THE PREDICTION OF THE PVT/PHASE BEHAVIOR OF THE GEOTHERMAL FLUID MIXTURES

H. Alkan, T. Babadagli and A. Satman

Istanbul Technical University, Department of Petroleum Eng.

Key words: PVT, Cubic equations of state, emprical correlations, wellbore modeling, reservoir modeling

ABSTRACT

The realistic estimation of the PVT/Phase behavior of geothermal fluid systems plays a very important role in reservoir performance and energy production studies. In this study, two methods to predict the PVT/phase behavior of geothermal systems were evaluated. As a first attempt, the use of a cubic equation of state (EOS) was applied. Experimental data were matched with the Peng-Robinson EOS and a strong dependence of binary interaction coefficients to temperature was observed The use of experimental correlations giving the solubility of CO_2 and related properties was observed more convenient for this purpose at the pressure-temperature-concentration ranges that are typical for geothermal reservoirs. Therefore, a PVT package which calculates the PVT/phase properties of H_2O-CO_2 systems using empirical correlations was developed. As a second step, the effects of salt content on the thermodynamic properties of geothermal fluids were added into the PVT package developed in the present study.
Then, the use of the PVT package for different purposes was evaluated incorporating it into softwares prepared to model reservoir performance and wellbore flow including calcite deposition modeling.

INTRODUCTION

The realistic estimation of the PVT/phase behavior of the fluids is often the most important part of the production and reservoir engineering studies of geothermal fields The simplest way of determining the PVT and phase behavior properties is to use the Steam Tables (1977) assuming that the reservoir contains pure water only However, it is the fact that geothermal fluids are not pure water and indeed, they become a brine solution as a result of their natural voyage through the crust of the earth

Geothermal brines are mainly sodium chloride solutions Sodium chloride (NaCI) is typically 70-80 % of the total dissolved solids (TDS) In addition to this. potassium is found in substantial quantities, being about 1/10 that of sodium on an atomic basis Calcium is the other major cationic constituent of geothermal brines Chloride ion is the only major anionic constituent and second most important anionic ingredient is bicarbonate Maxiumum amount of total dissolved solids reaches up to 200,000 ppm (USA, Salton Sea) and the average value of the world's geothermal fluids is around 10,000 ppm Beside the dissolved solids, geothermal fluids may contain considerable amount of gases CO_2 is the major gaseous component of most of the geothermal brines and generally it comprises more than 90 % of the total gas content by volume H_2S and NH3 are also found in some cases but the amounts of these gases are usually negligible

In the two fields in Turkey (Kizildere and Germencik), that are considered as the cases in this study, TDS values are approximately 4,000 and 5,000 ppm, respectively (except CO_2, HCO_3^- and CO_3^{-2}) The CO_2 content of Kizildere Geothermal Field was initially 10,000-15,000 ppm Currently, this amount has been decreasing and higher C02 concentration was detected in Germencik Field (up to 16,000ppm)

The initial performance prediction studies of the Kizildere Field were made with the assumption that dissolved C02 and salts have negligible effect on the PVT/phase behavior of the reservoir fluid (United Nations Report, 1974, Alkan and Satman, 1988) This was a realistic approach for salt content but the field data showed a two-phase flow in the reservoir as well as in the wellbore earlier than the predicted time This was naturally due to high C02 content of the reservoir and it was necessary to insert the C02 effect into the modeling studies

In this paper, a detailed study of PVT/phase behavior calculations of geothermal brines was conducted Initially, the effects of dissolved gases on the thermodynamics was studied using cubic EOS's The experimental data were matched to determine the unknown binary interaction coefficients (BIC) of Peng-Robinson EOS The effects of the polar atomic structure of the H_2O-CO_2 system was modeled using an alternative mixing rules for determining the BIC's

Although the temperature dependence of the BIC's was taken into account, the results showed that this approach has some deficiencies on predicting the PVT/phase properties of geothermal fluids Therefore, a thermodynamic package from empirical correlations was prepared and this package was determined to be more convenient to estimate the PVT/phase behavior of H_2O-CO_2 systems The effect of salt content on the thermodynamics of the geothermal brines was added to the package to minimize the errors arising from empirical analysis

After testing the performance of the PVT package, it was introduced into reservoir and production studies. Some of the results obtained using the resulting models are presented.

CUBIC EQUATION OF STATE APPROACH

The three parameter Peng-Robinson equation of state (EOS) (Peng and Robinson, 1975) was used to solve the above described problem The reasons for selecting the Peng-Robinson EOS were the molar volume correction proposed by Peneloux et al (1982) and its reported validity on modeling the PVT/phase properties of various fluid systems The modifications proposed by Peng-Robinson (1980) were taken into account This was mainly the temperature dependence of the EOS constant, $\alpha(T_r)$, for water On the other hand, the effect of salt content was taken into account as proposed by Soreide (1989) The "vapor pressure" lowering the effect of salt concentration was introduced into the EOS constant, a (T_r), using the suggested correlation

