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Guidelines for prediction of  
CO<sub>2</sub> corrosion in oil and gas  
production systems



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<b>Abstract</b> <p>A group of corrosion experts from different oil companies has prepared guidelines for use of CO<sub>2</sub> corrosion prediction tools. The guidelines are intended for use in design and engineering practice applied by companies operating oil and gas production facilities. This document attempts to set minimum guidelines that should be common to most companies. The document is sufficiently flexible to allow individual companies to adapt the information set forth in this document to their own environment and requirements.</p> <p>A methodology for defining the likelihood of corrosion and the impact on CO<sub>2</sub> prediction is developed. The CO<sub>2</sub> prediction is based on existing tools. An overview of available CO<sub>2</sub> corrosion prediction models evaluated by the participants is given. It is the responsibility of the operator to select which model to use.</p>			
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## 1 Preface

This publication is based on discussions in several meetings between corrosion experts in different oil companies. The meetings have been arranged by Institute for Energy Technology, but the initiative has been taken by the operators. The report incorporates inputs from BP, Chevron, ConocoPhillips, ENI, Gaz de France, Saudi Aramco, Shell, StatoilHydro, Total and IFE. The participants would like to thank IFE for organising the meetings and providing facilities for the meetings. Inputs are based on the experience acquired during involvement with the design, construction, operation and maintenance of processing units and facilities, and research and joint industry projects.

The objective is to give a recommended guideline for use of CO<sub>2</sub> corrosion prediction tools in design and engineering practice applied by companies operating oil and gas production facilities, and thereby to achieve maximum technical and economic benefit from standardization. This document attempts to set minimum guidelines that should be common to most companies. The document does not cover H<sub>2</sub>S corrosion, erosion-corrosion or corrosion by seawater or injection water, or choice of corrosion mitigation techniques. H<sub>2</sub>S corrosion may be covered in a later stage.

The information set forth in this publication is provided to users for their consideration and decision to implement. This is of particular importance where this document may not cover every requirement or diversity of condition at each location. The document is sufficiently flexible to allow individual companies to adapt the information set forth in this document to their own environment and requirements.

When Operating Companies, Contractors or Manufacturers/Suppliers use this document they shall be solely responsible for the quality of their work and the attainment of the required design and engineering standards. In particular, for those requirements not specifically covered, they will be expected to follow those design and engineering practices which will achieve the same level of integrity as reflected in this document.

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This document is issued as an open IFE report which can be ordered through the IFE library or accessed via IFE's website, [www.ife.no](http://www.ife.no). This has been chosen as a practical way of distributing the document openly. The document has been prepared mainly by the operators representatives in this group, with secretarial and editing assistance by IFE. IFE has also written Appendix 1 based on the IFE joint industry projects on CO<sub>2</sub> corrosion models evaluation. The main part of the document has been written as a group effort by the participants from the operators, and should not be interpreted neither as official IFE policy nor as official policy of any of the operators involved in the preparation of the document.

## 2 Introduction

### 2.1 Objectives

The objective is to produce an international guideline for the prediction of corrosion likelihood/corrosivity in CO<sub>2</sub> dominated environments in oil and gas production systems with emphasis on the design phase and risk based assessment.

A methodology for defining the likelihood of corrosion and the impact on CO<sub>2</sub> prediction is developed. The CO<sub>2</sub> prediction is based on existing tools, which are not covered in this document in depth. Selection of which CO<sub>2</sub> prediction tools to use will be the responsibility of each operator.

It is considered that corrosion is CO<sub>2</sub> dominated if the partial pressures ratio  $P_{CO_2}/P_{H_2S}$  is above 500 to 1000.

### 2.2 Guidance for use and regulatory considerations

This guideline is intended for use in oil and gas production facilities. The guideline does not cover every contingency. It is the responsibility of the user to recognise when additional resources need to be brought to bear on a question or decision.

