External Corrosion of Oil and Natural Gas Pipelines

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PIPELINES play an extremely important role throughout the world as a means of transporting gases and liquids over long distances from their sources to the ultimate consumers. The general public is not aware of the number of pipelines that are continually in service as a primary means of transportation. A buried operating pipeline is rather unobtrusive and rarely makes its presence known except at valves, pumping or compressor stations, or terminals. In the United States, there were approximately 217,000 km (135,000 mi) of hazardous liquid transmission pipelines, 34,000 km (21,000 mi) of crude oil gathering pipelines, 483,000 km (300,000 mi) of natural gas transmission pipelines, and 45,000 km (28,000 mi) of natural gas gathering pipelines in 2000 (Ref 1–3). There were approximately 60 major natural gas transmission pipeline operators and 150 major hazardous liquid pipeline operators in the United States in 1998 (Ref 4).

The first oil pipeline, which was 175 km (109 mi) in length and 152 mm (6 in.) in diameter, was laid from Bradford to Allentown, PA in 1879 (Ref 5). Since the late 1920s, virtually all oil and gas pipelines have been made of welded steel. Although the first cross-country pipeline that connected some major cities was laid in 1930, it was not until World War II that large-scale pipelines were laid connecting different regions of the country. In the 1960s, larger-diameter pipelines ranging from 813 to 914 mm (32 to 36 in.) were built. Discovery of oil on Alaska's North Slope resulted in the construction of the country's largest pipeline, the Trans-Alaska Pipeline System, with a 1219 mm (48 in.) diameter and 1287 km (800 mi) length. Demand continues to add more miles of pipelines.

Table 1 provides a summary of the major accidents reported to the U.S. Department of Transportation by the operators for the 6-year period between 1994 and 1999 (Ref 6). The data show that for transmission pipeline systems (both hazardous liquid and natural gas), approximately 25% of all reported accidents were due to corrosion. Of the hazardous liquid pipeline accidents caused by corrosion, 65% were due to external corrosion and 34% were due to internal corrosion. For natural gas transmission pipeline accidents,

36% were caused by external corrosion and 63% were caused by internal corrosion. For natural gas distribution pipeline accidents, only approximately 4% of the total accidents were caused by corrosion, and the majority of those were caused by external corrosion. The accidents reported in Table 1 are for major accidents that resulted in injury, fatality, or more than $50,000 in property damage. In addition to the reportable accidents, an average of 8000 corrosion leaks per year are repaired on natural gas transmission pipelines (Ref 7), and 1600 spills per year are repaired and cleaned up for liquid product pipelines.

In a summary report for incidents between 1985 and 1994, corrosion accounted for 28.5% of pipeline incidents on natural gas transmission and gathering pipelines (Ref 8). In a summary report for incidents between 1986 and 1996, corrosion accounted for 25.1% of pipeline incidents on hazardous liquid pipelines (Ref 9). These values correspond very well to the statistics for 1994 to 1999 presented in Table 1.

Given the implications of pipeline failures and the role that external corrosion plays in these failures, it is apparent that proper corrosion control can have a major impact on the safety, environmental preservation, and the economics of pipeline operation.

The vast majority of underground pipelines are made of carbon steel, based on American Petroleum Institute API 5L specifications (Ref 10). Typically, maximum composition limits are specified for carbon, manganese, phosphorous,

and sulfur. In some cases, other alloying elements are added to improve mechanical properties. Composition and tensile requirements for common line pipe steels are shown in Table 2.

These steels have inadequate alloy additions to be considered corrosion resistant and undergo

Table 1 Summary of corrosion-related accident reports on hazardous liquid, natural gas transmission, and natural gas distribution pipelines from 1994 to 1999

Category	Pipeline system type		
	Hazardous liquid transmission	Natural gas transmission	Natural gas distribution
Total accidents due to corrosion (1994–1999)	271	114	26
Total accidents (1994–1999)	1116	448	708
Total accidents due to corrosion, %	24.3	25.4	3.7
Corrosion accidents due to external corrosion, %	64.9	36.0	84.6
Corrosion accidents due to internal corrosion, %	33.6	63.2	3.8
Corrosion accidents cause not specified, %	1.5	0.9	11.5

Source: Ref 6

Table 2 Chemical and tensile requirements of common long seam welded line pipe steels

Grade	Composition, wt% max				Yield strength minimum		Ultimate tensile strength minimum	
	C	Mn	P	S	MPa	ksi	MPa	ksi
A	0.22	0.9	0.03	0.03	207	30	331	48
B	0.26	1.2	0.03	0.03	241	35	414	60
X42	0.26	1.3	0.03	0.03	290	42	414	60
X46	0.26	1.4	0.03	0.03	317	46	434	63
X52	0.26	1.4	0.03	0.03	359	52	455	66
X56	0.26	1.4	0.03	0.03	386	56	490	71
X60	0.26	1.4	0.03	0.03	414	60	517	75
X65	0.26	1.45	0.03	0.03	448	65	531	77
X70	0.26	1.65	0.03	0.03	483	70	565	82

Product specification level 1, Ref 10

a variety of corrosion failure modes/mechanisms in underground environments, including general corrosion, pitting corrosion, and stress-corrosion cracking (SCC).

The terms general corrosion and pitting corrosion are used rather loosely when describing the morphology of underground corrosion. The classical pitting often associated with passive metals (such as stainless steels) is typically not observed on underground pipelines, with the possible exception of cases where microbial activity is involved. Likewise, true general corrosion, where there is uniform metal loss, such as observed with carbon steel in a concentrated acid, is not commonly found on underground pipelines. The most common morphology of corrosion on underground pipelines is uneven metal loss over localized areas covering a few to several hundred square inches (Fig. 1). The most common mechanism causing this corrosion is referred to as differential corrosion cells. Microbes and stray direct current (dc) in the soil also can affect underground corrosion.

Because of the relatively poor corrosion resistance of line pipe steels in underground environments, a combination of mitigation strategies consisting of coatings and cathodic protection (CP) is required. In this article, the most common causes and contributing factors for corrosion and SCC, as well as prevention, mitigation, detection, and repair are discussed.
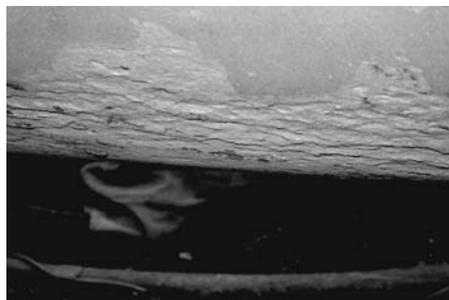

Fig. 1 Example of external corrosion of an underground pipeline. Lower quadrant of pipeline shown after coating removal and abrasive cleaning

Differential Cell Corrosion

In the case of true general corrosion of a metal, the oxidation and reduction reactions occur physically at or very near the same location on a metal. At any given moment, one atom is being oxidized while the reduction reaction is occurring at an adjacent atomic site. Corrosion of a metal in an acid solution is a common example of this type of behavior. It is also possible for the oxidation and reduction reactions to be separated on a metal surface, where the metal oxidation occurs predominantly at one site while the reduction reaction occurs predominantly at another site. This is referred to as a differential corrosion cell. Underground corrosion of pipelines and other structures is often the result of differential corrosion cells of which a variety of different types exist. These include differential aeration cells, where different parts of a pipe are exposed to different oxygen concentrations in the soil, and cells created by differences in the nature of the pipe surface or the soil chemistry. This behavior is sometimes obvious when excavating an old, bare pipeline in which some areas are in excellent condition but other areas only a few feet away are severely corroded.

