



Standard Practice

Control of Internal Corrosion in Steel Pipelines and Piping Systems

This NACE International (NACE) standard represents a consensus of those individual members who have reviewed this document, its scope, and provisions. Its acceptance does not in any respect preclude anyone, whether he or she 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 NACE standard are responsible for reviewing appropriate health, safety, environmental, 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 potential health and safety problems or environmental hazards associated with the use of materials, equipment, and/or operations detailed or referred to within this standard. Users of this NACE International standard are also responsible for establishing appropriate health, safety, and environmental protection practices, in consultation with appropriate regulatory authorities if necessary, to achieve compliance with any existing applicable regulatory requirements prior to the use of this standard.

CAUTIONARY NOTICE: NACE standards are subject to periodic review, and may be revised or withdrawn at any time in accordance with NACE technical committee procedures. NACE International requires that action be taken to reaffirm, revise, or withdraw this standard no later than five years from the date of initial publication. The user is cautioned to obtain the latest edition. Purchasers of NACE International standards may receive current information on all standards and other NACE International publications by contacting the NACE International FirstService Department, 1440 South Creek Drive, Houston, Texas 77084-4906 (telephone +1 [281] 228-6200).

Approved 2006-12-01
NACE International
1440 South Creek Drive
Houston, TX 77084-4906
+1 281/228-6200

ISBN 1-57590-208-7
©2006, NACE International

Foreword

The purpose of this NACE standard practice is to describe procedures and practices for achieving effective control of internal corrosion in steel pipe and piping systems in crude oil, refined products, and gas service. Because of the complex nature and interaction between constituents that are found in gas and liquid (e.g., oxygen, carbon dioxide, hydrogen sulfide, chloride, bacteria, etc.), certain combinations of these impurities being transported in the pipeline may affect whether a corrosive condition exists. Identification of corrosive gas and liquid in a pipeline can only be achieved by analysis of operating conditions, impurity content, physical monitoring, or other considerations. Therefore, gas, liquids, and operating conditions must be monitored and evaluated on an individual basis in order to accurately assess the effects of their presence or absence in the pipeline. This standard presents general practices and preferences in regard to control of internal corrosion in steel piping systems. This standard is intended for use by pipeline operators, pipeline service providers, government agencies, and any other persons or companies involved in planning, designing, or managing pipeline integrity.

This standard was prepared by Task Group (TG) 038 on Control of Internal Corrosion in Steel Pipelines and Piping Systems. TG 038 is administered by Specific Technology Group (STG) 35 on Pipeline, Tanks, and Well Casings. This standard is issued by NACE International under the auspices of STG 35.

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 good and is recommended but is not mandatory. The term *may* is used to state something considered optional.

**NACE International
Standard Practice**

Control of Internal Corrosion in Steel Pipelines and Piping Systems

Contents

1. General.....	1
2. Definitions.....	1
3. Structure Design	2
4. Corrosion Detection and Measurement	4
5. Methods for Controlling Corrosion	5
6. Evaluating the Effectiveness of Corrosion Control Methods.....	7
7. Operation and Maintenance of Internal Corrosion Control Systems.....	7
8. Corrosion Control Records.....	9
References.....	9
Appendix A: Typical Gas Quality Specification (Nonmandatory)	11
Appendix B: Publications Providing Information Necessary for Determining the Quantity of Impurities (Nonmandatory).....	12
Appendix C: Impacts of Common Impurities (Nonmandatory)	13

Section 1: General

1.1 This standard presents recommended practices for the control of internal corrosion in steel pipelines and piping systems used to gather, transport, or distribute crude oil, petroleum products, or gas.

1.2 This standard serves as a guide for establishing minimum requirements for control of internal corrosion in the following systems:

- (a) Crude oil gathering and flow lines
- (b) Crude oil transmission
- (c) Hydrocarbon products
- (d) Gas gathering and flow lines
- (e) Gas transmission
- (f) Gas distribution

(g) Storage systems

1.3 This standard does not designate practices for every specific situation because the complexity of pipeline inputs and configurations precludes standardizing all internal corrosion control practices.

1.4 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 or related practical experience, are qualified to engage in the practice of corrosion control and risk assessment on carbon steel piping systems. Such persons may be registered professional engineers or persons recognized as corrosion specialists by organizations such as NACE, or engineers or technicians with suitable levels of experience, if their professional activities include internal corrosion control of buried carbon steel piping systems.

Section 2: Definitions

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

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

Corrosion Inhibitor: A chemical substance or combination of substances that, when present in the environment, prevents or reduces corrosion.

Erosion-Corrosion: A conjoint action involving corrosion and erosion in the presence of a moving corrosive fluid or a material moving through the fluid, leading to accelerated loss of material.

Gas or Liquid: The material being transported through a pipeline.

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

Iron Count: The quantity of iron, usually expressed in parts per million or milligrams per liter, contained in a sample of the liquid that may be indicative of corrosive activity within the equipment that contained the liquid. Some produced

waters contain naturally occurring dissolved iron. This iron is detected when running iron counts in production systems can be mistaken for iron produced by corrosion. The presence of iron in produced water must be viewed along with the other indicators of corrosion to determine whether iron count values are significant. The probable occurrence of corrosion should always be confirmed by equipment inspection, downhole caliper surveys, and review of failure records before parameters for using iron counts as an indicator of corrosion are established.

Manganese Count: The concentration of manganese in iron alloys used in oilfield downhole equipment is typically 0.5 to 1.5%. Therefore, the supposition is that the ratio of manganese to iron in produced water should be about 1:100 if all the iron and manganese result from corrosion and no precipitation has occurred from the water.

Pigging: The operation of transporting a device or combination of devices (scraper, sphere, or flexible or rigid plastic) through a pipeline for the purpose of cleaning, chemical application, inspection, or measurement.

Section 3: Structure Design

3.1 Introduction

3.1.1 The purpose of this section is to provide design considerations that apply to pipelines made of steel used to transport natural and manufactured gas, crude oil, and refined products for the control of internal corrosion. A corrosion specialist should be consulted during pipeline design and construction.

3.2 Pipeline Design

3.2.1 Gas or Liquid Quality

Quality specifications for gas or liquids transported are individually negotiated in contracts between purchasers or pipeline companies and processors/producers. The specification limits can range over wide limits, depending on climatological conditions, end use, and other factors.¹

The amount of each of the components in the gas or liquid stream can significantly affect measurement, operation, pipeline efficiency, and potentially corrosion.

