

Controlling Internal Corrosion in Oil and Gas Pipelines

a report by

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Multiphase transport will have a major impact on offshore development during the next decade. In the past, emphasis was placed on processing the multiphase well stream through separation on platforms close to the wells. Drastic reductions in both investments and operating costs can be achieved when unprocessed, multiphase well streams can be transported over longer distances in carbon steel pipelines from subsea wells to main platforms, existing installations on neighbouring fields or onshore processing facilities.

The pipeline costs are a considerable part of the investment in subsea projects, and for long-distance, large-diameter pipelines, they can become prohibitively high if the corrosivity of the fluid necessitates the use of corrosion-resistant alloys instead of carbon steel. Better understanding and control of the corrosion of carbon steel can increase its application range and therefore have a large economic impact.

The presence of carbon dioxide (CO₂), hydrogen sulphide (H₂S) and free water can cause severe corrosion problems in oil and gas pipelines. Internal corrosion in wells and pipelines is influenced by temperature, CO₂ and H₂S content, water chemistry, flow velocity, oil or water wetting and composition and surface condition of the steel. A small change in one of these parameters can change the corrosion rate considerably, due to changes in the properties of the thin layer of corrosion products that accumulates on the steel surface.

When corrosion products are not deposited on the steel surface, very high corrosion rates of several millimetres per year can occur. The corrosion rate can be reduced substantially under conditions where iron carbonate (FeCO₃) can precipitate on the steel surface and form a dense and protective corrosion product film. This occurs more easily at high temperature or high pH in the water phase. When H₂S is present in addition to CO₂, iron sulphide (FeS) films are formed rather than FeCO₃, and protective films can be formed at lower temperature, since FeS precipitates much easier than FeCO₃.

Localised corrosion with very high corrosion rates can occur when the corrosion product film does not

give sufficient protection, and this is the most feared type of corrosion attack in oil and gas pipelines. An example of this type of localised corrosion attack in a pipeline is shown in *Figure 1*. The line had been in operation for several years without problems, but changes in the well composition over time led to more aggressive conditions, resulting in unacceptably high corrosion rates. In order to control the corrosion in pipelines, it is important to understand the underlying corrosion mechanisms and be able to predict whether localised corrosion will be initiated and how it can be prevented.

Prediction of Internal Corrosion in Pipelines

Several prediction models have been developed for CO₂ corrosion of oil and gas pipelines. The models are correlated with different laboratory data and, in some cases, also with field data from oil companies. The models have very different approaches to accounting for oil wetting and the effect of protective corrosion films, which can give large differences in behaviour between the models. It is important to understand how the corrosion prediction models handle, particularly, the effects of oil wetting and protective corrosion films when the models are used for corrosion evaluation of wells and pipelines.

In a joint industry project (JIP) at the Institute for Energy Technology (IFE), the different CO₂ corrosion prediction models have been evaluated and compared with actual field data gathered from the participating oil companies. This project showed that the different models can give markedly different corrosion rate predictions for the same field case, and which models were most successful in their prediction varied considerably from case to case. It is not possible to declare one or two models as better than the others. It is, however, important to understand the differences between the models in order to interpret the predictions. In particular, the effects of protective corrosion films and oil wetting are modelled quite differently in the various models, and these two effects may shift between very high and very low predicted corrosion rates. There is inevitably a high degree of uncertainty in these predictions, and

Figure 1: Local Corrosion Attack in Oil Pipeline from the North Sea

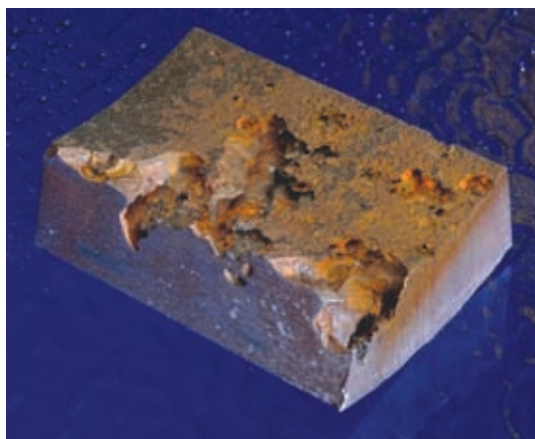
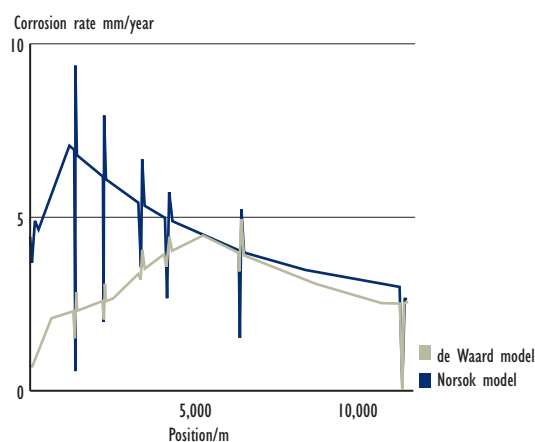


