EFFECT OF PRESSURE AND FLOW VELOCITY ON SWEET CORROSION IN HIGH PRESSURE HORIZONTAL MULTIPHASE PIPELINES

by

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ABSTRACT

This paper describes the effect of multiphase flow related corrosion in large diameter horizontal pipelines. Experiments, at a temperature of 40 C, have been performed to measure corrosion rates at different oil and saltwater concentrations. The effects of carbon dioxide partial pressure and flow velocity of the liquid mixtures have been observed. It is shown that the corrosion rate increases substantially with an increase in the liquid velocity. As the carbon dioxide partial pressure is increased, the corrosion rate increases significantly at all liquid velocities and oil concentrations up to 60%. Above 80% oil, the corrosion rate is small.

Key Words : corrosion, multiphase, oil concentration, partial pressure and flow velocity.

1. INTRODUCTION

Early in the life of an oil well, mostly oil and gas are produced. As the well gets older, enhanced oil recovery methods are used to recover the oil. This often involves the injection of saltwater and carbon dioxide. In remote places, eg. subsea, it is impractical to separate the oil, water and gas at the well site. The flows from several wells are usually combined into a single, multiphase pipeline which transports the fluids to a platform or central gathering station. This multiphase flow can cause severe corrosion problems. It can be difficult and uneconomical to carry out repair and maintenance work on these pipelines.

It is imperative to understand the cause and extent of the corrosion in these pipelines. Most previous studies on corrosion have been carried out by rotating cylinder electrodes, vertical flow loops and in small diameter single phase and two phase horizontal pipelines. The results obtained using vertical flow loops cannot be applied to horizontal flow because of the different flow characteristics. The fluids are usually well mixed in vertical flow but can be stratified in horizontal and inclined flows.

Different flow regimes exist in horizontal pipe flow depending on the liquid and gas velocities. At low gas and liquid velocities, smooth stratified and wavy stratified flow is observed. This changes to the rolling wave motion when the gas velocity is increased. Plug flow is encountered at low gas velocities but higher liquid velocities. This changes to slug flow as the gas velocity is increased. Pseudo slug and annular flow regimes are observed for high gas and liquid velocities.

Green, Johnson and Choi (1989) showed the effect of these flow regimes on corrosion rate to be significant. Very high instantaneous corrosion rates have been recorded in the slug flow regime while comparatively lower values have been obtained in stratified flow. Thus, it is essential to know the flow regime in which a pipeline is operating. The flow regimes exhibit similar mechanisms for a 10, 30 cm, and higher internal diameter pipelines, but, they are very different for smaller 1.25 and 2.5 cm ID pipelines. Since the flow mechanisms are different in small diameter flow systems, any flow and corrosion studies in these loops cannot be accurately applied to large diameter pipelines. It is, therefore essential, that corrosion research be conducted in large diameter pipelines.

Sydberger (1987) showed that flow induced corrosion involving the interaction between a metal and a fluid can be explained by different mechanisms. These are convective mass transfer controlled corrosion, phase transport controlled corrosion and erosion-corrosion.

A model to predict the corrosion rates in wet gas pipelines was developed empirically by De Waard and Milliams (1991). A "worst case" corrosion rate is predicted using their model. Rotating cylinder electrodes were used as the experimental apparatus to generate the data. The effect of carbon dioxide partial pressure, pH, temperature and Fe^{2+} concentration was considered in this model. Equations that incorporate the effects of protective carbonate film formation at high temperatures have been derived to serve as correction factors for the predicted corrosion rates. Later they added correction factors to account for the effect of liquid flow velocity on corrosion rate. But, flow regimes were not considered in this model and this could lead to gross errors in prediction.

The iron concentration in the solution has been shown to have a significant effect on corrosion. Tomson et al. (1991) showed that the adherence of ferrous carbonate films depends on temperature. At temperatures below 60 C, the film formed does not adhere tightly and can be eroded away from the surface. However, at temperatures higher than 150 C, the film is very stable and this can effectively inhibit corrosion. Videm and Dugstad (1984) observed that protective films can form below 50 C only if an alkaline substance was present in the solution. If no alkaline substances are present in the solution, then protective films can form above 50 C only if enough Fe^{2+} was present.

Iron carbonate is not the only reaction product formed. EDAX and SEM analysis of metal specimens show other products such as carbides, sulphates and chlorides. Some of these are present in the saltwater and are observed on the coupons.

