4 Understanding Stress Corrosion Cracking (SCC) in Pipelines

4.1 Scope Statement

"Compile a report summarizing the history of SCC on pipelines, explaining the causes and factors contributing to SCC initiation and growth, and discussing methods for prevention, detection and mitigation of SCC on pipelines, including effectiveness of ILI tools and other in-the-bell hole examination methods to detect SCC."

The scope statement was broken down into components of Understanding Stress Corrosion Cracking (SCC) in Pipelines (Chapter 4); Prevention of an SCC Problem (Chapter 5); Detection of SCC (Chapter 6); and Mitigation of SCC (Chapter 7).

This chapter summarizes the current state of knowledge of understanding the mechanism and characterization of SCC – both classical (high-pH SCC) as well as near neutral-pH SCC.

4.2 General Characterization (NEB 1996)

SCC in pipelines is a type of Environmentally Assisted Cracking (EAC). EAC is a generic term that describes the formation of cracks caused by various factors combined with the environment surrounding the pipeline. Together these determinants reduce the pressure carrying capacity of the pipe. When water (electrolyte) comes into contact with steel, the minerals, ions and gases in the water create corrosion that attacks the steel. These chemical or electrochemical reactions may result in general thinning, corrosion pits and/or cracks.

EAC includes two mechanisms that should be distinguished: Corrosion fatigue and SCC. "Corrosion fatigue" occurs when chemically reactive agents penetrate fatigue cracks. These agents can accelerate crack progression. The chemical condition within the crack can be more aggressive than on the free surface. Even if the metal surface at the crack tip passivates (forms an inert barrier) the next fatigue loading can crack the brittle deposit and reactivate the whole process. Thus, corrosion fatigue is the joint action of a *cyclic stress and a corrosive environment that decrease the number of cycles to failure*. Compared to the life of the pipe when no corrosion is present, the basic role of the corrosive environment is to decrease the life of the component. Similarly, SCC involves corrosive mechanisms and depends on both an *aggressive environment and tensile stress*. The tensile stress opens up cracks in the material and can be either directly applied or residual in form. Therefore, SCC occurs under sustained tensile loads, while corrosion fatigue occurs under cyclic loading. Appendix A indicates several research areas (see for example Section A.1.2) wherein the difference was difficult to distinguish.

SCC in pipelines is further characterized as "high-pH SCC" or "near neutral-pH SCC," with the "pH" referring to the environment at the crack location and not the soil pH. (pH is the measure of the relative acidity or alkalinity of water. It is defined as the negative log (base 10) of the hydrogen ion concentration. Water with a pH of 7 is neutral; lower pH levels indicate an increasing acidity, while pH levels above 7 indicate increasingly basic solutions.)

The most obvious identifying characteristics of SCC in pipelines, regardless of pH, is the appearance of patches or colonies of parallel cracks on the external surface of the pipe. There may be several of these colonies on a single joint of pipe and many joints of pipe may be involved. The cracks are closely spaced and of varying length and depth. These cracks frequently coalesce to form larger and longer cracks, which in some cases can lead to rupture. If the cracks are sparsely spaced, they might grow through the wall and leak, before they reach a length that is sufficient to cause a rupture.

In order for SCC to occur, three conditions must be satisfied simultaneously. They are listed below and in Figure 4-1:

1. A tensile stress higher than the threshold stress, frequently including some dynamic or cyclic component to the stress;
2. A material that is susceptible to SCC; and
3. A potent cracking environment.

