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ESTIMATING RESERVOIR STEAM FRACTION FROM CO_2, H_2S, AND H_2 CONCENTRATIONS IN THE SOUTHERN NEGROS GEOTHERMAL FIELD, PHILIPPINES

Bernardo Vidal Jr. and Danilo Hermoso
Philippine National Oil Company-Energy Development Corporation, PNPC Complex, Merritt Road, Ft. Bonifacio, Makati,
Metro Manila, Philippines

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ABSTRACT

A method to estimate reservoir steam fraction using CO_2, H_2S, and H_2 concentration in steam has been applied in the Southern Negros Geothermal Field, Philippines. The concentration of these gases in the unexploited reservoir is best approximated by thermodynamics-derived temperature functions assuming gas-mineral equilibrium as mainly controlling the gas concentrations (Arnorsson and Gunnlaugsson, 1985). The average steam fraction of the unexploited reservoir is –0.05%, or close to zero, which is realistic in a liquid-dominated system like the Southern Negros Geothermal Field.

With prolonged steam production, pressure drawdown in the field has resulted to boiling in the reservoir. This has caused steam fraction to increase to an average of 0.23% and 0.56%, estimated from Y_{HS} and Y_{HC} respectively, by 1998. These Y-estimates, independently derived from H_2S-H_2 and CO_2-H_2 pairs, especially differ in wells where oxidation of H_2S is occurring due to steam condensation by meteoric waters in shallow zones, resulting to positive Y_{HS} and negative Y_{HC}. Wells that were heavily affected by RI return (thus remained liquid saturated) continue to have slightly negative steam fraction with good agreement between Y_{HS} and Y_{HC}. Other wells with excess steam manifest higher Y_{HC} than Y_{HS} , likely because of the increased influenced of gas-gas reactions taking place in the vapor-dominated zone feeding these wells.

1. INTRODUCTION

The Southern Negros Geothermal Field, Philippines, also referred to as Palinpinon, has been in operation since 1983, supplying steam to power plants with a combined capacity of 192.5 MWe. The field is liquid-dominated and slightly saline, with parent fluids having a pre-exploitation Cl level of 4150 ppm. Liquid brine, with a temperature reaching to 320°C, is believed to upflow in the Lagunao area, and flow laterally through fractures towards the northeast and northwest of the field, where a total of 75 wells (exploration, production, and reinjection) have been drilled (Figure 1).

The continuous exploitation of the field has brought a pressure decline of approximately 6 MPa in the production sector due to heavy mass extraction. A salient effect of this is the increase in the discharge enthalpy of a number of wells due to reservoir boiling. For example, well OK2's discharge had initially saturated-liquid enthalpy, then turned nearly dry steam in 1991, at the height of production in Palinpinon. The expansion of a highly-unsaturated, two-phase zone overlying the liquid reservoir, has been verified by the drilling in the early 1990s of shallow wells like PN33 that had a high initial discharge enthalpy (>2000kJ/kg).

The use of gas chemistry to infer physical processes has become an important tool for monitoring field response to exploitation. Previous studies on gas chemistry in Palinpinon have applied knowledge on gas-gas equilibrium. D'Amore *et al.* (1993) correlated Fischer-Tropsch equilibrium and H_2S equilibrium with the pyrite-magnetite pair, while the more recent study, Siega *et al* (1999), has expanded the H_2S equilibrium to include such mineral pairs as pyrite-hematite and pyrite-pyrrhotite, with the former showing good applicability in Palinpinon.

This study aims to apply gas-mineral equilibrium controlling CO_2, H_2S, and H_2 concentrations in estimating reservoir steam fraction, as a potential tool for determining the different processes that are occurring in the field.

2. THEORY AND METHOD

2.2. Reservoir Gas Concentration

Arnorsson and Gunnlaugsson (1985) believed that CO_2 fugacity is controlled by equilibrium with epidote/clinozoisite + prehnite + calcite + quartz mineral buffer system at temperatures above 230°C, while H_2S and H_2 fugacities are controlled by equilibrium with pyrite + pyrrhotite + epidote + prehnite in the range 230 – 300°C for waters containing less than about 500 ppm chloride; and with pyrite + epidote + prehnite + magnetite or chlorite, for waters above 300°C, or in the range 230 – 300°C if containing over 500 ppm Cl. The following temperature functions, derived from thermodynamics data, express these equilibrium reactions:

$$\log CO_2 = 5.520 - 412.5/T + 0.0144*T - 5.029*\log T \qquad (1)$$
$$\log H_2S = 16.451 - 3635.08/T + 0.00839*T - 6.074*\log T \qquad (2)$$
$$\log H_2 = 17.266 - 4587.39/T + 0.00547*T - 5.356*\log T \qquad (3)$$

note: T (upper case) denotes temperature in Kelvin scale

A set of gas geothermometers has been calibrated based on observed correlation between gas concentrations and reservoir temperatures in different geothermal fields throughout the world (Arnorrson and Gunnlaugsson, 1985). This gives rise to the following semi-empirical equations expressing gas concentrations as functions of temperature:

$$\log CO_2 = -1.09 - 3894.55/T + 2.532*\log T \qquad (4)$$
$$\log H_2S = -11.80 - 0.06035*T - 17691.09/T + 27.163*\log T \qquad (5)$$
$$\log H_2 = -3.04 - 10763.54/T + 7.003*\log T \qquad (6)$$

In deriving the semi-empirical equations, gas concentrations in total discharge were used. Ideally, only wells with saturated-liquid enthalpies may give a reasonable estimate of the reservoir gas concentrations from total-discharge gas concentrations. Arnorsson and Gunnlaugsson, however, utilized wells with excess enthalpy, where they assumed heat gain from rocks as the main mechanism for producing excess steam, and the steam added is vapor free.

2.2. Reservoir Boiling Model

A simplified model of the boiling process in geothermal reservoirs has been proposed in Arnorsson *et al.* (1990) (Figure 2). In this model, two processes account for excess enthalpy in discharging wells: (1) phase segregation and preferential flow, wherein steam leaves behind the liquid component due to gravity or to the difference between rock permeability to steam and to water, and (2) enhanced evaporation of separated liquid by heat gain from rocks. The latter conserves gas concentrations of the deep reservoir in the well's total discharge; the former does not. Using this model, two equations to estimate reservoir steam fraction—one involving CO_2 and H_2 (Y_{HC}), the other H_2S and H_2 (Y_{HS})—were developed.

$$Y_{HC}=\frac{A_H - A_C}{55.51/P[(A_C/K_{H2})-(A_H/K_{CO2})] + [A_H - A_C]} \qquad (7)$$

The variable A_H stands for the ratio of steam H_2 concentration to the reservoir H_2 concentration, and A_C is the same ratio for CO_2. Y_{HS} is similar to equation (1) but with H_2S variables substituted for CO_2 variables. The equations Y_{HS} and Y_{HC} are independent estimates of the reservoir steam fraction, and as a single method, they shall be referred to as Y_{HSC} in subsequent discussions. The complete mathematical derivation of Y_{HSC}, together with the other boiling parameters included in the model, is presented in Arnorsson *et al.* (1990).

As shown in equation (1), it is necessary to supply the gas concentrations in steam and in the reservoir. The former can be obtained from the analyses of separated steam sampled using a weber separator. It is necessary that any of the two pairs of gas concentrations are taken from the same sample, or that the concentrations represent the same separation pressure. The latter could be obtained from equations 1-6, or from any specific gas geothermometer expressing reservoir gas concentrations as temperature functions, as long as it is applicable to a given field. The total pressure, P (bar_{abs}), can be approximated by Giggenbach's equation, P_{H2O}=5.51-2048/T. Henry's coefficient for the gases can likewise be evaluated if the reservoir temperature is known; Giggenbach (1980). The constant 55.51 converts molality into mole fraction ($m_g = 55.51n_g$). The solution to the equation further requires that the reservoir temperatures be known. Any suitable geothermometer or temperature obtained from well logging will do.

3. RESULTS AND DISCUSSION

3.1. Palinpinon Reservoir Gas Concentrations

Equations 1-6 are graphically represented in a plot of total-discharge gas concentrations of CO_2, H_2S, and H_2 against reservoir temperatures (Figures 3, 4 and 5). The total-discharge gas concentrations of some 19 wells presented in the plot are averages of pre-exploitation data selected from Jordan (1983). They represent the earliest data on the stabilized gas chemistries of the wells, when reservoir boiling is believed to have yet minimal effect on the total-discharge gas concentrations. Reservoir temperatures were those computed from the quartz geothermometer (T-quartz) of Fournier and Potter (1982). Similar plots of gas concentrations against temperatures from well logging and those obtained using the Na-K-Ca geothermometer, yielded slightly poorer correlation. Nevertheless, T-quartz deviated by an average of only 14°C from the measured temperatures, as reported in Jordan (1983).

