

Control of internal corrosion in multi-phase oil and gas pipelines

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CONTROL OF INTERNAL CORROSION IN MULTI-PHASE OIL AND GAS PIPELINES

IN MANY subsea projects under development the pipeline costs are a considerable part of the investment and often become prohibitively high if the corrosivity of the fluid necessitates the use of higher-quality steel than carbon steel. The selection of the steel is often based on corrosion-rate calculations with models which, in many cases, are conservative and cause disregard of carbon steel under conditions where it could be adequate. Better understanding and control of the corrosion of carbon steel can increase its application range and therefore have a large economic impact. The phenomena associated with material loss in a multi-phase 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 fields of special concern. Some of the fields which are developed or being considered for transport of unprocessed hydrocarbons in the Norwegian sector of the North Sea are briefly described, and new aspects of internal corrosion management of flow, or pipelines for specific fields, are discussed.

INTRODUCTION

Multi-phase production will have a major impact on offshore development during the next 10-15 years. In the past, the emphasis has been on processing the multi-phase mixture by separation on platforms situated close to the wells. Drastic reductions in both investments and operating costs can be achieved if unprocessed, multi-phase, well streams are transported in carbon steel pipelines from satellite wells to main platforms, or from neighbouring fields to existing installations or to onshore processing facilities.

One important aspect of multi-phase flow is to avoid serious material loss caused by corrosion and erosion, or a combination of these two processes. For transport lines in the North Sea, CO₂ corrosion is the major problem, and the present paper is limited to cover this specific aspect. The paper summarizes 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.

A brief description of some of the fields which are developed or being considered for transport of unprocessed hydrocarbons in the Norwegian sector of the North Sea is given in Table 1. Multi-phase transport over distances as long as 150km is presently being considered for future fields.

Short flowlines with multi-phase flow have been in use in the North Sea for 15-20 years. Phillips Petroleum experienced serious corrosion in some of its 2-3-km long lines in the mid-1970s. The problem was solved by a carefully-selected inhibitor program. It is 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 *Tommelitten* pipeline, duplex stainless steel was selected to handle the high CO₂ content. The flowline has been in operation for six years. The first Norwegian multi-phase pipeline of a significant length was the 20-in, 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 multi-phase flow development in the North Sea have fluid properties giving high corrosion rates for carbon-manganese steels. This applies for instance for the *Snobvitt* and *Sletpner* fields (Table 1), where conservative corrosion-rate predictions give unacceptably-high corrosion rates in the range 10-20mm/year. Selection of stainless steel will solve the technical problem, but add considerably to the costs.

In many of the subsea projects under development the pipeline costs are a considerable part of the investment. The economic impact of improved understanding and control of the corrosion of carbon steel is large. Having one pipeline built in carbon steel instead of stainless steel can result in several hundred millions NOK in investment cost savings.

Oil companies have spent much time and effort world-wide in understanding and solving the CO₂-corrosion problem of carbon steel in oil and gas production. In Europe, Shell and Elf Aquitaine have been particularly active and published data which have contributed significantly to the understanding of the phenomenon[1-7]. Institutt for energiteknikk (IFE) has for years carried out extensive research on CO₂ corrosion of carbon steel in projects conducted for oil companies and material suppliers[8-14].

CO₂ CORROSION - VARIOUS TYPES OF ATTACK

Corrosion-rate-determining parameters

CO₂ 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 which are listed below:

- temperature
- CO₂ partial pressure
- flow (flow regime and velocity)
- pH
- concentration of dissolved corrosion product (FeCO₃)
- concentration of acetic acid
- water wetting
- metal microstructure (welds)
- metal prehistory

The detailed influence of these parameters is still poorly understood and some of them are closely linked to each other. A small change in one of them may influence the corrosion rate considerably. If, for example, temperature (90°C), CO₂ partial pressure (2 bar), velocity (4m/s) and pH (5.0) are kept constant, while the amount of corrosion product in the water phase is varied, corrosion rates in the range < 1-20mm/year can be obtained. This is attributed to changes in the properties of the thin layer of corrosion products and scale which always accumulate on the steel surface. The morphology and the composition of this layer (Fig.1) determine whether the attack is worst-case corrosion, low corrosion under protective films, or mesa corrosion. The layer also seems to interact with the inhibitor transport to the surface and therefore plays an important role for the inhibitor performance.

'Worst-case' corrosion

The porous layer shown in Fig. 1a is iron carbide (Fe_3C) which remains unattacked on the steel surface when the iron phase in the steel corrodes and dissolves. This type of film does not give protection and can, under certain conditions, increase the corrosion rates due to galvanic effects. When very-small amounts of corrosion product deposit on the surface, or a porous film like the one shown in Fig. 1 is formed, generally very-high uniform-corrosion rates are obtained, even at low temperatures and high pH. The general trend for the effect of CO_2 content, temperature, flow, and pH under such conditions is illustrated in Fig. 2. 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.

Corrosion with protective film

When the solubility product for iron carbonate and other scales are exceeded, these constituents can precipitate and deposit on the steel surface giving a dense and protective film as indicated in Fig. 1b. It is seen that the porous film shown in Fig. 1a has been filled with precipitate (FeCO_3) close to the metal. The prediction of corrosion rates when films with protective properties are formed is much more complicated than worst-case predictions, due to the probabilistic nature of film formation. The challenge then is to predict if film formation is kinetically hindered, if the film can be removed mechanically, and if new film will form when a protective film has been destroyed locally.

The film formation is strongly dependent on the solubility and precipitation of iron carbonate, which again is influenced by temperature, pH, flowrate, 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, and the most important findings have been published [1]. 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 realize in order to understand the different mechanisms taking place when carbon steel corrodes.

