

Standard Recommended Practice Control of External Corrosion on Offshore Steel Pipelines

The National Association of Corrosion Engineers (NACE) issues this standard in conformance with the best current technology regarding the specific subject. This standard represents a consensus of those individual members who have reviewed this document, its scope, and provisions. It is intended to aid the manufacturer, the consumer, and the general public. Its acceptance does not in any respect preclude anyone, whether he has adopted the standard or not, from manufacturing, marketing, purchasing, or using products, processes or procedures not in conformance with this standard. Nothing contained in this NACE standard is to be construed as granting any right, by implication or otherwise, to manufacture, sell, or use in connection with any method, apparatus, or product covered by Letters Patent, or as indemnifying or protecting anyone against liability for infringement of Letters Patent. This standard represents minimum requirements and should in no way be interpreted as a restriction on the use of better procedures or materials. Neither is this standard intended to apply in all cases relating to the subject. Unpredictable circumstances may negate the usefulness of this standard in specific instances. NACE assumes no responsibility for the interpretation or use of this standard by other parties and accepts responsibility for only those official NACE interpretations issued by NACE in accordance with its governing procedures and policies which preclude the issuance of interpretations by individual volunteers.

Users of this standard are responsible for reviewing appropriate health, safety, and regulatory documents and for determining their applicability in relation to this standard prior to its use. This NACE standard may not necessarily address all safety problems and hazards associated with the use of materials, operations, and/or equipment detailed or referred to within this document.

CAUTIONARY NOTE: NACE standards are subject to periodic review, and may be revised or withdrawn at any time without prior notice. The user is cautioned to obtain the latest edition. NACE requires that action be taken to reaffirm, revise, or withdraw this standard no later than two years from the date of initial publication. Purchasers of NACE standards may receive current information on all standards and other NACE publications by contacting the NACE Publication Orders Department, P.O. Box 218340, Houston, Texas 77218 (telephone 713/492-0535).

Revised September 1988
Approved August 1975
National Association of Corrosion Engineers
P.O. Box 218340
Houston, TX 77218
713/492-0535

Copyright 1988, National Association of Corrosion Engineers

**Standard
Recommended Practice
Control of External Corrosion on
Offshore Steel Pipelines**

Contents

Foreword	1
1. General	1
2. Definitions	1
3. Corrosion Control Design	2
4. Coatings	3
5. Criteria for Cathodic Protection	5
6. Design of Cathodic Protection Systems	6
7. Installation of Cathodic Protection Systems	8
8. Control of Interference Currents	9
9. Operation and Maintenance	11
10. Corrosion Control Records	12

Foreword

The control of external corrosion on offshore pipelines is important to the oil and gas industry because of the need to protect capital investments in manpower and materials, conserve natural resources of oil and gas, and protect the offshore ecology. This NACE standard has been prepared to present procedures and practices for achieving effective control of external corrosion on offshore steel pipelines. No other standards that are based on the experience and expertise of the pipeline industry relating to this topic are available at this time.

This NACE standard is based on the procedures and practices set forth in NACE Standard RP0169-83, "Control of External Corrosion on Underground or Submerged Metallic Piping Systems."⁽¹⁾ However, because of some different procedures and practices and because offshore pipelines cannot always be inspected as readily as

onshore pipelines, this offshore pipeline standard is different from RP0169-83 in several areas.

This standard includes guidelines on external corrosion control design for offshore steel pipelines, including the use of protective coatings and criteria for cathodic protection, the design and installation of cathodic protection systems, control of interference currents, operation and maintenance recommendations, and corrosion control records.

This standard supercedes the original RP0675-75, "Control of Corrosion on Offshore Steel Pipelines," which was prepared by NACE Task Group T-10-2 and approved for publication in August 1975. This 1988 revision is issued by NACE under the auspices of Group Committee T-10 on Underground Corrosion Control and was prepared by Task Group T-10-2, which was composed of representatives from the major oil and gas offshore pipelines, major oil and gas production companies, and representatives from manufacturers and suppliers involved in offshore pipeline corrosion control.

⁽¹⁾ NACE Standard RP0169-83, "Control of External Corrosion on Underground or Submerged Metallic Piping Systems," National Association of Corrosion Engineers (NACE), Houston, TX.

Section 1: General

1.1 This standard presents acknowledged practices for the control of external corrosion on offshore steel pipelines under the following headings:

- Section 2: Definitions
- Section 3: Corrosion Control Design
- Section 4: Coatings
- Section 5: Criteria for Cathodic Protection
- Section 6: Design of Cathodic Protection Systems
- Section 7: Installation of Cathodic Protection Systems
- Section 8: Control of Interference Currents
- Section 9: Operation and Maintenance
- Section 10: Corrosion Control Records

1.2 This standard is intended to serve as a guide for establishing minimum requirements for control of external corrosion on offshore steel pipelines, when the need for corrosion control has been determined by physical, environmental, economic, and other factors.

1.2.1 New piping systems: Corrosion control by the use of coatings, supplemented with cathodic protection or by some other proven method, should be provided in the initial design and should be maintained during the service life of the piping system unless investigations indicate that corrosion control is not required.

1.2.2 Existing coated piping systems: Cathodic protection should be provided and maintained on all existing coated piping systems, unless investigations indicate that cathodic protection 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 should be taken.

1.3 This standard does not designate practices for every specific installation because the complexity of offshore pipeline installations precludes standardizing all external corrosion control practices.

1.4 Deviation from the recommendations of this standard may be warranted in specific situations; however, such deviations should achieve the objectives expressed in this standard.

1.5 This recommended practice does not include corrosion control methods based on the use of electrically conductive coatings.

1.6 Consideration should be given to coating pipe internally for those lines that transport corrosive commodities. See the latest revisions of the following documents: NACE Standard RP0175-75, "Control of Internal Corrosion in Steel Pipelines and Piping Systems"; NAPCA Bulletin 12-83, "Specifications for Mill Applied Fusion-Bonded Epoxy Coatings"; AWWA C213 Standard for Fusion-Bonded Epoxy Coating for the Interior and Exterior of Steel Water Pipelines; and API Recommended Practice for the Fusion Bonded Epoxy Internal Coating of Line Pipe. (See Table 1 for sources of these documents).

1.7 The provisions of this recommended practice 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 professional education and related practical experience, are qualified to practice external corrosion control on offshore steel pipelines. Such persons may be registered professional engineers or persons recognized as being qualified or accredited as corrosion specialists by the National Association of Corrosion Engineers if their professional activities include suitable experience in external corrosion control on offshore steel pipelines.

1.8 For more specific recommendations and performance requirements of applied coatings for buried or submerged pipe and pipe exposed to atmospheric conditions, see Section 4 of this standard.

Section 2: Definitions of Terms Related to Offshore Steel Pipelines

The terms listed below are defined as follows for the purposes of this standard.

Anode: An electrode at which oxidation of its surface or some component of the solution is occurring. Antonym: cathode.

Barrier coating: A protective overcoat applied to prevent damage by handling a weight coating applied to the anti-corrosion coating.

Cathodic disbondment: The loss of the bond force between a



coating and the surface coated caused by products of polarization resulting from cathodic protection.

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

Coating: A dielectric material applied to a steel substrate to separate it from the surrounding environment.

Continuity bond: A metallic connection that provides electrical continuity.

Corrosion: The deterioration of a material, usually a metal, caused by a reaction with its environment.

Current density: The current per exposed unit area.

Disbondment: The loss of the bond between a coating and the surface coated.

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

Electrode potential: The potential of an electrode as measured against a reference electrode. The electrode potential does not include any loss of potential in the solution caused by current passing to or from the electrodes, i.e., it represents the reversible work required to move a unit charge from the electrode surface through the solution to the reference electrode.

Electrolyte: A chemical substance or mixture, usually liquid, containing ions that migrate in an electric field. For the purposes of this recommended practice, electrolyte refers to the soil or liquid adjacent to and in contact with a buried or submerged metallic structure, including the moisture and other chemicals contained therein.

Environment: The circumstances, acts, or conditions to which a steel pipeline is subjected.

Foreign structure: Any metallic structure that is not an intended component of the system of interest.

Galvanic anode: A metal that provides sacrificial protection to another metal that is more noble when coupled in an electrolyte. These anodes are the current source in one type of cathodic protection.

Half-cell reference electrode: See Reference electrode.

Holiday: A discontinuity of coating that exposes the metal surface to the environment.

