MODELLING OF MULTIPHASE SLUG FLOW CHARACTERISTICS AND THEIR INFLUENCE ON CORROSION IN LARGE DIAMETER, HIGH PRESSURE HORIZONTAL PIPELINES

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ABSTRACT

To examine the effect of slug characteristics on corrosion rate in horizontal multiphase pipelines, experiments have been carried out in a10 cm diameter pipeline using oil, water, and gas at total pressures of 0.27, 0.45, and 0.79 MPa. Temperatures between 40 and 80 C were studied keeping the carbon dioxide partial pressure constant at 0.27 MPa. Oil with a viscosity of 96 cP at 40 C and water cuts of 40 and 80 % were examined.

From measurements of pressure drop across the slug, location of the entrained gas, and corrosion rates, it was found that the characteristics of slug flow were dependent on the water cut, total pressure and temperature of the system . These subsequently had a pronounced effect on the corrosion rate.

The pressure drop across the slug, which indicates the levels of turbulence there, increased with increase in total pressure at each Froude number. At a given pressure, the pressure drop across the slug increased as the Froude number increased but temperature had only a small effect.

At the bottom of the pipe where the corrosion rate is highest, the amount of gas present increased with both increase in pressure and increase in Froude number. This leads to an increase in gas density and gas bubbles impacting on the pipe wall there. As the temperature increased and the liquid viscosity decreased, the amount of gas present increased greatly at high Froude numbers. As the water cut is decreased, the amount of gas entrained decreased.

Due to the increase in pressure drop and gas present at the bottom of the pipe, the corrosion processes were enhanced and this gave an increase in the corrosion rate at these conditions. At a given pressure and Froude number, the corrosion rate increased with increase in temperature for all temperatures examined. The pH of the system increased with increase in temperature but the increase in turbulence had a greater effect. The corrosion rate decreased when the water cut was lowered.

The effect of pressure on corrosion rate was incorporated into the gas density and a model based on Jepson and Bhongale has been developed that accounts for this.

Keywords: Horizontal Multiphase Flow, Corrosion, High Pressure, Carbon Steel, Prediction, Model.

1. INTRODUCTION

The use of multiphase pipelines is now very common in the production of oil. The oil/water/gas mixture from several wells is often transported several tens of kilometers to a platform or central gathering station where separation takes place.

The flowrates of carbon dioxide and brine increases with age of the oilfield with typical levels of carbon dioxide and brine being as high as 30 and 90% respectively. The weak carbonic acid formed from these mixtures can cause high corrosion rates inside carbon steel pipelines. The oil and gas mixture usually contains additional components e.g. waxes, hydrates, hydrogen sulfide and sand.

Models for estimating the corrosion rate in these situations have been suggested by several workers. De Waard and Milliams (1975) determined corrosion rates by means of measurements in stirred beakers and related corrosion rate to partial pressure of carbon dioxide and temperature. Later, de Waard, Lotz and Milliams (1991) improved the model using correction factors for the non-ideality of carbon dioxide at high pressures, formation of iron carbonate scales and changes in pH and Fe^{2+} ion levels. Further, based on some limited flow studies, de Waard, Lotz and Dugstad (1995) proposed a semi-empirical model that combined the contribution of flow-independent kinetics of the corrosion reaction with flow dependent mass transfer of dissolved carbon dioxide. The effect of water cut was not taken into account.

Efird, Wright, Boros and Hailey (1993) carried out experiments using brine in 2.54 cm and 9 cm pipe diameter loops, and established a correlation between corrosion rate and wall shear stress. Kanwar and Jepson (1994) performed corrosion studies in a 10 cm diameter flow loop under full pipe flow conditions at carbon dioxide partial pressures up to 0.79 MPa, temperature of 40 C and two oils with viscosity of 2 and 18 cP and brine. They found similar results to Efird et al and included the effects of water cut and temperature.

For multiphase pipelines, many different flow patterns exist. At most viable production rates, many multiphase pipelines operate in the slug flow regime. Here, the flow is intermittent and highly turbulent. There has been a great deal of work carried out in this laboratory to study slug flow and its effect on corrosion rates. Recently, Jepson, Bhongale, and Gopal (1996) showed that the corrosion rate in horizontal multiphase slug flow could be predicted as:

$$CR = 31.15\, C_{oil}\, C_{freq}\, (DP/L)^{0.3}\, v^{0.6}\, P_{CO2}^{\;0.8}\, T \exp(-2671/T) \qquad (1)$$

where, DP/L is the pressure gradient taken across the slug mixing zone,
v is the water cut,
P_{CO2} is the partial pressure of carbon dioxide,
T is temperature,

C_{freq} is the term that includes the slug frequency.

The oil type was determined using Herce at al (1996) who measured corrosion rates for several different crude oils using an autoclave and showed that the oil type can be related to the corrosion rate by using the product on acid number and % nitrogen in the crude.

An important parameter in slug flow is the Froude number, Fr, calculated in the liquid film ahead of the slug and defined as:

$$Fr = (v_t - v_{LF}) / (g\, h_{EFF})^{0.5} \qquad (2)$$

C_{oil} is the factor that accounts for the oil type,

v_t	=	translational velocity of the slug,
v_{LF}	=	velocity of the liquid film ahead of the slug,
g	=	acceleration due to gravity,
h_{EFF}	=	effective height of the liquid film ahead of the slug.

This paper examines the effect of total pressure, water cut, and temperature on both the flow and corrosion characteristics and includes the effect of gas density on corrosion rate.

2. EXPERIMENTAL SETUP.

Figure 1 shows the experimental system and comprises a 10 cm diameter, 316 stainless steel pipeline designed to withstand a maximum pressure of 100 bars. A predetermined oil-water mixture is stored in a 1.4 m^3 tank, A, which also serves as a separator for the returning multiphase gas-oil-water mixture. The system temperature is controlled by two 3 kW heaters, M, connected to a thermostat. The liquid is pumped via a 5.2 kW centrifugal pump, N, into a 7.5 cm diameter pipeline where the flowrate is measured using an orifice plate, F. The liquid then passes into a 10 cm pipe where the gas is injected. Mixtures of carbon dioxide and nitrogen of known compositions are produced from high pressure gas tanks.

