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Carbonate Scaling Prediction: The Importance of Valid Data Input

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Abstract: In field work recently conducted, it was revealed that there were no scale control measures in place because scale prediction conducted earlier had concluded that there was no scaling risk. However, a field survey later observed calcium carbonate deposits. In view of the inconsistency between theoretical prediction and field observations, another scale prediction study was conducted to understand the real field scaling potential. Carbonate scale prediction is more challenging due to the CO_2 evolution and partitioning into all three (water/oil/gas) phases during production. Using a commercial available prediction software Multiscale, this paper describes the scale prediction conducted at three different scenarios: (1) prediction without hydrocarbon, i.e., only water production during the calculation; (2) prediction with water and gas, i.e., gas production is considered; and (3) prediction with all three phases, i.e., the true replication of the production. The effect of pH was studied in detail during sensitivity runs. In addition, the effect of power oil on scaling potential is also investigated. It is well known that pH increase has a profound effect to prompt calcium carbonate scaling potential; as a result, a local increase in pH contributed to the solid deposition observed in field. The exclusion of the oil and gas phases in the previous modeling underestimated the real scaling risk. The carbonate scaling potential increases significantly when hydrocarbon was included into the calculation. The addition of power oil has little effect on the overall scaling potential in this case. This is a typical case in demonstrating that invalid scaling prediction can cause misinterpretation of true scale potential and therefore insufficient scale control resulting in scale buildup in field. The aim of this work is to highlight the importance of validity and reliability of data input into scale prediction software, in particular for carbonate scale prediction. It is essential to have a comprehensive understanding of reactions in all three phases, i.e., the total alkalinity and CO_2 mass balance, to ensure an accurate prediction. Because CO_2 can partition into all the three phases (water, oil and gas), compositional analysis for both oil and gas at the water sampling/analysis condition should be obtained before an accurate scale prediction can be made. Prediction results from any scale prediction software are only accurate if the input information is correct and sufficient. Without the complete information set, the scale prediction can only be treated as indicative. Field observations and deposit analysis should be incorporated into the consideration to evaluate the true likelihood and severity of the scale problem.

Key words: Carbonate scale, scale prediction, prediction software, modeling.

Nomenclature

SR: Saturation ratio
ppt: Precipitate amount in g per cubic meter of water
GOR: Gas oil ratio
Bpd: barrels per day
scf/bbl: standard cubic feet per barrel
mscf/d: millions of standard cubic feet per barrel
T/P: Temperature/pressure

1. Introduction

Scale prediction software has been widely used in the industry to diagnose the scale type, location and severity [1-9]. It is used as part of the scale control and management process to identify when and where there is scaling risk and how to best control it. There are several industrial recognized scale prediction software packages including Multiscale, Scalechem, Scalesoft-pitzer, which are all based on thermodynamic (rather than kinetic) equations. They are more reliable in

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predicting the type of scale, the likelihood of scale formation and the maximum scale amount, but they are not sensitive in identifying when and how much scale will form at each concerning location. In this paper, commercial software multiscale has been used for all prediction calculations.

There are two main scale types: most of the sulphate scale formation is due to the mixing of formation water with the injecting brine while carbonate scale formation is due to the pressure decrease and therefore CO_2 evolution during production. Prediction results from any scale prediction software are only accurate if the inputs information is correct and sufficient. For carbonate scale prediction in particular, it is essential to have the total alkalinity and CO_2 mass balance correct to ensure an accurate prediction. Because CO_2 can partition into all the three phases (water, oil and gas), compositional analysis for both oil and gas at the water sampling/analysis condition should be obtained before an accurate scale prediction can be made. Without the complete information set, the scale prediction can only be treated as indicative. Field observations and deposit analysis should be incorporated into the consideration to evaluate the likelihood and severity of the scale problem. Most of the scale prediction software packages are less difficult to use in predicting sulphate scale but have more difficulty giving reliable carbonate scaling results. This is due to the nature of carbonate scale formation-CO_2 evolved during production when pressure decreases and carbonate forms as the result. Same as other types of modeling, the prediction result is only as good as the input data. In many of the cases, water analysis in particular pH and bicarbonate concentration are not reliable, plus the lack of oil and gas analysis data all lead to the inaccuracy in carbonate prediction.

In the case of this paper, the initial scale prediction work carried out prior to a field visit indicated that the likelihood of scale formation was low; however, the field visit later observed that solid deposits have built up in both producing wells and in process equipment. Deposit samples taken from two locations (production well and separator) were analyzed and were found to be predominantly acid soluble. This indicated that the scale deposits were probably predominantly carbonate. In view of the inconsistency between the previous prediction work and the field observation, a follow up scale prediction was carried out using all available data. Assuming that the water analysis was sufficiently close to the historic data, the change in water chemistry that would have the greatest impact upon calcium carbonate scale formation would be an increase in pH. Scenarios were therefore considered where there was a local increase of pH (up to pH 8) in this updated calculation. Furthermore, in the case of carbonate scaling, the CO_2 partition in all three phases is an important parameter. Therefore hydrocarbon analysis was considered to be included into this calculation. As with other field cases, the availability of a complete data set is limited; the calculations in this paper are therefore targeted to reflect the effect of these parameter on carbonate scale threat.

2. Outline of the Prediction

The scale prediction in this paper is carried out using an industry reputed commercial software manufactured by Petrotech [9]. The prediction model calculates Saturation Ratio (SR) for each mineral by which the water is oversaturated; the saturation ratio for a salt MX is defined as:

$$SR_{MX} = \frac{m_{M^+} \cdot m_{X^-}}{K_{sp}(MX)} \qquad (1)$$

where m is the molality, i.e., mole per kg of water in solution, and K_{sp} is the solubility product.

SR < 1, water is under saturated. Precipitation will not occur.