A differential aeration cell is probably the most common corrosion cell found on pipelines or other underground structures. One area of the pipeline is exposed to higher concentrations of oxygen and becomes the cathode in the cell, while another part of the structure is oxygen deficient and becomes the anode. Electrical current leaves the metal surface at the anode, increasing the corrosion rate, and flows to the oxygenated cathodic area, decreasing the corrosion rate. Differential aeration cells as well as other corrosion cells can be autocatalytic in that the chemical and electrochemical reactions, as well as ion migration, tend to produce conditions that promote the continuation of the cells. At the anode, the metal ions produced by the corrosion reactions hydrolyze (react with water), reducing the local pH. Corrosive negative halide ions migrate to the anodic sites to maintain charge neutrality. Both of these processes increase the corrosivity at the anodic sites. At the cathodic

sites, the reduction reactions increase the pH and improve the protective nature of the corrosion films.

Differences in soil properties, variation in the moisture content of the soil, the depth from the surface or oxygen barriers such as paved roads can produce differential aeration cells. An example is illustrated in Fig. 2, which shows a pipeline passing through two dissimilar soils. The corrosion potential of the pipeline in the clay soil is more negative than the corrosion potential in the sandy soil, resulting in an increase in the corrosion rate of the pipe in the clay and a decrease in the sand. Factors other than differences in the oxygen concentration of the soil can produce a differential corrosion cell such as the one shown in Fig. 2. For example, differences in the pH, or the concentration of aggressive ions such as chlorides in the soil, can produce differential corrosion cells.

Galvanic corrosion is another example of a differential corrosion cell. In the case of galvanic corrosion, the potential difference is created by the presence of different metals. Different metals have a different corrosion potential in a given environment. An example is the galvanic series for metals in soils, shown in Table 3 (Ref 11). When these metals are electrically coupled, the metal with the most positive corrosion potential is cathodically polarized, reducing its corrosion rate, while the more negative member of the couple is anodically polarized, increasing its corrosion rate. Galvanic corrosion can be very detrimental to an underground structure. Examples include the corrosion of iron in contact with copper or stainless steel fittings. However, galvanic corrosion can be used as an effective means of CP, as described in the section on CP.

The surface films present on a metal also can alter the corrosion potential and cause differential cell corrosion. For example, mill scale is created on line pipe steel during the manufacturing process (hot rolling) and, if not removed, the mill-scale-coated steel will act like

Table 3 Practical galvanic series and redox potentials of metals and alloys in neutral soils and water

Material	Potential (CSE)(a), V
Most Noble	
Carbon, graphite, coke	+0.3
Platinum	0 to −0.1
Mill scale on steel	−0.2
High-silicon cast iron	−0.2
Copper, brass, bronze	−0.2
Low-carbon steel in concrete	−0.2
Lead	−0.5
Cast iron (not graphitized)	−0.5
Low-carbon steel (rusted)	−0.2 to −0.5
Low-carbon steel (clean and shiny)	−0.5 to −0.8
Commercially pure aluminum	−0.8
Aluminum alloy (5% Zn)	−1.05
Zinc	−1.1
Magnesium alloy (Mg-6Al-3Zn-0.15Mn)	−1.6
Commercially pure magnesium	−1.75
Most Active	

(a) Measured with respect to copper sulfate reference electrode (CSE).
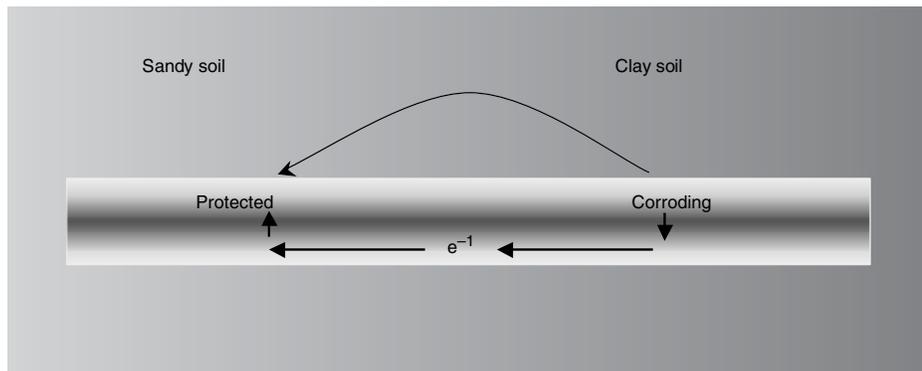Source: Ref 11

Fig. 2 Differential corrosion cell created by differences in soils. Arrows indicate the direction of ionic and electronic current flow.

a dissimilar metal in contact with non-mill-scale-coated pipe steel. The potential of the bare pipe steel surface will be more negative (active) than the mill-scale-coated surface, resulting in severe corrosion of the bare steel surface in low-resistivity soils. A similar condition can occur when new steel pipe is intermixed with old steel pipe. The potential of bright new steel is typically more negative than that of old rusted steel, resulting in rapid corrosion of the new steel unless the new section is electrically insulated from the old section and (or) cathodically protected. A similar corrosive condition can occur if, during work on an existing piping system, tools cut or scrape the pipe and expose areas of bright steel. The potential of these bright spots will be more negative than the remainder of the pipe, resulting in accelerated corrosion in low-resistivity soils.

The relative size of anodic and cathodic areas can have a significant effect on the severity of the differential corrosion cell. In general, the severity of corrosion of the anodic areas increases as the ratio of the anodic to the cathodic area decreases. When the anode is small and the cathode is large, the anode will be subject to a high density of current discharge per unit area, with the total amount of current flowing governed by the kinetics of the oxidation and reduction reactions and the soil resistivity. The current collected per unit area on the cathode is relatively low and may not be sufficient to result in any degree of polarization, which would tend to limit corrosion current. In a low-resistivity soil, corrosion can be rapid.

Microbiologically Influenced Corrosion

Microbiologically influenced corrosion (MIC) is defined as corrosion that is influenced by the presence and activities of microorganisms, including bacteria and fungi. It has been estimated that 20 to 30% of external corrosion on underground pipelines is MIC-related (Ref 5). Microorganisms located at the metal surface do not directly attack the metal or cause a unique form of corrosion. The by-products from the organisms promote several forms of corrosion, including pitting, crevice corrosion, and under-deposit corrosion. Typically, the products of a growing microbiological colony accelerate the corrosion process by either interacting with the corrosion products to prevent natural film-forming characteristics of the corrosion products that would inhibit further corrosion, or providing an additional reduction reaction that accelerates the corrosion process.

A variety of bacteria have been implicated in exacerbating corrosion of underground pipelines, and these fall into the broad classifications of aerobic and anaerobic bacteria (Ref 12). Obligate aerobic bacteria can only survive in the presence of oxygen, while obligate anaerobic bacteria can only survive in its absence. A third classification is facultative aerobic bacteria that prefer aerobic conditions, but can live under anaerobic conditions. Common obligate anaerobic bacteria implicated in corrosion include sulfate-reducing bacteria (SRB) and metal-reducing bacteria. Common obligate aerobic bacteria include metal-oxidizing bacteria, while acid-producing bacteria are facultative aerobes. The most aggressive attack generally takes place in the presence of microbial communities that contain a variety of types of bacteria. In these communities, the bacteria act cooperatively to produce conditions favorable to the growth of each species. Obligate anaerobic bacteria can thrive in aerobic environments when they are present beneath biofilms/deposits in which aerobic bacteria consume the oxygen. An example is shown in Fig. 3. In the case of underground pipelines, the most aggressive attack has been associated with acid-producing bacteria in such bacterial communities (Ref 5).

