University of Stavanger

Faculty of Science and Technology

MASTER'S THESIS

Study program/ Specialization: Offshore Technology- Risk Management	Spring semester, 2011 Restricted access
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Title of thesis: **Risk Based Inspection: Developing Empirical Formula to Calculate Inspection Coverage**	
Credits (ECTS):30	
Key words: Risk Based inspection, Finding rate, Degradation rate, Time interval, Optimum inspection Coverage.	Pages: ……87……… + Enclosure: …1……… Stavanger, 15 June 2011

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Developing Empirical Formula to Calculate Inspection Coverage

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Acknowledgment

I would like to thank Professor R.M. Chandima Ratnayke for giving me an interesting topic for my master thesis, his excellent supervision and opportunity to work with him.

I would like to thank Professor O.T. Gudmestad for supporting me to take this master thesis.

I would like to thank Mr. R.M. Zydeman, R. Gustavo and R. Tho Hagland for their help me as external supervisors and using their experiences.

I would like to thank my parents and my spouse, Faraz, who always encourage me.

Finally I acknowledge the University of Stavanger and Department of Science and Technology for giving me good working conditions.

Stavanger, June 2011

Mina Jalali

Abstract:

The Risk Based Inspection (RBI) method prioritizes the process equipment, by calculating separate likelihood and consequence values for each piece of equipment. The combination of likelihood and consequence can be evaluated in a variety of ways to indicate critical equipment for action. Using the tools of Risk Based Inspection, it has been confirmed that equipment can be operated safely for a period of time, if inspections closely monitor the condition to eliminate uncertainties inherent in predicting the damage rates such as corrosion and erosion. The developing RBI tools for the Oil and Gas industries show promise as being effective and practical for decision making regarding equipment inspection (Conley and Reynolds, 1997). A Risk-based inspection approach helps in designing an alternative strategy to minimize the risk resulting from failures. Adapting a risk-based maintenance strategy is essential in developing cost-effective maintenance policies (Bertolini et al., 2009)

On the Norwegian Continental Shelf (NCS), some of the production and process facilities are reaching to the end of their design life and need of inspection activities is more critical. Stricter environmental and safety regulations and barriers coupled with increasing emphasis on cost reductions have been forcing the industry to use development inspection techniques and materials (Santos and Hajri, 2000). These returns to the questions: how much is the inspection coverage?

In this study, the Technical Condition (TC) of a sub-system in a production and process facility is evaluated based on findings and historical data. Wall thicknesses of piping components inherently decrease due to degradation mechanisms such as corrosion and erosion. The minimum wall thickness is defined based on the standards and regulations. Based on the TC, reports are made for future inspection purposes as well as to present to the asset owner (Operator Company). The report recommends number of inspection that has to be carried out annually based on The TC.

Based on the remaining design life of the process facility, finding rate, criticality of the system, materials specification changes, degradation rate, unexpected degradation behaviours and the experience of the inspection planners, the thesis suggests an empirical model for inspection coverage by using risk based inspection strategy and previous inspection data to be used on an aged platform. The thesis also discusses about developing an inspection model as well as validating it based on past inspection data (Santos and Hajri, 2000).

Table of Contents

Abbreviation:

PL	Process Hydrocarbons - Liquid	WJ	Jet Water	DP	Control Surface
PT	Process Hydrocarbons - Two Phase	BD	Blow Down	PV	Preventive Maintenance Program Based Maintenance
PV	Process Hydrocarbons - Vapours	VF	Vent to Flare	HVIR	Eddy current control
LP	Local control panel	OH	Oil Hydraulic	I.A.	Not applicable
PCDA	Process control & data acquisition	OF	Oil Fuel	KUI	Corrosion Under Insulation
PSV	Pressure safety valves.	C	Chemicals	CM	corrective maintenance / Needs Based Maintenance
EHV	Emergency hand valves.	HM	Heating Medium	LCI	Life Cycle Information
PW	Produced Water	AI	Air Instrument	LTP	Long-term (for containers and pipes Framework RBI analysis)
GR	Gas Re-injection	KM	Kill Mud	MIC	microbial induced corrosion
WF	Water Fire	SW	Sea Water	MPI	Magnetic Particle Inspection
FG	Fuel Gas	GVI	General visual inspection	NDT	Non destructive testing
RBI	Risk Based Inspection	PoD	Probability of detection	NVI	Near visual inspection
RL	Remaining life time	RKT	Radiographic control	SIP	structure inspection program Statoil
CSSLC	Company Structured Surface Long-Term Care Concept	RIS	Pipe inspection program Statoil	SRB	Sulphate-reducing bacteria
IOW	Integrity operating window	TC	Technical Condition	ESV	Emergency shutdown valve
SSV	Surface safety valve				

1 Introduction

1.1 Background and scope

Owners and users of Oil and Gas plant have the option to manage the integrity of their plant and plan inspection from assessments of the risks of failure. They need to be able to demonstrate that the risk assessment and inspection planning processes are being implemented in an effective and appropriate manner (Wintle et al., 2001). The aim of this report is to identify inspection coverage by using the inspection activities data for aged platform Statfjord B. In order to do this research these steps are followed:

1. Study of risk based inspection and RBI reports of Statfjord B
2. Revise the systems, sub-system of the platform in terms of process, inspection and RBI and select two main critical sub-system
3. Observations and formation of the topic
4. Gathering inspection data and analysis the inspection data to identify finding rate and coverage rate
5. Identify factors which are affected the inspection coverage
6. Develop empirical formula based on the factors and inspection engineer experiences
7. Validate the formula by the previous inspection data

1.2 Main themes (Collection of Data)

By using risk based inspection (RBI) philosophy, it is possible to calculate the inspection coverage. The main data that are used in this study are as below:

- Drawings (PFD, P&ID)
- Historical inspection data from Client data base RIS
- Inspection summery including: total number of locations in each equipment group, total number of locations which are inspected, material, type of inspection, corrosion rate, minimum wall thickness, Technical condition etc
- RBI report including: PoF and CoF for each equipment group, inspection interval, remaining life time and risk criteria

1.3 Reflection of collecting data

The inspection plan is structured by equipment groups. Equipment groups are defined for the main process and utility systems. The various equipment groups (sub-systems) are sorted into categories. In this study, the RBI reports from an aging platform for two main subsystems are discussed; Flow lines and production lines. Corrosion is seen as one of the significant challenges for the assets, so these sub-systems ranked in high critically area in risk matrix. Risk assessment has revealed that corrosion is due to material of which they are made (i.e. carbon steel). Corrosion propagation can be modelled based on the wall thickness and this is named as technical condition (TC). TC is divided to several intervals based on the wall thickness. Number of the finding in different parts of TC exists in the inspection summery. The inspection interval and remaining wall thickness can be recognized from RBI report.

1.4 Aims and Objectives

Optimization of inspection programs by using the RBI analysis can be effected by several factors. This study is based on the technical condition of the critical components. The inspection results of an aged platform (SFB) are used to create an empirical formula for inspection coverage. The empirical formula is developed by two main factors which can affected by material, TC and type of inspection. The inspection coverage is condition based, so these two factors may change due to different condition by decision making of inspection engineer. In summary, the study provides the details about: 1) determining high-risk sub-systems concentrating on their RBI reports; 2) calculation of finding rate; 3) evaluation of inspection coverage; 4) optimization of inspection coverage by selecting the correct combination of factors to be assessed.

2 Risk Based Inspection Methodology

Risk- based inspection (RBI) is an approach designed to make decision for inspection planning based on risk by combining two separate factors: the probability of failure (PoF) and the consequences of the failure (CoF). This method is using a 5×5 matrix to provide the simple evaluation. RBI values are used to optimize inspection program and recommend monitoring testing plans for production system. The final work of the RBI studies is showing the critical rating damages and inspection strategy for each piece of equipment(Bolinger et al., 1999). To carry out the RBI analysis, the probability of failure and the consequences of failures are calculated separately and they are jointed to find out the risk of failure. Figure 2-1 illustrates the basic Risk based inspection concept. The left side of the diagram shows the degradation mechanisms, each of them may or may not lead to the loss of containment and if any degradation model exists the probability of failure is estimated numerically, or by using of engineering judgment.

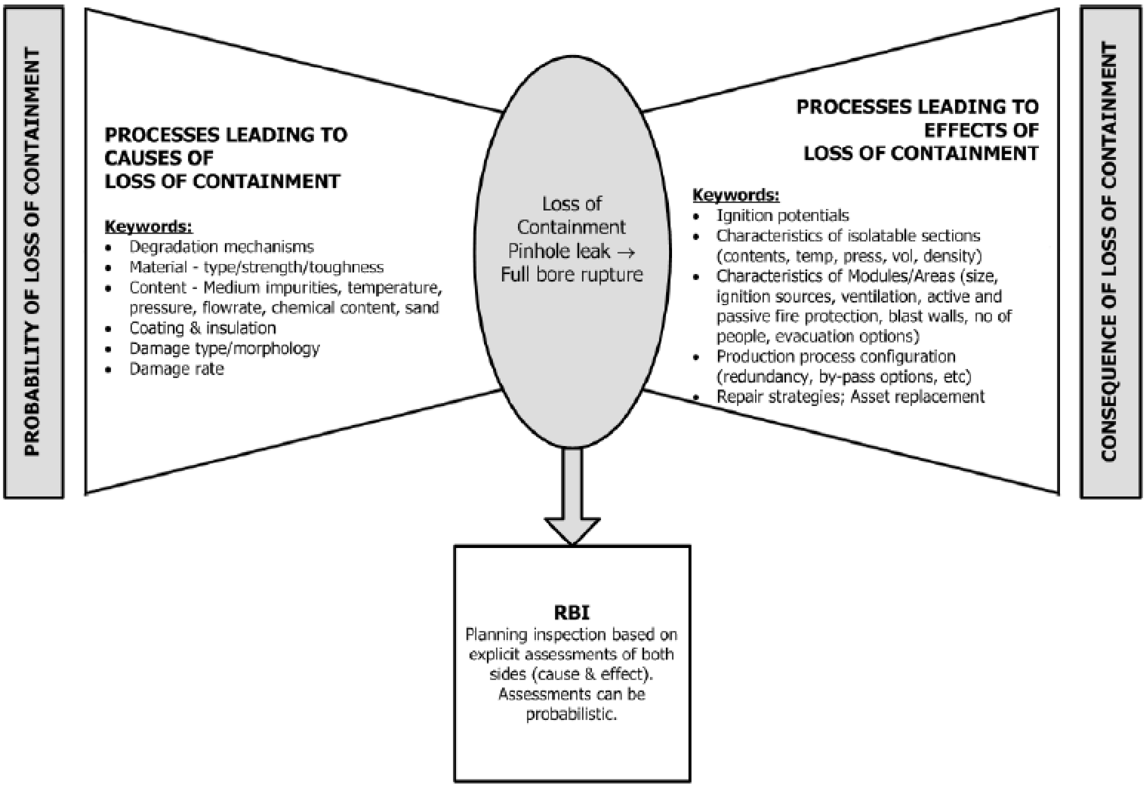


Figure 2-1 RBI Basic concept(DNV, 2010)

2.1 Fundamentals aspects of RBI

Inspection planning based on the RBI assessment is a cost/benefit decision framework for determining:

- Where to inspect
- What to inspect
- How to inspect

- When to inspect

And to document those requirements with respect to the safety of personnel and environment(Dewanto et al., 2004). The domain of the inspection planning is shown in the Figure 2-2

Figure 2-2 Risk based inspection domain (API, 2009)

The complexity of inspection planning and maintenance is due to the:

- Large number of parameters involved in the RBI problem
- The complexity of units
- The large amount of components needed to be considered
- The theoretical structure used for the risk analysis

2.2 RBI Methods

Risk based inspection can be done using quantitative or qualitative methods but usually are carried out by using both the methods which is called semi-quantitative.

Quantitative:

The quantitative method assigns risk values to risk ranks by expressing in qualitative terms for probability of failure and consequences of failure. The numerical value is calculated and the system is systematic and it can update easily. The quantitative approach involves computer to calculate risk and inspection program. The quantitative approach consists of event tree and fault tree to estimate the probability of each accident sequence and the result of this approach presents as risk numbers.

Qualitative:

In the qualitative method, instead of numerical values an expressive ranking is given such as a low, medium or high. It is usually based on engineering judgment and it can be completed quickly and with low initial cost and the result is understandable although it cannot update easily. The accuracy of the results is dependent on the background and experiences of the risk analysis team (DNV, 2010).

Semi-quantitative

A third method is a combination of Semi-quantitative/ Semi-qualitative and it obtains the main benefits of the two previous approaches. It is possible to have different cases such as below:

- The consequence of a failure is qualitative and the probability of the failure is quantitative.
- The CoF and PoF are quantitative with respect to the risk ranking and time of inspection is qualitative.

The results are usually presented in consequences and probability categories or as a risk numbers but numerical values are connected with each category to calculate risk. The management of the organization determines approach to use the risk analysis spectrum should be considered to be a continuum with qualitative and quantitative approaches and everything in between being the semi-quantitative approach (API, 2009, DNV, 2010) (Figure 2-3)

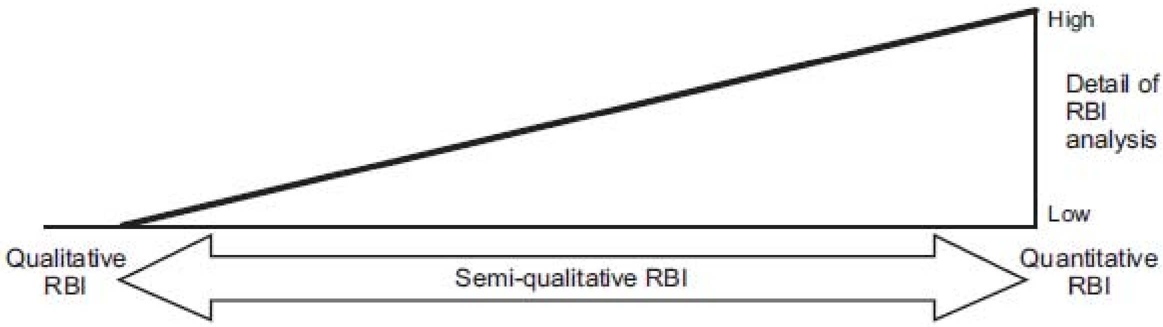


Figure 2-3 Continuum of RBI approaches (API, 2009)

2.3 RBI working process

Large diversity of equipment in offshore hydrocarbon production facilities leads to use of a conductive RBI analysis for such facilities, Figure 1-4 shows that the RBI approach is a stepwise approach. The RBI process is divided into the five main steps:

1. Data and Information gathering
2. Selection of assessment
3. Detailed assessment
4. Planning
5. Execution and evaluation

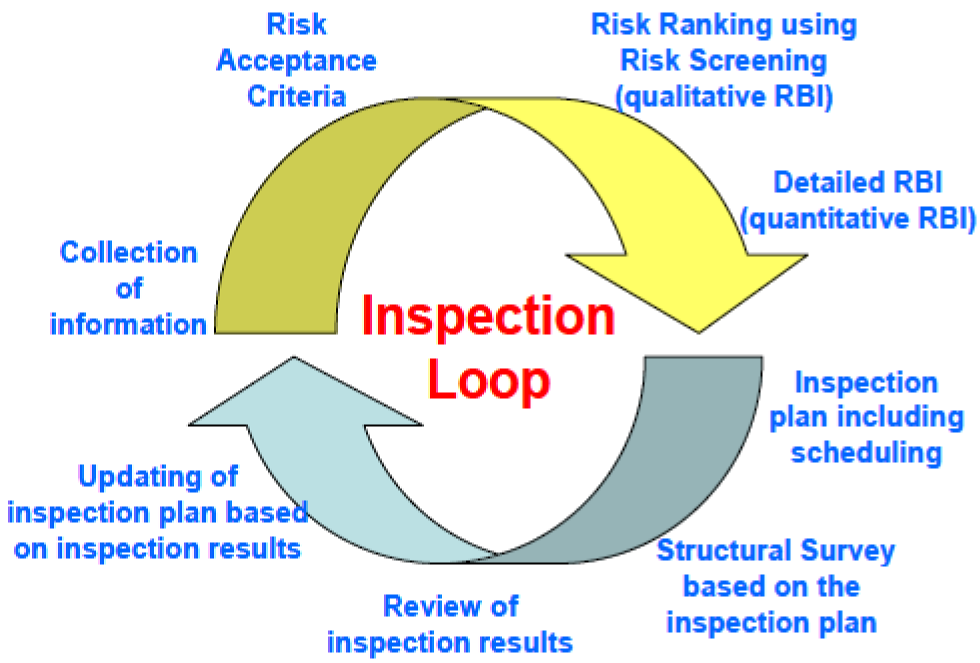


Figure 2-4 RBI Approach (Lanquetin et al., 2007)

2.3.1 Data and Information gathering

The objective of this step is to provide an overview of the data that may necessary to assess potential damage mechanisms, potential failure modes, probabilities and consequences to develop inspection planning and RBI plan. The main groups of data need to carry out the RBI analysis are divided to:

- Inspection data: The data which are expected to come out from inspection activities. Each degradation mechanism has its own specification.
- Consequences data: Specification should be prepared to show what is expected from quantified risk analysis.
- Engineering / process data: basic data such as temperature, pressure and dimensions which are generated by engineering and operation disciplines (DNV, 2010).

2.3.1.1 RBI Data needs

- Management of static data: Information including the updated version of basic equipment/piping data, design data, material information, inspection history, schedule planning, associated equipment data, material supplied data that are effectively gathered and networked with inspection procedures, documents, graphic files, damage photos and monitored equipment data.
- Analysis of equipment inspection: A complete database that meets international standards is created to include calculation equations and material reference Tables as requires by ASME, API, BS, amongst other references (Tien et al., 2007).

2.3.1.2 Data quality

The accuracy of the RBI analysis has a direct relation with the quality of data. It is helpful if the data are up-to-date and validated by knowledgeable persons. Assumptions are another sources which can significantly impact the analysis, for instance, if nominal thickness may be used because the baseline inspection were not performed, this assumption effects corrosion rate and it impacts on equipment life. In addition, comparing data from inspection to the expected damage and rates is another source of error and statistics may be useful to compare with previous measurements on that system or similar systems at the site.(Schröder and Kauer, 2004, DNV, 2010)

2.3.2 Selection of assessment

The purpose of this step is to evaluate which of the elements are judged to make a major contribution to the risk levels. The consequences of failure and probability of failure are assessed separately to find out they are significant or insignificant (resulting in high, low or medium risk). Generally low risk items will require minimum inspection and medium and high risk items will need more detailed evaluation.

2.3.2.1 Facilities Screening

Screening at facility level may be carried out by a simplified qualitative RBI in all types of plants such as oil and gas production facilities, oil and gas processing and transportation terminal, refineries and pipelines, liquid natural gas etc. and it includes:

(a) History of degradation and failures in each facility

(b) Age of facility

(c) Product value

(d) Closeness to environmentally sensitive area and public

2.3.2.2 Process Units Screening

The initial step is screening the process units to categorize the relative risk and based on the higher priority areas suggest which process units to begin with. It also provides level of detailed assessment in the various units.

2.3.2.3System within process unit screening

The process units are divided into sub systems and components. Process flow diagrams can be used to recognize the systems plus information about process condition, historical problems and damage mechanisms. The consequences of failure and probability of failure are assessed depending on information which is available.

When the RBI assessment defines a process unit, it is usually best to include all sub systems within the unit based on the relative risk of sub-systems, relative consequence of failure of sub-systems, expected benefit of sub-system and relative reliability of sub-system. So, those subsystems and components which need more assessment are identified (DNV, 2010).

2.3.3 Detailed assessment

The elements with identified medium or high risk from previous stages are considered in more detail. The objective of this assessment is identifying the degradation mechanisms, estimating the extent of damage, estimating inspection time which leads to acceptable risk level. The detailed RBI assessment includes review of both PoF and CoF for normal operating. (Figure 2-5)

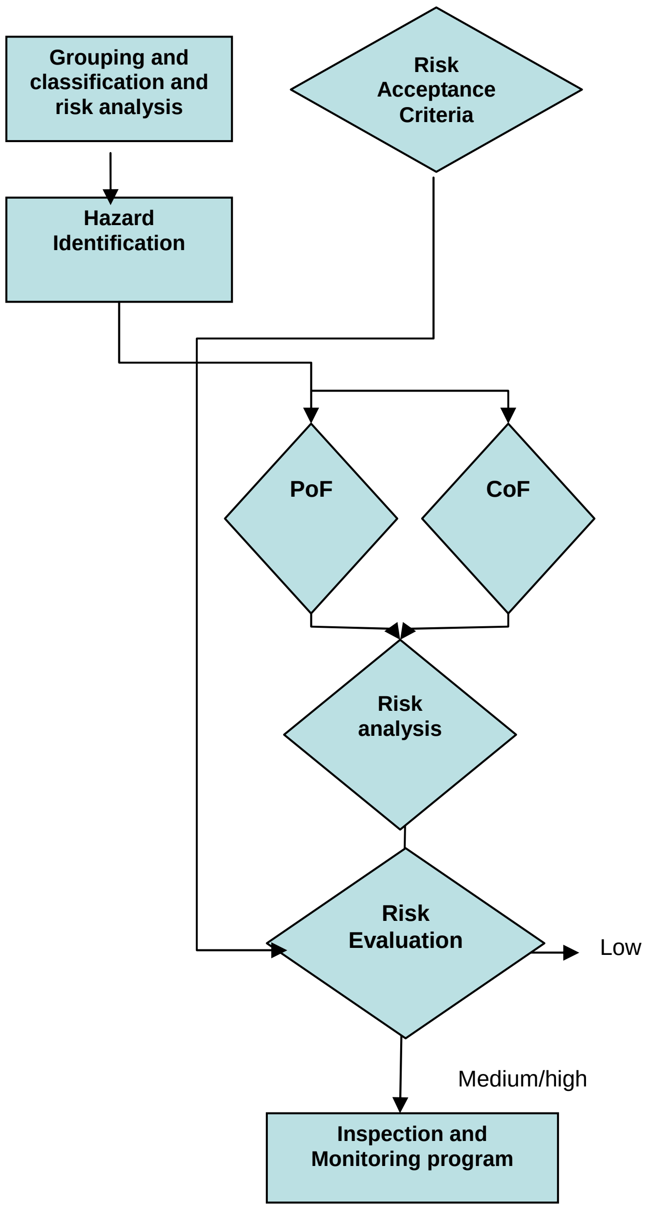


Figure 2-5: RBI framework (DNV, 2010)

2.3.4 Planning

The results of the RBI screening and detailed assessment are used as an input for inspection planning. As a result of their interaction between RBI analysis and planners, a preliminary inspection plan including time schedule are provided considering the available personnel, extent of shut down necessary, interaction with maintenance activities and data base set up. The results of this part of the assessment provide the basis for final inspection planning.

2.3.5 *Execution and Evaluation*

All of the data from pervious steps should be stored in the inspection management data base. The amount of data depends on the capacity of the database; some part of the data base can also store pictures, documents and videos. The following issues should be considered:

1) Data quality: the quality of data should be checked and data relationship should be maintained to help coordination with maintenance data.
2) Working process: The working process for both maintaining and inspection findings should be evaluated.
3) Updating: The changes in plans and data are evaluated by personnel for their effect on installation safety and operation.
4) Data storage: Location of data storage should be considered and the data server should be sufficient for necessary traffic , in addition in the case of network failure or damage, assess to the server should be possible.
5) Infrastructure capacity: the data server is to be accessed from a distance for instance from offshore or at remote locations and must be able to handle the necessary traffic in addition to normal operational traffic (DNV, 2010).

2.4 Assessing Probability of failure

Probability analysis in RBI is carried out to estimate the probability of consequence from a loss of containment that leads to the damage mechanism. In RBI analysis the risk value determines the inspection plan and high risk equipment becomes the main focus of inspection resources. The total probability of failure is the sum of the probabilities of all events that can cause failure.

$PoF_{technical}$ = It is related to the natural random normal man-made uncertainty

$PoF_{accidental}$= It is related to the accidental events including environmental loads, those can predict from historical data.

$PoF_{gross\text{-}error}$= Gross error happens during design, fabrication, installation, and operation. Gross errors are as result of human error and it is difficult to predict the probability of gross errors, however the management system tries to avoid this error.

$PoF_{unknown}$= It is related to the unexpected phenomena. Usually there is low probability even though sometimes they have high consequences.

$\mathbf{PoF_{total}= \sum PoF_{technical}, PoF_{accidental}, PoF_{gross\text{-}error}, PoF_{unknown}}$ (API, 2009, Tien et al., 2007)

2.4.1 Units of measure in the PoF analysis

The probability of failure is usually expressed by the frequency and frequency is the number of events occurring during a specific time which is called fixed interval. So, the frequency is expressed as number of events per interval. In qualitative analysis PoF is categorized e.g. high, medium and low. Table 2-1 is an example of six levels for PoF (API, 2009, Peterson and Jablonski, 2003).

Table 2-1: Probability of failure

Possible Qualitative Rank	Annual failure Probability or Frequency
Remote	**<0.00001**
Very low	**0.00001 to 0.0001**
Low	**0.0001 to 0.001**

Moderate	**0.001 to 0.01**
High	**0.01 to 0.1**
Very high	**>0.1**

2.4.2 *Types of probability analysis*

The probability of failure can be considered in quantitative or qualitative forms which are discussed as below.

2.4.2.1 Quantitative assessment method

Quantitative method is the probabilistic approach where specific failure data are used to calculate PoF, so, $PoF_{technical}$ is normally addressed. When there is insufficient failure data on specific component, the general data of the company are used and by increasing or decreasing the predicted failure frequencies for the specific component, the modified values may be prepared.

2.4.2.2 Qualitative PoF analysis

The probability of failure is carried out for each units, group or equipment item depend on the different methodology, the categories may defined as low, medium, high or may have numerical descriptors. The estimation of probability is in qualitative manner and is presented by the experienced personnel.

2.4.3 Determination of PoF

Depending on which types of probability analysis are chosen, the probability of failure is determined by damage mechanism rates of the equipment (internal or external) and effectiveness of the inspection program.

2.4.3.1 Degradation mechanisms

Degradation may occur in different form of corrosion, erosion, crack, fatigue and stress and all of these forms can lead to failure and disastrous consequences of the system. The marine operation and process condition and also materials of construction result in operational challenges due to damage mechanisms (Markeset and Ratnayake, 2010).

The RBI objective is to guide management's decision process and prioritize resources to manage risk. Inspection affects the uncertainty of the risk evaluation by identifying of deterioration and probability of failure and it leads to risk reduction. In-service inspection is mainly concerned with detection and monitoring of degradation. Failure of equipment is not avoided by inspection activities unless the inspection affects the PoF. The PoF due to such deterioration is a function of four factors:

- Deterioration type and mechanism
- Rate of deterioration
- Probability of deterioration states with inspection techniques
- Equipment tolerance based on the type of deterioration

One way of describing the damage mechanism is to group components that have the same material and are exposed to the same internal and external environment:

1. Construction material
2. Product services
3. Environment surrounding
4. Protective measure
5. Operating conditions (DNV, 2010)

The following factors should be considered in the determination of damage rates:

a) process temperature
b) pH value
c) amount of dissolved oxygen
d) component geometry
e) material
f) wall thickness
g) coating condition
h) flow velocity
i) CO_2 level
j) humidity
k) pressure (API, 2009)

The frequency of failure is used to determine the probability of failure. The history of all equipment failures are stored in the data bases and it can be organized by the software.