SR = 1, water is saturated.

SR > 1, water is over saturated or supersaturated. Precipitation may occur.

For the case SR > 1, the Precipitated Amount (ppt) in g/m^3 (gram of scale per cubic meter of water produced) will be automatically calculated by the model.

However, depending on the kinetics of the reaction, precipitation might not start spontaneously even if the water shows to be highly supersaturated. Kinetic considerations are not included in this software. It only calculates the thermodynamically stable solution. saturation ratio (SR) provides the likelihood of scale deposition to occur while the precipitated amount (ppt) gives the quantity of scale if the deposition reaction does occur. It should be remembered that scale predictions indicate when the system becomes supersaturated and not when precipitation starts or when scale is deposited.

This paper describes the scale prediction conducted at three different scenarios:

Scenario 1: only water composition available for calculation. Therefore no adjustment ("tuning" is used in later text) of total alkalinity can be carried out and no CO_2 mass balance in oil and gas produced considered.

Scenario 2: uses the gas analysis provided. Considers CO_2 mass balance in both water and gas phases; tuning of total alkalinity is carried out using the gas analysis.

Scenario 3: create a reasonable full alkyl chain oil composition based on the oil property and the gas analysis data provided with the aid of the prediction software. This represents the calculation is done by considering CO_2 mass balance in all three phases, the tuning of alkalinity is carried out using the hydrocarbon analysis. If all data input can be trusted, then the prediction result from this calculation should be the most reliable one since it best replicates the true production conditions.

In addition, pH sensitivity runs were performed for Scenarios 1 and 3; the effect of oil rate was investigated in Scenario 3.

As with other field cases, due to the lack of information, initial assumptions were made. The assumptions made are:

(1) Both the water and gas samples were taken from the same separator and the temperature and pressure are same as for the well head. Production data is assumed to be from the same separator.

(2) The ion concentrations analyzed from the water sample is a true represent of the field scaling ions, i.e., no scale deposit occurred before the water sampling.

(3) The saturation ratio (SR) of Calcium Carbonate is equal to 1 in reservoir condition, i.e., in equilibrium with water/oil/gas and rock in reservoir condition.

(4) For Scenario 1, the bicarbonate concentration is treated as the total alkalinity in calculations. Surface pH has to be adjusted (in this case to be lowered) to meet SR = 1, or the CO_2 mole% in the gas phase has to be adjusted (in this case to be increased) to meet SR = 1.

(5) For Scenario 2, the total alkalinity in water composition was tuned (i.e. calculated) by the prediction software to make the calcium carbonate equilibrium with both water and gas in reservoir conditions.

(6) For Scenario 3, the total alkalinity in water composition was tuned by the prediction software to make the calcium carbonate equilibrium with all three phases–water, oil and gas in reservoir conditions.

Based on the assumptions above, three scenarios (only water composition available for calculation; both water and gas compositions available for calculation and all three phase composition available for calculation) have been studied and discussed below. Note that the unknown parameters indicate we need to be cautious in interpreting prediction result based on assumptions. The predictions performed based on these scenarios have highlighted the need for a more complete and reliable data set and the importance of careful interpretation of scale prediction results.

3. Prediction Results

The temperature and pressure profiles are shown in Table 1, while the water analysis result for one unpreserved water sample available is shown in Table 2.

In addition to the water composition, one gas analysis data and production data were provided and used as shown in Tables 3 and 4. The gas was taken from the separator but the condition for sampling was poor with approximately 30% air left in the gas bomb. It was therefore agreed to recalculate the realistic composition by deducting the air from the composition (air was assumed to only contain nitrogen with no oxygen). In addition, the effect of power oil has been looked at in Scenario 3; the rate of power oil addition can be found in Table 4. For Scenario 3, since there was no full alkyl chain oil analysis data available, we have created a reasonable full alkyl chain oil composition based on the oil property and the gas analysis data provided with the aid of the prediction software.

Table 1 Temperature and pressures.

Step	Location	T (°C)	P (bar)
1	Reservoir	53	69
2	Wellhead / Separator	30	2
3	Water analysis	20	1

Table 2 Water compositions @ 1 bar, 20 °C.

Ion	Mg/L
Na	27320
K	255
Ca	3800
Mg	1720
Ba	3.8
Sr	585
Fe	2
HCO_3	205
SO_4	150
Cl	55450

Table 3 Gas compositions @ 2bar, 30 °C (separator).

Gas Analysis	Mol%, measured	Mol%, calculated
Oxygen	6.49	0
Nitrogen	25.24	1.05
CO_2	4.03	5.81
Methane	29.13	42.02
Ethane	3.83	5.52
Propane	8.72	12.58
Iso-butane	5.03	7.26
n-butane	7.75	11.18
Other pentanes	1.07	1.54
Iso-pentane	3.77	5.44
n-pentane	3.37	4.86
Others	1.57	2.27

Table 4 Production sata @ 2 bar, 30 °C (separator).

Produced oil, m^3/day	52
Produced water, m^3/day	329
Produced gas, mscf/day	6.52
Produced gas, sm^3/day	185
GOR , scf/bbl	20
GOR, sm^3/m^3	3.6
GWR, sm^3/m^3	0.6
GLR, sm^3/m^3	0.5
Power oil, m^3/day	636
GOR when power oil added, sm^3/m^3	0.3

Quality of Available Data

It is always important to evaluate the quality of data provided before inputting the data into prediction software. As scale is normally formed in the water phase due to the reaction between scaling cations (e.g., Ca, Ba, Sr) and scaling anions (e.g., HCO_3 and SO_4), the accuracy of scaling ion concentrations are one of the most important parameters in affecting the scaling potential. In this paper, we presume the ion concentrations analyzed from the only water available is a true represent of the field without any scale deposits before water sampling. As sulphate scale is less dependent on pressure, it can normally be accurately predicted with reliable ion concentrations alone. However, accurate carbonate scaling prediction relies not only upon accurate ion concentrations but also depends upon the accurate measurement of pH, total alkalinity and CO_2 mass balance in all three phases. The CO_2 mass balance in all three phases can normally be predicted accurately using prediction software by inputting reliable water, oil, and gas analysis and production data. However, getting reliable water analysis itself can be difficult in the field, let alone the requirement for accurate pH, total alkalinity, hydrocarbon analysis and production data. It is therefore more difficult to predict carbonate scale accurately. In order to determine a realistic carbonate scaling threat, there are demands for an expert analysis of existing data, making reasonable assumptions and making the full use of the prediction software to reasonably predict unknowns. In this paper, all data available for carbonate scale prediction has been fully evaluated for its validation and reliability.

