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HOW TO CONTROL CORROSION/EROSION PROBLEMS IN MULTIPHASE PIPELINES FOR OIL AND GAS

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ABSTRACT

Material loss due to CO_2 corrosion can be a limiting factor for the use of carbon steels in pipelines for unprocessed hydrocarbons. In many subsea projects the pipeline costs are a considerable part of the investment and the economical impact of improved understanding and control of the CO_2 corrosion of carbon steel is large. This report summarises the effect of the most important parameters on CO_2 corrosion, and gives an overview of corrosion prediction models for this type of corrosion. Fields in the Norwegian part of the North Sea are used as examples. New and untraditional methods for significant reduction of corrosivity in gas/condensate pipelines are briefly mentioned. The report concludes with a discussion on how these problems may be handled in future long distance transport lines for unprocessed hydrocarbons.

INTRODUCTION

One important aspect of multiphase flow is to avoid serious material loss caused by corrosion and erosion or a combination of these two processes. The phenomena associated with material loss in a multiphase pipeline are very complex, involving the chemistry of the pipeline fluids, the metallurgy of the pipeline material and the pipeline hydraulics, which all interact in a complex way. Inhibition of corrosion and inhibitor distribution along the pipeline are also of special concern. This report summarises the effect of the most important parameters affecting corrosion and concludes with a short discussion on how these problems may be handled in future long distance transport lines for unprocessed hydrocarbons.

FIELDS WITH MULTIPHASE FLOW TECHNOLOGY

Short flowlines with multiphase flow have been in use in the North Sea for 15-20 years. Phillips Petroleum experienced serious corrosion with 2-3 kilometre long lines in the mid seventies, the problem was solved by a carefully selected inhibitor program. It can be seen from Table 1 that predicted corrosion rates for carbon steels show large variation from one field to the other. For the 12 km long Tommeliten pipeline duplex stainless steel was selected to handle the high CO_2 content. The flowline has been in operation for 4 years. The first Norwegian pipeline of a significant length was the 20", 48 km long TOGI-pipeline (Troll-Oseberg Gas Injection) designed to transport unprocessed well fluid from a subsea installation to an offshore production platform. The carbon-manganese steel gas line has been successfully operated since January 1991.

Several of the wells evaluated for multiphase flow development have fluid properties giving high corrosion rates for carbon-manganese steels. This applies for example for Lille-Frigg, Hild and Snøhvit fields where conservative corrosion rate predictions give unacceptable high corrosion rates in the range 10-20 mm/year. Selection of stainless steel would solve the technical problem but add considerably to the costs.

In many subsea projects under development the pipeline costs are a considerable part of the investment. The economical impact of improved understanding and control of the corrosion of carbon steel is large. Having one pipeline built in carbon steel instead of duplex steel can give several hundred millions NOK in investment savings. The rationale for research CO_2 corrosion of carbon steel is therefore obvious.

CO_2 CORROSION THE MAJOR PROBLEMS

The material loss in production tubes and pipelines may be caused by corrosion, erosion or a combination of these two mechanism. For transport lines in the North Sea CO_2 corrosion is the major problem and the present paper is limited to cover this specific task.

Different oil companies have spent much time and effort in order to improve understanding and solve the CO_2 corrosion problem of carbon steel in oil and gas production. In Europe, Shell and Elf Aquitaine A/S have been particularly active and published data which have contributed significantly to the understanding of the phenomena [1-6]. Institutt for energiteknikk (IFE) has for years carried out extensive research on CO_2 corrosion of carbon steel in projects conducted for oil companies and material suppliers [7-14]. This report discusses some of the problem areas which are regarded important in order to make more realistic corrosion rate predictions in the future.

Corrosion of carbon steel used in oil production and transportation (when a liquid water phase is present) is influenced by a large number of parameters. Some of them are listed below.

- Temperature
- CO_2 partial pressure
- Flow regime and velocity
- pH
- Concentration of dissolved corrosion product ($FeCO_3$)
- Concentration of acetic acid

- Water wetting
- Metal micro structure (welds)
- Metal prehistory

The influence of many of these parameters is poorly understood. Experiments have shown that some of them are closely linked to each other. Changing one of them may influence the corrosion rate considerably. If e.g. temperature (90 °C), CO_2 partial pressure (2 bar), velocity (4 m/s) and pH (5.0) are kept constant while the amount of corrosion product in the water is varied, corrosion rates in the range <1 mm/year to 20 mm/year can be obtained. This is attributed to changes in the properties of protective corrosion products film.

"Worst case" corrosion

Generally very high corrosion rates are obtained when protective films do not form, even at low temperatures and high pH. The general trend for the effect of CO_2-content, temperature, flow and pH are illustrated in Figure 1. This "worst case" corrosion is the easiest type to study and reproduce in the laboratory and several prediction models have been developed for this type of corrosion. These prediction models often over predict the corrosion rate of carbon steel. It is therefore possible that carbon steel is disregarded in applications where it could have been adequate.