2.4.3.2Degradation Modelling

The degradation modelling and PoF evaluation purpose are as follow:

- Assess the current probability for each tag
- Evaluate the damage development with respect to time
- Expected damage that may be subjected at a component
- Access recording of various inspection programs

- Provide a method of risk evaluation (API, 2009)

The expected damage rate is categorized in three types:

(a) Insignificant model: There is no significant degradation expected for the component (PoF=10-5 per year). Inspection of the components in this model is not necessary expect for checking that the location of inspection is valid.

(b) Unknown model: When the product is an unknown substance then the initially probability of failure should be assigned and the need for further investigation of consequences of failure should be indicated.

(c) Rate Model: The rate model is related to the damages resulting in a decrease of wall thickness. The rate of wall thickness depends on material properties, wall thickness, fluid properties and operating conditions.

(d) Susceptibility model: In this model, damages of components occur because of external event after unknown duration (DNV, 2010).

2.5 Assessing Consequence of failure

The consequence of failure is related to all consequences which are important for operator, including economic effects (lost production, repair), environment (short and long term) and safety and health of personnel and people outside of facility(Schröder and Kauer, 2004). Consequences of Failure are usually discussed to consist of four aspects, i.e. safety (CoF_{safety}), health (CoF_{health}), environment ($CoF_{environment}$) and business ($CoF_{business}$).(Heerings and den Herder, 2003)

2.5.1 Types of consequences analysis

The consequences of failure have been categorized as quantitative and qualitative methods. These assessments are described below:

2.5.1.1 Quantitative assessment methods

Quantitative method use logic model to illustrate the combination of events to present effect of failure on people, environment and property. This model calculates the CoF based on some factors and result of quantitative analysis is usually numerical:

- Type and states of process fluid in the equipment
- Process operating variables such as pressure and temperature
- Failure mode and leak size (DNV, 2010)

2.5.1.2 Qualitative assessment methods

The qualitative assessment method is based on the engineering judgement as result of equipment operating condition and process liquids. The consequence of failure is estimated for each unit and categorized such as high, medium and low(DNV, 2010, Dewanto et al., 2004)

2.5.1.2.1 Screening Level

Screening is commonly carried out by expert judgment without any numerical analysis for the four different aspects of CoF: Safety, Health, Environment and Business. Highest rating of the four aspects is determined by overall consequence level on the different aspects. This means that it is necessary to balance the screening classification on the different aspects. It is reasonable to organize the classes cover the consequence of failure from smallest to largest possibility in different aspects. An example of possible classification is given in different Tables (2-2 to 2-5) as below (Heerings and den Herder, 2003, Peterson and Jablonski, 2003, Tien et al., 2007) :

Table 2-2 possible classification for CoF_{safety}

Consequence Class	Description
5	Fatalities
4	Permanent injuries
3	Injury with hospital treatment
2	Injury
1	No injury

Table 2-3 possible classification for CoF_{health}

Consequence Class	Description
5	Long term health effects with possible death
4	Permanent health problems
3	Short term health effects
2	Minimal health effects
1	No effect

Table 2-4 possible classification for $CoF_{environment}$

Consequence Class	Description
5	Serious damage
4	Damage, no mitigation possible
3	Damage, no mitigation possible
2	Minor damage
1	No damage

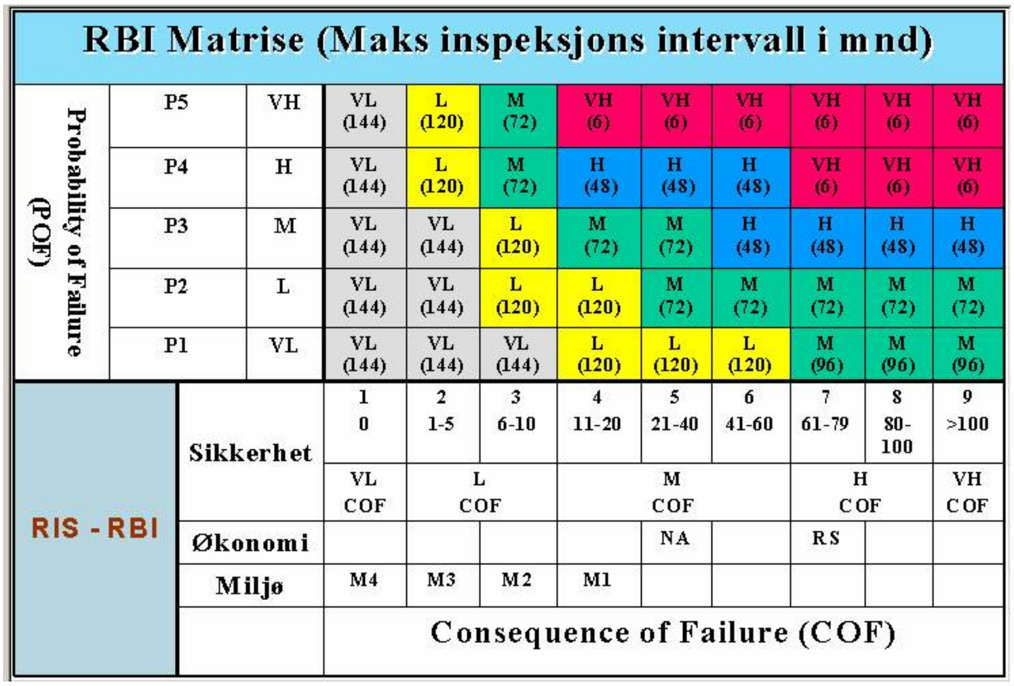
Table 2-5 possible classification for $CoF_{business}$

Consequence Class	Description ($)
5	> 10,000,000
4	1,000,000-10,000,000
3	100,000-1,000,000
2	10,000-100,000
1	<10,000

2.6 Risk assessment using risk matrix

For risk ranking, the consequence and probabilities of failure are categorized and presented in risk matrix. However, the company is free to choose the number of classes, and it is not necessary to use the same number of classes for consequences as for probabilities. It should also be mentioned that often the risk scale (low, medium, high) or the colour scheme (red, yellow, green) implicitly introduces risk acceptance criteria, thus should be carefully selected. Below is shown an example of a risk decision matrix for use in consequence classification, maintenance planning, inspection planning and for prioritising work orders Statfjord B.

The probability of failure is divided in five steps and the time interval for inspection is mentioned as 6, 72,120 etc months. The consequences of failure are categorized from 1 to 9 for health, economy and environment.



RBI Matrise (Maks inspeksjons intervall i mnd)

Probability of Failure (POF)	P5	VH	VL (144)	L (120)	M (72)	VH (6)	VH (6)	VH (6)	VH (6)	VH (6)	VH (6)
	P4	H	VL (144)	L (120)	M (72)	H (48)	H (48)	H (48)	VH (6)	VH (6)	VH (6)
	P3	M	VL (144)	VL (144)	L (120)	M (72)	M (72)	H (48)	H (48)	H (48)	H (48)
	P2	L	VL (144)	VL (144)	L (120)	L (120)	M (72)	M (72)	M (72)	M (72)	M (72)
	P1	VL	VL (144)	VL (144)	VL (144)	L (120)	L (120)	L (120)	M (96)	M (96)	M (96)
RIS - RBI	Sikkerhet		1 0	2 1-5	3 6-10	4 11-20	5 21-40	6 41-60	7 61-79	8 80-100	9 >100
			VL COF	L COF		M COF			H COF		VH COF
	Økonomi						NA		RS		
	Miljø		M4	M3	M2	M1					
			Consequence of Failure (COF)								

Figure 2-6 Risk matrix used for consequence classification and for decisions (Helgesen and Birkeland, 2009)

2.7 Summary of Risk Based Inspection Methodology:

Risk based inspection is a systematic, structured and participative approach for developing inspection plans using risk management techniques that identify the likelihood of failure by a certain degradation mechanism and the consequences of such failure from the human, environmental, and commercial viewpoints (Santos and Hajri, 2000). In this chapter the main issues about RBI is described which are the basis of this study. RBI is a methodology to improve the management of risk through closely focussing on the critical areas of the plant, and reducing efforts on the non-critical areas. In order to this aim in next chapter the function and criticality of the subsystems on Statfjord B are discussed.

3 Inspection strategy for subsystems on Statfjord B

The purpose of this chapter is to describe the construction strategy for condition monitoring of static process, structures, subsea installations and equipment on the Statfjord B field. Statfjord B started production 3 years after Statfjord A, in 1982. The Statfjord B platform supplies Kårstø with oil and gas. The concrete structure is 175m high, has 4 shafts and 24 cells and providing facilities for drilling, production, oil storage and accommodation. The topside production capacity is 250 000 bopd and 6 500 million m3/d gas (www.akerSolutions.com) . The inspection strategy will provide guidelines on how state control activity is desired cared for and contribute to safe operation and the desired regularity of the system throughout the facility life. This will partly be achieved by the use of risk assessments and condition and performance monitoring of specific barriers.

In sections 3-3 and 3-4 are described detailed strategies for pipes, valves and tanks / containers. For structures, subsea installations and equipment, this document only references to established Framework and the annual program. The strategies will form the basis for the preparation of long-term plans, annual plans and detailed inspection program.

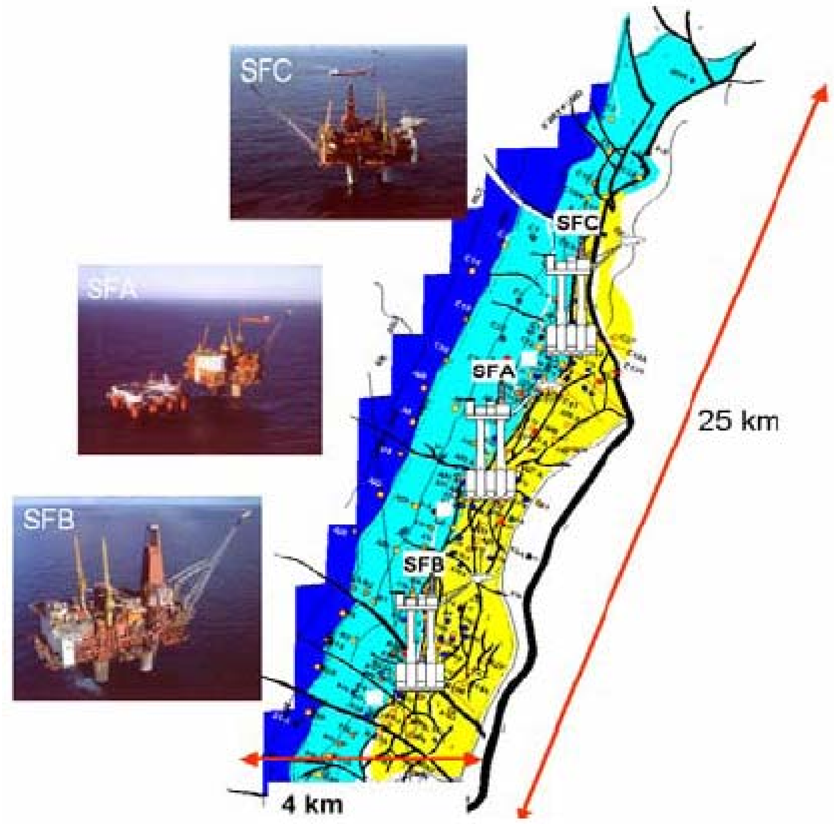


Figure 3-1: Statfjord A and B, C(Technology, 2009)

The basis for the choice of strategy is based on:

- Statutory Requirements
- Statoil governing requirements
- Operating Conditions
- Inspection history and experience
- Quality of material and corrosion protection
- Incidents
- RBI analysis
- DFI-resume
- Academic assessment of technical condition
- Experience from other operating units
- Condition of insulation, cladding and surface protection

Maintenance will be as far as possible be condition based, i.e., predicting the appropriate time for maintenance by means of state control and state analysis to avoid unintended fatalities, unnecessary maintenance and downtime for the plant. For condition monitoring of piping, valves, containers / tanks, structures, pipelines and subsea installations be established discovery management process followed to ensure the integrity of the equipment. Construction strategy and long-term plan will be reviewed annually for revision.

3.1 Requirements to work process

3.1.1 Strategy

Selected strategy for condition monitoring identifies and prioritizes of components in the planning of state control based on extensive use of risk assessments. Risk assessments should include operational experience results from the inspection and monitoring, analysis, modification and any change in operating parameters govern the determination of inspection intervals and scope. It should also be clearly stated in the program established degradation mechanisms governing the activity, so the failure modes that are under development or has occurred are identified and corrected.

Control loop for condition monitoring is a key element for the choice of strategy and illustrates the relationship between various sub-activities additions. Activities that are included here are the development of inspection programs and plans, construction inspection, reporting and evaluation of results. (Helgesen and Birkeland, 2009)

3.1.2 Long-term plans, annual plans and detailed program

Based on the strategy for condition monitoring long-term plan is developed for each installation. Long-term plan is the strategic basis for the preparation of annual plans and detailed program. Long-term plan describes the pipes, containers and tanks that will be subject to state control the individual years. Long-term plan are reviewed for update annually.

Year of condition monitoring equipment are determined for each group (pipes) and container, where the number of inspections determined by the experiences they have from previous inspections. The annual plans and detailed program will include results from man-RBI analysis, inspection history, monitoring data, the expected degradation rate, time from the previous inspection and any changes in process parameters applied. For each program that are established shall be prepared a brief summary of the priorities that form the basis for the program. Regardless of the analysis will be established annual program for area-based general visual inspection (GVI) where the structure and all the static process, regardless of the system and product code, shall be inspected externally with regard to map of general condition.

Program Establishment and its execution shall safeguard the initiation, execution, reporting, evaluation and follow-up of the condition of the equipment development. Detailed programs will be categorized in programs for:

- not stop depending on inspection
- stop depending on inspection (Helgesen and Birkeland, 2009)

3.1.3 Retail Program for state control that requires closure

An inspection program shall be prepared dependent on closure of production critical equipment. The implementation of turnaround every two years, but the program is also relevant for other planned shutdowns. The program possible extension can be coordinated with other activities such as suspension modifications, other FV programs and execution of corrective maintenance. In some cases, state control activities defined in the application the premises for the duration of shutdown. In such cases, the need for state control activities specifically documented with respect to risk or cost/benefit- assessments.

3.1.4 Reporting, treatment of the findings and evaluation of state

All inspection results should be reported in the Company's respective computer system, respectively, for the RIS process piping and pressure vessels and subsea installations. Any repairs and replacements must also be registered in the same systems. Inspection results from the inspection of valves should be reported to the drawing / sketch and this should be entered in the RIS. Reporting of inspection history should be according to the fixed level of detail to allow for good analysis for the optimization of inspection programs. All thickness measurements / corrosion findings reported with measured values.

The degree of detail of the report should be sufficient to carry out the necessary evaluation and any additional analysis. Report is completed by drawings, photos, video, sketches and documentation to be used as substrates in further evaluation.

For underwater systems and structures under water their own established management system used. All findings are listed here, are reviewed together with system/field manager, and actions defined and documented (Helgesen and Birkeland, 2009). Technical condition will be evaluated on an ongoing basis and described in established software tools. The evaluation will be a short text description of the technical condition of the system. It should here partly reflected the inspection results, the result was as expected, the damage mechanism expected, degradation rate, as well as to provide input to any recommended priorities for the coming inspection program and update of plant strategy.

3.2 Inspection Types

3.2.1 General Visual Inspection (GVI)

The inspection is intended to provide a general picture of the condition of the inspection object. GVI is usually performed as area-based inspection, i.e. all static equipment in a specific area inspected, but GVI can also be specified for individual equipment and components. In connection with entry and visual inspection of containers, all interior equipment inspected. When performing a visual inspection checklists used established in the RIS.

3.2.2 Near visual inspection (NVE)

Near visual inspection (NVE) aims to provide a more accurate picture of the condition of inspection object. The distance to the inspection object is relatively small (approximately 0.5 m) and inspection object should be sufficiently clean.

3.2.3 Non-destructive Inspection (NDT)

Non-destructive Inspection (NDT) is defined as where an inspection using the technical equipment is in able to detect and to some extent size chart different types of degradation, which is not without further can be mapped visually. Examples of such devices may include ultrasound, radiography, eddy current, magnetic particle, penetrating fluid, vibration measurement equipment, etc. Choice of inspection method should be based on the method's probability of detection of the expected degradation mechanism.

It is recommended to use an inspection method with a PoD value of at least 0.5. Interfaces, what is covered by the construction strategy product codes and the containers / tanks that are discussed in sections 3-3 and 3-4 are part of the strategy.

The strategy initially covers the piping and pressure vessels, including mechanical connectors, support ring, valves, manifolds, equipment packages possibly untagged pipes in packs, exhaust ducts, flexible hoses, cyclones, plate exchangers, day tanks, hull and deck tanks, pulse suppressors, accumulator bottles, unless otherwise specified (Out et al., 1995).

3.2.4 Surface coating and insulation

Surface condition monitoring and maintenance is based on the Company's Structured Surface Long-Term Care concept (SOLV), where Task Manager surface maintenance - Statfjord, is responsible for performing a condition survey as required. Task Manager surface maintenance is responsible for monitoring the insulation condition and maintenance of insulation, including pipe penetrations and passive fire protection.

It is noted that the execution of site based general visual inspection shall be reported injuries insulation that may indicate water penetration and subsequent likelihood of corrosion under isolation. Completion of area-based visual inspection is established as a summary report observation with respect to insulation condition. This will be reviewed with the Task manager surface maintenance. Follow-up of previously reported findings and observations are performed. For pipes and equipment with high risk sampling, check of state under insulation even if the enclosures seem complete, shall be carried out (Helgesen and Birkeland, 2009)

3.2.5 Monitoring

It will be carried out monitoring of important parameters that may be significant with respect to state and state control. Parameters to be monitored, but are not limited to, among other things:

- The results of erosion monitoring
- Sand Production / sand monitoring
- H_2S in the well flow
- Oxygen and chlorine content in water injection
- pH, chlorine quantity and amount of nitrite in cooling and heating medium

3.3 Condition monitoring of piping systems

The strategy for condition monitoring is determined based on the material / medium combination, is failure probability and consequence of a failure with respect to safety and production regularity. Condition monitoring of piping systems on Statfjord B are given in the RBI analysis, annual plan and detailed application. The plan is structured by equipment groups.

Equipment groups are defined for the main process and utility systems. The various equipment groups (sub-systems) are sorted into categories. Figure 3-1 shows definition of sub systems.

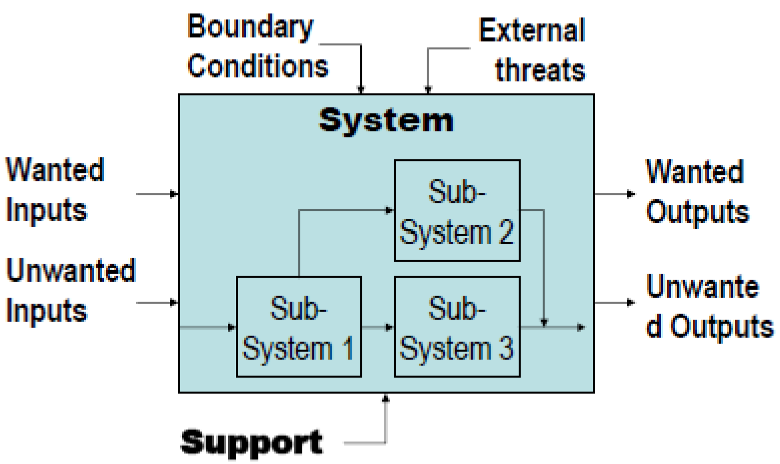


Figure 3-1: Subsystems (http://www.scribd.com/doc)

3.4 Sub systems (Equipment Groups)

The following categories are used:

- Flow lines - producers (oil / gas) & water / gas injector
- Production piping - two-phase, liquid, gas
- Ventilation to the flare / Depressurization
- Closed drainage
- Produced water
- Gas re-injection
- Gas lift
- Oil sludge
- Condensate
- Fuel gas
- Water Injection
- Jet water
- Ballast
- Seawater
- Fire Water
- Kill mud
- Glycol
- Heating medium
- Chemicals / Methanol
- Diesel
- Front draining from classified site
- Instrument air
- Hydraulic oil, lube and seal oil
- Other systems (Helgesen and Birkeland, 2009)

The RBI reports are including this information and Figure 3-2 shows the sample of RBI report on Statfjord B for one of the production flow line which is defined for different equipment groups:

- Description of equipment group
- Process Description for equipment group
- Corrosive content Injury Probability (POF)
- Comment damage mechanism
- Last main inspection performed
- Next estimated inspection
- The next scheduled major inspection
- The minimum calculated inspection interval (months)
- Number of primary inspections

RIS - RBI ***Rør/utstyrsgruppe status med RBI data*** **StatoilHydro** **STATFJORD B**

Utstyrsgruppe: **10-B01-WI** Strømningsrør til B01 - Vanninjektor

Starter: 57-WI-03 (MV10151)
Stopper: Wingventil ESV10103
Utstyr inkludert:

Har tag med:	Material	og	Prosessinnhold
	2205 ALLOY		WS
	CS		WS

Prosessparametre for utstyrsgruppe:

Trykk	263	barg	Temperatur - min.	10 °C
Temperatur - maks.	30	°C		

Kommentar til utstyrsgruppe:
Inneholder kun tag fra system 10.

Beskrivelse av utstyrsgruppe:

Prosessbeskrivelse for utstyrsgruppe:

Inspeksjoner på rørtag i utstyrsgruppe:

Antall hovedinspeksjoner:
Siste utførte hovedinspeksjon: Ikke inspisert
Neste planlagte hovedinspeksjon: Ikke planlagt
Minste beregnede inspeksjonsintervall (mnd): 6
Grunnlag for neste beregnede inspeksjon:
Neste beregnede inspeksjon:
Neste inspeksjon (valgt):

Vurdert skademekanisme:

No known internal corrosion mechanism **Materiale: 2205 ALLOY**

Korroderende innhold Skadeform: GSK Sannsynlighet (POF): Very Low

Kommentar til skademekanisme:
Det tilsettes biocid, oksygenfjerner og avleiringshemmer til sjøvannet. Deox. Sjøvann <5 ppb oksygen.

Sept-07 (Børvik): Det forventes ikke korrosjon for dette materialet i det aktuelle miljøet så framt oksygenfjerningen fungerer.

April-08 (Skauby): Brønn B01 er ikke lengre vanninjektor, men produsent. Må oppdateres i neste RBI-runde mhp sikkerhetsvurderinger og skademekanismer. Vi lar den stå som den er nå, da den uansett har samme inspeksjonsintervall for begge materialtyper som de andre produsent/brønngruppene.

Kommentar til levetid:

14. juli 2008 *Utstyrsgruppe: 10-B01-WI* *Page 1 of 511*

Figure 3-3: Sample of RBI report (AkerSolutions data base)

Sub-system	Material Quality	Degradation mechanisms	Inspection History	Strategy
Flow line oil producing **(P/PT)**	Carbon steel	CO_2 corrosion, MIC, H2S, erosion, corrosion and Atmospheric KUI.	Corrosion of flange	extended inspection of lines of separation trains at least 3 months before the shutdown
Flow lines gas producers **(P / PT)**	Mainly Duplex, but some prick in carbon steel	CO_2 corrosion, erosion, MIC, H2S and atmospheric corrosion.	Sand production	The carbon steel should be followed up with more frequent inspection schedule for inspection three times a year, The plans for random checks on selected erosion vulnerable points are followed up with NDT.
Water injection flow lines **(WI)**	Carbon steel, but newer pipelines are used duplex and 6Mo	Water injection: carbon steel - corrosion in water (inside), Stainless - Corrosion in water (inside), atmospheric corrosion	Corrosion in bends, welds pipes / and reduces the flanges	<u>Water injectors in carbon steel:</u> performed internal visual inspection of using NDT methods (thickness measurements. <u>Water injectors in the duplex:</u> NDT, especially focusing on drainage plugs
Flow lines gas injection **(FG)**	Carbon steel.	CO_2 corrosion and Atmospheric corrosion	Inspection Volume has been relatively low	Inspection carried out mainly by means of NDT methods, and concentrated on areas where there is danger of condensation due to failure of the gas drying system, pressure reduction, etc
Process hydrocarbon two-phase **(P / PT)**	Carbon steel	CO_2 corrosion, erosion, MIC, atmospheric corrosion, and KUI	Corrosion and erosion	Expanded inspection of lines of separation trains at least 3 months before the shutdown. Duplex systems inspected at random by some erosion in exposed areas inspected.
Process hydrocarbon liquid **(P / PL**	Carbon steel	CO_2 corrosion, erosion, MIC, KUI and atmospheric corrosion.	Corrosion problems are mainly located between main separator pipelines	high inspection volume especially for oil sludge and oil recycling system

Sub-system	Material Quality	Degradation mechanisms	Inspection History	Strategy
Process hydrocarbon gas **(P / PV)**	Carbon steel	CO_2 corrosion, KUI and atmospheric corrosion	Corrosion rate is low	Inspected annually by NDT.
Condensate (P / PL)	Carbon steel	CO_2 corrosion, KUI and atmospheric corrosion	Exterior surface corrosion and KUI are revealed on some pipelines.	Annual GVI and spot checks with emphasis on focus areas.
Gas re-injection **(GR)**	Carbon steel	CO_2 corrosion, KUI and atmospheric corrosion.	Inspections are carried out, has mainly been directed towards the drainage lines where there is a risk of condensation.	GR-lines will still be subject to annual inspection
Gas lift **(GL)**	Mainly is carbon steel and duplex	CO_2 corrosion, KUI and atmospheric corrosion.	This system has not been a part of the initial strategy in the past	
Ventilation to the flare **(VF)**	Mainly carbon steel, 316 is also used	CO_2 corrosion, erosion, MIC, KUI, atmospheric corrosion and pitting on the exterior 316	External corrosion	The current inspection volume terms to internal corrosion and erosion
Closed drainage **(CD)**	Carbon steel and GRE	CO_2 corrosion, MIC, atmospheric corrosion, KUI	High corrosion rates	Annual performance monitoring will continue to be implemented with a focus on hydrocarbon lines.

Sub-system	Material Quality	Degradation mechanisms	Inspection History	Strategy
Slurry Oil **(P / PL)**	Carbon steel	CO_2 corrosion, MIC, atmospheric corrosion, and KUI	Inspection history shows many discoveries that can be caused by MIC.	MIC should be performed yearly thickness measurements with the increased volume on the focus areas. Bacterial measurements recommended in the monitored system.
Water injection **(WI)**	Carbon steel	Carbon Steel - Corrosion in water (inside), CO_2 corrosion (PWRI), MIC and atmospheric corrosion	Visual inspection and sampling of NDT.	Condition monitoring is performed using the NDT methods
Water **(WF)**	Carbon steel, duplex, titanium, ELASTIC PIPE and GRE.	Carbon Steel - Corrosion in water (inside), Stainless - Corrosion in water (inside), KUI and atmospheric corrosion	Leaks in the system	As visual inspections an annual random sampling (NDT) of selected nozzles (<= 4).
Fuel Gas **(FG)**	Carbon steel, but also 316 and 321	CO_2 corrosion, KUI, atmospheric corrosion and pitting on the exterior 316	External corrosion	Because of previously reported external corrosion inspection system expands the scope.
Ballast **(WB, WL)**	Cement-coated carbon steel, as well as some GRE and high alloy material. Larger dimensions are inside segment coated.	Carbon Steel - Corrosion in water (inside), MIC, KUI and atmospheric corrosion	NDT inspection methods have been relatively limited	LTP and possibly in connection with video inspection turn around.

