Maximising the life of corroding tubing by combining accurate multi-finger caliper data with corrosion modelling
M A Billingham, Intetech Consultancy Ltd
B King, Tullow Oil Ltd
A Murray, READ Cased Hole Ltd

Abstract
The purpose of this paper is to discuss the relationship and value brought by empirical field data measurement, extensive interpretation and analysis of that measured field data and powerful predictive modelling with the input of multiple production parameters, for the prediction of rate of corrosion in downhole completions.

This paper involves studies conducted upon Tullow Oil’s Bangora Field in Block 9, Bangladesh. Compositional analysis of the gas produced from discovery well Bangora 1 identified CO₂ as being present at a concentration of around 0.6 mol%. Initial corrosion modelling highlighted that carbon steel completions were not suitable for long term production in this environment, however carbon steel completions were installed for logistical reasons and a corrosion monitoring programme utilising multi-finger caliper surveys was put in place. These surveys identified extensive corrosion of production tubing within a short period of production.

Accurately calibrated multi-finger sensor measurement was performed and repeated four times within a 2 year timeframe by Read Well Services. Intetech Ltd was engaged to carry out detailed corrosion modelling and prediction with input parameters including fluid production rates, well head and bottom hole pressures and temperatures and produced fluids composition. This modelling and direct measurement of the corrosion rates showed a good level of agreement and have given confidence to the life of the completion in relation to the rate of corrosion before expected failure.

The technical benefit of this work has been that it has reduced the risk that a tubing leak arises, which would require the well to be shut-in resulting in significant deferred production and associated loss of revenue while waiting mobilization of workover equipment. Cost savings have arisen by being able to safely defer the time to workover of the wells in a location where workover equipment is not readily available and to reduce the frequency of caliper surveys. Tubing replacement is planned at as late a date as possible consistent with the modelling predictions, thus maximising the useful life of the string.
Introduction

The Bangora Field is located in Block 9, Bangladesh, approximately 100km East of Dhaka, Figure 1. The field was discovered in 2004 with the drilling of Bangora 1. Production testing of Bangora 1 showed substantial gas flows from three separate zones. Follow-up wells Bangora 2, 3 & 5 also encountered prolific reservoir sections.

Corrosion had not been previously identified as being a problem within Bangladesh and any gas discovery was expected to be ‘sweet’. Compositional analysis of the gas produced from Bangora 1 identified CO₂ as being present at a concentration of about 0.6 mol%. The potential corrosion issues and the limitations of using carbon steel completion materials were identified in the well design process. However, due to the lead times associated with sourcing CRA tubing and completion equipment, as well as various commercial and regulatory issues, using alternative completion materials was not practical in the time available. A decision was taken to install carbon steel completions, which were considered a temporary solution to allow initial well testing and early start of production from selected zones. Bangora 1 was completed as a cemented monobore, Bangora 2, 3 and 5 were completed conventionally, all using 12.6 ppf N80 carbon steel production tubing, although Bangora 3 was later recompleted with 13Cr tubing following a completion failure unrelated to CO₂ corrosion, Figure 2.
Bangora Well Completion Schematics (not to scale)

Key to Symbols: 
- TRCSSV
- SSD
- Nipple
- Stickplug
- Perfs

Bangora-1 Bangora-2 Bangora-5

Depth
15m 20" 20" 20"

200m 13 3/8" 13 3/8" 13 3/8"

750m 4 1/2" 4 1/2" 9 5/8"

2500m
A Sand gas gas gas

B Sand gas gas gas

C Sand gas gas gas

3000m
Upper D Sand gas gas gas

3050m
Lower D Sand gas gas gas

3150m
E Sand gas gas gas

Figure 2: Well Completion Schematics, Bangora 1, 2 and 5.
A corrosion monitoring program was identified as being necessary from the outset and four caliper survey campaigns were carried out from November 2006 to December 2008. Undertaking these surveys was challenging with significant associated mobilization costs due to the lack of available local oilfield services and the remoteness of the location. Surveys were very successful in showing how the condition of the tubing was developing. However, it is difficult to derive tubing life predictions from inspection data when ongoing changes in operating conditions are affecting the corrosion behaviour. Tullow Oil therefore decided to model the corrosion behaviour of the wells in order to predict future corrosion rates and tubing life. The aims were to determine if it was possible to extend the interval between caliper surveys, and to plan for the eventual work-over of the wells.