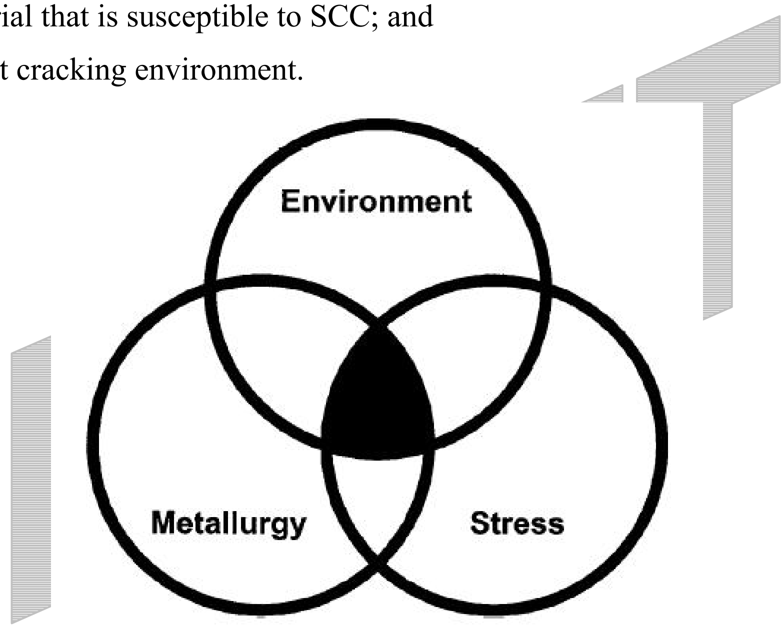

Figure 4-1 Three Conditions Necessary for SCC

SCC cracking is usually oriented longitudinally in response to the hoop stress of the pipe, which is usually the dominant stress component resulting from the internal pressure. However, in some cases (reported as 10 to 20 percent in Canada) SCC also occurs in the circumferential direction (C-SCC) when the predominant stress is an axial stress, such as stresses developed in response to pipe resistance of soil movement, at a field bend, or due to the residual welding stresses at a girth weld (CEPA 1997).

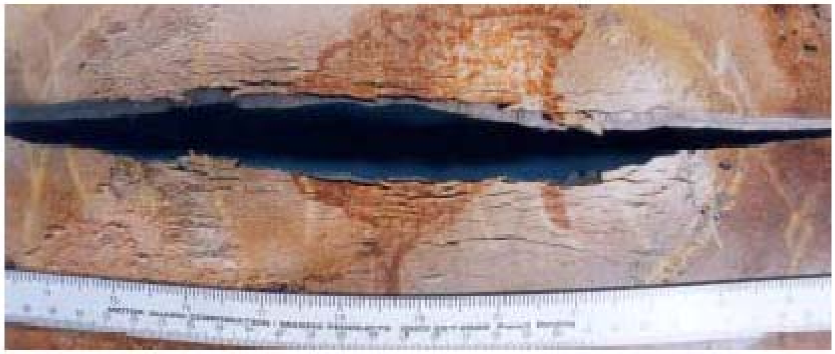

Figure 4-2 SCC Colony on a Large-Diameter, High-Pressure Transmission Gas Pipeline

(http://www.corrosioncost.com/pdf/gasliquid.pdf)

There are two known forms of SCC that have caused failures on pipelines: high pH or "classical" and low pH or "near-neutral pH." These forms are described in more detail in the following sections.

4.2.1 High pH SCC (NEB 1996)

When pipeline steel is exposed to the surrounding environment due to some form of coating failure, it is vulnerable to corrosion. Because soil corrosion is an electrochemical reaction, cathodic protection is used to mitigate corrosion by passing an electrical current through the soil thus giving the pipe a cathodic potential. A concentrated carbonate-bicarbonate (CO_3-HCO_3) solution has been identified as the most probable environment responsible for high-pH SCC. This environment develops as a result of the interaction between hydroxyl ions produced by the cathode reaction and CO_2 in the soil generated by the decay of organic matter. Cathodic protection (CP) causes the pH of the electrolyte beneath disbonded coatings to increase, and the CO_2 readily dissolves in the elevated pH electrolyte, resulting in the generation of the concentrated CO_3-HCO_3 electrolyte. The pH of this electrolyte depends on the relative concentration of CO_3 and HCO_3 and the cracking range is between pH 8 and 11.

The fractured surface of the cracks normally exhibits a dark, discolored coating of oxidized material (primarily magnetite) at the mouth of the crack. The last portion of the pipe wall to fracture, i.e., the rapid fracture region, remains a shiny silver color. The presence of black thumbnail-like flaws on the fracture surface normally indicates that SCC caused the failure.

Analysis of the liquid trapped in the disbonded area or in the crack itself indicates a carbonate-bicarbonate solution with a pH of 8 to 9, or more. Metallographic examination of a section across the crack shows the fracture path to be intergranular, often with small branches, as shown in Figure 4-3. Laboratory simulation with small test specimens indicates that this form of SCC is temperature sensitive and occurs more frequently at higher temperature locations above 100°F. This supports field reports that demonstrate a greater likelihood of SCC immediately downstream of the compressor stations where the operating temperature might reach 150°F.

