

Design of a Typical Offshore Transportation System for External Corrosion

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ABSTRACT: The external corrosion assessment of a typical offshore transportation system has been presented. Cathodic protection design was carried out for the pipeline and it was found that a bracelet square weld on anode of $L = 195\text{mm}$, $G = 101.6\text{ mm}$, Thickness = 70mm , $M = 149.75\text{ kg}$, $\Phi = 1.2235\text{mm}$, $N = 128$ and $s = 300\text{m}$ was found to be satisfactory in providing secondary/ backup protection for the 48 inches pipeline in the external environment provided. The external anticorrosion coating selected is the Three layer polyethylene (3LPE) coating based on the dimensions of the pipeline and the design temperature of 80°C . The 3LPE external corrosion coating will comprise of an inner layer fusion bond epoxy, a middle layer: adhesive and an outer layer: High density polyethylene (HDPE) base with additives.

I. INTRODUCTION

In the Oil and Gas industry, corrosion is one of the main issues that have to be considered from basic design phase until decommissioning of a system under service. Estimates of annual cost of corrosion in oil and gas pipelines have indicated tremendous economic loss and much can be done to reduce this (Fontana, 1986). Weakening of the pipeline by corrosion will reduce the resistance of the pipeline to external forces and will accentuate materials and fabrication weaknesses (Palmer and King, 2006). The battle against corrosion and its devastating effects is never ending in all engineering disciplines (Roberg, 2000).

The three main reasons for the importance of corrosion assessment are economics, safety, and conservation (the structure must be safe to prevent contamination of the environment and reduce wastage of resources). Examples of losses resulting from corrosion include shutdown, loss of product, loss of efficiency and contamination of product (Revie and Uhlig, 2008).

Corrosion can be described as the destructive attack of a metal by chemical or electrochemical reaction with its environment (Revie and Uhlig, 2008). The process by which metals convert to the lower-energy state is called corrosion. The following are the four requirements of an aqueous corrosion cell (Jp Kenny, 2008):

1. There must be an ionic path or an electrolyte (such as moisture containing internal fluids and the surrounding seabed soil containing sea water)
2. There must be a metallic path electrically connecting the anode and cathode where electron transfer can take place (Normally, this will be the pipeline itself)
3. There must be an anode which suffers corrosion or corrodes preferentially and is a site where oxidation reaction occurs and removal of electrons.
4. There must be a cathode.

Elimination of any of the four requirements for the corrosion cell stops the corrosion reaction. See Appendix A for the Corrosion reactions. Appendix B shows the Data for a certain field used for this work. There are various types of corrosion which could occur externally on the pipeline some of which have been presented in Appendix C.

1.1 Scope

The purpose of this work is to undertake the external corrosion assessment for the proposed pipeline so as to evaluate and nominate candidate materials on the basis of code compliance and materials performance within the expected operating environment and to satisfy the requirement of high standards for Material selection and corrosion control (to have a pipeline system that can provide a safe, robust, reliable, durable and cost-effective means of transporting crude oil). Selection of an appropriate coating material, design of cathodic protection and employment of the best method of application is covered.

1.2 External Corrosive Environments

Carbon steels immersed in seawater is affected by the pH as the cathodic reaction increases with decreasing pH (causing a corresponding increase in corrosion rate). Increasing salt concentration in seawater combined with dissolved oxygen increases the electrical conductivity of the electrolyte and will result in increasing corrosion rate. Several anions present in seawater such as chlorine have been found to result in high corrosion rates.

The highest corrosion rates occur at the splash zone as the metal is frequently covered with air saturated water (high amounts of dissolved oxygen). Corrosion at the tidal region is due to oxygen concentration cell between the highly aerated tidal zone and the submerged zone just below. Sites in the tidal zone where oxygen concentration is high acts as cathodes while the fully submerged zone just below is anodic. As the water deepens, the oxygen concentration diminishes and corrosion rate reduces (Heidersbach, 2011).

II. EXTERNAL CORROSION ASSESSMENT

Unprotected carbon steel is corroded in seawater and will therefore require external protection by both a protective coating and cathodic protection (CP). Oxygen corrosion, organic acid attack and microbiological corrosion can be prevented by the selection of an appropriate external anti-corrosion coating combined with a suitable CP system. The external corrosion coating providing primary protection while the CP system acting as back up. The purpose of using CP is to provide current to areas not protected by the coating (areas of bare metal) especially in the event of coating failure.

2.1 Mechanism for External Corrosion

Corrosion is as a result of two separate reaction processes on the metal surface which are the loss of metal and the production of electrons at the anodic areas and the consumption of these electrons at the cathodic areas. Hence, the overall rate of corrosion on the pipeline external surface depends on the anode cathode area ratio, the cathodic reactant concentration and the resistivity of the environment which determines the rate of ionic transfer. Typical cathode reaction in seawater is oxygen reduction due to pH of seawater which is highly alkaline (≥ 8.2). The iron hydroxide formed reacts with oxygen in sea water to form a range of iron oxides and hydroxides. The oxides usually found on pipelines are usually black magnetite (Fe_2O_3), white to green lepidiotite ($FeOH$), and mixtures of brown to red ferrous and ferric compounds.

Low temperature as well as high velocity of flow of seawater entails more oxygen can come in contact with the metal surface which can lead to a high rate of corrosion. Pipeline burial under seabed sediment could be a method to prevent corrosion since oxygen content would be low. However, the presence of highly organic sediments and sediments containing sulphate reducing bacteria can cause severe corrosion. Organic sediments contain organic acids usually of high concentrations that can dissociate near the pipe to form hydrogen ions that act like cathodic reactants. SRB metabolise organic acids and oxidize them to produce large amounts of sulphide. This is a form of Microbial Induced Corrosion mechanism and could lead to localized attack at sites of bacteria activity (Palmer and King, 2006). Protection against MIC can be included in the design for a system by the selection of materials which do not encourage microbial growth, use of cathodic protection, and/ or the use of protective coatings (Hiedersbach, 2011).

2.2 External Anti-corrosion Coating

The coating isolates the pipeline steel from the soil and seawater and presents a high resistance path between the anodic and cathodic areas. According to several authors (Palmer and King, 2006; Peabody and Bianchetti, 2001; DNV, 2010; Breastrup et al., 2005), the following properties are considered desirable for pipeline coatings:

(1) Resistance to seawater absorption (2) Resistance to chemicals in seawater (3) Resistance to cathodic disbondment (4) Adhesion to the pipe surface (5) Flexibility to accommodate strains imposed during laying, transportation or handling (6) Impact and abrasion resistance (7) Resistance to weathering (8) Compatibility with cathodic protection (9) Adequate temperature stability (10) Ease of application (11) Acceptable unit price (12) Resistance to biodegradation (13) Non toxicity, environmental neutrality, safety in application and handling. (14) Ease of patch repair at areas of damage (15) Ultraviolet (UV) stability for the period during storage. (16) Compatibility with CP and capability of reducing current demand for CP if applicable. (17) Compatibility with concrete coating (18) Availability.

