CANADA'S OIL & NATURAL GAS PRODUCERS

Best Management Practice

Mitigation of Internal Corrosion in Carbon Steel Water Pipeline Systems

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The Canadian Association of Petroleum Producers (CAPP) represents companies, large and small, that explore for, develop and produce natural gas and crude oil throughout Canada. CAPP's member companies produce about 80 per cent of Canada's natural gas and crude oil. CAPP's associate members provide a wide range of services that support the upstream crude oil and natural gas industry. Together CAPP's members and associate members are an important part of a national industry with revenues from crude oil and natural gas production of about $101 billion a year. CAPP's mission, on behalf of the Canadian upstream crude oil and natural gas industry, is to advocate for and enable economic competitiveness and safe, environmentally and socially responsible performance.

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1 Overview

Internal corrosion is a dominant contributing factor to pipeline failures and leaks. To deal with this issue, the CAPP Pipeline Technical Committee has developed industry recommended practices to improve and maintain the mechanical integrity of upstream pipelines. They are intended to assist upstream oil and gas producers in recognizing the conditions that contribute to pipeline corrosion incidents, and identify effective measures that can reduce the likelihood of corrosion incidents.

This document addresses design, maintenance and operating considerations for the mitigation of internal corrosion in water handling systems. In this document, water pipelines are defined as those constructed with carbon steel materials and transporting fresh or produced water. Typically, these would be pipelines used to convey fresh source water, produced water for water flood purposes, water sent for disposal in disposal wells, or steam condensate. This document does not address the deterioration of aluminum and non-metallic pipelines.

This document complements to CSA Z662 and supports the development of corrosion control practices within pipeline integrity management programs, as required by CSA Z662 and the applicable regulatory agency. In the case of any inconsistencies between the guidance provided in this document and either CSA Z662 or regulatory requirements, the latter shall apply.

This document is intended for use by corrosion professionals involved with the development and execution of corrosion mitigation programs, engineering teams involved in the design of gathering systems, and operations personnel involved with the implementation of corrosion mitigation programs and operation of wells and pipelines in a safe and efficient manner. It contains a consolidation of key industry experience and knowledge used to reduce internal corrosion. However it is not intended to be a comprehensive overview of all practices.

Additional corrosion mitigation best management practices:

- Mitigation of Internal Corrosion in Carbon Steel Gas Pipeline Systems
- Mitigation of Internal Corrosion in Carbon Steel Oil Effluent Pipeline Systems
- Mitigation of External Corrosion on Buried Carbon Steel Pipeline Systems

Leak detection is addressed in a separate best management practice called Pipeline Leak Detection Programs. The use of HDPE lined pipelines and reinforced composite pipe (non-metallic pipelines) are also addressed in separate best management practices.

These documents are available free of charge on the CAPP website at www.capp.ca.

2 Pipeline performance

The current pipeline inventory in Canada is approximately 825,000 km, consisting of about 250,000 km of gathering lines (four to 12 inches), 25,000 km of feeder lines, 100,000 km of large diameter transmission lines (four to 48 inches) and 450,000 km of local distribution lines (one-half to six inches), according to Natural Resources Canada. Much of this pipeline inventory – about 426,000 km – is located in Alberta and is regulated by the Alberta Energy Regulator (AER).

Data from the AER serves as an illustrative example for how pipeline performance has continuously improved: over the past 10 years, the length of pipelines in Alberta grew by 11 per cent while the number of pipeline incidents dropped by 48 per cent, driving the pipeline failure rate to 0.98 incidents per 1,000 km of pipeline in 2017 compared to 2.08 incidents in 2008. This decrease is due to improved requirements, industry education, improvements to inspection programs and a greater focus on pipeline safety within industry.

Nonetheless, operators recognize that pipeline performance must continue improving. This includes focus on internal corrosion, ranked as the top failure type, as part of industry's effort to reduce the potential for pipeline releases and mitigating releases.

Current pipeline performance data can be viewed on the websites of most regulators in Canada.