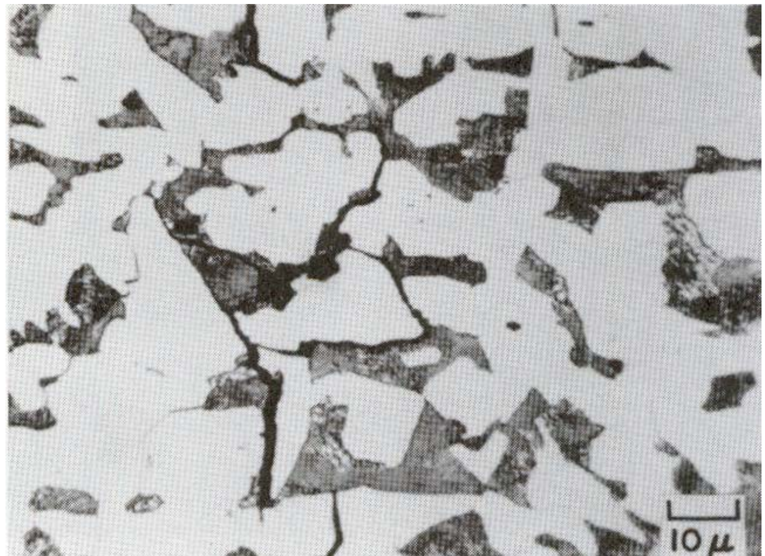

Figure 4-3 An Example of Intergranular Cracking of Pipeline Steel (Revie 2000)

4.2.2 Near neutral-pH SCC (NEB 1996)

This form of SCC was not documented until the late 1970s and was first identified on buried pipelines in Canada where tape-wrapped pipe contained wrinkles in the coating that trapped water with a pH between 5.5 and 7.5. In the case of near neutral-pH SCC, the cracking environment appears to be a diluted groundwater containing dissolved CO_2. The source of the CO_2 is typically the decay of organic matter and geochemical reactions in the soil. This form of cracking occurs under conditions where there is little, if any, CP current reaching the pipe surface, either because of the presence of a shielding coating, a highly resistive soil, or inadequate CP. Typically, the SCC colonies initiate at OD surface locations where there is already pitting or general corrosion, which is sometimes obvious to the naked eye and other times very difficult to observe.

Metallographic examination of near neutral-pH SCC reveals the cracks are predominately transgranular (see Figure 4-4) and are wider (more open) than the high-pH form, i.e. the crack sides have experienced metal loss from corrosion. This morphology implies that the fracture mechanism is different; however, the direct visual appearance of a pipe fracture surface is similar to that of high-pH SCC.

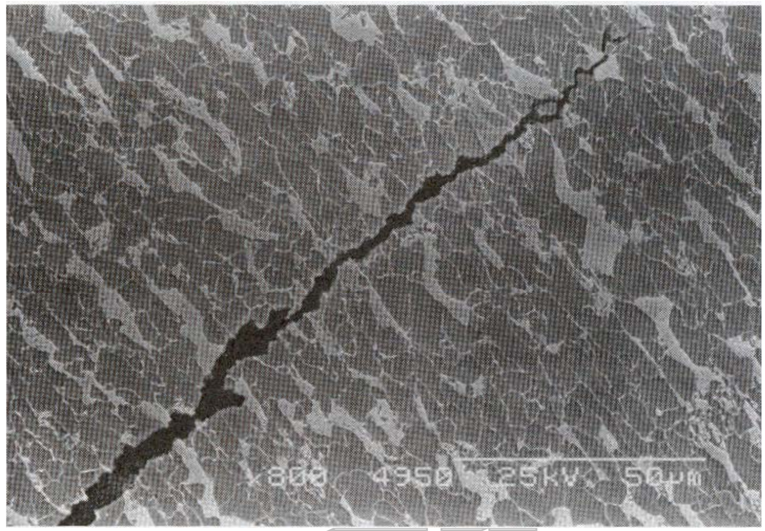

Figure 4-4 Transgranular Cracking in Pipeline Steel (Revie 2000)

4.2.3 Crack Characteristics

There are many similarities between the two forms of SCC. Both occur as colonies of multiple parallel cracks that are generally perpendicular to the direction of the highest stress on the external pipe surface. These cracks can vary in depth and length and grow in two ways. They increase in depth and length and tend to coalesce, or link together, to form longer cracks. At some point these cracks may reach a critical depth and length combination that can result in a rupture. A leak will occur if a crack grows through the pipe wall before it reaches a critical length for rupture. Note that critical size SCCs do not need to fully penetrate the pipe wall for a rupture to occur, i.e., a shallow crack may reach a length that becomes critical. The strength and ductility of the remaining wall determines the critical size at which the crack behavior changes from a slowly growing stress corrosion mechanism to an extremely rapid brittle or ductile stress overload.