Stray Current Corrosion

Corrosion of underground pipelines can be accelerated by stray dc flowing in the soil near the pipeline. Sources of direct electrical current include foreign pipelines that are not properly bonded to the pipeline and ground currents from dc sources. Electrified railroads, mining operations, and other similar industries that utilize large amounts of dc sometimes allow a significant portion of current to use a ground path return to their power sources. These currents often utilize pipelines in close proximity as a part of the return path. This "stray" current can be picked up by the pipeline and discharged back into the soil at some distance down the pipeline close to the current return. Current pickup on the pipe is the same process as cathodic protection, which tends to mitigate corrosion. The process of discharge of a dc off the pipe and through the soil accelerates corrosion of the pipe wall at the discharge point, causing stray current corrosion. The morphology of stray current corrosion tends to be very localized at holidays (defects or holes) in the pipeline coating. Rates of attack can be very high, resulting in rapid perforation of a pipeline.

In the case of stray current corrosion from a foreign pipeline, the pipeline acts as a return current path for the cathodic protection system on the foreign pipeline. Stray current corrosion occurs where the dc discharges from the pipeline and collects onto the foreign pipeline, as shown in Fig. 4. While relatively rare, cathodic protection rectifiers are occasionally connected backwards, such that dc current is discharged from the pipeline and the impressed current "anode" actually collects rather than discharges current. This can result in severe stray current corrosion of the pipeline (Fig. 5).
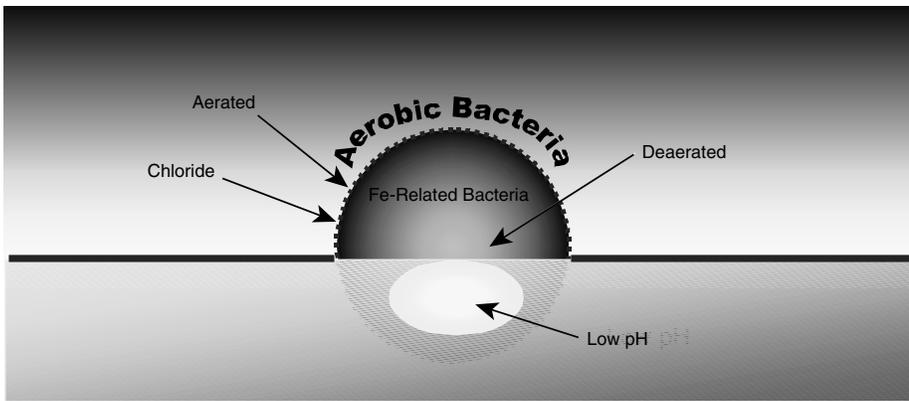

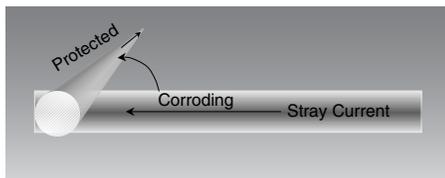**Fig. 3** Iron-related bacteria creating a differential oxygen and pH cell on a metal surface

Fig. 4 Stray current corrosion caused by foreign pipeline

Fig. 5 Pipeline that experienced stray current corrosion caused by inverting the electrical leads to a cathodic protection rectifier

Field experience and laboratory research results indicate that stray alternating current (ac) also can cause accelerated corrosion of underground pipelines (Ref 13). The most common sources of stray ac are induced ac from power lines and pipelines in a common right of way and ground faults from ac power transmission. It is generally agreed that ac-enhanced corrosion rates are only a small fraction (<1%) of those of dc currents. Nevertheless, corrosion damage can be extensive where the ac currents are large.

Stress-Corrosion Cracking

Stress-corrosion cracking (SCC) is defined as cracking of a material produced by the combined action of corrosion and tensile stress. There are two forms of external SCC on underground pipelines: high-pH SCC (also referred to as classical SCC) and near-neutral-pH SCC (also referred to as low-pH SCC). A characteristic of both forms of SCC is the development of colonies of longitudinal surface cracks in the body of the pipe that link up to form long, shallow flaws. In some cases, growth and interlinking of the stress-corrosion cracks produce flaws that are of sufficient size to cause leaks or ruptures of pipelines. An example of an SCC colony that caused a pipeline failure is shown in Fig. 6.

The high-pH form of SCC is intergranular (Ref 14), the cracks propagate between the grains in the metal, and there is usually little evidence of general corrosion associated with the cracking
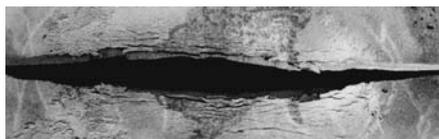
(Fig. 7). The near-neutral-pH form of SCC is transgranular—the cracks propagate through the grains in the metal—and it is associated with corrosion of the crack faces and, in some cases, with corrosion of the external surface of the pipe as well (Fig. 8). This form of cracking was first reported on a polyethylene-tape coated pipeline on the TransCanada Pipelines Ltd. (TCPL) system in the 1980s (Ref 15, 16).

Stages of SCC

Figure 9 shows a "life" model for a pipeline containing stress-corrosion cracks (Ref 17). The model consists of four stages. In stage 1, the conditions for the initiation of SCC develop at the pipe surface. The coating disbonds, a cracking electrolyte develops at the pipe surface, and the pipe surface may become pitted or modified in other ways as a result of the presence of the electrolyte. Cracks begin to initiate in stage 2, and continued initiation, growth, and crack coalescence occur in stage 3. In stage 4, large cracks coalesce and final failure occurs. The coalescence of individual stress-corrosion cracks helps to determine whether a colony of cracks is an integrity concern. If cracks nucleate in close proximity to one another, crack growth may be dominated by the coalescence of collinear cracks. Coalescence can occur throughout the SCC life cycle. Depending on the size of the crack, either environmental or mechanical forces can cause the cracks to grow during stage 3. In stage 4 of growth, coalescence may occur primarily by tearing, when mechanical loading has a stronger effect in producing crack growth.

Conditions for SCC

Three conditions are necessary for SCC initiation and propagation in stages 2 and 3 to occur. These conditions generally differ for the two types of cracking:

- A potent environment develops at the pipe surface.
- The pipe steel is susceptible to SCC.
- A tensile stress of sufficient magnitude is present.

Further discussion of these three conditions for high-pH and near-neutral-pH SCC is given in this section.

Potent Environment. The two forms of external SCC are associated with two distinct environments that develop at the surface of underground pipelines. In the case of near-neutral-pH SCC, the cracking environment appears to be a dilute groundwater containing dissolved CO_2. The source of the CO_2 is typically the decay of organic matter and geochemical reactions in the soil. This form of cracking occurs under conditions in which there is little if any CP current reaching the pipe surface, either because of the presence of a shielding coating, a high-resistivity soil, or inadequate CP design (Ref 18). In the case of high-pH SCC, CO_2 is also involved. Cathodic protection causes the pH of the electrolyte beneath disbonded coatings to increase, and the CO_2 readily dissolves in the elevated-pH electrolyte, resulting in the generation of a concentrated CO_3-HCO_3 electrolyte (Ref 14). Four factors determine whether either of these potent environments can develop at the pipe surface: coating, soil, CP, and temperature.

Coating. To date, one or both forms of SCC have occurred under polyethylene/polyvinyl chloride (PVC) tapes, coal-tar enamel, wax, and asphalt coatings. With these coatings, the SCC is associated with coating disbondment and shielding of the CP current by the coating. The near-neutral-pH form of SCC is most prevalent on tape-coated pipelines, while high-pH SCC has occurred most frequently on coal-tar-coated pipelines. Fusion-bonded-epoxy (FBE)-coated pipelines are very resistant to SCC. This resistance has been attributed to the grit-blasted surface preparation used with FBE coatings, which imparts a compressive residual stress, as well as the resistance of FBE coatings to disbondment and CP shielding (Ref 19–22). Other newer coatings, such as urethanes, also have these beneficial characteristics.

