

Control of Internal Corrosion in Steel Pipelines and Piping Systems

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ABSTRACT

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. It is meant to serve as a guide for establishing minimum requirements for control of internal corrosion in crude oil gathering and flow lines, crude oil transmission, hydrocarbon products, gas gathering and flow lines, gas transmission, and gas distribution. This standard is maintained by Task Group 038.

KEYWORDS

Pipelines, internal corrosion, corrosion control.

Foreword

The purpose of this NACE standard practice is to describe procedures and practices for achieving effective control of internal corrosion in carbon steel pipe and piping systems used to gather, transport, or distribute crude oil, petroleum products, and gas, including produced water and water injection pipe. Certain constituents that are found in the gas and liquid transported in these systems (e.g., oxygen, carbon dioxide, hydrogen sulfide, bacteria, etc.) can cause corrosion. Additionally, the complex nature and interaction between constituents in the pipeline may affect whether a corrosive condition exists, or increase the severity of a corrosive condition. These corrosive conditions can lead to localized pitting corrosion, underdeposit corrosion, microbiologically influenced corrosion and general corrosion. The predominant failures occur by localized pitting mechanism; therefore controlling pitting corrosion is paramount. Identification of potentially corrosive gas and liquid in a pipeline can only be achieved by analysis of operating conditions, fluid composition, physical monitoring and/or inspection results, or other considerations. There are many mitigation methods that can be implemented in systems where corrosive conditions exist. This standard presents general practices 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. It was revised in 2018 by TG 038. 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. The terms **shall** and **must** are used to state a requirement, and are considered mandatory. The term **should** is used to state something good and is recommended, but is not considered mandatory. The term **may** is used to state something considered optional.

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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 natural gas.
- 1.2 This standard serves as a guide for establishing minimum requirements for management 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
 - (h) Produced water lines
 - (i) Injection water lines
- 1.3 This standard does not designate specific practices for every situation because the complexity of systems precludes standardizing internal corrosion control practices.
- 1.4 This document does not cover internal cracking mechanisms, nor does it address steam lines.
- 1.5 Corrosion control of equipment such as tanks, vessels, processing units, valves etc. is outside the scope of this document.
- 1.6 This document does not specifically address corrosion resistant alloys (CRAs) or well tubulars. Although many of the same principles could be applied to these materials and environments, there will be exceptions.
- 1.7 The internal corrosion control process described in this document is a continual feedback loop. It begins with performing an internal corrosion threat assessment to identify relevant internal corrosion mechanisms and contributing factors for the pipeline/system, creating a corrosion control plan to evaluate, mitigate and monitor those threats, and utilizing information obtained from monitoring, inspection and other activities (e.g., maintenance) as feedback to update the identified threats and corrosion control plan.
- 1.8 Local government regulations or permits may dictate particular requirements related to implementation of various section of this standard.
- 1.9 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 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, scientists or technicians with suitable levels of experience, and their professional activities include internal corrosion control of buried carbon steel piping and pipeline systems.

Section 2: Definitions

Archaea: Unicellular microorganisms that are generally distinct from bacteria, which often inhabit extreme environmental conditions.

Atomization: To a chemical to fine particles or spray.

Biocide: A chemical product that is intended to kill biological microorganisms or render them harmless.

Biofilm: Microbial growth at an interface in which individual cells are bound within a matrix of extracellular polymeric materials.

Cavitation: The formation and rapid collapse of cavities or bubbles of vapor or gas within a liquid resulting from mechanical or hydrodynamic forces.

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.

Deadlegs: Lengths of pipe that are isolated by valves (such as those associated with blind flanges, stubs, laterals) or locations that have no flow for more than three consecutive months.¹

Deaeration: The removal of air/oxygen from a gas or liquid.

Drip: A configuration of a pipeline that captures liquids and allows them to be removed.

Electrolyte: Medium, usually a liquid that conducts an electric field by the migration of ionic species, e.g., sulfate, chloride, carbonate, and ferrous ions.

Emulsifier: A substance that aids in creating or maintaining water dispersed in a liquid hydrocarbon.

ErosionCorrosion: 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.

Fungi: Nucleated, usually filamentous, spore-bearing parasitic microorganisms devoid of chlorophyll, which include molds, mildews, smuts, mushrooms, yeasts, and others.

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

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

Hot Tap Coupon: A small circular section of a pipeline removed during the process of hot tapping the line (i.e., the pipe material that is removed in the area where a connection is added).

Hygroscopic: A substance that can absorb moisture (i.e., water) from the surrounding environment.

In-Line Inspection (ILI): An inspection of a pipeline from the interior of the pipe using an in-line inspection tool. Also called *intelligent* or *smart pigging*.

Intrusive Monitoring: Monitoring that requires penetration through the pipe.

Launcher: A device used to insert an in-line inspection tool into a pressurized pipeline. It may be referred to as a pig trap or scraper trap.

Lining: A coating or layer of sheet material adhered to or in intimate contact with the interior surface of a container used to protect the container against corrosion by its contents and/or protect the contents of the container from contaminations by the container material. For the purpose of this standard, the container is a pipeline.

Localized Pitting: Preferential loss of metals at small areas that results in a pinhole leak. The surrounding areas of pits may not suffer from any metal loss.

Microbiologically Influenced Corrosion (MIC): Corrosion affected by the presence or activity, or both, of microorganisms. (The microorganisms that are responsible for MIC are typically found in biofilms on the surface of the corroding material. Many materials, including most metals and some nonmetals, can be degraded in this manner.)

Microorganism: An organism of microscopic or ultramicroscopic size. Bacteria, *Arcaea*, and fungi are microorganisms.

Multiphase: Having more than one phase, including gas, liquid, and or solid.

Non-Intrusive Monitoring: Monitoring from the outside of the pipe wall without having to gain access to the interior.

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.

Receiver: A pipeline facility used for removing a pig from a pressurized pipeline. It may be referred to as a pig trap or scraper trap.

Siphon: A small diameter pipe inserted into a gas pipeline that, when opened to atmosphere, uses the pipeline pressure to force liquids present into the pipeline through the small diameter pipe, thus removing the liquids from the pipeline.

Surfactant: A substance that lowers the surface tension between two liquids or between a liquid and a solid.

Underdeposit Corrosion: Corrosion taking place beneath a solid material (e.g., sand, debris, or solid).

Venturi Injector: An injector that forces chemical through conical shaped body in order to create a pressure differential, which creates a chemical spray.