If national and/or local regulations exist in which some of the requirements may be more stringent than in this guideline, the user shall determine by careful scrutiny which of the requirements are the more stringent and which combination of requirements will be acceptable as regards safety, environmental, economic and legal aspects. In all cases the Contractor shall inform the Principal of any deviation from the requirements of this guideline which is considered to be necessary in order to comply with national and/or local regulations. The Principal may then negotiate with the Authorities concerned with the object of obtaining agreement to follow this guideline as closely as possible.

### 2.3 Definitions

The **Contractor** is the party that carries out all or part of the design, engineering, procurement, commissioning or management of a project, construction, or operation of a facility. The Principal may sometimes undertake all or part of the duties of the Contractor.

The **Manufacturer/Supplier** is the party that manufactures or supplies equipment and services to perform the duties specified by the Contractor.

The **Principal** is the party that initiates the project and ultimately pays for its design and construction. The Principal will generally specify the technical requirements. The Principal may also include an agent or consultant authorised to act for, and on behalf of, the Principal.

The word **shall** indicates a requirement.

The word **should** indicates a recommendation.

## 2.4 Abbreviations

a	Fugacity coefficient
A	Availability fraction of corrosion inhibitor
ATL	Acceptable thickness loss, defined as the total wall thickness (including corrosion allowance) minus the wall thickness required for the (design) pressure rating. This equates to the corrosion allowance plus possible extra available thickness with time due to, for example pressure decrease, allowances for laying stresses etc.
CA	Corrosion allowance
CI	Corrosion inhibitor
CRA	Corrosion resistant alloy
CR <sub>i</sub>	Inhibited corrosion rate
CR <sub>u</sub>	Actual or predicted uninhibited corrosion rate.
CTL	Cumulative thickness loss, defined as the total wall thickness (including corrosion allowance) minus the current wall thickness
f <sub>CO2</sub>	CO <sub>2</sub> fugacity = a x p <sub>CO2</sub>
MACR	Measured actual corrosion rate
p <sub>H2S</sub>	Partial pressure of H <sub>2</sub> S
p <sub>CO2</sub>	Partial pressure of CO <sub>2</sub>
RBI	Risk based inspection
TLC	Top of line corrosion. It takes place at top of the line surface in wet multiphase gas lines operated in stratified flow due to water condensation as a result of external cooling.

### **3 Corrosion and corrosivity assessment**

#### **3.1 Use of prediction models**

Corrosion prediction models help the corrosion engineer to make decisions for the design of oil and gas production and treatment facilities, e.g. the use of CRA versus carbon steel, the need for corrosion inhibitor (CI) injection, to determine the corrosion allowance (CA) or other mitigation measures.

The objective is to predict the order of magnitude of the CO<sub>2</sub> corrosion rate, including localised corrosion. Models that have been evaluated using field data should preferably be used for the prediction of CO<sub>2</sub> corrosion rates. An example of model evaluation using field data can be found in Appendix 1 and Reference 1. A list of models which have been evaluated against these field data is included in Appendix 1. However none of these models were evaluated against field data for top of line corrosion (TLC) prediction.

The predicted corrosion rates are used for the definition of the severity levels (section 3.4).

Finally the possibility to use inhibition is evaluated taking into account inhibitor availability and critical velocity.

#### **3.2 Principles of corrosion prediction models**

Prediction models may be categorised as either being mechanistic or empirical. A mechanistic model takes the chemical, electrochemical and transport processes into account, whereas an empirical model starts with some simple empirical correlations. However, both "types" use data from laboratory testing and field data for calibration.

The results of the corrosion rates calculated by the studied models do not depend significantly on whether the model is mechanistic or empirical. The main differences between the models are attributed to how the protectivity of the corrosion films and the effect of oil wetting are included in the prediction.

A corrosivity prediction including all relevant corrosion mechanisms is described in Figure 1. Only a few models include all these modules. Models have a different approach to how the various mechanisms and parameters are treated.

Special focus should be put on the effect of H<sub>2</sub>S on localised corrosion, the effect of organic acids on localised corrosion, and the effect of organic acids on TLC. Several models do not include these effects.