In using the Peng-Robinson cubic EOS, its semi-emprical nature necessiates a matching procedure to regress the uncertain parameters such as volume shift, acentric factor and binary interaction coefficients (BIC) and even critical parameters (p_c and T_c) for complex hydrocarbon mixtures All critical parameters and acentric factors for the components of a geothermal brine (H_2O and C02 in our present case) are well known from experimental studies Thus, **BIC** between H20 and C02 was the only possible regression parameter Note that the matching of the phase equilibna was our first objective, therefore, volume shifts were not incorporated into the regression operation The temperature dependence of the volume shifts (V(T)) for H_2O were assured introducing the thermal expansion coefficient, c, with the following formula

$$V(T) = V_i(T_o)[1 + c(T - T_o)] \qquad (1)$$

where T_o is the reference temperature

Because of the highly polar nature of water and the asymetric structure of H_2O-CO_2 system, an unconvential mixing rule proposed by Panagiotopoulos and Reid (1986) was used,

$$a_{i,j} = \sqrt{a_i a_j}[1 - k_{i,j} + (k_{i,j} - k_{j,i})n_i] \qquad (2)$$

As can be seen in this equation, the $k_{i,j}$ were treated as linear functions of the composition, i e of the mole fraction of the component (i), n_i The $k_{i,j}$'s suggested by Panagiotopoulos and Reid (1986) were used and experimental data from literature (Todheide and Frank, 1963, Takenauchi and Kennedy, 1964, Gillespie and Wilson, 1982, Malinin, 1959) on the phase equilibria of H_2O-CO_2 systems were tried to be matched In the first attempts, no significant variations of the $k_{i,j}$ depending on the CO_2 mole ratios for the typical range of geothermal brines were observed and conventional interaction coefficient concept and mixing rule were introduced into the program On the contrary, a critical effect of temperature on BIC between H_2O and CO_2 was noticed as reported also by Soreide and Whitson (1992) Experimental data for the given temperatures were matched separately and BIC was adjusted for each case Finally, BIC's as a function of temperature were tabulated and the relationship between temperature and BIC's was plotted as shown in Fig 1

Note that at least five experimental vapor-liquid equilibria values were used for each case (i e for each temperature) and the "root-mean square" error between calculated and observed values are not higher than 0 09 which indicates a good approximation Fig 2 shows the results for two temperature values which are typical for geothermal reservoirs

The performance of the new EOS data on predicting the PVT/phase behavior of the H_2O-CO_2 system was retested by comparing the calculated critical parameters (critical pressure and temperature) with observed ones The resulting graph is shown in Fig 3 **A** reasonable match with the experimental data was obtained in the region of the critical parameters of water This means that when the CO_2 ratio **is** decreasing in the mixture, the performance of the Peng-Robinson EOS on predicting the real beavior is increasing This is a positive aspect of using cubic EOS because the C02 mass ratio is often not higher than 1% for most of the geothermal systems

The results described above give an optimistic overview of EOS to describe the PVT/phase behavior of the geothermal systems. Nevertheless, the use of Peng-Robinson equation was inconvenient for practical usage. First of all, the experimental data are not good both quantitatively and qualitatively; especially at the low pressure-temperature ranges ($p<10$ MPa and $T<200$ °C) that can represent a typical geothermal system. Some discrepencies occurs amoung various references giving the equilibrium values. This fact, along with the insufficient number of data, can create important errors in spite of resulting rapid and easy regression process. On the other hand, the strong dependence of EOS on BIC's may remove the practical use of cubic EOS for the aimed objective. Although a correlation from Fig. 1 can be used for each temperature step, this may be disadvantageous especially for higher CO_2 content if the polar and asymetric structure of H_2O-CO_2 system is considered. For these reasons, as well as the reason of simplicity, the empirical correlations were used in the continuation of the study.

EMPIRICAL CORRELATION APPROACH

The thermodynamic properties of pure water were obtained from empirical correlations prepared based on **AIME** Steam Tables (1977) In addition to saturation pressure and temperature, specific volume, densities, enthalpies, internal energy and entropies were calculated using these polynomial tvpe correlations The effect of salt and CO_2 content on the PVT/phase behavior of geothermal fluids were introduced by following rules explained below

Compressed Liquid Phase

In compressed liquid phase state, the density of water is calculated using the following formula obtained from the data reported by Chierci et al (1981)

$$\rho_{cw} = \rho_w[1 + a\rho_w(p - p_{sat})] \qquad (3)$$

where

$$a = 10^{b-13} \qquad (4)$$

and

$$b = -5.308 + 4\ 033017 * 10^{-2}\, T - 9\ 38612 * 10^{-5}\, T^2 + 7\ 734 * 10^{-8}\, T^3 \qquad (5)$$

p is the actual pressure and p_{sat} is the saturation pressure in Pa and densities, ρ_w and ρ_{cw} in kg/m^3

The enthalpy, h_{cw}, and the viscosity of compressed water, μ_{cw} are calculated using the formulas given by Chierici et al (1981) and Toronyi and Farouq-Ali (1975)

