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MASTER'S THESIS

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Writer: Fery Simbolon	………………………………………… (Writer's signature)

Faculty supervisor: Professor Tore Markeset PhD, UiS

External supervisor(s): Erik W Mikkelsen MSc, FORCE Technology Norway AS

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ABSTRACT

In oil and gas industries, KPIs are normally required in order to evaluate the asset integrity performance. KPIs are selected from the most crucial performance indicators to the asset integrity. KPIs can also be used as a tool to manage risk from RBI analysis on Alvheim FPSO Topside. As part of corrosion management strategy, RBI analysis determines the risk level of each system by calculating the probability of failure (PoF) and consequence of failure (CoF) for particular systems. The risk levels depend on the actual process parameters on Alvheim FPSO Topside thus any change to the process parameters will of course affect the RBI analysis and Alvheim corrosion management system. All changes on the crucial process parameters are captured on the corrosion KPIs.

The purpose of this thesis is to evaluate and improve the corrosion and inspection management system at Alvheim FPSO Topside by developing the performance indicators of all plausible internal degradation mechanisms. The most crucial performance indicators are selected as KPIs. Each KPI has individual thresholds values that need to be compared to the measured data so the percentage of compliance can be determined.

On Alvheim FPSO Topside, it has been noticed that the actual CO_2 content in the hydrocarbon system is higher than the threshold KPI. The trend of average corrosion KPI compliance is stagnant due to zero compliance on the CO_2 threshold content. Future corrective actions need to be agreed between the corrosion engineer, integrity engineer, process engineer, production engineer and chemical vendor. Further investigation on CO_2 corrosion is required; it might be the calculated corrosion rate is too conservative as there have been no findings so far from the last inspection campaign. The most suitable corrective action is to increase the threshold of CO_2 content by altering the injecting rate of the corrosion inhibitors. These inhibitors reduce the CO_2 corrosion rates thus the threshold of CO_2 content can be increased.

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NOTATION AND ABBREVIATION

22Cr	Duplex Stainless Steel
25Cr	Super Duplex Stainless Steel
API	American Petroleum Institute
ASM	ASM Materials-Formerly American Society for Metals
CA	Corrosion Allowance
CAPEX	Capital Expenditures
CIMS	Corrosion and Inspection Management System
CoF	Consequence of Failure
CR	Corrosion Rate
CRA	Corrosion Resistant Alloys
CS	Carbon Steel
CuNi 90/10	Copper Nickel with approximately 90% of Cu and 10% Ni
DNV	Det Norske Veritas
FPSO	Floating Production Storage and Offloading vessel
JIP	Joint Industry Project
KPI	Key Performance Indicator
KRI	Key Result Indicator
LTCS	Low Temperature Carbon Steel
LTV	Life Time Value
MIC	Microbiologically Influenced Corrosion
MONAS	Marathon Oil Norge AS
NDT	Non Destructive Testing
NPS	Nominal Pipe Size
NORSOK	Norsk Sokkels Konkuranseposisjon
PFD	Process Flow Diagram
PI	Performance Indicator
P&ID	Piping and Instrumentation Diagram
PM	Preventive Maintenance
PoF	Probability of Failure
PPB	Part per Billion
PSV	Pressure Safety Valve
RBI	Risk Based Inspection
RP	Recommended Practice
RuBI	FORCE's software for carrying out a RBI analysis
SCC	Stress Corrosion Cracking
SMLS	Seamless
SRB	Sulfate Reducing Bacteria
SS	Stainless Steel
SSC	Sulphide Stress Cracking
UDC	Under Deposit Corrosion
VUD	Vessel Upper Deck
WT	Wall Thickness
UT	Ultrasonic Testing

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1. INTRODUCTION

The aim of this chapter is to introduce the background and the aim of this thesis. The contributions and limitations are also explained.

1.1. Background

A corrosion management system for Alvheim FPSO Topside is required in order to mitigate and control corrosion because corrosion is a primary threat to the asset integrity. Together with risk based inspections and a monitoring program; this corrosion management system will reduce and control the risk, ensuring asset integrity and reliability in a cost-effective manner. Corrosion risk assessment is the core element of a corrosion management system. Corrosion risk assessment is also known as RBI analysis and it defines the risk level of each system by calculating the probability of failure (PoF) and consequence of failure (CoF) for particular systems. These CoF and PoF levels depend on the actual process parameters on Alvheim FPSO Topside thus any change to the process parameter will of course affect the RBI analysis and Alvheim's corrosion management system. Because of that, the most crucial process parameters need to be monitored by performance indicators in order to ensure the Alvheim RBI analysis or Alvheim corrosion management strategy are relevant and up to date.

In oil and gas industries, KPIs are normally required in order to evaluate the asset integrity performance. KPIs are selected from the most crucial performance indicators to the asset integrity. KPIs can also be used as a tool to manage risk from RBI analysis on Alvheim FPSO Topside.

1.2. Problem Description

Some challenges occurred during establishing the corrosion KPIs for Alvheim FPSO Topside as follows:

1. Selection of the most plausible internal corrosion threat of each system.
2. Determine the threshold value of each performance indicator. It has been decided to follow the threshold value from the FORCE (2011) as it is more conservative than NORSOK M-001 (2004) and Stott (2003). These KPIs are live tools and if necessary need to be updated due to latest findings and experiments from third parties. Normally, the threshold values are taken from experiments or operator experience.
3. Measurement locations for some performance indicators have to be decided later on due to time constraints.

1.3. Aim of the Thesis

The purpose of the thesis is to evaluate and improve the corrosion and inspection management system at Alvheim FPSO Topside by developing the performance indicators of all plausible internal degradation mechanisms. The most crucial performance indicators are selected as KPIs. Each KPI has individual threshold values that need to be compared to the measured data so the percentage of compliance can be determined.

1.4. Scope of Work

In order to achieve the aim of the thesis, the project shall look into the following:

1. Identify all plausible internal corrosion threats of each system on Alvheim FPSO Topside.
2. Determine the highest risk level of each system from RuBI (FORCE's software for carrying out a RBI analysis)
3. Develop corrosion performance indicators of all plausible internal degradation mechanisms.
4. Determine the threshold value of each performance indicator.
5. Determine the KPIs from corrosion performance indicators.
6. Collect all available data from Alvheim FPSO Topside and compare it with the threshold value.
7. Generate the graphic of plotted average monthly KPI against the target level.
8. Suggest risk mitigation or corrective action in order to increase the average KPI compliance.

1.5. Limitation

The limitations of this thesis are:

1. Only Alvheim FPSO Topside pipework is considered in this thesis. All change in process parameters will also affect both pipework and static equipment but the static equipment is expected to be the least affected by process parameter change as it has a big volume and fluids are mixed inside.
2. Only internal corrosion threats are considered in this thesis.
3. Except for CO_2 corrosion, the probabilities of failures are taken directly from FORCE (2011) without any further evaluation.
4. A FORCE (2001) is used for RBI methodology. This procedure has the same main principles with DNV RP G101 (2009).

2. STUDY LITERATURE

In order to select the correct corrosion key performance indicators at Alvheim FPSO Topside, a comprehensive understanding of RBI analysis or corrosion risk assessment, performance indicators and process parameters that affect internal corrosion of pipework are necessary. In this chapter, all necessary information will be explained based on literature studies and author's knowledge and experience.

2.1. RBI Analysis

In tight operational budgets, correct design and selection of the piping system, pressure vessel, pressure safety valve or components that need to be inspected is vital. This selection shall consider the process conditions, component materials, geometry system, external factors and historical records. Figure 2.1 shows the effects of increasing expenditure on safety and inspection. Good business means users spend a reasonable amount of money to do limited inspection programs without increasing the asset risk.

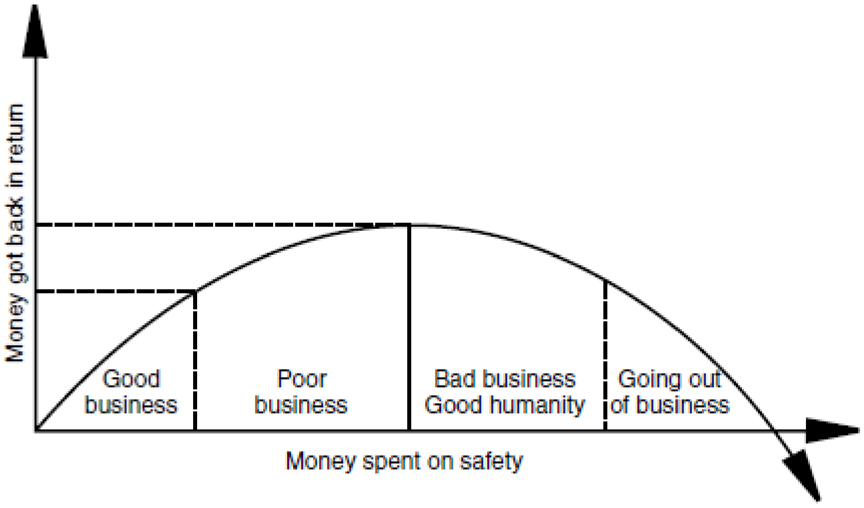


Figure 2.1. The effects of increasing expenditure on safety and inspection (Roberge, 2007)

RBI is used in order to prioritize and manage the inspection programs of asset equipment. It uses the risk analysis philosophy that risk is a multiplication of probability of failure and consequence of failure. Based on history as stated by Roberge (2007), RBI has been used since the late 1980s by several companies but its methodologies in the oil industry were developed in 1993 by a Joint Industry Project (JIP) and the American Petroleum Institute (API). Some key elements in RBI include knowing potential deterioration mechanisms that may lead to equipment failures, probability or likelihood of failures and the consequence of failures. The output of an RBI program can be used to demonstrate the value of proactive corrosion control and can be used as a communication tool to influence the decision makers and stakeholders in asset integrity and reliability.

In an RBI program, equipment with high risk is inspected more frequently than other equipment. High risk equipment is defined as equipment that has a high probability of failure and severity consequence when it fails, refer to Figure 2.2. Probability of equipment failure is determined based on knowledge of the corrosion process for calculating the corrosion rate, knowledge of normal and upset conditions and any inspection histories. This probability of failure may have to be updated due to ageing and major change in process conditions. Consequence of equipment failure is determined based on the fluid type and hazards that may be released, fluid volume and release rate. In API RP 580 (2009), there are three approaches for reducing the risk of operating equipment as follows:

1. Optimizing inspection-monitoring.

It is important that the existing inspection plan addresses all potential deterioration mechanisms and it is also beneficial to consider the inspection optimization in high risk and low risk systems. Changes should be made if the optimization will reduce the risk in the high risk system and changes should also be made if the optimization will reduce the inspection cost but not increase the risk in the low risk system.

2. Material of construction changes.

Any change in material selection will of course affect the probability of failure. High reliability material reduces the risk and the cost of inspection but increases the installation cost. For example, titanium or CuNi 90/10 material may be used for fire water piping systems due to their corrosion resistance in a seawater system but CuNi 90/10 material has lower reliability than titanium and therefore will incur higher maintenance costs. A life cycle cost analysis will help users during selection of the best material both in reliability and total cost.

3. Key process parameters.

The deterioration rate of equipment is influenced by process parameters such as fluid composition, temperature, pH, fluid velocity etc. These process parameters shall be monitored and maintained especially for the parameter that has greatest impact in the deterioration rate of equipment. Based on investigation experience, many failed equipment has been operating beyond one or more of the process parameter limits.

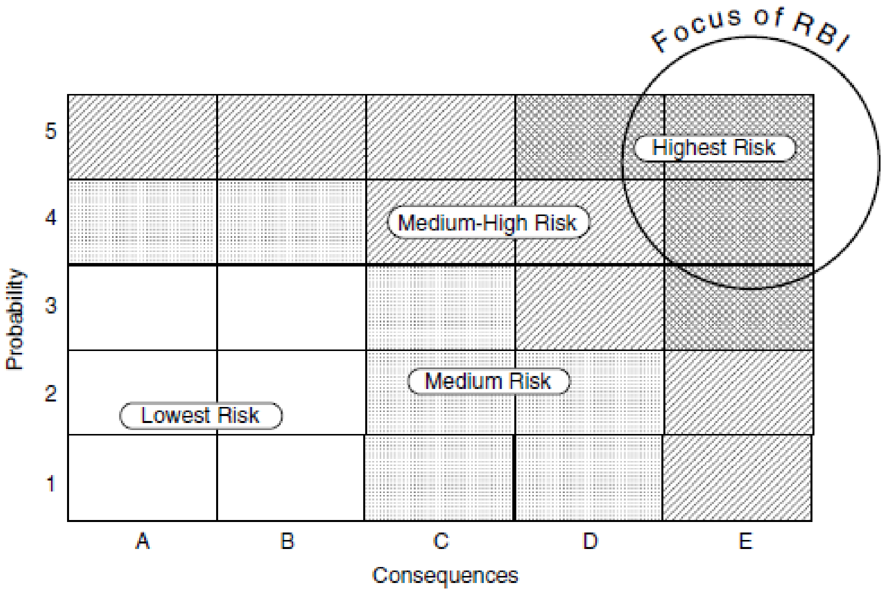


Figure 2.2. Typical risk matrix (Roberge, 2007)

RBI is a technique for completing inspection plans based on risk and provides some benefits such as inspection optimization, monitoring recommendation and production system testing plans. The benefits of an RBI application are shown in Figure 2.3. RBI delivers information such as a list of components to be inspected, inspection intervals, expected areas of components to be inspected, the inspection method and a findings report for continuous improvement. Generally, RBI is used for static equipment, e.g.: pipework, pressure vessels, tanks, heat exchangers etc. Failure risk of these components can be obtained by carrying out the RBI analysis where consequence failure and probability failure are treated separately.

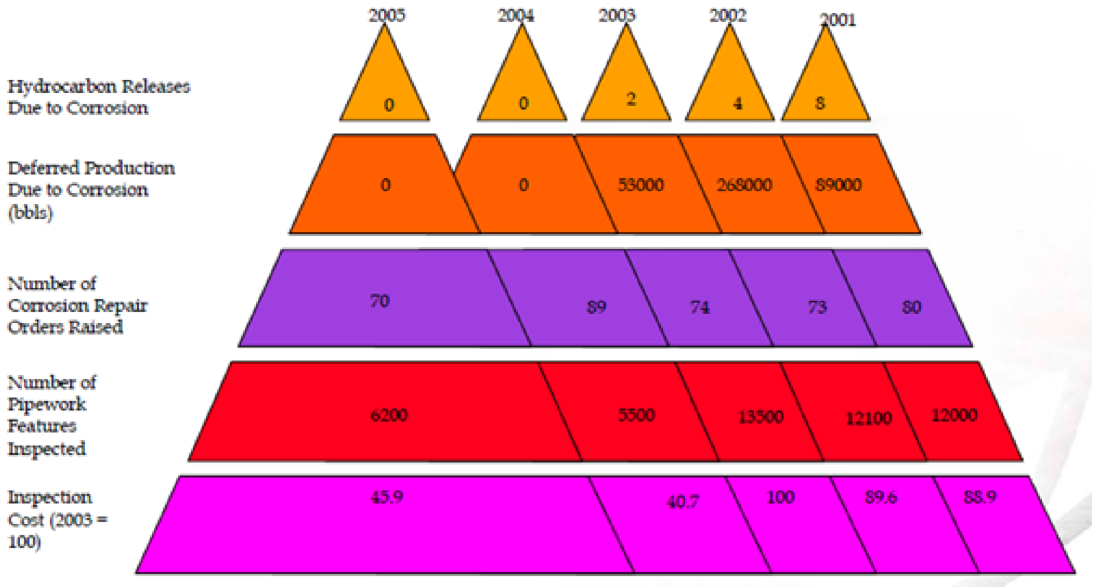


Figure 2.3. The benefits of an RBI Application (Morshed, 2009)

2.2. Performance Indicators

In the operation of an oil and gas asset, it is beneficial to know beforehand what parameters are affecting the operational performance and hence these parameters shall be controlled. These parameters are usually called performance indicators (PIs) and key performance indicators (KPIs). These can be used in order to optimize the need and sequence of inspection and other maintenance activities. The PIs and KPIs are ways to periodically assess the performance of a risk based inspection program. It is important to establish these PIs and KPIs in such a way so as to be understandable, meaningful and measurable.

According to Parmenter (2007), there are three types of performance measures as follows:

1. Key Result Indicators (KRIs).

Typically these indicators are reviewed on a monthly basis which is a longer period of time than KPIs. In this thesis, KRIs and PIs are the same indicators.

2. Performance Indicators (PIs).

These indicators are lying in between KRIs and KPIs. The performance indicators which most affect the performance of operation will be selected as KPIs.

3. Key Performance Indicators (KPIs).

Typically these indicators are reviewed on a daily basis and these indicators change the performance dramatically.

If we refer to Parmenter's definition, the author observed that many performance measures are incorrectly termed KPIs. Many organizations have a lot of KPIs, some of which do not change the organization's performance dramatically.

The above performance measurements according to Parmenter can be illustrated in Figure 2.4.

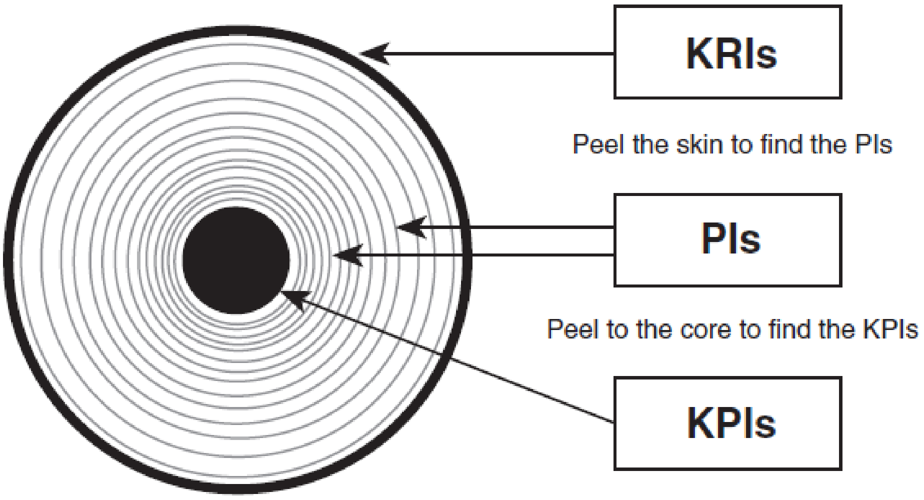


Figure 2.4. Three types of performance measures (Parmenter, 2007)

The performance indicators need to be established in the asset corrosion management strategy. These indicators will monitor the performance of the corrosion management strategy on a regular basis in order to ensure the strategy is always up to date and efficient. A corrosion management strategy can be defined as a strategy to maintain the asset integrity by mitigating the corrosion during operation of an oil and gas asset and managing all identified corrosion threats. The performance indicators are significantly maintaining and improving the pressure system integrity of an oil and gas asset. The following are benefits of using performance indicators as part of corrosion management strategy as stated by Morshed (2008):

1. Safety, Health and Environment is improved.
2. Asset downtime is reduced.
3. Maintenance costs for inspection campaigns and chemical treatment is reduced.

2.3. Process Parameters

As mentioned earlier, some process parameters will affect the deterioration rate of equipment. These parameters will be discussed as follows:

1. Flow Effect

The flow regime in a piping system can be laminar or turbulent flow. These two flow types can be defined by the Reynolds number which is dependent on flow velocity, pipe diameter, fluid viscosity and fluid density. A turbulent flow may increase the corrosion rate as the turbulent flow makes difficult for a corrosion inhibitor to cover all areas of a piping system and also introduces cavitation and erosive conditions. The mechanical disturbance, e.g.: abrasion, impingement, turbulence and cavitation, may attack the protective film of metals and start the corrosion. Many erosion-corrosion happens where there are sudden changes in direction or flow such as pumps, valves, elbows, impellers etc. Flow regime affects the mass transfer to the metal surface and the shear stress on the metal surfaces thus influencing the corrosion rates on the metal surface.

According to NACE (2007), flow assisted corrosion is defined as the combined action of corrosion and fluid flow and the type of flow assisted corrosion as follows:

1. Erosion-corrosion.
   It occurs when the velocity of the fluid is sufficient to remove protective films from the metal surface. The flow is normally parallel to the material surface.
2. Impingement
   It caused by turbulence or impinging flow where entrained air bubbles tend to accelerate the corrosion and this turbulence flow is directed roughly right angles to the material surface.
3. Cavitation
   It is a mechanical damage process caused by collapsing bubbles in a flowing liquid.

High flow rate or high flow velocity also cause higher corrosion rates by destructing the protective film on the metallic surface. Figure 2.5 shows a copper tube corroded due to a combination of localized high water velocity and cavitation. These localized high water velocity and cavitation occurred due to an interruption of smooth flow by the rough edge of the left elbow. Systems should be designed to limit fluid flow velocities to levels that can be tolerated by the materials. Generally, the fluid flow velocities are most commonly controlled by the proper selection of pipe sizes and the installation of instrument devices that are able to measure and control fluid flow so the maximum velocity is not exceeded. According to Copper (2012), the recommended maximum velocity for a cold water system in copper tubing is 2.5 m/s.

Figure 2.5. Corrosion on copper piping due to high water velocity and cavitation (Copper, 2012)

2. Pressure

Roberge (2007) states the presence of fluid phases in equipment may be affected by pressure thus these new phases produce different corrosive environments. For example, the amount of CO_2 dissolved in water is affected by the CO_2 partial pressure thus the fluid corrosivity will be changed. Sulfide stress corrosion cracking corrosion on some alloys are affected by H_2S partial pressure. NORSOK M-506 (2005) also shows the corrosion rate of CO_2 increases with increasing the pressure.

3. Temperature

The effect of temperature in corrosion rate is complex. In many cases, increasing temperature causes higher corrosion rates by increasing the chemical reaction rate or diffusion rates of ions to the surface films. In other cases, increasing the temperature can reduce corrosion rates at higher temperature by reducing the gas solubility. In a gas system, a dew point temperature plays an important part in the monitoring of corrosion rates. FORCE (2011) states a gas is called dry if the water dew point at the operational pressure is at least $10^{o}C$ lower than the actual operating temperature thus no internal corrosion will be expected.

4. Fouling

Fouling is an accumulation of unwanted material of organic and inorganic substances from a fluid stream that may cause under deposit corrosion and pressure drop due to flow restriction.

5. Microbes

Microbes are present almost everywhere in soils, freshwater, seawater and air. The presence of a microorganism may cause Microbiologically Influenced Corrosion (MIC). Microorganisms refer to organisms that can’t be seen by the naked eye such as microalgae, bacteria and fungi. MIC cause a lot of problems in localized corrosion such as pitting, de-alloying, enhanced erosion corrosion, enhanced galvanic corrosion, stress corrosion cracking and hydrogen embrittlement. MIC may occur at unpredicted locations with high corrosion rates. Except for titanium and high chromium-nickel alloys, all alloys have been affected by MIC. Systems affected by MIC are seawater, fresh water, hydrocarbon fuels, process chemicals, sewage etc. Stott (2003) states the most common bacteria causing MIC is Sulfate Reducing Bacteria (SRB) which is active only in anaerobic (oxygen free) environments. There are two types of SRB which are planktonic and sessile. Planktonic is floating or swimming in water meanwhile sessile is attached to the metal surface in biofilms. Most of the SRB and other bacteria present in water systems are sessile. SRB oxidizes sulfur compounds to sulfuric acid, as shown in Figure 2.6. Other acid-producing microorganisms including both bacteria and fungi may also cause MIC.