The most obvious differences between the two forms are the temperature sensitivity of high-pH SCC, the fracture morphology, and the pH of the pipe environment. The characteristics of high-pH and near neutral-pH SCC are summarized in Table 4.1.

Table 4.1 Comparison of SCC types (NEB 1996; CEPA 1997)

Factor	Near-neutral pH SCC	High pH SCC (Classical)
Location	• Associated with specific terrain conditions, often alternate wet-dry soils, and soils that tend to disbond or damage coatings	• Typically within 20 km downstream of pump or compressor station • Number of failures falls markedly with increased distance from compressor/pump and lower pipe temperature
Temperature	• No apparent correlation with temperature of pipe • May occur more frequently in the colder climates where CO_2 concentration in groundwater is higher	• Growth rate increases exponentially with temperature increase
Associated Electrolyte	• Dilute bicarbonate solution with a neutral pH in the range of 5.5 to 7.5	• Concentrated carbonate-bicarbonate solution with an alkaline pH greater than 9.3
Electrochemical Potential	• –760 to –790 mV ($Cu/CuSO_4$) • Cathodic protection does not reach pipe surface at SCC sites	• –600 to –750 mV ($Cu/CuSO_4$) • Cathodic protection contributes to achieving these potentials
Crack Path and Morphology	• Primarily transgranular (across the steel grains) • Wide cracks with evidence of substantial corrosion of crack side wall	• Primarily intergranular (between the steel grains) • Narrow tight cracks with almost no evidence of secondary corrosion of crack wall

4.2.4 Crack Growth

The cycle of SCC crack growth is normally modeled as a four-stage process as shown in Figure 4-5. The first stage is the development of conditions conducive to SCC and is followed by the crack "initiation" stage. These cracks then continue to grow and coalesce, while additional crack initiation also occurs during stage 3. Finally, in stage 4, large cracks coalesce and failure occurs. Appendix A discusses the background and research of the crack growth rate in more detail.

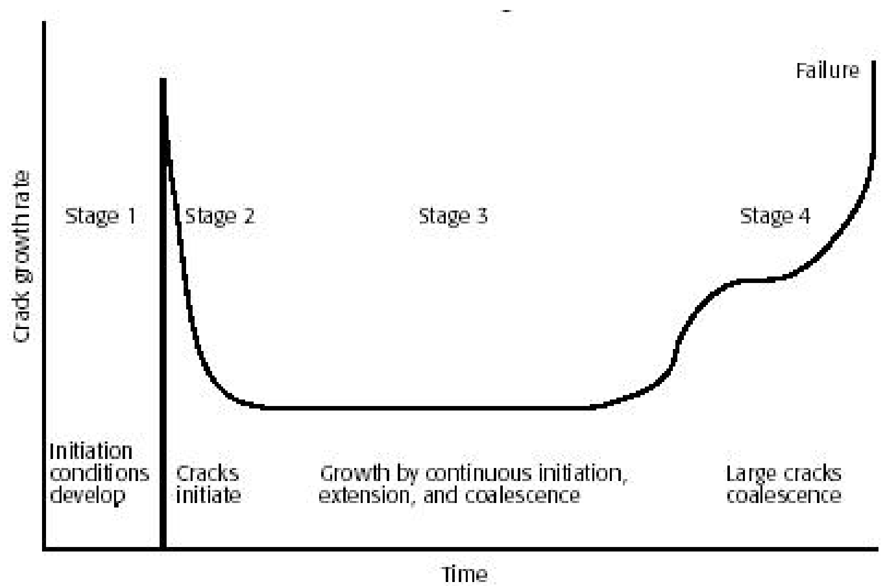

Figure 4-5 Four Stage Process of SCC Growth

While a single crack might grow large enough to cause a leak, coalescence typically is necessary for the defect to grow long enough to cause a rupture. If cracks form close to one another, crack growth may be dominated by coalescence into collinear cracks and can occur throughout the SCC life cycle. A combination of environmental and mechanical forces can cause cracks to grow. In the final stage of growth, after cracks have coalesced sufficiently for tearing to begin, the environment no longer plays a role. In some cases, tearing is preceded by a stage of crack growth in which fatigue is the dominant crack propagation mechanism.

