Corrosion Assessment of Pig Receiver and Gas Lift Riser

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Clovis Nzonlie Fosso

School of Natural Sciences

Department of Materials

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Abbreviations

ACFM: Alternating current field measurement

AIM: Asset integrity management

API: American petroleum institute

ASME: American society of mechanical engineers

CVI: Close visual inspection

CO_2: Carbon dyoxide

DNV RP: Det norske veritas recommended practice

DPT: Dye penetration testing

ECT: Eddy current testing

ESDV: Emergency shut down valve

Fe: Iron

Fe^{2+}: Iron ion

$Fe(OH)_2$: Iron (II) hydroxide or ferrous hydroxide

$Fe_2O_3.H_2O$: Iron (III) oxide or rust

GVI: General visual inspection

H_2O: Water

H_2S: Hydrogen sulfide

HSE: Health and Safety Executive

HIC: Hydrogen inducd cracking

LoF: Likelihood of failure

MIC: Microbial influenced corrosion

mm: Millimeter

m: Meter

Mmscf: Million standard cubic feet

MPT: Magnetic particle testing

NACE: National Association of Corrosion Engineers

NDE: Non-destructive examination

NDT: Non-destructive testing

OH^-: Ion hydroxide

PA: Phase array

pptb: Pounds per thousand barrels

UDC: Under deposit corrosion.

UT: Ultrasonic testing

V: Velocity

RBI: Risk Based inspection

RBA: Risk-based assessment

RT: Radiographic testing

SOHIC: Stress-oriented hydrogen induced cracking

SSC: Sulphide stress cracking

SSCC: Sulphide Stress Corrosion Cracking

SWC: Step wise cracking

TOFD: Time of flight diffraction

1 Abstract

The corrosion assessment of a pig receiver and gas lift riser following the failure of the gas lift is discussed in this dissertation. Corrosion evaluation is a critical component of asset and facility management. Most equipment/system failures are caused by a lack of corrosion evaluation and poor material selection. In general, an effective corrosion evaluation should be carried out to solve this problem. This dissertation outlines a risk-based assessment that was conducted to determine an appropriate non-destructive testing method for the pig receiver and gas lift riser. Internal examination was performed using the chosen non-destructive testing method and the corrosion rate was determined using API 510 Standard. The minimum thickness required for the gas lift riser was obtained using ASME B31.3, and the minimum thickness required for the pig receiver was calculated using ASME Section VIII Div. 1. General visual inspection was also conducted in accordance to API 570. Both the pig receiver and the gas lift riser were deemed to be fit to remain in operation under acceptable operating conditions (temperature, pressure, etc..) after examination. External coating degradation, crevice corrosion and rust on the surface of the gas lift riser were discovered during a general visual inspection (GVI), however this did not preclude the equipment/system from continuing service. To plan inspections or estimate the maximum inspection frequency during routine inspections, the remaining life of the pig receiver and gas lift riser was calculated.

2 Declaration

No portion of the work referred to in the thesis has been submitted in support of an application for another degree or qualification of this or any other university of other institution of learning.

3 Copyright Statements

4 Dedication

The work is dedicated to my lovely late father Mr Justin Fosso for who I remember every

day for the legacy you left behind and all your sacrifices you did for me, brothers and sisters. I know you are proud of me for this achievement, to my dear lovely mother Mrs Pauline Njimhouo Fosso, to my dear lovely wife Bamidele Adewuyi Nzonlie, to my lovely son Darel John Adewuyi Nzonlie, to my dear lovely daughters Aurielle Fortune Njinang Nzonlie and Evanie Sorelle Njimhouo Nzonlie

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Above all, I appreciate God Almighty for His grace and strength all through the studies. Despite all the challenges, His presence in my life makes the difference.

6 Introduction

Most of the equipment/system in oil and gas industry is made of metals (1). It is estimated that about 90% of oil and gas distribution equipment/system are cast iron and steel (1). Due to their long-term service and exposure to aggressive environment, ageing and deterioration, high rate of failures which can be mechanical, localized corrosion or general corrosion are expected (1, 2). The consequences of equipment/system failures can result in substantial disruption of daily operation, considerable economic loss, environmental pollution, damage to company reputation and even casualties.

Due to different environments, the mechanisms of corrosions are different for internal and external surfaces of equipment/system. Corrosion is an oxidation process. This means that metallic iron will react with oxygen and form iron oxide (rust) (2). The reaction will progress at different rates depending on several conditions. In general, the worst conditions will be when the iron or steel is immersed in seawater. The corrosion reactions will involve a transfer of electrons in the presence of an electrolyte (2, 3) (see figure 1 below). Seawater is a very good electrolyte because of its high salt concentration.

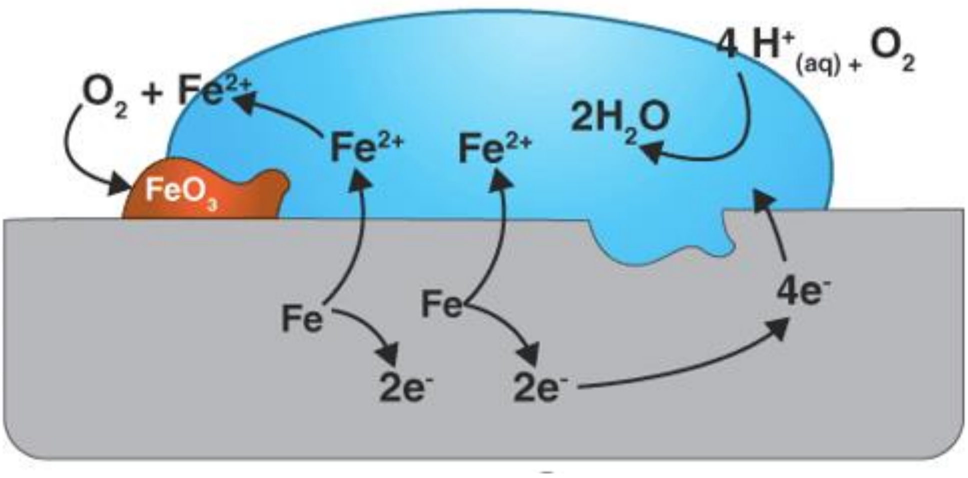


Figure 1: Corrosion reaction with transfer of electron (4)

For iron and steel to corrode, anodic and cathodic reactions must take place (see figure 2 below).

For the anodic reaction: $Fe \rightarrow Fe^{2+} + 2\ e^{-}$

And for the cathodic reaction: $O_2 + 4\ e^{-} + 2\ H_2O \rightarrow 4\ OH^{-}$

Combining the above anodic and cathodic reaction gives: $Fe^{2+} + 2\ OH\text{-} \rightarrow Fe\ (OH)_2$

Figure 2: Corrosion process – Anode and Cathode (5)

Fe $(OH)_2$ is an insoluble salt that precipitates on the surface. It is then further oxidized by dissolved oxygen to hydrated ferric oxide, commonly known as rust (see figure 3 below). Fe $(OH)_2$ + O_2 + H_2O --> $Fe_2O_3.H_2O$ (Rust) (1, 6).

Figure 3: Rust on carbon steel (7)

Moisture, temperature, pH values, mineral salt content, sulphides, organics, precipitates, etc. are major factors that contribute to internal/external corrosion of equipment/system (2, 8). The understanding and knowledge of corrosion deterioration and mechanical properties of metals can prevent equipment failures.

Assessment using appropriate pipeline integrity management system (PIMS) has been undertaken on the effect of corrosion on pig receiver and gas lift riser materials. Risk-based assessment used was to describe the overall process or method to Identify hazards and risk factors that have the potential to cause harm (hazard identification), to determine appropriate ways to eliminate the hazard, or to control the risk when the hazard cannot be eliminated (risk control). For the risk-based inspection, ultrasonic testing for thickness, general visual Inspection, long-range ultrasonic testing and corrosion mapping were conducted to assess the internal and external condition of pig receiver and gas lift riser during the assessment.

7 Literature review

Corrosion is the deterioration of metal by direct chemical and electro-chemical reaction with its environment (3, 6). Corrosion is the largest single cause of plant and equipment breakdown in the process industries (9, 10). For most applications, it is possible to select materials of construction that are completely resistant to attack by the process fluids. In practice, it is normal to select materials that corrode slowly at a known rate and to make an allowance for this in specifying the material thickness or chemical treatment to reduce the corrosivity of fluid (9). However, a significant proportion of corrosion failures occur due to some form of localised corrosion, which results in failure in a much shorter time than would be expected from uniform corrosion (10).

API RP 581 developed risk-based inspection (RBI) methods and methodology, an integrated methodology that analyses both the likelihood and effects of equipment/system failure as a basis for prioritizing and monitoring an in-service equipment/system inspection program (11). API RP 581 was developed using the knowledge and experience of various global risk-based inspection practitioners with substantial implementation experience. The suggested practices for calculating corrosion rates in hydrocarbon production and process systems where the corrosive agent is CO_2 is presented in NORSOK M-506 (12).

In sour oil and gas production, NACE MR 0175 specifies techniques for qualifying and selecting materials that are resistant to cracking. The need for natural gas was recognized shortly after World War II, and the oil and gas industry began an exploratory program to meet the need. Unfortunately, part of the gas reserves discovered contained hydrogen sulphide (H_2S), which resulted in sulphide stress cracking (SSC) failures in metals employed in production equipment/system (13). In 1950, the National Association of Corrosion Engineers (NACE) organized a committee at the request of the companies concerned to better understand and prevent these occurrences. Following subsequent equipment/system failures, a combined Canadian industry task group was formed to find answers to the challenges. Later, this organization became affiliated with NACE and contributed to a NACE report which was published in 1963 (13).

According to DNV RP C302, 60% of the world's offshore constructions have exceeded their theoretical design life of 20 years, with many more nearing the end of their design life. Offshore structures are frequently kept operational for longer than their design lives (14). To guarantee the integrity and safety of these ageing structures, material deterioration must be managed. Carbon steel materials are widely used in the oil and gas production industry because of its availability, constructability, and relatively low cost. However, there are limits to the durability of carbon steel because of its low corrosion resistance (10, 15). Carbon steel will corrode if left unprotected or inadequately protected from the natural environment (16, 17).

Effective management of assets in the oil and gas industry is vital in ensuring equipment/system availability, increased output, reduced maintenance cost, and minimal non-productive time (13, 18). Due to the high cost of assets used in oil and gas production, there is a need to enhance performance through good assets management techniques (13). Failures experienced in oil and gas production industry is associated with different type of corrosions in equipment/system (16, 18-20).

Main types of corrosion are (20):

- Uniform corrosion
- Pitting corrosion
- Environmental induced cracking
- Hydrogen induced cracking
- Crevice corrosion
- Inter-crystalline (inter-granular) corrosion
- Galvanic corrosion
- Fretting corrosion
- CO_2 corrosion
- Microbial induced corrosion
- Preferential weld corrosion
- Filiform corrosion

Uniform corrosion – This corrosion results from the continual shifting of anode and cathode regions of the surface of a metal in contact with the electrolyte and leads to a nearly uniform corrosive attack on the entire surface. An example of such corrosion is the rusting of steel plate in seawater (18-21). Uniform corrosion takes place on unprotected carbon steel and on zinc-coated steel under atmospheric conditions (see figure 4 below).

Figure 4: Uniform corrosion (21)

Pitting corrosion – Pitting corrosion is a localized form of corrosion which leads to the creation of small holes or pits in the steel. The pits or holes are obscured by a small amount of corrosion product (rust) on the surface. When a cathodic reaction in a large area (coating) sustains an anodic reaction in a small area (exposed metal), a pit, cavity or small hole will form (see figure 5 below) (22). Pitting corrosion may occur in stainless steels in neutral or acid solutions containing halides, primarily chlorides (Cl^-), such as seawater (22-24).

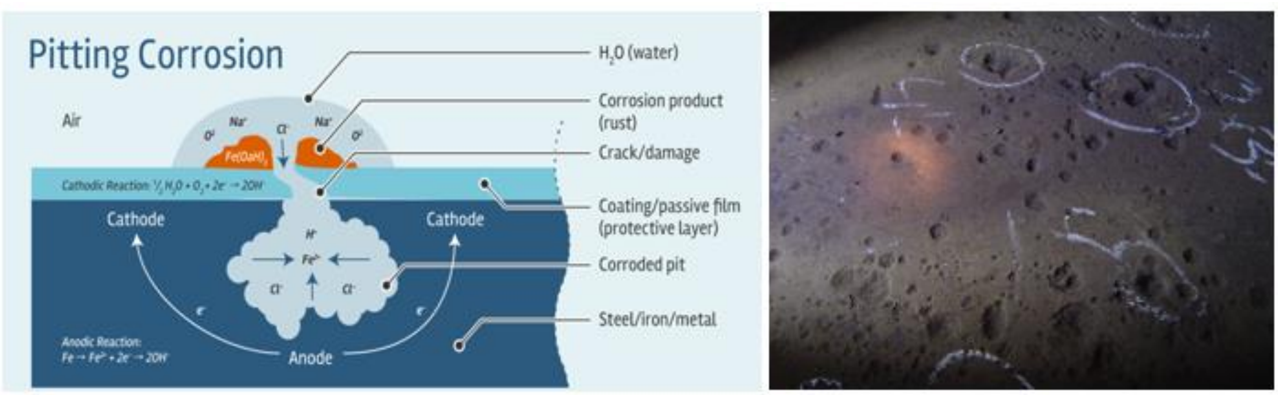


Figure 5: Pitting corrosion (22)

Environmental induced cracking – There are two types of environmental induced cracking. These are stress corrosion cracking, and hydrogen induced cracking (25, 26).

Stress corrosion cracking is a highly specific form of corrosion which occurs only when the following three different requirements are fulfilled at the same time (see figure 6) namely: mechanical (load, stress), material (susceptible alloy, e.g... steel), and environment (highly corrosive, chlorides) (18, 26-28). It can lead to unexpected sudden brittle failure of normally ductile metals subjected to stress levels well below their yield strength. Internal stresses in a material can be sufficient to initiate an attack of stress corrosion cracking (26-29).

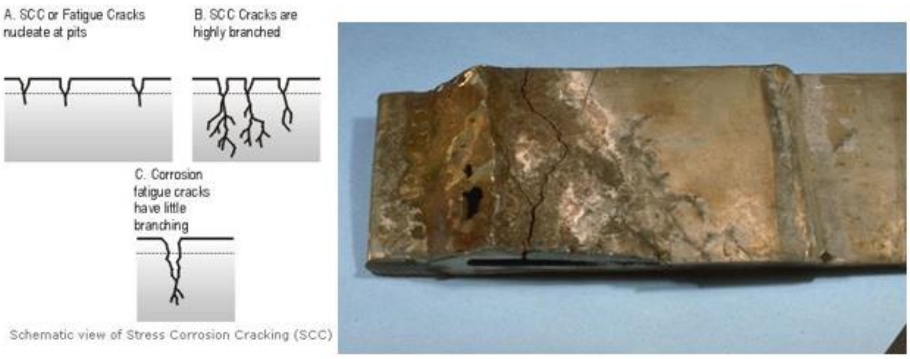


Figure 6: Stress corrosion cracking (28)

Hydrogen induced cracking is caused by the diffusion of hydrogen atoms into the steel (30, 31). The presence of hydrogen in the lattice weakens the mechanical integrity of the metal and leads to crack growth and brittle fracture at stress levels below the yield strength (32). Like stress corrosion cracking, it can lead to sudden failure of steel parts without any detectable warning signs (32, 33). In common applications, hydrogen damage is usually only relevant for high-strength steel with a tensile strength of around 1 MPa or higher (see figure 7) (18, 32-34).

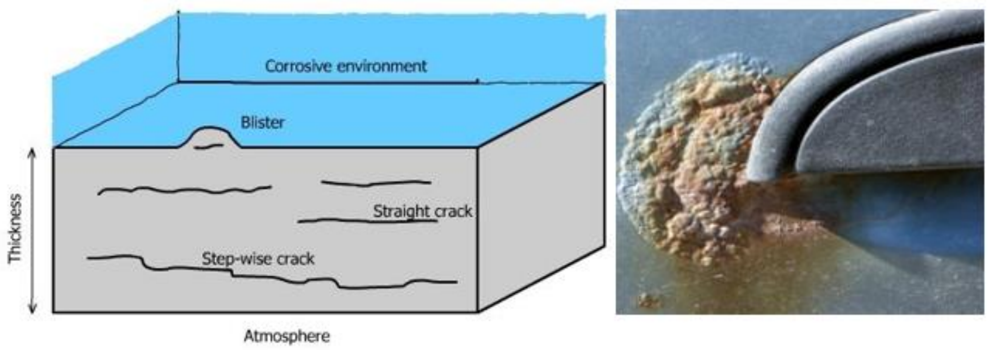


Figure 7: Hydrogen induced cracking (34)

Crevice corrosion – Crevice corrosion refers to corrosion occurring in cracks or crevices formed between two surfaces (made from the same metal, different metals or even a metal and a non-metal) (see figure 8) (35-37). This type of corrosion is initiated by the restricted entrance of oxygen from the air by diffusion into the crevice area leading to different concentrations of dissolved oxygen in the common electrolyte (19, 35-38).

Figure 8: Crevice Corrosion (38)

Inter-crystalline (inter-granular) corrosion – Inter-crystalline corrosion is a special form of localized corrosion, where the corrosive attack takes place in a quite narrow path preferentially along the grain boundaries in the metal structure (see figure 9) (29, 39-41). Is generally considered to be caused by the segregation of impurities at the grain boundaries or by enrichment or depletion of one of the alloying elements in the grain boundary areas (29, 42-45). The most common effect of this form of corrosion is a rapid mechanical disintegration (loss of ductility) of the material (46-48).

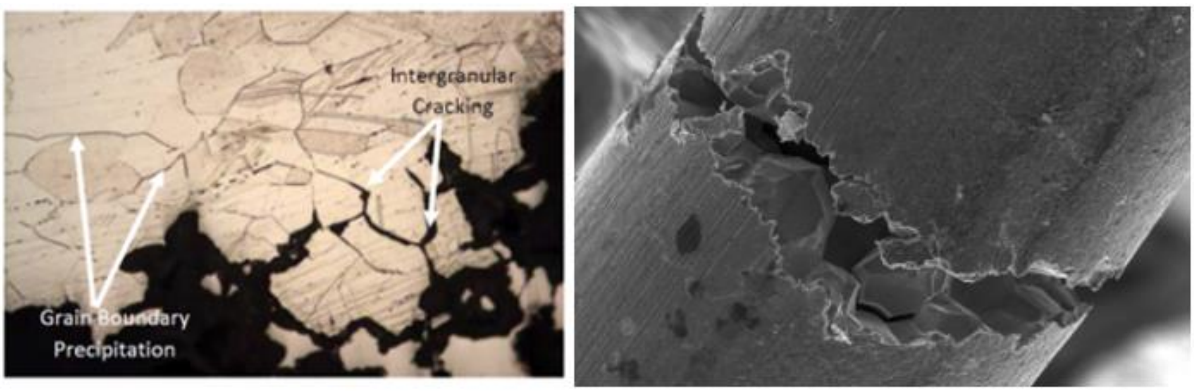


Figure 9: Inter-granular corrosion (48)

Galvanic corrosion – Galvanic corrosion refers to corrosion damage where two dissimilar metals (cathode and anode) have an electrically conducting connection and are in contact with a common corrosive electrolyte (29, 49-50). Electrolytes act like a wire connecting an electrical circuit between two metals, enabling galvanic corrosion (see figure 10) (50, 51).

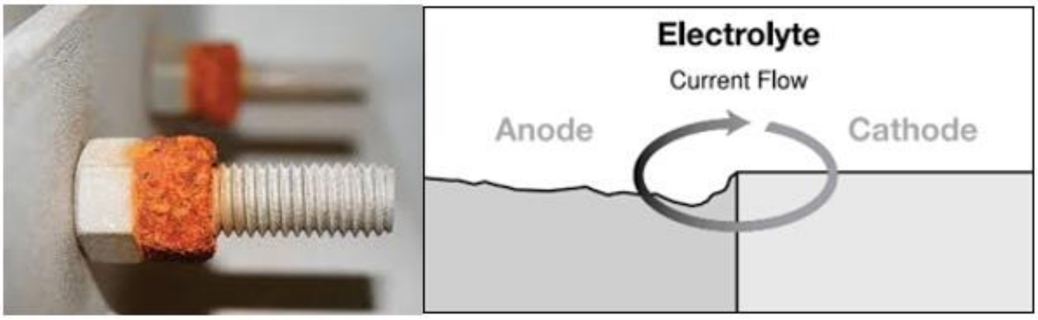


Figure 10: Galvanic corrosion (51)

Fretting corrosion – A rapid localized attack which occurs on mated surfaces under load when a small amount of slip is allowed to occur (29, 52-53). It is often observed on bearings, shafts, and mounted gears in vibrating machinery (see figure 11) (54, 55). Depending on the material or application used, fretting can have abrasive wear, adhesive wear, or both. Abrasive wear occurs when a surface slides across another surface, the former having a rougher surface than the latter (56-58). This causes material loss on the softer surface. Adhesive wear occurs during direct frictional contact whereby both surfaces begin to lose material fragments (59, 60). This type of wear can increase roughness and create protrusions. Since the fragments cannot escape contact during fretting, they further contribute to wear (61).

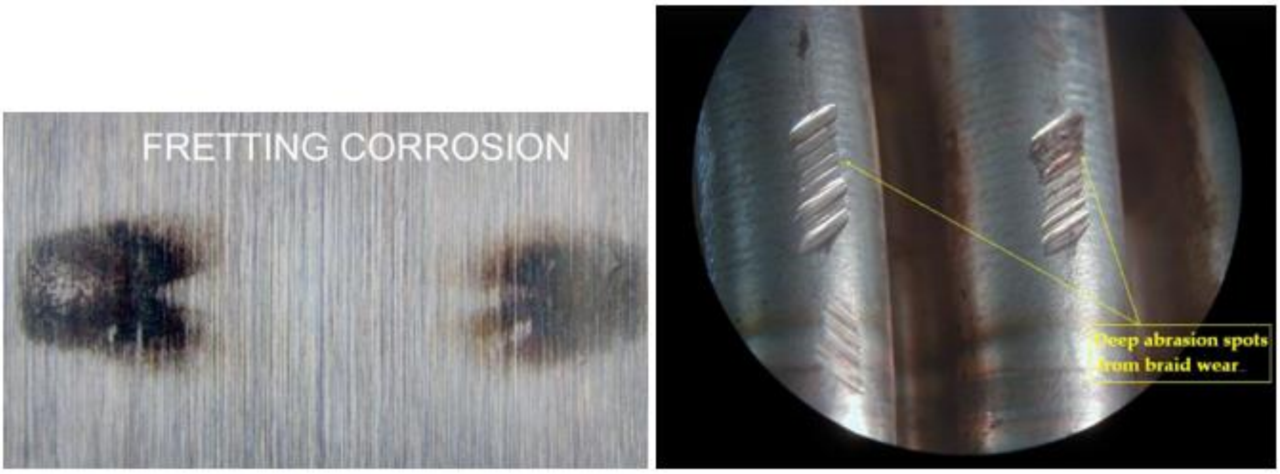


Figure 11: Fretting corrosion (55)

CO_2 corrosion – is a form of degradation that occurs when dissolved CO_2 in condensate forms carbonic acid (H_2CO_3), which corrodes steels and low alloys to form an iron carbonate scale (see figure 12) (62-64). Carbonic acid is formed by gaseous carbon dioxide first dissolving into water, and then reacting to it (65, 66). CO_2 corrosion is most typically found in boiler condensate return systems that are not adequately treated with corrosion inhibitors is a complex process and many variables are involved, such as: pH, temperature, chloride concentration, fugacity, and system total pressure (66, 67).

