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EVALUATION OF RECENT TEMPERATURE AND PRESSURE DATA FROM WELLS IN TENDAHO GEOTHERMAL FIELD, ETHIOPIA AND FROM WELL HG-1 AT HÁGÖNGUR, ICELAND

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ABSTRACT

The Tendaho geothermal field is a geothermal prospect area in N-Ethiopia, which has both shallow and deep wells. Detailed analysis of downhole temperature data from the wells shows that the hottest part of the well field is in the vicinity of well TD5. The reservoir pressure is also at maximum in the same area suggesting an upflow zone near well TD5. Data from short term production tests of wells TD5 and TD6 were analysed. The results of well TD5 discharge indicate an average thermal output of 24.5 MWt at 18 bar-g wellhead pressure. This suggests that TD5 is capable of producing 2.4 MW of electricity. Generally, the wellhead pressures are stable at well shut-in conditions except for wells TD5 and TD6. TD5 showed rising wellhead pressure in 2002 and 2003.

Hágöngur is a geothermal area located in Central Iceland. Surface exploration started in 1995 with a reconnaissance geological survey and mapping of the geothermal manifestations because of plans to construct a hydro dam in the area. The studies suggested the presence of a central volcano, and a semi-circular alignment of rhyolitic domes implies the possibility of an underlying caldera. A transient electromagnetic (TEM) resistivity survey indicates a subsurface high-temperature geothermal anomaly in an area covering 20-40 km^2. Sampling and analyses of gas and fluid from geothermal manifestations indicated subsurface temperatures up to 290°C. The first well, HG-1, was drilled to 2360 m depth in 2003 in the central part of the anomaly. The observed bottom hole temperature is over 310°C.

1. INTRODUCTION

This report deals with two geothermal areas. Well data from the Tendaho geothermal field in Ethiopia are described in Section 2, but in Section 3 the focus is on the first exploration well in the Hágöngur geothermal field in Iceland. In the Tendaho geothermal field (Figure 1), detailed geological, geochemical and geophysical investigations have been carried out. Three shallow and three deep exploration wells have been drilled to a maximum depth of about 2200 m giving maximum temperature of 260°C. The Hágöngur geothermal field is a large geothermal field in Central Iceland classified as a high-temperature area. The first deep exploration well (HG-1, 2360 m) was drilled in 2003 and subsurface temperatures up to 310°C were found.

The report presents an evaluation of temperature and pressure data together with data processing and interpretation from the wells in Tendaho and the well in Hágöngur. Results from geological mapping and drilling of the exploration wells are used to establish a conceptual model of the high-temperature systems.

2. TENDAHO GEOTHERMAL FIELD

Geothermal exploration began in Ethiopia in 1969 with a regional geological-volcanological mapping and hydrothermal manifestation inventory in most of the Ethiopian Rift. The source of the thermal anomalies (Figure 1) is locally represented by magmas injected along the sub-vertical fractures of tectonically active zones. Rifting in Afar (Figure 1) began during lower Miocene on a continental arch where basaltic activity was present (Aquater, 1979). The second stage is characterized by the deposition of a large volume of acid lavas with subordinate basaltic and intermediate lavas. In the third stage emplacement of the basaltic Dalha series took place. The Afar depression is believed to have reached its present geological setting during the Pleistocene period. Most recent basalts, the Afar stratoid series, are tectonically characterized by open fissures and active normal faults, which define a pattern of NW-SE elongated blocks (Gresta et al., 1997). At Tendaho downhole temperature and pressure measurements, discharge tests and monitoring of the wells as well as a feasibility study have been done. The current study indicates that four production wells (out of six) could supply enough steam to operate a pilot power plant of about 5 MWe. The total potential of the explored area has been estimated to be about 20 MWe.

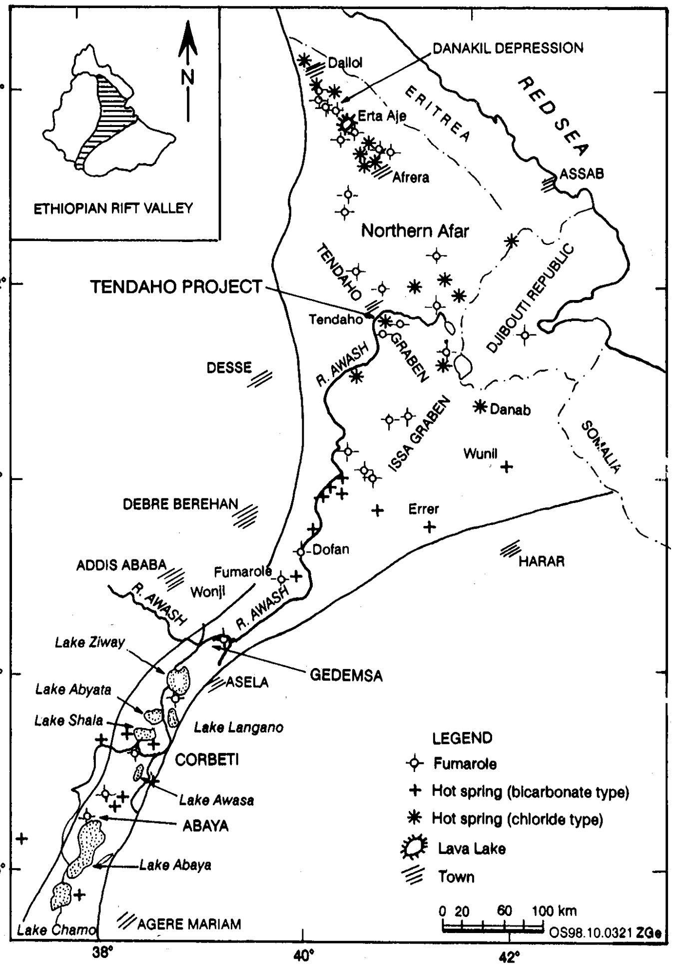

FIGURE 1: Location of the geothermal prospect areas in Ethiopia (modified from Gebregziabher, 1998)

2.1 General information about Ethiopian geothermal fields

With a technical cooperation agreement between the Ethiopian and Italian governments the first phase of exploration drilling at Tendaho was carried out from October 1993 to May 1995. Three deep exploration wells (maximum depth 2200 m) and one shallow exploration well (466 m) were completed. These wells proved the existence of a shallow reservoir (TD4, 466 m) and a promising deep reservoir (TD2, 1881 m). The proven productivity of shallow well TD4 induced the second phase of the drilling activity. Two additional shallow wells (TD5 and TD6) were drilled from December 1997 to February 1998 with the support from the Government of Ethiopia. General information on the Tendaho geothermal wells is shown in Table 1.

TABLE 1: General information for the Tendaho geothermal wells

Well no.	Drilling		Location (UTM)		Elevation (m a.s.l.)	Casing depth (m)				Depth (m)	Remark
	Started	Finished	Easting (m)	Northing (m)		20”	13 3/8”	9 5/8”	7” liner		
TD1	29-10-93	27-02-94	732377	1303746	365.9	130.5	575	850	800-1500	2196/ 1550*	Non-productive *Current depth
TD2	13-03-94	10-05-94	731412	1302823	365.7	111	607	854.5	809-1807	1881	Productive
TD3	07-09-94	19-10-94	728652	1309451	366.8	62	404.5	830	681-1362	1989	Non-productive
TD4	27-04-95	09-05-95	731363	1302941	365.2	24	109	210	181-463	466	Productive
TD5	20-12-97	14-01-98	731558	1302900	366.3	47.6	136	220	202-508	516	Productive
TD6	01-02-98	20-02-98	731670	1302919	366	40	123	217	209-504	505	Productive

Tendaho is the second geothermal field in Ethiopia explored by drilling. The first one was the Aluto-Langano geothermal field (Figure 1), where eight deep exploration wells were drilled to a maximum depth of 2500 m in 1981 - 1985. The first two wells LA-1 and LA-2 were drilled on the southern and western flanks of the Aluto volcano and six wells LA-3 to LA-8 were located within the Aluto volcanic complex. Results from wells LA-1 and LA-2 show low temperature and low permeability down to depths of 1317 and 1602 m, respectively. The remaining six wells, drilled on top of the volcanic complex delineate the lateral and vertical extent of a water-dominated reservoir. Four of the above wells are productive. A pilot plant with a capacity of about 7MWe has been operated in Aluto-Langano, utilizing these wells. Currently, it is not producing.

2.2 Location and accessibility

Tendaho geothermal field is located in the Northeastern part of Ethiopia in the Afar-administrative region about 600 km from Addis Ababa (Figure 1). The geothermal field is located 12 km eastwards from the crossing of the asphalt road between Addis Ababa and Assab, and the road to Dubti (Figure 2) (Battistelli et al., 2002). The Tendaho area is mostly flat terrain at an elevation of 360-380 m a.s.l., with scattered isolated hills, corresponding to volcanic edifices.

The geothermal manifestations are found within the Tendaho cotton plantation (Figure 2) and are represented by mud cones, pools, small fumaroles and low mounds. In some areas numerous fossil

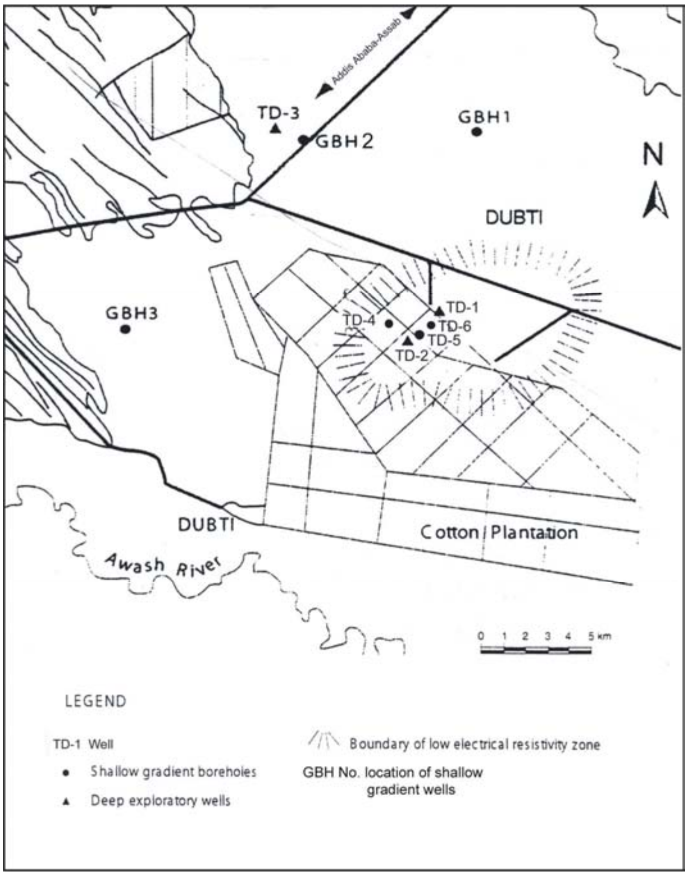

FIGURE 2: Location of the Tendaho geothermal area and the exploration wells (Battistelli et al., 2002)

and active surface manifestations can be found. Tendaho geothermal field is located in the lower areas. It is characterized by mainly semi-arid to sub-desert lowlands, including extensive grasslands and steppes, rocky and hilly lands and alluvial plains, some saline to varying degrees. Rainfall is very scarce and agriculture is not possible without irrigation. The main rainy season is from July to September, while a minor rainy season takes place from March to May.

During the year, the seasonal temperature varies in the range 29-40°C. The local inhabitants are the Afar tribe. Their language is Afar but some of them speak Amharic. They are engaged primarily in breeding cattle, goats, sheep and camels, and a few are engaged in agriculture. The only concentrated settlement nearby is the Tendaho cotton plantation (Figure 2). Transportation is difficult and drinking water is hard to find for the inhabitants of the region.

2.3 Previous work

Drilling in the Dubti area (600–2000 m) shows that the upper 600-700 m of the crust consist of lacustrine sequences with interlayered basalts. The lower parts are dominated by the Afar stratoid series, a basaltic sequence that represents the floor of the Tendaho sedimentary basin (Aquater, 1996). Yiheyis Amdeberhan (UNU Fellow in 1998) evaluated reservoir data from the Tendaho geothermal field (Amdeberhan, 1998). The main conclusions from his work are summarized as follows:

- The downhole temperature and pressure measurements in well TD1 indicate that the heat transfer in the uppermost 600 m is by conduction with an average temperature gradient of about 370°C/km. Temperature increases from the surface down to 950 m and is then constant to about 1100 m. At 1700-2300 m the temperature gradient is 20°C/km.
- The downhole temperature and pressure measurements in well TD2 show the existence of a boiling reservoir at about 400 m depth. From 425 to about 800 m a temperature reversal is seen and from 800 to about 1400 m, the temperature increases slightly but is constant below 1400 m to the well bottom (~ 1900 m). The shallow reservoir is characterized by boiling and pressure potential in equilibrium with the water level at surface. The deep reservoir has an over-pressurized water level above the surface. The reservoir fluid state is in single-phase liquid conditions.
- Temperature measurements during drilling of well TD3 indicated hot fluid at 50 m depth. Generally the formation temperature gradient is about 250°C/km in the upper part of the well. Below 550 m the gradient is less than 20°C/km. Despite many trials to discharge test the well by air lifting, the well was not able to flow because of poor permeability and low temperatures.
- Two major feed zones, at around 250 and 330 m depth, were identifiable from temperature profiles taken during the drilling of well TD4 (Aquater, 1995). The initial reservoir pressure was about 22 bar at the 250 m feed zone. Wellhead pressure in shut-in condition varies between 20 and 22 bar. The fluctuation may be due to a cyclic boiling level in the well near the feed zone at 250 m.
- The downhole temperature and pressure measurements in well TD5 show feed zones at about 300 and 500 m depth. A short term flow test indicated that the well could produce about 48 kg/s of fluid (steam and water) at 9.4 bar-g wellhead pressure. The flow test measurements through 4, 5 and 6” diameter lip pipes show that inflow temperature decreases with increasing flow from the well (discharge pipe diameter).
- From downhole temperature and pressure measurements in well TD6 the pressure profile pivot point indicates that the major feed zone is at about 300 m depth. Initially the reservoir pressure at 300 m depth was about 18.5 bar.

