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Evaluation of Probability of Failure of Static Equipment in Pressurized Mud Systems on an Offshore Drilling Installation

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Abstract

Degradation of pressurized topside static mud equipment is a very complex process. Inspection is a helpful tool to monitor degradation and helps reduce the number of critical failures. If it is left undetected and unchecked, it can lead to leakage resulting in accidents. To set up an effective inspection program, the concepts of Risk-Based Inspection (RBI) can be utilized. RBI helps to develop an optimum inspection program by evaluating the probability of failure (PoF) and consequence of failure (CoF), and combining them to estimate risk. The parts that have risk higher than the acceptable limit are then prioritized for inspection. This thesis studies the probability of failure in static equipment in pressurized mud systems on an offshore drilling installation, due to different degradation mechanisms and its influencing factors.

Det Norske Veritas (DNV), suggests a number of models to estimate internal and external degradation. By analyzing inspection data from the industry, it is observed that the models can at times be inconvenient to use when the degradation process is complex. For example, it is difficult to develop a simple, yet reliable, model that can accurately predict rate of degradation in situations where corrosion and erosion are simultaneously taking place. In static equipment in high pressurized mud systems, inspection have shown that the main reason for internal degradation is high amounts of solids in the fluid, high velocity, presence of seawater, and corrosive chemicals. DNV-RP-G101 does not present any model for this situation. For external corrosion, the current models presented in DNV-RP-G101 can be used to analyze inspection data.

In an old installation, the accurate quantitative records are often not available due to a number of reasons, like difficulty in measuring, old data management system, unsystematic inspections or lost records. Thus, it often becomes difficult to develop any qualitative model. On the other hand, the inspection and maintenance engineers have extensive experience that may be utilized for developing effective subjective models. In this thesis, based on some simplified parameters, a methodology for evaluating probability of failure is established. The methodology is divided into external and internal degradation, where the subjective judgments are more evident for internal degradation. Simplified flowcharts and tables are developed to easily evaluate probability of failure.

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June 2015

"Der har du det. Noen kjøper konfekt og blomster, og snakker seg til det. Jeg går meg til det."

— Marve Fleksnes, Lageringeniør

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Abbreviations

CBM	Condition Based Maintenance
CC	Carbon Steel
CoF	Consequence of Failure
CUI	Corrosion Under Insulation
CVI	Close Visual Inspection
DNV	Det Norske Veritas
GVI	General Visual Inspection
HIC	Hydrogen Induced Corrosion
HP	High Pressure
HPHT	High Pressure High Temperature
ISO	International Organization for Standardization
LP	Low Pressure
MIC	Microbiologically Induced Corrosion
NDT	Non-Destructive Testing
O&G	Oil and Gas
PoF	Probability of Failure
PSV	Pressure Safety Valve
RBI	Risk Based Inspection
RCM	Reliability Centered Maintenance
SCC	Stress Corrosion Cracking
SS	Stainless Steel
UTM	Ultrasonic Thickness Measurements

Definitions

Availability *Ability of an item to be in a state to perform a required function under given conditions at a given instant of time or over a given time interval, assuming that the required external resources are provided.*

[NS-EN13306, 2010]

Consequence of Failure *The outcomes of a failure. This may be expressed, for example, in terms of safety to personnel, economic loss, damage to the environment.*

[DNV, 2010]

Damage *The observed effect on a component of the action of a degradation mechanism. The damage type gives rise to the failure mechanism of a component.*

[DNV, 2010]

Degradation *The reduction of a component's ability to carry out its function.*

[DNV, 2010]

Degradation Mechanism *The means by which a component degrades. Degradation mechanisms may be chemical or physical in nature, and may be time- or event-driven.*

[DNV, 2010]

Equipment *Equipment carries out a process function on offshore topsides that is not limited to transport of a medium from one place to another, and therefore comprises but is not limited to: pressure vessels, heat exchangers, pumps, valves, filters.*

[DNV, 2010]

Failure *Termination of the ability of an item to perform a required function.*

[NORSOK, 2011]

Maintenance *Maintenance is defined as a combination of all technical, administrative and managerial actions, including supervision actions, during life cycle of an item intended to retain it in, or restore it to, a state in which it can perform the required function*

[NORSOK, 2011]

Non-Destructive Testing *Inspection of components using equipment to reveal the defects, such as magnetic particles or ultrasonic methods*

[DNV, 2010]

Probability of Failure *The probability that failure of a component will occur within a defined time period.*

[DNV, 2010]

Risk *Risk is a measure of possible loss of injury, and is expressed as the combination of the incident probability and its consequences.*

[DNV, 2010]

Risk-Based Inspection *A decision making technique for inspection planning based on risk - comprising the probability of failure and consequence of failure.*

[DNV, 2010]

System *A combination of piping and equipment intended to have the same or similar function within the process.*

[DNV, 2010]

Chapter 1

Introduction

The petroleum industry has over the last decades increased its focus on safety. Better procedures and requirements has led to less serious incidents in the industry. Simultaneously huge effort has been contributed to maximize asset performance, efficiency, profit and up-time for O&G exploration and production installations. Maintenance and integrity management has played an vital part to reach those goals. Different approaches and tools has been developed over the last years to focus maintenance towards where it gives maximum benefit to both safety and economy. The result is a more proactive maintenance management instead of the traditional run-to-failure approach [Panesar et al., 2009]. Risk based inspection (RBI) is a decision making technique for inspection planning of topside static equipment based on perceived risk associated with failure of individual equipment. The risk shall be considered as a comprising of probability of failure (PoF) and consequence of failure (CoF). The RBI analysis helps focus the inspection where it gives maximum safety against unwanted incidents with minimum efforts [DNV, 2010].

Degradation of piping and pressure vessels can lead to failures with severe consequences to personnel, environment and economy. To reduce the probability of failure inspection can be used as a useful tool to monitor degradation. Degradation is a very complex process depending on material, content, operating environment and protective measures. Internal and external corrosion is one of the major problems in the oil and gas industry. Det Norske Veritas' (DNV) recommended practice DNV-RP-G101 provide a number of models to estimate the rate of degradations of pipes and pressure vessels subjected to various types of internal and external corrosion. With use of these models, probability of failure due to different damage mechanisms, can be estimated [DNV, 2010].

1.1 Aim and Background

Use of the quantitative models, provided in the recommended practice by DNV [2010], can at times be time consuming and/or misleading. Axess As, an inspection and integrity management company, has ongoing inspection programs on a number of offshore drilling installations. This has provided substantial amount of inspection data. A large part of the information collected from inspection is qualitative and therefore reflect personal judgment of the complex degradation processes. Hence, there is a requirement of a methodology to decide the probability of failure subjectively.

The aim for the research will be to establish a methodology for selecting probability of failure considering different degradation mechanisms. The focus will be on internal and external corrosion. The methodology is mainly fitted for high pressure mud systems, with basis from inspection data, current literature and recommended practices. The main result of the work is several flow charts that consider the various factors that influence the degradation processes and will be a guidance to evaluate the probability of failure.

1.2 Scope of Work

The thesis will focus on the following topics:

- A general description of the RBI methodology, including a overview of maintenance and integrity management.
- Overview of degradation mechanisms on static pressurized equipment, common material, and inspection methods used to detect and monitor degradation.
- Description of the current models for assessing probability of failure based on degradation mechanisms.
- Analysis of degradation mechanism and influencing factors based on inception data from pressurized mud systems.
- Development of a simplified methodology for evaluation of probability of failure of static equipment in pressurized mud systems, considering different degradation mechanisms.

1.3 Limitations

The thesis is limited to current literature, practices and procedures in the industry, including discussions with inspectors and company experts. The inspection data used in the analysis is mainly from offshore drilling installations. Hence, the suggested methodology is limited to drilling installations. Despite its limitations, the guideline may be convertible to other facilities and industries as well. The methodology is limited to internal corrosion/erosion and external corrosion. Other damage mechanisms like fatigue from vibrations and mechanical wear from external objects, is not discussed and analyzed at the same depth. The methodology is limited to pressurized mud systems when considering internal degradation, while external degradation can be transferred to other systems. Highlighted materials in the methodology are carbon steel and stainless steel.

1.4 Structure of Thesis

Chapter 1 includes a short introduction and highlights the aim and background of the thesis, in addition to limitations and structure of thesis.

Chapter 2 Introduces maintenance and integrity as concept and describes the RBI method based on current literature.

Chapter 3 present common degradation mechanisms on pressurized systems in the petroleum industry. The focus is put on external and internal corrosion mechanisms.

Chapter 4 describes the different models that can be used to model probability of failure based on degradation mechanism. Also here the focus is on internal and external corrosion, and stainless steel and carbon steel are considered.

Chapter 5 is a case study of pressurized mud systems on offshore drilling installations. Different mud systems are here closely described. Inspection data from high pressure mud systems are analyzed and discussed.

Chapter 6 presents the methodology for evaluation of probability of failure. The methodology focus on static equipment in high pressure mud systems. The methodology is based on inspection data from Chapter 5 together with current methodologies from recommended practices.

Chapter 7 consists of discussion and conclusion.

Appendix A consists of a spreadsheet with inspection data that is analyzed through the case study.

Chapter 2

Introduction to Risk Based Inspection Methodology

2.1 Maintenance and Integrity Management

As a very simplified approach, one can divide maintenance in two categories: preventive and corrective maintenance [Barabady and Kumar, 2007]. Preventive maintenance meaning that the maintenance is performed in advance at set intervals to prevent the failure to occur [Barabady and Kumar, 2008]. This is in the most cases a very effective method, but can be very expensive. It can be expensive in the way that components are replaced long before they are worn out. However, when considering high-risk systems and its severe consequences of failure, preventive maintenance can be an appropriate approach.

Corrective maintenance meaning that the components are run until they fail [Moubray, 1997]. In other words, the components are given maximum lifetime. However, this is not recommended for most systems. The reason for this is the severe consequences of a breakdown, which can lead to hazards to personnel, environment and economy. It can for instance be very expensive to close down the whole facility, only to replace one component.

In Figure 2.1 the different types of maintenance are illustrated. Corrective maintenance can be both planned and unplanned, while preventive maintenance is of course planned. Preventive maintenance can again be divided into period based and condition based maintenance [Markeset, 2013].

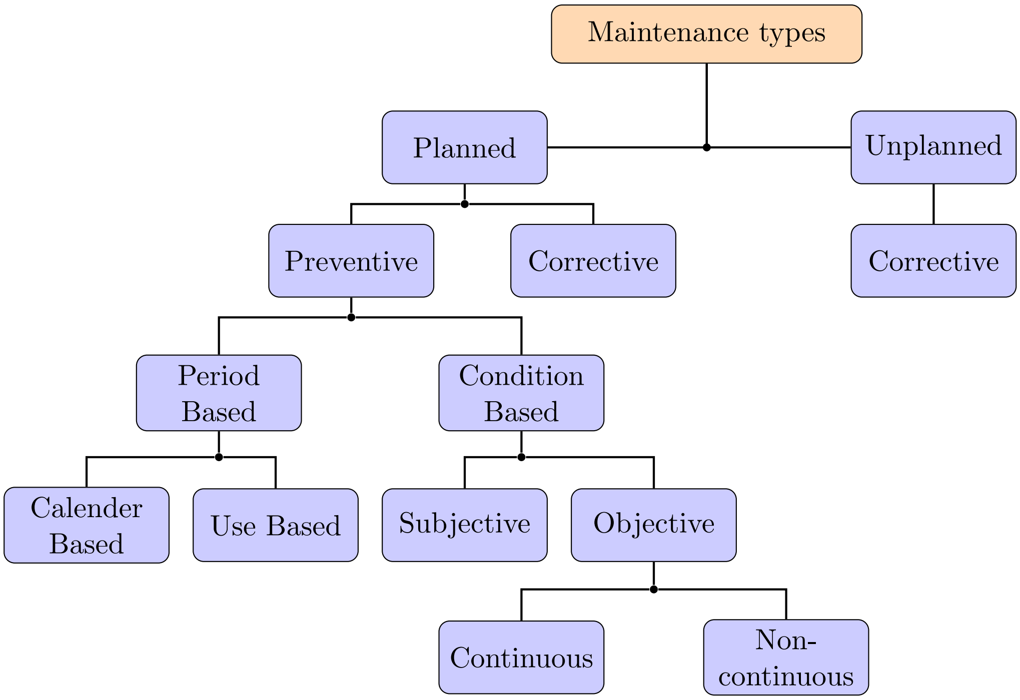


Figure 2.1: The different types of maintenance illustrated. Preventive and corrective maintenance are the two main types, where corrective maintenance can be both planned and unplanned [Markeset, 2013].

2.1.1 Condition based maintenance

One maintenance strategy can be to use a combination of preventive and corrective maintenance, using condition based maintenance (CBM). CBM is an approach where repair and replacement of components are based on the actual or future condition of the asset [Raheja et al., 2006]. This implies that reliability and criticality of the competent will be the basis for the maintenance interval. By knowing the condition of the component, the optimal balance between cost and maintenance frequency may be reached. To get the best knowledge and information about a components current condition, one needs to perform inspection activities.

2.2 Risk Based Inspection (RBI)

A facility have a high number of components that should be subject to inspection, and the time between inspections should not be too long. This can be a big challenge, and it is beneficial to establish a priority list of which components that should be inspected. To do this, Risk Based Inspection (RBI) can be a useful tool [Moura et al., 2015]. RBI is a decision-making technique for inspection planning based on risk. The combination of probability of failure and consequence of failure forms the risk picture of the given component. In a ideal situation RBI is designed to develop an optimized inspection plan, in addition to monitoring and testing plans for the system. The main motivation for focusing on inspection, integrity management and maintenance has been to reduce the consequences of a system failure. The consequences can either be regards to safety, environment or economy [DNV, 2010].

A Risk Based Inspection approach will include both preventive and corrective maintenance. Planned corrective maintenance will be issued for low risk components, while components with higher risk will be subject to preventive maintenance in the form of condition monitoring. Condition motoring can either be continuous monitoring, periodic monitoring or predictive maintenance, as illustrated in Figure 2.2 [Markeset, 2013]. By using the RBI methodology, a systematic and documented breakdown of the installations risk is ensured. The high-risk components are highlighted, and the most effective inspection and monitoring methods in association with the expected degradation mechanisms, is chosen. This leads to an effective inspection program that focus on the high risk equipment and reduces the effort on the low risk equipment. An acceptance criteria is set in advance and the RBI methodology will make sure that this limit in not exceeded in the future [Vika, 2011].

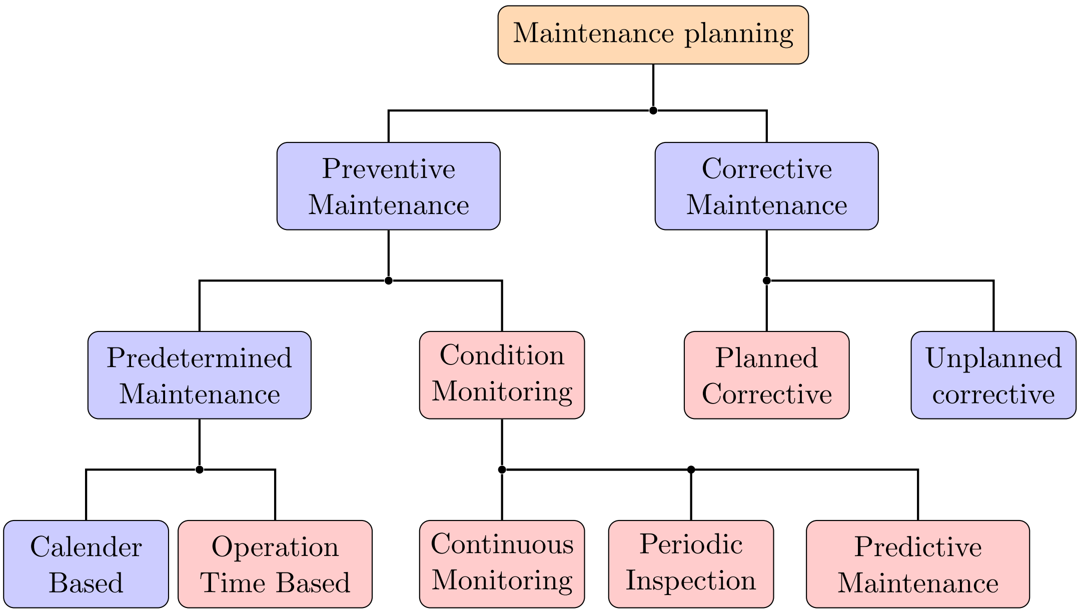


Figure 2.2: Schematic illustration of different types of maintenance planning. The red boxes indicated the approaches related to risk based inspection [Markeset, 2013].

RBI is often used for planning of inspection of offshore structures and pipelines. The determination of risk can be done for each component, but it is often seen that whole systems get a common risk level as well. The RBI program is formed after the acceptance criteria and the requirements the industry is subject to. In this way the operation throughout the assets lifetime is ensured, both economical and regards to safety. Almost all systems will at some time experience degradation in form of corrosion or other mechanisms. It is common to compare the degradation with the acceptance criteria to evaluate if the degradation is acceptable. To control the development of the degradation, inspection routines is set up. The main advantages with RBI are increased plant availability, less failures, reduction on the level of risk due to failure, and reduction in inspection costs [Khan et al., 2006].

2.2.1 Working process

The RBI working process can be divided into several parts. The process starts with preparations and data collections and an initial screening. Then a detailed RBI assessment is performed and an inspection plan is established. After inspection is executed the data from inspection reports are evaluated and the RBI assessment is updated based on current data, and the process will repeat it self [DNV, 2010]. The process is illustrated in Figure 2.3, and further described in Section 2.4.

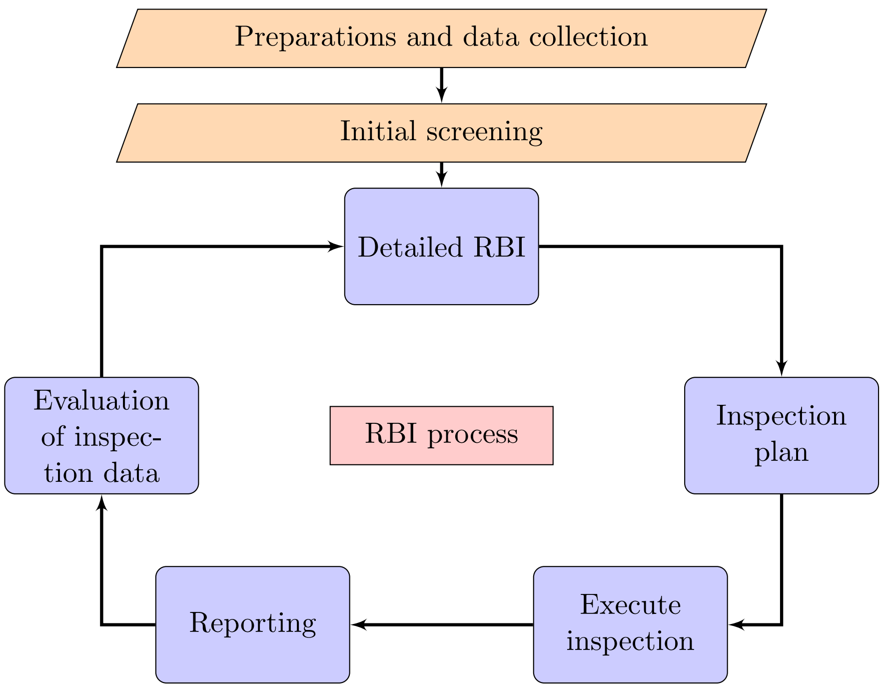


Figure 2.3: Illustration of Risk Based Insepction work process [DNV, 2010].

2.3 Recommended Practices and Relevant Standards

The most common practices for the RBI concept in the O&G industry are

- Recommended Practice **DNV-RP-G101**: Risk Based Inspection of Offshore Topsides Static Mechanical Equipment, made by Det Norske Veritas.
- API 580/581 Risk Based Inspection, made by The American Petroleum Institute.

The basis for this thesis is the recommended practice made by DNV. The practice is used as a guideline for most of the installations in norwegian waters, and is used by Axess, together with other technical procedures and documents. The **NORSOK** standards are also a basis for maintenance and inspection strategies in norwegian waters, and the most important standards are short described in this section.

DNV-RP-G101 The objective of the practice is to describe a method for establishing and maintaining risk-based inspection plan for offshore pressure system. It includes guidelines and recommendations to support the inspection planning process. The guidelines is materialized in customized methods and working procedures. The recommended practice is fitted to in-service inspection for offshore static mechanical pressure systems, where a failure is considered as loss of containment. The working process, described in Section 2.4, and the modeling of probability of failure, in Chapter 4, is based on the recommended practice. [DNV, 2010]

DNV-OSS-101 Rules of Classification of Offshore Drilling and Support Units is of interest for integrity of pressurized equipment. The standard presents "*the terms and procedures for assigning and maintaining classification, including listing of the applicable technical references to be applied for classification.*" [DNV, 2014]

NORSOK The Norwegian Petroleum Safety Administration states through 'Aktivitetsforskriften' that: "*Fault modes which constitute a risk to health, environment or safety, cf. Section 43 on classification, shall be systematically prevented by means of a maintenance program. The program shall comprise activities for monitoring of performance and technical condition, which will ensure that fault modes that are developing or have occurred, are identified and corrected. The program shall also contain activities for monitoring and control of failure mechanisms that may lead to such fault modes.*"

[PTIL, 2014]

The NORSOK standards can be considered as reflection of the regulations made of the Norwegian Petroleum Safety Administration. NORSOK Z-008, Z-013 and Z-016 could be of special interest considering maintenance integrity management.

