CATHODIC PROTECTION CRITERIA

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Summary: The understanding, application, and monitoring of cathodic protection, and its limitations are reviewed and discussed The criteria for cathodic protection that measure its effectiveness are discussed in detail from the perspective of the NACE International Recommended Practice RP0169-96 and the limitations and modifications the criteria entail. The role of cathodic protection and the criteria in a corrosion integrity management program are reviewed in detail from the programmatic view of monitoring, condition assessment, risk assessment, mitigation, and reporting.

Key Words: corrosion, criteria, cathodic protection, pipelines, integrity management.

INTRODUCTION

Pipeline integrity is a key issue for the pipeline operators of today. With escalating costs to build new pipelines and rehabilitate older ones, and dwindling staff and budgetary resources to maintain them, industry has become acutely aware of the necessity to maintain the integrity of existing facilities in the most cost efficient manner. No longer can an operator manage a pipeline system as a declining asset, but must preserve it through a well-planned and prioritized risk-based maintenance program. As a result, pipeline integrity management activities have become aligned and interact with risk management.

There are a number of threats to the pipeline integrity that constitute risk for a pipeline operating company. Two of those threats are external corrosion and stress-corrosion cracking (SCC), both caused, in part, by interaction of the steel pipe with the environment. The principal way of managing the threat from corrosion and SCC is an effective anti-corrosion coating and cathodic protection system. The efficacy of cathodic protection begins with a thorough understanding of the application of cathodic protection, its monitoring practices, and interpretation with respect to the criteria used by industry world-wide, and the use of supplemental inspection, such as in-line inspection or inspection digs, to validate effective operation.

This paper discusses the understanding, application, and monitoring of cathodic protection, and its limitations. The criteria for cathodic protection that measure its effectiveness are discussed in detail from the perspective of the NACE International Recommended Practice RP0169-96[(1)] and the modifications and limitations that have been placed on them. The role of cathodic protection and the criteria in an integrity management program are reviewed also.

BACKGROUND

The application of cathodic protection to any federally regulated underground pipeline requires that it be monitored.[2,3,4] Monitoring includes periodic checks and measurements of the current sources that provide protection, and electrochemical measurements of the pipe potential or potential change with respect to minimum criteria, to ensure effective operation for corrosion control.

Cathodic Protection

Cathodic protection entails the application of an external direct current to a structure to shift its potential sufficiently in the cathodic or more electronegative direction for the purpose of reducing the corrosion rate. The relationships among current, structure potential, and corrosion rate for cathodic protection are best illustrated as a kinetic process[5] by an Evans or E-log I diagram, as shown in Figure 1. The E-log I relationships in this figure are a function of the material to be protected, its surface condition, the environment, temperature, and time.

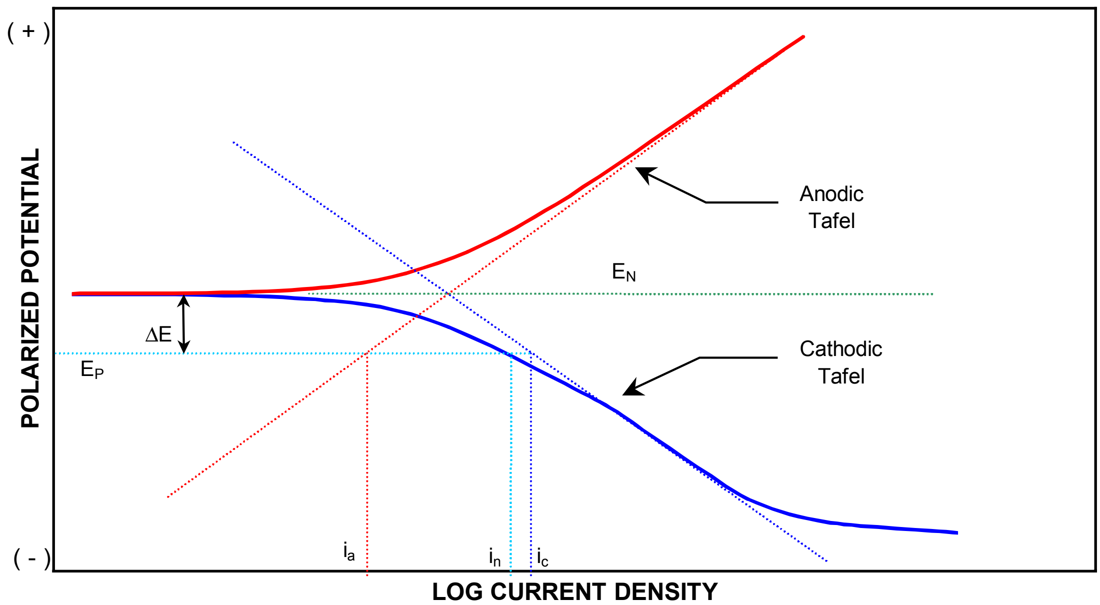


Figure 1. E-Log I Illustration of the Cathodic Protection

If a metal is buried or immersed in an environment, it will acquire a potential E_{COR}. At this native or free-corrosion potential, the metal corrodes at a rate expressed by the current density i_{COR} and Faraday's Law. This rate occurs when the cathodic and anodic current densities are equal. If an external cathodic current is now applied, the potential shifts in the more negative direction, following the cathodic portion of the curve until a steady-state potential E_P is achieved. The potential will follow the anodic portion of the curve if an anodic current were applied. The anodic and cathodic curves represent the measured net current expressed algebraically by the difference between the cathodic and anodic partial current densities i_a and i_c. In the portions of the curve were the relation between the anodic or cathodic partial current densities are linear, called the anodic and cathodic Tafel regions, respectively, the net currents are essentially either all anodic or all cathodic.

The corrosion rate can be estimated for any cathodic potential using Figure 1. This is done by extending the anodic Tafel line into the cathodic region of the curve and determining the anodic current density at the polarized potential. For example, at the cathodic polarized potential E_P, the associated anodic and cathodic current densities are i_a and i_c. Using Faraday's Law, the anodic current density can be used to calculate the corrosion rate. Thus, making the potential more electronegative, the associated cathodic current density increases as the corrosion current decreases in magnitude. However, because of the relation of potential to logarithm of current density (i.e., corrosion rate), the corrosion rate is never zero, but it decreases to sufficiently small values that for all practical purposes the corrosion rate is zero.

Criteria

According to Figure 1, the application of increasing amounts of cathodic current continues to reduce the corrosion current (rate) until a polarized potential of about –1200 mV ($Cu/CuSO_4$) is achieved.[6] At that potential, or nearly so, increasing the applied current density has no significant effect on the polarized potential, but only continues to increase the surface pH by production of more hydroxide ions (OH^-) and hydrogen gas (H_2) from reduction of water or oxygen in the environment. Further, there is no additional decrease in corrosion rate because the potential is essentially fixed in value thereby fixing the corrosion current or rate. Therefore, to give the application of cathodic protection practical boundaries, industry has adopted minimum requirements or criteria to establish when adequate corrosion control has been achieved. None of the criteria, the defining organizations, or adopting agencies, however, clearly define what the corrosion rate should be when a criterion is met. The simple reason is that it depends on the environment, the metal polarized, and time, just as the E-log I relationship depends on these factors.

Years ago, attempts were made at the U.S. Bureau of Standards to directly measure the corrosion rate for various potentials, and to define corrosion control criteria by means of E-log I curves.[7,8,9,10,11] These attempts were not successful and later abandoned in favor of more indirect measures of potential or potential shift without definition of the corrosion rate when a criterion was met. Some definition of these rates has been made in research on the criteria that will be discussed later.

In the United States, NACE International developed criteria or minimum requirements for cathodic protection of buried and submerged structures. The first Recommended Practice RP0169 was issued in 1969[12] and embodied five criteria that were accepted in 1970 by the Department of Transportation in their Code of Federal Regulations for corrosion control of buried pipelines.[2] Over the years, RP0169 was reviewed by NACE International, but not changed substantially until 1992. That and the later 1996 version[1] set forth three criteria, namely the (a) –850 mV ($Cu/CuSO_4$) polarized potential, (2) –850 mV ($Cu/CuSO_4$) potential corrected for IR drops, and (3) 100 mV polarization criteria. Discussions have been held to begin the process of incorporating those three criteria into the Code of Federal Regulations, but to date, that effort has not been completed.