Production tests of the wells were carried out only for a short period. Well TD1 produced only a few kg/s of high-enthalpy fluids and could only maintain the flow for a few hours. So it is considered a non-productive well. The discharge of well TD2 through 3, 4, 5 and 6” diameter lip pipes for a total of 23 days showed a maximum production of about 15 kg/s total fluid at a wellhead pressure of 3 bar-g. The enthalpy of the fluid was estimated to be 920 kJ/kg, corresponding to a fluid inflow temperature of 220°C. Well TD3 is non-productive. The results show that during the discharge of well TD4, through a 4” lip pipe for 26 days, the average fluid production (steam and liquid) was about 50.4 kg/s at a wellhead pressure of 14.4 bar-g. The fluid enthalpy was about 1065 kJ/kg and the steam flowrate 14 kg/s. The flow test results for well TD5 show that during discharge through a 5” diameter pipe in 5, 6, and 7 days, the total flowrate was about 48.5 kg/s at a wellhead pressure of 10.4 bar-g. Well TD6 discharged for 7 days through a 6” diameter pipe. The average production rate at a wellhead pressure of about 5 bar-g was 33 kg/s and the fluid enthalpy was about 990 kJ/kg, corresponding to an inflow temperature of about 235°C.

2.4 Recent downhole temperature and pressure measurements

The reservoir data, analyzed in this report (Table 2), were collected during the last 4 years (1999 to 2003) by the Ethiopian geothermal reservoir team. Wellhead pressures were collected during these years for all six wells and several pressure and temperature profiles measured in wells TD4, TD5 and TD6. Short time production tests for wells TD5 and TD6 were also carried out.

TABLE 2: Downhole temperature and pressure measurements carried out during 1999-2003 for the Tendaho wells

Well no.	**Temperature measurement**		**Pressure measurement**	
	Date	**Number**	**Date**	**Number**
TD4	04-02-99	T13	05-02-99	P10
TD5	01-02-99	T13	30-01-99	P12
	21-03-02	T14	20-03-02	P13
	22-03-02	T15	19-03-03	P14
	23-03-02	T15B	22-03-03	P15
	19-03-03	T16	*	*
TD6	05-04-99	T5	12-02-99	P8
	10-04-00	T9	17-02-99	P9
	29-03-02	T10	20-04-99	P10
	01-04-02	T11	22-03-00	P11
	23-03-03	T12	01-04-00	P12
			14-04-00	P13
			14-04-00	P14
			17-04-00	P15
			27-03-02	P16
			28-03-02	P16B
			30-02-02	P17
			27-03-03	P18
			29-03-03	P19

Well TD4. Downhole temperature run T13 was measured at static conditions (Table 2). This survey shows an isothermal steam in the well above 225 m depth, and then gradually increasing liquid temperatures to 454 m (Figure 3). Below 225 m the temperature follows the Boiling Point for Depth-curve (BPD) and it is estimated that formation temperature of this well follows the BPD-curve from surface to bottom (Figure 3). The wellhead is always very hot, and the upper part of the well filled with a hot steam-gas mixture.

Downhole pressure run P10 was measured at static conditions (Table 2). The pressure log is shown in Figure 4. The log shows a constant pressure of 19.8 bar for the steam above 225 m. Below 225 m the survey shows hydrostatically increasing pressures down to the bottom following the BPD curve to at least 350 m depth. The initial reservoir pressures at this well are, therefore, estimated to follow the BPD-curve from surface to bottom.

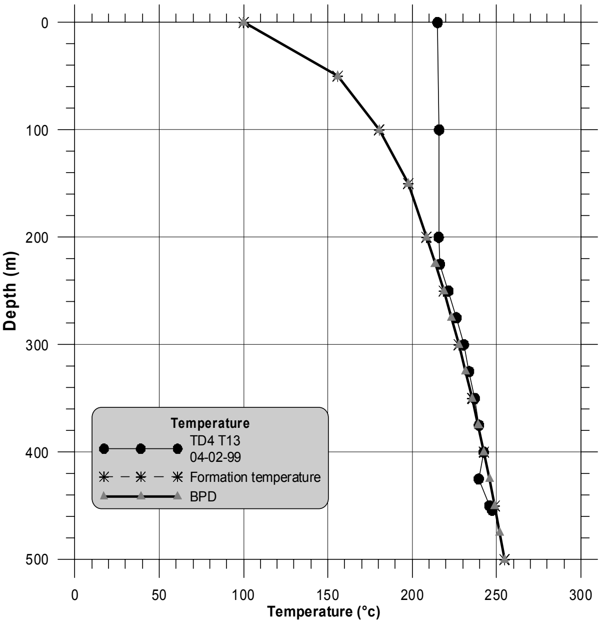

FIGURE 3: Downhole temperature run T13 in well TD4

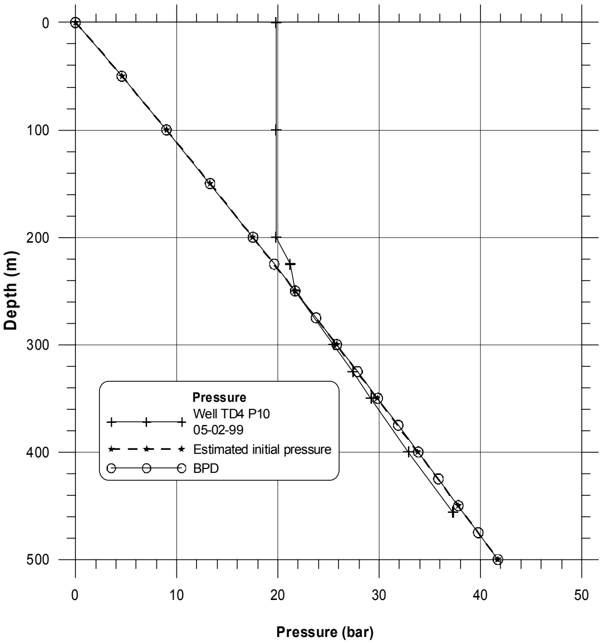

FIGURE 4: Downhole pressure run P10 in well TD4

Well TD5. The downhole temperature logs (see Table 2) were all measured in static conditions and are shown versus depth in Figure 5 along with the formation temperature estimated from earlier data (Amdeberhan, 1998). Amdeberhan concluded that the formation temperature at TD5 followed the BPD-curve with the water level at surface. The new data in Figure 5 show consistently higher temperatures than earlier estimated. The formation temperatures have therefore, been revised and are now believed to follow a BPD-curve with the water level at 50 m above the surface. This means that the shallow reservoir is overpressurized in the vicinity of well TD5. The first calculated BPD profile (symbol **Δ**) is lower than the measured temperature profiles. Therefore, a new BPD estimate (symbol +) was made to fit all temperature runs. From 400 m to the bottom the runs show isometric constant temperature. The results of all runs are nearly the same for the bottom depth temperature profiles (Figure 5). The maximum measured downhole temperature is 253°C at the bottom of the hole (~ 500 m). The plots of the downhole pressure logs in TD5 are shown in Figure 6 (measured in static

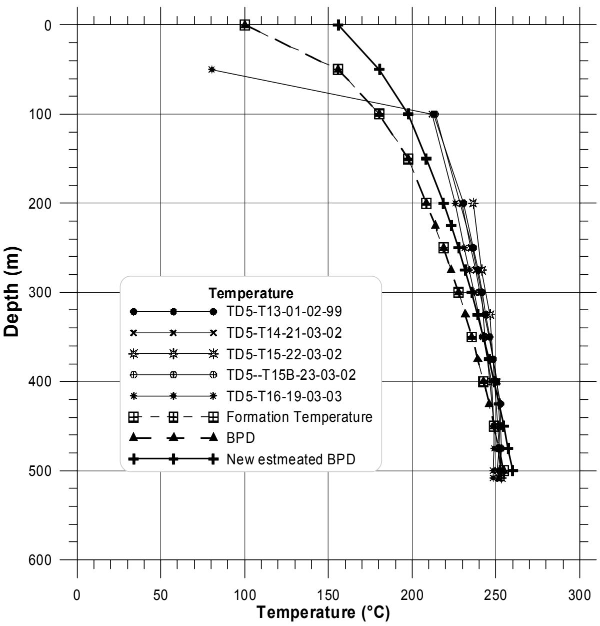

FIGURE 5: Downhole temperature profiles recorded under shut-in condition in well TD5

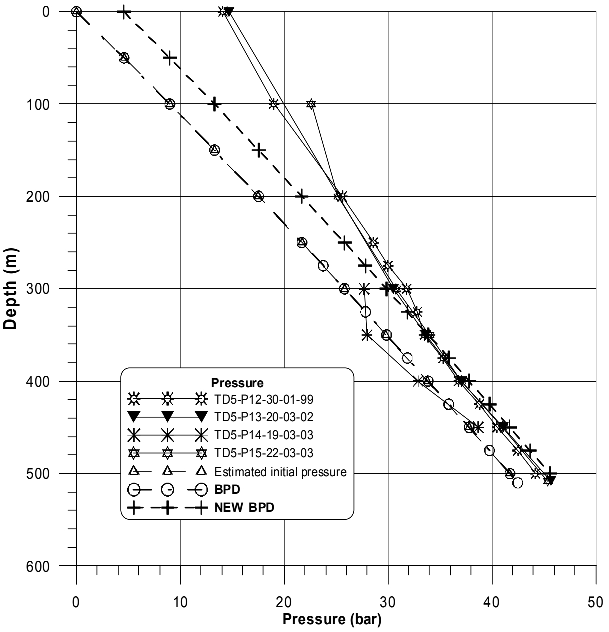

FIGURE 6: Downhole pressure profiles recorded under shut-in condition in well TD5

conditions). The recent pressure logs show higher reservoir pressure than previously estimated and fit to a BPD-curve corresponding to a water level at 50 m above the surface. This is in good agreement with the temperature data in Figure 5.

Well TD6. A hydrothermal eruption occurred only a few metres from well TD6 on April 27, 2000. The well was, therefore, not accessible for logging until two years later (see Table 2). The logs were performed at static conditions. The static temperature data are shown in Figure 7 along with the estimated formation temperature from Amdeberhan (1998). Even though the recent data is scattered around the formation profile of Amdeberhan, it still seems to be the best estimate that the formation temperature follows the BPD-curve with a water level at surface. Dynamic temperature logs T5 and T9 were done in 1999 and 2000 during discharge through a 5" diameter pipe. In Figure 8 the profiles are not exactly the same despite the same discharge pipe size. The latest temperature profile (T9) is higher than that of T5 by about 2%. This could be due to a longer discharge time during the T9 measurement. It should be pointed out that lower temperatures during discharge than in static conditions are due to boiling causing pressure drawdown in the well and the formation during discharge.

