Onshore Engineering Nigeria
(Materials and Corrosion
Engineering Discipline)

Corrosion Assessment and Management Strategy for Obigbo Water Injection Plant

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May, 2017

SPDC-2017-05-00000005

Document Revision: A01

ECCN: Not Applicable EAR99

Revision History

REVISION STATUS			SIGNATORIES		
Rev.	Date	Description	Originator	Reviewer	Approver
R01	17/05/2017		Oladipo Alonge	Ojemeni Kenechi	Ezeifedi Humphrey

- Preliminary issue will be issued as P01
- Revisions for review will be issued as R01, with subsequent come as R02 etc.
- Revisions approved for Implementation/Design Issue/Eng. will be issued as A01, with subsequent come as A02 etc.
- Revisions approved for Tender will be issued as T01, with subsequent come as T02 etc.
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Signatures for this revision

Role	Name	Signature	Date
Originator	Oladipo Alonge	Oladipo Alonge Digitally signed by Oladipo Alonge Date: 2017.05.17 15:37:12 +01'00'	
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Approver	Humphrey Ezeifedi	Humphrey.Ezeifedi Digitally signed by Humphrey.Ezeifedi Date: 2017.05.17 16:02:22 +01'00'	

More field(s) could be added for signature if additional agreement/approval is required.

EXECUTIVE SUMMARY

This report presents the results of external and internal corrosion assessment (using the HYDROCOR corrosion prediction tool) for the static equipment—vessels and piping—at Obigbo Water Injection Plant. It also recommends an optimized corrosion control strategy based on the corrosion assessment results, water chemistry provided and operations/inspection history.

Atmospheric corrosion was identified as the only external corrosion risk. Its **mitigation can be achieved through painting and subsequent maintenance for long term protection** of all carbon steel equipment.

The internal corrosion assessment results indicate that the control of oxygen and microbial induced corrosion is necessary. With a good corrosion control program, corrosion rates can be adequately managed.

An effective corrosion management for Obigbo WIP will be achieved on implementing the following:

- Commence **chemical treatment by the injection of oxygen scavenger** and **biocide** when the plant is in injection mode. The plant operating manual should therefore be revised to include only chemical treatment by injection of oxygen scavenger and biocide.

- The corrosion monitoring program for the plant should include water sampling and analysis. It is recommended that a **Maintenance Plan is created for the water sampling and analysis program.**

- A Risk Based Inspection workshop for the Obigbo WIP held in 2016 and the optimized inspection plan was determined. It is **recommended that the asset implements all recommendations from the optimized inspection program**. 8 No. Dead legs and 18 Normally No Flow (NNF) lines were identified during the RBI workshop. These are risk areas for microbial induced corrosion; therefore, **they must be regularly flushed where practicable by the Operations team.**

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1. INTRODUCTION

The Obigbo North Water Injection Plant was commissioned in 1978, preceded by a pilot plant in 1974 and consists of one horizontal low pressure separator, a vertical surge vessel and designed to inject 15,000 bbl/day of water into the Obigbo North D1.3A reservoir to maintain the reservoir pressure at 2000 – 2100 psig and safeguard the ultimate recovery of 17MMstb.

Gas from Obigbo North AGG Plant or inter-field manifold is used to lift water from 21T & 41T (source water wells) to the WIP's LP Separator (30 psig) via the inlet header. The source water is from B1A sand, which is compatible with the D1.3A. In the low pressure separator, gas is separated from the water/gas mixture and flows to the flow station flare system. Water with a small amount of gas flows to the surge vessel where further stabilization takes place. The water from the surge vessel is pumped using the reciprocating pump(s) National- J275 to a pressure of anywhere between 2 bar to 60 bar and routed to water injection wells 22T, 30T and 31T.

