incidents (1988 – August 2008)

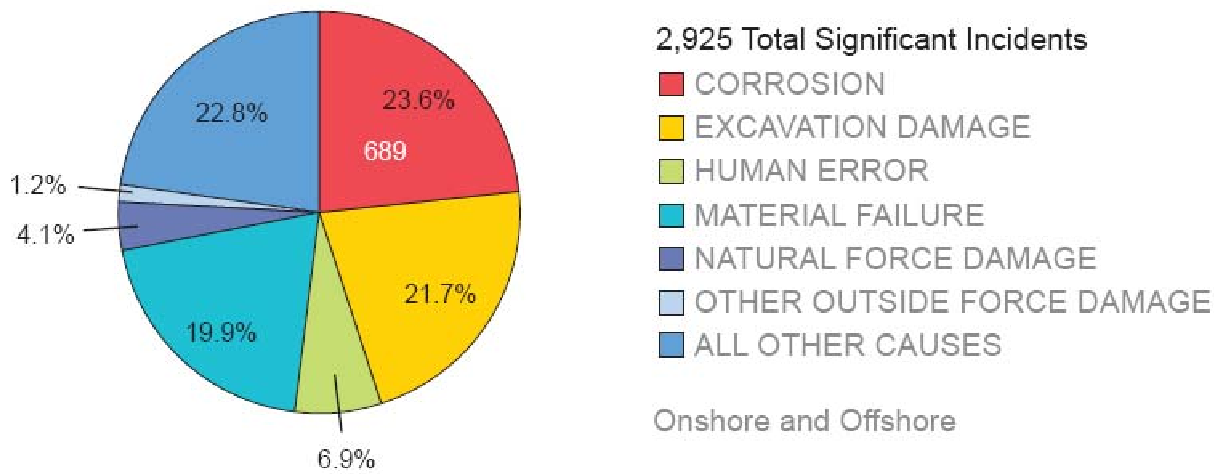

Figure 1.3 – Causes of significant incidents in onshore and offshore hazardous liquid transmission pipelines (Source: PHMSA Filtered Incident Files)

Gas Transmission Pipeline Significant Incidents (1988 – August 2008)

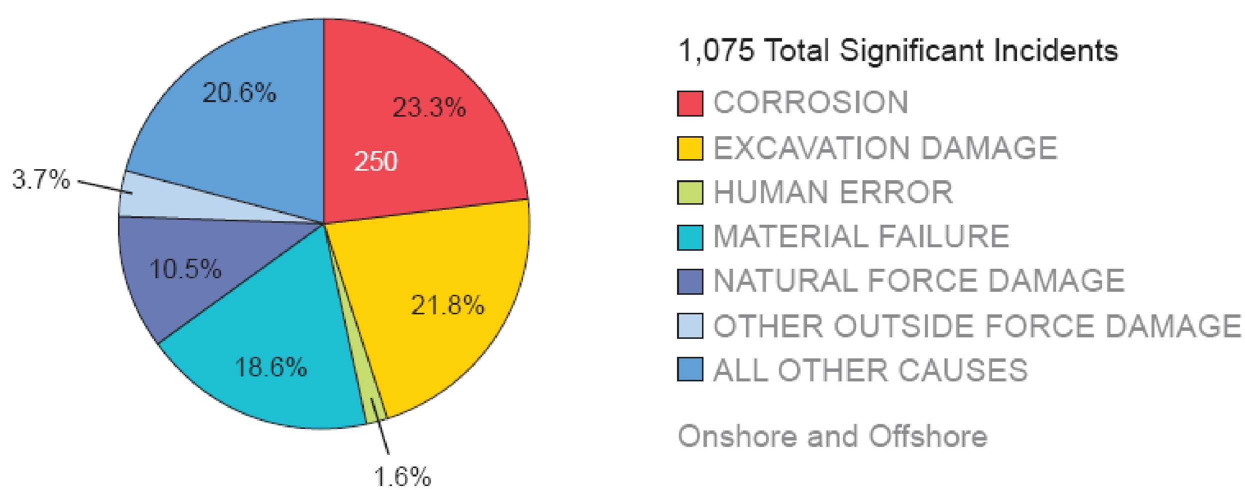

Figure 1.4 – Causes of significant incidents in onshore and offshore natural gas transmission pipelines (Source: PHMSA Filtered Incident Files)

Corrosion failures can be either leaks or ruptures. Leaks are more common. Leaks from gas pipelines generally do not cause property damage, because the escaping gas disperses into the atmosphere. However, leaks from a liquid line can contaminate the soil, groundwater or surface water. Conversely, ruptures in a gas pipeline are more likely to cause an explosion and fire, thus resulting in more fatalities and injuries on average.

Almost all of the corrosion incidents in liquid pipelines have involved onshore lines. The few impacting offshore lines have caused neither fatalities nor injuries, which is not surprising, since the probability of an individual being in proximity to an offshore failure is extremely remote.

On a per-mile basis, a disproportionate number of reported corrosion failures in gas transmission pipelines occurred offshore, but 97 percent were due to internal corrosion. Conversely, 77 percent of the onshore incidents were due to external corrosion.

1.2.3 Natural Gas Distribution Pipelines

External force damage is much more prevalent for distribution pipelines than for transmission pipelines since the majority of distribution pipelines are non-metallic and generally are located in more densely populated areas. The failure rate of distribution pipelines due to various causes is shown in Figure 1-5.

Gas Distribution Pipeline Significant Incidents (1988 – August 2008)

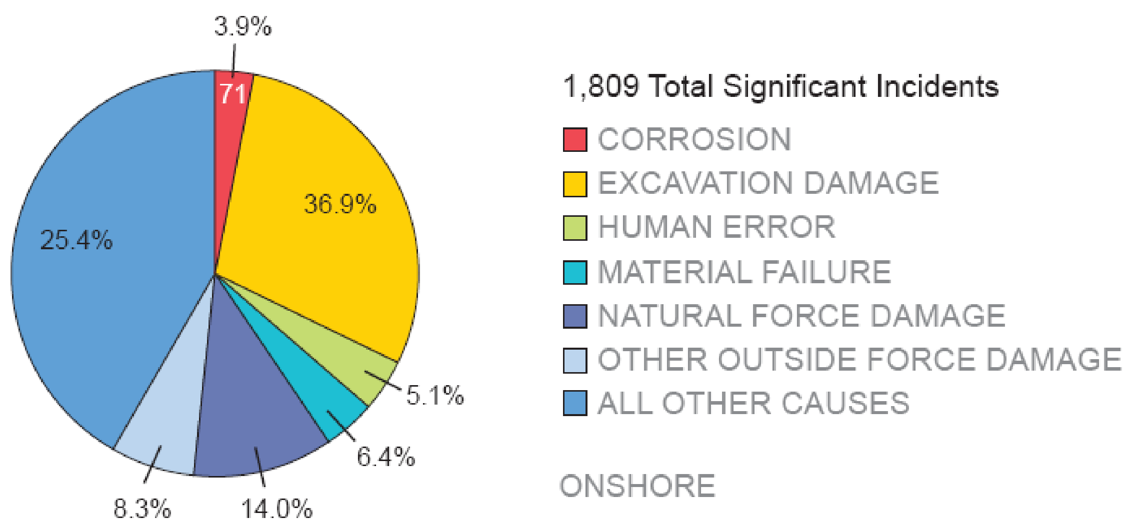

Figure 1.5 – Causes of significant incidents in natural gas distribution pipelines (Source: PHMSA Filtered Incident Files)

External corrosion causes more than 90 percent of corrosion-related failure in distribution pipelines. Prior to the implementation of 49 CFR Part 192 in 1970, distribution pipelines were required neither to be coated nor to have cathodic protection. In the 1950s, many operators did coat their distribution mains and services but did not provide cathodic protection until required to do so. Therefore, older distribution systems may contain many miles of pipe that have been unprotected for some time and have suffered corrosion damage.

Distribution pipelines are not thought to be as prone to internal corrosion as transmission pipelines because they are located further downstream from gathering and production systems which might introduce water into the gas stream. Since many of the gathering and transmission systems have equipment to scrub and clean the gas stream, internal corrosion in the gas transmission system is not as prevalent a threat as it was prior to the installation of cleaning and conditioning equipment. Early transmission lines did not perform this function, and there is evidence that they may contain inactive internal corrosion.

If a distribution pipeline is near a storage field and the transmission system operator does not sufficiently dehydrate and clean the stored gas prior to its introduction into the distribution system, internal corrosion in the distribution pipeline can occur. Distribution companies have tariffs and specifications that limit the amount of water that can be present in their delivered gas (whether from a transmission pipeline or storage field).

1.2.4 Gas Gathering Lines

Gas gathering lines account for very few corrosion failures, and those failures that have occurred resulted in no fatalities and very few injuries. More than 90 percent of the reported incidents were caused by internal corrosion.

1.2.5 Non-U.S. Experience

There are substantial differences between the Canadian pipeline system and the U.S. system. Besides encompassing only 20 percent as many miles, the Canadian pipelines are of much more recent construction, on average, which not only means that they have had less time to corrode, but also that they have benefited from newer and better coatings as well as more consistently applied cathodic protection. In addition, because of the low population density in Canada, outside force damage is extremely low. Consequently, the Canadian experience, as illustrated in Figure 1-6, is somewhat different from the U.S. experience. Corrosion failures, including stress-corrosion cracking (SCC), made up about half of the failures in Canadian gas transmission systems – more than twice the proportion realized in the United States.

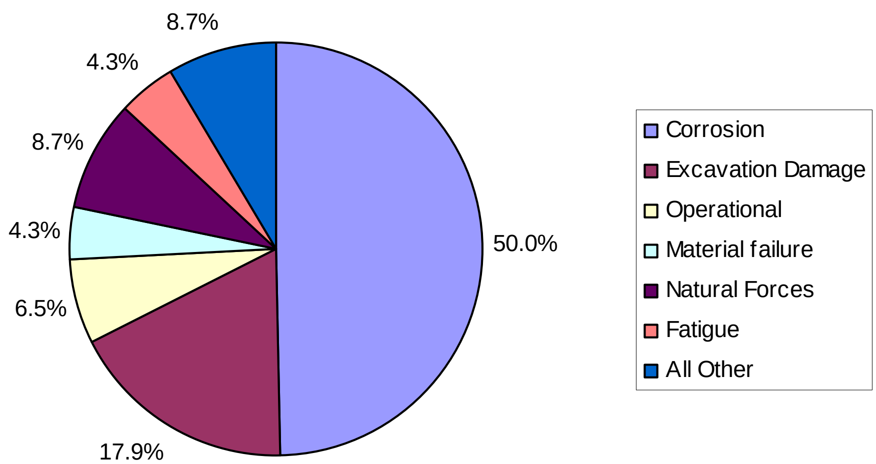

Figure 1.6 – Causes of the 46 ruptures that occurred in Canadian pipelines from 1984-2004 (Source: National Energy Board. [2008, July]. Focus on Safety and the Environment. A Comparative Analysis of Pipeline Performance, 2000 – 2006)

As is shown in Figure 1-7, Europe, on the other hand, has experienced a slightly lower proportion of corrosion failures but a much higher proportion of outside force damage failures. This can be attributed to high population density, which has significantly increased the outside force failure rate.

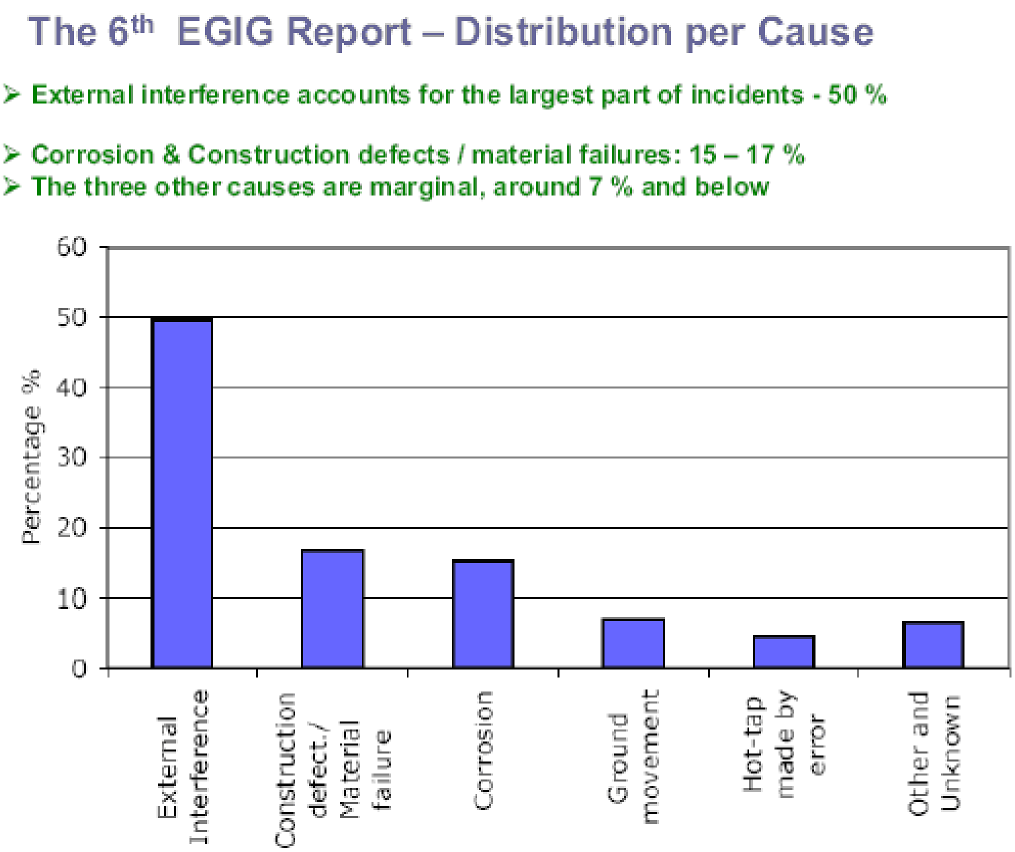

Figure 1.7– European pipeline incident causes
(Source: The 6th EGIG Report, 1970 – 2004. [2005, December]. Gas Pipeline Incidents. Doc. Number EGIG 05.R.0002)

Figure 1-8 shows that the U. S. experience with corrosion failures as a percentage of total incidents (not on a per-mile basis) falls within the middle range between the European (lower) and Canadian (higher).This difference probably is primarily due to differences in population density.

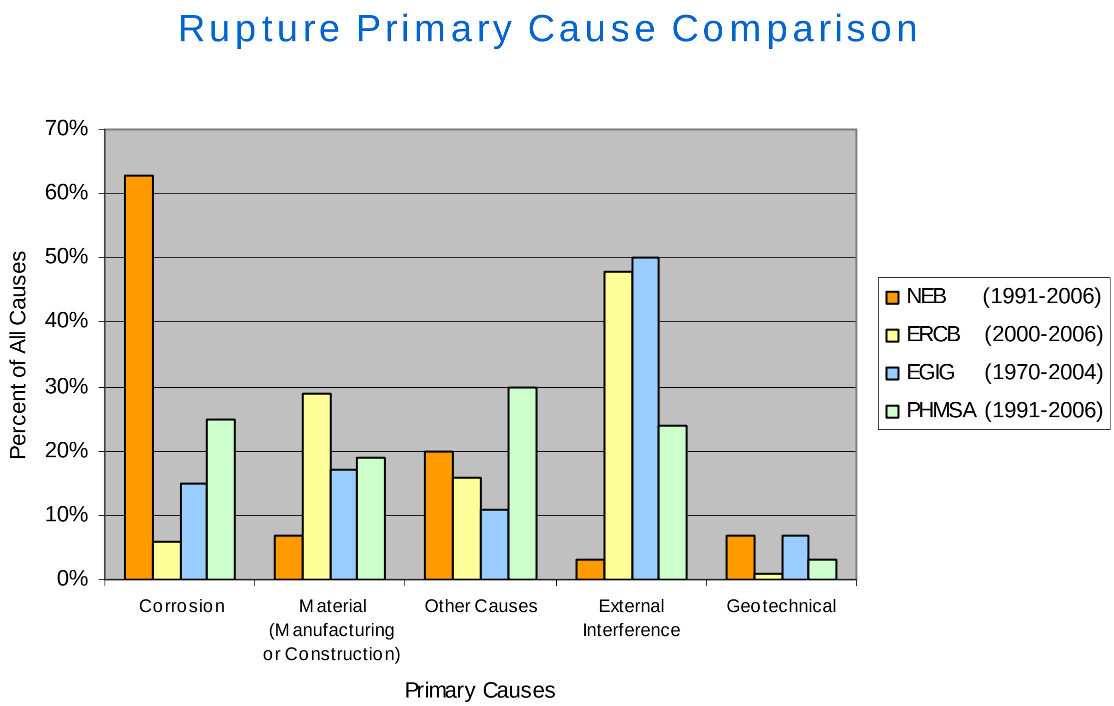

Figure 1.8 – Comparison of pipeline failure causes for Canada (NEB and ERCB), Europe (EGIG) and the US (PHMSA)
(Source: National Energy Board. [2008, July]. Focus on Safety and the Environment. A Comparative Analysis of Pipeline Performance, 2000 - 2006)

1.3 State of Knowledge Regarding Corrosion

From a scientific point of view, corrosion is well understood, both in terms of causal mechanisms and method of control. The corrosion behavior of a piece of steel in a beaker of salt water is predictable and controllable.

However, despite the current level of industry knowledge, pipelines continue to experience a modest but significant number of failures due to corrosion. The reason is that the corrosion behavior of a buried pipeline is much more complicated than that of a piece of steel in a beaker of salt water. The most important factors that complicate the investigation and/or mitigation of corrosion include the following:

- The chemical properties of the environment surrounding a buried pipeline are not adequately understood.
- Variations in the oxygen content, moisture content, and chemical composition of the soil along the pipe length and from top to bottom of the pipe can act as concentration cells that promote corrosion.
- Moisture content and oxygen content of the soil also vary with time.
- Coating quality varies along the length of a pipeline.
- Coatings sometimes become disbonded from the pipe surface, allowing groundwater to contact the steel but shielding the steel from cathodic-protection currents.
- Disbonded coating will prevent aboveground survey detection of underlying corrosive conditions.
- Physical variations in soil characteristics and placement (gaps, etc.) affect the distribution of cathodic-protection current.

- Visual inspection of the outside of the pipe and the coating require excavation.
- Stray currents from nearby buried structures can interfere with a pipeline's cathodic-protection system.

Thus, the pipeline engineer is faced with a challenging problem – preventing corrosion in a very lengthy (and frequently large-diameter) metal structure contained within a unique environment of predominantly undetermined chemical and physical properties – without the means for direct observation of the majority of the structure's length.

2 Background

2.1 Problem Statement

A reduction in the number of corrosion incidents is desirable both a safety and financial standpoint. The Pipeline and Hazardous Materials Safety Administration (PHMSA), industry trade organizations, and the scientific community have worked to increase pipeline safety and reduce incidents and related costs for many years and, in fact, have made significant improvements to corrosion detection, assessment, and mitigation technology. However, not all stakeholders and decision-makers engaged in discussions of issues such as continued research funding, regulatory review and legislative oversight of corrosion-related issues have a fundamentally sound understanding of pipeline corrosion.

2.2 Project Scope

This project was initiated to facilitate communications among all stakeholders engaged in the discussion of corrosion-related issues, including PHMSA personnel, state and federal regulators, elected officials and their staffs, representatives form the pipeline industry and the research community, as well as the general public by producing a document that would provide all stakeholders with a common, high-level understanding of the issues involved.

2.3 Report Outline

This report has been structured to address the following subjects:

- Description of the types of corrosion found on pipelines and the methods of management for each
- Factors to consider in deciding which types of corrosion may be a threat to a specific pipeline
- Current methods to assess the extent or severity of corrosion on an existing pipeline
- Standards and regulations governing pipeline corrosion inspection and management
- Methods used by the industry to manage the risk of corrosion
- Current research and development programs directed at developing better tools and methods to manage corrosion, and identifying gaps that are not being addressed
- Elements of an effective corrosion integrity management program

3 Corrosion in Pipelines

3.1 Understanding the Process

Although there are various definitions of corrosion, the definition used by NACE International (NACE), the primary support organization in the corrosion industry, is "The deterioration of a material, usually a metal, which results from a reaction with its environment." With respect to pipeline corrosion, the metal is line-pipe steel, primarily comprised of iron with one to two percent alloy for strength and toughness (alloys have been determined essentially irrelevant to the corrosion process). In regards to external corrosion, the environment would be groundwater or moist soil for onshore pipelines and seawater for offshore pipelines. For internal corrosion, the environment would be water containing sodium chloride (salt), hydrogen sulfide, and/or carbon dioxide. The deterioration would be dissolution of the iron into the environment, which reduces the strength of the pipeline.

When iron dissolves, it does so as a positively charged ion. The process, represented as follows, is referred to as an anodic reaction (see Figure 3-1):

$$Fe \rightarrow Fe^{++} + 2e^{-}$$

The electrons produced from the reaction move through the metal pipe to another location where they are in turn consumed in a reaction that produces hydroxyl ions. The specific reaction depends on the nature of the electrolyte, but typically is one of the following:

$$O_2 + 2H_2O + 4e^{-} \rightarrow 4OH^{-}$$
$$2H_2O + 2e^{-} \rightarrow H_2 + 2OH^{-}$$

The reactions represented above are referred to as cathodic reactions. Movement of the ions through the electrolyte completes the electrical circuit. The iron ions typically react with the water and/or oxygen to form a corrosion deposit of rust or some other iron oxide, but, in some cases, they may react with carbon dioxide or hydrogen sulfide to form iron carbonate or iron sulfide.