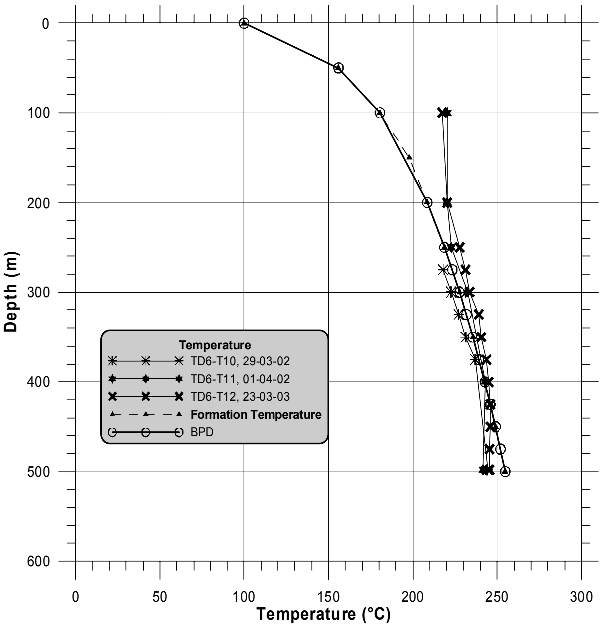

FIGURE 7: Downhole temperature profiles recorded under shut-in conditions in well TD6

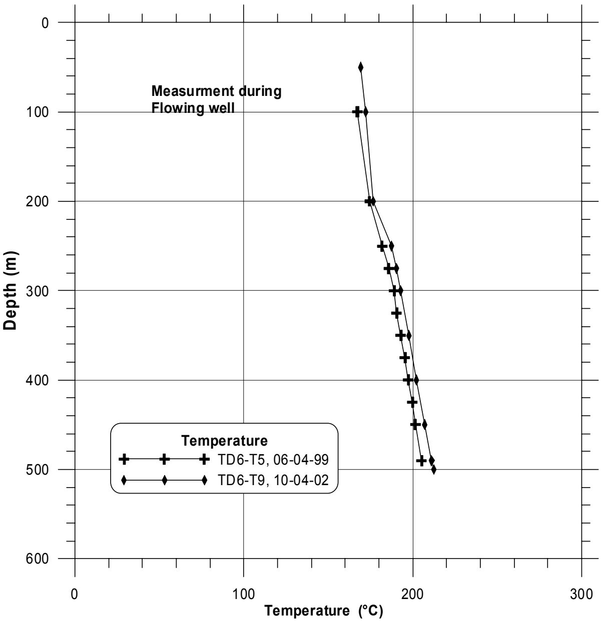

FIGURE 8: Downhole temperature profiles recorded under flowing conditions in well TD6

The plot of the downhole pressure logs P8, P9, P11, P13, P14, P15, P16, P16B, P17, P18, and P19 versus depth are shown in Figure 9. These measurements were all taken during static conditions. There are considerable differences between the different logs. Some of these are probably due to calibration errors of the Kuster gauges, but other logs are run shortly after the well had discharge, before the pressure had recovered. The bottom hole pressure is about 40 bar in static conditions (Figure 9) but is only 14-17 bars during flow tests (Figure 10).

The dynamic pressure logs in Figure 10 were done in 1999 and 2000 during discharge through a 5" diameter pipe. The plots of pressure runs P10 and P12 show not exactly the same pressure values even though the same size discharge pipe is used (Amdeberhan, 2000). The flowing pressures in 2000 are a few bars higher than in 1999. This could be due to lower flowrate from the well or an increased productivity coefficient of the feed zones.

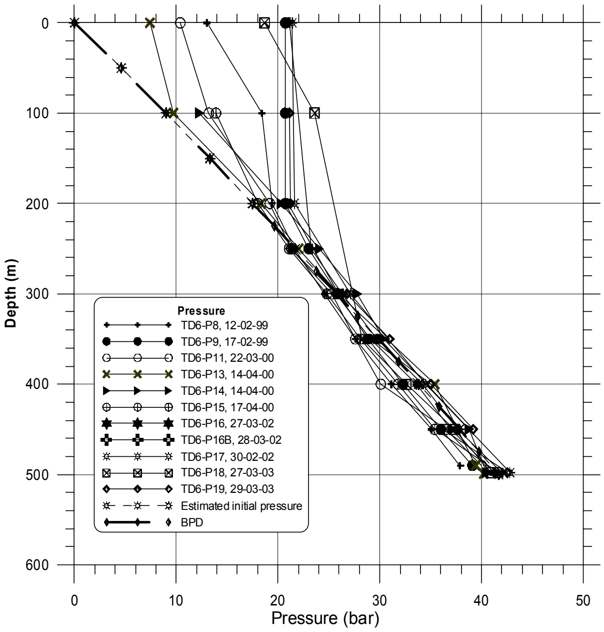

FIGURE 9: Downhole pressure profiles in well TD6 recorded under shut-in conditions

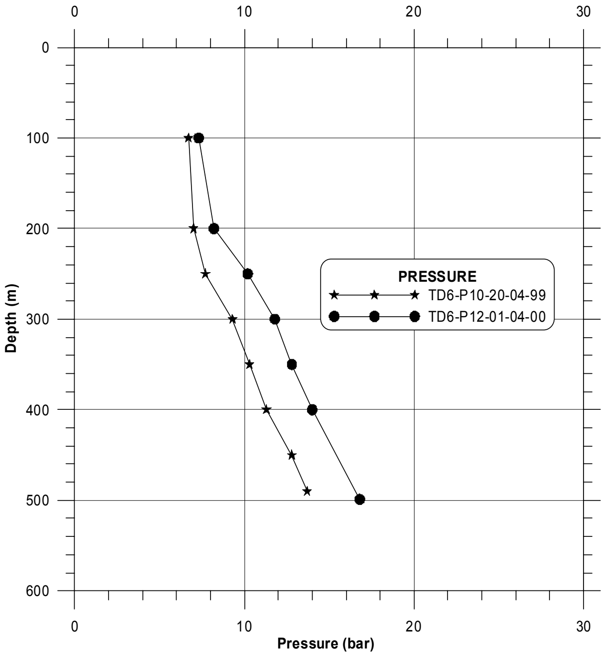

FIGURE 10: Downhole pressure profiles in well TD6 recorded under flowing conditions

2.5 Temperature and pressure contour maps and cross-sections

It is important to note that the estimated reservoir temperatures and initial pressures are based on the measured profiles but some inaccuracies should be taken into consideration. Data collection can have inaccuracies (i.e. production test for TD6). New estimations of formation temperature and initial pressures were done for all the wells (data from 1999-2003). These are shown in Table 3. Figures 11-20 show contour maps and cross-sections for temperature and pressure for all the wells, using the new estimations. The shallow production wells show an anomaly.

TABLE 3: New estimates on formation temperatures and initial pressures for the Tendaho wells

Depth (m a.s.l.)	Well no.	Formation temperature (°C)	Initial pressure (bar)
100	TD1	168.2	30
100	TD2	220.9	28.2
100	TD3	100.5	23.1
100	TD4	224.4	22.9
100	TD5	225.1	24.52
100	TD6	215.8	20.42
0	TD1	201.9	38.6
0	TD2	237.8	36.4
0	TD3	135.3	32.3
0	TD4	235.5	27.6
0	TD5	244.6	35.1
0	TD6	237.9	31.23
-100	TD1	226.9	46.9
-100	TD2	244.4	44.3
-100	TD3	155.89	41.3
-100	TD4	249.4	39
-100	TD5	256.4	43
-100	TD6	250.9	39.1

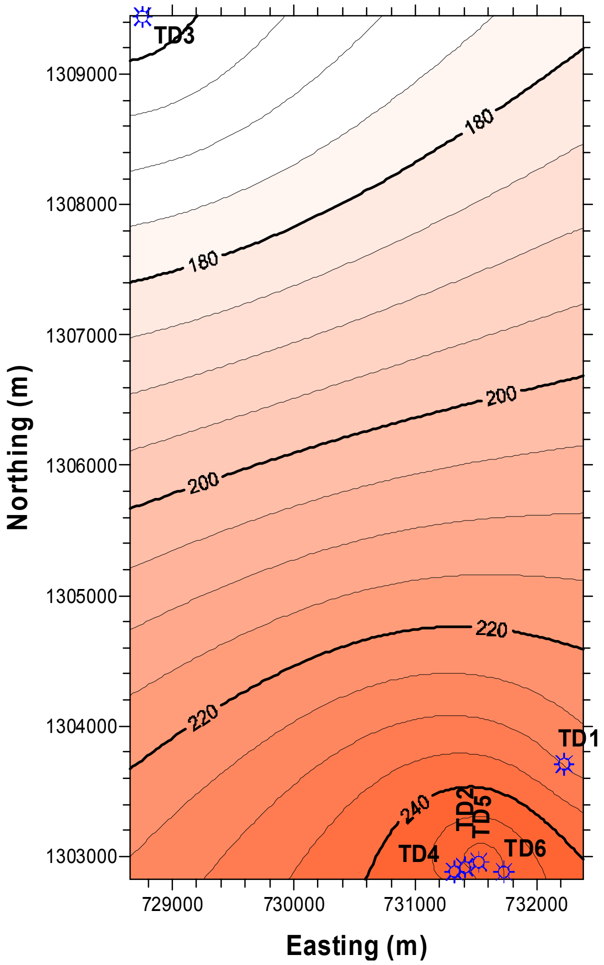

FIGURE 11: Temperature contours (°C) at -100 m a.s.l. for all Tendaho wells

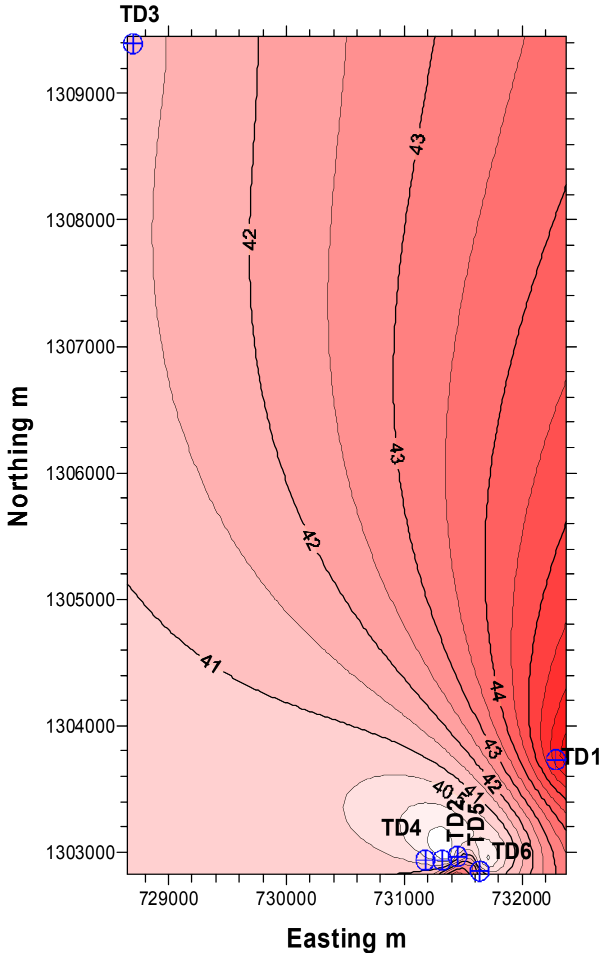

FIGURE 12: Pressure contours (bar) at -100 m a.s.l. for all Tendaho wells

Figures 11 and 12 show temperature and pressure contour maps at 100 m below sea level. In these figures, the hot reservoir fluid recharges the well field from the southeast and can more clearly be seen in the temperature contour map than in the pressure contour map.

Figures 13 and 14 show NW-SE temperature and pressure cross-sections between 100 and -100 m a.s.l. in the Tendaho geothermal field. The high temperatures at shallow depth indicate the presence of

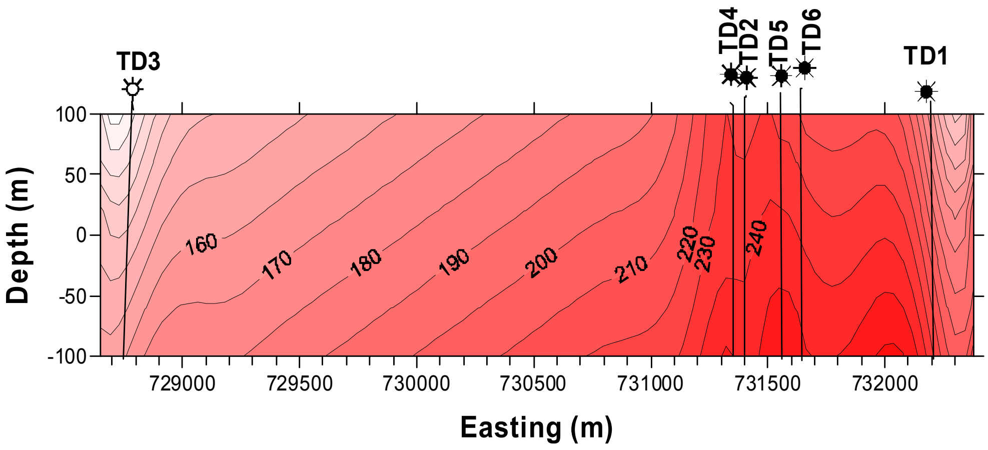

FIGURE 13: Tendaho geothermal well field, NW-SE temperature cross-section (°C)

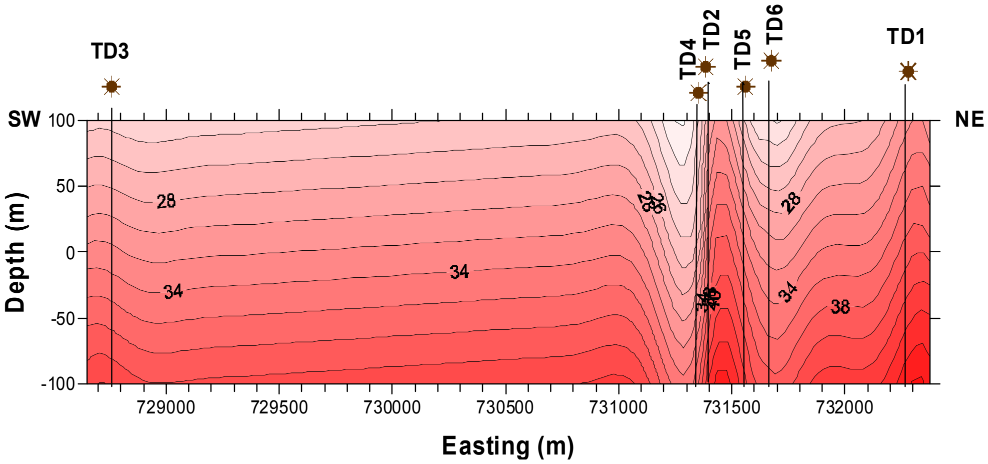

FIGURE 14: Tendaho geothermal well field, NW-SE pressure cross-section (bar)

an upflow zone or a shallow reservoir near the wells in the southeast (Figure 13). In Figure 14 it seems there is some disturbance in the cross-section, probably because of the bridging procedure of the contour program and that well TD3 is very far away from the other wells. Due to this, well TD3 has been omitted in the cross-sections in Figures 15 and 16. They show temperature and pressure cross-sections through wells TD4, TD2, TD5, TD6 and TD1 in the southeast corner of the well field between 100 and -100 m (m a.s.l.). From both the temperature and pressure cross-sections, an upflow zone near well TD5 can be seen.

