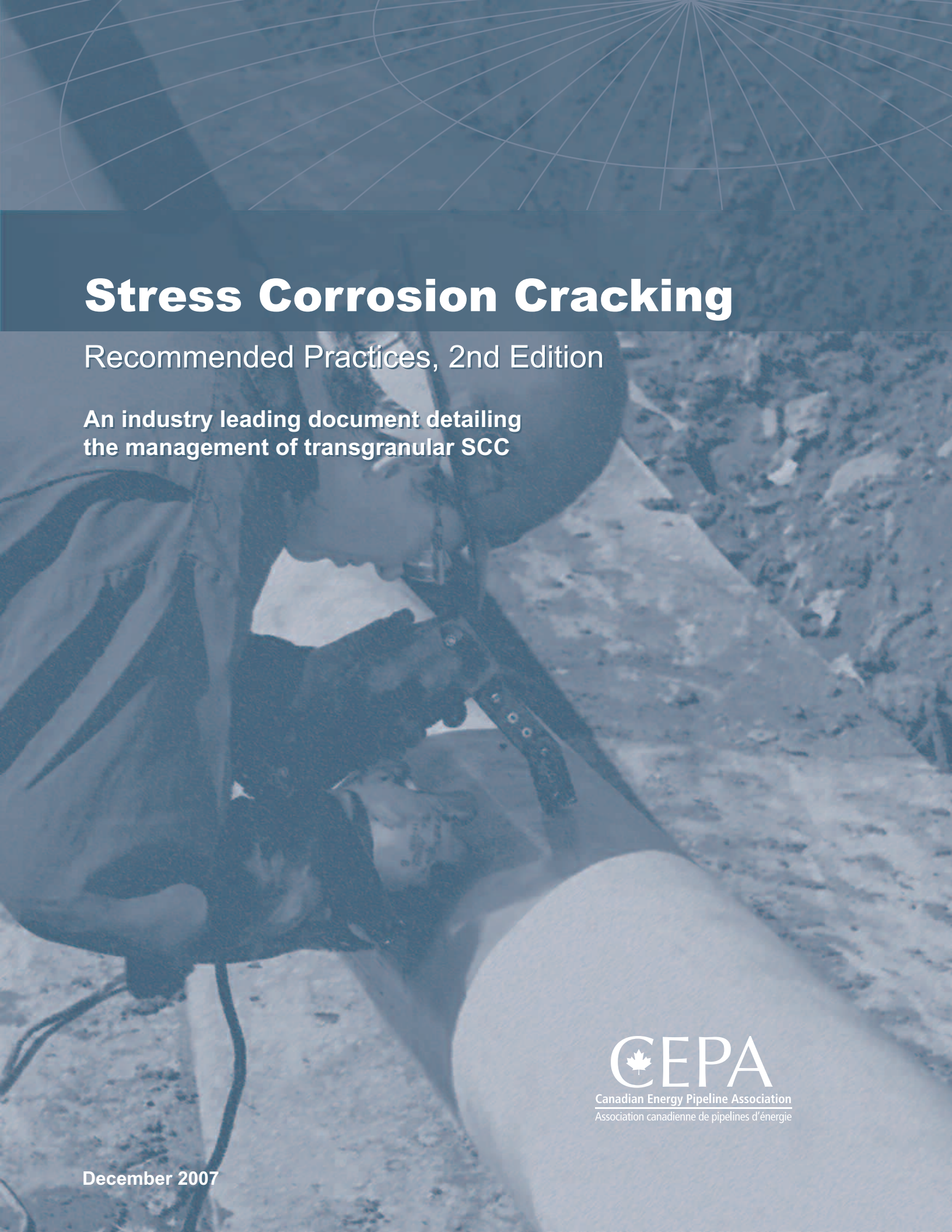




Stress Corrosion Cracking

Recommended Practices, 2nd Edition

An industry leading document detailing
the management of transgranular SCC



Canadian Energy Pipeline Association
Association canadienne de pipelines d'énergie

December 2007

Notice of Copyright

Copyright © 2007 Canadian Energy Pipeline Association (CEPA). All rights reserved. Canadian Energy Pipeline Association and the CEPA logo are trademarks and/or registered trademarks of Canadian Energy Pipeline Association. The trademarks or service marks of all other products or services mentioned in this document are identified respectively.



1860, 205 – 5 Avenue SW
Calgary, Alberta
CANADA T2P 2V7

phone: (403) 221-8777
fax: (403) 221-8760
web: www.cepa.com

Disclaimer of Liability

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 a 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. The second edition has been issued to update the original document with the latest scientific knowledge and the changes in field practices of CEPA companies that have evolved since the issue of the first edition.

Use of these Practices described herein is wholly voluntary. The Practices described are not to be considered industry standards and no representation as such is made. It is the responsibility of each pipeline company, or other user of these Practices, to implement practices regarding SCC that suit their specific pipelines, needs, operating conditions, and location.

Information concerning SCC continues to grow and develop and, as such, these Practices are revised from time to time. For that reason, users are cautioned to confer with CEPA to determine that they have the most recent edition of these SCC Recommended Practices.

While reasonable efforts have been made by CEPA to assure the accuracy and reliability of the information contained in these Practices, CEPA makes no warranty, representation or guarantee, express or implied, in conjunction with the publication of these Practices as to the accuracy or reliability of these Practices. CEPA expressly disclaims any liability or responsibility, whether in contract, tort or otherwise and whether based on negligence or otherwise, for loss or damage of any kind, whether direct or consequential, resulting from the use of these Practices. These Practices are set out for informational purposes only.

References to trade names or specific commercial products, commodities, services or equipment constitutes neither an endorsement nor censure by CEPA of any specific product, commodity, service or equipment.

The CEPA SCC Recommended Practices are intended to be considered as a whole, and users are cautioned to avoid the use of individual chapters without regard for the entire Practices.

Table of Contents

1. Foreword	1-1
2. Introduction to the Recommended Practices	2-1
3. Definitions and Abbreviations	3-1
4. SCC Management Program	4-1
5. SCC Investigation Programs	5-1
6. In-Line Inspection	6-1
7. CEPA Recommended Data Collection	7-1
8. SCC Condition Assessment	8-1
9. Prevention and Mitigation	9-1
10. Risk Assessment	10-1
11. Post Incident Management	11-1
12. Circumferential SCC	12-1

1. Foreword

In continuing their lead role in transgranular SCC management, CEPA and its member companies have undertaken a revision of the 1997 SCC Recommended Practices in this current document. This revised document will incorporate the advancements to date in the understanding of transgranular SCC and in the practices with which a pipeline operator can manage transgranular SCC.

Although much of this document is similar in content and format when compared to the 1997 SCC Recommended Practices, several major changes were made in this new document. The major technical changes in the 2007 CEPA SCC Recommended Practices include;

- The removal of the original definition of “Significant” SCC.
- A new SCC management flowchart that aligns more closely with current industry best practices.
- The introduction of a multi-level SCC severity assessment method to guide pipeline companies in determining the seriousness of any SCC discovered, as well as the mitigation required.
- Clarification of the use of the terms “interlinking” and “interacting”.
- Increased guidance in assessing SCC within corrosion.
- The formal incorporation of circumferential SCC within the document.
- The addition of guidance during post SCC incident investigation and pipeline return to service.
- Less emphasis on the use of soils models as the primary SCC assessment and risk reduction tool.

1.1 Scope

The “CEPA SCC Recommended Practices” deals exclusively with the transgranular (also known as near-neutral pH or low pH SCC) form of SCC (hereafter simply referred to as “SCC”) and, although some of the management techniques may be similar to those dealing with the intergranular form of SCC (also known as classical SCC or high-pH SCC), this document does not specifically address the intergranular form of SCC. However the document addresses both axial and circumferential Transgranular SCC.

2.	Introduction to the Recommended Practices	2-2
2.1	The Canadian Energy Pipeline Association	2-2
2.2	CEPA and Stress Corrosion Cracking	2-2
2.3	Goals & Objectives.....	2-3
2.4	SCC Overview.....	2-3

2. Introduction to the Recommended Practices

2.1 The Canadian Energy Pipeline Association

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 100,000 kilometres of pipeline across Canada, transporting natural gas and liquid petroleum products to North American markets, providing for the energy needs of millions of consumers.

2.2 CEPA and Stress Corrosion Cracking

The discovery of a new form of stress corrosion cracking (SCC) in the early 1980s on a CEPA member pipeline posed a new and little understood integrity issue for this particular pipeline. Prior to the discovery of this new form of cracking, SCC was thought to be a relatively well-understood, intergranular cracking phenomenon occurring on the external surface of pipelines. This original form of Intergranular SCC was first discovered in 1965 in the southern U.S.A. and was constrained to pipeline surfaces subject to a well defined window of elevated temperatures, elevated pH and depressed cathodic potential. The new form of SCC was markedly different in both its growth mechanism and in the environmental conditions in which it was found. This new form of SCC propagated in a transgranular fashion and was found on surfaces in contact with a dilute, near-neutral pH electrolyte, at relatively low pipeline surface temperatures, and under coatings believed to shield the pipe from the cathodic protection system. As such, the newly discovered form of SCC is equally referred to as **Transgranular SCC** or **Near-Neutral pH SCC**.

Subsequent to the first discovery of Transgranular SCC, several other Canadian pipeline operators have also detected Transgranular SCC on their systems. As well, pipeline operators in Europe, Asia, Australia and the U.S.A have since documented the presence of Transgranular SCC. This phenomena has been identified as the cause of several in-service pipeline failures and continues to be an integrity threat for existing commodity transmission pipelines.

Maintaining pipeline integrity is a priority for the industry today and will be in the future. In 1994, CEPA recognized the challenge posed by Transgranular SCC and established an ad-hoc **SCC Working Group** to share SCC experience and develop pipeline industry protocols to address the issue of SCC. An outcome from the CEPA SCC Working Group was the original 1997 edition of the "**CEPA SCC Recommended Practices**." This document has been well received by the industry and continues to be a valuable reference in both the management and understanding of Transgranular SCC by pipeline operators, regulators, vendors and the research community. An additional document titled "**Addendum on Circumferential SCC**" was published in 1998 that specifically addressed the much less-common Circumferential SCC.

Since the publishing of the original SCC documents, the CEPA Pipeline Integrity Working Group (PIWG) has been accountable for reviewing the Recommended Practices and ultimately for revising and publishing this second SCC Recommended Practices document. The PIWG includes volunteers from all CEPA full and technical member companies. Collectively, these personnel have experience and technical expertise in a variety of areas related to pipeline operations, system integrity and risk assessment. In addition, various industry experts and researchers were hired to review and comment on the revised Recommended Practices before it was published to ensure that CEPA experiences and knowledge aligned with the latest accepted scientific research and published technical documents. The PIWG received guidance from, and reports to the CEPA Operations Standing Committee, which in turn reports to the CEPA Board of Directors comprised of senior representation from all CEPA full member companies. More information on CEPA can be found at www.cepa.com.

2.3 Goals & Objectives

The SCC Recommended Practices is presented with the goal of providing a detailed working document based on the latest Canadian industry practices relating to the management of SCC. These recommended practices will allow for the safe and consistent management of Transgranular SCC on pipelines in general, and Canadian pipelines in particular.

The goal stated above is based on the following objectives:

1. Protecting the safety of the public and pipeline company employees;
2. Protecting the environment, private and company property; and
3. Maintaining the reliable and economical operation of the Canadian pipeline system.

2.4 SCC Overview

Transgranular SCC (hereafter referred to as “SCC”) on buried, high-pressure commodity pipelines occurs as a result of the interaction of a susceptible metallic material, tensile stress, and an aggressive electrolyte. SCC initiates on the external pipeline surface and grows in both depth and surface directions. Growth along the surface is perpendicular to 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.

Crack growth is typically characterized as brittle and exhibits a cleavage-like fracture surface through the grain. However, evidence of small amounts of plasticity is often associated with the fracture path, suggesting a more complex growth mechanism is involved. Mechanisms have been proposed to explain the observed brittle propagation in an otherwise ductile material. These mechanisms typically speculate that atomic hydrogen plays a role in causing embrittlement of strained material immediately ahead of the crack tip. The final failure of the remaining ligament joining the crack tip to the inside wall of the pipeline is

typically a ductile fracture, except perhaps in pipelines with very low fracture toughness. SCC failures occur at applied stresses below the yield strength of the bulk material and can occur at locations where there is otherwise minimal wall loss due to corrosion.

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 depicted in Figure 2.1.

The “bathtub model” suggests a period exists 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 to reach the pipe surface and/or 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 forces act to cause coating failure.

After a coating fails, electrolytes reach the pipe surface and SCC may initiate as a result of surface residual stresses, metallic imperfections, stress concentrations or a combination of these (Stage 2). The relatively high crack velocity of the initiating SCC has been observed to decrease rapidly after initiation is complete. SCC growth continues as a consequence of an environmental growth mechanism at a relatively low rate of growth (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 (see Figure 2.2).

This continued growth and coalescence could result in an SCC feature that is of sufficient size that mechanical forces can begin to act synergistically with the environmental growth mechanism to accelerate the SCC growth rate. This increase in SCC growth velocity 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.

At the end of Stage 4 and during the final fracture, mechanical loading conditions become increasingly more important when compared to environmental growth.

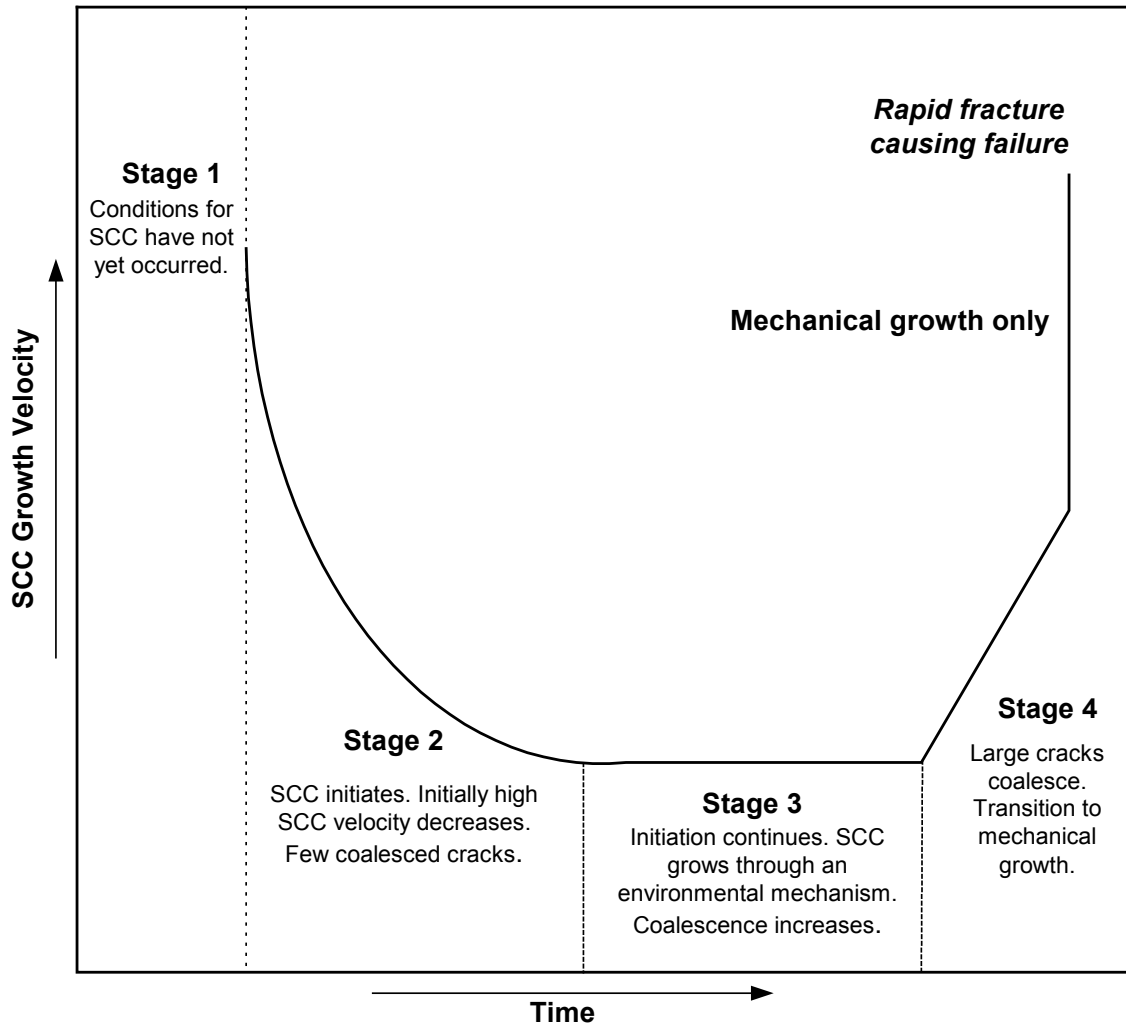


Figure 2.1: Bathtub Model: Life Cycle of SCC Growth in Pipelines (Parkins, 1987)

Field data support a number of relatively consistent observations that, when used in combination, can reliably discriminate transgranular SCC from other types of SCC. Some of these observations include:

1. SCC occurs beneath a mechanically failed coating in the absence of adequate cathodic protection current, or when the failed coating acts to shield the steel surface from cathodic current while allowing the ingress and trapping of an electrolyte against the surface.
2. SCC is capable of forming in the absence of general corrosion but also may initiate in slow or dormant corrosion, the bottom of corrosion pits, in the pipe body or along the toe of a weld.

3. 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 this SCC has very low or non-detectable growth rates. SCC colonies forming along the toe of a long seam weld are often constrained by the smaller area of non-adhered coating as it “tents” over the weld. Therefore, these “toe of the weld” SCC colonies have relatively linear colony dimensions (see Figure 2.2).
4. There can be little surface metal loss associated with SCC colonies and it is typically not visible on the pipe surface without the aid of imaging techniques. For these reasons, a simple metal-loss in-line inspection and excavation program is not a reliable means to passively detect and locate SCC.
5. SCC often exhibits evidence of corrosion of the crack walls, leading to relatively wide cracks when examined as a metallographic cross section.
6. Failures are typically composed of several coalesced cracks.
7. A high length to depth ratio is typical, often in the range of 20-50: 1 (length to depth).
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.

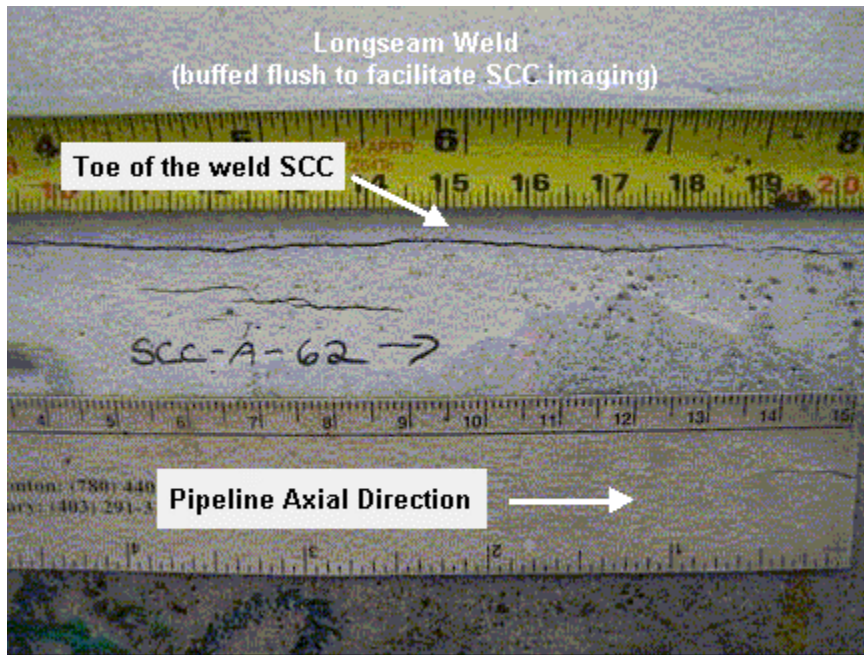


Figure 2.2: Individual SCC features aligning along the toe of the longseam weld beneath the tenting of the polyethylene tape coating (removed).

Much of the following recommended practices are built upon the concept of the life cycle model and the inherent supposition that no one single growth mechanism or growth rate can consistently define the life cycle of SCC. Current theories of SCC initiation and growth, although very important in understanding SCC, are still under debate. As well, due to recent improvements in detection technology and management processes, the management of SCC is a rapidly evolving field. CEPA will continue to support the advancement of the understanding of SCC through the assimilation of the collective knowledge of pipeline operators and the vendors who provide support for SCC management.

3.	Definitions and Abbreviations	3-2
-----------	--	------------

3. Definitions and Abbreviations

-A-	
AC	Alternating Current
ACFM	Alternating Current Field Measurements
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 uncombined 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 longitudinal direction.
-B-	
BWMPI	Black on White Magnetic Particle Inspection
-C-	
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 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.
collapse limit (plastic collapse limit)	The maximum stress, strain or load which may be applied prior to onset of plastic collapse.
colony	A grouping of stress corrosion cracks (cluster) 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

-D-	
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
DSAW	Double Submerged Arc Weld
-E-	
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 pipeline system.
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
ERW	Electric Resistance Weld
-F-	
false call	An inspection indication that is erroneously classified.

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, which is 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 specimen geometry.
fracture toughness	A measure of a material's resistance to static or dynamic crack extension. A material's property used in the calculation of critical flaw size for crack-like defects.
fusion bonded epoxy (FBE)	An inert, shop-applied, two-part powder coating that is applied by heating the pipe to melt and adhere the coating to the metal surface.
-G-	
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.
-H-	
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.
hoop stress	Circumferential stress in a pipe or pressure vessel that results from the internal pressure.
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”.
-I-	
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”) that travels in the pipeline with the fluid being transported.
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 SCC.
interlinking	Describes cracks whose tips are close enough that the stress field in front of the propagating crack are relieved and they physically join to eventually form one crack.
investigative dig	An inspection of a section of pipeline whereby that section is physically exposed to allow for a detailed examination of the pipeline surface, then recoated and backfilled.
-J-	
J or J-integral	A factor used to characterize the fracture toughness of a material having appreciable plasticity before fracture.
-L-	
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.
-M-	
magnetic flux leakage (MFL)	Tools 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 thereof may be operated at based on its design and qualification by pressure testing.
MFL	Magnetic Flux Leakage
mill scale	The oxide layer formed during hot fabrication or heat treatment of metals.
MTR	Mill test records
-N-	
NACE	National Association of Corrosion Engineers
natural gas	A compressible mixture of hydrocarbons with a low specific gravity comprised mostly 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 materials.
NEB	National Energy Board
NGL	Natural Gas Liquids
NPS	Nominal pipe size
-O-	
operating stress	The stress in a pipe or a structural member under normal operating conditions.
-P-	
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: $\text{pH} = -\log_{10} (a\text{H}^+)$ 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 SCC risk compared to adjacent segments. A pipeline segment can vary in length from a few joints to tens of kilometres.
pipeline	Those items through which oil or gas industry 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 results 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 Committee International
pressure	A measure of force per unit area.
-R-	
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 material.
-S-	
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 SCC risk compared to adjacent segments. A pipeline segment can vary in length from less than a pipe joint to tens of kilometres.
shielding	The effect of preventing cathodic protection from 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
SMYS	Specified Minimum Yield Strength
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
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.
-T-	
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 SCC.
TSB	Transportation Safety Board
-U-	
USWM	Ultrasonic Wall Measurement

UT	Ultrasonic Testing
UV	Ultraviolet
-V-	
valve section	A segment of a pipeline isolated by valves.
-W-	
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.
-Y-	
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.

4.	SCC Management Program	4-2
4.1	Introduction	4-2
4.2	Concepts used in the SCC Management Program	4-2
4.2.1	Risk Based Decisions	4-2
4.2.2	SCC Lifecycle and Management Methods	4-3
4.2.3	Representative SCC Data for a Pipe Segment.....	4-4
4.3	Description of the SCC Management Program.....	4-4
4.3.1	Pipe Segment Susceptibility Assessment.....	4-6
4.3.2	Investigate for the presence of SCC.....	4-7
4.3.3	Determine the SCC Susceptibility Reassessment Interval.....	4-10
4.3.4	Classify the Severity of SCC.....	4-11
4.3.5	Determine and Implement a Pipe Segment Safe Operating Pressure.....	4-15
4.3.6	Plan and Implement SCC Mitigation.....	4-17
4.3.7	Review and Evaluate Mitigation Activities	4-18
4.3.8	Document, Learn and Report.....	4-19
4.3.9	Condition Monitoring	4-19

4. SCC Management Program

4.1 Introduction

The SCC Management Program (SMP) for transgranular SCC constitutes a high level, risk-based program that is based on the industry's current understanding of SCC and the factors that may influence SCC occurrence and severity. The SMP should be part of a pipeline company's overall Integrity Management Program (IMP). The extent to which a pipeline company implements this SMP depends on their unique pipeline system and operating conditions.

An essential component of the SMP is the requirement for continuing monitoring of pipelines found to be susceptible to SCC, as well as mitigation for those pipelines found to have SCC that could potentially affect the pipe integrity. The monitoring and mitigation methods provided are based on industry best practices and are technically supported. Use of this program should allow a pipeline to be operated in a safe and reliable manner with respect to SCC.

This chapter highlights the main components of the SMP and describes categories of SCC severity and the mitigation options associated with each category.

4.2 Concepts used in the SCC Management Program

The following three concepts are used extensively within the SMP provided in this section.

1. Risk based decisions.
2. The impact of the SCC lifecycle on management methods.
3. Representative SCC data for a pipe segment.

A basic understanding of these concepts is required for the user to recognize the logic in methodology, as well as the limitations of the SMP. Greater detail of these concepts is provided elsewhere in this document as referenced.

4.2.1 Risk Based Decisions

The operator is required to make several decisions to proceed through the management program. Each decision is based on analysis of factors that influence SCC, with each factor having a level of uncertainty. These factors, and their associated uncertainty, can be quantified to produce a probability of a given event, for example, an SCC failure. This probability, in conjunction with the associated consequence, yields a risk that the adverse consequence being managed by the SMP may still occur. This risk is never zero. It is the operator's responsibility to ensure that the level of risk allowed by the SMP is compatible with the goals of all stakeholders.

This chapter deals primarily with the probability component of risk. Chapter 10 provides a more comprehensive discussion on risk analysis.

4.2.2 SCC Lifecycle and Management Methods

The second concept used in the SMP relates to the different events that compose the SCC lifecycle, how often these events occur, and the significance of these events on the different components of the SMP.

The SMP incorporates the occurrence of three SCC life cycle events. These events impact different components of the SCC management plan (Figure 4.1).

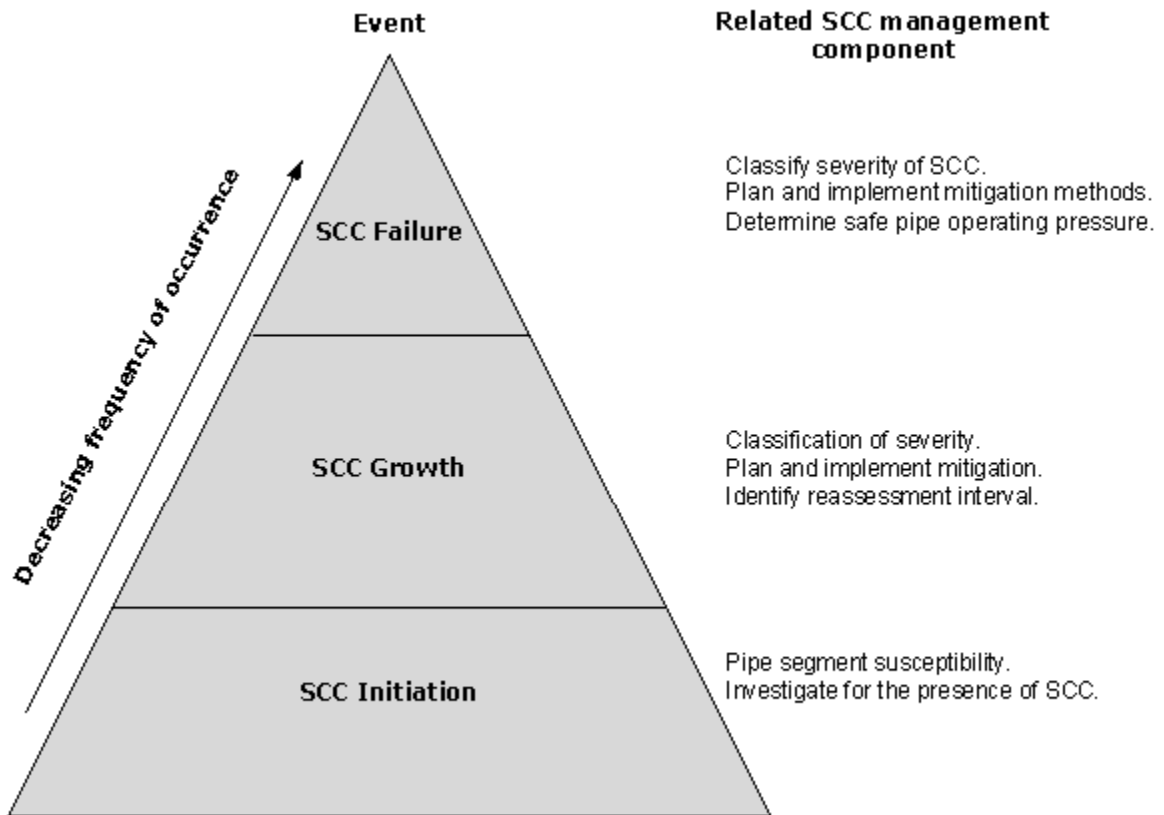


Figure 4.1: The frequency of occurrence of SCC lifecycle events and the related SCC management component

Figure 4.1 suggests that, of the large amount of SCC that may initiate on a pipeline, substantially fewer of these initiated SCC features will have sustained growth. Within the growing SCC subset, very few of these features will reach failure. As such, in a particular exploratory excavation, the likelihood of finding small SCC features is much greater than finding SCC near to failure.

The factors that influence each of the above events can be mutually exclusive. As such, the factors that influence one event in the SCC lifecycle do not necessarily apply to another event.

Example: An environmental SCC model, which may allow an operator to regularly detect the many locations that have conditions that have allowed SCC features to initiate on a

pipe segment, may not necessarily allow the operator to reliably detect the very few locations where conditions are such that SCC features have progressed to a size near to failure. In the latter case, a completely different assessment using hydrotesting or ILI tools may be required.

4.2.3 Representative SCC Data for a Pipe Segment

SCC inspection data from a limited data set is often used to indicate the condition of an entire pipe segment.

When in-line crack inspection or hydrotest results are not available, the severity of SCC in a pipe segment is often estimated from a representative sample of field inspection data. Such programs alone do not, however, reliably detect the most severe features in a pipe segment.

A **pipe segment** is defined as a length of pipe bounded by changes in pipeline attributes, which, in the operator's experience, justify a measurable change in the probability of SCC compared to adjacent segments. A pipeline segment can vary in length from a few joints to tens of kilometers. Prior to undertaking a susceptibility assessment, pipe segmentation will be required as described in section 5.1.

Example: *An operator has determined that a 4 kilometer length of pipeline has an equivalent probability of SCC based on factors that the operator understands will influence SCC initiation and growth. The operator then defines this 4 kilometer length as a single "pipe segment". The operator then discovers shallow SCC colonies in this pipe segment during an excavation that was selected with an SCC environmental model. No other direct measurements such as hydrotesting or SCC ILI exist for this segment. Even though the discovered SCC was repaired, the operator must now assume that additional SCC occurs at yet undiscovered locations within this pipe segment.*

4.3 Description of the SCC Management Program

The SCC management program is composed of nine main activity blocks as follows:

1. Pipe segment susceptibility assessment.
2. Investigate for the presence of SCC.
3. Determine the SCC susceptibility reassessment interval
4. Classify the severity of the SCC.
5. Determine and implement a pipe segment safe operating pressure.
6. Plan and implement mitigation.
7. Review and evaluate mitigation activities.
8. Document, learn and report.
9. Condition monitoring

A flowchart is provided detailing the interaction between the nine components described above (Figure 4.2).