Figure 2: Predicted Corrosion Rate in a Subsea Pipeline



no model should be believed to have more than $\pm 50\%$ accuracy for a wide range of conditions.

An example of corrosion rate prediction in a subsea gas condensate pipeline is shown in *Figure 2*. Here, two of the most commonly used corrosion prediction models were combined with a three-phase fluid flow model in order to calculate corrosion rate profiles along a pipeline. This can help to identify locations where variation in flow regime, flow velocity and water accumulation may increase the risk of corrosion damage. For this pipeline, the temperature was 90°C at the inlet and 20°C at the outlet, and the decrease in predicted corrosion rates towards the end of the pipeline is mainly a result of the decreasing temperature. The lower corrosion rates close to the pipeline inlet are due to the effect of protective corrosion films at high temperature, which is predicted differently by the two corrosion models used. The peaks in predicted corrosion rates result from variation in flow velocity due to variations in the pipeline elevation profile.

Even with considerable uncertainties in the corrosion prediction models, the uncertainty in the required

input parameters will, for practical field situations, often be even higher. When the prediction models are used in the design phase of a project, the available input data are often very limited. The actual water chemistry may not be known in detail, and the predicted temperature, pressure and flow velocity profiles for the lifetime of the installation may be very uncertain. In many cases, formation water samples are very scarce during the first well tests. Another uncertainty is when and how much formation water will actually be produced.

The pH Stabilisation Technique

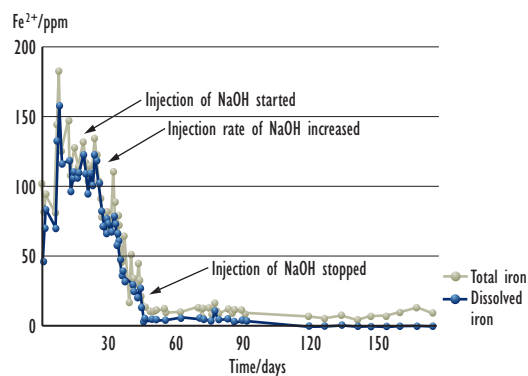
The corrosion rate in gas condensate pipelines can be substantially reduced by increasing the pH of the water phase. The technique is called pH stabilisation and it has been used successfully in several gas condensate pipelines. Corrosion rates below 0.1mm/year have been achieved, even with CO_2 partial pressures higher than 10bar. The reduction in corrosion rate is based on a pH increase in the water phase, which enhances the precipitation of protective corrosion product films on the steel surface. The pH stabilisation technique is well suited for use in combination with glycol as hydrate preventer, because the pH stabiliser will remain in the regenerated glycol. This means that there is no need for continuous renewal of the pH stabiliser.

Experiments for qualification of the pH stabilisation technique at the IFE have shown that protective films form in a short time at temperatures between 40°C and 100°C , reducing the corrosion rate to less than 0.1mm/year . At lower temperatures, around 20°C , the FeCO_3 precipitation is very slow, and it may take several months to obtain protective corrosion films. However, the initial corrosion rate is low at 20°C and high pH, and it can be acceptable to wait a few months for a protective corrosion film to form.

A major application for the pH stabilisation technique is the Troll pipelines. The Troll field is the largest gas field in the North Sea. The field started operating in 1996. The gas has a low CO_2 content of 0.3%, and it was decided to perform a simple processing with only removal of free water offshore. This solution meant that wet gas with CO_2 had to be transported in two 91.5cm pipelines over a distance of 65km from the platform to shore. Monoethylene glycol (MEG) is injected at the pipeline inlet in order to control hydrate formation and corrosion. The target was to reach a corrosion rate of less than 0.2mm/year .