Figures 17 and 18 show temperature and pressure contour maps at -100 m (m a.s.l.) around the wells in the southeast part of the well field. From these maps it is clear that the hottest reservoir fluid is present near TD5 and that this well is closest to the upflow zone.

The downhole well pressure and temperature measurements in the shallow wells indicate a reservoir thickness of about 250 m (220-255°C) for TD4, about 300 m (230-253°C) for TD5 and about 200 m (230-245°C) for TD6. Figures 19 and 20 show the upflow zone for a cross-section through shallow wells TD4 to TD6.

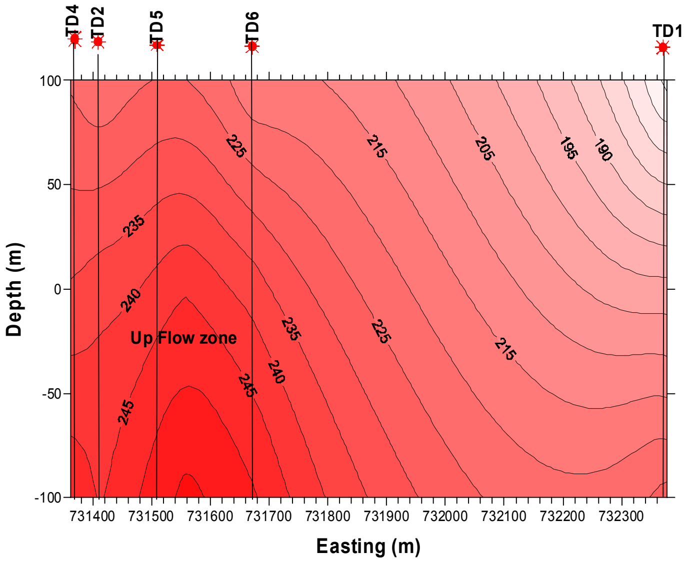

FIGURE 15: A W-E temperature (°C) cross-section without TD3

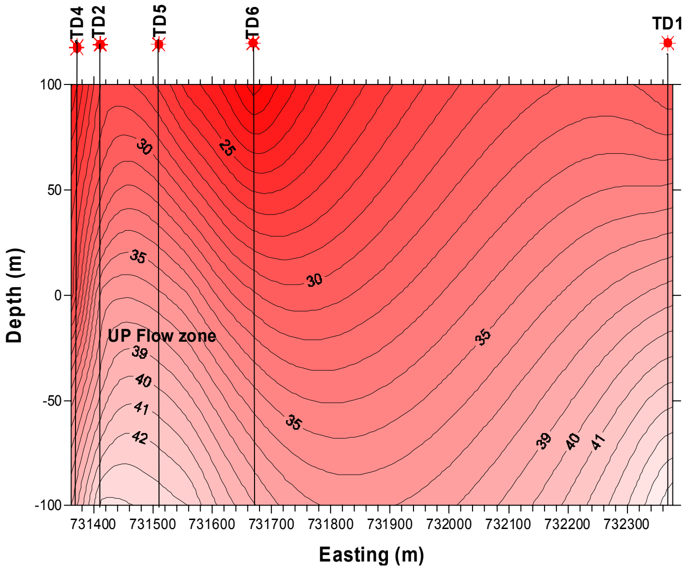

FIGURE 16: A W-E pressure (bar) cross-section without TD3

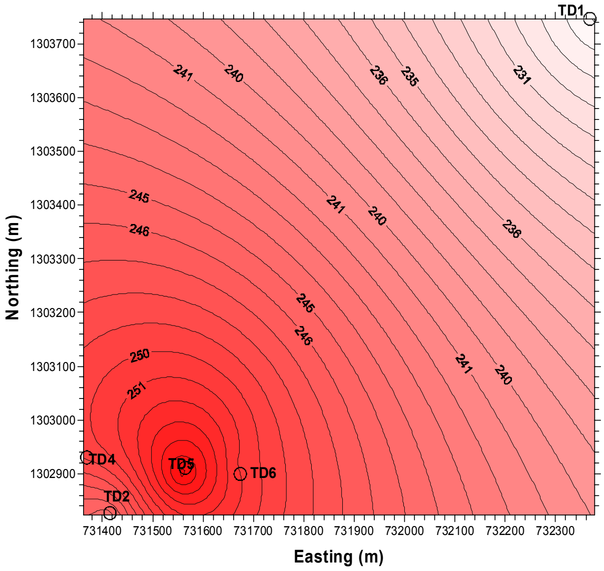

FIGURE 17: Temperature contours (°C) (without TD3) at -100 m depth a.s.l.

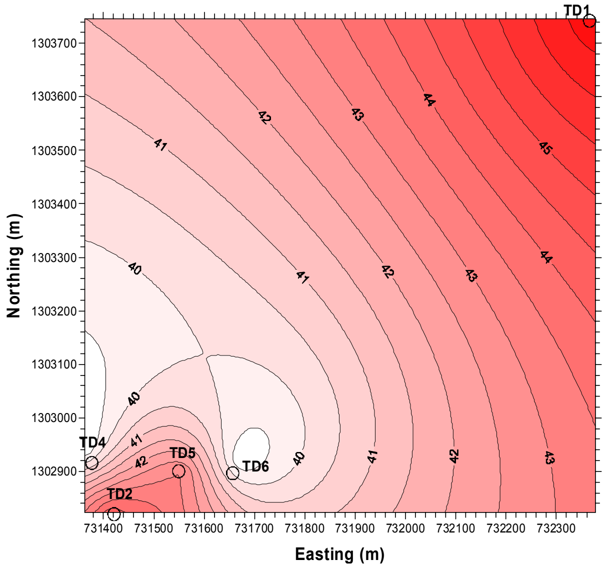

FIGURE 18: Pressure contours (bar) (without TD3) at -100 m depth a.s.l.

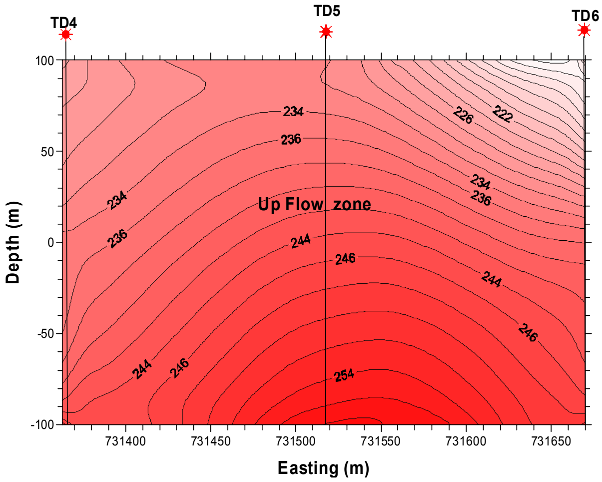

FIGURE 19: Temperature cross-section through the shallow wells

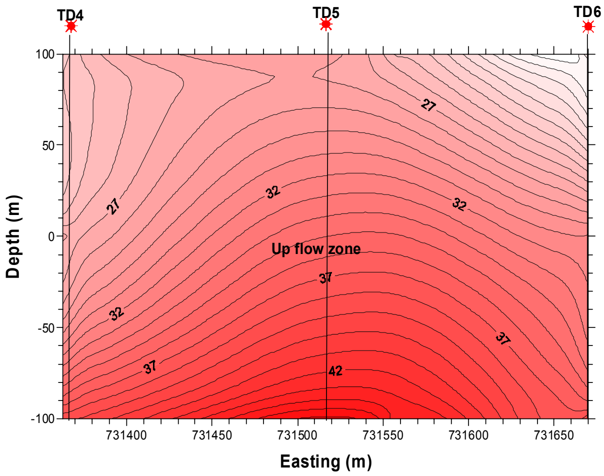

FIGURE 20: Pressure cross-section through the shallow wells

2.6 Production tests

Production tests (discharge tests) are performed to obtain the discharge character of a well, and to estimate its production capacity. There are several methods that are used to estimate the output of a well. The most common ones are the separator method and the lip pressure method. The lip pressure method was employed for the discharge tests at the Tendaho geothermal field. The wells were discharged through lip pipe of diameters 4", 5", and 6". Measured parameters are wellhead pressure, wellhead temperature, lip pressure and water height in the weir box throughout the test period. From this data it is possible to calculate the total mass flow, the discharge enthalpy and thermal power of the discharge well. Wells TD5 and TD6 in Tendaho were production tested for a few weeks during the years 1999-2003. A summary of these is given in Table 4, with each of the tests discussed in the following sections.

TABLE 4: Production test results (average values) from 1999 to 2003

Well no.	Discharge days	Total mass flow rate (kg/s)	Steam flow rate (kg/s)	Water flow rate (kg/s)	Enthalpy (kJ/kg)	Well head pressure (bar-g)	Well head temperature (°C)	Lip pipe Diameter (")
TD5	25-03-03 - 13-04-03	19.2	7.3	11.9	1275	18.3	211.8	4
TD6	23-02-99 - 16-03-99	33.4	7	26.4	890	4.8	-	6
TD6	31-03-99 - 07-04-99	38.4	8.7	29.7	970	6.5	-	5
		37.4	9.3	28.1	970	5.4	160	6
TD6	23-03-00 - 27-04-00	36.5	9.6	26.8	1010	6.6	168	5
		38	10.5	27.4	1035	9.5	180	4

2.6.1 Well TD6 production test in 1999

Well TD6 was discharged through a 6" diameter lip pipe for three weeks in February and March 1999 (Table 4). The results are shown in Figures 21, 22 and 23. During this test the average total mass flow was 33.4 kg/s at 4.8 bar-g wellhead pressure. The enthalpy of the fluid ranged mostly between 864 and 1000 kJ/kg and the average enthalpy was 890 kJ/kg (Figure 23). This corresponds to a water inflow temperature of 210°C which is lower than expected from temperature logs in the well.

According to Figure 21, the flowrate remained relatively constant through the test period. Well TD6 was then discharged through a 5" diameter lip pipe for one week in the beginning of April 1999 (Figures 24, 25, and 26 and Table 4). The total flow was about 39 kg/s, of which 9 kg/s, were steam. During this test the average total mass flowrate was 38.4 kg/s at a mean wellhead

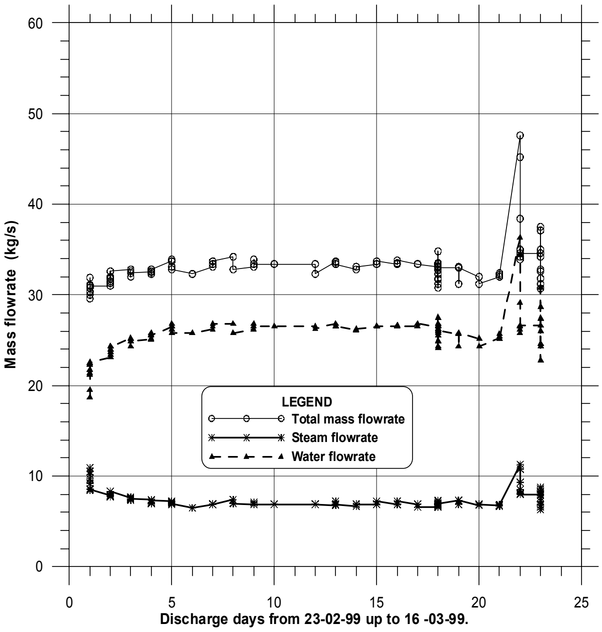

FIGURE 21: Well TD6 discharge through 6" pipe during the period 23-02-99 - 16-03-99