Protective film formation

The prediction of corrosion rates is much more complicated when films with protective properties may form. The challenge is then to predict if film formation is hindered, if the film can be removed mechanically and if new film will form when a protective film has been locally destroyed (mesa corrosion).

Film formation is strongly dependent on the solubility and precipitation of iron carbonate which again is influenced by temperature, pH, flow rate and the presence of the corroding steel. This relationship has generally been given little attention and is usually not included in prediction models. The effect of solubility, precipitation and supersaturation of iron carbonate has been studied in detail at IFE over the last 5 years and the most important findings are recently published [14]. Experiments have shown that precipitation rate of $FeCO_3$ is a slow, temperature dependent process and that a high degree of supersaturation can be maintained in a corroding system. This is important to realise in order to understand the different mechanisms taking place when carbon steel corrodes.

Some of the results obtained in the solubility experiments are shown in Figure 2 where the amount of dissolved $FeCO_3$ is given as a function of temperature when carbon steel corrodes in a system with a low and constant steel to water ratio. It is seen that the supersaturation decreases with increasing temperature because the precipitation rate of $FeCO_3$ increases. This has a large impact on the protective properties of the corrosion film formed.

At temperature below 60 °C when the solubility limit is exceeded the iron carbonate films that form are often porous with poor protective properties. The corrosion rate is therefore maintained very high even after thick films have formed and large amount of corrosion products have been released to the water. Under these conditions a constant high corrosion rate can be achieved.

When the temperature increases above 60 °C, the precipitation rate increases while solubility decreases and more dense protective iron carbonate films are formed. The corrosion rate is therefore often reduced from several mm/years to less than 0.1 mm/year after a few days exposure. Both practical experience and laboratory experiments have shown that the corrosion rate increases with temperature and goes through a maximum in the temperature range 60-90°C.

The corrosion rate decreases with increasing pH. When the pH is increased protective films are more easily formed because the solubility of iron carbonate is reduced. This is illustrated in Figure 3 which shows the iron carbonate solubility as a function of pH at 60 °C. It is seen that the amount of $FeCO_3$ which can be dissolved in the water is significantly reduced when the pH increases above pH 5. The same reduction is seen on the corrosion rate when the bulk water is under saturated with respect to $FeCO_3$ (Figure 4). If the amount of corrosion product in the water is increased above saturation protective films may form and a considerable reduction in corrosion rate can be achieved.

Localised corrosion (mesa attack)

Understanding of local film destruction is of the utmost importance as localised attack is the type of attack usually found in pipelines and flow lines. The characteristic feature of CO_2 induced mesa attack in practice is the formation of severely corroded, flat regions separated with a sharp steps from neighbouring areas with very little attack, (Figure 5). Mesa attack is well known and feared in practice. The mechanisms for mesa attack has been discussed by several researchers [6, 14, 20]. In our loop experiments at 60-90 °C initiation of mesa attack occurred only when water was saturated or supersaturated with corrosion products (iron carbonate). In those cases protective films form. When these films are damaged locally mesa attack can probably be initiated because a galvanic cell is established where the film covered surface is cathodic and the mesa attacked area is anodic. The hydrogen reduction reaction on the cathodic film covered area increases the pH in the film and the film is therefore stabilised. If the main part of the cathodic reaction takes place on the film covered surface the pH in the mesa attacked areas will be less than the pH on a fresh exposed steel surface. The reformation of film on localised attacked steel therefore requires higher concentration of corrosion products in the water compared to formation of film on a fresh steel surface and is therefore difficult.

Corrosion rate prediction

Bottom of the line corrosion

Various prediction models have been developed and are used by different oil companies. Among them are the de Waard et. al model (Shell), CORMED (Elf Aquitaine), LIPUCOR (Total) and IFE-CORR (IFE). It is only the de Waard et al. model which has been released for publication in the available literature and is therefore the only one described in detail here. The corrosion rates calculated in Table 1 are based on the last published version of de Waards formulas [1].

The original de Waard and Milliams equation was published in 1975 and is based on stirred glass cell experiments carried out at 0.1- 1 bar CO_2 partial pressure and at different temperatures [15]. A modified version correcting this deficiency was published in 1990 and has later been refined and presented at the NACE conference in 1991 [2]:

$$\log CR = 8.3 - \frac{2320}{t + 273} - 0.00555 * t + 0.67 * \log (pCO_2) \qquad (2)$$

where CR is the corrosion rate in mm/year, t the temperature (°C), T is the absolute temperature, and pCO_2 is partial pressure in CO_2 bars. The equation gives the corrosion rate in <u>unbuffered</u> water at pH 3.9-4.1 when protective films do not form.

