ESTIMATION OF INITIAL STEAM FRACTION IN BOILING GEOTHERMAL RESERVOIRS

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ABSTRACT

The gas content of steam from wet-steam wells has been used to estimate the initial steam to water ratio in the producing aquifers. For this estimation there are essentially two approaches. One assumes various gas-gas equilibria and that the total well discharge composition is the same as that of the initial reservoir fluid. The other approach considers various mineral-gas equilibria and takes into account possible segregation of the flowing water and steam in the aquifer. Such segregation will cause the discharge composition to differ from that of the parent reservoir fluid. The results obtained by the two approaches often yield very different results. There are considered to be two main reasons for the difference. One is that phase segregation may occur in the producing aquifer. The second reason relates to the assumption of specific chemical equilibria in the undisturbed reservoir fluid. In order to study whether or not specific gas-gas or mineral-gas equilibria are closely approched in geothermal reservoirs it would be of interest to study liquid enthalpy well discharges and preferably those where the first level of boiling is in the well. Under such circumstances the initial reservoir fluid comosition can be assessed with confidence.

1. INTRODUCTION

The gas composition of geothermal steam from wells and fumaroles provides information on various production characteristics of geothermal reservoirs, such as the quality of the steam for various uses, subsurface temperatures (D'Amore and Panichi, 1980; Giggenbach, 1980; D'Amore and Truesdell, 1980; Nehring and D'Amore, 1984; Arnórsson and Gunnlaugsson, 1985) and the initial steam fraction in boiling geothermal reservoirs (D'Amore and Celati, 1983; D'Amore and Truesdell, 1985; McCartney and Lanyon, 1989; Arnórsson and Gunnlaugsson, 1986; Arnórsson, 1990, 1991; Arnórsson et al., 1990). In this short contribution the methods developed to estimate the initial steam fraction in geothermal reservoirs are reviewed and an explanation sought for the large discrepancies often observed between the results of the different methods.

2. WELL DISCHARGE ENTHALPY AND BOILING IN PRODUCING AQUIFERS

Measurements of temperature and pressure in drillholes in many geothermal fields have demonstrated that the water is at the boiling point, at least, to the level of the deepest wells. Thus, both water and steam is present in the reservoir. Such two phase geothermal reservoirs represent an unstable physical system. The steam, because of its lower density, tends to rise faster than the boiling water. The different rates of ascent of the water and steam phases create steady state conditions that **fix** the steam to water ratio in the rising fluid body. According to Donaldsson's (1968) theory for stationary flow one would expect that the steam to water ratio in a boiling system to be almost entirely controlled by the ratio of mass flow **per** unit area to the permeability of the rock. Estimated permeability in many exploited geothermal reservoirs, such as Nesjavellir in Iceland (Biidvarsson et al., 1990) is sufficiently high to maintain the steam to water ratios at low levels, only few tens of percent by volume at the most, or trivial in terms of mass. In other systems, such as Olkaria in Kenya impervious or, at least, impeding cap rock possesses sufficiently low permeability to generate a vapour rich cap on top of a liquid dominated boiling, hot water reservoir (Bodvarsson and Pruess, 1984).

Wells producing from boiling geothermal reservoirs often have liquid enthalpy when first discharged, but the discharge enthalpy frequently increases with time. The wells become "high enthalpy" or "excess entalpy" wells. The rate of increase varies greatly between wells. Some wells retain liquid enthalpy for only a few hours of flow, others for weeks, even monrhs. The increase in the discharge enthalpy is not expected to be the product of natural or initial conditions in the reservoir, but caused by the pressure drop that is created in the formation around the well when discharging. The pressure drop leads to extensive boiling in producing aquifers and a large increase in the volume of the reservoir fluid through steam formation. The increase in enthalpy may be caused by one or both of the following two processes: (1) flow or gravity segregation of water and steam, the steam flowing preferentially to the well and leaving the water behind and (2) enhanced vaporization of the boiling water by flow of heat from the rock to that water. Such heat flow tends to occur whenever the water has cooled by adiabatic boiling as a result of the pressure drop.

