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Field Data Collection, Evaluation and Use for Corrosivity Prediction and Validation of Models

Part II: Evaluation of Field Data and Comparison of Prediction Models

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ABSTRACT

A corrosion field database has been developed by collecting corrosion field data gathered by several operators. This has proven to be a difficult exercise, as the amount of reliable corrosion field data is scarce. The amount of available data varied considerably from case to case. For many of the cases where corrosion problems were encountered it was difficult to trace back to obtain all the relevant information from earlier stages of the history of the field.

The different corrosion prediction models were evaluated against field data by running different corrosion prediction models for a set of cases taken from the corrosion field database. It varied considerably from case to case which models were most successful in their prediction, and it was not possible to declare one or two models as better than the others. An evaluation of any model against field data can be strongly dependent on the selection of field data used for the evaluation or validation and the validity and accuracy of the field data. It is important to understand the limitations and uncertainties in the corrosion prediction models.

Keywords: CO_2 corrosion, carbon steel, field data, internal corrosion, prediction models

INTRODUCTION

Oil companies and research institutions have developed a large number of CO_2 corrosion prediction models. Several of the models are mainly based on empirical correlations with laboratory data. Other models are partly based on field data and can often predict much lower corrosion rates for situations where oil wetting effects are important. Some of the models are based on mechanistic modeling of the different chemical and transport reactions. Very different results can be obtained when the models are run for the same cases due to the different philosophies used in the development of the models.

All model developers want to be able to validate their models against real field data. For CO_2 corrosion prediction models for the oil and gas industry this has proven to be a difficult exercise, as the amount of reliable corrosion field data is very scarce. When one starts to study available corrosion field data, it is rapidly realized that much of the available field data is either unreliable or insufficient for model validation purposes, or biased against specific field conditions. Many of the models require quite detailed input data, and for field data cases all the necessary input parameters for the corrosion prediction models are often not known in sufficient detail or with sufficient accuracy in order to be able to run the models for validation purposes. Part I of this paper describes some of the pitfalls one may encounter during field data collection and some of the considerations which must be taken when field data for model validation are collected[1].

Another important consideration for validation of models by field data is that the available set of good field data from a single operating company may be too scarce or too biased. If a model is validated for a set of field data of similar type from one company and maybe also from just one field, or similar or neighbour fields, a good correlation for the conditions specific for that field may be obtained, but extrapolation of the model to other fields or conditions different from the ones used in the validation may become highly uncertain.

As a result of these considerations several operators decided to join forces in an effort to collect reliable corrosion field data from a number of operators into a database which can be used for sharing field experience between operators and for model validation purposes. This has been done through three consecutive joint industry projects conducted at Institute for Energy Technology. The first project started in 1998 and the third project will continue until the end of 2006. Thirteen different companies have participated in these projects. In these projects field data with actual corrosion measurements have been gathered from the participating oil companies. The different available CO_2 corrosion prediction models have been evaluated by performing sensitivity studies for the different models, running the different corrosion models for a set of the field cases, and comparing predicted corrosion rates with the actual measured corrosion rates. The present paper describes how these field data were collected and evaluated, and gives some examples of how the field data were used for comparing and evaluation of the different corrosion prediction models.

MODELS USED IN THE EVALUATION

Most available CO_2 corrosion prediction models have been evaluated in the project. Altogether seventeen different models have been evaluated. In the present paper it is focused on the models which is most frequently used in the oil and gas industry, and the following six models have been selected:

- NORSOK M-506
- Hydrocor
- Cassandra
- de Waard model
- Lipucor
- ECE

A brief description of these models is given below. A more detailed description of all the models evaluated in the project is outside the focus of the present paper, but has been given previously[2].

The Norsok M-506 model is an empirical model developed by the Norwegian oil companies Statoil, Norsk Hydro and Saga Petroleum[3-5]. The model is fitted to much of the same lab data[6] as the de Waard 95 model, but includes in addition more recent experiments[7] at 100 to 150 °C. The model takes larger account for the effect of protective corrosion films at high temperature and high pH than several of the other models. In the second revision of the model, issued in 2005, the lower temperature limit for the model was extended from 20 to 5 °C and a lower limit of 0.1 bar CO_2 partial pressure was introduced[4, 5]. This version has been used in the present work.

Hydrocor was developed by Shell to combine corrosion and fluid flow modeling and is now Shell's preferred tool for corrosion prediction[8 - 10]. A relatively weak protection from corrosion product films is assumed, but only when formation water is not present due to risk for localized attack. Oil wetting effects are included for crude oil systems, but not for gas condensate systems where water separation is likely to occur. Version 1.04 was used in the present work.

