MODELLING CaCO₃ DEPOSITION IN GEOTHERMAL WELLBORES

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INTRODUCTION

The capacity of a geothermal liquid to carry calcium varies mainly with the concentrations of CO₂ and HCO₃⁻, temperature and ionic strength, of which the CO₂ concentration (pressure) changes most in the wellbore. Wellbores models that carry accurate computations for CO₂ and other gas pressures might be adapted to compute profile thicknesses of CaCO₃ scale.

A general model for carbonate scale deposition in a wellbore must make a simultaneous accounting for pressures of H₂O, CO₂, and two or three other gases plus salt effects on those pressures. In addition, the elevation of flash initiation must be accurately identified and combined with profiles of temperature, etc., in the 2-phase zone. Such a model has been developed and its principle features are described here, including calibration of some factors with measured scale deposits.

The model provides insight about the scale deposition processes through parametric studies. Tactics and strategies for confronting the effects of CaCO₃ deposition in wells and wellfields can be explored with the model. Modelling of specific wellbores/wellfluids can help quantify risks and benefits concerning scale inhibition, wellfluid monitoring, timing of consequences relating to failure of scale inhibiting apparatus, urgency of remedial actions, and other aspects.

BASIS OF THE MODEL

The main features are a computed solubility of calcite, identification of where flash initiation begins, temperature profile above the bubble point, and incremental deposition of calcite through the temperature (elevation) interval.

Calcite Solubility

The solubility of CaCO₃ (calcite or aragonite) in geothermal waters commonly is represented by a solubility product, $K_s$, that varies with temperature; $K_s = [Ca^{++}][CO_3^{--}]$. $K_s$-values are thermodynamically defined stability coefficients varying only with temperature.

The molar solubilities of calcite and aragonite differ trivially and the numerical distinction is not relevant for modelling. However, aragonite scales tend to be softer and less adherent than calcite, so, an indicator of which polymorph actually forms has operational merit. Their numerical values range from less than 0.2 through 0.9 in the overall spectrum of geothermal resources and must be computed specifically for each temperature step in a wellbore model.

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Most geothermal wells penetrate rocks which contain calcite, hence produced liquids are saturated (equilibrated) at the local static conditions. Typically, there is an imperfect match between the apparent, or measured, field solubility of calcite and the theoretical solubility calculated with activity and stability coefficients and measured bicarbonate. Thus, factor $A$ in Eq. 1 represents a local, well-specific constant that makes the computation of Eq. 1 correspond to the initial field saturation of calcium.

Elevation of the Bubble Point

A lowest elevation in a well that involves vapor phase corresponds to the initiation of boiling and the loss of CO₂ from the liquid. This begins the activation of scale-forming reactions. Elevation of this bubble point (BPE) can be accurately computed without reference to any factors of the two-phase zone or of the wellhead conditions. Essentially, overpressured fluid below the BPE rises to the location where the fluid's total vapor pressure (TVP) equals the local hydraulic pressure; equation 2 applies. Scaling initiated in the wellbore requires that BPE>\(Z_{inflow}\) but scaling initiated in reservoir rocks can be accommodated by the model.
TVP is the sum of H₂O vapor pressure of the liquid (due to its temperature) and the Henry's law pressures (HLP) for all other "gas" species dissolved in the liquid.

\[
\text{TVP}_{\text{BPE}} = (\text{P}_{\text{H₂O}} + \text{HLP}_{\text{CO₂}} + \text{HLP}_{\text{CH₄}} + \text{HLP}_{\text{N₂}} + \text{HLP}_{\text{H₂}} + \ldots)_{\text{BPE}}
\]

All these vary markedly with temperature and HLPs are much more sensitive to salt effects than is \( \text{P}_{\text{H₂O}} \). Wellbore heat losses between the inflow elevation and BPE should be accounted for when computing TVP_{app}, which is different from TVP_{ref}. Without accurate handling of HLP sum, BPE will be misidentified and the pressure gradient wrongly computed in the early stages of steam development, where scale deposition is most significant.

