Health and Safety Executive

Reliable corrosion inhibition in the oil and gas industry

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Reliable corrosion inhibition in the oil and gas industry

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The objective of the work was to undertake a literature review on the subject of corrosion inhibition in the offshore oil and gas industry to understand the current issues. The application of chemical corrosion inhibitors can significantly reduce the rate of corrosion of carbon steel pipelines due to the presence of CO2 and/or H2S. An inhibited corrosion rate of 0.1 mm/year can typically be achieved, which is largely independent of the uninhibited corrosion rate.

The report covers the main factors affecting the effectiveness of chemical corrosion inhibitors; they are not effective against corrosion due to the presence of oxygen or microbacterial corrosion. High flow rates, high temperature, solids (either dissolved or suspended) and pre-existing corrosion can all have a negative effect on corrosion inhibitor effectiveness.

The role of Key Performance Indicators (KPIs), the main factors affecting the performance of inhibition injection systems, and the levels of inhibitor availability that can be assumed at the design stage and achieved in practice are also discussed.

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EXECUTIVE SUMMARY

Objectives

To undertake a literature review on the subject of corrosion inhibition in the oil and gas industry to understand the current issues.

Main Findings

- The application of chemical corrosion inhibitors can significantly reduce the rate of corrosion of carbon steel pipelines due to the presence of CO_2 and/or H_2S. An inhibited corrosion rate of 0.1 mm/year can typically be achieved, which is largely independent of the uninhibited corrosion rate;

- Various factors can affect the effectiveness of chemical corrosion inhibitors; they are not effective against corrosion due to the presence of oxygen or microbacterial corrosion. High flow rates, high temperature, solids (either dissolved or suspended) and pre-existing corrosion can all have a negative effect on corrosion inhibitor effectiveness;

- The main Key Performance Indicator (KPI) used for assessing effectiveness of corrosion inhibitors is based on the proportion of time that the correct dosage of inhibitor is applied (termed inhibitor availability);

- Maintaining a high level of availability can be difficult in the long term, due to a number of factors, the main factors being failure of the diaphragm in the pump and failure of the pressure control valves;

- The maximum availability that can safely be assumed for design calculations has been a matter of debate:

    - The NORSOK M-001 standard specifies that inhibitor availabilities above 95% should not be used in a design assessment;

    - BP Amoco have also used an upper limit of 95% availability;

    - Shell have allowed an availability of 99% to be assumed;

    - A recent paper by BP Exploration has stated that designs based on 99% availability are becoming increasingly common, and demonstrated a pilot skid that achieved 99.8% availability, albeit with an assessment time of just a few months.

- A review of inhibition availability by Ionik Consulting found that systems with target availability of over 95% were unable to achieve this level of availability, with actual availability between 85% and 95%.

1 INTRODUCTION

Pipelines are required to transport oil and gas products from the well, sometimes over long distances. In addition to oil and/or gas, it is common that wells produce other products that are likely to cause corrosion, such as water and carbon dioxide. As the pipelines often have design lives in the order of decades, steps need to be taken to ensure integrity over the life of the plant and therefore, steps need to be taken to manage the levels of corrosion.

During the design stage, decisions need to be taken on how corrosion is to be managed. There are two main options where a corrosive environment is present; 1) use corrosion resistant alloys (CRA) or 2) use cheaper carbon steel and employ corrosion reduction techniques. There is often a conflict between the capital cost (CAPEX) and the operational cost (OPEX) of plant, with CRAs being more expensive in terms of capital expenditure, but having a lower operational cost.

Chemical corrosion inhibitors can be very effective in reducing corrosion rates, with the potential to reduce corrosion rates by 99% or more given a suitable concentration of an appropriate inhibitor. Inhibitors work by forming a film on the surface of the steel, preventing corrosive attack. With corrosion rates being so much lower in the presence of corrosion inhibitor, the key in determining the overall rate of corrosion over the life of a pipeline becomes the proportion of time for which the corrosion inhibitor is available at the correct concentration.

With pressure to reduce the capital expenditure and employ carbon steel instead of corrosion resistant alloys, designers are specifying higher corrosion inhibitor availabilities to enable acceptable lifetime corrosion rates to be achieved, especially in highly corrosive environments. With higher specified corrosion inhibitor availabilities comes the requirement for more reliable corrosion inhibitor injection systems. These require sophisticated monitoring systems, reliable logistics in often remote locations, suitable backup systems and a commitment on behalf of the operator to make corrosion inhibition a priority.

Another driver for high levels of corrosion inhibition is life extension of ageing plant. This can involve the added complication of lower corrosion inhibitor efficiencies where corrosion is already present.

Pipeline failures due to corrosion could be very costly in terms of safety, environmental damage and cost. Therefore, effective corrosion inhibition is of high importance to the industry and a lot of research has been carried out on the factors affecting inhibitor effectiveness. There would appear to be less work published on the subject of practical inhibitor delivery issues.

However, a number of documents have been written as a guide to corrosion inhibition systems, such as the 1995 BP report 'Corrosion Inhibitor Guidelines; A practical guide to the selection and deployment of corrosion inhibitors in oil and gas production facilities' [1]. Although this document was produced by BP, it was written after consultation with other oil companies, such as Shell, Elf, Conoco and Statoil. More recently, the European Federation of Corrosion has published 'The use of corrosion inhibitors in oil and gas production' [2]. This report covers the basic principles of corrosion inhibition, selection and performance testing, deployment issues, suitable approaches for difference systems, and management issues.

2 CORROSION INHIBITION

Facilities for the production of oil and gas often have to cope with corrosive environments. The difficulties in protecting plant become more acute when the facilities are in a hostile and remote offshore setting. Assessment of the potential corrosion for a new facility may lead to the choice of either using corrosion resistant alloys or using carbon steels with corrosion inhibitors. For existing, ageing installations, treatment of the produced fluids with corrosion inhibiting chemicals is often the only feasible option.

The main mechanisms for internal corrosion of pipelines are aqueous corrosion caused by soluble corrosive gas, such as carbon dioxide, hydrogen sulphide, or oxygen, and corrosion influenced by microorganisms. The water can arise from being part of the original reservoir products (formation water) or from water injection used to increase pressure. Corrosion inhibitors work by forming a protective film on the metal preventing corrosive elements contacting the metal surfaces, as illustrated in Figure 1.

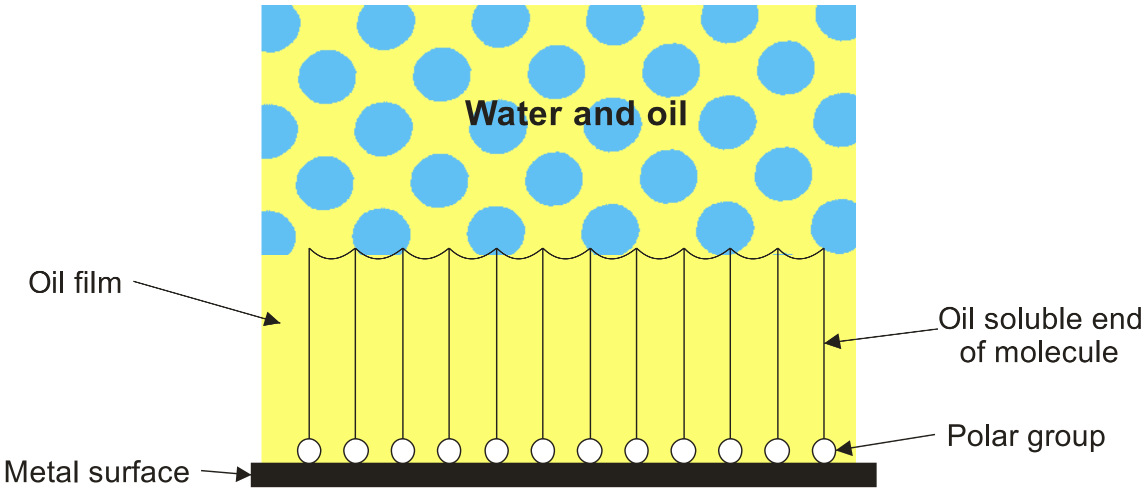

Figure 1 Simple schematic showing how inhibitor film prevents water contacting a metal surface

Corrosion inhibitors are chemical compounds that are added to a fluid to reduce the rate of corrosion in materials in contact with the fluid. For example, an inhibitor will be injected into the stream of hydrocarbons (oil or gas) near to the wellhead to reduce corrosion in the steel of the pipeline. The composition of the flow from the wellhead can vary greatly, with the water content varying from between 1 and 99%, for example, and this has a significant effect on the natural corrosion potential in the untreated system. Other factors, such as temperature and pressure also affect corrosion rates.

