Effect of non-condensable gases on the flow of water and steam in geothermal wells

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RESUMEN

Se describe el efecto de los gases incondensables (IGs), representados por dióxido de carbón, sobre la características de flujo de agua y vapor simuladas numéricamente en pozos geotérmicos. La presencia de IGs afecta las condiciones termodinámicas que dominan el proceso de flujo en un pozo o yacimiento; sin embargo, la simulación normalmente supone que el agua y el vapor son sustancias puras. La mayoría de los fluidos geotérmicos se componen de una mezcla de agua y vapor y de cantidades substanciales de IGs y sales disueltas. Las concentraciones de gas varían a menudo en un campo geotérmico y, por ende, pueden ser herramientas útiles para inferir los patrones de flujo en los pozos y los yacimientos. Los fluidos geotérmicos también contienen sólidos y sales disueltas en gran cantidad. Esta constitución química compleja hace que sus propiedades termodinámicas difieran de las del agua pura. Así, la simulación del flujo de fluidos geotérmicos en pozos y tuberías requiere que sus propiedades termodinámicas y de transporte deban ser calculadas apropiadamente. Por ello, se usaron varias ecuaciones y correlaciones para estimar las propiedades de la mezcla H_2O-CO_2 en la simulación. Los resultados muestran que la presencia de CO_2 altera significantemente el punto de flasheo en el pozo y la cantidad de vapor producido.

PALABRAS CLAVE: Pozos geotérmicos, características de producción, gases incondensables, simulación de flujo, flujo en dos fases.

ABSTRACT

This paper describes a study on the effects of non-condensable gases (IG) represented by carbon dioxide, on the numerically simulated flow characteristics of water and steam in geothermal wells. The presence of IG affects the thermodynamic conditions dominating the flow process in the well or within the reservoir. Most geothermal fluids are generally composed of a mixture of water and steam and substantial amounts of IG and salts. Gas concentrations often vary considerably in a geothermal field. They can be useful tools for inferring flow patterns both in wells and within geothermal reservoirs. Geothermal fluids also carry a high content of dissolved solids and salts. Well and pipeline flow simulation of geothermal fluids requires that thermodynamic and transport properties be properly accounted for. Several equations and correlations were used to estimate the properties of the H_2O-CO_2 mixture during simulations. The results revealed that the presence of CO_2 affects significantly the location of the flashing point in the well and the amount of steam produced.

KEY WORDS: Geothermal wells, production characteristics, incondensible gases, flow simulation, two-phase flow.

INTRODUCTION

Numerical simulation is one of the techniques that have been widely used during the exploitation of geothermal resources for the generation of electricity (Faust and Mercer, 1975). The application of such models plays an important role in may aspects related to the study of the main physico-chemical and flow processes that dominate in the production of geothermal fluids and also, in the correct design and manufacture of generation plant equipment. In general, these models can provide information that cannot be obtained by means of experimentation tests because these are complicated and expensive to realise. At present, there exist numerical codes that can be applied to evaluate the flow characteristics of geothermal wells (Gould, 1974; Palacio-Pérez, 1985; Michaelides and Shafaie, 1986; Freeston and Hadgu, 1987; Tanaka and Nishi, 1988; García *et al.*, 1995; Aragon *et al.*, 1998; among others). These models consider different sets of assumptions, such as thermodynamic phase-equilibrium, phase slip or homogeneous flow, unsteady heat transfer, one dimensional flow, and others. Some of these models assume that geothermal fluids are composed only of water (steam and liquid phases). However, most geothermal fluids are generally composed of a mixture of water and steam with a considerable amount of incondensible gases and salts.

The vapour phase of geothermal reservoirs has a heterogeneous composition, showing a wide range of incondensible gas concentrations, between 1% and 9% of total gas weight for geothermal reservoirs and between 2% and 8% at separator conditions (Santoyo, 1991; Suárez *et al*., 2000). Incondensible gases often contain CO_2, NH_3, CH_4, O_2, H_2, He, N_2, and Ar. Carbon dioxide is the major constituent of these gases, representing between 70% and 99% in total gas weight, with the highest CO_2 content being often found in shallow wells with high steam content. Thus, since gas concentrations often vary considerably across a geothermal field (Nieva *et al*., 1987), hence they can be useful tools in inferring flow patterns both in wells and within geothermal reservoirs. Also, geothermal fluids are characterised by a high content of dissolved salts (SiO_2, NaCl and KCl, etc.) whose salinity may vary between 5% up to 30%. This complex chemical constitution of geothermal fluids makes their thermodynamic properties to differ far from those of pure water (H_2O). Thus, simulation of the flow of geothermal fluids in wells and pipelines requires that their thermodynamic and transport properties be computed properly.

