How accurate are scale prediction models? An example from a gas condensate well.

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Abstract

Scale prediction models are an important scale management tool. Common applications of these models include:

- Prediction of production scaling risks on fields under development.
- Use of scale predictions to understand the causes of scaling on existing fields where a scaling problem has been identified.
- Prediction of the scaling potential of produced water on existing fields.

In each case, the scale predictions aid scale mitigation planning.

Commercial scale prediction models have been developed so that they are capable of modelling production processes reasonably closely and they make use of the best available thermodynamic data obtained from both theoretical and laboratory sources. However, the accuracy of their predictions under field conditions can only really be assessed on producing fields where scale has either been predicted and has been allowed to form (e.g. where occasional mechanical or chemical removal is undertaken) or has formed unexpectedly. In these circumstances, there may be sufficient field data that can be compared with model predictions to determine the accuracy of the latter.

This paper discusses such a case where scale (aragonite) was unexpectedly identified during a routine PLT on a gas condensate well. Although the primary objective of the subsequent scale predictions was to understand the cause of scaling in the well, it was also possible to compare the following prediction results with equivalent field data:

- The type of scale deposited.
- The location of scale deposition.
- The mass of scale deposited.
- The produced water rate.
- The produced water Ca and Cl concentration.

The paper will discuss the comparison and associated uncertainties, the perceived accuracy of the predictions, and the implications of the results with respect to use of field data to validate scale prediction software.

Introduction

Precipitation of inorganic scale (e.g. $CaCO_3$, $CaSO_4$, $BaSO_4$, etc) is a common phenomenon associated with oil and gas production. This scale can deposit from produced water in the formation adjacent to the well, within the well, and within the surface facilities. Inorganic scale is a risk to production and so it is important to manage it effectively.

To aid scale management, a number of scale prediction software packages have been developed. These can simulate (a) production of fluids (water, oil, gas) from the reservoir through the surface facilities or (b) the mixing of waters, and in each case can calculate the scaling potential (Saturation Ratio, SR, and the predicted mass of scale, SM) of the waters involved. Typically, these packages are used during new field development planning to predict future production scaling risks. They can also be used on existing fields where scale has been identified and the cause of scaling needs to be understood, or where scale is being mitigated and the scale risk is being monitored. In each case, the simulation results are used to help develop and manage scale mitigation plans.

The more complete scale prediction software packages (e.g. MultiScale, ScaleChem, etc) include a model for aqueous equilibria (e.g. Pitzer), and a complete PVT-model which can calculate the bubble point and phase distribution in the fluids, especially for H_2O, CO_2 and H_2S. The models selected by each software developer have been chosen because they are appropriate for the types of fluid and scale expected under typical oilfield conditions. Similarly, the associated thermodynamic data (e.g. mineral solubility data) have been selected from available laboratory data by each developer as those most likely to be valid under the same conditions. It can be assumed that the developers have tried to produce software that can generate accurate predictions. Indeed, they will usually have partially validated the software by (a) undertaking simulations of laboratory experiments and (b) achieving a good match between the simulation and laboratory results. But, these experiments are typically conducted under a limited set of conditions. For example, the solubility of a particular scale mineral may have been measured in water of a particular composition at various temperatures. These experiments do not reflect the complexity of field scaling conditions so for users of the software there are uncertainties over the accuracy of scaling predictions under such conditions. It is important to understand these uncertainties because scale mitigation plans are based on the predictions and these plans may involve significant CAPEX and OPEX.

One approach to reduce this uncertainty is to use the software to simulate production conditions where scale occurs. For example, this might be in wells where scale is deposited before occasionally being removed mechanically or chemically, or where scale occurs unexpectedly. Similarly, the software could also be used to simulate production conditions where scale is known to not occur. Where the predictions match observed field data (e.g. location, type, and mass of scale), this would be a good indicator that the software is capable of accurate predictions, at least under the

production conditions of each case. By undertaking this exercise on multiple cases, a better understanding of the accuracy of the software under a wider range of conditions could be achieved.

Although this approach should be effective, it can be a challenge to ensure that the simulation conditions match those in the well. For example, is the input data used in the model representative of the field conditions? Also, does the software account for all those factors affecting the fluids during production?

In this paper we present an example of simulation of production conditions in a gas condensate well where scale has deposited. The original purpose of this work was to understand the causes of scaling in the well to aid scale management planning (McCartney et al., 2014). But, comparison of the simulation results with observed production data also provides an opportunity to consider the accuracy of the software in this case. In undertaking this comparison, we demonstrate the challenges of this approach.

Background: Well A and Field X

Well A is a vertical well located near the crest of gas condensate Field X. The well was drilled and completed (perforated) in four reservoir zones. Two are located in Formation 1 and they are in pressure communication so for the purposes of this study, these have been considered as one production zone. The other two zones are in Formation 2 (2a and 2b) and are separated by an intermediate shale. These are not in pressure communication and have been considered separately in this study. Formation 1 is not in pressure communication with Formation 2 and is the shallowest formation. Formation 2a is deeper and Formation 2b the deepest.

Well A had been producing for approximately 2 years (766 days) before a decision was made to perforate a new reservoir zone. Prior to re-perforation there was a steady decline in reservoir pressure (from ~810 to 730 bar) with associated decline in gas flow rate (5.7 to 4.1 MSm^3/d) and bottomhole pressure (from ~710 to 580 bar) reflecting reservoir depletion (Figure 1). The drawdown pressure at the well was approximately 125 bar during this 2-year period.

