**Understanding $CaCO_3$ precipitation during oil recovery**

Extended abstract

by

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## Introduction

Deposition of $CaCO_3$ scale in production wells and surface facilities is a complex process that is dependent on many different interrelated factors including pressure, temperature, water composition, petroleum composition, and precipitation kinetics. Although the influence of each individual factor on the scaling risk is generally understood, the relative importance of each factor is rarely evaluated because, with the exception of operating pressure, it is not usually possible to modify them to reduce the scaling risk. Not only is little known about the relative importance of each factor in determining the level of scaling risk on individual developments, no previous studies have sought to explain why the risk differs from one field to another. This raises the questions: what are the most important factors determining the level of $CaCO_3$ scaling risk in oilfield developments and under what conditions are each of these factors dominant? Factors controlling the $CaCO_3$ scaling risk include:

- Formation water composition:
  - $Ca^{2+}$-concentration
  - Anion/cation ratio
  - Salinity
  - Alkalinity
- Temperature and pressure gradients:
  - Their effects on mineral solubility
  - Their effects on water evaporation/condensation
  - Their effects on $CO_2$ migration between water and gas phase
- Water rate
  - Absolute water rate
  - Water cut
- Petroleum $CO_2$

The effects of $Ca^{2+}$-content, salinity, water cut and $CO_2$ pressure on the scaling risk under various conditions are investigated thoroughly. In doing so, not only have we been able to identify those conditions where $CaCO_3$ scaling risk would be expected to be negligible, we have also determined what combination of factors and conditions give rise to the ‘perfect storm’.

## Selected results and Discussion

There are many speculations associated with when a $CaCO_3$ scale problem may be significant. One is the very simple assumption that formation waters with high $Ca^{2+}$-content give larger scale problems than formation waters with low $Ca^{2+}$. To some extent this is true for topside facilities if a basic $H_2S$ scavenger has to be used to reduce the amount of $H_2S$ that could otherwise be produced. Generally, however, the statement is not correct. Some calculations were performed to investigate the effects of a changing $Ca^{2+}$-content in formation water (FW). The following production path was used for a large part of the calculations:

| | |
|---|---|
| Reservoir P&T: | 699 bar, 160ºC |
| Well toe inlet P&T: | 600 bar, 162ºC |
| Well heal outlet P&T: | 550 bar, 159ºC |
| Separator P&T: | 40 bar, 90ºC |

Figure 1 shows the $CaCO_3$ scaling potentials (SR and kg/day) as a function of $Ca^{2+}$-content in the FW when producing water and hydrocarbons from reservoir conditions; 699 bar and 160ºC to well inlet conditions; 600 bar 162ºC. The hydrocarbon phase contained 1mole% $CO_2$ and the water cut at standard conditions was 1.2%. It can be seen that while SR is close to constant over the range of $Ca^{2+}$-concentrations investigated, the amount that can precipitate depend very much on the $Ca^{2+}$-content. For this particular case there is a peak in precipitated $CaCO_3$ when the $Ca^{2+}$ concentration is approximately 280mg/l. This concentration is rather low compared to most formation waters (Warren and Smalley, 1994). In general, this means that a low $Ca^{2+}$-content increases the scale problem while a higher $Ca^{2+}$-concentration reduces the problem. In short, this can be explained by means of low pH buffer capacity in a FW with high $Ca^{2+}$ and consequently low $HCO_3^-/CO_3^{2-}$ at a given SR compared to a FW with low $Ca^{2+}$ and high $HCO_3^-/CO_3^{2-}$at the same SR. A more detailed explanation and discussion will be given in the presentation.

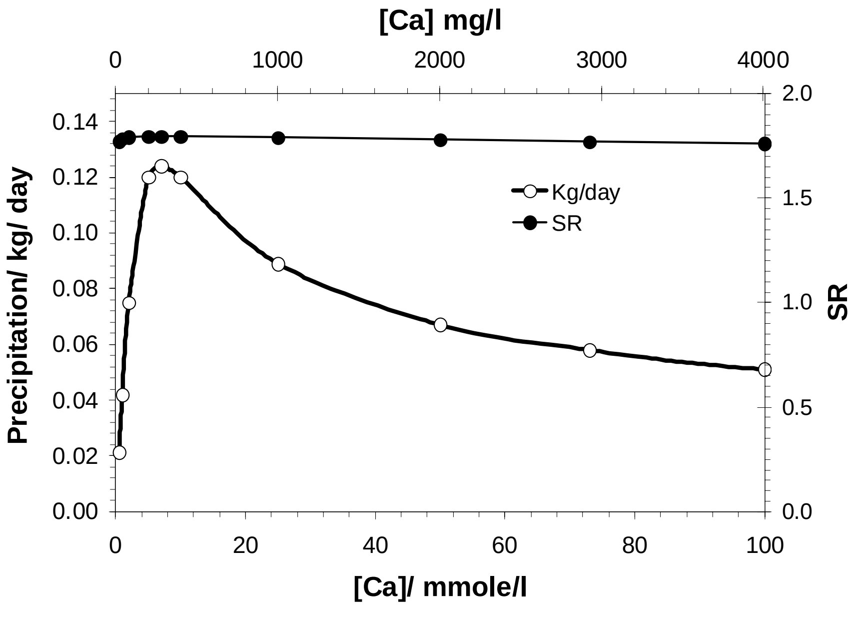


Figure 1: Amount of $CaCO_3$ precipitation and SR as a function of $Ca^{2+}$-concentration in formation upon producing water and hydrocarbons from reservoir conditions; 699 bar and 160ºC to well inlet conditions; 600 bar 162ºC. The hydrocarbon phase contained 1mole% $CO_2$ and the water cut at standard conditions was 1.2%.