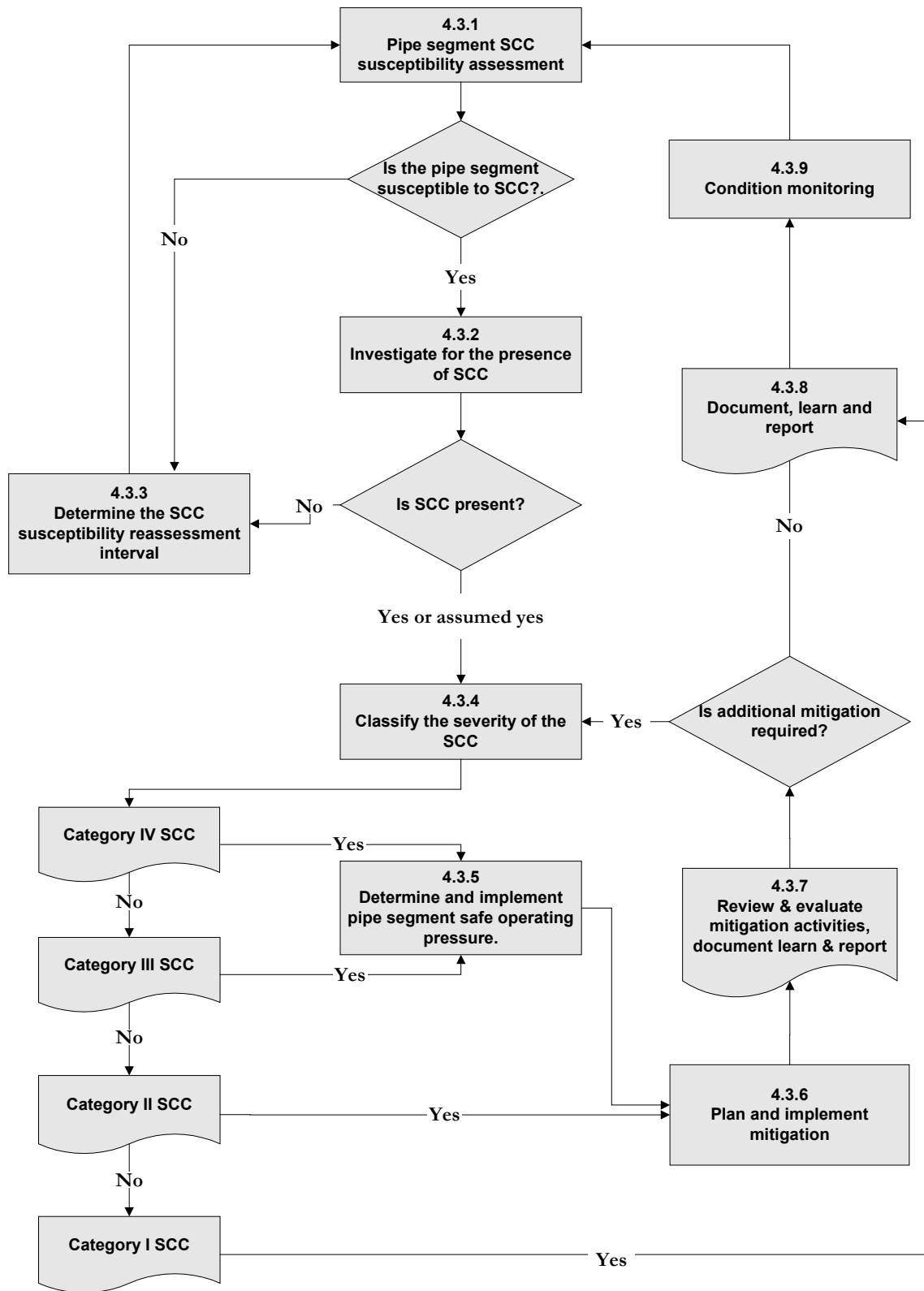


Figure 4.2: The CEPA SCC Management Program

4.3.1 Pipe Segment Susceptibility Assessment

This activity block applies to pipe segments that:

- i. Have not yet had an SCC susceptibility assessment; or
- ii. Have seen a change in SCC probability during condition monitoring; or
- iii. Have had mitigation that dramatically decreases the SCC probability for a pipeline; or
- iv. Have been previously assessed but that have been found not to be susceptible.

An initial SCC susceptibility assessment is required on every pipeline segment within a pipeline system.

Notwithstanding the contribution of other factors, SCC can only occur if the external coating becomes disbonded from the pipe surface in a manner that allows electrolyte to become trapped between the pipe surface and the coating.



Figure 4.3: Polyethylene tape coating showing evidence of disbondment

Consequently, prior to undertaking an initial susceptibility assessment, a pipeline company must assemble all construction and maintenance records that will allow for a determination of the types of external coatings present within their pipeline system. If no current or reliable information is available which details the type of external coating that was used on a given segment(s), excavations should be conducted to determine or verify the pipe segment coating type.

For those pipeline segment(s) that are entirely covered with coating that has not shown susceptibility to SCC including girth weld joints (section 5.1.1.1), section

4.3.3, titled “Determine the SCC susceptibility reassessment interval” becomes applicable based on a negative response to “Is the pipe segment susceptible to SCC?”. (Figure 4.2). The reasoning for the negative response should be documented and this reasoning should be validated into the future against any new information relating to the SCC susceptibility of pipelines coated non-SCC susceptible coatings.

In addition to coatings, there are several other factors to consider that may influence the SCC susceptibility of a pipe segment assessment. These are discussed in greater detail (section 5.1).

If the pipe segment is determined to be susceptible to SCC, the SCC management plan requires an investigation for the presence of SCC as detailed in section 4.3.2.

4.3.2 Investigate for the presence of SCC

This activity block applies to pipe segments that:

- i. Have been determined to be susceptible to SCC and
- ii. Have unreliable or absent SCC historical data.

A field program to investigate for the presence of SCC is required for each pipe segment determined to be susceptible to SCC. The field program in this phase of the SMP can be quite limited and should be designed to initially determine if SCC does actually exist 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. However, the operator should document this field investigation and be able to support the amount of investigation performed using historical data or statistical analysis.

Typically, resources do not allow for every pipe segment to be investigated simultaneously, and therefore some prioritization of the pipe segments is required as described (section 5.2).

The most common method used to investigate for the presence of SCC is the use of “exploratory” excavations at sites selected by SCC ILI, at sites selected by SCC models, or at opportunistic sites.

Note



The use of ILI crack detection tools will typically always detect some crack-like feature and, as such, requires confirmatory excavations to refute or confirm the presence of SCC in a pipe segment.

Alternately, an SCC hydrotest is capable of detecting SCC above a minimum size (section 9.3).

4.3.2.1 Exploratory Excavations

Exploratory excavations of the pipeline often provide the first initial investigation for the presence of SCC. Although this phase of the SMP is not specifically designed to either determine the size distribution of SCC that may be present or to detect injurious SCC, some of the investigative methods used may have the added benefit of also finding more severe cracking.

A statistically valid number of exploratory excavations in locations with a high probability of SCC occurrence (section 5.4) are necessary to determine the appropriate response to the question posed in Figure 4.2 “Is SCC present?”

Three common types of exploratory excavations are as follows:

1. Excavations based on SCC models.

Using criteria provided in Chapter 5.3, SCC model excavations are designed to have the greatest chance of successfully finding SCC that may have initiated on the pipe surface. The reliability in detecting SCC is company specific; however, the amount of the pipe segment inspected to determine if SCC is present should be supported by a documented SCC site selection probability analysis of other similar pipe segments. If similar data or experienced personnel are not available, an experienced consultant with demonstrated SCC site selection ability can be used. This method of selecting excavations can have a very high probability of detecting non-injurious (shallow) SCC, which generally occurs with a high frequency in pipelines that have SCC. However, this method has a low probability of detecting any possible injurious SCC that may exist and should not be relied on to do this.

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 was not yet investigated for the presence of SCC. Five excavations were then performed within this pipe segment where the excavation locations were selected using the equivalent environmental 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 the level of confidence attained was acceptable, the pipe segment was determined not to have SCC present and was moved into the activity block defined in section 4.3.3 “Determine the SCC susceptibility reassessment interval.”*

2. Opportunistic inspections.

Opportunistic inspection for SCC within the susceptible pipe segment at locations such as corrosion or dent remediation excavations can provide a cost effective method of accumulating larger amounts of data when compared to SCC model excavations alone. An advantage in using opportunistic inspections is an ability to sample a cross section of locations that may have

high, medium or low probability of SCC occurrence. However, additional SCC model excavations should be planned if none of these opportunistic excavations fall within high probability locations. Again, these types of excavations should not be relied on to detect injurious SCC.

Example: *An operator has recently determined that a pipe segment coated with extruded polyethylene is susceptible to SCC due to the use of tape wrapping as a girth weld coating. As the operator is planning extensive corrosion excavations on this pipeline, rather than planning further SCC model excavations, the operator decides to investigate for the presence of SCC by inspecting all adjacent girth welds for SCC at every corrosion excavation, including all locations thought to have a high or low probability of finding SCC.*

3. SCC in-line inspection correlation excavations

Use of in-line crack inspection followed by correlation excavations provides a method for determining if SCC exists on a pipe segment and may also provide an ability to detect the injurious SCC features that have a lower frequency of occurrence (Figure 4.4). The use of this method is dependent on the availability of a sufficiently reliable ILI tool. Dependence on the tool without correlation excavations and direct inspection is not recommended. However the use of an ILI tool with less than proven reliability will still likely increase the operator's probability of detecting SCC when compared to SCC modeling alone. Chapter 6 provides additional information on ILI technology.

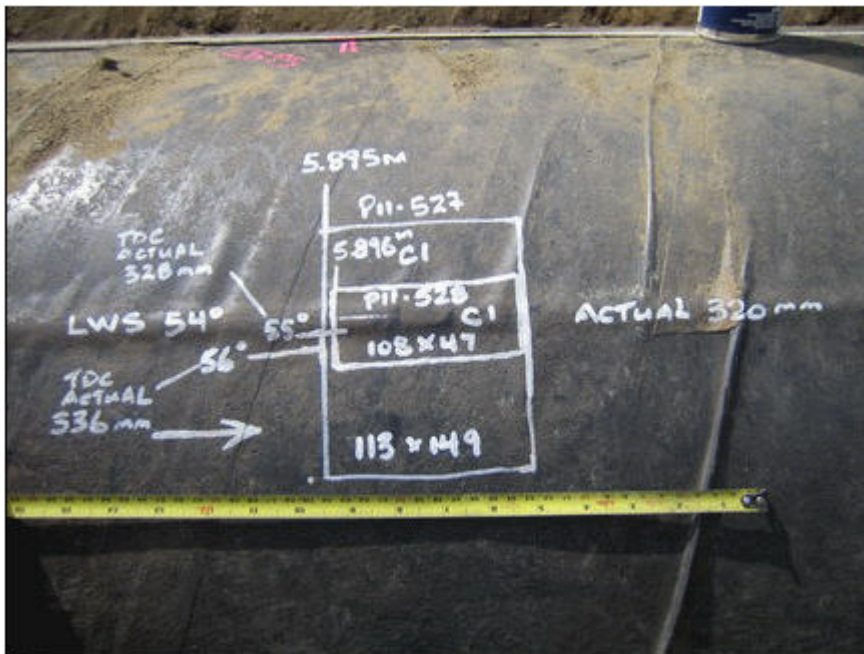


Figure 4.4: SCC excavation selected on the basis of an in-line inspection

4.3.2.2 Hydrotesting to detect SCC

An SCC hydrotest, as detailed in section 9.3, can be a valid way of determining whether SCC, of a minimum size that will fail the hydrotest, exists on a susceptible pipe segment. An SCC hydrotest can provide data for a large length of pipe with the added benefit of verifying the pipeline integrity of this pipe length against an SCC failure for a period of time. 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. Therefore, when utilizing an SCC hydrotest alone to investigate for the presence of SCC, as detailed in section 4.3.2, the operator will be required to answer “assumed yes” in response to the question posed in Figure 4.2 “Is SCC present?”

4.3.3 Determine the SCC Susceptibility Reassessment Interval

This activity block applies to pipe segments that:

- i. Were determined to be not 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.

No further SCC activities are required until the next pipe segment 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 can change within the susceptible pipe segment resulting in an increase in SCC susceptibility, such as, for example, time dependent coating deterioration.
- The probability of detection of the inspection program used to investigate for the presence of SCC.
- A consequence assessment for the location of the pipeline.

The reassessment interval should not exceed ten years under ideal conditions. In assessing the above “non-ideal” conditions the operator may choose a shorter reassessment interval. As well, the operator should choose to further inspect for SCC if an opportunity allows itself, such as through excavations for other purposes. This will allow the operator to validate or even extend the reassessment interval.

4.3.4 Classify the Severity of SCC

This activity block applies to pipe segments:

- i. That were determined to be susceptible to SCC; and
- ii. Where SCC was detected.

The relatively few excavations required to investigate for the presence of SCC in section 4.3.2 likely did not provide for an adequate representation of the distribution of SCC severity on the pipeline required in this section. As such, increased inspection is required to provide an adequate sample of the SCC size distribution for the pipe segment using techniques described in section 4.3.2.

Note



Adequately sampled infers that a statistically supported amount of pipeline has been inspected in areas where SCC is thought to have the greatest probability of sustained growth, based on an experienced review of the susceptible pipe segment.

The resultant measured SCC dimensions are then assessed using industry standard software or a similar engineering analysis that can determine the failure pressure of the SCC feature (Chapter 8).

The SCC failure pressure is then compared to a failure pressure range which enables a classification of the SCC feature into one of the four severity categories listed (Table 4.1).

Table 4.1: SCC Severity Categories

Category		Definition	Description
I	$SCC_{failure\ pressure} \geq 110\% \times MOP \times SF$	A failure pressure greater than or equal to 110% of the product of the MOP and a company defined safety factor. (Typically equating to 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 in this category.
II	$110\% \times MOP \times SF > SCC_{failure\ pressure} \geq MOP \times SF$	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	$MOP \times SF > SCC_{failure\ pressure} > MOP$	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	$MOP \geq SCC_{failure\ pressure}$	A failure pressure equal to or less than MOP.	An in-service failure becomes imminent as the MOP is approached.

Note

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.

The most severe feature (or feature with the lowest failure pressure) should be used to define the severity of SCC for that particular segment(s) of pipe.

If a hydrotest was used to detect the presence of SCC, the failure pressure of the most severe SCC feature (typically the first SCC hydrotest break) will be used to define the severity category. Consecutive hydrotesting will then be applied in the “Plan and implement mitigation” phase (Figure 4.2) to assess the possibility of SCC growth.

Example: An operator uses an SCC hydrotest rather than investigative excavations to determine if SCC is present on a pipe segment (section 4.3.2). The pipeline fails due to SCC at a pressure equal to 92 % of the product of the MOP and safety factor. Upon repair of the first failure, an immediate second retest reaches the required test pressure of 110% of the product of the MOP and safety factor without failing. The operator has determined that SCC is present and initially classifies the severity of SCC on the pipe segment as Category III based on the first failure. Figure 4.2 directs the operator to plan and implement mitigation, at which point the retest result is

applied. On review and evaluation of the hydrotest results the pipeline was deemed suitable to operate at MOP for a period after which additional mitigation is required. The additional mitigation is required despite the assumption that only Category I remains after the second hydrotest. However, a third hydrotest conducted at a point in the future at a pressure of 110% of the product of the MOP and safety factor, that does not fail, can allow the operator to move into the condition monitoring phase for this pipe segment.

If no failures occurred during the hydrotest the operator would classify the severity of SCC to be either Category I or Category II, depending on the minimum pressure obtained.

Note

Because of the small fraction of large SCC features, it is very unlikely that Category III or IV SCC (As described in Table 4.2) will be detected by methods other than a hydrotest or a reliable SCC ILI. However, in pipe segments where Category II SCC does exist, the ratio of Category II SCC over Category I SCC, is typically sufficiently large as to allow for the detection of some Category II SCC 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 positively determine the presence of Category III or IV SCC.

Figure 4.5 provides an illustration of the relationship between a severity category and SCC dimensions as determined by standard failure pressure calculation programs.

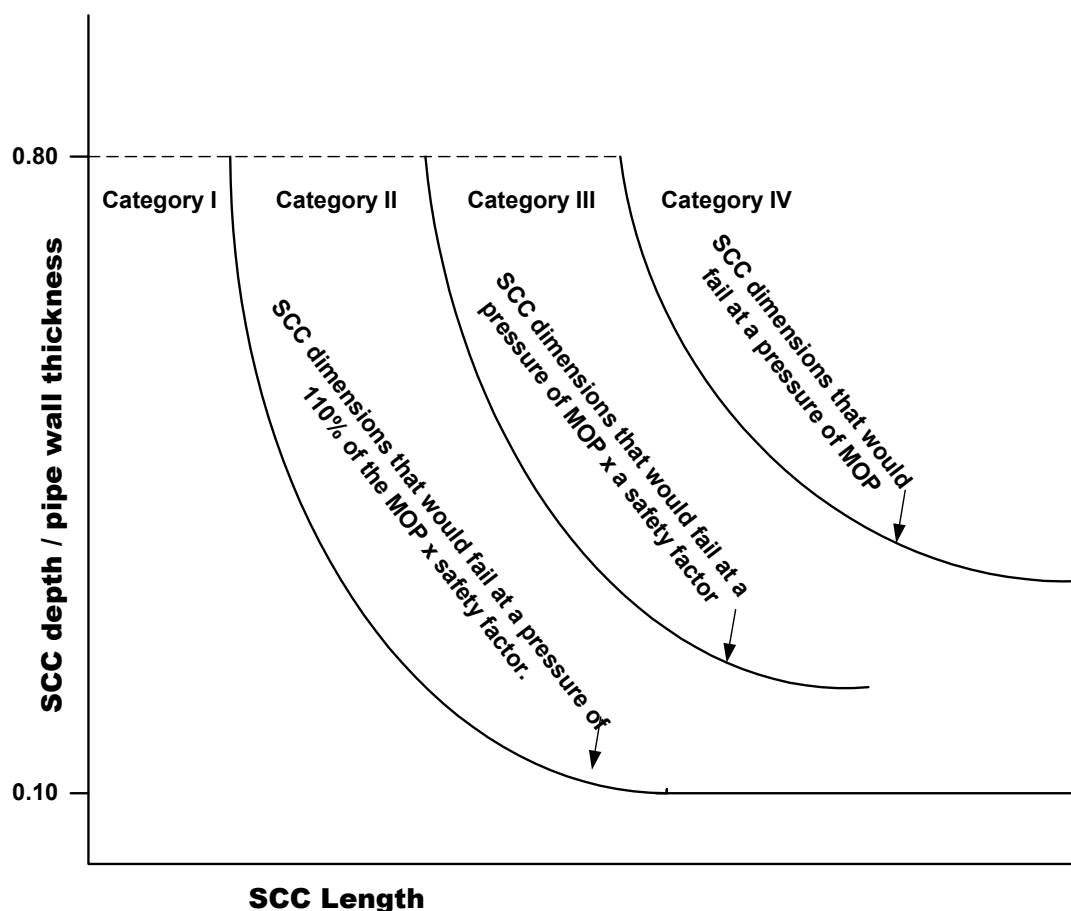


Figure 4.5: An Illustration of SCC Severity Categories

Cautionary notes and explanations required in the application of Figure 4.5 and Table 4.1 are as follows:

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.

Example: *The absolute dimensions of SCC found at a thick walled road crossing should be applied to all Class 1 or thinner-walled pipe within the pipe segment.*

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 400mm 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 versus removal by buffing, for a number of reasons as follows:
 - 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 in place of SMYS to account for over designed piping that is often found within the pipeline systems of CEPA member companies.

4.3.5 Determine and Implement a Pipe Segment Safe Operating Pressure.

This activity block applies to pipe segments where:

- i. Category III or Category IV SCC was detected.

If the operator requires that a pipe segment with Category III or IV SCC is to be returned to service or is to continue in service before pipe segment mitigation occurs, the re-establishment of a safe operating pressure is advised as follows:

A. Category III SCC.

For pipe segments found to contain Category III SCC that was discovered by;

- I. Excavations selected by SCC models or at opportunistic excavation sites (section 4.3.2.1), a) – c) below apply;
 - a) It must be assumed that similar SCC is still present on the remaining pipe segment on which the category III SCC was found.
 - b) A conservative approach to re-establishing a safe operating pressure would be 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.

- c) The safe operating pressure would then be this 60 day maximum pressure divided by the company defined safety factor, where the company defined safety factor cannot be less than 1.25.

II. Hydrotesting:

The safe operating pressure would be the lesser value of a) and b) below:

- a) The hydrotest pressure at failure obtained (see Chapter 9) divided by a company defined safety factor; or
- b) The maximum operating pressure experienced by the pipe segment within the last 60 days, excluding the hydrotest pressure.

III. An ILI for SCC

The safe operating pressure would be the lesser value of a) and b) below

- a) The lowest calculated failure pressure of all ILI features (accounting for error limits) divided by a company defined safety factor; or,
- b) The maximum operating pressure experienced by the pipe segment within the last 60 days.

B. 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 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;

- 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. A greater pressure reduction should be considered if the pipeline segment is found in higher class locations.

Plan and implement SCC mitigation immediately. If this is not possible, a further pressure reduction may be required, based on an engineering assessment.

4.3.6 Plan and Implement SCC Mitigation

This activity block applies to 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.

Table 4.2 provides recommendations for pipe segment mitigation for each SCC category that requires mitigation. For Category I SCC, no pipe segment mitigation is required. Discovery of Category I SCC requires the operator to;

- Review, Document and Learn (section 4.3.8) and
- Condition Monitor (section 4.3.9)

Table 4.2: Mitigation Activities

SCC Severity Category	Mitigation
II	Perform an engineering assessment. Suggested factors to consider within the engineering assessment include; ➤ A maximum SCC growth rate. ➤ A growth mechanism and/or the critical factors affecting growth. ➤ Commonalities of the SCC that will aid further detection. (e.g. toe of the longseam weld cracking, versus body cracking, quadrant location of the SCC, etc.). Determine the appropriate timeline for mitigation. Mitigation activities should commence within 4 years of the discovery of this category of SCC or within the mitigation timeline determined by the engineering assessment. Implement a mitigation plan for the pipe segment that will include at least one of : ➤ 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 procedure as described in section 4.3.5. Perform mitigation activities as described for Category II SCC above with the exception that mitigation activities should commence within two years of the discovery of Category III SCC or within the mitigation timeline determined by the engineering assessment.
IV	Implement the safe operating pressure procedure as described in section 4.3.5. Perform mitigation activities as described for Category II SCC above with the exception that mitigation activities 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 the engineering assessment.

Note

Repair of the detected SCC feature during the investigative excavations should not be confused with an SCC mitigation activity for the pipeline segment. SCC repair applies only to the actual SCC anomaly detected. SCC mitigation applies to the entire pipeline segment.

4.3.7 Review and Evaluate Mitigation Activities

This activity block applies to pipe segments that:

- i. Have undergone some form of pipe segment mitigation as described in Table 4.2.

Review and evaluate the mitigation activity to answer the question posed by Figure 4.2 “Is additional mitigation required?”

If the mitigation activity performed was using:

- SCC hydrotesting - The SCC hydrotest will only remove SCC features with a failure pressure less than the maximum pressure obtained at each point in the test section. Additional future mitigation will be required after the first mitigation hydrotest to assess the growth of these features, whether that is a second hydrotest or other mitigation. The timing of the next hydrotest will be dependent on an SCC growth rate analysis of the SCC detected or suspected; however there is both a minimum and maximum time period between tests. This concept is presented in section 9.3.
- Reliable In-line Crack Inspection - Determine the smallest SCC feature that can be reliably identified by the ILI tool. Further in-line inspections will be required in the future if this remains the preferred mitigation activity. The timing of the next in-line inspection will be dependent on an SCC growth rate analysis of the SCC detected.
- 100% Surface NDT for SCC, Repair and Recoat - If a high performance modern coating is used in the recoat procedure, further initiation of SCC will be prevented and no further SCC mitigation activities will be required. However, if the coating performance is at all in question, it is suggested that follow-up excavations should be performed within a 5-10 year time frame to ensure that the coating is performing as expected.
- Replacement of the Susceptible Section - Pipe segments replaced in accordance with modern construction practices and with a high integrity modern coating do not require further SCC mitigation activity.

4.3.8 Document, Learn and Report

This activity block applies to pipe segments that:

- i. Contain Category I SCC only, or;
- ii. Have undergone SCC mitigation and no longer require additional SCC mitigation.

A key step in the SMP 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 that the SMP is providing.

4.3.9 Condition Monitoring

This activity block applies to pipe segments that:

- i. Contain Category I SCC only, or;
- ii. Have undergone SCC mitigation and no longer require additional SCC mitigation, and;
- iii. Have been completely documented as to the SCC activities performed.

Condition monitoring is a process that captures evidence that the probability of SCC is changing over time. It is a structured process for collecting, regularly reviewing, interpreting and responding to all the SCC-relevant information obtained during on-going operational and integrity management activities (section 5.6.1).

The decision to move from the "Condition monitoring" phase of the SMP into a "Pipe segment SCC susceptibility assessment" is 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).

5.	SCC Investigation Programs	5-2
5.1	Pipeline Segmentation	5-2
5.1.1	SCC Susceptible Pipe Conditions.....	5-3
5.1.2	Creating Pipeline Segments from Factors	5-8
5.2	Susceptibility Assessment of Pipeline Segments.....	5-8
5.2.1	Risk Based Prioritization	5-8
5.2.2	Prioritization Using Indexing of Susceptibility Factors	5-9
5.2.3	Review of Background Data	5-9
5.3	SCC Site Selection.....	5-10
5.3.1	Operator Experienced with SCC.....	5-10
5.3.2	Operator Not Experienced with SCC	5-10
5.3.3	Investigative Methods	5-11
5.4	SCC Site Prioritization.....	5-13
5.5	Investigative Program Scheduling.....	5-14
5.6	Re-inspection Intervals.....	5-14
5.6.1	Gather Information on Changes to SCC Susceptibility Factors.....	5-14
5.6.2	Document and incorporate the results into a formal susceptibility assessment tool and/or probabilistic risk model	5-15
	References.....	5-16

5. SCC Investigation Programs

Industry experience to date has shown that SCC investigation program development can be highly dependent on the specific characteristics of particular pipeline systems, segments and geographical areas. This section discusses the framework of a process that may be considered in investigating and prioritizing pipeline segments with respect to SCC susceptibility. Once pipeline segments are prioritized for SCC susceptibility, investigations should be conducted to collect data, confirm the presence of SCC (Figure 5.1), mitigate risks associated with SCC (via repairs) and validate the assumptions used in the segmentation/site selection identification and prioritization.

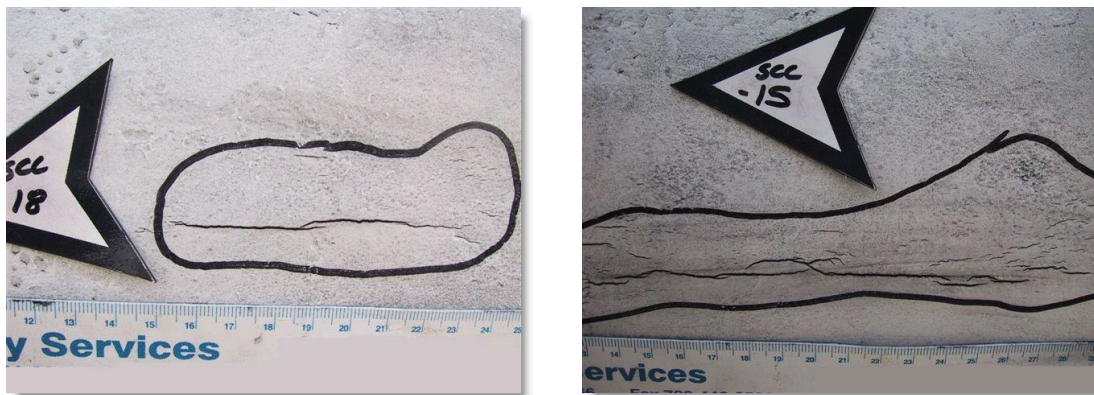


Figure 5.1: Examples of transgranular SCC

The processes described in this section are best used as a starting point for the pipeline operator. If the operator has previous experience with SCC, that experience should be used to improve upon this framework. If the operator is embarking on an SCC program for the first time it should be kept in mind that the results obtained from SCC investigations will have to be used to refine and customize their future programs and processes.

5.1 Pipeline Segmentation

A pipe segment is defined as a length of pipe bounded by changes in pipeline attributes, which, in the operator's experience, justify a major change in the SCC risk between adjacent segments. A pipeline segment can vary in length from less than a pipe joint to tens of kilometers. The SCC risk within pipeline segments is an assessment of the SCC susceptible pipe conditions present. Additionally, other factors (not strictly related to SCC susceptibility) may be used to create manageable subsets of the primary segments. The SCC risk could also be different for lengths of pipe of the same SCC susceptibility because of differences in the consequences of an SCC failure.

5.1.1 SCC Susceptible Pipe Conditions

Based on our current level of understanding, the primary factor that determines susceptibility to SCC initiation is the type of external coating on the pipeline [1,2]. Coating type should always be considered in a susceptibility assessment. A SCC susceptible coating simultaneously allows ingress of an electrolyte to the steel surface, traps the electrolyte against the steel surface, and shields the electrolyte and steel interface from the cathodic protection system.

Secondary factors that may influence SCC susceptibility of the pipeline segment are steel properties, pipeline operating conditions, environmental conditions and maintenance history. These factors have less certainty in determining SCC susceptibility when compared to coating type alone. To use these factors in pipeline segmentation, an operator should gain experience and supporting data for each factor used for segmentation that is specific to the pipeline system under investigation. These factors may ultimately be more useful in prioritizing segments for investigation rather than determining whether a segment is, or is not, susceptible to SCC.

5.1.1.1 Coating Type and Coating Condition

To date, SCC has been found beneath field applied polyethylene tape (Figure 5.2), and to lesser degrees field-applied asphalt enamel, coal tar and some girth weld shrink sleeves. No SCC has been documented in association with fusion-bonded epoxy (FBE), field applied epoxy or epoxy urethanes, or extruded polyethylene. 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.

Data gathered by CEPA and its member companies identifies 37 failures (17 leaks and 20 ruptures) attributed to SCC between 1977 and 2007 on Canadian transmission pipelines. Of these, most of the failures were associated with polyethylene tape, while fewer were associated with asphalt enamel and coal tar coatings.



Figure 5.2: Disbonded polyethylene tape

These failure data indicate that polyethylene tape has the greatest susceptibility to SCC that may cause a failure when compared to all other coatings. Among these, many were associated with the longitudinal weld.

5.1.1.2 Pipeline Attributes

- Age and season of construction: Older pipelines potentially have a greater period of exposure of their steel surfaces to the surrounding electrolyte although this exposure time is also dependent on the time necessary for coating failure. Therefore, with all other factors being equal, older pipelines have a greater probability of containing larger SCC features. SCC of varying extent and severity has been detected in pipelines constructed between 1953 and 1982. Additionally, coatings field applied during winter construction are historically associated with a higher probability of adhesion problems.
- Manufacturer: May impact susceptibility in terms of manufacturing process used for plate production and pipe forming, as well as the steel chemistry and weld procedures. However, at this time, only one pipe identified by the NEB [3], from Youngstown Sheet and Tube, which was manufactured during the 1950s, has shown elevated susceptibility to SCC.
- Diameter: May impact susceptibility in terms of increased pipe to soil interaction as pipe size increases. 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.
- Longseam 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 direct correlation with SCC susceptibility has been determined.
- Pipeline alignment: Can be related to SCC susceptibility in several ways. 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 older over-the-line methods). Also, vertical bends in the alignment may indicate changes in the terrain, and associated changes in SCC susceptibility.
- Stress concentrators: The presence of features that lead to an increase in stress, such as dents, gouges, the long-seam weld, residual stress, and areas of corrosion, are associated with an increased occurrence of SCC [3].

