

Thermodynamic classification of vapor and liquid dominated reservoir and fluid geochemical parameter calculations

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RESUMEN

Se presenta una definición termodinámica para clasificar los yacimientos geotérmicos en vapor o líquido-dominantes. El yacimiento vapor-dominante contiene un volumen específico de fluido (de vapor y líquido conjunto) mayor que el volumen crítico del agua, mientras que el yacimiento líquido-dominante contiene un volumen específico menor. El yacimiento vapor-dominante no es necesariamente un yacimiento de vapor supercalentado: puede contener vapor y líquido. Las características PVT de fluido geotérmico han sido consideradas como de agua pura.

Se desarrolló un método de flujo bifásico para calcular los parámetros termodinámicos de fluido: especificación química, presión y temperatura en un yacimiento geotérmico por los parámetros del fluido (de vapor y líquido) a condiciones de separación en el pozo. El flujo estacionario sin pérdida o ganancia de calor por conducción térmica en el pozo geotérmico ha sido considerado. Igualmente, se introdujo la conservación de masa y de energía total (mecánica y térmica). La caída de presión por fricción es despreciada en comparación con la caída de presión por gravedad y aceleración. Una aplicación de dicho método al pozo M-19A en Cerro Prieto indica que el yacimiento del Cerro Prieto es bifásico de vapor-dominante.

PALABRAS CLAVE: Sistema hidrotermal, yacimiento geotérmico, flujo bifásico, cálculo geoquímico, geotermia, termodinámica de fluido, Cerro Prieto, México.

ABSTRACT

A thermodynamic definition is presented to classify vapor and liquid-dominated geothermal reservoirs. The vapor-dominated reservoir has a specific volume of fluid (i.e. combined vapor and liquid) greater than the critical volume of water, whereas the liquid-dominated reservoir has a lower specific volume. A vapor-dominated reservoir is not necessarily a superheated steam reservoir; it can have both vapor and liquid. The PVT characteristics of geothermal fluid are considered as of pure water.

A two-phase flow approach is developed to calculate fluid thermodynamic parameters; chemical speciation, pressure and temperature in a geothermal reservoir from the parameters measured in the geothermal fluid (vapor and liquid) at the wellhead separator. Steady-state flow and no heat loss or gain due to thermal conduction in the geothermal well are assumed. Conservation of mass and of total (mechanical and thermal) energy is introduced. The frictional pressure drop in the well is neglected with respect to gravitational and accelerational pressure drops. An application to well M-19A at Cerro Prieto shows that the Cerro Prieto is a two-phase vapor-dominated reservoir.

KEYWORDS: Hydrothermal system, fluid-geochemistry, two phase flow, geochemical calculation, geothermal system, fluid thermodynamics, Cerro Prieto, Mexico.

1. INTRODUCTION

The classification of vapor- and liquid-dominated hydrothermal systems is useful to understand the production characteristics and geochemistry of reservoirs. Some authors consider the presence of both vapor and liquid (White *et al.*, 1970; Truesdell and White, 1973) in a vapor-dominated reservoir, while others accept the existence of only superheated steam (Donaldson and Grant, 1981; Economides and Miller, 1986; and Miller, 1987). In this article we demonstrate thermodynamically that both vapor and liquid may exist in a vapor-dominated geothermal system. Thus the combined specific volume (of vapor and liquid) of the fluid in the reservoir becomes a fundamental parameter to define the tendency of vapor or liquid domination. A simplified two-phase flow approach is applied to calculate the combined specific volume of the fluid in the reservoir.

Earlier approaches to calculate the geochemical parameters from the fluid obtained at the surface are based on the

conservation of fluid enthalpy (Henley *et al.*, 1984; Giggenbach, 1980; Arnórsson *et al.*, 1990). Verma (1994a,b) has shown that the fluid enthalpy in a geothermal well is not a conservative parameter. Pressure and temperature must be measured independently at the wellhead. There are gravitational, accelerational and fractional pressure drops as the fluid rises in the well. Thermal energy converts to mechanical energy. Thus, the total energy is conservative, not the thermal energy. While the amount of mechanical energy is smaller than the thermal energy of the fluid, it could be included for more accurate computation of the geochemical parameters. Further, we must distinguish between *the reservoir enthalpy and the production enthalpy*. The enthalpy of a well measured at the separator is a function of pressure and temperature of the separator and wellhead: this is the production enthalpy. The reservoir enthalpy cannot be altered by changing the wellhead parameters (Verma, 1996).