The effects of changing amount of $CO_2$ in the hydrocarbon (HC)-phase were also investigated. Figure 2 shows the changes in amount of $CaCO_3$ precipitation as a function of $Ca^{2+}$-content and mole% $CO_2$ in the HC-phase. It can be seen that the $CO_2$ content plays a major role for the potential $CaCO_3$ scale problem as the amount of scale that can form increases with the $CO_2$ content. This is somewhat counterintuitive since more $CO_2$ would lower the pH and increase the solubility of $CaCO_3$. However, since the reservoir is calcite cemented this simply means that more $CaCO_3$ is dissolved in FW to give SR = 1 at reservoir conditions. More dissolved $CaCO_3$ gives a higher alkalinity, which in turn increases pH and buffer capacity of the FW. Peak-Ca also shifts towards higher calcium content with increasing $CO_2$. Further discussions and explanations will be given in the presentation.

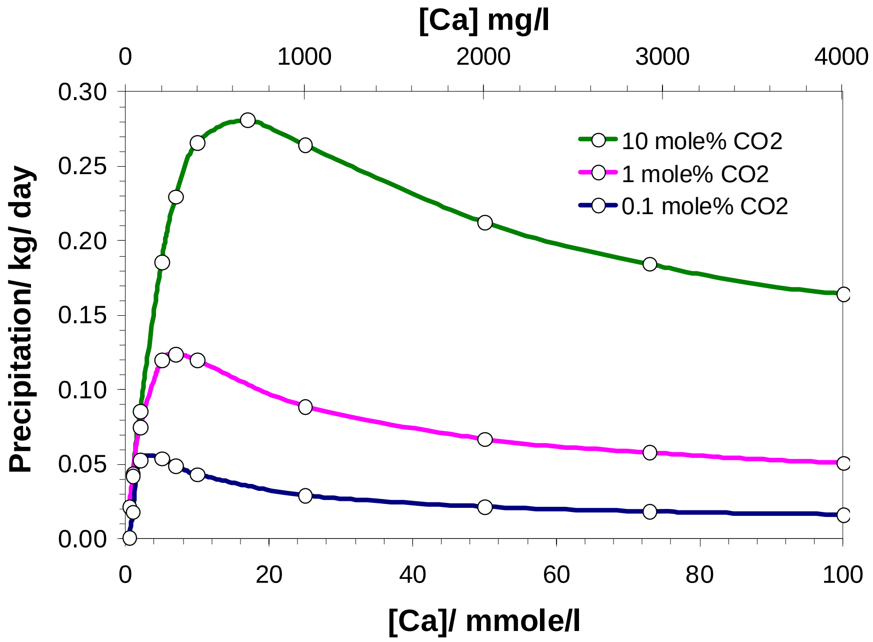


Figure 2: Amount of $CaCO_3$ precipitation as a function of $Ca^{2+}$-concentration in FW and $CO_2$ in HC-phase upon producing water and hydrocarbons from reservoir conditions; 699 bar and 160ºC to well inlet conditions; 600 bar 162ºC. The water cut at standard conditions was 1.2%.

In addition to the $Ca^{2+}$-content and $CO_2$ in HC-phase, the effects of salinity and water cut will be presented and discussed in the presentation. It will be shown under which conditions each parameter seems to be of more or less importance.

**Some additional key findings:**

- $SR_{CaCO3}$ along a production path is relatively unaffected by changes in FW $Ca^{2+}$. The mass of CaCO3 precipitated (kg/day), however, strongly depends on FW $Ca^{2+}$.
- $SR_{CaCO3}$ along a production path is relatively unaffected by changes in the amount of $CO_2$ in the HC-phase, whilst the mass of $CaCO_3$ precipitated does depends on this $CO_2$.
- Low water cut produces more extreme $SR_{CaCO3}$ due to more relative water evaporation, which means that a higher MIC is required to stop precipitation. However, the mass of $CaCO_3$ precipitated increases almost proportionally with the water cut, given that the pressure and temperature gradients do not change with the water cut. A change in water cut does not change the relative effects of $Ca^{2+}$-content in FW and $CO_2$ in the HC-phase on the amount of $CaCO_3$(s) formed.
- The effect of salinity is more complex. In general, however, increased salinity increases the $CO_2$ solubility in the FW at reservoir conditions while it reduces the $CO_2$ solubility at separator conditions. The net result is an increased scaling risk at separator conditions with increasing salinity. At the well inlet no such correlation was observed in the calculated data.

**Reference:**

Warren E. A. and Smalley P. C. (1994). North Sea Formation Water Atlas. In *Geological Society Memoir No. 15*, pp. 208. Geological Society.