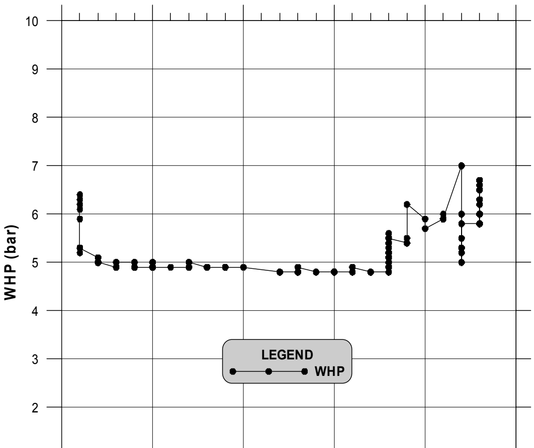

FIGURE 22: Well TD6 wellhead pressure (WHP) variation during discharge through 6" pipe in the period 23-02-99 - 16-03-99

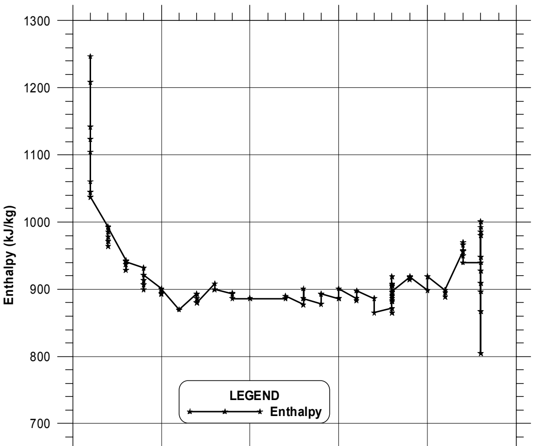

FIGURE 23: Enthalpy of well TD6 discharge test through 6" pipe during the period 23-02-99 - 16-03-99

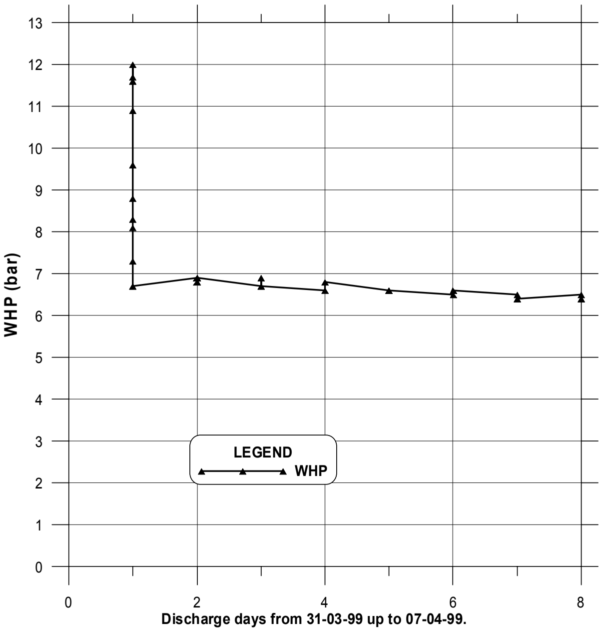

FIGURE 24: Well TD6 wellhead pressure variation during discharge through 5” pipe during the period 31-03-99 - 07-04-99

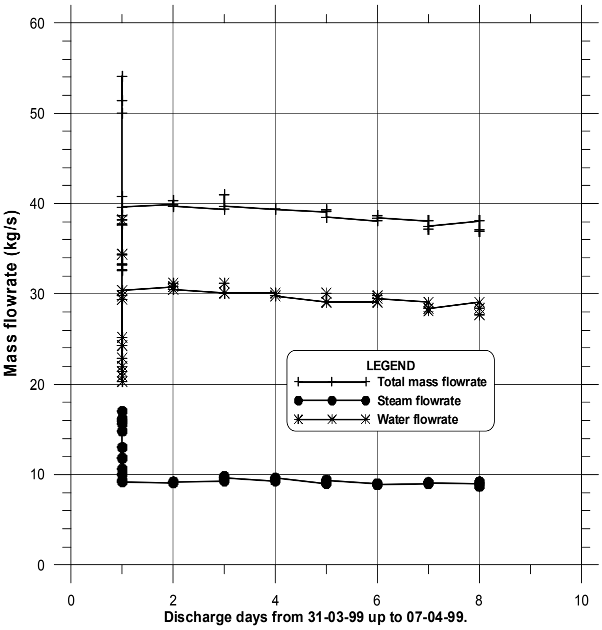

FIGURE 25: Well TD6 discharge rates through 5”pipe during the period 31-03-99 - 07-04-99

pressure of 6.5 bar-g. The corresponding mean enthalpy and steam flowrate were 970 kJ/kg and 8.7 kg/s, respectively.

A comparison of the two tests shows that the well head pressure increases from 4.8 to 6.5 bar when going from a discharge through a 6” to a 5” lip pipe. This is normal behaviour when going from a bigger pipe to smaller one. What is not normal is that the flowrate and the enthalpy increase at the same time. This is hard to explain. The change in enthalpy could be due to an interference of two feed zones of different temperatures, with the hotter one contributing more to the flow when the well is discharged through the narrower lip pipe, but the total flow should not increase. The only reasonable explanation seems to be that the conditions of the well and its feed zones changed between the two tests. This could happen if a feed zone plugged by drill cuttings would regain its productivity.

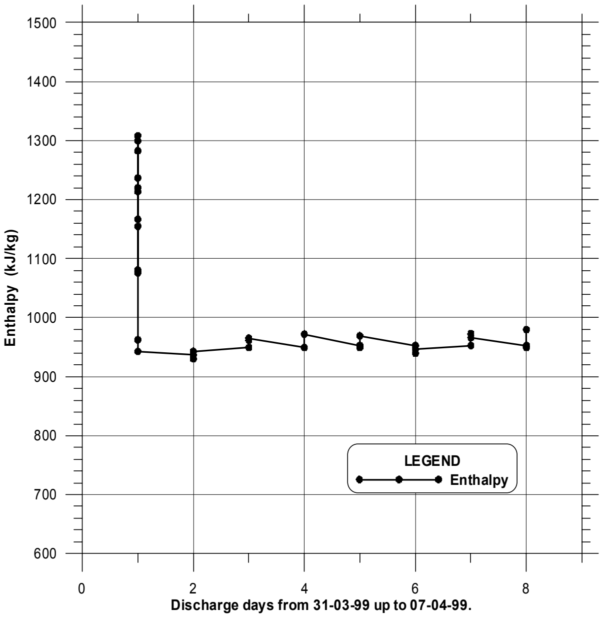

FIGURE 26: Enthalpy of well TD6 in discharge test through 5” pipe during the period 31-03-99 - 07-04-99

2.6.2 Well TD6 production test in 2000

Well TD6 was production tested again in 2000 and this time for one month (Table 4) starting on March 23rd. The test had to be terminated on 27 April 2000 because of a hydrothermal eruption occurring only a few metres from the wellhead. The well was discharged through 6, 5 and 4” diameter lip pipes. Figures 27, 28 and 29 show the results of the test. The figures show increasing well head pressure and slightly increasing flowrate with decreasing lip pipe diameter. This is similar to the test in 1999 but unusual because one would expect more flow and less wellhead pressure with increasing diameter of the lip pipe.

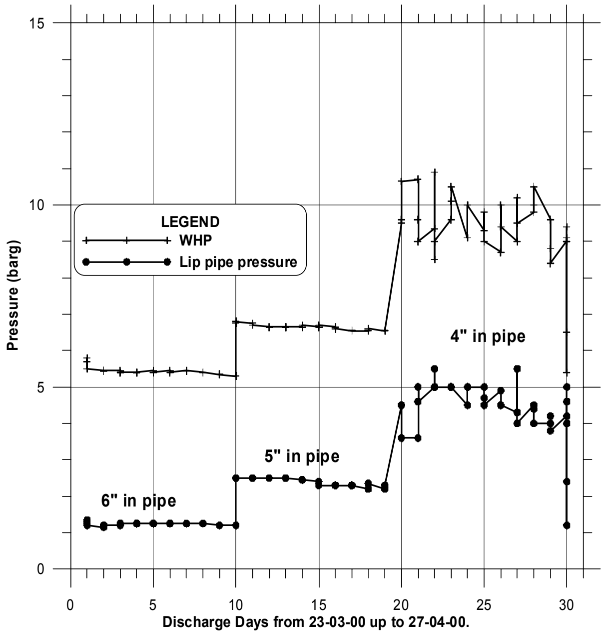

FIGURE 27: Well TD6 wellhead pressure variation during production test through 4, 5 and 6” pipes in the period 23-03-00 - 27-04-00

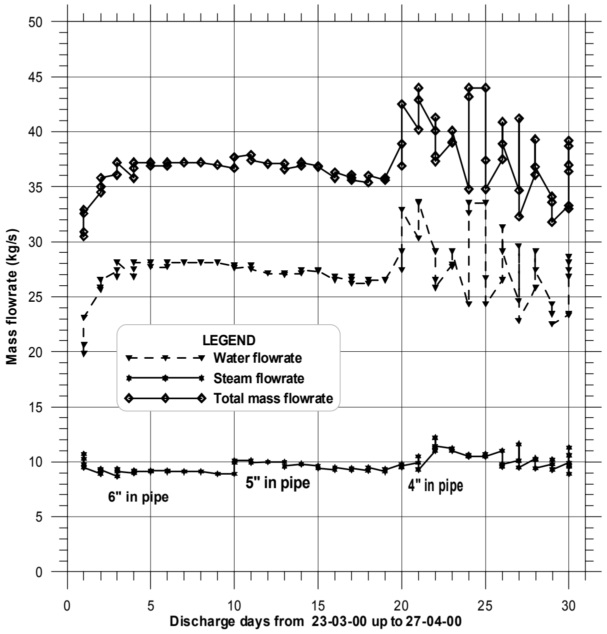

FIGURE 28: Well TD6 flowrate variation during production test through 4, 5 and 6” pipes in the period 23-03-00 - 27-04-00

The enthalpy of the fluid started at 1200 kJ/kg with the 6” pipe but levelled out at about 970 kJ/kg at a wellhead pressure of 5.4 bar-g. During discharge through the 5” lip pipe the average stable wellhead pressure was 6.6 bar-g, average mass flowrate was 36.5 kg/s, and enthalpy 1010 kJ/kg. The discharge through the 4" pipe showed much scattering in all parameters as seen in Figures 27-29. The average mass flow was some 38 kg/s at 9.5 bar-g wellhead pressure, and the average enthalpy and steam flow rate 1035 kJ/kg and 10.5 kg/s, respectively. The data from the flow test of well TD6 in 2000 have been used to draw the output curve for the well, which is shown in Figure 30. The shut-in pressure for the well is estimated at 20 bar.

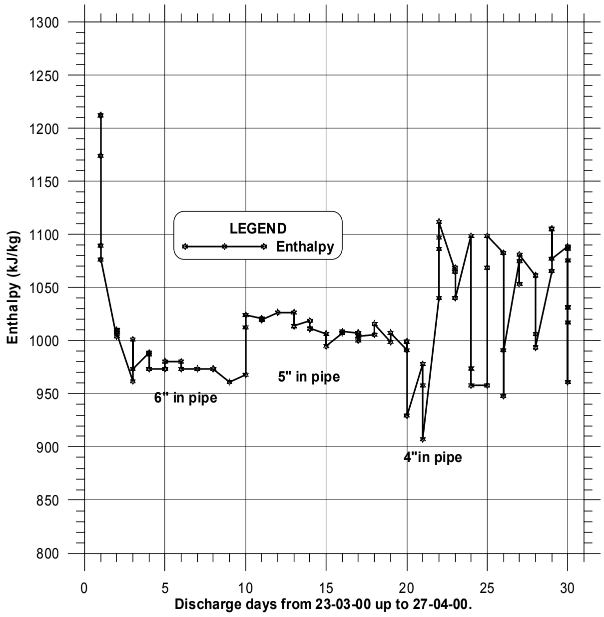

FIGURE 29: Well TD6 enthalpy variation during production test through 4, 5 and 6” pipes in the period 23-03-00 - 27-04-00

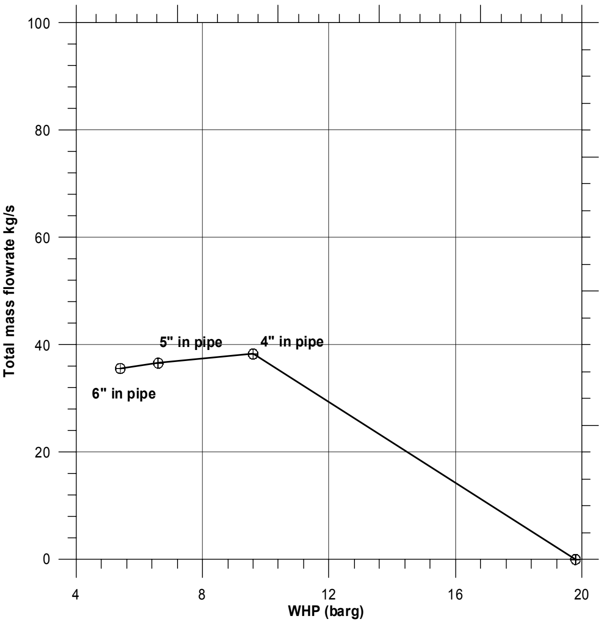

FIGURE 30: Well TD6 flow rate vs. wellhead pressure during production test through 4, 5 and 6” pipe in the period 23-03-00 - 27-04-00

2.6.3 Well TD5 production test in 2003

A fully instrumented flow test was carried out for well TD5 for 20 days in March/April 2003 (Table 4). The well was discharged through a 4” lip pipe. Measured parameters were wellhead pressure, wellhead temperature, lip pressure and the water height in the weir box. From this data, calculations were carried out for the total mass flow, steam flow, the discharge enthalpy and thermal power of the well. During the discharge test wellhead pressure varied from 19.5 to 17.5 bar-g (Figure 31). The average stable wellhead pressure during discharge test was 18.3 bar-g. The wellhead pressure prior to the test was 26 bar-g.