Intetech performed the first modelling exercise in 2009, using production data up to the end of June 2009 and data from the four caliper survey campaigns. A second modelling exercise was performed in January 2011, and a third modelling exercise in June 2011 after a caliper survey campaign in May 2011.

**Caliper Surveys**

Read Well Services performed the inspection surveys using 40-arm multi-finger caliper (MFC) tools. Additionally, an electro-magnetic thickness tool (ETT) was run in the October 2007 campaign. The caliper tools surveyed the whole of the production tubing strings, however only certain parts of the tubing strings could be logged with the ETT due to the impact of the casing strings on the ETT measurement. Based on the combination of the MFC and ETT data in the intervals where both tools recorded valid data it was determined that the OD of the tubing remained close to the nominal value (4.5") and there was no evidence of any thinning from the OD side. As corrosion damage is not anticipated from the annulus side under normal circumstances, tubing penetration values have been calculated from the MFC data based on an unchanged outer diameter.

In each instance, MFC data was processed to remove individual arm drift and to match the depths of reference completion items with the well completion diagrams. This allows time-lapse comparison between the successive surveys.

**Corrosion Morphology**

The anticipated morphology of CO₂ corrosion in the Bangora conditions is isolated pitting [Crolet 1994; Sydberger 1996]. The Bangora wells are producing relatively low quantities of water and parts of the tubing may not be wetted, or only intermittently so, depending on the temperature and pressure profile up the wells. The caliper surveys confirmed the expectation that pitting is the mode of attack. The measured mean ID did not change significantly between successive surveys, indicating that the majority of the tubing surface was undamaged, Figure 3.

![Time-Lapse Tubing Body Measured Mean ID vs. Depth Plot](image)

**Figure 3: Example showing development of tubing mean ID data (Bangora 1)**

Even in the latest survey (2011), the majority of the MFC measurements were at or near the original ID. However, the
maximum measured ID increased with time, Figure 4.

![Time-Lapse Tubing Body Measured Maximum ID vs. Depth Plot](image)

Figure 4: Example time-lapse caliper data showing development of tubing maximum ID (Bangora 1)

Detailed examination of the survey data indicated isolated pitting-type features. By the 2011 surveys, there was a clear tendency to low-side pitting over the more highly deviated parts of the tubing. However, even within the low-side track the depth of penetration is very variable with the deeper pitting features being short and isolated. As an example, the maximum depth feature for Bangora-1 at 2011 is shown, Figure 5.

![MFC Survey Results Table](image)

Figure 5: Extract from 2011 campaign MFC data showing the maximum depth feature in Bangora 1. Plot indicates minimal change of ID over the majority of the tubing surface.

Localised pitting does not have a significant impact on pressure or load-bearing capacity of the tubing, because of the support of surrounding, uncorroded, material. This can be shown by calculation, for example using formulae such as those in DNV Recommended Practice RP F101 [DNV 2004]. Consistent with this analysis, field experience is that failures from $\text{CO}_2$...
corrosion in downhole tubing typically exhibit as leakage into the annulus while the tubing remains mechanically intact, rather than as collapse or bursting due to general thinning. It is expected that the Bangora production tubing can tolerate local pitting corrosion to virtually the full wall thickness before failure and that failure would first occur by leakage to the annulus, rather than by burst or collapse.

Therefore, for the purpose of estimating tubing life time, the minimum allowable wall thickness as per API 5CT was used, namely 6.02 mm for these production strings [API 2004].

**Corrosion Modelling**

**Initial Corrosion Modelling**

Corrosion modelling was performed using Intetech’s software model, the Electronic Corrosion Engineer (ECE ®). This software enables estimation of carbon steel corrosion rates in CO2- and H2S- dominated systems and additionally evaluation of various CRAs in different fluid characteristics. The corrosion model within ECE is based upon the well-known de Waard – Lotz corrosion equations, which have been used in the oil industry for many years. The implementation within ECE has been further developed by Smith and de Waard and calibrated with field experience; a full description has been published [Smith 2005].