NORSOK Z-008 Risk Based Maintenance and Consequence Classification, provides "*requirements and guidelines for establishing a basis for preparation and optimization of maintenance programs for new and in service facilities offshore taking into account risk related to: personnel, environment, production loss and direct economical cost.*"

[NORSOK, 2011]

NORSOK Z-013 Risk and Emergency Preparedness Analysis, has the purpose to "*establish requirements for effective planning and execution by using risk management tools like regularity analysis, reliability centered maintenance and risk based inspection.*

[NORSOK, 2001a]

NORSOK Z-016 Regularity Management and Reliability Technology, has the purpose to "*establish requirements and guidelines for systematic and effective planning, execution and use of reliability technology to achieve cost-effective solutions.*"

[NORSOK, 2001b]

2.4 RBI Methodology

According to DNV [2010], the RBI assessment can be performed in three ways: qualitatively, quantitatively or semi-quantitative/semi-qualitative. The quantitative analysis is based on calculations, and requires a high number of correct input data. Theoretical the analysis will produce an accurate result, but practically it is difficult to collect the amount of data needed. The qualitative analysis is highly dependent on subjective expert analysis from engineers, which often can be inadequate. Having in mind the characteristics of quantitative and qualitative analysis, a combination of these two will be the best way to perform a RBI assessment. By doing this the available data and expert knowledge can be integrated, and give the basis for further decisions.

From the RBI assessment, the following will be highlighted:

1. What to inspect
2. When to inspect
3. Where to inspect
4. How to inspect
5. What to report

Components that should be subject to inspection are first listed. This often means that high-risk components are prioritized. Further, the inspection intervals and inspection location are determined. To determine the locations to inspect, the expected damage mechanisms is evaluated. Next, the most effective inspection techniques is selected. To improve the RBI assessment it is important to report all relevant data. By doing this the assessment can be continuously improved.

2.4.1 Preparation, data collection and initial screening

Based on company policy and national regulations an acceptance criteria can be established. If the risk exceeds this limit at a later stage, actions must be addressed to decrease the probability of failure or the consequence of failure, or even both. For each consequence class it is useful to have one acceptance criteria.

To get a overview of the facility it can be convenient to first look at piping and instrument diagrams and other relevant documents. From this, the relevant items for inspection can be found. The most important here is to qualitatively find the items with insignificant risk. The highlighted items can be removed from the analysis. When the relevant items are found, a more detailed assessment can be executed. Here both probability of failure and consequence of failure are included, and finally, risk is estimated.

2.4.2 Detailed RBI

Probability of failure

Probability of failure (PoF) can be defined as the probability that a failure of a component will occur within a defined time period [DNV, 2010]. In the case of static equipment, this means unwanted leak in form of loss of containment from a pipe or valve. PoF for static equipment like piping is determined by evaluating the degradation for the different corrosion groups in combination with the nominal wall thickness. In addition, the uncertainties in the calculations should be included in the assessment. PoF can be ranked either quantitatively or qualitatively [DNV, 2010]. Table 2.1 showing ranking of PoF.

Table 2.1: Description of probability of failure according to DNV [2010].

Cat	Annual failure probability		Description
	Quantitative	Qualitative	
5	$> 10^{-2}$	Failure expected	In a small population, one or more failures can be expected.
			Failure has occurred several times a year in location.
4	$10^{-3} - 10^{-2}$	High	In a large population, one or more failures can be expected annually.
			Failure has occurred several times a year in operating company.
3	$10^{-4} - 10^{-3}$	Medium	Several failures may occur during the life of the installation for a system comprising a small number of components.
			Failure has occurred in operating company.
2	$10^{-5} - 10^{-4}$	Low	Several failures may occur during the life of the installation for a system comprising a large number of components.
			Failure has occurred in industry.
1	$< 10^{-5}$	Negligible	Failure is not expected
			Failure has not occurred in industry.

Consequence of failure

Consequence of failure (CoF) can be defined as the outcome of a failure, which may be expressed in terms of safety to personnel, economic loss or damage to the environment [DNV, 2010]. Safety consequences meaning effect to human health, often expressed in potential loss of life (PLL). Economic consequences are here defined as the consequences to the companies economy, expressed in financial terms. Environmental consequences are expressed in terms of mass or volume of pollution released to the environment. It can be useful to express it in financial terms as the cost of cleaning up the spill, fines and other compensations.

The recommended practice is to evaluate the classes individually since they can differ. The CoF will be ranked after severity, given by Table 2.2. Considering factors as reputation and environment, CoF must be evaluated qualitatively.

Table 2.2: Classification of consequence levels according to ISO [2000]

Rank	Personnel Safety	Environment	Economic
A	Insignificant	Insignificant	Insignificant
B	Slight / minor injury	Slight / minor effect	Slight / minor damage
C	Major injury	Local effect	Local damage
D	Single fatality	Major effect	Major damage
E	Multiple fatalities	Massive effect	Extensive damage

Estimation of risk

Combination of the values of PoF and CoF can be combined in a risk matrix to establish a risk picture. This can be presented in a risk matrix either quantitative, qualitative or a combination of both. In Figure 2.4 an example of this is presented. The matrix expresses three levels of risk. The risk must be below the defined acceptance criteria. If the risk is higher then the given limit, actions must be taken to lower the consequence and/or probability of failure. From this, a list of items sorted after risk can be developed, which will be the basis for the determining the time to next inspection [DNV, 2010].

Low risk Acceptable risk level. Still actions can be made to make sure that risk remains at this level, which can be general visual inspection (GVI), cleaning etc.

Medium risk Acceptable risk level. To measure the degradation, action should be taken. This includes NDT, functional testing and other condition monitoring. In this way one make sure that risk nor rise to the high level.

High risk Unacceptable risk level. The probability and/or consequences must be reduced to an acceptable level by taking necessary actions.

PoF Ranking	PoF Description	A	B	C	D	E
5	(1) In a small population, one or more failures can be expected annually. (2) Failure has occurred several times a year in the location.	YELLOW	RED	RED	RED	RED
4	(1) In a large population, one or more failures can be expected annually. (2) Failure has occurred several times a year in operating company.	YELLOW	YELLOW	RED	RED	RED
3	(1) Several failures may occur during the life of the installation for a system comprising a small number of components. (2) Failure has occurred in the operating company.	GREEN	YELLOW	YELLOW	RED	RED
2	(1) Several failures may occur during the life of the installation for a system comprising a large number of components. (2) Failure has occurred in industry.	GREEN	GREEN	YELLOW	YELLOW	RED
1	(1) Several failures may occur during the life of the installation for a system comprising a large number of components. (2) Failure has occurred in industry.	GREEN	GREEN	GREEN	YELLOW	YELLOW
CoF Types	Safety	No Injury	Minor Injury Absence < 2 days	Major Injury Absence > 2 days	Single Fatality	Multiple Fatalities
	Envirnoment	No pollution	Minor local effect. Can be cleaned up easily.	Significant local effect. Will take more than 1 man week to remove.	Pollution has significant effect upon the surrounding ecosystem (e.g. population of birds or fish).	Pollution that can cause massive and irreparable damage to ecosystem.
	Business	No downtime or asset damage	< € 10.000 damage or downtime < one shift	< € 100.000 damage or downtime < 4 shifts	< € 1.000.000 damage or downtime < one month	< € 10.000.000 damage or downtime one year
CoF Ranking		A	B	C	D	E

Figure 2.4: Description of risk according to DNV [2010]. Risk is here expressed in three different levels.

2.4.3 Inspection plan

From the risk ranking the relevant items for inspection is highlighted. In addition, it is important to find out where to do the inspection on each item. Based on historical data and guidance from manufacturer the locations for inspection is found. After finding the best location for inspection, meaning the locations that gives the best indication of the degradation, the relevant inspection technique must be found. NDT, non-destructive testing, is the most common method used, including methods like visual inspection, radiography, thermography and ultrasonic testing. Based on information needed about the equipment condition, the inspection method is chosen. Finally a inspection program can be developed [Dyrland, 2011].

2.4.4 Evaluation of inspection data

Data from the performed inspection will be collected and stored in a database. In general, equipment that are close to the acceptance criteria should be reported, together with the items that was highlighted as important in the planning/screening phase. When all the data is collected it should be evaluated by a team of experts. Extra focus should be put on items with values that not correspond with the expected data. After evaluation, a report with systems integrity and recommended actions is developed. Finally, one can reanalyze the results compared to the last report, and by this improve the inspection program before next survey. The program will be more effective, and less conservative assumptions can be made. The expert team will get better knowledge of the system and the calculation can be done more precisely (with less uncertainties) [Dyrland, 2011].

Chapter 3

Degradation Mechanisms on Static Pressurized Systems in the Petroleum Industry

In this chapter the different degradation mechanisms in the petroleum industry is presented. Corrosion in different forms are the main reason to degradation, and experiences from drilling rigs are highlighted.

3.1 Corrosion

Corrosion is the destructive attack of a material by reaction with its environment [Roberge, 2000]. In association with oil and gas production and transportation facilities, corrosion is considered as a natural potential hazard, and there is a numerous of complex conditions with aqueous environment which will lead to corrosion [Popoola et al., 2013]. The corrosion process consists of three elements: an anode, a cathode, and a electrolyte [Corbin and Wilson, 2008].

Anode Site of the corroding metal.

Cathode Forms the electrical conductor in the cell that is not consumed in the corrosion process.

Electrolyte Corrosive medium that makes the transfer of electrons from the anode to the cathode possible.

Carbon dioxide, hydrogen sulfide and free water are highly corrosive media, which is present in oil and gas wells and pipelines [Lusk et al., 2008]. The oil and gas components will over time suffer from corrosion effects due to extraction of CO_2, H_2S and free water. The degradation of the materials will lead to loss of mechanical properties, which again will lead to loss of materials, reduction in thickness, and in worst case, a ultimate failure. Corrosion in one of the biggest challenges in the industry and the effects of corrosion can almost never be ruled out during the lifetime of the equipment [Popoola et al., 2013]. In the oil and gas industry, the most common form of corrosion is when steel comes in contact with an aqueous environment and rusts [Corbin and Wilson, 2008]. The factors that influence the corrosion mechanisms in a given piping will be the fluid composition, service location, geometry, temperature, material etc [Popoola et al., 2013]. The most common forms of corrosion in the oil and gas industry is presented in the next sections.

3.1.1 CO_2 corrosion

CO_2 corrosion is a major problem in the oil and gas industry. CO_2 dissolved in an aqueous phase can cause an electrochemical reaction between steel and the aqueous phase. The most important influencing factors are temperature, composition of the aqueous stream, increase in pH-value, presence of non-aqueous phases, flow conditions and metal characteristics. If there is a rise in temperature, iron carbide scale is formed as a protective scale, and the metal will start to corrode [Popoola et al., 2013]. Theoretically, the corrosion rates can be 25-250 mm per year, and the corrosion form can either be uniform or in the form of pits [NALCO, 2004]. The corrosion will take place in all water-wetted locations in hydrocarbon systems. Pipework straights, bends, tees and reducers will especially be critical. In addition welds can experience corrosion [EI, 2008].

3.1.2 H_2S corrosion

H_2S corrosion, or sour corrosion, is due to contact with hydrogen sulfide and moisture. Drill pipes especially experience damage due to sour corrosion. Together with water, H_2S can be severely corrosive and can lead to pipeline belittlement [Popoola et al., 2013]. Corrosion forms can either be pitting, stress cracking or blistering. Stress cracking, or Sulphide stress and hydrogen induced cracking will occur especially at locations where there is high stress. Blistering will typically be the corrosion form for carbon steel pipework and vessels [EI, 2008]. All water-wetted systems in sour hydrocarbon service will be susceptible to corrosion.

3.1.3 Oxygen corrosion

Oxygen will react quickly with metal and is known to be a very strong oxidant. It is also one of the major reasons for corrosion of drill pipes. Drill pipes have high flow of drill fluids, and there will be a continuously supply of oxygen to the metal. Concentration as low as 5 ppb can be destructive [Popoola et al., 2013]. Oxygen corrosion can be present at all aerated water-wetted locations, pipework and vessels. Water injection systems, seawater systems, firewater systems, open drains, and heating and cooling medium is especially susceptible for corrosion [EI, 2008]. The corrosion form can be uniform or pitting [NALCO, 2004].

3.1.4 Galvanic corrosion

In cases where two materials with different electrochemical potential are in contact with each other in an electrolytic environment, galvanic corrosion can occur [Popoola et al., 2013]. The anode will sacrifice itself and start to corrode at the benefit of a protected cathode. To balance the electron flow, the anode loses metal ions. If the ratio between cathode and anode is high the corrosion problems will be significant [Brondel et al., 1994]. In the industry incorrect weld metallurgy and defects in coatings can be the cause of galvanic corrosion. Occurrence of galvanic corrosion is especially present at welds, screwed fittings, some types of gaskets, noble metallic coatings and where dissimilar metals are present in pumps. The systems that are prone to corrosion are seawater systems, water injection systems, hydrocarbon systems, drains, electroless nickel plated pipework and vessels and corrosion resistant alloy clad carbon steel vessels [EI, 2008].

The most serious galvanic corrosion attacks on drilling rigs are related to carbon steel plates in contact with titanium heat exchangers in sea water service [Axess AS, 2015a]. There are three types of galvanic corrosion:

Active Cases where the material corrodes even though there is not any galvanic connections to another alloy, like black steel in sea water.

Passive Slow corrosion of the material due to protective and passive layer caused by a reaction with the environment. E.g. chromium dioxide layer on stainless steel.

Immune No corrosion present, no reaction with the environment. Carbon steel that is cathodically protected, in sea water, is an example of this.

3.1.5 Localized corrosion

Localized corrosion is characterized by small attacks in areas with high corrosion rate, and the corrosion normally takes place where materials is protected by passivating layer. Stainless steel is a typical example of this. Since passivating layers only are stable in stable environments, deviation from the design parameters, pH and unwanted containment can ruin the protecting layer fast.

It is seldom experienced any serious degree of localized corrosion on drilling rigs. But in general, stainless steel can be attacked in marine atmosphere in almost any temperature. Before stress corrosion cracking occurs, pitting and crevice corrosion is often observed. Stains and small corrosion pits on stainless steel can occur more often on newer rigs. This might be due to poor pickling of the tubing prior to the installation or low level of alloying elements [Axess AS, 2015a].

Crevice corrosion and pitting

This is a localized type of corrosion, which normally occurs in narrow crevices or clearances in the metal. Crevice or pitting corrosion attacks is a result of the electrochemical potential differences [Popoola et al., 2013]. Metals with good protecting coating often suffer from crevice corrosion. The localized corrosion will occur where the protective layer does not get underneath [NALCO, 2004]. Drilling fluid, which contains dissolved oxygen can often cause crevice or pitting attack of metal in the shielded area of the drill string [Popoola et al., 2013]. Susceptible systems are all systems, both carbon steel and stainless steel, but seawater systems which contain oxygen are especially prone[EI, 2008].

Stress corrosion cracking (SCC)

This form for corrosion is caused by the combination of tensile stresses and the action of a corrodent. Stress corrosion cracking in a pipeline is highly associated with the environment surrounding the pipe. High pH of the surroundings and appearance of patches is examples of identifying characteristics of SCC [Popoola et al., 2013]. SCC can both be internally and externally. Stainless steel, duplex stainless steel and high strength carbon steel can experience SCC. Areas with stress concentration, like welds, are especially prone to SCC [EI, 2008].

3.1.6 Erosion

Solids - like sand - can cause erosion, leading to general wall thinning inside the pipe where the product flow is in contact with the pipe wall at areas where there is a change in direction or obstruction that causes eddy currents. With more solids and higher velocity, the rate of wall loss will be higher. Acoustic motoring, examination of coupons and frequency of separator jetting can be used to detect and estimate the sand rate [DNV, 2010].

3.1.7 Erosion corrosion

Rust scale and metal removal by fluid forces will lead to increased corrosion reaction. When the thin film of corrosion products, which stabilize and slows down the corrosion, is removed by the turbulence and high shear stresses, the corrosion rate will increase. Where the flow load is high and the corrosion rate is significant erosion corrosion is expected. Erosion corrosion is dependent on fluid flow rate and the density and morphology of the solids in the fluid [Popoola et al., 2013]. The occurrence of erosion corrosion is on all water-wetted locations, but especially at location where there is flow acceleration. Pipework experience erosion corrosion at straight, bends, tees, welds, valves and downstream of pumps. Vessels, especially nozzles, are prone to erosion corrosion. All systems can experience erosion corrosion, but three phase systems, produced water and seawater/water injection systems are most susceptible [EI, 2008].

3.1.8 Microbiologically corrosion (MIC)

MIC is caused by bacterial activities. Bacteria can multiply and form large colonies if the conditions are good, and this can lead to enhanced corrosion. The organisms can produce corrosive chemicals like CO_2 and H_2S. The growth of these bacteria will take place in neutral water, and especially in areas with stagnant flow. Appearance of a black slimy water material or nodules on the pipe surface, in addition to pitting on the pipe wall underneath, will indicate MIC [Popoola et al., 2013]. Sulphate Reducing Bacteria(SRB) is known to cause most corrosion attacks in the industry. In carbon steel systems which carries water and where oxygen is depleted and adequate amounts of nutrients is expected in the fluid, SRB are likely to form [Axess AS, 2015a]. Water injection systems, produced water treatment and re-injection systems, firewater system, drains and seawater systems can experience MIC. Occasionally it is experienced in hydrocarbon processing systems as well [EI, 2008].

3.1.9 General external corrosion

Due to exposure to marine atmosphere external corrosion will occur. Normally a coating is applied to the pipework to avoid corrosion [DNV, 2010]. On drilling rigs the paint work is often degraded or damaged. Thus, corrosion is often experienced in areas where the paint is thin or damaged. It is observed that drilling rigs often tends to have rough material handling, quick-fix problem solving approaches and uses temporary modifications due to lack of time. In many cases, this generate faster degradation of paint on drilling installations than other places in the petroleum industry. A corrosion rate at deck level in Norway is typically 0,05 - 0,1 mm per year, dependent on the moist and the exposure of salt [Axess AS, 2015a]. Experiences indicates that in tropical areas where the climate is hotter and more humid, the corrosion rates can increase to approximately 1,0 mm per year [Axess AS, 2015a]. It is seldom that external corrosion is a major threat to larger parts of piping systems. Corroded surfaces can increase the probability of fatigue.

Ballast tanks are constant or frequent wetted and may experience higher corrosion rates than in normal weather exposed environment. In Figure 3.1 general external corrosion on pipes through a ballast tank is illustrated. The surface will become more uneven when the wall thickness loss is high.

Figure 3.1: Picture showing general external corrosion on pipes through a ballast tank. Rust scale is removed on the picture to the right. [Axess AS, 2015a]

3.1.10 General internal corrosion

On drilling installations, there are three systems that usually are more exposed to general internal corrosion without being influenced by other corrosion mechanisms:

- Vent and sounding pipes for ballast tanks
- Undrained well test lines to burner booms
- Deluge systems

The main reason for the high corrosion rate could be the combination of high availability of oxygen and constant water wetting, in addition to non-galvanized lines. It is especially a problem on rigs older than 10 years [Axess AS, 2015a]. The corrosion rates will depend on the salinity of the water. Ordinary seawater has close to ideal salinity with respect to corrosion rate [Hasan, 2010]. Increase in salinity leads to an increase in electrolyte properties, but then the oxygen containment falls. In Figure 3.2 internal corrosion on a well test pipe is illustrated. Internal corrosion has led to holes in the bend of the pipe.

Figure 3.2: Internal corrosion on a well test pipe [Axess AS, 2015a].

3.1.11 Corrosion under insulation (CUI)

Figure 3.3: Picture showing an insulated and head trace pipe which have experienced CUI [Axess AS, 2015a].

This is a corrosion form that takes places under insulation, pften caused by wet insulation, damaged or missing coating and degraded seals on sheet metal coating. The rate of corrosion will be higher on warm pipework, 40 °C - 80 °C for carbon steel, and where salt is present [EI, 2008]. Lowered pH can also be a significant factor for development of localized corrosion for duplex and stainless steel. CUI appears locally and is therefore very difficult to handle [Axess AS, 2015a]. On drilling rigs, rockwool is often used for thermal and noise reducing purposes. Rockwool has the ability to absorb water and lead to a wetted steel surface [Wever and Kipp, 1998]. In addition, Rockwool can lower the pH of the absorbed water. Lines that often experience CUI is steam/condensate lines, exhaust piping, high pressure mud, firewater and well test lines. Indications of CUI can often be dripping and sagging insulation, pipe insulation in contact with deck plates, rust color wear coming from the insulation, damaged jacket allowing large amount of rainwater and sea water to run into lagging, and hot pipe surfaces [Axess AS, 2015a]. In Figure 3.3 corrosion on an insulated and head traced pipe is illustrated.