Localized corrosion

Localized corrosion (so-called 'mesa' corrosion) in pipelines and flowlines is the most-feared type of corrosion attack in practice. The attack is characterized by the formation of severely-corroded regions separated with sharp steps from neighbouring areas with much less attack (Fig. 3). Mesa attack develops when the steel surface is partly covered with a protective film (Fig. 1c). The attack is usually associated with high flowrates. However, experiments have shown that localized attack can also be initiated and propagate under semi-stagnant conditions [14]. The mechanism is based on a fine balance between film growth and film dissolution or mechanical film removal. The corrosion rates in the mesa-attacked areas are somewhat higher than those obtained on steel without protective films. The higher corrosion rate is attributed to the galvanic cell established between the non-attacked and the attacked areas.

Some flowlines from fields in the Norwegian sector have recently suffered serious localized attacks. In one case, penetration rates as high as 5-10mm/year were observed, and a replacement had to be undertaken. The attack was not of the mesa type, but more like the serious pitting or crater formation shown in Fig. 4. The line had been in operation for some years without problems. Changes in the well composition over time led to more-aggressive conditions giving unacceptably-high corrosion rates.

The actual penetration rate of localized corrosion is a useful fact to know, but for practical purposes it is more important to understand the underlying mechanism and to be able to predict when and where localized corrosion will be initiated, and how it can be prevented. This will be one of the important challenges for the future.

PREDICTION MODELS

Bottom-of-the-line corrosion

Various prediction models have been developed and are used by different companies. Among them are the de Waard *et al.* model (Shell), CORMED (Elf Aquitaine), LIPUCOR (Total), and a new electrochemically-based model developed at IFE. Due to the complexity of the various corrosion controlling mechanisms involved and a built-in conservatism, the corrosion models often over-predict the corrosion rate of carbon steel. It is likely therefore that carbon steel is disregarded in applications where it could have been adequate.

The Shell model (de Waard *et al.*) is most commonly used. The first version was published in 1975[1]. The model has been revised several times since, in order to make it less conservative, by including new knowledge and information[2]. The original formula of de Waard and Milliams implied certain assumptions which necessitated the application of correction factors for the influence of environmental parameters and for the corrosion product scale formed under various conditions.

The corrosion rate calculated from the original formula with its correction factors is independent of the liquid velocity. To account for the effect of flow, a new model was proposed[3] which takes the effect of mass transport and fluid velocity into account by means of a so-called resistance model:

$$\frac{1}{V_{corr}} = \frac{1}{V_r} + \frac{1}{V_m} \quad (1)$$

The resistance model combines a maximum possible mass-transfer rate V_m (expressed in mm/y) at a given fluid velocity with a maximum possible kinetic (e.g. charge transfer) rate V_r . V_{corr} is the predicted corrosion rate in mm/y.

In multi-phase turbulent pipeline flow, V_m depends on the velocity and the thickness of the liquid film, while V_r depends on the temperature, CO_2 pressure, and pH. For example, for a pipeline steel containing 0.18% C and 0.08% Cr, the equations for V_r and V_m for liquid flow in a pipeline are:

$$\log V_r = 4.93 - \frac{1191}{t + 273} + 0.58 \log pCO_2 - 0.34(pH_{actual} - pH_{CO_2}) \quad (2)$$

and

$$V_m = 2.45 \frac{U^{0.8}}{d^{0.2}} pCO_2 \quad (3)$$

where t is the temperature ($^{\circ}C$), U is the liquid velocity (m/s), d is the hydraulic diameter (m), pCO_2 is the CO_2 partial pressure (bar), and pH_{CO_2} is the pH of pure water in equilibrium with CO_2 at the prevailing conditions.

These equations represent a best fit to a large number of flow loop data measured at IFE[9]. For other steel compositions and metallurgies, corrections have to be made. A more-detailed discussion will be present elsewhere[15].

The CORMED prediction model[7], which qualitatively estimates the probability of corrosion attack, is based on a detailed analysis of Elf Aquitaine's field experience on 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 for attack.

At IFE a new predictive model of CO_2 corrosion is made, based on modelling of individual electrochemical reactions occurring in a water - CO_2 system[13]. In the present stage, this model takes into account the following electrochemical reactions: hydrogen ion reduction, carbonic acid reduction, direct water reduction, oxygen reduction and iron dissolution. It applies for the case

when no surface films are present. The constants in the model were determined based on a large number of electrochemical corrosion experiments in glass cells and a glass loop conducted at IFE. This electrochemical model was tested against some of the previously-mentioned models, and it performed similar to the 1993 version of the model of de Waard and Lotz[3] without losing the physical picture of the underlying mechanisms. This theoretical approach will be continued by adding a transport model, which takes into account the fact that a multitude of electrochemical, chemical, and transport processes occur simultaneously. Development of such a model is proposed for a new multi-client project at IFE (KSC-V project), and will enhance our understanding and prediction capabilities for the case of corrosion under surface films.

Top-of-the-line corrosion

In gas/condensate pipelines the corrosion rate will vary from the top to the bottom of the pipe. The most-important rate-determining parameters in top-of-the-line corrosion are condensation rate, temperature, and CO_2 partial pressure.

The water condensing on the inner pipe wall is rapidly saturated with corrosion products. The pH in the water will therefore increase and cause formation of more or less protective corrosion product films covering the steel surface. These films can 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 condensing water.

IFE experiments have shown that the corrosion rate can be calculated when the condensation rate and the solubility of iron carbonate in the condensed water are known, and a simple model was developed[10]. At moderate condensing rates ($< 0.25\text{g/m}^2\text{s}$) the corrosion rate will be less than 0.1mm/year over a wide range of CO_2 partial pressures (0-12 bars) and temperatures (20-100°C).

It is also possible to calculate corrosion rate from the Shell model as a condensation factor is included. The factor F_{cond} is equal to unity for high condensation rates ($= 2.5\text{g/m}^2\text{s}$) and is reduced to $F_{\text{cond}} = 0.1$ when the condensation rate is less than $0.25\text{g/m}^2\text{s}$. The factor is regarded as conservative.

High corrosion rates can be mitigated by the following actions: reducing the cooling rate of the pipe wall, reducing the dewpoint with glycol, methanol etc., avoiding cold spots, and applying inhibitors. It seems to be generally accepted that no serious corrosion problems have been experienced in gas pipelines with CO_2 only, but that traces of H_2S have led to attacks in a few cases.