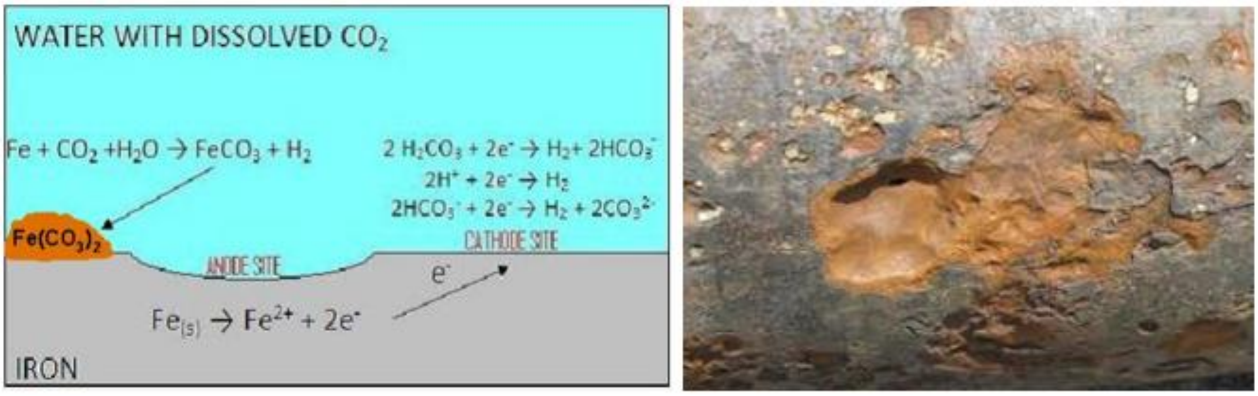


Figure 12: CO_2 corrosion (63)

H_2S corrosion – is a form of aqueous corrosion that can occur on all upstream steel components exposed to H_2S, such as well tubing, flow lines, transport pipelines and processing equipment/system (see figure 13) (68-70). All water-wet internal surfaces are prone to H_2S corrosion, either by produced water in the bottom of the line or condensed water in the top-of-line (68, 71).

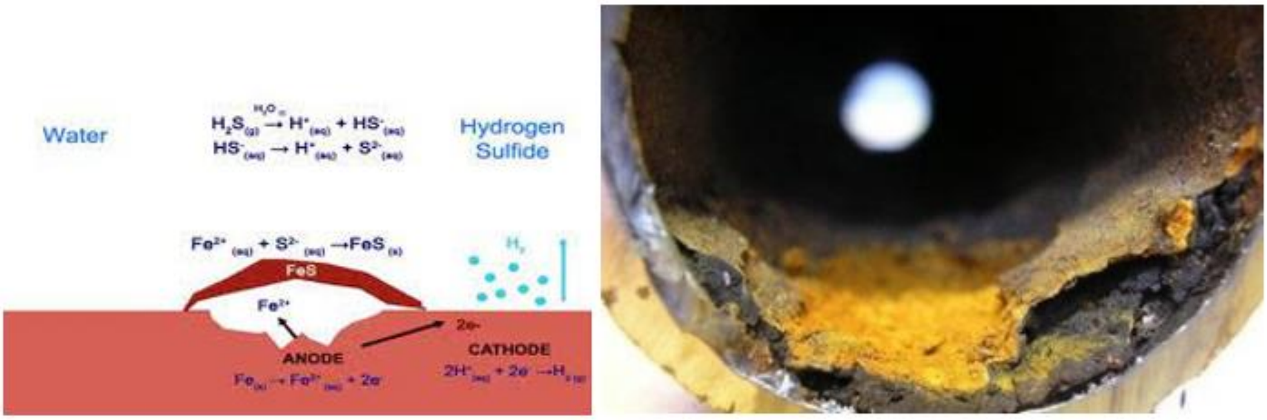


Figure 13: H_2S corrosion (70)

Microbial induced corrosion – is the deterioration of a metal by corrosion processes that occurs directly or indirectly because of the metabolic activity of microorganisms in cold water systems (72-75). This type of corrosion results in severe pitting of metals, leading to rapid failures (see figure 14) (76, 77). The type of bacteria that cause this type of corrosion are anaerobic, they can only thrive in oxygen-deprived regions under deposit (78).

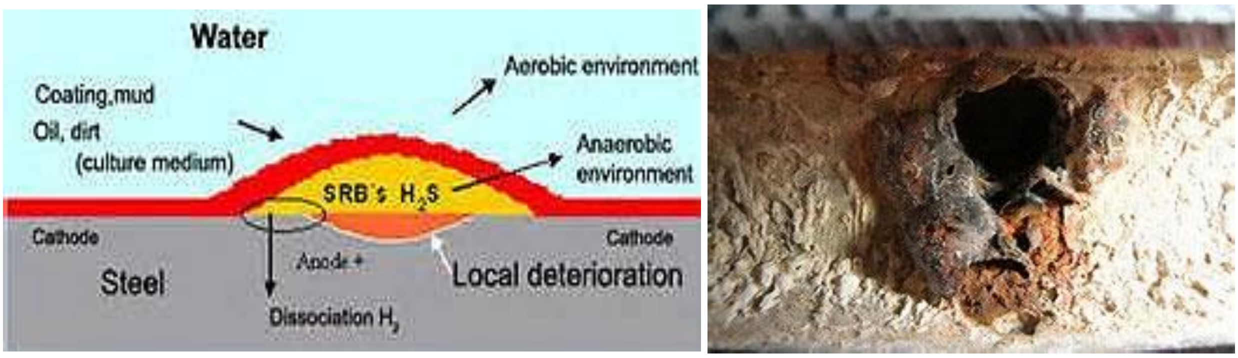


Figure 14: Microbial induced corrosion (77)

Preferential weld corrosion – (also known as grooving corrosion, knife-line attack or trench-like corrosion) is a selective and rapid corrosion of a weld or bond line (79). The corroded area formed is groove shaped and is thus a potentially severe defect (see figure 15) (80-83). It tends to form a relatively sharp notch in material which is also usually less tough than the parent material (79, 82).

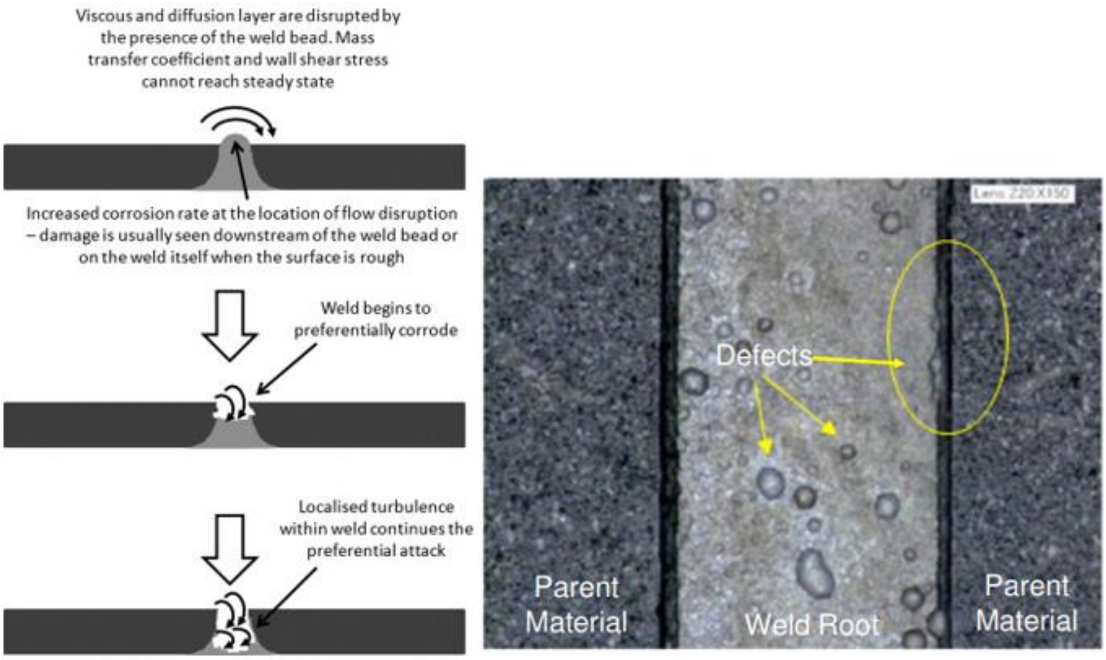


Figure 15: Preferential weld corrosion (83)

Filiform corrosion – is a form of corrosion specific to painted steel, aluminium and magnesium surfaces. It results in a detachment of the coating from its metallic support, which is caused by the surface corrosion of the underlying metal at the metal/coating interface (see figure 16) (84, 85)

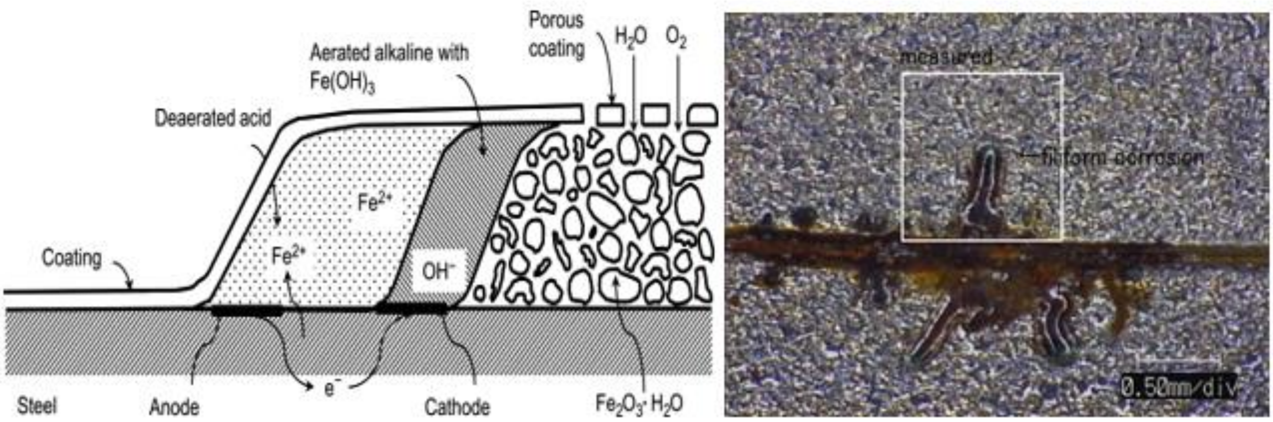


Figure 16: Filiform corrosion (84)

The major risk of corrosion in oil and gas production requires the understanding of the failure mechanism and procedures for assessment and control (86). The rate of corrosion of carbon steels is dependent on both the environmental conditions, structural and compositional properties of the steel (87, 88). Carbon steel which includes mild steels is by its nature has limited alloy content, usually less than 2% by weight for the total of all additions (89). Small additions of copper, chromium, nickel, and/or phosphorus complement their properties which reduces the corrosion rate of carbon steel (90).

To reduce equipment failure and enhanced life cycle, corrosion specialist should understand the mechanisms of corrosion, the risk assessment criteria and mitigation strategies (91, 92). This dissertation explores existing corrosion in equipment, to show the mechanisms, the risk assessment methodologies, and the framework for mitigation.

8 Methodology

8.1 Corrosion risk assessment

Corrosion risk assessment is the backbone to any corrosion management system as it provides the information to enable appropriate selection of inspection, monitoring and mitigation strategies (implementation and analysis) (11, 91-93). The output of the inspection and monitoring processes is then fed back into the risk assessment process to enable continual improvement (monitoring and measuring performance and review of system performance) (11, 91-93).

8.2 Risk-based assessment methodology and overall procedure

Corrosion is a combination of multiple interactions of physical, chemical and mechanical properties and predicting the long-term behavior of equipment/system present a major challenge in oil and gas industry (11, 94, 95). An understanding these phenomena interactions makes it possible to effectively choose the most appropriate material which agrees with the standard specification and appropriate protection method (11, 96-101). The methodology describes how the risk-based assessment was carried out.

Risk-based assessment is a term used to describe the overall process or method where we comprehensively evaluate the internal and external factors affecting equipment failure and the severity of the failure consequences, enabling the risk level of each segment to be determined as the basis of maintenance works (see figure 17 below) (11, 96-101).

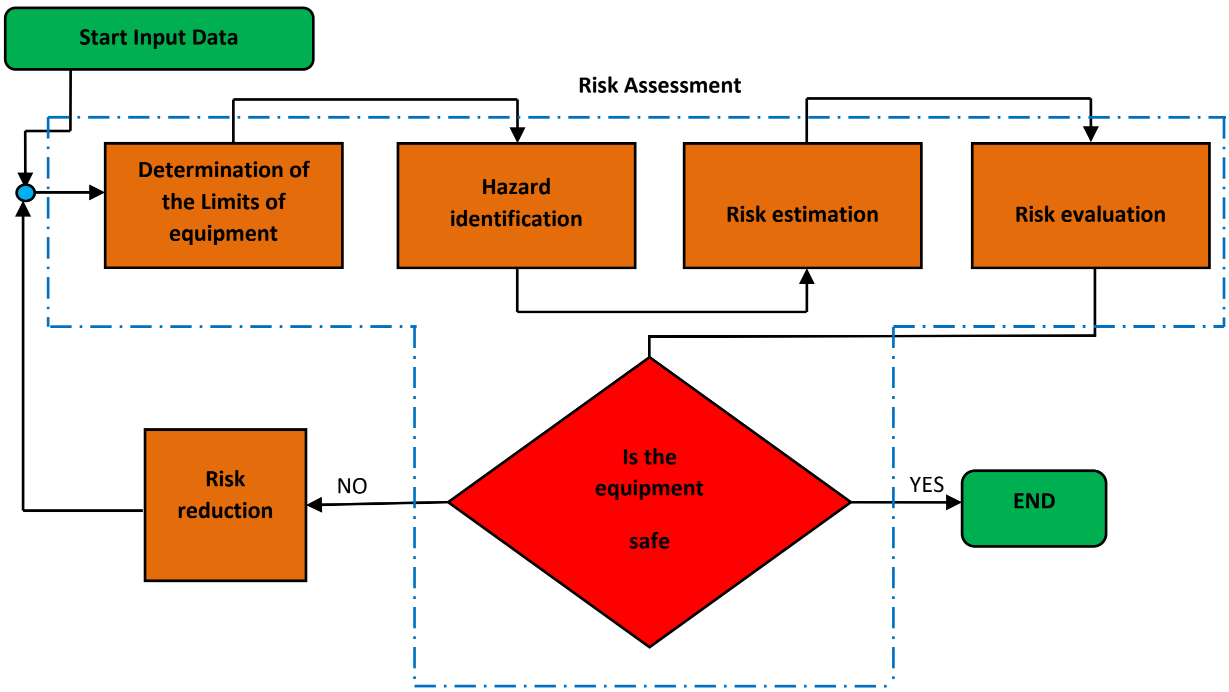


Figure 17: Overview risk-based assessment process

Figure 17 above described the overview of risk-based assessment process of an equipment starting with collation of all relevant data/information, determination of the limit of equipment and grouping them if necessary. This is followed by identification of all applicable threats/hazards, evaluation of probability and consequence assessment of each identified hazard. Then the risk evaluation which is the resultant combination of the probability evaluation and consequence assessment of each hazard to determine the level of criticality (risk). Finally, determination of any required risk reduction or mitigation and their implementation.

The overall process of risk-based assessment is listed below:

- Input data
- Equipment grouping/sectioning
- Probability assessment
- Consequence evaluation
- Criticality (Risk)
- Confidence rating
- Inspection interval
- Development of integrity strategy
- Risk-based assessment actions
- Peer review
- Audit
- Inspection method
- Inspection evaluation and reporting

Each of the parameter in the overall process of risk-based assessment is described in section 8.2.1 to section 8.2.13 below.

8.2.1 Input data

Risk-based assessment (RBA) and overall asset integrity management (AIM) systems are highly dependent on data, with the accuracy of assessments often being dependent on the amount of quality input data available for consideration including the reliability of the inspection technique and methods used (11, 96-101). The required input data include as a minimum the following: CO_2 content, H_2S content, water-cut, gas-oil ratio, water chemistry, operating parameters/boundaries (pressures, temperatures, flow rates, sand/solid content, etc.), chemical applications, geographical layout, variations in terrain along equipment/system route, major component parts, operating intent, cathodic protection design, incidents during construction/fabrication/installation and any unique/special design features (11, 96-101). Incidents during construction and fabrication may need to be captured and reviewed during the first year of operation once the relevant documentation becomes available. Latest and historic inspection data, any failure/degradation report and maintenance reports will also be required (11, 96-101). A good general sectioning of the system arrangement is essential before any risk assessment and subsequent inspection schemes can be developed (11, 96-101).

It is standard practice to conduct the risk assessment with input from engineers and experts from many disciplines (materials, corrosion, inspection, maintenance, process, etc..) to guarantee that all sides are examined. It's important to note that the approach is heavily reliant on expert technical judgement, yet it nonetheless assures that a consistent process is followed. The first step is to examine the operating conditions/environment and remove any corrosion processes/threats that are not applicable to the system, circuit, or vessel in question. The process next takes the evaluation team through each corrosion mechanism one by one. When employing the electronic database technique, all relevant system information is displayed together with guideline notes, recognized concerns, and standard industry practice when each present mechanism/hazard is addressed (11, 101).

The evaluation team determines a likelihood of failure ranking for each mechanism based on this information, which is recorded together with justification remarks. The information required for the risk-based assessment are as follow (11, 101):

- Platform operating procedures and safety case
- Marine operations procedures
- Inspection reports (current and historical)
- Process and instrumentation diagrams
- Process flow diagrams
- General and specific basis of design documents.
- General arrangement drawing
- Oil and gas fluid properties
- Operations Manuals
- Current/design maximum allowable operating pressure or initial hydro-test pressures of the systems
- General environmental data

- Other operations that may affect the system under assessment

8.2.2 Equipment grouping/sectioning

Equipment grouping/sectioning simplify the process of subsequent inspection and maintenance routine preparation and implementation. Equipment grouping involve sectioning individual components and then collecting common components into groups to allow an efficient assessment of the equipment/system (see below table 1) (11, 96-101).

Group	Equipment	Comments
Group 1	Pig receiver	Pig receiver collects pigs and it is design in form of the vessel
Group 2	Gas lift riser	Gas lift riser is the pipeline used for lifting gas from the reservoir to topsides/surface process equipment
Group 3	Pipe support, clamp, flange	Pipe supports and clamps are metals used for supporting pipes. Flanges are used for joining sections of pipes or equipment. This are all exposed to threat of crevice corrosion
Group 4	ESDV	ESDV (emergency shutdown valve) is the safety critical equipment used during emergency to shot down the flow of fluid

Table 1: Equipment sectioning example

8.2.3 Hazard Identification and Probability assessment

After sectioning, the degradation mechanisms are identified and reviewed to ensure that every hazard is properly captured. For the internal and external probability assessment, a total of thirteen degradation mechanisms (6 internal and 7 external) are considered and is outlined in table 2 and 3. Also the description of probability ranking is outline in table 4 below.

Probability assessment is likelihood that a piece of equipment will fail at a given time and an important part of effective risk analyses (11, 93-94, 98). Probability assessment is carried out qualitatively and quantitatively where a quantitative risk assessment focuses on measurable and often pre-defined data, whereas a qualitative risk assessment is based more on subjectivity and the knowledge of the assessor. Qualitative probability assessment is taken from table 5 to table 10 below (11, 13, 93-101).

A practical application of the probability assessment is used for the assessment of the gas lift riser and pig receiver in section 10.1 and 10.2.

The factors considered when assessing the probability are:

- Design data.
- Historical inspection data.
- In-service failures from own and other assets.
- Historical repairs.
- On-line corrosion monitoring data.
- Mitigation methods.
- Process conditions.
- Operating conditions and operational data.
- Lessons learnt from similar operators.
- Material type used and resistance to any specific aggressive environment

Corrosion type	Influencing factor	Possible failure scenario
CO_2 corrosion	CO_2 + water, corrosion inhibition failure	Pitting due to carbonic acid attack, localized loss of wall thickness perhaps leading to more generalized metal loss. Subsequent loss of containment.
Sulphide stress corrosion cracking; Hydrogen induced cracking	H_2S + water	Local weakening of material by stress-initiated cracking. Possible hydrogen blistering. Mechanical strength compromised affecting pressure retention ability. Subsequent loss of containment.
Microbial induced corrosion. Under deposit corrosion	Sulphate reducing bacteria contamination	Deep localized loss of wall thickness, pitting, and subsequent loss of containment.
Galvanic corrosion	Dissimilar metals	Very localized loss of wall thickness close to galvanic couple, loss of containment.
Erosion	Entrained solids in fluid	Local loss of wall thickness, possibly exacerbated by erosion corrosion. In severe cases will lead to loss of mechanical strength and possible loss of containment.
Preferential weld corrosion	Weld material susceptible to preferential attack, weld misalignment.	Very localized loss of wall thickness in heat affected zone (knife line attack) or preferential corrosion of weld metal, generally in lower half of equipment/system. Can lead to cracking and failure of weld. Major loss of containment.

Table 2: Internal failure modes

Corrosion Type	Influencing Factor	Possible Failure Scenario
Impacts	Excavation, dropped object, transportation System Accident	Damaged coating, gouging, dents, and other mechanical damage, which could lead to localized areas of increased hardness and subsequent cracking.
External corrosion	Coating damage. Cathodic protection system failure; Cathodic protection System Interference, cathodic protection system inadequate, dissimilar metals in contact, contaminated land.	General or localized loss of wall thickness, loss of containment, filiform corrosion (corrosion under coating damage).
Stress corrosion or Environmental Cracking	High strength steels (Above X-65), coating integrity, cathodic protection potentials, pH, temperature of equipment/system.	Damaged coating/holidays allowing corrosive medium to contact equipment. pH and temperature within range, high strength equipment steels > inter-granular and trans-granular cracking phenomena.
Structural	Expansion/Buckling, crossing overload, vibration/pressure cycling, tunnel/casing collapse.	Overstressing and/or fatigue. Loss of mechanical strength loss of pressure retention ability, loss of containment.
Material	Weld defect, steel defect.	Local weakness in material leading to overstressing and/fatigue crack initiation and subsequent propagation. Loss of containment.
Fire/Explosion	Accidental, malicious.	Fire melts equipment/explosion ruptures equipment (structural). Loss of containment.
Natural hazards	Flooding/Scour, subsidence/earthquake.	Overstressing and/or fatigue, loss of mechanical strength and pressure retention ability. Loss of containment.

Table 3: External failure modes

Probability	Definition
High	Item highly susceptible to degradation.
Medium	Item susceptible to degradation under normal conditions.
Low	Item susceptible to degradation under upset conditions.
Very Low	Item not susceptible under normal operating conditions.
Negligible	Item under normal operating conditions-no susceptible degradation.

Table 4: Description of probability ranking

The probability ranking is assessed based on table 5 below.

