CEPA Recommended Practices for Managing Near-neutral pH Stress Corrosion Cracking 3rd edition

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The Canadian Energy Pipeline Association (CEPA) is a voluntary, non-profit industry association representing major Canadian transmission pipeline companies. The original 1997 CEPA Stress Corrosion Cracking Recommended Practices (hereafter referred to as the "Practices") were prepared and made public by CEPA in response to the National Energy Board of Canada's public inquiry MH-2-95 into the problem of stress corrosion cracking (SCC) in oil and gas pipelines. A second edition was issued to update the original document with the latest scientific knowledge and the changes in field practices of CEPA companies. This third edition provides a further update of the status of the scientific and engineering knowledge and of the current best practices employed by CEPA companies.

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Contents

Executive Summary

This 3rd edition of the CEPA Recommended Practices for Stress Corrosion Cracking builds on the 1st and 2nd editions published in 1999 and 2007, respectively. These Recommended Practices represent an overview of the methods used by CEPA member companies to manage near-neutral pH SCC on their gas and liquid pipeline systems.

The Recommended Practices have been extensively revised for this 3rd edition, with a focus on the CEPA SCC Management Program. This SCC Management Program comprises nine well-defined steps encompassing three main areas:

- Susceptibility assessment
- Condition assessment and mitigation
- Condition monitoring

The SCC Management Program and the nine steps are presented as the main text of the 3rd edition of the Recommended Practices along with a new Management Program for circumferential SCC.

The main body of the RP is supported by a number of informational appendices describing:

- SCC susceptibility factors and SCC models
- In-the-ditch protocols
- Field data collection
- Condition assessment
- SCC mitigation and repair

The Recommended Practices should be read as a whole, including the main text and appendices. Users of these Practices need to be aware that technologies for detecting, managing, and mitigating SCC are continually improving and should ensure they are up to date with developments through discussion with other pipeline operators and vendors and service providers.

Glossary of Terms

TERM	DEFINITION
AC	Alternating Current
Alternating current field measurement (ACFM)	An electromagnetic technique for detecting and sizing surface breaking defects in metals.
Aerobic	Containing oxygen.
Ambient temperature	The temperature of the surrounding medium in which piping is situated or a device is operated.
Anaerobic	Free of air or oxygen.
ANSI	American National Standards Institute
API	American Petroleum Institute
ASME	American Society of Mechanical Engineers
ASNT	American Society for Nondestructive Testing
Asphalt coating	Asphalt based anti-corrosion coating.
ASTM	American Society for Testing of Materials
Axially	In the pipe longitudinal direction.
BWMPI	Black on White Magnetic Particle Inspection
Category I SCC	SCC features with a failure pressure greater than or equal to 110% of the product of the MOP and a company defined safety factor (failure pressure typically equating to 110% of SMYS).
Category II SCC	SCC features with a failure pressure less than 110% of the product of the MOP and a company defined safety factor, but greater than or equal to the product of the MOP and a company defined safety factor (failure pressure typically 100% of SMYS).
Category III SCC	SCC features with a failure pressure less than the product of the MOP and a company defined safety factor but greater than the MOP.
Category IV SCC	SCC features with a failure pressure equal to or less than the MOP.
Cathodic protection	A technique to reduce the corrosion of a metal surface by making that surface the cathode of an electrochemical cell.
CEPA	Canadian Energy Pipeline Association
CGSB	Canadian General Standards Board
Chainage measurement	Linear distance of the pipeline system measured by kilometre or mile post.
Charpy test	A mechanical test to measure the fracture energy of a material under impact loading.
CIS	Close Interval Survey
Class location	A geographical area classified according to its population density and other characteristics that are considered when a pipeline is designed and pressure tested.
Classical SCC	A form of SCC on underground pipelines in which the crack growth or crack path is between the grains in the metal. The cracks are typically branched and associated with an alkaline electrolyte (pH greater than 9.3). Also referred to as intergranular or high-pH SCC.
Coal tar	A hot-applied external coating made with coal tar pitch.
Coating disbondment	The loss of adhesion between a protective coating and the pipe substrate.

TERM	DEFINITION
Collapse limit (plastic collapse limit)	The maximum stress, strain or load which may be applied prior to onset of plastic collapse.
Colony	An area of stress corrosion cracks occurring in groups of a few to thousands of cracks within a relatively confined area.
Compressive stress	Stress that compresses or tends to shorten the material.
Compressor station	A facility containing equipment that is used to increase pressure to compress natural gas for transportation.
CORLAS™	Software package for Corrosion-Life Assessment of Piping and Pressure Vessels used to evaluate the safety factor of a specific defect involving corrosion and cracking.
Corrosion	Metal loss by chemical or electro-chemical dissolution that occurs as a result of the interaction of the metal (steel) with its environment.
CP	Cathodic Protection
CP rectifier	AC powered device that provides direct current for cathodic protection.
Cracking	The formation of cracks or fissures.
Critical flaw size	The dimensions (length and depth) of a flaw that would fail at a given level of pressure or stress.
CSA	Canadian Standards Association
DC	Direct Current
DCVG	Direct Current Voltage Gradient
Defect	An anomaly in the pipe wall that reduces the pressure-carrying capacity of the pipe.
Dent	A depression caused by mechanical means that produces a visible disturbance in the curvature of the wall of the pipe or component without reducing the wall thickness.
DFGM	Ductile Flaw Growth Model
Diameter, outside	The specified outside diameter (OD) of the pipe, excluding the manufacturing tolerance provided in the applicable pipe specification or standard.
Double submerged arc weld (DSAW)	A method of welding the long seam of a pipe in which the seam is submerged under a solid flux while being welded from both the internal and external surfaces of the pipe.
DP	Dry Powder
Eddy current	Electric current induced within a pipe wall by movement of a non-uniform magnetic field.
Elastic-plastic fracture mechanics	The consideration of both elastic and plastic deformation to predict the fracture behaviour of materials.
Electric resistance weld (ERW)	A method of welding the long seam of a pipe during manufacture in which the two sides of the seam are first heated by the application of an electrical current and then forced together to form a bond.
Electrolyte, undercoating	Soil or liquid between a disbonded coating and a buried or submerged pipe.
Electromagnetic acoustic transducer (EMAT)	Tool employed for in-line inspections where electromagnetic forces are used to induce ultrasonic waves into the pipe steel.
Engineering assessment (EA)	A documented assessment of the performance of a structure based on engineering principles and material properties.
ERP	Emergency Response Plan
False call	An inspection indication that is erroneously classified.

TERM	DEFINITION
Fatigue	The phenomenon leading to fracture of a material under repeated or fluctuating stresses having a maximum value less than the tensile strength of the material.
Flow stress	An arbitrarily defined stress between yield and ultimate, used to predict plastic collapse.
Fluid, service	The fluid contained, for the purpose of transportation, in an in-service pipeline system.
Fracture mechanics	A quantitative analysis for evaluating structural reliability in terms of applied stress, crack length, and geometry.
Fracture toughness	A measure of the resistance of a material to static or dynamic crack extension, used in the calculation of critical flaw size for crack-like defects.
Fusion bonded epoxy (FBE)	An inert, shop-applied, powder coating that is applied by heating the pipe to melt and adhere the coating to the metal surface.
Girth weld	The circumferential weld that joins two sections of pipe.
GIS	Geographic Information System
Gouge	A surface imperfection caused by mechanical damage that reduces the wall thickness of a pipe or component.
GPS	Global Positioning System
Ground water	Water present in the soil, which may be static or flowing.
High vapour pressure (HVP liquid)	Hydrocarbons or hydrocarbon mixtures in the liquid or quasi-liquid state with a vapour pressure greater than 110 kPa absolute at 38 degrees C, as determined using the Reid method (see ASTM D 323), e.g., ethane, butane, propane.
Holiday, coating	A discontinuity in a protective coating that exposes the unprotected metal surface to the surrounding environment.
Hoop stress	The stress in the wall of a pipe or component that is produced by the pressure of the fluid in the piping, any external hydrostatic pressure, or both, and that acts in the circumferential direction.
Hot tapping	The process of attaching a branch connection to an operating pressurized pipeline.
Hydrostatic test	Pressure testing a pipeline by filling it with water and pressurizing it until the nominal hoop stresses in the pipe reaches a specified value.
Hydrotest	See "hydrostatic test".
Integrity Management Program (IMP)	An Integrity Management Program is a documented program that defines the goals, objectives, policies and records used as well as condition monitoring practices and review processes for maintaining pipelines suitable for continued safe, reliable and environmentally responsible service.
In-line inspection (ILI)	The inspection of a pipeline from the interior of the pipe using a sophisticated tool ("smart pig").
Interacting	Describes cracks whose tips are close enough together that the stress fields in front of the propagating crack tip overlap.
Intergranular SCC	A form of SCC on underground pipelines in which the crack growth or crack path is between the grains in the metal. The cracks are typically branched and associated with an alkaline electrolyte (pH greater than 9.3). Also referred to as classical or high-pH SCC.
Interlinking	Describes cracks whose tips are close enough that the stress fields in front of the propagating cracks are relieved and they physically join to eventually form one crack.
Investigative dig	An inspection of a section of pipeline in which the pipe is physically exposed to allow for a detailed examination of the pipeline surface, then recoated and backfilled.
J or J-integral	A factor used to characterize the fracture toughness of a material having appreciable plasticity before fracture.

TERM	DEFINITION
Launcher	A pipeline facility used for inserting a pig into a pressurized pipeline.
Leak	Product loss through a small hole or crack in the pipeline.
Liquid wheel ultrasonics (LWUT)	Tool employed for in-line inspections where ultrasound waves are injected to detect the wave reflections via transducers in a liquid-filled couplant wheel.
Longitudinal stress	The stress at any point on the pipe cross-section acting in the longitudinal direction (longitudinal stress includes the effects of both bending moments and axial forces).
Low vapour pressure (LVP) liquids	Hydrocarbons or hydrocarbon mixture in the liquid or quasi-liquid state with a vapour pressure of 110 kPa absolute or less at 38 degrees C, as determined using the Reid method (see ASTM D 323), e.g., crude oil.
Magnetic flux leakage (MFL)	Tool employed for in-line inspections where the pipe wall is saturated with magnetic flux that 'leaks' from the wall where metal is missing and is detected by coils or active sensors.
Magnetic particle inspection (MPI)	A non-destructive inspection technique for locating surface cracks in a steel using fine magnetic particles and a magnetic field.
Magnetic particle medium	A suspension of magnetic particles in conditioned water or a light petroleum distillate used in the wet magnetic particle inspection technique.
Maximum operating pressure (MOP)	The maximum pressure at which a pipeline system or segment may be operated based on its design and qualification by pressure testing.
Mill scale	The oxide layer formed during hot fabrication or heat treatment of metals.
MTR	Mill Test Records
NACE International	National Association of Corrosion Engineers International
Natural gas	A compressible mixture of hydrocarbons with a low specific gravity primarily consisting of methane CH_4 that occurs naturally in a gaseous form.
NDT	Non-destructive Testing. The inspection of piping to reveal imperfections using radiographic, ultrasonic, or other methods that do not involve disturbance, stressing or breaking of the material.
Near-neutral pH SCC	A form of SCC on underground pipelines associated with a near-neutral pH electrolyte in which the crack growth or crack path is through or across the grains of a metal. Typically this form of cracking has limited branching and is associated with some corrosion of the crack walls and sometimes of the pipe surface. Also referred to as transgranular SCC.
NEB	National Energy Board
NGL	Natural Gas Liquids
NPS	Nominal Pipe Size
Operating stress	The stress in a pipe or a structural member under normal operating conditions.
PAFFC	Software package for Pipe Axial Flow Failure Criterion to determine the failure conditions associated with a single external axial flaw in a pipeline.
Peen	To mechanically work the surface of a metal to impart a compressive residual stress.
pH	Measure of the acidity or alkalinity of a substance or solution written as: pH=-log10 (aH^+) where H^+ = hydrogen ion activity = the molar concentration of hydrogen ions multiplied by the mean ion-activity coefficient.
Pipe	A tubular product used to transport fluids and manufactured in accordance with a pipe specification or standard.
Pipe segment	A length of pipe bounded by changes in pipeline attributes which, in the operator's experience, justify a change in the probability of SCC compared to adjacent segments. A pipeline segment can vary in length from a few joints to tens of kilometres.

TERM	DEFINITION
Pipeline	Those items through which oil or gas fluids are conveyed, including pipe, components, and any appurtenances attached thereto, up to and including the isolating valves used at stations and other facilities.
Pipeline company	The individual, partnership, corporation, or other entity that operates a pipeline system.
Pipeline rupture	A large-scale failure of a pipeline, as occurs when the flaw exceeds the critical dimension to initiate longitudinal propagation; typically resulting in an uncontrolled release of the fluid.
Pipeline system	Pipelines, stations and other facilities required for the measurement, processing, storage and transportation of fluids.
Pipe-to-soil potential	The potential difference between the surface of a buried or submerged metallic structure and the electrolyte that is measured with reference to an electrode in contact with the electrolyte.
Plastic collapse	A failure mechanism whereby there is unstable plastic deformation originating at a defect.
Polyethylene tape coating	Polyethylene tape and adhesive used as a pipeline coating system.
PRCI	Pipeline Research Council International
Pressure	A measure of force per unit area.
RSTRENG	A computer program designed to calculate the pressure-carrying capacity of corroded pipe.
R-ratio or R-value	A measure of the magnitude of a cyclic fluctuation; the ratio of the minimum value to the maximum value, for example, in terms of stress or pressure.
Rainflow counting	A technique for decomposing a random fluctuating signal (i.e. pressure) to characterize the frequency and magnitude of reversals (i.e. signals) and subsequently normalized to projected durations.
Receiver	A pipeline facility used for removing a pig from a pressurized pipeline.
Reinforcement repair sleeve	Full-encircling sleeve that reinforces a weakened area of the pipe to prevent failures by restricting bulging of the defective area and/or transferring load from the pipe section to the sleeve.
Residual stress	Stress present in an object, in the absence of any external loading, which results from the previous manufacturing process, heat treatment or mechanical working of the material.
SCC	Stress Corrosion Cracking
SEEC™	Self Excited Eddy Current
Segment	A length of pipe bounded by changes in pipeline attributes which, in the operator's experience, justify a change in the probability of SCC compared to adjacent segments. A pipeline segment can vary in length from less than a pipe joint to tens of kilometres.
Shielding	The prevention of cathodic protection reaching the pipe surface under disbonded coating; occurs for coatings or soils with high dielectric strength.
Smart pig	An instrumented device or vehicle that uses a non-destructive testing technique to inspect the pipeline from the inside or that uses sensors and other equipment to measure one or more characteristics of the pipeline. Also known as an in-line inspection tool.
SMP	SCC Management Program
Sour gas	Natural gas containing hydrogen sulphide in such proportions as to require treating in order to meet domestic sales gas specifications.
Specified minimum yield strength (SMYS)	The minimum yield strength of a material prescribed by the specification or standard to which the material is manufactured.
Spiral weld	The weld formed when spiral pipe is manufactured.
SSPC	Steel Structures Painting Council

TERM	DEFINITION
Stress	The force per unit area when a body is acted upon.
Stress concentration or raiser	A discontinuity, such as a crack, gouge, notch, or geometry change that causes an intensification of the local stress.
Stress corrosion cracking (SCC)	Cracking of a material produced by the combined action of corrosion and tensile stress (residual or applied).
Stress intensity factor (K_I)	A factor used to describe the stress intensification of applied stress at the tip of a crack of known size and shape.
Supervisory Control and Data Acquisition (SCADA)	A computer system for remotely gathering and analyzing real time data.
Tape coated pipe	For the purposes of this document this refers to pipe coated with polyethylene tape unless otherwise detailed.
TDC	Top Dead Centre
Tensile stress	Stress that tends to elongate the material.
Tenting	A tent-shaped void formed along the seam weld of a pipeline where the external coating bridges from the top of the weld to the pipe.
Terrain conditions	Collective term used to describe soil type, drainage, and topography.
Transverse field magnetic flux leakage (TFMFL)	MFL tool, where the magnets and sensors have been rotated 90 degrees to induce a magnetic field along the circumference of the pipe.
TOFD	Time-of-flight diffraction
Transducer	A device for converting energy from one form to another; for example, in ultrasonic testing, conversion of electrical pulses to acoustic waves and vice-versa.
Transgranular SCC	A form of SCC on underground pipelines associated with a near-neutral pH electrolyte in which the crack growth or crack path is through or across the grains of a metal. Typically this form of cracking has limited branching and is associated with some corrosion of the crack walls and sometimes of the pipe surface. Also referred to as near-neutral pH SCC.
TSB	Transportation Safety Board
USWM	Ultrasonic Wall Measurement
UT	Ultrasonic Testing
UV	Ultraviolet
Valve section	A section of a pipeline isolated by valves.
Wall thickness, nominal	The specified wall thickness of the pipe.
Wet fluorescent inspection (WFMPI)	An MPI technique that uses a suspension of magnetic particles that are fluorescent and visible with an ultraviolet light.
Yield strength	The stress at which a material exhibits the specified limiting offset or specified total elongation under load in a tensile test as prescribed by the specification or standard to which the material is manufactured.

1. Introduction to the Recommended Practices

1.1. SCOPE

The CEPA SCC Recommended Practices (the Practices) deal exclusively with external near-neutral pH SCC, also known as transgranular or low-pH SCC. Both axial and circumferential cracking are considered.

Although some of the management techniques may be similar, the Practices do not specifically address intergranular SCC, also known as classical or high-pH SCC.

The aim of these Practices is to provide an overview of the latest Canadian transmission pipeline industry practices for the management of SCC, with the goals of:

- protecting the safety of the public and pipeline company employees;
- protecting the environment, private and company property; and
- maintaining the reliable and economical operation of the Canadian pipeline system.

1.2. STRUCTURE OF THE 3RD EDITION

For the 3rd edition, the format of the Practices has been re-structured to focus on the SCC Management Program first described in the 1st edition [CEPA 1997] and subsequently revised in the 2nd edition [CEPA 2007]. For this 3rd edition, therefore, the SCC Management Program forms the main body of the Practices and is supported by a number of informational appendices.

The entire text has been re-written and updated, with significant changes in the following areas:

- A new section on SCC Characteristics and Trends (Section 1.4.2) has been added.
- A recommended hydrostatic test procedure is defined (Section 2.3.6.2, and Appendix E) and a method for estimating re-test intervals is presented (Section 2.3.7.2).
- A flow chart for the active management of known SCC is provided (Section 2.3.7.1).
- A comparison is made between the capabilities of EMAT ILI technology and hydrostatic testing for detecting SCC (Section 2.3.7.3).
- The advantages and disadvantages of various crack repair methods are summarized (Table 2.5).
- The discussion of circumferential SCC has been updated and a Management Program developed for CSCC (Section 2.4).
- A comparison of the methods for predicting failure pressures of SCC is given in Appendix D.
- The section on in-line inspection (ILI) technology has been updated and incorporated into a new appendix on mitigation and repair methods (Appendix E).

1.3. CEPA AND STRESS CORROSION CRACKING

The Canadian Energy Pipeline Association (CEPA) represents energy transmission pipeline companies that transport over 97% of the crude oil, petroleum products, and natural gas produced in Canada. CEPA's member companies own and operate more than 130,000 kilometres of pipeline across Canada and the

United States, transporting natural gas and liquid petroleum products to North American markets, providing for the energy needs of millions of consumers.

CEPA has played an important role in the study and management of SCC for many years. It was extensively involved in the National Energy Board of Canada's (NEB) hearing into external SCC in 1995 [NEB 1996]. CEPA developed the definition of "significant SCC" which was used in the transmission pipeline industry for many years and has championed the study and use of high-performance pipeline coatings which have been responsible for many of the improvements in SCC performance of newer pipelines. CEPA is also well-known for its SCC Recommended Practices, now in its 3rd edition.

1.4 SCC OVERVIEW

1.4.1 Near-neutral pH SCC

Near-neutral pH SCC (referred to here simply as "SCC") on buried, high-pressure commodity pipelines is the result of the interaction of a susceptible metallic material, tensile stress, and a suitable environment. SCC initiates on the external pipeline surface and grows in both depth and length directions. Cracks always propagate in a direction perpendicular to the direction of the principal stress, typically the hoop stress, resulting in crack alignment along the longitudinal axis of the pipeline. Occasionally complex stresses occur, which may alter the direction of propagation from the longitudinal axis, e.g., as in the case of circumferential SCC (Section 2.4).

A number of characteristic features of near-neutral pH SCC have been developed from field observations made by CEPA members and other pipeline operators, including:

1. SCC generally occurs underneath a disbonded coating in the absence of adequate cathodic protection (CP). Disbondment allows electrolyte to reach the pipe surface and the absence of CP (either because the disbonded coating "shields" the pipe surface or because the CP system is inadequate or current is prevented from reaching the pipe due to resistive soil) means that the potential at the pipe surface is conducive to cracking. Although not typically found in Canada, SCC has also been observed on uncoated pipe in the absence of adequate CP.
2. Crack growth always occurs perpendicular to the direction of the principle tensile stress. The vast majority of SCC is aligned axially due to the hoop stress generated by the pressure of the gas or liquid being transported. Occasionally, however, cracks may be aligned circumferentially where bending stresses predominate (Section 2.4).
3. SCC may form in the absence of general corrosion but may also initiate in slow or dormant corrosion.
4. Cracking is sometimes associated with features that increase the local tensile stress, such as areas of corrosion, dents, gouges, or weld seams.
5. SCC in the pipe body forms as colonies containing a number of shallow cracks (<10% of the pipe wall in depth). The vast majority of these cracks appear to be dormant and exhibit very low or non-detectable growth rates. SCC colonies forming along the toe of a long seam weld are often constrained by the geometry of the disbonded coating as it "tents" over the weld. Therefore, these "toe of the weld" SCC colonies tend to have relatively linear colony dimensions.
6. SCC often exhibits evidence of corrosion of the crack walls, leading to relatively wide cracks when examined as a metallographic cross section.
7. Failures typically result from the coalescence of a number of shorter cracks, resulting in a high length to depth ratio, often in the range of 20:1 to 50:1.
8. The pH of the solution contacting the colony is near-neutral, in the range of 6-8 pH units.
9. Crack tip propagation occurs in a transgranular fashion when observed through cross-sectioning or careful application of in situ metallography.
10. Almost without exception, SCC is associated with field-applied coatings, with mill-applied high-

performance coatings seemingly providing better resistance.

11. Unlike high-pH SCC, there is no apparent effect of temperature on the occurrence or severity of near-neutral pH SCC.

Understanding the life cycle of SCC is useful in the development of SCC management techniques. An analysis of the life cycle illustrates differences in SCC growth rate and mechanism that assist in understanding SCC severity and in determining the timing of mitigation. The SCC life cycle is often described generically in terms of a "bathtub model", as illustrated in Figure 1.1**Error! Reference source not found.**.[1]

The bathtub model includes a period where conditions for SCC have not yet occurred (Stage 1). This period is often associated with the time necessary for the protective coating to fail and electrolyte (soil solution) to reach the pipe surface and/or for a suitable environment to be generated. As such, the length of this incubation period is often difficult to assess, as a coating may fail soon after construction if improperly applied, or years later when soil stresses, high temperatures or other factors lead to coating failure.

After a coating fails, electrolyte reaches the pipe surface and SCC may initiate as a result of surface residual stresses, metallic imperfections, stress concentrations or a combination of these factors (Stage 2). The (depth-wise) crack velocity is high at the moment of initiation but then decreases as the surface stresses relax.

The crack then enters a long period of relatively slow growth during which an environmental growth mechanism predominates (Stage 3). This period may extend for years or even decades with much of the SCC becoming blunted by corrosion and essentially dormant. A small percentage of SCC will continue to grow and an even smaller subset of this actively growing SCC will have sufficient alignment in the longitudinal and hoop direction to coalesce and form a much larger and injurious crack (Figure 1.2).

[1] Although the bathtub model was originally developed to interpret the lifecycle of high-pH SCC cracks, the same evolution of behaviour also holds for near-neutral pH SCC.

Figure 1.1: Bathtub Model – Life Cyle of SCC Growth in Pipelines [after Parkins 1987]

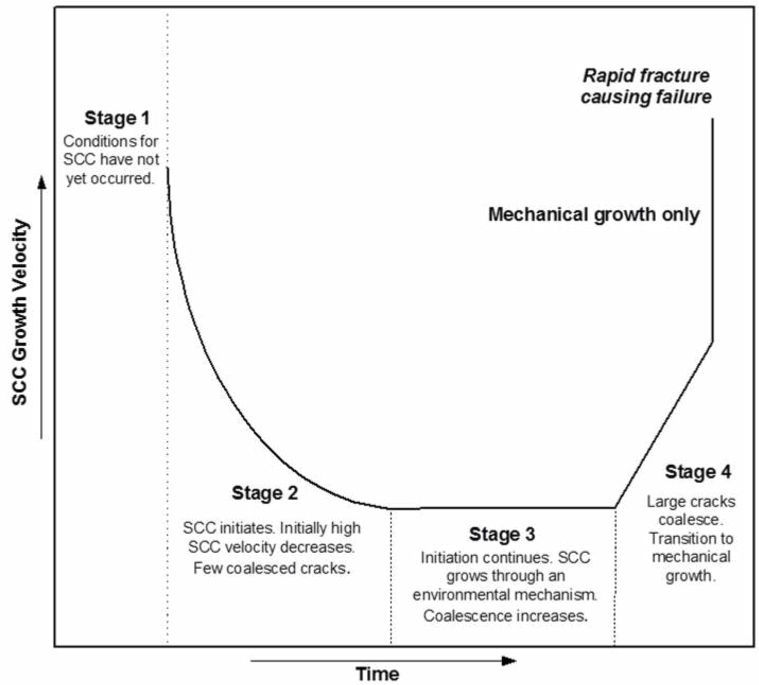
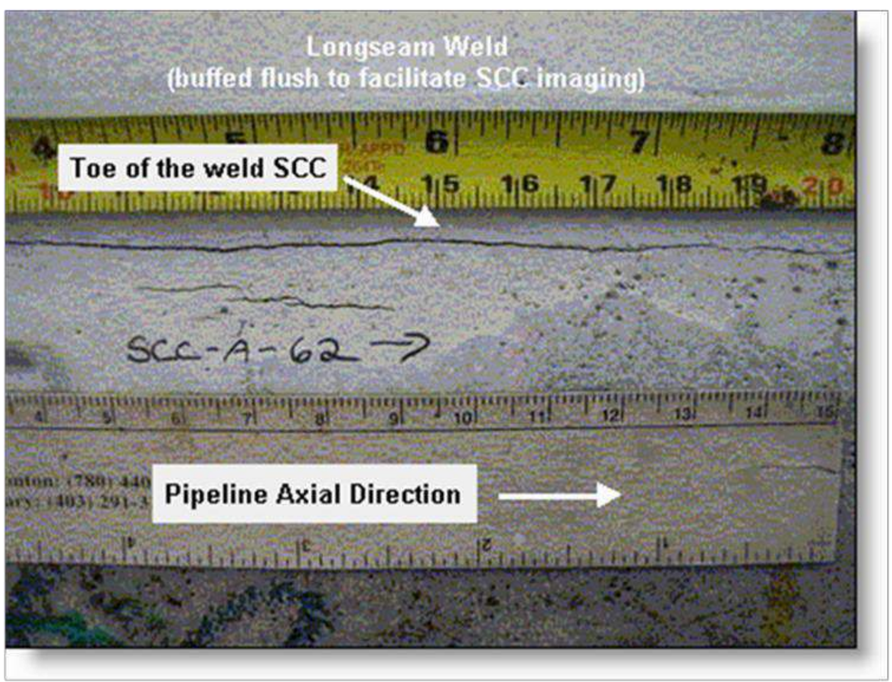


Figure 1.2: Individual SCC Features Aligning Along the Toe of the Longseam Weld Beneath the Tenting of the Polyethylene Tape Coating (removed).



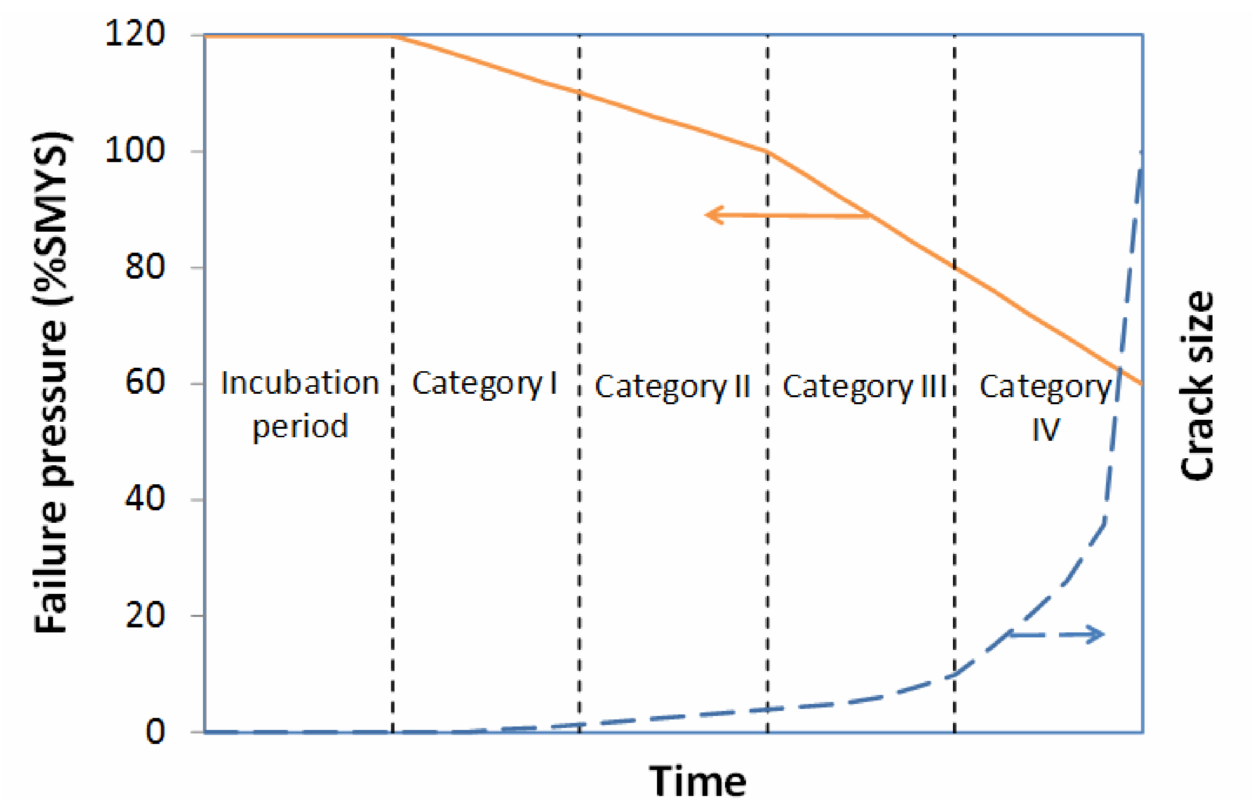
This continued growth and coalescence can result in an SCC feature that is of sufficient size that mechanical forces begin to act synergistically with the environmental growth mechanism to accelerate the SCC growth rate (early Stage 4). This increase in SCC growth rate due to mechanical growth depends primarily on the pipeline's operating cyclic loading regime and the shape and size of the crack, especially the ratio of length to depth. The point at which this mechanical growth mechanism becomes important may be different for a liquid pipeline, for which the pressure cycles are typically deeper and of higher frequency, than for gas pipelines, which are typically subject to smaller and less frequent pressure cycles.

At the end of Stage 4 and during the final crack growth leading to failure, mechanical loading is the primary driving force.

An alternative representation of the life cycle of an SCC crack is illustrated in Figure 1.3 where the failure pressure and crack size are shown as a function of time. Also shown on the figure are the CEPA crack severity categories discussed in more detail in Section 2.3.4. The "crack size" is used here as a qualitative measure of the extent of depthwise and lengthwise crack growth. The figure illustrates, again in a qualitative fashion, that a crack or crack colony spends much of its life in Categories I-III and that it should be possible to manage such cracks before they become the more-serious Category IV cracks.

The CEPA SCC Recommended Practices are built upon these concepts of the life cycle of stress corrosion cracks.

Figure 1.3: Life Cycle of an SCC Crack or Crack Colony Showing the Increase in Crack Size and Corresponding Gradual Decrease in Failure Pressure as Time Progresses.



1.4.2 SCC Trends

The analysis of SCC failures and of crack colonies found during excavations can provide useful insights into the cracking behaviour. Information from failures, either in-service or from hydrostatic testing, can provide insights into conditions that lead to the severest forms of cracking. On the other hand, information on less-severe cracks can provide additional insights into the earlier stages of SCC development.

Caution should always be exercised when using information from field databases as various factors may bias the data. First, any correlation between an SCC property and its location can be biased by the tendency to focus inspections in certain locations, typically immediately downstream of the compressor or pump station. Data collected by in-line inspection tend to be less-susceptible to such bias as ILI runs generally cover a larger fraction of the pipe than hydrotesting or SCC excavations. Second, incomplete or inconsistent data collection can comprise the integrity of the data. For example, the coating condition may be interpreted and reported differently from one contractor to another. Failure to collect or report all data fields can also reduce the usefulness of the database. Nevertheless, notwithstanding these potential limitations, field observations can provide useful insights into the cracking phenomenon.

Of the 35 ruptures on the NEB on-line database for which a cause of failure is given, SCC was reported to be the underlying cause in six of the incidents (although no distinction is made between near-neutral and high-pH SCC) [NEB 2014]. These statistics are for ruptures on Canadian-regulated liquid and gas pipelines from 1992 to 2014. Virtually all of these failures occurred on vintage (pre-1980's) pipelines constructed before the widespread use of mill-applied coatings. Figure 1.4 shows data for in-service and hydrotest failure data from eight major North American gas pipeline operators (CEPA and non-CEPA members) which confirms this trend. In a 2011 survey of operating experience, of a total of 183 failures, only one occurred on a pipeline constructed after 1980 [Fessler et al. 2013]. Together these companies operate over 250,000 km of high-pressure gas pipelines, representing much of the North American gas transmission network.

As mentioned, some of the apparent improvement for recently constructed pipelines can be attributed to the use of mill-applied coatings. Figure 1.5 shows the distribution of in-service and hydrotest failures as a function of distance downstream of the compressor station for various field-applied coating types from the same group of eight North American gas pipeline operators [Fessler et al. 2013]. Up to the end of 2010, none of these companies had reported an SCC failure on a pipeline with mill-applied coating. It is not possible to determine which type of coating is more susceptible from these data as the number of failures has not been normalized against the total length of pipe for each type of coating. Interestingly, however, whereas the frequency of high-pH SCC failures tends to decrease with increasing distance downstream of the compressor because of a strong effect of temperature for that form of cracking (not shown), this is not the case for near-neutral pH SCC failures shown in Figure 1.5, especially for asphalt-coated pipe.

Figure 1.4: Distribution of In-service and Hydrotest SCC Failures Based on the Year of Construction for Eight Major North American Gas Pipeline Operators [after Fesser et al. 2013].