Another factor which affects the selection is the seabed condition such as salinity, bacterial action and extent of pipeline burial below the seafloor. Coating materials which have the above mentioned characteristics are the 3 layer polyolefin's. The three-layer coatings consists of an epoxy primer, a co-polymer adhesive, and a top layer of polyethylene (PE), polyurethane (PU) or polypropylene (PP). The main difference between the three options is increasing temperature tolerance, which is matched by increasing price levels (Breastrup et al., 2005).

According to the same author, PE should not be used for service temperatures exceeding 85°C, whereas up to 100°C can be permitted for PU systems, and PP coatings perform satisfactorily between 75°C and 140°C.

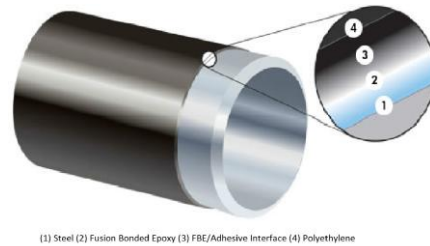


Figure 1: The Three Layer Polyethylene. Source: Bredero Shaw (2008)

The design temperature for this project is 80°C and the external anti-corrosion coating will be a three-layer polyethylene (3LPE) coating. The 3LPE will not only ensure a long term robust protection against corrosion but also a viable method of application. The coating principle is illustrated in figure 2.

The 3LPE external corrosion/ anti-corrosion coating will comprise of (Nesic et al., 2005; Bredero-Shaw 2008): (a) An inner layer: fusion bonded epoxy (FBE) (b) A middle layer: adhesive (c) An outer layer: high density polyethylene (HDPE) base with additives.

The following is the recommended procedure for applying the 3LPE for this project (Brestrup et al., 2005):

1. Fresh water washing with hot water or steam is used to remove all salts or other contaminants from the pipe surface after which the surface is dried and preheated. Tests for salt contamination may be carried out for sensitive coatings such as FBE, acceptable maximum levels being in the order of 20-40mg/m². Using steel grit, the external surface is blast cleaned to a uniform grey appearance (surface quality SA 2.5 according to ISO 8501 – 1). The blast cleaned surface is vacuumed to remove any dust and any steel surface defects are removed by light grinding. The pipe interior is emptied of abrasives or other foreign matter, in order not to contaminate the external coating, which should be applied within a specified time after blast cleaning. In order to ensure proper bond between the epoxy and steel surface, chemical pre-treatment is carried out using phosphoric acid or chromate wash of the substrate.
2. The pipe is electrostatically heated to approximately 220°C before entering the FBE coating booth. The epoxy powder is applied by airless guns, and electrostatically attracted to the pipe, where it sinters together on the hot surface. The epoxy primer thickness should be 250 micron in order to achieve a superior performance. When the epoxy is gelling, but has not completely cured, the polyethylene co-polymer adhesive is spray applied to a thickness of 140-200 micron.
3. The process of applying the polyethylene top coat as described by Lam et al. (2010) will be adopted which is described thus: Immediately after, the application of adhesive, polyethylene powder should be deposited by the use of vibration pans. A minimum of 2.2mm thick high density polyethylene (HDPE) will then be side rapped extruding it over the GSPO system to build up the thickness (For a pipeline of diameter of 48" the HDPE is recommended). Side extrusion application method is ideal for large diameter pipes (Lam et al., 2010). The GSPO system is used to achieve a high performance composite coating which represents the latest technology in anti-corrosion systems. The coated pipes will be quenched with water internally and the externally. This process is illustrated diagrammatically in figure 4. This method of application can provide exceptional uniform coverage of external welds, successfully eliminate weld tenting and significantly reduce stresses in the coatings.
4. In order to eliminate the possibility of loss of adhesion between the FBE and the pipeline surface, it is particularly important to take care of the following issues: (a) Abrasive blast profile (b) Partially applied abrasive blast cleaning (c) Surface contamination by dust and soluble salt (d) inadequate application of an inappropriate FBE type.

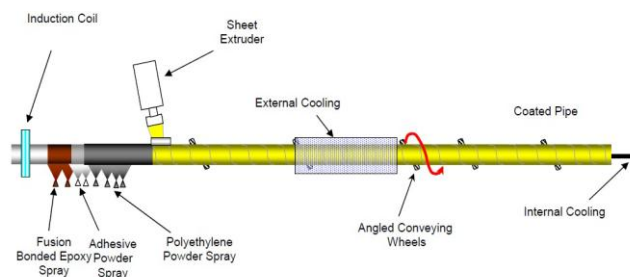


Figure 2: the new side-wrapped composite coating process. Source: Lam et al. (2010)

Table 1: Properties of the selected three layer polyethylene. Adapted from (Hall-Longmore, 2008; SICBV, 2003; BSENISO21809-1, 2011)

Property	Value
Density	950kg/m ³ (Hall-Longmore, 2008)
Thickness	4.2mm (SICBV, 2003; BSENISO21809-1, 2011)
Minimum Pipe Diameter	90mm (Hall-Longmore, 2008)
Maximum Pipe Diameter	1220mm
Minimum Pipe length	5.5m
Maximum Pipe length	24.4m
Maximum recommended operating temperature	85°C

As shown in Figure 2 the fusion between the layers is achieved such that there will be no distinct interface and a smooth transition from rigid FBE to much tougher PE is achieved. This is in order to eliminate inter layer adhesion failure, provide excellent uniform coverage of any raised weld and allow production of lower thickness coatings than is possible with conventional 3LPO coating process.

BS EN ISO 21809 – 1 (2011) specifies requirements of plant-applied external three-layer polyethylene- and polypropylene- based coatings for corrosion protection of welded steel pipes for pipeline transportation systems.

Table 1 herein shows the properties of the 3LPE selected. The coating thickness selected was as specified in table 2 of BS EN ISO 21809-1 (2011).

2.3 Field Joint Coating

Concrete coated pipelines will be transported to the lay vessel, where they will be welded together. Before the lay-down procedure takes place, a field joint coating will be applied externally around the welded pipe joints to fill in the remaining space between the concrete coating on each side of the field joint and to protect the joint against corrosion. In accordance with DNV-RP-F102, the field joint coating system will comprise a heat-shrink sleeve made of high-density polyethylene. Two-component polyurethane foam will be injected into the void between the heat-shrink sleeve and the aluminum sheet former through a port created on top of the former (PIH, 2000). The foam will rise and cure to fill the joint volume and is able to withstand impact from dropped objects. The heat-shrink sleeve will be approximately 2 mm thick and have a density of about 900kg/m³. The high density polyurethane foam (HDPUF) will have a moulded density of approximately 160kg/m³ and a saturated moulded density of approximately 1025kg/m³ when in place. The field joint coating will be flush with the concrete. The coating cutback length selected is 200mm in accordance with DNV.

Similar method of implementing the parent coating should be used for the field joint coating. This should include grit blasting to maintain similar appearance and pre-heating to the required temperature (usually 220°C) for curing of the epoxy powder. It is recommended that the use of external anti-bacterial coatings should be explored.