Soil. High-pH SCC has occurred in a wide variety of soils, covering a range in color, texture, and pH. The moisture content of the soil, the ability of the soil to cause coating damage, and localized variation in the level of CP are the primary soil-related factors affecting high-pH SCC (Ref 23). Recent research results have suggested that some minimum concentration of soluble cations in the soil, such as sodium or potassium, must be present for high-pH SCC to occur (Ref 24). This notion is not altogether surprising in that such ions must be present

Fig. 6 Example of colony of stress-corrosion cracks on external surface of high-pressure gas transmission pipeline. The top scale is inches and the bottom is centimeters.
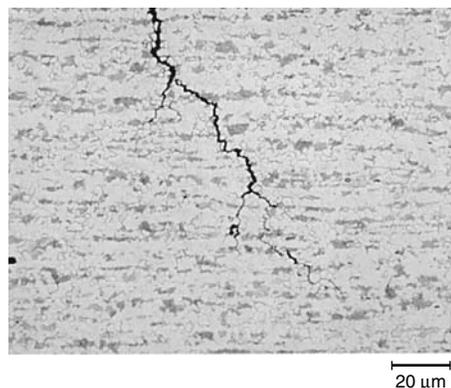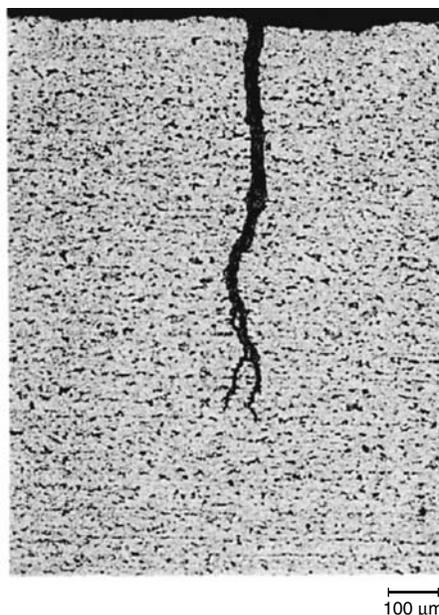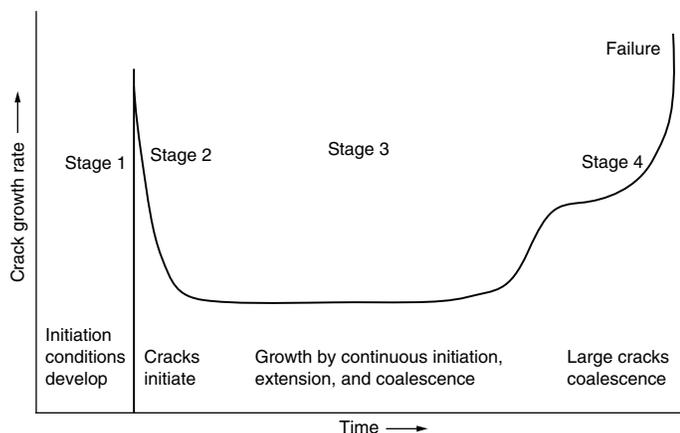

20 µm

Fig. 7 Intergranular high-pH stress-corrosion crack in line pipe steel. Nital etchant. Original magnification: 400×

100 µm

Fig. 8 Transgranular near-neutral-pH stress-corrosion crack in Nital etchant. Original magnification: 100×

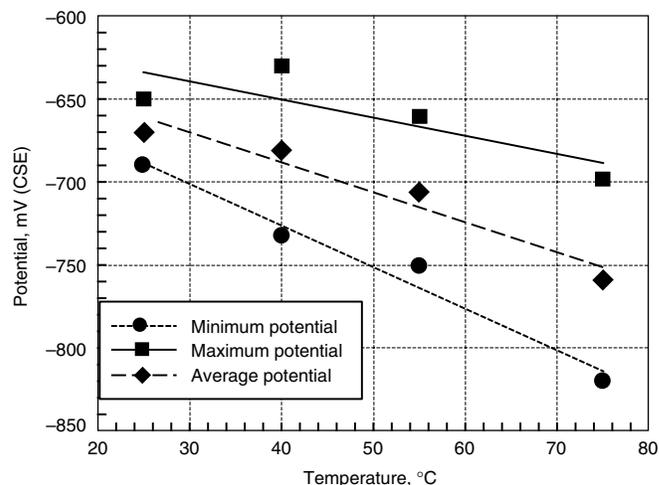**Fig. 9** Life model for a colony of stress-corrosion cracks. Source: Ref 17

Fig. 10 Effect of temperature on the potential range for cracking in a simulated high-pH cracking environment containing 12 g/L Na_2CO_3 and 37 g/L $NaHCO_3$. CSE, copper/copper sulfate electrode. Source: Ref 28

to maintain solubility of the carbonate and bicarbonate ions.

Near-neutral-pH SCC of tape-coated pipelines has been predominantly located in imperfectly to poorly drained soils in which anaerobic and seasonally reducing environmental conditions were present (Ref 18, 25). On asphalt-coated pipelines, near-neutral-pH SCC has been found predominantly in extremely dry terrains consisting of either sandy soils or a mixture of sand and bedrock. There was inadequate CP in these locations, based on pipe-to-soil potential measurements or pH measurements of electrolytes found beneath disbonded coatings (Ref 17).

Cathodic protection is closely related to the high-pH cracking process. The CP current collecting on the pipe surface at disbondments, in conjunction with dissolved CO_2 in the groundwater, generates the high-pH SCC environment. Cathodic protection can also place the pipe-to-soil potential in the potential range for cracking. The potential range for cracking generally lies between the native potential of underground pipelines and the potential associated with adequate protection (-850 mV copper/copper sulfate electrode, or CSE) (Ref 26–28). Because the rate of generation of the cracking environment is related to the CP current, it is likely that seasonal fluctuations in the CP system are associated with the cracking process. The potent cracking environment might be generated during portions of the year when CP levels are high, while cracking might occur when adequate protection is lost, such as in the summer months when the soil dries out.

It has been concluded from the results of extensive field investigations (Ref 18, 25) that near-neutral-pH SCC occurs in the absence of significant CP. At dig sites on tape-coated pipelines, where near-neutral-pH SCC is found, the cracking is associated with locations where CP current was shielded from the pipe surface, based on pH measurements of electrolytes. The lower

occurrence of SCC on the asphalt-coated portions of the system probably can be attributed to the higher levels of CP associated with this type of coating.

Temperature. The incidence of high-pH SCC increases significantly with an increase in the operating temperature of a pipeline. Service failures have been reported at temperatures as low as 13 °C (55 °F), but 90% of the service and hydrostatic test failures have occurred within 16 km (10 miles) downstream from compressor stations (Ref 27). This behavior has been attributed to a decrease in the width of the potential range for cracking, as shown in Fig. 10, coupled with a decrease in the maximum cracking velocity with decreasing temperature. Laboratory data and field experience indicate that there is less temperature dependence for near-neutral-pH SCC than for high-pH SCC.

Susceptible Line Pipe Steel. Both forms of SCC have occurred on a variety of sizes, grades, and vintages of line pipe steel. Stress-corrosion cracking has been found in flash welded, submerged arc welded (SAW), electric resistance welded (ERW), and seamless pipe. The chemical compositions of the failed pipes are typical for the vintage and grade, and there are no obvious unique metallurgical characteristics associated with the failures. The bond line of the weld seam of ERW pipe seems to have a lower resistance to near-neutral-pH SCC than the base metal, possibly because of the presence of a more SCC-susceptible microstructure at the weld, a higher-than-normal residual stress, pits and arc burns associated with the ERW manufacturing process, or a lower fracture toughness (Ref 17). The coarse-grained heat-affected zone (CGHAZ) adjacent to the double submerged arc weld (DSAW) also has been found to be more susceptible to cracking than the base material in the near-neutral-pH environment (Ref 29). Results of recent research suggest that residual stresses from the pipe manufacturing process are

important in affecting susceptibility to near-neutral-pH SCC (Ref 30).