All models have limitations in use with respect to environmental conditions and systems which they can be applied to. Any prediction model to be applied for a specific project should be verified to be applicable for the actual system and conditions. The empirical models can be used with confidence within the range of data that they were developed from. Mechanistic models are verified over a range of data and they can be used with confidence within this range of data.

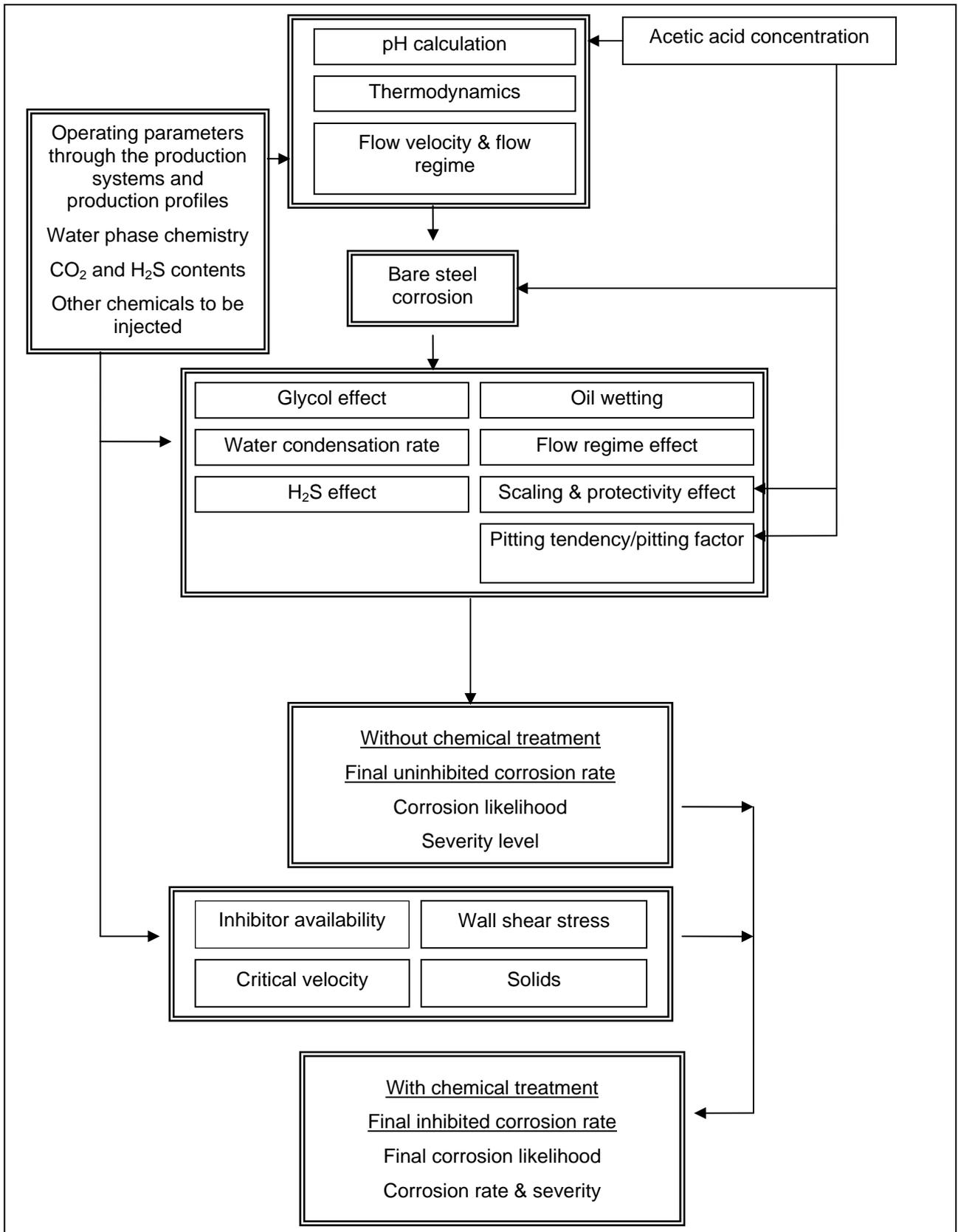


Figure 1: Example of CO<sub>2</sub> corrosion prediction

The effect of the corrosion inhibitor on the final predicted corrosion rate can be evaluated in a separate study and does not need to be included in the prediction model itself. Such evaluation should include parameters as shown in Figure 1.

