



## ASSESSMENT OF OLKARIA-NORTHEAST GEOTHERMAL RESERVOIR, KENYA BASED ON WELL DISCHARGE CHEMISTRY

**James Macharia Wambugu**

Kenya Power & Lighting Company Ltd.,  
Olkaria Geothermal Project,  
P.O. Box 785, Naivasha,  
KENYA

### ABSTRACT

Chemical data from twenty-one deep wells in Olkaria-Northeast field have been used to evaluate the reservoir processes and to try to build a field reservoir model based on geochemical evidence. The field under consideration produces basically a sodium-chloride type of water with deep reservoir Cl concentrations ranging from 300 to 550 ppm and deep water pH in the range of 6.7-7.4. The hot geothermal fluid upflow seems to be located in the central part of the drilled field with cold recharge coming from the east and northwest, including nearby Lake Naivasha water, while the hot fluid flows southward at deeper levels under a continuous tight caprock, to be tapped from the current producing field, Olkaria-East located a few hundred metres to the south. Both solute and gas geothermometers indicate temperatures of about 270-290°C in this reservoir. Fluid-mineral equilibria indicate an amorphous silica saturation temperature of about 170°C, while calcite solubility is limited to temperatures of about 200°C. It has been shown that no scaling problems are expected, at least for these minerals, and silica deposition may only be a problem as regards discharge of effluent with no problems in production if proper separation is carried out.

### 1. INTRODUCTION

The Olkaria-Northeast (NE) geothermal field is a part of the greater Olkaria field which is located in the Hells Gate National Park in the Kenyan Rift Valley about 120 km to the northwest of the capital, Nairobi (Figure 1). This field is located within a proposed caldera and also within a less than 40  $\Omega$ m apparent resistivity zone (KPC, 1986).

#### 1.1 General information

To date a total of thirty-one deep wells have been sunk in this field which measures about 6 km<sup>2</sup> in area. In addition to the deep wells, three shallow wells M1, M2, and M3 have been drilled as field monitoring

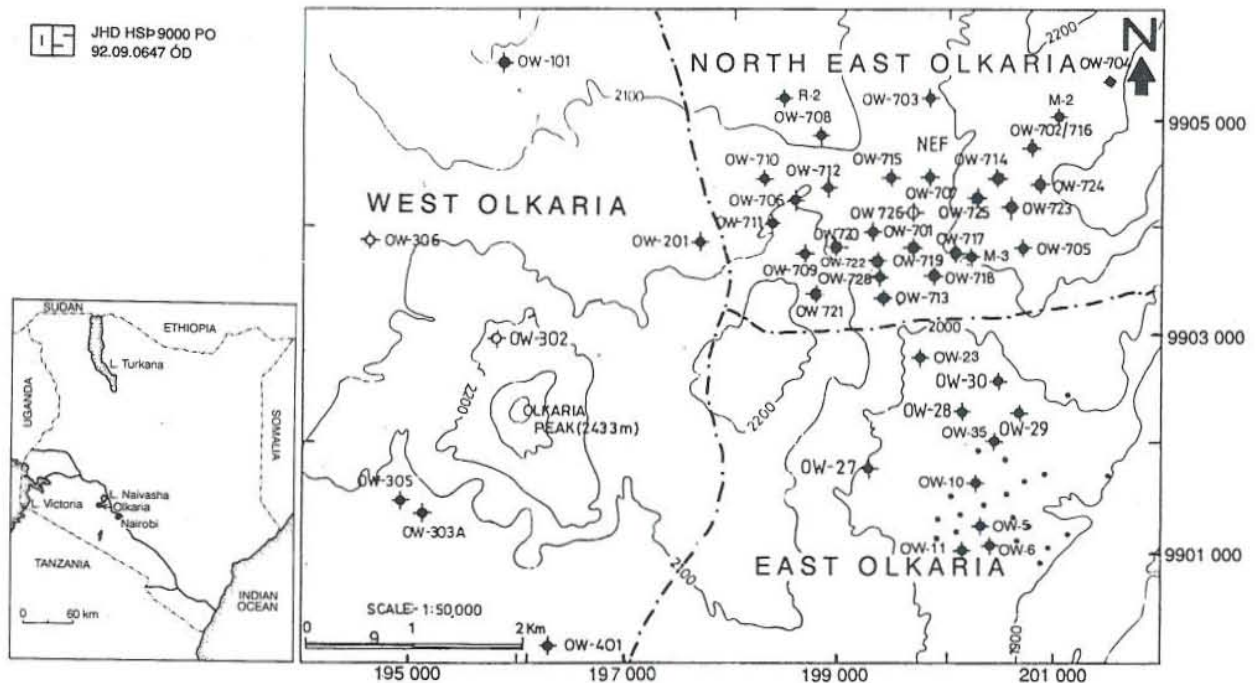


FIGURE 1: The Olkaria-NE geothermal field and location of wells

wells, ranging in depth from 595 to 603 m. The deep wells include two re-injection wells, R2 and R3, which were drilled for the purpose of subsurface waste water disposal from this field upon commencement of production. The well casing programme consists of 20" diameter surface casing, 13 3/8" anchor casing, 9 5/8" production casing and 7" slotted liners. The production casing usually extends to 600-900 m depth while the drilled depths of the wells range between 1800 and 2500 m.

## 1.2 General geological set-up

The area is predominantly covered with Quaternary ash and pyroclastics with poor outcropping of structures. The main rock types include trachytes/rhyolites, comendites which are sodic rhyolites, tuffs and pyroclastics with a predominance of trachytes occurring by volume, while the comendites are the main outcrops (Odongo and Muchemi, 1985). The subsurface geology indicates that the main rock types below the surface include tuffs, rhyolites and basalts which are considered to act as the reservoir caprock. The basaltic lavas have been considered dominant at depths below 1700 m, while acid tuffs take their place at relatively higher levels (Healy, 1972). The reservoir is considered to be bounded by arcuate faults forming a ring structure, with intrusions at deep levels inside the ring structure representing the magmatic heat source. The prominent structures in the area have general N-S and E-W trends with some inferred faults striking almost NW-SE. These are considered to be the source of the vertical permeability in the area. The hydrothermal mineral assemblages found in this field include zeolites, epidote-actinolite, Fe-minerals (pyrite, magnetite, haematite), albite, Ca-minerals (anhydrite and calcite), quartz, adularia and clays (chlorites and illite) (Agonga, 1992).

## 1.3 Main objective

This report brings together all the geochemical data available at present from this field. A previous report on the Olkaria-NE (Muna, 1988) considered data from seven wells which had already been drilled

at that time and included wells OW-X2, OW-501, OW-701, OW-702D, OW-703, OW-704 and OW-705. That report gave an overview of the characteristics of the geothermal fluid in the field and proposed a hot geothermal water up-flow in the central part of the field between wells OW-703 and OW-705. The present report attempts to synthesize all the available chemical data and tries to build a conceptual model (or confirm the previously envisaged one) based on results from the discharge tests of twenty-one wells. These results are also used to assess the fluid-mineral equilibrium reactions in the reservoir, an approach which has not yet been applied to Olkaria data. It is also an objective of this report to try to assess the scaling tendencies in the field with respect to some mineral phases and also the validity of using solute geothermometers for the purpose of sub-surface temperature estimation.

## 2. ANALYTICAL DATA

The wells in the Olkaria-NE field have been discharged for varying periods ranging from a few months to about two years. During the discharge period, both water and gas samples were collected for chemical analysis for all the major geothermal gases and major ions. The water samples were collected from the well weirbox while the gas sampling was done under pressure. To be able to make meaningful interpretation of these analytical results, it is necessary to re-calculate the concentrations of either gas or water phase to a common pressure, and also to calculate the total discharge composition which is considered representative of the reservoir fluid. The chemical composition of the fluid samples collected at the surface cannot be considered representative of the original reservoir fluid composition due to the various chemical and physical changes that are bound to take place in the geothermal fluid as it ascends to the surface. Because the hot fluid is being discharged through the wells, the flow is expected to be very large. It is, therefore, safe to assume that the only appreciable changes affecting the migrating fluid is phase separation, in which the hot water is separated from the steam formed by boiling as the water moves from a single-phase liquid reservoir towards the well, caused by the resultant pressure drop in the well. Owing to their different flow characteristics, the steam, which is lighter than water, is preferentially discharged through the well as compared to the water phase. There is no clear evidence to suggest boiling in the reservoir in the initial state and boiling is, thus, assumed to start upon movement of the fluid up the fissures with a resultant pressure drop. It is also assumed here that since the wells in this field have only been discharged for relatively short periods, the heat flow from the rocks is taken to contribute negligibly towards chemical changes in the reservoir.

### 2.1 Sampling and analysis

All the samples for which chemical data is discussed in this report were collected from discharging boreholes. Four 150 ml plastic sampling bottles were filled with water at the sampling site (at the well weirbox) and two of them acidified with a drop of concentrated hydrochloric acid to a pH of about 2, while the other two were left untreated. The acidified samples were used for the determination of the major cations while the untreated ones were used for the analysis of the major anions. The water temperature was measured using a thermocouple thermometer at the sampling site before being cooled to about 20°C in the laboratory for the actual pH measurement, which was carried out using a glass electrode pH meter. Steam samples were collected from the steam delivery pipe using a 2" cyclone separator which was situated about one metre from the master valve. Lip pressure and diameter of the delivery pipe were used to calculate the discharge enthalpy. The carbon dioxide and hydrogen sulphide were determined immediately at the sampling site by titration methods to get an idea of the actual concentration of these gases in the steam before final analysis in the laboratory.

The analysis was conducted for the major anions and cations using various methods for different ions.

The atomic absorption spectrometric method was used to analyse for the metal cations of Na, Li, Ca, Mg, and K, while SiO<sub>2</sub> and B were determined using spectrophotometric methods with yellow ammonium molybdate  $\beta$ -complex and methylene blue complex, respectively. CO<sub>2</sub>, H<sub>2</sub>S and SO<sub>4</sub><sup>-</sup> were determined by titration methods using pH adjustment from 8.20 with 0.1 N HCl to 3.80, HgAc<sub>2</sub> with dithizone as indicator, and barium perchlorate with thorin as indicator, respectively. Cl and F were determined using selective ion electrodes (ORION) while the TDS determination was by evaporation.

## 2.2 Water chemistry data

From the above discussion it is clear that water samples collected at the surface represent hot water which has undergone phase separation and in order to get a representative reservoir sample the WATCH program, updated version 2.1 (Arnórsson et al., 1982, Bjarnason, 1994) has been used here to calculate the deep composition of the fluid in discharging wells. To be able to obtain accurate results, a certain liquid enthalpy is assumed to exist in the reservoir (undisturbed state reservoir) and an appropriate phase separation temperature is sought, a temperature value believed to prevail in the reservoir (in this case calculated geothermometer temperature values were used). A representative sample for every well was selected to be used for all the calculations described here (Table 1). This representative sample was selected on the basis of the stable discharge of the well, taking into account the discharge time to avoid samples of non-thermal waters, and more importantly on account of the charge balance of the major ions. The charge balance was calculated for all samples from each well and a sample with a value of 5% or less was taken to be representative. However, in a few cases the reproducibility of constituents that do not contribute to the charge balance, especially silica, was poor. In such cases the samples were tested for random errors by calculating the charge balances for all the samples from that particular well and adding them together. In this method of assessment, if the ionic balance sums to a value approaching zero, then the error is taken to be random and in such cases an average value can be sought to represent the analytical result for a particular component. In the few cases mentioned above, the errors were found non-randomly distributed, and the most probable explanation may be errors in the sampling techniques

TABLE 1: Chemical composition of well discharge for Olkaria-NE, water phase (ppm)

Well no.	WHP (bar-g)	GSP (bar-g)	Enth. (kJ/kg)	pH	B	SiO <sub>2</sub>	Na	K	Mg	Ca	F	Cl	SO <sub>4</sub>	CO <sub>2</sub> tot	H <sub>2</sub> S
OW-701	11.7	4.5	1153	9.4	3.2	686	542	125	0.2	0.7	45	714	18	128	5.3
OW-702D	4.25	3.56	1551	9.27	3	747	569	112	0.4	7.4	39	722	35	213	0.82
OW-703	8.39	4.94	1257	9.2	1.2	886	710	176	0.1	0.2	83	884	24	217	1.42
OW-705	4.07	2.97	1468	9.28	n.d.	768	534	68	0	0	64	463	17	251	11.9
OW-706	6.41	4.83	1851	9.28	3	822	510	107	0.13	0.04	68	642	32	194	3.1
OW-707	7.24	2.9	1752	9.16	4	875	520	97	0	0	53	621	140	150	8
OW-708	2.41	0.69	1318	9.31	2.6	379	505	79	0.2	0.04	33	507	129	261	0.26
OW-709	6.3	1.88	1954	9.45	5.5	873	830	213	0	0	164	789	53	290	4.1
OW-710	8.28	2.76	1082	8.73	1.7	396	448	98	0	0	40	517	22	198	1.4
OW-711	5.77	2.76	1233	9.14	1.3	706	554	120	0	0	70	569	29	245	6.46
OW-712	4.48	2.62	2036	9.82	4.4	796	710	82	0	0	46	590	63	155	6.8
OW-713	2.76	2.07	1696	9.14	1.5	741	517	78	0	0	30	574	26	224	7.14
OW-714	17.93	2.76	1454	9.58	3.8	850	620	118	0	0	54	642	33	186	2.7
OW-716	3.59	2.76	2645	6.77	6.9	438	535	110	0.33	0.2	28	797	90	58	0.44
OW-718	8.28	2.76	956	9.44	4.3	694	500	80	0	0	51	474	41	152	3.1
OW-719	6.55	2.9	1167	9.5	3.3	753	540	87	0.3	0.2	46	507	39	198	6
OW-721	10.34	2.07	1706	9.61	3	845	650	77	0	0	62	468	71	193	10
OW-724	5	2.9	1446	8.77	3.2	538	450	50	0	0	38	477	68	144	4
OW-725	6.6		1380	9.85	5	677	700	88	0	0	58	588	34	247	27
OW-726	6.76	2.97	1602	8.9	5	785	570	88	0	0	37	675	61	167	7.8
OW-727	5.52	3.03	1720	8.54	4.2	818	500	67	0	0	37	576	77	147	5.1

employed or possibly analytical errors. Such data is of little use and that is the reason why fluid from some of the wells has been omitted in the interpretation presented in this report.