By inspection, the semi-empirical equations (equations 4-6) of Arnorsson and Gunnlaugsson (1985) have slightly underestimated CO_2 and H_2S reservoir concentrations in the pre-exploited Palinpinon field. The thermodynamics-derived equations (equations 1-3) have overestimated H_2S and H_2 concentrations by just as much. By adjusting the activities of some minor minerals participating in the buffer reactions (i.e., prehnite and pyrrhotite, both excluded in the major mineral assemblages of Palinpinon reported by Reyes and Tolentino (1982)) to less than one, the thermodynamics-derived function can even be made closer to the best logarithmic-fit of the data points. The resulting equations, taking prehnite activity to be 0.8, and pyrrhotite activity to be 0.2, are as follows:

$$\log CO_2 = 5.665-412.5/T+0.0144*T-5.029*\log T \qquad (8)$$
$$\log H_2S = 16.153-3635.08/T+0.00839*T-6.074*\log T \qquad (9)$$
$$\log H_2 = 16.269-4587.39/T+0.00547*T-5.356*\log T \qquad (10)$$

The above functions may represent the best approximation to the reservoir gas concentrations in Palinpinon, assuming the mineral-gas equilibrium to hold true. Nevertheless, the best-logarithmic fit lines for the three gases have coefficient of determination of 0.5 and less ($r^2 \leq 0.5$), with H_2 having the lowest at less than 0.1. So even with the most representative total-discharge gas concentration data of the pre-exploited field, only a weak correlation between temperature and gas concentrations is demonstrated. Arnorsson and Gunnlaugsson (1985) listed five factors that contribute to the scatter of data points in their own study of gas reservoir concentrations:

1. departure from equilibrium
2. differences in the composition of minerals
3. imperfections in crystal structures
4. errors in selected reference temperatures
5. presence of equilibrium vapor in the reservoir

It is beyond the scope of this study to individually account for the factors mentioned above. It is recognized that even in the early stages of the field's development, physical processes were already occurring that could cause an upset of the chemical and phase equilibrium of the gases. In the data set considered, well discharge enthalpies have an excess ranging in magnitude of –150 to 270 kJ/kg over the saturated-liquid enthalpies computed from their T-quartz. From this, one can infer the effects of drilling fluids, and the effects of excess steam coming from a natural two-phase zone in Palinpinon.

3.2 Reservoir Steam Fraction Estimates

Two sets of Y_{HSC} values are presented in Table 1, each corresponding to a set of equations for estimating the reservoir gas concentrations: first, the temperature-function equations 4-6 of Arnorsson and Gunnlaugsson (1985), and second, the site-calibrated thermodynamics-derived equations 8-10. In both instances, pre-exploitation steam gas concentrations and T-quartz reported in Jordan (1983) were used. Although both generally show good agreement between Y_{HC} and Y_{HS}, using the site-calibrated functions results to closer agreement between the two Y-estimates, as indicated by their close averages and standard deviations. One other difference is the more negative average steam fraction obtained from the semi-empirical equations (-0.14% and –0.22%) compared to that obtained from the site-calibrated equations, which is –0.05%. The latter value, which is closer to zero, reflects better the liquid-dominated condition of the pre-exploited Palinpinon reservoir, wherein the first level of boiling is in the wells.

Table 2 summarizes average Y_{HSC} calculated using steam gas concentrations analyzed from samples taken in 1998, nearly 16 years after the source-samples of the data reported in Jordan (1983) were collected. Here, a significant difference between the values obtained using the two sets of equations become apparent. Although the estimates using semi-empirical equations retain a relatively good agreement between Y_{HC} and Y_{HS}, their averages (-0.15 and –0.10, respectively) differed insignificantly to the pre-exploitation values, indicating still close to zero steam fraction. This is unrealistic considering the present state of the reservoir wherein a two-phase zone has expanded at depths of +100 to –400 mSL (Amistoso and Orizonte, 1997). To appreciate the effects of prolonged field utilization, pre-exploitation and 1998 CO_2 total-discharge data are plotted against temperature (T-quartz) in Figure 6, where the semi-empirical equation for CO_2 (equation 4) is also graphically represented along with its corresponding saturated-vapor line. As indicated by the 1998 data points, at least two major processes occurring in the field have altered total-discharge gas concentrations in opposite ways. The return of reinjection fluids to the production sector has caused a decline in total-discharge gases especially in wells nearer the reinjection sink to the north (e.g. PN14, PN28, and PN29D), shifting them below the saturated-liquid line. On the other hand, wells producing from the shallow vapor-dominated zone manifest an increase in their total-discharge gases, shifting data points towards the saturated-vapor line.