During the re-perforation activities a gauge cutter and catcher were run and these were returned to surface with a sample of white solid scale from the well. XRD analysis demonstrated this was predominantly aragonite ($CaCO_3$) scale although AAS/XRF/ICP analysis also indicated that minor amounts of sulfate mineral(s) might also be present (possibly $SrSO_4$, $BaSO_4$?). Caliper logs run during a subsequent PLT indicated narrowing of the liner at and just above Formation 1 perforations (see Figure 2). It was inferred that this was due to $CaCO_3$ scale build-up and was the source of the scale sample. In contrast very little narrowing appears to be present across Formations 2a and 2b and no scale was identified shallower in the well. The mass of scale associated with Formation 1 is estimated to be between 172 and 248 kg after allowing for uncertainties in the pipe ID, and using the density of aragonite

(2.91 g/cm^3). The maximum scale thickness across Formation 1 is low (between 4 and 5mm) and the average thickness is between 1.6 and 2.3mm. The mass of scale adjacent to Formation 2 was too small to estimate.
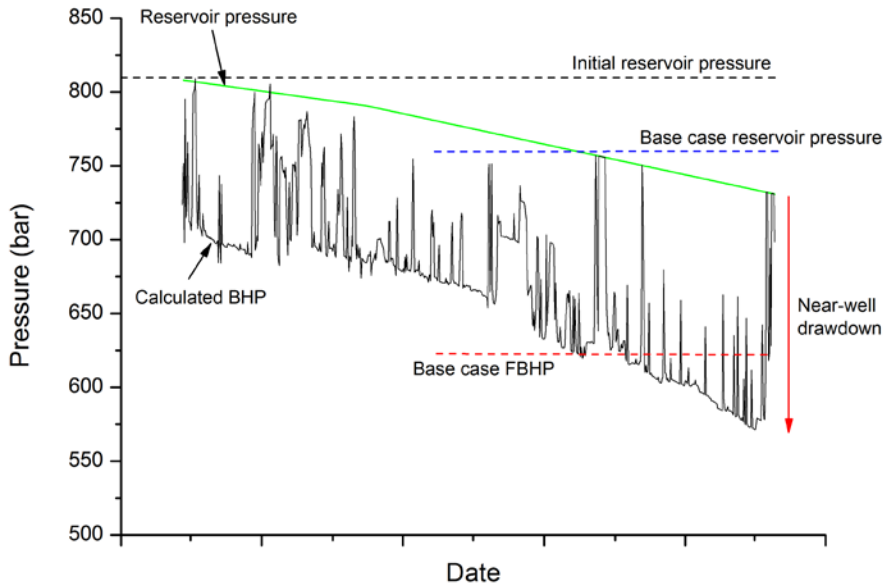

Figure 1   Variation in bottomhole pressure for Well A and reservoir pressure over time. Initial reservoir pressure (black dashed line), average reservoir pressure (blue dashed line) and average flowing bottomhole pressure (red dashed line) shown for reference. Average pressures are for the 12 months prior to re-perforation.

The PLT results for well A show that the majority of the flow was coming from Formation 2b (~70%) at that time and the remainder was primarily from Formation 1; little to no flow was from Formation 2a. Based on the location of scale identified from the caliper log it is likely that formation water was almost exclusively being produced from Formation 1 during the previous two years. The PLT results also indicated that the fluid temperature on entry to the well is approximately 1.9^{o}C higher than static temperature logs. This is due to a reverse Joule-Thomson effect during production.

During the two years before re-perforation, water was being produced from the well at low rates (i.e. between 2 and 19 m^3/day with an average of 7 m^3/day). Although this appeared to be benign (i.e. no scaling potential), low salinity water (see Table 1), it was actually a mixture of formation water and water condensed from the produced gas. The produced water rates and produced water Cl concentrations for Well A are shown in Figure 3. It can be seen that other than for one sample (4050 mg/L Cl), all the produced water analyses have less than 1,200 mg/L Cl (410-1200 mg/L Cl; average = 850 mg/L Cl) although there are no results for earlier production. The Ca

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concentration of the produced water samples is generally 13-19 mg/L (one value is 64 mg/L). These samples were collected from the separator and are therefore affected by both condensation and by precipitation of $CaCO_3$ downhole.
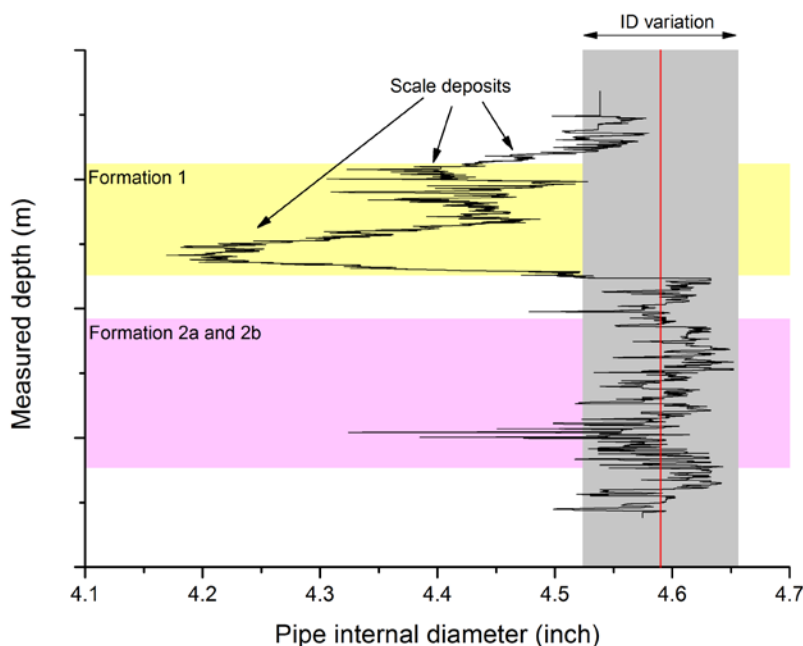

Figure 2   Caliper log (black line) across Formations 1 (yellow), 2a and 2b (purple) showing the location of the scale deposits, the average ID of the pipe (red line) and the uncertainty about this ID (grey).

Table 1   Average composition and range of compositions of produced water from Well A.