Two phase flow corrosion research has been conducted by Nesic and Lunde (1993). Their experimental flow loop comprised a 316 stainless steel test section, 3.2 cm internal diameter. Two other sections, 2.2 and 5 cm ID were also used. Water and carbon dioxide were used as the fluids. They found that an increase in partial pressure, temperature or flow velocity increased the corrosion rates respectively. However, at very high temperatures the corrosion rates decreased as protective films formed. The protective films were found to be iron carbonate films. A loose porous iron carbide film was also observed. However, this film did not reduce the rate of corrosion. The effect of addition of oil into the system has not been considered in the study.

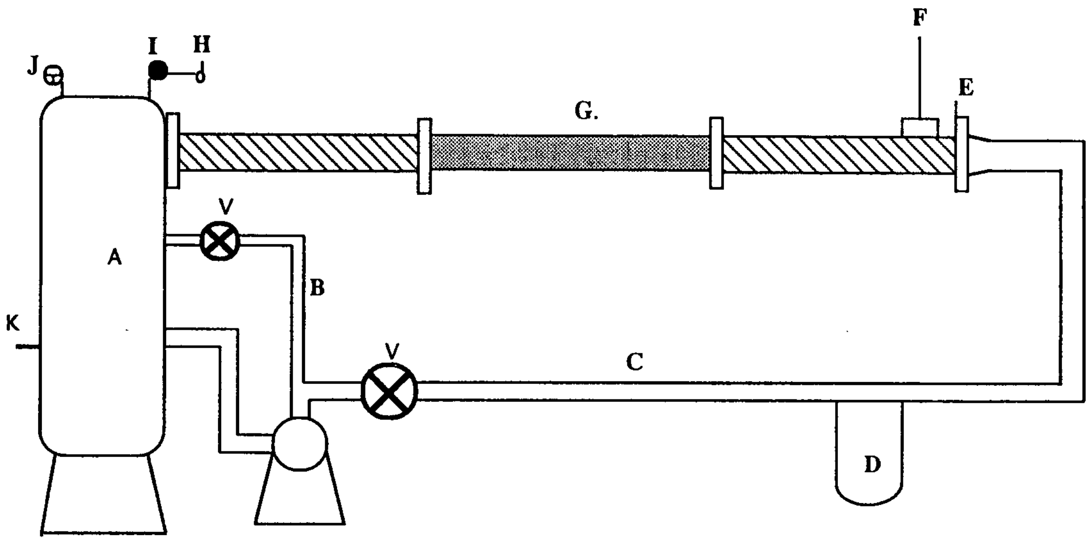
Efird et al (1993) measured corrosion in horizontal pipe flow, jet impingement and rotating cylinder apparatus at the same fluid concentrations and conditions. The jet impingement technique did correlate well with pipe flow. However, the corrosion rates measured using the rotating cylinder apparatus were much lower than for pipe flow. This work clearly shows that rotating cylinders used to measure rate of corrosion could lead to large errors where pipe flow is concerned. They showed that corrosion rate could be related to wall shear stress.

6) Tomson, M. B., Rice, U., & Johnson, M. L. (1991). How ferrous carbonate kinetics impacts oilfield corrosion. Society of Petroleum Engineers, 21025, 257-264.

7) Videm, K., & Dugstad, A. (1989, April). Corrosion of carbon steel in an aqueous carbon dioxide environment. Part 2: Film formation. Materials Performance, 46-50.

Figure 1

Layout of The Experimental System



A. Liquid Tank
B. Liquid Recycle
C. Liquid Feed - 7.62 cm Stainless Steel Pipe
D. Orifice Plate with a Pressure Transducer
E. Flow Height Control Gate
F. Carbon dioxide Feed Line

G. Test Section - 10.16 cm Stainless Steel Pipe
H. Gas Outlet with filters
I. Pressure Gauge with Back Pressure Control
J. Safety Valve
K. Heater
V. Flow Control Valves