The present work is limited to include the effects of incondensible gases, represented by CO_2, on the numerically simulated flow characteristics of water and steam in geothermal wells. Several equations and correlations were used in order to estimate the properties of the H_2O-CO_2 mixture. The effect produced by the presence of salts was neglected at the present time due to discrepancies and lack of sufficiently accurate equations, which predict its behaviour at hydrothermal conditions.

PHYSICAL MODEL

Figure 1 shows the schematics of a productive geothermal well, where z* is the flashing depth and *p*, *h* and *x* are pressure, enthalpy and steam quality, respectively. The well is fed at its bottom with reservoir fluid. This fluid can be liquid water, dry steam or a mixture of two-phase flow. The most common feature of these systems is the existence of single phase (liquid) flow at the bottom of the well, near the geothermal reservoir, at high temperature and pressure (Jerónimo, 1993; Santoyo *et al*., 1991). For the typical case of liquid water in the reservoir, the water flashes inside the well when the pressure drops to its saturation pressure ($p=p_{sat}$) due to gravity, acceleration and frictional pressure losses. At the well exit, the fluid is dry or wet steam, whose quality is different from well to well and from field to field.

As the solution rises in the well its static pressure is decreased and one of the following processes can occur:

- The CO_2 content in the fluid exceeds the solubility of CO_2 under the new pressure; hence, CO_2 is released from the solution to form gaseous bubbles.
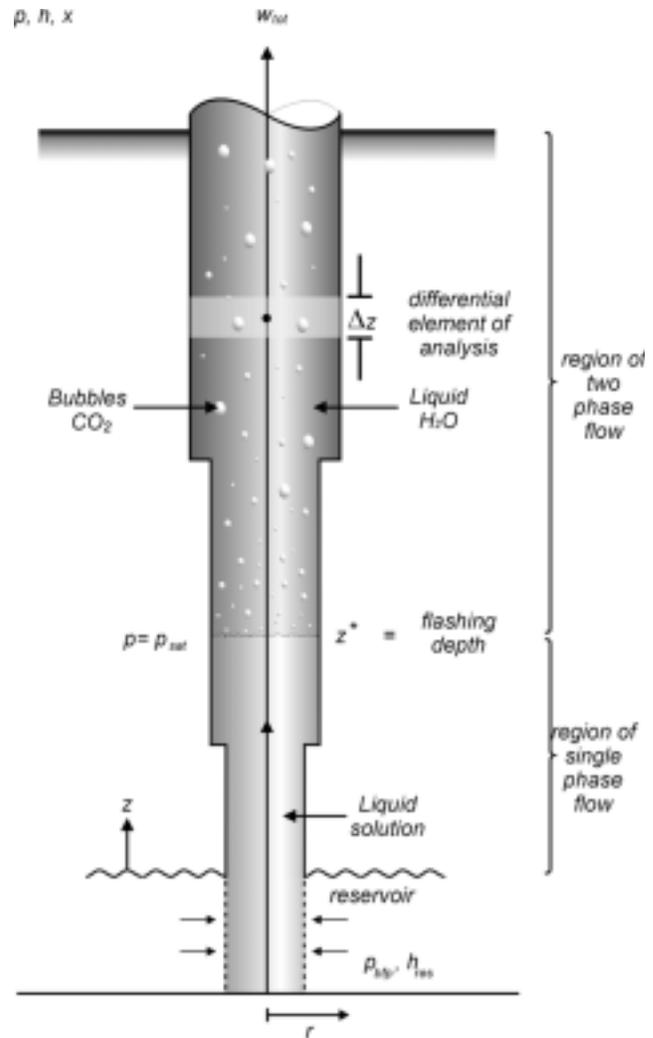

Fig. 1. Schematic diagram of a productive geothermal well with a liquid feed, flashing inside the well and presence of CO_2.

- The pressure becomes equal to the saturation pressure of water under the given temperature conditions; hence, water begins the boiling process to form steam bubbles with some CO_2.