Starting from this predicted "worst case" corrosion rate, correction factors can be applied to quantify the influence of environmental parameters and of the corrosion product scale formed under various conditions. Equations are proposed for each factor. The decrease of corrosion rates caused by dissolved $FeCO_3$ is accounted for with a pH correction factor. The effect of the presence of a liquid hydrocarbon phase is included. Equations are presented which enable the effect of glycol injection on corrosion to be calculated. For many of these parameters, the correction factors are uncertain. In these cases the model usually gives conservative estimates.

The CORMED prediction model [3, 7] which qualitatively estimates the probability of corrosion attack is based on a detailed analysis of Elf Aquitaine's field experience of CO_2 corrosion. The model takes the CO_2 partial pressure, in-situ pH, Ca^{2+} concentration and the amount of acetic acid into consideration and predicts either a low risk, medium risk or a high risk of attack.

IFE has developed a model which can be used to predict corrosion rate in unbuffered water and in water with higher pH under conditions where <u>protective films do not form.</u> The model is based on a large number of loop experiments where the effect of pH, flow rate, temperature, CO_2 partial pressure, amount of corrosion products in the water and the composition of the steel have been studied. The input parameters in the model are:

- pH
- flow rate expressed as a mean-wall-shear stress
- temperature
- CO_2 partial pressure
- composition of steel (Cr content in the range 0-1.4 %)

The model is developed within a multiclient project and is not yet released for publication.

Top of the line corrosion

In gas/condensate pipelines the corrosion rate will vary from the top to the bottom of the pipe. In top of line corrosion, the most important rate determining parameters are condensation rate, temperature and CO_2 partial pressure. An example on how the corrosion rate is influenced by the cooling rate is shown in Figure 6. It is seen that the corrosion rate increased very much with increasing difference between steel wall temperature and the flowing gas temperature.

The water condensing on the inner pipe wall is rapidly saturated with corrosion products. The pH in the water will therefore increase and more or less protective corrosion films covering the steel surface are formed. These films reduce the corrosion rate. A constant corrosion rate is obtained when the corrosion rate has been reduced so much that it is balanced by the rate at which corrosion products are transported away from the surface by the condensed water.

A simple model has been developed at IFE [11, 13]. The model is based on laboratory experiments. From these experiments it was shown that the corrosion rate could be calculated when the condensation rate and the solubility of iron carbonate in the condensed water is known.

$$Cr = k \cdot P_{con} \cdot C_{FeCO_3}$$

where P_{con} is the condensate rate and C_{FeCO_3} is the amount of dissolved iron carbonate in the water. At moderate dewing rates, the water will always be saturated with dissolved $FeCO_3$. At high temperature where protective iron carbonate films are formed the dissolved iron carbonate concentration will be below or close to the thermodynamic solubility which can be easily calculated.

At lower temperatures much more $FeCO_3$ can be dissolved in the water due to a high supersaturation. An increase in corrosion rate can therefore take place when the temperature is reduced even though the condensation rate is lower. The necessary input parameters for the model are temperature profile, condensation profile, and CO_2 partial pressure.

At moderate condensing rates <0.25 (g/m² s) the corrosion rate will probably be less than 0.1 mm/year over a wide range of CO_2 partial pressures (0-12 bars) and temperatures (20-100 °C).

It is also possible to calculate the 12 ' clock corrosion rate from the de Waard and Lotz [1] equation as a condensation factor has been included in the last version of the formula. The factor F_{cond} is equal to 1 for high condensation rates (= 2.5 g/m² s) and is reduced to $F_{cond} = 0.1$ when the condensation rate is less than 0. 25 g/m² s. The factor is regarded as conservative.

High corrosion rates in case of top-of-the-line-corrosion can be mitigated by the following actions: Reducing the cooling rate of the pipe by insulation, reducing the dew point with glycol, methanol etc. avoiding cold spots, and applying inhibitors.

MEANS TO REDUCE MATERIAL LOSS IN MULTIPHASE PIPELINES

In the following text alternative methods to reduce the corrosion rate of carbon steel in transport lines for hydrocarbons to acceptable level are discussed. The methods suggested are:

- Application of corrosion inhibitors
- Prevention of hydrate formation
- Reduction of water wetting
- Increase of the pH
- Reduction of the temperature
- Reduction of the CO_2 partial pressure
- Selection of optimised materials
- Avoidance of flow obstacles

Some of these measures are described in more detail below.