Cassandra is a tool representing BP's implementation of the de Waard model and including BP's experience in using this model[11, 12]. Oil wetting effects are not considered in Cassandra, and the effect of protective films at high temperature is weaker than in the de Waard model. However, it is not distinguished between effect of corrosion films for cases with and without formation water. The 1998 version was used in this work, but similar results are obtained with later versions.

The model developed by de Waard and coworkers has for several years been the most widely used CO_2 corrosion model. The first version was published in 1975 and was based on dependence of temperature and pCO_2 only[13]. The model has been revised several times since, when different correction factors have been added to the original equation[14, 15]. The 1995 version[15] represents a best fit to a large number of corrosion flow loop data generated at Institute for Energy Technology[6]. The de Waard model includes only moderate effects of protective iron carbonate films. An on/off factor is used for oil wetting effects in crude oil systems. The 1995 version has been used here.

The Lipucor model is developed by Total and is correlated with a large amount of field data[16]. The correlation with field data where oil wetting effects are important makes this model considerably less conservative for many cases than most of the other models discussed here. After the merger between Total and Elf this model will be combined with the Cormed tool developed by Elf into a new corrosion prediction tool called Corplus.

The ECE model developed by Intetech is based on the de Waard 95 model, but includes a new oil wetting correlation and effects of small amounts of H_2S and acetic acid[17, 18]. The oil wetting factor is dependent on the oil density, the liquid flow velocity and the inclination of the flow. Small amounts of H_2S can give a considerable decrease in the predicted corrosion rate. The model includes a module for calculation of pH from the water chemistry and bicarbonate produced by corrosion. Version 4 was used in this work.

COLLECTION OF CORROSION FIELD DATA

The corrosion field data were collected by the operators representatives in the joint industry project. Most of the field data used for models evaluation were failure cases where failure reports were available. The amount of available data varied considerably from case to case. For some cases detailed corrosion data along the pipeline or well were available in the form of caliper surveys or intelligent pigging data. For other cases corrosion data were only available at single points or as maximum rates. Some of the cases included full well deviation or pipeline elevation information, while others had no such information. For some of the cases the full production rate history was available, while others only stated typical production rates. Reservoir and wellhead temperatures were usually given only as typical values without variation over the production history. Water chemistry data was available for most cases, but not variation in water chemistry due to changing amount of formation or condensed water. Typical for many of the cases was that when corrosion problems are encountered, it is often difficult to trace back to obtain all the relevant information from earlier stages of the history of the field. Even when the operators representatives in the project were actively seeking for field data within their own organization it was often difficult to find all the necessary data to be able to run the different models. When field data are to be used for corrosion prediction model evaluation or validation it is necessary to restrict the analyses to uninhibited cases, and this of course limits the number of available field data that can be used considerably.

In order to be able to run the different corrosion prediction models the following data from the field cases were specified as a minimum:

- Temperature, inlet and outlet
- Pressure, inlet and outlet
- CO_2 mole %
- Bicarbonate, acetate and calcium content in the water
  (preferably full ionic water composition)
- Gas, water and oil production rates
- Pipe inner diameter
- Bubble point pressure or pressure in last separator stage for full liquid systems

There is often a considerable difference in both temperature, pressure and flow velocity from downhole to wellhead in a well or from inlet to outlet of a pipeline. Most of the corrosion models are point models, and running the corrosion models with only inlet or outlet temperatures and pressures will not give a corrosion prediction representative for a location with a measured corrosion rate in a location away from the inlet or outlet. It is essential to run the models with temperature, CO_2 partial pressure and flow conditions representative for the location of interest. In the present study a three phase fluid flow model was run for all the field data cases in order to obtain temperature, CO_2 partial pressure and liquid flow velocity values for the locations in the well or pipeline where the actual corrosion measurement had been done.

The corrosion field data collected in these projects have been collected in a database with detailed information about all the parameters listed above and detailed information about the actual corrosion measurements. The database is updated once or twice a year. At the time of writing this paper the database contained about 80 different field cases with about 120 individual corrosion measurements. 45 % of the corrosion measurements were from inspection of corroded wells or pipelines or time to leakage. 25 % of the corrosion measurements were from caliper runs or intelligent pigging. 10 % were low corrosion data resulting from many years service without well failure. 10 % were from weight loss coupons, and the remaining 10 % were from electrochemical measurements, ultrasonic thickness measurements, ER probes and FSM measurements. 20 % of the corrosion measurements were from inhibited cases where corrosion problems occurred with inhibition, while the other cases were from uninhibited systems.