Whichever of the two events occur, there exists a transition from one-phase flow to two-phase flow, and since the static pressure continues decreasing, more steam is released. Therefore the steam phase that rises to the wellhead is increased at the expense of the liquid phase to values up to 25% by weight.

MATHEMATICAL MODEL

Some general assumptions are inherent in the equations that describe flow in geothermal wells (Jerónimo, 1993). These are complemented by other assumptions that are explicitly stated in this work. The general assumptions are:

- The flow in the reservoir is radial, isothermal and one-dimensional.

- Flashing does not occur within the reservoir (formation).

- Well temperature is a boundary condition for the heat conduction model in the formation.

- There is no phase slip in the two-phase zone of the well.

- The phases are in thermodynamic equilibrium.

- The geothermal reservoir produces compressed water.

- An equivalent CO_2 content describes the influence of all non-condensable gases.

- Salts content in the geothermal fluid is neglected.

The fluid mixture is treated as a pseudo-fluid that obeys the usual equations of single-component flow. The wellbore model incorporates thoroughly tested heat transfer correlations and accurate thermodynamic and formation properties to allow for reliable calculations. Fluid flow in the well is considered to be under steady state. However, the heat transfer between the well and the formation is computed using radial and transient heat conduction in the formation. Additionally, some particular considerations related to the occurrence of typical processes in geothermal wells were included in a previous version of this model, called GEOPOZO V2.0 (García *et al*, 1995). The general equations that describe these processes are:

Wellbore model

The wellbore model is based on the conservation of mass, momentum and energy equations for steady one- and two-phase flow given by Wallis (1969) for homogeneous flow:

$$\left(\frac{dw}{dz}\right) = 0 \tag{1}$$

$$\left(\frac{dp}{dz}\right) - \left[\left(\frac{dp}{dz}\right)_f + \left(\frac{dp}{dz}\right)_{ac} + \left(\frac{dp}{dz}\right)_g\right] = 0 \tag{2}$$

$$w\left(\frac{de_t}{dz}\right) - Q = 0, \tag{3}$$

where e_t is the specific total energy (enthalpy, kinetic and potential energy), Q is the heat exchange between the well and the surrounding formation, w is mass flowrate, z is the vertical coordinate and p is pressure. The first term in square brackets (Equation 2) represents pressure loss due to friction, the second denotes pressure loss due to acceleration, and the last term is the gravitational pressure loss. The de-

tailed expressions for these terms can be found in Wallis (1969). Equations (1)-(3) are solved subject to the following conditions:

$$w_l^i + w_g^i = \text{constant} \tag{4}$$

$$p = p_{bfp} \qquad \text{at } z = 0 \tag{5}$$

$$e_t h_{res} + gz \qquad \text{at } z = 0, \tag{6}$$

where the superscript i denotes the component considered, the subscripts l and g are liquid and gas phases, respectively, p_{bfp} is the bottomhole flowing pressure, h_{res} is the specific enthalpy of the reservoir and $z = 0$ is bottomhole depth (Figure 1). The friction pressure loss is given by

$$\left(\frac{dp}{dz}\right)_f = \frac{f}{2}\frac{(w/A_f)^2}{D\rho_m}, \tag{7}$$

where f is the friction factor, D is the hydraulic diameter, A_f is the flow area and ρ_m is the two-phase mixture density. Single-phase friction factors are given by Sánchez (1990) while two-phase friction factors are considered constant, $f = 0.025$ (Wallis, 1969). The two-phase mixture density is given by

$$\rho_m = \varepsilon_g \rho_g + (1 - \varepsilon_g)\rho_l, \tag{8}$$

where ε_g is the void fraction, and ρ_g and ρ_l are the gas and liquid densities, respectively. If a secondary feedzone occurs in the well, then total mass flowrate w_{tot} is given by

$$w_{tot} = w + w_{sec}, \tag{9}$$

where w is the main feed flow rate and w_{sec} is the secondary feedzone flow rate. If the reservoir pressure at the secondary inflow zone is unavailable, the pressure at the mixing point is assumed to occur at the pressure at that point in the well (Bjornsson, 1987):

$$p_j = p_{sec}, \tag{10}$$

where p_{sec} is the pressure in the well at the depth of the secondary feedzone. Heat losses to the formation are calculated from the standard heat transfer equation

$$Q = U A \Delta T, \tag{11}$$

where U is the overall heat transfer coefficient, A is the area for heat transfer from the well to the surrounding rock and ΔT is the temperature difference between the fluid and the surrounding rock. The definition of U is well known and is given by Willhite (1967):

$$U = \frac{1}{\frac{1}{h_c} + \sum R_{th,c}}, \tag{12}$$

where h_c is the convective heat transfer coefficient, and $\sum R_{th,c}$ is the sum of the conductive thermal resistances to heat flow due to the various casings and cemented zones.