5.1.1.2 Operating Conditions

- Stress level: No relationship between the operating stress and SCC initiation has been validated however SCC in pipelines operating at a lower stress will require more time for SCC to grow to failure.
- Pressure cycling: Current 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) should be considered.
- 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. In turn, the current demand on the cathodic protection system also increases. Such conditions typically occur in close proximity to the downstream side of compressor stations (gas pipeline systems). However, this does not mean that SCC will not occur where temperatures are lower than stated. Such pipe segments (or sites) may still warrant investigation.
- Distance Downstream of a Compressor and Pump Station: Transgranular SCC seems to be more severe at distances closer to the discharge side of a compressor and pump station. This observation is likely linked to the greater incidence of coating disbondment possibly caused by higher discharge gas temperatures. A second effect may be due to increased stress fluctuations and higher stress levels. However these possible causes for the observed increased severity of SCC in proximity to the station are not thoroughly substantiated.

5.1.1.3 Environmental Conditions

- Terrain: Topography and soil types have shown correlation to 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 was and was not found, the pipeline operator can determine which terrain conditions correlate best with SCC susceptibility.
- Soil Type and Soil Drainage Types: Industry has identified that locations with wet and dry seasonal fluctuations in poorly drained environments tend to correlate to SCC features (i.e. clays). The amount of swelling-type clay can affect the amount of soil stress available to disbond tape. Therefore, polyethylene tape coated pipelines in clay type soils should be assigned a high priority for the investigation of the presence of SCC (Table 5.1 [3])

Table 5.1: 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 to level, level undulating, ridged, depressional	Very poor, poor, imperfect to poor
Moraine tills (variable soil texture – sand, gravel, silt, and clay with a stone content >1%)	Inclined	Poor, imperfect to poor

The occurrence of SCC shows good correlation with well-drained sandy areas and glacial fluvial till environments. This may be explained by the wet/dry condition created by asphalt coatings and sandy areas. Typically over time, asphalt coatings tend to crack and delaminate while remaining somewhat adhered to the surface of the pipe. Waters and salts from the surrounding soils are then able to leach through the cracks in the coating and contact the pipe surface, causing an SCC susceptible environment (Table 5.2 [4]).

Table 5.2: 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	Good
Glaciofluvial (sandy and/or gravel textured soils)	Inclined level Undulating ridged	Good
Moraine till (sandy/ clay soil texture with a stone content >1%)	Inclined level Undulating ridged	Good
Sites that do not meet the –850mV “off” criteria in a close pipe to soil survey (exclusive of the three sets of terrain conditions discussed above)	Any	Any

- Drainage patterns - recent industry experience has shown that static drainage conditions (i.e. the soil is always wet or always dry) correlate less with SCC than drainage that is seasonal (intermittent wet-dry conditions).

5.1.1.4 Pipeline Maintenance Data

- In-line inspection (ILI) data: Can assist in determining the location of SCC, or the location of external corrosion and 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: Industry experience has identified that most forms of SCC are found where coatings partially 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.
- Historical excavation records: These records can be used to determine the likelihood of SCC occurrence, if the pipeline was inspected for SCC 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).

5.1.2 Creating Pipeline Segments from Factors

Once susceptibility factors have been selected for a pipeline system (section 5.1.1) the operator should look for the occurrence of those factors to create “pipeline segments”.

Dynamic segmentation based on susceptibility factors is used for establishing pipeline segments for SCC investigation. However, other practical considerations related to pipeline system operating parameters described below may be used to facilitate the type of SCC mitigation procedures considered for a segment.

Practical considerations may influence how a pipeline operator segments a pipeline system and may include such considerations as:

- Length: The operator can choose to divide a pipeline system into segments of equal or reasonable lengths;
- Valve sections. Existing valve sections can provide convenient segmentation of a pipeline system;
- ILI sections. For pipelines that are fitted with in-line inspection launch and receive traps, existing trap-to-trap sections may be deemed appropriate for segmentation purposes;
- Geography. For large pipeline systems it may be worthwhile to segment on the basis of different geographic or operating areas;
- Elevation: 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.

The process of pipeline segmentation will not determine whether a segment has SCC but will aid the operator in organizing subsequent investigation(s).

5.2 Susceptibility Assessment of Pipeline Segments

The susceptibility assessment assists the pipeline operator in reducing the scope of investigation within their pipeline system. As required in section 4.3.1, the pipe segment must be classified as either susceptible or non-susceptible. Those segments identified as being susceptible to the occurrence of SCC can then be prioritized for timely investigation for the actual presence of SCC. A combination of known parameters related to SCC susceptibility, based on industry experience (section 5.1.1), can be used to develop such a process for determining prioritization.

5.2.1 Risk Based Prioritization

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 (i.e. qualitative) or complex (i.e. fully quantitative). The method chosen is highly dependent on the operator and pipeline system under consideration.

5.2.2 Prioritization Using Indexing of Susceptibility Factors

This approach is similar to the process followed in the development of qualitative risk assessments. Factors affecting pipe susceptibility (section 5.1.1) would be identified and assigned a weighting. Sub-factors for each of the identified conditions would be developed and assigned relative scores. An example is provided in Table 5.3.

Table 5.3: Example for pipeline segmentation prioritization

Coating Type	Relative Score
Polyethylene Tape	10
Coal Tar	5
FBE	1

Pipe Coating (Overall weight = X%)

In this example, a series of factors would be assessed and appropriately weighted. The weightings would be structured to represent the sensitivity of the pipeline system to SCC occurrence versus the particular factor. The relative scores for the pipeline segment, based on the summation of these factors, would provide the pipeline operator with a relative probability of SCC occurrence. This probability could then be further used in conjunction with a consequence analysis to prioritize the segments based on total SCC risk.

Industry experience has shown that the factors that influence the occurrence of SCC depend on the individual pipeline systems. At present there is no universal approach available.

Regardless of the method chosen for segment prioritization, the first step is to compile and review available data for each pipeline segment.

5.2.3 Review of Background Data

Alignment sheets, as-built records and geographic information systems (GIS) are useful sources for facility data that may influence SCC. These data include the following:

- Surveyed or known reference points with an associated “chainage” such as test lead posts, rivers or roadways;
- Pipe grade, wall thickness, diameter;
- Design factor;
- Manufacturer, manufacturing method;

- Type of seam weld or lack of one;
- Year and season of construction;
- Length of individual valve sections;
- Maximum allowable operating pressure and;
- Coating type.

Industry experience has demonstrated that terrain conditions can influence SCC initiation and growth as described in section 5.1.1.3. Terrain conditions can be coarsely determined with commercially available soil and topography maps. For a more detailed assessment of terrain conditions, GIS-related data sets can be used, such as ortho-rectified aerial photographs, digital elevation models or soil databases.

5.3 SCC Site Selection

After completing the prioritization of the pipe segments, selection of discrete sites for excavation and SCC inspection is required to investigate for the presence or severity of SCC. The sophistication and level of detail applied in the selection and prioritization process will largely depend on that operator's specific experience with SCC. An operator with a large amount of data related to known SCC occurrences may take a different approach than would an operator with limited or no data on known SCC.

5.3.1 Operator Experienced with SCC

For an operator experienced with SCC, the site selection process will be influenced by the historical SCC data available and greater experience in using complex methods of SCC investigation, such as in-line crack inspection tools, hydrotesting or well-developed SCC models. Experienced operators will select SCC sites based on:

- In-line crack inspection using both low-resolution and high-resolution tools.
- 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.

Using the above methods, experienced operators typically have a quantified and statistically supportable probability of determining both the presence and severity of SCC on a pipe segment with relatively few excavations.

5.3.2 Operator Not Experienced with SCC

SCC prioritization and site selection is more challenging for an operator with limited or no experience related to SCC on their system. Such operators may initially need to rely solely on a few well-quantified factors, such as coating type.

Areas with higher consequences resulting from an SCC-related failure should also be considered in the prioritization process.

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.

5.3.3 Investigative Methods

A number of methods can be used to identify sites, within an identified pipeline segment, where investigative digs should be conducted. Listed below are typical processes to develop an SCC site investigative program.

5.3.3.1 Use of In-line Crack Inspection Data

Current crack detection ILI technology (Chapter 6) provides the pipeline operator with an increasingly accurate, efficient method to locate SCC. These technologies have been used in numerous investigation programs and allow the operator to manage SCC risk in a manner very similar to that used for metal loss. Additional analysis of the ILI data may be required, taking into account fracture mechanics and crack growth rates, to prioritize sites for investigation and possibly repair.

5.3.3.2 Integration of Multiple Data Sets (SCC Modeling)

When the use of crack detection ILI is not feasible, it may be possible for the operator to develop a model for SCC occurrence within the subject pipeline segments. As discussed earlier, industry experience has shown that many factors can contribute to the formation and severity of SCC along a pipeline. Because of this, the integration of various types of data can be useful in selecting specific sites for SCC investigation.

Before data sets can be integrated and examined together, 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.

Once the data sets have been properly aligned into a common spatial reference system, analysis is required to determine correlations to SCC. The level of detail of the analysis will depend on the amount of SCC-related data the operator has acquired. Differing approaches will be required if the operator has limited or no data on historical SCC occurrences, versus an operator with a large SCC database.

If limited (or no) historical SCC data are available to the operator, site selection may be accomplished by looking for areas where common SCC related factors occur concurrently. Because these factors are based on industry wide

observations, the prediction accuracy to a particular pipeline will likely be reduced, compared to a model created from pipeline specific SCC related data. If other historical data sources are unavailable, the pipeline operator can use the SCC related factors discussed in section 5.1.1 as a basis for a site selection model. This list of factors is not intended to be exclusive, as factors unique to particular pipelines or areas may exist. It is also critical for the operator to re-evaluate the site selection process after investigations are conducted and to refine the model as often as possible.

5.3.3.3 Hydrostatic Testing

Hydrostatic testing has been employed to identify if SCC is present (section 4.3.2), the severity of SCC (section 4.3.4), and as a mitigation method (section 4.3.6). Specific sites are identified through hydrotest failures, which allow site-specific causal factors to be developed. Armed with this information models for SCC occurrence can be developed for the pipeline segment which can lead to the identification of additional sites to be investigated.

5.3.3.4 Opportunistic Excavation

Operators routinely expose pipelines for purposes other than SCC investigation. All operators should view these occurrences as an opportunity to investigate for the presence of SCC. Data gathered during opportunistic excavations allow pipeline operators to enhance their SCC models by gathering data at locations with varying degrees of SCC susceptibility. It can also provide an opportunity to validate lack of susceptibility at locations where SCC is not suspected, such as under FBE coatings.

5.3.3.5 Tough Questions

- How long should an investigative excavation be? It is critical to understand that that investigative digs are a means of data collection and not a pipe segment mitigation method when based solely on SCC models, or at opportunistic excavations. Industry experience suggests that when there is a large lengths of susceptible pipe, investigative excavations alone do not significantly reduce the risk of an SCC failure. As such, the operator must determine if the length of inspected pipe provides a reasonable representation of the data required for a particular location.
- How many excavations are necessary? The operator 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 those who have little experience with SCC. The operator should always ask “Has enough data been gathered to assess the actual or potential occurrence of SCC in this pipe segment?”

5.4 SCC Site Prioritization

Prioritization of SCC sites for investigative purposes may be required if the resources are not available to excavate all locations within the excavation season. If all sites can be investigated within the same season, it may be useful to prioritize these sites based simply on logistics and efficiency.

If in-line crack inspection data is available as an investigative method (rather than a mitigation method), priority should be given to those features exhibiting the most injurious attributes. This is typically indicated by depth, but also to a lesser extent, by length and location on the pipe. Consequence should also be considered.



Figure 5.3: SCC site investigative dig

Depending on the number and complexity of the logistics involved, other considerations for site prioritization and scheduling for investigation may also include:

- Risk factors;
- Site condition considerations;
- Permit requirements; and/or
- Jurisdictional requirements.

Qualitative prioritization methods similar to those described in section 5.2.2 can be readily developed to aid the operator in site prioritization. Alternately, quantitative methods may need to be developed.

5.5 Investigative Program Scheduling

The time frame associated with implementing an investigative program to address all potentially susceptible pipeline segments within a company's system is dependent on several factors, but the most important factors to consider are as follows:

- The number of potentially susceptible segments within a company's system;
- The relative susceptibility of those various segments; and
- The consequences of an incident occurring within those various segments.

It is not the intent of these Practices to establish a set time frame for each company to complete their investigative portion of the SMP. The company should develop a prudent time frame by considering the three aforementioned factors and their own particular operating situation. As well, the company should document the rationale as to the time lines chosen for implementing an investigative program in the various potentially susceptible segments of their system.

If the presence of SCC was detected on the pipeline, the operator will need to continue and assess the severity of the SCC found (see Chapter 4 and Chapter 8). If no SCC was detected the operator will document these results and proceed to the "Identify reassessment interval" (section 4.3.3).

5.6 Re-inspection Intervals

Based on the results of the investigations (i.e. ILI data, excavation results, survey analysis or hydrotesting), the operator should complete the SCC susceptibility analysis again using new weightings or factors based on the results from the first round of investigation. For example, if an operator originally prioritized 1980s vintage pipe as low priority and several SCC colonies were confirmed to only exist in the 1980s vintage pipe, then any other 1980s vintage pipe would need to be re-evaluated at a higher priority for investigation and condition monitoring.

5.6.1 Gather Information on Changes to SCC Susceptibility Factors.

Condition monitoring, as suggested in the SMP in section 4.3.9, is conducted by performing and analyzing data from the following activities:

- Inspecting for SCC at opportunistic excavations as described in section 4.3.2.1.
- Monitoring for increased evidence of coating disbondment, such as that inferred by MFL inspection.
- Supporting and/or conducting SCC research and development projects that may allow for a change in risk factors within SCC risk models.

- Monitoring CP system effectiveness, which can provide insight to whether the pipeline has been adequately protected.
- Performing CIS/DCVG surveys to provide insight as to the current coating condition, where applicable. Trending of multiple surveys may be correlated to coating degradation in some cases.
- Assessing indications from geometry tools such as dents, wrinkles and buckles that can indicate coating damage. Mechanical damage tends to correlate with material property changes and stress risers where SCC may be associated.
- Changing 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 increased mechanical damage probabilities. It may also modify soil/water compositions that may transform an environment that was less susceptible to SCC to highly susceptible to SCC, or vice versa.
- Monitoring geotechnical activities, i.e. ground movement, which may disbond coatings and cause additional transverse stresses, making a segment of pipe more susceptible to SCC or C-SCC (Chapter 12).
- Monitoring environmental conditions, i.e. Changes in water tables or drainage, which relate to crack initiation and growth.
- Participating in industry groups that share industry SCC experience and discuss acceptable practices is an invaluable tool to advance an operator's SCC knowledge and assessments.

Pipeline operators must use the information gained through these activities to continually re-assess the susceptibility of their pipeline systems to the occurrence of SCC.

5.6.2 Document and incorporate the results into a formal susceptibility assessment tool and/or probabilistic risk model

A formal process is required to document and assess the information gathered through condition monitoring. A qualified person with extensive knowledge of SCC should perform the assessment. The information gathered will become the basis for the next pipe segment susceptibility assessment required in the SCC Management Program.

References

- [1] Canadian Energy Pipeline Association, “CEPA Stress Corrosion Cracking Database: First Trending Report”, January 16, 1998.
- [2] Canadian Energy Pipeline Association, “CEPA Stress Corrosion Cracking Database: Second Trending Report”, August 17, 2000.
- [3] National Energy Board Report of the Inquiry, *Stress Corrosion Cracking on Canadian Oil and Gas Pipelines*, MH-2-95, November 1996, pp. 30 – 31.
- [4] ANSI/NACE Standard RP0204-2004, *Stress Corrosion Cracking (SCC) Direct Assessment Methodology*, p. 22, [2004].

6.	In-Line Inspection	6-2
6.1	In-Line Inspection Tools	6-2
6.1.1	Considerations	6-3
6.1.2	ILI Technologies	6-7
6.1.3	Running an ILI Program	6-15
6.1.4	Data Analysis	6-15
6.1.5	Identification of SCC	6-16
6.1.6	Calibration/Verification of ILI Reports	6-17
	References	6-18

6. In-Line Inspection

6.1 In-Line Inspection Tools

Pipeline operators have the option of using in-line inspection (ILI) technology to inspect operating pipelines for the presence of cracks. However, crack tool technology is not available for all pipeline sizes and generally has not been proven to the extent of Magnetic Flux Leakage (MFL) and ultrasonic metal-loss tools, especially in gas pipelines.

As of the time of printing, inspection companies are continually making strides in overcoming signal/noise, discrimination and reliability issues through R&D, field testing and in-service inspections. A handful of ILI companies have crack tools in development or commercially available in Canada. Sizes range from NPS 10 to 56, with new sizes being developed to meet specific pipeline requirements. Current tools can operate in various product environments, operating pressures and can negotiate various bends, obstacles and even diameter changes.

Since this technology is evolving very rapidly, users of these Recommended Practices are encouraged to consult with other pipeline operators, as well as ILI companies, to review their specific needs prior to deciding to use ILI. Specific performance data for each ILI company may be available from laboratory or pull-through tests, or from actual inspection runs.

There are currently two main crack detection technologies, ultrasonics and Electromagnetic Acoustic Transducer (EMAT), commercially available for SCC in-line inspection.

CEPA also knows of one other ILI technology currently under development using Self Excited Eddy Current (SEEC™) technology. In addition, MFL tools whose magnets are circumferentially oriented have the ability to detect some seam weld and pipe body cracks in some circumstances, but generally cannot detect 'tight' cracks such as SCC.

Existing metal loss tools, both MFL and ultrasonic, can not directly detect SCC cracks, but the corrosion data reported offers insight into regions of the pipeline that may have damaged coating, cathodic protection (CP) shielding and local environments that correlate with areas of SCC.



Figure 6.1: In-line inspection tool being loaded into a 'pig launching barrel'

6.1.1 Considerations

6.1.1.1 Choosing In-line Inspection for SCC Crack Detection

A pipeline operator has various 'tools' for verifying the integrity of a pipeline with respect to SCC. Hydrotesting is an absolute method for finding and eliminating all critical and near-critical SCC defects in an entire pipeline section as discussed in Chapter 9. Likewise, excavations with 100% in-the-ditch NDE inspection can find and eliminate all external SCC features exposed. Unfortunately, both options have major financial and technical drawbacks for many pipeline systems.

Hydrotesting requires an entire segment of pipeline to be taken out of service, which causes significant direct costs to the pipeline company and significant disruption of service for its shipper customers – not to mention land, logistical and water disposal issues. In addition, hydrotesting yields no direct information on remaining SCC features that may be growing, resulting in a company choosing a conservative growth-to-failure timeline to determine re-testing intervals. Although in-the-ditch NDT yields accurate data for all inspected pipe surfaces, there is always a remaining uncertainty about the condition of the pipeline joints that were not directly excavated and inspected. An excavation (or Direct Assessment) program can also become prohibitively expensive if a large number of excavations are required.

Alternatively, an ILI crack inspection program is performed while the pipeline is in service, at full or reduced flows. An ILI tool has the added advantage of gathering location and sizing data on all detected features, including non-critical defects. This extra information on the entire inspected segment allows the company engineers to make educated calculations and decisions on repair locations, time-

to-failure, remaining strength, risk levels and ultimately helps determine when and where integrity dollars can be best spent to reduce the SCC risk.

Currently there are limitations to crack ILI technologies. However, the crack ILI technology is developing well when compared to the historic life cycle development of MFL tools. For gas pipelines, the tool technologies are not as 'mature' as MFL and ultrasonic metal-loss tools, therefore tool reliability and crack detection or discrimination capabilities are generally not as good as for metal loss. For liquid lines, ultrasonic crack tools are further along in their development evolution, and are more widely accepted as a reliable alternative to hydrotesting.

In-line inspection companies have dedicated time and money to technology development, laboratory tests and pull testing. In addition, CEPA companies have committed direct and indirect funding to the development and field testing of different ILI technologies. It is important for both groups to collaborate on crack tool evolution along with researchers and other industry stakeholders. Pipeline companies have a part to play in providing a market for proven tools, as well as supplying inspection run opportunities and feedback data for tools in various stages of development. ILI companies have the expertise and opportunity to apply technologies and bring tools to market that match the needs of the pipeline operator. ILI companies must also be forthcoming with tool capabilities, reliability, and limitations and continually address technology shortfalls.

For different companies the choice to use ILI crack tools in addition to, or instead of, hydrotesting or other methods, will be based on specific company factors. The relative SCC hazard, presence of other hazards, size of line, flow conditions, product shipped, length of segment, pipe attributes, coating, presence of 'looped' lines, customer contracts, site access, launcher facilities, risk tolerances and other factors help determine which, if any, ILI crack technology is appropriate to run. Ultimately, a pipeline company's management, in discussion with their pipeline integrity engineers, must decide if and what ILI technology to run within the constraints of the company's SCC IMP and conform to all regulatory requirements and applicable laws.

6.1.1.2 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 required cleanliness of the pipeline.

The line must be configured so the tool can travel from launch trap to receive trap in a single nominal pipeline diameter with full bore opening valves and large (tool specific – typically 3D) radius bends. The required condition of the line must be confirmed with the ILI company to ensure that the specific tool can successfully inspect the line without damage to the tool or pipeline system. In some circumstances the ILI company and pipeline company can work together to allow

the tool to negotiate specific challenging physical conditions, including bore reductions and tight bends.

6.1.1.3 Operating Condition of the Pipeline

Generally ultrasonic tools must operate in a liquid line with the product flow or must have a liquid couplant 'slug' to operate in a gas system. However, other technologies such as EMAT, eddy current or liquid wheeled ultrasonics are also available for running in gas lines. To date, the best results in CEPA operating pipelines (with respect to crack detection, discrimination and sizing) have been demonstrated with the liquid operating tools.



Figure 6.2: Pig launching barrel equipped with manifold to run 'liquid slug' in a natural gas pipeline

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 tools produce optimum results providing they are traveling between 1.0 and 2.0 m/s (3.6 – 7.2 km/h). These constraints vary with different technologies and specific ILI companies.

Enhancements are underway to facilitate running the tools at increased flow rates using variable bypass ports, or by attaching the tools to 'tractor pigs' with variable speed bypass. Consistent and reliable results are best achieved by maintaining a relatively constant flow rate once the tool has been launched in the pipeline. Speed control has a double advantage of minimizing impact to pipeline flows by allowing the tool to run at a significantly slower speed than the pipeline product. As well, a more consistent tool speed is maintained regardless of pipeline terrain and changes in product flow speed and pressure changes. Because of size limitations, smaller tools usually are not available with speed control, as space cannot be spared for a bypass bore down the center of the tool.



Figure 6.3: MFL ILI tool with bypass – product flow is allowed to ‘bypass’ through internal bore and tool travel speed is controlled by valves

6.1.1.4 Tool Capabilities

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 and the threshold for defect sizing. Pipeline companies can assist by supplying the ILI contractor 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.

6.1.2 ILI Technologies

6.1.2.1 Shear Wave (Liquid-coupled) Ultrasonics

Also known as ‘traditional’ Ultrasonic Crack Detection, these tools generate a shear wave (typically directed at 45 degrees) that travels through the liquid pipeline product into the pipe wall and ‘reflects’ off cracks and linear surfaces regardless of their width. This ILI crack technology has the most inspection kilometers to date, is the most reliable technology, has the highest detection capabilities and the lowest false call (false positive) rate. This tool is analogous to the MFL definition of ‘high-resolution’ and has demonstrated delectability limits significantly below critical crack size.

ILI companies will typically quote crack detection limits as low as 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. Unfortunately the technology requires a liquid couplant with the pipe wall and cannot be run in a gas line without water, diesel or some other liquid ‘slug’ being introduced into the natural gas line. Running a liquid couplant slug is at least as troublesome and expensive as performing a hydrotest in a gas pipeline, and (like a hydrotest) requires the inspected segment of line to be taken completely out of service for a number of days.



Figure 6.4: Shear wave ultrasonic tool being retrieved from temporary receiver barrel

Since the pipeline product fluid is used to couple the ultrasonic waves, 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, however caution must be taken that the tool is properly calibrated for the specific commodity in which it is run. Also, other factors like H_2S , extreme pH and 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 company before inspection.

6.1.2.2 Liquid Wheel Ultrasonics (LWUT)

In the 1980s one ILI company introduced a tool that could be run in both liquid and gas lines by injecting ultrasound waves and detecting the wave reflections via transducers in a liquid-filled couplant wheel. This technology also has many historical runs including an extensive SCC inspection program by CEPA companies in the late 1990s. The tool has successfully detected SCC, long seam defects and other linear defects. To date, only large diameter (> NPS 24) tools have been built.

Compared to traditional Ultrasonic Crack detection, LWUT is a lower resolution tool. The tool cannot reliably resolve sub-critical defects and has discrimination issues when trying to characterize SCC and injurious cracks versus other benign reflectors. These problems are due to complex data-interpretation challenges and technology constraints and signal-noise issues. Some CEPA companies have found the best detection results are achieved by comparing multiple inspection runs. By overlaying and comparing the ILI data with a previous LWUT run, only the features that have changed over time are considered active cracks.

Features that have not changed significantly over time are considered to be either benign reflectors or dormant cracks that are not an integrity concern. Although this data-interpretation approach can be used for most ILI technologies, it has shown promise of being especially effective at overcoming discrimination issues in the liquid wheel UT tool where the problem of discrimination of growing SCC versus benign features is more of a problem.



Figure 6.5: Liquid wheeled ultrasonic tool

6.1.2.3 Electromagnetic Acoustic Transducer (EMAT)

A number of ILI companies have EMAT crack detection tools commercially available or in development. EMAT tools use electromagnetic forces to induce ultrasonic waves into the pipe steel. The technology promises to combine the high resolution detection limits of the traditional UT tools with the ability of LWUT to run in both liquid and gas lines. This technology became commercially available in 2003 for some pipe sizes.

At the time of printing only a few CEPA companies have had experience running EMAT and minimal historical performance data is available to industry. The ILI companies offering this technology promise reliability, detection limits and discrimination results significantly better than LWUT, and almost as good as traditional UT crack tools. Each new generation of a tool offers improvements over the previous version. Each company should independently verify the detection and discrimination ability for their own system.

Inspection runs and pull-tests have shown evidence in detecting sub-critical defects in both liquid and gas lines. However, that there still exists defect discrimination issues similar to LWUT, until a significant amount of in-service commercial runs can be completed and the ILI companies can analyze and improve their data interpretation algorithms. This evolution is expected for a new and complicated technology. EMAT technology can be further advanced with commercial inspection runs and excavation feedback from pipeline companies to the ILI company.



Figure 6.6: EMAT crack detection tool

6.1.2.4 Magnetic Flux Leakage (Traditional 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. Some ILI companies have made improvements to the number and orientation of sensors, resulting in an improvement in the ability to size dents and detect and classify dents with combined damage such as circumferential cracking and gouging. Experience among CEPA companies shows 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. 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 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 can be considered an enhancement to an overall SCC data gathering and management effort and should never be the sole/primary tool to assess the SCC condition of a pipeline system.

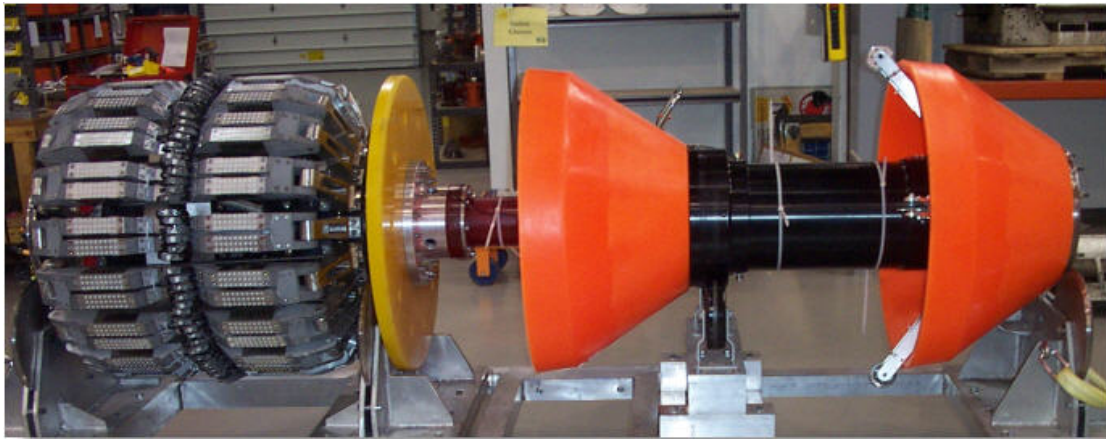


Figure 6.7: MFL ILI tool

6.1.2.5 Transverse Field Magnetic Flux Leakage (TFMFL)

A number of ILI companies offer a modified MFL tool, where the magnets and sensors have been rotated 90 degrees to induce a magnetic field along the circumference of the pipe. 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 has not been shown to reliably detect tight cracks such as SCC and should not be relied on as a primary SCC detection method.

6.1.2.6 Ultrasonic Wall Measurement (USWM)

These tools are used to measure the remaining wall thickness in pipe by direct measurement of the reflection of a 90 degree ultrasound wave through the pipe steel and off the outside surface of the pipe. This tool is very accurate at 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 at that location.

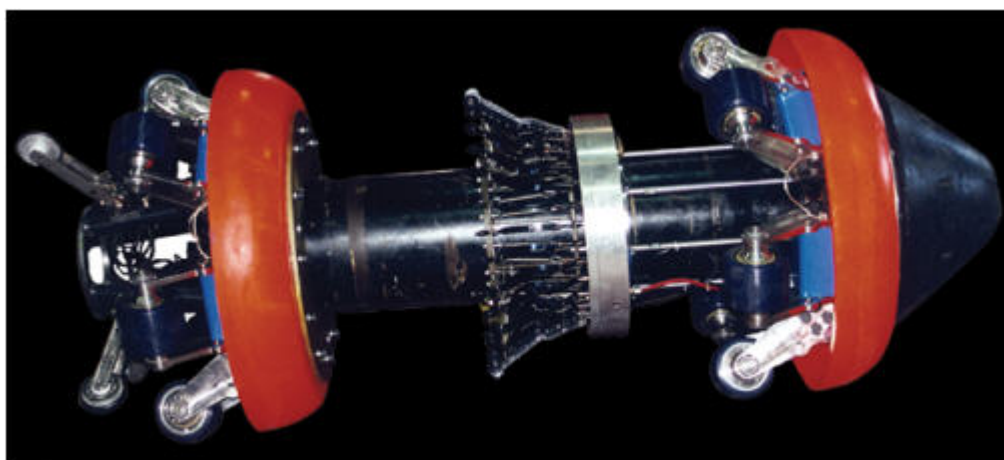
Industry has seen challenges with this technology for pipelines with internal corrosion issues due to the debris and line cleanliness. However, this technology is unable to detect linear features such as SCC, and is unable to run in a gas pipeline. As with MFL, detected areas of corrosion may correlate with the presence of SCC.

6.1.2.7 Eddy Current

At the time of printing, one company has recently developed a self-excited eddy current technology tool. This company is presently in the process of field validation efforts from in-service inspections of a CEPA member's pipeline system. 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, therefore, lessening the operational and economic impacts of an SCC inspection run. It is anticipated that this technology will be commercially available in the later part of 2007.

6.1.2.8 Geometry and Caliper ILI 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. Some more advanced tools are equipped with gyroscopes and high technology logic to determine very subtle movements and strains in a 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).



Note 'caliper' arms in the center of the tool and odometer wheels at the rear. This tool is equipped with gyroscopes to determine precise location and pipe movements with respect to GPS reference points.

Figure 6.8: Geometry ILI tool

These tools have no ability to directly detect SCC or any other defect on the OD [outside] surface of a pipeline. Like MFL ILI, geometry tool findings are still valuable for the assessment of SCC. Dents caused by external interference or rocks in the ditch often correlate with damaged coating, shielded CP current, surface gouging, and cold working/embrittlement of the pipe steel. Damaged

coating and shielded CP can result in environments that are conducive to SCC initiation and growth. Also, dents and buckles may 'flex' or fatigue at greater amplitudes and frequencies than the nominal pipeline, driving existing cracks to quicker failure than would otherwise be expected. Finally, moving slopes and axial pipe strains are often a contributing factor to circumferential SCC (further described in Chapter 12).

A special caution to the pipeline operator is to ensure that the NDT examination of the pipe surface for SCC is always performed when analyzing all geometric features in the ditch. The NDT technician must be aware that the SCC colonies will not necessarily be aligned axially along the pipe surface as the residual stresses and other stress regimes at geometric defects will often grow SCC cracks in unexpected directions.

Table 6.1 summarizes existing and developing crack tool technologies.

