Analysis of the remaining life of API 5L grade B gas pipeline in the flare gas recovery unit

M Y M Sholihin¹, H S Kusyanto², B Soegijono³

¹ Department of Mechanical Engineering, Pancasila University Srengseng Sawah St., Lenteng Agung, Jakarta 12640, Indonesia
² Material Science Department, Physics Faculty, University of Indonesia, Depok 16424, West Java, Indonesia
³ Material Science Department, Physics Faculty, University of Indonesia, Depok 16424, West Java, Indonesia

y.masduky@ui.ac.id

Abstract. Carbon steel pipe material API 5L grade B is commonly used for distribution in oil and gas industry. Internal corrosion is one of the biggest corrosion problems in carbon steel material that could impact production and cause economic losses. In this work, corrosion rate, remaining life, fluid composition, and corroded sample of API 5L grade B are analysed and calculated by development of microstructure, mechanical denaturing, and change of chemical composition by comparing with new pipe sample. The results show that the thickness of the pipe API 5L grade B applied as distribution line significantly decreased from 8.4 mm to 7.1 mm in only one year with a high corrosion rate of 1.32 mm/year based on ultrasonic testing inspection during the years of 2000 - 2016. It was found that the deterioration of pipe material was caused by gas composition contain mostly gas hydrocarbon with CO₂ 10.1% mole and water composition containing 57.3 mg/L Cl⁻ ion. This chemical composition decreased the pH of liquid to 4.5, creating a good corrosion environment for this pipe. It caused the active corrosion rate significantly increase in just one year. Based on calculations, the remaining life of this pipe line was found to be just 3.6 years because of internal corrosion. XRF, XRD, and SEM analyses were done to determine the composition of the corrosion product. Based on those analysis, the main causes of the corrosion are found to be CO₂ and O₂. It is concluded that, the mechanical properties of this corroded pipeline still satisfy the standard for API 5L grade B with a tensile strength of 441 MPa and hardness of 74.

1. Introduction
Pipelines and piping are the most economical and efficient means of large scale fluid transportation for natural gas and crude oil. Pipeline and piping are commonly made of carbon steels due to some reasons: carbon steel have good mechanical properties, low cost and wider availability despite their corrosion resistance is relatively low. This corrosion happen due to the presence of high corrosion agents such as CO₂, H₂S and chlorine compound. The corrosion agents are dissolved in the fluid that can accelerate corrosion process inside of the pipelines. Internal corrosion due to dissolved CO₂ is commonly occurred in natural gas pipelines. The content of formation water (containing chloride ions) and dissolved CO₂ can cause uniform corrosion in pipeline. At distribution of natural gas in pipeline, formation water is a distribution medium for natural gas produced from the wells [1]. Therefore, a big concern must be given...
to formation water in controlling CO$_2$ corrosion. Corrosion could cause production and economic losses that is followed with pollution to the environment and disaster [2].

Flare Gas Recovery Unit (FGRU) is a process unit for recovering waste gas that are usually vented or burned, so they can be used as fuel gas elsewhere in the facility. This process can reduce emissions and production cost. The existence of units in addition to having a positive impact to the environment. After a few years, at the FGRU there are several points that occur rapid depletion of the pipe thickness. The impact when there is leaking in the unit due to corrosion is very dangerous for the environment such as fire and environmental pollution. In addition, the company will suffer huge losses.

By analyzing and investigating the cause of corrosion, we could prevent losses and avoid similar incidents. It is useful to determine the remaining life of the piping system. The remaining life is simulated to the level of risk that the output of forming, planning, inspecting, and making integrated maintenance strategy. In order to support the implementation of the activities, it is necessary to include data on aspects of design, metallurgical, fabrication, measurement and field testing UT in the various operating conditions and operational historical data [3].

2. Experimental method

![Diagram of Experimental method](https://example.com/diagram)

**Figure 1.** Experimental method.

This experiment is focusing to analyse corrosion which occurred on flare gas recovery unit. The corrosion rate, remaining life, fluid composition, and corroded sample of API 5L grade B were analysed and calculated by developing of metallographic, mechanical denaturing and change of chemical composition comparing with standard pipe sample. Corrosion rate, maximum allowable working...
pressure (MAWP) and remaining life data are taken and calculated from Ultrasonic data testing from year 2000 until 2016.