2.4 Riser Splash Zone

The splash zone of a riser is particularly susceptible to external corrosion during operation, especially if it operates at a temperature as in the case of this project, where corrosion rates and evaporation rates are increased. The external corrosion threat of the riser is elevated as a result of a number of reasons, including: (1) The inability for the CP system to provide any protection to sections of the riser that was not fully submerged in water. (2) The constant wetting and evaporation above the waterline, which concentrates chlorides on the riser surface. (3) Marine growth found at this location (including hard marine growth), which can damage and degrade coating systems. (4) The 'mixed environment' which the coating system must be able to withstand (wet, dry, ultraviolet exposure, marine growth damage). (5) The increased probability of coating damage in this location due to external impact (vessel impact / bumps, floating debris, etc).

Section 6-D204 of DNV OS-F101 (2010) recommends that an additional 3mm of external corrosion allowance is added to carbon steel risers of safety class Medium and High in the splash zone (in addition to the internal corrosion allowance). For risers carrying hot fluids (>10 degrees above ambient seawater), it states that a higher corrosion allowance should be considered, at least for the splash zone. The splash zone is particularly prone to corrosion, and this is because the CP system cannot always protect the metal (while the metal is not submerged), and the constant evaporation of water leads to very high chloride concentration levels.

According to section 4.3.4 of NORSOK M-001 (2004), at elevated temperature, the corrosion allowance is recommended to be increased by 1 mm per 10°C increase in operating temperature above 25°C. For this riser, an external corrosion allowance of at least 3 mm, and preferably 5 mm, in addition to the 3 mm internal corrosion allowance is recommended for the splash zone. Thus a corrosion allowance for the riser (in the splash zone, as a minimum) should ideally be 8 mm, but at least 6 mm in an addition to a suitable external anti-corrosion coating (such as neoprene, density = 1340kg/m³ (Bredero Shaw, 2008))(Jain, 2012).

2.5 Cathodic Protection

To ensure the integrity of the pipelines over their design operational life, secondary anti-corrosion protection will be provided by sacrificial anodes of a galvanic material. This secondary protection will be an independent system that will protect the pipelines in case of damage to the external anti-corrosion coating (Nord Stream, 2008). To protect pipelines using CP alone without the use of anti-corrosion coatings will be extremely expensive (Palmer and King, 2006). The most common method of cathodic protection used for offshore pipelines is the bracelet sacrificial anode type. Cathodic protection of pipelines using sacrificial anodes is based on the same principles as the galvanic cell such that current is applied to oppose the anodic reaction.

The areas of bare metal not covered by the coating or holidays as a result of coating failure are protected due to the electrons supplied by the sacrificial anode. However, the use of CP has some limitations such as coating disbondment and hydrogen related cracking (especially for high strength steel). DNV RP-F103 (2010) specifies a set of guidelines to prevent such problems from happening. The material to be used as sacrificial anode is the Aluminium Alloy (AlZnIn) due to higher activity (i.e. higher electropositivity) and resistance to reversal. The same code gives recommendations on anode manufacture and installation. The following are the reasons why sacrificial anodes are usually used: (1) A source of power is not required (2) Less interference (3) No risk of polarization involved except Zn at high temperature. While the disadvantages include: (1) Only effective in low resistivity environments (2) Low current output (3) Low spread (4) Difficult to control stray current in the protected structure.

According to DNV RP B401 (2010) and Gou et al. (2005), designs must satisfy two requirements: (a) The total net anode mass must be sufficient to meet the total current demand over the design life. (b) The final exposed anode surface area must be sufficient to meet current demand at the end of design life.

2.5.1 Cathodic Protection (CP) Design for the Pipeline

The type of anode that will be adopted for use in this project is the square ended type such that the two half shell are installed by welding (known as the Bracelet square weld-on (Gauss Anode, 2000)). The minimum thickness for the anodes is 40 mm and the maximum length is 1 m for practical purpose (Peabody and Bianchetti, 2001).

The design for the Cathodic protection is carried out as follows (DNV-RP-B401, 2010; DNV-RP-F103, 2010; Gou et al., 2005; Robinson, 2011):

MathCad was used to carry out this design and several iterations were made in order to select the most appropriate dimension for the anode (See appendix D). Since the seabed will be trenched the design considers pipeline burial. Calculating the coating breakdown factor for 3LPE with concrete coating according to DNV (using tables A1 and A2 in the code), we have,

$$a = \frac{0.1}{100} = 0.001$$

$$b = \frac{0.003}{100} = 0.00003$$

Where t_f is the anode design life = 35 years,

$$f_{cm} = a + 0.5bt_f = 1.525 \times 10^{-3}$$

$$f_{cf} = a + bt_f = 2.05 \times 10^{-3}$$

Calculating the coating breakdown factor for the Field Joint coating for 3LPE shrink sleeve with PU infill

$$a = \frac{1}{100} = 0.01$$

$$b = \frac{0.03}{100} = 0.0003$$

$$f_{cm} = a + 0.5bt_f = 0.01525$$

$$f_{cf} = a + bt_f = 0.0205$$

All parameters are same as defined in the code.

Length of pipeline = 38350m, the Area of pipeline,

$$A_c = \pi DL = \pi \times 1.2192 \times 38350 = 146889.3114m^2$$

Where i_{cm} is the design mean current density 25mA/m², f is the coating breakdown factor (f'_{cm} is the 'mean coating breakdown factor' calculated as a mean value for linepipe and field joint coating) and $r = 0.033$, is the ratio of the lengths of the cutbacks and the linepipe coating for this pipeline. Hence,

$$f'_{cm} = f_{cm}(\text{Linepipe}) + r.f_{cm}(\text{FJC}) = 1.525 \times 10^{-3} + 0.033 \times 0.01525 = 2.028 \times 10^{-3}$$

Mean current demand can be expressed as,

$$I_{cm} = i_{cm} A_c f'_{cm} = 0.025 \times 146889.3114 \times 2.028 \times 10^{-3} = 7.448A$$

Where t_f is the design life, u is the anode utilization factor, ϵ is the electrochemical capacity. The total net anode mass can be expressed as,

$$M = \frac{I_{cm} t_f 8760}{u \varepsilon} = \frac{7.448 \times 35 \times 8760}{0.8 \times 850} = 3358.17kg = 3.36tonnes$$

The internal diameter of anode = external diameter of pipe + corrosion coating thickness = 1.2193+0.0042 = 1.2235m.

$$L_{anode} = 195mm$$

$$t_{anode} = 70mm$$

The mass of anode,

$$M_{anode} = \rho_{anode} \pi L_{anode} [(r_{anode} + t_{anode})^2 - r_{anode}^2] = 2700 \times \pi \times 0.195 \times [0.6817^2 - 0.6117^2]$$

$$M_{anode} = 149.75kg = 0.149tonnes$$

Number of anodes,

$$N = \frac{M}{M_{anode}} = \frac{3.36}{0.149} = 22.43$$

f'_{cf} is the 'final coating breakdown factor' calculated as a mean value for linepipe and field joint coating.

$$f'_{cf} = f_{cf}(linepipe) + r.f_{cf}(FJC) = 2.05 \times 10^{-3} + 0.033 \times 0.0205 = 2.7265 \times 10^{-3}$$

Total final current demand is expressed as,

$$I_{cf} = i_{cm} A_c f'_{cf} = 0.025 \times 146889.3114 \times 2.7265 \times 10^{-3} = 10.01 A$$

Area of Anode surface exposed,

$$A = \pi(D_{anode} + 2t_{anode})L_{anode} = \pi \times (1.2235 + 2 \times 0.07) \times 0.195 = 0.835m^2$$

Using Mc Coy's formula,

$$R_{af} = \frac{0.315 \rho_{seabedsoil}}{\sqrt{A}} = 0.315 \times \frac{1.3}{\sqrt{0.835}} = 0.45ohm$$

Given that E_a^0 is the design closed circuit anode potential and E_c^0 is the design protective potential. The final anode current output is expressed as,

$$I_{af} = \frac{\Delta V}{R_{af}} = \frac{(E_c^0 - E_a^0)}{R_{af}} = \frac{-0.8 - (-1)}{0.45} = 0.45A$$

Required number of anodes,

$$N = \frac{I_{cf}}{I_{af}} = \frac{10.01}{0.45} = 22.43$$

Number of anodes,

$$N = 23$$



Figure 3: The bracelet square weld on anode. Source: GaUS anodes (2008).