Impressed current: Direct current supplied by a power source external to the electrode system.

Interference: Any electrical effect on a structure caused by the action of other parties (see Paragraph 8.1.2).

Interference bond: A metallic connection designed to control electrical current interchange between generally isolated metallic

systems in contact with a common electrolyte.

Interference current: A direct current from a source foreign to the affected pipeline.

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

Isolation: See "Electrical isolation."

"J" tube: A conduit that supports and guides one or more pipe risers.

Lead wire: An insulated metallic connecting wire.

Line current: The direct current flowing on a pipeline.

Pipeline: The terms "pipeline," "pipe," or "piping" as used in this document are conduits on the platform, between offshore structures, or between offshore structures and shore.

Platform: An offshore structure used to accommodate pipelines and related appurtenances.

Polarization: The deviation from the open circuit potential of an electrode resulting from the passage of current. In this recommended practice, polarization is considered the change of potential of a metal surface resulting from the passage of current directly to or from an electrolyte.

Reference electrode: A device whose open circuit potential is constant under similar conditions of measurement.

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

Riser: That section of pipeline extending from the ocean floor up the platform.

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

Stray current corrosion: Corrosion resulting from current(s) flowing through paths other than the intended circuit.

Splash zone: The area of pipeline that is intermittently wet and dry because of wave and tidal action.

Structure: A facility in contact with the electrolyte.

Structure-to-electrolyte voltage (also, pipe-to-electrolyte potential): The voltage difference between a submerged metallic structure and a reference electrode in contact with the electrolyte.

Structure-to-structure voltage (also, structure-to-structure potential): The difference in voltage between metallic structures in a common electrolyte.

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

Weight coating: A coating applied to a pipeline to counteract buoyancy.

Section 3: Corrosion Control Design

3.1 Introduction

3.1.1 The purpose of this section is to provide acceptable external corrosion control practices for use in the design of steel pipeline systems for offshore installations.

3.2 Coatings

3.2.1 All steel pipe, valves, and related fittings, whether buried submerged, in the splash zone, or exposed to atmosphere, should be externally coated.

3.2.2 Coatings should perform effectively under the following conditions:

- (a) Attack by marine organisms
- (b) Mechanical damage and stresses
- (c) Weathering
- (d) Cathodic protection
- (e) Operating temperature

3.3 Pipe Risers

3.3.1 Pipe risers should be installed in areas of minimum boat and barge traffic.

3.3.2 Pipe risers installed on the outer portion of platform legs and braces subject to boat damage should be protected by bumper guards or similar devices.

3.3.3 "J" tubes should be internally cleaned to remove weld burn-through and marine and other crustaceous matter prior to installation of coated riser pipe.

3.4 Cathodic Protection

3.4.1 Except as noted in Paragraph 1.2, cathodic protection should be applied to all buried or submerged steel pipelines.

3.4.2 For detailed descriptions and recommendations of various cathodic protection systems, see Sections 5, 6, 7, 8, and 9 of this standard.

3.5 Electrical Isolation

3.5.1 Electrical isolating devices should be installed where electrical isolation is needed for effective corrosion control.

3.5.1.1 Consideration should be given to the external and internal coating and/or lining of electrical isolating devices (see Paragraph 4.4.3.1).

3.5.2 Typical locations where electrical isolating devices may be required are as follows:

- (a) At the junction of dissimilar metals.
- (b) On riser pipe where electrical isolation from platform is desired. Electrical isolation devices for riser pipe should be located above splash zone level and be readily accessible.
- (c) At the onshore termination of the pipeline.

3.5.3 Selection of the electrical isolating device and location of the device should take into consideration:

- (a) External forces that may act on the device (i.e. bending, tension, torsion, wave action).
- (b) Gas or liquid being transported by pipeline.

3.5.4 Special consideration should be given to the selection and use of any electrical isolating device under water.

3.5.5 If the design of an offshore cathodic protection system incorporates electrical isolating flanges or unions, placement of each electrical isolating device in vertical piping will minimize internal shorting caused by accumulation of salts, metallic residue, or other conductive material.

3.5.6 The use of dielectric material in the lining of supporting devices for pipeline boarding or departing structures is necessary where the intent is to isolate these pipelines from the structure and/or each other.

3.6 Auxiliary Installations

3.6.1 To facilitate pipeline internal corrosion control programs, the following installations should be considered (see NACE Standard RP0175-75, "Control of Internal Corrosion in Steel Pipelines and Piping Systems"):

- (a) Access and related fittings adaptable to use of internal monitoring equipment.
- (b) The installation of identifiable markers to serve as location check points during internal monitoring evaluation.
- (c) Access fittings for the insertion of corrosion coupons and/or probes.
- (d) Fittings to permit injection of chemical inhibitors.
- (e) Storage space for inhibitor containers.
- (f) Dehydration facilities.
- (g) Pigging facilities.

Section 4: Coatings (Buried, Submerged, Splash Zone, and Atmospheric)

4.1 Introduction

4.1.1 This section contains recommended practices for the selection, handling, inspection, application, and installation of piping systems coated with electrically insulating materials, weighted materials, or a combination of both, and identifies minimum requirements for testing, evaluating, and selecting coating systems for external corrosion control.

4.1.2 The function of coatings in corrosion control is to isolate from the environment the external surfaces of piping, valves, and fittings that are in buried, submersion, splash zone, or atmospheric service.

4.1.2.1 Coating characteristics to be considered are:

- (a) Ease of application.
- (b) Ease of repair.
- (c) Good adhesion to pipe surface.
- (d) Ability to resist environments to which the coating will be exposed.
- (e) Ability to resist damage from handling, storage, and installation.
- (f) Ability to resist cracking.
- (g) Resistance to disbondment.
- (h) Chemical resistance.

4.1.2.2 Additional characteristics of coatings for buried or submerged piping to be considered are:

- (a) Ability to maintain substantial electrical resistivity with time.
- (b) Resistance to cathodic disbondment.
- (c) Resistance to aging, cold flow, and embrittlement at operating temperatures.
- (d) Specific gravity for negative buoyancy.
- (e) Flexibility to withstand installation stresses.
- (f) Compatibility with weight coatings.

4.1.2.3 Additional characteristics of coatings for splash zone piping to be considered are:

- (a) Ability to maintain substantial electrical resistivity with time.
- (b) Resistance to cathodic disbondment.
- (c) Compatibility with coatings used for mechanical protection.
- (d) Resistance to ultraviolet and infrared radiation.
- (e) Resistance to intermittent salt fog.
- (f) Resistance to mechanical damage.
- (g) Resistance to abrasion.

4.1.2.4 Additional characteristics of coatings for piping subject to atmospheric exposure to be considered are:

- (a) Resistance to ultraviolet and infrared radiation.
- (b) Resistance to intermittent salt fog.
- (c) Compatibility with coatings used for mechanical protection.

4.2 Selection of Coatings

4.2.1 Important factors to be considered when selecting a pipe coating are:

- (a) Environment (buried, submerged, splash zone or atmospheric exposure).
- (b) Method of pipeline installation.
- (c) Depth of water.
- (d) Operating and ambient temperature.
- (e) Length of service.
- (f) Geographic and physical location.
- (g) Size of pipe.
- (h) Handling and storage.
- (i) Cost.
- (j) Design and type of cathodic protection.

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

4.2.2.1 Table 1 is a listing of all applicable references, giving title and sponsoring source. In this table each document is given a reference number for convenient use thereafter.

4.2.2.2 Table 2 is a listing of types of coating systems and the appropriate references for material specifications or recommended practices for application.

4.2.2.3 Table 3 is a list of references for use during installation and inspection, regardless of coating type.

4.2.2.4 Table 4 is a list of coating system characteristics related to environmental conditions. It contains references to suggested laboratory tests for various properties.

4.2.2.5 Table 5 is a list of coating system characteristics related to design and construction, with appropriate suggested laboratory tests for evaluating these properties.

4.2.2.6 Table 6 lists the methods that are useful in field evaluation of coating systems after the pipeline has been installed.

4.2.2.7 Table 7 is a list of the physical properties of neoprene.

4.2.2.8 Table 8 is a list of the physical properties of polyurethane.

4.2.2.9 Table 9 is a list of the physical properties of barrier coatings.

4.3 Handling and Inspection

4.3.1 Handling

4.3.1.1 Damage to coating can be minimized by careful handling, using proper pads and/or slings, and using barrier coatings (see Table 9).