To be able to calculate the deep chemistry components of the well discharge, the WATCH program uses the reference temperature to calculate the steam fraction and from this, the chemical components in both water and steam fractions can be calculated and these values used to calculate the reservoir fluid composition by using the following relationship, where  $C_{total}$  is the reservoir composition:

$$\frac{\text{Water fraction at } P_{atm}}{\text{Water fraction in reservoir}} \times \text{Concentration of component in water at } P_{atm} = C_{total} \quad (1)$$

where

$$P_{atm} = \text{Atmospheric pressure.}$$

This will give the total composition in the water phase while it will be the same in the steam phase:

$$\frac{\text{Steam fraction at } P_{atm}}{\text{Steam fraction in reservoir}} \times \text{Concentration of component in steam at } P_{atm} = C_{total} \quad (2)$$

The total reservoir composition is, thus, given by the sum of components in both the water and the steam phases.

The steam fraction is calculated using the knowledge of the enthalpy values, which may be measured values or calculated, and with these the steam fraction can be calculated using the relationship:

$$X = \frac{H_o - H_w}{H_{st} - H_w} \quad (3)$$

where

$$\begin{aligned} X &= \text{Steam fraction;} \\ H_o &= \text{Total enthalpy (measured or calculated);} \\ H_w &= \text{Water enthalpy;} \\ H_{st} &= \text{Steam enthalpy.} \end{aligned}$$

The enthalpy values,  $H_o$ , can be obtained by using the critical lip pressure method by James (1962), which involves discharge through a lip pressure pipe into a silencer and measuring the critical pressure in the lip pipe together with the water flowrate from the silencer (from weirbox). The following relationship can be used to calculate the discharge enthalpy:

$$\frac{W}{808.7 \times AP^{0.96}} = \frac{2666 - H}{H^{1.102}} \quad (4)$$

where

$$\begin{aligned} A &= \text{Cross-sectional area of the lip pipe (m}^2\text{);} \\ P &= \text{Critical pressure at the end of the lip pipe (bar-absolute);} \\ H &= \text{The total fluid enthalpy (kJ/kg).} \end{aligned}$$

The calculated total fluid composition is shown in Table 2.

TABLE 2: Calculated total fluid composition (ppm) for the wells in the Olkaria-NE field

Well no.	B	SiO <sub>2</sub>	Na	K	Mg	Ca	F	Cl	SO <sub>4</sub>	CO <sub>2</sub>	H <sub>2</sub> S
OW-701	2.16	462.4	365.3	84.2	0.13	0.47	30.3	481.2	12.1	1453	56.1
OW-702D	1.49	372	283	55.8	0.2	3.69	19.4	359.6	17.4	3364	25.6
OW-703	0.75	556.4	445.9	110.5	0.06	0.13	52.1	551.2	15.1	1825	23.8
OW-705	0	410.9	285.7	36.4	0	0	34.2	247.7	9.1	4480	169.2
OW-706	1.1	300	186.2	39.1	0.05	0.01	24.8	234.3	11.7	4013	111.2
OW-707	1.64	357.9	212.7	39.7	0	0	21.7	254	57.3	3933	133.5
OW-708	1.56	227.8	303.5	47.5	0.12	0.02	19.8	304.7	77.5	3054	2.3
OW-709	1.76	279.4	265.6	68.2	0	0	52.5	252.5	17	1685	47.6
OW-710	1.2	279.6	316.3	69.2	0	0	28.2	365	15.5	1282	48
OW-711	0.83	451.1	354	76.7	0	0	44.7	363.6	18.5	1343	47.1
OW-712	1.25	225.3	200.9	23.2	0	0	13	167	17.8	2965	94.6
OW-713	0.65	321.6	224.4	33.8	0	0	13	249.1	11.3	3957	137.8
OW-714	2.06	459.8	335.4	63.8	0	0	29.2	347.3	17.8	1791	27.5
OW-716	0.09	5.7	7	1.4	0.004	0.003	0.4	10.4	1.2	3657	56
OW-718	3.27	528.8	381	61	0	0	38.9	361.2	31.2	383	2.7
OW-719	2.2	503	360.7	58.1	0.2	0.13	30.7	338.7	26.1	1755	22.9
OW-721	1.29	362.5	278.8	33	0	0	26.6	200.8	30.5	n.g.	n.g.
OW-724	1.74	292.7	244.8	27.2	0	0	20.7	259.5	37	n.g.	n.g.
OW-725	2.87	388.6	401.8	50.5	0	0	33.3	337.5	19.5	n.g.	n.g.
OW-726	2.38	372.9	270.8	41.8	0	0	17.6	320.6	29	3006	191.1
OW-727	1.78	346	211.5	28.3	0	0	15.6	243.6	32.6	3935	122.8

n.g. = No gas analysis

### 2.3 Gas chemistry data

The gas sampling from the discharging wells was done under pressure with varying pressure values for different wells depending on the wellhead pressures. The samples were analysed for the major geothermal gas components by gas chromatography for most of the gases, except for condensable components like CO<sub>2</sub> and H<sub>2</sub>S which were analysed for by titration methods. The results in mmol/100 mol steam are presented in Table 3.

It is clear from the results in Table 3 that the wellhead pressures are generally higher than the gas sampling pressures. This is due to the different sampling points

TABLE 3: Results of gas analysis for the wells in the Olkaria-NE field (in mmol / 100 mol steam)

Well no.	GSP (bar-g)	WHP (bar-g)	Enth. (kJ/kg)	CO <sub>2</sub>	H <sub>2</sub> S	CH <sub>4</sub>	H <sub>2</sub>	N <sub>2</sub>
OW-701	4.5	11.7	1153	235	11.71	0.34	8.95	2.57
OW-702D	3.56	4.25	1551	305	2.82	1.87	1.76	3.62
OW-703	4.94	8.39	1257	246	4.29	2.71	18.29	4.45
OW-705	2.97	4.07	1468	439	21.24	2.26	9.7	6.35
OW-706	4.83	6.41	1851	284	10.16	0.99	6.26	1.46
OW-707	2.9	7.24	1752	294	12.82	0.4	0.94	3.56
OW-708	0.69	2.41	1318	314	0.26	0	0.01	15.1
OW-709	1.88	6.3	1954	101	3.82	0	4.38	6.43
OW-710	2.76	8.28	1082	206	10.99	0	1.55	2.93
OW-711	2.76	5.77	1233	163	7.64	0	4.5	4.21
OW-712	2.62	4.48	2036	177	7.15	5.15	2.65	8.02
OW-713	2.07	2.76	1696	302	13.55	0	2.45	1.67
OW-714	2.76	17.93	1454	173	3.45	0	2.55	12.56
OW-715	2.76	10.34	1458	332	7.65	0	0.72	13.14
OW-716	2.76	3.59	2645	156	3.11	0	5.44	8.41
OW-718	2.76	8.28	956	65	4.06	0.6	1.83	4.53
OW-719	2.9	6.55	1167	251	8.35	0.76	2.76	8.15
OW-726	2.97	6.76	1602	256	21.22	1.36	9.63	2.52
OW-727	3.03	5.52	1720	302	12.14	1.4	7.35	3.51
OW-025*	4.8	5	1631	156	14.58	0.28	8.58	1.06

\* OW- 025 is well no. 25 in the Olkaria-East production field

GSP = Gas sampling pressure

WHP = Well head pressure

Enth. = Discharge enthalpy

along the delivery pipe from the wellhead. However, it would be more appropriate to sample the gases as close as possible to the wellhead master valve where the pressures would be almost equal (gas sampling and wellhead pressures), since this pressure difference may cause inaccuracy as a result of possible boiling occurring in the separator. To be able to use the gas concentrations, it was necessary to re-calculate these values to atmospheric conditions and this was done by using the relationship:

$$C_{atm} = C_{gsp} \times \frac{X_{gsp}}{X_{atm}} \quad (5)$$

where

- $C$  = Concentration of the gas in steam;  
 $X$  = Steam fraction;  
 $atm$  = Atmospheric pressure;  
 $gsp$  = Gas sampling pressure.

The calculated gas compositions at atmospheric pressure in mmol/mole of steam are presented in Table 4. The same is shown in Table 5 except that the gas concentrations are given in mmol/kg of steam. Here it was assumed that no chemical reaction causes changes in relative gas concentrations from sampling pressure to atmospheric pressure, and that only the increase in steam fraction due to the pressure drop (from gas sampling pressure to atmospheric pressure) causes the decrease in the gas concentrations, i.e. from sampling pressure to atmospheric pressure, there is no change in non-condensable gas but an increase in the amount of steam and, therefore, a decrease in non-condensable gas concentration.

TABLE 4: Calculated gas composition at atmospheric pressure for the Olkaria-NE wells, in mmol / mol steam

Well no.	CO <sub>2</sub>	H <sub>2</sub> S	H <sub>2</sub>	CH <sub>4</sub>	N <sub>2</sub>	CO <sub>2</sub> /H <sub>2</sub> S	CO <sub>2</sub> /H <sub>2</sub>	CO <sub>2</sub> /N <sub>2</sub>
OW-701	1.716	0.0854	0.065	0.0022	0.188	20.09	26.4	9.13
OW-702D	2.655	0.0261	0.0157	0.0165	0.0314	101.72	169.11	84.55
OW-703	1.857	0.0325	0.1382	0.0204	0.034	57.14	3.44	54.63
OW-705	3.824	0.185	0.084	0.02	0.056	20.67	45.52	68.29
OW-706	2.539	0.091	0.0563	0.0089	0.0107	27.9	45.1	237.3
OW-707	2.682	0.1167	0.0082	0.0036	0.033	23	327	81.2
OW-708	2.97	0.0028	0	0	0.142	1060.7		20.92
OW-709	0.957	0.036	0.042	0	0.061	26.58	22.74	15.69
OW-710	1.59	0.085	0.012	0	0.022	18.71	132.5	72.27
OW-711	1.344	0.063	0.037	0	0.035	21.33	36.32	38.4
OW-712	1.666	0.068	0.025	0.049	0.075	24.5	66.64	22.21
OW-713	2.79	0.126	0.023	0	0.016	22.14	121.3	174.2
OW-714	1.507	0.03	0.023	0	0.1097	50.23	65.52	13.74
OW-715	2.902	0.067	0.0061	0	0.114	43.31	475.7	25.46
OW-716	1.515	0.03	0.052	0	0.082	50.5	29.13	18.48
OW-718	0.459	0.029	0.013	0.0042	0.032	15.83	35.31	14.34
OW-719	2	0.067	0.022	0.0064	0.065	29.85	90.91	30.77
OW-726	2.281	0.189	0.086	0.012	0.022	12.07	26.52	103.68
OW-727	2.74	0.1096	0.07	0.013	0.032	25	39.14	85.63
OW-025	1.34	0.126	0.074	0.0024	0.009	10.63	18.11	148.9

TABLE 5: Calculated gas composition at atmospheric pressure for the Olkaria-NE wells, in mmol / kg steam

Well no.	CO <sub>2</sub>	H <sub>2</sub> S	H <sub>2</sub> '	CH <sub>4</sub>	N <sub>2</sub>	CO <sub>2</sub> /H <sub>2</sub> S	CO <sub>2</sub> /H <sub>2</sub>	CO <sub>2</sub> /N <sub>2</sub>
OW-701	95.3	4.74	3.6	0.122	10.44	20.11	26.5	9.13
OW-702D	147.5	1.45	0.87	0.92	1.74	101.7	169.5	84.8
OW-703	103.2	1.81	7.68	1.13	1.89	57.14	3.44	54.63
OW-705	212.4	10.3	4.67	1.11	3.11	20.67	45.52	68.29
OW-706	141.1	5.1	3.13	0.479	0.59	27.7	45.1	239.2
OW-707	148.9	6.48	0.46	0.2	1.83	23	323.7	81.4
OW-708	165	0.16	0	0	7.89	1031		20.92
OW-709	53.2	2	2.33	0	3.4	26.6	22.83	15.6
OW-710	88.3	4.7	0.67	0	1.22	18.8	131.8	72.4
OW-711	74.7	3.5	2.1	0	1.94	21.3	35.6	38.5
OW-712	92.6	3.8	1.39	2.72	4.2	24.5	66.64	22.1
OW-713	155	7	1.28	0	0.89	22.14	121.3	174.2
OW-714	83.7	1.67	1.28	0	6.09	50.12	65.4	13.74
OW-715	161.2	3.72	0.34	0	6.33	43.31	474.1	25.46
OW-716	84.2	1.67	2.89	0	4.56	50.5	29.13	18.48
OW-718	25.5	1.61	0.72	0.23	1.78	15.83	35.41	14.34
OW-719	111.1	3.72	1.22	0.36	3.61	29.85	91.1	30.77
OW-726	126.7	10.5	4.78	0.67	1.22	12.07	26.52	103.85
OW-727	152.2	6.09	3.89	0.722	1.78	25	39.14	85.51
OW-025	74.4	7	4.11	0.133	0.5	10.63	18.11	148.9

### 3. DISCUSSION

#### 3.1 Characteristics of the geothermal fluids

The chemical composition of well discharges differs from one field to another. It also varies between wells within the same field. These changes may be partly due to reactions with the wall rocks, changes in the composition of the reservoir fluid flowing towards the well caused by boiling processes which are also responsible for changes in the discharge enthalpy, and also by possible mixing with dilute cooler waters. Taking the above into consideration, it is possible to group the chemical components in geothermal fluids into two distinct categories (mineral forming and conservative components.) The mineral forming components (SiO<sub>2</sub>, Na, K, Ca, Mg, S - H<sub>2</sub>S and SO<sub>4</sub>, C - CO<sub>2</sub>, F, Al, Fe, Mn, etc.) have proven extremely useful in obtaining information on the conditions in the reservoir which control reservoir temperatures, about reservoir processes like boiling, chemical reactions like precipitation which are responsible for scale formation, and ion exchange. On the other hand, the conservative components are useful in obtaining information on the source of the reservoir fluids (natural recharge or even injected water). Of vital importance in this group are the components Cl, B and stable isotopes such as deuterium and oxygen-18.