Anode spacing for the pipeline,

$$S = \frac{Length}{N} = \frac{38350}{23} = 1667.39m$$

But this is more than the maximum spacing recommended by DNV RP F103 i.e.

$$1667.38m > 300m$$

In this case, according to section 5.6.1 (Guidance notes) of the same code, 'For medium and long distance export pipelines with concrete coating, the concept of using pre-installed anode and with a default maximum distance of 300m is adequate for most purposes. Except for very long design lives (> 30years), a typical bracelet anode size (i.e. convenient for casting) will then give an installed anode net mass that exceeds the calculated required net anode mass' (DNV-RP-F103, 2010).

According to the same code section 5.6.9, the maximum distance between bracelet anodes (L as defined in the code) is given as,

$$S = \frac{d(D - d)}{\rho_{ME} D f'_{cf} i_{cm}} \left\{ -\frac{2R_{af} I_{cf} (tot)}{L_{tot}} + \sqrt{\frac{4R_{af}^2 I_{cf}^2 (tot)}{L_{tot}^2} + \frac{2\rho_{ME} i_{cm} f'_{cf} D}{d(D - d)} (E_c^0 - E_a^0)} \right\} \tag{1.2}$$

Where ρ_{ME} is the electrical resistivity of the pipeline material = $0.2 \times 10^{-6} Ohm$, d is the pipeline thickness. The loss of an anode is taken into account therefore S is taken as the design spacing. For the section having a thickness of 25mm, the spacing of the anodes

$$S = 853.96m$$

Table 2: anode specification and design according to design

Property	Specification
Anode Type	Bracelet square weld on
Length (mm)	195.0
G (mm)	101.6
Thickness (mm)	70.0
Mass of anode (kg)	149.75
Total Weight of anode (tonnes)	3.36
Diameter (mm)	1,223.50
Number of anodes	128
Spacing of anodes (m)	300

Therefore, using DNV RP B401, 2010 and Gou et al., 2005, Spacing selected,

$$S = 300m$$

Number of anodes,

$$N = \frac{38350}{300} = 127.83 \approx 128 \text{ anodes}$$

The following requirements must be met by the cathodic system design (DNV RP B401, 2010; Gou et al., 2005),

$$N \times M_a \times \varepsilon \times u \geq 8760 \times I_{cm} \times t_d$$

And

$$N \times I_a \geq I_c$$

$$N \times M_a \times \varepsilon \times u = 128 \times 149.75 \times 850 \times 0.8 = 1.3 \times 10^7$$

$$8760 \times I_{cm} \times t_d = 2.28 \times 10^6$$

$$N \times I_{af} = 57.12$$

$$I_{cf} = 10.01$$

The condition is satisfied since,

$$N \times M_a \times \varepsilon \times u > 8760 \times I_{cm} \times t_d$$

$$N \times I_{af} > I_{cf}$$

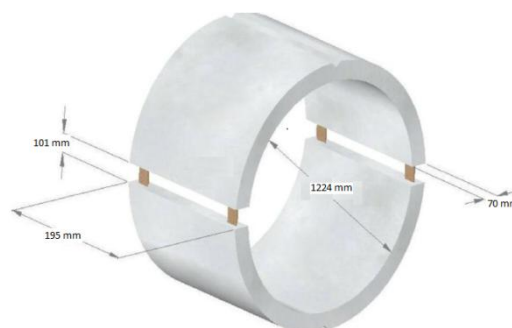


Figure 4: Dimension of anode selected

The dimension of anode selected based on design is as shown in Table 2 herein and Figure 4. It can be said that the current supplied by the anodes on the pipeline should be able to protect both the riser at VS1 and VS2.

An attempt to examine the protection of the rigid risers at VS1 and VS2 was made taking into consideration unburied condition and neoprene (Polychloroprene) of thickness 25mm (Bedero-shaw, 2008) used as anti-corrosion coating. The length of the riser at VS1 is 41m and that at VS2 is 30m as provided. Both risers are having the same outer diameters of 1.2292m.

According to section 5.6.3, DNV RP F103 (2010), The length of a pipeline L that can be protected by anodes located on a secondary structure assuming that the cathodic current is largely uniformly distributed on L can be expressed as,

$$L = \sqrt{\frac{2\Delta E_{Me} d(D-d)}{\rho_{Me} D f_{cf}' i_{cm}}}$$

$$\Delta E_{Me} = E_c^0 - E_c'$$

For neoprene anti-corrosion coating (Table A1 of the code),

$$f_{cf}' = f_{cf}(\text{linepipe}) + r f_{cf}(FJC) = 4.5 \times 10^{-3} + 0.033 \times 0.0205 = 5.177 \times 10^{-3}$$

E_c' is the global cathodic potential considering seawater = -0.95 V. Other parameters are as defined earlier.

$$\Delta E_{Me} = 0.15 \text{ V}$$

$$L = 1.842 \times 10^4 \text{ m}$$

Prior to installation, the performance and durability of different sacrificial alloys in the Sea environmental conditions may be evaluated with dedicated tests in order to assess the electrochemical effect of the salinity on the Al alloy. Where it is observed that seawater has significant effect, Zinc anodes may be designed for use in such cases.

2.5.2 Electrical Connection

The electrical contact between the sacrificial anode and the steel pipe is established via copper cable which is attached to the surface of the pipe by Thermit welding. The copper wire being an integral part of the anode and a small area of the 3LPE removed so that the contact area on pipeline can be exposed (DNV-RP-F103, 2010).

2.5.3 Finishing

This is carried out in such a way that the area between the concrete and sacrificial anode is filled with concrete. Also the same applies to the field joints so that consistency with the parent material is achieved. Prior to the filling of spaces the anti-corrosion coating also are replaced following specified guidelines (DNV-RP-F103, 2010).

In order to isolate CP systems from other CP systems (for example, impressed current system of land pipeline, CP for the platforms, etc.), the use of isolation flanges or monolithic joint should be employed.

2.6 Concrete Weight Coating

Concrete weight coating will be applied on the anti-corrosion coating in order to provide stability (or negative buoyancy) of the pipeline on the seabed during installation and when the pipeline is in operation. It also protects the pipeline against impact like from dropped objects and also rugged terrains. The ends of each pipe are left uncoated to allow ease of welding.