Section 3: Internal Corrosion Threat Assessment

3.1 Introduction

- 3.1.1** In order to effectively control internal corrosion, it is essential to understand the corrosion mechanisms affecting the pipeline. The purpose of this section is to provide guidance regarding performing internal corrosion threat assessments in order to identify internal corrosion mechanisms and other contributing factors potentially influencing corrosion in the pipeline system. For new pipelines, the identification of potential internal corrosion mechanisms and contributing factors should be based on industry knowledge, the anticipated operating conditions and fluid composition for the entire range of operating conditions, and the pipeline operator's experience with similar systems. For pipelines in operation, the identification of internal corrosion mechanisms and contributing factors should be based on data regarding system operation, sample collection and analysis, monitoring, inspection, etc. Identification of corrosion mechanisms includes consideration of the presence of potentially corrosive constituents as well as consideration of operating conditions (i.e., pressure, temperature, and velocity).
- 3.1.2** Certain constituents that are found in the gas and liquid transported in these systems (e.g., oxygen, carbon dioxide, hydrogen sulfide, chloride bacteria, etc.) can cause corrosion and/or influence the mechanism of corrosion. Additionally, the complex nature and interaction between constituents in the pipeline may affect whether a corrosive condition exists, or increase the severity of a corrosive condition. Identification of potentially corrosive gas and liquid in a pipeline can only be achieved by analysis of operating conditions, fluid composition, physical monitoring and/or inspection results, or other considerations. These corrosive conditions can lead to localized pitting corrosion, underdeposit corrosion, microbiologically influenced corrosion, and general corrosion. The predominant failures occur by localized pitting corrosion mechanism. Localized pitting corrosion can occur either in the presence or absence of microbial activities as well as in the presence or absence of solids. Therefore controlling internal localized corrosion is paramount.
- 3.1.3** A threat assessment shall be performed for each pipeline or pipeline system in order to identify potential corrosion mechanisms. When assessing internal corrosion threat not one single factor mentioned below will drive the corrosion severity of the fluid; instead it is combination and the synergistic interaction of all these factors that should be used to determine the internal corrosion threat.
- 3.1.4** Fluid composition may change over time. Therefore potential corrosion mechanisms shall be evaluated over the life of the pipeline or be re-evaluated as composition changes. Systems should also be re-evaluated when new input sources are added.
- 3.1.5** See Appendix A (nonmandatory) for a list of standards and other publications that provide information on how to determine the quantity of potentially corrosive constituents present.
- 3.1.6** Knowledge of the gas, liquid, and/or solid composition allows predictions of the type and severity of damage mechanisms that could result from their presence.

3.2 Presence of Water

- 3.2.1** In order for corrosion to occur, water or other electrolyte must be present; therefore, the identification of the potential for water to be present is essential. If there is no water present on a steel surface, no corrosion should occur, even in the presence of potentially corrosive gases (H_2S , CO_2 , and O_2).
- 3.2.2** For production environments, such as multiphase flow pipelines, water may be assumed to be present in the pipelines.
- 3.2.3** For liquid gathering and transportation pipelines basic sediment and water (BS&W) content should be reviewed. While some amount of water may be present in these pipelines, it is necessary for the surface of the pipeline to become water wet in order for internal corrosion to occur. Corrosion conditions in oil pipelines depend on type of emulsion (water in oil or oil in water), wettability (oil wet, water wet, mixed wet) and partitioning of chemicals between oil phase and water phase. ASTM G205 provides guidelines on conditions when water drops out and wets the carbon steel surface causing corrosion. (See Paragraph 3.9 for additional information regarding flow modeling.)

- 3.2.4** For gas pipelines, water may be present as a result of upsets or through condensation of water vapor in the gas. The potential for water condensation to occur should be determined based the pipeline's operating temperature and pressure, and the water content of the gas. Phase diagrams, calculations, or other methods can be used for determination of water condensation. Consideration should be given to the presence of hygroscopic solids, localized areas with temperatures lower than the bulk temperature, and the potential for lower temperatures to exist at the pipe wall. Hygroscopic salt deposits on the steel surface can allow the formation of an invisible water film on the surface below dewpoint conditions that can cause corrosive attack.

3.3 Potentially Corrosive Gases

For pipelines that contain a gas phase, the CO₂, H₂S, and O₂ content of the gas can be measured and used in combination with the pipeline operating pressure to determine the partial pressure of potentially corrosive gases. For liquid pipelines the partial pressure of CO₂, H₂S, and O₂ at the time of gas separation can be used as the partial pressure for the pipeline. Alternatively, the dissolved CO₂, H₂S, and/or O₂ content in the water phase can be measured.

3.3.1 Carbon Dioxide

Internal corrosion can occur as a result of dissolved carbon dioxide (CO₂) in water. The potential for internal corrosion to occur is impacted by the partial pressures of CO₂, operating conditions (flow velocity and temperature), and water chemistry. 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*.²

As a general rule of thumb:

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.

This rule of thumb was developed many years ago, and since that time much research has been done regarding CO₂ corrosion, including the development of many CO₂ corrosion prediction models. Therefore, this rule of thumb should be used with care. Additionally, caution should be used with the above guidelines in the presence of low molecular weight organic acids (acetic, propionic, etc.), H₂S, or O₂.

3.3.2 Hydrogen Sulfide (H₂S)

Internal corrosion can occur as a result of dissolved hydrogen sulfide (H₂S). H₂S is 200 times more soluble than oxygen and 3 times more soluble than CO₂ in water at atmospheric pressure and temperature. Kinetics of formation of iron sulfide surfaces are three times faster than formation of iron carbonate surface layer (insert reference). As with CO₂, the potential for internal corrosion to occur is impacted by the partial pressures of H₂S, operating conditions (flow velocity and temperature), and water chemistry. Internal corrosion associated with H₂S is governed by the production of a weak acid and the formation of sulfide scales, some of which are slightly cathodic to steel.

3.3.3 Oxygen (O₂)

Oxygen is not naturally present in production formations; however, oxygen contamination in gas, hydrocarbon liquid, or multiphase flow pipelines can occur as a result of enhanced oil recovery methods, leaking pumps or seals, or other means. When oxygen is present, even in minor concentrations, corrosion can occur. The potential for oxygen corrosion is particularly of concern in produced water and seawater pipelines.

3.3.4 Combinations of CO₂, H₂S, and/or O₂

When multiple potentially corrosive gases are present, the corrosion effects from any individual gas is affected by the presence of others (e.g., the potential corrosion severity of CO₂ is impacted by the presence of H₂S and/or O₂). For systems containing both CO₂ and H₂S, the corrosion is generally considered to be dominated by CO₂ if the ratio of the CO₂ to H₂S content is greater than 5000 to 1.³

3.4 Organic Acids

Organic acids (e.g., acetic acid, formic acid, propionic, etc.) can be present in a pipeline as a result of the activities of microorganisms or where present in the formation. Organic acids can accelerate corrosion rates and destroy or weaken protective coatings. Organic acids may be present in the gas phase and condense depending on pipeline operating temperature and pressure. Condensing organic acids can cause high corrosion rates on the top of the pipe when present in the gas phase at ppm levels.^{4,5} Organic acids may also be present in crude oils and may preferentially partition into any water present. 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.

3.5 Sulfur

The presence of elemental sulfur can result in high corrosion rates. Elemental sulfur may be present in formations and carried into the pipelines with the product or it may occur as the result of oxidation of H_2S gas due to oxygen entry. This oxidation is detrimental for two reasons: it produces elemental sulfur, which can cause severe corrosion, and further it produces water which can make dry and non-corrosive H_2S wet and corrosive.

3.6 Chlorides

Water present in a pipeline may be produced from the formation or condensed from the gas phase (or in the case of water injection lines, it may be seawater).

