NACE SP0169-2007
(formerly RP0169)
Item No. 21173

Standard Practice

Control of External Corrosion on Underground or Submerged Metallic Piping Systems

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This NACE Standard is being made available to you at no charge because it is incorporated by reference in the U.S. Code of Federal Regulations (CFR) Title 49. "Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards," Part 195.

Although the 2007 version of SP0169 is cited in regulations, the standard has been revised and the current edition is 2013. **Click here to access the 2013 edition.**

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Reaffirmed 2007-03-15
Reaffirmed 2002-04-11
Reaffirmed 1996-09-13
Revised April 1992
Revised January 1983
Revised September 1976
Revised January 1972
Approved April 1969

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ISBN 1-57590-035-1

Foreword

This standard practice presents procedures and practices for achieving effective control of external corrosion on buried or submerged metallic piping systems. These recommendations are also applicable to many other buried or submerged metallic structures. It is intended for use by corrosion control personnel concerned with the corrosion of buried or submerged piping systems, including oil, gas, water, and similar structures. This standard describes the use of electrically insulating coatings, electrical isolation, and cathodic protection (CP) as external corrosion control methods. It contains specific provisions for the application of CP to existing bare, existing coated, and new piping systems. Also included are procedures for control of interference currents on pipelines.

This standard should be used in conjunction with the practices described in the following NACE standards and publications, when appropriate (use latest revisions):

SP0572[1] RP0177[2] RP0285[3] SP0186[4] SP0286[5] SP0387[6] SP0188[7]
TPC 11[8] TM0497[9]

For accurate and correct application of this standard, the standard must be used in its entirety. Using or citing only specific paragraphs or sections can lead to misinterpretation and misapplication of the recommendations and practices contained in this standard.

This standard does not designate practices for every specific situation because of the complexity of conditions to which buried or submerged piping systems are exposed.

This standard was originally published in 1969, and was revised by NACE Task Group (TG) T-10-1 in 1972, 1976, 1983, and 1992. It was reaffirmed in 1996 by NACE Unit Committee T-10A on Cathodic Protection, and in 2002 and 2007 by Specific Technology Group (STG) 35 on Pipelines, Tanks, and Well Casings. This standard is issued by NACE International under the auspices of STG 35, which is composed of corrosion control personnel from oil and gas transmission companies, gas distribution companies, power companies, corrosion consultants, and others concerned with external corrosion control of buried or submerged metallic piping systems.

In NACE standards, the terms *shall*, *must*, *should*, and may are used in accordance with the definitions of these terms in the NACE Publications Style Manual, 4th ed., Paragraph 7.4.1.9. *Shall* and *must* are used to state mandatory requirements. The term should is used to state something considered good and is recommended but is not mandatory. The term may is used to state something considered optional.

NACE International
Standard Practice

Control of External Corrosion on Underground or Submerged Metallic Piping Systems

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Section 1: General

1.1 This standard presents acknowledged practices for the control of external corrosion on buried or submerged steel, cast iron, ductile iron, copper, and aluminum piping systems.

1.2 This standard is intended to serve as a guide for establishing minimum requirements for control of external corrosion on the following systems:

1.2.1 New piping systems: Corrosion control by a coating supplemented with CP, or by some other proven method, should be provided in the initial design and maintained during the service life of the piping system, unless investigations indicate that corrosion control is not required. Consideration should be given to the construction of pipelines in a manner that facilitates the use of in-line inspection tools.

1.2.2 Existing coated piping systems: CP should be provided and maintained, unless investigations indicate that CP is not required.

1.2.3 Existing bare piping systems: Studies should be made to determine the extent and rate of corrosion on existing bare piping systems. When these studies indicate that corrosion will affect the safe or economic operation of the system, adequate corrosion control measures shall be taken.

1.3 The provisions of this standard should be applied under the direction of competent persons who, by reason of knowledge of the physical sciences and the principles of engineering and mathematics, acquired by education and related practical experience, are qualified to engage in the practice of corrosion control on buried or submerged metallic piping systems. Such persons may be registered professional engineers or persons recognized as corrosion specialists or CP specialists by NACE if their professional activities include suitable experience in external corrosion control of buried or submerged metallic piping systems.

1.4 Special conditions in which CP is ineffective or only partially effective sometimes exist. Such conditions may include elevated temperatures, disbonded coatings, thermal insulating coatings, shielding, bacterial attack, and unusual contaminants in the electrolyte. Deviation from this standard may be warranted in specific situations provided that corrosion control personnel in responsible charge are able to demonstrate that the objectives expressed in this standard have been achieved.

1.5 This standard does not include corrosion control methods based on chemical control of the environment, on the use of electrically conductive coatings, or on control of internal corrosion.

Section 2: Definitions [(1)]

Amphoteric Metal: A metal that is susceptible to corrosion in both acid and alkaline environments.

Anode: The electrode of an electrochemical cell at which oxidation occurs. Electrons flow away from the anode in the external circuit. Corrosion usually occurs and metal ions enter solution at the anode.

Anodic Polarization: The change of the electrode potential in the noble (positive) direction caused by current across the electrode/electrolyte interface. (See *Polarization.*)

Backfill: Material placed in a hole to fill the space around the anodes, vent pipe, and buried components of a cathodic protection system.

Beta Curve: A plot of dynamic (fluctuating) interference current or related proportional voltage (ordinate) versus the corresponding structure-to-electrolyte potentials at a selected location on the affected structure (abscissa) (see Appendix A [nonmandatory]).

Cable: One conductor or multiple conductors insulated from one another.

Cathode: The electrode of an electrochemical cell at which reduction is the principal reaction. Electrons flow toward the cathode in the external circuit.

Cathodic Disbondment: The destruction of adhesion between a coating and the coated surface caused by products of a cathodic reaction.

[(1)] Definitions in this section reflect common usage among practicing corrosion control personnel and apply specifically to how the terms are used in this standard. In many cases, in the interests of brevity and practical usefulness, the scientific definitions are abbreviated or paraphrased.

Cathodic Polarization: The change of electrode potential in the active (negative) direction caused by current across the electrode/electrolyte interface. See *Polarization*.

Cathodic Protection: A technique to reduce the corrosion of a metal surface by making that surface the cathode of an electrochemical cell.

Coating: A liquid, liquefiable, or mastic composition that, after application to a surface, is converted into a solid protective, decorative, or functional adherent film.

Coating Disbondment: The loss of adhesion between a coating and the pipe surface.

Conductor: A material suitable for carrying an electric current. It may be bare or insulated.

Continuity Bond: A connection, usually metallic, that provides electrical continuity between structures that can conduct electricity.

Corrosion: The deterioration of a material, usually a metal, that results from a reaction with its environment.

Corrosion Potential (E_{corr}): The potential of a corroding surface in an electrolyte relative to a reference electrode under open-circuit conditions (also known as *rest potential*, *open-circuit potential*, or *freely corroding potential*).

Corrosion Rate: The rate at which corrosion proceeds.

Criterion: Standard for assessment of the effectiveness of a cathodic protection system.

Current Density: The current to or from a unit area of an electrode surface.

Diode: A bipolar semiconducting device having a low resistance in one direction and a high resistance in the other.

Distributed-Anode Impressed Current System: An impressed current anode configuration in which the anodes are "distributed" along the structure at relatively close intervals such that the structure is within each anode's voltage gradient. This anode configuration causes the electrolyte around the structure to become positive with respect to remote earth.

Electrical Isolation: The condition of being electrically separated from other metallic structures or the environment.

Electrical Survey: Any technique that involves coordinated electrical measurements taken to provide a basis for deduction concerning a particular electrochemical condition relating to corrosion or corrosion control.

Electrode: A conductor used to establish contact with an electrolyte and through which current is transferred to or from an electrolyte.

Electroosmotic Effect: Passage of a charged particle through a membrane under the influence of a voltage. Soil or coatings may act as the membrane.

Electrolyte: A chemical substance containing ions that migrate in an electric field. For the purpose of this standard, electrolyte refers to the soil or liquid adjacent to and in contact with a buried or submerged metallic piping system, including the moisture and other chemicals contained therein.

Foreign Structure: Any metallic structure that is not intended as a part of a system under cathodic protection.

Galvanic Anode: A metal that provides sacrificial protection to another metal that is more noble when electrically coupled in an electrolyte. This type of anode is the electron source in one type of cathodic protection.

Galvanic Series: A list of metals and alloys arranged according to their corrosion potentials in a given environment.

Groundbed: One or more anodes installed below the earth's surface for the purpose of supplying cathodic protection.

Holiday: A discontinuity in a protective coating that exposes unprotected surface to the environment.

Impressed Current: An electric current supplied by a device employing a power source that is external to the electrode system. (An example is direct current for cathodic protection.)

In-Line Inspection: The inspection of a steel pipeline using an electronic instrument or tool that travels along the interior of the pipeline.

Insulating Coating System: All components of the protective coating, the sum of which provides effective electrical isolation of the coated structure.

Interference: Any electrical disturbance on a metallic structure as a result of stray current.

Interference Bond: An intentional metallic connection, between metallic systems in contact with a common electrolyte, designed to control electrical current interchange between the systems.

IR Drop: The voltage across a resistance in accordance with Ohm's Law.

Isolation: See *Electrical Isolation*.

Line Current: The direct current flowing on a pipeline.

Long-Line Current: Current through the earth between an anodic and a cathodic area that returns along an underground metallic structure.