	Average	Range	
	(mg/L)	Low (mg/L)	High (mg/L)
Na	1596	336	5061
K	31	12	71
Ca	24	13	64
Mg	5.0	1.7	9.1
Cl	1380	410	4050
Ba	<0.1	<0.1	<0.1
Sr	1.1	<0.1	4.6
SO4	836	205	2280

Although an aquifer is present down-dip of the well at the flanks of the field, given the distance from the well and the time the field has been on production, it is most likely that the formation water was being produced from the hydrocarbon gas-leg.   The

actual mechanism of production, however, is currently uncertain. In other fields where formation water is produced from the gas-leg this has been attributed to the presence of zones with high S_w (Place and Smith, 1984) and increases in S_w as a result of pressure drawdown (i.e. expansion of water) and compaction (i.e. reduction of pore size) (Dietzel et al., 1998).
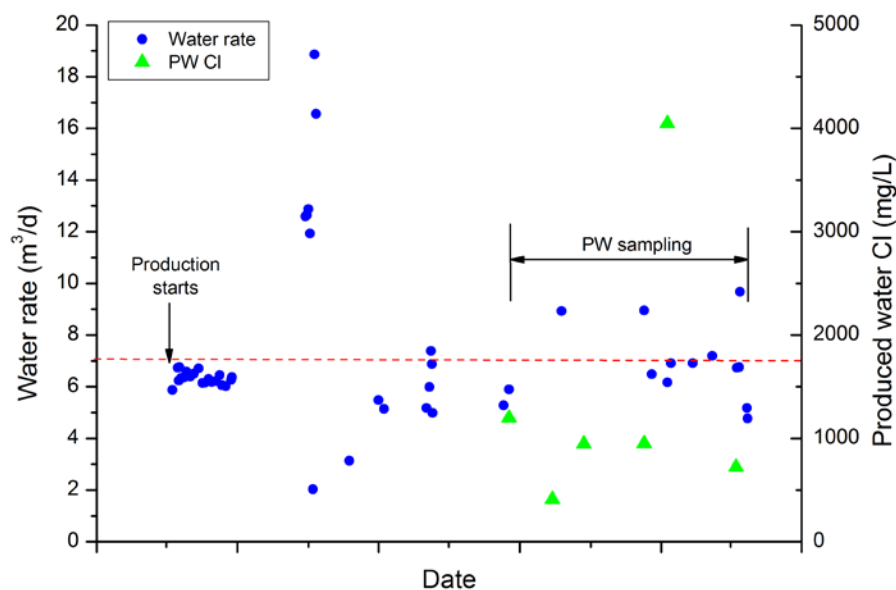

Figure 3   Variation in produced water rates and produced water Cl concentrations over time for Well A.

Formation water analyses from the field were obtained from the aquifer (MDT samples and centrifuged core samples) and the hydrocarbon-leg (centrifuged core samples). Despite the availability of these data, the composition of formation water entering the well is uncertain because there is significant variation in hydrocarbon-leg formation water compositions (e.g. see Figure 4). To constrain the composition of the formation water entering the well a novel method was adopted (see McCartney et al., 2014). This involved the use of Na/Cl ratio and Cl concentration data for the formation water analyses for the field and the produced water analyses for Well A. This indicated that the Cl concentration of the formation water entering the well was ~8.05±2.95 g/L (between 5.1 and 11 g/L Cl). Within this range of concentrations, formation waters from Formations 1, 2b and 2d (water-leg and hydrocarbon-leg) have Ca concentrations between 28 and 461 mg/L.

Given the average formation water Cl concentration (8050 mg/L), the average produced water rate and Cl concentration (see above) and using Equation 1, the estimated average rate of formation water entering the well is ~0.74 m^3/d.

$$FW_{Rate} = PW_{Rate} \cdot \frac{PW_{Cl}}{FW_{Cl}} \qquad\qquad \text{Eq. 1}$$

Where:

PW_{Rate} = Produced water rate (m^3/day)

PW_{Cl} = Produced water Cl concentration (mg/L)

FW_{Rate} = Formation water rate (m^3/day)
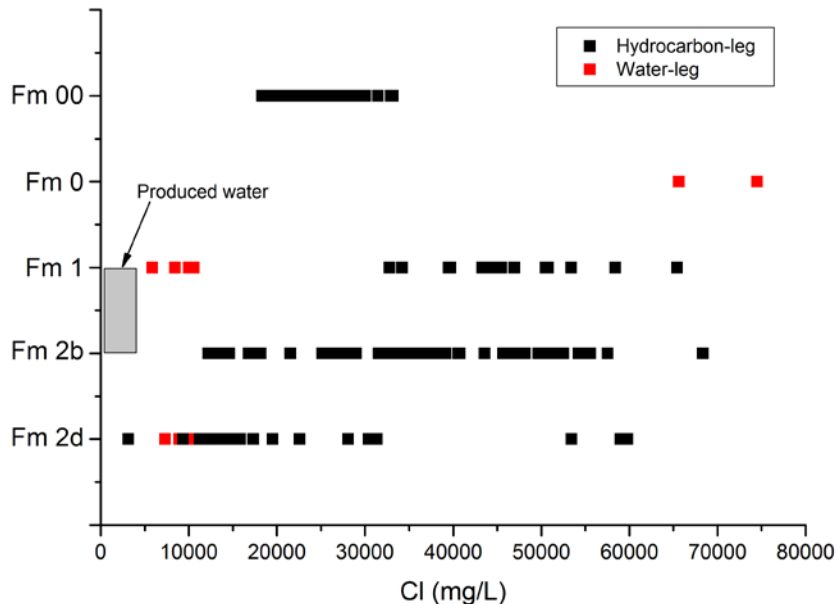
FW_{Cl} = Formation water Cl concentration (mg/L)

Figure 4   Variation of formation water Cl concentrations in hydrocarbon- and water-leg samples from formations in Field A (grey box shows the range of Cl concentrations in produced water).   Note the large variation of Cl concentrations in the hydrocarbon-legs.

