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MODELLING $CaCO_3$ DEPOSITION IN GEOTHERMAL WELLBORES

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INTRODUCTION

The capacity of a geothermal liquid to carry calcium varies mainly with the concentrations of CO_2 and HCO_3, temperature and ionic strength, of which the CO_2 concentration (pressure) changes most in the wellbore. Wellbore models that carry accurate computations for CO_2 and other gas pressures might be adapted to compute profile thicknesses of $CaCO_3$ scale.

A general model for carbonate scale deposition in a wellbore must make a simultaneous accounting for pressures of H_2O, CO_2, 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 $CaCO_3$ 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 $CaCO_3$ (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-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. A predictor can be based on contrasts of mechanisms for crystal growth and this model includes such an indicator.

Since neither the original calcium concentration nor the carbonate ($CO_3^{=}$) concentration can be directly measured in a geothermal context, additional equilibrium constants must be introduced, which lead to components that can be measured, specifically CO_2 and HCO_3^-.

$$K_0 = [H_2CO_3]/P_{CO2}$$
$$K_1 = [H^+][HCO_3^-]/[H_2CO_3]$$
$$K_2 = [H^+][CO_3^{=}]/[HCO_3^-]$$

Here, it is useful to express $CaCO_3$ solubility as a liquid's "carrying capacity" for calcium, as in Eq. 1.

$$(Ca) = K_0K_1K_SP_{CO2}A/K_2(HCO_3^-)^2a_{+2}a_{-1}^2 = mol/l \qquad (1)$$

Parentheses denote concentrations which are related to activities (brackets, []) through activity coefficients, $a_i = [i]/(i)$, that represent a chemical effectiveness. a-values vary with temperature, ionic strength, and properties of specific ions; a_{-1} and a_{+2} refer to bicarbonate and calcium respectively. 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.

CO_2 pressure and concentration of bicarbonate vary within the wellbore profile and may be considered as chemical determinants for the liquid's capacity to carry dissolved calcium. They are the dominant forms of carbon in geothermal systems and may be accurately sampled and measured in surface fluids

Most geothermal wellbores 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 CO_2 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 accomodated by the model.

$$TVP_{BPE} = P_{res} - pg(BPE-Z_{res}) - F(BPE-Z_{inflow}) - R/PI \quad (2)$$

P_{res} represents a static reservoir pressure at some reference elevation, (Z_{res}) a hydraulic head ($\rho g \delta Z$) appears between the elevations of the reservoir reference and BPE, a friction effect (F) exists between the elevation of fluid inflow to the wellbore and BPE, and a drawdown is represented as the ratio of discharge rate (R) to productivity index (PI). Z_{BPE} may be computed explicitly by rearranging (2).

TVP is the sum of H_2O 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.*

$$TVP_{BPE} = \{P_{H2O} + HLP_{CO2} + HLP_{CH4} + HLP_{N2} + HLP_{H2} + \ldots\}_{BPE}$$

All these vary markedly with temperature and HLPs are much more sensitive to salt effects than is P_{H2O}. Wellbore heat losses between the inflow elevation and BPE should be accounted for when computing TVP_{BPE}, which is different from TVP_{res}. 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 CO_2 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 Karmen 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 procedure 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 obscurred by the liquid layer in any case).

Incremental Deposition of $CaCO_3$

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 CO_2 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 H_2O vapor pressure in an overpressured context. HLPs for each gas species are additive to the H_2O 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 CO_2 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 CO_2 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.

$$\begin{aligned} HLP_{CO2} &= 0.281 - 0.000232\,|T-175|^{1.3} + \\ &\quad (9.98\text{x}10^{-7} + 5.4\text{x}10^{-9}T)Cl_{eq} = \text{MPaa/(g/kg)} \end{aligned} \qquad (3)$$

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);
$Cl_{eq} = Cl^- + 0.58HCO_3^- + 0.74SO_4^{=} = \text{mg/kg}$.

For non-CO_2 gases, HLPs can be computed conveniently using equations with the form of (4). Factor S is a salting-out coefficient described later.

$$HLP_g = S\{a + b/(T+273)\} \qquad (4)$$

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.

	a	b	$T_{lower\ limit}$
CH_4	-12.2	7860	116
N_2	-11.5	7440	111
H_2	-82.1	53100	84

Although CO_2 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 CO_2 comprises 90 (mole) percent of the non-condensible gases, it contributes only 50 percent of the overall sum of HLPs. Thus, disregarding non-CO_2 gases can yield a serious underestimate of overall gas effects on BPE.