The anode and cathode components of a corrosion cell can be next to each other or separated by many feet.

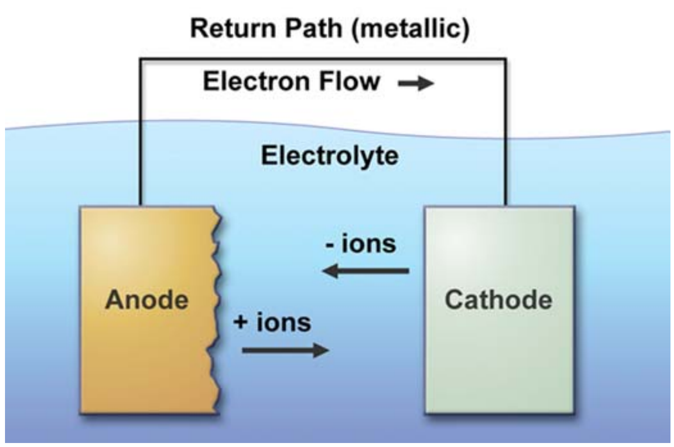

Figure 3.1 – Basic corrosion cell
(Source: NACE Corrosion Training Material)

3.2 Uniform vs. Localized Corrosion

3.2.1 Pitting

Typically, corrosion in pipelines manifests as pits rather than as a uniform reduction of the wall thickness. This is because the environment at an anodic area tends to become more acidic, since the iron ions in solution react with the hydroxyl ions of the water to leave an excess of hydrogen ions.

$$Fe^{++} + H_2O \rightarrow FeOH + H^+$$

Conversely, as indicated in Figure 3-1, hydroxyl ions will be produced at the cathodic areas, making the environment more alkaline and less corrosive. Therefore, once a pit starts to form, subsequent corrosive attack tends to be concentrated at that location.

Sometimes the pits will be isolated from each other, and, other times, they will be so close together that they overlap and produce a general but irregular thinning of the pipe wall. Both features are illustrated in Figure 3-2. Isolated pits may be seen in the top half of the picture. The overlapping pits shown in the bottom portion of the picture have caused enough thinning of the pipe wall to result in a rupture.

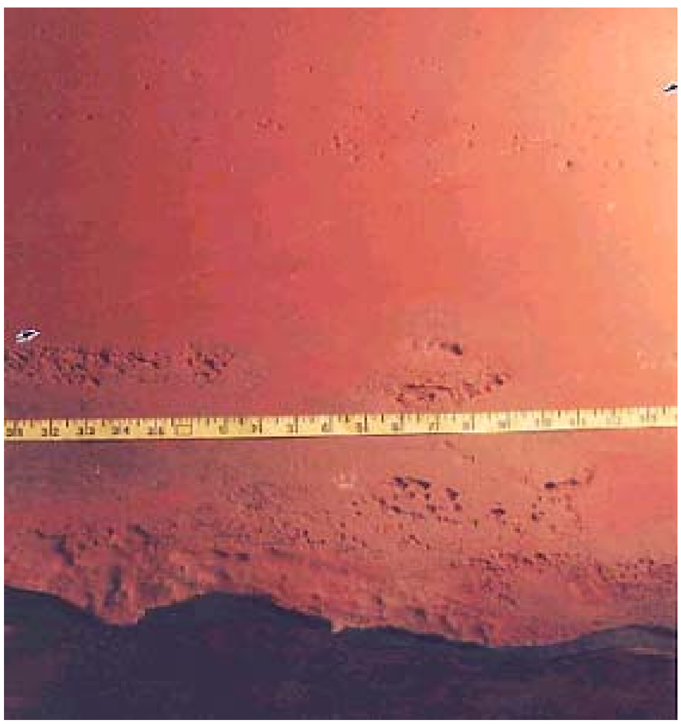

Figure 3.2– Pipeline damage from pitting
(Source: http://www.ntsb.gov/Events/2003/Carlsbad/Carlsbad_Board_Meeting.ppt#496, Slide 28)

3.2.2 Selective Seam Corrosion

Although seamless pipes have been used in some systems, most line pipe contains a longitudinal weld, or seam. The long seam, as it is called, most frequently is made by submerged-arc welding or upset-butt welding. A submerged-arc weld contains a filler metal that has a composition slightly different from that of the body of the pipe, and the heat-affected zone next to the weld metal has a microstructure different from that of the rest of the pipe. Although upset-butt welds, which can be either electric-resistance welds or flash welds, do not contain filler metal, they also have a heat-affected zone that has a different microstructure. Because these different microstructures can be more susceptible to corrosion than the surrounding metal, selective corrosion at the seam can sometimes occur with little adjacent corrosion-related damage. If the seam also contains cracks or discontinuities that, by themselves, are not large enough to cause a failure, corrosion in the same area might enlarge such flaws to critical size and precipitate a leak or rupture. Certain vintages of pipe, including pre-1971 manufactured low frequency electric weld resistance (ERW) pipe, have exhibited seam-related problems that might be particularly susceptible to selective seam corrosion. Additional information is contained in PHMSA Report on longitudinal seam failures in low frequency ERW pipe can be found at:
http://primis.phmsa.dot.gov/iim/docstr/TTO5_LowFrequencyERW_FinalReport_Rev3_April2004.pdf

3.2.3 Microbial Corrosion

MIC (Microbiologically influenced corrosion) is caused by microbes whose actions initiate the corrosion cycle. There are several types of microbes that, while producing different effects, have been found to promote either external or internal corrosion. The main types are sulfate-reducing bacteria (SRB) and acid-producing bacteria (APB). Bacteria can promote external corrosion by depolarizing the pipe through the consumption of hydrogen gas formed at the pipe surface by the cathodic protection currents. Once the pipe is depolarized, corrosion can take place. One way that internal corrosion can occur is by bacteria forming an acidic biofilm that traps electrolytes and acids. Internal MIC is more common in liquid pipelines than in gas pipelines. The corrosion mechanism is illustrated schematically in Figure 3-3. Part of a pipeline that has experienced MIC is shown in Figure 3-4.

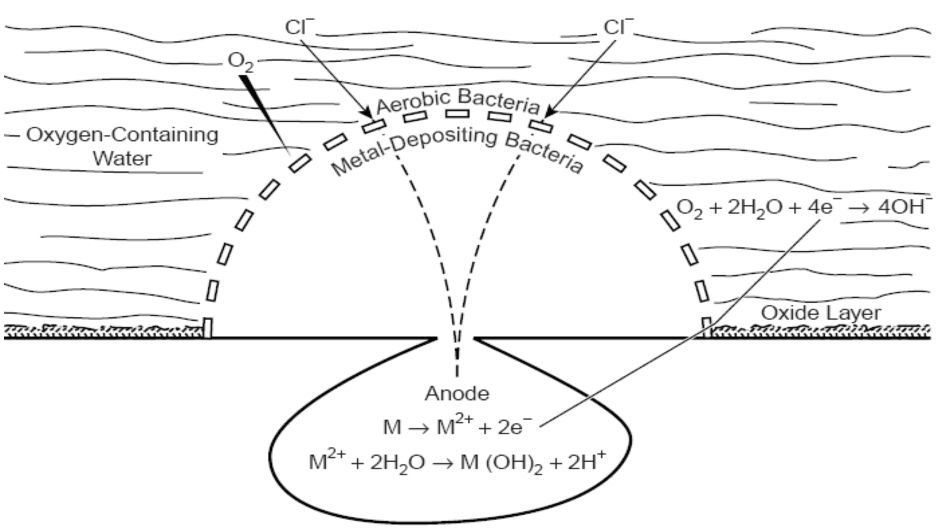

Figure 3.3– Possible reactions under tubercles created by metal depositing bacteria. (Source: Peabody's Control of Pipeline Corrosion, 2nd Edition, p. 280)

3.3 External Corrosion

3.3.1 Factors that Affect External Corrosion

3.3.1.1 Onshore Buried Pipelines

A number of correlations between the characteristics of a soil and its corrosivity have been found through research and practical experience. Since corrosion requires movement of ions through the electrolyte (soil), factors that increase the electrical conductivity of the soil tend to increase its corrosivity. Thus, higher moisture contents, poor drainage, and high salt contents tend to increase corrosivity. Higher oxygen contents also tend to increase corrosivity. However, corrosivity is only one of many factors, and not even a primary factor, that determine the rate of external corrosion on a pipeline.

One of the main factors that influence the rate of external corrosion is the differences in the characteristics of the soil from place to place along a pipeline, as well as from top to bottom. Differences in aeration, moisture content, and soil composition in these areas can produce strong driving forces for corrosion.

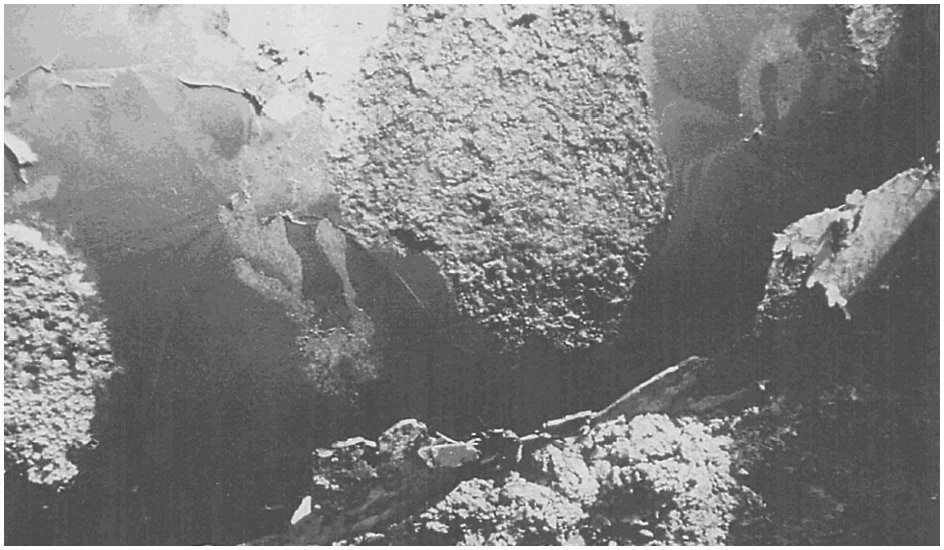

Figure 3.4 – Disbonded pipeline coating associated with external localized MIC. (Source: Peabody's Control of Pipeline Corrosion, 2nd Edition, p. 274. Courtesy Dan Pope, Bioindustrial Technologies, Inc.)

Although low-conductivity soils tend to exhibit relatively low corrosivity, they also retard the flow of cathodic-protection currents to the pipe and thus may precipitate pipeline corrosion to a greater extent than anticipated.

The soil type also can affect the rate of deterioration of the coating. For example, heavy clay soils can pull the coating away from the pipe as they expand and contract with changes in moisture content. Rocky soils, while expected to be well drained and therefore of low corrosivity, might puncture the coating, and their high resistivity might block the cathodic protection currents from the pipe at those locations.

If there is a second pipeline in the area, cathodic protection currents in the soil going to or from the second pipeline might jump onto and off of the first pipeline. Places where the current discharges from the first pipeline would be highly anodic.

As detailed below, the two most important factors in reducing or preventing the development of external corrosion on a pipeline are the level of cathodic protection and the quality of the pipeline coating.

3.3.1.2 Offshore Pipelines

While not a focus of this study, it is important to contrast the issue of external corrosion in onshore buried pipelines with external corrosion of offshore pipelines. Although salt water is much more corrosive than most soil environments, cases of significant external corrosion on offshore pipelines are extremely rare. The ability to control external corrosion has been mastered to a high degree, as compared to onshore performance. This is particularly due to the homogeneity of the offshore environment, and the predictability of coating and cathodic protection. The offshore environment is very uniform in composition and of high conductivity, thus enabling the uniform and consequently effective application cathodic protection. Furthermore, the alkaline environment produced by the cathodic protection causes calcareous deposits (primarily magnesium carbonate) to precipitate at the coating holidays (holes), essentially plugging the holidays and separating the steel from the water.

Failures that do occur on offshore pipelines occur predominately on the riser as a result of corrosion. The consistent wetting and drying in the splash zone combined with defects in the coatings are the usual contributors to the problem. Risers will fail often, but the failure is rarely catastrophic and downtime is usually minimal as compared with onshore pipeline failures due to corrosion.

3.3.2 Methods to Prevent or Mitigate External Corrosion on Buried Pipelines

The primary method of preventing or 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 an external source and thus overriding the local anodes, rendering the entire exposed pipeline surface cathodic. Coatings function to separate the steel from the electrolyte, and thus prevent corrosion.

The application of cathodic protection alone to protect against corrosion would not be practical, because the amount of current required is proportional to the exposed area, and it would be too expensive to cathodically protect a long, bare pipeline. Therefore, coatings are needed to reduce the amount of exposed area as much as possible, and are therefore, the primary method of corrosion control and prevention. Coatings by themselves also would not be totally effective, because it is impossible to produce a perfect coating over an entire pipeline. As well, some damage during construction and degradation over time are inevitable. Therefore, cathodic protection is needed to prevent corrosion at the breaks (holidays) in the coating.

3.3.2.1 Coatings

Pipeline coatings have undergone dramatic technological changes over the past two decades. Coatings now must perform at higher in-service operating temperatures, must not be damaged in handling during construction or in operation by soil stress or soil movement, and must provide exceptional corrosion protection. Coatings also must be user friendly and must be able to be applied in a mill or in the field.

Since the 1950s, corrosion coatings have continuously improved. During the period of 1950 to 1960, common coatings included coal tar-based coatings, asphalt coatings, early grease coatings, early coldand hot-applied tapes, and the first coal tar enamel coatings. All of these coatings were designed to isolate the pipe from its environment and to prevent water from reaching the pipe surface. In addition, they offered some dielectric strength (i.e., resistance to the passage of electrical current from the environment to the pipe surface). Unfortunately, many of these coatings were difficult to apply and almost always did not uniformly bond to the pipe surface, resulting in voids, pinholes, and other imperfections. Most of these coatings also degraded in the ground over time. Degradation reduced their ability to resist soil strain and moisture. After a number of years, many would become porous, or worse, disbond from the surface of the pipe.

In the 1960s, newer and more long-lasting coatings were produced and applied, and the use of certain kinds of grease wraps was discontinued during this time. Also, the adhesive capability of coal tar products was improved.

In the 1970s and 1980s, the early epoxy products and new cold-applied tapes were introduced. New wax or grease products were introduced to accommodate irregularly shaped features such as valves and fittings. Improvements continued in the development of the other types of coatings, including durability when subjected to soil strain, moisture, and other environmental stresses.

In the 1990s, better and more effective dry powder and wet-applied epoxies appeared and were widely utilized. These coatings possessed good dielectric properties and degraded relatively slowly over time from environmental exposure. However, they lacked mechanical strength. Rough handling would cause coating voids; moisture would subsequently penetrate the voids, forming blisters. Polyolefin coatings were also developed which adhered very well to the pipe surface. In addition, polyolefin provided good soil and mechanical damage resistance. However, polyolefin coatings were also expensive, and, if they did disbond, shielding could potentially occur. Two- and three-layer polyolefin coatings have become particularly popular outside of the United States.

Fusion-bonded epoxy (FBE) coating, sometimes called thin-film epoxy, is an epoxy-based powder coating that is currently widely used to protect pipelines, including valves. FBE coatings are thermoset polymer coatings. The name is derived from resin cross-linking and method of application, which is different from that of a conventional liquid paint. FBE coatings are made from dry powder. The resin and hardener parts of the dry powder remain unreacted at normal storage conditions. At typical coating application temperatures, usually in the range of 180° C to 250 °C (350° F to 480 °F), the contents of the powder melt and transform to a liquid. The liquid FBE film flows onto and wets the steel surface and, assisted by heating, soon becomes a solid coating by chemical cross-linking. This process is known as “fusion bonding.” The chemical cross-linking reaction that takes place in this case is irreversible, which means that, once the curing takes place, the coating cannot be converted back to its original form by any means. The coating process is illustrated in Figure 3-5.

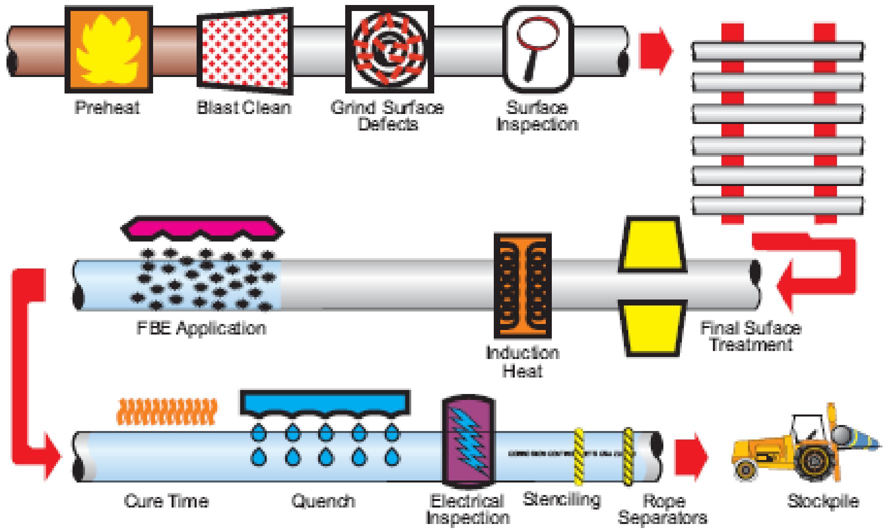

Figure 3.5 – Fusion Bonded Epoxy (FBE) powder application schematic (Source: Peabody's Control of Pipeline Corrosion, 2nd Edition, p. 18)

In the 1950s and 1960s, many of the coatings -- especially coal tar, asphalt, and tape -- were applied continuously by machine in the field after the pipe joints were welded together and cleaned by scraping or wire brushing. Those cleaning methods were not particularly effective, and the remaining dust and mill scale interfered with a good bond between the coating and the pipe. More recently, many of the coatings, including FBE, have been applied in the coating mill after the pipe surface was cleaned by grit blasting. This resulted in a far superior surface finish and better bonding. However, the ends of each joint had to be coated in the field after the girth welds were made. These field-applied coatings for joints and other fittings have evolved from very simple tar to multipart epoxy and heat-shrink sleeves. Each has its strengths and weakness.

The earliest field-applied joint coating was a "granny ragged" hot tar coating applied using a saturated cloth. Its application involved little or no surface preparation of the joint. Because the hot tar would run down the pipe, cloth reinforcement was required in some cases. Nevertheless, the coating at the top of the pipe was considerably thinner than at the bottom, and it could also contain pin holes. Moisture could enter the pin holes, but could not drain because the bottom was waterproofed. Therefore, pockets of water resulted, with the potential to create a corrosive environment. Besides not being very effective, this method of coating field joints was very labor intensive and subject to contamination by dirt.

Cold-applied tapes, another type of field-applied coating, had limited success. The tapes were wrapped over the field joint, and, depending on the adequacy of surface preparation, could either adhere or disbond. If the tape adhered well to the joint, no problems would result. However, if tapes disbonded, they could adhere to one another and also establish a shielded environment, which would promote localized corrosion. Soil strain and the manner in which the pipe was lowered into the trench were other concerns associated with the application of tape coatings. In some cases, especially during warm weather, the slings used to lower a pipeline with fittings into a trench could cause cold-applied tape to bunch, creating voids and areas that exposed pipe surfaces.

In the 1990s, a field-applied epoxy system (see Figure 3-6) was used to complement the (FBE) coatings on piping systems. Similar to the factory-applied FBE, when the field-applied coatings fail, they do not cause shielding. Instead, they allow the cathodic protection currents to reach the bare pipe.

Figure 3.6 – Field applied joint coating
(Source: http://www.pih.co.uk/uploads/files/fusion_bonded_epoxy.pdf)

Also at this time, shrink sleeves (Figure 3-7) were widely used. Shrink-sleeve coating systems consist of thermoset plastic that, when applied to the joint and heated, will shrink around the joint. Some shrink sleeves, particularly those utilized in directionally drilled pipe installations, may require epoxy primer application or surface preparation. If the surface is not properly prepared, a shrink sleeve will not adhere, the coating will fail, and water will collect in the failed coating voids. Moreover, the shrink wrap will shield the voids from cathodic protection and the pipeline could corrode. If the installation is done incorrectly or if the pipe is not sufficiently heated, voids can form beneath the sleeve. The sleeve will subsequently disbond from the pipe, causing shielding. If a pin hole is present, then moisture can enter, and because of the shielding, a corrosion cell can form.

Oftentimes, offshore pipelines also incorporate concrete coatings to offset buoyancy as well as to prevent fatigue damage and flow-induced vibrations due to wave or current forces by providing stability across irregular seafloor topography or where there is scouring or local differences in load bearing capacities of the soil.

Figure 3.7 – Shrink sleeve application
(Source: http://www.covalencecpg.com/documentos/casos/JR-013-WaterWrap.pdf)

The use of thermal sprayed metallic coatings (Aluminum and Zinc) has been gaining popularity in submerged offshore applications, including some pipelines. This coating offers the benefits of low cost with excellent corrosion protection over a wide range of temperature and conditions. While thermal sprayed coatings do provide a measure of cathodic protection, they still require supplemental anodes but the quantity can be significantly reduced. These coatings are still under development for broad-based pipeline applications but expect to see continued progress.