Quality of water analysis is shown in Table 2. This is the only water composition data available and it is used as the starting point.

For carbonate scale prediction in oil wells, due to the involvement of CO_2 partitioning into all three phases, it becomes crucial to have reliable input of pH, total alkalinity, CO_2 mole%, GOR/GWR and hydrocarbon analysis.

As discussed earlier, the pH measured onshore normally varies a lot from the realistic value. To examine the accuracy of pH reported in the water analysis data, a single point calculation to reservoir condition can be carried out. For the water composition (as shown in Table 2) at a given pH of 7, the predicted saturation ratio of calcium carbonate is 6, i.e., SR ($CaCO_3$) >>1. Considering reservoir rock in Northsea are calcite containing or calcite cemented, this is not possible since the calcium carbonate should be saturated and at equilibrium with the environment in the realistic reservoir situation. The supersaturation ratio of calcium carbonate should be equal to 1, i.e., SR ($CaCO_3$) = 1 at reservoir condition.

Before conducting sensitivity runs, it is always advisable to check the measured pH at the analytical condition to determine if it is a realistic value. If not, the pH of water should be adjusted to a realistic value. To do this, a prediction run that set SR ($CaCO_3$) = 1 at reservoir condition was carried out to predict the pH at different locations. The pH predicted at different temperature and pressures is shown in Table 5.

As shown in Table 6, the pH of 7 measured onshore for the water analysis condition cannot be representative of downhole and system conditions with different temperatures and pressures. A predicted value of 6.1 is in line with SR ($CaCO_3$) = 1 at reservoir condition. This pH value is also more consistent with the onsite measurement of pH = 6.35 during the field visit. The greater pH of 7 measured onshore indicated the possibility of further CO_2 evolution and deposition of carbonate during the transport and storage before analysis. In the following calculations, pH 6.1 was used as the Base Case 1 in Scenario 1.

Table 5 pH predicted when SR ($CaCO_3$) = 1 at reservoir condition.

Step	Location	T (°C)	P (bar)	pH
1	Reservoir	53	69	6.0
2	Wellhead / Separator	30	2	6.1
3	Water analysis	20	1	6.1

Table 6 Prediction results–5.81 CO_2 mol% input to the model instead of pH.

Step	Location	SR ($CaCO_3$)	pH
1	Reservoir	0.5	5.7
2	Wellhead / Separator	0.8	6.1
3	Water Analysis	0.8	6.2

We also note that there is no total alkalinity value given where bicarbonate concentration has been used as the total alkalinity, it is therefore possible to decrease the input total alkalinity value until getting SR ($CaCO_3$) = 1 at reservoir condition while keeping the pH of 7. However, reduced total alkalinity would have suggested the addition of acid, which is in contradiction to the fact that the field has used a pH adjustment chemical to increase pH for corrosion protection purposes. Therefore, we believe that the bicarbonate concentration, i.e., the total alkalinity input cannot be smaller than the current number. In Scenario 1, pH 6.1 is used as the base line for comparison while keep the total alkalinity unchanged.

There were suggestions from the field that the simulations should take account of the potential of local pH increases based on pH adjustment chemical being pumped down hole. The effect of increase in pH is therefore studied in details in Cases 2, 3, 5 and 6 where pH was increased to 7 and 8.

The total alkalinity and the organic acid concentrations in this case are unknown so the measured bicarbonate concentration has to be inputted as the total alkalinity. However, this is only true in waters without other acids rather than CO_2; the total alkalinity will have the same value as the bicarbonate concentration if pH is in the range of 7-9. Unlike the bicarbonate concentration, the total alkalinity is considered a conservative property that is defined as the sum of all pH independent ions; therefore it can be measured in the lab accurately [10]. Without a measured organic acid and total alkalinity values, the reliability of the bicarbonate value is unknown in this case, however, we can use the software to tune (i.e. calculate) for a realistic total alkalinity value which will be demonstrated in Scenarios 2 and 3.

Other factors controlling the carbonate scaling such as CO_2 mol%, GOR/GWR and hydrocarbon analysis come from the reliability of hydrocarbon analysis which is discussed below.

Quality of hydrocarbon analysis is shown in Table 3. For carbonate scaling evaluation, it is important that we obtain reliable hydrocarbon (both oil and gas) analysis. However, in this case we only have one gas analysis data with no full alkyl oil composition data available. This can undermine the reliability of the prediction which will be demonstrated in Scenarios 2 and 3 calculations.

One way to check the reliability of the gas analysis is to use the analyzed CO_2 mol% at the separator as the input instead of pH measured at water analysis condition. We now input CO_2 mol% of 5.81 mol% instead of pH to the model and then ask the model to calculate the SR and pH at reservoir, separator and water analysis conditions. The result is shown in Table 6.