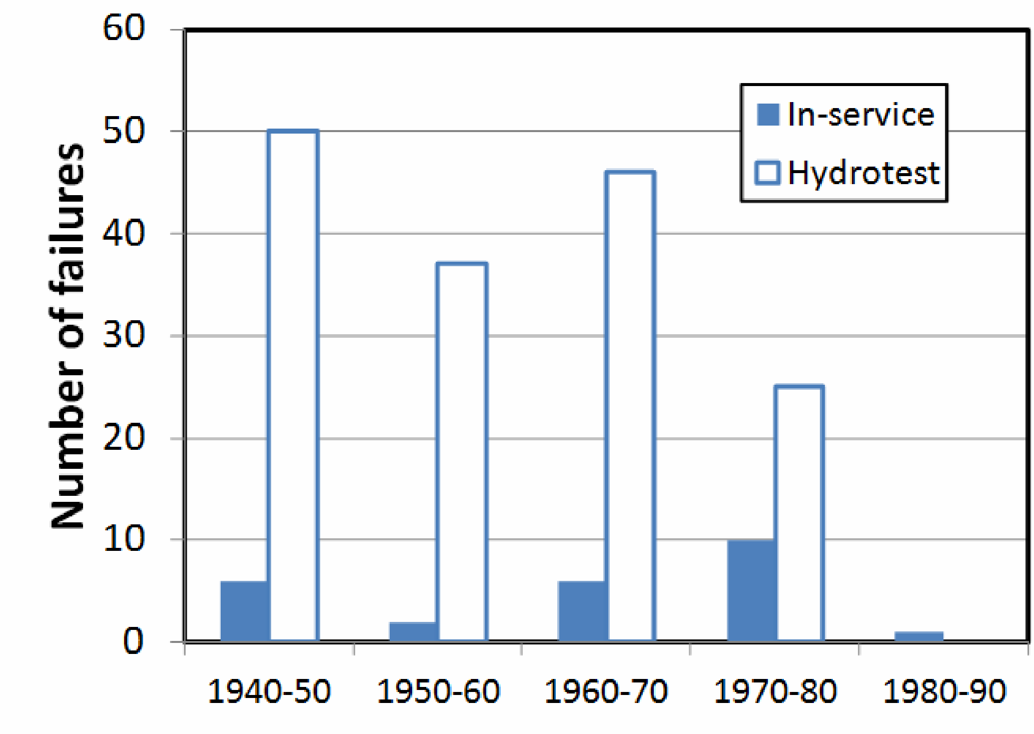
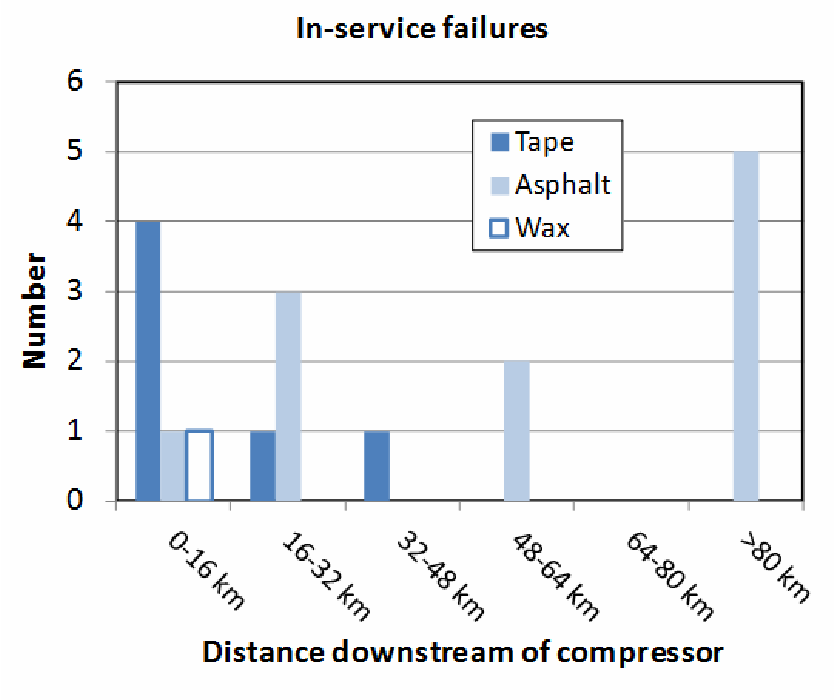
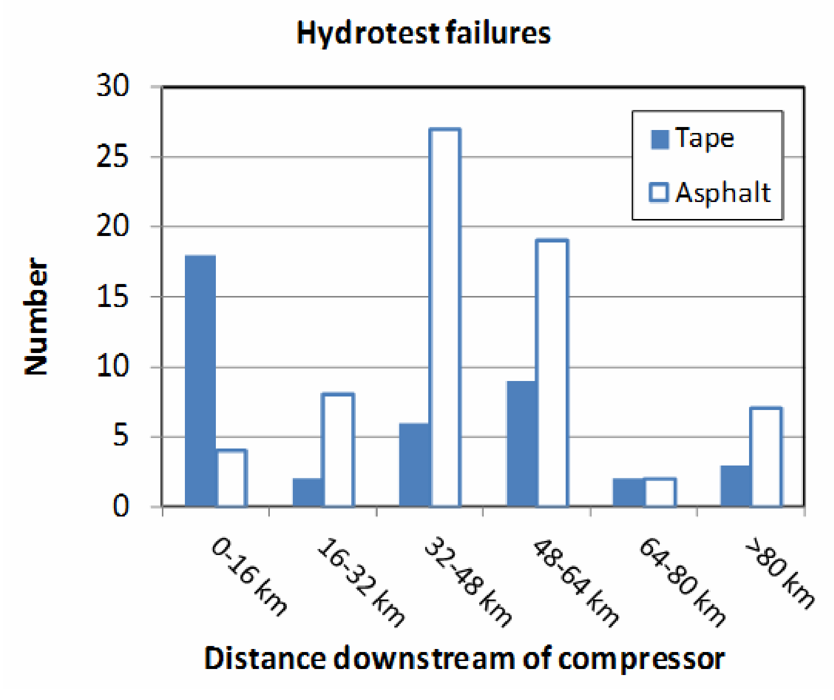


Figure 1.5: Dependence of In-service and Hydrotest Near-neutral pH SCC Failures on Distance Downstream of Compressor Stations as a Function of Coating Type. Data taken from the records of eight North American gas pipeline operators [after Fesser et al. 2013].





The NEB maintains a database of "significant SCC" (see Section 2.3.4.1 and Appendix D.3), which federally-regulated gas and liquid pipeline operators are required to report. "Significant SCC" features are crack colonies which may eventually lead to failure in the future and whose behaviour may provide insights into earlier stages of crack growth and colony development.[1]

As of December 2014, there were over 800 colonies in the NEB "significant SCC" database dating back to 1997. Of the crack colonies for which coating information was provided, 89% occurred on single- or double-wrapped polyethylene tape coating, 11% were associated with asphalt coating, and only a single case of "significant SCC" was found on a coal-tar coated line. The predominant methods of detection were ILI (82%) and varying forms of site selection model (17%), with only five colonies detected in association with a hydrotest program. Where the nature of the ILI tool was defined (See Appendix E), electromagnetic acoustic transducer (EMAT) tools accounted for the majority of reports, although more than 30 colonies were found following a magnetic-flux leakage (MFL) metal-loss inspection. Most of the reported "significant SCC" colonies have been found in the toe of the longseam weld (81%), with a further 13% of reports describing both toe and body of-the-pipe SCC, and only 6% exclusively in the pipe body.

Figure 1.6 shows the distribution of the features with respect to the location of the upstream compressor or pump station for the 391 colonies for which such information was reported. The data suggest a peak number of "significant SCC" colonies at a distance of 20-30 km downstream of the station, unlike the predominance of in-service and hydrotest failures on tape-coated gas pipelines within a distance of 16 km shown in Figure 1.5 (note that approximately 90% of the "significant SCC" colonies in the NEB database are associated with tape coating).

Figure 1.7 compares the reported length and depth of the "significant SCC" colonies. The term "significant SCC" covers both relatively non-injurious short and/or shallow features as well as longer and deeper crack colonies. Partly for this reason, CEPA have moved towards a more-detailed categorization of the severity of the crack colonies, as described in Section 2.3.4 of these Practices.

More-detailed analyses of the NEB "significant SCC" database are provided by Paviglianiti et al. [2008].

[1] Although CEPA introduced the concept of "significant SCC" in the first edition of these Recommended Practices [CEPA 1997], CEPA no longer uses this designation and instead favours the use of crack severity categories which provide greater discrimination between the threat level posed by different features (see Section 2.3.4.1).

Figure 1.6: Distribution of "Significant SCC" with Respect to the Location of the Upstream Compressor or Pump Station.

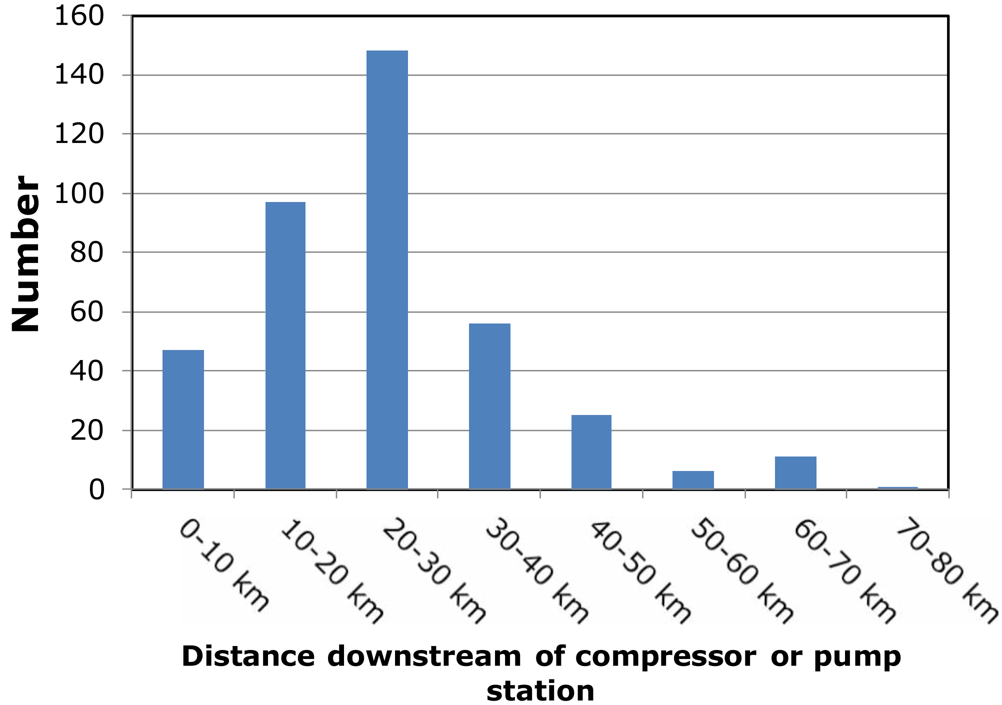
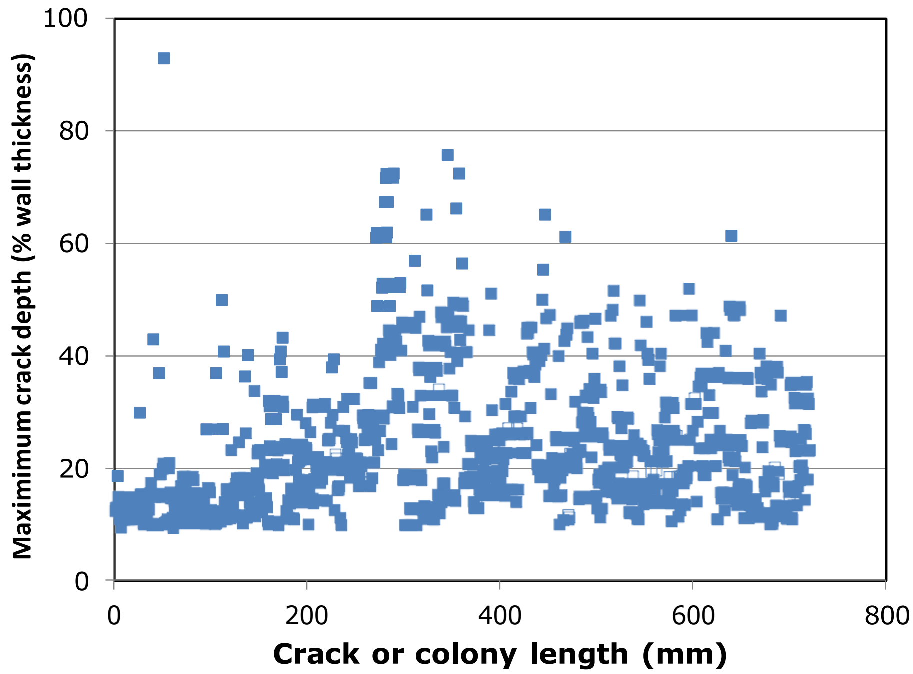


Figure 1.7: Comparison of the Length Versus Maximum Depth of Crack Colonies in the NEB "Significant SCC" Database.



2. CEPA's SCC Management Program

2.1 INTRODUCTION TO THE SCC MANAGEMENT PROGRAM

The CEPA SCC Management Program (MP) for near-neutral pH SCC is based on the transmission pipeline industry's current understanding of SCC and the factors that affect the occurrence and severity of cracking. The SCC MP should be part of a pipeline company's overall Integrity Management Program (IMP). The extent to which a pipeline company implements this SCC MP depends on their unique pipeline system and operating conditions. The MP is designed to be of use to both operators for whom SCC is a new or unknown threat as well as to operators with a broader experience of managing SCC.

Three underlying concepts are used throughout the MP:

1. For integrity management purposes, the pipeline is divided into segments.
2. The MP is consistent with a risk-based approach to integrity management.
3. The MP is structured around the SCC life cycle described in Chapter 1.

This chapter provides a concise description of the overall SCC Management Program illustrated in the SCC MP flow chart in Section 2.2. Each of the nine steps or activities in the MP are then described in more detail in Section 2.3. Additional supporting information is provided in the appendices. Finally, although the MP applies equally to axial and circumferential cracking, specific issues associated with circumferential SCC are discussed in Section 2.4.

2.2 SCC MANAGEMENT PROGRAM FLOW CHART

Figure 2.1 illustrates the SCC MP in the form of a flow chart showing the links between the various steps in the program.

There are three basic components of the SCC MP: susceptibility assessment, characterization and mitigation of SCC, and condition monitoring. Within this overall framework, the SCC MP comprises nine steps or activities that a company should follow to safely manage the threat from SCC. How far along that sequence of steps it is necessary to proceed depends on the extent and severity of the SCC that is found, if any.

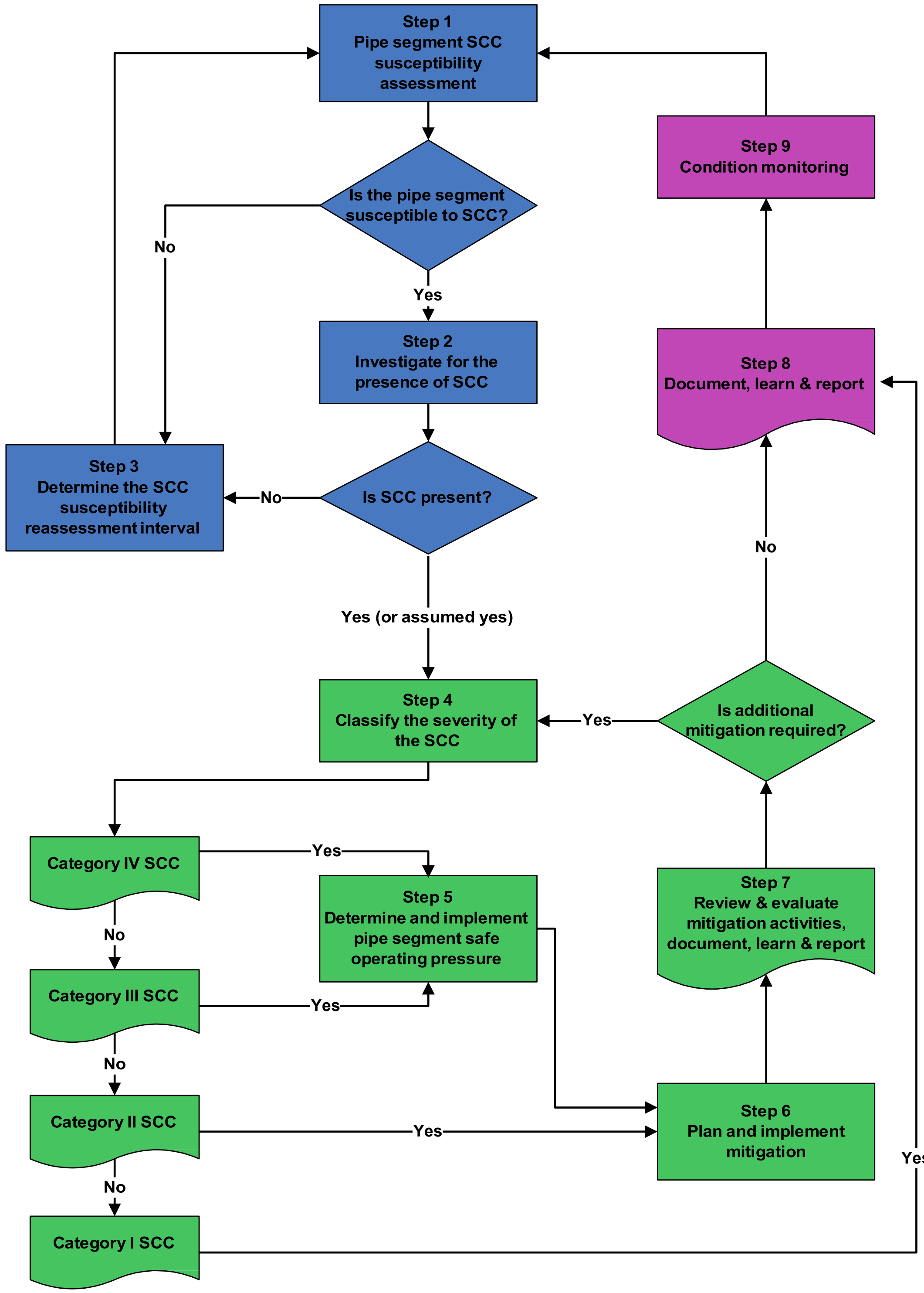
2.2.1 Susceptibility Assessment

The susceptibility assessment component of the program refers to either the initial assessment of a pipeline segment or to the ongoing assessment of a segment previously shown not to contain SCC. A pipeline segment that contained SCC that has been mitigated, and which has been shown by condition monitoring to have a significantly reduced probability of cracking, may also fall into this region of the MP.

The individual steps or activities within the susceptibility assessment part of the program are:

- Step 1: Pipe segment SCC susceptibility assessment (Section 2.3.1).
- Step 2: Investigate for the presence of SCC (Section 2.3.2).
- Step 3: Determine the susceptibility reassessment interval for segments found not to contain SCC (Section 2.3.3).

Figure 2.1: The CEPA SCC Management Program Flow Chart. The three main components of the program are colour coded blue for Susceptibility Assessment, green for Characterization and Mitigation of SCC, and red for Condition Monitoring.



2.2.2 Characterization and Mitigation of SCC

If the susceptibility assessment reveals the presence of SCC, then the next step is to classify the severity of the cracking and to implement a suitable mitigation program. All but the most minor SCC must be mitigated, with the mitigation schedule determined by the severity of cracking. Active crack management may involve an ongoing program of in-line inspection and/or hydrotesting, with the repair of the most-severe cracks or hydrotest failures. Alternatively, cracks may be permanently repaired or the pipe segment replaced, in which case the segment can be moved to the condition monitoring phase of the SCC MP.

The individual steps or activities within the SCC characterization and mitigation part of the program are:

- Step 4: Classify the severity of the SCC (Section 2.3.4).
- Step 5: Determine and implement a pipe segment safe operating pressure (Section 2.3.5).
- Step 6: Plan and implement mitigation (Section 2.3.6).
- Step 7: Review and evaluate mitigation activities (Section 2.3.7).

2.2.3 Condition Monitoring

Finally, if the SCC is minor, or if more-severe cracking is successfully mitigated, then the pipeline segment can be moved to the condition monitoring phase of the SCC MP. A repaired and/or mitigated pipeline segment may be returned to the susceptibility assessment regime if it can be shown that the probability of continued growth of existing cracks, if any, or the initiation of new cracks is low.

The two steps involved in condition monitoring are:

- Step 8: Document, learn, and report (Section 2.3.8).
- Step 9: Condition monitoring (Section 2.3.9).

The SCC MP is applicable to both gas and liquid pipelines, although the specifics of certain steps or activities may differ. Any such differences will be highlighted in the following sections.

As well as the information provided in Sections 2.3.1-2.3.9 for each of the steps in the SCC MP, further information is provided in the appendices. Table 2.1 lists the sources of information for each of the nine steps in the management program.

Table 2.1: Sources of Information for Each of the Nine Steps in the CEPA SCC Management Program.

STEP #	STEP DESCRIPTION	ADDITIONAL INFORMATION
1	Pipe segment SCC susceptibility assessment	Section 2.3.1, Appendix A
2	Investigate for the presence of SCC	Section 2.3.2, Appendices A, B, and C
3	Determine the susceptibility reassessment interval	Section 2.3.3
4	Classify the severity of SCC	Section 2.3.4, Appendix D
5	Determine and implement a pipe segment safe operating pressure	Section 2.3.5
6	Plan and implement mitigation	Section 2.3.6, Appendix E
7	Review and evaluate mitigation activities	Section 2.3.7, Appendices D and E
8	Document, learn, and report	Section 2.3.8
9	Condition monitoring	Section 2.3.9

2.3 CEPA SCC MANAGEMENT PROGRAM

2.3.1 Pipe Segment Susceptibility Assessment

A susceptibility assessment is carried out for pipe segments that:

Have not yet had an SCC susceptibility assessment; or

Have seen a change in SCC probability during condition monitoring; or

Have had mitigation that dramatically decreases the probability of SCC; or

Have been previously assessed but were found not to be susceptible.

The purpose of this step is to:

Determine if a pipeline segment is susceptible to SCC based on a comparison of the pipe and terrain characteristics, pipe operating conditions, and operating history with those conditions known to support SCC. This activity will need to be repeated periodically as the pipeline ages and/or as conditions change.

The prior step is:

None or Step 9: Condition monitoring (if a pipe segment has undergone SCC mitigation to significantly lower the probability of cracking).

The following steps are:

Step 2: Investigate for the presence of SCC (if the pipe segment is deemed to be susceptible) or

Step 3: Determine the SCC susceptibility reassessment interval (if deemed to be non-susceptible)

An initial SCC susceptibility assessment is required on every segment within a pipeline system and should be repeated periodically if the segment is found to be non-susceptible. In addition, for pipeline segments previously found to contain SCC but which has been extensively mitigated, a periodic susceptibility assessment is required, especially if condition monitoring suggests a change in susceptibility.

If the pipeline segment is deemed to be susceptible to SCC then the pipe should be inspected for the presence of cracking (Step 2 in Figure 2.1, Section 2.3.2). If the pipeline segment is deemed not to be susceptible to SCC at this time then the reassessment period should be determined since the susceptibility may change with time (Step 3 in Figure 2.1, Section 2.3.3), as may the understanding of factors determining SCC susceptibility. As discussed in this section, findings of susceptibility or non-susceptibility should be based on the occurrence (or not) of various factors associated with SCC. All evidence and decisions should be documented.

2.3.1.1 DEFINITION OF A PIPELINE SEGMENT

The first step in assessing the SCC susceptibility is to divide the pipeline into one or more segments. For the purposes of these Practices, a pipeline segment is defined as follows:

A pipeline segment is a continuous length of pipe having a similar susceptibility to SCC.

A pipeline segment can vary in length from a few joints to a few tens of kilometres.

Pipeline segments are defined in terms of the probability of finding cracking or in terms of the probability of failure, rather than in terms of the risk from SCC. This implies that, within a given segment, the risk associated with cracking may vary if the segment contains areas with varying consequence or class location. Pipeline operators may choose to also include the consequence of failure when defining pipe segments, but this will result in a larger number of segments requiring assessment.

Practical considerations may also influence how a pipeline operator segments a pipeline system, such as:

<u>Length</u> The operator may choose to divide a pipeline system into segments of equal or reasonable lengths;

<u>Valve sections</u> Existing valve sections may provide convenient segmentation of a pipeline system;

<u>ILI sections</u> For pipelines that are fitted with ILI launch and receipt traps, existing trap-to-trap sections may be deemed appropriate for segmentation purposes;

<u>Geography</u> For large pipeline systems it may be worthwhile to segment on the basis of different geographic or operating areas;

<u>Elevation</u> If hydrotesting is to be considered as a mitigation method, the pipeline segment may require further segmentation to accommodate large elevation changes, or conversely, several segments may be joined into a single segment to accommodate workable hydrotest lengths.

2.3.1.2 SUSCEPTIBILITY ASSESSMENT

SCC is a multivariate phenomenon that involves a number of interacting factors that determine the overall susceptibility of a pipeline segment to cracking. Operator experience has shown that some of these factors are more useful than others in identifying susceptible segments. Pipeline operators with little or no prior experience of SCC should rely on these primary indicators of susceptibility. More-experienced operators may also make use of a large number of secondary factors that have been shown to be associated with one or more stages in the crack life cycle.

2.3.1.2.1 PRIMARY SCC SUSCEPTIBILITY FACTOR

SCC is only possible if the coating disbonds from the pipe and ground water (electrolyte) is able to contact the pipe surface. The nature and condition of the pipe and joint coatings is, therefore, the primary factor on which the susceptibility to SCC can be assessed. An “SCC-susceptible coating” simultaneously allows ingress of an electrolyte, traps the electrolyte against the steel surface, and shields the electrolyte and steel from the cathodic protection system.

To date, SCC has been found beneath field applied polyethylene tape (Figures 2.2 and 2.3), as well as field-applied asphalt enamel, coal tar and some girth weld shrink sleeves (Section 1.4.2). No SCC has been documented for fusion-bonded epoxy (FBE), field applied epoxy or epoxy urethane, or extruded polyethylene coatings. While actual performance data are not yet available for three-layered coatings, the presence of an FBE layer in contact with the pipe surface may provide protection if the outer polyethylene layer is damaged.

However, even though the pipe may be coated with one of the coatings associated with SCC, this does not necessarily mean that cracking will develop. In fact, the majority of disbonded regions of polyethylene tape, asphalt and coal tar enamel will exhibit no cracking. Crack initiation is a complex function of a number of parameters, only one of which is coating disbondment.

In determining the susceptibility of a pipeline segment to SCC, it is important to consider not only the mainline coating but also the coating applied to the girth welds. There have been cases where the majority of the pipe has been protected by a mill-applied coating that remains bonded but where the joints have exhibited SCC because of failure of the field-applied girth weld coating.

Although relatively uncommon in Canada, bare pipe with no external coating has been found to be susceptible to SCC in the U.S. [Fessler et al. 2013].

Information about the nature of the pipe and joint coatings can be obtained from construction and maintenance records. The nature of the coating(s) is of such fundamental importance that if no current or reliable information is available that details the type of external coating that was used on a given segment(s), excavations should be conducted to determine or verify the type of coating.

Figure 2.2: Polyethylene Tape Coating Showing Evidence of Disbondment.

If the pipeline segment is entirely covered with coating that has not shown susceptibility to SCC, including girth weld coatings, the segment may be deemed to be "non-susceptible". The susceptibility reassessment interval (Step 3 in Figure 2.1, Section 2.3.3) should then be determined since the susceptibility to SCC may change with time as the pipeline and coating age. The rationale for the non-susceptibility should be documented and this reasoning should be validated in the future against any new information relating to the SCC susceptibility of pipelines coated with non-SCC susceptible coatings.

If the pipeline segment is covered by a coating which has been associated with SCC, and if there are no other mitigating factors, then the segment is deemed to be susceptible and should be investigated for the presence of cracks (Step 2 in Figure 2.1, Section 2.3.2).

Figure 2.3: Disbonded Polyethylene Tape.

2.3.1.2.2 SECONDARY SCC SUSCEPTIBILITY FACTORS

In addition to the coating type, a number of other factors have been associated with the presence, or the absence, of SCC. These factors can be useful for defining pipeline segments of similar susceptibility or, even if the pipeline is coated with a susceptible coating, can be used for a more in-depth assessment of SCC susceptibility. However, such in-depth assessments require a degree of expertise or familiarity with SCC and should only be used to assess susceptibility if the pipeline operator has prior experience in managing SCC.

The various susceptibility factors are discussed in more detail in Appendix A ("SCC Susceptibility Factors and SCC Models") but broadly fall into four main categories: pipeline attributes, operating conditions, environmental conditions, and pipeline maintenance data.

Pipeline attributes that may indicate susceptibility to SCC include:

- Age
- Season of original construction
- Pipe manufacturer
- Pipe diameter
- Long-seam type
- Pipe alignment (bends)
- Surface preparation
- Coating type (primary susceptibility factor)
- Stress concentration factors
- Location of weights and anchors
- Location of casings
- Mechanical damage
- Backfilling practices Operating

conditions relevant to SCC include:

- Stress level
- Pressure cycling
- Temperature
- Distance downstream of the compressor or pump station
- CP level and possibility of shielding
- Product type

Relevant environmental conditions include:

- Terrain
- Soil type
- Drainage characteristics
- Land use
- Soil CO_2

Useful pipeline maintenance data include:

- In-line inspection (ILI) data
- Cathodic protection (CP) data
- Excavation records
- Coating condition
- Leak/rupture history
- Hydrotest history

In addition to helping assess the susceptibility of a segment to SCC, these factors are also useful for defining the segments in the first instance and for prioritizing segments considered to be susceptible.

It is apparent from this extensive list of secondary susceptibility factors that there are not many factors that are not potentially useful for assessing the susceptibility of a pipeline segment to SCC. Factors that are currently not known to correlate with SCC susceptibility are limited to:

- Pipe grade
- Pipe wall thickness

2.3.1.3 DATA INTEGRATION AND SCC MODELS

Data integration involves the development of models or algorithms to assess the susceptibility to SCC. These models are useful for operators with some prior experience with SCC and who have a database that includes information about the occurrence (and, possibly, the severity) of SCC and the various factors thought to be linked to SCC susceptibility. SCC models are also used for prioritizing susceptible segments for further investigation, for identifying specific locations for investigative digs, or for planning mitigation activities.

There are different approaches to developing SCC models, ranging from reliance on "expert opinion" to the use sophisticated statistical or analytical methods. The knowledge and experience of subject matter experts (SME's) can be used to develop weighting factors for the different primary and secondary factors listed above, which can then be combined to derive an overall "score" or ranking for the susceptibility for a given pipeline segment. Statistical analyses tend to be less subjective than expert-based ranking models but are still dependent on the types of data selected for the analysis. Analytical expert systems, such as neural network, fuzzy logic, or genetic algorithm approaches, may be useful for identifying correlations between SCC and the various susceptibility factors.

Care should be taken when applying a model developed for one pipeline system or by one company to a different system or a different company's assets as such models are not necessarily "portable." Models developed on the basis of data from other systems should be carefully validated against data for the system of interest.

Furthermore, the user needs to understand what the model or algorithm is capable of predicting. If the model is developed on the basis of the <u>occurrence</u> of SCC then it does not necessarily follow that it can also predict the <u>severity</u> of SCC or presence of deep cracks that might present an integrity threat.

As with any sort of predictive model, the accuracy of the predictions depends to a large extent on the quality and quantity of data available. Generally speaking, the larger the database the better. Datasets should be complete and, ideally, will cover locations where SCC does and does not occur. The model or algorithm should be developed or "trained" on a subset of the data and validated against the remaining data. Some subjectivity remains because of the choice of what types of data to include in the correlation, but such subjectivity can be reduced by using a wide range of parameters. Information, and the associated model(s), about where SCC does not occur can be as equally useful as models for predicting the occurrence of cracking.

2.3.1.4 DIFFERENCES BETWEEN LIQUID AND GAS PIPELINES

Many of the primary and secondary factors listed above are equally applicable to liquid and gas pipelines. Of the factors listed, the only ones for which there may be a difference in relevance (and, therefore, a difference in weighting during data integration) are:

- Operating temperature – gas pipelines will generally run hotter than liquid pipelines, especially close to the discharge of the compressor station, although this difference may be mitigated by the use of gas coolers.
- Pressure cycles – because of the incompressible nature of liquids and the ability to run in batch mode, pressure fluctuations on liquid lines tend to be larger and more frequent.

2.3.1.5 DOCUMENTATION

Regardless of whether a segment is deemed to be susceptible or non-susceptible to SCC, it is necessary to document the reasoning behind the decision.

When using a model or algorithm for data integration, it is important to document the basis for the model or algorithm and the results of validation studies.

2.3.2 Investigate for the Presence of SCC

The presence of SCC should be investigated for pipe segments that:

i. Have been determined to be susceptible to SCC, or

ii. Have unreliable or absent SCC historical data.

The purpose of this step is to:

Determine if SCC is actually present in pipeline segments deemed to be susceptible.

The prior step is:

Step 1: Pipe segment susceptibility assessment

The following steps are:

Step 3: Determine the SCC susceptibility reassessment interval (if SCC is not found) or

Step 4: Classify the severity of the SCC (if SCC is found)

A field program to investigate the presence of SCC is required for each pipe segment determined to be susceptible to SCC. The field program in this phase of the SCC MP can be quite limited with the aim only of determining if SCC is actually present within the pipe segment, regardless of severity. The extent of the field program necessary to determine if SCC does or does not exist within a pipe segment is dependent on the previous experience of the pipeline operator and the tools available to the operator for SCC detection.

If cracks are found, the operator should then assess the severity of the SCC (Step 4 in Figure 2.1, Section 2.3.4). If SCC is not found, the operator should document the results of the investigation and then determine the SCC susceptibility reassessment interval (Step 3 in Figure 2.1, Section 2.3.3).

2.3.2.1 INVESTIGATION METHODS

The most common method used to investigate for the presence of SCC is the use of exploratory excavations (or "digs"). Excavation sites may be selected based on:

- SCC models – depending upon the amount and type of data available, the experience of the operator, and the extent to which the model has been validated on similar systems, this method can exhibit a high probability of detecting non-injurious (shallow) SCC, which generally occurs with a high frequency in pipelines susceptible to cracking. The ability to find injurious cracks is not as good and SCC models should not be relied upon for locating deep cracks. SCC models should be developed by experienced personnel within the company or external SME's with demonstrated SCC site selection ability.

- Opportunistic digs – if the pipe is exposed for other inspection or maintenance activities, the opportunity should be taken to inspect susceptible segments for SCC. Opportunistic digs provide a cross section of sites that may have high, medium, or low probability of SCC. However, additional SCC model excavations should be planned if none of these opportunistic excavations fall within high probability locations. Again, opportunistic excavations should not be relied upon to detect injurious SCC.

- ILI correlation excavations – whenever an ILI crack detection tool is run correlation excavations should be conducted to confirm the accuracy and reliability of the tool. Compared with the use of SCC models or opportunistic digs, this method should be more reliable for locating injurious cracks.

Alternatively, hydrostatic testing is capable of detecting SCC above a minimum size. An SCC hydrotest can provide data for a long length of pipe with the added benefit of verifying the pipeline integrity for a period of time following the test. However, a hydrotest that did not result in a failure does not allow the operator to conclude that SCC is not present on a pipe segment, as SCC can be present with dimensions that do not fail at the hydrotest pressure achieved.

2.3.2.2 PRIORITIZATION AND SCHEDULING

Typically, resources do not allow for every pipe segment to be investigated simultaneously, and therefore some prioritization of the pipe segments is required (Appendix A).

Risk-based approaches, where the consequences of an SCC-related failure are considered in conjunction with the likelihood of SCC occurring, are a common means of prioritization. The method of consequence modeling used can be relatively simple (e.g., prioritize high-consequence areas over regions of lower consequence) or complex (e.g., a quantitative assessment of the probability and consequence of failure for each pipe segment). The method chosen is dependent on the operator, their level of experience and expertise, the general approach used by the operator for integrity assessment, and the characteristics of the pipeline system under consideration.

Prioritization can also be based purely on the probability of finding SCC using the susceptibility factors summarized in Section 2.3.1 (see also Appendix A). The various factors are combined using suitable weighting factors to arrive at an overall assessment of the probability of finding SCC. Operators with little prior experience of SCC may initially need to rely solely on a few well-quantified factors, such as coating type, whereas more-experienced operators may make use of a wider range of susceptibility factors.

The time frame for implementing an investigative program to address all potentially susceptible pipeline segments depends on several factors, including:

- The number of potentially susceptible segments.
- The relative susceptibility of those segments.
- The consequences of an incident occurring within those segments.
- The safety of the public and pipeline company employees.
- Protection of the environment, private and company property.
- Maintaining the reliable and economical operation of the Canadian pipeline system.

It is not the intent of these Practices to establish a set time frame for each company to complete this investigative portion of the SCC MP. The company should develop a prudent time frame by considering the factors above and their own particular operating situation and the rationale should be documented.