3.3.2.2 Cathodic Protection

As stated earlier, anodic areas, where corrosion occurs, discharge current to the cathodic areas, where corrosion does not occur. By driving current to the pipe through the environment, as illustrated in Figure 3-8, the anodic currents can be overridden, and the entire pipe can be made to behave like a cathode. At the same time, a benign alkaline environment is produced at the pipe surface. In sea water and many soils, a calcareous deposit will form in that alkaline environment and further protect the steel.

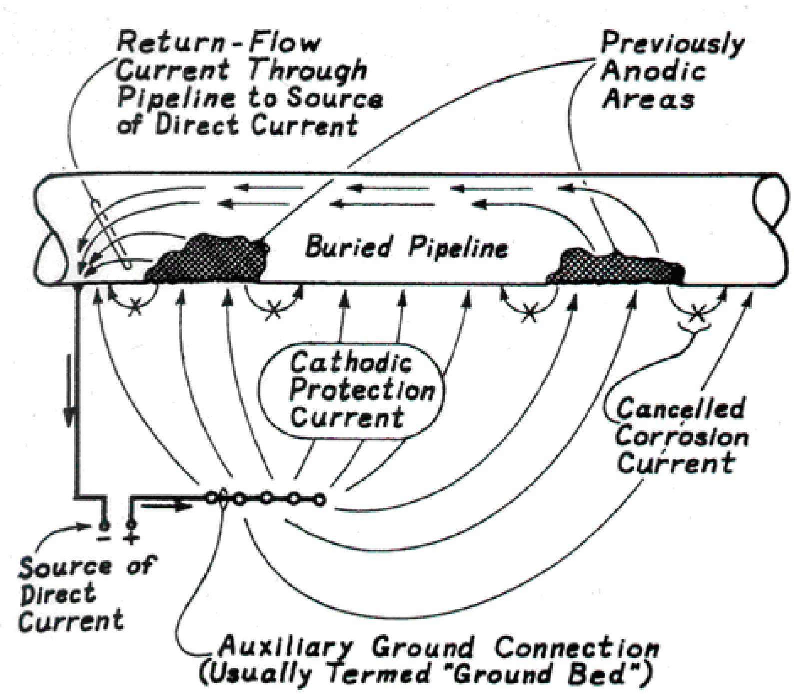

Figure 3.8 – Basic concept of cathodic protection
(Source: Steel Structures Painting Council)

There are two types of cathodic protection systems: sacrificial anode and impressed current anode. Sacrificial anode systems utilize an externally connected sacrificial metal with a relative activity value greater than steel (iron) and thereby protect steel from corrosion. Alloys of zinc and magnesium are the sacrificial metals most commonly employed. The sacrificial anode is connected to the pipeline via a wire and placed some distance from the pipeline. The current flows from the anode into the surrounding soil (electrolyte) and is picked up by the pipeline at coating holidays. The circuit is completed by a wire that connects the anode to the pipe. The number and placement of anodes is based on the site-specific requirements of the particular pipeline that is to be protected. A well-coated pipeline with a few small holidays does not require many anodes.

Impressed-current anode systems, shown in Figure 3.9, involve the application of direct-current voltage between an anode and the pipeline. Impressed-current anodes can be made from graphite, high-silicon cast iron, lead-silver alloys, precious metals, mixed-metal oxides, or steel. As with sacrificial anodes, the shapes, locations, and number depend on the geology of the area and the nature of the pipeline system.

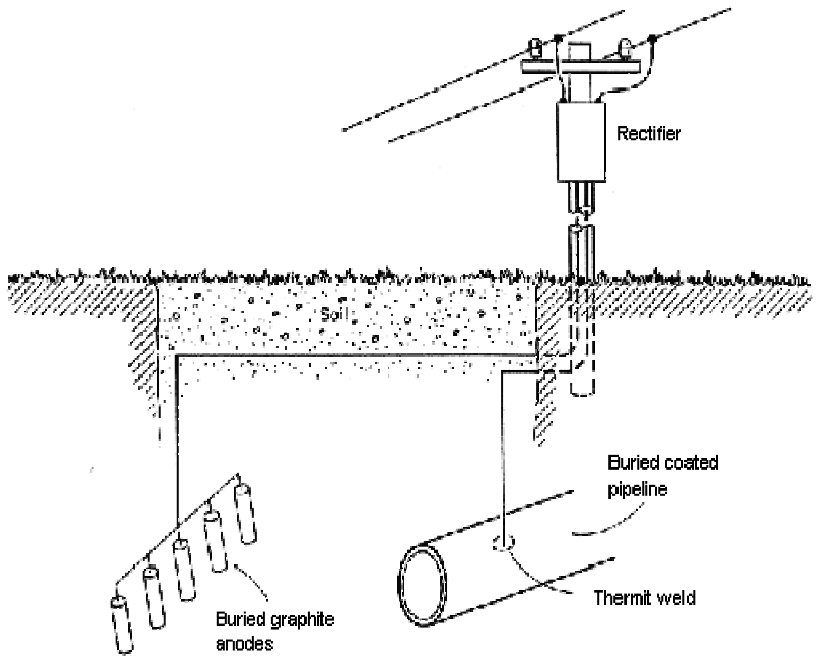

Figure 3.9 – Impressed-current cathodic protection of a buried pipeline (Source: http://www2.mtec.or.th/th/research/famd/corro/cathodic.htm)

3.3.2.3 Other Preventive/Mitigative Measures

Placing a metallic pipe within another pipe that contains nonconductive filler in its annular space is yet another method to protect the structure from environmental impact and thus reduce or eliminate its potential for corrosion. This "pipe-in-pipe" method may be suitable for short sections of pipeline, such as those that pass under streams or rivers. This technique was used in the horizontally directionally drilled (HDD) 4,300-foot crude oil pipeline crossing of the Colville River on the North Slope of Alaska, as shown in Figure 3-10.

Figure 3.10 – Installing casing insulators on product pipe prior to installation in casing pipe – 4300-foot HDD Colville River Crossing (Source: ASCE Presentation, Michael Baker, Jr. Inc.1999)

3.3.3 Monitoring Techniques for External Corrosion

Just as a battery, which consists of two different metals in contact with an electrolyte, produces a voltage, a steel pipeline in contact with the soil will produce a voltage between itself and another piece of metal that is in the soil and in electrical contact with the pipe. The voltage will depend on the relative differences in corrosion tendency of the two metals in the environments that surround each. This concept is the basis for the method that is used to monitor external corrosion on buried pipeline without excavating it. The pipeline in contact with the soil or seawater is one half of the "battery," and a piece of copper in contact with a saturated solution of copper sulfate is commonly used as a standard reference for the other half of the "battery." The potential (voltage) generated between a pipeline and the standard reference can be correlated with the tendency of the pipeline to corrode. The numerical value of the voltage is referred to as the pipe-to-soil potential. The primary way to make sure that the pipeline is not undergoing significant corrosion is to monitor the pipe-to-soil potential. If the pipe-to-soil potential is found to be insufficient, the cathodic-protection system should be adjusted by increasing the output of the rectifiers for an impressed-current system or by increasing the number of sacrificial anodes.

Although the exact value of pipe-to-soil potential necessary to prevent significant corrosion will be different for different environments, experience has shown that a value more negative than –850 mV versus the copper/copper sulfate electrode (CSE) or at least 100 mV more negative than the native (freely corroding) potential would be adequate in almost all soils. However, if MIC is involved, a potential of –950 mV versus CSE or a shift of at least 300 mV is recommended.

49 CFR part 192 requires that pipe-to-soil readings for cathodically protected pipeline systems must be taken annually at all test stations, at intervals not to exceed 15 months from the previous read. Typically, these test stations are installed at convenient locations, such as road crossings. Occasionally, more detailed surveys, as illustrated in Figure 3-11, may be conducted every few feet along the pipeline. Some operators also will momentarily interrupt the cathodic protection system once or twice a minute to obtain readings free from errors caused by the current flowing in the soil between the position of the reference electrode and the pipe. The reading with the current flowing is called the "on potential," and the reading with the cathodic protection interrupted is referred to as the

"off potential" or the "instant off potential." The difference between the two values is termed the "IR drop," because it is equal to the current, I, in the soil times the resistance, R.

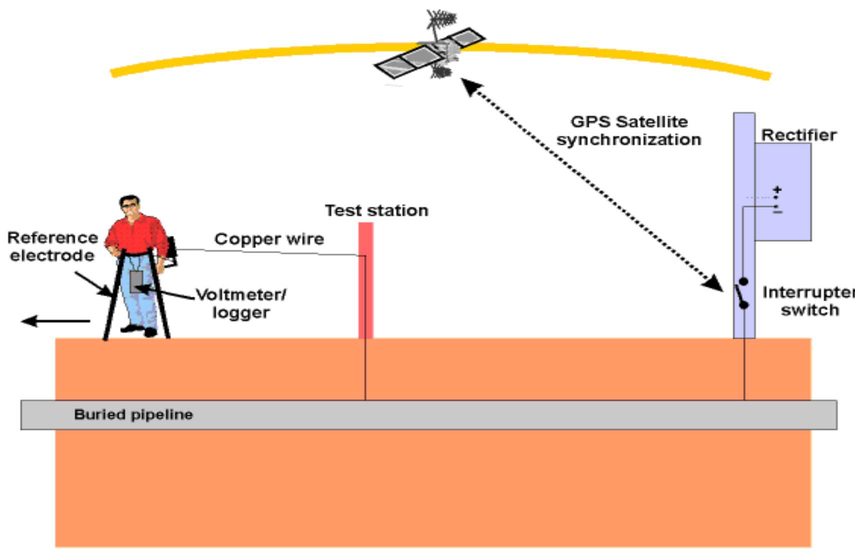

Figure 3.11 – Close-interval pipe-to-soil potential survey
(Source: http://www.corrosion-club.com/images/cips1.gif)

3.4 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 (such as glycols from dehydration processes) are needed to form the electrolyte. Also, other chemicals usually must be present: for example, carbon dioxide (CO2) 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.

3.4.1 Gas Pipelines

Typically, sales-quality dry gas will not corrode pipeline interior surfaces. However, natural gas, as it comes from the well, may contain small amounts of contaminants such as water, carbon dioxide, and hydrogen sulfide. If the water condenses, it can react with the carbon dioxide or hydrogen sulfide to form an acid that might collect in a low spot and cause internal corrosion.

3.4.2 Liquid Pipelines

Similarly, internal corrosion can occur in hazardous liquid pipelines carrying corrosive liquids or liquids containing corrosive contaminants. Liquid pipelines can experience internal corrosion anywhere along their length where electrolytes or solids drop out and wet the surface or provide a place for electrolytes to collect. An example of internal corrosion in a liquid pipeline is shown in Figure 3-12.

Figure 3.12 – Internal corrosion of a crude oil pipeline
(Source http://www.corrosioncost.com/pdf/gasliquid.pdf)

3.4.3 Preventive/Mitigative Measures for Internal Corrosion

3.4.3.1 Dehydration

Dehydration is the most commonly applied measure to protect against internal corrosion in gas pipelines (and also in liquid pipelines that contain oil with free water or other electrolytes). Dehydration removes condensation and free water that, if permitted to remain, would allow internal corrosion to occur at points where water droplets precipitate from the gas stream to either form liquid puddles at the bottom of the pipe, or adhere to the top of the pipe. Where the gas stream is usually dry, topside corrosion rarely takes place. Complete dehydration is very effective, but, because the systems are neither 100 percent effective nor 100 percent dependable, there always is the potential to introduce water and other electrolytes into a gas pipeline.

Several methods may be used to dry gas. The most common method is dehydration, which involves the use of devices to chemically "scrub" the gas stream to remove moisture and reduce the gas dew point. Glycol is the scrubbing agent most frequently used. Provided that the glycol is removed from the gas stream, the environmental conditions that promote corrosion are eliminated.

There also are physical methods of eliminating entrained moisture – the most commonly utilized are scrubbers that employ cyclone separators to remove the water or glycol droplets from the gas stream. However, physical methods cannot significantly reduce the dew point, so periodic upsets can occur. Most gas gathering system and storage operators utilize dehydration devices to scrub gas of humidity by removing the moisture present in the produced gas. The process reduces the gas stream dew point so that the gas becomes "tariff gas" that contains less than seven pounds of moisture per million cubic feet.

Liquid pipelines that contain free water also can experience internal corrosion. The fluid can sometimes be treated to remove both free water and dissolved water. When water is present, pigging is required to move the water from areas where it accumulates due to local flow conditions. Water is removed from crude oil by gravity separation, but there always is a percentage of water remaining in the product crude oil. Hydrocarbon products may use a salt dryer or other means of removing water; however, because the systems are not totally reliable or efficient, there is always the possibility of introducing water or an electrolyte into the pipeline. These upset conditions, and the corrosion that they can cause, must be monitored and mitigated.

3.4.3.2 Inhibitors

Inhibitors are chemicals that can be added to a pipeline to reduce the rate of corrosion. They can adsorb onto the metal surface or react with it to form a protective film, or they may react with the corrodent to make it less corrosive. Many different chemicals are available commercially. The choice will depend on the type of product in the pipeline and the type of corrodent. Other considerations include cost, availability, toxicity, and environmental friendliness.

3.4.3.3 Coatings

Internal coatings have been used on some gas transmission pipelines to improve product flow by reducing drag and eliminating dust. Such coatings can be somewhat effective in controlling internal corrosion, but they are very difficult to apply uniformly, which impacts their effectiveness. In lieu of coatings, some operators have attempted to install plastic or high-density polyethylene liners or inserts in their pipelines. Plastic liners are an effective barrier against corrosion but are not fail-safe. Problems occur if pinholes are present and allow corrosive materials to migrate behind a pipe's liner. Relying solely on liners or coatings may not be prudent since it is very unlikely that the problems associated with each can be remedied. Many operators who do use liners or coatings also apply additional preventive measures.

3.4.3.4 Buffering

In principle, buffering agents that change the chemical composition of fluids that remain in the pipeline can be utilized to prevent internal corrosion (see Figure 3-13). The introduction of a buffering agent, such as a mild or dilute alkaline mixture, can significantly reduce the corrosivity of any standing liquid, predominantly by raising its pH value above seven (neutral), so that it turns from acidic to alkaline. Alkaline liquids cause virtually no harm to steel. In general, buffering is not very effective because it is difficult to cover the entire pipe surface.

3.4.3.5 Cleaning Pigs

The frequent use of cleaning pigs to scour the internal surfaces of a pipeline is another viable preventive measure. There are many types of cleaning pigs. The choice of which type of pig to use depends on the product carried by the pipeline and the contaminant to be removed. Although their application may preclude the use of internal corrosion direct assessment (ICDA) models, cleaning pigs can effectively direct both liquids and corrosive solids to pig traps for removal from the pipeline. It is noted that the buildup of solids also can create internal corrosion, since the solids can entrap corrosive or low-pH liquids in a corrosive matrix.

Routine pigging will channel any liquid pools away from low points and, if performed properly, out of the entire pipeline. Cleaning pigs also will displace the solids and remove them from the pipeline via the pig trap at the end of the pipeline, provided that the pipeline is properly configured (i.e. no dead legs or other features that would trap liquids or solids and prevent cleaning pig access). Pigging effectiveness is a function of the pigging velocity, pigging distance, and characteristics of the materials targeted by the pig run.

3.4.3.6 Biocides

Biocides can be used in the pipeline to inhibit the corrosive actions of the microbes that cause MIC and thereby reduce or eliminate MIC. Biocide is injected into the pipeline in the stream of a non-electrolytic carrier. In many cases, the biocide is added to the buffering agent so that only one addition to the gas stream is needed.

There are also other active agents that can be added, such as film-formers that aid in forming a passive barrier at the pipe surface and agents that promote the evaporation of electrolytes. Many of these agents are expensive, and, depending on the gas flow at the time of injection or use, may or may not reach the location where the electrolytes and microbes are trapped.

3.4.3.7 Additional Preventive Measures

System designs that include features to trap contaminants can prevent corrosion within a complete piping system. The simplest design alternative consists of the installation of separators at the system's entry point or at a location just downstream of the point where liquids could be entering the gas stream (such as at the end of gathering systems or outlets from storage fields). Separators, which are typically designed to handle a range of flow rates, can be configured in parallel to facilitate their addition or removal from the equipment train, according to flow velocity requirements.

Drip legs or logs (also known as traps/drips) are another design mechanism to prevent internal corrosion. These devices are designed to trap liquid contaminants and prevent them from traveling downstream. The drips can be pumped so the liquids can be removed before significant internal corrosion can take place. However, if the liquids are not removed in a timely manner, the drips themselves can corrode. Some drips are filled with heavy oils that permit an aqueous layer to form overtop and, in this manner, enable removal of the contaminants. The use of drips began at the time when manufactured gas was the only gas available and was stored in tanks with water seals. The use of the water seals, in combination with the manufacturing process, yielded gas saturated with water vapor and tars. The water vapor and tars were actually beneficial in preserving the integrity of the early pipelines that were constructed of wood, but proved detrimental to the operation of cast iron, wrought iron, and steel pipelines. As the gas progressed through a metallic pipeline, the water vapor and tars would condense and coat the inside of the pipe. Their accumulation at low points would result in the development of a corrosion cell.

3.4.3.8 Preventive/Mitigative Measures for Selective Seam Corrosion

Most pipelines in the United States are constructed with the longitudinal seam weld in the top half of the pipe to keep water from contacting the seam on the inside of the pipe. Other methods focus on either alleviating the integrity problems of the seam by replacing the pipe or inhibiting corrosion by applying one or several of the measures previously discussed.

3.4.3.9 Preventive/Mitigative Measures for MIC on Gas Pipelines

To prevent or correct internal MIC, the internal environment must be changed by eliminating the electrolyte at the pipe wall. This can be accomplished by drying the gas and eliminating any design features in which liquids or wet solids can accumulate. The use of buffers or other pH-altering chemicals also can modify the environment and possibly eliminate the growth of the bacteria that cause MIC.

3.4.4 Monitoring Internal Corrosion

There are several monitoring methods that are effective in evaluating internal corrosion as well as the conditions conducive to its development. One method involves the installation and periodic examination of removable corrosion coupons in areas of the pipeline known to be susceptible to internal corrosion. This method can provide data on corrosion rates and the conditions that are causing the corrosion. Correct placement of the coupons is critical to the accuracy of the evaluation. Coupons must be placed as close as possible to the entry point of the electrolyte and in direct contact with it. There are several designs to accomplish this, but, at present, there is no industry guidance or standard to direct operators in proper coupon placement. To highlight the disparity, some operators have suggested that the removable corrosion coupons be installed at low points in the pipeline, raised just above the bottom surface of the pipe, so that the coupons would be exposed to any liquids that might have become trapped; however, a contrary view is that this does not work well, because the water present may only be a wetting film on the surface of the pipe, and the coupon would never touch the water. The operator then would have falsely non-conservative information, thinking no corrosion is occurring and not investigating farther.

Probes also can be effective in monitoring for internal corrosion if placed in the proper location and oriented where they will contact any electrolytes present. Probes that measure liquid conductivity are used to determine if electrolytes are present, while pH probes can be used to determine the pH of the liquid, which may or may not indicate the corrosion potential. Ultrasonic probes installed around the pipe can be used to determine if metal loss is occurring.

Permanently placed ultrasonic measuring probes can be utilized to measure the pipe wall in areas believed to be at risk for internal corrosion. The Pipeline and Hazardous Materials Safety Administration (PHMSA) notes that this is a very “iffy” type of monitoring, unless the corrosion is general corrosion, as in acid corrosion. Such probes probably would not reliably detect pitting corrosion, but instead would yield a false non-conservative reading, leading to the misconception that corrosion is occurring. The probes measure the remaining pipe wall and can provide real-time data on the amount of internal corrosion occurring in a particular section of pipeline but only if it is general overall corrosion or the probe happens to be placed on an active pit that is still corroding.

The use of an indirect monitoring technique involving continuous moisture monitors enables operators to determine whether electrolytes are being introduced into the pipeline from entry or supply points. The moisture monitors only detect water vapor in the gas; they do not monitor for liquids. Moisture monitoring must be conducted in conjunction with a means of detecting liquid water/electrolyte in the pipeline.

3.5 Environmentally Assisted Cracking

Another form of degradation that would fall within the NACE definition of corrosion is environmentally assisted cracking (EAC), in which the combined action of a tensile stress and a corrosive environment causes cracks to form in the metal. There are a number of different cracking mechanisms within the category of EAC, including stress corrosion cracking (SCC), corrosion fatigue, hydrogen-stress cracking, hydrogen-induced cracking (HIC), hydrogen-induced loss of ductility, and sulfide-stress cracking (SSC). Compared to pitting corrosion, EAC results in relatively few significant incidents.

3.5.1 Stress-Corrosion Cracking (SCC)

3.5.1.1 External SCC

Since its discovery in 1965 as a possible cause of failures in pipelines, SCC has caused, on average, one to two failures per year in the U. S.

Two types of environments have been associated with external SCC. High-pH SCC is caused by a concentrated solution of sodium carbonate and sodium bicarbonate with a pH that typically is between nine and 10.5. Near-neutral-pH SCC is caused by a relatively dilute solution of carbon dioxide and sodium bicarbonate with a pH that typically is between six and seven.