The gas/liquid mixture flows through a 10 m long, horizontal pipeline, which includes the test section and then back into the holding tank where the gas and liquid are separated. A back pressure regulator K, maintains the pressure in the system.

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 flush mount the ER probes with the pipe wall for the corrosion rate measurement. Metal samples are also inserted for both weight loss measurements and for the study of the corrosion products. The positions P are pressure tappings, which are connected to a pressure transducer and from these the pressure drop across the slug can be determined. ST is the sampling probe used to take out samples of the flowing fluid to determine the local and average void fraction, local oil/water distributions, and oxygen and iron concentrations in the system.

The fluids used were a refined oil with a viscosity of 96 cP at 40 C and density of 820 kg/m^3 and ASTM standard sea water.

The experiments were performed at a fixed carbon dioxide partial pressures of 0.27 MPa with the total system pressure being increased to 0.45 and 0.79 MPa using nitrogen. The temperature was maintained at 40, 60, and 80 C. The values of the film Froude number ahead of the slug of were 9 and 12 (corresponding to approximate slug velocities of 4.5 and 6 m/s respectively). Water cuts of 80, and 40 % were used.

3. RESULTS.

From the measurements of pressure drop, void and oil/water fractions, total pressure and corrosion rate, the multiphase flow characteristics and the effect on corrosion rate can be examined.

From the pressure transducer, the pressure drop across the slug was measured and the effect of temperature, total pressure and Froude number are indicated in Figure 3 at an input water cut of 80 %.

As the temperature is increased from 40 to 80 C, the pressure drop across the slug decreases only slightly. This is mostly due to the lower liquid viscosity at the higher temperature.

The effect of increasing total pressure is more pronounced. For example, at a Froude number of 12 at 40 C, the pressure drop increases from 2.50 to 3.14 and then to 4.24 kPa as the total pressure is increased from 0.27 to 0.45 and 0.79 MPa respectively. At the higher pressures, the slug entrains more gas and, together with the higher gas density, higher levels of turbulence and hence pressure drop are attained. The pressure drop also is dependent on the Froude number. At 80 C and 0.79 MPa, the pressure drop across the slug increases from 3.21 to 4.15 kPa as the Froude number was increased from 9 to 12. This has been shown to be true in earlier work by Jepson.

The amount of gas entrained and the distribution of the gas across the pipe is of great importance to both pressure drop and the corrosion characteristics. Tables 1 and 2 show the void fraction at the bottom, center, and top of the pipe for 80 and 40 % water cuts. In each case, it can be seen that the void fraction is greatest at the top of the pipe. However, there is always gas present at the bottom of the pipe and it has been indicated by Jepson et al that this gas is in the form of pulses of bubbles that impact the wall there and sometimes bubble collapse can occur. The frequency of these pulses depends on the amount of gas present in the slug. At each Froude number, increasing the total pressure from 0.45 to 0.79 MPa, gives an increase in the void fraction. In Table 1, at 80 % water cut and a Froude number of 12, the amount of gas at the bottom of the pipe increases from 10 to 14 % as the total pressure increases from 0.45 to 0.79 MPa.

At a water cut of 40 %, Table 2 shows that the gas present at the bottom of the pipe is lower than the 80 % water cut at each Froude number and pressure. At a Froude number of 12 and 0.79 MPa, the percentage of gas is only 5 % as compared to 14 % at 80 % water cut.

These effects together with that of temperature are clearly shown in Figure 4. At a pressure of 0.79 MPa and a Froude number of 12, increasing the temperature from 40 to 80 C, the gas at the bottom of the pipe increases from 7 to 11 and then 14 % respectively. Similar results are noticed for a Froude number of 9. At the lower pressure of 0.45 MPa, the increases are more noticeable as the temperature is increased from 60 to 80 C. The increase in gas entrainment with increase in temperature can be attributed to the corresponding decrease in apparent viscosity of the liquid which fell from 96 cP at 40 C to only19 cP at 80 C.

The turbulence levels as indicated by the pressure drop across the slug and the gas presence at the bottom of the pipe both greatly influence the corrosion rate. This is presented in Figures 5, 6, 7, and 8.

Figure 5 shows the corrosion rate for 80 % water cut and a carbon dioxide partial pressure of 0.27 MPa. It is seen that, at each total pressure and Froude number, the corrosion rate increased as the temperature was increased from 40 to 80 C. For example, at a Froude number of 12 and a total pressure of 0.79 MPa, the corrosion rate increased from 11.0 to 15.4 and 21.1 mm/yr as the temperature was increased from 40 to 60 and then 80 C respectively.

The chemistry of the system depends on the pH and the rate of the reaction at each temperature. The corresponding pH increased from 5.0 to 5.5 which tends to give lower corrosion rates but the reaction rate increased. This, together with the enhanced mixing from the higher levels of gas entrainment, yields these corrosion rates.

At each temperature and pressure, an increase in the Froude number gave an increase in the corrosion rate. At 60 C and 0.79 MPa, the corrosion rate increased from 11.3 to12.9 mm/yr as the Froude number was increased from 9 to 12.

For a given Froude number and temperature, the effect of total pressure is more pronounced. At 80 C and a Froude number of 9, the corrosion rate increased from 12.3 to 18.2 mm/yr as the total pressure was increased from 0.27 to 0.79 MPa. This is due to the increase in the gas entrained, the increase in gas density, and in the increase in turbulence levels as shown in Figure 3.

Similar results are noted for the 40 % water cut as shown in Figure 6. A comparison of Figures 5 and 6 indicates that the corrosion rate decreases with decrease in water cut. At a Froude number of 12 and a total pressure of 0.45 MPa, the corrosion rate for the 40 % water cut at 40, 60, and 80 C is 5.4, 6.7, and 9.3 mm/yr respectively. The corresponding values for 80 % water cut are 6.2, 8.0, and 15.4 mm/yr.

