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FAILURE ANALYSIS OF 18-INCH DIAMETER GAS PIPELINE

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ABSTRACT
Incidents of failure due to corrosion / stress-corrosion cracking of high-pressure gas pipelines in Pakistan have been observed to occur after about 15-20 years of service. The present paper constitutes the failure analysis of an 18-inch diameter electric-resistance-welded gas pipeline. The rupture was characterized as a stress-corrosion failure, on the basis of all the available evidence, and the metallurgical examination carried out on the ruptured pipe. A prominent feature associated with this rupture was that the crack had initiated at a longitudinal 'stress raiser'. This stress raiser, which was essentially a manufacturing defect, constituted a longitudinal 'step' that had resulted from the faulty trimming/shaving of the weld-flash. The findings of this study, thus, emphasize the need for the care that must be taken during the shaving-off of the weld-flash.

Keywords: Stress-corrosion cracking, Cathodic Protection, Intergranular

1. INTRODUCTION
Pakistan has large reserves of natural gas in the southern part of the country. Accordingly, it also has a sizable network of high-pressure gas–transmission pipelines. The main transmission lines, which supply the gas to the northern part of the country, were laid down essentially at two different times. The earlier lines of 16-inch and 18-inch diameter were longitudinally seam-welded pipes, coated with coal-tar based compound for protection against corrosion. The more recent lines of 30-inch and 36-inch diameter are spiral-welded pipes protected with poly-ethylene tape coating.

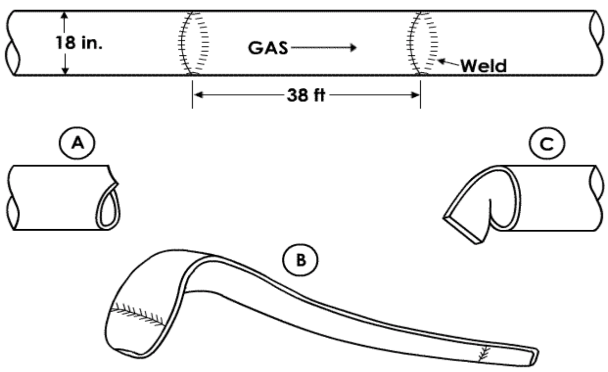


Figure 1. Schematic illustration of the geometry of rupture. A ~40 ft long portion of the pipe, labeled 'B' broke off the main line, and was thrown away to a distance of ~50 feet.

The 16-inch line suffered from a number of corrosion-related failures after about 15-20 years of service, while the only two ruptures occurred in 18-inch line were in 1993 and 1996. The larger diameter lines, which are coated with PE-tape, have so far not exhibited any catastrophe due to aging or corrosion.

The present paper constitutes the failure analysis of the first rupture of the 18-inch diameter line that occurred in 1993. This line was commissioned in 1971, and hence, the line had lasted for about 22 years before developing its first rupture.

2. HISTORY OF RUPTURED PIPELINE
2.1 Location of Rupture
At about 0840 hours on 3 November 1993, the 18-inch diameter main gas pipeline ruptured at about 8 miles downstream of compressor station 'AC1'. The rupture occurred in a 38 feet long section of the pipe, and extended a few feet beyond the weld-joints at both ends. This is schematically illustrated in Figure 1. As a result of the rupture, a portion of the pipe had separated from the main line and was thrown away to a distance of about 50 feet. The separated piece of pipe is labeled as 'B' in Figure 1, while the corresponding pipe upstream has been labeled as 'A', and that on the downstream side as 'C'.

Following the rupture, the escaping gas caught fire presumably as a result of some sparking on the wires of the nearby power-lines. No damage was caused by the fire, but unfortunately, one person was hit by the flying metal sheet and was killed.

Since the location of the rupture was only 8 miles downstream the compressor station, the temperature and pressure of gas at this location could be estimated from the daily operating log-sheet of the gas-transmission department. It was worked out that at the location of the rupture, about 146 MMCFD gas at 1198 psi and at 130-deg F was flowing through the 18-inch diameter pipe just before the rupture occurred.

