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Prediction of Internal Corrosion in Oilfield Systems from System Conditions

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Foreword

NACE technical committee reports are intended to convey technical information or state-of-the-art knowledge regarding corrosion. In many cases, they discuss specific applications of corrosion mitigation technology, whether considered successful or not. Statements used to convey this information are factual and are provided to the reader as input and guidance for consideration when applying this technology in the future. However, these statements are not intended to be recommendations for general application of this technology, and must not be construed as such.

The purpose of this technical committee report is to bring together state-of-the-art knowledge about corrosion prediction from system conditions, mostly for upstream oil and gas. The material presented is mostly based on observed industry practices for upstream oil and gas. However, the principles could be suitably applied in other petrochemical areas, such as midstream and downstream. Essentially, the discussion is based on second principles (applied) rather than first principles (fundamental).

The report intends to provide corrosion practitioners worldwide with a concise guide of the most important parameters impacting the prediction of corrosion rate like CO_2 and H_2S concentrations, presence of microbes, corrosion inhibitors, presence of hydrocarbons, nature of the steel (carbon steel or corrosion resistance alloys), presence of oxygen, and flow and erosion effects.

The prediction of corrosion rates from system conditions is usually done with the help of mathematical—and sometimes empirical—models. Attention is dedicated to existing prediction models, their limits of application, availability, as well as relevant specific references. An important effort was made to include all known models as well as their most relevant characteristics, limitations, availability, and range of application; however other models exist that were not brought to the attention of the technical committee.

In spite of the state-of-the-art knowledge and corrosion prediction models presented in this report, the gap between the predicted and actual corrosion rates is still significant. This is partially caused by the lack of precise definition of the actual environment, system conditions, and complex corrosion processes that are interacting with each other in the target application that is being simulated.

Scope

Section 1 provides the reader with an overview of critical parameters. Section 2 describes the main differences between the corrosion models considered in the report and provides a high-level guideline to engage in corrosion prediction. Sections 3 to 11 provide details on each parameter considered.

Task Group (TG) 076 on Oil and Gas Production, Corrosion Prediction prepared this report in 2017. TG 076 is administered by Specific Technology Group (STG) 31 on Oil and Gas Production—Corrosion and Scale Inhibition, and is sponsored by STG 60 on Corrosion Mechanisms and STG 61 on Inhibition—Corrosion and Scaling. This report is issued by NACE International under the auspices of STG 31.

Introduction

This technical committee report brings together state-of-the-art knowledge about corrosion prediction from system conditions, mostly for upstream oil and gas. The material presented is mostly based on observed industry practices for upstream oil and gas. However, the principles could be suitably applied in other petrochemical areas, such as midstream and downstream. Essentially, the discussion is based on second principles (applied) rather than first principles (fundamental). It includes a comprehensive list of references, figures, and equations to create a concise guide of the most important parameters impacting the prediction of corrosion rate. This report is maintained by TG 076.

Keywords: CO_2, H_2S, MIC, oxygen corrosion, corrosion prediction models, oil and gas

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Section 1: Overall Corrosion Prediction

There are numerous models available to provide an assessment on the likely corrosiveness (aggressiveness) of oil field fluids. The majority is aimed at assessing the expected corrosion rates for carbon steel components, but some also cover expected performance of corrosion resistant alloys (CRAs) as well.

The various models considered (listed in Appendix A) cover the principal corrosion threats in oilfield fluids:

- Carbon dioxide (sweet) corrosion
- Hydrogen sulfide (sour) corrosion
- Microbiologically induced corrosion (MIC)
- Oxygen corrosion

They also consider the impact of variations as a result of flow, hydrocarbons, metallurgy and performance of corrosion inhibitors. Many of the sweet (CO_2) models are based on the original work by De Waard, Milliams, Lotz, and Dugstad.[1-3]

Some sour corrosion models are developed primarily based on field data and field tests from Canadian sour gas and oil production pipelines.

The main differences between the different models relate to the extent to which they take into account the different factors that directly affect the general and pitting corrosion rate of carbon steel, such as formation of protective or semi-protective iron carbonate ($FeCO_3$) or iron sulfide (FeS) films, "oil wetting," flow effects, etc.[4]

The role of this report is to highlight some key issues to clarify the options available. NACE TG 4[illegible]7 is currently developing a report on steps to follow to select an appropriate model for a particular condition.