Sub-system	Material Quality	Degradation mechanisms	Inspection History	Strategy
Water Jet **(WJ)**	Carbon steel	Carbon Steel - Corrosion in water (inside), MIC, erosion and atmospheric corrosion.	Severe corrosion and high corrosion rates.	Annual state control is maintained. This is performed by NDT methods,
Seawater **(SW)**	Carbon steel, Cuni and GRE. Larger sizes in carbon steel are segment coated.	Carbon Steel - Corrosion in water (inside), Cuni - corrosion in water (inside), KUI and atmospheric corrosion.	Visually inspected internally and inspection through NDT	LTP and possibly video inspection in connection with turnarounds
Kill mud **(KM)**	Carbon steel	CO_2 corrosion, MIC, erosion, atmospheric corrosion.	severe corrosion findings	Follow-up inspection of previous discoveries and random control
Glycol / Rich glycol **(KG / KW)**	Carbon steel, but something Duplex	CO_2 Corrosion, KUI and atmospheric corrosion.	History is not complete	Corrosion rate is too low to initiate the inspection
Chemicals **(C)**	Carbon steel, 316, 321, 6Mo, duplex and titanium	Little or no internal degradation expected Atmospheric corrosion	History is not complete	Annual GVI with a focus on external conditions
Diesel **(OF)**	Carbon steel, 316 and 6Mo	Carbon Steel - Corrosion in water (inside), MIC, atmospheric corrosion, KUI and external pitting on 316	History is not complete	General visual inspection is performed annually with a special focus on lines that cross over hot surfaces.
Open drainage from the classified area **(OD)**	Carbon steel, but 316, Cuni and GRP	CO_2 corrosion of carbon steel - corrosion in water (inside), Cuni - corrosion in water (inside), MIC, KUI	History is not complete	Annual GVI with a focus on external conditions.

Sub-system	Material Quality	Degradation mechanisms	Inspection History	Strategy
Instrument Air **(IA)**	Carbon steel and 316	Carbon Steel - Corrosion in water (inside), atmospheric corrosion, KUI and external pitting on stainless.	History is not complete	Annual GVI and monitoring function to air-dry plant.
Hydraulic oil, lubricating oil and seal oil **(HO / OH / OL / OS)**	Carbon steel, 316, 304, 6Mo and Duplex	Corroding water, atmospheric corrosion KUI and outer pitting on 316	History is not complete	Annual GVI and monitoring water content in oils.

3.5 Difficulties of separating system into the equipment groups

It is often advantageous to group equipment within a process unit into systems, loops, or circuits, where common environmental operating conditions exist based on process chemistry, pressure and temperature, metallurgy, equipment design and operating history. By separating a process unit into systems, the equipment can be screened together saving time in compare of treating each piece of equipment separately. In case the risks of each piece of equipment in the system show a common sensitivity to changes in process conditions, then a screening can create one single category with common variables and ranges for the whole system (API, 2009, William, 1981). Although, group of systems is arranged in a specific fashion to produce a product or service, sometimes engineers are faced with some problems when following equipment groups which are separating a process unit.
In the Statfjord plant, the RBI analysis has been done by client. The Inspection Engineers believe the RBI analysis should be done by who knows exactly the process of the plant. Hence, this section is mentioned some difficulties which happened in the Statfjord plant by separating the equipment group.

- On Statfjord A, there are two different groups WB-002 and WB-003. The WB-002 is the ballast water system and WB-003 is the drainage system. The water flows to and from cell 51, which store the reclaimed oil, is controlled by the ballast water tank in the utility shaft that has inlet system from the sea. The line DC-3151 goes to the system and makes it possible to flash the line in ballast system but the problem is that this line should be in the drainage group, not ballast water group system (William, 1981). The leakage happened in this subsystem and because access to this line is difficult, the inspection engineers decided to change the material into duplex steel. The P&ID diagram of this equipment group is illustrated in the Figure 3-4 and the DC-3151 shows with red colour.

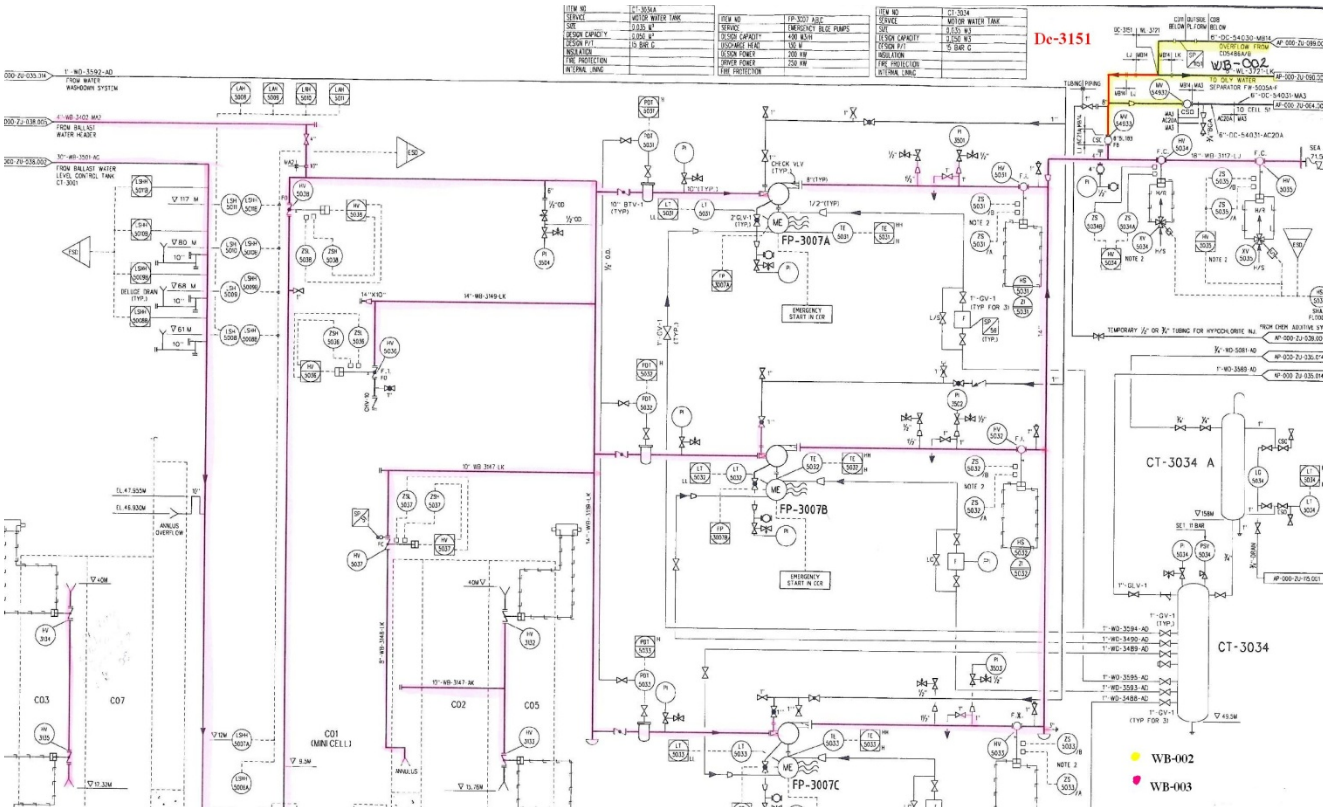


Figure 3-4: P&ID diagram of the equipment group (AkerSolutions data base)

- Another example is the equipment seawater group WS-004, which has the probability of consequences from 2 to 8 .When we look at different tag numbers in one equipment group; we expect that they have same condition. It could be reasonable that after and before of one valve, we have different probabilities of failure but diverge of consequences of failure is not uNDTrstandable. So, there is a question; is this equipment group selected correct or not?

- When two equipment groups are separated by the valves, the line between them are included in both equipment groups and the Inspection analysis for the line has been done twice. Sometimes, one equipment group is categorized by high risk and the other one is in low risk and usually the line is included in the high risk. In Figure 3-5, the valve F is analysed twice for both equipment groups on the left and right side.

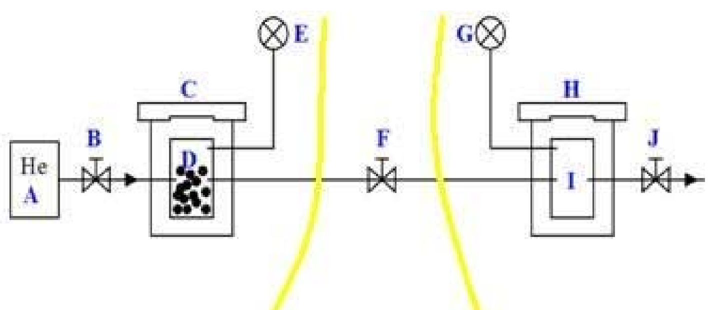


Figure 3-5: Separating to equipment group (http://people.bath.ac.uk/cestjm/equipment.html)

- There are tag numbers that occur in more than one equipment group and they have same condition but the tags inspection results should be analysed for all of them. As a result, several of the same analyses will be repeated and this leads to overall increase in the cost. For example, Figure 3-6 illustrates, the line 8-Gr-1001-MJ1 in the Statfjord B, has been analysed for 6th times

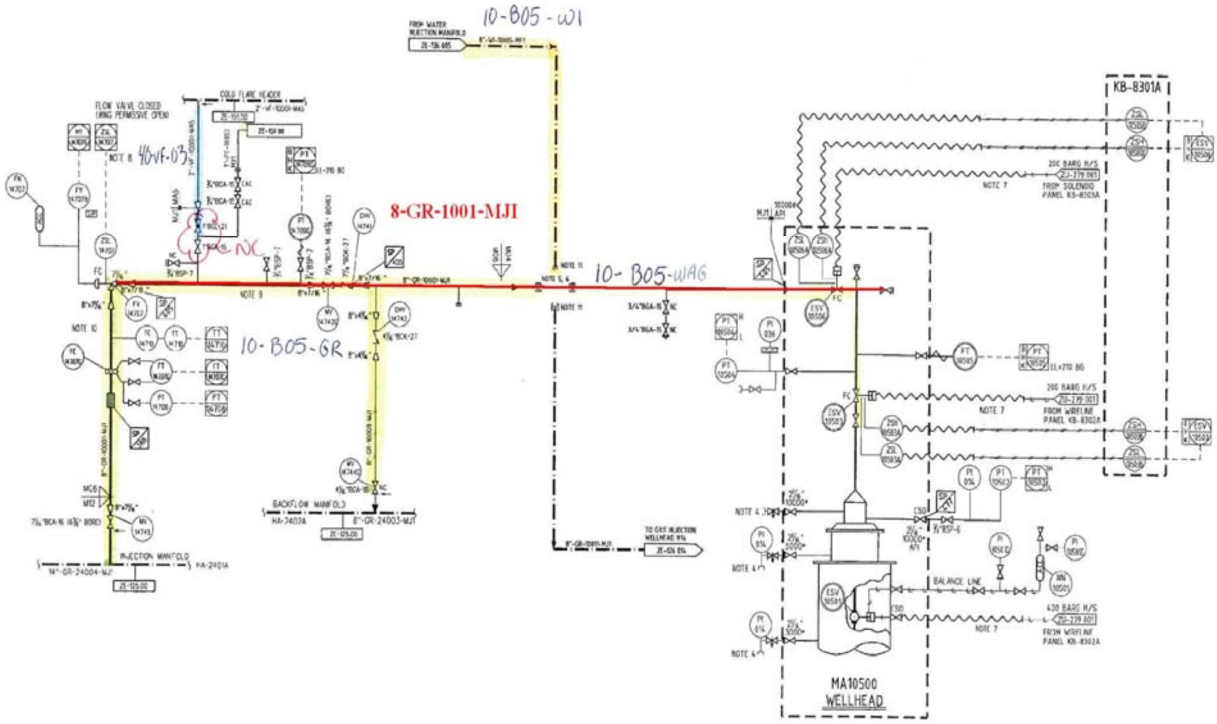


Figure 3-6: Line 8-Gr-1001-MJ1 group (AkerSolutions data base)

3.6 Risk matrix for different sub-systems

Figure 3-7 illustrates a risk decision matrix for different subsystems on Statfjord B. In the other words the risk classification of different sub system which are discussed above are summarized in this matrix. This matrix is created by using the RIS data which shows the level of POF and COF for each sub-system.

RBI MATRIX											
PROBABILITY OF FAILURE	P5	VH			EC WJ WS	PW	WJ PW WS	CD PW	CD VF PW	VF WP	PT PL CD VF WJ WP
	P4	H							PV EC	PV EC	PT PL PV
	P3	M		WJ			PW	PW	VF PW	PV PW	PT PV PW
	P2	L							PV CD	PL PV CD	PL PV
	P1	VL					PW	PW	PL EC GF HM VF PW	PL VF PW WS	PT PL WJ PW
RIS-RBI		SAFETY	1	2	3	4	5	6	7	8	9
			VL COF	L COF		M COF			H COF		VH COF
		ECONOMY					NA		RS		
		ENVIRONMENT	M4	M3	M2	M1					

Figure 3-7: Risk Matrix for the subsystems on Statfjord B group (Helgesen and Birkeland, 2009)

- Very high risk
- High risk
- Medium risk
- Low risk
- Very low risk

NA: Not applicable, RS: Shutdown

3.7 Summary of Inspection strategy for Subsystems:

This chapter mentions plan strategy of inspection and condition monitoring of different equipment group on Statfjord B. The inspection strategy will provide guidelines on how state control activity is desired cared for and contribute to safe operation and the desired regularity of the system throughout the facility life. This will partly be achieved by the use of risk assessments and condition and performance monitoring of specific barriers. The system divides to several sub systems and by using RBI reports, the most important issues such as material quality, degradation mechanisms and inspection history of each sub systems are covered in the Table. In addition, some of the problems which are caused because of dividing the system to different equipment groups are discoursed. Moreover, there is risk matrix for Statfjord B based on the different subsystems which show criticality of them.

4 Selecting critical Sub systems

In chapter 3, all of the subsystem is involved on Statfjord B is described. In this chapter, 3 main subsystems, production, flow line and closed drainage are discussed.

4.1 Flow line Subsystem (wells)

The purpose of the wellheads and manifolds is to control of oil flow from the reservoir until emergency shutdown valve (ESV) in front of the inlet and test separator. The purpose of the gas lift is to increase oil recovery. Gas export quality is headed down the production tubing to make the well flow is lighter and lifting production fluid.
Gas lift is installed on the installation due to pressure reduction in the reservoir. The subsystem includes well-controlled surface safety valve (SSV), Christmas trees, flowlines, valves and manifolds. Statfjord B platform has 42 slots in total. These slots are used to drill:

- Production wells
- Water injection
- Gas injection

Fluid flow taken from the reservoir is a complex mixture of oil and gas. In addition, it comes with some water and solid particles in fluid flow. Fluid flow under high pressure must be controlled and regulated carefully. This is done by using a series of valves placed in the well and wellhead equipment. The fluid flows from each well through the wellhead and the corresponding low pressure production manifold, then, flow on to the production process. The flow from each well can also be controlled to the test manifold and further to the test separator.

On top of production casing and the Christmas tree is located. Christmas tree consists of hydraulic and manual valves for operation during the operation and well maintenance. A throttle valve (choke) is placed on the flow tube between the Christmas tree and manifold. This has the task of regulating the flow of oil from the well. Each well is shut-off valve and check valve in front of the manifold.

4.1.1 System Connection:

Instrument air Hydraulic System Chemicals Reservoir Stream	Wellhead and manifold	Inlet separator CD2001 Flare Separator CD2002 Test separator CD-2014

4.1.2 Description of process

After the flow from each well has passed the check valve, the flow is controlled into its production, manifold or test low pressure manifold. This control is done using the motor operated valves. In production manifold HA2002A / B and HA2005A / B fluid flows from the production wells to the inlet separator CD2001. This is the first step in the main process. The well stream from wells with low pressure goes to the low pressure manifold HA2003/HA2004. Each test manifold HA2001A / B and HA2006A / B has a connection with each of the production wells in the line it is associated. When in use, it will only treat the flow from one well at a time. The flow from the test manifold is then further to the test separator CD2014 (Oma and Birkeland, 2009) (Figure 4-1).

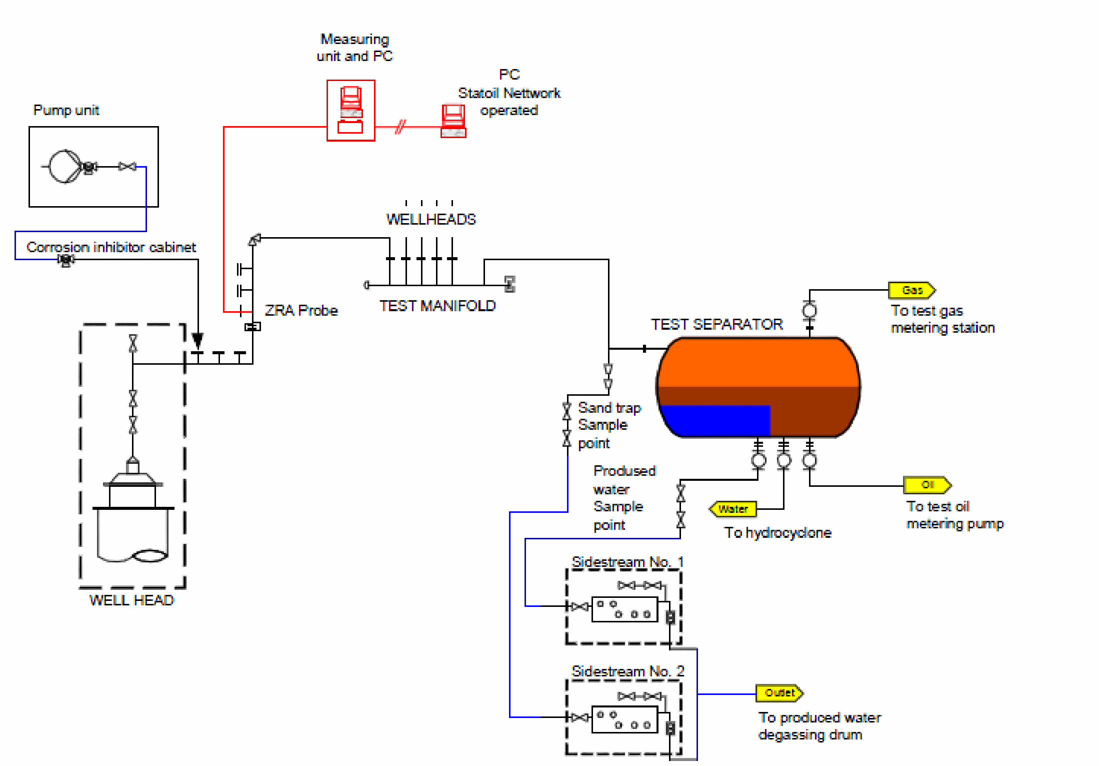


Figure 4-1: Flow diagram from wellhead to test separator (Knudsen et al., 2006)

4.1.3 Reasons for criticality of flow lines

Corrosion is seen as one of the biggest problems for the assets in the Oil and Gas industry. Most of the leakages in machines are caused by corrosion. Today companies are using high grade steels such as duplex in order to lower or avoid the corrosion. But in a lot of cases this high investment is not done from the beginning or the composition of the crude changes over time. So corrosion is an ongoing battle for the operators in the Oil and Gas. Risk assessment at Statfjord field has shown corrosion in most of the flow lines because the flow lines are made of carbon steel, Figure 4-2. Pipeline and flow line material is selected with respect to potential corrosion and scaling due to CO_2

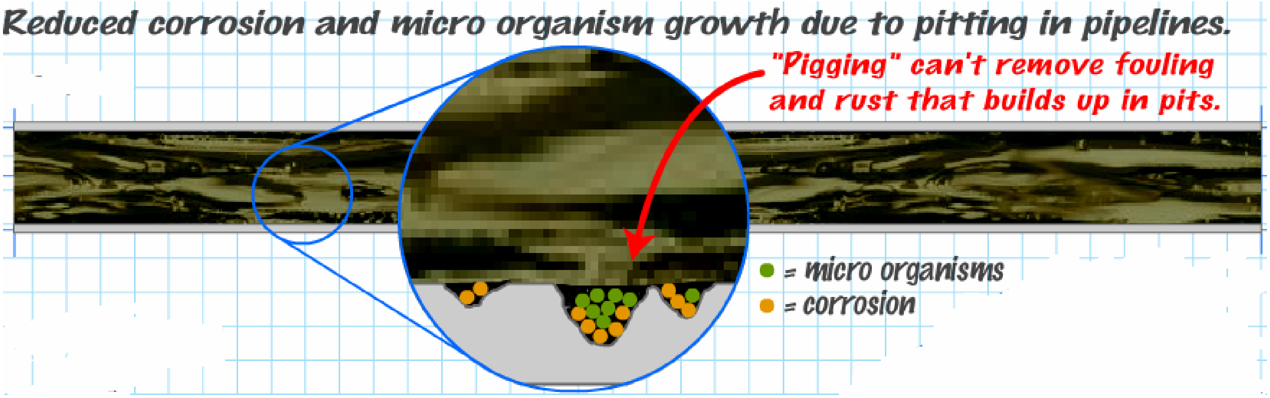


Figure 4-2: Co2 Corrosion in pipeline (Source: merusoilandgas.com)

and water production. The other important challenge in this subsystem is erosion. Production of sand creates disposal issues and several integrity challenges. Sand is erosive and may affect the functionality of valves and regularity equipment. To regulate the out pressure in the flow lines check valves are used and reducing the pressure leads to high speed and because of sand in the flow, erosion happens.

In summery the consequence of failure and probability of failure in most of flowlines are high, so the system is most exposed to degradation and the risk factor is high, as the flow lines contains mixture of oil and gas.

4.2 Production Subsystem

The fluid which comes from the reservoir is a complex mixture of hydrocarbons uNDTr high pressure. In addition, the mixture condition, some contaminants such as water, sand and other solids. At high reservoir pressure is most of these hydrocarbons are in liquid form. This will however, change as the reservoir fluid is transported from the reservoir up to surface, and then through the process equipment to the storage tanks. During this process, the pressure decreases and some of the hydrocarbons will change from liquid to gas.

The purpose of the crude oil separation process is to ensure

- Controlled separation of gas and oil
- The removal of water, sand and other contaminants

The process thus ensures that the crude is free of gas and water and remains in as stable condition so that it can be stored and transported. The crude oil separation process on the Statfjord B has a capacity of approx. 250 000 barrels of oil and associated gas per day. The water content after separation should be no higher than 0.3% by weight. Evaporation pressure shall not be higher than 10.5 and 11 psi (Oma and Birkeland, 2009)

Oil and gas are separated into four steps as below and this study includes the first and second separators.

- Step 1: inlet, CD2001
- Step 2: Separator No. 1, CD2002
- Step 3: Separator No. 2, CD2003
- Step 4: Separator No.3, CD2004

The term "inlet" is only used to explain that this is closest to the well. This reservoir fluid passes through different stages. At each step, pressure is lowered (from 68 bars at Step 1 to 1.6 bars at step 4). This means that we have separation, first by the light hydrocarbons and later of the heavier. The separated gas is transported on to the gas process. The inlet and separators No. 1 and 2 are three-phase separators. They separate the oil, gas and water. Separator 3 is a two-phase separator, i.e., it separates the oil and gas. The water contained in the reservoir liquid is mostly removed in the inlet separator, and water accompanies the out gas removed in the gas process. Water that is still present in oil after separator No. 3 will normally be in the emulsion. This emulsion is then removed in separator 4. The separator is the almost water-free oil sent through a pre filter and through oil coolers and Crude oil filters to storage tanks in the bottom cells. Coolers reduce the crude oil temperature from 70 º C to 35 º C. This ensures that all readily volatile liquid condenses and makes crude oil so that it can be stored and transported safely. Cooling also helps prevent the buildup of tension in the storage tanks' concrete walls. Crude oil filters remove the last remnants of the solids that had existed in crude oil (Oma and Birkeland, 2009).

4.2.1 System Connection

The sketch below shows the connection between the components of the crude oil separation system.

Electric power **Hydraulic System** **Jet water/ Seawater** System Chemicals Crude oil from the wellhead Fuel gas Ballast System	→	Crude oil -separation	→	**Fuel gas system** **Gas** Re-compressive system System for produced water Crude oil storage tanks PCDA (Process control & data acquisition)

4.2.2 Description of process equipment

4.2.2.1 The inlet separator

The reservoir fluid flows through a container to reduce fluid flow rate and pressure to a level that enables to separate. The gas must be able to be separated from the liquid, and the oil and water must be given time to the separation because of difference in weight. This is called the setting time season. All Separators with different components are designed to regulate and increase the process efficiency. In order to this, it is possible to use small separators with minimal setting time. Separator area is a horizontal, rectangular tank with an available volume of 96 m^3. This gives a setting time of about 5 minutes at a production of 240 000 barrels of fluid per day. Separator operates at a pressure of 59 bars (preferably reduced to 29 bars during LP operation) and a temperature of 82 º C.

The reservoir fluid enters the separator through a cyclone unit. When the reservoir liquid enters into the separator the pressure and gas is released. The cyclone device consists of 8 cyclones and because of its design it is easier to release the gas. After passing the cyclone unit, gas and vapor in the upper part of the separator area is collected, while oil, water and solids are collected in the lower section. Overflow plates ensure that the water and the solids are separated from the oil by letting the oil pass over the plates to the end. Turbulence dampers are fitted at the gas and oil outlet. These dampers care to prevent turbulence and streamline the flow at the respective outlets. The turbulence dampeners consist of a section of fine mesh. Sand and other solids accumulate distinguish between the plates and must be removed periodically (Smith et al., 2002, Helgesen and Birkeland, 2009, Oma and Birkeland, 2009).

For effective separation of the fluid there is an oil level divider between the oil and the water. In addition, the gas temperature is monitored and flow data for water and gas are measured in order to create a complete production report. Below a brief explanation of regulations, measurements and alarm functions associated with the inlet separator. The Chemicals are added to increase the separation in the inlet separator. One uses defoamer ("Antifoam") to prevent foam build-up in the separator and emulsion breaker and also separation of oil and water is better (by dividing) Figure 4-3 illustrates the different outlets.

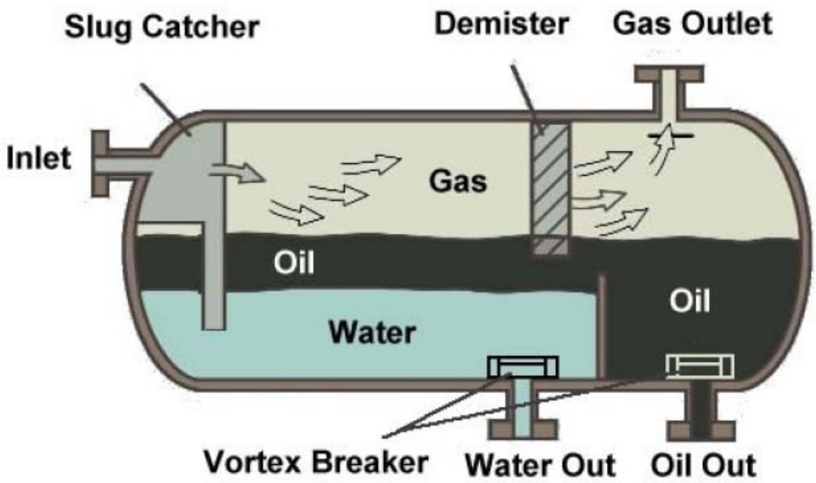


Figure 4-3 Separator

The pressure in the separator is monitored primarily by the pressure control loop that regulates the pressure valve. This is located in the outlet for the gas, so the pressure remains at 59 bars. In addition, the separator is protected by PSV (pressure safety valve) and EHV (Emergency hand valves) (Fauske, 2009).

