



Corrosion Rate of Carbon Steel A106 Gr B in Amine-CO₂ Contained Solutions

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ABSTRACT

Carbon dioxide (CO₂) is one of the corrosive element which exists in oil and gas industries. To prevent CO₂ corrosion on carbon steel pipelines, amine-base solvent and caustic solutions are commonly applied. Accordingly, effectiveness of amine base solvent and caustic solutions to reduce risk of corrosion becomes key parameters in determining service lifetime of pipelines made of carbon steel. In this research, the corrosion rate of carbon steel A106 Gr B in amine solutions combined with saturated CO₂ gas and caustic solution was studied. The experiments were carried out in static conditions and the Linear Polarization Resistance (LPR) technique was used to measure the corrosion rate (as per ASTM G 5-94). It was found that the corrosion rate in the amine-based solution had shown remarkable results. Somehow, the corrosion rate in an amine-based solvent containing saturated CO₂ gas has increased to 200%. The temperature increment to 50°C from room temperature has also increased the corrosion rate. Meanwhile, the caustic addition in amine solution has reduced the corrosion rate of carbon steel.

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1. INTRODUCTION

The corrosion of carbon steel due to the presence of carbon dioxide (CO₂) gas in oil and gas industries is considered to be severe. In order to prevent the corrosion, the use of amine-based solvents, such as monoethanolamine (MEA), diethanolamine (DEA), methyldiethanolamine (MDEA), and diisopropanolamine (DIPA) is common in CO₂ capture plant (Asma,

Asmara, & Mokhtar, 2011; Asmara & Ismail, 2012; Asmara & Kurniawan, 2018). A quantum model simulation conducted by (Rashid & Khadom, 2020) had confirmed that amine based solution was an effective tool in optimizing structure of inhibitor. Amine also can be used for additive of corrosion resistance coat. It had improved the inhibitive performance (Caldona, Wipf, & Smith, 2021). Single amine solvent have the ability to remove

CO₂ content on the solutions which can reduce corrosion process (Ooi et al., 2020). However, amines were not acceptable for protecting materials of S235 and Inconel that is exposed to CO₂ environmental conditions. Coarse general corrosion was found on the surface (Hjelmaas et al., 2017).

In amine-based CO₂ capture processes, the amine system is designed to form soluble salts from the reaction of amine with acid gas (CO₂) in the absorber, and to reverse the process in the regenerator, releasing the acid gas to the regenerator overhead called alkanolamine. It is based on the reaction of a weak base (alkanolamine) and a weak acid (H₂S and/or CO₂) to give a water-soluble amine acid gas salt. The presence of CO₂ and small amounts of H₂S can generate the formation of iron sulfide film and iron carbonate film in the corrosion of carbon steel (Lee, 2004).

The use of primary amines such as MEA leads to a more corrosive environment than secondary (DEA) and tertiary (MDEA) amines because it is a stronger Lewis base than DEA and MDEA, which is the weakest (Sun & Nestic, 2007). Both MEA and DEA form carbamate (R₃NCOO⁻) with CO₂ while the tertiary amine, MDEA, does not. Carbamates have a great impact on the corrosiveness of amine solutions. Thus, MDEA is the most forgiving amine from a corrosion standpoint (Videm & Dugstad, 1989).

It is reported that the corrosion rate of carbon steel is increased as the temperature increased at the temperature lower than 60°C in the CO₂ saturated NaCl solutions. However, at higher temperature the corrosion rate is decreased due to the formation of FeCO₃ (protective corrosion layer) (Li et al., 2019).

