PROCEEDINGS, Eighteenth Workshop on Geothermal Reservoir Engineering
Stanford University, Stanford, California, January 26-28, 1993
SGP-TR-145

CORRELATION BETWEEN GAS COMPOSITIONS AND PHYSICAL PHENOMENA AFFECTING THE RESERVOIR FLUID IN PALINPINON GEOTHERMAL FIELD (PHILIPPINES).

D'Amore F., Nuti S.*, Ruaya J.R.°, Ramos-Candelaria M.N.°, and Seastres J.S.°*

*CNR, International Institute for Geothermal Researches, Pisa, Italy
°PNOC- Energy Development Corp., Fort Bonifacio, Makati, Philippines

ABSTRACT

Using thermodynamic gas equilibria to calculate temperature and steam fraction in the reservoir, three main physical phenomena due to exploitation of Palinpinon field are identified. 1) Pressure drawdown producing a local increase in the computed steam fraction, with the fluid maintaining high temperature values (close to 300°C). Strong decline in flow rate is observed. 2) Irreversible steam losses from the original high temperature liquid phase during its ascent through fractures in upper zones of the reservoir. Steam is generally lost at temperatures (e.g. 240°C) lower then those of the original aquifer. 3) Dilution and cooling effects due to reinjection fluid returns. These are function of the local geostructural conditions linking through fractures the injectors and production wells. The computed fraction of the recovered reinjected brine can in some case exceed 80% of the total produced fluid. At the same time the computed gas equilibration temperatures can decline from 280-300°C to as low as 215-220°C. Comparing these values with the well bottom measured temperatures, the proposed methodology based on gas chemistry gives more reliable temperature estimate than water chemistry based geothermometers for fluids with high fractions of injected brine.

INTRODUCTION

The Southern Negros geothermal field lies at the southern tip of Negros Island in an andesitic system characterized mostly by a vertically fractured medium (Ruaya et al., 1991). The under study Puhagan zone of the field has been providing steam for the 112.5 MWe Palinpinon I geothermal power plant since June 1983 from its 22 production wells (Fig.1). Ten reinjection wells are located in the identified major outflow region north and northeast of the production area. They accept the separated brine, having a salinity up to about 11,000 mg/kg in chloride content, by gravity flow through two reinjection lines. Injection at high pressure (about 0.8 MPa) started immediately after production. Harper and Jordan (1985) assessed the geochemical changes observed in response to early production and reinjection. The reinjection strategy adopted has been described by Ruaya and Salera (1990).

The hydrothermal system in Palinpinon is a single-phase neutral alkali-Cl hot water with less than 2% by weight in gas content, and an average reservoir Cl concentration, before any injection contribution, of about 4,200 mg/kg at a saturated water temperature of up to 330°C. Typical production temperatures, however, are about 280-300°C at near saturation conditions. For most Puhagan wells, different zones of the reservoir contribute to total production, such as a deep zone at high pressure and temperature close to 300°C, in most cases gas depleted, and a shallow, relatively gas rich, two-phase zone at much lower pressure and a temperature close to 240°C (Ruaya et al., 1991).

From 1983 to October 1989, wastewater injection was confined at the Puhagan sector. During this period rapid fluid communication between the injectors and the production wells was observed, using primarily chloride (Harper and Jordan, 1985). At the end of 1989, the bulk of reinjection was transferred farther away, northeast from the production area, to the Ticala/Malaunay sector to reduce the return of reinjection fluids. With the reduced mass injection at Puhagan the field reinjection fluid returns substantially declined in the production sector down to a maximum of 30-50%.

Table 1 reports gas compositions in total discharges and some physical parameters for selected wells of the field in Puhagan zone. It is evident a quite high variability in fluid production pressures and enthalpies together with an extremely high change in total gas content, H_2/CO_2 and H_2/H_2S ratios.

D'Amore and Truesdell (1985) and D'Amore (1991) proposed a general suitable graphical method in which measurable chemical parameters are represented as coordinates, while physical parameters, such as temperature and steam fraction generate a theoretical "grid" inside the diagram. It involves the use of chemical species ratios derived from chemical reactions. In this paper two chemical reactions are used to represent gaseous species in chemical equilibria. Essentially the method is based on the application of the mass action law on the two following chemical reactions at thermodynamic equilibrium conditions:

$$CO_2 + 4H_2 = 2H_2O + CH_4 \quad (1)$$

$$H_2 + 3/2\ FeS_2 + 2\ H_2O = 3\ H_2S + 1/2\ Fe_3O_4 \quad (2)$$

This paper attempts to model, using gas compositions, the changes due to exploitation covering several years until 1991 affecting production wells at Puhagan sector. The described geochemical models are highly simplified, due to the very little information available on the kinetics of the single chemical reactions involved. However H_2S species seems to be fastly reequilibrating with respect to H_2 probably because of the high content of sulphydes in the reservoir rock, allowing buffering of H_2S partial pressure. Morerover we try to demonstrate that through the application of gas chemistry it is possible to correlate easily measurable wellhead chemical parameters with physical reservoir parameters, such as temperature and steam fraction useful in evaluating some geothermal well performance. All original chemical data are from D'Amore et al., 1993.