The concentrations of gases in the steam **of** discharging wells and of dissolved solids in the water may be used to evaluate which of the above mentioned boiling processes is the cause of the increase in the discharge enthalpy of wells (Glover, *et al.*, 1981; Arnórsson and Gunnlaugsson, 1986). This requires monitoring the chemical composition of well discharges over a period of time when discharge enthalpy changes. If the concentrations of both gases and dissolved solids remain constant in the total well discharge despite changes in the discharge enthalpy, this indicates that the increase in the discharge enthalpy is caused by enhanced Vaporization of the boiling water by heat flow from the rock. If, on the other hand, the concentrations of the gases and solids in the steam and water discharged, respectively, remain about constant, this indicates that flow or gravity segregation of water and steam in the producing aquifer is responsible for the changes in the discharge enthalpy. In the first case total discharge composition can be taken to correspond to that of the initial reservoir fluid. In the second case, on the other hand, the total discharge will be enriched in the gaseous components, because they are enriched in the steam phase, and at the same time the discharge has become depleted in the dissolved solids that are confined to the water phase.

Data from well 6 at Nesjavellir, SW-Iceland, is presented in Figs. 1 and 2 to demonstrate this. As may be seen from Fig. 1 the concentration or Na in the water from the well has remained approximately constant despite an increase in enthalpy from about 1200 kJ/kg to about 2600 kJ/kg and, therefore, its concentration in the total discharge has decreased. The H_2S concentration in the steam has also remained about constant and increased in the **total** discharge (Fig. 2). The constancy of the composition of the water and steam phases in the discharge of well 6 at Nesjavellir, despite large increases in discharge enthalpy, clearly indicate that the cause of the enthalpy increase is phase segregation in the aquifer.

