Stress Corrosion Crack Identification with Direct Assessment Method in Pipeline Downstream from a Compressor Station

H. Gholami, M. Jalali Azizpour

Abstract**—**Stress Corrosion Crack (SCC) in pipeline is a type of environmentally assisted cracking (EAC), since its discovery in 1965 as a possible cause of failure in pipeline, SCC has caused, on average, one of two failures per year in the U.S, According to the NACE SCC DA a pipe line segment is considered susceptible to SCC if all of the following factors are met: The operating stress exceeds 60% of specified minimum yield strength (SMYS), the operating temperature exceeds 38°C, the segment is less than 32 km downstream from a compressor station, the age of the pipeline is greater than 10 years and the coating type is other than Fusion Bonded Epoxy(FBE). In this paper as a practical experience in NISOC, Direct Assessment (DA) Method is used for identification SCC defect in unpiggable pipeline located downstream of compressor station.

Keywords**—**Stress Corrosion Crack, Direct Assessment, Disbondment, Transgranular SCC, Compressor Station.

I. Introduction

SCC in pipeline is a type of environmentally assisted cracking (EAC). Since its discovery in 1965 as a possible cause of failure in pipeline, SCC has caused, on average, one of two failures per year in the U.S [4].

Stress corrosion cracking, as found in pipeline are classified into two major category as named high-PH SCC and low –PH SCC.

High-PH SCC, also named classical SCC, occurs more frequently at location where the immediate environment of the pipe and resulting electrolyte has a PH of between 8 and 9, or higher in conjunction with concentrated solution of sodium carbonate and sodium bicarbonate. Near-neutral PH SCC is caused by at relatively dilute solution of carbon dioxide and sodium bicarbonate with a PH that typically is between six and seven [4], [5].

There are three methods to investigate for presence of SCC in the pipeline segments as hydrostatic test, in-line inspection and SCCDA. For older pipeline, high-pressure tests (e.g., above 100 percent of SMYS) may not be practicable, because the testing could potentially fail long numbers accepted corroded areas. This could be a signification parameter when procuring the materials is a problem. With lower pressure tests, the hydrostatic retesting period maybe short enough to make hydrostatic retesting impracticable [4].

For pipelines that aren't piggable, using the ILI is impractical. SCCDA Determine whether pipeline system is susceptible to SCC or to significant SCC. SCCDA is complementary with other inspection methods and is not necessarily an alternative or replacement for these methods is all instances. ILI and hydrostatic testing may not be warranted if the initial SCCDA indicates that significant and extensive cracking is not present on a pipeline system. SCCDA can be used to prioritize a pipelines system for more accurate inspection [2].

SCCDA is most related to our current level of understanding from failure mechanism of SCC in pipeline system. In the NACE SCCDA some factors have been determined as initial selection of susceptible pipeline segments for high PH SCC, consist to the operating pressure, operating temperature, distance from compressor station, age of pipeline and coating type. These factors extended to near neutral PH, with exception of the temperature criterion [5].

The assessment covers approximately 7.700 km of gas line as named E-Branch in Ahwaz region with 16" pipe diameter, pipe material 5L-X65, pipe wall thickness 19.05 mm, design pressure 250 BAR and Design temperature 60°C. The pipeline was constructed and commissioned in 1978 and was externally coated with PVC cold wrapping. The pipe line is not piggable, so and located downstream of compressor station.

II. Theory and Hypothesis

According to the NACE SCC DA a pipe line segment is considered susceptible to SCC if all of the following factors are met [1],[2]:

The operating stress exceeds 60% of specified minimum yield strength (SMYS); the operating temperature exceeds 38°C (100 F), the segment is less than 32 km (20Km) downstream from a compressor station, the age of the pipeline is greater than 10 years and the coating type is other than fusion-bonded epoxy.

Above segmentation includes wide area in pipeline system (about 32 km) and doesn't mentioned to sites and spots inside the segment that probability of finding SCC be in maximum level.

Stress corrosion cracking recommended practice of Canadian Energy Pipeline Association (CEPA), mentioned to the near neutral pH SCC, in detail. CC technology's final report for SCC corrosion cracking study, gathered

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characteristics of high PH and near-neutral SCC, simultaneously.

As described in SCC final book, 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.

Based on our current level understanding, the primary factor that determines susceptibly to SCC initiation is the type of external coating on the pipeline. The majority of high PH SCC failures have been associates with bituminous coating (coal tar or asphalt), while the near –neutral PH SCC failures have occurred most frequently on tape- coated pipelines. An intact coating that prevents contact of electrolyte with the steel surface will mitigate all integrity threats associated with external corrosion including SCC [5].

