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MODEL FOR SWEET CORROSION IN HORIZONTAL MULTIPHASE SLUG FLOW

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ABSTRACT

A model has been developed that can predict the corrosion rate in horizontal slug flows. The effect of the slug frequency and oil type on corrosion rate have been included. The model has been compared to experimental data, and, to the model and field data of Gunaltun (1996). For all conditions, the corrosion rate increased with increase in slug frequency until a maximum in corrosion rate is reached at approximately 35 slugs/minute.

At 60 C, the model compares well with that of Gunaltun (1996) if a slug frequency of 10 to 12 is used. For 80 C, the Gunaltun model is in good agreement if a frequency of 1 slug/minute is used. His model does include a term that predicts a maximum in the corrosion rate between 60 and 80 C. This has not been noticed in this laboratory for slug flows.

For horizontal pipelines, field data suggests that, the slug frequency is usually in the range of 1 to 20 slugs/minute, depending on the liquid velocity. When the pipe is inclined, the slug frequency can increase to values much greater than these and this may lead to higher levels of corrosion.

The oil type is accounted for using the suggestion of Efird (1989) based on the product of oil acid number and % nitrogen. When this relation is used, the results compare very well with those of Efird for the oils he studied.

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

1. INTRODUCTION

In remote areas such as Alaska or subsea, it is usually not economical to separate locally the oil/water/gas from each well. Consequently, the oil/water/gas mixture from several wells is transported to a central gathering station through large diameter pipelines, where separation takes place.

Levels of carbon dioxide and brine in mature wells can be as high as 30 and 90% respectively. This multiphase oil-water-gas mixture forms weak carbonic acid which can cause much higher corrosion rates inside carbon steel pipelines. The oil and gas mixture may also contain additional components e.g. waxes, hydrates, hydrogen sulphide and sand.

Predictive models for the corrosion rate have been suggested by several workers.. De Waard and Milliams (1975)[1] determined corrosion rates by means of weight loss coupons and polarization resistance measurements in stirred beakers. They found that the corrosion rate increased with increase in carbon dioxide partial pressure and initially increases with increase in temperature from 30 to 60 C, reaches a maximum between 60 to 70 C and thereafter decreases until 90 C. Vuppu and Jepson (1994)[2] obtained similar results from experiments in flow loops under full pipe (oil/water) flow conditions.

Later, de Waard, Lotz and Milliams (1991)[3] provided an improved model which included correction factors for the non-ideality of carbon dioxide at high pressures, formation of iron carbonate scales at high temperatures and changes in pH and Fe^{2+} ion levels. Further, they (1993)[4] produced a revised correlation that included flow velocity. From a limited set of data obtained from a high pressure test facility, de Waard, Lotz and Dugstad (1995)[5] 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. No effect of oil composition was taken into account.

From experiments performed in 2.54 cm and 9 cm pipe diameter loops, Efird, Wright, Boros and Hailey (1993)[6] established a correlation between corrosion rate and wall shear stress. This relation is:

$$R_{COR} = a\,\tau_w^{\,b} \tag{1}$$

where,

	R_{COR}	=	corrosion rate in mm/year
	τ_w	=	wall shear stress in N/m^2
	a & b	=	constants

Only brine was used so different values of a and b are required if other fluids were being examined.

A more comprehensive study was carried out by Kanwar and Jepson (1994)[7] who performed corrosion studies in a 10 cm diameter flow loop under full pipe (oil/water) flow conditions, at carbon dioxide partial pressures up to 0.79 MPa, temperature of 40 C with two oils of viscosities 2 and 18 cp and brine. Following Efird et al.(1993), they suggested:

$$R_{COR} = k\,P^{c}\,\tau_w^{\,b} \tag{2}$$

where,

	R_{COR}	=	corrosion rate in mm/year
	P	=	carbon dioxide partial pressure in MPa
	τ_w	=	wall shear stress in N/m^2
	b & c	=	constant exponents with values of 0.1 and 0.83 respectively
	k	=	constant $(mm/year)(MPa)^{-0.83}(N/m^2)^{-0.1}$

This relation was valid for water cuts between 100 and 40 %. Later, Kanwar (1994)[8] determined the effect of temperature on the corrosion rate for temperatures up to 80 C. He found that the coefficient "k" could be represented as a function of temperature.