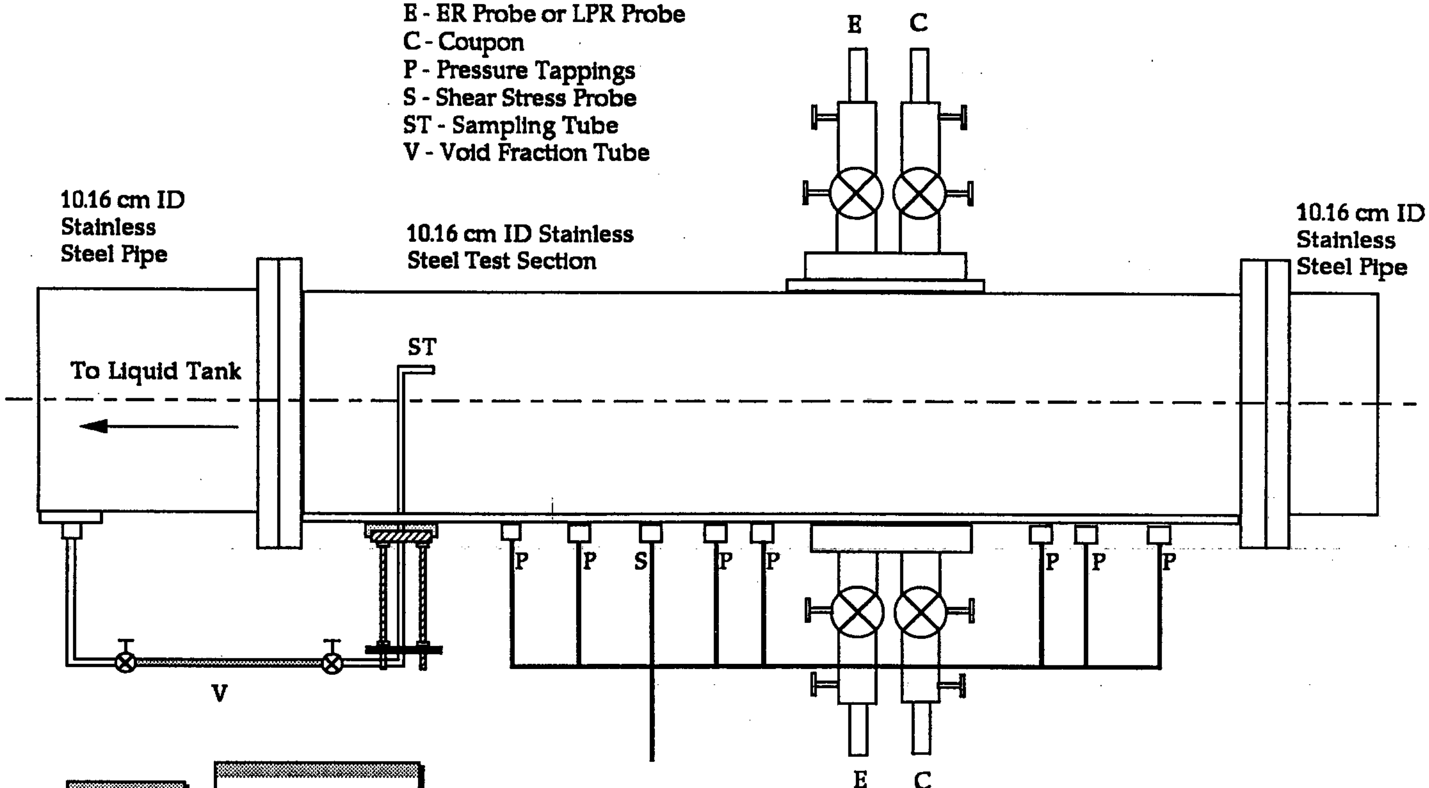


Figure 2

Plot for Test Section

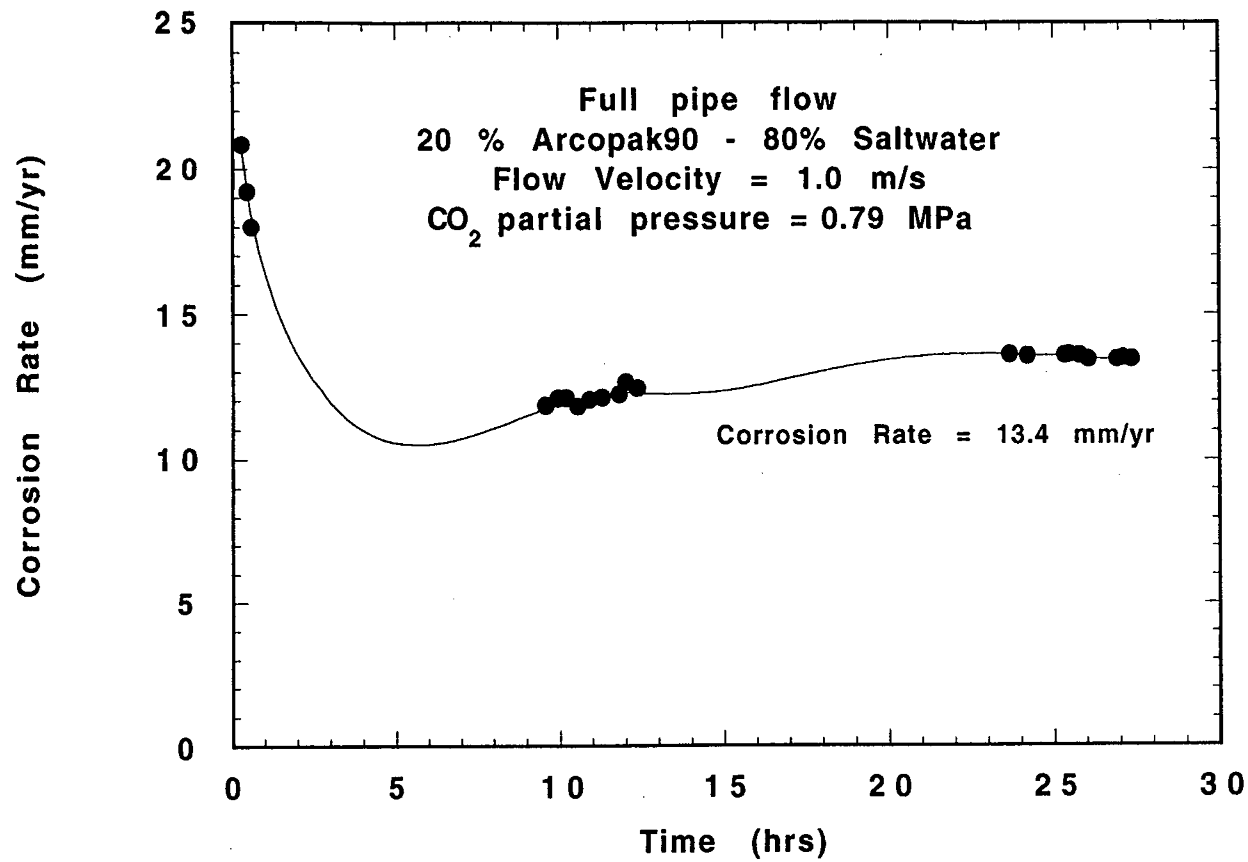