Tensile Stress. Most of the intergranular (high-pH) stress-corrosion cracks found in gas transmission pipelines have been oriented in the longitudinal direction (Ref 14). This orientation indicates the importance of the hoop stress produced by the internal pressurization on the cracking process. The failures have occurred at hoop stresses ranging from 160 to 270 MPa (23 to 39 ksi), which corresponded to 46 to 76% of the specified minimum yield strength (SMYS) of the pipe steels. Most of the high-pH SCC failures have initiated at locations at which there was no indication of secondary stresses. These observations indicate that the typical field stresses experienced by operating gas transmission pipelines are sufficient for high-pH SCC to occur.

The majority of near-neutral-pH SCC failures are associated with features that enhance the local stress, indicating that the behavior is fundamentally different from high-pH SCC with regard to the role of stress in the crack initiation process. In most cases, near-neutral pH SCC has been associated with corrosion, gouges, or stress concentrations from the toe of the weld seam that raise the local stress above the hoop-stress levels calculated based on the internal pressurization (Ref 17). Significant SCC has not been reported in class 2 and 3* pipeline locations, indicating that the hoop stress also is important (Ref 17).

Cyclic pressure fluctuations that normally occur on operating pipelines also affect SCC behavior. It has been demonstrated that the cyclic stress that results from these pressure

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*Class locations for high-pressure gas pipelines are defined by the US. Department of Transportation based on the consequences of a pipeline failure. Class 1 locations have the lowest consequence and are allowed to operate at a maximum pressure that is equivalent to 72% of SMYS. Class 4 locations have the highest consequence of failure and are allowed to operate at a maximum pressure that is equivalent to 40% of SMYS (Reference CFR Part 192.111).

fluctuations reduce the threshold stress for initiation of high-pH SCC (Ref 31) and increase the rate of propagation of near-neutral-pH stress-corrosion cracks (Ref 32).

Prevention and Mitigation of Corrosion and SCC

The most effective method to prevent corrosion or SCC on new pipelines is to use high-performance coatings, applied to a surface abrasive blast cleaned to a white (Ref 33) or near-white (Ref 34) metal surface finish, in conjunction with effective CP. An intact coating that prevents contact of electrolyte with the steel surface will prevent external corrosion or SCC. The surface abrasive blast cleaning promotes good coating adhesion. A high-quality abrasive blast cleaning also will impart compressive residual stresses in the pipe surface that improve SCC resistance.

All coatings contain some defects or holes, referred to as holidays, that expose the bare pipeline steel to the underground environment. The function of the CP system is to protect these bare areas from corrosion.

Methods of preventing corrosion and SCC on existing pipelines include minimizing the operating temperature and controlling the CP levels to values more negative than −850 mV CSE. Minimizing pressure fluctuations on operating pipelines also is effective in preventing SCC initiation. A more detailed discussion of coatings and cathodic protection is given in this section.

Coatings

Inadequate coating performance is a major contributing factor in the corrosion and SCC susceptibility of an underground pipeline. The function and desired characteristics of a dielectric-type pipeline coating are covered in NACE RP-0169 (Ref 35). This specification states that the function of such coatings is to control corrosion by isolating the external surface of the underground or submerged piping from the environment, to reduce CP requirements, and to improve (protective) current distribution. Coatings must be properly selected and applied, and the coated piping must be carefully installed to fulfill these functions. The desired characteristics of the coatings include:

- Effective electrical insulation
- Effective moisture barrier
- Good adhesion to the pipe surface
- Applicable by a method that will not adversely affect the properties of the pipe
- Applicable with a minimum of defects
- Ability to resist the development of holidays with time
- Ability to resist damage during handling, storage, and installation
- Ability to maintain substantially constant resistivity with time

- Resistance to disbonding
- Resistance to chemical degradation
- Ease of repair
- Retention of physical characteristics
- Nontoxic to environment
- Resistance to changes and deterioration during above-ground storage and long-distance transportation

Descriptions of common coatings used on underground pipelines follow.

Bituminous enamels are formulated from coal-tar pitches or petroleum asphalts and have been widely used as protective coatings for more than 65 years. Coal-tar and asphalt enamels are available in summer or winter grades. These enamels are the corrosion coating; they are combined with various combinations of fiberglass and/or felt to obtain mechanical strength for handling. The enamel coatings have been the workhorse coatings of the industry, and when properly selected and applied, they can provide efficient long-term corrosion protection.

Enamel systems can be designed for installation and use within an operating temperature range of −1 to 82 °C (30 to 180 °F). When temperatures fall below 4.4 °C (40 °F), added precautions should be taken to prevent cracking and disbonding of the coating during field installation. Enamels are affected by ultraviolet rays and should be protected by kraft paper or whitewash. Enamels are also affected by hydrocarbons, and the use of a barrier coat is recommended when known contamination exists. Bituminous enamel coatings are available for all sizes of pipe.

In recent years, the use of enamels has declined for these reasons:

- Reduced number of suppliers
- Restrictive environmental and health standards from the Occupational Safety and Health Administration, the Environmental Protection Agency, and the Food and Drug Administration
- Increased acceptance of other coating types
- Alternative use of coating raw materials as fuels

Asphalt mastic pipe coating is a dense mixture of sand, crushed limestone, and fiber bound together with a select air-blown asphalt. These materials are proportioned to secure a maximum density of approximately 2.1 g/cm³ (132 lb/ft³). This mastic material is available with various types of asphalt. Selection is based on operating temperature and climatic conditions to obtain maximum flexibility and operating characteristics. This coating is a thick (12.7 to 16 mm, or ½ to ⅝ in.) extruded mastic that results in a seamless corrosion coating. Extruded asphalt mastic pipe coating has been in use for more than 50 years.

Asphalt mastic systems can be designed for installation and use within an operating range of 4.4 to 88 °C (40 to 190 °F). Precautionary measures should be taken when handling asphalt mastics in freezing temperatures. Whitewash is used to protect it from ultraviolet rays, and this should be maintained when in storage. This system is not intended for use above ground or in hydrocarbon-contaminated soils.

Liquid Epoxies and Phenolics. Many different liquid systems are available that cure by heat and/or chemical reaction. Some are solvent types, and others are 100% solids. These systems are primarily used on larger-diameter pipe when conventional systems may not be available or when they may offer better resistance to operation temperatures in the 95 °C (200 °F) range.

Generally, epoxies have an amine or a polyamide curing agent and require a near-white blast-cleaned surface (NACE No. 2 or SSPC SP10). Coal-tar epoxies have coal-tar pitch added to the epoxy resin. A coal-tar epoxy cured with a low-molecular-weight amine is especially resistant to an alkaline environment, such as that which occurs on a cathodically protected structure. Some coal-tar epoxies become brittle when exposed to sunlight.

Extruded plastic coatings fall into two categories based on the method of extrusion, with additional variations resulting from the selection of adhesive. The two methods of extrusion are the crosshead or circular die, and the side extrusion or T-shaped die. The four types of adhesives are asphalt-rubber blend, polyethylene copolymer, butyl rubber adhesive, and polyolefin rubber blend.

To date, of the polyolefins available, polyethylene has found the widest use, with polypropylene being used on a limited basis for its higher operating temperature. Each type or variation of adhesive and method of extrusion offers different characteristics based on the degree of importance to the user of certain measurable properties.

Fusion-bonded epoxy (FBE) coatings are heat-activated, chemically cured coating systems. The epoxy coating is furnished in powdered form and, with the exception of the welded field joints, is plant applied to preheated pipe, special sections, connections, and fittings using fluid-bed, air spray, or electrostatic spray methods.