2.2 Mechanical Characteristics of Pipe

The ruptured pipe was 18-inch diameter with a 0.312-inch wall-thickness, made by longitudinal butt-welding by high-frequency electric-resistance-welding process. The pipe, which conformed to API-5L X-52 grade, was manufactured by Nippon Steel Kawasaki and Sumitomo Metal Industries, Japan. The X-52 grade means a steel having a specified minimum yield strength (SMYS) of 52,000 psi. The pipeline, prior to commissioning in January 1971, was hydrostatically tested at 1530 psig for 24 hours.

The pipeline was also retested hydrostatically in April 1987, when the gas company decided to test 15 mile portions of all the main lines downstream the compressor stations. This decision was taken after the 1984 and 1986 ruptures of the 16-inch diameter line. These ruptures had occurred within a few miles downstream the compressor stations where the temperatures of gas were higher than the stable levels further downstream.

In a pressurized pipe, the value of 'Hoop Stress' (or Circumferential Stress) can be conveniently estimated from the equation:

$$\sigma = PD/2t$$

where σ is the Hoop Stress in psi, P is the gas pressure in psi, D and t are the diameter and wall-thickness of the pipe in inches. Using the values of gas-pressure, and the diameter and wall-thickness of the pipe, the Hoop Stress is worked out to be about 34,000 psi, which is about 66.5% of SMYS, as against 72% maximum allowable.

2.3 Protection of Pipeline

The ruptured pipeline had been coated with coal-tar based enamel having fibre-glass inner and outer wraps. Impressed current cathodic protection system [1,2] was installed for the mitigation of corrosion. Pipe-to-soil potential measurements were taken every three months and adjustments, if required, made to attain a minimum of –0.85 volt pipe-to-soil potential (with respect to Cu/CuSO4 reference electrodes). This cathodic protection system had been in place ever since the pipeline was commissioned in January 1971.

It is important to point out that the section of the pipeline in which the rupture occurred, had showed inadequate cathodic protection during a routine survey carried out in May 1992. Accordingly, adjustments were made and this section was found to be adequately protected during the survey of November 1992. However, it was again found to be inadequately protected during the survey of February 1993, indicating that the poor condition of the coating could be causing a shielding effect. It was thus planned to replace the deteriorating coating, but before any replacement work could begin, the line exhibited the rupture, in November 1993.

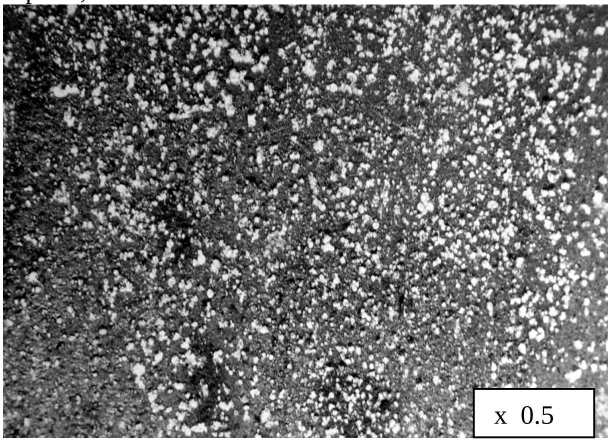


Figure 2. Small-sized white deposits on the pipe surface, exposed by gently peeling-off the coating from piece 'A' of Figure 1. These were identified to be carbonates and bicarbonates of sodium.

3. EXAMINATION OF RUPTURED PIPE

3.1 Examination of Coating and the Pipe Surface

Following a catastrophe with a gas pipeline, the first priority obviously is to repair the line and restore the gas supply as quickly as possible. Accordingly, the line was repaired and the gas supply restored in about 32 hours. The failure investigation team, of which the author (FH) was a member, arrived the following morning to examine the rupture site. The ~40 feet long portion of the pipe that had axially ruptured (labeled as 'B' in Figure 1), and the two end pieces cut off the broken line (labeled as 'A' and 'C' in Figure 1) were available for examination at the rupture site. The ruptured piece B had not been removed from the point where it was thrown to by the force of the blast. Although the ruptured line had been repaired, the crater formed by the rupture was yet to be filled.

On the fractured piece 'B', the coating had been completely removed from the entire surface of the pipe, presumably due to the flattening of the pipe-sheet during rupture. However, piece 'A' had most of its coating present on it. At many locations the coating had lost its adherence to the pipe surface and was easy to peel-off. When the coating was gently removed, the pipe surface was found to be covered with a significant amount of 'reddish-brown' rust. Additionally, very small-sized patches of a white deposit were also present on the pipe surface. These deposits, shown in Figure 2, were carefully scrapped off the surface and analysed by X-ray diffraction.