3.1.12 Classification of chemicals

DNV [2010] suggest separating chemicals into three groups: Proprietary chemicals, drilling chemicals and identifiable chemicals.Proprietary and drilling chemicals is often non-corrosive and innocuous, but can be corrosive and toxic at high concentration. Identifiable chemicals includes chemicals with more available corrosion data, but due to variation in corrosiveness, they should be evaluated individually.

3.2 Other Damage Mechanisms

3.2.1 Fretting

Fretting is a damage process related to small-scale vibrations [Szolwinski and Farris, 1996]. A pipe that vibrate relative to the item it is rubbing against will experience wear. This applies for all piping systems. On drilling rigs high pressure mud and high pressure cement pipes experience heavy vibrations and is thus more exposed to fretting [Axess AS, 2015a].

3.2.2 Cavitation damages

Figure 3.4: Picture showing area which have been exposed to collapsing steam bubbles in a water containing heat exchanger [Axess AS, 2015a].

Cavitation damage ia a term used for sudden collapse of steam bubbles in a liquid, and can be caused by pressure drop induced by a flow, followed by a rapid pressure rise [Mahulkar et al., 2008] or by hammering steam that enters a liquid [Axess AS, 2015a]. Cavitation is quite noisy process [Chudina, 2003]. When a steam bubble collapse there will be a rapid and local pressure rise. If this happens close to a metallic surface, there will be some kind of hammering effect. The result of this is tiny pieces of metal that are mechanically broken loose. A damaged surface will in general be porous-like. Impellers, propellers, flow regulation valves and similar objects that experience rapid flow with pressure fluctuations are in general exposed to cavitation [Axess AS, 2015a]. In Figure 3.4 a pipe with cavitation damages due to collapsing steam bubbles, is illustrated.

3.2.3 Fatigue

Failure due to varying or repeated loads. The loads needed to cause failure is significant lower than the static breakdown load [Forrest, 2013]. To prevent fatigue it is important with smooth geometry of objects. Corrosion leads to reduced stresses over the cross section of the object and concentration of stresses due to roughening of the surface. It is only objects with low frequencies of fatigue that is possible to monitor or detect through inspections. It is experienced that fatigue is one of the most important cause for leakages on high pressure mud pumps on drilling rigs. Areas that are more prone to fatigue is often welded bulkhead penetrations, welded supports and weld on piping close to high pressure pumps [Axess AS, 2015a].

3.2.4 Hydrogen induced cracking (HIC)

Hydrogen formation inside the pipe material can lead to degradation, detected by cracks. Atomic hydrogen enters the steel and mix with trapped molecules, and causes very high gas pressure internally in the material [Xue and Cheng, 2011]. Hydrogen atoms can be developed and present close to cathodic protected steel surfaces, H_2S containing fluid flow or when using wet electrodes during welding. Steel of high strength is vulnerable to HIC, due to its high hardness with high level of tensile stresses [Axess AS, 2015a].

3.2.5 Brittle fracture

Brittle fracture is fracture due to sudden overload that involves little or no plastic deformation [Tec—Eurolab, 2015]. Brittle fracture can cause rapid crack growth[Axess AS, 2015a]. Ferritic steels are most exposed due to its rapid growth in ductility around -50 °C [Bernauer et al., 1999].

3.3 Inspection Methods

To detect degradation and damage different inspection methods are used. The most common methods are methods like ultrasonic thickness measurements, general visual inspection, close visual inspection, radio graphic testing, eddy current testing and magnetic particle testing. The three first methods are further described.

3.3.1 General visual inspection - GVI

The main purpose of GVI is to detect global or larger defect for the system/item. Usually it does not require closeness to object/system and cleaning is not mandatory. According to Axess AS [2010], typical defects that can be identified through inspection of pressurized systems are:

- Quantification of paint damages.
- Damage to insulation and indication of wet insulation.
- Leaks through pipe walls, welds, flanges and connections.
- Local and global deformation.
- Damaged or unsuitable support.
- Indication of vibration that might cause damage.

3.3.2 Close visual inspection - CVI

If indication of defects are indicated trough GVI, CVI should be carried out. CVI is used to indicate local damages like cracks, local deformation and loss of wall thickness. The object prone to inspection should be fairly clean and the inspector should be quite close to the object. CVI is often planned at locations that are subject to fatigue. The three first methods are further described here [Axess AS, 2010].

3.3.3 Ultrasonic thickness measurements - UTM

UTM is most commonly used to monitor internal loss of wall thickness on piping and vessels. It is simple to use and has logistical and economic advantages and is rated as good inspection method for high pressure systems with thick walls. It is not suitable to find small local thin walled areas due the uneven internal surface that often is present [Axess AS, 2010].

Chapter 4

Modeling Probability of Failure

Degradation of a component can either be externally or internally and is dependent on the following parameters DNV [2010]:

- Material of construction
- Contents of the parts, for internal degradation
- Environment surroundings
- Protective measures
- Operating conditions

The PoF assessment can either be quantitative or qualitative. It can be very time consuming to use full probabilistic models to estimate PoF qualitative; therefor some simplified models are developed. If the assessment is done qualitatively it is assumed that the all elements are represented [DNV, 2010]. The damage mechanisms are divided into internal and external damage. DNV [2010] suggest four models to estimate PoF for expected degradation: unknown model, insignificant model, rate model and susceptibility model. In Figure 4.1 the three latter models are illustrated. The unknown model is not illustrated since the degradation is unknown. Modeling degradation can be divided into different steps, where the main steps are:

1. Find expected degradation mechanism
2. Determine damage rate/PoF. Either time dependent or susceptibility mechanisms.
3. Determine damage morphology.
4. Define hole size expected on failure.

The two last steps are related to the evaluation of consequence of failure.

The insignificant model applies for components where no degradation is expected. In this model, a fixed probability of 10^{-5} is used, independent of time. **The Unknown**

Model is used when the product is unknown, or when the combination of materials and product have no defined model. The probability is then set to 1. To determine if the component should be inspected, the consequence of failure need to be investigated.

The rate model is used when damage results in local or general wall thinning of the component. The model assumes that the damage increases with time and resulting in general wall thinning, meaning that the PoF increases with time. Material properties, wall thickness, fluid properties and operating conditions will be influencing factors. A simplified rate model can be described by distribution type, mean and standard deviation. To fit the rate model to the actual situation, inspection data can be used. For normal distribution, Monte Carlo Simulation can be used to determine PoF. The PoF will be dependent on wall thickness and the allowed corrosion.

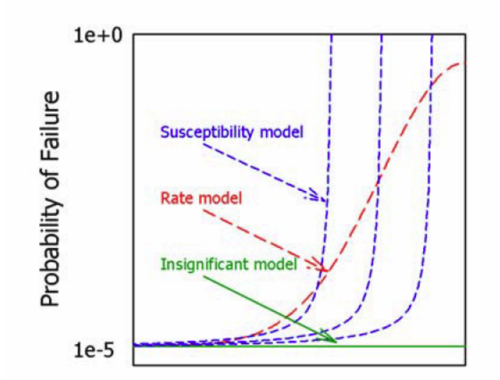


Figure 4.1: Models used to estimate degradation DNV [2010].

The susceptibility model is used for damage caused by an external event after a unknown period of time. When the damage is triggered, the failure occurs very quickly. Factors related to operating conditions will influence the probability of failure. The damage type related to this model is difficult to detect, meaning that the condition is difficult to follow by inspections. But it is however useful to monitor key parameters.

Stainless steel and **carbon steel** are the most common materials used in the petroleum industry. Carbon steel meaning carbon and carbon-manganese steels, and low alloy steels. Stainless steel includes austenitic stainless steel types, duplex and super-duplex steel, and super austenitic stainless steel (6Mo) [DNV, 2010].

4.1 External Damage

The external environment and conditions of the surface protection are the main factors to external damage. Insignificant model, unknown model, rate model or susceptibility model is used to estimate the damage rate. This is evaluated independently of any internal degradation/damage. Material with or without coating are here considered [DNV, 2010]. The external degradation models can be used for materials that are exposed to marine atmosphere, or are expected to be wetted to the marine atmosphere. Also taking account the materials that are expected to be wetted by seawater, including pipe supports, clamps etc, which can collect seawater and lead to corrosion on uninsulated piping.

To reduce the corrosion rate a coating is often applied to the surface. After a time period it is expected that the coating starts to fail. The time it starts to fail will depend on the type of coating and maintenance activities. If there is no information about the coating, the pipe is treated as there was no coating. In Figure 4.2 the expected degradation of coating is given as function of time. After 15 years, it is expected that all coating is removed.

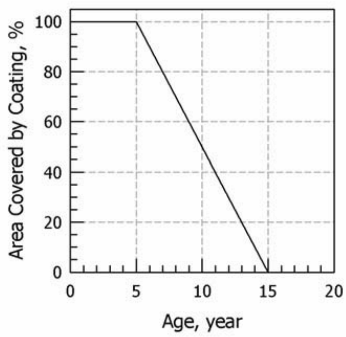


Figure 4.2: Degradation of coating as a function of time [DNV, 2010].

4.1.1 External corrosion - uninsulated

Carbon steel

Due to exposure to marine atmosphere, uninsulated carbon steel will experience external corrosion. The external corrosion rate is a function of temperature and modeled by using normal distribution. Mean corrosion rate and standard deviation for different temperatures are described in Table 4.1 and given as annual loss of wall thickness. If the temperature is under -5 °C there is no model applicable and the PoF is estimated to 10^{-5}. If the temperature is over 100 °C it is recommended to refer to a specialist.

Table 4.1: External corrosion rates for uninsulated carbon dependent temperature. Standard deviation and mean is given in mm/year [DNV, 2010].

Temperature T	Mean	Standard Deviation
$-5°C < T < 20°C$	0.1	0.05
$20°C < T < 100°C$	0.3547 x ln(T) - 0.9334	0.3929 x ln(T) - 1.0093

Stainless steel

Stainless steels have good resistance to atmospheric corrosion, but the presence of deposits or crevices can lead to local attacks. For uncoated stainless steels it can be expected that the PoF will be 10^{-4} per mm wall thickness. The effect of coating can also be added to the evaluation and will lower the probability of failure. In Figure 4.2 the coating degradation is presented as a function of the time. The coating effectiveness factor is $\frac{100-\text{effectiveness}}{100}$ and can be multiplied to the probability of failure.

4.1.2 External corrosion - insulated

It is difficult to visually inspect under insulated pipes. In cases where water penetrates the protection, high amount of salt can be accumulated on the surface of the metal, which can lead to local corrosion. It is important to collect all the details about the insulation and the conditions before an assessment is carried out. Under the insulation, it might be effective to have a coating, but then the degradation of the coating must be considered as well [DNV, 2010].

Carbon steel

Insulation will trap moisture in its porous structure and attack the external wall of the piping, which results in external corrosion in the form of local and uniform attacks. Content of water and rise in temperature will increase the corrosion rate. The corrosion rate is modeled by normal distribution according to DNV [2010]. In Table 4.2 mean corrosion rate and standard deviation for different temperatures are given. If the temperature is under -5 °C the model is not suitable and PoF is estimated to 10^{-5}. On the other hand, if the temperature is over 100 °C, it is recommended to refer to a specialist.

Table 4.2: External corrosion rates for insulated carbon steel piping. Standard deviation and mean is given in mm/year [DNV, 2010].

Temperature T	Mean	Standard Deviation
$-5°C < T < 20°C$	0.434	0.286
$20°C < T < 100°C$	0.0067 x T + 0.3000	0.286

Stainless steel

The external corrosion of insulated stainless steel is related to saline water retained in the insulation and deposits. The corrosion takes place as random distributed pits, but is often more dominant at welds. The probability of failure will be dependent on temperature and the type of stainless steel. Coating can off course lower the probability of failure, but the degradation of the coating over time must be considered. In Figure 4.3 the probability of failure for different types of stainless steel are

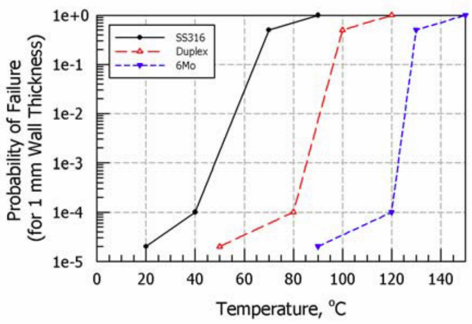


Figure 4.3: Probability of failure for local external corrosion of stainless steel as a function of temperature [DNV, 2010].

presented. The probability of failure is presented as function of temperature, and the probability of failure is per mm of wall thickness.

4.2 Internal Damage

Internal damage mechanisms are a product of material of construction, operating conditions and fluid flowing in the pipes. The product service codes used for topside offshore topside systems is useful to get an indication of the type of fluid expected in the pipe and by this determine the possible degradation mechanisms for the component.

4.2.1 Internal corrosion

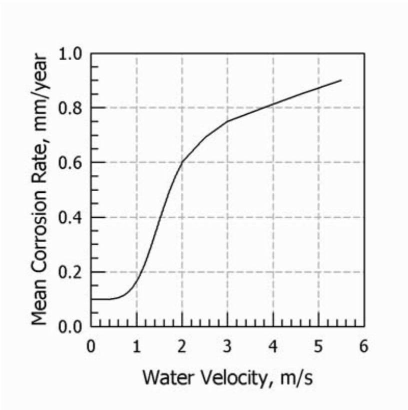
Carbon Steel

Water can cause internal corrosion of carbon steel piping. DNV [2010] suggests corrosion rates and standard deviation for different types of water. The rate of corrosion can be described by normal distribution. In Table 4.3 mean corrosion rates and standard deviation for different types of water are listed. Increase in oxygen, flow rate and temperature will increase the corrosion rate [DNV, 2010]. For raw seawater, seawater with biocides/chlorination and exposed drains, the corrosion rates will be given by water velocity, according to Figure 4.4a. The standard deviation is here given as 0.1. Sanitary drains will be experience MIC and this will be dependent on temperature, given in Figure 4.4b.

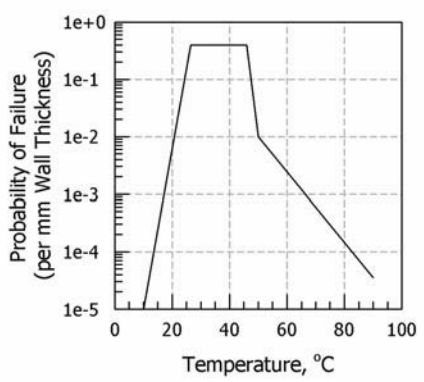
Table 4.3: Corrosion rates for carbon steel piping by different categories of water. Standard deviation and mean rate given by mm/year [DNV, 2010].

Water type	Mean	Standard deviation
Seawater Low Oxygen	0,01	0,01
Seawater Low Oxygen and Biocide	0,01	0,01
Seawater Low Oxygen and Chlorination	0,01	0,01
Seawater Low Oxygen , Biocide, Chlorination	0,01	0,01
Fresh water	0,25	0,1

CO_2 corrosion is one other problem causing internal damage. CO_2 on carbon steel will be present in gas-water-hydrocarbon multiphase systems. Rise in CO_2 and pressure will increase the corrosion rate. CO_2 corrosion can lead to both local and uniform attacks. NORSOK [2005] suggests a model to estimate the rate of CO_2 corrosion. The calculated mean value, with certain modifications, can be used as the mean rate in a Weibull distribution to estimate both local and uniform corrosion. The coefficient of variance will be different from local to uniform attacks [DNV, 2010]. In addition can erosion



(a) Corrosion rates of carbon steel according to flow rate of sea water.



(b) Probability of failure per mm of wall thickness of stainless due to microbial corrosion

Figure 4.4: Mean corrosion rates and probability of failure for carbon steel with respect to flow rate of sea water (a) and microbial corrosion (b) [DNV, 2010].

be a major problem for carbon steel. The rate of erosion can be described by normal distribution [DNV, 2010]. DNV [2007] suggest models to estimate mean erosion rate. The modeling process can be very time consuming considering the influence of different geometries. The mean rate can be misleading. [DNV, 2010] suggest to use a variance of 0.2, which means a standard deviation of approximately 0.45.

Stainless steel

Water systems may experience internal corrosion. Degradation of stainless steels in water will result in local attacks. This can be characterized by pitting or crevice corrosion and is highly dependent on temperature. The probability of failure can be estimated from Figure 4.5 and 4.6 given the material and water conditions. The probability of failure is per mm of wall thickness.

Considering raw seawater, the probability will be high for relatively low temperatures. For fresh water, it is only SS316 that will have high probability of failure. Considering sea water with low oxygen, SS316 and Duplex steel could experience failure when temperature is over 60 °C. For closed loops SS316 can experience failure if the temperatures is over 100 °C.

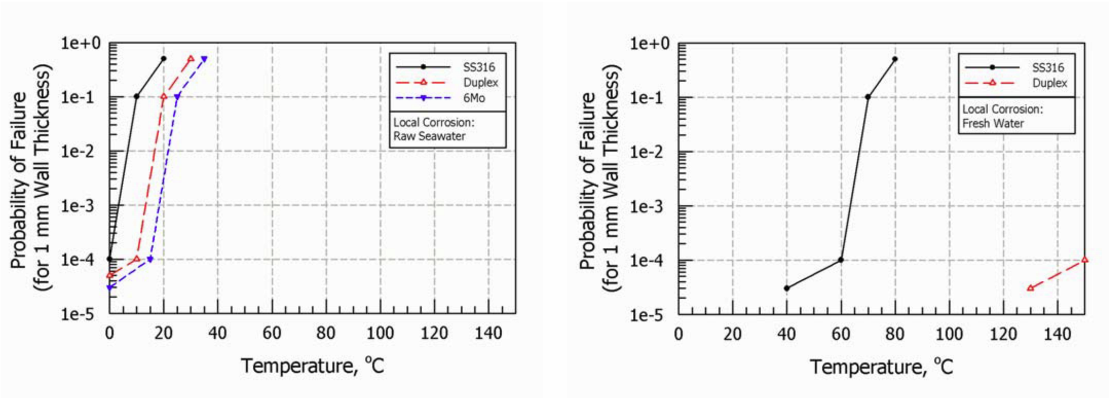


Figure 4.5: Probability of failure based on temperature for internal corrosion on stainless steel for raw seawater and fresh water. Probability of failure expressed per mm of wall thickness [DNV, 2010].

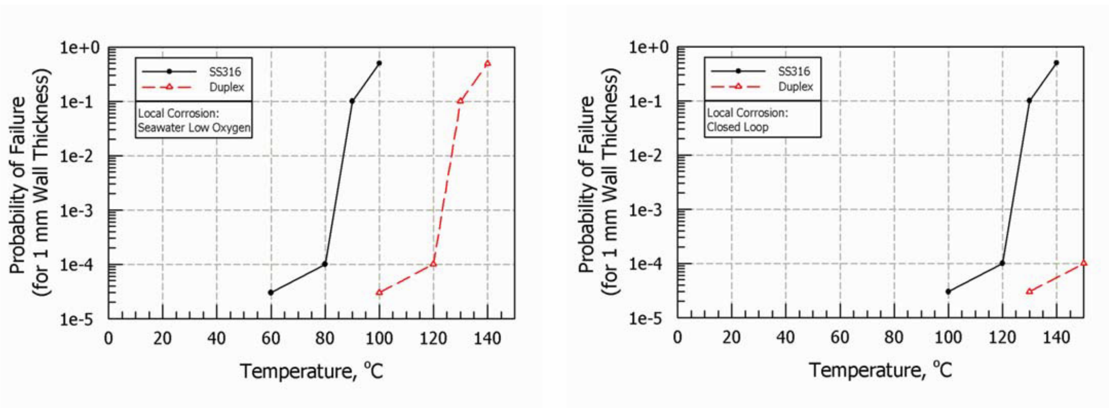


Figure 4.6: Probability of failure based on temperature for internal corrosion on stainless steel for seawater with low oxygen and water in closed loop. Probability of failure expressed per mm of wall thickness [DNV, 2010].

Chapter 5

Case study: Pressurized Mud Systems on an Offshore Drilling Installation

Axess As is a substantial inspection and integrity management company in the oil and gas industry and has ongoing risk based inspection programs on a wide range of drilling rigs in both norwegian and international waters. Through their inspection programs, Axess have collected a high amount of inspection data from pressurized topside systems. In this chapter, a case study is performed with focus on pressurized mud systems on drilling rigs. The different systems are closely described in Section 5.1. In Section 5.2 analysis of inspection data provided by Axess As is performed to get a better understanding of the damage mechanisms and its influencing factors. In Chapter 6 the most important findings from the analysis is combined with knowledge from current literature and standards to establish a guideline for evaluating probability of failure with respect to different damage mechanisms and materials.

5.1 Description of Mud Systems

5.1.1 Drilling fluid

Drilling fluid can be divided into water-based drilling muds and oil-based drilling muds. The classification is dependent on the characteristics of the contentious phase of the mud [Guichard et al., 2008]. Further classification can be based on alkalinity, dispersion and the type of chemicals in the mud. Lyons and Plisga [2005] suggest to divide drilling muds into fresh-water muds, inhibited muds, low-solids mud, emulsions and oil-based mud.