3 Corrosion mechanisms and mitigation

3.1 Pitting corrosion

Pitting corrosion along the bottom of the pipeline is the more common corrosion mechanism leading to failures in uncoated carbon steel water pipelines. However, water line failures due to pitting corrosion attack at other circumferential positions have been observed as well.

The common features of this mechanism are:

- Presence of water containing any of the following: O_2, CO_2 (aq), H_2S (aq), bacteria, chlorides, scale or solids.
- Pipelines with low or intermittent flow where water and solids can accumulate.

3.2 Other failure mechanisms

Other failure causes that can occur with water pipelines include:

- Improper design or construction of internally coated pipeline systems (e.g., poor coating application, uncoated risers, uncoated flange faces, use of metallic gaskets).
- Presence of deteriorated, damaged or ineffective coatings, linings or joining systems. (Note: Recent incident statistics for water pipelines show that the internal corrosion incident rate for thin film coated operating pipelines was actually higher than that of internally bare.)

Tables 1 and 2 describe the most common contributors, causes and effects of internal corrosion in water pipelines. The tables also contain corresponding industry-accepted mitigation measures to reduce water pipeline corrosion. These apply to internally bare carbon steel pipeline systems and coated or lined pipelines where deterioration or damage has allowed water contact with the steel substrate.

Table 1: Contributing factors – mechanisms

Contributor	Cause/Source	Effect	Mitigation
Oxygen	• Ingress from vented water storage tanks or ineffective gas blanketing systems • Present in surface source waters	• O_2 can accelerate corrosion at concentrations as low as 50 parts per billion • Typical organic inhibitor effectiveness can be reduced by the presence of O_2	• Use gas blanketing, vacuum deaeration, and O_2 scavengers
Aqueous Carbon Dioxide (CO_2)	• Often present in water • CO_2 concentration can be increased through miscible floods (CO_2 floods)	• CO_2 dissolves in water to form carbonic acid • Corrosion rates increase with increasing levels of dissolved CO_2	• Effective pigging and inhibition programs
Aqueous Hydrogen Sulphide (H_2S)	• Sometimes present in water • H_2S concentration can be increased through formation souring • Can be generated by sulfate-reducing bacteria	• H_2S dissolves in water to form weak acidic solution. • Corrosion rates increase with increasing H_2S levels • Hydrogen sulphide can form protective iron sulphide scales • Localized breakdown of iron sulphide scales results in pitting initiation	• Effective pigging and inhibition programs • Small amounts of H_2S (e.g., in ppm level) can be beneficial as a protective FeS film can be established
Microorganisms (bacteria, fungi, algae and protozoa)	• Produced from the reservoir • Present in contaminated source water • Contaminated production equipment • Contaminated drilling and completion fluids	• Acid producing and sulfate reducing bacteria can lead to localized pitting attack • Solid deposits provide an environment for growth of bacteria	• Effective pigging program • Treat with inhibitors and biocides • Eliminate introduction of bacteria (i.e., treat the source of the problem)

Contributor	Cause/Source	Effect	Mitigation
Scale Formation	• Porous non-protective scales can adhere to pipe surface • Scale can form due to pressure and/or temperature changes, or from co-mingling waters	• The scale breakdown may trigger pitting initiation and create a stagnant environment for localized corrosion attack behind scales	• Install pigging facilities and maintain an effective pigging program • Acid removal of scale • Scale inhibitor chemical treatments
Solid Accumulations	• Mainly produced from the formation, can include sand or scale • May originate from drilling fluids, workover fluids, and scaling waters • May include corrosion products from upstream equipment • Low fluid velocity or poor pigging practices allow solids to accumulate in the pipeline	• Can contribute to under-deposit corrosion • Solids can reduce the corrosion inhibitor concentration available to protect the pipe • Solids can prevent corrosion inhibitors from filming the pipe wall.	• Install pigging facilities and maintain an effective pigging program • Control corrosion through effective inhibition