The water stored in this geothermal reservoir is mostly present as a liquid together with a little amount of coexisting vapor phase at equilibrium conditions. In some cases, the vapor formed at equilibrium becomes irreversibly lost during ascent of the fluid to the surface, before the discharge fluid reaches the wellhead. The in-place steam fraction y of the local reservoir, in equilibrium with the liquid (positive y values) or irreversibly lost at a given temperature from the original liquid (negative y values), at phase equilibrium is defined as:

$$y = n_v/(n_v+n_l) \qquad (3)$$

where n represents the number of moles of steam (n_v) or liquid water (n_l), contained in a given volume of rock. Y value can represent an average value of the steam mass fraction, locally present or lost, over the drainage volume of the well.

Through chemical equations (1) and (2) it is possible to develop the FT-HSH grid diagram having as coordinates the following chemical parameters measured at the total discharge point "d":

$$FT_d = 4\log(H_2/H_2O) - \log(CH_4/CO_2) \qquad (4)$$

$$HSH_d = 3\log(H_2S/H_2O) - \log(H_2/H_2O) \qquad (5)$$

The following equations are used for positive or negative y values to link the chemical with the physical parameters in the reservoir:

y > 0:

$$\begin{aligned} FT_d = {} & -15.35-3952.8/T^\circ+4.635\log T^\circ \qquad (6)\\ & +4\log(y^\circ+(1-y^\circ)/B^\circ_H+\log(y^\circ\\ & +(1-y^\circ)/B^\circ_{CO2})-\log(y^\circ+(1-y^\circ)/B^\circ_{CH4}) \end{aligned}$$

$$\begin{aligned} HSH_d = {} & 6.449-6149.7/T^\circ-0.412\log T^\circ \qquad (7)\\ & +3\log(y^\circ+(1-y^\circ)/B^\circ_{H2S})\\ & -\log(y^\circ+(1-y^\circ)/B^\circ_{H2}) \end{aligned}$$

y < 0:

$$\begin{aligned} FT_d = {} & -15.35-3952.8/T^\circ+4.635\log T^\circ \qquad (8)\\ & -4\log B^\circ_{H2}-\log B^\circ_{CO2}+\log B^\circ_{CH4}\\ & -4\log(1+y-y\,B_{H2})-\log(1+y-y\,B_{CO2})\\ & +\log(1+y-y\,B_{CH4}) \end{aligned}$$

$$\begin{aligned} HSH_d = {} & 6.449-6149.7/T^\circ-0.412\log T^\circ \qquad (9)\\ & -3\log B^\circ_{H2S}\log B^\circ_{H2}\\ & -3\log(1+y-y\,B_{H2S})+\log(1+y-y\,B_{H2}) \end{aligned}$$

In equations (8) and (9), B_i° refers to the original temperature T° of the aquifer, while B_i refers to the temperature of the steam loss.

FT and HSH values from gas data of Table 1 are plotted in Fig.2. Both computed temperatures and steam fractions from these data are quite variable and do not provide much information in characterizing the behavior of each well. This is the main reason why selected wells of the field presenting typical behaviors through several measured data have been chosen to correlate their physical performance with time as function of gas compositions.

In some case, like for well OK-5, gas compositions measured during several years produce a cluster of points in the grid diagram with equilibration temperatures in the range 300-310°C from an almost pure liquid phase (y=0). In these cases the clustering of data indicates that the well draws fluid from deep undisturbed zones of the reservoir, which until the present remains unaffected by exploitation of the field. This is usually observed for wells located in the western zone of Puhagan area, on the border of the still unexploited Sogongon zone of the field, developed to produce about 80 MWe.

In most cases, observed chemical variations from ideal equilibrium behavior in pure liquid, brought about by exploitation of the Puhagan field have been attributed to different physical phenomena. The wells selected in this paper are representative of groups showing similar peculiar time variations both in chemical and physical characteristics.

STEAM ADDITION TO AN ORIGINAL LIQUID DUE TO PRESSURE DRAWDOWN.

During exploitation, several wells show increases in gas content and discharge enthalpies (exceeding 2,000 kj/kg). These wells are found south of Puhagan sector (such as PN20D, 27D, 9D, 13D and 10D). Well PN20D, which is located within the hottest part of the field close to the Lagunao Dome, has been selected as the most representative of this group. The well became a producer in October 1986. The computed FT and HSH values are represented in Fig.3. At starting conditions the gas composition suggests little steam loss in the deep reservoir fluid (y=-0.007) at low flow rate. With time there is a significant increase in steam fraction, up to about 2% in 1991. The computed temperatures in the diagram are quite high, between 287 and 306°C. The lowest temperatures are observed along the y =0 line in the period 1988-89 when the amount of injected brine in Puhagan sector was very high. For this well in that period the fraction of recovered injected water was close to 30% (D'Amore et al., 1993). At the end of 1989 wastewater injection was shifted to Ticala/Malaunay sector and fluid injection was substantially reduced in Puhagan area.