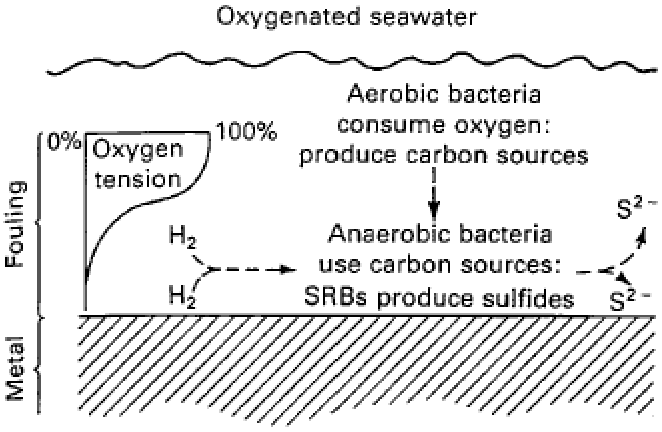


Figure 2.6. Association of anaerobic and aerobic bacteria (Sastri, 2007)

The corrosion rate is increased when acidic products of bacterial action are trapped at the biofilm-metal interface. This biofilm is created when microbes adhere to metal surface. Revie (2008) stated that in the presence of hydrogen or organic matter, SRB easily reduce inorganic sulfates to sulfides and this reaction is helped by the presence of an iron surface as shown by the following possible reaction sequence:

Anode : $4Fe \rightarrow 4Fe^{2+} + 8e^-$
Cathode : $8H_2O + 8e^- \rightarrow 8H_{\text{ads on Fe}} + 8OH^-$

$$8H_{ads} + Na_2SO_4 \xrightarrow{\text{bacteria}} 4H_2O + Na_2S$$

Here the bacteria acts as depolarizers

$$Na_2S + 2H_2CO_3 \rightarrow 2NaHCO_3 + H_2S$$

Summary : $4Fe + 2H_2O + Na_2SO_4 + 2H_2CO_3 \rightarrow 3Fe(OH)_2 + FeS + 2NaHCO_3$

The corrosion products are ferrous hydroxide $Fe(OH)_2$ and ferrous sulfide (FeS) with the ratio of 3:1 moles. Figure 2.7 shows the action of SRB in removing hydrogen from the steel surface to form FeS and H_2S. The corrosion due to SRB can be confirmed qualitatively by adding a few drops of hydrochloric acid to the rust and smelling for hydrogen sulfide.

Several approaches for controlling SRB stated by Review (2008), as follows:

- Combination of low temperature and low humidity will reduce the presence of SRB but fungi are still capable of growing in this condition so it is less effective.
- Regular cleaning to prevent biofilm formation and subsequent corrosion.
- Chlorination eliminates the bacteria but may not be good for the environment.
- Aerated water reduces the MIC but creates another problem with dissolved oxygen corrosion.
- Biocide can be beneficial but microorganism may become resistant after long term use so it is better to combine several chemicals or increase the dose of biocide. If the bacterial colonies have been established for an extended period the biocide treatment may have a limited effect without mechanical cleaning.

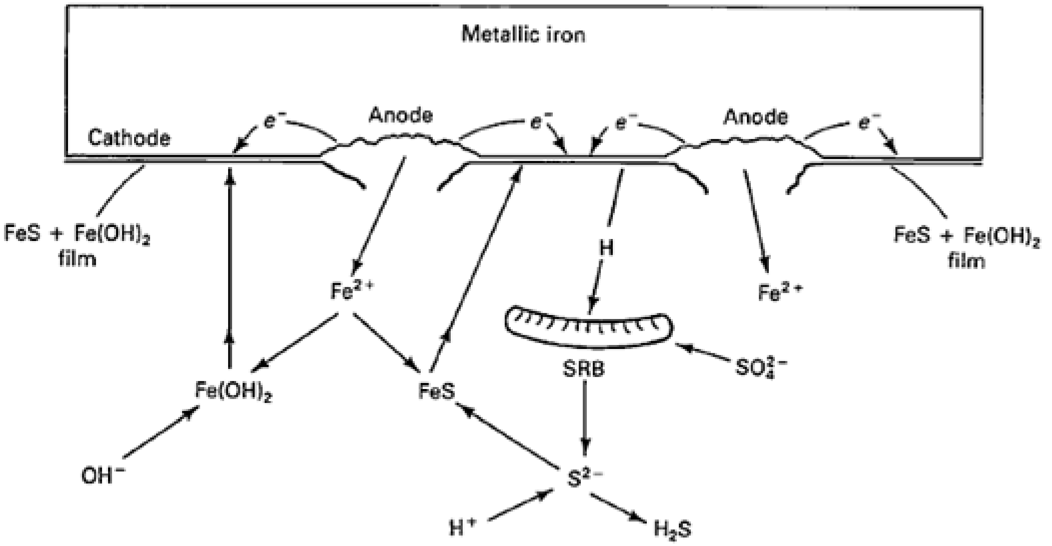


Figure 2.7. Steel corrosion in presence of Sulfate Reducing Bacteria (SRB) (Sastri, 2007)

6. CO_2 (Carbon Dioxide)

As stated by Kermani (2003), CO_2 corrosion failures have been reported to account for some 25% of all safety incidents, 2.8% turnover, 2.2% tangible asset, 8.5% increase on CAPEX, 5% of lost production and 11.5% increase to the lifting costs. This corrosion failure is common in carbon and low-alloy steel and usually classed as a sweet corrosion. In oil and gas production, dry CO_2 gas is not corrosive but when dissolved in an aqueous phase, the CO_2 will promote an electrochemical reaction between steel and the contacting aqueous phase. The CO_2 is soluble in water and brines (salt water). In water it will dissolve to give carbonic acid (H_2CO_3) as shown by the following possible reaction sequence as stated by George (2007):

$$CO_2 + H_2O \leftrightarrow H_2CO_3 \leftrightarrow H^+ + HCO_3^-$$

$$HCO_3^- \leftrightarrow H^+ + CO_3^{2-}$$

Direct reduction of H_2CO_3:

$$H_2CO_3 + e^- \rightarrow H + HCO_3^-$$

Direct reduction of hydrogen ions:

$$H^+ + e^- \rightarrow H$$

The solutions containing H_2CO_3 are more corrosive to mild steel than solutions of strong acids such as HCl (hydrochloric) and H_2SO_4 (sulfuric) at the same pH. Kermani (2003) states the above reductions are still a topic of debate whether the H_2CO_3 is directly reduced on the metal surface or not, but it has been accepted that the H_2CO_3 is an additional source of hydrogen ions thus will lead to higher corrosion rates. It has been agreed between experts that the direct reduction of H_2CO_3 dominates at high partial pressures of CO_2 and high pH meanwhile the reduction of hydrogen ions dominates at low CO_2 partial pressures and low pH.

CO_2 corrosion usually occurs in the general corrosion form and localized corrosion form. There are three variants of localized corrosion which are pitting corrosion, mesa attack corrosion and flow-induced localized corrosion. The rate of CO_2 corrosion is affected by the following parameters according to Kermani (2003):

- Temperature.
- CO_2 and H_2S content.
- Steel surface including the morphology of corrosion film, wax presence and ashphaltene.
- Fluid dynamics.
- Steel chemistry.
- Water chemistry, pH, water wetting, hydrocarbon characteristic and phase ratios

The above parameters that affect CO_2 corrosion are shown in Figure 2.8; these parameters are interdependent and can interact in many ways to influence CO_2 corrosion. It is noted that not all of these parameters are considered in the CO_2 corrosion rate calculation model of NORSOK M-506 (2005).

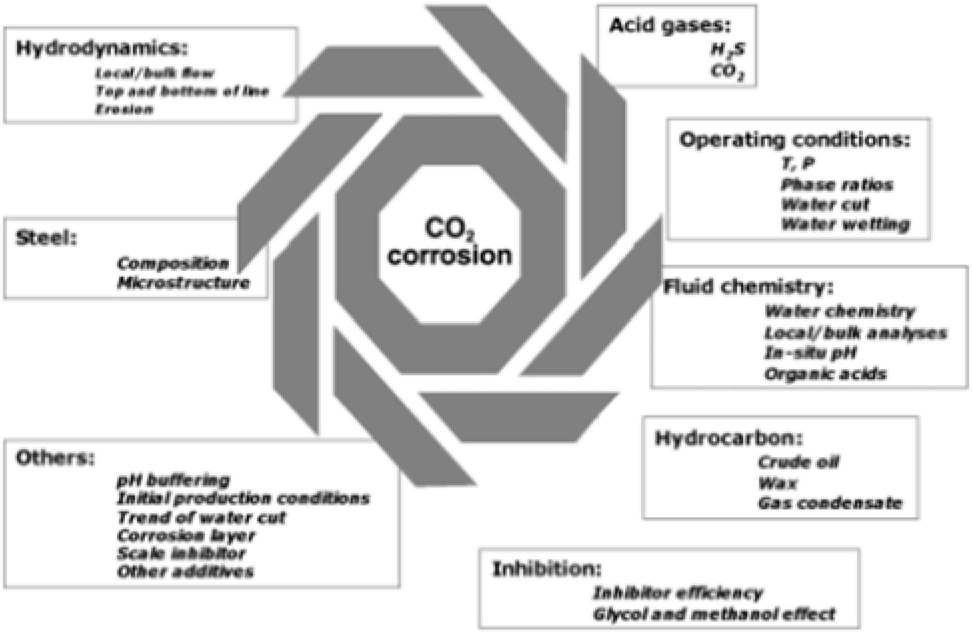


Figure 2.8. The influential parameter on CO_2 corrosion (Kermani, 2003)

In an oil and gas production asset, the following methods can be used to prevent CO_2 corrosion as stated by Kermani (2003):

- Operational parameters to be modified by removing water content and control the flow and temperature at recommended range.
- System design to be modified by removing the sharp bends, deadlegs and crevices.

- Chemistry of the environment to be modified by removing O_2 in production flow, lowering CO_2 partial pressure, removing H_2S, adding corrosion inhibitor and increasing pH.
- Interfacial condition of the metal to be modified by implementing cathodic protection or painting.
- Using corrosion resistant alloys such as duplex stainless steel instead of carbon steel.
- Using nonmetallic products such as GRP or GRE.

7. H_2S (Hydrogen Sulphide)

In sour environments, the hydrogen sulfide promotes hydrogen absorbed into steel which will cause hydrogen embrittlement. Hydrogen embrittlement is the process of high-strength steel becoming brittle and fracturing following exposure to hydrogen, this type of failure is usually classed as sulphide stress cracking (SSC) as shown in Figure 2.9. This cracking phenomenon occurs when ordinary water is present in a sour system containing hydrogen sulfide gas, without water the SSC will not occur.

According to Davis (2000), the following parameters affect the susceptibility to SSC:
- The susceptibility to SSC increases with increasing hydrogen sulfide concentration.
- The susceptibility to SSC increases with increasing H_2S partial pressure.
- The susceptibility to SSC decreases with increasing pH, when above pH 8 and below 101 Pa (0.001 atm) partial pressure of H_2S.
- The susceptibility to SSC increases with increasing nickel content in steel. Steels containing more than 1% Ni are not recommended for service in sour environments.
- The susceptibility to SSC increases with increasing strength of steels.

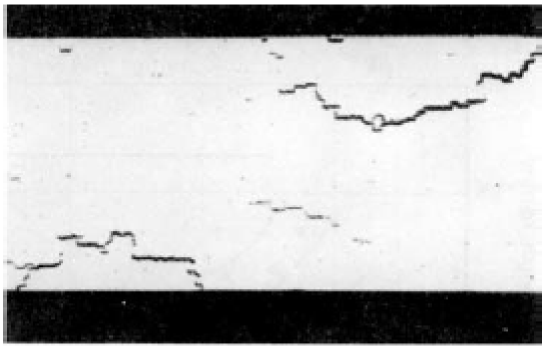


Figure 2.9. Sulphide stress cracking on steel pipeline (Davis, 2000)

The SSC failure can be prevented by following methods as stated by Davis (2000):

- Using more resistant materials, such as lower-strength materials instead of higher-strength materials. If lower-strength material can’t be used, the high-strength material needs to be tempered carefully for lowering the strength and improving the toughness.
- Coating and lining to shield the material from sour environment.
- Shot peening, grit blasting and face milling the steel surface to improve the resistance to SSC.
- Using low-hydrogen welding rods during welding and carefully store the welding rod in a dry room.

8. Chloride

Presence of chloride ions may have a major impact on corrosion behavior such as pitting corrosion as shown in Figure 2.10, crevice corrosion and chloride stress-corrosion cracking (SCC) as shown in Figure 2.11. Chloride is the most common agent for initiation of pitting as the passive film can break down locally and result in a pit forming. When a pit is formed, the local chemical environment is more aggressive than the bulk environment. Chloride SCC failure is common in 304 SS and 316 SS but not in high-nickel and high-molybdenum grades. These last two grades are resistant to SCC.

According to Davis (2000), the following parameters affect the susceptibility to SCC:
- The susceptibility to SCC increases with increasing chloride concentration.
- The susceptibility to SSC increases with increasing intregranular precipitation which is a function of alloy composition, fabrication and heat treatment.

The SCC failure can be prevented by following methods as stated by Davis (2000):

- Apply barrier coating to stainless steel that prevents chloride contact with the stainless steel.
- Change to SCC-resistant alloy such as high-nickel and high-molybdenum grades.
- Shot peening to the steel surface improves the resistance to SCC.

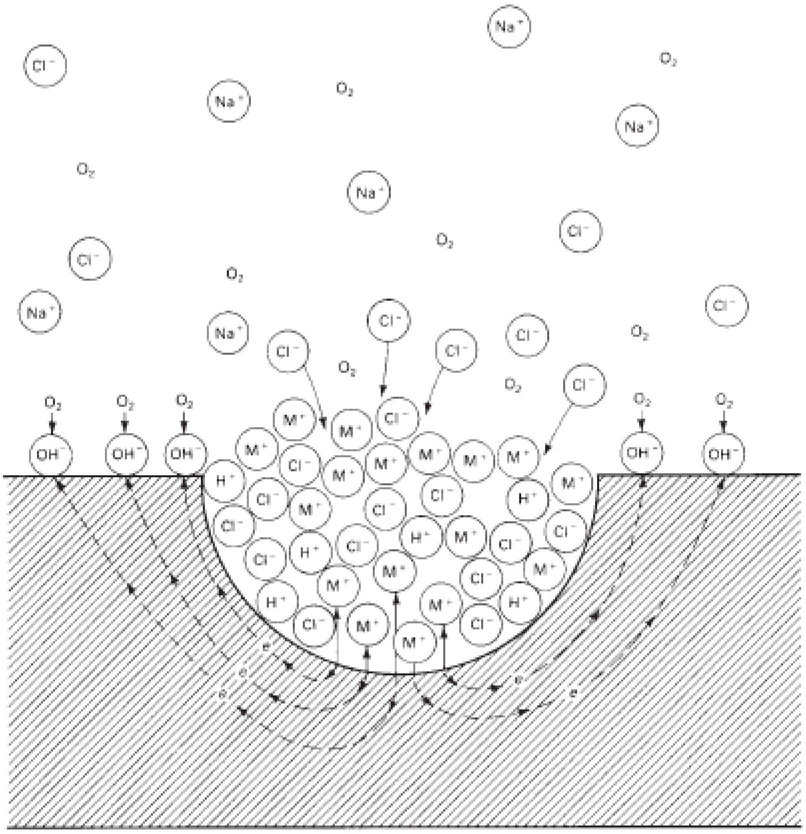


Figure 2.10. Pitting corrosion by an aerated sodium chloride (Davis, 2000)

Figure 2.11. Stress corrosion cracking on 316L stainless steel (Energy Institute, 2008)

9. Effect of sand on erosion.

Wall thinning on the pipe or vessel wall is often generated by sand erosion. This degradation typically occurs at an elbow and area close to the valve or restriction orifice. The erosion rate is increased with increasing the sand quantity and the fluid flow rate. Acoustic monitoring is one of the methods to monitor the sand erosion rate. NDT, such as ultrasonic and radiographic examination, can also be applied for checking the presence of sand erosion.

10. O_2 (Oxygen).

In the aqueous corrosion situation, the dissolved oxygen quantity is playing an important role in the corrosion rate. As a cathodic depolarizer, oxygen reacts with hydrogen atoms thus allowing corrosion attack to continue and grow at an accelerated rate. The corrosion form is a localized corrosion such as pitting; the corrosion mechanism is shown in Figure 2.12 and the following possible reaction sequence as stated by Nalco (2000).

Anode : $Fe^0 \rightarrow Fe^{+2} + 2e^-$
Cathode : $2e^- + H_2O + 1/2O_2 \rightarrow 2OH^-$

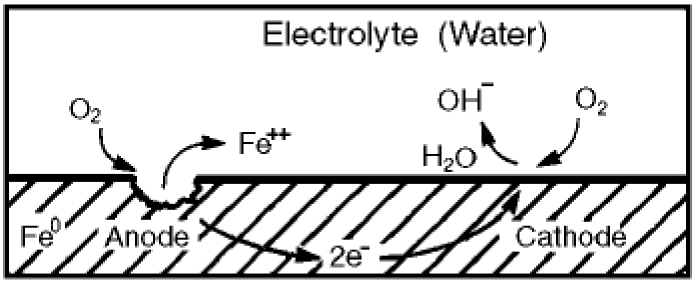


Figure 2.12. Oxygen corrosion mechanism on steel (Nalco, 2000)

Figure 2.13 shows the effect of oxygen concentration on the corrosion rate of low carbon steel in tap water at different temperatures, the corrosion rate increases with increasing temperatures. Oxygen corrosion can be minimized by both mechanical and chemical process. Mechanical process means mechanical deaeration such as heating the water in a boiler to reduce its solubility and releasing it out of the system via venting, this process may reduce the oxygen content to less than 20 ppb. Roberge (2007) stated that reducing oxygen levels to below 20 ppb has a significant effect on the corrosion of carbon steel boilers but according to Nalco (2000), even with less than 20 ppb oxygen, the oxygen corrosion may still occurs thus a chemical scavenger is used as a supplement to mechanical deaeration to reduce the oxygen level to zero. One example of chemical scavenger is Nalco chemical which is sodium sulfite based.

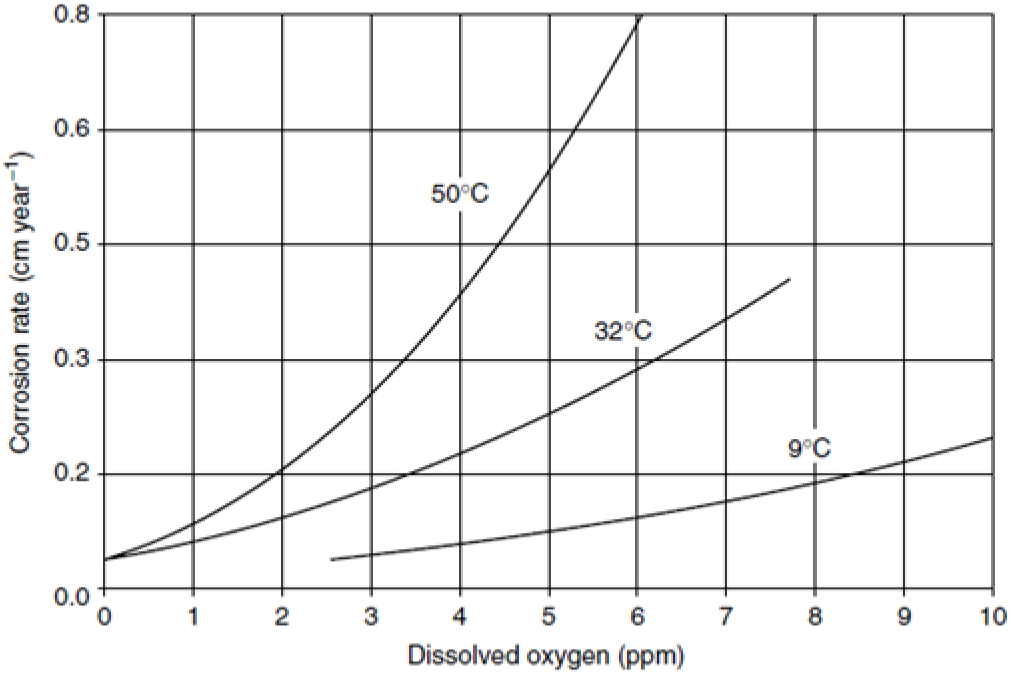


Figure 2.13. Effect of oxygen concentration on the corrosion of low carbon steel in tap water at different temperatures (Roberge, 2007)

11. Corrosion inhibitor effect on corrosion.

Corrosion inhibitor prevents or reduces corrosion without significant impact to the components and is mainly used in closed systems that have good circulation so the inhibitor concentration can be controlled. Due to the potential variety of metals in a closed system, the inhibitor shall be selected with caution as inhibitors can provide good corrosion protection for one metal but may cause corrosion for other metals in the same system. Generally, corrosion inhibitors control corrosion by forming thin films that modify the environment at the metal surface.

Davis (2000) states the corrosion inhibitors can be grouped based on its function, as follows:

1. Anodic inhibitors.

These inhibitors will selectively cover the anodic sites on the metal surface thus the corrosion rate will be decreased. It is critical to maintain the concentration of anodic inhibitors otherwise insufficient concentrations will accelerate the localized attack at the unprotected layer. Chromates, nitrites, nitrates, phosphates, tungstates and molybdates are examples of these inhibitors.

2. Cathodic inhibitors.

These inhibitors reduce corrosion rates by blocking the cathodic sites by precipitation so the reduction reaction rate of the electrochemical corrosion cell is reduced. NACE (2007) stated that arsenic, bismuth and antimony compounds are examples of cathodic inhibitors.

3. Ohmic inhibitors

These inhibitors have strong adsorption to the metal surface and reduce the corrosion rate by decreasing the mobility of ionic species between anodes and cathodes on the corroding metal surfaces. Amines are examples of these inhibitors.

4. Precipitation inhibitors.

These inhibitors reduce the corrosion rates by promoting the formation of a bulky precipitation film over the entire surface. These inhibitors include silicates and phosphates.

5. Vapor-phase inhibitors.

These inhibitors neutralize moisture and promote the passive films formation when adsorbed on metal surfaces. The passive films will protect the metal surface from corrosion.

3. ALVHEIM FPSO TOPSIDE CORROSION MANAGEMENT

In order to ensure the Alvheim corrosion management is relevant and up to date, the following bullet actions need to be made:

- Identify all plausible internal corrosion threats of each system on Alvheim FPSO Topside.
- Determine the highest risk level of each system from RuBI (FORCE's software for carrying out a RBI analysis)
- Develop corrosion performance indicators of all plausible internal degradation mechanisms.
- Determine the threshold value of each performance indicator.
- Determine the KPIs from corrosion performance indicators.
- Collect all available data from Alvheim FPSO Topside and compare it with the threshold value.
- Generate the graphic of plotted average monthly KPI against the target level.
- Suggest risk mitigation or corrective action in order to increase the average KPI compliance.

3.1. Introduction to Alvheim FPSO

The Alvheim FPSO was converted from a multipurpose shuttle tanker. It has an overall length of 252 m, a 42 m breadth and 23 m depth with deadweight of 92000 tons. The Alvheim FPSO is illustrated in Figure 3.1. As of 2012, the daily oil production is approximately 142,000 bopd (barrels oil per day) from six oil production lines which are East Kameleon, Boa, Kneler A, Kneler B, Vilje and Volund. These production lines are routed from the wells via risers to the topside process separation. Any water and gas will be separated from crude oil in the separators and the finest crude oil will be stored in cargo tanks and transferred by offloading to shuttle tankers. Gas from the separators will be treated and exported via the SAGE pipeline and some will be routed to the wells as gas lift. Water from the separators will be treated and disposed to overboard and disposal wells near the East Kameleon field. The topside facility design life is 20 years and it has at least 22 systems including process and utility systems which are described in Appendix A.

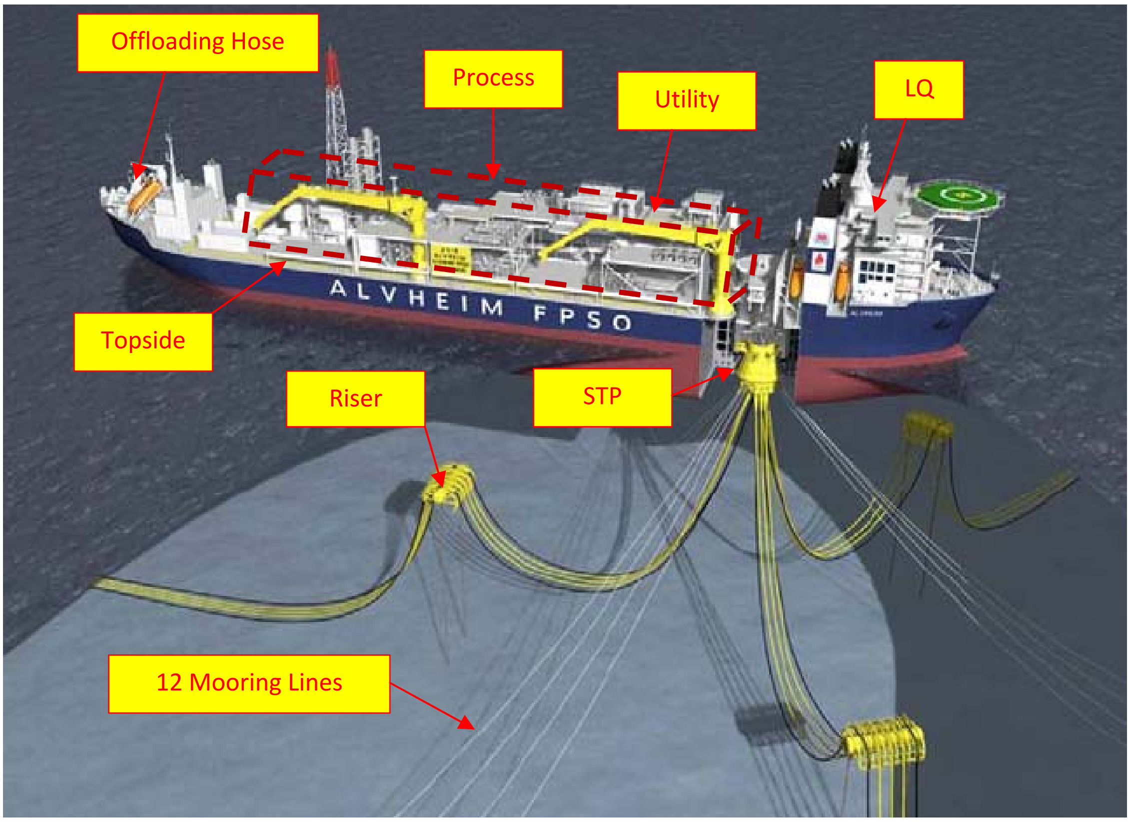


Figure 3.1. The Alvheim FPSO

3.2. Corrosion and Inspection Management System (CIMS)

A Corrosion and Inspection Management System (CIMS) is essential to be applied at Alvheim FPSO as corrosion is a major factor for risk contribution to the process facility integrity. The process facility includes piping systems, pressure vessels and other related equipment but not the PSVs and rotating equipment such as pumps and compressors. The main objective of a CIMS is to reduce the total cost of controlling corrosion by selecting correct materials, chemical and surface treatment and also by creating a risk based inspection and monitoring program for controlling or reducing the risk thus ensuring the asset integrity.