Corrosion process of carbon steel in amine solutions is suspected due to the

formation of heat stable salts (HSS) (Asmara et al., 2015). HSS are formed in the presence of acids which are substantially stronger than CO₂. These acids can be formed directly from flue gas components such as sulfur dioxide (SO₂) and sulfur trioxide (SO₃) or can be formed from amine degradation products. For example, if formic acid is produced, it will react with MDEA to form a formate HSS. The HSS typically promote corrosion in the systems because they will lower the pH and increase the conductivity of amine solutions. This can decrease the efficiency of CO₂ capture because of the irreversible reaction with the amine. Therefore, this paper studies the corrosion rate of carbon steel A106 Gr B in amine solutions combined with saturated CO₂ gas and caustic solution.

2. METHODOLOGY

In this paper, the experiment was performed in stagnant condition (static test). The procedure of experiment was based on the ASTM G 5-94 (G5-94, 2011). The working electrode was carbon steel A106 Gr B. The sample is in the shape of cylindrical with a diameter of 12 mm and length of 10 mm. Before immersion, the specimen surfaces were polished successively with 240, 400 and 600 grit SiC paper, rinsed with methanol and degreased using acetone (G1-90, 1999).

2.1 Static Test

Figure 1 shows the static experimental apparatus similar to that used in Asmara et al. (2020). The test assembly consists of one liter glass cell bubbled with CO₂. The experiments are conducted at two temperatures of solution, i.e. 27°C (room temperature) and 50°C. The required test temperature was set using the hot plate.

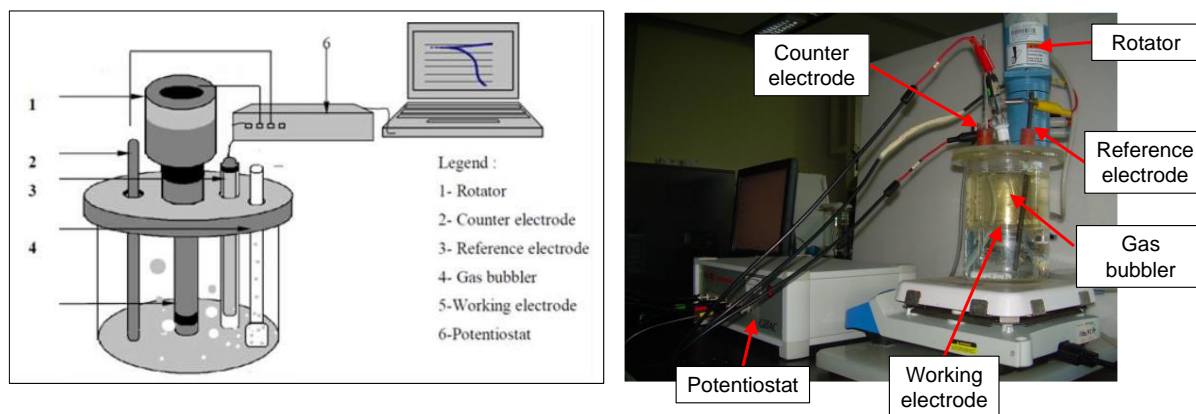


Figure 1. Schematic static test (left) (Asmara et al., 2020) and static test apparatus (right).

The electrochemical measurements were based on a three-electrode system, using a commercially available potentiostat with a computer control system. The reference electrode used was Ag/AgCl and the auxiliary electrode was a platinum electrode. The electrochemical technique measurements of Linear Polarization Resistance (LPR) technique was used to measure the corrosion rate. The procedure was based on ASTM G 5-94. The tests were conducted until it reaches steady state condition.

2.2 Composition of Tested Solutions

Experiments were conducted in saturated CO₂ gas environment. In CO₂ gas system, the experiments used saturation condition of CO₂ gas where compositions and the pH solutions in the glass cell were described in **Table 1**. There are five compositions with various pH used as the

tested solutions. The solutions consist of KS-1 (solution from plant), water and several concentration of caustic (NaOH).

3. RESULTS AND DISCUSSION

3.1 KS-1 properties

The first step conducted in this experiment is to identify the composition of KS-1 which is received from the plant. Composition of the KS-1 as received from the plant was analysed with gas chromatography – mass spectrometry (GC-MS). The composition of the KS-1 is shown in **Figure 2**, which consist of active compound of methyldiethanolamine (MDEA) and piperazine. KS-1 is a type of liquid inhibitors which works as passivation media. It forms a protective layer on metallic surface through dispersion techniques.