Both forms of SCC have similar appearances. As is illustrated in Figure 3-14, the cracks occur in clusters, and the fracture surface contains a black corrosion deposit that corresponds to the size of the cracks just prior to failure. However, the two forms can be distinguished by metallographic examination: high-pH stress-corrosion cracks are intergranular (the cracks follow the grain boundaries of the metal), while near-neutral stress-corrosion cracks are transgranular (the cracks run through the grains of the metal) and also exhibit more corrosion along their sides.

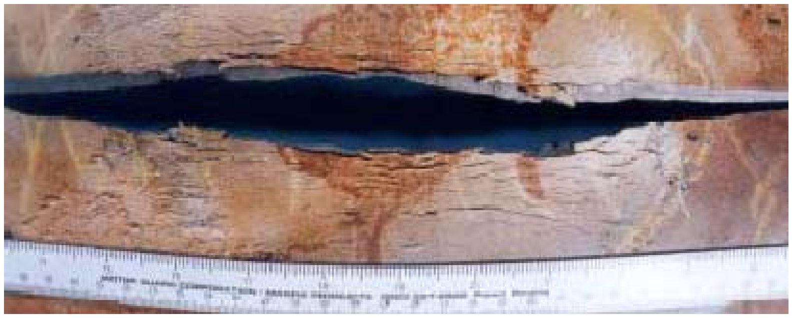

Figure 3.14 – SCC colony on a large-diameter, high-pressure transmission gas pipeline (Source: http://www.corrosioncost.com/pdf/gasliquid.pdf)

Typically, the cracks are oriented in the axial direction, because they grow perpendicular to the direction of largest tensile stress, which usually is the hoop stress due to the internal pressure. However, there have been some instances of circumferential cracks in areas, particularly on slopes, where soil movement caused high longitudinal stresses.

Although high-pH SCC can occur at normal ground temperatures, the crack growth rate increases with increasing temperature. Therefore most high-pH SCC has been found within 20 miles (32 km) downstream of gas compressor stations and rarely on liquid pipelines. Near neutral-pH SCC is not strongly affected by temperature, and such cracks have been observed on both gas and liquid pipelines and at all distances from compressor and pump stations. However, the majority of in-service failures have occurred within the first valve section (typically 15 to 20 miles [24 to 32 km]) downstream from compressor or pump stations. This is thought to be due to the more rapid coating deterioration downstream of compressor stations and larger pressure fluctuations near pump stations. Neither form of SCC has been detected on offshore pipelines.

External SCC has been observed only under field-applied coatings. Despite the fact that some mill-applied coatings, particularly FBE, have been in service for more than 40 years, no SCC has been found beneath those coatings. This is thought to be due to several factors, including better surface preparation, compressive residual stresses from grit blasting, and improved coating properties. It is widely accepted that the use of such coatings is an effective way to prevent SCC.

A comprehensive report on SCC prepared for PHMSA is available at http://primis.phmsa.dot.gov/iim/docstr/SCC_Report-Final_Report_with_Database.pdf.

3.5.1.2 Internal SCC

To date, there have been no reported cases of internal SCC in North America. However, since ethanol is increasingly being used as an additive to gasoline, the pipeline industry is considering shipping denatured ethanol in its pipelines. Recently, concern has been raised about the possible development of internal SCC in pipelines that would transport ethanol, because SCC has been observed inside storage tanks and user terminals that contain fuel-grade ethanol. The determination of safe conditions for the transport of ethanol is currently the subject of intense debate.

3.5.2 Corrosion Fatigue

When a metal within a corrosive environment is subjected to cyclic stresses, fatigue cracks will grow more rapidly and at lower stress levels than they would in the presence of dry air. Corrosion fatigue rarely is reported as a cause of failure of a pipeline. However, because fatigue cracks are transgranular and thus difficult to distinguish from near-neutral-pH SCC, it has been speculated that corrosion fatigue may have contributed to some failures that were attributed to near-neutral-pH SCC.

3.5.3 Hydrogen Embrittlement

The term “hydrogen embrittlement” is sometimes used loosely to refer to one of several different ways that hydrogen can degrade the properties of a metal. With respect to pipelines, three forms of hydrogen damage are of interest: hydrogen-stress cracking, hydrogen-induced cracking, and loss of ductility.

3.5.3.1 Hydrogen-Stress Cracking

Hydrogen-stress cracking is a delayed-failure mechanism that sometimes occurs in high-strength steels that have absorbed hydrogen that was produced at the surface through an electrochemical reaction (corrosion or cathodic protection). Line-pipe steels with normal properties for grades up to and including at least X80 are not considered to be susceptible to hydrogen-stress cracking. However, some hydrogen-stress cracking failures have occurred in unusually hard regions of X52 pipe. (Fessler, 1977). Those failures usually are called hard-spot failures. The hardness pattern associated with one such failure is shown in Figure 3-15. A Brinell hardness of approximately 180 would be typical for X52 pipe. The hardness values near the center of the hard spots were equivalent to an ultimate tensile strength in excess of 200,000 psi, which is more than twice as high as would be expected. The origin of such hard spots has been attributed to upsets during the hot rolling of the steel plate in the steel mill.

Hard spots can be detected with magnetic-flux leakage in-line inspection pigs, and the preferred method of preventing hard-spot failures is to locate and remove the hard spots rather than try to eliminate the source of hydrogen.

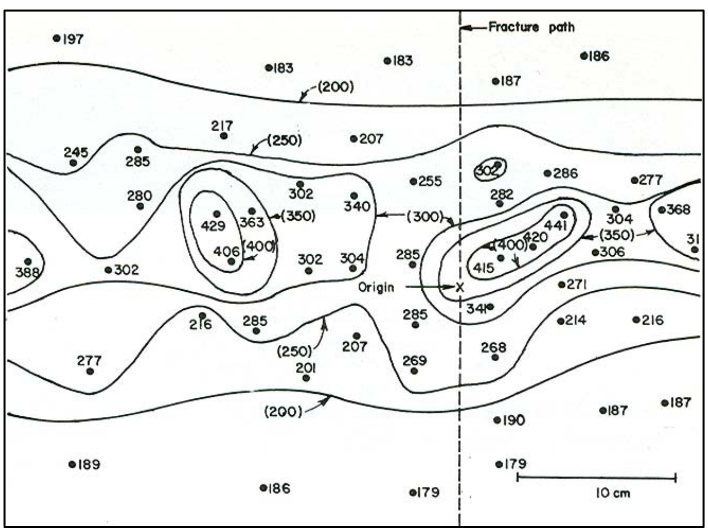

Figure 3.15 – Brinell hardness pattern associated with a hard-spot failure in X52 pipe (Source: Fessler, R.R. “Characteristics of Environmental Cracking”, Sixth Symposium on Line Pipe Research, American Gas Association, Arlington, VA 1979, pp N-1 to N-18.)

3.5.3.2 Hydrogen-Induced Cracking

Some cathodic reactions, either from corrosion or cathodic protection, can deposit atomic hydrogen on the external or internal surface of a pipeline. Some of the hydrogen atoms combine with other hydrogen atoms to form molecular hydrogen gas (H2), which leaves the surface and enters the soil around the pipe or the fluid inside the pipe. Some of the atoms will be absorbed by the steel and diffuse to the opposite surface where they will then combine with other hydrogen atoms and leave as a gas molecule. However, if the hydrogen atoms encounter an internal discontinuity such as a lamination or large inclusion in the steel, they may combine to form hydrogen gas at that location. By that mechanism, it is possible to create pressures up to 2,700 psi (18.7 MPa), which is sufficient to cause internal cracks in the pipe wall, even in the absence of an externally applied stress. Such cracks usually are oriented parallel to the surfaces of the pipe, because most discontinuities are parallel to the surfaces. At times, the pressures are large enough to create a blister in the pipe wall. Occasionally, the stresses at the ends of the blister can increase enough to cause a through-wall defect. If there are multiple cracks at various positions through the wall thickness and the pipe experiences a high hoop stress, the cracks sometimes join to form a through-wall crack; this phenomenon is termed stress-oriented hydrogen-induced cracking.

3.5.3.3 Loss of Ductility

When pulled in tension, line-pipe steels typically can be stretched 10 to 20 percent before they will break. However, if the steel contains a large amount of hydrogen, the steel will not be able to exhibit that level of plastic deformation. This form of hydrogen embrittlement is not of concern for operating pipelines because they never undergo any significant amount of plastic deformation.

3.5.3.4 Implications for Pipelines in a National Hydrogen Economy

Hydrogen is foreseen by many as an important energy carrier in the future sustainable energy society. Currently, hydrogen is transported primarily by way of railroad cars, tanker trucks, tanker ships and a limited amount of pipeline built specifically for hydrogen transport. Over the road transportation is very expensive due to the energy density of hydrogen. For long distance transportation, pipelines will be the most economical transportation mode. As discussed above, hydrogen’s ability to embrittle steel has been well documented. However, the long term effect of high pressure hydrogen transmission through commercial grade steel pipelines of various qualities and properties has not been thoroughly explored.

3.5.4 Sulfide-Stress Cracking

SSC is a type of spontaneous brittle failure experienced by steels and other high-strength alloys when they are in contact with moist hydrogen sulfide and other sulfidic environments. SSC is also referred to as hydrogen sulfide cracking, sulfide cracking, sulfide corrosion cracking, and sulfide stress-corrosion cracking. The variation of the name is due to the lack of agreement regarding the cracking mechanism. Some researchers consider SSC a type of SCC, while others consider it a type of hydrogen-stress cracking.

SSC in pipelines 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. Internal SSC is far more common than external, which is rare.

Susceptibility to SSC is a function of a number of variables: two of the more important are strength or hardness of the steel and the level of tensile stresses. For any steel, there is a minimum level of applied stress, called the threshold stress, below which failure due to SSC will not occur. The threshold stress decreases as the steel's strength level increases. For example, a steel with a yield strength of 200,000 psi might fail at a stress of only 30,000 psi, while a steel with a yield strength of 80,000 psi must be stressed above 80,000 psi before it will fail. (Snape, 1981). Therefore, the common way to prevent SSC failures in steel pipelines that could be exposed to wet hydrogen sulfide environments is to ensure that the pipe design incorporates steel with a maximum strength level of 80,000 psi. It also is important to control the welding processes to make sure that they do not induce regions of high hardness and high residual stress.

4 Corrosion Threat Identification

4.1 Overview

U.S. Department of Transportation (DOT) regulations governing the maintenance and preservation of pipelines require that pipeline operators identify and evaluate all potential threats to every high-consequence area (HCA) along their pipeline system. HCAs, which typically are areas where there is a relatively high population density or sensitive environment near the pipeline, are defined in the regulations. The rules for the integrity management of gas pipelines are contained in Title 49 CFR Part 192, Transportation of Natural Gas and Other Gas by Pipeline: Minimum Federal Safety Standards. Rules relating to liquid pipelines are contained in Title 49 CFR Part 195, Transportation of Hazardous Liquids by Pipeline.

Part 192.917 specifically mentions internal corrosion, external corrosion, and stress corrosion cracking (SCC) as three of the threats that must be considered for gas pipelines. Part 195.452, the equivalent section for liquid pipelines, does not specifically define which threats must be considered, but internal corrosion, external corrosion, and cracking are mentioned often enough that it is clear that those three threats also should be considered for liquid pipelines.

4.2 External Corrosion

It seems reasonable to assume that any buried or submerged pipeline should be identified as susceptible to external corrosion, although, in principle, it might be possible for a segment to be located in a soil that is not corrosive. The burden of proof would rest upon the pipeline operator and would be considerable.

4.3 Internal Corrosion

Internal corrosion would not be identified as a threat for any pipeline that could be confirmed to be free of liquid water. However, for the majority of pipelines, the possibility of introducing some water with the supply gas or liquid cannot be ignored, so an evaluation of the threat of internal corrosion would be appropriate.

4.4 Stress Corrosion Cracking

Since the conditions for producing SCC are far more limited than those for producing uniform or pitting corrosion, it would not be appropriate to identify SCC as a threat for all pipeline segments or HCAs. Appendix A3 of ASME B31.8S, a part of ASME's integrity management standard for gas pipelines, states that SCC would not be identified as a threat unless the following three conditions are present:

- Operating stress level greater than 60% of the specified minimum yield strength (SMYS)
- Age of pipe coating greater than 10 years
- Any corrosion coating system other than plant-applied or field-applied FBE or liquid epoxy (when abrasive surface preparation was used during field coating application). Bare pipe is included, and field joint coating systems also should be considered for their susceptibility.

High-pH SCC also would be eliminated unless:

- The operating temperature was above 100° F (38° C),and
- The distance from an upstream compressor station is less than 20 miles (32 km).

However, it is necessary to evaluate any segment in which one or more service incidents or hydrostatic test breaks or leaks have been caused by one of the two types of SCC.

Similar criteria have not been defined for liquid pipelines, but presumably the same criteria should apply.

5 Corrosion Damage-Assessment Methods

5.1 Overview

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

- In-line inspection (ILI)
- Hydrostatic testing
- Direct assessment (DA)

These standards also allow implementation of alternative assessment methods, if these can be shown to be effective. Selection of the most appropriate approach depends upon a variety of technical and economic factors, as described below.

5.2 In-line Inspection

ILI, sometimes referred to as "pigging," presents certain advantages over hydrostatic testing in that it can locate defects that are smaller than those that would fail at the hydrostatic-test pressure, thus potentially providing greater margins of safety. Also, in contrast to DA, ILI provides the potential for 100 percent coverage. However, there is a finite probability that larger defects might be missed, and some defects may be detected but not identified correctly or sized accurately. Furthermore, in many cases the cost is higher than that for hydrostatic testing, and data analysis can be very time consuming.

To be prepared for ILI, pipelines that have never been pigged may require extensive modification, such as valve and fitting replacement, removal of old repairs, reinforcement of pipe spans, installation of pig launchers and receivers, and performance of several trial pigging runs with gauge plates to ensure that the line can be pigged. Cleaning a pipeline in preparation for ILI can cost several hundred dollars per mile. The costs for the actual ILI run vary with the type of inspection, the length and diameter of the pipe to be inspected, and the type of information processing and reporting required after the inspection. High resolution magnetic-flux inspection can cost $1,500/inch diameter/mile for short segments; the cost can drop to $2,000/mile for long segments (100 miles [160 km]). The cost increases if high resolution or specialty pigs are used, or if caliper, geometry, or global positioning system (GPS) data are captured. A summary table of the costs is shown in Table 5-1.

Table 5.1 – Summary of ILI Costs for Inspection of Transmission Pipelines

Activity	Cost of ILI for Natural Gas Pipelines		Cost of ILI for Natural Liquid Pipelines	
	Low Estimate ($ per mi)	High Estimate ($ per mi)	Low Estimate ($ per mi)	High Estimate ($ per mi)
Cleaning	500	500	2,500	2,500
Inspection	2,000	3,500	2,000	3,500
Operator Oversight	100	100	100	100
Loss of Throughput	600	1,200	0	0
Totals	$3,200	$5,300	$4,600	$6,100

(Source: http://www.corrosioncost.com/pdf/gasliquid.pdf)

ILI tools, which sometimes are referred to as "pigs," can be divided into three classes: caliper tools, magnetic-flux leakage (MFL) tools, and ultrasonic tools. Caliper, or geometry, tools (shown in Figure 5-1), measure the internal dimensions of the pipeline and are used to identify locations where the pipe may be out of round or exhibit dents or wrinkles. Geometry tools may be used independently of or in combination with other ILI tools.

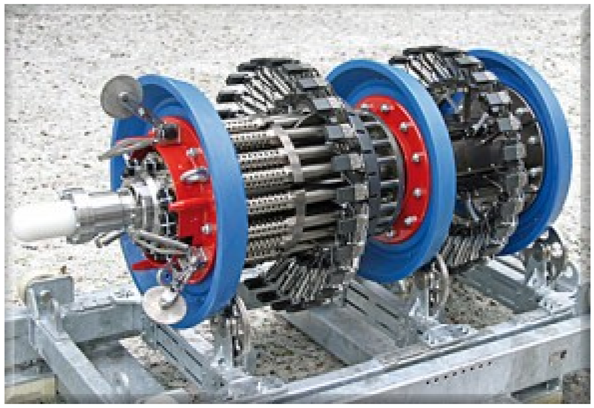

Figure 5.1 – Geometry inspection tool (courtesy of Rosen Group)
(Source: http://www.ppsa-online.com/about-pigs.php)

MFL tools, as exemplified in Figure 5-2, induce a magnetic field into the pipe wall. At any change of wall thickness, such as would be caused by corrosion or cracking, some of the flux will leak from the pipe and can be detected by the tool's sensors. The MFL tool can size corrosion pitting on both the internal and external surfaces of the pipeline, and the data can be reported numerically or displayed visually, as shown in Figure 5-3.

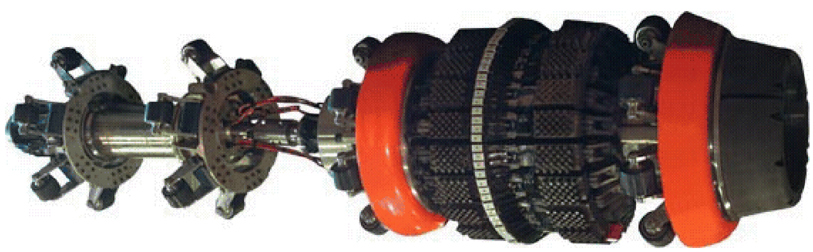

Figure 5.2 – MFL inspection pig (BJ Pipeline Inspection Services)
(Source: http://www.bjservices.com/website/pps.nsf/PS/0DB8733098ECA13F86257283007564ED)

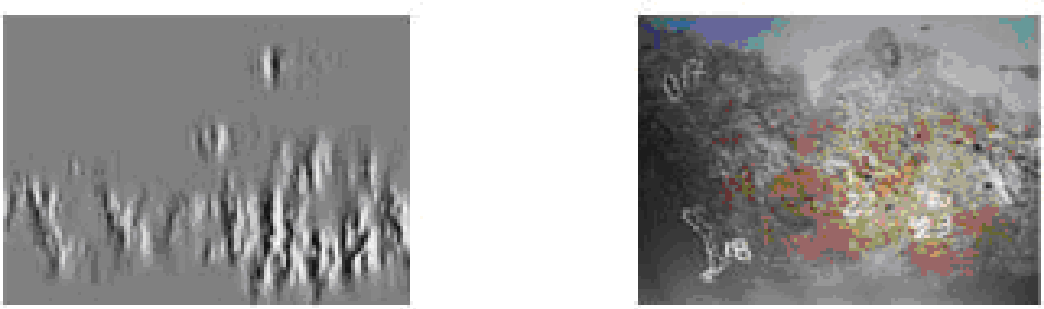

Figure 5.3 – Grayscale image of defect from display software (left), compared to a photograph of the actual corrosion defect on the right
(Source: http://www.geoilandgas.com)

MFL tools can be low or high resolution, depending on the number and the sensitivity of their magnetic pickup points. The low-resolution tool enables general sizing of pitting and indications. The high-resolution tool permits a more precise determination of the pit depth and length so that the remaining pipe strength can be calculated.

Most MFL tools produce a magnetic field that is oriented in the axial direction of the pipe, which makes them sensitive to corrosion pits or circumferential crack-like defects. To detect longitudinal crack-like defects such as those that are located along the longitudinal seam, it is necessary to orient the magnetic field in the hoop direction. For that purpose, special MFL tools have been developed that incorporate a rotating head and a transverse field. While such tools can detect selective seam corrosion, they generally have not been successful at detecting SCC because the stress-corrosion cracks are too tight to produce enough flux leakage for reliable detection and sizing.

Ultrasonic tools are much more sensitive in detecting cracks, and they also can measure changes in wall thickness. They introduce a high-frequency sound wave into the pipe wall that is reflected by any discontinuity in the wall surface, such as a crack or a lamination.

Traditional ultrasonic technology requires a liquid or gel to transmit the signal between the tool and the pipe. The product in a liquid pipeline can serve that purpose, but the technology can only be used in gas pipelines if the pig is surrounded by a slug of water, which is so cumbersome and expensive that it is considered impractical by most gas pipeline operators. To overcome that problem, tools have recently been developed that use electromagnetic acoustic transducers (EMAT), which are capable of transmitting and sensing the ultrasonic signals through a gas. Such tools currently are being evaluated by several gas transmission companies.

5.3 Hydrostatic Testing

Hydrostatic testing involves filling a section of the pipeline with water and pressuring it to a level significantly above the normal operating pressure. The main purpose is to detect and remove joints of pipe that contain defects, such as corrosion pits or cracks, by causing them to leak or rupture without causing an explosion or release of a hazardous liquid and to demonstrate the structural integrity when the pipe passes the test. It also is used to determine whether leaks exist in the pipeline.

Hydrostatic tests typically have the lowest direct costs, but the highest associated operational costs and impacts. The direct costs include the costs to isolate the line for testing, purge product from the line, fill the line with water, gather the test data, find and repair any pipe failures, purge the water from the line, dry the line, re-pack the line with product, and return the line to service. Hydrostatic testing requires removing the line from service, perhaps for more than a week, and may require making arrangements for alternative sources to deliver product to downstream customers. Waste disposal costs can also be significant, since hydrotest water cannot always simply be discharged to the ground upon completion of the test. A summary table of the costs is shown in Table 5-2.