The film heat transfer coefficient of Equation (12) is obtained from Gnielisnki (1976):

$$Nu = \frac{(f/8)(Re-1000)Pr}{1+12.7\sqrt{(f/8)}(Pr^{2/3}-1)} \ , \qquad (13)$$

where $f=[1.82\log(Re)-164]^{-2}$, Nu is the Nusselt number and Pr is the Prandtl number.

Equations (1)-(3) are transformed into discrete equations using the finite differences technique to obtain numerical solutions. This scheme is easy for code programming and can be validated by comparison with measured data and with analytical solutions. The concept of donor cell is used for parameter lumping purposes whereby the fluid exit conditions are the same as the fluid conditions in the node itself. The parameters to be determined in each cell are pressure and enthalpy

Rock formation model

The transient temperature distribution in the surrounding rock formation, assuming radial symmetry, is given by:

$$\frac{\partial T_r}{\partial t} = \frac{\alpha}{r}\frac{\partial}{\partial r}\left(r\frac{\partial T_r}{\partial r}\right), \qquad (14)$$

where T_r is the temperature of the surrounding rock, α is the rock thermal diffusivity, r is the radial coordinate and t is time. Vertical heat conduction is neglected since radial temperature gradients are much greater than vertical gradients (García *et al.*, 1998a). Particular solutions also require the values of boundary and initial conditions. These are:

$$B.C.1 \qquad T_r = (t, r = r_w) = T_i \qquad (15)$$

$$B.C.2 \qquad T_r = (t, r = \infty) = T_g \qquad (16)$$

$$I.C \qquad T_r = (t = 0, r) = T_g, \qquad (17)$$

where T_i is the temperature of the fluid-rock interface and is determined from Equation (15), T_g is the stable formation temperature as a function of depth [$T_g = f(z)$], and r_w is the wellbore radius (well-rock interface). The T_1 temperature is obtained from standard series thermal resistances and heat flow continuity in the radial direction (e.g. Karlekar and Desmond, 1982).

The solution of the partial differential equation given by Equation (14) with boundary and initial conditions given by Equations (15)-(17) to obtain the complete temperature distribution of the rock formation as function of time and space is based on implicit finite difference techniques. In the present case, the surrounding formation is represented by a one-dimensional mesh-centered grid which consists of a variable number of radial elements. The difference equations for each node have the form

$$A_j T_{j-1}^{n+1} + B_j T_j^{n+1} + C_j T_{j-1}^{n+1} = D_j, \qquad (18)$$

where A, B and C are the matrices of coefficients, T^{n+1} is the solution vector and D is a vector of constants. This equation has the form of a tridiagonal matrix which can be solved by the Thomas algorithm (Patankar, 1980) which is the most efficient algorithm for this type of matrix. The governing equations [Equations (1)-(3) and (14)] are solved using a fractional time step in each cell.

Reservoir model

The bottomhole pressure P_{bfp} behaviour at flowing conditions is approximated (Ascencio, 1990) by

$$P_{bfp} = P_0 - \frac{\mu_0 W}{4\pi\rho_0 \kappa H}ln\left(\frac{4\alpha_H t}{r_w^2 \gamma}\right), \qquad (19)$$

where P_0 is the reservoir pressure, ρ_0 and μ_0 are the reservoir water density and viscosity, W is the mass flow rate, t is time, (κH) is the permeability-thickness product; α_H is the hydraulic diffusivity, and r_w is the wellbore radius.

PHYSICAL PROPERTIES OF H_2O-CO_2 MIXTURES

The following fluid properties are required to perform the numerical simulation with the computer code. Several sources of data have been used to obtain the equations of state for estimation of the thermodynamic and transport properties of H_2O-CO_2 mixtures.