-850 mV ($Cu/CuSO_4$) Polarized Potential

The –850 mV potential criterion is the most widely used criterion in industry today. From RP0169-96, this criterion is stated as

> *"A negative polarized potential of at least 850 mV relative to a saturated copper/copper sulfate reference electrode."*

The definition of the polarized potential in this document is understood to mean only the potential across the structure and electrolyte interface and algebraically is the sum of the corrosion potential and cathodic polarization. Figure 2 illustrates this criterion operationally. The polarized potential is that potential measured without inclusion of IR drops across the coating, in the soil, and in the pipe. This potential is usually measured by syncronous interruption of all of the influencing cathodic protection current sources.

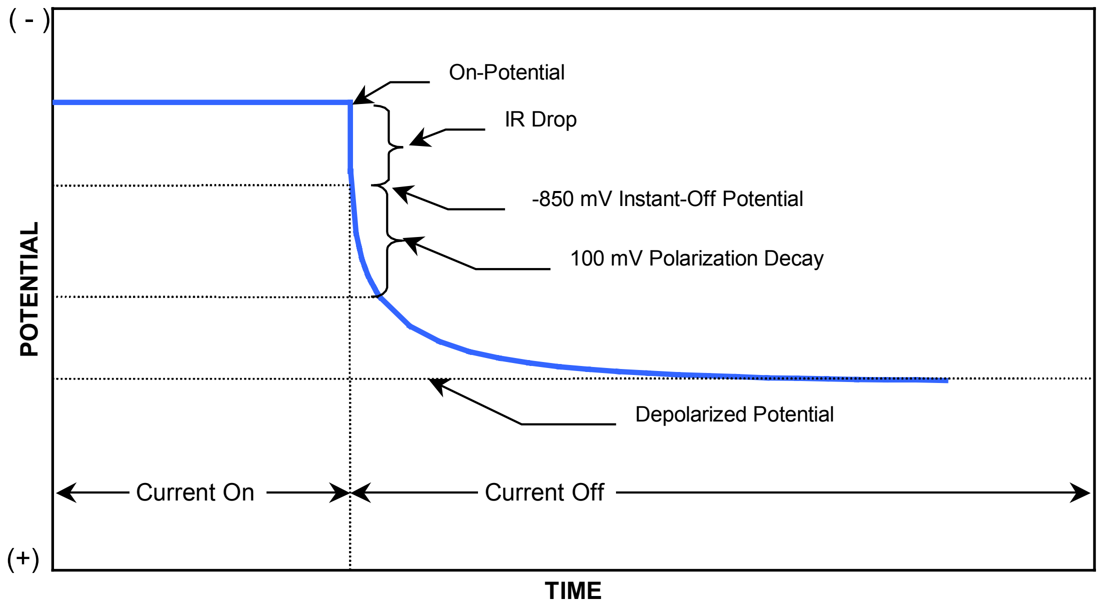


Figure 2. Illustration of the Operational Definitions of the Criteria for Cathodic Protection

-850 mV ($Cu/CuSO_4$) IR Drop Corrected Potential

This criterion is similar to the –850 mV ($Cu/CuSO_4$) polarized potential, but with definition of the IR drop correction methods

> *"A negative (cathodic) potential of at least 850 mV with the cathodic protection applied. This potential is measured with respect to a saturated copper/copper sulfate reference electrode contacting the electrolyte. Voltage drops other than those across the structure-to-electrolyte boundary must be considered for valid interpretation of this voltage measurement."*
>
> *"NOTE: Consideration is understood to mean the application of sound engineering practice in determining the significance of voltage drops by methods such as:*
>
> - *Measuring or calculating the voltage drop(s);*
> - *Reviewing the historical performance of the cathodic protection system*
> - *Evaluating the physical and electrical characteristics of the pipe and its environment; and*

- *Determining whether or not there is physical evidence of corrosion."*

This criterioin is illustrated in Figure 2 also and should result in the same potential as the –850 mV ($Cu/CuSO_4$) polarized potential criterion when IR drop corrections are made.

100 mV Polarization

The 100 mV polarization criterion is stated as follows:

> *"A minimum of 100 mV of cathodic polarization between the structure surface and a stable reference electrode contacting the electrolyte. The formation or decay of polarization can be measured to satisfy this criterion."*

Figure 2 illustratess this criterion in relation to the other two criteria assuming this criterion is measured during decay of polarization. In the case of polarization decay, protective current sources are shut off synchronously and the potential measured with time. As illustrated in Figure 2, the potential shifts immediately to a less negative value with the current interruption and then decays monotonically with time. The rate of decay will depend upon many factors, some of which include the type of environment, coating condition, magnitude of polarization, and length of time polarized.

To satisfy this criterion, the potential need only decay 100 mV or more as determined by the difference between the value for the instant-off potential and the decaying potential at any time. As a result, all of the influencing current sources need not be interrupted once a minimum of 100 mV of polarization has been achieved. Ultimately, the decaying potential will reach a steady-state value, which is the rest or depolarized potential for the current-off condition. To determine the total amount of polarization, however, it is necessary to determine the instant-off potential and the depolarized potential when all influencing current sources are shut off.

RP0169-96 recognizes some special conditions explicitly and implicitly when applying these criteria. From RP0169-96, they are

- In some situations, such as the presence of sulfides, bacteria, elevated temperatures, acid environments, and dissimilar metals, the criteria may not be sufficient
- When a pipeline is encased in concrete or buried in dry or aerated high resistivity soil, values less negative than those listed above may by sufficient
- Caution is advised against using polarized potentials less negative than –850 mV [($Cu/CuSO_4$)] for cathodic protection of pipelines when operating pressures and conditions are conducive to stress-corrosion cracking.

CRITERIA APPLICATION AND LIMITATIONS

For cathodic protection to be most effective, it is most often used in combination with a good, high-dielectric anti-corrosion coating. The primary role of the coating is as a corrosion barrier that separates the steel pipe from the environment. It also limits the exposure of bare steel thereby reducing the current required for cathodic protection. Cathodic protection, however, is supplemental and intended to provide corrosion control at those exposed areas or holidays in the coating. In this regard, if a moisture path exists between the environment and the steel through the coating, then cathodic protection current should follow that moisture path to provide protection to the steel when a criterion is met. Limitations exist that sometimes defeat the purpose of the cathodic protection current.

Application

As mentioned above, federally regulated pipelines are required to be monitored regularly with respect to one (or sometimes more) of the criteria. The –850 mV ($Cu/CuSO_4$) potential, whether as an instant-off or IR drop compensated potential, is by far the most frequently used criterion. Although the 100 mV polarization criterion is used by many companies, it is usually used only on older lines and over a small portion of the line primarily when the –850 mV potential criterion cannot be met.(13) One of the primary reasons why the –850 mV potential criteria is used more frequently is the relative ease with which those measurements can be made, although some do not find the 100 mV polarization criterion measurements difficult.(14)