Application of corrosion inhibitors

Traditional inhibitors contains surface active compounds which adhere to the metal surface and prevent corrosion. This type of inhibitors will loose their efficiency above a certain wall shear stress. This limit is determined by the aggressivity of the environment and the type of inhibitor. Although high flow velocities improve inhibitor distribution, the production rate should not be so high that inhibitors are removed from the surface. This situation has been experienced in production tubes, but most probably is not a problem in pipelines. For smooth pipes inhibitor efficiency is sometimes quoted to be as high as 95 %. However, wall-shear forces increase drastically for surface irregularities like weld beads and corrosion pits. It is advised therefore to assume an inhibitor efficiency of not more than 80 % at these locations.

Inhibitor distribution in a gas condensate pipeline is a matter of special concern since the corrosion rate is expected to be different in the bottom and at the top of the line. Water and oil soluble inhibitors may protect the bottom of the line. According to our knowledge gas phase inhibitors, which can efficiently prevent the top of the line, are not available. The situation can be improved by pigging at regular intervals and by increasing the gas flow rate to increase the droplet generation. Annular mist flow may be achieved in short pipelines with large pressure drops. In that case the whole circumference of the pipe is covered by the inhibitor.

Prevention of hydrate formation

It has been shown that DEG, MEG and methanol (used as hydrate preventers) can reduce the corrosion rate considerably. A/S Norske Shell has proposed to use DEG in the TROLL pipeline as the main corrosion preventer. According to Shell, diluting the water with 80 % DEG reduces the corrosion rate with 90 % while 50% DEG reduce the corrosion rate approximately 70% [1]. Glycol reduces the corrosion rate, most probably by reducing the water concentration. In order to reduce the top of line corrosion the glycol must be transported first from the liquid to the gas phase and then from the gas to the condensing liquid film on the wall or impact the wall as a droplet. The condensing water may after a sufficient times wash the glycol out of the gas phase - in that case the top of the line is left unprotected.

Reduction of water wetting

Most oil wells produce some water already from the beginning. The amount of water will increase over the lifetime. It is not easy to predict potential corrosion from the amount of produced water, since it depends strongly on water wetting of the wall and flow conditions. "Free" water may be contained within an oil emulsion as long as the flow is sufficient to entrain the water and give a continuous oil film at the steel surface. The amount of water which can be so entrained depends upon the type, viscosity and temperature of the oil, some oils being capable of carrying as much as 30% water in an oil emulsion [1]. M. Wicks and J.P. Fraser found that most oils can safely entrain a minimum water cut of 20% as long as the flow velocity is above the critical level of typically about 1 m/s [16]. Operational experience has shown that stagnant regions where water may accumulate, such as low points in piping, are at risk even at water cuts below 5%.

So far there are no models available which can predict water wetting of the wall as function of fluid composition and flow regime. The conservative approach is to assume full water wetting and calculate corrosion rate as function of the various parameters described previously.

Increase of the pH

When Crolet and Bonis several years ago compared various fields with different fluid properties they found that pH was the parameter that gave the best correlation with corrosion rate. In many cases pH gave even a better correlation than the CO_2 content [3]. This finding has later been confirmed and explained via extensive loop experiments. It has been shown that increased pH has a large impact on protective film formation and the corrosion rates. At high pH (6-7) protective films are more easily formed because the solubility of Fe^{2+} is reduced several orders of magnitude (<<1ppm) below the solubility in pure water and CO_2. The low solubility implies that the films can not be easily dissolved. The films can therefore only be removed mechanically (flake off) or be eroded away. Results from exposures in a two-phase gas-water loop at IFE is given in Figure 7. It is seen that increasing pH from 5 to 6 led to a drastic reduction in corrosion rate. The protective film was not destroyed after 4 weeks exposure with severe slugging.

The pH can be increased artificially in gas condensate lines by adding pH stabilisers together with the hydrate preventer (glycol, methanol etc.). Elf Aquitaine has studied artificial increase of pH for several years and actually applied this method with success in a field in the Netherlands. Elf Aquitane Norge A/S has for the last year conducted a comprehensive test program at IFE to determine the optimum amount of pH stabiliser required to handle the corrosion problems foreseen in sub-sea lines in the Lille-Frigg field. The predicted corrosion rate without inhibitors will be in the range of 10-20 mm/year, as seen from Table 1. With pH stabiliser this is reduced to acceptable levels. Details on this pH stabilising method will be published by Elf Aquitaine Norge A/S in the near future. The method appears to be very promising for wells with low contents and no formation water.

Environmental considerations may limit the use of more traditional inhibitors in the future. The pH-stabilisers can be regenerated at the platform and re-used. It is also possible to search for chemicals that will increase pH without having any detrimental effect on the environment. Norsk Hydro and Statoil are now evaluating such alternatives for the Snøhvit pipeline.