During the first year of production, precipitation of corrosion products from the pipeline started to create problems in the onshore glycol regeneration units. The dissolved iron from the pipeline caused formation of scales on the surfaces in the heat exchangers and boilers, and particles that settled in

Figure 3: Iron Content after pH Stabilisation of the Troll Pipelines



Fe²⁺ = ferrous iron, NaOH = sodium hydroxide.

low-flow areas such as tanks, drums and slug catchers. The estimated amount of corrosion products was 20t the first year of operation. This was not regarded as a corrosion problem in the pipelines, but as a process problem in the onshore processing plant. In order to reduce the amount of dissolved corrosion products in the pipeline and avoid a costly rebuilding of the gas processing plant, the operator, Statoil, decided to reduce the corrosivity in the pipelines further by applying the pH stabilisation technique.

The pH at the outlet of the pipelines prior to pH stabilisation was close to 6. Based on results from laboratory testing and calculations at the IFE, it was decided to increase the pH in the pipeline to 7.4. This was achieved by injecting a sodium hydroxide (NaOH) solution into the lean MEG tank. The concentration of dissolved iron, which has the potential to form scale in the process equipment, was reduced from approximately 100 parts per million (ppm) to less than 5ppm after six weeks, as shown in Figure 3. This corresponds to a corrosion rate far below 0.1mm/year. Very little precipitation takes place in the process system today, and the system has been operated with success since the treatment was carried out in 1997.

The main limitation of the pH stabilisation technique is that it cannot be used for pipelines carrying large quantities of formation water, due to carbonate scale formation close to the pipeline inlet at the elevated pH. When the glycol is regenerated, the salts will accumulate in the regenerated glycol, which can also cause precipitation problems. More detailed knowledge of the kinetics of scale precipitation in glycol systems can lead to less conservative evaluation of the application limits for the pH stabilisation technique.

A newly started JIP at the IFE is focused on developing tools and knowledge for prediction of scale and particle formation in glycol systems for long pipelines carrying unprocessed wet gas.

The pH stabilisation technique has been used mostly for wet gas pipelines without H₂S in the gas, but is now being taken into use also for pipelines in the Persian Gulf, where there are considerable amounts of H₂S in addition to CO₂. There, the corrosion product depositing on the surface will be FeS instead of FeCO₃. These sulphide films have different protective properties to the FeCO₃ films forming in sweet systems. Localised corrosion in the form of pitting is the critical factor in systems containing H₂S. The application limits for the pH stabilisation technique in wet gas pipelines containing high amounts of H₂S and CO₂ are being studied in an on-going JIP at the IFE.

Use of Corrosion Inhibitors

Due to the fact that the pH stabilisation technique cannot be used for oil pipelines or gas condensate pipelines where large quantities of formation water are transported, injection of corrosion inhibitors is the most used corrosion control method for such pipelines. These are organic molecules that are added to ppm levels and form surface layers that prevent the corrosion reaction on the steel. Different inhibitors are used depending on the actual conditions in each pipeline. New inhibitors are continuously being developed to handle more aggressive conditions and comply with more stringent environmental regulations. At present, one of the largest challenges is to develop environmentally friendly corrosion inhibitors for high-temperature fields. Better understanding of the mechanisms for inhibition at high temperatures and development of better test procedures for inhibitors at high temperature are the focus of a JIP starting at the IFE in 2005.

Selection and qualification of inhibitors in the laboratory prior to implementation in the field is essential, and, most often, dedicated laboratory experiments will have to be performed with candidate inhibitors for each field or pipeline. A number of factors may influence inhibition in multiphase pipelines. Factors such as temperature, oil/water partitioning, water chemistry and flow conditions have been widely studied. In the past, less attention was given to factors such as the composition and microstructure of the steel, the type of corrosion products formed on the steel surfaces, inhibitor adsorption on suspended particles in the produced water and inhibitor accumulation on bubbles and oil/water droplets. Laboratory experiments at the IFE have shown that steel microstructure, corrosion products on the steel surface and presence of very small clay particles or oil/water emulsions can strongly affect inhibitor performance. New test methods and equipment are being developed to account for the effects of multiphase flow and steel surface conditions. ■