In many multiphase pipelines, the dominant flow regime is slug flow. This is very different from full pipe flow in that 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 it's effect on corrosion rates. Recently, Jepson, Bhongale, and Gopal (1996)[9] showed that the corrosion rate in horizontal multiphase slug flow could be predicted as:

$$CR = 31.15 \left(\frac{\Delta P}{L}\right)^{0.3} v^{0.6} P_{CO2}{}^{0.8} T e^{(-\frac{2671}{T})} \quad (3)$$

where, $\Delta P/L$ = pressure gradient across slug mixing zone, N/m^3
v = water cut
P_{CO2} = carbon dioxide partial pressure, Mpa
T = system temperature, K
CR = corrosion rate, mm/yr

The model was based on slugs that were stationed directly over corrosion monitoring probes. This corresponded to high frequency slug flows. The effect of oil viscosity was examined but oil type was not included. The pressure gradient is a function of the liquid film Froude number ahead of the slug defined as:

$$Fr = \frac{v_t - v_{LF}}{\sqrt{g h_{EFF}}} \quad (4)$$

where, Fr = Froude number in the liquid film ahead of the slug
v_t = translational velocity of the slug, m/s
v_{LF} = velocity of the liquid film ahead of the slug, m/s
g = acceleration due to gravity, m/s^2
h_{EFF} = effective height of the liquid film ahead of the slug, m

This paper improves the above model by including the effect of slug frequency and oil type.

Efird and Jasinski (1989)[10] measured corrosion rates for several different crude oils using an autoclave. He showed that the oil type can be related to the corrosion rate by using the product on acid number and % nitrogen in the crude.

Gunaltun (1996)[11] produced a model called "Lipucor"based on de Waard's model and field data. This models accounts for the systems pH, water chemistry, and liquid velocity but does not account for slug frequency. If the results of Lupicor are compared to Jepson[9], Lipucor predicts lower rates of corrosion.

2. EXPERIMENTAL SETUP AND PROCEDURE

The experimental setup is shown in Figure 1. The 10 cm diameter, 316 stainless steel system is inclinable and is designed to withstand a maximum pressure of 150 bars. A predetermined oil-water mixture is stored in a 1.4 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 3 kW heaters, connected to a thermostat. The liquid is pumped into a 10 cm diameter pipeline where carbon dioxide is injected. The gas/liquid mixture flows through a 20 m long pipeline which can be inclined to any angle between horizontal and vertical and back into the holding tank where the gas and liquid are separated. A back pressure regulator K, maintains the pressure in the system. Both upward and downward flows are studied simultaneously.

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. The positions P are pressure tappings, which are connected to two separate pressure transducers. The measurements are examined and the slug frequency and velocity are calculated. 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 0.13, 0.27, 0.45 and 0.79 MPa, temperature of 40 C and Froude numbers of 6, 9 and 12 (corresponding to slug velocities of 3, 4.5 and 6 m/s respectively). Water cuts of 100, 80, 60, 40 and 20% were used.

3. RESULTS

From the pressure transducers, the pressure drop across the slug, slug frequency, and slug velocity are measured. Figure 3 shows the effect of slug frequency on corrosion rate for 40% water cut, at Froude numbers of 8 and 12.3, at 40 C and carbon dioxide partial pressure of 0.13MPa at an upward inclination of 5 degrees. It is seen that at each Froude number, the corrosion rate increases linearly with increase in slug frequency up to approximately 35 slugs per minute. Above this frequency, the corrosion rate remains constant. Similar results are obtained for other inclination angles ranging from horizontal to 15 degrees.

The effect of slug frequency on corrosion rate can be represented by the normalized relation:

$$\mathbf{Cr_{freq} = 0.023\,F + 0.214} \qquad \mathbf{(5)}$$

where Cr_{freq} is the normalized factor to account for slug frequency and $0<Cr_{freq}<1$
and F is the measured slug frequency up to a maximum of 35 slugs/minute.