Section 2: Differences between Models

Because of the wide variety of CO_2 based models, most reviews normally use at least two and often three different models to provide improved confidence in any predictions.[5,6] Where the results from different models for the same process simulation (i.e., combination of CO_2 partial pressure, operating temperature, flow rate, water cut, etc.) give predicted corrosion rates of similar value (typically within ± 20%) then it is normally considered that the predictions are consistent. However, where the predicted natural corrosion rates vary significantly (typically by more than ± 50%, or even more), then this is usually taken as indicative that the different assumption(s) used in the models is (are) significant with respect to the particular condition being considered.

A good example of this is the difference between the NO[a] and CA models, in the temperature range 60 to 150 °C (140 to 302 °F), as shown in Figure 1 below. This shows the predicted corrosion rates for 8 mol% CO_2, in a produced brine (200 mg/L bicarbonate and total ionic strength of 50 g/L), at an operating pressure of 500 kPa, with moderate flow (1 m/s). The NO model gives a peak corrosion rate (for carbon steel) of 9.5 mm/y at a temperature of approximately 60 °C (140 °F), which then drops away to a limiting value of 3.2 mm/y at 93 °C (200 °F) and drops down to 0.26 mm/y at 150 °C (302 °F) for temperatures greater than 130 °C (266 °F). The predicted corrosion from CA under the same conditions gives similar values up to about 70 °C (158 °F), but then does not show any reduction in corrosion rate with increase in temperature, giving a limiting value of approximately 14 mm/y (in the absence of any inhibitor).

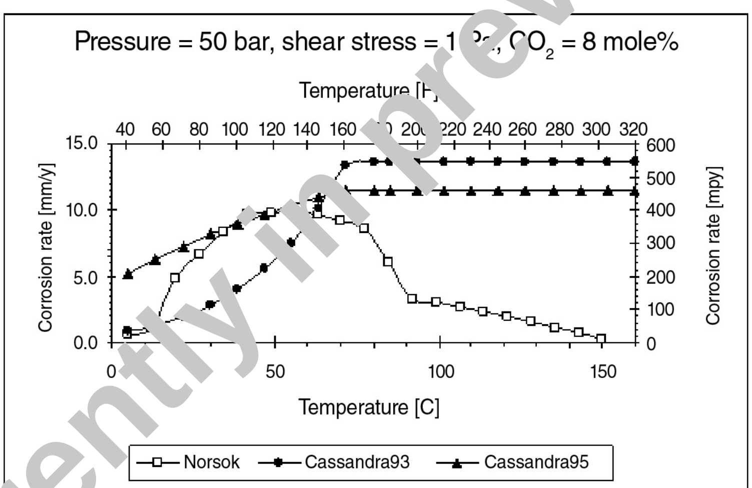

FIGURE 1: Comparison of Different Model Outputs for Same Input Parameters

The reason for this difference is the extent to which formation of a protective $FeCO_3$ scale is allowed for in the two models (while NO includes the formation of a protective scale, CA considers it to a limited extent). Similar variations are found between other models, especially where the effects of "oil wetting," presence of protective FeS film, or inhibitor performance with respect to flow rate are concerned.[5]

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[a] Refer to Appendix A for the model name acronyms used throughout this report.

Such variations do not mean that one model is wrong and the other right, just that in these circumstances the assumptions and degree that the model is considered to be conservative (that is, erring on the side of caution). The decision as to which prediction to use is in turn typically dependent on the person who is doing the assessment. Material selection reviews using the more optimistic (least conservative) model(s) (i.e., taking maximum contribution from oil wetting, scale formation, inhibitor performance, etc.) are used to "justify" selection of carbon steel; while others prefer a more cautious approach, taking the least contribution from these factors or even discounting them altogether, recognizing that they are likely identifying a worst case (and in some cases "non-credible") condition.

A good example of this is the issue of oil wetting, where significant benefits (i.e., reduction in corrosion rate) are expected under normal operation conditions; however, many operators ignore this and expect the model to assume 100% water wet surface.