Reduction of the temperature

The corrosion rate will normally increase with temperature up to about 80 °C. One possible way to reduce corrosion is therefore to reduce temperature. This can be done by using stainless steel pipe without thermal insulation in the first part of the line where temperature is high and continue with carbon steel when the temperature has reached a low acceptable value. However, this solution has its drawbacks. The condensed water is pure without any corrosion products and will be very aggressive, for well streams with high CO_2-content. A rough estimate of several of the fields described in Table 1 indicate that the water will have a pH of about 4 when it comes in contact with the carbon steel. Estimated corrosion rate may be in the range of 5-10 mm/year for a CO_2 pressure of 5 bar even at a temperature as low as 30 °C. If the water contains small amount of formation water, higher pH is obtained and lower corrosion rate is predicted. Further, the coupling of carbon steel to duplex or stainless steel may increase the corrosion rate of the carbon steel close to the coupling by a galvanic effect.

Reduction of the CO₂ pressure

Reduction of the total pressure to the half by choking will reduce the CO_2 partial pressure correspondingly. The corrosion rate is also reduced, but at a lower rate. Generally, reduced total pressure will reduce the corrosion rate. The question arises if this is an economically feasible solution of the problem. This solution is considered for the Sleipner field with up to 9 mol % CO_2.

Selection of optimised materials

From various studies of CO_2 corrosion of steels it can be concluded that chromium presence in the steel is found to be most effective in improving the corrosion resistance [12, 17]. Significant effects occur even for small amounts of chromium as shown in Figure 8. Too high chromium contents can be detrimental for the welding properties, so an optimum amount of chromium is being search for. Pipeline material with 0.5 % Cr is presently being considered for offshore use by several oil companies in Norway.

The effect of Ni is being more disputed. Experiments at IFE shows conclusively that Ni in base material and weldments leads to higher corrosion rates than without Ni. However, Conoco researchers recommend a minimum level of nickel and copper for production tubing [18]. The effect of Ni in CO_2 corrosion of carbon steel has practical significance since nickel alloyed filler material is often used for metallurgical reasons. It is important therefore to distinguish how this element affects the corrosion behaviour.

No general recommendation can be given as to the steel micro-structure. Jasinski [19] and Stegman et al. [20] have shown that the carbide phase in the steel affects the adherence of the $FeCO_3$ film. It is also known that a pure Fe_3C can increase the corrosion rate by a galvanic action under conditions with small amounts of corrosion products in the water. This effect is responsible for the drastic increase in corrosion rate shown in the first part of the exposure, Figure 7. Experiments at IFE have shown that this effect can last for weeks and that the effect increases with carbide film thickness.

Avoidance of flow disturbances

In the vicinity of flow disturbances such as grooves and welds the local turbulence level can be significantly increased. This can destroy protective films locally and increase the corrosion rate considerably. It is also well known that water wets the wall more readily after obstacles and in bends. The welding methods and other design and construction procedures should be selected to minimise the flow disturbances in the pipeline.

CONCLUSIONS AND RECOMMENDATIONS

At the present time, available corrosion prediction models have uncertainties which will be gradually improved as more laboratory and field data accumulate. Also more fundamental models that integrate water chemistry and transport phenomena are under development and will be helpful tools in the future.

An important aim is to be able to predict under which conditions and where in a pipeline the surface is water wet. Carefully designed experiments to determine water wetting around the pipe geometry in a three-phase flow loop are required. Such experiments have been initiated at IFE. Water wetting under various flow regimes will be modelled on the basis of these experiments.

Field studies related to the initiation and development of localised attack should be given highest attention. When localised attack is possible the local corrosion rate is generally so high that carbon steel can not be applied. In order to understand the initiation of localised attack it is necessary to understand how films form and how the film stability is influenced by small variation in the micro structure and steel composition.

The steel composition and structure have a considerable impact on the corrosion rate. This is of special importance for detailed understanding of the corrosion of welds. Experiments for optimisation of welding consumables and welding methods for carbon steel are required.

The pH stabilising method appears to be a very interesting approach allowing the use of carbon steels where stainless steel would otherwise be selected. Cost savings can be several hundred millions NOK per pipeline. In order to utilise the new knowledge a joint effort from reservoir engineers, fluid flow and corrosion specialist is important.