REDUCING MATERIAL LOSS IN MULTI-PHASE PIPELINES

In the following we will discuss alternative methods for reducing the corrosion rate to an acceptable level in carbon steel transport lines for hydrocarbons. The methods suggested are:

- apply corrosion inhibitors
- apply hydrate preventers
- reduce water wetting
- increase the pH
- reduce the CO_2 partial pressure
- select optimized materials
- avoid flow disturbances

Some of these measures are commented upon below. The most obvious and traditional method is to apply corrosion inhibitors.

Apply inhibitors

Traditional inhibitors contain surface-active compounds which adhere to the surface and prevent corrosion. This type of inhibitor will lose its efficiency above a certain wall shear stress.

This limit is influenced by the aggressiveness of the environment and the type of inhibitor. High flow velocities improve inhibitor distribution, but the production rate should not be so high that inhibitors are removed from the surface. This situation has been experienced in production tubes, but is most probably not a problem in pipelines. For smooth pipes, inhibitor efficiency is sometimes quoted to be as high as 95%. However, shear forces and turbulence levels increase drastically for surface irregularities like pipe fittings, weld beads, and corrosion pits, leading to less-efficient inhibition. The term 'inhibitor efficiency' has been much used, but is not well defined and can be misleading. The trend nowadays is, therefore, rather to focus on the ultimate performance of the inhibitor, which is what really matters.

The inhibitor performance is strongly dependent on the flow conditions, the water and oil chemistry, the treatment rate, and the composition and morphology of the corrosion products and the scale which cover the steel surface. The influence of many of these variables are complex and poorly understood, and it is out of the scope of this paper to go into a detailed discussion.

Apply hydrate preventers

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 (36-in gas pipeline in the North Sea) as the main corrosion preventer. According to Shell, diluting the water with 80% DEG reduces the corrosion rate in the bottom of the line by 90%, while 50% DEG reduces the corrosion rate by approximately 70%[3]. Glycol reduces the corrosion rate, most probably because it reduces the water concentration on the wall.

In the top of the line where fresh water is condensing, the corrosion rate is only affected by glycol if the glycol is transported first from the liquid to the gas phase, and then from the gas to the condensing liquid film on the wall, or if it impacts the wall as a droplet. IFE was engaged by Shell to study if glycol could reduce the top-of-the-line corrosion in the *Troll* pipeline. Experiments with radioactively-marked glycol showed that the glycol added for hydrate prevention most probably reached the top of the pipeline, and ensured that an acceptably-low corrosion rate can be achieved in the pipeline[17].

Reduce water wetting

Most oil wells produce some water right from the beginning of production. This amount of water will increase over the well's lifetime. It is not easy to predict possible corrosion from the amount of water, since water wetting of the steel wall depends on the type, viscosity, density and temperature of the oil, interfacial tension between water and oil, and local flow conditions. As a rule of thumb, it has been assumed that most oils can entrain a minimum water cut of 20% as long as the flow velocity is higher than 1m/s^2 [16]. However, unexpected pipeline failures have shown that this is not always the case.

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

Increase 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 a better fit than CO_2 content. This finding has later been confirmed and explained via extensive loop experiments, see Fig.5. 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 by several orders of magnitude ($\ll 1\text{ppm}$) below the solubility in pure water and CO_2 when the pH is increased (Fig.6). The low solubility also implies that protective films will not be easily dissolved. Protective films, once formed, can therefore only be removed mechanically (flake off), or by erosion.

The pH can be increased artificially in gas-condensate lines by adding pH stabilizers alone or 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 [18]. Elf Aquitaine Norge A/S has conducted a comprehensive research program at IFE to determine the optimum amount of pH stabilizer required to handle the corrosion problems foreseen in a sub-sea lines in the *Lille-Frigg* field in the North Sea. The predicted corrosion rate without inhibitors will be in the range of 10-20mm/year, as seen from Table 1. With MDEA as pH stabilizer, the corrosion rate is reduced to acceptable levels.

The pH stabilization technique can be an interesting alternative for many gasfields. From an environmental point of view, MDEA is not the ideal pH stabilizer. A research project partly financed by the Norwegian Research Council and five oil companies has therefore been initiated at IFE, in which the aim is to investigate if it is possible to use environmentally-friendly alkaline chemicals, such as bicarbonate and ammonia, instead of MDEA.

It is important to note that the pH stabilization method is restricted to condensed water only. When formation water is present, heavy scaling can take place.

Reduce CO₂ pressure

Reduction of the total pressure by half by choking will reduce the CO₂ partial pressure correspondingly. The corrosion rate is also reduced, but at a lower rate. Generally speaking, reduced total pressure will reduce the corrosion rate. The question is whether this is an economically-feasible solution to the problem. This solution is discussed for the *Sleipner* field in the North Sea which contains up to 9mol% CO₂.

Avoid flow disturbances

The local near-wall turbulence level can be significantly increased behind grooves and at obstacles such as weld beads. This can destroy the protective corrosion product films or the inhibitor film locally, and increase the corrosion rate considerably. It is also well known that water separates out more easily after obstacles and in bends. The welding methods and other design and construction procedures should be selected to give a minimum of flow disturbances in the pipeline.

Select optimal carbon steels

Various studies have shown that chromium can improve the corrosion resistance of carbon steels. Significant effects occur even for small amounts in chromium level, as shown in Fig. 7. Too-high chromium contents can be detrimental for the welding properties, so an optimum amount of chromium is being searched for. Pipeline material with 0.5% Cr is presently being considered for offshore use by several oil companies in Norway, and has been selected for the production and water-injection lines on the *Tordis* field.

The effect of Ni is being more disputed. Experiments at IFE show consequently 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 [19]. The effect of Ni in CO₂-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 structure. Jasinski [20] and Stegman *et al.* [21] have shown that the carbide phase in the steel affects the adherence of the FeCO₃ film. It is also known that a pure Fe₃C can increase the corrosion rate by galvanic action.