Table 1. Compositions and pH for the tested solutions.

Solution conditions	pH
KS-1	12.7
KS-1+saturated CO ₂	8.0
KS-1+saturated CO ₂ + 50 ppm caustic	8.4
KS-1+saturated CO ₂ + 250 ppm caustic	8.3
Water/KS-1 (50:50) + CO ₂	7.9

Pk#	RT	Area%	Library/ID
1	1.727	4.90	C:\Database\NIST05a.L Ammonia Water
2	3.232	88.80	C:\Database\NIST05a.L Ethanol, 2-(ethylamino)- Ethanol, 2-(ethylamino)- N,N-Dimethyl-2-aminoethanol
3	3.822	6.30	C:\Database\NIST05a.L Piperazine Piperazine Piperazine

Figure 2. GCMS analytical result of KS-1 composition.

3.2 Corrosion rate of A106 Gr B in KS-1

The corrosion behavior of A106 Gr B with KS-1 at room temperature and 50°C was investigated and shown in **Figure 3**. Corrosion rate of A106 Gr B at room temperature and 50°C is negligible in the order of 0.0015 mm/yr and 0.018 mm/yr, respectively. Based on the results, it shows that KS-1 is not corrosive to A106 Gr B carbon steel due to inhibitor properties (piperazine) of the KS-1 solution.

3.3 Corrosion rate of A106 Gr B in KS-1 saturated with CO₂ (Entrained acid gases)

3.3.1- Effects of water in KS-1 solution

The effect of water in KS-1 solution was investigated and found that the corrosion rate of the A106 Gr B is not significant although a bit higher than KS-1 alone as shown in **Figure 4**. The corrosion rate is recorded in the order of 0.003 mm/yr.

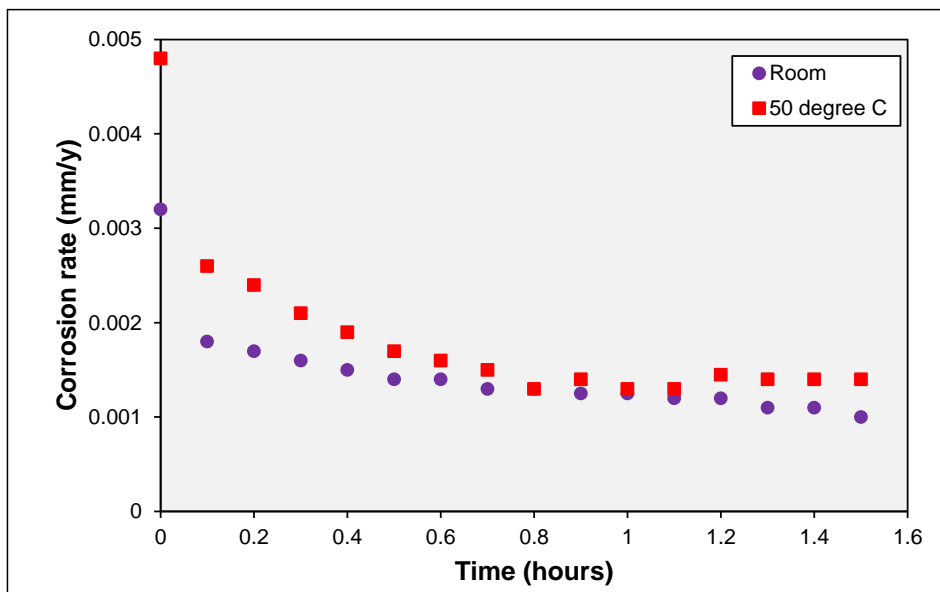


Figure 3. The corrosion rate of A106 Gr B in KS-1 solution at room temperature and 50°C.