2.3.2.3 SITE SELECTION FOR EXPLORATORY EXCAVATIONS

For exploratory excavations other than those used to confirm ILI indications or those done opportunistically for other reasons, a method is required to select where to dig within the susceptible segment.

For an operator experienced with SCC, the site selection process will be influenced by the historical SCC data available and by the greater experience in using complex methods of SCC investigation. Experienced operators will select SCC sites based on:

- The results of in-line crack inspection.
- Well-developed SCC models that incorporate terrain, CP data, historical data and analysis of other non-SCC in-line inspection records.
- Results from SCC hydrotests, either previously performed on the pipeline segment or on other segments with similar SCC characteristics.
- Complex risk analysis algorithms.

Site selection is more challenging for an operator with limited or no experience of SCC on their system. Operators with limited SCC experience will need to perform many excavations to statistically support the presence or severity of SCC on a pipeline segment. However, as SCC experience is obtained, the investigation of other pipeline segments should require a decreasing number of excavations.

More guidance on site selection is provided in Appendix A.

2.3.2.4 DATA COLLECTION AND DOCUMENTATION

Although the purpose of this step in the SCC MP is solely to determine if SCC is present, there is also the opportunity to collect additional information for use in other steps. During excavations, the following crack characteristics should be measured and documented:

- Crack length and density (spacing)
- Crack depth
- Crack position relative to other features, such as welds, stress raisers, or areas of corrosion

In addition, data should be collected relating to the site characteristics and of any other factor considered to be relevant to SCC.

Further information on SCC characterization and field data collection are given in Appendix B ("In-the-Ditch Protocols") and Appendix C ("Field Data Collection"), respectively.

2.3.2.5 CHALLENGES IN DECIDING THAT SCC IS NOT PRESENT

Deciding that SCC is present is easy. Deciding that SCC is not present is more challenging. Hydrostatic testing cannot be used to prove the absence of SCC because small cracks will not lead to failure during the test. Similarly, crack detection ILI tools have a threshold size below which cracks are not reliably identified, although confirmatory digs can be used to improve the confidence in the tool capabilities.

The most reliable method for proving that SCC is not present is through exploratory excavations. On the assumption that some type of SCC model has been used to target the digs, the question then is how many excavations are necessary to demonstrate that cracks are not present in a given pipe segment?

There is currently no definitive method for deciding how many digs are necessary and the answer is dependent on the nature of the pipeline system under investigation and prior operator experience. Research projects are under way to develop methods for estimating the number of digs and pipeline operators should make themselves aware of advances in this area. At the current time, the best general advice is that operators should perform the number of excavations required to statistically support the SCC management path chosen at the probability level that is acceptable to all stakeholders. For operators with more refined site selection models, greater experience, or more accurate tools to direct their investigations, the required number of excavations will be less than that for those who have little experience with SCC.

Example: *An operator has analyzed an historical SCC excavation data set and found that SCC was detected at 50% of the excavations within a pipe segment containing SCC, where the excavation locations were selected using an SCC environmental model. A similar pipe segment was thought to be susceptible to SCC but had not yet been investigated for the presence of cracks. Five excavations were then performed within this pipe segment with the dig sites selected using the same SCC site selection method that generated the historical data set. The operator did not detect SCC at any of these excavations. Therefore, the operator has determined with a 94% confidence level that SCC does not exist on this pipe segment. After confirming with all stakeholders that this level of confidence is acceptable, the pipe segment was determined not to have SCC present and was moved to Step 3: Determine the SCC susceptibility reassessment interval.*

2.3.2.6 DIFFERENCES BETWEEN LIQUID AND GAS PIPELINES

The only aspects in which the investigation for SCC on liquid lines may differ from that for gas pipelines is in terms of prioritization of pipeline segments and site selection for exploratory excavations. The consequences of failure of liquid lines differ from those for gas lines and this may influence the prioritization of susceptible segments based on risk. In addition, the different influences of operating temperature and pressure fluctuations for liquid and gas lines may impact the prioritization of pipe segments and the selection of specific sites for excavation.

2.3.3 Determine the SCC Susceptibility Reassessment Interval

This activity block applies to pipe segments that:

i. Were determined not to be susceptible to SCC; or

ii. Were determined to be susceptible to SCC but no SCC was detected after a statistically valid number of evaluations were performed.

The purpose of this step is to:

Determine the reassessment interval for pipe segments with no known SCC since the susceptibility to cracking may change over time.

The prior steps are:

Step 1: Pipe segment susceptibility assessment, or

Step 2: Investigate for the presence of SCC

The following step is:

Step 1: Pipe segment susceptibility assessment

For pipeline segments either deemed to be non-susceptible or for which no SCC was found during investigation, no further activities are required until the next susceptibility assessment is performed. To determine the timing of the next SCC susceptibility assessment, the following points should be considered:

- The possibility that an SCC attribute may change resulting in an increase in SCC susceptibility, such as the time-dependent deterioration of the coating.
- The probability of detection of the inspection program used to investigate for the presence of SCC.
- A change in the consequence of SCC failure within the pipeline segment.

The reassessment interval should not exceed ten years. The operator may choose a shorter reassessment interval based on the considerations listed above. In addition, the operator should make use of opportunistic excavations to inspect for SCC. This will allow the operator to validate or, possibly extend, the reassessment interval.

2.3.4 Classify the Severity of SCC

The severity of SCC should be assessed for pipe segments:

i. That were determined to be susceptible to SCC; and

ii. Where SCC was detected.

The purpose of this step is to:

Classify the severity of the SCC to enable decisions to be made regarding suitable crack mitigation.

The prior steps are:

Step 2: Investigate for the presence of SCC (for newly discovered cracks), or

Step 7: Review and evaluate mitigation activities (if some crack mitigation has previously occurred).

The following steps are:

Step 5: Determine and implement a pipe segment safe operating pressure (for Category III and IV SCC).

Step 6: Plan and implement mitigation (for Category II SCC).

Step 8: Document, learn, and report (for Category I SCC)

If cracks are found during the SCC investigation phase (Step 2), or are still present following an earlier round of mitigation (Step 7), the SCC should be classified according to the four severity categories described below. The SCC severity categories are a key component of the CEPA SCC MP since they not only provide an indication of the condition of the pipeline but are also used to define appropriate mitigation procedures (Step 6), the timing of such mitigation (Step 6), and the pressure at which the pipeline can be safely operated before mitigation is completed (Step 5).

2.3.4.1 CEPA SCC SEVERITY CLASSIFICATIONS

The CEPA SCC severity categories are defined in terms of the calculated failure pressure $P_{F,SCC}$ (Table 2.2). Figure 2.4 shows a schematic representation of the four severity categories in terms of the length and depth of the SCC.

The calculated failure pressures are based on measured or inferred crack dimensions (see Section 2.3.4.2) and standard failure pressure algorithms (see Section 2.3.4.3).

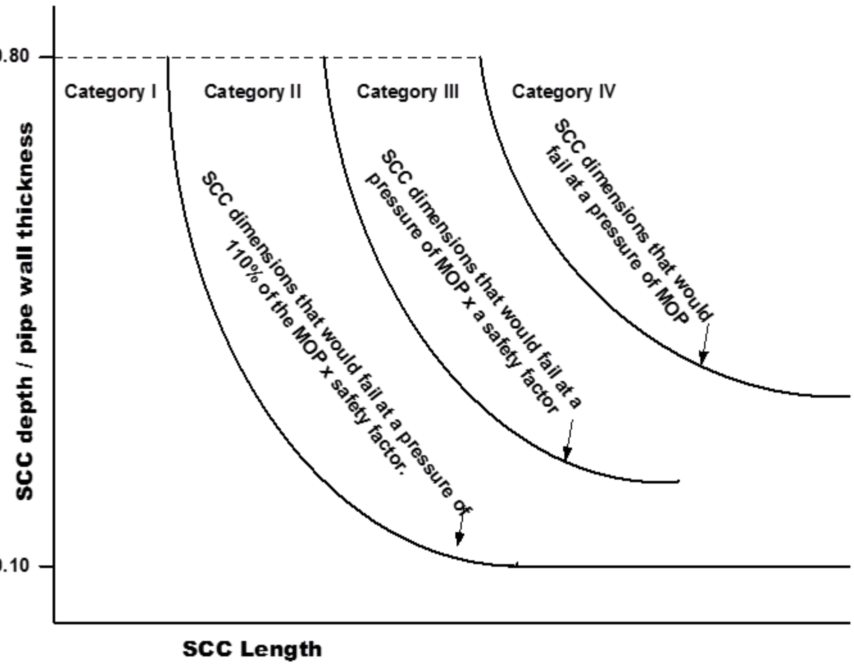
Table 2.2: CEPA SCC Severity Categories

CATEGORY		DEFINITION	DESCRIPTION
I	$P_{F,SCC} \geq 110\% \times MOP \times SF$	A failure pressure greater than or equal to 110% of the product of the MOP* and a company defined safety factor (SF). The failure pressure for Category I SCC typically equals 110% of SMYS.	SCC in this category does not reduce pipe pressure containing properties relative to the nominal pipe properties. Toughness dependent failures are not expected for this category of SCC.
II	$110\% \times MOP \times SF > P_{F,SCC} \geq MOP \times SF$	A failure pressure less than 110% of the product of the MOP and a company defined safety factor, but greater than or equal to the product of the MOP and a company defined safety factor.	No reduction in pipe segment safety factor.
III	$MOP \times SF > P_{F,SCC} > MOP$	A failure pressure less than the product of the MOP and a company defined safety factor but greater than the MOP.	A reduction in the pipe segment safety factor.
IV	$P_{F,SCC} \leq MOP$	A failure pressure equal to or less than MOP.	An in-service failure becomes imminent as the MOP is approached.

* MOP – the maximum operating pressure is the highest pressure at which a pipeline can be operated based on its design and qualification by pressure testing [CSA 2011].

The safety factor (SF) is a value defined by each pipeline company. Minimum values may be between 1.25 and 1.39 for pipeline segments in Class 1 areas. However, the SF should incorporate not only minimum values prescribed by applicable codes for new pipelines but also historical data relating to possible unique material properties of the pipeline segment, failure history (SCC or otherwise), consequences not captured by Class locations, uncertainty in data, and any other relevant information about the pipeline segment that would suggest a greater SF is required.

Figure 2.4: Schematic Representation of the Four CEPA SCC Severity Categories in Terms of the Crack Length and Depth.



When using this classification, the following points should be considered:

1. SCC deeper than 80% of the pipe wall thickness should not be evaluated using standard failure pressure calculations as the models that support these calculations have not been verified beyond this depth. SCC features deeper than 80% of pipe wall thickness should be treated with a high degree of conservatism equal to that of a Category IV SCC feature.
2. When using representative SCC data to evaluate the condition of a pipe segment, the SCC severity should be evaluated on the basis of the minimum pipe grade, wall thickness and toughness properties found within the pipe segment regardless of where the SCC occurred.
3. All the current failure calculation programs become increasingly inaccurate for SCC lengths greater than 400 mm. In most cases the level of conservatism in the failure pressure calculation for SCC greater than 400 mm is so large that the results become unusable, especially for very long and shallow SCC. An engineering assessment by a person experienced in failure pressure determination for SCC will be required to assess the severity of SCC greater than 400 mm in length.
4. SCC less than 10% of the wall thickness does not necessarily pose a greater risk if left in the pipeline at excavations than if it is removed by buffing because:

   - The driving force for fatigue growth of SCC in gas pipelines with a depth of less than 10% of wall thickness is extremely small. Therefore no fatigue growth is expected for these shallow cracks. However, for liquid lines, fatigue growth may be significant and should be assessed for each individual pipeline operating condition.
   - Sandblasting followed by recoating with high performance coating has been shown to prevent further environmental growth.
   - Removal of shallow SCC by buffing does not provide a benefit in terms of increasing the failure pressure when the original crack is compared to the resultant buffed area.

5. The stress developed at MOP times the safety factor is used here in place of SMYS to account for over-designed piping that is often found within the pipeline systems of CEPA member companies.

In the first edition of the Practices [CEPA 1997], CEPA defined the dimensions of what was called "significant SCC." This terminology was not included in the second edition [CEPA 2007] in which the SCC severity categories described above were introduced. However, the definition is still referred to and operators with pipelines regulated by the Canadian National Energy Board are still required to report instances of "significant SCC" to the regulator. A comparison of the CEPA SCC severity categories and "significant SCC" is given in Appendix D ("Condition Assessment").

2.3.4.2 SOURCES OF DATA

The crack dimensions required to calculate a failure pressure can be obtained from a number of sources:

- Excavations – if exploratory excavations are used as the primary source of crack data, a sufficiently large area of the pipe should be inspected to provide confidence that the most severe features in the pipe segment have been located. The fraction of pipe that needs to be inspected should be supported by a statistical analysis based on the conditions considered to support crack growth on the pipeline. This is likely to mean that additional excavations are required beyond those necessary to establish the presence of SCC in Step 2 of the SCC MP. The SCC feature with the lowest failure pressure should be used to define the severity category for the entire segment.

- Hydrotest – if a hydrotest is used to inspect for SCC, then the severity category is defined by the failure pressure of the most severe SCC feature, typically the first SCC hydrotest break. If no failures occurred during the hydrotest the operator would classify the severity of SCC as either Category I or Category II, depending upon the maximum pressure used during the test.

- In-line inspection – the capability of ILI tools to detect and correctly size SCC in both liquid and gas lines is continually improving. Prior to running the tool, the operator should ensure that the vendor will supply sizing data that will permit the calculation of the SCC severity category and will allow discrimination between Categories II, III, and IV. The reported dimensions of crack-like features should be verified by excavation.

- In-service failure – an in-service SCC failure will provide a direct measure of the failure pressure and the corresponding crack severity category.

Because of the small fraction of large SCC features, it is unlikely that Category III or IV SCC will be detected by methods other than a hydrotest or a reliable SCC ILI. In pipe segments where Category II SCC exists, the ratio of Category II SCC to Category I SCC is typically sufficiently large that some Category II features will be detected by performing an adequate number of exploratory excavations. In practice, the operator should perform enough pipe inspection to rigorously demonstrate that Category II SCC does not exist, as the discovery of Category II SCC triggers more direct methods of pipe segment assessment/mitigation that will then indicate whether Category III or IV SCC is present.

Further information on the sources of SCC dimensions and their reliability can be found in Appendix D.

2.3.4.3 FAILURE PRESSURE CALCULATION

The following information is required to calculate the failure pressure:

- The maximum interacting SCC length (Section 2.3.4.4).
- The maximum depth of the feature. For interacting SCC, a depth profile is useful to reduce some of the conservatism associated with the calculation of the failure pressures for such features.
- The actual (measured at the SCC location) or nominal pipe yield strength, ultimate strength, toughness (such as a Charpy value), wall thickness and pipe diameter. Nominal properties typically provide conservative failure pressures, although care should be taken in selecting the values in the case of older pipe with low toughness. Actual pipe properties should be used whenever available.
- Identification of abnormal stresses that may influence the SCC feature in addition to the normal hoop and longitudinal stresses (Section 2.3.4.5).

These data can then be used with one of the following standard methods to calculate the failure pressure for the SCC feature:

- "Log-secant" method
- Pipe axial flaw failure criterion (PAFFC)
- CorLAS™
- Fitness-for-service criteria for crack-like flaws in API 579 or BS 7910

Each of these methods is discussed in more detail in Appendix D, along with a comparison of the relative degree of conservatism for actual SCC failures.

The operator should be aware of the potential sources of error and conservatism in the calculated failure pressures.

2.3.4.4 CRACK INTERACTION

SCC interaction refers to the effect of the overlapping crack tip stress fields of two adjacent SCC features, even though visually the cracks may not appear to be connected. For interacting cracks, the total length encompassed by the two (or more) SCC features must be used in the failure pressure calculation.

Interaction is assessed in both the circumferential and the axial directions. Two SCC features are deemed to be interacting in the circumferential direction if [Parkins and Singh 1990]

$$Y \leq \frac{0.14(\ell_1 + \ell_2)}{2} \qquad (2\text{-}1)$$

where Y is the circumferential distance between the two cracks of lengths ℓ_1 and ℓ_2.

Two SCC features are deemed to be interacting in the axial direction if

$$X \leq \frac{0.25(\ell_1 + \ell_2)}{2} \qquad (2\text{-}2)$$

where X is the axial spacing between the two SCC features.

Both the axial and circumferential criteria must be met for the SCC features to be interacting. If either X or Y is greater than the calculated limit, the SCC features can be treated as individual features for failure calculation purposes.

When a third SCC feature is to be assessed adjacent to two SCC features already determined to be interacting, the non-interacting lengths of adjacent SCC features are to be used in the assessment.

2.3.4.5 CRACKS IN ASSOCIATION WITH OTHER FEATURES

SCC is sometimes found in association with other features that modify the local stress field, either through stress concentration or through a reduction in the wall thickness. Historically, SCC has been found:

- Aligned at an angle to the pipe axial direction due to the presence of a sag or non-construction bend or intermittent or constant external loading on poorly supported pipe.
- Associated within dents, wrinkles, or buckles.
- In areas of mechanical damage, such as gouges or tears.
- Associated with external corrosion.
- In areas of high residual stress.

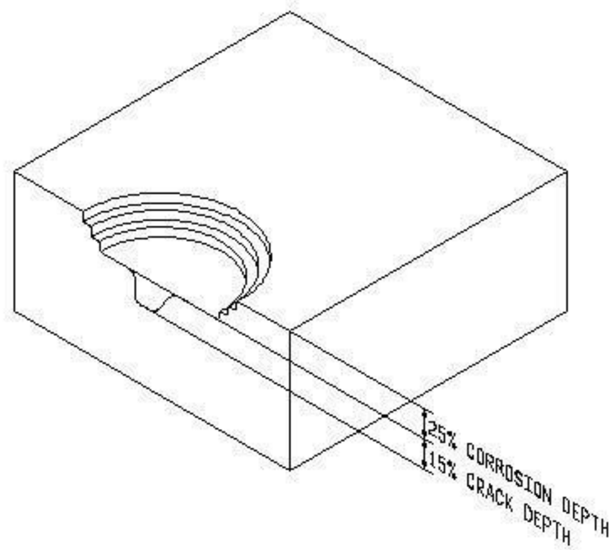
Each of these features modifies the stress field experienced by the crack, often in a complex fashion. Aside from the calculation of the hoop stress, the quantification of other stresses can be complex and often requires the use of experts skilled in the application of finite element analysis. Such methods of analyses are outside of the scope of this document, but operators should take note of any feature in the region of the SCC that may modify the stress field.

As noted above, SCC is commonly found in areas of corrosion (Figure 2.5). It is usually difficult to determine whether the crack has initiated from the area of corrosion (i.e., the crack is active) or whether the corrosion is “eating out” the crack (i.e., the crack is non-active). The distinction is important because active SCC will continue to pose an integrity threat, whereas non-active SCC will eventually be totally consumed by the corrosion. CEPA members typically conservatively assume that the crack is active.

When estimating the depth of SCC in areas of corrosion, CEPA members typically use the sum of the crack depth and the depth of corrosion (or other cause of metal loss). When using ILI data, it is common to use the depth reported by the crack detection tool only, which is generally found to be equal to the sum of the depths of SCC and corrosion. Using the sum of the crack depth from a crack-detection tool and the depth of corrosion from a separate metal-loss tool run is found to lead to an overly conservative assessment of the effective crack depth.

Example: *A corrosion pit penetrates 25% into the pipe wall. The SCC located at the base of the corrosion penetrates an additional 15% of the pipe wall thickness. The crack depth for assessment purposes is then assumed to be 40% of the pipe wall thickness.*

Figure 2.5: Schematic Illustrating an SCC Feature in the Bottom of Metal Loss



2.3.4.6 DIFFERENCES BETWEEN LIQUID AND GAS PIPELINES

The definition of the crack severity categories, the calculation of failure pressures, and the characterization of interacting cracks are identical for SCC on liquid and gas pipelines.

2.3.5 Determine and Implement a Pipe Segment Safe Operating Pressure

A safe operating pressure should be defined for pipe segments in which:

i. Category III or Category IV SCC has been detected.

The purpose of this step is to:

Determine a safe operating pressure for pipe segments containing Category III or IV SCC prior to mitigation.

The prior step is:

Step 4: Classify the severity of the SCC.

The following step is:

Step 6: Plan and implement mitigation.

The presence of Category III or IV SCC reduces the safety factor of the pipe segment and a reduction in pressure is required if the line is to continue in service prior to mitigation.

2.3.5.1 SAFE OPERATING PRESSURE FOR CATEGORY III SCC

For Category III SCC, the recommended safe operating pressure depends on the method used to identify the cracks.

For Category III SCC discovered by opportunistic excavations or excavations selected on the basis of SCC models, the following guidelines apply:

- It must be assumed that Category III SCC exists elsewhere on the pipe segment.
- It is conservative to assume that the largest remaining SCC feature has a failure pressure slightly greater than the maximum pressure recorded for the pipeline segment in the last 60 days.
- The safe operating pressure is then the maximum pressure experienced in the 60 days prior to finding the crack divided by the company defined safety factor, where the company defined safety factor should not be less than 1.25.

For Category III SCC discovered by a hydrotest, the safe operating pressure is the lesser of:

a) The hydrotest failure pressure divided by a company defined safety factor.

b) The maximum operating pressure experienced by the pipe segment within the last 60 days, other than during the hydrotest.

For Category III SCC discovered by an ILI crack tool, the safe operating pressure is the lesser of:

a) The lowest calculated failure pressure of all ILI features (accounting for error limits) divided by a company defined safety factor.

b) The maximum operating pressure experienced by the pipe segment within the last 60 days.

2.3.5.2 SAFE OPERATING PRESSURE FOR CATEGORY IV SCC

Category IV SCC is defined by an SCC failure pressure less than MOP. Therefore, any Category IV SCC discovered through inspection at SCC model-identified excavations, opportunistic excavations, or in-line crack inspection correlation excavations likely did not fail only as a result of either the conservatism in the failure pressure calculation or by a current operating pressure that was less than MOP (or both). Within this pipe segment, other similarly large and mechanically unstable SCC anomalies may still exist and may be growing mechanically at a rapid rate. On discovery of Category IV SCC, the operator should;

- Implement an immediate pressure reduction to the maximum pressure experienced by the anomaly at the location within the last fifteen days divided by a company defined safety factor, which should be no less than 1.25.
- Consider a greater pressure reduction if the pipeline segment is in higher class locations.

Mitigation should be planned and implemented immediately. If this is not possible, a further pressure reduction may be required, based on an engineering assessment.

2.3.6 Plan and Implement SCC Mitigation

Mitigation is required for pipe segments that:

i. Contain Category III or Category IV SCC and may have failed or are operating under a pressure restriction, or;

ii. Contain Category II SCC and are operating with normal pressure levels.

The purpose of this step is to:

Define the most appropriate mitigation and repair methods for Category II, III, and IV SCC and the corresponding mitigation timeline.

The prior steps are:

Step 4: Classify the severity of SCC (if Category II SCC is present)

Step 5: Determine and implement a pipe segment safe operating pressure (if Category III or IV SCC is present).

The following step is:

Step 7: Review and evaluate mitigation activities, document, learn and report.

Following the discovery of Category II, III, or IV SCC, suitable mitigation should be planned and implemented. In the case of the discovery of Category III and IV SCC, a reduction in operating pressure should be implemented if the line is to remain in service prior to mitigation. Following the initial mitigation, the need for an on-going mitigation program should be reviewed in Step 7 of the SCC MP.

Category I SCC does not require mitigation. Instead, the operator should document the SCC found (Step 8, Figure 2.1) and continue to monitor the condition of the pipeline (Step 9, Figure 2.1).

2.3.6.1 RECOMMENDED MITIGATION STRATEGIES FOR CATEGORY II, III, AND IV SCC

The four recommended mitigation and repair strategies for SCC are (Table 2.3) are:

- Hydrotesting and repair of failed defects
- In-line crack inspection and repair of SCC defects
- 100% surface NDT for SCC and repair of defects
- Pipe segment replacement

Each of these mitigation strategies is briefly described here and discussed in more detail in Appendix E ("SCC Mitigation and Repair").

Table 2.3: CEPA Recommended Mitigation Strategies for Category II, III, and IV SCC.

SCC SEVERITY CATEGORY	MITIGATION
II	Perform an engineering assessment to determine the timeline for mitigation, taking into account: • The initial defect dimensions. • The maximum SCC growth rate. • Any factors that may impact the growth rate, such as the presence of stress raisers. Mitigation activities should commence within the mitigation timeline determined by the engineering assessment or within a maximum of 4 years* of the discovery of Category II SCC. Implement a mitigation plan for the pipe segment that includes at least one of the following methods: • SCC hydrotesting and repair of failed defects. • Reliable in-line crack inspection and repair of SCC defects. • 100% surface NDT for SCC and repair of SCC defects. • Pipe segment replacement.
III	Implement the safe operating pressure as described in Step 5. Perform mitigation activities as described for Category II SCC. Mitigation should commence within the mitigation timeline determined by an engineering assessment based on the initial crack size and a suitable crack growth rate at the reduced operating pressure or within a maximum of 2 years of the discovery of Category III SCC.
IV	Implement the safe operating pressure as described in Step 5. Perform mitigation activities as described for Category II SCC above. Mitigation should commence within 90 days of the discovery of Category IV SCC if the pipeline is still in operation or within the mitigation timeline determined by an engineering assessment, whichever is shorter.

* The maximum period of 4 years for the mitigation of Category II SCC is based on the estimated time for the largest possible Category II SCC feature to grow to become a Category IV crack.

2.3.6.2 HYDROSTATIC TESTING

Hydrostatic testing not only detects and removes the most severe SCC features but also demonstrates the integrity of the line for a future period of service (Appendix E).

The CEPA recommended hydrotest procedure involves a short pressure spike at relatively high pressure followed by a leak test [Fessler et al. 2013].

For the spike test, it is recommended that:

- the spike pressure should be as high as possible within the range 100-110% SMYS, but should not be so high as to cause bulging of the pipe
- the spike hold time should only be long enough to verify the pressure, and not more than one hour

For the leak test, it is recommended that:

- the leak test be performed either by maintaining a low water pressure for a longer time or, in the case of gas pipelines, using flame ionization after the pipeline is re-pressurized
- if a water-pressure test is used, the pressure should be at least 10% lower than the spike pressure and 10% higher than the maximum allowable operating pressure
- the pressure should be monitored for a period of eight hours, but shorter times may be sufficient if the pressure remains constant

Failed SCC defects should be repaired using one of the methods summarized in Section 2.3.6.7 and described in more detail in Appendix E.

2.3.6.3 IN-LINE INSPECTION

Reliable in-line inspection for SCC is now available for both liquid and gas pipelines (Appendix E). In theory, ILI crack tools provide information on the size and location of all SCC features (and other crack-like defects) larger than a certain threshold size. The probability of identification (POI) and probability of detection (POD) of SCC features can be improved by performing confirmation excavations and feeding back information from these investigations to the ILI vendor.

ILI technology is continually improving and operators should consult with other operators and with ILI vendors for the latest information.

Defects should be repaired using one of the methods summarized in Section 2.3.6.7 and described in more detail in Appendix E.

2.3.6.4 SURFACE NDT

For relatively short pipeline segments, it is feasible to excavate and inspect 100% of the pipe surface and repair any SCC defects that are found.

Defects should be repaired using one of the methods summarized in Section 2.3.6.7 and described in more detail in Appendix E.

2.3.6.5 PIPE SEGMENT REPLACEMENT

Under some circumstances it may be appropriate to replace the entire pipe segment, or a portion of it, with new pipe material using state-of-the-art construction practices. Pipe replacement provides remediation of 100% of the SCC features.

2.3.6.6 COMPARISON OF MITIGATION METHODS

Table 2.4 summarizes the advantages and disadvantages of each of the mitigation methods described above.

2.3.6.7 REPAIR METHODS

Table 2.5 summarizes the various options for the repair of SCC along with their respective advantages and disadvantages. Further details of these methods are provided in Appendix E.

2.3.6.8 DIFFERENCES BETWEEN LIQUID AND GAS PIPELINES

All four mitigation methods are appropriate for liquid and gas pipelines. Historically, ILI was more favoured for liquid pipelines because of the lack of a tool that could be run in a gas pipeline without the use of a liquid slug. However, the recent improvements in EMAT technology now make ILI an equally viable mitigation method for gas lines.

All of the repair methods are appropriate for use on both liquid and gas pipelines.

Table 2.4: Comparison of SCC Mitigation Methods

MITIGATION METHOD	ADVANTAGES	DISADVANTAGES
Hydrostatic testing	Removes all critical defects that would fail at the spike pressure. Demonstrates integrity of pipeline. Can slow crack growth for a period of time after test.	Line must be taken out of service. Need to obtain and dispose of test water. Does not provide any information about non-critical SCC. Expensive.
ILI	Can be done without taking line out of service. In theory, provides information on all SCC present (above a threshold size). Allows prioritization of repairs.	Need tool launch and receipt facilities on pipe. Tools may not be available in all sizes. Expensive.
100% surface NDT	All SCC detected and, after repair, mitigated.	Becomes increasingly impractical for long pipe segments.
Pipe replacement	Restores pipe to original condition (or better).	Line out of service for period of time.

Table 2.5: Comparison of SCC Repair Methods

REPAIR METHOD	ADVANTAGES	DISADVANTAGES
Grinding and buffing	Provides information on crack depth for tool validation purposes.	Time consuming if many crack colonies. Reduces load-bearing capacity. May need reinforcement.
Pressure containment sleeve	Can be used for leaking defect. Does not require grinding of cracks.	Requires in-service welding on pipe.
Pipe replacement	Restoration of original pipe strength.	Involves interruption of service. Expensive.
Steel reinforcement sleeve*	Restoration of original pipe strength Does not require welding.	Requires prior grinding of SCC.
Steel compression reinforcement sleeve*	Restoration of original pipe strength.	Requires prior grinding of SCC.
Fiberglass reinforcement sleeve*	Restoration of original pipe strength.	Requires prior grinding of SCC.
Hot tap	No interruption of service.	
Direct weld deposition*	Suitable for repair of SCC in bends Cheaper than sleeving.	Requires prior grinding of SCC. Danger of burn through. Possibility of hydrogen cracking.
Recoating	Inexpensive. Effective way of treating large errors of minor SCC.	Leaves crack-like features in pipe.

* Requires removal of cracks by grinding prior to repair.

2.3.7 Review and Evaluate Mitigation Activities

This activity block applies to pipe segments that:
Have undergone some form of pipe segment mitigation as described in Step 6.
The purpose of this step is to:
Manage SCC remaining in the pipe.
The prior step is:
Step 6: Plan and implement mitigation.
The following steps are:
Step 4: Classify the severity of the SCC (if cracks remain)
Step 8: Document, learn, and report (if cracks have been mitigated)

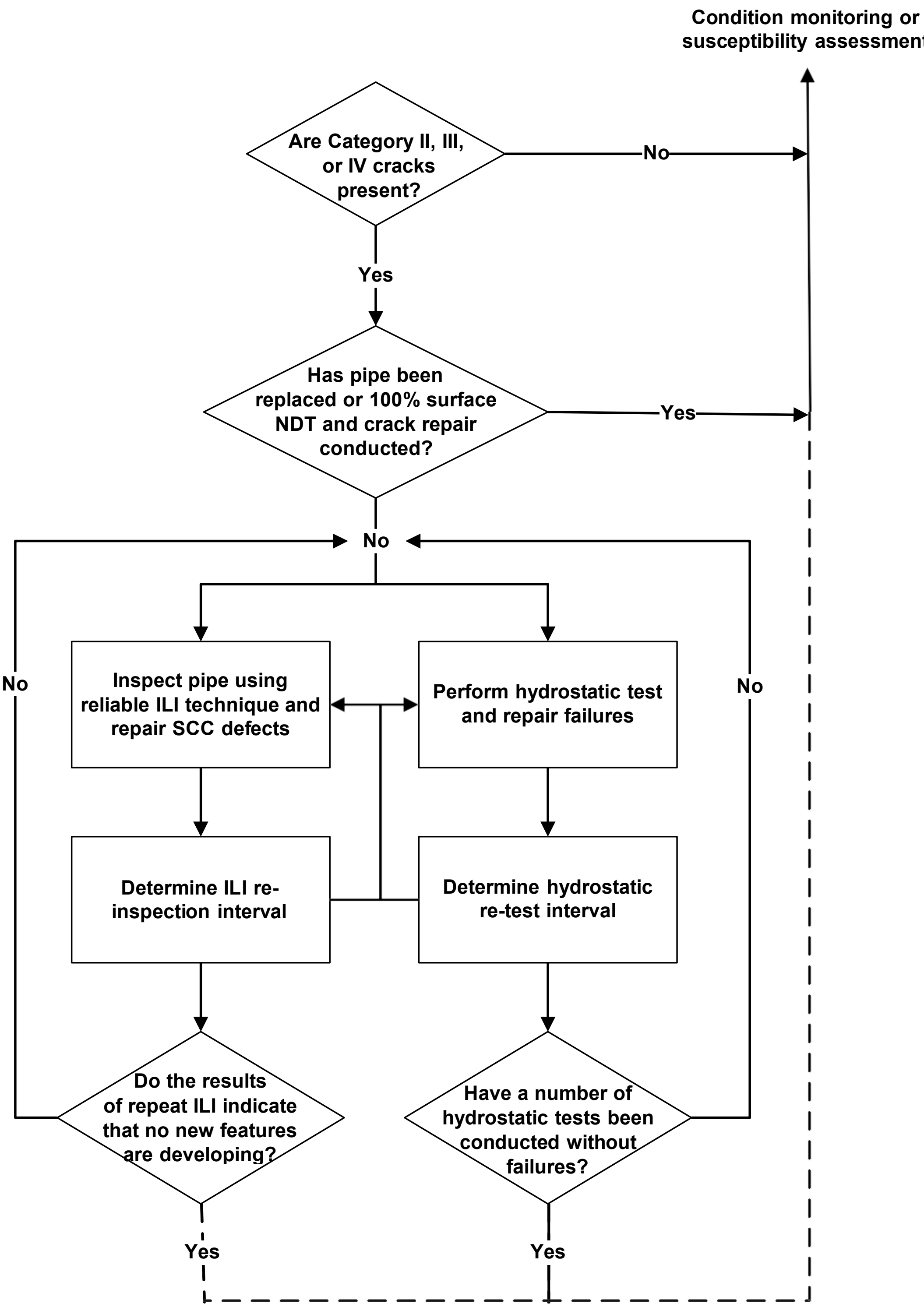
2.3.7.1 MITIGATION FLOW CHART

Following the initial mitigation of Category II and III cracks in Step 6 of the SCC MP (all Category IV features having been repaired or removed from the pipe), it is necessary to establish an on-going SCC mitigation program for the remaining SCC features.[3]

Figure 2.6 shows a flow chart for an on-going mitigation program based on the use of either hydrotesting or ILI. Following the initial mitigation of Category II, III, and IV cracks in Step 5, periodic hydrotesting or ILI should be used to determine if the remaining SCC features are continuing to grow. Re-inspection by hydrotesting or ILI should be performed at suitable intervals (see Section 2.3.7.2). It is not necessary to use the same procedure for each subsequent inspection (e.g., after an initial ILI inspection, it is possible to then use hydrotesting or a mixture of hydrotesting and ILI for subsequent inspections).

[3] If pipe replacement using modern construction practices was used as a mitigation strategy in Step 5, the pipe segment does not require further mitigation. If 100% surface NDT and repair of SCC was used as a mitigation strategy in Step 5 and the pipe was re-coated with a modern high-performance coating, no further mitigation is required.

Figure 2.6: Recommended Practices for On-going SCC Mitigation Program.