When this relation is applied to Equation (3), the corrosion rate can be determined at any slug frequency. This is illustrated in Figures 4 and 5. Figure 4 shows the effect of slug frequency on corrosion rate at 60 C for different Froude numbers, water cuts and carbon dioxide partial pressures. The uppermost data points is Jepson's[9] model which is based on experimental data and corresponds to a slug frequency of 35 slugs/minute. When Jepson's data is compared to Gunaltun's[11] model which does not include any frequency term, the Jepson's corrosion rate is much greater. However, if the slug frequency term is added to Jepson's model the effect of deceasing slug frequency can easily be seen. For example, at a corrosion rate of 33 mm/year which the corrosion rate for a Froude number of 12, 80 % water cut and pressure of 7.9 bar, as the frequency is decreased from 35, to 20, 10 and 1 slugs per minute, the corrosion rate is reduced to 22, 15, and 8 mm/year respectively.

Gunaltun's model predicts 18 mm/year. This corresponds to the corrosion rate at a slug frequency of approximately 12 slugs per minute. This is very similar for all the other data points.

For 80 C, at the same operating conditions, the effect of decreasing slug frequency is again seen to decrease the corrosion rate substantially. However, the corrosion rate from Gunaltun's model is much lower than the Jepson's experimental data and now corresponds to a slug frequency of about 2 slugs/minute. This is probably due to the Gunaltun's model being based on the de Waard model which assumes that a maximum in corrosion rate is achieved somewhere between 60 and 80 C. It has ben shown in this laboratory that the maximum in corrosion rate occurs at much higher temperatures, greater than 110 C, especially in slug flow.

In many field situations where the pipeline is horizontal, the slug frequency is usually between 1 and 10 slugs per minute depending on the superficial liquid velocity. However, if there is an incline in the pipeline, even 0.5 degree, the slug frequency can be increased significantly with greater than 60 slugs per minute being generated.

The effect of oil type on corrosion rate can be included using the data generated by Efird and Jasinski[10] based on the acid number and percent nitrogen of the oil. By calculating the equation of the line in their data, the following is found:

$$\mathbf{Cr_{crude}} = \mathbf{10^{**}(log(acid\ number\ x\ \%\ nitrogen) + 0.38)\ /\ 24000} \qquad \mathbf{(6)}$$

where Cr_{crude} is the normalized factor to account for crude oil type and $0<Cr_{crude}<1$

and the product of acid number x % nitrogen has a value of 0.0001 for brine where the corrosion rate is 24 mm/year.

This factor was then included in Equation 3 and the corrosion rates were calculated for different oils at a Froude number of 6 at the conditions used by Efird A comparison of these results with Efird's is given in Figure 6. The corrosion rates are very close in each case.

When Equations 5 and 6 are incorporated into Equation 3, the following is obtained:

$$CR = 31.15\ Cr_{freq}\ Cr_{crude} \left(\frac{\Delta P}{L}\right)^{0.3} v^{0.6}\ P_{CO2}^{\ 0.8}\ T\ e^{\left(-\frac{2671}{T}\right)} \qquad (5)$$

This equation can then be used for water cuts from 100 to 20%, partial pressures of carbon dioxide up to 10 bars and temperatures up to 100 C.

4. CONCLUSIONS

A model has been developed that can predict the corrosion rate in horizontal slug flows. From experimental data, relations that account for the slug frequency and oil type have been produced. The model has been compared to that of Gunaltun which has some field data included.

For all flows considered, the corrosion rate increased with increase in slug frequency. A maximum in corrosion rate is noted at approximately 35 slugs/minute.

At 60 C, the model compares well with that of Gunaltun if a slug frequency of about 12 is used. For 80 C, the Gunaltun model compares well with a frequency of 1 slug/minute. However, his model does include the de Waard relation that predicts a maximum in the corrosion rate between 60 and 80 C. This has not been noticed in this laboratory for slug flows.

Field data suggests that for horizontal pipelines, the slug frequency is usually in the range of 1 to 20 slugs/minute depending on the liquid velocity. However, if the pipe is inclined, the slug frequency can increase to values much greater than these. This may lead to higher levels of corrosion.