Table 2: Contributing factors – operating practices

Contributor	Cause/Source	Effect	Mitigation
Detrimental Operating Practices	• Ineffective pigging • Ineffective inhibition • Intermittent operation • Inadequate pipeline suspension practices • Commingling of incompatible waters (i.e., mixing waters can create scale problems) • Operating pipelines past the expected life of the internal coating	• Accelerated corrosion	• Design pipeline to be piggable • Design pipelines to allow for effective shut-in and isolation • Develop and implement proper suspension procedures, including pigging and inhibition • Test for fluid compatibilities
Exceeding Maximum Operating Temperature of Coating or Lining Materials	• Change in operating temperature	• Coating deterioration and corrosion damage • High temperatures can damage internal and external coatings	• Limit operating temperature
Management of Change (MOC)	• Change in production characteristics or operating practices • Well re-completions and work overs • Lack of system operating history and practices • Changing personnel and system ownership	• Unmanaged change may result in unexpected corrosion	• Implement an effective MOC process • Maintain integrity of pipeline operation and maintenance history and records • Re-assess corrosivity on a periodic basis

4 Recommended practices

Table 3 describes the recommended practices for mitigation of internal corrosion in water pipelines during design and construction.

Table 4 describes the recommended practices for mitigation of internal corrosion in water pipelines during operation.

Note: The primary method for controlling corrosion in water pipeline systems is the use of properly installed coated, lined or non-metallic pipelines.

Table 3: Recommended practices – design and construction

Element	Recommended Practice	Benefit	Comments
Materials of Construction	• Consider using corrosion resistant non-metallic materials such as HDPE or composite materials as per CSA Z662 Clause 13 • Consider using internally coated carbon steel pipeline systems (e.g., nylon or epoxy coated) with an engineered joining system	• Non-metallic materials are corrosion resistant • Properly coated or lined steel pipelines are corrosion resistant	• Non-metallic materials may be used as a liner or a free standing pipeline depending on the service conditions • Internally bare steel risers and components are susceptible to corrosion
Pipeline Isolation	• Install valves that allow for effective isolation of pipeline segments from the rest of the system • Install spec blinds for effective isolation of inactive segments	• Allows for more effective suspension and discontinuation of pipeline segments	• Removes potential deadlegs from the gathering system • Be aware of creating deadlegs between isolation valve and mainline at tie-in locations (e.g., install 12 o'clock tee tie-ins, or above ground riser tie-ins) • Develop shut-in guidelines for the timing of required steps to isolate and lay up pipelines in each system

Element	Recommended Practice	Benefit	Comments
Pigging Capability	• Install or provide provisions for pig launching and receiving capabilities • Use consistent line diameter and wall thickness • Use piggable valves, flanges and fittings	• Pigging is one of the most effective methods of internal corrosion control • Pigging improves the effectiveness of corrosion inhibitor treatments	• Multi-disc/cup pigs have been found to be more effective than ball or foam type pigs • Use pigs that are properly oversized, undamaged and not excessively worn. • Receivers and launchers can be permanent or mobile
Inspection Capability	• Install or provide capability for inspection tool launching and receiving • Use consistent line diameter and wall thickness • Use piggable valves, flanges and fittings	• Internal inspection using inline inspection (intelligent pigs) is the most effective method for confirming overall pipeline integrity • Proper design allows for pipeline inspection without costly modifications or downtime	• Consideration should be given to the design of bends, tees and risers to allow for navigation of inspection devices

Table 4: Recommended practices – operations

Element	Recommended Practice	Benefit	Comments
Corrosion Assessment	• Evaluate operating conditions (temperature, pressure, water quality) and prepare a corrosion mitigation program • Communicate corrosion assessment, operating parameters and the mitigation program to all key stakeholders, including field operations and maintenance personnel, and involve field key stakeholders for feedback • Re-assess corrosivity on a periodic basis and subsequent to a line failure	• Effective corrosion management comes from understanding and documenting design and operating parameters	• Refer to CSA Z662 Clause 9 - Corrosion Control • Define acceptable operating ranges consistent with the mitigation program • Consider the effects of H_2S, CO_2, O_2, chlorides, bacteria and solids
Corrosion inhibition and monitoring	• Develop and communicate the corrosion inhibition and monitoring program to all key stakeholders, including field operations and maintenance personnel **NOTE**: Ensure personnel understand their responsibilities and are accountable for implementation and maintenance of corrosion management programs. • Develop pipeline suspension and discontinuation procedures	• Allows for an effective corrosion mitigation program	• Refer to Section 5 for Corrosion Mitigation Techniques • Refer to Section 6 for Corrosion Monitoring Techniques • Refer to CSA Z662 Clause 9 - Corrosion Control • Number and location of monitoring devices depend on the predicted corrosivity of the system • Consider provisions for chemical injection, monitoring devices and sampling points