Gas or liquid quality standards are set, in part, to minimize internal corrosion. However, gas or liquid corrosiveness cannot be determined from these standards alone. Industry experience has shown that water and corrosive impurities can unintentionally enter the pipeline due to operational upsets, or accumulate in low spots despite gas or liquid quality monitoring that shows adherence to quality standards. Because of the complex nature and interaction between constituents that are found in gas or liquid (e.g., oxygen, carbon dioxide, hydrogen sulfide, chloride, bacteria, etc.), certain combinations of these impurities being transported in the pipeline may affect whether a corrosive condition exists. Identification of corrosive gas or liquid in a pipeline is achieved by analysis of operating conditions, impurity content, monitoring data, mitigation schemes, and other considerations.

For companies that use many different quality specifications—typically gas and condensate—quality specifications are listed in Appendix A (nonmandatory). Appendix A is described as a typical gas and condensate quality specification.

3.2.1.1 The quality of the gas or liquid to be transported should be determined. Examples of impurities from a corrosion standpoint are:

- (a) Bacteria
- (b) Carbon dioxide (CO₂)
- (c) Chloride (Cl)

- (d) Hydrogen sulfide (H₂S)
- (e) Organic acids
- (f) Oxygen (O₂)
- (g) Solids or precipitates
- (h) Sulfur-bearing compounds
- (i) Water (H₂O)

See Appendix B (nonmandatory) for a list of standards and other publications that provide information on how to determine the quantity of impurity present.

3.2.1.2 Knowledge of the impurity content and gas or liquid composition allows predictions of the magnitude of harmful effects that might result from their presence. See Appendix C (nonmandatory), "Impacts of Common Impurities." Principal harmful effects that should be considered are:

3.2.1.2.1 Physical deterioration of the pipe as a result of thinning, pitting, hydrogen blistering, hydrogen embrittlement, or stress corrosion cracking (SCC).

3.2.1.2.2 Contamination of gas or liquid by corrosion product.

3.2.1.3 If the specified quality of the gas or liquid is such that transportation will result in harmful corrosion of the pipeline system, coordination should be established with the supplier to provide for additional treatment that may reduce the gas or liquid corrosiveness.

3.2.1.4 The designer should consider the cost of additional treatment to reduce corrosiveness of the gas or liquid in relation to the cost of other corrosion mitigation methods such as increased pigging, use of corrosion inhibitors, internal coating of the pipeline, or a combination of these methods.

3.2.1.5 Satisfactory performance of the design requires that the specified quality be maintained and that internal corrosion of the pipeline is minimal.

3.2.2 Flow Velocity

3.2.2.1 Design consideration shall be given to control of flow velocity within a range that minimizes corrosion. The lower limit of the flow velocity range should be that velocity that will keep impurities suspended in the gas or liquids, thereby

minimizing accumulation of corrosive matter within the pipeline.² The upper limit of the velocity range shall be such that erosion-corrosion, cavitation, or impingement attacks are minimal. API⁽¹⁾ 14E includes a section for calculation of erosional velocity in gas/liquid two-phase lines.³

3.2.3 Intermittent Flow

3.2.3.1 Intermittent flow conditions should be avoided when possible. If operating criteria dictate the need for intermittent flow, design consideration should be given to obtaining an operating velocity that will pick up and sweep away water or sediment that accumulates in lower places in the line during periods of no flow or low flow.

3.2.3.2 If water, sediment, or other corrosive contaminants are expected to accumulate in the pipeline, pigs should be used to clean the line. The design should include pig loading and receiving traps. Operating procedures for adequate cleaning shall be developed and implemented.

3.2.4 Line Size Changes

3.2.4.1 Changes in line size diameter should be designed to provide a smooth hydraulic transition, thereby eliminating pockets of altered flow velocity, where corrosive contaminants can collect.

3.2.4.2 Dead ends associated with blind flanges, stubs, laterals, or tie-ins shall be avoided in design. If they are necessary, blow-offs, traps, or drains shall be included in the design so that all accumulated contaminants, including sand, can be periodically removed.

3.2.5 Dehydration and Dewpoint Control

3.2.5.1 If there is no water present on a steel surface, no corrosion should occur, even in the presence of corrosive gases (H₂S, CO₂, and O₂). Hygroscopic salt deposits on the steel surface can cause the formation of an invisible water film on the surface below dewpoint conditions that can cause corrosive attack. When the presence of water in a gas or liquid could cause harmful corrosion during transportation in the pipeline, dehydration should be considered. Dehydration to reduce the dewpoint is often the only measure needed for corrosion control in gas pipelines. The line should be monitored using probes or coupons to detect the presence of corrosive attack (see Paragraph 4.3). If reductions of the water content alone will not control the expected corrosion, other mitigation methods—such as pigging, internal coating, and chemical inhibition—may be used in

conjunction with dehydration to provide adequate corrosion control.

3.2.6 Deaeration

3.2.6.1 The pipeline system should be designed to eliminate any air entry. The presence of oxygen in a gas or liquid can cause corrosion during transportation in the pipeline. Deaeration of gas or liquid to reduce its oxygen content to an acceptable level shall be considered (see Paragraph 5.3.2). If removal or reduction of oxygen alone does not control the corrosion, other mitigation methods such as use of corrosion inhibitor or internal coatings (see Paragraph 5.5) may be used in conjunction with deaeration to provide adequate corrosion control.

3.2.7 Chemicals

3.2.7.1 When the addition of chemicals such as corrosion inhibitors, oxygen scavengers, or biocides are used to mitigate corrosion, design shall include facilities adequate for treatment of the pipeline or facility (see Paragraph 5.4).

3.2.7.2 The following information for each chemical used shall be on hand:

- (a) Material safety data sheet (MSDS),
- (b) Technical data sheet, and
- (c) Data on corrosiveness of the chemical toward materials of construction and sealing materials.

3.2.8 Internal Coatings

3.2.8.1 When a corrosion problem is anticipated, internal coatings may be considered (see Paragraph 5.5). In some cases, such applications leave the circumferential weld area bare. Additional corrosion mitigation methods such as chemical inhibitors should be used for protection of these areas, as well as bare areas resulting from coating holidays.

3.2.9 Monitoring Facilities

3.2.9.1 In design of pipelines handling corrosive commodities, and especially when chemicals will be used for purposes of corrosion control, strategically located corrosion monitoring facilities should be installed for determining gas or liquid corrosiveness and evaluating effectiveness of corrosion mitigation methods.^{4,5} Monitoring facilities may include pipe spools, gas or liquid perturbation methods (field signature), or hydrogen probes. Details of various monitoring methods are

⁽¹⁾ American Petroleum Institute (API), 1220 L St. NW, Washington, DC 20005.

samplers, weight loss corrosion coupons, corrosion rate measuring probes, potential presented in NACE Publication 3T199.⁶ Designs may include provisions for monitoring corrosion through the use of in-line inspection (ILI) tools, and the pipeline should be designed to permit free passage of these ILI tools. Design features that should be considered include pipeline bends, valves, and traps. See NACE Standard RP0102⁷ for information on design considerations.