Table 5.2 – Summary of Hydrostatic Testing Costs				
Activity	Cost of Hydrostatic Testing for Natural Gas Pipelines		Cost of Hydrostatic Testing for Liquid Pipelines	
	Low Estimate ($ per mi)	High Estimate ($ per mi)	Low Estimate ($ per mi)	High Estimate ($ per mi)
Preparation	1,250	5,000	1,250	5,000
Inspection	2,000	2,000	2,000	2,000
Loss of Throughput	6,890	22,960	27,650	92,160
TOTALS	$10,140	$29,960	$30,900	$99,160
(Source: http://www.corrosioncost.com/pdf/gasliquid.pdf)				

Hydrostatic testing has proven to be a very popular and valuable tool with some operators because it provides 100 percent inspection, cannot miss large flaws, and does not require full-opening valves, smooth bends, launchers, or receivers, as does ILI. However, it requires interruption of service, a source of water, and disposal of the water, and it may leave unknown small defects in the pipeline. In addition, it may be impractical for use on gas pipelines in areas with significant differences in elevation, as the hydrostatic head itself causes large pressure differences.

The most important parameters in a hydrostatic test are the pressures and the hold times. Based upon considerable research into the behavior of cracks during a hydrostatic test (Kiefner et al., 1980; Leis and Brust, 1992), the most effective approach appears to be the use of a “spike” hydrostatic test, where a short-time, high-pressure spike is followed by a longer hold time at a lower pressure to check for leaks. The higher the pressure, the smaller the defect that can survive the test, which means a greater safety factor and longer intervals until the next test is needed.

A number of gas pipeline companies have found that a flame ionization test, performed after the pipe is re-pressurized with gas to maximum-allowable operating pressure (MAOP), is a more sensitive method to detect leaks than is a hydrostatic test. Therefore, flame ionization should be an acceptable alternative to leak testing with water pressure.

5.4 Direct Assessment

DA represents an alternative to hydrostatic testing or ILI and is especially important for unpiggable pipelines where an interruption of service would be impractical. DA also can complement ILI when it is used to validate ILI data. However, unless the pipeline segment is very short, DA typically does not provide 100 percent coverage, so it is very important to perform excavations at locations where the probability of corrosion is the highest in the segment. Continual field validation of predictive algorithms is important.

DA involves the following four steps, the first two of which are directed at selecting appropriate excavation sites:

- **Step 1: Pre-assessment –** involves obtaining as much information about the pipe as possible from existing records and knowledgeable employees.
- **Step 2: Indirect inspections –** involves making measurements in the field to supplement the data gathered during Step 1.
- **Step 3: Direct examinations –** involves excavating and examining the pipe at selected locations.

- **Step 4: Post assessment –** involves analyzing the data and determining what future actions related to remediation and re-inspection are needed.

DA uses a combination of corrosion technologies, accompanied by physical inspections, to assess a pipeline segment. The initial indirect assessment surveys can be as inexpensive as $500/mile for close interval, pipeline current mapping, and direct current voltage gradient surveys (many times these surveys can be performed simultaneously). This information must be complemented by physical inspections that can cost $5,000 or more per site. PHMSA has estimated DA costs at $4,800 per mile, while industry estimates range up to $20,000 per mile. A summary table of the costs is shown in Table 5-3.

Table 5-3 Summary of Direct Assessment Costs

Activity	Cost of Direct Assessment for Natural Gas Pipelines		Cost of Direct Assessment for Liquid Pipelines	
	Low Estimate ($ per mi)	High Estimate ($ per mi)	Low Estimate ($ per mi)	High Estimate ($ per mi)
Preparation	0	0	0	0
Inspection	2,000	6,000	2,000	6,000
Loss of Throughput	720	3,600	0	0
TOTALS	*$2,720*	*$9,600*	*$2,000*	*$6,000*

(Source: http://www.corrosioncost.com/pdf/gasliquid.pdf)

5.4.1 External Corrosion Direct Assessment

External Corrosion Direct Assessment (ECDA) is a process used to identify the areas of a pipe that are likely to exhibit or are actually undergoing external corrosion. ECDA is a continuous improvement process. Through successive ECDA applications, a pipeline operator can identify and address where corrosion activity has occurred, is occurring, or may occur. Results from ECDA are used to prioritize future actions.

Pre-assessment is a very important step of the ECDA process. Its purpose is to identify the appropriate indirect inspection tools (i.e., aboveground measurement tools) and to identify ECDA regions, which are portions of a pipeline segment that have similar physical characteristics and similar operating and corrosion history, are anticipated to exhibit similar future corrosion conditions, and are suitable for evaluation using the same assessment method. The NACE ECDA standard provides guidance regarding the numerous data points that must be collected during pre-assessment.

The second step of the process is indirect inspection, which involves the application of two or more indirect inspection tools within each ECDA region. Commonly used tools include close-interval pipe-to-soil potential surveys to measure the level of cathodic protection, potential gradient surveys to indicate the locations of coating defects (see Figure 5-4), or soil-resistivity surveys to obtain an indication of the corrosivity of the soil. Data gathered up to this point are integrated and include the indirect inspection results, third party damage/foreign line crossing data, and pre-assessment data. Each suspect location is then prioritized according to an overall rating of urgency for attention, ranging from “immediate” (high priority), to “scheduled” (moderate priority), to “monitored” (low priority). Immediate indications must be excavated and directly examined. Scheduled indications may or may not need to be excavated, depending on the degree of metal damage found during previous investigations. Monitored indications are not required to be excavated unless no immediate or scheduled indications exist. In the event that no indications have been detected, ECDA procedures require that selective excavations nonetheless be performed on those pipeline segments most likely to incur corrosion damage.

Figure 5.4 – Collecting indirect inspection information
(Source: http://www.gepower.com/prodserv/serv/pipeline/en/downloads/extcorrofactsheet.pdf)

Direct examination of indications and determination of the root cause of corrosion damage is the third step of the ECDA process. When corrosion damage is discovered, a remaining strength calculation must be performed to determine the pressure-carrying capacity of the pipe. The data obtained during the direct examination must be integrated with the indirect inspection data and the pre-assessment data to determine if the damage (or lack thereof) is consistent with the data from the other steps. If there are inconsistencies, the ECDA process may be determined to be ineffective and therefore must not be used on the subject pipeline. Similarly, consistency among the data confirms that the ECDA process has been effective.

The last step in the investigation is post-assessment, which is performed as final verification of the results of the ECDA process. Post-assessment involves performing one or more additional direct examination excavations. One of these excavations must be at a location for which no indications have been identified. This confirms that the process is capable of detecting areas both with and without indications. A reassessment interval is calculated using the largest non-unique corrosion damage anomaly and the half-life at either the actual corrosion rate or at a prescribed default corrosion rate. Also, the metrics of the ECDA are reviewed to confirm that the ECDA is valid and has detected the proper areas. Feedback on what has worked and what needs to be changed also must be documented.

While ECDA may appear to be a new technology, it is actually an integration of existing technologies to provide a greater degree of understanding of anomalies and to improve anomaly detection using aboveground tools. To date, properly performed ECDAs have met these criteria.

5.4.2 Internal Corrosion Direct Assessment for Gas Pipelines

Pre-assessment is an essential first step in Internal Corrosion Direct Assessment (ICDA) and is similar to the ECDA pre-assessment phase. ICDA regions are determined based on inlets and outlets, pipe diameter changes, pressure and temperature changes, and flow direction for each segment being assessed. ICDA requirements during pre-assessment include determining the highest flow rate in the segment being assessed (utilizing data relating to cleaning pigs as well as the highest pipeline pressures and temperatures) and identifying incidents that could have resulted in liquids that contain electrolytes entering the pipeline system.

There are a limited number of locations in a gas pipeline where water can collect. As is illustrated in Figure 5-5, those locations will be low spots or places where the pipeline goes up a steep slope such that the gas velocity is insufficient to carry the water over the next high point. The critical angle of ascent will depend primarily on the velocity of the flow and the diameter of the pipe. The critical angle represents the angle of inclination of the pipeline at which the velocity (forward movement) is balanced with gravity (downward movement or resistance). Since the driving forces are balanced at this level of inclination, entrained liquids could settle to the bottom of the pipe. The second step, indirect inspection, consists of using the pre-assessment data to calculate the critical angle using a mathematical flow model. Currently, there are two flow models that have been validated for use in the ICDA process: the Gas Research Institute (GRI) model, developed in Norway, and a second model developed for lower pressures and higher velocities. Both of the models yield the critical angle for the highest flow rate.

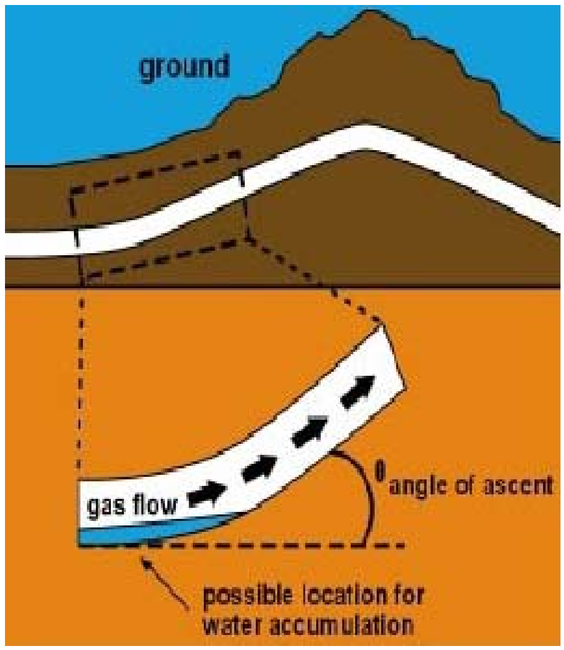

Figure 5.5 – ICDA modeling to predict likely locations of water accumulation (Source: http://primis.phmsa.dot.gov/rd/mtgs/020707/AndrewPulsifer.pdf)

During indirect inspection, all of the angles of inclination must be calculated, along with those of any low points where entrained liquids could accumulate at low flow rates. The inclination data are used to determine the first critical angle and to identify the low points upstream of that point that should be considered for direct assessment. Identification of these locations is predicated on the theory that internal corrosion can only take place somewhere between the first low point (low flow) and the first critical angle at high flow, because these are the only locations where liquid could accumulate. The low flow area would be the first low point after the entry and the high flow area would be the first critical angle. There should be no liquids that can go past the critical angle if the pre-assessment data are correct (the highest flow rate at the pressure and temperature yielding the highest velocity). If the pipeline operator does not have data that depict the highest flow rate, it may be necessary to perform several excavations at several angles to determine that no internal corrosion has occurred or is occurring.

In the third step, direct examination, excavations are performed and the pipe wall is measured to verify internal corrosion. 49 CFR Part 192.927 requires that at least two excavations in a covered segment be performed. One of the excavations must be at the first low point (low flow) in the ICDA region and the other at the first critical angle (high flow). The pipeline must be exposed during the excavation, and measurements must be taken at locations where entrained liquids could have settled and thus caused internal corrosion. If no internal corrosion is discovered, then it is assumed that the ICDA region is free from internal corrosion. If internal corrosion is found, then additional excavations must be performed. If it is determined that the application of ICDA is not feasible, another method of assessment must be employed. Lastly, when internal corrosion is found, the remaining strength of the pipeline must be calculated according to an approved method.

Post assessment, the fourth and final step, requires that the remaining life of the pipeline be calculated. Since there are no default corrosion rates for internal corrosion, the operator must select a rate and justify it. The effectiveness of the ICDA assessment must be evaluated within a year of its completion. If internal corrosion anomalies are discovered, monitoring of the pipeline is required, and a program for the monitoring must be established. Monitoring can consist of placing corrosion coupons in the appropriate locations in the pipeline or using electronic or ultrasonic probes. If liquids are found, they should be withdrawn from the pipeline and tested to determine the likelihood that they could precipitate corrosion.

There is a NACE Standard Practice (SP) that addresses ICDA for pipelines that convey dry gas which is more rigorous than the CFR regulation but has not yet been adopted by reference in Subpart O.

5.4.3 Stress Corrosion Cracking Direct Assessment

The NACE International (NACE) recommended practice (RP), NACE RP 0204, which addresses SCC DA, is applicable to high-pH SCC and near-neutral-pH SCC and to gas and liquid pipelines. Until the standard is adopted by reference in Subpart O, operators are only required to perform those tasks prescribed by the American Society of Mechanical Engineers (ASME) B31.8S standard. If they want to follow the NACE RP standard for near-neutral-pH SCC, they must file a notification.

NACE RP 0204 lists the factors to consider for the pre-assessment and indirect inspection. They are similar to those for external corrosion, but the most important factors are related to the ASME B31.8S criteria for SCC susceptibility. However, the direct assessment step is more difficult because, in contrast to corrosion pits, stress-corrosion cracks are usually not visible to the unaided eye. Typically, magnetic particle inspection (MPI) is needed to reveal the cracks and ascertain their length. Determining crack depth is particularly challenging. Many companies assess crack depth by successively buffing or grinding the cracks until they disappear and then measuring the depth of the grind or the remaining wall thickness. Non-destructive methods using ultrasonics or eddy currents also are being developed. The accuracy of those methods has been shown to be very dependent on the skill of the operator.

5.5 Emerging Technologies

Highlights of several promising alternative detection technologies presently in the research and development phase are provided below.

5.5.1 Long-Range Guided-Wave Ultrasonic Testing (LRGWUT or GWUT)

Long-range ultrasonic inspection, or guided-wave ultrasonic testing, was commercially introduced in early 1998 for in-service monitoring of pipes and pipelines. The principal advantage of this technology is that it permits the examination of long segments of pipe (i.e., 90 to 130 feet in each direction for buried pipe and 300 feet or greater, also in each direction, for aboveground pipe) from a single test point. It has gained acceptance as a valid means of assessing the condition of pipelines where inspection preparation or access is difficult or expensive. The use of the technology is especially significant in view of the high percentage of unpiggable gas pipelines in the United States. The technique has been used in the field to evaluate the condition of pipes ranging from two to 48 inches in diameter. Several validation exercises have been partially funded by PHMSA in conjunction with research on this methodology. However, the technique is very operator dependent and susceptible to overlooking corrosion or other anomalies.

GWUT utilizes ultrasonic guided waves to determine if there has been metal loss in the cross-sectional area of the pipe wall. As is shown in Figure 5-6, a collar containing transmitters and receivers must be placed directly on the pipe. The wave front that is created propagates along the axis of the pipe, interacting with features in and on the pipe, such as metal loss from corrosion, welds, attachments, branches, etc. Reflected and refracted sound is returned from pipe features and read on the data screen of the inspection equipment. (Valve bodies and flanges are restrictions to GWUT.) Sensitivity is between three percent and nine percent of the cross- sectional area of the pipe, depending on the defect shape and orientation to the wave front, i.e., features such as corrosion pits with nearly vertical side walls will yield stronger responses than saucer-shaped defects. However, relatively shallow, broad areas of localized corrosion also are detected. (Lebsack, 2004)

Figure 5.6 – GWUT tool position setup for inspection of a cased crossing
(Source: http://www.ultrasonic.de/article/wcndt2004/pdf/guided_waves/818_lebsack.pdf)

One disadvantage is that attenuation in the soil as well as the pipeline's coating can limit the range of the ultrasonic waves. In addition, the method cannot directly size an anomaly and cannot determine if the metal loss is internal or external, i.e., GWUT is a screening tool and must be used as such. It also is not effective for identifying and categorizing cracks.

5.5.2 Remote Field Testing (RFT)

RFT uses electromagnetic waves and an array of receivers to determine if a pipe has incurred metal loss. RFT may also be referred to as RFEC (remote field eddy current) or RFET (remote field electromagnetic technique). As is shown in Figure 5-7, RFEC inspection requires a transmitter coil, which can be much smaller than the diameter of the pipe, and even smaller sensor coils, which usually are mounted on an independent module. The technique is already available commercially for inspecting small-diameter piping without restrictions, several hundred feet at a time. Gas Technology Institute (GTI) is modifying this technology to operate in a non-tethered tool that can bypass common pipeline restrictions and inspect miles of pipeline. This project is sponsored by the U.S. Department of Energy; Operations Technology Development (OTD), and Pipeline Research Council International, Inc. (PRCI).

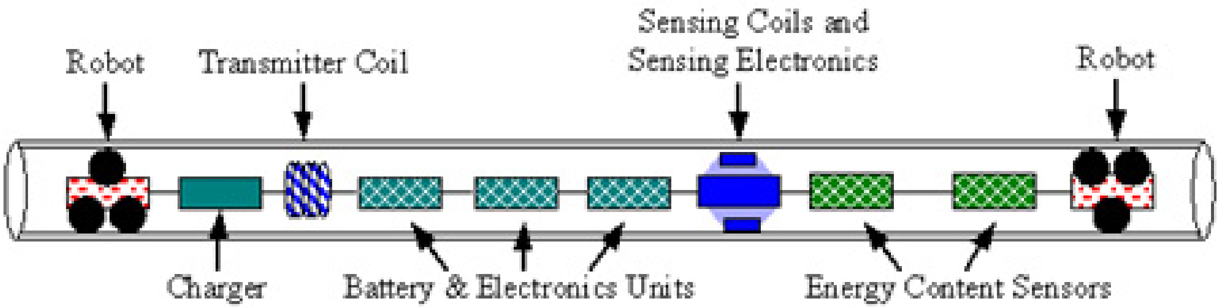

Figure 5.7 – Conceptual design for Remote Field Eddy Current (RFEC) (Source: http://www.gastechnology.org/webroot/app/xn/xd.aspx?it=enweb&xd=4reportspubs%5C4_8focus%5Cremotefieldeddycurrenttechnology.xml)

5.5.3 Robotic Investigation

To assess segments of pipe that are difficult to access, the use of robots with various technologies such as MFL, ultrasonic testing (UT), and photography currently is being investigated. Advantages are that such a vehicle could be capable of negotiating tight bends, obstructions, varying pipe diameters, and out-of-round sections. It could use existing valves for launch and recovery, generate power from the product flow, and not unduly interfere with product flow. Because robots can stop in the pipe, previously unused non-destructive testing (NDT) technologies could be utilized to better characterize pipe defects, corrosion, or damage.

One potential drawback is the limited distance over which robots can be advanced through the pipe before it must be removed for data download or recharging. One design concept, which is shown in Figure 5.8, is TIGRE, a robotic, long-range, self-powered, non-destructive evaluation (NDE) inspection system for unpiggable transmission and high-pressure distribution gas pipelines. Co-funded by Northeast Gas Association (NGA), PHMSA, OTD, PRCI and Southern California Gas Company, the robot will be able to propel itself independently of flow conditions, and will be able to negotiate all obstacles encountered in a pipeline, such as mitered bends and plug valves.

Figure 5.8 – PHMSA/NYSEARCH TIGRE Robot (Source: NYSEARCH/NGA)

5.5.4 Sound-Wave Testing

A technology to monitor natural gas pipelines for leaks relies on acoustic signals transmitted via the natural gas itself. A high-pressure leak generates vibrations in the pipe wall with a wide range of frequencies. In addition to leak detection, the system may be able to sense physical impacts to a gas pipeline, such as made by excavating equipment or even sabotage. The technology consists of installing low-cost portable acoustic monitoring packages (PAMP), which include a pressure-compensating microphone, a monotone calibrator, and a signal recorder. The systems are installed on pipeline access ports, which are located near line shut-off valves. The Department of Energy's National Energy Technology Laboratory (NETL) has worked with West Virginia University for the last two years to investigate the system, which is illustrated in Figure 5-9.

Figure 5.9 – Acoustic system being tested on Dominion line in West Virginia.
(Source: http://www.osti.gov/bridge/servlets/purl/838440-wIQSSF/native/838440.PDF)

5.5.5 NoPig

The "NoPig" pipeline inspection system analyzes the magnetic field of a pipeline from above ground. To create the magnetic field, a current is induced between two contact points on the pipeline, preferably existing points on the pipe, e.g., cathodic protection (CP) test posts. The current is the superposition of a low- and high-frequency current. The low frequency fills up the whole cross section of the pipe wall, while the high frequency only travels near the outer surface of the pipe.

The distribution of current will be influenced by a metal loss defect. A defect on the outer surface of the pipe will influence both the high- and low-frequency parts of the current distribution, while a defect on the inside surface of the pipe will affect only the low frequency current. By measuring the change of magnetic field above ground, the metal loss can be detected.

5.5.6 Buried Reference Cell Monitoring

Another assessment method involves the use of buried reference cells connected to a remote monitoring system to permit continuous observation of the pipe and thereby alleviate the need to perform excavations. This technology can instantly alert an operator to problems such as the failure of a pipe's cathodic protection system and is typically applied on critically important pipeline systems and system components, including pipe segments with protective bonds.

5.6 Specialized Techniques

5.6.1 Microbiologically Influenced Corrosion Monitoring Techniques

Monitoring for Microbiologically Influenced Corrosion (MIC) can be relatively easy. There are 'Quick Kits" available to test soil samples for bacterial activity, and many laboratories can provide a quick turnaround on soil tests that assess the presence of specific microbes. There also are on-site kits to determine the specific type of microbes in the soil.

In addition, there are some simple techniques to determine whether or not external MIC is likely to occur. Sulfate-Reducing Bacteria (SRB) microbes are commonly found in areas undergoing MIC and emit a strong odor (similar to that of spoiled eggs) that is easily detected in the excavation. Visual assessment of the environment in which the pipeline is located may also provide clues as to the likelihood of MIC development. External MIC requires a source of nutrients. Bogs, landfills, refuse sites, and similar areas offer sufficient nutrients to promote MIC development, if the other necessary elements are also present.