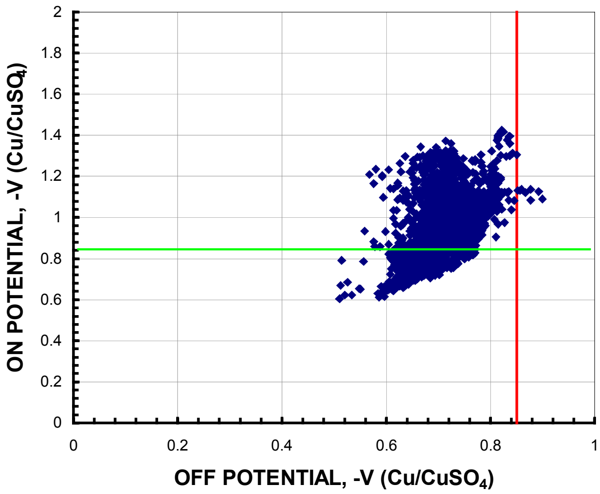
Despite their relative ease of measurement, the –850 mV ($Cu/CuSO_4$) potential criteria are more conservative than the 100 mV polarization criterion. Implicit in the 100 mV polarization criterion is that the instant-off or polarized potential need not be more negative than –850 mV ($Cu/CuSO_4$).(15,16,17) Figure 3 shows data from a close-interval survey of the on, instant-off, and depolarized potentials along nominally 25 km of a 40-year old pipeline coated with coal tar. These data illustrate the relationships among the criteria parameters. Figure 3a shows that only six locations out of 3112 (0.2%) exceed the –850 mV ($Cu/CuSO_4$) instant-off or polarized potential criterion when the on-potential without correction for IR drops exceeds the –850 mV ($Cu/CuSO_4$) potential. Moreover, an on-potential of at least –1100 mV ($Cu/CuSO_4$) would be required to assure the –850 mV ($Cu/CuSO_4$) polarized potential was achieved. For these data, potentials in excess of –850 mV ($Cu/CuSO_4$), regardless of whether or not corrected for IR drop, more than exceed 100 mV of polarization, as seen in Figures 3b and 3c. In this case, over 300 mV of polarization is obtained when the instant-off potential exceeds –850 mV ($Cu/CuSO_4$).

These results point our the conservative nature of the –850 mV ($Cu/CuSO_4$) polarized potential criterion and that using the –850 mV ($Cu/CuSO_4$) potential without correction for IR drops may satisfy the –850 mV ($Cu/CuSO_4$) polarized potential in only a small number of cases. The primary reason for this is the variability of the IR drop in the potential. Figures 3d and 3e show the distribution of IR drop and its relation to the on-potential. The IR drops in this sample of data occur over a 700 mV range, and point out the need to quantify rather than assume them.

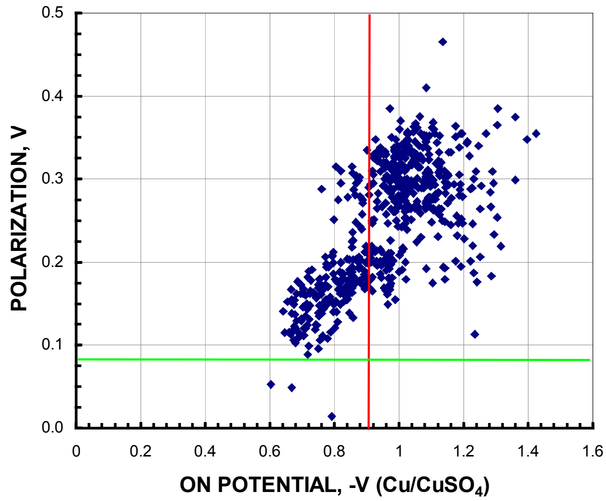
Once IR drops are measured, however, it is reasonable to use this information to benchmark a minimum on-potential to assure either the –850 mV ($Cu/CuSO_4$) polarized potential criterion or the 100 mV polarization criterion. This can be done as long as conditions have not changed, or according to NACE International RP0169-96,

> *"Methods for determining voltage drop(s) shall be selected and applied using sound engineering practices. Once determined, the voltage drop(s) may be used for correcting future measurements at the same location, providing conditions such as pipe and cathodic protection system operating conditions, soil characteristics, and external coating quality remain similar."*

Implicit in the 100 mV polarization criterion is the likelihood that the associated polarized potential will be less negative than –850 mV ($Cu/CuSO_4$).(15) That can be seen in Figure 3c. The only case where the polarized potential will be –850 mV ($Cu/CuSO_4$) or more negative is



a.



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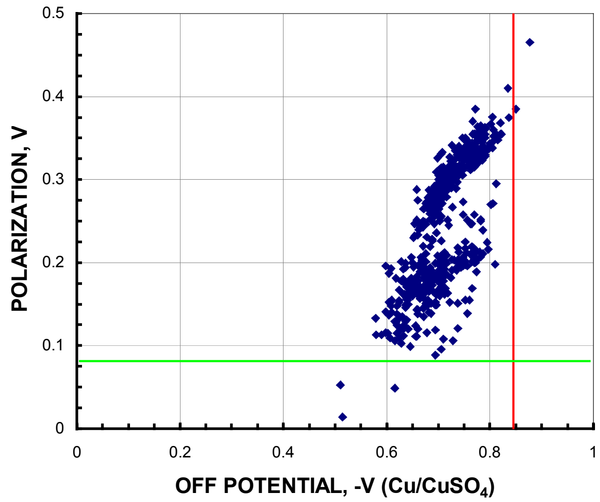

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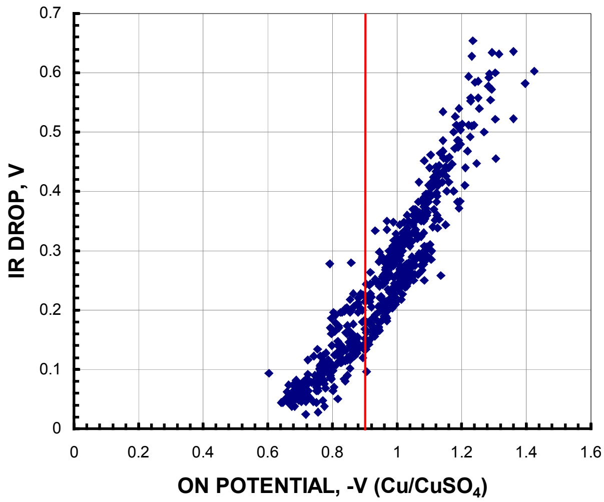

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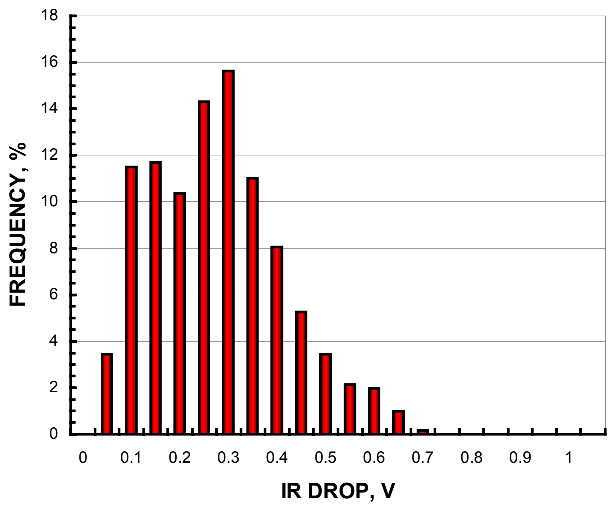


e.

Figure 3. Relationships Among Criteria Parameters Over 25 Km of a Pipeline

for the case when the free-corrosion potential is –750 mV ($Cu/CuSO_4$). Research studies have shown that this condition only occurs for uncorroded steel that has not been polarized very long in very moist, partly deaerated environments.[15,16,17,18] Moreover, those same studies have shown that as the amount of moisture decreases or the soil contains more sand, the aeration level increases and the free-corrosion potential decreases in magnitude. As the time at polarized potentials increases, the depolarized potential decreases also in magnitude, effectively increasing the amount of polarization. Figure 4 illustrates the decrease in magnitude of the depolarized potential of steel coupons in soils as a function of the amount of polarization, all having a free-corrosion potential initially around –725 mV ($Cu/CuSO_4$).