Note: Below table 6 to table 10 are the continuities of table 5

No.	Internal failure mechanism	Probability	Probability ranking
1	Internal corrosion - general and/or localised due to corrosive fluids in the Equipment/System example: carbon dioxide and water. Note: This is the predicted corrosion rate prior to operations. It assumes that no inhibition will be used, or that the inhibition system requires being verified as capable of meeting design proposals.	Equipment/System will definitely not meet the design requirements for resistance to degradation from internal corrosion and failure well before the end of the design life is certain.	High
		Equipment/System may not meet the design requirements for resistance to degradation from internal corrosion and failure before the end of the design life is probable.	Medium
		Equipment/System will meet the design requirements for resistance to degradation from internal corrosion.	Low
		There is no possibility of equipment/system failure during the design lifetime attributable to the predicted corrosion rate.	Negligible

Table 5: Guidelines on allocation of Probability Grading

No.	Internal failure mechanism	Probability	Probability ranking
2	Erosion of carbon steel. (Reference-IA Erosion guidelines Revision 2.1:1999).	Equipment/System may not meet the design requirements for resistance to degradation from internal corrosion and failure before the end of the design life is probable.	Medium
		Equipment/System will meet the design requirements for resistance to degradation from internal corrosion.	Low
		There is no possibility of equipment/system failure during the design lifetime attributable to the predicted corrosion rate.	Negligible
		Flow velocity is more than 20m/s in inhibited equipment/system or actual erosion rate more than 0.1mm/yr or V actual/V erosional is equal or less than 1.	High
3	Preferential Weld Attack applies to uncoated internal weldments of process equipment/system constructed from carbon steel. May be exhibited in the form of loss of weld root or knife line attack of the heat affected zone predominantly in the bottom half of the equipment/system.	Flow velocity is higher than design, but nominally solids free (less than1 pptb for liquid systems or <0.1lb/mmscf for gas systems).	Medium
		V actual /V erosional more than 0.8 but less than 1.	Low
		No foreseeable occurrence of erosion or velocity actual /velocity erosional is equal or less than 0.8.	Negligible
		Equipment/System in wet hydrocarbon or water service, not inhibited. Weld misalignment observable on equipment/system sections. Oxygen may be present.	High

Table 6: Guidelines on allocation of Probability Grading

No.	Internal failure mechanism	Probability	Probability ranking
4	Microbiologically Influenced Corrosion. Note: This mechanism is synergistically linked with sulphide stress corrosion cracking.	Sulphate reducing bacteria identified temperature less than 60^0C and liquid water present.	High
		Sulphate reducing bacteria identified, and no liquid water present or temperature greater than 60^0C and liquid water present.	Medium
		Sulphate reducing bacteria identified temperature greater than 60^0C and no liquid water present OR no sulphate reducing bacteria (SRB) identified temperature less than 60^0C, no water present.	Low
5	Sulphide Stress Corrosion cracking. Note: This mechanism is synergistically linked with microbiologically influenced corrosion.	Liquid water present, operating in sour Service (NACE MR-01-75) and non-NACE compliant material.	High
		Liquid water present, operating in sour service (NACE MR-01-75) and NACE compliant material.	Medium
		Non-sour service (NACE MR-01-75).	Negligible

Table 7: Guidelines on allocation of Probability Grading

No.	Internal failure mechanism	Probability	Probability ranking
6	Impacts by mechanical interference, dropped objects.	Positive evidence of the equipment/system has been violently impacted by mechanical means. Equipment/System coating have become damaged or Dis-bonded by impact or equipment is inadequately protected and runs through congested/confine locations.	High
		Equipment/System may have been impacted by mechanical means. Equipment coating has become damaged or dis-bonded by impact or mechanical handling problems. Equipment/System runs in congested area.	Medium
		Equipment/System run in congested area but is well protected and there is no history or recent evidence of mechanical interference.	Low
		Equipment/System does not run through congested area and is deeply buried or protected or sleeved or in protective conduit.	Negligible
		Cathodic protection readings and trends ‘normal’ and anode wastage rates ‘normal’ and evidence gathered within last three months.	Negligible

Table 8: Guidelines on allocation of Probability Grading

No.	Internal failure mechanism	Probability	Probability ranking
7	External Corrosion (sacrificial cathodic protection system).	Inconclusive cathodic protection readings or changes in cathodic protection trends and/or evidence that system is over performing - high anode current outputs (magnesium anodes) or equipment/system to soil potential more negative than -0.7V where related to clean carbon steel on 13Cr or duplex stainless-steel).	High
		Changes in cathodic protection trends and/or evidence that system is underperforming - low anode wastage rates or passivated anodes provided that evidence has been gathered within last three months. If not, then probability is high ‘H’.	Medium
		Cathodic protection readings and trends ‘normal’ and anode wastage rates ‘normal’ but evidence gathered more than three months ago but less than one year ago. More than one year, then probability is ‘M’.	Low
		Cathodic protection readings and trends ‘normal’ and anode wastage rates ‘normal’ and evidence gathered within last three months.	Negligible

Table 9: Guidelines on allocation of Probability Grading

No.	Internal failure mechanism	Probability	Probability ranking
8	Under Deposit Corrosion	Solids and sulphate reducing bacteria (SRB) AND water reported.	High
		No solids but sulphate reducing bacteria (SRB) and water reported or solids, sulphate reducing bacteria (SRB) and no water reported.	Medium
		Solids reported or sulphate reducing bacteria or water reported.	Low
		No solids, sulphate reducing bacteria or water reported.	Negligible
		Equipment does not run through congested area and is deeply buried or protected or sleeved or in protective conduit.	Negligible
		Cathodic protection readings and trends 'normal' and anode wastage rates 'normal' and evidence gathered within last three months.	Negligible
9	Hydrogen Induced Cracking	Equipment/System where materials of construction cannot be certified to be HIC resistant and in sour service (NACE MR-01-75).	High
		Equipment/System where materials of construction cannot be certified to be hydrogen induced cracking resistant but classed as non-sour service (NACE MR-01-75).	Medium
		Materials of construction certified hydrogen induced cracking resistant or Materials of construction not HIC resistant but in non-corrosive service e.g., dry gas.	Low

Table 10: Guidelines on allocation of Probability Grading

8.2.4 Consequence evaluation

The consequence of the system is determined by assessing business consequence, health/safety and environmental consequence separately (11, 93-94, 98). The consequence is evaluated for each sectioning of the equipment/system as described table 1 in section 8.2.2. The consequences are divided into three areas described in tables 11, 12 and 13 below. The worst-case consequence scoring is applied to all the threats in the risk-based assessment for the section.

Definition	Description
High	Shutdown of production for more than 24hours resulting in significant loss of income above £5000000 or adverse national/international media attention or enforcement action such as probation notice from the regulatory authority.
Medium	Loss of production for less than 24hours or loss of income is above £200000 and less than £5000000 or adverse local media attention or enforcement such as an improvement notice from the regulatory authority.
Low	Would not affect production or loss in production OR loss of income is above £200000 and less than £200000 Or No media attention - Adverse peer group or stakeholder commentary on a Specific issue.
Very low	Loss of income is above £200000 or no commentary within the immediate stakeholder community.

Table 11: Business Consequence Assessment

Definition	Description
High	Multiple/Single Fatalities. Or Major injury to more than one person or a localised component failure, or systematic failure to meet defined safety critical element performance standard.
Medium	Single major injury or minor injury to more than one person or Failure of a defined safety critical element.
Low	Single minor injury or first aid treatment to more than one person.
Very low	Single first aid case.

Table 12: Safety Consequence Assessment

Definition	Description
High	Major or Significant release as classed under reporting of injuries, diseases and dangerous occurrences regulations or uncontrolled and sustained environmental release with widespread or long-term environmental impact or Release of hazardous material that cannot be contained, or a catastrophic component failure.
Medium	Minor release as classed under reporting of injuries, diseases and dangerous occurrences regulations with localised or short- term environmental impact OR Release of hazardous material that can be contained, or a localised component failure, or systematic failure to meet defined safety critical element performance standard.
Low	Environmental release with no significant environmental impact or resulting in permit non-compliance.
Very low	Environmental release with no environmental impact of short duration and within permit/consents.

Table 13: Environmental consequence assessment

8.2.5 Criticality (Risk)

Criticality is the product of the consequence and the probability and represents the overall risk to integrity of an equipment/system. The criticality is assigned using table 14 below. It is assessed for each relevant failure mode and the highest of business, safety and environmental consequence is assigned as the worst case. There are five categories of criticality, very high (VH), high (H), medium (M), low (L) and very low (VL). Very high "VH" denotes extreme criticality requiring an action plan to lower the criticality (11-14, 93-101).

		Probability of failure			
		VL	L	M	H
Consequence of loss of integrity	H	M	H	VH	VH
	M	L	M	H	VH
	L	VL	L	M	H
	VL	VL	VL	L	M

Table 14: Criticality matrix

Table 14 define the level of risk identify for each equipment grouping by considering the category of probability or likelihood against the category of consequence severity.

8.2.6 Confidence rating

Confidence rating is an important input parameter to the risk-based assessment methodology and the integrity review process (11-14, 93-101). Confidence can be assessed by reviewing the following:

- The predictability of the degradation mechanism.
- The number and reliability of inspections.
- The reliability of monitoring of the operating parameters.

Confidence rating is carried out differently for internal and external degradation mechanisms. The confidence assessment is based on answers to a questionnaire. The questionnaire is based on the answers to appropriate inspection results or information (11-14, 93-101).

If equipment/system is accessible by an inspection technique that has been used and reliable data been produced, then the confidence assessment will be medium or high (11-14, 93-101). If an inspection technique has been used and reliable data has not been produced, then the confidence assessment will depend on the answers to operational technique carried out (if any) (11-14, 93-101). Confidence in this instance can only be very low, low, or medium. The final score is applied to the overall rating (see table 15 and table 16 below).

Age related degradation confidence questions	If 'Yes' score	If 'No' score
Is the failure mode unstable and/or uncontrolled and/or poorly understood?	-1	0
Has reliable and accurate inspection been carried out?	+1	-1
Has a reliable assessment of the failure mode been carried out?	+1	0

Table 15: Confidence Questionnaires

Confidence rating total score	Confidence rating
2	High
0 or 1	Medium
-1	Low
-2	Very Low

Table 16: Confidence rating

A practical application of the confidence rating is used for the assessment of the gas lift riser and pig receiver in section 10.1 and 10.2.

8.2.7 Inspection interval

The inspection interval is dependent on the criticality in above table 14 and the confidence assessment. All intervals assigned should be thoroughly peer reviewed and formally accepted. The inspection intervals in the table 17 below are shown in years (11, 94). There are five categories of criticality and confidence rating, very high (VH), high (H), medium (M), Low (L) and very low (VL).

	Confidence rating			
Criticality	VL	L	M	H
VH	1	2	3	4
H	1.5	3	4	6
M	2	4	6	8
L	4	6	8	10
VL	8	9	10	12

Table 17: Inspection interval matrix

Table 17 define the interval of inspection period per year by considering the confidence rating and criticality which means when combine both, example: if the level of criticality is low and the confidence rating is low then the interval period of inspection will be shorter accordingly, if the level of criticality is low and the confidence rating is high then the interval period of inspection will be extended accordingly.

8.2.8 Development of integrity strategy

The result of risk-based assessment is utilised to develop integrity strategy for the equipment/system concerned. This strategy will schedule all mitigation and the monitoring measures identified by the risk-based assessments with appropriate inspection techniques (11, 93-94).

On completion of the risk-based assessment, a written scheme of examination and data management technique is established for storing inspection and corrosion related information. This is to facilitate easy access and allow for the regular updates of the strategy (11, 93-94).

Integrity status of all equipment should be reviewed and formally reported on an annual basis to verify that the equipment operating procedures address the threats identified in the operational safety risk-based assessment (11, 93-94).

8.2.9 Risk-based assessment actions

The actions that are produced from the risk-based assessment are transferred into the Integrity Action database. The action tracker is used as a central location and to monitor the closeout of actions (92). When the risk-based assessments are revisited as part of the ongoing integrity management, the assessment will have to be updated with the information from the integrity report and the closed-out actions ready for the review (11, 93-94).

8.2.10 Peer review

On completion of the risk-based assessment, a peer review is performed. The purpose of the review is to confirm the accuracy of any assumptions or data used in assessing the criticality and inspection intervals, and to advice on any operational changes, which could affect the assessment (11, 93-94, 96).

The peer review is performed by a team comprising of personnel responsible for the equipment within the Asset Integrity Engineering Service provider and the owner of the facility. The asset integrity Engineering Service provider is responsible for providing the corrosion and inspection expertise and to ensure the technical aspects related to the probability and consequence of failure are fully evaluated (11, 96-98). The asset integrity engineering service provider team is comprising a minimum of corrosion Engineer, inspection engineer, process engineer and Integrity Engineer (11, 96-98). The Integrity Engineer is responsible for the selection of participants in line with capabilities, ensuring all necessary information is distributed and action items collated. The site's owner where the assignment is performed is responsible for providing sufficient personnel from integrity department, operations, maintenance, HSE and other disciplines as necessary to ensure that the consequences of failure and criticalities can be fully evaluated (11, 96-98).

The peer group have responsibility to review the equipment immediately after the risk-based inspection and thereafter annual operational review is conducted (8, 96-98).

8.2.11 Audit

Audits are important component of any management system to quantify how well it functions and to identify any areas of improvement. Audits is carried out by various personnel. An external audit is carried out on a frequency of no greater than 3 years to ensure conformance with the methodology and that best practises are included within the methodology (11, 96-100).

8.2.12 Inspection method

Some intrusive and non-intrusive methods are developed to inspect equipment/system and take the geometric measurements (diameter, wall thickness, metal loss, crack and other defects) (11, 101).

Inspection techniques available for defects detection and measurements are:

- General visual inspection
- Close visual inspection
- Eddy current testing
- Magnetic particle inspection
- Dye penetration testing
- Radiographic testing
- Ultrasonic testing
- Guided wave inspection method (Long range UT)
- Internal rotating inspection system - UT-Tubes (Ultrasonic)
- Intelligent pigging - in line inspection
- Corrosion mapping
- Phase array
- Time of flight diffraction

The probability of failure evaluation gives an estimation of likely degradation mechanisms, together with their morphology and the data required to estimate the resulting probability of failure (11, 96-101). This information is used to optimize the inspection procedures and techniques, and to select which data is recorded so that the risk-based inspection analysis is updated after an inspection. The choice of inspection method is based on optimizing several factors that characterize each technique. For example:

- Confidence in detecting the expected damage state.
- Cost of technique/method, including manpower and equipment.

- Extent of maintenance support required (scaffolding, process shutdown, opening of equipment.

During operation, non-destructive testing inspections is used to assess the current defect state of equipment, monitor defect mechanisms, and make informed decisions for remaining equipment life evaluations (e.g., RBI, FFS) (11, 101). See below table 19 to table 22 non-destructive testing method versus defect type (11, 93-101).

Note: Below table 19 to table 22 are the continuities of table 18

Damage type	Non-destructive testing method/technique	Capability/limitations
Corrosion/Erosion (Internal).	General Visual Inspection (Vessels Only) – Internal	Good detection capability but requires internal access. Limited sizing capability (Depth/remaining wall thickness).
	Manual Ultrasonic Testing/0° Probe – External	Generally good detection and sizing capability (can be poor if corrosion isolated, particularly the detection of pitting).
	Automated Ultrasonic Testing/0° Probe Mapping – External	Very good detection and sizing capability (application limited to equipment/system sections where simple manipulation can be facilitated). Corrosion maps allow accurate comparison of data between repeat inspections.
	Continuous Ultrasonic Monitoring – External	Good detection and sizing capability (at specific monitoring locations).
	Profile Radiography (Piping Only) – External	Good detection and sizing capability (at specific monitoring locations).

Table 18: Non-destructive testing method versus damage

Damage type	Non-destructive testing method/technique	Capability/Limitations
Weld-root Corrosion/Erosion	TOFD and Phase Array – External	Very good detection and sizing capability (depth/remaining wall thickness). Access to both sides of weld cap required.
	Manual/Automated Ultrasonic Testing/0° Probe – External	Good detection and sizing capability but require extensive surface preparation i.e., removal of weld cap.
	Manual/Automated Ultrasonic Testing/0° Probe – External	Detection and sizing capability but can be unreliable.
Stress Corrosion Cracking (Internal/External)	Surface Testing	Penetrant/Magnetic particle (not austenitic)/Eddy current (not ferritic) techniques - good detection capability but access required to crack surface. Techniques require plant shutdown.
	Ultrasonic Testing – External	Fair detection capability; can be used on-line. Specialist techniques have some capability to determine crack features (orientation and dimensions (Inc. height)).
	Acoustic Emission – External	On-line detection of growing SCC in large component systems too complex to be inspected by other techniques. Extraneous system noise can produce false indications.

Table 19: Non-destructive testing method versus damage

Damage type	Non-destructive testing method/technique	Capability/Limitations
Fatigue Cracking (Internal/External)	Magnetic Particle Testing	Good detection capability but requires access to fatigue crack surface. Good length sizing capability. Some surface preparations usually required.
	Penetrant Testing/Eddy Current	As above, for non-magnetic materials.
	Ultrasonic Testing/Angle Probe(s)	Good detection and sizing capability (length and height), enhanced by use of automated systems - TOFD gives very accurate flaw height measurement and allows in-service crack growth monitoring. Enhanced by use of automated systems - TOFD gives very accurate flaw height measurement and allows in-service crack growth monitoring.

Table 20: Non-destructive testing method versus damage

Damage type	Non-destructive testing method/technique	Capability/Limitations
Fatigue Cracking (Internal/External	ACFM (Can be used in-lieu of surface techniques stated above)	Good detection capability but requires access to fatigue crack surface. Length and some depth sizing capability. Unlike Magnetic Particle does not usually require surface preparation and can be used through coatings. Better for inspecting welds than Eddy Current.
Hot Hydrogen Attack (Internal)	Ultrasonic Testing - External 0°Probe/High Sensitivity	Detection capability/base material but can give false indications. Use of mapping system facilitates monitoring. For welds, removal of cap is required.
	Angle Probe(s)/Medium Sensitivity	Detection capability/welds but cannot detect microscopic stages of HHA. Use of automated system facilitates monitoring of macro-cracking.
	TOFD	Detection capability/welds although discrimination between micro-cracking and other weld defects a problem. However, establishment of a baseline facilitates monitoring of micro cracking.

Table 21: Non-destructive testing method versus damage

Damage type	Non-destructive testing method/technique	Capability/limitations
Hydrogen Induced Cracking, Stepwise cracking.	Ultrasonic Testing - External - 0° probe - 45°/60°/70° angle probe	Good detection at later stages, but there is no proven early warning (susceptibility to cracking).
Creep damage	Surface Testing	Tests for on-site inspection.
	Ultrasonic Testing - Attenuation/Loss of back wall echo - Backscatter - Velocity measurement	Magnetic measurements of Barkhuizen noise, Differential Permeability or Coercivity are possible but also affected by other parameters e.g., stress and heat treatment. Surface Replication can be used to examine microstructure.

Table 22: Non-destructive testing method versus damage

8.2.13 Inspection evaluation and reporting

When internal or external corrosion is detected, fixed key points at several selected locations are built to monitor the corrosion growth at a frequency decided by the corrosion and inspection engineers; unless this cannot be justified within the remaining economic life of the equipment (93, 97).

Non-destructive testing measurements can be taken from an existing corrosion monitoring points to substantiate corrosion coupon readings if applied. This method is used in all locations where coupon results indicate corrosion more than design corrosion criteria (11, 97-98).

Inspection data evaluation should include as a minimum:

- Assessment of inspection findings
- Estimation of existing minimum wall thickness
- Estimation of corrosion rate
- Remaining life calculations
- Maximum Allowable Working Pressure calculations
- Establishment of retiring thickness
- Conclusions on integrity status
- Recommendations as to further action

The overall evaluation of integrity status because of inspection activity is carried out and the findings of inspection, including the evaluations should be verified. The effectiveness of the inspection activities is assessed periodically where the frequency and the revision of planned activities provide the continued assurance of equipment integrity. Reports of the effectiveness of the planned activities in assuring the required integrity and reliability is produced and reviewed by the management. Part of the review include the effectiveness of the inspection procedures and routines in ensuring individual equipment is maintained fit for service (11, 93-102).

9 Inspection method used

The main inspection methods used in this dissertation are:

- Corrosion mapping inspection
- Long range ultrasonic testing and ultrasonic testing

General visual inspection is part of inspection method used to inspect both equipment.

9.1 Corrosion mapping inspection and long-range ultrasonic testing inspection

9.1.1 Corrosion mapping equipment information and internal cracking criteria evaluation

Corrosion mapping tools information

Item	Gas lift riser	Location	Offshore
Material	Carbon steel	Thickness	28mm
Diameter	363m	Coating	Paint
Scanner	Accutrak	Software	Pros can
Probe type	Triplex (0°, -45°, +45°)	Serial No.	TRI-01
Reference block	Steep/IIW V2	Reference block	FBH, SDH, Step
Frequency	5Mhz	Scanning gain	80% of TCG
Reference block thickness	2mm to 10mm & 12.5mm	Cable type	Coaxial

Table 23: Corrosion mapping tools information

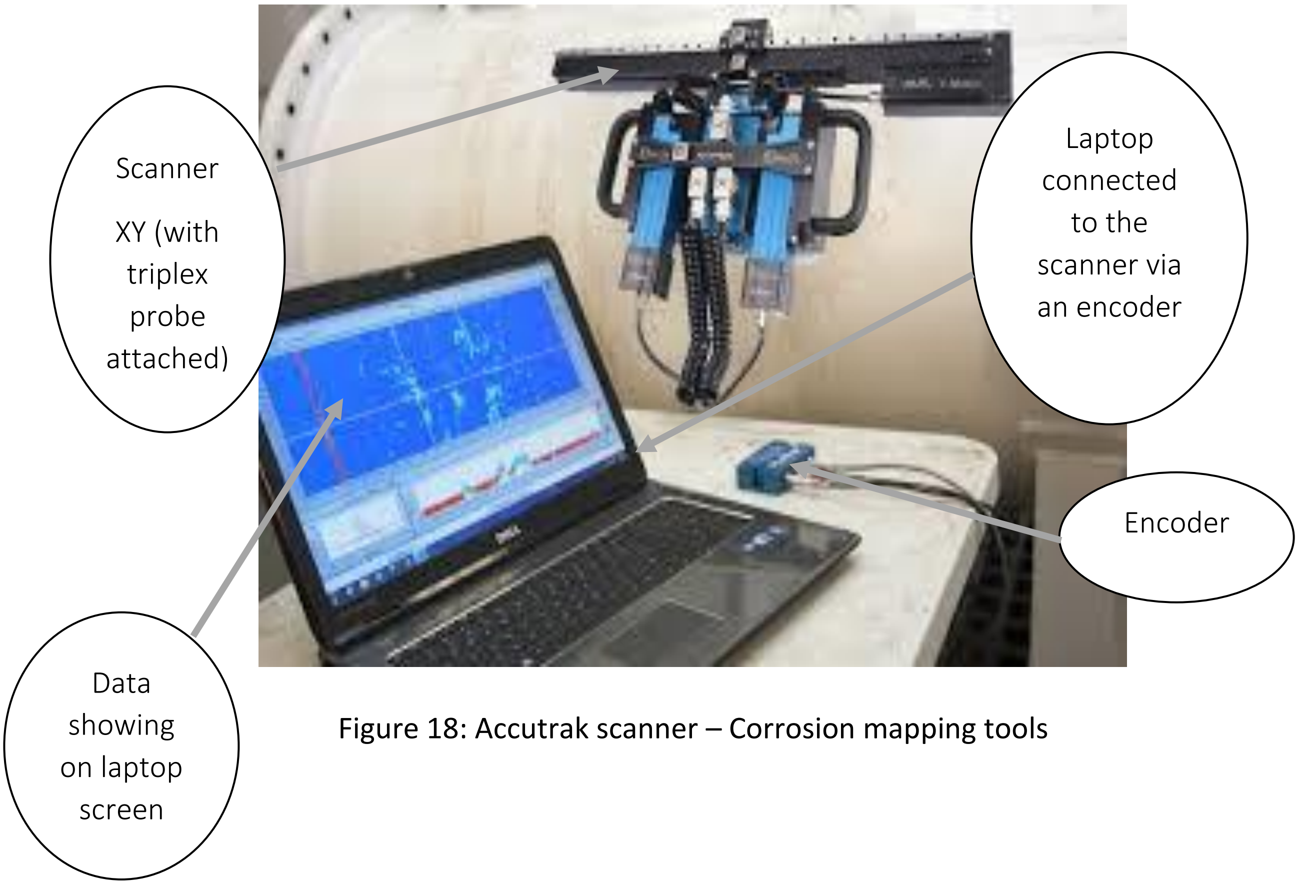


Figure 18: Accutrak scanner – Corrosion mapping tools

Internal cracking evaluation criteria

Damage rating assessment (1-5) - Terms and definitions guide	
HIC	Hydrogen induced cracking (literal definition); general term referring to Wet H_2S service damage mechanisms such as SOHIC, blistering, incipient hydrogen induced cracking and stepwise cracking.
DRA-1	Inclusions: Small inherent fabrication anomalies as scattered or flattened into typical laminations.
DRA-2	Laminar inclusions: Inherent inclusions or laminations that may have been affected by H_2S service showing initial signs of concentrations.
DRA-3	Laminar blistering: Laminar inclusions that show initial signs of blistering. Typically, the 0º backwall responses are diminished and may or may not have complete loss in backwall. And/or Potential shallow inner diameter cracking that may or may not be associated with hydrogen induced cracking.
DRA-4	Blistering: Confirmed blistering with total loss in the 0º backwall response. And/or Confirmed cracking with established lengths and thru-wall depths in excess of 10% thickness.
DRA-5	Stepwise cracking: Blistering that has linked up (multi-level) with cracks usually imbedded And/or cracking, SOHIC or stress orientated hydrogen induced cracking, usually in weld heat affected zones and/or inner diameter connected cracking in excess of 25% thickness.