The oil type is accounted for using the suggestion of Efird based on the product of oil acid number and % nitrogen. If this relation is added to Equation 3, the results compare very well with those of Herce et al for the oils he studied.

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Figure 1: Corrosion Loop Process Flowsheet

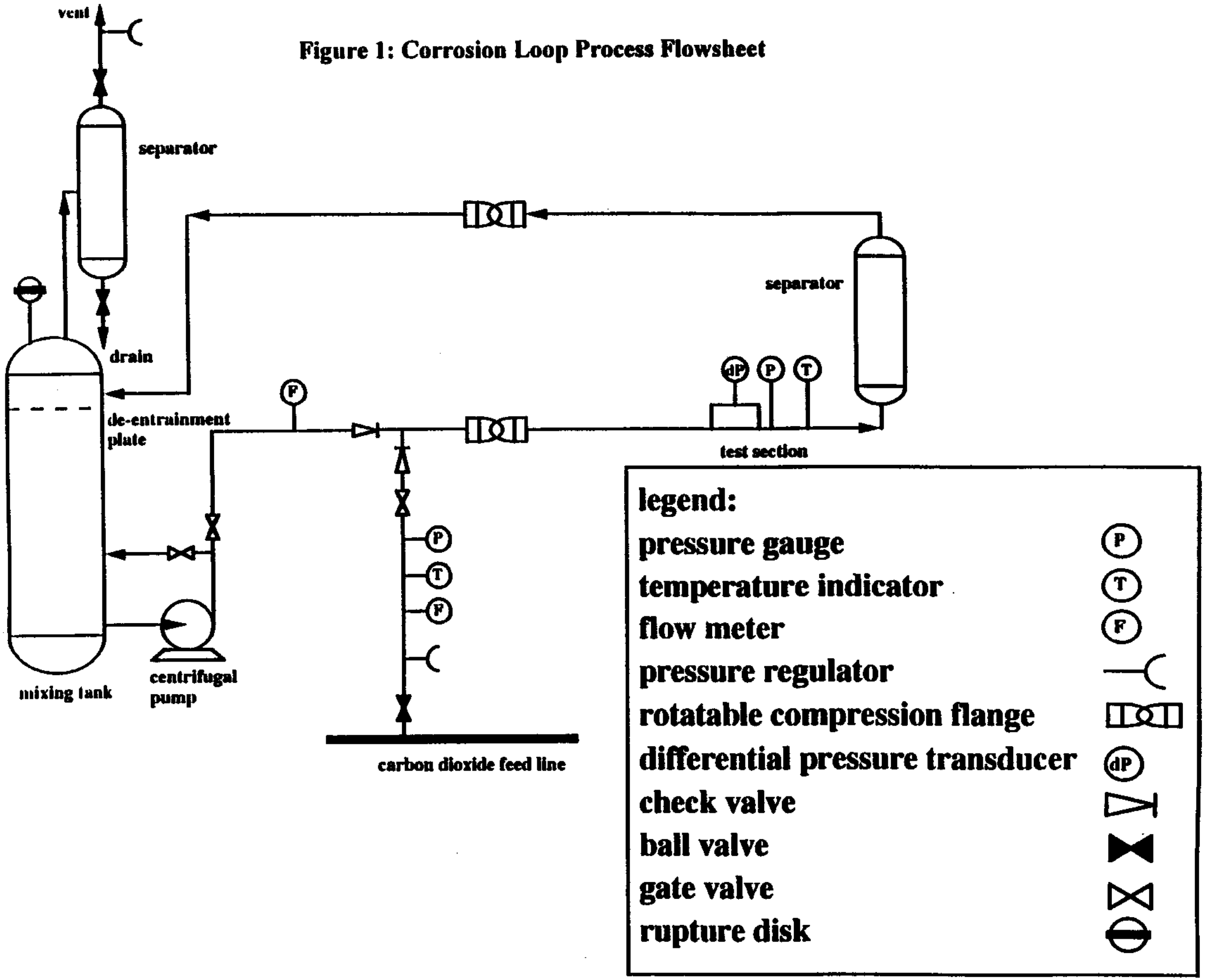
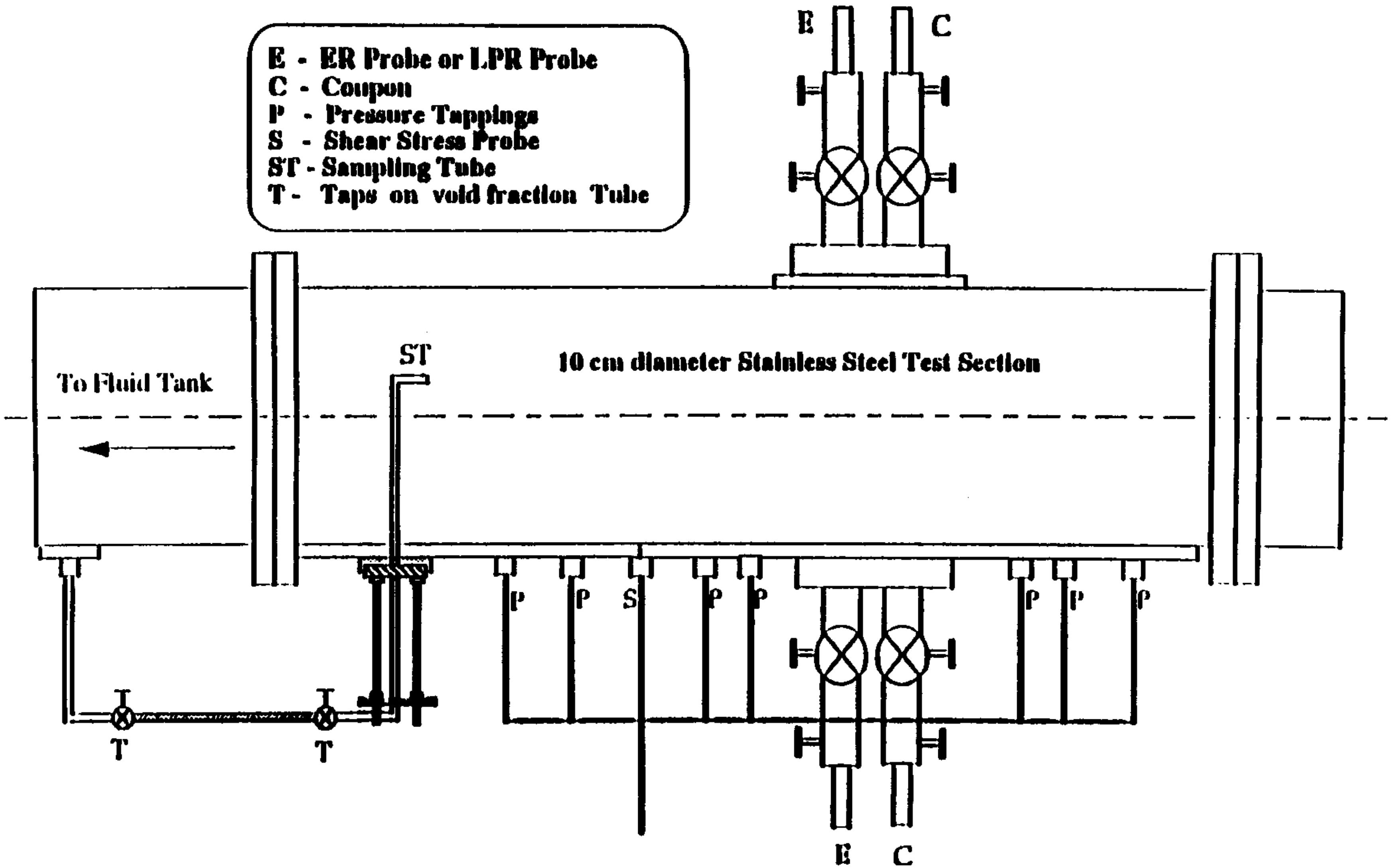