Element	Recommended Practice	Benefit	Comments
Inspection Program	• Develop an inspection program or strategy • Involve field operations and maintenance personnel in the development of inspection strategy	• Creates greater buy-in and awareness of corrosion mitigation program • Provides assurance that the corrosion mitigation program is effective.	• Refer to Section 7 for Corrosion Inspection Techniques • Refer to CSA Z662, Clause 9 - Corrosion Control • Risk assessments should be used to prioritize inspections • Adjust the corrosion mitigation program based on the results of inspection
Failure Analysis	• Recover an undisturbed sample of the damaged pipeline • Conduct a thorough failure analysis • Use the lessons learned from the failure analysis to reassess the corrosion mitigation program	• Improved understanding of corrosion mechanisms detected during inspections or as a result of a failure • Allows for corrosion mitigation program adjustments in response to inspection results	• Adjust the corrosion mitigation program based on the results of the failure analysis • Some onsite sampling may be required during sample removal (e.g., bacteria testing)
Repair and Rehabilitation	• Inspect to determine extent and severity of damage prior to carrying out any repair or rehabilitation • Based on inspection results, use CSA Clause 10 to determine extent and type of repair required • Implement or make modifications to corrosion control program after repairs and failure investigation, so that other pipelines with similar conditions are inspected and mitigation programs revised as required	• Prevents multiple failures on the same pipeline • Prevents reoccurrence of problem	• Refer to Section 7 for Corrosion Inspection Techniques • Refer to CSA Z662 Clause 10 for repair requirements
Leak Detection	• Integrate a leak detection strategy	• Permits the detection of leaks	• Technique used depends on access and ground conditions

Element	Recommended Practice	Benefit	Comments
Management of Change (MOC)	• Implement an effective MOC process • Maintain pipeline operation and maintenance records	• Ensures that change does not impact the integrity of the pipeline system • Understand and document design and operating parameters	• Unmanaged change may result in accelerated corrosion, using inappropriate mitigation strategy for the conditions (outside the operating range)

5 Corrosion mitigation techniques

Table 5 describes common techniques that should be considered for the mitigation of internal corrosion in water pipelines.

Table 5: Recommended practices – corrosion mitigation

Technique	Description	Comments
Oxygen Control	• Use gas blanketing, vacuum deaeration and O_2 scavengers	• O_2 ingress will accelerate the corrosion potential • It can also create elemental sulfur compounds and non-protective sulfur compound films in sour systems
Pigging	• Periodic pigging of pipeline segments to remove solids and debris	• Pigging is one of the most effective methods of internal corrosion control • Can be an effective method for cleaning pipelines and reducing potential for bacteria colonization and under-deposit corrosion • Selection of pig type and sizing is important to ensure effectiveness • Requires facilities for launching and receiving pigs