The two-phase flow approach is applied to well M-19A of the Cerro Prieto geothermal system, showing that it

provides a clear understanding of the type of geothermal reservoir.

2. VAPOR- AND LIQUID-DOMINATED HYDROTHERMAL SYSTEMS

There is no unanimous definition of vapor- and liquid-dominated geothermal reservoirs. If superheated steam reservoirs are vapor-dominated, then compressed liquid systems will be liquid-dominated. Why should two-phase reservoirs be considered liquid-dominated?

On the other hand, if both phases can be present together in the vapor- and liquid-dominated reservoirs, then the proportion of the phases becomes important to distinguish between vapor- and liquid-dominated geothermal reservoirs. Suppose a 1 l container (Figure 1c) having 400 g of total water as vapor and liquid. The specific volume of the fluid is $2.5 \text{ cm}^3/\text{g}$. This situation is represented by point J in Figure 1c(i). Let the initial temperature (T_2) be 25°C , as for the point J on the isotherm T_2 in Figure 1b. If we heat the container, the volume of liquid will continuously increase and the container will be filled with liquid at $\sim 373^\circ\text{C}$ (see steam table from Henley *et al.*, 1984). This is the liquid saturation point P in Figure 1b. The heating process is represented by the path from J,K,L to P in the PT diagram (Figure 1a). On further heating the process can be described by the constant specific volume ($2.5 \text{ cm}^3/\text{g}$) path PV' in the liquid phase region (Figure 1a). The slope of this path will depend on the compressibility and expansivity properties of water.

Now, if the container has only 200 g of total water (i.e. combined vapor and liquid), the specific volume of the fluid will be $5 \text{ cm}^3/\text{g}$. This initial situation is represented by point K in Figure 1c(iii), or by the point K on the isotherm T_2 in Figure 1b. If we heat the container, the container will be filled with vapor at $\sim 370^\circ\text{C}$. This is the vapor saturation point N in Figure 1b. The heating process can be represented by the path from point J,K,L to point N in the PT diagram of Figure 1a. On further heating the process may be described by the constant specific volume ($5 \text{ cm}^3/\text{g}$) path PV in the vapor region in Figure 1a.

In the third situation, when the specific volume of the fluid is equal to the critical volume of water ($3.16 \text{ cm}^3/\text{g}$), the heating process can be described by the path J,K,L through C to V_c in Figure 1a. There will be no distinction between vapor and liquid beyond the critical point C.

In conclusion, the combined specific volume (vapor and liquid) of the fluid in a container can be either larger, equal or less than the critical volume of the fluid. If the specific volume is larger than the critical volume, then on heating all the liquid will convert to vapor. If the specific volume is less than the critical volume, there will be only liquid in the container on heating. When the specific volume is equal to the critical volume of the fluid, the heating path will be from point J,K,L to C and to the constant volume (V_c) dashed path; but there will be no distinction between liquid and vapor.

Thus a geothermal system can be classified as vapor- or liquid-dominated depending on whether the specific volume of the fluid in the reservoir is smaller or greater than the critical volume, respectively. If the specific volume of the reservoir fluid is smaller than the critical volume, all the fluid will convert to liquid as it gets heated in the reservoir, and vice versa. Yet both types of reservoir can produce vapor only at the wellhead, depending on pressure and temperature conditions of production and in the reservoir. It is not correct to define the type of geothermal reservoir by the characteristics of the geothermal fluid at the wellhead. Thus, it is necessary to calculate the deep reservoir fluid specific volume from the fluid characteristics at the wellhead to classify the geothermal system.

3. RESERVOIR PARAMETER CALCULATION

Producing aquifers often yield compressed liquid reaching the well after passing through the permeable strata of the reservoir. As the liquid rises in the well, its pressure drops by gravitational, frictional, and accelerational effects. At some level in the well, the hydrostatic pressure becomes equal to the saturation pressure corresponding to the fluid temperature, and boiling begins. This level is called the 'flash horizon'. Beyond this point, the fluid exists as a mixture of liquid and vapor of increasingly quality (Michaelides and Shafaie, 1986). In the separator the mixture is separated into vapor and liquid at a specified pressure. The separated water is flashed in the weirbox to atmospheric pressure. Samples of water from the weirbox and steam from the separator are collected for analysis of chemical composition.