4.3.2 Inspection

4.3.2.1 Qualified personnel should supervise every phase of the coating operation.

4.3.2.2 Surface preparation, primer application, coating thickness, temperatures, bonding cure, product and

other specific requirements should be checked periodically using suitable test procedures for conformance with specifications.

4.3.2.3 The use of holiday detectors is recommended to detect faults that would not be observed visually. These detectors should be operated in accordance with manufacturer's instructions and at voltage levels appropriate to the electrical characteristics of the coating systems.

4.3.2.4 The extent of underwater inspection depends on line size, water depth, and environmental conditions.

4.4 Installation of Coated Pipelines

4.4.1 Careful consideration should be given to the selection of coatings that will withstand the forces involved in the method of laying.

4.4.2 Weight Coatings

4.4.2.1 Care should be exercised to prevent damage from weight coating application over anti-corrosion coatings and/or thermal insulation.

4.4.3 Joints, fittings, and tie-ins should be coated with a material compatible with the pipeline coating.

4.4.3.1 Consideration should be given to the use of specialty coatings in electrical isolating devices with openings exposed to the environment.

4.4.3.2 Consideration should be given to the use of a water sealant compound in the atmospheric environment to prevent water seepage between thicker riser coatings and the pipe.

4.4.4 Coating defects should be repaired with compatible materials.

4.4.5 The pipe should be lowered carefully into the water to avoid coating damage.

4.4.6 Pipe burial methods should be selected to minimize damage to coatings.

4.4.7 Consideration should be given to applying a thick resilient impact and abrasion resistant coating to that portion of the riser pipe in the splash zone area.

4.5 Methods for Evaluating Coating Systems

4.5.1 Method for Evaluating an Established System Proven by Successful Use

4.5.1.1 Coating systems that have given satisfactory service for at least five years should continue to do so in the same environment. Such coating systems may be selected for use under similar conditions. Experience may indicate satisfactory service if no significant current increase attributable to deterioration of the coating system has been required to maintain adequate cathodic protection.

4.5.2 Method for Evaluating an Established or Modified System for New Environments

4.5.2.1 This method is intended for use where coating systems will continue to be used and are qualified under Paragraph 4.5.1 or where application will be extended to

new environments or where a system revision to utilize new developments is desired.

4.5.2.1.1 The use of applicable standards, material requirements, material specifications, and recommended practices for application as given in Table 2 is recommended.

4.5.2.1.2 The use of applicable references in Table 3 is recommended unless previously covered in applicable references in Table 2.

4.5.3 Method for Evaluating a New Coating System by Laboratory Tests and In-Service Field Performance

4.5.3.1 The purpose of this method is to evaluate a new coating material by subjecting it to laboratory tests appropriate for the intended service. After laboratory tests have been conducted and indicate that the coating system appears to be suitable, application and installation are carried out 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 needed thereafter.

4.5.3.1.1 Applicable sections of Tables 4 and 5

are recommended for the initial laboratory test methods.

4.5.3.1.2 Applicable sections of Tables 2 and 3 are recommended for conditional use during steps 2 and 3.

4.5.3.1.3 During a period of five years or more, the use of the evaluation methods given in Table 6 after Item 1, 2, or 3 (or all three) is recommended. In-service field performance tests (see Paragraph 4.5.3.1) may be used as a supplementary means of obtaining relevant data for correlation with laboratory tests.

4.5.4 Method for Evaluating a Coating System by In-Service Field Performance Only

4.5.4.1 The purpose of this method is to evaluate a coating system where none of the first three methods given in Paragraph 4.5.3.1 have been or will be used. This method should be limited to minor pilot installation.

4.5.4.1.1 The use of at least one of the first three methods given in Table 6 is recommended on the basis of at least one investigation per year for five consecutive years.

4.6 Internal Pipe Coatings

4.6.1 Internal pipe coatings should be considered as a means of controlling internal corrosion (see NACE Standard RP0175-75).

Section 5: Criteria for Cathodic Protection

5.1 Introduction

5.1.1 The purpose of this section is to list criteria for cathodic protection that, when complied with either separately or collectively, will indicate if adequate cathodic protection of a steel system in its electrolyte has been achieved.

5.2 General

5.2.1 The objective of using cathodic protection is to control the corrosion of metallic surfaces in contact with electrolytes.

5.2.2 The selection of a particular criterion for achieving the objective in Paragraph 5.2.1 depends, in part, on past experience with similar pipelines and environments wherein the criterion has been used successfully.

5.2.3 The criteria in Paragraph 5.3 have been developed through laboratory experiment or empirically determined by evaluating data obtained from successfully operated cathodic protection systems. It is not intended that indication of protection be limited to these criteria if it can be demonstrated by other means that the control of corrosion has been achieved.

5.2.4 Voltage measurements are to be made with the reference electrode located in the electrolyte as close as practicable to the pipeline. For valid interpretation, consideration shall be given to voltage (IR) drops other than those across the pipeline/electrolyte boundary, the presence of dissimilar metals, and the influence of other structures.

5.2.5 No single criterion for evaluating the effectiveness of cathodic protection has proven satisfactory for all conditions. Often a combination of criteria is needed for a single pipeline.

5.3 Criteria

5.3.1 A negative (cathodic) voltage of at least 0.85 V as measured between the pipeline surface and a saturated copper/copper sulfate reference electrode in contact with the electrolyte. Determination of this voltage is to be made with the protective current applied. (Refer also to Paragraphs 5.2.4, 5.4.1, and 5.6.1.)

5.3.2 A minimum negative (cathodic) voltage shift of 300 mV, produced by the application of protective current. The voltage shift is measured between the pipeline surface and a reference electrode contacting the electrolyte. This criterion of voltage shift applies to pipelines that are not in contact with dissimilar metals.

5.3.3 A minimum negative (cathodic) polarization voltage decay of 100 millivolts measured between the pipeline surface and a reference electrode in contact with the electrolyte. This voltage decay is to be determined by interrupting the protective current and measuring the decay. When the current is initially interrupted, an immediate voltage decrease will occur. The voltage reading after the immediate decrease shall be used as the base reading from which to measure polarization decay.

5.3.4 A net protective current from the electrolyte onto the pipeline surface as measured by an earth current technique.

5.4 Alternative Reference Electrodes

5.4.1 Other reference electrodes may be substituted for the saturated copper/copper sulfate reference electrode. Three commonly used reference electrodes are listed below with their

voltage equivalent to -0.85 V referred to a saturated copper/copper sulfate reference electrode:

5.4.1.1 Saturated KCl calomel reference electrode: -0.78 V.

5.4.1.2 Silver/silver chloride reference electrode in seawater: -0.80 V (adjusted for chloride concentration).

5.4.1.3 High purity zinc reference electrode: +0.25 V.

5.4.2 In addition to these 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 has been established.

5.5 Special Considerations

5.5.1 Conditions sometimes exist wherein a single protection criterion is ineffective or only partially effective. Such conditions

may include elevated temperatures, disbonded coatings, shielding, bacterial attack, oxygen and salinity variations, water velocity and unusual contaminants in the electrolyte.

5.6 Precautionary Notes

5.6.1 In moving water, precautions should be taken to maintain the reference electrode in a stationary position near the pipeline being tested. Significant movement of the reference electrode away from the pipeline, particularly in high resistivity waters, will introduce IR drops into the potential measurement (see Paragraphs 5.2.4 and 5.3.1).

5.6.2 Copper/copper sulfate reference electrodes should be cleaned, flushed, and recharged with fresh saturated solution at least daily during use (see Paragraph 9.2.6).

5.6.3 Indications are that some organisms may affect the stability of all electrodes.

5.6.4 It is important that the reference electrodes used for offshore surveys be specifically designed, built, and maintained for underwater use.

Section 6: Design of Cathodic Protection Systems

6.1 Introduction

6.1.1 The purpose of this section is to recommend procedures and practices for designing offshore steel pipeline cathodic protection systems that will provide effective corrosion control as indicated by satisfying one or more of the criteria listed in Section 5 and exhibit maximum reliability over the designed operating life of such systems.

6.1.2 In the design of an offshore cathodic protection system, considerations should include the following:

6.1.2.1 Recognition of conditions prevailing at the proposed installation site(s) and the selection and specification of materials, equipment, and installation practices that will ensure the safe installation and operation of the cathodic protection system.

