The United Nations University

GEOTHERMAL TRAINING PROGRAMME
Orkustofnun, Grensásvegur 9,
IS-108 Reykjavík, Iceland

Reports 2002
Number 14

EVALUATION OF WELLBORE PARAMETERS FOR WELL HE-4, HELLISHEIDI, SW-ICELAND

Fessaha Tareke
Geological Survey of Ethiopia
Hydrogeology, Engineering Geology and Geothermal Studies Department
P.O. Box 33816, Addis Ababa
ETHIOPIA
geology@telecom.net.et

ABSTRACT

The Hellisheidi geothermal prospect is part of the Hengill high-temperature geothermal area and is considered to be a promising potential field for further exploration. Two deep exploration wells, HE-3 and HE-4, were directionally drilled in 2001. After completion of drilling, HE-4 was tested for its pressure response to step injection flow rates of 20.7, 30.6 and 45 l/s. The data was analysed to evaluate transmissivity, formation storage, wellbore storage and the skin of well HE-4 using semi-log analysis, type curve matching and the Lokur program. Furthermore, temperature and pressure logs were performed during injection, dynamic and warm-up periods of well HE-4. These profiles were analysed and revealed three main feed zones and two minor feed zones. They were also used to estimate the formation temperature and initial pressure near the well. Initial pressure at the well is evaluated using the PREDYP program and the formation temperature is estimated using the BERGHITI program. The program BERGHITI has two options, the Horner method and the Albright method. These two methods were used to evaluate the formation temperature of well HE-4 from the warm-up temperature profiles. The dynamic profiles were simulated by varying the number of feed zones, flow rate, and enthalpy contribution of each feed zone and the total enthalpy at wellhead, at wellhead pressure of 15 bar-a, using the wellbore simulator HOLA. A long-term production test was performed for well HE-4 in the year 2002. The well's discharge history for 147 days was analysed. Enthalpy of the well simulated by HOLA and the enthalpy obtained from the production test were compared and discussed.

1. INTRODUCTION

Iceland is located on the Mid-Atlantic ridge at the diverging plate boundaries of the American and European plates. The spreading direction is N10˚E and the drift velocity about 1 cm/year (Björnsson et at., 1986). A tectonic and volcanic active zone crosses the country in a complicated manner from southwest to northeast. In South Iceland, it is divided into two parallel branches but in the north, it is confined to one branch (Figure 1). The axial rift zone is under tensional stress parallel to the spreading

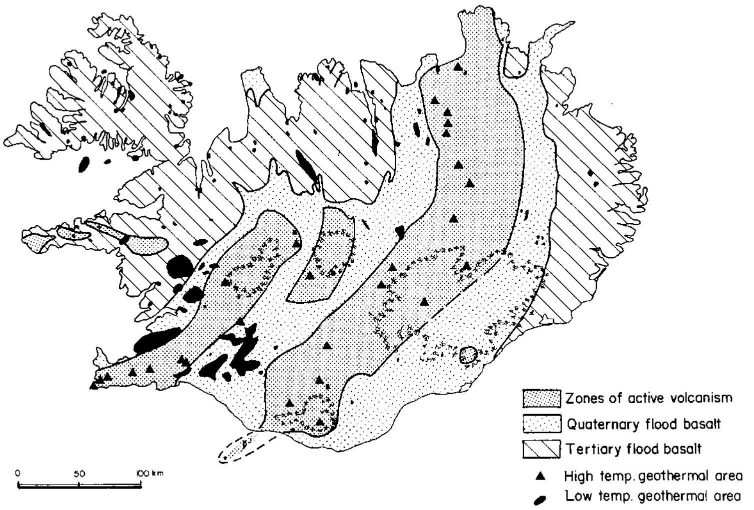

FIGURE 1: Geological map of Iceland

direction. Consequently, regional heat flow is very high (Pálmason, 1973) compared to most parts of the world.

Hydrothermal activity is widespread in the country (Bödvarsson, 1961). The thermal areas are divided into two categories on the basis of the maximum temperature in the uppermost kilometre. The base temperature is thus higher than 200°C in the high-temperature areas, but lower than 150°C in the low-temperature areas. The high-temperature areas are confined to, or on the margins of the active zones of rifting and volcanism (Pálmason and Saemundsson, 1974), and the heat source for each high- temperature area is thought to be local accumulation of igneous intrusions cooling at a shallow level in the crust. The low temperature areas are, on the other hand, in Quaternary and Tertiary volcanic terrain, and are thought to draw heat from the regional heat flow.

The Hellisheidi geothermal field is located in the southern part of Hengill geothermal area within the western branch of the Neovolcanic zone in SW-Iceland. Two major volcanic systems are situated within the Hengill geothermal area. One, the presently active Hengill system near the crest of the axial rift zone, is characterized by a major fissure swarm on which Hellisheidi geothermal prospect is located. The other, the extinct Hveragerdi volcanic system, has drifted about 5 km to the east, away from the rift axis during the last 500 thousand years.

As Hellisheidi is part of the Hengill high-temperature geothermal area, the active Hengill central volcano and its fissure swarms characterize its geology. Volcanic rocks of either tholeiitic or olivine tholeiitic basaltic composition characterize the surface geology of Hellisheidi geothermal prospect. The hyaloclastite ridges in the northeast, north and west of the field are composed of pillow lavas, breccias and tuffs formed during the last glacial period. Flat lying basaltic lavas covering the central part of Hellisheidi area are Postglacial and erupted 5000 and 2000 years ago (Figure 2). The major tectonic features include NE-SW trending normal fault swarms that are covered by Postglacial lavas in the central part of the field, but emerge out of the lava in the south. A few major faults and eruptive fissures cut through the lava and the hyaloclastite ridges in the east and the west.

Surface manifestations of geothermal activity in Hellisheidi geothermal field show both fossil and active thermal expressions as: steam vents, steaming grounds, warm soils and altered grounds (Saemundsson, 1995). There are no active geothermal manifestations found associated with Postglacial volcanic fissures. However, steam vents and warm soils are located along the eastern and western faults.

Geophysical surveys performed in Hellisheidi area outlined major geothermal prospects and located the most promising geothermal fields. The Hengill geothermal area, of which Hellisheidi is a part, is characterized by a resistivity low of 110 km^2 area at 200 m depth below sea level. Its central part contains a high-resistivity body below a low-resistivity layer that could be caused by dense intrusions, change in alteration minerals and transition from a water-dominated to a two-phase system at depth. In Hellisheidi geothermal area, the high-resistivity response is recorded at a depth where chlorite and epidote are the dominant minerals indicating temperatures above 230°C (Steingrímsson et al., 2001, Árnason et al., 2000).