Hydrogen sulfide (H_2S) 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,

$$\log(n_v/n_l) = \log B = d+eT \qquad (5)$$

where n=mole fraction of a gas in the vapor (v) and liquid (l) phases, T in Celsius. Values of d and e listed below are from Giggenbach (1980) and refer to salt-free water.

	(d)	(e)
CO_2	4.7593	-0.01092
CH_4	6.0783	-0.01383
N_2	6.4426	-0.01416
H_2	6.2283	-0.01403

Salting-out effects are similar for all gas species because salts operate more strongly on H_2O molecules than on the dissolved gas molecules. Equation (3) evaluated with and without a chloride concentration (Equation 6) yields a multiplier (S) for the salt effect on Henry's law pressures. Although S is based on CO_2 it can be directly applied to the other gases.

$$S = (HLP_{CO2})_{salty}/(HLP_{CO2})_{no-salt} \qquad (6)$$

Salt effects on properties of H_2O are computed with correlation equations based on Haas, (1976).

CALIBRATION OF THE MODEL

Defects in the Equilibrium Assumption

A straight forward application of the model is a presumption of equlibrium. This implies that change in calcite solubility and the physical deposition of scale on the wellbore keep pace with the rate of temperature drop and exhalation of CO_2 from liquid. Equilibrium for the ionic aspects of the overall reaction mechanism is reasonable. Specifically, chemical steps represented by $2HCO_3^- \text{-->} CO_3^= + H_2O$ and $Ca^{++} + CO_3^= \text{-->} CaCO_3$ have been observed to operate in 2 to 5 milliseconds in the context of pressure jumps in mist flow circumstances. These times include delays for transport of liquid droplets to pipeline walls (Michels, 1984 and unpublished research). When parcels of activated liquid (eventually) reach the casing wall, diffusion of scale components to growth sites occurs in the boundary layer and scale deposition reaction reactions proceed quickly.

Two factors in the wellbore near BPE are important. (i) Degassing of liquid requires nucleation of bubbles, which can be slow or incomplete (soda-pop effect) at a defined temperature. Thus, a real residual liquid is less activated to deposit scale than an equilibrium liquid. (ii) The ionic reactions of scale formation do not occur isolated in the liquid phase but require a physical surface for crystal nucleation and growth and dissipation of energy released during bond formation. Crystal growth (which is scale deposition) occurs on the casing walls where it is found. [*A common perception holds that scale forms in the liquid and deposits on casing due to physical effects. This is definitely incorrect for calcite and probably incorrect for aragonite.*] Thus, fluid in the interior of the wellbore that becomes saturated in calcite just above the BPE does not de-saturate until fluid eddies carry it to the casing wall. This is a mixing-length effect, a process involving several meters of elevation (with subsequent additional activation due to decreased pressure, etc. along the pathway). These non-equilibrium features require empirical calibration of the model.

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 effectve" 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 theoretic 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 squarred) 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.]

<u>Degassing</u> 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 $f \text{-->} 0.2+$ if $a \approx 0.00X$, (f = 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).

<u>Mixing length</u> 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 (.255 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 separator. 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_1) 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 $\exp\{-Z_i/(m\Sigma Z)\}$, when ΣZ 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.

<u>Calibration values</u> 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 under-measured by the caliper fingers.

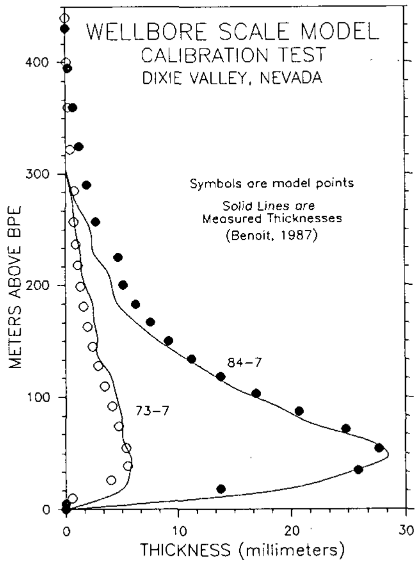


Figure 1: CALIBRATION RESULTS

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.