Produced water and seawater contain high levels of chlorides. Increases in chloride concentration increase the conductivity of the water and generally correlate with increases in corrosion rate. Although chlorides are not directly involved in the corrosion reaction, they can negatively impact the effectiveness of corrosion inhibitors and the formation and stability of protective scales.

3.7 Microorganisms

3.7.1 There are many types of microorganisms that may be present in pipelines including bacteria, archaea, and fungi. Types of bacteria include acid-producing bacteria (APB), sulfate-reducing bacteria (SRB), metal-reducing bacteria, and metal-oxidizing bacteria. Some of the bacteria are planktonic, free floating in the liquids; others are sessile and are attached to the surfaces in the system and form biofilm. The environment within the biofilm may be extremely different from the bulk environment of the pipeline.

3.7.2 Microbiologically influenced corrosion (MIC) is the result of the presence and activities of microorganisms and/or the products they produce. Microorganisms must be present in order for MIC to occur; however the presence of bacteria alone does not mean that MIC is occurring. Factors that promote the occurrence of MIC include low flow velocities, deposit accumulations, the presence of water, and increased bacteria numbers in biofilms. NACE TM0212⁶ provides instructions on identifying whether MIC is occurring. TM0194⁷ can be used as guidance for performing bacteria testing.

3.8 Solids

3.8.1 Solid deposits on the pipe surface can originate from scale formation, wax and asphaltene precipitation, corrosion of the pipe material and deposition of particulates carried in the fluid. The presence of solids in the pipelines can increase the potential for under deposit corrosion (UDC) and promote MIC. The locations and volumes of accumulations, and the composition of solids can be used to determine the potential for corrosion resulting from the solids. Additionally, solids flow modeling can be used to determine if solids accumulation is expected to occur.

3.8.2 Contrary to condensed water, produced water and seawater contain high levels of total dissolved solids (TDS). Increases in TDS concentration increases the conductivity of water and generally correlates with increases in corrosion rate. But at the same time increases in TDS will decrease gas solubility and this decrease corrosion rates.

3.9 Flow Velocity Effects

Flow velocity plays an important role in single and multiphase flow and can impact potential internal corrosion mechanisms as well as corrosion rate. In pipelines with single phase flow, increases in flow velocity create an increase in turbulence which can increase the corrosion rate. On the other hand, decrease in flow velocity may impact the potential for water dropout of oil transmission pipelines and condensation of water in gas pipelines^{8,23}. In pipelines with multiphase flow, flow turbulence can be much higher than in pipelines with single phase flow. Flow turbulence in multiphase flow is dependent on the expected flow regime.

3.9.1 Flow Modeling

Flow modeling can be used to determine the pressure, temperature, and velocity profiles along the length of a pipeline. For systems that transport multiple phases, flow modeling can be utilized to determine the expected flow regimes within the system. Understanding flow regime is important because it will define where water is expected to be present along the length of the pipeline. Refer to NACE SP0208,⁸ NACE SP0110,⁹ and NACE SP0116¹⁰ for additional guidance regarding flow modeling in liquid petroleum wet gas, and multiphase systems, respectively. See ASTM G205 for determining if water will wet the steel surface or not.²⁶

3.9.2 Erosion and Erosion-Corrosion

Systems with a high velocity that also contain solids may be susceptible to erosion or erosion-corrosion particularly at changes in flow direction. API⁽¹⁾ RP14E includes a section for calculation of erosional velocity in gas/liquid two-phase lines.⁵⁶

3.9.3 Low and Stagnant Flow

Dead legs and other locations with low or stagnant flow may have increased susceptibility to water and solids accumulation and thus increased potential for underdeposit corrosion and MIC.

3.10 Temperature Effects

In general, corrosion rate increases with increasing temperature. Operating temperature impacts condensation of water vapor and the effects of organic acids, and TDS as described previously, and also affects the solubility of corrosive species and tendency for scale precipitation. Increasing temperature decreases the solubility of CO₂, H₂S and O₂, which may decrease the corrosion severity of the fluids. Increasing temperature increases the tendency for scale precipitation. On the other hand, decreasing temperature below the water dewpoint may lead to accelerated corrosion due to water dropout.

3.11 Corrosion Rate Modeling

Corrosion rate modeling can be utilized to predict corrosion rates that are expected to occur in a pipeline.¹¹⁻¹⁴ There are several publically and commercially available corrosion rate models that can be used. Depending on the combined effects of various parameters, internal corrosion may occur as localized pitting corrosion, UDC, top of the line corrosion (TLC), MIC, erosion, or general corrosion. When performing corrosion rate modeling, consideration should be given to whether the model utilized considers all influencing parameters and can provide a corrosion rate based on the prevailing mechanism(s). For example, rate of general corrosion shall not be used to predict localized corrosion. See NACE Technical Document 2140, "Selection of Flow and Internal Corrosion Models" and Technical Report 21413, "Prediction on Internal Corrosion in Oilfield Systems from System Conditions" for additional information on various internal corrosion models and for selection of flow and corrosion models.^{54,55}

Section 4: Internal Corrosion Management Plan

4.1 Introduction

4.1.1 Each pipeline (or pipeline system) should have an internal corrosion management plan that describes how internal corrosion will be managed for that pipeline or system. The plan should consider the internal corrosion mechanisms and other contributing factors (described in Section 3) that are relevant to the pipeline and then identify the methods that will be utilized to evaluate, mitigate, and monitor those mechanisms and factors, as necessary. The internal corrosion management plan should include the locations and frequency at which inspection, monitoring, sampling and mitigation are applied. The corrosion management plan should also identify design modifications (including retrofits) that will be performed. The following sections outline in detail the various elements that are included in the management plan.

4.2 Barrier Analysis

4.2.1 In order to determine additional measures that may be needed to evaluate, mitigate or monitor internal corrosion threats a barrier analysis should be performed. A barrier analysis consists of identifying methods that are in place to monitor or mitigate (i.e., barriers) each internal corrosion threat that has been identified for the pipeline. The effectiveness of each barrier should be considered when determining whether additional barriers are needed.

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

4.3 Data Management

- 4.3.1** The internal corrosion management plan should specify the format (paper, database, etc.) in which internal corrosion activities (e.g., maintenance pigging) and data (e.g., coupon monitoring) are recorded and stored. The manner in which the information gets from the field (or location) where it is generated to the person responsible for reviewing it should be addressed in the plan. Performing corrosion rate monitoring, sampling, etc. does no good if the person responsible for making decision cannot access the data. See Section 9 for additional information regarding internal corrosion related data that should be stored.

Section 5: System Design

5.1 Introduction

- 5.1.1** The purpose of this section is to provide design considerations for the control of internal corrosion. Corrosion control should be considered during pre-front end engineering design (FEED) and FEED meetings; representatives from the corrosion control group should attend these meetings, including hazard and operability study (HAZOP)/hazard identification (HAZID) meetings.
- 5.1.2** This standard does not address material selection such as using CRAs. However, if materials other than carbon steel are being considered, material selection needs to be considered in conjunction with the other elements described in this section.

5.2 Gas or Liquid Corrosion Severity Reduction

Gas and liquid quality should be considered with respect to the constituents described in Section 3. Where possible, consideration should be given to restricting levels of potentially corrosive constituents. Note: Monitoring should be performed to confirm that the potentially corrosive constituent has been reduced to an acceptable level.