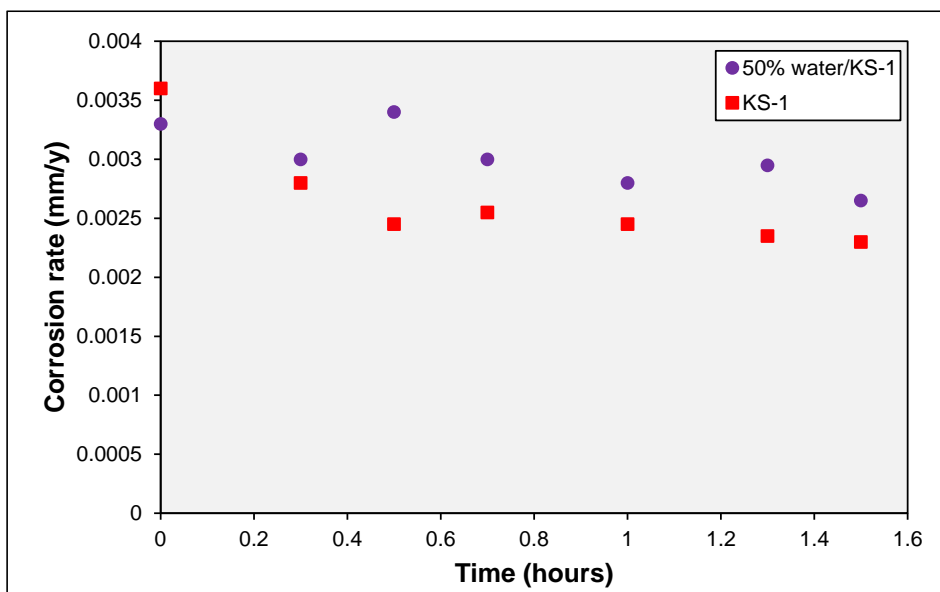


Figure 4. Effects of water on corrosion rate in KS-1 solution at room temperature without CO₂ gas.

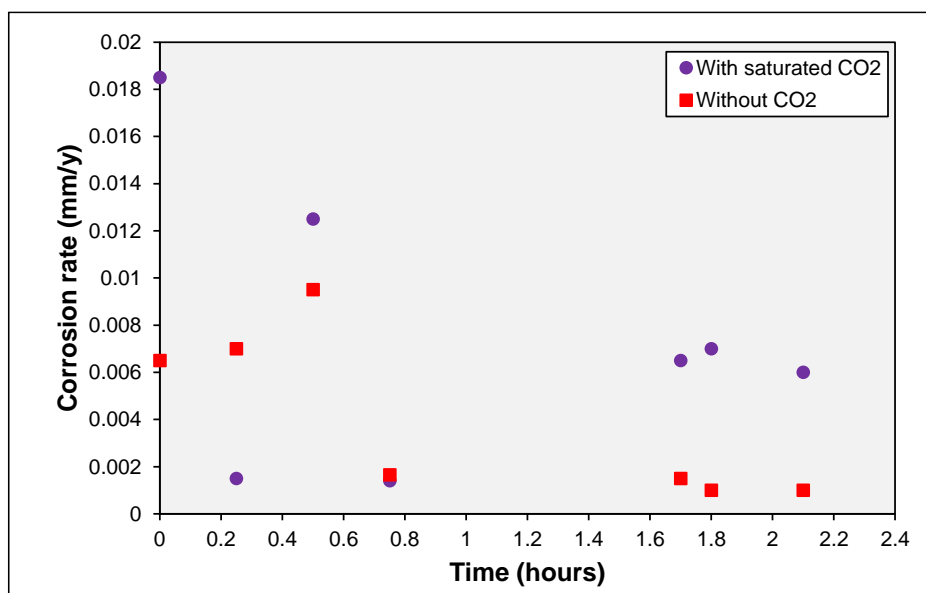


Figure 5. Effects of saturated CO₂ on corrosion rate in KS-1 solution at room temperature.