6.1.2.2 Specification of materials and installation practices to conform with all applicable codes, regulations, and recommended practices. These may include but not be limited to those issued by the following:

- (a) National Association of Corrosion Engineers (standard recommended practices).
- (b) National Fire Protection Association (National Electrical Code NFPA 70).
- (c) US Coast Guard.
- (d) Minerals Management Service.
- (e) US Department of Transportation.
- (f) US Army Corps of Engineers.
- (g) US Navy.
- (h) Local agencies as applicable.

6.1.2.3 Selection and design of the cathodic protection system for optimum economy of installation, maintenance, and operation.

6.1.2.4 Selection and specification of materials and installation practices that will ensure dependable service throughout the operating life of the cathodic protection system.

6.1.2.5 Selection of a system to minimize excessive protective currents or excessive earth (sea) potential gradients that may have detrimental effects on pipe, coatings, or neighboring buried or submerged metallic structures.

6.1.2.6 Notification of all interested parties in the area of proposed installation during the design period.

6.1.2.7 Cooperative investigations to determine the effects of the proposed cathodic protection system on the systems of others (or their future expansion) and on the proximity to paths of areas of proposed pipeline, well, or platform construction.

6.2 Major Objectives of Offshore Steel Pipeline Cathodic Protection System Design

6.2.1 Deliver sufficient current to the pipeline to be protected and distribute the current so that the selected criteria for cathodic protection are efficiently attained.

6.2.2 Minimize the effects that operation of the proposed system may have on other pipelines or structures.

6.2.3 Provide the anode system with a design life commensurate with the design life of the protected steel pipeline, or provide adequate rehabilitation procedures for the anode system.

6.2.4 Allow for anticipated changes in current requirements both from the standpoint of aging and from additions to the pipeline to be protected.

6.2.5 Placement of all cathodic protection system components where the possibility of disturbances or damage is minimal.

6.3 Information Useful for Offshore Steel Pipeline Cathodic Protection System Design

6.3.1 Pipeline system construction specifications and practices:

- (a) Route maps, alignment sheets, navigation charts, construction "as-built" drawings.
- (b) Construction dates.

- (c) Pipe, fittings.
- (d) Coatings.
- (e) "J" tubes, risers, and clamps.
- (f) Corrosion control test stations, bond boxes, etc.
- (g) Electrical isolating devices.
- (h) Bond locations.
- (i) Foreign pipeline crossings.
- (j) Adjacent facilities.
- (k) Availability of power.
- (l) Installation accessibility.
- (m) Safety requirements.

6.3.2 Pipeline site conditions:

- (a) Existing and proposed cathodic protection systems.
- (b) Possible interference sources (see Section 8).
- (c) Special environmental conditions and regulations.
- (d) Neighboring metallic pipelines and structures, including location, ownership, and corrosion control practices.
- (e) Electrical isolation from foreign pipelines or structures and maintenance of such isolation.
- (f) Water currents and tidal effects.

6.3.3 Field survey data, corrosion test data, and operating experience:

- (a) Protective current requirements to meet applicable criteria.
- (b) Resistivity and temperature of the electrolyte.
- (c) Electrical continuity.
- (d) Electrical isolation.
- (e) Coating integrity.
- (f) Cumulative leak history.
- (g) Interference currents (see Section 8).
- (h) Deviation from construction specifications.
- (i) Chemical analysis of environment.
- (j) Pipe surface temperature.
- (k) Water velocity.
- (l) Other maintenance and operating data.

6.3.4 Completed field survey work prior to actual application of cathodic protection is not always required if previous experience and test data are available for estimating current requirements. Certain aspects of field surveys are necessary, however, to effect an orderly solution to the problem of providing effective cathodic protection of offshore steel pipelines.

6.4 Types of Cathodic Protection Systems for Offshore Steel Pipelines

6.4.1 Galvanic Anode Systems

6.4.1.1 Galvanic anodes may be of such materials as magnesium, zinc, or aluminum. Alloys of these may be obtained in such shapes and sizes as to deliver maximum protection to the specific pipeline network. The method used to attach the anode to the pipeline may be governed by the type and application, but solid electrical continuity must be maintained.

6.4.1.2 The composition of the alloy is critical to the performance of galvanic anodes in seawater, particularly in the case of zinc and aluminum. Only those alloys proven successful for seawater applications should be used.

6.4.1.3 Magnesium anodes are subject to high rates of decomposition in seawater and may not be suitable for applications where frequent replacement is impractical without specific designing.

6.4.1.4 Consideration should be given to conducting periodic checks on quality control during manufacture.

6.4.2 Impressed Current Anode Systems

6.4.2.1 Impressed current anode materials may include high silicon cast iron, lead-silver, platinum, graphite, scrap steel, or magnetite. They are connected with an effectively insulated conductor, either singly or in groups, to the positive terminal of a direct current source such as a rectifier or generator. The pipeline is connected to the negative terminal of the direct current source.

6.4.2.2 Consideration should be given to conducting periodic checks on control during manufacture.

6.5 Considerations Influencing Selection of the Type of Cathodic Protection System for Offshore Steel Pipelines:

6.5.1 The lack of an external power source may preclude the use of an impressed current system.

6.5.2 On offshore steel pipelines where stray currents are not present and where an external power source is available, the magnitude of protective current required is a dominant factor in the selection of a cathodic protection system. The feasibility of protection with galvanic anodes can be established where consideration is given to:

- (a) Resistivity of the electrolyte.
- (b) Current requirements for protection.
- (c) Anode-to-pipe voltage.
- (d) Freedom from mechanical damage in installation, launching, and operation.
- (e) Useful life expectancy of anode material.
- (f) Temperature of electrolyte.

Test data and calculations needed for design should reflect the above considerations.

6.5.3 The physical space available will be determined by the proximity of foreign structures and pipelines and by construction and maintenance factors.

6.5.4 Future developments of the offshore area and future expansions of the pipeline system being protected.

6.6 Factors Determining Anode Current Output, Operating Life, and Efficiency

6.6.1 Various anode materials have different rates of consumption when discharging a given current density from the anode surface in a specific environment. Therefore, for a given current output, the anode life will depend on the anode material, shape and weight and the number of anodes in the cathodic protection system. Established anode performance data may be used to calculate the probable deterioration rate.

6.6.2 Data on the dimensions, depth, and configuration of the anodes and electrolyte resistivities may be used to calculate the resistance-to-electrolyte of the anode system. Formulas and graphs relating to these factors are available in various engineering handbooks (for anode data, see NACE Standard RP0176-83, "Corrosion of Steel Fixed Offshore Platforms Associated with Petroleum Production").

6.6.3 Proper design of a galvanic anode system must consider pipe-to-anode potential with resultant current output and, in special cases, anode lead wire resistance.

6.6.4 Where galvanic anodes are installed individually or in large numbers, there are many situations where it is impractical to design each installation individually. In such cases, the use of statistical techniques is suggested to determine the best anode design that will provide cathodic protection in a high percentage

of installations. Sampling based on a percentage of the total installations can be used to establish the success of such anode designs.

6.6.5 The useful life of impressed current anodes can be extended by one or more of the following, depending on the type of anode selected:

- (a) Encased anodes and suitable entrance provided for anode cable that is both watertight and free of direct strain on cable connection.
- (b) Anode strings suspended from platforms protected by sleeves or chutes capable of withstanding wave action and constructed of a material that is chemically inert. Consideration should be given to the choice of clamps, cables, bolts, plastic rope, and other components of the suspension system.
- (c) Suspended individual anodes or strings may be equipped with winches or other methods of retrieving them for inspection and maintenance as damage prevention measures in adverse weather conditions.
- (d) Anodes and cables on the ocean floor should be buried in the vicinity of structures and also at the physical location of the anode(s). Depth of burial will depend on the type of bottom, traffic anticipated in the area, and water depth. Anodes or cables extending above the mudline of the ocean floor will be vulnerable to dragging anchors, trawls, or nets (Pb or Pb/Ag anodes must not be buried).

6.7 Design Drawings and Specifications

6.7.1 Suitable drawings should be prepared to designate the overall layout of the piping to be protected and the location of significant items of hardware, test stations, bond boxes, electrical isolating devices, and neighboring buried or submerged metallic structures.

6.7.2 Layout drawings should be prepared for each impressed current cathodic protection installation and should show details and the location of its components with respect to the pipeline to be protected and to known landmarks, platforms, benchmarks, or navigation aids. Included with these drawings should be right-of-way information and government permit regulations, assigned numbers, and restrictions.