5.2.1 Water Separation/Removal

Separation devices can be utilized to remove bulk water. The volume of water transported as well as the system flow rates are utilized in order to appropriately size separation vessels. Consideration should also be given to the use of level alarms in separation equipment in order to prevent overflow and introduction of water downstream of the separator.

5.2.2 Dehydration

Gas/oil dehydration can be used to reduce the water content downstream from separation devices or in systems where bulk/free water is not present. If reductions of the water content alone will not control the expected corrosion, other mitigation methods—such as maintenance pigging, internal coating or lining, and chemical inhibition including biocides—may also be used to provide adequate corrosion control.

5.2.3 Deaeration

The pipeline system should be designed to eliminate any air entry. However, there are some instances, such as water pipelines, where oxygen entrainment is unavoidable. In such situations, deaeration of gas or liquid to reduce its oxygen content to an acceptable level shall be considered. If removal or reduction of oxygen alone does not control the corrosion, other mitigation methods such as use of an oxygen scavenger, corrosion inhibitor, or internal coatings or linings may be used in conjunction with deaeration to provide adequate corrosion control (for additional information on coatings and linings see paragraphs).

5.2.4 Solids Removal

Separators and filters can be utilized to remove bulk solids. Data regarding the type, volume and physical characteristics of the solids that will be handled should be utilized in order to determine the proper separator design and select the appropriate internal components, including filter size. In-line filters should be considered in front of pressure control and measurement equipment to protect them from solid particles transported in the gas or liquid.

5.2.5 CO₂, H₂S, and/or O₂ Removal

Amine units, scavengers, or other methods may be utilized in order to reduce the content of CO₂ and/or H₂S in the gas or liquid. Scavengers may be utilized in order to reduce the content of O₂ in gas or liquid. See paragraphs 5.6 and 7.4 for additional information regarding the use of chemical treatment.

5.3 Flow Velocity

5.3.1 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 the velocity that will keep potentially corrosive constituents suspended in the gas or liquids, thereby minimizing accumulation of corrosive matter within the pipeline.¹⁵ The upper limit of the velocity range should be such that erosion-corrosion, cavitation, or impingement attacks are minimal. API RP14E includes a section for calculation of erosional velocity in gas/liquid two-phase lines.⁵⁶

5.3.2 Diameter

5.3.2.1 Where the flow velocity is expected to be below the velocity necessary to suspend potentially corrosive constituents or prevent accumulation of corrosive matter, removal of corrosive constituents should be considered during system design.

5.3.2.2 Where the flow velocity is expected to be at or above the velocity where erosion or erosion corrosion is expected to occur, consideration should be given to increasing the pipeline diameter or minimizing features that are more prone to erosion damage.

5.3.2.3 The potential for intermittent or varying flow conditions shall be considered during the design phase. If operating criteria dictate the need for intermittent or varying 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.

5.4 Piggability of Pipelines

5.4.1 Pipelines should be made piggable if possible when water, sediment, or other potentially corrosive constituents are expected to be present and when in-line inspection (ILI) will be used to monitor internal corrosion. The design should include pig loading and receiving traps.

5.4.2 Design features that shall be considered in order to allow pig passage include changing diameters, pipeline bends, valves, and traps. See NACE SP0102¹⁶ for information on design considerations.

5.5 Pipeline Configuration

5.5.1 Dead legs, drips, and other features with low or no flow where water or solids could accumulate should be avoided in design. If such features are necessary, siphons, traps, or drains shall be included in the design so that all accumulated materials, including sand, can be periodically removed or the features should be designed to be flushable. Coatings and linings may be considered for these areas.

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

5.5.3 Headers are locations where water or solids accumulation may occur because they have a larger diameter than their associated pipelines. Consideration should be given to the potential for water and solids removal in headers. However, the suitability of the coating to the operating conditions should be evaluated.

5.6 Chemical Treatments

5.6.1 When the addition of chemicals such as corrosion inhibitors, scavengers, or biocides will be used to mitigate corrosion, system design shall include facilities adequate for treatment of the pipeline or facility.

5.6.2 The appropriate locations for chemical injection points should be determined to provide maximum benefit to the pipeline system and ensure treatment of the identified segment/pipeline/system. For example, injection on the suction side of pumps takes advantage of pump turbulence to promote mixing of inhibitor with fluid. The means of injecting the chemical shall be determined.

5.6.2.1 Injector designs include gravity feed injectors, as well as complex proportioning chemical injection pumps and venturi injectors.

5.6.2.2 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.

5.6.2.3 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.

5.6.2.4 Chemical injection quills or spray nozzles shall be utilized versus direct injection into the pipeline.

5.6.3 Where continuous injection will be utilized, consideration should be given to the need for chemical storage tanks, chemical injection pumps or nozzles, flow controllers, flow meters for injection pumps, and check valves for safety. Chemical availability should be considered during the design phase to determine the need for redundancy (i.e., back up pumps).

5.6.4 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.

5.6.5 Where chemical treatment facilities are being designed, monitoring facilities to determine the effectiveness of mitigation shall also be designed into the system (see Paragraph 5.8).

5.7 Internal Coatings and Lining

5.7.1 Internal coatings and lining may be utilized for a variety of reasons including anticipated corrosion rates, chemical treatment feasibility (especially for areas such as dead legs), or economics. Coatings and linings such as epoxies, cement or concrete, high density polyethylene (HDPE), plastics, or metallic compounds can be used for selected applications.

5.7.2 Internal coatings/linings may be utilized for an entire pipeline or may 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.

5.7.3 The coating or lining should have suitable resistance to degradation by the gas or liquid being transported, as well as by any chemical additives contained in it. The quality of the transported gas or liquid should not be compromised. The effect of maintenance pigging or ILI on the condition of the coating should be carefully considered.

5.7.4 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.^{17,18}

5.7.5 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.¹⁹ 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.

5.7.6 In some cases, internal coating/lining applications may leave the circumferential weld area bare. Internal corrosion at girth welds is a concern that should be considered in such cases. Coating holidays and damage in internal corrosion resistance coatings can also create enhanced internal corrosion conditions. Damaged areas should be suitably repaired, if at all feasible, to maintain overall coating integrity. Additional corrosion mitigation methods such as chemical inhibitors should be considered for protection of areas, with bare circumferential welds as well as bare areas resulting from coating holidays or coating damage. The compatibility of the coating and corrosion inhibitor should be ensured. (add statement that the perfect coating does not exist and precautions need to be taken)

5.7.7 Solids that deposit on top of internal coatings/linings may need to be removed for operational purposes. Removal methods such as pigging or chemical cleaning may damage the internal coating/lining, which should be considered.

5.8 Internal Corrosion Monitoring Facilities

5.8.1 Monitoring facilities shall be considered during the design stage of a pipeline system.^{6,7} Monitoring facilities may include pipe spools, taps for insertion of monitoring devices, access fittings, sampling ports, side-streams and vault boxes to allow for monitoring at buried locations. Above ground valve locations, stations or manifolds may also serve as good monitoring locations.