Table 24: Internal cracking evaluation criteria (62, 63)

Table 24 described damage rating assessments (DRA) identified. A damage rating assessment of 1 (DRA-1) is typical for a vessel showing no signs of service-related damage for the data collected. The damage rating assessments of 2-4 (DRA-2 - DRA-4) are typical for vessels having varying degrees of potential damage and can be subjective depending on the level of analysis performed, technicians' interpretations and can be influenced by comparison with previous inspection data. A damage rating assessment of 5 (DRA-5) is typical for a vessel showing conclusive evidence of severe damage for the data collected.

9.1.2 Long range ultrasonic testing Tools Information and criteria evaluation

Long range ultrasonic testing tools information

Item	Gas lift riser	Location	Offshore
Material	Carbon steel	Thickness	9.53mm
Diameter	6 Inches	Coating	Paint
Long range ultrasonic testing	MK4 teletest	Software	Pi teletest
Probe type	Multiple probe compression mode zero degre (0°)		

Table 25: Long range ultrasonic testing tools Information

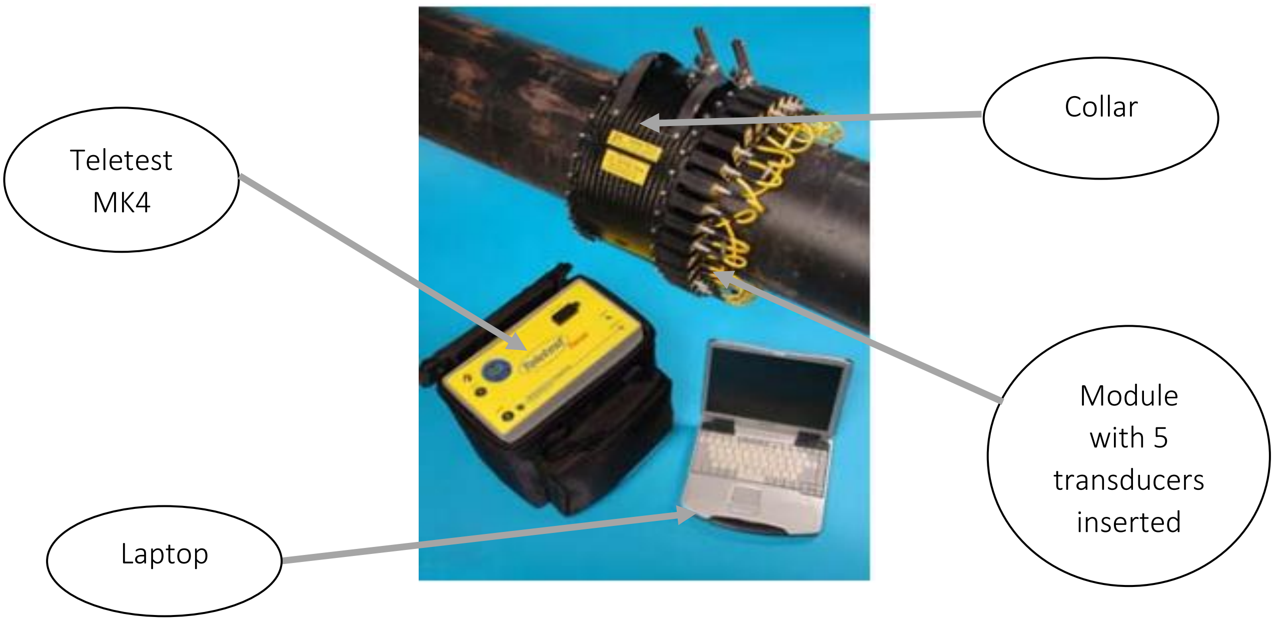


Figure 19: Long range ultrasonic testing Tools

Long range ultrasonic testing evaluation criteria

Long range ultrasonic testing is performed using a system which is made up of a low frequency flaw detector, a pulses receiver unit, some transducer rings, and a laptop computer which contains the software that controls the system. To begin, the transducer rings are fixed around a pipe, through which they will then generate a series of low frequency guided waves (103). It is the uniform spacing of the ultrasonic transducers around the circumference of the pipe that allows for the guided waves to propagate symmetrically along the pipe axis, providing 100% coverage of the pipe wall, including areas such as at clamps and sleeved or buried pipes (104, 105). The waves are then reflected back to the transducer whenever they reach a change in wall thickness, which is how the process is able to detect corrosion, metal loss, or discontinuities (105). Indications identified on the A-scan plots are evaluated based on a combination of:

- The signal amplitude
- The directionality of the focused response

This considers that large amplitude responses will be from a large cross-sectional area defect. Small defects cannot produce large amplitude reflections. A small amplitude response does not necessarily mean that the defect is small, as the response may be affected by several factors.

To provide a means of identifying defects which are potentially significant in terms of the integrity of the equipment, it is necessary to examine how localised the response is in terms of the equipment circumference. Responses are assessed only in terms of amplitude, with the categories being 'minor', 'moderate' and 'severe', the signals are now described as Amplitude Category 1, 2 or 3, with Category 3 being the highest (105). There is an additional Distance Amplitude Curve (DAC) curve added to the analysis screen. This is a red line at -20dB compared with a 100% reflector (equivalent to a pipe end), so that it plots in between the blue weld line (-14dB) and the green 9% reflector line (-26dB). This defines the boundary between Categories 2 and 3 anomalies. The bold black line is the 100% reflector curve (105-109). The broken black line is used for determining the valid length of an inspection (107-109). A representation of the DAC curves is shown in Figure 20, below:

- Category 1 responses are those which are lower than the green -26dB line. <Minor>
- Category 2 responses are those above the -26dB line but are lower than the new red line at -20dB. <Moderate>
- Category 3 responses exceed the new red -20dB line. <Severe>

Note: Any signal which is recognisable above the baseline noise level should be evaluated by the interpreter such that a decision is made regarding recommended follow up.

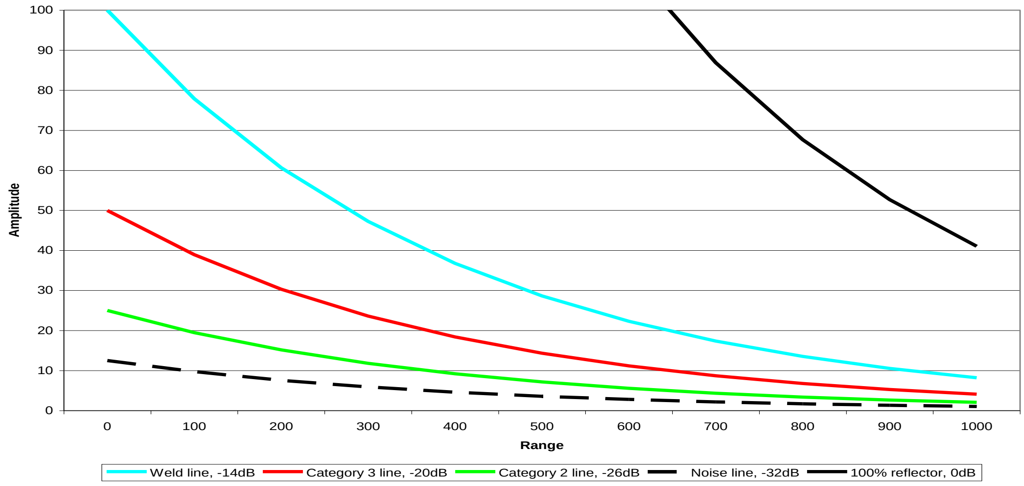


Figure 20: Schematic of the teletest A-scan, showing the amplitude categories (109)

The collection of focused data from suspected defects is an integral part of the test regime. The results from focused tests on each defect are analysed in terms of the directionality of the response (108-109).

If the polar plot shows a high level of directionality, indicated by a single peak in the plot at one focus angle, it is classed as Directionality 3 (figure 21). This indicates that the defect is highly localised on a narrow part of the circumference, so that it is likely to be deep for a given amplitude of response (105).

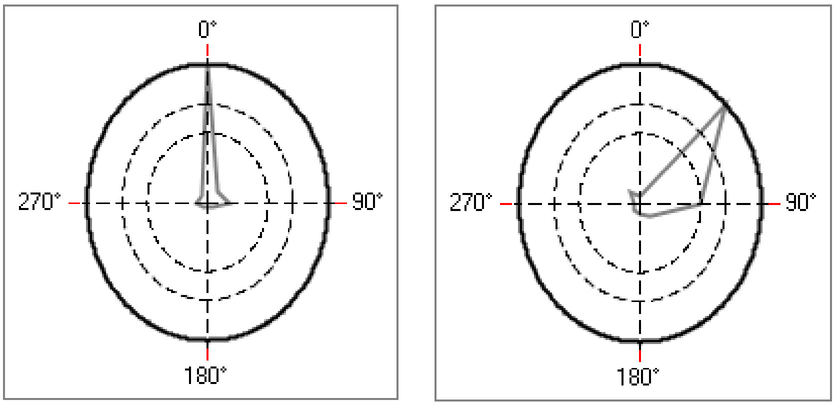


Figure 21: Directionality 3 responses from focused tests (105)

If the polar plot has two adjacent high amplitude responses it is classed as directionality 2. This is shown in figure 22. This suggests that the defect is localised but has some circumferential length (105).

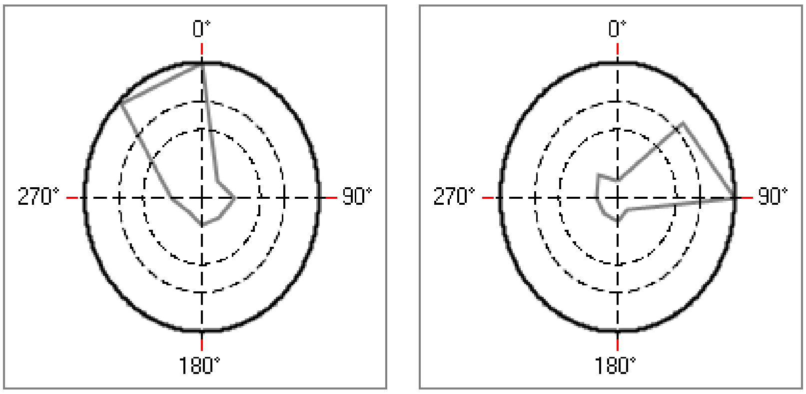


Figure 22: Directionality 3 responses from focused tests (105)

If the polar plot has 3 or more adjacent high amplitude peaks (figure 23) it is classed as directionality 1. This suggests that it is spread over a wide area of circumference, so that it is likely to be less deep for a given response amplitude (105).

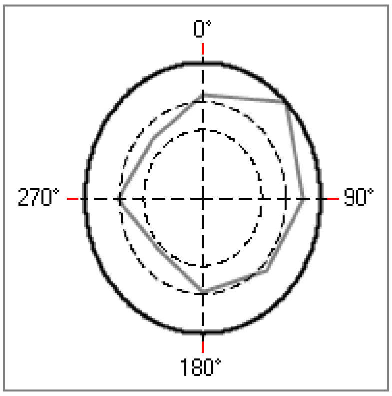


Figure 23: Directionality 3 responses from focused tests (105)

Note, there is also a directionality 0, which corresponds to the approximately uniform response around the circumference obtained from a weld, figure 24 (105).

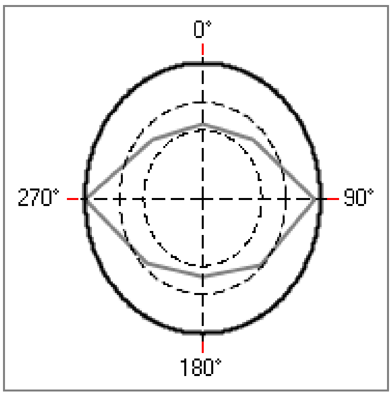


Figure 24: Directionality 0 responses from a weld from a focused test (105)

The overall classification is obtained by multiplying the two values, amplitude x directionality, obtained from an anomaly. A score of 3 or greater gives a recommendation for a high priority follow up, a score of 2 gives a medium priority and a score of 1 gives a low priority (105-109). This is summarised in table 26.

Amplitude	Directionality	Score	Follow up priority
3	3	9	High
3	2	6	High
3	1	3	High
3	0	0	Weld
2	3	6	High
2	2	4	High
2	1	2	Medium
1	3	3	High
1	2	2	Medium
1	1	1	Low

Table 26: Anomaly evaluation matrix

Hence a defect with a high amplitude response always results in a high priority follow up (unless deemed to be a feature such as a weld), as does a low amplitude response which is highly directional (109-112). Quantitative inspections such as general visual inspection (GVI), close visual inspection (CVI), eddy current testing (ET), remote field eddy current (ET-remote), magnetic particle inspection (MT), dye penetration testing (PT), radiographic testing (RT), real time radiography (RT-RTR), ultrasonic testing (UT), internal rotating inspection system-ultrasonic testing-tubes, intelligent pigging-in line inspection, corrosion mapping, phase array (PA), time of flight diffraction (TOFD), are recommended on all classifications of anomalies.

10 Results & discussion shell No.3 pig receiver and 6 inches gas lift riser

10.1 Risk-based inspection: case study on a hydrocarbon shell No.3 of pig receiver

10.1.1 Internal corrosion assessment on a hydrocarbon shell No.3 of pig receiver

Corrosion risk assessment was conducted for a proposed hydrocarbon shell No.3 pig receiver 2.315m in length commissioned in March 2004. The construction material is a plain carbon steel, API 5L X60. Along with hydrocarbon liquids, the sour gas in the pig receiver contained some quantities of dissolved CO_2, however accordingly to NACE MR0175 standard, natural gas is usually considered sour if:

- if the system pressure is 10Mpa and hydrogen sulphide concentration is at least 1000ppm
- if potential hydrogen (PH) is at least 3.5 and minimum partial pressure is 0.001 bar
- if there are more than 5.7 milligrams of H_2S per cubic meter of natural gas

The anticipated degradation mechanism of the pig receiver under the operating conditions will likely be sulphide stress corrosion cracking, hydrogen induced cracking, step wise cracking, stress-oriented hydrogen induced cracking, erosion-corrosion, CO_2 corrosion, preferential weld corrosion (10, 99-101, 106). As shown in table 27 below due to the presence of H_2S and CO_2. Furthermore, hydrogen sulphide when dissolved in water, forms a weak acid and a source of hydrogen ions and which is therefore corrosive (13, 99-101, 107). The corrosion products are iron sulphide (FeS) and hydrogen (100-102). Hydrogen produced in the reaction may lead to hydrogen embrittlement (13, 100-102). However, the probability failure category, the consequence evaluation, the risk/criticality evaluation, the confidence evaluation rating is assessed below in table 28 to table 32.

Susceptible corrosion mechanisms	Internal environment	Operating temperature	Operating pressure	Flowrate	Material type
Hydrogen Induced Cracking; Step Wise Cracking; Stress-Oriented Hydrogen Induced Cracking; Sulphide Stress Cracking, Erosion-Corrosion; CO_2 corrosion, Preferential Weld Corrosion.	Hydrogen Sulphide (H_2S) + CO_2 + water + entrained solids.	Above 35^0C	Above 70barg	1m/s	Carbon steel

Table 27: Anticipated internal corrosion mechanisms within pig receiver

Threat	Probability	Probability justification
Hydrogen Induced Cracking	High	In sour service, material used is not NACE MR0175 compliant, where possibility of leakage of hydrocarbons fluid expected to propagate through the cracks.
Step Wise Cracking	High	In sour service, material used is not NACE MR0175 compliant, where possibility of leakage of hydrocarbons fluid expected to propagate through the cracks.
Stress-Oriented Hydrogen Induced Cracking	High	In sour service, material used is not NACE MR0175 compliant, where possibility of leakage of hydrocarbons fluid expected to propagate through the cracks.
Sulphide Stress Cracking	High	Liquid water present, operating in sour Service (NACE MR-01-75) and non-NACE compliant material
Erosion-Corrosion	Low	Solid presence within the hydrocarbon fluid but the effect is minimized by the design of the receiver
Preferential Weld Corrosion	Medium	Equipment in wet hydrocarbon with oxygen present and not corrosion inhibitor.
CO_2 Corrosion	Medium	Equipment in wet hydrocarbon with oxygen and CO_2 present and not corrosion inhibitor.

Table 28: Probability evaluation - pig receiver

Threat	Consequence	Consequence justification
Hydrogen Induced Cracking	High	Failure with lead to hydrocarbon leak which can resulting shutdown of platform and cause damage/death of personnel.
Step Wise Cracking	High	Failure with lead to hydrocarbon leak which can resulting shutdown of platform and cause damage/death of personnel.
Stress-oriented Hydrogen Induced Cracking	High	Failure with lead to hydrocarbon leak which can resulting shutdown of platform and cause damage/death of personnel.
Sulphide Stress Cracking	High	Failure with lead to hydrocarbon leak which can resulting shutdown of platform and cause damage/death of personnel.
Erosion-Corrosion	High	Failure with lead to hydrocarbon leak which can resulting shutdown of platform and cause damage/death of personnel.
Preferential Weld Corrosion	High	Failure with lead to hydrocarbon leak which can resulting shutdown of platform and cause damage/death of personnel.
CO_2 Corrosion	High	Failure with lead to hydrocarbon leak which can resulting shutdown of platform and cause damage/death of personnel.

Table 29 Consequence evaluation - pig receiver

Based on matrix table 14 on section 8.2.5 risk matrix above, putting together the above probabilities and consequences, the risk matrix is assessed in the table 30 below.

Threat	Criticality	Criticality justification
Hydrogen Induced Cracking	Very high	Probability high, consequence high
Step Wise Cracking	Very high	Probability high, consequence high
Stress-Oriented Hydrogen Induced Cracking	Very high	Probability high, consequence high
Sulphide Stress Cracking	Very high	Probability high, consequence high
Erosion-Corrosion	high	Probability low, consequence high
Preferential Weld Corrosion	Very high	Probability medium, consequence high
CO_2 Corrosion	Very high	Probability medium, consequence high

Table 30: Criticality evaluation - pig receiver

Based on matrix table 15 and table 16 on section 8.2.6 confidence rating is assessed in the table 31 and table 32 below.

Note: Below table 32 is the continuity of table 31.

Threat	Confidence rating	Confidence rating justification
Hydrogen Induced Cracking	High (total score result is 2)	Is the failure mode unstable and/or uncontrolled and/or poorly understood? No, where the score is 0.
		Has reliable and accurate inspection been carried out? Yes, where the score is 1.
		Has a reliable assessment of the failure mode been carried out? Yes, where the score is 1.
Step Wise Cracking	High (total score result is 2)	Is the failure mode unstable and/or uncontrolled and/or poorly understood? No, where the score is 0.
		Has reliable and accurate inspection been carried out? Yes, where the score is 1.
		Has a reliable assessment of the failure mode been carried out? Yes, where the score is 1.
Stress-Oriented Hydrogen Induced Cracking	High (total score result is 2)	Is the failure mode unstable and/or uncontrolled and/or poorly understood? No, where the score is 0.
		Has reliable and accurate inspection been carried out? Yes, where the score is 1.
		Has a reliable assessment of the failure mode been carried out? Yes, where the score is 1.
Sulphide Stress Cracking	High (total score result is 2)	Is the failure mode unstable and/or uncontrolled and/or poorly understood? No, where the score is 0.
		Has reliable and accurate inspection been carried out? Yes, where the score is 1.
		Has a reliable assessment of the failure mode been carried out? Yes, where the score is 1.

Table 31: Confidence rating evaluation - pig receiver

Threat	Confidence rating	Confidence rating justification
Erosion-Corrosion	High (total score result is 2)	Is the failure mode unstable and/or uncontrolled and/or poorly understood? No, where the score is 0.
		Has reliable and accurate inspection been carried out? Yes, where the score is 1.
		Has a reliable assessment of the failure mode been carried out? Yes, where the score is 1.
Preferential Weld corrosion	High (total score result is 2)	Is the failure mode unstable and/or uncontrolled and/or poorly understood? No, where the score is 0.
		Has reliable and accurate inspection been carried out? Yes, where the score is 1.
		Has a reliable assessment of the failure mode been carried out? Yes, where the score is 1.
CO_2 Corrosion	High (total score result is 2)	Is the failure mode unstable and/or uncontrolled and/or poorly understood? No, where the score is 0.
		Has reliable and accurate inspection been carried out? Yes, where the score is 1.
		Has a reliable assessment of the failure mode been carried out? Yes, where the score is 1.

Table 32: Confidence rating evaluation - pig receiver

Based on the criticality in above table 14 and the confidence assessment. The inspection interval was assessed in the table 33 below.

Threat	Inspection interval	Inspection interval justification
Hydrogen Induced Cracking	4 years	Criticality very high, confidence rating high
Step Wise Cracking	4 years	Criticality very high, confidence rating high
Stress-Oriented Hydrogen Induced Cracking	4 years	Criticality very high, confidence rating high
Sulphide Stress Cracking	4 years	Criticality very high, confidence rating high
Microbial Influenced Corrosion	4 years	Criticality very high, confidence rating high
Erosion-Corrosion	6 years	Criticality high, confidence rating high
Preferential Weld Corrosion	4 years	Criticality very high, confidence rating high
CO_2 Corrosion	4 years	Criticality high, confidence rating medium

Table 33: Inspection interval pig receiver

10.1.2 External corrosion assessment on a hydrocarbon shell No.3 of pig receiver

General visual inspection carried out shows no signs of coating damage or deterioration on the pig receiver externally. However, as shown in table 34 due to ultraviolet exposure, precipitated salt, condensation and windy conditions blowing sand, dust, chloride and other pollutants against the pig receiver, atmospheric corrosion producing rusty precipitates or scales is expected or anticipated on the pig receiver externally over time.

Susceptible corrosion mechanisms	External environment	Operating temperature	Operating pressure	Flow rate	Material type
Atmospheric Corrosion	Sunlight, precipitated salt, condensation, atmospheric sea exposure (pollutants, dust, and sand).	Above 35^{0}C	Above 70barg	1m/s	Carbon steel

Table 34: Anticipated external corrosion mechanisms within the shell No.3 pig receiver

The probability failure, the consequence evaluation, the risk/criticality evaluation, the confidence evaluation rating is assessed below in table 35 to table 38.

Threat	probability	probability justification
Atmospheric Corrosion	Low	no sign of coating damage externally on the pig receiver during the general visual inspection.

Table 35: Probability evaluation - pig receiver

Threat	Consequence	Consequence justification
Atmospheric Corrosion	High	Failure with lead to hydrocarbon leak which can resulting shutdown of platform and cause damage/death of personnel.

Table 36: Consequence evaluation - pig receiver

Based on matrix table 14 on section 8.2.5 risk matrix above, putting together the above probability and consequence, the risk matrix is assessed in the table 37 below.

Threat	Criticality	Criticality justification
Atmospheric Corrosion	High	Probability low, consequence high

Table 37: Criticality evaluation - pig receiver

Based on matrix table 15 and table 16 on section 8.2.6 confidence rating is assessed in the table 38 below.

Threat	Confidence rating	Confidence rating justification
Atmospheric Corrosion	High (total score result is 2)	Is the failure mode unstable and/or uncontrolled and/or poorly understood? No, where the score is 0.
		Has reliable and accurate inspection been carried out? Yes, where the score is 1.
		Has a reliable assessment of the failure mode been carried out? yes, where the score is 1.

Table 38: Confidence rating - pig receiver

Based on the criticality in above table 14 and the confidence assessment. The inspection interval was assessed in the table 39 below.

Threat	Inspection interval	Inspection interval justification
Atmospheric Corrosion	10 years	Criticality low, confidence rating high.

Table 39: Inspection interval - pig receiver

10.2 Risk-based inspection case study on a 6 inches gas lift riser

10.2.1 Internal corrosion assessment

Corrosion risk analysis was conducted for a proposed hydrocarbon 6 inches gas lift riser. A section of the riser was replaced in January 2017 by new spool (refer to figure 27 below). The material of construction is a plain carbon steel API 5L X60.

Along with hydrocarbon liquids, the sour gas in the 6 inches gas lift riser contained very small quantities of dissolved CO_2. Corrosion risk analysis is required to formulate guidelines for a risk-based inspection plan. The CO_2 content is very low to cause any appreciable corrosion damage.