A possible explanation for the observed gas composition can be due to two contemporaneous phenomena.

The first phenomenon affecting fluid composition seems to be due to moderate amount of recovered injected water in this area. Because of the localized high heat flow in this zone, injection produces cooling of only about 15°C in contrast to the central Puhagan wells showing cooling up to 90°C.

The second one could be the drawdown of the liquid water in the reservoir. During the first months of 1991 compared to early 1990, at the same wellhead pressure of 0.7 MPa, enthalpy increases from about 1800 to about 2,400 kj/kg and the monthly cumulative mass withdrawal declines from about 90,000 tons to less than 20,000 tons. The drawdown hypothesis seem to be supported by the shut-in pressures measured in the monitoring well PN25D. From 1990 to 1991 shut-in pressure declined from about 9 to 6 MPa (Fig. 4). Initially, the well PN20D was producing from two main permeable zones located at vertical depths of 1730-1937 and 1215-1391 m. With time, anhydrite deposits have been detected between these two production zones. Anhydrite deposition is believed to have partly blocked fluid contribution from the deeper permeable zone having y values close to zero. The effect of this phenomenon is a decline in production due to decrease in liquid volume available in the local reservoir because of a decrease of permeability. This local depressuration induced also the inflow of acidic fluids (Gerardo et al., 1993) which probably enhanced the anhydrite deposits. In Palinpinon acidic fluid can be present in upper shallow layers were the lost steam condensates and mixes with local meteoric water. This can form shallow, cold and oxidizing waters with low pH, high content of sulfate as well as low content of H_2 and chloride. These waters were detected during shallow drillings. In 1992, when the contribution of this fluids becomes significant, due to pressure drawdown, the total discharge composition results in lower pH (4-5), lower chloride (< 1.000 mg/kg) and high sulfate (> 200 mg/kg) contents in the liquid fraction. The gas composition is showing lower values in H_2 and higher H_2S content probably because of partial reduction of sulfate.

STEAM LOSSES AT LOWER TEMPERATURES FROM AN ORIGINAL LIQUID

In the Southern sector of Puhagan, several wells (e.g. PN23D, 27D, 30D, 31D) present generally negative values of computed y using FT and HSH chemical parameters under high wellhead pressure condition, and also for a period of time after shut-in (that is when the well is set on-line for production). Well PN30D has been selected as representative of this group.

Its maximum temperature monitored at well bottom is 305°C. Its relatively constant concentration in chloride (in average 4,100 + 400 mg/kg) and enthalpy (1400-1600 kj/kg) exclude any large influence from reinjection fluids. The relative positions of y and temperature on the grid diagram are shown for selected analyses in Fig.5. The scattering in the position of the points show a quite high variability in y values, from about zero to -0.1, with relatively constant values of the computed temperatures between 285 to 300°C. The pre-exploitation fluid temperatures at the main entries were about 250°C at 1340-1440 m and about 300°C at 2770-2865 m (vertical depths). Y values are very negative in the diagram when H_2 concentrations are very low. H_2S content varies correspondingly but to a degree where computed temperature remains almost stable indicating preservation of chemical equilibrium.

A good correlation is observed between H_2 concentration and the cumulative monthly mass withdrawal with time (Fig.6). This indicates that at high wellhead pressure the local deep reservoir liquid looses large amounts of gas boiling during its ascent through fractures. It must be considered that the close by wells are producing generally at low wellhead pressure. Fluid displacement and boiling is then induced by pressure differential at high temperature in the reservoir. Some steam is irreversibly lost at lower temperature from the original fluid moving through fractures towards other wells on line for production, and it can accumulate as a condensate layer in shallow zones with respect to the main reservoir. This process is schematically outlined in Fig.7. Steam separation produces at a given temperature partitioning of gases in the newly formed steam as a function of different gas solubilities. This can explain the observed variability in H_2/H_2S or H_2S/CO_2 ratios. At high production, after some time, gas composition recovers to initial undisturbed conditions attaining the original thermodynamic equilibrium. However, the reequilibration is not completed at a similar rate. H_2S rapidly recovers its original concentration, due probably to the buffering effect of sulphydes minerals, while H_2 takes longer time to recover from water dissociation reaction. In this process ammonia content is almost unaffected by steam losses because of its extremely high solubility relative to other gases: for example at 250°C the ratio of distribution coefficients between H_2 and NH_3 is about 110.

