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MASTER'S THESIS

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Andreas Eriksson

Abstract

The aim of this thesis is to identify and recommend vessels that are suitable for inspection according the NII methodology, DNV-RP-G103. The theoretical guideline used during the analysis, DNV-RP-G103, was chosen since it is the acknowledged and recommended standard in the inspection industry, and it is also according to internal technical requirements in Statoil ASA. The thesis also includes a cost benefit assessment and discussion whether or not the methodology reduces the risks at for tail production field that has been in service for over 30-years. The scope of the thesis includes all of the production vessels in one of the production trains, including the test separator. A total number of six vessels, that historical has been opened for IVI during shutdowns where this is still the chosen inspection strategy, have been selected.

This thesis is mainly divided into four parts; (1) A theoretical introduction of the NII methodology, (2) NII detailed analysis of selected pressure vessels, (3) cost benefit analysis, and (4) a discussion part followed by a final conclusion. The thesis focus on the detailed NII analysis part, since all of the data collection and decisions are performed in this section, which includes; (a) corrosion risk assessments, (b) offshore survey of the vessels, (c) collection of process and inspection data, (d) detailed NII analysis of selected vessels, and (e) selection of inspection zones and methods.

NII is not recommended for any of the vessels considered in this thesis. It is possible to perform NII of four out of six vessels after the detailed analysis, which also is supported by a cost benefit analysis that estimates IVI to be more or less about twice the cost compared to NII. However, when looking at the maintenance management loop there is a challenge in the future related to corrosion of sealing surfaces. It is possible to inspect them, but old flaws are repaired by coating and would appear as a new flaw during external inspection with NDT methods. There are not any detailed reports describing the exact location and morphology of previous defects, and this leads to a need for close visual inspection of the sealing surface, to ensure that there are not any ongoing degradation. Implementation of NII would increase the costs for inspection of these vessels, and the risks and benefits of performing NII are no longer valid. The analysis is performed for the most corrosive part of the installation, and the results may have been different if the analysis was performed in other parts of the process. However, this analysis is considered useful as a basis for analysis of other vessels onboard the installation.

During the analysis the recommended practice (RP) is considered to be a very useful guideline. It uses flow diagrams combined with detailed text and case examples that are very useful and understandable throughout the analysis. However, during the work with this thesis it has been identified sections and text that should be improved; These are (1) missing text and explanation to some of the flow chart boxes, (2) the RP states that it doesn't consider the impact of external degradation, but it has been found to be actively used in the RP in evaluation during high level decision process and in one case example, and (3) in the coverage selection it uses the confidence of the whole corrosion risk assessment (CRA) during selection. This is misleading, and the assessment should be performed zone by zone. The author would report back the publisher, and purposed improvements of the DNV RP.

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Abbreviation

NII	Non-Intrusive Inspection
HOIS JIP	Harwell Offshore Inspection Service – A Joint Industrial Project
JIP	Joint Industrial Project
NDT	Non Destructive Testing
IVI	Internal Visual Inspection
HSE	Health, Safety and Environment
DNV	Det Norske Veritas
CRA	Corrosion Risk Assessment
SAP	A Maintenance and Management system in Statoil
POD	Probability of detection
Sizing	Ability to provide quantities information regarding flaw size and wall thickness.
STIDtips	Technical Information Portal in Statoil.
CO_2	Carbon dioxide
H_2S	Hydrogen sulfide
MIC	Microbial corrosion
RF	Raised Faced flange
FeS	Iron Sulfide
ppm	Part per million
pH	Negative log of the activity of the hydrogen ion in an aqueous solution
mol%	The amount of a constituent (expressed in moles), n_i, divided by the total amount of all constituents in a mixture,n_{tot}. Given in percent with a denominator of 100.
RTJ	Ring Type Joint
RF	Raised Faced
API	American Petroleum Institute
RP	Recommended Practice
RBI	Risk Based Inspection
TOFD	Time-of-flight diffraction
LOWT	Loss of wall thickness

1 Introduction

1.1 Background

The NII methodology was already discussed as early as in the late 90`s. A group of companies in the HOIS JIP environment saw an opportunity in performing inspection of pressure vessels externally with the usage of NDT methods instead of the traditional IVI (Fauske and Burch, n.d.). The main benefits of this methodology is reduced loss of production, mechanical damages during preparation for internal inspection and HSE risks due to entering of the vessels during preparation activities and inspection.

In retrospect it turns out that NII is varied used within Statoil ASA since it was first discussed about 15 years ago. It is therefore desirable to use the methodology on an installation that has been in production for over 30 years, and discuss which vessels that should be inspected externally with NDT according to the NII methodology.

1.2 Aims of the thesis

The aim of this thesis is to identify and recommend vessels that are suitable for inspection according the NII methodology, and fully replace traditional IVI. This will also include a cost benefits assessment and discussion around whether or not the NII methodology reduces the risks.

1.3 NII methodology selection and Scope

It is chosen to only use the DNV recommended practice as literature for this thesis, DNV-RP-G103", published in 2011. There are of course many available guidance documents that are aimed to assist in the planning and justification of NII. However, the recommended practice from DNV was actually developed to bring all these documents together in one single cover, and it is also the recommended guideline within the HOIS JIP environment.

The scope of the thesis is manly divided into four parts; (1) A theoretical introduction of the NII methodology, (2) To carry out the NII detailed analysis of pressure vessels, (3) To carry out a cost benefit analysis, and (4) a discussion part followed by a final conclusion.

The theoretical part will just briefly consist of the main elements and points of the recommended practice to ensure that the reader gets familiar with the DNV-RP-G103. The thesis is mainly dominated by the detailed NII analysis part, since all of the data collection and decisions is carried out in this section. This part will include the following;

- The CRA assessments
- Offshore survey of the vessels
- Screening of vessels
- Collection inspection history in SAP
- Recommendation of vessels that could be inspected according to the NII methodology

- Inspection plan that includes selection of inspection methods and areas to be inspected

When the detailed NII analysis and the cost benefit assessment are finished, a final conclusion/discussion part is performed to consider which of the identified vessels recommended for NII that actually should be inspected externally with NDT. The assessment includes discussion of whether or not NII is reducing the risk, and if the benefits are larger than the costs of performing inspection according to the NII methodology.

The thesis is limited to the theoretical part of the NII methodology. This means that the actual execution of NDT externally and the evaluation of the inspection results according to the NII procedure aren’t included. These activities must be performed at a later stage if the client chooses to implement the NII inspection strategy of recommended vessels.

2 Non-Intrusive Inspection Methodology

2.1 Introduction

This part consists of a short summary of the whole DNV-RG-G103 (DNV, 2011) recommended practice. It includes general information about how to perform Non-Intrusive Inspection analysis to ensure that the reader gets short introduction and understanding of the recommended practice. The whole chapter 2 in the thesis is obtained from the DNV RP, and it is therefore not chosen to cite each text the sections below.

2.1.1 Background and objectives

There are many available guidance documents aimed to assist in the planning and justification of NII. The recommended practice from DNV is developed to bring all these documents together in one single cover, and it is now also the recommended guideline within the HOIS JIP environment.

The main benefits of this methodology is reduced loss of production, mechanical damages during preparation for internal inspection and HSE risks due to entering of the vessels during preparation activities and inspection.

2.1.2 Scope and overview of the Recommended Practice

The recommended practice is aimed at the inspection of welded vessels from metals. It includes attached equipment to the vessels like fittings and connections associated with them and it provides a guideline for the following;

- Determining when NII is applicable in principle
- The information required to perform NII analysis
- Defining requirements for the NII method(s) selected
- Selecting methods that meets these requirements
- Evaluating the results of inspections performed
- Requirements related to documentation

The guideline is limited by the following constraints;

- It does not say when the next inspection should be performed. This is taken care of by the different company’s inspection philosophy and internal requirements
- Relative cost of different inspection options isn`t included
- It is manly just developed for pressure vessels
- Legislative requirements aren`t included
- It does not consider the impact of external corrosion mechanisms

The implementation of NII would require a step change in the way of how inspection is performed and planned, and this is why the recommended practice provides a staged and systematic process to ensure that all the needed considerations are included. The overview is shown in Figure 2-1.

To briefly introduce the reader it starts mainly with a collection of all the data and information needed, and explaining the different levels and requirements of CRA (Part 1. Integrity Review), all of the data and information is then used in the second stage (Part 2. Decision Process) to screen out which of the vessels that are recommended for NII. This process is divided in to two parts, first a preliminary screening to screen out obvious vessels that aren`t recommended for NII. Then at last a detailed/high level screening is performed to ensure higher or at least the same accuracy and quality of obtained inspection results compared with traditional the IVI. The three last stages consist mainly of planning where and how to inspect (Part 3. Planning Process), carry out the inspections (Part 5. Inspection) and at last an evaluation of the results obtained (Part 6. Evaluation). The two last stages aren't a part of this thesis, as earlier explained above in the introduction part. Though it is a very important part of the recommended practice, to ensure that the inspection activities performed in the field meets the minimum NII requirements.

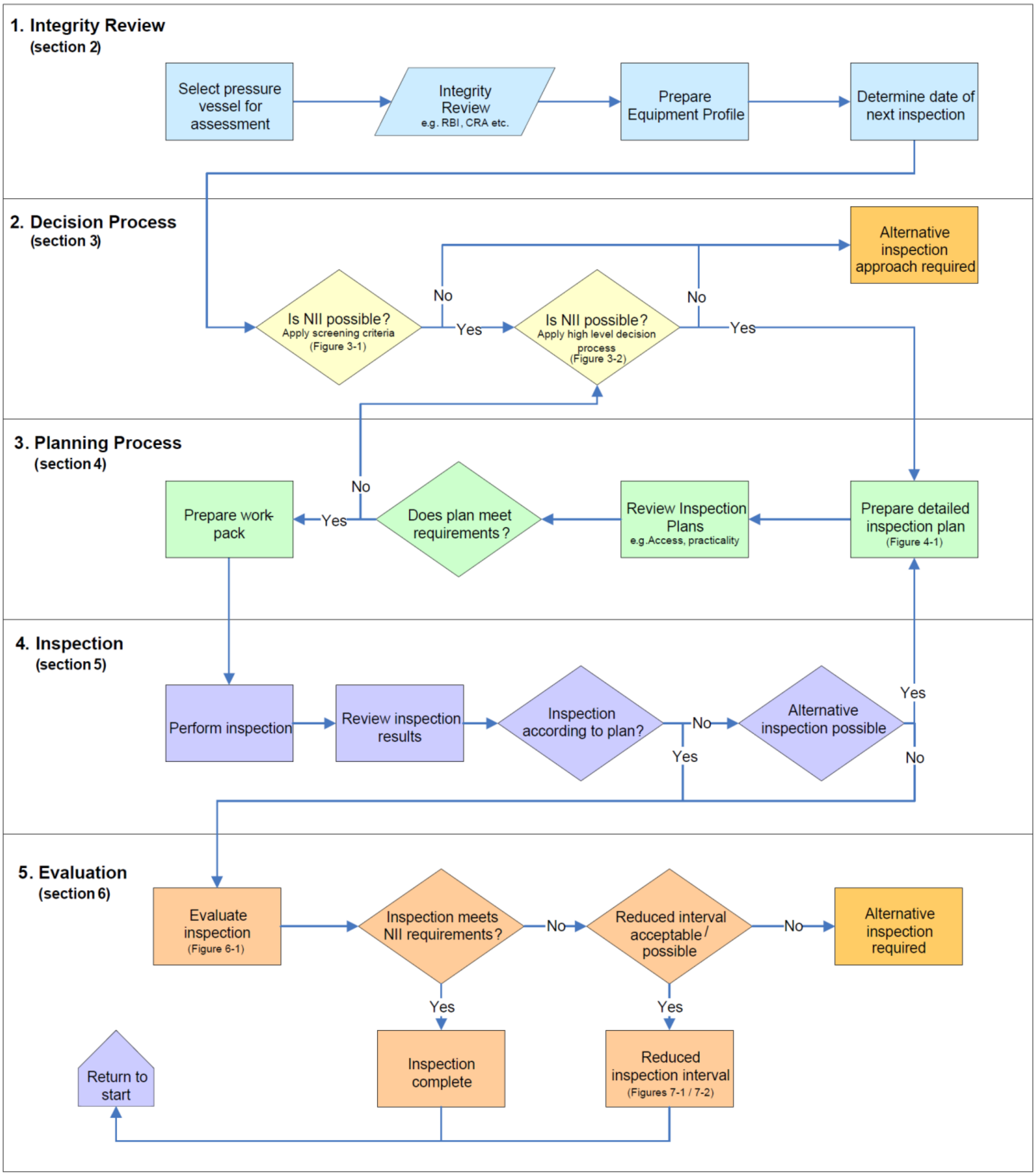


Figure 2-1: Overview of the whole NII procedure, including all of the steps from the Integrity Review containing the CRA, to the last stage where the evaluation of executed NDT is performed (DNV, 2011).

2.2 Integrity Review

The integrity review is mainly an overview of which data and information requirements that are needed to perform the NII analysis. This would include information like; type off vessel, material and design data, drawings, general experiences, historical repairs and/or modifications, accessibility to performed the NDT externally, minimum required wall thickness, historical inspection results, possible degradation mechanisms and operational experiences. The data requirements mentioned is essential to perform a screening to ensure that the risk levels are at the same levels or lower compared to traditional IVI.

It is important to underline the importance of the CRA. It is essential in the NII methodology to have a detailed knowledge about the degradation mechanisms, their location and morphology to ensure appropriate selection of inspection methods and coverage. All inspection methods have different capabilities and limitations for detecting and sizing flaws. “You need to know what you are looking for, before you start looking”. If not, then the risk would increase and there may also be ongoing degradation in parts that has not been taken into account.

There are four different CRA levels mentioned in the recommended practice. The lowest level, just using historical inspection results and experiences, to the highest level (CRA Type 4) a detailed risk assessment also including theoretical calculations. The CRA is important and will influence the high level screening, which is performed later in the decision process. A poor CRA may result in not recommending a vessel to be performed with NII since the confident in the ability to predict both location and type of degradation is low.

2.3 Decision Process

In this part it is decided if vessels are suitable for non-intrusive inspection or not. The process is divided in to two parts, first a preliminary screening to screen out obvious vessels that aren`t recommended for NII and then a high level screening that ensures sufficient information is available and that the required inspection efficiency is being met.

2.3.1 Preliminary screening

The main purpose in this section is to rapidly identify which vessels that is not recommended, this could for example be due to that the vessel is not designed to perform NDT externally or it is not possible to attain the required information. The questions to be answered are shown in the flow diagram in Figure 2-2.

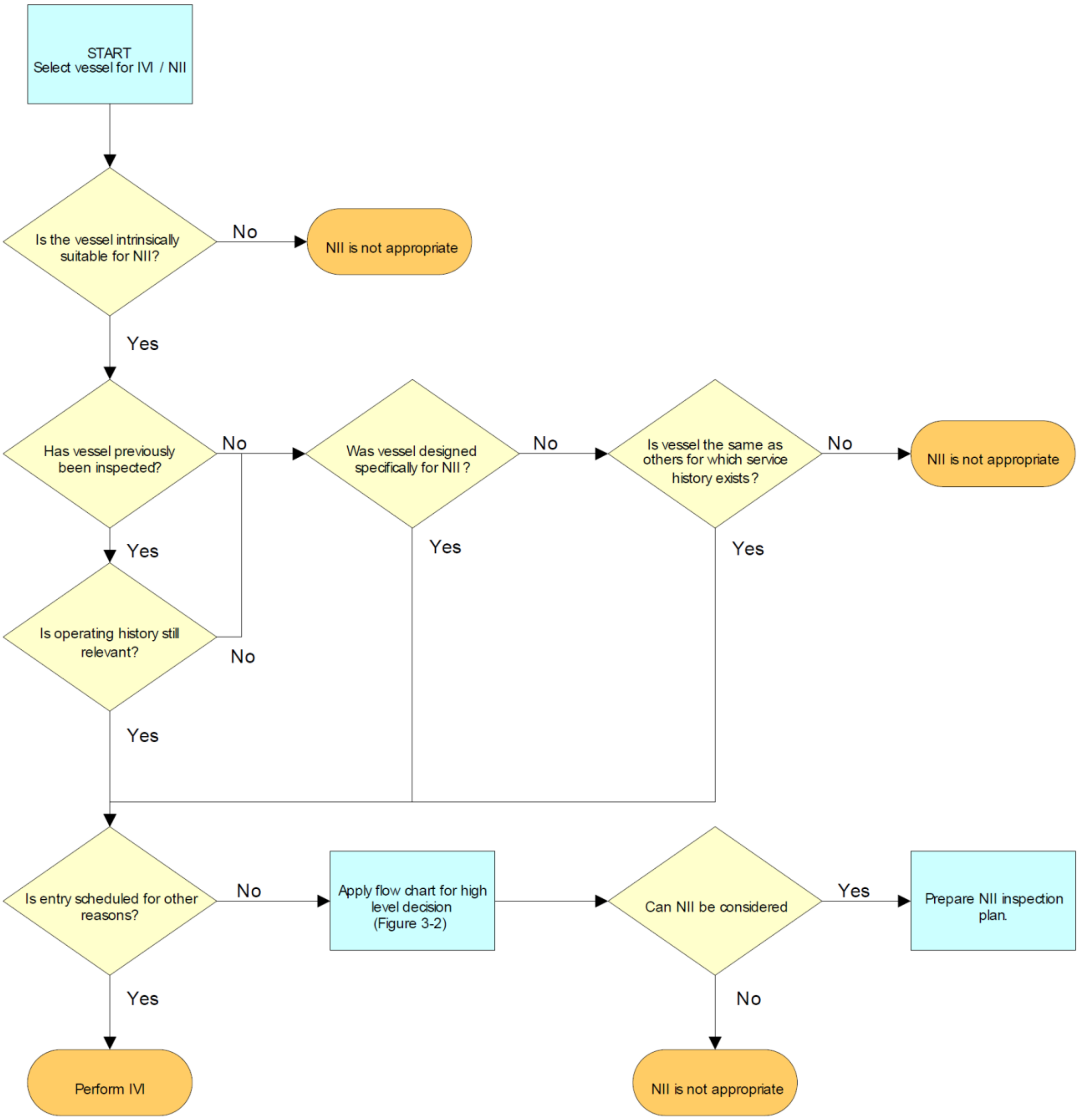


Figure 2-2: The NII preliminary screening procedure, where each questions answered leads to the final recommended decision (DNV, 2011).

It is chosen to explain the definition of the first question *"Is the vessel intrinsically suitable for NII?"* It means that if there are any obstacles for the NII being performed. This may for example be; no access to surface, constraints in geometry, extremely high temperatures, or other relevant obstacles prohibiting the externally NDT. The rest of the questions answer themselves.

2.3.2 High-level decision process

The high-level decision process is used to determine whether or not NII is appropriate in principle, and the decision is mostly based on the decision tree shown in Figure 2-3. The considerations taken in the decision tree are;

1) *Confidence in the ability to predict type and location of flaws*

   The ability to predict would depend on a large number of different factors, but the two main sources is evidential (From same or similar vessels) or theoretical (depending on the nature of the management system employed). The credibility of the evidence is directly linked to the amount information/data available from previously performed inspections. The confidence has therefore been divided into three categories, high, medium and low. Details of how to select the right category are given in the recommended practice. But as an example a “High” confidence level requires a thorough assessment. As a theoretical source it would require insurance that all relevant degradation mechanisms and their locations are predicted, which is graded as a CRA Type 4.

2) *Effectiveness of previous inspections performed*

   This is included to ensure that probability of failure is managed. Its intent is to compare effectiveness of the last inspection performed relative to the traditional IVI. The categories are divided into high, medium and low levels. High meaning better probability of detecting flaws than IVI, medium the same as IVI and low meaning lower than IVI. Details of how to select the right category are given in the recommended practice.

3) *The rate and severity of any predicted or known degradations*

   The worst affected zone of the vessel is used to consider if the severity and rate is threatening the integrity of the vessel within the remaining lifetime. The categories are divided into high, medium and low levels. High meaning that there can be a reasonable damage that threatens the integrity within the lifetime, medium that there are observable rates and degradation, but it is not expected to threaten the integrity during the vessels lifetime. And low meaning that there are degradation expected or just superficial degradation.

The decision whether NII is suitable or not is given directly from the flow chart in Figure 2-3. It is important to understand that the flow chart is covering cases where the intention is to fully replace traditional IVI with NII. However, the recommended practice can also be used for cases where NII is applied as a deferment of IVI, even if NII is not recommended according to the screening procedure in Figure 2-3. Details of how this is performed are covered in the recommended practice “Section 8”.

Figure 2-3: The NII High-level screening procedure, where each questions answered leads to the final recommended decision (DNV, 2011).

2.4 Planning process

2.4.1 Introduction

The main objective is to develop an inspection plan to ensure a satisfactory level of confidence until the next planned inspection. There are of course a lot of other considerations, and there may also be certain legislative requirements. The non-intrusive plan would include which parts that should be inspected, which methods should be used and the selection of coverage needed. The steps in planning and implementation of NII are the same, regardless whether the requirements are determined by a RBI or a more perspective choice. This means that if there is already a RBI of the piping in and out of the vessel, then a lot of the data is already available from this analysis which could be used in the NII analysis. The recommended practice provides a guideline of the elements that should be analyzed, which is shown in a flow chart (Figure 2-4).

The inspection planning team should consist of personnel with the competence within the following areas;

1) General knowledge about construction of vessels, fabrication, materials and material processing
2) Material and corrosion technology
3) Knowledge about the systems which is being under consideration, operational history and general knowledge
4) Knowledge about non-destructive testing

It is not required that the inspection planning team consist of individual specialists in all the different fields mention above. The team who is planning the inspections could be a small one to ensure that it is effective, but it is then very important that the skills or competence within the team is high enough to avoid overlooking something.

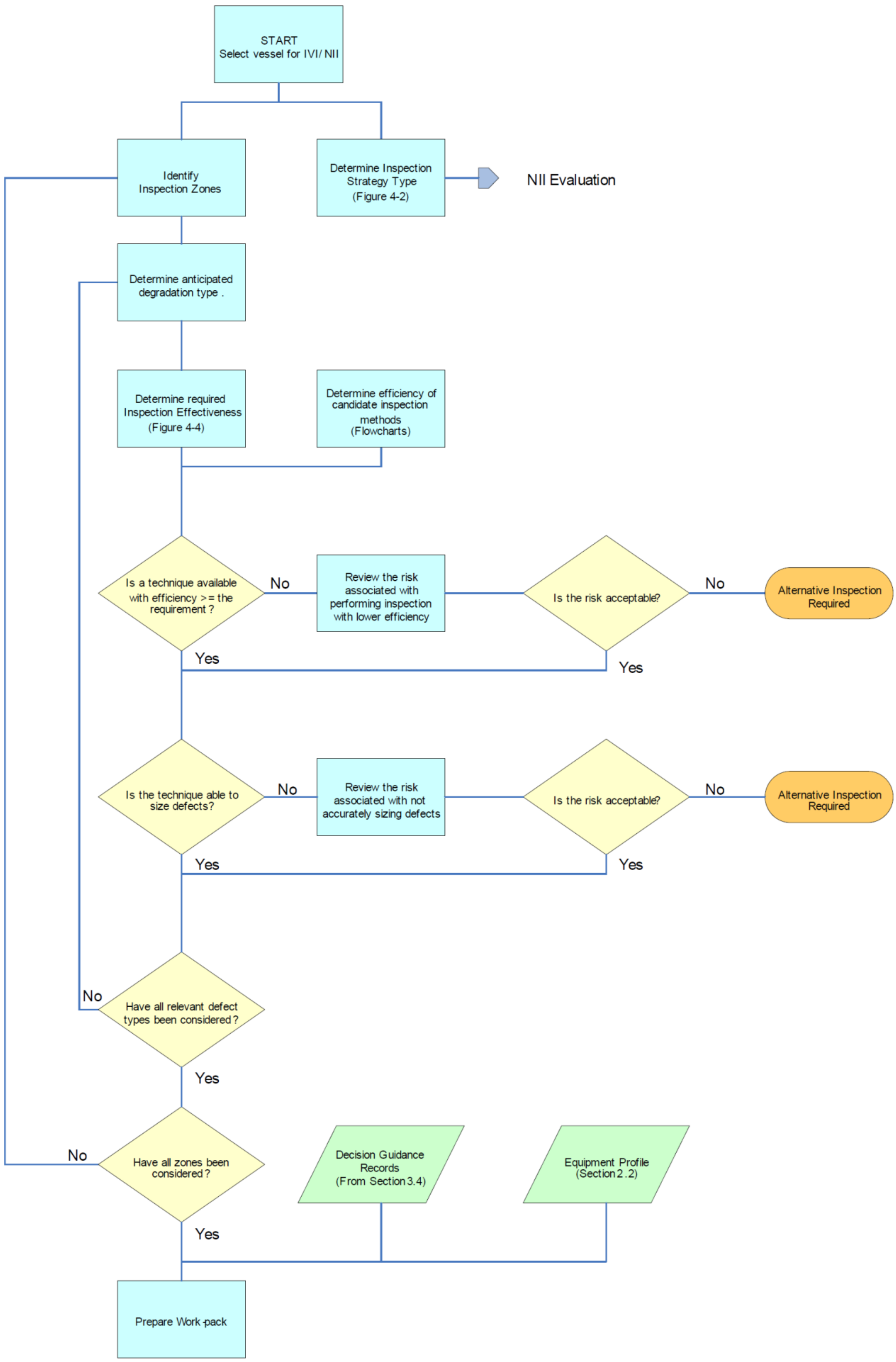


Figure 2-4: Inspection planning flow chart (DNV, 2011).

2.4.2 Inspection strategy type

The main objective is to ensure that any degradation with potential to threaten the integrity is detected before the next inspection. This means that the following three closely linked aspects must be taken into consideration, (1) degradation method, (2) potential to threaten integrity and (3) degree of assurance.

It is also important to give a degree of assurance that unexpected degradation mechanisms are not occurring during the development of the inspection program. This underlines the importance of knowing what, where and how possible degradation mechanisms occur, which is part of the CRA. This would also include information or evaluation related to a prognosis of future operational conditions, and not just evaluation of historical evidences.

There are defined three inspection types in the recommended practice which is a useful framework during the establishment of the inspection plan, and later during evaluations like the treatment of non-conformances. The definitions of each of the types are described in Table 2-1.

Type	*Definition*
A	Degradation mechanism NOT expected to occur. Inspection is required to confirm there is no onset of the degradation mechanism.
B	Degradation mechanism expected, with low / medium progression. Location of degradation can be predicted. Not anticipated to impact on vessel integrity in the medium term (typically at least 2 outage periods). Inspection required to confirm CRA predictions.
C	Degradation expected with medium / high progression. Location of degradation can not be predicted. MAY impact on vessel integrity in the medium term (two-outage timeframe). Inspection required to confirm absence of flaws of critical size.

Table 2-1: Definition of Inspection Types. Detailed information of each type is found in the recommended practice (DNV, 2011).

The selection of proper inspection types involves considerations of the degradation likelihood, degradation extent and degradation rate. The type is found by following the guidance presented in Figure 2-5. It is important to understand that the type categorization may vary from one zone to another, and it is therefore unique to a particular degradation mechanism.