The Y_{HSC} values obtained by using the site-calibrated equations have large differences between Y_{HC} and Y_{HS}, but give more realistically positive values: average of 0.56% for Y_{HC} (excluding PN25D and PN20D because of very large standard deviations) and 0.23% for Y_{HS}. To account for the difference in the two Y-estimates, an x-y plot of Y_{HC} versus Y_{HS} values is constructed (Figure 7). The resulting plot is divided into quadrants, not different from the quadrants of a Cartesian plane. This is done for ease of classifying the wells as to how they differ between the two Y-estimates. For comparison, the pre-exploitation Y-estimates are also shown, as well as the line representing equivalent Y_{HC} and Y_{HS}. Majority of the wells plot in the positive Y_{HS} and Y_{HC} quadrant, as expected of the drawndown state of the reservoir. Wells with very positive steam fractions (e.g., PN16D, PN18D, PN24D, and PN32D) have indicated high-enthalpy discharge (1900 kJ/kg to 2700 kJ/kg) in some time or another, even though PN18D and PN32D both measured low discharge enthalpies during the period of sampling (Table 2). Well PN18D has experienced a blockage in its casing and was completely blocked by November of 1998; prior to this blockage the well's discharge enthalpy went as high as 2700kJ/kg. Well PN32D is one of the shallow wells drilled in the early 1990s to specifically tap the vapor-dominated zone in the northwest sector of Puhagan, thus its high-enthalpy discharge right from the start of utilization. Another well, PN25D (not shown in the graph because of its very wide range of Y_{HC} values) also taps in this sector, and has an enthalpy of 2100 kJ/kg during the same period when PN32D's discharge turned liquid-saturated. This implies that a liquid-enthalpy discharge does not necessarily mean a non-boiling reservoir, at least not in Palinpinon. Rather, because of the presence of a liquid reservoir underneath the vapor-dominated zone, and because of the multiple feed system in most wells, it could mean that the well is preferentially tapping from this deeper liquid reservoir. The xy-plot of Y_{HS} versus discharge enthalpy (Figure 8) suggests the direct relation of steam fraction and excess steam, despite the above stated exception.

Another observation on wells plotting in the positive Y_{HC} and Y_{HS} quadrant is the consistently higher Y_{HC} values than Y_{HS} values. This is especially the case as steam fraction becomes more positive, as in the wells mentioned above. Our hypothesis is that, as the reservoir becomes more vapor-dominated, the influence of gas-gas reactions on the gas concentrations increases. The Fischer-Tropsch reaction, for example, results to four moles of H_2 for every mole of CO_2 produced from the breakdown of CH_4. Such an uneven increase in the two gas components will produce the effect of increasing the numerator of the Y_{HC} equation (equation 7), and consequently the Y_{HC} value itself. The relative success of applying the Fischer-Tropsch reaction in vapor-dominated systems (e.g., Lardarello and the Geysers) supports this hypothesis.

Wells that plot in the positive-Y_{HS}, negative-Y_{HC} quadrant are high-enthalpy wells that intersect a common structure, the Odlumon Fault. This structure has been identified to be one of the major conduits of acid-SO_4 waters in Palinpinon (Seastres et al., 1995). These wells, namely OK10D, PN15D, and PN22D, have been affected by acid-SO_4 inflow during some periods in the past, before increasing the reinjection return along Odlumon Fault to provide pressure support to these wells. One well, PN20D, which continues to discharge acid-SO_4 fluid, has very negative and variable Y_{HC} values, and for this reason is not shown in Figure 6. The mechanism of acid-SO_4 production in the shallow zones of Palinpinon involves the oxidation of H_2S to $SO_4^=$, as steam is condensed by percolating meteoric water. The net result is a decline in H_2S relative to the other gases. This would result to higher Y_{HS} values (equation 7). However, results obtained for these wells do not indicate an abnormally high Y_{HS} compared to most other wells in the positive Y_{HC} and Y_{HS} quadrant; only an abnormally lower and very negative Y_{HC}. Another process is envisaged to be taking place, involving H_2 oxidation to H_2S, as in the pyrite-magnetite or pyrite-hematite reaction. This reaction will have the effect of lowering H_2 concentrations relative to CO_2 (resulting to a decline in Y_{HC}), while offsetting the effect of H_2S consumption during acid-SO_4 production.