The presence of internal MIC can be confirmed through the testing of the biofilm on a pipe. Analysis of the decay products from biological activity can indicate the type of bacteria that is present and its relative activity. If sulfur is found in the biofilm, SRB are probably present; if acid is detected (or if a fluid exhibits a low pH value), it is likely that acid-producing bacteria are present.

5.7 Assessing the Severity of Corrosion

If corroded areas are found on the pipe, the severity of corrosion (reflected in pipe failure pressure) can be calculated by several similar techniques; the most common is predicated on ASME B31G, Manual for Determining the Remaining Strength of Corroded Pipelines, which is based on research completed by Battelle Memorial Institute in 1971. ASME B31G, Section 1.2, LIMITATIONS, specifically notes: "This Manual applies only to defects in the body of line pipe which have relatively smooth contours and cause low stress concentrations (e.g. electrolytic or galvanic corrosion, loss of wall thickness due to erosion)." However, the methods described in the manual can be used to evaluate the remaining strength of a segment of pipe from which stress-corrosion cracks were removed by grinding or buffing (which leaves a smooth depression in the pipe wall).

ASME B31G was later modified to reduce perceived conservatism in the model. A total of 86 burst tests were conducted on samples of line pipe containing corrosion defects to validate the Modified ASME B31G method. The Remaining Strength of Corroded Pipe (RSTRENG) method was developed from the ASME B31G method and enables assessment of a "river bottom" profile of the corroded area to more accurately predict remaining pipe strength.

Figure 5.10 presents a comparison of the current methods for determining the area of metal loss caused by a corrosion defect.

RSTRENG is an iterative technique that computes the "effective area" of a flaw, which is a close approximation of the actual "river bottom" profile of the defect. The ASME B31G method is a single mathematical expression that produces a conservative result using an assumed parabolic profile for short corrosion and a rectangular profile for long corrosion. The Modified ASME B31G is also a single mathematical formula that assumes a rectangular profile with a depth of 0.85 of the maximum depth recorded.

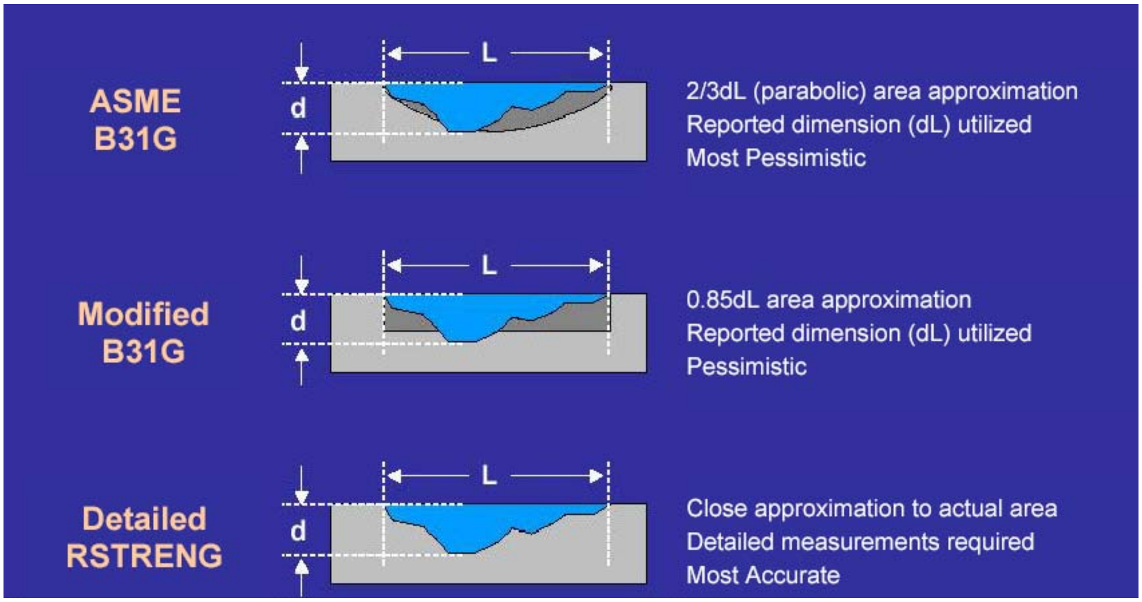

Figure 5.10 – Comparison of ASME B31G and related methodology.

All three methods allow a maximum defect depth of 80 percent of nominal wall thickness and predict failure stress based on an assumed flow stress (1.1 Specified Minimum Yield Strength [SMYS] for ASME B31G and SMYS plus 10 ksi for Modified ASME B31G) and the ratio of area of metal loss to original area utilizing an applied geometry correction factor (Folias Bulging Factor). A defect is considered acceptable if the predicted failure stress level is greater than or equal to the SMYS (i.e., if the burst pressure of the defect is greater than the pressure equivalent to 100 percent of the SMYS).

5.8 Assessing the Severity of Stress Corrosion Cracking

As stated above, the B31G or RSTRENG methods are applicable only to smooth-bottom areas of metal loss. Similar methods also have been developed for sharp flaws like stress-corrosion cracks. They include:

- SURFFLAW [J.F. Kiefner, W.A. Maxey, R.J. Eiber, and A.R. Duffy, "Failure stress levels of flaws in pressurized cylinders," Progress in Flaw Growth and Fracture Toughness Testing, ASTM STP 536, 1973, pp 461-481.]
- PAFFC [B.N. Leis and N.D. Ghadiali, Pipeline Axial Flaw Failure Criteria – PAFFC, PRCI Report 51720, May 1994.]
- CorLas® [C.E. Jaske, J.A. Beavers and B.A. Harle, "Effect of stress corrosion cracking on integrity and remaining life of natural gas pipelines," Paper 255 presented at NACE Corrosion 96, March 1996]
- API RP 579 – Recommended Practice for Fitness-for-Service

SURFFLAW, which is alternately known as log-secant, NG-18, and KAPA, is the most conservative and is used by many pipeline operators; it is readily available and easy to use. The other approaches are more complicated and less conservative, but more accurate.

6 Standards Review

6.1 Overview

As stated previously, U.S. DOT regulations concerning the maintenance and preservation of pipelines are contained in several sections under 49 Code of Federal Regulations [CFR] Part 192 (gas) and Part 195 (hazardous liquids). The regulations prescribe the minimum requirements that all operators must follow to ensure the safety of their pipelines and pipe systems. The regulations not only set requirements, but provide guidance on preventive and mitigative measures, establish time frames for upgrades and repairs, and incorporate other relevant information. They often incorporate standards in whole or in part that are developed by various industry consensus organizations.

6.2 Standard Development Organizations

6.2.1 NACE International

NACE International (NACE [originally the National Association of Corrosion Engineers]) is the principal professional organization for the development of corrosion control standards and test methods. NACE currently publishes three classes of standards: standard practices (with the designation “SP”), standard material requirements, and standard test methods. Prior to June 23, 2006, standard practices had been referred to as “standard recommended practices,” with the designation “RP.”

6.2.2 American Society of Mechanical Engineers

ASME, founded in 1880 as the American Society of Mechanical Engineers, establishes industrial and manufacturing codes and standards that enhance public safety. The ASME standards for the structural integrity of piping and pipelines are particularly relevant to pipeline corrosion.

6.2.3 American Petroleum Institute

The American Petroleum Institute (API) represents all aspects of America’s oil and gas industry, and it maintains more than 500 standards and recommended practices related to the operation of petroleum and petrochemical equipment.

6.2.4 ASTM International

ASTM International, originally known as the American Society for Testing and Materials, was formed more than a century ago. It is one of the largest voluntary standards development organizations in the world – a trusted source for technical standards for materials, products, systems, and services. Known for their high technical quality and market relevancy, ASTM International standards have an important role in the information infrastructure that guides design, manufacturing, and trade in the global economy.

6.2.5 American Society for Nondestructive Testing

The American Society for Nondestructive Testing (ASNT) is the world’s largest technical society for nondestructive testing (NDT) professionals. Of particular interest are its standards related to In-Line Inspection (ILI) and nondestructive measurements of crack sizes.

6.2.6 American National Standards Institute

The American National Standards Institute (ANSI) promotes and facilitates voluntary consensus standards in a wide range of areas. Essentially, it sets standards for the development of standards. It is the official representative to the International Organization for Standardization (ISO).

6.2.7 International Organization for Standardization

The International Organization for Standardization (ISO) is an international body of technical standards for various industries.

6.2.8 Det Norske Veritas

Det Norske Veritas (DNV) was founded in Norway in 1864 to inspect and evaluate the integrity of Norwegian merchant vessels. It has grown and expanded its scope to include many safety-related activities, including establishing international standards for the oil, gas, and petrochemical industries.

6.2.9 British Standards Institute

The British Standards Institute (BSI) is the UK's national standards organization and produces standards and information products that promote and share best practices for a wide range of industries, including oil and gas.

6.3 U.S. Regulations and Standards

6.3.1 U.S. Regulations

49 CFR Part 192, Subpart I is entitled "Requirements for Corrosion Control." The first paragraph, 192.451 Scope, states: "This subpart prescribes minimum requirements for the protection of metallic pipelines from external, internal, and atmospheric corrosion." §192.451 to 491 address requirements for both external and internal corrosion control and remediation for natural gas pipelines and also set time frames for testing and repairing systems that are not in compliance.

49 CFR Part 195, Subpart H is entitled "Corrosion Control." The first paragraph, 195.551, states "This subpart prescribes minimum requirements for protecting steel pipelines against corrosion." §195.551 to 589 set forth regulations and guidance for the operation of hazardous liquid pipelines, which are similar to those for gas pipelines.

In December, 2007, PHMSA published a report examining the effectiveness of the internal corrosion control regulations set forth in Subpart H, 49 CFR Part 195 mandated by Congress under the Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006 (PIPES). The mandate was to determine if the regulations were adequate to ensure that the pipeline facilities subject to the regulations will not present a hazard to public safety or the environment. In addition to regulations, accident history, research findings and activities in consensus with standard development organizations were thoroughly reviewed. The report indicated that existing standards to protect against internal corrosion are generally sufficient to allow PHMSA to achieve safety and environmental protection goals. The complete report can be found at http://phmsa.dot.gov/staticfiles/PHMSA/DownloadableFiles/S10-080623-001-Signed.pdf.

6.3.2 U.S. Standards

Parts or all of the following standards and publications are applicable to corrosion of pipelines:

- Safe operation of pipelines, in general
  - ANSI/ASME B31.8S, Gas transmission and distribution piping systems. (New York, New York: ASME).
  - ANSI/ASME B31.4, Pipeline transportation systems for liquid hydrocarbons
  - and other liquids. (New York, New York: ASME).
  - ASME B31.3, Process piping guide for gathering systems (New York, New York: ASME).
  - API 1160, Managing system integrity for hazardous liquid pipelines. (Washington, D.C.: API).

- Corrosion prevention in pipelines, general:
  - NACE Standard SP0169-2007, Control of external corrosion on underground or submerged metallic piping systems. (Houston, Texas: NACE).
  - NACE Standard SP0106-2006, Control of internal corrosion in steel pipelines and piping systems. (Houston, Texas: NACE).
  - NACE Standard RP0177 (latest revision), Mitigation of alternating current lighting effects on metallic structures and corrosion control systems. (Houston, Texas: NACE).
  - NACE MR0175/ISO 15156, Petroleum and natural gas industries-materials for use in H2S-containing environments in oil and gas production. (Houston, Texas: NACE).

- Cathodic protection
  - NACE Standard SP0207-2007, Performing close-interval potential surveys and dc surface potential gradient surveys on buried or submerged metallic pipelines. (Houston, Texas: NACE).
  - API Recommended Practice 1632, Cathodic protection of underground petroleum storage tanks and piping systems.
  - NACE Standard TM0497, Measurement techniques related to criteria for cathodic protection on underground or submerged metallic piping systems. (Houston, Texas: NACE).
  - ANSI/NACE Standard RP0104-2004, The use of coupons for cathodic protection monitoring applications. (Houston, Texas: NACE).
  - NACE Standard SP0286-2007, Electrical isolation of cathodically protected pipelines. (Houston, Texas: NACE).
  - NACE Standard SP0572-2007, Design, installation, operation, and maintenance of impressed current deep anode beds. (Houston, Texas: NACE).
  - NACE Standard SP0492-2006, Metallurgical and inspection requirements for offshore pipeline bracelet anodes. (Houston, Texas: NACE).
  - NACE Standard SP0387-2006, Metallurgical and inspection requirements for cast galvanic anodes for offshore applications. (Houston, Texas: NACE).

- Coatings
  - NACE Standard RP0394-2002, Application, performance, and quality control of plant-applied, fusion-bonded epoxy external pipe coating. (Houston, Texas: NACE).
  - NACE Standard RP0399-2004, Plant-applied external coal tar enamel pipe coating systems: Application, performance, and quality control. (Houston, Texas: NACE).
  - NACE Standard RP0291, Care, handling, and installation of internally plastic-coated oilfield tubular goods and accessories. (Houston, Texas, NACE).
  - NACE Standard RP0402-2002, Field-applied fusion-bonded epoxy (FBE) pipe coating systems for girth weld joints: Application, performance, and quality control. (Houston, Texas: NACE).
  - NACE Standard SP0188-2006, Discontinuity (holiday) testing of new protective coatings on conductive substrates. (Houston, Texas: NACE).
  - NACE Standard TM0186 (latest revision), Holiday detection of internal tubular coatings of 250 to 760 µm (10 to 30 mils) dry-film thickness. (Houston, Texas: NACE).
  - NACE Standard SP0490-2007, Holiday detection of fusion-bonded epoxy external pipeline coating of 250 to 760 µm (10 to 30 mil)" (Houston, Texas: NACE).
  - NACE Standard RP0191, The application of internal plastic coatings for oilfield tubular goods and accessories. (Houston, Texas: NACE).

- Field monitoring techniques
  - NACE Publication 3T199, Techniques for monitoring corrosion related parameters in field application. (Houston, Texas: NACE).
  - NACE Standard RP0775, Preparation, installation, analysis, and interpretation of corrosion coupons in oilfield operations. (Houston, Texas: NACE).
  - ASTM G 57, Standard test method for field measurement of soil resistivity using the wenner four-electrode method. (West Conshohocken, Pennsylvania: ASTM).
  - NACE Standard TM0194 (latest version), Field monitoring of bacterial growth in oilfield systems. (Houston, Texas: NACE).

- In-Line Inspection
  - NACE Standard RP0102-2002, In-line inspection of pipeline. (Houston, Texas: NACE).
  - NACE Publication 35100, In-line nondestructive inspection of pipelines. (Houston, Texas: NACE).

- Direct Assessment
  - ANSI/NACE Standard RP0502-2002, Pipeline external corrosion direct assessment methodology. (Houston, Texas: NACE).
  - NACE Standard SP0507-2007, External corrosion direct assessment (ECDA) Integrity Data Exchange (IDX) Format. (Houston, Texas: NACE).
  - ANSI/NACE Standard RP0204-2004, Stress corrosion cracking (SCC) direct assessment methodology. (Houston, TX: NACE).
  - NACE Standard SP0206-2006, Internal corrosion direct assessment methodology for pipelines carrying normally dry natural gas (DG-ICDA). (Houston, Texas: NACE).

- Evaluating structural integrity
  - ANSI/ASME B31G, Manual for determining the remaining strength of corroded pipelines: A supplement to B31, Code for pressure piping. (New York, New York: ASME).
  - RSTRENG for Windows. (Houston, Texas: NACE).
  - ANSI/API 579, Fitness for service. (Washington, D.C.: API).

- Analytical and testing techniques
  - ASTM G 1, Preparing, cleaning and evaluating corrosion test specimens. (West Conshohocken, Pennsylvania: ASTM).
  - ASTM D 3370, Sampling water from closed conduits. (West Conshohocken, Pennsylvania).
  - ASTM D 1945, Standard test method for analysis of natural gas by gas chromatography. (West Conshohocken, Pennsylvania: ASTM).
  - ASTM D 888, Standard test methods for dissolved oxygen in water. (West Conshohocken, Pennsylvania: ASTM).
  - ASTM D 512, Chloride ion in water. (West Conshohocken, Pennsylvania: ASTM).
  - ASTM D 513, Standard method for total and dissolved carbon dioxide in water. (West Conshohocken, Pennsylvania: ASTM).
  - ASTM D 4810, Standard test method for hydrogen sulfide in natural gas using length-of-stain detector tubes. (West Conshohocken, Pennsylvania: ASTM).
  - ASTM D 5504, Standard test method for determination of sulfur compounds in natural gas and gaseous fuels by gas chromatography and chemiluminescence. (West Conshohocken, Pennsylvania: ASTM).
  - ASTM D 4658, Standard test method for sulfide ion in water. (West Conshohocken, Pennsylvania: ASTM).

- ASTM D 3227, Standard test method for (thiol mercaptan) sulfur in gasoline, kerosene, aviation turbine, and distillate fuels (potentiometric method). (West Conshohocken, Pennsylvania: ASTM).
- ASTM G 170.01a, Evaluating and qualifying oilfield and refinery corrosion inhibitors in the laboratory. (West Conshohocken, Pennsylvania: ASTM).
- ASTM G 184, Standard practice for evaluating and qualifying oil field and corrosion inhibitors using rotating cage. (West Conshohocken, Pennsylvania: ASTM).
- ASTM G 185, Standard practice for evaluating and qualifying oil field and corrosion inhibitors using the rotating cylinder electrode. (West Conshohocken, Pennsylvania: ASTM).
- ASTM D 1796, Standard test method for water and sediment in fuel oils by the centrifuge method (laboratory procedure). (West Conshohocken, Pennsylvania: ASTM).
- ASTM D 6304, Standard test method for determination of water in petroleum products, lubricating oils, and additives by Coulometric Karl Fisher titration. (West Conshohocken, Pennsylvania: ASTM).
- ASTM D 5907, Standard test method for filterable and nonfilterable matter in water. (West Conshohocken, Pennsylvania: ASTM).

6.3.3 Relevant Non-U.S. Standards

Following are some of the most important non-U.S. standards and recommended practices:

- Canadian Standard Z662-07, Oil and gas pipeline systems. Covers the design, construction, operation, and maintenance of oil and gas industry pipeline systems that convey liquid hydrocarbons, oilfield water, oilfield steam, carbon dioxide, and gas.
- Canadian Energy Pipeline Association. (2007). Recommended Practices for Stress Corrosion Cracking, 2nd edition.
- BS 7910, Guide on Methods for Assessing the Acceptability of Flaws in Metallic Structures. (London, England: BSI).
- DNV Standard RP-F10, Corroded pipelines. (Oslo, Norway: Det Norske Veritas).

6.4 Role of Industry Best Practices Regarding Corrosion

The larger pipeline operators often make presentations and provide information to operator associations on lessons learned and operating techniques. The American Gas Association (AGA) hosts periodic conferences for gas local distribution companies (LDC) that highlight best practices for maintenance and operating methods, in support of asset preservation and incident reduction. Several research organizations also prepare topical reports on industry best practices. There are similar conferences and associations for gas transmission operators and hazardous liquid operators.

Operators also perform benchmarking to determine if they have met risk reduction requirements. The benchmarks have been used for economic ranking but can also be used to evaluate how risk is being mitigated and controlled through the use of new technology and improved systems.

7 Corrosion Risk Management

This section discusses various approaches to assessing the risk of corrosion using industry- accepted risk management methodologies.

7.1 Overview

The U.S. Department of Transportation (DOT) Integrity Management Rule requires operators to follow a risk assessment approach in prioritizing threats to the integrity of pipeline segments located in high-consequence areas (HCA). Even prior to the rule, many operators used risk assessment methodologies to evaluate the susceptibility of all of the pipelines in their system and subsequently allocated funds to investigate and mitigate threats to those pipelines considered to be at highest risk.

Risk is the product of the likelihood of a failure times the consequences of the failure. Failure in gas transmission pipelines is generally defined as a leak or a rupture, with the latter being of primary concern. Failure in gas distribution pipelines in most cases is a leak, but, since these pipelines are typically located in populated areas, the consequences can be significant. The consequences from both ruptures and leaks in a liquid pipeline can be significant, due to the potential for environmental damage.

Risk assessment is a process used to determine the likelihood and consequences of a failure due to a potential threat. Risk management generally refers to a programmatic approach that involves identifying potential threats, assessing the risk associated with the threats (in terms of the likelihood and consequences of failure), mitigating the risk, and then monitoring the effectiveness of the program in reducing the risk.

In concept, the DOT Integrity Management Rule is fundamentally a risk management approach for pipelines in HCAs.

External corrosion risk can be quantified using several techniques that involve simultaneous consideration of the nature of the operating environment, the grade and type of steel, the safety factors of the pipeline, and the operational and inspection history of the pipeline. External corrosion in one location may not necessarily indicate pervasive external corrosion, but can provide a good indication of the likelihood of external corrosion at other, similar locations.

Valuable lessons for internal corrosion have also been learned through practical experience. Most pipeline operators can determine the likelihood of internal corrosion based on the quality of gas and the degree of electrolyte removal.

7.2 Risk Assessment Methodologies

There are various methodologies used to assess risks to pipeline integrity. Common methodologies (presented in order of increasing difficulty in obtaining sufficient data) include the following:

- Subject Matter Expert (SME) Method
- Relative Risk Ranking Method
- Probabilistic-Based Model

Some operators employ a combination of models, which enables them to compare one model against another for relative accuracy (i.e., utilizing an SME model to verify the data from a relative risk model).

