7 Mitigation of SCC

"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 how to mitigate SCC.

7.1 Repair and Mitigation Options

7.1.1 Pressure Reduction

Though it is not a long-term solution, pressure reduction can be used to decrease the likelihood of an immediate or near-term SCC failure. The pressure reduction provides time for the operator to assess the pipeline integrity and determine a long-term mitigation and management strategy.

Reduction in pressure increases the critical crack size necessary to cause failure and reduces the driving force for crack growth. Typically, a 20 percent reduction is specified following a pipeline incident. The logic is that the previous operating pressure is equivalent to a "test" pressure which is 125 percent (5/4) of the new operating pressure. Therefore, the new operating pressure should be 80 percent (4/5) of the last "test" pressure. The maximum operating pressure may be raised back to the previous level if the integrity of the pipeline can be assured through some means of inspection, such as hydrostatic testing or ILI.

7.1.2 Hydrostatic Testing and Repair

Hydrostatic testing and repair can be used to reduce the likelihood of a stress corrosion failure. Hydrostatic testing will cause critical cracks (at the test pressure) to fail. By repairing these ruptures, critical cracks are eliminated, although near critical cracks could remain undetected.

Using hydrostatic testing alone requires retest on a regular basis to catch any stress corrosion cracks that may have grown since the previous test. Establishing an appropriate retest interval remains a challenge for operators.

While there is data that suggests hydrostatic tests inhibit subsequent SCC crack growth by imparting a compressive residual stress at the crack tip, some of the surviving cracks may continue to grow. Barlo reported that two leaks were discovered in a pipeline operating at 71 percent SMYS two and four months following a retest at 90 percent SMYS (Barlo 1979). He also reported six ruptures that occurred 1.7 to 8.3 years following retests. There was a general correlation between higher retest pressures and longer times to rupture. Many other portions of the pipelines had survived 10 to 12 years following a retest without an additional failure. The field behavior is consistent with the theoretical predictions of Leis, which showed that, while retesting to 95 percent SMYS produces almost no benefit in terms of increasing remaining life, test pressures above this level can be very beneficial (Leis 1999). Pressures between 105 and 110 percent SMYS appear to be most beneficial. When tests to these pressures are for short durations, they are known as "spike tests" (see Section 6.2.1).

7.1.2.1 Selective Crack Blunting

Blunting of cracks may be obtained by hydrostatically testing the pipeline. The hydrostatic pressure is held in a range where yielding can occur at the crack tip of large cracks that survive the hydrotest. Yielding at the crack tip causes compressive residual stresses around the crack tip and rounding, or blunting, of the crack tip. Once the crack tip is blunted, additional crack growth is minimal until a new crack grows at the end of the blunted crack.

The blunting effect may be reinforced by the residual compressive stress that is created immediately below the crack tip when the pressure is relieved.

7.1.3 Recoating

Disbonded coating or tape is frequently a contributor to SCC. In addition, mill scale remaining on the pipe surface after coating surface preparation has also been linked to SCC.

Recoating the pipeline can improve the resistance of the pipe to SCC. During recoating, any remaining mill scale can be removed during surface preparation and the pipe recoated. Grit blasting conducted during the surface preparation process increases resistance to SCC by imparting a compressive residual stress on the pipe surface (Koch, 1983).

Coatings selected for recoating of pipelines must resist cathodic disbondment, adhere well to the pipe, resist mechanical damage, and resist moisture degradation. Additionally, they should not shield cathodic protection if they do disbond. Many protective coatings are available for use in reconditioning existing lines in the ditch, including cold-applied tapes, hot-applied tapes, and liquid-based coatings (CEPA 1997). Often, performance testing of several coatings is necessary to select a coating for each reconditioning application.

Unfortunately, the current coating of choice by most operators for initial application, FBE, is not typically practical for recoating applications. FBE application requires a controlled environment to apply the powder and heat the surface to properly fuse the coating to the pipe. In lieu of this, other recoating systems must be applied as mentioned above.

A written procedure for the recoating is strongly recommended to ensure the integrity of the pipe and protective coating. It is further recommended that the operator review this procedure with the contractor prior to field implementation. The procedure should address, as a minimum: 1) surface preparation requirements, 2) ambient weather conditions, 3) compatibility with existing coatings, 4) geographical and physical location, 5) health and safety codes and considerations, and 6) Quality Assurance.

7.1.4 Extension of Exclusion Zones

Exclusion zones beyond the existing ROW zone limits and separation requirements can be extended to supply an additional safety margin against damage that may result from failure. This measure does nothing to address or remedy the root cause of the concern; however, between the time a concern arises and the concern is investigated and satisfactorily remedied, extending and enforcing exclusion zone limits may be a consideration.