Until now, it has been common practice to measure only the wellhead and separator pressures or temperatures assuming thermodynamic equilibrium between liquid and vapor at every stage. Either pressure or temperature is considered sufficient to describe the system thermodynamically. However, if one gets only vapor at the wellhead, the geothermal fluid will be in the vapor region in the PT diagram (Figure 1). Thus pressure and temperature must be measured independently.

3.1 Conservation of mass and thermal energy

Any conservative quantity may be used to write a mass and energy balance equation. By assuming equilibrium between liquid and vapor in the well and in the separator one can write the energy (enthalpy) balance equation as (Henley *et al.*, 1984)

$$H_R = y H_v + (1 - y) H_l \quad (1)$$

where y is the fraction by weight of vapor in the separator and H_R is the total discharge enthalpy, which is determined from the separator pressure or temperature, and from the flow rates of steam and water from the separator (Grant *et al.*, 1982). H_R is commonly known as reservoir fluid enthalpy and is used to describe the geochemistry of geothermal systems. It is usually assumed that there is only water in the reservoir. H_v and H_l represent the enthalpy of vapor and water, respectively, at the pressure in the separator,

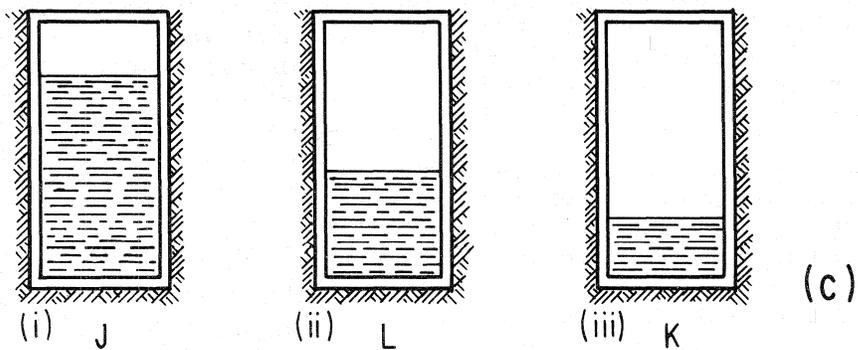
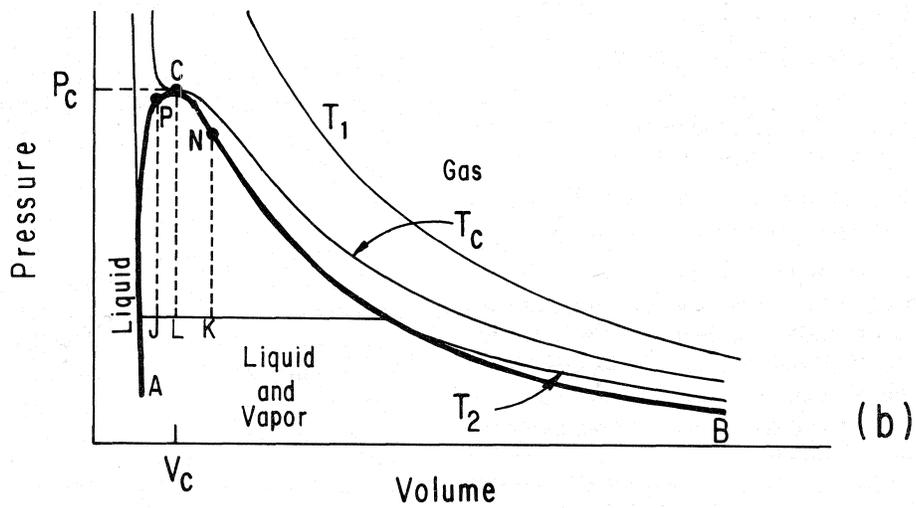
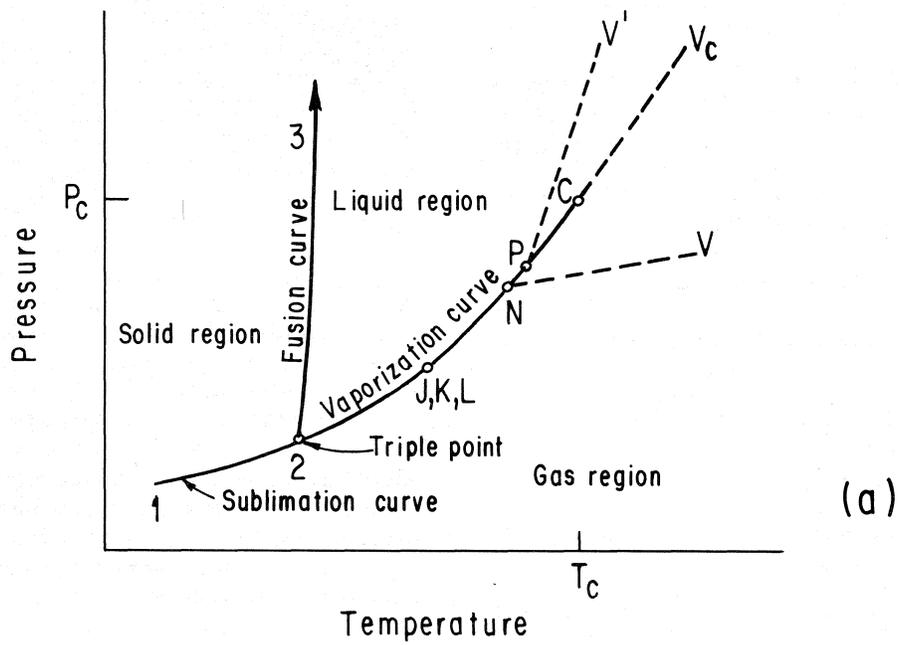