5.1.2 High pressure mud systems

High pressure mud system starts at mud pumps and continues all the way to the drill string . Mud is pumped through the drill string during operation, and on the way back the mud reach the diverter house and is directed into flow lines for processing before recycling [Skaugen, 2013]. The pressure in the system is typically between 5000 and 7500 psi [Ardoin, 2014]. Normally there are 3 to 4 mud pumps on a drilling rig. These are powerful reciprocating pumps, which often run at the same time. Pulsation dampeners are used to reduce the strokes, and will lower the vibration and smooth out the pressure peaks. Normally two stand pipes goes all the way to the derrick via a mud manifold at drill floor, where only on pipe is used at the time. Located over drill floor there is something called a *goose neck* which terminated in a 150 degrees bend. From the goose neck there is a HP hose to the drilling machine [Axess AS, 2015b].

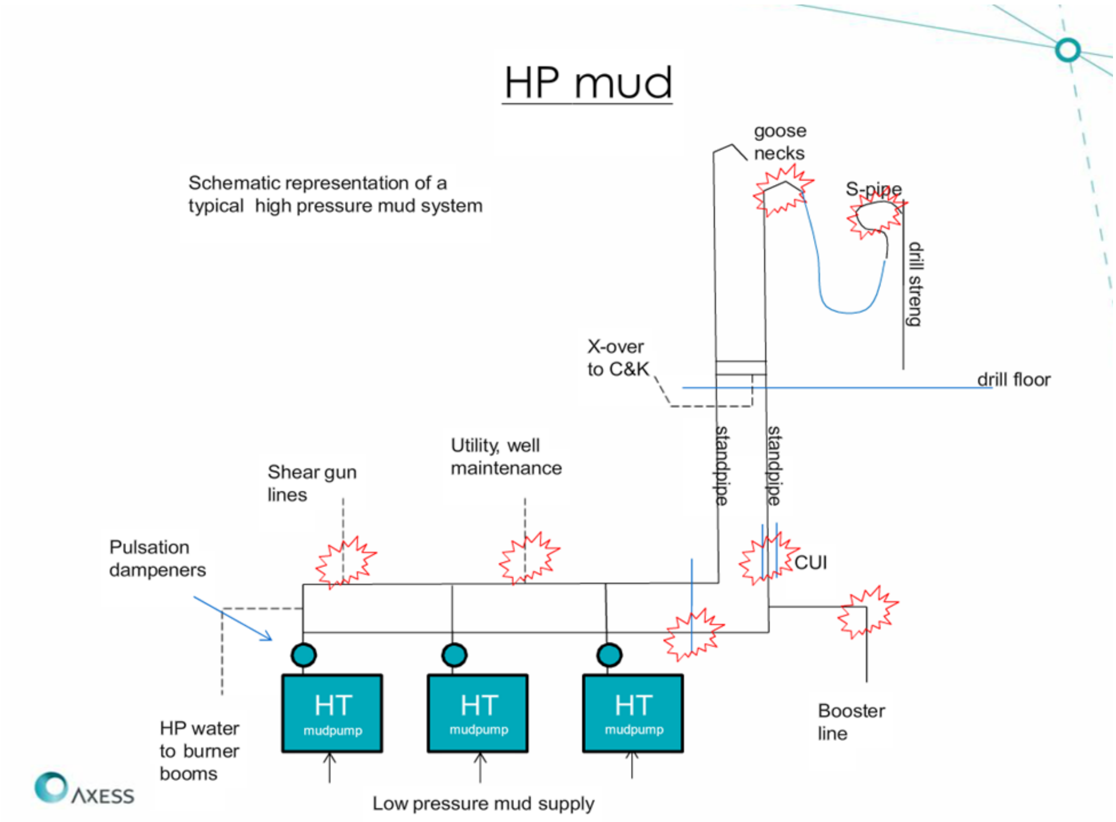


Figure 5.1: A general schematic representation of a typical high pressure mud system on a drilling rig [Axess AS, 2015b].

On the drilling machine, there is a receiving end, which is called a *S-pipe*. The S-pipe normally has smaller diameter than the stand pipes, typically 4”. Among mud piping, the S-pipes experience the highest flow load, and normally the piping is changed at certain time intervals, or they are subject to regular inspections. The booster line will also experience high flow loads. These lines are used for quick filling of the annual before drilling. The velocity is high here, but the pressure is not significant high, 5000 psi at a maximum. The booster lines is often protected with pressure safety valves (PSV), and the lines are less used than the S-pipes. HP mud may contain a range of mud mixtures and completion fluids like acidic, alcaline, water, oil bases, polymers, including mineral additives as baryte and bentonite. The lines are in general made of carbon steel [Axess AS, 2015b].

Other lines included in HP mud are shear gun lines, water curtain lines and utility branches for well maintenance. The mentioned lines have smaller diameter compared to the standpipes and higher velocities. The shear gun lines might have internal wastage if frequently used. In Figure 5.1 a typical high pressure mud system on a drilling rig is illustrated. The areas where degradation and damage are expected are marked with red danger marks. Corrosion rate for HP mud systems is typically 0,1mm/year, but with high flow loads it can be up to 1,0 mm/year. Cracks can occur due to vibration from the HP pumps, and can lead to leakages. Close to the mud pumps, non-flexible lines can be subject to fatigue cracking, especially at piping welds. Axess focus their inspections on small bore appendages, booster line, bulkhead penetrations, pipe support, CUI, goose neck and S-pipes [Axess AS, 2015b]. Inspection methods are GVI and UTM and are focused on hot spots like S-pipe. Well control systems and mud-gas separator can also be treated as high pressure systems [NORSOK, 2012].

Well control system

Kill and choke lines are a well control system and is counted as a secondary barrier system [NORSOK, 2012]. The excessive fluids and pressure is let off via the choke line and the choke valves. Kill mud is injected through the drill string. Gas from the formation fluids is let off in the top of the derrick with the *poor boy degasser*. Kill line has the same function as the choke line, but it is used as a back up and for pressure monitoring purposes. Well control systems may be designed for various working pressures, from 2000 psi to 25000 psi [NORSOK, 2012]. Pressure upstream is typically 15000 psi, while downstream the pressure is approximately 5000 psi [Axess AS, 2015b]. The wastage rate is very little in the system. Some wastage is experienced in erosion nipples downstream. Inspection routines are strict, especially for high pressure high temperature(HPHT) systems DNV [2014]. Inspection will be dependent on well control experiences. In Figure 5.2 choke and kill system from one of Axess' rigs is illustrated. Choke and kill system can look a bit different from rig to rig. Despite that they have more or less the same function. Normally the choke and kill lines consists of [Axess AS, 2015b]:

- One choke line
- One kill line

- One choke and kill manifold with connection towards a mud-gas separator.

Choke and kill lines are usually made of carbon steel. Well control systems contain the same fluids as HP mud, in addition to well fluids.

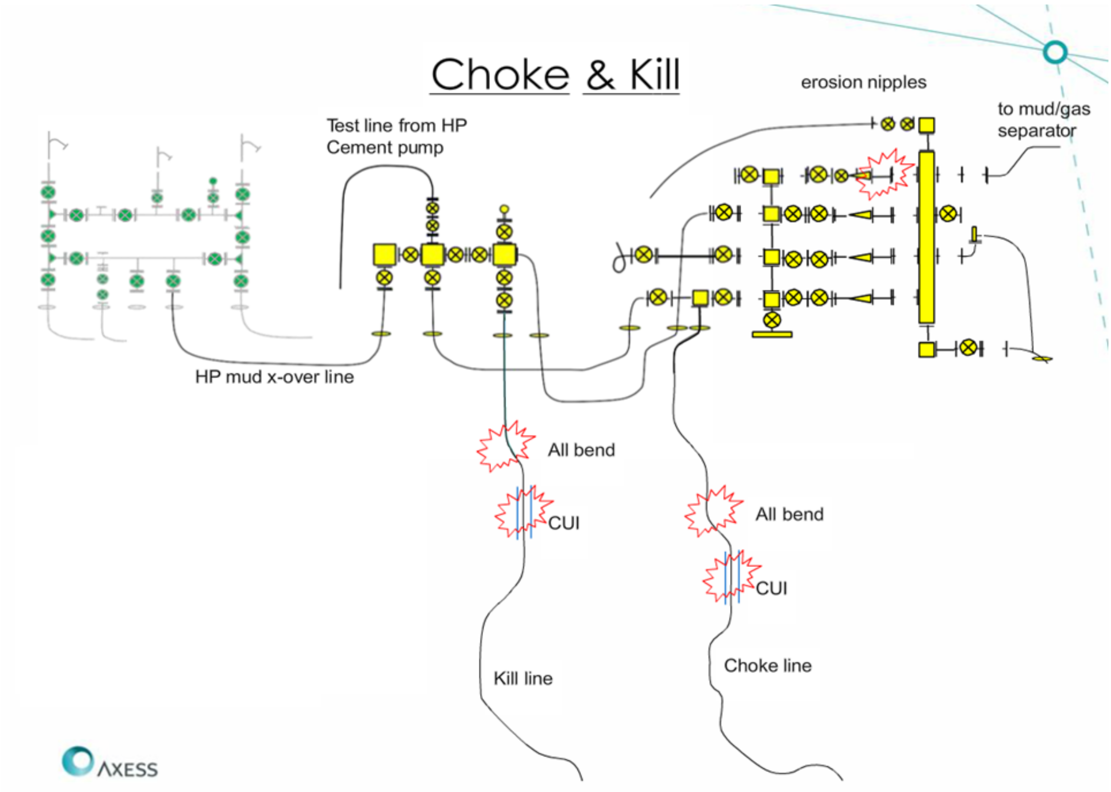


Figure 5.2: Sketch of a choke and kill system on one of Axess rigs. Red danger signs indicates areas where degradation is expected [Axess AS, 2015b].

Mud-gas separator

From the choke manifold one of the outlets is routed to a mud gas separator, called a poor boy degasser. Fluids are here separated. Gas is routed over the top of the derrick into a vent line. Degasser mud will go via a flow line or trip tank to the shaker. The degasser is rarely used, but rigs that include mud-gas separator in mud processing will use the system more frequent. According to NORSOK [2012] the diameter of the vent lines shall be minimum 10" and routed minimum 4 meter over the derrick or to another safe area. The degasser system shall also have pressure integrity enough to be filled up to the top of the vent line with mud having specific gravity of 2.2, meaning approximately 12 bar pressure. High pressure high temperature (HPHT) wells should have a liquid gas seal, and the hydrostatic pressure should be equal to the pressure of 6 meter mud or more. A simplified sketch of a typical mud-gas separator system is illustrated in Figure 5.3. U-tube, liquid seal tank and trip tank is illustrated, where all of them have the same function to prevent gas to flow out through the bottom exit of the mud-gas separator and further to the mud processing facilities. The system is seldom used, and not so often inspected. On older rigs it is often experienced that the bottom mud exit pipes is heavily corroded internally. On rigs older than 15 years with little or no history, connection lines should be subject to inspection. Mud exit line and gas/liquid seal shall be prioritized [Axess AS, 2015b].

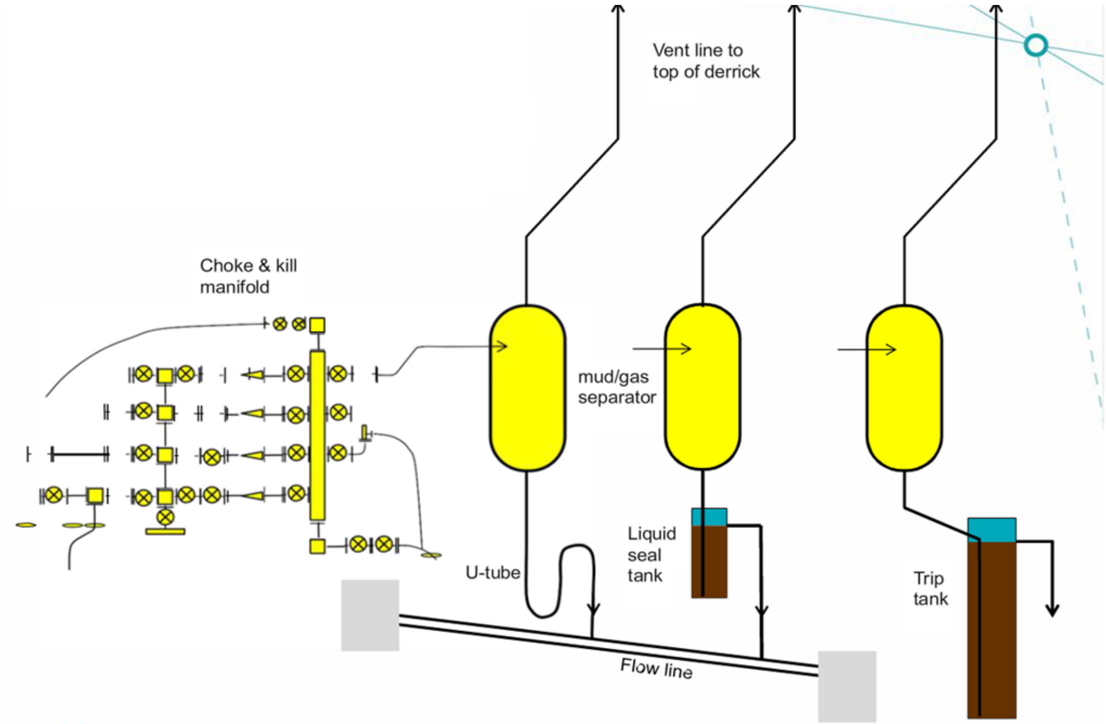


Figure 5.3: Illustration of three different arrangements using the same principle to prevent gas to flow out through the bottom exit of the mud-gas separator [Axess AS, 2015b].

5.1.3 Low pressure mud

The main purpose here is to transport oil-based mud, where the main ingredients are barite, ilemenite etc. By length, it is one of the largest systems on board on a drilling rig. System include storage, transfer, mixing, degassing and reconditioning of mud in different phases. It is not always good knowledge present on how all parts of low pressurized mud system is used. It is important to find out what lines that is used the most. Parts of the piping systems are clearly exposed to heavy external wastage, and corrosion erosion is the most dominant damage mechanism. Piping with high flow load is the most exposed sections. Certain parts have safety functions and must be intact, including trip tank and diverter lines. The system consists of a range of lines and pumps. The frequency that the pumps are used will be a good indicator for expected degradation. LP mud lines are normally made of carbon steel[Axess AS, 2015c].

Trip tank circuit

This circuit often experience heavy erosion corrosion. The circuit is gravity fed from the atmospheric return mudflow line that brings mud from the marine riser and into the shale shakers during drilling operations. It is connected so if there is a excessive amount of mud flowing back from the well, it will feed the trip tank. The main purpose of the trip tank is to monitor volume changes in the well during drilling and it has the function to give an early warning of an ongoing well kick [NORSOK, 2012]. Trip tank circuits normally experience leakage on inaccessible locations. A leakage will lower the sensitivity of the trip tank to sudden rises in mud level. In Figure 5.4 a trip tank circuit is illustrated. The line from the tank back to the return point against the flow line is exposed to erosion corrosion, and is marked with red warning indicators. The lines that fills up the trip tank is usually designed with a larger diameter and larger wall thickness [Axess AS, 2015c].

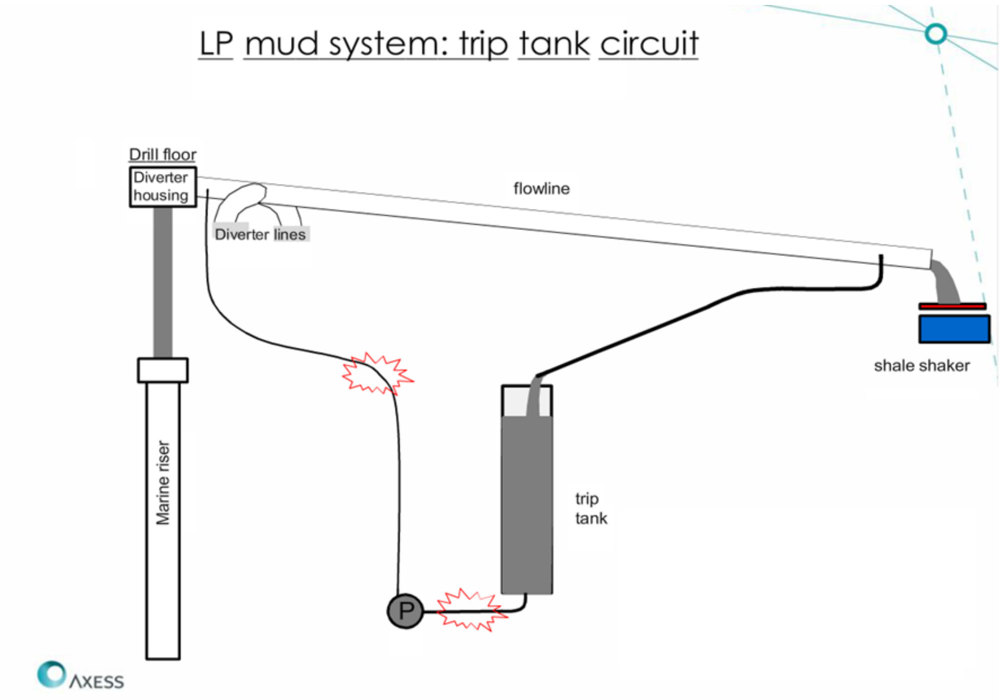


Figure 5.4: Simplified sketch of a typical trip tank circuit. Erosion corrosion on the line from the trip tank to the return point is often a problem [Axess AS, 2015c].

Diverter lines

Diverter lines are overboard lines for return of mud/formation fluid which include a wide range of mud mixtures and completion fluids like acidic, alcaline, water, oil bases, polymers, including mineral additives as baryte and bentonite[Axess AS, 2015c]. The system is used as an emergency system during a well kick and they are designed with inclination the lead an uncontrolled well flow away from the rig[NORSOK, 2012]. This is not always the case since the fluids often have high viscosity[Axess AS, 2015c]. Diverter lines are part of safety critical system and extensive wall thickness loss and blockage is not acceptable. During kick and blow out there has been incidents with leakage. I.e West Vanguard in 1985, where the steel material in a bend was eroded away in few minutes and causing a leak with severe consequences [Vinnem, 1999]. After the Macondo blowout in 2012 there has been a new focus on diverter lines. The lines should at least be 4 meters beyond shipside, self-draining and minimum bore is 305mm [NORSOK, 2012]. After 2012 the erosion rate calculations is based on designed flow conditions to check if the lines can survive a critical situation. The wall thickness acceptance criteria is based on erosion calculations, not pressure integrity alone. In Figure 5.5 a sketch of a typical diverter lines is illustrated. In some cases the diverter lines are routed directly out from the diverter housing and not as branches on the flow line as Figure 5.5. Red danger indicators marks where degradation is most likely to be expected. Diverter lines are usually made of carbon steel [Axess AS, 2015c].

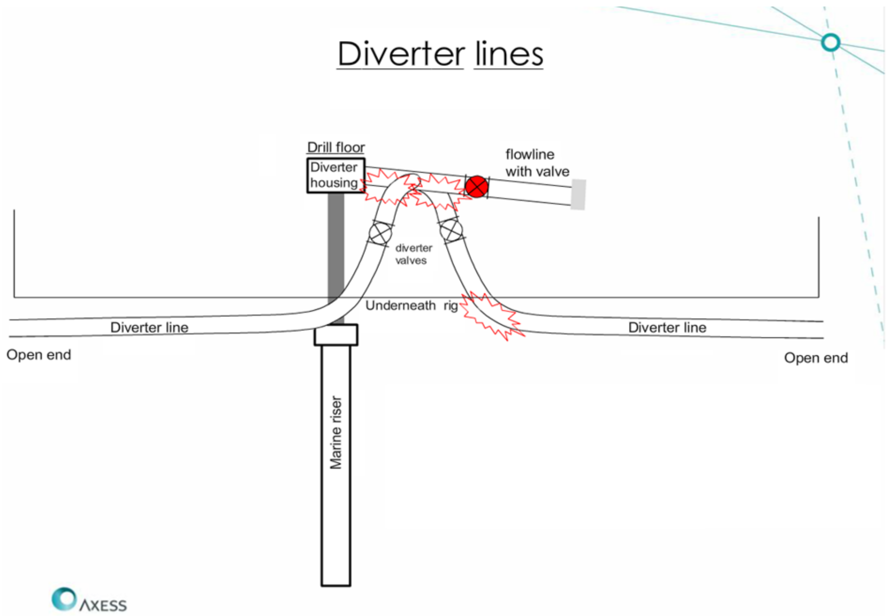


Figure 5.5: Sketch of diverter lines on a drilling rig. Red warning signs indicating locations prone to degradation [Axess AS, 2015c].