6.7.3 The locations of galvanic anodes should be recorded on drawings or in tabular form with appropriate notes as to anode type, weight, and spacing.

6.7.4 Specifications should be prepared for all materials and installation practices that are to be incorporated in the construction, inspection, and operation of the cathodic protection system.

6.7.5 Suitable as-built drawings should be prepared during and at the conclusion of installations and should include any deviations from the original design. Such drawings may be made from field notes by the inspector or engineer and should be made a permanent part of the records for such installations.

6.7.6 Details of offshore cathodic protection installations are a significant aid in trouble-shooting and future design; therefore, maintenance of complete records is suggested.

Section 7: Installation of Cathodic Protection Systems

7.1 Introduction

7.1.1 The purpose of this section is to recommend procedures and practices that will result in the installation of cathodic protection systems that achieve protection of the pipeline when the design considerations recommended in Sections 3 and 6 have been followed.

7.1.2 A cathodic protection installation installed onshore to protect an offshore pipeline should comply with NACE Standard RP0169-83, Section 8.

7.2 Construction Specifications

7.2.1 All construction work performed on cathodic protection systems should be done in accordance with construction drawings and specifications. The construction specifications should be in accordance with the recommended practices in Sections 3 and 6.

7.3 Construction Supervision

7.3.1 All construction work performed on cathodic protection systems should be under the supervision of qualified personnel to verify that the installation is in strict accordance with the drawings and specifications. Exceptions will be made only with the approval of qualified personnel responsible for corrosion control.

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

7.4 Galvanic Anodes

7.4.1 Inspection and Handling

7.4.1.1 Galvanic anodes in bracelet or ingot form should be inspected to ensure that dimensions and weight conform to design specifications and that any damage 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, the coating should be repaired before the anodes are installed.

7.4.1.2 Lead wire must be securely connected to the anode. Lead wire should be inspected for damage and all defects repaired.

7.4.1.3 When a separate suspension is used to support the weight of an anode, the suspension system should be inspected for damage and all defects repaired.

7.4.2 Installing Anodes

7.4.2.1 Anodes should be installed according to construction specifications.

7.4.2.2 When anodes are mounted directly on the pipeline, pipe coating beneath the anode should be free of holidays. Care should be taken to prevent damage to the coating when installing anodes. 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.

7.4.2.3 Bracelet anodes should have a minimum of two connections to the pipeline assembly.

7.5.2.1 All galvanic anode installations should be tested to ensure that electrical continuity exists between the anode and the pipeline.

7.5.2.2 When separate suspension is required, care should be exercised when installing a suspended anode to ensure that the lead wire is not in sufficient tension to damage the anode lead wire, its insulation, or connections.

7.5.3 Systems

7.5.3.1 Handling

7.5.3.1.1 The rectifier or other power source should be inspected to ensure that internal connections are mechanically secure and that no damage has occurred during installation. Rating of the direct current power source should comply with construction specifications. Care should be exercised in handling and installing.

7.5.3.1.2 Suspended current anodes should be inspected to ensure compliance to specifications as to correct anode size, length of lead wire, and security of connections. Care should be exercised to avoid damaging the anode during handling and installation.

7.5.3.1.3 The lead wire should be carefully inspected to detect insulation defects and electrical discontinuity. If the lead wire must be repaired or the anode replaced.

7.5.3.2 Provisions

7.5.3.2.1 Rectifiers or other power sources should be installed to minimize possibility of damage, vandalism, or unauthorized entry.

7.5.3.2.2 Connections to rectifiers shall comply with local and national codes or requirements of utility suppliers. An external disconnect switch on AC wiring should be provided. The rectifier case must be properly grounded.

7.5.3.2.3 Thermoelectric generators, a reverse current diode should be installed to prevent galvanic action between the bed and pipe if the flame is extinguished.

7.5.3.2.4 Suspended current anodes should be installed in accordance with construction specifications.

7.5.2.5 The conductor (negative lead wire) should be connected to the pipeline as described in Paragraph 7.6. Conductor connections to the rectifier must be mechanically secure and electrically conductive. Before the power source is energized, it must be verified that the negative conductor is connected to the pipeline to be protected and the positive conductor is connected to the anodes and that the system is free of shorts. After the direct current power source has been energized by authorization of the qualified personnel responsible for corrosion control, suitable measurements should be made to verify that the connections and polarity are correct.

7.5.2.6 Connections between header cable and conductors from anodes should be mechanically secure and electrically conductive. All connections between anode lead wires and header cable should be insulated and sealed to prevent moisture penetration and to ensure electrical isolation from the environment.

7.5.2.7 When installing a suspended anode where separate suspension is required, care should be exercised to ensure that the lead wire is not in sufficient tension to damage the anode lead wire, its insulation or connections.

7.6 Corrosion Control Test Stations, Connections, and Bonds

7.6.1 Installation Provisions

7.6.1.1 Corrosion control test stations and current bonds are not recommended on the submerged portions of offshore pipelines, except in special cases where deemed necessary by qualified personnel responsible for corrosion control.

7.6.1.2 Connections of test lead wires to pipelines above water must be installed so as to be mechanically secure and electrically conductive. Pipe and test lead wires should be clean, dry, free of foreign materials, and properly coated.

7.6.1.3 Conductive connections to other pipelines or across electrical isolating devices should be mechanically secure, electrically conductive, and suitably coated. Bond connections should be accessible for testing.

7.7 Other Considerations

7.7.1 Electrical Isolating Devices

7.7.1.1 Inspection and electrical measurements should ensure that electrical isolation is adequate.

Section 8: Control of Interference Currents

8.1 Introduction

8.1.1 The purpose of this section is to recommend practices for control of interference currents. On pipelines where conventional interference testing is not practical, interference may be tested for and controlled in Section 9 of NACE Standard RP0675-88.

8.1.2 Interference is any electrical effect on the structure caused by the action of other parties.

8.1.1.2 These effects can be innocuous, beneficial, or detrimental and can be caused by alternating and/or direct current.

8.1.1.3 Detectable electrical effects are considered innocuous on a structure where additional corrosion or a safety hazard does not result.

8.1.1.4 Detectable electrical effects are considered beneficial on a structure where corrosion or a safety hazard is reduced.

8.1.1.5 Detectable electrical effects are considered detrimental where corrosion or a safety hazard is increased.

8.1.2 The magnitude of interference is dependent on voltage gradient, resistivity of the electrolyte, and integrity of coating on pipelines.

8.2 Mechanism of Interference Current Corrosion (Stray Current Corrosion)

8.2.1 Interference current corrosion on buried or submerged metallic pipelines and other structures differs from other causes of corrosion damage in that the direct current, which causes the corrosion, has a source foreign to the affected pipelines. Usually, the interfering current is collected from the electrolyte by the affected pipeline from a direct current source not metallurgically bonded to the affected pipeline.

8.2.1.1 Detrimental effects of interference currents usually occur at locations where the currents are discharged from the affected pipeline to the electrolyte.

8.2.1.2 Coatings may become disbonded at the area where voltage gradients in the electrolyte force current onto the affected pipeline. Should the coating become disbonded, a greater area of metal will be exposed. This can increase the demand for cathodic protection current and may create shielding problems.

8.2.2 The severity of corrosion (metal loss) resulting from interference currents depends on magnitude, time and current density, all of which are influenced by the following:

8.2.2.1 Separation and routing of the interfering and affected pipelines.

8.2.2.2 Integrity of the coating or absence of a coating on the pipelines involved.

8.2.2.3 Location and operating level of the interfering current source.

8.2.3 Sources of Interference Currents

8.2.3.1 Constant current--Sources such as cathodic protection rectifiers and thermoelectric generators have essentially constant direct current output.

8.2.3.2 Fluctuating current--Sources such as welding machines and direct current power systems have a fluctuating direct current output.

8.3 Detection of Interference Currents

8.3.1 During corrosion control surveys, personnel should be alert for interference from a nearby source, which could be indicated by electrical or physical observations such as the following:

8.3.1.1 Pipe-to-electrolyte potential changes on the affected pipeline caused by the foreign direct current source.

8.3.1.2 Changes in line current magnitude or direction caused by the foreign direct current source.

8.3.1.3 Localized pitting in areas near or immediately adjacent to a foreign structure.

8.3.1.4 Breakdown of protective coatings in a localized area near an anode bed or near any source of stray direct current.