The Olkaria-NE field basically discharges a near neutral sodium-chloride type water with a deep water pH value ranging from 6.7-7.4 on average. The reservoir sodium (Na) concentrations range from 330 to 400 ppm on average while the reservoir chloride (Cl) concentrations average 350-500 ppm. The waters may be considered relatively dilute with total dissolved solids (TDS) concentrations of less than 2500 ppm in most cases, only in a few well samples do the TDS values exceed 3000 ppm (wells OW-703 and OW-709). The reservoir total carbonate concentration calculated as CO<sub>2</sub> ranges from 1000 to 2000



ppm in most well fluids, with a few exceptions in which very low values were encountered (in well OW-718, see Table 2). On the other hand a higher value of 3176 ppm is observed for OW-705 fluid. This well may be considered as discharging a mixed  $\text{NaCl-HCO}_3^-$  water.

The gas concentrations of the steam discharges from this field are dominated by carbon dioxide,  $\text{CO}_2$ , in the range 200-300 mmol/100 mol steam on average, followed by hydrogen sulphide,  $\text{H}_2\text{S}$ , with an average of 7-15 mmol/100 mol steam with a few exceptions in which higher values were observed (well OW-705 and OW-726 fluids with values of 21.24 and 21.22 mmol/100 mol, respectively). Such high values may be taken at the onset to imply closer proximity of the wells to the source of the gas. If  $\text{H}_2\text{S}$  gas is taken to be of magmatic origin as is often the case, then these wells may be thought to be closer to the magmatic heat source and within relatively good permeability zones. The nitrogen gas ( $\text{N}_2$ ) concentration in the reservoir ranges from 2 to 15 mmol/100 mol steam across the field, with lower values being observed in fluids from some wells (less than 2 mmol/100 mol steam in fluids from OW-713 and OW-706), while others exhibit relatively higher values like well OW-708 fluid. Higher  $\text{N}_2$  gas values would most likely suggest some contamination of the geothermal fluid with atmospheric air. There is no analytical data for  $\text{O}_2$  gas, which would have been a very useful indicator of shallow atmospheric air contamination.

For classification of geothermal waters, Giggenbach (1991) has presented a triangular plot comparing the relative concentrations of  $\text{Cl}^-$ ,  $\text{SO}_4^{2-}$  and  $\text{HCO}_3^-$  of waters discharged from geothermal fields. This diagram gives an idea of the mixing relationships of geothermal waters, and characterizes them in terms of mature waters (fully equilibrated), peripheral waters which are high in  $\text{CO}_3^{2-}$ , and  $\text{SO}_4^{2-}$  rich waters which are mainly steam-heated waters. The high  $\text{CO}_3^{2-}$  waters are mainly considered to form at the margins of a system due to the interaction of the  $\text{CO}_2$  charged fluids at lower temperatures. The concentration of these anions have been plotted in this type of diagram (Figure 2) and most of the well waters have been classified as  $\text{Cl}^-$  rich mature waters. Maturity of water in this case reflects the attainment of chemical equilibrium between the geothermal water and the reservoir rocks/minerals. Using this classification it is, therefore, safe to consider the waters from this field as suitable for use in geothermometry applications for subsurface temperature estimation. In general, waters plotting in the  $\text{HCO}_3^-$  or  $\text{SO}_4^{2-}$  corners often reflect reactive water whose equilibrium with secondary minerals may be disturbed, rendering such water unsuitable for use in geothermometry calculations.

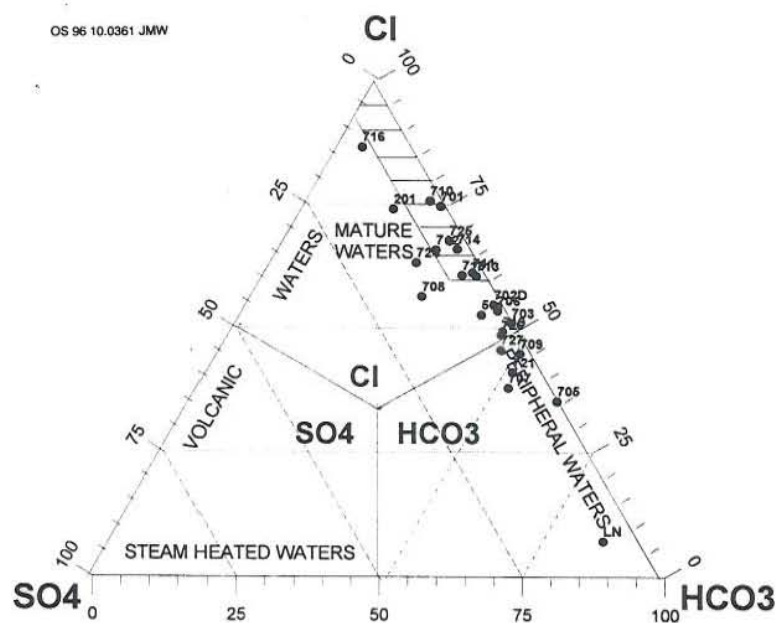


FIGURE 2:  $\text{Cl-SO}_4\text{-HCO}_3$  diagram for the Olkaria-NE wells waters, LN is Lake Naivasha water

### 3.2 Origin of the water and reservoir processes

The conservative components of geothermal waters can be used to trace the recharge of the water in a reservoir and also to infer some of the processes that take place there. Both Cl and B are conservative

elements and their sources are considered to be rock dissolution only. Due to their mobility, these components are, as a rule, not incorporated in hydrothermal minerals and, once in water, will remain in solution. It follows that the ratio Cl/B is very useful and this ratio in the discharge fluids will reflect ratios similar to those in the reservoir rocks (Shigeno and Abe, 1983). In this field, the reservoir rocks are mainly acidic-intermediate and basaltic and the Cl/B ratio in basaltic rocks in Iceland lies in the range 50-160 (Arnórsson et al., 1993). It is, therefore, generally accepted that the ratios of these components in this field are expected to lie close to this range.

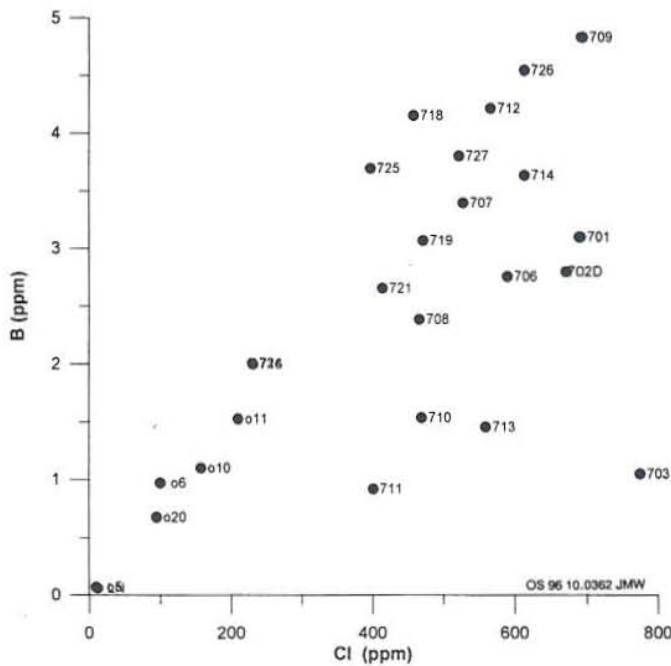


FIGURE 3: The relationship between Cl and B in waters from the Olkaria-NE wells, also including some Olkaria-East well waters

Figure 3 shows the relationship between Cl and B in the Olkaria-NE wells. There is strong evidence that the Olkaria-NE field receives recharge water from Lake Naivasha, about 3 km to the north of it (Arusei, 1991). Stable isotope values reported by Allen and Darling (1987), Sveinbjörnsdóttir (1988) and Clarke et al. (1990) support this contention. Darling et al. (1990) estimated up to a 50% contribution from Lake Naivasha to the inflow to the Olkaria-East production field. A Cl/B ratio of 192 has been recorded for Lake Naivasha water (Arusei, 1991). This ratio lies in the range 169-241 for fluid from wells OW-701, 702D, 706, 708 and 714 suggesting that they may receive relatively unmodified water from Lake Naivasha. The same ratio lies in the range 110-155 for most of the remaining Olkaria-NE fluids, probably because they are fluids of the same origin which have been modified by the uptake of chemicals from the rock and approached the ratio for

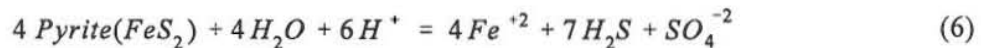
the rocks. These values correspond well with values obtained for fluids from wells OW-5, 6, 10 and 11 in the Olkaria-East field, to the south of the Olkaria-NE field (Muna 1982). The Cl/B ratios for fluids from wells OW-710, 711, 713 and especially OW-703 are, however, considerably higher and suggest that they be may at least partly of a different origin. High values for the Cl/B ratio have been observed for ground waters to the west, e.g. close to the Mau escarpment (Clarke et al., 1990), and to the east of Olkaria, e.g. in the Musyokas borehole, about 6 km to the east of well OW-703 (Arusei, 1991). If high Cl/B values are due to a distant origin, they are likely to be observed at the margins of the field as they will be modified to approach the ratios of the rocks as the fluid flows through the system. This fits most of the present observations, especially if it is borne in mind that the relative positions of subsurface aquifers tapped by individual wells need not correspond exactly to surface geographical positions of the wells.

In the centre of the field, boiling processes which tend to concentrate the dissolved solids in the water phase while the steam thus formed is less concentrated may be responsible. As this steam migrates from the up-flow, it may condense due to possible mixing with waters of different temperature signatures and this will form waters with relatively low solid content. Furthermore, boron is believed to partition into the steam phase (Arnórsson, pers. comm.) at high temperatures (> 250°C) and if boiling is taking place around these wells, then their fluids are expected to reflect high Cl/B ratios since Cl is not partitioned into the steam phase at any temperature. This is considered a possible explanation for the concentration

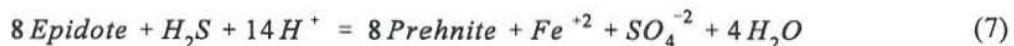
of these components in wells OW-703 (Cl=575 ppm, B=0.78 ppm), OW-713 (Cl=393 ppm, B=1.03 ppm) and OW-711 (Cl=395 ppm, B=0.9 ppm). On the other hand, low Cl/B ratios close to the reservoir rock composition is a good indication that the waters discharged by such wells are truly representative of the geothermal reservoir conditions as shown by wells in the central part of the field and the Olkaria-East wells.

The sulphate,  $SO_4^{-2}$ , concentration of the waters from the Olkaria-NE field ranges from 11 to 50 ppm, on the average with the exception of those from a few wells which discharge water with a relatively high  $SO_4^{-2}$  content. These include wells OW-707, 708, and 716 with  $SO_4^{-2}$  concentrations of 91, 92 and 58 ppm, respectively. Well OW-707 is located in the central part of the field while both OW-708 and OW-716 are on its margin (Figure 1). High  $SO_4^{-2}$  values are often observed in waters where the  $SO_4^{-2}$  is formed by oxidation of  $H_2S$  gas. However, it should be noted that  $SO_4^{-2}$  is a reactive component and can also be formed through acid dissolution of anhydrite which may occur in this field.

Most of the well waters show a Cl/ $SO_4$  ratio varying from 5 to 20 with a few cases where the ratio is much higher. Water from wells OW-701, 703, 705 and 710 have values 39.7, 36.9, 27.3 and 23.5, respectively. High ratios imply that the waters from these wells are least oxidized. In other cases the ratio is found to be very low, as in wells OW-708 (3.9), 724 (5.4) and 704 (5.6) and such low ratios imply that  $H_2S$  has been oxidized to form  $SO_4^{-2}$ . The oxidation of  $H_2S$  to  $SO_4^{-2}$  is not likely to be due to mixing with a cooler water containing atmospheric oxygen. Reactions involving  $H_2S$  and  $SO_4^{-2}$  have been known to take place in geothermal fluids. The origin of oxygen may be deep, probably from mantle-derived  $SO_2$ ,  $H_2O$  and  $CO_2$ . These reactions can be used to explain the ratios in the central part of the field. Pyrite is a common hydrothermal mineral in this field occurring at deeper levels as reported for well OW-716 (Agonga, 1992). Acid dissolution of this mineral may increase the amount of  $SO_4^{-2}$  in the waters through a possible reaction of the following type:



while at deep levels epidote may react with  $H_2S$  to form  $SO_4^{-2}$  through the reaction



### 3.3 Geothermometry

The chemical composition of geothermal fluids has been used successfully to estimate reservoir temperature, at least for producing aquifers. Several types of subsurface temperature indicators (geothermometers) have been proposed by many different researchers for different uses and all are based on the water-rock interaction processes taking place in different geothermal reservoirs whose rock types and mineral assemblages are quite different. To be able to use these geothermometers accurately, there are several assumptions held applicable in the respective reservoirs of which the backbone remains an assumption of equilibrium between the reservoir rocks/minerals and the reservoir fluids. The composition of the fluids discharged to the surface from a geothermal reservoir is mainly controlled by the composition of the reservoir rocks and the temperature. Both experimental studies and experience have shown that there are some geothermal fluid components whose solubility is controlled by temperature and this is the basis of geothermometry. These components can be divided into two main groups which include water-based (solute) and steam-based (gas) geothermometers. Here both types of geothermometers are discussed.