Allowing for the uncertainty on the formation water Cl concentration (i.e. 5100-11000 mg/L), the rate could lie in the range 0.54-1.16 m^3/day. On two days produced water rates were measured when produced water samples were collected. Again, using these rates, the Cl concentrations of the samples and the average formation water Cl concentration, the estimated formation water rates from Equation 1 are 0.88 and 1.04 m^3/day respectively. Each of these methods is therefore giving very similar formation water rates.

An estimation of the pressure-temperature profile for well A during the initial 2-year production period was calculated using PROSPER (Petroleum Experts Ltd) (see Table 2). This profile was generated using the following typical production conditions (at the separator; 148.2 bar, 59.6°C) for the 12 months prior to scale identification:

- 4.28 MSm^3/d gas flow rate.

- 623 bar and 99.5°C first node pressure and temperature.

- 3.37 WGR (Sm^3/MSm^3).

- 3021 GOR (Sm^3/Sm^3).

Samples of the produced hydrocarbons were collected from the separator just after the scale was identified. The recombined composition at reservoir conditions is shown in Table 3.

Table 2 Pressure-temperature profiles used in the scaling predictions.

Location	Pressure (bar)	Temp ($^{\circ}$C)
Separator	148.2	59.6
Top 7" tubing	335.4	73.8
Top 5 1/2" liner	560.8	99.1
Bottomhole	610.1	99.5
Near-well	735.1	96.1
Initial reservoir	811.0	96.1

Scale predictions

Software

The scale predictions were undertaken using MultiScale 7.1 (Petrotech, 2006). This is one of the more established oilfield scale prediction software packages and includes a Pitzer aqueous model and full PVT module. The working range of MultiScale is reported by the vendor to be up to 1000 bars and 300°C whilst its operational range (i.e. supported by laboratory data) is probably up to ~200°C and ~500 bar for fluids with salinity up to 3 molal (i.e. ~6 times seawater concentrations) (Kaasa, 1998). Most of the simulations undertaken in this study are within this operational range but in some cases the pressures exceed 500 bar (i.e. up to 816 bar). This does not mean that the results at these pressures are incorrect, but there is greater uncertainty associated with them.

Although the CaCO$_3$ scale identified in Well A is aragonite, calcite is the only CaCO$_3$ polymorph included in MultiScale and so the SR and SM values for calcite have been calculated and reported in this study. Aragonite is slightly less stable (more soluble) than calcite so the calculated SR and SM values reported will be slightly

higher than those for aragonite but this will not significantly affect the conclusions in this paper (e.g. SR for calcite is only ~0.3 higher than SR for aragonite at 25°C, 1 bar).

Table 3   Composition of hydrocarbons produced from Well A (reservoir composition).

Component	Mole %	Molecular weight (g)	Density (kg/m^3)
N$_2$	0.246	28.01	809
CO$_2$	0.177	44.01	817
C1	90.596	16.04	300
C2	3.247	30.07	356
C3	1.114	44.1	507
iC4	0.192	58.12	563
nC4	0.516	58.12	584
iC5	0.154	72.15	624
nC5	0.224	72.15	631
C6	0.226	84	685
C7	0.414	96	723
C8	0.471	107	744
C9	0.356	121	762
C10+	2.068	243	852
Dew point	9615 psia (662.9 bar)		
Res temp	212°F (100°C)		

Input data and modelling approach

The scale prediction simulations modelled production of formation water and gas from initial reservoir conditions through the pressure-temperature profile in Table 3 to separator conditions.

It was assumed that production was only from Formation 1 although calculations showed that similar results were obtained if production was assumed only to be from either Formation 2a or 2b. The pressure-temperature profile used in the scaling predictions is that in Table 2 and the hydrocarbon composition used is that in Table 3. The hydrocarbon rate was selected to give the same gas flow rate at the separator as used in the PROSPER calculations (i.e. 4.28 MSm^3/d).

The average formation water Cl concentration (8050 mg/L) was used to estimate the concentrations of the remaining ions (except Ca) via the average ion ratios of the produced water (see Table 4). Because the produced water Ba concentration was less than 0.1 mg/L, Ba was set to 0.0 mg/L in the simulations. The Ca concentration of the formation water is a primary influence on the amount of scale predicted to precipitate in the well and ideally should be tightly constrained. But, in this case the Ca concentration in the formation water is uncertain (i.e. between 28 and 461 mg/L). Therefore simulations were undertaken using 28 and 300 mg/L Ca in the formation water. The former was the lowest observed formation water Ca concentration and the latter was identified as that Ca concentration giving the highest scaling risk in this well as discussed in (Larsen et al., 2010).

Table 4 Composition of formation water used in the scale predictions.

Constituent	Concentration (mg/L)
Cl	8050
Na	7413
K	250
Ca	28-300
Mg	20
Sr	4
Ba	0
SO_4	4554

With the above gas rate it was not possible to undertake simulations with 0.74 m^3/d formation water because total evaporation of the formation water was predicted to occur at the perforations. This is because the formation water entering the well in the simulations is accompanied by all the produced gas whereas in reality the formation water is only accompanied by 30% of the produced gas. So, the simulations were undertaken at the lowest formation water rate possible without total evaporation occurring (i.e. 4.5m^3/d) and the results were then scaled according to the lower formation water rate entering the well (see below).

The hydrocarbons and formation water were first equilibrated with each other and calcite (calcite is present in the reservoir) at initial reservoir conditions using MultiScale's 'tuning' procedure (see Table 1). The pressure was then reduced to the near-well pressure and any oversaturated minerals were allowed to precipitate (i.e. so SR_{CaCO3} =1 at the near-well pressure) to simulate the deposition of these minerals in the reservoir during depletion. The remaining fluids were then passed through the pressure-temperature profile obtained from PROSPER (Table 1).