Fig. 1. P-V-T diagram for a geothermal fluid without considering the effects of dissolved constituents (after Smith and Ness, 1975). (a) P-T diagram, (b) P-V diagram and (c) a hypothetical case of water-vapor ratio in a geothermal system to show the three possible options: i. liquid dominated, ii. critical condition and iii. vapor dominated reservoir.

which can be read from saturated steam tables at the separator pressure. Thus the fraction of vapor y can be calculated.

Similarly, the distribution of any chemical component C_R in the reservoir fluid can be retrieved for analysis of vapor and liquid samples C_v and C_l collected from the separator using the following mass balance equation

$$C_R = y C_v + (1 - y) C_l \quad (2)$$

The concentration of any species in the vapor and liquid phase from the separator (i.e. C_v and C_l), H_v and H_l from measured wellhead pressure and steam tables, and H_R yield an estimate of C_R . In order to calculate the concentration of liquid at the separator from the weirbox liquid phase concentration, we use

$$C_l = C_{atm} (1 - y^*) \quad (3)$$

where y^* is the steam fraction lost during flashing from the separator to the weirbox.

The noncondensable species such as CO_2 , H_2S , CH_4 , etc. are only measured in vapor phase. In order to calculate the concentration of these species in liquid phase at the separator, we define the experimental distribution coefficient for the species at the separation pressure

$$B = \frac{C_v}{C_l} \quad (4)$$

In case of the isotopic species we deal with the isotopic ratio and the distribution coefficient is called the fractionation coefficient.

The above calculations assume a single phase (liquid) in the reservoir (see equation 1). In order to obtain the fraction of steam in the feeding zone of a geothermal well, Henley *et al.* (1984) compare the measured enthalpy (H_R) with the enthalpies corresponding to the temperatures obtained with quartz and Na-K-Ca geothermometers. Giggenbach (1980) proposed a more complicated approach to determine this excess steam using the distribution of gaseous components such as methane, hydrogen, carbon dioxide and vapor. Arnórsson *et al.* (1990) extended this method to evaluate boiling processes in the producing aquifer of "high enthalpy" geothermal wells. The water and steam separated in the aquifer is evaluated as well as the amount of enhanced evaporation due to heat flow from the rock to the boiling water.