The quality of the field data in the database varied considerably. Many of the cases were taken from failure reports where detailed failure investigations were available, while other cases had more sparse information. All the data were quality checked for consistency and reliability before entering in the database, and for most of the cases further queries were done towards the supplier of the data in order to ensure the reliability of the data or to obtain further details.

A selection of the available field data was made for use in the corrosion models evaluation. Only cases from uninhibited systems without glycol or methanol injection were used in the models evaluation, as all the models essentially predict the unmitigated corrosion rate, and uncertainty in inhibitor efficiency or availability will overshadow all other parameters for inhibited cases. Further the models evaluation was based on the cases where detailed and reliable information was available for both production characteristics, geometry and water chemistry, and where CO_2 corrosion was identified as the corrosion mechanism. This means that only the most reliable, uninhibited CO_2 corrosion cases were used in the evaluation of the different CO_2 corrosion prediction models.

TABLE 1. Overview of selected field data

	Oil line 3	Gas line 3	Oil well 5
Temperature °C	58 - 65	55	70 - 110
CO_2 partial pressure bar	0.05 - 0.15	1.2	1.6
Bicarbonate mg/l	49	0	181
Acetate mg/l	100		
Calcium mg/l	4800		770
Chloride mg/l	114000		20000
At location with max. corrosion			
Temperature °C	59	55	70 - 80
CO_2 partial pressure bar	0.07	1.2	1.6
Water cut %	30	10	5 - 80
Liquid flow velocity m/s	11	2.8	1.3 - 2.0
Corrosion rate mm/y	1.1	4.1	4.6
Corrosion measurement	Leakage, pigging	Ultrasonic testing	Leakage, caliper run

An overview of a few of the field data cases is shown in Table 1. This shows three examples from the selection of field data cases used in the models evaluation. In all these cases the corrosion rates were relatively high, from 1 to 5 mm/y. Two of these cases resulted in leakages, and for these cases corrosion measurements were also available at other locations from intelligent pigging or caliper runs. The third case is from an onshore pipeline with ultrasonic wall thickness measurement.

The case called Oil line 3 is a multiphase oil line which suffered multiple leakages after seven years of operation. After the leakages this case was extensively investigated with intelligent pigging, inspection and detailed studies of metallurgy and water chemistry[19, 20]. This pipeline had a low CO_2 content but presence of acetate. Production history data showed that the production conditions had remained quite stable during the seven years of operation. The flow regimes in the pipeline ranged from low velocity, stratified flow at the inlet to high velocity, slug flow close to the outlet. At the locations with the largest corrosion damage the flow regime was slug flow with high liquid velocity.

The Gas line 3 case is from a short onshore gas line with condensed water only and 10 % water cut. Ultrasonic wall thickness measurements were done in different bends just before the slug catcher after one year of operation. The highest measured corrosion rate was 4.1 mm/y.

The Oil well 5 is an oil well where a leakage occurred after 18 months of service. Contrary to the belief during design, the well started to produce formation water very soon, with water cut increasing from 5 % after 2 months to 80 % after 17 months. The CO_2 molar fraction in the gaseous phase was 30 %, and the bubble point pressure was 5.2 bar. The wellhead pressure was always higher than this, so this was a liquid-only oil well with a CO_2 partial pressure of 1.6 bar. The calculated pH is between 5 and 5.5. Here both detailed caliper data over the whole depth and detailed inspection of the recovered well string was available[21]. The tubing had penetrating mesa attack close to the top of the well, at around 100 m depth, corresponding to 4.6 mm/y corrosion rate based on the total production period. A section of the tubing where penetrating localized attack was found is shown in Figure 1. Further down in the well the corrosion rate was measured to 0.3 - 0.9 mm/y by caliper data.

FIGURE 1 - Penetrating localized attack in Oil well 5.

EVALUATION OF MODELS AGAINST FIELD DATA

The different corrosion prediction models have been evaluated against field data by running the corrosion models for a set of cases taken from the field data collected in the joint industry projects. A selection of the available field data was made by concentrating on a number of cases where sufficient detailed and reliable data was available. Not all the collected field data had enough detailed or reliable information to run the corrosion models properly and achieve predictions which can be regarded as representative for the actual field case. For instance it is necessary to have reliable information about the water chemistry and representative values for the temperature and CO_2 partial pressure at the location where the corrosion is measured in order to make corrosion predictions which can be compared with the actual corrosion measurements. In the present study a three phase fluid flow model was run for the field data cases in order to obtain temperature, CO_2 partial pressure and liquid flow velocity values for the locations in the well or pipeline where the actual corrosion measurement had been done. It is also desirable to have information about the production history for the actual well or pipeline, and it was concentrated on cases where production history data were available or it was known that the production conditions had remained stable. For the cases where the production history was known the models were run for different time steps during the production and the predicted corrosion integrated over the production history. For the cases where corrosion had been measured at different locations in a well or pipeline the models were run for the conditions at these locations.