8.3.2 In areas where interference currents are suspected, appropriate tests should be conducted. The type of test will depend on water depth and accessibility of the pipelines. Any one or a combination of the following test methods can be used:

8.3.2.1 Measurement of pipe-to-electrolyte potentials with recording or indicating instruments.

8.3.2.2 Measurement of current flowing on the pipeline with indicating or recording instruments.

8.3.2.3 Measurement of the variations in current output of the suspected source of interference current and correlation with measurements obtained in Paragraphs 8.3.2.1 and 8.3.2.2.

8.4 General Methods for Resolving Interference Corrosion Problems (It should be understood that each interference problem is unique, and the solution should be mutually satisfactory to the parties involved.)

8.4.1 Prevention of the pick-up or limitation of interfering current through a submerged pipeline.

8.4.2 Removal of the detrimental effects of interfering current from a submerged pipeline by means of a metallic conductor connected to the return (negative) side of the interfering current source.

8.4.3 Counteraction of the effect of interfering current by means of cathodic protection.

8.4.4 Removal or relocation of the interfering current source.

8.5 Specific Methods of Resolving Interference Problems (The methods used will depend on water depth and accessibility of the pipelines in order to conduct valid testing and attach metallic bonds. These methods may be used individually or in combination.)

8.5.1 Design and installation of metallic bonds of proper resistance between the affected structures is a common technique of interference control.

8.5.1.1 A resistor may be necessary in the metallic bond circuit to control the electrical current from the affected to the interfering structure. At the proper bond resistance, the discharge of interfering current from the affected pipeline to electrolyte is stopped.

8.5.1.2 If cathodic protection exists on the interfering structure, the attachment of metallic bonds can reduce the magnitude of protective voltage. Supplementary cathodic protection may then be required on the interfering structure to compensate for this effect.

8.5.1.3 In the case of a cathodically protected bare or poorly coated pipeline that is causing interference on a coated pipeline, a metallic bond may not resolve the problem but may increase the detrimental current discharge. Coating of the bare pipe in the interference area or installing local galvanic anodes on the coated pipe may mitigate the interference effects (see Paragraph 8.5.2).

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

8.5.2 Cathodic protection current can be applied to the affected pipeline at those locations where the interfering current is being

discharged. This discharge will usually occur at locations where the pipelines are in proximity. If galvanic anodes are used to supply this cathodic protection current, they should be placed immediately adjacent to that portion of the affected pipeline that is discharging current.

8.5.3 The use of galvanic anodes instead of an impressed current system for cathodic protection may reduce the interference problem.

8.5.4 Adjustment of the current output from the source may resolve interference problems.

8.5.5 Proper location of groundbeds for impressed current units can reduce or eliminate the pickup of interference current on nearby pipelines.

8.5.6 Careful routing of proposed pipelines may remove sources of interfering current.

8.5.7 Properly located electrical isolating devices in the affected pipeline may reduce or resolve interference problems.

8.5.8 Application of coating to strategic area(s) may reduce or resolve interference problems by decreasing the circuit conductance.

8.6 Methods of Determining That Interference Has Been Resolved

8.6.1 The difficulty in locating the pipeline, making proper electrical contact with the pipeline, and placing the reference electrode in the desired location will limit the use of these methods on most offshore pipelines.

8.6.1.1 Restoration of the pipe-to-electrolyte potentials of the affected structure to the values that existed prior to the interference.

8.6.1.2 Measurement of line currents on the affected pipeline to ensure that interference current is not being discharged to the electrolyte.

8.6.1.3 Neutralization of interference current discharge may be evaluated by use of earth current measurement techniques applied in the electrolyte between the affected pipeline and interfering structures in the area of maximum current discharge.

8.7 Construction Practices That Will Help Minimize Interference Problems

8.7.1 Maintain adequate clearance from all foreign structures.

8.7.2 Maintain a maximum distance between foreign pipelines, structures and cathodic protection rectifier ground beds.

8.7.3 Install all new pipelines with care to minimize coating damage and avoid coating damage on existing pipelines.

Section 9: Operation and Maintenance

9.1 Introduction

9.1.1 The purpose of this section is to provide recommended practices for operation and maintenance of external corrosion control systems. (See NACE Standard RP0175-75 for recommended practices for internal corrosion control).

9.2 Cathodic Protection System

9.2.1 The purpose of this section is to designate procedures and practices for energizing and maintaining continuous, effective, and efficient operation of cathodic protection systems.

9.2.1.1 Electrical measurements and inspections are necessary to determine that protection has been established according to applicable criteria and that each part of the cathodic protection system is operating properly. Conditions that affect protection are subject to change with time. Corresponding changes are required in the cathodic protection system to maintain protection. Periodic measurements and inspection are necessary to detect changes in the cathodic protection system. Conditions may exist where operating experience indicates that surveys and inspections need to be made more frequently than recommended herein, such as following severe storms.

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

9.2.2 A survey should be conducted after each cathodic protection system is energized to determine if it satisfies applicable criteria and operates effectively. This survey should include one or more of the following type of measurements:

- (a) Pipe-to-electrolyte potential (See Paragraph 5.3.1).
- (b) Earth current (See Paragraph 5.3.4).
- (c) Structure-to-structure potential.
- (d) Line current.

9.2.3 Periodic surveys to ensure the continuity of cathodic protection are suggested as follows (the electrical measurements used in the surveys may include one or more of the measurements listed in Paragraph 9.2.2):

9.2.3.1 An annual survey should be conducted where cathodic protection of the piping system is the objective.

9.2.3.2 Where complete periodic surveys are impossible because of inaccessibility, surveys should be made on a sampling basis consistent with accepted engineering principles.

9.2.4 Inspection and tests of cathodic protection facilities should be made to ensure their proper operation and maintenance as follows:

9.2.4.1 All sources of impressed current should be checked at intervals not to exceed two months. Evidence of proper functioning may be current output, normal power consumption, a signal indicating normal operation, or satisfactory electrical condition of the protected piping.

9.2.4.2 Reverse current switches, diodes, and interference bonds, whose failure would jeopardize pipeline protection, should be inspected for proper functioning at intervals not to exceed two months.

9.2.4.3 All impressed current protection facilities should be inspected annually as part of a preventive maintenance program to minimize in-service failure. Inspections

may include a check for electrical shorts, ground connections, meter accuracy, efficiency, and circuit resistance.

9.2.4.4 The effectiveness of electrical isolating devices and continuity bonds should be evaluated during the periodic surveys. This may be accomplished by on-site inspection or by evaluating corrosion test data.

9.2.5 Where practical, pipe that has been exposed and is accessible should be examined for evidence of corrosion. Pipe-to-electrolyte potential measurements taken by divers provide useful data on the level of cathodic protection.

9.2.6 The test equipment used for obtaining each electrical value should be maintained in good operating condition and checked periodically for accuracy. Reference electrodes should be checked frequently for contamination (see Paragraph 5.6.2).

9.2.7 Remedial measures should be taken where periodic surveys and inspections indicate that protection is no longer adequate according to applicable criteria. These measures may include:

9.2.7.1 Repair, replacement, or adjustment of cathodic protection system components.

9.2.7.2 Providing supplementary cathodic protection facilities where additional protection is necessary.

9.2.7.3 Use of coating to increase cathodic protection effectiveness.

9.2.7.4 Repair, replacement, or adjustment of continuity and interference bonds.

9.2.7.5 Removal of accidental metallic contacts.

9.2.7.6 Repair of defective electrical isolating devices.

9.3 Protective Coatings

9.3.1 Where known coating damage jeopardizes pipeline protection, repairs should be made to the fullest extent practical.

9.4 Splash Zone

9.4.1 All risers should be inspected for damage in the splash zone area. Those having no visible damage but having splash zone protection such as vulcanized rubber, concrete, fiberglass reinforced plastic, or alloy sheathing may require the use of additional inspection techniques.

9.4.1.1 The results of these inspections should be recorded and retained.

9.5 Atmospheric

9.5.1 All piping or associated facilities should be inspected and maintained for protection from corrosion.

9.5.2 The results of all periodic surveys and inspection and all remedial action taken as a part of corrosion control programs for the system should be recorded and retained.

Section 10: Corrosion Control Records

10.1 Introduction

10.1.1 The purpose of this section is to describe a system of corrosion control records that will document data pertinent to the design, installation, operation, maintenance, and effectiveness of external corrosion control measures. (See NACE Standard RP0175-75 for information on records for internal corrosion control.)