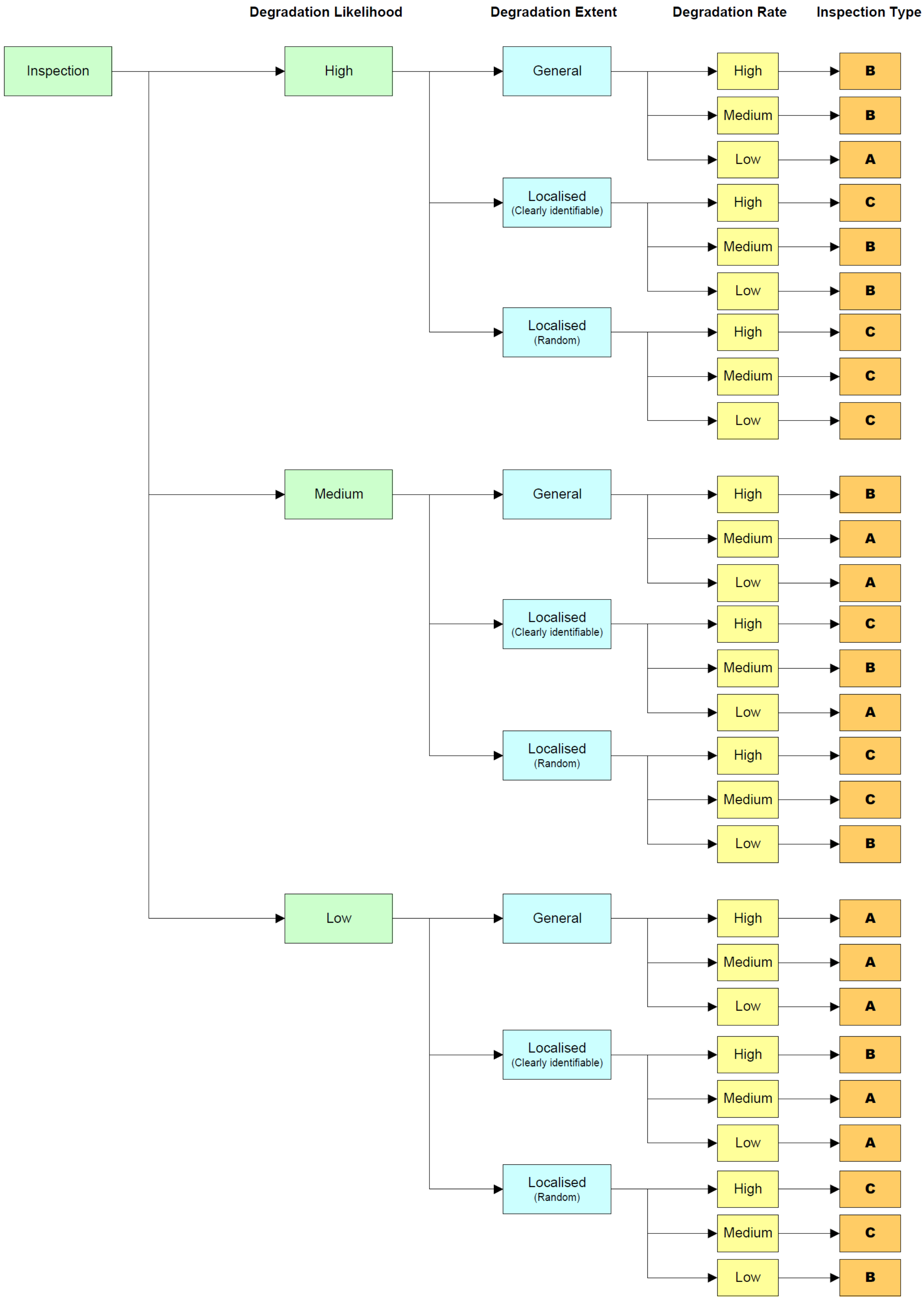
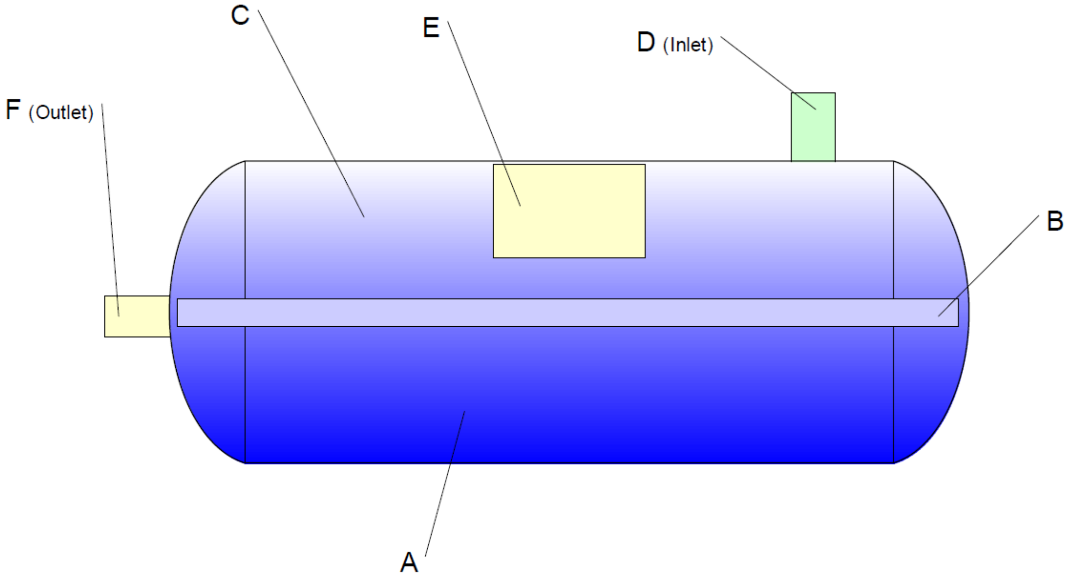


Figure 2-5: Selection of Inspection type (DNV, 2011).

2.4.3 Definition of vessel zones

Inspection methods have different capabilities and limitations, and it is also general impractical to perform NII of the entire vessel. The concept is to choose the most suitable inspection method for each zone, which represents different combinations of likelihood of degradation, remaining life tolerance and the practicality for inspection. There are many different factors that must be considered, like historical results, material, type and size of the degradation, and so on. All of the factors mentioned above provides a basis for which zone that should be inspected and is used to select a suitable method.

To simplify the selection, it is recommended to evaluate factors such as “design”, “inspection history” and “operational” separately. It is also important to mention that zones which are separate could be considered as one. This would apply if and only if the mechanism and inspection method capabilities allow them to be treated as one. Figure 2-6 below shows an example of how different zones may be defined for a vessel.



Zone	*Zone Identifier*
Liquid phase	A
Interface	B
Vapour phase	C
Inlet (liquid)	D
Previously reported corrosion	E
Outlet (mixed phases)	F

Figure 2-6: An example of how different zones may be defined (DNV, 2011).

2.4.4 Definition of degradation type

The main objective is to identify the expected degradation at each location/zone. It is important that the flaws are defined by its associated morphology, since this is the factor that would mostly effect the selection of the suitable inspection method. It is recommended to categorize the different flaw types at each location, like general loss of wall thickness, localized loss of wall thickness, cracks, and so on. As an example, it may be helpful to develop a matrix as shown in Table 2-2.

Vessel Feature	*Flaw type*			
	Localised LOWT	*Generalised LOWT*	*Localised cracking*	*Generalised cracking*
Set on Nozzle N1				
Shell welds				
Shell plate				
Saddle plate				

Table 2-2: Example of a matrix used to define flaw and feature combinations (DNV, 2011).

2.4.5 Required inspection effectiveness

The minimum required inspection effectiveness is defined for each of the vessel zones. The requirement will mainly depend on the likelihood of degradation, previous inspection results, tolerance to degradation and the consequence of vessel failure. The selection is performed by using the flow chart in Figure 2-7.

<u>Inspection grade;</u> is selected depending on the number of previously inspections, rate and predictability of the degradations. Detailed examples of the different grades and how the selection is performed are found in the recommended practice.

<u>Current tolerance to degradation;</u> is graded from low to high. High is defined as "no degradation expected or just superficial degradation occurring on the surface", medium "known or predicted degradation are observable during the lifetime, but not threatening the technical integrity of the vessel", and low "Degradation with a rate that would or may threaten the integrity during the lifetime".

<u>Consequence of failure;</u> is considered to ensure safe and reliable operation of the installation, which would influence the level of inspection required. It is recommended to divide the consequence by two areas "HSE" and "Cost of Business interruptions and consequence". The consequence would in many cases be defined by the company, but there are also a lot of standards that is helpful in the decision of how you should perform the consequence classification.

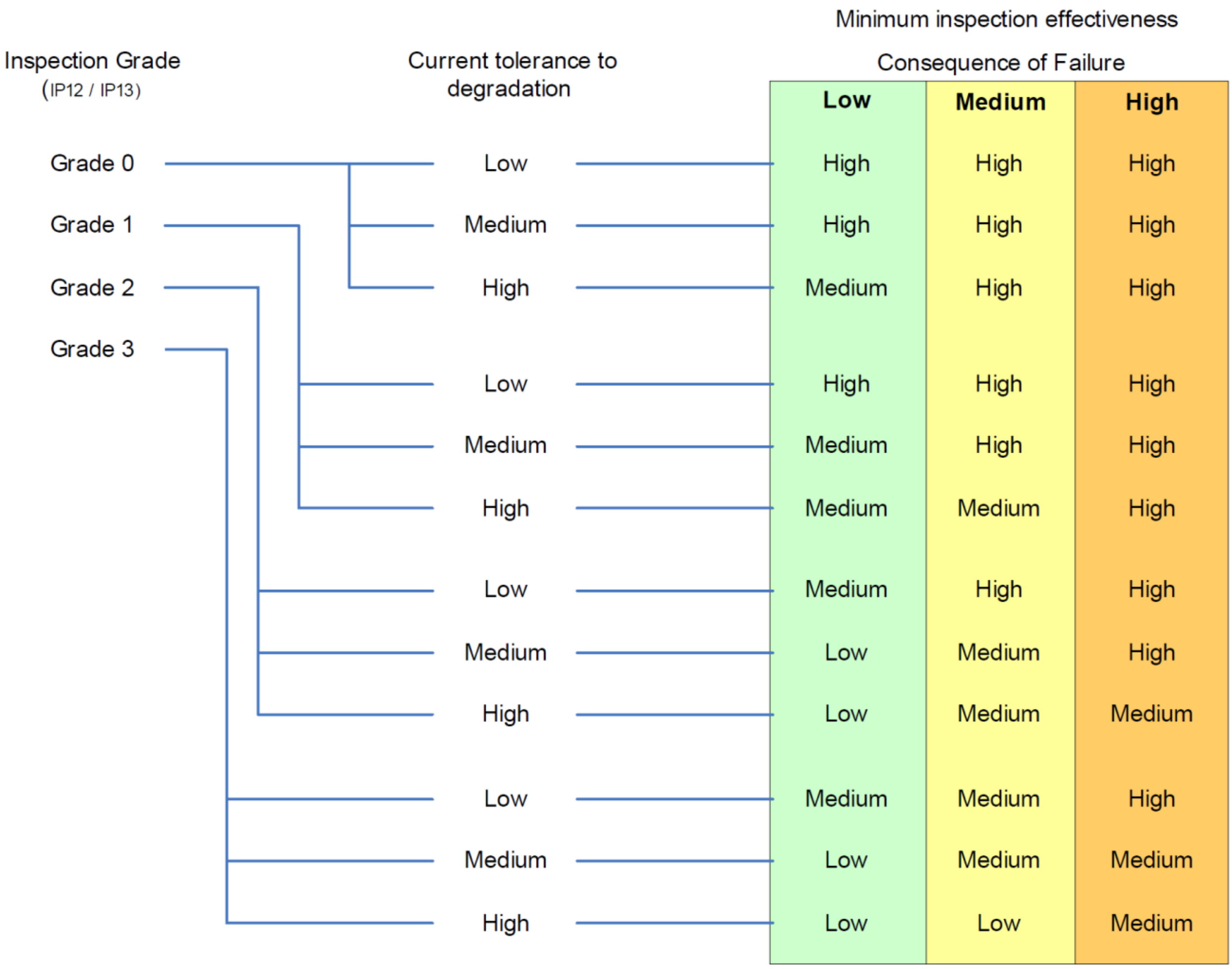


Figure 2-7: Inspection minimum effectiveness flow chart (DNV, 2011).

The flow chart provides the minimum required effectiveness for each zone, and the effectiveness is based on a qualitative measure of the probability of detecting flaws, including the coverage. The effectiveness is a function of the POD and coverage (Effectiveness=f(POD,xCoverage). There are given three categories, where high implies higher effectiveness than for IVI, medium similar to IVI, and low lower than IVI.

2.4.6 Coverage

The main intent is to establish a framework to ensure that the coverage is consistent with the ability to predict potential flaw areas and select the most suitable inspection method. It is important to underline that the defined coverage selectiveness requirements are not intended to determine the exact coverage for each zone of the vessel. This is covered in the chapter 2.4.3 “Definition of vessel zones”.

<u>Three different categories are defined;</u> the selection is determined according to the response given in the question in ability to detect flaws in Figure 2-3.

1. <u>Targeted;</u> selected if there is a high confidence in the ability to predict both type and location of degradation. The inspection could be restricted to where the degradation is expected.

2. Targeted plus exploratory; selected if there is a medium confidence in the ability to predict both type and location of degradation. Both uncertain and known areas of degradation must be inspected.

3. Global; selected if there is a low confidence in the ability to predict both type and location of degradation. The entire area under consideration must be inspected.

2.4.7 Selection of inspection method

Routine or specialized methods are selected depending on factor like access, geometry, morphology, surface, material and so on. The main purpose is selecting the correct inspection method(s) to safeguard the integrity of the equipment between inspections. The degradation likelihood would vary zone by zone and it is therefore important to consider how applicable each inspection method is in each of the zones. This is essential to ensure that the integrity of each zone is at an acceptable level between inspections.

The methods have different strength and weaknesses, and a flow chart has been developed to be able to select the proper method for the most common used methods in the context of NII. These charts are available in "Appendix F – NDT decision flow charts". It is important to underline that the method capability (POD/sizing) in the charts are classified in comparison with IVI, and they are defined according to the following three levels in Table 2-3;

Level	***POD***	***Sizing***
High	*Method with higher POD than IVI*	*Method able to give accurate, quantitative information about wall thickness or flaw size.*
Medium	*Method with similar POD compared with IVI*	*Method able to give semi-quantitative or comparative information about wall thickness or flaw size.*
Low	*Method with lower POD than IVI*	*Method able to provide limited, general quantitative information about wall thickness or flaw size.*

Table 2-3: POD and Sizing definitions (DNV, 2011).

The correct method is selected based on meeting the minimum required effectiveness given in Figure 2-7. This is performed by following each of the stages in the NDT decision flow charts in the following order;

Vessel feature → Flaw Type → Surface → Temperature → Thickness → Access

Typical vessel features considered in the guidance are limited to those shown in Figure 2-8 below.

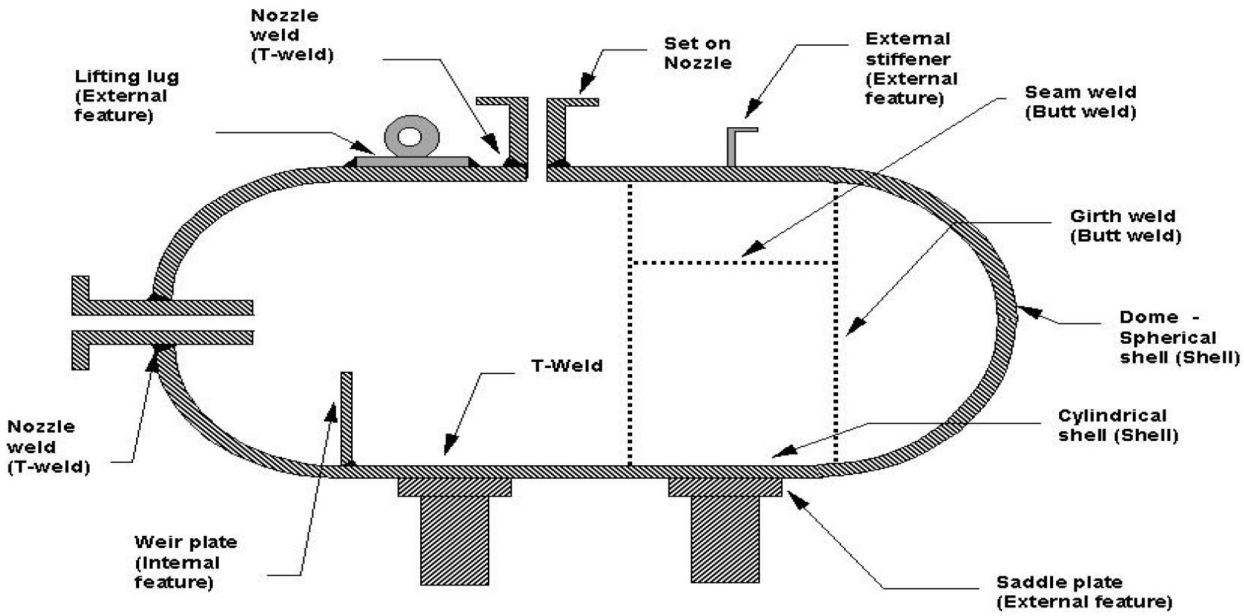


Figure 2-8: Vessel design, showing features considered (DNV, 2011).

It is important to mention that previously inspection effectiveness has a direct influence on the inspection plan and the decision whether the vessel is recommended for NII or not. This should also be taken into account when planning, due to alternative implications of effectiveness that may influence future inspections.

There are statistical methods available for the inspection planning process, but this is not part of the thesis, and is therefore not covered is this section.

3 Performing NII analysis

Legislative requirements are not included in the recommended practice, and to make sure that this is taken care of the requirements from the Norwegian petroleum authority are included. These are covered in the management regulations, mainly the paragraph §47 "Maintenance programs", which requires identification of failure modes that could pose HSE-risks. These modes require programs with activities to monitor degradation to ensure safe and reliable production (PSA, 2014). The company must according to the authority define its one strategy and requirements to ensure that the risks is on an acceptable level according to §47. This is covered in Statoil`s technical requirement, *TR1987 "Program activity for static process equipment and load-bearing structures*".

The technical requirement for pressure vessels states; *"For vessels where possible internal failure mechanisms that are suitable for periodic inspection has been identified, it shall be evaluated whether this can be handled by use of Non-intrusive Inspection according to DNV RP-G103"* (TR1987, 2014).

Based on the information above, the results in this thesis meet the requirements given by the Norwegian petroleum authority and the internal Statoil ASA technical requirements.

3.1 Scope of work

The scope of the thesis includes all of the production vessels in one of the production trains, including the test separator. A total number of six vessels, that historical has been opened for IVI during shutdowns where this is still the chosen inspection strategy, have been selected. (Specialist 4, 2015).

The offshore installation considered in the thesis has been in service for over 30-years, and the field has an increased water and decreased oil and gas production profile the last 10-20 years. It is more or less a tail production field, and the remaining life is assumed to be about 5 years. The topside oil processing system consists of two separate parallel production trains, and all of the wells could be routed to the most desirable train seen from a production viewpoint. The process flow is shown in Figure 3-1, and the production profile is available in Appendix C (Specialist 4, 2015).

The main function of the oil processing system is separating gas and water from the oil in several pressure stages by mainly decreasing the pressure in each of the flash drums. The test separator has the function by its name, and is mainly a vessel to measure and collect process information from each well. This may for example be information about sand production, oil, gas and water rates, and other relevant process information if required/needed.

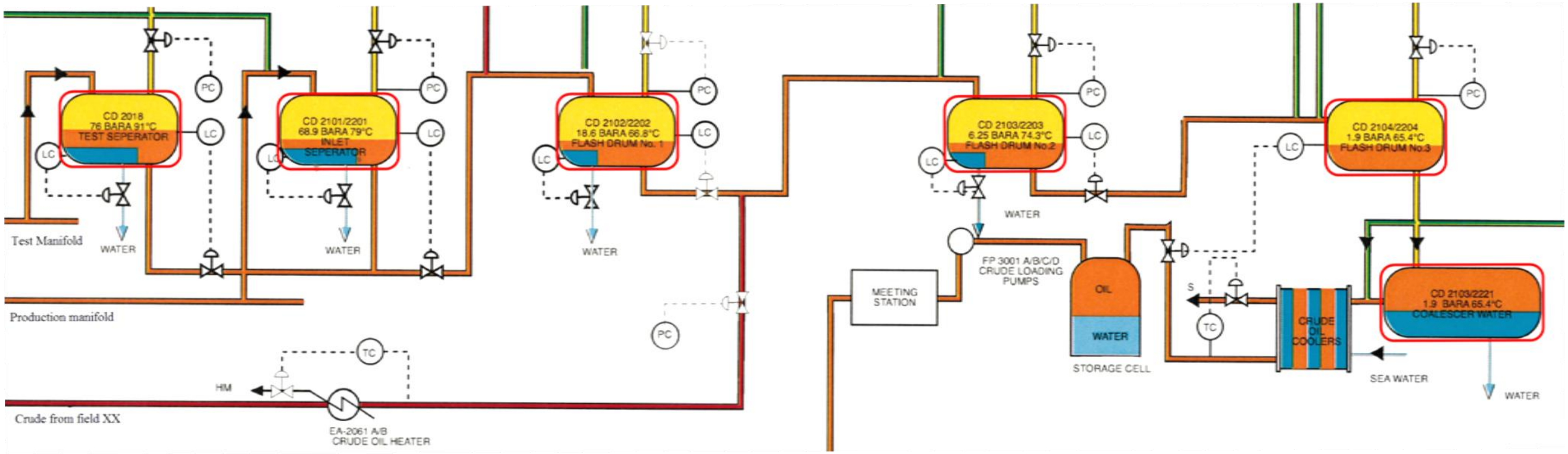


Figure 3-1: Process flow for the installation. The red rings marks out all of the vessels in the NII scope. The color coding is given as blue (water), yellow (gas), brown (Three phase, oil, water and gas) and green (Condensate) (SO0167, 2010).

3.2 Obtaining and collection of data

A large amount of the data from different systems within Statoil needs to be collected and summarized when performing the NII analysis. This is important to highlight as the information is essential. It is one of the foundations used in the screening procedures and to ensure a high quality analysis, which requires a lot of work and effort from the author. The raw data is not presented or attached as an appendix since it is internal and contains some confidential information.

<u>The systems used during data collection in Statoil:</u>

1. PI Processbook: A system that is used to collect process data, which may be used for trending, analyzing or visualization of parameters like flow, pressure, temperature and so on. Collecting and obtaining relevant process data used for example in the corrosion risk assessment.
2. SAP: A Maintenance and Management system in Statoil. Collecting and obtaining data related to maintenance programs, inspection history, costs and reported failure modes.
3. STIDtips: Technical Information Portal in Statoil. Used to collect and obtain mechanical design data, general arrangement drawings, process flow diagrams, and so on.

Data collected and obtained is summarized in a one-pager for each vessel, which is then used as the basis for the NII analysis. These are attached in Appendix A, and contain information about design data, process description, CRA and Inspection History. This is also referred as the "Integrity Review" according to the DNV recommended practice.

3.3 NII analysis of selected pressure vessels

The NII analysis methodology is similar for all vessel, and it is therefore chosen to present a detailed analysis of three selected pressure vessel in this chapter. The selection of presented vessels is not random, they are specifically chosen based on their different complexity and results. The results from the rest of the remaining vessels are shortly summarized chapter 3.4, and all the details are available in Appendix A to E. This is done to limit the number of pages in the main chapter, showing diversity in the decision making and at last a simplification in the review of the thesis.

3.3.1 Detailed NII analysis of the test separator CD2018

The author and specialists in inspection and corrosion technology in Statoil does not see the value in using a lot of hours in performing a detailed analysis. The vessel was part of the early scope, but the main reason for the early screening is based on;

1) <u>Corrosion point of view:</u> The test separator is used to test wells, which involves continuously change in vessel pressure, process medium, sand, temperature, CO2,

H2S and so on. It is therefore only possible to develop a corrosion risk assessment that is valid for each well test (Specialist 1, 2015).

2) Inspection point of view: The supporting structure limits access to a large amount of the bottom part of the vessel. Previous inspection history reports corrosion/erosion in the bottom level, which implies that this is one of the areas that would require a hundred percent coverage and access. Further, there is also an experience of corrosion in the sealing surface at the flanges. There are no known available inspection methods which can be used to inspect the sealing surface of the RTJ-flanges (Specialist 4, 2015).

The DNV recommended practice is a guideline of how the analysis should be performed. In this case the author together with specialists in the corrosion and inspection field has chosen to screen the vessels based on "sound engineering and commercial judgment by competent personnel". The above decision is according to and also highlighted in the DNV recommended practice. The data used in the above decision is available in the "Integrity Review" and the "NII analysis" respectively available in Appendix A and D.

3.3.2 Detailed NII analysis of CD2101

The author and specialists in inspection technology in Statoil does not see the value in using a lot of hours in performing a detailed analysis. The vessel was part of the early scope, but the main reason for the early screening is based on;

1) Inspection point of view: There is an experience of corrosion in the sealing surface at the flanges, and there are no known available inspection methods which can be used to inspect the sealing surface of the RTJ-flanges (Specialist 4, 2015).

The screening is based on the same principle as the test separator, "a sound engineering and commercial judgment by competent personnel". The data used in the above decision is available in the "Integrity Review" and the "NII analysis" respectively available in Appendix A and D.

3.3.3 Detailed NII analysis of Crude flash drum No. 3-CD2104

The worst location is chosen to be considered when answering the different questions and performing the analysis below. It provides an example that shows how the NII analysis is performed in detail. The rest of the areas/locations follows the same methodology, and are listed in tables under each chapter.

A) Integrity review

The data and information used in this section is available in one-pagers for each vessel in Appendix A.

A1) Mechanical and process data

Table 3-1 below summarizes the necessary mechanical and design data for the inlet pressure vessel.

Design Code	Design ASME VIII Div. 1
Design Pressure (barg)	3,4
Design Temperature (°C)	121
Material	Carbon Steel/SA-285-GR C
Corrosion Allowance (mm)	3,0
Thickness head/shell (mm)	10,5
Insulation	No
Sealing surface Nozzles	RF

Table 3-1: Mechanical data for crude flash drum no. 3 - CD2104 collected from the data system in Statoil ASA (STIDtips, 2015)

Table 3-2 below summarizes the necessary process data for the inlet pressure vessel.

Operating Pressure(barg)	0,95
Operating Temperature (°C)	66,5
CO_2 (mol%) measured 2013	0,5
H_2S (ppm)	12
Phase (Liquid, Gas, Water)	Three Phase
pH	9,1

Table 3-2: Process data for crude flash drum no. 3 - CD2104 collected from the data system and chemical responsible in Statoil ASA (STIDtips, 2015; Specialist 2, 2015; PI Processbook, 2015)

A2) Process description

Feed from crude flash drum No. 2 (CD2103) enters vessel in the top head section. The pressure is decreased to flash out lighter hydrocarbon components from the oil stream. The main function of the vessel is to separate gas from the oil stream. The vessel is directly connected with the underlying Coalescer (CD2121), which entails that there is not any water level inside the flash drum no. 3 (SO0167, 2010).

Comments: (Other relevant information, for example: dead legs, piece of equipment out of service, critical operations, planned modifications, "special operating conditions" for example change of media in vessel)

There is no known overview of nozzles that are dead legs, and these must be identified as experiences from other field's shows higher probability of CO_2 corrosion attacks due to accumulation of water and stagnant conditions. A case example in Appendix G is available to support the above statement (Specialist 4, 2015).

The vessel is coated with ceramic painting (Type CK54) from 5 to 7 o`clock (17% of internal surface coated) due to previous experience with corrosion attacks in the bottom part of vessels (SAP, 2015).

A3) Inspection history

The vessel has been opened for IVI in 2000, 2006 and 2009. The data below is collected from the maintenance and management system, SAP in Statoil ASA. Date of the data collection 2015-04-08.

Last inspection in 2009:
Reported overall good condition. No corrosion attacks were found on the wall surface or internally in any of the nozzles. However, corrosion was reported in the sealing surface of the manhole and nozzle K3A (% degradation of the sealing surface not reported, but the areas needed to be repaired during the shutdown). Small areas of the coating were damaged, these was not repaired and are known damages which shows no further developments since last IVI in 2006. Baseline thickness head/shell= 13/12 mm (SAP, 2015).

Historical inspections:
Previous inspections performed in 2000 and 2006 have reported overall good condition. Generally flange sealing surfaces have been repaired during shutdowns, which imply that there is a need to continuously inspect sealing surfaces in future shutdowns (SAP, 2015).

A4) Corrosion Risk Assessment (CRA)

Damaged Mechanisms
H_2S, CO_2, MIC, Erosion (Specialist 1, 2015).

CO_2: Calculations for CO_2 corrosion rate have been performed according to the Norsok M-506 model, and the results show an expected corrosion rate of approximately 0,25 mm/year. The allowed pH range of the model is pH 3,5 to 6,5, and an accurate corrosion rate for pH higher than 6,5 could not be calculated. The combination of 0,5mol% CO_2 and a pressure lower than 19barg causes the CO_2 fugacity to be lower than the area of validity in the model. The expected corrosion rate for pH 9,1and at a pressure lower than 19 barg will most likely be lower than 0,25 mm/year (Specialist 1, 2015; NORSOK M-506, 2005).