It can be seen that using the 5.81 CO_2 mol% as the input instead of unrealistic pH (7) value, the model has predicted SR ($CaCO_3$) in the reservoir as 0.5 which is much below 1. This is not in line with our expectation as the calcium carbonate should be at equilibrium condition in reservoir, although it is possible for a reservoir being under saturated with calcium carbonate. The resulting pH at water analysis condition however, is very close to the pH value predicted in Table 5. These results indicate the gas analysis is much more reliable than the measured water pH; the gas analysis was used for the following calculations to represent one of the hydrocarbon phases.

As discussed earlier, the CO_2 mass balance in all three phases can normally be calculated accurately under the conditions of reliable water, oil, and gas analysis and production data. Once the CO_2 mass balance in all three phases being reliable calculated, the model is then able to predict the carbonate scale accurately. In this case, we only have one gas analysis data with no oil analysis data at all. Therefore no recombined fluid composition can be calculated, and we will have to trust the GOR number. Due to the lack of oil composition, there is no way to back checking each parameter that controls the CO_2 partition in all 3 phases.

3.1 Scenario 1 Results: Only Water Composition Involved in Calculation

Scenario 1 represents the case when there is only water composition available as listed in Table 2. In this case, no CO_2 partition in phases can be considered due to lack of hydrocarbon analysis. The accuracy of prediction is purely depending on the accuracy in pH, ion concentration and total alkalinity of water at given temperature and pressure condition. The data cannot be back calculated or tuned to more realistic values. It is well known that pH measured from a produced sample can vary a lot from the real situation and the total alkalinity is represented by the bicarbonate concentration where organic acids have been excluded from the calculation. Both of these can cause great discrepancy in prediction of carbonate scale. In our calculations below, pH is adjusted to pH 6.1 in Case 1 as the base line for comparison; the effect of pH changes is then studied in details.

Base Case 1: pH 6.1. Results and Discussions. Tables 7 and 8 give the prediction results in terms of Saturation Ratio (SR) and Precipitate (ppt) amount for pH 6.1 condition.

At this pH condition, the Calcium Carbonate SR = 1 in the reservoir condition (Step 1), and SR <1 when moving to topside (Step 2–Wellhead/Separator). These

Table 7 Case 1 (pH = 6.1)-saturation ratios (SR).

Step	SR($CaCO_3$)	SR($CaSO_4$A)	SR($CaSO_4$ G)	SR($BaSO_4$)	SR($SrSO_4$)	SR($CaSO_4$ H)
1	1.0	0.1	0.1	1.2	0.5	0.1
2	0.7	0.0	0.1	2.4	0.5	0.0

Table 8 Case 1 (pH = 6.1)-precipitate amount (ppt).

Step	ppt($CaCO_3$) (g/m^3)	ppt($CaSO_4$A) (g/m^3)	ppt($CaSO_4$ G) (g/m^3)	ppt($BaSO_4$) (g/m^3)	ppt($SrSO_4$) (g/m^3)	ppt($CaSO_4$ H) (g/m^3)
1	0	0	0	1.0	0	0
2	0	0	0	3.8	0	0

indicate that no calcium carbonate deposition was predicted as a result of using only water analysis data at this pH 6.1 condition. There is some Barium Sulphate deposition potential (SR slightly >1) with maximum SR = 2.4 and maximum precipitation 3.8 g per cubic meter of water. However, this small amount of $BaSO_4$ deposition is believed not to cause operational difficulty. There is no other type of scale deposition predicted (SR <1).

Clearly the conclusion of no $CaCO_3$ scaling threat predicted here does not match up the field observation. The results in Case 1 represent the results in initial scaling prediction where a false conclusion was drawn upon, i.e., no scaling threat for the field.

Case 2: pH 7. Results and Discussions. Following the field visit and proved carbonate scale deposit in field, it was speculated that the increase in scaling threat from the initial scale prediction may be a result of local increase in pH (up to pH 8) due to the application of high pH adjustment chemical. Tables 9 and 10 therefore give the prediction results in terms of Saturation Ratio (SR) and Precipitate (ppt) amount for pH 7 condition.

Case 2 was simulated by using pH 7 on the surface then back calculated what the scaling threat would be at downhole (Step 1) and Wellhead/Separator (Step 2) conditions. As shown in Tables 9 and 10, there is higher scaling potential for $CaCO_3$ with a SR of 6.0 at downhole and 4.6 at Wellhead/Separator conditions. If these were allowed to fully deposit, the maximum amount of $CaCO_3$ scale could reach 66 g/m^3 at downhole or 54 g/m^3 at Wellhead/Separator conditions. This represents a worse $CaCO_3$ scaling threat than that of Case 1 should local pH was increased due to the addition of another chemical. In terms of $BaSO_4$ deposition potential, the predicted scaling potential and scaling amount remain the same as in Case 1; the small amount is believed not to cause any operational difficulty. Again, there is no other type of scaling threat present with SR <1 for other scales.

Case 3: pH 8. Results and Discussions. Tables 11 and 12 give the prediction results in terms of Saturation Ratio (SR) and Precipitate (ppt) amount for pH 8 condition.

In Case 3, another sensitivity test is run by increasing pH to 8 to see the effect of this pH increase. As shown in Tables 11 and 12, again the scaling threat and precipitated amount for $BaSO_4$ deposition remain same and there is no other scale types predicted. However, for $CaCO_3$ the scaling potential SR has increased to 32 at downhole and 38 at Wellhead/Separator condition. This represents a more severe scaling threat with maximum precipitate amount of 90 g/m^3 at downhole or 82 g/m^3 at Wellhead/Separator if allowed to be fully deposited.

In summary, sensitivity runs in Cases 1-3 has shown that pH increase can greatly affect the scaling potential of $CaCO_3$ by changing it from no scaling at pH 6.1, possible scaling at pH 7 and severe scaling potential at pH 8. No effect to $BaSO_4$ deposition potential. These sensitivity test results suggest the importance to have reliable pH data for an accurate carbonate scaling potential. The addition of other production chemicals (e.g., pH adjustment chemical) can greatly affect the carbonate scaling threat therefore a safe operation

Table 9 Case 2 (pH = 7)-saturation ratios (SR).