4.2.2.2Separator No. 1, CD2002

Separator No. 1 is almost equal to the inlet separator. It is a three-phase separator which separates oil, gas and water. The second stage separator is quite similar to the first stage HP separator. In addition to output from the first stage, it will also receive production from wells connected to the Low Pressure manifold.

Separator No. 1 pick up the

- crude oil from the inlet separator CD2001
- condensate main knock-out drum in fuel gas system, CD6001
- crude oil from the test separator CD2014
- crude oil from the low pressure manifolds
- water / oil mixture from the hydro-cyclones for inlet

Figure 4-4 illustrates the modification in the separator to handle increased volumes of water from the low pressure manifold.

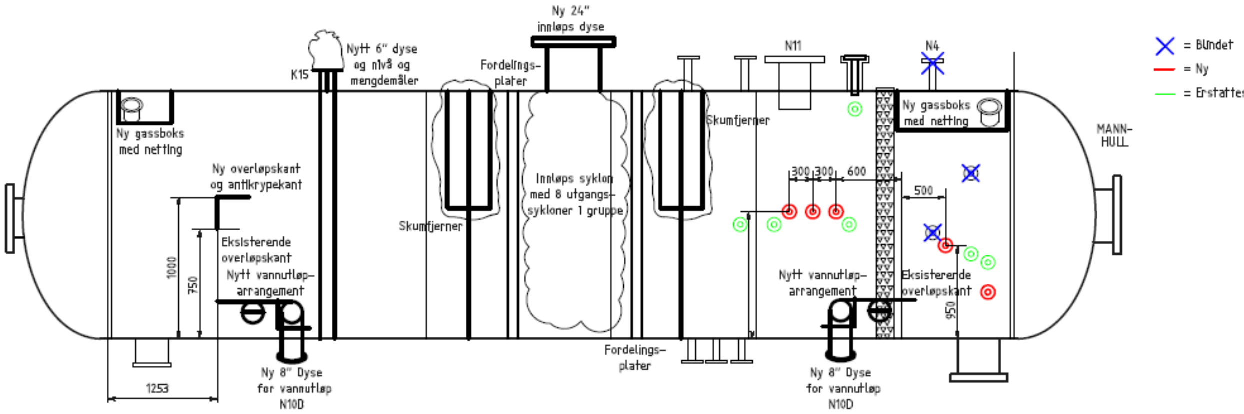


Figure 4-4 Modifications in the CD2002 (Oma and Birkeland, 2009)

Instrumentation and controls separator No. 1 which monitors and regulates the pressure, water and oil level and gas flow are similar to that used on the inlet separator. In addition, Tracerco profiles are installed as level and volume measures to improve reading. Profile performs direct density measurements in the process medium is present between a gamma-ray source and a detector wand in the tank, Figure 4-5.

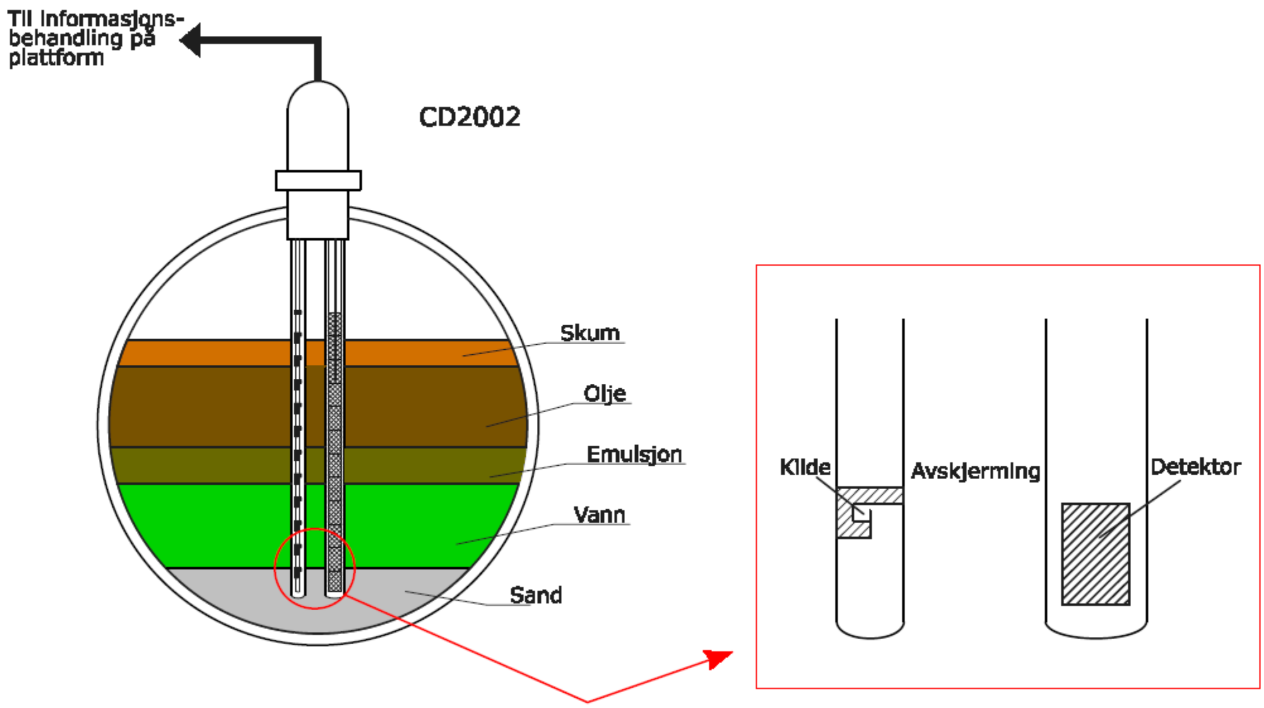


Figure 4-5: Tracerco profiles (Schröder and Kauer, 2004, Choi and Bomba, 2003)

The device can measure the level of gas, foam, oil, emulsion, water and sand. Changes in process density measured directly. There is no need for temperature compensation. The radioactive source is low energy Am241 (Americium). The detectors are Geiger-Muller detectors. Sensor strips can be pulled back during operations. In addition, the separator is protected by PSV and EHV according the API.

4.2.3 Reasons for criticality of production lines

Some of the reasons which make this subsystem more critical in comparison with the other ones are as fallow:

1. The most important process lines are in this subsystem because the untreated product goes through these two vessels for the first time and there are a lot of process activities.
2. The piping system on the Statfjord B is made carbon steel and duplex where as the proportion of corrosion-resistant materials are increasing. The lines are also un-isolated. So, use of carbon steel leads to additional degradation mechanisms.
3. The system is exposed between a high-pressure and low pressure production system and subsequently the volume increases.
4. There is high range of consequences in case of failure in this equipment group
5. Because of high temperature there is danger of solid particle in the well flow.

5 Inspection analysis

5.1 Inspection Data

Carrying out physical inspection is the basis for the Inspection Program development. Inspection results are a part of the data to verify the technical condition of the equipment. The inspection Program is established for each loop corrosion / product code / system on each platform. A specific inspection program would appear from the approved annual plans for each platform. Statfjord produces from two main reservoirs, Statfjord and Brent. In the beginning of the project, the reservoir pressure ranged from 300 to 330 bars but this would be reduced down to 80-90 bars. The Statfjord field reservoirs are poorly to extremely compacted and some sand production has been observed during the production history (Høvring et al., 2009).

An inspection program consists of two parts:

i. The inspection program is recorded in the RIS (inspection database) for the platforms.
ii. An inspection Program in hard copy for use offshore in the performance of the inspections.

Data concerning the inspection method and calibration should be recorded in the report, together with inspector and qualification level. Findings for each equipment items should be entered into the inspection management database. These data includes:

• Inspection data in RIS (SAP).
• Finding Reports.
• Status reports.
• Technical Reports on the state

Inspection data evaluation should include as a minimum:

— Assessment of inspection findings

— Estimation of existing minimum wall thickness

— Estimation of corrosion rate

— Remnant life calculations

— Maximum acceptable Working Pressure

— Establishment of retiring thickness

— Conclusions on integrity status

— Recommendations as to further action.

The overall evaluation of the integrity status as a result of the inspection activity should be carried out and the findings of inspection, including the evaluations, shall be confirmed. (www.akerSolutions.com)

5.2 Flow lines' inspection methods

Radiographic testing (RK), Radiographic contact method (RKT), Ultra sonic (UL) and visual inspection (VISN) are four types of inspection methods which are used on the Statfjord B. Figure

5-1 illustrates the percentage of each method in selected sub systems. Visual Inspection represents the highest percentage of inspection methods for the production flow lines on Statfjord B. The lines between 0-8 inches are inspected by the RKT method and for lines between 10-20 inches the UL method is usually utilized.

The visual inspection is taking into account the eye's limitations. Under good lighting, an eye without aids see a circle a diameter of about 0.25 mm and a line of approx. 0025 mm wide. The normal eye cannot focus on a subject that is closer than 150 - 250mm. The purpose of visual inspection is to determine the condition of systems, parts of systems, components, parts, joints or other parts of the installations (PEM, 2010). Figure 5-2 illustrates how many percentages of each production flow line (16 out of 42) are inspected with each of method during 1994 till 2011.

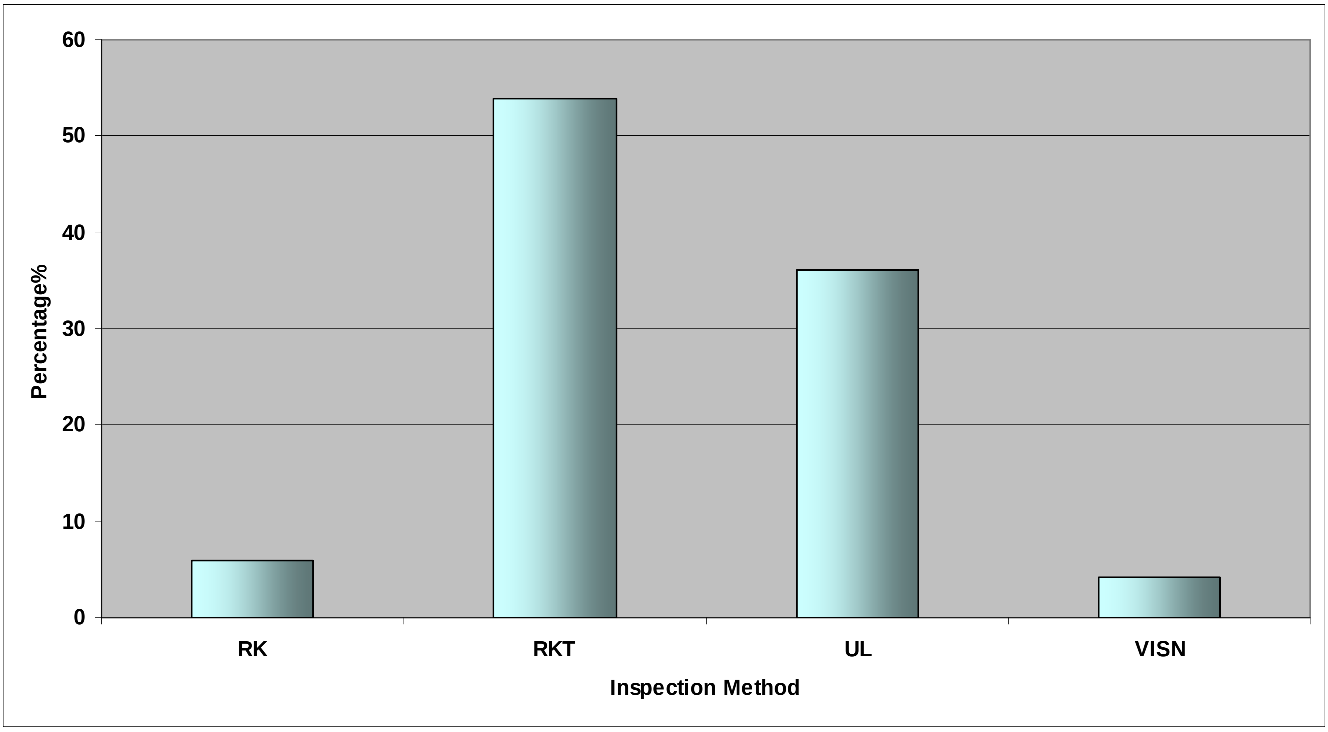


Figure 5-1: Indication of different types of inspection method during 1994-2011 on Statfjord B (AkerSolutions database)

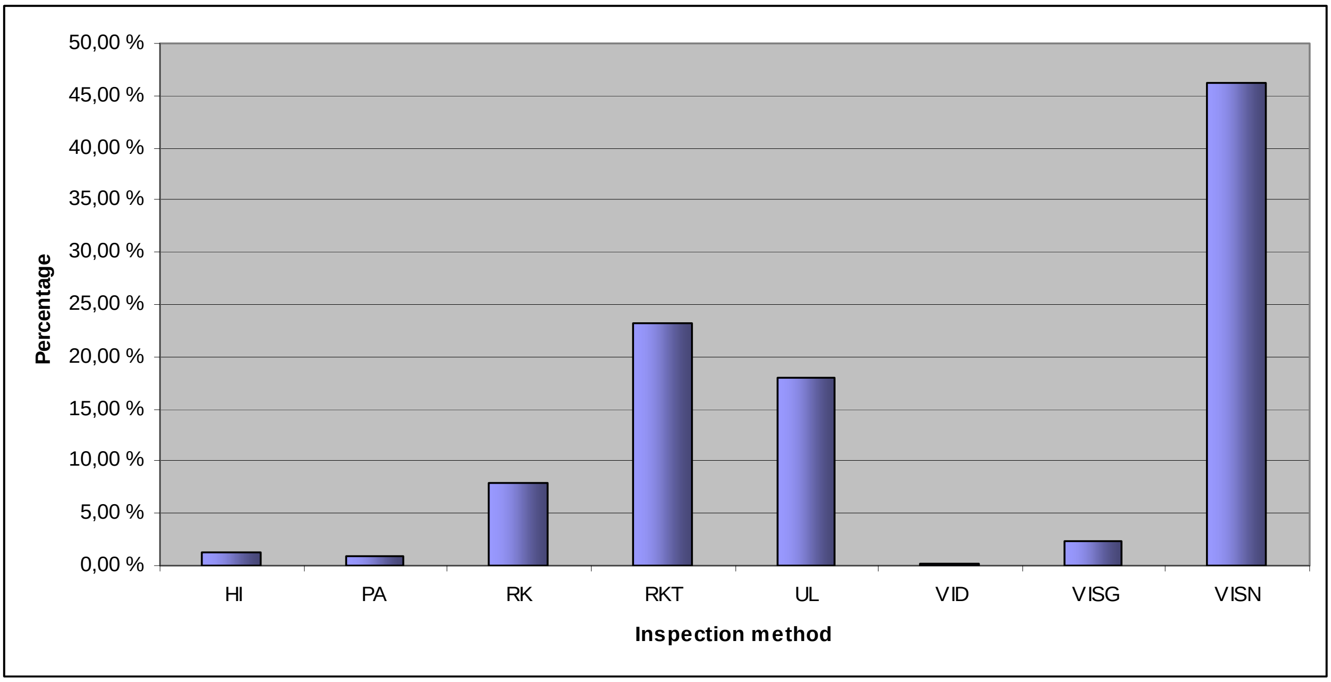


Figure 5-2: Indication of different types of inspection method during 1994-2011 in production flow lines (AkerSolutions database)

5.3 Flow lines' Monitoring

The results of monitoring carried out are used as the basis for the preparation of annual program / detailed program and / or other necessary corrective or compensatory measures safeguarding the technical condition. For example, the erosion rate is shown in Figure 5-3.

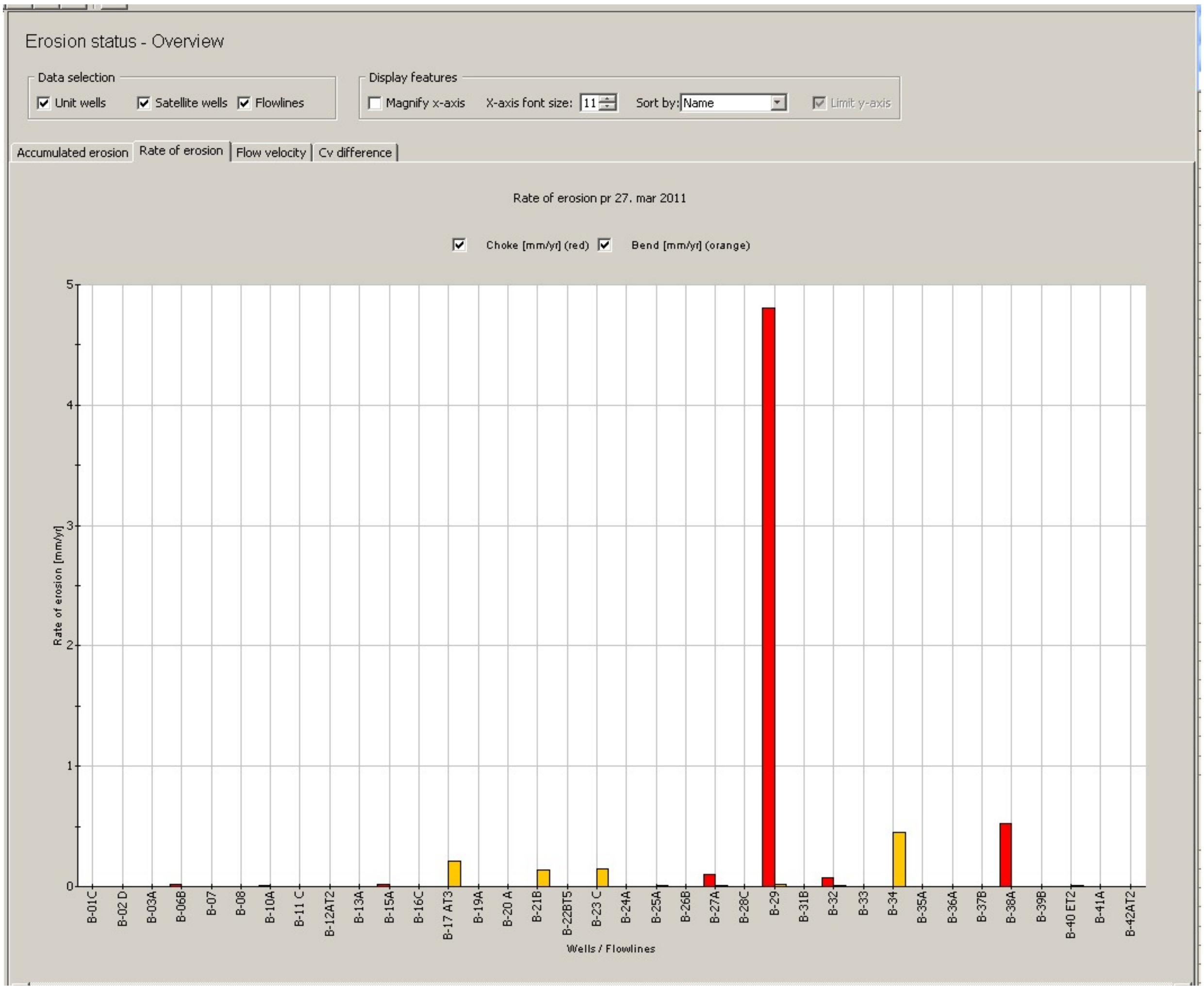


Figure 5-3: Erosion rate for different wells on Statfjord B (AkerSolutions database)

5.4 COF and POF of Flow lines

In order to analyse how critical a given functional failure is, it is necessary to carry out evaluation of probability and evaluation of consequences. Risk evaluation is based on the decision-making matrix illustrated in chapter 2.

The flow lines go through the manifolds M04 and M06. The probability of CO_2 corrosion and the consequence of failure are diverse from high to very high in most of the flow lines and this leads to risk level between medium to high. Sometimes, there is sand production in the wells and because of the high flow velocity the line and also some of the flanges are corroded, so they may change the material from CS to duplex. The velocity limit is 10 m/s and Figure 5-4 shows the velocity rate for different wells. The possibility of erosion is high in some flow lines because of the high sand rate. Figure 5-5 illustrates the sand rates in the B-29 wells during 12 months which has high erosion rate based on the Figure 5-2.

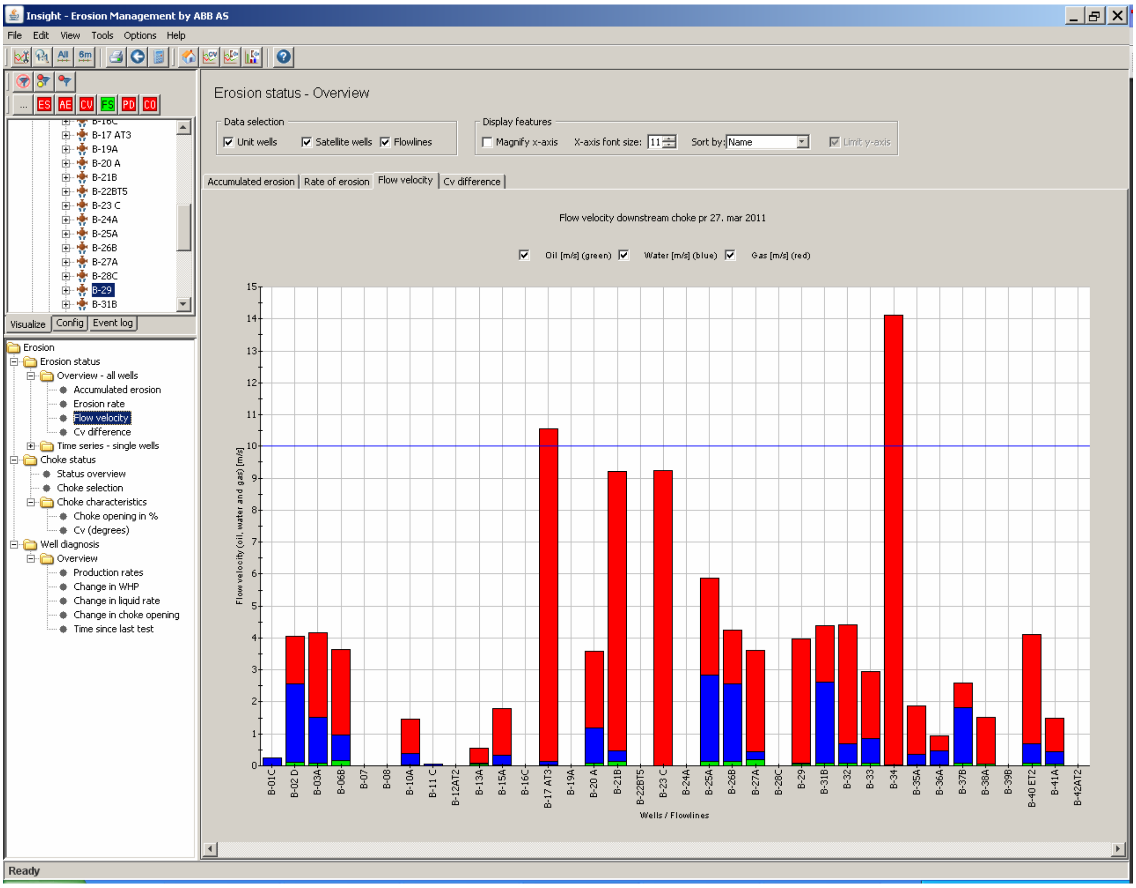


Figure 5-4: Flow velocity for different wells on Statfjord B (AkerSolutions database)

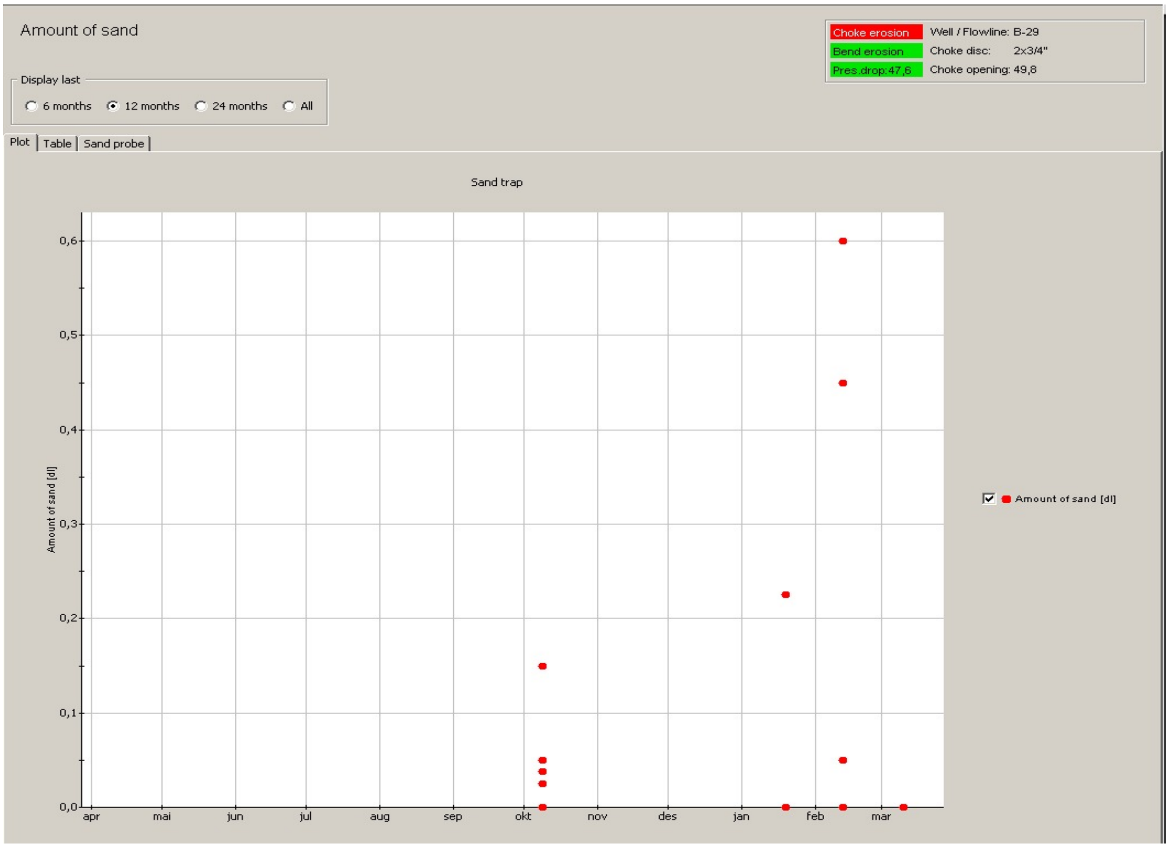


Figure 5-5: Sand rate for different well B-29 on Statfjord B (AkerSolutions database)

5.5 Production lines' inspection method

These two separators CD2002 and CD2003 separate the oil and gas and also water contained in the reservoir liquid is mostly removed in the inlet separator. These groups are illustrated in Table 5-1.