A summary of Alvheim FPSO CIMS is illustrated in Figure 3.2. An inspection program is created following the corrosion management strategy and risk assessment, the inspection program includes visual inspection and Non Destructive Testing (NDT). The interval of the inspection program is calculated based on the RBI result. On Alvheim, corrosion monitoring is performed continuously using corrosion coupons. These coupons installed inside pipework and are replaced frequently. The replaced coupon will be analyzed in order to check the weight loss and the type of corrosion. The weight loss of a coupon is used to calculate the actual corrosion rate and compare it with the calculated corrosion rate in the corrosion management strategy. Process monitoring during operation is also part of monitoring as described in chapter 2, some process parameters may dramatically increase the actual corrosion rate. These process parameters will be monitored after performance indicators have been established and agreed.

Some benefits of regularly monitoring after Alvheim CIMS implementation as follows:

1. The performance and efficiency of Alvheim CIMS can be measured and evaluated. As shown in Figure 2.1, good business means users spend a reasonable amount of money to do limited inspection programs without increasing the asset risk.
2. To ensure the Alvheim CIMS is up to date.
3. The performance of Alvheim CIMS can be improved by improving the average KPI compliances.

Some corrosion mitigations are taken during operation such as chemical treatment, surface protection and selecting reliable material during modification works. On Alvheim, chemicals such as corrosion inhibitor, wax inhibitor and scale inhibitor are injected frequently. Surface protection such as coating and insulation of pipework or equipment has to be properly maintained in order to reduce the probability of failure from an external degradation mechanism.

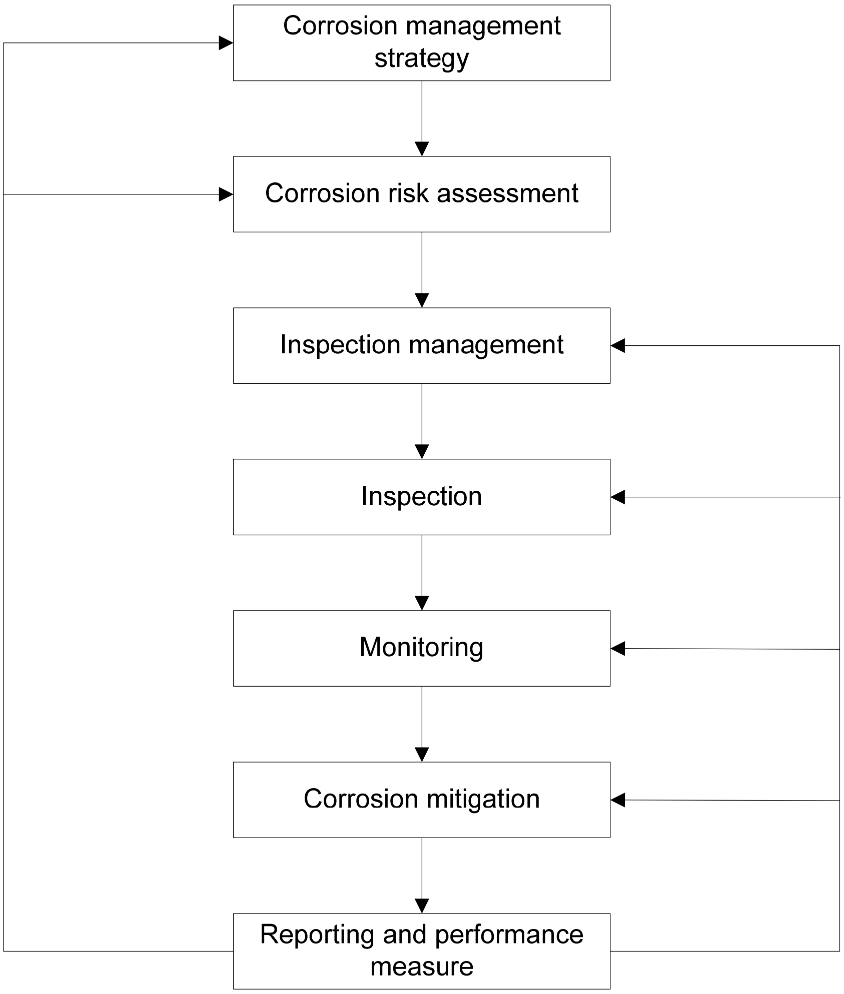


Figure 3.2. Alvheim FPSO CIMS (MONAS, 2008)

The objectives of the Alvheim FPSO Topside Corrosion Management Strategy as stated in MONAS (2008) are as follows:

1. To provide a management directive with the purpose of controlling and minimizing the corrosion risk and cost over the lifetime of the field.
2. To ensure that all relevant regulatory requirements are followed
3. To keep high focus and minimize corrosion problems in high risk areas where loss of integrity will have impact on personnel safety, environment and economy/oil production.
4. To minimize leaks caused by corrosion or erosion in high risk areas.
5. To ensure that corrosion risk assessment reviews or updates are performed regularly to determine the need for inspection, corrosion and process monitoring, or enhancement of the corrosion mitigation by chemical treatment, surface protection or corrosion resistant materials.
6. To ensure that all relevant corrosion performance data is available in an easily accessible management system.
7. To define clear responsibility, accountability, and ownership of corrosion management throughout the Alvheim organization.
8. To ensure that corrosion management is considered in the design stages of any modification project.

3.3. RBI Analysis for Alvheim FPSO Topside

A corrosion risk assessment is also known as a RBI analysis and the following information from Alvheim FPSO-Topside is needed during RBI analysis:

- Process Line List which shows process parameters of line numbers such as pressure, temperature, flow, density, type of fluid etc.
- Process Flow Diagram (PFD) which shows the mass balance or mole fractions of fluid flowing in the pipework.
- P&ID (Piping and Instrumentation Diagram) which shows the piping of the process flow together with the installed equipment and instrumentation.
- Piping material specification which shows the material of pipework including the thickness of the pipes.
- Design life time is also required for RBI Analysis. Alvheim FPSO-Topside is designed for 20 years life time.
- Specification of coating and insulation for pipework and pressure vessel.
- Historical data from inspection and monitoring, if available.

As the line list contains more than 2800 line tags, the corrosion groups are needed for grouping these line tags which have similar parameter boundaries thus the possible degradation mechanisms of these tags in one corrosion group is the same. In general, there are two degradation mechanisms of corrosion which are internal degradation mechanism and external degradation mechanism. The external degradation mechanism will not be discussed in this thesis. The steps of RBI analysis are illustrated in Figure 3.3.

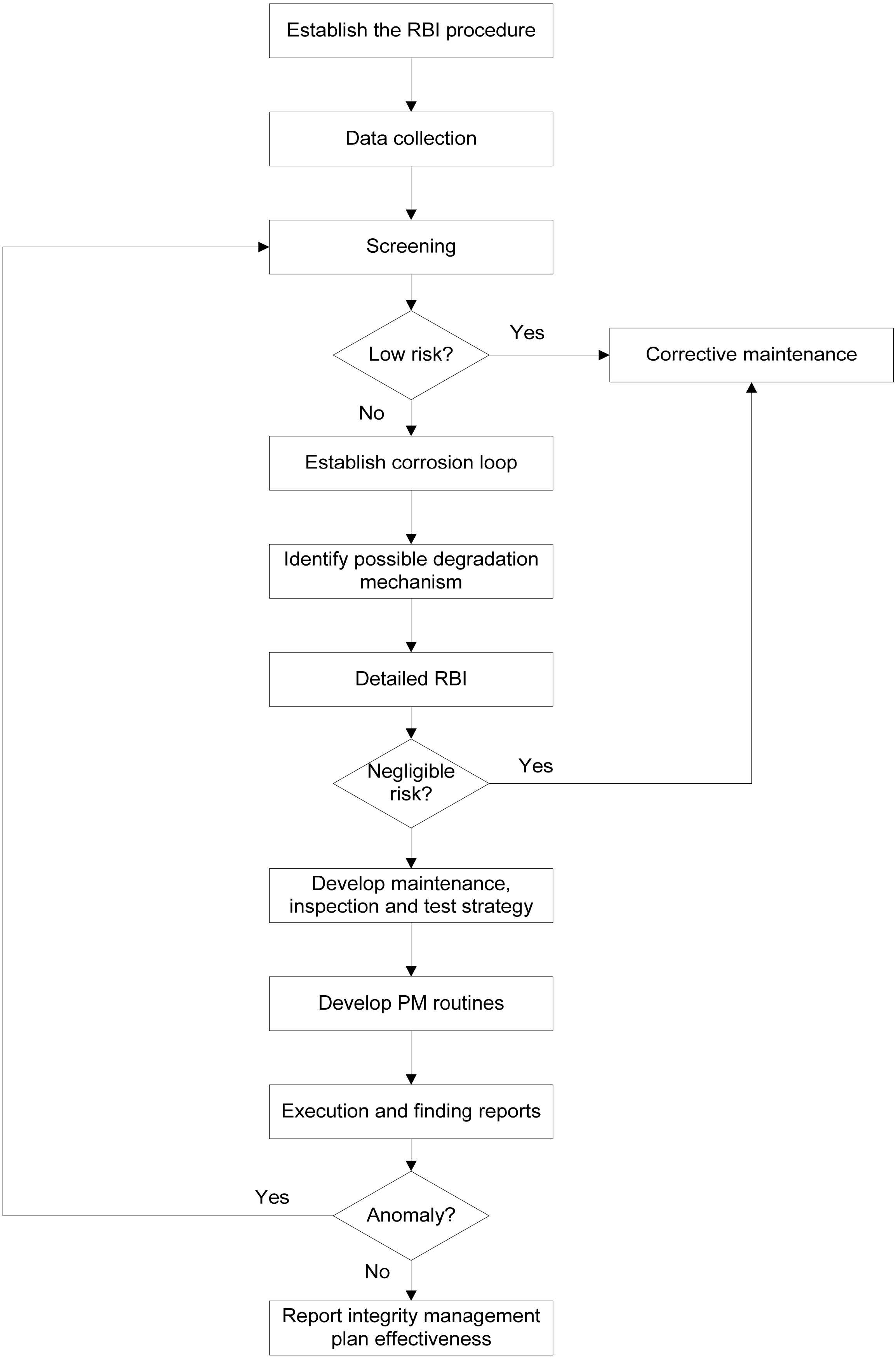


Figure 3.3. The steps of RBI process

A screening assessment has to be done before a detailed RBI analysis which allows user to define systems or subsystems that will not be included in a detailed RBI analysis. In this thesis, RBI is only applied to the static equipment on Alvheim FPSO-Topside such as pipework, pressure vessels, heat exchangers and other static equipment. The risk matrix 2 x 2 as shown in Table 3.1 is used during the screening stage. This screening assessment complies with the generic RBI process stated in DNV RP-G101 (2009).

The formula for calculating risk is defined as follows:

Risk = Probability of Failure (PoF) x Consequence of Failure (CoF) (Eq. 3.1)

Table 3.1. Risk matrix during screening stage (FORCE, 2011)

PROBABILITY	A leak can occur **(Significant)**	**Inspection or mitigation** can be used but is normally not cost effective. Normally **not included** in detailed RBI	**Detailed RBI** to be performed
	Negligible Probability of a leak **(Negligible)**	**Inspection or mitigation** normally not performed due to very low PoF and CoF. **Not included** in detailed RBI	**Detailed RBI** normally done due to high CoF.
		ACCEPTABLE	UNACCEPTABLE
		CONSEQUENCE	

Probability of Failure (PoF) during screening stage can be defined in Table 3.2.

Table 3.2. Probability of Failure (PoF) during screening stage (FORCE, 2011)

PoF	Description
Significant	A leak can occur
Negligible	Negligible possibility of a leak A leak is not assumed under normal operation

Meanwhile, the Consequence of Failure (CoF) during screening stage can be defined in Table 3.3.

Table 3.3. Consequence of Failure (CoF) during screening stage (FORCE, 2011)

CoF	Description	Consequence Categories
Significant	A leak can occur which is flammable, high-pressure or toxic	Safety/Personnel
	A leak will only result in toxic pollution	Environment
	A leak will result in downtime and loss of production	Economy
Negligible	A leak is not flammable, low-pressure or non-toxic	Safety/Personnel
	A leak will only result in small non-toxic pollution	Environment
	A leak will not result in downtime and loss of production	Economy

The systems or subsystems which are not included in detailed RBI will be subject to a corrective or reactive management strategy.

The risk matrix during detailed RBI is wider than the risk matrix during screening stage; refer to Table 3.4 for risk matrix 5x5.

Table 3.4. The risk matrix during detailed RBI (FORCE, 2011)

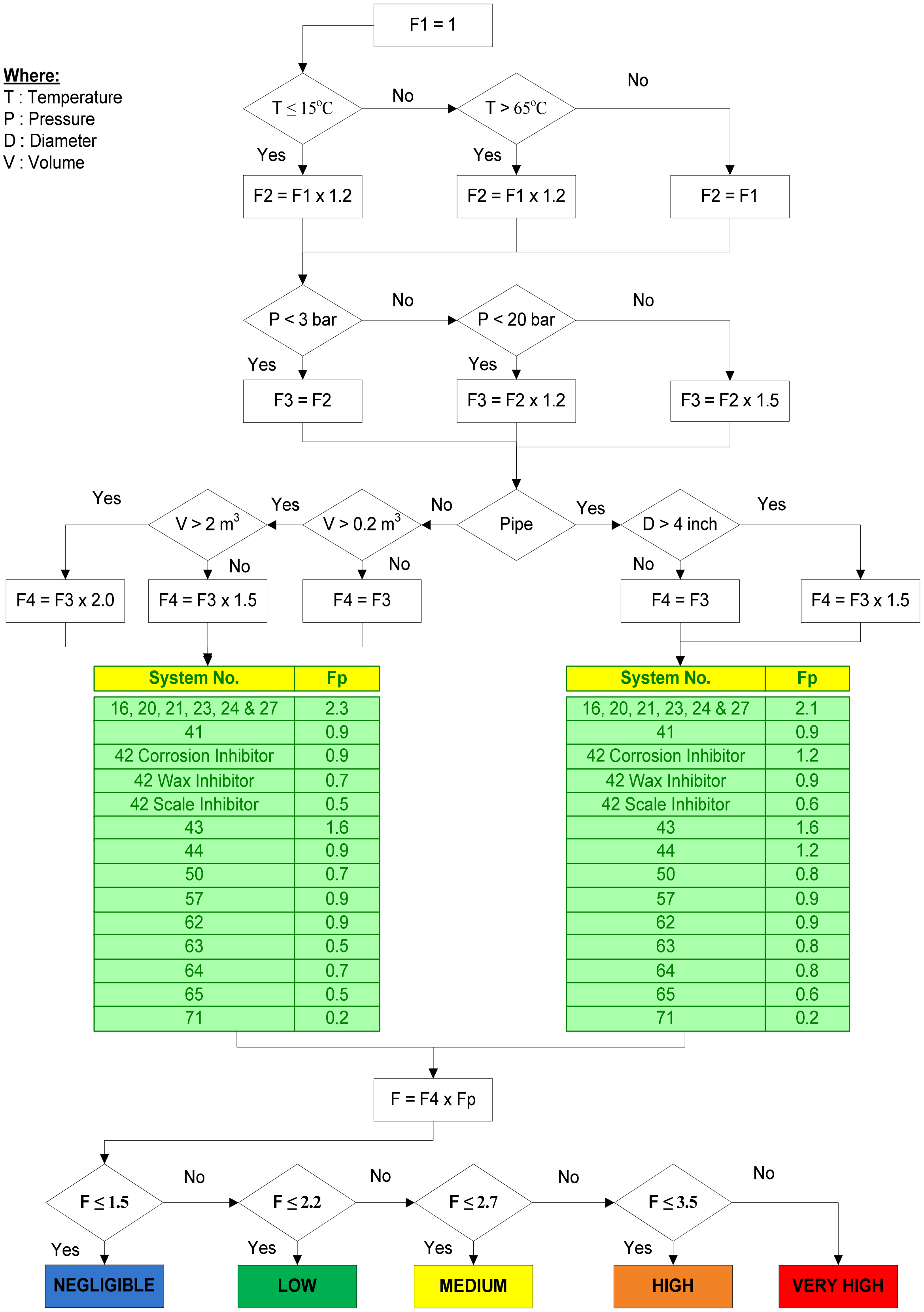
RISK		**CoF**				
		N	L	M	H	VH
PoF	VH	N	M	H	VH	VH
	H	N	M	H	H	VH
	M	N	L	M	H	H
	L	N	L	M	M	H
	N	N	L	L	M	M

Where:

Risk : PoF x CoF
PoF : Probability of Failure
CoF : Consequence of Failure
VH : Vey High Risk
H : High Risk
M : Medium Risk
L : Low Risk
N : Negligible Risk

The above risk levels are evaluated based on its consequence to personnel, environment and economy and its probability of failure. The highest consequence from these three consequences will be chosen during a detailed RBI.

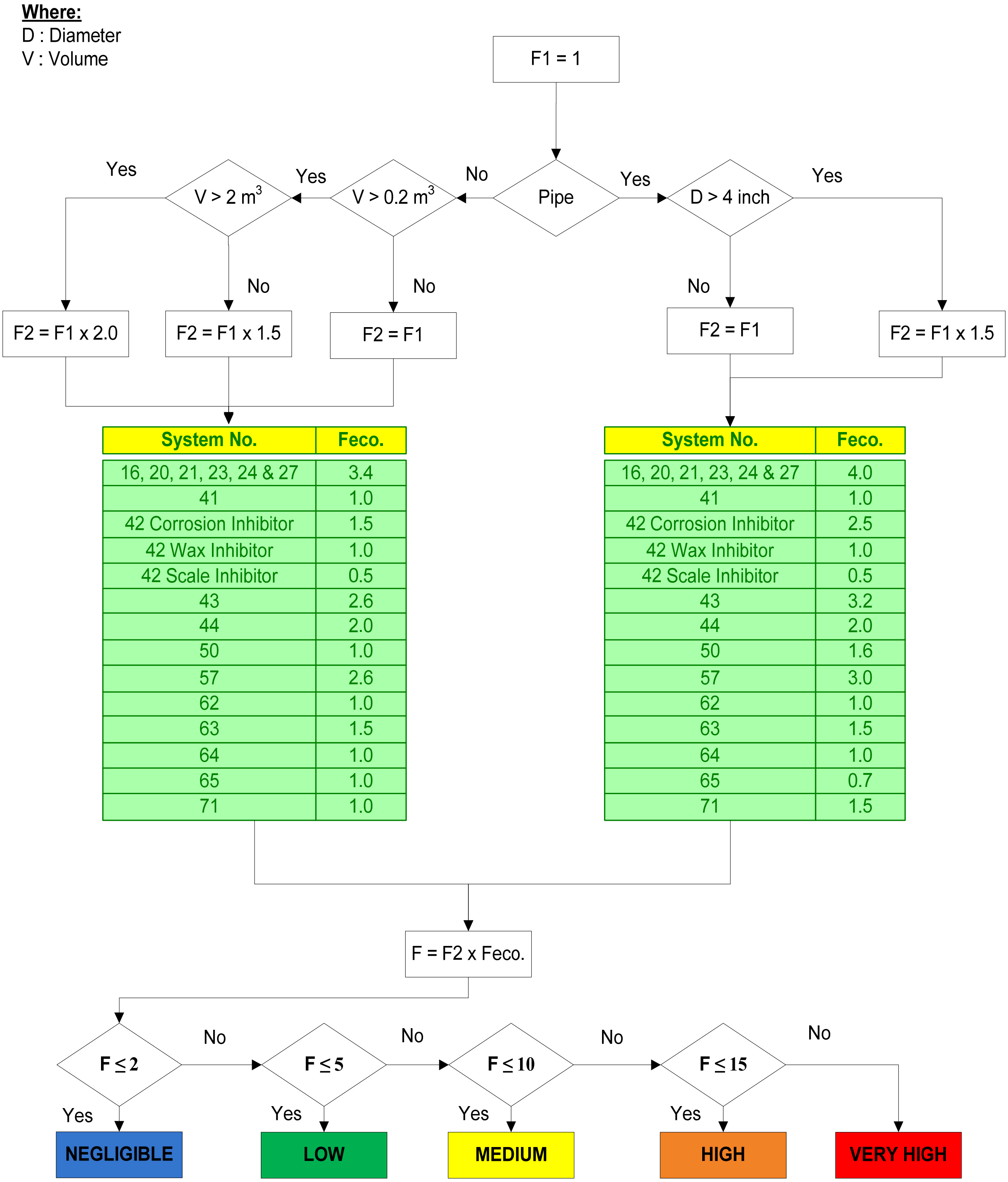
The decisions trees as shown in Figure 3.4, 3.5 and 3.6 are used to determine the consequence of failure. These trees were taken from FORCE (2011) and modified to fit with the system numbers on Alvheim FPSO Topside. From these trees, it is noted that the multiplication factor increases with increasing temperature, volume and pressure. It also noted that the multiplication factor for hydrocarbon system (system no.16, 20, 21, 23, 24 &27) is higher than others.