**Temperature Profile in the Wellbore**

Temperature profile above the bubble point is computed according to principles described earlier (Michels 1985). Unlike most other wellbore simulators, in this, total pressure is treated as a dependent variable (joint function of temperature and multiple fluid components and gases). The CO₂ pressure component is applied in equations (1) and (2), providing for accurate coordination of the temperature profile with local calcite solubility.

Friction effects in this temperature-drop model conform to von Kármán principles in the region of 1-phase liquid, extended, with modification, to modest elevations above the BPE. At higher elevations, two-phase fluid friction may be computed without reference to a mechanical roughness of the casing. Instead, concepts and procedures have been developed to compute the interaction between the liquid layer on the casing and the moving two-phase fluid in the bore. The concept incorporates liquid surface tension in a way that drag (friction) becomes a property of the fluid, which varies with temperature, and not a property of the casing metal (which is obscured by the liquid layer in any case).

**Incremental Deposition of CaCO₃**

Within the well profile, local solubility of calcite is computed in terms of the residual liquid's capacity to carry calcium (Eq. 1). Incremental deposition is computed as the difference between the carrying capacities at the ends of temperature-defined intervals. If the two-phase zone is long enough, a minimum calcite solubility occurs within the wellbore, marking the upper limit of scale deposition.

**Pressures of CO₂ and Other Gases**

Three concepts of gas pressures are required to make a proper accounting: Henry's Law pressure of the gas species in liquid, distribution of gas species between liquid and vapor, and effect of salt content on the solubility and distribution.

The Henry's law pressure (HLP) commonly is considered as a solubility, but is more accurately considered as an escaping tendency of gas species from the liquid. It was originally defined as the concentration of a gas species in liquid under a vapor phase pressure, but the presence of a vapor phase is not essential. HLP (of a gas species) may be visualized similarly to the H₂O vapor pressure in an overpressured context. HLPs for each gas species are additive to the H₂O vapor pressure when computing TVP. The correlations between HLPs and temperature are unique for each gas species and dissolved salts in the liquid increase their escaping tendency -- a salting-out effect.

For CO₂ in geothermal engineering circumstances the data from Ellis and Golding (1963) is most useful because it provides for simultaneous accounting of temperature and salt effects. A functional equation for the HLP_{CO₂} based on their data for temperature, salt content and CO₂ pressure, is given by Eq. 3, which applies from 100-350°C and 0 to >70,000 mg/kg chloride. Chloride is useful as a convenient indicator of overall salt content in the liquid.

\[
\text{HLP}_{\text{CO₂}} = 0.281 - 0.000232 \times (T-175) \quad ^{1.3 + 9.98 \times 10^{-7} + 5.4 \times 10^{-9} T} \times \text{Cl}_{\text{eq}} \quad \text{MPa}/(g/kg)
\]

Equation (3) shows a minimum solubility at 175°C, a prominent (+) salt effect, and a strong (+) salt-temperature interaction. Commonly, chloride is the dominant anion and an equivalent chloride concentration can be constructed from measured concentrations (adjusted for steam loss); 

\[
\text{Cl}_{\text{eq}} = \text{Cl}^- + 0.58 \text{HCO}_3^- + 0.74 \text{SO}_4^{2-} \quad \text{mg/kg}
\]

For non-CO₂ gases, HLP can be computed conveniently using equations with the form of (4). Factor S is a salting-out coefficient described later.

\[
\text{HLP}_{g} = S(a + b/(T+273))
\]

Values for a and b given below are based on Himmelblau (1960) and apply only at temperatures higher than the solubility minima, T in Celsius.