The diffraction results showed the presence of iron-oxides, iron-carbonate, sodium-bicarbonate and quartz. The quartz was believed to have come from the surrounding soil, fine particles of which may have seeped through the microcracks in the coating.

The soil samples collected from the site were also analyzed. The various compounds found to be present included; quartz, calcite, chlorite, illite, and albite. The presence of substantial quantities of quartz in the soil supported the view that the quartz particles on the surface of the pipe had actually come from the soil, and also that the microcracks must have been present in the coating.

The above observations clearly show that the coating on the pipe surface had deteriorated, i.e., it had developed ‘disbonds’ as well as ‘holidays’. This in turn also means that a ‘corrosive environment’ had been present between the coating and the pipe surface. The presence of carbonates and bi-carbonates further indicates that a high-pH environment must have been present for a considerable length of time [3].

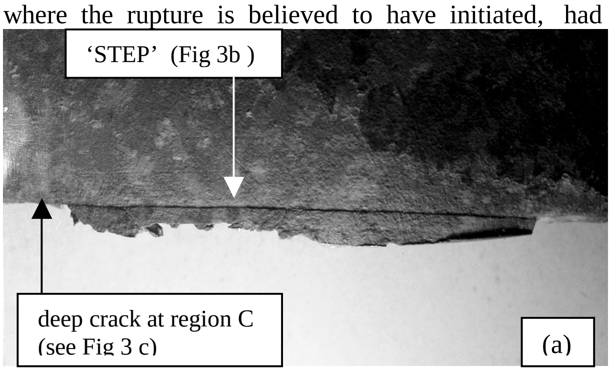
Although, the pipe surface showed significant rusting, there was no evidence of any ‘pitting’ or weight-loss corrosion, i.e., there was no measurable thinning of the pipe-wall.

3.2 Examination of the fracture Surface

The total fractured crack essentially comprised three portions; the ~40 feet long axial (or longitudinal) crack that through the ruptured piece B, and the two transverse (or circumferential) cracks at the two ends of this portion.

The entire fractured face on the rupture piece ‘B’ was closely examined with a magnifier (of magnification x10). The location at which the rupture had initiated was identified with the help of ‘chevron’ marks [4] on the fracture-surface. Photographs showing the details of the region of the crack-initiation are given in Figure 3.

More than one longitudinal (or axial) cracks had formed in this area, while the crack of greatest depth, where the rupture is believed to have initiated, had



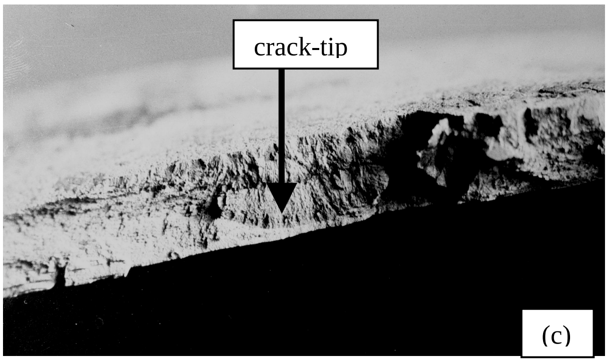


Figure 3. (a) The fractured edge of the pipe showing a longitudinal ‘STEP’ on the outer surface of the pipe, (b) The crack formed at the root of the step – ‘the stress raiser’, and (c) The deepest crack observed on the fractured-face, where the fracture is believed to have initiated .

formed at region ‘C’, indicated in Figures 3a and 3c. It may also be noted in Figure 3a and 3b, that there was a longitudinal ‘step’ present on the pipe surface, and that the region ‘C’ existed on this ‘step’.

It was also important to note that the entire length of the ruptured pipe had actually parted along the ‘step’. This observation suggests that cracks must have formed at many points on the ‘step’ along the length of the pipe.

It shall be quite relevant to mention here that this ‘step’ was a manufacturing defect. During the manufacturing of the pipe by electric-resistance welding method [5], the weld-flash on the outer surface of pipe has to be neatly removed so as to leave a smooth surface free from any stress-raisers like steps or grooves. In the present case, however, it appears that that the weld-flash was removed with a shaving tool which was not properly aligned or shaped in accordance with pipe surface, and this had given rise to the formation of the longitudinal step. This explanation is schematically illustrated in Figure 4.