System No.	Fp
16, 20, 21, 23, 24 & 27	2.3
41	0.9
42 Corrosion Inhibitor	0.9
42 Wax Inhibitor	0.7
42 Scale Inhibitor	0.5
43	1.6
44	0.9
50	0.7
57	0.9
62	0.9
63	0.5
64	0.7
65	0.5
71	0.2

System No.	Fp
16, 20, 21, 23, 24 & 27	2.1
41	0.9
42 Corrosion Inhibitor	1.2
42 Wax Inhibitor	0.9
42 Scale Inhibitor	0.6
43	1.6
44	1.2
50	0.8
57	0.9
62	0.9
63	0.8
64	0.8
65	0.6
71	0.2

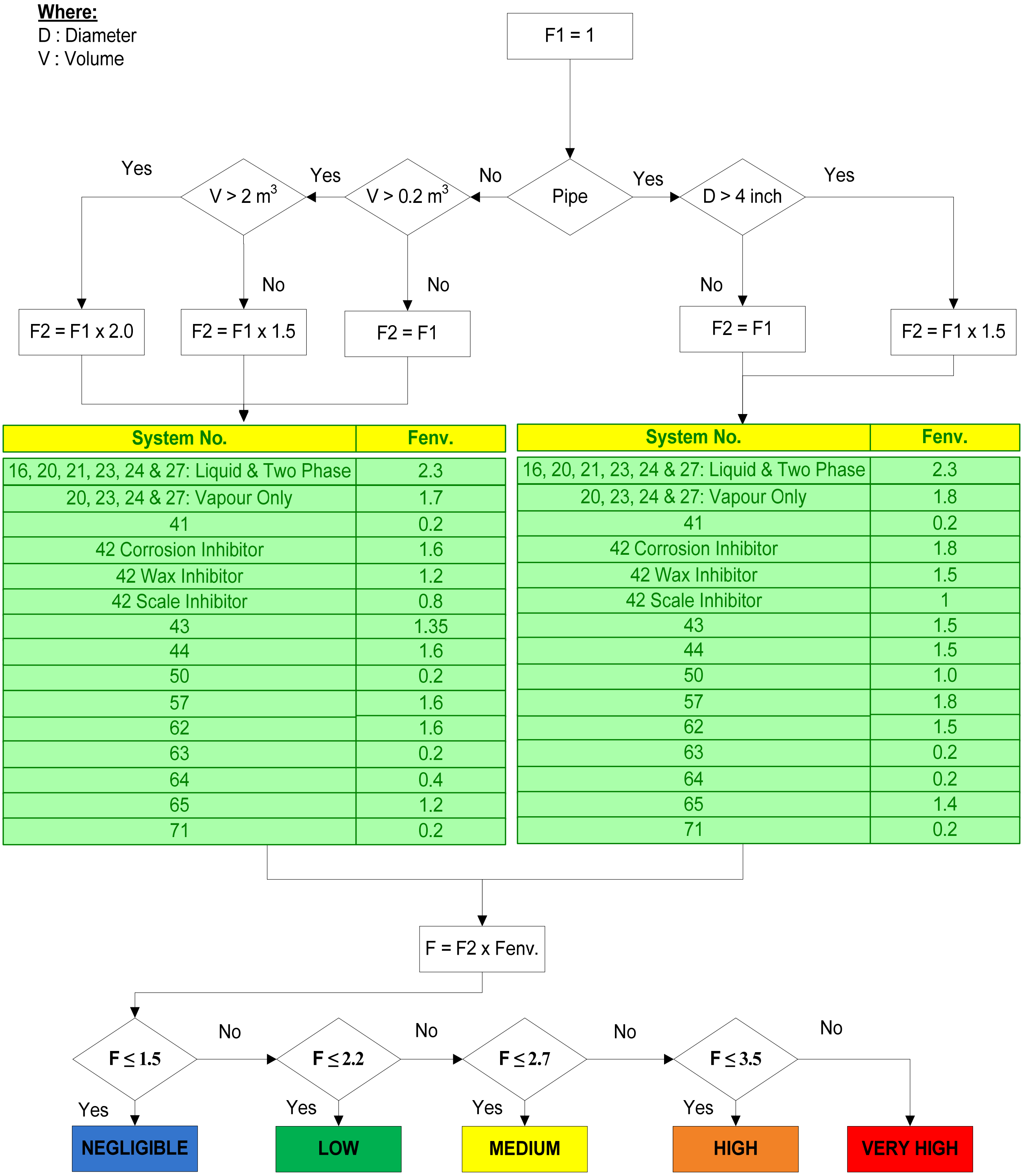
Figure 3.4. Consequence of failure to personnel safety (Modified from FORCE (2011))



System No.	Feco.
16, 20, 21, 23, 24 & 27	3.4
41	1.0
42 Corrosion Inhibitor	1.5
42 Wax Inhibitor	1.0
42 Scale Inhibitor	0.5
43	2.6
44	2.0
50	1.0
57	2.6
62	1.0
63	1.5
64	1.0
65	1.0
71	1.0

System No.	Feco.
16, 20, 21, 23, 24 & 27	4.0
41	1.0
42 Corrosion Inhibitor	2.5
42 Wax Inhibitor	1.0
42 Scale Inhibitor	0.5
43	3.2
44	2.0
50	1.6
57	3.0
62	1.0
63	1.5
64	1.0
65	0.7
71	1.5

Figure 3.5. Consequence of failure to economy (Modified from FORCE (2011))



System No.	Fenv.
16, 20, 21, 23, 24 & 27: Liquid & Two Phase	2.3
20, 23, 24 & 27: Vapour Only	1.7
41	0.2
42 Corrosion Inhibitor	1.6
42 Wax Inhibitor	1.2
42 Scale Inhibitor	0.8
43	1.35
44	1.6
50	0.2
57	1.6
62	1.6
63	0.2
64	0.4
65	1.2
71	0.2

System No.	Fenv.
16, 20, 21, 23, 24 & 27: Liquid & Two Phase	2.3
20, 23, 24 & 27: Vapour Only	1.8
41	0.2
42 Corrosion Inhibitor	1.8
42 Wax Inhibitor	1.5
42 Scale Inhibitor	1
43	1.5
44	1.5
50	1.0
57	1.8
62	1.5
63	0.2
64	0.2
65	1.4
71	0.2

Figure 3.6. Consequence of failure to environment (Modified from FORCE (2011))

An example of calculating CoF:

System Number = System 21
Pipe Material = 6” NPS Schedule 40 A3336 6 SMLS (LTCS)
Operating Temperature = 85°C
Operating Pressure = 14 bar
The CoF to personnel safety = Very High, as F = 1 x 1.2 x 1.2 x 1.5 x 2.1 = 4.536 > 3.5
The CoF to economy = Medium, as F = 1 x 1.5 x 4 = 6 > 5 and 6 < 10
The CoF to environment = High, as F = 1 x 1.5 x 2.3 = 3.45 > 2.7 and 3.45 < 3.5
The highest CoF will be used during detailed RBI so CoF above pipework = Very High.

According to FORCE (2011), the probability of failure in a detailed RBI can be defined as a function of Lifetime Values (LTV) shown in Table 3.5.

Table 3.5. PoF is defined as a function of LTV (FORCE, 2011)

LTV	Probability of Failure	
>4	5	Very High
1-4	4	High
0.5-1	3	Medium
0.2-0.5	2	Low
<0.2	1	Negligible

LTV can be calculated as follows:

$$LTV = \frac{CR_t}{CR_{critical}} \quad \text{(Eq. 3.2)}$$

Where:

CRt is the wall thinning rate due to corrosion or erosion at time t which is given below:

$$CR_t = a*CR_{insp} + b*CR_{mon} + c*CR_{calc} \quad \text{(Eq. 3.3)}$$

Where:

a, b and c are weight factors and sum of a, b and c are equal to 1.

CR_{insp} = Wall thinning rate due to corrosion or erosion based on inspection data such as UT etc.

CR_{mon} = Wall thinning rate due to corrosion or erosion based on monitoring data such as metallic corrosion coupons etc.

CR_{calc} = Wall thinning rate due to corrosion or erosion based on calculated data such as CO_2 corrosion rates in NORSOK M-506 etc. NORSOK M-506 (2005) uses an empirical corrosion rate model for carbon steel in water containing CO_2 at different temperatures, pH’s, CO_2 fugacities and wall shear stresses.

Only CR_{calc} will be used for calculating LTV value as the value of CR_{insp} and CR_{mon} are not always available in every system thus the value a and b are set to zero.

Depending on the specific material and environment, the corrosion rate of uniform degradation can be linear, decreasing with time or increasing with time. Long term projection of corrosion damage is possible when the corrosion rate is linear or decreases with time. It is more difficult to predict long-term corrosion damage if the corrosion rates increase with time.

$CR_{critical}$ is the critical wall thinning rate for complete utilization of the wall thickness without loss of piping integrity which is defined in Eq. 3.4.

$$CR_{critical} = \frac{WT_n - WT_{critical}}{L_{TD}} \qquad \text{(Eq. 3.4)}$$

Where:

L_{TD} = Design life time (years). Alvheim FPSO Topside is designed for 20 years life time.

WT_n = Nominal wall thickness (mm). This value is taken from piping material specification.

$WT_{critical}$ = Minimum required wall thickness (mm). This value does not include the allowances such as corrosion allowance and mill tolerance. It can be calculated from formula 3a in ASME B31.3 (2010), as shown in Eq. 3.5.

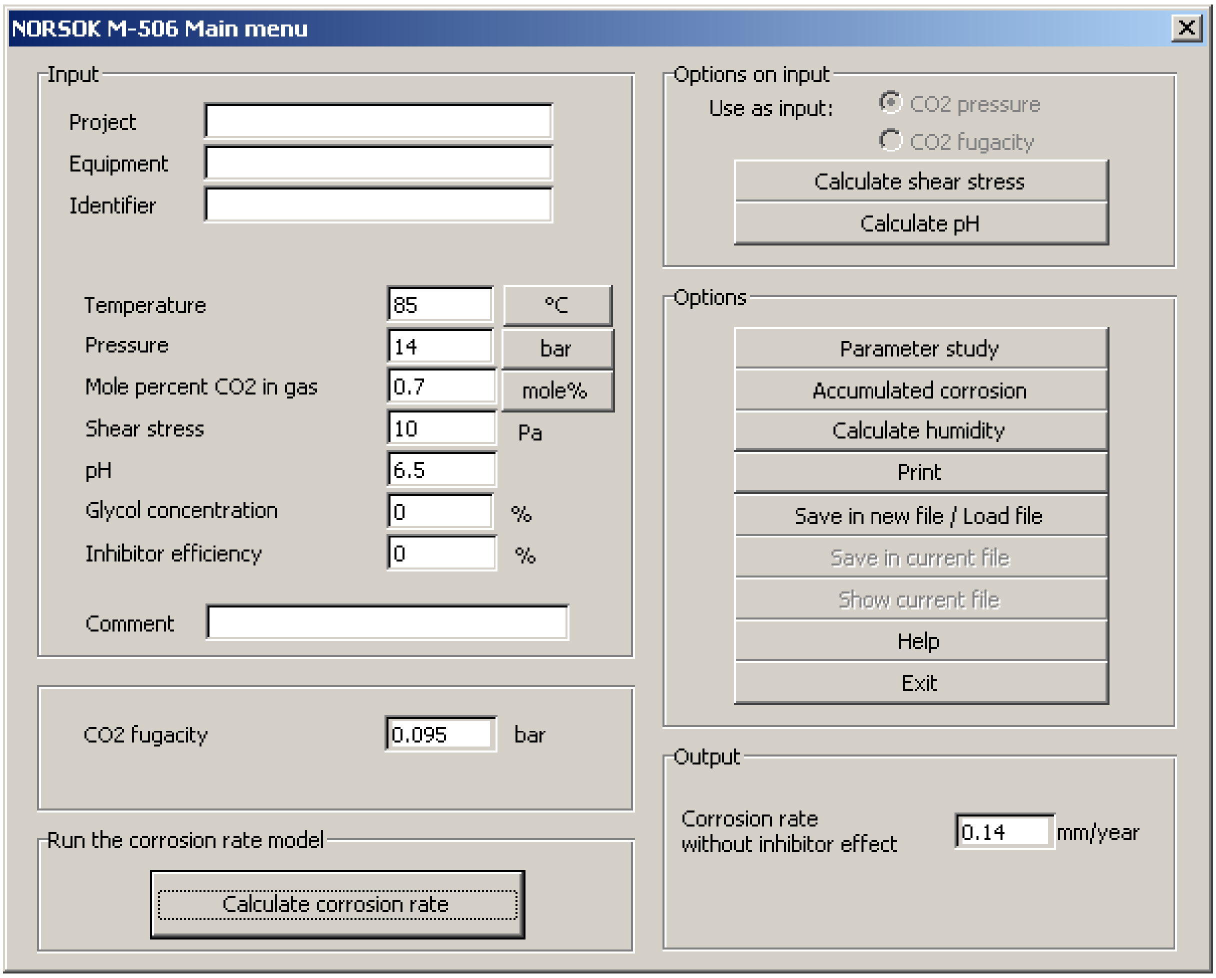
$$WT_{critical} = \frac{PD}{2(SHE + PY)} \qquad \text{(Eq. 3.5)}$$

Where:

P = Internal design pressure (barg)
D = Outside diameter of the pipe (mm)
SH = Allowable stress of the pipe at design temperature (N/mm^2)
E = Basic quality factors for longitudinal weld joints in pipes, tubes and fitting. Usually the value is equal to 1 for seamless pipe.
Y = Coefficient value and usually the value is equal to 0.4 for ductile metals.

An example of calculating PoF:

System = 21
Pipe Material = 6” NPS Schedule 40 A333 Grade 6 SMLS (LTCS)
Operating Temperature = 85^{o}C
Operating Pressure = 14 bar
Mol% CO2 in gas = 0.7 mol%
Shear Stress = 10 Pa
pH = 6.5
Glycol concentration = 0%
Inhibitor efficiency = 0%
CR_{calc} in accordance to NORSOK M-506 = 0.14 mm/year as shown in Figure 3.7.



Use as input: ● CO2 pressure ○ CO2 fugacity

Temperature 85 °C

Pressure 14 bar

Mole percent CO2 in gas 0.7 mole%

Shear stress 10 Pa

pH 6.5

Glycol concentration 0 %

Inhibitor efficiency 0 %

CO2 fugacity 0.095 bar

Corrosion rate without inhibitor effect 0.14 mm/year

Figure 3.7. CO_2 corrosion rate (NORSOK M-506, 2005)

The minimum required wall thickness of 6” LTCS (Low Temperature Carbon Steel) under internal pressure of 14 barg at 85°C using Eq. 3.5 as follows:

$$\mathrm{WT_{critical}} = \frac{14\ \mathrm{barg}*168.3\ \mathrm{mm}}{2(1379\ \mathrm{barg}*1+14\ \mathrm{barg}*0.4)} = 0.851\ \mathrm{mm}$$

The nominal thickness of 6” pipe schedule 40 is equal to 7.11 mm thus the $\mathrm{CR_{critical}}$ is calculated from Eq. 3.4 as follows:

$$\mathrm{CR_{critical}} = \frac{\mathrm{WT_n}\text{-}\mathrm{WT_{critical}}}{\mathrm{L_{TD}}} = \frac{7.11\ \mathrm{mm}\text{-}0.851\ \mathrm{mm}}{20\ \mathrm{year}} = 0.313\,\frac{\mathrm{mm}}{\mathrm{year}}$$

The LTV is calculated from Eq. 3.2 as follows:

$$\mathrm{LTV} = \frac{\mathrm{CR_t}}{\mathrm{CR_{critical}}} = \frac{\mathrm{CR_{calculated}}}{\mathrm{CR_{critical}}} = \frac{0.14\ \mathrm{mm/year}}{0.313\ \mathrm{mm/year}} = 0.45$$

According to the LTV as shown in Table 3.5, the probability of failure of 6” LTCS Pipe due to internal degradation mechanism is Low (PoF = 2).

The risk of 6” NPS Schedule 40 A333 Grade 6 SMLS LTCS in system 21 is high as it has low PoF and very high CoF, refer to Table 3.4.

3.4. Material for Piping and Static Equipment on Alvheim FPSO Topside

On Alvheim FPSO Topside, the materials of piping and static equipment were selected based on CO_2 corrosion calculations of NORSOK M-506 and process simulations for the design case of 2018 as this case has the highest CO_2 content. To a large extent, carbon steel material should be selected for pipework and equipment in order to reduce cost of CAPEX. Alvheim piping specification has a maximum of 3 mm corrosion allowance for carbon steel thus the Corrosion Resistant Alloy (CRA) shall be selected if the CO_2 calculated corrosion rate of carbon steel exceeds 0.15 mm/year due to the design life of 20 years. The service class summary of Alvheim FPSO Topside with its internal corrosion threats is shown in Table 3.6. This table also shows that Alvheim FPSO Topside has at least five different materials for pipework which are carbon steel, austenitic stainless steel (316 SS), duplex stainless steel (22Cr), super duplex stainless steel (25Cr) and titanium (Ti). Carbon steel has many internal corrosion threats compare to other materials. Titanium is the most reliable material but it is the most expensive material compared to others.

Table 3.6. Internal corrosion threat on Alvheim FPSO topside

MATERIAL	C.A	SYSTEM NUMBER	SERVICE	INTERNAL CORROSION THREATS
CS	3 mm	20	Crude Oil Stabilization and Separation	CO_2 Corrosion, SSC, MIC, UDC, Galvanic Corrosion, Erosion-Corrosion, Corrosion Fatigue
		21	Crude Oil metering	CO_2 Corrosion, SSC, MIC, UDC, Galvanic Corrosion, Erosion-Corrosion, Corrosion Fatigue
		23	Re-Compression	CO_2 Corrosion, SSC, MIC, UDC, Galvanic Corrosion, Erosion-Corrosion, Corrosion Fatigue
		24	Gas Dehydration	CO_2 Corrosion, SSC, MIC, UDC, Galvanic Corrosion, Erosion-Corrosion, Corrosion Fatigue
		27	Gas Export	CO_2 Corrosion, SSC, MIC, UDC, Galvanic Corrosion, Erosion-Corrosion, Corrosion Fatigue
		41	Heating Medium	O_2 Corrosion, MIC, UDC, Galvanic Corrosion and Erosion-Corrosion
		43	Flare, Vent, VOC Recovery and Blanket Gas	CO_2 Corrosion, SSC, MIC, UDC, Galvanic Corrosion, Erosion-Corrosion & Corrosion Fatigue
		45	Fuel Gas	CO_2 Corrosion, SSC, MIC, UDC, Galvanic Corrosion, Erosion-Corrosion & Corrosion Fatigue
		46	Methanol	None
		57	Closed Drain	CO_2 Corrosion, SSC, MIC, UDC, Galvanic Corrosion, Erosion-Corrosion & Corrosion Fatigue
		63	Compressed Air	None
		64	Inert Gas	None
22Cr Duplex	0 mm	16	Topside flowlines and manifold	SSC and Erosion-Corrosion
		20	Crude Oil Stabilisation and Separation	SSC and Erosion-Corrosion
		27	Gas Export	SSC and Erosion-Corrosion
		29	Water Injection	SSC and Erosion-Corrosion
		44	Produced Water	SSC and Erosion-Corrosion
		53	High Pressure Fresh Water	None
		56	Open Drain	O_2 Corrosion
		57	Closed Drain	SSC and Erosion-Corrosion

(table continued on next page)

MATERIAL	C.A	SYSTEM NUMBER	SERVICE	INTERNAL CORROSION THREATS
25Cr Duplex	0 mm	50	Sea Water	O_2 Corrosion and Erosion-Corrosion
		56	Open Drain	O_2 Corrosion
316SS	0 mm	16	Process Blow Down	SSC and Erosion-Corrosion
		20	Crude Oil Stabilisation and Separation	SSC and Erosion-Corrosion
		23	Re-Compression	SSC and Erosion-Corrosion
		24	Gas Dehydration	SSC and Erosion-Corrosion
		27	Gas Export	SSC and Erosion-Corrosion
		42	Chemical Injection	None
		43	Flare	SSC and Erosion-Corrosion
		46	Methanol	None
		53	Fresh Water	None
		57	Closed Drain	SSC and Erosion-Corrosion
		62	Diesel Oil	SSC and Erosion-Corrosion
		63	Compressed Air	None
		64	Inert Gas	None
		65	Hydraulic Oil	SSC and Erosion-Corrosion
Titanium	0 mm	47	Electro Chlorination	Immune if the operating temperature below 85^oC
		50	Sea Water	Immune if the operating temperature below 85^oC
		71	Fire Water	Immune if the operating temperature below 85^oC

More than 2800 line tags including equipments are analyzed in detailed RBI. FORCE has developed software for handling and organization of all data considered necessary for carrying out a detailed RBI analysis and this software is called RuBI. A result from RuBI has been used to generate Table 3.7 that shows the highest risk due to internal degradation mechanism of each system.

Table 3.7. Risk of internal corrosion for each system on Alvheim FPSO Topside

MATERIAL	SYSTEM NUMBER	SERVICE	CoF Personnel	CoF Environment	CoF Economy	PoF	Risk of Internal Corrosion
CS	20	Crude Oil Stabilization and Separation	Very High	High	High	High	Very High
	21	Crude Oil metering	Very High	High	High	Very High	Very High
	23	Re-Compression	Very High	Medium	High	Very High	Very High
	24	Gas Dehydration	Very High	Medium	Medium	High	Very High
	27	Gas Export	Very High	Medium	High	Very High	Very High
	41	Heating Medium	Low	Medium	Low	Negligible	Low
	43	Flare, Vent, VOC Recovery and Blanket Gas	Medium	Low	Medium	High	High
	45	Fuel Gas	High	Medium	Medium	Negligible	Medium
	46	Methanol	Low	Low	Low	Low	Low
	57	Closed Drain	Very High	High	High	High	Very High
	63	Compressed Air	Low	Low	Low	Low	Low
	64	Inert Gas	Low	Low	Low	Low	Low
22Cr Duplex	16	Topside flowlines and manifold	Very High	High	High	Low	High
	20	Crude Oil Stabilisation and Separation	Very High	High	High	Medium	High
	27	Gas Export	Very High	High	High	Negligible	Medium
	29	Water Injection	Low	Medium	Medium	Negligible	Low
	44	Produced Water	Medium	Medium	Medium	Negligible	Low
	53	High Pressure Fresh Water	Low	Low	Low	Low	Low
	56	Open Drain	Negligible	Negligible	Low	Negligible	Low
	57	Closed Drain	High	Low	Medium	Negligible	Medium

(table continued on next page)

MATERIAL	SYSTEM NUMBER	SERVICE	CoF Personnel	CoF Environment	CoF Economy	PoF	Risk of Internal Corrosion
25Cr Duplex	50	Sea Water	Negligible	Negligible	Negligible	Very High	Medium
	56	Open Drain	Negligible	Negligible	Low	Negligible	Low
316SS	16	Process Blow Down	High	Medium	Medium	Negligible	Medium
	20	Crude Oil Stabilisation and Separation	Very High	Medium	High	Negligible	Medium
	23	Re-Compression	High	Medium	Medium	Negligible	Medium
	24	Gas Dehydration	Very High	High	High	Negligible	Medium
	27	Gas Export	High	Medium	Medium	Negligible	Medium
	42	Chemical Injection	Negligible	Low	Low	Negligible	Low
	43	Flare	High	Medium	Medium	Negligible	Medium
	46	Methanol	Low	Low	Low	Low	Low
	53	Fresh Water	Negligible	Negligible	Negligible	Negligible	Negligible
	57	Closed Drain	High	Low	Medium	Negligible	Medium
	62	Diesel Oil	Negligible	Negligible	Negligible	Negligible	Negligible
	63	Compressed Air	Negligible	Negligible	Negligible	Negligible	Negligible
	64	Inert Gas	Negligible	Negligible	Negligible	Negligible	Negligible
	65	Hydraulic Oil	Negligible	Negligible	Negligible	Negligible	Negligible
Titanium	47	Electro Chlorination	Low	Low	Low	Low	Low
	50	Sea Water	Low	Low	Low	Low	Low
	71	Fire Water	Low	Low	Low	Low	Low

3.5. Internal Degradation Mechanisms on Alvheim FPSO Topside

In order to determine the corrosion performance indicators, the following plausible internal corrosion threats on Alvheim FPSO Topside need to be discussed together with the method for finding its threshold:

- CO2 corrosion
- O2 corrosion
- Sulphide Stress Cracking (SCC)

- Microbiologically Influenced Corrosion (MIC)
- Under Deposit Corrosion (UDC)
- Galvanic Corrosion
- Erosion Corrosion
- Corrosion Fatigue

We will focus deeply on CO2 corrosion as it is the most relevant threat to Alvheim FPSO Topside integrity.

3.5.1. CO_2 Corrosion

Generally, only carbon steel is susceptible to this internal degradation mechanism. Several factors affecting the corrosion rate of CO_2 were discussed in Chapter 2. FORCE has developed software for CO_2 corrosion rate calculation based on NORSOK M-506. In this software, author noticed that an interpolation has been made for the condition when CO_2 fugacity is outside the range limit of NORSOK M-506. The range limit of CO_2 fugacity as stated in NORSOK M-506 is 0.1 to 10 bara thus the calculation made by FORCE software for the CO2 fugacity lower than 0.1 bara or above 10 bara is uncertain. This uncertainty will not be discussed in this thesis due to time constraint, but all calculation related to CO2 corrosion are using FORCE software except for Figure 3.7.

By using FORCE software, the prediction of CO_2 corrosion rate is changed due the following effects:

1. Effect of temperature.

The effect of temperature to predict the corrosion rate may vary. From Figure 3.8, we know that the predicted corrosion rate increases with increasing the temperature from 0^o C to 40^o C then reducing afterwards.