<u>For the modelling</u>, data for chloride, bicarbonate, and sulfate conformed to wellfluid 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_{CO_2}. Other major factors affecting calcium carrying capacity are (initial) bicarbonate and 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.

CO_2 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 CO_2 contents at a single model reservoir temperature and fluid composition. Greater CO_2 concentrations cause significant lowering of the BPE and modest increases in wellhead pressure without changing the essential shape ofthe pressure profile.

Contrastingly, the CO_2 effect on temperature profiles changes the shape so strongly that the order of curves in the family inverts between the BPE and wellhead. Without CO_2, the temperature profile near the BPE is concave up whereas with higher CO_2 concentrations it is concave down. All lowerings of BPE in Figures 2 are assignable to CO_2.

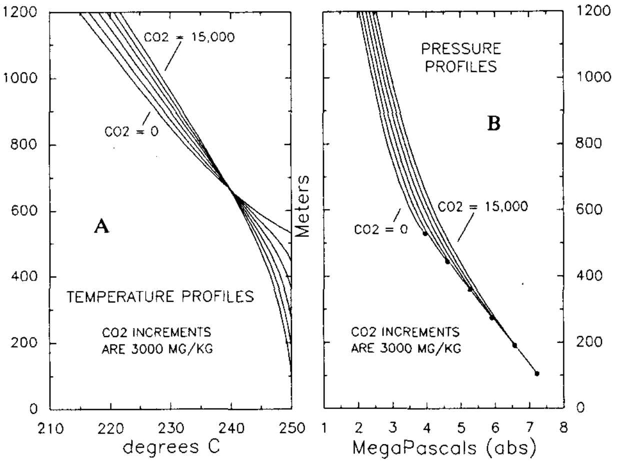


Figure 2: CO_2 EFFECT ON P-T PROFILES

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, CO_2, 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 H_2O which is consequent of the higher temperature(s) [CO_2 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.

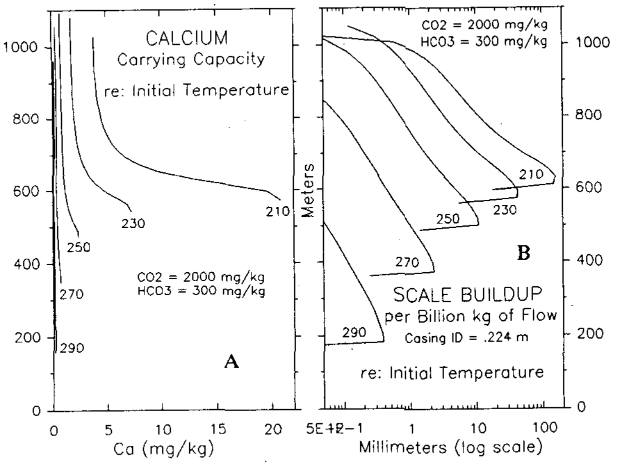


Figure 3: INITIAL TEMPERATURE EFFECTS

CO_2 Effect on Scale Profiles

Figures 4A and 4B also show calcium carrying capacity and scale build-up rates at one initial temperature with variable initial CO_2 content. Other factors are the same as for Figures 2. For 4A and 4B the initial ratio of $Ca/HCO_3^- << 1$ and the initial calcium concentrations vary in nearly direct proportion to the CO_2 contents. The thickness of scale and length of the scale deposition zone also increase in nearly direct proportion to the initial CO_2 content. [Irregularities in the peak shapes are artefacts from the plotting program.]

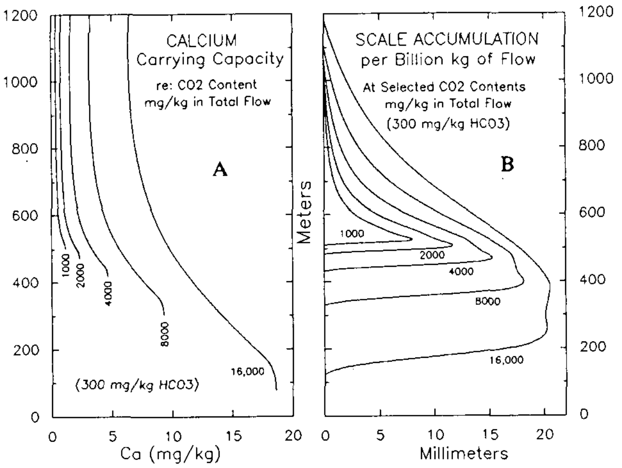


Figure 4: INITIAL CO_2 EFFECTS

HCO_3^- Effect on Scale Profiles

Figures 5A and 5B show calcium carrying capacity and scale buildup rate for various HCO_3^- concentrations with other factors similar to those for Figures 4. For Figures 5, $Ca<<HCO_3^-$ and scale deposition *decreases* strongly with increasing HCO_3^-. This contrasts with Figures 6A and 6B, wherein $Ca>HCO_3^-$ and scale deposition *increases* with increasing HCO_3^-.