H_2S: The influence of H_2S could affect the corrosion rate depending on the H_2S/CO_2 ratio, but there are no available recognized standards that could be used to estimate the effects. This phenomenon needs more research. Sour service due to H_2S is not applicable since the partial pressure is lower than 0,3 kPa, however the sulfur may lead to general corrosion. This could be seen as a layer of FeS internal in the vessel (Specialist 1, 2015; TR2023, 2014).

Erosion: The damage mechanism is neglected since there is not a water jet system in combination with solids/sand. Further the amount of solids are lighter, more or less clay. There could however be a small amount of sand/solids that follows the oil stream when the water jet system is used in flash drum No. 2 (CD2103). The main reason is that sand particles could be stirred up during operation of the water jet system. The particles/solids are than mixed with the oil stream, and further on carried over in the oil outlet (Specialist 1, 2015; Specialist 3,2015).

MIC: Analysis performed during the shutdown in 2012 ranked possible MIC corrosion to be at the risk level medium/high. However corrosion would not occur if the coating is intact (Specialist 1, 2015).

CO_2 damage mechanisms would occur in the gas zone of the vessel, especially in areas where water condensates and accumulates. The corrosion can be relatively uniform (General corrosion). All of the above mentioned mechanisms could take place in the oil and water zone in the vessel. MIC and erosion can be highly localized (Localized corrosion). However, corrosion of the bottom part of the vessel will not occur if the coating is intact (Specialist 4, 2015).

A5) Structural integrity assessment

Fitness for service analysis according to API 579 Level 2 for local metal loss is performed. A localized corroded area of 15x15mm, with a remaining wall thickness of 3,5mm is allowed. This includes an uncertainty of 0,5mm for depth measurement performed with standard ultrasound inspection method (Specialist 5, 2015).

B) NII Decision process

Information and data used is available in Appendix A to D.

B1) Preliminary screening

Preliminary screening preformed according to Figure 2-2 in chapter 2.3.1 above.

A) Is the vessel intrinsically suitable for NII?
Yes, the vessel surface is easily accessible and there are no obvious limitations of performing NII. Based on offshore survey, see pictures in Appendix B.

B) Has the vessel previously been inspected?
Yes, several times and last inspected in 2009.

C) Is operating history still relevant?
Yes, there are no major changes that effects the operating history the last 6-years and for the future operation of the vessel. Details are available in Appendix C “Production profile and data”.

B) Is entry scheduled for other reasons?
No, there are no activities in the SAP maintenance management system that requires entry.

Preliminary screening result: Perform a high-level decision according to Figure 2-3 in chapter 2.3.2.

B2) High-level decision process

High-level decision performed according to Figure 2-3 in chapter 2.3.2.

A) Confidence in the ability to predict type and location of degradation?
Medium, based on a theoretical source CRA Type 2 performed. Selection of medium is also supported by an evidential source, the inspection history of three previously inspections summarized above for the vessel under consideration.

B) Previously inspection effectiveness?
Medium, based on that previous inspection is performed with IVI.

C) Severity and rate of degradation?
High, based on the degradation experience and repair history of sealing surfaces at the raised faced flanges. Sealing surfaces would require opening and repairs within the next 5 years (Within the expected lifetime of the installation).

High-level decision result: NII not possible mainly based on the answer given in the last question. However, if the previous inspections effectiveness had been high, then NII would be possible. A high previously inspection effectiveness would not change the experience related to degradation of flanges and NDT of sealing surfaces would actually reduce the risk of a potential failure prior to scheduled shutdowns. NII is possible and risk reducing based on the above justification.

C) Planning process

C1) Identify inspection zones

The inspection zones are first of all mainly divided based on the likelihood and type of degradation, areas with same or similar operational service. If needed, each zone is again divided based on previously inspection history and mechanical design and manufacturing factors. Data source used in the selection is available in chapter A) "Integrity Review". Description and location of each zone is found in Table 3-3 and Figure 3-2.

<table>
<tr><th>Tag No.</th><th>Description</th><th>Location</th><th>Zone</th><th>Feature</th></tr>
<tr><td rowspan="7">CD2104</td><td rowspan="7">Crude flash drum No 3</td><td rowspan="4">Above fluid level</td><td>A</td><td>Cylindrical Shell A</td></tr>
<tr><td>B</td><td>Cylindrical Shell B</td></tr>
<tr><td>C</td><td>Nozzles</td></tr>
<tr><td>D</td><td>Raised Faced surface</td></tr>
<tr><td rowspan="3">Below fluid level</td><td>E</td><td>Cylindrical Shell D</td></tr>
<tr><td>F</td><td>Nozzles</td></tr>
<tr><td>G</td><td>Raised Faced surface</td></tr>
</table>

Table 3-3: Inspection zones, locations and features for flash drum no. 3 - CD2104.

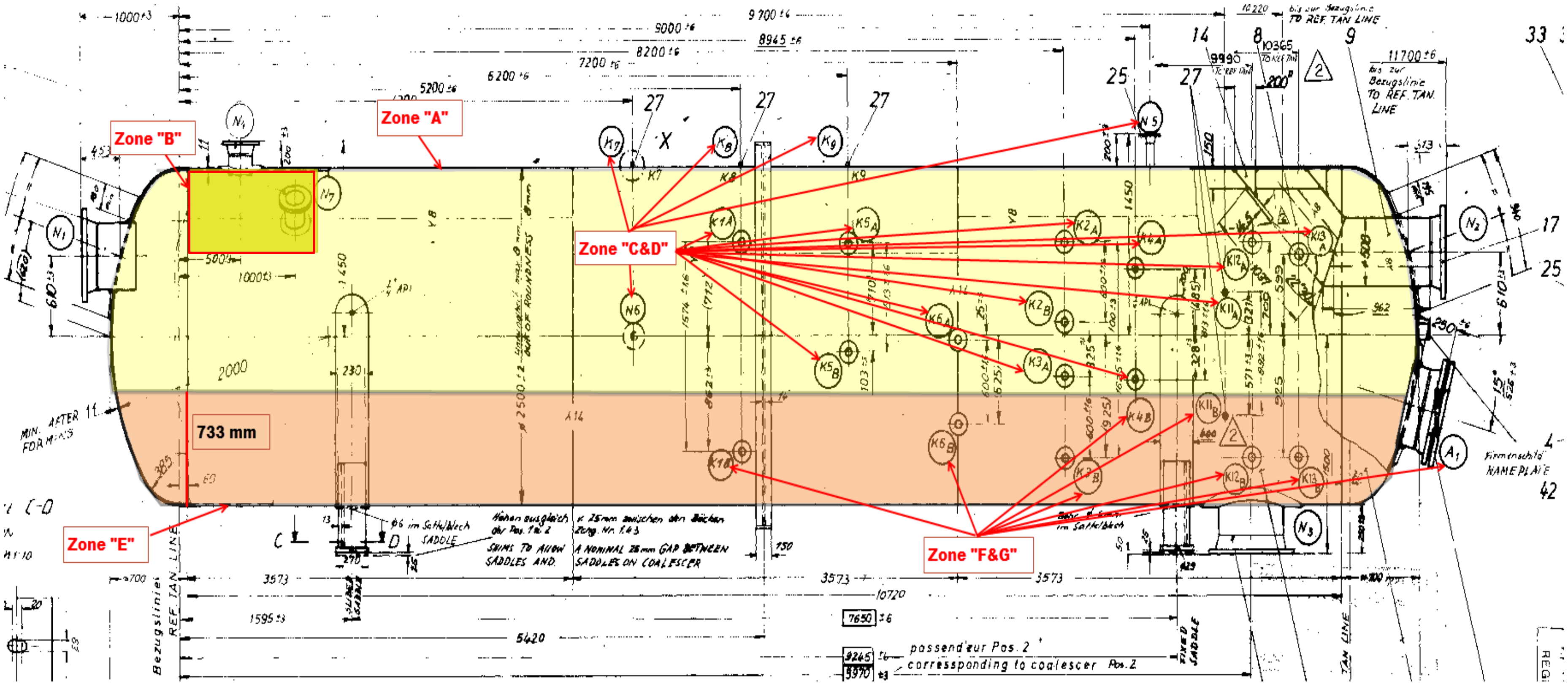


Figure 3-2: Inspection zones, locations and features flash drum no. 3 - CD2104. Brown area marks out the area with liquid (oil and water), and the yellow area the gas level (STIDtips, 2015).

C2) Definition of degradation type

Table 3-4 below shows the expected degradation mechanism and the corresponding defect type for each inspection zone. Data source used in the selection is available in chapter 3.3.3 A) “Integrity Review”.

Zone	Feature	Degradation Mechanism	Defect Type
A	Cylindrical Shell A	CO_2/H_2S	General Corrosion
B	Cylindrical Shell B	CO_2/H_2S	General Corrosion
C	Nozzles	CO_2/H_2S	General Corrosion
D	Raised Faced surface	Corrosion	Localized Corrosion
E	Cylindrical Shell D	MIC CO_2/H_2S	Localized Corrosion General Corrosion
F	Nozzles	MIC CO_2/H_2S	Localized Corrosion General Corrosion
G	Raised Faced surface	Corrosion	Localized Corrosion

Table 3-4: Degradation mechanism and defect type for each inspection zone for flash drum No. 3 - CD2104.

C3) Determine inspection strategy type

Inspection strategy type performed according to Figure 2-5 in chapter 2.4.2 .

A) Degradation likelihood?
High, based on the degradation experience and repair history of sealing surfaces.

B) Degradation extent?
Localized (Clearly identifiable), based on the degradation experience and repair history of sealing surfaces.

C) Degradation Rate?
High, based on the degradation experience and repair history of sealing surfaces at the raised faced flanges. Sealing surfaces would require opening and repairs within the next 5 years (Within the expected lifetime of the installation).

Inspection type result: Inspection Type C, based on sealing surface corrosion experience which is the worst location of the vessel. However, Table 3-5 shows that degradation internally in the shell and nozzles is rated differently.

Zone	Feature	Degradation Likelihood	Degradation Extent	Degradation Rate	Inspection Type	Comment
A	Cylindrical Shell A	Medium	General Corrosion	Medium	A	Based on CRA probability and corrosion rate
B	Cylindrical Shell B	Medium	General Corrosion	Medium	A	Based on CRA probability and corrosion rate
C	Nozzles	Medium	General Corrosion	Medium	A	Based on CRA probability and corrosion rate
D	Raised Faced surface	High	Localized Corrosion (Clearly identifiable)	High	C	Based on inspection history
E	Cylindrical Shell D	Medium	Localized Corrosion General Corrosion	Medium	A	Based on CRA probability and corrosion rate
F	Nozzles	Medium	Localized Corrosion General Corrosion	Medium	A	Based on CRA probability and corrosion rate
G	Raised Faced surface	High	Localized Corrosion (Clearly identifiable)	High	C	Based on inspection history

Table 3-5: Inspection strategy type for each inspection zone in flash drum No. 3 - CD2104.

C4) Determine minimum inspection effectiveness and coverage

Minimum inspection effectiveness and coverage performed according to Figure 2-7 in chapter 2.4.5 and 2.4.6.

A) Inspection grade?
Grade 0, rate of degradation high based on the degradation experience and repair history of sealing surfaces at the raised faced flanges.

B) Current tolerance to degradation?
Low, failure at sealing surfaces at raised faced flanges expected within the remaining lifetime of the installation (Next 5 years).

C) Consequence of failure?
High, based on the criticality assessment of the equipment (Containing oil and gas, and a failure may lead to high HMS consequences)

D) Coverage?
Targeted plus, but justified to Global due to experience of damages at raised faced flanges.

Minimum inspection effectiveness and coverage: High minimum inspection effectiveness and coverage Global, based on sealing surface corrosion experience which is the worst location of the vessel. However, Table 3-6 below shows that effectiveness and coverage internally in the shell and nozzles is rated differently. The coverage from the bottom part of the vessel is changed from targeted puss to global, since corrosion would occur in areas where the coating is damaged.

Zone	Feature	Inspec-tion grade	Current tolerance of degradation	Consequence of failure	Minimum inspection effectiveness	Confi - dence (Figure 2-3)	Coverage
A	Cylindrical Shell A	Grade 3	Medium	High	Medium	Medium	Targeted plus
B	Cylindrical Shell B	Grade 3	Medium	High	Medium	Medium	Targeted plus
C	Nozzles	Grade 3	Medium	High	Medium	Medium	Targeted plus
D	Raised Faced surface	Grade 0	Low	High	High	Medium	Global
E	Cylindrical Shell D	Grade 3	Medium	High	Medium	Medium	Global
F	Nozzles	Grade 3	Medium	High	Medium	Medium	Global
G	Raised Faced surface	Grade 0	Low	High	High	Medium	Global

Table 3-6: Minimum inspection effectiveness and coverage for each inspection zone in flash drum No. 3 -CD2104.

C5) Determine efficiency of candidate inspection methods

The inspection methods are chosen based the experience/knowledge of the inspection responsible in Statoil and it is therefore not needed to work through all of the NDT flow charts in Appendix F. The flow chart for the selected inspection method is consulted to ensure that the method has at least the minimum inspection effectiveness required according to Table 3-6. The required information and selection of inspection methods are given in Table 3-7.

Zone	Feature	Defect Type	Surface	Surface temperature	Thickness	Minimum inspection effectiveness	Selected technique (POD/sizing)
A	Cylindrical Shell A	General	Paint	About 60°C	13/12 mm	Medium	Phased Array – XY scanner(H/H)
B	Cylindrical Shell B	General	Paint	About 60°C	13/12 mm	Medium	Phased Array – XY scanner(H/H)
C	Nozzles	General	Paint	About 60°C	Various	Medium	TOFD/Phased Array(H/H)
D	Raised Faced surface	Localized	Paint	About 60°C	Various	High	Flange scanner – Phased Array (H/H)
E	Cylindrical Shell D	Localized General	Paint	About 60°C	13/12 mm	Medium	Phased Array – XY scanner(H/H)
F	Nozzles	Localized General	Paint	About 60°C	Various	Medium	TOFD/Phased Array(H/H)
G	Raised Faced surface	Localized	Paint	About 60°C	Various	High	Flange scanner – Phased Array (H/H)

Table 3-7: Selection of NDE techniques for each inspection zone in flash drum No. 3 - CD2104.

All of the techniques in the table above meet the minimum required effectiveness. The list does not cover exact dimensions and location of each zone. This must be provided in a specified work package before execution of the NII inspection scope. Welds are considered to be ground flat at cylindrical shell, if there are areas where welds aren`t ground flat TOFD is to be used. HT (High temperature) equipment is available if needed.

3.4 Summarized results from the remaining vessels

The data used in the decisions is available in Appendix A to D. It is worth mentioning that all of the vessels from CD2102 to CD2121 have a lower pressure class, and they do not have any RTJ-flanges. However, all of the vessels have the same experience related to corrosion of sealing surfaces at the flange connections.

3.4.1. NII result Crude flash drum No. 1 (CD2102)

NII is possible. Inspection zones, coverage and selected inspection methods are defined in Appendix D, and detailed drawings of vessel marked with inspection zones are available in appendix E.

3.4.2. NII result Crude flash drum No. 2 (CD2103)

NII is possible. Inspection zones, coverage and selected inspection methods are defined in Appendix D, and detailed drawings of vessel marked with inspection zones are available in appendix E.

3.4.3. NII result Coalescer (CD2121)

NII is possible. Inspection zones, coverage and selected inspection methods are defined in Appendix D, and detailed drawings of vessel marked with inspection zones are available in appendix E.

4 Performing cost benefit analysis

The four vessels that could be inspected externally according to the NII methodology are selected in the cost benefit analysis. Actual costs are used in the detailed assessment, but due to confidentially the rates and amounts are removed in the thesis. Instead it is chosen to use a fraction factor.

Table 4-1 lists up the cost benefit results for each vessel and all combined.

TAG	Description	Scaffolding	Insulation	Area(m^2)	Fraction(Cost IVI/Cost NII)
CD2102	Crude flash drum No. 1	NA	YES	66	2,21
CD2103	Crude flash drum No. 2	YES	YES	67	1,61
CD2104	Crude flash drum No. 3	NA	NA	42	0,8
CD2121	Coalescer	YES	NA	115	3,6
Total fraction (Tot. costs IVI divided tot. costs NII)				**290**	**2,24**

Table 4-1: Cost benefit analysis of vessels possible for NII. Area given in the table indicates the vessel surface that needs to be inspected.

The cost benefit analysis performed indicates that the cost of IVI is about twice as high that NII. The estimate above does not include the production loss due to opening of equipment when performing IVI. The fraction above would be higher if production loss is included, but the calculation would depend on several factors, some of them listed below;

A) The amount of vessels that are not opened during a future shutdown.
B) If some of these are in the critical line of work, governing for the finish date of the shutdown.
C) Maximum allowed resources onboard the installation during the shutdown.
D) The amount of mechanical resources available during the shutdown.
E) Location of the process equipment.

These are just some of the factors, and in combination all of these would affect the time needed to finish within a given timeline during a shutdown. Hours saved on one vessel could not be directly calculated as saved loss of production days. The amount of resources released works in many different disciplines, and just a small amount of hours is directly released to decrease the timeline of the shutdown. The maximum number of allowed resources onboard the installation will also affect the calculation. This is just a small example that shows that it is not possible to develop a standard practice to calculate the reduction of days. Each case must be treated separately to ensure reliable estimates.

However, the estimated cost related to production loss would not affect the decision it this case since the costs of performing IVI is higher than the costs of NII. The estimated loss of production would just strengthen the decision to recommending NII.

Benefits of performing NII: (1) Reduced loss of production and costs, (2) Removes the uncertainty of potential mechanical damages during preparation for internal inspection, and

(3) Reduces HSE risks due to no entering of the vessels during preparation activities and inspection.

The recommendation is clear, NII is cost reducing combined with several HSE benefits. NII should be performed based on the above justification.

5 Discussion

The discussion is divided into three parts, following the structure of the thesis. The first part covers a discussion of the theoretical part of the NII methodology, followed by a discussion of the NII analyze results, some recommendations and viewpoints, and at last challenges during the thesis.

5.1 NII methodology

<u>Section 2 of the DNV recommended practice;</u>

Figure 2-1 shows a flow chart “overview of the process”. Two headline boxes are recommended to be changed. The first one, “selection of vessels”, is not explained in the detailed text part of the RP and the reader would be confused since he would look through the text without finding any explanation of how to select vessels. There should be added a headline, and a short recommendation of who, what and how to select vessels.

The second one, “Determining the next inspection date”, is not explained in the detailed text part of the RP and the reader would be confused since he would start looking through the text without finding any explanation of determining the next inspection date. The headline box should be removed, the next inspection date does not have any influence on the decision whether NII is possible or not.

<u>Section 3 of the DNV recommended practice;</u>

In the high-level screening process the question of “Confidence in the ability to predict type and location of degradation”, the RP has an example under the evidential requirement for selecting high. Quoting the sentence “Note that extensive experience is taken to mean that data is available covering at least eight inspections in total and not less than two inspections for the longest serving single vessel used in making the judgment, at least one of which should have been a close visual inspection (internal or external depending on the nature of the degradation)” (DNV, 2011). It is not understandable why the RP is mentioning visual external inspection, when the whole methodology is based on internal degradation. It is also stated in the scope of the RP, in chapter 1.3, that it does not consider the impact of external degradation. The impact of external corrosion is however used in a case example in the RP, rating the “severity and rate of corrosion” based on external corrosion. The details of the case example are available in chapter 3.5.3 “Separator vessel”. This is not consistent with the methodology, and it is recommended to correct the content in the RP.

<u>Section 4 of the DNV recommended practice;</u>

Figure 2-4 shows the whole inspection planning process. However, the order of the boxes should be changed. To be able to select and determine inspection strategy type, you must first identify the zones, and then determine anticipated degradation type at each zone.

The coverage selection is a weakness of the standard. The coverage selected and used as a framework should be selected zone by zone, and shall not be based on a general response given in the question “Confidence in ability to predict types and locations of degradation” in Figure 2-3. For example, when the response is high or medium, the RP states targeted or targeted plus coverage. This does not consider if the vessel is internally coated in the bottom part, which implies that there should be a global coverage of this zone. It does not help the user/reader to select the recommended coverage, and it is recommended to include text stating that the coverage should be assessed zone by zone as part of the standard.

5.2 NII Analysis Results

NII inspection is recommended for four out of six vessels. The decision is also supported by the cost benefit analysis, which implies that the costs are reduced together with increased benefits. The two first separators (inlet and test) were mainly screened-out due to no available inspection methods for inspection of the sealing surface of RTJ-flanges.

It is important to highlight the experience of corrosion in sealing surfaces. This is a known mechanism applicable to all of the vessels. The common repair practice is coating with Belzona, which is a ceramic filled epoxy coating. When the NDT operator scans a flange with an old damage, it would appear as a corroded area. This would be reported as a finding, and previous reports contain limited information about the accurate location and morphology of the old flaws/repairs. The question if this is an old or new damage is raised? Based on the above justification, the answer would be that it is probably an old damage, but it would be far from certain. A new inception must be scheduled to document if there is ongoing degradation. There are always uncertainties in all of the inspection methods, and the newly scheduled inspection may show a slight increase in degradation even if there has not been any further development. The above case would generate a decision to open the flange for close visual inspection, which requires a shutdown of the installation. To support the justification above, old case examples of corroded sealing surfaces are attached in Appendix G.

The above case example show how a decision to perform NII can be made, which is also supported by a cost benefit analysis. But it is in this case a poor decision that actually will increase costs and unnecessary usage of resource. Scanning of the flanges will report findings that actually would require a shutdown to perform close visual inspection of the sealing surfaces.

5.3 Recommendations and viewpoints

NII is not recommended to fully replace traditional IVI before there are available detailed reports of each sealing surface, which must include exact location, depth and morphology of the repaired damage. This requires opening of the nozzles during the next scheduled shutdown and inspection of the flanges. If earlier repairs are considered fit for service, meaning that old repairs are not damaged and the rest of the sealing surface are not corroded, then the surface must be scanned with phased array. The results from the scan must be saved and used as a blueprint for future inspections when performing NII.

The recommendation above enables implementation of NII for all vessels with raised faced sealing surfaces, and to enhance the usage of NII there should be increased focus on future development of methods which can be used to inspect the sealing surfaces of RTJ flanges.

A much more sustainable alternative for the future is the usage of corrosion resistant materials, which in this case could be achieved through welding the sealing surfaces with corrosion resistant material. This would remove the uncertainties related to corrosion and inspection of the sealing surfaces.

The above alternatives are not recommended for this installation due to the short remaining lifetime. The installation would not benefit from these since there is just one last scheduled shutdown in the future. However, similar installations with a longer remaining lifetime with two or more scheduled shutdowns should consider the above recommendations.

Implementation of NII should also be seen in correlation with challenges in the industry related to corrosion under insulation. There are significant benefits of combining NII and a corrosion under insulation program. Cost and scope is reduced since parts of the insulation must be removed to get access to the external surface during NII.

The NII methodology reduces risks related to potential leakages since there is no need to disassemble pipe/nozzle connections, which could be misaligned during mechanical assembly of the connections.

It is important to emphasize that the installation under consideration has an old design philosophy, and it has been in service for over 30-years. It is not surprising that implementation of NII is a challenge, and there may, as mentioned earlier in the thesis, be other less corrosive vessels where the NII methodology is more suitable. It is not part of the thesis, but it is important to mention that newer installations usually designs vessels with corrosion resistant cladding internal, and the NII analysis would be completely different for these. But these vessels are not completely free of challenges, and there are a lot of experiences today with cladding flaws from fabrication in the nozzle to shell connections. And as an example, both IVI and external NDT would not detect areas where the cladding is to thin (Specialist 4, 2015).

5.4 Challenges during the thesis

The main challenge during the writing process was that a lot of the work and information is confidential. The author therefore had to consider the data very carefully before presenting it in the thesis. As a result it was difficult to justify some of the decisions and present details of the work in the thesis, especially when certain facts and evidence had to be left out.

6 Conclusion

The conclusion is divided into two parts, the first a specific that covers the NII analysis of the vessels in this thesis, and the last a general which covers mainly the theoretical parts of the thesis, the DNV-RP-G103.

6.1 General

During the analysis the RP is considered to be a very useful guideline. It uses flow diagrams combined with detailed text and case examples that are very useful and understandable throughout the analysis. However, during the work with this thesis it has been identified sections and text that should be improved; These are (1) missing text and explanation to some of the flow chart boxes, (2) the RP states that it doesn't consider the impact of external degradation, but it has been found to be actively used in the RP in evaluation during high level decision process and in one case example, and (3) in the coverage selection it uses the confidence of the whole CRA during selection. This is misleading, and the assessment should be performed zone by zone. The author would report back the publisher, and purposed improvements of the DNV RP.

6.2 Specific

NII is not recommended for any of the vessels considered in this thesis. It is possible to perform NII of four out of six vessels after the detailed analysis, which also is supported by a cost benefit analysis that estimates IVI to be more or less about twice the cost compared to NII. However, when looking at the maintenance management loop there is a challenge in the future related to corrosion of sealing surfaces. It is possible to inspect them, but old flaws are repaired by coating and would appear as a new flaw during external inspection with NDT methods. There are not any detailed reports describing the exact location and morphology of previous defects, and this leads to a need for close visual inspection of the sealing surface to ensure that there are not any ongoing degradation.

Implementation of NII would increase the costs for inspection of these vessels, and the risks and benefits of performing NII are no longer valid. The analysis is performed for the most corrosive part of the installation, and the results may have been different if the analysis was performed in other parts of the process. However, this analysis is considered useful as a basis for analysis of other vessels onboard the installation

7 References

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Appendix A – One pager design data, process description, CRA and Inspection History of vessels – Integrity Review

All of the "one pagers" (Integrity Review) developed below for each vessel is built up from multiple sources and references. These are the same under each heading and vessel, therefore it is chosen to list up which references and systems that are used for each heading. This is done to simplify the review and avoiding repeating these for each vessel/heading.

Reference and system overview;

- Mechanical Data (STIDtips, 2015)
- Process Data (STIDtips, 2015; Specialist 2, 2015)
- Process Description (SO0167, 2010; Specialist 4, 2015; SAP, 2015).
- Inspection History (SAP, 2015)
- Corrosion Risk Assessment – CRA (Specialist 1, 2015; NORSOK M-506, 2005; Specialist 1, 2015; TR2023, 2014; Specialist 3, 2015).

A.1 Test separator CD2018

Mechanical Data: (Design ASME VIII Div. 2)

Design Pressure (barg)	89,7
Design Temperature (°C)	121
Material	Carbon steel SA-516-GR70
Corrosion Allowance (mm)	3,0
Thickness head/shell (mm)	70/65
Insulation	Yes
Sealing surface Nozzles	RTJ&RF*

Process Data: (In operation)

Operating Pressure(barg)	0 to 55
Operating Temperature (°C)	10 to 85
CO_2 (mol %) measured 2013	0,5
H_2S (mol %)	N/A
Phase (Liquid, Gas, Water)	Three Phase
pH	7,0

*Note: Raised faced (RF) and Ring Type Joint (RTJ)

Process Description:

Feed is based on which well that is tested, and time on test for each well can vary which is the main reason for the variety in the operational parameters listed above. The main function of the vessel is to collect process information from each well, for example information about sand production, oil, gas and water rates. The H2S is not listed above due to high variation in depending on which well that is tested.

Comments: (Other relevant information, for example: dead legs, piece of equipment out of service, critical operations, planned modifications, "special operating conditions" for example change of media in vessel)

There is no known overview of nozzles that are dead legs, and these must be identified as experiences from other fields show higher probability of CO_2 corrosion attacks due to accumulation of water and stagnant conditions. A case example in Appendix G is available to support the above statement.

The vessel is coated with Belzona from 2 to 10 o`clock due to previous experience with corrosion attacks in the vessel. Three anodes are mounted in the bottom part of the vessel (Type ZT780, New in 2007).

Inspection History **Date of collection 2015-03-03**

The vessel has been opened for IVI in 2006, 2007, 2009, 2011 and 2014. Baseline thickness head/shell = 76/66mm

Last inspection in 2014:
Reported overall good condition. No corrosion attacks were found on the wall surfaces or internally in any of the nozzles. However, corrosion was reported in the sealing surface of the manhole and the nozzles K1B and N9 (from 50 to 100% of primary sealing surface on RTJ flanges). Small areas of the Belzona coating were damaged and the damages were localized in the area where the coating was repaired in 2011. The anode consumption was lower than 5% (New installed in 2007).

Historical inspections:
Previous inspections performed in 2006, 2007, 2009 and 2011 reported localized corrosion in the bottom part of the vessel, with depths up to 10,0 mm. These are known damages, and no further development of the corrosion attacks have been observed. Generally Belzona and flange sealing surfaces have been repaired during each shutdown, which implies that there is a need to continuously maintain the coating and inspect sealing surfaces in future shutdowns.