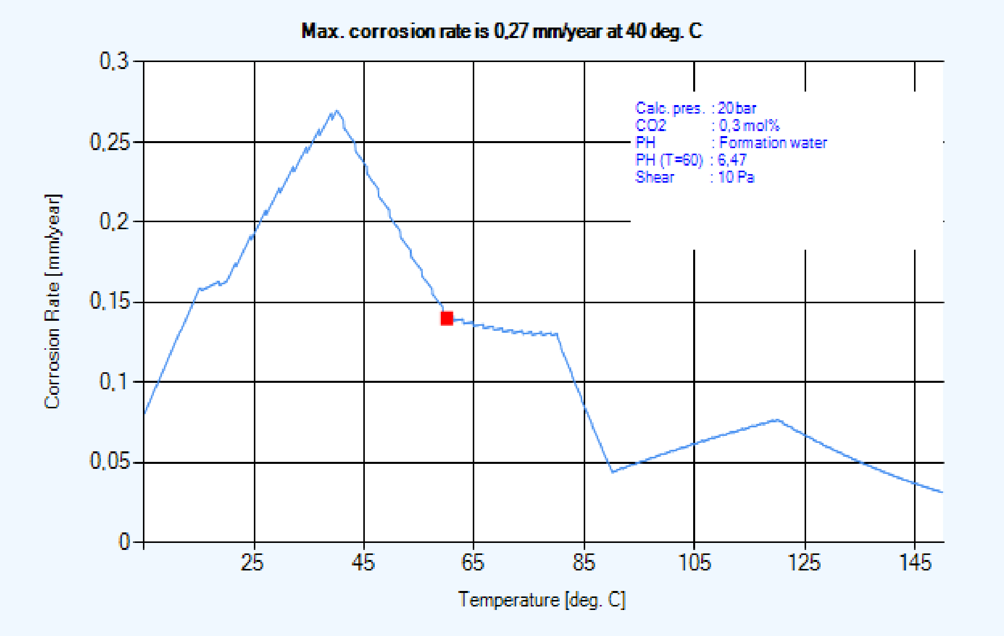


Figure 3.8. Effect of temperature on CO_2 corrosion rate (FORCE, 2011)

2. Effect of pressure.

The predicted corrosion rate increases with increasing internal operating pressures of the system. The correlation between pressure and corrosion rate is a linear correlation as shown in Figure 3.9. According to NORSOK M-506 (2005), the predicted corrosion rate can be calculated by using the following formulas:

For temperature 20°C, 40°C, 60°C, 80°C, 90°C, 120°C and 150°C:

$$CR_t = K_t \text{ x } f_{CO2}^{0,62} \text{ x } (S/19)^{0,146 + 0,0324 \log (fCO2)} \text{ x } f(pH)_t \text{ (mm/year)} \qquad \text{(Eq. 3.6)}$$

For temperature 15°C:

$$CR_t = K_t \text{ x } f_{CO2}^{0,36} \text{ x } (S/19)^{0,146 + 0,0324 \log (fCO2)} \text{ x } f(pH)_t \text{ (mm/year)} \qquad \text{(Eq. 3.7)}$$

For temperature 5°C:

$$CR_t = K_t \text{ x } f_{CO2}^{0,36} \text{ x } f(pH)_t \quad \text{(mm/year)} \qquad \text{(Eq. 3.8)}$$

Where:
CR_t : Corrosion Rate at temperature t in mm/year.
Kt : The constant value for the temperature t used in the corrosion rate calculations.
S : The wall shear stress in Pa. We use 10 Pa for all calculation in this report.
$f(pH)_t$: The pH factor at temperature t.
T : The operating temperature of the system given in Kelvin.
P : The operating pressure of the system given in bara.
f_{CO2} : The fugacity of CO_2 in bar. It is a function of internal pressure of the system, temperature and CO_2 concentration.
f_{CO2} : $10^{P \text{ x } (0,0031 - 1,4/T)}$ x (mole% CO_2 in the gas phase/100%) x P, for $P \leq 250$ bara

Example 1:
pH = 6.5
Shear stress = 10 Pa
Mole% CO_2 = 0.3
Pressure = 20 bara, 30 bara, 40 bara and 50 bara. (varies)
Temperature = 60°C, 80°C and 90°C (varies)
In this example, we would like to see the effect of pressure to CO_2 corrosion rate with varying the temperature. Figure 3.9 shows the CO_2 corrosion rate increases linearly with increasing operating pressure. It also noted that the corrosion rate is slightly increased when we increase the operating temperature to 80°C but the corrosion rate is suddenly dropped when we increase the operating temperature to 90°C.

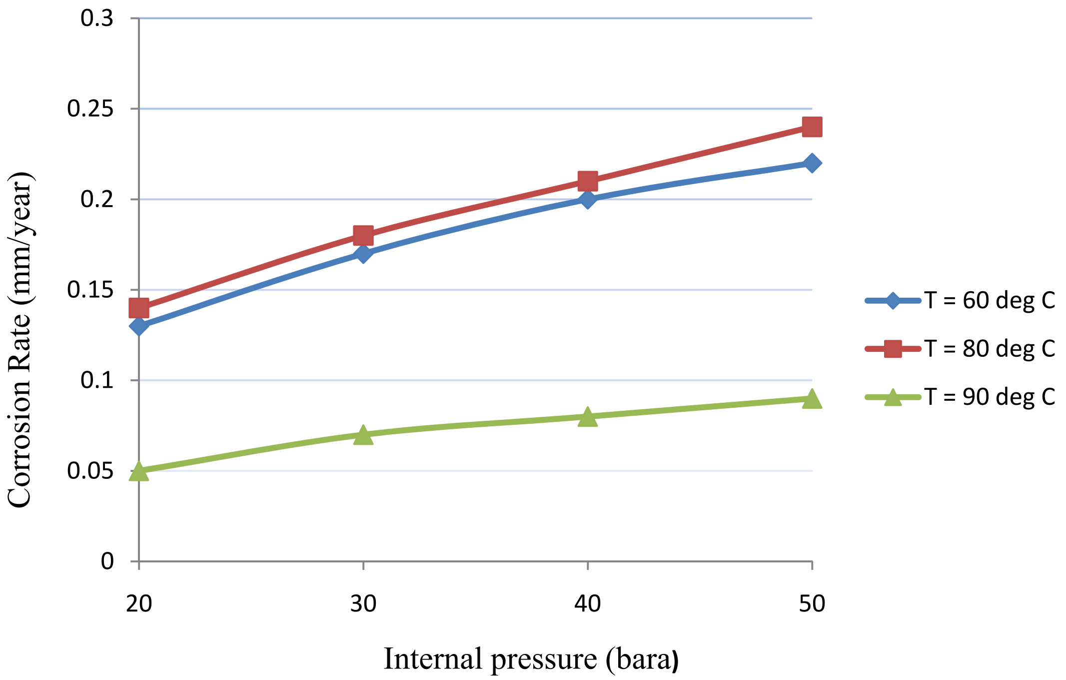


Figure 3.9. Effect of pressure on CO_2 corrosion rate

3. Effect of CO_2 content.

The predicted corrosion rate increases with increasing the CO_2 concentration of the system. The correlation between CO_2 concentration and corrosion rate is a linear correlation as shown in Figure 3.10.

Example 2:

pH = 6.5
Shear stress = 10 Pa
Temperature = 60^{o} C
Pressure = 20 bara, 30 bara and 40 bara. (varies)
Mole% CO_2 = 0.3, 0.4, 0.5, 0.6 and 0.7 (varies)

In this example, we would like to see the effect of CO_2 content to CO_2 corrosion rate with varying the pressure. Figure 3.10 shows the CO_2 corrosion rate increases linearly with increasing CO_2 content and pressure.

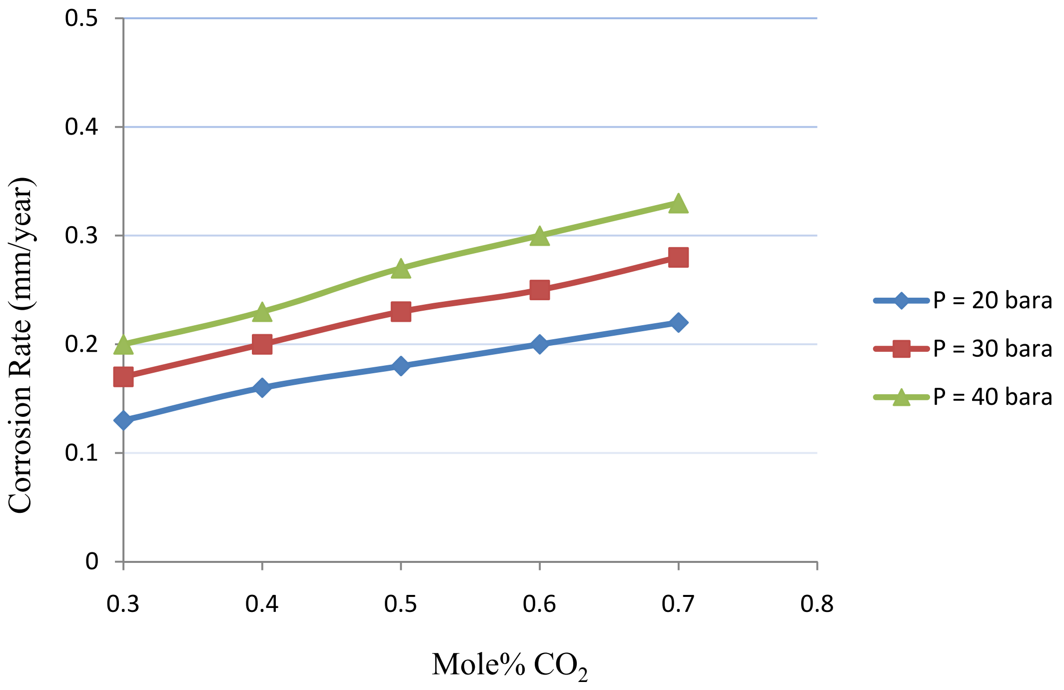


Figure 3.10. Effect of mole% CO_2 on CO_2 corrosion rate

4. Effect of pH.

Usually reported pH in water analysis is measured after depressurization and the sample is exposed to the atmosphere thus this data gives no information about in-situ pH which is mandatory for corrosion rate calculation. NORSOK M-506 (2005) helps us to calculate the in-situ pH by giving three options in water chemistry of fluid. The three options are condensed water with no Fe^{2+} saturation, condensed water with Fe^{2+} saturation and formation water. Usually, the formation water will give a higher pH thus the predicted CO_2 corrosion rate will be reduced. Figure 3.11 shows the predicted corrosion rate increases with increasing acidity of the system (lower pH).

Example 3:
Shear stress = 10 Pa
Temperature = 60^o C
Mole% CO_2 = 0.3
Pressure = 20 bara, 30 bara and 40 bara. (varies)
Calculated pH = 4.5, 5.0, 5.5, 6.0 and 6.5 (varies)

In this example, we would like to see the effect of calculated pH to CO_2 corrosion rate with varying the pressure. Figure 3.11 shows the CO_2 corrosion rate reduces dramatically with increasing calculated pH.

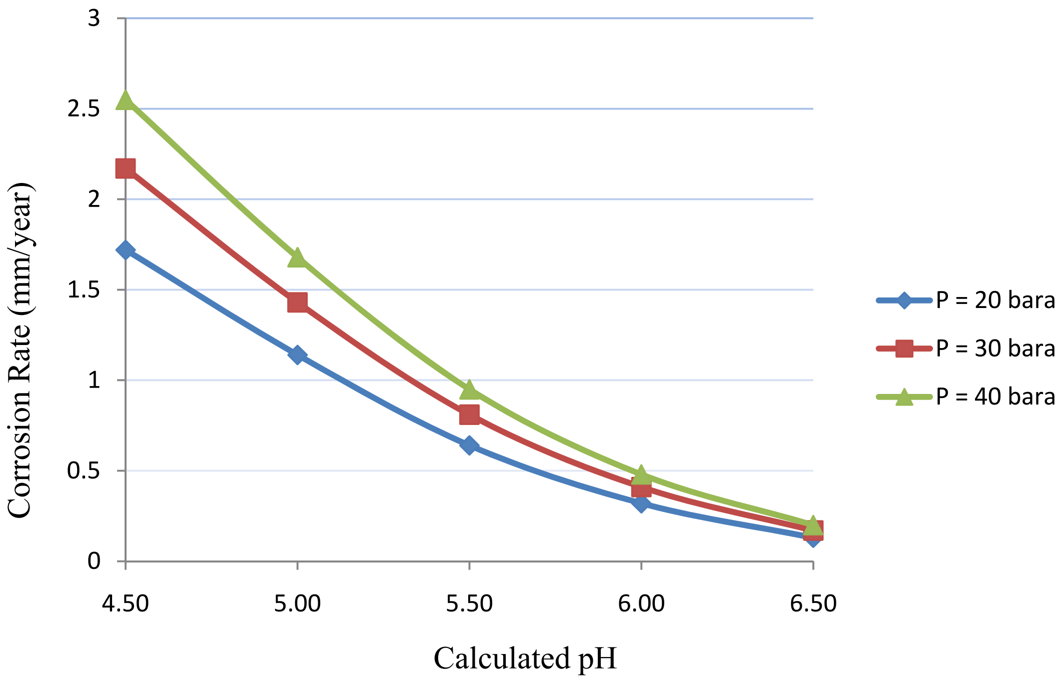


Figure 3.11. Effect of pH on CO_2 corrosion rate

5. Effect of glycol and corrosion inhibitors.

NORSOK M-506 (2005) states the effects of glycol and corrosion inhibitor on the corrosion rate are used as a reduction factor and the effect giving the highest reduction factor will be used on the corrosion rate calculation. This effect will not be evaluated in this thesis as none of them are used during the CO_2 corrosion rate calculation.

More than 2800 line tags including equipment are analyzed in a detailed RBI. As mentioned in Table 3.6, CO_2 corrosion only occurs in carbon steel material but when carbon steel material is exposed to dry gas, no internal corrosion occurs. All tags that affected by CO_2 in RuBI (FORCE's software for carrying out a RBI analysis) have been filtered and sorted out to get 46 corrosion groups as shown in Table 3.8. These groups represent all topside carbon steel pipework and equipment thus any change in process parameters will affect the actual corrosion rate and life time of all topside carbon steel pipework and equipment. Operating temperature and pressure are taken from Alvheim line lists, CO_2 concentration is taken from process simulation or PFD in year 2018. The pH value and CO_2 corrosion rate are calculated by using FORCE software based on NORSOM M-506. Corrosion rate critical (CR critical) and Life Time Value (LTV) are calculated from Eq. 3.4 and Eq. 3.2 respectively. PoF is selected based on Table 3.5 and corrosion rate upper (CR upper) and corrosion rate lower (CR lower) are calculated based on PoF range in Table 3.5 and Eq. 3.2. For example as follows:

1. Corrosion group 24-07 with tag 0002-PL-24L0020-AC11-00.

   Definition of tag 0002-PL-24L0020-AC11-00 based on Alvheim specification as follows:
   - 0002 means 2" NPS (Nominal Pipe Size)
   - PL means Process hydrocarbons liquid.

- 24L0020 means system no. 24 with line number L0020
- AC11 means piping class AC11 as stated in NORSOK L-001 (1999)
- Piping material description is A333 6 SMLS as stated in NORSOK L-001 (1999)
- Outside pipe diameter of 60.3 mm as stated in NORSOK L-001 (1999)
- Piping allowable stress of 1379 barg is taken from ASME B31.3 (2010)

Nominal wall thickness = 5.54 mm
Operating temperature = 87°C
Operating pressure = 10 bara.
Mol CO2% = 0.3%
Calculated pH = 4.73
CO2 corrosion rate = 0.43 mm/year
WT critical can be calculated from Eq. 3.5 as follows:

$$WT_{critical}=\frac{9\text{ barg}*60.3\text{ mm}}{2(1379\text{ barg}*1+9\text{ barg}*0.4)}=0.33\text{ mm}$$

$CR_{critical}$ is calculated from Eq. 3.4 as follows:

$$CR_{critical}=\frac{WT_n\text{-}WT_{critical}}{L_{TD}}=\frac{5.54\text{ mm-}0.33\text{ mm}}{20\text{ year}}=0.26\frac{\text{mm}}{\text{year}}$$

The LTV is calculated from Eq. 3.2 as follows:

$$LTV=\frac{CR_t}{CR_{critical}}=\frac{CR_{calculated}}{CR_{critical}}=\frac{0.43\text{ mm/year}}{0.26\text{ mm/year}}=1.65$$

CR upper is calculated based on the highest LTV value can be in a High PoF level and meanwhile CR lower is calculated based on the lowest LTV value can be in a High PoF level, refer to Table 3.5.

CR upper = Highest LTV x $CR_{critical}$ = 4 x 0.26 = 1.04 mm/year
CR lower = Lowest LTV x $CR_{critical}$ = 1 x 0.26 = 0.26 mm/year

According to Table 3.8, only five corrosion groups meet our requirement criteria during material selection because these groups have calculated corrosion rate less than 0.15 mm/year. As mentioned earlier, the corrosion allowance of carbon steel in Alvheim piping specification is 3 mm and the topside design life time is 20 years thus the maximum corrosion rate of carbon steel is 3 mm/20 years or equal to 0.15 mm/year otherwise CRA has to be selected. These five corrosion groups are 20-08, 20-14, 20-17, 23-06A and 23-06B. The first two digits show the system number of the corrosion group so the five groups are located in system 20 and system 23 respectively. The remaining 41 groups have higher calculated corrosion rate than 0.15 mm/year but 11 out of 41 groups have higher CR critical than CR CO_2 meaning the calculated corrosion rates are still within allowable limits. We may say the CR critical is the allowable corrosion rate as mentioned in Eq. 3.4. These 11 groups are 20-9, 20-11, 20-12, 20-13, 20-16, 23-01A, 23-01B, 23-02A, 23-02B, 23-03A and 23-03B. The PoF of these 11 groups is medium and will not lose its integrity during 20 years in operation as long as there is no increase in the operating pressure and temperature. The CR critical reduces when increasing the operating temperature and pressure thus the probability of failure is increased.

The remaining 30 groups may have lost their integrity within 20 years operation as the PoF ≥ high and these groups need further investigation. An additional inspection program has to be performed such as radiography testing on dead leg pipework in order to confirm the corrosion. Dead leg location is chosen as it is the low point and water condensation may be trapped there and also debris may settle there.

Table 3.8. CO_2 calculated corrosion rate of carbon steel material on Alvheim FPSO Topside

Tag number	Nominal wall thickness (mm)	Operating temperature (°C)	Operating pressure (bara)	Mol CO_2 from PFD 2018 (%)	pH	Corrosion rate (CR) upper (mm/year)	Corrosion rate (CR) lower (mm/year)	Corrosion rate (CR) CO_2 (mm/year)	Corrosion rate (CR) critical (mm/year)	Current life time value	PoF	Corrosion group
0002-PL-20L0083-AC11-04	5.54	75	2	0.3	6.50	0.05	0.00	0.04	0.26	0.15	Negligible	20-08
0008-PV-20L0036-AC11-00	6.35	75	2	0.3	5.03	0.26	0.13	0.19	0.26	0.72	Medium	20-09
0008-PB-20L0033-AC11-37	6.35	75	2	0.3	5.03	0.26	0.13	0.19	0.26	0.72	Medium	20-11
0002-PV-20L0068-AC11-03	5.54	75	2	0.3	5.03	0.26	0.13	0.19	0.26	0.73	Medium	20-12
0006-PL-20L0093-AC11-04	7.11	75	2	0.3	5.03	0.31	0.16	0.19	0.31	0.61	Medium	20-13
0016-PL-20L0042-AC11-03	7.92	75	2	0.3	6.50	0.06	0.00	0.04	0.29	0.14	Negligible	20-14
0006-PV-20L0095-AC11-04	7.11	75	2	0.3	5.03	0.31	0.16	0.19	0.31	0.61	Medium	20-16
0010-PL-21L0003-AC11-37	6.35	75	2	0.3	6.50	0.05	0.00	0.04	0.25	0.16	Negligible	20-17
0010-PL-21L0010-AC11-06	6.35	40	7.8	0.3	4.60	0.99	0.25	0.73	0.25	2.94	High	21-01
0012-PV-23L1001-AC11-37	6.35	75	2	0.3	5.03	0.24	0.12	0.19	0.24	0.81	Medium	23-01A
0012-PV-23L2001-AC11-37	6.35	75	2	0.3	5.03	0.24	0.12	0.19	0.24	0.81	Medium	23-01B
0012-PT-23L1002-AC11-07	6.35	30	2	0.3	4.86	0.24	0.12	0.21	0.24	0.89	Medium	23-02A
0012-PT-23L2002-AC11-07	6.35	30	2	0.3	4.86	0.24	0.12	0.21	0.24	0.89	Medium	23-02B
0012-PV-23L1003-AC11-08	6.35	30	1.55	0.3	4.91	0.24	0.12	0.17	0.24	0.72	Medium	23-03A
0012-PV-23L2003-AC11-08	6.35	30	1.55	0.3	4.91	0.24	0.12	0.17	0.24	0.72	Medium	23-03B
0008-PT-23L1007-AC11-07	6.35	101	5.8	0.3	4.90	0.26	0.13	0.14	0.26	0.53	Medium	23-06A
0008-PT-23L2007-AC11-07	6.35	101	5.8	0.3	4.90	0.26	0.13	0.14	0.26	0.53	Medium	23-06B
0010-PV-23L1008-AC11-08	6.35	30	5.07	0.3	4.66	0.99	0.25	0.41	0.25	1.65	High	23-07A
0010-PV-23L2008-AC11-08	6.35	30	5.07	0.3	4.66	0.99	0.25	0.41	0.25	1.65	High	23-07B
0004-PB-23L1045-BC11-37	6.02	106	21	0.3	4.65	0.96	0.24	0.54	0.24	2.26	High	23-08A
0004-PB-23L2045-BC11-37	6.02	106	21	0.3	4.65	0.96	0.24	0.54	0.24	2.26	High	23-08B
0008-PV-23L1006-AC11-38	6.35	101	14	0.3	4.71	1.05	0.26	0.36	0.26	1.37	High	23-10A
0008-PV-23L2006-AC11-38	6.35	75	14	0.3	4.61	1.05	0.26	1.04	0.26	3.97	High	23-10B

(table continued from previous page)

Tag Number	Nominal wall thickness (mm)	Operating temperature (°C)	Operating pressure (bara)	Mol CO_2 from PFD 2018 (%)	pH	Corrosion rate (CR) upper (mm/year)	Corrosion rate (CR) lower (mm/year)	Corrosion rate (CR) CO_2 (mm/year)	Corrosion rate (CR) critical (mm/year)	Current life time value	PoF	Corrosion group
0003-PT-24L0010-DC11-00	7.62	30	61	0.3	4.15	0.99	0.99	2.06	0.25	8.33	Very High	24-02
0003-PT-24L0012-DC11-00	7.62	30	80	0.3	4.11	0.99	0.99	2.37	0.25	9.58	Very High	24-06
0002-PL-24L0020-AC11-00	5.54	87	10	0.3	4.73	1.04	0.26	0.43	0.26	1.65	High	24-07
0002-PV-27L1022-BC11-07	5.54	106	21	0.3	4.65	0.93	0.23	0.54	0.23	2.33	High	27-01
0002-PV-27L2022-BC11-07	5.54	110	21	0.3	4.66	0.93	0.23	0.50	0.23	2.16	High	27-02
0003-PV-27L1020-BC11-00	5.49	30	18.3	0.3	4.39	0.83	0.83	1.03	0.21	4.96	Very High	27-05B
0003-PV-27L2020-BC11-00	5.49	30	18.3	0.3	4.39	0.83	0.83	1.03	0.21	4.96	Very High	27-06B
0006-PV-27L1012-DC11-37	10.97	95	57	0.3	4.40	1.12	1.12	1.74	0.28	6.23	Very High	27-07
0006-PV-27L2012-DC11-37	10.97	95	57	0.3	4.40	1.12	1.12	1.74	0.28	6.23	Very High	27-08
0003-PB-27L1030-DC11-37	7.62	125	62	0.3	4.49	0.99	0.99	1.17	0.25	4.73	Very High	27-11
0003-PB-27L2030-DC11-37	7.62	125	62	0.3	4.49	0.99	0.99	1.17	0.25	4.73	Very High	27-12
0010-PT-27L1007-DC11-07	15.06	22	57	0.3	4.14	1.27	1.27	1.50	0.32	4.74	Very High	27-13
0002-PL-27L1009-DC11-00	8.71	22	57	0.3	4.14	1.36	1.36	1.50	0.34	4.42	Very High	27-15
0002-PL-27L2034-DC11-04	8.71	22	57	0.3	4.14	1.36	1.36	1.50	0.34	4.42	Very High	27-16
0004-PV-27L1035-DC11-00	8.56	22	57	0.3	4.14	0.98	0.98	1.50	0.25	6.12	Very High	27-17
0004-PV-27L2035-DC11-00	8.56	22	57	0.3	4.14	0.98	0.98	1.50	0.25	6.12	Very High	27-18
0006-PB-27L1045-FC11-37	21.95	127	57	0.3	4.52	2.31	0.58	0.99	0.58	1.71	High	27-19
0006-PB-27L2045-FC11-37	21.95	127	57	0.3	4.52	2.31	0.58	0.99	0.58	1.71	High	27-20
0002-PB-27L0032-FC11-07	11.07	50	185.2	0.3	4.04	1.47	1.47	4.88	0.37	13.29	Very High	27-21
0004-PV-45L0040-BC11-00	6.02	39	19	0.3	4.41	0.83	0.83	1.34	0.21	6.48	Very High	45-02
0002-PL-45L0003-BC11-00	5.54	19	19	0.3	4.35	0.91	0.23	0.69	0.23	3.03	High	45-03
0002-PV-45L0043-BC11-00	5.54	47	39	0.3	4.29	0.91	0.91	2.25	0.23	9.90	Very High	45-04
0003-PV-45L0015-BC11-01	5.49	47	18	0.3	4.45	0.81	0.81	1.39	0.20	6.90	Very High	45-05

The next step of a detailed RBI is to establish the inspection strategy and inspection intervals as mentioned in Figure 3.3. The inspection interval depends on the calculated remaining life time of material and risk level. The risk levels depend on PoF and CoF and the remaining life time of material depends on calculated corrosion rate. According to FORCE (2011), the interval inspection can be calculated based on Eq. 3.9:

$$\text{Inspection interval } (T_{NI}) = L_R \times F_{RL} \times F_{CV} \qquad \text{(Eq. 3.9)}$$

Where:

T_{NI} = Time to next inspection or inspection interval.
L_R = Theoretical remaining life which is calculated based on corrosion rate in Eq. 3.3 and critical wall thickness in Eq. 3.5.
F_{RL} = Factor depending on risk level. F_{RL} increases with decreasing the risk level and reduces with increasing the risk level.
F_{CV} = Factor depending on confidence level of remaining wall thickness. F_{CV} increases with increasing the confidence level of remaining wall thickness.