While corrosion inhibitors are effective against CO_2 and H_2S, if oxygen is present they are either ineffective or require very high concentrations to achieve the desired inhibited corrosion rate [3]. In these conditions, scavengers are used to remove the oxygen. Also, any water injected into the well would be treated to remove oxygen before injection.

3 FACTORS AFFECTING CORROSION RATES AND INHIBITOR EFFICIENCY

The aim of this section is to give a brief overview of the factors affecting uninhibited corrosion rates and inhibitor efficiency. There is a wealth of research into these areas and a full assessment of the latest research in all these areas is beyond the scope of this review.

The following factors have been identified as affecting the corrosion rates and inhibitor efficiency:

- Flow rate and type of flow;
- Amount of water;
- Presence of oxygen, carbon dioxide and hydrogen sulphide;
- Temperature;
- Welds;
- Pre-existing corrosion.

The BP 'Corrosion Inhibitor Guidelines' report [1] gives a basic table listing some of the process parameters which can affect corrosion rate, which is reproduced in Table 1.

Table 1 Some process parameters which can affect corrosion rate (from BP Guidance document **[1]**)

Parameter	*Change*	*Action*
Flow rates (oil/water/gas)	+ or -	Alter CI delivery rate to maintain concentration in the water
Water cut	+ or -	May increase or decrease CI delivery depending on its o/w partitioning properties
Temperature	+ -	Increase [CI] Scope to reduce [CI]
pCO_2 and pH_2S in gas	+ -	Increase [CI] Scope to reduce [CI]
pO_2 in gas	+	May need to reselect CI
pH	+ -	Scope to reduce [CI] Increase [CI], may need to reselect
Sand	+	Reselect CI and/or increase [CI], reduce velocity, install downhole sand screen

In their review paper on corrosion inhibitor developments and testing in 2004 [4], Gregg and Ramachandran make the following observations:

- When water is present, corrosion due to carbon dioxide increases with temperature to a point where precipitation of a corrosion product layer occurs;
- The greater the partial pressure of carbon dioxide, the greater the corrosion rate;
- Increased liquid velocities increases corrosion rates due to rapid transportation of reactant and product species;
- Higher liquid velocities result in greater turbulence that increases wall shear stress. This can increase corrosion due to damage being caused to coatings of inhibitor or corrosion product on the pipe wall.

3.1 PRE-CORROSION

The effectiveness of corrosion inhibitors on surfaces with pre-existing corrosion would appear to be mixed. Some reviewers have found that some inhibitors were able to penetrate deep into rusted layers (Kowata and Takahashi [5]) while some have even found an improved inhibitor performance on pre-corroded surfaces (Dougherthy and Stegman [6]). Others have found negligible effect (Hausler *et al* [7]) or a negative effect (Kapusta *et al* [8] and Gulbrandsen *et al* [9]).

Gulbrandsen *et al.* [9] investigated the effect of precorrosion on the effectiveness of corrosion inhibitors. They performed laboratory corrosion tests on carbon steel specimens using the following conditions; 20-50 °C, pH 5, 1 bar CO_2 and 1-3 w% NaCl. The specimens were allowed to corrode for up to 18 days in the medium prior to the inhibitor addition. The following conclusions were drawn from the research:

- Inhibitor performances were, in general, impaired after long period of precorrosion under the given conditions;
- Poor inhibition resulted in localised corrosion attacks with deep spherical pits;
- The detrimental effect of precorrosion is co-determined by the steel properties and the inhibitor composition. The precorrosion effect seems to be related to the presence of a cementite layer at the steel surface;
- The results showed that the problem could be overcome with careful selection of inhibitors. Therefore, when choosing inhibitors, laboratory tests should be performed on steels in a condition likely to represent those encountered during service.

3.2 FLOW CHARACTERISTICS

There are many variables affecting flow in pipelines, such as laminar or turbulent flow, continuous or slug and phase separation. These can cause particular problems for corrosion inhibition. For example, in multiphase natural gas pipelines, top of the line corrosion (TLC) can be a problem due to the difficulty of applying the inhibitor to the top of the pipe where the liquid phase does not contact, as illustrated in Figure 2. Recent work by Shen *et al* [10] has investigated inhibitors for effective TLC inhibition. They found that the first formula tested worked well in the liquid phase and protected the bottom of line (6 o'clock position) but was not effective in the vapour phase so did not provided adequate protection at the 12 o'clock position (top of line). From tests on a range of potential inhibitors, two further formulations were created and tested, and these showed promising results for the vapour phase. They concluded that further research was necessary to achieve the aim of better TOL protection.

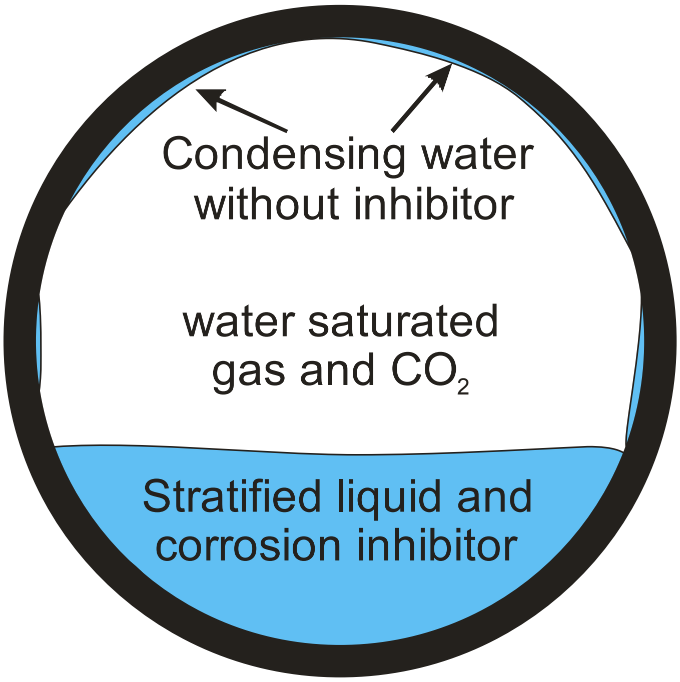

Figure 2 Schematic of possible conditions in a wet gas pipeline

The effects of flow velocities were investigated by Swidzinski *et al* [11]. They observed that in multiphase flows, the corrosion rate reduced with increases in gas velocity. The highest corrosion rate recorded in their tests was at 7.5 m/s gas velocity, where the predominant flow regime was slug flow. Since slug flow generates the highest flow turbulence, the corrosion rate was higher than for higher gas velocities, where the flow regime changes to annular flow. For single phase liquid flow, it was found that higher velocities lead to higher corrosion rates. In both cases, good inhibition was found to be possible if an appropriate inhibitor was used at the correct concentration.

The optimum inhibitor concentration may vary according to flow conditions, with higher concentrations generally required for more arduous conditions, such as high shear stress flow. However, Zvandasara [12] has shown that increasing the inhibitor concentration beyond the optimum level may have a detrimental effect on the effectiveness of the inhibitor and therefore the corrosion rate. However, no mechanism for this effect was suggested.

3.3 TEMPERATURE

As noted earlier, Gregg and Ramachandran [4] state the general observation that corrosion rates for CO_2 in the presence of water increase with increasing temperature, up to the point at which precipitation of a corrosion product layer occurs.