Table 6.1: Summary of In-line Inspection Technologies for Crack [SCC] Detection

Technology	Pros	Cons	Run in operating		Available since...	Notes
			Gas?	Liquid?		
Shear Wave (Liquid-coupled) Ultrasonics Pulse of ultrasound emitted circumferentially into the pipe wall via angled shear waves.	- Most proven detection. - Description and sizing capabilities.	Requires liquid slug to run in gas line.	NO	YES	1990s	Most proven crack tool. Hi-resolution able to size cracks <30mm long & 1mm deep.
EMAT Ultrasonic compression waves are generated in the pipe wall using electromagnetic forces eliminating the requirement for liquid coupled transducers.	- Run in either liquid or gas lines with higher-resolution than LWUT. - Reliability, detectability and discrimination issues will improve as technology matures.	- New technology. - Mechanical and reliability issues. - Discrimination and detectability performance not as good as traditional shear wave tools at the time of printing.	YES	YES	2003	New technology for gas and liquid. Medium to high resolution potential.
TFMFL Uses standard MFL technology rotated 90 degrees— wall is magnetized in circumferential direction.	- 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.	YES	YES	1990s	Proven to detect sharp axial defects with some width. Not recommended as primary SCC detection method.
LWUT Ultrasonic waves injected into wall in both clock and counter clockwise direction at a 65 degree angle via a fluid filled transducer wheel.	- Most operational kilometres in gas pipelines. - Gas-bypass speed control is available. Tool reliability is good.	- Lower resolution than traditional shear wave ILL. - Signal/ noise and discrimination issues.	YES	YES	1980s	Signal / noise and discrimination issues can be minimized by comparing multiple run data sets. Low resolution crack detection.
SEEC™ (Self Excited Eddy Current)	- Does not require a liquid medium. - Can effectively manage higher pipeline product speeds.	New technology is currently being proven.	YES	YES	late 2007	Currently undergoing field validation tests in CEPA member pipeline. It is anticipated that this will result in a commercially available tool.
New technologies Research organizations and ILL companies currently studying the practicality of various electromagnetic technologies for crack inspection in liquid and gas pipelines.	Evolving technologies and improvements to electronics, memory and interpretation algorithms will result in new tools and improvements to existing technologies.	Crack tool development is expensive and complex.	YES	YES	Future	ILL tool development requires cooperation between researchers, industry groups, ILL companies and pipeline operators to bring new technologies to market.

6.1.3 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. Pipeline companies should coordinate the specific line conditions with the requirements of the tool by thorough communications with the ILI tool contractor. A company can refer to NACE Standard RP0102 “Standard Recommended Practice - In-line Inspection of Pipelines” [4] for guidance on issues that need to be considered when planning and performing an in-line inspection. CSA Z662, Annex D [3] offers guidelines for in-line inspection for corrosion, but clauses D.3 to D.6 can be referenced with slight modifications for a crack tool inspection program. Pipeline and ILI companies should also ensure that the requirements of API 1163 “In-line Inspection System Qualification Standard” [2] are met.

To get the best results from an In-line crack inspection program, an agreement with the ILI company should include disclosure of data from a series of pull-tests that include artificial or natural crack-like defects in the pull-test pipe. In this way, the ILI company 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 (i.e. memory, batteries, filters, gains, etc.) to maximize performance during the inspection run.

The ILI company can initially size and report on only the most serious defects. After analyzing this data and performing a number of calibration excavations a company can then determine if it is warranted to request a more detailed report. Details of this arrangement must be negotiated with the ILI company.

6.1.4 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. Because of the level of expertise required to accurately interpret and prioritize the data, this 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 contractor may then provide staged reports according to the priorities of the operating company.

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 contractor will give data on the location of the indication, along with any other specific notations observed in the interpretation process, for each site.

Some anomalies (e.g. long, non-injurious inclusions) can appear similar to cracks when observed ultrasonically by ILI tools. Older steels contained 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 companies are continually developing new algorithms, neural networks and analysis methods to increase sizing accuracy and crack discrimination while decreasing the interpretation and reporting time. Along with increased skill of data analysis personnel, significant strides are expected in crack tool reporting capabilities in the foreseeable future.

The pipeline company should ensure that the appropriate personnel from the ILI company are qualified and are adequately trained to meet the requirements of the most recent version of ANSI/ASNT ILI-PQ-2003, “In-line Inspection Personnel Qualification and Certification” [1]. A company should consider the advantages of 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 are some advantages to overlaying multiple crack tool data sets in the same pipeline over a period of a few years. Firstly, the comparison of these data sets may allow for crack growth rate calculations to determine probabilities of failures over time and ultimately to better choose future inspection and mitigation schedules. 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.

6.1.5 Identification of SCC

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.

To facilitate the advancements in ILI crack tool performance in SCC defect discrimination and interpretation, it is paramount that pipeline companies 'feedback' actual detected defect data to the ILI company from excavations. Pipeline companies are a critical link in the feedback improvement process. Qualitative and quantitative information on the accuracy of the ILI defect report helps the ILI company learn and improve. Positive and negative feedback is equally valuable. Actual defect characterization, size and location accuracies help the ILI company modify automated algorithms as well as assist with future manual interpretation.

6.1.6 Calibration/Verification of ILI Reports

Once the ILI contractor's report has been submitted, the 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.

When deciding on the scope of an excavation program, the integrity engineer must realize that (to date) crack tools do not have the demonstrated reliability and accuracy of traditional metal-loss tools; therefore more conservatism should be built into the decisions on which, and how many, defects should be excavated. A pipeline engineer should also anticipate some frequency of 'false-calls' or benign defects. This reality is expected to persist for some ILI technologies until more inspections, tool enhancements, field validations, and software algorithm improvements are made over the coming years. For further guidance on calibration and verification refer to API 1163 [2].

References

- [1] ANSI/ASNT ILI-PQ-2003, *In-line Inspection Personnel Qualification and Certification*, 2003.
- [2] API 1163, *API In-line Inspection Systems Qualification Standard*, First Edition, Aug 2005.
- [3] CAN/CSA-Z662-07, *Oil and Gas Pipeline Systems*, 2007.
- [4] NACE Standard RP0102-2002, *Standard Recommended Practice - In-line Inspection of Pipelines*, 2002.

7.	CEPA Recommended Data Collection.....	7-2
7.1	Learning from All SCC Opportunities	7-2
7.2	Data Collection.....	7-2
7.2.1	Inspection Excavations	7-2
7.2.2	Standardized Field Data Collection.....	7-2
7.2.3	Spatial Referencing.....	7-3
7.3	Excavation Data Collection and Tables	7-3
7.3.1	Weld and Pipe Characteristics Table.....	7-4
7.3.2	Terrain Data	7-5
7.3.3	Buoyancy Table	7-6
7.3.4	Pipe-to-Soil Potentials Table.....	7-7
7.3.5	Coating Characterization	7-7
7.3.6	Sampling and Analysis.....	7-8
7.3.7	SCC Table.....	7-8
7.3.8	Toe Cracks Table.....	7-10
7.3.9	Pipe Surface Damage.....	7-11
7.3.10	Data Dictionary.....	7-12
	References.....	7-24

7. CEPA Recommended Data Collection

This chapter deals with the collection of data identified by CEPA to be of potential value for the management of SCC. These data include parameters that can be used to conduct initial assessments of initiation susceptibility and 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 being discussed have demonstrated a relation to some aspect of SCC. In other cases, the link is plausible given the results of operation or research and 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 parameters are valuable.

7.1 Learning from All SCC Opportunities

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

7.2 Data Collection

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

7.2.1 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.

7.2.2 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. This section, therefore, deals with these issues of spatial-referencing and a data dictionary.

7.2.3 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.

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 positions 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.

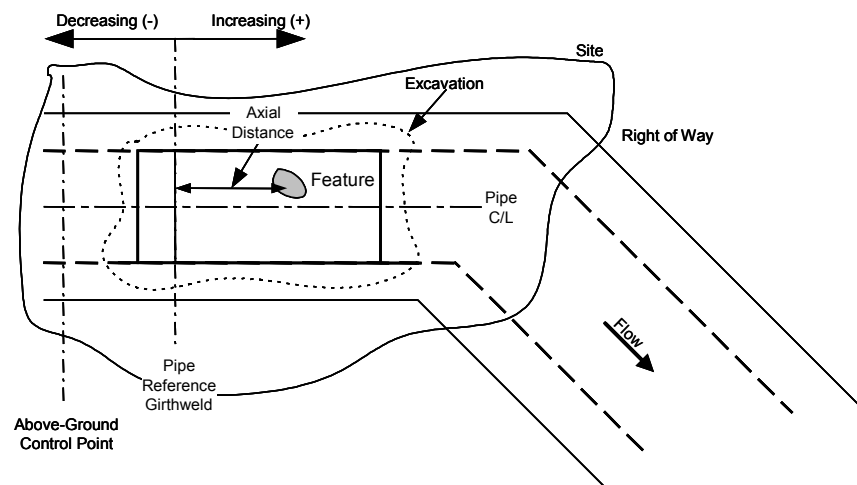


Figure 7.1: Axial and Circumferential Referencing

7.3 Excavation Data Collection and Tables

The appendix to this section provides a data dictionary that includes the CEPA recommended data parameters. Specific inspection sites would be selected and prioritized based on susceptibility parameters and the pipeline attributes contained within the pipeline system inventory.

The dig data table shown in the appendix may be used to collect data relating to the excavation site and consists mainly of information collected ahead of the excavations 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 includes planning and administrative information including the excavation date, the name or line number, the location relative to the upstream pump or compressor, the location and type of above ground reference point, etc. It is advised that these data be compiled during the planning or site surveying phase ahead of the actual excavation (Table 7.2).

A company might augment this with administrative information relating to the contractor or the company representative involved.

7.3.1 Weld and Pipe Characteristics Table

In each SCC excavation, observed features above and below ground are recorded relative to axial and circumferential references (Table 7.3). Each girth weld in the excavation is assigned a Weld_ID, generally in reference to a particular ILI run.

As the pipe is exposed the first task is to establish the axial reference system as detailed in Figure 7.1 using the welds and direction of flow. In addition to recording girth weld data, also confirms the dimensions of the pipe diameter, wall thickness, joint length, long seam weld type and circumferential position and manufacturer. The extent of pipe to be cleaned and inspected is also recorded here.

To aid in referencing observations, it is advised that a scale be applied to the pipe. This is frequently achieved by marking off meters, using spray paint, moving upstream and downstream of the reference girth weld.

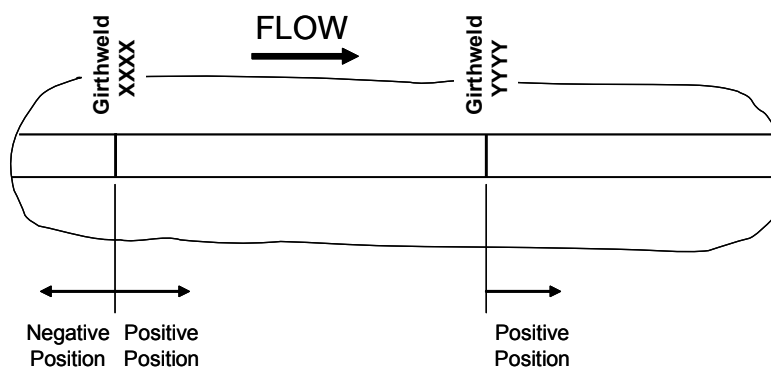


Figure 7.2: Data Axial Position References Girth Welds

As illustrated in Figure 7.2, all feature positions are documented relative to the upstream girth weld. For features located upstream of the first girth weld, the

position is recorded as negative from the first girth weld, either upstream (negative) or downstream of the reference point.

7.3.2 Terrain Data

As discussed in the first edition of these practices, some companies have made correlations between SCC and certain terrain features. Such parameters have included the local topography, soil texture or particle size and drainage. Terms relating to deposition modes have also been used.

Various standards and systems of soil classification exist [1,2]. 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:

- Coating performance: the presence of clay, particularly swelling clays on tape coating;
- The presence of air at pipe depth: aerobic environment, evidence of soil gleying;
- The presence of water to contribute to corrosion processes: groundwater presence or soil mottling;
- Soil resistivity & CP: particle size and drainage characteristics of the soil.

Given the specialized and varied needs of pipeline companies, rather than adhering to any one classification system, operators have tended to borrow and mix terms from various conventions. These Recommended Practices do not advocate any single 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 to record SCC soil characterization, Terrain Linear Features and Soil 2-D Features.

7.3.2.1 Terrain – Linear Features Table

This table 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 (Table 7.4). 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 will enhance understanding.

7.3.2.2 Soil 2-D Features Table

This table records the characteristics of the major soil blocks coinciding with the pipe at depth along the excavation (Table 7.5). 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 oxygen presence, gleying, water movement, and mottling. Multiple entries may be required if conditions at pipe depth vary significantly along the excavation or pipe.

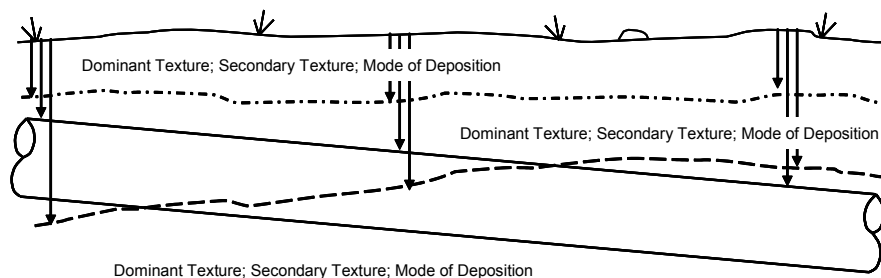


Figure 7.3: Documentation of Below Ground Soil Features

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.

7.3.3 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 weight placement during construction or weight movement during operation. 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 on either side of the concrete buoyancy control weights and could either favour or impede the development of SCC.

The table has an entry for weight “*Composition*”. 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. While such sulphur-containing weights are not in common usage and HIC is not the issue of these Recommended Practices, the conditions found beneath the weights were strongly anaerobic, a condition also associated with near-neutral pH SCC. This table aims to identify locations of such sulphur-containing weights (Table 7.6).

7.3.4 Pipe-to-Soil Potentials Table

The on-potential of the pipe should be recorded during the excavation. A pipe-to-soil measurement should be recorded at the soil surface and, as the pipe is exposed, measurements should also be made closely adjacent to the pipe at the top, side and bottom of the pipe. The measurements should be taken with respect to the reference girthweld (Table 7.7).

7.3.5 Coating Characterization

Two different tables address coating characterization, one corresponding to general observations and the other to coating damage.

7.3.5.1 General Coating Condition Table

This table records 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 (Table 7.8). It has been observed or suggested that some mill-applied coatings provide a higher degree of protection than field-applied coatings. The apparent application, in this context, will be recorded.

The condition of the coating is documented using the semi-quantitative criteria given in Table 7.1. These measures provide a quantitative component that can be used in analysis of findings.

Table 7.1: Terms used to characterize pipe coatings

Coating Condition	Extent of Tenting (applicable to tape 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 soil stresses with no associated deposits; good adhesion
Fair	Intermittent	10 to 50% disbondment; intermittent soil stress; 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 disbondment with associated deposits; coating damage; very brittle coating (asphalt)
Very Poor	Continuous	> 80% coating failure; no adhesion, numerous holidays; interlinked soil stress disbondment with associated corrosion deposits; coating damage; very brittle coating (asphalt)

(Source – J.E. Marr & Associates, 1996)

7.3.5.2 Discrete Coating Damage Table

This table enables the mapping of coating damage, including tape “tenting”, on the pipe relative to the excavated pipe reference system (Table 7.9). Table 7.9 should be used to document all disbondments on the excavated pipe. As above, photographs or drawings would enhance documentation.

7.3.6 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 are suggested to be correlated to either the presence or absence of SCC and can provide information related to the chemical environment beneath disbonded coatings (Table 7.14).

Corrosion deposits are documented according to physical attributes such as color, texture and distribution. A color test kit (e.g. MIC Kit™) can be used to qualitatively identify their composition.

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 is compatible with even superficial moisture on the pipe.

Transgranular 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 8.4.

In the case of transgranular SCC, the under-coating water can contain dissolved carbon dioxide that, over time, can evolve with an attendant rise in pH. pH measurements should, therefore, 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 ferric ions that result.

7.3.7 SCC Table

Following removal of the coating and the completion of MPI the appropriate binary response to ‘SCC_Detected?’ is given (‘1’ signifying presence, or ‘0’ for no SCC presence).

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-oriented where the operational hoop stress is the dominant stress. Where external bending loads act on the pipe or where local stress

raisers (i.e. dents) are present, the dominant stress direction can shift to the circumferential-orientation or some intermediate angle. Figure 7.4 shows an example of circumferentially-oriented SCC, the result of local pipe bending.



Figure 7.4: Circumferentially-oriented cracks that resulted in a natural gas leak in NPS 8 pipe

The term ‘SCC colony’ has no explicit definition and relates to the grouping of the SCC and, by inference, the approximate size, shape and orientation of the coating disbondment. Comparing the summed number of colonies per joint has been used to describe the relative SCC susceptibility of pipe.

Crack interlinking provides an indication of crack development or extension. Cracks having a stair-case pattern with axial spacing less than 1 mm, or overlapping cracks showing indications of coalescence, are termed interlinking and are considered to be effectively the same crack. Figure 7.5 shows an example.



Figure 7.5: Interlinking SCC

In terms of the residual strength of the pipe, individual and interlinking cracks may interact in the same way metal-loss features do to affect the strength of the pipe.

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 interlinking cracks, the density of cracking, the position and orientation of cracks on the pipe, and measurements pertaining to any grinding conducted on cracks (Table 7.10).

The presence or absence of toe cracks is indicated, though the details are to be recorded separately.

Companies are encouraged to measure and record the depth of a percentage of cracks found both to assess the severity of the findings as well as 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 crack morphology, i.e., whether cracks are intergranular or transgranular.

7.3.8 Toe Cracks Table

Cracks located at the toe of the longseam weld may or may not be SCC. As a result of their position, colinear orientation and mechanistic uncertainty toe crack data is 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 table records crack length, depth, and tip-to-tip spacing (see Table 7.11). 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 methodologies have given results with good levels of accuracy.

7.3.9 Pipe Surface Damage

Where either metal-loss corrosion or pipe surface damage is present in the excavation, their relative circumferential and axial positions and geometries should be documented. Pipe surface damage can consist of a number of types including dents and/or gouges, arc strikes, wrinkles or metallurgical hard spots. This information is recorded in the Coincident Corrosion (Table 7.12) and Coincident Mechanical Damage (Table 7.13) tables.

7.3.10 Data Dictionary

Table 7.2: 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

<i>Physiographic Regions</i>	<i>Land Use Types</i>
Canadian Shield	Abandoned
Coastal	Agriculture
Cordilleran	Aquatic
Interior Plains	Commercial
St. Lawrence Lowlands	Cultivated
Mississippi Valley	Desert
	Grassland
	Gravelled
	Grazing
	Paved
	Prairie
	Residential
	Rock
	Woodland
<i>Vegetative Legend</i>	
Boreal	
Coastal	
Deciduous	
Desert	
Grasslands	
Montane Alpine	

Table 7.3: 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

<i>Manufacturer</i>	<i>Seam_Weld_Type</i>
Alberta Phoenix	DSAW
AO Smith	Flash
BHP	ERW
Berg	Lap
Bergrohr	
Bethlehem	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 7.4: Terrain – Linear Features Table**Terrain - Linear Features**

<i>FIELD NAME</i>	<i>UNITS</i>	<i>DESCRIPTION</i>
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

<i>Max. Slope Percent</i>	<i>Slope Position</i>	<i>Topography</i>
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 7.5: 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 7.6: 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 7.7: 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 7.8: 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 7.9: Discrete Coating Damage Table**DISCRETE COATING DAMAGE**

<i>FIELD NAME</i>	<i>UNITS</i>	<i>DESCRIPTION</i>
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

<i>Type of Coating Damage</i>
Disbondment
Holiday

<i>Wet Underneath</i>
Yes
No
Unknown

Table 7.10: 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°-30°
30°-60°
60°-90°

Table 7.11: 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		Crack Morphology Method
Grinding		In-Situ Metallography
NDT		Not Determined
Visual		
		Evidence of Cracks Interlinking
		Yes
		No
		Unknown
Crack Morphology		
Intergranular		
Transgranular		
Unknown		

Table 7.12: Coincident Corrosion Table**COINCIDENT CORROSION**

<i>FIELD NAME</i>	<i>UNITS</i>	<i>DESCRIPTION</i>
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

<i>Corrosion Type</i>
Channeling
General
Pitting
Superficial

<i>Angle</i>
0°-30°
30°-60°
60°-90°

<i>Associated Cracks</i>
Yes
No
Unknown

Table 7.13: 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

<i>Type of Mechanical Damage</i>
Buckle
Crack
Wrinkle
Dent
Gouge
Hard Spot
Arcburn

Table 7.14: 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	Distribution
Coating	Continuous
Deposit	Dense
Groundwater	Intermittent
Soil	
Water from undercoating	
Method of Assessment	Test Taken/Adhere to Coating & Pipe
Visual	Yes
Field Test Kit	No
Colour	Corrosion Deposit Description
Black	Continuous
Blue	Dense
Brown	Intermittent
Clear	
Green	
Grey	
Light Green	
Orange	
Red	
White	
Yellow	
Composition	Texture
CaCO ₃	Crystal
Electrolyte	Film
Fe-Oxide/Hydroxide	Hard
FeCO ₃	Liquid
FeS	Metallic
LGF	Pasty
NaHCO ₃	Powdery
Organic	Scaly
Unknown	Waxy

References

- [1] Soil Classification Working Group, *The Canadian System of Soil Classification*, 3rd ed., National Research Council Research Press, 1998.
- [2] ASTM Standard D 2488-00, *Standard Practice for Description and Identification of Soils (Visual-Manual Procedure)*, 2007.

8.	SCC Condition Assessment	8-2
8.1	Data Sources for an SCC Condition Assessment.....	8-2
8.1.1	SCC Excavation Data	8-3
8.1.2	SCC Pressure Testing Data.....	8-18
8.1.3	SCC Inline Inspection Data.....	8-18
8.1.4	SCC In-Service Failure Data.....	8-19
8.1.5	Uncertainty in Data.....	8-19
8.2	SCC Condition Assessment Methodologies	8-21
8.2.1	Condition Assessment of SCC Severity.....	8-21
8.2.2	Condition Assessment for the Mitigation of Category II-IV SCC	8-25
Appendix 8: Analytical Methods in the Calculation of Failure Pressure of SCC.....		8-30
A1.	“Log-Secant” Approach	8-30
A2.	Pipe Axial Flaw Failure Criterion (PAFFC).....	8-31
A3.	CorLAS™	8-31
A4.	Fitness for Service of SCC-like Flaws based on API 579 or BS 7910 requirements.	8-32
References.....		8-34

8. SCC Condition Assessment

An SCC condition assessment is a type of engineering assessment (EA). CSA Z662-07 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 plan presented in Chapter 4, an SCC condition assessment is required to:

1. Assess the severity of individual SCC features.
2. Assess the need for immediate and future pipe segment mitigation due to the presence of SCC.

Assessment 1. listed above has a well-defined scope and requires relatively non-subjective physical data such as SCC depth, SCC length, material properties and stress levels. However, the assessment (II) listed above has a much broader scope and incorporates both the results of the first assessment as well as more subjective variables such as quantification of SCC growth rates. Both assessments require high quality input data as well as an understanding of the uncertainty associated with this data.

This chapter will provide detail as to the data required for an SCC condition assessment, the method and sources of collecting this data, the uncertainty associated with this data and the methodology of the condition assessments required within the SCC management plan.

8.1 Data Sources for an SCC Condition Assessment

Data can be extracted from several sources when performing an SCC condition assessment. The typical sources include:

- Field investigations at pipeline excavation locations
- SCC pressure testing
- Inline inspections for SCC
- 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 data sources allow for direct measurement, while other data sources require the equivalent data to be calculated. For some data sources, only a maximum or minimum limit is obtainable while others provide absolute values.

In most cases, data from at least two sources is desirable to both complement and verify against each other.

Example: SCC failure pressures calculated from SCC length and depths measured at an excavation can be verified with SCC pressure testing. In this example sources of uncertainty within the calculated value can be identified and subsequently reduced with the complimentary pressure test data source. This provides benefit in accuracy for future calculations.

8.1.1 SCC Excavation Data

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

This section describes the in-the-ditch measurement techniques as well as other necessary considerations related to conducting field investigations. These other considerations include surface preparation, SCC detection and the need to provide a safe working pressure for those conducting these inspections by means of a pressure reduction.

Although the focus of this section is on MPI, it is not the intention to preclude the use of other methods, rather it is suggested that their use requires validation and an understanding of limitations associated with other factors; these include surface preparation (i.e. profile, cleanliness), surface geometry (i.e. within metal loss or associated with a weld), and SCC depth. Some of the other technologies that are being developed include; penetrant techniques, ultrasonic techniques, eddy current technologies, and ACFM (alternating current field measurements).

8.1.1.1 Pressure Reductions 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 Z662-07 Clause 10.9.1.3 provides only minimal guidance in that “the piping is depressurized as necessary to an operating pressure that is considered safe for the proposed work.” [1]. The magnitude of an appropriate pressure reduction for SCC excavations must consider multiple factors that can change between various pipelines. As such the guidance provided below is not intended to be all encompassing.

The Pipeline Repair Manual recommends a pressure reduction "...to no more than 80% of what was first reported at the location..."[2]. The concept of a reduction to 80% (or a 20% reduction) is consistent with the 0.80 minimum design factor for new piping. A report by Coote & Keith confirmed that many CEPA companies use a 20% minimum pressure reduction for SCC inspection, assessment and repair excavations [3].

An appropriate pressure reduction should be calculated on a case by case basis with consideration of pipeline properties, working conditions or stresses which are atypical. Minimum guidance suggests that a pressure reduction for work performed at SCC excavations should be the lesser value of 1 to 4 below.

1. 80% of the highest operating pressure seen at that location on the pipeline in recent history (30 days to 1 year, depending on characteristics of pipeline operations).
2. 80% of the failure pressure of the most severe anomaly detected and sized by an inline inspection tool.
3. 80% of the calculated failure pressure of the most severe SCC feature detected at an excavation.
4. 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 under 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-ditch inspection can be undertaken at any pressure greater than atmospheric.

8.1.1.2 Magnetic Particle Inspection (MPI)

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

The three available MPI techniques are;

1. Dry powder (DP)
2. Wet fluorescent (WFMPI)
3. Black on white (BWMPI)

All three techniques are proven methods to detect external SCC, but dry powder is the least sensitive (due to particle size) and is not commonly used nor recommended as a primary SCC inspection method. Table 8.1 provides a

comparison of the sensitivity and the relative advantages and disadvantages of the three types of MPI methods.

Although the materials and equipment differ between the three methods, the basis for each of these techniques is approximately equivalent and can be described as:

- 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 8.1 (a), (b))
- The application of ferromagnetic particles to the surface. These particles will align within the magnetic flux leakage caused by the presence of a crack.
- Visualization of the contrasting particles and background surface.

ASTM E709-95 [4] is the common standard that 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 8.1: Bottom of pipe In-the ditch SCC assessment using BWMPI technique



Figure 8.2: Top of pipe in-the ditch SCC assessment using BWMPI technique

8.1.1.2.1 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 to complete an MPI inspection. The most commonly used yoke for SCC investigations is the AC type of yoke 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.

8.1.1.2.2 Inspection Personnel Qualification

The knowledge and skill of the technician is a critical factor in obtaining a reliable inspection for SCC. 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 8.1: Advantages and Disadvantages of Various MPI Methods

MPI Method	Ultimate Sensitivity	Advantages	Disadvantages
Dry Powder (DP)¹	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 DP 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 as 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 light-retarding tarp). • inspection sensitivity can be affected by low pipe surface temperature.
Wet 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, and make it 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 as 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.

¹ NOTE: Not recommended for SCC detection and inspection due to low sensitivity

8.1.1.2.3 Surface Preparation for Inspection

Proper surface preparation for MPI is necessary 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 in such a manner that the SCC is receptive to the magnetic particle and is conversely not “peened” shut, thereby becoming masked from the magnetic particles.

The three methods of surface preparation is with the use of water blasting, abrasive blasting or using a rotating wire brush. The most common and preferred by CEPA member companies is abrasive blasting.

CEPA sponsored independent testing of surface preparation techniques that were selected based on the experience of the CEPA Member Companies. Table 8.2 summarizes the advantages and disadvantages of these surface preparation techniques.

SCC detection sensitivity is dependant on the type of surface preparation used. CEPA sponsored research has shown 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 [5]. For BWMPI, a commercial blast surface should be achieved in accordance with SSPC-SP6 [6].

CEPA experience has also shown that detection limits are maximized when the resultant roughness profile of the steel is below 0.074 mm (2.9 mils). NACE RP0287 offers guidance for surface profile measurements [7].

In addition to the optimizing detection limits, the user may wish to consider such factors as convenience, cost, and cleaning rate as summarized in Table 8.3.

The detection limits provided in Table 8.3 are based on CEPA testing for specific brands and types of media examined and can provide guidance on the media that can allow for the required minimum size of the SCC features to be detected.

In addition to the type and grade of abrasive, other factors contribute to the resultant surface profile. Some of these contributing factors are operator knowledge and experience, the type and condition of the equipment used, and the ambient conditions during blasting.

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

Table 8.2: Summary of Surface Preparation Techniques Used Prior to Wet MPI

Technique	Description	Advantages	Disadvantages
Water Blasting	Uses potable water at high pressures (i.e. >25,000 psi).	- No surface roughness created, therefore eliminating concern for SCC masking. - Used with additives to remove greasy residues.	- Doesn't always remove tenacious corrosion products. - Only potable water can be used and these resources are not reliable. - Excavation site becomes muddy. - Freezing concerns in winter. - Safety concerns with high pressure discharge.
Abrasive Blasting (Walnut Shells)	Walnut shells are used as abrasive medium, employing same equipment common to sand and slag abrasive blasting.	Masking is unlikely as walnut shells are relatively soft.	- Doesn't always remove tenacious corrosion products. - Leaves oily residue which may affect subsequent pipe recoating effectiveness (residue can be removed with cleaning agents). - Possible allergic reactions. - Environmental management of abrasive blasting by-products requires consideration.
Abrasive Blasting (Silica Sands, Coal Slag, Metal Slag, and 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 differing 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 for worker health concerns from misuse. - Environmental management of abrasive blasting by-products requires consideration.
Power Wire Brush	Electric or pneumatic grinding tools fitted with 180 Grit Flapper Wheel ("3M Clean & Strip Disk" or equivalent).	Simple to use with little maintenance and refuse.	- Consistent cleaning quality across inspection surface can be difficult to achieve. - Not generally used for SCC inspection.

Table 8.3: Comparison of Surface Preparation Techniques vs. Detection Limits and Cost

Technique	Detection	SCC Sizes Detectable		Cost (1=least expensive)	Cleaning Rate
		Using WFMPI (mm)	Using BWMPI (mm)		
Water Blasting	Excellent, as long as all corrosion products etc. can be removed.	1	1-2	4	Satisfactory cleaning rate but cannot remove some corrosion deposits.
Walnut Shells	Excellent, as long as all corrosion products etc. can be removed.	1	1-2	3	Good cleaning rate but cannot remove some corrosion deposits.
Sand & {Slag}	Very good.	1-2	1-2	2	Overall, provides best cleaning rate of all techniques. Somewhat dependent on abrasive sharpness.
Wire Wheel, etc.	Satisfactory, minor (1- 2mm) SCC features can be masked.	No Data	2-3	1	Slow for large areas, but will remove tenacious substances.

8.1.1.2.4 Typical MPI Inspection Practice

Described below is a representative MPI procedure for examining a steel pipe surface for the presence of SCC.

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)²
- 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/cm² at a distance of 380 mm from the lens face to the inspection surface)²
- Fluorescent indicating medium (particle concentration between 0.1 to 0.5 wt % (within Standard Guidelines) of solid particles)²
- Visible black particle prepared bath^{**} (particle concentration 1.2-2.4 wt %)
- White contrast paint³

Note



The visible prepared bath and contrast paint must be kept from low temperatures that will adversely affect particle mobility and method sensitivity.

2. Procedure

All inspection surfaces must be prepared as described in section 8.1.1.2.3 Surface Preparation for Inspection on page 8-8.