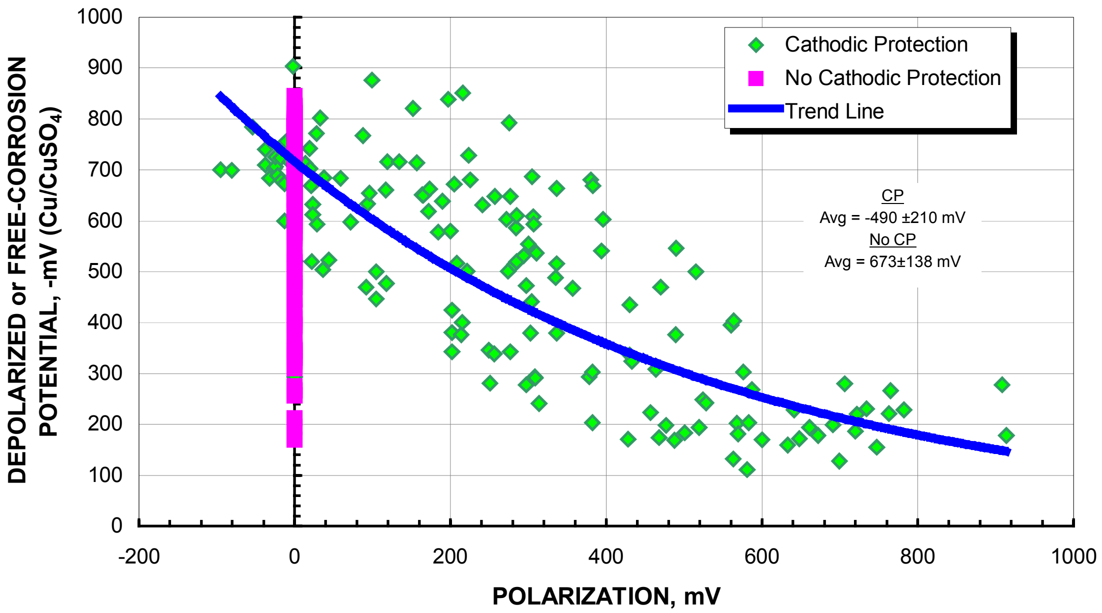
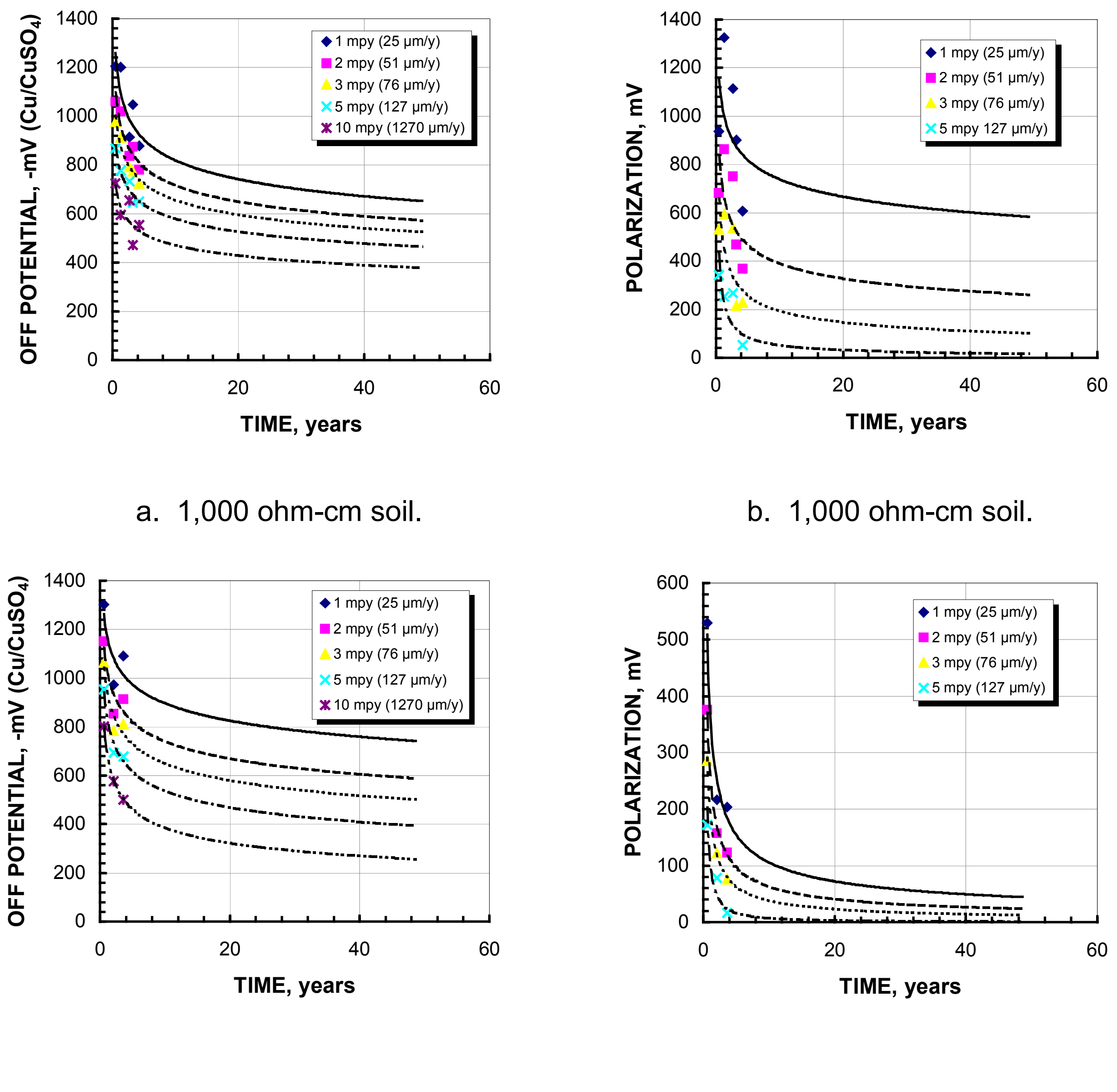


Figure 4. Effect of Polarization on the Depolarized Potential[19]

Despite the popularity of the –850 mV ($Cu/CuSO_4$) polarized or IR drop corrected potential criteria, polarization has been found to be the fundamental requirement for corrosion control regardless of the criterion used.[15,16,17] Furthermore, polarization is embodied in each criterion, but the exact requirements to control corrosion to some predetermined corrosion rate will vary with the material, the amount of polarization, the environment, and time. Based on the discussion for Figure 2 and the time dependence of corrosion rates, particularly the pitting rates, the corrosion rate will not be zero even when the criteria are greatly exceeded. This conclusion is supported by observation and calculation.[15,19] It means that some amount of corrosion may be expected to be found on a pipeline that has been effectively cathodically protected, but the depth of corrosion and the pitting rate are not expected to affect the integrity of the pipeline.[19,20]

The reason for observed corrosion even though the criteria have been exceeded is related to the parabolic time dependence of the pitting rates, and, therefore, the criteria.[19] The same is probably true for general corrosion rate, but the general corrosion rates are usually sufficiently lower than pitting (2 to 5 times, for example) that the time dependence is not usually noticeable. According to this view, the criteria values of –850 mV ($Cu/CuSO_4$) or 100 mV polarization are valid for pitting corrosion in the more limiting case of longer times of exposure when corrosion may be noted, but the rate is very low.

Figure 5 shows this more quantitatively. These results are from a field study where clean, uncoated steel coupons were exposed to nominally 1,000 ohm-cm and 1,360,000 ohm-cm soil at various protection levels for up to 4 years.[19] The level of polarized potential and polarization needed to obtain overall average maximum pitting rates (maximum depth/exposure time) at various times are shown. These figures indicate that the requirements for cathodic protection will depend on time, the environment, and the pitting rate to be achieved. To reduce the maximum pitting rate to lower values requires amounts of polarization greater than 100 mV and polarized potentials in excess of –850 mV ($Cu/CuSO_4$). Alternatively, if the polarized potential or polarization is held at some value, the corrosion rate will decrease progressively with time. The results of this study provides a basis for quantifying the corrosion rate with the criteria values, and demonstrating that corrosion is not stopped but reduced to sufficiently low values in time.



a. 1,000 ohm-cm soil.

b. 1,000 ohm-cm soil.

c. 1,360,000 ohm-cm soil.

d. 1,360,000 ohm-cm soil.