Select corrosion-resistant alloys (CRAs)

Stainless steels are generally immune to well fluids with high CO₂ and salt concentration, and can be an alternative material for especially-aggressive wells. Duplex stainless steel was actually selected for the 12km long *Tommeliten* pipeline, for which corrosion rates of about 15mm/year were expected. Also, for high-pressure pipes, stainless clad carbon steel pipes have been considered and such pipes were selected for a minor field in the British sector of the North Sea in the 1980s. The price difference between stainless steel and carbon steel is considerable, so a large incentive exists for finding improved solutions for safe use of carbon steel, particularly for aggressive well streams.

COST COMPARISONS

The final selection of pipeline material is based on the optimal balance between cost and acceptable corrosion allowance considerations for safe operation over the estimated lifetime. The costs of the corrosion-resistant alloys (CRAs) will increase with the amount and type of alloying additions. The more corrosion resistant the steel, the higher is the price. Equally important for selection of material is its strength. Flowlines and pipelines will have an internal pressure normally varying from 100 to 300 bars, so strength and wall thickness are important factors for cost estimation. Table 2 compares the price of various stainless steels relative to carbon steel, showing that stainless steel can cost up to 10 times more than carbon steel. The high-strength materials are preferred, and the material most-commonly considered is the 22Cr duplex steel. The less expensive 13Cr steel could give sufficient corrosion protection for many applications, but its poor welding properties restrict the use of this material. New welding methods for 13Cr steel are under development, which will lead to significant cost reductions if they prove to be successful.

The use of carbon steels with stainless cladding has caught increased interest lately, particularly for high-pressure pipes where thick walls are required. Stainless clad carbon steels can now be installed for the same or lower costs than 22Cr duplex steel.

Material cost is one of many factors that influences the total cost for a completed pipe or flowline. Other costs of importance are:

- mobilization costs before laying;
- costs for external corrosion protection, weight addition, and thermal insulation;
- laying costs including welding;
- costs for connections to platform or underwater installation;
- costs for shore connections;
- burying and gravelling costs;
- pressure-testing costs;
- costs for the equipment and supply pipes for chemicals.

The use of carbon- or stainless steel will influence the various cost factors differently. When stainless steel is selected, no corrosion allowance is required, nor supply pipes for chemicals. Operational costs are much higher for carbon steels, including chemicals, corrosion control, and internal inspections.

We have asked oil companies for comparative cost figures for fields under evaluation or in operation. We can not refer to figures from specific fields, but there seems to be reasonable agreement in the cost figures given by the various oil companies. Fig.8 gives the difference in total costs for a stainless and carbon steel pipeline as function of pipeline length or distance. The figures give the total costs of the installed pipeline before it is taken into operation. For the 22-km long 12-in *Lille-Frigg* flowline, the cost savings by selecting carbon steel were in the range of NOK 200million. Another oil company found cost differences in the same order. For two 10-in flowlines, cost differences were NOK 100-200 million for distances in the range of 10-20km.

As expected, the difference increases with pipeline length. Evaluation from 1987 for a 140-km long, 34-in pipeline gave cost estimates of 2.5 billion NOK for a carbon steel line compared to 6.5

billion NOK for the stainless alternative. The use of stainless steel in long-distance lines may therefore be prohibited from an economic point of view, and this fact indicates the strong demand for acceptable solutions to reduce CO₂ corrosion and ensure safe use of carbon steel pipelines.

CONCLUSIONS AND RECOMMENDATIONS

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.

The water production increases with time and originally non-corrosive fields can lead to serious problems after some years of production. An important aim is to predict under which conditions and where in a pipeline corrosion will occur. Three-phase flow models including water are available, but so far only bulk compositions are modelled. Carefully-designed experiments to determine water wetting around the pipe circumference 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 localized attack should be given highest attention. The local corrosion rate is generally so high that carbon steel can not be applied when localized attacks take place. In order to understand the initiation of local attack it is necessary to understand how films form and how the film stability is influenced by small variations in the microstructure and steel composition.

The pH stabilizing method appears to be a very interesting approach for gas-condensate fields, allowing the use of carbon steels where stainless steel would otherwise be the only choice. Cost savings can be several hundred millions NOK per line. For oilfields more-traditional inhibitors are used to keep the corrosion rate at an acceptable level. A challenge for the future is to find more environmentally friendly inhibitors that can give sufficient corrosion protection.

Another cost-efficient challenge is to improve and develop new welding techniques for low-cost stainless steels (13Cr) to allow the use of this material in flowlines.

A joint effort from reservoir engineers, fluid-flow experts, and materials' specialists is important in the future. The reservoir engineers must supply the corrosion specialist with better information about the amount and composition of produced water and oil. The fluid flow experts can contribute by developing better models which describe the water behaviour in different oil and condensate mixtures. Without such information corrosion rates are calculated based on 100% water wetting with fresh water contacting the wall continuously. Such calculation may be very conservative in many cases and cause disregard of carbon steel under conditions where it could be adequate.

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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 (90 °C) 15 (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	13 (80 °C) 15 (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	897	1996
Sleipner West Statoil	Gas/oil	12.5	9	150	90	6.8	30	12 (90 °C) 19 (56 °C)	1994/95

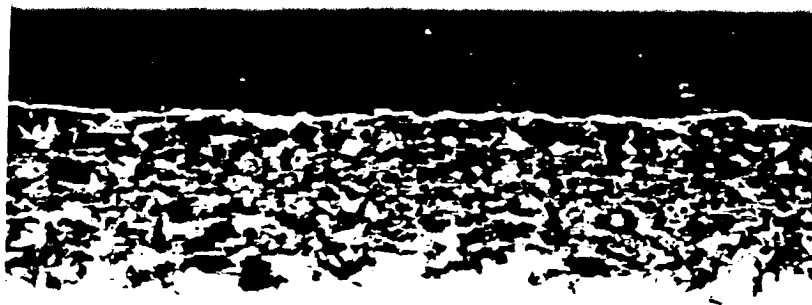
The corrosion rates are calculated with 1993 version of the Shell model².