Corrosion Risk Assessment (CRA)

Damage Mechanisms

H_2S, CO_2, MIC, Erosion.

CO_2: Calculations for CO_2 corrosion rate have been performed according to the Norsok M-506 model, and the results show an expected corrosion rate of approximately 0,15 mm/year. The allowed pH range of the model is pH 3,5 to 6,5, and an accurate corrosion rate for pH higher than 6,5 could not be calculated. The expected corrosion rate for pH 7 will most likely be lower than 0,15 mm/year.

H_2S: The influence of H_2S could affect the corrosion rate depending on the H_2S/CO_2 ratio, but there are no available recognized standards that could be used to estimate the effects of H_2S on the corrosion rate. Sour service and risk of cracking due to H_2S is not applicable as the partial pressure is lower than 0,3 kPa. However, H_2S may contribute to corrosion if an iron sulphide is deposited on the steel surface

Erosion: Erosion can occur in the bottom part of the vessel shell where the water jet system is used to remove sand and solid that have settled in the bottom of the vessel. The erosion rate depends on the amount of sand/solids, particle size, nozzle orientation and water pressure when operating the water jet system. (Skriv heller noen få ord om erfaringer med erosjon pga jetting, og at dette er en reell risiko).

MIC: Analysis performed during the shutdown in 2012 ranked possible MIC corrosion to be at the risk level medium/high.

Corrosion of the bottom part of the vessel will not occur if the Belzona coating is intact and if the sacrificial anodes are working properly.

The test separator is used to test many different wells, and this causes continuous changes in vessel pressure, temperature, process medium, flow rates, sand content, temperature, CO_2-/H_2S-content, and so on. Due to frequent changes of wells being tested there is a risk that the corrosion risk assessment will not be valid for the true operational conditions. The corrosion risk assessment should not be used as a basis for future expected corrosion mechanisms and corrosion rates, as these will change for every well being tested.

A.2 Inlet separator CD2101

Mechanical Data: (Design ASME VIII Div. 2)

Design Pressure (barg)	89,7
Design Temperature (°C)	121
Material	Carbon Steel SA-516-GR70
Corrosion Allowance (mm)	3,0
Thickness head/shell (mm)	100,7
Insulation	Yes
Sealing surface Nozzles	RTJ&RF*

Process Data: (In operation)

Operating Pressure(barg)	38
Operating Temperature (°C)	52
CO_2 (mol%) measured 2013	0,5
H_2S (ppm)	10
Phase (Liquid, Gas, Water)	Three Phase
pH	7,0

*Note: Raised faced (RF) and Ring Type Joint (RTJ)

Process Description:

Feed for multiple wells enter the top middle section the vessel. The mixture from the wells creates an average temperature and pressure at 52°C and 38 barg respectively. The vessel has two oil outlets and is designed as a two in one separator. The main function of the vessel is to separate water and gas from the oil stream.

Comments: (Other relevant information, for example: dead legs, piece of equipment out of service, critical operations, planned modifications, "special operating conditions" for example change of media in vessel…)

There is no known overview of nozzles that are dead legs, and these must be identified as experiences from other fields shows higher probability of CO_2 corrosion attacks due to accumulation of water and stagnant conditions. A case example in Appendix G is available to support the above statement.

The vessel is coated with Belzona from 3 to 9 o`clock (50% of internal surface coated) due to previous experience with corrosion attacks in the vessel. Five anodes are mounted in the bottom part of the vessel (Type ZT780, new in 2007)

Inspection History **Date of collection 2015-03-15**

The vessel has been opened for IVI in 2006, 2009, 2011 and 2014. Baseline thickness head/shell = 102/110 mm

<u>Last inspection in 2014:</u>
Reported overall good condition. No corrosion attacks were found on the wall surface or internally in any of the nozzles. However, corrosion was reported in the sealing surface of the manhole and the nozzles N10 and N5 (from 30 to 100% of primary sealing surface on RTJ flanges). Small areas of the Belzona coating was damaged, and the damages most probably in the same areas reported in 2011 which wasn`t renewed. The anode consumption was lower than 10% (New in 2007).

<u>Historical inspections:</u>
Previous inspections performed in 2006, 2007, 2009 and 2011 reported localized corrosion in the bottom part of the vessel, with depths up to 7,0 mm(last reported in 2006). These are known damages, and no further development of the corrosion attacks have been observed since 2006. Generally Belzona and flange sealing surfaces have been repaired during each shutdown, which implies that there is a need to continuously maintain the coating and inspect sealing surfaces in future shutdowns.

Corrosion Risk Assessment (CRA)

Damaged Mechanisms
H2S, CO2, MIC, Erosion.

CO_2: Calculations for CO_2 corrosion rate have been performed according to the Norsok M-506 model, and the results show an expected corrosion rate of approximately 0,36 mm/year.

The allowed pH range of the model is pH 3,5 to 6,5, and an accurate corrosion rate for pH higher than 6,5 could not be calculated. The expected corrosion rate for pH 7 will most likely be lower than 0,36 mm/year.

H_2S: The influence of H_2S could affect the corrosion rate depending on the H_2S/CO_2 ratio, but there are no available recognized standards that could be used to estimate the effects. This phenomenon needs more research. Sour service due to H_2S is not applicable since the partial pressure is lower than 0,3 kPa, however the sulfur may lead to general corrosion. This could be seen as a layer of FeS internal in the vessel.

Erosion: May occur in the bottom part of the vessel shell where the water jet system is used in combination with sand particles. The rate depends highly on the amount of sand, particle size, nozzle orientation and water pressure when operating the water jet system. It is possible to get high rates, since this may introduce the same effects as you would get from sandblasting a metallic material.

MIC: Analysis performed during the shutdown in 2012 ranked possible MIC corrosion to be at the risk level medium/high. However corrosion would not occur if the Belzona coating is intact or when the anodes protect the carbon steel with an electro potential lower than -900 mV.

Corrosion of the bottom part of the vessel will not occur if the Belzona coating is intact and if the sacrificial anodes are working properly.

A.3 Crude flash drum No. 1 CD2102

Mechanical Data: (Design ASME VIII Div. 2)

Design Pressure (barg)	34,5
Design Temperature (°C)	121
Material	Carbon Steel SA-516-GR70
Corrosion Allowance (mm)	3,0
Thickness head/shell (mm)	44,5/37
Insulation	Yes
Sealing surface Nozzles	RF*

Process Data: (In operation)

Operating Pressure(barg)	16
Operating Temperature (°C)	52
CO_2 (mol%) measured 2013	0,5
H_2S (ppm)	11
Phase (Liquid, Gas, Water)	Three Phase
pH	7,0

*Note: Raised faced (RF)

Process Description:

Feed from inlet separator (CD2101) enters vessel in top head section. The pressure is decreased to flash out lighter hydrocarbon components from the oil stream. The main function of the vessel is to separate water and gas from the oil stream.

Comments: (Other relevant information, for example: dead legs, piece of equipment out of service, critical operations, planned modifications, "special operating conditions" for example change of media in vessel…)

There is no known overview of nozzles that are dead legs, and these must be identified as experiences from other fields shows higher probability of CO_2 corrosion attacks due to accumulation of water and stagnant conditions. A case example in Appendix G is available to support the above statement.

The vessel is coated with Belzona from 3 to 9 o`clock (50% of internal surface coated) due to previous experience with corrosion attacks in the vessel. Four anodes are mounted in the bottom part of the vessel (Type ZT780, new in 2014).

Inspection History **Date of collection 2015-03-23**

The vessel has been opened for IVI in 2006, 2007, 2011 and 2014. Baseline thickness head/shell = 48,5/37 mm

Last inspection in 2014:
Reported overall good condition. No corrosion attacks were found on the wall surface or internally in any of the nozzles. However, corrosion was reported in the sealing surface of the nozzle K1A (50% of primary sealing surface on RF flange). Small areas of the Belzona coating was damaged, these areas were repaired during the shutdown. The anode consumption was 40% (Last changed 2007). New anodes mounted during the shutdown.

Historical inspections:
Previous inspections performed in 2007 and 2011 reported localized corrosion in the bottom part of the vessel, with depths up to 9,0 mm(last reported in 2007). These are known damages, and no further development of the corrosion attacks have been observed since 2007. Generally Belzona and flange sealing surfaces have been repaired during shutdowns, which imply that there is a need to continuously maintain the coating and inspect sealing surfaces in future shutdowns.

Corrosion Risk Assessment (CRA)

Damaged Mechanisms

H2S, CO2, MIC, Erosion.

CO_2: Calculations for CO_2 corrosion rate have been performed according to the Norsok M-506 model, and the results show an expected corrosion rate of approximately 0,25 mm/year. The allowed pH range of the model is pH 3,5 to 6,5, and an accurate corrosion rate for pH higher than 6,5 could not be calculated. The combination of 0,5mol% CO_2 and a pressure lower than 19barg causes the CO_2 fugacity to be lower than the area of validity in the model. The expected corrosion rate for pH 7 and at a pressure lower than 19 barg will most likely be lower than 0,25 mm/year.

H_2S: The influence of H_2S could affect the corrosion rate depending on the H_2S/CO_2 ratio, but there are no available recognized standards that could be used to estimate the effects. This phenomenon needs more research. Sour service due to H_2S is not applicable since the partial pressure is lower than 0,3 kPa, however the sulfur may lead to general corrosion. This could be seen as a layer of FeS internal in the vessel.

Erosion: May occur in the bottom part of the vessel shell where the water jet system is used in combination with sand particles. The rate depends highly on the amount of sand, particle size, nozzle orientation and water pressure when operating the water jet system. It is possible to get high rates, since this may introduce the same effects as you would get from sandblasting a metallic material. The probability of erosion is lower than the inlet separator since most of the solids/particles are separated in the first separator.

MIC: Analysis performed during the shutdown in 2012 ranked possible MIC corrosion to be at the risk level medium/high. However corrosion would not occur if the Belzona coating is intact or when the anodes protect the carbon steel with an electro potential lower than -900 mV.

Corrosion of the bottom part of the vessel will not occur if the Belzona coating is intact and if the sacrificial anodes are working properly.

A.4 Crude flash drum No. 2 CD2103

Mechanical Data: (Design ASME VIII Div. 1)

Design Pressure (barg)	9,7
Design Temperature (°C)	121
Material	Carbon Steel SA-285-GR C
Corrosion Allowance (mm)	3,0
Thickness head/shell (mm)	16,5/15,5
Insulation	Yes
Sealing surface Nozzles	RF*

Process Data: (In operation)

Operating Pressure(barg)	6,5
Operating Temperature (°C)	66
CO_2 (mol%) measured 2013	0,5
H_2S (ppm)	7
Phase (Liquid, Gas, Water)	Three Phase
pH	8,3

*Note: Raised faced (RF)

Process Description:

Feed from crude flash drum No. 1 (CD2102) enters vessel in top head section. The pressure is decreased to flash out lighter hydrocarbon components from the oil stream. The main function of the vessel is to separate water and gas from the oil stream.

Comments: (Other relevant information, for example: dead legs, piece of equipment out of service, critical operations, planned modifications, "special operating conditions" for example change of media in vessel…)

There is no known overview of nozzles that are dead legs, and these must be identified as experiences from other fields shows higher probability of CO_2 corrosion attacks due to accumulation of water and stagnant conditions. A case example in Appendix G is available to support the above statement.

The vessel is coated with Belzona from 3 to 9 o`clock (50% of internal surface coated) due to previous experience with corrosion attacks in the vessel. Five anodes are mounted in the bottom part of the vessel (Type ZT780, new in 2009).

Inspection History **Date of collection 2015-03-31**

The vessel has been opened for IVI in 2007, 2009, 2011 and 2014. Baseline thickness head/shell = 19/15,5 mm

<u>Last inspection in 2014:</u>
Reported overall good condition, and no corrosion attacks were found on the wall surface. However, localized corrosion was reported internally in nozzle N8C (5,0mm deep, nominal thickness is 13,0mm), internally surface corrosion in nozzle N6C, and corrosion in the sealing surface of the nozzle K6B (30% of primary sealing surface on RF flange). Small areas of the Belzona coating was damaged, these areas were repaired during the shutdown. The anode consumption was 5% (Last changed 2009).

<u>Historical inspections:</u>
Previous inspections performed in 2007, 2009 and 2011 reported localized corrosion in the bottom part of the vessel, with depths up to 5,0mm (last reported in 2007 after sandblasting). These are known damages, and no further development of the corrosion attacks have been observed since 2007. Generally Belzona and flange sealing surfaces have been repaired during shutdowns, which imply that there is a need to continuously maintain the coating and inspect sealing surfaces in future shutdowns.

Corrosion Risk Assessment (CRA)

Damaged Mechanisms

H2S, CO2, MIC, Erosion.

CO_2: Calculations for CO_2 corrosion rate have been performed according to the Norsok M-506 model, and the results show an expected corrosion rate of approximately 0,25 mm/year. The allowed pH range of the model is pH 3,5 to 6,5, and an accurate corrosion rate for pH higher than 6,5 could not be calculated. The combination of 0,5mol% CO_2 and a pressure lower than 19barg causes the CO_2 fugacity to be lower than the area of validity in the model. The expected corrosion rate for pH 8,3 and at a pressure lower than 19 barg will most likely be lower than 0,25 mm/year.

H_2S: The influence of H_2S could affect the corrosion rate depending on the H_2S/CO_2 ratio, but there are no available recognized standards that could be used to estimate the effects. This phenomenon needs more research. Sour service due to H_2S is not applicable since the partial pressure is lower than 0,3 kPa, however the sulfur may lead to general corrosion. This could be seen as a layer of FeS internal in the vessel.

Erosion: May occur in the bottom part of the vessel shell where the water jet system is used in combination with sand particles. The rate depends highly on the amount of sand, particle size, nozzle orientation and water pressure when operating the water jet system. It is possible to get high rates, since this may introduce the same effects as you would get from sandblasting a metallic material. The probability of erosion is lower than the inlet separator since most of the solids/particles are separated in the first separator.

MIC: Analysis performed during the shutdown in 2012 ranked possible MIC corrosion to be at the risk level medium/high. However corrosion would not occur if the Belzona coating is intact or when the anodes protect the carbon steel with an electro potential lower than -900 mV.

Corrosion of the bottom part of the vessel will not occur if the Belzona coating is intact and if the sacrificial anodes are working properly.

A.5 Crude flash drum No. 2 CD2104

Mechanical Data: (Design ASME VIII Div. 1)

Design Pressure (barg)	3,4
Design Temperature (°C)	121
Material	Carbon Steel SA-285-GR C
Corrosion Allowance (mm)	3,0
Thickness head/shell (mm)	10,5
Insulation	No
Sealing surface Nozzles	RF*

Process Data: (In operation)

Operating Pressure(barg)	0,95
Operating Temperature (°C)	66,5
CO_2 (mol%) measured 2013	0,5
H_2S (ppm)	12
Phase (Liquid, Gas, Water)	Three Phase
pH	9,1

*Note: Raised faced (RF)

Process Description:

Feed from crude flash drum No. 2 (CD2103) enters vessel in top head section. The pressure is decreased to flash out lighter hydrocarbon components from the oil stream. The main function of the vessel is to separate gas from the oil stream. The vessel is directly connected with the underlying Coalescer (CD2121), which entails that there aren`t any water level in the flash drum no. 3.

Comments: (Other relevant information, for example: dead legs, piece of equipment out of service, critical operations, planned modifications, "special operating conditions" for example change of media in vessel…)

There is no known overview of nozzles that are dead legs, and these must be identified as experiences from other fields shows higher probability of CO_2 corrosion attacks due to accumulation of water and stagnant conditions. A case example in Appendix G is available to support the above statement.

The vessel is coated with ceramic painting (Type CK54) from 5 to 7 o`clock (17% of internal surface coated) due to previous experience with corrosion attacks in the bottom part of vessels.

Inspection History **Date of collection 2015-04-08**

The vessel has been opened for IVI in 2000, 2006 and 2009. Baseline thickness head/shell = 13/12 mm.

Last inspection in 2009:
Reported overall good condition. No corrosion attacks were found on the wall surface or internally in any of the nozzles. However, corrosion was reported in the sealing surface of the manhole and nozzle K3A (% degradation of the sealing surface not reported, but the areas needed to be repaired during the shutdown). Small areas of the coating were damaged, these wasn`t repaired and are known damages which shows no further developments since last IVI in 2006.

Historical inspections:
Previous inspections performed in 2000 and 2006 have reported overall good condition. Generally flange sealing surfaces have been repaired during shutdowns, which imply that there is a need to continuously inspect sealing surfaces in future shutdowns.

Corrosion Risk Assessment (CRA)

Damaged Mechanisms

H2S, CO2, MIC, Erosion.

CO_2: Calculations for CO_2 corrosion rate have been performed according to the Norsok M-506 model, and the results show an expected corrosion rate of approximately 0,25 mm/year. The allowed pH range of the model is pH 3,5 to 6,5, and an accurate corrosion rate for pH higher than 6,5 could not be calculated. The combination of 0,5mol% CO_2 and a pressure lower than 19barg causes the CO_2 fugacity to be lower than the area of validity in the model. The expected corrosion rate for pH 9,1and at a pressure lower than 19 barg will most likely be lower than 0,25 mm/year.

H_2S: The influence of H_2S could affect the corrosion rate depending on the H_2S/CO_2 ratio, but there are no available recognized standards that could be used to estimate the effects. This phenomenon needs more research. Sour service due to H_2S is not applicable since the partial pressure is lower than 0,3 kPa, however the sulfur may lead to general corrosion. This could be seen as a layer of FeS internal in the vessel.

Erosion: The damage mechanism is neglected since there aren`t a water jet system in combination with solids/sand. Further the amount of solids are lighter, more or less clay. There could however be some small amount of sand/solids that follows the oil stream when the water jet system is used in flash drum No. 2(CD2103). The main reason is that sand particles could be stirred up during operation of the water jet system. The particles/solids are than mixed with the oil stream, and further on carried over in the oil outlet.

MIC: Analysis performed during the shutdown in 2012 ranked possible MIC corrosion to be at the risk level medium/high. However corrosion would not occur if the coating is intact.

Corrosion of the bottom part of the vessel will not occur if the coating is intact.

A.6 Coalescer CD2121

Mechanical Data: (Design ASME VIII Div. 1)

Design Pressure (barg)	4,1
Design Temperature (°C)	121
Material	Carbon Steel SA-516-GR 70
Corrosion Allowance (mm)	3,0
Thickness head/shell (mm)	14,5
Insulation	No
Sealing surface Nozzles	RF*

Process Data: (In operation)

Operating Pressure(barg)	0,95
Operating Temperature (°C)	66,5
CO_2 (mol%) measured 2013	0,5
H_2S (ppm)	12
Phase (Oil & Water)	Two Phase
pH	9,1

*Note: Raised faced (RF)

Process Description:

Feed from crude flash drum No. 3 (CD2104) enters vessel in top head section. The main function of the vessel is to separate water from the oil stream. The vessel is directly connected with the overlying Crude flash drum N0. 3 (CD2104), which entails that there aren`t any gas level in the flash Coalescer.

Comments: (Other relevant information, for example: dead legs, piece of equipment out of service, critical operations, planned modifications, "special operating conditions" for example change of media in vessel…)

There is no known overview of nozzles that are dead legs, and these must be identified as experiences from other fields shows higher probability of CO_2 corrosion attacks due to accumulation of water and stagnant conditions. A case example in Appendix G is available to support the above statement.

The vessel is coated with Belzona from 3 to 9 o`clock (50% of internal surface coated) due to previous experience with corrosion attacks in the vessel. Six anodes are mounted in the bottom part of the vessel (Type ZT780, new in 2014).

Inspection History **Date of collection 2015-04-17**

The vessel has been opened for IVI in 2006, 2009, 2011 and 2014. Baseline thickness head/shell = 17,5/15 mm.

Last inspection in 2014:

Reported overall good condition. No corrosion attacks were found on the wall surface or internally in any of the nozzles. However, corrosion was reported in the sealing surface of the vales to nozzle K6C, N6D and K1A (From 20 to 50% of primary sealing surface on RF flanges). Small areas of the Belzona coating was damaged, these areas were repaired during the shutdown. The anode consumption was 30-50% (Last changed 2006). New anodes mounted during the shutdown.

Historical inspections:

Previous inspections performed in 2006, 2009 and 2011 reported localized corrosion internally in several nozzles. Several repaired with Belzona, and some with welding. Generally Belzona and flange sealing surfaces have been repaired during shutdowns, which imply that there is a need to continuously maintain the coating and inspect sealing surfaces in future shutdowns.

Corrosion Risk Assessment (CRA)

Damaged Mechanisms

H2S, CO2, MIC, Erosion.

CO_2: Calculations for CO_2 corrosion rate have been performed according to the Norsok M-506 model, and the results show an expected corrosion rate of approximately 0,25 mm/year. The allowed pH range of the model is pH 3,5 to 6,5, and an accurate corrosion rate for pH higher than 6,5 could not be calculated. The combination of 0,5mol% CO_2 and a pressure lower than 19barg causes the CO_2 fugacity to be lower than the area of validity in the model. The expected corrosion rate for pH 9,1and at a pressure lower than 19 barg will most likely be lower than 0,25 mm/year.

H_2S: The influence of H_2S could affect the corrosion rate depending on the H_2S/CO_2 ratio, but there are no available recognized standards that could be used to estimate the effects. This phenomenon needs more research. Sour service due to H_2S is not applicable since the partial pressure is lower than 0,3 kPa, however the sulfur may lead to general corrosion. This could be seen as a layer of FeS internal in the vessel.

Erosion: The damage mechanism is neglected since the amount of solids are lighter, more or less clay. There could however be some small amount of sand/solids that follows the oil stream when the water jet system is used in flash drum No. 2(CD2103). The main reason is that sand particles could be stirred up during operation of the water jet system. The particles/solids are than mixed with the oil stream, and further on carried over in the oil outlet.

MIC: Analysis performed during the shutdown in 2012 ranked possible MIC corrosion to be at the risk level medium/high. However corrosion would not occur if the Belzona coating is intact or when the anodes protect the carbon steel with an electro potential lower than -900 mV.

Corrosion of the bottom part of the vessel will not occur if the Belzona coating is intact and if the sacrificial anodes are working properly.

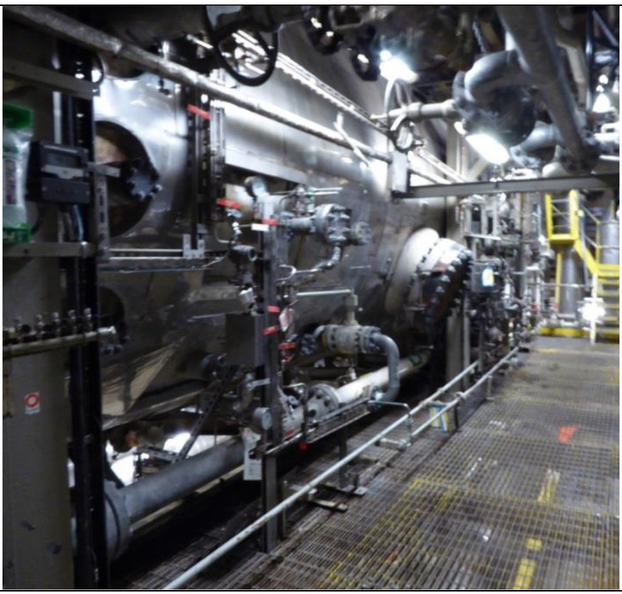
Appendix B – Pictures taken during offshore survey of pressure vessels

Test Separator CD2018

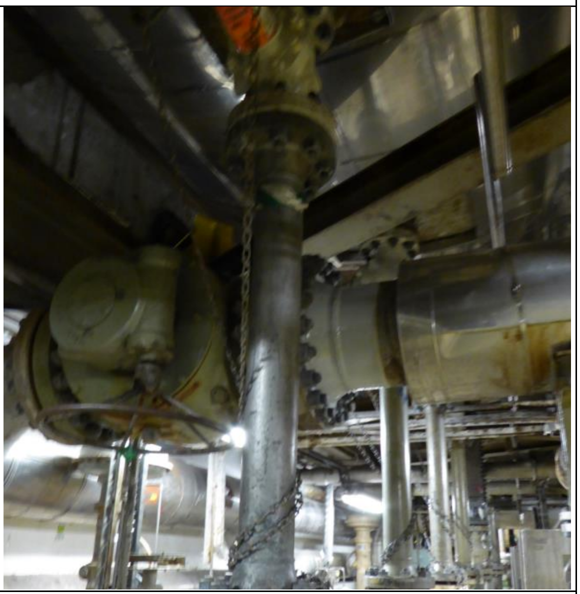
Picture 1. Separator insulated, picture taken from manhole side.

Picture 2. Separator insulated, picture taken from the bottom part. Lack of access due to supporting structure.

Train 1 - Inlet Separator CD2101

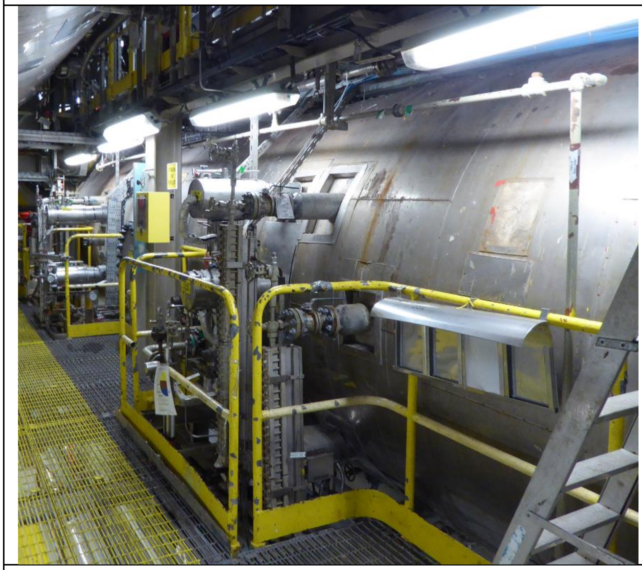


Picture 3. Separator insulated, picture taken from manhole side.



Picture 4. Separator insulated, picture taken from the bottom part. Lack of access due to supporting structure.

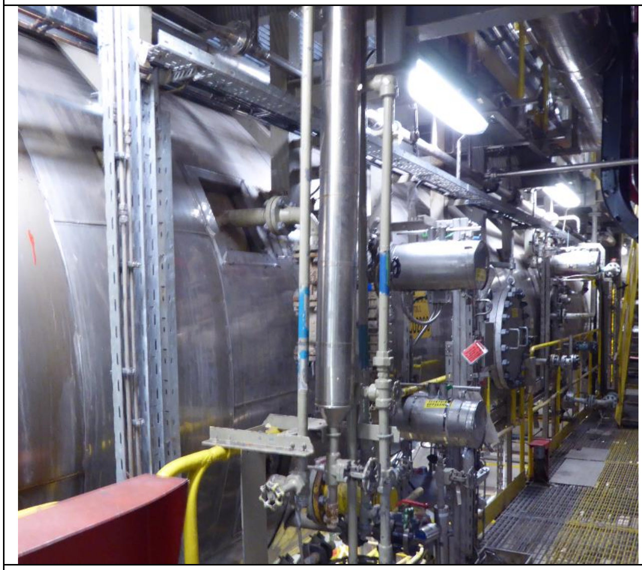
Train 1 - Flash Drum No. 1 CD2102



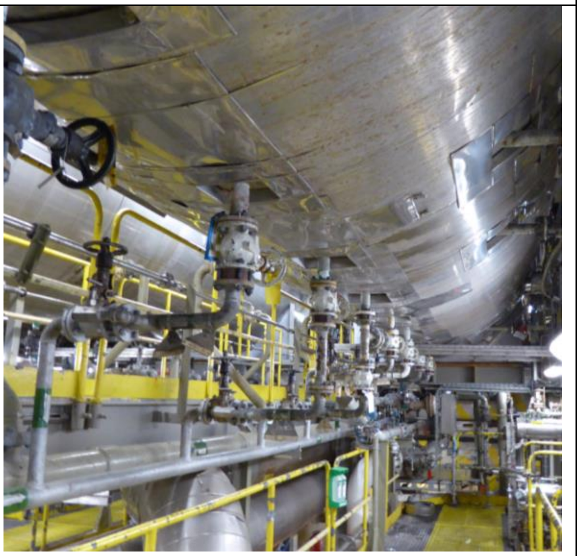
Picture 5. Separator insulated, picture taken from manhole side.