3.2.9.2 Differences in pressure, temperature, and the concentration of water and other corrosives between the monitoring location and other locations of interest in the pipeline must be considered in locating monitoring facilities and evaluating their results. In-line filters should be installed in front of pressure control and measurement equipment to protect them from solid particles transported in the gas or liquid.

Section 4: Corrosion Detection and Measurement

4.1 Introduction

4.1.1 This section describes methods of determining the presence of internal corrosion in piping systems, the degree to which it has progressed, and the cause of the corrosive condition.

4.1.2 For pipelines that normally carry dry products but may suffer from short-term upsets of liquid water (or other electrolyte), internal corrosion is most likely to occur where water accumulates (e.g., at the bottom of inclines). Predicting locations of water accumulation may serve as a method for targeting local examinations (e.g., inspection, monitoring, and sampling).⁸

4.2 Visual Inspection

4.2.1 If a piping system is opened to allow visual access to the inside of the system, observations shall be conducted by qualified personnel to determine the following:

4.2.1.1 Evidence of corrosion on internal pipe surfaces. Types of damage should be identified (e.g., etching, pitting, and elongation of attack) to characterize the type of corrosion.

4.2.1.2 Measurement of wall thickness in the most deeply corroded areas if corrosion damage does exist.

4.2.1.3 Circumferential and longitudinal extent of corrosion on the pipe surface or any discernible pattern of attack.

4.2.1.4 Position of attack with respect to the horizontal at the corroded section and with respect to the elevation of adjacent pipe sections.

4.2.1.5 Existence of deposits and corrosion under the deposits. A sample of the deposit shall be obtained for analysis.

4.3 Coupons and Probes (see also Paragraph 6.2)

4.3.1 The use of properly located coupons and probes can be an effective method for determining the existence, rate, and type of internal corrosion. Procedures for preparing, installing, and analyzing metallic corrosion coupons or other monitoring devices can be found in NACE Standard RP0775⁴ and ASTM⁽²⁾ G 1.⁹

4.3.1.1 Coupons and probes are installed in the gas or liquid to simulate the internal surface exposed.

4.3.1.2 The exposure time for coupons and probes in the stream is based on the type of gas or liquid, velocity of its flow, objective of the survey, and the expected corrosion rates. Part 192-477 of the U.S. Code of Federal Regulations, Title 49 states, "If corrosive gas is being transported, coupons or other suitable means must be used to determine the effectiveness of the steps taken to minimize internal corrosion. Each coupon or other means of monitoring internal corrosion must be checked two times each calendar year, but with intervals not exceeding seven and a half months."¹⁰

4.3.1.3 Coupon or probe results may be more difficult to interpret when coupons or probes are installed in systems in which the gas or liquid contains sufficient amounts of paraffin or other insoluble materials that may deposit on the coupon.

4.3.1.4 Coupons or probes using various techniques (NACE Publication 3T199⁶) of operation and installation are used for periodic and continuous results.

4.3.1.5 Intrusive coupons or probes would prevent pigging of a pipeline segment.

⁽²⁾ ASTM International (ASTM), 100 Barr Harbor Dr., West Conshohocken, PA 19428-2959.

4.4 Sampling and Chemical Analysis

4.4.1 Representative samples should be taken when they can be used to determine the iron count, manganese count, pH, and concentrations of significant corrosive constituents in the gas or liquid and for performance tests.

4.4.1.1 Samples shall be taken only by experienced personnel or by those who have been instructed in the proper procedures.

4.4.1.2 Clean valves, spigots, containers, and sampling environment are necessary for taking dependable samples.

4.4.1.3 If liquid water is present in the system, analyses may be made for CO₂, H₂S, bacteria, acids, and other corrosive constituents.^{11,12} Analysis of CO₂ and H₂S should be made in the gaseous phase. See Appendix B for methods of analysis for each of the preceding.

4.4.1.4 Analyses to determine other undesirable compounds in the gas or liquid, such as those that cause scaling and plugging, may be made periodically.

4.4.1.5 The frequency and comprehensiveness of chemical analysis of any gas or liquid should be determined by the variations and quantities of the gases or liquids in the pipeline system.

4.5 ILI Tools

4.5.1 ILI tools may be employed for detecting corrosion damage. Refer to NACE Standard RP0102⁷ for information on these tools.

4.5.1.1 Correlation between corrosion indications on the log and actual distances on the ground is vital to enable exact determination of corrosion sites.

4.5.1.2 Verification is necessary to confirm the accuracy of the inspection.

4.6 Pressure Drop Measurements

4.6.1 Changes in pressure drop measurements across a given segment of a pipeline can be indications of corrosion or deposit accumulations and shall be investigated.

Section 5: Methods for Controlling Internal Corrosion

5.1 Introduction

5.1.1 This section describes accepted practices for the control of internal corrosion in steel pipelines and piping systems.

5.1.2 If past experience has shown that the products being transported, particularly in distribution piping, are not corrosive to the system, some or all of these considerations may be rejected.

5.2 Line Cleaning

5.2.1 Cleaning pigs are used to improve and maintain internal pipe cleanliness by removing contaminants and deposits within the pipe. Periodic line cleaning with pigs can be used in conjunction with other corrosion mitigation measures such as chemical inhibition or dehydration. Some corrosive situations that can be remedied at least in part by pigging include:

5.2.1.1 Water and other fluids that settle out of the transported gas or liquid due to insufficient flow velocity for entrainment, intermittent flow, or pressure/temperature-related solubility changes. These fluids can contain oxygen, H₂S, CO₂, salts, acids, and other corrosives.

5.2.1.2 Loose sediment, including corrosion products, scale, sand, and dirt, that may promote

formation of local corrosion cells on the pipe's bottom quadrant, especially in conjunction with conditions in Paragraph 5.2.1.1.

5.2.1.3 Corrosion products, wax, or other solid deposits adhering to the pipe wall that can shield actively corroding areas, thereby limiting effectiveness of other corrosion mitigation measures, such as chemical inhibition.

5.2.2 A variety of pig designs with differing degrees of line cleaning capability are available. Some have spring-loaded steel knives, wire brushes, or abrasive grit surfaces for removal of adhering contaminants. Others are semi-rigid, nonmetallic spheres. In addition, flexible foam pigs can traverse line pipe of different sizes and can pass through short radius bends.