Henley *et al.* (1984) used measured and liquid enthalpies derived from chemical geothermometers (SiO_2 and NaKCa) to calculate excess enthalpy in the reservoir. They propose that the reservoir fluid could be classified as:

Normal enthalpy fluid	$t_{\text{NaKCa}} > t_{\text{quartz}}$ $H_{\text{TD}} \equiv H_{\text{NaKCa}} > H_{\text{quartz}}$
High enthalpy fluid	$t_{\text{NaKCa}} \gg t_{\text{quartz}}$ $H_{\text{TD}} > H_{\text{NaKCa}} > H_{\text{quartz}}$
Low enthalpy fluid	$t_{\text{quartz}} < t_{\text{NaKCa}}$ $H_{\text{TD}} \equiv H_{\text{quartz}} > H_{\text{NaKCa}}$

The high enthalpy fluid results from reservoir boiling with preferential steam flow to the well, whereas low enthalpy discharge may occur when multiple feed zones intersect the well or when exploitation has led to an inflow of relative cold water. They used the terms "excess steam" for the fraction of steam produced due to boiling of water by pressure drop, and "excess enthalpy" to the enthalpy associated with this excess steam in the reservoir.

Giggenbach calculated excess steam from the distribution of gaseous components, methane, carbon dioxide, hydrogen and vapor. This approach is widely used in the literature. It is an outcome of work on geothermal gas equilibria (Giggenbach, 1980). The equilibrium constants of the Fischer-Tropsch reaction and/or dissociation of ammonia into N_2 and H_2 are used. Because of large differences in the solubilities of these gases, a small variation in the amount of deep vapor can lead to large variations in the relative gas contents. Nieva *et al.* (1984) modified this approach for the case of high concentration of volatile species other than steam in the vapor phase.

3.2 Two phase flow method

The preceding method is based on two assumptions: *equilibrium between vapor and water in the well and conservation of enthalpy*. These assumptions are not always valid in a geothermal system. Superheated steam has been predicted in various geothermal reservoirs, but the production characteristics of even the steam producing wells is not used for geochemical calculations in the literature. Wells which receive superheated steam should produce superheated steam at the wellhead. One has to measure both temperature and pressure at the separator and at the wellhead, and use steam tables for compressed liquid and superheated steam to assess the geochemistry of the system correctly. In the case of wells which produce a mixture of vapor and liquid, one can still assume the existence of equilibrium between vapor and liquid as there are usually no data on temperature and pressure measured independently in a geothermal well.

Enthalpy is not a conservative parameter in a geothermal system. The fluid entering at the bottom of a well has practically no velocity, so it has a small kinetic energy. Yet the measured high flow rate of steam and separated water after the separator is a direct indication of high kinetic energy of the fluid at the wellhead. Similarly, as the fluid ascends to the surface its potential energy increases. Thus the heat energy is converted to mechanical energy (potential and kinetic). The total energy is conservative but not the enthalpy. Secondly, the production enthalpy can be changed by changing the well configuration (i.e. well diameter, depth, and wellhead pressure). In equation (1), the measured discharge enthalpy is considered as reservoir enthalpy. The measured enthalpy H_R is compared with the enthalpies corresponding to reservoir temperature estimated with NaKCa and SiO_2 geochemical thermometers in order to obtain the vapor fraction in the reservoir. The comparison of two different types of enthalpy is fundamentally incorrect.

Here we also assume steady state flow and no heat loss by conduction in the well. As the liquid rises in the well, its pressure drops by gravitational, frictional, and acceleration effects. The gravitational pressure drop is dominant and friction accounts for only a few percent (2-5%) of the total pressure drop in the well (Bilicki *et al.*, 1982). Therefore, the frictional pressure drop may be neglected to simplify our approach.