Variations in Conditions

It is commonly recognized that the operating conditions for a field/section of pipeline/item of equipment in a process plant are not the same everywhere or for all time. Hence, any assessment usually considers variations in location and in time. In some cases, any changes typically result in insignificant variations to the predicted corrosion rate (typically less than ± 10%); however, in other cases, this sometimes results in major variations of the corrosion rate (± 100% or more). This is often the case where the changes in conditions cross a threshold value. For example, the EC model assumes that once the linear velocity for a system exceeds the API[(1)] critical erosional velocity, all protective films become unstable and hence less effective. Small changes in the fluid conditions (such as flow rate, pressure, temperature, gas-oil ratio (GOR), etc.) could result in an increase of 2x to 5x in the predicted corrosion rate[7]. Hence, for system evaluation, the normal practice is to run the prediction models for different combinations of operating conditions.

Some models inherently take into account the variation of localized corrosion rates as a function of variation in operating parameters and have established boundaries. For example, the IF model inherently adjusts the localized corrosion rate based on field operating variations, based on established variation of the localized corrosion rate as a function of oil production rate, water production rate, gas production rate, solids, temperature, pressure, H_2S partial pressure, CO_2 partial pressure, and the effects of sulfate, bicarbonate, and chloride.

The effect of variations is typically accommodated by either running the selected model(s) with individual combinations of operating conditions, (for example on a year-by-year basis, based on changing predictions as described in the NO model) or by plotting the predicted corrosion rate with respect to one or two different variables (such as operating temperature and shear stress or operating temperature and pH, see Figure 2.)

Generic Uncertainty Modeling Approach

An alternative approach is to apply a risk-based assessment (which sometimes includes an uncertainty, statistical or stochastic assessment). That is, the different input parameters, which are normally taken as fixed variables, are replaced with uncertain values, using distributions (instead of a single number) for the variable in the calculation. The distributions for the different parameters (flow rate, pressure, temperature, CO_2, H_2S, bicarbonate, water cut, inhibitor availability, etc.) are normally estimated based on analysis of historical variations (for an existing field) or based on engineering judgment and experience for new developments.

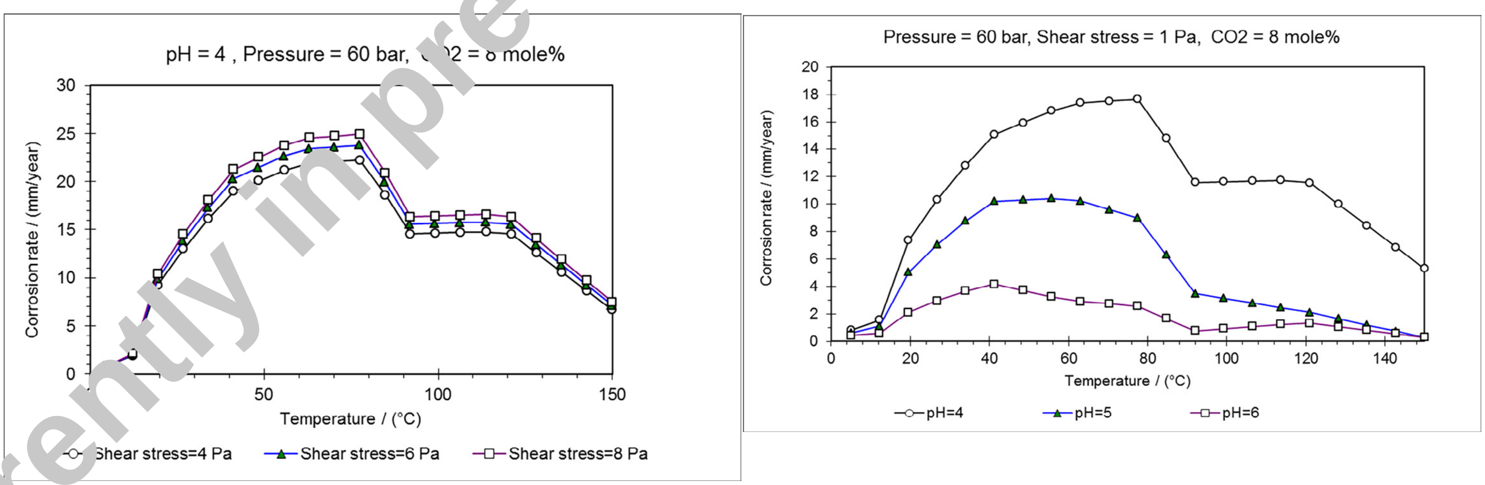

FIGURE 2: Example of Parameter Studies, Using the NO Model

[(1)]American Petroleum Institute (API), 1220 L St. NW, Washington, DC, 20005-4070.