Mixed Potential: A potential resulting from two or more electrochemical reactions occurring simultaneously on one metal surface.

Pipe-to-Electrolyte Potential: See Structure-to-Electrolyte Potential.

Polarization: The change from the open-circuit potential as a result of current across the electrode/electrolyte interface.

Polarized Potential: The potential across the structure/electrolyte interface that is the sum of the corrosion potential and the cathodic polarization.

Reference Electrode: An electrode whose open-circuit potential is constant under similar conditions of measurement, which is used for measuring the relative potentials of other electrodes.

Reverse-Current Switch: A device that prevents the reversal of direct current through a metallic conductor.

Shielding: (1) Protecting; protective cover against mechanical damage. (2) Preventing or diverting the cathodic protection current from its intended path.

Shorted Pipeline Casing: A casing that is in direct metallic contact with the carrier pipe.

Sound Engineering Practices: Reasoning exhibited or based on thorough knowledge and experience, logically valid and having technically correct premises that demonstrate good judgment or sense in the application of science.

Stray Current: Current through paths other than the intended circuit.

Stray-Current Corrosion: Corrosion resulting from current through paths other than the intended circuit, e.g., by any extraneous current in the earth.

Structure-to-Electrolyte Potential: The potential difference between the surface of a buried or submerged metallic structure and electrolyte that is measured with reference to an electrode in contact with the electrolyte.

Telluric Current: Current in the earth as a result of geomagnetic fluctuations.

Voltage: An electromotive force or a difference in electrode potentials expressed in volts.

Wire: A slender rod or filament of drawn metal. In practice, the term is also used for smaller-gauge conductors (6 mm^2 [No. 10 AWG[(2)]] or smaller).

Section 3: Determination of Need for External Corrosion Control

3.1 Introduction

3.1.1 This section recommends practices for determining when an underground or submerged metallic piping system requires external corrosion control.

3.1.2 Metallic structures, buried or submerged, are subject to corrosion. Adequate corrosion control procedures should be adopted to ensure metal integrity for safe and economical operation.

3.2 The need for external corrosion control should be based on data obtained from one or more of the following: corrosion surveys, operating records, visual observations, test results from similar systems in similar environments, in-line inspections, engineering and design specifications, and operating, safety, and economic requirements. The absence of leaks alone is insufficient evidence that corrosion control is not required.

3.2.1 Environmental and physical factors include the following:

3.2.1.1 Corrosion rate of the particular metallic piping system in a specific environment (see Appendix B [nonmandatory]);

3.2.1.2 Nature of the product being transported, the working temperature, temperature differentials within the pipeline causing thermal expansion and contraction, tendency of backfill to produce soil stress, and working pressure of the piping system as related to design specification;

(2) American Wire Gauge.

3.2.1.3 Location of the piping system as related to population density and frequency of visits by personnel;

3.2.1.4 Location of the piping system as related to other facilities; and

3.2.1.5 Stray current sources foreign to the system.

3.2.2 Economic factors include the following:

3.2.2.1 Costs of maintaining the piping system in service for its expected life (see Appendix B [nonmandatory])

3.2.2.2 Contingent costs of corrosion (see Appendix C [nonmandatory]); and

3.2.2.3 Costs of corrosion control (see Appendix D [nonmandatory]).

Section 4: Piping System Design

4.1 Introduction

4.1.1 This section provides accepted corrosion control practices in the design of an underground or submerged piping system. A person qualified to engage in the practice of corrosion control should be consulted during all phases of pipeline design and construction (see Paragraph 1.3). These recommendations should not be construed as taking precedence over recognized electrical safety practices.

4.2 External Corrosion Control

4.2.1 External corrosion control must be a primary consideration during the design of a piping system. Materials selection and coatings are the first line of defense against external corrosion. Because perfect coatings are not feasible, CP must be used in conjunction with coatings. For additional information, see Sections 5 and 6.

4.2.2 New piping systems should be externally coated unless thorough investigation indicates that coatings are not required (see Section 5).

4.2.3 Materials and construction practices that create electrical shielding should not be used on the pipeline. Pipelines should be installed at locations where proximity to other structures and subsurface formations do not cause shielding.

4.3 Electrical Isolation

4.3.1 Isolation devices such as flange assemblies, prefabricated joint unions, or couplings should be installed within piping systems in which electrical isolation of portions of the system is required to facilitate the application of external corrosion control. These devices should be properly selected for temperature, pressure, chemical resistance, dielectric resistance, and mechanical strength. Installation of isolation devices should be avoided or safeguarded in areas in which combustible atmospheres are likely to be present. Locations at which electrical isolating devices should be considered include, but are not limited to, the following:

4.3.1.1 Points at which facilities change ownership, such as meter stations and well heads;

4.3.1.2 Connections to mainline piping systems, such as gathering or distribution system laterals;

4.3.1.3 Inlet and outlet piping of in-line measuring and pressure regulating stations;

4.3.1.4 Compressor or pumping stations, either in the suction and discharge piping or in the main line immediately upstream and downstream from the station;

4.3.1.5 Stray current areas;

4.3.1.6 The junction of dissimilar metals;

4.3.1.7 The termination of service line connections and entrance piping;

4.3.1.8 The junction of a coated pipe and a bare pipe; and

4.3.1.9 Locations at which electrical grounding is used, such as motorized valves and instrumentation.

4.3.2 The need for lightning and fault current protection at isolating devices should be considered. Cable connections from isolating devices to arresters should be short, direct, and of a size suitable for short-term high-current loading.

4.3.3 When metallic casings are required as part of the underground piping system, the pipeline should be electrically isolated from such casings. Casing insulators must be properly sized and spaced and be tightened securely on the pipeline to withstand insertion stresses without sliding on the pipe. Inspection should be made to verify that the leading insulator has remained in position. Concrete coatings on the carrier pipe could preclude the use of casing insulators. Consideration should be given to the use of support under the pipeline at each end of the casing to minimize settlement. The type of support selected

should not cause damage to the pipe coating or act as a shield to CP current.

4.3.4 Casing seals should be installed to resist the entry of foreign matter into the casing.

4.3.5 When electrical contact would adversely affect CP, piping systems should be electrically isolated from supporting pipe stanchions, bridge structures, tunnel enclosures, pilings, offshore structures, or reinforcing steel in concrete. However, piping can be attached directly to a bridge without isolation if isolating devices are installed in the pipe system on each side of the bridge to isolate the bridge piping electrically from adjacent underground piping.

4.3.6 When an isolating joint is required, a device manufactured to perform this function should be used, or, if permissible, a section of nonconductive pipe, such as plastic pipe, may be installed. In either case, these should be properly rated and installed in accordance with the manufacturer's instructions.

4.3.7 River weights, pipeline anchors, and metallic reinforcement in weight coatings should be electrically isolated from the carrier pipe and designed and installed so that coating damage does not occur and the carrier pipe is not electrically shielded.

4.3.8 Metallic curb boxes and valve enclosures should be designed, fabricated, and installed in such a manner that electrical isolation from the piping system is maintained.

4.3.9 Insulating spacing materials should be used when it is intended to maintain electrical isolation between a metallic wall sleeve and the pipe.

4.3.10 Underground piping systems should be installed so that they are physically separated from all foreign underground metallic structures at crossings and parallel installations and in such a way that electrical isolation could be maintained if desired.

4.3.11 Based on voltage rating of alternating current (AC) transmission lines, adequate separation should be maintained between pipelines and electric transmission tower footings, ground cables, and counterpoise. Regardless of separation, consideration should always be given to lightning and fault current protection of pipeline(s) and personnel safety (see NACE Standard RP0177[2]).

4.4 Electrical Continuity

4.4.1 Nonwelded pipe joints may not be electrically continuous. Electrical continuity can be ensured by the use of fittings manufactured for this purpose or by bonding across and to the mechanical joints in an effective manner.

4.5 Corrosion Control Test Stations

4.5.1 Test stations for potential, current, or resistance measurements should be provided at sufficient locations to facilitate CP testing. Such locations may include, but are not limited to, the following:

4.5.1.1 Pipe casing installations,

4.5.1.2 Metallic structure crossings,

4.5.1.3 Isolating joints,

4.5.1.4 Waterway crossings,

4.5.1.5 Bridge crossings,

4.5.1.6 Valve stations,

4.5.1.7 Galvanic anode installations,

4.5.1.8 Road crossings,

4.5.1.9 Stray-current areas, and

4.5.1.10 Rectifier installations.

4.5.2 The span of pipe used for line current test stations should exclude:

4.5.2.1 Foreign metallic structure crossings;

4.5.2.2 Lateral connections;

4.5.2.3 Mechanical couplings or connections such as screwed joints, transition pieces, valves, flanges, anode or rectifier attachments, or metallic bonds; and

4.5.2.4 Changes in pipe wall thickness and diameter.

4.5.3 Attachment of Copper Test Lead Wires to Steel and Other Ferrous Pipes

4.5.3.1 Test lead wires may be used both for periodic testing and for current-carrying purposes. As such, the wire/pipe attachment should be mechanically strong and electrically conductive.

4.5.3.2 Methods of attaching wires to the pipe include (a) thermit welding process, (b) soldering, and (c) mechanical means.

4.5.3.3 Particular attention must be given to the attachment method to avoid (a) damaging or penetrating the pipe, (b) sensitizing or altering of pipe properties, (c) weakening the test lead wire, (d) damaging internal or external pipe coatings, and (e) creating hazardous conditions in explosive environments.