7.2.1 Subject Matter Expert Model

The SME methodology taps into the experience and knowledge of the operator's personnel and industry consultants in ranking pipeline segments from highest to lowest in terms of likelihood of failure and consequences of failure. These experts usually have a wealth of practical knowledge gained through many years of experience. They also possess anecdotal knowledge relating to issues and problems that have arisen in the past.

A simple matrix that depicts low, medium, and high likelihood of consequences is often used to capture the decisions of these field experts. This approach can be implemented relatively easily; however, subjectivity can cloud the process and the validity of results can therefore be of concern. Using SME models to validate the results of other models is very appropriate and valuable.

7.2.2 Relative Risk Model

Relative risk ranking models are the most widely used in the industry. These models identify all of the risk variables that contribute to the likelihood and consequences of a failure with respect to a specific threat, such as external corrosion or third-party damage. The models provide a system to numerically rank the conditions that could be associated with a model variable, as well as to evaluate the relative contribution of each variable.

The relative risk model utilizes information that includes the physical characteristics of the facility, the nature of recurring problems, and the root cause of major problems. Most of the data are available either from the operator's files or via SMEs. The numerical weighting factors used to characterize each variable are often established based on the performance of the operator's system, DOT incident databases, and industry databases that have been established over the years through cooperative forums. For example, coatings are the first line of defense against external corrosion, and the type and condition of the coating are key factors that have been documented to contribute to the risk of external corrosion. In the case of external corrosion, age is also a driving variable that must be considered, as external corrosion is a time-based damage mechanism. In the case of internal corrosion, operational data, including flow rate, water content, and CO_2 content, are very important, along with pipeline elevation profiles.

Integrating operations and maintenance historical data to develop appropriate weighting for a variable is extremely important. For example, if a pipeline segment has a documented history of external corrosion and/or leakage due to corrosion, the assigned weighting factor for these conditions would be very high.

These models are particularly valuable in determining the relative impact of each threat on a particular pipeline segment. The models allow the operator to assess risks independently, or to compare risks, such as those due to internal versus external corrosion. This capability provides added value by enabling the operator to focus assessments or data-gathering efforts on addressing the particular factors of a specific damage mechanism that are contributing to an elevated threat.

In summary, relative risk ranking models provide a consistent approach to assessing the integrity of and assigning a risk factor to a pipeline segment. While they are not considered to be quantitative, these models are very valuable in aiding operators to prioritize pipeline segments according to the need for assessment.

7.2.3 Probabilistic Model

Probability-based models are the most complex, requiring substantial amounts of data for proper development. Many operators prefer to use probabilistic models since the models can quantify risk. However, care should be taken, since often there are not enough actual data to yield meaningful results, and hence it is necessary to estimate missing data, or to follow conservative assumptions.

The results from application of a probabilistic model are generally expressed as the probability of an event occurring (e.g., 1x10-6 incidents per mile per year) times the probable consequences of such an event. The probability rating can then be compared with the overall risk history of the operator's pipeline, level of desired performance, and industry-accepted rates.

Probabilistic models can be particularly meaningful when calibrated by the actual incident frequency rates of an operator's system. However, the "quantitative" results must be carefully scrutinized when extrapolated to new situations. All of the individual conditions (risk variables) of a particular pipeline may not be included in the model. Therefore, the ability of the model to define the risk at any particular location along the pipeline should be carefully reviewed for site-specific applicability.

7.3 Characteristics of an Effective Risk Assessment

There are a number of key elements that are characteristic of all effective risk assessments:

- **Resources –** Sufficient personnel and funding must be allocated to implement the desired approach to risk assessment. Frequent data integration and re-assessment of risks must be performed to continually account for changing conditions on the pipeline.
- **Commitment –** The operator must commit to the approach and must be willing to take appropriate action to mitigate identified risks.
- **Quality of Data –** The quality of the data used in the models must be continually assessed and improved. Conservative assumptions must be used when data do not exist or are determined to be of poor quality. Trending analysis must be used to identify data that must be obtained to more accurately reflect risk to a particular segment.
- **Weighting Factors –** A structured set of weighting factors must be identified and consistently applied. Sensitivity analysis should be performed to ensure that there is a clear understanding of how each of the factors will drive the relative risk score. Additionally, risk modifiers or "spikers" can be incorporated into the models to elevate assumed risks, if specific conditions are known to exist.
- **Segmentation –** A structure that clarifies how the weighting factors are assigned relative to individual pipeline segments must be established. Initially, entire pipeline systems may be unfairly "penalized" with a high risk rating, even though a specific deleterious condition exists within only one segment. The model must clearly define how this situation is to be accounted for and the approach required to limit the risk rating to the area of the segment for which the risk drivers actually apply.
- **Documentation –** Documenting risk decisions and all of the data used to arrive at the decisions is very important, as it supports the technical basis for assignment of risk. All of the procedures used to facilitate the process, including the source for each of the data elements, must be documented.
- **Continuous Improvement –** It is expected that each risk assessment approach will be continually refined, based on lessons learned in data-gathering and risk-mitigation efforts. Commitment to continuous improvement is an extremely important part of a comprehensive risk assessment approach.

7.4 Summary

Risk assessment and risk management are processes essential to the successful management of pipeline integrity. These processes provide the foundation for prioritizing efforts on the highest risk pipelines and serve as the technical basis for the actions implemented to mitigate the threats to the pipeline. Integrating quality data into the models ensures that the risk models accurately reflect the conditions of and relative risks to the pipeline. These processes must be continually evaluated and improved by utilizing the lessons learned from experience – both of the individual operator as well as within the industry.

8 Corrosion Research

8.1 Overview

Since corrosion is one of the major causes of pipeline failures, a considerable amount of work continues to be expended to determine the mechanisms of failure and methods to prevent it.

8.2 Corrosion R&D Funding Organizations

At present, there are three main sources of research and development (R&D) funding: individual pipeline companies, associations of owners and operators of facilities, and government entities. Generally, these groups do not conduct research themselves, but rather fund third-party research. Research funded by individual companies usually is considered proprietary. Since the passage of the pipeline integrity regulations in 2002, much of the recent research strategy is crafted in collaboration and has focused on developing and perfecting new technologies and strengthening consensus standards to assess the integrity of pipelines.

The operator associations and their related foundations include the American Gas Association (AGA), the Interstate Gas Association of America (INGAA), Pipeline Research Council International (PRCI), the Southern Gas Association (SGA), Operations Technology Development Company (OTD), and the Northeast Gas Association (NGA). Liquid pipeline operators also fund R&D efforts targeted to their specific needs. Some of the funding is through PRCI, and other funding is through liquid pipeline associations, such as the American Petroleum Institute (API) and Association of Oil Pipelines (AOPL).

As part of recent pipeline integrity legislation, U.S. DOT has been authorized to fund additional R&D through PHMSA. Unfortunately, appropriations have not matched authorizations. The U.S. Department of Energy (DOE) and the U.S. Department of the Interior (DOI) have also been funding corrosion-related work. Corrosion detection and mitigation technology, as well as the fundamental mechanisms of corrosion, are being investigated through these efforts.

In Canada, similar funding for specific issues is primarily handled by the government through the National Energy Board (NEB) and by industry through the Canadian Energy Pipeline Association (CEPA).

More information on PHMSA Corrosion Research is found at http://primis.phmsa.dot.gov/matrix/ by sorting with the Advanced Search option.

8.3 Current Corrosion R&D Efforts

Appendix A contains a list of currently funded corrosion R&D projects.

8.3.1 Prevention

With the relatively recent discovery of internal stress corrosion cracking (SCC) in storage facilities containing fuel-grade ethanol, concern has been raised about the possibility of SCC in pipelines, and a significant amount of research is being directed at ways to prevent it.

Conversely, with respect to preventing external corrosion, internal corrosion, and external SCC, very little R&D is being performed because the preventive measures are already fairly well documented.

While the actual detailed mechanisms and interactions that precipitate certain types of corrosion may not be fully understood, measures to prevent corrosion that are in current use have been shown to be relatively effective.

8.3.2 Detection

Many of the R&D projects involving detection are being driven by direct assessment (DA) issues. Detection of external corrosion, internal corrosion, and environmentally assisted cracking is an integral part of the DA process, so R&D that enhances corrosion detection also improves the DA process.

Many of the currently funded projects involve detecting corrosion in locations that are difficult to access, in cased crossings, and under insulation.

One of the leading methods (that is also garnering significant R&D funding) is long-range guided-wave ultrasonic testing (LRGWUT or GWUT). A combination of PHMSA and industry funding is being used to validate and improve the technology so that it can be used to determine the pressure-carrying capacity of a pipe. Currently, the technology can detect metal loss within a cross-sectional area, but cannot be used reliably to calculate failure pressures, which require metal loss depth and length. Equipment manufacturers have made some improvements, and the latest machines are in their third generation. In addition, improvements that expand the range of the equipment without eliciting significant false positives are needed. Each generation of the equipment has yielded improved results. Some equipment manufacturers or service providers are currently claiming they can estimate the depth and length of metal loss and thus provide an estimate of pipe pressure-carrying capacity. GWUT does not distinguish between internal and external corrosion and can be used to assess both.

8.3.3 Assessment

A considerable amount of work is being done on corrosion assessment technology, mainly driven by DA-related investigations. The success of any DA depends on selecting locations where the probability of corrosion or SCC is the highest. This is not a trivial issue, especially for SCC, and therefore is the subject of much current research. Important research also is being conducted to develop ways to measure the size of stress-corrosion cracks nondestructively so that the strength of the pipe can be determined.

Another critical issue is determining the appropriate intervals for re-assessments, which has motivated research on predicting rates of corrosion or crack growth.

R&D work also is being performed to develop industry standards for assessing “wet” gas pipelines with Internal Corrosion Direct Assessment (ICDA) and for using ICDA on liquid-carrying pipelines. This work is being undertaken with the assistance of NACE International (NACE).

8.3.4 Mitigation

The mechanisms for external pitting corrosion, coating degradation, and repairs are generally well documented and understood. What is not well documented (or well known) are details of the mechanisms that precipitate the development of external microbiologically influenced corrosion (MIC) and why the potential needed to overcome the action of the bacteria is higher than that for plain or regular external corrosion.

Regarding internal corrosion, there is some concern for developing a model that accurately and consistently predicts what the corrosion growth rate is when internal corrosion is supplemented with MIC. There appears to be a divergence of opinions on the best pH level to buffer electrolytes in order to minimize the likelihood of MIC growth. The bacteria seem to be able to adapt to the particular surroundings to which they are exposed.

Details of the growth mechanisms and the induction periods for both forms of external SCC are not well known and therefore are the subject of several research projects.

8.4 Corrosion R&D Requirements

There are active projects in many of the areas of need in corrosion R&D. The predominant gaps where additional R&D should occur lie in developing technology to assess difficult-to-access structures; determining the rate of internal corrosion, MIC, and SCC crack growth; and developing accurate mechanism models for SCC. Listed below are some of the specific needs where additional work is suggested.

- External corrosion
  - Methods to reliably assess segments such as water crossings, directionally bored pipelines, cased crossings, etc.
  - Methods to determine the rate of corrosion in MIC areas
  - A definitive cathodic protection potential to fully mitigate and prevent external MIC corrosion

- Internal corrosion
  - A method to accurately and effectively determine internal corrosion growth rate

- Stress-corrosion cracking
  - Development of a practical and effective tool for in-line inspection (ILI) of gas pipelines

- Other Corrosion Needs
  - Continued validation of DA techniques, especially ICDA and SCC DA.
  - Statistical validation of emerging technology, such as GWUT, especially when used in combination with DA for difficult-to-access locations.

8.5 Summary of Corrosion R&D Activities

PHMSA is either co-funding or funding much of the pipeline R&D activities in the United States. Industry groups, including PRCI, INGAA, AGA, SGA, API, AOPL, OTD, and NGA (through NYSEARCH) are other major funding sources and often provide the co-funding to PHMSA.

Specific research is being conducted on issues of immediate industry concern. Many of these issues are a direct result of the enacted pipeline regulations for transmission pipelines and the proposed distribution pipeline integrity management requirements. Specifically, a considerable amount of research is being focused on validation of DA technologies, such as ECDA, ICDA, and SCC DA, as well as technology that could aid DA, such as LRGWUT or GWUT.

Some industry groups are collaborating with standards-writing organizations to develop new standards that could be referenced by PHMSA in regulations. An example of this is ICDA for gas pipelines that once carried wet gas.

9 Elements of an Effective Corrosion Integrity Management Program

9.1 Overview

Proactive management is one of the key elements of an effective corrosion integrity management program because it promotes early identification of potential threats and outcomes and thereby enables problems to be resolved at the earliest possible stage. Using the code requirements as the zero point or "base case," effective corrosion control programs then may go beyond these minimum requirements to anticipate where and when problems may arise and to proactively apply appropriate preventive and mitigative measures.

The specific details of an integrity management program will be unique to each pipeline. An integrity management program should be continually reviewed and modified to reflect lessons learned from operator experience, conclusions drawn from results of the integrity assessments, and data obtained from other maintenance and surveillance efforts, and must include evaluation of the consequences of a failure within each high-consequence area (HCA).

While the requirements of an exceptional external corrosion control program are well known, understanding is not as robust for internal corrosion, stress corrosion cracking, and microbiologically influenced corrosion (MIC). There is a wealth of practical data and experience relating to the latter topics, but additional detailed technical data on mechanisms and preventive and mitigative measures is required.

9.2 Technology

An effective program evaluates available technology and may use a combination of tools to focus on specific system issues. Existing technologies, discussed throughout this report, include the following:

- Internal Corrosion Inspection Surveys
- Pressure Testing
- Guided Ultrasonic (GUL) Surveys
- Cathodic Protection (CP) Surveys
- Excavations
- In-Line Inspection

9.3 Components of an Effective Integrity Management Program

At a minimum, a written integrity management program must contain the following elements:

- A process for identifying which pipeline segments are in an HCA.
- A baseline assessment plan. Acceptable methods of assessment include a) use of an internal inspection tool capable of detecting corrosion, b) hydrostatic testing, c) direct assessment, or d) other technology that the operator demonstrates can provide an equivalent understanding of the condition of the pipe.
- An analysis that integrates all available information about the integrity of the pipeline and the consequences of a failure.
- Criteria for remedial actions to address integrity issues raised by the assessment methods and information analysis.
- A continual process of assessment and evaluation to maintain the integrity of the pipeline.

- Identification of preventive and mitigative measures to protect HCAs.
- Methods to measure the effectiveness of the program.
- A process for review of integrity assessment results and information analysis by a person qualified to evaluate the results and information.

Operator commitment to proactive planning and the effective allocation of resources is integral to the success of a corrosion integrity management program. As in any company program, accountability, responsibility, and ownership of the entire corrosion process are key ingredients for success.

9.4 Resource Requirements (after Byrd, 2004)

An integrity management program requires an in-house manager to effectively coordinate and oversee the activities of the program. For a large pipeline or pipeline system, this position is often full-time. In addition, support is needed from engineering and operational staff. A rule of thumb is to allocate one position (i.e., one full-time equivalent [FTE] person) per every 200 miles of pipeline, although the position often requires the part-time input of several personnel. For example, if the pipe is to be inspected using in-line tools, associated duties include answering data needs and questionnaires from the pigging vendors; coordinating permitting for field operations, such as site access; developing procedures for field operations, such as cleaning, drying, pigging, reconfiguration, valve replacement, installation and removal of temporary traps, and removal of coupons and other probes before pigging; coordinating the cleaning, caliper inspection, aboveground marker (AGM) system placement, pig runs, and lost pig tracking and recovery; and performing follow-up investigations and repairs.

In its Final Regulatory Evaluation reports, PHMSA has estimated that the cost to develop, implement, mitigate repairs, and maintain a pipeline integrity management program for gas and liquid pipelines is $3,500 to $6,000 per mile. These are industry-wide estimates that will vary widely from operator to operator. Average cost per mile will likely be higher for certain companies:

- Small operators,
- Operators of older pipelines (especially those whose system contains pre-1970 electric-resistance welded [ERW] pipe),
- Operators of pipe located in urban areas,
- Operators of short segments of pipe, and
- Operators of pipe that requires direct assessment.

The first costs an operator is likely to encounter are program development costs. Written integrity management programs are complex and must consider detailed information about each pipeline and its environment. Template programs typically cost $40,000-$60,000 and must then be customized for the particular pipeline operator and pipeline segments involved. Many operators use specialized software as part of their integrity programs. Software license costs of $40,000 are typical, with annual maintenance costs of several thousand dollars.

Once the integrity program is developed, it must be implemented, including baseline assessments that must be conducted for each affected pipeline segment. The assessments are typically performed through in-line inspection (ILI), hydrostatic testing, or direct assessment (DA). A high-level summary of the main advantages and disadvantages is shown in Error! Reference source not found.. More details about each method are given in Section 5.

Table 9.1 – 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: http://www.corrosioncost.com/pdf/gasliquid.pdf)		

Once the baseline assessment is conducted, pipeline repairs may be required (Figure 9-1). The cost of repairs will depend on the type and location of defects found. Additional costs may be incurred for repairs to specialty pipe/high yield strength pipe, areas requiring specialized personnel protection (confined space entry; aboveground work), and areas that are difficult to access. One rule of thumb is to anticipate a cost of $1,000 for each composite sleeve repair or $5,000 for full-encirclement weld-on repair sleeve installations. The operator must bear in mind that the base repair cost does not include associated expenses for excavation and resource mobilization.

Figure 9.1 – Inspection dig and pipeline repair.
(Source: http://www.corrosioncost.com/pdf/gasliquid.pdf)

Excavation costs may include associated costs for property damage. There also may be situations in which pipe removal is required to determine the root-cause of a problem or to retain evidence of damage caused by a third-party. The costs associated with pipe replacement will include the inherent "out of service" revenue losses, but also could include additional costs for mechanical testing, analytical testing, and, in some instances, expert witness testimony.

Once the program is developed, baseline assessments are conducted, and initial repairs are completed, there will be ongoing program costs for data analysis and integration, program updates, reassessments, and software license renewals (typically, $5,000 or more per year). Ongoing costs include data management, such as keeping track of ILI and DA information for the life of the pipeline system. In addition to the direct costs associated with the integrity management program, there will be indirect costs, such as lost revenue from downtime and pipeline restrictions.

10 Summary and Conclusions

10.1 Frequency and Consequences of Corrosion Incidents

During the 20-year period from 1988 to 2007, corrosion has been responsible for 18 percent of the significant incidents in pipelines carrying natural gas or hazardous liquids. Corrosion was second only to excavation damage as a cause of incidents. Excavation damage caused 26 percent of the incidents during that time period. An incident is defined by the Pipeline and Hazardous Materials Safety Administration (PHMSA) as significant if it causes a fatality, an injury requiring in-patient hospitalization, cost of $50,000 or more, release of five barrels or more of a highly volatile liquid, release of 50 barrels or more of other liquids, or release of a liquid resulting in an unintentional fire or explosion.

On average, there have been 52 significant corrosion incidents per year on pipelines in the United States. Sixty-three percent of the incidents involved onshore hazardous liquid pipelines and 15 percent involved onshore gas transmission pipelines. The remaining incidents occurred on offshore gas transmission pipelines, gas distribution lines, gas gathering lines, and offshore liquid lines.

On average, those incidents resulted in 1.4 fatalities and 5.2 injuries per year, and caused about $25 million of property damage per year. In comparison with gas pipelines, liquid pipelines experienced more incidents and caused more property damage but resulted in fewer fatalities and injuries.

10.2 Prevention of Corrosion in Pipelines

Corrosion is defined as the deterioration of a material, usually a metal, that results from a reaction with its environment. Pipelines can be subject to external corrosion and internal corrosion. The most common form of corrosion is pitting corrosion, but various forms of environmentally assisted cracking, such as stress-corrosion cracking (SCC), hydrogen-stress cracking, hydrogen-induced cracking, and sulfide-stress cracking (SSC), also have been observed.

External corrosion is controlled with coatings and cathodic protection. Cathodic protection is a method to prevent corrosion by imposing a direct current onto the pipe at places where the coating is missing. Corrosion problems can arise if the coating becomes disbonded from the pipe and allows groundwater to contact the steel pipe but shields that portion of the pipe from the cathodic-protection currents.

Preventive measures for internal corrosion vary according to the type of product carried in the pipeline and the type of contamination.

Typically, sales-quality dry gas will not corrode interior surfaces of a pipeline. However, natural gas, as it comes from the well, may contain small amounts of contaminants such as water, carbon dioxide, and hydrogen sulfide. If the water condenses, it can react with the carbon dioxide or hydrogen sulfide to form an acid that might collect in a low spot and cause internal corrosion.

Internal corrosion also can occur in hazardous liquid pipelines that carry corrosive liquids or liquids that contain corrosive contaminants. Liquid pipelines can experience internal corrosion anywhere along their length where electrolytes or solids drop out and wet the surface or where sags in the pipeline provide a place for electrolytes to collect.

Dehydration is the most commonly applied measure to protect against internal corrosion in gas pipelines and in liquid pipelines that contain oil with free water or other electrolytes.

Coatings or plastic liners sometimes are used to control internal corrosion, but they are not failsafe because breaks in the coating or pinholes in the liner can allow liquids to contact the pipe. Therefore, many operators who use coatings or liners also employ additional preventive measures.

Other preventive measures include the use of buffering agents, cleaning pigs to remove corrosive liquids or solids, and drip legs to trap contaminants.

If microbiologically influenced corrosion (MIC) is a problem in liquid pipelines, biocides can be injected into the pipeline. To prevent MIC in gas pipelines, the electrolyte at the pipe wall must be removed by drying the gas.