Wells affected by RI returns like PN14, PN28, and PN29D have zero to slightly negative Y_{HS} and Y_{HC} values, with the two Y values in good agreement. This is consistent with the liquid-saturated state of these wells.

4. CONCLUSIONS

The reservoir gas concentrations of CO_2, H_2S, and H_2 of the pre-exploited Palinpinon reservoir may be defined by thermodynamics-derived functions assuming mineral-gas equilibrium. Estimating the reservoir steam fraction using these temperature functions and pre-exploitation data on steam gas concentrations yield close to zero values, consistent with the initial liquid-dominated state of the reservoir. Over the years, steam utilization in the field has caused reservoir pressures to decline, and the reservoir to boil, causing a vapor zone to expand at depths of –400 to +100 mSL. The reservoir steam fractions calculated from gas concentrations analyzed from well steam samples collected in 1998, resulted to more positive values in the order of 0.20 to 0.60%. The slightly positive values reflect the present state of the field, wherein a liquid reservoir continues to exist at deeper parts, beneath an expanding steam cap or vapor-dominated zone. Differences in Y_{HC} and Y_{HS} values reflect other reactions involving the three gas species, which may give indication of processes affecting the reservoir. A very low (or negative) Y_{HC} and positive Y_{HS}, may point to acid-SO_4 production in shallow levels, apart from reservoir boiling. A higher value of Y_{HC} than Y_{HS}, observed in wells that have extensively tapped the vapor-dominated zone, indicates the greater influence of gas-gas reactions in the vapor-dominated zone, which can alter the relative gas compositions of the three gas species. Wells that are being affected by reinjection returns have negative to zero steam fractions, with good agreement between Y_{HC} and Y_{HS}.

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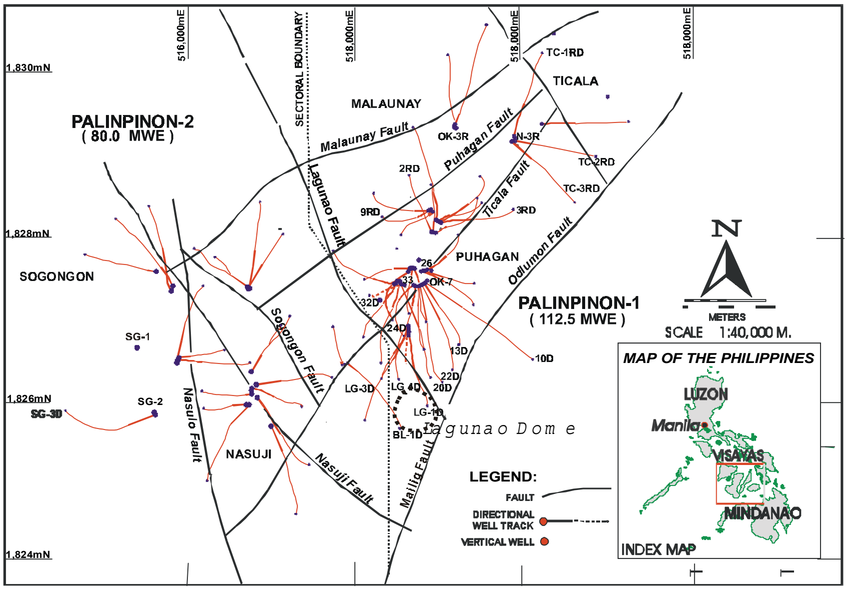

Figure 1. Map of Palinpinon showing structures and well tracks. Inset: the Philippines.

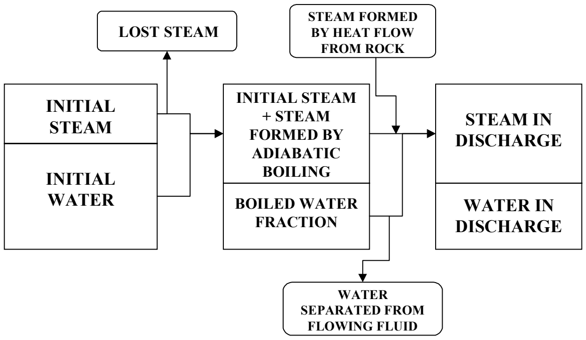

Figure 2. Schematic model of reservoir boiling, Arnorsson *et al* (1990).