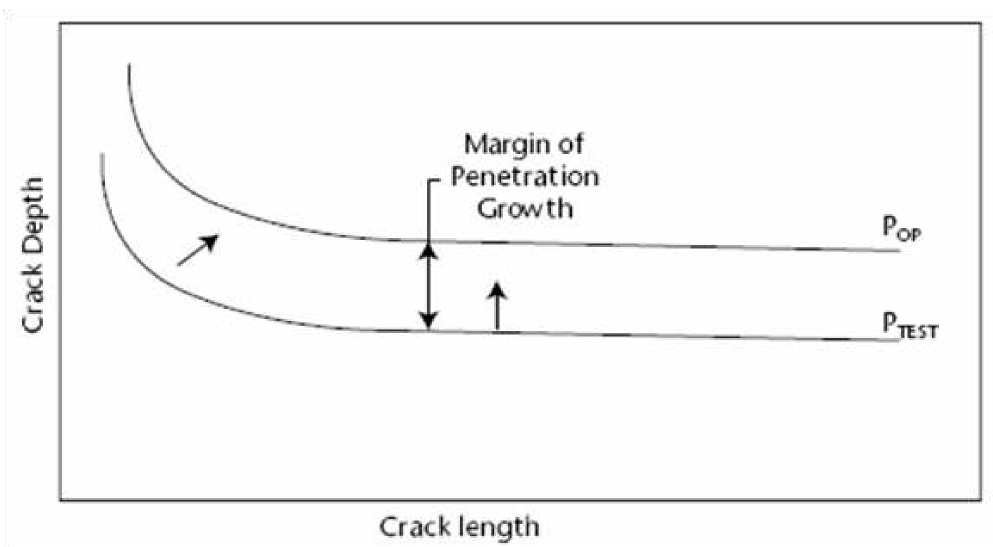


If the results of repeat ILI indicate that existing SCC features are not growing and that no new features have initiated, it may be possible to justify transferring the pipe segment from the on-going mitigation program to the condition monitoring phase (Step 9 of the SCC MP). Similarly, if a series of hydrotests have been conducted without any failures, the pipe segment may be transitioned to a condition monitoring state. Any decision to move a pipe segment from the mitigation program to the condition monitoring state (indicated by the dashed lines in Figure 2.6) must be supported by an engineering assessment.

2.3.7.2 RE-INSPECTION INTERVALS

Remaining SCC features require re-inspection at suitable intervals to ensure that in-service failure does not occur. Figure 2.7 illustrates the principle behind the estimation of the re-inspection interval. The upper curve defines the combination of crack depth and length at which an SCC feature will fail at the operating pressure P_{OP}. The lower curve represents the combination of depth and length of the severest existing cracks in the pipe, as determined either from an ILI run or from a hydrotest conducted at a spike pressure of P_{TEST}. The maximum re-inspection interval is then the length of time that it will take the existing cracks to grow from the curve labeled P_{TEST} to the curve labeled P_{OP}.

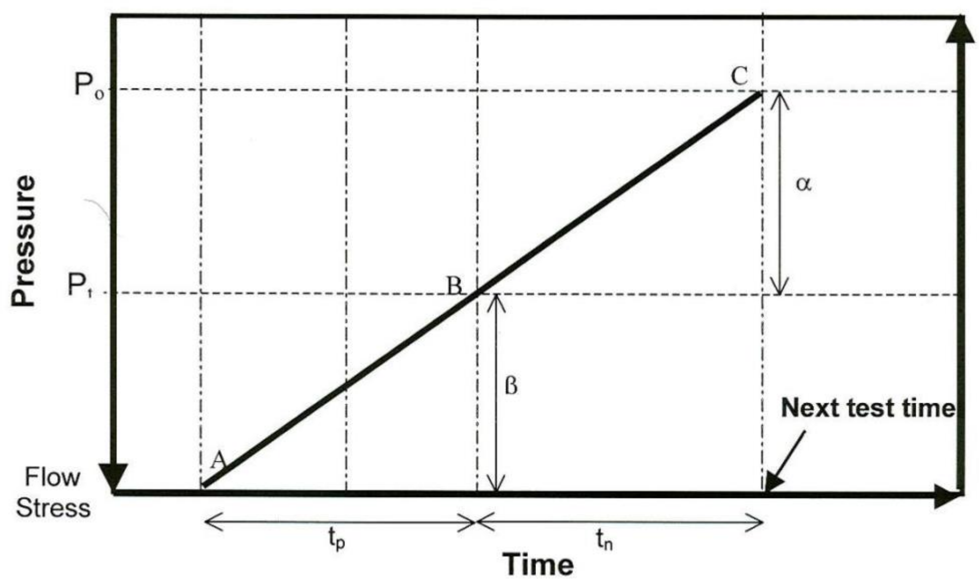
Figure 2.7: Schematic Illustration of the Principle Underlying the Estimation of the Re-inspection Interval.



The re-inspection interval can be estimated based on either the time dependence of the failure pressure P_F or on the crack growth rate. If hydrotesting is used for mitigation, it clearly makes more sense to base the re-inspection interval on P_F, since (a) the value of P_F at the time of the test is known and (b) there is no unique value of crack depth and length provided by the hydrotest to define the existing defect size. If ILI is used for mitigation, it may make more sense to base the calculation of the re-inspection interval on the crack growth rate since the initial dimensions of the crack are known from the results of the ILI run, although these crack dimensions can always be converted to failure pressures using one of the methods described in Section 2.3.4.3 and Appendix D.

A novel procedure has been developed for estimating hydrostatic re-test intervals based only on the mechanical properties of the pipe and the hydrostatic test history [Fessler and Rapp 2006; Fessler et al. 2008, 2013]. The method is illustrated in Figure 2.8.

Figure 2.8: Method for Establishing Subsequent Hydrotest Interval Based on Previous Intervals [Fessler and Rapp 2006].



In this figure, P_t and P_o represent the test pressure and operating pressure (equivalent to P_{TEST} and P_{OP} in Figure 2.7), respectively, point A represents the smallest initial defect size, and points B and C represent the largest surviving defect following the previous hydrostatic test and the size of the defect that would lead to future failure at the operating pressure. The interval t_p is the total period up to the prior hydrostatic test (during which time there may have been a number of tests) and t_n is the future test interval that we are trying to predict. The slope of the line ABC represents the defect growth rate. One of the advantages of this method is that, although P_t and P_o correspond to a specific crack size (in terms of a crack length and depth), the method is based solely on a knowledge of the pressures and it is not necessary to know the actual dimensions of the defect.

Based on these considerations, the re-test interval t_n is simply given by

$$t_n = t_p\left(\frac{\alpha}{\beta}\right) \tag{2-3}$$

where α is the difference between the test pressure and the MOP and β is the difference between the flow stress and the test stress. This simple relationship indicates that re-test intervals can be extended by testing at higher pressures and, somewhat surprisingly, are longer for pipe material with higher flow stress (this is because the difference between the test and flow stresses is correspondingly smaller). Another consequence of this procedure is that short early test intervals followed by successively longer intervals are more effective than repeated uniform intervals.

The procedure is based on a number of key assumptions, including:

- The growth rate of surviving cracks is no greater than that of cracks that have already failed.

- New cracks that may initiate will not fail prior to existing cracks.
- Future operating conditions are no more severe than historical operating conditions.
- The crack growth behaviour can be represented by a linear growth rate over the intervals of interest.

The validity of this approach has been demonstrated by analysis of historical hydrostatic test data, which indicates that, had it been applied, the procedure would have prevented more in-service ruptures whilst conducting fewer hydrotests.

The continuing validity of the procedure has been re-examined based on recent experience from a group of gas pipeline companies using this method [Fessler et al. 2013]. In particular, there is no evidence for rapidly growing cracks that are faster than existing cracks, which would otherwise invalidate the method based on the assumptions above. In addition, only one exception was found where an in-service rupture had occurred prior to the predicted re-test interval. In this case, it is believed that failure resulted from the coalescence of two previously existing cracks. Such exceptions are considered to be rare, although it may be prudent to specify a re-test interval of no longer than 4 years for tape-coated DSAW pipe (where alignment of cracks within the tented region is possible) in high-consequence areas or with a prior history of SCC.

When estimating the re-inspection interval based on the crack growth rate, it is necessary to predict growth in both the depthwise and lengthwise directions. There are a number of potential sources of crack growth data (see Appendix E for a more detailed discussion):

- Mechanistic crack growth models.
- Laboratory tests conducted under simulated field conditions.
- “Beach marks” from the fracture faces of hydrotest failures that have been pressure tested a number of times previously.
- Defect matching from multiple SCC ILI runs with tools of similar accuracy (although CEPA members have had little success with this method).
- SCC size distributions from field inspection data.
- Growth rates derived from failures.

Generally, the crack growth rates derived from these different sources vary from approximately 2×10^{-9} mm/s (0.06 mm/yr) to 2×10^{-8} mm/s (0.6 mm/yr). A similar growth rate seems to apply for both the depthwise and lengthwise directions. Uncertainty in the rate to use is likely the source of greatest uncertainty in predicting re-inspection intervals based on the rate of crack growth. There is also uncertainty in the probability of crack coalescence, which would result in faster surface (lengthwise) crack growth, although the recent experience with the hydrotest re-test method described above suggests that this is not a common occurrence.

2.3.7.3 EMAT EQUIVALENCY TO HYDROTEST

Significant improvements have been made in the development of EMAT ILI technology in recent years, to the extent that a number of gas pipeline companies consider in-line inspection to be as reliable as hydrostatic testing for assessing the condition of the pipeline [Fessler et al. 2013]. Using ILI as an alternative to hydrostatic testing has the advantages that service is not interrupted and avoids the need to dispose of large volumes of water. In addition, ILI provides information about the number, location, and size of sub-critical defects which is useful for on-going integrity assessment.

It is generally accepted that hydrostatic testing will identify all critical defects that will fail at the maximum pressure used during the test. In order for ILI to be equally as effective, it is necessary that the POD and POI for these critical SCC features are close to one and that the detected and identified cracks are accurately sized and the failure pressures accurately predicted (or, at least, not over-estimated).

To demonstrate the equivalency of EMAT and hydrostatic testing, a recent study [Fessler et al. 2013] considered operator experience where a hydrostatic test had been performed within a period of 1-2 years after an EMAT ILI run. Following the earlier ILI runs, a total of 119 features had been excavated and remediated. Subsequent hydrostatic testing was conducted on a total of 560 km of previously inspected pipeline. Only one failure due to SCC occurred in 16 subsequent hydrotests. That one feature, which failed during a hydrostest at 109% SMYS, had been detected by the EMAT ILI but had not been excavated.

This experience seems to confirm the reliability of EMAT ILI technology for detecting SCC that would fail a hydrostatic test. However, the experience largely results from a single operator, although tools from two vendors had been used and both pipe-body and weld-toe SCC had been detected.

2.3.7.4 DIFFERENCES BETWEEN LIQUID AND GAS PIPELINES

The review and planning of on-going mitigation follows much the same principles for both liquid and gas pipelines. Because of the longer history of reliable crack tools for use in liquid lines, there is perhaps greater reliance on ILI as a mitigation procedure for liquid pipelines than for gas lines. However, the recent developments in EMAT technology now make ILI a viable mitigation procedure for gas pipelines as well.

2.3.8 Document, Learn and Report

This activity block applies to pipe segments that:

i. Contain Category I SCC only, or

ii. Have undergone extensive SCC mitigation and now only require condition monitoring.

The purpose of this step is to:

Document all aspects of the SCC Management Program performed to this point.

The prior steps are:

Step 4: Classify the severity of the SCC (in the case of Category I cracks).

Step 7: Review and evaluate mitigation activities (for Category II-IV cracks).

The following step is:

Step 9: Condition monitoring.

A key step in the SCC MP process involves documenting the decision processes used in evaluating the susceptibility of a pipeline company's pipeline system. It is also necessary to record any information collected during the program relating to locations where SCC was and was not encountered. The documentation process should be designed with the intent of demonstrating the reduction in threat that the SCC MP has provided.

2.3.9 Condition Monitoring

Condition monitoring is used for pipe segments:

i. That contain Category I SCC only, or

ii. That have undergone extensive SCC mitigation and now only require condition monitoring, and

iii. For which all SCC activities have been documented.

The purpose of this step is to:

Monitor the condition of the pipeline (and the local environment) for changes that might impact the SCC susceptibility of the pipe segment.

The prior step is:

Step 8: Document, learn, and report.

The following step is:

Step 1: Pipe segment susceptibility assessment.

Condition monitoring is a process in which all relevant information regarding the susceptibility of the pipe segment to SCC is monitored, recorded, and analyzed to determine if the susceptibility is changing over time. The operator should put in place a process for collecting, regularly reviewing, interpreting and, responding to all the SCC-relevant information obtained during on-going operational and integrity management activities.

If, through this process, the SCC susceptibility is deemed to have changed, the pipe segment is moved from the condition monitoring phase (Step 9) to the susceptibility assessment phase (Step 1) of the SCC MP. The decision to move from condition monitoring to a re-assessment of the SCC susceptibility could be triggered by:

- a change in the probability of SCC for the pipe segment as determined by the information provided by condition monitoring,
- previous mitigation that dramatically decreases the probability of SCC for the pipeline segment, such that the pipe segment is no longer susceptible to SCC (e.g., pipe replacement), or
- a change in service conditions, such as a reversal of the direction of flow or changes to the nature of the commodity being transported.

Condition monitoring may involve one or more of the following activities:

- Inspecting for SCC at opportunistic excavations.
- Monitoring for increased evidence of coating disbondment, such as that inferred by MFL inspection.
- Being aware of the latest developments in SCC R&D that may indicate a change in the SCC susceptibility factors or their relative ranking.

- Monitoring CP system effectiveness to determine whether the pipeline is adequately protected.
- Performing CIS/DCVG surveys to provide evidence for the current condition of the coating, where applicable. Changes in survey results may indicate coating degradation.
- Assessing indications from geometry tools such as dents, wrinkles and buckles that can indicate coating damage. Mechanical damage also tends to correlate with material property changes and stress risers which may be associated with SCC.
- Being aware of changes in pipeline pressure trends. Increasing magnitude and frequency of cyclic loading can have an impact on SCC propagation.
- Reviewing discharge temperatures at compressor/pumping stations. Higher temperatures have historically correlated with damaged coating.
- Monitoring changes to land use that can result in an increase in the probability of mechanical damage. Changes to the land use may also modify the soil/water compositions and create an environment that is more supportive of SCC, or vice versa.
- Monitoring geotechnical activities, i.e., ground movement, which may cause coatings to disbond or lead to additional transverse stresses, making a segment of pipe more susceptible to SCC or circumferential SCC (see Section 2.4).
- Monitoring environmental conditions, e.g., changes in water tables or drainage patterns, which may impact the SCC susceptibility.
- Participating in groups that share transmission pipeline industry SCC experience and discuss acceptable practices.

Pipeline operators should use the information gained through these activities to continually re-assess the susceptibility of their pipeline systems to SCC. As with all other aspects of the SCC MP, information and evidence from the condition monitoring program should be properly documented.

2.4 CIRCUMFERENTIAL SCC

Although the majority of SCC encountered on gas and liquid pipelines is orientated axially, a small fraction is orientated circumferentially and is referred to as circumferential SCC (CSCC). At the time of the 1995 NEB hearings, 6 of 22 in-service failures were the result of CSCC, with the remaining due to axially orientated cracks [NEB 1996].

The content of this section is largely based on a recent PRCI study of CSCC [Fessler and Batte 2013, Fessler and Sen 2014] which, in part, reviewed the characteristics of 55 occurrences of circumferential cracking in North America and Europe.

2.4.1 Definition and Characteristics of CSCC

2.4.1.1 DEFINITION OF CSCC

Circumferential SCC is SCC that is orientated predominantly circumferentially to the pipe axis.

2.4.1.2 SOURCES OF STRESS

As for all forms of SCC, circumferential cracks grow perpendicular to the principle tensile stress. In the case of CSCC, therefore, the tensile axial stress must exceed the hoop stress resulting from the pressure of the gas or liquid being transported.

The potential sources of axial stress are [Fessler and Batte 2013]:

- Poisson effect, with expansion in the hoop direction leading to contraction in the axial direction and a resulting stress of 30% of the hoop stress (for a constrained pipe) or up to 50% of the hoop stress for unconstrained pipe.
- Thermal expansion (or contraction) due to differences between the operating temperature and a higher (or lower) temperature at the time of construction. For example, a construction temperature 30°C higher than the operating temperature would result in an axial stress of 72 MPa, equivalent to 16% SMYS for Grade 448 (X-65) pipe,
- Bending stresses from cold bends up to yield magnitude on either the convex side (no springback allowed after bending) or the concave side (springback allowed) of the bend, depending upon the angle of the bend.
- Soil movement on unstable slopes.
- Bending stresses due to bottom-side dents caused by the pipe sitting on a large rock.

One or more of these sources of stress could act upon the pipe and if the sum of the axial stresses exceeds the hoop stress then CSCC is possible.

2.4.1.3 CHARACTERISTICS OF CSCC

Based on an analysis of 55 incidents of CSCC, the typical characteristics of circumferential cracking include [Fessler and Batte 2013]:

- Occurs on both gas and liquid pipelines.
- Most common form of cracking is near-neutral pH SCC (90% of known cases), although incidents of high-pH CSCC have also been reported.
- In-service failures have tended to be leaks (94%) rather than ruptures.
- In addition to in-service failures, CSCC has also been discovered by excavation and

hydrotesting.

- Has occurred on pipelines less than 10 years old up to 70 years old, with the majority in the range 30-50 years old.
- Occurs predominantly on tape-coated lines (86%), but also found on asphalt and coal-tar coated lines and under shrink sleeves. No reports of CSCC under FBE or other high-performance coating systems.
- Has occurred for pipe grades ranging from X42 to X80, as well as Grade B pipe. Majority of cases reported for X52 and X60 pipe, although this may be a reflection of the coating type and/or age of the line.
- Has occurred on NPS6 to NPS40 pipe, with wall thicknesses of 2.5-12.5 mm.

2.4.2 CSCC Management Program

Although there is less experience with CSCC than the normally observed axial cracking, a management program following the same three overall phases defined in Figure 2.1 can be defined for circumferential SCC.

2.4.2.1 SUSCEPTIBILITY ASSESSMENT

Step 1: Pipe segment SCC susceptibility assessment

Pipe segmentation and susceptibility assessment for CSCC follows a similar process to that for axial SCC, as described in Section 2.3.1, albeit with slight differences because of differences in the factors controlling circumferential cracking.

As for axial cracking, CSCC has not been reported for FBE and other high-performance coatings. Because the database of CSCC incidents is much smaller than that for axial cracking, it is not yet clear whether these coatings can be considered to be "non-susceptible."

Based on the review of the 55 reports of CSCC, the susceptibility factors that should be considered are [Fessler and Batte 2013]:

- Coating type
- Proximity to previously discovered CSCC or axial SCC
- Year of construction
- Construction season (a surrogate for the temperature at the time of construction)
- Age of the pipe
- Terrain (surrogate for the possibility of pipe movement and/or unstable slopes)
- Grade of pipe
- Pipe diameter
- Wall thickness

Step 2: Investigate for the presence of SCC

Direct assessment is particularly useful for investigating the presence of CSCC because the factors that lead to the necessary axial stress are well characterized and can be relatively easily identified.

Fessler and Batte [2013] provide suggested numerical ranking factors within each of the susceptibility factor categories listed above (e.g., different rankings for different coating types) which pipeline operators may find useful for prioritizing different pipeline segments, as well as weighting factors for combining the overall effect of these categories.

Once the susceptible pipeline segments have been identified, a second set of factors should be used to select specific sites for excavation [Fessler and Batte 2013]:

- Coating condition (disbonded, well-bonded)
- Deformations (dents or buckles)
- Bends
- Angle of terrain (greater or less than 10º)
- Location on slope (crest, mid-slope, toe)
- Soil type for tape-coated pipe (clay vs. other)
- Soil type for asphalt-coated pipe (sandy vs. other)
- Soil moisture for tape-coated pipe
- Soil moisture for asphalt-coated pipe
- Pitting corrosion in the joint

Fessler and Batte [2013] provide suggested numerical rankings for each of the factors listed above which pipeline operators may find useful for identifying specific locations for inspection/excavation, as well as weightings for combining the overall effect of these factors.

Although hydrostatic testing has located two cases of CSCC, a more appropriate investigation method is the use of exploratory excavations with sites selected as described above. Some CEPA members have also had good experience detecting CSCC using circumferential ultrasonic ILI tools.

As for axial SCC, the number of excavations that should be performed should be sufficient to examine a statistically significant fraction of the susceptible pipe segment (Section 2.3.2.5)

<u>Step 3: Determine the SCC susceptibility reassessment interval</u>

If the pipe segment was deemed to be non-susceptible to CSCC or if a susceptible segment was found not to contain cracks, the susceptibility assessment should be periodically repeated. The re-assessment interval should take into account any time-dependent changes in the susceptibility factors described above.

It is recommended that the reassessment interval should not exceed 10 years.

2.4.2.2 CONDITION ASSESSMENT AND MITIGATION

<u>Step 4: Classify the severity of the SCC</u>

There are no formal CEPA crack severity categories for circumferential SCC.

Because CSCC is typically discovered due to an in-service leak or during excavation, it is common for all cases of circumferential cracks to be repaired or removed from the pipe.

Fessler and Batte [2013] provide guidance on determining whether a particular CSCC feature will fail by rupture or by leak, which is useful if crack dimensions are available from an ILI run capable of detecting and sizing circumferential crack-like features.

Step 5: Determine and implement pipe segment safe operating pressure

Although the operating pressure is not the primary source of the principle stress driving crack growth, it is necessary to implement a pressure reduction prior to repair of any discovered CSCC. It is recommended that a pressure reduction equivalent to that for Category III/IV axial SCC should be implemented prior to repair.

In addition, measures should be taken to reduce the level of axial stress prior to mitigation, such as relieving any soil loading or protecting exposed pipe from large temperature gradients.

Step 6: Plan and implement mitigation

The options for mitigating CSCC include:

- Pipe replacement
- Removal of cracks by buffing (along with suitable reinforcement and strain relief)
- Repair using a pressure containment (Type B) sleeve
- Leave in pipeline and recoat
- ILI
- Hydrostatic testing

Use of a reinforcement sleeve is not a suitable repair method as such sleeves are designed to provide support for the pipe in the hoop direction which is not the principle stress for CSCC.

The source of axial stress should be identified and relieved to prevent re-occurrence of CSCC, for example, by:

- cutting the pipe, allowing the residual stress to relax, and inserting new pipe
- adjusting the pipe alignment to relive axial stress due to bends
- removing rocks from bottom-side dents
- stabilizing pipe movement on unstable slopes

Step 7: Review and evaluate mitigation activities

Unlike axial SCC where less-injurious crack features can be managed by an ongoing program of ILI or hydrostatic testing (Section 2.3.7), these mitigation methods are less widely used for CSCC.

The most common mitigation methods for CSCC are to either remove it or to permanently repair the defect using a pressure containment sleeve. In these cases, the pipe can be considered to have been completely mitigated (especially if the source of axial stress has been removed or relieved) and the condition of the pipe segment need then only be monitored as part of Step 9 of the SCC Management Program.

However, if hydrostatic testing is used to mitigate CSCC, the recommended re-inspection interval is 2 years [Fessler and Batte 2013].

2.4.2.3 CONDITION MONITORING

Step 8: Document, learn, and report

As for axial cracking, a key step in the CSCC Management Program is the documentation of the decision processes used in evaluating the susceptibility of the pipeline system. It is also necessary to record any information collected during the program relating to locations where CSCC was and was not encountered. The documentation process should be designed with the intent of demonstrating the reduction in threat that the CSCC Management Program has provided.

Step 9: Condition monitoring

As for axial cracking, the operator should put in place a process for collecting, regularly reviewing, interpreting, and responding to all CSCC-relevant information obtained during on-going operational and integrity management activities.

In addition to the factors described in Section 2.3.9 that impact the probability of SCC in general, the following factors that particularly affect the CSCC susceptibility should be monitored:

- Movement on unstable slopes
- Unusually large rainfall in areas subject to soil movement
- Large changes in operating temperature that may increase (or decrease) the thermal stress in the axial direction
- Leak detection along the right-of-way

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This bibliography provides a listing of SCC reference materials, standards, and recommended practices and references to recent technical publications that the interested reader may find useful. The recent technical publications are taken primarily from the proceedings of the biennial International Pipeline Conference for the period 2008-2014 and from recent studies published by the Pipeline Research Council International (PRCI). This listing is not exhaustive, but should provide those seeking more detailed information sources for further information.

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APPENDIX A

SCC SUSCEPTIBILITY FACTORS AND SCC MODELS

A.1 SCC SUSCEPTIBILITY FACTORS

SCC susceptibility factors are used:

- To determine the susceptibility of a pipe segment to SCC (Step 1 of the SCC Management Program (SCC MP)).
- When analyzed using some sort of SCC model, to prioritize susceptible pipe segments and to select sites for exploratory excavations (Step 2 of the SCC MP).

The SCC susceptibility factors fall into four broad categories: pipeline attributes, operating conditions, environmental conditions, and pipeline maintenance data.

A.1.1 Pipeline Attributes

Age and Season of Construction

With increasing age, there is an increased probability of coating failure and of the initiation and growth of SCC. Therefore, all other factors being equal, older pipelines have a greater probability of containing larger SCC features. For example, Figure 1.4 in the main text shows the distribution of SCC failures for eight major North American gas pipeline operators as a function of the year of construction. SCC of varying extent and severity has been detected in pipelines constructed between 1953 and 1982.

Additionally, coatings applied in the field during winter construction are historically associated with a higher probability of adhesion problems.

Pipe Manufacturer

The identity of the pipe manufacturer, and even the specific mill at which the pipe was made, may impact the susceptibility to SCC due to differences in the manufacturing process used for plate production and pipe forming, as well as the steel chemistry and weld procedures. However, as of this time, only one pipe (manufactured during the 1950's by Youngstown Sheet and Tube) has shown elevated susceptibility to SCC, in this case because of the process used to perform the long seam weld [NEB 1996].

Diameter

Increasing pipe diameter may lead to increased pipe to soil interaction and higher soil stresses on the coating. The susceptibility to soil stress for tape and asphalt/coal tar enamel coatings appears to be proportional to the pipe diameter. However, SCC-related incidents have occurred in pipelines ranging from NPS 4 to NPS 42.

Long Seam Type

SCC-related service incidents and hydrotest failures have been associated with longitudinal DSAW and ERW long seams, but SCC has also been detected in DSAW spiral, seamless and flash butt-type long seams.

Grade

Currently, no pipe grade has been shown to be immune to SCC or to have a lower susceptibility, although this does not mean that there may not be some, as yet unknown, correlation to steel properties.

Pipeline Alignment

Changes in the pipe alignment (i.e., bends) may serve as stress concentrators or as locations where it was more difficult to properly apply the coating (especially for older over-the-line methods). Also, vertical bends may indicate changes in the terrain and associated changes in SCC susceptibility.

Surface Preparation

The use of shot blasting to create an anchor profile for the application of modern mill-applied coatings is known to impart a compressive surface residual stress, resulting in lower susceptibility to crack initiation.

Coating Type

The type of external coating and whether it was applied under well-controlled conditions in a mill or whether it was field-applied is a primary factor in determining the susceptibility to SCC (see Section 2.3.1.2.1).

Stress Concentrators

The presence of features that lead to an increase in stress, such as dents, gouges, the long-seam weld, and areas of corrosion, are associated with an increased occurrence of SCC [NEB 1996].

Areas of high surface tensile residual stress are also more susceptible to crack initiation.

Location of Weights and Anchors

Depending on their design, weights and anchors used for buoyancy control may damage the pipe coating and/or shield the pipe from the CP system, leading to increased susceptibility.

Location of casings

Cased pipe may be more susceptible to SCC because of coating damage during construction and/or an increased probability of CP shielding.

Mechanical damage

Mechanical damage, as can occur during construction due to contact by excavators or poor backfilling procedures, can result in microstructurally altered material and/or regions of elevated residual stress.

Impacts can also lead to coating damage, disbondment and the access of electrolyte to the pipe surface.

Backfilling practices

Poor backfilling practices can result in coating damage, shielding by large backfill, and/or dents on the bottom of the pipe leading to high residual stress or stress concentration.

A.1.2 Operating Conditions

Stress level

No relationship between the operating stress and SCC initiation has been validated, possibly because of the presence of high residual stresses. However SCC in pipelines operating at a lower stress will require more time for SCC to grow to failure.

Pressure cycling

Research indicates that a fluctuation in stress (and strain) levels in the pipe wall, due to changing operational pressures, influences the growth rate of SCC. Ultimately this relationship affects the time it takes SCC to cause a failure. Analysis of pressure fluctuations (e.g., using rainflow counting or some other cycle counting method) may be useful in the prediction of crack growth rates.

Temperature

Consideration should be given to pipe segments downstream of compressor stations that may have operated at high temperatures for a period of time during commissioning and then reduced operational temperatures after installation of coolers. High operating temperatures (greater than approximately 40°C) can cause coating degradation and have been known to dry out the soil surrounding the pipe causing higher soil electrical resistance. There appears to be a correlation between SCC failures and the proximity to compressor stations for tape coatings, but not necessarily for asphalt coating (Figure 1.5 in the main text).

Distance Downstream of a Compressor and Pump Station

As noted above (and as illustrated in Figure 1.5 of the main text), there appears to be an increased probability of hydrotest and in-service failures on gas pipelines closer to the discharge side of the compressor station for tape-coated pipelines. This observation is likely linked to the greater incidence of coating disbondment due to the elevated temperature and the higher stress level at these locations.

The trend for asphalt-coated lines is less clear, with some suggestion of a higher probability of failure at some intermediate distance between compressor stations. This distribution suggests two opposing effects of the proximity to the compressor station, resulting in a maximum susceptibility at some distance downstream of the discharge.

CP level and possibility of shielding

Near-neutral pH SCC occurs in locations where the pipe is inadequately protected by the CP system, due either to disbonded shielding coating or an improperly functioning CP system. Close-interval surveys and the CP history may indicate locations of increased susceptibility.

Product type

The product type may impact the SCC susceptibility in different ways. Pressure fluctuations tend to be larger and of higher frequency for liquid lines because of the incompressibility of the fluid. Effects due to elevated temperature (e.g., enhanced coating damage) are more likely to be observed close to compressor stations on gas pipelines.

A.1.3 Environmental Conditions

Terrain

Certain topography and soil types have been shown to correlate with SCC susceptibility. The strength of the correlation between terrain conditions and SCC can vary between different pipeline systems. By examining historical field records from excavations where SCC has and has not been found, the pipeline operator can determine which terrain conditions correlate best with SCC susceptibility for their particular system (see Section A.2.2).

Soil Type

The amount of swelling-type clay can affect the amount of soil stress and, hence, the likelihood of coating disbondment. Therefore, polyethylene tape coated pipelines in clay type soils should be assigned a high priority for the investigation of the presence of SCC.

Drainage Patterns

Recent experience has shown that static drainage conditions (i.e., the soil is always wet or always dry) correlate less well with SCC than locations where the drainage is variable (intermittent wet-dry conditions).

Land Use

The type of land use may affect the likelihood of external loads on the pipeline and resulting coating damage or damage to the pipe itself.

In addition, some surface activities may lead to ground contamination that results in a higher (or lower) probability of coating failure and/or the development of a suitable environment for SCC.

Soil CO_2

It is known from R&D studies that the presence of CO_2 is important for SCC (most likely to control the pH of the electrolyte in the correct range for cracking), although there is no known correlation between SCC susceptibility and the amount of CO_2. Nevertheless, there may be some correlation between conditions that support soil CO_2 production (generally, the presence of moisture and higher temperatures) and the susceptibility to SCC.

A.1.4 Pipeline Maintenance Data

In-line Inspection (ILI) Data

In-line inspection can be used directly to identify the location of SCC or indirectly to locate areas of external corrosion or mechanical damage and associated coating deterioration. Current crack detection ILI technology has been successful in accurately locating SCC on pipelines. Metal loss ILI data has also been used successfully for correlating SCC susceptibility. Areas of minor metal loss are indicative of disbonded coating and either shielded cathodic protection (for polyethylene tape coatings) or inadequate cathodic protection levels (for asphalt/coal tar enamel coatings). Minor metal loss may be symptomatic of an environment conducive to SCC and may indicate low metal loss rates (which would allow the SCC mechanism to dominate). SCC can also be associated with coating disbondment found at dented areas and bends. In addition, dents are also typically associated with stress risers, which can lead to crack initiation.

Cathodic Protection (CP) Data

Experience has shown that most forms of SCC are found where coatings partially or completely shield proper cathodic protection. For asphalt/coal tar enamel coated pipelines, inadequate levels of CP have been used to identify SCC susceptible areas. Seasonal fluctuations in CP levels (due to moisture level changes in the soil around the pipe and anode beds) should be accounted for when examining CP data. For electrically insulating coatings, such as polyethylene tape, it is difficult to identify locations where the pipe surface is shielded by disbonded coating.

Historical Excavation Records

Excavation records can be used to determine the likelihood of SCC occurrence, provided the pipeline was inspected for cracking during the excavation. By performing non-destructive testing (NDT) such as magnetic particle inspection (MPI) at all dig sites, the operator can establish a database of SCC occurrences (or conversely determine where it is not occurring).

Coating Condition

Because of the paramount importance of the coating type and condition in the occurrence of SCC

(Section 2.3.1.2.1), all sources of such information should be collected and analyzed.

Leak/rupture History

Clearly, the history of leaks or ruptures due to SCC on the line or similar pipelines is a key indicator of SCC susceptibility.

Hydrostatic Re-test History

Similarly, the history of hydrotest SCC failures on the line or similar pipelines is a key indicator of SCC susceptibility.

A.2 SCC MODELLING

A.2.1 General Considerations

SCC modelling can take a wide range of forms, ranging from simple correlations between coating type and SCC susceptibility all the way through to sophisticated multivariate statistical analyses. The aim of all SCC models, however, is to increase the probability of locating SCC based on an analysis of observable and derived parameters. As noted in Section A.1, SCC models can be used for:

- Pipe segmentation
- Susceptibility assessment
- Segment prioritization
- Site selection for excavations

Before developing an SCC model, the operator should define what the model is to be used for, as this will determine the type and amount of input data required. For example, if the model is to be used for site selection for exploratory digs, then the input data must have sufficient "granularity" that specific sites of elevated susceptibility can be identified. If the model is to be used for locating more-severe Category II and III SCC, then data relating to the occurrence of SCC (Category I cracks) should not be used to develop the model.

Models tend to be highly specific to the pipeline system for which they were developed. Operators should be wary about using a model developed on one system or based on data from one geographical location to predict the occurrence of SCC for another pipeline or region. Models should always be validated against a subset of data from the pipeline system under study.

When trying to correlate a number of different data sets, the pipeline operator must ensure that the data are reasonably accurate and are referenced to a common spatial system. Spatial referencing can range from the use of a common distance or "chainage" measurement along the pipeline to the use of global positioning system (GPS) coordinates. Simple distance referencing can be done manually or using commercial spreadsheet applications, while GPS referencing is most efficiently (and accurately) accomplished via the use of a GIS platform.

When prioritizing pipe segments for inspection or selecting sites for excavation, additional factors may impact the decision, including:

- Risk factors
- Site condition considerations
- Permit requirements

- Jurisdictional requirements

A.2.2 Types of SCC Model

An SCC model is simply a means of correlating the occurrence or severity of cracking with one or more observable properties or parameters that, in theory, should be related to SCC. This correlation may be achieved through the use of expert judgment or by using statistical or expert system methods.

For example, based on the results of hundreds of excavations at SCC (and non-SCC) sites, one operator was able to develop correlations between certain soil characteristics, the local topography, and drainage patterns and sites where SCC was observed. Different correlations were found for polyethylene-tape (Table A.1) and asphalt/coal tar enamel-coated (Table A.2) pipelines.