3.3.2 Effect of water in KS-1 and CO₂ solution

Corrosion rate of carbon steel A106 Gr B in KS-1 saturated with CO₂ without water is in the order of 0.006 mm/yr as shown in **Figure 5**, which is doubled than without CO₂. This justify that the CO₂ has an important factor in the corrosion of carbon steel A106 Gr B.

3.3.3 Effect of KS-1/water + CO₂

Corrosion effect of KS-1/water in saturated with CO₂ on carbon steel A106 Gr B is low in the order of 0.06 mm/yr as shown in **Figure 6**. Corrosion rate at 50°C is about the same as at room temperature. However, at 50°C, initial values of corrosion rate was high which indicated formation of scales were interrupted as effects of water.

3.4 Effects of Caustic concentration in KS-1 / water / CO₂

The effects of various concentration of caustic from 50 – 500 ppm in KS-1 solution, on corrosion rate of A106 Gr B are presented in **Figure 7** and **Figure 8** respectively.

The figures show that the increase in caustic leads to decrease corrosion rate in

several conditions; with/without CO₂, KS-1/KS-1/water and in both room temperature and 50°C. The decrease in corrosion rate due to caustic concentration is related to the role caustic in increasing pH (Nešić, 2007). It can be seen from **Figure 7**, initial values of corrosion rate was high for without caustic. It can be indicated that the formation of scales were interrupted as effects of water.

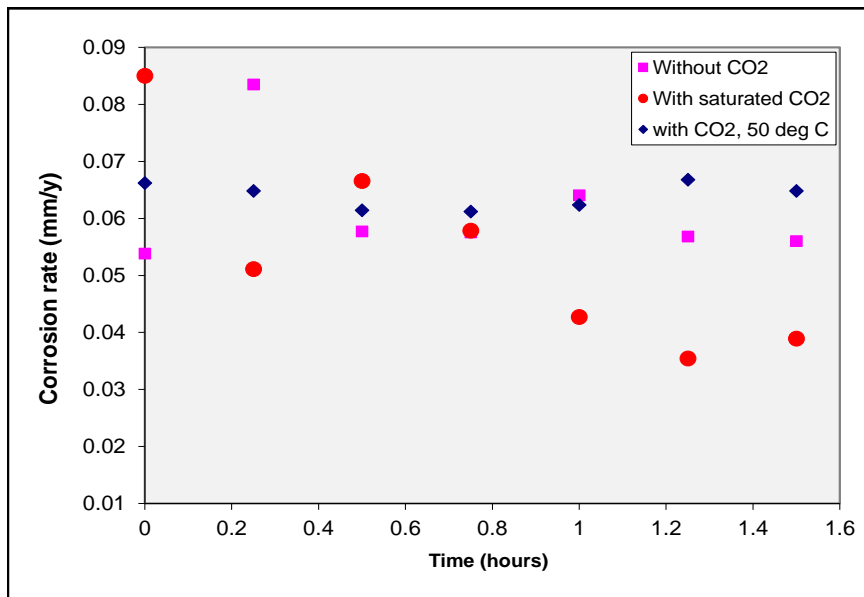


Figure 6. Effects of saturated CO₂ on corrosion rate in KS-1/water solution at room temperature and at 50°C.