The original undisturbed fluid conditions for well PN30D before any steam loss can be estimated by the use of the data considered during the periods corresponding to the maximum contents of H_2 at high flowrate (September-December 1985, October-December 1986, and June-October 1990). The application of the FT-HSH grid to these data results in a value of y=0 at a computed temperature of 290°C. Fixing then this temperature for the original liquid before steam losses, by the use of equations 8 and 9, it is possible to calculate for any gas composition showing negative y values on the grid, the temperature at which the steam is lost and the corresponding lost steam fraction in non isothermal conditions. Infact the observed extremely high negative y values in the grid are considered to be apparent as computed by the use of the FT and HSH parameters represented in the grid at isothermal conditions. In these cases a more realistic alternative is that steam loss occurs at a much lower temperature than the original reservoir liquid temperature. As an example, the gas composition of April 1987 can be considered. On the grid the corresponding point is consistent with a temperature of 300°C and y=-0.1. Using the non isothermal method, and fixing an original temperature of 290°C in a pure liquid phase, a steam loss temperature of 240°C is computed corresponding with a value of y=-0.025.

WELLS AFFECTED BY REINJECTED BRINE

Most wells (e.g. PN26, PN28, OK7) located in the northeast portion of the field are strongly affected by the separated brine reinjected in Puhagan and then later in the Ticala/Malaunay sector. Gas chemistry may prove useful in monitoring reinjection returns and in providing realistic reservoir temperature estimates .

This section aims to quantify the fraction of produced fluid due to reinjected water (X) and the equilibration temperature in the reservoir (T°) by using gas composition at wellhead.

As a typical example, the method is applied to well PN28. The grid diagram representing the available data is shown in Fig.8. The point representing initial condition (°) is based on the analytical data of the adjacent well PN26 (July 1983) since gas data for PN28 at undisturbed condition are not available. Despite that, an initial temperature close to 280°C for an almost pure liquid phase can be estimated, which is consistent with the temperature evaluated from the SiO_2 content. Based on computed y values, it is evident that this well is little affected by steam losses ($y > -0.01$). The temperatures computed from the grid (Tg) show that the mixing with the injected brine produces a progressive cooling down to 215°C, consistent with well bottom physical measurements (from point 1 to point 14 in Fig.8) in October 1989, when fluid injection was confined at Phuagan sector. This trend (Fig.9) is consistent with the progressive increase in chloride concentration (from less then 5,000 to more then 10,000 mg/kg) and discharge enthalpy decline with time (down to about 1,000 kj/kg). When the bulk of the injected fluid was shifted to the Ticala sector, at northeast, a recovery in grid temperature, Tg, up to about 255°C, and a decline in chloride concentration are observed.

The proposed method consists of a convergence routine to calculate T° when a fraction X of injected brine is contributing to the total produced fluid generating the measured concentrations $C_{H2,d}$ and $C_{H2S,d}$. The equations used (D'Amore et al., 1993) are reported in Table 2. The value of T° is obtained when $X_{FT} = X_{HSH}$. From selected gas analyses of this well computed values of T° and X vs time are reported with computed Tg values and chloride concentrations in Fig.9. The observed trends of all these parameters are consistent among them. The computed T° has a different value than Tg. The T° value represents the theoretical temperature in the fractured medium where the fluid is in contact with the rock; that is the temperature in the producing cell of the reservoir where after mixing the fluid and the rock are in thermodynamical equilibrium. This thermal condition is a function of the balance between the heat lost because of the local inflow of the injected brine and the heat supplied by the local and surroundings rocks in that particular portion of the reservoir where thermodynamical equilibrium is supposed to be attained. The Tg value approaches the actual measurable well bottom temperature after dilution and cooling of the fluid at the moment of sampling. This fluid might not be fully chemically equilibrated because of the high local permeability and the fast recovery of the injected brine. We assume then that the local large fractures allows the transfer of the mixed fluid at well-head in a very short time. For this reason Tg < T°.

CONCLUSIONS

The Puhagan sector at Southern Negros geothermal field shows a large variability of gas composition both in space and time. This may be due to three main physical phenomena affecting the original fluid stored in the deep reservoir. (1) Local pressure drawdown in the original liquid phase present in the reservoir feeding a single well. This phenomenon produces a local increase in the steam fraction in phase equilibrium with the liquid maintaining high measured temperature values. Low local permeability is the main factor producing drawdown. Moreover, drawdown seems to induce inflow of acidic fluids from shallow layers into the main reservoir.(2) Steam loss from an original liquid at high temperature when the wellhead pressure is very high or after shut-in condition. The assumed phenomenon and the applied methodology shows that from a given volume of reservoir with high local permeability feeding a well, the original liquid at high pressure and temperature moves through fractures during low production period towards shallower levels. This movement is induced by pressure differential through fluid communication with adjacent producing wells. The original liquid during rise through local fractures boils at lower temperature irreversibly loosing steam in phase equilibrium. Each gas species partitions between liquid and steam at this new temperature as a function of its solubility. (3) Reinjection of the brine separated at high pressure. This reinjection fluid returns are a function of the local geostructural conditions linking through fractures the injectors and the producers. The production wells affected by this mixing show a well bottom temperature decline from 280-300°C to as low as 215-220°C. These last values are close to the measured temperatures when most of the produced fluid is due to the injected brine. Water-rock equilibration temperature in the reservoir can be computed as well as the contribution of the injected brine to the total produced fluid. The most common water geothermometers seem not applicable to wells highly affected by reinjection returns because of lack of reequilibration.