Eq. 3.9 confirms that the very high risk corrosion group requires more frequent inspection than other corrosion groups. Refer to Table 3.8; the inspection interval of corrosion group 27-21 will be shorter than 27-20 as PoF of 27-21 is higher than PoF of 27-20 by assuming the same CoF applied for both groups. Based on this explanation, the validity of inspection intervals of corrosion groups needs to be monitored by checking the valid range of corrosion rates versus the current corrosion rates as shown in Figure 3.12, 3.13, 3.14 and 3.15. These figures are generated from table 3.8 and can be explained as follows:

1. Figure 3.12 for corrosion group 21-01
   From Table 3.8, the current corrosion rate of corrosion group 21-01 is 0.73 mm/year with maximum and minimum corrosion rate in order to keep High PoF is 0.99 mm/year and 0.25 mm/year respectively. If the actual corrosion rates is higher than 0.99 mm/year or lower than 0.25 mm/year thus the actual PoF becomes Very High or Medium respectively.

2. Figure 3.13 for corrosion group 23-01A
   From Table 3.8, the current corrosion rate of corrosion group 23-01A is 0.19 mm/year with maximum and minimum corrosion rate in order to keep Medium PoF is 0.24 mm/year and 0.12 mm/year respectively. If the actual corrosion rates is higher than 0.24 mm/year or lower than 0.12 mm/year, then the actual PoF becomes High or Low respectively.

3. Figure 3.14 for corrosion group 24-07
   From Table 3.8, the current corrosion rate of corrosion group 24-07 is 0.43 mm/year with maximum and minimum corrosion rate in order to keep High PoF is 1.04 mm/year and 0.26 mm/year respectively. If the actual corrosion rates is higher than 1.04 mm/year or lower than 0.26 mm/year, then the actual PoF becomes Very High or Medium respectively.

4. Figure 3.15 for corrosion group 27-21
   From Table 3.8, the current corrosion rate of corrosion group 27-21 is 4.88 mm/year. In order to improve a PoF level from Very High to become High PoF, the corrosion rate shall be reduced at least to 1.47 mm/year.

In this thesis, the corrosion rate using PFD 2018 is assumed as the current corrosion rate because the latest process simulation is not available. The current corrosion rate will be updated based on the latest process simulation and findings during inspection campaigns and corrosion monitoring. If the current corrosion rate is outside the valid range, the interval of inspection needs to be adjusted either making it shorter or longer interval.

In Figure 3.12 and 3.13, all current corrosion rates are still within the valid range of PoF thus the interval of inspection does not require any adjustment. In Figure 3.14 and 3.15, many current corrosion rates are outside the valid range and the inspection intervals have to be adjusted, in this case the interval shall be shorter because the current corrosion rate is higher than the maximum corrosion rate for its PoF. The inspection interval of the following corrosion groups needs to adjusted to a shorter interval:

1. Corrosion group 24-02, 24-06, 27-05B, 27-06B, 27-07, 27-08, 27-11 & 27-12 in Figure 3.14.
2. Corrosion group 24-02, 24-06, 27-05B, 27-06B, 27-07, 27-08, 27-11 & 27-12 in Figure 3.15.

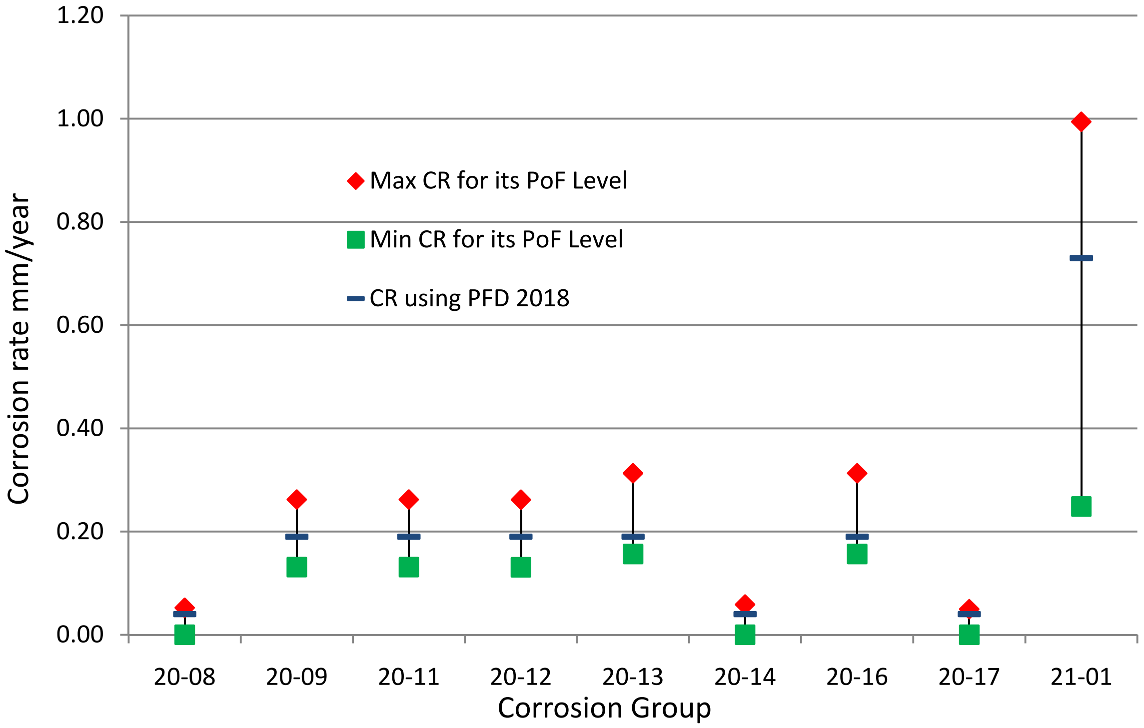


Figure 3.12. Valid range of CO_2 corrosion rates for PoF of internal degradation in system 20 and system 21

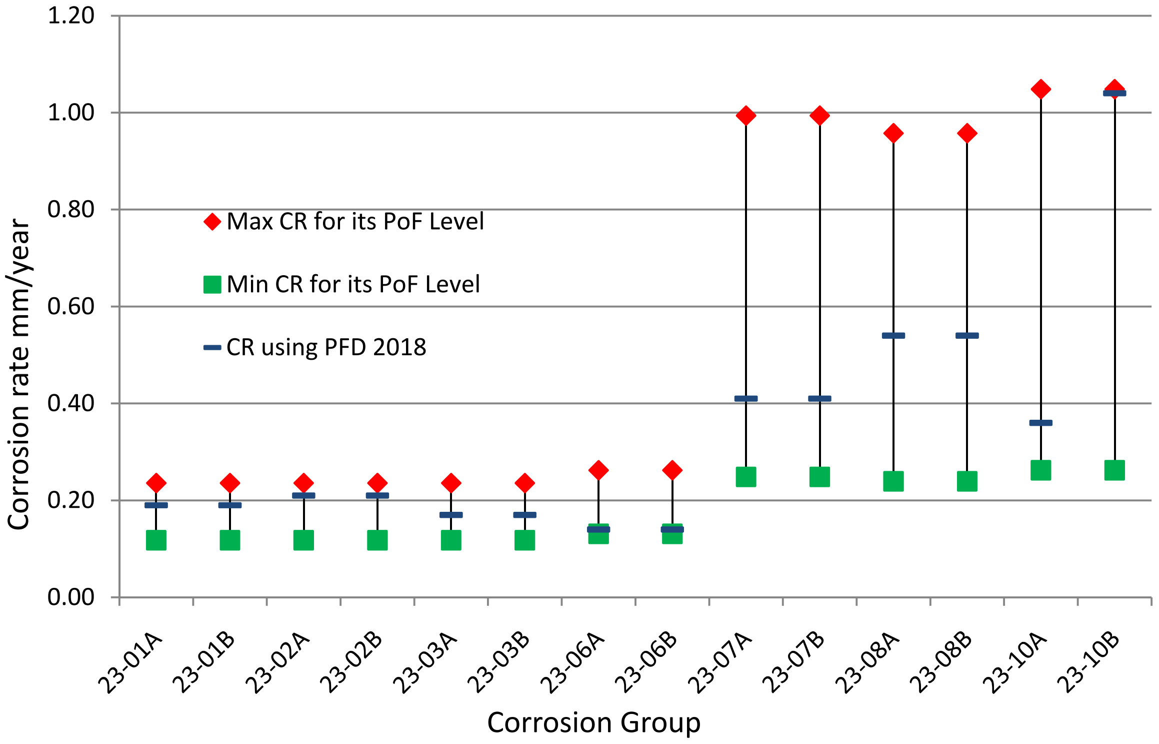


Figure 3.13. Valid range of CO_2 corrosion rates for PoF of internal degradation in system 23

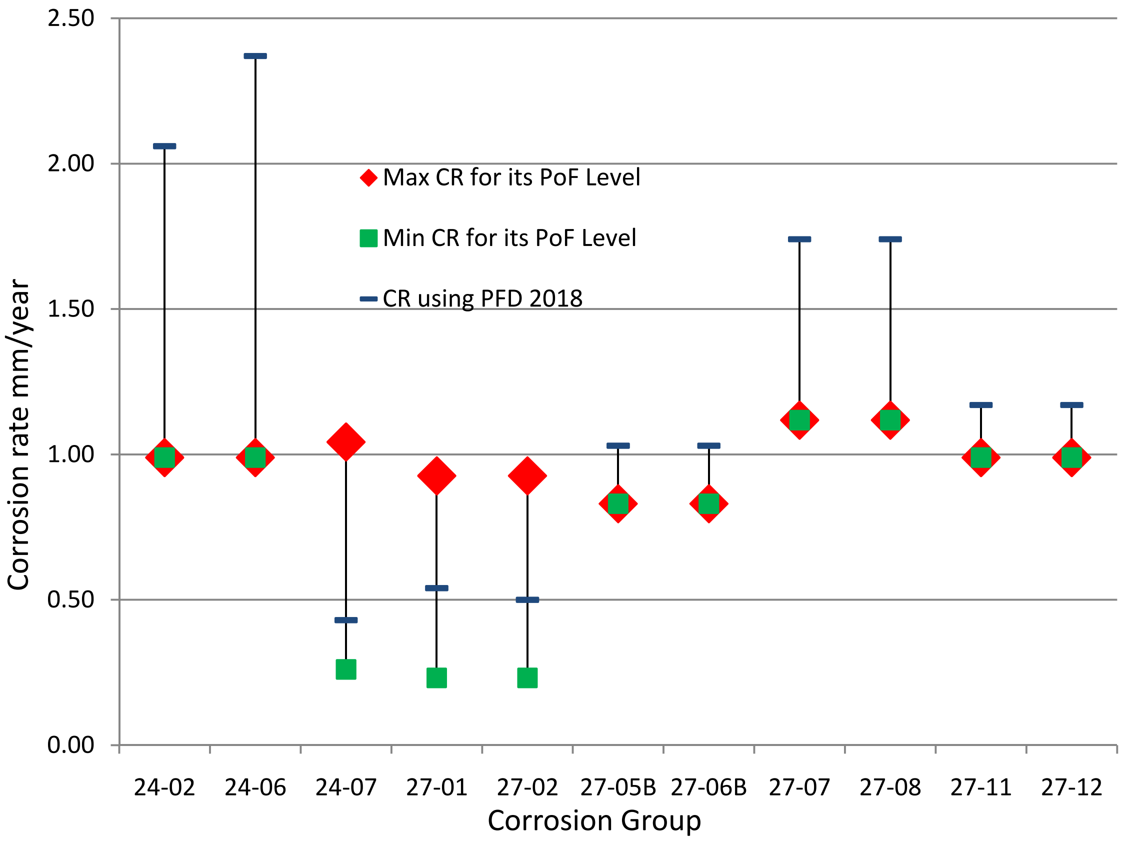


Figure 3.14. Valid range of CO_2 corrosion rates for PoF of internal degradation in system 24 and system 27

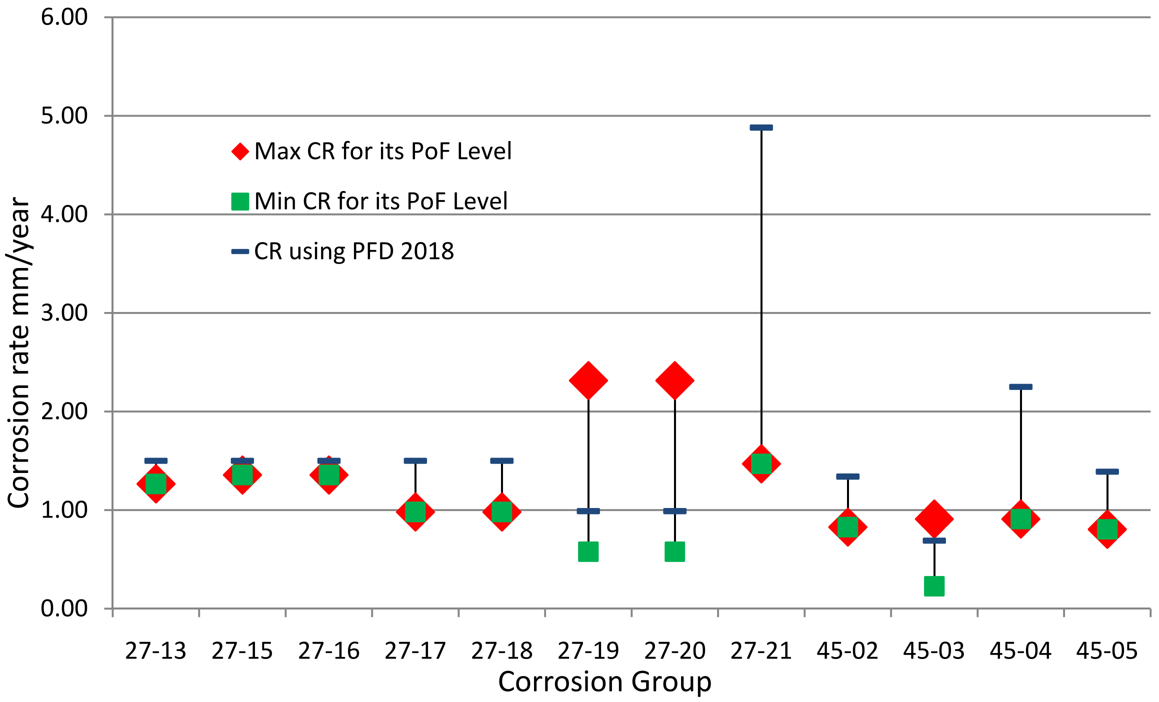


Figure 3.15. Valid range of CO_2 corrosion rates for PoF of internal degradation in system 27 and system 45

In order to get the threshold of mol % CO_2, corrosion group 23-02A was selected for calculating the CO_2 threshold as it has the highest LTV in medium PoF. As stated earlier, corrosion groups which have PoF ≥ High will need further investigation outside of this thesis due to time constraints and these groups cannot be used for determining the threshold of CO_2 as it will end up with very low mol % CO_2, for example as follows:

The highest LTV in Table 3.8 is corrosion group 27-21 which has LTV of 13.29 and calculated corrosion rate of 4.88 mm/year. In order to reduce the calculated corrosion rate close to CR critical, the mol % of CO_2 has to be reduced to 0.0085 mol %.

By using corrosion group 23-02A, we get the threshold of mol % CO2 is equal to 0.37 mol% as shown in Figure 3.16. With 0.37 mol% CO_2, the calculated corrosion rate will be equal to CR critical or CR upper and it is still within the valid range of the CO_2 corrosion rate as shown in Figure 3.13.

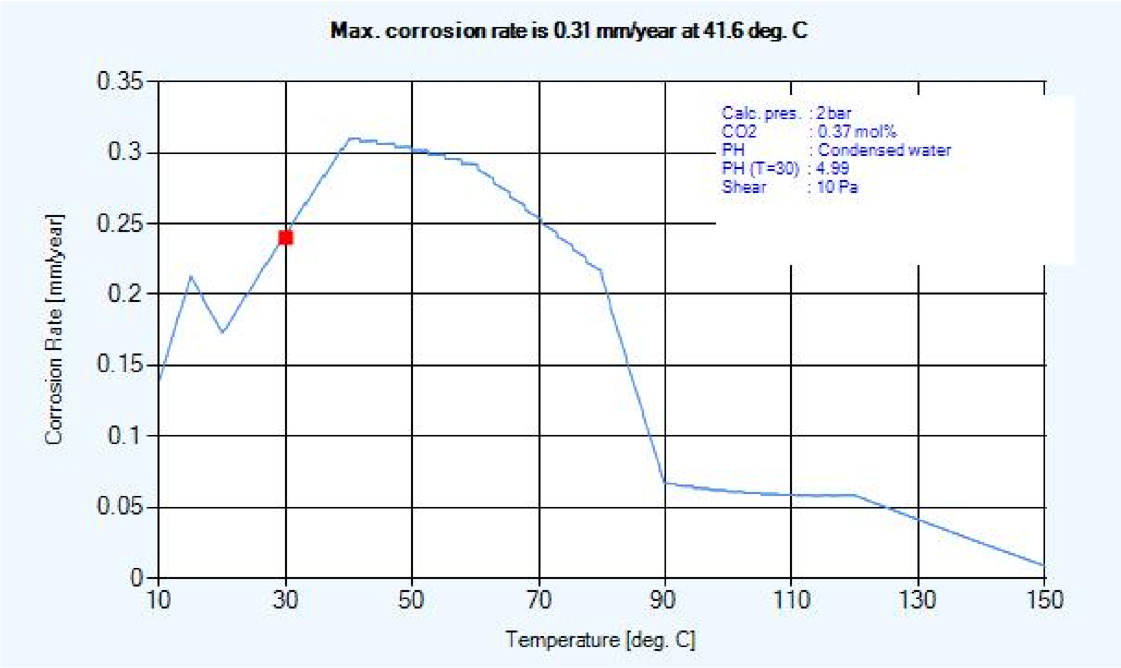


Figure 3.16. Effect of temperature on CO_2 corrosion rate (FORCE, 2011)

3.5.2. O_2 Corrosion

As shown in Table 3.6, Duplex Stainless Steel (22Cr and 25Cr) in the system exposed to sea water is susceptible to this internal degradation mechanism. On Alvheim, the produced water from the separators is inserted into the reservoir so we may conclude that the water injection system has no susceptibility to O_2 corrosion. The PoF ranking for O_2 corrosion is mentioned in Table 3.9. This table is directly taken from FORCE (2001) and no further evaluation is taken. Meanwhile, NORSOK M-001 (2004) recommends the maximum oxygen equivalent level is 50 ppb for 90% of its time in operation and 200 ppb for 10% of its time in operation in a non continuous system and Roberge (2007) states that reducing oxygen levels to below 20 ppb has a significant effect on corrosion of carbon steel boilers. In this case, Roberge (2007) confirms the O2 threshold from FORCE (2001).

Table 3.9. PoF ranking for O_2 corrosion in seawater and open drain system (FORCE, 2011)

Material	PoF Ranking	Criteria/Comment
22Cr	High	$O_2 \geq 20$ ppb and $Cl_2 \geq 100$ ppb
	Medium	$O_2 \geq 20$ ppb and $Cl_2 < 100$ ppb
	Low	$O_2 < 20$ ppb and $Cl_2 < 100$ ppb
25Cr & 6Mo	Medium	$O_2 \geq 20$ ppb and $Cl_2 \geq 100$ ppb
	Low	$O_2 \geq 20$ ppb and $Cl_2 < 100$ ppb
	Negligible	$O_2 < 20$ ppb and $Cl_2 < 100$ ppb

3.5.3. Sulphide Stress Cracking (SSC)

Although no H_2S concentration in the production lines is stated in Alvheim's basis of design, the H_2S need to be monitored as the hydrocarbon composition might change due to new production wells or reservoir treatments during oil production. In general, a well stream containing above 3 mbar partial pressure of H_2S is called sour service condition and may suffer from sulphide stress cracking if the materials are not designed for handling this sour service. On Alvheim FPSO topside, all parts exposed to hydrocarbons are designed for sour service requirements in accordance to NACE MR-0175/ISO 15156. The H_2S concentration and material grade used will affect the ranking of PoF for SSC in hydrocarbon environment as mentioned in Table 3.10. This table is directly taken from FORCE (2001) and no further evaluation is taken. Meanwhile, NORSOK M-001 (2004) states higher H_2S limits for generic CRA classes, for example: maximum partial pressure H_2S for 22Cr and 25Cr is 20 mbar and 100 mbar assuming free oxygen in the system and limited amount of chlorine.

Table 3.10. PoF ranking for SSC in hydrocarbon environment (FORCE, 2011)

PoF Ranking	Criteria
High	Partial pressure of $H_2S \geq 3$ mbar and materials do not comply with the requirements in NACE MR-0175
Medium	Not Available
Low	Not Available
Very low	Partial pressure of $H_2S < 3$ mbar or materials comply with the requirements in NACE MR-0175

3.5.4. Microbiologically Influenced Corrosion (MIC)

Generally, only carbon steel and lower grade stainless steel in hydrocarbon system are susceptible to this internal degradation mechanism as shown in Table 3.6. The CRA's such as stainless steel, duplex, supper duplex and titanium are generally resistant to MIC. As stated in chapter 2.3, the most common bacteria causing MIC is SRB and it has two forms which are planktonic and sessile. FORCE (2011) states the ranking of PoF for MIC can be defined as mentioned in Table 3.11 and Table 3.12. Meanwhile, Stott (2003) states any planktonic SRB counts above 1000/ml and sessile SRB counts above 1000/cm^2 are indicating a rapid growth of bacteria in the system and the MIC concern has to be addressed.

Table 3.11. PoF ranking for MIC of Carbon Steel in hydrocarbon environment (FORCE, 2011)

PoF Ranking	Criteria	Typical corrosion rates
High	Solids present. High level of SRB[1]. No effective biocide dosing.	0.5 – 2.0 mm/y
Medium	Solids present. High level of SRB. Effective biocide dosing.	0.2 – 0.5 mm/y
Low	Solids present. Low level of SRB.	0.1 – 0.2 mm/y
Very low	No solids present. Low level of SRB.	< 0.1 mm/y

Note:
1). High level of SRB means the environment has sessile more than 100/cm^2 and planktonic more than 100/ml

Table 3.12. PoF assessments for MIC in hydrocarbon environment with O_2 present (FORCE, 2011)

Material	Ranking	Criteria/Comment
CS	Not Available	Individual Assessment
316 & 22Cr	Not Available	Individual Assessment
25Cr & 6Mo	Unlikely	Immune to MIC
All CRA's	Unlikely	No Ingress of O_2

Spot samples taken from water injection system of Alvheim FPSO Topside confirm no oxygen ingress in the system 44.

3.5.5. Under Deposit Corrosion (UDC)

UDC occurs when deposits form on the metal surface either from settling out of suspended solids such as sands or corrosion products or precipitation of dissolved chemical species. This deposit creates either differential aeration or differential acidity (pH) on the metal surface and it may increase the microbial activity. Any differential aeration and acidity will create a differential cell corrosion system similar to a crevice corrosion mechanism thus the area under the deposit will be anodic and corrode. The PoF ranking of this degradation mechanism is not straight forward thus individual assessment is normally performed. No process parameters need to be monitored for this degradation mechanism.