7.1.5 Grinding

"Grinding" is addressed in the Pipeline Repair Manual (Kiefner, Bruce and Stephens 1999). When SCC can be definitively located, excavation and inspection, with consequent grinding/buffing of the stress corrosion cracks and recoating, is recommended: "…if (1) the stress-concentrating effect of the defect or imperfection is eliminated, (2) all damaged or excessively hard material is removed, and (3) the amount and distribution of metal removed does not significantly reduce the pressure-carrying capacity of the pipe." B31G/RSTRENG can be used to determine whether the remaining wall is adequate to resist operational loads (see Section 8.2.4). Note that most of the operators interviewed (see Section 10.4) mention grinding as the preferred repair technique. As per the *Pipeline Repair Manual*: "The operating pressure should be reduced to 80% of that at which the defect was discovered (or to 80 percent of a recently demonstrated high pressure)." Subsequent to grinding, the pipe must be recoated (see Section 7.1.3).

7.1.6 Pipe Sleeves

Pipe sleeves and bolt-on clamps that are able to permanently restore the serviceability of the pipe can also be used. A sleeve installation often follows grinding of an excavated section of pipe, where the depth of grinding results in a wall thickness less than the minimum required for safe operations. The ground area is filled with a non-shrinking filler when a sleeve is used to mitigate SCC.

The expectation is that the repair system used should meet the same expected results as from replacing damaged or corroded pipe. Only full-encirclement sleeves should be used for repair of SCC. Bolt-on clamps are always full-encirclement. The main types of full-encirclement sleeves are: Type A (Reinforcing), Type B (Pressure containing), Mechanical (bolt-on) and Composite Reinforced.

Type A sleeves consist of two halves of a cylinder of pipe or curved plate that are placed around the carrier pipe and joined by welding the side seams. This type of sleeve's role is solely to restrain bulging of the defective area. The main disadvantages of Type A sleeves are:

- It is not useful for circumferential-oriented defects.
- It cannot be used to repair a leak.
- It creates a potential corrosion problem by the formation of an annular space between the sleeve and the carrier pipe that may be difficult to cathodically protect (no failures in this manner are known).

Compressive sleeves are Type "A" sleeves, and are lap welded with a fillet weld on both sides of the pipe in lieu of a groove weld that uses the pipe as backing. This type of sleeve is installed in a similar fashion to Type A and B sleeves, but actually induce a compressive stress into the carrier pipe and rely on a high-strength epoxy to bond them to the carrier pipe. Compressive sleeves are currently not recommended for repair of leaks.

Type B sleeves are similar to Type A sleeves, but in addition to the side seams, circumferential welds are installed between the sleeve and the carrier pipe. Because this type of sleeve may contain pressure and/or longitudinal stress, it must be designed and installed in a manner to ensure its structural integrity. Since Type B sleeves are designed to contain pressure, they may be installed to repair leaks, though they are often used to repair non-leaking defects as well.

Extensions of the traditional pipe sleeve concept include encirclement systems. These are currently strictly for pipe wall reinforcement and must not be used for leak containment. This may consist of a woven fiberglass/epoxy resin material that results in monolithic composite pipe reinforcement. The composite material has been proven by extensive lab testing, with the basic materials proven by over 30 years of field experience in the petro-chemical and related industries. Another type of encirclement system consists of a fiberglass/polyester composite material coiled with adhesive in layers that reinforce steel pipe having certain non-leaking defects. According to tests and analyses by the Gas Research Institute (GRI), when properly installed, the system permanently restores the pressure-containing capability of the pipe. Based on GRI field and lab performance data, OPS concluded that this technology provides at least the same level of safety on high-stress transmission lines as pipe replacement or a full encirclement split sleeve. As a result, OPS allowed, by waivers, certain operators to use this repair system on their pipelines.

7.1.7 Pipe Replacement

Replacement of selected sections of pipe can be used to eliminate stress corrosion colonies. When ILI or hydrostatic testing indicates the presence of SCC, removing the section of pipe is often the most effective method of repair. The section of pipe removed can be given metallurgical evaluation to better understand the SCC mechanism (e.g. high-pH or near neutral-pH SCC) for possible use in subsequent SCCDA. Whatever the case, the sections of the pipeline affected by SCC can be replaced and the pipeline returned to normal operation.

7.1.8 Options Discussion

As discussed, SCC is usually associated with coating failure. Therefore, new or replacement design should consider the use of FBE coating (FBE has been shown to be an effective barrier to the SCC susceptible environment) or possibly other coating systems that have not been associated with SCC. However, for existing pipelines, pipe replacement is seldom realistic except for specific pipe segments that are in imminent danger of failure.

If SCC can be definitively located, excavation and inspection, with consequent grinding/buffing of the stress corrosion cracks and recoating, is recommended if the remaining wall is adequate to resist operational loads.

The most problematic case is an existing pipeline, which has been found to be generally susceptible to SCC, but where detailed investigation and remedial action is not practical, and specific locations are difficult to detect and assess. In this case, the choice is usually between an ILI investigation and hydrostatic testing (or both), accompanied by the equivalent of an ECA to ensure that the measures and/or testing intervals will be effective in proactively identifying SCC before it becomes critical and/or otherwise affects pipe integrity.

7.2 References

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