Step	SR($CaCO_3$)	SR($CaSO_4$A)	SR($CaSO_4$ G)	SR($BaSO_4$)	SR($SrSO_4$)	SR($CaSO_4$ H)
1	6.0	0.1	0.1	1.2	0.5	0.1
2	4.6	0	0.1	2.4	0.5	0

Table 10 Case 2 (pH = 7)-precipitate amount (ppt).

Step	ppt($CaCO_3$) (g/m^3)	ppt($CaSO_4$A) (g/m^3)	ppt($CaSO_4$ G) (g/m^3)	ppt($BaSO_4$) (g/m^3)	ppt($SrSO_4$) (g/m^3)	ppt($CaSO_4$ H) (g/m^3)
1	66	0	0	1.0	0	0
2	54	0	0	3.8	0	0

Table 11 Case 3 (pH = 8)-saturation ratios (SR).

Step	SR($CaCO_3$)	SR($CaSO_4$A)	SR($CaSO_4$ G)	SR($BaSO_4$)	SR($SrSO_4$)	SR($CaSO_4$ H)
1	32	0.1	0.1	1.2	0.5	0.1
2	38	0	0.1	2.4	0.5	0

Table 12 Case 3 (pH = 8)-precipitate amount (ppt).

Step	ppt($CaCO_3$) (g/m^3)	ppt($CaSO_4$A) (g/m^3)	ppt($CaSO_4$ G) (g/m^3)	ppt($BaSO_4$) (g/m^3)	ppt($SrSO_4$) (g/m^3)	ppt($CaSO_4$ H) (g/m^3)
1	90	0	0	1.0	0	0
2	82	0	0	3.8	0	0

envelope should be maintained by careful selection of the target pH in the system.

The factors controlling carbonate scaling include GWR/GOR, total alkalinity and/or HCO_3^-, hydrocarbon analysis, pH and CO_2 mol%. It is worth to note that the carbonate prediction result shown in Scenario 1 is unlikely to be reliable due to the lack of reliable data from these factors. When there is only water present in the model, all CO_2 is forced to dissolve in water phase; this is unrealistic as CO_2 can partition into all three phases. With the missing hydrocarbon analysis, the prediction result in Scenario 1 is for demonstration purpose only. But it does show that pH affect carbonate scaling greatly and this is to compare with the results in Scenarios 2 and 3 to highlight the importance of getting all valid input data in particular a valid hydrocarbon analysis data.

3.2 Scenario 2 Results: Water as Well as Gas Phase Involved in Calculation

Scenario 2 represents the situation where not only water sample analysis but gas analysis is available and incorporated into the model. Without the presence of oil, the hydrocarbon gas will be treated as free gas balancing with water phase; i.e., CO_2 is dissolved/ partitioned into both water and gas phases according the mass balance. The addition of a gas phase makes it possible to tune the alkalinity in the reservoir to a value where calcium carbonate is in equilibrium; i.e., SR ($CaCO_3$) = 1. As there is no oil present, the prediction result cannot replicate the actual field condition either.

It was discussed earlier that the total alkalinity is an important factor controlling carbonate scaling. However, there is no measured total alkalinity value available and the measured bicarbonate concentration is used instead in Scenario 1. This alone can cause huge differences in prediction results. The prediction software has the capability to back calculate a total alkalinity value when there is a gas hydrocarbon phase in the system. A gas composition was given in Scenario 2, this has made it possible for the model to tune the total alkalinity while keep the SR ($CaCO_3$) = 1 under the assumed reservoir condition. Prediction results are shown below.

Case 4: with gas-CO_2 5.81 mol%. In Case 4, we considered using the measured CO_2 mol% of 5.81 (at

Table 13 Case 4-tuned with gas-saturation ratios (SR).

Step	SR($CaCO_3$)	SR($CaSO_4$A)	SR($CaSO_4$ G)	SR($BaSO_4$)	SR($SrSO_4$)	SR($CaSO_4$ H)
1	1.0	0.1	0.1	1.2	0.5	0.1
2	2.5	0.0	0.1	2.4	0.5	0.0

Table 14 Case 4-tuned with gas-precipitate amount (ppt).

Step	ppt($CaCO_3$) (g/m^3)	ppt($CaSO_4$A) (g/m^3)	ppt($CaSO_4$ G) (g/m^3)	ppt($BaSO_4$) (g/m^3)	ppt($SrSO_4$) (g/m^3)	ppt($CaSO_4$ H) (g/m^3)
1	0	0	0	1	0	0
2	277	0	0	4	0	0

separator condition) as our original water input, add the gas analysis as a free gas phase and carry out the tuning calculations. Following tuning the composition to SR ($CaCO_3$) = 1 under reservoir condition, the calculated total alkalinity became 946 mg/L. This is a huge increase from original input of 205 mg/L (based on bicarbonate concentration). This suggests that the predictions conducted earlier using the bicarbonate concentration as the total alkalinity input was incorrect. Using the tuned water analysis data, the prediction results are shown in Tables 13 and 14. Comparing with the results in Base Case 1 (Tables 7 and 8), there is calcium carbonate scaling potential at separator condition predicted with SR ($CaCO_3$) = 2.5 and maximum amount of 277 g/m^3 of $CaCO_3$ per cubic meter of water. This result is in better agreement with the field observation of carbonate scale. The barium sulphate scaling potential is unchanged which indicates the barium sulphate scaling is much less affected by CO_2 and pH change.