Picture 6. Separator insulated, picture taken from the bottom part. Easy access from floor.

Train 1 - Flash Drum No. 2 CD2103



Picture 7. Separator insulated, picture taken from manhole side.



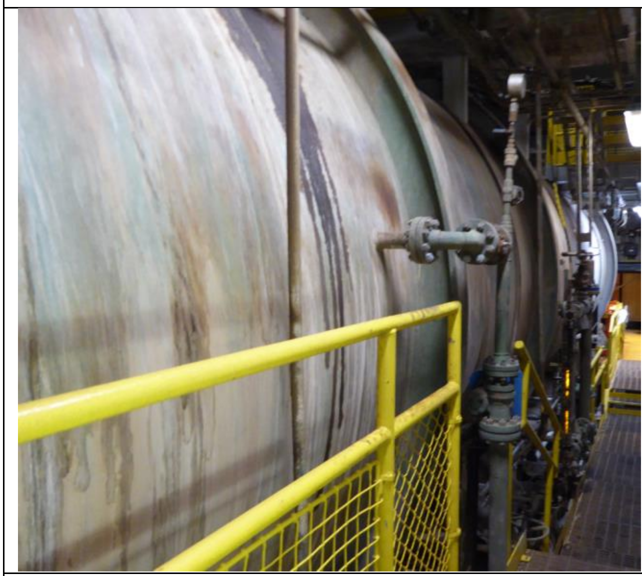
Picture 8. Separator insulated, picture taken from the bottom part. Easy access from deck.

Train 1 - Flash Drum No. 3 CD2104

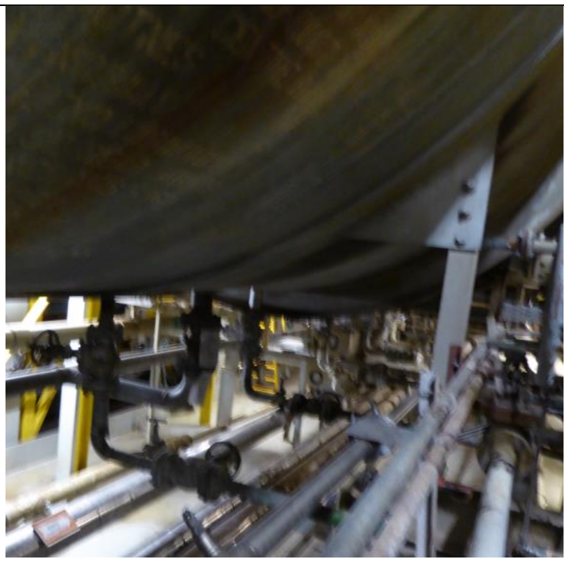
Picture 9. Separator not insulated, picture taken from manhole side.

Picture 10. Separator not insulated, picture taken from the bottom part. Easy access from lower vessel.

Train 1 – Coalescer CD2121



Picture 11. Vessel not insulated, picture taken from south side.



Picture 12. Vessel not insulated, picture taken from the bottom part. Easy access from deck.

Appendix C – Production profile and data

The water level is at a peak now, and the prediction is that is should decrease in the feature. The gas would increase until 2017/18, but due to limitations of the topside compressors it would be more or less constant gas production. The oil level is predicted to decrease each year, and drop to about no oil production at 2021.

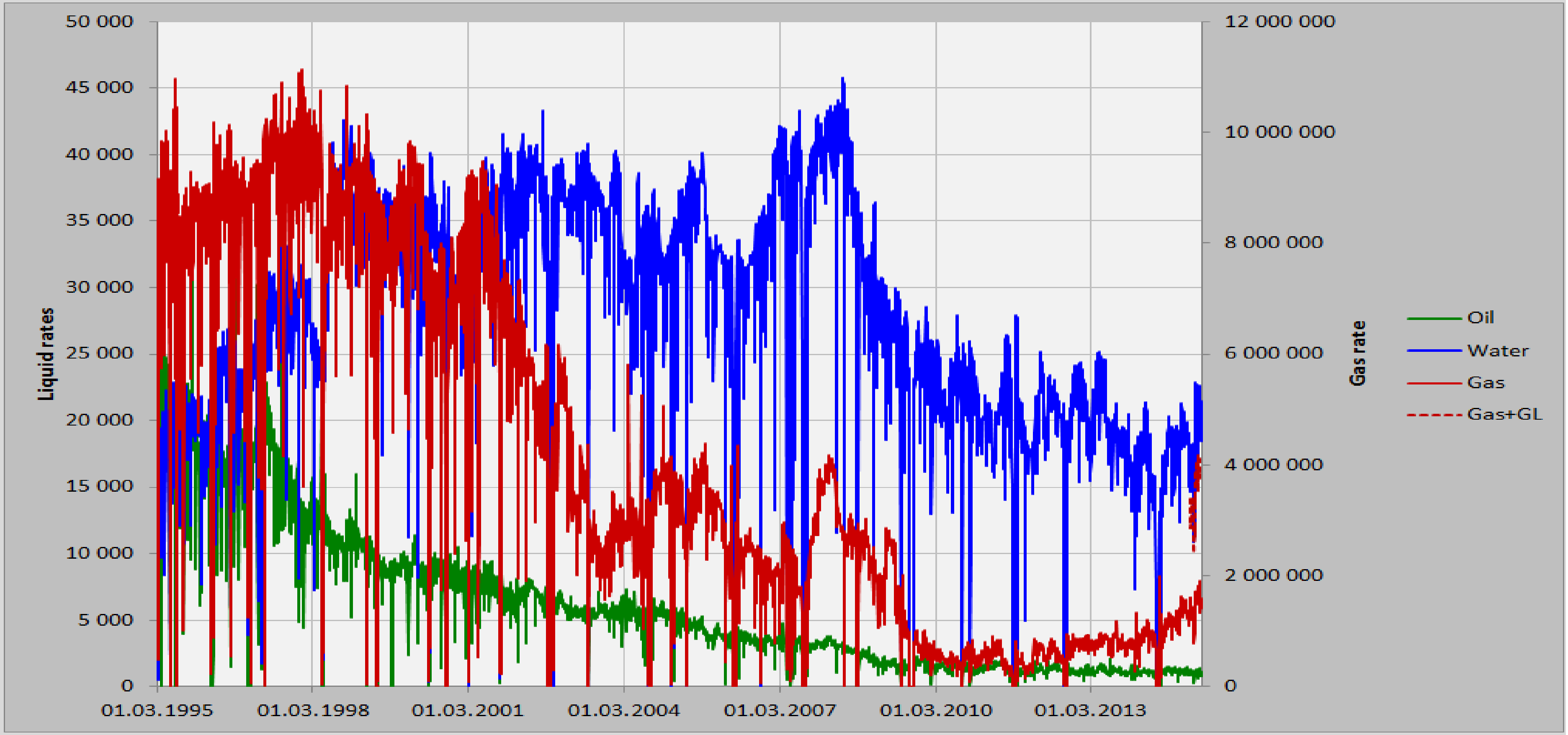


Chart C-1: Production profile since 1995 to 2014. Oil and gas production has decreased, and the water rate is dominating the total production (PI Processbook, 2015; Specialist 3, 2015).

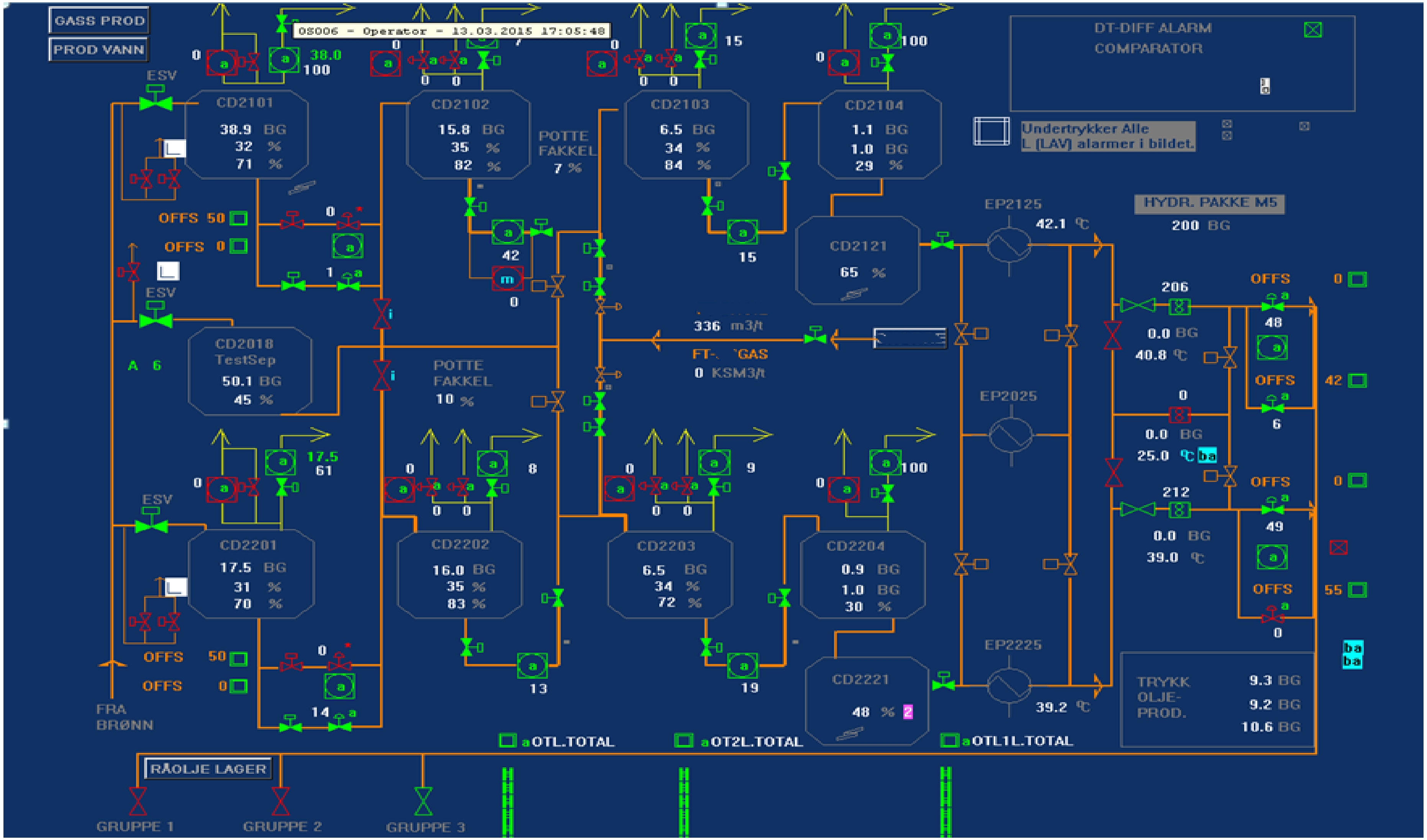


Chart C-2: Production layout. A snap shot of the oil and gas production system, which includes both separation trains (PI Processbook, 2015, Specialist 3, 2015).

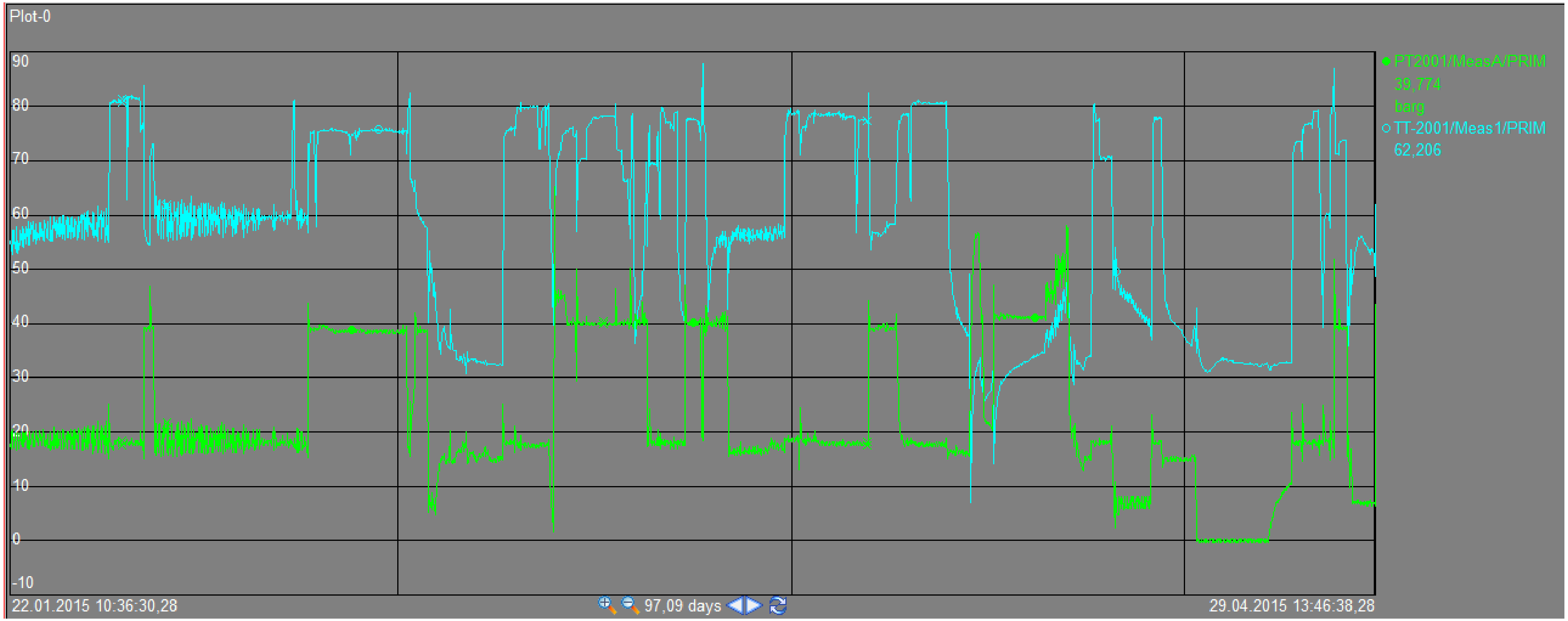


Chart C-3: Trending of the temperature and pressure in the test separator (CD2018) in a period of 97 days. The light blue line indicates the temperature in degrees of Celsius, and the green line the pressure in barg (PI Processbook, 2015).

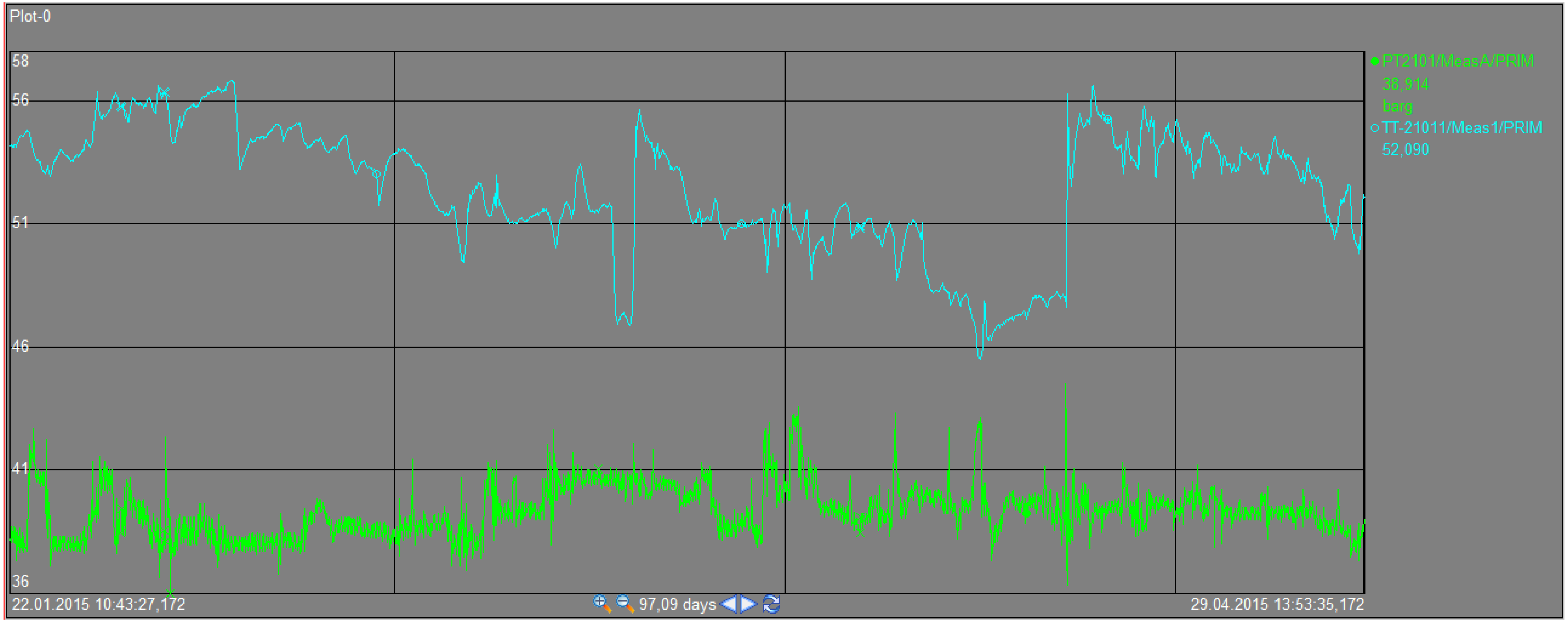


Chart C-4: Trending of the temperature and pressure in the inlet separator (CD2101) in a period of 97 days. The light blue line indicates the temperature in degrees of Celsius, and the green line the pressure in barg (PI Processbook, 2015).

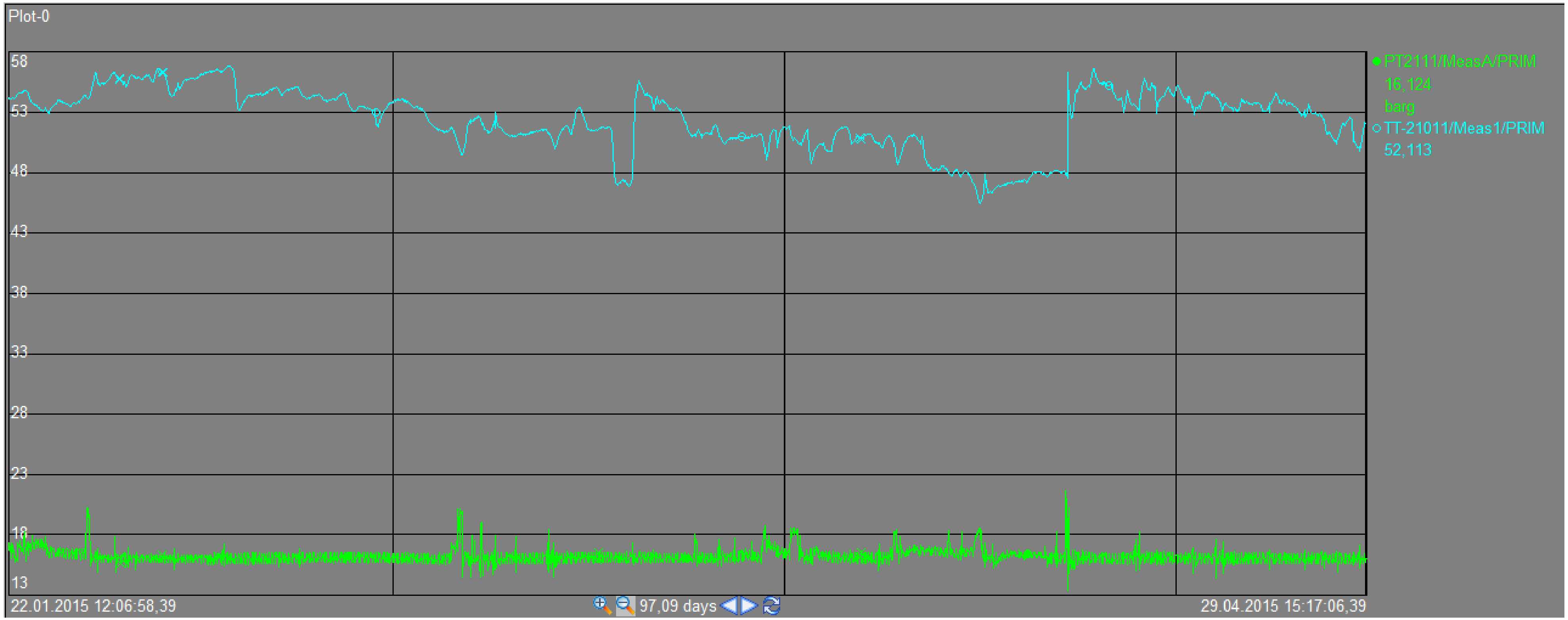


Chart C-5: Trending of the temperature and pressure in the crude flash drum No.1 (CD2102) in a period of 97 days. The light blue line indicates the temperature in degrees of Celsius, and the green line the pressure in barg (PI Processbook, 2015).

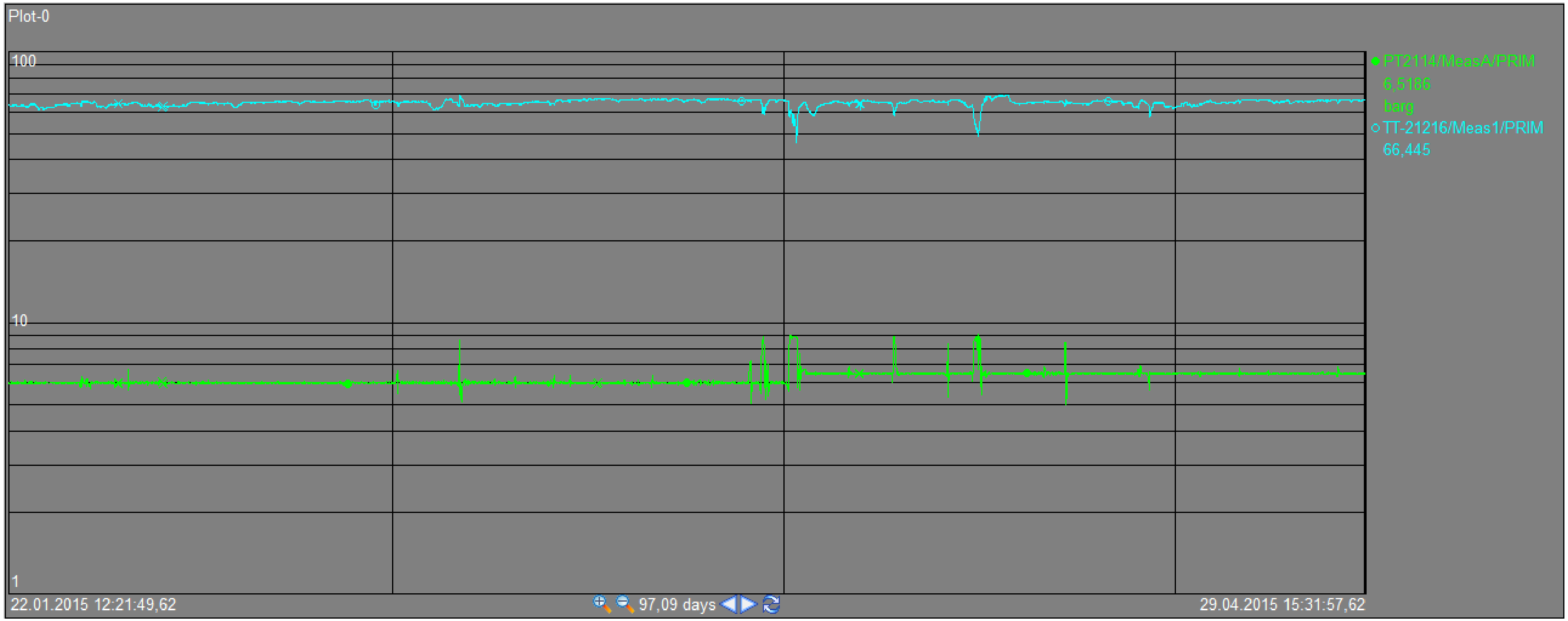


Chart C-6: Trending of the temperature and pressure in the crude flash drum No.2 (CD2103) in a period of 97 days. The light blue line indicates the temperature in degrees of Celsius, and the green line the pressure in barg. The scaling is logarithmic in the y-axis to better view pressure changes (PI Processbook, 2015).

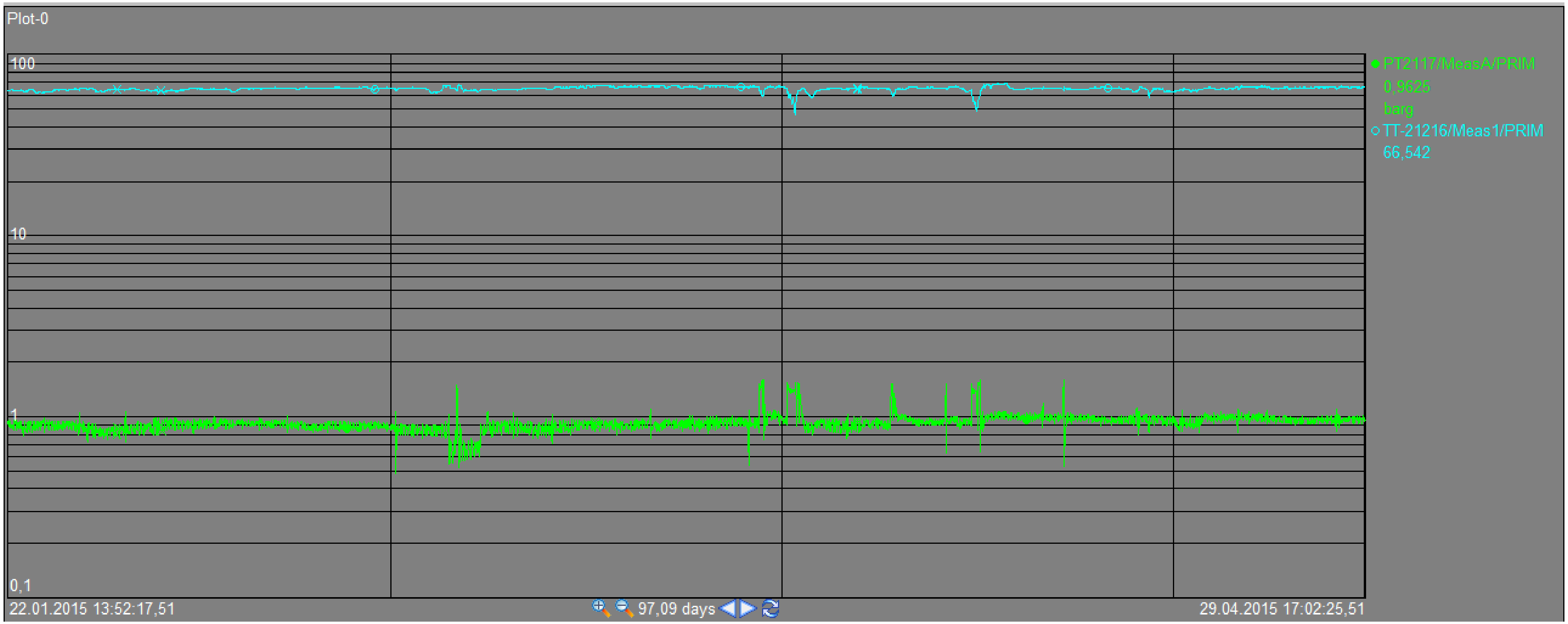


Chart C-6: Trending of the temperature and pressure in the crude flash drum No.3 (CD2104) and the Coalescer (CD2121) in a period of 97 days. The light blue line indicates the temperature in degrees of Celsius, and the green line the pressure in barg. The scaling is logarithmic in the y-axis to better view pressure changes (PI Processbook, 2015).

Appendix D – NII analyze results of selected vessels

D.1 NII Preliminary screening

NII preliminary screening results are provided in Table D-1 below, which also includes information about the criticality of each vessel.