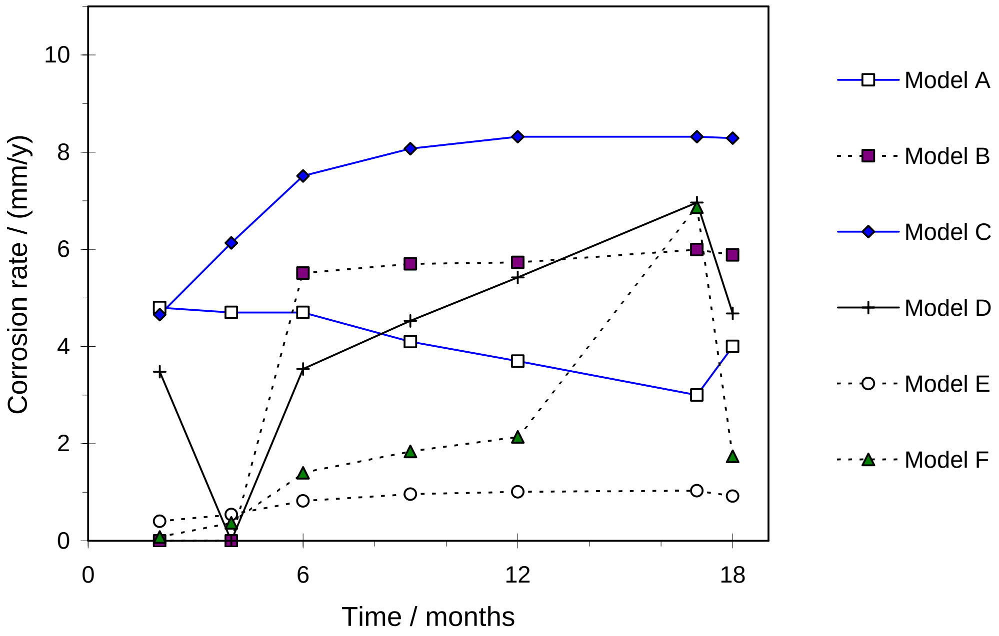

FIGURE 2 - Variation in predicted corrosion rates with varying temperature profile and water cut over the production history in Oil well 5.

Figure 2 shows an example of how the predicted corrosion rates may vary over the life of an installation. The figure shows the variation in predicted corrosion rate for the Oil well 5 case described above. The models have been anonymized for commerciality reasons. For this case the production history was available, and the predictions were done for different times during the production histories with different production rates and consequently varying temperature profiles and water cut. The predictions shown in Figure 2 were done for the location in the well close to the wellhead where the actual failure occurred. The variation in predicted corrosion rate with time for Model A and C is a result of variation in liquid flow velocity and temperature profile. For Model B, D and F there is also an effect of variation in predicted oil wetting. For this case there is an increase in water cut from 5 to 80 % from month 2 to month 17 and an increase in calculated liquid velocity from 1.3 to 2 m/s in the same period. This causes a shift from almost total predicted oil wetting to almost total predicted water wetting for some of the models.

The total corrosion damage predicted by a model at a given point in the well can be calculated by integrating the predicted corrosion rate over the production history as shown in Figure 2. This example shows that prediction of the corrosion rate only based on the conditions at the end of the production history, which is often the quoted production data in a failure analysis, may give very misleading results if the model predictions are compared with actual field data for cases with a large variation in production parameters during the history of the field.

For the Oil well 5 case the predictions at different times during the production history were done for different depths of the well. At each depth the predicted corrosion damage was then calculated by integrating these predictions over the production history. The resulting accumulated predicted corrosion at different depths in the well is shown in Figure 3 as average corrosion rate over the field life. This is then compared with the actual corrosion damage measured by caliper runs and inspection of selected parts of the recovered tubing string. The corrosion damage was relatively small with general corrosion with corrosion rates around 0.5 mm/y in the lower part of the well, and more severe in the upper part of the well with localized attack, and penetrating mesa attack at around 100 m depth.