Figure 3. Corrosion Rate vs Time

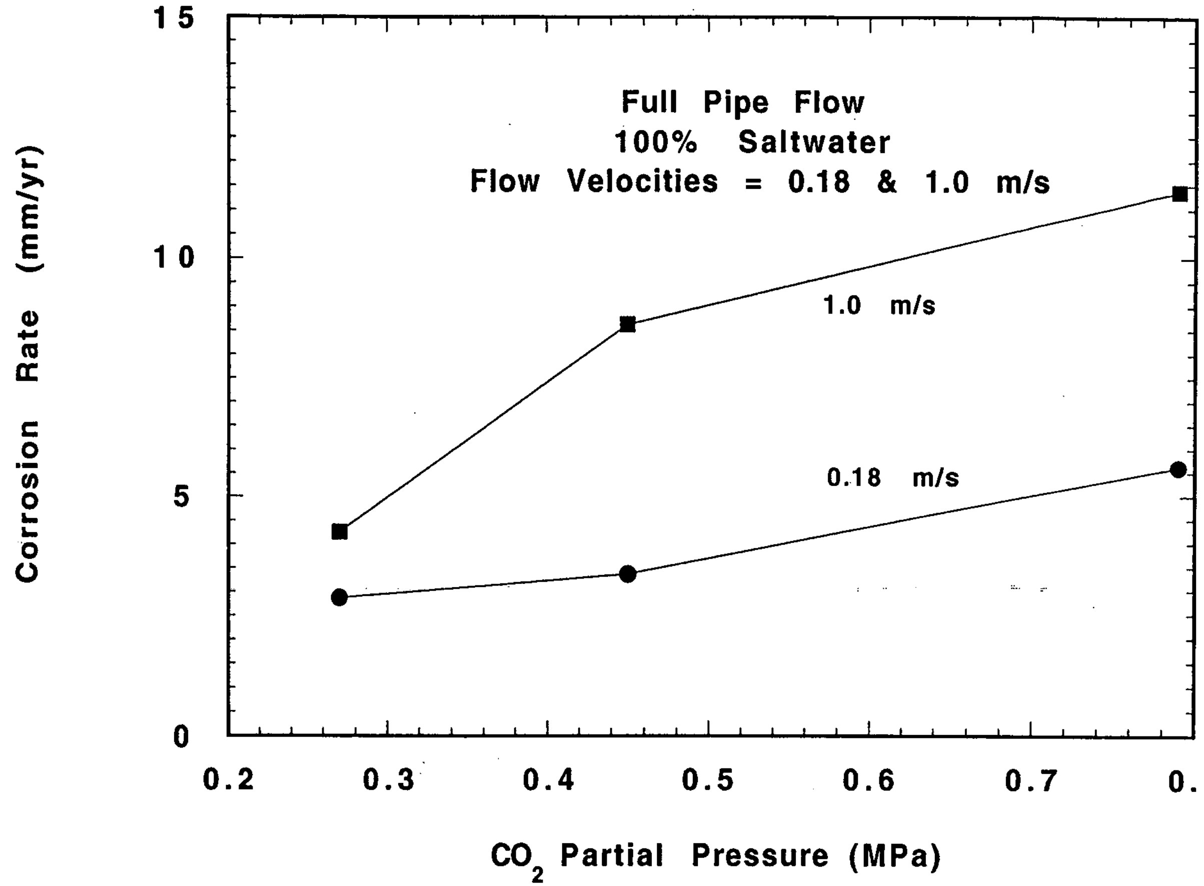


Figure 4. Corrosion Rate vs