5.2.3 The choice of pig type depends on the following:

- (a) Ability of pig to remove contaminants present
- (b) Ability to traverse pipe segment
- (c) Compatibility of materials of construction with gas or liquid
- (d) Feasibility of its use from an operations standpoint. Possible problems may exist when a pig is run in a line that has any quill, probe, coupon, or

SP0106-2006

anything that protrudes into the line that could interfere with the pig.

(e) Presence of corrosion inhibitor films or plastic coatings

5.3 Removal of Corrosive Constituents from the Gas or Liquid

5.3.1 Dehydration of the gas or liquid being transported can be used when water is present in amounts sufficient to cause corrosion problems.

5.3.1.1 Free water associated with crude oil and products may be removed by settling out at storage locations or by using water separators, coalescers, or sand filters.

5.3.1.2 Water associated with gas can be removed at various locations in the system by water separators, refrigeration, or dehydrators of various types (glycol or dry desiccant). Dewpoint control can be used to prevent the formation of free water in the system.

5.3.2 Deaeration can be used to remove oxygen in the commodity. In conjunction with deaeration, the entire pipeline system should be searched for points at which air may enter or otherwise contact the liquid. Careful equipment design is important to ensure that air does not enter the system.

5.3.2.1 Oxygen-scavenging chemicals such as alkaline sulfites or vacuum deaeration can be used to lower the oxygen content of the commodity to suitable levels.^{13,14} Effectiveness of oxygen-scavenging chemicals is often limited in the presence of H₂S.

5.3.3 Other corrosive constituents, such as acid gases (H₂S, CO₂, and low-molecular-weight organic acids, e.g., acetic and propionic acids) can be removed from the gas or liquid by acid gas strippers and scrubbers.

5.4 Corrosion Inhibition

5.4.1 Addition of corrosion inhibitors should be considered a corrosion mitigation measure when corrosive gases or liquids are transported.

5.4.2 Numerous types and formulations of corrosion inhibitors—each with various chemical, physical, and handling characteristics—are commercially available. A corrosion inhibitor package contains one or more inhibitors, surfactants, and solvents. The inhibitor can be classified as anodic, cathodic, or both.^{15,16} Inhibitors containing phosphorous (e.g., phosphate esters or phosphonates) are anionic and used to mitigate corrosiveness of low ppm levels of oxygen. Cationic inhibitors containing nitrogen and carrying a positive charge (e.g., amine-containing compounds) are used to mitigate H₂S and CO₂ corrosion. Nitrogen-

containing compounds with long carbon chains (e.g., imidazolines) can act as a cathodic and anodic inhibitor. The inhibitor should be soluble in the liquid being transported to ensure the inhibitor can get to the area where it is needed. In predominantly dry gas systems, the inhibitor should be applied as a batch treatment between two pigs.

5.4.3 Of foremost importance in choosing a corrosion inhibitor is a firm understanding of the corrosion problem and its cause. The choice further depends on compatibility with the gas or liquid and other additives, ease of handling and injection, and possible adverse effects on downstream processes.

5.4.4 Laboratory tests, field tests, industry experience, and inhibitor manufacturer's recommendations can be useful for screening inhibitors as to their effectiveness, degree of solubility, compatibility, or required injection rates.^{17,18,19,20,21}

5.4.5 To increase inhibitor effectiveness, consideration should be given to the use of other corrosion mitigation procedures, such as line cleaning or dehydration, in conjunction with the inhibition program.

5.5 Internal Coating or Lining

5.5.1 Internal coating of pipelines should be considered as an internal corrosion control measure. Internal coatings should also be considered for selected areas, such as in-station manifold piping or small-diameter gathering lines, where it is not feasible or economical to use other corrosion control measures.

5.5.2 The coating should have suitable resistance to attack by the gas or liquid being transported, as well as by any contaminants, corrosives, or additives contained in it. The quality of the transported gas or liquid should not be compromised.

5.5.3 Coatings and linings such as epoxies, cement or concrete, plastics, or metallic compounds can be used for selected applications.

5.5.4 Internal coating can be accomplished joint-by-joint at a coating plant, or by coating entire line segments in place. Regardless of where coating takes place, coating performance is dependent on suitable pipe cleaning and surface preparation as well as use of proper application procedures.^{22,23}

5.5.5 Plant-applied internal coatings can be electrically inspected; however, verification of in-place coating integrity is not usually feasible. Spot checks by cutting coupons or removing test spools are often used for this purpose.²⁴ When a holiday-free coating cannot be guaranteed and aggressive corrosive service is anticipated, additional corrosion mitigation measures, such as chemical inhibition, may be required to control internal corrosion adequately.

Section 6: Evaluating the Effectiveness of Corrosion Control Methods

6.1 Introduction

6.1.1 This section recommends multiple techniques to be used to evaluate the effectiveness of corrosion control methods in a pipeline system. Some of the methods used to evaluate the effectiveness of corrosion control measures may be the same methods used for corrosion detection (see Section 4).

6.2 Coupons and Probes (see also Paragraphs 4.3 and 3.3.9.1)

6.2.1 Coupons and probes can be used to determine the effectiveness of corrosion control methods employed.

6.2.2 Coupons and probes should be positioned at points within the system to provide meaningful corrosion-related measurements.

6.2.3 Coupons and probes that are used should provide representative and reproducible measurements for the particular application.

6.2.4 Coupon or probe results can be useful for determining time-related changes in corrosive conditions. The results can be used to identify changes in the corrosiveness of gas or liquid due to changes in operating parameters or chemical treatment programs. Procedures for preparing, installing, and analyzing metallic corrosion coupons or other monitoring devices can be found in NACE Standard RP0775.4

6.2.5 The exposure time for coupons and probes is based on the type of gas or liquid, velocity of its flow, and the expected corrosion rates. Part 192-477 of the U.S. Code of Federal Regulations, Title 49 states, "If corrosive gas is being transported, coupons or suitable means must be used to determine the effectiveness of the steps taken to minimize internal corrosion. Each coupon or other means of monitoring internal corrosion

must be checked two times each calendar year, but with intervals not exceeding seven and a half months."¹⁰

6.3 Sampling and Chemical Analysis (see also Paragraph 4.4 for additional direction regarding sampling and analysis)

6.3.1 Gas or liquid sampling can be used to determine a change in the corrosive medium being transported in the pipeline system.