5.8.2 Differences in pressure, temperature, and the concentration of water and other potentially corrosive species between the monitoring location and other locations of interest in the pipeline shall be considered in selecting the location for monitoring facilities.

5.8.3 When designing monitoring facilities for intrusive devices, consideration shall be given as to whether or not the device will be installed and removed under line pressure. Safety, Health and Environmental (SHE) factors shall also be considered when making that determination.

- 5.8.4** Consideration should be given to operability of monitoring devices and the need to replace and/or repair them over time. Accessibility of the monitoring location shall be considered. Additionally, for devices such as coupons that need routine removal and replacement, tool clearance should be considered. The potential for solids accumulation in valves on the bottom on lines (potentially resulting in valve inoperability) should be considered for monitoring locations being selected for the bottom of the pipeline.

Section 6: Internal Corrosion and Related Parameter Measurement

6.1 Introduction

- 6.1.1** This section describes methods for determining the presence of internal corrosion in piping systems, the rate at which it is occurring, and the cause of the corrosive condition. Monitoring results can also be useful for determining time-related changes in corrosive conditions that may results from operating parameters, chemical treatment programs, or other factors.
- 6.1.2** NACE technical committee report 3T199²⁰ provides in depth discussion regarding techniques for monitoring corrosion and related parameters. Procedures for preparing, installing, and analyzing metallic corrosion coupons or other monitoring devices can be found in NACE SP0775²¹ and ASTM⁽²⁾ G1.²²
- 6.1.3** Consideration should be given to redundant monitoring for systems that have high criticality.
- 6.1.4** The corrosion rates determined by monitoring devices may not be representative of actual wall loss on the asset being monitored (e.g., a protective scale is present on the pipe surface but not on a newly installed coupon); therefore it is helpful to integrate monitoring data with inspection data.
- 6.1.5** Monitoring, inspection, and sampling shall only be performed as per documented procedures.
- 6.1.6** See Section 5.8 for discussion regarding design of monitoring facilities, including SHE and operability considerations.

6.2 Selection of Monitoring, Inspection, and/or Sampling Locations

- 6.2.1** Selection of location for monitoring, inspection, and sampling is important in order to ensure that meaningful results are generated.
- 6.2.2** Monitoring devices should ideally be used at locations that are representative of or more severe than the environment they are intended to monitor.
- 6.2.3** Monitoring devices shall be installed such that they are exposed to the phase where corrosion is expected to occur. This is typically the water phase; however, consideration should also be given to top of the line corrosion resulting from condensing water vapor.
- 6.2.4** For pipelines that normally carry dry gas but may experience 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). Refer to NACE SP0206 for additional guidance on predicting locations of water accumulation in dry gas systems.²³
- 6.2.5** Identifying locations for monitoring in multi-phase systems is more complicated. Flow modeling and corrosion rate modeling can be used as 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 RP0775²¹ and ASTM G1.²²
- 6.2.5.1** Coupons and probes are installed in the gas or liquid to identify locations where water and/or solids accumulation is expected. Refer to NACE SP0208⁸ and NACE SP0110⁹ for additional guidance regarding liquid petroleum and wet gas systems, respectively.
- 6.2.6** Process conditions that can adversely affect the corrosion environment inside the pipeline (such as flow, pressure, temperature, etc.) should be considered when selecting monitoring locations.

⁽²⁾ ASTM International, 100 Barr Harbor Dr., PO Box C700, West Conshohocken, PA 19428-2959.

6.3 Selecting Monitoring Devices

6.3.1 Techniques described in NACE 3T199, NACE 31014, and/or ASTM G199²⁰⁻²² shall be used for monitoring internal corrosion. Consideration should be given to limitations of the techniques selected, as described in the document.

6.3.2 Intrusive non-flush mounted coupons or probes could prevent maintenance pigging or ILI of a pipeline segment. In such configurations, flush mounted devices shall be utilized. Alternatively, the coupons or probes may be temporarily removed in order to permit passage of an ILI tool or cleaning pig through the pipeline.

6.4 Monitoring, Inspection, and Sampling Frequency

6.4.1 The frequency at which monitoring, inspection, and sampling is performed shall be based on the technique being utilized as well as the expected/measured corrosion rate. Additionally, sampling should be performed on a frequent enough interval that trending can be performed and decisions made based on relevant and applicable information (e.g., decisions are not made based on a singular data point). Therefore, it is reasonable for frequencies to vary based on system type and corrosion history.

6.4.2 Where seasonal (or other) variations exist in gas or liquid composition, sampling and monitoring frequencies shall be established such that the impact of said variations can be determined. For example, where possible, corrosion rate monitoring in gas storage fields should be performed during either injection or withdrawal season (not crossing both) so that the differences in corrosion rate between the two seasons can be determined.

6.4.3 Consideration should be given to the potential for upset conditions when establishing frequency.

6.5 Sampling and Sample Analysis

6.5.1 Samples can be used to determine the physical and/or chemical characterization of the gas, liquid, and/or solid in the pipeline. Opportunities for sample collection include: cleaning pig runs, drip blowing (for gas systems), and pipeline maintenance/cut outs.

6.5.2 Sample Collection and Preservation

6.5.2.1 Samples shall be collected in a manner such that they are representative of the pipeline environment from which they were collected.

6.5.2.2 Clean sample collection equipment and sample containers are necessary for taking uncontaminated samples.

6.5.2.3 Samples shall also be properly preserved, identified, and analyzed. Specific sample preservation is needed for some types of analysis. The requirements for temperature, aerobic/anaerobic preservations, etc. need to be well understood and communicated to all parties involved. NACE TM0212⁶ provides guidance regarding preservation of bacteria samples.

6.5.2.4 Certain components will change or deteriorate over time; therefore considerations should be given to the impact of time during sample collection and preservation. Various conditions to consider and methods to minimize errors should be considered.

6.5.3 Types of Analyses

6.5.3.1 NACE 3T199²⁰ identifies some liquid analyses that can be performed for water samples.

6.5.3.2 Appendix A contains a list of references that contain methods for testing constituents associated with corrosion in liquid samples.

6.5.3.3 Types of solids analyses include spot testing for the presence of carbonates and sulfides, elemental composition determination using Electron Dispersive Spectroscopy (EDS) and compound determination using x-ray diffraction (XRD).

6.5.3.4 NACE TM0194⁷ provides guidance regarding determination bacteria concentration using serial dilution methods. NACE TM0212⁶ provides additional guidance regarding various microbiological analysis techniques, including molecular microbiological methods (MMM).

6.5.3.5 Where chemical treatment is being administered for corrosion control, chemical residual should be monitored in order to determine that the chemical is reaching the targeted location at the desired concentration. Residual monitoring should consider the active species of the mitigation chemical rather than just the carrier or some other non-active component.

6.6 Inspections

- 6.6.1 NACE 3T199²⁰ identifies multiple inspection methods that may be employed for detecting corrosion damage. Additionally, in-line inspection (ILI) may be performed. Refer to NACE SP0102¹⁶ for information related to ILI.
- 6.6.2 Non-destructive inspections can be utilized to determine the presence and extent of corrosion at selected locations.
- 6.6.3 Inspection data can be used to help determine corrosion rates in conjunction with additional information/knowledge about operating parameters and fluid composition. For systems that constantly change, a linear internal corrosion rate should not be assumed.
- 6.6.4 Inspection and monitoring results should be integrated for interpretation.
- 6.6.5 If a piping system is opened to allow visual access to the inside of the system, a visual inspection should be performed in order to document the information described in Appendix B (mandatory). Visual inspection may be regulatory required for some assets.