The increase in the total pressure yields an increase in the gas density. Figures 7 and 8 give the variation of corrosion rate with gas density. In each case, the corrosion rate increases with increase in gas density. For example, at 80 % water cut, Figure 7 shows that, at a Froude number of 9 at 80 C, the corrosion rate increased from 12.3 to 12.8 and then 18.2 as the gas density increased from 3.8 to 5.6 and 8.9

respectively. The higher gas densities yield greater pressure drops and hence more turbulence which contributes to the increase in the corrosion rate. Similar results for the 40 % water cut are presented in Figure 8 where it is seen that the corrosion rates are again lower for this water cut.

To incorporate the effects of increasing total pressure on corrosion rate, all the data was examined in a similar way to Jepson and Bhongale (1996). It was found that the effect could be included in Equation 1 as follows:

$$CR = 31.15\, C_{oil}\, C_{freq}\, (DP/L)^{0.3}\, v^{0.6}\, P_{CO2}^{\ 0.8}\, T \exp(-2671/T)\, (\rho / \rho_{ref})^{0.26} \qquad (3)$$

Where, ρ is density of the gas mixture and
ρ_{ref} is the density of carbon dioxide alone at the given pressure and temperature.

All other variables are defined earlier and the brine type is incorporated into the constant term.

4. CONCLUSIONS.

Experiments have been carried out in a10 cm diameter pipeline using oil, water, and gas at total pressures of 0.27, 0.45, and 0.79 MPa and temperatures between 40 and 80 C keeping the carbon dioxide partial pressure constant at 0.27 MPa. Oil with a viscosity of 96 cP at 40 C and water cuts of 40 and 80 % were examined.

It was found that the characteristics of slug flow were dependent on the water cut, total pressure and temperature of the system and subsequently had a pronounced effect on the corrosion rate.

The pressure drop across the slug increased with increase in total pressure at each Froude number. At a given pressure, the pressure drop across the slug increase as the Froude number increased but temperature had only a small effect.

The amount of gas entrained and passed to the bottom of the pipe increased with both increase in pressure and increase in Froude number. This leads to an increase in gas density and gas bubbles impacting on the pipe wall there. As the temperature increased and the liquid viscosity decreased, the amount of gas present at the bottom of the pipe increased greatly at high Froude numbers. As the water cut is decreased, the amount of gas entrained decreased.

The increase in pressure drop and gas present at the bottom of the pipe enhanced the turbulence levels and this gave in increase in the corrosion rate at these conditions. At a given pressure and Froude number, the corrosion rate increased with increase in temperature for all temperatures examined. The pH of the system increased with increase in temperature but the increase in turbulence had a greater effect. The corrosion rate decreased when the water cut was lowered.

The effect of pressure on corrosion rate was incorporated into the gas density and a model based on Jepson and Bhongale has been developed that accounts for this.

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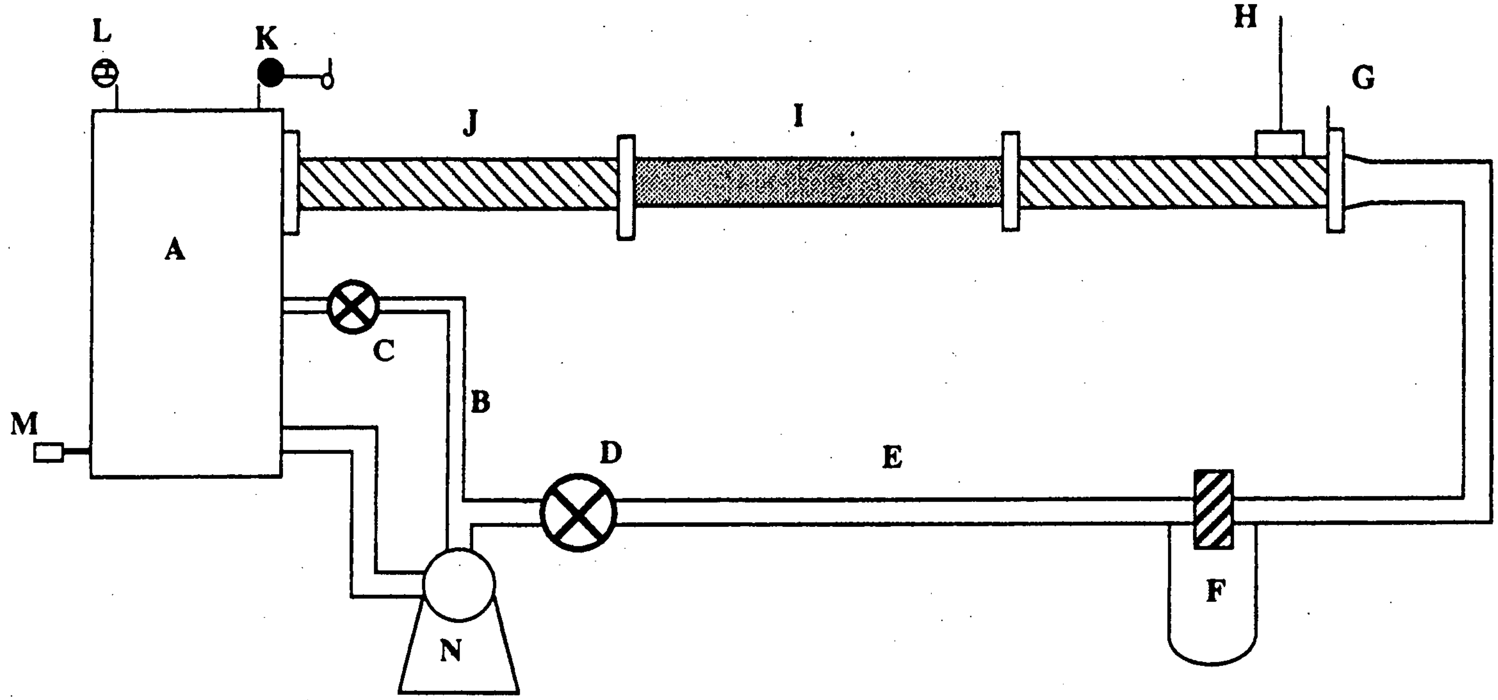