<table>
<thead>
<tr>
<th>Gas</th>
<th>a</th>
<th>b</th>
<th>T_{lower limit}</th>
</tr>
</thead>
<tbody>
<tr>
<td>CH₄</td>
<td>-12.2</td>
<td>7860</td>
<td>116</td>
</tr>
<tr>
<td>N₂</td>
<td>-11.5</td>
<td>7440</td>
<td>111</td>
</tr>
<tr>
<td>H₂</td>
<td>-82.1</td>
<td>53100</td>
<td>84</td>
</tr>
</tbody>
</table>

Although CO₂ generally is the dominant gas component in terms of mole fraction, its pressure effects may be less dominant. This is due to the lower molecular solubilities of methane, nitrogen, and hydrogen. Nominally, if CO₂ comprises 90 (mole) percent of the non-condensables, it contributes only 50 percent of the overall sum of HLPs. Thus, disregarding non-CO₂ gases can yield a serious underestimate of overall gas effects on BPE.

Hydrogen sulfide (H₂S) has important safety and environmental aspects, but is generally insignificant in its contribution to TVP. HLP_{H₂S} may be disregarded in other than exceptional circumstances; some Hawaiian wells are exceptional. Sulfide mineral scales are sometimes important and profiles of their deposition potentials can be appended to this basic model. They are not considered further at this time.

**Distribution of gas species between liquid and vapor** becomes important after a vapor phase develops. The distribution is most conveniently described by the form of equation 5.
The equilibrium assumption results in maximum scale thickness at the BPE (abrupt step from zero thickness) with subsequent deposition decreasing upwardly at a decreasing rate. That is, topography of the scale surface predicted by the equilibrium assumption is everywhere concave toward the wellbore interior, which is not observed.

**Measured Scales in Wellbores**

Scale thickness profiles were carefully measured *in situ* (multifinger caliper) in seven geothermal wells at Dixie Valley, Nevada (Benoit, 1987). Only two wells (84-7 and 73-7) had relatively stable production rates prior to scale measurements, so, presumably, their BPEs were stable. Well 73-7 had the smallest measured scale thickness and other events compromised the measurement details, thus, 84-7 is the strongest reference well for calibrating the model. Other wells had decreasing production rates that indicated falling BPEs. Lengths of deposition zones ranged from 300 to more than 500 meters, but the longer zones belonged to wells with falling BPEs. Additional data included recalculated reservoir brine compositions, CO$_2$ contents, estimates of total scale masses deposited in wells, and total liquid volumes.

All measured surface profiles (Benoit, 1987) showed deposition maxima, variously 30 to 100 meters above the lowest elevation of scale. Lowest maxima, 35 and 45 meters were for wells 73-7 and 84-7 which had stable BPEs. These wells also had profiles that were concave toward the well interior at elevations above the maximum thickness. Other wells had profiles that were variously concave, linear, or convex, plausible consequences of unstable BPEs and indicators of unsuitability for calibration.

Modelling indicates that the first 50 meters or so above the BPE are involved with bubble flow; adiabatic temperature decreases there are 0 to >2 degrees, fluid speeds are 0.5 to 4 m/s and vapor volume fractions of 0 to 0.25.

**Objectives in Calibration**

Three components of the model require empirical calibration; delayed degassing of the liquid, mixing length effect, and A-factor for initial saturation of calcium. Degassing effects and the A-factor may be cast as multipliers of the brine's local carrying capacity for calcium, yielding a local "net effective" carrying capacity. Deposition within a temperature step is computed as the difference between "net effective" capacities at the ends of the step. A mixing length effect applies to this difference.

**Using an A-Factor in Eq. 1** accepts the theoretical calcite solubility as having the correct shape and approximate magnitude for a geothermal context. Thus, magnitude of the A-Factor essentially addresses a local calibration. It may be chosen so the model wellhead concentration of calcium matches the measured concentration of residual calcium. [This empirical step merely collects overall errors and imprecisions involved with the calcite solubility calculation, of which there are several. For example, two activity coefficients (one of them squared) are uncertain due to extension of the Debye-Hückel calculation method beyond its concentration range of applicability. The four separate K-values involved are based on experiments of contrasting characteristics and precision. Furthermore, those experimental matrices had undefined relevance to geothermal conditions. Error in reported bicarbonate concentration also finds compensation in A.]