ECE version 4 was used in the 2009 study. In 2011, both ECE version 4 and the newly developed ECE version 5 were used. For the Bangora conditions, there is no fundamental change in the model between versions 4 and 5 and no major differences in the results obtained. However, there are changes in the implementation of the model in the software package which mean that ECE version 5 is more convenient to use. One of these relates to modelling of water condensation or evaporation up the tubing: ECE 5 allows the user to input the liquid-phase water rate at the well-head (which is what the field Daily Production Reports record) and automatically back-calculates the water rate at all points down the tubing. This is useful in Bangora conditions where water rates are very low and the parts of the well may be water dry under particular operating regimes.

The quality of input data is of critical importance in corrosion modelling, and poor quality or missing data is often one of the main barriers to achieving useful and reliable results.

The Daily Production Reports provided complete data for production rates and for well head flowing pressures. These are the most critical inputs to the corrosion model.

Bottom hole temperatures and pressures and well-head flowing temperatures were estimated from original well test data for each well and the daily production data. Variations in these derived inputs affect the estimated corrosion profile down the well to some extent (for example, the depth at which corrosion rate is greatest and the estimated corrosion rates at bottom hole or at the surface), but had little impact on the value of the maximum corrosion rate which is the key output for estimating the remaining tubing life.

**Table** 1 summarises the source of the principal inputs used in modelling.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Source</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tubing dimensions</td>
<td>Well completion diagrams, caliper surveys</td>
</tr>
<tr>
<td>Gas, water &amp; condensate rates</td>
<td>Actual, from Daily Production Reports</td>
</tr>
<tr>
<td>CO2 content</td>
<td>Actual, 0.59% (from well testing)</td>
</tr>
<tr>
<td>Tubing deviations</td>
<td>Actual, from deviation survey reports</td>
</tr>
<tr>
<td>WHFP</td>
<td>Actual, from Daily Production Reports</td>
</tr>
<tr>
<td>BHFP</td>
<td></td>
</tr>
<tr>
<td>BHFT</td>
<td>Estimate, based on actual values in Well Test data and daily production reports</td>
</tr>
<tr>
<td>WHFT</td>
<td></td>
</tr>
</tbody>
</table>

No liquids analysis data was available. Water was assumed to be entirely condensed water with no salts or bicarbonate content; this is reasonable for gas wells with very low water rates.

Corrosion modeling can be carried out on an automated, on-line basis, for example by software such as Intetech Well Integrity Toolkit (iWIT) which can feed on-line production data into the corrosion model and thereby calculate daily corrosion rates and wall thickness losses. However, for the small number of wells in the present study, a semi-manual approach was more efficient. The production histories were split into several time periods with similar conditions and corrosion rates calculated for each time period. These were combined to give total wall thickness loss values for comparison
The key factors influencing the CO₂ corrosion rate in these gas wells are the temperature gradient; the partial pressure of CO₂ and the velocity of the fluids. These factors are incorporated in the ECE corrosion model.

The temperature gradient is typically from 215°F at bottom-hole to 100-150 °F at the surface. Other factors being equal, corrosion rate typically increases with increasing temperature from ambient, but towards the bottom of the wells the temperatures are high enough for protective iron carbonate scale to be formed, so corrosion rates are expected to reduce.

The partial pressure of CO₂ is lower at the top of the well (due to the lower total pressure at wellhead compared with bottom-hole), which tends to reduce the corrosion rate towards the surface.

On the other hand, gas and liquid velocities increase towards the wellhead as the gas pressure drops, and this factor acts to increase the corrosion rate. The overall production rate (mmscfd) is a critical factor in determining corrosion rates because of its relation to fluid velocities in the tubing.

The ECE model predicts that corrosion rates are quite sensitive to gas production rates in these particular conditions. Caliper data from well B2 provided an illustration of this, Figure 6: no significant wall loss was measured between surveys 2 and 3, a period when gas rates were low, at around 4-10 Mmscfd; while higher wall losses were measured between surveys 3 and 4 when gas rates were typically 20 to 25 mmscfd. Also, corrosion is expected to be minimal for periods when the wells are not producing.

Figure 6: Minimal wall penetration between surveys 2 and 3, a period with low production rates; greater penetration between surveys 3 and 4, with higher production rates.