6.3.1.1 Gas or liquid sampling should be performed at regular periods.

6.4 Visual Inspection (see also Paragraph 4.2)

6.4.1 Visual inspection of solid contaminants may be used to monitor protection effectiveness.

6.4.2 Changes in volume or weight of corrosion products removed from filters and traps can indicate variations in corrosion prevention.

6.5 Physical Methods

6.5.1 Periodic monitoring (magnetic, electronic, ultrasonic, or radiographic) may be helpful on some pipeline systems.

6.5.1.1 Adequate knowledge of the diameter, length, joint type, age, and location of the pipeline system is necessary to determine the appropriate method to be used.

6.5.1.2 Subsequent measurements shall be made at the same location. This does not preclude the incorporation of additional locations where future periodic measurements may be made.

6.5.2 Pressure-drop measurements on the same segment of pipeline can be used to monitor the effectiveness of the corrosion control program.

Section 7: Operation and Maintenance of Internal Corrosion Control Systems

7.1 Introduction

7.1.1 This section provides practices for operation and maintenance of internal corrosion prevention systems.

7.2 Line Cleaning (see Paragraph 5.2)

7.2.1 Any pig inserted into a pipeline shall be clean and in good repair.

7.2.2 Pigging frequency should be adequate to remove contaminants before internal pipe damage occurs due to corrosion.

7.2.3 Routine observations of type and amount of contaminants removed shall be made to evaluate efficiency of pigging. Changes in pig type and frequency used shall be made to accomplish desired pipe cleanliness.

SP0106-2006

7.2.4 Seasonal changes may require a change in pigging frequency or type of pigs used. Lower temperatures during winter months may require removal of water or wax that might result in freezing, plugging, or corrosion problems.

7.3 Inhibitor Treatment or Injection (see also Paragraph 5.4)

7.3.1 Inhibition can usually be accomplished by one of two general methods: batch (intermittent) treatment or continuous injection, or a combination of the two methods.

7.3.1.1 The preferred batch treatment method normally entails pumping a slug of inhibitor solution through the line between two pigs. Frequency of the treatment is governed by the remaining effectiveness of the inhibitor after a specified amount of gas or liquid has been moved through the line.

7.3.1.2 Continuous injection consists of constant addition of a specific proportion of inhibitor to the gas or liquid being transported through the pipeline.

7.3.2 Injection facilities vary in design and operation. In general, the installation includes the following:

- (a) Inhibitor storage vessel
- (b) Injector (pump or nozzle)
- (c) Measurement device (meter or calibrated sight glass)
- (d) Flow controller (needle or valve—the control can be built into the injector)
- (e) Connection to the pipeline
- (f) Associated piping and electrical and control hook-ups

7.3.2.1 Injector designs as simple as gravity feed injectors, as well as the more complex proportioning chemical injection pumps and venturi injectors, can be used successfully. Adjustable-capacity positive-displacement chemical pumps are widely used in liquid pipeline systems.

7.3.2.2 Atomization of inhibitor to produce a fine mist or fog in gas pipelines can be achieved by properly designed injection quill or venturis. The venturi throat should be sized to attain gas movement at the highest practical (sonic) velocity.

7.3.2.3 Care must be exercised in location of such systems, particularly in distribution piping, so that flow-borne mist will not adversely affect the operations of pilot operated regulatory systems.

7.3.2.4 Materials of construction for the equipment should be suitable for continuous service in contact with the inhibitor. The chemical supplier's recommended materials of construction should be used. Stainless steel should be considered for small-diameter piping or tubing in which even minor rusting could cause plugging or make pumping of more viscous liquids difficult. When nitrogen-based inhibitors (amines, amides, and nitrites) are handled, copper or copper-based alloys shall be avoided because SCC might result. Nonmetallic seal and packing materials shall be checked for compatibility with the inhibitor formulation.

7.3.3 Points of injection shall be chosen to provide maximum benefit in the pipeline system. Injection on the suction side of pumps takes advantage of pump turbulence to promote mixing of inhibitor with fluid. Injection through a tube into the center of the pipeline also aids mixing. When a venturi is used as an injection device, installation in a smaller-diameter bypass is preferred because gas flow at high velocity can be maintained more easily.

7.3.4 Premixing or dilution of the inhibitor can improve handling and promote more rapid dissolution, especially between immiscible phases. Injection point damage can occur due to low pH of the additive or flashing of solvents leaving a solid deposit. Viscous inhibitors can be diluted with a compatible, miscible hydrocarbon carrier to decrease viscosity, making pumping easier and metering more accurate, especially at low usage rates. Premixing water before injection greatly facilitates mixing of inhibitor with line water.

7.3.5 Premixing and dilution of inhibitor should be performed only if the supplier indicates no adverse impacts on the handling or performance of the inhibitor will result. Impacts can include emulsification, separation, or the formation of solids.

7.4 Internal Coating

7.4.1 If an internally coated pipeline is opened, the coating shall be inspected. Damaged areas shall be suitably repaired, if at all feasible, to maintain overall coating integrity. If coating damage is too widespread or repair is otherwise not feasible, supplemental mitigation measures shall be considered.

Section 8: Corrosion Control Records

8.1 Introduction

8.1.1 This section describes a system of corrosion control records that can be used to document data pertinent to the design, installation, operation, maintenance, and effectiveness of internal corrosion control measures.

8.2 Relative to design considerations, the following shall be recorded:

8.2.1 Analysis of gas or liquid, including impurity content.

8.2.2 Physical design consideration including pipe size, wall thickness, grade, flow velocity, line size changes, internal coating, and type.

8.2.3 Considerations for treatment such as dehydration, deaeration, chemicals, internal coatings, and monitoring facilities.

8.3 Relative to detecting, controlling, and evaluating corrosion problems and operations maintenance, the following shall be recorded:

8.3.1 Visual inspections by qualified personnel, including a consideration of the elements in Paragraph 4.2 whenever a piping system is opened.

8.3.2 Inspection and tests of probes, coupons, and other monitoring devices such as samples, chemical analysis, bacteria results, and internal inspection tool runs.

8.3.3 In-line inspection and line cleaning pig runs including date, type of pig, and amounts of water and solids removed by locations.