### 3.3.1 Solute geothermometers

Solute geothermometers are solely dependent on the attainment of water-mineral equilibria in the reservoir. To make good use of them, a thorough knowledge of the reservoir geology is necessary because most or all known geothermometer functions are calibrated using specific mineral phases through which equilibrium is attained. However, there are some empirically calibrated temperature functions which are assumed to be of universal use, regardless of the reservoir geology of a particular system like that due to Na-K-Ca. The temperature functions used here are those believed to be due to the respective secondary mineral phases present in the Olkaria field and include the silica geothermometers (quartz and chalcedony) and the alkali feldspar geothermometers (Na/K ratio geothermometer). The silica geothermometers are based on the experimentally determined solubility of quartz and chalcedony and assume equilibrium between the aqueous  $H_4SiO_4^0$  species and the respective solids. The solubility of these silica minerals has been shown to be positively related to temperature, whereas the feldspar geothermometer is based on ion exchange reactions with temperature dependent equilibrium constants of the type shown below:



By assuming the concentration to be equal to activity, and activity of the solid phases equal to unity, then

$$K_{equil.} = \frac{(Na^+)}{(K^+)} \quad (9)$$

where

$K_{equil.}$  is the equilibrium constant of the exchange reaction; it is temperature dependent and forms the basis for particular geothermometer.

Here the reported temperature values have been calculated by using the WATCH program of Arnórsson et al. (1982) and Bjarnason (1994), the results are given in Table 6. For temperature calculations, it uses the functions by Fournier and Potter (1982) for the quartz geothermometer, Fournier (1977) for the chalcedony geothermometer, and Arnórsson et al. (1983) for the Na/K ratio geothermometer.

For proper use of these solute geothermometers for temperature estimation, it is necessary to ascertain equilibrium conditions in the water whose solute contents are to be used. To be able to weed out unsuitable water in terms of attainment of chemical equilibrium with the reservoir rocks/minerals, Giggenbach, (1988) presented a triangular plot relating Na, K and Mg in terms of equilibrium and the temperature of the aquifers producing such waters. The well discharges from the Olkaria-NE field have been plotted in this diagram (Figure 4) for waters with determinable Mg concentrations. However, some of the waters in this field plot in the region of partial equilibration. This is a good indication that the waters can safely be used for geothermometry calculations. Partial equilibration may be due to reactions with the wall rocks during re-equilibration or could result from mixing. It would be inaccurate to use waters plotting in the immature region, implying that these waters have not attained equilibrium with the reservoir rocks. From this plot, the waters in the Olkaria-NE field range in Na-K temperature from 240°C to about 300°C, indicated in well OW-703. These temperatures compare quite well with calculated temperatures using the Na/K geothermometer and also with the actual measured downhole temperature. However, the waters exhibit low temperatures indicated by the same plot using the K-Mg geothermometer ranging from 180 to about 240°C, shown in well OW-703 while wells OW-708, 719 and 702D indicate lower temperatures of 180-190°C. These values deviate by rather a large margin from the actual temperatures in the wells, probably due to the low Mg content of the waters. In addition, the

TABLE 6: Calculated geothermometer temperatures for the Olkaria-NE wells (in °C)

Well no.	T(Quartz)	T(Chalc.)	T(Na/K)	T(H <sub>2</sub> S)	T(CO <sub>2</sub> /H <sub>2</sub> )	T(CO <sub>2</sub> )	T(H <sub>2</sub> )	T(DP)
OW-701	238.1	224.4	293.4	277	301	261	289	307
OW-702	259.5	246.9	274.4	254	278	275	276	212
OW-703	274.3	260.8	300.1	258	326	264	296	288
OW-705	262	249.4	227.3	292	294	286	291	283
OW-706	267.8	254.9	281.4	278	294	274	288	273
OW-707	273.5	260.1	262.3	283	270	276	270	228
OW-708	202.2	183.5	245.6	211	n.d.	279	n.d.	
OW-709	271.2	258	302.4	260	303	241	285	
OW-710	195.2	175.4	286.5	277	281	259	274	
OW-711	254.4	241.8	285.7	271	297	248	284	
OW-712	264.1	251.4	214.5	273	290	260	280	242
OW-713	258.9	246.3	245.6	285	282	277	280	
OW-714	270	256.9	270.8	257	290	257	280	
*OW-716	206	187.8	276.3	257	300	257	287	
OW-718	251.2	238.5	251.6	256	297	209	274	279
OW-719	259.9	247.3	252.1	272	286	266	279	251
OW-721	304.3	284	214.2					
OW-724	220.5	204.4	206					
OW-725	240.2	226.8	228					
OW-726	263.9	251.2	246.4	293	301	271	292	299
OW-727	267.6	254.7	229.5	282	296	276	290	276

The gas geothermometry functions are from Arnórsson and Gunnlaugsson (1985) and the calculations done using concentrations in mmol/kg steam

T(Quartz) = Temperature calculated using the quartz geothermometer (Fournier and Potter, 1982)

T(Na/K) = Temperature calculated using the Na/K ratio (Arnórsson et al., 1983)

T(DP) = Temperature calculated using the gas function by D' Amore and Panichi (1980)

\*OW-716: The SiO<sub>2</sub> concentration is low in the sample

K/Mg geothermometer is expected to give low values as the reaction involved is extremely quick to re-equilibrate and quite often reflects the sampling temperature (Árnannsson, pers. comm.). Values obtained for these well waters can be considered high enough to reflect reasonably good samples which should give confidence in the higher results for the other geothermometers.

The temperatures calculated using the Na/K ratio geothermometer show highest values

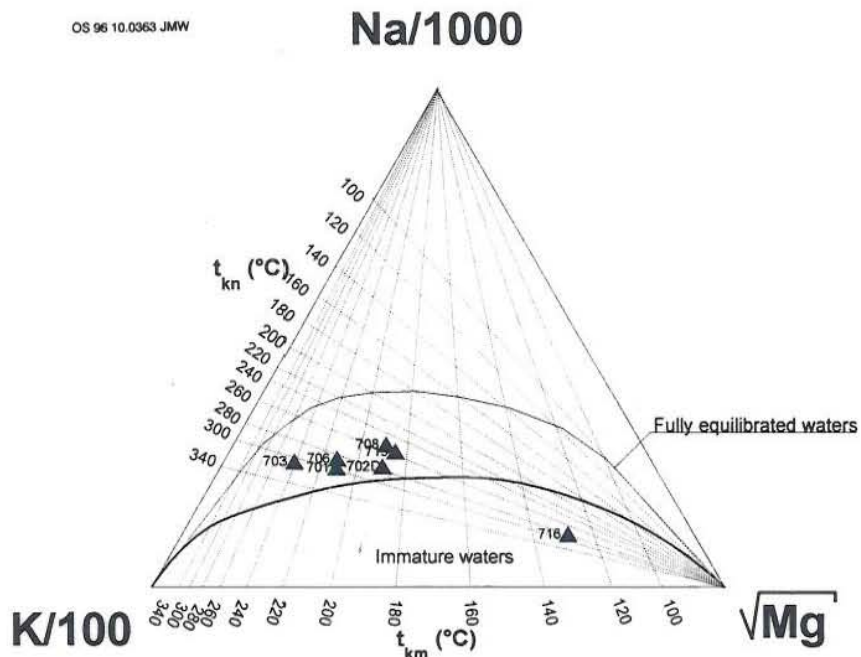


FIGURE 4: Na-K-Mg equilibrium diagram for some well waters in the Olkaria-NE field

around well OW- 703 (300°C). The temperatures decrease gradually to the western side of the field towards well OW-708 (245°C) and increase again towards the southwestern side around wells OW-710 and 709 (280-286°C). The temperatures also decrease eastwards towards well OW-724 (206°C). The direction of temperature decrease indicates the cooling direction of the reservoir which may result from cold water inflow into the system, or the direction of flow of the hot fluids from the source which causes temperature drop as the hot fluid moves across the field. If the fluid movement is lateral and at sufficiently shallow levels, then the hot water is expected to lose heat to the surrounding colder rock bodies near the surface.

The SiO<sub>2</sub> geothermometer indicates relatively high reservoir temperatures in the central part of the field (Figure 5) with a wider range than the Na/K geothermometer. The highest temperature, 304°C, was recorded in well OW-721, but high temperatures, ranging from 267 to 274°C, were also recorded around wells OW-712, 706, 707, 727, 714, 703 and 709. Lower temperatures are found with values of 202°C around wells OW-708 and 710 to the northwest and 220-180°C to the east around wells OW-724, 704 and 716. The temperature decrease to the south is very gradual. This trend may be explained for the Na/K case where colder water may be inferred to be approaching the field from the east and northwest. However, the reservoir temperatures alone may not be conclusive enough to suggest cold water inflow from the direction of cooling, because the cooling may result as well from out-flowing cooler waters from a central hot source (up-flow) which would classify these cooling zones as discharge areas. Thus, further evidence is necessary to categorize areas as discharge or recharge zones.

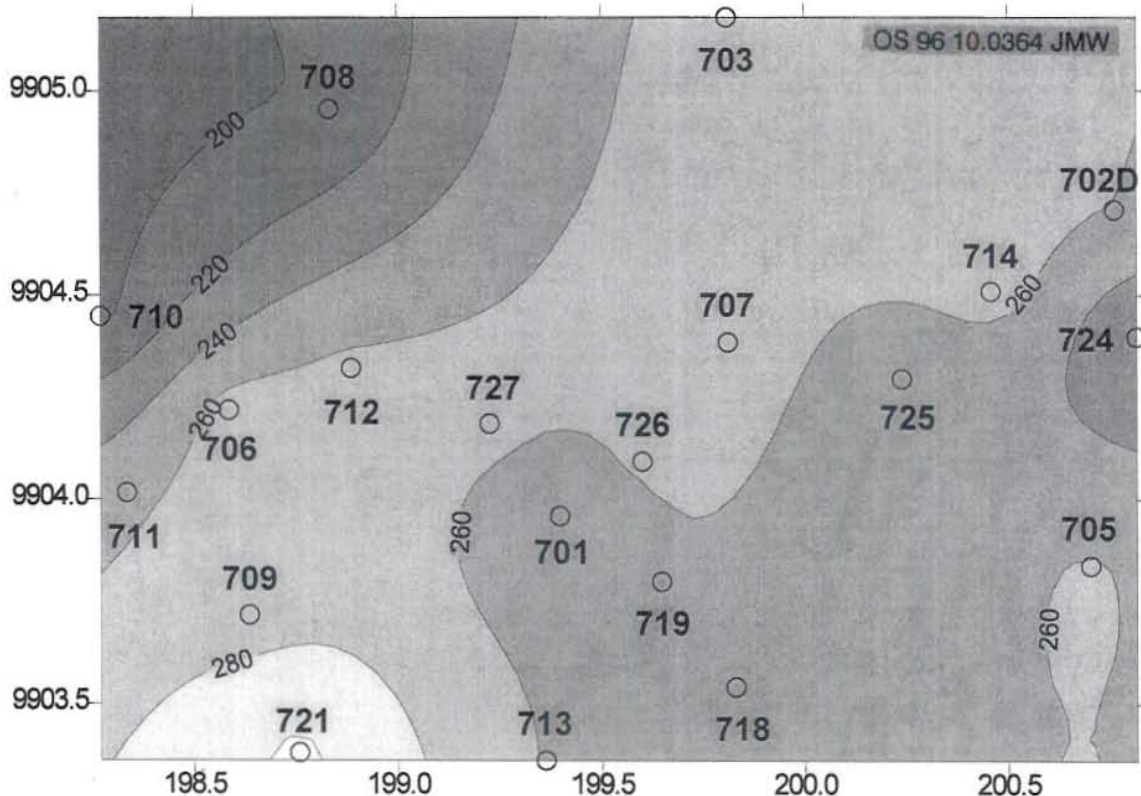


FIGURE 5: Quartz geothermometer temperatures for the Olkaria-NE field (°C)

### 3.3.2 Gas geothermometers

In addition to the solute geothermometers, gas geothermometers have also been used. Their results seem to agree quite well with the solute geothermometer results (Table 6). The gas geothermometers are from Arnórsson and Gunnlaugsson (1985) based on the concentrations of CO<sub>2</sub>, H<sub>2</sub>S and H<sub>2</sub> and from D'Amore

and Panichi (1980) which also take account of the  $\text{CH}_4$  concentration. It has been shown that in many geothermal fields of high temperatures ( $>200^\circ\text{C}$ ), temperature dependent gas-gas and/or mineral-gas equilibria control the concentration of the geothermal gases and their ratios (Giggenbach, 1980; Nehring and D'Amore, 1984; Arnórsson and Gunnlaugsson, 1985). The functions of Arnórsson and Gunnlaugsson (1985) were calibrated using actual drillhole data, while most of the other functions can be termed thermodynamically derived. The calibration of these functions assumes that the boiling in the up-flow zones is adiabatic from the temperature at which the gas-mineral equilibrium is attained to atmospheric pressure. The choice of the functions used in this report was based on the fact that the mineral buffer, pyrite + pyrrhotite + epidote + prehnite, apparently controls the fixation of the aqueous concentration of the gases  $\text{H}_2\text{S}$  and  $\text{H}_2$ , while the mineral assemblage calcite + quartz + epidote + prehnite is thought to control the  $\text{CO}_2$  concentration. The occurrence of these mineral phases in the Olkaria field (Agonga, 1992) makes it reasonable to assume that the above mineral buffers are active in this reservoir. Furthermore, the concentration of  $\text{H}_2\text{S}$  gas in the Olkaria reservoir water is considered to correspond well with equilibrium with the above mineral assemblage (Arnórsson et al., 1990). From the above, the following equations from Arnórsson and Gunnlaugsson (1985) and D'Amore and Panichi (1980) have been used in the temperature calculations (gas concentrations are in mmol/kg of steam):

$$T_{\text{H}_2\text{S}}(^{\circ}\text{C}) = 246.7 + 44.81 \times m \text{H}_2\text{S} \quad (10)$$

where  $T_{\text{H}_2\text{S}}$  is temperature derived from the  $\text{H}_2\text{S}$  concentration, and  $m\text{H}_2\text{S}$  is the concentration of the gas.