Figure 5. Time Dependence of the Criteria for Different Overall Maximum Pitting Rates[19]

Modifications

The section above indicated several special conditions in which the criteria may be modified. Those primarily were associated with the elevated temperatures, bacteria, sulfides, acid environments, and dissimilar metals.

Laboratory research has indicated that elevated temperatures will increase the amount of polarization need to achieve the same level of protection at ambient room temperatures.[(16)] For example, 200 to 300 mV of polarization are needed at 60°C as opposed to 100 mV of polarization at room temperature, 23°C. Depending upon the effect of temperature on the free-corrosion potential, this may require more negative polarized potentials.

Those same studies have addressed the effect of anaerobic sulfate-reducing bacteria (SRB) on the criteria. They showed a similar increase in the polarization required. Because natural environments that support deaerated conditions tend to be wet areas or those with clay-type soils that hold water, the free-corrosion potentials tend to be more negative and the associated polarized potentials tend to be more negative than –850 mV ($Cu/CuSO_4$). The effect of other types of bacteria, such as acid-producing bacteria (APB), aerobic bacteria, and iron-facultative or iron-depositing bacteria, have not been studied sufficiently to draw any conclusions regarding modifications to the present criteria values.[(21)] Of these bacteria, the one that likely poses the greatest challenge is the iron-facultative bacteria. Because these bacteria tend to build hard deposits or shells around the corrosion site, protective current may be shielded from the more acid environment within the shell.

Sulfides, which are a by-product of the SRB, promote an acid environment that reduces polarization from alkaline cathodic protection reactions. Thus, the current required is higher, and the amount of polarization is likely to be of the order of that required with SRB. No studies have defined the amount of polarization more precisely.

The requirements in acid environments have not been studied thoroughly, although some of the soils studied in laboratory had a pH of about five.[(16)] In that environment, the requirements were not significantly different, although the current to achieve protection may have been greater than in other soils. However, in environments with lower pH, the protective current will be higher than in less acidic environments because of the neutralizing effect of the acid on the more alkaline environments generated by cathodic protection. Thus, more negative polarized potentials may be required to achieve protection. No studies have quantified the requirements for protection in acid environments.

Dissimilar metals have an effect primarily on the 100 mV polarization criterion. The presence of interconnected dissimilar metals can setup galvanic cell that, during the current-off condition of depolarization, provide current that may have two effects: (1) create a secondary IR drop in the environment that creates an error in the apparent depolarizing potential, and (2) create a more or less depolarized condition on the metal under test that can lead to misinterpretation regarding the amount of polarization and the level of protection.

There are conditions in which the criteria may be more than sufficient for protection also. Some of those conditions have bee discussed above with regard to dryer, more aerated soils in which the polarized potential for protection associated with the 100 mV polarization criterion is less negative than –850 mV ($Cu/CuSO_4$). This occurs in the field because the dryer the soil becomes or the more sand it contains, the lower the moisture content and the more aerated it becomes. In turn, the free-corrosion potential becomes less negative. Thus, applying the 100 mV polarization criterion results in an associated polarized potential less negative than –850 mV ($Cu/CuSO_4$).

When encased in concrete, its more alkaline environment produces an environment like that generated by the cathodic protection current. Thus, the requirements for protection may be less than if the concrete were not there. However, it should be noted that corrosive conditions have occurred where concrete was used to weight a pipeline in a swamp. The moist environment created deaerated conditions conducive to SRB activity, but because the level of protection was not sufficiently high, corrosion occurred. Thus, the complete environmental conditions should be noted before assuming the presence of concrete will be sufficient alone to make up for deficiencies in protection level.

Limitations

All of the studies on the criteria ever undertaken have been carried out on steel samples freely exposed to the environment.(15,16,17,19,22,23) Implicit in the statements for the criteria is the understanding that the protective current has complete access to the surface to affect corrosion control. In reality, this is not always the case. Coatings develop holidays from rock impingement and soil stress, age, degrade from high temperature exposure, and disbond from cathodic protection reaction products and poor bond. If any of these conditions result in shielding of the pipe from cathodic protection current, then a reduction in protection at exposed steel can occur with an increase in the corrosion rate. Unfortunately, monitoring of the polarized potential or polarization cannot detect the shielding condition or the reduced protection levels. The primary reason is the high resistance that restricts current flow in a shielding condition is operative in the potential or polarization measurement circuit involved, thereby permitting only the lower resistance or the unshielded condition to be measured.(6) As a result, if shielding is suspected, other measurement methodologies must be used, namely in-line inspection.

As coatings age, they may also become more conductive to cathodic protection current. To counteract this, additional cathodic protection current and/or sources are needed to maintain the desired level of protection. Figure 6 illustrates the experience of one company with the current required to maintain protection on their pipeline system with various coatings over time.(24) The data are meant to illustrate the experience is not necessarily reflective of all systems, partly because these and individual company experiences combine a multitude of factors, including changes in the criterion used, which can have a significant effect on the trends. However, the data follow a pattern that could be anticipated based on moisture absorption characteristics of the coatings involved, with asphalt coatings absorbing more moisture than coal tar, polyethylene tape, and FBE.

Except for excessive polarized potentials that can lead to coating disbonding and/or shielding, such as with a tape coating, the –850 mV ($Cu/CuSO_4$) polarization criterion has few other limitations. Application of the 100 mV polarization criterion, however, must take into account the possibility of the associated polarized potential being in the stress-corrosion cracking range for those high pressure pipelines for which this is a concern. The primary area of concern is the mid-range shown in Figure 7 for the high pH form of SCC.(25) Potentials that are very negative (i.e., more negative than about –1100 mV [$Cu/CuSO_4$]) may become problematic if the hydrogen gas generated effectively shields the disbonded coating from cathodic protection current, thereby allowing the potential to decay into the SCC range. Until recently, the only option was to avoid polarization that resulted in polarized potentials in the SCC range of Figure 7. Recently, however, some guidelines regarding operating temperature and pressure, coating, steel surface condition, and soil groundwater chemistry have been developed that may provide a better basis for judging the need to avoid the SCC range.[26]

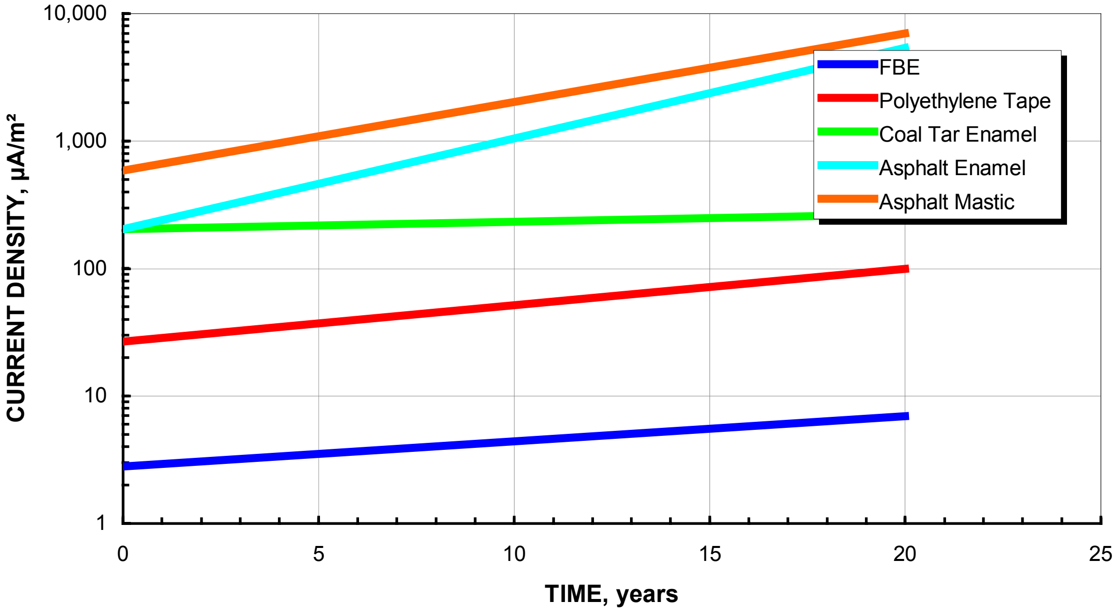


Figure 6. Current Requirement for Various Coatings[24]