NII Screening	**Client: Statoil ASA**	**Author: Andreas Eriksson**	**NII Preliminary screening (Figure 2-2)**					
Functional Location	**Description**	**Overall Criticality (HSE, production, costs and containment)**	**A: Is the vessel intrinsically suitable for NII? If NO = No NII**	**B: Has vessel previous been inspected? If NO Go to C, If YES Go to E**	**C: Was vessel designed specifically for NII? If NO Go to D, If YES Go to F**	**D: Is vessel the same as others for which service history exists? If NO = NO NII, If YES Go to F**	**E: Is operating history still relevant? If NO Go to C If YES Go to F**	**F: Is entry scheduled for other reason? If NO = Apply High level decision, If YES= Perform IVI)**
CD2018	Test separator	**Very high**	NO	NA	NA	NA	NA	NA
CD2101	Inlet separator	**Very high**	NO	NA	NA	NA	NA	NA
CD2102	Crude flash drum No.1	**Very high**	YES	YES	NA	NA	YES	NO
CD2103	Crude flash drum No.2	**High**	YES	YES	NA	NA	YES	NO
CD2104	Crude flash drum No 3	**High**	Yes	Yes	NA	NA	Yes	NO
CD2121	Coalescer	**High**	Yes	Yes	NA	NA	Yes	NO

Table D-1: NII preliminary screening of all vessels in production train one.

D.2 NII High level screening

NII high level decision is provided in Table D-2 below, also including justification and comments for the selection.

NII Screening	Client: Statoil ASA	Author: Andreas Eriksson	NII High Level screening (Figure 2-3)				
Functional Location	**Description**	**Overall Criticality (HSE, production, costs and containment)**	**Confidence in ability to predict type and location of degradation**	**Previous inspection effectiveness**	**Severity and rate of degradation**	**NII Possible**	**Comments**
CD2018	Test separator	**Very high**	NA	NA	NA	NA	The vessel is screened due to: 1) Corrosion risk assessment is not adequate/valid for future operational conditions. 2) The supporting structure limits access to the bottom part which is of interest, and there are no known NDT methods for inspection of the RTJ sealing surfaces.
CD2101	Inlet separator	**Very high**	NA	NA	NA	NA	The vessel is screened due to: 1) There are no known NDT methods for inspection of the RTJ sealing surfaces.
CD2102	Crude flash drum No.1	**Very high**	Medium	Medium	High	NO, changed to Yes based on justification comment.	Same as CD2104

CD2103	Crude flash drum No.2	**High**	Medium	Medium	High	NO, changed to Yes based on justification comment.	Same as CD2104, and the same justification applies for the high corrosion rates at nozzle N8C.
CD2104	Crude flash drum No 3	**High**	Medium	Medium	High	NO, changed to Yes based on justification comment.	NII not possible mainly based on the answer given in the last question. However, if the previous inspections effectiveness had been high, than NII would be possible. A high previously inspection effectiveness wouldn't change the experience related to degradation of flanges and NDT of sealing surfaces would actually reduce the risk of a potential failure prior to scheduled shutdowns. NII is possible and risk reducing based on the justification above.
CD2121	Coalescer	**High**	Medium	Medium	High	NO, changed to Yes based on justification comment.	Same as CD2104

Table D-2: NII high level screening of all vessels in production train one.

D.3 Definition of vessel zones and selection of degradation type

Definition of vessel zones and selection of degradation types within each inspection zone is listed in Table D-3 bellow.

Functional location		A) Definition of Vessel Zones			B) Definition of Degradation Type	
Tag No.	**Description**	**Location**	**Zone**	**Feature**	**Degradation Mechanism**	**Defect Type**
CD2104	Crude flash drum No 3	Above fluid level	A	Cylindrical Shell A	CO_2/H_2S	General Corrosion
			B	Cylindrical Shell B	CO_2/H_2S	General Corrosion
			C	Nozzles	CO_2/H_2S	General Corrosion
			D	Raised Faced surface	Corrosion	Localized Corrosion
		Below fluid level	E	Cylindrical Shell D	MIC CO_2/H_2S	Localized Corrosion General Corrosion
			F	Nozzles	MIC CO_2/H_2S	Localized Corrosion General Corrosion
			G	Raised Faiced surface	MIC CO_2/H_2S	Localized Corrosion General Corrosion
CD2102	Crude flash drum No.1	Gas zone	A	Cylindrical shell A	CO_2/H_2S	General Corrosion
			B	Nozzles B	CO_2/H_2S	General Corrosion
		Oil and water zone	C	Cylindrical shell B	MIC & Erosion CO_2/H_2S	Localized Corrosion General Corrosion
			D	Nozzles C	MIC & Erosion CO_2/H_2S	Localized Corrosion General Corrosion
		All zones	E	Raised faced surface	Corrosion	Localized Corrosion
CD2103	Crude flash drum No.2	Gas zone	A	Cylindrical shell A	CO_2/H_2S	General Corrosion
			B	Nozzles B	CO_2/H_2S	General Corrosion
		Oil and water zone	C	Cylindrical shell C	MIC & Erosion CO_2/H_2S	Localized Corrosion General Corrosion

			D	Nozzles C	MIC & Erosion CO2/H2S	Localized Corrosion General Corrosion
		All zones	E	Raised faced surface	Corrosion	Localized Corrosion
CD2121	Coalescer	Oil and water zone	A	Top Cylindrical shell A	MIC CO2/H2S	Localized Corrosion General Corrosion
			B	Nozzles B	MIC & Erosion CO2/H2S	Localized Corrosion General Corrosion
		Water zone	C	Cylindrical shell C	MIC & Erosion CO2/H2S	Localized Corrosion General Corrosion
			D	Nozzles D	MIC & Erosion CO2/H2S	Localized Corrosion General Corrosion
		All zones	E	Raised faced surface	Corrosion	Localized Corrosion

Table D-3: Definition of vessel zones and selection of degradation type for all vessels in production train one.

D.4 Selection of inspection strategy types

Selection of inspection strategy type for each vessel and their zones is listed in Table D-4 bellow.

Functional location	**A) Definition of Vessel Zones**			**C) Inspection Strategy Type**				
Tag No.	**Location**	**Zone**	**Feature**	**Degradation Likelihood**	**Degradation Extent**	**Degradation Rate**	**Inspection Type**	**Comment**
CD2104	Above fluid level	A	Cylindrical Shell A	Medium	General Corrosion	Medium	A	Based on CRA probability and corrosion rate
		B	Cylindrical Shell B	Medium	General Corrosion	Medium	A	Based on CRA probability and corrosion rate
		C	Nozzles	Medium	General Corrosion	Medium	A	Based on CRA probability and

								corrosion rate
		D	Raised Faced surface	High	Localized Corrosion (Clearly identifiable)	High	C	Based on inspection history
	Below fluid level	E	Cylindrical Shell D	Medium	Localized Corrosion General Corrosion	Medium	A	Based on CRA probability and corrosion rate
		F	Nozzles	Medium	Localized Corrosion General Corrosion	Medium	A	Based on CRA probability and corrosion rate
		G	Raised faced surface	High	Localized Corrosion (Clearly identifiable)	High	C	Based on inspection history
CD2102	Gas zone	A	Cylindrical shell A	Medium	General Corrosion	Medium	A	Based on CRA probability and corrosion rate
		B	Nozzles B	Medium	General Corrosion	Medium	A	Based on CRA probability and corrosion rate
	Oil and water zone	C	Cylindrical shell B	Medium	Localized Corrosion General Corrosion	Medium	A	Based on CRA probability and corrosion rate
		D	Nozzles C	Medium	Localized Corrosion General Corrosion	Medium	A	Based on CRA probability and corrosion rate
	All zones	E	Raised faced surface	High	Localized Corrosion (Clearly identifiable)	High	C	Based on inspection history

CD2103	Gas zone	A	Cylindrical shell A	Medium	General Corrosion	Medium	A	Based on CRA probability and corrosion rate
		B	Nozzles B	Medium	General Corrosion	Medium	A	Based on CRA probability and corrosion rate
	Oil and water zone	C	Cylindrical shell C	Medium	Localized Corrosion General Corrosion	Medium	A	Based on CRA probability and corrosion rate
		D	Nozzles C	High	Localized Corrosion General Corrosion	High	C	Based on inspection history, Nozzle N8C
	All zones	E	Raised faced surface	High	Localized Corrosion (Clearly identifiable)	High	C	Based on inspection history
CD2121	Oil and water zone	A	Cylindrical shell A	Medium	Localized Corrosion General Corrosion	Medium	A	Based on CRA probability and corrosion rate
		B	Nozzles B	High	Localized Corrosion General Corrosion	High	C	Based on inspection history
	Water zone	C	Cylindrical shell C	Medium	Localized Corrosion General Corrosion	Medium	A	Based on CRA probability and corrosion rate
		D	Nozzles D	High	Localized Corrosion General Corrosion	High	C	Based on inspection history

	All zones	E	Raised faced surface	High	Localized Corrosion (Clearly identifiable)	High	C	Based on inspection history

Table D-4: Selection of inspection type at the inspection zones for all vessels in production train one.

D.5 Selection of minimum inspection effectiveness and coverage

Selection of minimum inspection effectiveness and coverage for each vessel and their inspection zones is listed in Table D-5 bellow.

Functional location		**A) Definition of Vessel Zones**			**D) Minimum Inspection Effectiveness and Coverage**					
Tag No.	**Descript-ion**	**Location**	**Zone**	**Feature**	**Inspec-tion grade**	**Current tolerance of degradation**	**Consequence of failure**	**Minimum inspection effectiveness**	**Confidence (Figure 2-3)**	**Coverage**
CD2104	Crude flash drum No.3	Above fluid level	A	Cylindrical Shell A	Grade 3	Medium	High	Medium	Medium	Targeted plus
			B	Cylindrical Shell B	Grade 3	Medium	High	Medium	Medium	Targeted plus
			C	Nozzles	Grade 3	Medium	High	Medium	Medium	Targeted plus
			D	Raised Faced surface	Grade 0	Low	High	High	Medium	Global
		Below fluid level	E	Cylindrical Shell D	Grade 3	Medium	High	Medium	Medium	Global
			F	Nozzles	Grade 3	Medium	High	Medium	Medium	Global
			G	Raised Faced surface	Grade 0	Low	High	High	Medium	Global
CD2102	Crude flash	Gas zone	A	Cylindrical shell A	Grade 3	Medium	High	Medium	Medium	Targeted plus

	drum No.1		B	Nozzles B	Grade 3	Medium	High	Medium	Medium	Targeted plus
		Oil and water zone	C	Cylindrical shell B	Grade 3	Medium	High	Medium	Medium	Global
			D	Nozzles C	Grade 3	Medium	High	Medium	Medium	Global
		All zones	E	Raised faced surface	Grade 0	Low	High	High	Medium	Global
CD2103	Crude flash drum No.2	Gas zone	A	Cylindrical shell A	Grade 3	Medium	High	Medium	Medium	Targeted plus
			B	Nozzles B	Grade 3	Medium	High	Medium	Medium	Targeted plus
		Oil and water zone	C	Cylindrical shell C	Grade 3	Medium	High	Medium	Medium	Global
			D	Nozzles C	Grade 0	Low	High	High	Medium	Global
		All zones	E	Raised faced surface	Grade 0	Low	High	High	Medium	Global
CD2121	Coalescer	Oil and water zone	A	Cylindrical shell A	Grade 3	Medium	High	Medium	Medium	Targeted plus
			B	Nozzles B	Grade 0	Low	High	High	Medium	Global
		Water zone	C	Cylindrical shell C	Grade 3	Medium	High	Medium	Medium	Global
			D	Nozzles D	Grade 0	Low	High	High	Medium	Global
		All zones	E	Raised faced surface	Grade 0	Low	High	High	Medium	Global

Table D-5: Selection of inspection type at inspection zones for all vessels in production train one

D.6 Selection inspection methods

Selection of inspection methods to meet the minimum required inspection effectiveness is listed in Table D-6 bellow.

Functional location		A) Definition of Vessel Zones			B) Definition of Degradation Type		Determine efficiency of candidate inspection methods			
Tag No.	Descript-ion	Location	Zone	Feature	Degradation Mechanism	Defect Type	Surf-ace	Insul-ated	Thickness(mm)	Selected technique (POD/sizing)
CD2104	Crude flash drum No.3	Above fluid level	A	Cylindrical Shell A	CO2/H2S	General Corrosion	Paint	NO	head/shell = 13/12 mm	Phased Array – XY scanner(H/H)
			B	Cylindrical Shell B	CO2/H2S	General Corrosion	Paint	NO	head/shell = 13/12 mm	Phased Array – XY scanner(H/H)
			C	Nozzles	CO2/H2S	General Corrosion	Paint	NO	Various	TOFD/Phased Array(H/H)
			D	Raised Faced surface	Corrosion	Localized Corrosion	Paint	NO	Various	Flange scanner – Phased Array (H/H)
		Below fluid level	E	Cylindrical Shell D	MIC CO2/H2S	Localized Corrosion General Corrosion	Paint	NO	head/shell = 13/12 mm	Phased Array – XY scanner(H/H)
			F	Nozzles	MIC CO2/H2S	Localized Corrosion General Corrosion	Paint	NO	Various	TOFD/Phased Array(H/H)
			G	Raised Faced surface	MIC CO2/H2S	Localized Corrosion General Corrosion	Paint	NO	Various	Flange scanner – Phased Array (H/H)
CD2102	Crude flash drum No.1	Gas zone	A	Cylindrical shell A	CO2/H2S	General Corrosion	Paint	YES	head/shell = 48,5/37 mm	Phased Array – XY scanner(H/H)

			B	Nozzles B	CO2/H2S	General Corrosion	Paint	YES	Various	TOFD/Phased Array(H/H)
		Oil and water zone	C	Cylindrical shell B	MIC & Erosion CO2/H2S	Localized Corrosion General Corrosion	Paint	YES	head/shell = 48,5/37 mm	Phased Array – XY scanner(H/H)
			D	Nozzles C	MIC & Erosion CO2/H2S	Localized Corrosion General Corrosion	Paint	YES	Various	TOFD/Phased Array(H/H)
		All zones	E	Raised faced surface	Corrosion	Localized Corrosion	Paint	YES	Various	Flange scanner – Phased Array (H/H)
CD2103	Crude flash drum No.2	Gas zone	A	Cylindrical shell A	CO2/H2S	General Corrosion	Paint	YES	head/shell = 19/15,5 mm	Phased Array – XY scanner(H/H)
			B	Nozzles B	CO2/H2S	General Corrosion	Paint	YES	Various	TOFD/Phased Array(H/H)
		Oil and water zone	C	Cylindrical shell C	MIC & Erosion CO2/H2S	Localized Corrosion General Corrosion	Paint	YES	head/shell = 19/15,5 mm	Phased Array – XY scanner(H/H)
			D	Nozzles C	MIC & Erosion CO2/H2S	Localized Corrosion General Corrosion	Paint	YES	Various	TOFD/Phased Array(H/H)
		All zones	E	Raised faced surface	Corrosion	Localized Corrosion	Paint	YES	Various	Flange scanner – Phased Array (H/H)
CD2121	Coalescer	Oil and water zone	A	Cylindrical shell A	MIC CO2/H2S	Localized Corrosion General Corrosion	Paint	NO	head/shell = 17,5/15 mm	Phased Array – XY scanner(H/H)
			B	Nozzles B	MIC & Erosion CO2/H2S	Localized Corrosion General	Paint	NO	Various	TOFD/Phased Array(H/H)

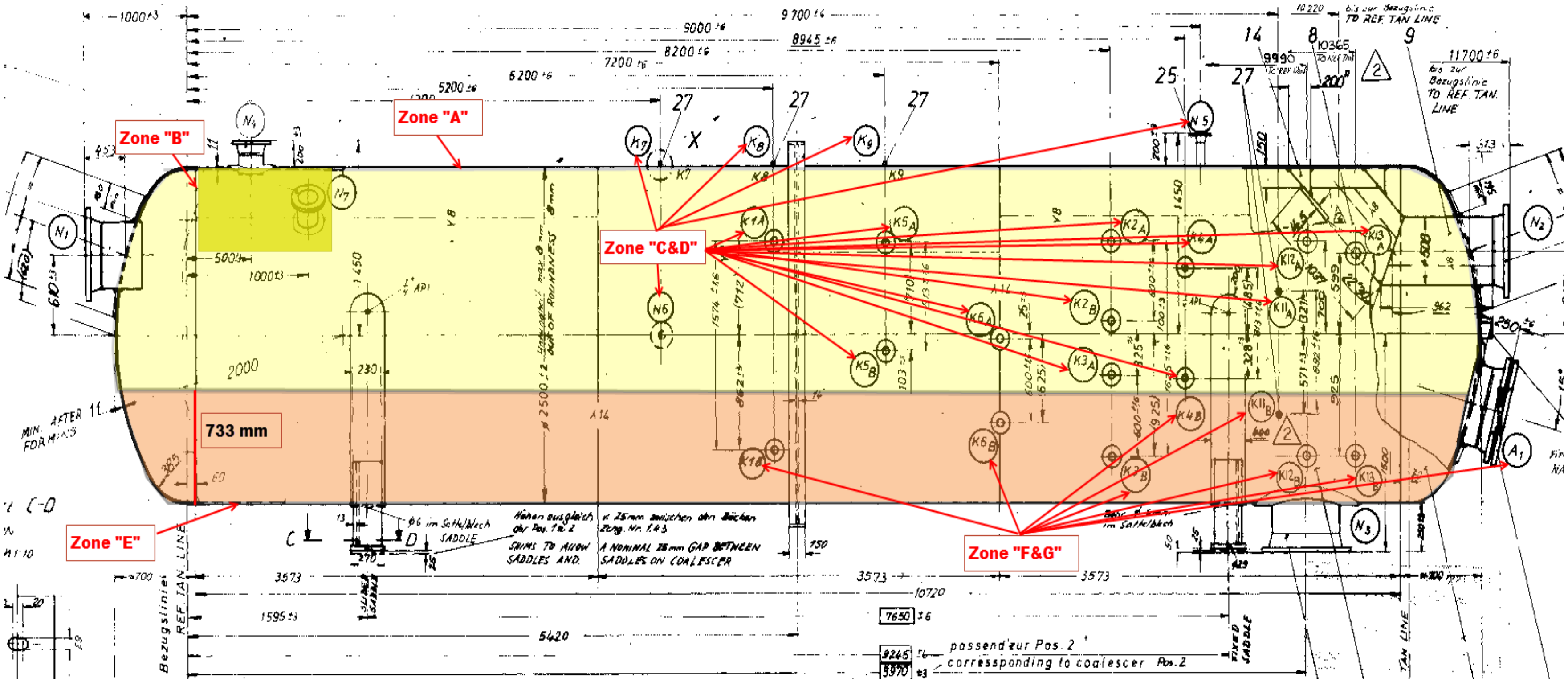
						Corrosion				
		Water zone	C	Cylindrical shell C	MIC & Erosion CO2/H2S	Localized Corrosion General Corrosion	Paint	NO	head/shell = 17,5/15 mm	Phased Array – XY scanner(H/H)
			D	Nozzles D	MIC & Erosion CO2/H2S	Localized Corrosion General Corrosion	Paint	NO	Various	TOFD/Phased Array(H/H)
		All zones	E	Raised faced surface	Corrosion	Localized Corrosion	Paint	NO	Various	Flange scanner – Phased Array (H/H)

Table D-6: Selection of inspection methods for each inspection zone that meets the minimum required inspection effectiveness all vessels in production train one.

Appendix E – General arrangement drawings with marked out inspection zones

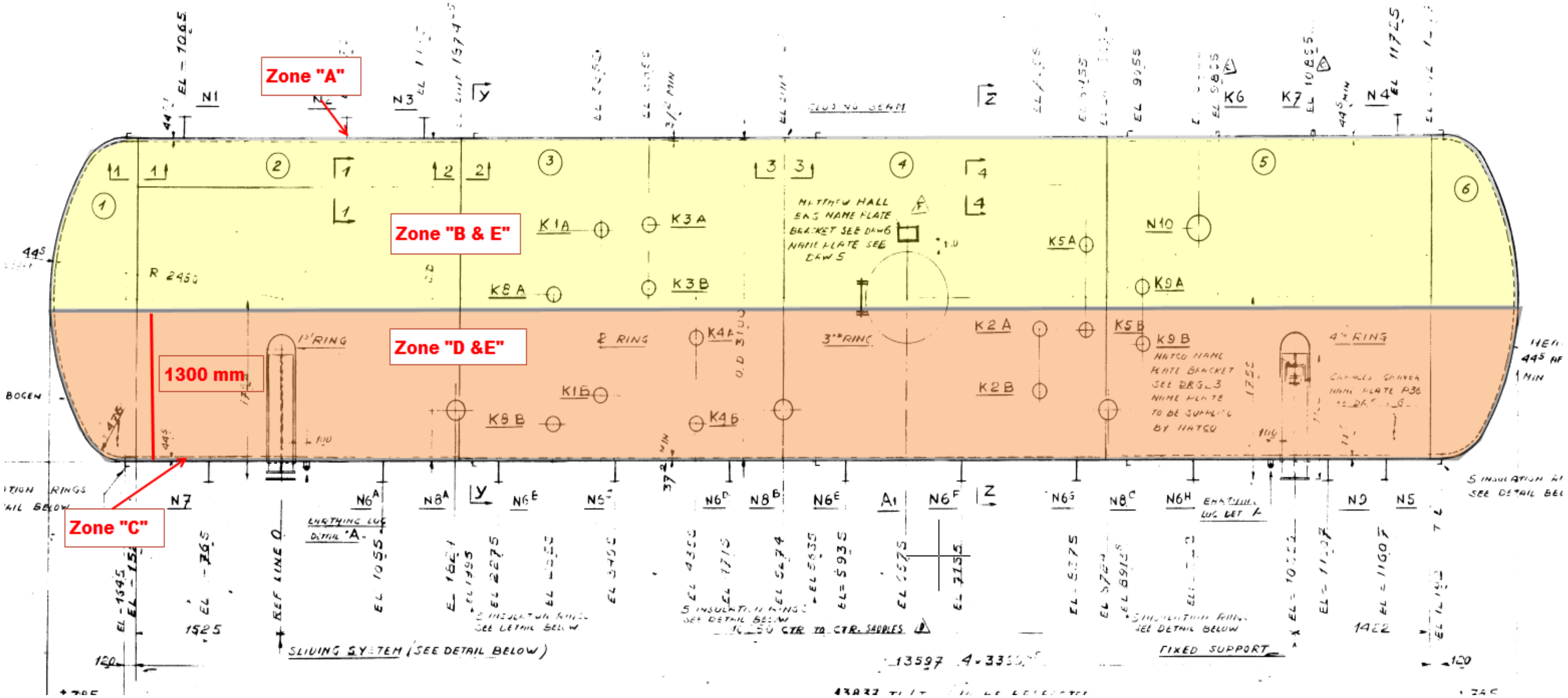
General arrangement drawings for all vessels are listed below. Each inspection zone is marked out with a suffix (A-Z), which is used as a reference of each zone in the tables in Appendix D.

E.1 Crude flash drum No. 3(CD2104)



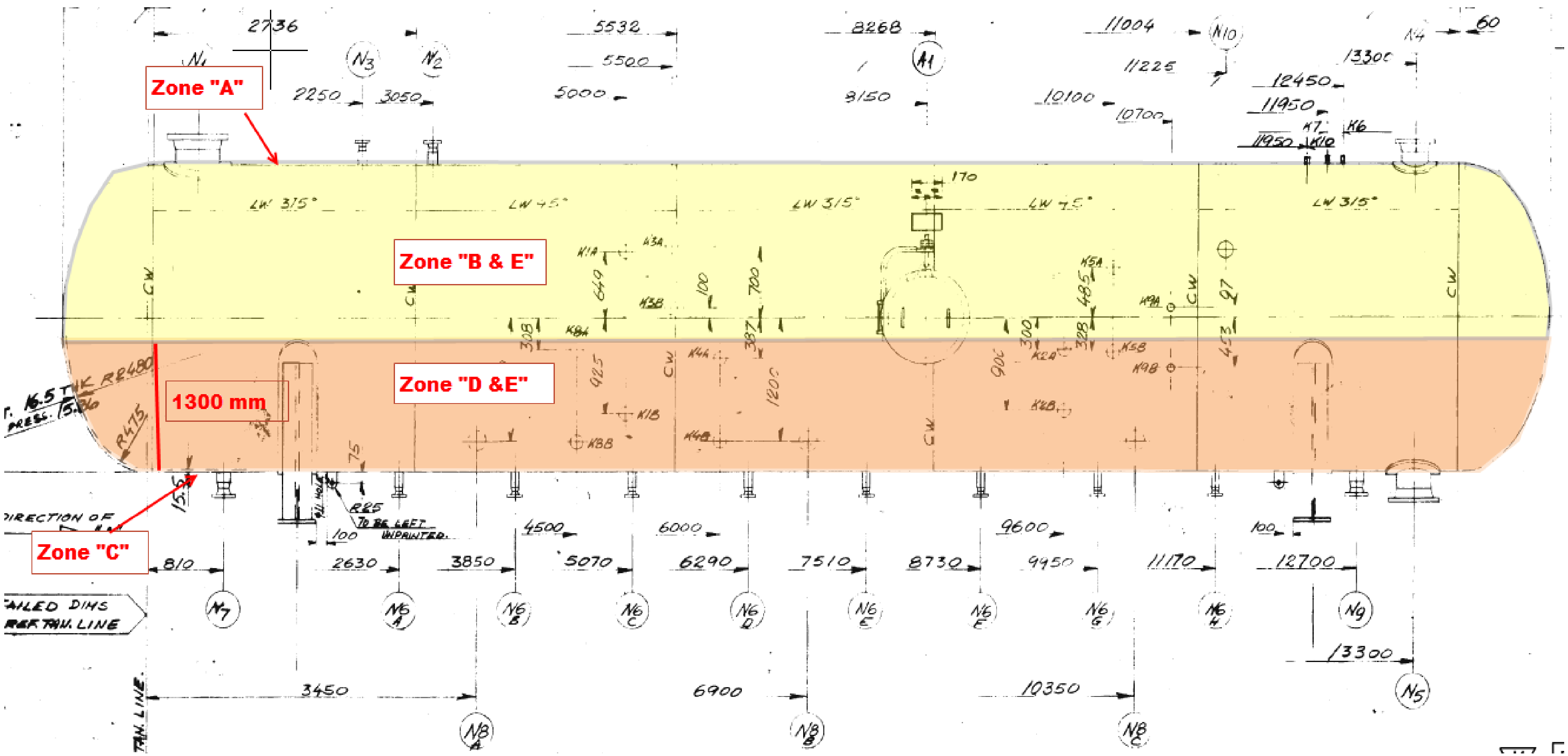
Drawing E-1: General arrangement drawing of crude flash drum No. 3 (CD2104), each inspection zone and location is marked with a suffix (From A-Z). Brown are marks out the area with liquid (oil and water), and the yellow area the gas level (STIDtips, 2015).

E.2 Crude flash drum No. 1(CD2102)



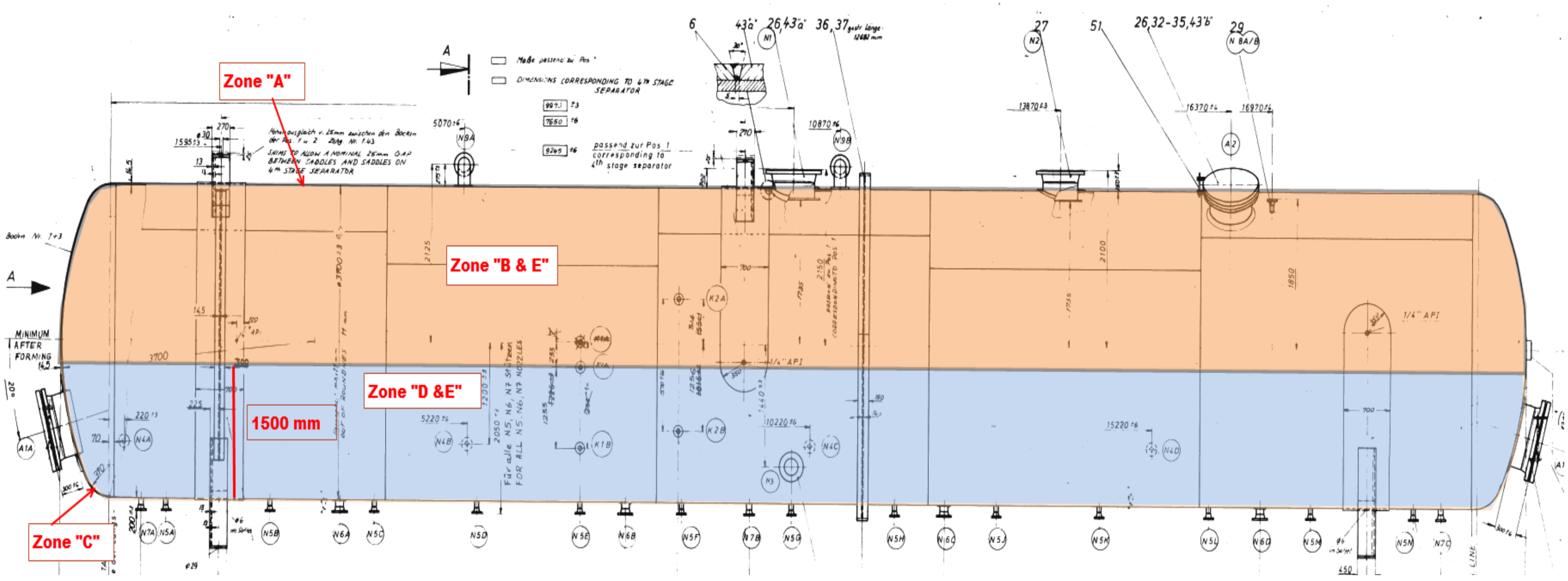
Drawing E-2: General arrangement drawing of crude flash drum No. 1 (CD2102), each inspection zone and location is marked with a suffix (From A-Z). Brown are marks out the area with liquid (oil and water), and the yellow area the gas level (STIDtips, 2015).