If there is liquid and vapor in equilibrium at the separator, the wellhead parameters can be calculated in terms of the separator liquid-vapor parameters. The mass and energy balance equations can be written as

$$m_{l,hd} + m_{v,hd} = m_{l,sp} + m_{v,sp} \quad (5)$$

$$\begin{aligned} \frac{1}{2} m_{l,hd} u_{l,hd}^2 + \frac{1}{2} m_{v,hd} u_{v,hd}^2 + m_{l,hd} H_{l,hd} + m_{v,hd} H_{v,hd} = \\ \frac{1}{2} m_{l,sp} u_{l,sp}^2 + \frac{1}{2} m_{v,sp} u_{v,sp}^2 + m_{l,sp} H_{l,sp} + m_{v,sp} H_{v,sp} \end{aligned} \quad (6)$$

The steam volumetric saturation or void fraction (Griffith, 1985) which is the fraction of cross section area occupied by vapor phase is defined as

$$\alpha_{hd} = \frac{V_{v,hd} m_{v,hd}}{V_{v,hd} m_{v,hd} + V_{l,hd} m_{l,hd}} \quad (7)$$

The mass flow rates for vapor and liquid phase at the wellhead can be expressed as

$$m_{v,hd} = \frac{V_{v,hd} \alpha_{hd} A_{hd}}{V_{v,hd}} \quad (8)$$

$$m_{l,hd} = \frac{V_{l,hd} (1 - \alpha_{hd}) A_{hd}}{V_{l,hd}} \quad (9)$$

We have five equations (4 to 8) to calculate the five unknown quantities $m_{l,hd}$, $m_{v,hd}$, α_{hd} , $u_{l,hd}$ and $u_{v,hd}$. The procedure can be repeated by dividing the well height in small segments, until liquid saturation conditions are reached. Below this point, the pressure of the liquid increases and one has to use compressed-water steam table data. One has to include the potential energy in the energy conservation equation in the well. The equation for concentration calculations is the same as in the previous method with a slight modification. The vapor fraction must be calculated as

$$y_{sp} = \frac{m_{v,sp}}{m_{v,sp} + m_{l,sp}} \quad (10)$$

If there is only superheated steam at the separator, the wellhead parameters can be calculated assuming the vapor to behave as an ideal gas and a reversible adiabatic process

$$\begin{aligned} \frac{1}{2} m_{v,hd} u_{v,hd}^2 + m_{v,hd} H_{v,hd} = \frac{1}{2} m_{v,sp} u_{v,sp}^2 + m_{v,sp} H_{v,sp} + \\ \frac{RT_{sp}}{\gamma - 1} \left[1 - \left(\frac{P_{hd}}{P_{sp}} \right)^{\frac{\gamma - 1}{\gamma}} \right] \end{aligned} \quad (11)$$

where R and γ are the gas constant and the ratio of heat capacities of water at constant pressure and constant volume, respectively (Smith and Ness, 1975). The value of γ for vapor is 1.3. The temperature and pressure relation can be expressed as

$$\frac{T_{sp}}{T_{hd}} = \left(\frac{P_{sp}}{P_{hd}} \right)^{\frac{\gamma - 1}{\gamma}} \quad (12)$$

The calculation must be repeated as discussed above, dividing the well depth into small segments until vapor saturation is reached. Below this point the two phase flow concepts must be used.

From the fraction of vapor and specific volumes of vapor and liquid in the reservoir one can calculate the specific volume of the fluid (i.e. combined specific volume of vapor and liquid) as

$$V_R = y_R V_{v,R} + (1 - y_R) V_{l,R} \quad (13)$$

Here it is assumed that the vapor and liquid do not show preferential flow to the well in the reservoir. Thus the flow rates are proportional to the quantity of vapor and liquid in the reservoir. Similarly, all the space in the reservoir is either filled with liquid or vapor. The homogeneous flow method is simple and provides reasonably good precision (Griffith, 1985).

4. RESERVOIR PARAMETER CALCULATION FOR WELL CP-M19A

A computer program in FORTRAN-77 has been written to perform the calculation of reservoir parameters using the two approaches. It uses input data for liquid phase as the chemical composition of separated water at atmospheric pressure in weirbox, and for vapor phase the chemical composition of gases on dry basis, gas fraction in vapor conduit in the separator and wellhead and separator pressures. In addition the data on well and the conduits of vapor and liquid are also required. Some of the important subroutines of the program are the following:

i. *StmTbl* provides the saturated steam table from 0°C to the critical point of water (375.15°C). ii. *FracCoeff* computes the fractionation coefficients of the gases, CO₂, H₂S, NH₃, CH₄, N₂ and H₂ at a specified temperature. iii. *WellHead* calculates the vapor and liquid phase compositions at wellhead using input data and conservation of mass and total energy (thermal and mechanical energy). iv. *WellPos*: Once the fluid compositions at wellhead are known, the subroutine WellPos starts calculating the compositions by dividing the well into small segments (say, 10 m length) in an iterative way until reaching the bottom of the well. The details of the computer program will be presented elsewhere (Verma, 1997).