Input parameters depend on the modules to be used. Some inputs (like temperature) are common to most modules. Guidance for input parameters is defined in Table 2.

### 3.3 Accuracy of input parameters

The total uncertainty involved in the prediction of CO<sub>2</sub> corrosion is a result of combined uncertainties for all factors involved. In addition to the inherent uncertainty of the prediction model itself, there are uncertainties linked to input parameters. The final corrosion rate will also strongly depend on the actual efficiency and the availability of the inhibitor.

The input parameters should include the operating parameters through the production systems (as a minimum covering the inlet and outlet conditions) and the production profiles for all the modes of operation and for the whole life of the facility.

For a system that has been in operation, the actual operating parameters may be obtained and used in a prediction. In a design phase, however, the water chemistry is typically determined based on a few samples and the operating parameters are determined from estimated production profiles and fluid simulations. The actual operating parameters may be very different from those initially estimated. The predicted corrosion rates in all design phases should therefore be considered only being in the right order of magnitude, and not an accurate data point.

### 3.4 Severity levels

Unmitigated predicted corrosion rate can be categorised in severity levels as defined in Table 1. Unmitigated means free of any chemical inhibition (by added chemicals or present in the hydrocarbon phase). To evaluate the corrosion likelihood, mitigation methods must be considered also.

The severity level is evaluated in two steps: Step I is normally used for the preliminary design or early assessment when limited data are available (feasibility of conceptual levels). Step II is used for the assessment of predicted corrosion rate when all data or more detailed data is available. In most cases, Step II evaluation shall be used for the final design.

**Table 1: Severity levels**

Severity level	Unmitigated corrosion rate (mm/yr)		
1	<		0.01
2	0.01	-	0.1
3	0.1	-	1.0
4	1.0	-	10.0
5	>		10.0

Severity levels represent different ranges of corrosivity. To find the position within the severity range for a given corrosion prediction, the severity index can be calculated as  $[\text{Log}_{10}(\text{CR}_{\text{mm/yr}})+4]$ .

Severity level assessment should consider all operating conditions. Some parameters to be considered for Step I and Step II are defined in Table 2.

**Table 2: Parameters to be used in each step for the evaluation of severity levels**

Step I		
Basic or 1 <sup>st</sup> pass corrosion rate for preliminary design or early assessment with limited knowledge		
Factors to be considered	Input parameters	notes
Carbon dioxide	$P_{\text{Total}}, \% \text{CO}_2, f_{\text{CO}_2} = a \cdot P_{\text{CO}_2}$	(1)
CO <sub>2</sub> / H <sub>2</sub> S ratio	$P_{\text{CO}_2} / P_{\text{H}_2\text{S}} > 500 - 1000$	
Temperature	T	
calculated pH	HCO <sub>3</sub> <sup>-</sup> , P <sub>CO2</sub> , P <sub>H2S</sub> , total organic acid species	(2), (3)
Prediction model	P <sub>CO2</sub> , T, pH	(4)
Step II		
Rigorous assessment of predicted corrosion rate for final design and assessment (5)		
Factors to be considered	Input parameters	notes
Protectiveness of the film	T, P <sub>CO2</sub> and pH for FeCO <sub>3</sub> film	(6)
Flow factors	Flow regime and velocity	(7)
Type of corrosion	Pitting or general	
Wetting effect	Oil/water wetting properties	
Organic acids impact	Total organic acid species, pH (Impact on the protectiveness)	(8)
pH effect	Total organic acid species, consistency check of formation water	(3) (9)
Prediction model	Operator defined	(4)

**Notes**

- (1) If model allows the use of fugacity of CO<sub>2</sub>, this should be used rather than the partial pressure of CO<sub>2</sub>. Fugacity coefficients are available in the literature.
- (2) The effect of acetate is limited to the impact of acetate on the calculated pH, there is no further adjustment of the predicted corrosion rate in Step I.
- (3) Default values for acetic acid are given in Appendix 2.