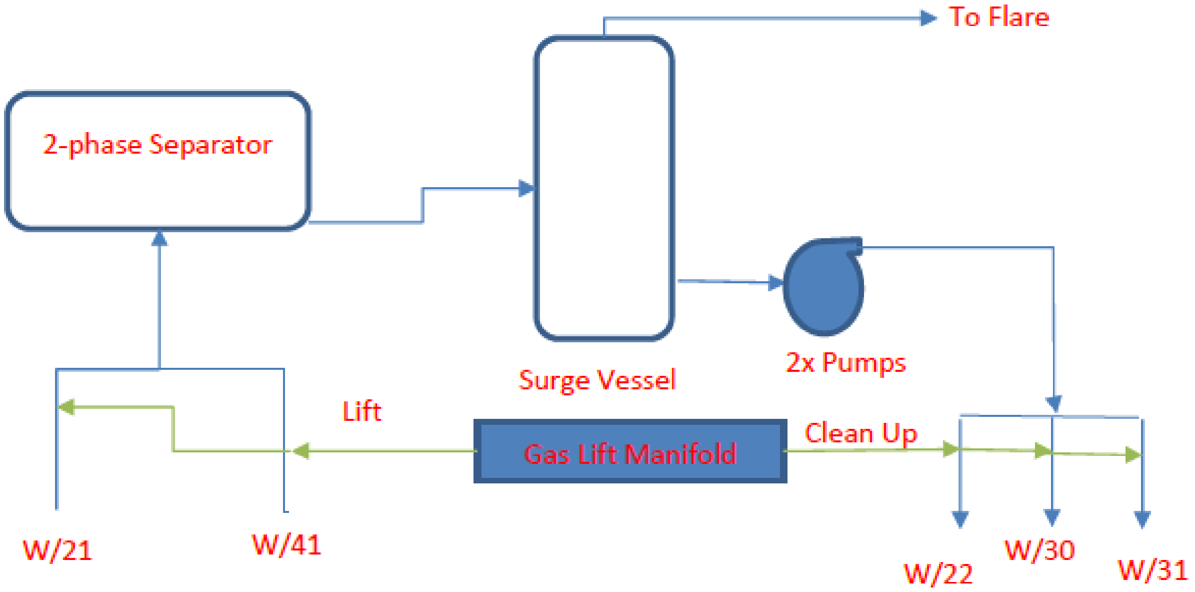

Figure 1: Overview of the Obigbo Water Injection Plant

The plant has been shut down since 2012 and in flush mode to improve the quality of water that will be filtered through the Cuno filters. During flushing, the bypass isolation valves on the Cuno filters are opened while the inlet and outlet isolation valves on both filters are closed. The isolation valve on the flush line to the open drain pit is opened while the main isolation valve to the wellhead after the flush line is closed.

A survey was conducted in February 2016 and results indicated that reservoir pressure had declined to 1929 psia (39% decline from initial reservoir pressure). According to Section 9, Subsection 42 of the Petroleum (Drilling and Production) Regulations, prior to or upon the attainment of a 10% decline in the initial reservoir pressure of a pool or reservoir, a study should be done to determine the economic practicability of instituting a secondary recovery or pressure maintenance project.

The Obigbo WIP restoration project provides an opportunity to recommence/optimize water injection into the D1.3A reservoir in order to maintain its pressure and increase ultimate recovery.

There are corrosion risks associated with operating the facility and these risks should be reduced to ALARP. Past water chemistry indicated high levels of dissolved oxygen, CO_2 and bacteria. The WIP

Operating Manual issued in 2010 recommends chemical treatment with corrosion inhibitor and biocide while the plant is in injection mode. The WIP restoration scope includes the optimization of the corrosion control program based on the credible corrosion risks in the facility.

1.1. Scope

This report presents the results of internal corrosion assessment using the HYDROCOR corrosion prediction tool for Obigbo Water Injection Plant. It also recommends an optimized corrosion control strategy based on the corrosion assessment results.

1.2. Abbreviations

The following abbreviations may be used in the text of this document.

CO_2	Carbon dioxide
CML	Corrosion Monitoring Locations
CRA	Corrosion Resistant Alloy
CS	Carbon Steel
MIC	Microbial Induced Corrosion
RBI	Risk Based Inspection
SRB	Suplhate Reducing Bacteria
NWT	Nominal Wall Thickness
WTM	Wall Thickness Measurement

2. OVERVIEW OF CORROSION THREATS

2.1. CO_2 Corrosion

CO_2 corrosion is one of the most frequently encountered corrosion mode in oil and gas production.