CO_2 Partial Pressure

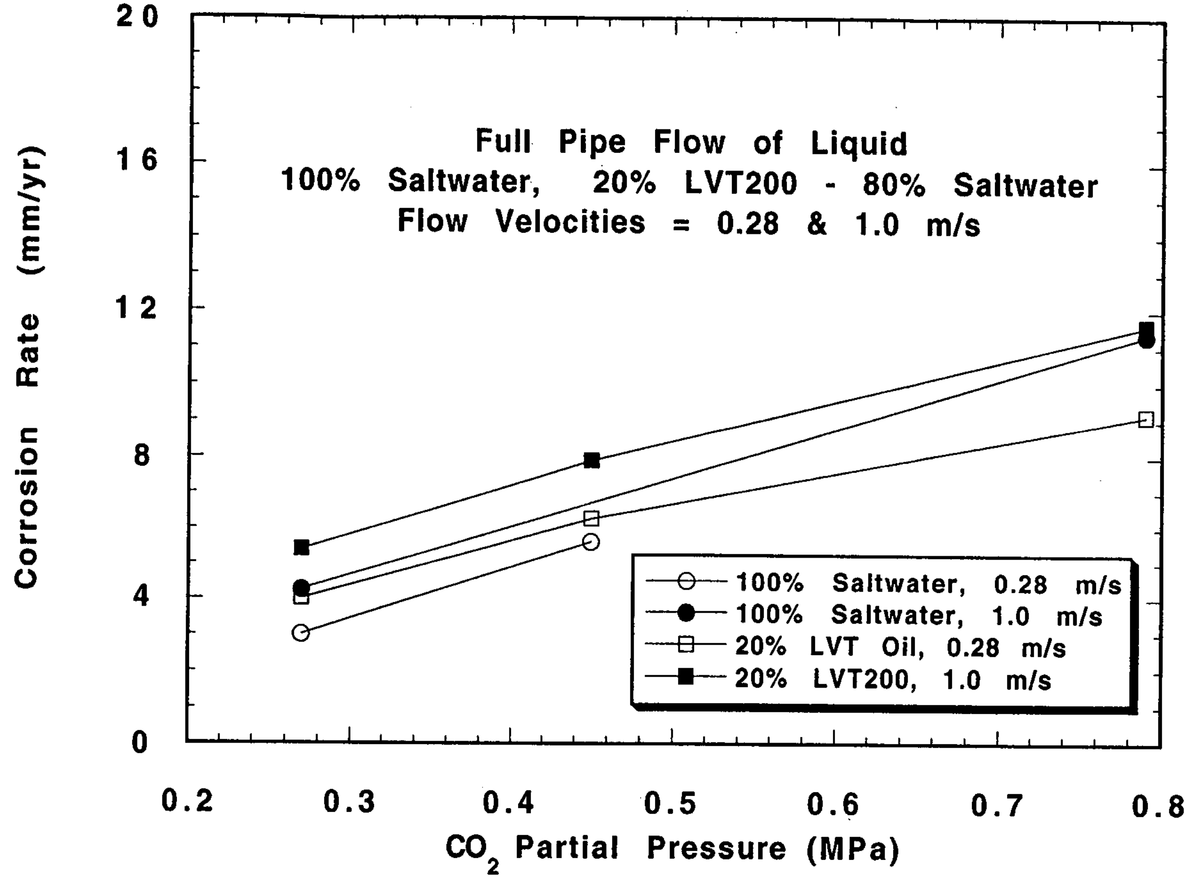


Figure 5. Corrosion Rate vs CO_2 Partial Pressure