4.5.3.4 Attachment by mechanical means is the least desirable method. Such a connection may

loosen, become highly resistant, or lose electrical continuity.

4.5.3.5 The connection should be tested for mechanical strength and electrical continuity. All exposed portions of the connection should be thoroughly cleaned of all welding slag, dirt, oils, etc.; primed, if needed; and coated with materials compatible with the cable insulation, pipe coating, and environment.

4.5.4 Attachment of Aluminum Test Lead Wire to Aluminum Pipes

4.5.4.1 Aluminum test lead wire, or aluminum tabs attached to aluminum wire, may be welded to aluminum pipe using the tungsten inert-gas shielded arc (TIG) or metal inert-gas shielded arc (MIG) process. Welded attachments should be made to flanges or at butt weld joints. Attachment at other sites may adversely affect the mechanical properties of the pipe because of the heat of welding.

4.5.4.2 Test lead wire may be attached to aluminum pipe by soldering. If low-melting-point soft solders are used, a flux is required. Flux residues may cause corrosion unless removed.

NOTE: The use of copper test lead wire may cause preferential galvanic attack on the aluminum pipe. When copper wire or flux is used, care must be taken to seal the attachment areas against moisture. In the presence of moisture, the connection may disbond and be damaged by corrosion.

4.5.4.3 Aluminum tabs to which test lead wires have been TIG welded can be attached by an explosive bonding technique called high-energy joining.

4.5.4.4 Mechanical connections that remain secure and electrically conductive may be used.

4.5.5 Attachment of Copper Test Lead Wire to Copper Pipe.

4.5.5.1 Copper test lead wire, or copper tabs attached to copper wire, may be attached to copper pipe by one of the following methods. The relative thickness of the wire and the pipe wall dictates, in part, which of the methods can be used.

4.5.5.1.1 Arc welding (TIG, MIG, or shielded metal);

4.5.5.1.2 Electrical resistance (spot) welding;

4.5.5.1.3 Brazing;

4.5.5.1.4 Soldering; or

4.5.5.1.5 Mechanical connection.

4.5.5.2 Attention should be given to proper joining procedures to avoid possible embrittlement or loss of mechanical properties of the metals from the heat of welding or brazing.

4.5.5.3 A flux may be required, or self-produced, when brazing with some filler metals or soldering with some low-melting-point soft solders. Because flux residues may cause corrosion, they should be removed.

Section 5: External Coatings

5.1 Introduction

5.1.1 This section recommends practices for selecting, testing and evaluating, handling, storing, inspecting, and installing external coating systems for external corrosion control on piping systems.

The function of external coatings is to control corrosion by isolating the external surface of the underground or submerged piping from the environment, to reduce CP current requirements, and to improve current distribution.

5.1.2 External coatings must be properly selected and applied and the coated piping carefully handled and installed to fulfill these functions. Various types of external coatings can accomplish the desired functions.

5.1.2.1 Desirable characteristics of external coatings include the following:

5.1.2.1.1 Effective electrical insulator;

5.1.2.1.2 Effective moisture barrier;

5.1.2.1.3 Application to pipe by a method that does not adversely affect the properties of the pipe;

5.1.2.1.4 Application to pipe with a minimum of defects;

5.1.2.1.5 Good adhesion to pipe surface;

5.1.2.1.6 Ability to resist development of holidays with time;

5.1.2.1.7 Ability to resist damage during handling, storage, and installation;

5.1.2.1.8 Ability to maintain substantially constant electrical resistivity with time;

5.1.2.1.9 Resistance to disbonding;

5.1.2.1.10 Resistance to chemical degradation;

5.1.2.1.11 Ease of repair;

5.1.2.1.12 Retention of physical characteristics;

5.1.2.1.13 Nontoxic to the environment; and

5.1.2.1.14 Resistance to changes and deterioration during aboveground storage and long-distance transportation.

5.1.2.2 Typical factors to consider when selecting an external pipe coating include:

5.1.2.2.1 Type of environment;

5.1.2.2.2 Accessibility of piping system;

5.1.2.2.3 Operating temperature of piping system;

5.1.2.2.4 Ambient temperatures during application, shipping, storage, construction, installation, and pressure testing;

5.1.2.2.5 Geographical and physical location;

5.1.2.2.6 Type of external coating on existing pipe in the system;

5.1.2.2.7 Handling and storage;

5.1.2.2.8 Pipeline installation methods;

5.1.2.2.9 Costs; and

5.1.2.2.10 Pipe surface preparation requirements.

5.1.2.3 Pipeline external coating systems shall be properly selected and applied to ensure that adequate bonding is obtained. Unbonded coatings can create electrical shielding of the pipeline that could jeopardize the effectiveness of the CP system.

5.1.3 Information in this section is primarily by reference to other documents. It is important that the latest revision of the pertinent reference be used.

5.1.3.1 Table 1 is a listing of types of external coating systems, showing the appropriate references for material specifications and recommended practices for application.

5.1.3.2 Table 2 is a grouping of references for general use during installation and inspection, regardless of coating type.

5.1.3.3 Table 3 is a list of external coating system characteristics related to environmental conditions containing suggested laboratory test references for various properties.

5.1.3.4 Table 4 is a list of external coating system characteristics related to design and construction, with recommended laboratory tests for evaluating these properties.

5.1.3.5 Table 5 lists the references that are useful in field evaluation of external coating systems after the pipeline has been installed.

5.2 Storage, Handling, Inspection, and Installation

5.2.1 Storage and Handling

5.2.1.1 Coated pipe to be stored should be protected internally and externally from atmospheric corrosion and coating deterioration.

5.2.1.2 Damage to coating can be minimized by careful handling and by using proper pads and slings.

TABLE 1
Generic External Coating Systems with Material Requirements and Recommended Practices for Application(A)

Generic External Coating System	Reference
Coal Tar	ANSI(B)/AWWA(C) C 203[10]
Wax	NACE Standard RP0375[11]
Prefabricated Films	ANSI/AWWA C 214[12] ANSI/AWWA C 209[13]
Fusion-Bonded Epoxy Coatings	*Peabody's Control of Pipeline Corrosion*[14] ANSI/AWWA C 213[15] API(D) RP 5L7[16] CSA(E)Z245.20M[17] NACE Standard RP0394[18]
Polyolefin Coatings	NACE Standard RP0185[19] DIN(F) 30 670[20] ANSI/AWWA C 215[21]

(A) NOTE: Many other references are available, and this table is not comprehensive. Listing does not constitute endorsement of any external coating system in preference to another. Omission of a system may be due to unavailability of reference standards or lack of data.
(B) American National Standards Institute (ANSI), 1819 L St. NW, Washington, DC 20036.
(C) American Water Works Association (AWWA), 6666 West Quincy Ave., Denver, CO 80235.
(D) American Petroleum Institute (API), 1220 L St. NW, Washington, DC 20005-4070.
(E) CSA International, 178 Rexdale Blvd., Toronto, Ontario, Canada M9W 1R3.
(F) Deutsches Institut fur Normung (DIN), Burggrafenstrasse 6, D-10787 Berlin, Germany.

TABLE 2
References for General Use in the Installation and Inspection of External Coating Systems for Underground Piping

Subject	Reference
Application of Organic Pipeline Coatings	ANSI/AWWA C 203[10] NACE Standard RP0375[11] *Peabody's Control of Pipeline Corrosion*[14] ANSI/AWWA C 213[15] API RP 5L7[16] CSA Z245.20M[17]
Film Thickness of Pipeline Coatings	ASTM(A) G 128[22]
Inspection of Pipeline Coatings	NACE Standard RP0274[23]

(A) ASTM, 100 Barr Harbor Dr., West Conshohocken, PA 19428-2959.

TABLE 3
External Coating System Characteristics Relative to Environmental Conditions(A)

Environmental Factor	Recommended Test Methods(B)
General underground exposure with or without CP	*Peabody's Control of Pipeline Corrosion*[14] ANSI/AWWA C 213[15] API RP 5L7[16] CSA Z245.20M[17] ASTM G 8[24] ASTM G 19[25] ASTM G 42[26] ASTM G 95[27]
Resistance to water penetration and its effect on choice of coating thickness	ASTM G 9[28]
Resistance to penetration by stones in backfill	ASTM G 17[29] ASTM D 2240[30] ASTM G 13[31] ASTM G 14[32]
Soil stress	*Underground Corrosion*[33] ASTM D 427[34]
Resistance to specific liquid not normally encountered in virgin soil	ASTM D 543[35] Federal Test Standard(C) No. 406A, Method 7011[36] ASTM G 20[37]
Resistance to thermal effects	ASTM D 2304[38] ASTM D 2454[39] ASTM D 2485[40]
Suitability of supplementary materials for joint coating and field repairs	ASTM G 8[24] ASTM G 19[25] ASTM G 42[26] ASTM G 95[27] ASTM G 9[28] ASTM G 18[41] ASTM G 55[42]
Resistance to microorganisms	ASTM G 21[43] Federal Test Standard No. 406A, Method 6091[44]

(A) NOTE: Apply only those factors pertinent to the installation.
(B) No specific criteria are available. Comparative tests are recommended for use and evaluation as supplementary information only.
(C) Available from General Services Administration, Business Service Center, Washington, DC 20025.