- (4) Any model evaluated for this purpose. A brief description of some models is given in Appendix 1.
- (5) Level II corrosion prediction assessments carry a varying degree of complexity and are Principal and situation specific. Some typical parameters and reference are provided for information only and their use should be reviewed and approved by Principal's Subject Matter Experts.
- (6) Any model having the required module (see Appendix 1).
- (7) Any model having the required module (see Appendix 1) or dedicated flow models.
- (8) HAc is the amount of non-dissociated acetic acid (i.e.: non-dissociated part of total acetates). HAc is used to represent all types of volatile organic acids.
- (9) Check formation water chemistry for electroneutrality, the differentiation between  $\text{HCO}_3^-$ , acetates and alkalinity, calcium carbonate saturation at the reservoir conditions. Values may have to be adjusted if they do not make sense, which may affect the pH.

### 3.5 Likelihood of corrosion

For materials that are subject to corrosion, the risk assessment is based on a combination of the consequence of failure and the likelihood of corrosion. The consequence of failure is not covered in this document; the likelihood of corrosion can be standardised across the industry.

Depending on the predicted corrosivity, mitigation measures need to be put in place to make the risk to as low as reasonably practical. Even after mitigation, a certain low, residual corrosion rate may remain and the availability of mitigation systems may be less than 100 %. These two factors need to be accommodated by a corrosion allowance.

The likelihood of corrosion is defined the ratio of the calculated cumulated thickness loss (CTL) to the acceptable thickness loss (ATL):

$$\frac{\text{CTL}}{\text{ATL}}$$

Essentially a high cumulative wall thickness loss (high corrosion rate systems) is acceptable as long as it has been designed for and the system has a high acceptable metal loss (this usually equates to a high corrosion allowance or short production lifetime), whereas a low cumulative wall thickness loss (low corrosion rate systems) can give integrity problems if this was not designed for, and the acceptable metal loss (corrosion allowance) is inadequate. Low to moderate corrosion rate systems (for the unmitigated situation) may cause more problems as they are not given the same attention as the highly corrosive systems. The issue is how well the design corrosion rate predicts the corrosion rate eventually measured in the field. Appropriate definition of the severity level for the unmitigated situation at the design stage can solve this problem to some extent.

If the ATL is not known, this can be approximated to CA, the corrosion allowance. ATL will be equal or greater than the CA (see definition of ATL (2.5)), so this is a conservative assumption.

If the CTL does not vary over time, then the likelihood can also be defined as the ratio of the measured actual corrosion rate (MACR) to the maximum allowable corrosion rate:

$$\frac{\text{MACR}}{\text{maximum allowable corrosion rate}}$$

This is a reasonable definition at the start of production. The actual corrosion rate is generally subject to changes during the field life, and then the first definition should be used.

If CTL or MACR have not yet been measured or cannot be measured accurately, they can also be assessed from the corrosion rate from a corrosion model, if sufficient and reliable data is available for the corrosion modelling (i.e. as a minimum at least recorded production profiles, changes in temperature and pressure, water chemistry, CO<sub>2</sub> and H<sub>2</sub>S concentrations and corrosion inhibitor system availability). For inhibited systems the MACR can be assessed using the inhibitor availability equation:

$$CR = CR_i \times A + CR_u \times (1 - A)$$

Where:

CR = corrosion rate

CR<sub>i</sub> = inhibited corrosion rate

CR<sub>u</sub> = actual or predicted uninhibited corrosion rate, usually assessed from a corrosion model

A = availability fraction of the corrosion inhibitor.

The availability is defined as the fraction (f) or percentage (A%) of time that the inhibitor is applied at the correct dosage. In many cases this has proven to be the weakest link for a corrosion inhibitor application. Delivery issues, pump problems and poor communications regularly mean that the inhibitor is either switched off or not at the required dosage

Then the MACR can be approximated by CR. Given the conservative nature of corrosion models, CR determined from a corrosion model is likely to be higher than a MACR. The CTL is then CR multiplied by the time the system has been operated.