The surface temperature of the inspection area must allow the MPI indicating medium to maintain an acceptable viscosity to ensure the sensitivity of the inspection. In the event the inspection surface temperature is below an acceptable range, the indicating medium becomes too viscous and the inspection method becomes unreliable. In such instances a surface “pre-heat” is required.

² WFMPI method only

³ BWMPI method only

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

3. MPI Documentation

BWMPI produces a more permanent visualization of SCC and is therefore facilitates easier documentation of SCC colonies than does WFMPI. Documentation using WFMPI requires considerably more effort. Once the SCC colonies have been identified, the colony characteristics should be measured and documented in a consistent format, as outlined in section 7.3.7 and Table 7.10. A photographic record of the detected SCC colonies should be considered.

8.1.1.3 SCC Sizing

Sizing SCC requires the measurement of the SCC length, depth and density. As well, intrinsic to sizing SCC, is a requirement to carefully measure the wall thickness of the pipe at the location of the SCC feature.

Pipe wall thickness, SCC length and SCC density measurements are always quantitatively determined. Conversely, SCC depth can be measured with both qualitative and quantitative methods. Qualitative methods provide an indirect estimate of SCC dimensions. Quantitative methods provide a direct measurement of SCC dimensions. At excavations where large colonies of SCC are found, typically a mix of both qualitative and quantitative methods are required to fully document large areas of SCC in an efficient manner.

8.1.1.3.1 Pipe Wall Thickness Measurement

To obtain an accurate wall thickness of the pipeline being investigated, a calibrated ultrasonic thickness gauge (i.e. D-Meter) typically with a 0.25" or 0.50" diameter compression wave (90°) probe should be used. Calibration utilizes 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.

8.1.1.3.2 SCC Length and Density Measurements

SCC length is measured as the total longitudinal length of the SCC feature before buffing occurs. The measurement is typically made using a calliper tool or ruler with precision down to 1 mm.

There are two aspects to measuring SCC density. The first aspect is to measure the endpoints of an SCC feature in relation to adjacent SCC features in both the

circumferential and axial direction. These measurements are required to assess SCC interaction (section 8.2.1.1.)

The second aspect of measuring SCC density is the assignment of SCC features to one of four possible groups as follows:

1. Toe of the weld SCC.
2. Isolated SCC
3. SCC in sparse colonies
4. SCC in dense colonies.

Toe of the weld SCC refers to SCC located within the heat affected zone of the longseam weld. Isolated SCC refers to individual features that do not fall into either the sparse or dense colony definitions. Sparse and dense colonies are defined as adjacent features with circumferential spacing as described in Table 8.4. [12]

Table 8.4: Definition of SCC Density

SCC Density	Approximate Circumferential Spacing
Dense	< 0.2 wall thickness
Sparse	> 0.2 wall thickness

The importance of defining SCC colonies as sparse or dense is related to differences in the incidence of SCC leaks and ruptures as follows [12]:

- 'Sparse' SCC colonies were found at and near the position of failure, and
- 'Dense' SCC colonies were found remote from the failure.

The rational supporting these failure correlations suggest that SCC spaced in close circumferential proximity shield each other from the hoop stress and tend toward dormancy with a final depth of less than 10% of the wall thickness. Conversely, sparsely spaced SCC features have a lesser amount of stress shielding and as a result have an increased potential for continuous growth both by penetration and coalescence. Failure data support that these non stress shielded SCC features are usually responsible for the failure. 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 when providing an input data source in the calculation of SCC severity.

8.1.1.3.3 Qualitative SCC Depth Sizing

Qualitative SCC depth determination is typically used to document large areas of shallow SCC (<10% of wt) where sizing by buffing removal may not be practical due to time constraints or the proximity of one SCC feature to another.

Qualitative SCC depth determination utilizes the intensity and length of the SCC indication, as determined by MPI, to estimate depth. The short, less intense indications observed in Figure 8.3 typically have a depth less than 10% of wall thickness, while the longer, darker indications have a depth greater than 10% of wall thickness. Observations of intensity should be combined with conservative aspect ratio rules. The minimum aspect ratio that will allow for an estimation of SCC less than 10% should be determined for the pipe segment by sequentially buffing short SCC features until confidence is obtained in the aspect ratio chosen. This value may differ between pipelines with large differences in wall thickness.

Example: Based on a depth and length assessment of short SCC for a pipe segment with a 10 mm wall thickness, an aspect ratio of 8:1 was found to be the minimum aspect ratio for SCC less than 10% of the wall thickness. Therefore, SCC with lengths less than 8 mm was estimated to be less than 10% of the wall thickness.

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

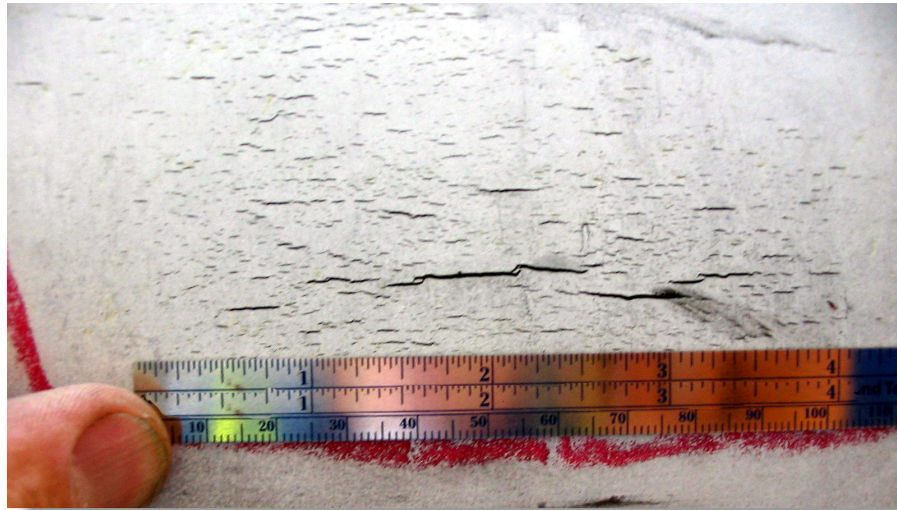


Figure 8.3: In-the ditch SCC assessment using BWMPI technique

In qualitatively determining 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 longest SCC indications should be buffed out to verify the specific depth estimation process.

- Where qualitative assessment estimates SCC depth as >10%, the operator should confirm this depth using a quantitative assessment.
- Qualitative depth determination should not be applied to those SCC features located at the toe of the longitudinal weld seam

Qualitative SCC depth determination is technician dependent and pipeline specific, as such, 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 (i.e. sequential buffing, ultrasonic measurement techniques, etc.)

8.1.1.3.4 Quantitative SCC Depth Measuring

Quantitative SCC depth determination 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. Although ultrasonic crack sizing is the most common and most mature SCC depth measuring technique, new techniques such as eddy current are being developed and may be commercially available in the future.

1. Ultrasonic Depth Determination

Ultrasonic crack sizing continues to be an evolving process. In addition to conventional shear wave method using standard or non-focused probes there are now a multitude of 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 will 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 estimation of the depth of shorter, isolated individual SCC features or in determining the deepest location of a long toe SCC before buffing removal. This estimation of depth is important in the calculation of a safe pressure for buffing activities.

Ultrasonic depth determination becomes increasingly more accurate when:

- 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 equally important that this information should be passed back to the technician conducting the ultrasonic testing.

2. Sequential buffing

The methodology of sequential buffing is detailed in Chapter 9 (section 9.4.2).

3. Other Methods of Depth Determination

There are continual developments in inspection technologies. For example, laser coupled ultrasonic inspection is currently under development and may provide some advantages over the existing liquid coupled ultrasonic technologies due to the reduced probe contact size.

8.1.1.3.5 Measuring SCC within metal loss

SCC that occurs within metal loss is evaluated based on the summation of the depth of the SCC and metal loss.

Example: A corrosion pit penetrates 25% into the pipe wall thickness. The SCC located at the base of the corrosion penetrates an additional 15% of the pipe wall thickness. The measured SCC depth is then determined to be 40% of the pipe wall thickness (see Figure 8.4)

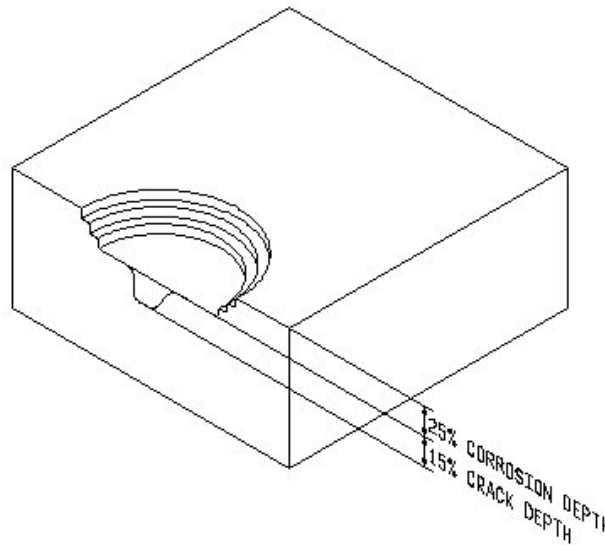


Figure 8.4: Schematic Illustrating an SCC feature in the Bottom of Metal Loss

8.1.2 SCC Pressure Testing Data

SCC pressure testing methodologies are described in section 9.3. SCC pressure testing data available for an SCC condition assessment can be summarized as follows:

- The minimum failure pressure for all SCC features within the pipe segment is determined as being greater than the maximum pressure obtained during the test. In this case, the failure pressure is not a calculated value from SCC dimensions, but is a measured value which is not influenced by the conservatism or non-conservatism associated with engineering calculations.
- Conversely, the SCC features that have not failed can be composed of a multiple combination of SCC lengths and depths as well as unknown variables in pipe wall thickness, toughness properties and interacting features and stresses.
- Single SCC features that fail the pressure test can be completely characterized with respect to the failure pressure, the pipe material properties, physical SCC dimensions and SCC interaction in the depth and length directions. The failure must be removed and examined in a laboratory to achieve this.
- SCC that is most likely to fail is typically composed of several coalesced features with little likelihood of further coalescence.
- The quantity, density and location of SCC features that do not fail within a pipe segment remain unknown.
- In the case where no SCC failure occurs, the determination as to whether any SCC features exist within a pipe segment remains unknown.

This data can be extracted from a successful SCC pressure test only. A successful SCC pressure test achieves a pressure of at least the maximum allowed operating pressure times the company defined safety factor without incurring a failure. However, the successful test may occur after a one or more failed tests.

8.1.3 SCC Inline Inspection Data

SCC Inline inspection methodologies and tools are described in Chapter 6. SCC Inline inspection data available for an SCC condition assessment can be summarized as follows:

- The quantity, density and location of the SCC features are known within the pipe segment.
- The maximum SCC feature length and depths are known within the range “bins” provided by the tool.

- Measured minimum failure pressures are known within the data accuracy, although the failure pressure may not have a well defined minimum value for SCC deeper than 40% of wall thickness. These deeper SCC features are often annotated as “> 40%” on the ILI report. However detection and discrimination capability of most ILI tools is greatest for deeper and longer SCC features.
- Calculated individual failure pressures are known to the accuracy provided by the tool measurements (within the defect groupings and ranges within each grouping).

8.1.4 SCC In-Service Failure Data

SCC failure inspection data available for an SCC condition assessment can be summarized as follows:

- Single SCC features that fail can be completely characterized as to the failure pressure, pipe material properties, physical SCC dimensions and interaction.
- A minimum failure pressure for SCC features can be calculated for the remaining pipe segment by assuming that the most severe feature has failed, however this pressure is typically at or below the operating pressure.
- The quantity, density and location of SCC features that do not fail within a pipe segment remain unknown.

8.1.5 Uncertainty in Data

Lifetime predictions involve subtracting the size of the largest possible remaining flaw from the size that would be critical at operating pressure and then dividing that difference by the crack growth rate. Probably the largest source of uncertainty is from the assumed growth rate. However, errors also can be introduced from the calculations of the crack sizes. To be conservative, it is important not to underestimate the size of the largest surviving flaw and not to overestimate the size of a critical flaw at operating pressure.

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

When predicting lifetime 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, any errors that are introduced will cancel out when the sizes are subtracted from each other,

but, when uncertainty regarding the input data exists, it would be prudent to use various reasonable values to ensure a conservative result.

Example: To illustrate this, consider a 25 cm long flaw in a 762 mm diameter, 7.93 mm wall thickness, Grade 359 pipe. Using the log-secant method, the effect of toughness on the depths of flaws that would survive a 110% SMYS hydrotest and that would fail at 72% SMYS were calculated and are shown in Figure 1, along with the differences between those two sizes. The predicted lifetime would be proportional to the difference in depth.

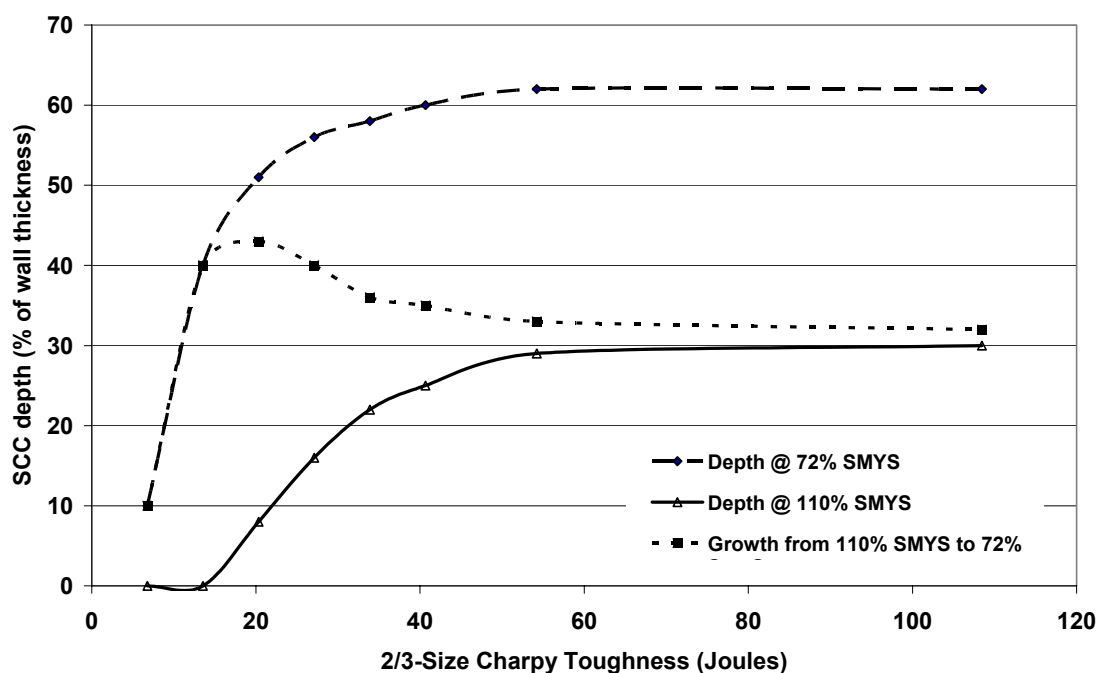


Figure 8.5: Effect of Toughness on Depth of a 25 cm-Long Flaw That Would Fail at 110% SMYS and 72% SMYS (Based on Log-Secant Method)

Example: If the actual toughness were 15 joules but was assumed to be 7.5 joules, the predicted lifetime would be overly conservative by a factor of approximately 4. If the actual toughness were 30 joules but assumed to be 15 joules, the predicted lifetime would be correct. If the actual toughness were 50 joules but assumed to be 25 joules, the predicted lifetime would be non-conservative by approximately 20 %. If the actual toughness were 100 joules but assumed to be 50 joules, 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 (e.g., low toughness) of input data would produce a conservative or non-conservative prediction of lifetime.

8.2 SCC Condition Assessment Methodologies

SCC condition assessments are performed within the framework of the SCC management plan to provide the following information:

1. Categorize the severity of the SCC (section 4.3.4) including;

- The determination of short term fitness for service of individual features and need for repair.
- To assess the need for a temporary pressure reduction (section 4.3.5)
- To provide SCC severity data representative for the pipe segment and required for (II) below (section 4.3.6)

2. To plan and implement mitigation for Category II to IV SCC. (section 4.3.6) including:

- The determination and application of SCC growth rates in the calculation of the appropriate interval between pressure tests and/or ILI inspections.

8.2.1 Condition Assessment of SCC Severity

The severity of individual SCC features is defined by the calculated failure pressure of that feature. The failure pressure is then compared to the appropriate criteria for a particular severity category, as provided in Table 4.1. The severity category is then used directly to fulfill the SCC condition assessment objectives listed in section 8.2 (part 1) above.

The minimum SCC failure pressure for a pipe segment can be directly determined from the failure pressure of an SCC feature failing during an SCC pressure test or in-service failure.

In addition, failure pressures can be calculated from measurements obtained at an excavation of the pipeline where SCC has been documented or from SCC ILI data where features have been identified.

The information required for the determination of SCC severity by the calculation of failure pressure is as follows:

- The maximum interacting SCC length as determined in section 8.2.1.1.
- The maximum depth of the feature as determined in section 8.1.1.4. For long, interacting SCC, a depth profile would be useful to eliminate some of the unnecessary conservatism associated with the failure pressures of these features.
- The actual (measured at the SCC location) or nominal pipe yield strength, ultimate strength, toughness (such as a Charpy value), wall thickness and

diameter. Nominal properties typically provide conservative failure pressures useful when comparing and extrapolating results in the determination of pipe segment severity. Conversely, actual pipe properties provide failure pressures, which may allow a more realistic comparison to measured failure pressures from SCC pressure testing or in-service failures.

- Identification of abnormal stresses that may interact with the SCC feature in addition to the normal hoop and longitudinal stress. The source of these stresses is detailed in section 8.2.1.2.
- A failure pressure equation as provided in section 8.2.1.3.
- A consideration of the sources of error in the data and calculations.

8.2.1.1 Assessing SCC Interaction

SCC interaction occurs when the crack tip stress fields of two adjacent SCC features overlap, despite a lack of visual connection. When it is determined that an interaction exists, the total length encompassed by the two SCC features is used in the calculation of failure pressure. Therefore, when completing a failure pressure calculation, the SCC length must be determined by calculating a cumulative interacting length between all adjacent SCC.

Interaction is assessed in both the circumferential and the axial directions. The interacting circumferential distance (Y) between two SCC features is evaluated using the following formula:

$$Y \leq \frac{0.14 (l_1 + l_2)}{2} \quad (1)$$

Where:

Y is the actual circumferential separation between two SCC features; and

l_1 , l_2 , are the SCC lengths

The axial separation distance between two SCC features is evaluated using the following formula:

$$X \leq \frac{0.25 (l_1 + l_2)}{2} \quad (2)$$

Where:

X is the actual axial separation between two SCC features; and

l_1 , l_2 , are the SCC lengths

Both the axial separation (X) and the circumferential separation (Y) must be less than the calculated limit in order to conclude that an interaction exists. If either value of X or Y is greater than the calculated limit, the SCC features can be treated as an individual feature 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 consecutive assessments.

8.2.1.2 SCC in Association with other Features

The accuracy of the failure pressure calculation is dependant on the accuracy of the calculation of stress, which is influencing the SCC feature. Aside from the calculation of hoop stress, the quantification of other stresses can be complex and often require the use of experts skilled in the application of finite element analysis. This method of stress analysis is outside the scope of this document. However identification of abnormal stresses is necessary. Observable indications of abnormal stresses are:

- SCC alignment which deviates from the axis of the pipe, often in conjunction with:
 - The presence of a sag or non-construction bend.
 - Intermittent or constant external loading on poorly supported pipe.
- SCC within dents, wrinkles or buckles.
- SCC within mechanical damage, such as gouges or tears.

When encountering SCC with the above associated stress sources, these SCC features should be assessed as a data set that may not be representative of the pipe segment severity (section 4.3.4) but can be indicative of the presence of SCC for a pipe segment (section 4.3.2). For SCC interacting with other integrity defects, the interacting defect should be considered the primary integrity threat and managed with the appropriate detection and mitigation methods for this defect. However, the discovery of SCC within these features may require an increase in the risk of the interacting feature.

8.2.1.3 SCC Failure Pressure Calculations

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 allow for a determination of the mode of failure for the SCC feature, that being a leak or a rupture. At pressures associated with both normal operation as well as higher pressures from SCC pressure 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 the 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 of the generation of pipe where SCC has been identified, resulting in a rupture as the normal mode of failure.

Literature has been published on quantifying the relationship between SCC and failure pressure in pipelines. Most of this has been based on the extensive work performed by the Battelle Memorial Institute in the 1970s [8-12]. 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 [18] & BS 7910 [19]

These methodologies are presented in Appendix 8.

These methodologies generally produce conservative results as demonstrated in the previous edition of the CEPA Recommended Practices. Both PAFFC and CorLAS™ have been used for SCC failure pressure assessments and have shown improved correlations to SCC burst test results when compared to the Log-Secant method. Improvements to these SCC failure pressure calculations occur at irregular intervals; therefore the latest revision should be obtained.

Additional techniques for analyzing the predicted failure pressure of SCC in pipelines are described in standards such as API 579 [18] and BS 7910 [19]. Many of these standards were developed to analyze a variety of equipment types including pressure vessels. The proper use of these techniques can result in reasonable failure pressure estimations.

Two limits should be considered for the application of these equations:

1. SCC length limit - The failure pressure calculations were based on and correlated against burst testing using more typical aspect ratios than the large aspect ratios found with long toe of the weld SCC. Therefore the calculations should be limited to SCC lengths less than approximately 400 mm.
2. SCC depth limit - Failure pressure calculations beyond 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 with these methods.

8.2.2 Condition Assessment for the Mitigation of Category II-IV SCC

Condition assessments for the mitigation of Category II to IV SCC require:

- A determination of SCC growth rates.
- Utilization of SCC growth rates to establish intervals for mitigation.

8.2.2.1 SCC Growth Rates

SCC growth is a complex process involving synergistic influences from environmental, operating, and material conditions. Both mechanistic models and empirical observations exist to attempt to predict this growth. SCC growth rates will likely introduce the greatest source of error in the calculation of a retest or re-inspection interval when compared to the error associated with data and failure pressure calculations.

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.

Example: *Recent research has shown that the tendency of an SCC feature to either become dormant or continue to grow may depend on the pressure fluctuation characteristics of the pipe segment [20]. This research indicates that the magnitude of the individual pressure cycle (R-ratio) and the time required to complete the pressure cycle (strain rate) play a role in determining SCC growth.*

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.

Empirically observed growth rates currently provide a more reliable method of predicting SCC growth rates. Empirical observations that can be used to provide SCC growth rates include the following:

1. Laboratory testing which simulates field conditions.

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/year) to 2.8×10^{-8} mm/s (0.88 mm/yr). Laboratory surface extension rates on pipelines have been measured to be of the same order of magnitude as the penetration rates.

2. “Beach mark” observations

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 seen as a bifurcation of the SCC tip in the axial direction (Figure 8.6).

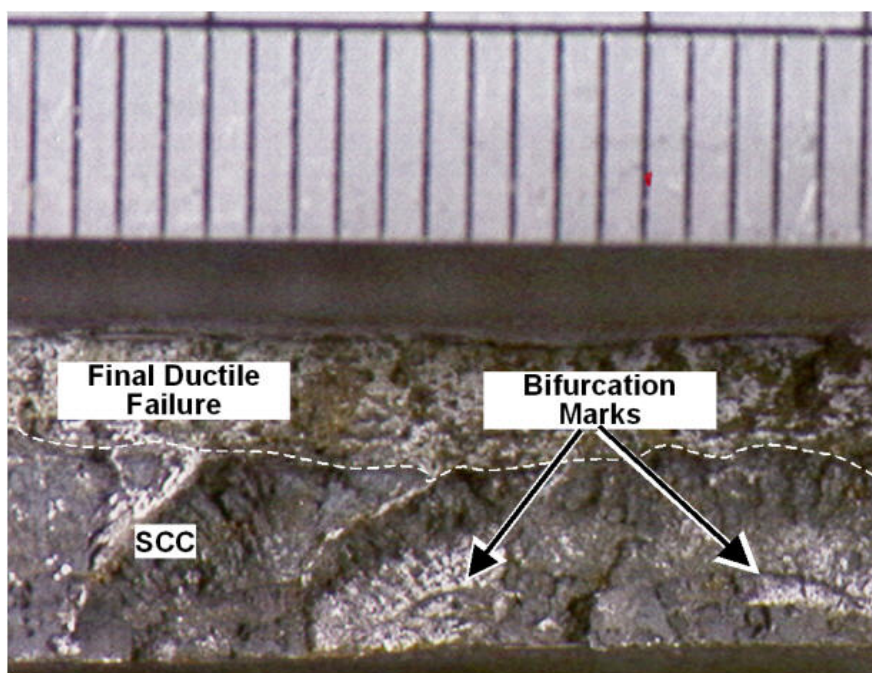


Figure 8.6: Bifurcation lines on the fracture surface of a failed SCC feature

To use beach marking in the calculation of SCC growth rates, the SCC feature must have experienced at least one hydrotest in the past to demarcate a start point of 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 a 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. However the first hydrotest and the removal of the feature must be separated by a minimum time period of at least three years; however five or more years would be preferable. This time separation should allow for enough growth to occur to allow for both a resolvable spatial resolution between the beach mark and crack tip as well as to reduce the time averaged effect of the SCC tip blunting that can occur during a hydrotest, as the blunting will temporarily slow growth.

3. Multiple SCC ILI inspections separated by several years.

Consecutive inline inspections for SCC can provide a large amount of data with respect to growth rates, however with generally lower accuracy than with

hydrotesting. One analysis may involve rigorously matching SCC features identified in repeat tool runs and determining the associated change in depth and length. In a second method, which may help to overcome some of the inaccuracies associated with sizing using an ILI tool, data can be presented as plots showing frequency of the length and depth distributions from the ILI data. By comparing depths or lengths of two inspection runs at the equivalent frequency, growth rate estimates can be calculated as a simple difference. As well, observations of where the growth occurs within the distribution can be made. Similar to hydrotesting, the consecutive ILI inspections must be separated by several years to achieve adequate resolution in growth. No growth rates have yet been published using this technique due to the relatively recent deployment of SCC ILI tools.

4. SCC size distributions generated from field inspection data.

The largest data set available to most operators is simply the lengths and depths of SCC detected and sized during pipeline excavations. Although the start point, or incubation period (Figure 2.1, Stage 1) is unknown, with sufficient data and growth periods extending into decades, the start point has a decreasing weighting in the calculation of growth. Nonetheless, some additional conservatism should be applied to account for the possibility of underestimating growth due to overestimating the growth period. Typical field inspection data suggest growth rates in the order of 10^{-9} mm/sec for non-failing SCC features.

5. Growth rates derived from failures

Reported SCC growth rate measurements determined from operating failures to date relate primarily to depth-wise growth. To date, time-averaged growth rates due to an environmental mechanism (Stage 3 of the Bathtub Model shown in Figure 2.1) observed on an NPS 36 pipeline was 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 $(1 \text{ to } 4) \times 10^{-9}$ mm/s (0.03 to 0.13 mm/yr).

Growth rates used for estimating the remaining life of SCC features 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 this growth 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 2.1, 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. In practice, SCC growth rates should not be used to estimate life expectancy up to the point of failure, but to some point before failure where rapid mechanical growth of the feature is not occurring.

8.2.2.2 Calculation of Pressure Retest or ILI Interval

Of the mitigation techniques presented in Table 4.2, both the SCC pressure test and SCC ILI inspection require an assessment of a re-inspection or retest period within the management plan.

Conceptually, the calculation below can apply equally to both mitigation techniques. In reality, there are a few significant differences that need to be considered as follows:

- SCC dimensions - An ILI inspection provides length and depth directly, and the failure pressure is calculated. An SCC pressure test provides a minimum failure pressure and the SCC dimensions are calculated.
- Resolution of SCC dimensions - The SCC pressure test will provide a lower resolution in failure pressure with resultant larger SCC dimensions that will form the start point for growth projections. This will result in comparatively shorter retest intervals. Conversely, SCC ILI has a relatively greater resolution in SCC sizing, possibly resulting in comparatively longer re-inspection intervals.
- Uncertainty - An SCC pressure test has almost no uncertainty in determining a minimum SCC failure pressure for a pipe segment. Conversely, probability of detection (POD) and probability of identification (POI) associated with an ILI tool need to be considered.

To be conservative when determining retest intervals, the estimated failure pressure should not be overestimated. With SCC pressure testing, the test pressure can be used as a conservative estimate of the failure pressure. When calculating the failure pressure from SCC size as determined from ILI or in-the-ditch measurements, the lowest reasonable value for toughness should be used, and care should be taken with SCC-interaction rules so as not to underestimate the SCC size. The rules in section 8.2.1.1 are suitable for this purpose.

Figure 8.7 illustrates failure dimensions for two pressures, an ILI calculated failure pressure or hydrostatic test pressure (P_{TEST}), and the pipeline operating pressure (P_{OP}). After a hydrotest, it can be safely assumed that all surviving SCC features have dimensions below the P_{TEST} curve. Similarly, following completion of the ILI and repair program, a critical failure pressure for the largest remaining flaws can be calculated (similar to the P_{TEST} curve).

Subsequent to the second hydrotest or ILI, surviving SCC features from below the P_{TEST} line may grow in length and depth (arrows) toward the failure curve at P_{OP} . The difference in SCC depth and length at the two pressures is the minimum margin of growth available, and life, until a given SCC feature fails in service. The greater the difference between the test and the operating pressures the longer the expected life of any surviving SCC feature. The time between these two periods is simply the difference in SCC dimensions divided by the growth rate determined for this SCC feature. The retest or re-inspection interval is this calculated time less a period that provides a safety factor at P_{OP} .

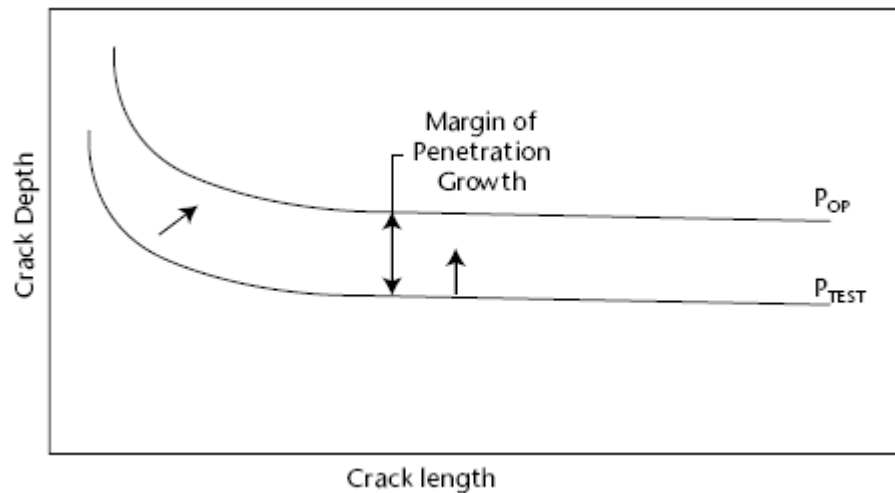


Figure 8.7: Hypothetical Critical SCC Dimensions at Hydrotest and Operating Pressure

It should be assumed that the SCC dimensions fall on the P_{test} curve should be used unless more detailed information, such as provided by an SCC ILI report is available. This contributes toward a conservative, minimum estimate of remaining life and retest interval. Whether or not a second hydrostatic test results in an SCC rupture, the operator can leverage this information to confirm SCC growth rates and refine the hydrostatic test interval [21]. The operator should assess the applicability of any assumptions that are made when refining a hydrostatic test interval.

Appendix 8: Analytical Methods in the Calculation of Failure Pressure of SCC.

A1. “Log-Secant” Approach

The “Log-Secant” approach has its origins in a strip-yield formulation for a slit in a sheet (based on a through-wall SCC). A strip yield model of this form was originally introduced by Battelle [8] in 1973, in which the collapse limit and toughness dependence were formulated empirically to fit experimental results. The relationship could be rearranged to allow the calculation of the failure stress for a flaw. The basic equation had the following form:

$$K^2 = \frac{8c_{eq} \overline{\sigma}^2}{\pi} \ln \sec \left[\frac{\pi}{2} \frac{M_p \sigma}{\overline{\sigma}} \right] \quad (3)$$

where:

K is the stress intensity;

σ is the applied stress;

$\overline{\sigma}$ 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, which has been shown to have a safety factor of as much as two [9].