Fusion-bonded epoxy coatings were introduced in 1959 and were first used as an exterior pipe coating in 1961 and currently are the coatings most commonly used for new installations of large diameter pipelines (Ref 36). These coatings are applied to preheated pipe surfaces at 218 to 244 °C (425 to 475 °F). Some systems may require a primer system, and some require postheating for complete cure. A NACE No. 2 (SSPC SP10) near-white blast-cleaned surface is required. The coating is applied to a minimum thickness of 0.3 mm (12 mils); in some applications, coating thicknesses range to 0.64 mm (25 mils), with the restriction not to bend pipe coated with a film thickness greater than 0.4 mm (16 mils). The FBE coatings exhibit good mechanical and physical properties and are the most resistant to hydrocarbons, acids, and alkalies.

A primary advantage of the FBE pipe coatings is that they cannot hide apparent surface defects; therefore, the steel surface can be inspected after it is coated. The number of holidays that occur is a function of the surface condition and the thickness of the coating specified. Increasing the thickness minimizes this problem, and the excellent resistance to the electrically induced disbondment of these coatings has resulted in their frequent use as pipeline coatings.

Tape. Field and mill-applied tape systems have been in use for more than 30 years on pipelines. For normal construction conditions, prefabricated cold-applied tapes are applied as a three-layer system consisting of a primer, corrosion-preventive tape (inner layer), and a mechanically protective tape (outer layer). The function of the primer is to provide a bonding medium between the pipe surface and the adhesive or sealant on the inner layer. The inner-layer tape consists of a plastic backing and an adhesive. This layer is the corrosion-protective coating; therefore, it must provide a high electrical resistivity, low moisture absorption and permeability, and an effective bond to the primed steel surface. The outer-layer tape consists of a plastic film and an adhesive composed of the same types of materials used in the inner tape or materials that are compatible with the inner-layer tape. The purpose of the outer-layer tape is to provide mechanical protection to the inner-layer tape and to be resistant to the elements during outdoor storage. The outer-layer tape is usually a minimum of 0.64 mm (25 mils) thick.

The cold-applied multilayer tape systems are designed for plant coating operations and result in a uniform, reproducible, holiday-free coating over the entire length of any size pipe. The multiple-layer system allows the coating thickness to be custom designed to meet specific environmental conditions. These systems have been engineered to withstand normal handling, outdoor weathering, storage, and shipping conditions.

Three-Layer Polyolefin. The three-layer polyolefin pipeline coating was developed in the 1990s as a way to combine the excellent adhesion of FBE with the damage resistance of extruded polyethylene and tape wraps. These systems consist of an FEB primer, an intermediate copolymer layer, and a topcoat consisting of either polyethylene or polypropylene. The function of the intermediate copolymer is to bond the FBE primer with the polyolefin topcoat.

Variations in these three-layer systems exist, most notably the use of either polyethylene or polypropylene for the topcoat. Polypropylene offers a higher temperature resistance but is more costly, both as a raw material and because higher temperatures are required for application. Most topcoats are side extruded similar to extruded polyethylene coatings, although at least one product uses flame-spray polyolefin for a topcoat. Another variation in the three-layer systems is the thickness of the FBE primer layer. Early generations of this product utilized a 50–75 μm (2–3 mil) primer which often proved to be inadequate to achieve the desired performance. More recent three-layer systems utilize a 200–300 μm (8–12 mil) primer as a standard thickness.

Wax coatings have been in use for more than 50 years and are still employed on a limited basis. Microcrystalline wax coatings are usually used with a protective overwrap. The wax serves to waterproof the pipe, and the wrapper protects the wax coating from contact with the soil and affords some mechanical protection. The most prevalent use of wax coatings is the over-the-ditch application with a combination machine that cleans, coats, wraps, and lowers into the ditch in one operation.

Special-Use Coatings

Polyurethane Thermal Insulation. Efficient pipeline insulation has grown increasingly important as a means of operating hot and cold service pipelines. This is a system for controlling heat transfer in above- or belowground and marine pipelines. Polyurethane insulation is generally used in conjunction with a corrosion coating, but if the proper moisture vapor barrier is used over the polyurethane foam, effective corrosion protection is attained.

Concrete. Mortar linings and coatings have the longest history of use in protecting steel or wrought iron from corrosion. The alkalinity of the concrete promotes the formation of a protective iron oxide (passive) film on the steel. This protective passive film can be compromised in underground applications by permeation of chlorides into the coating. Typically, external application is usually employed over a corrosion-resistant coating for armor protection and negative buoyancy in marine environments.

Metallic (Galvanic) Coatings. Pipe coated with a galvanic coating, such as zinc (galvanizing) or cadmium, should not be utilized in direct burial service. Such metallic coatings are intended for the mitigation of atmospheric-type corrosion activity on the substrate steel.

Evaluating Coatings

As described previously, the different types of coatings used on underground pipelines have different strengths and weaknesses. When first installed, most pipeline coatings are effective in meeting their required function: isolate the external surface of an underground pipeline from the environment, reduce the CP current requirements, and improve the CP current distribution. On the other hand, coatings vary significantly in their long-term performance. Ultimately, the effectiveness of a coating system in preventing corrosion is related to two primary factors: (a) the resistance of a coating to degradation over time and (b) the ability of the coating to conduct CP current should the coating fail (minimize shielding). For SCC resistance, these factors as well as the type of surface preparation used with the coating are important.

The ability of a coating to resist degradation is a primary performance property of coatings and affects all forms of external pipeline corrosion. The second factor, the ability of a coating to pass CP current, should it fail, is the inverse of shielding of the CP current beneath a disbonded coating. Corrosion or SCC can occur beneath a disbonded coating that shields CP current even though the pipeline is apparently effectively protected, based on ground-level measurements.

Surface Preparation

The nature of the surface preparation is probably more important in mitigating SCC than other forms of corrosion. Historically, the primary purposes of the surface preparation have been to clean the surface and create an anchor pattern to promote good adhesion of the coating to the pipe surface. The surface preparation requirements for different coating types vary. For example, bituminous coatings have good adhesion properties on commercial blast-cleaned surfaces (NACE No. 3/SSPC-SP 6) or even on wire-brushed surfaces, whereas fusion-bonded epoxy (FBE) coatings require a white (NACE No. 1/SSPC-SP 5) or near-white (NACE No. 2/SSPC-SP 10) grit-blasted surface finish for proper adhesion. Laboratory research and field experience have demonstrated that grit-blasted surfaces are generally more resistant to SCC initiation than wire-brushed mill-scaled surfaces, primarily because grit blasting imparts a compressive residual stress in the pipe surface (Ref 20, 21, 36). A white or near-white surface finish was found to be required to impart SCC resistance, whereas commercially blasted surfaces were found to be more susceptible to SCC than wire-brushed milled scaled surfaces.

The Canadian Energy Pipeline Association (CEPA) member companies have recommended that the following coatings be considered for new construction based on SCC performance (Ref 37):

- Fusion-bonded epoxy
- Liquid epoxy
- Urethane
- Extruded polyethylene
- Multilayer or composite coatings

Fusion-bonded epoxies, liquid epoxies, and urethane coatings meet all three requirements of an effective coating: (a) they are resistant to degradation over time, (b) they conduct CP current should they fail, and (c) they are typically applied over a white or near-white grit-blasted surface. Extruded polyethylene coatings meet requirements 1 and 3, but will shield CP current should disbondment occur. Furthermore, the type of coating used on the field joints frequently limits the performance of extruded polyethylene-coated pipelines. Multilayer or composite coatings typically consist of an FBE inner layer and a polyolefin outer layer with an adhesive between

the two layers. These new coatings are promising from the standpoint of resistance to disbondment, mechanical damage, and soil stresses, but the polyolefin outer layer will shield CP current should disbondment occur. Additional field experience is needed to establish the performance of these coatings.