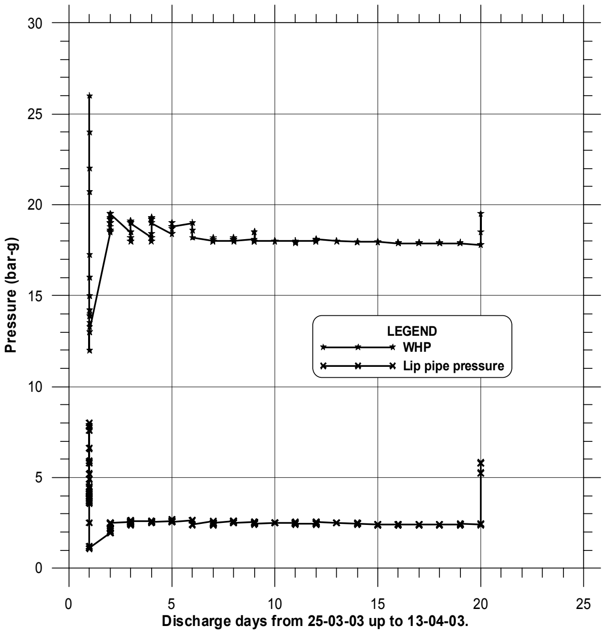

FIGURE 31: Well TD5 pressure variation during discharge through 4” pipe in the period 25-03-03 - 13-04-03

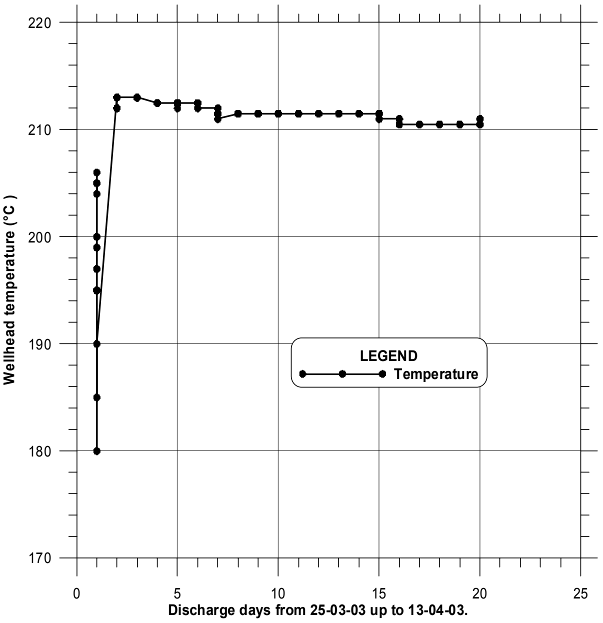

FIGURE 32: Well TD5 temperature variation during discharge through 4” pipe in the period 25-03-03 - 13-04-03

The wellhead temperature during the discharge test was between 210.5 and 213°C, in good agreement with the wellhead pressure (boiling point relationship). The average wellhead temperature (WHT) was 211.8°C (Figure 32). According to Figure 33 the total mass flowrate remained relatively constant at about 19 kg/s. The cumulative total mass flowrate taken from the well during the discharge time was about 33,177 tons.

As seen in Figure 33 the steam flowrate remained relatively constant at about 7 kg/s. Similarly, the water flowrate remained relatively constant at about 12 kg/s. During the test the cumulative water discharge was about 20,630 tons.

During the discharge test the fluid enthalpy stabilized at about 1260 kJ/kg (Figure 34). The thermal power of the well TD5 calculates to 24.5 MWt. This suggests that well TD5 is capable of producing about 2.4 MWe, of electric power.

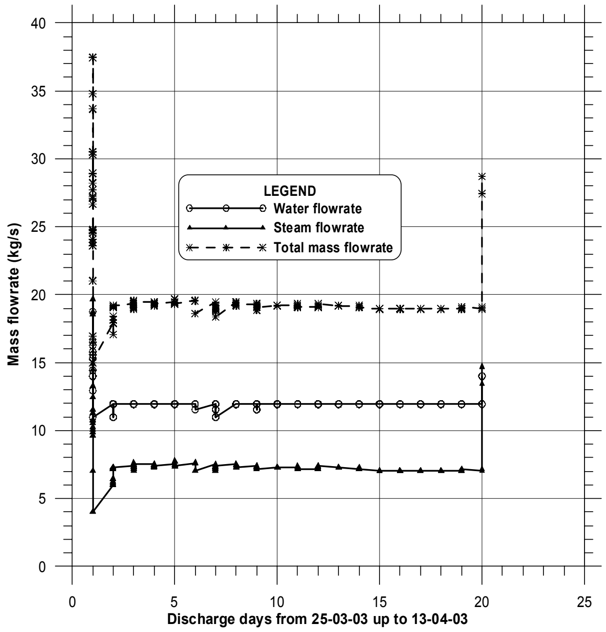

FIGURE 33: Well TD5 flowrate variation during discharge through 4” in the period 25-03-03 - 13-04-03

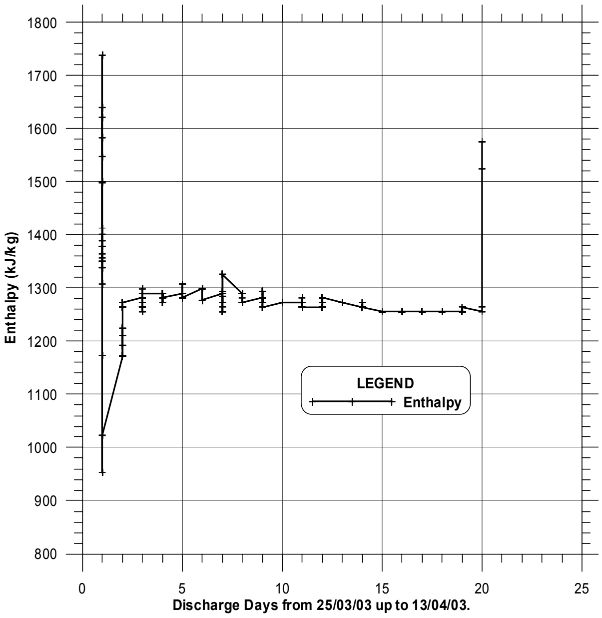

FIGURE 34: Well TD5 enthalpy variation during discharge through 4” pipe in the period 25-03-03 - 13-04-03

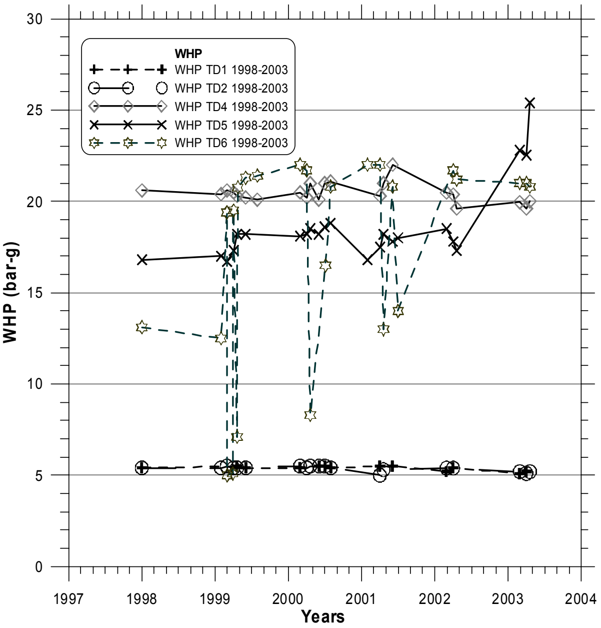

FIGURE 35: Wellhead pressure for wells TD1-TD6 in the years 1998 to 2003

2.7 Evaluation of wellhead pressure

The behaviour of the wellhead pressure monitored for wells TD1to TD6 from 1998 to 2003 at shut-in conditions is shown in Figure 35. The wellhead pressure for wells TD1 and TD2 has been fairly stable for the last 5 years. During this time the measured wellhead pressure in TD1 and TD2 has been about 5.4 bar-g. The wellhead pressures for TD4 shows some fluctuation in the range 19.6-22 bar-g. The maximum wellhead pressure was recorded in 2001 ~22 bar-g and a possible small decline with time, the average for the last 5 years being about 20.5 bar-g. The wellhead is always very hot, full of steam and a water/H_2S gas mixture. The wellhead pressure in well TD5 fluctuates between 17 and 25 bar-g. Compared to other years, the recording in 2003 shows increasing wellhead pressure, from about 18 bar-g to 25.4 bar-g, just before the flow test in March. This may be the result of increasing geothermal activity. The average wellhead pressure was about 18.6 bar-g. For well TD6 the minimum measured wellhead pressure (5 bar-g) was measured during the flowing test. At shut-in conditions some fluctuations of 20-22 bar-g are seen. The average wellhead pressure for the last 5 years was about 21 bar-g. Generally, the wells show stable wellhead pressure at well shut-in conditions, except for TD5 which showed rising wellhead pressure in late 2002 and early 2003.

3. HÁGÖNGUR GEOTHERMAL FIELD

3.1 Location and accessibility

Hágöngur geothermal field is located within the active volcanic zone in Iceland in the central-highlands, a few kilometres off the western edge of the Vatnajökull glacier. This area is far from habitation and very remote. Access to the area is provided from the Sprengisandur highland road, on a mountain track heading towards Vonarskard at an elevation of about 800 m a.s.l. A new 10 km track had to be built to the HG-1 drill site (Figure 36).

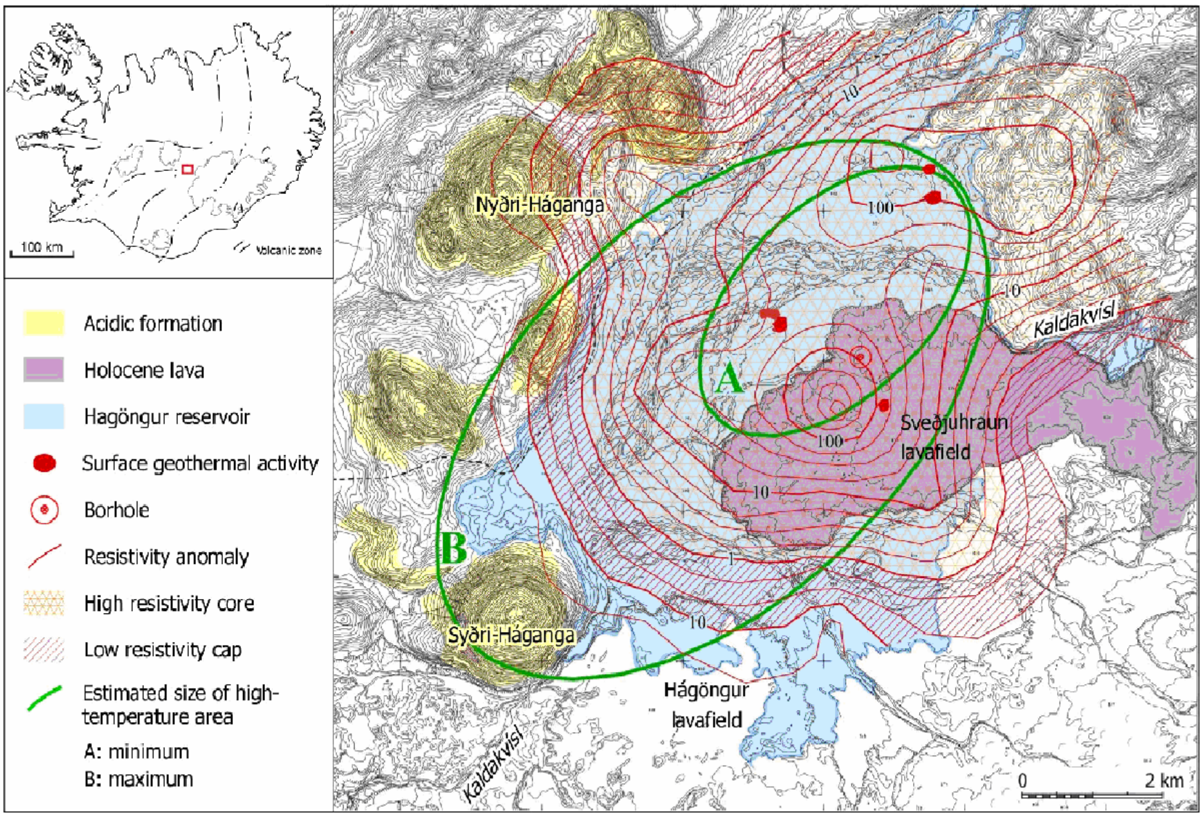

FIGURE 36: Location of the Hágöngur high-temperature area with a simplified geological map from Vilmundardóttir and Kaldal (1995) and the resistivity anomaly at sea level (isolines in Ωm) from Karlsdóttir (2000) (Jónsson et al., 2004)

3.2 Geology

General geological investigations have been sporadic and scarce in the central highlands of Iceland, between the glaciers Vatnajökull and Hofsjökull. Rather little is known about the Hágöngur high-temperature area except that it is being confined to the northern margin of the Eastern Volcanic Zone with an abundance of exposed Pleistocene and Holocene volcanics. The Hágöngur area is an independent central volcano (Jóhannesson and Saemundsson, 2003). However, it has also been suggested that the Hágöngur area is in direct relation to and a part of an elongated central volcano from Tungnafellsjökull (including Vonarskard) from the northeast, extending southwards to the Hágöngur mountains (Fridleifsson et al., 1996). All exposed volcanic formations in the area have a normal magnetization and are thus younger than 700,000 years (Piper, 1979). Compared with other high-temperature areas in Iceland, the Hágöngur high-temperature area is unique as it is almost entirely buried in glacio-fluvial sediments, supposedly filling an old lake basin. Any direct connection with recent volcanic or tectonic activity is lacking.