The main equations and model for the derivation of the “Log-Secant” approach are provided in the original reference [8]. There have been numerous PRCI reports that have also commented on the approach, the latest of which is Topical Report #208 [9]. The 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.

A2. Pipe Axial Flaw Failure Criterion (PAFFC)

The PAFFC model arose 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 [10, 11] in response to those requirements. 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, 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 in Topical Report 193 [10].

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 will not be uniformly spaced with respect to flaw depth/wall thickness ratios. These visual outputs will look different than those from the “Log-Secant” approach. PAFFC is available as a commercial software program.

A3. CorLAS™

CorLAS™ is a computer model that can be used to evaluate flaws. It has been developed by CC Technologies for corrosion life assessment of pressurized piping and cylindrical vessels and is a composite of the “Log-Secant” 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.

Note

Since the CorLAS™ model uses the R-STRENG approach as part of its analysis of flaws, the R-STRENG approach has not been analyzed in this review.

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 employed. The details of the model and the key equations and references can be found in “Effect of Stress Corrosion Cracking on Integrity and remaining Life of Natural Gas Pipelines.” [16].

CorLAS™ uses the effective flaw length method [references 2 to 6 in reference (16)], to compute critical flaw size and pressure based on a flow-strength failure criterion and inelastic fracture mechanics [references 10 and 13 in references (16)], to compute critical flaw size and pressure based on the JIC fracture toughness failure criteria. The lower of these two values is then predicted to be 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 JIC fracture toughness failure criterion is used. A tearing instability analysis using a complete J-R curve, (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.

A4. Fitness for Service of SCC-like Flaws based on API 579 or BS 7910 requirements.

API 579 [18] and BS 7910 [19] provide similar approaches to assessing SCC-like flaws in pressure-containing equipment and structures, including pipelines, using a failure assessment diagram (FAD), which is based on the principles of fracture mechanics.

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 8.8. 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,

$$K_r = \frac{K_I}{K_{mat}} \quad (4)$$

Where K_I is the applied stress intensity factor, 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,

$$L_r = \frac{\sigma_{ref}}{\sigma_y} \quad (5)$$

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 BS7910 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 8.8. Various levels of assessment and assessment curves are provided in the two referenced documents, with the appropriate level of assessment being dependant on the specific situation being analyzed and the available information.

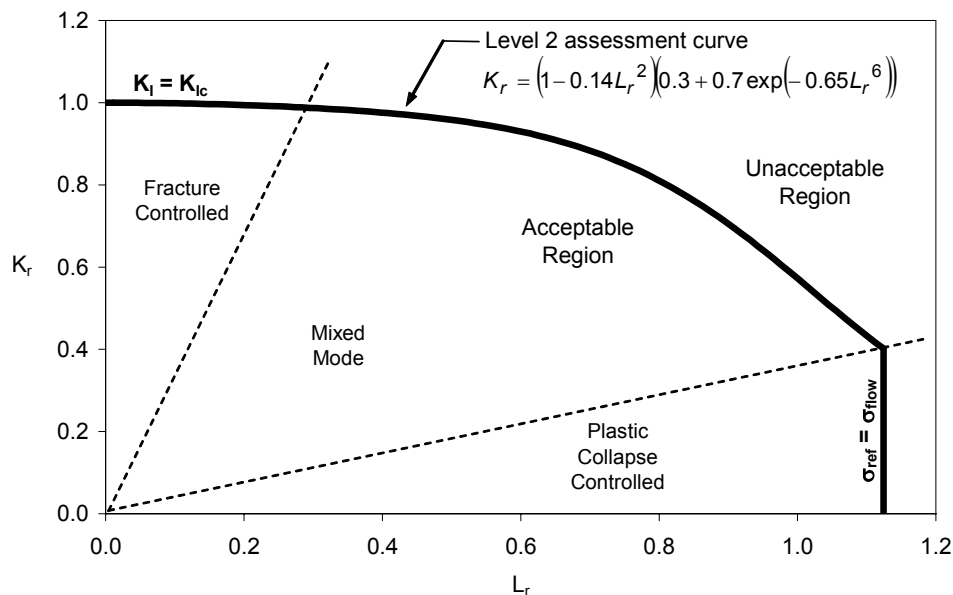


Figure 8.8: API RP 579 / BS 7910 Failure Assessment Diagram (FAD)

References

- [1] CSA Standard Z662, *Oil and Gas Pipeline Systems*, Clause 10.9.1.3, 2007.
- [2] Carl E. Jaske, Brian O. Hart, William A. Bruce, "Updated Pipeline Repair Manual, Revision 6", Catalogue No. L52047, Pipeline Research Council International Inc., August 28, 2006.
- [3] Coote, Robert I. Coote Engineering Ltd. and Keith, J. Kyle, TransCanada, "Pressure Reductions and Pipeline Excavation IPC 04-0395", October 2004.
- [4] ASTM Standard E 709-95, *Guide for Magnetic Particle Examination*, 2000.
- [5] NACE Standard SSPC- SP 10 (No. 2), *Near White Metal Blast Cleaning*, 2000.
- [6] NACE Standard SSPC-SP 6 (No. 3), *Commercial Blast Cleaning*, 2000.
- [7] NACE Standard RP0287-2002, *Field Measurement of Surface Profile of Abrasive Blast-Cleaned Steel Surfaces Using a Replica Tape*, 2002.
- [8] Kiefner, J.F., Maxey, W.A., Eiber, R.J., and Duffy, A.R. "Failure Stress Levels of Flaws in Pressurized Cylinders" ASTM STP 536, 1973.
- [9] Eiber, R.J., Bubenik, T., and Maxey, W., "Fracture Control Technology for Natural Gas Pipelines" Final Report to A.G.A. NG-18 Report 208, Dec. 1993.
- [10] Leis, B.N, Brust, F.W., and Scott, P.M. "Development and Validation of a Ductile Flaw Growth Analysis for Gas Transmission Line Pipe" Topical Report NG-18 No 193, June 1991.
- [11] Leis, B.N, and Brust, F.W., "Development and Validation of a Ductile Flaw Growth Analysis for Gas Transmission Line Pipe" A.G.A. Catalogue No. L51665, 1992.
- [12] Leis, B.N., and Mohan, R. "Failure Criteria for Semicircular Flaws" PRC/EPRG 9th Biennial Joint Technical Meeting, Houston, May 1993.
- [13] British Standards Institution Standard PD6493, *Guidance on the methods for assessing the acceptability of flaws in fusion welded structures*, 1991.
- [14] Newman, J.C. Jr., and Raju, I.S. "An empirical stress intensity factor equation for the surface SCC," *Eng. Fracture Mechanics*, vol. 15, 1981.
- [15] Shen, G. and Tyson, W.R., "Ligament-yield load of plates and cylinders with an axial semi-elliptical flaw," *Fatigue Fracture Eng. Mater. Struc.*, vol. 18, 1995.
- [16] Jaske, C.E., Beavers, J.A., and Harle, B.A. "Effect of Stress Corrosion Cracking on Integrity and remaining Life of Natural Gas Pipelines" Corrosion 96, NACE, March 1996, Paper 255.
- [17] Leis, B.N., "Stress-Corrosion Cracking in Gas Transmission Pipelines -The Interplay between Serviceability and Inspection", Proceedings of the Ninth Symposium on Pipeline Research, paper no. 23, Sept. 30 - Oct. 2, 1996 - PRC International, Houston, Texas, 1996.
- [18] API 579-1/ASME FFS-1, *Fitness-For-Service*. American Petroleum Institute and The American Society of Mechanical Engineers. June 2007.

- [19] BS 7910:2005, *Guide to methods for assessing the acceptability of flaws in metallic structures*. British Standards Institute, London, England. July 2005.
- [20] J.A. Beavers, "Near-Neutral pH SCC: Dormancy and Re-Initiation of Stress Corrosion Cracks," Report prepared for the Gas Research Institute, GRI-7045, 2004.
- [21] R.R. Fessler and S. Rapp, "Method for Establishing Hydrostatic Re-Test Intervals for Pipelines with Stress-Corrosion Cracking," Proceedings of International Pipeline Conference, 2006, ASME Paper IPC 2006-10163.

9.	Prevention and Mitigation.....	9-2
9.1	Coatings	9-2
9.1.1	Performance characteristics	9-2
9.1.2	Coatings for New Pipelines	9-3
9.1.3	Conclusion	9-6
9.1.4	Bell Hole Excavation (Investigative Dig Program) Recoating	9-7
9.2	Cathodic Protection	9-13
9.2.1	Cathodic Protection Criteria	9-14
9.2.2	Cathodic Protection Surveys for SCC by Coating Type	9-15
9.3	Hydrostatic Retesting	9-16
9.3.1	Hydrostatic Retest Pressure Limits and Duration	9-17
9.3.2	Retest Frequency	9-22
9.3.3	Procedures	9-22
9.4	Repairs	9-22
9.4.1	Sleeves	9-23
9.4.2	Sequential Buffing	9-26
9.4.3	Pipe Replacements	9-27
	References	9-29

9. Prevention and Mitigation

9.1 Coatings

Inadequate coating performance is the central contributor to pipeline SCC susceptibility and the pipeline company should place emphasis on developing coating procedures so that future coating failure susceptibility, especially disbondment, is minimized.

A balance between performance properties and application constraints must be considered when selecting the appropriate coating material. The pipeline company must have knowledge of the exposure conditions that the pipeline coating will face as well as the practical challenges that are typically involved when applying a coating intended for long-term performance. Geotechnical considerations, operating temperatures, soil types and chemistry, groundwater effects, cathodic protection (CP), transportation handling, and many other parameters affect coating performance. If historical data are not available to describe a particular coating's suitability in a given environment, accelerated laboratory testing can be performed.

9.1.1 Performance characteristics

Coatings should possess the following performance characteristics:

- Adhesion/Resistance to Disbanding - This is a primary performance property that describes the coating's ability to serve as a barrier from the effects of moisture. Materials with good adhesive properties are less likely to be affected by the mechanical action of soils, which expand and contract during periods of wet/dry or freeze/thaw cycles. Further, materials with good adhesive properties will be better able to resist the effects of water vapour transmission through the coating. For example, fusion bond epoxies can experience a relatively high water vapour transmission in and out of the coating. But, due to the material's excellent adhesive properties, corrosion cells do not develop at the coating-steel interface. Further, coatings with good adhesion generally also have good cathodic disbondment resistance, which is a measure of a coatings ability to withstand the rigors of continuous electrical current exposure.
- Low Water Permeability - Water vapour transmission into the coating may result in coating disbondment where less than optimal coating adhesion is present. This disbondment could lead to further exposure to moisture. As well, electrical conductivity through the coating increases as water absorption increases. This results in a higher drain of cathodic protection current and potentially reduced levels of cathodic protection elsewhere. The impact of this is greater electrical costs in operating the cathodic protection system or inadequate protection.
- Effective Electrical Insulator - Good electrical properties will limit the long-term exposure effects on the coating from the cathodic protection system.

Electrical costs will also be minimized. However, if the coating disbonds, an electrically insulating coating will shield cathodic protection from reaching the pipe.

Coatings that provide good electrical insulation perform well if overall coating adhesion is good. However, if the coating disbonds, and therefore shields the CP current, isolated corrosion cells form which cause high levels of localized corrosion.

- Abrasion and Impact Resistance - Pipe contact with mechanical equipment or rocks could create coating damage. Good abrasion and impact resistance will minimize this damage.
- Temperature Effects/Sufficiently Ductile - Coatings must remain sufficiently ductile to resist cracking in the range of temperatures expected to be encountered during pipe bending, handling, installation and during the pipeline's operational life.
- Resistance to Degradation - The importance of this is based on the chemical composition of the soil surrounding the pipe and/or the pipe's operating temperature. For example, some coating materials, such as polyethylene tape are not resistant to hydrocarbons or high temperature.
- Retention of Mechanical/Physical Properties - Over time, it is possible that a coating's properties (tensile, hardness, elongation, etc.) may change while in service. For example, polyethylene tapes have been observed to stretch over time, and old FBE coatings have been known to become brittle.
- Non-shielding to Cathodic Protection if Disbonded - Wherever a coating disbonds, cathodic protection must have adequate access to the bare pipe at that location. If disbondment occurs, some coatings will disbond both adhesively (completely removed away from the pipe surface) and cohesively such that adequate CP can reach in behind the disbondment. On the other hand, some materials, such as cold applied tapes, will disbond only adhesively creating a gap, or tent, in the coating where water can collect but not necessarily allow adequate access for CP.

9.1.2 Coatings for New Pipelines

The selection of pipe coating systems should be based on their overall effectiveness for service. This section will focus solely on the effectiveness of coatings in preventing SCC initiation in new pipelines. In addition, coating should have the properties listed in NACE Standards, NEB MH-2-95, CGA OCC-1 and the latest version of CSA Z662 (clause 9.2).

The information presented in this section is based on historical operating experience and the results of research conducted to date. However, the performance of new coatings may surpass their historical effectiveness due to new improved materials and application procedures. Consequently it would be appropriate for pipeline companies to keep abreast of new developments in coating technology.

9.1.2.1 Preventing SCC Initiation with Coating Systems

The most proven method of reducing SCC initiation on new pipelines is with the use of high performance coatings and effective CP. The effectiveness of preventing initiation of SCC in pipelines is primarily related to the following coating requirements:

- Coating Requirement #1 - Prevent the environment/electrolyte that causes SCC from contacting the pipeline steel surface (i.e. resistance of a coating to disbonding).
- Coating Requirement #2 - Ability to pass current through the coating, or under disbonded tents, and thereby protect the disbonded regions and prevent the initiation of SCC.
- Coating Requirement #3 - Although not strictly a property of the coating, surface preparation prior to coating application should alter the pipe surface condition to render it less susceptible to SCC initiation.

Consideration should also be given to mechanical properties of the coatings as they relate to flexibility, impact resistance, temperature and abrasion resistance in terms of specific requirements for resistance to damage and disbonding during installation and service.

CEPA member companies have experienced that the above considerations and requirements contribute to the prevention of SCC initiation on new pipeline installations. From this experience, the following coatings should be considered for new construction:

- Fusion bond epoxy (FBE)
- Urethane and liquid epoxy
- Extruded polyethylene
- Multi-layer or composite coatings.

Historically, using coatings other than the above (e.g. Bituminous Enamel coatings or tape coatings) has shown more susceptibility to SCC. Consequently, pipeline companies need to exercise due diligence by considering their unique situation when selecting coatings for new installations.

9.1.2.2 Fusion Bond Epoxy

Fusion Bond Epoxy (FBE) applied in accordance with the requirements in [8], will meet the three requirements discussed above. FBE is a high-integrity coating with excellent bonding strength and is resistant to deterioration from CP, soil stress, and chemicals. While FBE may infrequently disbond due to osmotic blistering, the coating properties continue to allow CP current through the coating, thereby protecting the steel pipe surface below.

During pipe surface preparation prior to FBE application, the mill scale from pipe manufacture is removed with grit blasting. The grit blasting imparts a residual compressive stress on the pipe surface, thereby improving its resistance to SCC initiation.

FBE has been used by industry for 30 years with no reported incidents of SCC even in locations known to exhibit SCC on parallel asphalt or tape-coated pipelines.

9.1.2.3 Liquid Epoxy and Urethanes

Liquid epoxy and urethane coatings applied according to the manufacturer's instructions will meet the three requirements discussed above. These are considered high-integrity coatings with excellent bonding strength and resistance to deterioration. Should for some reason the coating disbond from the pipe surface, CP continues to be effective.

During pipe surface preparation prior to the application of liquid epoxy and urethane, the mill scale from pipe manufacture is removed with grit blasting. The grit blasting imparts a residual compressive stress on the pipe surface improving its resistance to SCC initiation.

In over 20 years of experience with liquid epoxies and urethanes, there have been no reported incidents of SCC.

Liquid epoxies are used extensively as a repair coating, and have proven to be a superior choice to coat field joints (i.e. girth welds) on FBE-coated pipelines.

9.1.2.4 Extruded Polyethylene

Extruded polyethylene applied in accordance with the requirements in [9] and the manufacturer's specifications will meet coating requirements #1 and #3 discussed previously. Extruded polyethylene is an effective coating with good adhesion properties. However, should the polyethylene jacket become damaged and disbondment occurs, CP is not able to penetrate beneath and protect the pipe surface within the disbondment. Fortunately, the polyethylene/mastic interface rather than the mastic/pipe interface tends to fail. The mastic is thought to provide the necessary corrosion protection even though the environment (e.g. ground water) may be present between the coating layers.

During pipe surface preparation prior to application of this coating system, the mill scale from pipe manufacture is removed with grit blasting. The grit blasting imparts a residual compressive stress on the pipe surface improving its resistance to SCC initiation.

Extruded polyethylene coatings have been used by industry for over 30 years with few reported cases of SCC.

9.1.2.5 Multi-Layer or Composite Coatings

Multi-layer coatings consist of an inner layer of FBE and an outer polyolefin layer held together with an adhesive. Composite coatings are layered with an inner FBE, graded FBE and modified polyethylene, and a polyethylene outer layer.

In theory multi-layer coatings may shield cathodic protection current, but in practice are extremely resistant to mechanical damage and adhesion failure.

9.1.2.6 Bituminous Enamel

There has been historical evidence of SCC susceptibility on pipelines coated with bituminous enamel coatings such as asphalt and coal tar. Bituminous enamel coatings can satisfy coating requirements #1 and #2 discussed above, but will not meet coating requirement #3 (section 9.1.2.1).

Of the two types of coating, coal tar has proven a better in-service coating with respect to trans-granular SCC than asphalt coatings. However there are no experimental data that explains this difference in behavior.

Cleaning the pipe surface in preparation for application in the field is usually completed by brush blasting or wire brush cleaning. This process does not remove pipe mill scale. Consequently this process does not produce a pipe surface resistant to SCC initiation.

9.1.2.7 Polyethylene Tape Coatings

There is significant historical evidence of SCC susceptibility on pipelines coated with tape coatings. The tape coating can satisfy coating requirement #1 discussed above but generally will not meet coating requirements #2 and #3.

The effectiveness of tape coatings is conditional on the tape remaining bonded to the pipe thereby keeping the soil environment away from the pipe. When tape coating disbonds, tents over the weld, or tents at the tape overlap, the tape shields CP from beneath the disbondment.

Cleaning the pipe surface in preparation for tape, much like bituminous enamel coating preparation, is usually accomplished by brush blasting or wire brush cleaning in field operations. This process does not remove pipe mill scale. Consequently this process does not produce a pipe surface resistant to SCC initiation.

Experience has shown that polyethylene tape coating is ineffective at mitigating the risk of SCC occurrence on pipelines and is not recommended as a new pipe, joint or repair coating.

9.1.3 Conclusion

The use of effective, high-performance coatings for new pipeline design and installation is, at this time, the most practical way of reducing susceptibility to SCC initiation on pipelines. FBE, liquid epoxies, and urethanes are the preferred coatings for mitigating SCC. Multi-layer, Yellow Jacket and extruded polyethylene are also acceptable coatings that can be used to mitigate the threat of SCC.

The type of coating should be selected in relation to the specific installation concerns, operating conditions, and long-term use and life cycle cost of the new pipeline under consideration.

9.1.4 Bell Hole Excavation (Investigative Dig Program) Recoating

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.

The following items summarize the many variables to consider when developing recoating procedures:

9.1.4.1 Types of Coating Materials

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

9.1.4.1.1 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, assist in speeding 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 provide the material's specified adhesion qualities. Cold applied tapes can be further categorized as follows:

- Thin Polyethylene Tapes - This material comprises of a thin polyethylene backing (approximately 9-15 mils) 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.
- Petrolatum Tapes - This material is consists of a synthetic fabric impregnated with a waxy compound. It is designed normally 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.
- Bitumastic Tapes - 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 and is typically laminated to a thin (approximately 4-8 mils) polyvinyl chloride backing 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.

9.1.4.1.2 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. These materials 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.

- Coal Tar Tape - A reinforcing fabric is impregnated with coal tar pitch. In its “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 its 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 that of thin polyethylene tapes and the backing has been 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 is formulated 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 pipe. Sleeves can be purchased for various diameter pipes but do not exceed a length of approximately one meter. 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.

9.1.4.1.3 Liquid Based Coatings

Liquid coatings can be applied using brushes and rollers or relatively sophisticated spray equipment. Although these materials are not as user friendly as tape materials, the performance properties are usually better. 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 chemistries packaged in two separate containers, the contents of which must be properly mixed together to form the final formulation. 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 an enormous range of different chemistries such as epoxies, urethanes, coal tar epoxies, and blends of each.



Figure 9.1: Application of Liquid Based Coating after Bell Hole Inspection

9.1.4.1.4 Powder Based Coatings

Fusion bond 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.

9.1.4.2 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, slags, 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 tool cleaning or hand tool cleaning are also used. However, the company must be aware that such techniques provide a diminished level of surface preparation compared to abrasive blasting. The company should follow the coating manufacturer's and blast media supplier's surface preparation specifications. Care should be taken to use an effective blast media that does not mask or remove SCC cracks prior to pipe inspections.

9.1.4.3 Integrity Assessment

With the old coating removed and essentially bare pipe now exposed, the company has the opportunity to inspect the pipe surface for the existence of SCC, as well as measure any metal loss anomalies, dents, or other defects. Mitigation of defects or selective pipe replacement may be required at this stage.

9.1.4.4 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 settle 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. In some cases, over heating of the coating due to sun exposure can also be detrimental.



Figure 9.2: Hording-In an Excavation Site for Winter Recoating

9.1.4.5 Compatibility With Existing Coating

The recoating operation should ensure that the transition area where the new coating meets the parent coating is properly sealed. Normally, the new coating will be applied directly over the transition and parent coating. If the parent coating is polyethylene tape, or multi-layer extruded polyethylene (i.e. "Yellow Jacket"), many recoat materials will not bond to these 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 material 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 would be of benefit 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 will be necessary to apply a full circumference wrap type material (i.e. mastic blanket or bitumastic/petrolatum tape) over the transition as described above.

9.1.4.6 Geographical and Physical Location

Some recoating operations require the use of compressors, spray units or other equipment that must be stationed ditch side. 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.

9.1.4.7 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.

9.1.4.8 Health and Safety Codes

Selection of blast media should be made with an awareness of all regulations controlling hazardous products, and the company should be prepared to handle applicable materials in accordance with the 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 work-safe fashion. Today there are numerous alternate materials available which will suitably prepare the surface for inspection and recoating. Materials such as walnut shells have been used with limited success and may cause an allergic reaction to people with nut allergies in close proximity to the work site and especially those in direct contact with the material. Similarly, some workers may be sensitive to solvents or other components contained in primers or liquid based coatings.

9.1.4.9 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 company may decide to hire a qualified inspector to monitor the progress of the

job. Record keeping should include information about the materials shipped to site, 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 results of a high voltage holiday test.

9.1.4.10 Industry Standards

There is a wealth of information available to the company which details all of the information provided above. Some of the organizations that can provide insight into any component of recoating operations include the following:

- SSPC: Steel Structures Painting Council
- NACE: National Association of Corrosion Engineers
- ASTM: American Society for Testing and Materials
- CSA: Canadian Standards Association

9.2 Cathodic Protection

Transgranular SCC was first discovered in the mid-1980s and occurs in dilute electrolytes containing dissolved carbon dioxide. This form of cracking has predominately transgranular morphology and is associated with corrosion of the crack faces and, in some cases, corrosion of the pipe surface. The environmental conditions required to create near-neutral pH cracking do not appear to be very specific.

Transgranular SCC can only occur when there is an inadequate level of cathodic protection (CP) on the pipe surface. This form of cracking is much more prevalent on pipelines with tape coatings that disbond and shield the CP current, but allow carbon dioxide to diffuse through or under the coating. This type of SCC has been observed on other coatings such as coal tar and asphalt where the coating is disbonded and where CP levels are inadequate. Inadequate levels of CP protection often occur in areas with high resistivity soils.

In the field, transgranular SCC appears to occur at or near the native potential of the pipe steel, in the electrolyte that forms beneath the disbonded coating. In practice, areas along a pipe surface exposed to CP current are not susceptible to transgranular SCC. The CP currents reaching the pipeline will alter the environment at the pipe surface and thereby mitigate this form of SCC. Support for this statement comes from the observation that near-neutral pH SCC has not been observed on FBE coated pipelines, or on coal tar and asphalt enamel-coated pipelines that receive adequate CP.

The minimum level of CP required to mitigate transgranular SCC has not yet been established. However, it is generally accepted that this form of cracking will not occur where the standard CP criteria (e.g. -850mV off or 100 mV shift) [Ref 6,10] are achieved and the coating does not promote shielding of CP current.

In conclusion, transgranular SCC only occurs where there is intermittent (e.g. due to seasonal conditions) or ineffective CP or the coating shields the CP current completely from the pipe surface, which is why this type of SCC is often associated with external corrosion in close proximity.

Note



Alternatively, high-pH SCC occurs in a narrow range of potentials that is between the native potential and an adequate cathodic-protection potential. Such a condition usually is associated with a disbonded coating that partially shields the cathodic-protection current.

It is important that a pipeline company strive to achieve adequate levels of CP along the entire pipeline to prevent SCC and corrosion. However, overprotection can also be detrimental as it can promote coating degradation, and the formation of alkaline environments conducive to high-pH SCC. Hydrogen gas generation and accumulation beneath disbonded coatings are also side effects of overprotection. The gas collected within the disbonded regions can also create a high resistivity path and results in a loss of CP within these regions.



Figure 9.3: CP rectifier

9.2.1 Cathodic Protection Criteria

Cathodic protection criteria and procedures should conform to applicable regulations and cathodic protection standards in NACE Standard RPO169 [10] or the Canadian Gas Association (CGA) Recommended Practice OCC-1 [6]. These

recommended practices give guidance in applying adequate levels of CP, which in turn can prevent the formation of transgranular SCC. Personnel or contractors who are knowledgeable in corrosion control practices should conduct the design and installation of cathodic protection systems.

The following pipe-to-soil voltage criteria may be used in addition to the standards outlined in the NACE Standard RP0169 [10] and CGA Recommended Practice OCC-1 [6].

The recommended polarized or “off” potential range for the operation of cathodic protection systems is between -850 mV and -1100 mV. It is recommended to avoid potentials more negative than -1100 mV because they may promote the generation of hydrogen. Hydrogen can possibly lead to hydrogen embrittlement of the pipe material, blistering and ultimately shielding of the coating materials.

The 100 mV shift criterion, outlined in both NACE Standard RP0169 [10] and the CGA Recommended Practice OCC-1 [6], may promote potentials that are in the cracking range for high-pH SCC. Therefore, this criterion should be applied with caution when associated with high-pH SCC conducive environments.

Pipe-to-soil potentials are to be measured with a Cu/CuSO₄ half-cell electrode (or alternative with the appropriate potential adjustment) and with the CP currents instantaneously interrupted on the protected structure. All measurements must be free of induced AC or DC interference from nearby foreign structures or foreign CP systems. It is recognized that the contribution of long line currents, telluric currents, and high resistivity soil conditions can have an appreciable effect on the aforementioned potentials (especially if surface measurements are taken). Seasonal variations can also influence ground conductivity by variation in soil moisture content. The corrosion personnel charged with adjusting and monitoring individual CP systems should modify these potential criteria, as necessary, to account for these variables.

9.2.2 Cathodic Protection Surveys for SCC by Coating Type

SCC is typically found in locations where CP is shielded from the pipe surface or is inadequate. Therefore, various cathodic protection surveys have a limited effectiveness in identifying SCC susceptible locations.

9.2.2.1 Polyethylene Tape

The polyethylene backing on tapes typically shields cathodic protection from the pipe and prevents remote detection of disbonded areas. This is attributable to the electrical insulating properties of the polyethylene backing material. Consequently, pipe-to-soil surveys have limited use for identifying SCC susceptible sites in tape-coated pipe.

9.2.2.2 Coal Tar Enamel & Asphalt Enamel

Asphalt enamel and coal tar coatings sometimes fail in a manner that will not shield CP. Therefore, CP surveys might be useful for identifying SCC susceptible locations. However, because some shielding by either the coating or a high-

resistivity soil is possible, ground-level potential readings cannot provide conclusive evidence of the possibility of SCC.

9.3 Hydrostatic Retesting

Hydrostatic retesting has been shown, through operating experience and research, to be a very 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 retest 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. Statistical analysis using crack growth rate models may be used to determine repair criteria and hydrostatic retest intervals. Pipeline companies have historically used hydrostatic retesting for a variety of reasons ranging from:

- Qualifying a section of pipeline for higher maximum operating pressures.
- Qualifying 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), SCC, construction damage, and manufacturing defects.

This section will address the design and use of hydrostatic retesting 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.

Note that the resulting hoop stress 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 particularly useful for assessing pipeline integrity from the standpoint of circumferentially oriented defects such as circumferential SCC. Since pipeline integrity is much more likely to be affected by longitudinally oriented defects than by circumferentially oriented defects, hydrostatic testing is one of the best ways to demonstrate the integrity of a pipeline.

Pipelines designed for gas service versus those designed for liquid service will require different "hydrotest procedures" to facilitate testing. In areas of large elevation differential, it may not be feasible to hydrotest gas pipelines due to overstressing low-lying sections of the pipeline.



Figure 9.4: Hydrotest 'test head' and manifold set-up

9.3.1 Hydrostatic Retest Pressure Limits and Duration

Hydrostatic retests need to remove the smallest SCC defects possible from the pipeline while minimizing the possibility for growth during the retest of the sub-critical SCC flaws that survive the retest. Research conducted at Battelle Laboratories [11] resulted in the development of an "optimum" procedure to achieve these objectives. This procedure involves two components, namely 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 instead have resulted in a leak.



Figure 9.5: Excavated Hydrostatic Test Failure

It is vitally important for a company to examine their particular situation when developing a hydrostatic retest procedure. Factors that the company should take into consideration when developing a hydrostatic retest procedure include, but are not limited to, the following:

- 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 retest 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 retest from a potential SCC service failure.
- Test pressure level - The highest feasible test pressure level should be used when hydrostatic retesting 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 intervals.
- 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 ready 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 Kiefner “spike” test as described in 9.3.1.1.

- 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 of the 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 retest 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 retest.
- Retest frequency - The pipeline company should consider how often they are prepared to retest the given segment of pipeline. Obviously, the lower the test pressure is during the "high" pressure integrity test, the lower the safety factor achieved by the retest. Consequently the more frequent the retesting will have to be done 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 retest the given segment of pipeline to a higher safety factor than was used as the basis for past repairs.

9.3.1.1 Hydrostatic Retest Pressures and Hold Times

It is the sole responsibility of the pipeline company to develop and implement a hydrostatic retesting program that best addresses their individual needs and concerns. To provide some guidance in this area, this section outlines both the Leis and Brust [11] procedures, along with those in CSA Z662 [7].

Table 9.1 outlines the minimum and maximum test pressure limits for both the “high” pressure integrity test and the “low” pressure leak test recommended by Leis and Brust [11] and CSA Z662 [7].

Note

When a pipeline is tested to a level in excess of 100% of SMYS, a pressure-volume plot should be made to limit yielding. Also, a test may be terminated short of the initial pressure target, if necessary, to limit the number of test breaks as long as the maximum operating pressure (MOP) guaranteed by the test is acceptable to the pipeline operator.

Table 9.1: Hydrostatic Retest Pressures and Hold Times

Procedure	“High” Pressure Intensity Phase		“Low” Pressure Phase	
	Min	Max	Min	Max
Battelle Test Pressures	100% SMYS (Min.)	110% SMYS (Max.)	90% SMYS (Min.)	100% SMYS (Max.)
Battelle Hold Times	1 hour		2 hours assuming pressure stabilization achieved	
CSA-Z662 Test Pressures	125% MOP (Min.)	110% SMYS (Max.)	110% MOP (Min.)	125% MOP (Max.)
CSA-Z662 Hold Times	4 hours		4 hours assuming pressure stabilization achieved	
Kiefner & Associates, Inc.	Spike Test as high as possible. (5 minutes)		Conduct CSA 8 hour test at a level at least 5% below spike test level.	