5.2 Analyzing Inspection Data

The data set consists of approximately 2400 findings from 55 drilling installations in the time period 2006-2013. For each installation, Axess has an inspection program. The inspection program is establish through a risk screening and is updated after each inspection survey. Based on the screening a inspection plan is established, where the main inspection methods are general visual inspection (GVI), close visual inspection (CVI) and ultrasonic thickness measurement (UTM). UTM is the main inspection method and a high number of test point are pointed out on critical locations. In the inspection program a acceptance criteria is selected, which is normally based on wall thickness of piping. For high pressure systems minimum wall thickness is calculated based on hydrostatic pressure based on formulas in ASME B31.3 [LANL, 2009]. For low pressure systems minimum wall thickness is based on NORSOK requirements [NORSOK, 1999]. If the measured thickness is close to or under minimum thickness, further evaluation is issued where DNV is included. A fitness for purpose calculation can state the reason for further use of the equipment. UTM will above all indicate internal degradation of the equipment. For external degradation the results are from GVI and CVI , meaning that the results can be difficult to quantify.

In the data set, the following information is provided:

- Type of installation
- Year of build
- Date of survey
- Inspection method
- System
- Object that is subject to damage
- Line/equipment
- Location
- Material
- Description of finding
- Proposed action / recommendation

From inspection reports, further information can be found related to each finding. The findings listed in the data set is regarding wall thickness close to or under minimum wall thickness, or other critical condition of the line or equipment. In addition, data for all test points from the installation can be found in the different inspection programs. Since there is a huge amount of test points, the analysis is focused on the critical findings. It is also the critical findings that are the best indicators of damage and degradation. To get a better and more accurate analysis high pressure mud systems have been highlighted. The description of the analyzing method is found in next subsection and all the results is listed in the spreadsheet in Appendix A.

5.2.1 Analyzing method

The spreadsheet in Appendix A describes the critical inspection findings from high pressure mud systems. In addition to the information provided in the raw data, the following is included:

Nominal thickness $\mathbf{T_{nom}}$ The designed thickness of the pipe.

Minimum thickness $\mathbf{T_{min}}$ The acceptance criteria decided from standards or hydrostatic pressure calculation.

Thickness measured $\mathbf{T_{measured}}$ The measured thickness using ultrasonic measurements.

Possible cause of degradation From the inspection reports the possible degradation mechanisms are listed. Internal damage include erosion and corrosion problems, while external damage include external corrosion, vibration and other factors like wear from external objects.

Location object prone to degradation To get a better understanding of the degradation the location where to degradation takes place is outlined. Typically that could be at bends, bottle necks, welds, weather exposed areas etc.

Cause of location The location where the degradation takes place can be further analyzed. The cause of degradation location can be analyzed to completely understand the degradation process. The cause of location can be higher flow load, reduced pipe size, marine atmosphere, different materials etc.

Degradation rate/degradation process From T_{nom} and $T_{measured}$ the rate of degradation can be determined. The degradation rate is expressed as loss of wall thickness per year (mm/year). If there is no data from previous inspections, the difference in nominal thickness and measured thickness is used together with information about when the equipment was installed. If there is no information about when equipment was installed, the age of the rig is used for young rigs($<$ 5 years). For rigs older than 5 years, the time period of degradation is set to 5 years. For degradation where rate model can be used, the ranking of the degradation process is described in slow, medium or fast degradation in Table 5.1. Damage caused by vibration, pitting, crevice corrosion and external wear is categorized as susceptible or unknown due to its unpredictability. Once the damage is detectable the failure will normally occur immediately.

Table 5.1: Classification of degradation used in analysis of inspection data

Rank	Loss of wall thickness (mm/year)
Slow	> 0,1
Medium	0,1- 0,5
Fast	> 0,5
Susceptible/ Unknown	N/A

5.2.2 Inspection findings

In this section, the inspection findings are further described and discussed according to the factors mentioned in the above section.

Internal damage

Internal corrosion and erosion can at times lead to severe degradation to high pressure mud systems. The reason for the degradation can be very complex. However, the most important influencing factors can to some extent be generalized into different categories. The high pressure mud systems are in general made of carbon steel.

The most serious degradation problem is related to erosion and corrosion. Erosion will lead to a more exposed surface and corrosion will be enhanced. Locations prone to high erosion/corrosion rates are bends, after bends, welds, flanges and bottlenecks. In other words, these are locations where there will be fluctuations in velocity. Especially goose necks and s-pipes experience severe degradation rates due to the high flow load. In the most severe occasions degradation rate can be up to 5 mm/year, but normally the rate is 0,25-0,70 mm/year, which will be located in the upper part of the degradation process scale. Bends on standpipes is also exposed to high material loss. In the most serious cases there have been observed degradation rates is up to 7 mm/year. The reason for this can be many different factors. But a general observation is that high amount of solids, corrosive chemicals, and presence of seawater - not necessary combined - induce high degradation rates. This applies for almost all parts of high pressure mud systems. Raw seawater and seawater with biocide and chlorination will induce high corrosion rates, dependent on the flow. Low oxygen seawater have low corrosion rates, typically 0,01 mm annual loss of material for carbon steel [DNV, 2010]. Corrosive chemicals can often be present in drilling fluid. Additives is often added to the fluid to change its properties and can in many cases lead to a more corrosive environment.

Other lines that experience high erosion/corrosion rates are pop-off lines, bleed off lines, relief lines, x-over line and booster lines. These lines will also experience high flow loads.

Reduction in pipe diameter, a bottle neck, is present for many of the lines and will generate a higher velocity.

External corrosion

Damage painting and insulation is often a problem on offshore drilling installations. Quick-fix solutions is often utilized and there can be lack of sufficient painting programs and maintenance program in general as well. Insulation and heat tracing can often be present when it is not needed, which lead to unnecessary corrosion problems. General visual inspection and close visual inspection is in general the methods used to detect external corrosion. It is therefore seldom measurements on the exact rate of degradation. The degradations process is normally ranked in a subjective manner.

If there is no coating under the insulation it is observed that equipment will suffer from external corrosion. This especially applies for equipment that is exposed to high temperatures and/or humid environment. Uninsulated piping also suffer from external corrosion. That is mainly due to lack of good coating and/or marine atmosphere in weather exposed areas. It is also observed that it can be lack of coating in areas with pipe support. After removal of pipe support, it is revealed that corrosion is present, often in the form of pitting. One other problem related to pipe support is the use of wrong material. On some rigs, stainless steel clamps and support is used on carbon steel piping. This has led to significant galvanic corrosion. One other major problem is related to deck penetrations. Piping can in this scenario often be in contact with other materials than carbon steel. Galvanic corrosion can thus be a problem. In the most serious cases with interference between carbon steel and stainless steel, corrosion has removed up to 6mm of wall thickness. External corrosion problems have also been observed close to welds. Welding with wrong electrode, for instance stainless steel electrode, can lead to minor corrosion concerns.

Vibration

High pressure mud systems can be subject to significant vibrations. This applies especially for non-flexible pipes close to the mud pumps. To avoid vibration, vibration dampening and support is issued. From the inspection data, it is a trend that dampening and support is not according to desired standard. Vibration dampening is often in bad conditions, pipe support is often lacking or in bad condition, and pipe clamps and bolts are often loose. Eventually this can lead unwanted vibration and in worst case cracking and a leak which can have severe consequences.

External mechanical wear

High pressure mud systems consists of lines going through drill floor and derrick areas.

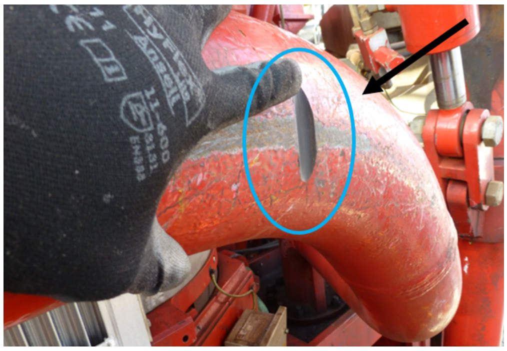


Figure 5.6: S-pipe with external wear.

In those areas it often tends to be rough handling of material and equipment. During drilling operations the drill floor can be quite busy and quick solution is often chosen to get the job done. In the derrick there are several tugger wires used for lifting purposes. These can often interfere with piping going to the drilling machine and lead to external wear. It is observed several cases with major external wear. The s-pipes and goose necks are the pipes that are most prone to such damage and local loss of wall thickness can be up to 5mm. In Figure 5.6 a picture is illustrating a s-pipe that has been exposed to major external wear Axess AS [2015b].

Rig details and operating environment

From the inspection data, some other factors that is not direct related to damage is found. Old rigs tend to have more critical findings, which is not a surprise. But on the other hand, new rigs (< 5 years), tend to have a higher amount of failures and critical findings than expected. The reason for this might be complex, but one reason may be run-in failures that are induced the first years. When a rig is new, it is likely that some of the equipment has wrong design or is used wrong and more failures might therefore occur. After 5 years, the rig is issued for a large survey, usually requiring a dry dock, and many of the possible causes for failures are most likely eliminated.

The operating environment of the rig can also be a important influencing factor. Rigs operating in tropic environment experience more external corrosion due high temperatures and humidity. In the latter years there has been exploration of oil and gas in arctic areas. In a cold environment, there will be longer sections with insulation and heat tracing. This could induce critical corrosion problems. One other problem at low temperatures is brittle fractures, but that is seldom experienced, and not observed on any high pressure mud systems in the inspection data set.

5.2.3 Uncertainties

The inspection data can be subject to uncertainties in measurements and in the subjective judgments. Ultrasonic thickness measurements is dependent on a even surface to get a accurate reading. Equipment will often experience uneven external surface due to corrosion and thus will the measurement be inaccurate. Degradation can also be very local. A measurement that indicate wall thickness below acceptance criteria might not be presentable for the whole section. And on the other hand, local degradation might not be observed from the measurements.

Chapter 6

Methodology for Evaluation of Probability of Failure

This chapter presents a methodology for evaluation of probability of failure for pressurized systems on offshore drilling installations. The focus is on high pressure mud systems, but some parts of the methodology can be transferred to other systems. Classification of probability, consequence and risk is first described. The degradation in divided into external and internal degradation.

6.1 Classification of Risk

It is necessary to establish a simplified risk matrix that can be used in the methodology, with focus on the probability of failure. DNV [2010] suggest a risk matrix in Figure 2.4, and probability of failure and consequence of failure are described in Table 2.1 and Table 2.2. The PoF are described both in a qualitative and quantitative manner, while the CoF is described qualitative.

6.1.1 Probability of failure

For the purpose of this guideline, probability of failure is simplified and divided into low, medium and high level, described in Table 6.1. The quantitative and qualitative ranking is based on the proposal from DNV [2010], but simplified. High probability of failure will in this methodology include both 'high probability' and 'failure expected' from DNV-RP-G101 [DNV, 2010]. Low and negligible probability of failure are combined in one category: low probability of failure.

Table 6.1: A simplified classification of probability of failure

Annual failure Qualitative	Annual failure Quantitative	Description
High	$> 10^{-3}$	Failure is expected during the lifetime of the equipment.
Medium	10^{-3} to 10^{-4}	Failure may occur sometime during the lifetime of the equipment.
Low	$< 10^{-4}$	Failure is unlikely to occur.

6.1.2 Consequence of failure

In order to establish a risk picture, consequences of failure must be ranked in different classes. Consequence of failure is in this case qualitative only, and based on DNV's proposal DNV [2010]. The consequence classes are here also simplified and divided into low, medium and high, with respect to safety, environment and economy. In Table 6.2 the consequence classes are further described.

Table 6.2: Description of consequence classes

Rank	Safety	Environment	Economic
High	Fatalities	Major effects	Major damage
Medium	Injuries	Minor and local effects	Minor and local damage
Low	Insignificant	Insignificant	Insignificant

6.1.3 Risk matrix

Based on probability of failure and consequence of failure a risk matrix can be described. In Table 6.3 a risk matrix is illustrated. Five different levels are here presented. Risk class A and B is acceptable, class C will need further evaluation to see if risk acceptable, while class D and E is unacceptable. From the risk level and the acceptance criteria a inspection program can be developed for different parts of the systems. For class A and B action can be made to ensure that the risk remains at the same level. For class C the degradation should be measured with use of NDT, functional testing or other condition monitoring methods. For class D and E action must be made to reduce the risk level.

Table 6.3: Risk matrix with description of the different risk levels

		CoF		
		Low	Medium	High
PoF	High	C	D	E
	Medium	B	C	D
	Low	A	B	C

6.2 Internal Degradation

From the inspections data it is highlighted that there are several factors that will influence the internal degradation of high pressure mechanisms. Rate of erosion will dependent on the amount of solids in the fluid and the velocity of the fluid. Presence of sea water and corrosive chemicals can in addition lead to high corrosion rates. The combination of erosion and corrosion is difficult to predict and thus probability of failure will be high if both mechanisms are present.

6.2.1 Erosion rate

To get a better understanding of the degradation it is convenient to first evaluate the erosion rate. In this methodology there are three main factors that are used to classify the erosion rate:

1. Amount of solids in the fluid(% of volume)
2. Fluid velocity
3. The number of bends, bottle necks, welds and flanges.

The density and the morphology of the solids are not considered. In Table 6.4 the amount of solids and fluid velocity are ranked in low, medium and high. A typical low-solid mud has 3-6 % of solids and is the baseline for the classification [Caenn et al., 2011]. In general mud pumps can transport approximately 1500-3000 liter mud per minute [Skaugen, 2013]. For a pipe with inner diameter of 100mm, which is typical for standpipes transporting mud to the drilling machine, the fluid velocity will be from 3 to 6 m/s.

The ranking of solids and velocity can be transformed to flow load in the matrix in Table 6.5. The flow load is ranked in five different categories from very low (VL) to very high (VH). This is a subjective ranking based on inspection data from the industry and current literature and it is very simplified.

The erosion rate will be significant higher in areas with bends, flanges, weld and bottle necks, due to fluctuations in velocity. To convert the flow load into erosion rate the

Table 6.4: Ranking of solids in fluid (a) and velocity of fluid (b).

(a)

Rank	Solids (% of volume)
Low	< 5
Medium	5 - 10
High	> 10

(b)

Rank	Velocity (m/s)
Low	$< 3{,}0$
Medium	3 - 4,5
High	$> 4{,}5$

Table 6.5: Matrix for evaluation of flow load based on solids and velocity

		Solids		
		Low	Medium	High
Velocity	High	M	H	VH
	Medium	L	M	H
	Low	VL	L	M

matrix in Table 6.6 can be used. To simplify the evaluation number of bends, bottle necks, flanges and welds are classified as *few* or *many*.

Table 6.6: Matrix for evaluation of erosion rates with respect to flow load and number of bends, bottlenecks, welds and flanges

		Number of bends, bottlenecks, welds and flanges	
		Few	Many
Flow load	Very low(VL)	Low Erosion	Low Erosion
	Low(L)	Low Erosion	Medium Erosion
	Medium(M)	Medium Erosion	High Erosion
	High(H)	High Erosion	High Erosion
	Very High(VL)	High Erosion	High Erosion

If there is *many* bends, flanges, welds and bottle necks present; low and medium flow load will be converted to medium and high erosion. The method is based on experiences from the inspection data and operating data from the rigs. The effect of obstacles will increase the erosion rate. How much it will increase the rate can be difficult to predict. Hence, calculation is not included here. The quantification of the erosion rates are listed in Table 6.7. The rates are described as annual loss of wall thickness, and the ranking is the same as used for degradation process in the analysis of the inspection data, c.f slow, medium and fast. The determination of erosion rate could be inaccurate at times. High corrosion rate is categorized as more than 0,5 mm/year, meaning that there could be large deviation in the actual erosion rate in that category. To be on the safe side the limit for high erosion is set relatively low. If erosion is the only significant degradation mechanisms, the probability of failure can be predicted from the annual loss of wall thickness, considering the wall thickness and allowed corrosion of the pipe.

Table 6.7: Ranking of erosion rates described as annual loss of wall thickness

Rank	Loss of wall thickness (mm/year)
Low	> 0,1
Medium	0,1- 0,5
High	> 0,5

6.2.2 Effects of sea water

If seawater is present in the system it could contribute to higher corrosion rates. Therefore the amount of seawater should be evaluated. The water cut could be used as a helpful parameter. The water cut is the amount of water produced in crude oil and hydrocarbons [Joshi et al., 2013]. Farelas et al. [2014] suggest that at a water cut of 30 %, CO_2 corrosion starts to be significant. For mud systems the corrosion will be in a aqueous form. But as an assumption, the same water level is used in this methodology as a critical level. Sea water is here considered as raw sea water or seawater with biocide/chlorination. Low oxygen seawater will give very low corrosion rates, and is not considered.

6.2.3 Carbon Steel

Carbon steel is the most common material used for high pressure mud systems, and is therefore the focus in this methodology. However, stainless steel can be used at special occasions, and is considered in next section, but not at the same depth as carbon steel. Description of the process for evaluating probability of failure is described in Figure 6.1. The main steps are:

1. From Table 6.4, 6.5 and 6.6, the erosion rate is determined.
2. If there is significant amount of corrosive chemical present, the probability is set to high, since it can be very difficult to predict degradation. Further investigations is needed here.
3. If there is insignificant amounts of corrosive chemicals present, the amount of seawater must be evaluated.
4. If sea water content is less than 30 % the probability of failure is based on erosion rate only. The probability of failure will be low if the erosion rate is low. If erosion rate is medium or high, the probability of failure can be estimated based

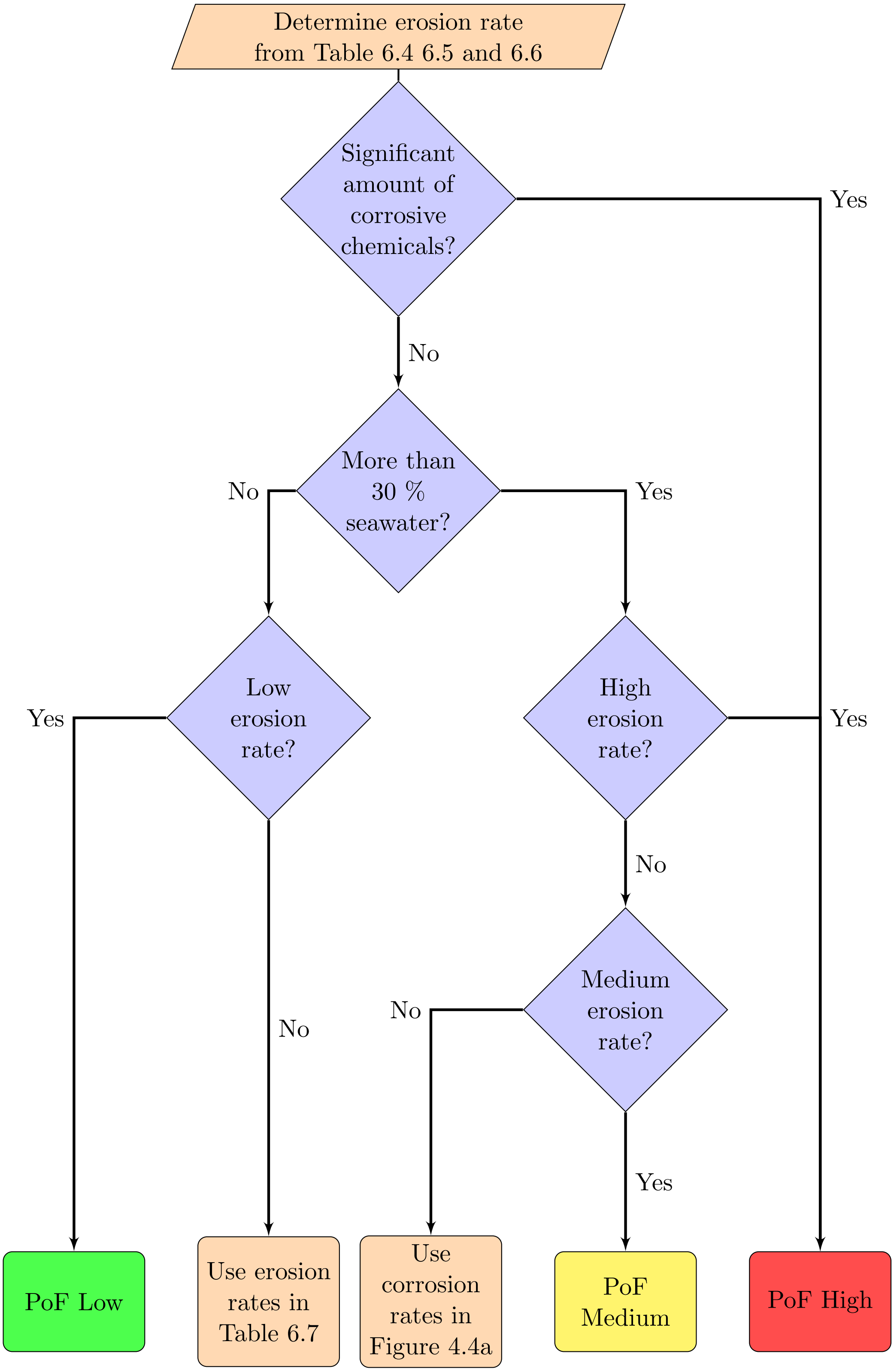


Figure 6.1: Flow chart describing the evaluation process to decide probability of failure due to internal degradation for pressurized carbon steel mud systems.

on erosion rates in Table 6.7, wall thickness and allowed corrosion. DNV [2010] suggest a standard deviation of 0.45. This can be used as a guideline.