During design stage the likelihood of failure can be estimated from:

$$\frac{CR \times L}{CA}$$

where L is the design life. During this design assessment (which is conservative), most systems will have a likelihood of failure = 1. The likelihood categories and the possible impact on the system life is given in Table 3. "System" means either "plant" or "pipeline" or "equipment":

Table 3: Evaluation of the likelihood of corrosion categories

<b>CTL/ATL</b>	<b>Likelihood of corrosion categories</b>	<b>Approximate Impact on system life for a new system</b>
≤0.5	Negligible	System will last longer than required with no failures
>0.5 and ≤1	Low	System will reach its design life without a failure
>1 and ≤4	Medium	System will only reach 25% of its design life before a failure occurs, if no action is taken
>4	High	A failure will occur before the system reaches 25% of its design life, if no action is taken

If the likelihood of corrosion is ≤0.5 (negligible), then a Step I corrosion prediction estimate model is normally acceptable for design. A higher ranking will probably require a more detailed Step II corrosion rate prediction estimate.

Following the completion of a Step II corrosion rate prediction estimate, if the likelihood of corrosion is ≤1 (negligible and low), the corrosion rate prediction estimate calculated using a model is normally acceptable for design. A higher ranking will probably require a further analysis and a more detailed Step II corrosion rate prediction estimate, including a larger suite of parameters.

For CRA, where no corrosion is expected, these systems are ranked as a “Negligible” likelihood of corrosion category.

The likelihood of corrosion category can be used in a risk based assessment.

## Appendix 1: Examples of models evaluated against field data

The models listed below have been evaluated against a set of corrosion field data collected within joint industry projects at Institute for Energy Technology (1, 2). In these projects field data with actual corrosion measurements were gathered from the participating oil companies. The different available CO<sub>2</sub> corrosion prediction models were 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. Application limits and strong and weak points of each model were identified.

The following sixteen models have been evaluated in the IFE joint industry projects:

- NORSOK model (Statoil, Saga, Hydro)
- de Waard model (Shell)
- Cassandra (BP)
- HYDROCOR (Shell)
- CORPLUS (Total)
- CORMED (Elf, no longer used)
- LIPUCOR (Total, no longer used)
- KSC Model (IFE)
- MULTICORP (Ohio University)
- ECE model (Intetech)
- PREDICT (InterCorr)
- Corpos (CorrOcean)
- SweetCor (Shell)
- Tulsa model (University of Tulsa)
- OLI model (OLI Systems)
- ULL model (University of Louisiana at Lafayette)

This list does not exclude other models from use within the framework of the present guidelines. Other models may also be used, but it is recommended that they are first evaluated against a set of corrosion field data in a similar way as described above. It is the responsibility of the operator to select which model to use.

A short description of these models with references is given below.

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 a large amount of laboratory data. The model takes larger account for the effect of protective

corrosion films at higher temperature and higher pH than several of the other models, as it is fitted to high temperature data up to 150 °C.

The model developed by de Waard and coworkers was for many years the most widely used CO<sub>2</sub> corrosion model (6). The model is based on empirical fitting to laboratory experiments, and has been revised several times, when different correction factors were added to the original equation to account for effects of pH, corrosion products and oil wetting (7). This model takes relatively little account for protective corrosion films.

Cassandra is an empirical tool representing BP's implementation of the de Waard model and including BP's experience in using this model (8). 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.

Hydrocor is a mechanistic model, developed by Shell to combine corrosion and fluid flow modelling (9, 10). Hydrocor is now Shell's preferred tool for corrosion prediction. A relatively weak protection from corrosion product films is assumed for condensed water cases. No protection from corrosion product films is assumed when formation water is 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.

Corplus is an empirical tool developed by Total and is a result of a merger of the Cormed tool developed by Elf (11, 12) and the Lipucor model developed by Total (13). Cormed and Lipucor are no longer used by Total and have been replaced by Corplus. Corplus is based on detailed analysis of the water chemistry including effects of CO<sub>2</sub>, organic acids and calcium, and a large amount of field data, particularly for wells.