Table A.1: SCC Susceptible Terrain Conditions for Polyethylene Tape Coated Pipelines

SOIL ENVIRONMENTAL DESCRIPTION	TOPOGRAPHY	DRAINAGE
Clay bottom creeks and streams (generally <5m (16ft) in width)		
Lacustrine (clayey to silty, fine-textured soils)	Inclined, level, undulating	Very poor
Lacustrine (clayey to silty, fine-textured soils)	Inclined, level, undulating, depressional	Poor
Organic soils (>1m (3ft) in depth) overlaying glaciofluvial (sandy and/or gravel-textured soils)	Level, depressional	Very poor
Moraine tills (variable soil texture – sand, gravel, silt, and clay with a stone content >1%)	Inclined, inclined to level, level undulating, ridged, depressional	Very poor, poor, imperfect to poor

Table A.2: SCC Susceptible Terrain Conditions for Asphalt/Coal Tar Enamel Coated Pipelines

SOIL ENVIRONMENTAL DESCRIPTION	TOPOGRAPHY	DRAINAGE
Bedrock and shale limestone (<1m (3ft) of soil cover over bedrock or shale limestone)	Inclined level Undulating ridged	Well
Glaciofluvial (sandy and/or gravel textured soils)	Inclined level Undulating ridged	Well
Moraine till (sandy/ clay soil texture with a stone content >1%)	Inclined level Undulating ridged	Well
Sites that do not meet the -850mV "off" criterion in a pipe to soil close interval survey (exclusive of the three sets of terrain conditions discussed above)	Any	Any

A common form of SCC model, especially for operators with relatively little prior experience of SCC or with limited data sets, is to prioritize based on weighting factors, typically determined using expert judgment. For example, weighting factors for the occurrence of SCC as a function of coating type are given in Table A.3.

Table A.3: Example Of SCC Susceptibility Weighting Factors Based on Coating Type

COATING TYPE	WEIGHTING FACTOR
Polyethylene Tape	10
Coal Tar	5
FBE	1

The raing based on the coating type would then be combined with similar ratings for other susceptibility factors deemed to be important to arrive at an overall "score" representative of the relative susceptibility of different pipe segments or site locations.

The development of an SCC model is an obvious starting point for the development of an integrated approach to managing SCC. Some operators continue to use SCC models alongside other, more direct, approaches such as hydrotesting and ILI. Table A.4 lists some of the advantages and disadvantages of SCC models.

Table A.4: Advantages and Disadvantages of SCC Models.

ADVANTAGES	DISADVANTAGES
Based on prior SCC history/experience Can incorporate both quantitative and qualitative (expert judgment) data Can be validated Can include mechanistic understanding	Can be biased by the input data selected for the model May be compromised by incomplete data sets May be subjective (e.g., in data selection, use of expert judgment) Generally not "portable" from one pipeline system to another Large data sets required Difficult to discriminate between SCC severity categories

A.2.3 Comparison With Other Approaches.

The three main approaches to managing SCC are SCC models, hydrostatic testing, and ILI. Table A.5 summarizes the advantages and disadvantages of each approach.

Table A.5: Comparison of Different Approaches for Managing SCC.

APPROACH	ADVANTAGES	DISADVANTAGES
SCC modelling	Can be conducted on all parts of the system (i.e., on non-piggable lines) Does not require an interruption of service	Cannot be relied upon to find most-severe defects Tend to be system-specific
Hydrostatic testing	Locates most-injurious cracks in the segment Proves integrity of segment for a period of time after the return to service Well-established methodology May slow crack growth for a period of time	Requires that the line be taken out of service Need to source/dispose of test water Expensive
In-line inspection	Provides indication of all SCC in the system (above a threshold size)	Tools not available in all pipe sizes Need tool launch and receipt facilities

REFERENCES FOR APPENDIX A

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Appendix B
In-the-Ditch Protocols

B.1 INTRODUCTION

In-the-ditch inspection provides an opportunity to measure SCC colony density, interaction and individual crack dimensions, as well as some pipe material parameters such as wall thickness.

This Appendix describes in-the-ditch measurement techniques as well as other necessary considerations for conducting field investigations including: (i) the need to provide a safe working pressure for those conducting these inspections by means of a pressure reduction, (ii) SCC detection, (iii) SCC characterization and sizing, and (iv) recoating the inspected pipe at the end of the dig.

The focus of this section is on the use of MPI. However, other techniques, such as penetrant techniques, ultrasonic techniques, eddy current technologies, and ACFM (alternating current field measurements) may also be used. The accuracy of these other techniques should be validated against suitable standards or, preferably, using real SCC cracks of known dimensions. The sensitivity of any technique to other factors, such as surface preparation (i.e., profile, cleanliness), surface geometry (i.e., within metal loss or associated with a weld), and SCC depth, needs to be understood.

B.2 PRESSURE REDUCTION FOR SAFE EXCAVATION AND FIELD INSPECTION

When undertaking any excavation where SCC may be present, a reduction in the pressure of the pipeline at the excavation location must be considered. A qualified person, familiar with pipeline integrity in general and more specifically with SCC, should determine the magnitude of the required pressure reduction and the activities that can be undertaken at the reduced pressure. As well, operational controls, procedures and monitoring will be necessary to ensure that the pressure will not rise during excavations and/or sufficient warning can be provided to workers if a pressure upset does occur.

CSA Z662-11 Clause 10.9.1.3 provides only minimal guidance, stating that "the piping is depressurized as necessary to an operating pressure that is considered safe for the proposed work." [CSA 2011]. The Pipeline Repair Manual recommends a pressure reduction "…to no more than 80% of what was first reported at the location…" [Jaske et al. 2006]. The concept of a reduction to 80% (or a 20% reduction) is consistent with the 0.80 minimum design factor for new piping. Coote and Keith [2004] reported that many CEPA companies use a 20% minimum pressure reduction for SCC excavations.

An appropriate pressure reduction should be calculated on a case-by-case basis with consideration of pipeline properties, working conditions, or particular stresses which are atypical. It is recommended that the pressure reduction for safe excavation and inspection at SCC digs should be the lesser value of:

- 80% of the highest operating pressure at that location on the pipeline in recent history (30 days to 1 year, with 60 days being the CEPA recommended period in Section 2.3.5.1 for the continued operation of pipelines with Category III SCC).
- 80% of the failure pressure of the most severe anomaly detected and sized by a recent in-line inspection tool run.
- 80% of the calculated failure pressure of the most severe SCC feature detected at an excavation.
- 80% of the calculated failure pressure of a metal loss defect that would result from a buffing repair of an SCC colony.

Further reductions should be undertaken if SCC is suspected within dents, gouges, buckles or in the presence of other complex stress regimes (such as geotechnical loading). Any SCC that is found in a direction that is not aligned parallel with the pipe axis is an indication that complex loading exists. In these cases, as well as in cases where leaking defects are suspected, a detailed engineering analysis should be completed to determine if an excavation and/or in-the-ditch inspection can be undertaken at any pressure greater than atmospheric.

B.3 MAGNETIC PARTICLE INSPECTION (MPI)

B.3.1 Introduction to MPI

Manual inspection for SCC involves in-the-ditch inspection techniques to identify the presence and the length and depth of surface breaking SCC. The dominant technique used by CEPA member companies is Magnetic Particle Inspection (MPI).

The three available MPI techniques are:

- Dry powder (DPMPI)
- Wet fluorescent (WFMPI)
- Black on white (BWMPI)

All three techniques are proven methods to detect external SCC, but dry powder is the least sensitive (due to the particle size) and is not commonly used nor recommended as a primary SCC inspection method. Table B.1 provides a comparison of the sensitivity and the relative advantages and disadvantages of the three methods of MPI.

Although the materials and equipment differ between the three methods, the basis for each of these techniques is similar and involves:

- The preparation of a background contrast on the pipe surface using either a spray-on lacquer or a cleaned original steel surface.
- The introduction of a magnetic field across and perpendicular to the SCC axis. (Figures B.1 and B.2).
- The application of ferromagnetic particles to the surface. These particles align with the magnetic flux leakage caused by the presence of a crack.
- Visualization of the contrasting particles and background surface.

ASTM E709-14 [ASTM 2014] describes MPI techniques to detect SCC features, including SCC in ferromagnetic materials. This ASTM standard is commonly referenced to develop, monitor and evaluate inspection procedures.

Figure B.1: Bottom of Pipe In-the Ditch SCC Assessment Using BWMPI.

Figure B.2: Top of Pipe In-the Ditch SCC Assessment Using BWMPI.

B.3.2 Application of a Magnetic Field

A reliable and practical method of applying a magnetic field perpendicular to the SCC axis is with the use of an energized hand yoke. Alternating current (AC) and direct current (DC) hand yokes are available. The most commonly used yoke for SCC investigations is the AC type as it was specifically designed for surface-breaking anomalies such as SCC. In addition, AC yokes are more portable and weigh significantly less than DC yokes, which make them more versatile in field conditions.

B.3.3 Inspection Personnel Qualification

The knowledge and skill of the technician is a critical factor. The technician should be able to demonstrate a knowledge and ability to detect and discriminate SCC from those indications resembling SCC, such as welding-related indications, indications formed during pipe fabrication, or features introduced during handling or construction. This discrimination requires a detailed knowledge of pipe manufacture, construction practice and operating conditions.

In Canada, NDT Technicians are certified by Natural Resources Canada (NRCan) according to the National Standard of Canada, CAN/CGSB-48.9712-2006 "Qualification and Certification of Non-Destructive Testing Personnel." Some pipeline companies have imposed their own specific qualification requirements.

Table B.1: Advantages and Disadvantages of Various MPI Methods.

MPI METHOD	SENSITIVITY	ADVANTAGES	DISADVANTAGES
Dry Powder MPI (DPMPI)*	2 to 5 mm long anomalies	Maximum portability. SCC replicas can be obtained.	Regardless of pipe cleaning technique, this technique when used with an AC yoke yields the lowest sensitivity of all the MPI techniques. Must have a clean and dry surface; dampness will affect particle distribution and mobility. Subject to climatic limitations (i.e., wind can blow the powder around and create a health and safety hazard for the technician).
Wet Fluorescent MPI (WFMPI)	1 mm long anomalies	Inspection rate can be faster than the DPMPI and BWMPI methods. Highest degree of sensitivity. Dry concentrate plus a water conditioner mixes readily with water.	Longer set up time. Requires more inspection equipment compared to BWMPI or DP methods. Difficult to document SCC due to darkness required during inspection. Seasonal conditions can cause overheating and malfunction of inspection equipment. Photography can be done, but more difficult compared to BWMPI method due to darkness required during inspection. Safety hazards in wet, sloppy excavation sites. Subject to climate limitations (i.e., wind can make it difficult to keep the light-retarding tarp in place and high ambient temperatures can make it hot and uncomfortable for the technicians underneath the tarp). Inspection sensitivity can be affected by low pipe surface temperature.
Black-on-White Contrast MPI (BWMPI)	1 to 2 mm long anomalies	Requires less set-up time than the other methods. Requires less MPI equipment than the other methods Easier to photograph SCC indications, weather permitting.	Contrast paint and ferromagnetic particles plus carrier are pre-mixed in aerosol form; therefore, a larger supply is required compared to the concentrated form of dry particles mixed with water or other carriers used for the WFMPI method. Inspection sensitivity can be affected by low pipe surface temperature. Aerosols can pose a health and safety hazard. Applying the white contrast can be time consuming.

* NOTE: Not recommended for SCC detection and inspection due to low sensitivity

B.3.3 Surface Preparation for Inspection

Proper surface preparation for MPI is necessary in order to:

- Remove deleterious substances such as dirt, oil, grease, corrosion products, and coating remnants that could prevent direct contact of the magnetic particle medium with the steel surface.
- Allow for magnetic particle mobility by providing a sufficiently smooth surface that can be properly "wetted".
- Remove scale and deposits over the SCC feature so that the magnetic particles can enter the crack, but not to the extent that the cracks are "peened" shut, thereby becoming masked from the magnetic particles.

The three methods of surface preparation are water blasting, abrasive blasting, and using a rotating wire brush. Abrasive blasting is the most common method and is preferred by CEPA member companies. Table B.2 summarizes the advantages and disadvantages of each preparation technique.

The sensitivity of SCC detection is dependent on the nature of the surface preparation (Table B.3). Work sponsored by CEPA shows that SCC lengths as small as 1 mm to 2 mm can be detected with the use of either WFMPI or BWMPI. To optimize the surface for WFMPI, a near white surface should be achieved in accordance with SSPC-SP10 [NACE 2006a]. For BWMPI, a commercial blast surface should be achieved in accordance with SSPC-SP6 [NACE 2006b].

CEPA-member experience suggests that greatest sensitivity can be achieved with roughness profiles less than 0.074 mm (2.9 mils). NACE RP0287 offers guidance for surface profile measurements [NACE 2002]. The factors that affect the surface profile include:

- the type and grade of abrasive,
- operator knowledge and experience,
- the type and condition of the equipment used, and
- the ambient conditions during blasting.

Any abrasive material or technique selected must meet the occupational health, safety and environmental requirements of the jurisdiction in which the pipe excavation is located.

In addition to optimizing detection limits, the user may wish to consider such factors as convenience, cost, and cleaning rate when selecting a surface preparation method (Table B.3).

Table B.2: Summary of Surface Preparation Techniques Used Prior to Wet Fluorescent and Black-on-White MPI.

TECHNIQUE	DESCRIPTION	ADVANTAGES	DISADVANTAGES
Water blasting	Uses potable water at high pressure (>25,000 psi).	No surface roughness created, so that masking of SCC is not of concern. Used with additives to remove greasy residues.	May not remove tenacious corrosion products. Requires availability of potable water. Excavation site becomes muddy. Freezing concerns in winter. Safety concerns with high pressure discharge.
Abrasive blasting (walnut shells)	Walnut shells used as abrasive medium with same equipment as sand or slag abrasive blasting.	Masking is unlikely as walnut shells are relatively soft.	May not remove tenacious corrosion products. Leaves oily residue which may affect subsequent pipe recoating (residue can be removed with cleaning agents). Possible allergic reactions. Environmental management of abrasive blasting by-products requires consideration.
Abrasive blasting (silica sand, coal slag, metal slag, minerals)	Hard abrasives, such as silica sand and coal slag, are discharged at a nozzle pressure of 100 psi.	Highest level of steel cleanliness of all techniques. Materials readily available. Abrasive grade can be adjusted to provide different steel profiles. Minimizes subsequent surface preparation for recoating.	Selection of an appropriate abrasive grade required to avoid masking small SCC features. Use of silica sand is regulated because of worker health concerns. Environmental management of abrasive blasting by-products requires consideration.
Power wire brush	Electric or pneumatic grinding tools fitted with 180 Grit Flapper Wheel	Simple to use with little maintenance or waste	Consistent cleaning quality across inspection surface can be difficult to achieve. Not generally used for SCC inspection.

Table B.3: Comparison of Detection Limits, Cleaning Rate, and Cost for Various Surface Preparation Methods.

TECHNIQUE	DETECTION CAPABILITY	SCC DETECTION LIMIT (mm)		COST (1 = LEAST EXPENSIVE)	CLEANING RATE
		USING WFMPI	USING BWMPI		
Water blasting	Excellent, as long as all corrosion products etc. are removed.	1	1-2	4	Satisfactory cleaning rate but cannot remove some corrosion deposits.
Abrasive blasting (walnut shells)	Excellent, as long as all corrosion products etc. are removed.	1	1-2	3	Good cleaning rate but cannot remove some corrosion deposits.
Abrasive blasting (silica sand, coal slag, metal slag, minerals)	Very good.	1-2	1-2	2	Overall, provides best cleaning rate of all techniques. Somewhat dependent on abrasive sharpness.
Power wire brush	Satisfactory, minor (1-2 mm) SCC features can be masked.	No data	2-3	1	Slow for large areas, but will remove tenacious surface deposits.

B.3.4 Typical MPI Inspection Practice

B.3.4.1 INSPECTION EQUIPMENT

The following equipment is required when undertaking either WFMPI or BWMPI inspection:

- Adequate power source (i.e. greater than 650 watts)
- Heavy grade black tarp (minimum 6 mil) [1]
- Calibrated CSA-approved portable AC yoke (the yoke should be calibrated using a standard 10 lb weight every 6 months, after a repair or when a malfunction is suspected)
- Portable CSA-approved UV lamp (must have a minimum intensity of 800 mW/cm^2 at a distance of 380 mm from the lens face to the inspection surface) 1
- Fluorescent indicating medium (particle concentration between 0.1 and 0.5 wt.% (within Standard Guidelines) of solid particles) 1
- Visible black particle prepared bath (particle concentration 1.2-2.4 wt %)
- White contrast paint[2]

> The visible prepared bath and contrast paint must not be exposed to low temperatures which will adversely affect particle mobility and method sensitivity.

B.3.4.2 PROCEDURE

All inspection surfaces must be prepared as described in Section B.3.3.

The surface temperature of the inspection area is an important factor in ensuring the sensitivity of the inspection. If the temperature is too low, the indicating medium becomes too viscous and the inspection method becomes unreliable. In such instances a surface “pre-heat” is required.

The MPI inspection should be completed using either the WFMPI or the BWMPI method depending on site circumstances. Typically, BWMPI is preferred for more-difficult site conditions (e.g., wet excavation site, one person crew, or small inspection area). As a minimum, the inspector should look for both axially and circumferentially oriented SCC by using two full 90-degree turns of the hand yoke within the inspection area.

B.3.4.3 MPI DOCUMENTATION

BWMPI produces a more permanent image of any SCC present and is, therefore, more useful than WFMPI for documenting SCC colonies. Once the SCC colonies have been identified, the colony characteristics should be measured and documented in a consistent format, as outlined in Appendix C. Photographs of the detected SCC colonies should be taken.

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[1] WFMPI method only
[2] BWMPI method only

B.4 SCC SIZING

Sizing SCC requires the measurement of the SCC length, depth and density (see Sections B.4.4 and B.4.5). The pipe wall thickness at the location of the SCC feature should also be measured. The cracks dimensions are typically reported for each SCC colony.

The pipe wall thickness, SCC length and SCC density are always determined quantitatively. In contrast, the SCC depth can be measured both qualitatively (i.e., based on expert judgement) and quantitatively. At excavations where large colonies of SCC are found, a combination of both qualitative and quantitative methods is generally used to fully document large areas of SCC in an efficient manner.

B.4.1 Pipe Wall Thickness Measurement

To obtain an accurate wall thickness of the pipeline being investigated, a calibrated ultrasonic thickness gauge (i.e., a D-Meter) or flaw meter with a 0.25" or 0.50" diameter compression wave (90°) probe should be used. Calibration is performed using a standard step wedge block. A suitable couplant is used to enable the sound energy to transfer into the pipe wall without scatter or interference, thereby, improving the accuracy of the wall thickness reading.

B.4.2 Colony Identification

The maximum crack length and depth is determined for each SCC colony. An SCC colony is defined as an independently acting feature, the dimensions of which (length and depth) would be used to estimate the failure pressure for that feature. For relatively deep cracks, the dimensions of the colony are defined by the crack interaction rules described in Section 2.3.4.4 of the main text. For shallow non-injurious cracks (<10% of the wall thickness), the exact dimensions of the colony are less important as such features do not represent an integrity concern. Because the vast majority of cracks tend to be shallow, technicians may define a larger crack colony that includes both interacting and non-interacting shallow cracks in order to reduce the total number of colonies to be characterized.

B.4.3 SCC Length and Density Measurements

The SCC length is defined as the total longitudinal length of the SCC feature prior to buffing. The measurement is typically made using a calliper tool or ruler with a precision of ±1 mm.

The relative positioning of cracks is important for two reasons. First, the endpoints of an SCC feature in relation to adjacent SCC features in both the circumferential and axial directions defines the degree of crack interaction (Section 2.3.4.4). Second, the relative positioning of cracks allows the colony to be categorized into one of four types:

- Toe of the weld SCC.
- Isolated SCC
- SCC in sparse colonies
- SCC in dense colonies.

Toe of the weld SCC refers to cracks located within the heat affected zone of the longseam weld. Isolated SCC cracks are individual features that do not fall into either the sparse or dense colony definitions. Sparse and dense colonies are defined as adjacent cracks with circumferential spacing as described in Table B.4. [Leis and Mohan 1993].

Table B.4: Definition of SCC Density.

SCC DENSITY	APPROXIMATE CIRCUMFERENTIAL SPACING
Dense	<20% of wall thickness
Sparse	>20% of wall thickness

The crack spacing within colonies has been found to be correlated with the incidence of SCC leaks and ruptures [Leis and Mohan 1993], with 'sparse' SCC colonies typically found at or close to the failure location and 'dense' colonies further away. Cracks in dense colonies are thought to shield each other from the hoop stress, increasing the probability of crack dormancy. Cracks in dense colonies have a depth of typically less than 10% of the pipe wall thickness. In contrast, cracks in sparse colonies are less likely to shield each other from the hoop stress, resulting in a greater probability of depth-wise growth and crack coalescence. As such, SCC features that are isolated, located at the toe of the weld or are located within sparse colonies should be targeted for detailed sizing.

B.4.4 Qualitative SCC Depth Sizing

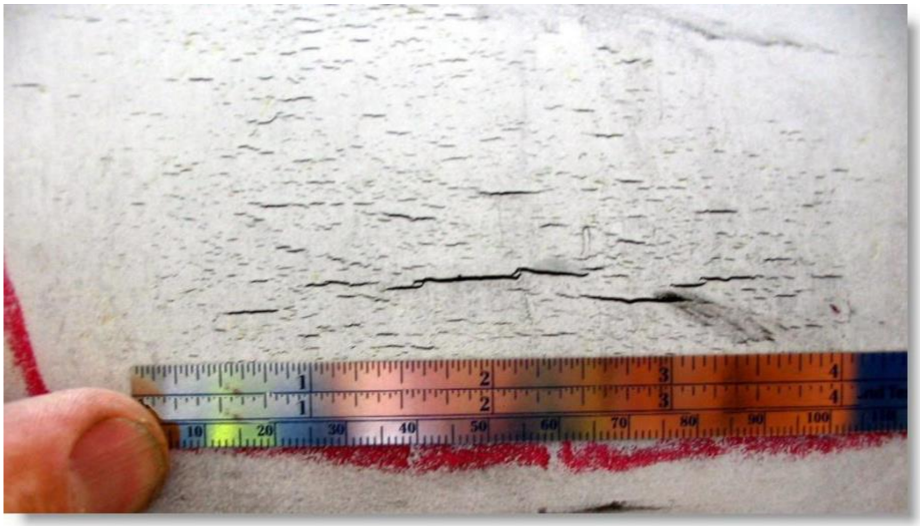
Qualitative SCC depth sizing is typically used to document large areas of shallow SCC (<10% of wall thickness) where sizing by buffing removal may not be practical due to time constraints or the proximity of one SCC feature to another. However, this method requires the technician have a significant level of skill and experience and operators may find that results vary from technician to technician.

Qualitative SCC depth determination is based on the intensity and length of the SCC indication, as determined by MPI. The short, less intense indications typically have a depth less than 10% of wall thickness, while the longer, darker indications have a depth greater than 10% of wall thickness (Figure B.3).

The crack depth can also be semi-quantitatively estimated based on the crack length and crack aspect ratio (the ratio of the length to the depth of the crack). The aspect ratio should be determined by sequentially buffing a sufficient number of short (in the length direction) cracks to determine the minimum (conservative) value of the aspect ratio.

However, there is no limit on the maximum aspect ratio. Maximum aspect ratios for SCC found within the base or "toe" of a longseam weld can vary widely and inconsistently, even within the same pipe joint.

Figure B.3: In-the-ditch SCC Assessment Using BWMPI.



When qualitatively estimating SCC depths, the following points should be considered:

- For shallow SCC in the pipe body (<10% of actual wall thickness), the longest SCC indication typically represents the deepest SCC anomaly.
- For each pipe joint, a representative number of the longer SCC indications should be buffed out to verify the depth estimation process.
- Estimated depths >10% should be confirmed by a quantitative assessment.
- Qualitative depth determination should not be applied to SCC features located at the toe of the longitudinal weld seam.

Qualitative SCC depth determination is technician-dependent and pipeline-specific and should only be undertaken by experienced technicians that have developed an ability to estimate SCC depths by continually validating their estimations using more accurate methods (e.g., sequential buffing, ultrasonic measurement techniques).

B.4.5 Quantitative SCC Depth Measurement

Quantitative SCC depth measurement is used to document the depths of isolated SCC, toe of the weld SCC, as well as the deepest SCC feature within a colony of SCC features.

B.4.5.1 ULTRASONIC DEPTH DETERMINATION

Ultrasonic crack sizing methods continue to evolve. In addition to the conventional shear wave method using standard or non-focused probes there are now procedures and equipment combinations available using technology such as time of flight diffraction (TOFD), phased array (PA), high angle dual element transducers, creeping and guided wave, and several specialized proprietary probes. Pipeline companies need to understand the limits of the specific procedure or method that they employ.

In practice, since SCC is typically removed by buffing, ultrasonic crack sizing has been most useful as a non-destructive method of providing an estimate of the depth of shorter, isolated individual SCC features or for determining the deepest location of a long toe crack before being removed by buffing. This estimation of the depth is important for calculating a safe pressure for buffing activities.

Ultrasonic depth determination becomes increasingly more accurate if:

- The SCC feature is isolated.
- The SCC feature is not located within a gouge, dent, or in corrosion.
- Calibration specimens are available that have similar crack-like characteristics as SCC.
- The technician has the appropriate skill and experience in sizing SCC.

To gain confidence in the specific method employed, the ultrasonically measured crack size and actual crack size should be compared and recorded. It is important that this information be passed back to the technician conducting the ultrasonic testing.

B.4.5.2 SEQUENTIAL BUFFING

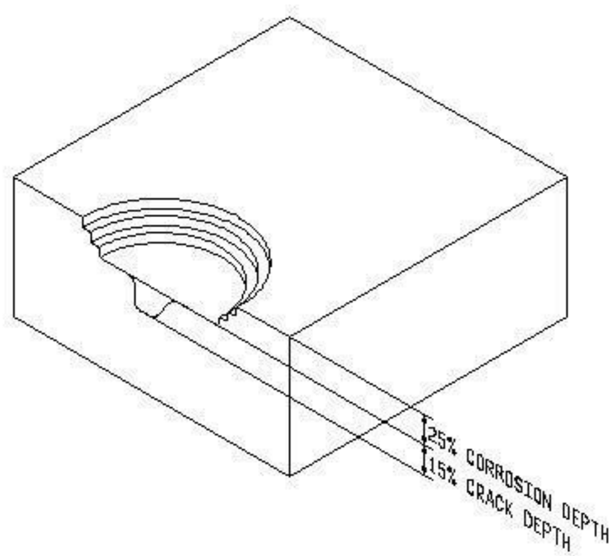
The methodology of sequential buffing is detailed in Appendix E.

B.4.6 Measuring SCC Within Metal Loss

SCC that occurs within metal loss is evaluated based on the sum of the depths of the SCC and metal loss (Figure B.4).

Example: *A corrosion pit penetrates 25% into the pipe wall. The SCC located at the base of the corrosion penetrates an additional 15% of the pipe wall thickness. The crack depth for assessment purposes is then assumed to be 40% of the pipe wall thickness.*

Figure B.4: Schematic Illustrating an SCC Feature in the Bottom of Metal Loss.



B.5 RECOATING AFTER AN EXCAVATION

During the course of buried pipeline inspection, the protective coating is removed to expose the bare steel surface. After the investigation is complete, it is necessary to recoat the pipeline to provide a barrier against environments that could lead to corrosion or SCC.

B.5.1 Types of Coating Material

There are many types and brands of pipeline coatings available for recoating operations. These can be grouped into the following general categories.

B.5.1.1 COLD APPLIED TAPES

These materials are supplied in rolls of varying widths and are typically hand applied to the pipe. Mechanical assistance, using either hand-held wrappers or machines which clamp around the pipe, can help speed up the work for longer lengths of pipe and usually produce a superior coating application with even overlaps and consistent tension. In most cases a primer is applied in advance of the coating to improve adhesion.

<u>Thin Polyethylene Tapes</u>

This material comprises a thin polyethylene backing (approximately 9-15 mils thick) and adhesive. Some of these tapes do not require the use of a primer but rather contain a pressure sensitive butyl rubber adhesive intended to supply the designed adhesion. This material was used extensively in North America on new pipelines built in the 1960s and 1970s. It has been found to be susceptible to soil stress and other factors which cause the tape to deteriorate and disbond. Due to its failure mechanisms in combination with its dielectric properties, cathodic protection is not effective in protecting the steel at shielded coating disbondments and hence SCC is commonly found under polyethylene tape.

<u>Petrolatum Tapes</u>

This material consists of a synthetic fabric impregnated with a waxy compound. It is normally designed for use on irregular shapes such as flanges and couplings. It is not typically used on straight runs of pipe where soil stresses are a concern.

<u>Bitumastic Tapes</u>

This class of cold applied tapes is normally composed of reinforced, non-woven synthetic fibres, fully impregnated and coated with a thick (approximately 40-80 mils) bituminous compound. It is typically laminated to a thin (approximately 4-8 mils) polyvinyl chloride or a woven fabric backing. Soil stress and cathodic shielding may still affect this material, but its performance is considered to be superior to the thin polyethylene tape. The bitumastic tape works well as a transition application, such as between old tape coating and new repair epoxy coating.

B.5.1.2 HOT APPLIED TAPES

These materials are normally supplied in rolls and, as with cold applied tapes, can be wrapped around the pipe by hand or with the use of mechanical equipment. Hot applied tapes are thermoplastic and are heated on one side using torch equipment creating a semi-liquid face that is directly applied to the bare steel. As the material cools, it hardens to its final state.

<u>Coal Tar Tape</u>

A reinforcing fabric is impregnated with coal tar pitch. In the "cold" state, the tape is brittle and crumbly. As it is heated, it becomes pliable and the heated side is directly applied to the steel surface. In the cooled state, it forms a hard, durable barrier that is resistant to soil stress and water vapour and typically does not shield cathodic protection.

Shrink Tape

This tape coating consists of a polyethylene backing that is coated with a thermoplastic adhesive. The backing and adhesive are thicker than for thin polyethylene tapes and the backing is modified so that it shrinks when heated giving it a tight wrap around the pipe. Performance properties are highly dependent on ensuring proper heat distribution on application.

Shrink Sleeves

This material has a formulation similar to shrink tapes. It is pre-packaged in a blanket form that wraps around the pipe and is heated to shrink it to the surface. Sleeves can be purchased for various diameter pipes but do not exceed a length (width) of approximately one metre. These materials are normally used only as girth weld coating materials for new construction. As with shrink tape, coating failures have been attributed to improper heating of the sleeve.

B.5.1.3 LIQUID BASED COATINGS

Liquid coatings can be applied using brushes and rollers or using relatively sophisticated spray equipment (Figure B.5). Although these materials are not as user-friendly as tape materials, the performance properties are usually superior. Materials that must be applied using brushes or rollers are typically only used when a short length of pipe is to be recoated.

Mastics

These materials are normally formulated from a solution of coal tar blended with plastic resins, such as vinyl. Normally it is brushed or rolled onto the pipe. As the material cures, solvents are released. These materials require a relatively long cure time.

Multi Component

These are modern formulations packaged in two separate containers, the contents of which must be properly mixed together to form the final product for application. Most types of multi-component coatings can be applied either with a brush and roller or with plural component spray equipment. Spray applied materials typically are not applied to very small diameter pipes since a great deal of overspray is created resulting in coating wastage. This category of coating comprises a wide range of different chemistries such as epoxies, urethanes, coal tar epoxies, and blends of each.

B.5.1.4 POWDER BASED COATINGS

Fusion bonded epoxy is the only powder-based coating that has been commercially used for pipelines. The application of this material requires the use of specialized pipe heating and powder spray equipment. In the field, it is not normally used as a recoating material but is sometimes used for the coating of girth welds during new pipeline construction.

Figure B.5: Application of Liquid Based Coating after Bell Hole Inspection.

B.5.2 Surface Preparation Requirements

Proper surface preparation of the steel is considered to be the single most important step in the coating application process. Cleaning solutions are used to remove grease or oil residue. Subsequently, any other deleterious substances, such as corrosion product or dirt should also be removed and the steel surface should be sufficiently roughened to improve the adhesive qualities of the coating.

MPI inspection usually results in a layer of "paint" which should be removed with a second abrasive blast. Abrasive blasting using sand, slag, or other such materials typically provide the best degree of cleanliness and surface roughness necessary for optimum coating performance. Shot peened steel pipe surfaces exhibit an increased level of resistance to the initiation of SCC. Other modes of surface preparation, such as power- or hand-tool cleaning are also used, but generally produce a poorer surface finish than blasting methods. The applicator should follow the surface preparation specifications provided by the coating manufacturer and blast media supplier.

B.5.3 Ambient Weather Conditions

The drying of tape primers and curing of liquid coatings will be affected by air temperature and humidity. Further, if the pipe temperature is less than the dew-point temperature, moisture will form on the pipe surface and create a rust bloom. As a result, it may be necessary to consider the use of heating or hoarding equipment to heat the steel surface or ambient air (Figure B.6). In some cases, over-heating of the coating due to sun exposure can also be detrimental.

Figure B.6: Hording-In an Excavation Site for Winter Recoating.

B.5.4 Compatibility With Existing Coating

Following recoating, the transition between the new coating and the parent coating should be properly sealed. Normally, the new coating will be applied directly over the transition and parent coating. Many liquid-based recoat materials will not bond to polyethylene tape or multi-layer extruded polyethylene (e.g., "Yellow Jacket") parent coatings. In these cases, the liquid-based coating should be applied right up to the polyethylene (some overspray is acceptable) and an additional tape-based material should be used as an overwrap, simultaneously covering both the parent and the recoat materials at the transition section.

If the parent material is asphalt or coal tar enamel, the parent coating should be roughened to aid adhesion and feathered at the edges to provide a smooth transition. If liquid materials are to be applied over this type of parent coating, it is advisable to apply a test patch to ensure chemical compatibility. In some cases, asphalt or coal tar enamel coatings contain a fibrous reinforcing material that may inhibit proper adhesion of liquid recoat materials. In these cases, it is necessary to apply a full circumference wrap type material (e.g., a mastic blanket or bitumastic/petrolatum tape) over the transition.

B.5.5 Geographical and Physical Location

Some recoating operations require the use of compressors, spray units or other equipment that must be stationed by the side of the ditch. In some cases, such as when the pipe is in a slough or on a steep slope, access to the pipe is difficult. Further, in remote locations such as the far North, the required equipment or qualified contractors may not be readily available.

B.5.6 Costs

The cost of the recoating operation is generally more affected by the level of surface preparation specified than the type of coating material selected. Costs increase as the level of surface preparation is improved. When contractors are employed to apply recoating materials, costs can be drastically improved if economies of scale are possible.

B.5.7 Health and Safety Codes

Some blast media can present a health hazard and should be handled and disposed of in accordance with the appropriate regulations. For instance, silica sand, when used for abrasive blasting operations, is considered a breathing hazard and workers are required to wear the appropriate breathing apparatus and handle the material in a work-safe fashion. Today there are numerous alternative materials available which will suitably prepare the surface for inspection and re-coating. Materials such as walnut shells have been used with some success, but may cause an allergic reaction to people with nut allergies. Similarly, some workers may be sensitive to solvents or other components contained in primers or liquid based coatings.

B.5.8 Quality Assurance

A clearly written specification outlining individual responsibilities, safety hazards, surface preparation and coating application requirements, record keeping, and quality control measures should be prepared in advance of the work. The operator may decide to hire a qualified inspector to monitor the progress of the job. Record keeping should include information about the materials shipped to the site, the degree of surface cleanliness and roughness, environmental conditions such as temperature, humidity and dew point, identification of any coating defects such as inappropriate thickness or insufficient overlap, and the results of high voltage holiday testing.

B.5.9 Industry Standards

There is a wealth of information available on the specification and application of pipeline coatings. The following organizations should be consulted for additional information on pipeline recoating:

- SSPC: Steel Structures Painting Council
- NACE: National Association of Corrosion Engineers International

- ASTM: American Society for Testing and Materials
- CSA: Canadian Standards Association

REFERENCES FOR APPENDIX B

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Appendix C
Field Data Collection

Collectively, CEPA-member companies have conducted thousands of SCC excavations over the past 30-40 years. Various types of data have been routinely collected during these excavations because of their potential value in the management of SCC. These data include parameters that can be used to conduct initial assessments of SCC susceptibility or for selection of excavation inspection sites. Depending on the volume of data collected, it may be possible to derive correlations for different aspects of crack development such as crack initiation, growth or other significant processes.

In many cases, the data described below have been shown to have a relationship to some aspect of SCC. In other cases, operational experience and the results from R&D studies suggest some correlation and the collection of these data is considered to have value in the context of continuous improvement of SCC management. The data set proposed in this section should be used as a guideline only. Each operator should evaluate their system and decide whether additional or alternative parameters are valuable in their particular case.

