Effect of Pressure, Temperature and Oil Composition on Corrosion Rate in Horizontal Multiphase Slug Flow

W. P. Jepson and S. Bhongale
NSF, I/UCRC Corrosion in Multi-Phase Systems Center
Department of Chemical Engineering
Ohio University
Athens, Ohio 45701
USA

SYNOPSIS

Experiments were performed in a 10 cm ID, three phase oil/water/gas multiphase horizontal pipeline under slug flow. Mixtures of 0, 20, 40, 60 and 80% oil-water compositions were studied for corrosion rates at carbon dioxide partial pressure of 0.27, 0.45 and 0.79 MPa and temperatures of 40, 60, 70, 80 and 90 C. It is found that the corrosion rate increases with increase in temperature and carbon dioxide partial pressure at each water cut. Also, the corrosion rate decreases with increase in oil salt water composition at each temperature and carbon dioxide partial pressure.

INTRODUCTION

Internal corrosion of carbon steel pipelines is a substantial problem encountered in the oil and gas industry. Many of the oil fields are located in remote areas such as Alaska or subsea. Many marginal oil fields are being discovered, and it is a common practice to transport the gas-liquid mixture from several wells, through a large diameter pipe, to a central gathering station where separation takes place.

As the well gets depleted, enhanced oil recovery methods, involving the injection of water and carbon dioxide, are used. This helps

maintain the pressure within the reservoir. However, some of the carbon dioxide and brine flows with the oil and gas and this flow of multiphase mixture creates of corrosion problems in the pipelines. Many wells operate at high water cuts as high as 80%. The added carbon dioxide forms weak carbonic acid in the presence of water. This acid being corrosive in nature, leads to higher corrosion rates in carbon steel pipelines. The oil and gas mixture may also contain waxes, hydrates, hydrogen sulphide and sand.

De Waard and Milliams (1975) performed experiments in stirred beakers and obtained corrosion rates. They found that for salt water, the corrosion rate increased with increase in temperature up to 60 C, reached a maximum between 60 and 70 C and then decreased, with further increase in temperature. Nesic and Lunde (1993), performed similar experiments but in recirculating flow loops and obtained similar variation of the corrosion rate with carbon dioxide partial pressure and temperature. Similar results were also obtained by Vuppu and Jepson (1994) who performed experiments with salt water in flow loops under full pipe flow conditions. They suggested that this was due to the formation of a protective film of corrosion products on the metal surface which restricts the access of the liquid phase to the metal surface.

Vuppu and Jepson further showed that for three phase oil-water-gas flow, the presence of up to 60% oil did not greatly affect the corrosion rates. However, at higher oil compositions the corrosion rates decreased to negligible values. Jepson and Menezes (1995) found that for a high viscosity (96 cp) oil, for both full pipe flow and slug flow, the corrosion rate increased with increase in oil composition up to 60% and then decreased to negligible values for oil composition of 80%. Zhou (1993), performed corrosion studies with a 2 cp viscosity oil at carbon dioxide partial pressure of 0.134 MPa under slug flow conditions and found that the corrosion rates decreased with increase in oil composition from 0% to 80%. Further, Zhou and Jepson (1994) showed that for slug flow, the impact and possible collapse of the gas bubbles entrained in the slug causes high levels of shear and turbulence at the bottom of the pipe, leading to higher corrosion rates.

The work by Dugstad, Lunde and Videm (1994) in flow loops

revealed that the corrosion rates were less sensitive to an increase in carbon dioxide partial pressures at higher pressures. Also, corrosion rates increased with increasing velocities at higher temperatures.

This work investigates the effect of temperature, carbon dioxide partial pressure and oil composition on corrosion rate under slug flow conditions.