Singh and Krishnathasan [13] state that at low temperatures (<50 ºC) patchy corrosion occurs due to softer multi-layered iron carbonate scales, with the protection this provides increasing as temperatures increase to about 70 ºC. At higher temperatures, damaging localised corrosion is observed as films lose stability and spall off, resulting in galvanic 'mesa' attack, although for some cases there may be a downturn in corrosion rates above about 80 ºC.

Temperature is also one of the four factors included in the Inhibitor Likelihood Success Score (ILSS), [14] with increasing temperature leading to higher ILSS values, and therefore, lower likelihood of successful inhibition (see section 3.5 for more details).

3.4 CORROSION MODELS

There are numerous models available to predict corrosion rates under a variety of conditions. Detailed analysis of the different models is outside the scope of this literature review, but the following are conclusions taken from a review paper published in 2007 [15]:

- Electrochemistry of mild steel dissolution in CO_2 solutions has largely been understood and modelled, with the outstanding issues primarily related to other environments (H_2S and acetic acid (HAc), inhibitors) and different steels;

- Key mechanisms leading to the formation of iron carbonate scales have been identified. Scaling tendency is identified as the parameter that effectively describes how the competition of precipitation and corrosion can lead to both protective and unprotective surface scales. The effect of other types of scales such as calcium carbonate, etc. is still largely unknown;

- The effect of pH on CO_2 corrosion is well established and successfully modelled, both at low pH typical for condensed water as well as higher pH when protective scales form. In almost all cases higher pH leads to lower corrosion rates;

- The presence of organic acids and their effect on CO_2 corrosion is an issue that was largely ignored until recently. However, major advancements in understanding of the role of HAc have been made in the past few years with a few open issues remaining, primarily related to the effect of HAc on localized attack;

- The effect of temperature, which is well known to accelerate all processes involved in CO_2 corrosion, has been clarified. At low pH when protective scales do not form, higher temperature accelerates corrosion rates. When conditions are favourable for iron carbonate to form, higher temperature leads to faster precipitation and often to lower corrosion rates;

- A way has been charted to account for the effect of flow and in particular multiphase flow on CO_2 corrosion. The most important effect related to water wetting/entrainment is now understood from a hydrodynamic point of view. The effect of violent slug flow on protective scale/inhibitor removal needs further investigation;

- It has been shown that various mild steels have approximately the same behaviour when it comes to scale-free CO_2 corrosion. The effect on protective scale formation as well as inhibitor performance is an open issue;

- Problems related to prediction of corrosion control by inhibition remain, particularly when it comes to the performance of inhibitors in slug flow, in the presence of surface scales, H_2S or HAc;

- Systematic work on understanding of the effect on CO_2 corrosion of inhibitors present in crude oil has been initiated, with a more dedicated follow-up needed that will cover a broader range of crude oils;

- Understanding of the effect of water condensation leading to Top of line corrosion (TLC) has been advanced significantly over the past decade. Remaining challenges relate to the effect of acetic acid (HAc), H_2S as well as effective mitigation techniques;

- Only rudimentary understanding of the effect of glycol/methanol on CO_2 corrosion exists. More fundamental work is needed before any meaningful modelling can be achieved;

- Localized attack, being the most dangerous type of CO_2 corrosion attack, is still difficult to predict. While many factors such as metallurgical, hydrodynamic to (electro) chemical can influence the onset of localized corrosion, it appears that much of the evidence points towards the existence of a ''grey zone'' where localized attack is more likely to occur. The ''grey zone'' seems to be associated with the formation of partially protective scales;

- Various mathematical modelling strategies can be used to capture our understanding of CO_2 corrosion:

    - Mechanistic models are the most direct translation of our knowledge of the underlying processes into mathematical functions. They are the hardest ones to construct and have the largest potential to help engineers in various stages of the design, operation and control of inhibitor systems;

    - Semi-empirical models, which have a limited amount of inbuilt understanding, rely on correction factors to perform well. These factors come in the form of arbitrary functions developed on sparse experimental data and have dubious interactions. While being significantly easier to develop than mechanistic models, the capability of semi-empirical models to extrapolate is questionable;

    - Empirical models consisting of arbitrary mathematical functions of varying complexity, can have reasonable or even excellent interpolation capabilities but have to be treated with utmost caution when used to predict outside the calibration range.

3.5 INHIBITOR EFFECTIVENESS

The effectiveness of corrosion inhibitors for a wide range of different operating conditions was investigated by BP Exploration, Intertek CAPCIS and DNV, with the results presented at the NACE Corrosion 2011 conference [14]. They introduced an Inhibitor Likelihood Success Score (ILSS) based on four factors; operating temperature, shear stress, total dissolved solids and predicted corrosion rate. The equation for calculating the ILSS is given as:

$$ILSS = \frac{Temp(°C)}{40} + \frac{ShearStress(Pa)}{240} + \frac{TDS(ppm)}{125{,}000} + \frac{Pred\_CR(mm/y)}{10} \qquad \textbf{Equation 1}$$

A high score would indicate that chemical corrosion inhibition would be unlikely to be successful without the use of very high concentrations, as detailed in Table 2.

Table 2 Summary of Inhibition Risk Categories and guidance from Crossland *et al* **[14]**

Category	*ILS*	*Description*
1	ILS ≤ 2.5	***Highly likely that corrosion inhibition will be successful.*** In this category there are a large number of successful inhibitors, typical concentrations, in brine, of up to 50 ppm may be expected. Inhibitor testing and selection may be carried out at Execute Stage.
2	$2.5 <$ ILS ≤ 4	***Corrosion inhibition expected to be successful.*** Corrosion inhibition has been proven to be effective under these conditions, however higher concentrations are likely, typically up to 100 ppm in brine. Inhibitor testing under simulated field conditions should be carried out for chemical selection during Define or Execute Stage. Highly reliable chemical injection systems are recommended
3	$4 <$ ILS ≤ 5.5	***Corrosion inhibition will be challenging.*** These are very challenging conditions for corrosion inhibition and there are signification problems in finding successful inhibitors. Inhibition is likely to be effective but a rigorous laboratory inhibition selection program should be implemented within the Define Stage of projects. Concentrations up to about 300 ppm or more in brine may be required. Highly reliable chemical injection skids should be implemented with integrated control systems to the control room.
4	ILS > 5.5	***Inhibition may not be viable.*** Projects need to be sure that there is an inhibitor available that can perform in their specific conditions **before** selecting carbon steel plus inhibitor. There may be inhibitors for these conditions but there has been little success in laboratory tests except at very high concentrations. Inhibitor concentrations in brine in well excess of 400 ppm are likely to be needed. The validity of corrosion inhibition for corrosion control, economics of dosage and practicality of managing injection systems should be confirmed at the Select Stage through laboratory testing and risk assessment before selecting this material option. Highly reliable chemical injection skids with integrated control systems and control room alarms should be implemented.

A table of examples of field data provided by vendors was included in the paper [14]. Interestingly, the only example to be classed in category 4 had the lowest dosage of the 7 examples, with a concentration of only 50 ppm inhibitor. Unfortunately, the paper does not say whether the inhibition was successful or not.

The laboratory data used were based on sweet conditions, with the absence of solids, oxygen levels below 5 ppm and with initially clean surfaces. Also, the maximum temperature was 120 °C and the maximum shear stress was 320 Pa. The use of this approach for conditions outside those tested may not be appropriate.

4 MONITORING

4.1 INJECTION SYSTEM MONITORING

In order to accurately assess the availability of corrosion inhibitor it is necessary to have some measure of the dosage of inhibitor being injected. At the most basic level, the dosing could be calculated by dividing the inhibitor used over a period of time by the production. This approach would give an estimate of availability over time, with the resolution depending on the frequency of recording of data, but would be unlikely to achieve high levels of availability.