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Degassing is promoted by increased surface/volume ratio for residual liquid. Thus, the approach toward equilibrium may be expected to improve exponentially as the vapor volume fraction increases. A suitable term has the form \(\exp(-a/f)\) which approaches unity as \(f \rightarrow 0.2+\) if \(a=0.001\), \((f=0.000X, (f=\text{vapor volume fraction})\). Calibration for delayed degassing involves selecting a value for \(a\) and using \(\exp(-a/f)\) as a multiplier to the carrying capacity of equation (1).

Mixing length involves an increment of scale deposition that is activated in a narrow elevation range but spread over a wider interval that includes the activation interval plus additional elevation above that interval. The mixing length effect is most apparent in the first few increments of elevation above the BPE. Elsewhere, deposition activated at lower elevations deposits in zones from which newly activated deposition escapes, providing a kind of compensation to the equilibrium deposition computed for higher elevation zones.

Higher fluid speeds increase turbulent shear and smaller bore diameters decrease the eddy diffusion distances to casing walls (scale deposition sites). Both factors would appear to favor shorter mixing lengths. Thus it seems puzzling that well 73-7, with larger bore than 84-7 (2.55 vs .224 m ID) and smaller 1-phase liquid velocity (0.5 vs 2.6 m/s) would show maximum scale deposition closer to the BPE (35 vs 45 m). Perhaps damage to the scale deposit in 73-7 (Benoit, 1987) resulted in under-measurement of maximum deposition in 73-7. Although defining a mixing length to incorporate bore diameter and fluid speed is appealing, calibration is not feasible with only one reliable scale profile, so these aspects will not be considered further in this report. Instead, only a height correlation will be used.

At the upward limit of scale deposition the mixing length effect becomes suppressed. Elevation of the upper limit of scale deposition is defined in the model by a minimum in the brine's carrying capacity for calcium. Above that elevation, the carrying capacity increases all the way to steam temperature. Consequently, activated scale potential that is unspent below the upper elevation limit may be partly resorbed by the liquid. Since scale deposition in this tail region will be small in any case, the mixing length effect is considered inconsequential.

Only a fraction of the scale deposition potential activated within the first increment of elevation \((Z_i)\) above the BPE is deposited within that increment. Yet, the net deposition within subsequent \(Z_i\) include activation from lower increments. Thus, the apparent fraction of available (equilibrium) activation that actually deposits in \(Z_i\) approaches unity as the fluid moves away from the BPE. The value of that "apparent" fraction is estimated here by \(\exp(-Z_i/(m\Sigma Z))\), where \(\Sigma Z\) is the sum of elevation increments between the BPE and lower bound of \(Z_i\) and \(m\) is chosen to make an empirical fit to the short interval involved with measured zero-to-peak scale thickness.

Calibration values are those that yield the match (Figure 1) between model and measured scale profiles for wells 84-7 and 73-7. For the calibration, \(A_{84-7} = 8.97\), \(A_{73-7} = 6.23\), \(a = .001\), and \(m = 0.8\.

Figure 1 should be construed as a test for only the shape of the scale topography. A mass balance (exact thickness match) was not feasible due to uncertainties in (i) amount of liquid involved with the measured scale, (ii) porosity of the measured scale, and (iii) whether a softer form of scale (aragonite?) in the upper deposition zone was underestimated by the caliper fingers.

A non-model multiplier for the model thickness was found which gave a good match with the peak thickness and then uniformly applied over the entire interval. This provides a fair test for model shape of the deposit.

A mass balance is best indicated by the match of calcium concentrations with, versus without scale inhibitor, determined from surface sampling (Benoit, 1991). For the case of 84-7, the "no-inhibitor" residual calcium concentration of 1.29 mg/kg was used to derive \(A = 8.97\). This yields a model concentration of pre-flash calcium = 3.60 mg/kg, which compares to the "with inhibitor" calcium measurement of 3.6 ppm. This result suggests that chemical aspects of modelling are satisfactory.