However, accordingly to NACE MR0175 standard, natural gas is usually considered sour if:

- the system pressure is 10Mpa and hydrogen sulphide concentration is at least 1000ppm
- potential hydrogen (PH) is at least 3.5 and minimum partial pressure is 0.001 bar
- there are more than 5.7 milligrams of H_2S per cubic meter of natural gas

This further means that sulphide induced corrosion, including sulphide stress corrosion cracking and hydrogen induced cracking, could occur in the 6 inches gas lift riser. The anticipated deterioration mechanism under the operating conditions will likely be hydrogen embrittlement (HE), hydrogen induced cracking, step wise cracking, stress-oriented hydrogen induced cracking, sulphide stress cracking, microbial influenced corrosion, erosion-corrosion, preferential weld corrosion, pitting corrosion and crevice corrosion. As shown in table 40 below due to the presence of H_2S, CO_2.

Furthermore, the riser is quite long, and the containment Gas is flammable (11, 13, 100-102), However, the probability failure category, the consequence evaluation, the risk/criticality evaluation, the confidence evaluation rating is assessed below in table 41 to table 47.

Susceptible corrosion mechanisms	Internal Environment	Operating temperature	Operating pressure	Flowrate	Material type
Hydrogen Embrittlement, Hydrogen Induced Cracking, Step Wise Cracking, Stress-Oriented Hydrogen Induced Cracking, Sulphide Stress Cracking, Microbial Influenced Corrosion, Pitting Corrosion, Erosion-Corrosion, Preferential Weld Corrosion, Crevice Corrosion.	Hydrogen Sulphide (H_2S) + CO_2 +water + entrained solids.	Above 35^{0}C	Above 70barg	1m/s	Carbon steel

Table 40: Anticipated internal corrosion mechanisms within 6 inches gas lift riser

Threat	Probability	Probability justification
Hydrogen Embrittlement	High	In sour service, material used is not NACE MR-01-75 compliant, where possibility of leakage of hydrocarbons fluid expected to propagate through the cracks.
Hydrogen Induced Cracking	High	In sour service, material used is not NACE MR-01-75 compliant, where possibility of leakage of hydrocarbons fluid expected to propagate through the cracks.
Step wise Cracking	High	In sour service, material used is not NACE MR-01-75 compliant, where possibility of leakage of hydrocarbons fluid expected to propagate through the cracks.
Stress-Oriented Hydrogen Induced Cracking	High	In sour service, material used is not NACE MR-01-75 compliant, where possibility of leakage of hydrocarbons fluid expected to propagate through the cracks.
Sulphide Stress Cracking	High	In sour service, material used is not NACE MR-01-75 compliant, where possibility of leakage of hydrocarbons fluid expected to propagate through the cracks.
Microbial Influenced Corrosion	High	Liquid water present, operating in sour Service (NACE MR-01-75) and non-NACE compliant material.
Pitting Corrosion	High	Liquid water present, operating in sour Service (NACE MR-01-75) and non-NACE compliant material.
Erosion-Corrosion	High	Solid presence within the hydrocarbon fluid but the effect is minimized by the design of the receiver.
Preferential Weld corrosion	High	Equipment in wet hydrocarbon with oxygen present and not corrosion inhibitor.
Crevice Corrosion	High	Failure with lead to hydrocarbon leak which can resulting shutdown of platform and cause damage/death of personnel.

Table 41: Probability evaluation - 6 inches gas lift riser

Threat	Consequence	Consequence justification
Hydrogen embrittlement	High	Failure with lead to hydrocarbon leak which can resulting shutdown of platform and cause damage/death of personnel.
Hydrogen Induced Cracking	High	Failure with lead to hydrocarbon leak which can resulting shutdown of platform and cause damage/death of personnel.
Step wise Cracking	High	Failure with lead to hydrocarbon leak which can resulting shutdown of platform and cause damage/death of personnel.
Stress-Oriented Hydrogen Induced Cracking	High	Failure with lead to hydrocarbon leak which can resulting shutdown of platform and cause damage/death of personnel.
Sulphide Stress Cracking	High	Failure with lead to hydrocarbon leak which can resulting shutdown of platform and cause damage/death of personnel.
Microbial Influenced Corrosion	High	Failure which can cause pin hole and lead to hydrocarbon leak which can resulting shutdown of platform and cause damage/death of personnel.
Pitting Corrosion	High	Failure which can cause pin hole and lead to hydrocarbon leak which can resulting shutdown of platform and cause damage/death of personnel.
Erosion-Corrosion	High	Failure with lead to hydrocarbon leak which can resulting shutdown of platform and cause damage/death of personnel.
Preferential Weld corrosion	High	Failure with lead to hydrocarbon leak which can resulting shutdown of platform and cause damage/death of personnel.
Crevice Corrosion	High	Failure with lead to hydrocarbon leak which can resulting shutdown of platform and cause damage/death of personnel.

Table 42: Consequence evaluation - 6 inches gas lift riser

Based on matrix table 14 on section 8.2.5 risk matrix above, putting together the above probabilities and consequences, the risk matrix is assessed in the table 43 below.

Threat	Criticality	Criticality justification
Hydrogen Embrittlement	Very high	Probability high, consequence high
Hydrogen Induced Cracking	Very high	Probability high, consequence high
Step Wise Cracking	Very high	Probability high, consequence high
Stress-Oriented Hydrogen Induced Cracking	Very high	Probability high, consequence high
Sulphide Stress Cracking	Very high	Probability high, consequence high
Pitting Corrosion	Very high	Probability high, consequence high
Erosion-Corrosion	Very high	Probability high, consequence high
Preferential Weld Corrosion	Very high	Probability high, consequence high
Crevice Corrosion	Very high	Probability high, consequence high

Table 43: Criticality evaluation - pig receiver

Based on matrix table 15 and table 16 on section 8.2.6 confidence rating is assessed in the table 44 to table 47 below.

Note: Blow table 45 to table 47 are the continuity of table 44.

Threat	Confidence rating	Confidence rating justification
Hydrogen Embrittlement	High (total score result is 2)	Is the failure mode unstable and/or uncontrolled and/or poorly understood? No, where the score is 0.
		Has reliable and accurate inspection been carried out? Yes, where the score is 1.
		Has a reliable assessment of the failure mode been carried out? Yes, where the score is 1.

Table 44: Confidence rating evaluation - 6 inches gas lift riser

Threat	Confidence rating	Confidence rating justification
Hydrogen Induced Cracking	High (total score result is 2)	Is the failure mode unstable and/or uncontrolled and/or poorly understood? No, where the score is 0.
		Has reliable and accurate inspection been carried out? Yes, where the score is 1.
		Has a reliable assessment of the failure mode been carried out? Yes, where the score is 1.
Step Wise Cracking	High (total score result is 2)	Is the failure mode unstable and/or uncontrolled and/or poorly understood? No, where the score is 0.
		Has reliable and accurate inspection been carried out? Yes, where the score is 1.
		Has a reliable assessment of the failure mode been carried out? Yes, where the score is 1.
Stress-Oriented Hydrogen Induced Cracking	High (total score result is 2)	Is the failure mode unstable and/or uncontrolled and/or poorly understood? No, where the score is 0.
		Has reliable and accurate inspection been carried out? Yes, where the score is 1.
		Has a reliable assessment of the failure mode been carried out? Yes, where the score is 1.
Sulphide Stress Cracking	High (total score result is 2)	Is the failure mode unstable and/or uncontrolled and/or poorly understood? No, where the score is 0.
		Has reliable and accurate inspection been carried out? Yes, where the score is 1.
		Has a reliable assessment of the failure mode been carried out? Yes, where the score is 1.

Table 45: Confidence rating evaluation - 6 inches gas lift riser

Threat	Confidence rating	Confidence rating justification
Microbial Influenced Corrosion	High (total score result is 2)	Is the failure mode unstable and/or uncontrolled and/or poorly understood? No, where the score is 0.
		Has reliable and accurate inspection been carried out? Yes, where the score is 1.
		Has a reliable assessment of the failure mode been carried out? Yes, where the score is 1.
Pitting Corrosion	High (total score result is 2)	Is the failure mode unstable and/or uncontrolled and/or poorly understood? No, where the score is 0.
		Has reliable and accurate inspection been carried out? Yes, where the score is 1.
		Has a reliable assessment of the failure mode been carried out? Yes, where the score is 1.
Erosion-Corrosion	High (total score result is 2)	Is the failure mode unstable and/or uncontrolled and/or poorly understood? No, where the score is 0.
		Has reliable and accurate inspection been carried out? Yes, where the score is 1.
		Has a reliable assessment of the failure mode been carried out? Yes, where the score is 1.
Preferential Weld Corrosion	High (total score result is 2)	Is the failure mode unstable and/or uncontrolled and/or poorly understood? No, where the score is 0.
		Has reliable and accurate inspection been carried out? Yes, where the score is 1.
		Has a reliable assessment of the failure mode been carried out? Yes, where the score is 1.

Table 46: Confidence rating evaluation - 6 inches gas lift riser

Threat	Confidence rating	Confidence rating justification
Crevice Corrosion	High (total score result is 2)	Is the failure mode unstable and/or uncontrolled and/or poorly understood? No, where the score is 0.
		Has reliable and accurate inspection been carried out? Yes, where the score is 1.
		Has a reliable assessment of the failure mode been carried out? Yes, where the score is 1.

Table 47: Confidence rating evaluation - 6 inches gas lift riser

Based on the criticality in above table 14 and the confidence assessment. The inspection interval was assessed in the table 48 below.

Threat	Inspection interval	Inspection interval justification
Hydrogen Embrittlement	4 years	Criticality very high, confidence rating high
Hydrogen Induced Cracking	4 years	Criticality very high, confidence rating high
Step Wise Cracking	4 years	Criticality very high, confidence rating high
Stress-Oriented Hydrogen Induced Cracking	4 years	Criticality very high, confidence rating high
Sulphide Stress Cracking	4 years	Criticality very high, confidence rating high
Microbial Influenced Corrosion	4 years	Criticality very high, confidence rating high
Pitting Corrosion	4 years	Criticality very high, confidence rating high
Erosion-Corrosion	4 years	Criticality very high, confidence rating high
Preferential Weld Corrosion	4 years	Criticality very high, confidence rating high
Crevice Corrosion	4 years	Criticality very high, confidence rating high
Erosion-Corrosion	4 years	Criticality very high, confidence rating high
Preferential Weld Corrosion	4 years	Criticality very high, confidence rating high
Crevice Corrosion	4 years	Criticality very high, confidence rating high

Table 48:Inspection interval - 6 inches gas lift riser Inspection interval

10.2.2 External corrosion assessment

A general visual inspection carried out showed signs of rust precipitates or scales due to external corrosion on the 6 inches gas lift riser. The anticipated degradation mechanism of the under the operating conditions will likely be Differential aeration corrosion, pitting corrosion, preferential weld corrosion (11, 13, 99-101). As shown in table 49 below due to the presence of H_2S and CO_2. However, the probability failure category, the consequence evaluation, the risk/criticality evaluation, the confidence evaluation rating is assessed below in table 50 to table 54.

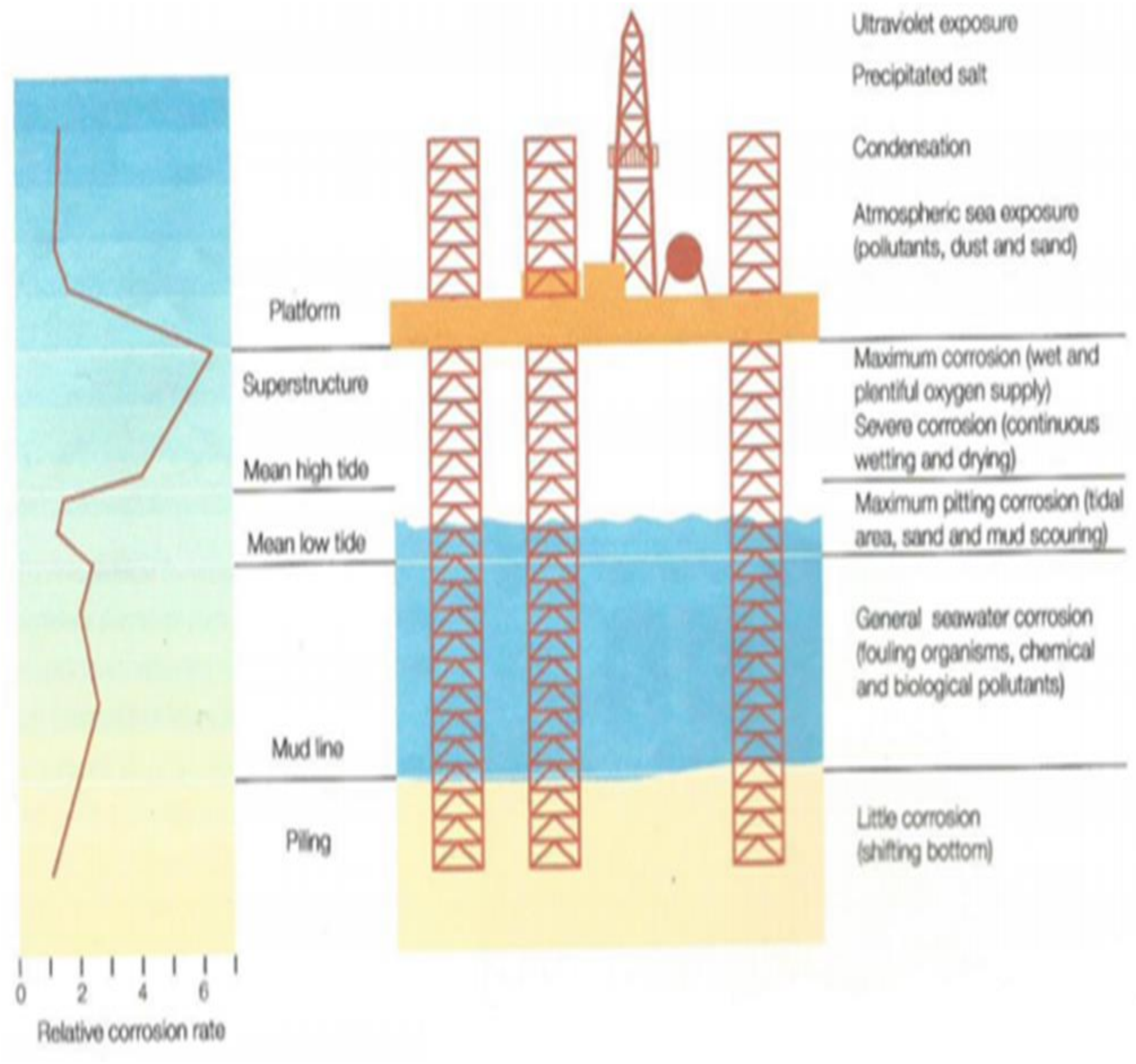


Figure 25 Offshore platform showing relative corrosion rate

Susceptible corrosion Mechanisms	External environment	Operating temperature	Operating pressure	Flowrate	Material Type
Differential aeration corrosion occurs during high tide. The surface of the riser becomes wet during high tide with plentiful supply of oxygen and maximum corrosion taking place in the splash zone. Furthermore, severe corrosion occurs due to continuous wetting and drying. Maximum pitting corrosion occur at the low tide area of the riser due to mud and sand accumulation plus the presence of sulphate reducing bacteria. Preferential weld corrosion.	Excessive supply of oxygen during high tide, bacteria in mud or sand at low tide region or zone of riser (see above figure 25: Offshore platform showing relative corrosion rate).	Above 35^0C	Above 70barg	1m/s	Carbon steel

Table 49: Anticipated internal corrosion mechanisms within 6 inches gas lift riser

Threat	probability	probability justification
Differential Aeration Corrosion	High	sign of coating damage externally on the riser during the general visual inspection. Excessive supply of Oxygen during high tide, bacteria in mud or sand at low tide region.
Pitting Corrosion	High	possibility of leakage of H_2S gas through the cracks or pit that is expected to propagate from the outside of the riser to the inside or internal walls and the toxicity associated with H_2S gas.
Preferential weld corrosion	High	In sour service, material used is not NACE MR0175 compliant, where possibility of leakage of hydrocarbons fluid expected to propagate through the cracks.

Table 50: Probability evaluation - 6 inches gas lift riser

Threat	Consequence	Consequence justification
Differential aeration corrosion	High	no sign of coating damage externally on the pig receiver during the general visual inspection. No possibility of shutdown of production.
pitting corrosion	High	Liquid water present, operating in sour Service (NACE MR-01-75) and non-NACE compliant material, possibility of hole within the parent metal which can cause hole due to pitting corrosion and lead to leakage of H_2S, which can cause Major injury to more than one person.
Preferential weld corrosion	High	Due to the leakage through the crack, possibility of shutdown of production for more than 24hours resulting in significant loss of income, impact or Release of hazardous material H_2S which can cause Major injury to more than one person.

Table 51: Consequence evaluation - 6 inches gas lift riser

Based on matrix table 14 on section 8.2.5 risk matrix above, putting together the above probability and consequence, the risk matrix is assessed in the table 52 below.

Threat	Criticality	Criticality justification
Differential Aeration Corrosion	Very high	Probability high, consequence high
Pitting Corrosion	Very high	Probability high, consequence high
Preferential Weld Corrosion	Very high	Probability high, consequence high

Table 52: Criticality evaluation - 6 inches gas lift riser

Based on matrix table 15 and table 16 on section 8.2.6 confidence rating is assessed in the table 53 below.

Threat	Confidence rating	Confidence rating justification
Differential Aeration Corrosion	High (total score result is 2)	Is the failure mode unstable and/or uncontrolled and/or poorly understood? No, where the score is 0.
		Has reliable and accurate inspection been carried out? Yes, where the score is 1.
		Has a reliable assessment of the failure mode been carried out? Yes, where the score is 1.
Pitting Corrosion	High (total score result is 2)	Is the failure mode unstable and/or uncontrolled and/or poorly understood? No, where the score is 0.
		Has reliable and accurate inspection been carried out? Yes, where the score is 1.
		Has a reliable assessment of the failure mode been carried out? Yes, where the score is 1.
Preferential Weld Corrosion	High (total score result is 2)	Is the failure mode unstable and/or uncontrolled and/or poorly understood? No, where the score is 0.
		Has reliable and accurate inspection been carried out? Yes, where the score is 1.
		Has a reliable assessment of the failure mode been carried out? Yes, where the score is 1.

Table 53: Confidence rating evaluation - 6 inches gas lift riser

Based on the criticality in above table 14 and the confidence assessment. The inspection interval was assessed in the table 54 below.

Threat	Inspection interval	Inspection interval justification
Differential Aeration Corrosion	4 years	Criticality high, confidence rating high
Pitting Corrosion	4 years	Criticality high, confidence rating high
Preferential Weld Corrosion	4 years	Criticality high, confidence rating high

Table 54: Inspection interval - 6 inches gas lift riser

10.3 Inspection of shell No.3 pig receiver and 6 inches gas lift riser

10.3.1 Inspection of shell No.3 pig receiver

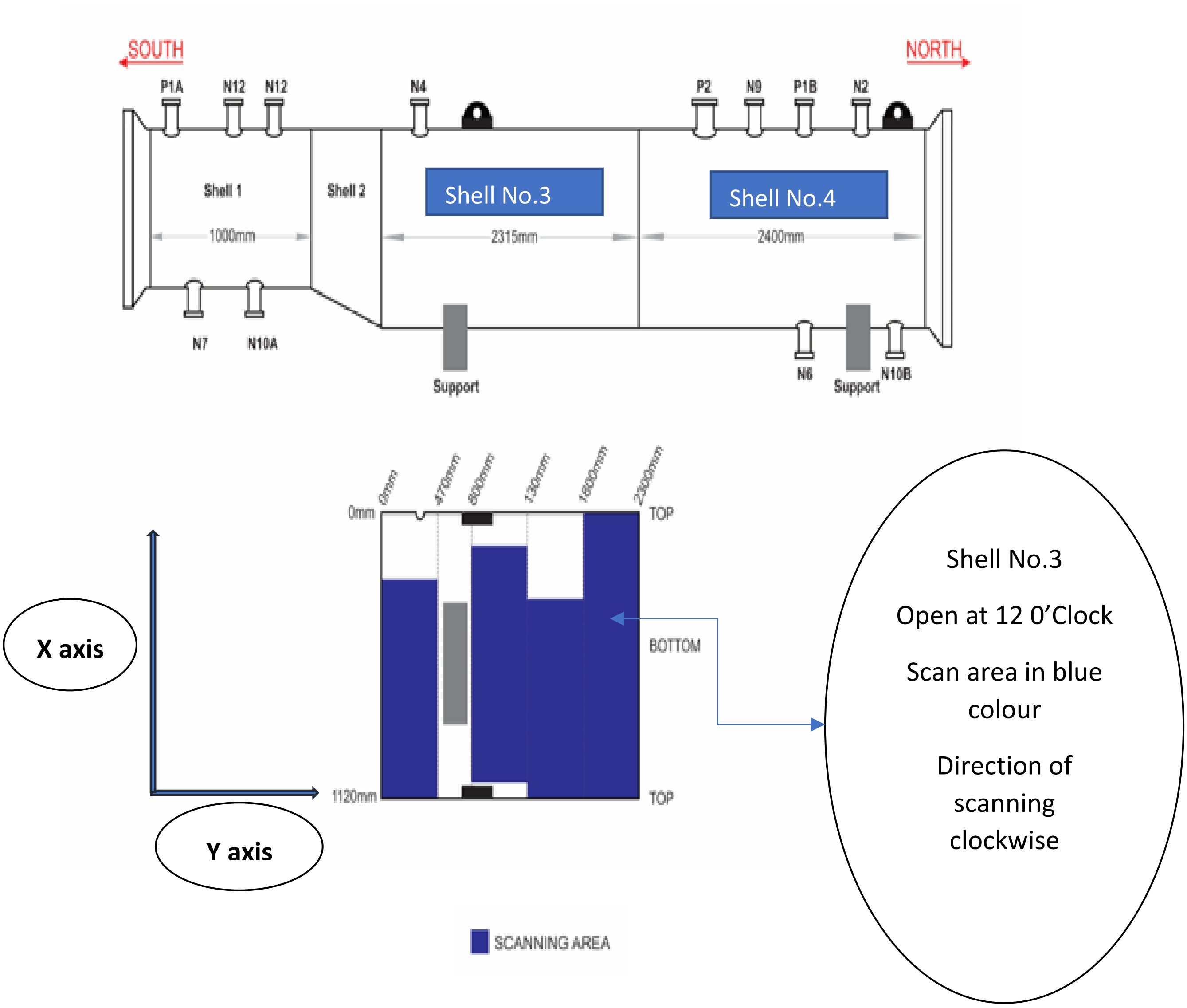


Figure 26: Shell No.3 pig receiver horizontal cross section 3 O'clock at 9 O'clock

Internal inspection of shell No.3 pig receiver was carried out and completed using the robotic XY axis Scanner motorized automated technique as shown in figure 18.

Note: Scanning area (in blue color) on shell No.3 pig receiver (see above Figure 26) has been covered with recordable robotic XY axis scanner motorized automated (also called accrutrak) where obstacles such as Nozzles and Plug were present.