$$T_{\text{CO}_2/\text{H}_2} (^{\circ}\text{C}) = 341.7 - 28.57 \times \log(\text{CO}_2/\text{H}_2) \quad (11)$$

where  $T_{\text{CO}_2/\text{H}_2}$  is the temperature derived from the ratio  $\text{CO}_2/\text{H}_2$ .

$$T_{\text{H}_2} (^{\circ}\text{C}) = 277.2 + 20.99 \times \log m_{\text{H}_2} \quad (12)$$

$$T_{\text{CO}_2} (^{\circ}\text{C}) = -44.1 + 269.25 \log m_{\text{CO}_2} - 76.88 (\log m_{\text{CO}_2})^2 + 9.52 (\log m_{\text{CO}_2})^3 \quad (13)$$

where  $m$  is the concentration of the gas. Finally

$$T_{\text{DP}} (^{\circ}\text{C}) = \frac{24775}{\alpha + \beta + 36.05} - 273.15 \quad (14)$$

where

$$\alpha = 2 \log \frac{\text{CH}_4}{\text{CO}_2} - 6 \log \frac{\text{H}_2}{\text{CO}_2} - 3 \log \frac{\text{H}_2\text{S}}{\text{CO}_2} \quad \text{and} \quad \beta = -7 \log P_{\text{CO}_2}$$

and  $P_{\text{CO}_2} = 0.1$  atm if  $\text{CO}_2$  (% by volume)  $< 75$ ,  
 $P_{\text{CO}_2} = 1.0$  atm if  $\text{CO}_2$  (% by volume)  $> 75$ ,  
 $P_{\text{CO}_2} = 10$  atm if  $\text{CO}_2$  (% by volume)  $< 75$ ,  $\text{CH}_4 > 2 \text{H}_2$  and  $\text{H}_2\text{S} > 2 \text{H}_2$ .  
 $\text{CH}_4$ ,  $\text{H}_2$ ,  $\text{H}_2\text{S}$  and  $\text{CO}_2$  are % by volume of the respective gases in dry gas.

Note that temperature values have been calculated directly from analytical results in mmol/kg of steam and no corrections for condensation have been done. Equation 14 is from D'Amore and Panichi (1980).

The temperatures calculated using these equations compare well with the results for the solute geothermometers and also with the measured downhole temperatures (Table 6). However, the CO<sub>2</sub> geothermometer gives relatively low but consistent temperature values as compared to the others for all wells, except well OW-718 for which a low temperature is recorded (209°C). This calibration probably yields lower values due to removal of CO<sub>2</sub> during upflow. This may result from the deposition of calcite which is a common hydrothermal mineral in this field. On the other hand, the function by D'Amore and Panichi (1980) gives generally erratic values ranging from 212 to 307°C recorded in wells OW-702D and 701, respectively. The low values from this geothermometer may result from the removal of H<sub>2</sub> and H<sub>2</sub>S from the steam during upflow. This may explain the low values observed in wells OW-707 and 702D. Furthermore, this geothermometer assumes a CO<sub>2</sub> source external to the system, which is not always the case as CO<sub>2</sub> may also originate in the reservoir from equilibration with a mineral buffer, in which case it would be considered inaccurate for use in such a system. The relatively good agreement between these gas temperatures and the solute temperatures rules out the presence of a steam zone in this field, except in well OW-716 where the SiO<sub>2</sub> geothermometer gives very low values. In the presence of a steam zone in the reservoir, the gas based geothermometers would be expected to give extremely high values compared to the solute ones due to the partitioning of the gases to the steam phase, making it richer in gas. This would be true if the wells were drawing from the steam zone.

The geothermometry results have been used in this report to infer the location of the major aquifers feeding the wells in this field by comparing the actual measured downhole temperatures of the feed zones with the calculated geothermometry temperatures (Table 7). However, using these results to locate

TABLE 7: Locations of and estimated temperatures for aquifer feed zones in the Olkaria-NE wells

Well no.	Feed zone (m a.s.l.)	Temperature (°C)							
		Measured	Quartz	Chalc.	Na/K	H <sub>2</sub> S	CO <sub>2</sub> /H <sub>2</sub>	CO <sub>2</sub>	H <sub>2</sub>
OW-701	1433-1353	230-240	238.1	224.4	293.4	277	301	261	289
	1107-1053	240-245							
	*1053-853	250-270							
OW-705	1305-1205	240-250	262	249.4	228	292	294	286	291
	*1155-850	260-270							
	below 400	300-320							
OW-706	1298-1148	220-230	267.8	254.9	281.4	278	294	274	288
	1048-948	250							
	748-648	260-270							
	*548-448	280-300							
OW-707	1303-1203	230-240	273.5	260.1	262.3	283	270	276	270
	*803-703	260							
OW-710	1419-1219	200-230	195.2	175.4	286.5	277	281	259	274
	*819-619	260-270							
OW-711	1455-1205	205-220	254.4	241.8	285.7	271	297	248	284
	*755-405	230-270							
OW-713	1336-836	250-260	258.9	246.3	245.6	285	282	277	280
	*486-386	270-280							
OW-714	1306-1056	230-260	270	256.9	270.8	257	290	257	280
	*606-506	270-275							
	250 to -341	280-300							
OW-716	1369-968	240-259	206	187.8	276.3	257	300	257	287
	*269 to -30	270-299							

m a.s.l. = metres above sea level  
-30 = 30 m below sea level

\* = Major feed zone elevation  
Measured = Actual measured temperature



aquifer zones feeding the wells is only straightforward if the well draws from only one aquifer with water of a similar chemical composition, as is indeed the case in most of the wells described here, the exceptions being wells OW-705 and 706 which seem to draw from more than one feed and most probably discharging a mixed water, which is difficult to correlate with calculated temperatures.

### 3.4 Geothermal fluid flow patterns

The chemical composition of the well discharges in the Olkaria-NE field can be used to infer the possible source and flow directions of the reservoir fluids and the processes affecting the migrating fluids. By assuming that the fluid originates in the hottest part of the reservoir, it is possible to use the reservoir temperatures to determine the direction in which the fluid migrates since, by considering heat balance relations, a flow from high to low heat zones will be favoured. Various temperature functions have been used to estimate the reservoir temperature in the field and the results indicate a general cooling trend from the central part around wells OW-707, 715, 701, 703, 727 and 726 to east and northwest. The hydrogen gas geothermometer shows the hottest part around well OW-703, at 294°C. Cooling is gradual to the southeast towards well OW-702D, at 278°C and to the west towards wells OW-708 and 710, within the same temperature range. The temperatures also seem to decline southwards from wells OW-701, 726 and 720 where it is 288°C towards well OW-718 at 278°C. A clearer picture of the temperature distribution in the field is suggested by the quartz geothermometer temperatures (Figure 5) which show the hottest zone to be in the central part encompassing wells OW-703, 715, 707, 706, 726, 701, 719, 721, 709 and 727, with reservoir temperature values fairly constant in the range 267-274°C. A cooling trend is observed from this part to the east and west. This would suggest a general fluid cooling direction from this part of the field to the east where the temperature decreases from 270°C to around 220°C in well OW-724, and to the west in wells OW-708 and 710 to 195°C.

The gas contents of fluids present in areas of high permeability and close to a hot geothermal fluid upflow are expected to be high, especially those of reactive gases like H<sub>2</sub>S. When the fluid travels for long distances there is a tendency for it to be depleted in such gases. On the other hand, a high concentration of N<sub>2</sub> gas in the discharge fluid is a clear indication of admixture with gas originating from atmospheric air which may be taken to imply possible mixing of the geothermal waters with cooler ground water. In terms of solubility of the common geothermal gases in water, the following order prevails: H<sub>2</sub>S > CO<sub>2</sub> > N<sub>2</sub> > H<sub>2</sub>. It is, therefore, clear that in a boiling system, the least water soluble gases are released fastest and the more water soluble ones more slowly. From this argument, close to the upflow the ratio of a less soluble to a more soluble gas should be high and decrease in the direction away from the upflow. From the gas ratios in the well waters in this field, the ratio CO<sub>2</sub>/H<sub>2</sub>S is observed to increase from low values in the central and southern part of the field away to the east and the north (Figure 6). Considering the reactivities of these gases, H<sub>2</sub>S is by far the most reactive. Its concentration may decrease away from the source and would give low ratios to less reactive gases at the source, increasing away from it. From the temperature values it is shown that the field is hottest in the central part, cooling to east and west and if this is taken to be the source of the hot geothermal fluids, then the ratio CO<sub>2</sub>/H<sub>2</sub>S is probably controlled by the relative gas reactivities rather than their solubilities in water. This would, therefore, imply movement of the hot fluids from an upflow in the central part to the east and west. Furthermore, the concentration of H<sub>2</sub>S can also be reduced through possible reactions in the reservoir. It is likely to react with hydrothermal minerals, such as epidote, to precipitate prehnite according to the reaction given in Equation 8. This is supported by the presence of epidote and prehnite at deep levels in the field. Analytical data on some hydrothermal minerals such as pyrite, pyrrhotite and prehnite would help in establishing more confidently the direction of the fluid flow from the upflow by considering their saturation indices which would be expected to act in the opposite direction to the water solubility.

Darling et al. (1995) suggested a mantle source of CO<sub>2</sub> under the Rift Valley which would be expected

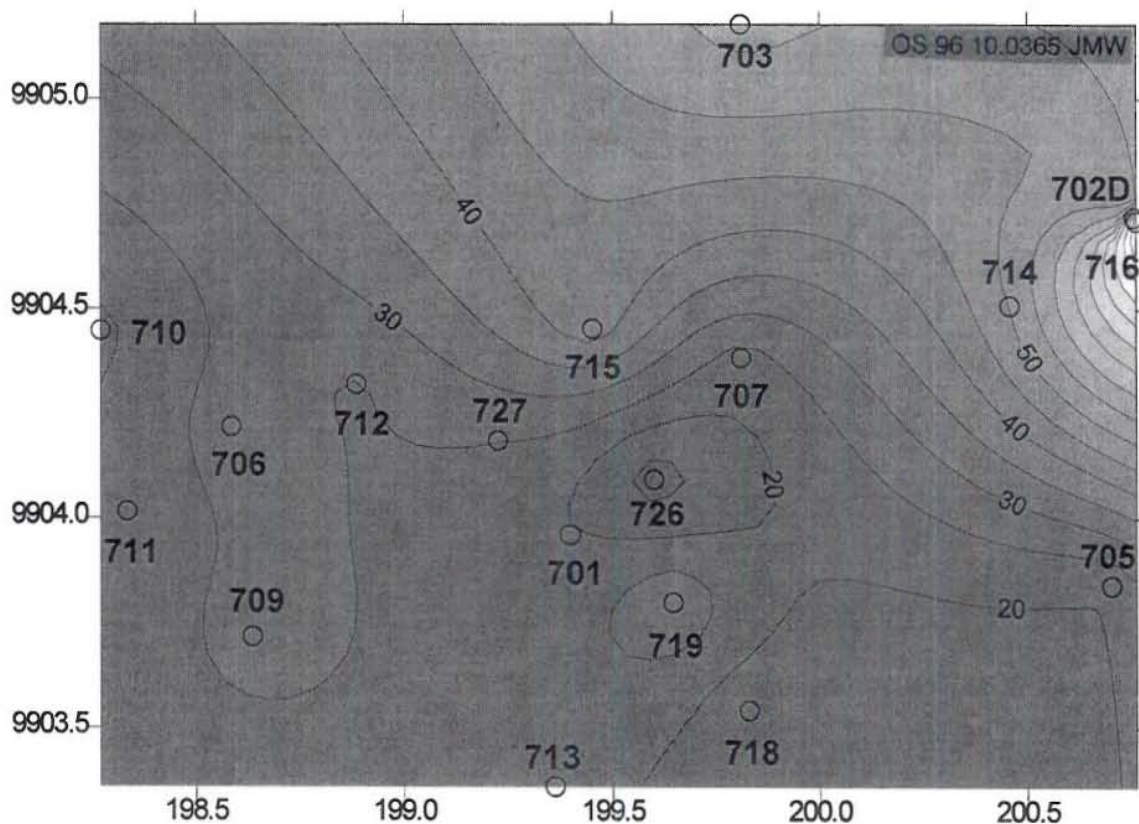


FIGURE 6:  $\text{CO}_2/\text{H}_2\text{S}$  gas ratios in well fluids for the Olkaria-NE field

to enter the geothermal system anywhere. If this is the case, the concentration of  $\text{CO}_2$  would not be expected to decline away from the purported upflow while those of other gases would. This would also imply the ratio  $\text{CO}_2/\text{H}_2\text{S}$  should increase away from the suggested upflow which is indeed the case observed. High ratios of  $\text{CO}_2/\text{N}_2$  would mean proximity to the hot source assuming the  $\text{CO}_2$  to be magmatic. This ratio shows high values in the central part of the field (Figure 7) but tends to decrease to the northwest, northeast and southwest. This means that the gas in the central part of the field is most likely to be representative of upflow waters. The decrease in this ratio is an indication that there may be cooler ground water coming into contact with the hot geothermal fluids from these directions. Hot fluids could be discharged from the central part of the field and flow laterally to the west, east and north and, as they migrate, encounter cooler waters which have been in contact with the atmosphere (e.g. possibly well OW-708 whose fluid has a relatively high concentration of  $\text{N}_2$  gas).

The chloride concentration of the fluid is highest in the north and east central parts of the field (Figure 8). There is some relationship between Cl concentration and enthalpy, e.g. the lowest concentrations are found in the highest enthalpy fluids. Very high enthalpies are expected at low permeability where pressure decrease has caused steam to separate from the water phase and leave the latter behind, lending the fluid excess enthalpy. As there is no chloride carried by the steam, the total chloride concentration will be low in such fluid and not significant when compared with Cl concentration of undisturbed fluid. Thus, the Cl concentration value for fluid from well OW-716 was left out when Figure 8 was constructed. The lowest chloride values are observed to the east, probably revealing mixing with a cooler less saline inflow, and to the south probably due to high enthalpy. The Cl results are compatible with a hot upflow from the north to the centre of the field.