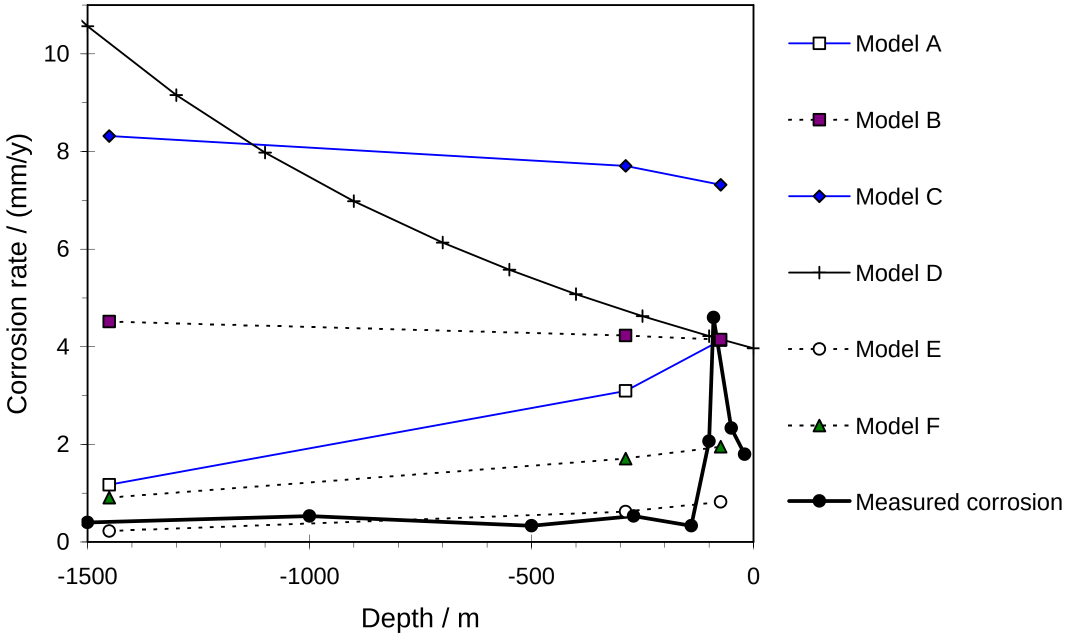

FIGURE 3 - Predicted and measured corrosion rates at different depths in Oil well 5.

Figure 3 shows marked differences between the various prediction models. Model E is quite successful in predicting the low corrosion rate in the lower part of the well, but is not able to predict the severe corrosion in the top of the well. This is because this model takes large effects of protective corrosion films and oil wetting. Model F gives also large effects of oil wetting for this case. Model B, C and D are all quite successful in predicting the severe corrosion in the top of the well, but are not able to predict the lower corrosion rate deeper in the well. This is because these models do not account for any effect of protective corrosion films for this case, and consequently predict higher corrosion rates deeper in the well where the temperature is higher. Model A is able to predict the high corrosion rate in the top of the well and also predicts lower corrosion rates in the lower part of the well, since this model takes larger effect of protective corrosion films at high temperatures.

The predicted corrosion rates for the field cases described in Table 1 are compared with the actual measured corrosion rates in Table 2 and Figure 4. Here the maximum corrosion rate measured for each case is compared with the predicted corrosion rates for the location where the highest corrosion rate was measured. Figure 5 shows the ratio between predicted and measured corrosion rate for the different models for these field cases.

TABLE 2. Maximum measured and predicted corrosion rates

Maximum measured and predicted corrosion rate mm/y	Oil line 3	Gas line 3	Oil well 5
Measured	1.1	4.1	4.6
Model A	0.8	10	4.1
Model B	1.5	8	4.1
Model C	1.1	5.9	7.3
Model D	0.4	4.3	4.2
Model E	2.6	3.3	0.8
Model F	0.9	4.3	2.0

The Oil line 3 case has the lowest measured corrosion rate of the cases in Table 1. This pipeline had a low CO_2 content but presence of acetate. Early water analyses showed 110 ppm bicarbonate. However, a later water analysis where acetate was looked for showed 49 ppm bicarbonate and 100 ppm acetate. This is an example of a case where presence of organic acids can lead to too high values for bicarbonate and hence too high calculated pH values[20]. The total alkalinity measured by standard titration will not give a correct measure for the bicarbonate content when organic acids are present, since the total alkalinity is the sum of bicarbonate and acetate, and varying amounts of acetate can be included in the titration depending on the end point of the titration. This means that some of the acetate may be interpreted as bicarbonate if the bicarbonate is taken as the total alkalinity and it is not analyzed for organic acids.