EXPERIMENTAL SETUP AND PROCEDURE

The experimental setup is shown in Figure 1. The system is made of 316 stainless steel and is designed to withstand a maximum pressure of 1500 psi. A predetermined oil-water mixture is stored in a 1.2 m^3 tank which serves as a storage tank as well as a separation unit for the multiphase gas-oil-water mixture. The system temperature is controlled by two 1.5 kW heaters, connected to a thermostat. The liquid is pumped by a 5.2 kW stainless steel, centrifugal pump into a 7.72 cm ID pipeline. An orifice plate is used to measure the flow rate. The pressure drop across the orifice plate is measured with a manometer. The liquid flow rate is controlled by adjusting the gate valve C on the bypass line, and valve D. The bypass also serves to keep the two liquid phases well mixed.

The liquid then passes into a 10.16 cm ID pipeline where carbon dioxide enters at the point H. The gas/liquid mixture then flows through the test section and back into the holding tank where the gas and liquid are separated. A back pressure regulator K, maintains the pressure in the system. The gas flow rate is controlled by a needle valve.

The test section is shown in Figure 2. The openings E and C at the top and the bottom of the pipe are used to insert the ER probes, for the corrosion rate measurement and the coupon holder probes used for weight loss measurements and for performing morphological studies like the Scanning Electron Microscopy (SEM). The positions P are pressure tappings, which are connected to a pressure transducer and are used to measure the pressure drop between various locations in the test section. S is a port for the insertion of a shear stress probe but is not used in this work. ST is the sampling probe used to take out samples

of the flowing fluid to determine oxygen, iron and carbon dioxide concentrations in the system.

The fluids used were a refined oil with a viscosity of 2 cp at 40 C and density of 800 kg/m^3 and ASTM standard sea water. Carbon dioxide is used as the gas phase.

The experiments were performed at carbon dioxide partial pressures of 0.27, 0.45 and 0.79 MPa, temperatures of 40, 60, 70, 80 and 90 C and a Froude number of 6 (corresponding to slug velocity of 3 m/s). Water cuts of 100, 80, 60, 40 and 20% were used.

RESULTS AND DISCUSSION

Effect of Temperature:

Figures 3 shows the variation of corrosion rate with temperature for brine at carbon dioxide partial pressures of 0.27, 0.45 and 0.79 MPa. It can be seen that at a given carbon dioxide partial pressure, the corrosion rate increases with temperature over the entire range of temperatures studied. For example, for brine at a carbon dioxide partial pressure of 0.45 MPa, the corrosion rate increases from 9.9 to 14.1 mm/year with increase in temperature from 40 to 60 C, then increases at a lower rate from 14.1 to 16.3 mm/year as the temperature is increased from 60 to 70 C and then again increases at a much higher rate from 16.3 to 46 mm/year with increase in temperature from 70 to 90 C. This is not seen in the results obtained by de Waard and Milliams (1975) and Vuppu and Jepson (1994) for brine under full pipe flow conditions who found that the corrosion rate reaches a maximum at a temperature between 60 to 70 C and then decreases thereafter with increase in temperature. They also showed from the morphological studies of the coupon surfaces that formation of protective iron carbonate scales occurs at 60 C.

The lower rates of corrosion in the temperature range of 60 to 70 C could be attributed to the distribution of the corrosion products at the pipe wall. However, the higher rates of corrosion in the temperature range 70 to 90 C, under slug flow conditions could be due to the removal of the protective layer of corrosion products at these higher

temperatures as shown by Vuppu and Jepson (1994). Also, morphological studies of the coupon samples using Scanning Electron Microscopy, indicate that the average thickness of the corrosion product layer on the slug flow coupons is lower than that in full pipe flow coupons. This suggests the possible stripping away of the poorly adherent layers of corrosion products due to high levels of shear and turbulence at the bottom of the pipe under slug flow conditions.

When oil is present, the corrosion rate increases almost linearly with temperature as shown in Figure 4, for the temperature range of 40 to 80 C. For example, for a water cut of 60% at a carbon dioxide partial pressure of 0.79 MPa, the corrosion rate increases from 8 to 25 mm/year with increase in temperature from 40 to 60 C and then increases from 25 to 42 mm/year with further increase in temperature from 60 to 80 C.