A. Liquid Tank
B. Liquid Recycle
C. Valve on Liquid Recycle
D. Valve on Liquid Feed
E. Liquid Feed- 7.5 cm PVC Pipe
F. Orifice plate, to pressure transducer
G. Flow Height Control Gate
H. Carbon dioxide Feed Line
I. Test Section- 10 cm Plexiglass pipe
J. 10 cm Plexiglass Section
K. Pressure Gauges & Back Pressure Regulator
L. Safety valve
M. Heater
N. Pump

Figure 1: Layout of the Experimental System

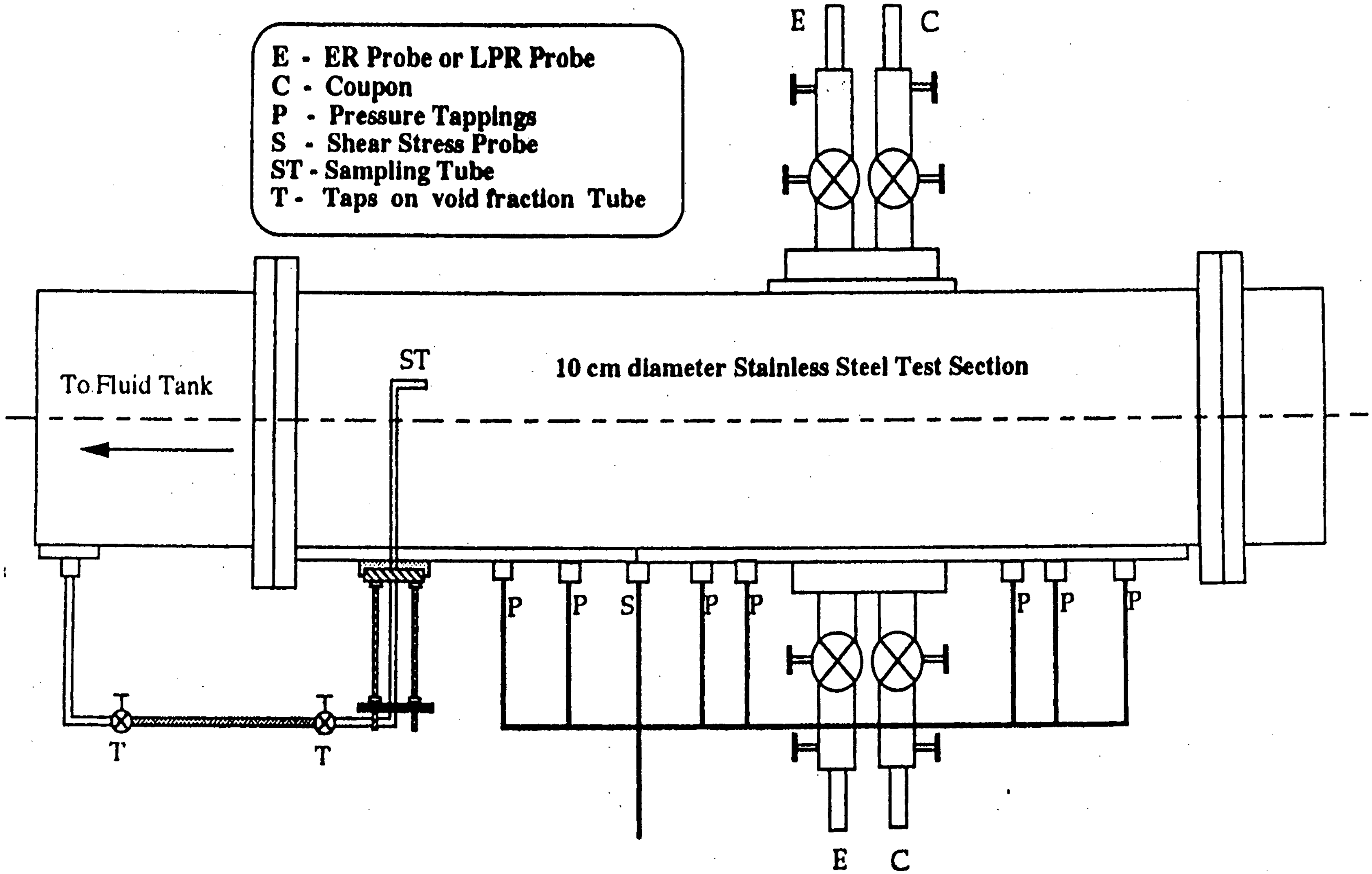

Figure 2: Test Section

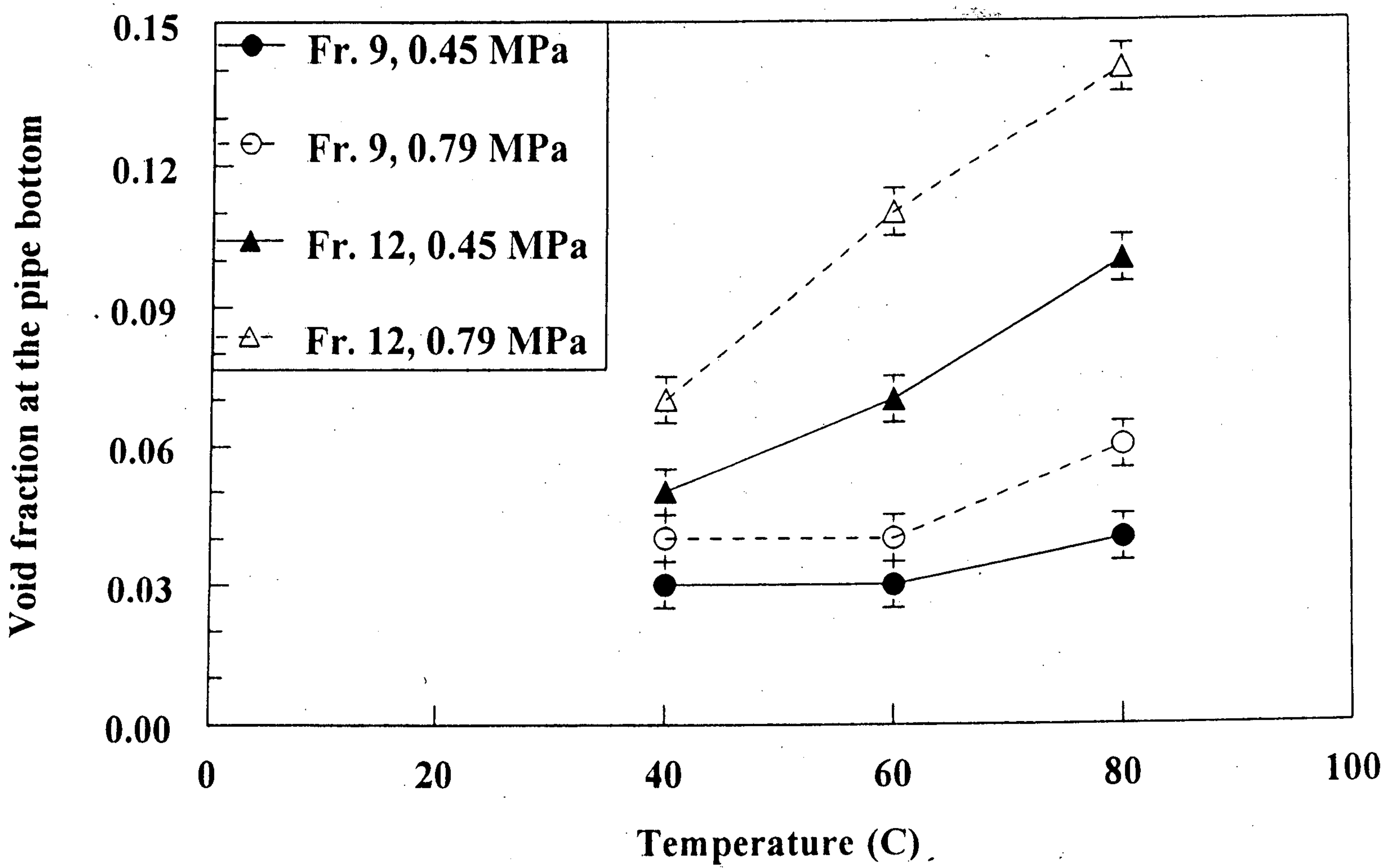

Figure 3: Variation of pressure drop across the slug with temperature at 80% water cut