TABLE 4
External Coating System Characteristics Related to Design and Construction

Design and Construction Factor	Recommended Test Methods[(A)]
Yard Storage, Weathering	ASTM G 11[45]
Yard Storage, Penetration Under Load	ASTM G 17[29] ASTM D 2240[30]
Handling Resistance, Abrasion	ASTM G 6[46]
Handling Resistance, Impact	ASTM G 13[31] ASTM G 14[32]
Field Bending Ability	ASTM G 10[47]
Driving Ability (Resistance to Sliding Abrasion)	ASTM G 6[46] ASTM D 2197[48]
Special Requirements for Mill-Applied Coating	ANSI/AWWA C 203[10] NACE Standard RP0375[11] ANSI/AWWA C 214[12] ANSI/AWWA C 209[13] *Peabody's Control of Pipeline Corrosion*[14] ANSI/AWWA C 213[15] API RP 5L7[16] CSA Z245.20M[17] NACE Standard RP0185[19] DIN 30 670[20] ANSI/AWWA C 215[21]
Special Requirements for Application of Coating Over the Ditch	ANSI/AWWA C 203[10] NACE Standard RP0375[11] ANSI/AWWA C 214[12] ANSI/AWWA C 209[13] *Peabody's Control of Pipeline Corrosion*[14] ANSI/AWWA C 213[15] API RP 5L7[16] CSA Z245.20M[17]
Backfill Resistance	ASTM G 13[31] ASTM G 14[32]
Resistance to Thermal Effects	ASTM G 8[24] ASTM G 19[25] ASTM G 42[26] ASTM G 95[27] ASTM D 2304[38] ASTM D 2454[39] ASTM D 2485[40]
Suitability of Joint Coatings and Field Repairs	*Peabody's Control of Pipeline Corrosion*[14] ANSI/AWWA C 213[15] API RP 5L7[16] CSA Z245.20M[17] ASTM G 8[24] ASTM G 19[25] ASTM G 42[26] ASTM G 95[27] ASTM G 9[28] ASTM G 18[41] ASTM G 55[42]

[(A)] No specific criteria are available. Comparative tests are recommended for use and evaluation as supplementary information only.

TABLE 5
Methods for Evaluating In-Service Field Performance of External Coatings

Title or Subject of Method	Reference	Basis for Rating
(1) Rate of Change in Current Required for CP	*Underground Corrosion*[33]	Comparison of initial current requirement with subsequent periodic determination of current requirement
(2) Inspection of Pipeline Coating	NACE Standard RP0274[23]	(a) With CP: no active corrosion found (b) Without CP: no new holidays showing active corrosion
(3) Cathodic Disbondment	ASTM G 8[24] ASTM G 19[25] ASTM G 42[26] ASTM G 95[27]	Purpose is to obtain data relative to specific conditions for comparison with laboratory data

5.2.2 Inspection

5.2.2.1 Qualified personnel should keep every phase of the coating operation and piping installation under surveillance.

5.2.2.2 Surface preparation, primer application, coating thickness, temperature, bonding, and other specific requirements should be checked periodically, using suitable test procedures, for conformance to specifications.

5.2.2.3 The use of holiday detectors is recommended to detect coating flaws that would not be observed visually. The holiday detector should be operated in accordance with the manufacturer's instructions and at a voltage level appropriate to the electrical characteristics of the coating system.

5.2.3 Installation

5.2.3.1 Joints, fittings, and tie-ins must be coated with a material compatible with the existing coating.

5.2.3.2 Coating defects should be repaired.

5.2.3.3 Materials used to repair coatings must be compatible with the existing pipe coating.

5.2.3.4 The ditch bottom should be graded and free of rock or other foreign matter that could damage the external coating or cause electrical shielding. Under difficult conditions, consideration should be given to padding the pipe or the ditch bottom.

5.2.3.5 Pipe should be lowered carefully into the ditch to avoid external coating damage.

5.2.3.6 Care should be taken during backfilling so that rocks and debris do not strike and damage the pipe coating.

5.2.3.7 Care shall be exercised when using materials such as loose wrappers, nonconducting urethane foam, and rock shield around pipelines as protection against physical damage or for other purposes, because these materials may create an electrical shielding effect that would be detrimental to the effectiveness of CP.

5.2.3.8 When a pipeline comes above ground, it must be cleaned and externally coated, or jacketed with a suitable material, for the prevention of atmospheric corrosion.

5.3 Methods for Evaluating External Coating Systems

5.3.1 Established Systems Proven by Successful Use

5.3.1.1 Visual and electrical inspection of in-service pipeline coatings should be used to evaluate the performance of an external coating system. These inspections can be conducted wherever the pipeline is excavated or at bell holes made for inspection purposes.

5.3.2 Established or Modified Systems for New Environments

5.3.2.1 This method is intended for use when external coating systems will continue to be used and are qualified under Paragraph 5.3.1, but when application will be extended to new environments or when it is desired to revise a system to make use of new developments, one of the following should be used:

5.3.2.1.1 The use of applicable material requirements, material specifications, standards, and recommended practices for application, as given in Table 1, is recommended.

5.3.2.1.2 The use of applicable references in Table 2 is recommended unless previously covered in applicable references in Table 1.

5.3.3 New External Coating System Qualification

5.3.3.1 The purpose of this method is to qualify a new external coating material by subjecting it to laboratory tests appropriate for the intended service. After laboratory tests have been conducted and indicate that the external coating system appears to be suitable, application and installation are conducted in accordance with recommended practices. In-service field performance tests are made to confirm the success of the previous steps. The steps of the method are (1) laboratory tests, (2) application under recommended practices, (3) installation under recommended practices, and (4) in-service field performance tests. If good results are obtained after five years, only Steps 2 and 3 are required thereafter.

5.3.3.1.1 Applicable sections of Tables 3 and 4 are recommended for the initial laboratory test methods.

5.3.3.1.2 Applicable sections of Tables 1 and 2 are recommended for conditional use during Steps 2 and 3.

5.3.3.1.3 During a period of five years or more, the use of the evaluation methods given in Table 5, Item 1 or 2 are recommended. The test method in Item 3 may be used as a supplementary means for obtaining data for correlation with laboratory tests.

5.3.4 Method for Evaluating an External Coating System by In-Service Field Performance Only

5.3.4.1 The purpose of this method is to qualify an external coating system when none of the first three methods given in Paragraph 5.3 has been or will be used. It is intended that this method should be limited to minor pilot installations.

5.3.4.1.1 The use of at least one of the first two methods given in Table 5 is recommended on the basis of at least one investigation per year for five consecutive years.

Section 6: Criteria and Other Considerations for CP

6.1 Introduction

6.1.1 This section lists criteria and other considerations for CP that indicate, when used either separately or in combination, whether adequate CP of a metallic piping system has been achieved (see also Section 1, Paragraphs 1.2 and 1.4).

6.1.2 The effectiveness of CP or other external corrosion control measures can be confirmed by visual observation, by measurements of pipe wall thickness, or by use of internal inspection devices. Because such methods sometimes are not practical, meeting any criterion or combination of criteria in this section is evidence that adequate CP has been achieved. When excavations are made for any purpose, the pipe should be inspected for evidence of corrosion and coating condition.

6.1.3 The criteria in this section have been developed through laboratory experiments or verified by evaluating data obtained from successfully operated CP systems. Situations in which a single criterion for evaluating the effectiveness of CP may not be satisfactory for all conditions may exist. Often a combination of criteria is needed for a single structure.

6.1.4 Sound engineering practices shall be used to determine the methods and frequency of testing required to satisfy these criteria.

6.1.5 Corrosion leak history is valuable in assessing the effectiveness of CP. Corrosion leak history by itself, however, shall not be used to determine whether adequate levels of CP have been achieved unless it is impractical to make electrical surveys.

6.2 Criteria

6.2.1 It is not intended that persons responsible for external corrosion control be limited to the criteria listed below. Criteria that have been successfully applied on existing piping systems can continue to be used on those piping systems. Any other criteria used must achieve corrosion control comparable to that attained with the criteria herein.

6.2.2 Steel and Cast Iron Piping

6.2.2.1 External corrosion control can be achieved at various levels of cathodic polarization depending on the environmental conditions. However, in the absence of specific data that demonstrate that adequate CP has been achieved, one or more of the following shall apply:

6.2.2.1.1 A negative (cathodic) potential of at least 850 mV with the CP 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:

6.2.2.1.1.1 Measuring or calculating the voltage drop(s);

6.2.2.1.1.2 Reviewing the historical performance of the CP system;

6.2.2.1.1.3 Evaluating the physical and electrical characteristics of the pipe and its environment; and

6.2.2.1.1.4 Determining whether or not there is physical evidence of corrosion.

6.2.2.1.2 A negative polarized potential (see definition in Section 2) of at least 850 mV relative to a saturated copper/copper sulfate reference electrode.

6.2.2.1.3 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.

6.2.2.2 Special Conditions

6.2.2.2.1 On bare or ineffectively coated pipelines when long-line corrosion activity is of primary concern, the measurement of a net protective current at predetermined current discharge points from the electrolyte to the pipe surface, as measured by an earth current technique, may be sufficient.

6.2.2.2.2 In some situations, such as the presence of sulfides, bacteria, elevated temperatures, acid environments, and dissimilar metals, the criteria in Paragraph 6.2.2.1 may not be sufficient.

6.2.2.2.3 When a pipeline is encased in concrete or buried in dry or aerated high-resistivity soil, values less negative than the criteria listed in Paragraph 6.2.2.1 may be sufficient.