To achieve high levels of availability, and therefore assure good corrosion protection, more sophisticated monitoring would be necessary to determine flow rates, pump and filter condition and storage tank levels. BP guidelines on corrosion inhibitor injection systems [16] recommend monitoring the following:

- Pump running;
- Diaphragm condition (via pressure sensors);
- Filter blockage (via a differential pressure sensor);
- Flow rate (coriolis flow rate monitors either on umbilical (low demand) or on each injector line (high demand));
- Flow rate in production line;
- Chemical storage tank level. Measurement could be made using a float level indicator, and/or a pressure based sensor.

In addition to the injection point monitoring, inhibitor residuals downstream could be measured and recorded.

4.2 CORROSION MONITORING

Monitoring the levels of corrosion inhibitor performance is an important aspect of managing corrosion of plant. Corrosion inhibitor residuals can be monitored downstream of the injection point, but this only informs the operator that the required inhibitor is being injected, not if the inhibitor is having the desired effect of reducing corrosion rates. The following methods are listed in the ASME article [17] for monitoring the results of inhibition in the field:

- Coupons;
- Spools, pump joints and pony rods;
- Iron counts;
- Copper ion displacement;
- Radioactive tracer methods;
- Calliper survey;
- Copra correlation, a quantitative assessment of deep, hot gas well corrosion;

- Electromechanical methods, such as resistance measurements, PAIR (polarization admittance instantaneous rate measurements), or potentiodynamic polarization measurements.

NACE International have produced Standard Recommend Practice or Standard Practice documents for the use of some of these methods. These include "Preparation, Installation, Analysis, and Interpretation of Corrosion Coupons in Oilfield Operations" [18] and "Monitoring Corrosion in Oil and Gas Production with Iron Counts" [19]. For each method, there are advantages and disadvantages. For example, using coupons gives average corrosion over the time for which the coupon has been in place and is just relevant to the location at which the coupon was located. Also, it may be difficult to replicate the condition of the materials to be protected from corrosion, e.g. existing corrosion in the pipeline may result in higher corrosion here than in an initially polished coupon.

Generally, methods such as these are most useful in identifying changes to the conditions which result in higher corrosion rates. The NACE Standard Practice for the use of iron counts [19] states that iron counts may only be considered a good corrosion monitoring method when iron counts have been gathered from the same sample point in the same manner and analysed by the same analytical method. In discussions with operators, they take manganese counts alongside iron counts as iron could be naturally present in the produced fluids, whereas manganese could only come from corroding steel.

Some corrosion monitoring techniques have the potential to provide continuous monitoring, such as the electromechanical methods. For example, electrical resistance probes evaluate the level of corrosion by detecting changes in the resistance of the probe. Probes may not be suitable for sour conditions, although some sour service probes are now available.

4.3 CONDITION MONITORING

In addition to monitoring the corrosion process, mainly by assessing corrosion of proxy samples, such as coupons or probes, the effect of corrosion on the structure of the protected components can be evaluated.

4.3.1 Continuous monitoring

Online thickness measurement systems, such as the Permasense system, provide continuous remote measurements of thickness from which corrosion rates can be ascertained. Although effectively point measurements, the continuous nature of the readings allows the effects of process changes to be assessed. As the devices just read the thickness at the point of contact, careful positioning is necessary to maximise the likelihood of detecting localised corrosion.

The Field Signature Method (FSM) is another online method that continuously monitors the pipe condition. The technique involves mounting pins around the area to be monitored and detecting changes to the electrical field pattern. Voltage measurements are compared to the "field signature", which provides the initial reference measurements for that area. Unlike the Permasense system, FSM monitors the entire surface area between the sensing pins, rather than just measuring the thickness directly under the probes.

4.3.2 Inspection Surveys

There are a large number of tools available for measuring corrosion in pipelines. These take the form of smart pigs, which are inserted into the pipeline and travel along the line collecting data. The monitoring can be based on ultrasonics, flux leakage or eddy current techniques.

With ultrasonics, a transducer can emit a pulse through the fluid in the pipe, and the time taken for the pulse to return to the transducer is measured, giving an accurate internal diameter. Therefore, any metal loss can be evaluated. Also, the frequency of the reflected wave gives an indication of the thickness, allowing external corrosion to be evaluated too.

Electromagnetic devices (such as flux leakage and eddy current techniques) use transmitters to generate an alternating magnetic field in the pipe. Changes to the pipe wall through corrosion cause changes to the magnetic field and electrical current, which can be detected to give an indication of the condition of the pipe [20].

5 KEY PERFORMANCE INDICATORS

5.1 INHIBITOR AVAILABILITY MEASURES

Key performance indicators (KPIs) have been developed to provide a method of monitoring the performance of corrosion management systems. Queen, Ridd and Packman of Shell and CorrOcean Ltd [21] described a method of assessing the cost of corrosion, inhibitor level and equipment maintenance completed using KPIs. The KPI proposed for corrosion inhibitor level was calculated by the following equation;

$$InhAv = \left(\frac{Ca}{Cr}\right) \times 100 \qquad \textbf{Equation 2}$$

where,

Ca = Actual concentration of corrosion inhibitor (ppm)
Cr = Required concentration of corrosion inhibitor (ppm)

The corrosion inhibitor availability KPI (*InhAv*) can be compared to the cost of corrosion damage KPI, which is based on the estimated number of replacement cycles to end of service life, replacement cost, required remaining field life and the days in the monitoring period. Figure 3 shows an example of use of these KPIs for corrosion management. The corrosion inhibitor availability is plotted for each quarter, but the method as described in the paper is not explicit as to how the quarterly value is obtained, or the frequency at which the corrosion concentration readings should be taken. If the quarterly inhibitor availability percentage were calculated using a simple average of daily readings, there could be a temptation to increase the inhibitor concentration to, say, twice the required concentration near the end of a quarter to make up for earlier shortfalls. This could give a false indication of the level of corrosion. The possible distortion of the KPI by concentration levels significantly higher than the required level could be avoided by setting an upper limit on the daily availability percentages of, say, 120%.

A more recent paper by Morshed [22] takes a slightly different approach. The proposed corrosion management strategy (CMS) approach involves listing a set of activities, detailing the person responsible, location, frequency, threshold and corrective actions. The examples given, pertaining to corrosion inhibition, are listed in Table 3.

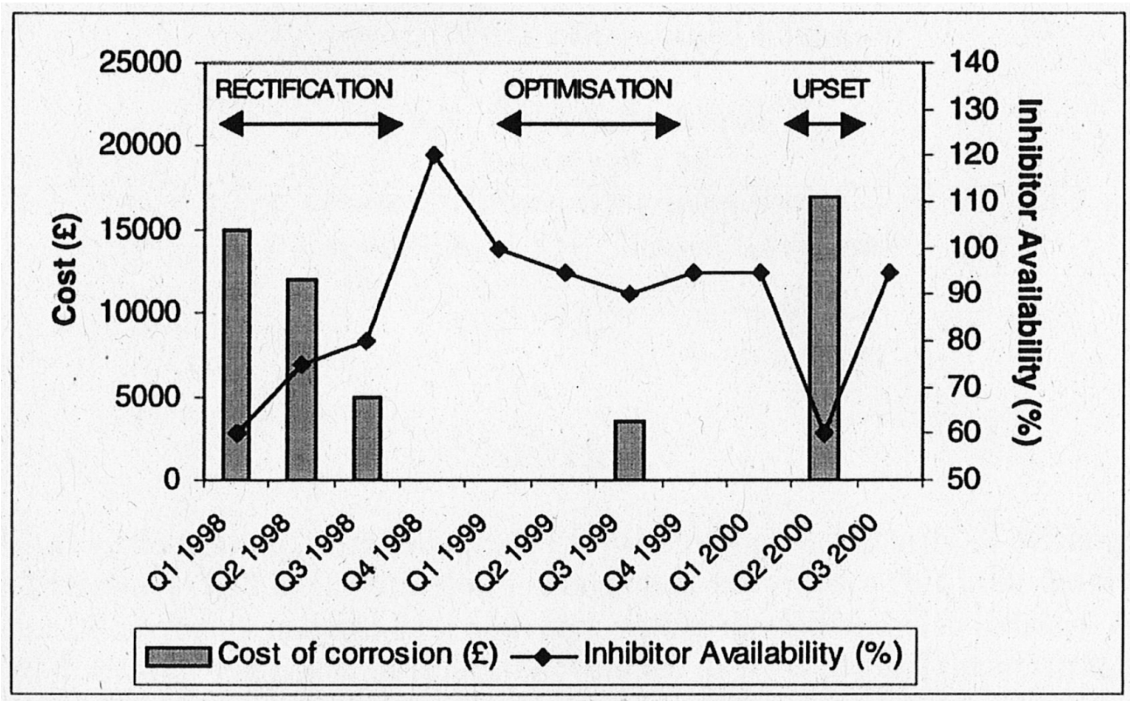

Figure 3 Example of Corrosion Cost and Inhibitor Availability KPIs demonstrating corrosion management performance (from Queen *et al*, 2001 **[21]**)