For the modelling, data for chloride, bicarbonate, and sulfate conformed to well fluid compositions in Benoit (1987) and model wellbore dimensions to actuals. Reservoir and well productivity data were not provided so model values were chosen to yield a BPE that matched the lower limit of scale deposition. A match to wellhead conditions was achieved by adjusting wellbore heat losses.

PARAMETRIC STUDIES

Two important factors in wellbore scale are how fast does it accumulate and where is it located. Both are related to the liquid's local carrying capacity for calcium, which varies with elevation in the wellbore largely due to decreases in temperature and \(P_{\text{CO}_2}\). Other major factors affecting calcium carrying capacity are (initial) bicarbonate and \(\text{CO}_2\) concentration. Physical factors for the model wellbore were set at nominal values, uniform among most figures. Wellbore heat losses were set at zero.
CO₂ Effect on Temperature and Pressure Profiles

Figures 2A and 2B do not depict scale, but show profiles of wellbore temperature and pressure for a variety of initial CO₂ contents at a single model reservoir temperature and fluid composition. Greater CO₂ concentrations cause significant lowering of the BPE and modest increases in wellhead pressure without changing the essential shape of the pressure profile.

Contrastingly, the CO₂ effect on temperature profiles changes the shape so strongly that the order of curves in the family inverts between the BPE and wellhead. Without CO₂, the temperature profile near the BPE is concave up whereas with higher CO₂ concentrations it is concave down. All lowerings of BPE in Figures 2 are assignable to CO₂.

**Figure 2: CO₂ EFFECT ON P-T PROFILES**

Temperature Effect on Scale Profiles

Figures 3A and 3B show the calcium carrying capacity and scale build-up rate for a range of initial fluid temperatures. Other factors, CO₂, overall salt content, etc., were held constant and the same as for Figures 2. Lower BPE in Figures 3 are due to the higher pressure(s) of H₂O which is consequent of the higher temperature(s) [CO₂ effect on TVP decreases with increasing temperature above 175°C]. At higher initial temperatures, the calcite saturation is smaller, reflecting a general knowledge that carbonate scales tend to be less severe in hotter wells.

**Figure 3: INITIAL TEMPERATURE EFFECTS**

HCOC₃ Effect on Scale Profiles

Figures 4A and 4B also show calcium carrying capacity and scale build-up rate at one initial temperature with variable initial CO₂ content. Other factors are the same as for Figures 2. For 4A and 4B the initial ratio of Ca/HCO₃⁻ is < 1 and the initial calcium concentrations vary in nearly direct proportion to the CO₂ contents. The thickness of scale and length of the scale deposition zone also increase in nearly direct proportion to the initial CO₂ content. [Irregularities in the peak shapes are artefacts from the plotting program.]

**Figure 4: INITIAL CO₂ EFFECTS**

Figure 6A and 6B also show calcium carrying capacity and scale build-up rate for various HCO₃⁻ concentrations with other factors similar to those for Figures 4. For Figures 5, Ca/HCO₃⁻ and scale deposition decreases strongly with increasing HCO₃⁻. This contrasts with Figures 6A and 6B, wherein Ca>HCO₃⁻ and scale deposition increases with increasing HCO₃⁻.
Figure 6: BICARBONATE EFFECTS with HCO₃⁻<Ca

Effect of a non-CO₂ Gas

Non-CO₂ gasses do not affect the chemical solubility of calcite (scale components) but they do affect the distribution of scale in the earliest stages, through their effect on the two-phase pressure profile. Figures 7A and 7B show the effect of variable methane (CH₄) concentrations on temperature profile and scale thickness profile, with uniform initial temperature and CO₂ content. Since the non-CO₂ gas effect operates over the zone of maximum scale deposition the matter could be critical to issues of near-closure of a bore by scale buildup.