The geometry of the crack colonies resulting from near neutral-pH SCC is important in determining whether the cracks coalesce and grow to failure (NEB 1996). Colonies of cracks that are long in the longitudinal direction yet narrow in the circumferential direction are a greater risk to pipeline integrity than colonies of cracks that are shorter in the longitudinal direction and wide in the circumferential direction. The individual cracks in long, narrow colonies are oriented head to tail and tend to link together, leading to rupture. However, for colonies that are about as long as they are wide, growth occurs mainly near the edges. Cracks located deeper within these colonies with circumferential spacing less than 20 percent of the wall thickness are generally shielded from stress and become dormant (NACE 2003).

4.3 History of SCC in Pipelines

The first documented case of SCC causing a pipeline failure was the Natchitoches, Louisiana, incident in the mid 1960s. This rupture was caused by high-pH SCC and resulted in a gas release, explosion and fire resulting in several fatalities. Spurred by this discovery, research on high-pH SCC in pipelines has been ongoing since that time. In the late 1960s, a concentrated carbonate-bicarbonate solution was identified as the most likely environment for SCC and evidence of this solution at the pipe surface was found in a limited number of cases (Fessler 1969).

Near neutral-pH SCC in pipelines was not identified until 1977. According to the *Stress Corrosion Cracking Study*: "Since 1977, SCC has caused 22 pipeline failures in Canada on both natural gas and liquid pipeline system[s]. Failures include 12 ruptures and 10 leaks. Most of the SCC-related failures occurred on pipelines coated with polyurethane tape and were installed between 1968 and 1973 with most of the reported failures occurred between 1985 and 1996." (Hall and McMahon 1999).

4.3.1 Canada/International (NEB 1996)

In the Introduction to *Stress Corrosion Cracking on Canadian Oil and Gas Pipelines* the NEB notes: "Our awareness of SCC on the Canadian pipelines we regulate began in 1985. TransCanada had three failures on the Northern Ontario portion of the pipeline between March 1985 and March 1986… These failures were attributed to stress corrosion cracking and were considered at the time to be the first evidence of SCC in Canada, although subsequently it was determined that SCC had been detected on other pipelines in the 1970s. The type of SCC which caused these failures was different from the 'high-pH' SCC that had been found on other pipelines in the world." (NEB 1996).

The NEB of Canada conducted an inquiry into SCC on pipelines in 1993, concluding that the situation was being managed appropriately. However, ruptures on the TransCanada Pipelines (TCPL) system in 1995 caused the NEB to reconsider SCC and begin a new inquiry. The result was a series of 27 recommendations to promote public safety as described in *Stress Corrosion Cracking on Canadian Oil and Gas Pipelines* (NEB 1996). Each pipeline company under NEB jurisdiction was required to develop and begin maintenance of an SCC integrity management program by June 1997, and additional research was to be conducted on SCC.

4.3.2 United States

Until recently, the United States concentrated on high-pH SCC. Recent failures, however, have been attributed to near neutral-pH SCC. No specific regulations pertaining to either design or operational assessment for SCC detection or control in pipelines existed in the United States until recently. With the publication of ASME B31.8S in 2002, *Managing System Integrity of Gas Pipelines*, which was incorporated by reference into Title 49 Code of Federal Regulations (CFR) Part 192 (49 CFR 192), there is now some guidance regarding high-pH SCC, at least for gas pipelines. Liquid operators may choose to follow these guidelines as well, with the appropriate modifications because codes for liquid pipelines do not currently address SCC in this detail. ASME B31.8S describes risk assessment procedures and outlines inspection and examination procedures for SCC, although it does not supply analytical or theoretical guidance for high-pH or near neutral-pH SCC threat assessment . Development of other guidance documents is currently ongoing; in particular, NACE International is writing a Direct Assessment Recommended Practice for SCC, which may be published before end of 2004. This is discussed further in Chapter 6 and Chapter 8 of this report.

4.4 Contributing Factors to SCC in Pipelines

4.4.1 Metallurgy

Metallurgy can affect SCC through composition and microstructure. However, pipeline steels, and certainly the conventional steels that have historically been used in the last 50 years, do not contain elements found in similar carbon-manganese steels used in literally hundreds of construction applications without reports of SCC.