*The pH at FeCO₃ saturation has been used in the corrosion rate calculation.

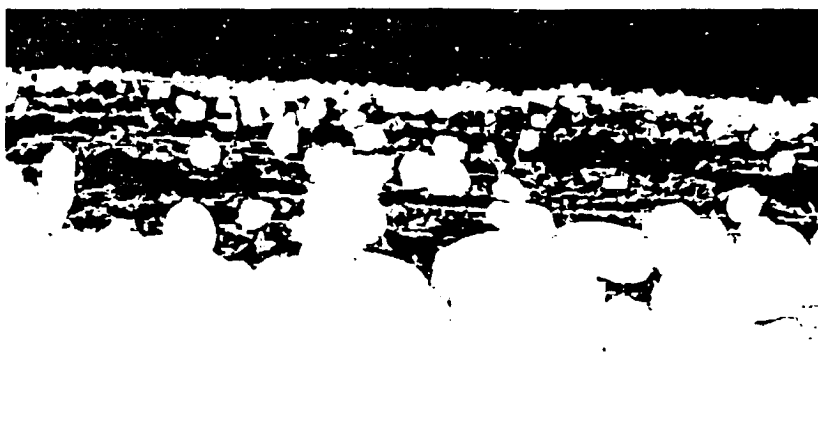
Table 1. Estimated corrosion rates of carbon-manganese steels for some fields in the Norwegian sector of the North Sea being developed or being considered for multi-phase transport.

Material	Cost factors on weight basis	Cost factors on strength basis
Carbon steel	1	1
13%Cr (AISI 420)	2	1.8
Mo-free Duplex	4	4
Stainless (316L)	4-6	9-14
22% Cr - Duplex	6-8	6-8
25% Cr - super-Duplex	9-11	7-9
Stainless (254SMo)	10-12	15-18

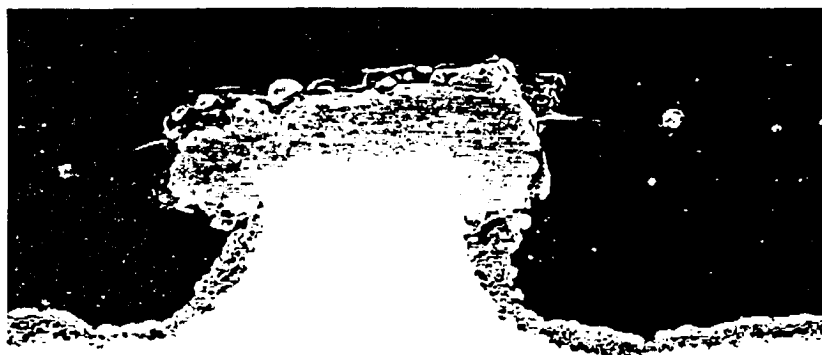
Table 2. Rough cost factors of stainless steels relative to carbon steel as a general guide. The figures are based on 1992 prices.



KSC10-90M25E
0001 20KV X500 100µm WD39



KSC11-90ML52
0001 20KV X250 100µm WD42



KSC21-90M52E
0002 20KV X150 100µm WD34

Fig.1. Cross section of carbon steel exposed at 2 bar CO_2 partial pressure.

- a) Porous Fe_3C film formed at 20°C .
- b) Porous film filled with protective iron carbonate formed at 80°C .
- c) Steel surface partly covered with protective film formed at 80°C