Using the model based on the grid diagram sketched in Fig.10, gas geochemistry offers interesting and low cost tools to evaluate phenomena occurring in the reservoir particularly usefull in field management.

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TABLE 1. Gas composition in total discharge (moles/moles x 10^5), maximum temperature measured at well bottom, and WH pressure and enthalpy for selected wells of Palinpinon geothermal field.

n	Well	Date	(Max) (°C)	P (MPaa)	H (kJ/kg)	CO_2	H_2S	H_2	CH_4	N_2	NH_3
1	OK5	03SEP90	310	3.69	2025	245	14.61	1.42	0.16	1.21	0.65
2	OK10D	04SEP90	270	0.80	1552	153	7.52	0.99	1.99	3.11	1.09
3	PN20D	12MAR91	324	0.71	2393	451	17.31	2.51	0.76	0.84	2.16
4	PN30D	27JAN90	305	2.67	1544	197	7.77	0.31	0.77	0.99	0.83
5	PN31D	05SEP90	322	1.02	1875	263	10.45	0.77	1.31	0.93	1.90
6	PN24D	09MAR91	316	0.83	1585	244	8.73	0.66	1.19	1.35	0.91
7	OK7	19APR90	318	0.68	1350	92	3.73	0.54	0.96	0.43	1.09
8	PN28	02JAN90	303	1.44	1203	60	1.17	0.04	0.58	0.30	1.17
9	PN32D	08AUG91	270	0.88	2524	450	14.83	2.42	2.19	2.20	-

Table 2. Equations used for computation of the recovered fraction of injected water (X) and water-rock equilibration temperature T°.

$$X_{FT} = \left[1 + \frac{\exp_{10} - ((FT^\circ + \log (CH_4{}^\circ/CO^\circ{}_2))/4)}{1/C_{H2,d} - (\exp_{10} ((FT^\circ + \log (CH^\circ{}_4/CO_2{}^\circ))/4))} \right]^{-1}$$

$$X_{HSH} = \left[1 + \frac{\exp_{10} - ((HSH^\circ/3) + ((FT^\circ + \log(CH_4{}^\circ/CO^\circ{}_2))/12))}{(1/C_{H2S,d}) - \exp_{10} - ((HSH^\circ/3) + ((FT^\circ + \log(CH^\circ{}_4/CO_2{}^\circ))/12))} \right]^{-1}$$

X_{FT} and X_{HSH} are respectively computed starting from chemical reactions (1) and (2). C_{H2} and C_{H2S} are the measured molar concentrations of H_2 and H_2S.

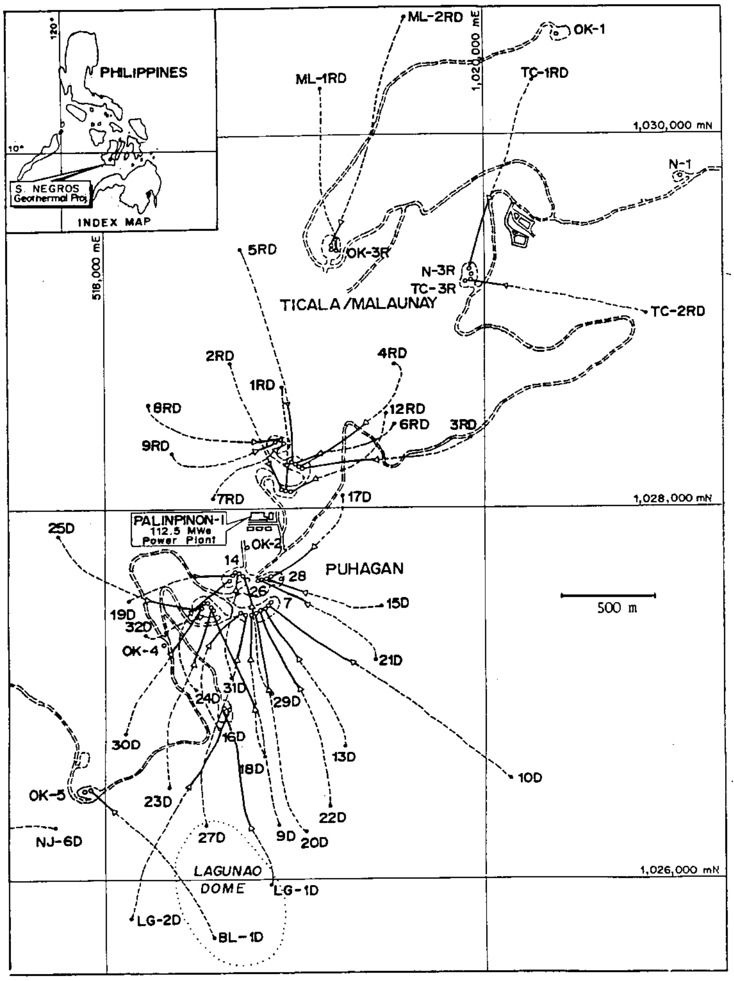


Fig.1. Palinpinon geothermal field in Negros Island (Philippines) and well locations in Puhagan and Ticala areas. Wells drilled directionally are marked with a "D". Reinjection wells are marked with a "R".