Table 5-1: Equipment groups of production lines

Process hydrocarbons Two-phase	**Process hydrocarbons Liquid**	**Process hydrocarbons Vapours**	**Produced Water**
20-PT-01	20-PL-01	20-PV-01	20-WP-02
20-PT-04	20-PL-02	20-PV-02	20-WP-03
	20-PL-03	20-PV-03	20-WP-05
	60-PL-01		20-WP-06

.

Figure 5-6 shows how many percentages of each line are inspected with each of method during

1994 till 2011. So, 20-PT-01 is inspected more than the others because it is two-phase line and comes from production header.

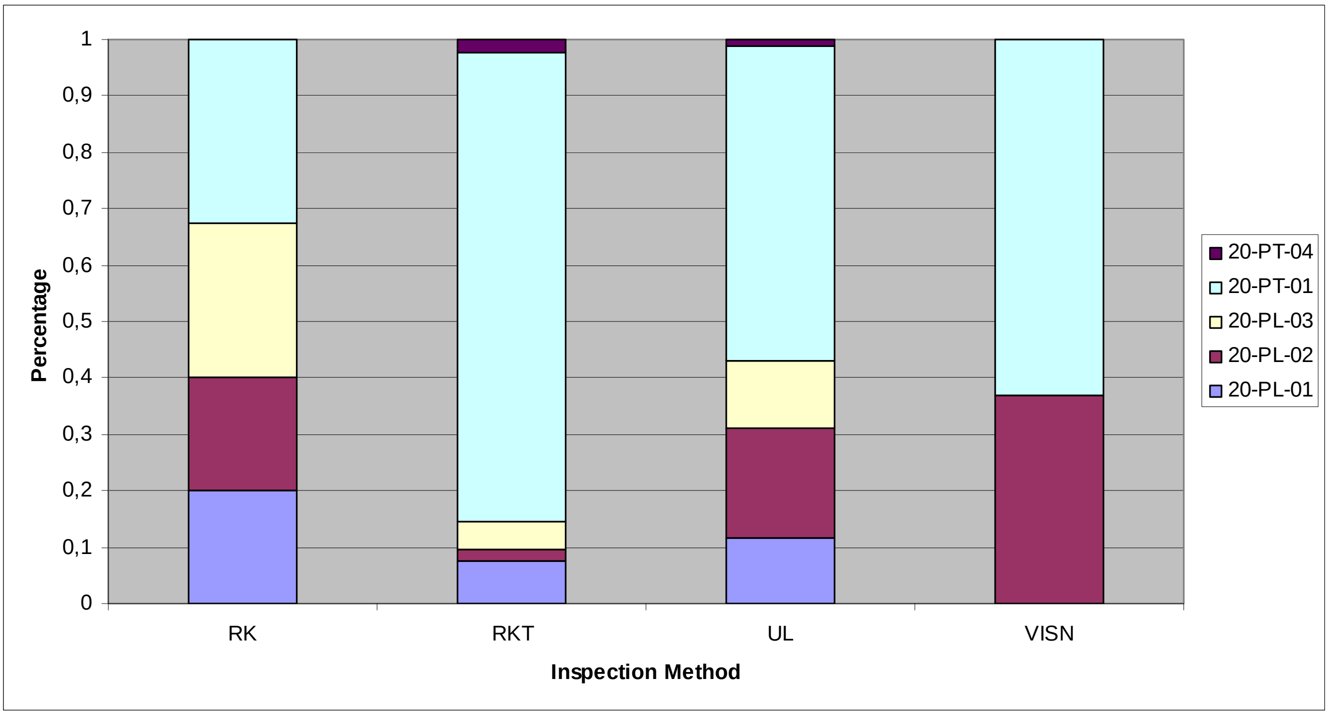


Figure 5-6: Percentage of group the equipments in the separation subsystem for each inspection method during 1994-2011 on Statfjord B

5.6 COF and POF of Production lines

In order to analyse how critical a given functional failure is, it is necessary to carry out evaluation of probability and evaluation of consequences. The risk evaluation is based on the decision-making matrix illustrated in chapter 2. This evaluation has been done by the RBI and the results for the 20-PL equipment groups are as below in Table 5-2:

Table 5-2: RBI data for 20-PL

Equipment group	Start	Stop	POF	COF	Risk Level
20-PL-01	CD-2001 (inlet separator)	CD2002 (crude flash drum no1)	Very low	Very high	Medium to High
20-PL-02	CD-2001 (inlet separator)	CD2002 (crude flash drum no1)	Very low	Very high	High
20-PL-03	CD2002 (crude flash drum no1)	CD2003 (crude flash drum no2)	Very high	Very high	High

Based on these information, we can conclude that this subsystem is critical because the high consequence of probability.

5.7 Material

Type of material is one of the main parameters that can avoid the degradation of a component can take place. Table 5-3 (DNV, 2010) shows the components of the different materials.

Table5-3: Definition of material (DNV, 2010)

Table A-1 Definition of materials		
Material Type	*Description*	*Includes*
CS	Carbon Steel	Carbon and carbon-manganese steels, low alloy steels with SMYS less than 420 MPa.
SS	Stainless Steel	Austenitic stainless steels types UNS S304xx, UNS S316xx, UNS S321xx or similar. 22Cr duplex UNS S31803 and 25Cr super-duplex UNS S32550, UNS S32750 stainless steels or similar. Super austenitic stainless steel type 6Mo, UNS S31254.
Ti	Titanium	Wrought titanium alloys.
CuNi	Copper Nickel Alloys	90/10 Cu-Ni or similar.
FRP	Fibre Reinforced Polymer	Fibre reinforced polymer materials with polyester or epoxy matrix and glass or carbon fibre reinforcement.
Ni	Nickel-based alloys	Nickel-based alloys.
Other	Material other than the above	All other materials not described above.

Most of the lines are carbon steel in this subsystem. But a portion of the stainless steel tubes have replaced the former carbon steel because of corrosion problems on many of these. One cannot exclude the possibility that the previously observed corrosion can have been caused by erosion, and could also be a problem in high risk areas for stainless steel tubes. Basically, says the strategy for sand control that the flow will be operated at speeds below 8 m / s and above there is danger of erosion problems. If at any time there have been recorded speeds above 8 m / s, one shall check whether there has been sand production in this period and the probability of erosion shall be reconsidered. In order to control any development in erosion problems, it is recommended that baseline measurements potential be carried out for erosion-prone areas. Degradation mechanism usually happened in two critical focus areas:

- Drainage points Figure 5-7 which have a corrosive environment and always liquid (oil, gas, water) is going down from the lines
- Low point which stop liquid from running away because of the gravity. This may result in dead points and lead to a corrosive environment and sometimes if those remain silent for long time macro bacterial corrosion happens.

Figure 5-7: Drainage points (AkerSolutions database)

5.8 Corrosion allowance

Selection of suitable piping materials to resist deterioration in service is required to provide a safe piping design. A corrosion/erosion allowance will need to be determined to provide the required wall thickness. The corrosion allowance shall be specified by ASME B31.3 (ASME, 2008, Choi and Bomba, 2003).

Points:

- Different pressure classes have different corrosion allowance for example for non-hazardous areas it's around 1.5 millimetres and for the pipes which come from wells, it is around 4.5

millimetres.

- Pressure has influence on the class specification of pipeline and higher pressure leads to more severity and increase the margins of corrosion allowance.

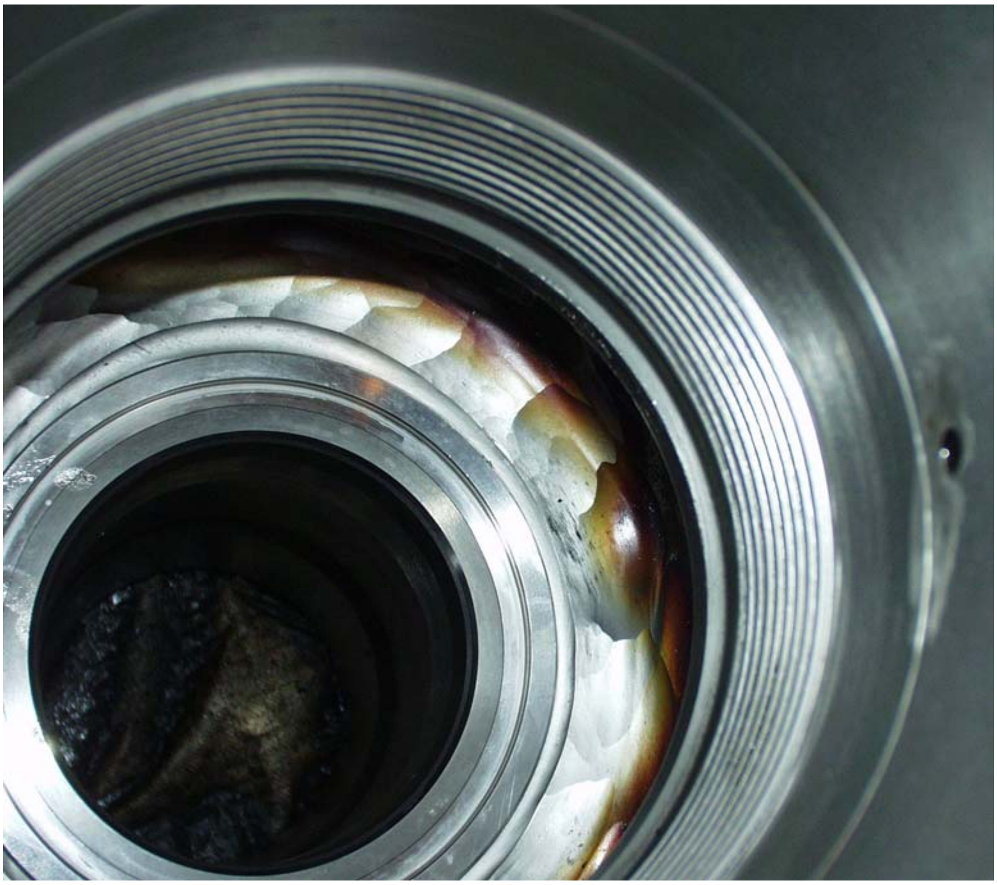


Figure 5-8 Erosion in chock valve (AkerSolutions database)

Figure 5-8 shows a duplex choke valve and the typical erosion is clear inside of the choke valve. Corrosion in carbon steel pipeline is shown in Figure 5-9.

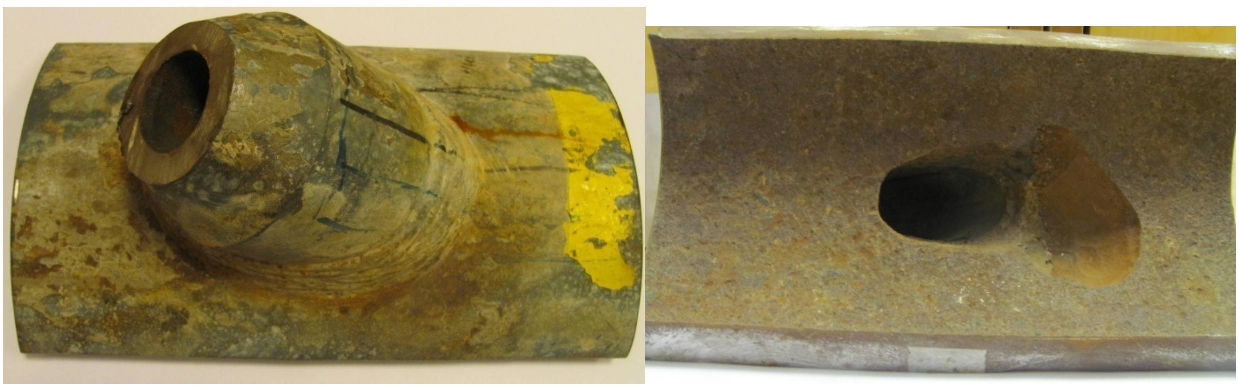


Figure 5-9: Corrosion in carbon steel pipeline (AkerSolutions database)

<u>An example:</u>

$T_{nominal}$: 7 mm
T_{min3}: 0.6 mm
T_{min2}: 3.4 mm
T_{min1}:4 mm
Corrosion allowance: 3 mm
In this case, when the thickness is between 7-4 millimetres the inspection planner is not worry but when corrosion increases, so, thickness between 4-3 millimetres the inspection should be began more often.

5.9 Wall thickness

In the "RIS" four levels of wall thickness of a pipe are defined:
$T_{nominal}$: Pipe wall thickness and dimension according to pipe classification/ specification
T_{min1}: Pipe wall thickness which equals to pipe classification minus pipe corrosion allowance
T_{min2}: Minimum wall thickness of pipes according to requirements of ASME B31.3, with pipe classification according to design pressure and temperature, plus additional corrosion.
T_{min3}: Minimum wall thickness of pipes according to requirements of ASME B31.3, with pipe classification design pressure and temperature (ASME, 2008, Markeset and Ratnayake, 2010).

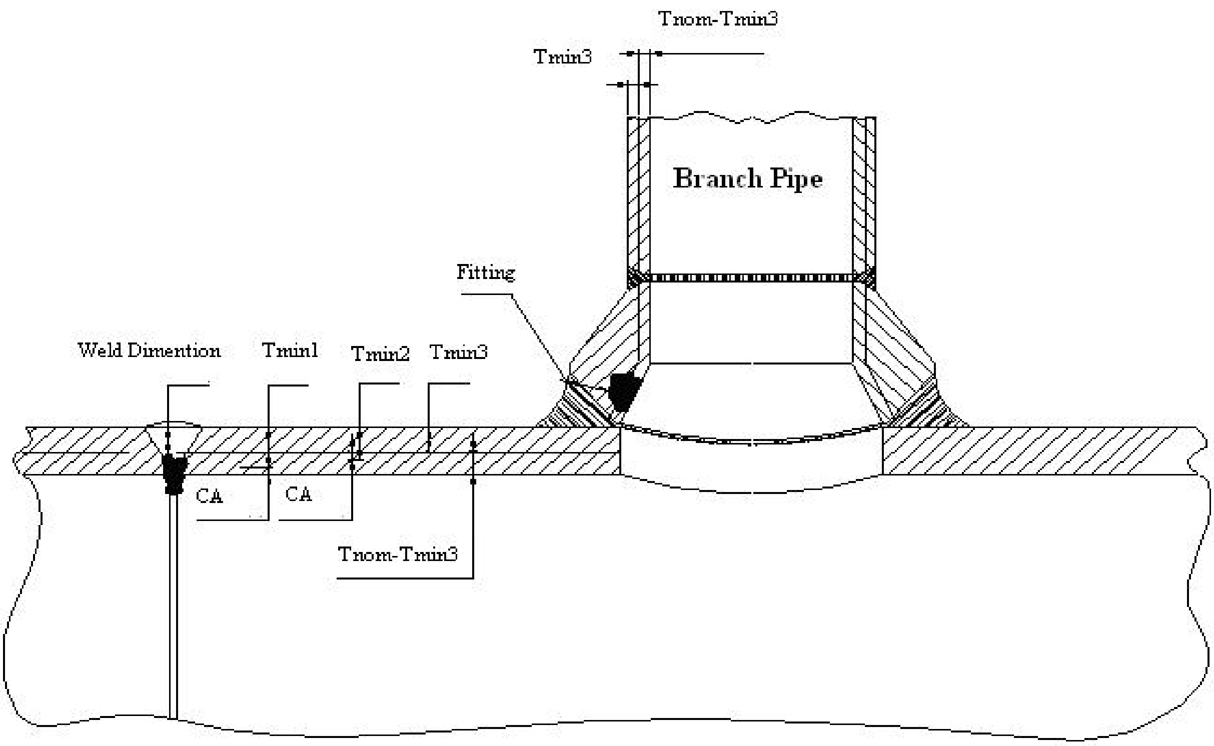


Figure 5-10 Wall thickness Criteria (AkerSolutions database)

Figure 5-10 illustrates different definition of wall thickness. Sometimes the T_{min2} is less than Tmin1 and it depends on the $T_{nominal}$ and corrosion allowance. For instance, $T_{nominal}$: 15, T_{min3}: 5, T_{min2}: 8, T_{min1}:12 and Corrosion allowance: 3. so, the T_{min2} is less than T_{min1}.

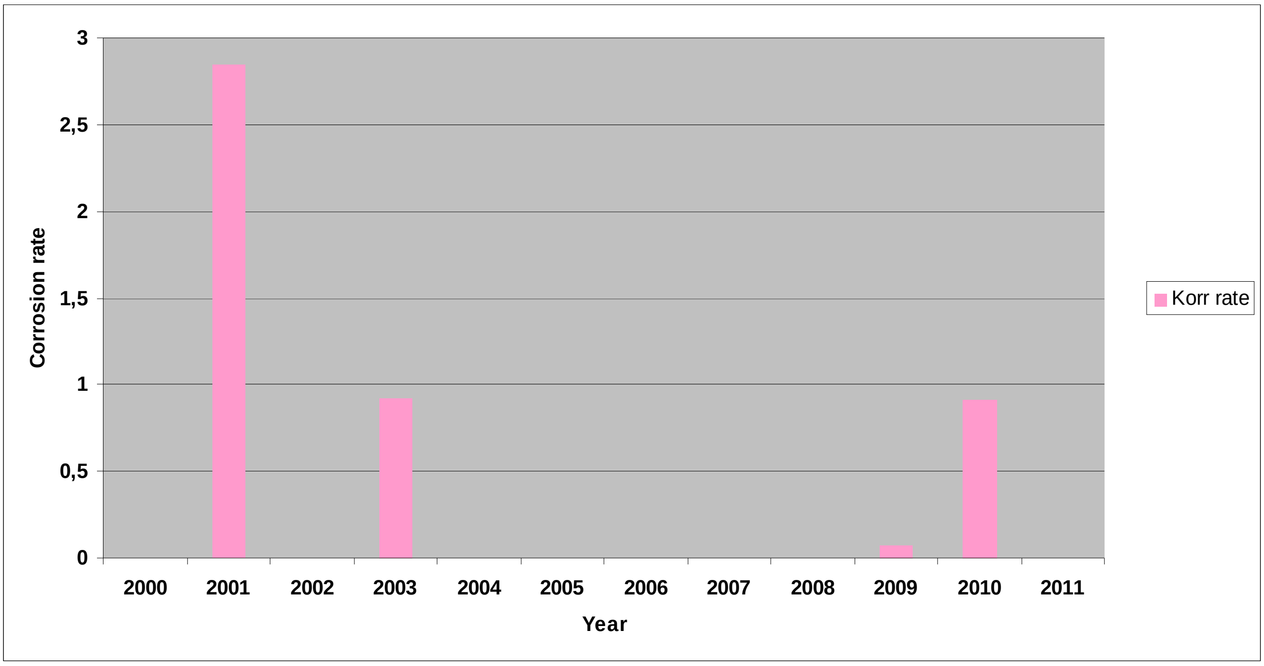


Figure 5-11: Corrosion rate for 20-PL-02

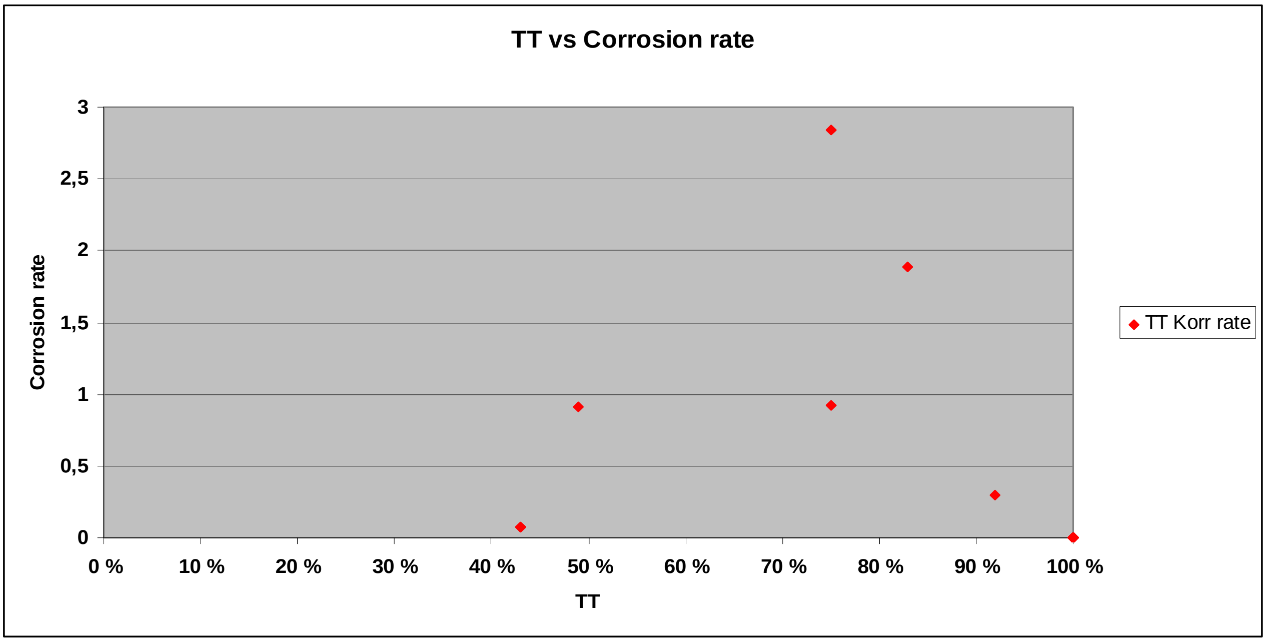


Figure 5-12: Technical thickness vs. Corrosion rate for 20-PL-02 from 2000-2011

Figure 5-11 shows Corrosion rate increase between 2009 and 2010. The reason is that in previous years they didn't use the RBI and the inspection coverage was less in the past but from

2009 the client start to use the RBI and the number of inspection have been increased, so they have a higher finding rate because they inspected more equipment groups in compare ion with previous years.

6 Most Important factors in Inspection Coverage

6.1 Finding Rate

Inspection findings can be reviewed to determine where future inspections should be focused. The overall evaluation of integrity status as a result of inspection activity should be carried out and the findings of inspection, including the evaluations shall be verified. Findings for each equipment item should be entered into the inspection management database (Markeset and Ratnayake, 2010). The finding rate is calculated based on the technical condition (TC).
Figure 6-1 shows that the technical condition is divided into five parts based on the thickness:

1. **=0%** (Because of corrosion, the minimum wall thickness of pipe remains, so, it is the critical condition for the pipeline.)
2. **0%<TC<40%**
3. **40%<TC<70%**
4. **70%<TC<100%**
5. **TC<100%.** (This is the best situation of the pipe.)

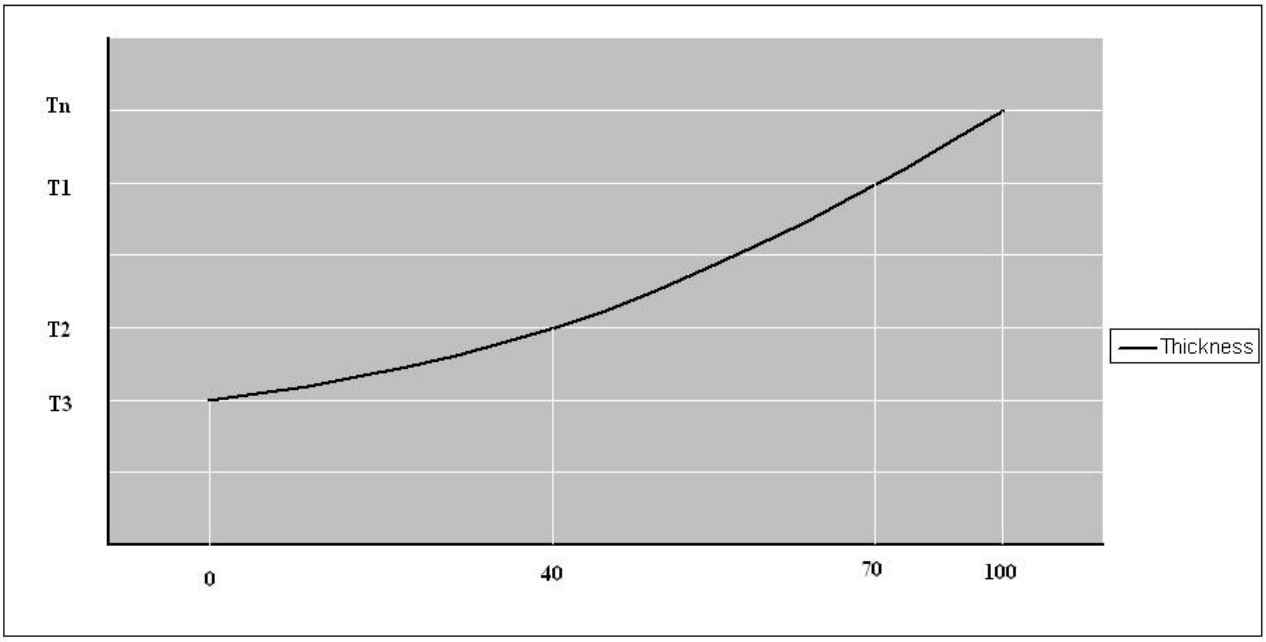


Figure 6-1: Technical condition of pipe based on the wall thickness

Based on data from 2000 to 2011, the number of inspection finding and also the number of inspection recommended are available, so the finding rate can be calculated by formula 6-1:

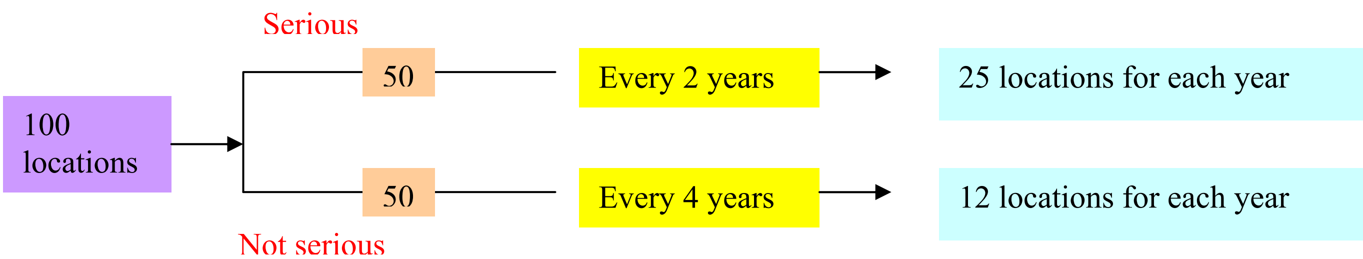
$$\text{Finding rate} = \frac{\text{Number of findings in} < 100\%}{\text{Number of inspections}} \tag{6-1}$$

Following criteria should be noted:

Corrosion pit depth exceeding 80% of the wall thickness ($T_{nominal}$): This criterion was developed to consider rupture of a part of corroded pipe. The section must be repaired or replaced if corrosion exceeds 80% of the wall thickness.
Corrosion pit depth less than 12.5% of the wall thickness ($T_{nominal}$): There is no limited to the length of corrosion when all of the measured pit depths are less than 12.5% of the wall thickness. Because the minimum wall thickness requirement for the same grade of API line pipe would be expected to determine (Choi and Bomba, 2003).