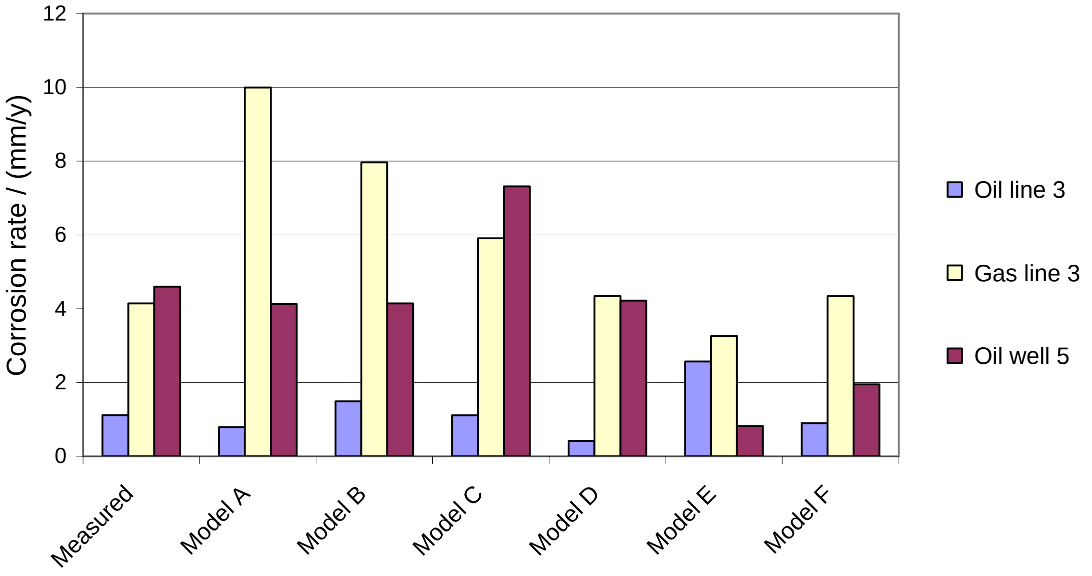

FIGURE 4 - Maximum measured and predicted corrosion rates for selected field data.

The Oil line 3 case was run for both water chemistries described above. The values calculated for the water chemistry with 49 ppm bicarbonate and 100 ppm acetate are used in Table 2 and Figures 4 and 5, since this is believed to the most representative water chemistry. However, comparison with the old water chemistry without acetate can illustrate the effect of not taking proper account for the presence of organic acids. Model F shows large differences in the predicted corrosion rates for the two water chemistries as this model predicts higher corrosion rates when organic acids are present. Model A and C show smaller differences due to different calculated pH for the two water chemistries. These models do not contain specific effects of organic acids on the corrosion rate. Model B, D and E showed little difference in the predicted corrosion rate between the two water chemistries. An early version of Model D was used in this project, where organic acid effects on corrosion were not incorporated. This has been done in later versions of this model, and it is expected that this would give higher predictions for this case.

The Gas line 3 is a case with only condensed water and a temperature of 55 °C. Under these conditions protective films are not expected to form, and a corrosion rate of 4 mm/y was measured by ultrasonic thickness measurements. Most of the models calculated a pH around 4 for this case, and the predicted corrosion rates varied from 3 to 11 mm/y. All the models were able to predict that unacceptably high corrosion rates would occur for these conditions.

It should be noted that these are only three examples from a database with a large number of field data. Many of the field data cases in the database do not have enough detailed or reliable data to obtain representative model predictions. However, these examples illustrate that an evaluation of any model against field data can be strongly dependent on the selection of field data used for the evaluation or validation and the reliability of these data. The cases described here are cases with high measured corrosion rates. An evaluation of prediction models could be quite different for cases with low corrosion rates. It is easy to see that an evaluation of the different models for the Oil well 5 case described above would have been quite different if this well did not have the localized attack close to the top, but only the low corrosion rates found deeper in the well. This may well be the situation for other wells in the same field.

A larger number of corrosion field data were included in the models evaluation in the project these examples are taken from. The project also included different sensitivity studies not described in this paper, showing the sensitivity of the models to variations in temperature, pH, flow velocity etc. A general conclusion which can be drawn from this work is that it varies considerably from case to case which models are most successful in their prediction, and it is not possible to declare one or two models as better than the others. It is however important to understand the differences between the models in order to interpret the predictions. Especially the effects of protective corrosion films and oil wetting are modeled quite differently in the various models, and these are the two effects that may shift between very high and very low predicted corrosion rates[2]. Some of the models are developed primarily for downhole conditions, while others are intended primarily for pipeline applications. Some of the models are empirical correlations to laboratory or field data, using a limited amount of input data in order to be used in an early design stage when available information is limited and uncertain. Other models include detailed mechanistic modeling and have their strength in understanding the mechanisms in controlled systems where detailed information is available. Another observation is that no model is able to predict the actual corrosion with reasonable accuracy for all different scenarios, and the author would be skeptic to any model claiming better than ± 50 % accuracy for a wide range of conditions. The accuracy will very easily become much less than this if the effects of protective films and oil wetting are not predicted successfully. On top of this it should be remembered that the accuracy of input data for the models from field data is often also lower than this.