In summary, with addition of a gas composition into the model, tuning of total alkalinity to a more realistic value becomes possible. Comparing with the base Case 1 where only water present, the prediction results have shown that a much increased total alkalinity is required to enable SR ($CaCO_3$) = 1 under reservoir condition. In Scenario 2, calcium carbonate scaling potential in the field is predicted with SR = 2.5 and maximum amount of 270 g/m^3 of scale. This is in line with the field observation where calcium carbonate scale has been found.

Note that scenario 2 considered the cases where only gas and water analysis available, therefore the prediction results are still not replicating the actual field conditions. This is because the most realistic tuning procedure requires both oil and gas information to enable mass balancing of CO_2 in the whole hydrocarbon phases.

3.3 Scenario 3 Results: All Three Phases (Water, Oil and Gas) Involved in Calculation

Scenario 3 represents the situation where analysis for all three phases available. This is the most realistic scenario since all three phases should be present in an oil well during production. In this scenario, CO_2 is dissolved/partition into all three phases according the mass balance. The addition of the hydrocarbon phase makes it possible to tune the alkalinity in the reservoir to the most realistic value where calcium carbonate is in equilibrium, i.e., SR ($CaCO_3$) = 1. Although we do not have full alkyl chain oil composition, we have data on the API[1] gravity, wax content and pour point for the field crude oil which gives an indication of the full alkyl chain distribution. We have used the prediction model to help creating a reasonable oil composition by conducting sensitivity runs using several assumed oil compositions. Based on the available gas analysis and available oil property, several assumed oil compositions were inputted to the model to calculate the GOR/GLR at separator condition. The oil composition that resulted in similar GOR/GLR as in Table 4 (GOR = 3.6 and GLR = 0.5 at separator condition) is considered to be of similar composition to the actual field oil. The created oil composition is shown in Table 15.

Using this oil analysis data, the resulting GOR = 3.9 and GLR = 0.5 at separator condition.

Case 5: with oil and gas-CO_2 5.81 mol%. In Case 5, the measured CO_2 mol% of 5.81 (at separator condition) was used as our original water input, adding both oil and gas analysis into the system. Following tuning the composition to SR ($CaCO_3$) = 1 under reservoir condition, the calculated total alkalinity is 651.03 mg/L. This is a huge increase from original input of 205 mg/L (based on bicarbonate concentration), but it's smaller than the value in Scenario 2. If the oil composition created is in line with the actual field oil analysis, then we trust this total alkalinity number calculated should be the most reliable number among the three scenarios. Using the tuned water analysis data, the prediction results are shown in Tables 16 and 17.

The involvement of oil phase into the calculation has resulted in a reduced total alkalinity of 651.03 mg/L after tuning. This is because the total mass of CO_2 has now been dissolved into both oil and gas phases therefore less CO_2 is forced to dissolve into the water phase comparing Scenario 2 where only one hydrocarbon phase present. With the reduced total alkalinity the scaling potential for calcium carbonate is reduced to SR = 1.2 and maximum amount of 39 g/m^3 at separator condition. This indicate a less severe carbonate scaling threat, however carbonate scaling potential exists which is in line with the field observation.

Case 6: with both oil and gas-power oil addition. It was required by the field to simulate the addition of power oil into the production stream and evaluate this effect on the scaling potential. The power oil addition rate is 636 m^3/day (vs. oil rate of 52 m^3/day). The following results in Tables 18 and 19 have shown that the addition of this amount of power oil would have little effect on carbonate scaling potential. The SR has reduced from 1.2 to 1.1 and the maximum precipitation amount has reduced from 39 g/m^3 to 24 g/m^3.

Table 15 Assumed full alkyl chain oil composition.

	mol%
H_2O	0
N_2	0.08
CO_2	1.67
H_2S	0
C1	0.77
C2	1
C3	1
iC4	1
nC4	1
iC5	2.09
nC5	2.58
C6	3.66
C7	5.62
C8	6.03
C9	5
C10+	68.5

Table 16 Case 5-tuned with both oil and gas-saturation ratios (SR).

Step	SR($CaCO_3$)	SR($CaSO_4$A)	SR($CaSO_4$ G)	SR($BaSO_4$)	SR($SrSO_4$)	SR($CaSO_4$ H)
1	1.0	0.1	0.1	1.2	0.5	0.1
2	1.2	0.0	0.1	2.4	0.5	0.0

Table 17 Case 5-tuned with both oil and gas-precipitate amount (ppt).

Step	ppt($CaCO_3$) (g/m^3)	ppt($CaSO_4$A) (g/m^3)	ppt($CaSO_4$ G) (g/m^3)	ppt($BaSO_4$) (g/m^3)	ppt($SrSO_4$) (g/m^3)	ppt($CaSO_4$ H) (g/m^3)
1	0	0	0	1	0	0
2	39	0	0	4	0	0

Table 18 Case 6-addition of power oil-saturation ratios (SR).

Step	SR($CaCO_3$)	SR($CaSO_4$A)	SR($CaSO_4$ G)	SR($BaSO_4$)	SR($SrSO_4$)	SR($CaSO_4$ H)
1	1.0	0.1	0.1	1.2	0.5	0.1
2	1.1	0.0	0.1	2.4	0.5	0.0

Table 19 Case 6-addition of power oil-precipitate amount (ppt).

Step	ppt($CaCO_3$) (g/m^3)	ppt($CaSO_4$A) (g/m^3)	ppt($CaSO_4$ G) (g/m^3)	ppt($BaSO_4$) (g/m^3)	ppt($SrSO_4$) (g/m^3)	ppt($CaSO_4$ H) (g/m^3)
1	0	0	0	1	0	0
2	24	0	0	4	0	0

3.4 Effect of pH

Using the software tuning facility with all three phases present, we believe the resulting total alkalinity 651.03 mg/L is the most reliable value and closest to reality in the field. In the following cases we will use this value to redo all the calculations in Scenario 1 when pH was increased from the saturation pH (6.1) to pH 7 followed by increasing to pH 8. This is to demonstrate the true extent of pH effect on carbonate scaling potential. Comparing Scenario 1, we will stick with the assumption that only water present in the model; but add the unknown parameters calculated in Scenario 3 to improve the reliability. To this end, we have a reliable total alkalinity being 651.03 mg/L, and GWR of 0.95. With these reliable values, we can define the true CO_2 dissolved in the water phase therefore the scaling threat predicted will be much more reliable than those of Scenario 1. Below Cases 7-9 are the results.