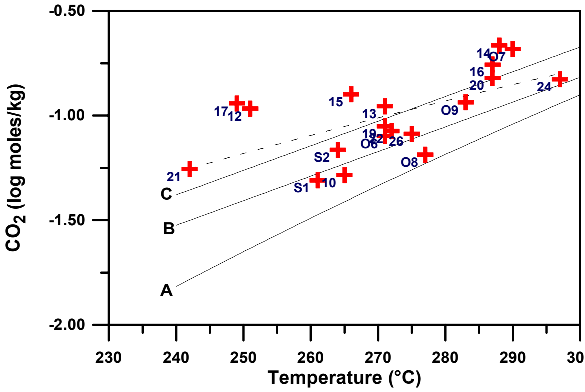

Figure 3. CO_2 in total discharge plotted against T-quartz; pre-exploitation data taken from Jordan (1983). **A** represents semi-empirical equation (equ. 4), **B** thermodynamics-derived equation (equ. 1), and **C** site-calibrated equation (equ. 8). Dashed line represents best logarithmic fit.

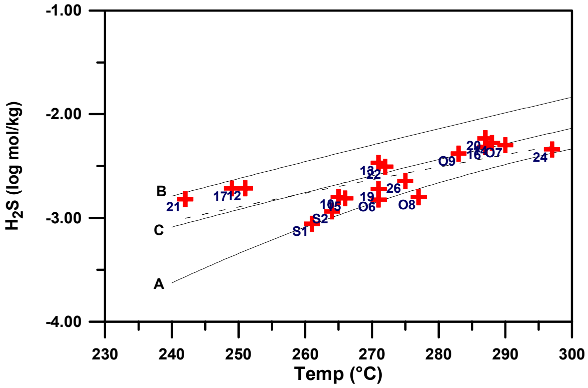

Figure 4. H_2S in total discharge plotted against T-quartz; pre-exploitation data taken from Jordan (1983). **A** represents semi-empirical equation (equ. 5), **B** thermodynamics-derived equation (equ. 2), and **C** site-calibrated equation (equ. 9). Dashed line represents best logarithmic fit.

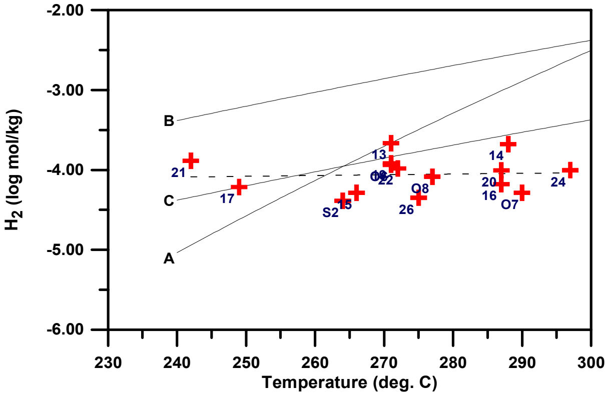

Figure 5. H_2 in total discharge plotted against T-quartz; pre-exploitation data taken from Jordan (1983). **A** represents semi-empirical equation (equ. 6), **B** thermodynamics-derived equation (equ. 3), and **C** site-calibrated equation (equ. 10). Dashed line represents best logarithmic fit.

Table 1. Average steam fraction estimates, $\%Y_{HC}$ and $\%Y_{HS}$, of pre-exploitation Palinpinon wells. **A** are values computed using the semi-empirical equations of Arnorsson and Gunnlaugsson (1985) (equ. 4-6); **B** are computed using the site-calibrated, thermodynamics-derived equations based on the assumption of mineral-gas buffering (equ. 8-10). Average deviations are also reported.