3. GEOCHEMICAL APPROACH

When using gas chemistry to estimate the initial steam fraction in boiling geothermal reservoirs from the gas content in steam of discharging wells various simplifying assumptions are made. Thus, specific gas-gas or mineral-gas equilibria are always assumed. For example Giggenbach (1980), D'Amore and Celati (1983) and D'Amore and Truesdell (1985) assumed that Fischer-Tropsch equilibrium ($CO_2 + 4H_2 = CH_4 + 2H_2O$) is attained in the reservoir outside the zone of pressure disturbance around discharging wells. D'Amore and Truesdell (1985) further assumed that equilibricm between H_2S and H_2 exists in the reservoir and that sulphur fugacity is fixed in addition to Fischer-Tropsch equilibrium allowing both initial steam fraction and aquifer temperature to be estimated. Alternatively, as pointed out by D'Amore and Celati (1983) H_2S, H_2 and sulphur fugacity equilibria may be used to estimate the initial steam fraction, on one hand and the Fischer-Tropsch equilibrium, on
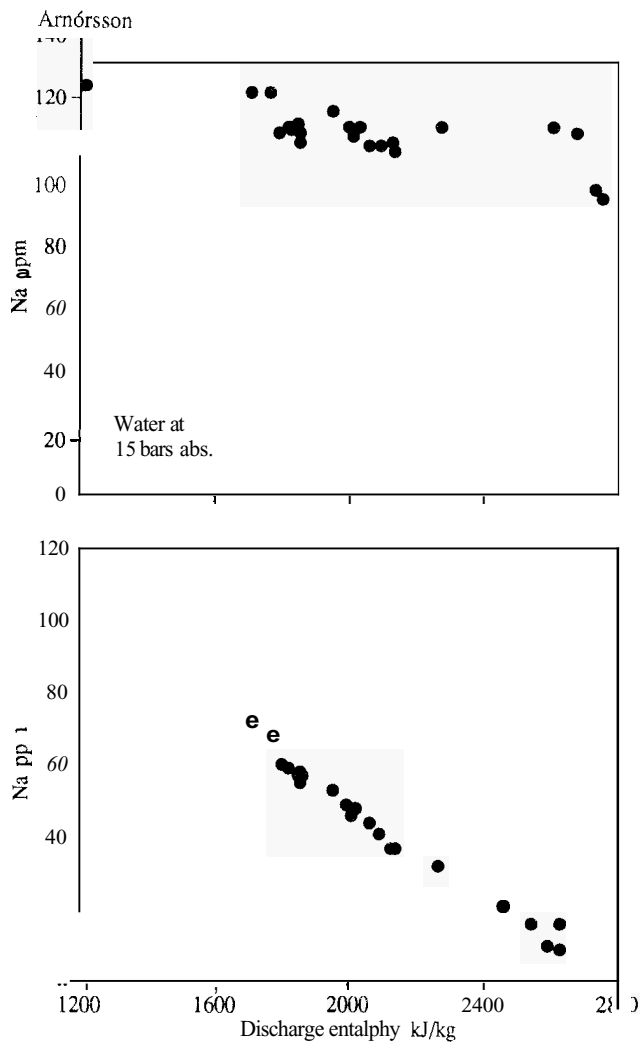
Fig. 1. Sodium concentrations versus discharge enthalpy in water and total discharge from well 6 at Nesjavellir, Iceland.
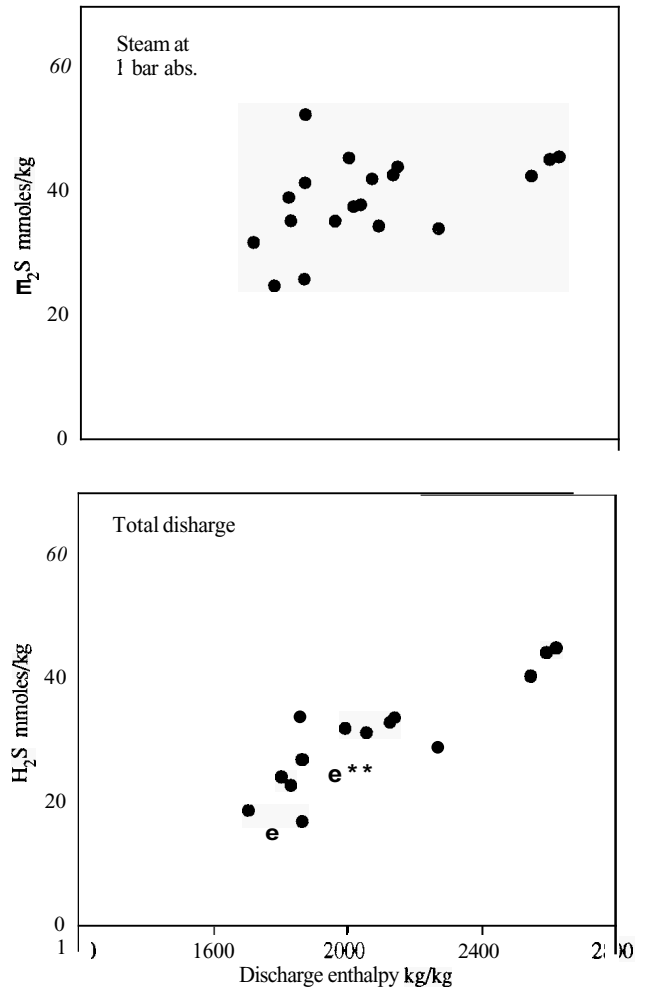

Fig. 2. Hydrogen sulphide concentrations versus discharge enthalpy in water and total discharge from well *6* at Nesjavellir, Iceland.

the other, if aquifer temperature **is** estimated by other means. Arnórsson and Gunnlaugsson (1985) have questioned whether Fischer-Tropsch equilibrium is generally closely approached in geothermal reservoirs. A way to verify or disprove this would be to analyze samples from wells that demonstratably withdraw fluid from single phase water reservoirs. Under these conditions it is possible to reconstruct with confidence gas concentrations in the initial reservoir water and test if Fischer-Tropsch equilibrium is attained.

Arnórsson *et al*. (1990) used a different approach from that of Giggenbach (1980) and D'Amore and co-workers. They assumed that specific mineral buffers control the aqueous concentrations of CO_2, H_2S and H_2 in geothernial waters. This assumption was based on the study of Arnórsson and Gunnlaugsson (1985). Further, Arnórsson *et al*. (1990) consider that total well discharges may not be representative of the undisturbed fluid, i.e. phase segregation may contribute to the "**excess** enthalpy" of wells. Ey contrast, other researchers have assumed that total well discharge composition is the same as that of the undisturbed reservoir fluid. **This** assumption implies that increased discharge enthalpy of wells is caused by enhanced evaporation of the boiling water flowing to the well by heat transfer from the **rock.**