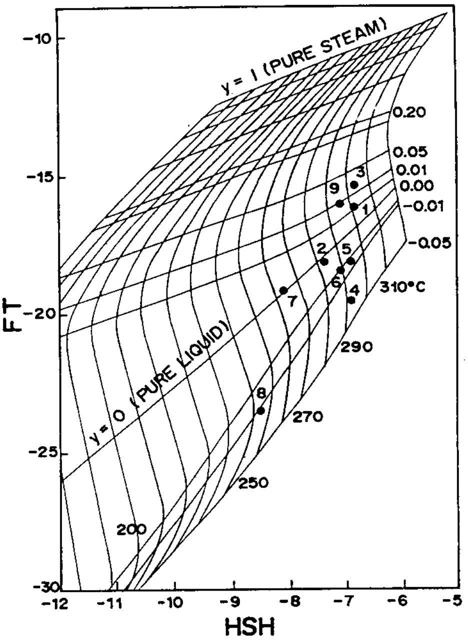


Fig.2. FT-HSH grid diagram from gas composition of wells shown in Tab. 1.

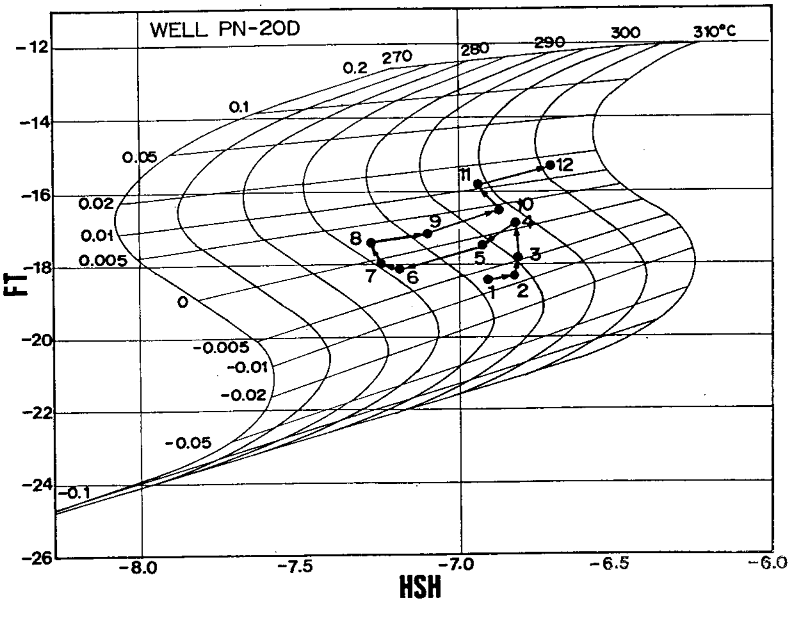


Fig.3. Grid diagram for well PN20D from gas compositions (1986-1992).

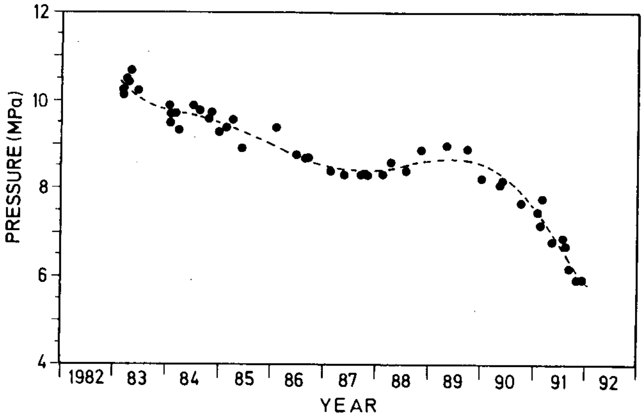
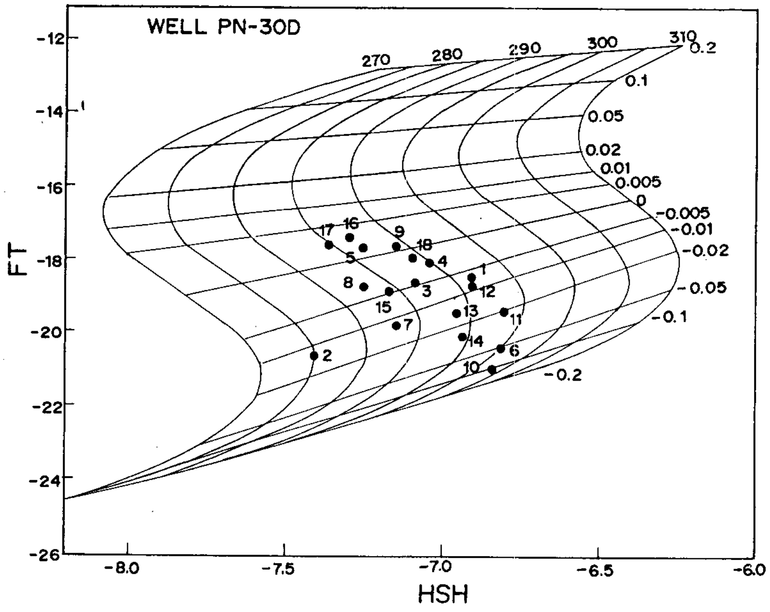


Fig.4. Shut-in pressure values vs time for the monitoring well PN25D.