SALT EFFECT

The density behavior of salt solutions is well studied **A** linear relationship between brine density and salt concentrations expressed as weight percent of NaCI, KCI and $CaCl_2$ is obvious and no significant differences were concluded among NaCI, KCI and $CaCl_2$ solutions in terms of the density behavior Since geothermal brines are generally 70 % or more NaCl solutions and the next major component KCI has a density fairly close to the density of NaCI, the following correlation given by Wahl (1977) for an "average" brine (nearly equal to NaCl solution) is used to calculate the density of geothermal brines

$$\rho_s = \rho_w + 0\ 73[1 + 1\ 6 * 10^{-6}(T - 273)^2]\omega_s \qquad (6)$$

where,

ρ_s density of brine solutions, g/cm^3

ρ_w density of pure water, g/cm^3

ω_s the salt concentration, weight ratio

We can deduce from Eq ***6*** that the density of a brine solution, 0 5 % by weight which reflects a maximum value for Kizildere and Germencik geothermal reservoirs, differs from the density of pure water only by 0 3-0 4 ***Yo*** This is a negligible correction compared to the errors by use of empirical correlations But, note that for strongly salty waters (>100,000 ppm), pure water assumption can cause errors as high as 10% and even more

Entalphy

The enthalpy of brine can be calculated from the following thermodynamical definition.

$$h = \int_{T_o}^{T} c\,dT \qquad (7)$$

where,

T : current temperature,
T_o : reference temperature,
c : the heat capacity.

The heat capacity of geothermal solutions in the temperature range of 100 to 200 °C and for the salt content below 10 % by weight can be defined as:

$$c = c_w(1-\omega_s) - 0\ 8371\omega_t \qquad (8)$$

where c_w is the heat capacity of pure water One can obtain the following expression for the geothermal salt water enthalpy

$$h_s = h_w(1-\omega_s) - 0.8371\omega_s(T-T_o) \qquad (9)$$

where the enthalpies are given in kJ/kg and reference temperature (T_o) is zero when T is in °C According to this equation, the enthalpy of a geothermal fluid including 10 % salt by weight differs from the enthalpy of pure water by 2-3% Obviously, this ratio will be much lower for the salinity range corresponding to the geothermal reservoirs in Turkey Eq 9 is based on the data obtained for NaCl solutions (Wahl, 1977) However, w can be taken as the ratio of TDS because the heat capacities of NaCl and KCI and even $CaCl_2$ solutions are nearly the same

Viscositv:

The viscosity of pure water which is not a PVT/phase property was calculated using a formula given in Steam Tables (1977) The effect of the salts on the pure water viscosity is computed according to the following formula which is arranged using mass ratio weighting mixing rule for an average geothermal brine

$$\mu_s = \mu_w(1+1.7\omega_s+9.95\omega_s^2) \qquad (10)$$

CO_2 *EFFECT:*

Since the amount of CO_2 in the liquid phase is small, the following assumptions for liquid density and viscosity were made

$$\rho_m = \rho_{sc} \text{ and } \mu_m = \mu_{sc} \qquad (11)$$

where ρ_m and μ_m are the properties of geothermal fluids including CO_2 and ρ_{sc} and μ_{sc} are those of compressed brine solutions

Finally, the enthalphy of the compressed geothermal brine solution with CO_2 content is determined by Sutton (1976)

$$h_m = h_s(1-\omega_c) t (h, +h_{sol})\omega_c \qquad (12)$$

where the enthalpy of gaseous CO_2, h_c, and the solution enthalphy, h_{sol}, are calculated using the following expression which is a curve fit to the data given by Sutton (1976):

$$\begin{aligned} h, &= -2.18*10^5 + 732(T+273) + 0\ 252(T+273)^2 \\ &\quad -2\ 63*10^{-5}(T+273)^3 \end{aligned} \qquad (13)$$

and

$$\begin{aligned} h_{sol} &= (-1.351 + 0\ 01692T - 7\ 5524*10^{-5}T^2 \\ &\quad +1.318*10^{-7}T^3)10^{-6} \end{aligned} \qquad (14)$$

Subscript (s) denotes "salty waters" in above equations

Saturated Phase:

Saturation is valid in the case where $p_{sys} \le p_{sat}$ p_{sat} for pure water can be easily calculated from steam tables for corresponding temperature or vice versa But, in the case of brine-CO_2 system, saturation pressure will be affected by the presence of dissolved CO_2 and salts

The saturation pressure of m molal NaCl water at temperature T is lowered by the amount of the following (Michaelidts, 1987)

$$\Delta p = \frac{18R(T+273.15)}{v_v - v_l}\ \frac{m}{55.56} \qquad (15)$$

where, **AP** is in kPa, T in °C, v_v and v_l are the specific volumes of steam and liquid water in m3/kg, and R is the universal gas constant, 8 3 14 kJ/kg °K for corresponding units