Between the near-well region and the separator, two methods were used to calculate the scaling potential (SR, SM) of the produced water:

- 'Leave scale' method. With this method, at each scale prediction point along the flow path, any oversaturated scale minerals were allowed to precipitate to equilibrium and were retained at that location. This method approximates what might occur if precipitation kinetics are rapid and reduces the scaling potential at downstream locations.

- 'Carry scale' method. With this model at each scale prediction point the scaling potential is calculated assuming no scale has precipitated upstream of that point. This model predicts where scale could precipitate if precipitation is delayed at upstream locations by kinetic factors, and predicts the maximum amount of scale possible at each location.

At each calculation point along the pressure-temperature profile, the composition of the fluids, the scaling potential, the scale mass and the water rate were recorded.

Scale prediction results

Only $CaCO_3$ was predicted to precipitate in the simulations. Table 5 summarises the predicted $CaCO_3$ scaling potential of formation water in the reservoir as a result of production induced depressurisation. These values were calculated at the start of the near-well region. They show that at the minimum formation water rate SR_{CaCO3} is between 1.74 and 1.85 and SM_{CaCO3} is between 36 and 168 mg/L. The scaling potential is higher with higher formation water Ca concentrations. The scaling potential reflects the effects of evaporation. H_2O preferentially partitions into hydrocarbons as pressure is reduced when the temperature is constant (McCartney and Østvold, 2005). At the minimum formation water rate ~15% H_2O is removed from the formation water.

Table 5 Scale predictions for formation water (4.5 m³/d) in the reservoir after pressure drawdown.

Ca (mg/L)	SR_{CaCO3}	SM_{CaCO3} (mg/L)	Scale rate (kg $CaCO_3$/d)
28	1.79	36	0.136
300	1.85	168	0.643

Figures 5 and 6 compare the $CaCO_3$ scaling potential (SR, SM) for the leave and carry scale simulations where formation water Ca concentrations are 28 and 300 mg/L. It can be seen that with both models, the scaling potential is initially higher at bottomhole than in the near-well region (where SR = 1 and SM = 0). This is due to pressure drawdown and Joule-Thomson heating, both of which cause evaporation of

the formation water as it enters the well. For the carry scale model, within the well the scaling potential initially increases as the fluid is produced up the well and then decreases. The increase reflects continuing evaporation in the well due to pressure loss. Higher up in the well condensation starts as cooling rather than pressure loss becomes the dominant effect on H_2O transfer between hydrocarbons and formation water. This leads to the reduction in scaling potential assisted by the increase in $CaCO_3$ solubility as cooling occurs. Also shown in Figures 5 and 6 are typical industry values for $SR_{critical}$ (2 to 3) and $SM_{critical}$ (>50 mg/L) for $CaCO_3$ below $100^{o}C$. SR and SM often have to exceed both these critical values for scale deposition to be significant. It can be seen in these figures that both $SR_{critical}$ and $SM_{critical}$ are exceeded only in the deepest half of the well. The high formation water Ca concentration (300 mg/L) causes the scaling potential to be higher downstream of bottomhole and to a shallower depth when compared with the case where the formation water Ca concentration is 28 mg/L. Based on these results, there is an evident scaling risk at the perforations (bottomhole) and in the bottom half of the well at low formation water rates (4.5 m^3/day) but the risk is removed closer to the wellhead and at the separator.
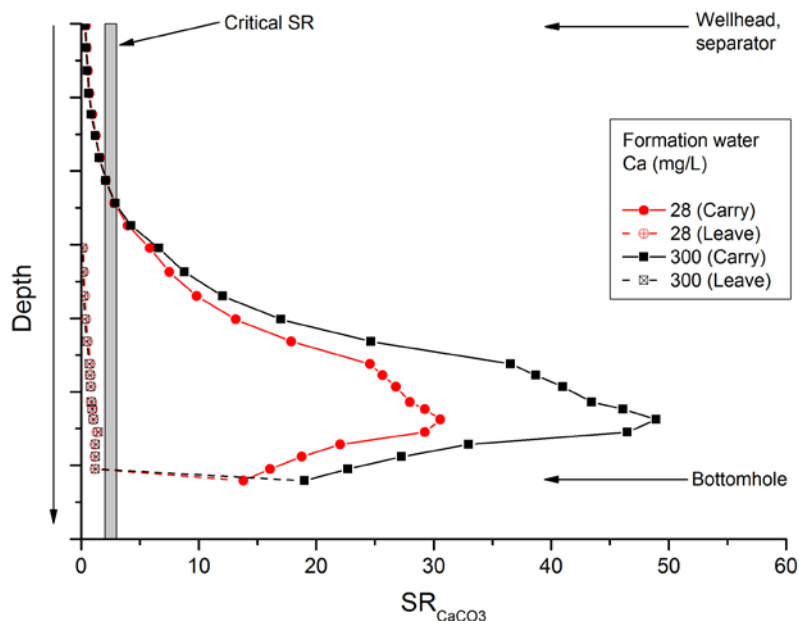

Figure 5 Variation of predicted SR_{CaCO3} with depth using the leave and carry scale models and 28 and 300 mg/L formation water Ca concentrations.

The 'carry scale' method indicates where scale <u>could</u> form, and how much <u>could</u> deposit, if it is not deposited anywhere upstream first. But, scale has only formed at the perforations so the 'leave scale' method results may be more pertinent to Well A. Figures 5 and 6 also show the 'leave scale' model SR_{CaCO3} and SM_{CaCO3} results in the bottom half of the well. These show that SR_{CaCO3} is between 13.8 and 19 and