5. It there is more than 30 % of sea water and erosion rates is high, the probability of failure will be high. The combination of sea water corrosion and high erosion rates is difficult to model and as a conservative assumption PoF is set to high. If the erosion rate is low, probability of failure is estimated according to corrosion rates in Figure 4.4a, considering wall thickness and allowed corrosion. If the erosion rates is medium the probability of failure is set to fixed medium level. Failures might occur during the lifetime of the quipment.

Example calculation Consider a pipe with nominal thickness of 19,1 mm and minimal thickness of 14,7 mm. From the last inspection the pipe was measured to be 15,5 mm, meaning that the allowed corrosion is 0,8 mm. Let us for example say that there is no significant amount of chemicals and the raw seawater content is over 30 %, and the erosion rate is expected to be low. Then the probability of failure can be calculated according to flow rates in Figure 4.4a. Considering a velocity of 2 m/s, the mean corrosion rate will be 0.6 mm and standard deviation is 0.1. Using normal distribution and Monte Carlo simulation, the annual probability will be 0,0243, which is more than 10^{-3}. Thus, high probability of failure. The simulation is illustrated in Figure 6.2.

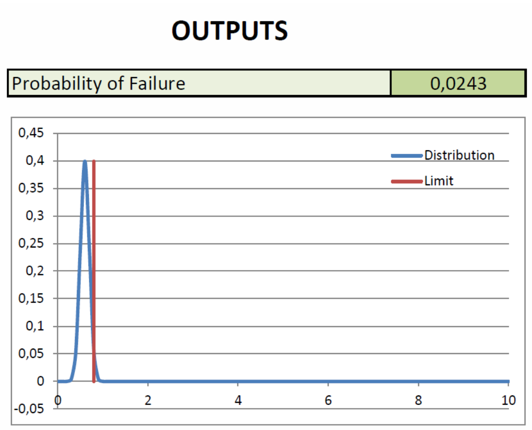


Figure 6.2: Output from simulation of probability of failure based on mean corrosion rate, allowed corrosion and standard deviation in a normal distribution [Singh, nd].

6.2.4 Stainless steel

It is seldom that stainless steel is used in high pressure mud systems. Non of the lines from the inspections data is made of stainless steel. If stainless steel is used, the main degradation problem will is expected to be in association with water in the lines. From Figure 4.5 the probability of failure can be determined according to temperature and type of water. The probability of failure is presented per mm of wall thickness [DNV, 2010].

6.3 External Corrosion

Evaluation of probability of failure for external corrosion is dependent on material and operating temperature, and can thus be very generalized for all systems. Stainless steel and carbon steel is most common materials and are included in this methodology. With use of simplified flowcharts and tables probability of failure can be evaluated.

6.3.1 Coating condition

The condition of coating can be classified according to DNV [2014] in good, fair and poor condition. In this methodology coating is classified into 'good' and 'not good', where 'not good' is considered as fair or poor. If the coating is not good, the probability of failure will be estimated like there was no coating present, which is a conservative assumption. The description of the classification is found in Table 6.8.

Table 6.8: Classification of coating conditions [DNV, 2014].

Ranking	Description
Good	Condition with only minor spot rusting.
Fair	Condition with local breakdown at edges of stiffeners and weld connections and/or light rusting.
Poor	Condition with general breakdown of coating over 20% or more of areas or hard scale at 10% or more of areas under consideration.

6.3.2 Stainless steel

The main external corrosion problem for stainless steel is pitting and local attacks. The inspection data does not cover prevalent used of stainless steel. Models from DNV [2010] is used as a guideline. The process of determining probability if failure for stainless steel is presented in the flow chart in Figure 6.3. The main steps are:

1. If there are no insulation present, the probability of failure will normally be at a low level, with a probability of failure of 10^{-4} per millimeter of wall thickness. The effect of coating is here not considered, since it will just lower the probability. Nevertheless, if crevices or deposits are observed, further investigations are needed and the probability is set at a fixed high level.
2. If the piping is insulated, the effect of coating must be considered. If coating is present and in good condition, the probability of failure is low.

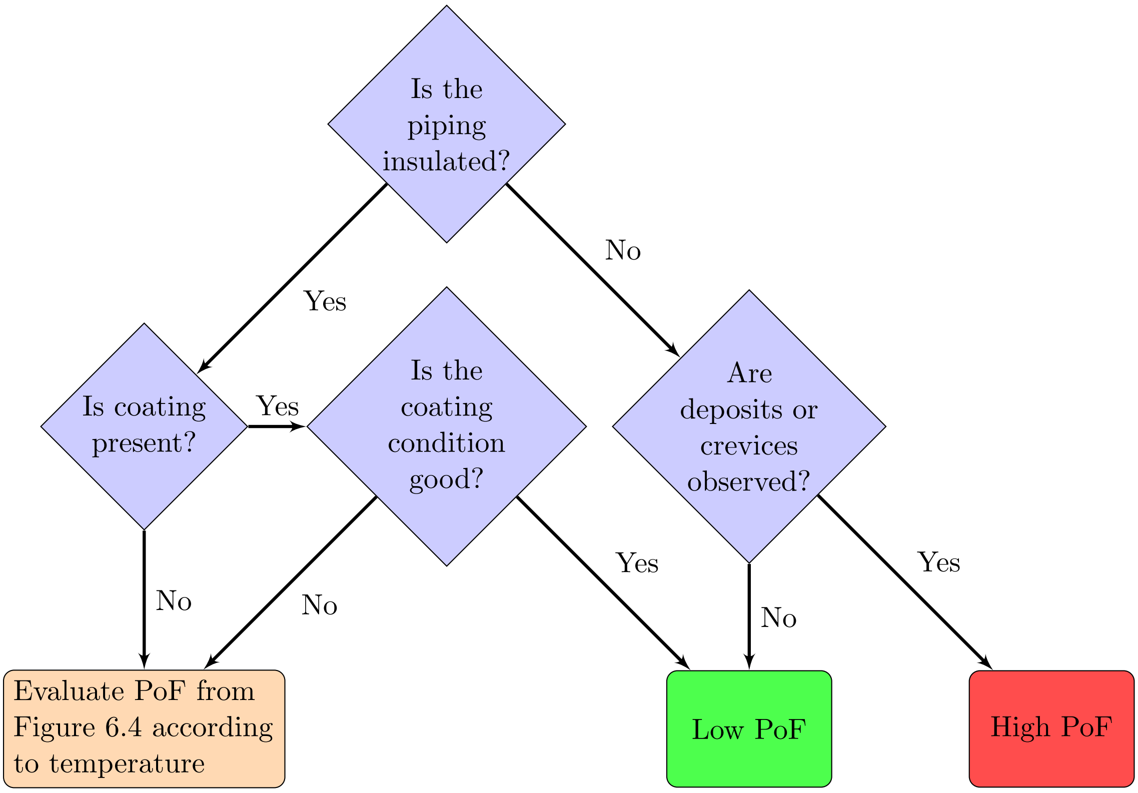


Figure 6.3: Flow chart illustrating the process for evaluating PoF due to external corrosion of stainless steel.

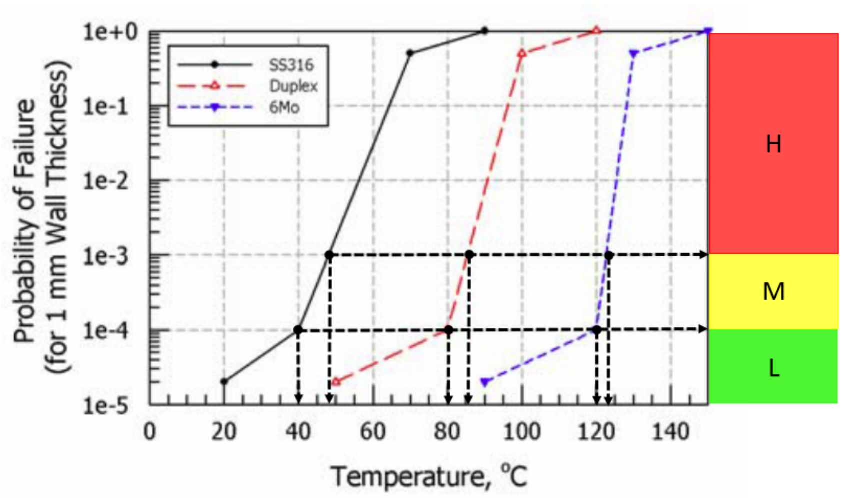


Figure 6.4: Probability of failure for different types of insulated stainless steel due to external corrosion based on temperature.

3. If the insulated pipe has no coating or coating that is fair or poor, the probability of failure can be evaluated from Figure 6.4 considering temperature and the different types of stainless steel. PoF is per mm wall thickness.

DNVs proposal for local corrosion of stainless steel under insulation can be used to determine probability of failure for different types of stainless steel [DNV, 2010]. In Figure 6.4 probability of failure for different types of stainless steel given operating temperature is described. The three different probability of failure classes - low, medium and high - are indicated with the corresponding colors green, yellow and red. For SS316 probability of failure will be low if temperature is under 40 °C. Between 40 °C and 48 °C PoF will be medium, while over 48 °C PoF will be high. For duplex steel the temperature where PoF transform from low to medium is somewhat higher. At 80 °C PoF will change to medium, and from approximately 86 °C PoF will be high. For 6Mo the temperatures will be even higher. At 120 °C PoF will change to medium, and at approximately 124 °C PoF will change to high. It should be highlighted that PoF is presented per mm of wall thickness, meaning that the probability in reality will be significant lower.

6.3.3 Carbon steel

Carbon steel can be subject to significant corrosion under right conditions, where temperature is the main factor to increased corrosion rates. As for stainless steel, the presence and condition of coating and insulation will influence the severity of the corrosion. The inspection data analyzed in Chapter 5 roughly fits the models suggested by [DNV, 2010]. The models are used together with simplified evaluation of coating and insulation. The work process for determining probability of failure are described in the flow chart in Figure 6.5.

The main steps are:

1. Assess the presence and condition of coating. If coating is present and the condition is good, the probability of failure will be low.

2. Assess the operating temperature. Operating temperature under -5 °C will generate low probability of failure, even if there is no coating present.

3. If the temperature is over -5 °C the presence of insulation must be considered. From Table 4.1 and 4.2 the corrosion rates and standard deviation can be found based on temperature. Using normal distribution the probability of failure can be estimated, considering allowed corrosion and wall thickness. If the temperature is over 100 °, which is seldom, it is recommended to involve a specialist for expert judgments.

Effect of interference with different materials leading to galvanic corrosion is not considered. This could be very difficult to predict. If there is a high number of stainless steel clamps used on carbon steel piping, the probability of failure might be increased.

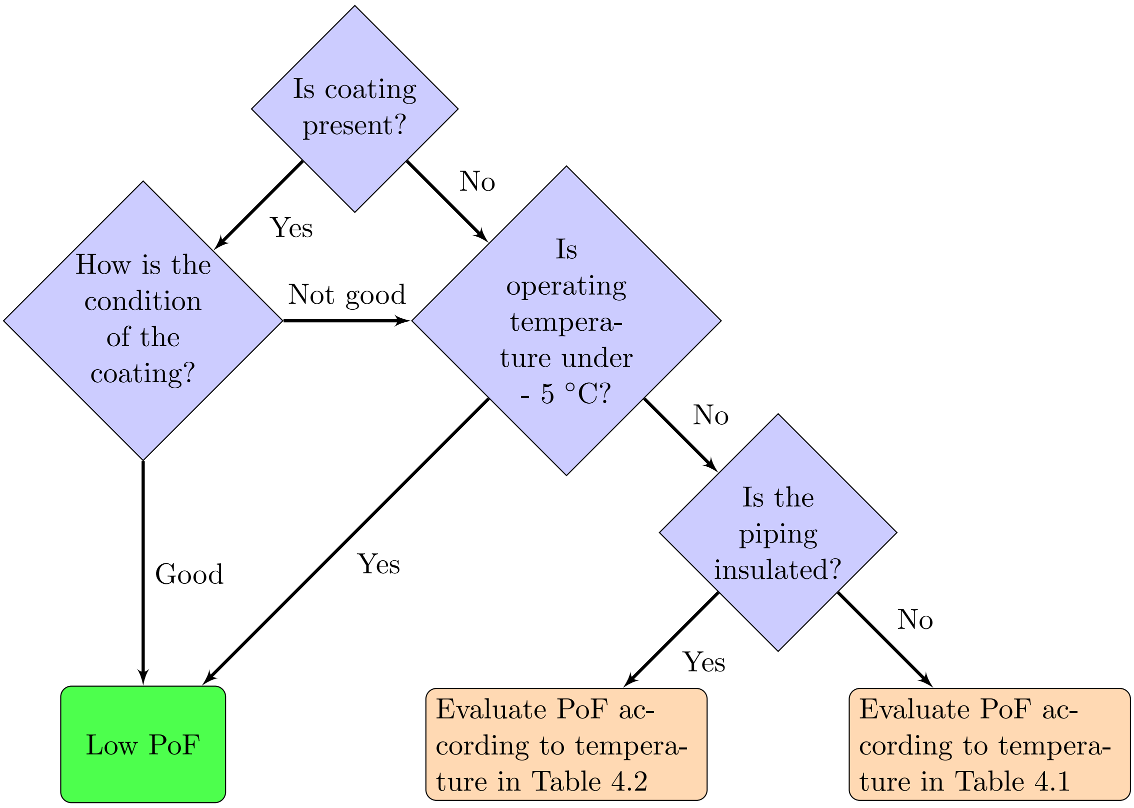


Figure 6.5: Flow chart used to evaluate PoF for carbon steel exposed to external corrosion.

The same applies for wrong welding. These factors can be considered as a result of poor workmanship, which is very difficult to predict or model.

6.4 Other Factors

In addition to external corrosion and internal corrosion, there are other factors that will influence the probability of failure. This type of damage is very difficult to predict using any model. As mentioned in Section 5.2.2, vibration, external mechanical wear and operating environment can influence degradation and failure rates.

6.4.1 Vibration

Vibration can cause fatigue and cracking and can be a major problem. To assess the probability of failure due to vibration different parameters should be evaluated. The most important factors are:

- Length of unsupported piping
- Wall thickness and diameter
- Material

A complete methodology is not included in this thesis. However, in a screening face, the following control questions can be asked:

1. Is equipment subject to significant vibration?
2. Is vibration dampening and pipe support in good condition?
3. What is the length of unsupported piping?

Answering YES to question 1 and NO to question 2 will certainly increase the probability of failure.

6.4.2 External mechanical wear

External mechanical wear due to interference with other objects might be a problem on drilling units and especially on drill floor and in the derrick. As mentioned in 5.2.2 s-pipes and goose necks are often the parts that are most exposed. In a screening face the following question can be asked to get an overview:

1. Are there good routines with respect to operations in the derrick?
2. Is there regular inspection and/or replacement of s-pipe and goose neck?
3. How long are the inspection intervals?

Answering YES to question 1 and 2 would most likely increase the probability of failure for certain part of systems.

6.4.3 Rig details and operating environment

Operations in tropic or arctic environment will most likely induce more failures. In addition can the age of the rig be related to probability of failure. It is difficult to quantify values to evaluate the different factors, but in a screening face the following control question can be asked:

1. Is the rig younger than 5 years?
2. Is the rig older than 15 years?
3. Is the rig operating in arctic or tropic environment?

It could be argued that answering YES to the questions will increase the probability of failure.

6.5 Discussion

The inspection findings indicates a number of factors that will influence the degradation. Through quantitative measurements the degradation rate is described, but the cause of degradation is often based on subjective judgments. This might be due to many reasons. On an old installation, there is often lack of good data management systems, it can be difficult to quantify the exact input data during drilling operations, and records of earlier experiences is often missing. The judgments is often based on discussion between experienced inspection and maintenance engineers, and the installation operator. The developed methodology, reflects this.

Inspection data of static equipment in pressurized mud systems, have shown that the combined erosion-corrosion degradation mechanism can lead to high rate of wall thinning. The erosion and corrosion problem due to different types of mud, is not completely covered in the current recommended practices. DNV's recommended practice DNV-RP-G101 suggest one model to estimate erosion rate. The model require a number of input parameters that are likely to vary during drilling operations. In addition, complex geometries generate complex calculation, where the result might not reflect the erosion rate. The methodology described in this chapter, suggests to evaluate probability of failure based on a number of important influencing factors. Some of the factors included in the evaluation are very generalized and might not reflect the reality. However, it can be argued that methodology can be used as a advantageous tool to get a indication of the probability of failure for the system as a whole.

Erosion rate is based on velocity, solid content and number of bends, flanges, welds and bottle necks. The four latter factors are evaluated only subjectively. The effect of *many* bends, bottlenecks, flangs and welds, are higher erosion rate. In most cases erosion rate are elevated to *high* level. With a wall thinning of more than 0,5 mm/year, erosion rate is classified as high. Thus, can there be large variation in erosion rate inside this level. For example are 0,6 mm/year and 6 mm/year, classified as high erosion rate. To assess probability of failure, further investigation on the exact erosion rate is recommended. One suggestion, if erosion is the only degradation mechanism, could be to use erosion rate from inspection data together with a given standard deviation, to calculate probability of failure, using a normal distribution.

DNV [2010] suggest different models to estimate external corrosion of carbon steel and stainless steel due to exposure to marine atmosphere. The models takes into account the presence of insulation and coating, and the operating temperature. The inspection data does not cover prevalent use of stainless steel. Hence, models from DNV [2010] have been adapted and used as a indication, together with simple evaluation criteria for insulation and coating. For carbon steel it seems like the suggested models, roughly, fits the actual degradation rates from the data. It should be mentioned that external degradation is seldom measured quantitatively.

Damage due to external mechanical damage can certainly be a problem, but is difficult to convert the damage to a model for estimation of probability of failure. Vibration can be monitored, and with good maintenance and inspection programs, failure rates might be reduced. Is it observed local external mechanical damage due to interference from external objects, like tugger wires used for lifting purposes, which often can be in conflict with piping in the derrick and at drill floor. The best way to avoid the damage, is good operating routines during drilling. Frequent inspection and/or replacement of critical parts will most likely lower the probability of a critical leakage.

Chapter 7

Conclusion

It is clear that degradation of pressurized static mud equipment is highly complex phenomenon, and can lead to failures if it is undetected. Results of different degradation mechanisms are difficult to predict and model. This thesis suggests a methodology for evaluation of probability of failure of static equipment in pressurized mud systems on an offshore drilling installation.

The methodology is based on analysis of actual inspection data from the industry and current literature and practices. Through the analysis of inspection data from static equipment in high pressurized mud systems, it is found that erosion together with corrosion can be a major problem, and lead to internal degradation. Presence of chemicals and sea water leading to corrosion, together with erosion, is found to be the most dominant reasons for internal degradation. The probability of failure can very difficult to predict, due to the complex degradation mechanisms and lack of qualitative input parameters. Therefore some important parameters have been selected to evaluate probability of failure. The external degradation process is easier to model and the inspection data correspond good to the current models suggested by Det Norske Veritas.

A simple methodology to evaluate the probability of failure has been developed. The results from the evaluation can be treated as a indication of probability of failure. Some factors have been neglected, and in cases where the methodology does not correspond to the expected degradation mechanisms, it is recommended to do further investigations.