Figure 2. Test section



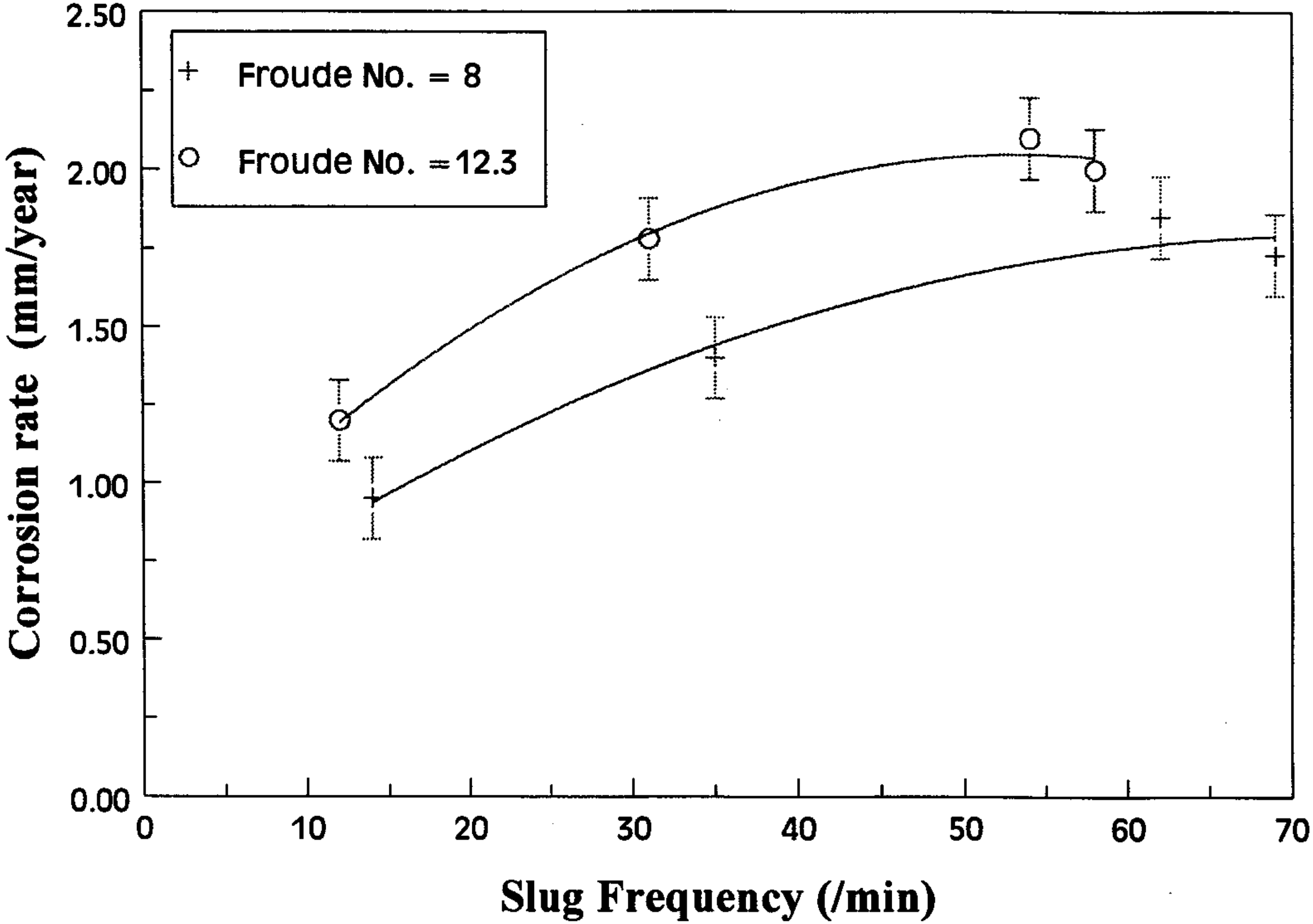


Figure 3 Corrosion rate vs Slug Frequency

At +5° For 60% Oil Cut

Figure 4: Effect of Slug Frequency on Corrosion Rates