Fig.5. Grid diagram for well PN30D from gas compositions (1985-1991).



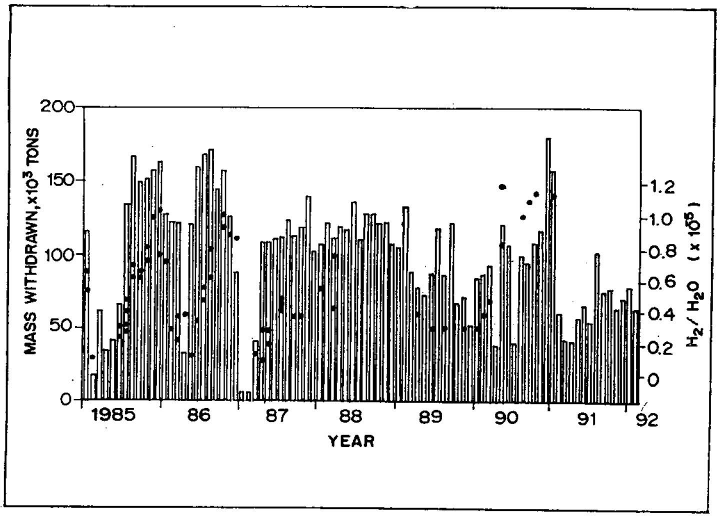


Fig.6. Monthly cumulative mass withdrawal and H_2/H_2O (molar concentration x 10^5) for well PN30D.

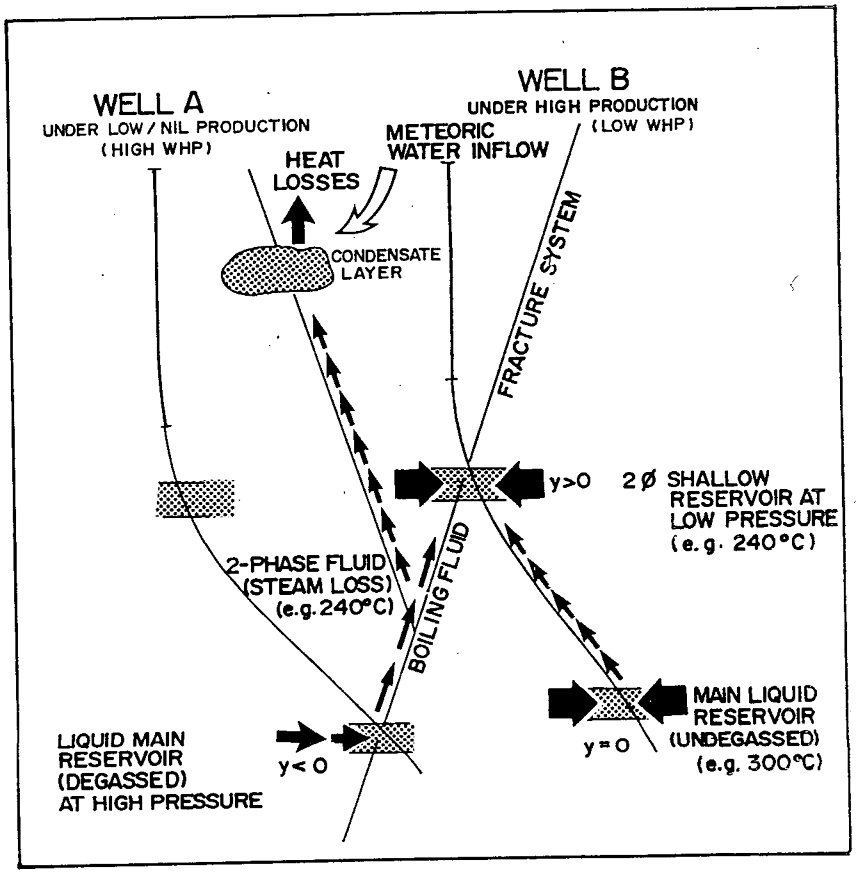


Fig.7. Sketch model for steam losses from well A (at high wellhead pressure) induced by pressure differential in the reservoir with respect to well B producing under low wellhead pressure.