6.2.2.3 PRECAUTIONARY NOTES

6.2.2.3.1 The earth current technique is often meaningless in multiple pipe rights-of-way, in high-resistivity surface soil, for deeply buried pipe, in stray-current areas, or where local corrosion cell action predominates.

6.2.2.3.2 Caution is advised against using polarized potentials less negative than -850 mV for CP of pipelines when operating pressures and conditions are conducive to stress corrosion cracking (see references on stress corrosion cracking at the end of this section).

6.2.2.3.3 The use of excessive polarized potentials on externally coated pipelines should be avoided to minimize cathodic disbondment of the coating.

6.2.2.3.4 Polarized potentials that result in excessive generation of hydrogen should be avoided on all metals, particularly higher-strength steel, certain grades of stainless steel, titanium, aluminum alloys, and prestressed concrete pipe.

6.2.3 Aluminum Piping

6.2.3.1 The following criterion shall apply: 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 this polarization can be used in this criterion.

6.2.3.2 PRECAUTIONARY NOTES

6.2.3.2.1 Excessive Voltages: Notwithstanding the minimum criterion in Paragraph 6.2.3.1, if aluminum is cathodically protected at voltages more negative than -1,200 mV measured between the pipe surface and a saturated copper/copper sulfate reference electrode contacting the electrolyte and compensation is made for the voltage drops other than those across the pipe-electrolyte boundary, it may suffer corrosion as the result of the buildup of alkali on the metal surface. A polarized potential more negative than -1,200 mV should not be used unless previous test results indicate that no appreciable corrosion will occur in the particular environment.

6.2.3.2.2 Alkaline Conditions: Aluminum may suffer from corrosion under high-pH conditions, and application of CP tends to increase the pH at the metal surface. Therefore, careful investigation or testing should be done before applying CP to stop pitting attack on aluminum in environments with a natural pH in excess of 8.0.

6.2.4 Copper Piping

6.2.4.1 The following criterion shall apply: 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 this polarization can be used in this criterion.

6.2.5 Dissimilar Metal Piping

6.2.5.1 A negative voltage between all pipe surfaces and a stable reference electrode contacting the electrolyte equal to that required for the protection of the most anodic metal should be maintained.

6.2.5.2 PRECAUTIONARY NOTE

6.2.5.2.1 Amphoteric materials that could be damaged by high alkalinity created by CP should be electrically isolated and separately protected.

6.3 Other Considerations

6.3.1 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, provided conditions such as pipe and CP system operating conditions, soil characteristics, and external coating quality remain similar. (Note: Placing the reference electrode next to the pipe surface may not be at the pipe-electrolyte interface. A reference electrode placed at an externally coated pipe surface may not significantly reduce soil voltage drop in the measurement if the nearest coating holiday is remote from the reference electrode location.)

6.3.2 When it is impractical or considered unnecessary to disconnect all current sources to correct for voltage drop(s) in the structure-to-electrolyte potential measurements, sound engineering practices should be used to ensure that adequate CP has been achieved.

6.3.3 When feasible and practicable, in-line inspection of pipelines may be helpful in determining the presence or absence of pitting corrosion damage. Absence of external corrosion damage or the halting of its growth may indicate adequate external corrosion control. The in-line inspection technique, however, may not be capable of detecting all types of external corrosion damage, has limitations in its accuracy, and may report as anomalies items that are not external corrosion. For example, longitudinal seam corrosion and general corrosion may not be readily detected by in-line inspection. Also, possible thickness variations, dents, gouges, and external ferrous objects may be detected as corrosion. The appropriate use of in-line inspection must be carefully considered.

6.3.4 Situations involving stray currents and stray electrical gradients that require special analysis may exist. For additional information, see Section 9, "Control of Interference Currents."

6.4 Alternative Reference Electrodes

6.4.1 Other standard reference electrodes may be substituted for the saturated copper/copper sulfate reference electrode. Two commonly used reference electrodes are listed below along with their voltage equivalent (at 25°C [77°F]) to -850 mV referred to a saturated copper/copper sulfate reference electrode:

6.4.1.1 Saturated KCl calomel reference electrode: -780 mV; and

6.4.1.2 Saturated silver/silver chloride reference electrode used in 25 ohm-cm seawater: -800 mV.

6.4.2 In addition to these standard reference electrodes, an alternative metallic material or structure may be used in place of the saturated copper/copper sulfate reference electrode if the stability of its electrode potential is ensured and if its voltage equivalent referred to a saturated copper/copper sulfate reference electrode is established.

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Section 7: Design of Cathodic Protection Systems

7.1 Introduction

7.1.1 This section recommends procedures for designing CP systems that will provide effective external corrosion control by satisfying one or more of the criteria listed in Section 6 and exhibiting maximum reliability over the intended operating life of the systems.

7.1.2 In the design of a CP system, the following should be considered:

7.1.2.1 Recognition of hazardous conditions prevailing at the proposed installation site(s) and the selection and specification of materials and installation practices that ensure safe installation and operation.

7.1.2.2 Specification of materials and installation practices to conform to the latest editions of applicable codes, National Electrical Manufacturers Association (NEMA)[7] standards, National Electrical Code (NEC),[8] appropriate international standards, and NACE standards.

7.1.2.3 Selection and specification of materials and installation practices that ensure dependable and economical operation throughout the intended operating life.

7.1.2.4 Selection of locations for proposed installations to minimize currents or earth potential gradients, which can cause detrimental effects on foreign buried or submerged metallic structures.

7.1.2.5 Cooperative investigations to determine mutually satisfactory solution(s) of interference problems (see Section 9).

7.1.2.6 Special consideration should be given to the presence of sulfides, bacteria, disbonded coatings, thermal insulating coatings, elevated temperatures, shielding, acid environments, and dissimilar metals.

7.1.2.7 Excessive levels of CP that can cause external coating disbondment and possible damage to high-strength steels as a result of hydrogen evolution should be avoided.

7.1.2.8 When amphoteric metals are involved, care should be taken so that high-pH conditions that could cause cathodic corrosion of the metal are not established.

7.2 Major objectives of CP system design include the following:

7.2.1 To provide sufficient current to the structure to be protected and distribute this current so that the selected criteria for CP are effectively attained;

[7] National Electrical Manufacturers Association (NEMA), 1300 North 17th St., Suite 1752, Rosslyn, Virginia 22209.
[8] National Fire Protection Association, Batterymarch Park, Quincy, MA 02269.

7.2.2 To minimize the interference currents on neighboring underground structures (see Section 9);

7.2.3 To provide a design life of the anode system commensurate with the required life of the protected structure, or to provide for periodic rehabilitation of the anode system;

7.2.4 To provide adequate allowance for anticipated changes in current requirements with time;

7.2.5 To install anodes when the possibility of disturbance or damage is minimal; and

7.2.6 To provide adequate monitoring facilities to test and evaluate the system performance.

7.3 Information Useful for Design

7.3.1 Useful piping system specifications and information include the following:

7.3.1.1 Route maps and atlas sheets;

7.3.1.2 Construction dates;

7.3.1.3 Pipe, fittings, and other appurtenances;

7.3.1.4 External coatings;

7.3.1.5 Casings;

7.3.1.6 Corrosion control test stations;

7.3.1.7 Electrically isolating devices;

7.3.1.8 Electrical bonds; and

7.3.1.9 Aerial, bridge, and underwater crossings.

7.3.2 Useful information on piping system site conditions includes the following:

7.3.2.1 Existing and proposed CP systems;

7.3.2.2 Possible interference sources (see Section 9);

7.3.2.3 Special environmental conditions;

7.3.2.4 Neighboring buried metallic structures (including location, ownership, and corrosion control practices);

7.3.2.5 Structure accessibility;

7.3.2.6 Power availability; and

7.3.2.7 Feasibility of electrical isolation from foreign structures.

7.3.3 Useful information from field surveys, corrosion test data, and operating experience includes the following:

7.3.3.1 Protective current requirements to meet applicable criteria;

7.3.3.2 Electrical resistivity of the electrolyte;

7.3.3.3 Electrical continuity;

7.3.3.4 Electrical isolation;

7.3.3.5 External coating integrity;

7.3.3.6 Cumulative leak history;

7.3.3.7 Interference currents;

7.3.3.8 Deviation from construction specifications; and

7.3.3.9 Other maintenance and operating data.

7.3.4 Field survey work prior to actual application of CP is not always required if prior experience or test data are available to estimate current requirements, electrical resistivity of the electrolyte, and other design factors.

7.4 Types of CP Systems

7.4.1 Galvanic Anode Systems

7.4.1.1 Galvanic anodes can be made of materials such as alloys of magnesium, zinc, or aluminum. The anodes are connected to the pipe, either individually or in groups. Galvanic anodes are limited in current output by the anode-to-pipe driving voltage and the electrolyte resistivity.

7.4.2 Impressed Current Anode Systems

7.4.2.1 Impressed current anodes can be of materials such as graphite, high-silicon cast iron, lead-silver alloy, precious metals, or steel. They are connected with an insulated cable, either individually or in groups, to the positive terminal of a direct-current (DC) source, such as a rectifier or generator. The pipeline is connected to the negative terminal of the DC source.

7.5 Considerations influencing selection of the type of CP system include the following:

7.5.1 Magnitude of protective current required;

7.5.2 Stray currents causing significant potential fluctuations between the pipeline and earth that may preclude the use of galvanic anodes;

7.5.3 Effects of CP interference currents on adjacent structures that may limit the use of impressed current CP systems;

7.5.4 Availability of electrical power;

7.5.5 Physical space available, proximity of foreign structures, easement procurement, surface conditions, presence of streets and buildings, river crossings, and other construction and maintenance concerns.