Experiences have shown that the optimal finding rate for planned inspection plan is between 20-25%. Inspection area is recognized based on the corrosion rate and the worst cases (highest speed in reducing TC) have highest priority. Sometimes the overall result of corrosion rate are same during several years but we cannot predict future, so some of the points which are not inspected should be included in the next plan because maybe they were corroded in future.

An example can briefly show the meaning of inspection volume and finding rate:
Total points for inspection are 100. The finding rate is 50%. So, these points should be inspected every 2 years based on the inspection plan and the remaining locations which are not critical now, should be inspected every 4 years. Based on this schedule, 37 locations should be inspected each year. To reduce the inspection volume, planned should be reduced, so in the next step, influence of the coverage rate on the finding rate will be discussed. The coverage rate shows the number of locations which are in the system.



6.2 Coverage rate

The Figures 6-5 and 6-6 show that the finding rate is between 15-20% for PT-20 and PL-20. So, the analysis will repeat again based on the coverage rate because it would more clearly by using the percentage. Formula 6-2 shows how we can find out the coverage rate:

$$\text{Coverage rate} = \frac{\text{Number of inspections}}{\text{Number of locations}} \tag{6-2}$$

Table 6-6 shows the calculation for the coverage rate and Figure 6-8 illustrates the results of analysis. In order, to be sure about the inspection planning, the analysis has been done for the other subsystems

6.3 Technical Condition

Inspection finding shall be categorized with finding code. For internal corrosion, the residual thickness less than the minimum acceptable thickness in accordance with relevant standards such as ASME B31G and API is dead point which means that equipment cannot be operated and must be taken out of service. On the other hand there could be serious failure development which is categorized by client as below. Figure 6-2 indicates the walls flow lines from front view.

Pipe Diameter (D)
Remaining Wall thickness ($T_{mål}$)

$$TC=0 \quad \begin{cases} D<8 \text{ mm and } T_{mål} <2 \text{ mm} \\ D>=8 \text{ mm and } T_{mål} <3 \text{ mm} \\ T_{mål} < T_{min3} \end{cases}$$

Otherwise:

$$TC\ (\%) = \frac{T_{mål} - T_{min3}}{T_{nomina} - T_{min3}}$$

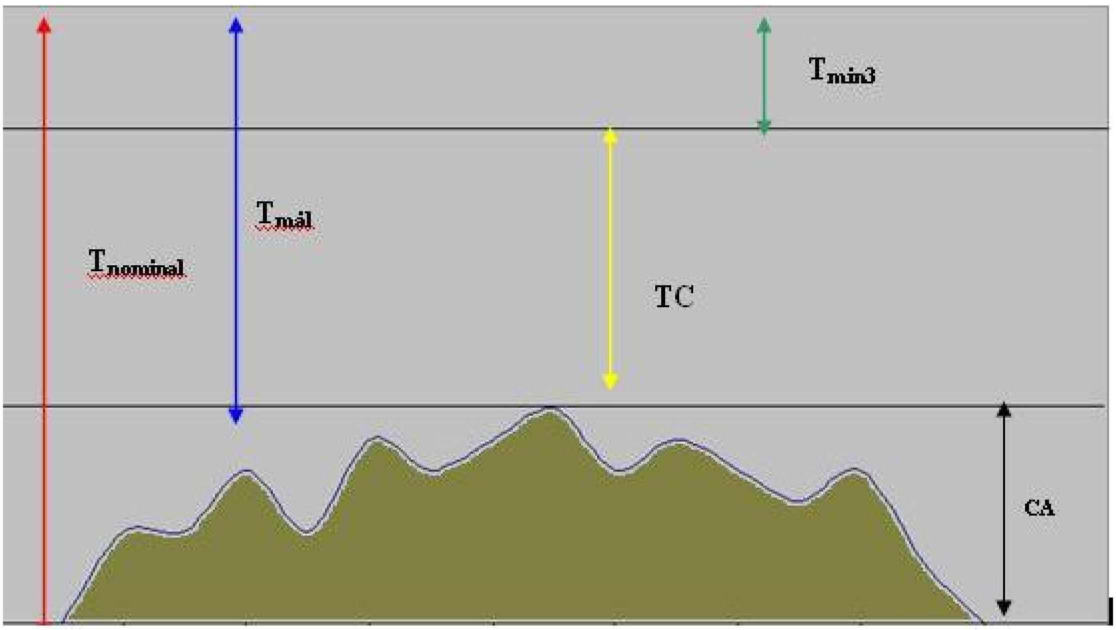


Figure 6-2: Flow line wall thickness

6.4 Analysis of finding rate

Inadequate inspection and maintenance schedules can lead to unacceptably low safety levels for the public, environmental damage, and monetary losses. Therefore, it is desirable that optimal or adequate inspection schedules are selected. On the other hand, inspection volume should be balanced with inspection finding rate. Figure 6-3 shows the schematics for inspection, condition assessment, and failure risk evaluation of pipes.

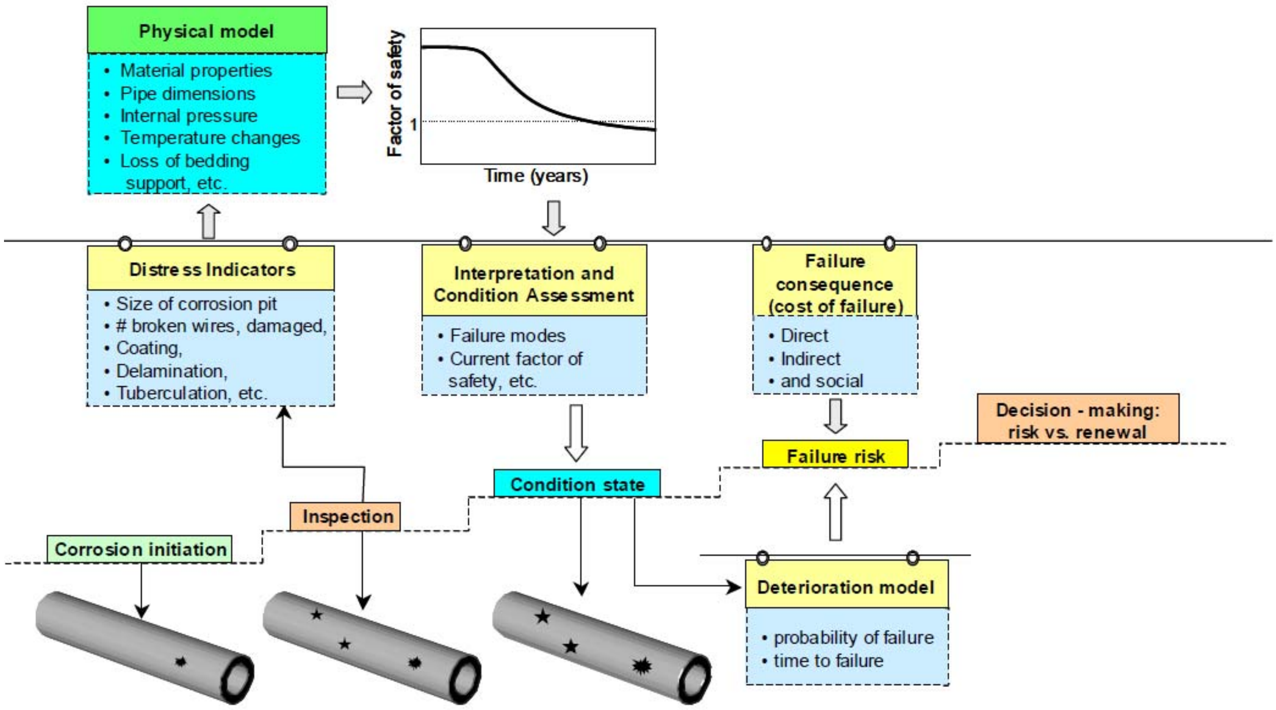


Figure 6-3: Inspection and condition assessment for pipes (Rajani, 2004)

Figure 6-4 illustrates the data which are got from the RIS data base. The analysis focus is inspection data from 2000 to 2011. The following steps have been done for this evaluation.

1. Select the equipment group for example 20-PL-01
2. Counting the inspection volume in different years from 2000 to 2011.
3. Counting the number of tag numbers with less than 100% wall thickness from 2000 to 2011.
4. Calculate the finding rate by formula 6-1
5. Create curve based on the inspection volume vs. finding rate
6. Repeat these steps for other equipment groups

Microsoft Excel - Mina (version 1) as at 9th March 2011 V1.xlsx [Read-Only]

E4316 '00-B08/V

1	GRUPPE	MODUL	TAG	TEGNING	PAKKE	D	SPOOL	NAVN	DEL_KD	OBJ_KD	STATUS	INSP_DAT
3815	20-PT-01	M04	08"-PT-10006-MF2	BP-PM-M04-PT-10006-MF2.001	01-B16	8	0	20	SV	1	B	22.11.
3990	20-PT-01	M04	08"-PT-10006-MF2	BP-PM-M04-PT-10006-MF2.001	01-B16	8	0	365	SV	1	B	22.11.
3997	20-PT-01	M04	08"-PT-10006-MF2	BP-PM-M04-PT-10006-MF2.001	01-B16	8	0	367	SV	1	B	22.11.
4001	20-PT-01	M04	08"-PT-10006-MF2	BP-PM-M04-PT-10006-MF2.001	01-B16	8	0	368	TR	1	B	22.11.
4017	20-PT-01	M04	08"-PT-10006-MF2	BP-PM-M04-PT-10006-MF2.001	01-B16	8	0	371	SV	1	B	22.11.
4044	20-PT-01	M04	08"-PT-10006-MF2	BP-PM-M04-PT-10006-MF2.001	01-B16	8	0	379	SV	1	B	22.11.
4175	20-PT-01	M04	08"-PT-10007-MF2	BP-PM-M04-PT-10007-MF2.002	00-B21/V	8	0	194	SV	1	B	30.5.
4206	20-PT-01	M04	08"-PT-10007-MF2	BP-PM-M04-PT-10007-MF2.002	00-B21/V	8	0	78	SV	1	B	30.5.
4215	20-PT-01	M04	08"-PT-10007-MF2	BP-PM-M04-PT-10007-MF2.002	00-B21/V	8	0	79	TR	1	B	30.5.
4222	**20-PT-01**	**M04**	**08"-PT-10007-MF2**	**BP-PM-M04-PT-10007-MF2.002**	**00-B21/V**	**8**	**0**	**80**	**SV**	**1**	**B**	**30.5.2**
4227	20-PT-01	M04	08"-PT-10007-MF2	BP-PM-M04-PT-10007-MF2.002	00-B21/V	2	0	81	OL	1	B	30.5.
4280	20-PT-01	M04	08"-PT-10007-MF2	BP-PM-M04-PT-10007-MF2.002	00-B21/V	8	0	95	SV	1	B	30.5.
4286	20-PT-01	M04	08"-PT-10007-MF2	BP-PM-M04-PT-10007-MF2.002	00-B21/V	8	0	96	FL	1	B	30.5.
4314	20-PT-01	M04	08"-PT-10041-MF2	BP-PM-M04-PT-10041-MF2.002	00-B08/V	8	0	105	SV	1	B	27.6.
4316	20-PT-01	M04	08"-PT-10041-MF2	BP-PM-M04-PT-10041-MF2.002	00-B08/V	8	0	106	FL	5	B	27.6.
4320	20-PT-01	M04	08"-PT-10041-MF2	BP-PM-M04-PT-10041-MF2.002	00-B08/V	8	0	107	FL	5	B	27.6.
4327	20-PT-01	M04	08"-PT-10041-MF2	BP-PM-M04-PT-10041-MF2.002	00-B08/V	8	0	108	SW	1	B	27.6.
4343	20-PT-01	M04	08"-PT-10041-MF2	BP-PM-M04-PT-10041-MF2.001	00-B08/V	8	0	10	SV	1	B	24.6.
4443	20-PT-01	M04	08"-PT-10041-MF2	BP-PM-M04-PT-10041-MF2.002	00-B08/V	8	0	114	SV	1	B	27.6.
4449	20-PT-01	M04	08"-PT-10041-MF2	BP-PM-M04-PT-10041-MF2.002	00-B08/V	8	0	115	FL	1	B	27.6.
4457	20-PT-01	M04	08"-PT-10041-MF2	BP-PM-M04-PT-10041-MF2.002	00-B08/V	8	0	116	FL	1	B	27.6.
4470	20-PT-01	M04	08"-PT-10041-MF2	BP-PM-M04-PT-10041-MF2.002	00-B08/V	8	0	117	SV	1	B	27.6.
4528	20-PT-01	M04	08"-PT-10041-MF2	BP-PM-M04-PT-10041-MF2.002	00-B08	8	0	123	RS	1	B	14.3.
4559	20-PT-01	M04	08"-PT-10041-MF2	BP-PM-M04-PT-10041-MF2.001	00-B08	8	0	14	RS	1	B	12.3.
4563	20-PT-01	M04	08"-PT-10041-MF2	BP-PM-M04-PT-10041-MF2.001	00-B08	8	0	15	SV	1	B	12.3.
4567	20-PT-01	M04	08"-PT-10041-MF2	BP-PM-M04-PT-10041-MF2.001	00-B08	2	0	16	OL	1	B	12.3.
4573	20-PT-01	M04	08"-PT-10041-MF2	BP-PM-M04-PT-10041-MF2.001	00-B08	2	0	17	SV	1	B	12.3.
4588	20-PT-01	M04	08"-PT-10041-MF2	BP-PM-M04-PT-10041-MF2.001	00-B08/V	8	0	1	FL	1	B	24.6.
4604	20-PT-01	M04	08"-PT-10041-MF2	BP-PM-M04-PT-10041-MF2.001	00-B08	2	0	24	OL	1	B	12.3.
4607	20-PT-01	M04	08"-PT-10041-MF2	BP-PM-M04-PT-10041-MF2.001	00-B08	2	0	25	SV	1	B	12.3.
4629	20-PT-01	M04	08"-PT-10041-MF2	BP-PM-M04-PT-10041-MF2.001	00-B08/V	8	0	2	SW	1	B	24.6.
4637	20-PT-01	M04	08"-PT-10041-MF2	BP-PM-M04-PT-10041-MF2.001	00-B08/V	8	0	30	SV	1	B	25.6.
4644	20-PT-01	M04	08"-PT-10041-MF2	BP-PM-M04-PT-10041-MF2.001	00-B08/V	8	0	31	TR	1	B	25.6.
4658	20-PT-01	M04	08"-PT-10041-MF2	BP-PM-M04-PT-10041-MF2.001	00-B08/V	8	0	32	SV	1	B	25.6.
4659	20-PT-01	M04	08"-PT-10041-MF2	BP-PM-M04-PT-10041-MF2.001	00-B08	8	0	32	SV	1	B	12.3.
4668	20-PT-01	M04	08"-PT-10041-MF2	BP-PM-M04-PT-10041-MF2.001	00-B08/V	8	0	33	FL	5	B	25.6.
4678	20-PT-01	M04	08"-PT-10041-MF2	BP-PM-M04-PT-10041-MF2.001	00-B08/V	8	0	34	SV	1	B	25.6.
4683	20-PT-01	M04	08"-PT-10041-MF2	BP-PM-M04-PT-10041-MF2.001	00-B08	8	0	35	RS	1	B	13.3.
4701	20-PT-01	M04	08"-PT-10041-MF2	BP-PM-M04-PT-10041-MF2.001	00-B08/V	8	0	3	RS	1	B	24.6.
4704	20-PT-01	M04	08"-PT-10041-MF2	BP-PM-M04-PT-10041-MF2.001	00-B08	8	0	40	SV	1	B	12.3.

Figure 6-4: Inspection analysis for flow lines (AkerSolutions database)

- Green: Inspected more than one (in the interval)
- White: Inspected just once
- Red: High corrosion rate (Critical)
- Purple: Under the minimal wall thickness (more than critical)

6.4.1 Flow lines

The analysis has been done for 16 flow lines among 42. First the inspection volume is calculated based on the formula 6-1 and then the coverage rate is calculated by using formula 6-2. The results for each flow lines are presented in the Table 6-4.

6.4.2 Separations

Table 6-4 is results from the following steps. The total number of inspection volume and finding rate is calculated and Figures 6-5 and 6-9 illustrate the results.

Table 6-4: Calculation of coverage rate for production lines:

10-B01-W1	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Inspection v	0	0	0	0	0	0	0	0	0	0	
Coverage rate	0,00 %	0,00 %	0,00 %	0,00 %	0,00 %	0,00 %	0,00 %	0,00 %	0,00 %	0,00 %	0,00 %
10-B03-PT	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Inspection v	23	18	18	19	47	49	59	68	47	75	80
Coverage rate	3,67 %	2,88 %	2,88 %	3,04 %	7,59 %	7,92 %	10,02 %	14,62 %	10,11 %	16,13 %	17,20 %
10-B11-PT	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Inspection v	76	84	69	111	92	114	113	89	1	37	16
Coverage rate	7,47 %	8,27 %	6,93 %	11,16 %	9,42 %	19,39 %	11,76 %	9,26 %	0,13 %	4,98 %	2,15 %
10-B12-PT	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Inspection v	74	107	79	120	97	151	121	130	104	151	168
Coverage rate	16,30 %	24,32 %	17,95 %	27,27 %	22,15 %	24,75 %	28,81 %	30,95 %	24,76 %	35,95 %	40,00 %
10-B13-PT	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Inspection v	89	87	92	97	128	84	101	154	155	154	165
Coverage rate	15,51 %	15,16 %	16,03 %	17,20 %	25,75 %	15,64 %	21,13 %	32,22 %	32,43 %	33,19 %	38,11 %
10-B15-PT	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Inspection v	71	83	66	82	127	175	180	96	161	181	263
Coverage rate	14,00 %	16,37 %	13,02 %	16,33 %	25,76 %	28,69 %	36,51 %	19,47 %	32,66 %	36,71 %	56,32 %
10-B17-PT	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Inspection v	22	20	13	0	104	36	40	96	14	94	91
Coverage rate	3,27 %	3,00 %	1,96 %	0,00 %	24,82 %	9,76 %	9,66 %	23,19 %	3,38 %	23,15 %	22,41 %
10-B23-PT	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Inspection v	75	113	100	147	110	136	132	120	116	197	198
Coverage rate	13,79 %	21,00 %	18,59 %	27,58 %	21,24 %	26,25 %	25,48 %	23,17 %	22,39 %	38,03 %	38,22 %

10-B24-PT	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Inspection v	76	57	60	147	70	93	132	177	61	165	147
Coverage rate	12,99 %	9,74 %	10,26 %	25,13 %	11,97 %	15,90 %	26,83 %	35,98 %	12,40 %	35,95 %	32,03 %
10-B27-PT	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Inspection v	63	105	66	115	65	134	86	137	108	177	168
Coverage rate	9,91 %	16,51 %	10,38 %	18,14 %	10,48 %	21,61 %	16,01 %	25,95 %	20,81 %	34,10 %	32,37 %
10-B29-PT	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Inspection v	71	71	52	90	115	168	77	263	51	169	172
Coverage rate	12,43 %	12,43 %	9,11 %	15,76 %	22,86 %	33,40 %	15,31 %	52,29 %	10,14 %	33,60 %	34,19 %
10-B33-PT	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Inspection v	71	71	52	90	115	168	77	263	51	169	172
Coverage rate	7,45 %	8,14 %	5,96 %	11,76 %	15,54 %	23,08 %	11,27 %	38,51 %	7,97 %	26,41 %	27,13 %
10-B35-PT	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Inspection v	20	59	28	97	44	99	77	89	102	93	151
Coverage rate	3,13 %	9,22 %	4,38 %	15,16 %	6,97 %	16,45 %	15,01 %	17,69 %	20,28 %	18,49 %	30,38 %
10-B37-PT	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Inspection v	61	86	68	136	92	127	196	131	129	191	168
Coverage rate	9,84 %	13,87 %	10,97 %	21,94 %	17,56 %	24,24 %	39,52 %	26,41 %	26,01 %	38,66 %	34,01 %
10-B38-PT	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Inspection v	20	64	37	58	13	52	34	100	118	112	109
Coverage rate	7,49 %	24,52 %	14,18 %	22,22 %	4,98 %	19,92 %	13,03 %	71,94 %	84,89 %	80,58 %	78,42 %
10-B40-PT	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Inspection v	53	65	63	87	97	118	124	155	52	121	148
Coverage rate	6,11 %	7,65 %	7,41 %	10,24 %	12,29 %	14,96 %	15,72 %	21,35 %	7,16 %	16,90 %	20,67 %

Table 6-5: Calculation of finding rate for production lines

EG	20-PL-01		20-PL-02		20-PL-03		20-PT-01		20-PT-04	
Year	Inspection Volume	Finding rate %	Inspection Volume	Finding rate %	Inspection Volume	Finding rate %	Inspection Volume	Finding rate %	Inspection Volume	Finding rate %
2000	29	6,90	1	0,00	39	20,51	280	28,57	0	0,00
2001	10	20,00	48	6,25	23	52,17	331	22,96	0	0,00
2002	14	14,29	30	6,67	47	2,13	548	22,99	0	0,00
2003	26	3,85	13	0,00	21	0,00	408	20,59	0	0,00
2004	39	7,69	15	0,00	20	0,00	562	23,67	0	0,00
2005	17	5,88	12	0,00	32	9,38	358	17,32	1	0,00
2006	27	3,70	6	0,00	28	7,14	686	24,49	1	0,00
2007	11	18,18	10	0,00	19	5,26	361	23,82	4	0,00
2008	63	3,17	49	16,33	64	3,13	566	19,96	9	0,00
2009	13	0,00	21	14,29	15	6,67	517	18,38	22	0,00
2010	2	0,00	10	0,00	12	0,00	143	24,48	0	0,00
2011	29	6,90	1	0,00	39	20,51	280	28,57	0	0,00

20-PT-01	Year	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**Active**
	H	79	143	61	145	525	417	181	235	168	2	264	76	
	Active													5750
Total Del nr		8459	8316	8255	8110	7585	7168	6987	6752	6584	6582	6318	6242	
Inspection v		280	331	310	548	408	562	358	686	361	566	517		
Coverage rate		3,31 %	3,98 %	3,76 %	6,76 %	5,38 %	7,84 %	5,12 %	10,16 %	5,48 %	8,60 %	8,18 %		
20-PT-04	Year	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**Active**
	H	0	0	0	0	0	1	9	2	1	0	0	0	
	Active													730
Total Del nr		8538	8538	8538	8538	8538	8537	8528	8526	8525	8525	730	730	
Inspection v		0	0	0	0	0	1	1	4	9	22	0	0	
Coverage rate		0,00 %	0,00 %	0,00 %	0,00 %	0,00 %	0,01 %	0,01 %	0,05 %	0,11 %	0,26 %	0,00 %	0,00 %	

Table 6-6: Calculation of inspection coverage for production lines

Table 6-7: Finding rate vs. Coverage rate

20-PL																		
Finding rate	6.9	20,00	3,85	5,88	3,17	0,00	0,00	6,25	0,00	0,00	16,33	14,29	20,51	52,17	0,00	9,38	3,13	6,67
Coverage rate%	7,34	2,54	3,95	4,80	17,80	3,69	0,25	12,12	3,76	3,52	15,51	6,65	10,03	6,08	5,56	8,47	17,83	4,18

20-PT																						
Finding Rate%	28,57	22,96	22,90	22,99	20,59	23,67	17,32	24,49	23,82	19,96	18,38	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
Coverage Rate%	3,51	4,23	3,99	7,19	5,57	8,42	5,51	10,96	5,93	9,29	8,87	0,00	0,00	0,00	0,00	0,00	0,00	0,01	0,01	0,11	0,26	0,00

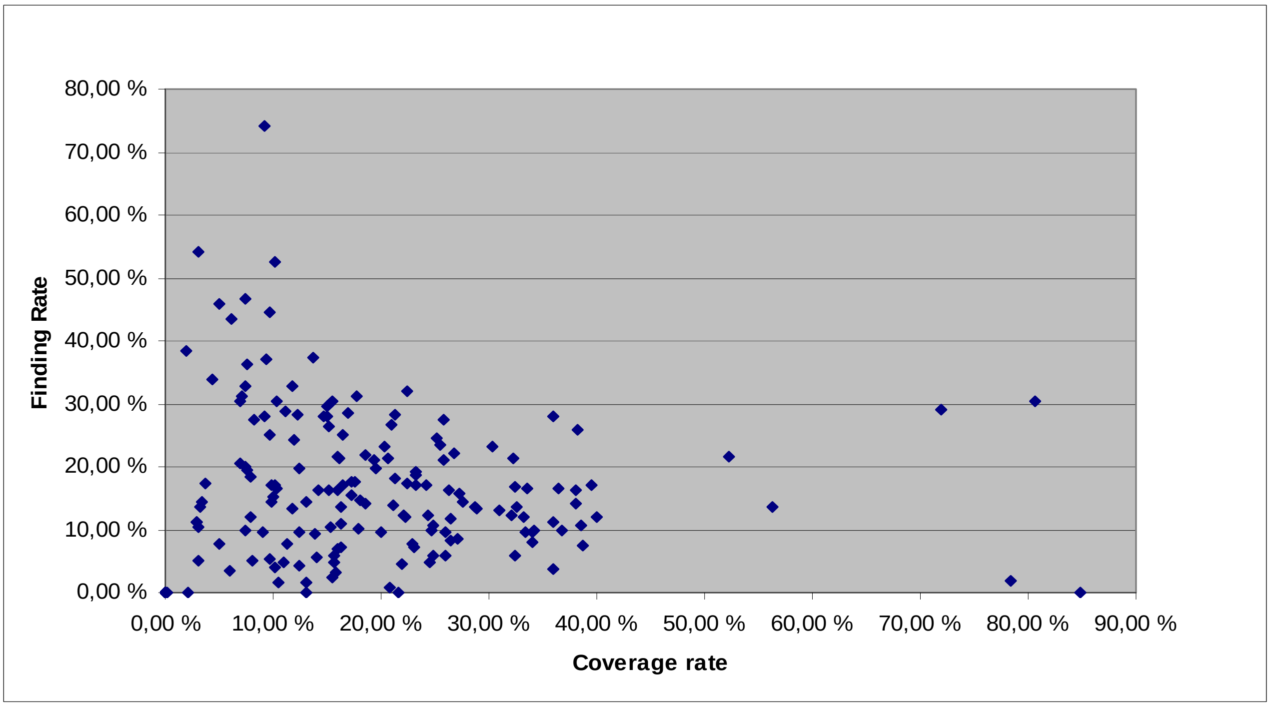


Figure 6-5: Inspection Volume vs. finding rate the flow lines (wells)