More recently, the yield strength of linepipe has gradually increased by the addition of micro-alloying elements such as vanadium, columbium and/or titanium. The addition of these elements tends to produce a finer grain in the microstructure, increasing both strength and toughness. Controlled rolling and cooling of the steel plate used to manufacture pipe has resulted in finer grained bainite steel microstructures.

A number of research investigations involving small-scale, laboratory-reproduced SCC and using both high- and low-pH environments have been conducted without achieving a meaningful correlation between steel chemistry and susceptibility to SCC. Danielson and Jones (2001) discuss the high-pH SCC testing of six different heats of X52, as well as three heats (X65, X70, X80) of modern steels. Their paper concludes: "In general, the microstructure/microchemistry had a small effect on the SCC behavior."

Nevertheless, certain batches of pipeline steel have been found to be much more susceptible to SCC than other batches with similar compositions and microstructures (Beavers and Harper 2004). A full understanding of this remains to be developed, but current research suggests that other characteristics of the steel, such as creep response to cyclic loading, may be important.

4.4.2 Manufacturing

Line pipe is manufactured using one of four processes: seamless pipe, electric resistance welded pipe made from steel coils, flash welded pipe from plate, and submerged arc-welded pipe made from steel plate. The vast majority of line pipe for gas transmission service is produced by one of the three seam welded processes. Pipe in grades X60 and higher achieves some of its strength from the controlled rolling procedures used to reduce the thickness of the original cast slabs to the final pipe wall thickness. These procedures include not only the hot work but also the cooling rate of the plate or strip after hot rolling. The microstructure may contain varying amounts of ferrite, pearlite and bainite with wide variation in the crystalline grain size. There is no strong evidence that any of the items above either promote or inhibit SCC.

The first reported cases of SCC exhibited intergranular cracking (high-pH SCC) in steels with a microstructure that consisted of grains of low-carbon ferrite and higher carbon colonies of pearlite. Typically, the more recently detected near neutral-pH SCC has occurred on slightly higher yield strength steels with a much finer grain size and a higher toughness. However, there are a number of cases of near neutral-pH SCC in older, large grained, low-strength steel and cases of high-pH SCC in newer, fine-grained steel. Thus, regarding reported cases of SCC, no generalizations regarding metallurgy can be made.

4.4.3 Mechanical Properties

The mechanical properties of highest interest for most gas transmission piping are the yield strength and the toughness. Generally, the best economics result from selecting the highest strength pipe material available for the design of a new pipeline system. As improved manufacturing procedures are being developed, higher grades of pipe is being purchased. There is no strong evidence that increasing strengths up to and through grade X70 increases susceptibility to SCC initiation or growth.

Increases in toughness, which have occurred in parallel with strength, have significantly increased the critical size of the crack necessary to produce ruptures. The use of toughness values in engineering evaluations of critical flaw sizes is discussed further in Sections 8.2.5 and 8.2.6.

4.4.4 Pipeline Operating Conditions

As previously discussed, SCC requires three conditions to be satisfied simultaneously: 1) a tensile stress above the threshold stress, 2) an appropriate environment at the steel surface, and 3) a susceptible material.

Below some value of tensile stress, referred to as the threshold stress, crack initiation does not occur. The threshold stress is difficult to accurately define but, depending on the range of stress fluctuation, is on the order of 40 to 100 percent of the yield strength for classical SCC. A threshold stress for near neutral-pH SCC has not been established (Beavers 1999).

The operator has at least some control of the applied tensile stress when it is strictly the result of internal pressure in the system. Unfortunately, residual tensile stresses from manufacture, bending stresses from pipe movement, overburden loads from soil, dents or gouges, or from heavy equipment can cause as much or more tensile stress as that caused by internal pressure, all of which is beyond the control of the operator.

Note that in Canada some 10 to 20 percent of the SCC reported is oriented in a circumferential direction, i.e., the dominant stress affecting the crack is oriented axially to cause crack growth (CEPA 1997). The direct longitudinal stress caused by pressure can be up to half of the hoop stress. However, pipe flexure will result in additional stress, and the resultant value can exceed the hoop stress, with the maximum/minimum values at the extreme fibers of bending. The C-SCC cases reported by CEPA are associated with undulating terrain where pipe loading resulted from soil creep or localized bending. Localized bending may also occur at dents resulting in higher axial stresses in the local region.