3.3 Geophysics

The geophysical TEM resistivity survey carried out in a 1998 survey revealed a high-resistivity core of 28 km^2 aerial size at about 1000 m depth. Including the low-resistivity cap surrounding the high-resistivity core, the size or confinement of the high-temperature area is close to 50 km^2, equivalent to the resistivity depicted at the same level in the Krafla high-temperature area N-Iceland (Karlsdóttir, 2000). In Figure 36 the resistivity anomaly at sea level (approx. 800 m depth) is shown with the low-resistivity cap and the high-resistivity core marked separately. Exploration well HG-1 is located near the centre of the high-resistivity core.

3.4 Drilling

Well HG-1 is the first deep exploration well drilled in the Hágöngur field. It was drilled to a total depth of 2360 m in 2002 and has the following casing programme:

1. Prior to primary section a 24” conductor casing was cemented to 3 m depth.
2. Primary section (small rig) 18⅝” surface casing cemented from surface to ~100 m depth.
3. First section (large rig): 13⅜” anchor casing cemented from surface to ~300 m depth.
4. Second section (large rig): 9⅝” production casing cemented from surface to ~800 m depth.
5. Third section (large rig): 7” perforated liner hanging from the end of production casing to near bottom (2310 m).

The well has yielded valuable information regarding the geological structure and lithology, state of alteration, permeability, formation temperature, reservoir pressure and chemical composition of the system’s geothermal fluid.

3.5 Lithology and evaluation in well HG-1

The lithology of well HG-1 indicates that the uppermost 330 m are predominately with intercalated tuffacious hyaloclastites and interglacial lava successions but intrusives are barely notable. From 330 m depth and down to about 760 m a thick acidic (rhyolite?) formation is very conspicuous, intersected by a roughly 100 m thick coarse-grained basaltic layer. Mostly highly altered tuffs underlie the acidic intrusion and reach a depth of about 940 m. From that point a fairly uniform succession of basaltic extrusive and intrusive formations extends to a depth of about 2200 meters, where an acid intrusion extends down to the bottom of the well at 2360 m depth, intersected by a 60 m thick gabbroic intrusion. The rocks below 940 m depth in HG-1 were probably formed in the early stages of the central volcano’s development, in aerial effusive eruptions. The hyaloclastites above 940 m were formed in sub-aerial eruptions during glaciations, and lava successions are intercalated with the hyaloclastites, formed in interglacial periods. In the later stages of a central volcano’s evolution acid volcanism is prominent, often followed by caldera collapse. Formation temperature exceeding 240°C was established at the production casing shoe (800 m depth) and slightly further below other temperature-indicating minerals appear. Wollastonite is found at 814 m, prehnite at 880 m and well defined fibres of amphibole (actinolite?) appear first at 862 m. Formation temperature is estimated to be slightly below boiling curve temperature (BPD) as calcite seems to be sporadically present to the very bottom of the well.

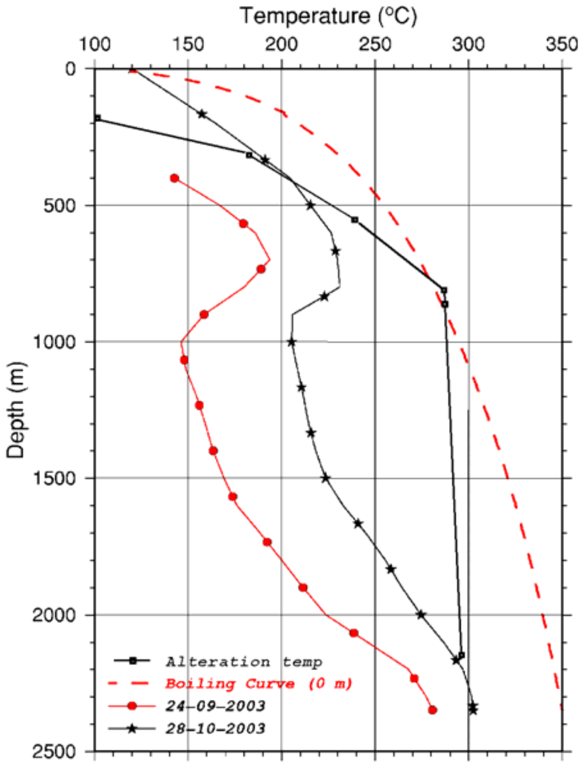

FIGURE 37: Formation temperature as indicated by alteration minerals, boiling curve and two measured temperature logs from HG-1 during warm up

3.6 Temperature and mineral equilibrium

Figure 37, shows two downhole temperature profiles, measured in September and October 2003, a boiling point depth curve (BPD) and finally the temperature suggested by the alteration of the formations drilled through. The temperature profiles were measured during warm up and are distorted near the most active aquifers, such as near and below 900 meters. As depth increases temperature is gradually increasing. About eight weeks after completion of the well the second temperature log was measured and shows significant heating of the well. Faster heating is observed in the part just around 900 meters than near the bottom. Looking at the formation temperature as indicated by the alteration minerals it confirms the expected conditions, being mostly confined inside the boundaries of the boiling curve.

The downhole recorded temperature shows a reversal just below 850 m. This pattern is due to cooling in the well's immediate vicinity through an aquifer and later stimulations during well completion. The formation near the aquifer (feed zone) is, therefore, slow in reaching temperature equilibrium (Jónsson et al., 2004).

3.7 Downhole temperature and pressure measurements

Figure 38 shows downhole temperature profiles in well HG-1, measured at static conditions after discharge. The results of these surveys show a steady increase in temperature from 200 down to 900 m depths. From 900 to about 1700 m the temperature is nearly constant at around 260°C. This is possibly due to down flow from the aquifer at around 900 m depth. Below 1700 m the temperature increases to 315°C at the bottom at 2360 m depth. The highest temperature recorded at the bottom was 315.6°C. The Boiling Point for Depth curve (BPD) versus the measured temperature curves indicates that the well is far from boiling conditions (Figure 38). The well intercepts the reservoir at about 900 m depth.

The plots of downhole pressure profiles for well HG-1 are shown in Figure 39. The measurements were done at shut-in conditions immediately after a few months discharge test. Complete pressure logs in well HG-1 were done on 22-07-04 and 04-08-04. All pressure logs indicate higher pressures than saturation pressures at the recorded temperatures. The log done on 04-08-04 indicates pressures higher than BPD at all depths. This is a further indication that the well is not at boiling conditions. A maximum downhole pressure of 191.6 bars was measured close to the bottom, at the depth 2350 m. The shape of the pressure profiles show hydrostatic gradient with depth indicating that the well is filled with water from the bottom up to the top.

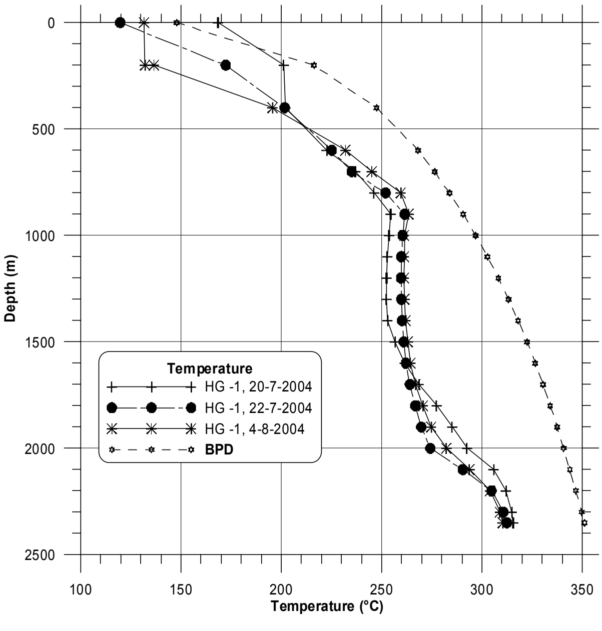

FIGURE 38: Downhole temperature profiles recorded under well shut-in conditions in well HG -1 after discharge

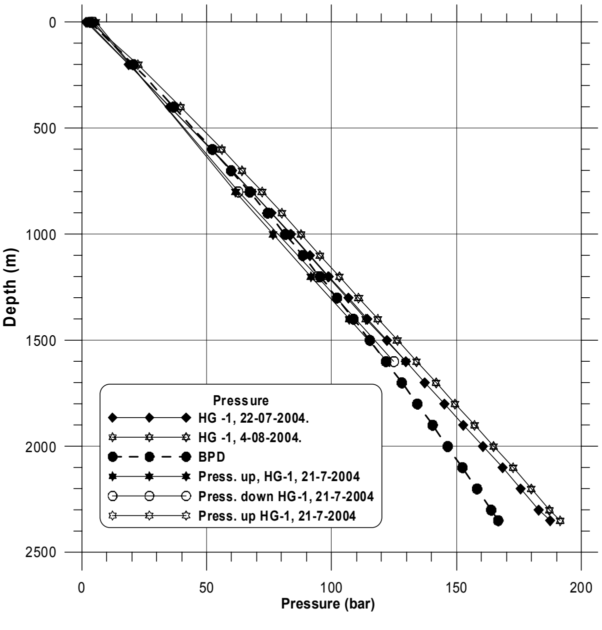

FIGURE 39: Downhole pressure profiles recorded under well shut-in conditions in well HG-1

3.8 Transmissivity and storativity calculations

At the end of the long term discharge test, well HG-1 was shut-in momentarily while a pressure gauge was lowered to 1600 m depth. This depth is believed to be near the pivot point in the well. With the gauge in the well, it was again put on production after less than 35 minutes shut-in. The production rate was adjusted to nearly the same flowrate as prior to this disturbance. Nearly 100 minutes of drawdown were monitored before the well was closed for recovery. The well had then been discharging for 265 days. The pressure recovery was monitored with a few measurements over the first two weeks. Below, the pressure transient during the short drawdown and during the recovery is analysed.

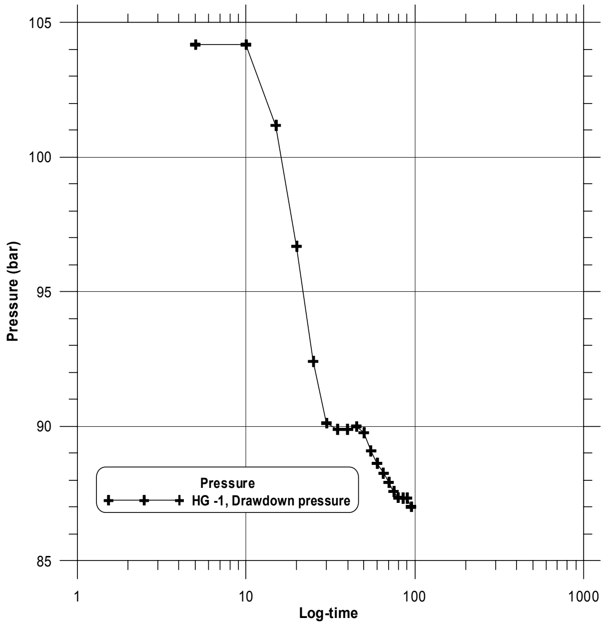

FIGURE 40: Pressure drawdown vs. log-time plot for HG-1

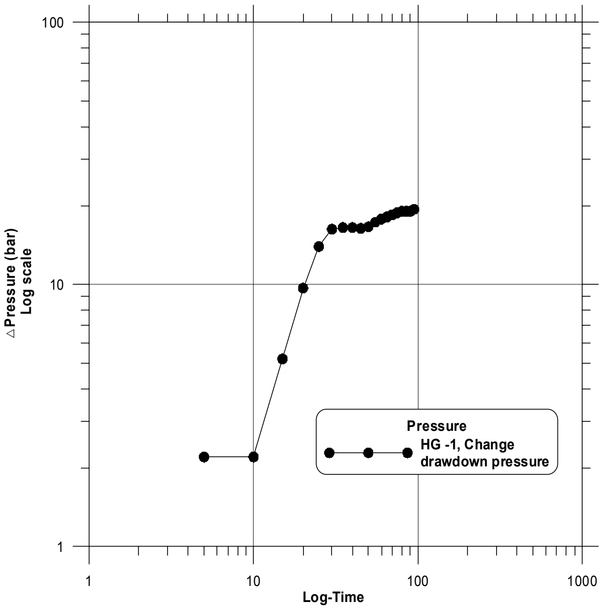

FIGURE 41: Well HG -1, change of pressure drawdown vs. log-time plot

Figure 40 shows a semi-log plot of the pressure drawdown in well HG-1. The early part of the test is disturbed by the flowrate adjustments, but the latter half of the test is done under constant flowrate conditions, 17 kg/s. Figure 41 shows the same drawdown data but plotted on a log-log graph.