3.3 Metallography of Crack

Microstructural examination of the samples taken from the area shown in Figure 3b, was conducted to study the morphology of the crack. The micrographs given in Figure 5 show that: (a) the cracks were, in general, intergranular, (b) the cracks exhibited extensive branching, and (c) corrosion products (dark-etching) were also observed to be present inside the crack.

These three characteristics, which are typical features of stress-corrosion cracks [1,2,4], clearly suggest that the failure was caused by stress corrosion cracking.

4. DISCUSSION

The mode of cracking that was observed in the ruptured pipe had all the characteristics of Stress-

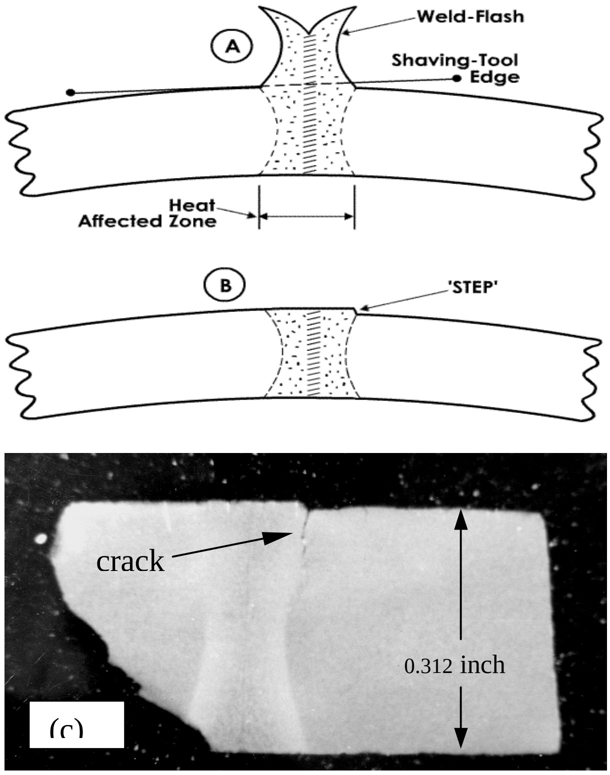


Figure 4. A schematic illustration of the formation of longitudinal step on the outer surface of the pipe during manufacturing. The shaving-tool edge indicated in the top part of the diagram, should have been carefully aligned in accordance with the profile of the pipe-surface, so as to leave a smooth surface.

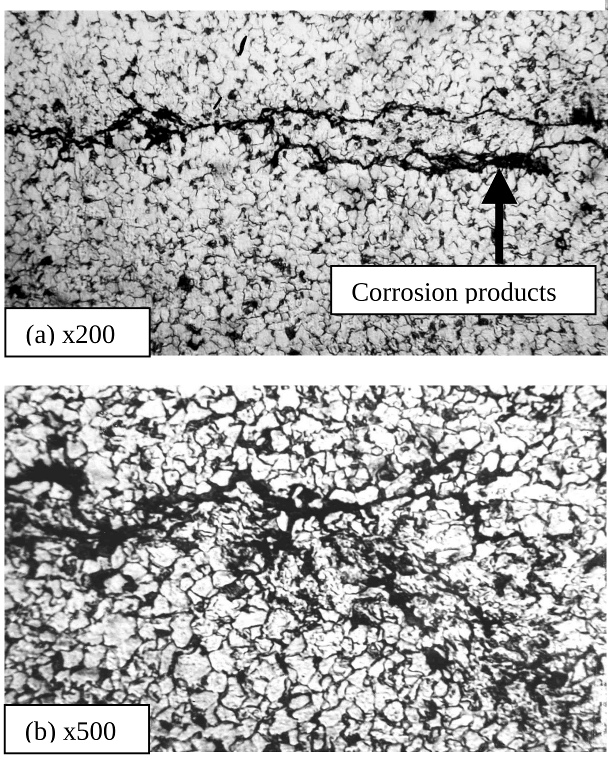


Figure 5. The micrographs taken from the sample shown in Figure 4 c, showing the intergranular morphology of the crack. The extensive branching of the crack, as well as the corrosion products inside the crack may be noted.