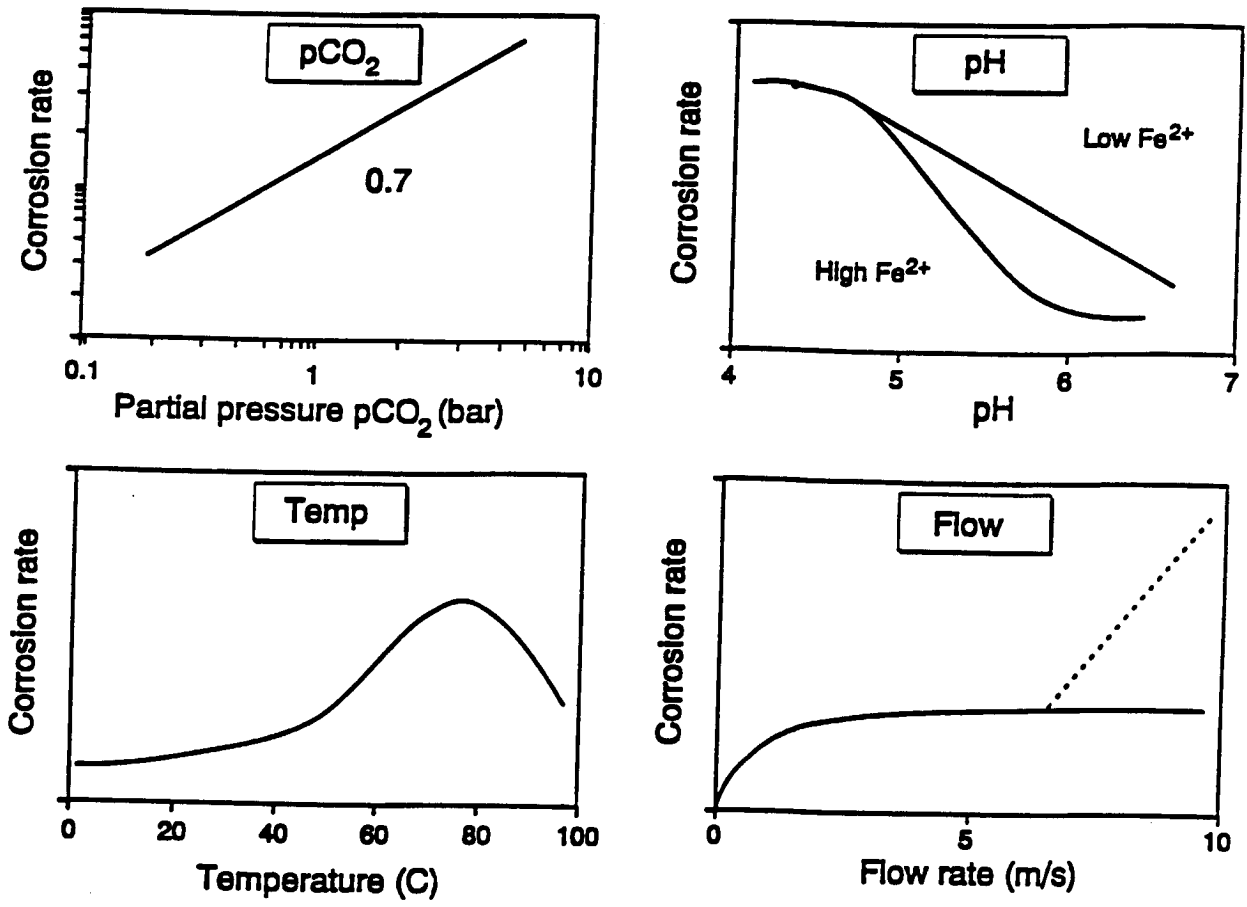


Fig.2. Schematic illustration of the effect of various parameters on CO₂-corrosion of carbon steel.

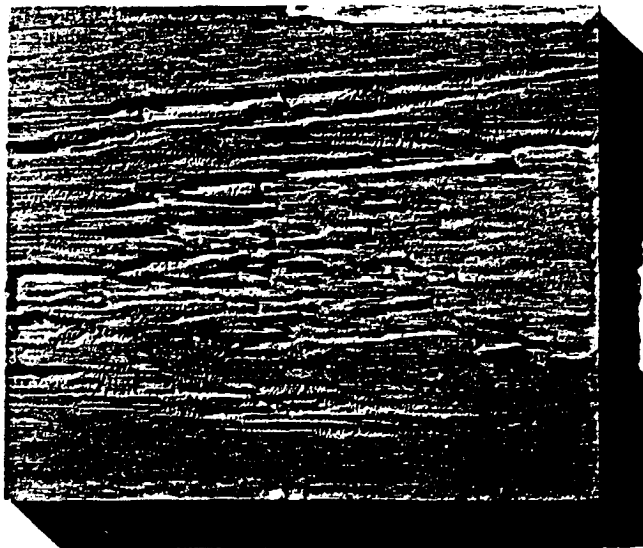


Fig.3. Carbon steel suffering mesa attack during exposure at 80°C, 2 bar CO₂ partial pressure, and a flow velocity of 6.8m/s.

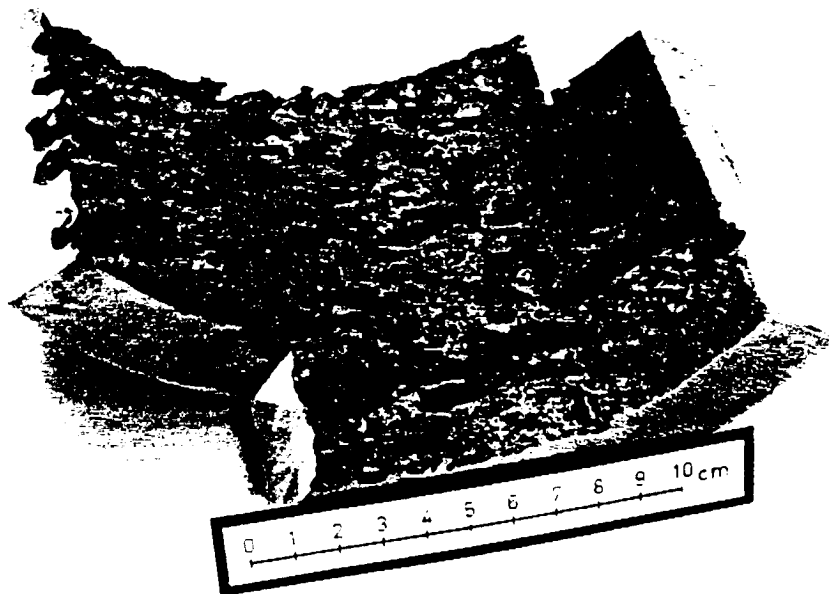


Fig.4. Carbon steel from a field in the North Sea. The penetration rate was 5-10mm/year.