Compressed liquid region

The thermodynamic properties of fluids in this region were estimated considering that the fluid is pure water. This assumption is valid because the CO_2 concentration in the liquid phase is extremely small (Nieva *et al.*, 1987). Thermodynamic properties for pure water are taken from standard correlations (IFC, 1967; Meyer *et al.*, 1968; Mercer and Faust, 1976).

Two-phase region

In this zone the liquid and steam phase properties were required to determine the two-phase mixture properties. The vapor phase of the mixture is composed only of water vapor and CO_2 because of the extremely low volatility of the salts.

This mixture in the vapor phase was assumed to form an ideal gas mixture. The properties of water vapor were calculated using standard correlations mentioned above, while those for carbon dioxide were estimated by means of several equations: solubility of CO_2 (Henry's law, Ellis and Golding, 1963; Michaelides and Nikitopoulos, 1986); specific density and enthalpy (Sutton, 1976) and viscosity (Zyvoloski and O'Sullivan, 1980).

The numerical model covers the liquid region up to 45 MPa, the full two-phase region and the superheated steam region up to about 16.5 MPa and an enthalpy of 2565 kJ/kg. Minimum and maximum enthalpies are 109 kJ/kg and 3174 kJ/kg, respectively.

COMPUTATIONAL PROCEDURE

The well flow problem is solved as an initial value problem by a step-by-step method. The main data necessary are: bottom temperature, pressure and mass fraction of CO_2, well diameters, well depth, mass flow rate of fluids (primary and secondary), and the petrophysical properties of the reservoir. The output yields information related to the well vertical profiles of the fluid properties, CO_2 distribution in the two phases, temperature and pressure, steam quality, mass flow rates of the two phases and flashing points.

Depending on the input data (temperature, pressure and mass fraction of CO_2) the system of equations of the model defines the flow regime of the well, as follows:

- Compressed liquid. This flow condition occurs if the input pressure is greater than the saturation pressure of pure water at the initial temperature, and if the CO_2 solubility in the liquid is greater than the input mass fraction of CO_2.

- Two phase (Steam-Liquid). This flow condition occurs if the input pressure is greater than the saturation pressure of pure water at the initial temperature but the CO_2 solubility in the liquid is less than the input mass fraction of CO_2.

RESULTS

The capabilities of the numerical solutions were evaluated by comparison with published data on numerical flow simulation of geothermal wells that are reported in the literature (Michaelides and Shafaie, 1981; Tanaka and Niki, 1981). The results show good agreement with published results. Subsequently, the computer code was applied to study the effect of incondensable gases (CO_2) on the flows that exist in geothermal wells. The case of pure water was also considered.

Figure 2 shows vertical pressure profiles that were obtained considering the effect of the CO_2 and without it. The

pressure behaviour in both cases indicates slope changes due to the existence of a "flashing point". This zone is identified as the level of the well at which the steam phase appears. Above this zone there exists an accumulation of incondensible gas (CO_2). In both cases, as the fluid ascends, the pressure decreases and remains about the same until the flashing point of the H_2O-CO_2 mixture is reached. From this point on, the two pressure profiles differ and separate while the pressure continues to decrease but at a smaller rate for the H_2O-CO_2 mixture due to the CO_2 content. Thus, for the H_2O-CO_2, the partial pressure of CO_2 dominates the pressure behaviour in this zone. For pure water, the pressure gradient is approximately of hydrostatic type.

Figure 3 shows the evolution of the vertical temperature profile for pure water and the H_2O-CO_2 mixture. It is observed that the temperature is approximately the same for both cases from the well bottom to the "flashing point". The flashing point appears at a greater depth for the H_2O-CO_2 mixture than for the pure water (H_2O) and this is expected due to the combined effect of pressure loss and CO_2 solubility. Above this point, both curves separate and cross each other near the wellhead. The liquid-phase distribution of CO_2 is shown in Figure 4. The behaviour of this profile indicates that CO_2 remains dissolved in the liquid phase from bottomhole to the flashing point. Above of this zone it is released from the solution to mix with the steam phase.

