Corrosion Prediction Model in Oil and Gas Industry

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Abstract: Corrosion is one of the major challenges in oil and gas industry. There are many techniques used such as the use of alternative materials, modification of microstructures, addition of new elements to existing alloys of metals, use of chemical inhibitors, and linings. But the act of corrosion has not been prevented from occurring. The growth in the demand of oil and gas around the world has increased the need of exploration in unfriendly terrains like deep waters and the Antarctica. The pipeline plays a major role in the transportation of oil and gas from the production section to refinery section. The overutilization of pipelines leads to reduction in life cycles and failures. To reduce the problem of corrosion and enhance tubing, wellhead and pipeline integrity, corrosion experts have worked on different corrosion prediction models in a bid to identify the best way to determine corrosion. The most important parameters that can enhance the result of corrosion prediction are those related to the steel properties, water chemistry, flow pattern, oil-versus-water wetting, and operating conditions.

Keywords: Corrosion, Inhibitors, Liners, Pipelines and Prediction Model

I INTRODUCTION

Corrosion of materials is a major challenge to maintaining the integrity of equipment in the industry. Mobile and static mechanical equipment like pipelines, vessels, tanks, compressors, turbines, and so forth have been periodically subjected to degradation and failure due to corrosion. The impact of corrosion in the oil and gas industry significantly contributes to the nonproductive time (NPT) of 20–30% lost from exploration to production. Corrosion also ranks second to the highest most frequent initiating factor leading to loss of containment in UK. While external corrosion, stress corrosion cracking, and microbiologically influenced corrosion have significantly resulted in pipeline failures, failure attributable to sour and sweet corrosion which results from activities of CO_2 and H_2S has contributed to over 50% of all pipeline failures [1, 2].

Corrosion prediction models that were aimed at the multiphase flow regime, pH, H_2S, CO_2, and so forth were used by some authors to establish the extent of internal corrosion of pipelines at different operating conditions. This helped to establish the point where mitigation is necessary in order to reduce the level of risk that corrosion poses on the pipeline [3]. Chemical inhibitors are injected in most instances to mitigate the effect of the corrodents while in extreme cases, more severe measures like replacement of the pipeline with more resistant materials are considered. A lot of authors have numerous corrosion experimental results that were not verified with field conditions; this resulted in numerous laboratory results not having good practical relevance in the field. It is, therefore, important to understand the trend that corrosion field data follows with respect to the operating condition in order to enhance the acquisition of corrosion prediction results that will have high practical relevance [4, 5].

Temperature increase has been shown to increase corrosion rate until a particular threshold when the increase stops to affect corrosion. Other authors utilized mechanistic modeling to predict corrosion rate in steel surfaces. This approach which involved homogenous chemical reaction, electrochemical reaction at the steel surface, and transportation of specie in the bulk solution was utilized by many authors in their prediction of CO_2 corrosion rate.

Due to the importance of wellheads in the transportation of oil and gas from the reservoir to the pipelines, it is necessary to maintain the integrity at all times; however, due to turbulence, corrosion, erosion, and other factors, they are continuously deteriorating in operation. To be able to understand more about this deterioration as a result of corrosion, the effect of certain operating parameters on the wellhead corrosion rates has to be studied.

Production tubing is the conduit through which fluids are transported from the reservoir to the surface facilities. The tubing has to withstand corrosion from any aqueous phase produced with hydrocarbons and containing dissolved acid gases (e.g. CO_2 and H_2S) and salts (e.g. chloride ions).

II CO_2 CORROSION MODELS USED IN THE OIL AND GAS INDUSTRY

2.1 De Waard Model

The model developed by de Waard and coworkers was for several years the most widely used CO_2 corrosion model. The first version was published in 1975 and was based on dependence of temperature and pCO_2only. The model has been revised several times since, when different correction factors .The model uses a scale factor to take account for corrosion product scales, but this gives only a minimum estimate of scale protectiveness. The model takes relatively little account for the effect of protective corrosion scales, especially at high temperature or high pH. The model was calibrated against laboratory data up to 80 - 90 °C, and the model does not give much account for formation of corrosion films with good protective properties above this temperature [6].