Tape coatings and bituminous coatings have been shown to be more susceptible to SCC than the aforementioned coatings and should be used only with careful consideration of all of the factors affecting SCC. Regardless of the coating selected, the pipe surface should be prepared to a white (NACE No. 1/SSPC-SP 5) or near-white (NACE No. 2/SSPC-SP 10) finish to aid in coating adhesion and impart sufficient residual compressive stresses to prevent SCC initiation. A lower-quality commercial blast (NACE No. 3/SSPC-SP 6) should not be used under any circumstances.

Cathodic Protection

External corrosion and SCC are electrochemical phenomena and, therefore, can be prevented or mitigated by altering the electrochemical condition of the corroding interface. Altering the electrochemical nature of the corroding surface is relatively simple and is done by altering the electrical potential field around the pipe. By applying a negative potential and making the pipe a cathode, the rate of corrosion (oxidation) is reduced (corrosion is prevented or mitigated) and the reduction process is accelerated. This means of mitigating (or preventing) corrosion, cathodic protection, also alters the environment at the pipe surface, which further enhances corrosion control. The pH of any electrolyte at the pipe surface is increased, the oxygen concentration is reduced, and deleterious anions, such as chloride, migrate away from the pipe surface.

Types of CP. There are two primary types of CP systems: sacrificial anode (galvanic anode) CP and impressed-current CP. Sacrificial anode CP utilizes an anode material that is electro-

negative to the pipe steel. When connected to the pipe, the pipe becomes the cathode in the circuit and corrosion is mitigated. Typical sacrificial anode materials for underground pipelines are zinc and magnesium. Impressed-current CP utilizes an outside power supply (rectifier) to control the voltage between the pipe and an anode (cast iron, graphite, platinum clad, mixed metal oxide, etc.) in such a manner that the pipe becomes the cathode in the circuit and corrosion is mitigated. Schematics of these two types of CP systems are shown in Fig. 11 and 12.

Cathodic protection is most often used in conjunction with a coating. There are always flaws in the coating due to application inconsistencies, construction damage, or the combination of natural aging and soil stresses. If left unprotected, the pipeline will undergo corrosion or SCC at these coating flaws (holidays). Often the rate of attack through the wall is much higher at the holiday than the general attack of a bare steel surface. The use of a coating greatly reduces the total amount of current required to achieve protection of the pipeline system; therefore, CP and external coatings are utilized together wherever possible.

Cathodic protection can be used to control all types of corrosion previously discussed (general, stray current, MIC, and SCC). Sometimes it is difficult to determine the level of CP necessary to mitigate the different corrosion mechanisms and to identify which type of corrosion is present. Stress-corrosion cracking presents additional problems. First, the high-pH form of SCC is only found on pipelines protected with CP. The products that result from cathodic reactions occurring on the pipe surface during CP in conjunction with soil chemistry produce the environment necessary for high-pH SCC. Since high-pH SCC propagates only in a very limited potential range, maintaining the potential of the pipe surface outside of this range by proper CP control will prevent growth of the high-pH SCC cracks. In addition, it has been established that proper CP control can inhibit the growth of near-neutral SCC cracks.

Electrical surveys have been performed to evaluate the level of CP ever since the application of CP to pipelines in the 1940s. These surveys consist of measuring the potential (pipe-to-soil potential) of the pipe surface with respect to a reference electrode (typically CSE). These measurements can be performed at permanent test station locations (test point surveys), or they can be performed continuously with a 1 to 2 m (3 to 6 ft) spacing along the entire length of the pipeline (close interval surveys). Pipe-to-soil potential surveys can be performed with the CP system energized (on-potentials) or with the CP system interrupted (off-potentials). There has been much discussion over the past 10 to 20 years as to the most appropriate survey methodology. While each method has its benefits, it is commonly accepted that the IR-voltage (voltage drop due to current, I, through a resistance, R) correction made by the off-potential measurement is most closely related to the corrosion condition of the pipeline. Figure 13 shows a schematic of a pipe-to-soil potential measurement.

The basic pipe-to-soil potential measurement techniques are applied to establish whether one or more of the recommended CP criteria are met. Criteria for establishing the effectiveness of a CP system to mitigate corrosion are outlined in the NACE International Recommended Practice RP0169-96 (Ref 35) and have been adopted, in part, in U.S. Department of Transportation (DOT) regulations CFR 49, Parts 192 and 195. In general, if one or more of the recommended criteria are met, the CP system is assumed to be applying a sufficient cathodic current to mitigate corrosion.

Certain pipeline conditions make conventional electrical survey techniques difficult to interpret. These include areas of stray or telluric currents, congested areas where multiple pipelines and other utilities share rights-of-way, and pipelines with noninterruptible sacrificial CP systems. In these areas, either significant care must be taken to interpret conventional surveys or other methods of monitoring must be utilized. One such technology is the use of coupon test
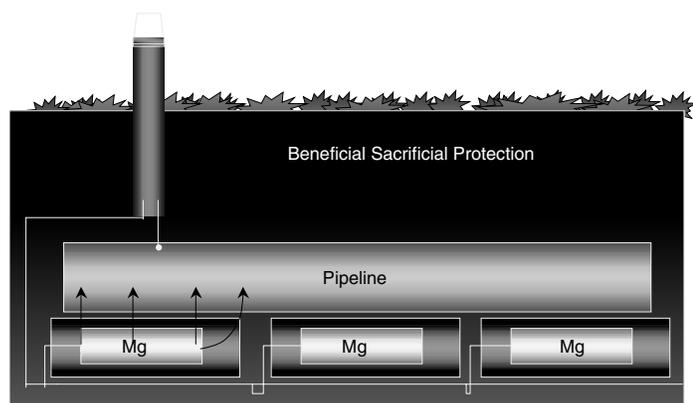

Fig. 11 Sacrificial anode CP system with distributed magnesium anodes and an aboveground test station
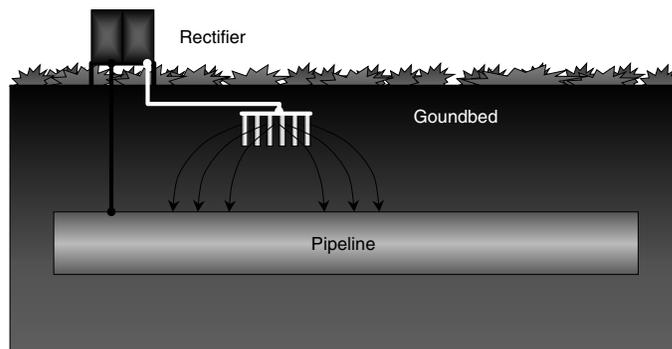

Fig. 12 Impressed current CP system with above-ground rectifier and a single remote anode groundbed

stations. The coupon test stations permit accurate potential measurements for a test specimen (coupon) that simulates a holiday on the pipe surface.

Detection of Corrosion and SCC

On existing pipelines, there are three methods to detect corrosion and SCC—hydrostatic retesting, field investigation programs (direct assessment), and in-line inspection.

Hydrostatic Testing. Hydrostatic retesting involves pressure testing the pipeline with water at a pressure that is higher than the operating pressure, typically 125% of the maximum operating pressure (MOP) of the pipeline. This is the most common method to ensure the integrity of a pipeline and establish a safe operating pressure, regardless of the types of flaws present in the pipeline. Any flaws that are larger than a critical size at the hydrostatic retest pressure are removed from the pipeline. However, subcritical flaws remain in the pipeline after a hydrostatic retest. If the defects are growing with time, as might be the case with corrosion or SCC, the pipeline is generally periodically retested to ensure integrity. Hydrostatic retesting is expensive and creates problems associated with the acquisition, treatment, and disposal of the water, especially for pipelines carrying liquid products.