C.1 LEARNING FROM ALL SCC OPPORTUNITIES

Data should be collected from all investigation activities such as in-line inspection validation digs, hydrostatic test repairs, in-service failures, and opportunistic digs.

With the increasing use of ILI, many digs are now being performed to validate the results of tool runs. During validation digs, it is important to collect data to allow a comparison between the reported ILI feature and that found from the excavation. This comparison should take into consideration the ILI vendor specifications with regard to interaction rules, crack size detection limits, etc. Feeding back this information to the ILI vendor can significantly improve the detection and sizing capability during the analysis of tool data.

C.2 DATA COLLECTION

Data analysis is used to assess the susceptibility of pipeline segments and to select sites to investigate for the presence of SCC or for condition monitoring. The basis of these decisions is the correlation between SCC and certain system attributes (e.g., construction, environmental, operating, and maintenance data).

C.2.1 Inspection Excavations

When a field excavation program is implemented there is the opportunity to record observations on several aspects of the pipe including the terrain where the excavation is located, the performance of the materials of construction, the environment in contact with the pipe, and possibly characteristics of cracking or other pipe anomalies.

C.2.2 Standardized Field Data Collection

Field data collected for the purpose of operational learning on a system requires that the data be documented consistently and spatially-referenced. Consistent terminology and data collection are required to enable meaningful organization and analysis.

C.2.3 Spatial Referencing

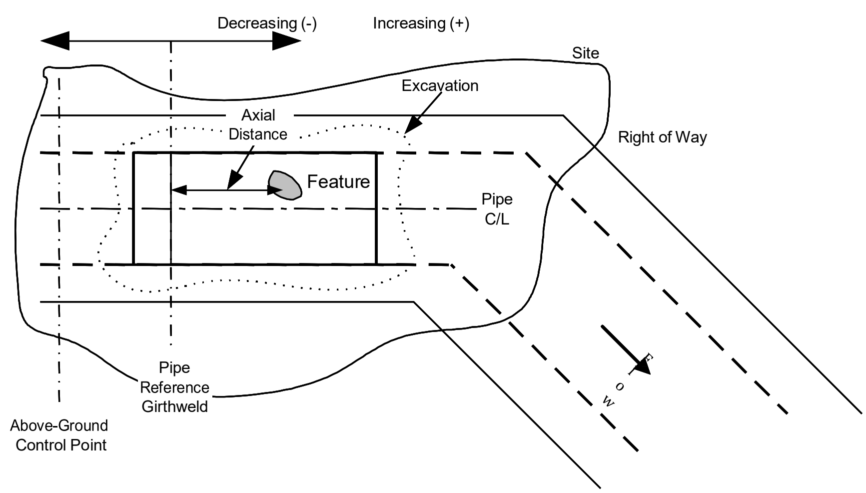
In the field, data collection progresses with operations, beginning with ground-level site observations and measurements and progressing to below-ground observations as the pipe is exposed (Figure C.1).

The position of an above-ground reference point is measured axially from a control point along the centre line of the pipe, such as a valve or a pipe transition. After excavation the reference system is extended
to the pipe. By convention, the pipe reference point is the girth weld furthest upstream in the excavation. It is recommended that GPS readings be obtained on at least the above-ground reference point and reference girth weld for validation tracking purposes.

Feature locations on the pipe (e.g., coating or pipe surface features) are recorded in terms of axial and circumferential position. Axial position is measured from the reference girth weld with positive distance increasing in the direction of flow and negative distance increasing in the upstream direction.

Circumferential positions on the pipe are recorded as either o'clock or distance from the top of the pipe in the clockwise direction. O'clock is estimated according to the circumferential position with 12:00 being the top and clockwise proceeding to the right when looking downstream along the pipe centre line.

Figure C.1: Axial and Circumferential Referencing



C.3 EXCAVATION DATA COLLECTION AND TABLES

Section C.3.10 provides a data dictionary and a set of tables to guide the collection of the recommended field data. Specific inspection sites should be selected and prioritized based on susceptibility parameters and the pipeline attributes.

The Dig Data Table (Table C.2) is used to collect data relating to the excavation site and consists mainly of information collected ahead of the excavation based on available records. This table contains information that could be useful to the company or its contractor to locate and survey the site. Such data include planning and administrative information including the excavation date, the name or line number, the location relative to the upstream pump or compressor station, the location and type of above ground reference point, etc. It is recommended that these data be compiled during the planning or site surveying phase ahead of the actual excavation.

A company may choose to augment this table with information relating to the contractor or the company representative involved.

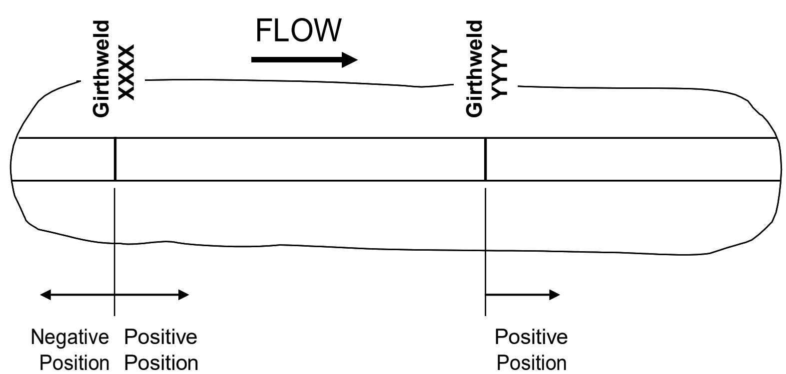
C.3.1 Weld and Pipe Characteristics Table

In each SCC excavation, observed features above and below ground are recorded relative to axial and circumferential references (Table C.3). Each girth weld in the excavation is assigned a Weld_ID, generally in reference to a particular ILI run, if performed.

As the pipe is exposed, the first task is to establish the axial reference system using the welds and direction of flow as illustrated in Figure C.1. In addition to recording girth weld data, the pipe diameter, wall thickness, joint length, long seam weld type and circumferential position, and manufacturer should be recorded. The length of pipe to be cleaned and inspected is also recorded.

To aid in referencing observations, it is recommended that a scale be applied to the pipe. This is frequently achieved by marking off metres, using spray paint, moving upstream and downstream of the reference girth weld. All feature positions are documented relative to the upstream girth weld (Figure C.2).

Figure C.2: Data Axial Position References Girth Welds.



C.3.2 Terrain Data

As discussed Section 2.3.1 and Appendix A, some companies have found correlations between SCC and certain terrain features. Potentially useful parameters include the local topography, soil texture or particle size, and the site drainage. Terms relating to deposition modes have also been used.

Various standards and systems of soil classification exist [ASTM 2009, NRC 1998]. These systems have been developed to provide classification related, for example, to the engineering use of soil, agricultural use, chemical and physical properties and the development of soil based on geology, climate and other factors. In the context of pipeline corrosion and SCC, the relevant aspects of the soil that could play a role in pipeline performance remain to be fully established. For example:

- the presence of clay, particularly swelling clays, may correlate to the degree of disbondment of tape coating;
- the degree of aeration may be indicated by the soil texture or soil gleying (characteristic of anaerobic conditions);
- the presence of groundwater, soil mottling, or poor drainage may indicate that sufficient water is available to support corrosion;
- alternatively, high soil resistivity or good drainage may indicate poor cathodic protection.

Given the specialized and varied needs of pipeline companies, rather than adhering to any one soil classification system, operators have tended to borrow and mix terms from various conventions. These Practices do not advocate any single soil classification standard. It is recognized that such differences will exist and that when sharing information among operators some interpretation of nomenclature will be required.

Two different data tables are used here to characterize soil conditions.

C.3.2.1 TERRAIN – LINEAR FEATURES TABLE

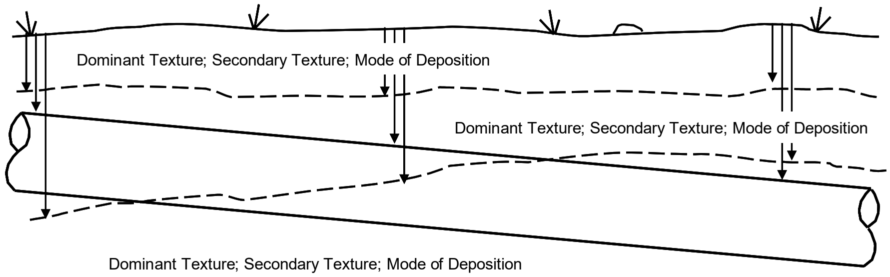
The Terrain – Linear Features table (Table C.4) records the general surface topography in the area of the excavation as well as the specific position of the excavation within the topography, the local drainage and the maximum slope percentage. Depending on the position of the excavation in the terrain, or the extent of a given drainage (e.g., if the site extends from a mid-slope position down to the slope toe), more than one entry may be made to best characterize a site. Photographs and sketches are useful.

C.3.2.2 SOIL 2-D FEATURES TABLE

The Soil 2-D Features table (Table C.5) records the characteristics of the major soil blocks at the pipe at depth along the excavation (Figure C.3). Soil blocks are recorded in terms of their individual lengths, depths and the position of the pipe within them. The attributes recorded for the soil blocks are the mode of deposition, and the dominant and secondary textures of the soils, as well as indications of the presence of oxygen, gleying, water movement, and mottling. Multiple entries may be required if conditions at pipe depth vary significantly along the excavation or pipe.

A geologist, hydro-geologist, soil specialist, geotechnical engineer or technician experienced and familiar with the classification of topography and soil characteristics should document the terrain conditions along the excavation.

Figure C.3: Documentation of Below Ground Soil Features



C.3.3 Buoyancy Table

Some cases of pipe deterioration, including the development of SCC, have occurred under concrete buoyancy control weights. At such locations, coating damage has been observed caused either by the placement of the weight during construction or movement of the weight during service. Localized environmental conditions have also been observed due to either depletion or concentration of particular environmental species. Such localized conditions could differ significantly from the pipe environment on either side of the concrete buoyancy control weights and could either favour or impede the development of SCC.

The Buoyancy table (Table C.6) has an entry for the composition of the weight. In the case of one transmission pipeline, a failure occurred due to hydrogen-induced cracking (HIC) initiated beneath buoyancy control weights fabricated with high sulphur content. Whilst such sulphur-containing weights are not in common usage and HIC is not the subject of these Practices, the conditions found beneath the weights were strongly anaerobic, a condition also associated with near-neutral pH SCC.

C.3.4 Pipe-to-Soil Potentials Table

The on-potential of the pipe should be recorded during the excavation. A pipe-to-soil potential measurement should be recorded at the soil surface and, as the pipe is exposed, measurements should also be made adjacent to the pipe at the top, side and bottom of the pipe. The measurements should be taken with respect to the reference girth weld (Table C.7).

C.3.5 Coating Characterization

Two different tables are used to characterize the coating, one capturing general observations and the other relating to coating damage.

C.3.5.1 GENERAL COATING CONDITION TABLE

The General Coating Condition table (Table C.8) summarizes the type(s) of coating present on the exposed pipe, as well as the general condition of the coating at the time of the excavation. It has been suggested that some mill-applied coatings provide a higher degree of protection than field-applied coatings. Therefore, the apparent mode of application should be recorded.

The condition of the coating is documented using the semi-quantitative criteria given in Table C.1. These descriptions include a quantitative measure of the coating quality that can be used for numerical analysis.

Table C.1: Categories of Coating Quality.

COATING CONDITION	EXTENT OF TENTING (TAPE COATING ONLY)	DESCRIPTION OF DISBONDED COATING
Excellent	Very minor to non-existent	Very good adhesion; less than 1% disbondment; an occasional holiday; asphalt exhibits continuous thickness; no electrolyte beneath the coating.
Well	Minor, intermittent	1 to 10% disbondment, scattered holidays; isolated disbondments due to soil stress with no associated corrosion deposits; good adhesion.
Fair	Intermittent	10 to 50% disbondment; intermittent soil stress disbondments; coating damage; scattered to numerous holidays; random areas of poor adhesion; brittle coating (asphalt).
Poor	Continuous	50 to 80% disbondment; numerous holidays; multiple or continuous areas of poor adhesion; interlinked soil stress disbondments with associated deposits; coating damage; very brittle coating (asphalt).
Very Poor	Continuous	> 80% coating failure; no adhesion, numerous holidays; interlinked soil stress disbondments with associated corrosion deposits; coating damage; very brittle coating (asphalt).

C.3.5.2 DISCRETE COATING DAMAGE TABLE

The Discrete Coating Damage table (Table C.9) documents the mapping of coating damage, including tape “tenting”, on the pipe relative to the excavated pipe reference system. Table C.9 should be completed for each disbondment on the excavated pipe. As above, photographs or drawings are useful.

C.3.6 Sampling and Analysis

Prior to, or during coating removal, the presence of corrosion deposit(s) or water beneath the coating should be noted. It is important that, if possible, corrosion deposits be identified. Combined with other specific environmental parameters, certain deposits may be correlated to either the presence or absence of SCC and can provide information related to the chemical environment beneath disbonded coatings (Table C.10).

Corrosion deposits are documented according to physical attributes such as colour, texture, and distribution. Commercially available test kits can be used to qualitatively identify the composition of deposits.

The pH of water samples should be determined as soon as possible after exposure of the pipe as the pH of trapped water can change with time. Litmus paper is the most common technique and can be used even if there is only superficial moisture on the pipe.

Near-neutral pH SCC has been observed to occur in the presence of under-coating waters with pH in the range 5.5 to 7.5. In contrast high-pH SCC occurs at pH greater than 9.3.

In the case of near-neutral pH SCC, the under-coating water can contain dissolved carbon dioxide that, over time, can evolve with a corresponding increase in pH. Therefore, pH measurements should be taken as soon as possible during inspection. The pH of the trapped water can also decrease over time due to the oxidation of dissolved ferrous ions and the subsequent hydrolysis of the resulting ferric ions.

C.3.7 SCC Table

Following removal of the coating and the completion of MPI, any SCC that is present is documented using the SCC table (Table C.11) and/or the Toe Cracks table (Table C.12).

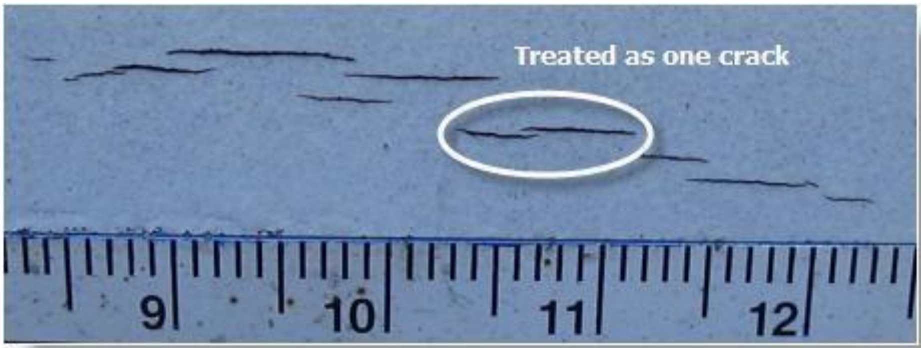
SCC occurs in patches or colonies typically containing from a few to thousands of individual cracks. Cracks are essentially parallel to one-another and oriented perpendicular to the local direction of maximum stress on the pipe. Typically cracks are axially-orientated when the hoop stress is the dominant stress. Where external bending loads act on the pipe or where local stress raisers (e.g., dents) are present, the dominant stress direction can shift to the longitudinal orientation or some intermediate angle. Figure C.4 shows an example of circumferentially-oriented SCC resulting from local pipe bending.

Figure C.4: Circumferentially-oriented Cracks that Resulted in a Leak in an NPS 8 Pipe.

An SCC colony is defined as an independently acting feature, the dimensions of which (length and depth) would be used to estimate the failure pressure for that feature. For relatively deep cracks, the dimensions of the colony are defined by the crack interaction rules described in Section 2.3.4.4 of the main text. For shallow non-injurious cracks (<10% of the wall thickness), the exact dimensions of the colony are less important as such features do not represent an integrity concern. Comparison of the number of colonies per joint has been used to characterize the relative severity of the SCC found.

Cracks often exhibit a stair-case pattern with axial spacing less than 1 mm. Overlapping cracks showing indications of coalescence are deemed to be "interacting" (Section 2.3.4.4) and are considered to be a single feature (Figure C.5).

Figure C.5: Interacting SCC.



For recording purposes, each colony is assigned a unique identifier. Each colony should be documented. The documentation of cracks within each colony includes the average and maximum lengths and depths of isolated and interacting cracks, the density of cracking, the position and orientation of cracks on the pipe, and measurements relating to any grinding conducted on cracks (Table C.11). The presence or absence of toe cracks is indicated, although the details are to be recorded separately.

Operators are encouraged to measure and record the depth of a percentage of cracks found, both to assess the severity of the SCC and to assess the depth distribution of cracks present at the site.

Where there is potential for more than one form of SCC, the morphology of cracking may also be determined. Some inspection companies offer in situ determination of the crack morphology, i.e., whether cracks are intergranular or transgranular.

C.3.8 Toe Cracks Table

Cracks located at the toe of the long seam weld may or may not be SCC. As a result of their position, co-linear orientation and mechanistic uncertainty, toe crack data are recorded separately from pipe body SCC.

When SCC inspections are conducted using MPI, a crack-like indication is often noted at the edges of the long-seam welds. Indications may be the result of weld imperfections, such as roll-over or undercut, or they may be more significant features, such as lack of fusion or cracking. Such indications need to be assessed with caution to avoid overlooking SCC. Frequently, lightly filing or buffing the cap of the weld flush with the pipe surface can facilitate interpretation of the indications.

The Toe Cracks table (Table C.12) records crack length, depth, and tip-to-tip spacing. As these cracks are often present as a line of cracks as opposed to colonies, non-destructive determinations of their depth can be reliable. Shear-wave, phased array and time-of-flight diffraction (TOFD) ultrasonic inspection provide suitable accuracy.

C.3.9 Pipe Surface Damage

Where either metal-loss corrosion or pipe surface damage is present in the excavation, the relative circumferential and axial positions and geometries should be documented. Pipe surface damage can be due to dents and/or gouges, arc strikes, wrinkles, or metallurgical hard spots. This information is recorded in the Coincident Corrosion (Table C.13) and Coincident Mechanical Damage (Table C.14) tables.

C.3.10 Data Dictionary

Table C.2: Dig Data Table.

DIG DATA

FIELD NAME	*UNITS*	*DESCRIPTION*
Dig_ID	NA	Unique identifier for the dig
Date	Date	Date of the dig
GPS_Latitude_Direction	NA	Latitude direction
GPS_Latitude	NA	Latitude (hours, minutes, seconds)
GPS_Longitude_Direction	NA	Longitude direction
GPS_Longitude	NA	Longitude (hours, minutes, seconds)
Line_Number	NA	Line number
Line_Name	NA	Line Name
Above_Ground_Marker	NA	Above ground marker type
Above_Ground_Site_Chainage_m	m	Distance from ground marker to start of dig or start stake
Upstream_Station_Name	NA	Name of the upstream compressor station
Distance_to_Upstream_Station_m	m	Distance from station to start of dig or start stake
Reference_Weld_Chainage_m	m	Distance from start of dig or start stake to the reference girthweld
MAOP_kPa	kPa	Max. Allowable Operating Pressure
Land Use	NA	Use of Land
Physiographic_Region	NA	Physiographic region
Vegetative_Legend	NA	Vegetation
Notes	NA	Other notes
Grade	MPa	Grade of pipe

RECOMMENDED DESCRIPTIONS

Physiographic Regions
Canadian Shield
Coastal
Cordilleran
Interior Plains
St. Lawrence Lowlands
Mississippi Valley

Vegetative Legend
Boreal
Coastal
Deciduous
Desert
Grasslands
Montane Alpine

Land Use Types
Abandoned
Agriculture
Aquatic
Commercial
Cultivated
Desert
Grassland
Gravelled
Grazing
Paved
Prairie
Residential
Rock
Woodland

Table C.3: Weld & Pipe Characteristics Table.

WELD & PIPE CHARACTERISTICS

FIELD NAME	*UNITS*	*DESCRIPTION*
Dig_ID	NA	Unique identifier for the dig
Weld_ID	NA	Unique identifier for the girthweld
Manufacturer	NA	Pipe manufacturer
Exposed_Joint_Length_m	m	How much of each joint was actually exposed
Inspected_Length_of_Cleaned_Pipe_m	m	Length of inspected pipe
Pipe_Diameter_mm	mm	Pipe diameter
Actual_Wall_Thickness_mm	mm	Actual wall thickness (10 measurements)
Avg_Width_of_Tenting_mm	mm	Average width of tenting
Seam_Weld_Type	NA	Type of seam weld
Spacing_of_Spiral_Seam_cm	cm	Spacing of the spiral seam
Long_Seam_TDC_o'clock	mm	Location of the long seam on the circumference of the pipe from the TDC
Notes	NA	Other notes

RECOMMENDED DESCRIPTIONS

Manufacturer	*Seam_Weld_Type*
Alberta Phoenix	DSAW
AO Smith	Flash
BHP	ERW
Berg	Lap
Bergrohr	
Bethelhem	Seamless
Camrose	Spiral
Camrose Tubes	
Canadian Phoenix	
Consolidated	
Eisenbau Kramer	
Estel Hoesch	
HME	
IPSCO	
SIAT	
South Durham	
Steel Mains	
Stelco	
Stewards Lloyds	
Sumitomo	
US Steel	
Vallourec	
Welland Tube	
Western	
Youngstown	

Table C.4: Terrain – Linear Features Table.

Terrain - Linear Features

FIELD NAME	***UNITS***	***DESCRIPTION***
Dig_ID	NA	Unique identifier for the dig
U/S_Weld_ID	NA	Unique identifier for the upstream girthweld that the soil is measured from
Feature_ID	NA	Unique identifier for the soil feature
Start_from_reference_GW_m	m	Location of the start of soil with respect to ref. GW
Length_m	m	Length of the soil
Maximum_Slope_Percent	%	Maximum Slope percent of the area around the pipe
Topography	NA	Topography of the area
Slope_Position	NA	Slope position of the pipe
Surface_Salts	NA	Are there any visible surface salts?
Notes	NA	Other notes

RECOMMENDED DESCRIPTIONS

Max. Slope Percent	*Slope Position*	*Topography*
0	Crest	Dunes
15	Depression	Floodplain
30	Level	Hummocky
45	Lower	Inclined
60	Middle	Level
75	Toe	Ridged
90	Upper	Rolling
		Stream Channel
		Undulating
		Depression

Table C.5: Soil 2-D Features Table.

SOIL - 2D FEATURES

FIELD NAME	*UNITS*	*DESCRIPTION*
Dig_ID	NA	Unique identifier for the dig
U/S_Weld_ID	NA	Unique identifier for the upstream girthweld that the soil is measured from
Feature_ID	NA	Unique identifier for the soil feature
Start_from_reference_GW_m	m	Location of the start of soil with respect to ref. GW
Length_m	m	Length of the soil at pipe depth
Depth_Start_m	m	Location of the start of pipe depth soil from ground surface
Depth_End_m	m	Location of bottom of pipe depth soil from ground surface
Depth_to_Pipe_m	m	Depth to the top of the pipe from the ground surface
Drainage	NA	Drainage of the soil around the pipe
Dominant Texture	NA	The dominant texture of the soil
Secondary Texture	NA	The secondary texture of the soil
Mode_of_Deposition	NA	The deposition process at pipe depth
Mottling	NA	Description of Mottling feature at pipe depth
Gleying	NA	Description of Gleying feature at pipe depth
Notes	NA	Other notes

RECOMMENDED DESCRIPTIONS

Texture
Silt
Clay
Sand
Till
Gravel
Rock
Peet

Mode of Deposition
Colluvium
Eolian
Fluvial
Glaciofluvial
Glaciolacustrine
Lacustrine
Organic
Shot Rock
Till (Moraine)

Gleying
Intensely Gleyed (Dark Bluish to Dark Greenish-Grey)
Strongly Gleyed (Dark Grey)
Moderately Gleyed (Light to Drab Grey)
Slightly Gleyed (Patches of Light Greyish-Brown)
Not Gleyed (Brown Color Dominates)

Drainage
Imperfect
Poor
Very Poor
Moderately Well
Well

Mottling
None
Faint
Distinct
Prominent

Table C.6: Buoyancy Table.

BUOYANCY

FIELD NAME	UNITS	DESCRIPTION
Dig_ID	NA	Unique identifier for the dig
U/S_Weld_ID	NA	Unique identifier for the upstream girthweld that the feature is measured from
Start_from_reference_GW_m	m	Location of the start of the buoyancy control device with respect to the reference girthweld
Length_m	m	Length of the buoyancy control device
Type	NA	Type of buoyancy
Composition	NA	Composition of the buoyancy control device
Removed	NA	Was the buoyancy control device removed?
Notes	NA	Other notes
RECOMMENDED DESCRIPTIONS		
Type		*Composition*
Anchor		Portland
River		Sulphurcrete
Saddle/Swamp Weights		Unknown
Screw Anchors		
Spray On		
Swamp		

Table C.7: Pipe to Soil Potentials Table.

PIPE to SOIL POTENTIALS

FIELD NAME	UNITS	DESCRIPTION
Dig_ID	NA	Unique identifier for the dig
U/S_Weld_ID	NA	Unique identifier for the upstream girthweld that the potential is measured from
Potential_ID	NA	Unique identifier for the potentials
Location_m	m	Location of the CP measurement with respect to the reference girthweld
Off_Potential	mV	Off CP potential measurement
On_Potential	mV	On CP potential measurement
Depolarized Potential / native	mV	Depolarized pipe potential
Notes	NA	Other notes

Table C.8: General Coating Condition Table.

GENERAL COATING CONDITION

FIELD NAME	UNITS	DESCRIPTION
Dig_ID	NA	Unique identifier for the dig
U/S_Weld_ID	NA	Unique identifier for the upstream girthweld that the feature is measured from
Coating_ID	NA	Unique identifier for the coating
Start_from_reference_GW_m	m	Start of coating with respect to reference girthweld
Length_m	m	Length of coating
Coating_Type	NA	Coating type at time of excavation
Coating_Condition	NA	Coating condition by CEPA definition
Coating_Application_Pipe	NA	Method of coating application on the pipe
Coating_Application_GW	NA	Method of coating application on the girthweld
Notes	NA	Other notes

RECOMMENDED DESCRIPTIONS

Coating Condition
Excellent
Well
Fair
Poor
Very Poor

Coating_Application_(Girthweld/Pipe)
Factory
Field - Hand
Field - Machine

Coating_Type
Asphalt
Bare
Coal Tar Enamel
Enamel
Fusion Bond Epoxy
Lagging
PE Tape Double
PE Tape Single
Polyethylene
Polyvinyl Chloride
Shrink Sleeves
Somastic
Urethane
Urethane Epoxy
Yellow Jacket1
Yellow Jacket2
Wax

Table C.9: Discrete Coating Damage Table.

DISCRETE COATING DAMAGE

FIELD NAME	UNITS	DESCRIPTION
Dig_ID	NA	Unique identifier for the dig
U/S_Weld_ID	NA	Unique identifier for the upstream girthweld that the feature is measured from
Coating_Damage_ID	NA	Unique identifier for the coating or damage
Start_from_reference_GW_m	m	Location of nearest point of damage with respect to the reference girthweld
Length_m	m	Length of the damage
Width_mm	mm	Width of the short dimension of the damage
Feature_from_TDC_o'clock	mm	Distance from TDC to center of feature
Type_of_Coating_Damage	NA	Type of damage
Wet_Underneath	NA	Is the disbondment wet underneath?
LS_Tenting_>50mm	NA	Is there longseam tenting that is greater than 50mm?
Notes	NA	Other notes

RECOMMENDED DESCRIPTIONS

Type of Coating Damage
Disbondment
Holiday

Wet Underneath
Yes
No
Unknown

Table C.10: Sampling and Analysis Table.

SAMPLING AND ANALYSIS TABLE

FIELD NAME	UNITS	DESCRIPTION
Dig_ID	NA	Unique identifier for the dig
U/S_Weld_ID	NA	Unique identifier for the upstream girthweld that the Test is measured from
Coating_ID	NA	Unique identifier for the corresponding Test
Test_ID	NA	Unique identifier for the corrosion Test
Sample Type	NA	Type of Sample(s) taken
Test_Material_Type	NA	Type of Test taken
Colour	NA	Test colour
Texture	NA	Test texture
Visual_Deposit_Type	NA	Visual Test type
Distribution	NA	Distribution of the Test on the pipe
Start Depth_m	m	Start depth of Test
Axial_Distance_m	m	Location of the measurement from the reference girthweld
Soil Test Depth	m	Depth at which soil Test was taken
Corrosion Deposit Description	NA	Distribution of corrosion deposits
Feature_from_TDC_mm	mm	Distance of the feature from the TDC of the pipe
pH_Field	NA	pH of the Test in the field
Method_of_Assessment	NA	Method of assessing the Test
Test_Taken	NA	Was a Test taken?
Adherence_To_Coating	NA	Does the deposit adhere to the coating?
Adherence_To_Pipe	NA	Does the deposit adhere to the pipe?
Composition	NA	Composition of the corrosion product - lab analysis recommended
Notes	NA	Other notes

RECOMMENDED DESCRIPTIONS

Sample Type
Coating
Deposit
Groundwater
Soil
Water from undercoating

Method of Assessment
Visual
Field Test Kit

Colour
Black
Blue
Brown
Clear
Green
Grey
Light Green
Orange
Red
White
Yellow

Composition
CaCO3
Electrolyte
Fe-Oxide/Hydroxide
FeCO3
FeS
LGF
NaHCO3
Organic
Unknown

Distribution
Continuous
Dense
Intermittent

Test Taken/Adhere to Coating & Pipe
Yes
No

Corrosion Deposit Description
Continuous
Dense
Intermittent

Texture
Crystal
Film
Hard
Liquid
Metallic
Pasty
Powdery
Scaly
Waxy

Table C.11: SCC Table.

SCC

FIELD NAME	UNITS	DESCRIPTION
Dig_ID	NA	Unique identifier for the dig
U/S_Weld_ID	NA	Unique identifier for the upstream girthweld that the feature is measured from
SCC_Colony_ID	NA	Unique identifier for the SCC colony
Start_from_reference_GW_m	m	Location of the start of the SCC with respect to the reference girthweld
Colony_LENGTH_mm	mm	LENGTH of the colony
Colony_Width_mm	mm	The width of the short dimension of the feature
Angle of the colony	degree	Angle of the SCC colony with respect to the pipe axial direction
Average_Crack_LENGTH_mm	mm	Average LENGTH of the cracks
Max_Crack_LENGTH_mm	mm	Maximum LENGTH of the cracks
Max_Crack_Depth_mm	mm	Maximum depth of the cracks
Depth_Determination_Method	NA	The method used to determine the depth of the crack
Evidence_of_Cracks_Interlinking	NA	Is there evidence of the cracks interlinking?
Max_Interlinked_Crack_LENGTH_mm	mm	Maximum interlinked crack LENGTH
Colony_Circumferential_Width_mm	mm	Width of the colony
Feature_from_TDC_mm	mm	Distance from center of colony to TDC of the pipe
Orientation	NA	Direction that the distance from the TDC was measured
Crack_Morphology	NA	Morphology of the crack
Crack_Morphology_Method	NA	Method of determining the crack morphology
Shape	NA	Shape of the colony
Toe_Crack	NA	Is there a toe crack?
Side_to_Side_Crack_Spacing_mm	NA	Horizontal distance between cracks
Tip_To_Tip_Crack_Spacing_mm	NA	Horizontal distance between cracks
Grind_Feature_Start_m	m	Location of the nearest point of the grind area with respect to ref. GW
Grind_Feature_LENGTH_mm	mm	LENGTH of the grind feature
Grind_Feature_Circum_Width_mm	mm	Circumferential width of the grind feature
Centre_of_Grind_Feature_TDC	NA	Location of the centre of the grind area on the circumference of the pipe
Orientation_of_Grind_Feature	NA	Direction that the location of grind area was measured
Average Depth of Grind Feature_mm	mm	Average depth of the grind area
Max Depth of Grind Feature_mm	mm	Max depth of the grind area
MPI Method	NA	Method of magnetic particle inspection used
Photos	NA	Yes / No
Notes	NA	Other notes

RECOMMENDED DESCRIPTIONS

Shape
Rectangular
Linear

Orientation
CCW
CW

MPI Method
Color Contrast
Fluorescent

Evidence of Cracks Interlinking
Yes
No
Unknown

Depth Determination Method
Grinding
NDT
Visual

Crack Morphology
Intergranular
Transgranular

Crack_Morphology_Method
In-Situ Metallography
Not Determined
Unknown

Angle
0^o-30^o
30^o-60^o
60^o-90^o

Table C.12: Toe Cracks Table.

TOE CRACKS

FIELD NAME	UNITS	DESCRIPTION
Dig_ID	NA	Unique identifier for the dig
U/S_Weld_ID	NA	Unique identifier for the upstream girthweld that the feature is measured from
Toe_Crack_ID	NA	Unique identifier for the SCC Toe_Crack
Start_from_reference_GW_m	m	Location of the start of the SCC with respect to the reference girthweld
Toe_Crack_LENGTH_mm	mm	LENGTH of the Toe_Crack
Toe_Crack_Width_mm	mm	The width of the short dimension of the feature
Average_Crack_LENGTH_mm	mm	Average LENGTH of the cracks
Max_Crack_LENGTH_mm	mm	Maximum LENGTH of the cracks
Max_Crack_Depth_mm	mm	Maximum depth of the cracks
Depth_Determination_Method	NA	The method used to determine the depth of the crack
Evidence_of_Cracks_Interlinking	NA	Is there evidence of the cracks interlinking?
Max_Interlinked_Crack_LENGTH_mm	mm	Maximum interlinked crack LENGTH
Feature_from_TDC_mm	mm	Distance from center of Toe_Crack to TDC of the pipe
Crack_Morphology	NA	Morphology of the crack
Crack_Morphology_Method	NA	Method of determining the crack morphology
Tip_To_Tip_Crack_Spacing_mm	NA	Horizontal distance between cracks
Grind_Feature_Start_m	m	Location of the nearest point of the grind area with respect to ref. GW
Grind_Feature_LENGTH_mm	mm	LENGTH of the grind feature
Average Depth of Grind Feature_mm	mm	Average depth of the grind area
Max Depth of Grind Feature_mm	mm	Max depth of the grind area
Notes	NA	Other notes

RECOMMENDED DESCRIPTIONS

Depth Determination Method
Grinding
NDT
Visual

Crack_Morphology_Method
In-Situ Metallography
Not Determined

Evidence of Cracks Interlinking
Yes
No
Unknown

Crack Morphology
Intergranular
Transgranular
Unknown

Table C.13: Coincident Corrosion Table.

COINCIDENT CORROSION

FIELD NAME	UNITS	DESCRIPTION
Dig_ID	NA	Unique identifier for the dig
U/S_Weld_ID	NA	Unique identifier for the upstream girthweld that the feature is measured from
Corrosion_ID	NA	Unique identifier for the corrosion
Start_from_reference_GW_m	m	Location of the nearest point of the corrosion with respect to the reference girthweld
Length_mm	mm	Length of the corrosion
Width_mm	mm	Width of the short dimension of the corrosion
Angle_degree	degree	The angle of the corrosion
Corrosion_Type	NA	Type of corrosion
Average_Depth_Measurement_mm	mm	Measured amount of average depth or remaining thickness
Maximum_Depth_Measurement_mm	mm	Measured amount of maximum depth or remaining thickness
Actual_WT_mm	mm	Actual wall thickness at the corrosion
Feature_from_TDC_o'clock	mm	Distance from the TDC to the center of feature
Associated_Cracks	NA	Are there cracks associated with the corrosion feature?
Notes	NA	Other notes

RECOMMENDED DESCRIPTIONS

Corrosion Type
Channeling
General
Pitting
Superficial

Angle
0^o-30^o
30^o-60^o
60^o-90^o

Associated Cracks
Yes
No
Unknown

Table C.14: Coincident Mechanical Damage Table.