SM_{CaCO3} is between 120 and 1239 mg/L for the 28 and 300 mg/L formation water Ca cases respectively at bottomhole; both $SR_{critical}$ and $SM_{critical}$ are exceeded. Based on the SM_{CaCO3} values, the mass of $CaCO_3$ scale predicted to deposit at bottomhole during the two years of production via the 'leave scale' method at the minimum formation water rate is between 127 and 1351 kg. It can be seen that if scale is allowed to deposit at the perforations, the predicted scale risk shallower in the well is removed (SR_{CaCO3} <1.47 where Ca = 28 or 300 mg/L).
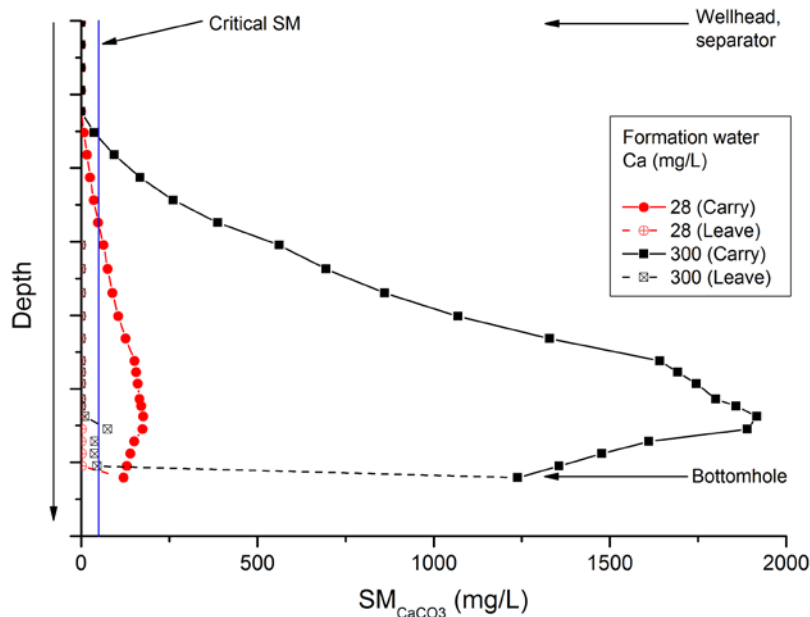

Figure 6 Variation of predicted SM_{CaCO3} with depth using the leave and carry scale models and 28 and 300 mg/L formation water Ca concentrations.

Comparison of predictions and observations

The accuracy of scale predictions can be assessed by comparing the predictions with field observations. MultiScale provides predictions of scale type, location, and mass which are most important for scale management consideration. But, the software also provides predictions of produced water rate and composition and the accuracy of these predictions is also an indication of the validity of the scale predictions.

Produced water rates. Using the PVT capability of MultiScale and assuming only 70% H_2O saturated hydrocarbon gas is entering the well from Formation 2b (i.e. no formation water), ~4.9 m^3/day condensation water is predicted to be generated at the separator from this source. Similarly, if the remaining 30% of the hydrocarbon gas (H_2O saturated) flowing into the well from Formation 1 is accompanied by formation water at the minimum rate (1.3m^3/day; i.e. 30% of 4.5 m^3/day from the initial scale

predictions), this will generate 1.3 m^3/day formation water and 1.1 m^3/day condensation water at the separator. The total water rate of 7.3 m^3/day is close to the average for the well (7 m^3/day).

Scale type. The simulations predict that the only significant scale to be deposited in well A should be $CaCO_3$ and this is consistent with observations.

Scale location. The 'leave scale' model predicts bottomhole as being the only location of scale deposition and this is consistent with the caliper log results. The 'carry scale' model predictions are the same as those of the 'leave scale' model at bottomhole but the predictions downstream of this location are not consistent with observations (i.e. the predictions indicate scale could occur but it is not observed).

Scale mass. The scale predictions were undertaken using the minimum rate which assumes that all hydrocarbons entering the well are accompanied by formation water. But, the PLT/caliper data for the well indicate that 70% hydrocarbon gas is entering the well from Formation 2b with no formation water, and the remaining 30% of the hydrocarbon gas flowing into the well from Formation 1 is accompanied by formation water (~1.3 m^3/day). Based on these data, and assuming the hydrocarbons are H_2O-saturated, the predicted scale mass at bottomhole at the end of 766 days of production using the 'leave scale' model is between 38 and 405 kg for formation water Ca contents of 28 and 300 mg/L respectively. The observed mass of scale (172-248 kg) lies within this range so the predictions are consistent with observations. To provide the same scale mass observed, the predictions require that the formation water Ca concentration to have been between 121 and 177 mg/L.

Produced water Cl concentration. Allowing for 70% H_2O saturated hydrocarbon gas entering the well from Formation 2b without formation water, the predicted produced water Cl concentration obtained from MultiScale is 1434±526 mg/L assuming the formation water Cl concentration is 8050±2950 mg/L. These predicted values are close to, but occasionally higher than, those measured (410-1200 mg/L, other than for one sample with 4050 mg/L Cl).

Produced water Ca concentration. Assuming the Ca content of the formation water entering the well is between 121 and 177 mg/L Ca, and the formation water rate is 1.3 m^3/day, the predicted produced water Ca concentration is between 3 and 8 mg/L respectively. These are slightly lower values than measured (generally 13-19 mg/L with one value of 64 mg/L).

Discussion: Accuracy of the predictions

Uncertainties to be considered in assessment of accuracy

For the simulations to be accurate, ideally the following criteria should be fulfilled:

1. The input data for the predictions are representative of the field conditions.

2. For the conditions being simulated, the software includes all significant factors/processes affecting scale deposition, the simulation of these factors/processes is appropriate and representative, and the associated supporting thermodynamic data/models are valid for the field conditions.

3. Field data obtained against which to compare the predictions are representative.

The input data for the simulations included the pressure-temperature profile, the formation water composition and rate, the hydrocarbon composition and rate, and the flow profile information from the PLT. It has been assumed that the input data are representative of production conditions during the two years of production prior to detection of scale. But, there are uncertainties associated with this assumption:

- The hydrocarbon flow rate was declining and this would cause the pressure-temperature profile to change over time.

- It is not known whether the formation water and hydrocarbon compositions varied over time.

- It has not been confirmed whether the hydrocarbons entering the well from Formation 2b are H_2O-saturated.

- There are uncertainties over the actual composition of the formation water, and particularly its Ca content.