Table 3 Corrosion management strategy (CMS) activities pertaining to corrosion inhibition (from Morshed **[22]**)

Ref. No.	*Responsible Person*	*Activity*	*Location*	*Frequency*	*Threshold*	*Corrective Actions*
1.1	Offshore chemist	Monitor corrosion inhibitor injection rate	Upstream of export manifold on platform	Daily	200 ppm (in water phase)	Optimize injection rate. Notify maintenance supervisor
1.4	Onshore chemist	Monitor pipeline fluid residual corrosion inhibitor	Slug catcher	Daily	220 ppm (in total fluids)	Notify maintenance supervisor

In this method, the calculation of the corrosion KPI is based on the number of days for which each of the appropriate thresholds are met for each activity that is selected as a KPI. The monthly KPIs for each activity are the number of days that it is considered to be compliant multiplied by 3.3%. The overall corrosion KPI is the average of the KPIs for each of the selected activities. This method has the advantage of providing a procedure to assess the performance throughout a month and avoids the possibility of a large overdose increasing the KPI. However, it provides a basic pass/fail method of assessment; a slight under-dosing for a number of days would give a poor KPI percentage even if levels were only slightly under the threshold and this might not accurately predict the level of corrosion, although the KPI would be conservative in this instance.

Morshed [22] lists the primary (direct) benefits of using KPIs as follows:

1) Corrosion KPIs are an efficient way of capturing, trending, and assessing data related to the most important activities affecting the integrity of the process pressure systems of an asset;

2) They can help to immediately identify shortcomings or problems during the implementation phase of the asset CMS. This is of great benefit; in particular, to the mature assets undergoing various acute corrosion problems;

3) They improve the supervision of the responsible corrosion engineer over the most crucial activities (related to the asset integrity) and the individuals who have to regularly carry them out;

4) They help improve motivation among the team as team members constantly endeavour to achieve higher individual and average KPI compliances;

5) Corrosion KPIs are an efficient, quick, and brief way of reporting issues related to asset integrity and asset corrosion management; in particular, to the senior management.

Since using corrosion KPIs maintains and improves the integrity of the process pressure systems of an asset, the following can be considered as the secondary or indirect benefits of using corrosion KPIs according to Morshed:

1) Improving personnel safety and environmental protection;

2) Reducing plant downtime through reducing the number of unplanned shutdowns;

3) Reducing the cost of maintenance, inspection, and chemical treatment.

The limitations of using a simple pass/fail approach to evaluating inhibitor availability were highlighted by Steve Turgoose of Intertek Capsis [23]. Examining data from a pipeline, basing the availability on the percentage of days for which the required inhibitor concentration was achieved, it was estimated that 16 mm of metal loss had occurred in a pipeline over a period of 12 years. This assessment was based on the steel corroding at the inhibited rate when the inhibitor was present at the required concentration and at the uninhibited rate when it was below the required concentration.

Looking at one month's data in more detail, it was seen that the inhibitor was below the required concentration for 14 days out of 30, but for only one of those days was the concentration below 90% of the requirement. For the 13 days for which the concentration was only slightly below target, it is obviously grossly conservative to assume that corrosion occurs at the uninhibited rate. Reassessing the corrosion, assuming a slightly higher inhibited corrosion rate for periods of inhibitor concentration slightly below target, resulted in a metal loss estimate of 4 mm. A further analysis was performed, assuming that the effectiveness of the inhibitor persisted for a day for each uninhibited event. This reduced the calculated metal loss to 2.5 mm.

5.2 CORROSION INHIBITOR AVAILABILITY REQUIREMENTS FROM DESIGN

When designing pipelines, and specifically when choosing the material to be used, assumptions must be made about the rate of corrosion, in order to achieve an acceptable design life. The traditional approach was to use the corrosion inhibitor efficiency model to estimate corrosion rates. Efficiency is defined as:

$$E\% = 100 \times (CRu - CRi)/CRu \qquad \textbf{Equation 3}$$

Where CRu is the uninhibited corrosion rate and CRi is the inhibited corrosion rate.

In a paper [24] presented at Corrosion 2000, Hedges, Paisley and Woollam, from BP Amoco identified concerns with the corrosion inhibitor efficiency model. Firstly, concentrating on the level of inhibitor efficiency may distract attention from the actual corrosion rate. An example is given from the Prudhoe Bay field in Alaska, where records showed efficiency values in the range of 98.6% to 99.7 %. However, due to high uninhibited corrosion rates, the inhibited corrosion rates were still high and only 40% of flowlines had "acceptable" rates of corrosion. The second concern identified by Hedges *et al* is that the efficiency model always assumes a set percentage reduction in corrosion rate. This may be unconservative in cases where the uninhibited corrosion rates are low, for example, an efficiency of 90% may be achievable if the uninhibited rate is high, but for low uninhibited corrosion rates, of say 0.2 mm/yr, the implied inhibited corrosion rate of 0.02 mm/yr would not be likely to be achieved, at least over the lifetime of a pipeline in the field.

Hedges *et al* [24] argued that the efficiency model is inaccurate because inhibitors do not reduce corrosion by a set amount, but rather the inhibited corrosion rate is largely independent of the uninhibited rate. This is supported by data from several oil and gas fields published by Shell [25], which is shown in Figure 4. In this data set, the lowest corrosion rates observed in practice were in the range of 0.1 mm/yr to 0.2 mm/yr. These lowest corrosion rates are somewhat higher than those that can be observed in laboratory experiments. Hedges *et al* offers the following suggestions for the higher corrosion rates in real pipework:

- Laboratory specimens tend to be clean, smooth specimens, free of the scales and deposits found in real pipework;

- Laboratory rates are mean corrosion rates over a small area and over a short period of time. Corrosion measured in real pipes is often after failure, at the location of the failure, where corrosion rates might be far higher than the average of the whole pipeline;

- The inhibitor may not be present in the system at all times.