The effect of CO_2 on the saturation pressure of the geothermal water is taken into the consideration with the partial pressure concept

$$p_{sat} = p_{sat,w} + \alpha_c(T)x_{cli} \qquad (16)$$

where $\alpha_c(T)$ is Henry Law constant for CO_2 and x_{cli} is the initial mole ratio of dissolved CO_2 $p_{sat,w}$, is the saturation pressure of pure water or of the brine of salt effects In order to estimate α_c for brine solutions, data given by Ellis and Golding (1963) were curve fitted and the following correlation was obtained

$$\begin{aligned} \alpha_c(T) &= 10135*10^8(0\ 401 + 4\ 64608*10^{-2}T + 7\ 595*10^{-5}T^2 \\ &\quad -7\ 37*10^{-7}T^3 + 0\ 790613m + 0\ 33259*10^{-2}T*m) \end{aligned}$$

$$\text{for } T<172 \text{ and} \qquad (17)$$

$$\begin{aligned} \alpha_c(T) &= 1\ 0135*10^8(7\ 927 + 5\ 55352*10^{-3}T - 7\ 24915*10^{-5}T^2 \\ &\quad +3\ 16579*10^{-5}T^3 + 0\ 94523m + 3\ 38482T*m) \end{aligned}$$

$$\text{for } T \ge 172 \qquad (18)$$

where m is NaCI molality The correlation gives a good match with observed data as shown in Fig 4

All the salts present in the geothermal fluids are non-volatile and hence, the gas phase in saturated state case is free of salts Therefore, the effect of salt content on the PVT/phase properties of the liquid phase can be calculated using Eq's 6 through 10 However, the gas phase of saturated geothermal fluid contains often the non-condensible gases, especially CO_2

When the system pressure reaches the saturation pressure, a two-phase (liquid-gas) state begins in the system After the steam quality of salt water (brine), **q**, is calculated from enthalphies for steam and liquid water, the mole number of H_2O for each phase can be found by the following equations

$$x_{wl} = (W_i - 44x_{cli})(1-q)/18 \qquad (19)$$

$$x_{wg} = (W_i - 44x_{cli})q/18 \qquad (20)$$

where W_i is the total amount of fluid in kg and x_{cli} is the initial CO_2 mole number in liquid phase

The mole number of CO_2 in the liquid phase is calculated using the CO_2 distribution coefficient given by Gggenbach (1980)

$$B = 10^{(4\ 7593-0\ 01092T)} \qquad (21)$$

and thus

$$x_{cl} = x_{cli}x_{wl}/(x_{wg}B + x_{wl}) \qquad (22)$$

The specific volume of CO_2 can be obtained using the formula given by Sutton (1976):

$$v_c = 8.31 * 10^3 (T + 273) / (44 p_c) \qquad (23)$$

where the specific volume of CO_2, v_c, is in m^3/kg, T is in °C, and p is in Pa The density of the gas phase will be the sum of the steam and C02 gas densities (i e $\rho_g = \rho_s + \rho_c$)

The other properties of the gas phase can be calculated according to the mass ratio weighting mixing rule i e ,

$$\mu_g = \mu_s(1 - \omega_{cg}) + \mu_c \omega_{cg} \qquad (24)$$

$$h_g = h_s(1 - \omega_{cg}) + h_c \omega_{cg} \qquad (25)$$

$$E, = E_s(1 - w_{cg}) + E_c \omega_{cg} \qquad (26)$$

Finally, the dew point pressure of a geothermal system, i e the minimum pressure where the two-phase exists, can be computed by the following formula

$$p_{dew} = \frac{p_{sat,s}}{(1 - x_{cg})} \qquad (27)$$

APPLICATIONS

The PVT package described above in detail was used in modeling studies to predict production performance and the wellbore flow characteristics of geothermal reservoirs Initially, it was incorporated into a lumped parameter model to estimate the production performance The model is based on the general material-energy balance equation given by Whiting and Ramey (1969) for geothermal reservoirs and the PVT package was inserted into this equation to simulate the PVT behavior more realistically A version of the model that includes the CO_2 effect only was well described by Alkan and Satman (1990) The model was improved with the PVT package including the salt effect Testing runs for three geothermal reservoirs, namely Cerro Prieto (Italy), Ohaaki (New Zealand), and Bagnore (Italy), were performed The reservoir and production data were the same as given by Alkan and Satman (1990) whereas the salinity of each reservoir fluid was taken from Wahl (1977) and Atkinson (1980) No significant difference from the previous results was observed for Ohaaki and Bagnore Fields for which a low salt content (in the range of 5,000 ppm) is reported For Cerro Prieto field, however, reported salinity is up to 25,000 ppm and a slight difference with the previous study, particularly in the pressure level where the reservoir reaches the saturation pressure, i e two-phase flow begins to occur, was observed The resulting match with the observed data is given in Fig 6

The reservoir performances of Kizildere and Germencik which are the largest geothermal fields in Turkey in terms of energy production capacity were also determined by Alkan and Satman (1992) The effect of salt content for both reservoirs, which is in the range of 4,000-5,000 ppm, was found to be negligible for both cases as expected Fig 7 shows the CO_2 fraction in gas phase and gas quality history in the reservoir according to time in the case of 10 MW energy production For this run, the initial CO_2 content of the reservoir was taken to be 15,000 ppm which reflects the maximum value for the field All data for Kizildere Field were taken from Alkan and Satman (1992) The data for Germencik Field provided by the same Ref were updated with respect to the recent reservoir and production studies and the new runs were conducted The results of performance studies are shown in Fig 8 One may conclude from the graph that the reservoir has a higher energy production performance than the Kizildere Field and an energy production of 60 MW can be expected with the reported rock and fluid properties