7.5.6 Future development of the right-of-way area and future extensions to the pipeline system;

7.5.7 Costs of installation, operation, and maintenance; and

7.5.8 Electrical resistivity of the environment.

7.6 Factors Influencing Design of CP Systems

7.6.1 Various anode materials have different rates of deterioration when discharging a given current density from the anode surface in a specific environment. Therefore, for a given current output, the anode life depends on the environment and anode material, as well as the anode weight and the number of anodes in the CP system. Established anode performance data may be used to calculate the probable deterioration rate.

7.6.2 Data on the dimensions, depth, and configuration of the anodes and the electrolyte resistivity may be used to calculate the resultant resistance to electrolyte of the anode system. Formulas and graphs relating to these factors are available in the bibliography literature and from most anode manufacturers.

7.6.3 Design of galvanic anode systems should consider anode-to-pipe potential, electrolyte resisivity, current output, and in special cases, anode lead-wire resistance. A separate design for each anode or anode system may not be necessary.

7.6.4 Galvanic anode performance in most soils can be improved by using special backfill material. Mixtures of gypsum, bentonite, and anhydrous sodium sulfate are most commonly used.

7.6.5 The number of impressed current anodes required can be reduced and their useful life lengthened by the use of special backfill around the anodes. The most common materials are coal coke, calcined petroleum coke, and natural or manufactured graphite.

7.6.6 In the design of an extensive distributed-anode impressed current system, the voltage and current attenuation along the anode-connecting (header) cable should be considered. In such cases, the design objective is to optimize anode system length, anode spacing and size, and cable size in order to achieve efficient external corrosion control at the extremities of the protected structure.

7.6.7 When it is anticipated that entrapment of gas generated by anodic reactions could impair the ability of the impressed current groundbed to deliver the required current, suitable provisions should be made for venting the anodes. For the same current output of the system, an increase in the surface area of the special backfill material or an increase in the number of anodes may reduce gas blockage.

7.6.8 When it is anticipated that electroosmotic effects could impair the ability of the impressed current groundbed to deliver the required current output, suitable provisions should be made to ensure adequate soil moisture around the anodes. Increasing the number of impressed current anodes or increasing the surface area of the special backfill materials may further reduce the electroosmotic effect.

7.7 Design Drawings and Specifications

7.7.1 Suitable drawings should be prepared to designate the overall layout of the piping to be protected and the location of significant items of structure hardware, corrosion control test stations, electrical bonds, electrical isolation devices, and neighboring buried or submerged metallic structures.

7.7.2 Layout drawings should be prepared for each impressed current CP installation, showing the details and location of the components of the CP system with respect to the protected structure(s) and to major physical landmarks. These drawings should include right-of-way information.

7.7.3 The locations of galvanic anode installations should be recorded on drawings or in tabular form, with appropriate notes on anode type, weight, spacing, depth, and backfill.

7.7.4 Specifications should be prepared for all materials and installation practices that are to be incorporated in construction of the CP system.

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Section 8: Installation of CP Systems

8.1 Introduction

8.1.1 This section recommends procedures that will result in the installation of CP systems that achieve protection of the structure. The design considerations recommended in Sections 4 and 7 should be followed.

8.2 Construction Specifications

8.2.1 All construction work on CP systems should be performed in accordance with construction drawings and specifications. The construction specifications should be in accordance with recommended practices in Sections 4 and 7.

8.3 Construction Supervision

8.3.1 All construction work on CP systems should be performed under the surveillance of trained and qualified personnel to verify that the installation is in strict accordance with the drawings and specifications. Exceptions may be made only with the approval of qualified personnel responsible for external corrosion control.

8.3.2 All deviations from construction specifications should be noted on as-built drawings.

8.4 Galvanic Anodes

8.4.1 Inspection, Handling, and Storage

8.4.1.1 Packaged anodes should be inspected and steps taken to ensure that backfill material completely surrounds the anode. The individual container for the backfill material and anode should be intact. If individually packaged anodes are supplied in waterproof containers, the containers must be removed before installation. Packaged anodes should be kept dry during storage.

8.4.1.2 Lead wire must be securely connected to the anode. Lead wire should be inspected for assurance that it is not damaged.

8.4.1.3 Other galvanic anodes, such as the unpackaged "bracelet" or ribbon type, should be inspected to ensure that dimensions conform to

design specifications and that any damage during handling does not affect application. If a coating is used on bands and the inner side of bracelet anode segments, it should be inspected and, if damaged, repaired before the anodes are installed.

8.4.2 Installing Anodes

8.4.2.1 Anodes should be installed according to construction specifications.

8.4.2.2 Packaged galvanic anodes should be backfilled with appropriately compacted material. When anodes and special chemical backfill are provided separately, anodes should be centered in special backfill, which should be compacted prior to backfilling. Care should be exercised during all operations so that lead wires and connections are not damaged. Sufficient slack should exist in lead wires to avoid strain.

8.4.2.3 When anodes in bracelet form are used, external pipe coating beneath the anode should be free of holidays. Care should be taken to prevent damage to the external coating when bracelet anodes are installed. After application of concrete (if used) to pipe, all coating and concrete should be removed from the anode surface. If reinforced concrete is used, there must be no metallic contact between the anode and the reinforcing mesh or between the reinforcing mesh and the pipe.

8.4.2.4 When a ribbon-type anode is used, it can be trenched or plowed in, with or without special chemical backfill as required, generally parallel to the section of pipeline to be protected.

8.5 Impressed Current Systems

8.5.1 Inspection and Handling

8.5.1.1 The rectifier or other power source should be inspected to ensure that internal connections are mechanically secure and that the unit is free of damage. Rating of the DC power source should comply with the construction specification. Care should be exercised in handling and installing the power source.

8.5.1.2 Impressed current anodes should be inspected for conformance to specifications concerning anode material, size, length of lead cable, anode lead connection, and integrity of seal. Care should be exercised to avoid cracking or damaging anodes during handling and installation.

8.5.1.3 All cables should be carefully inspected to detect defects in insulation. Care should be taken to avoid damage to cable insulation. Defects in the cable insulation must be repaired.

8.5.1.4 Anode backfill material should conform to specifications.

8.5.2 Installation Provisions

8.5.2.1 A rectifier or other power source should be installed so that the possibility of damage or vandalism is minimized.

8.5.2.2 Wiring to rectifiers shall comply with local and national electrical codes and requirements of the utility supplying power. An external disconnect switch should be provided in the AC circuit. A rectifier case shall be properly grounded.

8.5.2.3 On thermoelectric generators, a reverse current device should be installed to prevent galvanic action between the anode bed and the pipe if the flame is extinguished.

8.5.2.4 Impressed current anodes can be buried vertically, horizontally, or in deep holes (see NACE Standard RP0572[1]) as indicated in construction specifications. Backfill material should be installed to ensure that there are no voids around anodes. Care should be exercised during backfilling to avoid damage to the anode and cable.

8.5.2.5 The cable from the rectifier negative terminal to the pipe should be connected to the pipe as described in Paragraph 8.6. Cable connections to the rectifier must be mechanically secure and electrically conductive. Before the power source is energized, it must be verified that the negative cable is connected to the structure to be protected and that the positive cable is connected to the anodes. After the DC power source has been energized, suitable measurements should be made to verify that these connections are correct.

8.5.2.6 Underground splices on the header (positive) cable to the groundbed should be kept to a minimum. Connections between the header and anode cables should be mechanically secure and electrically conductive. If buried or submerged, these connections must be sealed to prevent moisture penetration so that electrical isolation from the environment is ensured.

8.5.2.7 Care must be taken during installation of direct-burial cable to the anodes (positive cable) to avoid damage to insulation. Sufficient slack should be left to avoid strain on all cables. Backfill material around the cable should be free of rocks and foreign matter that might cause damage to the insulation when the cable is installed in a trench. Cable can be installed by plowing if proper precautions are taken.

8.5.2.8 If insulation integrity on the buried or submerged header cable, including splices, is not

maintained, this cable may fail because of corrosion.

8.6 Corrosion Control Test Stations, Connections, and Bonds (see Paragraph 4.5)

8.6.1 Pipe and test lead wires should be clean, dry, and free of foreign materials at points of connection when the connections are made. Connections of test lead wires to the pipe must be installed so they will remain mechanically secure and electrically conductive.

8.6.2 All buried or submerged lead-wire attachments should be coated with an electrically insulating material, compatible with the external pipe coating and wire insulation.

8.6.3 Test lead wires should be color coded or otherwise permanently identified. Wires should be installed with slack. Damage to insulation should be avoided and repairs made if damage occurs. Test leads should not be exposed to excessive heat and sunlight. Aboveground test stations are preferred. If test stations are flush with the ground, adequate slack should be provided within the test station to facilitate test connections.

8.6.4 Cable connections at bonds to other structures or across isolating joints should be mechanically secure, electrically conductive, and suitably coated. Bond connections should be accessible for testing.

8.7 Electrical Isolation

8.7.1 Inspection and electrical measurements should ensure that electrical isolation is adequate (see NACE SP0286[5]).

Section 9: Control of Interference Currents

9.1 Introduction

9.1.1 This section recommends practices for the detection and control of interference currents. The mechanism and its detrimental effects are described.