Case 7: Tuned Alkalinity with pH = 6. Following tuning in Scenario 3 when both oil and gas present, the resulting total alkalinity is 651.03 mg/L, pH = 6, and a GWR of 0.95 at water analysis condition. Inputing these numbers into the water analysis, calculation is made for downhole (Step 1) and separator (Step 2) conditions. The results are listed in Tables 20 and 21. This Case 7 represent the base case where calcium carbonate is treated as saturated in the reservoir condition with SR = 1 and no carbonate scaling expected. This case is in a direct comparison with base Case 1 (Tables 7 and 8) where no oil and gas analysis available therefore unreliable total alkalinity inputted to the model. In comparison to Case 1, calcium carbonate SR at separator condition has increased from 0.7 to 1.3 that indicates the possibility of carbonate scale with maximum predicted amount of 58 g/m^3. This conclusion is much more realistic than Case 1 (i.e., no carbonate scale threat).

Case 8: Tuned Alkalinity with pH 7. Increase the pH input to pH 7, we have investigated the pH effect on scaling threat using the more reliable total alkalinity number 651.03 mg/L. Again, calculation is made for downhole (Step 1) and separator (Step 2) conditions. The results are listed in Tables 22 and 23. This Case 8 is in a direct comparison with Case 2 (Tables 9 and 10) where no oil and gas analysis available therefore unreliable total alkalinity inputted to the model. In comparison to Case 2, calcium carbonate scaling threat at downhole (Step 1) have increased from SR = 6 and ppt = 66 g/m^3 to SR = 22 and ppt = 331 g/m^3; at separator condition these numbers have increased from SR = 4.6 and ppt = 54 g/m^3 to SR = 17 and ppt = 300 g/m^3 in Case 8. These indicate a much more severe scaling threat the field would have experienced should the local pH has gone up to pH 7.

Case 9: Tuned Alkalinity with pH 8. Further increase the pH input to pH 8, calculation results for downhole (Step 1) and separator (Step 2) conditions are shown in Tables 24 and 25. This Case 9 is in a direct comparison with Case 3 (Tables 11 and 12) where no oil and gas analysis available therefore unreliable total alkalinity was inputted to the model. In comparison to Case 3, calcium carbonate scaling threat at downhole (Step 1) have increased from SR = 32 and ppt = 90 g/m^3 to SR =

Table 20 Case 7-(tuned alkalinity and pH = 6)-saturation ratios (SR).

Step	SR($CaCO_3$)	SR($CaSO_4$A)	SR($CaSO_4$ G)	SR($BaSO_4$)	SR($SrSO_4$)	SR($CaSO_4$ H)
1	1.0	0.1	0.1	1.2	0.5	0.1
2	1.3	0.0	0.1	2.4	0.5	0.0

Table 21 **Case 7-(tuned alkalinity and pH = 6)-precipitate amount (ppt).**

Step	ppt($CaCO_3$) g/m^3	ppt($CaSO_4$A) g/m^3	ppt($CaSO_4$ G) g/m^3	ppt($BaSO_4$) g/m^3	ppt($SrSO_4$) g/m^3	ppt($CaSO_4$ H) g/m^3
1	0	0	0	1	0	0
2	58	0	0	4	0	0

Table 22 **Case 8-(tuned alkalinity and pH = 7)-saturation ratios (SR).**

Step	SR($CaCO_3$)	SR($CaSO_4$A)	SR($CaSO_4$ G)	SR($BaSO_4$)	SR($SrSO_4$)	SR($CaSO_4$ H)
1	22	0	0	1	0	0
2	17	0	0	2	0	0

Table 23 **Case 8–(tuned alkalinity and pH = 7)-precipitate amount (ppt).**

Step	ppt($CaCO_3$) (g/m^3)	ppt($CaSO_4$A) (g/m^3)	ppt($CaSO_4$ G) (g/m^3)	ppt($BaSO_4$) (g/m^3)	ppt($SrSO_4$) (g/m^3)	ppt($CaSO_4$ H) (g/m^3)
1	331	0	0	1	0	0
2	300	0	0	4	0	0

Table 24 **Case 9-(tuned alkalinity and pH = 8)-saturation ratios (SR).**

Step	SR($CaCO_3$)	SR($CaSO_4$A)	SR($CaSO_4$ G)	SR($BaSO_4$)	SR($SrSO_4$)	SR($CaSO_4$ H)
1	102	0	0	1	0	0
2	120	0	0	2	0	0
3	120	0	0	3	0	0

Table 25 **Case 9-(tuned alkalinity and pH = 8)- precipitate amount (ppt).**

Step	ppt($CaCO_3$) (g/m^3)	ppt($CaSO_4$A) (g/m^3)	ppt($CaSO_4$ G) (g/m^3)	ppt($BaSO_4$) (g/m^3)	ppt($SrSO_4$) (g/m^3)	ppt($CaSO_4$ H) (g/m^3)
1	373	0	0	1	0	0
2	348	0	0	4	0	0
3	334	0	0	5	0	0

120 and ppt = 373 g/m^3 in Case 10; at separator condition these numbers have increased from SR = 38 and ppt = 82 g/m^3 to SR = 120 and ppt = 348 g/m^3 in Case 9. These indicate the most severe scaling threat the field would have experienced should the local pH has gone up to pH 8.