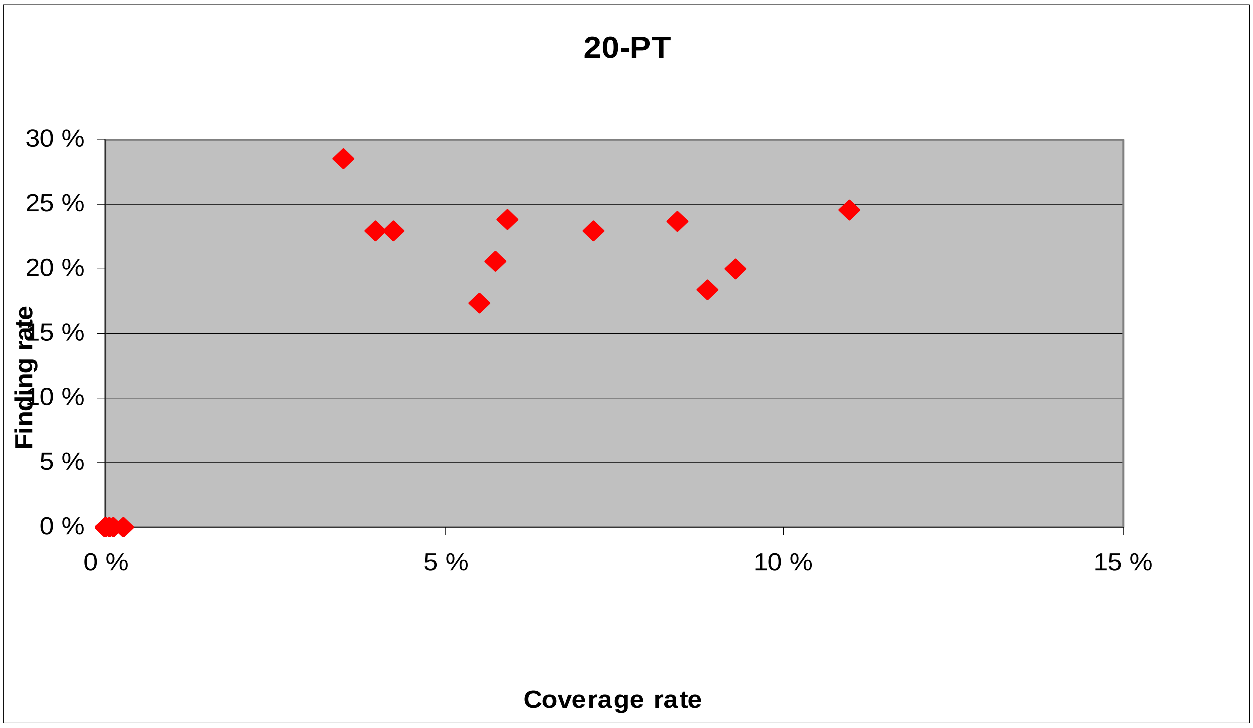


Figure 6-6: Inspection Volume vs. Finding rate in 20-PT

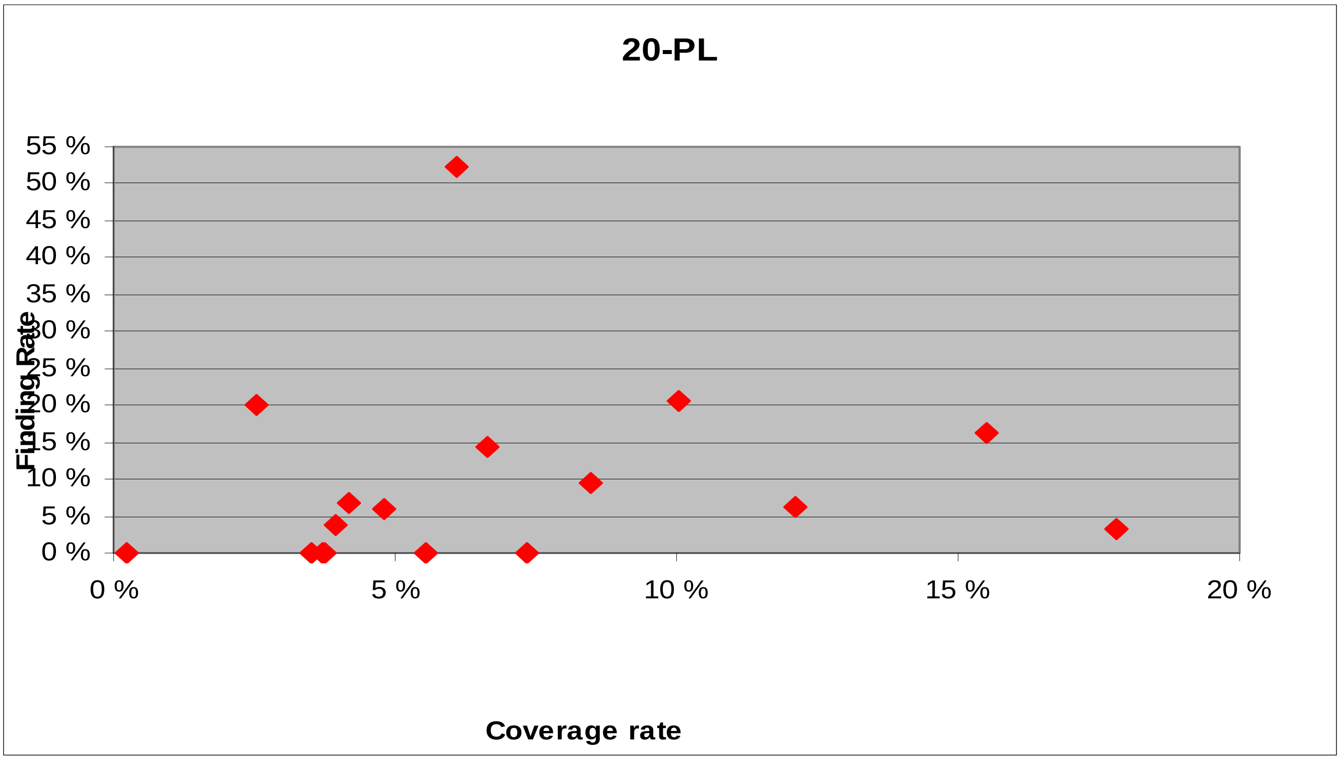


Figure 6-7: Coverage Rate vs. Finding rate in 20-PL

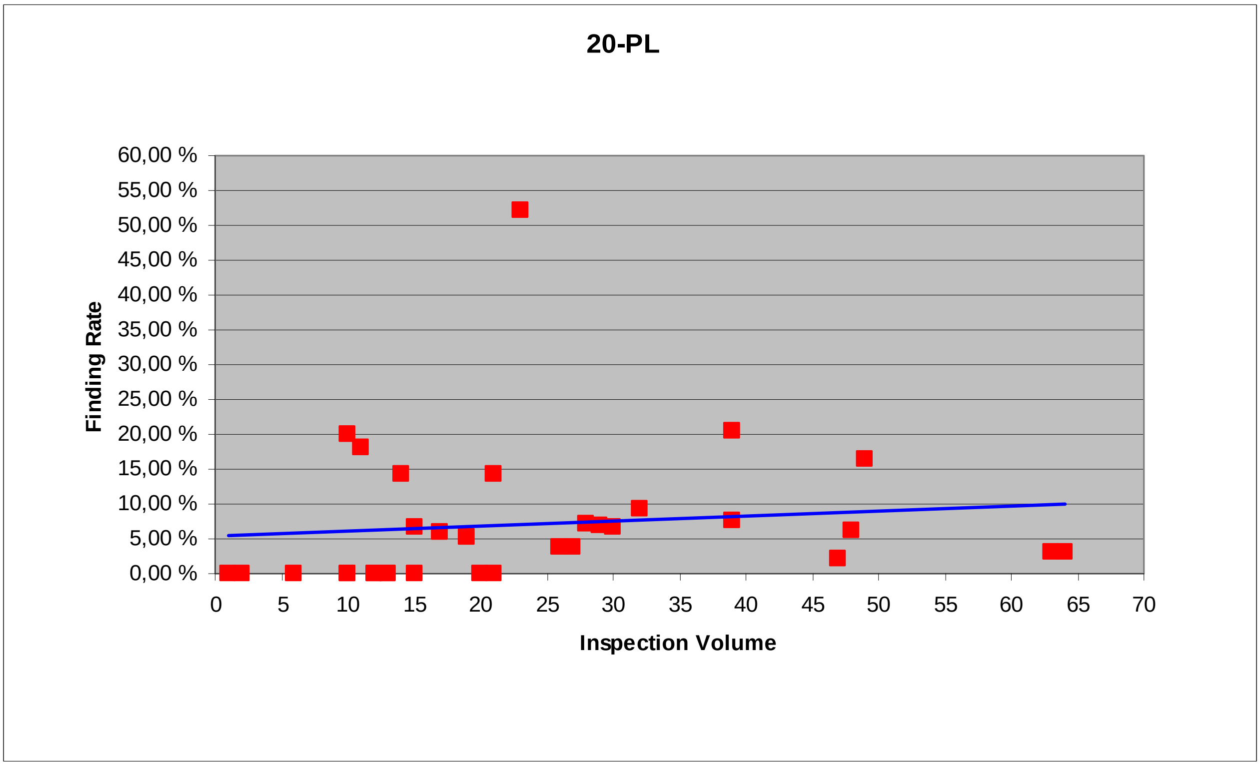


Figure 6-8: Inspection Volume vs. Finding rate in 20-PL

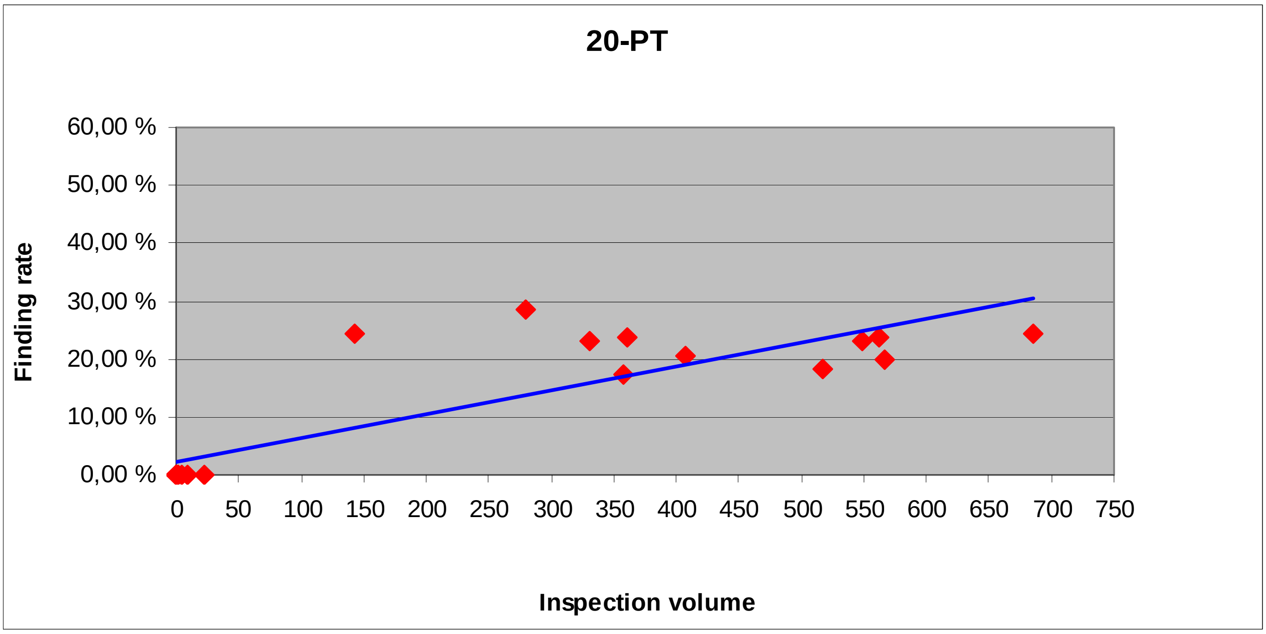


Figure 6-9: Coverage Rate vs. Finding rate in 20-PT

6.5 Summary of selecting critical sub-system

The overall evaluation of integrity status as a result of inspection activity should be carried out and the findings of inspection, including the evaluations shall be verified. Inspection finding shall be categorized with finding code. For internal corrosion, the residual thickness less than the minimum acceptable thickness in accordance with relevant standards such as ASME B31G and API is dead point which means that equipment cannot be operated and must be taken out of service. Findings rate is calculated founded on the technical condition (TC) and based on the number of inspection finding and also the number of inspection recommended are available, the finding rate can be calculated. Moreover, the coverage rate also is calculated based on the number of inspection and total number of points. In this chapter, this analysis has been done for the flowlines and production lines. The result shows that the finding rate is almost between 15-20%. This rate is the value that the inspection engineer expects to have; with minimal coverage around 15-20% finding rate.

7 Effect of cost

An effective inspection program is centred on knowing when, where and how to inspect. This enables the operator not only to control the integrity of the assets, but to control it with a focus on the economic value. In addition, having a documented trail for the inspection process allows for a focused and confident inspection plan updating should the operator undertake changes in operations, equipment, structures, personnel, contractors, company organization, etc. An Increase in inspection activities is thought to result in a safer installation, amid an increase in cost.

Risk-Based Inspection (RBI) focuses on the optimization of the inspection programs. RBI begins with the recognition that the essential goal of inspection is to prevent incidents that reduce the safety and reliability of the operating facilities. As a risk-based approach, RBI provides an excellent means to evaluate the consequences and likelihood of component failure from specific degradation mechanisms and develop an inspection approaches that will effectively reduce the associated risk of failure.

In practice, the RBI approach could be termed wholly qualitative (without use of any analytical tools) or wholly quantitative (without use of judgment) Almost all approaches are "semi-quantitative", which are discussed in the previous chapters. This combined methodology can often provide for the most approving and practical results for risk ranking and optimize the time expected on the assessment (ABS, 2003) (Figure 7-1).

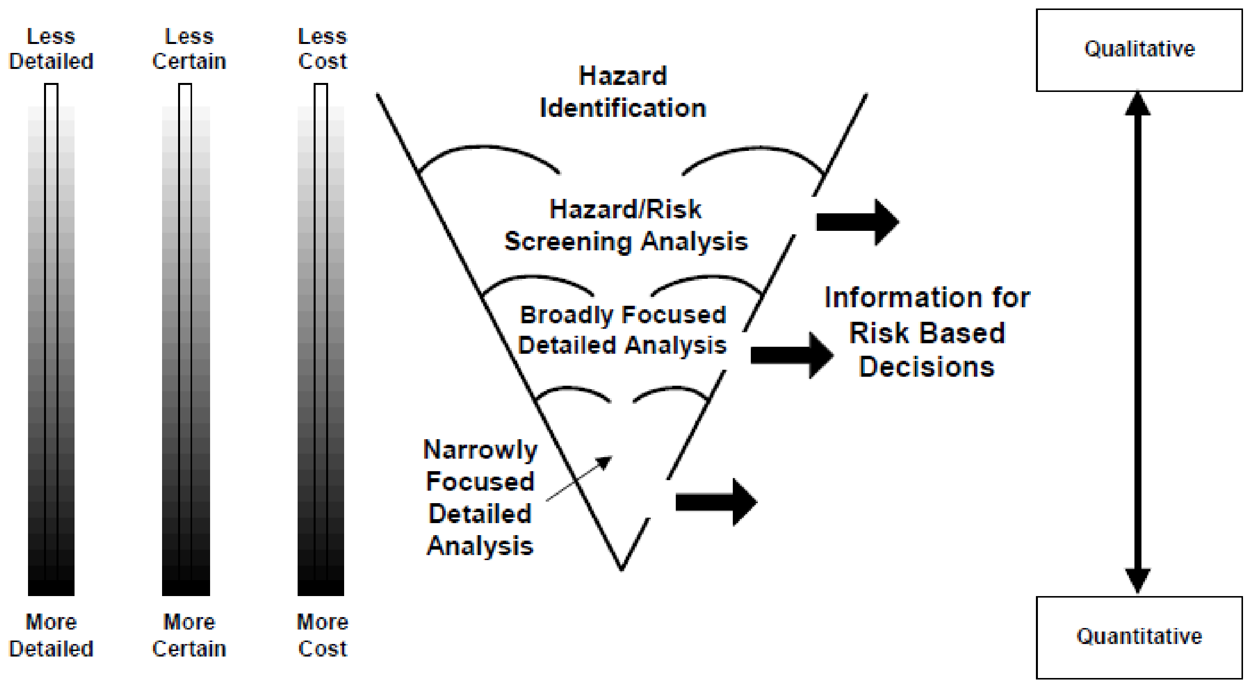


Figure 7-1: Level of RBI analysis based on the cost (ABS, 2003)

7.1 Influence of cost parameters

In order to understand the aspects influencing the costs of inspection and repair the following is implemented:

- Understanding the distribution of damage through a system
- Estimating corrosion rates
- Estimating minimum remaining thickness of lines
- Estimating the coverage rate
- Number of findings and inspection volume

Equally important is that the Design Engineers using the correct quality of data to produce design and develop the corresponding lifecycle strategies. Lack of information regarding fluid properties could lead to incorrect material selection, which in turn could lead to premature failure and either a design out or increase in inspection costs.
A typical inspection budget may include the following:

- Internal Company cost of man-hours for inspection
- Cost of training own staff
- Cost for specialist services, contract labour, transportation and accommodation offshore
- The costs of inspection and assessment staff from industry inspection services, visits of regulatory (HSE) inspection and statutory bodies for examination of the installation condition and general overall costs including transportation and accommodation costs offshore for service personnel.

An increase in inspection activities is thought to result in a safer installation, amid an increase in cost. But, there may be some exceptions as below:

i) If failure of a component does not result in significant risk exposure, then any inspection activity for that component will result in additional costs without any risk reduction and further inspection may not be necessary.
ii) The extra inspection could even cause a risk increase due to issues such as human error during inspection and damage to protective coatings.
iii) Inspection activities that do not focus on the detection of the specific degradation mechanisms to which the component is subjected to will result in cost without benefit (ABS, 2003).

7.2 Evaluation of inspection planning in terms of cost

Table 7-1 presents a summary of the inspections results for Statfjord B from 2006 to 2010. The objective index T/insp shows number of hours which are used per inspection. Usually, depending on the inspection planner experience, it is around one hour and if something special happen in the system it may be reduced or increased. The Table shows that when the finding rate increases the man hour increases as well. Moreover, Figure 7-2 illustrates the total number of inspection during 5 years on Statfjord B. RBI implementation and using RIS data base started from 2008 and the Figure briefly shows that the number of inspection is increased in 2009. Inspection plan has sinuses behaviour during several years because different parts of the system have various inspection intervals based on the RBI. This means that some of the parts which are inspected one year will not be inspected till 6 months or one year or 3 years later. Therefore, the inspection coverage decreases in 2010.

Table7-1: Inspection results for Statfjord B

Year	Finding	OK	Cancelled	Re-inspection	Finding rate	Total inspection	Man-hour	T/insp
2010	1988	9442	940	793	17 %	13163	16810	1,28
2009	2162	12601	1173	294	15 %	16230	18979	1,17
2008	1754	7914	449	512	18 %	10629	12799	1,20
2007	2502	10116	1267	641	20 %	14526	14146	0,97
2006	1557	7515	739	252	17 %	10063	12670	1,26

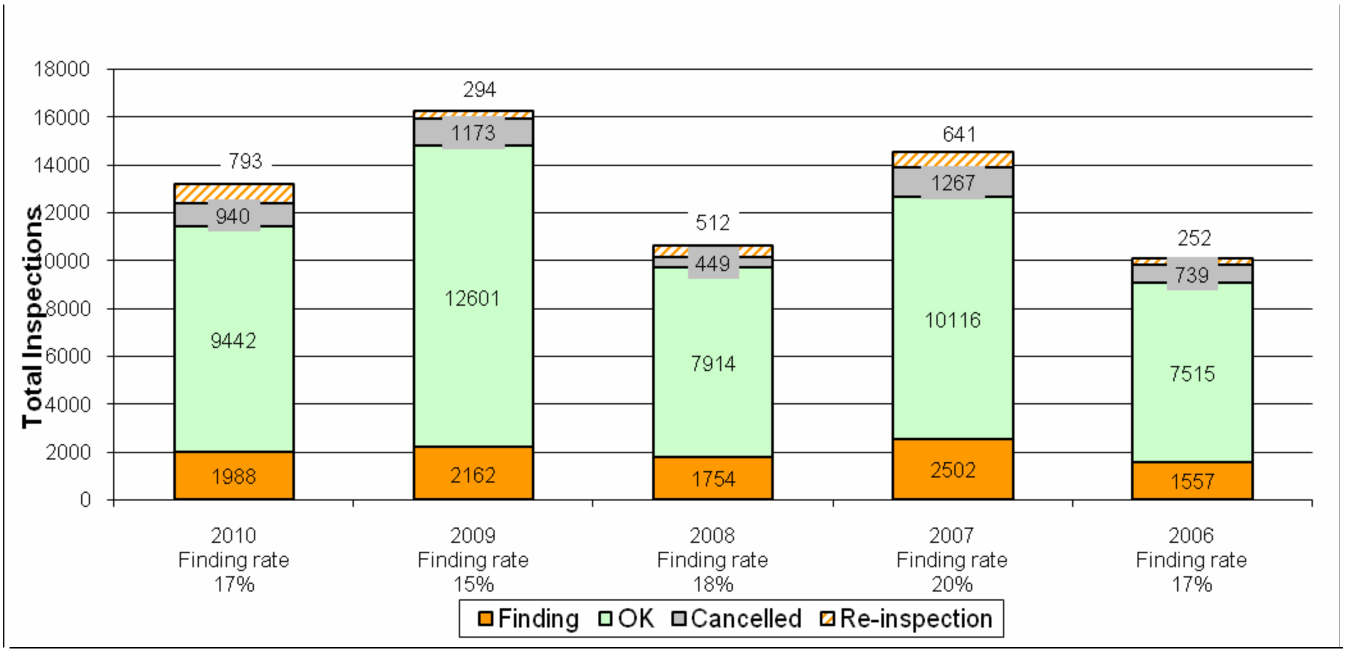


Figure 7-2: Inspection coverage from 2006 to 2010

7.3 Effect of RBI on Cost

RBI implementation helps to obtain an accurate balance of man hour for inspection during life time of the project. One of the major benefits of RBI is elimination of unnecessary inspection by focusing on the Risk level of the items also reducing the critical items for inspection leads to reducing large number of inspections (Hashemi et al., 2008). When the degradation mechanism is well understood, it is possible to use an approach when is it "worth spending the money"? When it comes to the cost of inspection, average values should be assumed initially, and if necessary, uncertainties can be included. Afterwards, it might become relevant to look at individual components in more detail (DNV, 2010). In other words, RBI helps to cost optimization; increased production availability; and safety.

Risk based inspection is cost effective strategy that should be included in a planned maintenance routine, especially as offshore structures approach their end of life. In today's environment where quality and cost are key points you need to choose the best solutions and most cost effective Test and Inspection equipment to meet your manufacturing needs. The maximum fault coverage rate or having maximum finding rate at the lowest cost and can be achieved by a number of different solutions.

7.4 Summary of effect of cost

The RBI strategy by using PoF and CoF helps to have focus on critical area and reduce risk of failure and optimize inspection coverage due to reducing the cost. In this chapter, the inspection coverage from 2008-2011 on Statfjord B are analysed which the RBI strategy and RIS data base has been utilized. Inspection plan has sinuses behaviour during several years because different parts of the system have various inspection interval based on the RBI. This means that some of the parts which are inspected this year will not be inspected till 6 months or one year or 3 years later. The man-hour increased by increasing the inspection coverage.

8 Mathematical modelling

Risk based inspection is used to manage the inspection program and effective risk based inspection programs leads to reduced level of risk. The risk based inspection methodology helps inspection resources to act with higher level of coverage on the high-risk items and with proper effort on lower risk equipment. The RBI methodology focus is on the equipment with high damage degradation by using the probability of failure and consequences of failure.

Risk = F (COF, POF, Inspection data, Time) $\Longrightarrow$ Risk = $C_s \times F_s$
S= Scenario
C_s= Consequences of scenario
F_s= Failure frequency of scenario

The framework for inspection optimization based on the RBI methodology is illustrated in Figure 8-1 (Nessim et al., 2000):

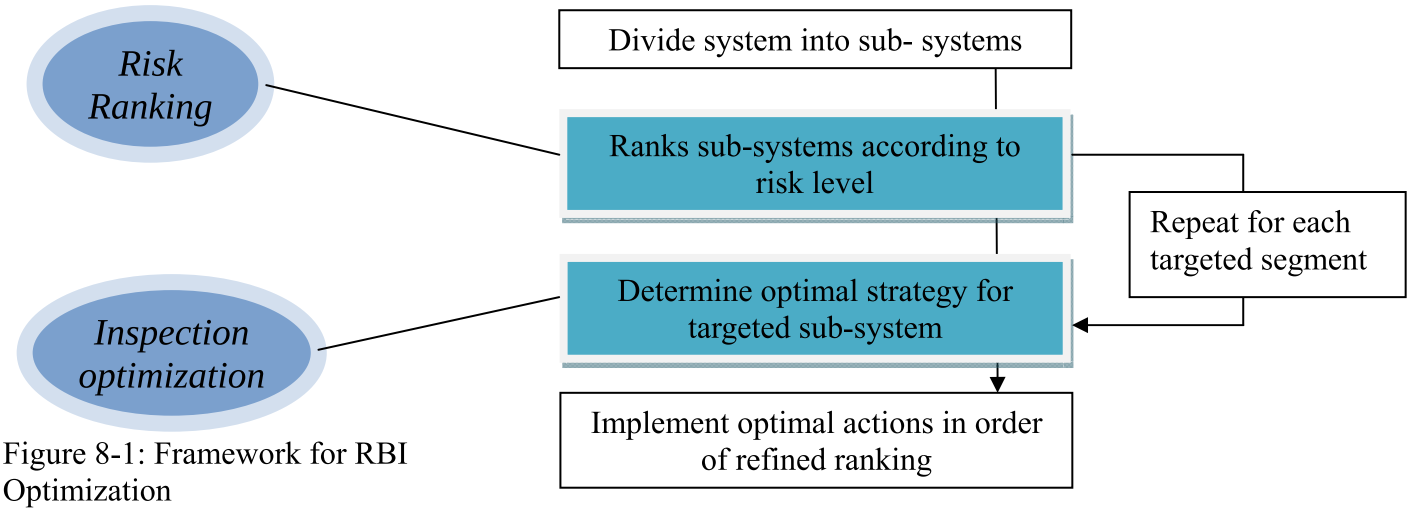


Figure 8-1: Framework for RBI Optimization

Inspection optimization based on understanding of risk can lead to some of the following benefits:

(a) eliminating unnecessary or inappropriate activities

(b) reducing inspection for low-risks items

(c) using more effective inspection methods instead of infrequent inspections

(d) reducing plant shut downs and minimizing unexpected shut downs due to failures (Hashemi et al., 2008)

8.1 Mathematical modelling (Empirical):

Inspection coverage programs is depend on the critically of a system or components by using the RBI analysis. The inspection coverage can be affected by utilization of NDT methods better identification of the damage mechanisms, adjusting the inspection coverage and adjusting the inspection frequency or a combination of them. In the last decades RBI practices have supplemented the historical empirical approach. A well defined risk matrix provides support in the screening process and identifying the critical area (Brandt and Eerten, 2005, Wisch and McMaster, 2009).The most important degradation on Statfjord platform is corrosion. Studies have shown that corrosion have been determined based on the wall thickness. So, Corrosion propagation can be modelled based on the wall thickness what it is named as technical condition (TC). Technical condition status is used to obtain finding rate which can be number of finding of wall thickness in less than 100% during the inspection. On the other hand, coverage rate shows how much points are covered in inspection planning. Both of these two parameters, finding rate and coverage rate are related to the number of inspection (Hashemi et al., 2008).

The main contributions of this research are the modelling, formulation, and inspection policies, so, first the inspection coverage is formulated and then the approach is developed by using parameters to find out the inspection coverage and it is based on the empirical approach. Figure 8-2 is a sample illustration of inspection interval versus inspection coverage during life time of the specific parts with two years inspection interval.