WELL	T-QTZ (°C)	A				B			
		$\%Y_{HC}$	$\% Y_{HS}$	Y_{HC} DEV	Y_{HS} DEV	$\%Y_{HC}$	$\% Y_{HS}$	Y_{HC} DEV	Y_{HS} DEV
OK7	290	-0.46	-0.46	0.01	0.00	-0.39	-0.37	0.05	0.03
PN13D	271	-0.19	-0.18	0.02	0.02	0.03	-0.02	0.08	0.05
PN14	288	-0.43	-0.42	0.01	0.02	-0.32	-0.27	0.07	0.12
PN15D	266	-0.18	-0.16	0.03	0.01	-0.09	-0.06	0.08	0.03
PN16D	287	-0.39	-0.37	0.03	0.05	0.03	-0.03	0.32	0.33
PN17D	249	-0.09	-0.08	0.02	0.01	-0.09	-0.07	0.02	0.01
PN19D	271	-0.20	-0.17	0.05	0.06	0.05	0.01	0.25	0.18
PN20D	287	-0.26	-0.25			-0.26	-0.25		
PN21D	242	1.80	0.10	1.19	0.06	0.33	0.06	0.14	0.04
PN22D	272	-0.24	-0.24	0.01	0.01	-0.16	-0.18	0.03	0.02
PN24D	297	-0.57	-0.56	0.00	0.01	-0.46	-0.41	0.05	0.07
PN26	275	-0.28	-0.27	0.01	0.01	-0.22	-0.21	0.04	0.03
OK5	285	-0.12	-0.25	0.13	0.01	0.66	0.60	3.27	0.07
OK6	271	-0.20	-0.11	0.02	0.07	0.01	0.22	0.11	0.23
OK8	277	-0.27	-0.23	0.01	0.01	-0.06	0.01	0.05	0.04
SG1	261	-0.05	-0.02	0.12	0.15	0.20	0.15	0.37	0.30
SG2	264	-0.18	-0.15	0.01	0.02	-0.14	-0.08	0.03	0.05
Ave		-0.14	-0.22			-0.05	-0.05		
SD		0.52	0.16			0.27	0.24		

Table 2. Average steam fraction estimates, %Y_{HC} and %Y_{HS}, computed from gas concentrations in steam of selected Palinpinon wells in 1998. **A** and **B** are computed on similar bases as Table 1. Average deviations are likewise reported.

WELL	DATE	ENTH kJ/kg	T-qtz °C	A				B			
				%Y_{HC}	% Y_{HS}	Y_{HC} DEV	Y_{HS} DEV	%Y_{HC}	% Y_{HS}	Y_{HC} DEV	Y_{HS} DEV
OK10D	9/1/98	1700	243	-0.72	0.47	0.03	0.05	-0.86	0.36	0.04	0.05
OK6	9/9/98	1450	278	-0.24	-0.24	0.02	0.02	0.25	0.02	0.09	0.03
OK9D	07/09/98	1435	269	0.04	-0.11	0.04	0.03	2.40	0.13	0.39	0.02
PN14	8/7/98	1287	276	-0.28	-0.25	0.02	0.02	-0.14	-0.11	0.04	0.04
PN15	10/5/98	1533	246	-1.39	0.36	0.26	0.04	-1.55	0.38	0.13	0.03
PN16D	10/26/98	1400-2700	296	-0.42	-0.42	0.04	0.03	2.27	0.46	0.58	0.09
PN18	9/15/98	1168	264	0.27	0.06	0.05	0.01	4.07	0.37	0.30	0.03
PN19D	8/4/98	1440	284	-0.29	-0.28	0.01	0.02	0.45	0.15	0.07	0.05
PN20D	10/1/98	1911	268	0.06	-0.08	0.11	0.02	-9.03	0.42	14.72	0.07
PN22D	9/1/98	1531	262	1.38	0.09	0.57	0.07	-2.64	0.43	0.64	0.04
PN23D	9/16/98	1334	263	0.00	-0.06	0.01	0.03	0.44	0.08	0.12	0.02
PN24D	10/26/98	1447	289	-0.40	-0.39	0.07	0.00	1.52	0.40	0.22	0.10
PN25D	5/21/98	2106	272	0.04	0.07	0.01	0.07	13.81	0.96	4.65	0.09
PN27D	9/18/98	1339	271	-0.08	-0.14	0.00	0.02	1.18	0.13	0.36	0.03
PN28	6/19/98	1234	256	-0.05	-0.05	0.06	0.00	0.01	0.01	0.09	0.06
PN29D	8/28/98	1040	255	-0.09	-0.09	0.01	0.04	-0.06	-0.07	0.00	0.01
PN30D	11/11/98	1309	274	-0.18	-0.19	0.00	0.00	0.27	0.04	0.02	0.01
PN31D	10/26/98	1900	296	-0.60	-0.59	0.08	0.01	0.56	0.15	0.02	0.02
PN32D	8/10/98	1283	266	0.01	-0.04	0.00	0.08	1.67	0.28	0.90	0.12
SG1	10/8/98	1358	267	-0.11	-0.13	0.02	0.01	0.19	0.03	0.04	0.02
Ave				-0.15	-0.10			0.74	0.23		
SD				0.51	0.25			4.01	0.25		