COINCIDENT MECHANICAL DAMAGE

FIELD NAME	UNITS	DESCRIPTION
Dig_ID	NA	Unique identifier for the dig
U/S_Weld_ID	NA	Unique identifier for the upstream girthweld that the feature is measured from
MD_ID	NA	Unique identifier for the mechanical damage
Type_of_Mechanical_Damage	NA	Type of mechanical damage
Start_from_reference_GW_m	m	Location of the start of the damage with respect to the reference girthweld
Length_mm	mm	Length of the damage from the start point
Width_mm	mm	Width of short dimension of damage
Feature_from_TDC_o'clock	mm	Distance from the TDC to center of damage
Depth_mm	mm	Depth of the dent
Actual_Wall_Thickness_mm	mm	Average wall thickness within the damage area
Peak_to_Peak_Depth_mm	mm	Peak to peak depth
Wavelength_mm	mm	Wavelength
Corrosion_In_Dent	NA	Is there corrosion in the dent
Crack_In_Dent	NA	Is there SCC in the dent
Notes	NA	Other notes

RECOMMENDED DESCRIPTIONS

Type of Mechanical Damage
Buckle
Crack
Wrinkle
Dent
Gouge
Hard Spot
Arcburn

REFERENCES FOR APPENDIX C

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Appendix D
Condition Assessment

An SCC condition assessment is a type of engineering assessment (EA). CSA Z662-11 defines an engineering assessment as "a documented assessment of the effect of relevant variables upon suitability, using engineering principles."

Within the scope of the SCC Management Program presented in Chapter 2, an SCC condition assessment is required to:

1. assess the severity of individual SCC features, and
2. assess the need for immediate and future mitigation due to the presence of SCC.

Both assessments require high quality input data as well as an understanding of the uncertainty associated with these data.

This Appendix describes the sources of the data required for an SCC condition assessment and the analytical methods that can be used to assess the failure pressure of the SCC feature, along with a discussion of the relative conservatism inherent in the different methods. Finally, a comparison is given between the CEPA SCC Severity Categories used in the 2nd and 3rd editions of these Practices and "significant SCC" defined in the 1st edition.

D.1 DATA SOURCES FOR AN SCC CONDITION ASSESSMENT

Crack dimension data can be obtained from several sources for an SCC condition assessment. Typical sources include:

- field investigations at pipeline excavation locations,
- SCC pressure testing,
- in-line inspections for SCC, or
- in-service failures due to SCC.

While each data source can provide similar and seemingly equivalent outputs, there are subtle but significant differences that can affect the reliability and accuracy of the resultant condition assessment. Some sources allow direct measurement of the crack dimensions, whereas others require the equivalent data to be calculated. Some of these data sources only provide information about the most severe crack(s), whereas others characterize the entire population of cracks.

Ideally, data should be obtained from at least two sources to ensure a robust analysis.

D.1.1 Data Sources

D.1.1.1 SCC DATA FROM EXCAVATIONS

One of the simplest and, possibly, most reliable sources of data is direct measurement of crack dimensions during excavations. The surface crack length and degree of interaction (dependent on the axial and circumferential crack spacings) can be measured directly or inferred from measurements made on the pipe. Crack depths can be determined by progressive buffing of the surface or by various hand-held devices.

D.1.1.2 SCC PRESSURE TESTING DATA

Pressure testing provides information about the failure pressure of SCC features in the pipe, but does not give any information about the crack dimensions (other than from an examination of the fracture surface of any hydrotest failures). Since the failure pressure is determined directly, it is not subject to errors introduced by the conservatism or non-conservatism associated with engineering calculations.

The following conclusions can be drawn from hydrotesting:

- The minimum failure pressure for all remaining SCC features within the pipe segment tested is greater than the maximum pressure obtained during the test.
- The SCC features remaining in the pipe will exhibit a range of lengths, depths, and spacing. In addition, the local pipe wall thickness, toughness properties, the characteristics of local stress raisers, and the level of residual stress may vary between the different SCC features.
- The quantity, density and location of SCC features that do not fail within a pipe segment remain unknown.
- If no SCC failure occurs, it is not possible to say whether the pipe segment contains SCC features or not.

Single SCC features that fail the pressure test can be completely characterized in terms of the failure pressure, the pipe material properties, physical SCC dimensions and SCC interaction in the depth and length directions. The section of pipe containing the failure should be removed and sent to an accredited laboratory for examination.

More information about pressure testing can be found in Appendix E.

D.1.1.3 SCC IN-LINE INSPECTION DATA

A reliable SCC ILI tool should be capable of providing the location and dimensions of all SCC features within the pipe segment above a certain threshold size. Features may be divided into a series of “bins” of varying depth (e.g., 10-25% through wall, 25-40% through wall, >40% through wall) or the dimensions of individual features may be provided. The precision of the results can be increased by providing the ILI vendor with the results of correlation digs, which can then be used to improve the reliability of the data analysis.

Failure pressures must be calculated from the reported crack dimensions using one or more of the methods described in Section D.2.1 using assumed or measured pipe properties. Thus, unlike the direct measurement of the failure pressure from hydrotesting, failure pressures inferred from ILI measurements are subject to uncertainty from the calculation method (and the assumed pipe properties). However, ILI provides failure pressures for all SCC features (above a threshold size), rather than a minimum failure pressure for all remaining SCC features.

More information about ILI can be found in Appendix E.

D.1.1.4 SCC IN-SERVICE FAILURE DATA

Single SCC features that fail in-service can be completely characterized in terms of the failure pressure, pipe material properties, physical SCC dimensions, and interaction distance.

The minimum failure pressure for the remaining SCC features in the pipe segment can be estimated by assuming that the most severe feature has failed.

However, the number and location of SCC features remaining in the pipe segment is unknown.

D.1.2 Data and Model Uncertainty

The main sources of uncertainty in condition assessments are:

- The dimensions of the (remaining) SCC features in the pipe segment, including the effect of crack interaction.
- The corresponding pipe properties at the feature location(s) (including the pipe tensile properties and toughness)
- Uncertainty and conservatism in the method used to convert the crack dimensions to a failure pressure (Section D.2.1).

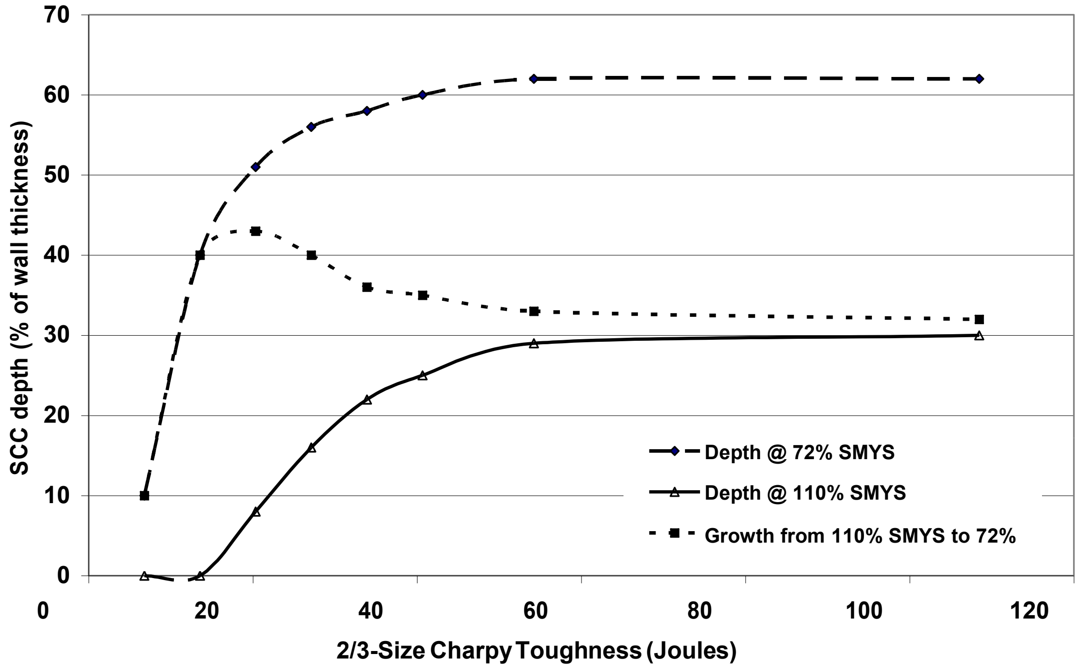
For ILI or in-the-ditch measurements, the size of the largest surviving flaw should, in principle, be determined directly, provided that any uncertainty in the measurements is taken into consideration. To avoid overestimating the failure pressure (or the size of the critical flaw at operating pressure), the minimum reasonable toughness should be used in the calculations.

When predicting the remaining life from hydrotest results, it is important to use the same input data and calculation method for determining both the size of the surviving flaw and the critical flaw size at operating pressure. In many cases, the sources of uncertainty will cancel out when the two calculated flaw sizes are subtracted from each other.

Uncertainty in the material toughness can introduce significant error in the estimated remaining life. Consider the following example of the effect of toughness on the remaining life calculated following a hydrotest.

Example: *Consider a 25 cm long flaw in a 762 mm diameter, 7.93 mm wall thickness, Grade 359 pipe. Using the log-secant method (Section D.2.1), the effect of toughness on the depths of flaws that would survive a 110% SMYS hydrotest and that would fail at 72% SMYS are shown in Figure D.1. The predicted lifetime is proportional to the difference in depth. If the actual toughness is 15 J but is assumed to be 7.5 J, the predicted lifetime would be overly conservative by a factor of approximately 4. If the actual toughness is 30 J but is assumed to be 15 J, the predicted lifetime would be accurate. If the actual toughness is 50 J but is assumed to be 25 J, the predicted lifetime would be non-conservative by approximately 20%. If the actual toughness is 100 J but is assumed to be 50 J, the predicted lifetime would be non-conservative by only approximately 3%. Thus, it can be seen that it is not possible to predict, in general, whether a conservative value (i.e., low toughness) would produce a conservative or non-conservative lifetime prediction.*

Figure D.1: Effect of Toughness on Depth of a 25 cm-Long Flaw That Would Fail at 110% SMYS and 72% SMYS (Based on the Log-Secant Method).



D.2 SCC FAILURE PRESSURE CALCULATIONS

D.2.1 Failure Pressure Calculation Methods

There are several analytical models available for determining SCC failure pressures. These methods rely on the relationship between the applied stress, the material properties, and the resultant tolerable SCC size.

Some of the analytical models also predict the mode of failure for the SCC feature, i.e., either a leak or a rupture. At pressures associated with both normal operation as well as higher pressures from hydrostatic testing, the metal ligament joining the tip of the SCC feature (in the depth direction) and the inner pipe wall will typically fail in a ductile manner, momentarily creating a through-wall feature. Axial propagation of the resultant leak may or may not occur, depending on the axial length of the leak, the applied stress, and the toughness of the steel. However, axial propagation is typical of SCC features for the generation of pipe for which SCC has been historically encountered, resulting in a rupture as the normal mode of failure.

Various studies have been published quantifying the relationship between SCC and failure pressure in pipelines. Most of these studies are based on the extensive work performed by the Battelle Memorial Institute in the 1970s [Eiber et al. 1993, Kiefner et al. 1973, Leis and Brust 1992, Leis and Mohan 1993, Leis et al. 1991]. Since that time, other failure criteria have been developed that incorporate elastic- plastic fracture mechanics. The failure pressure methods currently available include:

- Log-Secant
- Pipe Axial Flaw Failure Criterion (PAFFC)
- CorLAS ™
- API 579 [API/ASME 2007] & BS 7910 [BSI 2005]

Alternative techniques for analyzing the predicted failure pressure of SCC in pipelines are described in standards such as API 579 [API/ASME 2007] and BS 7910 [BSI 2005].

When using these methods for estimating the failure pressure, the following limitations should be taken into account:

SCC length limit - The failure pressure methods were developed and correlated against burst tests for more typical aspect ratios than the large aspect ratios found with long toe of the weld SCC. Therefore, the calculation methods should be limited to SCC lengths less than approximately 400 mm.

SCC depth limit - Failure pressure calculations for features with a depth greater than 80% of the pipe wall thickness have not been substantiated and may not be conservative. Therefore, SCC with depths greater than 80% of the pipe wall should not be evaluated using these methods.

D.2.1.1 "LOG-SECANT" APPROACH

The "Log-Secant" approach has its origins in a strip-yield formulation for a slit in a sheet (corresponding to a through-wall SCC feature). A strip yield model of this form was originally introduced by Battelle [Kiefner et al. 1973], in which the collapse limit and toughness dependence were formulated empirically to fit experimental results. The relationship can be rearranged to allow the calculation of the failure stress for a flaw of known dimensions. The basic equation has the following form:

$$K^2 = \frac{8c_{eq}\,\sigma_f^2}{\pi}\ln\sec\left(\frac{\pi M_p \sigma}{2\,\sigma_f}\right) \tag{D-1}$$

where K is the stress intensity factor, σ is the applied stress, σ_f is the flow stress, c_{eq} is a function of the flaw area and flaw depth for flow stress dependency (or flaw length for fracture), and M_p is the "Folias" factor.

This formulation was adapted to pipeline problems first by the inclusion of a bulging factor derived for long through-wall slits in cylinders. It was next calibrated for pipelines using an SCC data set for patched through-wall flaws dominated by NPS 30 pipe with strength and toughness typical of the X52 used in the 1950s and early 1960s. It was adapted to part-through-wall flaws by an empirical correction for the presence of a remaining ligament. This adaptation involved empirical correlations to either fracture- or flow-stress-controlled failures. The use of the empirical calibrations means that distinguishing between the two limiting criteria is artificial. The "Log-Secant" model reflects the fact that the criterion is based on a correlative SCC data set. However, the model does tend to provide a conservative estimate of failure pressure, with a safety factor of as much as two [Eiber et al. 1993].

The main equations and model for the derivation of the "Log-Secant" approach are provided in the original reference [Kiefner et al. 1973]. One potential limitation of the original "Log-Secant" model is the applicability of the correlating SCC data set to the specific scenario being analyzed. This can lead to large degrees of conservatism.

D.2.1.2 PIPE AXIAL FLAW FAILURE CRITERION (PAFFC)

The PAFFC model was developed as a result of problems that were found in applying the "Log-Secant" criterion to certain flaw geometries and classes of pipelines. The requirements for the model were that it should be simple, less conservative and more consistent than the "Log-Secant" approach, applicable to past as well as present steels, with demonstrated validity. In the 1990s, Battelle developed the ductile flaw growth model [Leis and Brust 1992, Leis et al. 1991]. This model was developed to address stable tearing not previously incorporated in the "Log-Secant" model. The fracture mechanics work was combined with a limit states criterion for the remaining ligament at a sharp SCC crack, which was derived from mechanics and materials principles, to produce what is termed the ductile flaw growth model (DFGM). The detailed equations for the model are provided by Leis et al. [1991].

The DFGM was validated against the original full-scale fracture SCC data set and a series of new tests. The model was able to predict the failure pressure of the validation "Log-Secant" tests, with a reduced error of less than half that of the "Log-Secant" model. Once validated for pipelines, the DFGM was formatted and released in a software form known as Pipe Axial Flaw Failure Criterion (PAFFC). The purpose of PAFFC is to determine the failure conditions associated with a single external axial flaw in a pipeline. Failure is determined concurrently in terms of two independent failure processes, fracture and/or net-section (plastic) collapse. These two criteria, however, are not analogous to the original "Log-Secant" criterion. In the empirical approach in the "Log-Secant" model, the toughness-related failure pressure is always less than or equal to the flow-stress related failure pressure. In the PAFFC model, the limit-states-related failure pressure can be less than or greater than the corresponding toughness-related value. In addition, because of the nonlinear approach within PAFFC, the predicted failure pressure curves are not uniformly spaced with respect to flaw depth/wall thickness ratios. These visual outputs are different from those for the "Log-Secant" approach. PAFFC is available as a commercial software program.

D.2.1.3 CORLAS™

CorLAS™ is a computer model that can be used to evaluate flaws. It was originally developed by CC Technologies for corrosion life assessment of pressurized piping and cylindrical vessels and is a composite of the "Log-Secant" method with provision for toughness dependency and control. It has been used to determine the effect of SCC on the failure pressure in pipelines. CorLAS™ applies flaw evaluation techniques and advanced inelastic fracture mechanics methods to evaluate the structural integrity and remaining life of pipes and vessels subject to corrosion and SCC. An effective flaw size model (often referred to as R-STRENG, an extension of the "Log-Secant" model) is used to evaluate the effect of the flaw or SCC on structural integrity.

Comparative results are also computed using the 0.85dL effective flaw length model and the ASME B31G criterion. Critical flaw and SCC sizes are determined for both flow stress and J toughness criteria. Remaining life is computed both for corrosion and for SCC growth. In the latter case, J integral and inelastic fracture mechanics are used. The details of the model and the key equations and references can be found in Jaske et al. [1996].

CorLAS™ uses the effective flaw length method (references 2 to 6 in Jaske et al. [1996]) to calculate the critical flaw size and pressure based on a flow-strength failure criterion and inelastic fracture mechanics (references 10 and 13 in Jaske et al. [1996]) to calculate the critical flaw size and pressure based on the J_{Ic} fracture toughness failure criterion. The lower of these two values is then defined as the actual failure stress.

The effective flaw method is expected to produce reasonably accurate predictions of flow-stress dependent failure when actual mechanical properties are used to calculate flow strength. Inelastic fracture mechanics is expected to give conservative failure predictions when the J_{Ic} fracture toughness failure criterion is used. A tearing instability analysis using a complete J-R curve (a plot of J integral versus SCC extension for the material) is needed to produce accurate predictions of fracture-toughness-dependent failure.

This approach has been shown to be effective when actual material properties are used as the input.

D.2.1.4 FITNESS FOR SERVICE OF SCC-LIKE FLAWS BASED ON API 579 OR BS 7910 REQUIREMENTS

API 579 [API/ASME 2007] and BS 7910 [BSI 2005] provide similar approaches to assessing SCC-like flaws in pressure-containing equipment and structures, including pipelines, using a fracture mechanics based failure assessment diagram (FAD).

The FAD is used to simultaneously consider the possibility of fracture and plastic collapse. The FAD defines the failure condition in terms of the fracture ratio (K_r) and the load ratio (L_r) as shown in Figure D.2. For a particular situation and assessment level, an assessment point that plots inside the curve is considered acceptable; a point on, or outside, the curve is considered not acceptable.

The fracture ratio is defined as

$$K_r = \frac{K_I}{K_{mat}} \qquad \text{(D-2)}$$

where K_I is the applied stress intensity factor and K_{mat} is the material toughness. Appendix C in API RP 579 and Annex M in BS 7910 contain stress intensity factor solutions for a range of flaw types and geometric configurations, including circumferential and axial surface flaws in pipes.

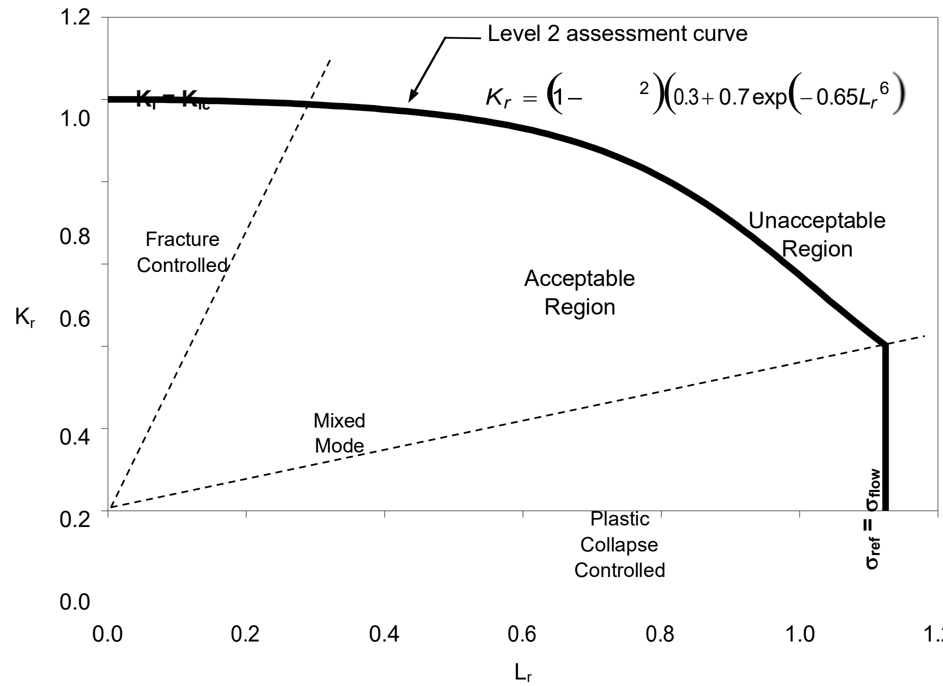
The load ratio is defined as

$$L_r = \frac{\sigma_{ref}}{\sigma_y} \qquad \text{(D-3)}$$

where σ_{ref} is the applied reference stress and σ_y is the yield strength of the material. Appendix D in API RP 579 and Annex P in BS 7910 provide formulae for determining the appropriate reference stress (i.e., the net section stress at the location of the flaw) for various structural configurations.

The acceptance boundary is defined by the failure assessment curve, as shown in Figure D.2. Various levels of assessment and assessment curves are provided in the two referenced documents, with the appropriate level of assessment being dependent on the specific situation being analyzed and the available information.

Figure D.2: API RP 579/BS 7910 Failure Assessment Diagram (FAD).



D.2.2 Comparison of Failure Pressure Calculation Methods

The relative degree of conservatism of the four techniques listed above has been assessed by comparing the predicted and actual failure pressures from pipeline ruptures and burst tests [Fessler et al. 2013, Kariyawasam et al. 2007, NEB 1996, Rothwell and Coote 2009]. All of the methods are generally conservative (i.e., the predicted failure pressure is less than the actual failure pressure), but the methods differ in the accuracy of the predictions and the nature of the cracks for which non-conservative failure pressures may be predicted.

In a recent study [Fessler et al. 2013], the various methods were compared using data from 101 failures, either reported in the literature or from participating pipeline companies, of which approximately 40 provided sufficient detail regarding the crack profile and pipe mechanical properties to allow a detailed analysis. The conclusions from the study were as follows:

- All four methods (log-secant, PAFFC, CorLas™, and API 579 level 2) can lead to large systematic and random errors, resulting in significant differences between the predicted and actual failure processes.
- The vast majority of predictions are conservative with the actual failure pressure being greater than the predicted value. These conservative errors do not affect safety, but may result in an excessive number of excavations.
- None of the non-conservative errors exceeded 20%, i.e., the predicted failure pressure did not exceed 120% of the actual failure pressure.

- Of the four methods, CorLas™ was found to be the most accurate (i.e., the best agreement between the predicted and actual failure pressures), with the log-secant method giving comparable accuracy in many cases.

- ## D.3 COMPARISON OF THE CEPA SCC SEVERITY CATEGORIES AND THE DEFINITION OF "SIGNIFICANT" SCC

In the 1st edition of the CEPA SCC Recommended Practices [CEPA 1997], the term "significant SCC" was defined to describe a crack colony requiring further assessment and, possibly, mitigation. This terminology was removed from the 2nd edition of the Practices [CEPA 2007] and a crack severity categorization introduced instead, partly in order to align the classification of cracks with other published approaches [ASME 2014, Fessler et al. 2008] and partly because of the connotation of the word "significant" for the majority of crack colonies that are relatively non-injurious. However, the Canadian federal regulator, the National Energy Board (NEB), still requires that operating companies report any instances of "significant SCC".

The definition of "significant SCC" from the 1st edition of the Practices is:

An SCC colony is assessed to be "significant" if the deepest crack, in a series of interacting cracks, is greater than 10% of wall thickness and the total interacting length of the cracks is equal to or greater than 75% of the critical crack length of a 50% throughwall crack at a stress level of 110% of SMYS.

This definition does not adequately discriminate between cracks of different severity. In fact, the definition of "significant SCC" is consistent with a Category I, II, III, or IV crack, which clearly have vastly different consequences for the integrity of the pipe. Consequently, CEPA no longer recommends the use of the term "significant SCC".

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Appendix E
SCC Detection, Mitigation, and Repair

Some form of SCC mitigation is required if Category II-IV cracks are discovered in the pipeline. Section 2.3.6 (Step 6: Plan and Implement SCC Mitigation) and Section 2.3.7 (Step 7: Review and Evaluate Mitigation Activities) of the main text provide an overview of the different SCC mitigation and repair methods available, their advantages and disadvantages (Tables 2.4 and 2.5), and of the recommended methods for estimating the re-inspection interval.

This appendix provides additional information on two of the major mitigation methods; ILI and hydrostatic testing. Additional information is also provided on sources of crack growth rates for estimating re-inspection intervals. Finally, the different repair techniques available to operators are described in some detail. This appendix should be read in conjunction with the relevant steps in the SCC Management Program.

E.1 IN-LINE INSPECTION

E.1.1 Planning

E.1.1.1 CHOOSING IN-LINE INSPECTION FOR SCC CRACK DETECTION

The advantages of ILI over other possible mitigation methods are summarized in Table 2.4 of the main text. In addition to these advantages (and disadvantages), there will be other, company-specific, factors that will determine which, if any, ILI crack technology is appropriate to run, including:

- the relative SCC risk
- the presence of other hazards
- the pipe diameter and whether a tool in that size is available
- the “piggability” of the line
- flow conditions
- product shipped
- length of segment
- pipe attributes
- presence of ‘looped’ lines
- shipper contracts
- site access
- tool launch and receipt facilities
- risk tolerances.

Since ILI technology is evolving rapidly, users of these Practices are encouraged to consult with other pipeline operators, as well as ILI vendors, to review their specific needs prior to deciding to use ILI.

E.1.1.2 PHYSICAL CONDITION OF THE LINE

With any ILI tool, the first consideration should be the "piggability" of the line. Crack detection ILI tools have many of the same inspection constraints found in geometry and metal loss tools. However, they may also have extra restrictions on internal pipe roughness, trap barrel length, commodity type, and the required cleanliness of the pipeline.

The line must be configured so the tool can travel from the launch trap to the receipt trap in a single nominal pipeline diameter with full bore opening valves and large radius bends (typically at least one-and-a-half times the pipe diameter). The required condition of the line should be confirmed with the ILI vendor to ensure that the specific tool can be successfully run in the line without damaging the tool or the pipeline system. In some circumstances the ILI vendor and pipeline company can work together to allow the tool to negotiate specific challenging physical conditions, including bore reductions and tight bends.

E.1.1.3 OPERATING CONDITION OF THE PIPELINE

Crack-detection ILI tools are commercially available for detecting and sizing SCC in both liquid and gas pipelines (see Section E.1.2). Some tools require a liquid couplant to transmit and receive the ultrasonic signals and, therefore, are suitable for use in liquid pipelines or in gas pipelines with the use of a liquid slug in which the tool is run. EMAT technology allows the inspection of SCC in gas pipelines without the use of a liquid couplant.

All ILI technologies have tool speed constraints. The tool reliability and data resolution will decrease if the speed constraints are exceeded during the inspection run. Extremely slow speeds and stops-and-starts also create problems with data gathering and odometer calculations. In general, most ultrasonic tools produce optimum results when traveling at speeds between 1.0 and 2.0 m/s (3.6 – 7.2 km/h). In some cases, tools are fitted with bypass ports to allow the inspection to be conducted at a slower rate than the product is flowing (Figure E.1). Speed constraints vary with different technologies and specific ILI vendors.

Figure E.1: MFL ILI Tool with Variable Bypass to Allow Product to Flow Through the Internal Bore with Tool Travel Speed Controlled by Valves.

E.1.1.4 TOOL CAPABILITIES

Crack-detection ILI tool capabilities are continually improving. The capabilities listed here are based on ILI vendor product literature as of mid-2014, but operators should consult with other operators and ILI vendors for the latest information.

Table E.1 summarizes some of the more important capabilities for a conventional UT tool used for liquid lines and the latest generation of EMAT tools for gas pipelines.

Table E.1: Tool Capabilities from ILI Vendor Product Literature*

CAPABILITY	CONVENTIONAL UT	EMAT
Tool speed	0-4.5 m/s	0-3 m/s
Inspection range	300 km	200-330 km
Minimum bend radius	1.5D**	1.5D
Minimum detectable crack depth	1 mm	2 mm
Minimum detectable crack length	≥25 mm	40-50 mm
Depth sizing accuracy	1 mm at 85% certainty	±0.15t** at 80% certainty
Length sizing accuracy	±10 mm at 85% certainty	±10 mm

* as of August 2014
** D and t are the pipe diameter and wall thickness, respectively.

The length of pipe that can be inspected in a single run is governed by the diameter, the number of anomaly indications (both cracks and non-cracks), the battery life within the tool, the data recording capabilities, and the threshold for detection of the various tools. The length of pipe that can be inspected varies from 40 to 300 km depending on the tool selected, the velocity of the product, and the threshold for defect sizing. Pipeline companies can assist by supplying the ILI vendor with a detailed list of the type and size of defects to be detected. Since these tools are capable of finding defects smaller than the size that could fail under typical operating pressures, establishing appropriate thresholds for reporting can shorten data analysis time. This can result in an increased inspection range as well as decreased reporting times.

Most crack tools can be equipped with odometer-based switches to allow for either delayed or multiple recording lengths. This particular capability can be used to inspect specific locations within a pipeline segment.

E.1.1.5 TOOL AVAILABILITY

Based on product literature from ILI vendors, crack-detection tools are available in the following sizes:

- Liquid lines: 6-56” (for both axial and circumferential SCC using shear wave UT)
- Liquid lines: 24-36” (phased array UT)
- Gas pipelines (EMAT): 12-48”

This information is current as of mid-2014 and operators should consult ILI vendors for the latest available ranges of tool size.

E.1.1.6 RUNNING AN ILI PROGRAM

In addition to ensuring the proper operating and physical condition of the pipeline, some tools, especially ultrasonic based technologies, may require cleaning programs to ensure successful coupling between the ultrasonic transducer and the pipe wall.

Prior to inspection, the ILI vendor and operator should reach agreement on the specifications and requirements for the in-line inspection. The Pipeline Operators Forum [2009] provides guidance for the factors that should be specified by the vendor for in-line inspection in general, as well as specific requirements for crack-detection ILI. Required general tool specifications include:

- Wall thickness range for full performance
- Speed range for full performance
- Number and type of defect detection and sizing sensors (or the circumferential sample interval in case of a rotating sensor system)
- Axial sample interval, specify distance or frequency (time) controlled
- Nominal circumferential centre to centre distance of primary measuring sensors
- Temperature range
- Maximum pressure
- Minimum pressure for operation
- Minimum bend radius

- Minimum bend to bend distance
- Minimum distance between T-openings
- Minimum internal diameter of straight pipe and bend sections
- Tool length, weight and number of bodies
- Differential pressure required to launch and run the tool
- Maximum length of pipeline that can be inspected in one run (may be coupled to maximum operating time and condition of the pipeline)
- Minimum length for launcher
- Minimum distance between receiver valve and reducer in the receiver
- Indication of by pass flow in case of stuck tool

In additional to these general requirements, further specifications for all crack-detection tools include:

- Crack depth and length detection threshold
- The orientation limits (angle to pipeline axis) of cracks that can be detected
- The certainty level for the detection of this minimum crack
- The accuracy of sizing of crack length and depth
- The certainty level for the sizing performance

Additional factors for conventional UT technology include:

- Nominal circumferential spacing of measuring sensors
- Dimensions of UT transducers
- Frequency of UT signal
- Angle of UT signal in steel
- Direction of angle of UT signal relative to pipe axis (longitudinal direction is 0º, circumferential is 90º).

Additional factors for phased array technology include:

- Number of phased array transducers
- Number and dimensions of active elements within each transducer
- Frequency of UT signal
- Range of angles of UT signal that is generated in pipe wall
- Direction of angle of UT signal relative to pipe axis (longitudinal direction is 0º, circumferential is 90º).

Additional factors for EMAT technology include:

- Number of EMAT transducers (transmitter/receiver)
- Type, mode and frequency of ultrasonic signal generated

Further guidance on the specification and requirements for an ILI run can be found in:

- NACE Standard SP0102-2010 "Standard Practice - In-line Inspection of Pipelines" [NACE 2010]
- CSA Z662, Annex D [CSA 2011] (guidelines for in-line inspection for corrosion, with clauses D.3 to D.6 referenced with slight modifications for a crack tool inspection program)
- API 1163 "In-line Inspection Systems Qualification Standard" [API 2013]

To get the best results from an in-line crack inspection program, an agreement with the ILI vendor should include disclosure of data from a series of pull-tests that include artificial or natural crack-like defects in the pull-test pipe. These pull tests should be performed using standard pipe wall thickness and be part of the vendors sizing modelling data pulls used to generate their specifications and confidence levels. For non-standard pipes (not within the vendors specifications stated ranges) additional pull testing should be carried out with sample pipe joints. In this way, the ILI vendor can test a number of different defect signals, as well as analyzing background 'noise' signals in the pipe steel. This will enable correlation to signals that will be recorded during the inspection run and allow the tool to be set up (e.g., memory, batteries, filters, gains, etc.) to maximize performance during the inspection run.

E.1.2 ILI Technologies

A wide range of ILI technologies are available to detecting and characterizing corrosion, cracking, and deformation of pipelines. Of primary interest here are those technologies that can detect (and size) SCC. However, ILI tools that can detect corrosion and pipe deformation can also provide useful information for the overall management of SCC and are also briefly described here.

E.1.2.1 CRACK DETECTION ILI

There are currently three main ultrasonic (UT) crack detection technologies commercially available for SCC in-line inspection, namely: shear wave, phased array, and electromagnetic acoustic transducer (EMAT). The use of eddy current ILI technology to detect SCC has been under development for some time but is not yet commercially available. In addition, magnetic flux leakage (MFL) tools with circumferentially oriented magnets have the ability to detect some seam weld and pipe body cracks in some circumstances, but generally cannot detect 'tight' cracks such as SCC. Table E.2 summarizes the advantages and disadvantages of these and other ILI crack detection tools.

E.1.2.1.1 SHEAR-WAVE ULTRASONICS

Also known as "traditional" or "conventional" UT ILI, these tools generate a shear wave (typically directed at a 45º angle) that travels through a liquid couplant into the pipe wall and 'reflects' off cracks and linear surfaces regardless of their width (Figure E.2). Thus, conventional UT ILI is ideally suited for inspection of liquid pipelines with the product acting as the couplant. Conventional UT has also been used to inspect gas pipelines with the tool travelling in a liquid slug. However, because of the resulting interruption of service and because of the recent development of EMAT technology, the use of conventional UT ILI for gas pipelines is now less common.

Conventional UT ILI has been used to inspect more kilometers of pipes than any other crack tool, is the most reliable technology, has the highest detection capability, and the lowest false call (false positive) rate. The tool capabilities are similar to those for "high-resolution" MFL metal-loss tools, with crack detection limits significantly below the critical crack size. The detection limits typically quoted by ILI vendors are of the order of 25 mm long and 1 mm deep, although historically these tools detect and size cracks that are much smaller. Historically this has been the ILI technology of choice for liquid pipeline companies.

Figure E.2: Shear Wave Ultrasonic Tool Being Launched from a Temporary Launch Barrel.

Because the pipeline product is used to couple the UT signal to the pipe wall, it is important that the tool is calibrated to run in the pipeline product at the pressures and temperatures to be encountered during the inspection. Some CEPA companies have experienced success in running in NGLs, provided that the tool is properly calibrated. Other factors, such as the presence of H_2S, extreme pH, or fluid impurities, may negatively affect tool performance or integrity. As with all inspection programs, it is important to discuss all pipeline specifics with the ILI vendor before inspection.

E.1.2.1.2 PHASED-ARRAY ULTRASONICS

Unlike the fixed-angle shear-wave transducers used for conventional UT tools, phased-array transducers can generate UT signals over a range of angles (Figure E.3). Thus, a phased-array ILI tool can simultaneously detect both metal loss (using 90º incident signals) and cracks (using angled UT signals). The reported sensitivity for phased-array UT is similar to that for conventional UT tools. The circumferential resolution can be doubled if the tool is run in crack detection mode only (i.e., no metal loss firing). This effectively doubles the number of virtual sensors being fired into the pipe compared to the conventional UT crack tools. This results in higher confidence levels.