60 Deg Celcius / Froude No. 6, 9, 12 / Pressure @ 2.7 bar and 7.9 bar
20%, 40%, 60% Oil

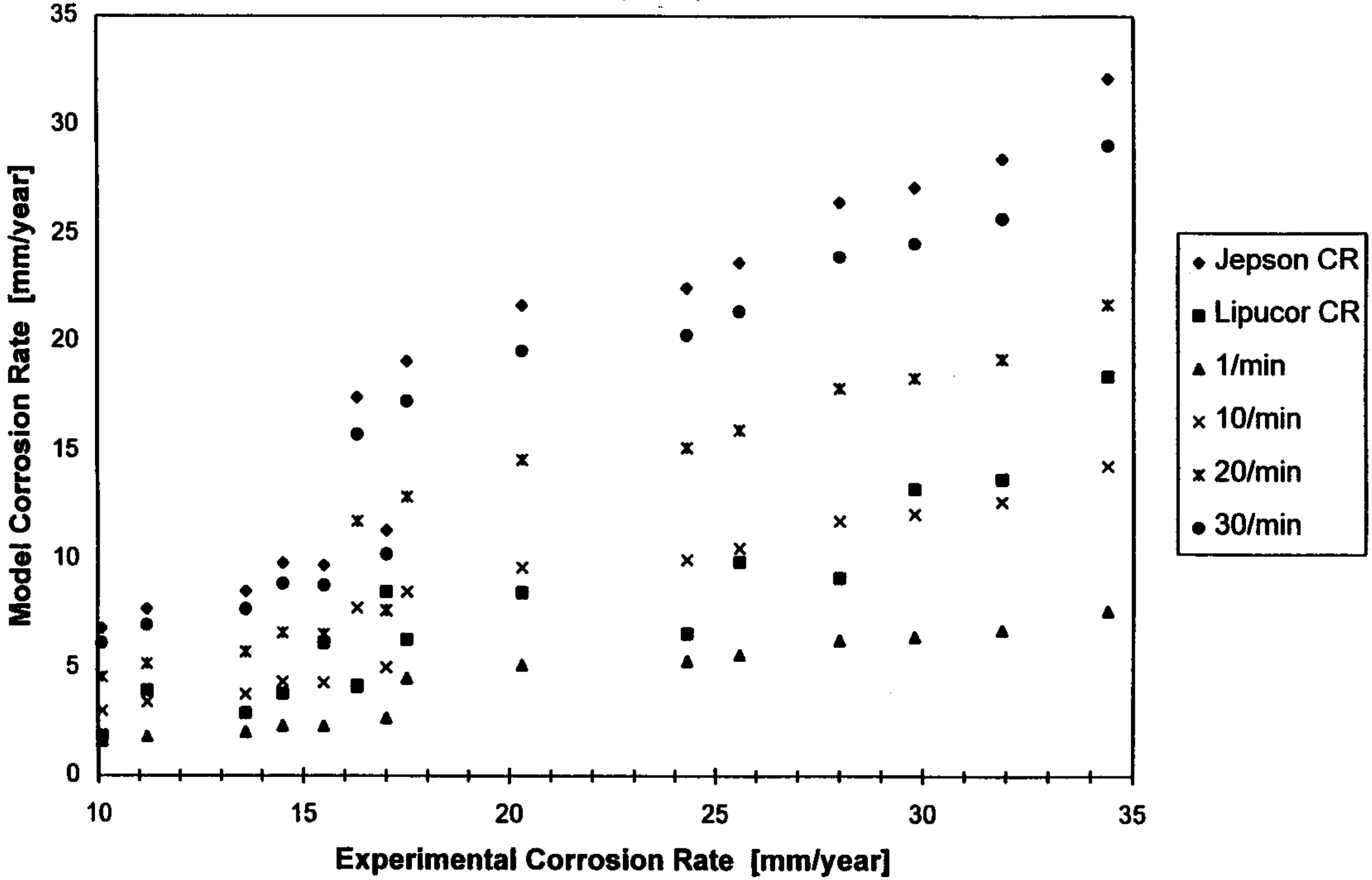


Figure 5: Effect of Slug Frequency on Corrosion Rates