For the WIP, the CO_2 present in the gas used to lift water from source wells 21T and 41T will dissolve in the aqueous phase to form carbonic acid. The February 2017 Obigbo AGG plant fuel gas composition analysis showed the CO_2 content as 0.76 Mol%. Also, the April 2017 water sampling and analysis results showed dissolved CO_2 concentration as 40 – 45ppm.

The CO_2 corrosion rate depends on many factors; the most important ones are the partial pressure of CO_2 in the gas phase, temperature, pH, flow regime and velocities etc.

Within Shell, CO_2 corrosion rates are modelled with the Hydrocor corrosion prediction tool. Mitigation of CO_2 corrosion is often by injection of a chemical corrosion inhibitor. Other options are process control and the use of corrosion resistant materials.

2.2. Oxygen Corrosion

The presence of oxygen as an impurity in the process stream will significantly increase the risk of corrosion. Although oxygen is not normally present in hydrocarbon fluids from the reservoir at detectable levels and certainly no more than 10 ppb in the water phase, oxygen may enter the process through seals, poor blanketing, re-injection of fluids, flush periods as in the case of Obigbo WIP, etc.

Shell practice has identified 10 ppb of dissolved oxygen in water as a limit to avoid oxygen corrosion in carbon steel. The April 2017 water sampling and analysis results showed high levels of dissolved O_2 concentration ranging from 1000 – 7000 ppb. This can be attributed to the fact that water sampling and analysis were conducted while the plant was in flush mode. There is a possibility that the concentration of dissolved oxygen would be lower if analysis was done with the plant in injection mode.

The presence of oxygen in CS and low alloy steel systems leads to pitting. Oxygen corrosion can be prevented by avoiding ingress of oxygen into the system. Injection of an oxygen scavenger can be applied as a mitigation measure.

2.3. Atmospheric Corrosion

Atmospheric corrosion is primarily external corrosion or 'weathering' of metal exposed to air under the prevailing environment conditions. There is no clear relationship between ambient temperature and atmospheric corrosion. However, frequent fluctuations in temperature with the resulting variations in humidity and occurrence of condensation can be of greater significance than average ambient temperature. Also, the presence of moisture is a dominant factor in atmospheric corrosion.

Proper surface preparation and coating/painting application and subsequent maintenance are critical for long-term protection of carbon steel.

2.4. Microbial Induced Corrosion

Sulfate Reducing Bacteria (SRB) and many other bacteria present in an aqueous environment can find an abundance of suitable niches in and around gas equipment. Bacteria can become concentrated in sessile bio films attached to process vessels and piping which contain hydrocarbon/water in stagnant or low flow environments. They may also exist as planktonic populations in large volumes of stagnant water. Bacteria can survive at temperatures ranging from -13^{0}C to 150^{0}C.

There are several problems associated with the growth of sessile or planktonic populations of bacterial. Sulfate reducing bacteria can result in the production of H_2S in systems that were not designed for H_2S service. This can lead to material issues such as Sulphide Stress Cracking (SSC) and H_2S corrosion. Safety issues can also arise as H_2S is a toxic gas. If bacterial growth is left unchecked, it can also lead to fouling (Biofouling) of separators and other equipment.

During periods of low flow such as start-up, shut down or turn down, it is possible for deposits to settle out onto the bottom of piping and equipment and cause under deposit corrosion of carbon steels particularly in oxygenated condition. Dead legs, drain lines and other stagnant areas must be identified as they are at risk of microbial induced corrosion.

The most effective control is keeping the process system clean. The use of biocide and its monitoring to determine the required frequency is also very effective.

3. INTERNAL CORROSION ASSESSMENT

An internal corrosion assessment was conducted using HYDROCOR 2013. HYDROCOR is an engineering tool developed for quantifying the corrosivity of the operating conditions associated with the transport of hydrocarbon fluid. The application of HYDROCOR was done in compliance with DEP 39.01.10.11-Gen and DEP 39.01.10.12-Gen.