The typical density of these coatings range from 1800 – 3450 kg/m³ using quality heavy aggregates and other key raw material components (Bredero-Shaw, 2008). Thickness typically ranges from 25mm (1") to 230mm (9") with thicker coatings available depending on pipe size, wall thickness and negative buoyancy requirements.

A concrete cutback length of 300mm is usually sufficient. The application of the concrete weight coating is achieved either by the use of the impingement, extrusion or slip-form processes. Since this project involves a large diameter pipeline (48") the impingement method of manufacturing is the most appropriate and is recommended. The minimum thickness for the concrete coating applicable by impingement is about 40mm, and the minimum thickness applicable by the extrusion process is 35mm. The concrete comprises of a mix of cement, water and aggregate (inert solid material such as crushed rock, sand, gravel).

The HevicoteTM Figure 5 a product of Bredero Shaw is compatible with anti-corrosion and insulation coating systems.

Portland cement is usually used and is specified in accordance with ASTM C 150 Type II. The density of the concrete can be increased by the use of iron ore, blast furnace slag and barytes. It is important to select aggregates which are resistant to damage by sulphate attack due to the sulphates present in seawater. Concrete coatings are usually reinforced with steel wire cage pre-fabricated to meet specification requirements (Nord stream, 2008).

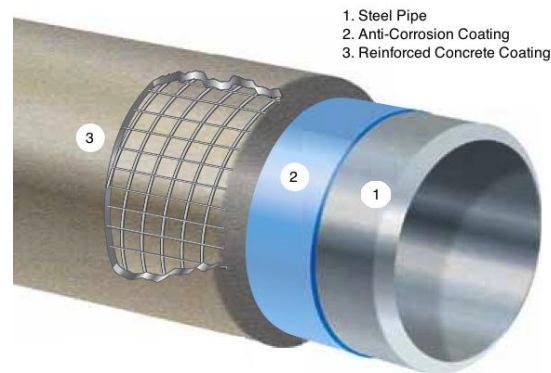


Figure 5: Hevicote™. Source: Bedero Shaw (2008)

2.7 Cathodic Disbondment

This occurs due to generation of hydrogen at the metal-coating interface where there is excessive protection current. Cathodic disbondment can lead to the destruction of adhesion between the coating and its substrate by products of a cathodic reaction and then resulting in premature failure of the coatings used. If the cathodic protection system is properly designed and operated, however, the evolution of hydrogen can be prevented (Davis, 2000; Roberge, 2000).

2.8 External Anti bacterial Coating against SRBs

According to Song et al. (2011), polyethylene heat shrinkable sleeves (HSS) used at field joints to protect girth welds usually disbands and if this happens the cathodic current will be unable to penetrate the pipeline surface due to impervious backing provided by coating as there is no contact of metal and the surrounding soil or seawater (the electrolyte which provides the ionic path has been eliminated). When this occurs coupled with the fact that welds are preferential sites for Microbial attack, SRB proliferates in the presence of high water content and organic matter resulting in severe corrosion occurring at girth welds. Reagents such as 5-chloro-2-(2,4-dichlorophenoxy) phenol (irgasan), 2-bromo-2-nitropropan-1,3-diol (BRONOPOL), etc. were used to test their efficacy in an attempt to provide antibacterial coating against SRB. Properties such as bond strength, peel strength, cathodic disbondment and lap shear strength were evaluated for adhesives used for polyethylene HSS integrated with each reagents at varying conditions. It was claimed that studies conducted have shown the possibility of developing antibacterial coating to the level of being a commercial product.

III. CONCLUSION

The external corrosion assessment of a typical offshore transportation system has been presented. Cathodic protection design was carried out for the pipeline and it was found that a bracelet square weld on anode of $L = 195\text{mm}$, $G = 101.6\text{mm}$, Thickness = 70mm , $M = 149.75\text{kg}$, $\phi = 1.2235\text{mm}$, $N = 128$ and $s = 300\text{m}$ was found to be satisfactory in providing secondary/ backup protection for the 48 inches pipeline in the external environment provided. The external anticorrosion coating selected is the Three layer polyethylene (3LPE) coating based on the dimensions of the pipeline and the design temperature of 80°C . The 3LPE external corrosion coating will comprise of an inner layer fusion bond epoxy, a middle layer: adhesive and an outer layer: High density polyethylene (HDPE) base with additives.

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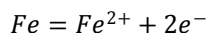
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APPENDIX A

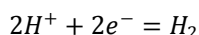
Corrosion Reactions

Reaction at the anode:

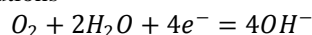


Reactions at the cathode are difficult to predict but can be categorized into one of the following reduction reactions:

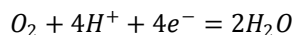
1. Hydrogen evolution



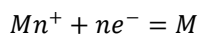
2. Oxygen reduction in neutral solutions



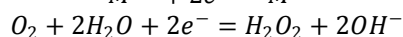
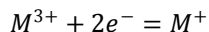
3. Oxygen reduction in acids



4. Metal deposition on cathode



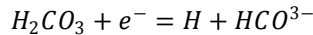
5. Metal ion reduction



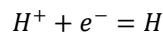
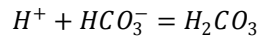
6. Sweet corrosion

Carbonic acid

Regeneration



Net reduction



APPENDIX B

Data:

Aim: To design a system of Pipelines that will convey hydrocarbons from a land based process facility to an offshore loading platform where it will be exported via bulk carriers.

Design life of pipelines: 30 years

Pipeline Material Data

Description	Units	Parameters
Linepipe Nominal Diameter	Inch (mm)	48 (1219)
Pipe Material	-	Carbon Steel
Linepipe Material Grade	-	L450
Manufacturing Method	-	SAW (Submerged Arc Welding)
Corrosion Allowance	mm	3

Corrosion Coating and Concrete Data

Anodes

Description	Units	Parameters	
Design Life	years	35	
Anode material	-	Aluminium Alloy (Al-Zn-In)	
Anode Density	Kg/m ³	2700	
Seabed Soil Resistivity	Ohm.m	1.3	
Utilization Factor	-	0.8	
Electrochemical Efficiency:	Unburied	A.h/kg	2000
	Buried	A.h/kg	850
Mean Current Density	mA/m ²	25	
Design Anode Closed Circuit Potential	Unburied	V	-1.05
	Buried	V	-1.00
Protective Potential	V	-0.8	

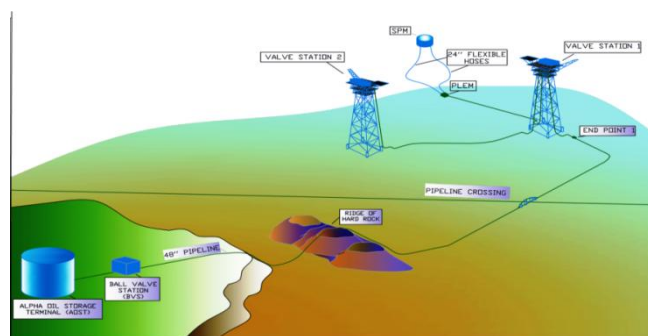


Figure B.1: Pipeline Field Layout. Source: Project Data

APPENDIX C

C.1. Corrosion Types

C.1.1 Uniform/ General Corrosion

Uniform attack can be described as metal loss which is fairly evenly distributed over the metal surface and consequently leading to a relatively uniform reduction in thickness. The product of the electrochemistry involved in general corrosion is the formation of hydrated ferric oxide (or rust). Homogeneous materials without any significant passivation tendency or immunity in a corrosive environment are liable to this form of corrosion (e.g. carbon steel). Uniform corrosion is assumed to be the most common form of corrosion and particularly responsible for most of the material loss (Bardal, 2004). As metal loss occurs only at the anode, a uniform corrosion rate over the surface results from the sites for anode and cathode reactions exchanging places at intervals thus at any given time multiple anodes and cathodes are operating on the metal surface.