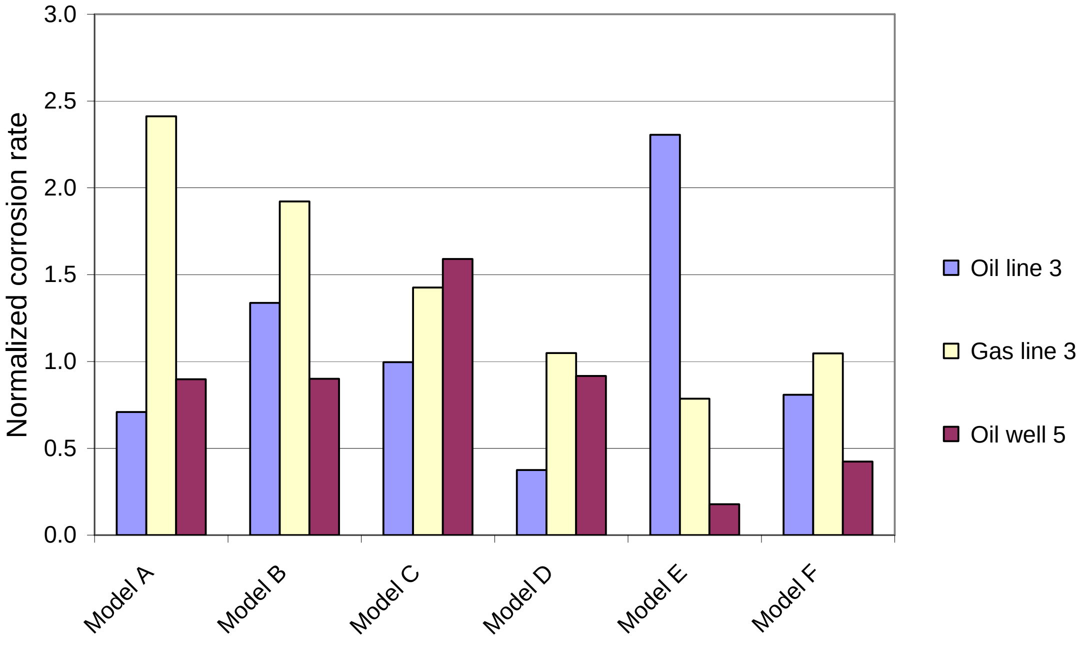

FIGURE 5 - Normalized corrosion rates (predicted/measured) for selected field data.

LIMITATIONS IN THE USE OF CORROSION PREDICTION MODELS

Even with the considerable uncertainties in the models as described above, the uncertainty in the required input parameters will for practical field situations often be even higher. When the prediction models are used in the design phase of a project, the available input data are often very limited. The actual water chemistry may not be known in detail, and the predicted temperature, pressure and flow velocity profiles for the lifetime of the installation may be very uncertain.

A realistic estimate of the actual pH in the water phase is a crucial aspect in the corrosion evaluation of oil and gas wells and pipelines. For cases with only condensed water this should include an evaluation of increase in the pH of the condensed water due to bicarbonate produced by corrosion. When formation water is produced it is important to obtain good water analysis data, especially with respect to bicarbonate and organic acids. In many cases formation water samples are very scarce during the first well tests. Another uncertainty is when and how much formation water will actually be produced. It is often very uncertain when formation water breakthrough will occur. The water chemistry and hence the pH and the resulting corrosion rate can change considerably if the water composition changes from pure condensed water only to condensed water with small amounts of formation water, or to a water chemistry dominated by formation water.

In addition to the CO_2/bicarbonate buffer system also the H_2S/sulphide and the acetic acid/acetate buffering systems can be important for determining the actual pH value. The presence of acetic acid and other organic acids can have a strong impact on corrosion rates, especially at low CO_2 partial pressures and for cases when top-of-line corrosion is a concern. As discussed above, presence of organic acids can give too high values for bicarbonate and hence too high calculated pH values if organic acids are not measured in the water analysis, which has been most typical until recently[20].