8.3.4 Name and quantity of inhibitor, biocide, and other chemicals used.

8.3.5 Leak and failure records.

References

1. Engineering Data Book, 11th ed., (Tulsa, OK: GPSA⁽³⁾).
2. M. Wicks, J.P. Fraser, "Entrainment of Water in Flowing Oil," *Materials Performance* 14, 5 (1975): p. 9.
3. API RP 14E (latest revision), "Recommended Practice for Design and Installation of Offshore Production Platform Piping Systems" (Washington, D.C.: API).
4. NACE Standard RP0775 (latest revision), "Preparation, Installation, Analysis, and Interpretation of Corrosion Coupons in Oilfield Operations" (Houston, TX: NACE).
5. T.G. Braga, R.G. Asperger, "Engineering Considerations for Corrosion Monitoring of Gas Gathering Pipeline Systems," *CORROSION/87*, paper no. 48 (Houston, TX: NACE, 1987).
6. NACE Publication 3T199 (latest revision), "Techniques for Monitoring Corrosion Related Parameters in Field Application" (Houston, TX: NACE).
7. NACE Standard RP0102 (latest revision), "In-Line Inspection of Pipelines" (Houston, TX: NACE).
8. O. Moghissi, B. Cookingham, L. Perry, N. Sridhar, "Internal Corrosion Direct Assessment of Gas Transmission Pipelines—Application," *CORROSION/2003*, paper no. 03204 (Houston, TX: NACE, 2003).
9. ASTM G 1 (latest revision), "Preparing, Cleaning and Evaluating Corrosion Test Specimens" (West Conshohocken, PA: ASTM).
10. U.S. Code of Federal Regulations (CFR) Title 49, "Internal Corrosion Control; Monitoring," Part 192.477 (Washington, DC: Office of the Federal Register,⁽⁴⁾ 1995).
11. ASTM D 3370 (latest revision), "Sampling Water from Closed Conduits" (West Conshohocken, PA).
12. ASTM D 4515 (latest revision), "Estimation of Holding Time for Water Samples Containing Organic Constituents" (West Conshohocken, PA: ASTM).
13. B.L. Carlberg, "Vacuum Deaeration—A New Unit Operation for Water Flood by Vacuum Deaeration," *SPE⁽⁵⁾-AIME⁽⁶⁾ Meeting*, paper no. SPE-6096 (Richardson, TX: SPE, 1976).

⁽³⁾ Gas Processors Supplier Association (GPSA), 6526 East 60th St., Tulsa, OK 74145.

⁽⁴⁾ The National Archives and Records Administration (NARA), 8601 Adelphi Rd., College Park, MD 20740-6001.

⁽⁵⁾ Society of Petroleum Engineers (SPE), 222 Palisades Creek Dr., Richardson, TX 75080.

⁽⁶⁾ American Institute of Mining, Metallurgical, and Petroleum Engineers (AIME), Three Park Ave., 17th Floor, New York, NY 10016-5998.

SP0106-2006

14. NACE Standard RP0278 (withdrawn), "Design and Operation of Stripping Columns for Removal of Oxygen from Water" (Houston, TX: NACE).
15. S. Papavinasam, "Corrosion Inhibitor," in Uhlig's Corrosion Handbook, 2nd ed., R.W. Revie, ed. (New York, NY: John Wiley and Sons Inc., 2000), p. 1089.
16. V.S. Sastri, Corrosion Inhibitors, Principles and Applications (New York, NY: John Wiley and Sons, 1998).
17. NACE Publication 5A195 (latest revision), "State-of-the-Art Report on Controlled-Flow Laboratory Corrosion Test" (Houston, TX: NACE).
18. NACE Publication ID196 (latest revision), "Laboratory Test Methods for Evaluating Oilfield Corrosion Inhibitors" (Houston, TX: NACE).
19. ASTM G 170.01a (latest revision), "Evaluating and Qualifying Oilfield and Refinery Corrosion Inhibitors in the Laboratory" (West Conshohocken, PA: ASTM).
20. ASTM G 184 (latest revision), "Standard Practice for Evaluating and Qualifying Oil Field and Corrosion Inhibitors Using Rotating Cage" (West Conshohocken, PA: ASTM).
21. ASTM G 185 (latest revision), "Standard Practice for Evaluating and Qualifying Oil Field and Corrosion Inhibitors Using the Rotating Cylinder Electrode" (West Conshohocken, PA: ASTM).
22. NACE Standard RP0191 (latest revision), "The Application of Internal Plastic Coatings for Oilfield Tubular Goods and Accessories" (Houston, TX: NACE).
23. NACE Standard RP0291 (latest revision), "Care, Handling, and Installation of Internally Plastic-Coated Oilfield Tubular Goods and Accessories" (Houston, TX: NACE).
24. NACE Standard TM0186 (latest revision), "Holiday Detection of Internal Tubular Coatings of 250 to 760 μm (10 to 30 mils) Dry-Film Thickness" (Houston, TX: NACE).
25. API 2544 (latest revision), "Method of Test for API Gravity of Crude Petroleum and Petroleum Products—Hydrometer Method" (Washington, DC: API).
26. NACE Standard TM0194 (latest revision), "Field Monitoring of Bacterial Growth in Oilfield Systems" (Houston, TX: NACE).
27. ASTM D 1945 (latest revision), "Standard Test Method for Analysis of Natural Gas by Gas Chromatography" (West Conshohocken, PA: ASTM).
28. ASTM D 513 (latest revision), "Standard Test Method for Total and Dissolved Carbon Dioxide in Water" (West Conshohocken, PA: ASTM).
29. ASTM D 512 (latest revision), "Chloride Iron in Water" (West Conshohocken, PA: ASTM).
30. ASTM D 4658 (latest revision), "Standard Test Method for Sulfide Ion in Water" (West Conshohocken, PA: ASTM).
31. ASTM D 4810 (latest revision), "Standard Test Method for Hydrogen Sulfide in Natural Gas Using Length-of-Stain Detector Tubes" (West Conshohocken, PA: ASTM).
32. B. Hedges, L. McVeigh, "The Role of Acetate in CO₂ Corrosion: The Double Whammy," CORROSION/99, paper no. 21 (Houston, TX: NACE, 1999).
33. J. Crolet, N. Thevenot, A. Dugstad, "Role of Free Acetic Acid on the CO₂ Corrosion of Steels," CORROSION/99, paper no. 24 (Houston, TX: NACE, 1999).
34. ASTM D 888 (latest revision), "Standard Test Methods for Dissolved Oxygen in Water" (West Conshohocken, PA: ASTM).
35. ASTM D 1796 (latest revision), "Standard Test Method for Water and Sediment in Fuel Oils by the Centrifuge Method (Laboratory Procedure)" (West Conshohocken, PA: ASTM).
36. ASTM D 5907 (latest revision), "Standard Test Method for Filterable and Nonfilterable Matter in Water" (West Conshohocken, PA: ASTM).
37. ASTM D 5504 (latest revision), "Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Chemiluminescence" (West Conshohocken, PA: ASTM).
38. ASTM D 3227 (latest revision), "Standard Test Method for (Thiol Mercaptan) Sulfur in Gasoline, Kerosene, Aviation Turbine, and Distillate Fuels (Potentiometric Method)" (West Conshohocken, PA: ASTM).
39. ASTM D 6304 (latest revision), "Standard Test Method for Determination of Water in Petroleum Products, Lubricating Oils, and Additives by Coulometric Karl Fisher Titration" (West Conshohocken, PA: ASTM).
40. H. Byars, Corrosion Control in Petroleum Production, 2nd ed. (Houston, TX: NACE, 1999).
41. C. de Waard, U. Lotz, "Prediction of CO₂ Corrosion of Carbon Steel," CORROSION/93, paper no. 69 (Houston, TX: NACE, 1993).
42. C. de Waard, U. Lotz, A. Dugstad, "Influence of Liquid Flow Velocity on CO₂ Corrosion—A Semi-Empirical Model," CORROSION/95, paper no. 128 (Houston, TX: NACE, 1995).
43. A. Anderko, R.D. Young, "A Model for Calculating Rates of General Corrosion of Carbon Steel and 13% Cr Stainless Steel in CO₂/H₂S Environments,"