9.3.1.1.1 “High” Pressure Integrity Test

The “high” pressure integrity test is intended to determine the integrity of the existing pipe within the test section. Depending on the procedure selected, the “high” pressure test should use a pressure that results in a hoop stress in the pipe wall at every point along the test section of between 100% and 110% SMYS in the case of the Battelle procedure, or between 125% MOP and 110% SMYS in the case of the CSA Z662 [7] procedure. To achieve the desired stress level along an entire test section, it is necessary to evaluate the various elevations in the given test segment of pipeline and break the segment into as many test sections as required to achieve the minimum hoop stress at every point along the test section.

For either procedure, the pressure at the test point (i.e. point of recording) must be established so that the pipeline within the test section is subject to a hoop stress between the minimum and maximum values (Table 9.1). The duration of the “high” pressure integrity test varies between one hour for the Battelle procedure and four hours for the CSA Z662 [7] procedure. To maintain the test pressure within the test parameters, it may be necessary to add or extract the testing medium.

It is always a good idea to conduct a “spike” test. Spike testing has been used for several years, and has been advocated for dealing with stress-corrosion cracking. The idea is to test to as high a pressure as possible, but hold it for only a short time (5 minutes is considered long enough). Then, if the company can

live with the resulting MOP, conduct a traditional CSA 8 hour test at a level of at least five percent below the spike test level. The spike test establishes the effective test-pressure-to-operating-pressure ratio; the remainder of the test is only for the purpose of checking for leaks and for meeting CSA regulatory requirements, when used to qualify new pipe.



Figure 9.6: Hydrostatic SCC Failure

9.3.1.1.2 “Low” Pressure Leak Test

As the “high” pressure test is utilized to confirm integrity or strength of a pipeline segment, the “low” pressure leak test identifies the presence of any leaks in the existing pipeline within the test section. Depending on the procedure selected, the “low” pressure test should use a pressure that produces a hoop stress in the pipe wall of between 90% and 100% SMYS in the case of the Battelle procedure, or between 110% MOP and 125% MOP in the case of the CSA Z662 [7] procedure.

For either procedure, the maximum pressure at any point in the test section should not exceed the maximum test pressure (Table 9.1). The duration of the “low” pressure leak test varies between two hours for the Battelle procedure and four hours for the CSA Z662 [7] procedure. The test pressures for the “low” pressure test should be monitored and maintained within +/- 2.5%.

The pressures during the “low” pressure leak test must remain constant unless the readings are fully explained by temperature variations. All pipe temperature variations during the leak test must be correlated with changes in pressure. If all temperature and pressure variations cannot be fully explained as outlined above, the “low” pressure test should be extended until the company's testing supervisor

has determined an acceptable test has been achieved or a leak has been detected.

9.3.2 Retest Frequency

The frequency necessary to retest a given section of a pipeline will depend on the following factors:

- The minimum test pressure experienced in the pipeline during the “high” pressure integrity test. This governs the maximum size of the flaw that could have survived the retest.
- The MOP of the pipeline in question. This governs the minimum size of the flaw that could fail in-service.
- Crack growth rate for the particular pipeline system used to help determine retest intervals. This governs how quickly an in-service failure could occur after a successful retest. In addition to historical hydrotest data, several iterations of ILI tool run data can also be analyzed to obtain a statistically valid growth rate model.

Section 8.2 SCC Condition Assessment Methodologies provides a more detailed outline for determining the retest frequency a company should employ on a given section of its system.

9.3.3 Procedures

All hydrotesting procedures should consider the methodology of Clause 8 of CSA Z662 [7].

9.4 Repairs

According to CSA criteria, pipe body surface cracks, including stress corrosion cracks, are considered to be defects unless determined by an engineering assessment to be acceptable. Pipe containing SCC defects can be repaired using one or more of the acceptable repair methods given in Table 10.1 of CSA Z662 [7]. The acceptable permanent repair methods for SCC include:

- 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

**Note**

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

Stress corrosion cracks should not be removed by grinding on pipe containing high pressure. With pipe containing high pressure, only 'buffing' using soft back discs should be carried out. Strong consideration should be given to determining a safe pressure prior to application of any crack removal process. 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.

9.4.1 Sleeves

Applying 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 include steel reinforcement sleeves, steel compression reinforcement repair sleeves, and the fiberglass reinforcement repair sleeves. These are designed to prevent radial bulging of the remaining steel and resulting failure of the defect.

9.4.1.1 Steel Reinforcement Sleeves

Applying structural reinforcement sleeves for permanently repairing SCC is restricted to either full compression reinforcing sleeves or after SCC that has been completely removed through buffing. If the buffing repair of SCC results in metal loss in excess of that permitted by the CSA Z662 [7], the metal loss defect can be permanently repaired with the installation of a reinforcing sleeve. An exception is that the reinforcement sleeve is restricted to the repair of metal loss less than 80%.

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



Figure 9.7: Steel Reinforcing Sleeve



Figure 9.8: Installation of a reinforcing sleeve after SCC removal

9.4.1.2 Composite Reinforcement Sleeves

Applying a composite reinforcement sleeve for repairing SCC is restricted to reinforcing SCC that has been completely removed by buffing. For SCC colonies in 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 (e.g. Clock Spring[®])[7]. This sleeve is also limited to the repair of metal loss defects less than 80% of the nominal pipe wall thickness.

Similar to the steel reinforcement sleeves, the composite reinforcement sleeves prevent 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, axial and circumferential length. A computer-based model, such as GRIWrap[™], 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 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 9.9: Composite reinforcement sleeve repair

9.4.2 Sequential Buffing

Sequential buffing is the most common and typically, the most accurate method of determining depth of SCC. As SCC is generally required to be removed as a repair or before other repairs can be completed, sequential buffing is also quite practical as it can be both the measurement and repair procedure. The methodology of sequential buffing is as follows.

- Select the isolated SCC feature, the deepest feature within a colony or the toe of the weld SCC feature to be assessed. In the case of the 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 (refer to 8.1.1.1). 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 than 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 (section 8.1.1.4.1).
- If the SCC is removed in the first step, calculate the depth as less than 10% of wt.
- If the SCC still exists within the buffed area, perform a second buffing removal of material 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 thickness and dependant 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 in item 2 above.
- Upon removal of the SCC, calculate the SCC depth as the difference between the remaining wall thickness and the original wall thickness as installed.
- 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 as to the amount of depth to be removed.

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 wider width characteristics near to its tip.

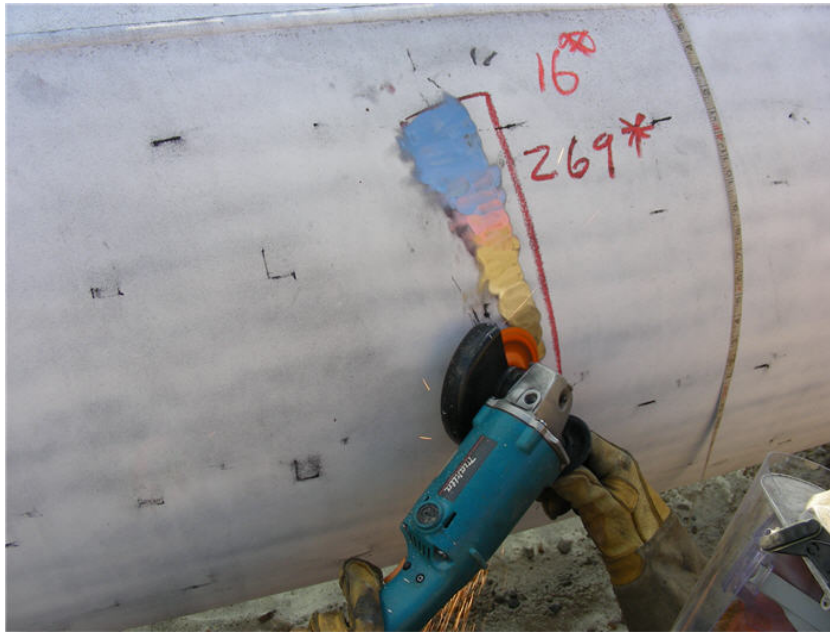


Figure 9.10: Buffing repair

9.4.3 Pipe Replacements

Selective pipe replacement is one of many options available in the mitigation of SCC on a given segment of pipeline, or portion thereof, determined to be susceptible to SCC. Pipe replacement, although highly effective, is very costly and requires a service interruption for installation. The effectiveness of a pipe replacement depends on the establishment of an adequate replacement distance to ensure the entire affected pipe has been replaced.



Figure 9.11: Repair by pipe replacement

9.4.3.1 Evaluation of Potential Pipe Replacement Locations

Evaluating potential pipe replacement locations can be based on two possible scenarios. The first scenario is that a company has detected SCC at an investigation site and has determined that a pipe replacement is the most suitable means of repair. The second scenario is that the company has identified discrete portions of a pipeline segment or segments that in their assessment may be susceptible to SCC. Under this scenario they may have subsequently determined a pipe replacement program in such areas would be the most effective method of addressing the situation.

9.4.3.2 Pipe Replacement Distance Criteria

Determining the appropriate length of pipe replacement at a given location depends on the basis for the replacement. If the reason for the pipe replacement is to repair SCC detected at an investigation site, then the length of the replacement should be such as to ensure the removal of SCC colonies at that specific site.

If the reason for the pipe replacement is to address a “discrete” portion of a pipeline segment assessed to be potentially susceptible to SCC, then the length of the repair should ensure the removal of all the pipe at that specific location that has been assessed to be susceptible to SCC.

References

- [1] Beavers, John A. and, Garrity, Kevin C., "Stress Corrosion Cracking of Underground Pipelines", CC Technologies, January 1997.
- [2] Gummow, R.A., "The Cathodic Protection Criterion for Underground Steel Structures", Proceedings of NACE Western Region Conference, Victoria, British Columbia, February 1993.
- [3] Kiefner, J.F., and Maxey, W.A., "The Benefits and Limitations of Hydrostatic Testing", API's 51st Annual Pipeline Conference & Cybernetics Symposium, 2000.
- [4] Coote, Robert I. Coote Engineering Ltd. and Keith, J. Kyle, TransCanada, "Pressure Reductions and Pipeline Excavation IPC 04-0395", October 2004
- [5] National Energy Board (NEB), Report of the Inquiry, "Stress Corrosion Cracking on Canadian Oil and Gas Pipelines", NEB MH-2-95, December 1996.
- [6] Recommended Practice OCC-1, *Control of External Corrosion on Buried or Submerged Metallic Piping Systems*, Canadian Gas Association, December 1, 2005.
- [7] CSA Standard Z662-07, *Oil and gas pipeline systems*, June 2007.
- [8] CSA Standard Z245.20-M02, *External Fusion Bond Epoxy Coating for Steel Pipe*, 2006.
- [9] CSA Standard Z245.21-M02, *External Polyethylene Coating for Pipe*, 2006.
- [10] NACE Standard RPO169-2002, *Control of External Corrosion on Underground or Submerged Metallic Piping Systems*, 2002.
- [11] Leis, B. N., and Brust, F. W., "Hydrotest Strategies for Gas Transmission Pipelines Based on Ductile-Flaw-Growth Considerations", American Gas Association, Pipeline Research Committee, NG-18 Report No. 194, July 27, 1992.

10.	Risk Assessment.....	10-2
10.1	Definitions	10-2
10.2	Risk Management Process	10-3
10.3	Risk Analysis.....	10-3
	10.3.1 Frequency Analysis.....	10-4
	10.3.2 Consequence analysis	10-4
10.4	Risk Evaluation	10-6
10.5	Conclusion	10-6
	References.....	10-8

10. Risk Assessment

The need for a risk assessment of an identified hazard, such as SCC, is identified as a non-mandatory procedure in CSA Z662-07 Annex N “Guidelines for Pipeline Integrity Management Programs.”

Guidance for a risk assessment is also provided as a non-mandatory guideline in CSA Z662-07 Annex B “Guidelines for Risk Assessment of Pipelines.” This section of the Recommended Practices will rely on Annex B as a primary reference and will simply be quoted as Annex B. It will be necessary for the user of this section to have Annex B available.

The basic concept of risk assessment for SCC on pipelines is provided in this section, and includes the following:

- Standard definitions;
- The components of the risk assessment process; and
- Frequency and consequence analysis specific to SCC of pipelines carrying different service fluids.

10.1 Definitions

The basic terminology to be used relative to the risk assessment of pipelines is given in Annex B Clause B.3. An important definition is that of risk itself. Risk is defined here as

“a compound measure, either qualitative or quantitative, of the frequency and severity of an adverse event.”

Additional definitions given below may be useful in the context of this section.

- Uncertainty: A state caused by a lack of knowledge where more than one possible outcome can be predicted.
- Measurement of Uncertainty: The assignment of a probability to each possible predicted outcome.
- Measurement of Risk: The probability assigned to the predicted outcome, which produces an adverse event (s).
- Receptor: A human, economic, or environmental resource that may, in the event of an incident, be exposed to the adverse effects of a hazard.
- Frequency analysis: The use of modeling, field observations, historical data, or expert judgment to estimate the expected frequency of occurrence of specific events¹.
- Consequence analysis: The use of modeling, site-specific analysis, or expert judgment to estimate the severity of the adverse effects of specific event on receptors.

¹ For pipelines, frequency is usually expressed as a function of time and length, e.g. occurrences per km year.

10.2 Risk Management Process

Annex B deals in some detail with the process of risk assessment. The specific definitions presented in Clause B.3, and the process diagram shown in Annex B Figure B.1, “The process of risk management” identify the components of risk assessment and their role within the broader context of risk management.

The overall process can be described as follows:

- Risk analysis of a defined system involves the identification of analysis objectives, the identification of hazards, and the combination of the results of frequency analysis and consequence analysis to produce an estimate of risk.
- In risk assessment, the results of risk analysis are compared with risk criteria in the process of risk evaluation. Depending on the context and purpose of the analysis, these criteria may be more or less specific. For the purpose of prioritizing maintenance activities, the results may simply come from other risk analyses (i.e. the hazards presenting the highest risks are addressed first). In other instances, the results may be compared against explicit standards of acceptability, established either internally or in collaboration with the appropriate stakeholder community (the public, regulatory bodies, environmental groups).
- If the applicable risk criteria are met, no further activity is required beyond documentation and on-going monitoring. If the criteria are not met, then an options analysis is carried out to identify potential risk reduction measures, and the system (as defined) must be modified and the process repeated until a satisfactory outcome is achieved.
- The term risk control is used to describe the process of decision-making and monitoring used to manage risk, so that risk management is the integrated process of risk assessment and risk control.

10.3 Risk Analysis

Risk analysis is at the core of the risk management process, and provides the key information required for decision-making. Its general role is described in Annex B Clause B.4.1.2. In the context of SCC integrity management, it can provide valuable guidance, concerning the need for, and the appropriate type, frequency, and extent of, both general and site-specific condition monitoring and mitigation measures.

The steps involved in risk analysis are described in Clause B.5.2. It is important to identify the objectives of the analysis clearly at the outset, since these will determine the type of analysis and degree of rigor needed. Risk ranking tools, if carefully chosen, may be adequate in the condition monitoring phase and in maintenance prioritization. A more detailed analysis may be necessary to establish site-specific mitigation requirements.

The other essential prerequisite for risk analysis is a clear definition of the system to be analyzed, including all relevant details regarding the characteristics of the pipeline and its surroundings. Depending on the type of pipeline and service fluid, a wide range of potential receptors may need to be included in the system, and in some cases, the system may need to be extended to some distance from the pipeline.¹

Clause B.5.2.3 gives some general requirements regarding hazard identification. In the case of pipelines susceptible to SCC, the major hazards are related to incidents involving release of the service fluid. Structured methods, such as event-tree and fault-tree analysis, may be of use both in determining the likelihood of release events and in developing pathways from the release to specific outcomes.

Risk analysis should be applied to the SCC management plan (Figure 4.2) to assess the level of risk associated with a decision point. The following three decision points in the SCC management plan are particularly associated with a level of risk:

- a. Is the pipe segment susceptible to SCC?
- b. Is SCC present?
- c. What is the severity of SCC?

10.3.1 Frequency Analysis

Frequency analysis is briefly described in Annex B Clause B.5.2.4. This analysis can, in general, be either qualitative or quantitative. The level of refinement of the data available generally dictates which method is more suitable. Often a combination of these methods can produce the desired accuracy in the decision making process. With the advent of better ILI inspection, more precise modeling and an increased fundamental knowledge of SCC mechanisms, quantitative SCC modeling has become more practical. However, basic users of the Recommended Practices will find qualitative frequency analysis initially more suitable. As more detailed or more sophisticated SCC information becomes available, such as, for example, SCC ILI runs or hydrotest data, an operator should re-evaluate the efficiency of the current frequency analysis and consider some quantification of frequency.

10.3.2 Consequence analysis

Consequence analysis is described in Annex B Clause B.5.2.5. This analysis involves the estimation of the contingent probabilities and severity of adverse effects on people, property, and the environment. Here, the degree of appropriate precision will be determined primarily by the objective of the analysis. For risk ranking purposes, a simple classification by release size may be

¹ The distance used in defining class location assessment areas in CSA Z662 (200 m on each side of the centre-line of the pipeline) does not provide useful guidance to the area to be considered. Depending on the service fluid and the attributes of the pipeline, the maximum distance from the pipeline within which receptors need to be considered may be less than or much more than 200 m.

sufficient. For site-specific mitigation, fairly rigorous modeling of release characteristics and effects may be needed.

Overall, potential public hazards whose consequences must be analyzed include those related to fire and explosion, toxicity, and environmental damage. In addition, hazards related to loss of product and throughput, and to property damage, will also need to be considered. The severity of the consequences will generally relate to the size and operating pressure of the pipeline, the service fluid, and the size of the release. In most cases, physical models will be required which describe the characteristics of the release and its effects. Five classes of service fluid are considered, as follows:

10.3.2.1 Sweet natural gas

The thermal radiation effects following an ignited release constitute the major physical consequences of the release of sweet natural gas. Clearly any major release in the proximity of a populated area will have consequences in terms of shock to the public. As a result, it will first be necessary to estimate the probability of ignition. Historical experience indicates that this probability is low. However, it increases with diameter and operating pressure, and ignition is a likely outcome for the largest transmission pipelines.

If ignition occurs, the resulting fire must be modeled to predict the distribution of thermal radiation in space and time, allowing the extent and severity of adverse effects on people and property to be determined. In the case of ruptures, potential adverse effects resulting from debris throw should be considered, though for ignited releases they are usually of secondary importance. Releases from transmission pipelines are typically unconfined in nature, and explosive over-pressures are not sufficient to cause significant physical harm to people, although they may cause minor damage to property.

10.3.2.2 Sour gas, HVP liquid, CO₂

Though the principal hazards associated with these three service fluids are quite different, the nature of the gases requires a somewhat similar approach to consequence analysis. This involves dispersion modeling to determine the spatial and temporal distribution of specific concentration levels.

In the case of sour gas, the concentrations and times of concern are those related to acute toxicity. For HVP liquids, the extent and composition of flammable hydrocarbon clouds is of concern in determining the probability, extent, and effects of fires and explosions. CO₂ is generally considered a less-hazardous fluid, but the volumes released from a ruptured pipeline could be very large, and could result in the formation of asphyxiating atmospheres in low-lying areas.

For all these types of release, atmospheric conditions (wind strength and direction, atmospheric stability) and local topography (presence of ditches, drainage, valleys) have an important influence, and should be taken into account.

10.3.2.3 LVP liquid

In most instances, the consequences from LVP liquid releases will be site specific. If there is no immediate public exposure, and no obstacle to effective remediation, the consequences are limited to the economic impact of the pipeline repair, site remediation, and loss of product and throughput. The potential for more extensive consequences depends on the surroundings, the nature of the spill, the characteristics of the liquid released, and the meteorological conditions. Modeling requires consideration of local topography and environmental resources, the type of surface on which the spill occurs, and vapour dispersion. Though ignition probability is small for all but the higher vapour pressure end of the LVP spectrum, pool fires and the associated thermal radiation will have to be modeled where appropriate. Potential toxicological effects may also need to be considered. The potential for more extensive environmental consequences depends on local factors such as the presence of vulnerable biota, water-courses and sub-surface resources.

A wide range of models for such factors as release rates and volumes, thermal radiation intensity, dispersion of hydrocarbon clouds, and hazard zones is available, some in the public domain and some of a proprietary nature. It is important to understand the applicability and limitations of any such models used. Unless they are regularly applied and well understood by the pipeline company, it will usually be necessary to seek specialist advice.

10.4 Risk Evaluation

Risk evaluation involves assessing the significance of the estimated risk resulting from the risk analysis. This may involve determining the relative importance of risks from a number of different hazard scenarios, or the relative effectiveness of alternative risk reduction measures. Such evaluations can be used, for example, in the selection and prioritization of maintenance activities. In the case of semi-quantitative or quantitative risk estimates, risk evaluation may also involve comparison against explicit internal or external standards of acceptability. In carrying out such comparisons, it is important that both the analysis and the criteria are based on identical assumptions, and that the evaluation appropriately recognizes and accounts for uncertainties inherent in the analysis.

10.5 Conclusion

This section has provided general guidance concerning the application of risk assessment in the integrity management of pipelines affected, or potentially affected, by SCC. Its recommendations are based on the current state of the technology, in terms of understanding and modeling phenomena connected with SCC, detecting and sizing existing SCC, and of analyzing the frequency and consequences of related pipeline failures. Each of these areas is in a state of rapid evolution, and it is important to monitor developments closely in order to take advantage of improved understanding, detection, and predictive capability.

Risk assessment is not, and of its nature can never be, a precise science. It is important to understand the implications of uncertainties in models and estimation methods. The more detailed the analysis undertaken, the more extensive the demands for data. It is clearly counter-productive to analyze beyond the capability of the data to sustain the conclusions.

Further, the more precise and definitive our risk estimates claim to become, the more they raise the challenge of establishing broadly acceptable levels of risk. It is inadvisable to envisage risk as the sole driver in the pipeline integrity decision-making process. Rather, it should be viewed as a valuable tool to help make rational choices.

References

- [1] CSA Standard Z662-07, Annex N, *Guidelines for Pipeline Integrity Management Programs*, 2007.
- [2] CSA Standard Z662-07, Annex B, *Guidelines for Risk Assessment of Pipelines*, 2007.

11.	Post Incident Management	11-2
11.1	Incident Investigation	11-3
11.2	Procedure.....	11-3
11.2.1	On-Site Incident Investigation	11-4
11.2.2	Background Information	11-9
11.2.3	Metallurgical Failure Analysis	11-10
11.3	Documentation	11-11
11.4	Return to Service Plan	11-11
11.5	Short Term Plan	11-12
11.5.1	Pipeline Repair.....	11-12
11.6	Regulatory Submission	11-13

11. Post Incident Management

The following section outlines steps operating companies may take to minimize the impact of an SCC failure incident. The steps outlined are not entirely unique from other failure mechanisms faced by the pipeline industry. However, industry experience indicates that certain steps are required and can prove to be beneficial in obtaining necessary assurance and approvals to return pipelines back to pre-failure operating conditions. For the purpose of this section “failure” is considered a rupture. These guidelines may also apply to an in-service leak; however, other repair options may be applicable aside from a cut out.

The immediate safety, environmental and regulatory reporting concerns associated with pipeline failure should be addressed. The next priority in post incident management is to secure the site and initiate steps for incident investigation. Evidence, including pipe samples, local site conditions and all pertinent operation conditions at the time of the failure, need to be collected, preserved and documented. Standard practice is to complete a metallurgical analysis of the pipe failure to confirm the failure mechanism. The metallurgical analysis may include pipe properties testing to identify any unique conditions of the failure area or pipe joint. This information will prove valuable when reviewing other segments, which may be susceptible to SCC failure. Detailed analysis of the SCADA information is required to establish operating parameters leading up to and during pipeline failure. In addition, historical operating parameters should be collected and evaluated. This information will establish pre-incident pressure maximums and assist in determining safe operating pressure limits once the line is placed back in service.

In conjunction with the detailed incident investigation, operating companies need to evaluate and set out a short term ‘Return to Service Plan’. At this point the failure mechanism is not usually confirmed, thus a review of all relevant integrity data is required. This data may include previous in-line inspection programs, hydrotest history, investigative dig programs on the pipeline segment, construction as-built information, geotechnical analysis, cathodic protection data, nearby crossings, as well as third party activity in the area.

Should the metallurgical report confirm the failure mechanism to be near-neutral SCC, operating companies can focus on development of a corrective action plan to address and mitigate risk of additional SCC-related failures. If an SCC Management Program (SMP) has not been developed and implemented as outlined in previous sections of these Recommended Practices, then the failure segment provides a starting point for the corrective action plan. The primary focus for this section is the premise that an operating company has established some form of a SMP and has subsequently experienced an SCC failure.

11.1 Incident Investigation

The following outlines a process for conducting pipeline incident investigations for pipeline failures. Incident investigations are performed in response to an in-service leak, rupture, or other type of incident that has occurred along the pipeline and will require an assessment to determine the cause of the occurrence and any necessary mitigation. This document will provide the approach to undertake an incident investigation, including an on-site investigation and a subsequent metallurgical failure analysis.

This document takes into consideration the latest technologies and mandatory requirements of the regulations and industry standards.

11.2 Procedure

The emphasis of an incident investigation should be fact finding rather than fault finding and should focus on determining the cause of the failure and the contributing factors.

An incident investigation must not commence until all of the necessary requirements (i.e. internal and external notifications, assessment of the incident's severity (i.e. leak, explosion, etc), product supply is isolated (block valves confirmed closed), isolation of hazard area and evacuation if necessary, establishment of site security, resource mobilization, etc.) outlined in Emergency Response Plans have been undertaken and completed. In some cases the Transportation Safety Board (TSB) and National Energy Board (NEB) have control of the site and the operator must wait until they have released the site prior to commencing the incident investigation.

Prior to notification that the incident site has been released for investigation, the coordination of the roles and responsibilities of those company personnel, and/or designated contractor(s) must be confirmed. In addition those government/regulatory agencies that have control/jurisdiction of the incident site must be identified, the primary investigating agency determined and the roles and responsibilities of this agency confirmed.

Once the initial Emergency Response Plan (ERP) procedures have been completed, the site has been deemed safe and is released by applicable regulatory agencies, the operator shall release the incident site for investigation and only at this time may the incident investigation commence.

It cannot be emphasized strongly enough that the most useful information related to many aspects of an incident investigation (i.e. witness interviews, evidence, site photographs) is gathered and generated immediately following the occurrence of the incident.

The following sections provide a detailed discussion of the various steps involved in conducting the on-site incident investigation and the subsequent metallurgical failure investigation at a company-approved laboratory (refer to Figure 11.1 for a visual depiction of the steps).

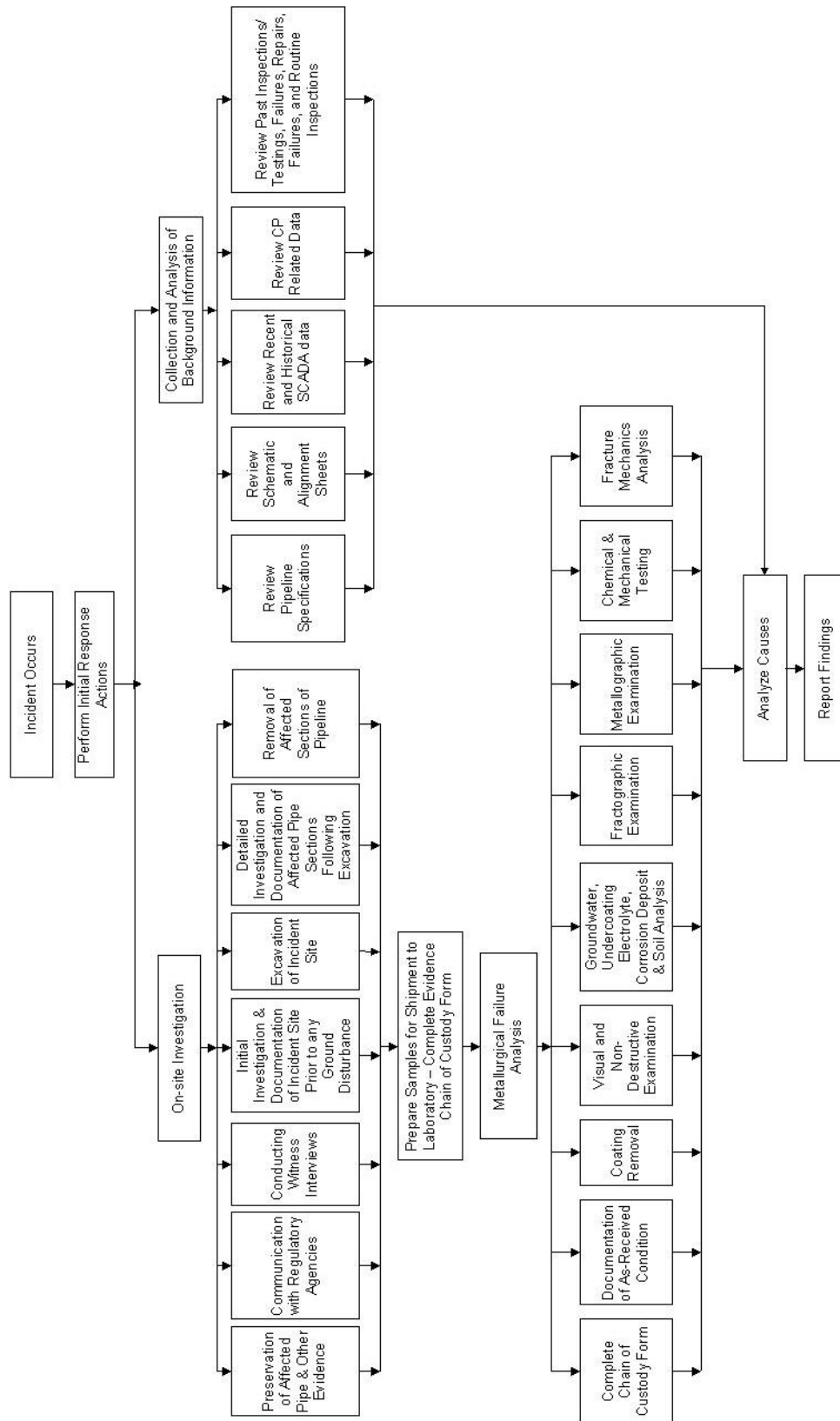


Figure 11.1: Flowchart of the Recommended Steps when performing an Incident Investigation

11.2.1 On-Site Incident Investigation

The primary purpose of the on-site incident investigation is to collect and document all relevant site information that will ultimately be used to assist in: a) the determination of the cause of the failure, b) the possible site-related and operating conditions that may have contributed to the failure and c) the damage caused by the failure.

To adequately conduct an on-site incident investigation, there are a number of tools and other items that are required by the individual conducting the on-site incident investigation. Provided below is a suggested list of tools and other items that may be used to help collect important site information and protect the evidence (pipe fragments) from damage during removal from the site:

- digital camera
- toothbrush
- water/antifreeze
- tape measure
- magnetic ruler
- survey wheel (for measuring long distances)
- gloves
- notepad and pencil
- metal detector
- magnifying glass
- alignment sheets to identify all pipelines and facilities in the area
- shovel
- ziploc bags and sample jars
- grease pens/paint markers/spray paint/pipe labels to mark pipe fragments
- survey stakes or flag markers
- jar of Vaseline or thick lubricant to protect the fracture surface
- foam tubing or rubber tubing and duct tape to protect the fracture surface
- banana knife

It is important to label pieces of evidence (i.e. pipe fragments) with the location, size, and description. In tall grassland areas, tall survey stakes with brightly colored flags help to locate various pipe fragments. Ziploc bags and sample jars are helpful for collecting soil samples, coating and ground water samples.

11.2.1.1 Preservation of Affected Pipe and Other Evidence

All necessary precautions must be taken to ensure the incident site is isolated from contamination and any evidence is preserved from loss and distortion. In addition, the company-designated personnel and/or the appropriate investigating agency must be protected against physical injury and health hazards that may be encountered during the process of the investigation.

An incident investigation is a methodical process that provides the means to evaluate the evidence. Significant clues to an analysis are often hidden within the edge of fractured sections of pipe, in characteristic patterns of buckled surfaces, in the residue of a charred structure, in fluids, etc.