3.5.6. Galvanic Corrosion

This internal degradation mechanism occurs when two dissimilar materials are electrically connected in the electrolyte environment. An electrolyte can be seawater, hydrocarbon containing water etc. Several methods may reduce the corrosion rate of galvanic corrosion as follows:

1. Sacrificial anode to be installed close to the connection between two dissimilar materials. The anode shall be more active than the protected metal.
2. Isolation gasket and bolt to be installed at flanged connections of two dissimilar materials. This method can be useless if the electron can easily move from anodic (less noble) to cathodic (more noble) material through another metallic path such as a piping support or instrument tubing.
3. Rubber lining of the more noble material for certain lengths will reduce the corrosion rate of galvanic corrosion at the anodic material.

The galvanic corrosion can be avoided during engineering design by avoiding the connection of two dissimilar materials or apply mitigation actions as mentioned above. No process parameters need to be monitored for this degradation mechanism.

3.5.7. Erosion Corrosion

This internal degradation mechanism occurs in flowing liquids or gases with or without abrasive particles when the velocity of the fluid is sufficient to remove protective films from the metal surface of pipework or equipment. It includes cavitation erosion and fretting corrosion. Under specific conditions, most metals are susceptible to erosion-corrosion. Soft metals such as copper and lead are quite susceptible to this internal degradation mechanism. Generally, stainless steels and titanium are resistant to erosion-corrosion in many environments because of the stability of the passive film formed but it can be destroyed by sand erosion and wear.

One example of cavitation corrosion is shown in Figure 3.17. It occurred in a seawater system made of CuNi 90/10 at Alvheim FPSO Hull and was due to flow turbulence and cavitation as the leaking points are close to the weld and the elbow curvature. None of this internal degradation mechanism occurs on Alvheim FPSO Topside as the material for the Topside pipework is better than the hull pipework with respect to reliability and corrosion resistance.

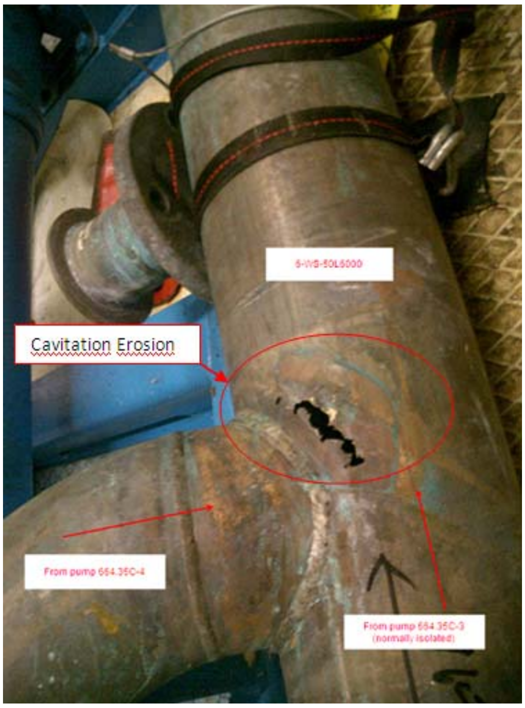


Figure 3.17. Cavitation inside CuNi 90/10 pipework

According to Alvheim's design basis, sand production is controlled in the wells by sand-screens thus no significant sand production is anticipated. Additional mitigation to this sand erosion has been installed at Alvheim such as tungsten carbide choke materials on production flowlines. The ultrasonic measurement downstream of choke valves is performed annually as part of the monitoring strategy for sand erosion. No other process parameters need to be monitored for this degradation mechanism.

3.5.8. Corrosion Fatigue

Initiation and propagation of cracking in materials under a combination of cyclic stress and a corrosive environment is called corrosion fatigue. All metals and alloys are susceptible to corrosion fatigue. In corrosive environment, the required stress to create initial cracking is lower than the required stress in an inert environment or non-corrosive environment. In a cyclic condition, the stress value to create initial cracking is usually lower than the yield stress of the material. Some mitigation to avoid this corrosion fatigue has been taken at Alvheim as follows:

1. Proper pipe stress analysis before construction.
2. Pipework supported properly.
3. Annual visual inspection
4. Vibration monitoring

No process parameters need to be monitored for this degradation mechanism.

3.6. Key Performance Indicators (KPIs)

All plausible internal degradation mechanisms of pipework and equipment on Alvheim FPSO Topside have been registered in Table 3.6 and the risk level for each system has been defined in Table 3.7. This risk level depends on the PoF and CoF of the corrosion group; CoF levels of existing groups are typically constant during the life time of the asset as long as no big changes in temperature and pressure of fluids have occurred. These changes may affect CoF to personnel but no change is expected for the CoF to environment and economy. Each system has a PSV (Pressure Safety Valve) in order to avoid a pressure build up that may burst the pipework or equipment, because of that the CoF to personnel is typically not monitored frequently. The PoF level is the one that needs to be monitored as it affects the risk level. The tool for monitoring this PoF level is a KPI and is a part of managing the risk on Alvheim FPSO Topside.

All thresholds for PoF of each internal corrosion mechanism have been established in section 3.5 to section 3.12 and can be summarized as shown in Table 3.13. Parameters that affect PoF are defined as performance indicator. The following performance indicators are given as additional parameters to the ones that were specified in previous sections:

1. Gas temperature of fuel gas.
   In a detailed RBI, fuel gas is specified as a dry gas thus no CO_2 corrosion on carbon steel pipework is expected but dry gas may condense if T_{dew} (dew point temperature) ≥ T_{gas} (operating gas temperature) + 10°C. This condensation may trigger the CO_2 corrosion; because of this the fuel gas temperature needs to be monitored frequently. On Alvheim, the dew point is normally equivalent to less than 10 ppm of water which is about -30°C at 40 barg. It may temporarily be operated to 42 ppm which is about -15° at 40 barg, but that will only be for short duration during start up.

2. Residual chlorine.
   NORSOK M-001 (2004) states the maximum free chlorine in a seawater system is 1.5 ppm for 25Cr material otherwise crevice corrosion will occur. Crevice corrosion is a form of localized attack in which the site of the attack is an area where free access to the surrounding environment is restricted. Typically, crevice corrosion occurs on the flange face of pipework as the flange has crevices on the surface, therefore any difference in the chloride concentrations of material inside and outside of the crevice may lead to crevice corrosion.

3. Seawater temperature
   NORSOK M-001 (2004) states the maximum operating temperature of chlorinated seawater is 20°C and 85°C for 25Cr and Titanium respectively otherwise crevice corrosion will occur. It shall be noted that the fluid temperature of seawater may increase due to heat radiation from surrounding equipment such as boilers etc.

The performance indicators shall be measured frequently with measurement locations chosen at the most plausible location where internal corrosion may occur and it should be easy to access. Some measurement locations are available online for the following data:

1. H_2S concentration in export gas fiscal metering of system 27.
2. CO_2 concentration in export gas fiscal metering of system 27.

3. Fuel gas temperature from instrument device of 45TT0121A in system 45.

Data for seawater temperatures are not available online but can be read from the existing temperature indicators on Alvheim which are 50TI0103, 50TI0220, 50TI0620 and 50TI0613.

Data for free chlorine in the seawater system is taken from 50V0750 (drain valve in system 50). The free chlorine concentration has been measured since 2009 to January 2012 and it shows the measured free chlorine exceeds the threshold value as shown in Figure 3.21.

Data for MIC are not available yet and the assessment of this MIC shall be addressed in co-operation with the corrosion engineer, production department and chemical vendor. Some testing kits and coupons are commercially available; the coupon is typically used for measuring the population of sessile SRB. Samples from dead ends of pipework are needed for measuring the population of planktonic SRB. Sampling from dead ends of pipework should be on a monthly basis meanwhile the coupon replacement should be done on a six month basis depending on the extent of concern.

From Table 3.13, only 3 parameters out of 11 parameters are selected as corrosion KPIs because of their crucial contribution to maintaining the integrity of the hydrocarbon system. These three parameters are partial pressure of H_2S, CO_2 content and fuel gas temperature. Some parameters in the seawater system are measured daily but these parameters are not included in the KPIs because the consequence of seawater system failure is low.

All parameters for KPIs were measured on a daily basis from 01/01/2011 to 30/05/2012 as shown in Figure 3.18, 3.19 and 3.20. The measured KPI is considered to be compliant if it does not exceed the threshold value. For a 30-day month, each day is equal to 3.3% compliance and at the end of the month. The number of compliant days are added and then multiplied by 3.3% to get the monthly percentage compliance for each KPI. The KPI average percentage compliance for each month can be calculated from all selected KPIs as shown in Table 3.14. Figure 3.22 shows the monthly average KPI compliance against the target compliance. It is noted that the CO_2 content KPI has very low compliance and any measures to ensure that the system can be improved needs to be implemented. Due to the high level of CO_2 content, radiography testing on dead legs of CS pipework of hydrocarbon systems has been done in November 2011 with none of them showing any CO_2 corrosion. The radiography testing will continue on other possible locations during the 2012 inspection campaign. After 4 years in operation, no CO_2 corrosion occurs on Alvheim's topside. Some mitigations of CO_2 corrosion were discussed in chapter 2 and the most suitable mitigation is to inject corrosion inhibitor. The overall target compliance has been set up to 65% and it will be increased later on when the corrective actions on the CO_2 compliance are being implemented.

Table 3.13. Performance Indicators for RBI Analysis of Alvheim FPSO Topside

Service	System	System description	Performance Indicator Description	Threshold	Measure frequency	Review frequency	Degradation Mechanism	Measurement location
Hydrocarbon	**16, 20, 21, 23, 24, 27, 43 & 57**	**Topside Flowline, Crude Oil Separation, Crude Oil Metering, Re-Compression, Gas Dehydration, Gas Export, Flare And Vent And Closed Drain**	**Partial pressure of H_2S**	**<3 mbar**	**Daily**	**Monthly**	**SSC - Duplex SSC - CS SSC - 316 SS**	**27AY0702A (System 27 Gas Export Metering)**
Hydrocarbon	**20, 21, 23, 24, 27, 43 & 57**	**Crude Oil Separation, Crude Oil Metering, Re-Compression, Gas Dehydration, Gas Export, Flare And Vent And Closed Drain**	**CO_2 content**	**<0.37 mol%**	**Daily**	**Monthly**	**CO_2 Corrosion - CS steel**	**27AY0702A (System 27 Gas Export Metering)**
Hydrocarbon	20, 21, 23, 24, 27, 43 & 57	Crude Oil Separation, Crude Oil Metering, Re-Compression, Gas Dehydration, Gas Export, Flare And Vent And Closed Drain	Planktonic SRB content	<100 /ml	Monthly	Monthly	MIC - CS steel	To be decided later on
Hydrocarbon	20, 21, 23, 24, 27, 43 & 57	Crude Oil Separation, Crude Oil Metering, Re-Compression, Gas Dehydration, Gas Export, Flare And Vent And Closed Drain	Sessile SRB content	<100 $/cm^2$	Every six months	Every six months	MIC - CS steel	To be decided later on
Produced Water	29, 44	Produced Water & Water Injection	Partial pressure of H_2S	<3 mbar	Monthly	Monthly	SSC - Duplex	To be decided later on
Fuel gas	**45**	**Fuel Gas**	**Fuel gas temperature**	**> (Water dew point + 10°C)**	**Daily**	**Monthly**	**CO_2-Corrosion - CS steel**	**45TT0121A**
Seawater	50	Treated Sea Water	Oxygen Equivalent = oxygen (ppb) + 0.1*chlorine (ppb)	<20 ppb	Monthly	Monthly	O_2 corrosion - 25Cr	To be decided later on
Seawater	50	Treated Sea Water	Free chlorine	<1.5 ppm	Daily	Monthly	Crevice corrosion - 25Cr duplex	Sample from 50V0750
Seawater	50	Treated Sea Water	Seawater temperature	<20 °C	Daily	Monthly	Crevice corrosion - 25Cr duplex	50TI0613
Seawater	50	Treated Sea Water	Seawater temperature	<85 °C	Daily	Monthly	Crevice corrosion - Titanium	50TI0103, 50TI0220 & 50TI0620
Open Drain	56	Open Drain	Oxygen Equivalent = oxygen (ppb) + 0.1*chlorine (ppb)	<20 ppb	Monthly	Monthly	O_2 corrosion - 22Cr	To be decided later on

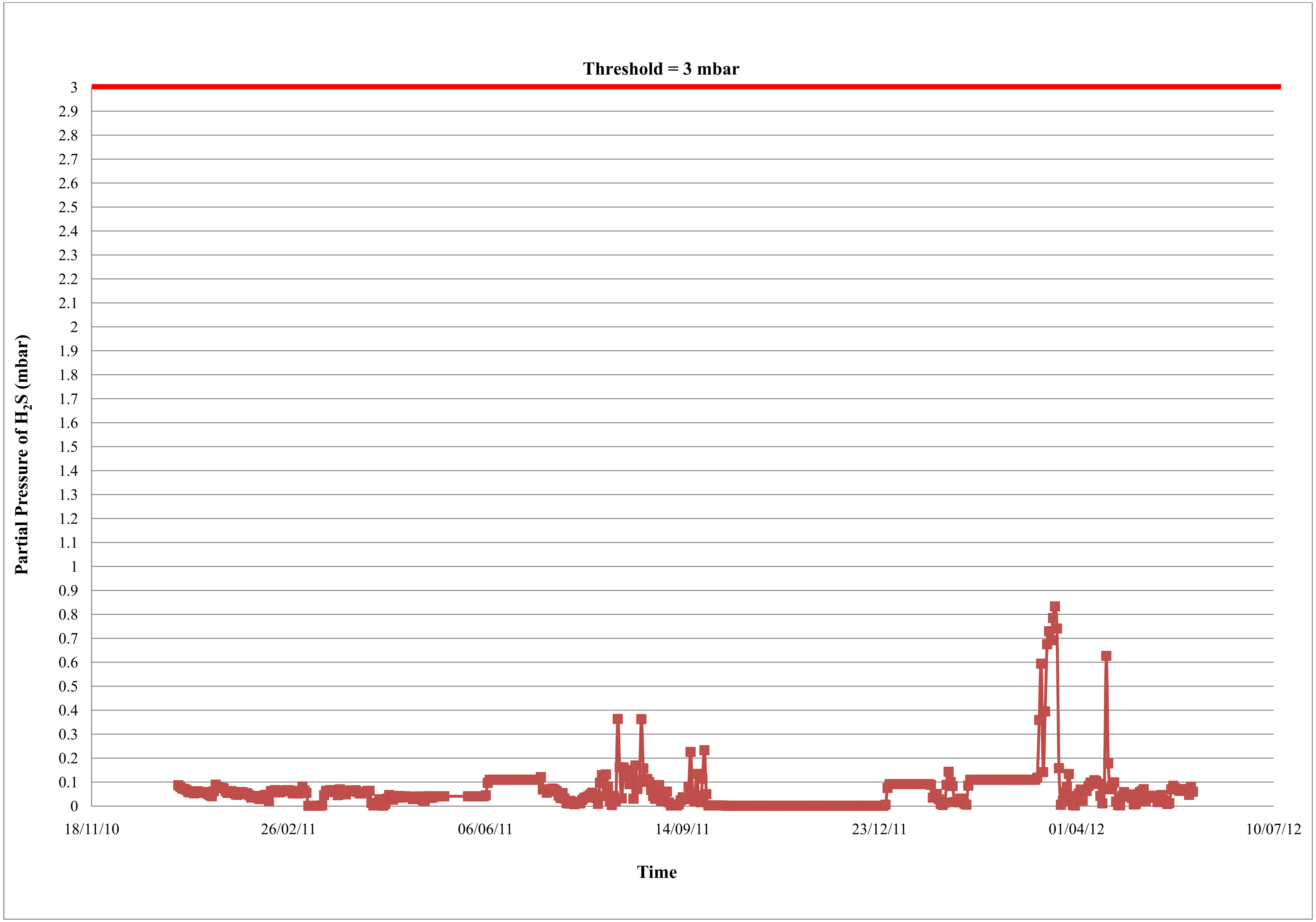


Figure 3.18. Data for partial pressure of H_2S from Gas Export Metering 27II001

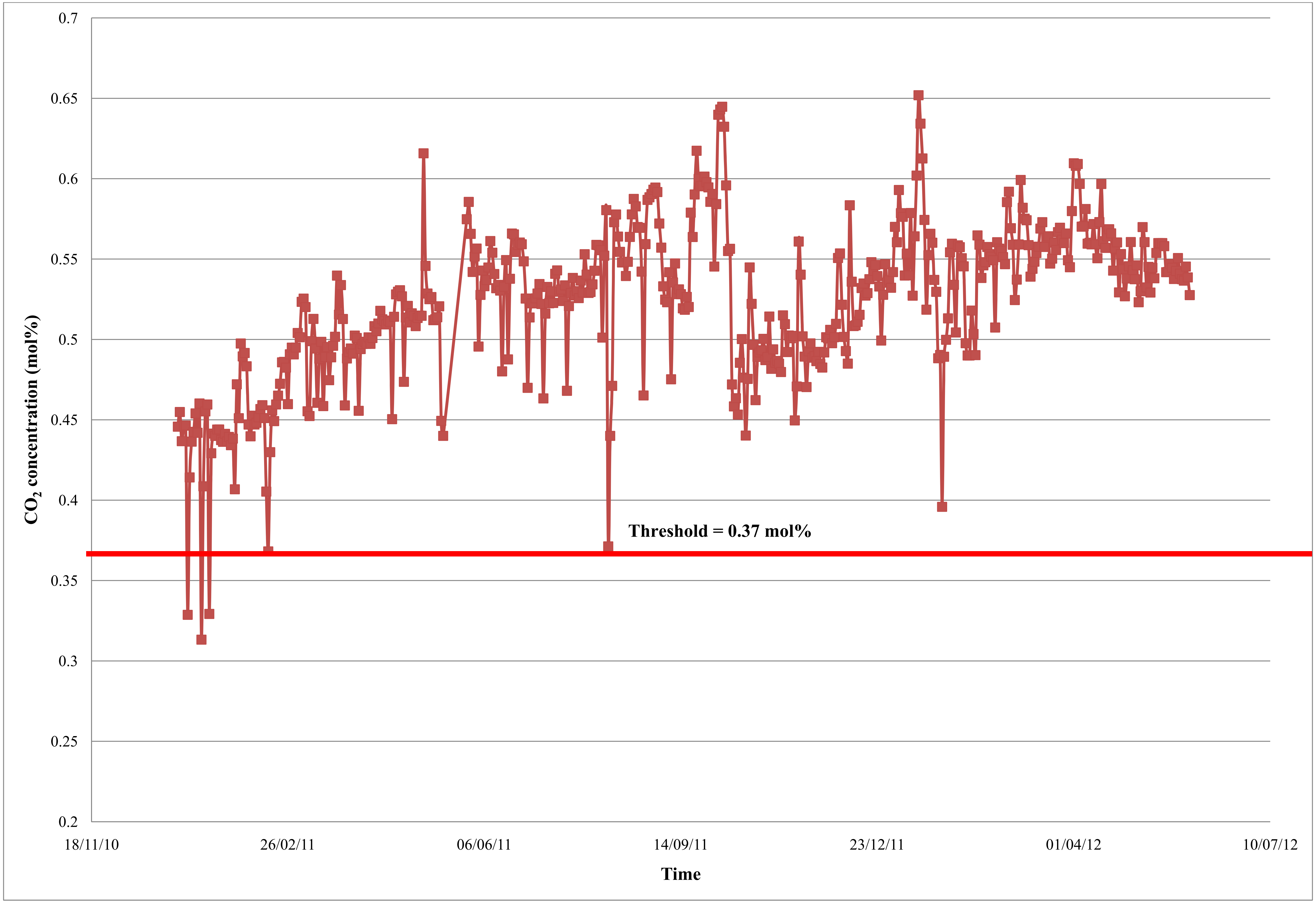


Figure 3.19. Data for CO_2 concentration from Gas Export Metering 27II001

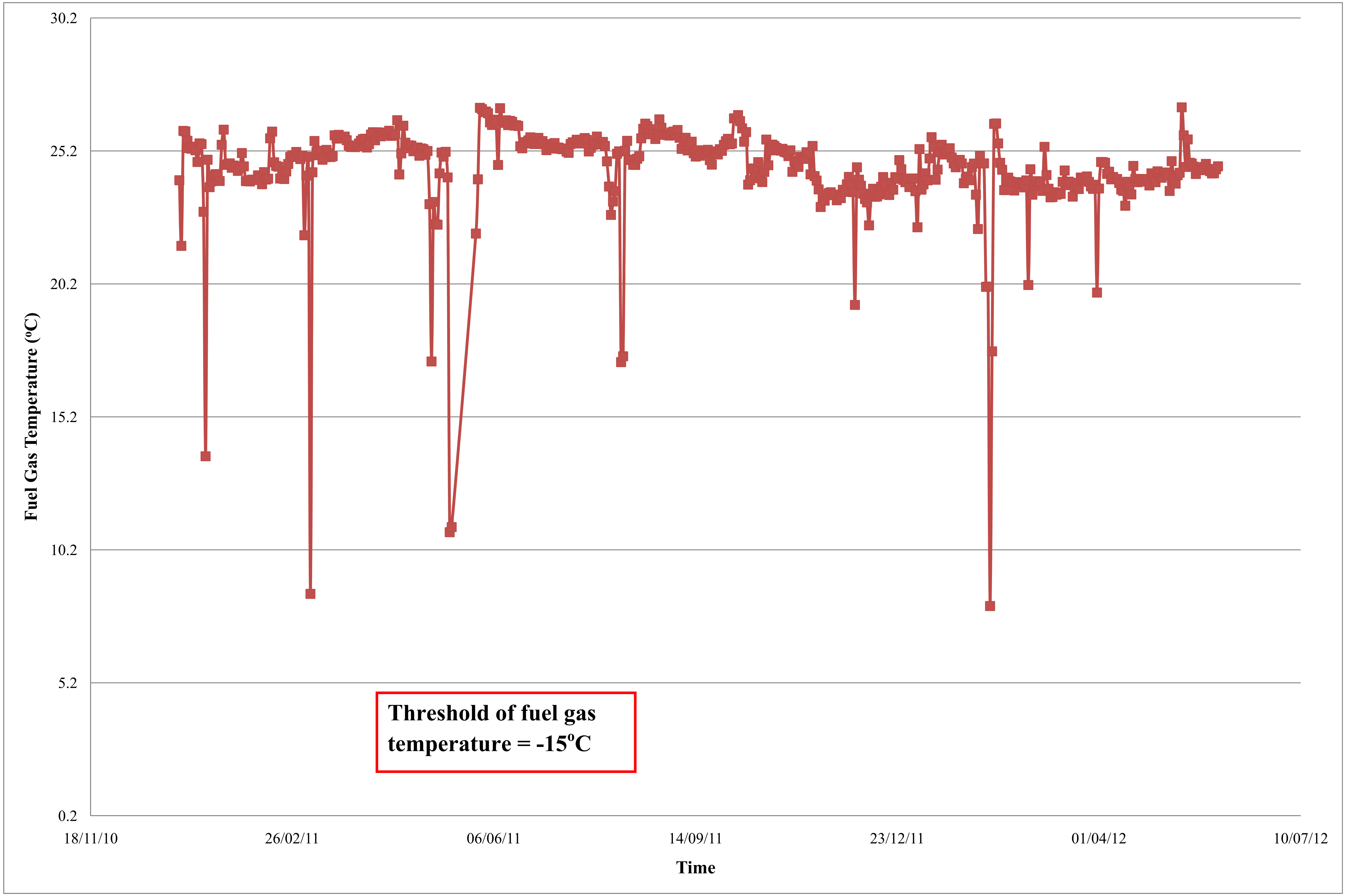


Figure 3.20. Data for fuel gas temperature from 45TT0121A

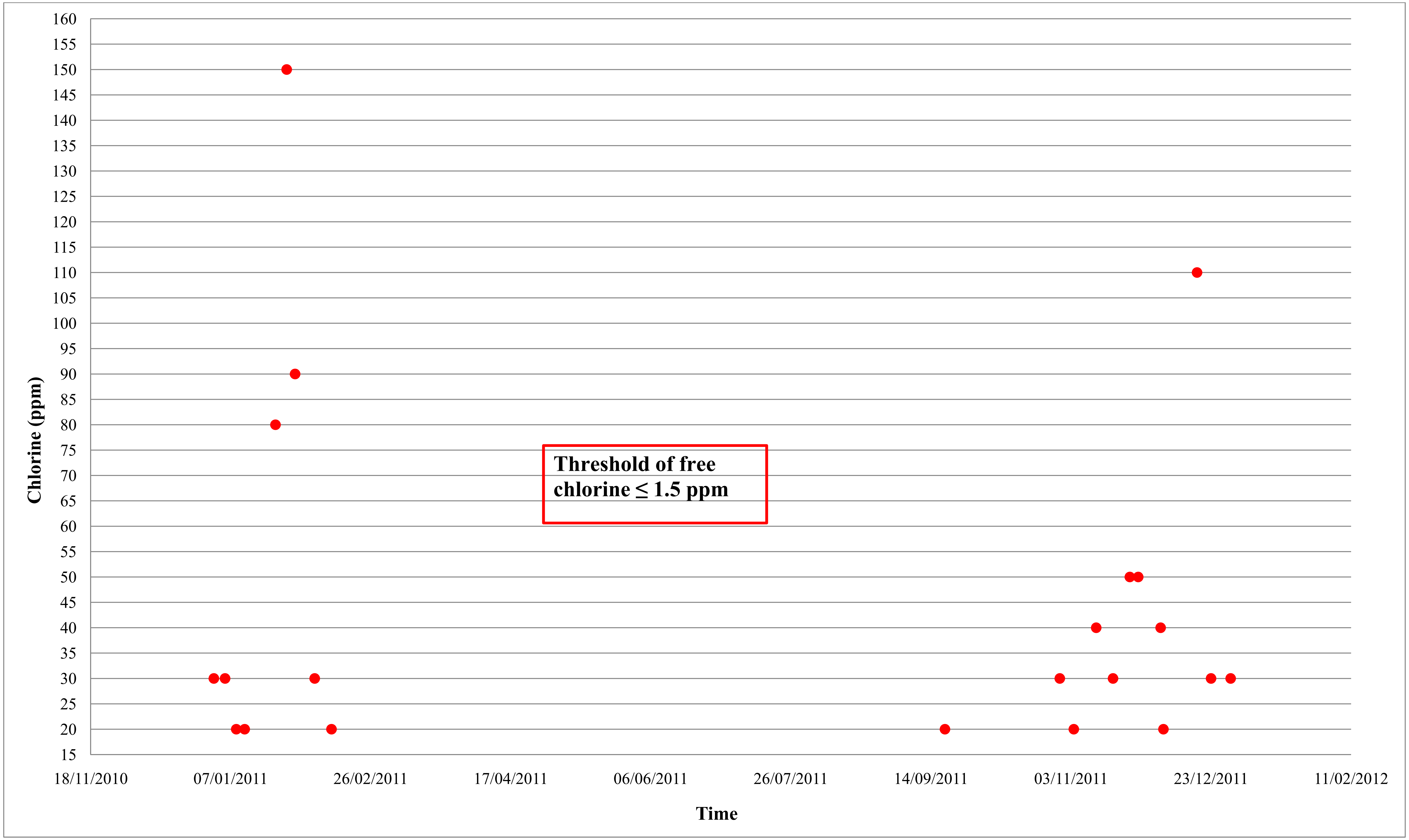


Figure 3.21. Data for free chlorine concentration from 50V0750

Table 3.14. Available KPI on Alvheim FPSO Topside integrity

KPI	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12
Partial pressure of H_2S (mbar)	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
CO2 concentration (mol%)	10%	4%	0%	0%	0%	0%	0%	3%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Fuel gas temperature (^{o}C)	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Average compliance	**70%**	**68%**	**67%**	**67%**	**67%**	**67%**	**67%**	**68%**	**67%**	**67%**	**67%**	**67%**	**67%**	**67%**	**67%**	**67%**	**67%**
Target compliance	**65%**	**65%**	**65%**	**65%**	**65%**	**65%**	**65%**	**65%**	**65%**	**65%**	**65%**	**65%**	**65%**	**65%**	**65%**	**65%**	**65%**