CORROSION/2001, paper no. 86 (Houston, TX: NACE, 2001).

44. S. Nestic, M. Nordsveen, R. Nyborg, A. Strangeland, "A Mechanistic Model for CO₂ Corrosion with Protective Iron Carbonate Films," CORROSION/2001, paper no. 40 (Houston, TX: NACE, 2001).

45. NACE MR0175/ISO 15156 (latest revision), "Petroleum and natural gas industries—Materials for use in H₂S-containing environments in oil and gas production" (Houston, TX: NACE).

46. A.K. Dunlop, "Stress Corrosion Cracking of Low Strength, Low Alloy Nickel Steels in Sulfide Environments," Corrosion 34, 88 (1978): p. 88.

47. L.W. Jones, Corrosion and Water Technology (Tulsa, OK: OGCI,⁽⁷⁾ 1992), p. 20.

48. R.A. Pisigan Jr, J.E. Singley, "Evaluation of Water Corrosivity Using the Langelier Index and Relative Corrosion Rate Models," Materials Performance 24, 4 (1985): p. 26.

Appendix A: Typical Gas Quality Specification (Nonmandatory)

Oxygen: The oxygen content shall not exceed 0.1 vol% of the gas, and the parties shall make reasonable efforts to maintain the gas or liquid free from oxygen.

Hydrogen sulfide (H₂S): The H₂S content shall not exceed 5.7 mg/m³ (0.25 grains/100 ft³).

NOTE: 1 grain/100 ft³ = 22.88 mg/m³.

Mercaptans: The gas shall not contain more than 5.7 mg/m³ (0.25 grains/100 ft³) of gas.

Total sulfur: The total sulfur content, including mercaptans and H₂S, shall not exceed 46 mg/m³ (2 grains/100 ft³).

Carbon dioxide (CO₂): The CO₂ content shall not exceed 2 vol.% of the gas.

Liquids: The gas shall be free of water and other objectionable liquids at the temperature and pressure at which the gas is delivered, and the gas shall not contain any hydrocarbons that might condense to free liquids in the pipeline under normal conditions and shall, in no event, contain water vapor in excess of 112 kg/million³ (7 lb/million ft³).

NOTE: 1 lb/million ft³ = 16 kg/million m³.

Dust/gums/solid matter: The gas shall be commercially free of dust, gum-forming constituents, and other solid matter.

Heating value: The gas delivered shall contain a daily, monthly, or yearly average heating content of not less than

36 MJ/m³ (975 BTU/ft³) and not more than 44 MJ/m³ (1,175 BTU/ft³) on a dry basis.

Temperature: The gas shall not be delivered at a temperature of less than 4.4°C (40°F), and not more than 49°C (120°F).

Nitrogen: The nitrogen content shall not exceed 3 vol% of the gas.

Hydrogen: The gas shall contain no carbon monoxide, halogens, or unsaturated hydrocarbon and no more than 400 ppm of hydrogen in the gas.

Isopentane and Heavier: The gas shall not contain more than 27 L/1,000 m³ (0.2 gal/1,000 ft³) of isopentane or heavier hydrocarbons.

NOTE: 1 gal/1,000 ft³ = 134 L/1,000 m³.

Condensate quality specification:

Sulfur content: Less than 0.05% by weight of the condensate.

Asphaltenes: Trace

API gravity: Minimum 35° API 25

B.S.&W. (The quantity of "basic sediment and water" contained in a liquid) and other impurities: Less than 0.5% of the condensate.

⁽⁷⁾ Oil & Gas Consultants International (OGCI), 2930 S. Yale, Tulsa, OK 74114.

Appendix B: Publications Providing Information Necessary for Determining the Quantity of Impurities
(Nonmandatory)

- | | | |
|-----|-------------------------|--------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| (a) | Bacteria | NACE Standard TM0194 (latest revision), "Field Monitoring of Bacterial Growth in Oilfield Systems" ²⁶ |
| (b) | CO ₂ | ASTM D 1945 (latest revision), "Standard Test Method for Analysis of Natural Gas by Gas Chromatography" ²⁷

ASTM D 513 (latest revision), "Standard Test Methods for Total and Dissolved Carbon Dioxide in Water" ²⁸ |
| (c) | Chloride | ASTM D 512 (latest revision), "Standard Test Methods for Chloride Ion in Water" ²⁹ |
| (d) | H ₂ S | ASTM D 4658 (latest revision), "Standard Test Method for Sulfide Ion in Water" ³⁰

ASTM D 4810 (latest revision), "Standard Test Method for Hydrogen Sulfide in Natural Gas Using Length-of-Stain Detector Tubes" ³¹

ASTM D 1945 (latest revision), "Standard Test Method for Analysis of Natural Gas by Gas Chromatography" ²⁷ |
| (e) | Organic acids | B. Hedges, L. McVeigh, "The Role of Acetate in CO ₂ Corrosion: The Double Whammy," CORROSION/99, paper no. 21 ³²

J. Crolet, N. Thevenot, A. Dugstad, "Role of Free Acetic Acid on the CO ₂ Corrosion of Steels," CORROSION/99, paper no. 24 ³³ |
| (f) | Oxygen | ASTM D 888 (latest revision), "Standard Test Methods for Dissolved Oxygen in Water" ³⁴