The KSC Model is a mechanistic model for CO<sub>2</sub> corrosion with protective corrosion films developed at Institute for Energy Technology (14). The model simulates electrochemical and chemical reactions and diffusion of corrosive species. The properties of protective corrosion films are correlated with a large number of loop experiments.

The Multicorp model is a mechanistic model, developed by Ohio University and is based on the KSC Model (14). This has been developed further by including modelling of multiphase flow, precipitation of corrosion product films and oil wetting effects (15, 16).

The Electronic Corrosion Engineer model developed by Intetech is based on the de Waard 95 model, but with a module for calculation of pH from the water chemistry and bicarbonate produced by corrosion, and new correlations for the effect of oil wetting based on tubing corrosion data from a light crude oil field (17, 18).

The Predict model is developed by InterCorr International (now a part of Honeywell). The basic part of the model is based on the de Waard model, but other correction factors are used together with a so-called effective CO<sub>2</sub> partial pressure calculated from the system pH (19, 20). The model includes very strong effects of oil wetting and protective corrosion films and has a strong dependence on pH.

Corpos is a tool developed by CorrOcean / Force Technology. The model is based on using input from an external fluid flow model combined with calculation of a probability of water

wetting and calculation of pH (21). The Norsok corrosion model is then used to calculate the corrosion rate in several points along the pipeline.

SweetCor was developed by Shell for analysis of CO<sub>2</sub> corrosion by managing a large database of corrosion data from laboratory experiments and field data (22). The approach is to group data by ranges of temperature and CO<sub>2</sub> partial pressure or by the stable corrosion product. Statistical analysis of the grouped data is used to make correlations for predicting corrosion rates for specific conditions.

The CO<sub>2</sub> corrosion model for pipe flow conditions developed at the University of Tulsa is a mechanistic single-phase flow model with detailed modelling of the kinetics of electrochemical reactions and mass transfer (23, 24). The Tulsa group has worked extensively on erosion and erosion-corrosion.

The corrosion model developed by OLI Systems combines a thermodynamic model for the concentration of molecular and ionic species of aqueous systems with an electrochemical corrosion model and a model for formation and dissolution of iron carbonate or sulphide scales (25, 26). The model is based on detailed mechanistic modelling of the phase behaviour and the various chemical and electrochemical reactions.

The ULL corrosion model for gas condensate wells is developed by the University of Louisiana at Lafayette (ULL) (27, 28). The model calculates temperature and pressure profiles, phase equilibria, flow conditions and then calculates the pH profile and predicts the corrosion rate profile along the well. The model puts much weight on calculating the flow regime and the location for condensation of water and hydrocarbons in the well. ULL has more recently developed a corrosion model for pipelines, but this model has not been evaluated in the IFE joint industry projects.

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**Appendix 2: Water composition for Corrosion prediction:  
Default values for total carboxylic species content in produced waters**

The following values are used within Total when no water analysis is available. These values are issued from general experience gathered since the 80's on organic species analyses of reservoir and condensed water. No guarantee is given that any particular case will be fully in line with these values but from experience the total organic acid content is likely to be closer to this value than to zero values when no data is available.

The temperature considered is the Bottom-Hole Temperature.

Organic acids = HAc + Ac<sup>-</sup>.

In meq/L *	≤1% CO <sub>2</sub> in gas	> 1% CO <sub>2</sub> in gas
T < 60 °C	0	0
T < 80 °C	1	1
T < 100 °C	3	5
T < 120 °C	5	10
T < 135 °C	3	5
T < 150 °C	1	1
T ≥ 150 °C	0	0

\* 1 meq/l is equivalent to 59 ppm.

ConocoPhillips considers when no water analysis is available, 150 ppm of acetate and 200 ppm of bicarbonate alkalinity (1).

Acetate/Acetic acid are used to represent the total volatile acid species present. The amount present in the salt (acetate) or acid (acetic acid) form will depend upon the pH in the system. In Hydrocor, Shell uses as input parameter:

Organic acids = HAc + Ac<sup>-</sup>

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