Table 1 shows a data set for geochemical analysis of geothermal well M-19A in Cerro Prieto. The chemical analysis data are taken from Henley *et al.* (1984) and the production and well depth data are from Aragon (1986).

Table 1

Data for the geochemical analysis of a geothermal well from Cerro Prieto (M-19A). The data are taken from Henley *et al.* (1984) and Aragon (1986)

Well No		Well head pressure	3.5 MPa
Well depth	1425 m	Well separator pressure	0.755 MPa
Well diameter	0.30 m	Atmospheric pressure	0.1 MPa
		Vapor production (at sep)	63.2 ton/hr
Date of sampling		Water production (at wairbox)	97.8 ton/hr
		Reservoir enthalpy	1203 J/gm

Chemical analysis of separated water at the weirbox

Na ⁺	7370 ppm ¹	Cl ⁻	13800 ppm
K ⁺	1660 ppm	SO ₄ ²⁻	18 ppm
Ca ²⁺	438 ppm	HCO ₃ ^{-T}	52 ppm
Mg ²⁺	0.4 ppm	SiO ₂	808 ppm
Li ⁺	200 ppm	pH (at 20°C)	7.4
B	14.4 ppm		
As	5 ppm		

Chemical analysis of vapor at the separator

Total gas in steam (xg) 5.88 mmol/mol steam

CO ₂	822 mmol/mol total gas
H ₂ S	79.1 mmol/mol total gas
CH ₄	39.8 mmol/mol total gas
H ₂	28.6 mmol/mol tot
N ₂ (+Ar)	5.1 mmol/mol total gas
NH ₃	23.1 mmol/mol total gas

¹ concentrations are in ppm by weight.

The reservoir enthalpy, calculated from the flow rate of water and vapor, and the pressure at the separator, is somewhat higher than the reported one.

The reservoir temperatures calculated by applying quartz and Na-K-Ca geothermometers are 285 and 281°C, respectively; whereas the liquid temperature to enthalpy is 273°C. The chemical geothermometers and enthalpy temperatures are in agreement, so it is possible that there is no loss or gain of enthalpy and the total discharge composition is the deep reservoir concentration. The chemical compositions of reservoir fluid calculated from this approach are given in the Table 2. Applying the Giggenbach method, one obtains a steam fraction of 1.53% in the reservoir. The chemical compositions of reservoir fluid calculated using this approach are given in Table 2.

The reservoir fluid compositions calculated with the two phase flow approach are also shown in Table 2 (column 2). If we change the depth of the well, we will get a different composition of the reservoir fluid. The columns 1 and 3 for the two phase flow approach show the physicochemical parameters of the reservoir fluid considering well depths of 500 and 3000 m, respectively. The characteristics of produced water and vapor are exactly the same. The parameters are quite different for different well depths. For example, the vapor fraction in the reservoir will be 22.4, 20.3 and 17.1%, if the depth is taken as 500, 1425,

and 3000 m, respectively. Similarly, the specific volumes calculated for different depths are 12.6, 9.6 and 6.6 cm³/g, respectively. Clearly, the well configuration plays an important role in controlling the production fluid characteristics.

In the first approach by Henley *et al.* (1984) and Giggenbach (1980) the well configuration is not important. If wells of different depth produce the same types of fluid at the wellhead, the reservoir fluid thermodynamic parameters (i.e. temperature, pressure, fraction of vapor, and concentration of dissolved constituents) should be exactly identical. This cannot be correct.

Similarly, the wellhead opening or the wellhead pressure contribute substantially to controlling the production fluid characteristics. If the wellhead orifice is reduced, the proportion of steam to separated water will be less, and the production enthalpy will be less. However, the chemical geothermometers will practically indicate the same temperature or the same reservoir enthalpy. The first approach provides different values of steam/water fraction for different wellhead apertures. The two-phase flow approach takes into consideration the changing of well head pressure with aperture.