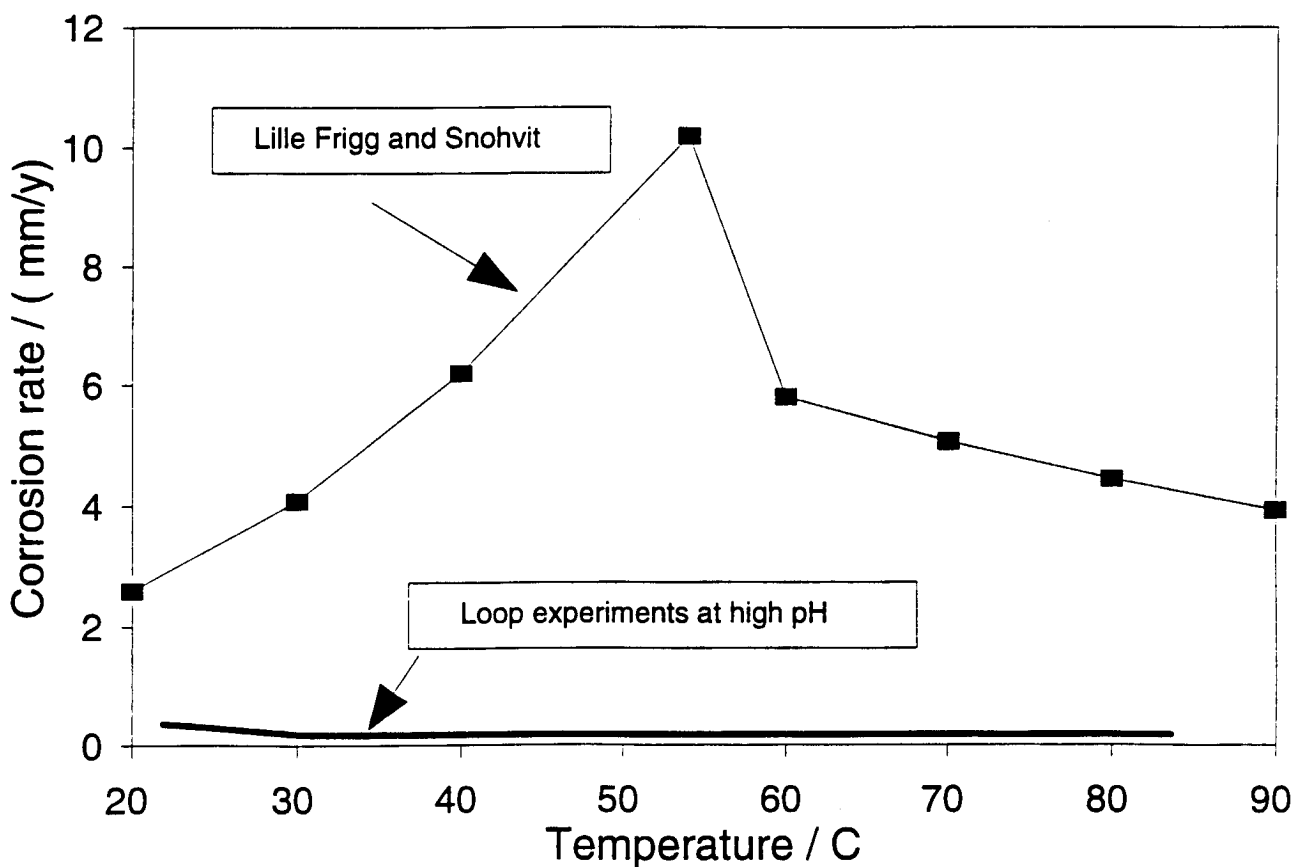


Fig.5. Corrosion rate calculated with the Shell model for Snohvit and Lille-Frigg conditions (Table 1) when 50% DEG is added to the water phase. The bottom line shows the corrosion rate obtained under similar conditions in corrosion-loop experiments when the pH is increased to 6.5 by adding MDEA.

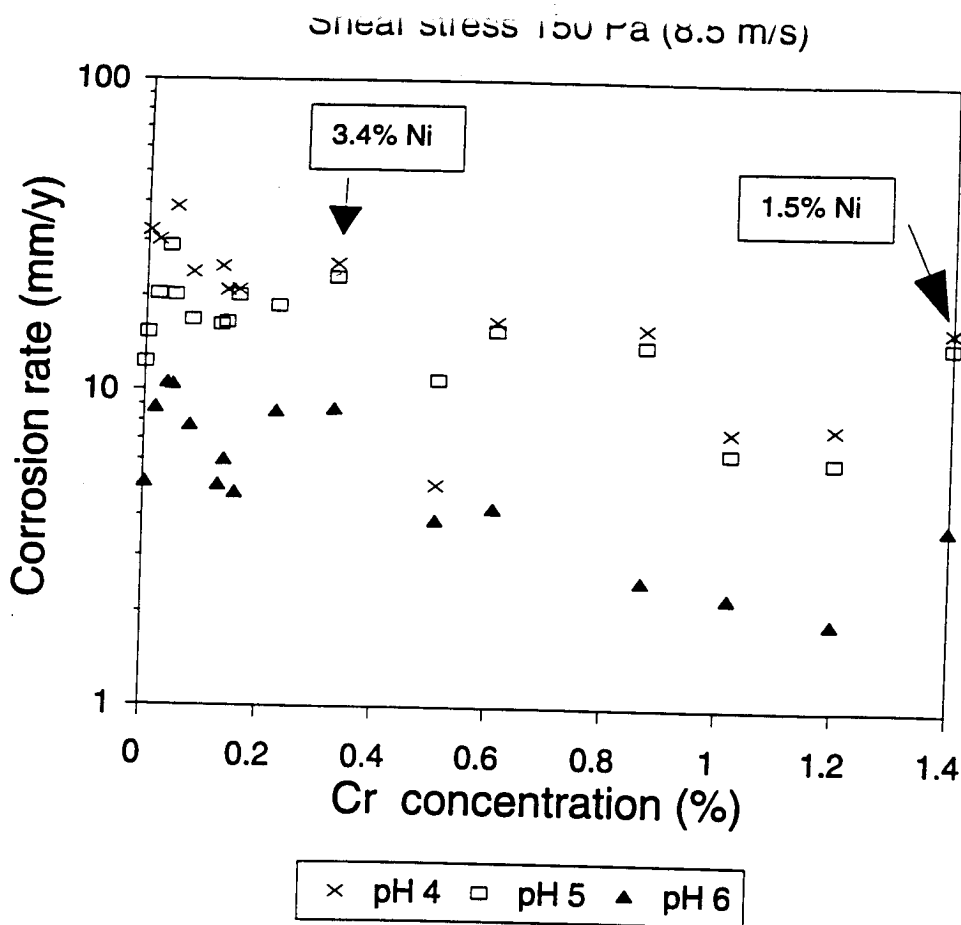


Fig.7. Corrosion rate as a function of the chromium content in the steel. The steels were exposed at 60°C, 2 bar CO₂ partial pressure and flowrate 8.5m/s (shear stress 150Pa). Two steels containing 3.35% and 1.45% Ni, respectively, are indicated.