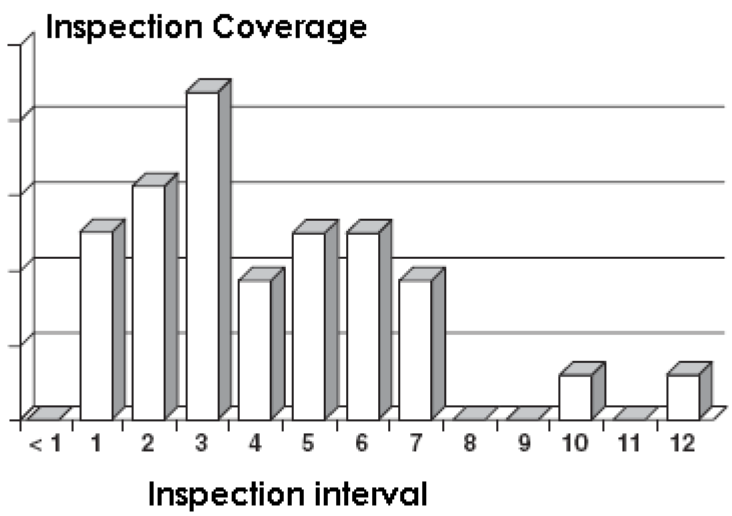


Figure 8-2: Inspection coverage vs. inspection interval

Let as define:

$t \longrightarrow$ Present time

$f_{t-1} \longrightarrow$ Finding rate for t-1

$c_{t-1} \longrightarrow$ Coverage rate for t-1

$T_{rm} \longrightarrow$ Remaining life time

$T_i \longrightarrow$ Inspection interval based on RBI for each equipment group (i=1, 2, 3…n)

$C_{t-1}^{total} \longrightarrow$ Total number of locations inspected by NDT methods in t-1

$C_{t-1}^{cancelled} \longrightarrow$ Some of the locations in each interval are cancelled

$C_{t-1}^{re-inspected} \longrightarrow$ Some of the locations are in TC<0%, so they need re-inspection program

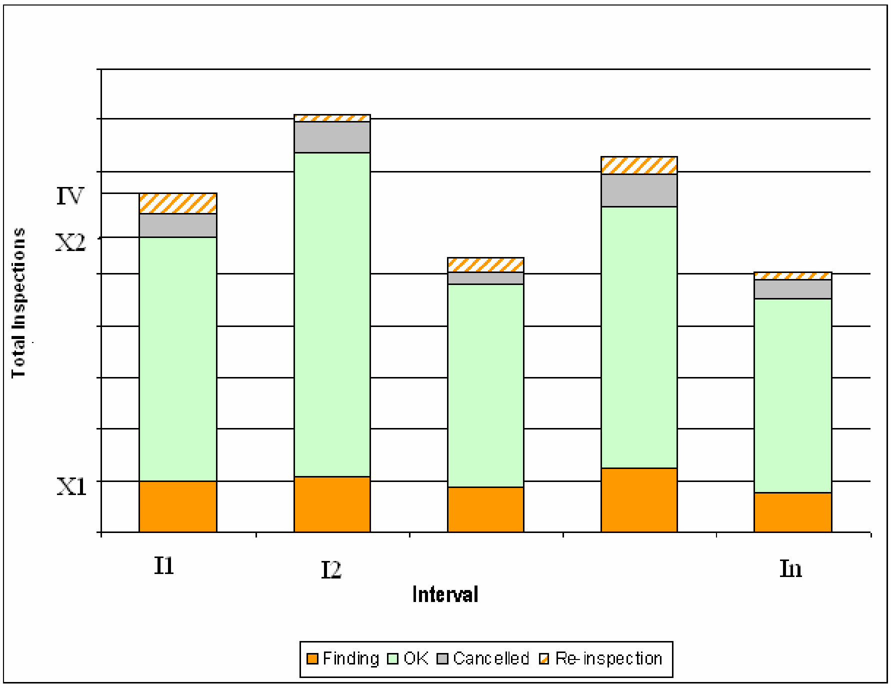


Figure 8-3: factors illustration

X₁: Number of failures (f_i) which is determined from last year inspections

X₂: $ac_i(1-f_i)$

a: re-operational factor

Ci : Number of inspection

IC: Inspection coverage

Figure 8-3 shows how we can divide inspection volume to find an empirical formula.

Hence, the inspection coverage can be considered as follows:

Among the number of locations which were inspected in the previous period, some of them failed, among these some of them are going to be inspected during the next period, based on their technical condition. C_k are the number locations in each categories of TC. (k=1, 2, and 3) that should be inspected:

1. 70%<TC<100% : $c_1 \times 1/3 = C_1$

2. 40%<TC<70% : $c_2 \times 1/2 = C_2$

3. 0%<TC<40% : $c_3 = C_3$

Hence,

$$C_k = \sum_k^3 c_k$$

On the other hand, there are some locations which have no failure on them, so based on f_{t-1}, we can find out how many of locations have not failed. Among these locations some of them should be inspected during the next period based on the factor "a" what will be set. Hence,

$$B = \left[C_{t-1}(1 - f_{t-1})\right] \times a$$

In addition, we know that some of the locations for in each equipment groups have not been inspected yet, these locations are separated based on their inspection interval and also their remaining life time and among these numbers of locations which should be inspected during each period, some of them are inspected and this would be recognized based on the factor "b".

$$C = \left(\frac{C_{t-1}^{total} - A}{\frac{T_{rm}}{T_i}} \right) \times b$$

Notice that $C_{t-1}^{re-inspected}$ are inspected in a separate re-inspect program. Finally, some of the locations are cancelled in each period and some of them should be re-inspected and these coverage rates should be reduced from total inspection coverage for next period.

$$IC_t = \left(A + B + C - C_{t-1}^{cancelled} - C_{t-1}^{re-inspected}\right) \tag{8-1}$$

$$IC_t = \left[\sum_k^3 C_k + a\left(C_{t-1}(1 - f_{t-1})\right) + \left(\frac{C_{t-1}^{total} - \sum_k^3 C_k}{\frac{T_{rm}}{T_i}} \right) \times b - C_{t-1}^{cancelled} - C_{t-1}^{re-inspected} \right] \tag{8-2}$$

Optimization is a mathematical discipline that concerns the finding of minima and maxima of functions. To find two factors "a" and "b" re-presents this optimization. "a" and "b" reflects several parameters which are determined by the inspection planner. He/She establishes these two factors "a" and "b" by some considerations which are discussed below:

- **Material:**

Material is the effective factor and one of the main reasons for some of the degradation such as corrosion. Table 8-1 describes inspection guidance of different types of material depends on the degradation mechanisms. In this formula, we assume that the material is CS but if the material will be changed to duplex or other types the factors helps us to reduce the inspection coverage.

Table 8-1: Summery of some external degradation mechanisms (DNV, 2010)

External corrosion descriptions			
Mechanism	*Material*	*Morphology*	*Inspection Guidance*
Atmospheric Corrosion	Carbon steel	Patches of damage leading to smaller size holes. Usually associated with coating damage and deterioration. Enhanced in areas where wetting is prolonged, including condensation. Significantly greater degree of corrosion can take place around supporting clamps.	Minimum surveillance is required to periodically confirm initial assumptions, particularly coating condition.
	Stainless steels Nickel-based alloys	Incipient attack, but small size holes associated with local attack where geometry allows damp salts to collect.	Visual surveillance is required to check conditions. Attention focused on geometry, clips, supports, etc. that can collect water and promote crevice attack. Coatings, if used, should be checked.
	Titanium	No damage expected.	Minimum surveillance.
Corrosion Under Insulation	Carbon steel	Damage as patches of attack where water can collect in insulation. Coatings may be used.	Damage controlled by water ingress through insulation. Deterioration of any coating will affect overall resistance. Visual inspection of weather protection, for leaks to locate potential areas. RT and UT can be used for sizing and monitoring.
	Stainless steels Nickel-based alloys	As above, welds likely to have lower resistance that parent material. Coatings may be used.	As above. Monitoring of damage by inspection is not recommended, due to rapid growth period. Corrective maintenance, for damage and preventative maintenance, of weather protection systems, is more important.
	Titanium	No damage expected.	Minimum surveillance.
External Stress Cracking Under Insulation	Stainless steels (not 6Mo type)	Surface cracks where water can collect at elevated temperatures under insulation. Welds particularly susceptible.	Damage controlled by water ingress through insulation. Deterioration of any coating will affect overall resistance. Visual inspection of weather protection, for leaks to locate potential areas. PT, RT and UT can be used to find cracks. Monitoring of damage by inspection is not recommended, due to rapid growth period. Corrective maintenance for damage and preventative maintenance of weather protection systems are more important.

- **Technical Condition (TC):**

TC can be defined as a remaining wall thickness. Criteria for inspection are presented in Table 8-2:

Table 8-2: Effect of TC on inspection interval

TC	Inspection interval
0%	Re-inspection program
%0<TC<40%	All of the points in Next year
40%<TC<70%	Half next year and the remain half in the other next year
70%<TC<100%	All of the points in every 3 years

It is obvious that the other factors discussed factor may change the inspection coverage. For instance, half of the failures between 40 %< TC<70% should be inspected next year so factor “a” could be $\frac{1}{2}$

- **Other types of inspection method**

In this formula, the total number of locations which are inspected by NDT are discussed, so, and some parts are also inspected by visual inspection.

- **Corrosion rate**

When the corrosion has progressed to the point where the minimum wall thickness has been reached the corrosion life is actually consumed; any associated defects become unacceptable, and the component needs repair or replacement. The effect of corrosion rate is appeared in the Technical condition (TC).

- **Criticality:**

RBI reports helps us to select the most critical areas and start the inspection plan based on the high risk ranking which are discussed in previous chapters. Depending on which type of product we have (water, gas and oil) the factor can be changed.

8.1.1 Remaining life time criteria

The rate of degradation increase in at the end of the expected lifetime. The degradation life cycle is an elegant measure to define stages in the life of a component, characterized by the level of damage that has developed, or is expected to have developed. It can be helpful to define certain regimes of inspection. (Figure 8-4)

The Design strategy set is based on the quality of data. In the case that the strategy is not followed, for example, lack of information properties could lead to incorrect material selection, which in turn could lead to premature failure and either through a wrong design or increase in inspection costs. Or the strategy is reviewed to ensure it is working the life of the installation. In a reassessment, a new degradation model is introduced based on new technology and the design life exceed the design strategy set. The optimum life cycle is that, there are no defects after the design life is finished (Ancel and Ugboaja, 2008, NORSOK 2010).

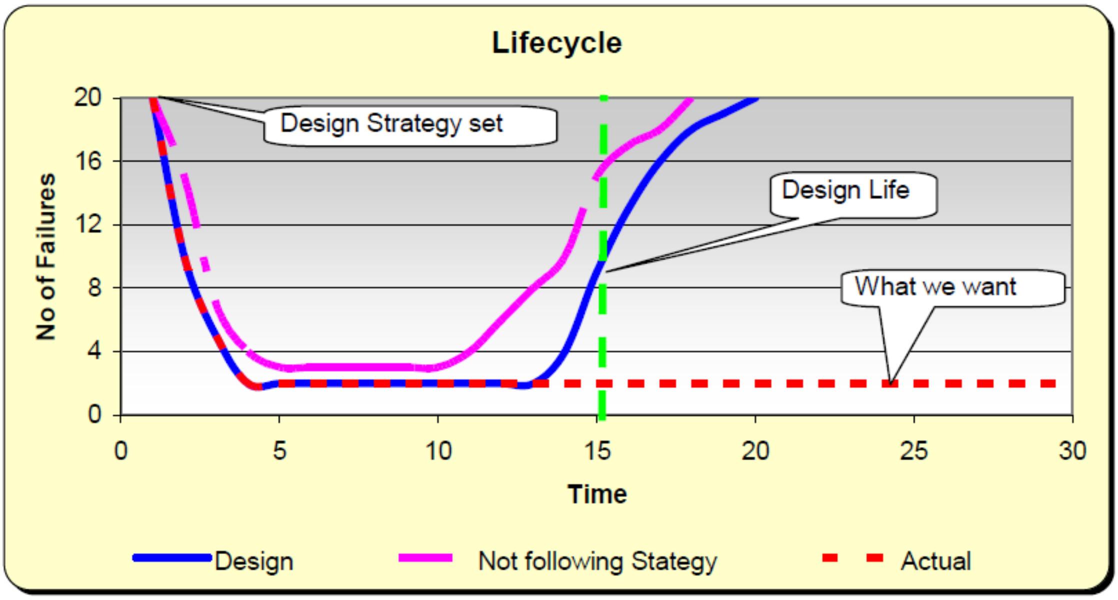


Figure 8-4: Lifecycle of a typical asset(Ancel and Ugboaja, 2008)

Assessment of the inspection interval for rate-based failure mechanisms shall be based on an estimate of the remaining life at the most recent inspection or at start-up of the equipment if no inspection has been carried out. Remaining life shall be calculated based on corrosion rate and difference between remaining wall thickness and minimum allowed wall thickness. The minimum allowed wall thickness which shall be used is the calculated thickness according to code requirements for pipes and pipelines, and nominal thickness minus corrosion allowance for vessels. Other criteria for determining remaining life can be used where suitable (Vandecamp et al., 2009).

In formula 8-2, the remaining life time is used. Consider Figure 8-5, Corrosion rate for failure is measured and also the time of first detection is known. Also, we know the corrosion allowance and wall thickness, so, we can find the remaining life time. For instance:

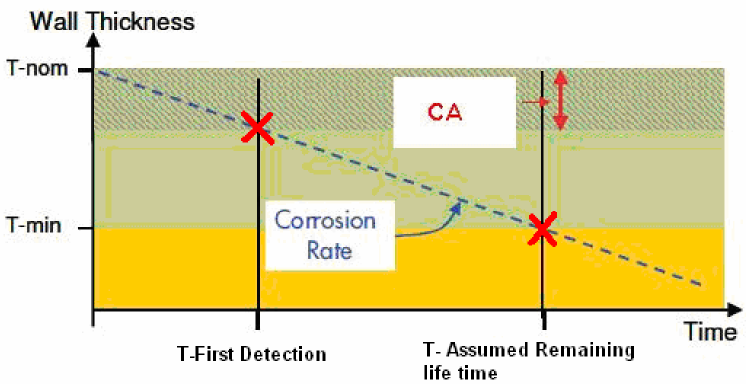


Figure8-5: Corrosion rate vs. Time (Vandecamp et al., 2009)

- The corrosion rate is: 1.5 mm/year
- Detection time is after 2 years
- Wall thickness is 8 mm
- Corrosion allowance is 3 mm

The assumed remaining life time can be calculated: $\frac{2\times(8-1.5\times 2)}{1.5\times 2}=3.3$ year

It means that the RL is around 3 years later.

In Statoil procedure TR1987, a factor is defined based on the criticality of the system which can help to find out the remaining life time. In this case, the acceptance criteria used shall be taken from Table 8-3:

Table 8-3: Interval as a function of remaining life (RL) and consequence classification (Fauske, 2009)

Consequence	Inspection interval
Extremely high	0.3 * RL
Very high	0.3 * RL
High	0.4 * RL
Medium	0.5 * RL
Low	No inspection

8.2 Validating the inspection empirical model based on past inspection data

In this section, we will show the results of the proposed methodology for the Statfjord B inspection data. The optimum inspection model is a decision-support model. It presents inspection coverage as function of the time versus updated condition based on inspection result. Inspection engineer experience has direct influence on the optimum inspection model. The optimum inspection coverage formula has been checked for two different flow lines, production and water drainage. By two parameters "a" and "b", the optimum inspection is determined. In this evaluation, these two factors are calculated as blew:

- The total number of failures in each categorization of TC is calculated. For TC greater than 70% , 1/3 of them are to be inspected, between 40% to 70%, half of them and between 0% to 40% all of them to be inspected and the sum of these creates α_1
- In inspection summary, the percentage of the pipe material is declared, so, the percentage of CS is considered as α_2
- In inspection summary, all of inspection are considered by using the NDT method and reduction factor α_3 can be selected to reduce number of inspection in next year
  In summary for the two factors "a" and "b",
  $\alpha_{a,b} = \alpha_1 \times \alpha_2 \times \alpha_3$

The results of the analysis of the two case studies using the proposed methodology are discussed in the following sections (Khan et al., 2004)

Case study 1 (Production lines)

Based on 2009 inspection data Table 8-4 illustrates the result and Figure 8-6 illustrates the results compares the result with the results of Client inspection planner for production lines

Table 8-4: Optimum inspection coverage for 2010 based on Empirical Formula 8-2

Equipment Group	C_{2009}	f_{2009}	C^{total}_{2009}	$C^{Cancelled}_{2009}$	$C^{fallowup}_{2009}$	T_{rm} (Year)	T_i (Year)	a,b	Risk level	IV_{2010}
20-PL-01	49	0,02	274	0	1	20	6	0,27	M	32
20-PL-02	40	0	252	0	0	11,5	8	0,24	VH	45
20-PL-03	38	0,06	238	0	0	1,2	0,5	0,26	VH	33
20-PL-04	33	0,11	196	1	0	5,5	0,5	0,32	VH	24
20-PL-05	30	0,14	98	0	1	8	0,5	0,31	VH	19
20-PL-06	36	0,14	347	1	0	1,6	0,5	0,28	VH	45
20-PL-07	675	0,04	3828	57	1	26	8	0,28	VH	616
20-PT-01	1255	0,14	6038	54	28	26	8	0,25	VH	938
20-PT-02	258	0,24	1481	60	9	26	8	0,28	VH	189
20-PT-04	10	0	730	0	0	26	8	0,0072	M	5
30-PL-01	153	0,01	1060	1	0	14	6	0,24	M	178

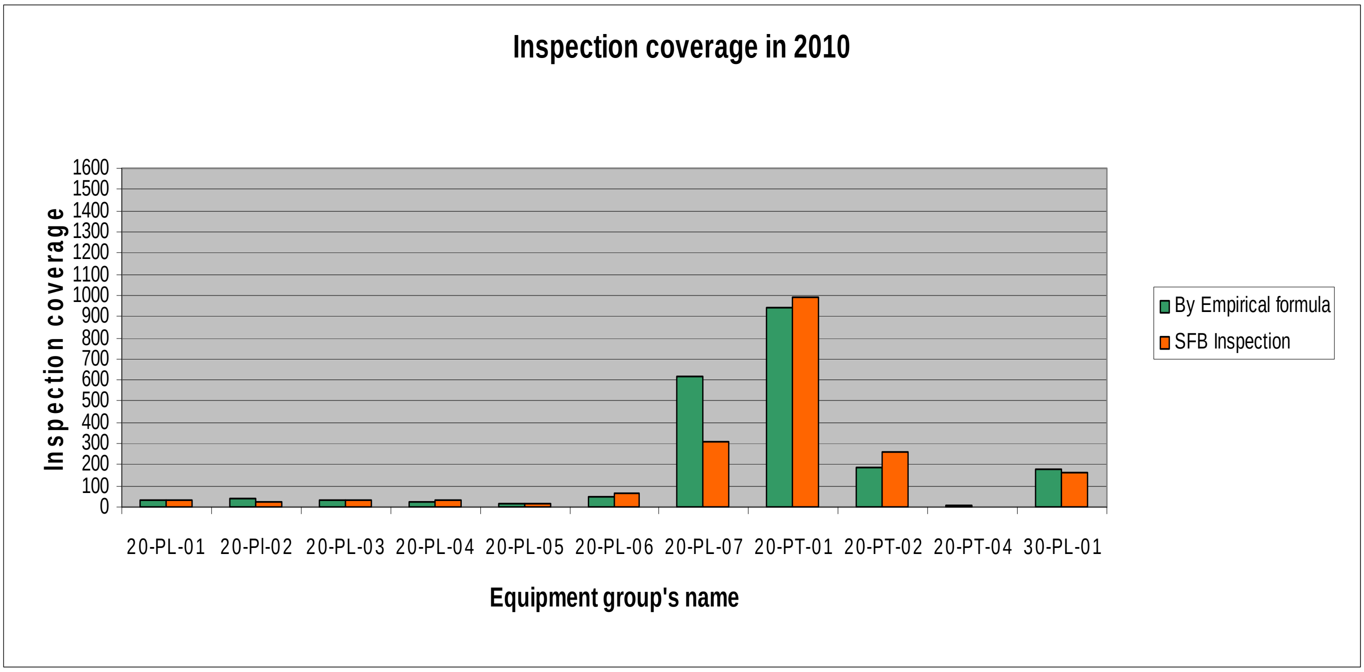


Figure 8-6: Comparison of inspection Coverage and results of empirical formula and SFB inspection team finding for 2010

Case study 2 (Water drainage lines)

Based on 2009 inspection Table 8-5 illustrates the result and Figure 8-7 compares the result with the result of Client inspection planner for water drainage lines.

Table 6-5: Inspection coverage for 2010 based on Empirical Formula 8-2

Equipment Group	C_{2009}	f_{2009}	C_{2009}^{total}	$C_{2009}^{Cancelled}$	$C_{2009}^{fallowup}$	T_{rm} (Year)	T_i (Year)	a,b	Risk level	IV_{2010}
20-EC-01	33	0,27	306	3	1	12	6	0,377	M	61
20-EC-02	26	0,04	78	0	0	16	8	0,21	M	18
20-EC-03	14	0,07	52	0	0	5,7	8	0,25	VH	21
20-EC-04	24	0,38	200	0	1	5,4	0,5	0,41	VH	23
20-EC-05	21	0,29	142	0	2	4,3	2	0,3	VH	17
20-EC-06	27	0,33	142	0	2	4,3	0,5	0,3	VH	17
54-EC-01	853	0,32	7672	30	46	26	8	0,28	VH	983

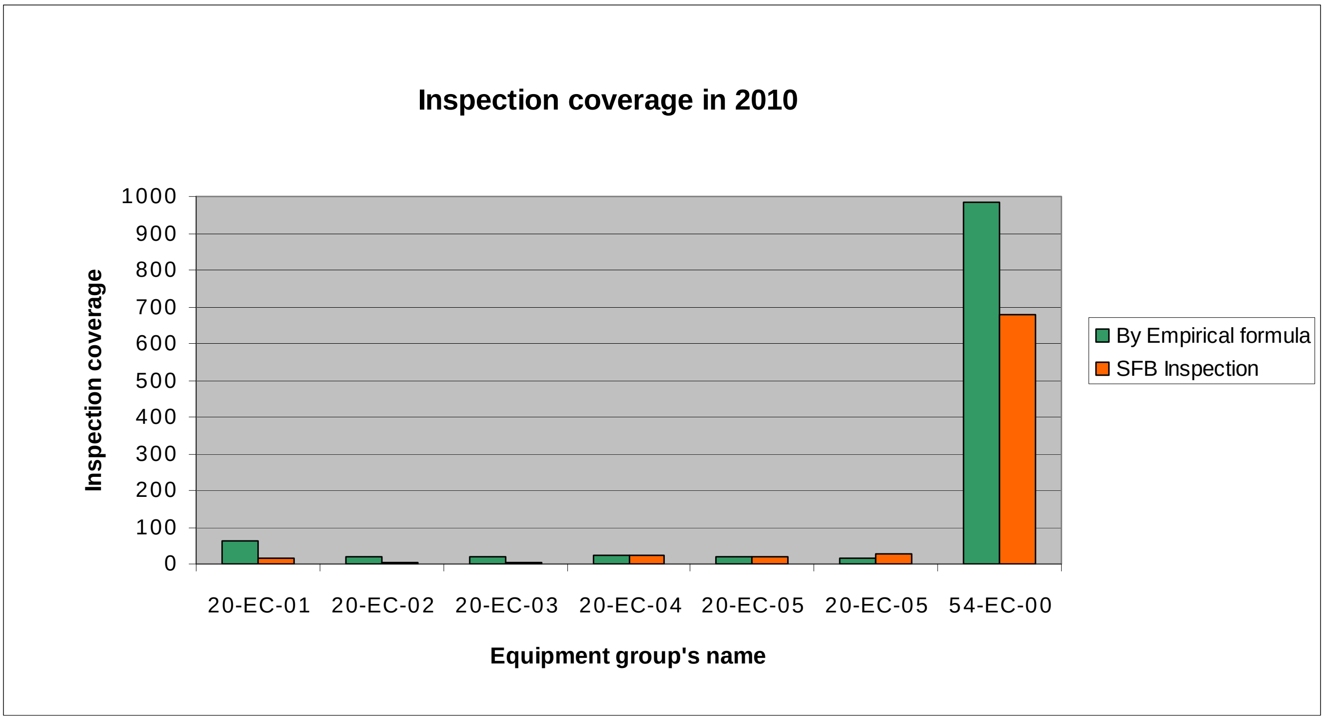


Figure 8-7: Comparison of inspection Coverage and result of empirical formula and SFB inspection team finding for 2010

8.3 Summary of mathematical modelling

The most significant degradation on Statfjord platform is Corrosion. Studies have shown the corrosion have been determined based on the wall thickness. Technical condition status is used to obtain finding rate which can illustrates number of finding in less than 100% of wall thickness in whole number of inspection. In this chapter, by using the inspection data base and the empirical approach a mathematical formula is found out to calculate inspection volume in each period. The formula is based on the inspection coverage at time t-1, finding rate at time t-1, time interval and remaining life time and also the two factors “a” and “b” presents this optimization of inspection coverage. “a” and “b” reflects several parameters which are determined by the inspection planner such as material, corrosion rate, TC. In this study, these two parameters are calculated the same, but it is obvious that they may change based on the inspection engineer experience. At the end of this chapter, the empirical formula is evaluated in two cases and the result compares with actual inspection which had been done in SFB.

9 Discussion and Conclusion

Risk-based inspection approaches have been practiced by industry to determine probable failure mechanisms, their likelihood of occurrence and the associated consequences. Overall, the RBI is a methodology to improve the management of risk through closely focusing on the critical areas of the plant, and reducing efforts on the non-critical areas. The data are then used to determine inspection frequencies (Santos and Hajri, 2000).

Planning inspections for process sub systems become more challenging if the system is built from many different diameters and thicknesses, and if it has developed a mature corrosion condition that requires regular replacement of sections of systems. Identifying inspection coverage by the correct view helps to cover high percentage of un-inspected points in the remaining life time of plants to reduce the shut down time and increase the productivity of the system and the inspection plan becomes more cost effective. In addition, inspection planner based on his/ her experience can select an accurate measure for factors to cover most of points in the early years of extension time rather than close to shut down deadline and this provide;

- Increase in plant availability
- Decrease in the number of failure occurrences
- Reduction in the level of risk due to failure
- Reduction in the direct inspection cost of the production and/or process facility
- Cost effective scheduling of inspection man hour in each year
- Reducing number of inspection in the years close to reaming life time
- Evaluate current inspection plans to determine priorities for future inspections.
- Evaluate future plans for decision making (Conley and Reynolds, 1997)

The thesis, suggest an empirical formula based on the available data and the experience of the inspection engineers in SFB. Although, the result of formula and the SFB inspection team are close, in some of the cases there are some differences. It is obvious two factors “a” and “b” has significant effect on inspection coverage. In this study we calculate these two factors based on the 3 items (Material, TC and NDT), but further studies can develop the formula by using other important factors such as corrosion rate. The inspection engineer based on her/his experiences can change the factors because the inspection plan is really condition –based and some unexpected event may change everything. This formula let the inspection engineer to consider every situation or condition by changing the factors (Vandecamp et al., 2009) .

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11 Appendix