In Table 2, the specific volume of a well (CP-M19A) for depth 1425 m is 9.6 cm³/g, which is greater than the

Table 2

The deep reservoir physical-chemical parameters of the fluid calculated with different approaches

Parameter	Henley <i>et al.</i> (1984)	Giggenbach (1980)	Two phase flow approach ¹		
			1	2	3
Temperature (°C)	281	281	248	260	276
Pressure (MPa)	6.51	6.51	3.87	4.69	6.01
Vapor Fraction	0	0.015	0.224	0.203	0.171
Specific Volume (cm ³ /g) ²			12.6	9.6	6.6
Liquid phase					
(concentrations are in ppm by weight)					
Na ⁺	5605	5692	6077	5921	5692
K ⁺	1263	1282	1369	1334	1282
Ca ²⁺	333	338	361	352	338
Mg ²⁺	0.3	0.3	0.3	0.3	0.3
Li ⁺	152	154	164	161	154
B	10.9	11.1	11.9	11.6	11.1
As	3.8	3.9	4.1	4.0	3.9
Cl ⁻	10495	10658	11379	11089	10658
SO ₄ ²⁻	13.7	13.9	14.8	14.5	13.9
HCO ₃ ⁻	39	40.1	42.9	41.8	40.2
SiO ₂	614	624	666	649	624
(concentrations are in 10 ⁻⁵ mol gas/mol water)					
CO ₂	116.19	66.90	6.71	9.84	16.67
H ₂ S	11.28	8.75	1.66	2.31	3.61
CH ₄	5.69	1.82	0.11	0.15	0.29
H ₂	4.03	1.02	0.09	0.08	0.15
N ₂ (+Ar)	0.72	0.01	0.05	0.01	0.02
NH ₃	4.49	4.30	3.18	3.47	3.90
Vapor phase (concentrations are in mmol gas/mol steam)					
CO ₂		32.82	7.55	8.19	9.37
H ₂ S		1.74	0.69	0.74	0.81
CH ₄		2.49	0.37	0.41	0.48
H ₂		1.97	0.27	0.29	0.35
N ₂ (+Ar)		0.02	0.05	0.05	0.06
NH ₃		0.17	0.15	0.16	0.16

¹ The concentrations are calculated utilizing well depths of 500, 1425 and 3000 m for cases 1, 2 and 3.

² The specific volume of the fluid in the reservoir including both vapor and liquid.

critical volume of water (i.e. 3.16 cm³/g). The vapor fraction is 20.3%. Thus there are both vapor and liquid in the reservoir under the well at Cerro Prieto. According to our definition, the well is producing from a two-phase vapor-dominated reservoir.

6. CONCLUSIONS

A reservoir which has a specific volume of fluid less than the critical specific volume is vapor dominated, whereas a reservoir having a fluid specific volume greater than critical specific volume is liquid dominated. The two-phase flow approach to calculate reservoir parameters is

based on valid theoretical concepts: *steady state two phase flow* and *total energy conservation*. It uses only parameters which can be measured directly at the wellhead and separator. Whether the fluid entering at the bottom of well is compressed liquid, mixture of vapor and liquid or superheated vapor can be determined without using any empirical relations. The main contribution of this study is that temperature and pressure, and chemical composition in the reservoir, are the parameters of fundamental importance in modeling geochemical processes in the geothermal reservoir. The approach can be improved by incorporating friction between vapor and liquid phases and the walls of the well, the effect of dissolved species on the properties of

vapor and liquid phases, and compressed liquid and superheated steam tables. The Cerro Prieto reservoir under well M-19A is a two-phase vapor-dominated reservoir according to this thermodynamic classification.

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Nomenclature

A - Area of cross section (m²)
B - Gas distribution coefficient
H - Specific enthalpy (J/g)
m - Flow rate (t/h)
P - Pressure (MPa)
T - Temperature (°C)
u - Flow velocity (m/sec)
V - Specific volume (cm³/g)
y - Fraction of vapor
 α - Void fraction
 γ - Ratio of specific heats of water at constant pressure and constant volume

Subscripts:

hd - wellhead
l - liquid phase
R - reservoir
sp - separator
v - vapor phase

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