Corrosion-Cracking (SSC). SSC is a phenomenon wherein cracking occurs under a combined effect of stress and corrosion. Cracks of fatal depths can develop without any significant corrosion of the surface of the metal [1,2,4]. Stress corrosion cracks are generally inter-granular, however, trans-granular cracks have also been reported under higher stresses and milder environments [6]. Additionally, cracks can exhibit extensive branching [2,4].

In the present rupture, the presence of deep cracks without any significant attack on the pipe surface (Figures 3, and 4c), the inter-granular nature of the cracks, and the branching exhibited by the cracks (Figure 5), clearly support the view that the present rupture was caused by SSC.

The two pre-requisites for the SSC, i.e., the stress and the corrosive environment were also present in the present case: the hoop stress of the level of ~65% of the SMYS caused by pressurized gas (see Section 2.2), and the corrosive environment, evidenced by the rusting of the pipe-surface beneath the coating, as well as the presence of carbonate and bi-carbonate of sodium, shown in Figure 2.

Although the SSC is generally stated to be influenced by various factors [1,2,7,8] including stress-level, temperature, stress-fluctuations, the pH of the environment etc., the onset of SSC in buried pipes is essentially dictated by the beginning of the deterioration of the coating. It is for this reason that that modern coatings like PE-tape, fusion-bonded epoxy, and urethane-based compounds have performed markedly better than the older coal-tar based coatings.

It appears that coal-tar based coatings, in a typical time of about 15-20 years, start to develop disbonds and holidays, such that the soil water and moisture (alongwith its soluble constituents) can have access to the pipe surface. This time may be markedly reduced by increased temperatures. The SSC failures in Pakistan have all occurred within a few miles downstream the compressor stations, reflecting that the higher temperatures of the gas (just after compression) had accelerated the deterioration of the coating, presumably by drying out the volatile constituents in the coal-tar.

The influence of temperature has been investigated by the corrosion scientists who have analysed the failures of gas pipelines in USA and Canada. Studies conducted during 1990’s have suggested a threshold temperature of about 115-deg F as the demarcation between operation nominally free from SSC versus the potential for stress-corrosion cracks to develop to near critical size [8,9]. The pipeline failures in Pakistan also confirm the role of temperature in the SSC of buried pipelines. However, the present work indicates that although the temperature may also influence the kinetics of SSC, the more vital role of the increased temperature is to deteriorate the coating. It can be argued that as long as the coating is ‘sound’ enough not to allow any access for the soil water (or moisture) to the pipe surface, the SSC shall not even take a start.

It also appears that once the coating has developed disbonds and holidays, the SSC may progress within only a couple of years. It is important to note that the

18-inch diameter pipeline under discussion had ruptured about two years after it started requiring adjustments in applied potential for cathodic protection. If it is argued that the potential adjustments were actually necessitated by the coating deterioration, then it should also follow that the process of SSC had also initiated at about the same time. Thus the SSC took only two years to progress to rupture.

The above explanation suggests that, for within a few miles downstream the compressor stations, it may be useful to replace the coating as soon as the applied potential between the pipe and the soil starts requiring adjustments. Coupled with this, an increase in the frequency of potential monitoring, may provide further benefit [10].

In the present failure, however, it seems highly probable that the time-to-rupture may have been markedly reduced by the stress-raiser that was present on the pipe surface. The longitudinal step on the outer surface of the pipe that was produced during the manufacturing, through careless shaving of the weld-flash, had acted as a very effective stress-raiser. The stress concentration at this step had in effect locally increased the value of Hoop stress in excess of PD/2t, thereby accelerating the stress-corrosion cracking of the pipe. The present study thus also emphasizes the need to take due care during the manufacturing of the pipe, so that no stress-raisers like steps or grooves are left on the pipe surface after the weld-flash is removed.

5. CONCLUSIONS

The rupture of 18-inch diameter gas pipeline was caused by SCC, which in turn had been effected by the deterioration of the coal-tar based coating over a period of 22 years. However, a stress-raiser had played an effective role in accelerating the rate of SCC. This stress raiser which was a longitudinal step on the pipe surface was essentially a manufacturing defect, produced by careless shaving of the weld-flash.

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