The abundance of igneous intrusions at a shallow depth, fissure swarms, fault swarms and geothermal surface manifestations, in addition to results of other surface exploration methods, make the Hellisheidi geothermal area a good prospect. As a result, the Hellisheidi geothermal prospect was selected as a

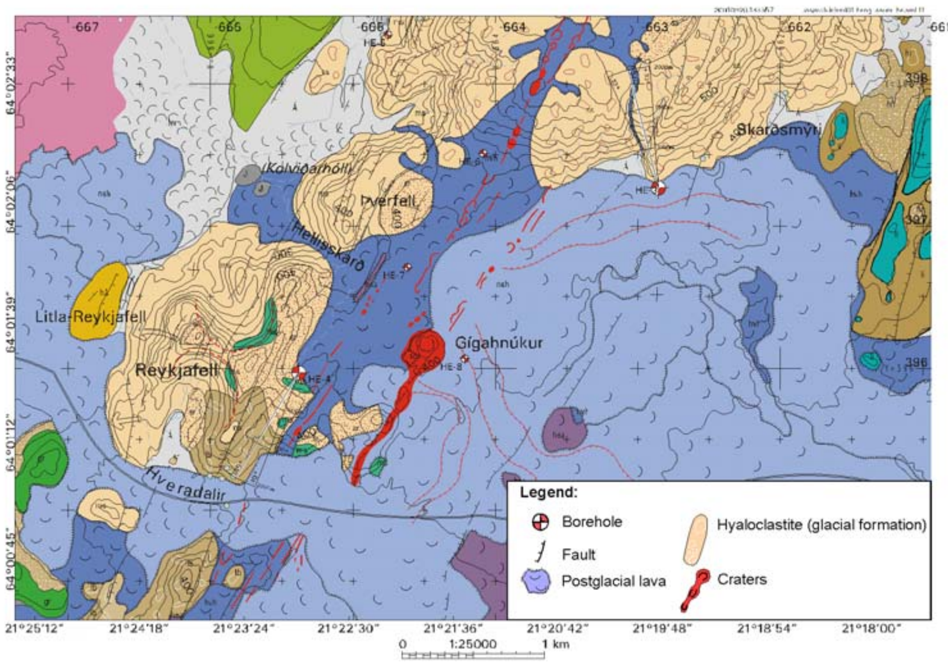

FIGURE 2: Gelogical map of the Hellisheidi area

promising potential field for further exploration and in 2001, two deep exploration wells, HE-3 and HE-4, were directionally drilled. Currently (2002), three additional deep exploration wells, HE-5, HE-6 and HE-7 are being drilled.

The purpose of this paper is to investigate the results of an injection test, a production test and determine formation temperature and formation pressure of the directionally drilled well HE-4 as a requirement for the author's completion of training in reservoir engineering for six months at the United Nations University Geothermal Training Programme. Well HE-4 is a directional well sited in Hellisheidi geothermal prospect within the Hengill high-temperature area and is located at coordinates (Lambert): X = 383491.82, Y = 393716.71 and 404 m elevation a.s.l. (Figure 2).

2. SUMMARY ON THE DRILLING OF WELL HE-4

HE-4 was directionally drilled to intersect a major fault, at an economic depth for exploiting geothermal energy. The fault is a tensional fault that is considered to be sub-vertical at the surface and inclining gradually with depth. The well was planned to have a depth of about 2000 m, kick-off point to be at about 300 m and an inclination build up of 2.5˚/30 m to an inclination of 30˚ in the direction of 208˚ +/-7˚. Drilling of the well was contracted and completed by an Icelandic drilling contractor, Jardboranir hf. The drilling plan, completion and casing programme of well HE-4 is given in Table 1 below and a diagram showing the casings design of the well is shown in Figure 3.

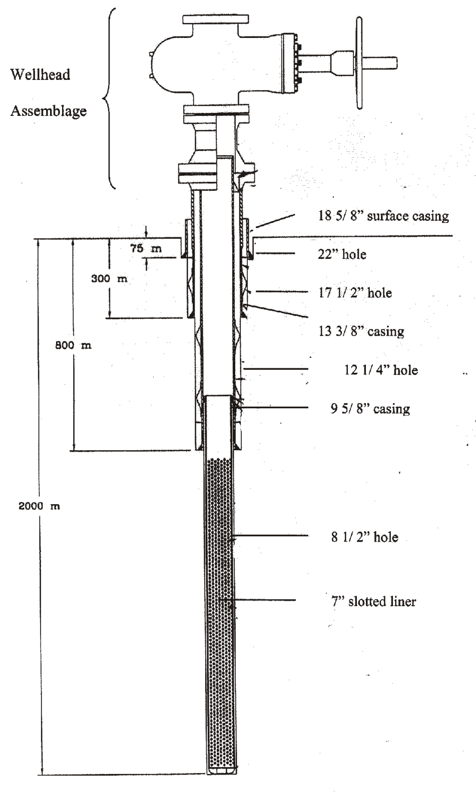

FIGURE 3: Planned design of casings of well HE-4

TABLE 1: Drilling plan, completion and casing programme of well HE-4

Casing type and diameter	Planned depth	Drilled depth from derrick	Actual casing depth (m)
Surface casing 18 ⅝”	75 m	78 m	77 m
Anchor casing 13 ⅜”	300 m	305 m	295 m from flange
Production casing 9 ⅝”	800 m	789 m	779 m from flange
Liner casing 7"	2000 m	2008 m	751 to 1981 m from flange

3. WELL TESTING

3.1 Theoretical background on well testing

In a well test, the pressure response in a well is monitored as production or injection is changed in order to evaluate the properties that govern the nature of the reservoir. The response is indicative for the characteristic of flow or deliverability properties of the reservoir. Mathematical models are then developed to relate pressure responses to flow rate history. The pressure diffusion equation is the basis for all models that are used to calculate the pressure response in the reservoir at a certain distance (r) from the producing or injected well after a given time (t).

3.1.1 Pressure diffusion equation

The three governing laws that are used in deriving the pressure diffusion equation are

a) Law of conservation of mass

$$mass_{in} - mass_{out} = rate\ of\ change\ of\ mass\ accumulation$$

b) Law of conservation of momentum - Darcy’s law

$$q = 2\pi h \frac{k}{\mu}\frac{\partial P}{\partial r} \tag{1}$$

c) Equation of state

$$c = \frac{1}{\rho}\left(\frac{\partial \rho}{\partial P}\right)_T \tag{2}$$

From the above mentioned governing laws and equation of state, the following radial pressure diffusion equation can be derived.

$$\frac{\partial}{\partial r}\left(\frac{r\,\partial P(r,t)}{\partial r}\right) = \frac{\mu c_t}{k}\left(\frac{\partial P(r,t)}{\partial t}\right) \tag{3}$$

The radial pressure diffusion equation is a partial differential equation that describes isothermal flow of fluid in porous media and how the pressure, $P(r, t)$, diffuses through the reservoir. Initial and boundary conditions are required to solve for $P(r, t)$. For an infinite acting reservoir, the boundary conditions are given as follows:

a) Initial condition

$$P(r,t) = P_i \qquad for\ t = 0, \quad r > 0 \tag{4}$$

b) Inner and outer boundary conditions

$$P(r,t) = P_i \qquad r \to \infty \quad and \quad t > 0 \tag{5}$$

$$q = 2\pi r \frac{kh}{\mu}\frac{\partial P}{\partial r} \qquad r \to 0 \quad and \quad t > 0 \tag{6}$$

The solution of the radial pressure diffusion equation for the above given time and boundary conditions is then

$$P(r,t) = P_i + \frac{q\mu}{4\pi kh} E_i\left(-\frac{\mu c_t r^2}{4kt}\right) \tag{7}$$

E_i is the exponential integral function and is defined as

$$E_i(-x) = -\int_0^{\infty} \frac{e^{-u}}{u} du \qquad with \quad x = \frac{\mu c_t r^2}{4kt}$$

For $x < 0.01$:

$E_i(-x) \cong 0.5772 + \ln x$, $\gamma = 0.5772$ is Euler`s constant and $\ln x = 2.303 \log x$.