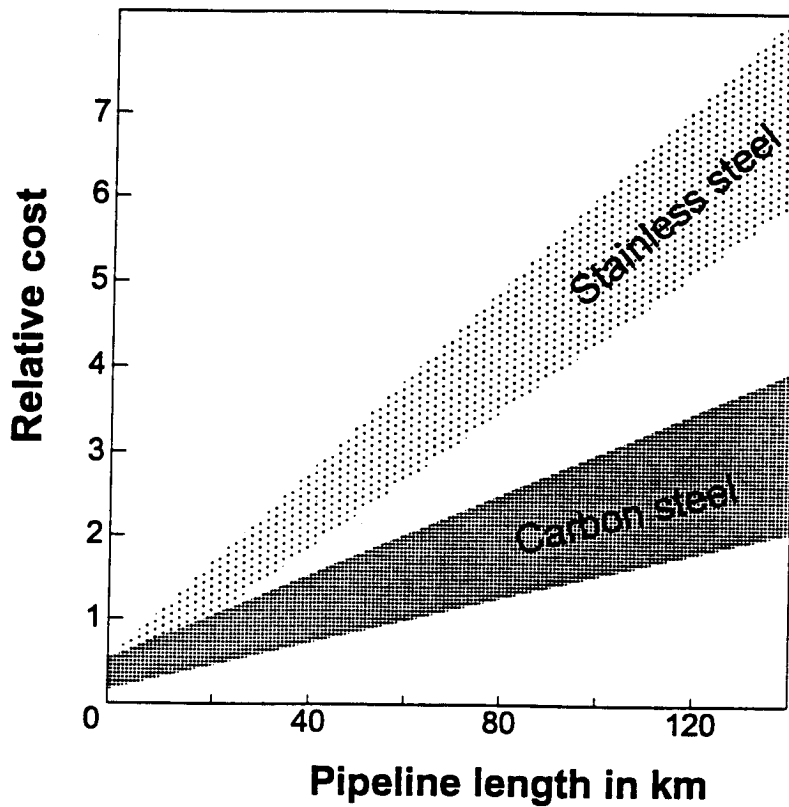


Fig.8. Relationship between total cost for pipelines in stainless steel and carbon steel as a function of length. The figures are collected from various oil companies and include material and all installation costs.

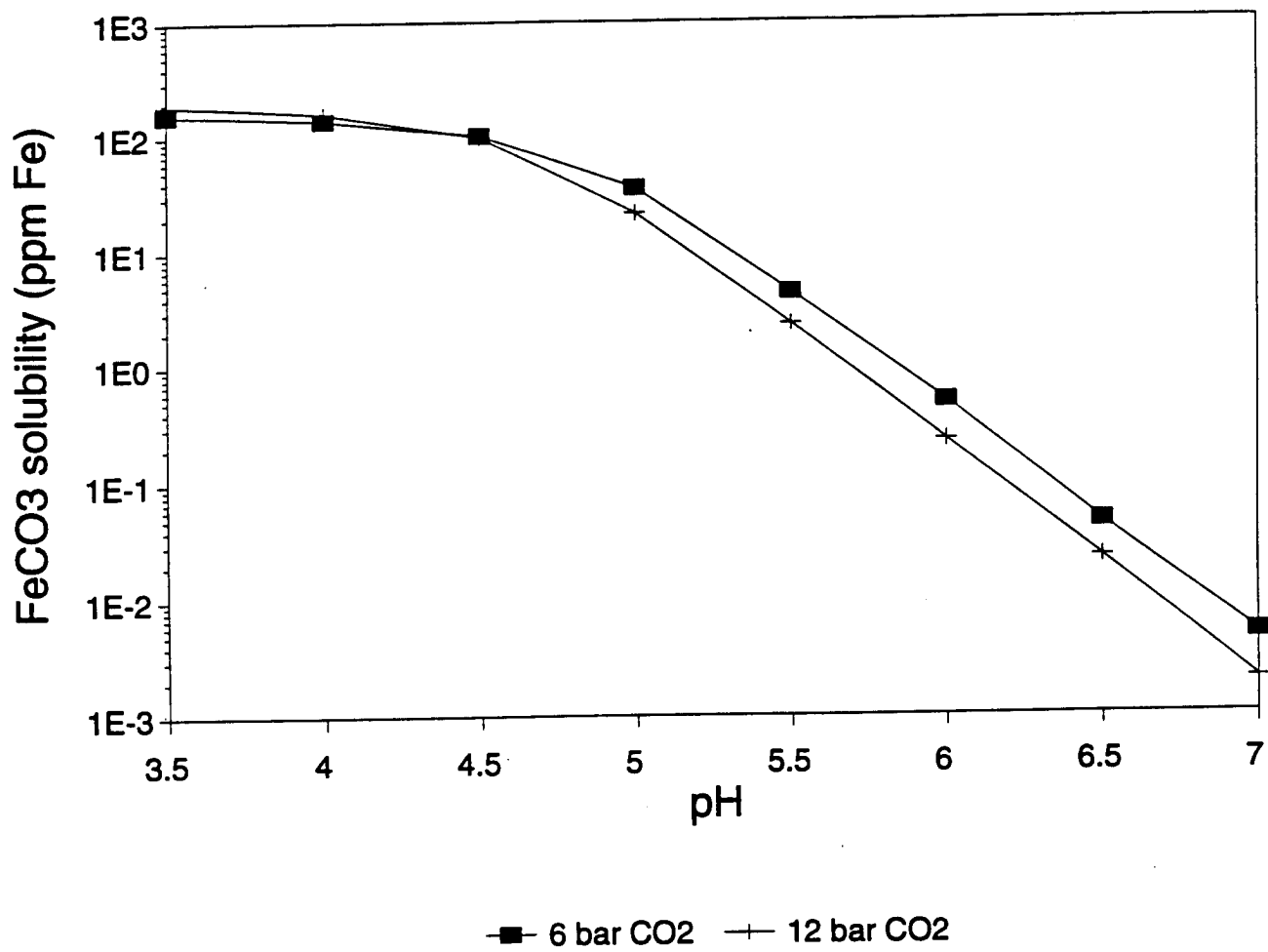


Fig.6. Solubility of iron carbonate in water with 6 and 12 bar CO₂ partial pressure respectively when the pH has been increased with MDEA.