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Appendix A

Inspection Findings High Pressurized Mud Systems

INSPECTION FINDINGS FROM HP MUD SYSTEMS

Degradation process(mm/year)	
<0,1	Slow
0,1-0,5	Medium
>0,5	Fast
External damage, vibration, pitting, crevice corrosion etc.	Susceptible / Unknown
Not Available	N / A

Inspection Method

GVI	General Visual Inspection
UTM	Ultrasonic Measurements
CVI	Close Visual Inspection

Material

CS	Carbon Steel
SS	Stainless Steel

Type installation	Date survey	Line / equipment	Location	Inspection method	Description of finding	mm	Tnom (mm)	Tmin (mm)	Tmeasured (mm)	Degradation rate (mm/year)	Possible cause of degradation / damage	Location / object prone to degradation	Cause of location	Degradation process
Column stabilised unit	jan.10	Booster line	Raiser set back/under deck	UTM	3" part of line has wrong dimension, below/close to Tmin. 3" measured with 6,5mm wall thickness, 1,5 below Tmin. Inconsistency in the system. Piping not recorded in the drawings like P and ID, ISO. Tmin calculated for pressure of 5000 psi. Recalculated for 3000 psi, which gives Tmin of 6,3mm. As long as the operational set up of the HP mud system (PSV valves above mud pumps) does not exceed 3000 psi, the thickness of the pipe is just enough. Hole system rated for 5000 psi.	CS	N/A	10,2 / 6,3	6,5	N/A	Decrease diameter of pipe. Internal corrosion / erosion	Pipe section with lower diameter.	Higher flow load	**N/A**
Column stabilised unit	mar.11	Booster line	Raiser set back/under deck	UTM	3" part of line has wrong dimension, below/close to Tmin. 3" measured with 6,5mm wall thickness, 1,5 below Tmin. Inconsistency in the system. Piping not recorded in the drawings like P and ID, ISO. Tmin calculated for pressure of 5000 psi. Recalculated for 3000 psi, which gives Tmin of 6,3mm. As long as the operational set up. Same as year before of the HP mud system (PSV valves above mud pumps) does not exceed 3000 psi, the thickness of the pipe is just enough. Hole system rated for 5000 psi.	CS	N/A	10,2 / 6,3	6,5	N/A	Decrease diameter of pipe. Internal corrosion / erosion	Pipe section with lower diameter	Higher velocity, higher flow load	**N/A**
Column stabilised unit	mar.11	Mud pump	Mud pump room	UTM	Pipe spools between mud pumps 1. and 2 and manifold + standpipe 1 and 2 to drill floor are below Tmin	CS	19,05	14,7	15,3-15,5	0,1-0,2	Internal corrosion/erosion	Bends between manifold and pumps, and further up on standpipe	Higher velocity, higher flow load	**Medium**
Column stabilised unit	mar.12	Standpipe	Drill floor	GVI	Both standpipes are externally in poor condition just after the deck penetration. Severe external corrosion has reduced wall thickness with 2mm locally at these spots. Cleaning and coating is recommended.	CS	N/A	N/A	N/A	N/A	External corrosion, galvanic corrosion	just after deck penetration	Poor coating, different materials	**Susceptible / Unknown**
Column stabilised unit	jul.13	Standpipes	Drill floor	GVI	Local severe corrosion was found on standpipes deck penetration. Wall thickness loss is about 2mm, and maximal 3mm at these corrosion.	CS	N/A	N/A	N/A	N/A	External corrosion, galvanic corrosion	Just after deck penetration	Poor coating, different materials	**Susceptible / Unknown**
Column stabilised unit	feb.09	HP mud pipes	Mud pump room, mud manifold	GVI	The 3 HP Mud pipes from the pumps experience strong vibrations including half of the manifold when all 3 pumps are running, especially No 2 pipe clamp seems loose.	CS	N/A	N/A	N/A	N/A	Vibration	Line from mud pump	Loose pipe clamps, lack of vibration dampening	**Susceptible / Unknown**

Type installation	Date survey	Line / equipment	Location	Inspection method	Description of finding	mm	Tnom (mm)	Tmin (mm)	Tmeasured (mm)	Degradation rate (mm/year)	Possible cause of degradation / damage	Location / object prone to degradation	Cause of location	Degradation process
Column stabilised unit	feb.09	PSV line	Mud pump 2	GVI	The support experience strong vibrations, an former repair shows that this is an old problem.	N/A	N/A	N/A	N/A	N/A	Vibration			**Susceptible / Unknown**
Column stabilised unit	mai.10		Mud pipes 1, 2, 3 above mud manifold in mud pump room	GVI	Damaged bolts on all three pipes	N/A	N/A	N/A	N/A	N/A	Damage bolts, can cause vibration			**Susceptible / Unknown**
Column stabilised unit	mai.10	PSV line	PSV line from mud pump2	GVI	Metal loss due to external damage on pipe from adjacent support	CS	N/A	N/A	N/A	N/A	External damage	section adjacent to support	Bad solution	**Susceptible / Unknown**
Column stabilised unit	mai.10	PSV line	Mud pump 2	GVI	The support experience strong vibrations, an former repair shows that this is an old problem.	N/A	N/A	N/A	N/A	N/A	Vibration	Support	No vibration dampening, bad solution	**Susceptible / Unknown**
Column stabilised unit	aug.11	PSV valve	Mud pump room, PSV	GVI	External damage on PSV line from adjacent support. Old finding. Temporary solution with strap used.	N/A	N/A	N/A	N/A	N/A	External damage, poor workmanship	section adjacent to support	Bad solution	**Susceptible / Unknown**
Fixed	nov.13	0080-ZMH-11-0218-LA-1-0-A	Mud pump room	GVI	Welded patch along bleed off line from HP mud Pump B.	CS	N/A	N/A	N/A	N/A	May lead to leak, weak point	Straight spool	Bad solution	**Susceptible / Unknown**
Fixed	nov.13	Pulsation dampener	Mud pump room	GVI	Possible leakage at HP mud pulsation dampener from HP mud pump C.	CS	N/A	N/A	N/A	N/A	Vibration	Pulsation dampener	Lack of dampening, support	**Susceptible / Unknown**
Fixed	nov.13	Standpipe	Derrick	UTM	Small area at gooseneck of standpipe is with low reading about 12mm	CS	N/A	14,7	12	0,5mm/year	Internal corrosion	Goose neck, bend	High flow load	**Fast**
Fixed	nov.13	Standpipe	Derrick	UTM	Thickness measurement close to Tmin	CS	19,1	14,7	15,5	N/A	Internal erosion/corrosion	Straight spool	High flow load, solids in fluid	**N/A**
Column stabilised unit	jun.09	Standpipe manifold	Standpipe manifold	GVI	Damaged coating on the manifold	CS	N/A	N/A	N/A	N/A				**N/A**
Column stabilised unit	jun.09	Standpipe 1 and 2 from standpipe manifold to the gooseneck	Drill floor / derrick	UTM	The first two bends after the manifold has been measured with a wall thickness below or close to Tmin. The calculated Tmin on the HP mud system is 14,7mm, and the measurements are recorded as 12-12,5mm. It has been carried out through fitness for purpose calculation, which shows that the piping may be utilized but should be replaced as soon as possible. TP: 11.2.28: 12,5mm 11.2.29:12 mm	CS	19,1	14,7	12-12,5	1,3-1,4	Internal corrosion / erosion	Bends	Higher flow load	**Fast**
Column stabilised unit	jun.09	HP mud lines, pop off lines and relief lines	Mud pump room	GVI	Damaged coating on the manifold	CS	N/A	N/A	N/A	N/A	External corrosion	Areas without coating. Marine atmosphere	Damaged coating	**Medium**
Column stabilised unit	jun.09	Stand pipe manifold	Below valve 21 on standpipe 1.	GVI	Pipe support removed and no coating on the location. External corrosion visible. 3mm reduction in wall thickness	CS	N/A	N/A	N/A	N/A	External corrosion / vibration	Areas without coating/support. Marine atmosphere	Damaged coating / no pipe support	**Fast**
Column stabilised unit	jun.09	HP mud pipes	Before entering drill floor	GVI	Pipe support removed and no coating on the location. External corrosion visible, with pitting appr 3-4mm depth	CS	N/A	N/A	N/A	N/A	External corrosion / vibration	Areas without coating/support. Marine atmosphere	Damaged coating / no pipe support	**Fast**
Column stabilised unit	jul.10	Stand pipes		GVI	Pipe support has been removed and revealed corrosion that has removed 5,5 mm wall thickness	CS	N/A	N/A	N/A	N/A	External corrosion, galvanic corrosion?	Under clamp	Different materials	**Fast**
Column stabilised unit	jul.11	Straight spool	After deck penetration, drill floor	UTM	Wall thickness below Tmin	CS	19,1	14,7	14	0,5	Internal corrosion / erosion	After deck penetration		**Fast**

Type installation	Date survey	Line / equipment	Location	Inspection method	Description of finding	mm	Tnom (mm)	Tmin (mm)	Tmeasured (mm)	Degradation rate (mm/year)	Possible cause of degradation / damage	Location / object prone to degradation	Cause of location	Degradation process
Column stabilised unit	jul.11	Standpipe 2	After first reinforced bend on standpipe 2 on drill floor	UTM	Wall thickness below Tmin	CS	19,1	14,7	14	0,75	Internal corrosion / erosion	Bend	Higher flow load	Fast
Column stabilised unit	jun.13	S pipe	Port loading station	GVI	External wear on S-pipe.	CS	N/A	N/A	N/A	N/A	External damage	S-pipe	Tugger lines clash at pipe.	Susceptible / Unknown
Column stabilised unit	jun.13	General	General	UTM	Some degradation experienced. Lowest readings 17-17,5mm. Nominal thickness is 19mm. Based on input from rig personnel, there has been a lot of sand in the system	CS	19	14,7	17-17,5	0,5-0,75	Internal erosion	All lines	Significant amount of sand in system can be the reason	Fast
Column stabilised unit	jan.13	General	Mud pump room	GVI	Generally not very high standard on HP mud supports	CS	N/A	N/A	N/A	N/A	May lead to vibration		Lack of support, pulsation dampening	Susceptible / Unknown
Column stabilised unit	jan.13	Connection to support	Mud pump room	GVI	Connection to support is missing. Generally a not low standard on support and much vibration due to lack of pulsation dampeners	CS	N/A	N/A	N/A	N/A	Vibration		Lack of pulsation dampener	Susceptible / Unknown
Column stabilised unit	jan.13	HP Mud system, below 325L4002 from	Mud pump room	GVI	Damaged support. Most likely by external damage.	CS	N/A	N/A	N/A	N/A	External damage		External objects	Susceptible / Unknown
Column stabilised unit	mar.08	Kill line, choke line, booster line,	Moon pool area	GVI	Sections of the HP line has paint in poor condition and has begun to degrade	CS	N/A	N/A	N/A	N/A	External corrosion	Areas with poor painting	Lack of painting, marine atmosphere	Slow
Column stabilised unit	sep.10	HP mud relief line	Mud pump room	UTM	TP 11.2-67 on mud pump relief line downstream bend. Thickness below minimum required thickness. Measured thickness is 6,5mm, minimum required thickness is 7,9mm. The damage seems to be very local, just downstream weld. The two other relief lines also show reduction in wall thickness in same area. According to rig personnel, these lines pop off quite often, and may expect significant wear.	CS	17,1	7,9	6,5	9	Internal corrosion / erosion	Local, Downstream bend, close to weld	High flow load, low strength close to weld. Possible SW in lines	Fast
Column stabilised unit	apr.12	Line to standpipe 1,2 and booster line	Mezzanine	GVI	Lines suffer from CUI	CS	N/A	N/A	N/A	N/A	CUI	Under insulation	High temperature, humidity	N/A
Column stabilised unit	sep.10	HP mud relief line	Mud pump room	UTM	TP 11.2-66/68/69 shows reduction in wall thickness. 3-4mm reduction in two years	CS	17,1	7,9	10-13,5	1,5-2,0	Internal corrosion/erosion	Straight spool, after reinforced bend	High flow load, low strength close to weld. Possible SW in lines	Fast
Column stabilised unit	sep.12	Standpipe #1 and 2 and booster line	Moon pool and upper deck level between shaker house and drill floor	GVI	Insulation sections on standpipe 1 and 2 and booster line. No need for insulation. Also insulation hinders inspection and might cause CUI.	CS	N/A	N/A	N/A	N/A	CUI	Under insulation	High temperature, humidity, salt	N/A
Column stabilised unit	sep.12	Standpipe 1 and 2	Mezzanine	GVI	Lines suffer from CUI	CS	N/A	N/A	N/A	N/A	CUI	Under insulation	High temperature,humidity	N/A
Column stabilised unit	aug.13	Stand pipe 1	Mud pump room	UTM	Internal degradation after the bend on standpipe 1 in mud pump room. The thickness was measured to be 11.5 mm. In 2010 and 2012 the thickness was 13.0 mm. Tmin on this pipe is 9.7 mm. 1.5mm degradation in approx. 1 ,5 year	CS	19,1	9,7	11,5	1	Internal corrosion, erosion	after bend	Higher flow load	Fast
Column stabilised unit	aug.13	Relief line from mud pump 3	Mud pump room	UTM	Erosion was revealed after the 1st bend (after the PSV) on the relief line after mud pump no 3. Thickness was measured to be 5.5 mm. (2012-9.0 mm).	CS	17,1	3	5,5	3,5	Internal corrosion, erosion	After bend	Higher flow load, solids in fluid, acceleration in fluid velocity	Fast

Type installation	Date survey	Line / equipment	Location	Inspection method	Description of finding	mm	Tnom (mm)	Tmin (mm)	Tmeasured (mm)	Degradation rate (mm/year)	Possible cause of degradation / damage	Location / object prone to degradation	Cause of location	Degradation process
Column stabilised unit	aug.13	X-over line from choke manifold to mud manifold	Below choke manifold	GVI	The coating condition of the line is fair	CS	N/A	N/A	N/A	N/A	Might cause external corrosion	Areas with poor coating	Lack of coating, marine atmosphere	Slow
Column stabilised unit	aug.13	Mud standpipe 1	shaker house, below drill floor and standpipe in derrick	GVI	The painting condition is POOR** on the mud standpipe line 1. Below drill floor and in derrick the pipe has been insulated, the insulation has been removed, but the line is not painted after removal of insulation. There are still bits of insulation, heat tracing attached to the line. This will continue to promote corrosion.	CS	N/A	N/A	N/A	N/A	External corrosion	Areas with no coating and areas with bits of insulation and heat tracing	Lack of coating, poor workman ship	Slow
Column stabilised unit	aug.13	Mud standpipe 2	shaker house, below drill floor and standpipe in derrick	GVI	The coating condition is FAIR** on the mud standpipe line 2 on one bend in the shaker house. The line suffers from external corrosion on the line and bend below the mud manifold below the drill floor.	CS	N/A	N/A	N/A	N/A	External corrosion	Areas with poor coating	Lack of coating, marine atmosphere	Slow
Column stabilised unit	aug.13	Booster line	Moon pool area	GVI	The coating condition of the booster line in moon pool area, cellar deck is FAIR**. It is still heat tracing left on the pipe that is not in use. It is recommended to remove the heat tracing, clean and recoat the line to prevent degradation.	CS	N/A	N/A	N/A	N/A	External corrosion	Areas with no coating and areas with bits of insulation and heat tracing	Lack of coating, poor workman ship	Slow
Column stabilised unit	aug.13	Booster line	Below the mud manifold	GVI	The booster line below the manifold suffers from light external corrosion.	CS	N/A	N/A	N/A	N/A	External corrosion		Lack of coating	
Fixed	aug.13	Vertical piping. ZMH-5258-LA1	Vertical piping from mud pump room	GVI	Insulation on pipe support is missing. Vibration can cause damages and water from cleaning can cause galvanic corrosion	CS	N/A	N/A	N/A	N/A	Possible galvanic corrosion, vibration	Areas with out insulation	Different materials, water from cleaning	Susceptible / Unknown
Fixed	aug.13	Standpipe. ZMH-5369-LA1	Standpipe to derrick, above cement gooseneck	GVI	Insulation/gasket in pipe support is released.	CS	N/A	N/A	N/A	N/A	Possible galvanic corrosion		Different materials, water from cleaning	Susceptible / Unknown
Fixed	aug.13	Mud shear line	D13 top tank area	GVI	Poor surface, nut welded with SS electrode.	CS / SS	N/A	N/A	N/A	N/A	External corrosion, Galvanic corrosion	Nut and flanges	Wrong welding, no coating	Susceptible / Unknown
Fixed	aug.13	Lines to process, ZMK-13-0071-LA1,ZCU-13-0070	Cellar deck	GVI	External corrosion on piping.	CS	N/A	N/A	N/A	N/A	External corrosion	Weather exposed areas	Poor coating, dirty pipe, humidity	Slow
Column stabilised unit	feb.13	Relief line from mud pump 1.	Mud pump room	UTM	Internal degradation was revealed on relief line 1 in 6 o'clock position. Wall thickness was measured to be 11.0 mm, which is close to Tmin. Tmin is calculated to be 11.2 mm.	CS	N/A	11,2	11,5	1,1	Internal corrosion	straight spool, 6 o'clock position	Highest wear, acceleration in fluid. (Corrosive chemicals in mud)	Fast
Column stabilised unit	feb.13	Relief line 2 from mud pump 2	Mud pump room	UTM	Internal degradation was revealed on relief line 2 in 6 o'clock position. Wall thickness was measured to be 10.0 mm, which is below Tmin. Tmin is calculated to be 11.2 mm.	CS	N/A	11,2	10	1,1	Internal corrosion	straight spool, 6 o'clock position	Highest wear, acceleration in fluid. (Corrosive chemicals in mud)	Fast

Type installation	Date survey	Line / equipment	Location	Inspection method	Description of finding	mm	Tnom (mm)	Tmin (mm)	Tmeasured (mm)	Degradation rate (mm/year)	Possible cause of degradation / damage	Location / object prone to degradation	Cause of location	Degradation process
Column stabilised unit	feb.13	Relief line 3 from mud pump 3	Mud pump room	UTM	Internal degradation was revealed on relief line 3 in 6 o'clock position. Wall thickness was measured to be 11,5 mm, which is close to Tmin. Tmin is calculated to be 11.2 mm.	CS	N/A	11,2	11,5	0,87	Internal corrosion	straight spool, 6 o'clock position	Highest wear, acceleration in fluid. (Corrosive chemicals in mud)	**Fast**
Column stabilised unit	feb.13	HP mud line 2	Shaker room,	GVI	At mud line #2 external corrosion has started close to a support.	CS/SS	N/A	N/A	N/A	N/A	External corrosion	close to support	Different materials	**Susceptible / Unknown**
Ship-shaped Drilling Unit	jan.13	S-pipe on DDM	Derrick	GVI	The S-pipe on main DDM has minor external damage, probably caused by wear from a tugger wire. The tugger wire should be deflected by a diverter block or the bumper	CS	NA	NA	NA	NA	External damage	S-pipe	Poor solution, tugger wire in conflict with pipe	**Susceptible / Unknown**
Column stabilised unit	mai.11	Booster line	Mud pit room	UTM	The bend has a very corroded uneven external surface causing uncertainties in the measurements which is believed to be around the minimum required wall thickness.	CS	N/A	5,2	4	N/A	Internal corrosion, erosion	Bend	Higher flow load	**N/A**
Column stabilised unit	mai.11	Standpipes	Shaker room	GVI	A cracked pipe support for the standpipes. Pipework vibrates heavily in this location.	CS	N/A	N/A	N/A	N/A	Vibration	Lines with out proper support	Cracked support	**Susceptible / Unknown**
Column stabilised unit	des.12	Standpipes	Mud pump room	GVI	Coating on this piping is fair with areas of coating breakdown and signs of external corrosion.	CS	N/A	N/A	N/A	N/A	External corrosion	Where coating is fair	Lack of coating, marine atmosphere	**Slow**
Column stabilised unit	des.12	Standpipes	Mud pump room	GVI	Coating on the lines in this area are in fair condition. A lot of the pipes running close to the floor are dirty with mud.	CS	N/A	N/A	N/A	N/A	External corrosion	Outdoor areas	Lack of coating, dirty pipes, marine atmosphere	**Slow**
Column stabilised unit	des.12	Pop off line	Mud pump room	GVI	Coating on the piping in the mud pit room is in fair condition. Only the pipes running close to the floor are dirty with mud.	CS	N/A	N/A	N/A	N/A	External corrosion	Areas with fair coating	Dirty pipes, lack of coating	**Slow**
Tension Leg Platform	des.13	HP mud pipe	Mud pump room	UTM	Measured to be 16,5 mm, which is below the Tmin 17.5mm	CS	24	17,5	16,5	0,1mm/year	Internal corrosion	T-joint	High flow load	**Slow**
Tension Leg Platform	des.13	Standpipes		GVI	External corrosion on standpipes	CS	N/A	N/A	N/A	N/A	External corrosion	Around welds in bends	Lack of coating, marine atmosphere	**Slow**
Tension Leg Platform	des.13	Pop off line	Mud pump room	GVI	External corrosion on pipes	CS	N/A	N/A	N/A	N/A	External corrosion	Around welds in bends	Lack of coating, marine atmosphere	**Slow**