In other respects, in particular the need for a liquid couplant, phased-array ILI has the same advantages and disadvantages as conventional UT.

Figure E.3: Phased Array Ultrasonic Tool

E.1.2.1.3 EMAT

Unlike shear-wave and phased-array UT transducers, electromagnetic acoustic transducers (EMAT) need neither a liquid couplant nor to make direct contact with the pipe surface (Figure E.4). An ultrasonic signal is induced in the pipe wall electromagnetically and detected by the tool. Because no liquid couplant is required, EMAT tools are ideally suited for the inspection of gas pipelines.

In association with ILI vendors, the operators of gas pipelines have been aggressively pursuing the development of EMAT technology over the past 5-10 years, to the extent that the accuracy of EMAT tools is now approaching that for conventional UT crack-detection tools and EMAT has been proposed as being equivalent to hydrostatic testing for crack mitigation (see Section 2.3.7.3 of the main text). Earlier so-called Generation I and Generation II EMAT tools have now been superseded by the latest Generation III tools, with improved reliability, run speed, POD, and particularly improved ability to discriminate SCC from other crack-like features (i.e., improved POI). At the current time, the detection limit for EMAT tools are of the order of 40-50 mm long by 2 mm deep (Table E.1).

In addition to cracks, EMAT tools can also detect coating disbondment, which can be a useful additional piece of information to correlate with the incidence (or non-incidence) of cracks in the pipeline.

Figure E.4: EMAT Crack Detection Tool.

E.1.2.1.4 EDDY CURRENT

For some time, one ILI vendor has been developing an ILI crack detection tool based on self-excited eddy current (SEEC) technology. The technology shows promise for detection of SCC in both natural gas and liquid pipelines and does not require a liquid couplant to perform the inspection. Theoretically, this technology is not as sensitive to pipeline product speed and can collect optimum data at higher speeds, thereby reducing the operational and economic impacts of an SCC inspection run. As of August 2014, this technology is not yet commercially available.

E.1.2.1.5 TRANSVERSE FIELD MFL

A number of ILI vendors offer a modified MFL tool, where the magnets and sensors have been rotated 90^{o} to induce a magnetic field along the circumference of the pipe (Figure E.5). Transverse field inspection (TFI) is proven (in the laboratory and field) to find narrow axial corrosion defects, longitudinal weld defects and other large cracks. This tool also has some of the dent and corrosion detection advantages of traditional MFL technology. However, this tool does not reliably detect tight cracks such as SCC and should not be relied upon as a primary SCC detection method.

Figure E.5: TFI ILI Tool.

Table E.2: Summary of In-line Inspection Technologies for SCC Detection.*

TECHNOLOGY	PRODUCT	ADVANTAGES	DISADVANTAGES	NOTES
Shear Wave Ultrasonics	Liquid	Good POD, POI, and sizing capabilities.	Requires liquid slug to run in gas line.	Most proven crack tool. High resolution able to size cracks <25 mm long by 1 mm deep.
Phased array	Liquid	Simultaneous measurement of metal loss and cracks. Similar resolution to shear wave UT tools. Double circumferential crack resolution can be used instead of using the metal loss component.	Requires liquid slug to run in gas line.	Single vendor
EMAT	Liquid or gas	Run in either liquid or gas lines with good resolution. Detects coating disbondments.	Resolution not quite as good as conventional UT tools.	Main technology now used for gas pipelines.
TFMFL	Liquid or gas	Proven technology for metal loss and 'wide' opening axial defects. Range of 350 km+ Secondary detection of corrosion and dents.	Only detects wide-opening axial defects – unreliable at detecting or sizing tight SCC cracks.	Proven to detect wide, sharp axial defects. Not recommended as primary SCC detection method.
Eddy current	Liquid or gas	Does not require a liquid medium. Can effectively manage higher pipeline product speeds.	New technology is currently being proven.	Not yet commercially available.

* As of August 2014.

E.1.2.2 OTHER ILI TECHNOLOGIES

Although metal loss tools, both MFL and ultrasonic, do not directly detect SCC, information from such tools may be useful for crack management. The incidence of corrosion may indicate regions of disbonded coating, inadequate or shielded cathodic protection (CP), or local environments that might also correlate with SCC. The detection of dents and areas of locally increased stress may also be useful for SCC management.

E.1.2.2.1 MAGNETIC FLUX LEAKAGE (MFL)

MFL tools are the most widely run inspection tool in all pipeline sizes in both liquid and gas lines. These tools have been proven reliable at accurately detecting, locating and sizing metal-loss features such as corrosion and mill defects. Other features such as dents, girth weld anomalies and close metal objects can also be located and to a lesser extent, sized. Experience among CEPA companies suggests that MFL tool performance and feature identification and classification varies greatly among tool vendors. As a result, pipeline companies should do a thorough analysis of their needs versus the demonstrated performance of the ILI tool before an MFL ILI contract is signed.

The MFL tool works by saturating the pipe wall with magnetic flux using two sets of large magnets (Figure E.6). In areas of the pipe surface where metal is missing (such as areas of corrosion) the magnetic flux ‘leaks’ from the wall and is detected by coils or active sensors. Algorithms interpret these signals to infer the size and shape of the defect. Because the magnetic flux is induced axially in the pipe wall, the tool is also able to see some girth weld anomalies and cracks that are wide enough to disrupt the passage of the magnetic flux. The tool has difficulty detecting these same features on the long seam, and generally cannot detect tight cracks (such as SCC) as the flux can flow axially around these features without disruption or leakage.

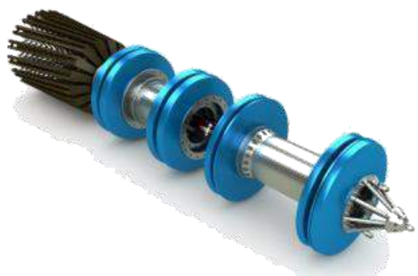
Despite MFL’s inability to directly detect SCC, there may be some limited use in an SCC management program. Areas of corrosion detected by MFL inspection can be used to infer which areas of the pipeline have damaged coating and poor CP coverage that may lead to SCC. Also, some ‘tell-tale’ corrosion signatures may correlate with the presence of SCC on some pipeline systems. MFL data can be used to enhance an SCC excavation program or can be overlaid with ILI crack tool data to determine the most likely locations of SCC. It should be stressed that MFL data should be considered an enhancement to an overall SCC data gathering and management effort but should never be the sole/primary tool to assess the SCC condition of a pipeline system.

Figure E.6: MFL ILI Tool.

E.1.2.2.2 ULTRASONIC WALL MEASUREMENT

Ultrasonic wall measurement (USWM) tools are used to determine the remaining wall thickness by direct measurement of the reflection of a 90º ultrasound wave through the pipe steel and off the outside surface of the pipe (Figure E.7). Such tools are accurate for measuring corrosion, mill defects, and internal laminations in liquid lines. This technology is sensitive to pipeline geometry changes and line cleanliness, factors that can create echo loss and result in dispersed ultrasound and no data for that location. Internal corrosion can also present challenges due to line cleanliness and the accumulation of debris. USWM tools cannot detect linear features such as SCC and cannot be run in a gas pipeline. As with MFL, areas of external corrosion may correlate with the presence of SCC.

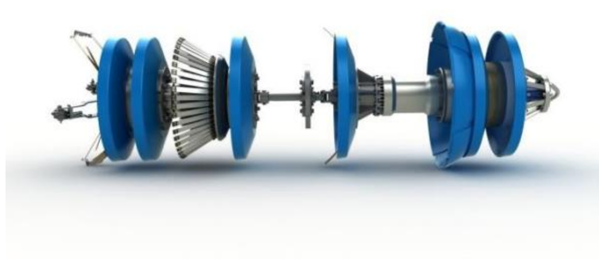
Figure E.7: USWM ILI Tool.



E.1.2.2.1 GEOMETRY AND CALIPER TOOLS

Geometry tools, of which 'caliper' tools are the most basic and common type, are used to find geometric anomalies in a pipe, such as dents, ovalities, buckles, and kinks (Figure E.8). More advanced tools are equipped with gyroscopes and high technology logic to determine subtle movements and strains in the pipeline. The most common use of geometry tools is to determine if there are any dents or bore restrictions in a new pipeline after construction. However, periodic geometry ILI runs during the operational life of a pipeline can find, characterize and size defects that may be caused by backfill settlement, mechanical interference (i.e., third party damage), axial pipeline strains, and geological ground movement (slopes, earthquakes, water bodies, etc.). As such, these tools may provide useful information for the management of both axial and circumferential SCC.

Figure E.8: Geometry ILI Tool.



Note 'caliper' arms in the center of the tool and odometer wheels at the rear. This tool is equipped with gyroscopes to determine the precise location and pipe movements with respect to GPS reference points. A number of MFL-type sensors record the presence of girth welds to assist in locating the tool.

E.1.3 Data Analysis

Both ultrasonic and EMAT crack detection data analysis is a highly complex process requiring skilled personnel to review and interpret the signals captured by the tool. The pipeline company should ensure that the appropriate personnel from the ILI vendor are qualified and are adequately trained to meet the requirements of the most recent version of ANSI/ASNT ILI-PQ, "In-line Inspection Personnel Qualification and Certification" [ANSI/ASNT 2010]. Because of the level of expertise required, interpretation and prioritization of the data can be a lengthy process compared to traditional metal-loss and geometry tool reporting. Pipeline companies are encouraged to understand the data analysis process so that they may provide guidance regarding priority sections or defects to be analyzed. The ILI vendor may then provide staged reports according to the priorities of the operating company.

Interaction between the ILI vendor and the pipeline operator is crucial to obtaining high quality information. Providing the ILI vendor with data from confirmatory excavations can improve the detection and sizing accuracy significantly. Positive and negative feedback is equally valuable. Actual defect characterization, size and location accuracies help the ILI vendor to modify automated algorithms as well as assist with future manual interpretation.

The importance of this step cannot be overstated as preliminary data can be forwarded in as little as a couple of weeks following a run, whereas detailed auxiliary (final) reporting may take more time. Preliminary and final report deadlines should be discussed with the ILI company and included in the inspection contract.

Crack detection ILI reports usually provide several characteristics about each identified defect. Most reports will give an indication of the type of defect (crack, crack in corrosion, weld anomaly, inclusion, etc.), as well as the interpreted depth and length of the indication. In addition, the vendor will give data on the location of the indication, along with any other specific observations made during the interpretation process.

Some anomalies (e.g., long, non-injurious inclusions) can appear similar to cracks when observed ultrasonically by ILI tools. Older steels contain more nonmetallic inclusions and other steel making anomalies. Inclusion populations may also vary from one steel manufacturer to another and from one steel heat to another. The number of indications can vary on a joint-to-joint basis. On pipe joints with high inclusion populations, the "false call" dig rate may increase correspondingly as non-injurious inclusions may be conservatively interpreted as cracks. ILI vendors are continually developing new algorithms, neural networks and analysis methods to increase sizing accuracy and crack discrimination while decreasing the interpretation and reporting time.

Pipeline companies should consider overlaying other pipeline data with crack detection ILI data. Site characteristics that have been shown to be related to the occurrence and severity of SCC include environmental data, soil drainage, CP potential readings, coating type/condition, and geometric or metal-loss tool data. This type of data overlay can assist in prioritizing locations and assist in defect discrimination, as well as assisting in prioritizing other pipeline segments for crack tool runs.

There may be some advantage in overlaying multiple crack tool data sets determined on the same pipeline over a period of a few years. Firstly, some ILI vendors have suggested that repeat ILI runs can be used to estimate crack growth rates, although the current resolution of crack detection tools makes this challenging. Secondly, by overlaying multiple run data, the discrimination of cracks versus benign features can be improved by detecting changes to raw feature signals. Signals that do not change from one run to another are likely benign indications that are not an integrity issue. Conversely, features that appear to be growing from one inspection run to another are more likely to be actual cracks that require further monitoring and/or mitigation.

SCC typically occurs as colonies of cracks making the resultant ILI signal difficult to interpret. Progress has been made recently in this area and further work is underway in the sizing of the colonies and the depth of each crack within a colony. Companies should always bear in mind that in-line crack inspection tools are designed to find all longitudinal through thickness defects, not just SCC.

E.1.4 Response to ILI Vendor Report

Once the ILI vendor report has been received, the pipeline company should decide what actions are necessary. This may vary from a few spot correlation excavations to confirm the inspection results, to large-scale excavation programs aimed at repairing any defects that could grow to failure. As more experience with these technologies is attained, pipeline companies may be able to target future excavations of sub-critical defects based on realistic projected growth rates.

In general, the reliability of crack tools is not currently as good as that for traditional metal-loss tools and, therefore, a greater degree of conservatism should be used in deciding which, defects should be excavated. The operator should also anticipate some frequency of 'false-calls' or benign defects. For further guidance on calibration and verification refer to API 1163 [API 2013].

E.2 HYDROSTATIC TESTING

Pipeline companies have historically used hydrostatic testing for a variety of reasons, including:

- Initial demonstration of integrity prior to service.
- Qualification of a section of pipeline for higher maximum operating pressures.
- Qualification of a section of pipeline for a change of service.
- Confirming the integrity of a section of pipeline from potential time-dependent threats such as corrosion (both external and internal) and SCC, construction damage, and manufacturing defects.

Hydrostatic testing has been shown through operating experience to be an effective means of safely removing near-critical axial defects, such as SCC, from both natural gas and liquid hydrocarbon pipelines. By removing those axial flaws that are approaching critical dimensions, a hydrostatic test provides the operating company with a margin of safety against an in-service failure in that section of line for a definable period of time.

This section will address the design and use of hydrostatic testing of a section of pipeline for axial SCC only, and as such, no inference should be drawn from this section to address other potential integrity threats.

The hoop stress developed during the test is due to the pressure of the hydrostatic test medium. Some amount of longitudinal stress is created in a pipeline by internal pressure, but the longitudinal stress created by the pressure test is rarely more than one half of the hoop stress (i.e., Poisson's ratio). For that reason, hydrostatic testing is not considered to be effective for assessing circumferential SCC (see Section 2.4).

Pipelines designed for gas service may require different hydrotest procedures to facilitate testing compared with those for liquid lines. For example, in areas of large elevation change, it may not be feasible to hydrotest gas pipelines due to overstressing low-lying sections of the pipeline.

E.2.1 Hydrotest Procedure

E.2.1.1 GENERAL CONSIDERATIONS

The hydrotest procedure should be designed to remove the smallest SCC defects possible while minimizing the possibility of growth of sub-critical SCC flaws that survive the test (Figure E.9). The optimum procedure involves a "high" pressure integrity test to remove all near-critical axial SCC defects greater than a certain size and a "low" pressure leak test to detect any defects that have not ruptured during the "high" pressure test but have instead resulted in a leak.

Figure E.9: Excavated Hydrostatic Test Failure.

When developing a hydrostatic test procedure, it is important that a pipeline operator take into account the particular features and characteristics of the line under test. Factors that the company should take into consideration when developing a hydrostatic test procedure include:

Test appropriateness - If and when it is appropriate to hydrostatically test a pipeline, the test should be carried out at the highest possible stress level feasible. The challenge is to determine if and when it should be done, the appropriate test level, and the test section logistics that will maximize the effectiveness of the test.

Level of safety factor to establish in the pipeline segment - The level of safety factor achieved by a hydrostatic test is based on the maximum operating pressure of the pipeline and the minimum test pressure used. The higher the test pressure, the higher the safety factor achieved by the test.

Test pressure level - The highest feasible test pressure level should be used when hydrostatic testing is conducted to revalidate the serviceability of a pipeline suspected to contain defects that are becoming larger with time, such as SCC. The higher the test pressure, the smaller the remaining SCC defects that can survive the test, resulting in a higher safety factor and/or longer re-test interval.

Pressure reversal - With increasing pressure, defects in typical line-pipe material begin to grow by ductile tearing prior to failure. If the defect is close enough to failure, the ductile tearing that occurs prior to failure will continue even if pressurization is stopped and the pressure is held constant. The damage created by this tearing when the defect is about to fail can be severe enough that if pressurization is stopped and the pressure is released, the defect may fail on a second or subsequent pressurization at a pressure level below the level reached on the first pressurization. This phenomenon is referred to as a pressure reversal and it is not desirable. Pressure reversals should be assessed on a case-specific basis, but usually can be avoided or rectified by performing a spike test (Section E.2.1.2).

Actual yield strength test - Testing a pipeline to its actual yield strength can cause some pipe to expand plastically. However, the number of pipes affected and the amount of expansion will be small if a pressure-volume plot is made during testing, and the test is terminated with an acceptably small offset volume or reduction in the pressure-volume slope.

Mill defects and test pressure - The presence, or suspected presence, of mill defects in the pipeline should be reviewed in relation to the original test pressure used to commission the segment of pipeline. Some 1950's vintage pipe has mill defects that are benign and pose no threat to the long-term integrity of the pipeline. Consequently, if the test pressure is selected to be higher than the original test pressure for commissioning the pipeline, the company could experience some test ruptures due to these mill defects during the re-test.

Re-test frequency - The pipeline company should consider how often they are prepared to re-test the given segment of pipeline. Obviously, the lower the test pressure during the high pressure integrity test, the lower the safety factor achieved by the test. Consequently the more frequent the re-testing will have to be to ensure the continued integrity of the given segment.

Safety and safety factors - The pipeline company should consider the proximity of both the public and pipeline workers. As well, the company should consider the historical pipeline design safety factor used when undertaking any repairs in the given segment of pipeline. The company may not want to test the given segment of pipeline to a higher safety factor than was used as the basis for past repairs.

E.2.1.2 CEPA RECOMMENDED HYDROTEST PROCEDURE

The CEPA recommended hydrotest procedure involves a short pressure spike at relatively high pressure followed by a leak test [Fessler et al. 2013].

For the spike test, it is recommended that:

- the spike pressure should be as high as possible within the range 100-110% SMYS, but should not be so high as to cause bulging of the pipe
- the spike hold time should only be long enough to verify the pressure, and not more than one hour

For the leak test, it is recommended that:

- the leak test be performed either by maintaining a low water pressure for a longer time or, in the case of gas pipelines, using flame ionization after the pipeline is re-pressurized
- if a water-pressure test is used, the pressure should be at least 10% lower than the spike pressure and 10% higher than the maximum allowable operating pressure
- the pressure should be monitored for a period of eight hours, but shorter times may be sufficient if the pressure remains constant

E.2.1.3 OPTIMIZATION OF THE HYDROTEST PROCEDURE

In addition to testing the pipe and removing sub-critical defects, hydrostatic testing can also be useful for arresting or slowing the subsequent growth of remaining cracks following the return of the pipeline to service. Clearly, regardless of the procedure used, there is a desire to avoid the growth of cracks due to the application of the test itself. Recent R&D studies have considered the optimization of the hydrostatic test procedure in order to (i) minimize crack growth during the test and (ii) to achieve the maximum post-test benefits [Chen et al. 2012].

Based on a mechanistic understanding of the underlying principles controlling SCC, it is suggested that crack growth during the hydrostatic test can be avoided by:

- Prior to filling the pipe with water, holding the pressure at the highest operating pressure possible for at least 24 hours.
- During the hydrostatic test itself, loading the pipe initially up to 75% SMYS over a period of at least 2 hours (and preferably longer) to achieve crack blunting and maintaining the

pressure at this level for several hours.

- Maintaining the load at the highest test level for at least one hour to further blunt cracks.

In order to maximize the post-test benefits of hydrostatic testing, it is suggested that:

- Following the hydrostatic test, the pressure should be held at the highest operating pressure for at least 24 hours to maintain the bluntness of remaining cracks.

- Severe pressure cycling should be avoided.

The nature of the crack cycles that can induce damage to the pipe is a function of the pressure range of the cycle, the maximum load, the frequency of loading, and the geometry of the cracks in the pipe. Further guidance regarding optimization of the hydrostatic testing and operating conditions to avoid crack growth are given by Chen et al. [2012].

E.3 RE-INSPECTION INTERVALS

If the mitigation of Category II or III SCC is conducted using either hydrotesting or ILI, periodic re-inspection is required (Section 2.3.7).

The two inspection methods provide different types of information which also have an impact on the estimation of the re-inspection interval.

<u>SCC dimensions</u> - An ILI inspection provides length and depth directly, and the failure pressure is then calculated using a suitable procedure (Section 2.3.4.3, Appendix D). A hydrostatic test provides a minimum failure pressure, from which the SCC dimensions can be calculated.

<u>Resolution of SCC dimensions</u> - The hydrotest procedure provides the dimensions of the largest SCC feature that could have survived the test, but provides no information about the existence or size of smaller cracks. This then results in comparatively shorter re-test intervals. Conversely, ILI has greater resolution, possibly resulting in longer re-inspection intervals.

<u>Uncertainty</u> – There is almost no uncertainty in determining a minimum SCC failure pressure for a pipe segment after conducting a hydrotest. Conversely, for ILI there is uncertainty associated with the probability of detection (POD) and probability of identification (POI) of features, as well as uncertainty associated with the failure pressure calculation methods.

To be conservative when determining re-test intervals, the estimated failure pressure should not be overestimated. With hydrostatic testing, the maximum test pressure can be used as a conservative estimate of the failure pressure. When calculating the failure pressure from crack dimensions determined from ILI, the lowest reasonable value for the pipe material toughness should be used, and care should be taken with crack-interaction rules so as not to underestimate the effective crack dimensions (Section 2.3.4.4).

E.3.1 Hydrostatic Re-test Interval

Section 2.3.7.2 of the main text provides a description of the recommended procedure for determining the hydrostatic re-test interval.

E.3.2 Re-inspection Interval Based on Crack Growth Rate

The re-inspection interval can be estimated based on the crack size at the time of the last inspection (either known from a reliable ILI run or an inferred maximum size based on the hydrotest spike pressure) and a suitable crack growth rate. In principle, the use of crack growth rates to estimate the re-inspection interval can be used if inspection is performed using either ILI or hydrotesting. However, the procedure outlined in Section 2.3.7.2 is recommended if hydrotesting is the preferred inspection method as it avoids uncertainties associated with (a) converting a test pressure to the maximum remaining defect size and (b) estimating the subsequent growth of the defect in both the depth and length directions.

Crack growth is a complex process involving synergistic influences from environmental, operating, and material factors. Growth of SCC features occurs both in the length and depth directions. Some of the methods described here provide a measure of the surface (length) growth rate, others the depth-wise growth rate, and some provide information of the rate of growth in both directions. Differences in the rate of surface crack growth and depth-wise crack growth will result in changes in the crack aspect ratio.

Growth rates used for estimating the re-inspection interval should be conservative, yet realistic. All SCC on pipelines exhibits a distribution of growth rates that have maximum, minimum, and average values. When using a single growth rate, an understanding of where in the distribution this value falls and the level of conservatism associated with the selected value is necessary.

Ideally the growth rates should be derived from SCC features that are isolated, located at the toe of the weld, or within sparse SCC colonies for the pipe segment under consideration. Rates derived from field observations should take precedence over laboratory results. In the absence of field growth data, however, laboratory results may initially be used for selecting appropriate growth rate values. Current failure criteria for SCC features apply to single or co-linear flaws. Although it is understood that, based on the growth model presented in Figure 1.1, the total SCC growth cycle is non-linear, linear growth can be approximated for each stage of the cycle. This approach implies limitations to the applicability of a calculated growth rate to the particular stage of growth. It also assumes uniform growth; that is, growth rates will be constant regardless of the depth, length, or proximity of SCC features.

Estimates of the crack growth rate can be derived from various sources, including:

<u>Mechanistic crack growth models</u> - Mechanistic SCC growth models range in complexity from simple models based on length and depth-wise growth of single SCC features or pairs, to highly complex models predicting growth of SCC features within colonies. Typically these models are built by attempting to numerically model a theoretical growth mechanism developed from laboratory growth studies or field observations.

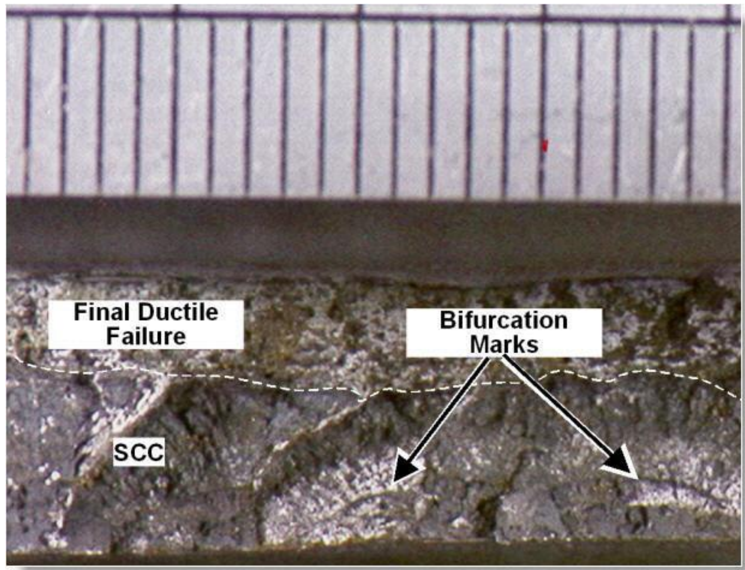
Most recently, R&D efforts have focused on crack growth modelling based on an assumed crack growth law and an analysis of SCADA pressure fluctuations. Various crack growth expressions have been proposed which invariably involve a growth component due to cyclic loading. Analysis of the pressure fluctuations for the pipe segment, for example, using rainflow counting, provides the required input for the crack growth models. The effects of stress concentrators, such as dents, bends, or long seam welds, can also be accounted for, if deemed appropriate. Before relying solely on the results of crack growth modelling to estimate the re-inspection interval, the predictions of the model should be validated against field data.

Although recent progress has been made, the current theoretical growth mechanisms do not yet have the necessary complexity to accurately describe the entire growth cycle of SCC. These models will require more validation before operating decisions can be based on them.

<u>Laboratory tests conducted under simulated field conditions</u> - SCC growth rates measured in laboratory tests which attempt to simulate field operating conditions provide a distribution of growth rates ranging from approximately 0.2×10^{-8} mm/s (0.06 mm/yr) to 2.8×10^{-8} mm/s (0.88 mm/yr). The measured surface extension rate is of the same order of magnitude as the crack penetration rate.

<u>Beach marks on fracture surfaces</u> - Differences in the depth of “beach marks” on the fracture face of an SCC feature can provide an estimate of SCC growth. Beach marks are visible as bifurcation marks on the fracture surface (Figure E.10).

Figure E.10: Bifurcation Lines on the Fracture Surface of a Failed SCC Feature.



In order to be able to use beach marking in the calculation of the SCC growth rate, the SCC feature must have experienced at least one hydrotest in the past to demarcate a starting point for growth with a beach mark. This SCC feature must then be removed from the pipeline at a point in the future for observation of the fracture surface. This removal can be the result of an in-service failure, a failure resulting from a second hydrotest, or by cutting out the feature before failure has occurred and manually fracturing the feature. The first hydrotest and the removal of the feature must be separated by a minimum time period of at least three years; although five or more years are preferable. This time period should permit sufficient growth to occur to be able to resolve the distance between the beach mark and the crack tip. In addition, the greater the interval between the initial hydrotest and the removal of the feature, the smaller the error due to the temporary decrease in the crack growth rate that occurs as a result of crack tip blunting during the hydrotest.

<u>Defect matching from multiple ILI runs</u> – Consecutive crack-tool ILI runs can be used to estimate the crack growth rate [Slaughter et al. 2010]. However, because of the poorer resolution of crack tools, the prediction of crack growth rates is not as well developed as the prediction of corrosion rates from metal-loss ILI runs. The crack growth rate may be estimated from the growth of carefully matched features from two or more ILI runs or from the change in the distributions of depth and length for a group of SCC features. For maximum accuracy, the period between successive ILI runs should be at least three years. Generally, CEPA members have had little success in estimating crack growth rates from repeat ILI runs.

<u>SCC size distributions from field inspection data</u> - Field-derived crack growth rates are typically time-averaged rates estimated from the depth of the crack divided by the lifetime of the pipe. Such rates may be non-conservative since there may have been a significant induction period prior to the onset of crack growth (Stage 1, Figure 1.1), resulting in an under-estimation of the crack growth rate. Typical field inspection data suggest growth rates of the order of 10^{-9} mm/s for non-failing SCC features.

<u>Growth rates derived from failures</u> - Reported SCC growth rate measurements determined from operating failures primarily refer to depth-wise growth. Time-averaged growth rates for the environmental component (Stage 3 of the Bathtub Model shown in Figure 1.1) observed on an NPS 36 pipeline were 1×10^{-8} mm/s (0.3 mm/yr) and 2×10^{-8} mm/s (0.63 mm/yr). SCC ruptures on NPS 8 and NPS 10 pipelines both resulted from a maximum time-averaged rate of 5×10^{-9} mm/s (0.16 mm/yr). SCC features adjacent to the failures grew at rates of $1\text{-}4 \times 10^{-9}$ mm/s (0.03 to 0.13 mm/yr).

E.4 REPAIR METHODS

According to CSA Z662, pipe body surface cracks, including stress corrosion cracks, are considered to be defects unless determined by an engineering assessment to be acceptable [CSA 2011]. Pipe containing SCC defects can be repaired using one or more of the acceptable repair methods given in Table 10.1 of CSA Z662 [CSA 2011]. The acceptable permanent repair methods for SCC are:

- Grinding and buffing repair
- Pressure containment sleeve
- Pipe replacement
- Steel reinforcement repair sleeve
- Steel compression reinforcement repair sleeve
- Fiberglass reinforcement repair sleeve
- Hot tap
- Direct deposition welding

There are limitations associated with several of the approved repair methods and some may be used only after a grinding (buffing) repair is completed and the resulting plain 'metal loss' defect is considered.

Sleeve repairs can be divided into two categories; pressure-containment and reinforcement. Pressure-containment repair sleeves are designed to retain the pressure of the pipeline fluid in the event of a failure of the parent pipe under the sleeve, or the parent pipe is "tapped" so that the sleeve/bottle becomes pressure containing and the defects no longer grow on the parent steel. Reinforcement sleeves are designed to prevent radial bulging of the remaining steel and resulting failure of the defect, and include steel reinforcement sleeves, steel compression reinforcement repair sleeves, and fiberglass reinforcement repair sleeves.

E.4.1 Grinding and Buffing Repair

Removal of SCC by buffing, with or without subsequent reinforcement, is a common repair procedure (Figure E.11). The SCC is generally removed by sequentially buffing the feature so that the minimum of pipe material is removed and so that information about the crack dimensions can be accurately collected during the repair.

Stress corrosion cracks should not be removed by grinding on pipe containing high pressure. Appendix B contains guidance for the recommended pressure reduction for excavation and field inspection. With pipe containing high pressure, only buffing using soft back discs should be carried out. The operator should determine a safe pressure prior to any repair process that reduces the load-bearing capacity of the pipe. If grinding or buffing results in localized metal loss that exceeds the limits specified in the code, a permanent repair can be made. This repair can be made with either a pressure-containment or reinforcement sleeve, or by hot tapping or pipe replacement. A temporary repair is also permitted with the use of a bolt-on split sleeve.

Figure E.11: Buffing Repair.

The sequential buffing process typically involves the following steps:

- Select the isolated SCC feature, the deepest feature within a colony, or the toe of the weld SCC feature to be repaired. In the case of a toe of the weld feature, the weld cap is typically removed flush to the pipe for the initial assessment.
- Review the pressure reduction established for the excavation (Appendix B). Considering the length of the crack being removed, determine the maximum safe depth of material that can be removed by buffing at the established pressure reduction.
- Depending on the estimated depth and precision of the data required, remove slightly less then 10% of the wall thickness and perform MPI to determine if any SCC remains within the buffed area.
- Measure the remaining wall thickness using an ultrasonic thickness gauge.
- If the SCC is removed in the first step, record the depth as less than 10% of wall thickness.
- If the SCC still remains within the buffed area, perform a second buffing followed by MPI inspection and wall thickness measurements. The amount of material removed in the second pass should be substantially less than the first pass, typically in the range of 1% to 3% of the nominal wall thickness, depending on the depth precision required.
- Continue the sequential buffing, MPI inspection and wall thickness measurements until either the SCC feature is completely removed or the safe buffing depth has been reached as established above.
- As the buffing progresses nearer to the crack tip, consecutive buffing should remove increasingly less material in the depth direction in order to increase precision of the measurement and minimize wall loss to the pipe.
- SCC typically quickly shortens in length when the crack tip is approached. This provides an indication of the amount of material to be removed.

- Upon removal of the SCC, record the SCC depth as the difference between the remaining wall thickness and the original wall thickness as installed.

Some companies have found sequential buffing can, in some instances, provide an indication of the sharpness of the crack tip when cross sectioning is not practical or possible. Generally, a sharper crack tip indicates that the SCC is active, while a broadened crack tip may indicate that the SCC has been corroded or blunted and is no longer growing in a crack-like manner. Physically a sharp crack tip exhibits a linear reduction in length of the SCC feature with each depth removal step, as well as tightly fitting crack walls in the width direction, especially near the crack tip. Conversely, blunted or corroded SCC features are often removed completely with significantly less reduction in length. The blunted SCC feature may also exhibit a greater width near the tip.

E.4.2 Steel Reinforcement Sleeves

If the buffing repair of SCC results in metal loss in excess of that permitted by CSA Z662 [CSA 2011], the metal loss defect can be permanently repaired with the installation of a reinforcing sleeve (Figures E.12 and E.13). The use of a steel reinforcement sleeve is restricted to the repair of metal loss less than 80%.

Reinforcement sleeves should be used following an engineering assessment. Refer to CSA Z662 Table 10.1 for the application of sleeves to repair pipe defects [CSA 2011].

Figure E.12: Steel Reinforcement Sleeve.

Figure E.13: Installation of a Reinforcement Sleeve After SCC Removal.

E.4.3 Composite Reinforcement Sleeves

Applying a composite reinforcement sleeve for repairing SCC is restricted to reinforcing an area from which SCC has been completely removed by buffing (Figure E.14). For SCC colonies for which the buffing repair has resulted in metal loss in excess of that permitted by CSA Z662, permanent repair can be achieved with the installation of a composite reinforcement sleeve [CSA 2011]. The use of a composite reinforcement sleeve is restricted to the repair of metal loss less than 80%.

As for the steel reinforcement sleeve, a composite reinforcement sleeve prevents failure of the defect through partial transfer of the hoop stress to the sleeve material, as well as providing restraint of localized bulging in the area of the defect.

A detailed engineering assessment of the defect and sleeve repair must precede installation of the composite reinforcement sleeve to ensure that the strength of the repair will be equivalent to that of the original carrier pipe. The engineering assessment must include a detailed mapping of the defect geometry including depth, and axial and circumferential lengths. A computer-based model can be used to calculate the effectiveness of the sleeve repair based on the metal loss geometry, pipe dimensions and material properties, and the operating pressure at the time of installation. For an effective repair, the sleeve repair strength should be greater than the design strength of the original pipe.

In strict accordance with the manufacturer's specifications, only trained technicians should install the composite reinforcement sleeve.

Figure E.14: Composite Reinforcement Sleeve Repair.

E.4.4 Pipe Replacement

Pipe replacement (Figure E.15), although an effective repair method, is costly and requires a service interruption for installation. The entire length of the affected pipe needs to be replaced for this to be an effective repair method.

Figure E.15: Repair by Pipe Replacement.

E.4.5 Repair of SCC by Re-coating

The vast majority of SCC colonies are shallow and (when examined in cross-section) the cracks appear to be blunt and dormant. Some CEPA member companies simply recoat these areas without prior grinding to remove the cracks. Continued crack propagation requires both a sufficient tensile stress and a suitable corrosive environment. By removing the environmental component, crack growth is prevented. It is important to use a high-performance repair coating such as a liquid epoxy or urethane or field-applied fusion-bonded epoxy.

R&D studies in Australia have shown that re-coated shallow SCC cracks subjected to pressure cycles equivalent to 50 years service of a gas pipeline exhibited only 0.1-0.4 mm of growth due to fatigue [Linton et al. 2007].

Re-coating crack colonies is typically limited to features with a maximum depth of 10% of the wall thickness.

REFERENCES FOR APPENDIX E

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