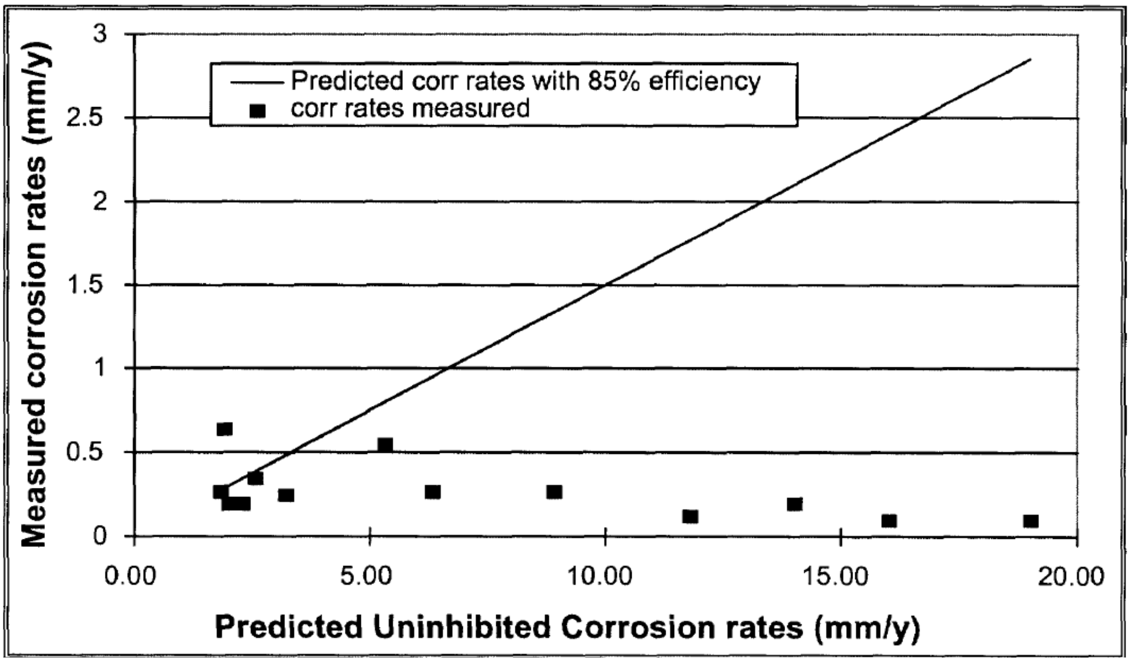

Figure 4 Corrosion rates for several oil and gas fields (from Kapusta *et al* **[25]**)

Hedges *et al* [24] also argue that the main role of corrosion inhibitors is not to reduce the mean corrosion rate, but to reduce the spread of rates, i.e. reduce the standard deviation, as shown in Figure 5. The elimination of the highest corrosion rates is seen as the primary benefit of inhibitor use. Using data from corrosion coupons at Prudhoe Bay, it is shown that to achieve a 97% compliance with the target corrosion rate of 0.05 mm/yr, the mean corrosion rate needed to be reduced to 0.02 mm/yr with a standard deviation of 0.04 mm/y.

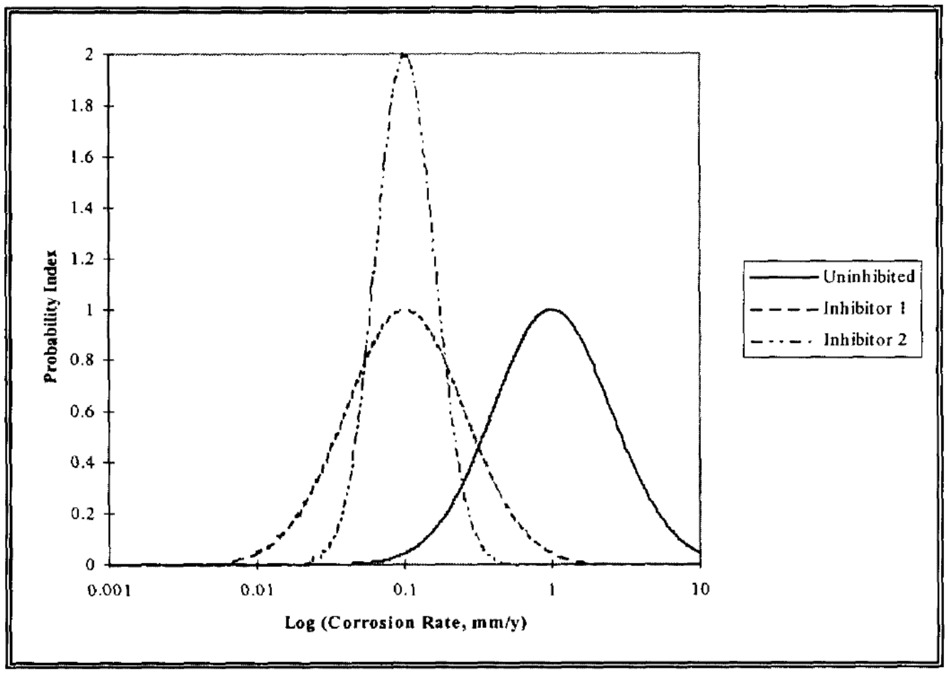

Figure 5 Distribution of inhibited and uninhibited corrosion rates (from Hedges *et al* **[24]**)

A move from the corrosion inhibitor efficiency model to the corrosion inhibitor availability model is proposed by Hedges *et al* [24] for the calculation of corrosion allowance. Here the Corrosion Inhibitor Availability (A%) is defined over the lifetime of the pipeline;

A% = 100 x Time Inhibitor is actually added at or above the minimum dosage / Lifetime

This definition of inhibitor availability is similar to the availability KPI described by Morshed [22], except that it is defined over the lifetime of the pipe, rather than on a monthly basis.

A corrosion allowance, CA, can then be calculated as follows:

$$CA = (CRi \times A\%/100 \times Lifetime) + (CRu \times [1-A\%/100] \times Lifetime) \quad \textbf{Equation 4}$$

The minimum inhibited corrosion rate is set at a practical minimum value of 0.1 mm/yr in BP Amoco for purposes of calculating corrosion allowances. They have also introduced a Corrosion Inhibitor Risk Category (see Table 4) to help project and operational engineers understand the criticality of the corrosion inhibitor. This table appeared in a BP Sunbury Report [26] and is cited as an example in the HSE Offshore Technology Report [27]. The maximum acceptable required Inhibitor Availability is set at 95%, not due to the availability of pumps and chemicals (which the authors claim can easily exceed 99%) but rather due to other factors that limit the effectiveness of inhibitor use in practice, as described earlier.

Table 4 Corrosion Inhibitor risk categories suggested by Hedges *et al* **[24]**

Category	*Maximum Required Availability*	*Maximum Expected Uninhibited Corrosion Rate (mm/yr)*	*Comment*	*Possible Category Name*
1	0%	0.4	Benign fluids where corrosion inhibitor usage is not anticipated (dry gas, stabilised oil). Predicted metal loss can be accommodated by corrosion allowance alone.	Benign
2	50%	0.7	Corrosion inhibitor will probably be required but at the expected corrosion rates there will be time to review the need for inhibition based on inspection data.	Low
3	90%	3	Corrosion inhibitor will be required for the majority of the field life but the facilities need not be available from day 1.	Medium
4	95%	6	Inhibition is relied on heavily and will be required for the lifetime of the operation. Inhibitor must be available from day 1 to ensure success of the inhibition programme.	High
5	>95%	>6	Carbon steel and inhibition is unlikely to provide integrity for the full field life. Select corrosion resistant materials or plan for repairs & replacements.	Unacceptable

Shell take a similar approach, based on corrosion inhibitor availability, which is detailed in a paper by Rippon [28]. The overall corrosion rate for an inhibited system is given by:

$$CR = f \times CRi + (1-f) \times CRu \qquad \textbf{Equation 5}$$

Where *f* is the fraction of time the corrosion inhibitor system is working. Rippon points out that this simplified approach does not take into account variables such as the persistency of the inhibitor or whether or not the production is shut down during uninhibited events. Both of these factors may lead to the CR value being conservative. A comprehensive table is provided listing a range of possible events leading to lack of corrosion inhibition, with methods of detection and control systems. This has been reproduced in Table 6.

The Shell approach differs from the BP Amoco approach in the set limits that can be assumed both for minimum inhibited corrosion rate and maximum corrosion inhibitor availability. A table of inhibited corrosion rates is given by Rippon [28] for different operating temperatures with values ranging from 0.05 mm/yr for temperatures up to 70 ºC to 0.2 mm/yr for temperatures between 120 ºC and 150 ºC. Inhibition is not recommended for temperatures above 150 ºC without specific testing. There is also the possibility of using lower inhibited corrosion rates, if lower rates are identified during testing.