Figure 7: EFFECT OF non-CO₂ GAS (Methane)

APPLICATIONS

Parametric studies show the multi-dimensional phenomenon of CaCO₃ scale deposition is too complicated for practical "rules of thumb". Modelling can accurately account for multi-dimensionality and there are several practical applications.

Monitoring Scale Inhibition Systems

Chemical methods of inhibiting carbonate scale are well-developed in regard to chemicals available and modestly developed in regard to hardware which places chemicals below the BPE. Importantantly, wells equipped with scale inhibition systems must be monitored to show that the complete system continues to function as intended.

Monitoring scale inhibitor systems may require frequent surface samples of liquid for direct analysis of some scale components. Frequency of sampling should be matched to a well's severity of scaling so that failure of the inhibition system is discovered before costly scale-up of the well occurs. Some wells may permit two weeks or more of uninhibited production, but a few can yield expensive problems in two or three days. Modelling studies can help balance the risks and costs of monitoring by identifying a most practical sampling frequency.

In addition to frequency of sampling, the chemical analysis method must be sensitive enough to give a clear signal of status. Calcium analysis is easy and practical for low-calcium waters, but greater sensitivity and reproducibility are needed for waters with intermediate calcium concentrations. Calcium analysis is not practical for monitoring high-calcium waters. Modelling can help define the analytical requirements and evaluate sampling for alternative components, such as HCO₃⁻ or pH, etc.

Coping With Emergency Conditions

When a scale inhibition system fails there may remain a motive to keep the well in production a while longer for any of several practical reasons, e.g., overall steam requirements, inadequate availability in other well capacities, scheduled maintenance, etc. Modelling can show how much time may be "bought" with temporary uninhibited production and identify the wellbore consequences. This greatly aids emergency decisions that affect operating costs versus revenues. Modelling can also explore the advantages of running the defective well at non-routine rates, possibly to shift the location of maximum scale buildup as a device to moderate the consequences.

Wellfield Development

Wellfields present a range of chemical and production conditions and this range may cross the boundary between problematic and no-problem wellbore scaling. The pattern of scaling across the field can be sharpened by modelling studies, thereby aiding in site selection for fill-in wells.

The decision of whether to budget for scale inhibition equipment on wells to be drilled near the boundary can be greatly aided by modelling which explores the consequences of not inhibiting.

Wellfield Operations

Some wells are only marginally in need of a scale inhibition system in the sense that costs of dealing with (forecast) uninhibited scale deposits might be similar to, or less than, the (forecast) costs of installing, maintaining, and monitoring an inhibition system. Decision-making in these near-border cases can be strongly supported by scale modelling studies.

Among the no-inhibition options are arcane alternatives, such as programmed decreases in production which raise BPE to avert a critical narrowing of the wellbore.
by scale. This can extend the time before cleanout, reduce the number of rig setups over the well life, and reduce annual wear on the wellbore. Modelling can show the border of practicality for such tactics including specifications for when and to where the BPE might be shifted from time to time, and how to establish the desired shift.

SUMMARY

Modelling CaCO₃ scale buildup in geothermal wells requires coordination of a wellbore simulator function with an accurate accounting for CO₂ pressure which fits with a chemical solubility calculation. A general model must include effects of salts and non-CO₂ gases. Some non-ideal and non-equilibrium factors can be calibrated with data from wellbore measurements. Such a model has been developed and partly calibrated.

Parametric model studies enable comprehension of how the many important factors of scale deposition inter-relate. One example concerned the effect of various initial bicarbonate concentrations on the consequent thickness of scale which develops. The sense of effect, increased versus decreased thickness, inverts with HCO₃⁻ > Ca or HCO₃⁻ ≪ Ca.

Uninhibited scale deposition may, or may not, cause specific wells to be uneconomical. Modelling studies can address such economic issues and provide refined guidance for operating marginal wells, whether or not scale inhibitors are used.

Modelling can also be applied to strategies of wellfield development, especially when the field involves a gradient of scale-forming tendencies among its wells.

REFERENCES


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