Four samples were characterized by using XRF, XRD and SEM EDS to know the composition, metallography, and morphology of the material [2, 5, 6]. New pipe and corroded pipe carbon steel samples are used to study mechanical properties of API 5L grade B by using tensile test and hardness test. Figure 1 show the experimental diagram of the research.

3. Experimental method

3.1 Piping integrity

Based on the data Table 1, there is a significant corrosion rate change at the 6 o’clock direction. The measurement of pipe thickness used ultrasonic tesine measurement which is done since 2000 until 2016. This fact is caused by the corrosive nature of the liquid carried to the pipe and the gas is not sufficiently dry. Changing of the operating condition on the piping, as resulting liquid is temporary hold up that will cause an internal corrosion of the pipe. Significantly corrosion rate changes between 2015 and 2016 to 1.32 mm/year with the remaining life 3.61 years. Assessment and examination need to be done to determine the cause of this significant corrosion rates, maintenance and inspection strategies to reduce the likelihood and risk of leakage occurring.

Table 1. FGRU piping integrity by UT measurement.

| Line Number   | Point | 2000 | 2008 | 2015 | 2016 | Long | Short | Remaining Life | MAWP |
|---------------|-------|------|------|------|------|------|-------|----------------|------|
| 10-G-B10A-7728| 1056  | 9.70 | 8.78 | 8.62 | 8.57 | 0.02 | 0.05 | 261.92         | 33.09|
| 10-G-B10A-7728| 1056  | 9.50 | 8.96 | 8.75 | 8.64 | 0.04 | 0.11 | 218.28         | 33.37|
| 10-G-B10A-7728| 1056  | 9.00 | 8.52 | 8.38 | 7.06 | 0.17 | 1.32 | 3.61           | 27.12|
| 10-G-B10A-7728| 1056  | 9.50 | 9.87 | 9.68 | 9.16 | 0.08 | 0.52 | 20.35          | 35.44|

Figure 2. Inspection and corroded pipe point.

At Figure 2 High Corroded point is marked by red marking, most of the corrosion is happened at 6 o’clock direction especially at point 1056 at the upstream of pressure control valve. This control valve
is set up at 5 Barg operating pressure. When the pressure is lower than 5 Barg, the valve will be closed and create liquid hold up at the bottom of the pipe. This phenomenon can propagate internal corrosion caused by water.

3.2 Fluid analysis
Operating parameter of FGRU shows in Table 2, where operating pressure is 5.5 barg (low pressure) and the pipe size is 10 inch. This condition make the fluid is easy to condense then trapped at the point 1056. The temperature of the process is 37 °C. When temperature is below 40 °C, it will reduce precipitation of iron carbonate (FeCO₃). It means the less protective layer is formed, the less corrosion rate increment [4].

Fluid of this unit contain gas and water, for gas is analysed by gas chromatography and water by ten ions with pH measurement. The gas composition contains most hydrocarbon with C1 to C10 89.9%, N₂ gas 0.067% and CO₂ gas 10.1%. The water composition contains ion Cl⁻ 57.3 mg/l. The water containment can propagate corrosion and lowering pH. pH is measured 4.5 showing that corrosion rate increase at this point. Solution pH plays an important role in the corrosion of carbon steels by influencing both the electrochemical reactions that lead to iron dissolution and the precipitation of protective scales [3]. Ion Cl⁻ can increase conductivity of the water. Three major effects of CO₂ will be addressed: The effect on the water chemistry, the effect on the electrochemical reactions, and the impact on the initiation and growth of corrosion product films [5].

| Specification          | Value            |
|------------------------|------------------|
| Pipe OD                | 10 in            |
| Wall thickness         | 7.1 mm           |
| Material               | API 5L grade B (Carbon Steel) |
| Operating Pressure     | 5.5 barg         |
| Operating Temperature  | 36 °C            |
| Flowrate               | 10 mmsfd         |
| Fluid                  | Gas + Water      |