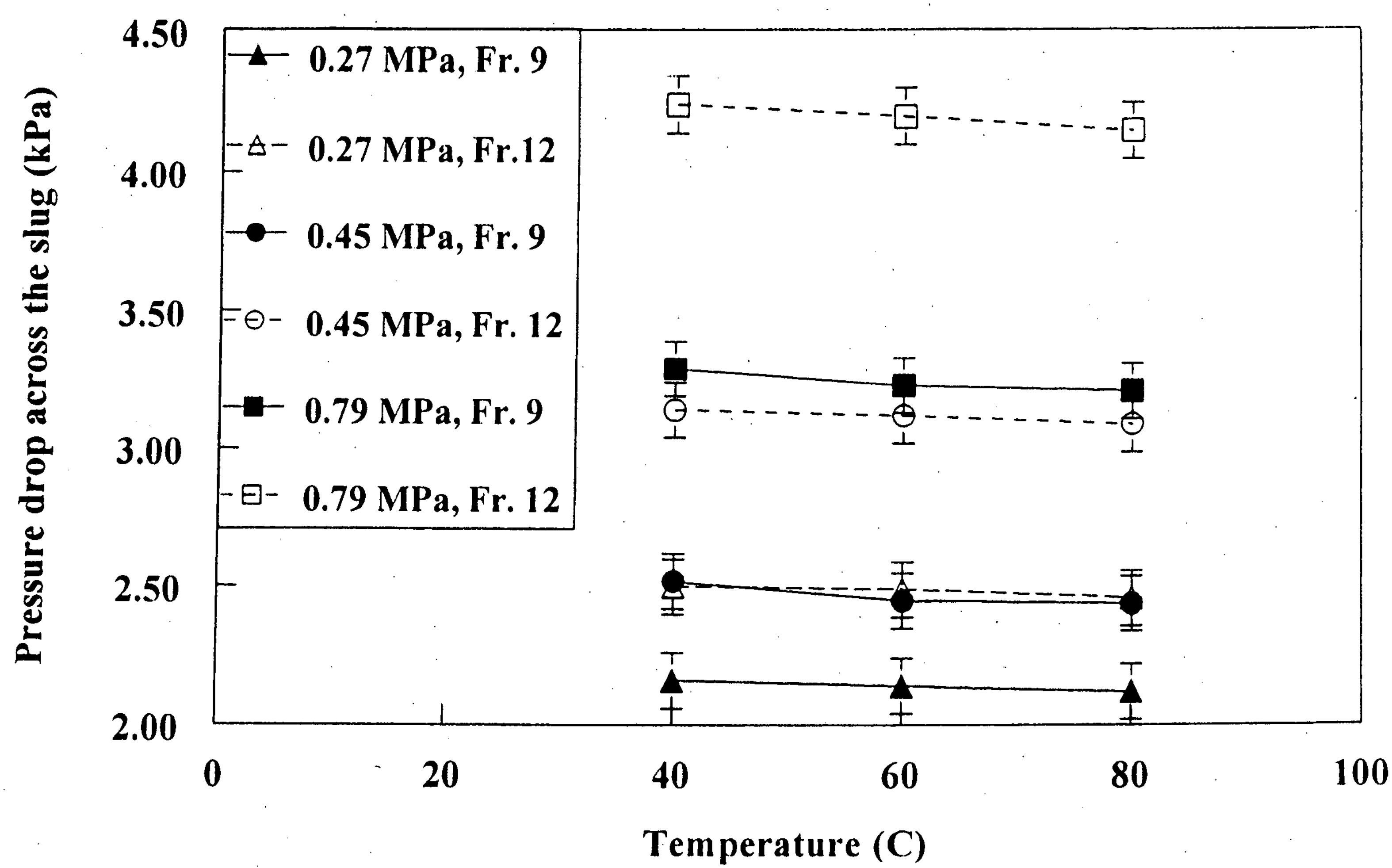

Figure 4: Effect of temperature on void fraction at the pipe bottom for 80% water cut

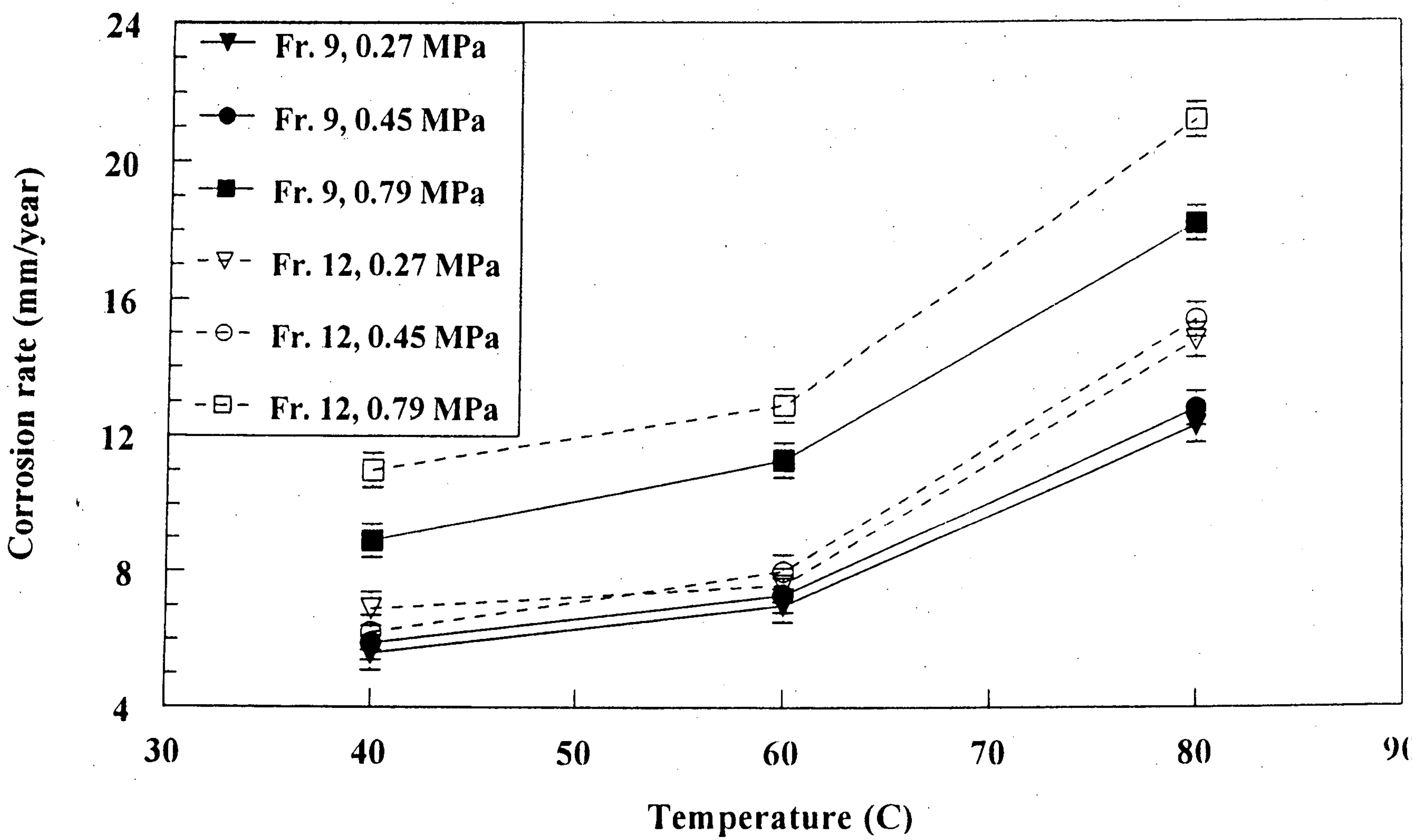

Figure 5: Variation of corrosion rate with temperature at constant CO_2 partial pressure of 0.27 MPa and 80% water cut