Therefore, if $t > 100\mu c_t r^2 / 4k$, then the solution for the radial pressure diffusion equation can be simplified as

$$P(r,t) = P_i + \frac{2.303\, q\mu}{4\pi kh}\left[\log\left(\frac{\mu c_t r^2}{4kt}\right) + \frac{\gamma}{2.303}\right] \tag{8}$$

This solution for the radial pressure diffusion equation is called the Theis solution or line source solution (Hjartarson, 2002). In deriving the Theis solution the following assumptions are inherent:

1. The flow is considered to be isothermal and radial;
2. The reservoir is homogeneous, isotropic, has infinite horizontal extent and uniform thickness;
3. The producing well penetrates the entire formation thickness;
4. The formation is completely saturated with a single-phase fluid.

3.1.2 Semi-logarithmic well test analysis

The Theis solution can be written as:

$$P_i - P(r,t) = \frac{2.303 q\mu}{4\pi kh}\left[\log\left(\frac{4k}{\mu c_t r^2}\right) - \frac{\gamma}{2.303}\right] + \frac{2.303\, q\mu}{4\,\pi kh}\log(t) \tag{9}$$

The above equation is in the form $\Delta P = A + m \log(t)$, which is a straight line with slope m on a semi-log graph where

$$\Delta P = P_i - P(r,t); \qquad A = \frac{2.303\, qu}{4\pi kh}\left[\log\left(\frac{4k}{\mu c_t r^2}\right) - \frac{\gamma}{2.303}\right]; \quad and \quad m = \frac{2.303\, q\mu}{4\,\pi kh}$$

Transmissivity, T, can be calculated from the slope of the semi-log straight line.

$$T = \frac{kh}{\mu} = \frac{2.303\,q}{4\pi m} \tag{10}$$

If the temperature is known, then the dynamic viscosity can be inferred from steam tables or the Icebox program Tafla and, thus, the permeability thickness, kh, may be calculated as follows:

$$kh = \frac{2.303\,q\mu}{4\pi m} \tag{11}$$

The formation storativity, $S = c_t\,h$, is then obtained from the intercept when the permeability thickness is known. The Theis solution can be written as

$$\Delta P = -\,m\left[\log\frac{S\mu r^2}{4kht} + \frac{\gamma}{2.303}\right] \tag{12}$$

$$\Rightarrow 10^{\frac{\Delta P}{m}} = \left(\frac{kh}{\mu}\right)\left(\frac{1}{S}\right)\left(\frac{t}{r^2}\right)\left(4 \times 10^{\frac{-\gamma}{2.303}}\right) \tag{13}$$

And the storativity can be obtained as:

$$S = 2.25\left(\frac{kh}{\mu}\right)\left(\frac{t}{r^2}\right) \times 10^{\frac{-\Delta P}{m}} \tag{14}$$

Since $kh/\mu = T$, then

$$S = 2.25\left(\frac{Tt}{r^2}\right) \times 10^{\frac{-\Delta P}{m}} \tag{15}$$

Thus a plot of ΔP versus log(t) gives a semi-log straight-line response for the infinite acting radial flow of a well and is referred to as **semi-log analyses**. The semi-log analysis is based on the location and interpretation of the semi-log straight-line response that represents the infinite acting radial flow behaviour of the well. However, as the wellbore has a finite volume, it becomes necessary to determine the duration of the wellbore storage effect or the time at which the semi-log straight line begins. The Theis solution for a constant rate drawdown test is based on the assumption that the down-hole production rate or injection rate changes instantaneously from zero to its constant value. However, due to wellbore storage effect, the fluid flow out of the wellhead is not always the same as the flow from the reservoir into the well. That is, if a well is suddenly opened, the wellbore pressure will drop causing expansion in boiling wells and water level depletion in non-boiling wells at the beginning. Similarly, if a well is suddenly shut in, the down-hole flow doesn't stop immediately but slowly tapers off. Several other factors can contribute to the wellbore storage effect but these above are the main factors. Therefore, it is always important to begin a semi-log analysis by considering the wellbore storage effect to gain confidence in locating the semi-log straight line correctly. The wellbore storage shows as a unit slop straight line on a log-log plot of ΔP versus t. As a working rule, there is about 1½ log cycles between the end of the unit slop straight line representing wellbore storage and the start of the purely infinite acting reservoir response. This 1½ log cycle rule provides a useful method of identifying the start of the semi-log straight line.

The wellbore storage coefficient, C (m^3/Pa), is defined as the volume of fluid that the wellbore itself will produce due to a given pressure drop and is written as

$$C = \frac{\Delta V}{\Delta P} \tag{16}$$

and for a well with free fluid level,

$$C = \frac{V_u}{\rho g} \tag{17}$$

where V_u = Wellbore volume per unit length in m^3;
ρ = Density in kg/m^3;
g = Gravitational acceleration in m/s^2.

The fluid expansion storage coefficient applies to a completely filled well and is given by

$$C = c_f\, V_w \tag{18}$$

where c_f = Fluid compressibility;
V_w = Volume of wellbore.

Sometimes, there is a zone surrounding the well that is invaded by mud filtrate, cement or cuttings during drilling and completion of the well, where the permeability is not the same as in the reservoir. This zone is called the skin zone and measures how well the borehole is connected to the reservoir. It produces an additional pressure change, ΔP_s, in the near vicinity of the wellbore to the normal reservoir pressure change due to production.

$$\Delta P_s = \frac{q\mu}{2\,\pi kh} \times s \tag{19}$$

where s is the skin factor which is dimensionless.

If the skin factor is negative, the permeability of the skin zone is greater than that of the reservoir and the well is said to be stimulated. On the other hand, if the permeability of the skin zone is less than that of the reservoir, the skin factor will be positive and the well is said to be damaged. Skin factor can be used to calculate the radius of the skin zone if the permeability of the skin zone k_s and the permeability of the reservoir k are known:

$$s = \left(\frac{k}{k_s} - 1\right)\ln\frac{r_s}{r_w} \tag{20}$$

Skin has a similar effect as changing the effective radius of the wellbore.

$$r_{wa} = r_w\, e^{-2s} \tag{21}$$

In a pumping well with skin, the total pressure change is given by

$$\Delta P_t = \Delta P + \Delta P_s \qquad or \qquad \Delta P_t = P_i - P(r_w, t) + \Delta P_s \tag{22}$$

or

$$\Delta P_t = \frac{-2.303\,q\mu}{4\pi kh}\left[\log\left(\frac{\mu c_t r_w^2}{4kt}\right) + \frac{\gamma}{2.303}\right] + \frac{2sq\mu}{4\pi kh} \tag{23}$$

The above equation is used to deal with the additional pressure drop due to the skin effect during well testing. In the semi-log analysis, the skin factor doesn't affect the evaluation of transmissivity but it does affect the evaluation of storativity as shown in the equation below:

$$c_t h e^{-2s} = 2.25\left(\frac{kh}{\mu}\right)\left(\frac{t}{r_w^2}\right)\times 10^{\frac{-\Delta P_i}{m}} \tag{24}$$

In general, the steps involved in a semi-log analysis are:

a) Draw a log-log plot of ΔP versus Δt;
b) Determine the time at which the unit slop line representing wellbore storage ends;
c) Note the time 1½ cycle ahead of that point, which is the time at which the semi-log straight line can be expected to start;
d) Draw a semi-log plot of ΔP versus Δt change in time;
e) Look for the straight line, starting at the suggested time point;
f) Estimate the transmissivity and storativity depending on the skin effect; and
g) Estimate the skin factor.