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

10.2.1 Causes of leaks, breaks, and replacements with appropriate dates and locations.

10.2.2 Inspections detailing condition of pipe and coating.

10.2.3 Records should be maintained on the buried depth and locations of:

- (a) Pipelines.
- (b) Cables.
- (c) Anodes.

10.3 Relative to pipeline design, the following should be recorded:

10.3.1 Coating--generic type, manufacturer, material specifications, and application specifications.

10.3.2 Design and location of electrical isolating devices, test facilities, and details of special corrosion control measures taken.

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

10.4.1 Results of current requirement tests where made.

10.4.2 Interference surveys and design of interference bonds and reverse-current switch installations.

10.4.2.1 Schedule of interference tests and correspondence with parties involved.

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

10.5.1 Installation of cathodic protection facilities

10.5.1.1 Impressed current systems

- (a) Location and date placed in service.
- (b) Type, weight, and spacing of anodes.
- (c) Specifications of direct current source.

10.5.1.2 Galvanic anode systems

- (a) Location and date placed in service.
- (b) Type, size, backfill and spacing of anodes.
- (c) Anode specifications.

10.5.2 Installation of interference bonds and reverse-current switches

10.5.2.1 Details of interference bond installation

- (a) Location and name of company involved.
- (b) Resistance value or other pertinent information.
- (c) Magnitude and polarity of drainage current.
- (d) Location of device.

10.5.2.2 Details of reverse-current switch installation

- (a) Location and name of companies involved.
- (b) Type and rating of switch device.
- (c) Data showing effective operations.
- (d) Location of device.

10.5.2.3 Details of other remedial measures

10.6 Record of surveys, inspections, and tests set forth in Sections 4, 7, 8, and 9 should be maintained to demonstrate that applicable criteria have been satisfied.

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

10.7.1 Maintenance of cathodic protection facilities

10.7.1.1 Repair of direct current source

10.7.1.2 Repair or replacement of anodes, connections, and cable

10.7.2 Maintenance of interference bonds and reverse-current switches

10.7.2.1 Repair and adjustment of interference bonds

10.7.2.2 Repair of reverse-current switches

10.7.3 Maintenance, repair, and replacement of coating, electrical isolating devices, and other corrosion control facilities.

10.8 Records sufficient to demonstrate the evaluation of, need for, and the effectiveness of corrosion control measures should be retained as long as the pipeline remains in service. Other related corrosion control records should be retained for such period as satisfies individual company needs.

TABLE 1 — Index of Coating References

Reference Number	Title	Sources ⁽¹⁾
1	a Standard for Coal-Tar Enamel Protective Coatings for Steel Water Pipe-AWWA-C203	AWWA 831 O-D Committee
	b Tentative Recommended Specifications and Practices for Coal-Tar Coatings for Underground Use	NACE 2G156
	c Synthetic Resin Primer for Coal-Tar Enamel, Research Report No. 8, U.S. Dept. of the Interior, Bureau of Reclamation	U.S. Govt. Printing Office
	d Specifications for Bituminous Saturated Glass Pipe Wrap	NACE 2J162
	e Proposed Standard for 3/16-Inch Thick Pipeline Padding	NACE 2J164
	f Specifications for Fibrous Glass Reinforced Type Underground Pipe Wrap	NACE 2J262
	g Specifications for Asbestos Pipeline Felt	NACE 2J362
	h Method for Lining Lease Production Tanks with Coal Tar Epoxy	NACE RP0372-72
2	a Asphalt Type Protective Coatings for Underground Pipelines—Mastic Systems	NACE 2H257
	b Asphalt Type Protective Coatings for Underground Pipelines—Wrapped Systems	NACE 2H157
	c Extruded Asphalt, Mastic Type Protective Coatings for Underground Pipelines	NACE RP0276-76
	d Asphalt Protective Coatings for Pipelines—Specification Series No. 7, SS-7	The Asphalt Institute
	e Asphalt Type Protective Coatings for Underground Pipelines	NACE 2H158
	f Specifications for Bituminous Saturated Glass Pipe Wrap	NACE 2J162
	g Proposed Standard for 3/16-Inch Thick Pipeline Padding	NACE 2J164
	h Method for Lining Lease Production Tanks with Coal Tar Epoxy	NACE RP0372-72
	i Specifications for Asbestos Pipeline Felt	NACE 2J362
3	a Application and Handling of Wax-Type Protective Coatings and Wrapper Systems for Underground Pipelines	NACE RP0375-75
	b Specifications for Bituminous Saturated Glass Pipe Wrap	NACE 2J162
	c Proposed Standard for 3/16-Inch Thick Pipeline Padding	NACE 2J164
	d Specifications for Fibrous Glass, Reinforced Type Underground Pipe Wrap	NACE 2J262
	e Specifications for Asbestos Pipeline Felt	NACE 2J362
4	a Material Requirements in Prefabricated Plastic Films for Pipeline Coatings	NACE MR0274-74

TABLE 1 — Index of Coating References
(continued)

Reference Number	Title	Sources ⁽¹⁾
	b Specifications for Bituminous Saturated Glass Pipe Wrap	NACE 2J162
	c Proposed Standard for 3/16-Inch Thick Pipeline Padding	NACE 2J164
	d Specifications for Asbestos Pipeline Felt	NACE 2J362
	e AWWA Standard for Tape Coating Systems for the Exterior of Steel Water Pipelines	AWWA C214
	f NAPCA Bulletin 15-83, Plant Applied Tape Coating Application Specification for the Exterior of Steel Pipe	NAPCA 15-83
	g NAPCA Bulletin 14-83, Application of Specifications for Polyolefin Pipe Coating Applied by the Crosshead Extrusion Method or the Side Extrusion Method	NAPCA 14-83
5	a Control of Pipeline Corrosion, pp. 9-18, A. W. Peabody, NACE, Dec. 1967	NACE
	b Application of Organic Coatings to the External Surface of Steel Pipe for Underground Use	NACE RP0275-75
	c NAPCA Bulletin 12-78 Specifications Mill Applied Fusion-Bonded Epoxy Coating	NAPCA 12-78
	d AWWA Standard for Fusion-Bonded Epoxy Coating for the Interior and Exterior of Steel Water Pipelines	AWWA C213
6	a Pipeline Corrosion and Cathodic Protection, pp. 136-145, Marshall E. Parker, Gulf Publishing Co., 1962	Gulf Publishing Company
	b High Voltage Electrical Inspection of Pipeline Coating Prior to Installation	NACE RP0274-74
7	Underground Corrosion, pp. 180-186, Nat. Bureau of Standards Circular 579, April 1957	National Technical Information Service
8	Nondestructive Measurement of Film Thickness of Pipeline Coatings on Steel	ASTM G 12
9	Test for Cathodic Disbonding of Pipeline Coatings	ASTM G 8
10	Test for Water Penetration into Pipeline Coatings	ASTM G 9
11	a Test for Rockwell Hardness of Plastics and Electrical Insulating Materials	ASTM D 785
	b Test for Penetration of Bituminous Materials	ASTM D 5
	c Test for Rubber Property—Durometer Hardness	ASTM D 2240
	d Test Method for Penetration Resistance of Pipeline Coatings (Blunt Rod)	ASTM G 17

TABLE 1 — Index of Coating References
(continued)

Reference Number	Title	Sources ⁽¹⁾
12 a	Underground Corrosion, pp. 134-135, Nat. Bureau of Standards Circular 579, April, 1957 (Out of print, but reproduced as PB-16 8350 Underground Corrosion)	National Technical Information Service
b	Test for Shrinkage Factor of Soils	ASTM D 427
13 a	Test for Resistance of Plastics to Chemical Reagents	ASTM D 543
b	Test for Chemical Resistance of Pipeline Coatings	ASTM G 20
c	Test Method for Resistance of Plastics to Chemical Reagents, Fed. Test Std. No. 406, Method 7011	General Services Administration
14 a	Thermal Evaluation of Rigid Electrical Insulating Materials	ASTM D 2304
b	Recommended Practice for Determining the Effect of Overbaking on Organic Coatings	ASTM D 2454
c	Test for Coatings Designed to be Resistant to Elevated Temperatures During Their Service Life	ASTM D 2485
15 a	Recommended Practice for Determining Resistance of Synthetic Polymeric Materials to Fungi	ASTM G 21
b	Test Method for Mildew Resistance of Plastics by Mixed Culture Method Agar Medium, Fed. Test Std. No. 406, Method 6091	General Services Adm.
c	Military Specification and Test Method for Fungus Resistance, MIL F-8261A (USAF)	U.S. Naval Publication
16	Test for Effects of Outdoor Weathering on Pipeline Coating	ASTM G 11
17	Test for Abrasion Resistance of Pipeline Coatings (Rolling Drum Method)	ASTM G 6
18	Test for the Bendability of Pipeline Coatings	ASTM G 10
19	Test for Adhesion of Organic Coatings	ASTM D 2197
20 a	Test for Impact Resistance of Pipeline Coatings (Limestone Drop Test)	ASTM G 13
b	Test for Impact Resistance of Pipeline Coatings (Falling Weight Test)	ASTM G 14
21 a	Test Method for Joints, Fittings, and Patches in Coated Pipelines	ASTM G 18
b	Standard Method for Pipeline Coatings and Patch Materials Evaluating	ASTM G 55
c	Suggested Procedures for Field Joint Application	NAPCA No. 6-69-5
22 a	Steel Structures Painting Council—Vol. No. 1: Good Painting Practices Vol. No. 2: Systems and Specifications	SSPC