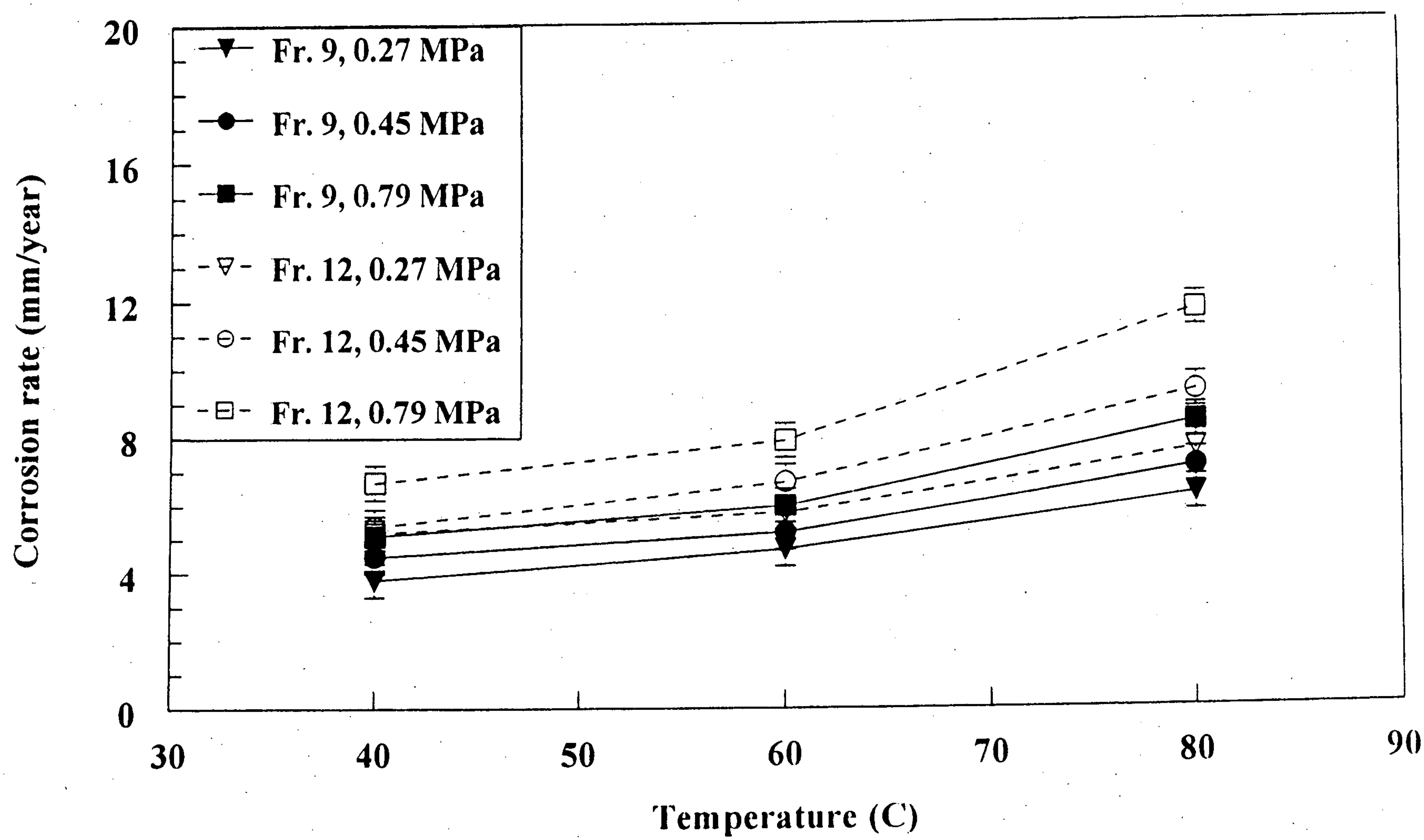

Figure 6: Variation of corrosion rate with temperature at constant CO_2 partial pressure of 0.27 MPa and 40% water cut