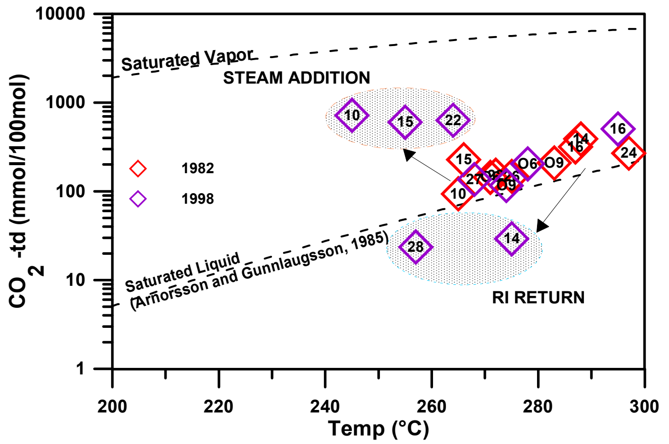

Figure 6. Plot of CO_2 in total discharge against T-quartz, showing shifts in the data points in 1998 as a result of reservoir boiling and reinjection returns.

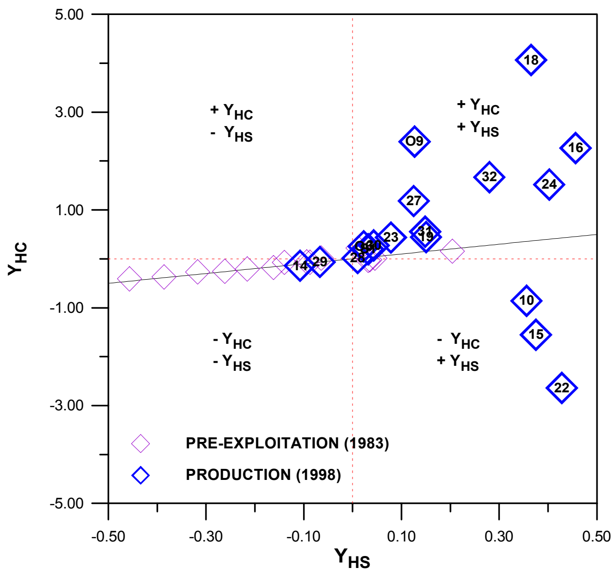

Figure 7. Cross-plot of Y_{HS} and Y_{HC}, classifying wells into four quadrants, each representing a different process. Positive Y_{HS} and Y_{HC} indicate reservoir boiling; positive Y_{HS}, negative Y_{HC} indicates acid-SO_4 production in shallow zones; and zero to negative Y_{HS} and Y_{HC} indicates unboiled reservoir or reinjection returns.

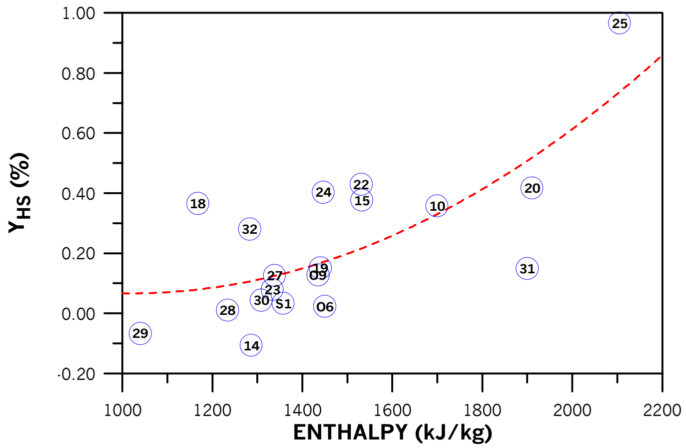

Figure 8. Plot of Y_{HS} against discharge enthalpy, suggesting direct correlation between reservoir steam fraction and excess steam.