TABLE 1 — Index of Coating References
(continued)

Reference Number	Title	Sources ⁽¹⁾
b	Weight Pipe Coatings—Bulletin	Bredero-Price
c	Paper on Concrete Coating Standards, 1967	ASME
d	Hydraulic Trenching of Submarine Pipeline (H. van Schwartz, Vol. 97, No. TE4, November, 1971)	ASCE
e	Test for Liquid Limit of Soils	ASTM D 423
f	Pipeline Installation Across Inundated Areas, February 1961	ASCE
g	Salt Spray (Fog) Testing	ASTM B 117
h	Standard Test Method for Resistance of Transparent Plastic Materials to Abrasion	ASTM D 1004
i	Strength Properties of Adhesives in Shear by Tension (Metal to Metal)	ASTM D 1002
j	Standard Test Method of Compressive Strength of Cylindrical Concrete Specimens	ASTM C 39

⁽¹⁾Addresses of sources:

American Petroleum Institute (API), 1220 L. Street, N.W., Washington, DC 20005.
 American Society of Civil Engineers (ASCE), 345 E. 47th Street, New York, NY 10017.
 American Society of Mechanical Engineers (ASME), 345 E. 47th Street, New York, NY 10017.
 American Society for Testing and Materials (ASTM), 1916 Race Street, Philadelphia, PA 19103.
 American Water Works Association (AWWA), 2 Park Ave., New York, NY 10016.
 Asphalt Institute, Asphalt Institute Building, College Park, MD 20740.
 Bredero-Price, 250 N. Belt East, Houston, TX 77060.
 General Services Administration, Business Service Center, Washington, DC 20025.
 Gulf Publishing Company, 3301 Allen Parkway, Houston, TX 77019.
 National Association of Corrosion Engineers (NACE), 1440 South Creek Drive, Houston, TX 77084.
 National Association of Pipe Coating Applicators (NAPCA), 717 Commercial National Bank Building Shreveport, LA 71101.
 National Fire Protection Association (NFPA), Batterymarch Park, Quincy, MA 02269.
 National Technical Information Service (NTIS), Springfield, VA 22161.
 Steel Structures Painting Council (SSPC), 4400 Fifth Avenue, Pittsburgh, PA 15213.
 U.S. Government Printing Office, Washington, DC 20402.
 U.S. Naval Publications and Forms Center, 5801 Tabor Road, Philadelphia, PA 19120.

**TABLE 2 — Generic Coating Systems
With Material Requirements and
Recommended Practice for Application**

Item No.	Generic Coating System	References (See Table 1)
1	Coal Tar	1
2	Asphalt	2
3	Wax	3
4	Prefabricated Films	4
5	Thin-Film Coatings	5

Note: Many other references are available and this table is not comprehensive. This listing does not constitute an endorsement of any coating system in preference to another. Omission of a system may be due to unavailability of reference standards or lack of data.

**TABLE 3 — References for General Use
in the Installation and Inspection of
Coating Systems for Underground Piping**

Item No.	Reference	Reference No. (See Table 1)
1	Application of Organic Pipeline Coatings	5
2	Film Thickness of Pipeline Coatings	8
3	Inspection of Pipeline Coatings	6

**TABLE 4 — Coating System Characteristics
Relative to Environmental Conditions**

Item No.	Environmental Factor	Recommended Test Methods ⁽¹⁾ (See Table 1 for References)
1	General underground exposure with or without cathodic protection	9
2	Resistance to water penetration and its effect on choice of coating thickness	10
3	Resistance to penetration by stones in backfill	11
4	Soil stress	12
5	Resistance to specific liquids not normally encountered in virgin soil	13
6	Resistance to thermal effects	14
7	Suitability of supplementary materials for joint coating and field repairs	9, 10, 21
8	Resistance to microorganisms	15

Note: Apply only those factors that are pertinent to the installation.

⁽¹⁾No specific criteria are available. Comparative tests are recommended subject to evaluation as supplementary information.

**TABLE 5 — Coating System Characteristics
Related to Design and Construction**

Item No.	Design and Construction Factor	Recommended Test Methods ⁽¹⁾ (See Table 1 for References)
1	Yard storage, weathering	16
2	Yard storage, penetration under load	11
3	Handling resistance, abrasion	17
4	Handling resistance, impact	20
5	Field bendability	18
6	Driving ability (resistance to sliding abrasion)	19
7	Special requirements for mill-applied coating	1, 2, 3, 4, 5, 9
8	Special requirements for over the ditch application of coating	1, 2, 3, 4, 5, 9
9	Backfill impact resistance	20
10	Resistance to thermal effects	14
11	Suitability of joint coatings and field repairs	9, 10, 21

Note: Apply only those factors that are pertinent to the installation.

⁽¹⁾No specific criteria are available. Comparative tests are recommended subject to evaluation on basis of any tolerable compensating measures that may be required.

**TABLE 6 — Methods for Evaluating
In-Service Field Performance of Coatings**

Item No.	Reference No. (See Table 1)	Title or Subject of Method	Criteria or Basis for Rating
1	7	Rate of change in current required for cathodic protection	Comparison of initial current requirement with subsequent periodic determination of current requirement
2	6	Inspection of pipeline coatings	a. With cathodic protection: no active corrosion found b. Without cathodic protection: no new holidays showing active corrosion
3	9	Cathodic disbondment	Purpose is to obtain data conditions relative to specific conditions for comparison with laboratory data

**TABLE 7 — Physical Properties of
Neoprene for Offshore Risers
(Compounded to Meet ASTM D 2000 3BC
723 Specifications)**

Hardness (Durometer).....	70
Elongation	300%
Ultimate Tensile Strength.....	2321 psi (16,000 kPa)
Modulus (100%)	375 psi (12,600 kPa)
Modulus (300%)	750 psi (5200 kPa)
Tear (Tensile).....	200 lb/in. (36 kg/cm)

**TABLE 8 — Minimum Acceptable
Physical Properties of Polyurethane for
Riser and Splash Zone Coatings**

Solids - (Volume)	100%
Specific Gravity	1.32
Adhesion.....	1500 psi (10,300 kPa)
Impact Resistance	136 ft-lb (19 m/kg)
Tensile Strength	2500 psi (17,200 kPa)
Hardness Shore "D"	57
Bulk Modulus (Compressibility)	4200 psi (29,000 kPa)
Elongation	70%
Temperature Limitations.....	250 F (121 C)

**TABLE 9 — Minimum Acceptable Properties
of Protective Barrier Coatings When Applied
Over Fusion Bonded Epoxy Powders**

Density	Material must not contribute to buoyancy of pipe
Impact resistance	Greater than 160 in. lb (185 cm. kg) per ASTM G 14 modified
Abrasion resistance	1.15 per ASTM D 1044 Taber Abrasion Wear Index using with 1000 g/5000 cycles with CS-35 wheels
Adhesion-cohesion	Adhesion - 500 psi (3400 kPa) Cohesive failed at greater than 400 psi (2757 kPa) per Elcometer Adhesion test
Shear bond	Greater than 600 psi (4100 kPa) per ASTM D 1002 modified
Electrical resistivity	No greater than weight coating (saturated with salt water)
Compressive strength	Greater than 1000 psi (6900 kPa) per ASTM C 39 (28 days). Use Tables 4 and 5 to determine methods for evaluating coating systems.