E.3 Crude flash drum No. 2 (CD2103)



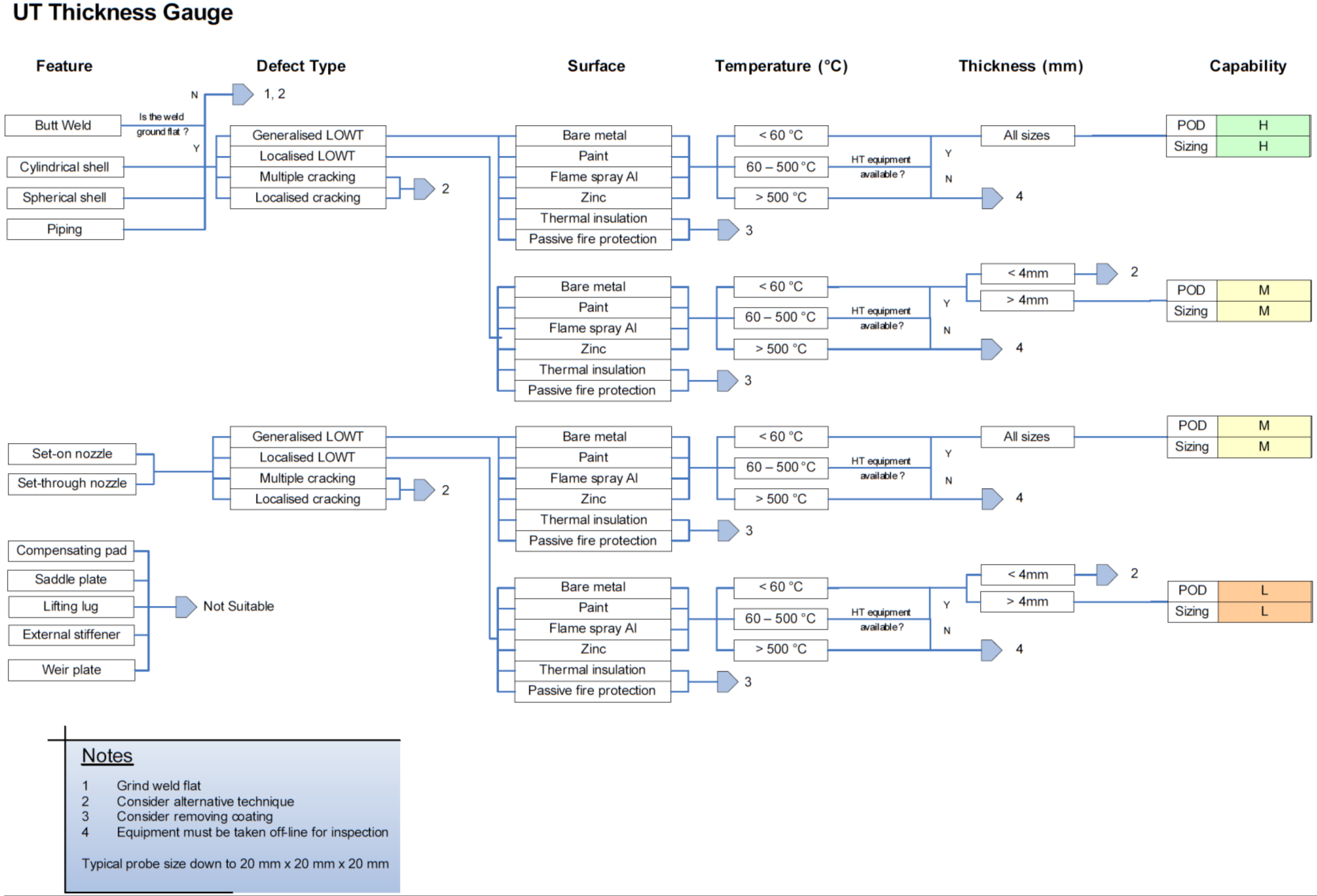
Drawing E-3: General arrangement drawing of crude flash drum No. 2 (CD2103), each inspection zone and location is marked with a suffix (From A-Z). Brown are marks out the area with liquid (oil and water), and the yellow area the gas level (STIDtips, 2015).

E.4 Coalescer (CD2121)

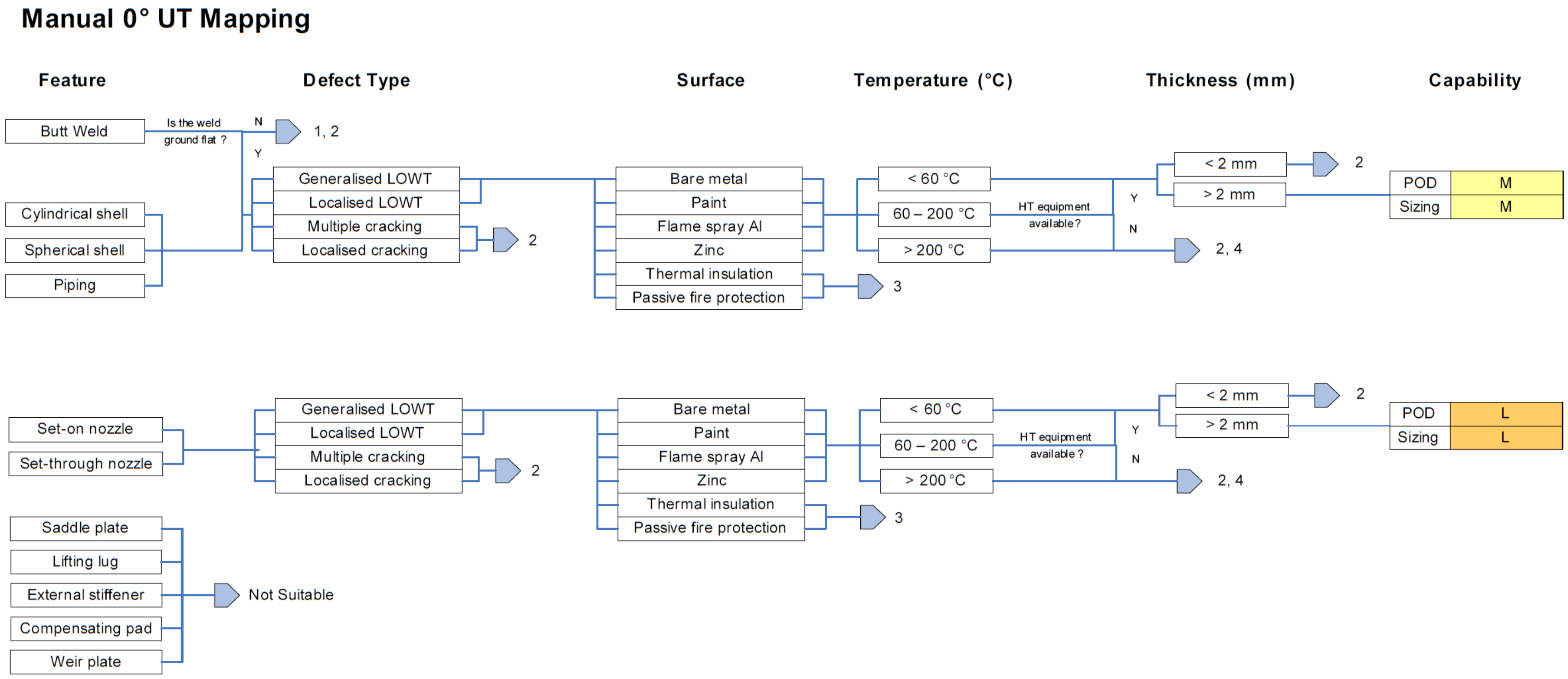


Drawing E-4: General arrangement drawing of Coalescer (CD2121), each inspection zone and location is marked with a suffix (From A-Z). Brown are marks out the area with liquid (oil and water), and the blue area the water level (STIDtips, 2015).

Appendix F – NDT Decision flow charts



Flow chart F-1: UT thickness gauge flow chart (DNV, 2011)

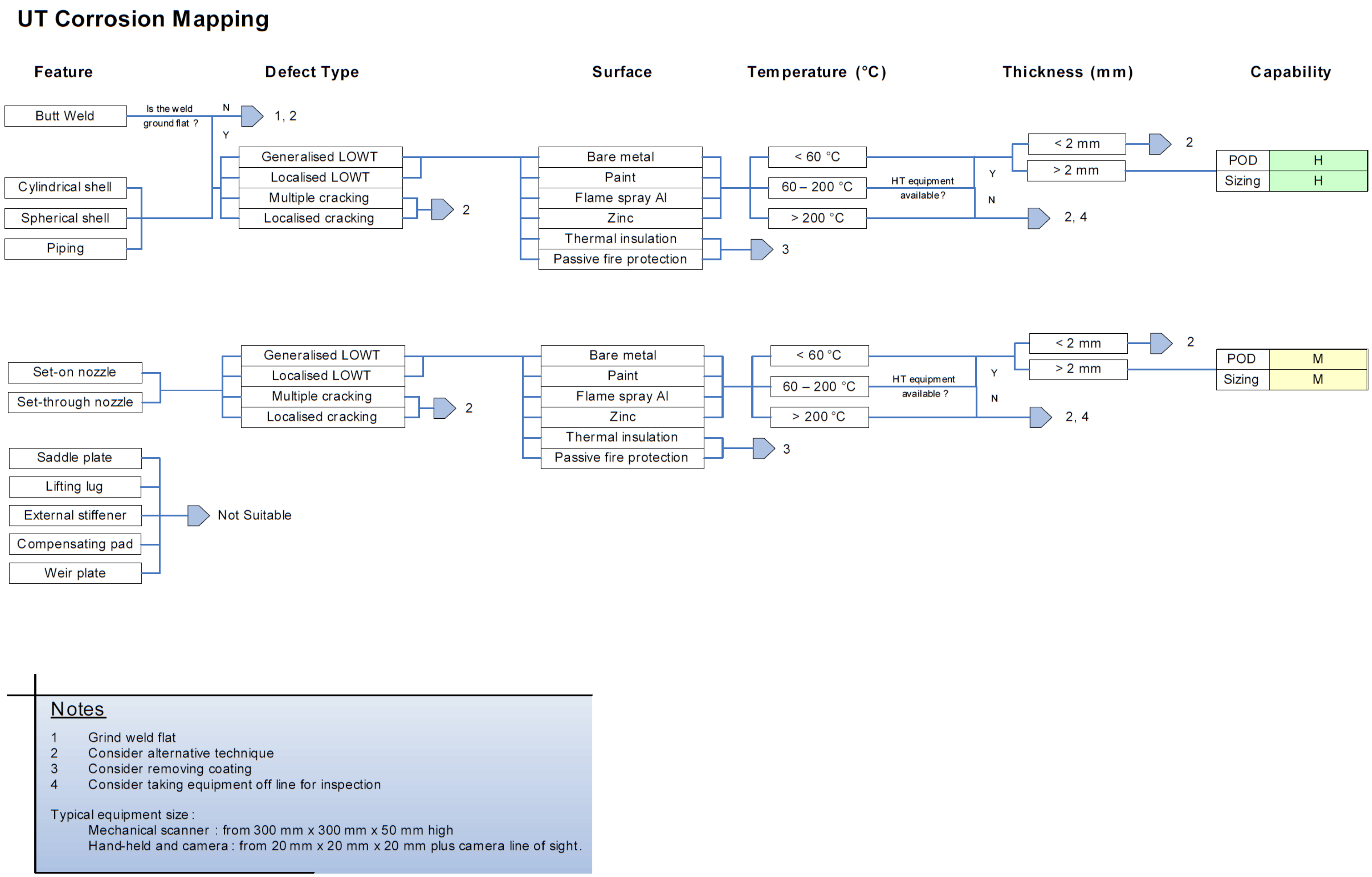


Notes

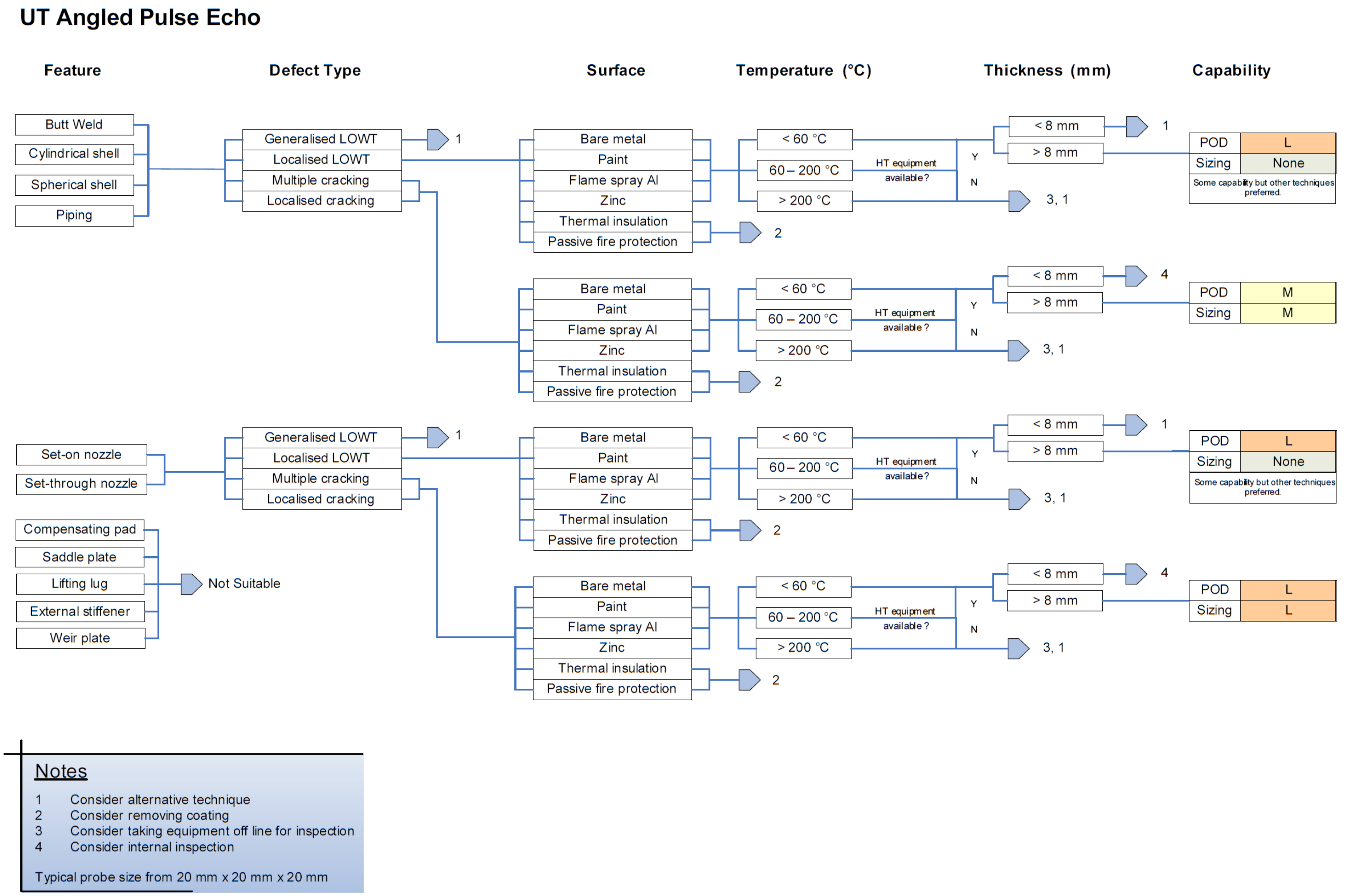
1 Grind weld flat
2 Consider alternative technique
3 Consider removing coating
4 Consider taking equipment off line for inspection

Typical equipment size:
Mechanical scanner : from 300 mm x 300 mm x 50 mm high
Hand-held and camera : from 20 mm x 20 mm x 20 mm plus camera line of sight.

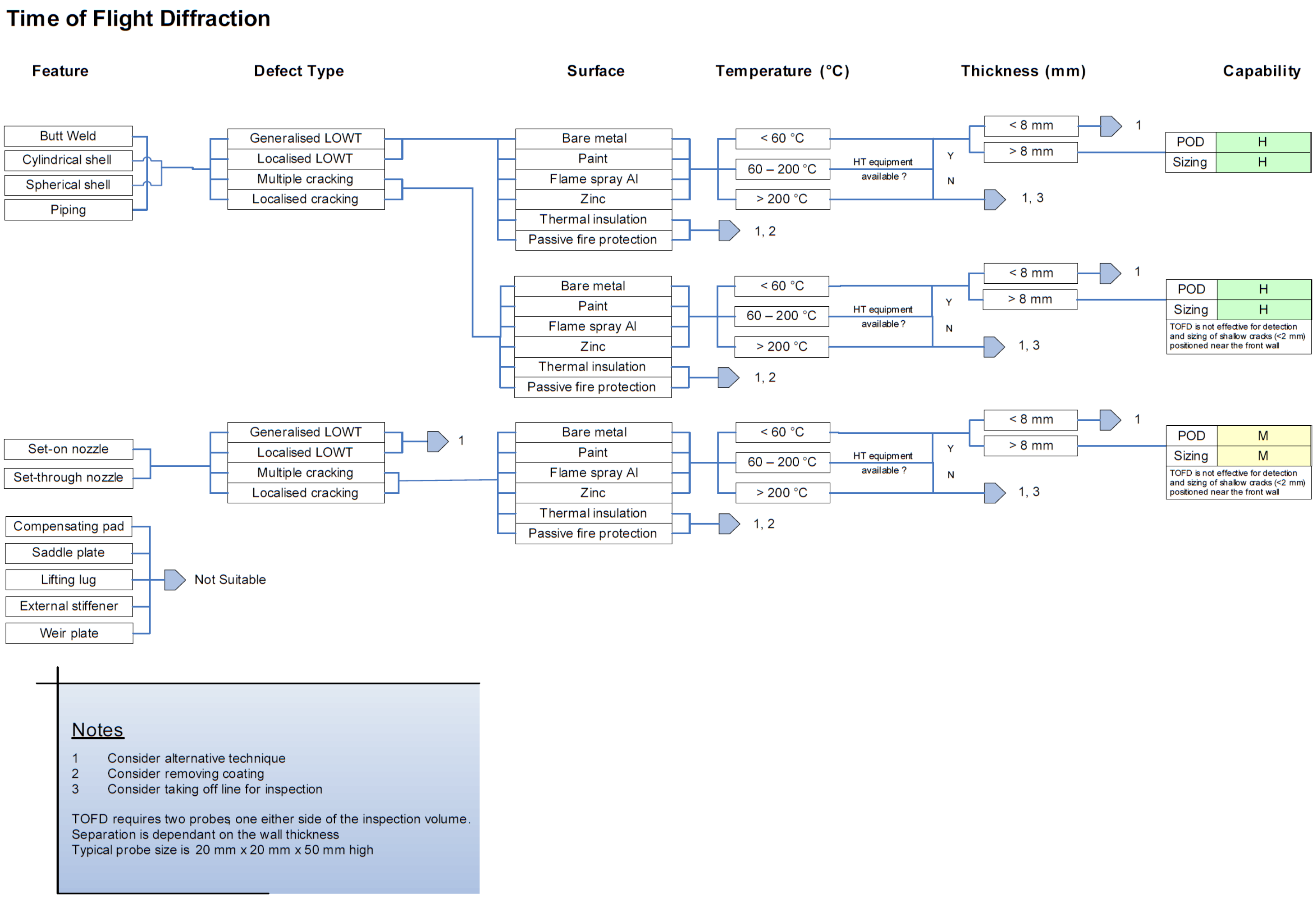
Flow chart F-2: Manual 0° UT Mapping flow chart (DNV, 2011)



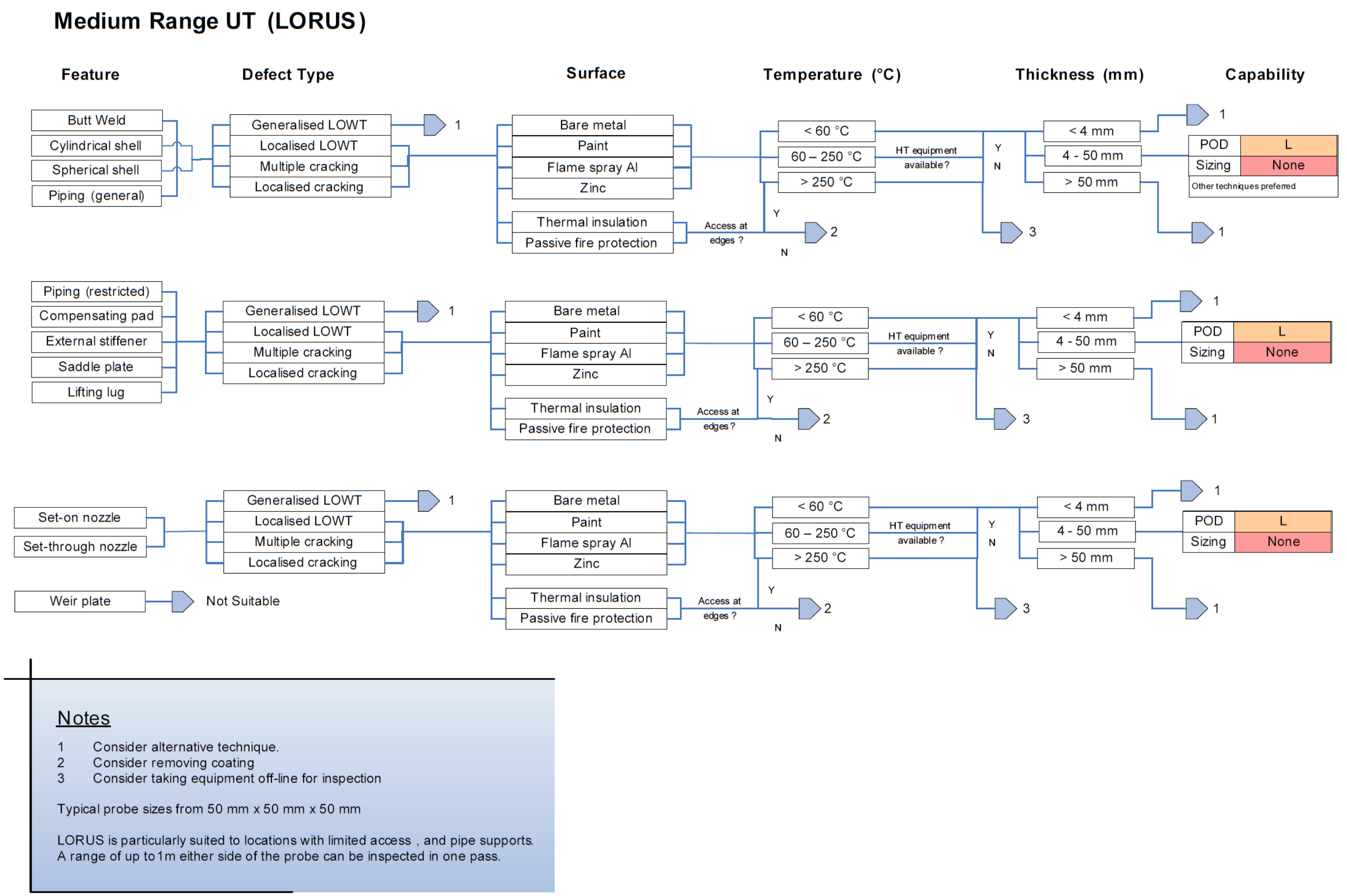
Flow chart F-3: UT Corrosion Mapping flow chart (DNV, 2011)



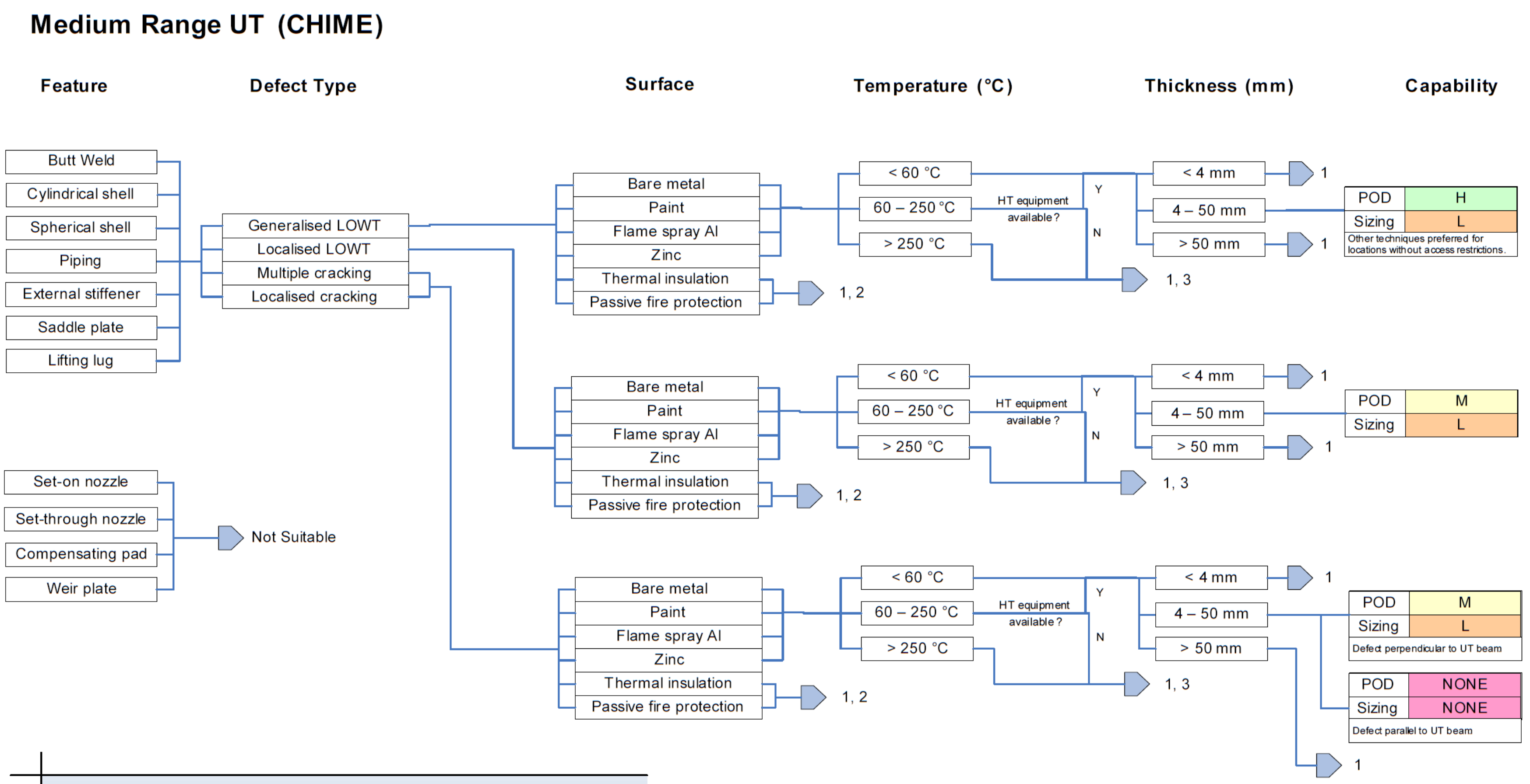
Flow chart F-4: UT Angled Pulse Echo flow chart (DNV, 2011)



Flow chart F-5: Time of Flight Diffraction flow chart (DNV, 2011)