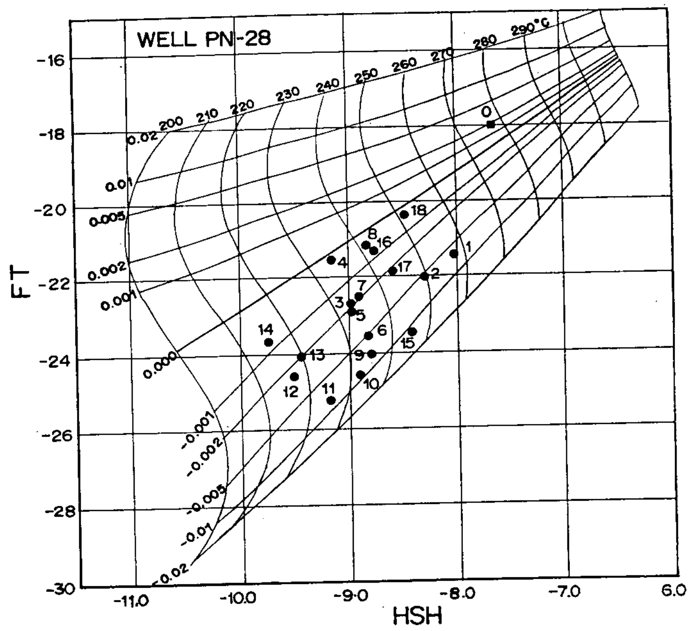


Fig.8. Grid diagram for well PN28 from gas compositions (1983-1991).

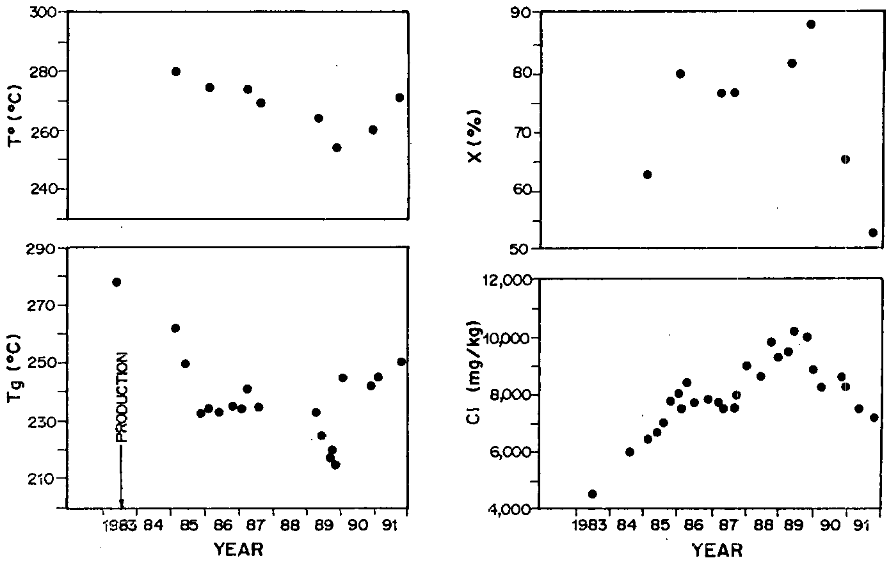


Fig.9. For selected samples following parameters are reported vs time for well PN28: chloride concentration in total discharge, Tg values computed from the grid (Fig.8), computed values of fluid-rock equilibration temperature T° and the corresponding percentage of recovered brine (X%).

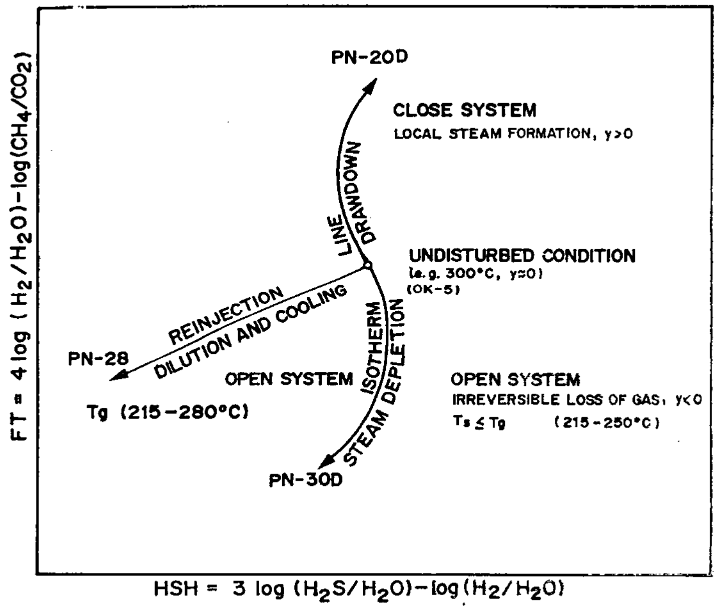


Fig.10. Sketch showing the main phenomena affecting the position of the points in the FT-HSH grid diagram, derived from gas composition. For y < 0,Ts indicates the steam losses temperature from the original liquid.