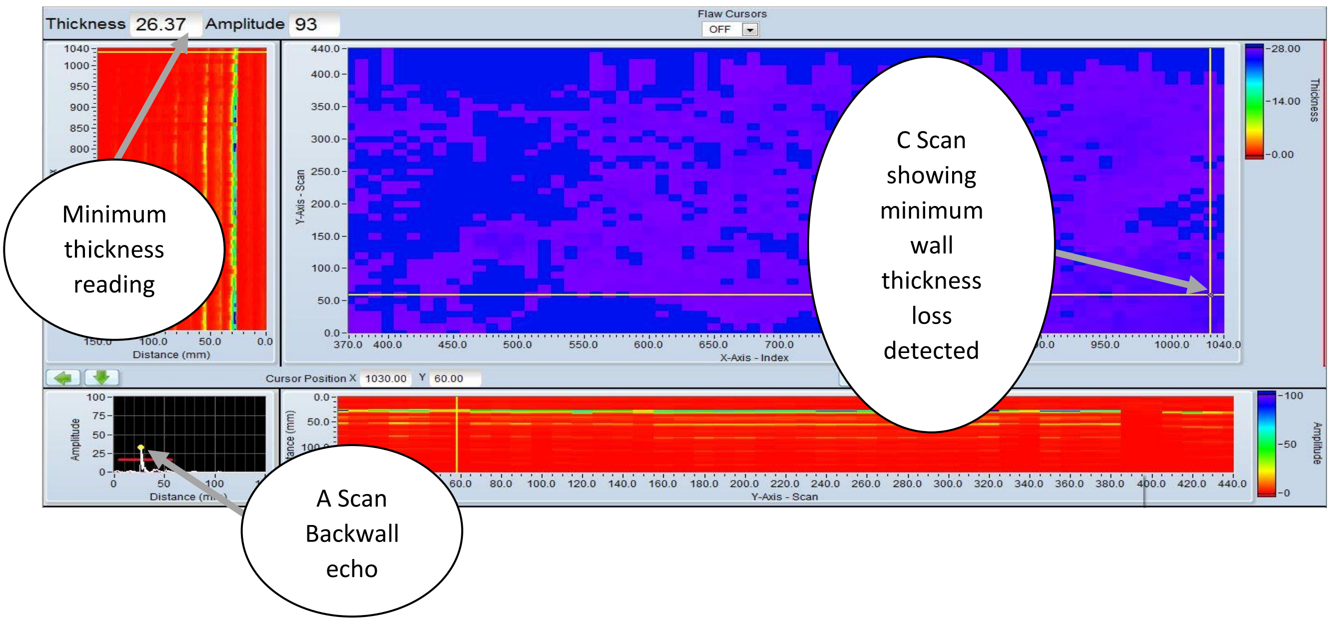
Recordable automated ultrasonic testing (Accutrack) was used to obtain the results below. Measurement is in millimetres (mm). These are from scan images and others	
Diameter	363
Shell thickness	28
Shell 3 width (Y axis)	2315
Circumferential length (X axis)	1140
Each scan width (Y axis)	500

Table 55: Pig receiver shell No.3 measurement XY axis

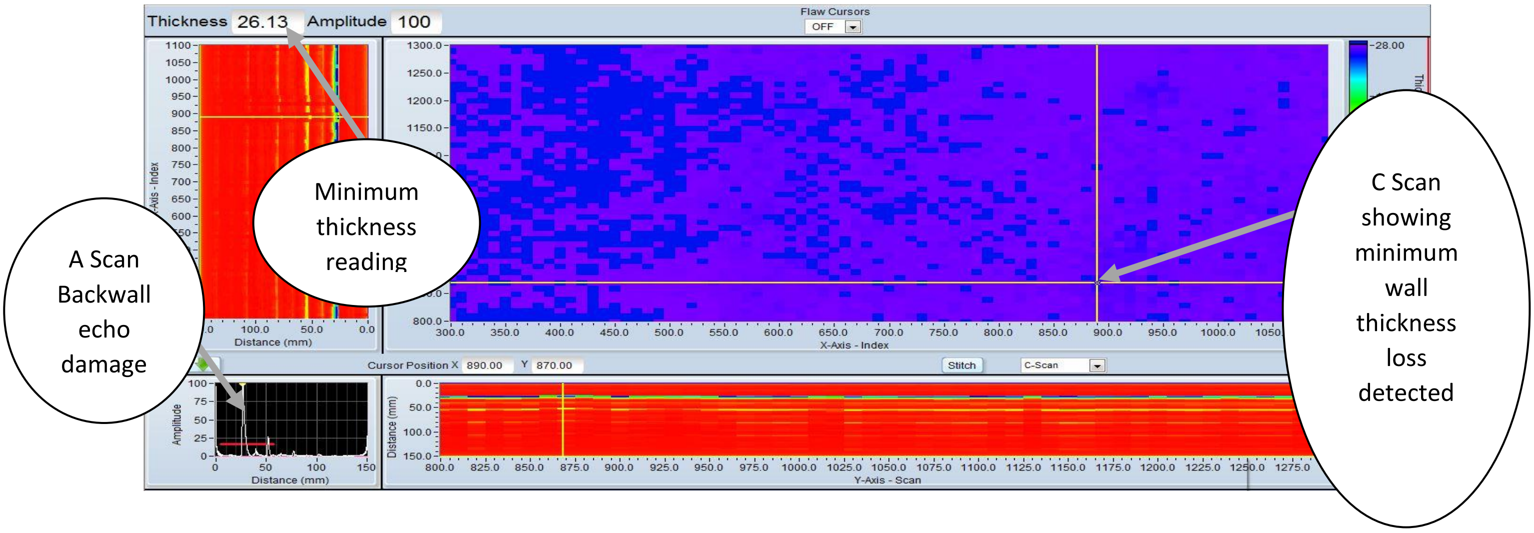
Datum point: Circumferential weld between shell No.3 from 12 O' Clock (0 degree) south to north in clockwise direction

10.3.2 Internal inspection data analysis - Scan images

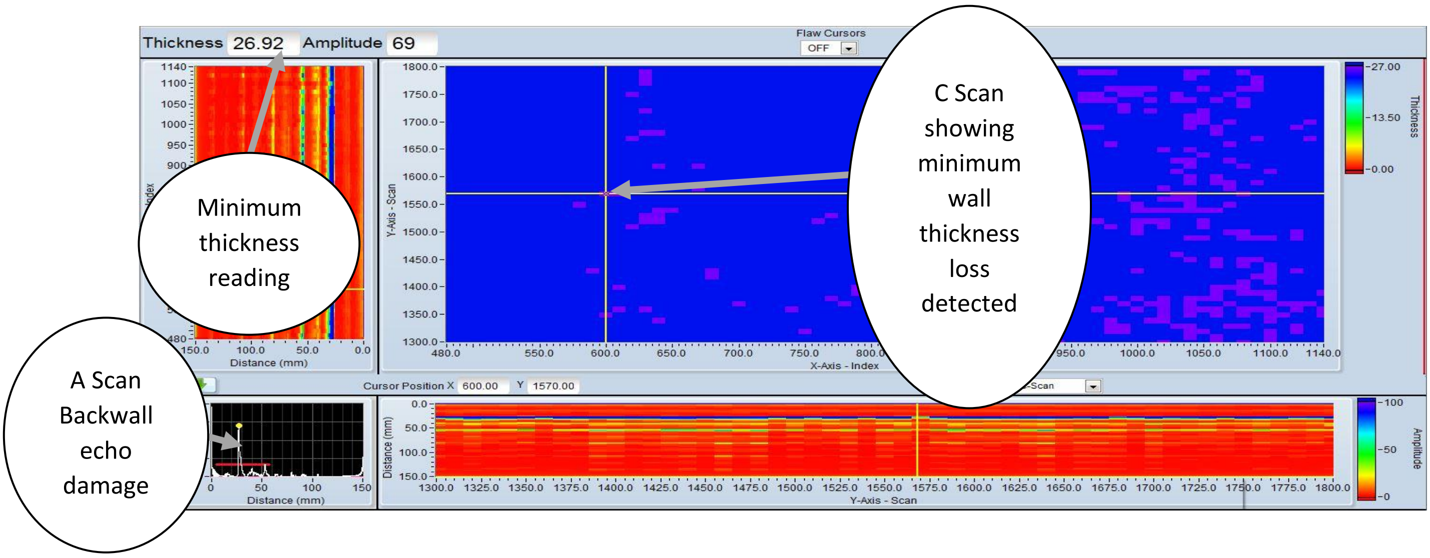
Y axis length 440mm [0mm to 440mm] and X axis length 670mm [370mm to 1040mm]



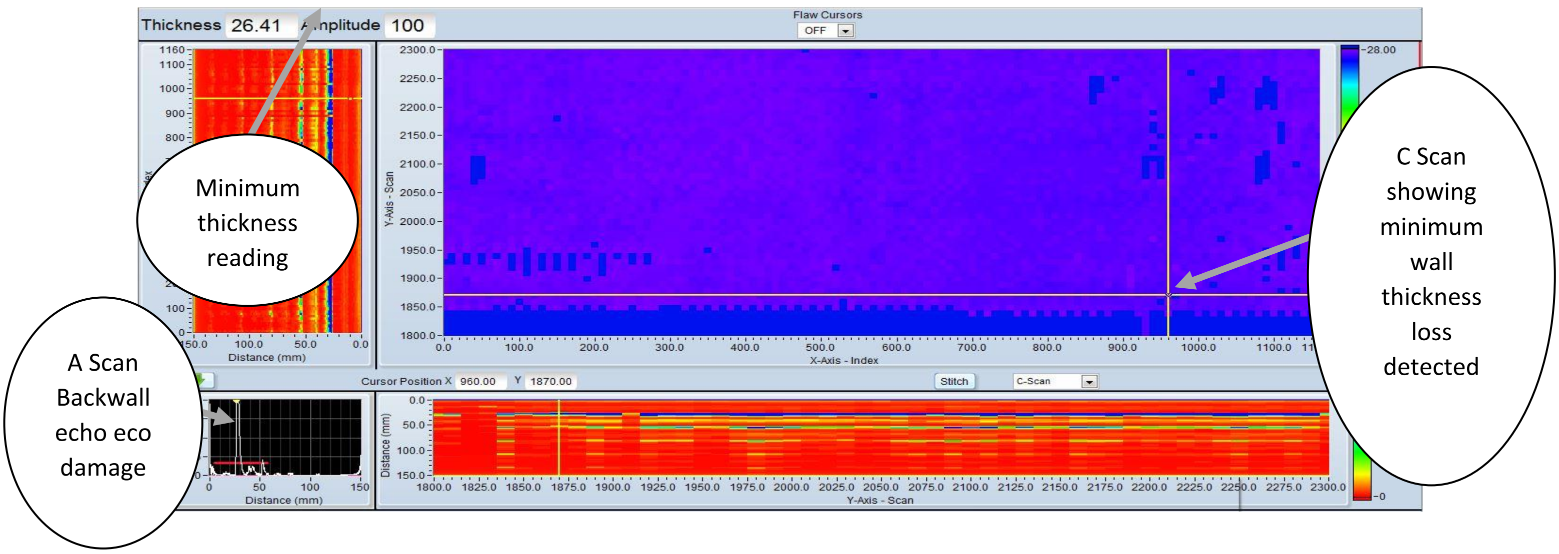
Y axis length 500mm [800mm to 1300mm] and X axis length 800mm [300mm to 1100mm]



Y axis length 500mm [1300mm to 1800mm] and X axis length 660mm [480mm to 1140mm]



Y axis length 500mm [1800mm to 2300mm] and X axis length 1160mm [0mm to 1160mm]



Internal inspection cracking finding

Corrosion mapping result table of shell No.3 pig receiver below:

Locations									
File name	X Start mm	X Stop mm	Y Start mm	Y Stop mm	X Incr. mm	Y Incr. mm	Min. 'T' mm	Ave 'T' mm	Nom. 'T' mm
Y0-440-X370-1040	370	1040	0	440	10	10	26.368	27.926	28
Y800-1300-X300-1100	300	1100	800	1300	10	10	26.129	27.83	28
Y1300-1800-X480-1140	480	1140	1300	1800	10	10	26.917	27.768	28
Y1800-2300-X0-1160	0	1160	1800	2300	10	10	26.410	27.542	28

Table 56: Pig receiver C-Scan measurement

Table 56 above represent the measurement for each scan section area at XY axis of shell No.3 pig receiver.

Example: interpretation of scan measurement taken from table 56:

Scan Y0-440-X370-1040

This scan was carried out to detect internal corrosion. The triplex angle probe (0°, -45°, +45°) attached to the arm of the motorized scanner of accrutrak moves from the left to the right at Y axis and covering the length of 440mm (Y0-440) on the surface of the shell No.3 Pig receiver. when the Y axis scanning is complete, then the accrutrak automatically move forward on the X axis with an increment of 10 set during the calibration of the accrutrak to allow the accrutrak to move forward. this is done sequentially within the X axis and the Y axis until the X axis length of 670mm (X370-1040) is covered to allow the triplex probe to detect the minimum wall thickness 26.36mm and average wall thickness 27.926mm of the material (refer to table 56 above) compared to the nominal thickness 28mm.

Pig receiver commissioned in March 2004 was inspected using corrosion mapping inspection. The type of inspection used was determined by the risk-based inspection outcome (11, 13). From the result of the inspection of the pig receiver, no relevant indications were found such as hydrogen embrittlement, Inclusion, lamination, blisters or hydrogen induced cracking, step wise cracking, stress-oriented hydrogen induced cracking, sulphide stress cracking, microbial influenced corrosion, erosion-corrosion, CO_2 corrosion or preferential weld corrosion.

Rough surface was observed during inspection period along the surface of the material. Base on C-scan measurement, shell course No.3 is identified to contain minor scattered isolated inclusions reflectors.

From the data analysis A-Scan and C-scan (see section 10.3.2 above) using the triplex probe with 0°, -45° and +45°angle beam attached on Accutrak, result shown that all isolated inclusions/laminations found less than 2mm with amplitude percentage less than 50% of full screen height which was assumed to be manufacturing defect. This result shows that it was not internal cracking presence.

To categorize this inclusion less than 2mm, the hydrogen induced cracking evaluation criteria (refer to table 24 above at section 9.1.1), shell No.3 in pig receiver is therefore evaluated and rated as DRA-1, defined as small inherent fabrication anomalies also known as scattered or flattened into typical inclusions/laminations.

10.3.3 Inspection of 6 inches gas lift riser

Long range ultrasonic Testing also called guided wave and conventional Ultrasonic Testing (UT) technique was completed on 6 inches gas lift riser below MSF (see below figure 27) in accordance with long-range ultrasonic testing procedure. The purpose of this examination is to determine the possible internal/external metal loss on sections of the line.

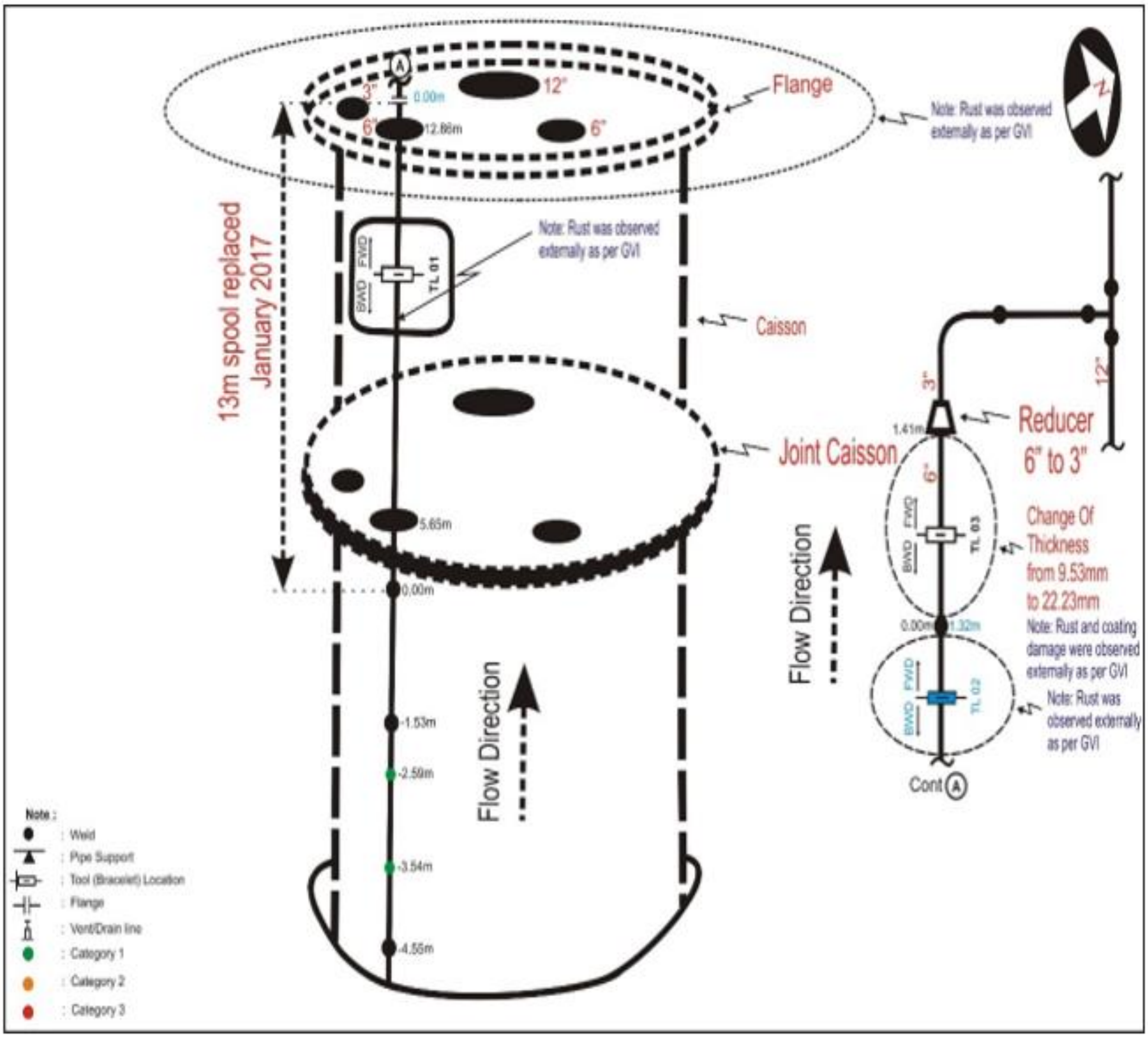


Figure 27*:* 6 inches gas lift riser (Long range ultrasonic testing inspection)

10.3.4 Long range ultrasonic testing data analysis

Client		Datum point	Tool positioned at 10.29m downstream of weld
Site location	Offshore	Test wave mode	Longitudinal
Tool location	TL01	Test direction	Both
Pipe Ident.	6 inches gas lift riser	Test operator	Clovis Nzonlie Fosso
Nominal Dia.	6 in	Test frequency	51 kHz
Wall Thickness	9.53mm	Tool type	Series 3 multi-mode modules, 30mm L
Procedure		Diagnostic length	-4.8m to 13.1m
Collection date	3/28/2020 5:45 PM	Project No	

Table 57: Gas lift riser-long range ultrasonic testing data information at test location 1 (TL01)

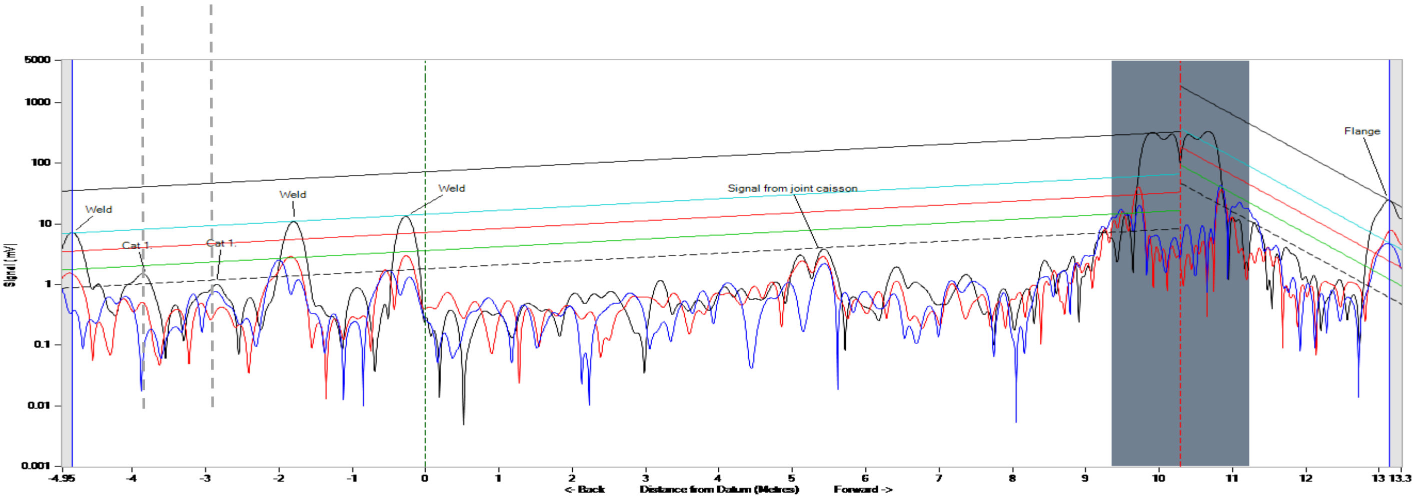
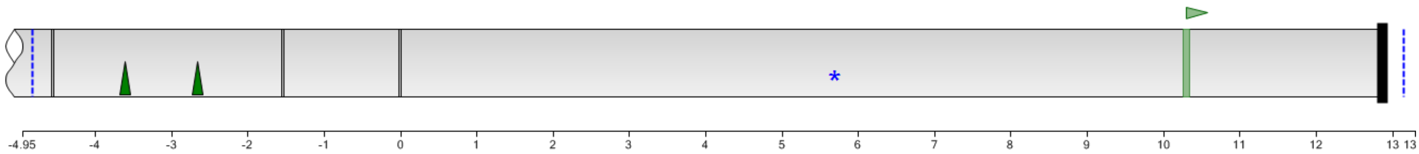


Figure 28 Long range ultrasonic testing A-Scan image test location 1 (TL01) - 6 inches gas lift riser



Distance relative to datum	Indication description	Comments	Priority
-4.55m	Weld		
-3.54m	Category 1 (Cat 1)		Low
-2.59m	Category 1 (Cat 1)		Low
-1.53m	Weld		
0.00m	Weld		
5.65m	See info	Signal from joint caisson	
12.86m	Flange		

Remarks / Conclusions

Category 1 indications were found in this section of pipeline in term of long-range ultrasonic testing inspection, further follow up required.