The bulk water chemistry is an important HYDROCOR input parameter; hence, water sampling and analysis were conducted in March and April 2017 by the Production Chemistry team and the results are summarized Table 1 below.

Table 1: Water Chemistry

Parameter	Source Well 21T	LP Discharge	Pump Discharge	D/S Cuno Filter (A)	D/S Cuno Filter (B)	D/S Cuno Filter (B)
Chloride ion, Cl^- (mg/l)	1.89	1.46				
Bicarbonate, $HCO3^-$ (mg/l)	34.2	29.3				
Total Iron (mg/l)	6.34	5.84	6.69	6.65	6.10	
pH	6.19	6.38	6.28	6.01	6.18	
Total Sus. Solids (mg/l)	0.051	0.028	0.050	0.001	0.01	
Dissolved O_2 (ppb)	2000	7000	2000	1000	1000	
Dissolved H_2S (ppm)	0	0	0.1	0.3	0.25	
Dissolved CO2 (ppm)	40	40	45	45	45	

As seen in Table 1, the high levels of dissolved O_2 concentration may be attributed to the fact that water sampling was conducted while the plant was in flush mode, which allowed the ingress of oxygen into the system. There is a possibility that the concentration of dissolved oxygen would be lower if sampling and analysis were done with the plant in injection mode. The dissolved oxygen concentration should be measured when the plant is in injection mode and the risk of oxygen should be reassessed.

The trace amounts of H_2S in the system could be due to presence of Sulphate Reducing Bacteria (SRB). The SRB count isn't available as at the time of issuing this report. The Production Chemistry team stated that it will be available on the 19th of May, 2017. The risk of Microbial Induced Corrosion should be reassessed as soon as the SRB count is known.

The input process parameters for the HYDROCOR modelling were obtained from the heat and mass balance data (Appendix A)—generated using UniSim based on the plant's current operating conditions—issued by the Operations Support and WRFM team. These are summarized in Table 2 below.

Table 2: Input Process Data

Streams	Pressure (psia)	Temp (°F)	Gas Flow Rate (mmscfd)	CO_2 mole%	Water Flow Rate (b/d)
Combined water with lift gas	130.5	85.99	0.15	0.0022	7000
Combined stream to LP Sep.	40.61	86.19	0.15	0.0022	7000
Water from LP Sep.	40.61	86.19	0.00169	0.0006	7000
Gas to flare/blanket gas to Surge Vessel	40.61	86.19	0.15	0.536	0
Water to Surge Vessel	17.40	86.25	0.00169	0.0006	7000
Water from Surge Vessel	17.40	86.25	0	0.0006	7000
Blanket gas for Surge Vessel	17.4	86.25	0.00169	1.19	0
Water to Pump 1 suction	17.40	86.25	0	0.0006	3500
Water to Pump 2 suction	17.40	86.25	0	0.0006	3500
Water from Pump 1 discharge	365.5	86.64	0	0.0006	3500
Water from Pump 2 discharge	365.5	86.64	0	0.0006	3500
Combined water from Pumps	365.5	86.64	0	0.0006	7000
Combined water to injection	351	86.68	0	0.0006	7000
Water to injection each injection Well 22T, 30T & 31T	351	86.68	0	0.0006	2310

3.1. Corrosion Modelling Results

As stated in Section 2, the dominant internal corrosion mechanisms are CO_2 corrosion, O_2 corrosion and MIC. Using the process conditions and the water chemistry provided, the Hydrocor tool was used to assess the maximum unmitigated corrosion rates for two cases; namely, Case 1: Internal CO_2 corrosion only and Case 2: Internal corrosion with CO_2, O_2 and SRB present. A summary of the corrosion rates are presented in Table 3 below.