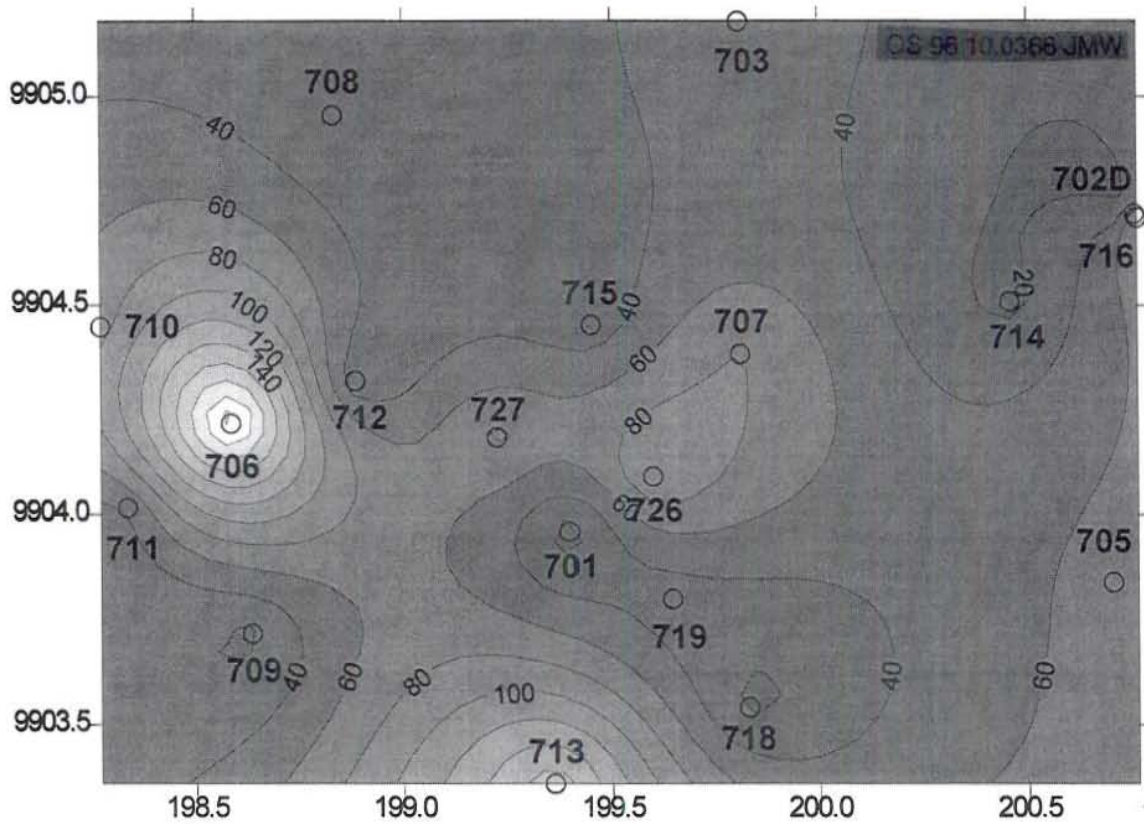


FIGURE 7: CO<sub>2</sub>/N<sub>2</sub> gas ratios in well fluids for the Olkaria-NE field

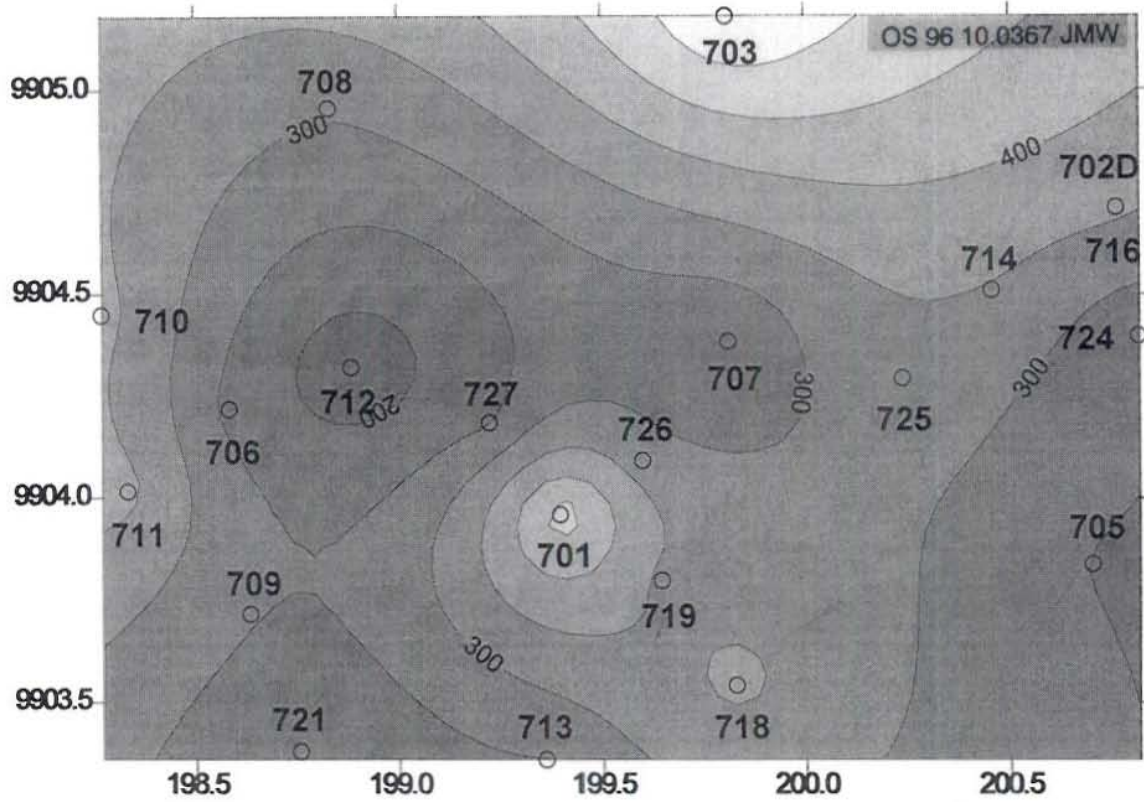


FIGURE 8: Chloride concentration in the well fluids for the Olkaria-NE field

### 3.5 Excess enthalpy discharges

When a well discharges steam with an enthalpy value higher than the saturation liquid enthalpy, its fluid is considered to have excess enthalpy. The saturation liquid enthalpy is normally calculated from the reservoir temperature which may be measured or calculated from geothermometer results. From the Olkaria-NE field, the measured enthalpy values of the well discharges range from 1100 to 1900 kJ/kg (Table 2), except for a few cases where elevated enthalpy values are observed. The relatively low values can be said to represent saturation liquid enthalpy. The discharge enthalpy of wells in the Olkaria-East field are relatively high, 2000-2600 kJ/kg (Muna, 1982). The wells are located just a few hundred metres from the field presently under consideration. An increase in enthalpy (steam:water ratio) is caused mainly by the separation (or partial separation) of the flowing water and steam due to their different flowing properties after boiling in the formation. Such values may also be the result of enhanced evaporation of the flowing water by heat from the rock. The enthalpies of the fluids from the Olkaria-East wells OW-712, 721, 709, 706 and 716 are elevated with values 2036, 1706, 1954, 1851 and 2645 kJ/kg, respectively. There is no corresponding Cl concentration decrease in these wells as would be expected if the elevation in discharge enthalpy is caused by relative permeability, and the solute deficient steam would be discharged into the well preferentially. For wells OW-712, 721, 709, 706 and 716, the elevated enthalpies may be explained by heat transfer from the rock to the flowing fluid, caused by progressive evaporation of the aquifer water. A drop in pressure will cause boiling to occur in the feeding aquifer, causing cooling of the migrating fluid which, in turn, causes thermal disequilibrium between the fluid and the rock. This will lead to heat flow from the hotter rock body towards the cooler fluid and enhanced evaporation of the water, which is expected to cause an increase in the solute concentration of the water phase, as observed in these wells. The excess steam thus formed is responsible for the high discharge enthalpy values.

If the excess steam from the wells is contained within the reservoir, e.g. by tight cap-rocks, then steam zones develop in the upper parts of the reservoir, as is believed to be the case in the Olkaria-East production field. However, there is no evidence at all to suggest the presence of a steam zone in this field as is shown by the stable pressure logs (Ouma, 1992). For a vapour zone to be inferred, the pressure profile should be constant in the wellbore below the casing level. Instead the water level is inferred from the production casing shoe downhole. In the Olkaria-East field most of the wells have feed zones at relatively shallow depths, located in the steam zone (700-1000 m deep, Muna, 1982), while the wells in the Olkaria-NE field are mainly fed by relatively deep aquifers located below 1300 m depth (Table 7) and are mainly water dominated. The presence of a steam zone in the Olkaria-East field in this context is further supported by the fact that saturation liquid enthalpy was observed for most well fluids when first discharged but the enthalpy rose to over 2000 kJ/kg during the first month of discharge. This has been explained to be due to extensive boiling in aquifers around the discharging wells (Arnórsson et al., 1990). This boiling process, which is responsible for the elevated enthalpies, may explain the low solid content of Olkaria-East waters compared to the relatively more concentrated waters in Olkaria-NE. Furthermore, the wells in Olkaria-NE have been discharged for varying periods of time ranging from a few months to about two years, and most of them still produce at saturation liquid enthalpies. It can, therefore, be said that the Olkaria-NE field produces fluid of relatively high salinity (Cl = 350-500 ppm) of deep reservoir composition, and which boils and condenses as it migrates southwards to grade into less saline fluids (Cl = 100-200 ppm) tapped from the Olkaria-East production field (note that Cl values represent the reservoir total composition).

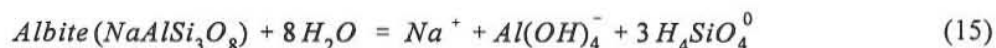
### 3.6 Fluid-mineral equilibria

In geothermal systems the chemical reactions (water-rock) involve dissolution of the primary rock minerals and subsequent precipitation of secondary (hydrothermal) minerals. It is believed that the

primary minerals, at least in the igneous rocks which are predominant in most high temperature fields Olkaria included, are more soluble than the alteration minerals, and that the water attains saturation with these alteration minerals while still undersaturated with the primary minerals. Thus, the water continues to dissolve the primary minerals as it keeps on precipitating the secondary ones. The secondary minerals are formed by the rock-forming components (refer to Chapter 3.1) while the conservative components stay in solution once there. When supersaturation is reached for a particular mineral, it tends to precipitate from the solution.

The study of fluid-mineral equilibria is a very useful tool in that it provides practical applications for the assessment of equilibrium/disequilibrium conditions for geothermal fluids, on which almost all the reservoir processes depend. Such applications are useful in the quantitative explanation of the water composition, in the assessment of cooling and boiling processes, as well as in the prediction of scaling and corrosion tendencies in a particular geothermal system. In addition, the fluid-mineral equilibria play a very important role in geothermometry calculations, which are universally based on the assumption of equilibrium between hydrothermal minerals occurring in a particular system and the geothermal fluid (liquid and gas). For a valid and accurate use of geothermometers for subsurface temperature estimation, the equilibrium assumption should be verified. To verify the attainment of this equilibrium between the alteration minerals and the sampled fluids (water or gas), equilibrium calculations from the chemical analysis of both water and gas samples are performed to determine the saturation indices for particular minerals at different temperatures. This is a sure way of assessing the extent of supersaturation.

Here, the computer program WATCH (Arnórsson et al. 1982, Bjarnason 1994) has been used to calculate the saturation indices (SI) for particular mineral phases believed to occur in the reservoir of the Olkaria-NE field. It calculates the aqueous speciation of the various components at several predetermined temperature values for each mineral to obtain a log  $Q/K$  versus temperature relationship (Reed and Spycher, 1984) for each mineral. This was done for minerals in wells OW-703 and 708 (Figures 9 and 10).  $Q$  and  $K$  are the reaction quotient and the equilibrium constant (in this case the solubility product), respectively, derived from dissolution reactions of the type



By assuming a pure form of albite and a very dilute aqueous solution, the activities of  $\text{NaAlSi}_3\text{O}_8$  and  $\text{H}_2\text{O}$  can be taken to be unity, then

$$a_{\text{Na}^+} \times a_{\text{Al(OH)}_4^-} \times (a_{\text{H}_4\text{SiO}_4^0})^3 = Q_{\text{albite}} \quad (16)$$

where

- $a$  = Activity of the species =  $m \times \gamma$ ;
- $m$  = Species concentration from the water analytical results;
- $\gamma$  = Activity coefficient, calculated by the WATCH program.

Thus, in practical applications,  $Q$  is obtained from analytical data, while  $K$  is the solubility constant for albite according to the equation above and is derived from chemical thermodynamic data.

- When  $Q = K$  there is equilibrium which denotes the saturation state;
- $Q > K$  there is a state of supersaturation with the respective mineral phase;
- $Q < K$  there is a state of undersaturation.

The WATCH program has been used here to compute the respective activities to obtain a value for  $Q$

while  $K$  is from the thermodynamic database also included in the program. To achieve this goal, the reservoir water is made to cool conductively from a predetermined temperature value (where the reservoir temperatures have been used) in successive temperature steps. The output from the computer program is in the form of  $\log Q$  and  $\log K$  from which  $\log Q/K$ , which is the saturation index (SI) of a particular mineral, can be computed. This ratio is different for different temperature values and based on this equilibrium curves are constructed from the data obtained. By allowing for conductive cooling of the water in the reservoir, the assumption is made that a single-phase fluid exists in the reservoir.