9.2 Mechanism of Interference-Current Corrosion (Stray-Current Corrosion)

9.2.1 Interference-current corrosion on buried or submerged metallic structures differs from other causes of corrosion damage in that the direct current, which causes the corrosion, has a source foreign to the affected structure. Usually the interfering current is collected from the electrolyte by the affected structure from a DC source not metallically bonded to the affected structure.

9.2.1.1 Detrimental effects of interference currents usually occur at locations where the currents transfer between the affected structures and the electrolyte.

9.2.1.2 Structures made of amphoteric metals such as aluminum and lead may be subject to corrosion damage from a buildup of alkalinity at or near the metal surface collecting interference currents.

9.2.1.3 Coatings may become disbonded at areas where voltage gradients in the electrolyte force current onto the affected structure. However, as the external coating becomes disbonded, a larger area of metal may be exposed, which would increase the demand for a CP current. This disbondment may create shielding problems.

9.2.2 The severity of external corrosion resulting from interference currents depends on several factors:

9.2.2.1 Separation and routing of the interfering and affected structures and location of the interfering current source;

9.2.2.2 Magnitude and density of the current;

9.2.2.3 Quality of the external coating or absence of an external coating on the structures involved; and

9.2.2.4 Presence and location of mechanical joints having high electrical resistance.

9.2.3 Typical sources of interference currents include the following:

9.2.3.1 Direct current: CP rectifiers, thermoelectric generators, DC electrified railway and transit systems, coal mine haulage systems and pumps, welding machines, and other DC power systems;

9.2.3.2 Alternating current: AC power systems and AC electrified railway systems; and

9.2.3.3 Telluric current.

9.3 Detection of Interference Currents

9.3.1 During external corrosion control surveys, personnel should be alert for electrical or physical observations that could indicate interference from a foreign source such as the following:

9.3.1.1 Pipe-electrolyte potential changes on the affected structure caused by the foreign DC source;

9.3.1.2 Changes in the line current magnitude or direction caused by the foreign DC source;

9.3.1.3 Localized pitting in areas near or immediately adjacent to a foreign structure; and

9.3.1.4 Damage to external coatings in a localized area near an anode bed or near any other source of stray direct current.

9.3.2 In areas in which interference currents are suspected, appropriate tests should be conducted. All affected parties shall be notified before tests are conducted. Notification should be channeled through corrosion control coordinating committees, when they exist (see NACE Publication TPC 11[8]). Any one or a combination of the following test methods can be used.

9.3.2.1 Measurement of structure-electrolyte potentials with recording or indicating instruments;

9.3.2.2 Measurement of current flowing on the structure with recording or indicating instruments;

9.3.2.3 Development of beta curves to locate the area of maximum current discharge from the affected structure (see Appendix A); and

9.3.2.4 Measurement of the variations in current output of the suspected source of interference current and correlations with measurements obtained in Paragraphs 9.3.2.1 and 9.3.2.2.

9.4 Methods for Mitigating Interference Corrosion Problems

9.4.1 Interference problems are individual in nature and the solution should be mutually satisfactory to the parties involved. These methods may be used individually or in combination.

9.4.2 Design and installation of electrical bonds of proper resistance between the affected structures is a technique for interference control. The bond electrically conducts interference current from an affected structure to the interfering structure or current source.

9.4.2.1 Unidirectional control devices, such as diodes or reverse current switches, may be required in conjunction with electrical bonds if fluctuating currents are present. These devices prevent reversal of current flow.

9.4.2.2 A resistor may be necessary in the bond circuit to control the flow of electrical current from the affected structure to the interfering structure.

9.4.2.3 The attachment of electrical bonds can reduce the level of CP on the interfering structure. Supplementary CP may then be required on the interfering structure to compensate for this effect.

9.4.2.4 A bond may not effectively mitigate the interference problem in the case of a cathodically protected bare or poorly externally coated pipeline that is causing interference on an externally coated pipeline.

9.4.3 CP current can be applied to the affected structure at those locations at which the interfering current is being discharged. The source of CP current may be galvanic or impressed current anodes.

9.4.4 Adjustment of the current output from interfering CP rectifiers may resolve interference problems.

9.4.5 Relocation of the groundbeds of cathodic protection rectifiers can reduce or eliminate the pickup of interference currents on nearby structures.

9.4.6 Rerouting of proposed pipelines may avoid sources of interference current.

9.4.7 Properly located isolating fittings in the affected structure may reduce or resolve interference problems.

9.4.8 Application of external coating to current pick-up area(s) may reduce or resolve interference problems.

9.5 Indications of Resolved Interference Problems

9.5.1 Restoration of the structure-electrolyte potentials on the affected structure to those values that existed prior to the interference.

9.5.2 Measured line currents on the affected structure that show that the interference current is not being discharged to the electrolyte.

9.5.3 Adjustment of the slope of the beta curve to show that current discharge has been eliminated at the location of maximum exposure (see Appendix A).

Section 10: Operation and Maintenance of CP Systems

10.1 Introduction

10.1.1 This section recommends procedures and practices for energizing and maintaining continuous, effective, and efficient operation of CP systems.

10.1.1.1 Electrical measurements and inspection are necessary to determine that protection has been established according to applicable criteria and that each part of the CP system is operating properly. Conditions that affect protection are subject to change. Correspondingly, changes may be required in the CP system to maintain protection. Periodic measurements and inspections are necessary to detect changes in the CP system. Conditions in which operating experience indicates that testing and inspections need to be made more frequently than recommended herein may exist.

10.1.1.2 Care should be exercised in selecting the location, number, and type of electrical measurements used to determine the adequacy of CP.

10.1.1.3 When practicable and determined necessary by sound engineering practice, a detailed (close-interval) potential survey should be conducted to:

(a) assess the effectiveness of the CP system;

(b) provide base line operating data;

(c) locate areas of inadequate protection levels;

(d) identify locations likely to be adversely affected by construction, stray currents, or other unusual environmental conditions; or

(e) select areas to be monitored periodically.

10.1.1.4 Adjustments to a CP system should be accompanied by sufficient testing to assure the criteria remain satisfied and to reassess interference to other structures or isolation points.

10.2 A survey should be conducted after each CP system is energized or adjusted to determine whether the applicable criterion or criteria from Section 6 have been satisfied.

10.3 The effectiveness of the CP system should be monitored annually. Longer or shorter intervals for monitoring may be appropriate, depending on the variability of CP factors, safety considerations, and economics of monitoring.

10.4 Inspection and tests of CP facilities should be made to ensure their proper operation and maintenance as follows:

10.4.1 All sources of impressed current should be checked at intervals of two months. Longer or shorter intervals for monitoring may be appropriate. Evidence of proper functioning may be current output, normal power consumption, a signal indicating normal operation, or satisfactory CP levels on the pipe.

10.4.2 All impressed current protective facilities should be inspected annually as part of a preventive maintenance program to minimize in-service failure. Longer or shorter intervals for monitoring may be appropriate. Inspections may include a check for electrical malfunctions, safety ground connections, meter accuracy, efficiency, and circuit resistance.

10.4.3 Reverse current switches, diodes, interference bonds, and other protective devices, whose failures would jeopardize structure protection, should be inspected for proper functioning at intervals of two months. Longer or shorter intervals for monitoring may be appropriate.

10.4.4 The effectiveness of isolating fittings, continuity bonds, and casing isolation should be evaluated during the periodic surveys. This may be accomplished by electrical measurements.

10.5 When pipe has been uncovered, it should be examined for evidence of external corrosion and, if externally coated, for condition of the external coating.

10.6 The test equipment used for obtaining each electrical value should be of an appropriate type. Instruments and related equipment should be maintained in good operating condition and checked for accuracy.

10.7 Remedial measures should be taken when periodic tests and inspections indicate that CP is no longer adequate. These measures may include the following:

10.7.1 Repair, replace, or adjust components of CP systems;

10.7.2 Provide supplementary facilities in which additional CP is necessary;

10.7.3 Thoroughly clean and properly coat bare structures if required to attain CP;

10.7.4 Repair, replace, or adjust continuity and interference bonds;

10.7.5 Remove accidental metallic contacts; and

10.7.6 Repair defective isolating devices.

10.8 An electrical short circuit between a casing and carrier pipe can result in inadequate CP of the pipeline outside the casing due to reduction of protective current to the pipeline.

10.8.1 When a short results in inadequate CP of the pipeline outside the casing, steps must be taken to restore CP to a level required to meet the CP criterion. These steps may include eliminating the short between the casing and carrier pipe, supplementing CP, or improving the quality of the external coating on the pipeline outside the casing. None of these steps will ensure that external corrosion will not occur on the carrier pipe inside the casing; however, a shorted casing does not necessarily result in external corrosion of the carrier pipe inside the casing.

10.9 When the effects of electrical shielding of CP current are detected, the situation should be evaluated and appropriate action taken.

Section 11: External Corrosion Control Records

11.1 Introduction

11.1.1 This section describes external corrosion control records that will document in a clear, concise, workable manner data that are pertinent to the design, installation, operation, maintenance, and effectiveness of external corrosion control measures.

11.2 Relative to the determination of the need for external corrosion control, the following should be recorded:

11.2.1 Corrosion leaks, breaks, and pipe replacements; and

11.2.2 Pipe and external coating condition observed when a buried structure is exposed.

11.3 Relative to structure design, the following should be recorded:

11.3.1 External coating material and application specifications; and

11.3.2 Design and location of isolating devices, test leads and other test facilities, and details of other special external corrosion control measures taken.