Table 3: Unmitigated CO_2 Corrosion Rates

Streams	Case 1: CO_2 Corrosion Rates (mm/yr)	Case 2: Corrosion Rates with O2 and SRB Present (mm/yr)
Combined water with lift gas	0.01	0.50
Combined stream to LP Sep.	0	0.56
Water from LP Sep.	0	1.03
Gas to flare/blanket gas to Surge Vessel	0.05	1.06
Water to Surge Vessel	0	1.04
Water from Surge Vessel	0	1.03
Blanket gas for Surge Vessel	0.02	0.75
Water to Pump 1 suction	0.01	0.48
Water to Pump 2 suction	0.01	0.48
Water from Pump 1 discharge	0.01	0.47

Water from Pump 2 discharge	0.01	0.47
Combined water from Pumps	0.01	0.47
Combined water to injection	0.01	0.47
Water to injection each injection Well 22T, 30T & 31T	0.01	0.47

Case 1 represents a scenario in which O_2 and SRB control through chemical treatment is done and oxygen corrosion and Microbial Induced Corrosion are eliminated. Internal corrosion in this case would be due to CO_2 corrosion only. As seen in Table 3, the unmitigated CO_2 corrosion rates (0 – 0.01mm/yr) for the plant are negligible. This can be attributed to the low operating temperature, low partial pressure of CO_2 and the presence of bicarbonate.

Also. Case 2 represents a scenario where O_2 and SRB control isn't done and the risks of oxygen corrosion and Microbial Induced Corrosion still exist. The unmitigated corrosion rates were predicted to be significant; ranging from 0.47 – 1.06 mm/yr. As hitherto stated, the dissolved oxygen concentrations should be obtained when the plant is in injection mode and a reassessment for this case should be done.

4. CORROSION CONTROL STRATEGY

External corrosion mitigation can be achieved through painting application and subsequent maintenance for long term protection of the carbon steel equipment.

The internal corrosion assessment results (Table 3) indicate that oxygen and microbial induced corrosion control is necessary. With a good corrosion control program, corrosion rates can be adequately managed as seen for Case1.

The most effective **oxygen corrosion mitigation measure** will be to maintain a system which excludes oxygen and this will require operational discipline/program that will be included in the plant operating manual. The avoidance of oxygen ingress might be impossible because flushing is required to improve the quality of water to be injected into the formation. Oxygen contamination will occur when the plant is in flush mode. This is the most likely cause of the high oxygen levels (2000ppb – 7000ppb) reported in the water analysis result. The Production Chemistry team should obtain water chemistry when the plant is in injection mode and oxygen corrosion should be reassessed.

Sulphate Reducing Bacteria (SRB) control can be achieved by keeping the system clean through treatment with biocide. Although the bacteria count isn't available as at the time of issuing this report, biociding can commence until MIC risk is reassessed using the bacteria count results.

It is **recommended that chemical treatment by the injection of oxygen scavenger** and **biocide** is done when the plant is in injection mode. **The production Chemistry team should provide documentation**—to be included in the plant's operating manual—that clearly describes the process to be followed, the concentration oxygen scavenger and biocide to be injected, the required availability of the injection system and Key Performance Indicators.

4.1. Inspection and Corrosion Monitoring

The corrosion monitoring program for the plant should include water sampling and analysis. This will help to determine the effectiveness of the chemical treatment program and also optimize the injection rates/chemical concentrations. It is recommended that a Maintenance Plan is created for the water sampling and analysis program.

A Risk Based Inspection workshop for the Obigbo WIP held in 2016 and the optimized inspection frequency for static pressure equipment in the plant is 3 Yearly. During the inspection, Ultrasonic Wall Thickness Measurement is conducted, thorough vessel inspection and external visual inspection. It is recommended that the asset implements all recommendations from the optimized inspection program.

8 No. Dead legs and 18 Normally No Flow (NNF) lines were identified during the RBI workshop. These are risk areas for microbial induced corrosion; therefore, they must be regularly flushed where practicable by the Operations team.

REFERENCES

1) Selection of Materials for Life Cycle Performance – Materials Selection and Corrosion Management, DEP 39.01.10.11 –Gen
2) EPE Library of Corrosion Degradation Mechanisms, EP200703200907.
3) Obigbo North Water Injection Plant Operating Manual

Appendix A. Heat and Mass Balance Data

Appendix B. Obigbo Water Chemistry