6.7 Measurement of Process Variables

- 6.7.1 Process variables should be used to determine the susceptibility of the pipeline or system to various internal corrosion mechanisms. NACE 3T199²⁰ describes on-line measurement of temperature and pressure.
 - 6.7.1.1 Pressure is utilized to determine the partial pressure of acid gases as well as dew point. Pressure is also used for corrosion rate modeling. For gas systems, changes in pressure drop measurements across a given segment of a pipeline can be indications of corrosion or deposit accumulations and shall be investigated.
 - 6.7.1.2 Temperature is utilized to determine whether operating conditions are above or below dew point. Temperature is also needed for corrosion rate modeling.
 - 6.7.1.3 Flow rates are utilized to determine velocity as well as flow regimes. Velocity is used in corrosion rate modeling and also can be used to determine susceptibility to erosion as well as low flow-related corrosion threats.

6.8 Other

- 6.8.1 Other information regarding product composition can be useful to track. For example, product composition and viscosity affect flow velocity and flow regime. Additionally, this information can be used to identify changes in that transported product that should trigger a review of the corrosion threats.
- 6.8.3 The injection of chemicals for means other than corrosion control should be tracked. Hydrate/methanol injection points, chemicals utilized, and frequency of injection should be tracked. The injection of process conditioning chemicals and drag reducing agents (DRAs) should also be monitored.

Section 7: Methods for Controlling Internal Corrosion

7.1 Introduction

- 7.1.1 This section describes suggested practices for the control of internal corrosion in steel pipelines and piping systems. Given the difference in operations and corrosion mechanisms and contributing factors, there will be differences in controlling internal corrosion in upstream, midstream, and downstream systems.
- 7.1.2 Prior to implementing mitigation techniques, the need for corrosion control shall be established as well as the predominant mechanism(s) and type of corrosion (e.g., general corrosion, localized pitting corrosion, erosion corrosion, UDC, TLC, and MIC) affecting the corrosion rate. Each company shall have a process and/or criteria by which it determines the need to implement mitigation.

7.2 System Design

- 7.2.1 System design is critical to preventing and controlling internal corrosion. Section 5 should be referenced for design systems to control internal corrosion (i.e., water separation/removal, internal coatings, etc.) and minimizing the introduction of deleterious matter that can lead to internal corrosion.

7.3 Chemical Treatment

- 7.3.1** Chemicals such as corrosion inhibitors, scavengers, biocides, scale and paraffin inhibitors, and asphaltene dispersants shall be considered to control internal corrosion. Their selection shall be based on the pipeline condition and the presence of corrosive constituents such as water, acid gases, bacteria, etc. The specific corrosion mechanism(s) affecting the pipeline shall be understood so that the proper chemical is selected. Chemical selection should be based on appropriate laboratory and field tests to determine the correct chemical and dose.^{26,27,49-52}
- 7.3.2** Chemical treatment is accomplished by batch (intermittent) treatment or continuous injection, or by a combination of the two methods. Treatment method should be decided based on the pipeline condition, fluid velocity, corrosivity of fluids, maintenance pigging program and logistics with regard to line servicing.
- 7.3.2.1** The batch treatment method normally entails pumping a slug of chemical solution through the line between two pigs. Frequency of the treatment is governed by the remaining effectiveness of the chemical after a specified amount of gas or liquid has been moved through the line and fluid velocity.
- 7.3.2.2** Continuous injection consists of constant addition of a specific concentration of chemical to the gas or liquid being transported through the pipeline.
- 7.3.3** Chemicals shall be compatible with the process fluid and other additives and the materials of construction. Additional considerations for chemical selection include ease of handling and injection and possible adverse effects on downstream processes.^{26,51}
- 7.3.4** Laboratory tests, field tests, industry experience, and chemical manufacturer's recommendations can be useful for screening chemicals as to their effectiveness, degree of solubility, compatibility, or required injection rates.²⁴⁻²⁸
- 7.3.5** The SHE implications of chemical usage shall be considered. The Safety Data Sheet (SDS) sheets should be read before handling chemicals and shall be stored at an easily accessible location. Appropriate personal protective equipment shall be worn and safety procedures followed when handling or working with chemicals.
- 7.3.6** Corrosion Inhibition
- 7.3.6.1** Addition of corrosion inhibitors should be considered as a corrosion mitigation measure when potentially corrosive gases or liquids are transported.
- 7.3.6.2** Numerous types and formulations of corrosion inhibitors—each with various chemical, physical, and handling characteristics—are commercially available. A corrosion inhibitor package typically contains one or more inhibitors, surfactants, and solvents. The inhibitor can be classified as anodic, cathodic, or both.^{29,30} 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 reach the area where it is needed. In predominantly dry gas systems, inhibitor can be applied as a batch treatment between two pigs.
- 7.3.6.3** To increase inhibitor effectiveness, maintenance pigging should be performed in conjunction with the inhibition program. Pump reliability, chemical availability and chemical compatibility also impact inhibitor effectiveness.
- 7.3.7** Biocides
- 7.3.7.1** Biocide treatment should be considered where microbiologically influenced corrosion has been identified as the primary internal corrosion mechanism.
- 7.3.7.2** Biocides include strong oxidants (e.g., chlorine), reactive aldehydes (e.g., glutaraldehyde), quaternary ammonium salts, amines (e.g., cocodiamine), tetrakis hydroxymethyl phosphonium sulfate (THPS), and acrolein.
- 7.3.7.3** Biocides need to be able to reach the pipe surface in order to kill the bacteria that are causing MIC. For piggable pipelines, biocide treatments should be preceded by a maintenance pig, when feasible, in order to remove solids, biofilms, or other materials that may be attached to the pipe surface. For non-piggable pipe, a surfactant or emulsified may be added to the chemical treatment to help penetrate solids and biofilms.
- 7.3.7.4** Biocides are not compatible with some oxygen scavengers. For example, glutaraldehyde reacts (and consumes) bisulfite oxygen scavengers. In systems where both biocides and oxygen scavengers are being used (and the chemicals will react), such as water systems, the biocide shall be injected a sufficient distance downstream from the oxygen scavenger such that the scavenger has had time to react.

7.3.8 Scavengers

7.3.8.1 Oxygen-scavenging chemicals such as alkaline sulfites can be used to lower the oxygen content of the commodity to suitable levels.³¹ Effectiveness of oxygen-scavenging chemicals is often limited in the presence of H₂S and also depends on pH. Care should be taken when using biocides in conjunction with other chemicals to ensure that there are not compatibility issues. Some oxygen scavengers can react with biocides (as described in Section 7.3.5.4).

7.3.8.2 H₂S scavengers such as triazines and ammonia can be used to lower the H₂S content of the pipeline fluid. H₂S scavenger reactions may increase the pH of the water present. When using H₂S scavengers, consideration should be given to impact on water chemistry, particularly scaling tendency.