11.4 Relative to the design of external corrosion control facilities, the following should be recorded:

11.4.1 Results of current requirement tests;

11.4.2 Results of soil resistivity surveys;

11.4.3 Location of foreign structures; and

11.4.4 Interference tests and design of interference bonds and reverse current switch installations.

11.4.4.1 Scheduling of interference tests, correspondence with corrosion control coordinating committees, and direct communication with the concerned companies.

11.4.4.2 Record of interference tests conducted, including location of tests, name of company involved, and results.

11.5 Relative to the installation of external corrosion control facilities, the following should be recorded:

11.5.1 Installation of CP facilities:

11.5.1.1 Impressed current systems:

11.5.1.1.1 Location and date placed in service;

11.5.1.1.2 Number, type, size, depth, backfill, and spacing of anodes;

11.5.1.1.3 Specifications of rectifier or other energy source; and

11.5.1.1.4 Cable size and type of insulation.

11.5.1.2 Galvanic anode systems:

11.5.1.2.1 Location and date placed in service;

11.5.1.2.2 Number, type, size, backfill, and spacing of anodes; and

11.5.1.2.3 Wire size and type of insulation.

11.5.2 Installation of interference mitigation facilities:

11.5.2.1 Details of interference bond installation:

11.5.2.1.1 Location and name of company involved;

11.5.2.1.2 Resistance value or other pertinent information; and

11.5.2.1.3 Magnitude and polarity of drainage current.

11.5.2.2 Details of reverse current switch:

11.5.2.2.1 Location and name of companies;

11.5.2.2.2 Type of switch or equivalent device; and

11.5.2.2.3 Data showing effective operating adjustment.

11.5.2.3 Details of other remedial measures.

11.6 Records of surveys, inspections, and tests should be maintained to demonstrate that applicable criteria for interference control and CP have been satisfied.

11.7 Relative to the maintenance of external corrosion control facilities, the following information should be recorded:

11.7.1 Maintenance of CP facilities:

11.7.1.1 Repair of rectifiers and other DC power sources; and

11.7.1.2 Repair or replacement of anodes, connections, wires, and cables.

11.7.2 Maintenance of interference bonds and reverse current switches:

11.7.2.1 Repair of interference bonds; and

11.7.2.2 Repair of reverse current switches or equivalent devices.

11.7.3 Maintenance, repair, and replacement of external coating, isolating devices, test leads, and other test facilities.

11.8 Records sufficient to demonstrate the evaluation of the need for and the effectiveness of external corrosion control measures should be maintained as long as the facility involved remains in service. Other related external corrosion control records should be retained for such a period that satisfies individual company needs.

References

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2. NACE Standard RP0177 (latest revision), "Mitigation of Alternating Current and Lightning Effects on Metallic Structures and Corrosion Control Systems" (Houston, TX: NACE).

3. NACE Standard RP0285 (latest revision), "Corrosion Control of Underground Storage Tank Systems by Cathodic Protection" (Houston, TX: NACE).

4. NACE SP0186 (latest revision), "Application of Cathodic Protection for Well Casings" (Houston, TX: NACE).

5. NACE SP0286 (latest revision), "The Electrical Isolation of Cathodically Protected Pipelines" (Houston, TX: NACE).

6. NACE SP0387 (latest revision), "Metallurgical and Inspection Requirements for Cast Galvanic Anodes for Offshore Applications" (Houston, TX: NACE).

7. NACE SP0188 (latest revision), "Discontinuity (Holiday) Testing of Protective Coatings" (Houston, TX: NACE).

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9. NACE Standard TM0497 (latest revision), "Measurement Techniques Related to Criteria for Cathodic Protection on Underground or Submerged Metallic Piping Systems" (Houston, TX: NACE).

10. ANSI/AWWA C 203 (latest revision), "Standard for Coal-Tar Protective Coatings and Linings for Steel Water Pipelines—Enamel and Tape—Hot Applied" (Washington, DC: ANSI and Denver, CO: AWWA).

11. NACE Standard RP0375 (latest revision), "Field-Applied Underground Coating Systems for Underground Pipelines: Application, Performance, and Quality Control" (Houston, TX: NACE).

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17. CSA Z245.20M (latest revision), "External Fusion Bond Epoxy Coated Steel Pipe" (Toronto, ON: CSA).

18. NACE Standard RP0394 (latest revision), "Application, Performance, and Quality Control of Plant-Applied, Fusion-Bonded Epoxy External Pipe Coating" (Houston, TX: NACE).

19. NACE Standard RP0185 (latest revision), "Extruded Polyolefin Resin Coating Systems with Soft Adhesives for Underground or Submerged Pipe" (Houston, TX: NACE).

20. DIN 30 670 (latest revision), "Polyethylene-Coatings for Steel Pipes and Fittings Requirements and Testing" (Berlin, Germany: DIN).

21. ANSI/AWWA C 215 (latest revision), "Extruded Polyolefin Coatings for the Exterior of Steel Water Pipe Lines" (Washington, DC: ANSI and Denver, CO: AWWA).

22. ASTM G 128 (latest revision), "Standard Guide for Control Of Hazards And Risks In Oxygen Enriched Systems" (West Conshohocken, PA: ASTM).

23. NACE Standard RP0274 (latest revision), "High-Voltage Electrical Inspection of Pipeline Coatings Prior to Installation" (Houston, TX: NACE).

24. ASTM G 8 (latest revision), "Standard Test Method for Cathodic Disbonding of Pipeline Coatings" (West Conshohocken, PA: ASTM).

25. ASTM G 19 (latest revision), "Standard Test Method for Disbonding Characteristics of Pipeline Coatings by Direct Soil Burial" (West Conshohocken, PA: ASTM).

26. ASTM G 42 (latest revision), "Standard Test Method for Cathodic Disbonding of Pipeline Coatings Subjected to Elevated Temperatures" (West Conshohocken, PA: ASTM).

27. ASTM G 95 (latest revision), "Test Method for Cathodic Disbondment Test of Pipeline Coatings (Attached Cell Method)" (West Conshohocken, PA: ASTM).

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Appendix A—Interference Testing

A beta curve is a plot of dynamic (fluctuating) interference current or related proportional voltage (ordinate) versus values of corresponding structure-to-soil potentials at a selected location on the affected structure (abscissa). If the correlation is reasonably linear, the plot will indicate whether the affected structure is receiving or discharging current at the location where the structure-to-soil potential was measured. Dynamic interference investigation involves many beta curve plots to search for the point of maximum interference-current discharge. Interference is resolved when the correlation of maximum current discharge has been changed to a correlation that shows that current pickup is being achieved in the exposure area by the corrective measures taken. These corrective measures may be accomplished by metallic bonding or other interference control techniques.

Appendix B—Method for Determining Probable Corrosion Rate and Costs of Maintaining Service

Maintenance of a piping system may include repairing corrosion leaks and reconditioning or replacing all or portions of the system.

In order to make estimates of the costs involved, it is necessary to determine the probability of corrosion or the rate at which corrosion is proceeding. The usual methods of predicting the probability or rate of corrosion are as follows:

(a) Study of corrosion history on the piping system in question or on other systems of the same material in the same general area or in similar environments. Cumulative leak-frequency curves are valuable in this respect.

(b) Study of the environment surrounding a piping system: resistivity, pH, and composition. Redox potential tests may also be used to a limited extent. Once the nature of the environment has been determined, the probable corrosiveness is estimated by reference to actual corrosion experience on similar metallic structures, when environmental conditions are similar. Consideration of possible environmental changes such as might result from irrigation, spillage of corrosive substances, pollution, and seasonal changes in soil moisture content should be included in such a study.

(c) Investigation for corrosion on a piping system by visual inspection of the pipe or by instruments that mechanically or electrically inspect the condition of the pipe. Condition of the piping system should be carefully determined and recorded each time a portion of the line is excavated for any reason.

(d) Maintenance records detailing leak locations, soil studies, structure-to-electrolyte potential surveys, surface potential surveys, line current studies, and wall thickness surveys used as a guide for locating areas of maximum corrosion.

(e) Statistical treatment of available data.

(f) Results of pressure testing. Under certain conditions, this may help to determine the existence of corrosion.

Appendix C—Contingent Costs of Corrosion

In addition to the direct costs that result from corrosion, contingent costs include:

(a) Public liability claims;

(b) Property damage claims;

(c) Damage to natural facilities, such as municipal or irrigation water supplies, forests, parks, and scenic areas;

(d) Cleanup of product lost to surroundings;

(e) Plant shutdown and startup costs;

(f) Cost of lost product;

(g) Loss of revenue through interruption of service;

(h) Loss of contract or goodwill through interruption of service; and

(i) Loss of reclaim or salvage value of piping system.

Appendix D—Costs of Corrosion Control

The usual costs for protecting buried or submerged metallic structures are for complete or partial CP or for external coatings supplemented with cathodic protection. Other corrosion control costs include:

(a) Relocation of piping to avoid known corrosive conditions (this may include installing lines above ground);

(b) Reconditioning and externally coating the piping system;

(c) Use of corrosion-resistant materials;

(d) Use of selected or inhibited backfill;

(e) Electrical isolation to limit possible galvanic action; and

(f) Correction of conditions in or on the pipe that might accelerate corrosion.

ISBN 1-57590-035-1
NACE International