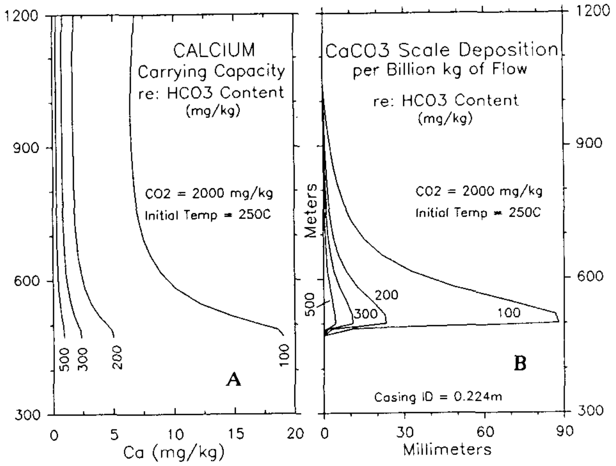
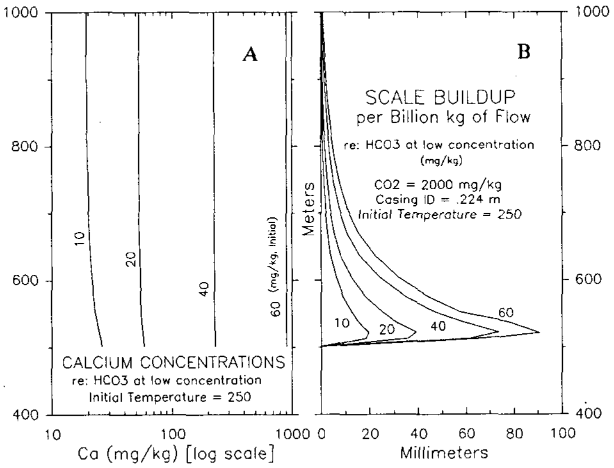


Figure 5: BICARBONATE EFFECTS with $HCO_3^->Ca$

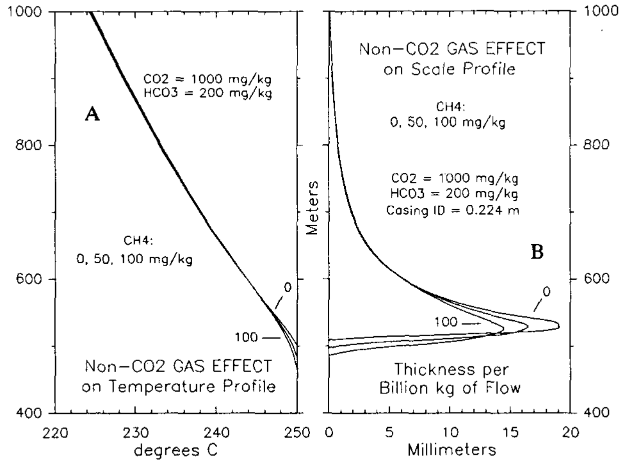
Figure 6: BICARBONATE EFFECTS
with $HCO_3^- < Ca$



Effect of a non-CO_2 Gas

Non-CO_2 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 (CH_4) concentrations on temperature profile and scale thickness profile, with uniform initial temperature and CO_2 content. Since the non-CO_2 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-CO_2 GAS
(Methane)



APPLICATIONS

Parametric studies show the multi-dimensional phenomenon of $CaCO_3$ 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. Importantly, 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 HCO_3^- 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 $CaCO_3$ scale buildup in geothermal wells requires coordination of a wellbore simulator function with an accurate accounting for CO_2 pressure which fits with a chemical solubility calculation. A general model must include effects of salts and non-CO_2 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 developes. The sense of effect, increased versus decreased thickness, inverts with $HCO_3^- >> Ca$ or $HCO_3^- << Ca$.

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.

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