In Summary, using the tuned values, the pH has an increased effect on carbonate scaling potential that has highlighted the importance in controlling pH and maintaining the pH under the safe carbonate scaling regime. The field should monitor the pH carefully when adding pH adjustment chemical and re-evaluate the scaling potential when there is any pH change. pH change has no profound effect on sulphate scaling potential.

It is worth to note that these final calculations are based on an assumed oil composition, which may not be representative to the actual field, therefore the results here is only to demonstrate the importance of reliable data input and how scaling threat can be affected by changing parameters.

4. Conclusions

Through 3 Scenarios and 9 Cases, this paper demonstrates the importance of valid data input into scale prediction software to ensure a representative carbonate scaling prediction. Carbonate scaling, e.g., calcium carbonate scaling is controlled by parameters such as scaling ion concentrations, oil and gas compositions, total alkalinity, pH, CO_2 mol%, and GOR/GWR/GLR values. Among these only the scaling ion concentrations and total alkalinity are conservative properties, while pH, CO_2 mol%, oil and gas compositions and GOR/GWR/GLR are non-conservative and can change with temperature and pressure at different locations. These have resulted in the difficulty in predicting carbonate scale accurately as very often not all these values are available or unreliable values provided. Even for the conservative parameters such as the total alkalinity, it is not very often measured in the field and only the bicarbonate concentration is reported. The scaling ion concentrations are sometimes measured from an unpreserved sample where the scale may have already deposited before the sample was taken.

The lack of reliable data input (accurate field determined water, gas, and oil analysis) has caused the inaccuracy in carbonate scaling prediction; Case 1 in Scenario 1 (Section 3.1) demonstrated the lack of data and the use of unreliable data has resulted in incorrect conclusion of no scaling threat where there is carbonate scale deposits found in the actual field. Scenarios 2 and 3 (Sections 3.2 and 3.3) demonstrated how we can improve the prediction accuracy by using all the available data and make valid inputs into the model based on our knowledge of the model capacity. Using an available gas analysis (Scenario 2), the total alkalinity can be tuned into a more realistic value and more realistic prediction can be made; by creating a reasonable oil analysis input (Scenario 3) we have demonstrated the most realistic total alkalinity and the most realistic carbonate scaling threat can be calculated by the model. In addition, the effect of power oil addition seems to have little effect on the actual carbonate scaling potential.

pH has a profound effect on carbonate scaling which is demonstrated in both Scenarios 1 and 3: locally increased pH has resulted in a much more severe carbonate scaling potential. Although the general trend is identical, there are big differences in terms of predicted saturation ratios and precipitated amounts for Scenario 1 (no tuning) and Scenario 3 (tuning by oil and gas phases). Since the total alkalinity has been tuned to the most realistic value using available hydrocarbon data, it is believed Scenario 3 represent the most realistic scaling threat. The effect of increased pH on carbonate scaling potential is much greater in Scenario 3, severe carbonate scaling are predicted for both downhole and separator conditions.

5. Recommendations

This paper has highlighted the importance of valid data input in order to get a representative carbonate scaling potential. The ultimate message is to get as much data as possible from all carbonate scaling contributing parameters (scaling ion concentrations, oil and gas compositions, total alkalinity, pH, CO_2 mol%, GOR/GWR/GLR values and T/P). In particular, a full reliable data set at one single location (same T/P) is most desired as the model can then predict all parameters and scaling potential at other locations accurately. The other advantage of getting a full data set is that the parameters can be counter checked against each other by calculating some parameters as unknowns while inputting minimum known parameters; by doing this, the reliability of the parameters can be evaluated.

It is recommended to measure the total alkalinity in the lab as total alkalinity is a conservative property and can be measured accurately after field sample being transported onshore. With a reliable total alkalinity, the model can predict carbonate scaling more accurately; the total alkalinity number can also be used to check if other parameters (e.g., water, oil and gas compositions) are reliable or not. As the severity of scaling is predicted based on the mass balance of scaling ions it is very important that the ion concentrations is measured on a downhole samples or from a preserved sample where no scale deposit has occurred prior to sampling.

As illustrated in this paper, we can derive a relative reliable prediction by using the model to calculate the unknowns with limited knowns. However, this will require an experienced modeler with comprehensive understanding of the model as well as available field data, which may not be readily available in some situations. It is therefore recommended to gather as much reliable data as possible from the field before attempting a carbonate scaling prediction. To ensure an accurate carbonate scale prediction, the following data are recommended:

Description of system

(1) Temperature and pressure profiles at key stages (reservoir, downhole, chokes, wellhead, separators etc.).

(2) Production data, e.g., at the separator.

Full water analysis

(1) Ion concentrations in mg/L. Na^+, K^+, Mg^{2+}, Ca^{2+}, Ba^{2+}, Sr^{2+}, Fe^{2+}, Cl^-, $SO4^{2-}$, HCO_3^-.

(2) pH.

(3) VFA's. Concentration of individual Volatile Fatty Acids.

(4) Total Alkalinity.

(5) Density. It can be estimated easily if not available.

Note: it is important to state how the sample was taken and treated during transit to lab and the method of analysis. It is recommended to take at least one preserved sample; sometimes it may need several samples with different preservation techniques.

Free gas analysis (e.g., samples from the separator)

(1) Gas composition in mol %.

(2) GWR with description of the temperature and pressure for the water flash analysis.

Full hydrocarbon analysis (e.g., samples from the separator)

(1) Gas composition in mol %.

(2) Oil composition in mol %; or recombined composition.

(3) GWR.

(4) GOR.

(5) Density of oil.

(6) Bubble point temperature and pressure.

Note: it is important to detailing the temperature and pressure of the location where the gas or oil samples were taken and the temperature and pressure of analysis.

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