3.1.3 Dimensionless variables and type curve well test analysis

Well test analysis often makes use of dimensionless variables in order to simplify the reservoir models by embodying the reservoir parameters, thereby generalizing the pressure equations and solutions. They have the advantage of providing model solutions that are independent of any particular unit system. Different reservoir models may have different boundary conditions giving rise to different solutions of the pressure diffusivity equation. Some of the solutions are mathematically complicated and are therefore expressed as type curves that are dimensionless solutions associated with a specific reservoir model. Each reservoir model has its own type curve that is independent of reservoir and fluid properties. The appropriate reservoir model of a well test is found by plotting pressure transient data from a well test on a log-log graph and comparing it with various type curves. The following dimensionless variables are substituted to the pressure diffusivity equation:

a) Dimensionless pressure, P_D

$$P_D = \frac{2\pi kh}{q\mu}\left(P_i - P(r,t)\right) \tag{25}$$

b) Dimensionless time, t_D

$$t_D = \frac{kt}{c_t \mu r^2} \tag{26}$$

c) Dimensionless radius or distance, r_D

$$r_D = \frac{r}{r_w} \tag{27}$$

Generally, the procedure for type curve analysis can be outlined as follows:

1. The data is plotted as log ΔP vs. log Δt in the same scale as that of the type curve.
2. The curves are then moved one over the other by keeping the vertical and horizontal grid lines parallel until the best match is found.
3. The best match is chosen and the pressure and time values are read from a fixed point on both graphs, ΔP_M, P_{DM}, Δt_M and t_{DM}.

4. For an infinite acting system the transmissivity is evaluated from

$$T = \frac{kh}{\mu} = \frac{q}{2\pi}\left(\frac{P_D}{\Delta P}\right)_M \tag{28}$$

5. And the storativity is calculated as

$$S = c_t h = \frac{kh}{\mu r_w^2}\left(\frac{\Delta t}{t_D}\right)_M \tag{29}$$

3.2 Injection test

In an injection test, fluid is injected into the well at a constant rate while the increase in downhole pressure is measured. It is conceptually similar to the drawdown test except that the fluid flows into the well rather than out of it. It is used as a primary test to deduce geothermal properties and future productivity of a newly drilled well. Transmissivity, storativity and skin effect are calculated from injection test data by using both semi-log analysis and type curve matching methods.

3.2.1 Analysis of injection test of HE-4

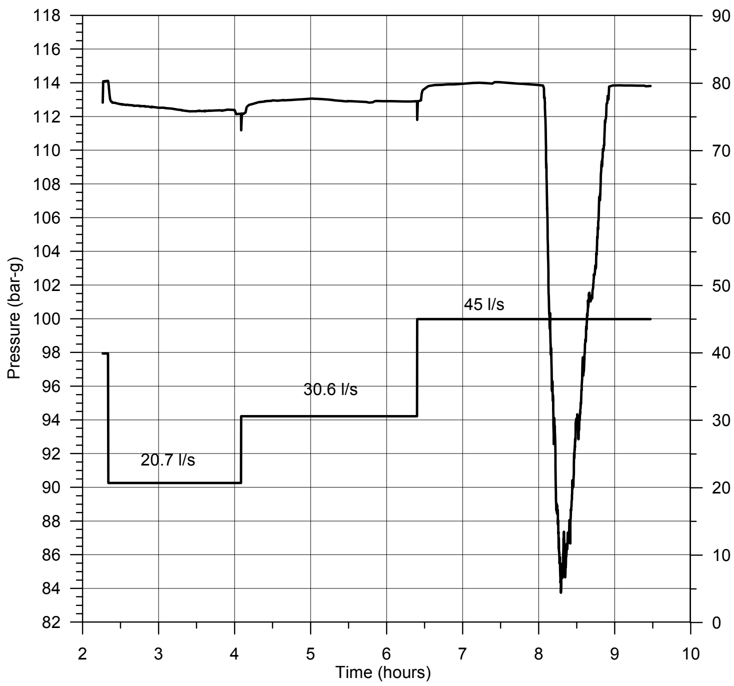

FIGURE 4: Pressure and flow rate variation during injection test

After completion of the drilling, well HE-4 was initially injected by 39.9 l/s of water to wash out formations from invasion of filtrate and cuttings formed during drilling. This will help to alleviate the skin effect problem and achieve a stabilized flow rate before the injection test. Thereafter, step injection flow rates of 20.7, 30.6 and 45 l/s were followed for the purpose of the injection test. The pressure gauge was located at a depth of 1710 m prior to the start of the injection test. Data collection was started before a change was made in the injection flow rate and saved before the rate was changed for the next step. There was no interruption in changing the flow rate from one to the other. The test was performed on 12/10/2001 from 02:15:00 to 09:30:00, the duration of each injection step being 110, 140 and 185 minutes for the 20.7, 30.6 and 45 l/s, respectively. Downhole pressure at 1710 m depth during the injection test and the flow steps are shown in Figure 4.

The injection test data were analysed by using semi-log (Figure 5) and type curve matching methods (Figure 6) to calculate the transmissivity and formation storage for the well. In the semi-log plot of ΔP vs. Δt, care was taken in identifying the infinitely acting radial flow straight-line part of the plot, in order to avoid the wellbore storage effect in the early time of the plot. Then, the straight line was inferred and its slope deduced in the calculation of transmissivity and formation storage. To use the type curve matching method, ΔP vs. Δt was plotted and matched for the best fit between the data and the theoretical

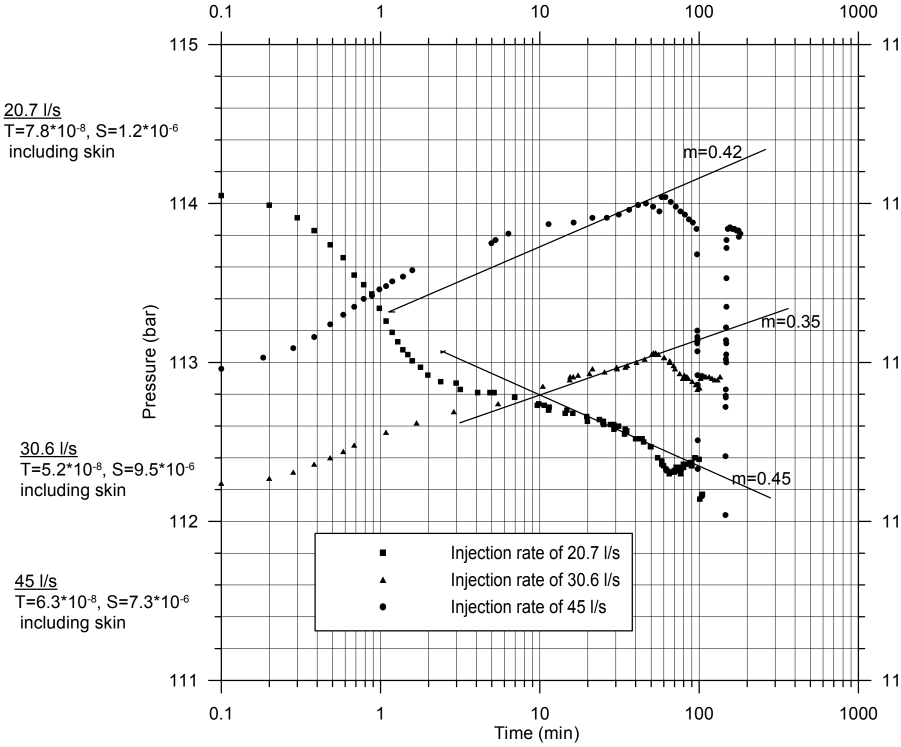

FIGURE 5: Plot of semi-logarithmic analysis of well HE-04

exponential integral solution for a single well in an infinite system, wellbore storage and skin effects included. A program called Lokur, an Icelandic program used to calculate wellbore parameters during well testing, was also applied to the injection test of well HE-4. Lokur enables the use of different models to be tried for the best fit of the raw data and calculates transmissivity, formation storage, wellbore storage and skin effects.