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Table 1. Estimated corrosion rates of carbon-manganese steels for some fields in the Norwegian sector of the North Sea developed or considered for multiphase transport

Field Operator	Type	Distance km	CO_2 content mol %	Operating pressure bar	Max temp. °C	Calculated pH	Design lifetime years	Estimated corr.rate mm/year	Start-up time
Tommeliten Statoil	Oil/Gas	12	3	235	90	6.1	20	11.2 (90°C) 14.8 (67°C)	1988
Snøhvit Statoil Norsk Hydro	Gas/cond.	147	6	120	60	Sat.*	20	14.0	> 1995
Lille-Frigg Elf Aquitaine	Gas/cond.	22	2.4	440	80	Sat.*	20	12.6 (80°C) 14.6 (68°C)	1993
TOGI Norsk Hydro	Gas	48	0.2	100	55	Sat.*	20	5.1	1991
TROLL Norske Shell	Gas	63	0.4	115	55	Sat.*	20	8.7	1996
Sleipner West Statoil	Gas/oil	12.5	9	150	90	6.8 (1 bar CO_2 20°C)	30	11.8 (90°C) 18.5 (56°C)	1994/95

The corrosion rates are calculated on the basis of the most recent de Ward et al. nomograms [6]

*The pH at $FeCO_3$ saturation has been used in the calculation.
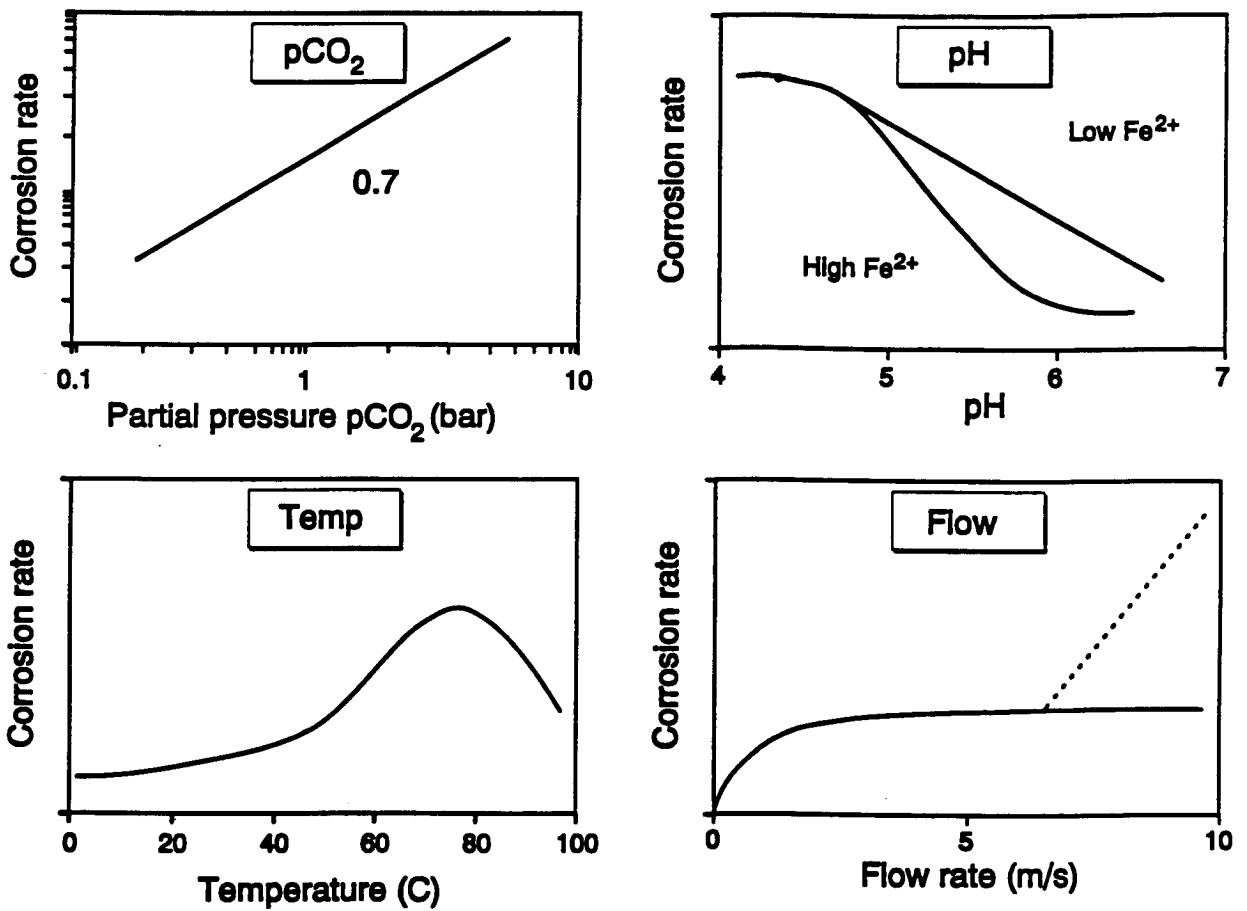
Figure 1.   Schematic illustration of the effect of various parameters on CO_2-corrosion of carbon steel.
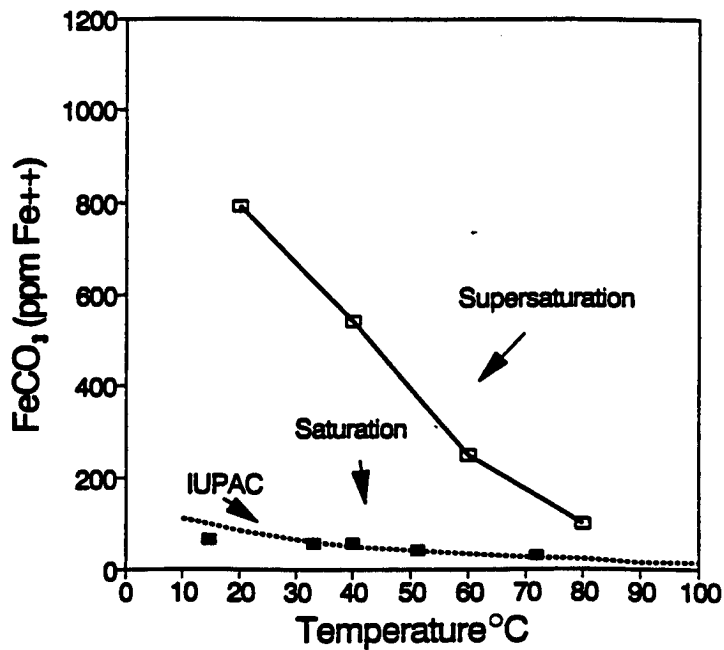