ASTM D 1945 (latest revision), "Standard Test Method for Analysis of Natural Gas by Gas Chromatography" ²⁷ |
| (g) | Solids or precipitates | ASTM D 1796 (latest revision), "Standard Test Method for Water and Sediment in Fuel Oils by Centrifuge Method (Laboratory Procedure)" ³⁵

ASTM D 5907 (latest revision), "Filterable and Non-Filterable Matter in Water" ³⁶ |
| (h) | Sulfur-bearing compound | ASTM D 5504 (latest revision), "Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Chemiluminescence" ³⁷

ASTM D 3227 (latest revision), "Standard Test Method for (Thiol Mercaptan) Sulfur in Gasoline, Kerosene, Aviation Turbine, and Distillate Fuels (Potentiometric Method)" ³⁸ |
| (i) | Water | ASTM D 6304 (latest revision), "Standard Test Method for Determination of Water in Petroleum Products, Lubricating Oils, and Additives by Coulometric Karl Fisher Titration" ³⁹

ASTM D 1796 (latest revision), "Standard Test Method for Water and Sediment in Fuel Oils by Centrifuge Method (Laboratory Procedure)" ³⁵ |

Appendix C: Impacts of Common Impurities (Nonmandatory)

- (a) **Bacteria** Microbes commonly found in oil and gas systems are sulfate-reducing bacteria (SRB) and acid-producing bacteria (APB). Some of the bacteria are planktonic, free floating in the liquids; others are sessile and are attached to the surfaces in the system. Samples of the liquids indicate the presence of the planktonic bacteria; however, their presence does not necessarily indicate that microbiologically influenced corrosion (MIC) has or will occur. Coupons placed in the system must be used for detection of the sessile bacteria. See NACE Standard TM0194²⁶ for details on monitoring to determine the presence, location, and severity of bacterial contamination. See chemical vendor for biocide recommendation and treatment concentration level.
- (b) **CO₂** If no liquid water is present, carbon dioxide (CO₂) is noncorrosive. In the presence of liquid water, the partial pressure of CO₂ (mole percent of CO₂ × system pressure in kPa [psi]) is used as a guideline to determine the corrosiveness of CO₂. See *Corrosion Control in Petroleum Production*.⁴⁰
1. A partial pressure of CO₂ above 207 kPa (30 psi) is usually corrosive in the presence of water.
 2. A partial pressure of CO₂ between 21 kPa (3 psi) and 207 kPa (30 psi)-may be corrosive in the presence of water.
 3. A partial pressure of CO₂ below 21 kPa (3 psi) is generally considered noncorrosive.
- Caution should be used with the above guidelines in the presence of low molecular weight organic acids (acetic, propionic, etc.) or H₂S that will interfere.
- A large number of predicative models have been developed for CO₂ corrosion. The rate of CO₂ can be calculated using the deWaard, et.al. model.^{41,42} The corrosion rate is calculated using the partial pressure of CO₂, temperature, and pressure of the system. Corrosion models by A. Anderko, et al.⁴³ and S. Nesic, et al.⁴⁴ take organic acids into account.
- (c) **Chloride** Steel must have a conductive solution on its surface to form a cell for corrosive attack to occur. The addition of salts containing chloride, commonly found in gas and oil production, increases the conductivity and corrosiveness of water, resulting in pitting or general corrosion.
- Chloride stress corrosion cracking (SCC) results from the interaction of chloride and mechanical tensile stresses. UNS S30400 cracks in the presence of parts per million (ppm) chloride. Pages 21-22 of *Corrosion Control in Petroleum Production*⁴⁰ include a table listing the susceptibility of metal to SCC.
- (d) **H₂S** H₂S is very soluble in water. It is 200 times more soluble than oxygen and 3 times more soluble than CO₂ in water at atmospheric pressure and temperature. H₂S corrodes steel forming various forms of iron sulfide, which result in pitting corrosion.
- Hydrogen blistering may occur in some steels in the presence of H₂S. Hydrogen atoms are sufficiently small to allow entry into and migration within the steel structural lattice. Some of the hydrogen atoms enter structural defects within the steel, such as voids, where they quickly react with other hydrogen atoms to form molecular hydrogen. This molecular hydrogen occupies a greater space and can no longer migrate through steel. Trapped hydrogen gas exerts pressure and can cause blister formation within the steel. If the blisters are sufficiently large, they can be detected by external deformation of the steel surface. Hydrogen gas trapped within higher-strength steels can lead to stepwise cracking (also called hydrogen-induced cracking [HIC]) within the steel. The hydrogen atoms in the metal migrate into a void and form hydrogen gas, eventually developing a blister on the surface of the steel. See pp. 17-18 of *Corrosion Control in Petroleum Production*.⁴⁰

Sulfide stress cracking (SSC) occurs in high-strength steels exposed to moist H₂S conditions. Four conditions are required for SSC to occur.

1. Presence of H₂S
2. Presence of water—trace amount is sufficient
3. High-strength materials
4. Steel must be under tensile stress or loading (stress may be residual or applied). Plain carbon steels with strength below 620 MPa (90,000 psi) and Rockwell hardness below 73.0 HR 15 or 22 HRC are not affected. See NACE MR0175/ISO 15156⁴³ for detailed hardness requirements. Steels with yield strengths above this level are susceptible to cracking. The time to failure increases as the H₂S concentration decreases. Cracking can occur at 0.1 ppm levels of H₂S in water with a very long time to failure.^{40,46}

(e) Organic acids Low-molecular-weight organic acids (acetic, propionic, etc.) can cause severe corrosion when present in the gas phase at ppm levels.^{32,33} The presence of low-molecular-weight organic acids, which will partition into the water, are often not detected in the water analysis due to the interference of bicarbonate present in the water.

(f) Oxygen If water saturated with air, containing 7 to 8 ppm oxygen, is used to hydrotest a pipeline, little corrosion of the pipeline results. The oxygen immediately interacts with steel and is removed from solution, resulting in very little corrosion loss. However, if a constant supply of water containing oxygen flows through the line, severe pitting of the pipeline results. When large quantities of water flow through steel pipelines, the oxygen content should be less than 1 ppm.⁴⁷

An equation to estimate the corrosion due to oxygen relates the corrosion rate to total dissolved oxygen concentration, mineral saturation index, and exposure time.⁴⁸

(g) Water If liquid water is not present in a steel pipeline, corrosion does not occur. The presence of oxygen, CO₂, or H₂S in a steel pipeline in the absence of liquid water does not cause corrosion at temperatures below 200°C (390°F).⁴⁸ Hygroscopic salt deposits on the steel surface can cause the formation of an invisible water film on the surface below dewpoint conditions, which can cause corrosive attack.