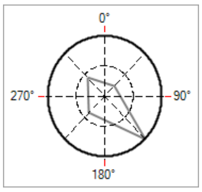
Focusing result		
Test frequency	51kHz	
Wave mode	Longitudinal	
Test direction	Backwards	
Focal distance	-13.83m	
Distance from datum	-3.54m	

Table 58: Focal distance -13.83m Result

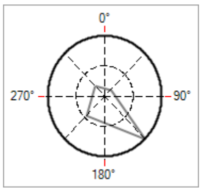
Focusing result		
Test frequency	51kHz	
Wave mode	Longitudinal	
Test direction	Backwards	
Focal distance	-12.88m	
Distance from datum	-2.59m	

Table 59: Focal distance -12.88m result

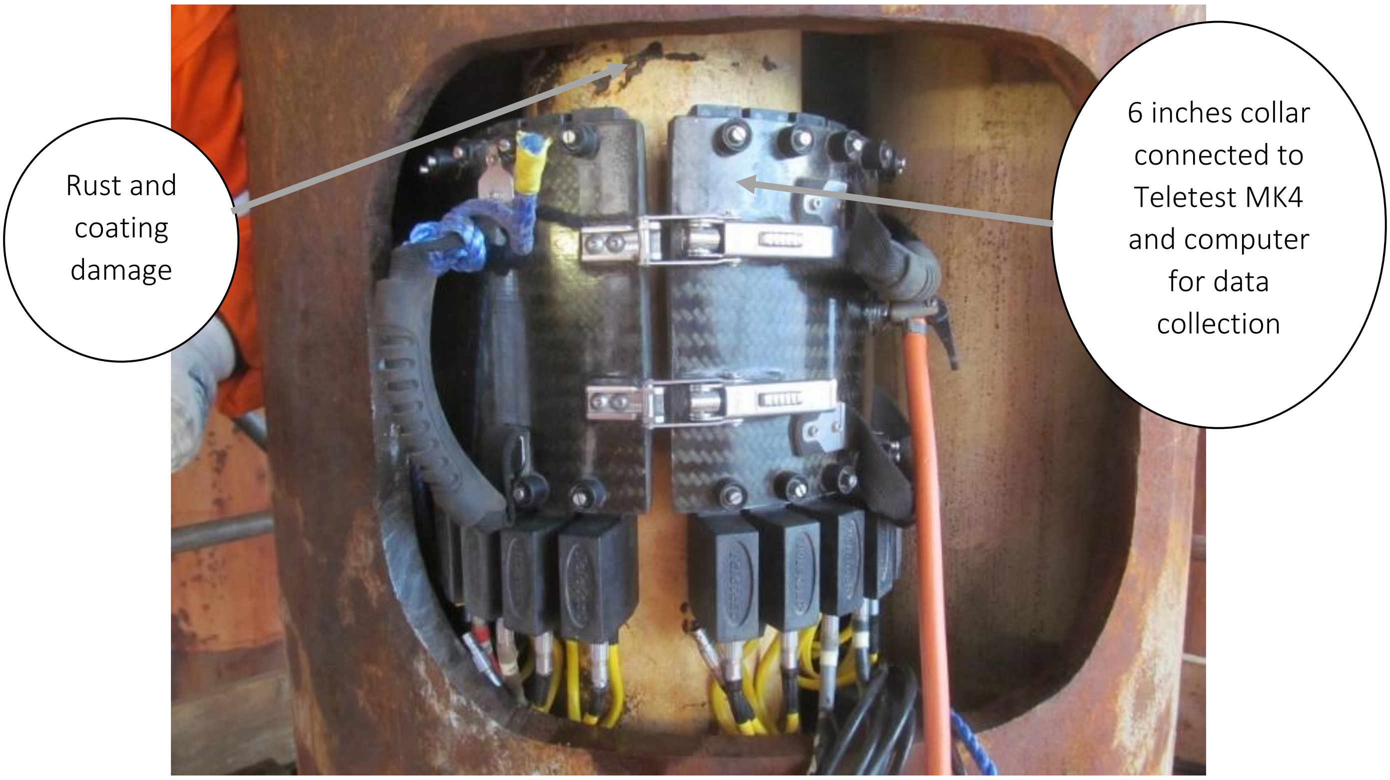


Figure 29: Vertical line – 6 inches collar attached to the gas lift riser at test location 1 (TL01)

Test location 1 (TL01) on gas lift riser-collected data explanation

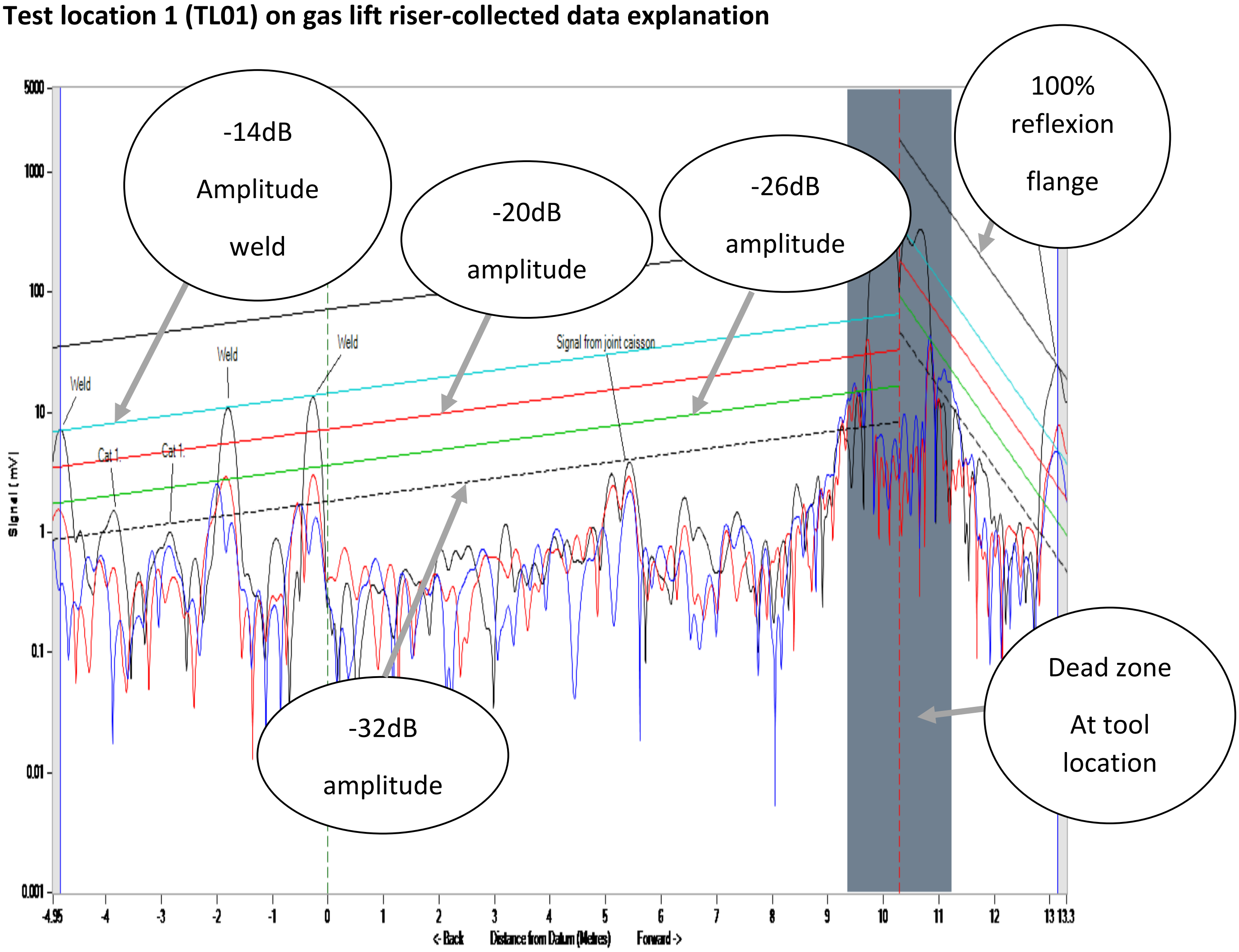
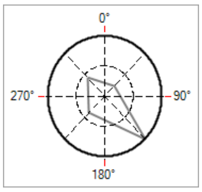


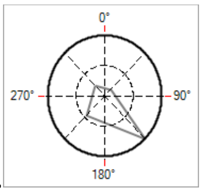
Figure 28 is the A scan data showing on the screen of laptop. A scan data was collected using multiple modules attached around the gas lift riser with 5 transducers inserted (three longitudinal and two torsional) which was via wave mode (torsional, longitudinal, and flexural) sent through the riser (torsional wave) to detect internal and external average thickness wall loss. The length of -4.8m in backward direction of the tool and 13.1m in forward direction of the tool was inspected. The distance amplitude curve (DAC) black line with 100% reflexion (0dB amplitude) used to identify feature as flange, blue line (-14dB amplitude) used to identify feature as weld, and the distance amplitude curve (DAC) which are red line (-20 dB), green line (-26dB) are used to identify the level of anomaly or defect severity (refer to section 9.1.2). The distance amplitude curve black line with100% reflexion (0dB amplitude) at a frequency of 51Khz show high flexural response signal from the longitudinal wave at forward direction from the tool location which represent the flange. it also observed that the noise level signal was below the distance amplitude curve -32dB where no change of wall thickness or defect detected. From the datum point at distance from the second weld in the backward direction of the tool as seen on figure 28, located at -3.54m and -2.59m, from the distance amplitude curve -32dB two flexural responses sign of wall loss thickness is observed and classified as category one (Cat 1) defect found.

Table 58 provide more information related to the exact location of the defect. Flexural signal response from the longitudinal wave mode at frequency of 51Khz, area of thickness wall loss which located at backward direction of the tool within 3 O'clock to 6 O'clock at the distance of -3.54m from the datum point with the focal distance length of -13.83m from the centre of the tool or collar attached around the riser to the flexural signal. The polar plot has 3 adjacent high amplitude peaks (refer to figure 23) it is classed as directionality 1. This suggests that it is spread over a wide area of circumference, so that it is likely to be less for a given response amplitude classified as one, therefor the score of one is given to it with priority classified to be low.



Polar Plot from table 58

Table 59 provide more information related to the exact location of the defect. Flexural signal response from the longitudinal wave mode at frequency of 51Khz, area of thickness wall loss which located at backward direction of the tool within 3 O'clock to 6 O'clock at the distance of -2.59m from the datum point with the focal distance length of -12.88m from the centre of the tool or collar attached around the riser to the flexural signal. The polar plot has 3 adjacent high amplitude peaks (refer to figure 23) it is classed as directionality 1. This suggests that it is spread over a wide area of circumference, so that it is likely to be less for a given response amplitude classified as one, therefor the score of one is given to it with priority classified to be low.



Polar Plot from table 59

Client		Datum Point	Tool positioned at 0.75m downstream of flange
Site location	Offshore	Test wave mode	Torsional
Tool location	TL02	Test direction	Both
Pipe Ident.	6 inches gas lift riser	Test operator	Clovis Nzonlie Fosso
Nominal Dia.	6 in	Test frequency	37 kHz
Wall thickness	9.53mm	Tool type	Series 3 multi-mode modules, 30mm L
Procedure		Diagnostic length	-0.2m to 1.5m
Collection date	3/28/2020 7:59 AM	Project No	

Table 60: Gas lift riser-long range ultrasonic testing data information at test location 2 (TL02)

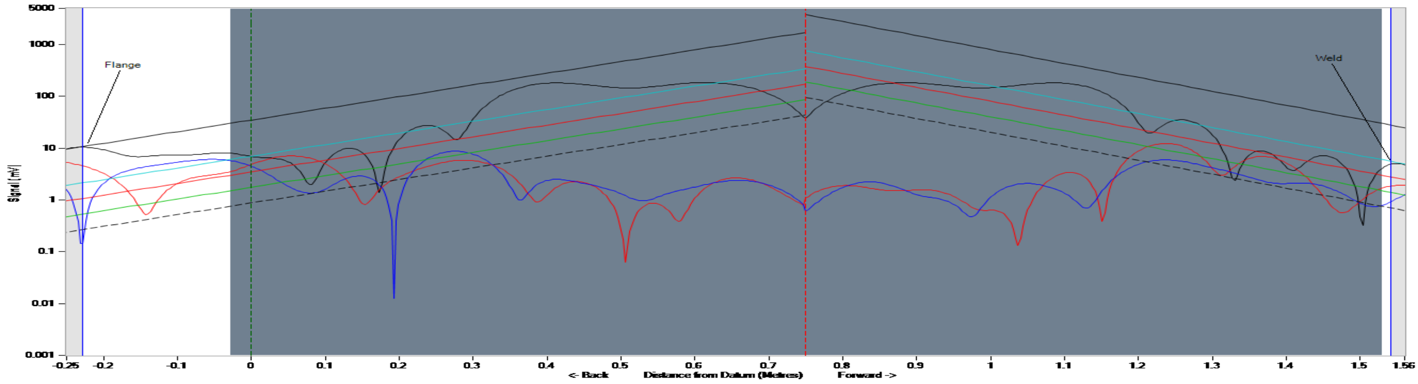
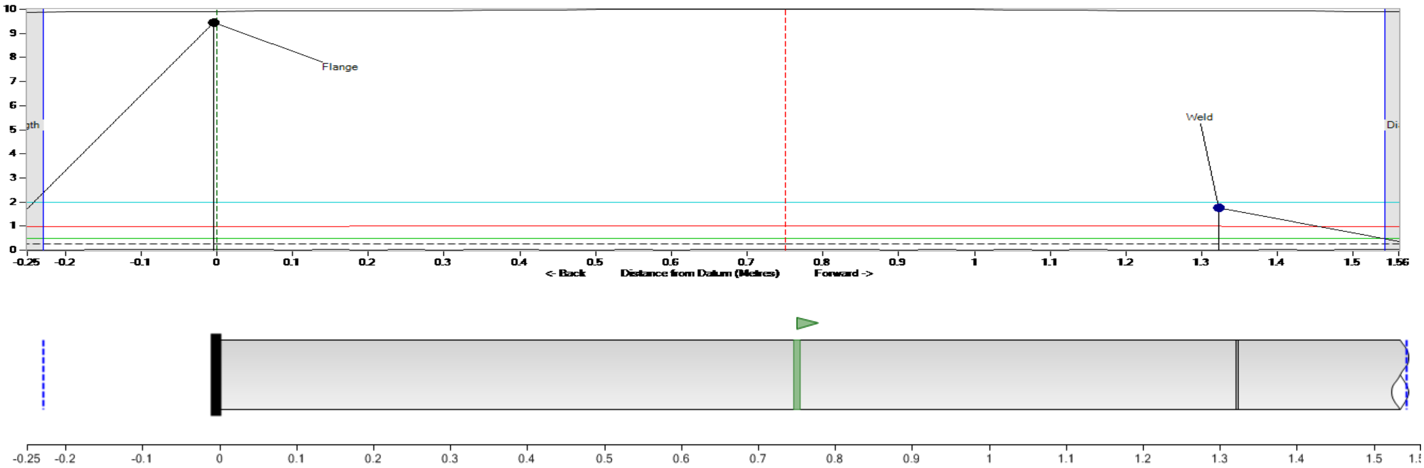


Figure 30: Riser-Long range ultrasonic testing A-Scan image test location 2 (TL02) - 6 inches gas lift riser



Distance relative to datum	Indication description	Comments	Priority
0.00m	Flange		
1.32m	Weld		

Remarks / Conclusions

No relevant indication was found in this section of pipeline in term of long-range ultrasonic testing inspection. Rust observed as per general visual inspection externally.

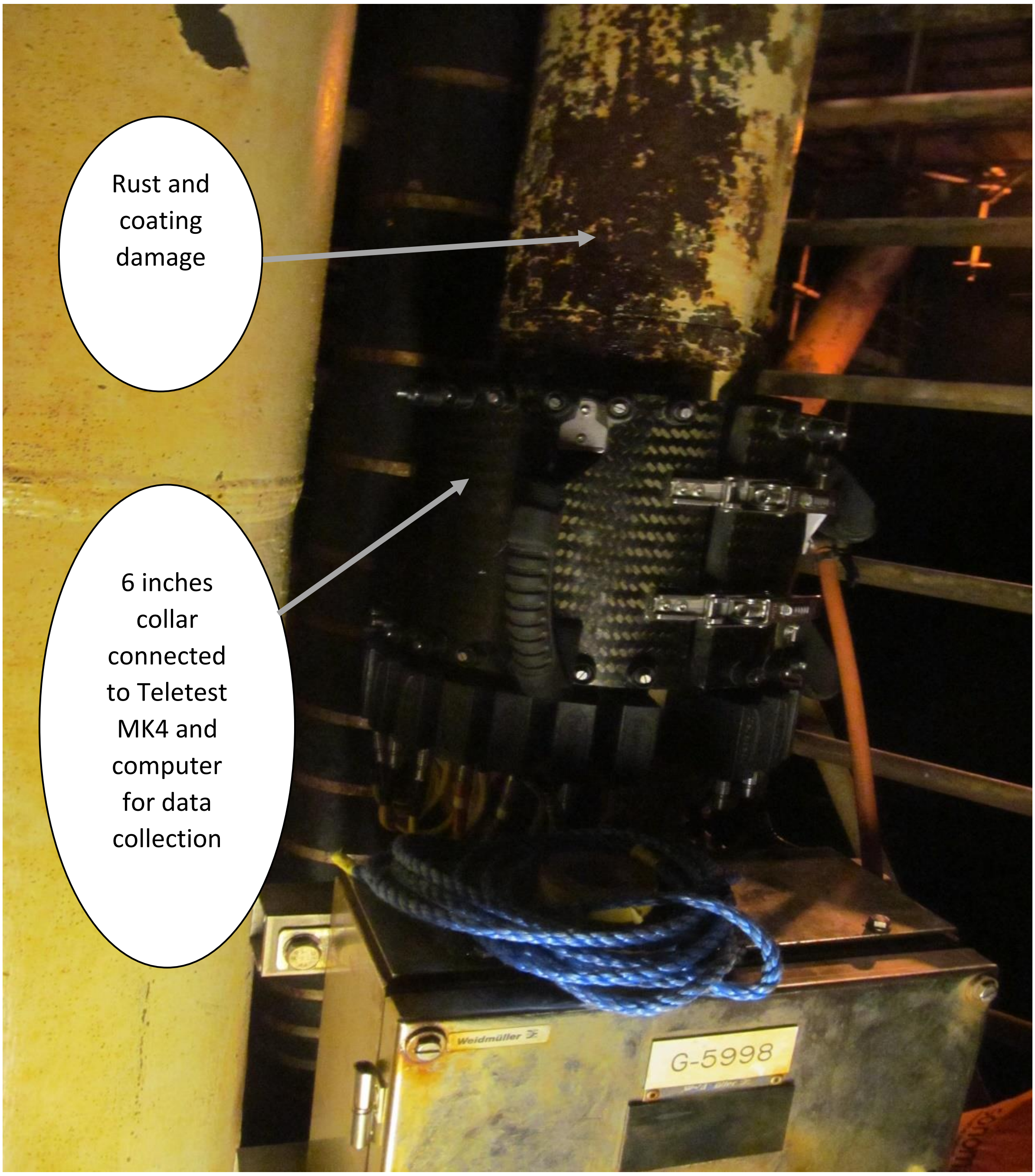


Figure 31: Vertical line – 6 inches collar attached to the gas lift riser at test location 2 (TL02)

Test location 2 (TL02) on gas lift riser-collected data explanation

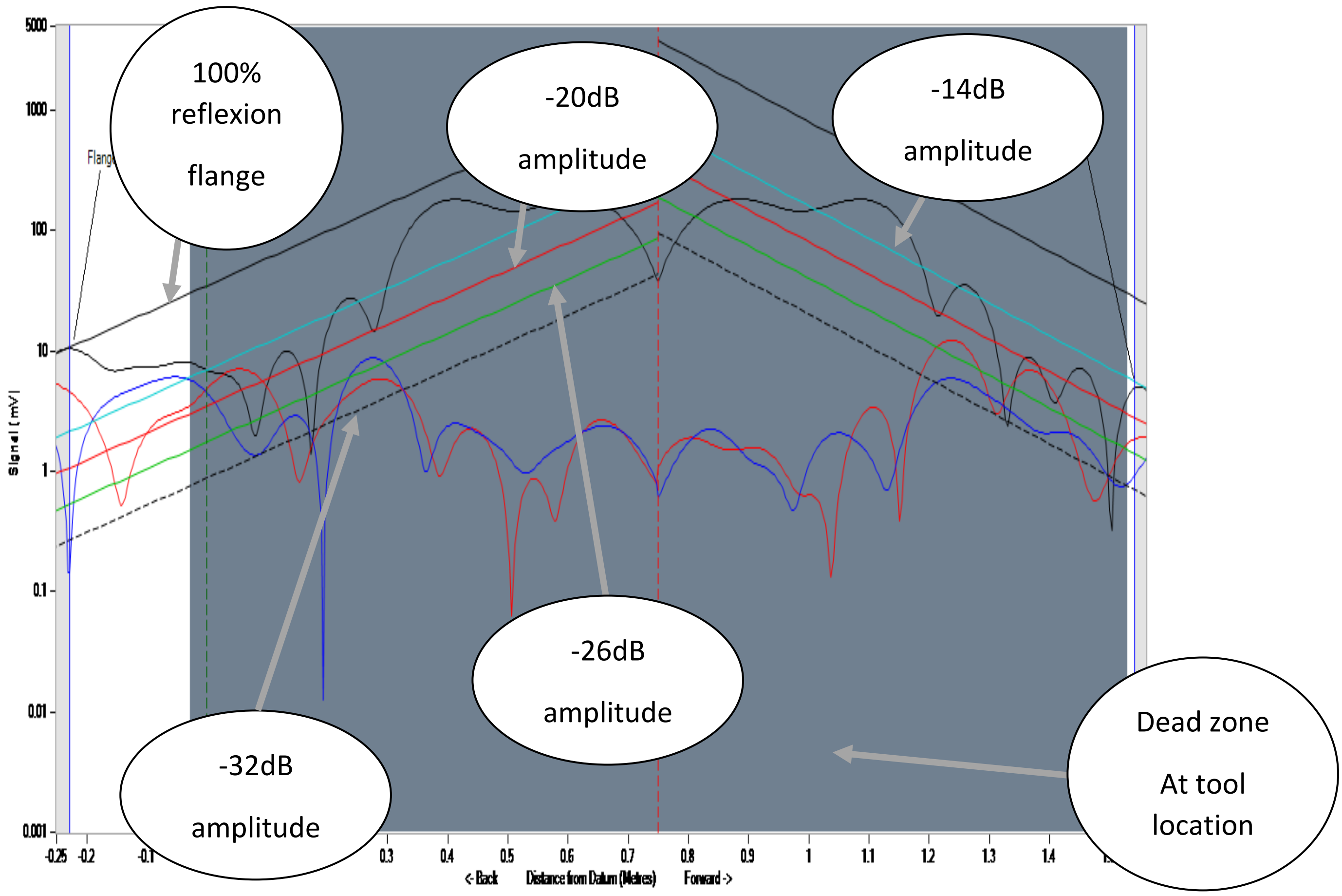


Figure 30 is the A scan data showing at the screen of laptop, data A scan collected using multiple modules attached around the gas lift riser with 5 transducers inserted (three longitudinal and two torsional). which assisted via wave mode (torsional, longitudinal, and flexural) sent through the riser to detect internal and external average wall loss thickness. The length of -0.2m in backward direction of the tool and 1.5m in forward direction of the tool was inspected. The distance amplitude curve (DAC) black line with 100% reflexion (0dB amplitude) used to identify feature as flange, blue line (-14dB amplitude) used to identify feature as weld, and the distance amplitude curve (DAC) red line (-20 dB), green line (-26dB) are used to identify the level of anomaly or defect severity (refer to section 9.1.2). As result from the A scan above no sign of defect along the inspected line was detected as the noise is highly attenuated below the black dotted line (-32dB amplitude). High flexural response signal from the torsional wave in the backward direction from the tool location touching the distance amplitude curve black line with100% reflexion (0dB amplitude) at a frequency of 37Khz shown as flange and flexural response signal from the torsional wave in the forward direction from the tool location touching the distance amplitude curve blue line (-14dB amplitude) at a frequency of 37Khz shown as weld.

Client		Datum point	Tool positioned at 0.75m downstream of weld
Site location	Offshore	Test wave mode	Longitudinal
Tool location	TL03	Test direction	Both
Pipe Ident.	6 inches gas lift riser	Test operator	Clovis Nzonlie Fosso
Nominal Dia.	6 in	Test frequency	50 kHz
Wall thickness	22.23mm	Tool type	Series 3 multi-mode modules, 30mm L
Procedure		Diagnostic length	-0.3m to 1.7m
Collection date	3/28/2020 7:49 PM	Project No	

Table 61: Gas lift riser-long range ultrasonic testing data information at test location 3 (TL03)

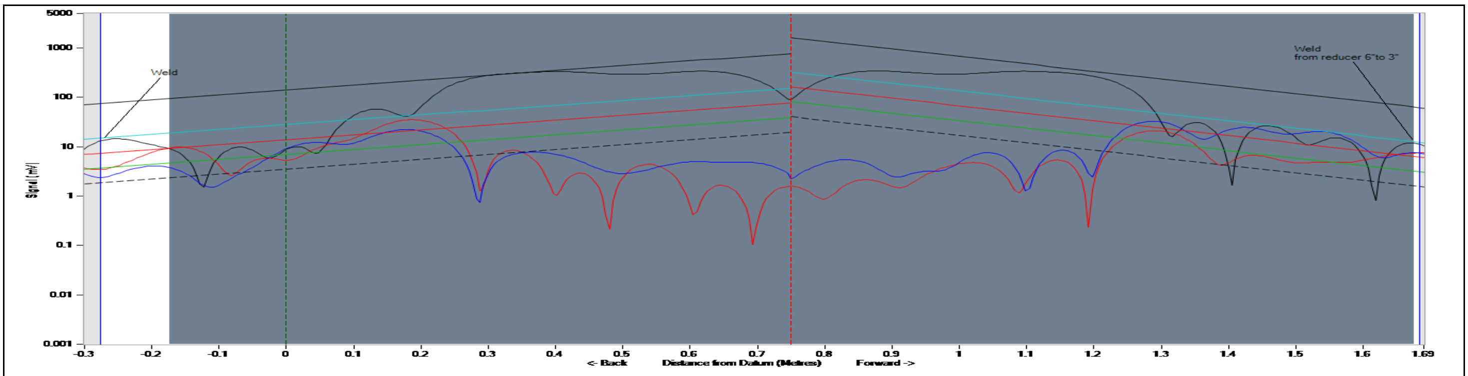
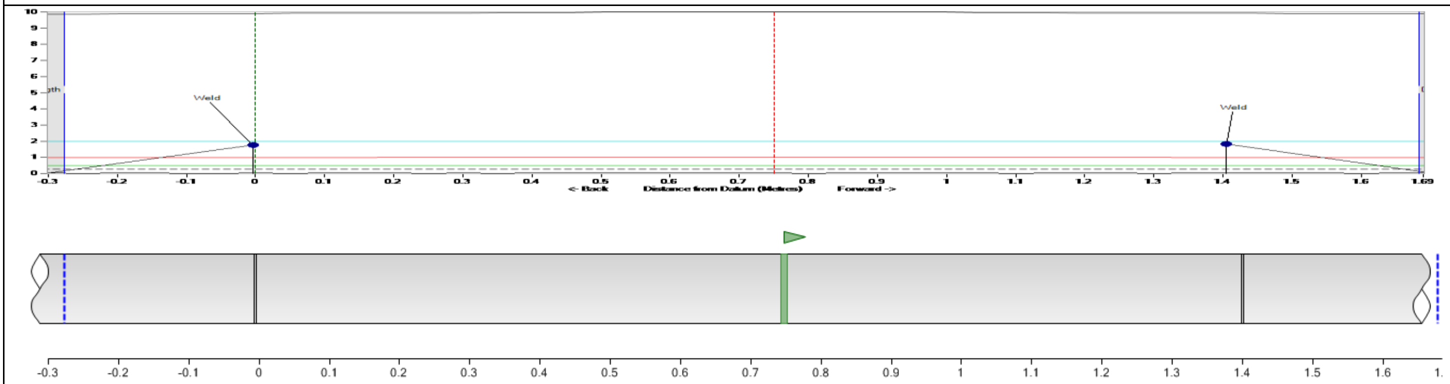


Figure 32: Long range ultrasonic testing A-Scan image test location 3 (TL03) - 6 inches gas lift riser



Distance relative to datum	Indication description	Comments	Priority
0.00m	Weld	Rust at weld surface	
1.41m	Weld	from reducer 6 inches to 3 inches (see Figure 24)	

Remarks / Conclusions
No relevant indication was found in this section of pipeline in term of long-range ultrasonic testing inspection. Rust observed as per general visual inspection externally.