A second application of the PVT package was performed using it in modeling the wellbore flow of geothermal fluids **A** detailed description of the model in which a calcite deposition estimation option was incorporated was given by Satman and Alkan (1988) The pressure drop during the compressed liquid phase flow in the wellbore is calculated isothermally using the well-known flow equations When the pressure in the wellbore reaches to the saturation pressure which is determined by PVT package depending on the temperature, CO_2 and salt content, a procedure presented by Orkiszewski (1967) with some modification was employed to determine two-phase pressure drop For a specified temperature drop, the steam quality was calculated initially and all other phase properties including the ratio of liquid water and steam, the ratio of CO_2 in liquid and gaseous phases as well as the densities and related flow properties were estimated using the package Then, the length of the interval in which the specified temperature drop occurs was calculated with the equation for proper flow regimes The procedure was repeated until the wellhead is reached A package to model the probable carbonate precipitation at any point of the wellbore is also incorporated into the program

Although the verification of the calcium carbonate deposition part of the model is highly difficult because of several practical reasons (data acquisition particularly). the comparison of the calculated pressure-temperature vs depth values with measured ones is possible if the related wellbore data is available The percentage deviations for various field cases give an average of 6 *6* as reported by Satman and Alkan (1988) **An** example of the comparison study is given in Fig 9 representing a good match to observed pressures **A** mass fraction of CO_2 of 0 02 is used and all other data are taken from Barelli et al (1982) The model was applied to estimate the wellhead and bottomhole pressure-temperature of some wells from Kizildere Field also The bottomhole pressure vs flow rate relationship for a selected well is given in Fig 10 In this graph, the static bottomhole pressure was estimated to be *63* 9 bar that matches with the actual data using an initial CO_2 mass fraction of 0 009 in the liquid phase which reflects a minimum value for Kizildere

CONCLUSION

The prediction of the PVT/phase behavior of geothermal fluids by using the equations of state (EOS) and empirical correlations were evaluated in this paper The effects of salt and CO_2 content on the phase behavior of geothermal fluids are considered simultaneosly for both methods The results were compared with experimental data provided in literature

Peng-Robinson was selected as the equation of state and the binary interaction coefficient (BIC) between water and CO_2 was attempted to adjust using available experimental data Taking into account the temperature dependence of the BIC, the EOS approach can be a useful tool especially in modeling wellbore and reservoir conditions that are outside the range considered in available correlations But. to model the systems with relatively high CO_2 content, the prediction capability of Peng-Robinson was found to be insufficient mainly because of the polar and assymetric molecular structure of H_2O-CO_2 system

An alternative package, that is based upon thermodynamical laws and correlated experimental data, was developed and the results on predicting the PVT/phase properties of geothermal fluid mixtures were presented The pressure-temperature-concentration range that is typical for geothermal reservoirs was covered principally and the correlations for brine-C02 systems fitted to experimental data reasonably well The modeling studies of reservoir and wellbore flow performances showed that the use of this package as a PVT simulation tool will improve the accuracy of the predictions

REFERENCES

Alkan, H and Satman, A (1988) Estimation of the Kizildere Geothermal reservoir performance *Petiol* (In Turkish), Vol 20 pp 39-55

Alkan, H and Satman. A (1992) Reseivoir performance study of two CO_2 containing geothermal fields in Turkey, *Industrial Uses of GeotherniaI Energy,* Reykjavik, Iceland, 2-4 September

ASME Steam Tables (1977) Third edition, The American Society of Mechanical Engineers

Atkinson, P G , Celati, R., Corsi, R, and Kucuk, F (1980) Behavior of the Bagnore steam/CO_2 geothermal reservoir, Italy, *Soc. Pet. Eng. J.* August, pp.228-238

Barelli, A., Corsi, R , Del Pizzo, G , and Scali, C. (1982) **A** two-phase flow model for geotherinai wells in the presence of non-condensible gas, *Geothermics,* Vol 11 **pp** 175-191

Chierici, G.L., Gionnane, G., Schiochi, G and Terzi, L (1981) **A** wellbore model for two-phase flow in geothermal reservoirs *56th Soc. of Petr. Eng. Annual Fall Tech. Conf.* San Antonio, TX

Ellis, E J and Golding, R M (1963) The solubility of CO_2 above 100 ^{o}C in pure water and in soduim chloride soiutions *Am J. Sci* Vol(261) pp 47-60

Giggenbach, W I (1980) Geothermal gas equilibria, *Geochem Cosmachim Acta* Vol.44, pp 2021-2032

Gillespie, P C and Wilson G (1982) *Vapor-Liquid and Liquid-Liquid Equilibria,* Water CO_2 Report, RR-48 Willer Research Co

Malinin, S D (1959) The system H_2O-CO_2 at high temperatures and pressures *Geochemistry* No 3 pp 235-245

Michaelides, E E (1987) *Thermodynamic Properties of Geothermal Fluids* Geothermal Resources Council. Transections, Vol 5