CONCLUSIONS

A numerical model was developed to describe the flow production characteristics of geothermal fluids considering
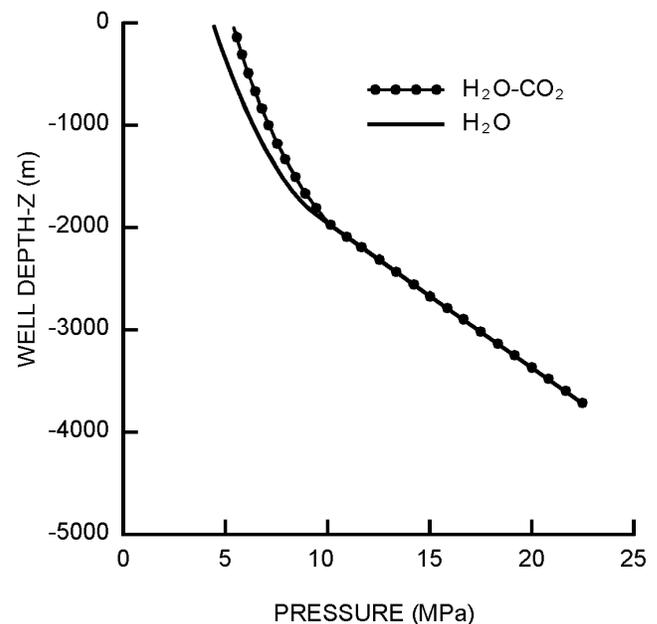
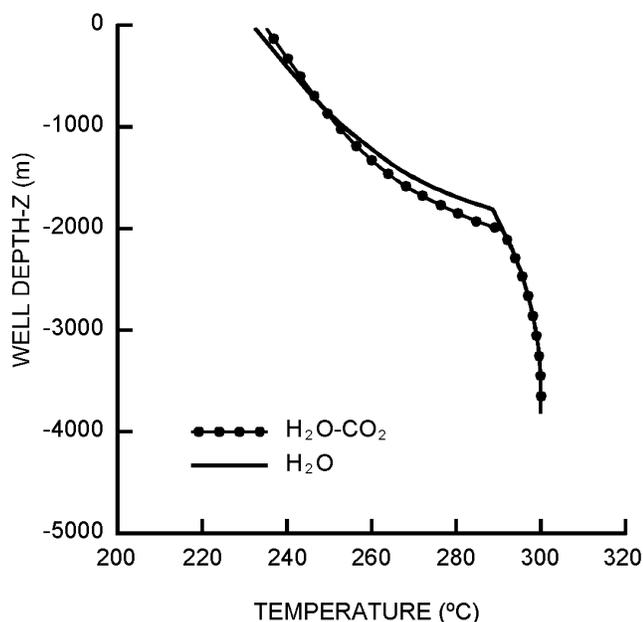Fig. 2. Vertical pressure profiles in a geothermal well considering two-types of produced fluids.

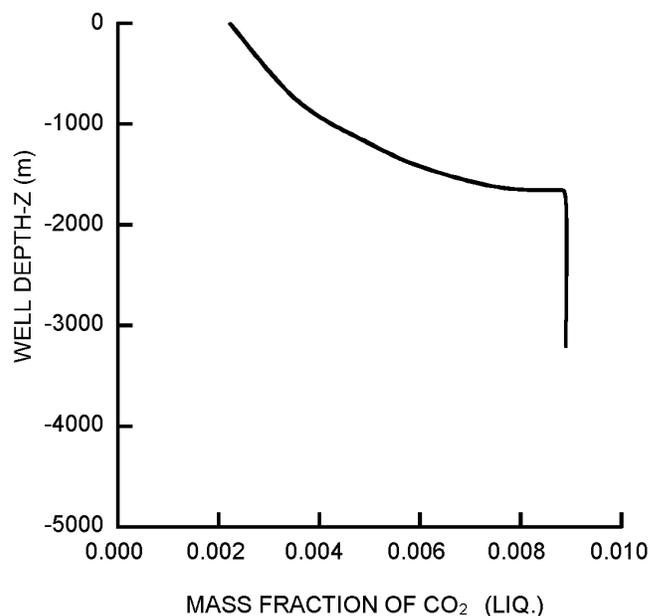Fig. 3. Vertical temperature profiles in a producing geothermal well.

Fig. 4. Vertical CO_2 concentration profiles in the liquid phase during production of geothermal fluids.

the effect of IGs. The model consists of three conservation equations for mass, momentum and energy and these are supplemented by several closure equations, equations of state, and a package of equations to evaluate the thermodynamic and transport properties of water and the H_2O-CO_2 system. The results of the computer program agree well with data reported in the literature and this enhances its validity. The present results agree with qualitative expectations and the results produced by other models.

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