Model Calibration

The caliper maximum penetration values were used for analysis: the caliper survey mean penetration values were in nearly all cases very close to zero.
The caliper reports are expressed in terms of the nominal wall thickness and % penetration calculated on the basis of nominal ID. It is not known what the actual baseline tubing dimensions were, and it is quite normal for the tubing wall thickness as-supplied to be less than the nominal on average. The first logging runs in each well were some time after the start of production, and the data show quite large % changes from the nominal dimensions. However, this is a combination of the initial tubing dimensions deviating from the nominal (a baseline offset) and actual metal loss. True penetration figures were derived between repeat sets of caliper data. For periods before the first survey and after the last survey, the wall penetration was estimated by corrosion modelling only.

First-pass corrosion rate estimates were larger than the figures derived from 2006-2008 caliper data by factors of around 2-3 times. The general trends of the estimates with depth were similar to caliper data, except that the caliper data indicated that corrosion was minimal towards the surface, while the model estimated significant corrosion rates near the surface.

The estimated corrosion rates are quite sensitive to the liquid velocity, and hence to the quantities of liquids present and to the liquid hold-up. The corrosion model was tuned by slightly increasing the liquid hold-up values to give lower corrosion rates more in line with the caliper surveys. Calculations were made with several hold-up values and compared with the caliper data. Deliberately, the model estimates were kept no lower than the mid-range caliper estimates so as to remain conservative. After calibration, the model estimates were within -0 + 20% of the measured calliper data for the three wells; see Table 2 below.

In early 2010 the Daily Production Report data all showed a step-change in the liquid condensate rate. This was an artefact caused by changes in operation and measurements at the Bangora gas processing plant (when a hydrocarbon dew-point controller was installed) rather than a sudden change in the make-up of the well fluids. For the purpose of corrosion modelling, the gas:condensate ratio from earlier periods was applied to data after this event. This ensured that the calculations are on the same basis as the 2009 calibration and modelling. This does illustrate an important benefit of having some actual inspection data and being able to perform a calibration, in that the calibration can account for uncertainties in the input data for modelling and other unknown or unmeasurable factors.

<table>
<thead>
<tr>
<th>Well</th>
<th>Period</th>
<th>Caliper data, maximum penetration in period</th>
<th>ECE-4 (tuned) estimate</th>
</tr>
</thead>
<tbody>
<tr>
<td>B1</td>
<td>Survey 1 to Survey 4 7/11/06 to 8/12/08</td>
<td>1.65 mm</td>
<td>1.9 mm</td>
</tr>
<tr>
<td>B2</td>
<td>Survey 1 to Survey 4 26/11/06 to 13/12/08</td>
<td>0.69 mm</td>
<td>0.83 mm</td>
</tr>
<tr>
<td>B5</td>
<td>Survey 1 to Survey 3 9/10/07 to 10/12/08</td>
<td>1.13 mm</td>
<td>1.16 mm</td>
</tr>
</tbody>
</table>

Calculations were made using the tuned model settings for the periods before the first caliper survey and since the last survey, and forwards to predict tubing lifetime.

**Details of Corrosion Modeling**

The following Figures 7 and 8 show typical corrosion profiles generated by the ECE model for two different operating conditions. The peak corrosion rate is usually predicted to be at an intermediate depth in these wells, but the position can be higher or lower with changes in operating regime. This is a consequence of the interactions between the factors influencing corrosion mentioned above, and how these change with depth down the well.
One possible reason for a sharp drop off in corrosion rates towards the bottom of the well is that very little or no condensed water is present in some conditions of temperature and pressure. The ECE software calculates the amounts of condensed water present with depth, making it easy to see if this is an important factor, Figure 9.
**Figure 9**: Water rates as a function of depth calculated for the conditions corresponding to Fig. 8 above.

**Lifetime Prediction**

The maximum wall thickness loss was calculated with a combination of caliper measurements and corrosion modelling data:

- For the period before the first caliper survey, the penetration rate is modelled using ECE and based on the actual production daily report data.
- Between the first and last caliper survey, the actual penetration from caliper surveys is used.
- From the last caliper survey up to the date of analysis, the penetration rate is modelled with ECE and based on the actual production daily report data.
- For the future period, the penetration rate is modelled with ECE based on the typical operating conditions at the time of analysis.