Colour code:

Green : Measure meet target
Amber : Measure not meeting target. Corrective action possible before dangerous outcome
Red : Immediate corrective action required to prevent dangerous outcome. Corrective action such as radiography testing in hydrocarbon system has been done during inspection campaign in November 2011 and the result shows no CO_2 corrosion occurs. Radiography testing for other locations will be performed during 2012 inspection campaign.

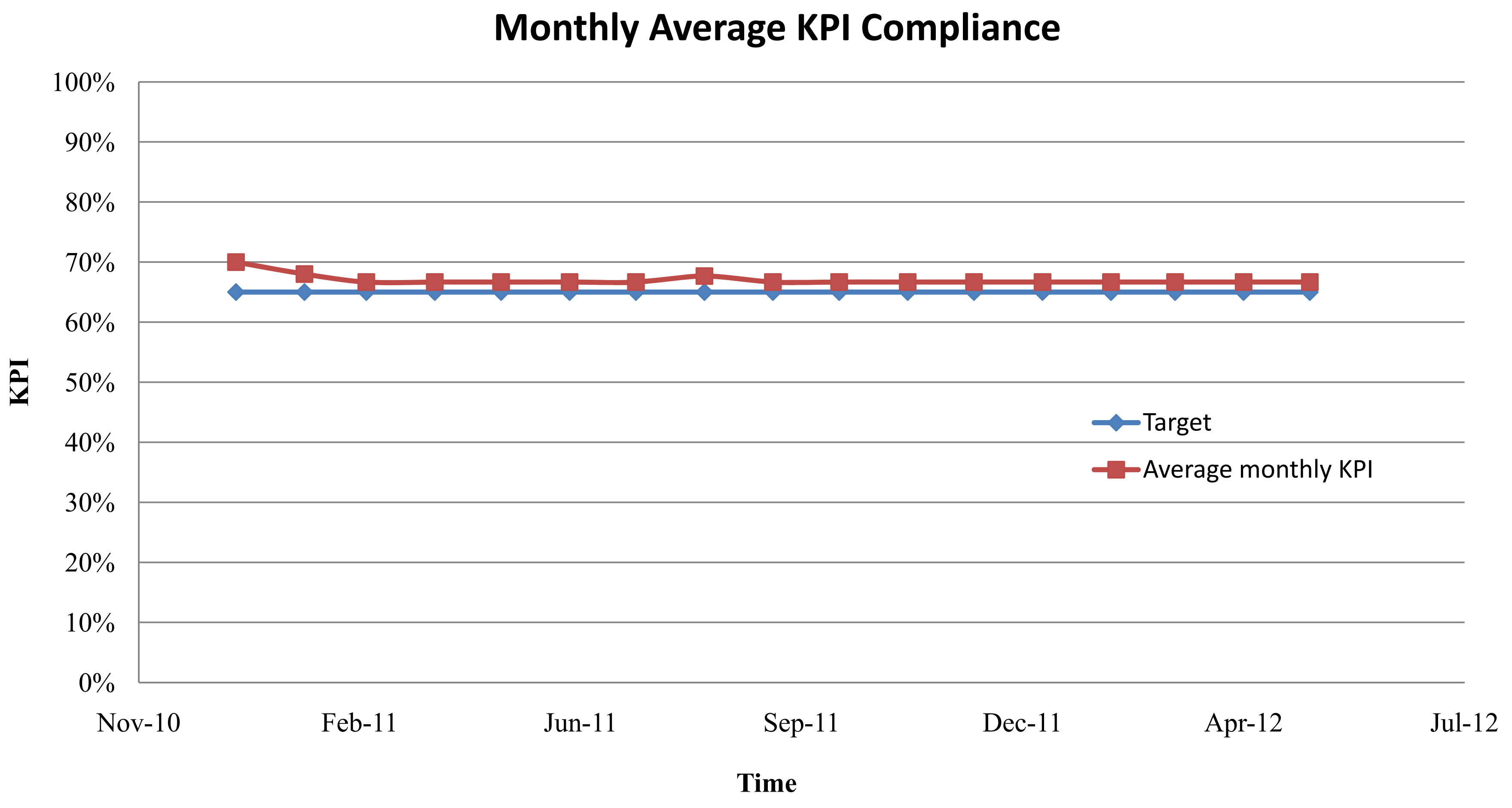


Figure 3.22. Plotted average monthly KPI against the target level

4. CONCLUSIONS AND RECOMMENDATIONS

In previous chapter, the author has identified all plausible internal corrosion threats of each system on Alvheim FPSO Topside, determined the highest risk level of each system, developed corrosion performance indicators of all plausible internal degradation mechanisms, determined the threshold value of each performance indicator, determined the KPIs from corrosion performance indicators, collected all available data from Alvheim FPSO Topside and compare it with the threshold value, generated the graphic of plotted average monthly KPI against the target level. Now it comes to some conclusions and recommendations.

Regularly monitoring and measuring performance indicators are part of the Alvheim CIMS as shown in Figure 3.2. Performance indicators of internal corrosion on Alvheim FPSO Topside have been established and those most affecting the integrity performance of Alvheim FPSO Topside are selected as KPIs. These KPIs are measured on a daily basis and the compliance percentage of each KPI is defined by comparing it with the agreed threshold value. It reveals that a correction action is needed on the CO_2 content KPI. The latest inspection campaign in November 2011 reveals no CO_2 corrosion occurs in the dead ends of CS pipework in hydrocarbon systems. It can be concluded that the KPIs have the following benefits:

1. KPIs are good tools for capturing and assessing data related that most affect the Alvheim FPSO Topside integrity.
2. KPIs can be used for identifying any problem during Alvheim CIMS implementation. In Alvheim's case, CO_2 higher than the threshold value may lead to loss of integrity of CS pipework.
3. KPIs improve topside integrity engineers monitoring of the indicators that have the greatest affection to Alvheim integrity.
4. KPIs can be used for reporting issues related to Alvheim's integrity to senior management as it provides info at a high level and is easy to follow.
5. KPIs are good tools for managing risks identified through RBI analysis of Alvheim FPSO Topside.

The recommendations related to KIPs are as follows:

1. In this thesis, only KPIs related to internal corrosion mechanisms were established. To get a better overview of Alvheim integrity, some KPIs of external corrosion mechanisms should be added, e.g.: implementation of Corrosion Under Insulation (CUI) inspection and implementation of a painting campaign.
2. The trend of average corrosion KPI compliance on Alvheim FPSO Topside is stagnant due to zero compliance on CO_2 content. Future corrective actions need to be agreed between the corrosion engineer, integrity engineer, process engineer, production engineer and chemical vendor.
3. Further investigation on CO_2 corrosion is required. It might be the calculated corrosion rate is too conservative as there have been no findings so far from the last inspection campaign.
4. Measurement frequency in Table 3.13 can be adjusted based on the latest findings, e.g.: six-month basis for measuring sessile SRB population can be reduced to quarterly basis if the findings show an increasing trend.

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APPENDIX A

System 16 Flowlines

The system consists of six production lines, e.g.: Kneler A, Kneler B, East Kameleon, Boa, Vilje and Volund, from STP Swivel to Alvheim inlet separator and 3rd party separator as shown in Figure A.1.

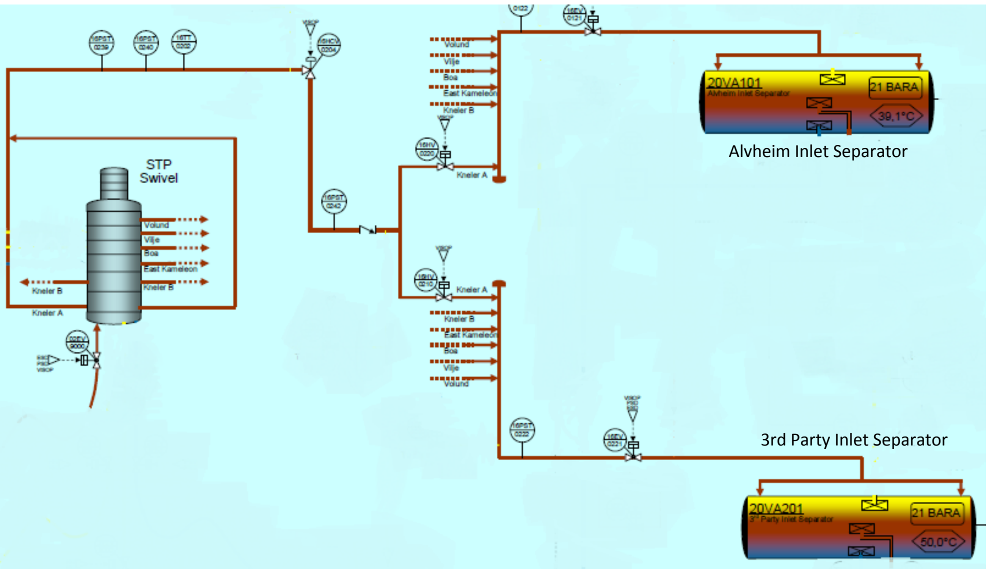

Figure A.1. Process sketch of system 16 (MONAS, 2005)

System 20 Crude Oil Separation and Stabilization

The system consists of two-stage separations with crude heating, coalesce and oil/water separator and its purpose is to stabilize the well streams to crude oil specifications. Gas and water will be separated from crude oil in the separators and oil export TVP (True Vapour Pressure) specification will be fulfilled by heaters. A system overview is shown in Figure A.2.

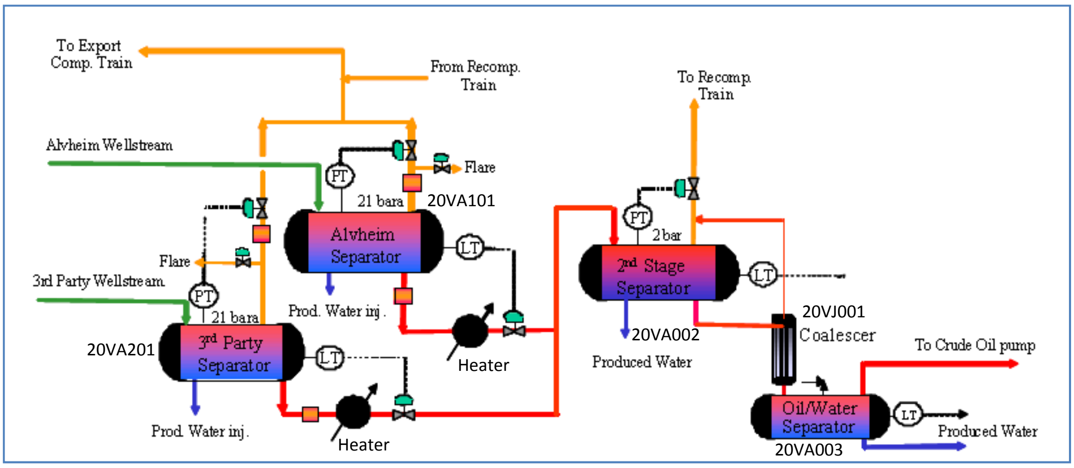

Figure A.2. Process sketch of system 20 (MONAS, 2005)

System 21 Crude Oil Metering

The system consists of crude oil pumps, crude oil coolers and a fiscal metering station for crude oil stabilization and its purpose is to control the temperature of the crude so no wax formation in the storage tanks, to meter the stabilized oil in accordance to fiscal standard and to deliver the crude oil to shuttle tanker via offloading hose. A system overview is shown in Figure A.3.

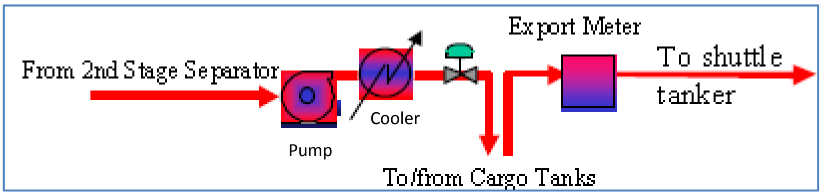

Figure A.3. Process sketch of system 21 (MONAS, 2005)

System 23 Re-Compression

The system consists of two parallel trains (2 x 50%) and each train consists of two compression stages with dedicated coolers and scrubbers as shown in Figure A.4. Its purpose is to raise the inlet gas pressure to match the operating pressure of inlet separators.

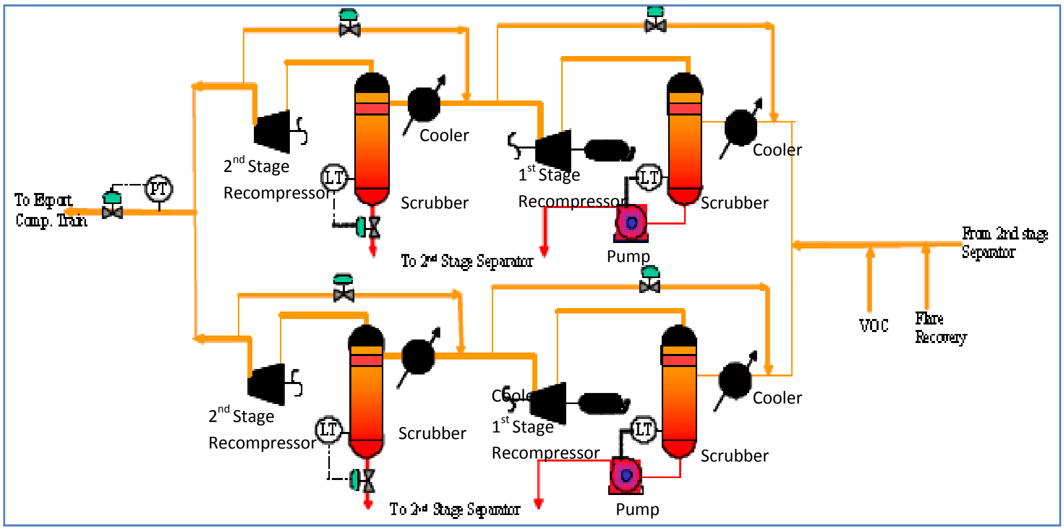

Figure A.4. Process sketch of system 23 (MONAS, 2005)

System 24 Gas Dehydration

The system consists of glycol contactor, dehydrator inlet scrubber and cooler as shown in Figure A.5. Its purpose is to remove any water inside of the gas by using glycol contactor in order to avoid any wet gas inside of gas export line. A wet gas may create corrosion, water condensation and plugs inside of gas export pipeline.

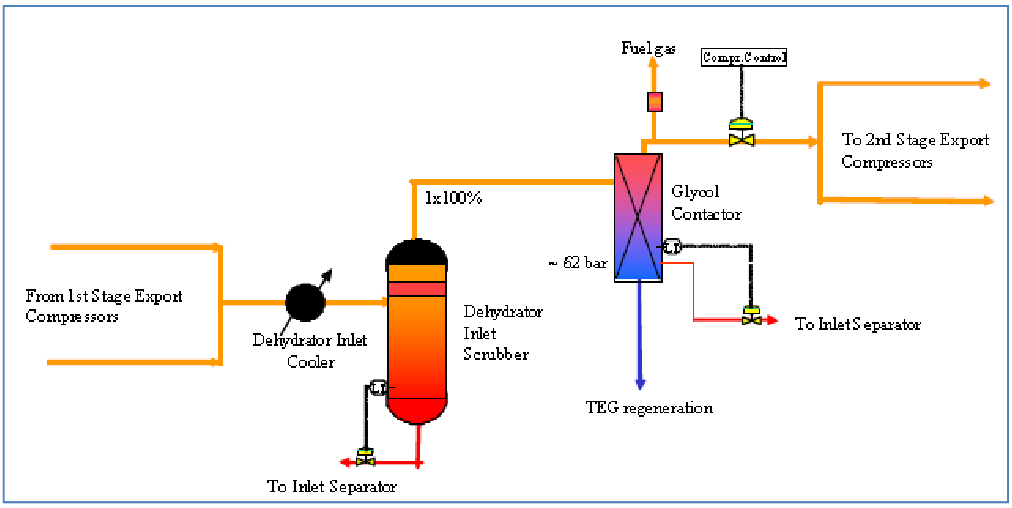

Figure A.5. Process sketch of system 24 (MONAS, 2005)

System 27 Gas Export

The system consists of two parallel two stage gas compression trains as shown in Figure A.6. Its purpose is to compress the produced gas to gas export pipeline pressure and treat the gas to cricondenbar specification in order to avoid condensation in the gas export pipeline.

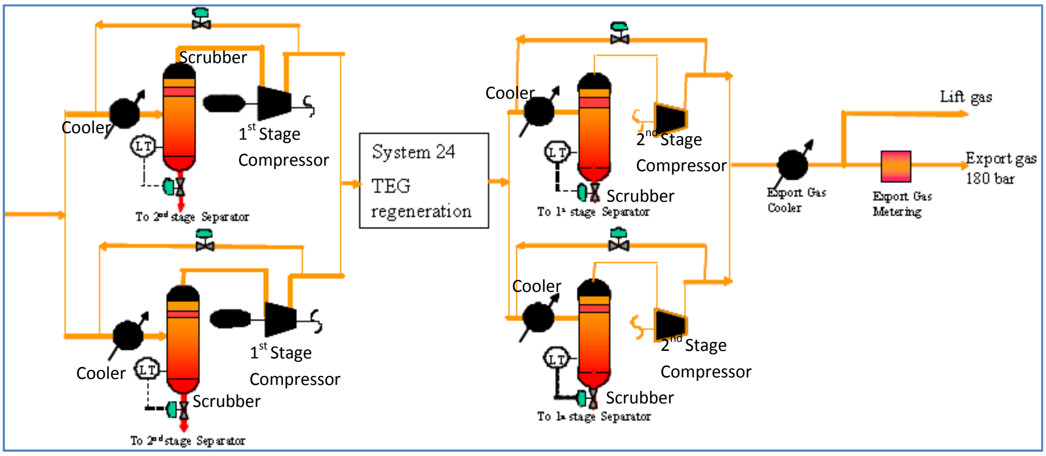

Figure A.6. Process sketch of system 27 (MONAS, 2005)

System 41 Heating Medium

The system consists of necessary pumps, heaters, WHRU's (Waste Heat Recovery Units), expansion tanks and pipework with the control valves to regulate the system. The heating medium is clean fresh water and the heat is recovered from the WHRU's in the power generator exhaust channels.

System 42 Chemical Injection

The system consists of all pipework associated with chemical injection including storage tanks and pumps. Its purpose is to inject chemicals to subsea manifold, separators, crude export metering and down-hole. Chemicals used in Alvheim such as corrosion inhibitor, scale inhibitor, demulsifier and wax inhibitor.

System 43 Flare and Atmospheric Vent

The system consists of all pipework and equipment downstream of relief valves and blowdown valves up to the flare tip.

System 44/29 Produced Water Treatment/Water Injection

The system consists of all pipework associated with water injection line including equipment's such as coalescer, produced water pump and hydrocyclone package. Its purpose is to treat the produced water to the required specification for water injection well or discharge it to overboard during upset conditions.

System 45 Fuel Gas

The system consists of all pipework associated with fuel gas distribution including scrubber, superheater and metering package. The fuel gas is extracted from the outlet of the dehydration system (glycol contactor) thus the gas is dry and no internal corrosion threat from a dry gas.

System 46 Methanol Injection System

The system consists of all equipment and pipework associated with methanol injection including storage tanks and pumps.

System 47 Electro chlorination

The system consists of all equipment and pipework associated with hypochlorite generation and distribution. Its purpose is to control biological growth in the seawater system by injecting hypochlorite to the seawater lift pumps.

System 50 Seawater

The system consists of all equipment and pipework associated with seawater distribution and utilization. Its purpose is to reduce the temperature of hydrocarbon liquid or gas by using seawater medium.

System 53 Freshwater

The system consists of all equipment and pipework associated with fresh water, potable water and high pressure water distribution and utilization.

System 56 Open Drain

The system consists of all pipework associated with the collection of spillage, wash water, deluge water and rain water including open drain tanks, pumps and centrifuge package. Its purpose is to treat the oily water before discharge it to overboard or route it to hull slop tank.

System 57 Closed Drain

The system consists of all pipework associated with the hydrocarbon liquid collection from vessels or other process hydrocarbon stream and its purpose is to collect hydrocarbon liquid drain, to safely dispose and degas the liquid thus drain the liquid to the hull slop tank.

System 62 Diesel Oil

The system consists of all equipment associated with the distribution of diesel oil up to the end user such as main generator.

System 63 Compressed Air

The system consist of all equipment associated with the utility air and instrument air distribution up to the end user and its purpose is to supply utility and instrument air to all consumers such as inert gas generation, pneumatic actuated valves etc.

System 64 Nitrogen Generation and Distribution

The system consists of all equipment associated with the nitrogen production from compressed air up to the end user and it will be used for blanketing and purging of another system during maintenance.

System 65 Hydraulic

The system consists of a hydraulic power package with supply and return line and its purpose is to serve all topside hydraulic oil users such as hydraulic operated EV, HV and XV valves.

System 71 Firewater

The topside firewater system consists of all pipework associated with the firewater distribution from firewater ring main on VUD (Vessel Upper Deck) to the firewater equipment such as firewater monitors and nozzles.