Effect of Carbon Dioxide Partial Pressure:

The variation of corrosion rate with carbon dioxide partial pressure for brine at temperatures of 40, 60, 80 and 90 C is shown in Figure 5. It can be seen that at each temperature, the corrosion rate increases with carbon dioxide partial pressure. For example, at a temperature of 80 C, the corrosion rate increases from 19.1 to 29.1 mm/year with increase in carbon dioxide partial pressure from 0.27 to 0.45 MPa and from 29.1 to 48.3 mm/year with a further increase in carbon dioxide partial pressure from 0.45 to 0.79 MPa. Similar, results were obtained for lower water cuts of 80,60 and 40%.

Thus for slug flow conditions, the carbon dioxide partial pressure has a significant effect on the corrosion rate. This is not seen in the results shown by Dugstad, Lunde and Videm (1994) who found that the corrosion rate is less sensitive to an increase in carbon dioxide partial pressure at higher pressures. However, it has been shown by Zhou and Jepson (1994) that slug flow involves the impact and possible collapse of the gas bubbles, entrained in the slug. Here, an increase in the density of gas bubbles due to increased carbon dioxide partial pressure and the subsequent impact at the bottom of the pipe can produce high levels of turbulence and shear on the metal surface. Also, there is an

increase in the reaction kinetics as the pressure increases.

Effect of Oil Composition:

Figure 6 shows the effect of oil composition on corrosion rate, at carbon dioxide partial pressures of 0.27 and 0.79 MPa and temperatures of 60 and 80 C. It is seen that the corrosion rate decreases slowly with increase in oil composition from 0 to 40%. It then decreases at a higher rate with increase in oil composition from 40 to 60% and finally the rate decreases to negligible values at an oil composition of 80%. For example, at a carbon dioxide partial pressure of 0.27 MPa and 60 C, the corrosion rate decreases from 16.1 to 13.6 mm/year with increase in oil composition from 0 to 40%, then decreases to 10.1 mm/year with increase in oil composition to 60% and finally decreases to negligible value at an oil composition of 80%. Similar results are obtained at a higher carbon dioxide partial pressure of 0.79 MPa.

Since the liquid phase is well mixed under slug flow, there is a decrease in the water fraction at the bottom of the pipe as the oil composition increases. Hence, little water comes into contact with the pipe wall at higher oil compositions, thus reducing the corrosion rates. The decrease in corrosion rates to negligible value at oil compositions greater than 60% is due to the transition from a water continuous phase to an oil continuous phase. However, corrosion studies with high viscosity (96 cp) oil by Menezes and Jepson (1995) showed that the corrosion rate increased sliightly with an increase in oil composition up to 60% and then decreased to negligible values for oil composition of 80%. This was due to the increase in viscosity of the oil-water mixture with increase in oil composition, thereby causing higher levels of shear stress at the bottom of the pipe leading to higher rates of corrosion.

CONCLUSIONS

Slug flow had considerable effect on the corrosion rates.

At a given carbon dioxide partial pressure and water cut, the corrosion rate increases with increase in temperature from 40 to 60 C,

then increases at a lower rate in the temperature range 40 to 60 C and finally increases at a much higher rate with further increase in temperature from 70 to 90 C. No maximum in the corrosion rate is observed at any of the temperatures studied.

For the low viscosity (2 cp) oil studied, at a given carbon dioxide partial pressure and temperature, the corrosion rate decreases with increase in oil composition from 0 to 60% and then decreases to negligible values for oil composition of 80%.

The corrosion rate increases at a high rate with increase in carbon dioxide partial pressure at each temperature and water cut.