Orkiszewski, J (1967) Predicting two-phase pressure drops in vertical pipes, *J. Pet Tech* June, pp 829-838

Panagiotopoulos, A Z and Reid, R C (1986) New mixing rule for cubic EOS for highly polar asymetric systems *Paper 009-4156 American Chemical Society*

Peneloux, **A ,** Rauzy, E and Freze, F (1982) A consistent correction for Soave-Redlich-Kwong volumes, *Fluid Phase Equilibria,* Vol *8,* pp 7-23

Peng, Y D and Robinson, D B (1975) A new two-constant EOS, *SPE Reprint Series, Phase Behavior* No 15 **pp** 46-51

Peng, Y D and Robinson, D B (1980) Two and three-phase equilibrium calculation for coal gasification and related precesses *Thermodynamics of Aqueous System with Industiral Application, ACS Symp Ser* Vol 393, pp 393-414

Satman, **A** and Alkan, H (1988) Modeling of wellbore flow and calcite deposition for geothermal wells in the presence of CO_2 *Society of Pet Eng Paper 21263*

Soreide, I. (1989) *Improved phase behavior predictions of petroleum reservoir fluids from a cubic EOS.* PhD Thesis, The Univ of Trondheim

Soreide I and Whitson C H (1992) Peng-Robinson predictions for hydrocarbons CO_2, N_2, and H_2S with pure water and NaCl brines *Fluid Phase Equilibria.* Vol 77 217-240

Sutton, F.M (1976) Pressure-temperature curves for a two-phase mixture of water and carbondioxide, *New Zealand Journal of Science.* Vol. 19, pp 2970301.

Takenauchi, S and Kennedy, G (1964). The binaiy system H_2O-CO_2 at high temperatures and pressures. *American Journal of Science,* Vol.262, pp 1055-1074

Todheide, K and Frank, U E (1963) Das zweiphasengebiet und die kritische kurve im system kohlendioxide-wasser bis zu drucken von 3500 bar. *Zeitschrift fur Physikalische Chemie, Vol.37.* pp 387-401

Toronyi, R M. and Farouq-Ali, S M (1975) Two-phase, two-dimensional simulation of a geothermal reservoirs and the wellbore system *SPE Paper 5521. 50th Soc. of Petr. Eng. Annual Fall Meeting.* TX.

United Nations (1974) *Geothermal Energy Sinvey of Western Anatolia, Project Findings mid Recommendations.* New York

Wahl, E F (1977). *Geothermal Energy Utilization.* New York, Wiley.

Whiting, R L and Ramey H J (1959) Apllication of material and energy balances to geothermal steam production, *J of Pet Tech* July pp 893-900