Whereas the BP Amoco approach assumes a maximum corrosion inhibitor availability of 95%, the Shell approach uses 95% availability as a starting point, This allows availability of up to 99% to be assumed, with the possibility of higher availability examined. A table is presented, giving the requirements that would need to be achieved in the design and operation of the corrosion inhibitor system to enable different levels of availability to be assumed. This is reproduced in Table 7. The higher the corrosion inhibitor availability required the more stringent the requirements, with more frequent checks, the use of automated alarms and the increased likelihood of production being stopped if there is an uninhibited event.

Table 5 Uninhibited Events (from Rippon, 2001 **[28]**)

Event	*Detection system*	*Control system options*	*Comment/ Impact*
Incorrect inhibitor arrives at site: • Inhibitor formulation changed by supplier (or their suppliers) • Supply mix up from supply base • Interference in supply	Physical tests on inhibitor when it arrives on site Probably detectable by inhibitor residuals	QC system on inhibitor supply	
Inhibitor runs out on platform due to inadequate stock levels on site or supply base	Monitoring amounts used and cross checking	Stock control system Automatic level gauges Tie in to control room alarms	KPIs
Wrong inhibitor loaded into tank by operators	Probably detectable by inhibitor residuals	Training and Procedures	KPIs

Table 6 (continued))

Event	*Detection system*	*Control system options*	*Comment/ Impact*
Inhibitor tank allowed to run empty	Inhibitor returns	Training and Procedures Tie in to control room alarms	KPIs
Inhibitor incorrectly diluted	Monitoring amounts used and cross checking	Training and Procedures	
Inhibitor Pump Breakdown	Inhibitor returns	Manual checking Flowmeters	Backup pump options (none, available in store, available on site, automatically switched over)
Power failure to pump, with production still continuing	Pump could be alarmed Inhibitor returns	Manual checking Flowmeters	Final option is to shut down production
Power failure to pump, which also stops production	Pump could be alarmed	Manual checking Flowmeters	May have little or no impact (depends on corrosion rate and inhibitor persistency in non-flowing conditions)
Inhibitor delivery from tank to injection location fails (line blockage, failure)	Inhibitor returns	Flowmeters	Inhibitor selection related. Use portable tanks (cleaned regularly), rather than permanent tanks which may build up deposits
Injection rate incorrectly set	Monitoring amounts used and cross checking	Training and Procedures	
Operating conditions change, requiring a change of injection rate which is not carried out		Training and Procedures	
Pigging required for distribution of inhibitor and not carried out.		Training and Procedures	
Oxygen allowed to enter the system; corrosion inhibitor ineffective against oxygen corrosion		Oxygen monitor installed	KPI
Bacteria allowed to enter the system; corrosion inhibitor ineffective against microbiologically induced corrosion	Cultures from water samples		KPI
Operating environment changes and inhibitor becomes totally ineffective			Replacement inhibitor has to be selected

Table 7 Criteria for inhibitor system design to meet a specified system availability (from Rippon, 2001 **[28]**)

Item	***f = 0.95***	***f = 0.99***	***f > 0.99***
Inhibitor demonstrated as suitable for the application	✓	✓	✓
Inhibitor injection pumps	Standard	High reliability	High reliability
Back up pumps	×	✓	✓
Check that pump is operating	Daily manual check	Automated alarm	Automated alarm
Pump planned maintenance	Annual	Annual	May be required more often
Inhibitor tank levels	Daily manual check	Automated alarm	Automated alarm
Report on inhibitor used (or report on compliance with key performance indicators) to responsible corrosion engineer	Monthly	Weekly	Daily
Quarterly manual check on pump injection rate	✓	✓	✓
No flow alarm (zero differential pressure across a critical component, or in line flow meters)	×	✓	✓
Liquid samples for analysis of residual inhibitor levels and water chemistry	Monthly	Monthly	May be required more often
Corrosion monitoring system response	At least annual manual measurement	On line ER probes; response time 1-7 days	On line fast response monitoring systems; response time 1-24 hrs
Comprehensive review of uninhibited events	Desirable	Required	Required
Persistency taken into account	×	×	✓
Allowed days inhibitor system downtime per year	18	4	0-4
Shut in if inhibition system goes down for greater than a defined period of time	Effectively never an issue	Possibly	✓
Identify Operations Technician with responsibility for the inhibition injection system	✓	✓	✓
Corrosion Engineering involvement	Monthly review	Weekly review	Daily review
Key Performance Indicators set for Operations Technicians and Corrosion Engineers	✓	✓	✓

The two approaches used by BP and Shell have been compared by Marsh and Teh of Ionik Consulting (now Wood Group Integrity Management) [29]. They looked at the different corrosion models and different corrosion inhibitor availability models used by the two companies. They highlight the fact that the limit for the BP approach is 95% corrosion inhibitor availability. This is embedded in the BP guideline document for the use of the Cassandra corrosion modelling program that states "even a >99% pump availability should not be used as a basis for assuming a >95% inhibitor availability. Carbon steel and a corrosion allowance with corrosion inhibition is unlikely to provided integrity for the full field life, thereby requiring repairs or replacements." Marsh and Teh also point out that the NORSOK M-001 standard [30] states that inhibitor availabilities above 95% should not be used in a design assessment, and that corrosion resistant alloys should be selected if corrosion inhibitor availability requirements are found to exceed 95%.

Ionik Consulting were asked to give an assessment of experience with respect to achievement of corrosion inhibitor availability in the UK sector of the North Sea. They acknowledged that there is very little useful data on this in the public domain. Therefore, they based their assessment on the experience of their own employees and also informally and anonymously canvassed a number of field corrosion engineers and chemical company personnel.

They found that where a system had been designed to achieve 90% corrosion inhibitor availability, the availability achieved in practice was typically between 85 and 90%. Achieving 85% availability would mean that corrosion rates could be at the uninhibited rate for 15% of the time compared to a target of 10%, a 50% increase. They also found that systems that were designed to high levels of availability (95% or higher) in practice also achieved between 85% and 95% availability. Marsh and Teh say "with respect to multiphase oil production in the UK sector of the North Sea, Ionik Consulting have yet to come across a positive example, either from in house experience or from third party discussion, where a 95% target has been consistently met throughout a field and over the longer term." For these systems, with a target of having uninhibited corrosion for a maximum of 5% of the time, having uninhibited corrosion for up to 15% of the time could potentially represent a three fold increase in corrosion rate, given the very large differences between inhibited and uninhibited corrosion rates assumed for these systems.

Marsh and Teh suggest that one of the primary causes for lower achieved corrosion inhibitor availabilities is due to the conflict between corrosion inhibition and production. With loss of production having an immediate financial effect, whereas the effects of lack of corrosion inhibition not being seen until months or years later, keeping production running may be tempting. While high inhibitor availabilities may be possible in theory, and achieved in some fields (believed to be onshore), they argue that high corrosion inhibitor availabilities alone should not be relied on during design.

A number of alternative and complimentary solutions are proposed by Marsh and Teh, such as hydrate control using methanol or MEG (monoethylene glycol) and pH stabilization.

They comment on the differences in approach used by different regulators, comparing HSE to the Norwegian sector. They state that HSE have authorised developments requiring levels of corrosion inhibitor availability as high as 98-99% in some cases, which would not be allowed under the NORSOK M-001 standard.

Although Ionik Consulting have prepared corrosion inhibitor injection and monitoring recommendations for systems with inhibitor availability requirements of up to 99% for oil production (in line with the recommendations described by Rippon [28]) they warn of the possible dangers and suggest that corrosion resistant alloys are investigated as an alternative.

Where Ionik consulting are asked for their recommendations, then a value of 90 to 95% is proposed, depending on the corrosion monitoring systems and corrosion inhibitor injection equipment to be used.

The limit recommended for corrosion inhibitor availability has been raised to 96% for oil producing systems by Ionik Consulting [29] with the following additional requirements:

- A top grade logistics supply and management structure will have to be set up well in advance;
- A strategic reserve of corrosion inhibitor and spare parts for the corrosion inhibitor injection system should be created on the production facility;
- A corrosion management system must be in place and ready to operate from day one of the production, and this must operate in a proactive and not a reactive manner;
- The organisation, management, skills and training of personnel will need to be of the highest quality;
- The operator will need to commit to maintaining these capabilities throughout the lifetime of the field;
- The operator must be willing to give preference to maintaining corrosion inhibition over production where conflicts arise.