The equation **below,** which is from Arnórsson *et al*. (1990), may be used to calculate the initial steam fraction in geothermal reservoirs:

$$Y_{HS} = \frac{A_H - A_S}{\frac{55.51}{P}\left(\frac{A_S}{K_{H_2}} - \frac{A_H}{K_{H_2S}}\right) + (A_H - A_S)} \qquad (1)$$

where $A_H = m_{H_2,c}^v/m_{H_2}^{f,l}$ and $A_S = m_{H_2S,c}^v/m_{H_2S}^{l,1}$. $m_{H_2,c}^v$ and $m_{H_2S,c}^v$ denote the concentrations (in moles/kg) of H_2 and H_2S, respectively, in a saturated steam sample collected at temperature c and $m_{H_2}^{f,l}$ and $m_{H_2S}^{f,l}$ stand for the concentrations (in moles/kg) of the same gases in the initial reservoir water. P is total pressure in **bars** abs. and K_{H_2} and

K_{H_2S} the solubility constants (Henry's Law Coefficients) of the respective gases. Y_{HS} is the initial reservoir steam fraction. In the equation above data on H_2 and H_2S were used to derive a value for the initial steam fraction. CO_2 and H_2 could also have been **used.** The reliability of the results is dependent on the difference in the solubility of the pair of gases selected to estimate Y. Using CO_2 and H_2S as a pair appears often to yield untrustworthy results because these gases have rather similar solubility in water.

By the method of D'Amore and Celati (1983) derivation of the initial steam fraction, Y, is based on the assumption of equilibrium for the following reactions:

$$CH4 + 2H_2O = CO_2 + 4H_2 \qquad (2)$$

and

$$H_2S = H_2 + \tfrac{1}{2}S_2 \qquad (3)$$
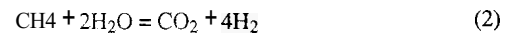
From $f_i = \gamma_i P_i$ and $P_i = X_{v,i}P_{total}$ the equilibrium constants for reactions *(2)* and (3), K_c and K_s, respectively, can be written as follows:

$$K_C = \frac{P_{total}^4 X_{v,H_2}^4 X_{v,CO_2}/X_{v,CH_4}}{f_{H_2O}^2 \gamma_{CH_4}\gamma_{H_2}^4\gamma_{CO_2}} \qquad (4)$$

and

$$K_S = \sqrt{f_{S_2}} \times \frac{\gamma_{H_2S}/\gamma_{H_2}}{X_{v,H_2S}/X_{v,H_2}} \qquad (5)$$

f_i represents the fugacity of the i-th compound, γ is the fugacity coefficient and P_i the partial pressure. $X_{v,i}$ denotes the molar fraction
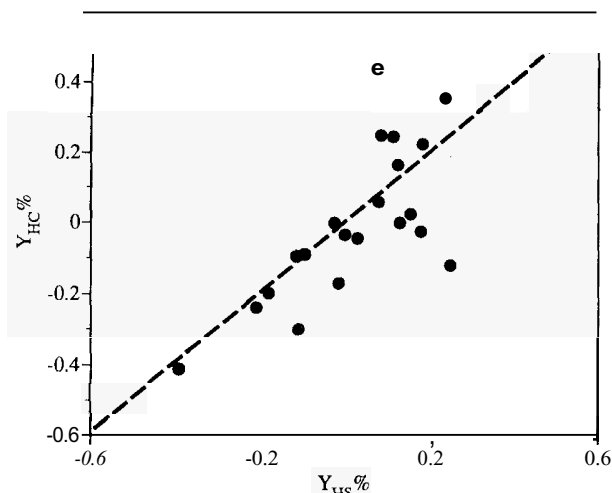
Fig. 3. Comparison between initial steam fraction values (Y) for wells at Olkaria, Kenya, obtained from the H_2 and H_2S content of the well discharges (Y_{HS}), on one hand, and from their H_2 and $CO2$ content (Y_{HC}), on the other. The numbers are in weight %.