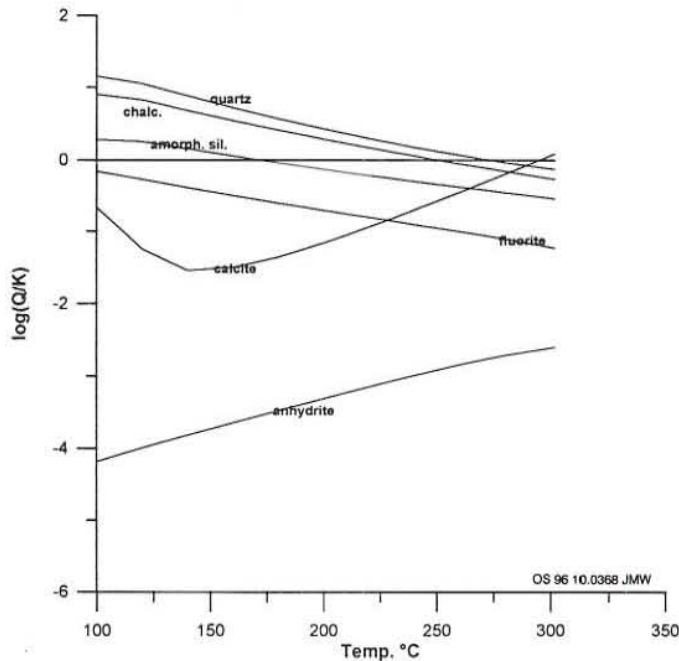


FIGURE 9: Equilibrium curves for various alteration minerals in water from well OW-703

In these equilibrium curves of  $\log Q/K$  versus temperature, a convergence to a zero value implies equilibrium and this equilibrium temperature is characteristic for each mineral assemblage. The more equilibrium curves that converge at a certain temperature value, the more definite a value is obtained for the equilibrium temperature (Tole et al, 1993). The Olkaria-NE data is represented here by analyses of samples from wells OW-703 and 708 as most of the wells do not have enough data on chemical constituents, such as Mg, Ca, Fe and Al. Figure 9 shows how equilibrium conditions for various alteration minerals in well OW-703 correspond to the reservoir temperatures. The diagram shows that quartz has an equilibrium temperature of about 275°C, which corresponds quite well to the calculated geothermometry temperatures for this well

(274°C for the quartz geothermometer and 300°C for the Na/K geothermometer). The  $\text{CO}_2/\text{H}_2$  and the  $\text{H}_2$  gas geothermometers give 326°C and 296°C, respectively, for this well (Table 6). The diagram also shows that the amorphous silica saturation temperature for the waters from this well is about 170°C and it is clear that below this temperature, precipitation of silica (if it is controlled by amorphous silica saturation) may be inevitable. To avoid this, the water must be maintained at temperatures higher than 170°C. The fluid seems to be supersaturated with respect to calcite from temperatures of about 290°C, and supersaturation increases with increasing temperatures as is expected since calcite solubility is negatively related to temperature. Fluorite and anhydrite are undersaturated in these waters and they do not seem to be a problem as regards scale formation although fluorite seems to be approaching equilibrium with decreasing temperature. At lower temperatures, the fluid is supersaturated with the silica minerals (chalcedony and quartz) and equilibrium is approached with increasing temperatures. Again this is as expected because the silica solubility is positively related to temperature.

For well OW-708, the quartz curve indicates an equilibrium temperature of about 200°C (Figure 10) which is quite low but compares reasonably with the  $\text{SiO}_2$  geothermometer temperature (202°C for quartz and 246°C for the Na/K geothermometer). The solution seems to be undersaturated with respect to amorphous silica even at very low temperatures, and heavily undersaturated with respect to anhydrite and fluorite. This means that these minerals are likely to remain in solution. Mixing by dilution is expected to lower the amorphous silica saturation temperature. Calcite becomes saturated at high temperatures, probably in excess of 300°C. The trend observed for the equilibrium curves for well OW-708 fluid can be explained in various ways. A probable explanation is that it could be a result of mixing

of the geothermal water with solutions of different chemical compositions which would have the effect of disturbing the equilibrium. If the waters thought to be mixing with the geothermal fluid are very dilute, then the positions at which the minerals are apparently at equilibrium should shift to lower  $\log Q/K$  values. This seems to be the case for the fluid in well OW-708 where the curves intersect below the equilibrium line, but not for well OW-703 waters in which equilibrium is reached for some minerals at higher temperatures. From the above, it is safe to conclude that there is a possibility of cooler and more dilute water entering the field from the direction of well OW-708. This confirms the suggestions inferred from other approaches like reservoir temperature distribution and reactive gas concentrations.

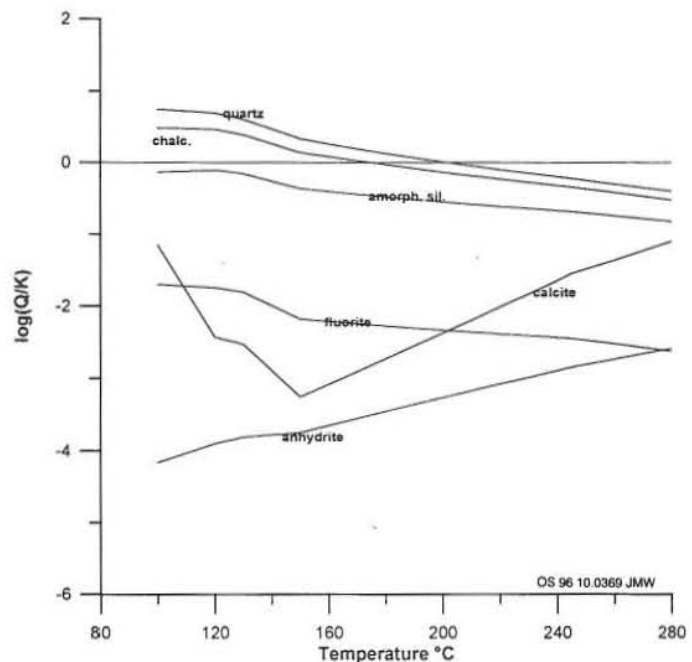


FIGURE 10: Equilibrium curves for various alteration minerals in water from well OW-708

However, it should be noted here that lack of analytical data for some important components makes a reasonable qualitative interpretation difficult. The lack of Al data for example made it impossible to confirm the equilibrium temperatures as depicted by the Na/K ratio geothermometer, which has albite and K-feldspar as the basis, as these are Al silicate minerals. Furthermore, it is important to note that the expression for  $Q$  in the above calculations ignores the formation of solid solutions, assuming pure solids instead, which is not always the case in reality.

### 3.7 Scaling tendencies

Fluid-mineral equilibria can be very useful in assessing the cooling and/or boiling conditions in a given reservoir as well as predicting the tendencies for a particular mineral phase to precipitate. Scale formation has been of grave concern in geothermal resource development and utilization as scales interfere with the production capacities of wells by clogging the boreholes and, in other cases, the pipes. This drastically reduces the amount of steam reaching the turbines thereby reducing the overall output or even shutting it out completely. The best known scale forming minerals in most geothermal fields in the world are calcite and silicate though other types of scale have been reported in some fields. Iron silicate and oxide, and sulphide scales have been reported from Djibouti and Salton Sea high-temperature brines and iron sulphide scales along with iron silicate and oxide scales from the magmatically affected Krafla fluids in Iceland (Ármannsson, 1996) while magnesium silicate scales have been reported in Iceland, too (Kristmannsdóttir et al., 1989). Here attention will be on calcite and silica deposition which is considered to be of importance for the Olkaria-NE field.

Again the WATCH computer programme has been used to calculate the saturation indices (SI) for calcite at varying temperatures to assess supersaturation in these fluids. This is achieved by allowing the reservoir water to boil adiabatically from a predetermined reservoir temperature which was chosen on the basis of the actual temperatures believed to prevail in the reservoir. The water is boiled in steps to the desired temperatures and SI ( $\log Q/K$ ) values for the particular minerals at different temperatures are obtained.

Calcite scaling is largely confined to wet steam wells, especially when the first level of boiling occurs in the well. Deposition begins at this level where it is expected to be most intense. Geothermal waters are always close to calcite saturation and a decrease in the gas partial pressure leads to supersaturation and subsequent precipitation. Calcite deposition is mainly controlled by the partial pressure of  $\text{CO}_2$  and this depends on temperature and pH as elevated temperatures will cause degassing of the water. This in turn raises the water pH, resulting in calcite deposition according to the equation

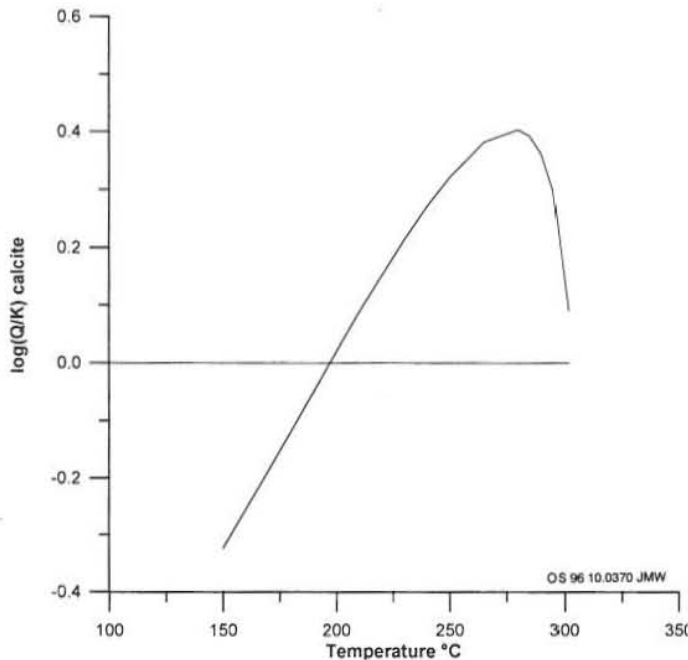
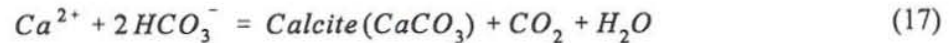


FIGURE 11: Saturation diagram for calcite in water from well OW-703 in the Olkaria-NE field

A saturation diagram for well OW-703 in the Olkaria-NE field has been used to predict the trend of calcite solubility and deposition (Figure 11). The well fluid is saturated with respect to calcite at about 200°C and above this temperature there is supersaturation which increases with temperature as is expected (Figure 11). This means that as the hot reservoir fluid cools below this temperature, calcite scale formation is not expected since the calcite will be maintained in solution. From the diagram, the solubility of calcite can be explained by a possible trend where the rate of supersaturation is seen to increase sharply as the reservoir fluids cool to temperatures of about 300°C, and reaches maximum at temperatures of about 275°C after which it is observed to decrease drastically to levels of

undersaturation below temperatures of about 200°C. The sharp rise in supersaturation may be caused by an onset of boiling either in the well itself or in the feeding aquifer which has the effect of degassing the fluids, thereby causing a rise in the water pH. Further boiling would cause more cooling and increase in calcite solubility from a supersaturation peak at 275°C towards saturation at temperatures of about 200°C, and further to undersaturation below this temperature. This supersaturation peak is taken to represent the first level of boiling. It would imply that effective boiling in this well takes place in the feeding aquifer at a temperature value of 300°C. In such a case, calcite deposition will be expected to occur in the formation and there would be no scaling problem in the wellbore. The cross-sectional area of pores in geothermal reservoirs is expected to be much greater than that of the wellbore itself even at short distances from the well and they can, therefore, cope with calcite deposition much longer without observable deterioration in permeability. On the other hand, quartz supersaturation is believed to be sluggish and silica is only removed from a solution at an appreciable rate if it becomes supersaturated with amorphous silica. In conclusion, it would seem safe to suggest that in this field silica deposition will only be a problem confined to the waste water discharged.



### 3.8 Conceptual model

From the discussion presented here, a reservoir model of Olkaria-NE field can be conceived based on the geochemical evidence. A deep NaCl type of water exists in the reservoir with chloride concentration of 300-550 ppm and temperatures of 270-290°C. This deep water flows up from the northern and central parts of the field around wells OW-703, 707 and 726 and laterally southwards under a tight caprock through hot reservoir rocks to build high enthalpies in the Olkaria-East production field, probably due to reduced permeability. It may also mix with locally heated ground water to form a relatively dilute fluid tapped at Olkaria-East. Cold recharge comes from the east and north-west and a part of the recharge is from nearby Lake Naivasha water which enters the field from northwest. However, it is difficult to come up with a comprehensive reservoir model from the geochemistry evidence alone. Results from other geoscientific disciplines are required to map the exact directions of the fluid flow and to differentiate between vapour and liquid phases. This may be achieved by pressure logging. Knowledge of the downhole geological stratigraphy of the field is necessary to place the different rock units and their locations in the reservoir model including the locations and nature of the cap rock. On the other hand, the chemistry of the fluids will give information on the nature and movement of the reservoir fluid, the reservoir temperatures and the location of major feed aquifers as well as the recharge or discharge zones, as has been shown here. The results of all the properties that affect origin and flow and have been studied are combined in a model of inflow, upflow and outflow in Figure 12.