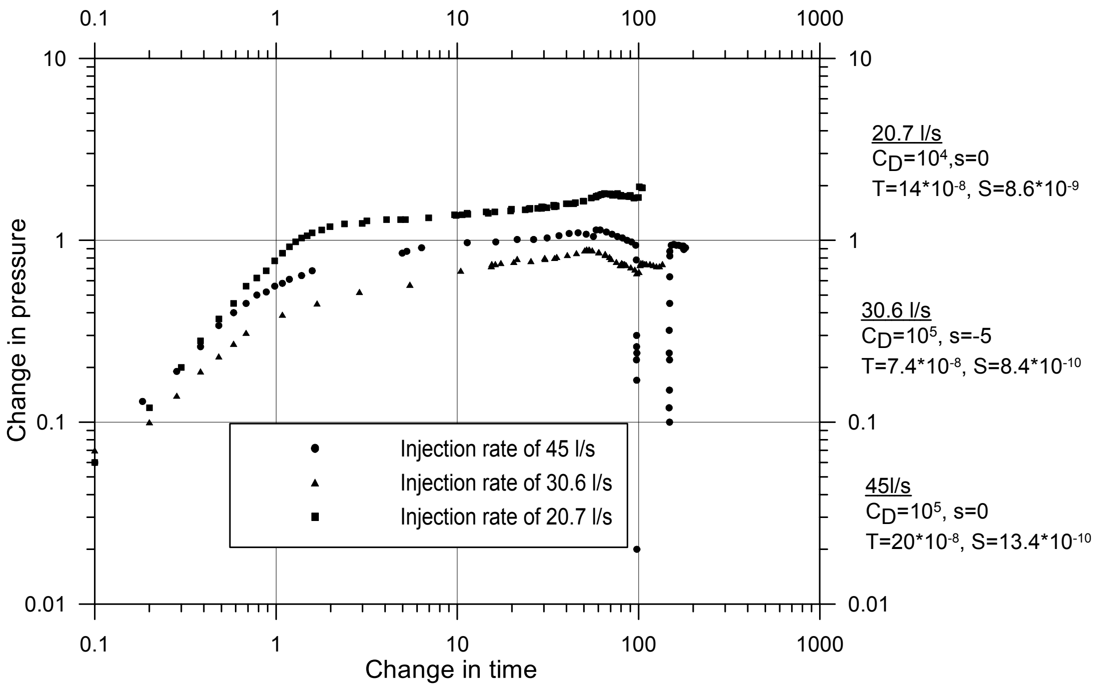

FIGURE 6: A log-log plot of injection test of well HE-04 used in the type curve matching analysis

The values of transmissivity, formation storage, wellbore storage and skin for HE-4 as calculated from injection test data by using the semi-log, type curve matching and the program Lokur are shown in Table 2 below, and the output plot of the Lokur program is shown in Figure 7.

TABLE 2: Results of the semi-log, type curve matching and Lokur program

Method	Injection rate (l/s)	Transmissivity (m^3/Pa s)	Formation storage (m/Pa)	Wellbore storage	Skin
Semi-log analysis	20.7	7.8×10^{-8}	1.2×10^{-6} skin effect included	-	-
	30.6	5.2×10^{-8}	9.5×10^{-6} skin effect included	-	-
	45	6.3×10^{-8}	7.3×10^{-6} skin effect included	-	-
Type curve matching	20.7	14×10^{-8}	8.6×10^{-9}	10^4	0
	30.6	7.4×10^{-8}	8.4×10^{-10}	10^5	-5
	45	20×10^{-8}	13.4×10^{-10}	10^5	0
Lokur program	20.7	5.1×10^{-8}	1.2×10^{-8}	8480	-1.7
	30.6	8.2×10^{-8}	7.5×10^{-8}	1516	-1.9
	45	14×10^{-8}	4.7×10^{-8}	2245	-0.05

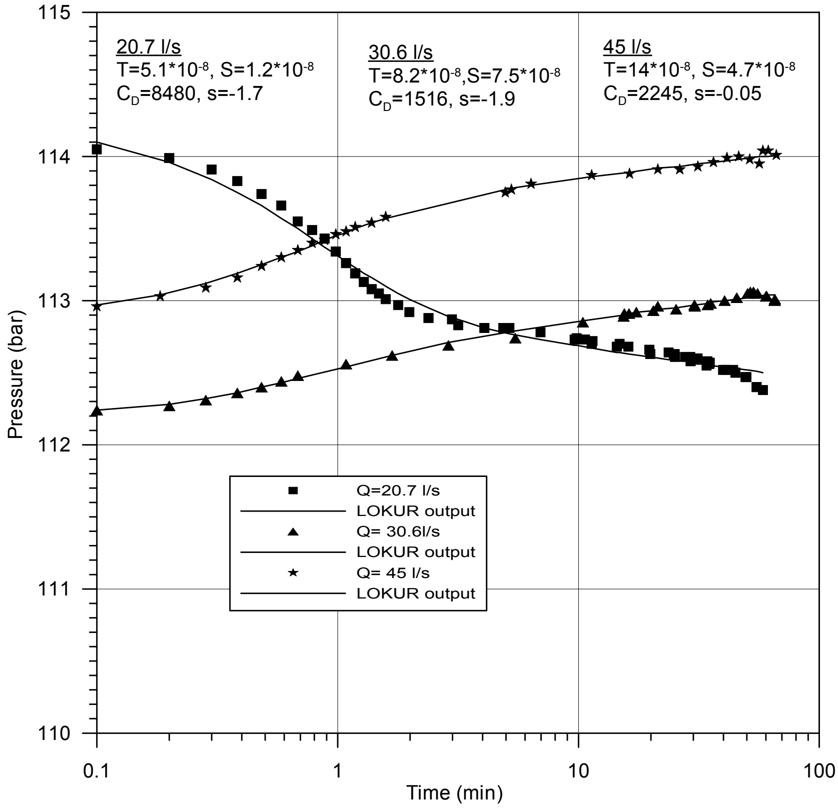

FIGURE 7: Semi-logarithmic plot of the output of Lokur program

The parameters calculated for the three step injection rates by semi-log analysis are closer in their values than those of the type curve matching method. This could indicate that when both semi-log and type curve analysis are possible, the semi-log analysis is preferable. On the other hand, it is often difficult to select the best type curve as the difference between the curves is small. It may be advantageous to have a rough estimate of some parameters beforehand, to select the most appropriate curve. The type curve analysis, in this case, is used to give some additional information. It shows that the early data for less than twenty minutes deviates from the later data not apparent in the semi-log analysis. The early data was influenced by wellbore storage and skin or other possible factors and therefore the semi-log plot was refined to get the correct straight line. The correct straight line was identified by taking into consideration the general working rule that the wellbore storage effect shows up as a unity slope line at the beginning of the log-log plot and the correct straight line starts 1 ½ cycle after the unit slope line ends. Using the type curves was difficult as the curves were very similar, so that any match would be imprecise. As a result, the parameters calculated by using semi-log analysis were considered more reliable than those obtained from the type curve matching.

The parameters calculated by using semi-log analysis were used as input parameters in the Lokur program. The program iterates the parameters to get the best fit and also evaluates the wellbore storage and skin, which is not possible in the semi-log method. The analytical models used to fit the data are the double porosity model and the Theis model with wellbore storage and skin present. Parameters calculated by using these two models had no significant difference in the results. Therefore, the double porosity model was preferred, as the well was drilled to intersect a sub-vertical fault at an economical depth that could be a fractured main feed zone. The results of the Lokur calculation are given in Table 2, and the match in Figure 7. The output parameters of the Lokur program were considered to be the most reliable of the three analysis methods and represent the response of well HE-4 to the step injection test.