C.1.2 Pitting Corrosion

Pitting corrosion is a form of localised corrosion of a metal surface where small areas corrode preferentially leading to the formation of deep holes in such a way that the bulk of the surface remains free from attack. The penetration rates of pitting corrosion are usually high since metal loss is concentrated at small anode sites and the cathodic reaction occurs over a large area of the metal surface. Pitting is the most insidious form of corrosion and it causes failure by perforation with only small percent of weight loss of the pipeline such that the detection of pits is usually difficult. The damage caused by pitting could entail that the whole structure be replaced as a remedy (Zaki, 2006; Revie and Uhlig, 2008; Fontana 1986).

Inclusions represented by manganese sulphide particles at the surface of carbon manganese steels (introducing inhomogeneity) can result in the initiation of pitting corrosion (David, 2000) Crevice corrosion and under-deposit corrosion usually results in pitting corrosion.

Loss of passivity on carbon steel surfaces may bring the potential to the transpassive range such that evolution of oxygen or the formation of hexavalent chromium ions leads to rapid dissolution (or metal loss). This results in pitting and perhaps stresses corrosion cracking in the presence of stress. Conditions within pits could become acidic as a result of hydrolysis of metal ions. Once the pit has been formed it is difficult for a wall of the pit to re-passivate thus the process is often described as being auto-catalytic. The presence of salt solution and differential aeration cell due to limited oxygen within the pit can contribute to further corrosion. According to Heidersbach, the Pitting Resistance Equivalent Number (PREN) can be expressed as:

$$PREN = W_{CR} + 3.3(W_{MO} + 0.5W_W) + 16W_N$$

Where: W_{CR} is the weight percent of the chromium in the alloy; W_{MO} is the weight percent of the molybdenum in the alloy; W_W is the weight percentage of the tungsten in the alloy; W_N is the weight percent of the nitrogen in the alloy.

A large value of PREN indicates that the material has greater resistance to pitting corrosion. Pitting is usually associated with stagnant conditions such as a liquid trapped in a low part of an inactive pipe system. Increasing velocity of fluid flow often decreases the tendency of pitting attack. If vibration is inherent in the structure such that relative motions exist between two substances in contact either one or both being metals could usually lead to a series of pits at the metal interface (Revie and Uhlig, 2008). This type of corrosion can be referred to as fretting corrosion and it is common at bolted joints (Zaki, 2006).

C.1.3 Galvanic corrosion

Galvanic corrosion occurs as a result of contact between two metals whereby one is more noble than the other and corrosion rate of the more electronegative is higher than that of (and can provide protection to) the more noble metal. There must be an electrolytic connection between the metals such that a closed circuit is established before the corrosion reaction can take place (Bardal, 2004).

It is apparent that the best way to control galvanic corrosion is to avoid the use of dissimilar alloy systems in the same electrolyte. When connections involving two incompatible metals are unavoidable, it is essential that the smallest metal must be cathodic to the surrounding metals. The use of a third metal active to both metals in the couple and sacrificial anodes such as Aluminium alloys (AlZnIn) can be a solution for any form galvanic couples or assemblies formed. In designing the components, replaceable parts should be used so that only the corroded parts could be replaced instead of the whole assembly (Zaki, 2006).

It is possible for galvanic corrosion to occur between or within the same metal provided variation in potential is inherent. Filler metals for welding should always be cathodic to the base metal being joined. Welding produces changes in metallurgical structure and improper welding procedures can lead to a galvanic cell such that the Heat Affected Zone (HAZ) becomes the anode and thus corrodes preferentially. (Heidersbach, 2011).

The use of electrical insulation in flanged connections involving two dissimilar metals can be employed in order to avoid galvanic corrosion. Ringworm corrosion is another type of galvanic corrosion which occurs when the metal in the HAZ near a welded tool joint corrodes. In order to deform a pipe it may be heated to a temperature of 750°C which leads to variation in micro-structure. Also the same occurs during welding as HAZ are created due to high temperatures involved in the process.

Luders bands also referred to as stretcher marks, Hartmann lines or Piobert lines are localized bands of plastic deformation that can occur on carbon steels and other materials in regions of localized plastic deformation. They form in carbon steel when the initial resistance to deformation has been exceeded and plastic deformation (or localized yielding) occurs. This localized deformation is usually at an angle approximately 45° to the primary stress axis and may form ripples known as Luders bands, when the deformation reaches the metal surface. This deformation indicates that parts of the metal have been stressed more than other parts which are at lower energy states and less susceptible to corrosion. If the difference in stress is not removed Luders Band corrosion is bound to occur.

Full length normalizing should be used to control luders band or ringworm corrosion. Also, it is important that large-diameter pipelines such as used this project (48") is handled and bent very carefully to avoid localized region of high stress and the formation of Luders bands.

Environmentally Induced Galvanic Corrosion can be caused by changes in the electrolyte. Typical examples include potential differences created due to colder oxygen depleted region at the seabed and warm oxygen rich area present at the surface. Galvanic difference can also be formed due to fresh low salinity water at the surface extending over several meters down before a denser saltwater becomes prevalent. Temperature and pH gradient can also cause variation in potential.

C.1.4 Crevice Corrosion

The mechanism of crevice corrosion is essentially the same with that of pitting since the chemical conditions which is formed in pits also occurs within crevices. Crevice corrosion is formed as a result of depletion of oxygen as well as high metal ion concentration in the crevice which polarises the cathodic reaction such that when passivity is lost the rest potential moves in the active direction. This type of attack is usually associated with small volumes of stagnant solution (Fontana, 1986).

Underdeposit corrosion can be said to be crevice corrosion by virtue of differential aeration cell mechanism. The differential aeration mechanism may lead to loss of passivity at sites where they exist which results in the formation of pits (or pitting corrosion).

The difference between the crevice and pitting corrosion is that the crevice which is the corrosion site is visible to the unaided eyes. Failures due to this form of corrosion are recorded mostly on bolted connections due to differential aeration cell created. Under deposit corrosion can be said to be crevice corrosion by virtue of the same differential aeration cell mechanism. The differential aeration mechanism may lead to loss of passivity at sites where they exist which results in the formation of pits (pitting corrosion).

The deposit can be caused by the presence of marine growth which is described as microbially influenced corrosion. Other areas where crevices are formed include partially lapped joints, holes, detached coatings, gaskets and flange gaps, and occur at similar rates to pitting (Palmer and King, 2006). All metals are susceptible to crevice corrosion provided the crevice width is sufficiently narrow (e.g. $1\mu\text{m}$ or less).