- The formation water rate is uncertain. The predictions used a formation water rate of $1.3 m^3$/day. This was the lowest possible using MultiScale (i.e. avoiding total salt deposition) given the 30% hydrocarbon flow coming from Formation 1. But, the produced water analyses support a lower formation water flow rate of $0.54-1.16 m^3$/day.

- It is not known whether the flow profile has changed over time.

Whether the software has all the attributes required above is difficult to determine and this is why assessments of the accuracy of predictions obtained from the software are of interest. Most notably, however, the software does not fully account for the influence of kinetics on scale deposition.

The field data against which to compare the predictions included the scale type, location, and mass, and the produced water rate and composition (Cl, Ca). Again it has been assumed that these are representative. But, there are uncertainties associated with these field data:

- Although the scale location in the well has been identified, it is not known whether scale is also present in the formation adjacent to bottomhole in the well nor whether scale has precipitated from the produced water but not adhered at bottomhole (i.e. has been flushed from the well in the produced water).

- Rather than being $7m^3$/day throughout the period of interest, the produced water rates have varied between 2 and $19m^3$/day and measurements have been sporadic.

- Measurement of low produced water rates from wells producing at high gas rates is a challenge.

- The produced water Ca and Cl concentrations vary during production. Also, there are no produced water analyses from the first year of production.

These uncertainties and omissions in the software need to be considered when assessing the accuracy of the predictions. In some cases, they may be significant and affect our view of prediction accuracy, but in others their influence will not be significant.

Assessment of accuracy

Scale type. Given that only $CaCO_3$ is predicted to precipitate, and this is what has been observed in the well[1] it suggests that MultiScale can accurately predict the scale type under the conditions of this case, albeit calcite rather than aragonite. Uncertainties in the input data and any limitations of the software do not appear to have been sufficient to have resulted in inaccurate predictions.

Scale location. The 'leave scale' model appears to correctly predict the location of scaling (i.e. at bottomhole but not shallower in the well) suggesting that MultiScale can accurately predict scale location under the conditions of this case when this model is used.

But, given the scale distribution in the well, $CaCO_3$ precipitation kinetics are likely to be relatively 'rapid'. This makes it likely that scale deposition will also have occurred in the formation adjacent to Well A because the conditions at bottomhole and adjacent to the well will be similar (i.e. high SR_{CaCO3} and SM_{CaCO3} due to evaporation, and elevated temperature). This does not mean that MultiScale has inaccurately predicted the scale location because scale precipitation was not allowed adjacent to the well in the simulations. But, if it were allowed, scale would also have been predicted to occur here. So, despite the uncertainties in the input data and the actual location of scale, it is considered likely that MultiScale can accurately predict scale location under the conditions of this case when the 'leave scale' model is used. But, it is important to note that this conclusion is in part, inferred rather than resulting from direct comparison of predictions and observed scale.

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[1] Although it has been noted that there might be minor sulphate minerals in the observed scale, this has not been proved.

For this case, the 'carry scale' model does not provide accurate predictions of scale location except at the bottomhole location where the predictions of both the 'leave scale' and 'carry scale' models are identical. The inaccuracy of the 'carry scale' model downstream of bottomhole is due to the rapid scale precipitation kinetics in this case.

Scale mass. Although the scale mass observed is consistent with the potential Ca concentration of the formation water it is not possible to confirm the accuracy of the predicted scale mass because of uncertainties in the actual scale mass precipitated. For example:

1. It is not known how much $CaCO_3$ scale has been deposited in the formation adjacent to the well.
2. The possibility that scale has precipitated from the produced water but has not adhered at the bottomhole location cannot be discounted.

Thus, the actual scale mass precipitated may be higher than measured.

There are also uncertainties in the input data which make it impossible to confirm the accuracy of the predicted scale mass. For example, although the predictions might be considered accurate were the formation water Ca concentration to be between 121 and 177 mg/L, the Ca concentration might equally be as low as 28 mg/L. Under these circumstances the predictions would be considered inaccurate because the predicted scale mass would be much lower (38 kg) than observed (172-248 kg).

Produced water rate. The simulations predict a total produced water rate of 7.3 m^3/day which is close to the average for the well (7 m^3/day). This suggests that MultiScale is making accurate predictions. Uncertainties in the representativeness of the PLT results do not affect the comparison because varying the flow distribution between 10:90 and 90:10 Formation 1:Formation 2b results in predicted water rates of between 7.1 and 8.1 m^3/day which are also close to the average for the well. There are, however, other uncertainties in input data and measured produced water rates noted above which could affect the predictions or comparisons, such that the accuracy of the predictions might be doubted. For example, if it is assumed that the gas entering Formation 2b is undersaturated with respect to H_2O and this were to be included in the simulations, the predicted produced water rates would be lower than those measured. Similarly, if the produced water rate measurements are in error, the average produced water rate might be significantly different from 7m^3/day and from that predicted. Further investigation of these uncertainties would be required before the accuracy of the MultiScale produced water rate predictions could be confirmed or otherwise for this case.

Produced water Cl concentration. The simulations predict produced water Cl concentrations close to, but occasionally higher than, those measured (410-1200 mg/L, other than for one sample with 4050 mg/L Cl). Possible explanations for this discrepancy include:

- The estimated formation water rate obtained from MultiScale is too high. There is some evidence for this based on the estimates obtained using Equation 1. If the latter estimates are correct (and this is dependent on the produced water rate, produced water Cl concentration and formation water Cl concentration being representative) this would suggest that the minimum formation water rate obtained from the predictions should have been between 1.8 and 3.3 m^3/day as opposed to 4.5 m^3/day obtained. This might be evidence for 'over-evaporation' in the simulations (i.e. erroneously high H_2O solubility in the hydrocarbon phase).

- During those periods when lower produced water Cl concentrations were measured, the proportion of gas produced from Formation 2b may have been higher than was used in the predictions. For example, if it were 90%, the predicted produced water Cl concentrations would have been 509±187 mg/L.