Corrosion rate estimations are based on the empirical corrosion model in ECE, and because of the calibration process, on the caliper data. Allowance has to be made for margin of error and uncertainties in both caliper data and modelling. The typical standard deviation for the corrosion predictions in the range of application of the model is about 25%. For a practical, yet conservative estimate of remaining life-time, the estimated corrosion rate + two standard deviations has been used in calculation of remaining life, i.e. a corrosion rate 50% greater than the headline calculated rate. Assuming a normal distribution, then the actual life time should be greater than this prediction with about 97% probability.

The corrosion model estimates made in January 2011, 24 months after the previous caliper surveys, were in very close agreement with the actual caliper data measured afterwards in May 2011, **Figure 10**. This has given good confidence in the corrosion estimates and the life-time predictions.
The following table summarises the forward predictions made in the 2009 study, the predictions in Jan 2011 (before May 2011 caliper surveys) and finally the latest predictions using the May 2011 caliper data.

<table>
<thead>
<tr>
<th>Well</th>
<th>Basic De Waard model</th>
<th>ECE 4 and ECE 5 Models</th>
<th>Date of estimate</th>
<th>At April 2009</th>
<th>At Jan 2011 with updated production data</th>
<th>At Jun 2011 with May 2011 caliper data</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bangora 1</td>
<td>Feb-2010</td>
<td>Aug-2011</td>
<td>Apr-2012</td>
<td>Sep-2013</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Bangora 2</td>
<td>NA</td>
<td>Nov-2014</td>
<td>July-2016</td>
<td>Dec-2017</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Bangora 5</td>
<td>Feb-2011</td>
<td>May-2011</td>
<td>Oct-2011</td>
<td>Jan-2013</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Using the May 2011 caliper data allowed greater precision in the predictions compared with the Jan 2011 estimates. Although the mid-range estimates (50% confidence) did not change that much, the confidence limits are tighter and the 97% confidence estimated are extended. The reason for this difference is that actual wall loss values from caliper surveys are now used for the period Dec 2009 – May 2011, rather than modelled corrosion rates. Hence, the +50% margin on corrosion rates is no longer applied to this period.

The estimated life for B2 is considerably longer than for B1 and B5 due to the lower production rates (and hence lower corrosion rates) in B2 compared with B1 and B5 wells.

**Ongoing operating conditions**
Reservoir pressures are expected to decline slowly, which will tend to reduce the CO₂ partial pressure and corrosivity slightly. However, it is anticipated that gas production rates will be maintained so far as possible, so fluid velocities could rise slightly. Corrosion modelling allows the impact of alternative future production scenarios to be be investigated.
Summary and Conclusions

The combination of caliper survey data and corrosion modeling has allowed much more accurate assessment and prediction of tubing life than using either single technique individually.

- Inspection data confirmed the morphology of corrosion attack and potential mode of failure
- Calibration of modelling against actual inspection data can overcome shortcomings or uncertainties in the input data and allow more precise use of corrosion modelling

Following this approach, the corrosion modelling predictions and actual corrosion losses turned out to be in very close agreement for the three Bangora wells completed with carbon steel tubing.

An important technical benefit of this work is that it has improved the knowledge of the tubing condition and therefore reduced the risk that a tubing leak arises due to corrosion, causing possible casing damage.

The first corrosion modelling exercise (in 2009) provided sufficient confidence to defer further caliper surveys, which had been performed approximately every six months up until that point, for about 30 months. This alone was estimated to save approximately $2 million.

Cost savings have also arisen by being able to safely defer the time to workover of the wells in a location where workover equipment is not readily available. Tubing replacement can be planned at as late a date as possible consistent with the modeling predictions, thus maximising the useful life of the string.

- Based on the initial 2009 exercise, it was possible to plan for eventual work-over and completion replacement with 13Cr materials in 2011.
- The second corrosion modelling exercise, and the third corrosion modelling exercise combined with the 2011 caliper survey campaign, allowed the scheduling of the work-overs to be pushed back further into 2013.

References


DNV Recommended Practice RP F101, Corroded Pipelines, October 2004, Høvik Norway: DNV