Any section of pipe that is suspected of failure, at the incident site, requires careful protection and preservation from the moment the incident occurred, through the process of investigative analysis, to the final destination for analysis (i.e. laboratory). All fracture surfaces must be coated with a lubricant and protected with a split rubber hose, foam tubing or similar item, as soon as practically possible. The fracture surfaces must not be touched or cleaned on-site unless completed by a qualified investigator.

11.2.1.2 Communication with Regulatory Agencies

Communication with the primary investigating agency must be performed, as outlined in the ERP, and any requested documentation must be provided to the regulatory agency in the required time period. Typically land groups, environmental groups, engineering, communications, legal and operations groups all play a role in a failure investigation. It is helpful to appoint one key person to collect all of the information, formulate the report and act as a single point of contact to the regulatory board.

11.2.1.3 Communication with Other Stakeholders

The company should recognize the importance of communications with other stakeholders. These stakeholders include: landowners, the general public, and the local and national press and broadcast media. A communications plan should be established.

11.2.1.4 Conducting Witness Interviews

The company-designated personnel and/or the appropriate investigating agency should interview any relevant witnesses to gather any preliminary information associated with the scope and nature of the incident. An observer's testimony is most credible immediately following the incident. The most readily recollected facts and events are those that have been recently learned or observed.

It is imperative that all interviews be documented and for each interview, the name of the witness, contact information for the witness, type of witness (i.e. general public, local authorities, company personnel, third party contractor, etc.) must be recorded along with their account of the events.

11.2.1.5 Initial Investigation and Documentation of Incident Site Prior to any Ground Disturbance

A preliminary visual survey of the failure area can ascertain which information should be recorded. Sketches of the failure area showing direction of flow and other prominent features can assist in the collection of data to aid in the analysis. The primary purpose of any sketches, diagrams, photographs and measurements taken at the site is for the purpose of analysis.

Provided below is a summary of the various types of information, data and/or samples that should be collected, prior to any ground disturbance, to adequately characterize and document the observed conditions associated with the incident site:

1. Digital aerial photographs.
2. Digital photographs must be taken of the overall landscape associated with the incident site to identify pipe fragments and potentially large scale geotechnical activities (such as slope movement) that may have contributed to the failure.
3. Digital photographs must be taken of the crater, if any, created by the incident.
4. Detailed drawings (top view and side view) must be created of the incident site with surveyed measurements of the upstream/downstream welds, the crater, if any, created by the incident, and the area of damage (indicated by discoloration/damaged vegetation).
5. The terrain conditions (i.e. soil type, drainage and topography) observed at the incident site must be described and digitally photographed.
6. If possible, pipe-to-soil potentials and cathodic protection potentials at test stations and rectifiers in close proximity (upstream and downstream) to the incident site should be collected and recorded. These measurements should be made prior to any cutting or removal of the failure section.
7. Soil samples should be collected at pipe depth, adjacent to the pipe (if possible, it is preferable to get as near as possible to the flaw that caused the incident) and >1 m perpendicular to the pipe in the ditch wall (i.e. native soil sample). The coating condition, in the immediate vicinity of the incident and upstream/downstream of the incident, should be described and digitally photographed.
8. If sufficient quantities of corrosion products are evident on the internal or external pipe surface, samples should be collected.

11.2.1.6 Excavation of Incident Site

All necessary precautions should be taken during the excavation to ensure that the affected section(s) of pipe in general and any fracture faces in particular are not damaged during the excavation process. If the pipeline ruptured, it is likely that a portion of the pipe fracture (i.e. fracture face, "flap" or "fish mouth") is

extended outside of the normal pipe diameter. Consequently, only hand excavation in the immediate area of any fracture faces is recommended.

Once all of the required hand excavating has been completed, and the fracture faces have been appropriately protected, mechanical excavation of the incident site can commence.

The length of the excavation must be such that the affected joint of pipe and at least one (1) full joint of pipe both upstream and downstream of the affected joint of pipe are completely excavated and inspected.

11.2.1.7 Detailed Investigation and Documentation

Upon completion of the excavation, the following activities must be undertaken prior to the affected section(s) of pipe being removed and shipped to an approved laboratory for the detailed metallurgical investigation:

1. If the incident resulted in an explosion and the ejection of some pipe from the pipeline then a thorough assessment must be conducted to ensure that all ejected pieces of pipe have been located and properly documented. This requires measuring the distance of pipe missing from the ditch and the total lengths of pipe found.
2. For any exposed section(s) of pipe, the upstream and downstream girth welds, along with the longitudinal seam weld, must be identified and clearly labelled. Also the joints should be numbered or labelled with a chainage or numbered.
3. The "top dead center (TDC)" of the pipe must be determined and clearly labeled with a paint stick or marker.
4. The "flow direction" must be clearly labeled along the exposed pipe.
5. If there is a bend existing within the excavated length of pipe, the profile of the bend must be characterized and documented.
6. An initial examination of all fracture faces must be conducted to identify the location and potential cause of the initiating defect that resulted in the incident.
7. A schematic of the affected section(s) of pipe involved in the incident must be created. The schematic should depict the axial and circumferential location of the failure initiation, running fracture and fracture arrest points, the locations of the upstream and downstream girth welds, length of each joint, locations of bends, the circumferential location of the longitudinal weld(s), and the direction of product flow.

11.2.1.8 Removal of Affected Sections of Pipeline

Once the activities described above in 11.2.1.7 have been completed, the affected section(s) of pipe can be removed and replaced with new pre-tested pipe.

As a minimum, those joint(s) of pipe containing at least some portion of the fracture face must be replaced in their entirety. In addition, if possible, one (1) full joint upstream and downstream of those joint(s) of pipe should also be removed. If it is not possible then the largest section of pipe must be removed with the length of pipe removed to be the minimum distance of two (2) pipe diameters away from the upstream and downstream failure arrest points. The girth welds immediately upstream and/or downstream of the cut-out sections, that were not removed, should be non-destructively examined (x-ray, UT or phased array) to verify that the stresses which the pipe may have incurred as a result of the failure did not cause defects in the weld(s). It is also valuable to ensure the tie-in location on the existing pipe is free of SCC and has a minimum wall thickness of 90% of the specified nominal wall thickness. Typically a four-inch wide band from the cut location should be inspected with MPI and UT around the pipe circumference.

When removing the section(s) of pipe, any indication of residual stress in the line should be documented. Spring or movement of the pipe when the first circumferential cut is completed would indicate the presence of residual stress. To further relieve the stress on the pipeline, additional joints may need to be exposed. Once the existing pipe has been stress relieved the offset distance should be measured and a cold bend may be required for proper fit-up of the pipe replacement.

The exact length and location of the removed section(s) of pipe must be documented and the removed section(s) of pipe digitally photographed.

Those section(s) of pipe containing a portion of the fracture face must be carefully wrapped to protect the fracture faces from deterioration and/or damage while the pipe is being transported to the company-approved laboratory for the metallurgical failure analysis.

11.2.2 Background Information

Background information relating to the pipe specifications, failure pressure, operating pressure history, historical operational related issues, and prior inspections/testing (in-line inspections, excavations, hydrostatic testing, etc.), repairs, and surveys performed along the pipeline that experienced the incident are necessary to the overall incident investigation and can provide valuable information which will assist in determining the factors that may have contributed to the incident.

Provided below is a summary of the background information that should be collected and reviewed:

1. Pipeline specifications (i.e. pipeline manufacturer, year and season of construction, type and grade of steel, type of longitudinal seam weld, coating type, etc.)
2. Schematic and alignment sheets of the pipeline system (i.e. locations of pump stations, block valves, hydrostatic profile, etc.)

3. Recent SCADA data - SCADA data from several days prior to the incident, during the incident and immediately following the incident, must be collected and reviewed. In addition, a chronology of the alarms received during the incident and actions taken in response to those alarms must be documented.
4. Historical SCADA data - Historical discharge and suction pressure, from as far back as possible, must be collected for the pump stations immediately upstream and downstream of the incident.
5. Cathodic Protection (CP) related data (date cathodic protection was applied to the pipeline, type of CP system, current and historic CP levels at location of the incident, etc.)
6. Summary of past inspections/testing (in-line inspections, excavations, hydrostatic testing, etc.), failures, repairs and routine inspections.
7. Pipe modifications or third party activities such as road construction, crossings or new casing installations.

The above documentation will be used in combination with the on-site documentation collected and the results from the detailed metallurgical failure analysis, to complete an overall and comprehensive incident report.

11.2.3 Metallurgical Failure Analysis

The primary objective of the metallurgical failure analysis is to identify the type of defect(s) that caused the failure and any metallurgical factors that may have contributed to the failure. The failure analysis may also identify issues that must be remediated to ensure the integrity of other sections of the failed pipeline, as well as other pipelines with similar characteristics (i.e. pipe manufacturer, seam type, grade, other specifications, coating type, and environmental conditions).

Prior to initiating the failure analysis and selecting an analysis method, it is advisable for the laboratory personnel to become as familiar as possible with any available general site information, preliminary findings and results which have been documented to date, regarding the incident and any investigations performed. In particular, the laboratory personnel must review the background information collected.

During any failure analysis essential engineering decisions must be made. The results of each step will dictate the next procedure or sequence of procedures in the assessment, or whether it may be necessary to modify the current procedure(s). The need for performing additional tests is determined throughout the investigation, and in some instances, additional samples of pipe (i.e. from adjacent pipe sections) may be required to perform additional testing. If testing will be performed on additional samples, the test plan should be modified to reflect these changes. It is not in the interest of conducting a prudent failure analysis to perform any testing which has no relevance to the failure. The following summarizes the essential steps that should be taken as part of a failure analysis:

1. Chain of Custody
2. Documentation of As-received Condition
3. Coating Removal
4. Visual and Non-destructive Examination
5. Groundwater, Undercoating Electrolyte, Corrosion Deposit and Soil Analysis
6. Fractographic Examination
7. Metallographic Examination
8. Chemical and Mechanical Testing
9. Fracture Mechanics Analysis

The metallurgical failure analysis summary report should provide the root cause of the failure and the supporting test results.

11.3 Documentation

All documentation relating to a failure investigation including correspondence, chain of events, site analysis, SCADA trends, geotechnical recommendations and metallurgical analysis reports must be securely tracked and stored for future reference. At any time insurance companies, lawyers, and regulators may request information from the investigation.

11.4 Return to Service Plan

Once the failure investigation is complete the operator should complete the following five key steps to return the pipeline to service:

1. Short Term Plan
2. SCC Management Model Review and Analysis
3. Corrective Action Plan
4. Long Term Plan – condition monitoring
5. Steps 3 and 4 are discussed in detail in Chapter 4 and illustrated in Figure 4.2 SCC Management Model. The occurrence of a pipeline failure due to transgranular SCC is a direct indication that a category IV crack exists on the pipeline. Therefore the operator must jump to the corrective action (mitigation) task in Figure 4.2 and re-evaluate the condition of the pipeline segment until the pipeline segment is safe to operate.

11.5 Short Term Plan

Once the root cause of the failure has been identified, an operator will outline a short-term plan or list of tasks they commit to completing in an effort to prepare the failed pipeline for service. The short-term plan should address key points such as the repair plan, environmental concerns, commitment to review and analyze the SCC management model and discuss the corrective action plan to ensure the pipeline is safe to return to service.

11.5.1 Pipeline Repair

Most operators have stockpile yards containing emergency pipe that has been pressure tested and coated for easy installation. However, most of the pipes found in stockpile yards are 20 to 30 years old and have been exposed to extreme weather conditions. Prior to shipping out joints for a pipe repair it is valuable to complete the following checks;

1. Confirm the mill test records (MTR) documents are available;
2. Confirm the pipe has been pressure tested to an acceptable pressure for the class location and MOP of the failure site;
3. Complete a visual inspection of the pipe for damage including coating condition (i.e. UV degradation or weather damage).

In addition, if the emergency pipe is tape coated the operator should consider recoating with a high performance coating (FBE or liquid epoxy or urethane) to prevent SCC susceptibility in the future.

While planning the repair the project engineer should consider the root cause of the failure and any contributing factors to prevent another failure. For example, if construction misalignment was a contributing factor then a new cold bend might be required to ensure accurate fit up and eliminate possible transverse/longitudinal stresses. If geotechnical movement was a contributing factor, modifications to the slope may be required to prevent other geotechnical issues. In some cases a retaining wall or terracing a slope may be required. As a long-term solution, strain monitoring equipment might be installed on the new joint to record increases in strain or alarm an operator's SCADA system in the event the actual strain reached exceeds a maximum limit. Another option is for an operator to install above-ground slope monitoring equipment.

In most cases an operator would like to return the pipeline to service as soon as possible due to operational constraints caused by the failure. In these cases the operator may request permission from the regulator to return to service at a reduced pressure after conducting the repair. A reduced pressure may be 80% of the 60-day highest pressure the pipeline experienced prior to failure (provided that was less than the MOP). This provides more time for an operator to evaluate the SCC susceptibility of pipe segments and to conduct investigations.

11.6 Regulatory Submission

The final regulatory submission provides the regulator with a summary of the failure investigation and plan forward for returning the pipeline to service. The summary report should provide:

- Description of the failure;
- Background/historical information on the pipeline;
- Results of the failure investigation – root cause;
- Short-term plan;
- SCC management model review and analysis;
- Corrective actions completed and outstanding;
- Timeframe for return to service;
- Impact of the outage to society, the environment and the operator;
- Long-term condition monitoring plan;
- Confirmation the pipeline is safe to put back into operation.

Communication with the regulator throughout the failure investigation is helpful in receiving a timely response. In addition, the operator may consider providing the regulator(s) with a presentation/overview of the summary report to facilitate detailed questions.

12.	Circumferential SCC.....	12-2
12.1	Scope	12-3
12.2	Failure Mechanisms	12-3
	12.2.1 Failure resulting in a leak	12-3
	12.2.2 Failure resulting in a rupture	12-4
12.3	Field Program Development	12-5
	12.3.1 Review of C-SCC Susceptible Conditions	12-6
	12.3.2 Review of Susceptible Environment	12-7
	12.3.3 Review of Axial Tensile Stress.....	12-7
12.4	Inspection.....	12-8
	12.4.1 In-Line Inspection Tools	12-8
12.5	Integrity Assessment.....	12-8
12.6	Prevention and Mitigation.....	12-9
	12.6.1 Hydrostatic Retesting	12-9
	12.6.2 Repairs	12-9
	References	12-10

12. Circumferential SCC

According to the NEB Report of the Inquiry (Order No. MH-2-95), six of the Canadian stress corrosion cracking (SCC) failures to that time had been leaks resulting from circumferentially oriented cracks. As a result, the NEB made Recommendation 6-9 “*that CEPA develop procedures for the detection and mitigation of circumferential SCC and include them in future versions of the Recommended Practices Manual.*” CEPA prepared and issued a report in December 1997 [1], reviewing the state of knowledge concerning circumferential SCC and its mitigation. The report was later presented at the International Pipeline Conference [2] in Calgary.

This chapter of the SCC Recommended Practices is based in large part on that report.

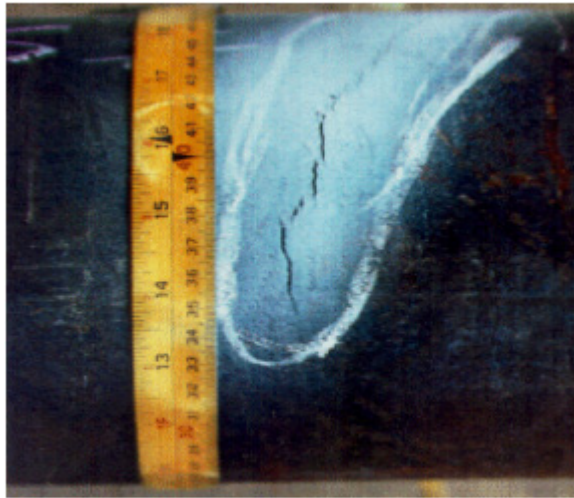


Figure 12.1: Example of circumferential stress corrosion cracking

12.1 Scope

This chapter of the CEPA Stress Corrosion Cracking Recommended Practices deals with the issue of circumferentially oriented stress corrosion cracking (C-SCC), which are cracks that deviate in direction from the longitudinal axis of the pipeline.

The chapter constitutes an integral part of the Recommended Practices (RP). As such, there will be minimal duplication of material in this chapter and it will reference only specific sections of the RP that are particular to circumferential stress corrosion cracking. The RP, including this chapter, are intended to be considered as a whole, and users are cautioned to avoid the use of individual chapters without regard for the entire RP.

Circumferentially oriented SCC (C-SCC) is a subset of transgranular SCC. In the case of C-SCC the principle stress acting on the crack is a bending stress, which is typically acting in a longitudinal direction. This bending stress is a different stress than the normal circumferential hoop stress generated from the internal pipe pressure. The bending stress may be due to differential settlement of the backfill beneath the pipe, geotechnical ground movement or possibly external loads other than soil.

12.2 Failure Mechanisms

12.2.1 Failure resulting in a leak

All but two of the C-SCC failures to date have been leaks. The cracks in the leak cases were either oriented circumferentially (perpendicular to the path of maximum axial stress) or displayed short circumferential cracks that “stepped” in a helical pattern following the path of the tape disbondment or tenting (Figure 12.2 and Figure 12.3).

Two forms of tape disbondment were associated with the C-SCC: the tape helix and wrinkles. The tape helix is essentially an area of tape tenting (Figure 12.2).

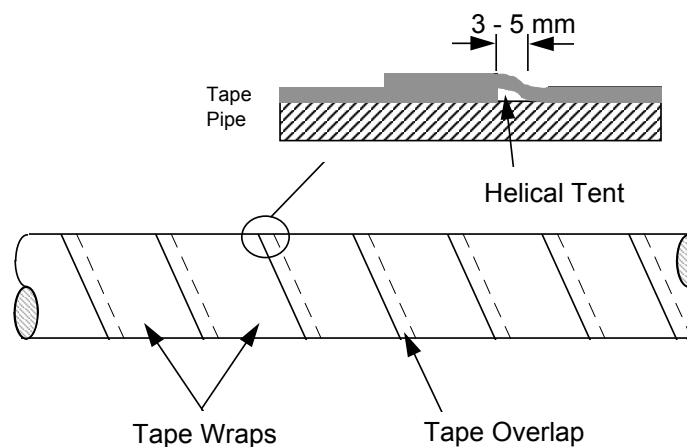


Figure 12.2: Polyethylene-Tape Helical Tent

As the tape was applied, successive wraps overlapped the previous wrap. As illustrated, a narrow tented area would be created at the edge of the previous wrap under the successive wrap. Normally this gap is dry. However, where damage to the coating occurs, water can gain entry.

Two patterns of tape wrinkles have been observed: longitudinal and circumferential. Longitudinal wrinkles are presumed to be a result of soil settlement in the trench. Relative movement between the pipe and the soil stretches the tape, causing it to 'bunch up' or wrinkle toward the bottom of the pipe. Circumferential wrinkles are seen on slopes and likely occur when coating adhesion fails in response to relative axial displacement between the pipe and the soil.

The C-SCC has been found to follow circumferential wrinkles or helical tenting. The cracking that follows the helical tenting starts as multiple smaller circumferential cracks located in the tented area that coalesce and form a larger crack that follows the tenting direction.

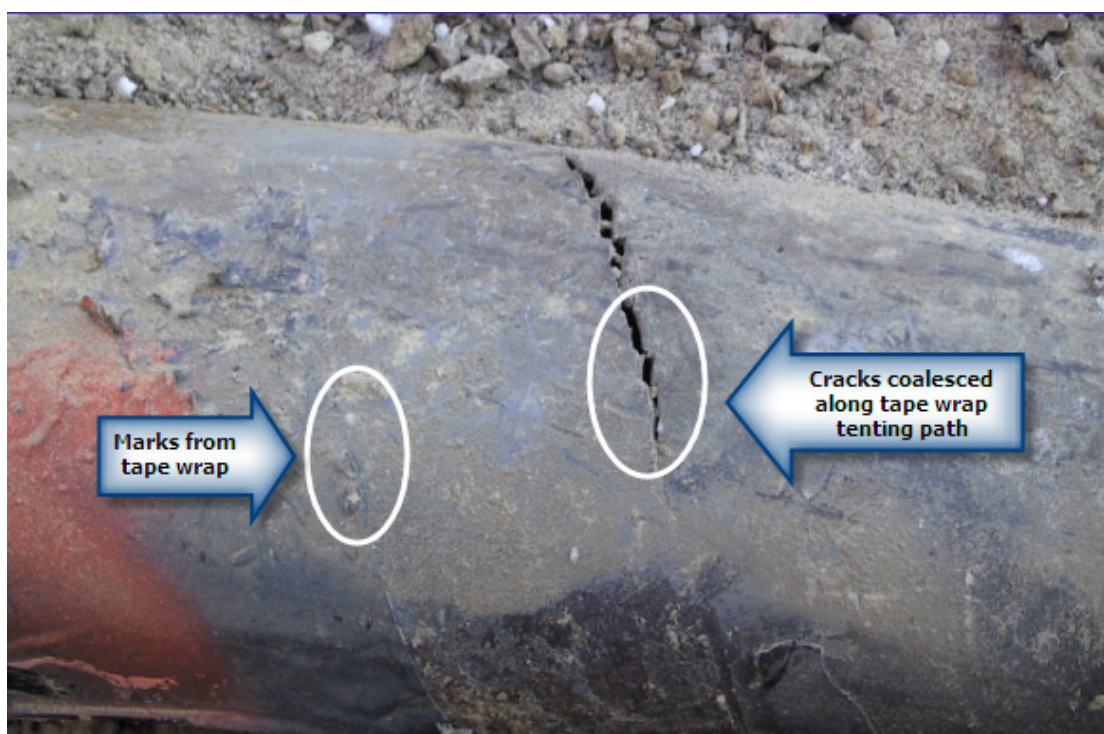


Figure 12.3: Cracks coalescing to follow the tape wrap tenting

12.2.2 Failure resulting in a rupture

There have been two known instances where C-SCC resulted in a rupture. One rupture occurred in 2001 on a liquid pipeline in Brazil and was a guillotine rupture. The other known rupture was in 2005 on a gas pipeline in Northern

Alberta. The Alberta failure is to date the only known case of C-SCC that involved spiral weld pipe.

The potential for rupture appears to increase when the change in angle between the initial crack direction and the preferred path of rupture is small, as can be the case for spirally welded pipe. In the case of spiral weld pipe the preferred path of rupture is parallel to the spiral weld (ie. parallel to the rolling direction of the skelp).

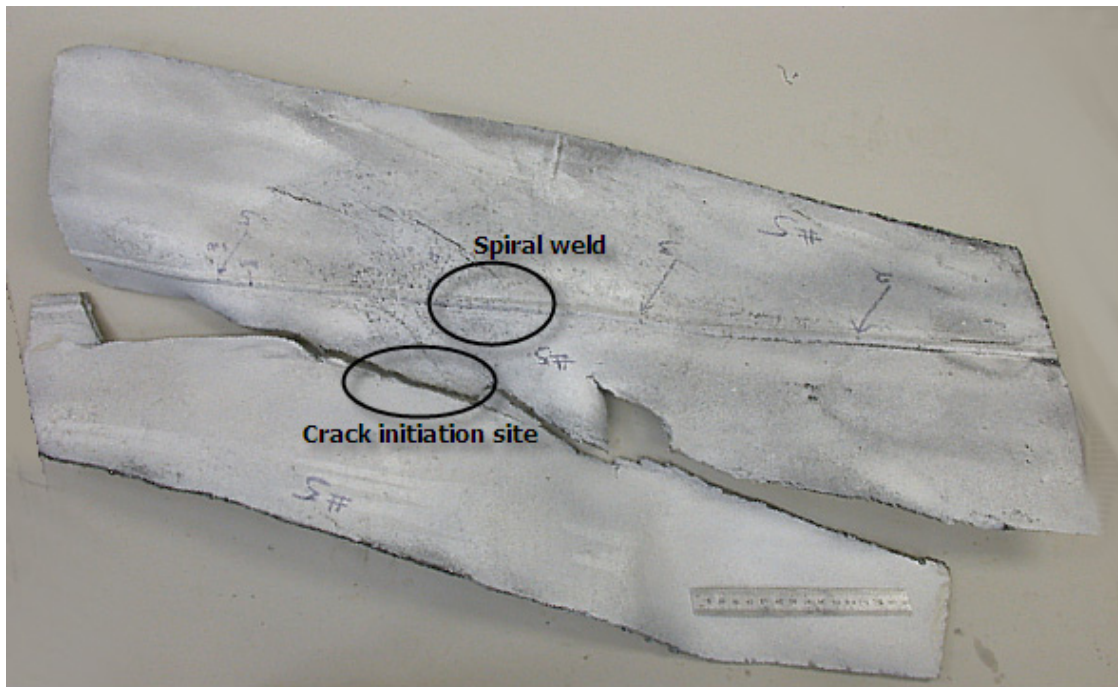


Figure 12.4: Ruptured pipe area showing crack initiation angle is close to the spiral weld angle

12.3 Field Program Development

Industry experience indicates that C-SCC has much the same growth factors as transgranular SCC (Figure 12.5), aside from the source of the principle stress. Therefore, as in the case of longitudinal SCC, a combination of known parameters related to susceptibility, can be used to develop a consistent process to assess and prioritize pipeline segments. In the case of C-SCC, the parameters related to SCC susceptibility are augmented by parameters that give rise to axial loading or bending of the pipe. The first step in this approach is to compile and review available operational, environmental and geotechnical data for each pipeline segment.

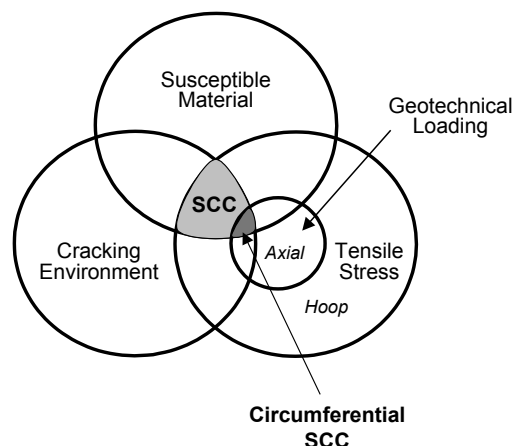


Figure 12.5: Circumferential SCC as a Subset of Pipeline SCC

12.3.1 Review of C-SCC Susceptible Conditions

The following conditions have been associated with the occurrence of C-SCC.

- Pipe - leaks occurred on lines constructed over a narrow range of years and involved ERW and DSAW long seam welded pipe. No pattern was observed in the pipe steel grades involved (290 to 448 MPa) or in terms of pipe diameters, which ranged from 168 to 914 mm.
- Pipe - a rupture occurred on one gas line constructed with spiral welded pipe. The pipe steel grade was 414 MPa, and the pipe diameter was 457 mm.
- Pipe - a rupture occurred on one liquid line constructed with longseam welded pipe. The pipe steel grade was 414 MPa, and the pipe diameter was 323.8 mm.
- Pipe condition - dents resulting from differential settlement at rocks or pipe wrinkles may be indicative of high axial stresses.
- Coating type - all service related incidents on CEPA-member systems have been associated with polyethylene tape. The two other known incidents occurred under a heat shrink sleeve and on damaged coal tar enamel that was over-coated with polyethylene tape.
- Coating condition - significant coating damage may not be a prerequisite for C-SCC as many of the incidents involved cracking that followed the helix of the tape overlap, and other minimal coating damage. Longitudinal and circumferential wrinkles indicate soil stress, and circumferential wrinkles are caused by relative axial displacement between the pipe and the soil.
- Operating stress level - may have a minimal impact on C-SCC as the hoop stress may contribute only a small portion to the axial stress.

12.3.2 Review of Susceptible Environment

The following factors have been associated with the occurrence of C-SCC:

1. Topography

- Topographical regions characterized as uplands of undulating and rolling topography with high annual levels of precipitation.
- Slopes of 10 degrees or greater.

2. Drainage

- Seepage at pipe depth may bring water to the pipe.

3. Soil

- Clay soils in contact with the pipe.
- Clays and water are known to play roles in soil movement on slopes.
- Rocks that bear against the pipe and become localized points of differential settlement and bending stresses on the pipe.

12.3.3 Review of Axial Tensile Stress

C-SCC initiates and grows under conditions of high axial stress generated by slow soil movement (slope creep) and/or localized pipe bending in the vicinity of rocks and dents. Construction practices can also induce axial stress in the pipe. This may occur where pipe was forced into alignment for welding at tie-in locations, for example at stream crossings, or at locations of field bends. Bending stress can occur at road crossings where the loads are too great for the cover and strength of the pipe.

12.3.3.1 Geotechnical Data

Geotechnical or pipe displacement data are required to assess susceptibility for differential settlement on slopes and axial loads or bending moments on the pipe. Such data and information sources as the following may be considered:

- Geotechnical surface maps
- Historical information on soil movement
- Visual observation of vegetation adjacent to the right-of-way indicating past soil movement and soil surface cracks indicating recent soil movement
- Inclinometers and land survey measurements of movement.
- Soil core analyses for slopes, including identification and composition of bedding planes and details of water seepage;
- Soil strength and composition data, including stoniness;
- Topographic maps or data combining climate and levels of precipitation;
- Construction records, including route selection data and survey notes;

- Pipeline as-built drawings showing the orientation of the pipe in the slope, the depth of cover, and any geotechnical construction details;
- Project files and pipeline maintenance records;
- Aerial photo interpretation and field verification in association with the aforementioned maps and data.

12.3.3.2 Operating and Maintenance Data

Current knowledge from the operating failures and field work has shown the following parameters as potentially indicating or identifying differential settlement on slopes and axial stress or bending moments on the pipe.

- In-line inspection (ILI) data – Various magnetic flux or caliper tools are capable of identifying certain pipe wrinkles, pipe ovality and dents that may result from differential settlement. Inertial tools can assist in determining the location of slope movements. Successive tool runs may enable calculations of the magnitude of pipe movement and the resulting strains. Some magnetic flux inspection tools may be capable of detecting corrosion associated with circumferentially oriented cracking or cracks that have sufficient opening.
- Databases of landslides and slope instability, locations of ditch plugs, berms, strain relief, and pipe re-routes.
- Strain gauges can provide detailed measurements of pipe strain. Pipe-soil interaction models may also be used as a predictive tool.

12.4 Inspection

12.4.1 In-Line Inspection Tools

In-line inspection capable of detecting circumferentially oriented cracks has shown promise, but has not been fully commercialized. Some high-resolution MFL tools may be capable of discriminating such cracking that has sufficient crack opening. UT and EMAT tools are also potentially capable of detecting circumferential cracks.

12.5 Integrity Assessment

Growth rates were calculated for six of the eight leaks [1,2] based on the maximum depths of cracks, and exhibited an average value of 5.9×10^{-9} mm/s. These rates are consistent with the range observed for transgranular SCC both in the laboratory, as well as in operation. In one of the leaks, an axial stress in excess of 100% SMYS was calculated as being applied by soil movement.

Failure criteria and life prediction can be modeled after the methods used for longitudinal SCC. However, this will require calculations or estimates of axial stresses.

12.6 Prevention and Mitigation

Prevention and mitigation of C-SCC on slopes may be largely addressed by effectively managing geotechnical concerns on slopes. Programs directed toward preventing soil movement, reducing the loading on the pipe, for example by strain relief, or relocating pipelines could all have benefit with respect to preventing C-SCC in susceptible areas.

Leak detection could prevent a small leak from progressing. Posting emergency phone numbers in the right-of-way will also improve prevention.

Other locations where high bending stresses may exist, such as tie-in locations, bends, and crossings should also be considered in a proactive program of locating C-SCC.

12.6.1 Hydrostatic Retesting

Hydrostatic retesting is not a suitable method of mitigating C-SCC as the axial component of the hoop stress may be insufficient to activate or remove critical defects.

12.6.2 Repairs

Repairing C-SCC by buffing removal and a resultant reinforcement, if required, is not recommended for C-SCC defects unless the source of the bending stress is positively identified and removed. Additional support for the pipe should be considered while the excavation is open.

References

- [1] The Canadian Energy Pipeline Association (CEPA), "The CEPA Report on Circumferential Stress Corrosion Cracking", Calgary, AB: CEPA, Dec 1997.
- [2] Sutherby, Robert L., "The CEPA Report on Circumferential Stress Corrosion Cracking," in Proc. 1998 International Pipeline Conference, 1998, v. 1, pp. 493-503.
- [3] CEPA SCC Recommended Practices, *Addendum on Circumferential SCC*, 1998.

