A Note on Pipeline Corrosion in the Nigerian Oil and Gas Industry

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ABSTRACT

Issues relating to pipeline corrosion and control with particular regard to Nigerian oil and gas industry are discussed. Particular interest is on the effect of carbon dioxide (CO_2) corrosion on pipeline degradation, failures and eventual product losses. Regulatory departments' inadequate corrosion condition monitoring planning program is identified as the major cause.

Keywords – Carbon dioxide corrosion, corrosion, corrosion monitoring, pipeline corrosion, planning for corrosion, temperature effects on corrosion, predicting CO2 corrosion rates.

1.0 INTRODUCTION

The demand of the central government annual developmental income is dependent on the oil and gas industry in Nigeria. This places enormous pressure on the production companies (mostly foreign players) to strive for maximising saleable output, if they are to also make a profit return to their home headquarters. Thus, emphasis is placed on production, thereby stretching installed equipment to limits. With time, these show degrading tendencies, from the chemical contact with the metals and erosive wear due to the flow. Problems of pipeline corrosion in Nigeria are traceable in most cases to neglect in terms of poor quality maintenance, and less to the often mouthed community vandalism [1]. The environmental impact of such neglect is a concern to the government. Engineers and scientists now place emphasis on different methods to control or eliminate corrosion problems on installed oil and gas pipelines.

2.0 CORROSION MECHANISMS

Being low in sulphur content, Hydrogen Sulphide is not a major concern in Nigeria's sweet oil. Carbon dioxide (CO_2) corrosion is the primary concern. The presence of carbon dioxide (CO_2), free water can cause severe corrosion problems in oil and gas pipelines. Internal corrosion in wells and pipelines is influenced by temperature, pressure, CO_2 content, water presence and ionic composition, flow velocity, scaling due to oil or water wetting and surface condition of the steel. Any change in one of these parameters can affect the corrosion rate.

Analysis of the effect of CO_2 corrosion on the pipelines should thus be a major concern at the design and post design, i.e., operational stage. The selection of materials for such installed projects is based on this. In this regard, stainless or corrosion resistance alloys may be the choice but limited by cost constraints. Costs considerations may lead to pruning down to other acceptable material types with built-in safety net with regards to having plans for maintenance (repair or replacement).

Maintenance preventative measures such as corrosion monitoring and inspection for possibility of failures caused by surface erosion and wear, leakages while in operation, are then used to address the risk element associated with such alternatives. Possibility of failures will imply that if corrosion monitoring plans and programs are well run, such protective measures that will address age related failures such as repainting for example can be instituted in place.

3.0 PREDICTING CO_2 EFFECTS ON PIPELINE CORROSION RATES

Carbon dioxide acts as a dominant corrosive agent in response to temperature and pressure. Models for the effects of CO_2 corrosion have been developed. The models allow for predicting the penetration rates due to surface wear. While some models are based on correlations that take into consideration, the operations effects due to the pressure and temperature, the flowing pipe fluids are subjected to, others have included the chemical nature of the fluids in terms of its pH value. Other models have looked at the scaling effects of fluid wetting and the resultant protective films. The choice of model can have a significant effect on the monitoring plans, programs and maintenance cost. [2]-[6]

To illustrate simple calculation methods to predict corrosion rates due to CO_2 corrosion, the metric equivalent of the de Waard relation given in Lyons [7] is selected, since, it suits the little or no sulphur internal pipeline corrosion mechanism in Nigeria. The data used were taken from one of Nigeria's oil production fields.

$$LogR = 8.78 - \frac{2320}{(T+273)} - \left(\frac{5.55T}{1000}\right)(0.67)Log\left(\frac{P_{CO_2}}{6895}\right) \quad (1)$$

Where,

R =corrosion rate (mm/year)
T= Operating Temperature (^{o}C)
P_{CO2} = carbon dioxide partial pressure (Pa)

Case 1: corrosion rate calculation for T=25 degC

Inputs	**T =**	25	degC
	System Pressure =	1.516 x 10^6	Pa
	Percent CO2=	1.60%	
Outputs	Partial Pressure=	24256	Pa
	Corrosion Rate=	**0.94**	**mm/year**

Case 2: corrosion rate calculation for T=50 degC

Inputs	**T =**	50	degC
	System Pressure =	2.096 x 10^6	Pa
	Percent CO2=	1.60%	
Outputs	Partial Pressure Pco2 =	33537	Pa
	Corrosion Rate=	**1.46**	**mm/year**

Added to this analysis, erosion can also be considered due to the flow velocity.

4.0 CLOSING

Corrosion rates are thus influenced by temperature rises. Localised corrosion due to scaling effects, and eventual film formation, results from these temperature rises due to the solubility of ions. Also of importance is pipe roughness. Films may not always give sufficient protection, thus resulting in corrosion attack.

Part of the monitoring programs should include in addition to site inspection, on-line monitoring capabilities.

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