80 Deg Celcius / Froude No. 6, 9, 12 / Pressure @ 2.7 and 7.9 bars

20%, 40%, 60% Oil

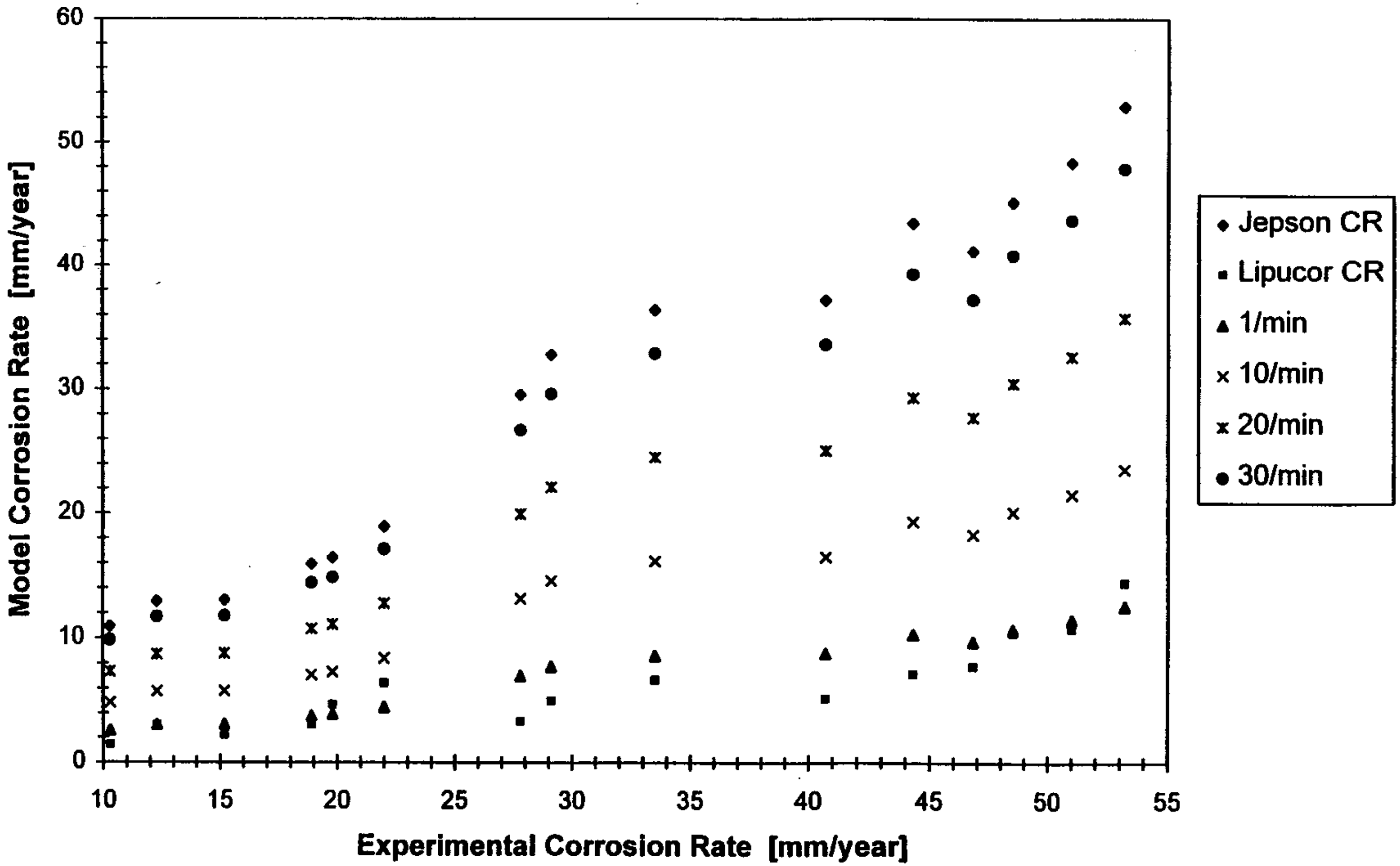


Figure 6: Corrosion Rate vs. Crude Oil
Crude Oil / 5% Brine Mixture