The evaluated skin effect of well HE-4 using the Lokur program for the 20.7 and 30.6 l/s injection rate is about –1.8. This became about –0.05 in the third step when the injection rate was 45 l/s, indicating that the skin effect was becoming more positive with increasing injection flow rate attributed to an increase in turbulence flow. Since the calculated skin factor was negative, drilling mud and cuttings should not have obstructed fluid flow to the well during the injection test.

4. TEMPERATURE AND PRESSURE LOGS OF HE-4

Downhole temperature and pressure logs are needed in the equations for sub-surface heat and mass flux as primary variables and are easily and directly collected in wells. They are also most important in quantifying geothermal reservoirs as a basis for conceptual and numerical reservoir models. Information obtained from pressure and temperature logs in a geothermal wells is useful in determining thermal gradients and heat flow, location of aquifers, reservoir temperature, the physical state of reservoir, flow patterns and management of geothermal fields. In addition during drilling, temperature logs are useful in blowout risk evaluation, cooling due to circulation and cold water pumping on the wellhead, and determining bottom hole temperature. The main problem with downhole measurements during disturbed conditions is that temperatures and pressures in the wellbore do not match those in the reservoir (Björnsson, 2002; Stefánsson, and Steingrimsson, 1990).

Temperature and pressure logs during drilling, during the injection test and after the injection test were taken from HE-4. These data were analysed to estimate the formation temperature and pressure, locate possible aquifer zones and simulate the flow pattern of the well.

4.1 Temperature logs

Downhole temperature profiles from HE-4 are shown in Figure 8. They include; one profile during injection, five profiles during the warm-up period and one profile when the well was flowing. The profiles were used to evaluate formation temperature and to locate the main feed zones. The injection temperature profile shows two main aquifers. One, an inflow aquifer is expressed as a step change, located at 1150 m depth.

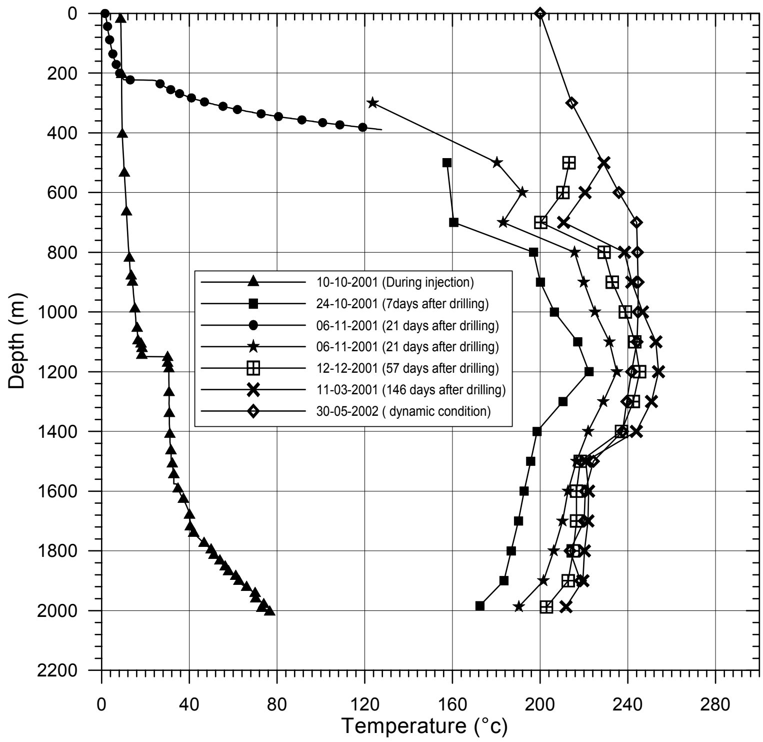

FIGURE 8: Injection, warm-up and dynamic temperature profiles of HE-4

The other, an outflow aquifer is indicated by a change in the temperature gradient, located at a depth of about 1550 m. Two additional minor aquifers are also indicated by the injection temperature profile as an increase in the temperature gradient and are located at 1720 m and near the bottom. The temperature warm-up profiles showed a similar pattern during the warm-up period. During warm-up, the interval from 800 m to 1150 m heated up by conduction. No aquifer cross flows were indicated by the temperature profiles and the well is blind-cased above 800 m depth. At about 1150 m depth, an aquifer flows into the well during injection and warm-up, indicated by a step temperature increase and change in temperature gradient, respectively. This caused a minor flow of fluid in the well from the 1150 m aquifer. The decreasing temperatures below 1400 m were partly due to cooling of the formation during drilling and partly due to lower formation temperatures below 1400 m measured depth. The warm-up temperature profiles indicated a main feed zone at about 1400 m depth, expressed as a change in the temperature gradient. The slight change in temperature of the warm-up profiles at the bottom of the well is also an indication of a possible minor feed zone. Generally, some of the aquifers identified from the injection profiles were also indicated in the warm-up temperature profiles. The aquifers deduced from the temperature profiles are summarized in Table 3.

TABLE 3: Possible aquifers (feed zones) in HE-4 deduced from the temperature profiles

Aquifer location (m)	Aquifer potential	Flow type	Remark
1150	main	Inflow	Indicated in the injection and warm-up temperature profiles
1400	controlling aquifer	Out flow	Manifested in the warm-up profiles
1550	main	Out flow	Expressed in the injection profile
1720	minor	Out flow	Manifested in the injection profiles
Bottom	minor	Out flow	Manifested in both profiles

4.2 Estimation of formation temperature of HE-4

During drilling, the well and the surrounding rock are cooled. When drilling stops, it takes the temperature some time to recover to its initial values. Whether aquifers warm up more rapidly than the dry rock part of the well depends on the well condition. When flow is not present in the well, the aquifers usually warm up more slowly than the rest of the well, as aquifers experience more cooling during drilling. If on the other hand, fluid flow or boiling exists in the well, the reverse situation may easily occur. Therefore, warm-up temperature profiles should be carefully analysed and associated to other information, especially on well conditions, in order to evaluate the formation temperature of a well.

Formation temperature serves as a base for conceptual models and is important in decision making on well completion. For this reason, the formation temperature of well HE-4 is evaluated from the warm-up temperature logs by considering the condition of the well during measurements and then extrapolating the data at each depth to an infinite time. The Icebox program, Berghiti, was used to estimate the formation temperature and compare it to the warm-up temperature values at different depths. The program uses a semi-analytical method to estimate formation temperature from a time series of temperature logs taken during well warm-up. Two methods, the Horner plot and the Albright plot, are used to estimate formation temperature with this program. The Horner plot of temperature recovery is applied for longer warm-up histories, (weeks to months), and the Albright method is applied for short time intervals, usually a few days.

The solution to the heat diffusion equation in radial coordinates is found by integrating the instantaneous response of a linear heat source over the cooling time duration t_o and is given by

$$T(t) - T_f = \frac{q}{4\pi K} \ln \frac{t}{t - t_o} \tag{30}$$

where t_o = Cooling time;
q = Rate of heat removed from rock;
t = Time passed from drill bit intersection;
T_f = Formation temperature; and
$T(t)$ = Temperature at any time in the well.