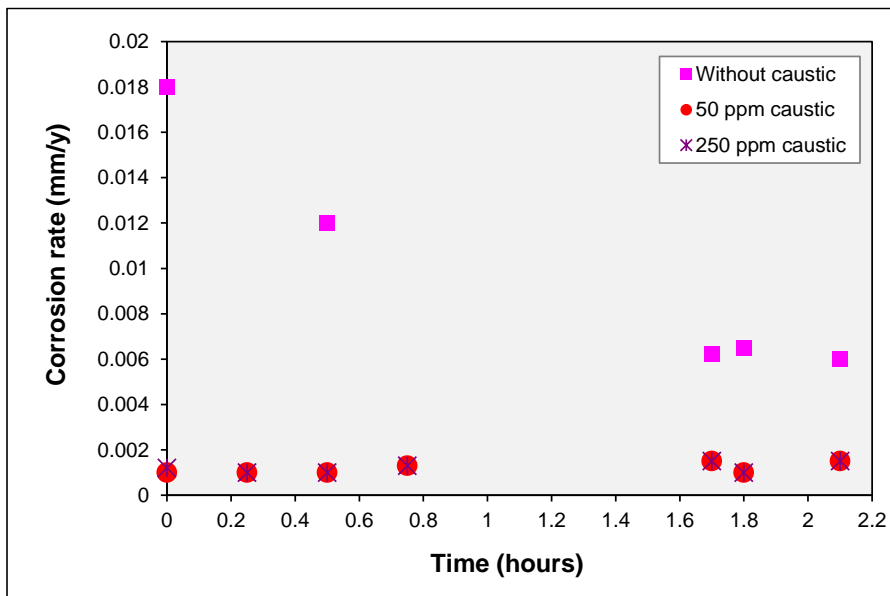


Figure 7. Comparison of corrosion rate in KS-1 solution without caustic, 50 ppm caustic and 250 ppm caustic, at room temperature and saturated CO₂.

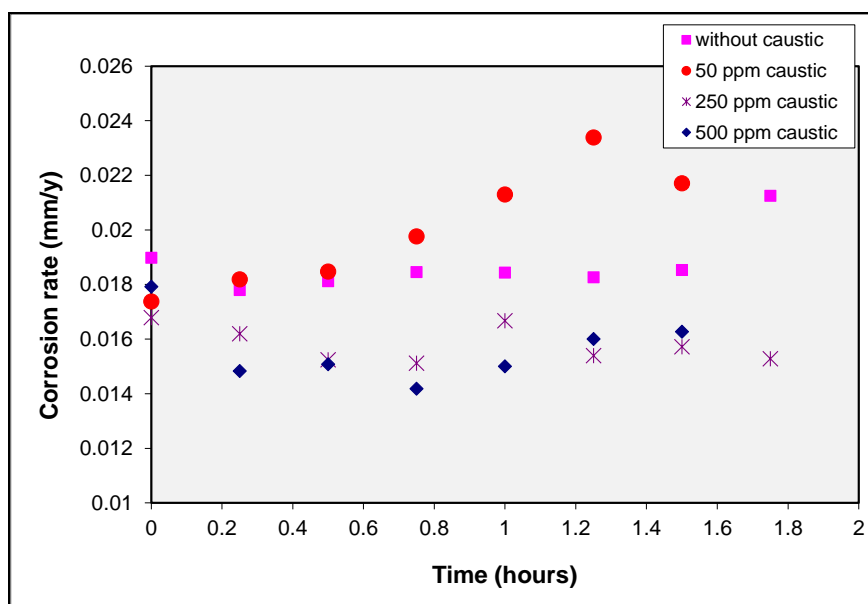


Figure 8. Comparison of corrosion rate in Water/KS-1 (50:50) and saturated CO₂ solution without caustic, 50 ppm caustic, 250 ppm caustic and 500 ppm caustic, at 50°C.

4. CONCLUSION

The corrosion rate of carbon steel A106 Gr B in amine CO₂ contained was studied. The properties of KS-1 (received from plant) is characterized and it contains a mixture of actives methyldiethanolamine (MDEA) and piperazine. KS-1 was

found to be non-corrosive to carbon steel A106 Gr B at both room temperature and 50° C. Corrosion rate of A106 Gr B is negligible in KS-1 saturated with CO₂ and water. Caustic addition up to 500 ppm did not cause corrosion rate increase to the parent metal of A106 Gr B.

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