Flow chart F-6: Medium Range UT (LORUS) flow chart (DNV, 2011)



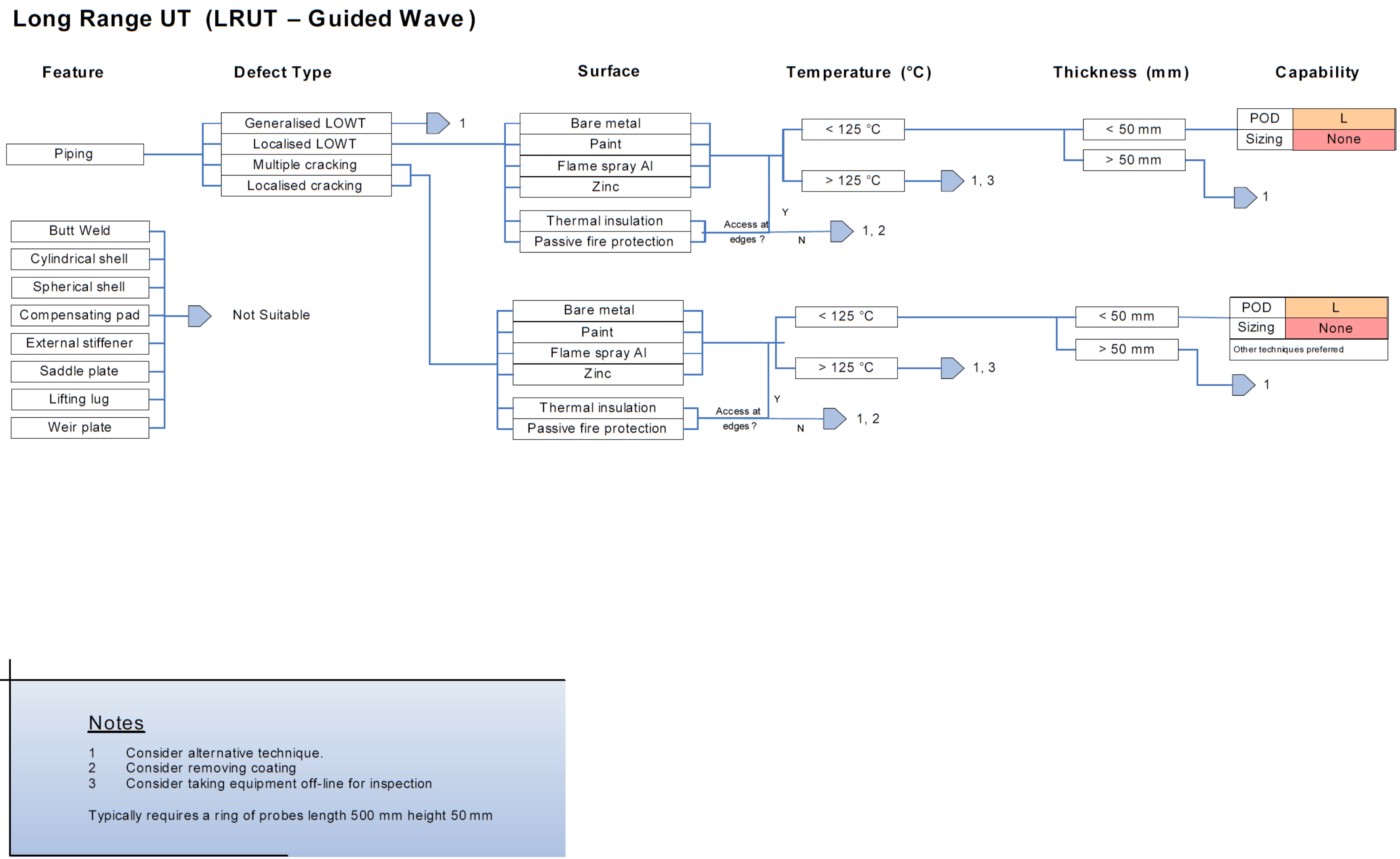
Notes

1 Consider alternative technique.
2 Consider removing coating
3 Consider taking equipment off-line for inspection

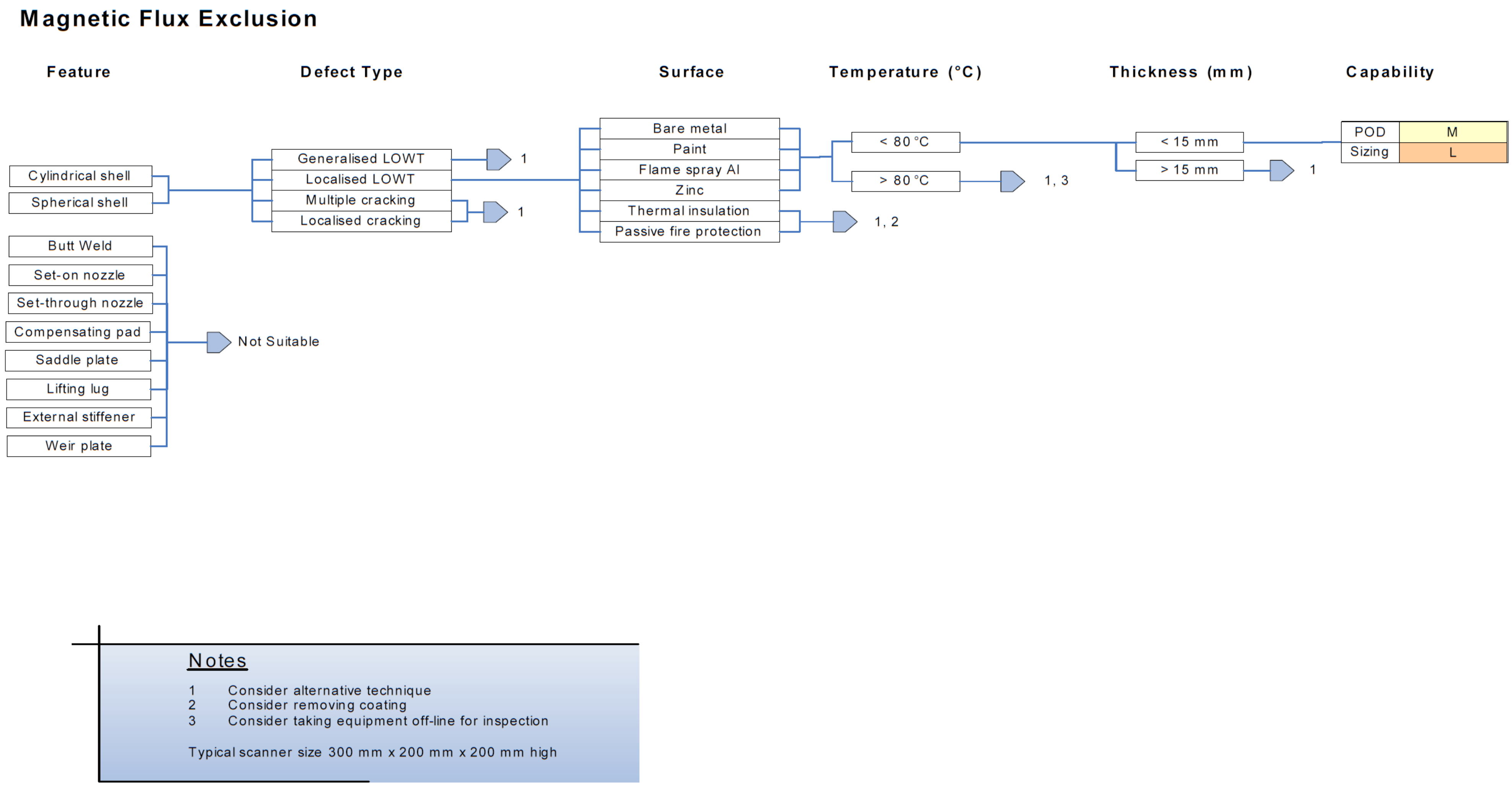
Typical probe sizes from 25 mm x 100 mm x 100 mm high

CHIME requires two probes positioned up to 1m apart.

Flow chart F-7: Medium Range UT (CHIME) flow chart (DNV, 2011)

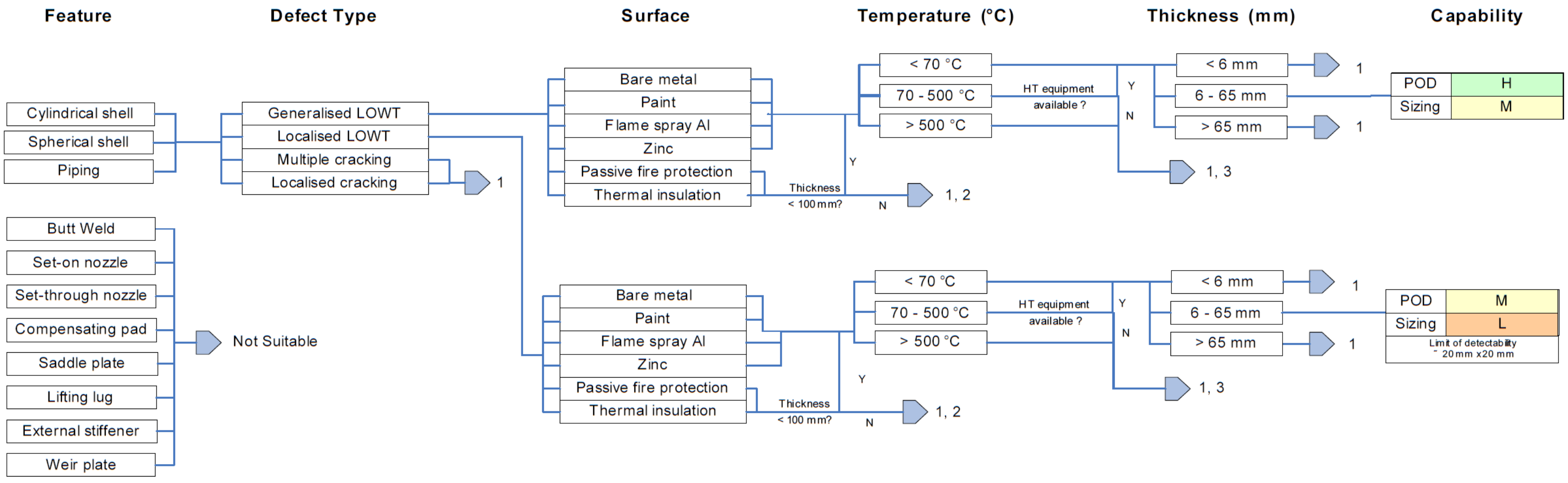


Flow chart F-8: Long Range UT (LRUT – Guided Wave) flow chart (DNV, 2011)



Flow chart F-9: Magnetic Flux Exclusion flow chart (DNV, 2011)

Pulsed Eddy Current



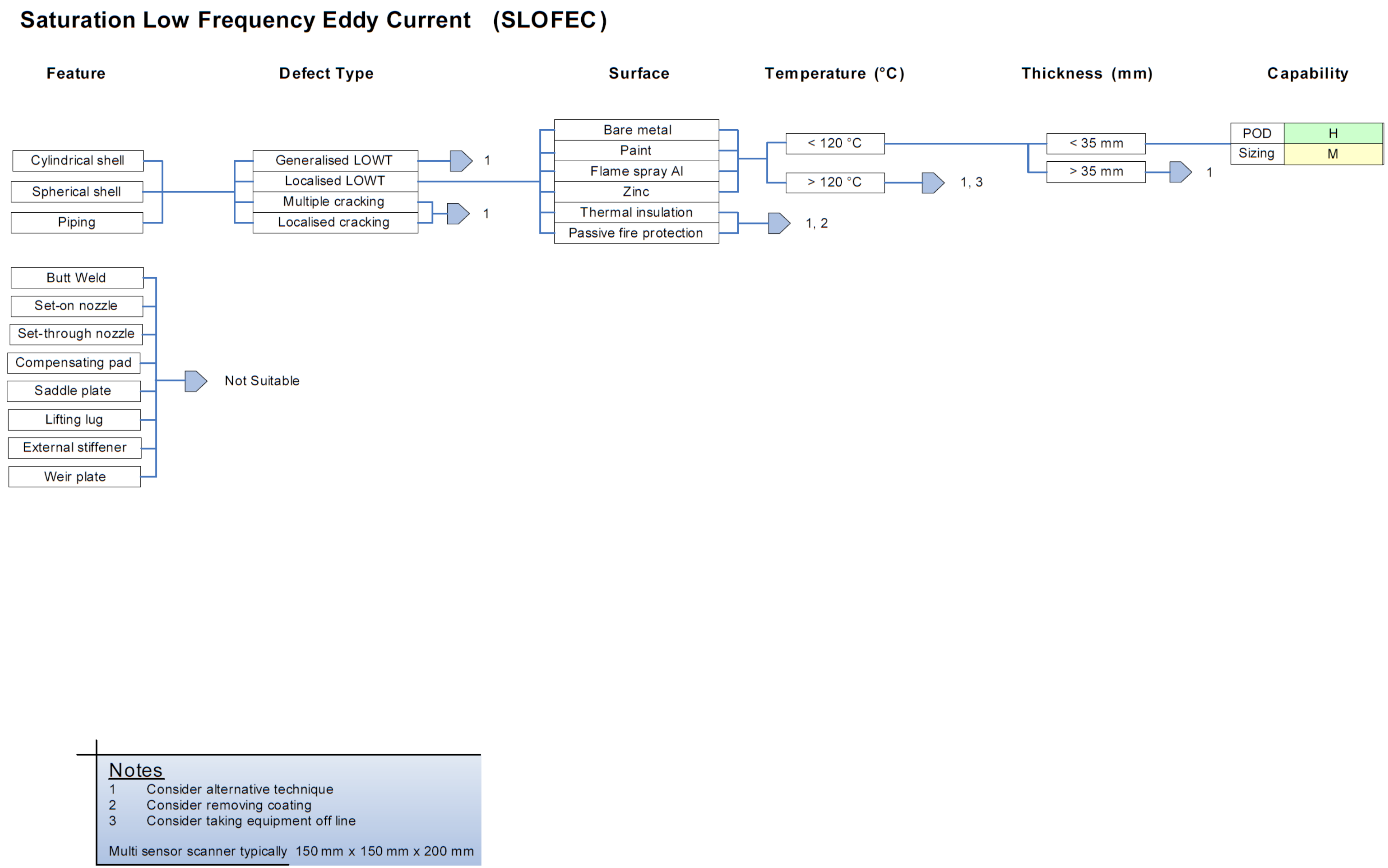
Notes

1 Consider alternative technique
2 Consider removing coating
3 Consider taking equipment off line for inspection.

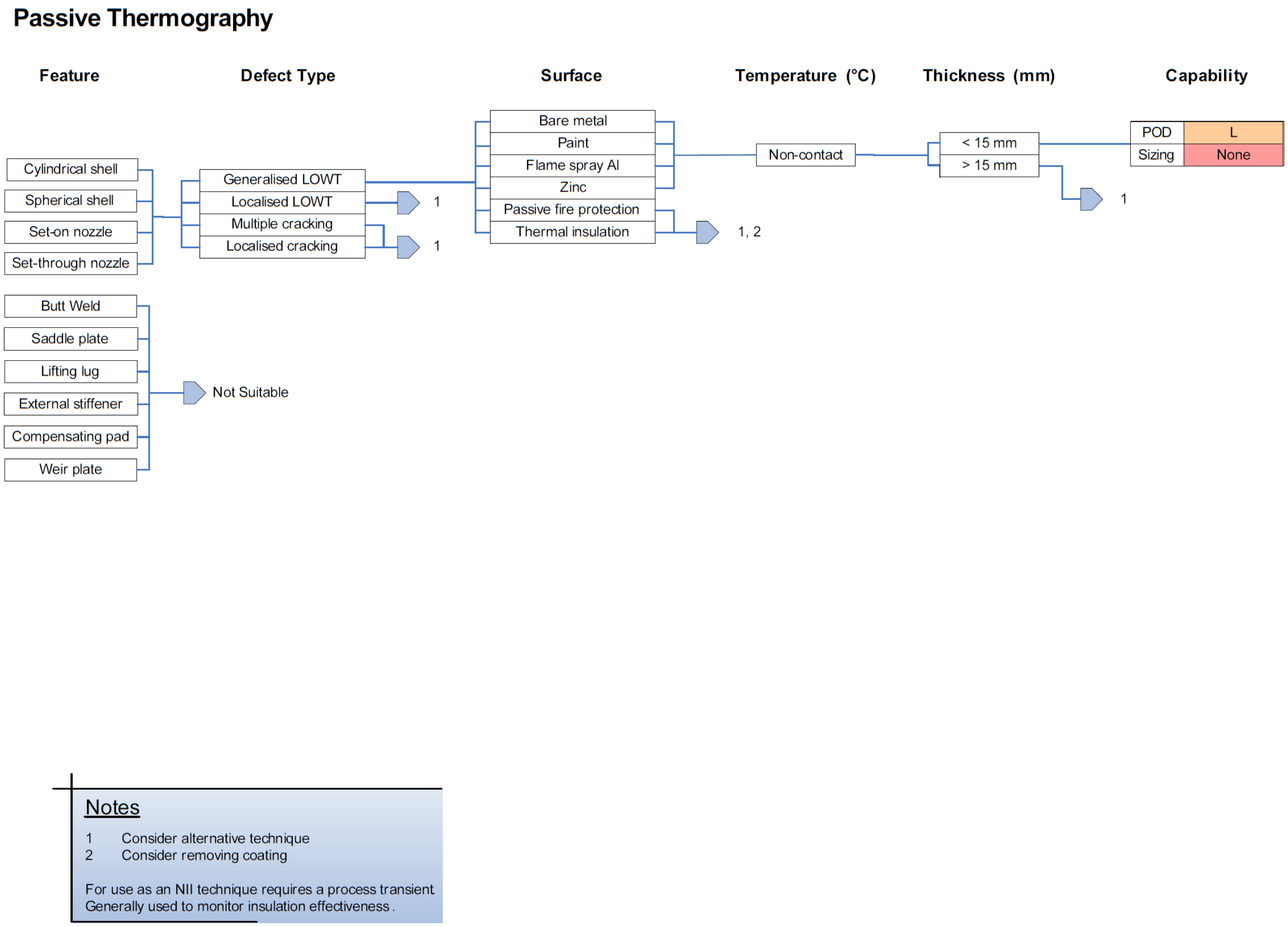
Particularly suitable for vessels and pipes with lagging or insulation, or thin metallic cladding made from aluminium, stainless steel or low alloy steel
Only suitable for use on low alloy steels.

Typical probe size 200 mm x 200 mm x 100 mm high, although specialist probes
Available down to 20 mm x 20 mm x 5 mm high

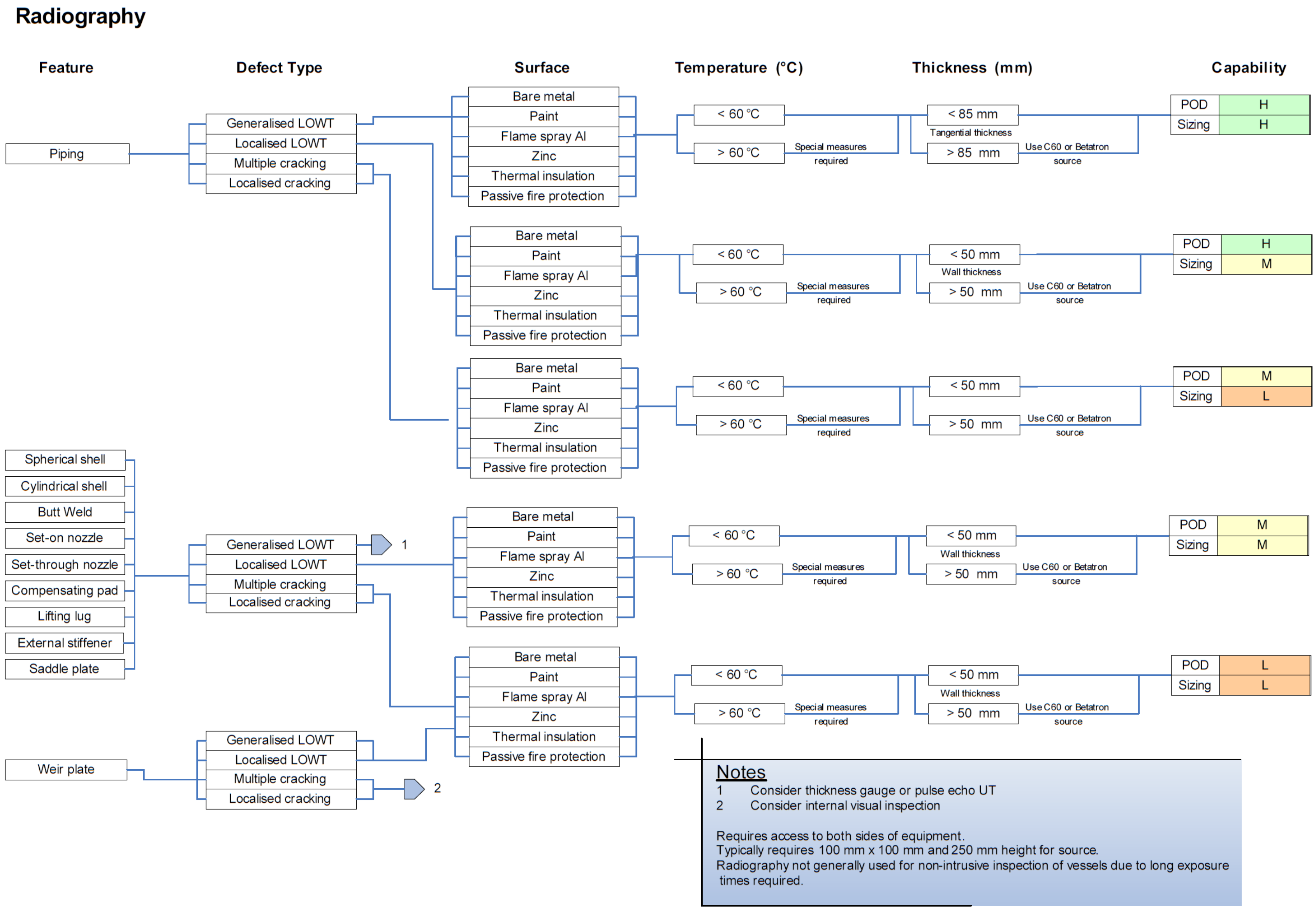
Flow chart F-10: Pulsed Eddy Current flow chart (DNV, 2011)



Flow chart F-11: Saturation Low Frequency Eddy Current (SLOFEC) flow chart (DNV, 2011)



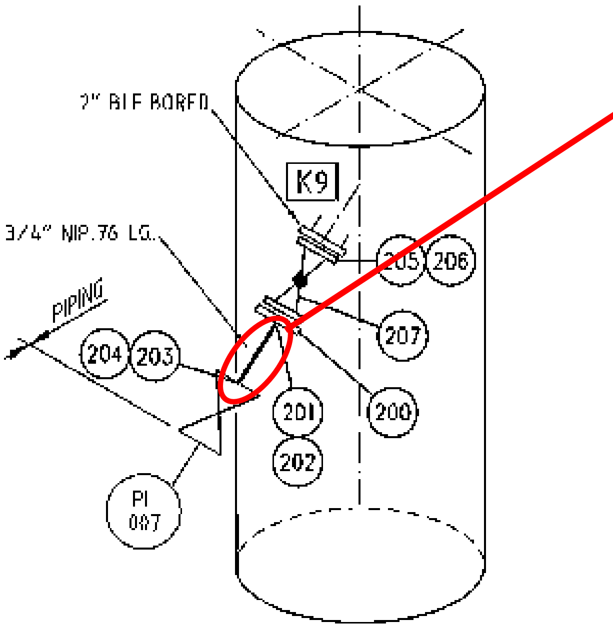
Flow chart F-12: Passive Thermography flow chart (DNV, 2011)



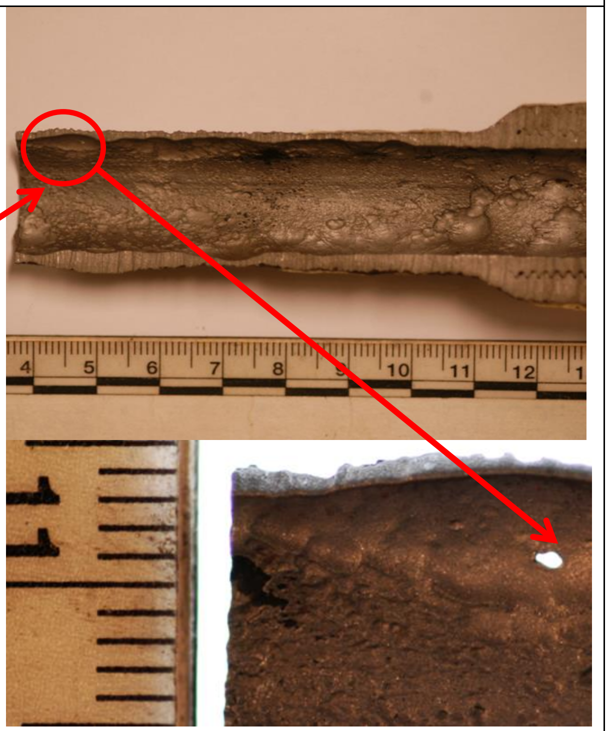
Flow chart F-13: Radiography flow chart (DNV, 2011)

Appendix G – Corrosion case examples

1. Scrubber - Nozzle dead leg. CO_2 due to condensation and accumulation of water.

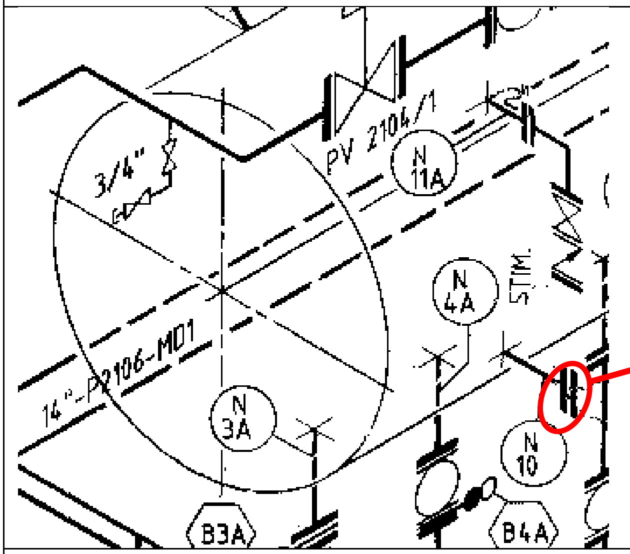


Drawing G-1: Internal corrosion in the ¾"-pipe marked out in the read ring.



Picture G-1: Areas of general corrosion and details of a small hole in the pipe wall. Corrosion rate 0,5mm/year.

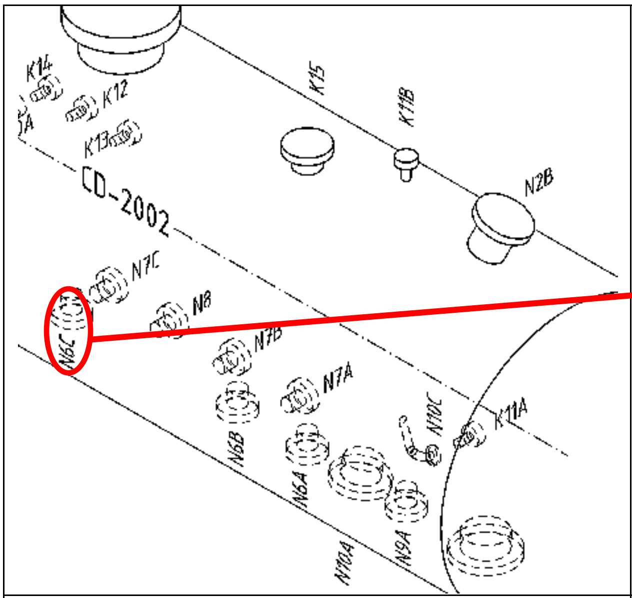
2. Separator – Corrosion of RTJ sealing surface.



Drawing G-2: Corroded RTJ-sealing surface at nozzle N10.

Picture G-2: RTJ - primary sealing surface 100% corroded and 50% of RTJ - secondary sealing surface after 3 years in service.

3. Separator – Corrosion of RF sealing surface.



Drawing G-3: Corroded RF-sealing surface at nozzle N6C.

Picture G-3: Primary RF - sealing surface 35% corroded after 6 years in service. Repaired with Belzona coating.