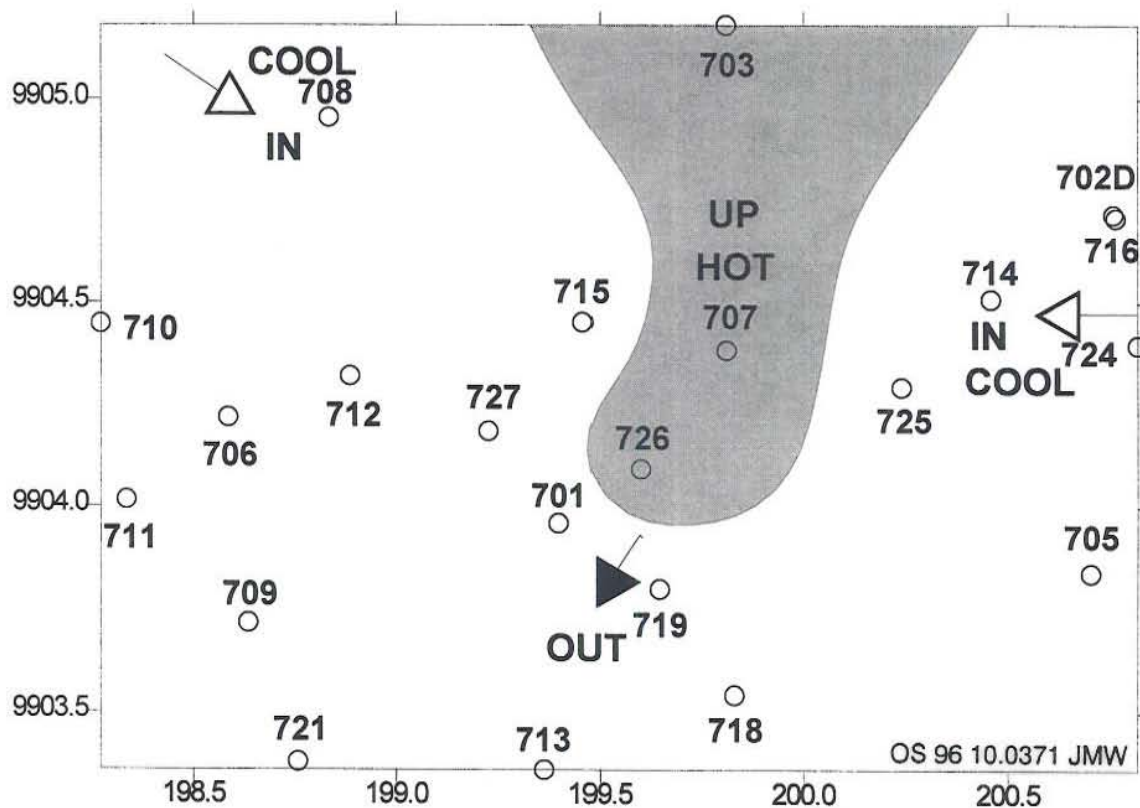


FIGURE 12: A reservoir model for the Olkaria-NE field, showing upflow and outflow of hot, deep reservoir water and inflow of cold recharge

#### 4. CONCLUSIONS AND RECOMMENDATIONS

From the discussion presented above, the following conclusions can be drawn. In addition, a few recommendations are made for future geochemical work in the Olkaria-NE field.

1. A hot NaCl type water reservoir exists with temperatures of 270-290°C at depth. Major feeding aquifers are located below 1300 m depth with a relatively saline fluid (Cl = 300-550 ppm). The main hot water upflow is located in the northern and central parts of the field. From there the hot fluid flows laterally southwards to be tapped by the current production field. This means the two fields, Olkaria-NE and Olkaria-East are connected, or comprise one and the same system. The eastern margin of the field is marked by well OW-724 while the northwestern margin is probably close to wells OW-708 and 710.
2. The main recharge to the system is from the northwest, including Lake Naivasha water from about 3 km to the north of the field, with a further recharge contribution from the eastern part of the field which may originate in the rift flank.
3. There is no chemical evidence to suggest the presence of a steam zone in Olkaria-NE and if it exists it must be confined to the uppermost parts of the reservoir (< 700 m depth) where it has been cased off. Most of the wells produce saturated liquid-enthalpy discharges and they are considered to draw from a single-phase reservoir.
4. There is no silica mineral scaling problem expected during production. The only silica deposition would be expected to occur at low temperatures, most likely at atmospheric conditions. This is mainly an environmental concern. However, upon re-injection which is planned, during production from the field, it would be advisable to re-inject the hot water at temperatures in excess of 170°C, the amorphous silica saturation temperature observed for the fluid from well OW-703. The calcite solubility is limited to temperatures of about 200°C and below. The well temperatures are higher than that and calcite supersaturation is substantial. Thus, calcite deposition could be a problem for wellhead pressures below 8 bar-a or temperatures below 170°C.

The following recommendations are made:

1. The fluid sampling methods should be improved, especially for the hot water well samples where the separated water is currently sampled from the well weirbox at atmospheric conditions. This is a problem for silica analysis since at atmospheric pressure silica polymerization may set in. The water residence time and the evaporation rate will also affect polymerization and deposition, and then the analytical results for silica. It would be most convenient to collect both the water and steam samples at the same pressure using the separator, as is currently being done in gas sampling. This should be done at pressures as close as possible to the wellhead pressures.
2. Interpretation and integration of all the available isotope data from this field and nearby fields is recommended for accurate determination of the origin of the geothermal fluids.
3. The chemical analysis should be extended to include Fe and Al which are important constituents of many hydrothermal minerals. Also, methods should be sought to determine low level concentrations of constituents which may be below the detection limit of the conventional methods of analysis, like Ca and Mg. The use of an atomic absorption spectrophotometer equipped with a carbon furnace for trace element analysis would be very useful for constituents occurring at levels which may be below the detection limit for the flame absorption method. An

alternative method would be to use an ICP or an ion chromatograph which will require extra metal columns to be installed. The ICP would be good for multi-element analysis, but a flameless AAS method is superior for determination of low concentrations. However, it is still possible to use the flame absorption method to determine concentrations as low as 0.01 ppm with carefully prepared calibrations and high grade standards for the metallic element analysis although Mg determinations need lower limits (0.001 ppm). On the other hand, the use of an ICP requires great care with calibration especially for Al analysis. For better results in determining elements occurring in low concentrations in geothermal waters such as Fe and Al, the flameless AAS method is recommended.

4. More sampling of water from Lake Naivasha and neighbouring boreholes is necessary, probably from different points and at different times of the year to be able to assess the actual relationship of this water and the geothermal fluids being exploited at Olkaria.
5. More work is recommended in this field and indeed in the entire greater Olkaria area on fluid-mineral equilibria to be able to assess quantitatively the reservoir processes in these fields. This will have a direct bearing on mixing and/or dilution processes, boiling, geothermometry and mineral deposition tendencies.

#### ACKNOWLEDGEMENTS

The Government of Iceland and the United Nations University are greatly acknowledged for availing me the opportunity to attend this very useful course. Special thanks go to the geochemistry staff of Orkustofnun, in particular Dr. Halldór Ármannsson, my adviser, for his tireless efforts and willingness to share his professional experience, for reading the manuscript of this report, and for his professional input. Dr. Jón Örn Bjarnason is thanked for his advice on the use of the geochemistry computer programs, and Kristján Hrafn Sigurdsson for his guidance in chemical analysis and instrumentation. Professor Stefán Arnórsson of the University of Iceland is acknowledged for his professional advice and lectures. The staff of the UNU Geothermal Training Programme (Dr. Ingvar Birgir Fridleifsson, Lúdvík S. Georgsson and Gudrún Bjarnadóttir) and the entire staff of Orkustofnun - the National Energy Authority of Iceland are thanked for their wonderful contributions in various ways. Finally, I wish to acknowledge the opportunity extended to me by the management of the Kenya Power and Lighting Company to attend this course and granting me leave of absence for the six months stay in Iceland, not forgetting my fellow colleagues who made the stay in Iceland enjoyable.

#### REFERENCES

- Agonga, O., 1992: *Geothermal geology: Stratigraphy and hydrothermal alteration of well OW-716, Olkaria geothermal area, Kenya*. UNU G.T.P., Iceland, report 10, 44 pp.
- Allen, D.J., and Darling, W.G., 1987: *Kenya Rift Valley geothermal project: Interpretation of fluid sample analyses from Magadi-Silali area*. British Geological Survey, Wallingford, U.K., 26 pp.
- Ármannsson, H., 1996: *Fluid chemistry and utilisation*. UNU G.T.P., Iceland, unpublished lectures from the specialized lecture course.
- Arnórsson, S., 1990: Gas chemistry of geothermal systems. In: Durrance, E.M., Gaimov, E.M., Hinkle,

- M.E., Reimer, E.M., Sugisaki, R., and Augustithis, S.S. (editors), *Geochemistry of gaseous elements and compounds*. Theophrastus publications, S.A., Athens, 187-222.
- Arnórsson, S., Andréðóttir, A., and Sveinbjörnsdóttir, Á.E., 1993: The distribution of Cl, B,  $\delta D$  and  $\delta^{18}O$  in natural waters in the Southern Lowlands in Iceland. *Geofluids '93, Extended Abstracts*, 313-318.
- Arnórsson S., Björnsson, S., Muna, Z.W., and Bwire-Ojiambo, S., 1990: The use of gas chemistry to evaluate boiling processes and initial steam fractions in geothermal reservoirs with examples from the Olkaria field, Kenya. *Geothermics*, 19, 497-514.
- Arnórsson, S., and Gunnlaugsson, E. 1985: New gas geothermometers for geothermal exploration-calibration and application. *Geochim. Cosmochim. Acta*, 49, 1307-1325.
- Arnórsson, S., Gunnlaugsson, E., and Svavarsson, H., 1983: The chemistry of geothermal waters in Iceland III. Chemical geothermometry in geothermal investigations. *Geochim. Cosmochim. Acta*, 47, 567-577.
- Arnórsson, S., Sigurdsson, S., and Svavarsson, H. 1982: The chemistry of geothermal waters in Iceland I. Calculation of aqueous speciation from 0°C to 370°C. *Geochim. Cosmochim. Acta*, 46, 1513-1532.
- Arusei, M.K., 1991: *Hydrochemistry of Olkaria and Eburru geothermal fields, Kenyan Rift Valley*. UNU G.T.P., Iceland, report 2, 40 pp.
- Bjarnason, J.Ö., 1994: *The speciation program WATCH, version 2.1*. Orkustofnun, Reykjavík, 7pp.
- Clarke, M.C.G., Woodhall, D.G., Allen, D., and Darling G., 1990: *Geological, volcanological and hydrogeological controls on the occurrence of geothermal activity in the area surrounding Lake Naivasha, Kenya, with coloured 1:100 000 geological maps*. Ministry of Energy, Nairobi, 138 pp.
- D'Amore, F., and Panichi, C., 1980: Evaluation of deep temperatures in geothermal systems by a new gas geothermometer. *Geochim. Cosmochim. Acta*, 44, 549-556.
- Darling, W.G., Allen, D.J., and Ármannsson, H., 1990: Indirect detection of outflow from a Rift Valley lake. *J. Hydrol.*, 113, 297-305.
- Darling, W.G., Griesshaber, E., Andrews, J.N., Ármannsson, H., and O'Nions, R.K., 1995: The origin of hydrothermal and other gases in the Kenyan Rift Valley. *Geochim. Cosmochim. Acta*, 59, 2501-2512.
- Fournier, R.O., 1977: Chemical geothermometers and mixing models for geothermal systems. *Geothermics*, 5, 41-50.
- Fournier, R.O., and Potter, R.W. II, 1982: A revised and expanded silica (quartz) geothermometer. *Geoth. Res. Council Bull.*, 11-10, 3-12.
- Giggenbach, W.F., 1980: Geothermal gas equilibria. *Geochim. Cosmochim. Acta*, 44, 2021-2032.
- Giggenbach, W.F., 1988: Geothermal solute equilibria. Derivation of Na-K-Mg-Ca geothermometers. *Geochim. Cosmochim. Acta*, 52, 2749-2765.
- Giggenbach, W.F., 1991: Chemical techniques in geothermal exploration. In: D'Amore, F. (Coordinator), *Application of geochemistry in geothermal reservoir development*. UNITAR/UNDP

publication, Rome, 119-142.

Healy, J., 1972: *Report on technical review meeting, December 1972*. U.N. Geothermal Exploration Project, report.

James, R., 1962: Steam-water critical flow through pipes. *Inst. Mech. Engrs. Proc.*, 176, 741-745.

KPC, 1986: Scientific review and well siting. In: *Scientific and technical review meeting. Future geothermal development, Olkaria*. KPC, GENZL, Acres International, Virkir.

Kristmannsdóttir, H., Ólafsson, M., and Thórhallsson, S., 1989: Magnesium silicate scaling in district heating systems in Iceland, *Geothermics*, 18, 191-198.

Muna, Z.W., 1982: *Chemistry of well discharges in the Olkaria geothermal field, Kenya*. UNU G.T.P., Iceland, report 8, 38 pp.

Muna, Z.W. 1988: *An overview of the geochemistry of Olkaria north-east field*. KPC, Kenya, report.

Nehring, N.L., and D'Amore, F., 1984: Gas chemistry and thermometry of the Cerro Prieto, Mexico, geothermal field. *Geothermics*, 13, 75-89.

Odongo, M.E.O., and Muchemi, G.G., 1985: *Petrography and stratigraphy correlation of the Olkaria Field*. Kenya Power Company Ltd., Olkaria Geothermal Project, report GL/OW/021.

Ouma, P.A., 1992: *Steam gathering system for the NE-Olkaria geothermal field, Kenya - preliminary design*. UNU G.T.P., Iceland, report 9, 47 pp.

Reed, M.H., and Spycher, N.F., 1984: Calculation of pH and mineral equilibria in hydrothermal water with application to geothermometry and studies of boiling and dilution. *Geochim. Cosmochim. Acta*, 48, 1479-1490.

Shigeno, H., and Abe, K., 1983: B-Cl geochemistry applied to geothermal fluids in Japan, especially as an indicator for deep-rooted hydrothermal systems. *Extended Abstracts of the 4<sup>th</sup> International Symposium on Water-Rock Interaction, Misasa, Japan*, 437-440.

Sveinbjörnsdóttir, Á.E., 1988: *The Kenya Power Company Limited. Results of stable isotope measurements on samples from the Olkaria and Eburru geothermal fields, Kenya*. Science Institute, University of Iceland, Reykjavík, 6 pp.

Tole, M.P., Ármannsson, H., Pang Z.-H., and Arnórsson, S., 1993: Fluid/mineral equilibrium calculations for geothermal fluids and chemical geothermometry. *Geothermics*, 22, 17-37.