Technique	Description	Comments
Batch Corrosion Inhibition	• Periodic application of a batch corrosion inhibitor to provide a protective barrier on the internal surface of the pipe • Initial batch treatment of the pipeline is critical at pipeline commissioning, after new pipeline construction, repairs or suspension • Batching is required after any activity that will disrupt the protective films (inspection, line repairs, workovers, etc.)	• Provides a barrier between corrosive elements and the pipe surface • Application procedure is important in determining effectiveness (i.e., volume of chemical, diluent used, contact time and application interval). • Should be applied between two pigs to effectively clean and lay down inhibitor on the pipe. • Should be used in conjunction with pigging to remove liquids and solids (i.e., the inhibitor must be applied to clean pipe to be the most effective)
Continuous Corrosion Inhibition	• Continuous injection of a corrosion inhibitor to reduce the corrosivity of the transported fluids or provide a barrier film	• Can be costly to treat high volumes of water • Continuous injection may be less effective at contacting full pipe surface, especially in a dirty system. Batch treatments may be more effective. • Chemical pump reliability is important in determining effectiveness • May not be overly effective in systems with very low oil residual
Water Treatment	• pH control through chemical additions	• Adjust pH in fluid to non-corrosive range
Biocide Chemical Treatment	• Periodic application of a biocide to kill bacteria in the pipeline system.	• Effective in killing bacteria in systems known to contain bacteria • Use in conjunction with pigging (to clean the line) will enhance effectiveness • Batch treatments are typically the most effective • Use of improperly selected biocides can create a foam that can be an operational issue • Identify the source of the microbial-induced corrosion, and consider addressing the cause and treat accordingly

6 Corrosion monitoring techniques

Table 6 describes the most common techniques for monitoring corrosion and operating conditions associated with internal corrosion in water pipelines.

Table 6: Corrosion monitoring

Technique	Description	Comments
Water Analysis	• Ongoing monitoring of general water chemistry (e.g., pH, chlorides), dissolved metals, bacteria, suspended solids, chlorine, oxygen and chemical residuals	• Changes in water chemistry will influence the corrosion potential • Trends in dissolved metal concentration (e.g., Fe, Mn) can indicate changes in corrosion activity (monitoring of iron-manganese ratio may not be as effective in H_2S system) • Chemical residuals can be used to confirm the level of application • Sampling location and proper procedures are critical for accurate results
Production Monitoring	• Ongoing monitoring of production conditions such as pressure, temperature and flow rates	• Changes in operating conditions will influence the corrosion potential • Production information can be used to assess corrosion susceptibility based on fluid velocity and corrosivity
Mitigation Program Compliance	• Ongoing monitoring of mitigation program implementation and execution	• Chemical pump reliability and inhibitor inventory control is critical where mitigation program includes continuous chemical injection • Corrosion mitigation program must be properly implemented and maintained to be effective • Impact of any non-compliance to the mitigation program must be evaluated to assess the effect on corrosion
Corrosion Coupons	• Used to indicate general and pitting corrosion susceptibility and mitigation program effectiveness	• Trends in coupon data can indicate changes in corrosion activity • Coupons should be used in conjunction with other monitoring and inspection techniques • Coupon type, placement and data interpretation are critical to successful application of this method

Technique	Description	Comments
Bio-spools	• Used to monitor for bacteria presence and biocide effectiveness	• Bio-spool placement and data interpretation are critical to successful application of these methods • Bio-spools should be used in conjunction with other monitoring and inspection techniques • Solids pigged out of pipelines (pig yields) can be tested for sessile bacteria levels • Bacteria presence on surfaces is considered a better way to quantify type and numbers present in the system
Electrochemical Monitoring	• There are a variety of methods available such as electrochemical noise, linear polarization, electrical resistance and field signature method	• Device selection, placement and data interpretation are critical to successful application of these methods • Continuous or intermittent data collection methods are used • Electrochemical monitoring should be used in conjunction with other monitoring and inspection techniques

7 Corrosion inspection techniques

Table 7 describes common techniques that should be considered for the detection of internal corrosion in water injection pipelines.

Table 7: Corrosion inspection techniques

Options	Technique	Comments
Inline Inspection	• Magnetic flux leakage is the most common technique • UT and Eddy Current tools are also available	• Effective to accurately determine location and severity of corrosion • Inline inspection can find internal and external corrosion defects • The tools are available as self-contained or tethered • Pipeline must be designed or modified to accommodate inline inspection • To run a tethered tool inspection it is often necessary to dig bellholes and cut the pipeline
Non-Destructive Examination (NDE)	• Ultrasonic inspection, radiography or other NDE methods can be used to measure metal loss in a localized area	• An evaluation must be done to determine potential corrosion sites prior to conducting NDE • The use of multi-film radiography is an effective screening tool prior to using ultrasonic testing • Use digital X-ray and verify with ultrasonic testing • NDE is commonly used to verify inline inspection results, corrosion at excavation sites and above-ground piping • Practical limitations of NDE methods and the factors affecting accuracy must be understood • Cannot directly measure depth of corrosion pits
Video Camera/ Boroscope	• Visual inspection tool to locate internal corrosion or coating damage	• Used to locate and determine the presence of corrosion damage, but it is difficult to determine severity • Technique may be limited to short inspection distances • Cannot directly measure the depth of corrosion pits