**Table 2. Operating parameter and piping size.**

**Figure 3. Fluid-velocity at FGRU in one month.**
Flow of the FGRU fluid fluctuated between 0 – 13 mmscfd, depending on feed from oil processing. Figure 4 shows fluid velocity of FGRU in one month. Erosion will occur in that condition, based on API 14E RP fluid velocity 4.5 m/s. It can cause the erosion, in 10 inch pipe means 0.730 mmscfd, that was below flow average of this current operation. Erosive fluids can damage the protective film, and remove small pieces of material as well, leading to a significant increase in penetration rate. The damage to the protect film may be the results of the fluid-induced mechanical forces or flowing-enhanced dissolution [8]. Beside the erosion, flow rate of gas containing water and CO$_2$ has two principal effects on film formation and corrosion rate and form. First, it prevents the formation and slows down its growth by reducing the local supersaturation. Second, flow can damage film locally to cause localized corrosion, especially mesa attack [4]. An increasing flow rate can increase the corrosion rate by enhancing the transport of corrosive species toward, or remove protective product from, the surface.

3.3 Visual examination
Figure 3 shows internal pipe visual examination result is uniform corrosion attack at the bottom of pipeline (6 o’clock). This type of corrosion leads to assume that corrosion is happened by electrochemical process. This process usually caused by water hold up as electrolyte that might contain be ion Cl$^-$ and CO$_2$. The color of this corrosion product is brown that might be contain hematite. Mesa type attack also formed at the bottom of pipe. Mesa attack is a type of localized corrosion and occurs in low to medium flow conditions where the protective iron carbonate film forms but it is unstable to withstand the operating regime [3]. However, this analysis need to be clarified and verified more detailed by some characterizations as shown later.

![Figure 4. Visual examination internal pipe.](image)

3.4 Analyze of corroded FGRU’s piping
Characterizations of the pipeline material were conducted using chemical composition, metallographic examination, and mechanical property test including tensile test and hardness test measurement. Table 3 below shows composition of corroded samples result by using XRF found that Fe contain reduce to 70.5 % compared with API 5L grade B standard is 98 %. The composition showed that the corroded pipeline composition still fulfills that API 5L grade B standard composition.

| Material      | Fe    | C    | Mn    | P     | S     | Ti    | V     | Ni    | Mo   | Cr   | Cu   | Cl   |
|---------------|-------|------|-------|-------|-------|-------|-------|-------|------|------|------|------|
| Pipeline      | 70.5  | -    | 0.636 | 0.135 | 3.739 | 0.09  | 0.009 | 0.11  | 0.02 | 0.15 | 0.13 | 0.153|
| API 5L grade B| 98    | 0.22 | 1.2   | 0.03  | 0.02  | 0.04  | 0.05  | 0.15  |

The Scanning Electron Microscope (SEM) examination provides information about the result of the interaction and process between the corrosive environment and steel pipe, specifically with regard to
the morphology of the metal surface, deposits and corrosion products. Deposits may be crystalline or amorphous [9]. Figure 4 shows morphology of corrosion layer at the corroded steel pipe. Corrosion deposits from steel formed in solution are mainly composed of insoluble products, undissolved constituents and trace amounts of alloying elements. They are formed in various oxides and carbides.

![SEM micrograph of FGRU corroded pipe.](image1)

**Figure 5.** SEM micrograph of FGRU corroded pipe.

In Figure 5 the image shows that corrosion products are formed almost all of the surfaces in the pipeline where the corrosion product has the same shape. To find out the content of corrosion layer is also tested by Energy Dispersive Spectroscopy (EDS) at 7 point in 1000x magnification. In corrosion studies EDS is used to provide chemical composition about the material being examined by SEM. The relative amounts of elements detected are categorized as major, minor and trace values.