7.3.9 Chemical Cleaning

7.3.9.1 Chemical cleaning using appropriate solvents, emulsifiers, surfactants, etc. may be used in cases of presence of detrimental amounts of deposits or other solids. Typically, when chemical cleaning is applied, it is performed in conjunction with maintenance pigging.

7.3.9.2 Chemicals used for cleaning can have a low pH and be very corrosive. Therefore, where chemical cleaning is utilized, care shall be taken to ensure removal of all of the chemical from the pipeline or the remaining chemical shall be neutralized/inhibited.

7.3.10 Scale Inhibitors

7.3.10.1 Scale inhibitors are utilized to control or prevent the deposition of scale on pipelines. Scale inhibition is primarily performed downhole. Sometimes the addition of scale inhibitor may have an adverse effect on the performance of corrosion inhibitors.⁵³

7.3.10.2 Scale inhibitors include phosphates and organic polymers such as carboxylic acid.

7.4 Mechanical Cleaning

7.4.1 Cleaning pigs are used to improve and maintain internal pipe cleanliness by removing contaminants and deposits within the pipe. Periodic line cleaning with pigs may 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 maintenance pigging include:

7.4.1.1 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.

7.4.1.2 Loose sediment, including corrosion products, scale, sand, and dirt, and biofilms that may promote formation of local corrosion cells, especially in conjunction with low flow conditions.

7.4.1.3 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.

7.4.2 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.

7.4.3 Cleaning pigs shall be selected based on the following:

- (a) Ability of pig to remove types of contaminants present and required cleanliness.
- (b) Ability to traverse pipe segment (reduce valves, ports, etc).
- (c) Compatibility of the pig materials of construction with the gas or liquid in the pipeline.
- (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 anything that protrudes into the line that could interfere with the pig. Pipeline flow rates may also limit usage or certain pig types. Barred tees can prevent the passage of pigs where branch lines connect to trunk lines.
- (e) Presence of corrosion inhibitor films or plastic coatings

- 7.4.4** Maintenance pigging frequency should be adequate to remove water and other contaminants before internal pipe damage occurs due to corrosion.
- 7.4.5** Seasonal changes may require a change in maintenance pigging frequency or type of pigs used. Lower temperatures during winter months may require removal of water, precipitated salts, paraffin or wax that might result in freezing, plugging, or corrosion problems.
- 7.4.6** Routine analysis of type and amount of water and other contaminants removed should be performed to evaluate efficiency of maintenance pigging. Changes in pig type and frequency used should be made to accomplish desired pipe cleanliness. In some cases, multiple pig types and runs may be required to remove the build-up of liquids and/or solids.
- 7.5** Where methods are being utilized to mitigate internal corrosion, monitoring shall be utilized to determine the effectiveness of mitigation. One or more of the methods described in Section 6 shall be utilized for this purpose.
- 7.5.1** Monitoring devices should be placed in locations appropriate to determine the impacts of mitigation. For example, monitoring devices placed solely upstream of chemical injection provide no information regarding the effectiveness of the chemical treatment.

Section 8: Feedback and Continuous Improvement

8.1 Introduction

Through continual application and review, internal corrosion control programs and processes should identify and address locations at which corrosion activity has occurred, is occurring, or may occur. This exercise should also identify the types of corrosion (e.g., localized pitting corrosion, general corrosion, erosion, MIC, TLC, and UDC). The continual review process involves collecting feedback from other groups that may be collecting data that are relevant to internal corrosion control as well as from processes implemented directly as part of internal corrosion control implementation. The review process should be used to update the internal corrosion management plan (described in Section 4).

8.2 Communication with Other Groups

Internal corrosion data collected by an operator's corrosion group, such as monitoring, sampling and inspection results, is not the only information that is utilized when managing internal corrosion. Activities that are performed outside of the corrosion group that need to be communicated include, but are not limited to, the following:

- Pipe inspection and/or bell hole inspections performed for purposes other than internal inspection.
- Hot tap coupons.
- Information regarding filter change out frequency and any observations of solids present on the removed filters.
- Operational data from measurement control (flow, pressure, viscosity, etc.).
- Water and/or solids collection/removal (e.g., drips, separators, tanks, etc.).
- Locations of new input sources.
- Future planned changes in operation or design.

8.3 Data Integration and Analysis

All monitoring and sampling data generated as part of the internal corrosion control program shall be collected and reviewed. This data shall be integrated with other information that is generated regarding internal corrosion from other sources (as described in Section 8.2). Information related to any internal corrosion failures, including the cause (mechanism) and root cause analysis (RCA), that occur should be collected. When integrating data, it is equally important to integrate data for locations where internal corrosion is not occurring.

8.3.1 Threat Review

Internal corrosion mechanisms and contributing factors that have been previously identified for the pipeline (or system) shall be re-reviewed. The data collected may indicate that new threats exist. Where new threats are identified, the need for additional sampling, monitoring, inspection and mitigation shall be determined.

8.3.2 Data Trending

Data integration should include trending the results from monitoring, inspection, and sampling. Trending may indicate an increase or decrease in the potential for corrosion. Multiple points may be needed before meaningful trends emerge. Trending may include the following activities:

- Plotting results to see if there is an upward or downward trend (or no change).
- Determining the percentage change from the previous result to the current results.
- Determining the percentage difference between the current result and the running average.
- Data across multiple assets can be compared to establish outliers or 'bad actors.'

8.4 Incorporating Lessons Learned

The lessons learned from any RCAs performed should be incorporated into the corrosion control program. Lessons learned may include information regarding internal corrosion mechanisms and contributing factors, the applicability of various monitoring, sampling or inspection techniques to a given pipeline system, shortcomings in data collection requirements, etc. Lessons learned from both internal (i.e., within the company) as well as external events should be considered.

8.5 Key Performance Indicators

Key performance indicators should be used to determine the overall effectiveness of the internal corrosion control program. Key performance indicators can be leading or lagging indicators. Leading indicators are those that indicate a trend (towards or away from) the desired result prior to corrosion damage occurring. Lagging indicators are those that indicate a trend (towards or away from) the desired result after the corrosion damage has occurred. The following key performance indicators should be tracked:

- Number of internal corrosion related failures (leaks/releases or company defined "failure" criteria).
- Number of corrosion monitoring devices per pipeline/area/unit of distance (by system type and control area).
- Percentage completion of intended mitigation activities.
- Volume of water and/or solids removed from the system from cleaning or other activities.
- Comparison of sample analysis results to targeted values.
- Number of upset conditions.
- Number of inspection locations with measured wall loss that exceeds a company specified threshold (could also include ILI indications).
- Maximum and average corrosion rate from monitoring devices.

Section 9: Corrosion Control Records

9.1 Introduction

9.1.1 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. Corrosion control records can also serve as important documentation of locations where no corrosion is present.

9.2 Relative to internal corrosion threat assessment, the following shall be recorded:

- 9.2.1** The process utilized to identify the relevant internal corrosion mechanisms for a pipeline or system.
- 9.2.2** The identified internal corrosion mechanisms and contributing factors for each pipeline or system.