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Tension Leg Platform	nov.12	Standpipe		GVI	External corrosion on pipes	CS	N/A	N/A	N/A	N/A	External corrosion, galvanic corrosion	Around of the welds and in contact with a U-clamp on straight spools.	Lack of coating, different materials,	**Susceptible / Unknown**
Tension Leg Platform	nov.12	Standpipe		GVI	Vibration in piping can cause cracks. Padding on pipe put of position	CS	N/A	N/A	N/A	N/A	External damage / vibration	Straight spool in contact with support	Lack of padding and vibration dampening	**Susceptible / Unknown**
Tension Leg Platform	nov.12	Pop off line		GVI	External corrosion on weld	CS	N/A	N/A	N/A	N/A	External corrosion	Around of the welds in a bend	Lack of coating, marine atmosphere, poor workmanship	**Susceptible / Unknown**
Column stabilised unit	des.12	Standpipe		UTM	Damage to pipe from excessive vibration. Leading to approx. 5mm material loss.	CS	N/A	N/A	N/A	N/A	Vibration / galvanic corrosion	Between pipe and support	Wrong materials/ no vibration dampening	**Susceptible / Unknown**
Column stabilised unit	des.12	Pipes in mud pump room	Mud pump room	GVI	General coating breakdown in area in pipe spools and supporting structure	CS	N/A	N/A	N/A	N/A	External corrosion		Lack of coating	**Slow**
Column stabilised unit	jun.10	Standpipes	Mezzanine deck	CVI	Poor surface condition. Corrosion product up to 2cm thick. Corresponds to 0,3mm material loss ca. Should be replaced	CS	N/A	N/A	N/A	N/A	External corrosion	All parts	Poor coating	**Medium**
Column stabilised unit	jul.11	Standpipes	Mezzanine deck	UTM	The wall thickness is below	CS	19,1	15,4	15	0,82	Internal corrosion	Beginning of bend	Higher flow load	**Fast**
Column stabilised unit	jul.11	Standpipes	Mezzanine deck	UTM	The bleed off pipe has a wall thickness below Tmin.	CS	15,2	9,7	8	7,2	Internal corrosion	Bleed off line	Small pipe diameter. Higher flow load	**Fast**
Column stabilised unit	jul.11	Standpipe 1	Mezzanine deck	GVI	Corroded in the area where it's not coated.	CS	N/A	N/A	N/A	N/A	External corrosion	Area with no coating	Lack of coating	**N/A**
Column stabilised unit	jun.10	standpipe 1	Mezzanine deck	UTM	Wall thickness below Tmin	CS	19,1	15,4	14,5	0,5	Internal corrosion, erosion	Beginning of bend	High flow load	**Fast**
Column stabilised unit	jul.11	Standpipe manifold	Drill floor	UTM	Bleed off pipe has a wall thickness below Tmin.	CS	15,2	9,7	8,5	0	Internal corrosion	Bleed of line	Small pipe diameter. Higher flow load	**Slow**
Column stabilised unit	jan.09	Standpipe 1 and 2	Main and spare HP mud standpipe to goosenecks, and mezzanine deck	CVI	Corrosion under insulation	CS	N/A	N/A	N/A	N/A	CUI	Under insulation	Heat, humidity, salt etc.	**N/A**
Column stabilised unit	jan.09	Standpipe	Mezzanine deck and gooseneck	UTM	Measured wall thickness less than Tmin	CS	19,1	15,4	15	0,75	Internal corrosion, erosion	Gooseneck	Higher flow load	**Fast**
Column stabilised unit	jan.12	Standpipe		UTM	Internal erosion. Test points close to Tmin	CS	19,1	14,1	14,5 - 15	1,25-1,4	Internal erosion	Standpipes. Downstream 45 degree bend and after T-connection	High flow load, solids	**Fast**
Column stabilised unit	okt.09	S-pipe	Drilling machine	GVI	Abrasion damage from tugger wire	CS	N/A	N/A	N/A	N/A	External damage	S-pipe	Interference with tugger wire	**Susceptible / Unknown**
Column stabilised unit	okt.08	Bleed off line	Mud pump room	GVI	Missing bracket in bleed off pipe to PSV mud pump no.2		N/A	N/A	N/A	N/A	N/A	N/A	N/A	**Susceptible / Unknown**
Column stabilised unit	okt.08	Standpipes	Drill floor	GVI	Missing bolt and several bolts are to short on pipe support structure for standpipe 1 and 2.		N/A	N/A	N/A	N/A	Can cause vibration and cracking	Standpipe	Missing bolts / support. Poor workman ship	**Susceptible / Unknown**
Column stabilised unit	okt.08	Relief line		GVI	Loose brackets and bolts on line from PSV to mud pits		N/A	N/A	N/A	N/A	Can cause vibration and cracking			**Susceptible / Unknown**
Column stabilised unit	okt.08	Standpipe	Drill floor	GVI	Deformation on standpipe resulting from use of hammer		N/A	N/A	N/A	N/A	External damage		Poor workmanship	**Susceptible / Unknown**

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Column stabilised unit	nov.11	PSV line		GVI	Poor pipe support		N/A	N/A	N/A	N/A	Can cause vibration and cracking			**Susceptible / Unknown**
Column stabilised unit	nov.11	PSV line		GVI	Missing pipe support		N/A	N/A	N/A	N/A	Can cause vibration and cracking			**Susceptible / Unknown**
Ship-shaped Drilling Unit	aug.13	Standpipe	Drill floor	GVI	External corrosion close to welds, and corroded support	CS	N/A	N/A	N/A	N/A	External corrosion	Close to welds	Lack of coating	**Susceptible / Unknown**
Ship-shaped Drilling Unit	okt.10	Booster line	Drill floor	GVI	A small part of the booster line suffers from external corrosion, with scaling of about 5mm.	CS	N/A	N/A	N/A	N/A	External corrosion		Lack of coating, marine atmosphere	**N/A**
Ship-shaped Drilling Unit	okt.09	All lines		GVI	Vibration on all lines during operation		N/A	N/A	N/A	N/A	Vibration. Missing support, dampening etc. Can cause cracks	Area missing support and dampening	Poor workmanship, bad solution	**Susceptible / Unknown**
Column stabilised unit	may.13	Booster line	Moon pool	GVI	Lines suffers from external corrosion	CS	N/A	N/A	N/A	N/A	External corrosion		Lack of coating	**Slow**
Column stabilised unit	may.13	Standpipes		GVI	Welds are not coated. External corrosion	CS	N/A	N/A	N/A	N/A	2. Stress corrosion cracking		Lack of coating	**Susceptible / Unknown**
Column stabilised unit	may.13		Below drill floor	GVI	Three 3" HP air line in stainless steel (SS) is in contact with vibrating carbon (CS) steel standpipe Two concerns: Destroyed oxide layer and resulting corrosion: Crevice and galvanic coupling between the pipes and carbon steel parts may lead to corrosion. The HP air steel line is exposed to vibration and stresses which may lead to fatigue and/or stress corrosion cracking. Primary concern is for the thinner SS piping.	CS / SS	N/A	N/A	N/A	N/A	1.Crevice and galvanic corrosion. 2. Stress corrosion cracking		1. Destroyed oxide layer: crevice and galvanic coupling between the pipes and carbon steel pipes. 2. Vibration and stresses	**Susceptible / Unknown**
Column stabilised unit	feb.12	S-pipe	Drilling machine	UTM	The remaining thickness measured below/close to Tmin	CS	17,1	11,9	11,5 / 12,5	0,9-1,1	Internal corrosion / erosion	S-pipe, bend	High flow load	**Fast**
Column stabilised unit	mar.11	Standpipe	Drill floor, mezzanine deck	UTM	Measured wall thickness below Tmin on two bends. One bend close to Tmin	CS	17,1	11,9	11,5	1,1	Internal corrosion / erosion	Bends	Higher velocity, higher flow load	**Fast**
Column stabilised unit	mar.11	Standpipes	Mezzanine deck	GVI	External corrosion on pipes	CS	N/A	N/A	N/A	N/A	External corrosion	Straight pipe	Lack of coating.	
Column stabilised unit	jun.12	All outdoor lines	outdoor areas	GVI	All HP mud lines are corroded in out door areas. Difficult to measure wall thickness	CS	N/A	N/A	N/A	N/A	External corrosion	Outdoor areas	Lack of coating. Marine atmosphere, salt, humidity.	**Slow**
Column stabilised unit	jun.12	Standpipes	Shaker room, mezzanine deck, drill floor	UTM	Two bends on standpipe before standpipe manifold has a wall thickness close to Tmin. Also a number of bends that are within 2mm of Tmin	CS	17,1	11,9	11,5	1,1	Internal corrosion / erosion	Bends	Higher velocity, higher flow load	**Fast**
Column stabilised unit	jun.09	Outlet from mud pump 1	Mud pump room	GVI	Poor welding	CS	N/A	N/A	N/A	N/A	Crack	weld	Poor welding	**Medium**
Column stabilised unit	nov.08	Booster line		UTM	Test point close to Tmin	CS	17,1	11,9	12,7	0,3	Internal corrosion / erosion	Bend	Higher velocity, higher flow load	**Medium**
Column stabilised unit	nov.08	Standpipe	Drill floor	UTM	Test point close to Tmin	CS	19,05	14,7	15,5	N/A	Internal corrosion / erosion	Bend	Higher velocity, higher flow load	**N/A**
Column stabilised unit	sep.13	Standpipe manifold	Drill floor	UTM	Test point close to Tmin	CS	19,05	15,8	14,5	0,7	Internal corrosion / erosion	Straight pipe		**Fast**

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Column stabilised unit	sep.13	Standpipe	Drill floor	UTM	Test point close to Tmin	CS	19,05	14,7	15	0,6	Internal corrosion / erosion	Bend	Higher velocity, higher flow load	**Fast**
Column stabilised unit	sep.13	Standpipe	Drill floor	UTM	Test point close to Tmin	CS	19,05	14,7	15,6	0,6	Internal corrosion / erosion	Bend	Higher velocity, higher flow load	**Fast**
Column stabilised unit	aug.10	Standpipe	Drill floor	UTM	Remaining wall thickness below recommended Tmin	CS	19,05	14,7	14,5	0,45	Internal corrosion / erosion	Bend	Higher velocity, higher flow load	**Medium**
Column stabilised unit	aug.10	Standpipe manifold	Drill floor	UTM	Wall thickness below Tmin	CS	19,05	15,8	13,5	0,45	Internal corrosion / erosion	Bend	Higher velocity, higher flow load	**Medium**
Column stabilised unit	aug.10	Standpipe	Drill floor	UTM	Remaining wall thickness below recommended Tmin	CS	19,05	14,7	14	0,4	Internal corrosion / erosion	Straight pipe		**Medium**
Column stabilised unit	aug.10	Standpipes	Drill floor	GVI	The insulation of red and yellow standpipes at weather exposed areas is damaged by impact and age. The heat tracing is broken at several places. CUI is present	CS	N/A	N/A	N/A	N/A	External corrosion, CUI	Weather exposed areas	Marine atmosphere, humidity, temperature.	**N/A**
Column stabilised unit	aug.10	Booster line	Moon pool	UTM	Crevice corrosion. Thickness close to Tmin	CS	7,14	3,8	4	0mm/year	Crevice corrosion			**Slow**
Column stabilised unit	sep.13	Standpipes	Out door areas	GVI	Severe external corrosion on both standpipes in weather exposed areas and areas under insulation	CS	N/A	N/A	N/A	N/A	External corrosion, CUI	Weather exposed areas and under insulation	Marine atmosphere, humidity, temperature. Lack of coating	**N/A**
Column stabilised unit	sep.13	Standpipes	Derrick	UTM	Wall thickness below Tmin	CS	19,05	14,7	11	1,6	Internal corrosion / erosion	Bend	Higher velocity, higher flow load	**Fast**
Column stabilised unit	sep.13	Standpipes	Derrick	UTM	Wall thickness below Tmin	CS	19,05	14,7	12	1,4	Internal corrosion / erosion	Bend	Higher velocity, higher flow load	**Fast**
Column stabilised unit	sep.13	Standpipes	Mezzanine deck	UTM	Wall thickness below Tmin	CS	19,05	14,7	14	1,1	Internal corrosion / erosion	Bend	Higher velocity, higher flow load	**Fast**
Column stabilised unit	sep.13	Standpipes	Mezzanine deck	UTM	Wall thickness below Tmin	CS	19,05	14,7	11	1,6	Internal corrosion / erosion	Bend	Higher velocity, higher flow load	**Fast**
Column stabilised unit	sep.13	Standpipe	Mezzanine deck	UTM	Wall thickness below Tmin	CS	19,05	14,7	13-14	1,1-1,2	Internal corrosion / erosion	Straight		**Fast**
Column stabilised unit	sep.13	Standpipe	Mezzanine deck	UTM	Wall thickness below Tmin	CS	19,05	14,7	13	1,21	Internal corrosion / erosion	Bends	Higher velocity, higher flow load	**Fast**
Column stabilised unit	sep.13	Standpipe	Mezzanine deck	UTM	Wall thickness below Tmin	CS	19,05	14,7	14	1,05	Internal corrosion / erosion	Straights		**Fast**
Column stabilised unit	sep.13	Booster line	Mud pump room	UTM	Wall thickness close to Tmin	CS	17,12	11,9	12	0,2	Internal corrosion / erosion	Bend	Higher velocity, higher flow load	**Medium**
Column stabilised unit	sep.13	Booster line	Moon pool	UTM	Wall thickness close to Tmin. No degradation since last inspection	CS	7,14	3,8	4	0	Internal corrosion / erosion	Straight, last part before hose		**Slow**
Column stabilised unit	sep.13	X-over line	From stand pipe manifold to choke manifold	UTM	Wall thickness is close to Tmin	CS	17,2	11,9	12,5	0,6	Internal corrosion / erosion	Bend	Higher velocity, higher flow load	**Fast**
Column stabilised unit	nov.09	Standpipe manifold	Drill floor	UTM	Remaining wall thickness below recommended Tmin	CS	19,05	15,8	14	0,4	Internal corrosion / erosion	Straight		**Medium**
Column stabilised unit	sep.13	Standpipe	Drill floor	UTM	Remaining wall thickness below recommended Tmin	CS	19,05	14,7	14	0,53	Internal corrosion / erosion	Bend	Higher velocity, higher flow load	**Fast**
Column stabilised unit	sep.13	Booster line	Moon pool	GVI	Crevice corrosion/pitting	CS	N/A	N/A	N/A	N/A	Crevice corrosion			**Susceptible / Unknown**
Column stabilised unit	sep.13	Standpipes	outdoor areas	UTM	The insulation of red and yellow standpipes at weather exposed areas is damaged by impacts and age. The heat tracing is broken at several places. CUI is present.	CS	N/A	N/A	N/A	N/A	External corrosion, CUI	Weather exposed areas	Marine atmosphere, humidity, temperature.	**N/A**
Column stabilised unit	mar.13	Pop off lines	Mud pump room	GVI	The coating condition of the pop off lines is fair. Damaged painting	CS	N/A	N/A	N/A	N/A	External corrosion		Lack of coating	**N/A**
Column stabilised unit	mar.13	Standpipe	Top deck	UTM	Small area of internal degradation and uneven wall thickness on standpipe. Wall thickness measured close to Tmin	CS	20,3	16,1	17	0,14	Internal corrosion / erosion	Straight spool		**Medium**

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Column stabilised unit	feb.10	Standpipe	Above standpipe manifold, mud pump room	UTM	Uneven internal surface and remaining wall thickness close to Tmin	CS	20,3	16,1	18	0,1	Internal corrosion / erosion	Straight spool from manifold		Slow
Column stabilised unit	feb.10	Standpipe from mud manifold	mud pump room	UTM	Wall thickness close to Tmin	CS	20,3	16,1	16,5	0,33	Internal corrosion / erosion	Straight spool from manifold		Medium
Column stabilised unit	feb.10	Mud pump	Mud pump room	UTM	Wall thickness close to Tmin	CS	20,3	16,1	16,8	0,3	Internal corrosion / erosion	Straight spool		Medium
Column stabilised unit	feb.10	Mud pump	Mud pump room	UTM	Wall thickness close to Tmin	CS	20,3	16,1	17,5	0mm/year		Straight spool		Slow
Column stabilised unit	feb.10	Standpipe	Mud pump room	UTM	Wall thickness close to Tmin	CS	20,3	16,1	17	0mm/year		Straight spool		Slow
Column stabilised unit	feb.10	S-pipe	Derrick	UTM	Wall thickness below Tmin	CS	N/A	12,5	N/A	0,4	Internal corrosion / erosion	S-pipe, bend		Medium
Column stabilised unit	feb.10	S-pipe	Derrick	UTM	Wall thickness below Tmin	CS	N/A	12,5	N/A	0,4	Internal corrosion / erosion	S-pipe, bend		Medium
Column stabilised unit	2012	Standpipes	Cellar deck	UTM	Wall thickness below Tmin	CS	20,3	16,1	14-16	0,8	Internal corrosion / erosion	Bends	Higher velocity, higher flow load	Fast
Column stabilised unit	des.12	S-pipe	Drill floor	UTM	A wire with heavy load has been scratching against the S-pipe and made a groove of 5.2 mm. Based on UTM adjacent to the groove, the wall thickness in the groove is above 26.3 mm (above the minimum thickness) and it is hence considered that further fitness for service calculations are not needed.	CS	N/A	N/A	26,3	1,04	External damage from wire	S-pipe	Poor workmanship, bad solution	Fast
Column stabilised unit	may.12	Pop off line to mud pit	Mud pit room	UTM	Severe internal degradation, only 4mm wall thickness at some places	CS	15,3	10,4	4	8,5	Internal corrosion / erosion	Straight spool, down stream last bend on spool	High flow load. Solids from mud might have led to high erosion rates. Erosion possible caused by extreme acceleration in fluid velocity close to mud pit tanks where pressure drops rapidly.	Fast
Column stabilised unit	may.12	Pop off line to mud pit	Mud pit room	UTM	Severe internal degradation, only 2.5 mm remaining wall thickness at some places	CS	15,3	10,4	2,5	11,5	Internal corrosion / erosion	Straight spool, down stream bend	High flow load. Solids from mud might have led to high erosion rates. Erosion possible caused by extreme acceleration in fluid velocity close to mud pit tanks where pressure drops rapidly.	Fast

Type installation	Date survey	Line / equipment	Location	Inspection method	Description of finding	mm	Tnom (mm)	Tmin (mm)	Tmeasured (mm)	Degradation rate (mm/year)	Possible cause of degradation / damage	Location / object prone to degradation	Cause of location	Degradation process
Column stabilised unit	may.12	Pop off line to mud pit	Mud pit room	UTM	Severe internal degradation, only 5mm remaining wall thickness at some places	CS	15,3	10,4	5	8,5	Internal corrosion / erosion	Straight spool, down stream bend	High flow load. Solids from mud might have led to high erosion rates. Erosion possible caused by extreme acceleration in fluid velocity close to mud pit tanks where pressure drops rapidly.	**Fast**
Column stabilised unit	may.12	Booster pop-off line to mud pit 2	Mud pit room	UTM	Severe internal degradation, only 6,5mm remaining wall thickness	CS	15,3	10,4	6,5	3	Internal corrosion / erosion	Straight spool, down stream bend	High flow load. Solids from mud might have led to high erosion rates. Erosion possible caused by extreme acceleration in fluid velocity close to mud pit tanks where pressure drops rapidly.	**Fast**
Self-elevating unit	sep.12	Standpipe 1 and 2	From main deck to goose necks	GVI/UTM	The foam was removed from the deck penetrations, and external corrosion was revealed. The loss of wall thickness on the reinforced bend on standpipe 1 was measured to approx. 5mm. The coating condition on both standpipes from the deck penetrations and up to pusher street is FAIR with light, external corrosion.	CS	N/A	N/A	N/A		External corrosion, galvanic corrosion	At deck penetration	Marine atmosphere, different material interference	**Fast**
Self-elevating unit	okt.12	Internal pipe spool	from pulsation dampener mud pump 2,	UTM	Internal erosion. Approximately 3mm loss of wall thickness	CS	N/A	17,7	18,5	0,6	Internal erosion	From pulsation dampener	High flow load, solids in fluid	**Fast**
Self-elevating unit	nov.12	Internal pipe spool	From pulsation dampener MP1	UTM	Internal erosion. Approximately 3mm loss of wall thickness	CS	N/A	17,7	17,5	0,75	Internal erosion	From pulsation dampener	High flow load, solids in fluid	**Fast**
Self-elevating unit	des.12	Standpipe 1	Machine room	UTM	Internal degradation. Below Tmin	CS	N/A	17,7	17,5	0,67	Internal erosion/corrosion	Straight spool		**Fast**
Self-elevating unit	jan.13	Standpipe 1	Drill floor standpipe manifold	UTM	Indication of internal degradation.	CS	N/A	14,9	15	0,6	Internal erosion/corrosion	Straight spool		**Fast**
Self-elevating unit	feb.13	S-pipe	On DDM	UTM	Internal degradation. Wall thickness below Tmin	CS	N/A	12,7	13	0,4	Internal erosion, corrosion	S-pipe, bend	Higher velocity, higher flow load	**Medium**
Self-elevating unit	mar.13	S-pipe	On DDM	UTM	Internal degradation. Wall thickness below Tmin	CS	N/A	12,7	13	0,5	Internal erosion, corrosion	S-pipe, bend	Higher velocity, higher flow load	**Fast**
Self-elevating unit	apr.13	Standpipe	Derrick	UTM	Internal degradation. Wall thickness close to Tmin	CS	N/A	14,9	17,5	0,25	Internal erosion	Goose neck	Higher velocity, higher flow load	**Medium**
Column stabilised unit	sep.12	Standpipes	From winch roof to hose connection in derrick	GVI	The conditions are FAIR.	CS	N/A	N/A	N/A	N/A	Possible external corrosion	Weather exposed areas	Lack of coating, marine atmosphere	**N/A**
Column stabilised unit	sep.12	Bleed off line	Standpipe manifold	GVI	The coating conditions for the bleed off line on drill floor is POOR. The coating condition on the rest of the line is GOOD	CS	N/A	N/A	N/A	N/A	Possible external corrosion		Lack of coating	**N/A**
Column stabilised unit	jun.13	Standpipes	Derrick	GVI	Poor coating conditions with following external corrosion	CS	N/A	N/A	N/A	N/A	External corrosion	Derrick, outside areas	Lack of coating	**N/A**

Type installation	Date survey	Line / equipment	Location	Inspection method	Description of finding	mm	Tnom (mm)	Tmin (mm)	Tmeasured (mm)	Degradation rate (mm/year)	Possible cause of degradation / damage	Location / object prone to degradation	Cause of location	Degradation process
Column stabilised unit	okt.10	Standpipes	Main rig	UTM	Internal degradation, wall thickness below Tmin	CS	19,05	15,1	14-15	0,6-0,9	Internal erosion	Straight spools	High flow load	**Fast**
Column stabilised unit	may.2012	HP mud lines	Outside derrick	UTM	All lines outside derrick aft, stbd side suffer from external corrosion in weather exposed areas	CS	N/A	N/A	N/A	N/A	External corrosion	Weather exposed areas	Marine atmosphere, humid, salt etc. Lack of coating	**N/A**