of gas i in the reservoir steam phase. The value of $X_{v,i}$ is given by:

$$X_{v,i} = \frac{X_{C,i}B_i/(1+g)}{Y^\circ B_i + (1-Y^\circ)\left(1 + \sum_{i \neq w} \frac{X_{C,i} \times g}{Y + \frac{1-Y}{B_i}}\right)} \quad (6)$$

where $X_{C,i}$ is $= n_i/n_{gas}$, the molar fraction in the dry gas. B_i is the coefficient of gas distribution between the steam and water phases, given in this case by:

$$B_i = (n_{s,i}/n_s)/(n_{w,i}/n_w) \quad (7)$$

where the subscripts s and w denote steam and water phases, respectively. The g in equation (6) is defined as the gas/discharge molar fraction ratio at the wellhead, $n_g/n_{(s+w)}$. Y° is given by:

$$Y^\circ = \frac{1}{\left[1 + \frac{\left(\frac{1-Y}{Y}\right)}{1+g}\right]} \quad (8)$$

Substituting equations (6) to (8) into equation (4) and calculation of the respective fugacity coefficients, which is described by D'Amore and Celati (1983). leaves two unknowns for solution of equation (4), the value of Y and the reservoir temperature, i.e. the temperature to be selected to calculate the distribution coefficient B,, which is temperature dependent. If the fugacity of S_2 is known, another and independent value of Y can be obtained with the aid of equation (5), or, alternatively, the reservoir temperature can be obtained by simultaneous solution of equations (4) and (5) for a common value of Y.

4. RESULTS

Calculated initial steam fractions by the methods of Arnórsson *et al.* (1990), on one hand, and D'Amore and Celati (1983). on the other, often differ greatly. Thus, Arnórsson (1991) report values for Y in the range of -0.16 to +0.76% by weight for water dominated geothermal reservoirs, whereas D'Amore and Celati (1983) and D'Amore and Truesdell (1985) report values between 0 and 50%. For example, at Cerro Prieto, Mexico, D'Amore and Celati (1983) obtain values generally in the range 1 to 3.5%, with a maximum of 6% by weight, whereas Arnórsson (1990) reports a value of 0.35% for one well. The corresponding numbers for Hveragerdi, Iceland, are -0.01% for Arnórsson (1990) and 0.3% for D'Amore and Truesdell (1985). For Nesjavellir and Námafjall, also in Iceland, D'Amore and Truesdell (1985) obtain Y values of about 25% but by the method of Arnórsson *et al.* (1990) values close to zero are obtained. All the above initial steam fraction numbers are in weight percentage. Converting them into volume percentage indicates, e.g., that the Námafjall and Nesjavellir reservoirs are vapour dominated. They are not as revealed by temperature and pressure measurements in wells. The Hveragerdi reservoir is of relatively low temperature (180-230°C) and all deep wells (>300 m) in the area are fed by a single liquid water phase, so Y

Table 1. Functions describing the temperature dependence of CO_2, H_2S and H_2 concentrations (log moles/kg) in equilibrated geothermal waters.

Gas	Temperature function (°K)
CO_2	-1.09 -3894.55/T +2.532•logT
H_2S[a]	-1.24 -4691.84/T +2.830•logT
H_2[a]	+11.98 +0.08489T +8254.09/T -27.587•logT
H_2S[b]	-11.80 -0.06035T -17691.09/T +27.163•logT
H_2[b]	-3.04 -10763.54/T +7.003•logT

[a]Valid for all waters below 200°C and waters in the range 200-300°C, if Cl <500ppm. [b]Valid for all waters >300°C and waters in the range 200-300°C, if Cl >500 ppm.

is demonstrably zero.