Thus, in the Horner plot, $T(t)$ vs. ln $(t/(t+t_o))$ is plotted and the temperature at which the line crosses the $T(t)$ axis is taken to be the formation temperature. The method does not require that q and K are known but q should be constant during drilling. The basic criterion for the technique is the straight line relationship between the maximum bottom hole temperature and ln τ and that $\lim_{t\to\infty} \ln\tau = 0$. Using this and the fact that the system must have stabilized after infinite time, the maximum bottom hole temperature as a function of $\ln\tau$ is plotted and then a straight line is inferred through the data. The formation temperature is obtained by extrapolating the straight line to $\ln\tau = 0$ (Arason and Björnsson, 1994).

The Albright method assumes that for an arbitrary time interval much shorter than the total recovery time, the rate of temperature relaxation depends only on the difference between the borehole temperature and the formation temperature. If the whole logging time is represented as $I = [t_1, t_N]$, where N is the number of data points in the log, then for any time interval $i \in I$, $i = [t_a, t_b]$, there is T_∞^i, c^i, and T_o^i for $\forall\, t \in i$ that gives the best solution to the equation

$$e^{-c^i t} = \frac{T_\infty^i - T^i(t)}{T_\infty^i - T_o^i} \tag{31}$$

where $T^i(t)$ = Temperature at time t, $t \in i$;
T_∞^i = Estimated equilibrium temperature for the time interval i;
T_o^i = Temperature at the beginning of the time interval i;
c^i = Constant.

The formation temperature is determined assuming a linear dependence of c^i on T_∞^i. Plotting c^i as a function of T_∞^i, a straight line is inferred through the data and extrapolated for the x-axis interception to find the value of $T^{ii}(t)$ as $t \to \infty$.

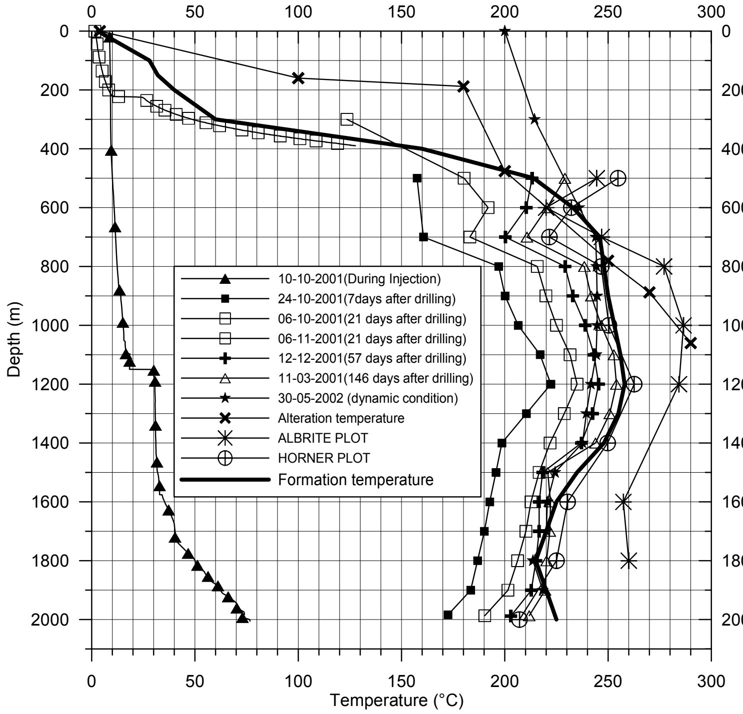

FIGURE 9: Horner, Albright and evaluated formation temperature plot with the other temperature profiles

The warm-up temperature data of HE-4 were analysed using the Horner and Albright methods to determine the formation temperature. Formation temperature obtained using the Horner and Albright methods is plotted with other temperature profiles for comparison (Figure 9). The warm-up temperature profiles got closer and closer as the warm-up period increased, implying that the well was approaching thermal equilibrium after a short time which was also reflected in the formation temperature evaluated using the Horner method. However, the Albright method and the alteration temperature seemed to overestimate the formation values compared to the other profiles. Moreover, the dynamic temperature profile reflected the formation temperature at the bottom of the hole. There is no down-flow of fluid in the well during dynamic conditions. Results of the analysis give the initial estimation of the formation temperature for well HE-4. The formation temperature values are shown in Table 4 and plotted in Figure 9.

4.3 Pressure logs

Pressure is a property that is directly related to the reservoir fluid. Reservoir pressures indicate fluid flow patterns and/or permeability variations. These pressures in a wellbore match the feed point pressure in the reservoir if there is only one feed. However, for multiple feeds the wellbore and reservoir pressures do not match even at the feed points, as there is interzonal flow. Thus, pressure logs of geothermal wells need to be transformed from well pressures to reservoir pressures. A pressure control point can be identified in multi-feed wells by finding a pivot point in the pressure profiles during warm-up. The main feed zone in a well is located at or close to the pressure pivot point where pressure is constant at this depth, due to good hydraulic connection to the reservoir; the warm-up pressure profiles revolve around this point (Björnsson, 2002; Stefánsson and Steingrímsson, 1990).

4.4 Estimation of initial reservoir pressure of HE-4

From the plots of pressure profiles during the warm-up period, the pivot point in well HE-4 is determined to be at a depth of about 1400 m as shown by an arrow in Figure 10. It also indicates that the controlling feed zone of the well is located at about this depth. Program PREDYP (Björnsson, 1993), in ICEBOX, was used to evaluate the initial pressure at the well. The program computes pressure in a static water column if the temperature of the column, and either the water level measured from wellhead or the well head pressure, are known. The pressure at the pivot point was used as a control point to determine the initial pressure below 700 m. The estimated formation temperature is used and the water level varied until the pressure at the pivot point is met. For the depth between 300 and 700 m, the controlling point is the over-pressure data taken during drilling, 51 bar at depth 500 m observed as blow-out, which is considered the exact initial pressure value of the feed zone at this depth. Initial pressure at the upper part of the well, above 300 m is evaluated by taking the regional water level of the cold ground water reservoir in the vicinity of the well. Thus, the initial pressure divides into three parts: the groundwater reservoir (0-300 m), a geothermal over-pressurized zone (300-700 m), and the main geothermal reservoir zone below 700 m. The evaluated initial pressures and formation temperatures are tabulated in Table 4 and plotted in Figure 11.