REFERENCES

1. De Waard, C. and Milliams, D.E (1975). Carbonic Acid Corrosion of Steel. Corrosion, 31(5), 177-181.
2. Dugstad, A.E., Lunde, L., and Videm, K. (1994). Parametric Study of CO_2 Corrosion of Steel. Corrosion/94, 14, 14/1-14/15.
3. Jepson, W.P. (1987). The Flow Characteristics in Horizontal Slug Flow. 3rd International Conference on Multi-Phase Flow, Hague, Netherlands, 18-20 May, Paper F2.
4. Jepson, W.P. and Menezes, R. (1995). The effects of oil viscosity on sweet corrosion in multiphase oil-water-gas horizontal pipelines. Corrosion/95, 106/1-106/16.
5. Nesic, S. and Lunde, L. (1993). CO_2 corrosion of carbon steel in two phase flow. Corrosion/93, 49,640/1-640/17.
6. Vuppu, A.K. and Jepson, W.P. (1994). Study of sweet corrosion in horizontal multiphase, carbon steel pipelines. Offshore Technology Conference, 7494/265-7494/276.
7. Zhou, X. (1993). Experimental Study of Corrosion Inhibitor Performance and Slug Flow Characteristics in Multi-Phase Pipeline. Master's Thesis, Ohio University Russ College of Engineering and Technology.
8. Zhou, X. and Jepson, W.P. (1994). Corrosion in Three-Phase Oil/Water/Gas Slug Flow in Horizontal Pipes. Corrosion/94, paper no. 94026, (Houston, TX: NACE International, 1994).
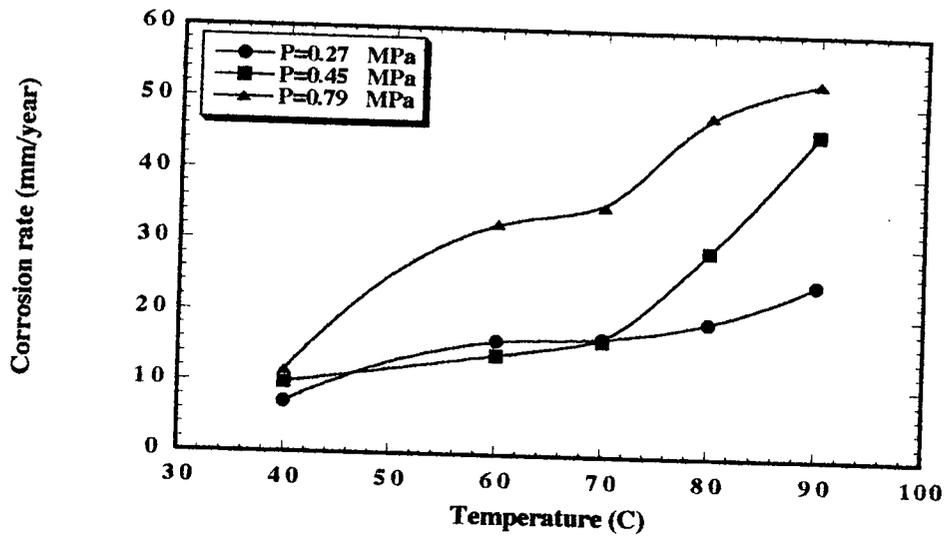
Figure 3 Corrosion rate vs Temperature for brine at Froude number 6
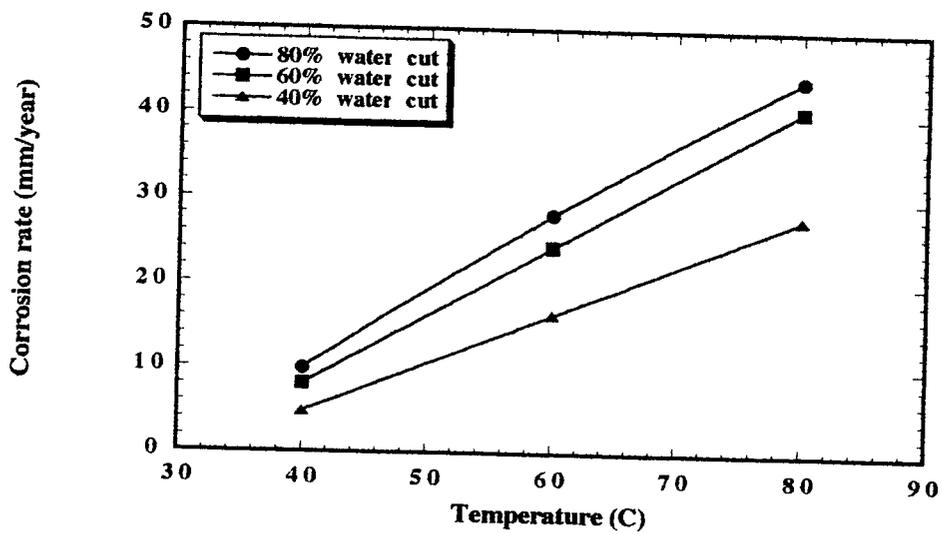
Figure 4 Corrosion rate vs Temperature for CO_2 partial pressure of 0.79 MPa and Froude number 6
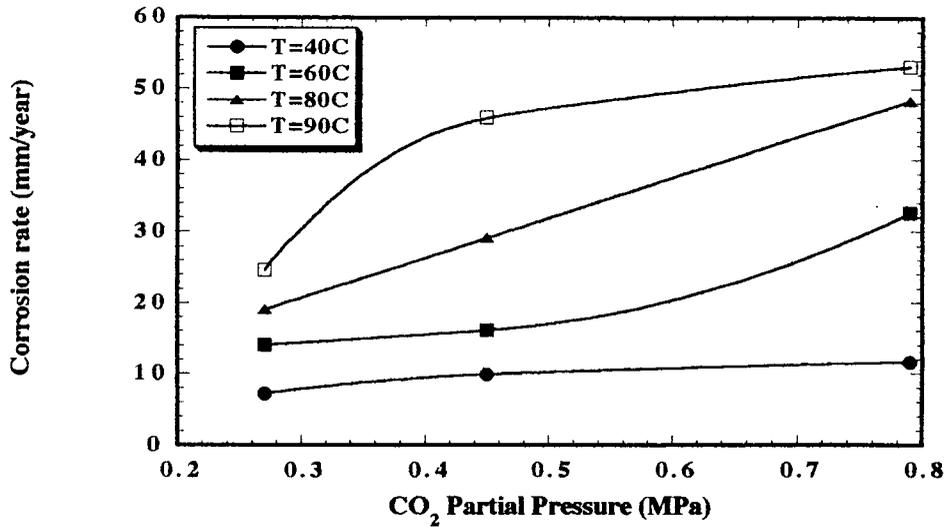
Figure 5 Corrosion rate vs CO_2 partial pressure for brine at Froude number 6
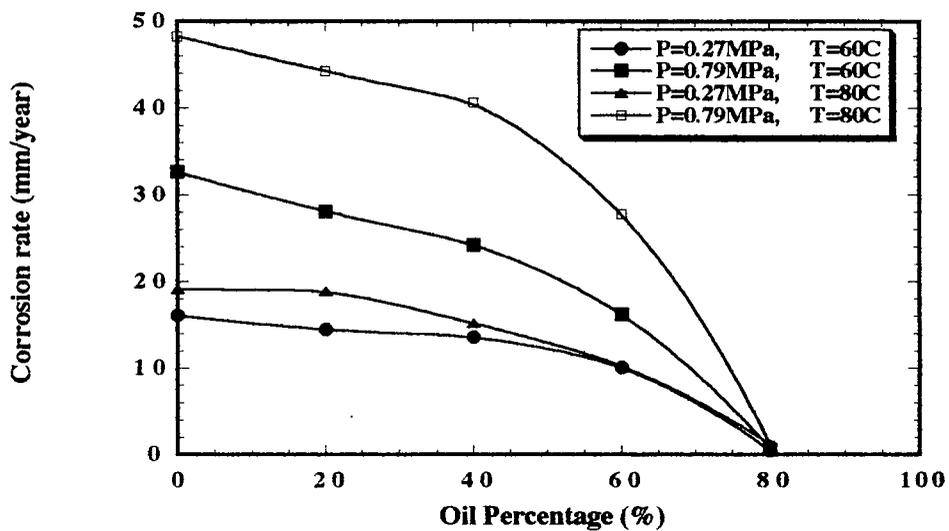
Figure 6 Corrosion rate vs oil percentage at Froude number 6