Secondary factor that may influence SCC susceptibility of the pipeline segment are steel properties, pipeline operating condition, environmental conditions and maintenance history. These factors have less certainly in determining SCC susceptibility when compared to coating type.

Notwithstanding the contribution of other factors, SCC can only occur if the external coating becomes disbonded from pipe surface in manner that allows electrolyte to become trapped between the pipe surface and the coating [4],[5]. The region of an adhesion loss caused by cathodic disbondment has led to questions as to a particular susceptibility to SCC. Cathodic disbondment is associated with damaged areas [6]. For this reasons, most probable sites for detecting the SCC are nearby the coating defects.

In this study, analog Direct current voltage gradient (DCVG) instrument used for detecting the coating defect, as most likely site of the existing SCC. Calculating the IR% for determining the coating fault severity has been done according to NACE TM0109-2009 [3].

III. Inspections and Findings

Records show that the 16 inch gas pipeline as named E-branch was constructed in 1978, using 19.05mm wall thickness, API 5L-X65 material. The maximum temperature of the fluid passing through is 60°C. The operating pressure is 250bar. PVC cold wrapping has been used as external coating. The pipeline has reported historical repairs however details of repair causes and locations are not available.

To find out the cathodic protection level in the pipeline, digital Close Interval Potential Survey (CIPS) instrument was used. A switching cycle of 1.6 second ON and 0.4 second OFF with a frequency of recording of 1 second was used for data recordings. This will maintain a ratio of ON to OFF of 4:1 reducing the risk of any long term depolarization effect to the pipeline system.

Inadequate cathodic protection level was detected in through of the pipeline according to the (-850mV) instant-off potential criterion, generally (Graph 1). This graph is a sample of CIPS results in this pipeline.

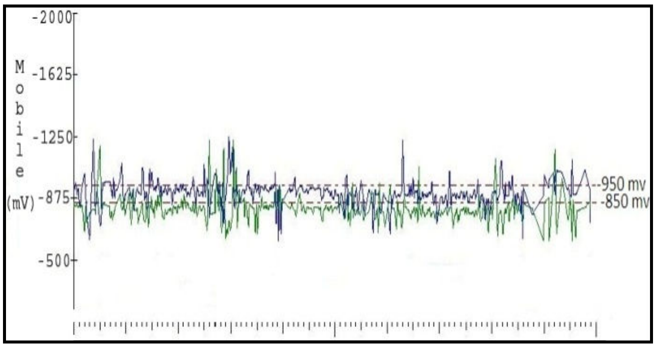


Fig. 1 CIPS results

A direct current voltage gradient survey is a technique to measure the voltage gradients in the ground created by the passage of direct current applied to a pipeline through resistive soil. At external coating defects measurable voltage gradients can be detected at ground level using a sensitive voltmeter and two reference electrodes. The larger the coating defect the greater current flow and voltage gradient The dc current is applied to the pipeline at the pulsed frequency using the cyclic interrupter, set to a moderate switch cycle 0.45 second on and 0.9 second off.

DCVG survey readings are sometimes broken into four groups based on approximate size, for example, as follows:

- Category 1: 1 to 15% IR
- Category 2: 16 to 35% IR
- Category 3: 36 to 60% IR
- Category 4: 61 to 100% IR

A total of 101 coating defects were located on the pipeline section, of which, 75 defects were classified as small (category 1). There were 24 defects which were classified as medium (category 2), and a further 2 defects which were classified as medium-large (category 3). There were no defects classified as large (category 4).

After excavation and preparing the pipe surfaces, at 43 locations with category 1, Magnetic Particle Inspection (MPI) was carried out. Furthermore, at 16 locations with category 2 and 2 locations with category 3, Magnetic Particle Inspection (MPI) has been conducted. Inspections were carried out using black and white contrast MPI. Wherever cracking was defined, the location marked clearly and identified with a unique reference. Eddy current inspection was used to characterize the depth and extent of the cracking.

IV. Results and Discussions

All the factors discussed in NACE standard are met in this pipe line. In addition, SCC is typically found in locations where CP is shielded from the pipe surface or is inadequate. CIPS results showed that potential is under-protection according to (-850 m.v “off”). So, results of CIPS show that this pipeline is susceptible to SCC.