Although another possible explanation is that the predicted produced water rate is erroneously low as a result of insufficient condensation from the gas phase, this is not supported by the close agreement between the predicted and average measured produced water rate.

Again, there is sufficient uncertainty in the input data that it is not possible to conclude whether MultiScale correctly predicts produced water Cl concentration in this case.

Produced water Ca. The predicted produced water Ca concentration (3-8 mg/L) is slightly lower than observed (generally 13-19 mg/L). If it is assumed that the formation water contains 225 mg/L Ca at a formation water rate of 1.3 m^3/day, the predicted and measured produced water Ca concentration can be matched but this would result in greater predicted scale deposition (311 kg) than observed. If the difference in scale mass is then assumed to occur in the formation adjacent to the well, the predictions could be considered accurate. Of course, if it is assumed that no or less scale is deposited adjacent to the well, then the predictions could be considered inaccurate. In this case, without knowing the scale mass adjacent to the well, accuracy cannot be demonstrated. Following this example, if the formation water rate were to be lower (i.e. within the range estimated from produced water analyses), the predicted produced water Ca concentration and scale mass can be matched with the observed values (implying accuracy) but now the formation water rate would be lower than the minimum predicted by MultiScale (implying inaccuracy).

Summary. In summary, based on this case, the accuracy of the MultiScale predictions appear to be reasonable with respect to scale type and location for the production conditions of Well A, but the accuracy of the predictions for scale mass, and produced water rate, Ca concentration and Cl concentration is uncertain.

Implications: Use of field data to validate scale prediction software

This study has shown that it is a challenge to try to validate $CaCO_3$ scale prediction software using field cases. The ideal field cases to use for validation are those where the production conditions under which scale has formed have remained fairly constant, representative model input data have been acquired and representative data against which to compare the predictions have also been obtained. Such cases may not exist so it may be necessary to identify field cases, such as that discussed above, where uncertainties can be identified and their effect quantified so that the accuracy of software can, at least partially, be assessed.

As discussed above, the most useful predictions for scale management are scale type, location and mass. With cases such as that for Well A, and where scale samples have been obtained and analysed, probably the easiest scale prediction to assess is scale type.

The Well A case also shows that the accuracy of scale location predictions can be assessed where caliper data are available and where inferences can be made with respect to scale deposition in the adjacent formation. For Well A the kinetics of deposition were rapid meaning that the 'leave scale' predictions could be directly compared with observed and inferred scale locations. In wells where the kinetics are slower (e.g. lower temperature, higher water rate), scale deposition may occur downstream of the location of first supersaturation. In these cases, an assessment of accuracy can still be made for the 'leave scale' model, but the predictions will evidently be inaccurate. For the 'carry scale' model, unless scale deposition is spread across all locations predicted by this model, it is likely that at best it will only be possible to state that the location of deposition is consistent with the predictions. For example, it would not be possible to confirm the accuracy of the model if scale were only found deeper in the well when the 'carry scale' model predicted that scale could precipitate throughout the well.

For scale mass, the best cases for accuracy assessment are those where:

- Caliper data are available.
- No deposition is expected in the formation adjacent to the well.
- No scale is produced with the produced water. Such cases might be available where produced water solids have been monitored for scale particles.
- The kinetics of deposition are rapid. Where the kinetics are slower, there is a risk that produced water may not fully precipitate its scale load deeper in the well before it becomes undersaturated at shallower locations due to cooling.

To assess the accuracy of produced water rate, and produced water Ca and Cl concentrations, cases similar to Well A are required. That is where the formation water rate is low so that the produced water rate and compositions are significantly affected by condensation and/or evaporation. If the formation water rates are higher, the produced water rates and compositions are likely to be unaffected and so the predicted produced water results will, by default, be the same as the equivalent input

formation water data. Also, to assess the accuracy of the produced water Ca concentrations, the formation water Ca concentration should not be too high because the predicted and observed effects of Ca precipitation may not be greater than the uncertainty on the produced water Ca analyses.

Similar arguments to the above can also be put forward when assessing the accuracy of predictions for other scaling minerals (e.g. $BaSO_4$) and associated produced water ion concentrations (e.g. Ba).

Only the large operators are likely to have the data sets required to validate scale prediction software over a large range of conditions. However, it would be benefit the oil industry if further evaluations of the type included in this study were undertaken and published by all operators. With more of these case studies, the accuracy of the software will become more evident allowing improvements to be sought and introduced.

Such work may also give rise to better understanding of critical values for SR and SM. These are used by different operators to identify where an operational scale problem is, or is not, expected (i.e. where critical values are, or are not, exceeded respectively). Different operators use different values and in part this might reflect the scale prediction software (and version) used by these companies.

Conclusions

For oilfield scale management, it is important that the accuracy of scale prediction software can be demonstrated so uncertainties in the use of predictions obtained from the software are minimised.

In this study, MultiScale scale prediction software has been used to make predictions of scale type, location and mass, and produced water rate and Ca and Cl concentration for gas condensate Well A. These predictions have then been compared with field measurements.

Based on these comparisons, the accuracy of MultiScale's predictions appear to be reasonable with respect to scale type and location for the production conditions of Well A. Although predictions for scale mass, and produced water rate, Ca concentration and Cl concentration are consistent with field measurements, there are too many uncertainties associated with the simulation input data and field measurements to confirm the accuracy of these predictions.

This study has shown that scale prediction validation is a significant challenge and requires the use of special field cases and data sets. But, it would benefit the industry if further studies such as that presented here were to be published by operators.

Disclaimer

Although MultiScale has been used in this study, this does not necessarily constitute or imply its endorsement, recommendation, or favouring by the authors, BP or Oilfield Water Services Limited. The views and opinions of the authors expressed herein do not necessarily state or reflect those of BP and Oilfield Water Services Limited and shall not be used for advertising or product endorsement purposes.

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