Figure 42 shows the semi-log plot of the pressure recovery data when the well was shut-in after discharge and Figure 43 shows the same data on a log-log plot. The pressure recovery follows the Theis reservoir model. At the end of recording, the pressure recovery process seems to be still ongoing. The plots in Figures 42 and 43 were used to compute the reservoir parameters of the well as seen below.

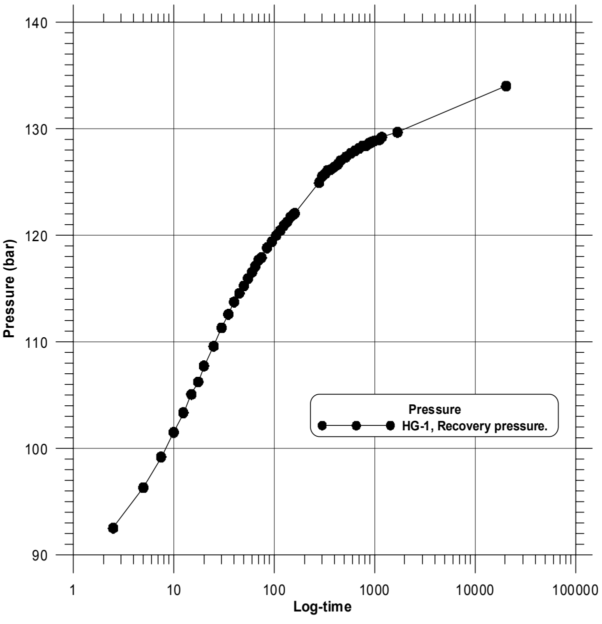

FIGURE 42: Well HG -1, recovery pressure vs. log-time plot

Figure 44 shows a Horner graph of the recovery data. A semi-log straight line is fitted to the late time data. The line has a slope, m = 4.3 bar per

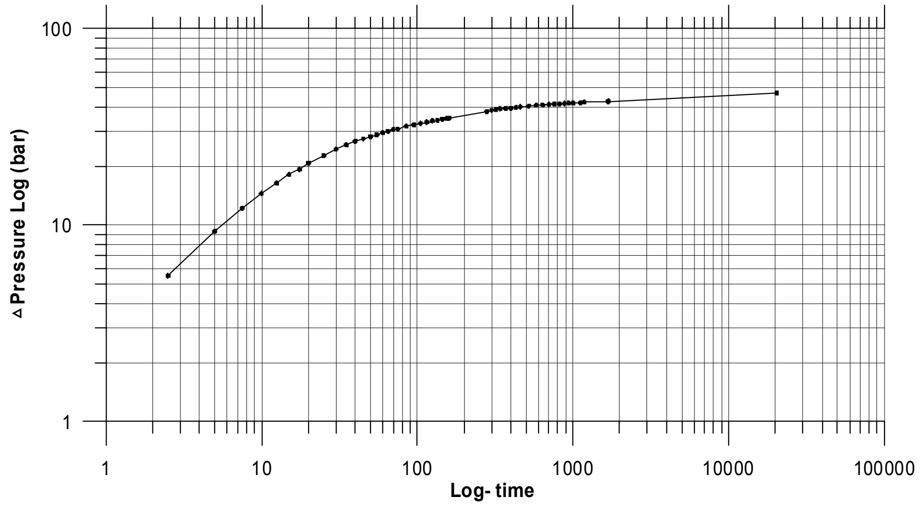

FIGURE 43: Well HG -1, change in recovery pressure vs. time, log-log plot

log cycle. Total mass flow before shut in was approximately Q = 17 kg/s and assuming inflow temperature of 255°C, the water density from steam tables is given as 791.7 kg/m^3, resulting in:

$$q = 2.1 \times 10^{-2}\ \text{m}^3/\text{s}$$

By using these parameters, the transmissivity is estimated as:

$$kh/\mu = (2.303 \times 2.1 \times 10^{-2})\ \text{m}^3/\text{s} \ / \ (4\text{x}\pi \times 4.3 \times 10^5)\ \text{Pa} \ = \ 9.0 \times 10^{-9}\ \text{m}^3/\text{Pas}$$

Figure 45 is an expanded view of the pressure recovery data on a semi-log plot. The semi log straight line is matched to the data starting from 19,000 sec. The early data are affected by well bore storage and skin effects. The later data do not indicate boundary conditions, possibly due to the short monitoring time. The slope of the straight line is:

$$m = 4.3 \times 10^5\ \text{Pa}$$

From Figure 45 the transmissivity (*kh/μ*) is calculated using the plot points A_1 and A_2 with the slope of the straight line $m = 4.3$. Hence, the calculated transmissivity is, the same as above, or:

$$kh/\mu = \ 9.0 \times 10^{-9}\ \text{m}^3/\text{Pas}$$

Using the above value for calculating the storativity, and with $\phi\, ch = 2.25\ kh/\mu\ (t/r^2)10^{-\Delta p/m}$, the change of pressure (Δp) can be determined as the intersection with the pressure axis Δp at point A_2 = 22 bar, and at the time of 1 second.

With $\Delta p/m$ = -22/4.3 = -5.1, the storativity with skin effect is:

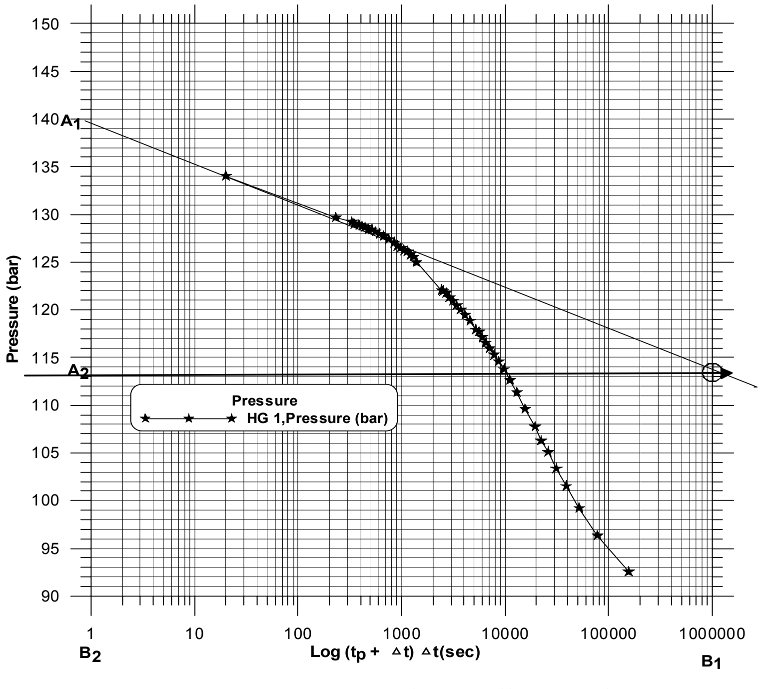

FIGURE 44: Horner graph of well HG-1 data, pressure vs. log time ratio (tp + Δt) /Δt

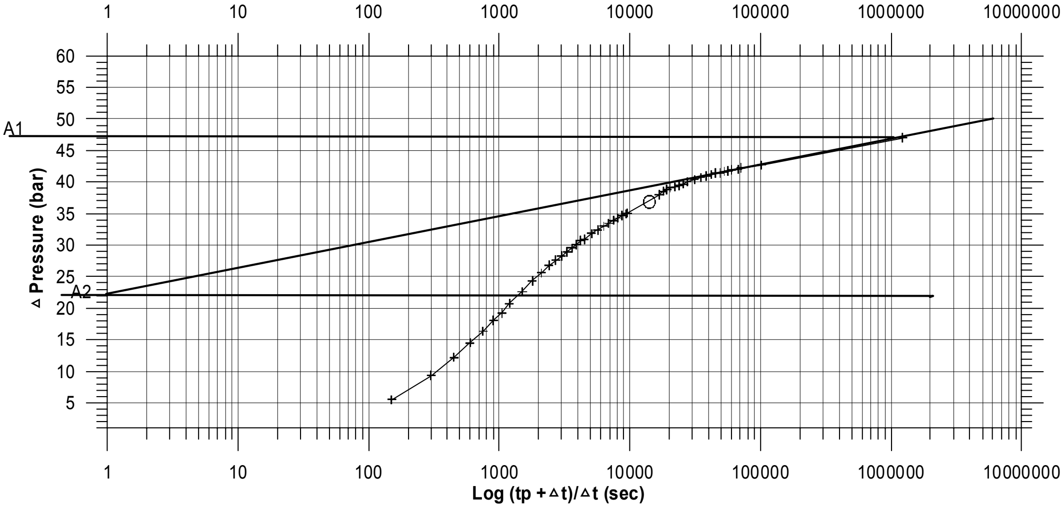

FIGURE 45: Change of pressure recovery vs. log-time plot for HG-1

$S\,e^{-2S} = 2.25 \text{ x } 9.0 \times 10^{-9} \times 10^{5.1} = 4.2 \times 10^{-1}$ m/Pa = 0.42 m/Pa

However, $S\,e^{-2S}$ = 0.42 m/Pa does not represent true conditions as such high values can only be obtained under phase transfer during boiling or in a reservoir with free liquid surface.

4. CONCLUSIONS AND RECOMMENDATIONS

The Tendaho high temperature field:

- The wells drilled in the Tendaho high-temperature field are promising but to estimate the power capacity of the production wells, a discharge test of at least six months' duration must be carried out. For detailed information / comparisons of all wells, downhole pressure and temperature measurements are required at static and dynamic conditions.
- Further production data are required for the development of a numerical reservoir model of the Tendaho reservoir.
- The maximum temperature measured in well TD5 (run T-16) is 248.8°C and maximum pressure measured at the bottom (508 m) is 45.4 bars.
- For the shallow wells (TD4, TD5 and TD6) starting from depth 250 m down to bottom 498 m, there is a general gradual step-by-step increase in temperature, from 227.8°C up to 245.8°C (well TD6). The maximum measured downhole pressure was during run P19 42.5 bar.
- The formation temperature profile estimated for well TD5 in 1998 is lower than the measured temperature profiles during the last 5 years. A new formation temperature profile was determined which follows a BPD curve with a water level at 50 m above surface. This confirms the existence of an upflow zone in the vicinity of well TD5. The maximum measured downhole temperature was 253°C at the bottom of the well.
- Generally, well TD6 pressure runs show small differences increasing step-by-step to the total depth. The maximum measured downhole pressure was in run P19, 42.5 bar. Wellhead pressure during downhole measurements P18 and P19 fluctuated from 21.5 to 22 bar-g. From below 300 m the curves for P13, P14 and P19 show slightly higher values than the BPD curve (Figure 9).
- The downhole well pressure and temperature measurements of the shallow wells indicate a reservoir thickness of about 250 m (220-255°C) for TD4, about 300 m (230-253°C) for TD5 and about 200 m (230-245°C) for TD6.

- During the production test of TD5 (2003 measurements) the steam flowrate, water flowrate and total mass flowrate remained nearly constant at a wellhead pressure of 18 bar-g, i.e. about 7 kg/s, 11.9kg/s and 19 kg/s, respectively. The average thermal power of the well was 24.5 MWt, which means that it is capable of producing about 2.4 MW of electricity.

The Hágöngur high temperature field:

- Maximum temperature recorded at the Hágöngur high-temperature field was 315.6°C, at a bottom depth of 2360 m. The Boiling Point for Depth curve (BPD) versus the measured temperature curves indicate that the well is below boiling conditions at all depths.
- Pressure logs indicate higher pressures than saturation pressures at the recorded temperatures. The maximum downhole pressure of 191.6 bars was measured at the bottom depth, 2360 m. The pressure logs show hydrostatic behaviour from the wellhead to the bottom of the well.
- The transmissivity (kh/μ) calculated (Figure 45) is about 9.0×10^{-9} m^3/Pas but formation storativity with skin effect 4.2×10^{-1} m/Pa. This does not represent true reservoir conditions. Such high values can only be obtained under phase transfer during boiling or in a reservoir with a free liquid surface. Neither is believed to be the case at the Hágöngur field.
- The well drilled in the Hágöngur field is promising but more wells are needed for prediction of the field's capacity.

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