2.2 Norsok M-506 Model

This model is an empirical model developed by the Norwegian oil companies Statoil, Norsk Hydro and Saga Petroleum. The model takes larger account for the effect of protective corrosion films at high temperature and high pH than DW and several of the other models. The model is considerably more sensitive to variation in pH than DW.

The model contains modules for calculating pH and wall shear stress. Three options for calculating pH are available. The pH in condensed water saturated with iron carbonate produced by corrosion can also be calculated. The model does not account for any effect of oil wetting. The model is not intended for corrosion prediction in systems where pH stabilization is used for corrosion control.

2.3 Hydrocor Model

This model (denoted Model HY) was developed by Shell to combine corrosion and fluid flow modeling. Different CO_2 corrosion models are coupled to models for multiphase flow, pH calculation and iron carbonate precipitation. Oil wetting and no corrosion is assumed when the water cut is below 40 % and the liquid velocity is above 1.5 m/s14. The scale factor is applied for condensed water cases, but not for formation water cases, as porous mixture scales may form with little protection. The program includes a fluid flow model which calculates pressure, temperature and flow profiles along a pipeline. This is then used for predictions of corrosion rate along the pipeline. The pH calculation takes account for production of iron and bicarbonate due to corrosion and to iron carbonate precipitation, giving an increase in pH along the pipeline [7].

2.4 Corplus Model

This model(denoted Model CO) is developed by Total and is a result of a merger of the Cormed tool (CM) developed by Elf and the Lipucor model (LI) developed by Total. CM and LI are no longer used by Total and have been replaced by Model CO. The model is based on detailed analysis of the water chemistry including effects of CO_2, organic acids and calcium, and a large amount of corrosion field data, particularly for wells. Free acetic acid and pH are identified as key parameters for corrosion prediction. Model CO gives a potential corrosivity without any protection from corrosion films or oil wetting [8]. Model CO gives recommendations on how to adjust the water chemistry if it is not evaluated as consistent with respect to calcium carbonate saturation.

2.5 Cassandra Model

This model (denoted Model CA) is BP’s implementation of Model DW, including company experience in using this model. In this model a pH calculation module is included, where the pH value is calculated from the CO_2 content, temperature and full water chemistry. The effect of protective corrosion films can be included or excluded by the user by choosing the scaling temperature. Above the scaling temperature the corrosion rate is considered constant instead of reduced with increasing temperature as in Model DW. The model thereby gives less credit for protective films at high temperature. Oil wetting effects are not included in this model [9].

2.6 KSC Model

This model (denoted Model KS) is a mechanistic model for CO_2 corrosion with protective corrosion films developed at Institute for Energy Technology. The model simulates electrochemical reactions at the steel surface, chemical reactions in the liquid phase, diffusion of species to and from the bulk phase and diffusion through porous iron carbonate films. The properties of the protective corrosion films are correlated with a large number of flow loop experiments. The model calculates the concentration profiles and fluxes of the different species and the resulting corrosion rate. The model calculates a corrosion rate without protective films, a corrosion rate with protective films and a risk for mesa attack. This model includes a relatively strong effect of protective corrosion films which is sensitive to pH and temperature, and therefore tends to predict low corrosion rates for high temperature and high pH. The model does not take any effect of oil wetting into account.

2.7 ECE Model

This model (denoted Model EC) developed by Intetech is based on Model DW, but includes a module for calculation of pH from the water chemistry and bicarbonate produced by corrosion, a new oil wetting correlation and effects of small amounts of H_2S and acetic acid. It is developed for wells and flowlines. For water cuts lower than the emulsion breakpoint the water is believed to be present as a water-in-oil emulsion, and the predicted corrosion is low, but not zero. The critical flow velocity for water dropout is taken as 1 m/s for horizontal flow and lower for inclined flow. The model includes a module for calculation of pH from the water chemistry and bicarbonate produced by corrosion.

III CONCLUSION

The effects of the operating parameters (temperature, CO2 partial pressure, pH, and flowrate) on the rate of corrosion of oil and gas wellheads was studied using the above models in the corrosion prediction. Other factors could have an impact on wellhead corrosion rate are organic and inorganic acids, bacteria, turbulence, erosion, erosion-corrosion, bubbles formation, and condensation resulting from the flow of the oil and gas.

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