Figure 33 Vertical line – 6 inches collar attached to the gas lift riser at test location 3 (TL03)

Test location 3 (TL03) on gas lift riser-collected data explanation

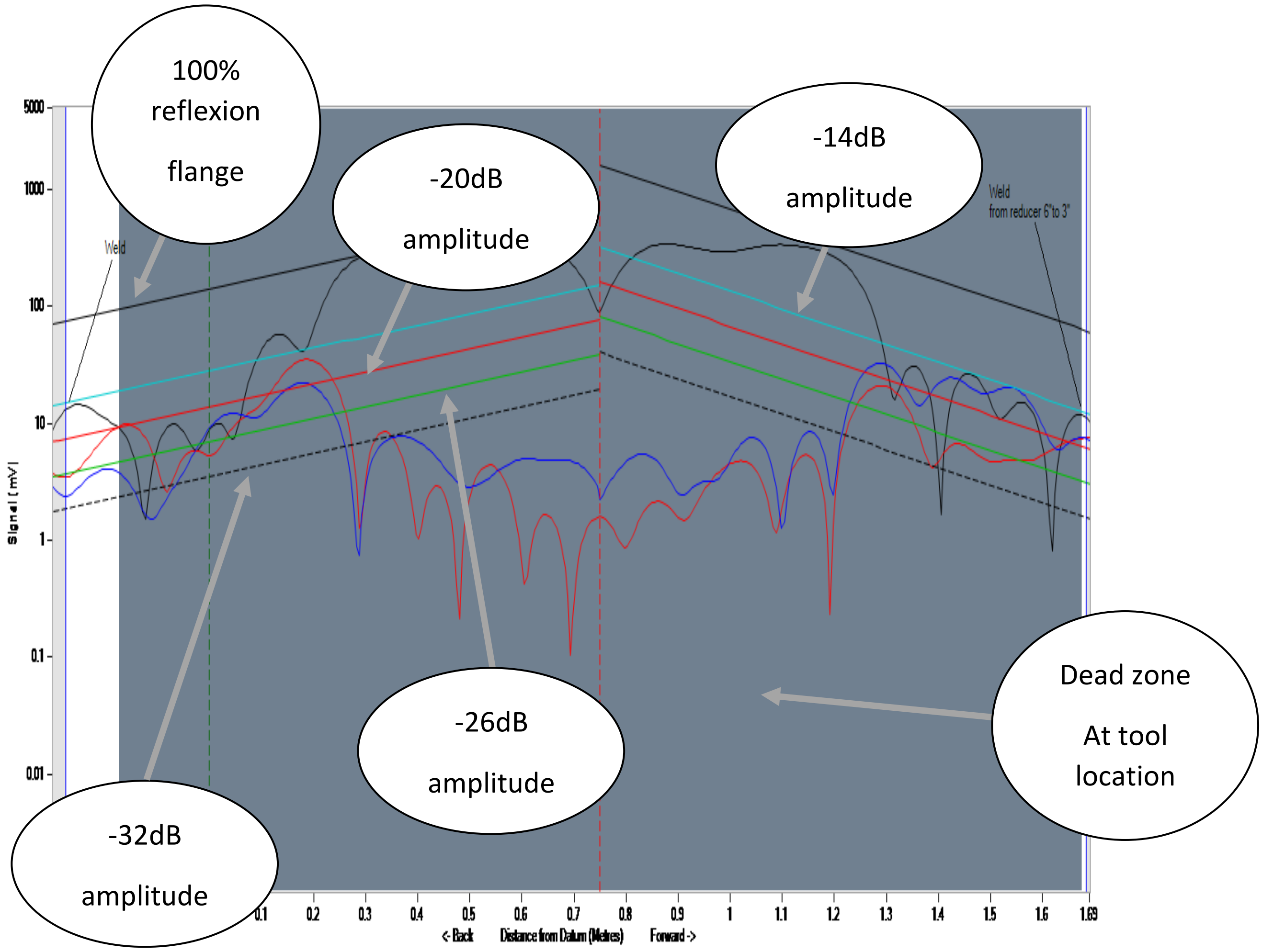


Figure 32 is the A scan data showing at the screen of laptop, data A scan collected using multiple modules attached around the gas lift riser with 5 transducers inserted (three longitudinal and two torsional). which assisted via wave mode (torsional, longitudinal, and flexural) sent through the riser (torsional wave) to detect internal and external average wall loss thickness. The length of -0.3m in backward direction of the tool and 1.7m in forward direction of the tool was inspected. The distance amplitude curve (DAC) black line with 100% reflexion (0dB amplitude) used to identify feature as flange, blue line (-14dB amplitude) used to identify feature as weld, and the distance amplitude curve (DAC) which are red line (-20 dB), green line (-26dB) are used to identify the level of anomaly or defect severity (refer to section 9.1.2). As result from the A scan above no sign of defect along the inspected line was detected as the noise is highly attenuated below the black dotted line (-32dB amplitude). Flexural response signal from the torsional wave in the backward direction and forward direction from the tool location touching the distance amplitude curve blue line (-14dB amplitude) with a frequency of 50Khz shown as weld.

Long range ultrasonic testing finding

General visual inspection was carried out from accessible locations of the limited exposed areas at test location 01 (TL01) above the caisson at flanges location, signs of crevice corrosion were observed (see below figure 34), Poor coating is observed along the surface of the inspected location at the time of long-range ultrasonic testing inspection at test location 1 (TL01), test location 2 (TL02) and test location 3 (TL03). Also, initial apparent signs of surface rusting (see figures 26, 28, 30 and 31).

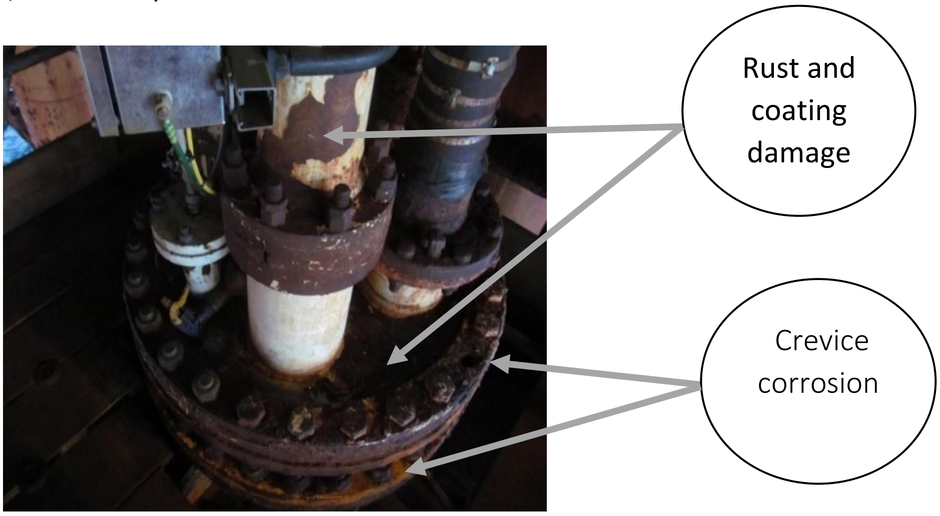


Figure 34: Showing corroded flange in backward direction test location 2 (TL02)

Long range ultrasonic testing examination identified two Category 1 metal loss indications within the 21.6m of the gas lift riser inspected. Category 1 indications are minor (see long-range ultrasonic testing principles of evaluation method above at section 9.1.2) and indicates that there is little deviation in cross sectional area along the length of the line other than at the schedule changes. As this level of indication detected by the technology is very small, it is generally not considered as a high risk. Further support is gained from the twelve thickness readings that were taken at each of the 3 tool locations plus the additional readings taken around test locations 2 (TL02) and test locations 3 (TL03). The analysis of these measurements showed that out of the total fifty-two (52) ultrasonic testing (UT) readings all demonstrated less than 5% material loss from the given nominal thickness (t_{nom}) which would not indicate a general internal corrosion concern in this riser. From the 52 ultrasonic testing scans near the tool locations, the largest percentage wall loss recorded is 3.5% which was observed at test location 1 (TL01). At this location the minimum recorded wall thickness was found to be 9.2mm as opposed to the given nominal of 9.53mm. The spool at Test Location 3 (TL03) is a much larger schedule with a nominal of 22.23mm wall thickness.

The spool lengths available at test location 2 (TL02) and test location 3 (TL03) were very short in nature and do not allow the guided wave (Long range ultrasonic testing) to form sufficiently to ensure good coverage of the line. To mitigate this, additional ultrasonic testing scan were taken at these locations to access their conditions.

10.3.5 General visual inspection

Pipe identification	6 inches gas lift riser
Location	Offshore below MSF

Sr.	Areas of Inspection	Sub classification	Code /standard	Comments
1	Leaks	Process ☐ Steam tracing ☐ Existing clamps ☐	API 570	No significant indications found.
2	Misalignment	Piping misalignment / Restricted movement ☐ Expansion joint misalignment ☐	API 570	No significant indications found.
3	Vibration	Excessive overhung weight ☐ Inadequate support ☐ Thin, small bore, alloy piping ☐ Threaded connections ☐ Loose support ☐	API 570	No significant indications found.
4	Supports	Shoes of support ☐ Hanger distortion or breakage ☐ Loose brackets ☐ Support/damage corrosion ☐	API 570	No significant indications found
5	Corrosion	Localized Corrosion ■ Coating / Painting deterioration ■ Soil to air Interface ☐ Metal to Metal contact ☐ Biological growth ☐ Scab / blistering Corrosion ☐	API 570	Painting deterioration and rust was observed externally as per General Vision Inspection. In backward direction of test location 2 (TL02) Long Range UT Scan 6 inches gas lift riser, at flanges location Rust and Crevice corrosion was observed.
6	Insulation	Damage/Penetration ☐ Missing Jacketing / Insulation ☐ Sealing deterioration ☐ Bulging ☐ Banding (broken / missing) ☐	API 570	No significant indications found
7	Small Bore Fitting	Chemical Injection Point ☐ Vents ☐ Drains ☐	API 570	No significant indications found.
8	Dead Legs		API 570	No significant indications found.

Table 62: General visual inspection summary

10.3.6 Long range ultrasonic testing summary table results of 6 inches gas lift riser

Site location	Offshore below MSF												
Pipeline name	Location	Test location	Distance from tool location in meter	Pipe Size	Original thickness in mm	Gauge thickness in mm. Clockwise direction				Lowest thickness reading in mm.	Gauged Mean in mm.	Percentage wall loss	
						12.0	3.0	6.0	9.0			mm	%
6' inches gas lift riser	Below MSF	TL01	At Tool Location	6''	9.53	9.40	9.40	9.50	9.50	9.4	9.5	0.1	1.4
			0.5m Forward	6''	9.53	9.40	9.50	9.40	9.40	9.4	9.4	0.1	1.4
			0.5m Backward	6''	9.53	9.20	9.50	9.50	9.50	9.2	9.4	0.3	3.5
		TL02	At Tool Location	6''	9.53	9.50	9.40	9.50	9.60	9.4	9.5	0.1	1.4
			0.5m Forward	6''	9.53	9.50	9.50	9.40	9.40	9.4	9.6	0.1	1.4
			0.5m Backward	6''	9.53	9.50	9.30	9.30	9.70	9.3	9.5	0.2	2.4
		TL03	At Tool Location	6''	22.23	22.20	22.10	22.40	23.20	22.1	22.5	0.1	0.6
			0.5m Forward	6''	22.23	22.20	22.20	22.20	23.30	22.2	22.5	0.0	0.1
			0.5m Backward	6''	22.23	22.80	22.30	22.50	21.90	21.9	22.4	0.3	1.5

Table 63: Summary of thickness results of gas lift riser

Table 63 above contain the actual thickness reading of the gas lift riser inspection taking from tool locations (TL01, TL02, TL03) at 0.5m north and south direction. at each direction, the tool is rotated clockwise direction to take reading at 12 O'clock, 3 O'clock, 6 O'clock and 9 O'clock Positions. The readings in show in table above is the lower thickness obtained from the four positions.

10.3.7 Ultrasonic testing measurement - minimum wall thckness at tool location of gas lift riser

Line	Tool location	Nominal wall thickness (mm) mm	Maximum measured at tool wall thickness (mm)	Minimum measured wall thickness (mm)	Coating type	Coating condition Good/Fair/Poor	Date commissioned
6 inches gas lift riser	TL01	9.53	10.2	9.2	Paint	Poor	March 2004
	TL02	9.53	9.8	9.3	Paint	Poor	
	TL03	22.23	23.2	21.9	Paint	Poor	

Table 64: Minimum wall thickness at tool location of gas lift riser

Table 64 above shows the riser coating, the coating condition and the actual minimum thickness reading of the gas lift riser inspection taking at location (TL01, TL02, TL03) in the clockwise direction (12 O'clock, 3 O'clock, 6 O'clock and 9 O'clock).

10.4 Fitness for service

Fitness-for-service is a standard and best practice for determining the fitness of in-service equipment before it is used again. The American Petroleum Institute (API) established the most widely used approach in API 579, which includes independent processes for assessing general metal loss, local metal loss, and pitting.

In general, most fitness for service assessment standards is broken into multiple levels. Each successive level (e.g., Levels 1, 2 and 3 of the engineering standards referenced in API 579-1/ASME FFS-1) requires increasing amounts of data, calculations, effort, and cost to arrive at the most accurate outcomes and possible longer equipment remnant life. In addition to calculations, fitness for service involves the consideration of additional data (e.g., pitting patterns and depths, corrosion morphology or shape and depth, crack depths and lengths, operating conditions, materials properties, etc.). Inspection information is often critical input to a fitness for service assessment.

10.4.1 Fitness for service - pig receiver

The rate of corrosion and the asset remaining life can be determined by monitoring the thinning of a wall thickness. During corrosion data collection, these factors are considered as part of the prediction and rejection criteria used to determine the remaining service life and usage worthiness. A non-destructive examination (NDE) method, such as automated ultrasonic testing, is used to acquire data. A horizontal pressure vessel can be inspected using this method. Following the API 579 standard's step-by-step instructions, you can get an estimate of the asset's remaining life. The following mathematical formulas are used to calculate the minimum needed wall thicknesses in circumferential and longitudinal planes.

Minimum thickness of shell No.3 in pig receiver:

With regards to the circumference stress when the thickness does not exceed one half of the inside radius (28<181.5) or pressure (P) do not exceed 0.3855E (1200<0.385x25000x1), the following formulas apply for minimum thickness (t^{C}_{min}) without corrosion allowance is:

$$t^{c}_{min} = \frac{PR_c}{SE - 0.6P}$$

Where:

E = weld efficient factor

S = allowable stress

P = maximum design pressure

R = pressure vessel radius

$$t_{min}^{c} = \frac{1200x181.5}{25000x1 - 0.6x1200}$$

$$t_{min}^{c} = 8.97mm$$

Minimum thickness (t_m) acceptable which agree with ASME Section VIII Division 1-UG27:

$$t_m = t_{min}^{c} + CA$$

Where:

CA= corrosion allowance

$$t_m = 8.97 + 3$$

$$t_m = 11.97mm$$

The minimum thickness (t_m) acceptable of shell No.3 in pig receiver in accordance with ASME Section VIII Division 1-UG27 is 11.97mm.

These two numbers are then compared which are the minimum thickness (t_m) acceptable of shell No.3 in pig receiver in accordance with ASME Section VIII Division 1-UG27 and the lower actual wall thickness measurement of shell No.3 in pig receiver collected from the recent ultrasonic testing inspection. The remaining life of the pressure vessel is determined by factoring the rate of corrosion and the time between measurements with the equations shown below. Corrosion rate determination pig receiver:

The long-term corrosion rate shall be calculated from the following formula:

$$\text{Corrosion Rate (LT)} = \frac{T_{initial-}T_{actual}}{\text{Year between initial and actual inpection}}$$

$$\text{Corrosion Rate} = \frac{28 - 26.129}{2020 - 2004}$$

$$\text{Corrosion Rate} = 0.1169\text{mm/year}$$

The short-term (ST) corrosion rate shall be calculated from the following formula:

$$\text{Corrosion Rate (ST)} = \frac{\text{T}_{\text{Previous}-}\text{T}_{\text{actual}}}{\text{Year between previous and actual inpection}}$$

$$\text{Corrosion Rate} = \frac{26.4 - 26.129}{2020 - 2019}$$

$$\text{Corrosion Rate} = 0.270\ \text{mm/year}$$

Remaining life calculation pig receiver:

The remaining life of the pig receiver (in years) shall be calculated from the following formula:

$$\text{Remaining life} = \frac{\text{t}_{\text{actual}-}\text{t}_{\text{required}}}{\text{Corrosion Rate}}$$

$$\text{Remaining life} = \frac{26.129 - 8.97}{0.270}$$

$$\text{Remaining life} = 63.55\ \text{years}$$

The remaining life will be 63.5 years.

were,

t_{actual} = The actual thickness of a condition monitoring location, in (mm), measured during the most recent inspection

$\text{t}_{\text{required}}$ = The minimum thickness acceptable without corrosion allowance

10.4.2 Fitness for service-6 inches gas lift riser

Fitness for service assessment approaches is developed from a basic straight pipe that ignores discontinuities; the technique of assessment chosen is determined by the available input parameters and which method will assure integrity without being unduly conservative.

A 6-inch gas lift riser below the MSF was used for long-range ultrasonic testing, also known as guided wave and conventional Ultrasonic Testing, in accordance with long-range ultrasonic testing Procedure. In this case, the goal is to establish whether there is a possibility of internal or external metal loss along the line. Following the API 579 standard's step-by-step instructions, you can get an estimate of the asset's remaining life. The following mathematical formulas are used to calculate the minimum needed wall thickness.

Basic equations used for thickness calculation according to ASME B31.3 are:

$$\mathrm{t_m = t_{min} + CA}$$

$\mathrm{t_{min}} = \text{minimum thickness}$ on design pressure without corrosion allowance

$$\mathrm{t_{min}} = \frac{\mathrm{PD}}{2(\mathrm{SEW} + \mathrm{PY})}$$

P= Internal design pressure (Psi)

D= Pipe outside diameter (inches)

S= Allowable stress in tension for material (for value refer to ASME B.31.3 TABLE A-1)

E=Longitudinal joint quality factor according (for value refer to ASME B.31.3 TABLE A-1B)

Y= Wall thickness correction factor (for value refer to ASME B.31.3 TABLE 304.1.1)

W= Weld joint reduction factor (for value refer to ASME B31.3 Section 302.3.5(e))

$$\mathrm{t_{min}} = \frac{\mathrm{PD}}{2(\mathrm{SEW} + \mathrm{PY})}$$

Minimum thickness ($\mathrm{t_{min}}$) without corrosion allowance

$$\mathrm{t_{min}} = \frac{1200\mathrm{x}152.4}{2(25000\mathrm{x}1 + 1200\mathrm{x}0.4)}$$

$$\mathrm{t_{min}} = 3.58mm$$

Minimum thickness (t_{min}) acceptable which agree with ASME B31.3

$$t_m = 3.58 + 1.53$$

$$t_m = 5.11\text{mm}$$

Corrosion Rate Determination for 6 inches gas lift riser:

Corrosion allowance (CA) =1.53mm

Minimum thickness collected at a recent inspection was 9.2mm (See above section: 10.3.7 - UT measurement table).

Thickness required is nominal thickness without corrosion allowance is:

$$\text{Thickness required} = t_{nominal-}\ \text{CA}$$

$$\text{Thickness required} = 9.53 - 1.53$$

$$\text{Thickness required} = 8\text{mm}$$

Metal loss calculation for 6 inches gas lift riser:

$\text{Metal loss} = t_{nominal-}\ t$ with t=9.2mm (See above section: 10.3.7 - UT measurement table).

$$\text{Metal loss} = 9.53 - 9.2$$

$$\text{Metal loss} = 0.33\text{mm}$$

Corrosion rate calculation for 6 inches gas lift riser:

$$\text{Corrosion rate} = \frac{\text{Metal loss}}{\text{Year between initial and actual inpection}}$$

$$\text{Corrosion rate} = \frac{0.33}{2020 - 2017}$$

$$\text{Corrosion rate} = \frac{0.33}{3}$$

$$\text{Corrosion rate} = 0.11\text{mm/year}$$

Remaining Life Calculation 6 inches gas lift riser:

$$\text{Remaining life} = \frac{t_{actual-}t_{required}}{\text{Corrosion Rate}}$$

$$\text{Remaining life} = \frac{9.2 - 8}{0.11}$$

$$\text{Remaining life} = 10.9$$

Where the remaining life for the gas lift riser will be 10.9years which can be consider to be approximately 11years

11 Conclusions and Recommendation

Routine inspection of the general pig receiver using corrosion mapping technique did not demonstrate any major hydrogen induced cracking concern. The acceptable minimum thickness of the pig receiver as per engineering standard ASME Section VIII Division 1 is 11.97mm. Therefore, the ultrasonic testing (UT) measurement or scanning carried out on the pig receiver must not be lower than this value at any location or points on the pig receiver during inspection. Inspections shall be carried as per risk-based assessment plan. All components on pig receiver shall be visually examined in accordance with written scheme of examination

The inspected section of the gas lift riser in terms of long-range ultrasonic testing inspection did not demonstrate a major corrosion concern. Data were also taken from the thickness readings at the tool location points as shown in tables above at section 10.3.6 and 10.3.7. From the general visual examination, external degradation has been observed at the surface of the riser (paint failure, large zone affected by rust and crevice corrosion). Consideration should be given for a follow up assessment of the Category 1 indication stated above at the next maintenance opportunity. However, any external surface contaminant (chloride, phosphorus, sulphide) should be removed, coating (paint) should be re-instated, and the primary method of reducing crevice corrosion risks should be follow up closely by eliminate small gaps which might trap electrolyte and lead to stagnation. Inspection should be carried out as per risk-based assessment plan. The minimum thickness acceptable for riser according engineering standard ASME B31.3 is 5.11mm (see above calculation of minimum acceptable thickness of gas lift riser). Therefore, the ultrasonic testing measurement or scanning carried out on the riser must not be lower than this value at any location or points on the riser during inspection.

Ensure adequate injection and monitoring of H_2S scavenger to reduce the amount of H_2S. The gas lift riser and pig receiver hardness should be measured in accordance with ASTM E 92. The hardness shall not exceed 325 HV10 under non-sour conditions and 248 HV10 under sour conditions.

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