Arnórsson *et al.* (1990) studied the gas chemistry of the Olkaria geothermal field, Kenya in some detail. In the 2 km² wellfield of the Olkaria reservoir producing for the first 45 MW power plant the reservoir is liquid dominated but capped with a 240°C steam zone at 550-700 m depth under an impeding formation of altered basalt. Arnórsson *et al.* (1990) obtained steam fractions ranging from -0.38 to +0.25% by weight. Two independent estimates of the initial steam fraction were made, one from the H_2S and H_2 content of the steam and the other from its CO_2 and H_2 content. The two estimates compare rather well (Fig. 3). Negative numbers for estimated initial steam fraction indicate that the respective well discharges are depleted in steam relative to the equilibrated reservoir water. In deriving these numbers Arnórsson *et al.* (1990) estimated the CO_2-, H_2S and H_2-concentrations in the initial aquifer water from the gas-temperature equations of Arnórsson and Gunnlaugsson (1985) (Table 1). For the temperature of the producing aquifers at Olkaria a value of 0.25% by weight corresonds approximately to 10% by volume. D'Amore and Truesdell (1985) present values for 3 Olkaria wells. Their Y values lie in the range of 5.0 to 7.5% by weight. For the same wells Arnórsson *et al.* (1990) give values in the range of 0.12-0.18%.

5. DISCUSSION AND CONCLUSIONS

There are considered to be essentially two main reasons for the discrepancy between the estimation of the initial steam fraction (Y) in geothermal reservoirs by the two methods described above. One is that phase segregation may occur in producing aquifers rendering one of the basic assumptions made by D'Amore and Celati (1983) invalid, namely that reservoir fluid is transferred to the wellhead without any mass gain or loss. The second reason relates to the assumption of chemical equilibrium, and even if it exists in the undisturbed reservoir, chemical reactions stimulated by boiling and cooling in the producing aquifer may change the gas content of the fluid significantly. Finally, the assumption of chemical equilibrium may be particularly uncertain
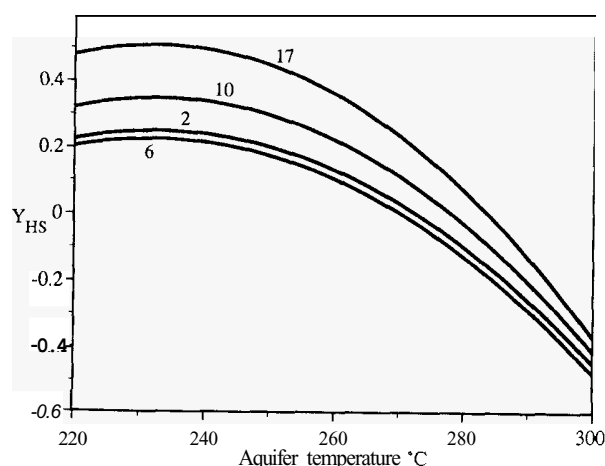

Fig. 4. The effect of selected initial reservoir water temperature on calculated initial steam fractions (Y_{HS}) in wells 2, 6, 10 and 17 of the wellfield at Olkaria, producing for the first 45 MW power station in the area. The steam fractions were calculated from the H_2 and H_2S gas content of the respective well discharges. Y_{HS} is in weight %.
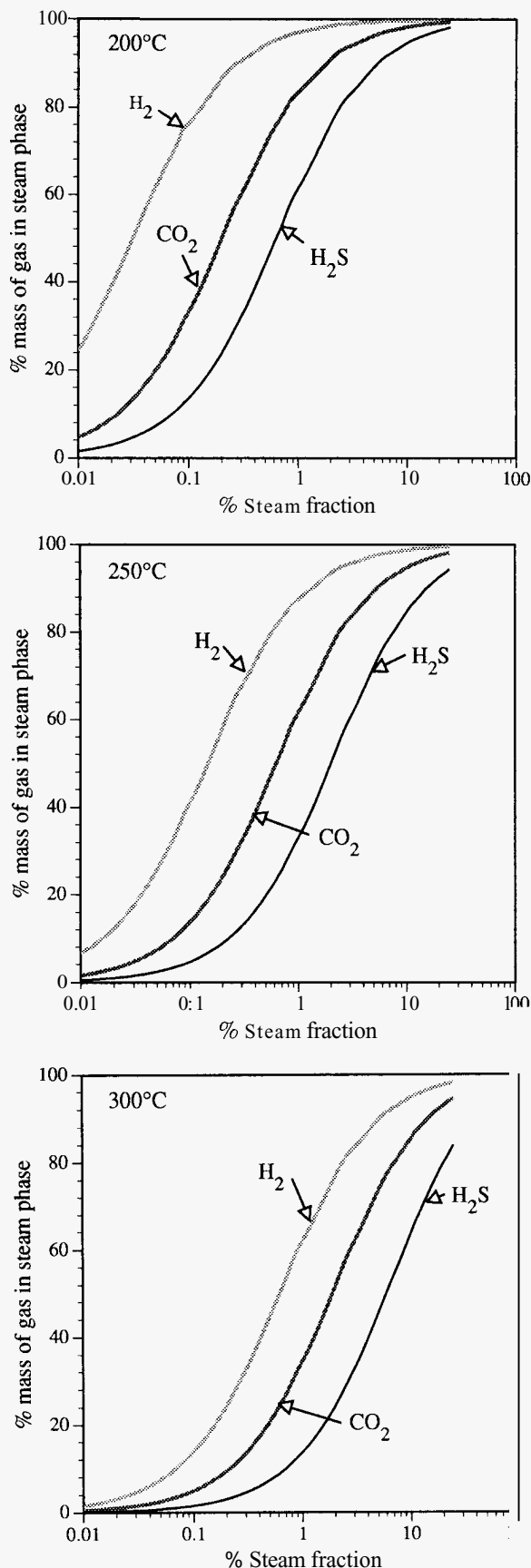
Fig. 5. Percentage mass of gas in steam of total mass in fluid (steam + water) in equilibrium with water at 200, 250 and 300°C. Values for CH_4 are not shown. Since, however, the solubility of this gas is similar to that of H_2, the hydorgen curves in the figure are approxmately valid for methane also.