Pipe that has been cycled into the plastic range multiple times sometimes may experience a condition known as cyclic softening. This appears as a loss of yield strength and can significantly reduce the threshold stress. Again, the operator has little control over cyclic softening.

In addition, the operator has little control over the pH of the groundwater and is unable to control the aggressiveness of the environment, except for new construction by installing a premium coating system. Unfortunately, these coating systems may not be considered suitable for recoating in the ditch. Note also that the pH of the groundwater will be modified by the electrochemical reaction at the pipe surface.

The operator does have some control over the operating temperature. For example, some operators have installed cooling towers to help control SCC.

4.4.5 Coating

Coating type and condition (sometimes a function of the installation procedure, associated quality control or lack thereof, and weather conditions at the time of installation) have a profound effect on SCC. This is especially true when the coating has a tendency to disbond (i.e. the coating comes away from the pipe but does not break), or forms holidays (i.e., breaks or gaps in the coating). This is true for tape coatings, such as the polyethylene-backed tapes used predominantly in the early 1960s to 1980s. These tapes are spirally wrapped around the pipe with an overlap at the helix line. “Tenting” occurs between the pipe surface and the tape along the ridge created by longitudinal, spiral, and girth welds. Tenting also occurs at the overlap between the helix of the wrap.

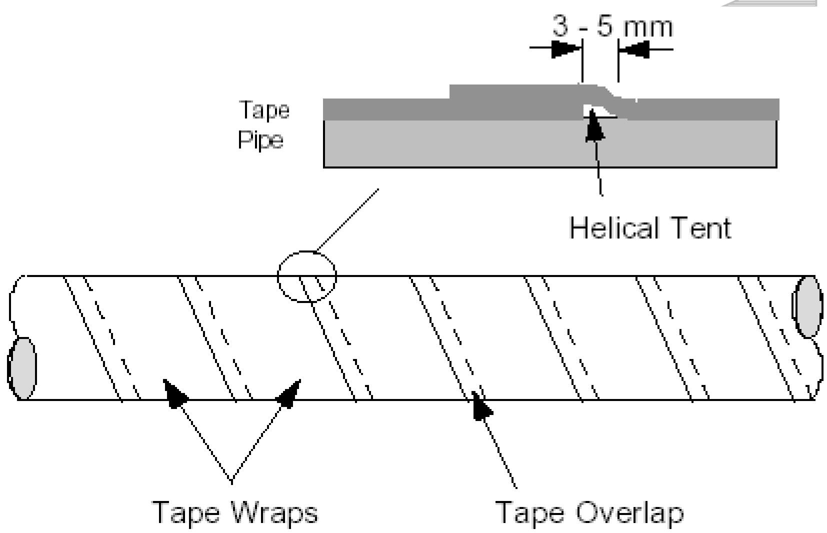

Figure 4-6 Polyethylene Tape Helical Tent (CEPA 1997)

When the tape disbonds from the pipe, moisture can accumulate beneath the tape surface. The tape itself has fairly high electrical insulation properties, thus preventing cathodic current from reaching entrapped moisture beneath the tape at the pipe surface. In Canada, about three-quarters of reported near neutral-pH SCC-related service incidents have occurred under these tape coatings. The cracks tend to occur at or near the toe of the seam weld where stress is concentrated and water has access, as well as where the coating has been damaged or disbonded (NEB 1996).

Asphalt and coal tar coatings are relatively thick and can be brittle. The coatings can disbond, especially due to poor surface preparation. Over time, the volatiles can disperse, leaving the coating relatively brittle. Unlike tape coatings, when these coatings disbond, they usually, but not always, become saturated with moisture and conduct cathodic current, thus protecting the pipe. If the coating is brittle, it may break into pieces, also allowing a path for the cathodic current protection. SCC might still occur when the soil is so resistive that the cathodic current cannot reach the pipe. For these coating types, there is no preferential location, but SCC might occur wherever disbondment or holidays occur (NEB 1996).

It is generally agreed that fusion-bonded epoxy (FBE) coatings, which are often the coating of choice for newly installed pipelines in the United States, are an effective protection against SCC. Extruded polyethylene, because the coating system is monolithic, also appears to be effective, except possibly at tape-wrapped girth welds.