![EDS micrograph of FGRU corroded pipe.](image2)

**Figure 6.** EDS micrograph of FGRU corroded pipe.
Table 4. EDS of FGRU corroded pipe.

| Element | Spectrum Location |
|---------|-------------------|
|         | 1     | 2     | 3     | 4     | 5     | 6     | 7     |
| C       | 5.58  | 6.17  | 7.1   | 7.16  | 5.82  | 6.23  | 7.33  |
| O       | 47.95 | 49.04 | 54.88 | 51.23 | 45.46 | 42.29 | 44.93 |
| S       | 0.82  | 1.04  | 0.9   | 1.38  | 1.05  | 1.58  | 1.19  |
| Mn      | 0.37  | 0.4   | 0.44  | 0.2   | 0.47  | 0.33  | 0.36  |
| Fe      | 45.27 | 43.35 | 36.69 | 39.63 | 47.2  | 49.56 | 46.19 |
| Al      |       | 0.17  |       |       |       |       |       |
| Si      |       | 0.23  |       |       |       |       |       |

Major elements in FGRU corroded pipe samples of corrosion products are C, Fe and O. Minor elements are Mn, Al, and Si. At points 1 to 7 it was found that the Fe content ranged from 36 to 49% wt while the oxygen content was 42 - 54% wt. This two elements will produce metal oxide as a form of corrosion oxide process, it shown the corrosion products that stick and form on the wall of the pipe. These high levels of oxygen content comes from the water due to turbulence processes that occur in the fluid flow process. Oxygen enters into a flow system in the form of dissolved. Oxygen comes from the reservoir when the gas is produced from the well. In addition, oxygen also comes from outside air processes when internal inspection work is done. Carbon content (C) is present with a minor amount of 5 - 7 wt%. This element is derived from CO₂ gas that also produced with natural gas. It will form formation of corrosion products such as siderite (FeCO₃) and carbides (Fe₂C).

The presence of other elements in corrosion products such as silicon (Si), possibly derived from fine sand (SiO₂) or other compounds that participate in the fluid and flows into the pipe. The sulfur element (S) is derived from a gas fluid containing H₂S, which can cause corrosion. The existence of flow turbulence in the pipeline causes the protective layer detached and dissolved again at the corrosion process. This intermittent and high speed flow will also sweep and form new corrosion products.

Metallographic examination is done by analysing phase formed and surface morphology. Phase formed based on X-Ray Diffraction refinement found corrosion products are Fe₂O₃ (Hematite), FeCO₃ (Siderit), FeO₂ (Geothite). Table 5 shows the percentage of corrosion product phase.

Figure 7. XRD analysis of FGRU corroded pipe.
Atom C present in corrosion products probably comes from hydrocarbon and/or bicarbonate (HCO\textsuperscript{3−}) whereas chloride ions (Cl\textsuperscript{−}) dissolved in water. CO\textsubscript{2} is one of the acid gas causing internal corrosion in the gas pipeline. This gas is not corrosive if it is dry and not dissolved in water. If dissolved in the water of this gas will form a weak acid H\textsubscript{2}CO\textsubscript{3} that is corrosive [5]. Generally, CO\textsubscript{2} dissolved in water will form carbonic acid by reaction because when CO\textsubscript{2} is dissolved in water it is partly hydrated and forms carbonic acid.

\[ \text{CO}_2 + \text{H}_2\text{O} \rightarrow \text{H}_2\text{CO}_3 \]  \hspace{1cm} (1)

Carbonic acid is diprotic and dissociates in two steps:

\[ \text{H}_2\text{CO}_3 \leftrightarrow \text{H}^+ + \text{HCO}_3^- \]  \hspace{1cm} (2)

\[ \text{HCO}_3^- \leftrightarrow \text{H}^+ + \text{CO}_3^{2-} \]  \hspace{1cm} (3)

When the steel corrodes, Fe\textsuperscript{2+} and an equivalent amount of alkalinity are released in the corrosion process.

\[ \text{Fe} + 2\text{H}_2\text{CO}_3 \rightarrow \text{Fe}^{2+} + 2\text{HCO}_3^- + \text{H}_2 \]  \hspace{1cm} (4)

The pH in the solution increases and when the concentrations of Fe\textsuperscript{2+} and CO\textsubscript{3}\textsuperscript{2−} ions exceed the solubility limit, precipitation of FeCO\textsubscript{3} can occur:

\[ \text{Fe}^{2+} + \text{CO}_3^{2-} \rightarrow \text{FeCO}_3^{(S)} \]  \hspace{1cm} (5)