for reservoirs that have been exploited for a long time. Recharge of cold water into such reservoirs may have been too rapid to allow equilibrium to be attained.

The concentrations of CO_2, H_2S and H_2 in equilibrated geothermal reservoir waters, at a particular temperature, used by Ambrsson *et al.* (1990) were derived by Arnórsson and Gunnlaugsson (1985) from the relationship between measured aquifer temperatures in selected wells and the analysed concentrations of their discharges (Table 1). This relationship can only be regarded as approximate, as the minerals involved in the gas equilibrium may have variable compositions, such as epidote, affecting the gas concentration at equilibrium.

Many geothermal wells produce from more than one aquifer having different temperatures. The discharge of such wells will inevitably be a mixture of fluids of different temperatures. The methods described above to estimate initial steam fraction values are, of course, not valid for such discharges. Even if a well receives fluid from only one aquifer, there will be an uncertainty in deriving that temperature, but the selected aquifer temperature affect the calculated value of Y. This is shown in Fig. 4 for selected wells in the Olkaria field in Kenya.

One way to test the validity **of** calculated Y-values in the case of wet-steam well discharges is to evaluate mineral saturation in the aqueous phase for its calculated gas content that is consistent with the derived Y-value. Geothermal waters are generally saturated with respect to calcite (Arnórsson, 1989). Calculated Y-values that are too high yield a low gas aquifer water. This, in turn will give a high pH and calcite supersaturated solution. Arnórsson *et al.* (1983) showed that all major cation to proton ratios in equilibrated geothermal waters have a fixed value at any particular temperature. Anomalously high calculated pH for geothermal reservoir waters should show up as systematically high cation/proton activity ratios.

By the method of Arnbrsson *et al.* (1990) the approximation was made that the gases initially dissolved in the aquifer water are quantitatively transferred to the steam phase when segregation of the flowing water and steam in producing aquifers occurs. In order to test the validity of the assumption the WATCH chemical speciation programme (Ambrsson *et al.,* 1982) has been expanded to calculate initial reservoir steam fractions. The expansion involved calculation **of** the aqueous speciation at the selected temperature of phase segregation and distribution of gases between the water and steam phases at that temperature. These more exact calculations gave quite similar Y-values to the more approximate approach.

Both of the methods described in this contribution to estimate the initial steam fraction in geothermal reservoirs are not sensitive for high values of Y. When a relatively large fraction of the presumed equilibrated reservoir fluid is represented by steam most of the mass of the gases in the system will occupy the steam phase. It affects the gas content of the total fluid very little whether the steam phase occupies 5% or more of total fluid by weight, particularly for the less soluble gases such as H_2 (Fig. 5). For this reason alone some of the high *Y* values reported by D'Amore and Celati (1983) and D'Amore and Truesdell (1985) are suspect.

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