Figure 2.   Concentration of dissolved $FeCO_3$ in pure water as a function of temperature at 1 bar CO_2 partial pressure. Open squares represent results obtained with corroding steel present, where the water volume to steel surface area ratio is 4 cm^3/cm^2. Filled squares are results obtained when solid $FeCO_3$ only is dissolved. The dashed line is iron carbonate solubility calculated from thermodynamic solubility data (IUPAC).
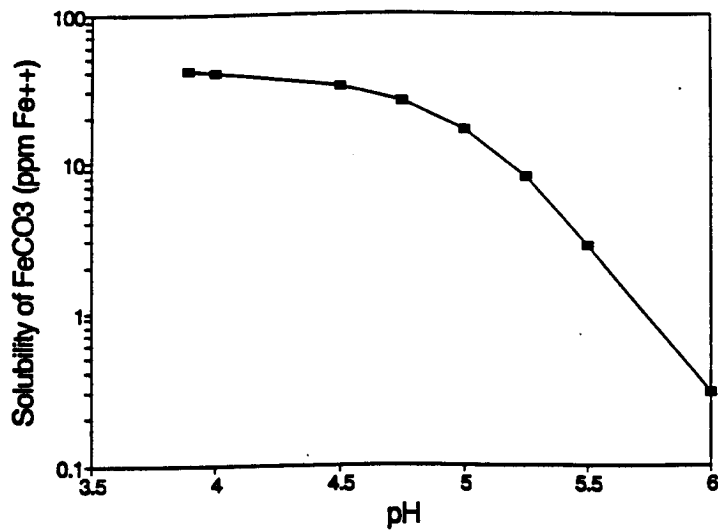
Figure 3.   Amount of $FeCO_3$ which can be dissolved in water containing no Fe^{2+} as a function of pH at 2 bar CO_2 partial pressure and 60ºC.
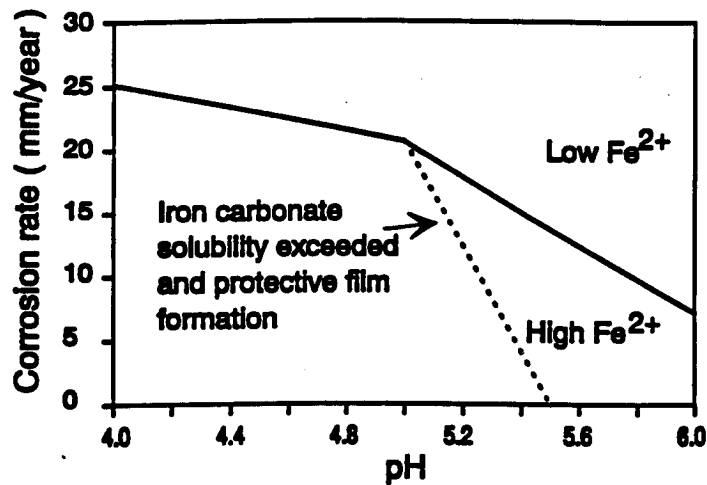
Figure 4.   Corrosion rate of API N80 steel as function of pH obtained at approximately 2 bar CO_2 partial pressure, 60ºC and with low and high concentration of dissolved $FeCO_3$.
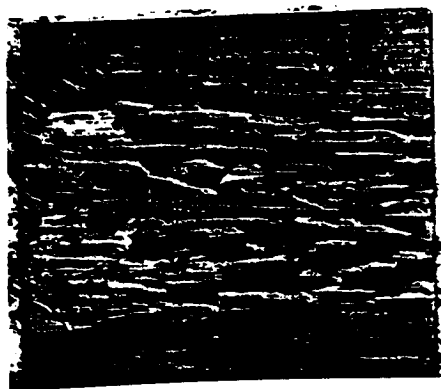