Direct Assessment. As a part of condition-monitoring programs, pipeline companies commonly use field investigation (direct assessment) programs. The overall condition of the coatings and pipelines is assessed, and it is determined whether corrosion or SCC is present on the system. Models are sometimes developed to predict the likelihood of the presence and severity of corrosion or cracking. This information is then used to prioritize the system for direct examination, hydrostatic testing, in-line inspection, recoating, or pipe replacement. Dig programs and the associated models are not generally considered as a replacement for hydrostatic testing as a means to ensure the integrity of a pipeline. See the article "External Corrosion Direct Assessment Integrated with Integrity Management" in this Volume.

In-line inspection (ILI) tools, also referred to as smart or intelligent pigs, are devices that are propelled by the product in the pipeline and are used to detect and characterize metal loss caused by corrosion and cracking. There are two primary types of metal-loss ILI tools: magnetic flux leakage (MFL) tools and ultrasonic tools (UT).

Magnetic flux leakage tools measure the change in magnetic flux lines produced by the defect and produce a signal that can be correlated to the length and depth of a defect. In recent years, the magnetics, data storage, and signal interpretation have improved, resulting in improved mapping of the flaw and a decrease in the number of unnecessary excavations. The high-resolution MFL tool is typically capable of readily detecting corrosion pits with a diameter greater than three times the wall thickness. Once detected, these tools can typically size the depth of the corrosion within $\pm 10\%$ of the wall thickness with an 80% level of confidence. The MFL tool can be used to inspect either liquid product pipelines or natural gas pipelines.

Figure 14 shows a typical MFL tool. The wire brushes in the front of the tool are used to transfer the magnetic field from the tool to the pipe wall. The ring of sensors between the wire brushes are used to measure the flux leakage produced by defects in the pipe. The drive cups are the mechanism that is used to propel the tool by the product in the pipeline. The odometer wheels monitor the distance traveled in the line and are used to determine the location of the defects identified. The trailing set of inside-diameter/outside-diameter sensors (ID/OD sensors) is used to discriminate between internal and external wall loss.

Ultrasonic tools utilize large arrays of ultrasonic transducers to send and receive sound waves that travel through the wall thickness, permitting a detailed mapping of the pipe wall. Ultrasonic tools can indicate whether the wall loss is internal or external. The typical resolution of a UT is $\pm 10\%$ of the pipe wall thickness with an 80% level of confidence. Ultrasonic tools are typically used in product pipelines (those carrying crude oil, gasoline, and the like) since the product in the pipeline is used as the required couplant for the ultrasonic sensors. This tool can be used to inspect natural gas pipelines, but requires introducing a liquid (such as water) into the pipeline for an ultrasonic couplant.

There is significant interest in the pipeline industry in developing ILI tools that can reliably detect and size stress-corrosion cracks. Crack-detection tools avoid problems associated with acquisition, treatment, and disposal of the water used in hydrostatic retesting. It is desirable for a fully developed tool to be capable of detecting and sizing subcritical cracks such that the pipeline can be repaired long before these cracks become an integrity concern. The detection of smaller cracks also extends the time interval between inspections. Ultrasonic tools are available that can detect stress-corrosion cracks in liquid pipelines, but the detection and sizing capability of the tools has not been fully established. These tools require the presence of a liquid couplant and therefore are difficult and expensive to use in gas pipelines.

Assessment and Repair of Corrosion and SCC

Once corrosion or SCC has been detected on a pipeline, the size of the defect must be determined, and the defect must then be assessed and sentenced. In-line inspection typically provides some measure of the size of the defect. The dimensions of ILI defects that potentially could affect the immediate integrity of the pipeline are typically confirmed by direct examination. In direct assessment (DA) programs, corrosion
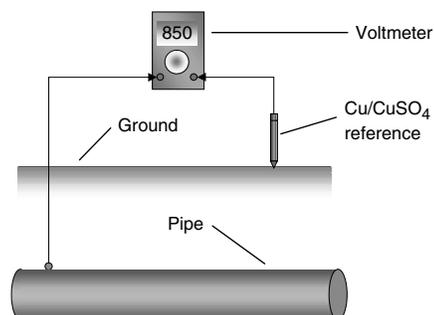

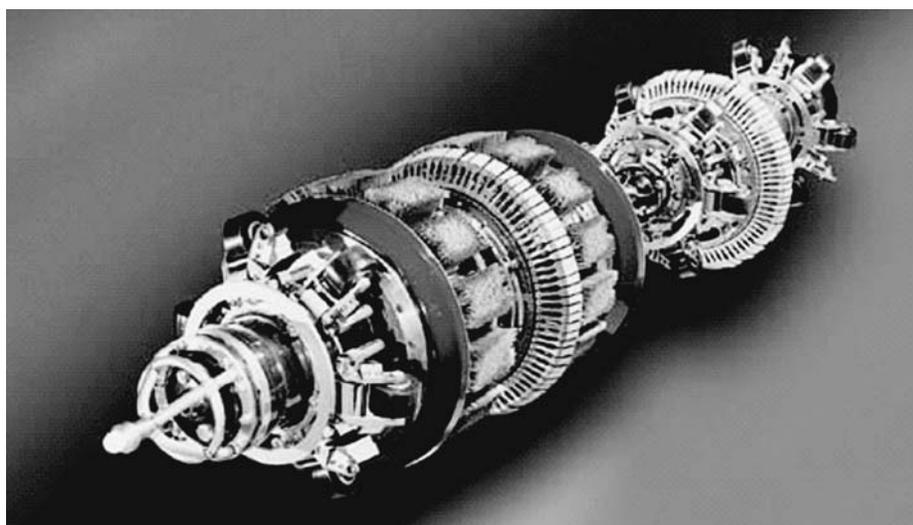**Fig. 13** Pipe-to-soil potential measurement

Fig. 14 Magnetic flux leakage tool for detection and sizing of corrosion defects in a pipeline. Courtesy of PII

flaws can be sized by direct measurement or by means of an ultrasonic thickness meter. Stress-corrosion cracks are generally sized, in the field, by a combination of magnetic-particle inspection (MPI) and grinding. The colony with the longest interlinked cracks in a dig is typically ground out to establish the maximum depth of cracking. In the ditch ultrasonic techniques also are being developed for crack dimension measurements, but the technology is difficult to apply to colonies of cracks.

A burst-pressure model such as R-STRENG (Ref 38) can be used to determine the failure pressure of corrosion defects or areas that contained cracks and were subsequently ground out. Fracture mechanics techniques must be used to determine the burst pressure of cracklike defects (Ref 17). The pipe is typically recoated if the burst pressure is within acceptable limits (typically above a pressure that is equivalent to 100% of the specified minimum yield strength of the line pipe steel). If this pressure is below acceptable limits, the pipe is typically replaced or repaired using a steel or composite reinforcing sleeve and recoated.

Pipe replacement is sometimes the only option in situations in which there is extensive corrosion or cracking localized within one area of a pipeline. If the corrosion or cracking is extensive, but not severe, it may be possible to recoat the affected areas of a pipeline. Enhancement of the CP system is also an option to minimize further corrosion or stress-corrosion crack growth in areas in which it has been established that the pipeline contains growing corrosion or SCC defects that are not an immediate integrity threat. Unfortunately, shielding coatings are not amenable to enhancement of CP because it is unlikely that the CP current can penetrate beneath coating disbondments. In the case of hydrostatic retest failures, the only available repair method is pipe replacement. The failed joint is cut out and replaced with new pipe.

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