Possible ways in arresting this form of corrosion include the careful selection of material, avoidance of the use of bolt connections and use of suitable coating materials. Flange faces can be machined with grooves which reduce capillary attraction and act as 'crevice breakers'. Filiform corrosion also known as underfilm corrosion is a filamentary corrosion underneath protective coatings on metal surfaces and is special form of crevice corrosion. Filament corrosion do not weaken the metallic component and usually occurs due to humidity (Fontana, 2006). The filaments of corrosion products which are long and thin extend through defects in the protective coating and provide galvanic contact between the oxygen-deficient anode near the metal-coating interface and the relatively high-oxygen environment outside the coating. The corrosion usually starts at coating defects usually along edges, and proceeds underneath the coating. It may lead to further disbonding and further extensive corrosion of the metal substrate (Heidersbach, 2011).

C.1.5 Intergranular corrosion

This can be described as a form of localized attack on the grain boundaries of a metal or alloy in corrosive media, which results in the loss of strength and ductility and the localized attack could lead to dislodgment of the grain (Zaki, 2012). Many metal objects are more prone to corrosion on surfaces perpendicular to the rolling direction, where grain boundaries are closer (Heidersbach, 2011). Generally this type of corrosion is rare and is not a threat in carbon steels and should not be a concern. However, intergranular corrosion could be an issue in carbon steel pipelines if an inappropriate weld procedure has been used. Sulphide and nitrate attack can result in this form of damage, though only sulphide damage is relevant in pipelines (Palmer and King, 2008).

C.1.6 Erosion Corrosion

Erosion Corrosion occurs as a result of a combination of chemical environment/ electrolyte and high fluid surface velocities (Heidersbach, 2011) or relative motion between the electrolyte and the corroding surface (Fontana, 1986). Hence, there is an increase in the rate of attack on the metal surface. This results in wearing a way of protective scale or coating on the metal surface as dissolved ions, or it forms solid corrosion products that are mechanically swept from the metal surface. The main cause of this type of corrosion is associated with turbulent flow and this exists mostly around pipeline bends, elbows, valves and joints. Grooves, gullies, rounded edges, and waves on the metal surface which usually indicates directionality, characterizes this form of damage (Roberge, 2000).

Velocity of the seawater plays a major role in the erosion corrosion of the external surface of the pipeline. Velocity often strongly influences the mechanisms of the corrosion reactions especially in this project

which is for shallow water. In shallow water, the seabed is usually unstable and the wave or current velocity should be considered. In this project the use of external corrosion coating, concrete coating and burial will provide sufficient external protection against this form of corrosion.

Galvanic corrosion involving two metals can influence erosion corrosion rates when two dissimilar metals are in contact in a flowing system, this can be referred to as galvanic effect. The galvanic effect may be nil under static conditions but may be greatly increased when there is movement (Bardal, 2004).

The following are methods which can be used for mitigating the damage due to erosion corrosion (Bardal, 2004) (1) Material with better resistance to erosion corrosion (2) Coatings (3) Cathodic protection, etc.

There are various forms of corrosion involving the interaction between a corrosive environment and stress, some of which are: (1) Stress corrosion cracking (SCC) which includes: sulphide stress corrosion cracking and chloride stress corrosion cracking. (2) Corrosion fatigue (cyclic stress) (3) Stress oriented hydrogen induced cracking (SOHIC) (Roberge, 2000).

C.1.7 Stress Corrosion Cracking

Stress corrosion cracking (SCC) can be described as the brittle failure of an otherwise ductile material due to the simultaneous presence of tensile stresses and a specific corrosive medium on a susceptible material. The stresses involved in SCC can be from applied loads or from residual stresses caused by fabrication processes such as deformation and welding (David, 2000), and due to the corrosion product (Fontana, 1986). The overall macroscopic stresses associated with this cracking are generally below the yield stress of the material in question.

The failures are more often sudden and unpredictable which may occur after as little as a few months or years of previously satisfactory service (Zaki, 2006) depending on the metal environment combination and the stress condition (Bardal, 2004). Carbon steels are susceptible to stress corrosion cracking in sea water (Schweitzer, 2010). The stages of the SCC processes are: (1) Generation of the environment that causes SCC. (2) Initiation of SCC (3) Propagation of SCC until failure occurs (See figure C.1).

The following are the conditions necessary for Stress Corrosion Cracking to occur: (1) There must be a susceptible material (2) there must be an appropriate temperature and pH (3) The presence of tensile stress (4) suitable environment.

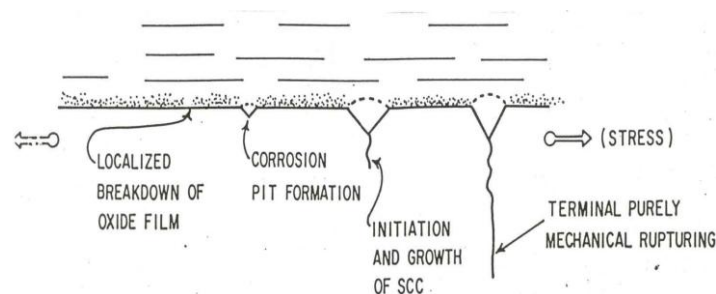


Figure C.1: Sequence of Events Leading to SCC. Robinson (2011)

Stress corrosion cracking is a term used to refer to most aqueous environmental cracking that is not clearly associated with hydrogen or H_2S . The most common attribute of environments that cause this form of corrosion for carbon steels is the presence of chlorides. Sites which may initiate SCC include pits, metallurgical defects, surface discontinuities, intergranular corrosion, and other sites which can cause stress concentration.

The susceptibility displayed by carbon steel due to the involvement of atomic hydrogen in the SCC mechanism(s) is an indication that corrosion control methods by cathodic protection should be used with caution. This is a reason why pipelines, in situations requiring corrosion control by a combination of protective coatings and cathodic protection, are seldom constructed with high-strength steel.

Most cathodic reduction reactions on carbon steel pipelines are due to oxygen reduction, especially beneath disbonded protective coatings, and is a potential site for SCC initiation (or initiation by formation of pits) (Heidersbach, 2011). Rupture due to SCC occurs either transgranularly or intergranularly or a combination of both.

The following are the various factors necessary for SCC (Zaki, 2006): (1) Notches, pits, irregularities, inclusions on the metal surface. (2) Hydrogen diffusion. (3) It requires a residual or applied tensile stress and the combined presence of water and H_2S (Heidersbach, 2011; Palmer and King 2006) (4) Environment: The H_2S concentration in partial pressure for a 552 MPa yield strength stress is 1.01kPa, and 0.01kPa for 896 MPa strength steel are critical values. (5) pH below 6.0 (6) Chloride has a significant effect on 12% Cr steels and little effect on low alloy steels. (7) Highest sensitivity is observed at 20°C. Metallurgical factors (1) Yield strength: Resistance to SCC decreases with increased strength. (2) Cold work: decreases the resistance to SCC.

(3) Hardness: Susceptibility to SCC increases with hardness. (4) Microstructure: It varies from one alloy system to another but it has a direct influence on SCC.

In order to mitigate the severity of SCC the following should be adopted: (1) the use of alloys less susceptible to SCC. (2) The use of steels with Rockwell hardness less than 22. (3) Avoidance of 20°C temperature (4) Minimize tensile stresses in the system.