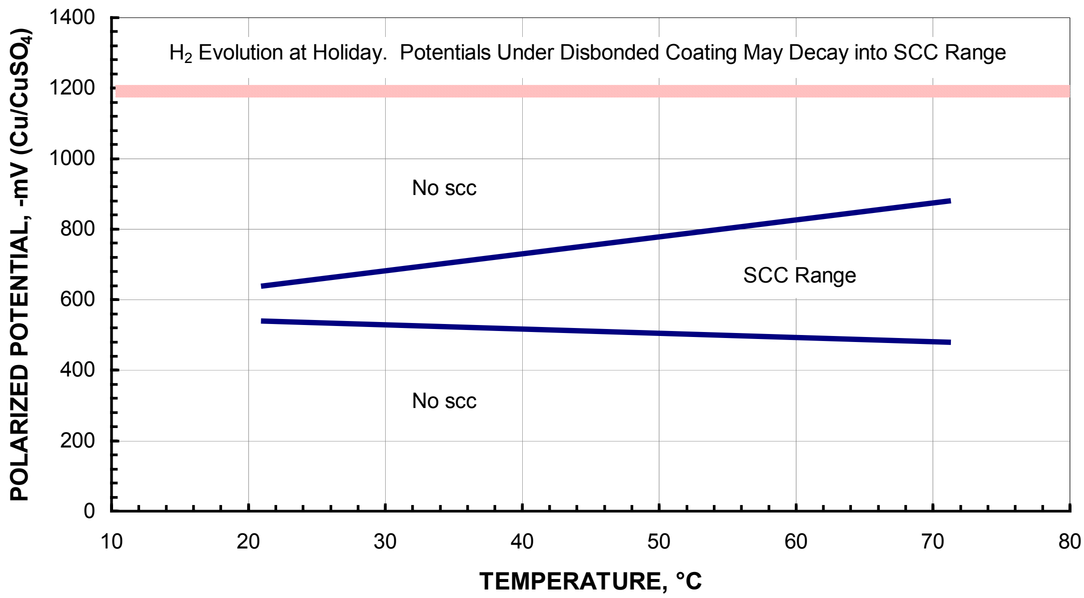


Figure 7. Range for High pH Stress-Corrosion Cracking[25]

INTEGRITY MANAGEMENT

One of the most popular systems to manage pipeline integrity is to utilize a scheme of monitoring, condition assessment, mitigation, and reporting in a systematic manner. For corrosion and SCC, monitoring includes the criteria-related measurements described above in a program that may include supplemental diagnostic and database systems to assess the condition and prioritize maintenance. Those diagnostic tools often include risk management, in-line inspection, and databases of the protection level and related parameters to better asses the pipeline condition.

Risk Assessment

Risk assessment is a pro-active approach to pipeline system integrity management adopted by many companies with relatively large or complex pipeline infrastructures. The guiding principle is the recognition that risk can not be totally eliminated, but can be controlled through effective resource allocations.(27) Risk assessment is used to determine the need for maintenance and to prioritize those maintenance activities, often on a meter-by-meter basis, to reduce the risk to an acceptable level consistent with budgetary resources and restraints. All areas of an operating pipeline system inherently contain some degree of integrity risk. However, for the pipeline structure, the focus is to prioritize areas of concern according to their perceived level of risk and then to address those areas on a priority basis.

This systematic process is designed to address integrity issues related to the possibility of a line leak or rupture. Many models of risk assessment define risk as the product of the probability or likelihood of a failure event and the consequences in the unlikely event of a failure,(28,29,30) or

Risk = (Probability of Failure) x (Consequences of Failure).

Because of its popularity today, there are commercially available risk assessment systems available that can be customized to an individual company's needs.(28,29) Most often, however, average values for the probabilities are too general and not representative of a particular company profile. Alternatively, some companies prefer to develop their own risk assessment or management system in-house to integrate their individual facilities and method of data management, and to insure future flexibility. Yet for other companies, the need for a more formal or quantitative risk assessment system is unnecessary, either because of the limited size or complexity of their pipeline infrastructure, or because of its relatively young age, or because of management decisions. In some cases, management may decide to accept the risk if the consequences are low, so-called zero consequences areas, and public perception of the decision is supported.

An integrity plan often has the following five goals incorporated into a mission statement:

- Ensure continued public and employee safety
- Ensure environmental protection
- Ensure reliability and competitive pipeline system
- Optimize cost/benefit of maintenance operations and asset preservation
- Minimize interruptions to service.

In most parts of the world, the integrity plan must also be crafted so that it addresses the prescriptive performance-based compliance requirements of a regulatory oversight agency. In the United States, a 1995 Congressional initiative put forth to evaluate federal rules in terms of costs and benefits opened the way to regulatory alternatives, such as ones based on the development of a risk management approach to pipeline safety(27).

Though other goals can be ascribed to a good integrity plan, those above capture the essence of many plans. Over the years, the Department of Transportation in the United States has compiled statistics that identify the areas of most concern to the natural-gas transmission industry because they adversely influence the goals above.[31] Those areas include the following:

- Third Party Damage
- External Corrosion
- SCC
- Materials Defects
- Construction Damage
- Internal Corrosion
- Operator Errors
- Acts of Nature
- Equipment Failures
- Other

Of the types of incidents shown, those on the left-hand side of the list above are often the subjects of risk assessment systems for natural-gas transmission pipelines. Those on the right-hand side are covered under other types of management systems. Figure 8 shows the percentage of those concern areas where failures have occurred as either an on-shore pipeline leak or rupture in the U.S. between 1984 and 1995.

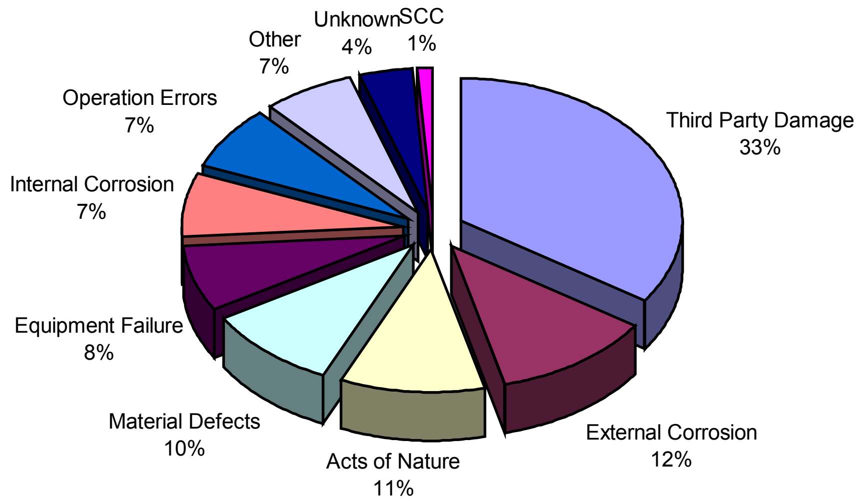


Figure 8. Distribution of Reportable Incidents from 1984 to 1995[31]

To address the five areas of concern above, a combination of available approaches are used. These include preventative, assessment, and remedial measures, such as investigative digs, in-line inspection, and pipe replacement. Table I shows a more complete list of these measures for each of the five areas of concern from above. Some of the measures, such as cathodic protection, address more than one area of concern. More will be said about these measures, particularly the risk assessment and predictive models below.