Options	Technique	Comments
Destructive Examination	• Physical cutout of sections from the pipeline	• Consideration should be given to locations where specific failure modes are most likely to occur

8 Repair and rehabilitation techniques

Table 8 describes common techniques for repair and rehabilitation of pipelines damaged by internal water injection pipeline corrosion.

Prior to the repair or rehabilitation of a pipeline the appropriate codes and guidelines should be consulted, including:

- CSA Z662, Clause 10, Permanent and Temporary Repair Methods
- CSA Z662, Clause 13, Reinforced composite, thermoplastic-lined, and polyethylene pipelines

Table 8: Repair and rehabilitation techniques

Technique	Description	Comments
Pipe Section Replacements	• Remove damaged section(s) and replace	• When determining the quantity of pipe to replace, consider the extent of the corrosion, and the extent and severity of damage or degradation of any internal coatings or linings along with the condition of the remaining pipeline • Impact on pigging capabilities must be considered (use same pipe diameter and similar wall thickness) • Replaced pipe section should be coated with corrosion inhibitor prior to commissioning or coated with an internal coating compatible with the existing pipeline

Technique	Description	Comments
Repair Sleeves	• Reinforcement and pressure-containing sleeves may be acceptable for temporary or permanent repairs of internal corrosion as per the limitations stated in CSA Z662	• For internal corrosion it may be possible in some circumstances for the damaged section to remain in the pipeline as per the requirements in CSA Z662 Clause 10 along with proper corrosion control practices to prevent further deterioration • Different repair sleeves are available including composite, weld-on and bolt-on types. Sleeves must meet the requirements of CSA Z662 Clause 10 • As per CSA Z662 Clause 10, if a reinforcement sleeve is to be used as a permanent repair, internal corrosion should have been arrested
Polymer Liners	• A polymer liner is inserted in the steel pipeline • The steel pipe must provide the pressure containment capability	• A variety of materials are available with different temperature and chemical resistance capabilities • Impact on pigging capabilities must be considered • Polymer liners may eliminate the need for internal corrosion mitigation, corrosion monitoring and inspection • Monitor interstitial space for pressure and liquids • Reduction of inhibition programs may impact the integrity of connecting headers and facilities constructed from internally bare carbon steel
Composite or Plastic Pipeline	• Freestanding composite or plastic pipe can be installed for new lines or pulled through old pipelines • This pipe must be designed to provide full pressure containment	• Variety of materials are available with different temperature and chemical resistance capabilities • Freestanding plastic pipelines may be limited to low-pressure service • Impact on pigging capabilities must be considered • Composite or plastic pipelines may eliminate the need for internal corrosion mitigation, corrosion monitoring and inspection • Reduction of inhibition programs may impact the integrity of connecting headers and facilities constructed from internally bare carbon steel

Technique	Description	Comments
Pipeline Replacement	• Using internally coated steel pipeline systems with an engineered joining system should also be considered • Alteration or replacement of the pipeline allows for proper mitigation and operating practices to be implemented	• Should be pig and inspection tool compatible • Refer to Section 4 Recommended Practices in this document for details • Ensure that when replacements in kind occur, the alteration or replacement of the pipeline allows for proper mitigation and operating practices to be implemented, and consider leak-detection options

9 Additional resources

For more information on pipeline corrosion, the reader should refer to:

- NACE International: http://www.nace.org/
- European Federation of Corrosion (EFC): http://www.efcweb.org/
- The American Society of Mechanical Engineers (ASME): http://www.asme.org/catalog/