It was considered that coating defects are most likely sites for creating the SCC. For this, some sites with coating defect, found with DCVG, were choose to inspection and MPI. From

43 locations with category 1, where MPI was carried out, in 33 locations, SCC was detected. From 16 locations with category 2, where MPI was carried out, in 12 locations, SCC was detected and for 2 locations with category 3, there was one location with SCC. That is to say, approximately, in 80% of locations with coating defects of category 1, SCC has been found. Same percentage is applicable for locations with category 2. Excavations and inspections for coating defects with category 3 weren't adequate to extend the result. Table I shows these findings. At least 3 meters assigned for testing with MPI, in each location.

TABLE I
SUMMARY OF THE SCC DETECTED LOCATIONS

	Total defect	*Total MPI location*	*Locations with detected SCC*	*Percentage of locations with detected SCC (%)*
DCVG Category 1	75	43	33	77%
DCVG Category 2	24	16	12	75%
DCVG Category 3	2	2	1	50%

So, to find the locations with SCC, determining the coating defects, are most desirable manner, although, it doesn't mean the most severe coating defect as per DCVG categories, most likely places to find out the SCC. It seems that the probability of the existing of SCC nearby the coating defects with category 1 is same for category 3. So, when the main problem of the pipeline is SCC, all categories of the coating defects could be considerable.

Fig. 2 illustrates disbondment area close to coating defects for a pipeline with PVC cold wrap coating and after 38 years from construction year. Extent of disbondment area next to the DCVG category 1 is approximately same in compare with category 3.

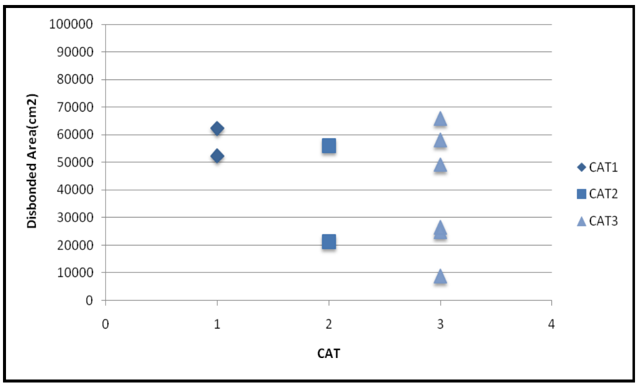
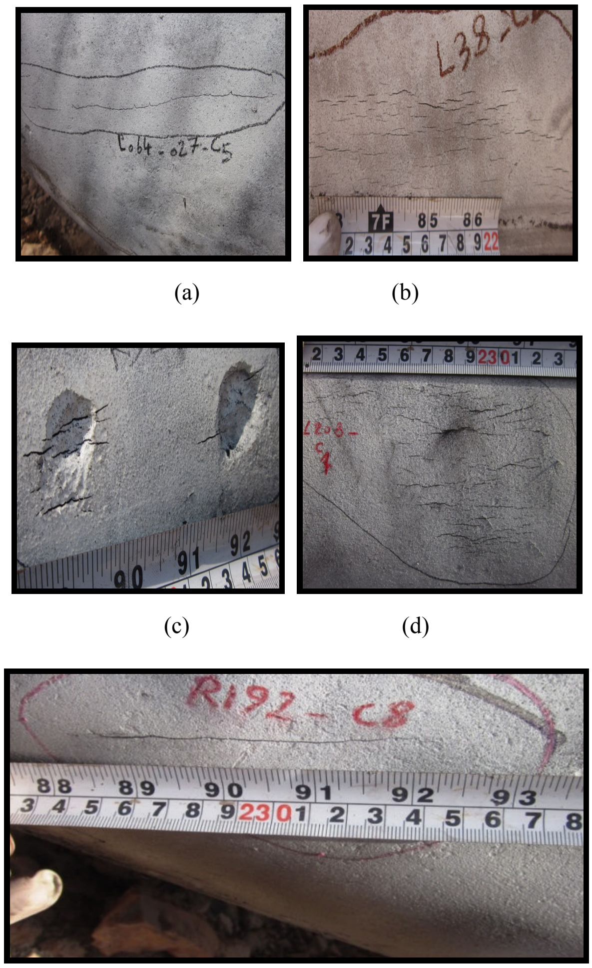


Fig. 2 The extent of disbondment in compare with the coating defect category

After finding the cracks with MPI, Eddy current inspection was carried out to determine the crack depth. The following table is a summary of all the actual SCC depth that was found:

TABLE II
CRACK DEPTH RANGE

Depth range	*Total*	*Percent of total the SCC found*
≤ 1mm	152	73.5%
1mm<depth≤3 mm	50	24%
3mm<depth≤5 mm	5	2.5%
Total	207	100%



(a) (b)

(c) (d)

(e)

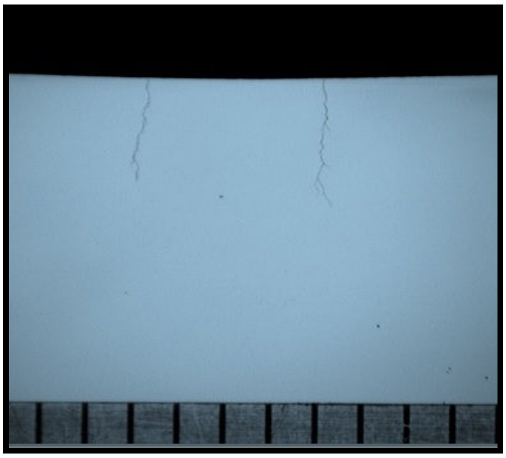
Fig. 3 (a), (b), (c), (d) and (e) Samples of SCC shapes, found place and orientation for E- Branch pipeline

SCC occurred in places with corrosion metal loss. The SCC was typically within areas of general corrosion and/or pitting (Fig. 3 (b)). SCC can occur in individual or colony form. Colonies typically contain from a few to thousands of individual cracks (Figs. 3 (c) & (d)). 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 operation 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 directions can shift to the circumferential-oriented or some intermediate angle (Figs. 3 (a) & (e)).

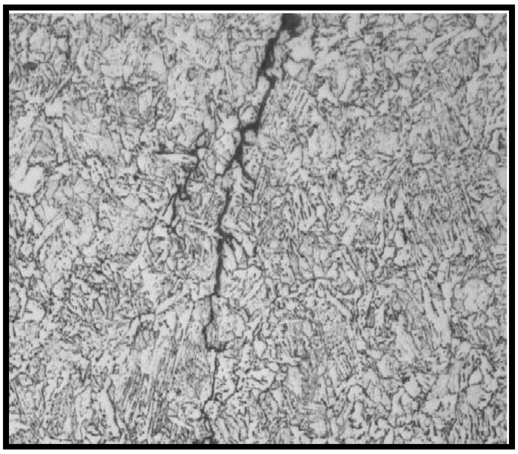
One sample was taken out from this pipeline to metallographic examination. These were prepared using standard metallographic techniques and examined using an optical microscopic. Fig. 4 shows these results. Intergranular phenomenon was detected in SCC sample. This type of SCC morphology considered in high-pH SCC. But, there is potential for neutral pH SCC in this pipeline, too.

In next study, it will conduct to evaluate all other parameters and situations that can be effective in detecting the SCC, for example, train type, chemical composition of soil and morphology of SCC. It is planning to carry out the MPI in 7.5 km of the pipeline, thoroughly. All other factors will discuss after finding the SCC sites, totally.

In this study, it was tried to determine the coating defect weight in finding the SCC susceptible sites, without considering the other parameters.



(a) Macrograph sample section



(b) Intergranular phenomenon

Fig. 4 Morphology of SCC in E-Branch pipeline

V. Conclusion

It has been discussed that where the in-line inspections and hydrostatic test is impracticable for the pipeline, SCCDA can be used to determine and detection of SCC. SCCDA is most related to our current level of understanding from failure mechanism of SCC in pipeline system. All other factors have less certainty in compare with disbondment. There is an agreement that SCC only occur in the coating disbondment area. In this study it was supposed that for thick coatings, disbondment is in conjunction with coating defect. So, coating defects, that detectable with DCVG, was supposed to primary factor in determining the SCC susceptible sites. Approximately, in 80% of locations with coating defects of category 1, SCC has been found. Same percentage is applicable for locations with category 2. Excavations and inspections for coating defects with category 3 weren't adequate to extend the result. It seems that the probability of the existing of SCC nearby the coating defects with category 1 is same for category 3. So, when the main problem of the pipeline is SCC, all categories of the coating defects can be considerable. Transformer rectifiers (T/R) should be used in maximum power, for detecting the small coating defects. Using the auxiliary ground bed will helpful to detect the small defects, as the SCC susceptible sites. Intergranular phenomenon was detected in SCC sample. This type of SCC morphology considered in high-pH SCC. But, there is potential for neutral pH SCC in this pipeline, too.

Acknowledgment

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