Integrity Programs

To address each of the areas of concern, integrity programs are designed with a degree of flexibility to permit responses to changing circumstances of the technical problem. Accordingly, the programs can consist of four major steps, which are (1) condition monitoring, (2) condition assessment, (3) mitigation, and (4) reporting. Each of the major steps constitutes a cycle and consists of one or more interrelated sub-steps to achieve the objective of the task, step, and plan. Here too, each meter of pipe is addressed in and integrated into the formal risk

Table 1. Summary of Integrity Concerns and Practical Measures to Address Them

Measures	Integrity Concerns				
	Corrosion	SCC	Material Defects	Construction Damage	Third Party Damage
Preventive					
Quality Assurance	•	•	•		
Public Awareness & Education					•
Coating & Cathodic Protection	•	•			
Construction Inspection	•	•	•	•	
Assessment					
Hydrostatic Testing	•	•	•	•	•
MFL, Caliper, & SCC ILI	•	•		•	•
Potential & Coating Surveys	•	•		•	
Investigative Digs & NDT	•	•	•	•	•
Aerial & Ground Surveys					•
Risk Assessment Models	•	•			
Predictive Models	•	•			
Remediation					
Pipe Replacement	•	•	•	•	•
Pipe Repair/Reinforcement	•	•	•	•	•
Pipe Recoating	•	•	•	•	•
Supplemental Cathodic Protection	•	•			
Regular Maintenance	•	•			
Hydrostatic Testing	•	•			
Increased Soil Cover & Barriers	•	•			•

assessment program with more discrete or predictive information and data from various supporting databases and research projects.

Such databases include parameters designed to enhance the knowledge base of the risk assessment model, and thereby improve its assessment capability. Databases or models that include information or predictive capability on the following topics are viewed as important and mutually complementary: (1) cathodic protection test point and close-interval pipe-to-soil potential surveys with rectifier and bond data, (2) pipe temperature history, (3) soil type and topography, (4) coating type, condition, and degradation model, (5) SCC soils and predictive model, (6) corrosion predictive model, (7) corrosion and SCC growth-rate models, and (8) in-line inspection tool run feature data. Ultimately, the ability to incorporate the databases and models into a geographic information system (GIS) software baseline will significantly enhance daily operations and decision making at many levels.[32]

Corrosion Integrity Program

A simplified flowchart for a corrosion integrity plan is shown in Figure 9. The flowchart is framed in terms of the four major management steps of condition monitoring, condition assessment, mitigation, and reporting. The cycle begins with application of a good anticorrosion coating and cathodic protection. The level of protection on the pipe based on the electrochemical measurement surveys and other supporting system measurements is made to monitor the corrosion status on a regular basis, usually dictated by prudent engineering practice and code compliance. In-line inspection tool runs supplement the electrical surveys. Information from the

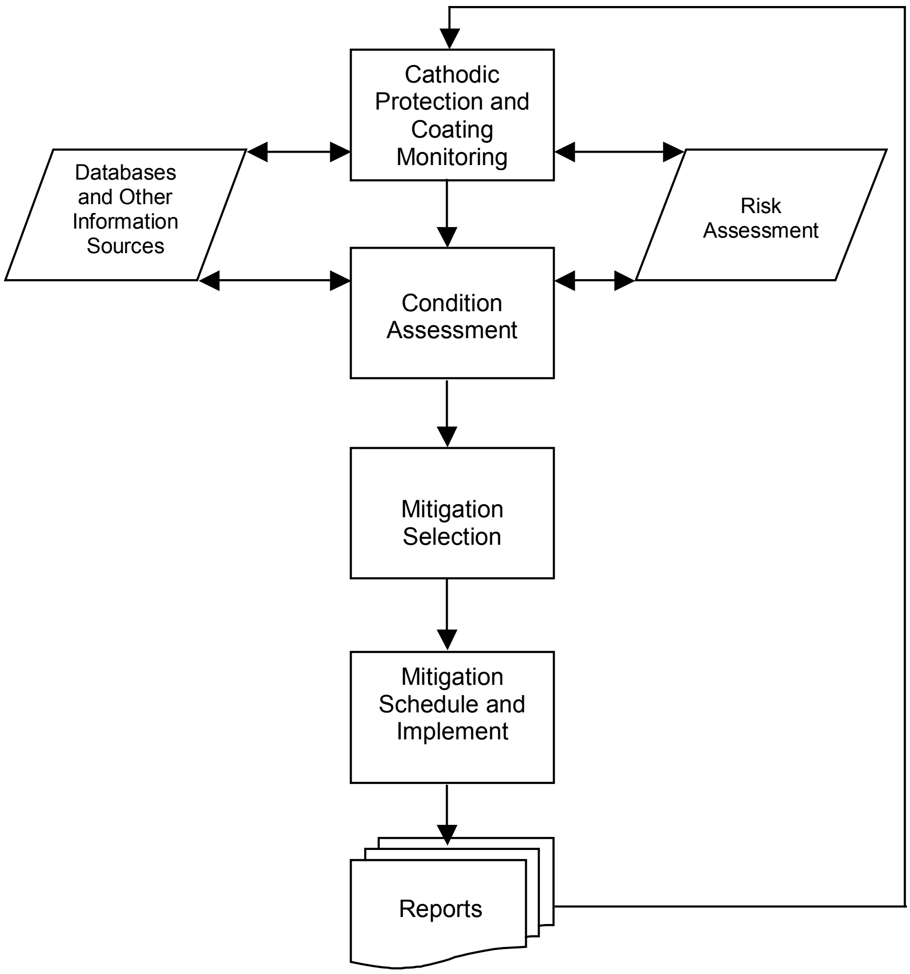


Figure 9. Integrity Program Flowchart for Corrosion

surveys and other supporting databases are used to assess the status of the pipelines by risk assessment and assign risk and mitigation priorities. For those sections at risk, mitigation schemes are defined, scheduled, and implemented. The results of the cycle are captured in reports that are used as input to the next evaluation cycle and databases.

Corrosion control begins with a good anti-corrosion coating and cathodic protection as mentioned previously. Older pipelines are often coated with coal tar, asphalt, or polyethylene or polyvinyl chloride (PVC) tape coatings, while newer lines are often coated with more advanced epoxy coatings, such as FBE, urethane epoxy, extruded polyethylene, double-wrap tape systems, or even composite coating systems based on a FBE undercoat and polyethylene outer coat. With newly coated pipelines, remote impressed current cathodic protection systems are employed because of the extended distribution of protection that is possible. However, as the coatings degrade and more current is needed over time to maintain accepted protection levels [e.g., -850 mV ($Cu/CuSO_4$)], sacrificial anodes or distributed impressed current systems are often installed to supplement protection. Alternatively, the 100 mV polarization criterion may be used because of its lower current required to achieve protection. Regular monitoring of rectifiers, bonds, and test points form the basic monitoring activities.

Cathodic Protection and Coating Monitoring

With the introduction of advanced technology, more sophisticated pipeline measurement equipment has found its way into today's pipeline industry. Because test points are often 1 km or more apart and test point measurements are not adequate to infer the potentials of the pipe between them, close-interval surveys increasingly are being used. Often, however, close-interval on-potential and instant-off potential surveys are used progressively over parts of a pipeline system over a period of several years to develop a database of the condition of the pipeline and coating. Alternatively, since newer pipelines with coatings such as FBE are protected to higher levels and have less damage (e.g., holidays) because of mill application and inspection of the coating, they are monitored at test points as required, but surveyed at close intervals less frequently (e.g., every 3 to 5 years). Pipelines with older coatings or coatings with more degradation may be monitored more frequently. In addition, increasing use of remote-monitoring units for rectifiers and other critical systems permit more frequent monitoring with apparently less labor than previously required. Incorporation of global positioning satellite (GPS) timing permit more accurate rectifier interruption for close-interval potential surveys and data collection. Many companies often handle monitoring data storage and retrieval now by computer databases, which permit ready analysis. Information from previous integrity analyses and databases of historical potential profiles are used to guide and prioritize where more monitoring may be needed.

Corrosion coupons are being used more frequently now also. They provide a means of monitoring where more conventional monitoring methods may not be effective or accurate, such as in areas of DC interference, where all current sources cannot be interrupted, and directly connected sacrificial anodes. Coupons are also being used to determine corrosion rates in various soils for use in projecting the growth rate of corrosion defects to more cost effectively schedule in-line inspection tool runs.[33]

In North America, close-interval potential surveys are used to infer the coating condition also. Areas of less negative or sub-criterion potentials (or polarization) and/or low IR drop in the on-potential are used as indicators of degraded coating quality. Often, this information in combination with in-line inspection anomaly data is used to assess pipeline condition. Though there are more specific coating defect survey techniques available (e.g., Pearson survey and DC voltage gradient [DCVG]), they are rarely used. The primary reason is that those methods are most useful for newer coatings with fewer and smaller defects.