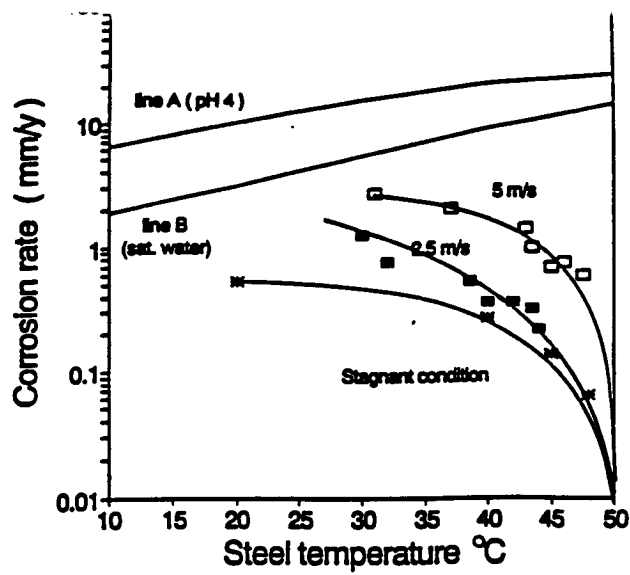Figure 5.   Mesa attack of a carbon steel exposed at 90ºC, Fe^{2+} saturated water and 2 bar CO_2 partial pressure.

Figure 6.   Vapour phase corrosion at different gas velocities as a function of steel temperature. Gas temperature is 50°C. pCO_2 = 5 bar. Line A and B represents calculated corrosion rate for St.52 steel in slowly flowing pure water and near Fe^{2+} saturated water, respectively.
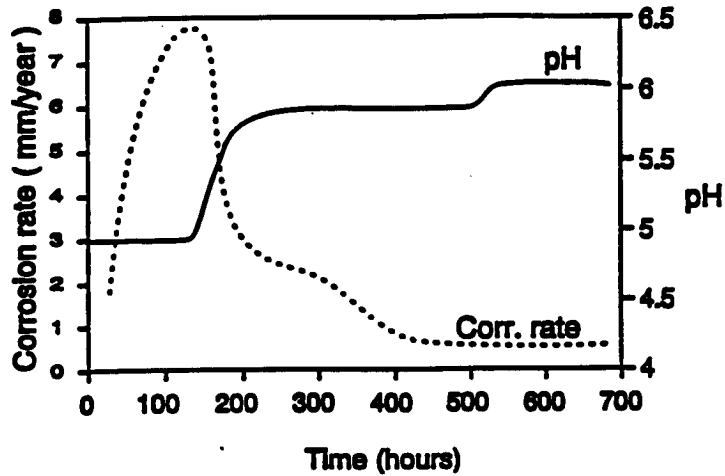

Figure 7.   The effect of pH adjustment on corrosion rate of carbon steel in a two-phase flow gas water loop. 1 bar CO_2 pressure partial 40°C.
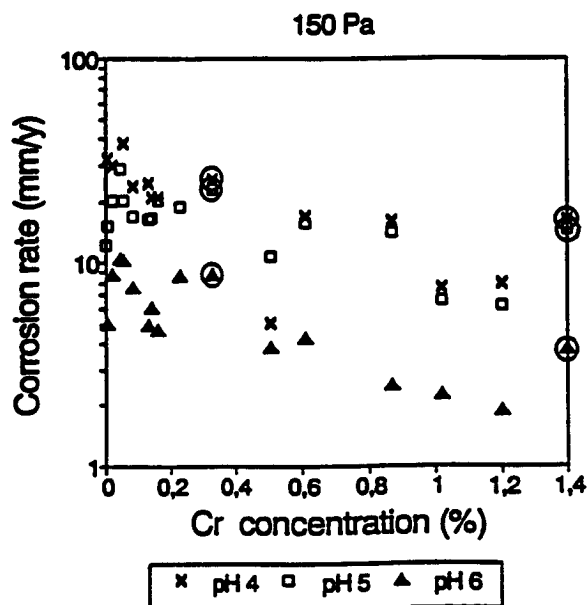

Figure 8   Corrosion rate as a function of the chromium content in the steel. The steels were exposed at 60°C, 2 bar CO_2 partial pressure and flowrate 8.5 m/s (shear stress 150 Pa). Two steels containing 3.35% and 1.45% Ni, respectively, are indicated with a circle.