Yawn, C L (1977) *Physical Properties* Mc Craw-Hill Publishing, New York, N Y

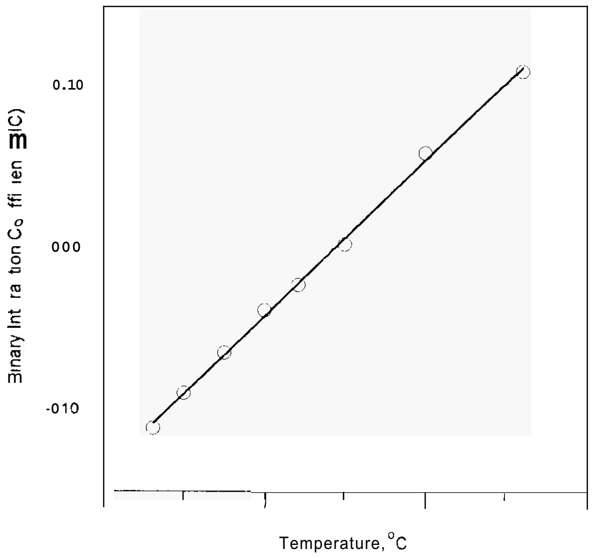

Figure 1 Temperature-BIC relationship for Peng-Robinson H_2O-CO_2 system

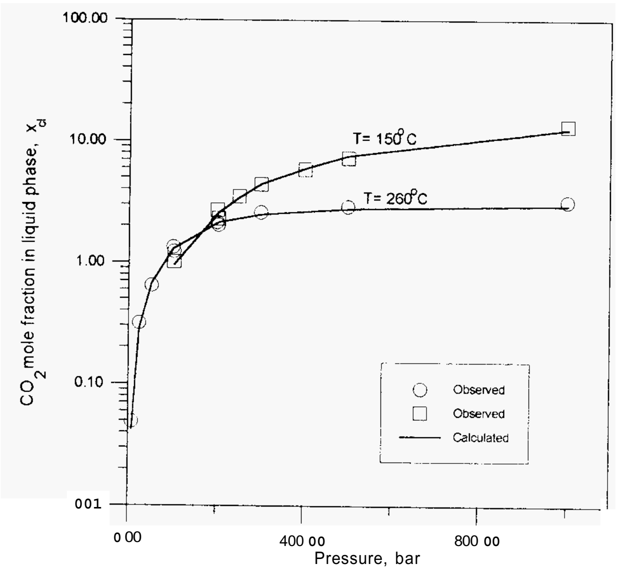

Figure 2 Peng-Robinson phase behavior prediction for H_2O-CO_2 system

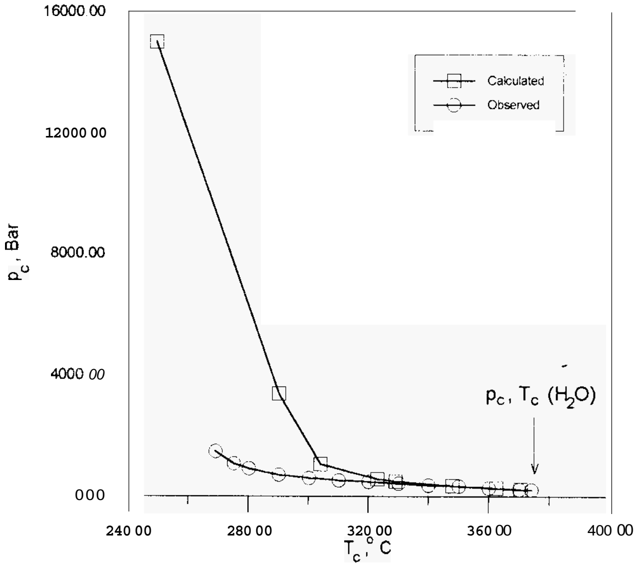

Figure 3 Peng-Robinson critical point prediction for H_2O-CO_2 system

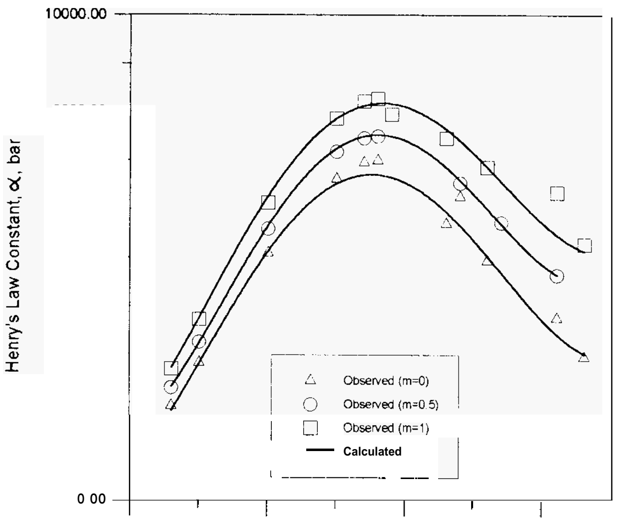

Figure 4 Henry's Law constant estimations for salt solutions

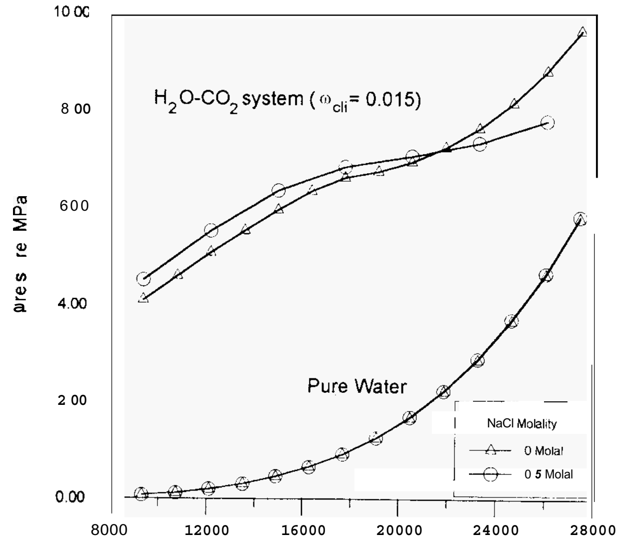