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

- 9.3.1** Gas and/or liquid composition utilized for design purposes.
- 9.3.2** Physical design specifications including pipe size (including locations of changes), wall thickness, grade, locations of launchers and receivers, and internal coating or lining (including type).
- 9.3.3** Anticipated minimum and maximum flow rates (or flow rates used for calculation purposes if different).
- 9.3.4** Inclusion of anticorrosion measures such as dehydration, deaeration, chemicals, internal coatings, and monitoring facilities.
- 9.3.5** Attendance at pre-FEED and FEED meetings (including HAZOPs/HAZIDs) by the corrosion professionals.

9.4 Relative to internal corrosion and related parameter measurement, the following shall be recorded:

- 9.4.1** Locations (including orientation) and results from all sampling, monitoring, and inspection activities, including justification for location selection.

- 9.4.2 Procedures.
- 9.4.3 Nonconformances.
- 9.4.4 Process variable measurements (might be covered by other groups in the company).
- 9.5 Relative to corrosion control (i.e., mitigation), the following shall be recorded:
 - 9.5.1 Name, type, manufacturer, method of application and quantity/frequency, and blend plant location for all chemical treatment.
 - 9.5.2 Qualification and test data (lab and field) used for chemical selection, including laboratory methodology and operating conditions for which the inhibitor qualification was carried out.
 - 9.5.3 SDS and technical data sheets for each chemical.
 - 9.5.4 Effectiveness criteria.
 - 9.5.5 Date, type(s), size, weight, and number(s) of pig, and amounts of water and/or solids removed (including associated analyses) by location for each mechanical cleaning pig run.
 - 9.5.6 Minimum velocity for intended maintenance pigging application and achieved velocity.
 - 9.5.7 Condition of pigs.
- 9.6 Relative to feedback and continuous improvement, the following shall be recorded:
 - 9.6.1 Leak and catastrophic failure records.
 - 9.6.2 RCA records.
 - 9.6.3 Data integration output.
 - 9.6.4 Change records.
 - 9.6.5 Key performance indicators.
 - 9.6.6 Frequency of corrosion review meeting.

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Appendix A

Typical Gas Quality Specification (Nonmandatory)

This appendix is considered nonmandatory, although it may contain mandatory language. It is intended only to provide supplementary information or guidance. The user of this standard is not required to follow, but may choose to follow, any or all of the provisions herein.

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.

Appendix B

Publications Providing Test Methods for Constituents Associated with Corrosion (Mandatory)

(a)	Bacteria	NACE Standard TM0194 (latest revision), “Field Monitoring of Bacterial Growth in Oilfield Systems” ⁷
(b)	CO ₂	ASTM D1945 (latest revision), “Standard Test Method for Analysis of Natural Gas by Gas Chromatography” ³² ASTM D513 (latest revision), “Standard Test Methods for Total and Dissolved Carbon Dioxide in Water” ³³
(c)	Chloride	ASTM D512 (latest revision), “Standard Test Methods for Chloride Ion in Water” ³⁴
(d)	H ₂ S	ASTM D4658 (latest revision), “Standard Test Method for Sulfide Ion in Water” ³⁵ ASTM D4810 (latest revision), “Standard Test Method for Hydrogen Sulfide in Natural Gas Using Length-of-Stain Detector Tubes” ³⁶ ASTM D1945 (latest revision), “Standard Test Method for Analysis of Natural Gas by Gas Chromatography” ³²
(e)	Organic acids	B. Hedges, L. McVeigh, “The Role of Acetate in CO ₂ Corrosion: The Double Whammy,” CORROSION/99, paper no. 21 ⁴ J. Crolet, N. Thevenot, A. Dugstad, “Role of Free Acetic Acid on the CO ₂ Corrosion of Steels,” CORROSION/99, paper no. 24 ⁵
(f)	Oxygen	ASTM D888 (latest revision), “Standard Test Methods for Dissolved Oxygen in Water” ³⁷ ASTM D1945 (latest revision), “Standard Test Method for Analysis of Natural Gas by Gas Chromatography” ³²
(g)	Solids or precipitates	ASTM D1796 (latest revision), “Standard Test Method for Water and Sediment in Fuel Oils by Centrifuge Method (Laboratory Procedure)” ³⁸ ASTM D5907 (latest revision), “Filterable and Non-Filterable Matter in Water” ³⁹
(h)	Sulfur-bearing compound	ASTM D5504 (latest revision), “Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Chemiluminescence” ⁴⁰ ASTM D3227 (latest revision), “Standard Test Method for (Thiol Mercaptan) Sulfur in Gasoline, Kerosene, Aviation Turbine, and Distillate Fuels (Potentiometric Method)” ⁴¹
(i)	Water	ASTM D6304 (latest revision), “Standard Test Method for Determination of Water in Petroleum Products, Lubricating Oils, and Additives by Coulometric Karl Fisher Titration” ⁴² ASTM D1796 (latest revision), “Standard Test Method for Water and Sediment in Fuel Oils by Centrifuge Method (Laboratory Procedure)” ³⁸

Appendix C

Impacts of Common Impurities (Nonmandatory)

This appendix is considered nonmandatory, although it may contain mandatory language. It is intended only to provide supplementary information or guidance. The user of this standard is not required to follow, but may choose to follow, any or all of the provisions herein.

Bacteria. Microbes commonly found in oil and gas systems are sulfate-reducing bacteria (SRB) and acid-producing bacteria (APB).

Requirements for Performing Visual Inspections

Presence of solids and/or liquids. For gas systems, both hydrocarbon and aqueous liquids should be noted. For liquid or multi-phase systems where hydrocarbon liquids are transported, only aqueous liquids should be recorded. Solids should be characterized as bulk solids (such as debris or sand), nodules, scale, deposits, and/or biological materials. The color of solid should be noted. The presence of a historical liquid level line within the pipe should also be noted. Samples of solids and liquids should be obtained for analysis. If solids are present, cleaning the pipe surface may be necessary to determine if corrosion is present. The location of solids shall be documented before cleaning occurs so that the location of any corrosion relative to the location of solids can be determined.

Evidence of corrosion on internal pipe surfaces. The type(s) of damage shall be identified (e.g., etching/general metal loss or pitting) to characterize the type of corrosion.

Measurement of corrosion. The circumferential and longitudinal extent of corrosion shall be recorded. Measurements for distinct areas of corrosion should be recorded separately. Where pitting is present, the pit diameters of the largest pits should be recorded. The depth of corrosion and/or pitting in the most deeply corroded areas should be recorded.

Orientation. The orientation of the corrosion shall be documented. Typically orientation is described considering the flow direction. For bi-directional pipe, an arbitrary direction may be selected for purposes of describing the orientation of corrosion features.

Position relative to other pipeline features. It should be noted if the corrosion is adjacent to welds or is located at features such as flanges or mechanical joints.

In addition to information collected from the internal surface of the pipe, the following information should also be collected so that the corrosion observations can be integrated:

- Elevation of the examined pipe with respect to the elevation of adjacent pipe sections (e.g., low spot).
- Locations of nearby inlets or outlets, processing equipment, chemical injection points, and heat sources/sinks or other cause for temperature change.

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