In a more recent paper from Wood Group Integrity Management [3], it would appear that the previous upper limit for corrosion inhibitor availability has been raised further. They state *"in the case of inhibition, if inhibitor availability can be guaranteed at a high level [of] 98% by recommendations on pumps back up or operational procedures, carbon steel can be used and the total lifecycle cost of a project can be reduced."*

BP Exploration presented a paper in 2010 [31] detailing their development of a high reliability corrosion inhibitor injector system. The authors state that *"as oil and gas exploration and production moves into deeper reservoirs and more challenging environments, higher temperatures, higher pressures and more corrosive environments make corrosion place increased demands on inhibitor availability, with designs based on over 99% availability becoming increasingly common."* They presented an analysis of equipment reliability and a design of a system that could increase the corrosion inhibitor availability while reducing the usage of inhibitor through careful control of dosing.

Their analysis of failures identified diaphragm failure as the key driver in downtime, responsible for 66% of downtime. The other factors were pressure control valves (20%), pump control (7%), startup (4%) gearbox (2%) and flow meter (1%). They argue that with suitable maintenance of duty and standby pumps, significant improvement in availability can be achieved. They developed a skid with the following elements:

- Standby and duty pumps (100% redundancy);
- Diaphragm condition monitoring and failure alarm;
- Flow metering (Coriolis);
- Closed loop control for dosage regulation;

- Chemical inventory monitoring;
- Filter condition alarm;
- Outlet pressure monitoring;
- Wireless communication to desktop.

With their pilot skid, inhibitor availability, using the definition of fraction of time that the inhibitor was injected at or above the target value, exceeded 99.8%. However, the assessment time was just a few months. Whether this level of availability could be maintained over the life of the plant has not been demonstrated. The closed loop control system also resulted in a 10% saving on chemical consumption, compared to the previous manual control method.

6 ASSESSMENT OF FAILURES

The Canadian Association of Petroleum Producers (CAPP) produced a series of 'best management practices' documents in 2009 [32], [33], [34], [35], that included failure statistics for oil effluent pipeline systems, sour gas pipelines, sweet gas gathering systems and oilfield water pipeline systems. In every case, the most common cause of incidents was internal corrosion with pitting corrosion along the bottom of the pipeline being identified as the primary corrosion mechanism. While the documents suggest inhibition as a mitigation technique, they do not go into any detail about inhibition requirements in terms of availability or ensuring reliability.

The common features leading to pitting corrosion were identified as:

- The presence of water containing any of the following; CO_2, H_2S, chlorides, bacteria, O_2, or solids;
- Pipelines carrying higher levels of free-water production (high water/oil ratio or water cut);
- The presence of liquid traps where water and solids can accumulate.

A number of cases of breakthrough due, at least in part, to failure of corrosion inhibition in pipelines operated by Elf are described in a paper by Bonis and Crolet [36]. The first failure described was in a 9.3 mm thick 10 inch pipeline carrying a mixture of about 90% water and 10% condensate. The gas concerned was sour, with about 6.5% H_2S and 10% CO_2. The failure occurred due to crater corrosion along the internal longitudinal axis after about 9 months service; corresponding to a corrosion rate of about 12 mm/yr.

In this case, the corrosion inhibition was not applied continuously. The inhibitor was applied using squeeze treatments, where the inhibitor is periodically injected into the well upstream and the line is protected by the inhibitor returning from the well. Two main causes were identified for the failure of the inhibition:

1. The squeeze treatments were performed every three months, and all the wells in a particular zone were treated in series over the course of a few weeks. This led to an initial large return of inhibitor on restarting, but left little protection for the rest of the 3 month period.
2. The inhibitor used was almost "water insoluble" and as the mixture was about 90% water, the inhibitor was not therefore in regular contact with the metal surface of the pipeline.

After the breakthrough, the most highly corroded sections were replaced and the inhibition was changed to continuous treatment using a water soluble inhibitor. At the time the paper was written (1998), the line had been in operation again for 10 years with no further breakthroughs. Interestingly, the uninhibited corrosion rate of approximately 12 mm/yr greatly exceeds the maximum of 6 mm/yr recommended in Table 4 for successful inhibition.

The second case examined by Bonis and Crolet [36] was in the same field as the previous case, with the same inhibition treatment, but in this case the pipeline was 14.3 mm thick and 12 inches in diameter. The failure occurred in a rising section of the line after about 11 months. Water had accumulated at the failure location because the gas flow velocity was not sufficient to provided adequate lifting. The modifications to the inhibition treatment were similar to those for the first case, and again, 10 years of satisfactory performance was obtained after repair and treatment changes.

Two further breakthroughs were reported, both occurring on the same line. In these cases, there was a suspected microbial contribution to the corrosion. As in the previous cases, the problems due to inhibition were at least partly due to solubility issues, which led to the effective concentration of inhibitor in the water being considerably lower than assumed. After repair, there was a complete change to the biocide and inhibition treatment, and an extremely detailed corrosion monitoring procedure was introduced. At the time of Bonis and Crolet writing, the line had been in service for a further seven years without further corrosion problems.

7 CONCLUSIONS

The following conclusions can be drawn from the literature review:

- The application of chemical corrosion inhibitors can significantly reduce the rate of corrosion of carbon steel pipelines due to the presence of CO_2 and/or H_2S. An inhibited corrosion rate of 0.1 mm/year can typically be achieved, which is largely independent of the uninhibited corrosion rate;

- Various factors can affect the effectiveness of chemical corrosion inhibitors; they are not effective against corrosion due to the presence of oxygen or microbacterial corrosion and; high flow rates, high temperature, solids (either dissolved or suspended) and pre-existing corrosion can all have a negative effect on corrosion inhibitor effectiveness;

- The main Key Performance Indicator (KPI) used for assessing effectiveness of corrosion inhibitors is based on the proportion of time that the correct dosage of inhibitor is applied (inhibitor availability);

- Maintaining a high level of availability can be difficult in the long term, due to a number of factors, the most frequently reported being failure of the diaphragm in the pump and failure of the pressure control valves;

- The maximum availability that can safely be assumed for design calculations has been a matter of debate:

    - The NORSOK M-001 standard specifies that inhibitor availabilities above 95% should not be used in a design assessment;

    - BP Amoco have also used an upper limit of 95% availability;

    - Shell have allowed an availability of 99% to be assumed;

    - A recent paper by BP Exploration has stated that designs based on 99% availability are becoming increasingly common, and demonstrated a pilot skid that achieved 99.8% availability, albeit with an assessment time of just a few months.

- A review of inhibition availability by Ionik Consulting (now Wood Group Integrity Management) found that systems with target availability of over 95% were unable to achieve this level of availability, with actual availability between 85% and 95%.

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Reliable corrosion inhibition in the oil and gas industry

The objective of the work was to undertake a literature review on the subject of corrosion inhibition in the offshore oil and gas industry to understand the current issues. The application of chemical corrosion inhibitors can significantly reduce the rate of corrosion of carbon steel pipelines due to the presence of CO_2 and/or H_2S. An inhibited corrosion rate of 0.1 mm/year can typically be achieved, which is largely independent of the uninhibited corrosion rate.

The report covers the main factors affecting the effectiveness of chemical corrosion inhibitors; they are not effective against corrosion due to the presence of oxygen or microbacterial corrosion. High flow rates, high temperature, solids (either dissolved or suspended) and pre-existing corrosion can all have a negative effect on corrosion inhibitor effectiveness.

The role of Key Performance Indicators (KPIs), the main factors affecting the performance of inhibition injection systems, and the levels of inhibitor availability that can be assumed at the design stage and achieved in practice are also discussed.

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