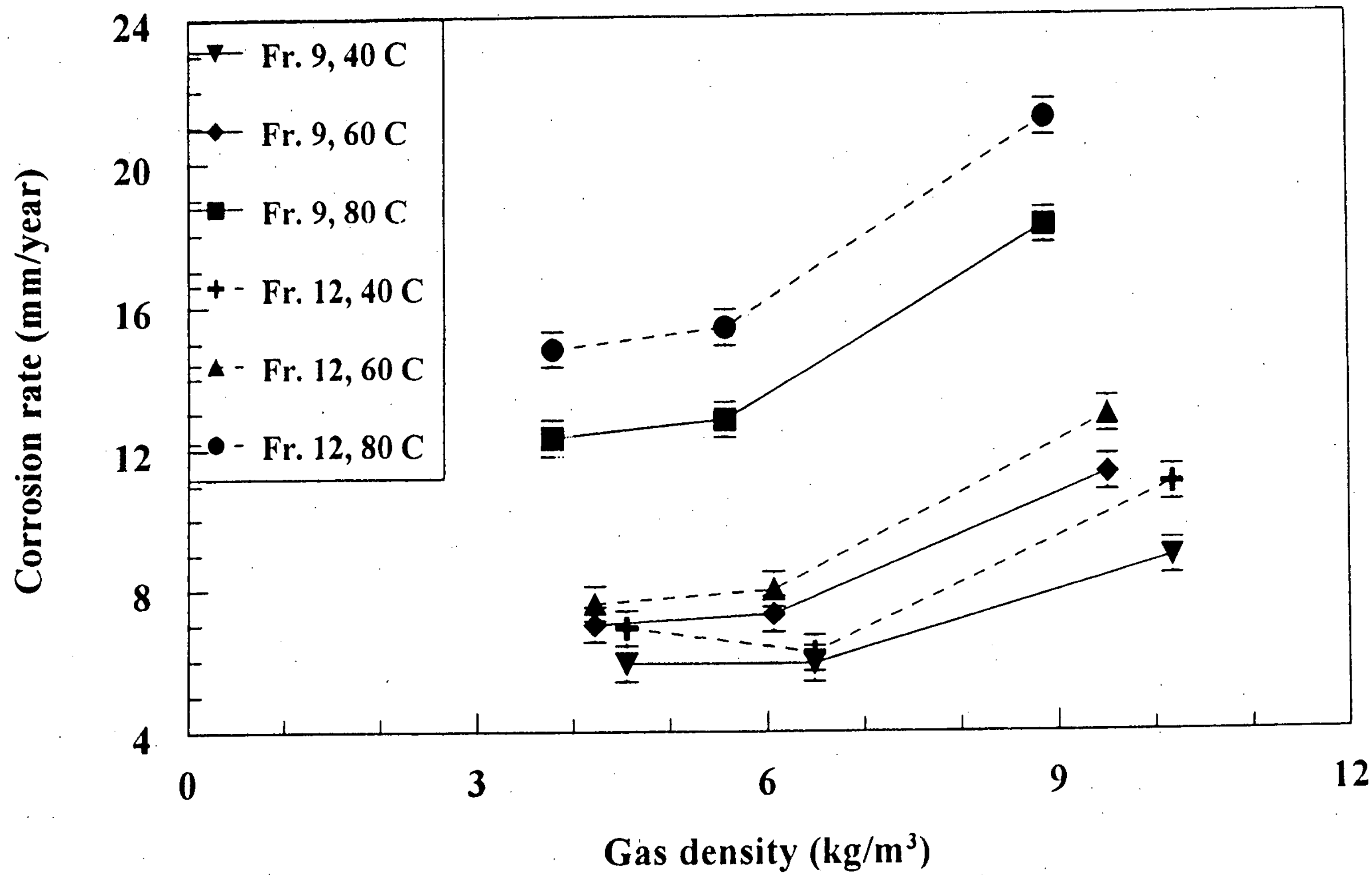

Figure 7: Variation of corrosion rate with gas density at constant CO_2 partial pressure of 0.27 MPa and 80% water cut

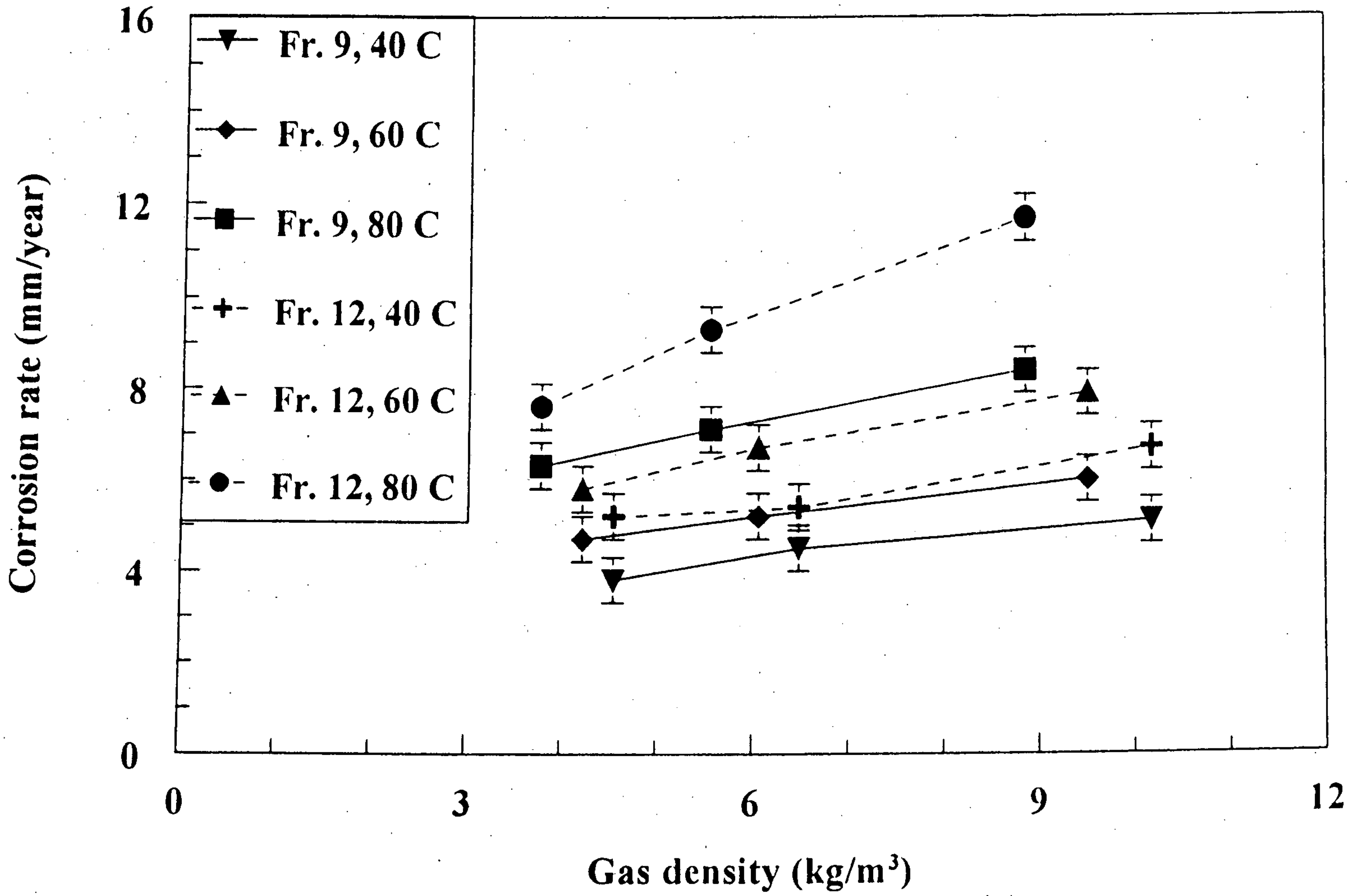

Figure 8: Variation of corrosion rate with gas density at constant CO_2 partial pressure of 0.27 MPa and 40% water cut

Froude number	Position	Void fraction at different total pressures	
		0.45 MPa	0.79 MPa
9	Bottom	0.03	0.04
	Middle	0.16	0.21
	Top	0.48	0.55
12	Bottom	0.05	0.07
	Middle	0.19	0.32
	Top	0.53	0.63

Table 1: Void fractions for 80% water cut at 40 C at different positions from the bottom of the pipe

Froude number	Position	Void fraction at different total pressures	
		0.45 MPa	0.79 MPa
9	Bottom	0.01	0.02
	Middle	0.19	0.24
	Top	0.52	0.59
12	Bottom	0.03	0.05
	Middle	0.21	0.27
	Top	0.58	0.66

Table 2: Void fractions for 40% water cut at 40 C at different positions from the bottom of the pipe