Methods for monitoring internal corrosion include the use of removable corrosion coupons or probes to measure moisture level, liquid conductivity, pH, or wall thickness.

Another form of degradation falls within the definition of corrosion is environmentally assisted cracking (EAC), in which the combined action of a tensile stress and a corrosive environment causes cracks to form in the metal. There are a number of different cracking mechanisms within the category of EAC; the most important are SCC, hydrogen-stress cracking, and SSC. In comparison with pitting corrosion, EAC results in relatively few significant incidents.

Since its discovery in 1965 as a possible cause of failures in pipelines, external SCC has caused, on average, one to two failures per year in the United States. The failures involved older pipe that had been coated in the field, or in one case, not coated at all. No instances of SCC have been reported for the newer pipe with mill-applied coatings, despite the fact that some pipelines with mill-applied coatings have been in service for more than 40 years. This is believed due to several factors that include better surface preparation, compressive residual stresses from the grit blasting, and improved coating properties. It is widely accepted that the use of such coatings is an effective way to prevent SCC.

To date, there have been no reported cases of internal SCC in North America. However, with the increasing use of ethanol as a gasoline additive, the pipeline industry is considering the transport of denatured ethanol in its pipelines. Recently, concern has been raised about the possibility of internal SCC in pipelines that would transport ethanol or ethanol/gasoline blends, as SCC has been observed inside storage tanks and user terminals that contain fuel-grade ethanol. The determination of safe conditions for transporting ethanol and ethanol/gasoline blends in pipelines is currently the subject of intense research.

Hydrogen-stress cracking is a delayed-failure mechanism that sometimes occurs in high-strength steels that have absorbed hydrogen produced at the surface through an electrochemical reaction (corrosion or cathodic protection). Line-pipe steels of grades up to and including at least X80 that exhibit normal properties are not considered susceptible to hydrogen-stress cracking. However, some hydrogen-stress cracking failures have occurred in unusually hard regions of X52 pipe. Hard spots can be detected with magnetic-flux leakage in-line inspection (ILI) pigs. The preferred method of preventing hard-spot failures is to locate and remove the hard spots rather than try to eliminate the source of the hydrogen.

SSC is a type of spontaneous brittle failure that occurs in steels and other high-strength alloys upon contact with moist hydrogen sulfide and other sulfidic environments. Some researchers consider SSC a type of SCC, while others consider it a type of hydrogen-stress cracking. SSC in pipelines 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 that contact the pipe. Reported failures due to SSC are relatively few. Internal SSC is far more common than external, which is rare. Susceptibility to SSC is a function of a number of variables; two of the more important are strength or hardness of the steel and the level of tensile stresses. For any steel, there is a minimum applied stress, called the threshold stress, below which failure due to SSC will not occur. The threshold stress decreases as the strength level increases. Therefore, the common way to prevent SSC failures is to maintain a maximum strength level of 80,000 psi for steel pipe that is exposed to wet hydrogen sulfide environments. It also is important to control the welding processes to make sure that they do not induce regions of high hardness and high residual stress.

10.3 Corrosion Threat Identification

U.S. Department of Transportation (DOT) regulations for the maintenance and preservation of pipelines require that pipeline operators identify and evaluate all potential threats to every high-consequence area (HCA) along the pipeline. HCAs, which typically are areas within which there is a relatively high population density or sensitive environment near the pipeline, are defined in the regulations.

It seems reasonable to assume that any buried or submerged pipeline should be identified as susceptible to external corrosion, although, in principle, it might be possible for a segment to be located in a soil that is not corrosive. The burden of proof would rest upon the pipeline operator and would be considerable.

Internal corrosion would not pose a threat to any pipeline whose product could be confirmed free of liquid water. However, in most cases, the possibility of introducing a certain amount of water with the supply gas or liquid cannot be ruled out; consequently, an evaluation of the threat of internal corrosion is appropriate for the majority of pipelines.

Since conditions for producing SCC are far more limited than those for producing general or pitting corrosion, it would not be appropriate to identify SCC as a threat for all pipeline segments or HCAs. SCC would not be identified as a threat unless the operating stress level is greater than 60 percent of the Specified Minimum Yield Strength (SMYS), the age of pipe coating is greater than 10 years, and the pipe is uncoated or coated with a corrosion coating system other than plant-applied or field-applied fusion-bonded epoxy (FBE) or liquid epoxy. High-pH SCC also would be eliminated unless the operating temperature was above 100°F (38°C) and the distance from an upstream compressor station is less than 20 miles (32 km). However, any segment which has experienced a service incident or hydrostatic-test break or leak caused by SCC should be evaluated.

10.4 Assessing the Severity of Corrosion

Although the preventive measures for external and internal corrosion are highly effective, they are not foolproof. Therefore, it is necessary to conduct periodic assessments of the integrity of a pipeline.

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

- ILI
- Hydrostatic testing
- Direct assessment (DA)

These regulations also allow implementation of alternative methods, if these can be shown to be effective Selection of the most appropriate approach will depend upon a variety of technical and economic factors, as described below.

ILI presents certain advantages over hydrostatic testing in that it can locate defects that are smaller than those that would fail at the hydrostatic-test pressure, thus potentially providing greater margins of safety. Also, in contrast to DA, ILI provides 100 percent coverage. However, there is a finite probability that larger defects might be missed, and some defects may be detected but not identified correctly or sized accurately. Furthermore, in many cases, the cost of ILI is higher than that of hydrostatic testing, and data analysis can be very time consuming.

ILI tools, which sometimes are referred to as "pigs," can be divided into three classes: caliper tools, magnetic-flux leakage (MFL) tools, and ultrasonic tools. Caliper, or geometry, tools measure the internal dimensions of the pipeline and are used to identify locations where the pipe may be out of round or contain dents or wrinkles. Geometry tools may be used independently or in combination with other ILI tools.

MFL tools induce a magnetic field into the pipe wall. At any change of wall thickness, such as that caused by corrosion or cracking, some of the flux will leak from the pipe and can be detected by the tool's sensors. The MFL tool can size corrosion pitting on both the internal and external surfaces of the pipeline, and the data can be reported numerically or displayed visually.

Ultrasonic tools are much more sensitive at detecting cracks, and they also can measure changes in wall thickness. They induce a high-frequency sound wave into the pipe wall that is reflected by any discontinuity within the wall, such as a crack, or a lamination. Traditional ultrasonic technology requires the use of a liquid or gel to transmit the signal between the tool and the pipe. The product in a liquid pipeline can serve that purpose, but the technology can only be used in gas pipelines if the pig is surrounded by a slug of water, which is so cumbersome and expensive that it is considered impractical by most gas pipeline operators. To overcome that problem, tools recently have been developed that use electromagnetic acoustic transducers (EMATs), which are capable of transmitting and sensing the ultrasonic signals through a gas.

Hydrostatic testing involves filling a section of the pipeline with water and pressuring it to a level significantly above the normal operating pressure. The main purpose is to detect and remove joints of pipe that contain defects, such as corrosion pits or cracks, by forcing the defects to leak or rupture without causing an explosion or release of a hazardous liquid and also to demonstrate structural integrity, if the pipe passes the test. It also is used to determine whether leaks exist in the pipeline.

Hydrostatic testing has proven to be very popular among some operators and considered a valuable tool because it provides 100 percent inspection, cannot miss large flaws, and does not require full-opening valves, smooth bends, launchers, or receivers, as required for ILI. However, it requires interruption of service, a source of water, and disposal of the water, and it may leave unknown small defects in the pipeline. In addition, it may be impractical for use on gas pipelines in areas with significant differences in elevation, as the hydrostatic head itself causes large pressure differences.

The most effective approach to check for leaks appears to be the "spike" hydrostatic test, in which a high-pressure spike is induced in the pipe for a short period of time, followed by reduction in pressure that is maintained over a longer interval. The higher the pressure, the smaller the defect that can survive the test, which means a greater safety factor and longer times until the next test is needed.

A number of gas pipeline companies have found that a flame ionization test performed after the pipe is re-pressurized with gas to its maximum allowable operating pressure (MAOP) is a more sensitive test for leak detection than the hydrostatic test. Therefore, flame ionization should be an acceptable alternative to leak testing using water pressure.

DA represents an alternative to hydrostatic testing or ILI and is especially important for unpiggable pipelines where an interruption of service would be impractical. DA also can complement ILI when it is used to validate the ILI data. However, unless the pipeline segment is very short, DA typically does not provide 100 percent coverage, so it is very important to perform excavations at locations where the probability of corrosion is the highest in the segment. Continual field validation of predictive algorithms is important.

DA involves the following four steps, the first two of which are directed at selecting appropriate excavation sites:

- **Step 1: Pre-assessment –** obtaining as much of the information as possible from existing records and knowledgeable employees
- **Step 2: Indirect inspections –** making measurements in the field to supplement the data from Step 1
- **Step 3: Direct examinations –** excavating and examining the pipe at selected locations
- **Step 4: Post assessment –** analyzing the data and determining the future actions for remediation and re-inspection that are needed.

If corroded areas are found on the pipe, the severity (failure pressure) can be calculated by utilizing several similar techniques; the most common are based on the American Society of Mechanical Engineers (ASME) B31G, Manual for Determining the Remaining Strength of Corroded Pipelines, which applies only to defects in the body of line pipe that exhibit relatively smooth contours and cause low stress concentrations (e.g., electrolytic or galvanic corrosion; loss of wall thickness due to erosion). However, the methods described in the manual can be used to evaluate the remaining strength of a segment of pipe from which cracks were removed by grinding or buffing (which leaves a smooth depression in the pipe wall). Similar methods also have been developed for sharp flaws such as stress-corrosion cracks.

10.5 Regulations and Standards

10.5.1 Regulations

U.S. DOT regulations for the maintenance and preservation of pipelines are contained in several sections under 49 CFR Part 192 (gas) and Part 195 (hazardous liquids). The regulations prescribe the minimum requirements that all operators must follow to ensure the safety of their pipelines and piping systems. The regulations not only set requirements, but provide guidance on preventive and mitigative measures, establish time frames for upgrades and repairs, and incorporate other relevant information. They often incorporate standards that are developed by various industry consensus organizations.

10.5.2 Standard Development 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 SP0169-2007, “Control of External Corrosion on Underground or Submerged Metallic Piping Systems” and SP0106-2006, “Control of Internal Corrosion in Steel Pipelines and Piping Systems,” as well as seven standards related to cathodic protection, eight related to pipeline coatings, three related to field monitoring techniques, and three on procedures for DA (external corrosion, internal corrosion for pipelines that carry normally dry gas, and SCC).

ASME has published two comprehensive standards that provide guidance for integrity management of pipelines: ASME B31.8S, “Gas Transmission and Distribution Piping Systems” and ASME B31.4, “Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids.”

The American Petroleum Institute (API) represents all aspects of America's oil and gas industry, and it maintains more than 500 standards and recommended practices related to the operation of petroleum and petrochemical equipment. Particularly relevant to pipeline integrity are API 1160, "Managing System Integrity for Hazardous Liquid Pipelines" and API 579, "Fitness for Service."

ASTM International (ASTM) has published many standards on test methods for the laboratory and the field, including analysis of contaminants in gas or liquids and the effectiveness of corrosion inhibitors.

The American Society for Nondestructive Testing (ASNT) has published standards related to ILI and nondestructive measurements of crack sizes.

The American National Standards Institute (ANSI) essentially sets standards for developing standards.

Important non-U.S. standards organizations include the International Organization for Standardization (ISO), which is an international body of technical standards for various industries; Det Norske Veritas (DNV), which establishes international standards for, among other things, the oil, gas, and petrochemical industries; and the British Standards Institute (BSI), which is the UK's national standards organization and produces standards and information products that promote and share best practices for a wide range of industries, including oil and gas.

Some of the most important non-U.S. standards and recommended practices are Canadian Standard Z662-07, "Oil and Gas Pipeline Systems," which covers the design, construction, operation, and maintenance of oil and gas industry pipeline systems that convey liquid hydrocarbons, oilfield water, oilfield steam, carbon dioxide, and gas; Canadian Energy Pipeline Association, "Recommended Practices for Stress Corrosion Cracking;" BS 7910, "Guide on Methods for Assessing the Acceptability of Flaws in Metallic Structures;" and DNV Standard RP-F101, "Corroded Pipelines."

10.6 Corrosion Risk Management

The DOT Integrity Management Rule requires operators to follow a risk assessment approach in prioritizing threats to the integrity of pipeline segments located in HCAs. Risk is the product of the likelihood of a failure times the consequences of the failure. Failure in gas transmission pipelines is generally defined as a leak or a rupture, with the latter being of primary concern. Failure in gas distribution pipelines in most cases is a leak, but, since these pipelines are typically located in populated areas, the consequences can be significant. The consequences from both ruptures and leaks in a liquid pipeline can be significant, due to the potential for environmental damage.

Risk management is a process used to determine the likelihood and consequences of a failure due to a potential threat. Risk management generally refers to a programmatic approach that involves identifying potential threats, assessing the risk associated with the threats (in terms of the likelihood and consequences of failure), mitigating the risk, and then monitoring the effectiveness of the program in reducing the risk.

The three most common methodologies used to assess integrity risks to pipelines are the subject matter expert (SME) method, the relative risk ranking method, and the probabilistic-based model. Some operators employ a combination of models which enables them to compare one model against another for relative accuracy (i.e., utilizing an SME model to verify the data from a relative risk model).

The SME methodology taps into the experience and knowledge of the operator's personnel and industry consultants in ranking pipeline segments from highest to lowest in terms of likelihood of failure and consequences of failure. This approach can be implemented relatively easily; however, subjectivity can cloud the process and the validity of results can therefore be of concern. Using SME models to validate the results of other models is very appropriate and valuable.

Relative risk ranking models are the most widely used in the industry. These models identify all of the risk variables that contribute to the likelihood and consequences of a failure with respect to a specific threat, such as external corrosion or third-party damage. The models provide a system to numerically rank the conditions that could be associated with a model variable. Relative risk ranking models provide a consistent approach to assessing and assigning a risk factor to a pipeline segment. While they are not thought of as being quantitative, these models are very valuable in aiding operators to prioritize pipeline segments according to the need for assessment.

Probability-based models are the most complex, requiring substantial amounts of data for proper development. Many operators prefer to use probabilistic models since the models can quantify risk. However, care should be taken, since often there are not enough actual data to yield meaningful results, and hence it is necessary to estimate missing data, or to follow conservative assumptions.

The results from application of a probabilistic model are generally expressed as the probability of an event occurring (e.g. 1x10-6 incidents per mile per year) times the probable consequences of such an event. The probability can then be compared with the overall risk history of the operator's pipeline, level of desired performance, and industry-accepted frequency rates.

10.7 Corrosion Research

A considerable amount of work continues to be expended in determining the mechanisms of failure and methods to prevent it. The most important areas of current research and development (R&D) include the following:

- Detecting corrosion in locations that are difficult to access using long-range guided-wave testing
- Developing ways to prevent internal SCC in pipelines carrying ethanol or blends of ethanol and gasoline
- Selecting excavation locations for DA for which the probability of corrosion or SCC is highest
- Developing ways to measure the size of stress-corrosion cracks nondestructively so that the strength of the pipe can be determined
- Determining appropriate intervals for re-assessments, which involves research into predicting rates of corrosion or crack growth
- Developing industry standards for assessing "wet" gas pipelines with internal corrosion direct assessment (ICDA) and for using ICDA on liquid-carrying pipelines
- Developing a model that accurately and consistently predicts the corrosion growth rate when internal corrosion is supplemented with MIC
- Determining the growth mechanisms and induction periods for both forms of external SCC.

The predominant gaps in R&D lie in developing technology to assess difficult-to-assess structures; determining the rate of internal corrosion, MIC, and SCC crack growth; and developing accurate mechanism models for SCC. Specific needs include the following:

- Methods to reliably assess segments such as water crossings, directionally bored pipelines, cased crossings, etc., for external corrosion
- Methods to determine the rate of external or internal corrosion in MIC areas
- A definitive cathodic protection potential to fully mitigate and prevent external MIC
- A method to accurately and effectively determine internal corrosion growth rate
- A practical and effective tool for ILI of gas pipelines
- Continued validation of DA techniques, especially for ICDA and SCC DA.

More information on PHMSA Corrosion Research is found at http://primis.phmsa.dot.gov/matrix/ by sorting with the Advanced Search option.

10.8 Corrosion Integrity Management Programs

The specific details of any integrity management program will be unique to each pipeline, and an integrity management program should be continually reviewed and modified to reflect operating experiences, conclusions drawn from results of the integrity assessments, other maintenance and surveillance data, and evaluation of the consequences of a failure in each HCA.

At a minimum, a written integrity management program must contain the following elements:

- A process for identifying which pipeline segments are within an HCA.
- A baseline assessment plan. Acceptable methods of assessment include a) use of an internal inspection tool capable of detecting corrosion, b) hydrostatic testing, c) DA, or d) other technology that the operator demonstrates can provide an equivalent understanding of the condition of the pipe.
- An analysis that integrates all available information about the integrity of the pipeline and the consequences of a failure.
- Criteria for remedial actions to address integrity issues raised by the assessment methods and information analysis.
- Continual process of assessment and evaluation to maintain the integrity of the pipeline.
- Identification of preventive and mitigative measures to protect HCAs.
- Methods to measure the effectiveness of the program.
- A process for review of integrity-assessment results and information analysis by a person qualified to evaluate the results and information.

Operator commitment to proactive planning and the effective allocation of resources is integral to the success of a corrosion integrity management program. As with any company program, accountability, responsibility, and ownership of the entire corrosion process are key ingredients.

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12 Appendix A

12.1 Listing of Relevant Current Research

12.1.1 PRCI funded R&D (from Web Site):

1) Re-inspection intervals for corroded pipelines
2) Structural significance of corrosion defect
3) Location and evaluation of coating disbondment and shielding coatings
    a) Large scale cathodic disbondment testing for CTE (coal tar enamel)
4) Accuracy of tools for corrosion mapping
5) Internal corrosion threat assessment
    a) Define operating conditions in which internal corrosion is extremely unlikely to exist
    b) Development and demonstration of internal corrosion threat assessment guidelines
6) Criteria for determining seam failure due to crack defects
7) Development of guidelines for identification of SCC sites and estimation of re-inspection intervals for SCC DA
8) Sensor technology for sizing and characterizing SCC cracks
    a) Detection, sizing and characterization of SCC and other cracks in dents
    b) External surface breaking SCC crack mapping using a flexible eddy current array probe
    c) Characterization of SCC using laser ultrasonics
9) Pipeline operational practices to prevent and minimize internal corrosion
    a) Behavior and consequences of solid contaminants in liquid pipelines
    b) Understanding sediment transport and deposition in liquid crude pipelines
10) Internal SCC prevention
    a) Identify environmental factors that produce SCC in ethanol pipelines and terminals
    b) Determine stress conditions that promote SCC in ethanol pipelines and terminals

12.1.2 PHMSA Funded R&D (not listed elsewhere)

1) Phase Sensitive Methods to Detect Cathodic Disbondment
2) Cathodic Protection Current Mapping In-Line Inspection Technology
3) Determining Integrity Reassessment Intervals Through Corrosion Rate Modeling And Monitoring
4) Development of ICDA for Liquid Petroleum Pipelines
5) Corrosion Assessment Guidance for Higher Strength Pipelines
6) Internal Corrosion Direct Assessment Detection of Water
7) MEIS System for Pipeline Coating Inspection
8) Application of Remote-Field Eddy Current Testing to Inspection of Unpiggable Pipelines
9) Improvements to the External Corrosion Direct Assessment Methodology by Incorporating Soils Data
10) Determining Integrity Reassessment Intervals Through Corrosion Rate Modeling And Monitoring
11) Evaluation and Validation of Aboveground Techniques for Coating Condition Assessment
12) Corrosion Assessment Guidance for Higher Strength Pipelines
13) Guidelines for Interpretation of Close Interval Surveys for ECDA
14) ECDA for Unique Threats to Underground Pipelines
15) Demonstration of ECDA Applicability and Reliability for Demanding Situations
16) External Pipeline Coating Integrity
17) Dissecting Coating Disbondments
18) An Assessment of Magnetization Effects on Hydrogen Cracking for Thick-Walled Pipelines
19) Task Order #1: External Corrosion of Line Pipe Steels
20) Task Order #2: Fatigue Fracture and Crack Arrest in High-Strength Pipeline Steels
21) Stage 2 Phased Array Wheel Probe for In-Line Inspection

22) Characterization of Stress Corrosion Cracking Using Laser Ultrasonics
23) Guidelines for the Identification of SCC Sites and the Estimation of Re-Inspection Intervals for SCCDA
24) Mechanical Properties and Crack Behavior in Line Pipe Steels
25) Validation and enhancement of long range guided wave ultrasonic testing: A key technology for DA of buried pipelines
26) Real-Time Active Pipeline Integrity Detection (RAPID) System for Direct Assessment of Corrosion in Pipelines
27) Enhancing Direct Assessment with Remote Inspection through Coatings and Buried Regions
28) Long Term Monitoring of Cased Pipelines Using Long-Range Guided-Wave Technique

12.1.3 NYSEARCH (Part of NGA)

1) Validation and Enhancement of TWI/Petrochem Guide Wave Ultrasonic Inspection Technology for Pipelines
2) Development of Corrosion Camera
3) Evaluation/Validation of ICDA

12.1.4 AGA

1) Effectiveness of DA on pipelines in casings and include some surveys of operators who have ILI data (in conjunction with INGAA)