In-line inspection is used to validate the effectiveness of cathodic protection and coatings. High-resolution, magnetic-flux leakage (MFL) tool runs and the resulting database of features can be detailed on a joint-by-joint basis for analysis with potential surveys to prioritize activities.[34] For example, the number of features per 100 m of pipe can be compared to the pipe-to-soil potential data for the area under investigation and used to prioritize remedial action.

Some companies take the opportunity to develop databases to help assess the integrity of their pipeline with regard to corrosion. The databases are sometimes singular, such as a detailed listing of coating type and type of soil along each meter of pipe, or they may be highly integrated electronically with supplementary relevant information. These databases are being expanded further from dig inspection for various reasons to include details such as the following: (1) soil chemistry from sample analysis, (2) presence of MIC bacteria, such as sulfate-reducing, acid producing, anaerobic, aerobic, and iron-depositing bacteria, (3) coating condition, (4) coating underfilm deposit and moisture analysis and pH, and (5) corrosion surface maps. This information is supplemented with local potential, topographical, other feature data, and historical and physical information to characterize the conditions under which corrosion has occurred. Ultimately, the objective is to develop a soils model that can be used to help prioritize high-risk areas of corrosion.

Condition Assessment

The integrity of a pipeline is usually determined by a combination of in-line inspection, potential, and coating survey information. For those pipeline companies either without proper valves and bends to accommodate an in-line inspection tool or without an in-line inspection program, reliance is on the potential and coating survey information primarily. The data for in-line inspection results and potentials can be overlaid in electronic or paper format or used separately.

An in-line inspection program is a key program to combine with a corrosion integrity plan. This combination links data and analysis to (a) address the risk assessment activity of prioritizing those areas most at risk of leak or rupture from corrosion features not discernable by potential or coating survey approaches, (b) ensure consistent and thorough handling of the data, (c) estimate the future growth of sub-critical flaws to allow long-term planning of future ILI runs or other mitigative measures, and (d) maximize the benefits of the in-line inspection runs and growth rate models by quantifying the long-term value in excavating and removing sub-critical features. A methodology for addressing this approach is based on a probability of exceedance (POE) concept and replaces a more deterministic approach based solely on identifying and excavating corrosion features greater than some minimum value, such as 70% wall loss or a predicted failure pressure of 100% SMYS or less.[35,36,37,38] The POE analysis is used to evaluate features with regard to a leak criterion based on an 80% through wall flaw. Similarly, the POE analysis is used to evaluate features with regard to a rupture criterion based on the failure pressure of the flaw being less than the maximum operating pressure. Here, ASME B31G, RSTRENG, CorLAS™, or other analytical predictive models have been used.[39,40]

Mitigation Selection

Mitigation measures for corrosion features include enhanced cathodic protection, recoating, hydrostatic retesting, pipe repair, or pipe replacement. Alternatively, nothing may be done if justifiable. Enhancements to cathodic protection are often implemented by conducting diagnostic testing to determine current requirements in a sub-criterion area, and weighing this alternative economically against others. Such alternatives may include limited coating repair, or complete mainline recoating if the addition of cathodic protection can no longer be effective with a coating in the soil encountered and/or with the number of corrosion features found by in-line inspection. Hydrostatic retesting is a destructive method to remove critical flaws that can fail below the test pressure. Alternatively, sample dig investigations may be conducted to evaluate the features; repair damaged coating; provide pipe repair with reinforcements such as steel or composite sleeves; or replace pipe.

Mitigation Schedule and Implementation

The failure pressure calculations are used with corrosion growth rate data to estimate the time interval before the existing corrosion features fail at the maximum operating pressure, and to prioritize mitigative measures. One of the obvious key parameters in this analysis is the corrosion rate to assign to the feature. Since the rate is determined by many factors, growth rate determinations are a prime area of interest. One approach is to use worst-case rates from unprotected corrosion coupons in the soils of interest, for example. Some attempts have been made to use pit growth rates from successive in-line inspection tool runs.[41,42] However, one problem is the reproducibility of selected features by the same or different tools and service providers, and different tools having different resolution capabilities. A considerable amount of attention is being given this area because of its value in prioritizing maintenance in cost effective manner.

Reporting

All of the documentation from the integrity cycle are analyzed and archived. New information developed from the dig and other investigations is incorporated into the database and used to make future integrity assessments, monitoring, and models more accurate and informative.

SUMMARY

The concepts and methodologies of risk assessment are being increasingly coupled with integrity programs. The two pipeline integrity areas where risk assessment has been applied rather vigorously are corrosion and SCC. Although the details of an integrity plan are very performance oriented, the prioritization of maintenance is becoming more risk based as pipelines age and budgetary and staff resources are reduced. Meaningful characterization of the pipeline for risk analysis purposes can only be based on accurate and specific quantification of important integrity-related parameters.

Corrosion is still one of the significant integrity threats to any buried or immersed structure whether operating at high pressure or low pressure. This threat is addressed through the application of an effective anti-corrosion coating system and cathodic protection, an monitored with respect to industry-accepted criteria. The primary criteria in use today are (a) the –850 mV ($Cu/CuSO_4$) polarized potential (b) the –850 mV ($Cu/CuSO_4$) IR drop corrected potential, and (c) 100 mV polarization. All of these criteria can be effective in reducing the corrosion rate, but the actual requirements may be achieved in some cases at less than the minimum values specified or at values greater than the minimum values specified depending on various conditions. While corrosion is assumed to stop once these or other values are exceeded, it is not stopped, but occurs at a sufficiently low rate to appear to be stopped for practical purposes. The present criteria, however, provide a practical measure on which to base the adequacy of protection, but are often supplemented with in-line inspection and inspection dig information in an integrity program to more clearly define the cathodic protection system effectiveness and limitations.

New technologies have given industry the ability to readily collect, store, retrieve, and analyze large amounts of field data in electronic format. Many companies have married the basic pipe-to-soil potential survey data collected in this way with in-line inspection tool feature data in electronic format to provide a more accurate picture of the corrosion status of their pipeline. This capability alone helps in identifying deficiencies, and prioritizing and scheduling mitigation. However, some companies have expanded that information base to include other databases and models to help improve integrity management. The CEPA database on SCC is a prime example, and one that has reached outside the bounds of single company proprietary information.[43] Other more proprietary company databases have been directed to the corrosion integrity issues. A soils database to help identify areas along a pipeline system where cathodic protection and/or certain coating systems may not be effective or in need of more stringent protection criteria is an area of active development.

Integrity management and risk assessment have benefited greatly from the availability of analytical failure models. The failure pressure for a corrosion flaw can be estimated from existing analytical failure models. However, the failure models are not just being used to calculate estimated failure pressures of known flaws, they are also being used in conjunction with more probabilistic approaches to judge integrity and prioritize maintenance. In the failure models, growth rates of corrosion are being used to estimate the interval of time before the flaw reaches a critical size or can fail if left unattended. The accuracy of the estimates critically depends on the growth rates to be used. Various approaches are being considered by different organizations to determine these values because of obvious benefit in prioritizing maintenance.

For companies committed to application of in-line inspection to its integrity and risk management programs, construction programs to install the needed launchers and receivers and modify valves where appropriate will be needed. The lack of such installations is a major barrier to wider use of in-line inspection, which is apparently the case for nearly half of the natural-gas transmission companies in North America.(26) For those companies, hydrostatic testing is an alternative if the lines are looped or gas supply can be achieved by other routes. As these barriers are addressed over time, development of new in-line inspection tools and capabilities is expected to continue to grow.(11,14,27) However, in-line inspection alone will not be the means of judging the integrity of a pipeline because of the expense and time intervals involved. In the interim, great reliance will remain on monitoring the corrosion protection status by measurements relative to the criteria for cathodic protection.

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