The rate of corrosion depends on the partial pressure of the CO\textsubscript{2} gas (P\textsubscript{CO}_2) and the operating temperature. Partial pressure gas CO\textsubscript{2} determines the pH of the solution and the concentration of solute based on its temperature. An increase of CO\textsubscript{2} partial pressure (P\textsubscript{CO}_2) typically leads to an increase in the corrosion rate. P\textsubscript{CO}_2 concentration in H\textsubscript{2}CO\textsubscript{3} will increase and accelerate the cathodic reaction and ultimately the corrosion rate [7]. In this FGRU unit the CO\textsubscript{2} partial pressure is 0.55 Barg, based on API level the corrosion level is unlikely the corrosion type is uniform corrosion with corrosion rate <0.1 mm / year [4]. At 37\textdegreeC temperatures the corrosion rate increases, because the higher the temperature the kinetic energy of the reacting particles will increase to exceed the magnitude of the activation energy and consequently the rate of reaction (corrosion) will also accelerate. While at a temperature of 80\textdegreeC FeCO\textsubscript{3} solubility in the solution decreased and high supersaturation led to precipitation of FeCO\textsubscript{3} which became protective scale formation [10].

Result of tensile and hardness test are shown in Table 6. The yield and tensile strength of the pipeline are 382 and 441 Mpa, respectively these data fulfill the minimum stresses specified by API 5L grade B. the hardness value of the pipeline does not exceed the maximum hardness specified by API 5L grade B standard. Based on the result of chemical composition and mechanical property tests. It is conclude that the pipeline material is closely match to standard API 5L grade B carbon steel.
Table 6. Tensile and hardness test.

| Sample Code       | Yield Strength Mpa | Tensile strength Mpa | Hardness |
|-------------------|--------------------|----------------------|----------|
| Standard API 5L Grade B | 245-450           | 415-760              | 82       |
| Corroded API 5L Grade B | 382              | 441                  | 74       |

4. Conclusion
Corrosion rate formed and increased at point in the 6 o'clock direction between 2015 and 2016 to 1.32 mm/year with the remaining life 3.61 years. That calculations are based on ultrasonic testing measurement since 2000 – 2016. Localized corrosion of this FGRU piping is caused by not only by water hold up in low point that contain Cl- increase the conductivity and CO₂ gasses which dissolved to the water, that can reduce pH to 4.5 but also the velocity of the fluid sometimes is changed. Alteration of fluid velocity cause erosion at the corrosion product. Examination of corroded pipe found that is corrosion product contain C, Fe, and O as major products. Phase formed are Fe₂O₃ (Hematite), FeCO₃ (Siderit), and FeO₂ (Geothite). The FGRU piping characterization and mechanical testing are still in the standard of API 5L grade B.

References
[1] Kermani M B Gonzales J C Turconi G L Perez T Morales C 2005 Mater. Optimiz. In Hydrocarbon Product. NACE
[2] Dariva C Galio F 2014 Corrosion Inhibitors – Principles, Mechanisms and Applications. Developments in Corrosion Protection
[3] Solihin Yudi M 2004 Piping System Oil and Gas Production By Using RBI Method 1st ed. Jakarta
[4] Kermani M B & Morshed A 2003 Carbon Dioxide Corrosion in Oil and Gas Production—A Compendium
[5] Ilman M N Kusmono 2014 Analysis Of Internal Corrosion In Subsea Oil Pipeline
[6] Rustandi Andi A Fadly M Subekti E Norman 2012 Makara J. of Tech.
[7] Nešić S 2007 Corrosion Science 49(12) 4308–38
[8] Baotung L 2013 Research and Reviews in Mater. Sci. and Chem. 2 Issue 1 19-60
[9] Martinez S V Groznadic Ivankovic A 2012 SEM/EDS Analysis Of Corrosion Products From The Interior Of a Crude Oil pipeline Scientific Paper
[10] Morland B H Dugstad A Svenningsen G 2016 13th Int. Conf. on Greenhouse Gas Contr. Tech.