4.4.6 Soil conditions

In 1973, Wenk described results of analyses of soil and water extracts (from the soil) taken from high-pH SCC locations (Wenk 1974). While supporting data were not provided, it was stated that SCC had occurred in a wide variety of soils, covering a range in color, texture, and pH. No single characteristic was found to be common to all of the soil samples. Similarly, the compositions of the water extracts did not show any more consistency than did the physical descriptions of the soils, according to Wenk. On several occasions, small quantities of electrolytes were found beneath disbonded coatings near locations at which stress corrosion cracks were detected. The principal components of the electrolytes were sodium carbonate and bicarbonate. Sodiumbicarbonate crystals were also found on pipe surfaces near some SCC colonies (Fessler 1973). Based on the presence of the sodium-based carbonates and bicarbonates, it is likely that these were high-pH SCC sites. Therefore, it is not surprising that these results are not consistent with the results of the TCPL studies performed in the 1980s and 1990s, when near neutral-pH SCC was found.

Mercer described the results of a field study conducted by British Gas Corporation in 1979 (Mercer 1979). Soil data from both the UK and U.S. were collected and analyzed. As in the study by Wenk, detailed information on the soil analyses was not provided, but it was concluded that soil chemistry had no obvious direct influence on high-pH SCC. The moisture content of the soil, the ability of the soil to cause coating damage, and localized variation in the level of CP were the primary soil-related factors identified.

Delanty and O'Beirne (Delanty and O'Beirne 1991, 1992) reported on the results of more than 450 investigative excavations performed on TCPL's system in the mid- to late-1980s. In the tape-coated portions of the system, near neutral-pH SCC was found in all of the various types of terrains and soils (e.g., muskeg, clay, silt, sand, and bedrock) present on the system. There was no apparent difference in the soil chemistry for the SCC and non-SCC sites. However, the SCC was predominantly located in imperfectly to poorly drained soils in which anaerobic and seasonally reducing environmental conditions were present.

In the same system, near neutral-pH SCC was found in the asphalt-coated portions of the system, predominantly (83 percent) in extremely dry terrains consisting of either sandy soils or a mixture of sand and bedrock. There was inadequate CP in these locations, based on pipe-to-soil potential measurements or pH measurements of electrolytes found beneath disbonded coatings. The remainder of the SCC sites on the asphalt-coated portions of the system had localized areas of inadequate CP, based on pH measurements of electrolytes.

Delanty and Marr developed an SCC severity rating model for near neutral-pH SCC for the tape-coated portions of TCPL's system in eastern Canada (Delanty and Marr 1992; Marr 1990). The predictors in that model were soil type, drainage, and topography. The soil classifications were based on method of deposition. The most aggressive soil types were lacustrine (formed by deposits in lakes), followed by organics over glaciofluvial (formed by deposits in streams fed by melting glaciers), and organics over lacustrine. The prevalence of SCC in glaciofluvial soils was about 13 percent of that in lacustrine soils, and about 17 percent of that in soils with organics over glaciofluvial or lacustrine. Very poorly or poorly drained soils were found to be the most aggressive, while level-depressed soil was found to be the most aggressive topography. The SCC model did not contain parameters associated with soil chemistry because the results of previous geochemical projects were inconclusive.

As described above, neither the early field studies conducted on high-pH SCC, nor the later field studies conducted on near neutral-pH SCC, detected a correlation between the occurrence of SCC and soil chemistry. On the other hand, high-pH SCC was not reported where the extensive field study of near neutral-pH SCC was performed in Northern Ontario (Delanty and O'Beirne 1991, 1992), suggesting that the soil conditions were not conducive to this form of cracking. Furthermore, no near neutral- or high-pH SCC was found in Northern Ontario where elevated pH electrolytes were detected, possibly because the soil conditions could not support the development of concentrated carbonate-bicarbonate solutions, even when the CP conditions were conducive to such development. These observations suggest that a further analysis of field soil data might provide insight into the role of soil/groundwater chemistry on the occurrence of SCC (Beavers and Garrity 2001).

Near neutral-pH SCC may be associated with local topographical depressions, e.g., at the base of hills or streams, where the groundwater either channels along the pipe or across it. Flowing water may help to maintain the near neutral-pH environment by supplying CO_2 to the electrolytic solution in a disbonded area. The majority of laboratory investigation has been performed in an NS4 electrolyte solution containing 5 percent CO_2. NS4 is a simulated trap water that is typical of liquids found beneath disbonded polyethylene tape coatings at locations where near neutral-pH SCC was found. Research shows that the crack growth rate increases with increasing CO_2 concentrations, and that the cracking becomes dormant in CO_2-free environments (Beavers et al. 2001).

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