In some cases the specified water chemistry from a water analysis can indicate supersaturation of calcium carbonate. It may be advisable to check the water analysis for supersaturation of calcium carbonate at reservoir conditions, which may indicate an erroneous bicarbonate or calcium analysis since supersaturation of calcium carbonate is not possible in the reservoir. In this case the bicarbonate value may be adjusted to the bicarbonate solubility at reservoir conditions with the actual calcium content. Most of the corrosion prediction models do not take this into consideration.

Several of the models are correlated with lab experiments with CO_2 partial pressures ranging from a few tenths of a bar to several bars, and are not particularly suited for very low CO_2 partial pressures. Many of the models may give quite uncertain predictions if used for CO_2 partial pressures below 0.1 bar. It should also be mentioned that a fugacity correction may be necessary when models developed from laboratory experiments at moderate pressure are used for wells or pipeline applications with total pressures in excess of 100 bar. Some of the models include a fugacity correction for high pressure situations while other models only use the CO_2 partial pressure without any fugacity correction.

For liquid only systems the CO_2 partial pressure is defined by the conditions in the last separator stage upstream the pipeline, or by the bubble point pressure for oil wells. Using the CO_2 mole % in the associated gas and the total pressure in an oil well without free gas can give much too high estimates for the CO_2 partial pressure. Some of the field data in the author's corrosion field database are difficult to use for model running as it is known that they are oil wells without free gas in most of the well, but the bubble point pressure is not given, and hence it is difficult to estimate the CO_2 partial pressure.

It is important to know whether water or oil wets the steel surface since corrosion takes place only when water is present at the surface. If the water is transported as a water-in-oil emulsion or dispersion corrosion can be substantially reduced. The degree of oil wetting depends heavily on flow conditions, water cut and the properties of the actual hydrocarbon. Some of the models have a very strong effect of oil wetting for some flow conditions, while other models do not consider oil wetting effects at all, usually because it is believed that water will wet the steel surface and cause corrosion somewhere in the pipeline anyway. Better understanding of the parameters controlling the entrainment of oil and the oil wetting mechanism has a potential to improve the corrosion predictions and increase the confidence in the models.

The prediction of corrosion in systems with H_2S in addition to CO_2 is little developed, and most of the CO_2 corrosion models are not suited when H_2S is present in addition to CO_2. When even small amounts of H_2S are present, the corrosion products will be iron sulfide rather than iron carbonate. Some of the models try to take this into account, but the steps to be taken when moving from sweet corrosion to sour corrosion prediction are large since the type of corrosion films, corrosion attacks and mechanisms to be predicted are very different. There is a need for H_2S corrosion models that take different iron sulfide films into account, but a mechanistic model for sour corrosion seems to be beyond the level of present knowledge. The most effective modeling approach for the near future may be a semi-empirical one, using lab and field corrosion experience as a foundation. The best advice for the time being is to be very careful in using the CO_2 corrosion models for situations with more than trace amount of H_2S.

CONCLUSIONS

Collection of oil and gas corrosion field data has proven to be a difficult exercise, as the amount of reliable corrosion field data is very scarce. Much of the available field data is either unreliable or insufficient for model validation purposes, or biased against specific field conditions. Many of the models require quite detailed input data, and for field data cases all the necessary input parameters for the corrosion prediction models are often not known in sufficient detail or with sufficient accuracy in order to be able to run the models for validation purposes.

A corrosion field database with about 80 different field cases has been developed in a series of joint industry projects with thirteen participating companies. The amount of available data varied considerably from case to case. For some cases detailed corrosion data along the pipeline or well were available, while other cases had only corrosion data at single points or as maximum rates. For some of the cases the full production rate history was available, while others only stated typical production rates. For many of the cases where corrosion problems were encountered it was difficult to trace back to obtain all the relevant information from earlier stages of the history of the field.

The different corrosion prediction models were evaluated against field data by running the corrosion models for a set of well-documented, uninhibited cases taken from the field data collected in the joint industry projects. It varied considerably from case to case which models were most successful in their prediction, and it is not possible to declare one or two models as better than the others. It is however important to understand the differences between the models in order to interpret the predictions. Especially the effects of protective corrosion films and oil wetting are modeled quite differently in the various models, and these effects may shift between very high and very low predicted corrosion rates. The models are developed for different situations: downhole conditions or pipeline applications; use in early design stage with limited information or for understanding the mechanisms in controlled systems where detailed information is available. An evaluation of any model against field data can be strongly dependent on the selection of field data used for the evaluation or validation and the reliability of these field data.

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