Figure 5 Phase diagram of a typical geothermal fluid system

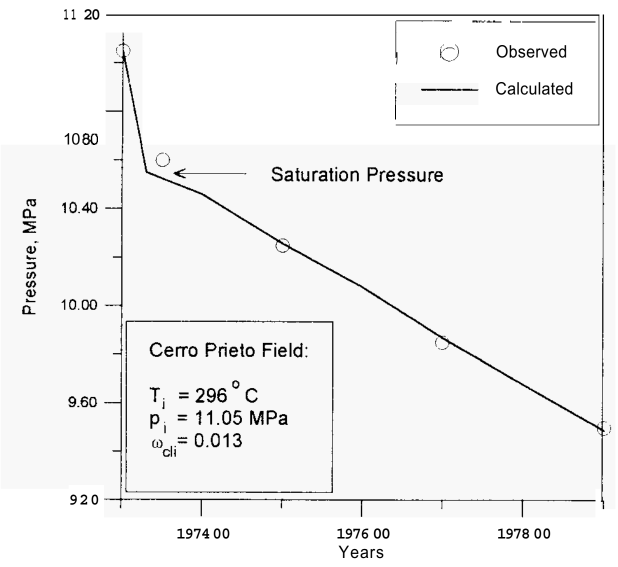

Figure 6: History matching for Cerro Prieto Field

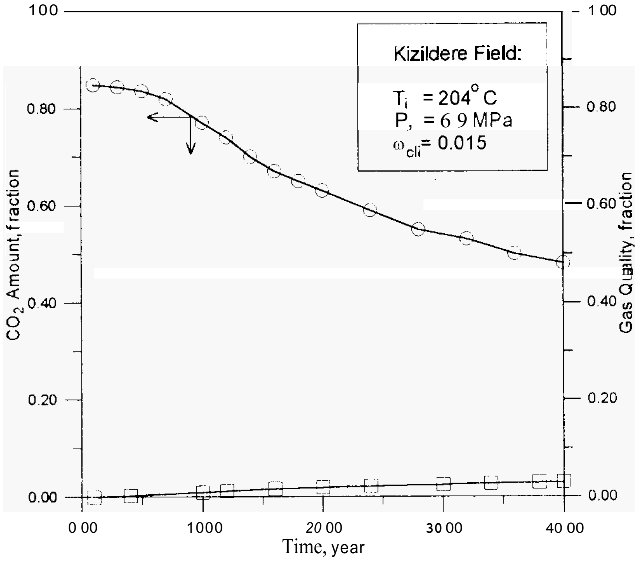

Figure 7 Estimation of CO_2 amount/gas quality history for the Kizildere Field

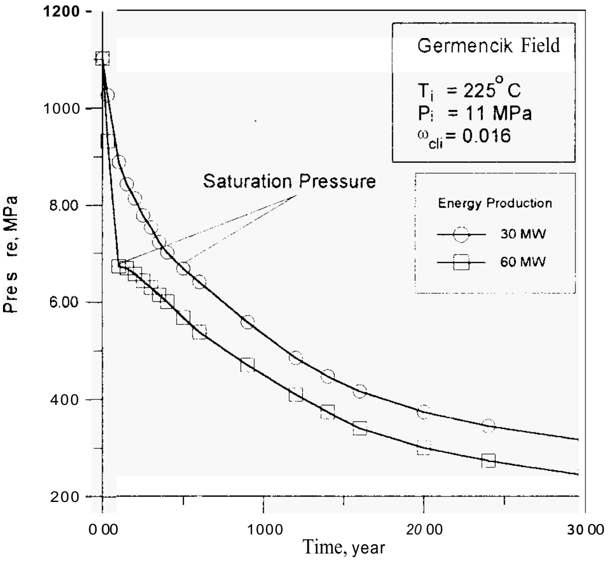

Figure 8 Reservoir performance study for Germencik Field

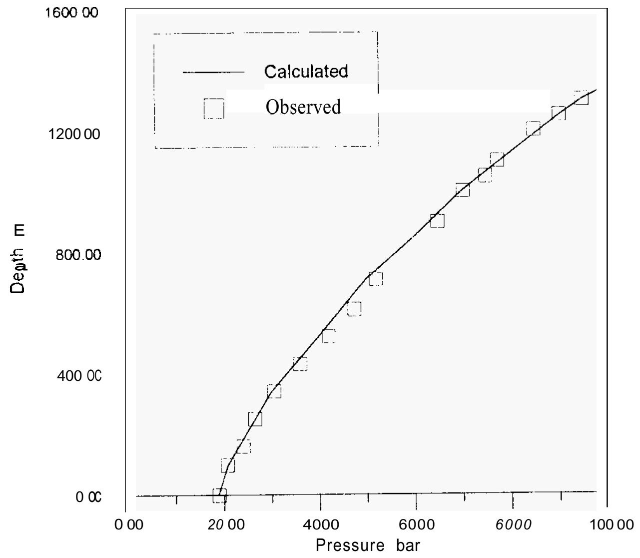

Figure 9 Depth-pressure profile match for Well W2-2 (Barelli et al 1982)

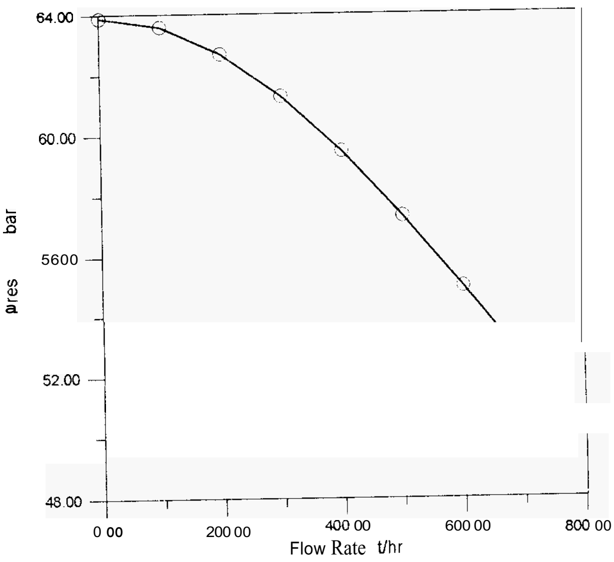

Figure 10 Estimated pressure-flop rate relationship foi Kizildere Field at bottomhole