SCC can be controlled by avoiding metal-environment combinations that cause such problem. Other methods of control include various methods of stress relief, for example post weld heat treatment, the use of protective coatings, corrosion inhibitors, and cathodic protection. Much of these controls are devoted to avoid the formation of stress raisers, small defects on the metal surfaces that serve as initiation sites for SCC which, once started, may be difficult to control.

C.1.8 Hydrogen Embrittlement

Hydrogen embrittlement can be described as a phenomenon whereby hydrogen is absorbed in the metal by diffusion, exerts local stresses, and leads to embrittlement of materials such as high strength steels (Heidersbach, 2011; Zaki, 2006). There are several situations which can cause HE some of which include poor manufacturing, poor fabrication processes, excessive overprotection currents from CP systems, sour environments, etc.

Improper welding procedures can also introduce monatomic hydrogen into metals. The exact mechanisms of HE in steels have not been completely understood.

Carbon steels are considered more susceptible to hydrogen embrittlement than austenitic alloys. HE can result in a reduction in the yield strength of carbon steels, cause severe embrittlement of the metal and then result in brittle fractures in the presence of stress. HE failures are associated with relatively low temperatures below 100°C. On the other hand, exposing carbon steels to high temperatures can have counteracting effects. The metal surface is being exposed to increased amount of hydrogen generated due to accelerated corrosion or other chemical reactions which enhances atomic diffusion as well as subsequent outgassing. Areas where HE is suspected can be treated using techniques which introduce compressive stresses on the surface (Zaki, 2006). The use of external corrosion coatings will be sufficient to provide protection to the pipeline to arrest external corrosion threats.

C.1.9 Corrosion Fatigue

Corrosion fatigue is a process in which a metal fractures by fatigue prematurely under conditions of simultaneous corrosion and repeated cyclic loading at lower stress levels than would be otherwise required in the absence of a corrosive environment (Zaki, 2006).

A component may be subjected to rapid cyclic stresses very quickly such that the effect of corrosion will be insignificant. Again, the environment may be highly corrosive such that the pipeline section corrodes to failure before the cyclic stress effect becomes significant. Wave loading on offshore structures have varying values of cyclic stresses as opposed to the simplistic assumption which suggests these values are the same on each repetition, thus inherent uncertainties like this increases the difficulty in modeling corrosion fatigue (Heidersbach, 2011).

Corrosion fatigue usually initiates from weak stress concentration sites such as corrosion pits, machined notches, Inclusions or second-phase particles, twin boundaries or surface scratches. Consequently, a combination of cyclic stress and localized fatigue leads to the development of occluded cell concentration variation compared with the environment and then the interaction between chemistry and mechanical loading becomes extremely complex. Fatigue failures occur when suspended pipelines encounter vortex shedding due to subsea or river currents. Usually, corrosion fatigue is rare in submarine pipelines but has been observed to occur on spanning pipe sections (Palmer and King, 2006). Material selection, cathodic protection, etc. are possible methods of preventing corrosion fatigue.

C.1.10 Stray Current Corrosion

Stray electric currents are those that follow paths other than the intended circuit, or they may be any extraneous currents in the earth. If currents of this kind enter a metal structure, they cause corrosion at areas where the currents leave to enter the soil or water (at the anode). Damage by direct current (DC) is usually more severe than alternating current (AC), with the resultant corrosion usually greater for lower frequency and less for higher frequency currents. Cathodic protection systems are common sources of DC stray currents and when located in the neighborhood of an unprotected pipeline, can produce significant damage (Revie and Uhlig, 2008). Galvanic anode systems do not cause interference-current problems on foreign neighboring structures. ISO 15589 – 2 (2010) gives general methods for resolving D.C. interference corrosion problems such as prevention of pick-up or limitation of flow of interfering current through a pipeline, counteraction of the interfering current effect by means of additional CP on the affected pipeline, etc.

C.1.10.1 The Design of crossings

A minimum vertical separation of 0.3 m should be kept between the pipeline and any other structures such as existing pipelines and submarine cables. Mats or equivalent means should be used for positive separation at crossing locations (Shell International Chemical, 2003).

APPENDIX D

View of MathCAD used for CP design calculations

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fcm := 0.0020282
fcf := 0.0027260
Do := 12190
Ip := 38350
icm := 0.025
tf := 35
w := 850
Δu := 0.3
Psb := 2700
fcmr := 0.0040
imode := 0.070
Psb := 1.3
Ec := 408
Ea := -1
Ac := π · Do · tf = 1.469 × 105
Icm := icm · Ac · fcm = 7.448
M := Icm · tf ·  $\frac{8760}{(w \cdot e)}$  = 3.358 × 103

rcm :=  $\frac{D_o + i_{cmr}}{2}$  = 0.612
Icf := icm · Ac · fcf = 10.012
Dcm := rcm · 2 = 1.223
X :=  $\frac{(E_c - E_a) \sqrt{\pi \cdot (D_{cm} + 2 \cdot i_{mode})}}{0.315 \cdot P_{sb}}$  = 1.001

d := 0.030
    
```

$$S_w := \frac{d \cdot (D_o - d)}{\rho_{me} \cdot D_o \cdot f_{cf} \cdot i_{cm}} \left[\frac{-2 \cdot R_{af} \cdot I_{cf}}{I_p} + \sqrt{\frac{4R_{af}^2 \cdot I_{cf}^2}{I_p^2} + \frac{2 \cdot \rho_{me} \cdot i_{cm} \cdot f_{cf} \cdot D_o \cdot (E_c - E_a)}{d \cdot (D_o - d)}} \right] = 854.103$$

$$N_2 := \frac{38350}{300} = 127.833$$

$$Y := \rho_{in} \cdot \pi \left[(r_{in} + t_{in,ode})^2 - r_{in}^2 \right] = 767.97$$

$$t_{in,ode} := \left(\frac{M \cdot X}{Y \cdot t_{cf}} \right)^2 = 0.195$$

$$t_{in} := 0.195$$

$$t_{cf} := \frac{E_c - E_s}{0.315 \rho_{sb}} \sqrt{\pi \cdot (D_{in} + 2 \cdot t_{in,ode}) \cdot t_{in,ode}} = 0.446$$

$$\frac{t_{cf}}{t_{in}} = 22.438$$

$$M_{in} := \rho_{in} \cdot \pi \cdot t_{in} \left[(r_{in} + t_{in,ode})^2 - r_{in}^2 \right] = 149.754$$

$$A_{in} := \pi \cdot (D_{in} + 2 \cdot t_{in,ode}) \cdot t_{in} = 0.835$$

$$R_{cf} := \frac{0.315 \rho_{sb}}{\sqrt{A_{in}}} = 0.448$$

$$\frac{M}{M_{in}} = 22.425$$

$$N_{in} := \frac{M}{M_{in}} = 22.425$$

$$N_1 := 128$$

$$N_1 \cdot M_{in} \cdot u \cdot e = 1.303 \times 10^7$$

$$t_{cm} \cdot t_r \cdot 8760 = 2.284 \times 10^6$$

$$N_1 \cdot t_{cf} = 57.118$$

$$t_{cf} = 10.012$$

$$\rho_{me} := 0.310 \times 10^{-6}$$