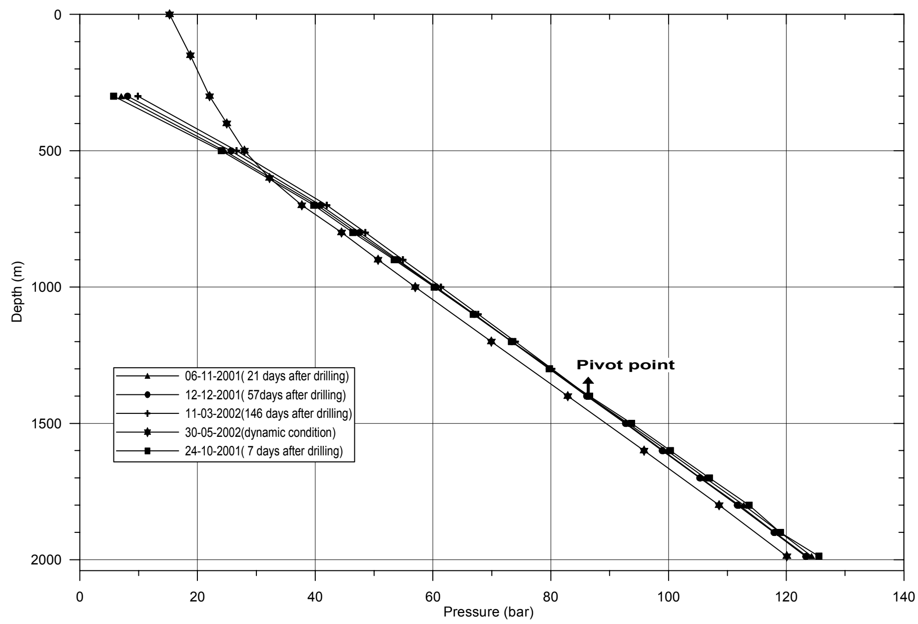

FIGURE 10: Warm-up and dynamic pressure profiles of HE-4

TABLE 4: Evaluated formation temperature and initial pressure of well HE-4

Measured depth (m)	Vertical depth (m)	Evaluated initial pressure (bar)	Evaluated formation temperature (C˚)
0	0	0	3
100	100	0	28
150	150	4.87	32
200	200	9.75	40
300	300	19.46	60
400	400	42.52	160
500	498	50.97	214
600	592	58.75	233
700	679	42.03	246
800	760	48.47	248
900	841	54.85	250
1000	922	61.2	253
1100	1002	67.45	256
1200	1083	73.7	258
1300	1162	79.89	255
1400	1241	86.12	248
1500	1322	92.61	235
1600	1400	99.03	225
1700	1478	105.48	220
1800	1555	111.86	215
1900	1629	118.06	220
2000	1700	123.98	225

4.5 Analysis of dynamic temperature and pressure profiles using the HOLA wellbore simulator

The wellbore simulator HOLA reproduces the measured flowing temperature and pressure profiles in flowing wells, and determines the relative contribution of each feed zone for given discharge conditions. The flow within the well is assumed in steady-state at all times, but time changing reservoir pressures are allowed. It can handle both single and two phase flows in vertical pipes. It solves numerically the differential equations that describe the steady-state energy, mass and momentum flow in a vertical pipe.

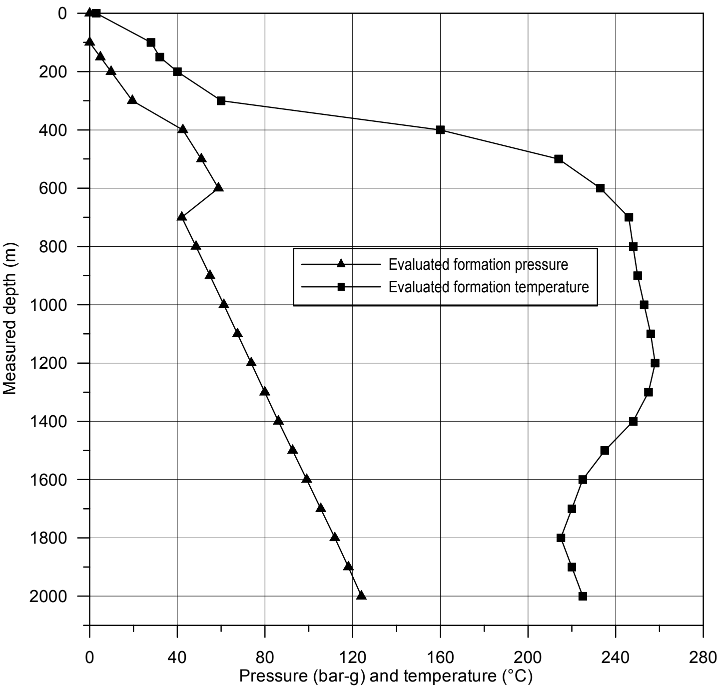

FIGURE 11: Evaluated formation pressure and temperature

The simulator HOLA offers six modes of calculating downhole conditions in geothermal wells. The six modes of calculating downhole conditions are briefly explained in its user's guide (Björnsson, et al., 1993). The

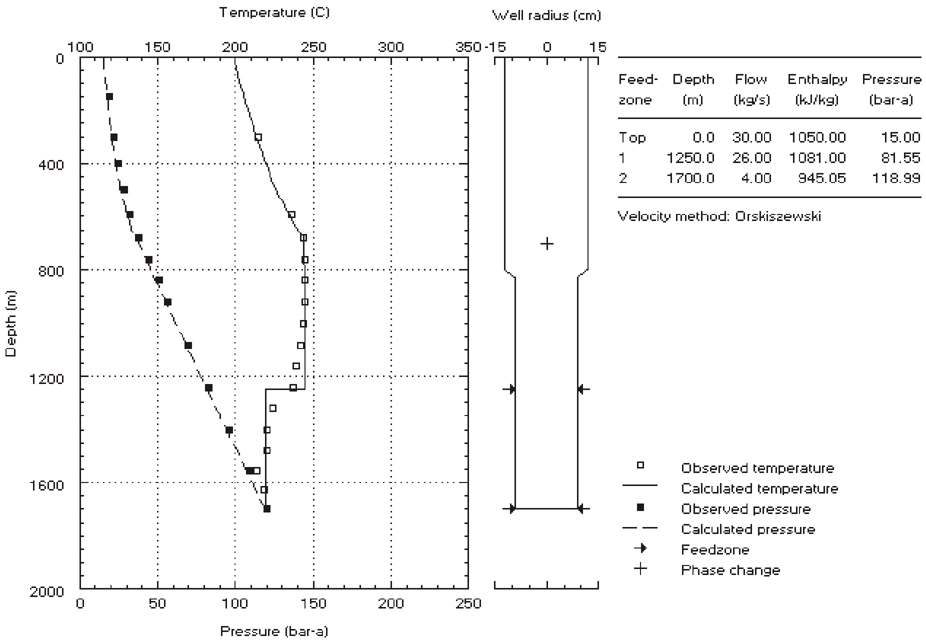

FIGURE 12: Output of Hola wellbore simulator of well HE-4

mode used for simulating the dynamic profiles of HE-4 is option 1: outlet conditions known at the wellhead that calculate pressure, temperature and saturation profiles from given wellhead conditions, and given flow rates and enthalpies at each feed zone except the bottom one.

One set of dynamic profiles from well HE-4 was simulated by varying the number of feed zones, enthalpy at wellhead of flow contribution and enthalpies of each feed zone. Wellhead pressure, 15 bar-a, was measured during the flow test. The output wellbore parameters, pressure and temperature, are then compared with that of the dynamic pressure and temperature logs taken during discharge. Accordingly, the best fit is found for two feed zone cases and wellhead enthalpy of 1050 kJ/kg. The two feed zones are found at 1250 m vertical depth (1400 m measured depth), and at the bottom. The simulated result shows that the fluid in the wellbore changes its phase from single phase to steam and water mixture at about 700 m vertical depth. The simulated dynamic wellbore parameters are given in Table 5, and the simulated profiles are shown in Figure 12.

Wellhead pressure (bar-a): 15 Wellhead temperature (˚C): 198.29
Wellhead dryness (%): 10.56 Wellhead enthalpy (kJ/kg): 1050
Wellhead total flow (kg/s): 30

Feedzone	Vertical depth (m)	Flow (kg/s)	Enthalpy (kJ/kg)
1	1250.0	26	1081
2	1700.0	4	945

TABLE 5: Simulated dynamic wellbore parameters using HOLA program

Depth (m)	Press (bar-a)	Temp (˚C)	Dryness (%)	H_W (kJ/kg)	H_S (kJ/kg)	H_T (kJ/kg)	V_W (m/S)	V_S (m/s)	D_W (kg/m^3)	D_S (kg/m^3)	Rad (mm)	Reg
0	15.0	198.3	10.6	845	2790	1050	5.86	10.44	866.7	7.6	120	Sl
100	16.5	202.9	9.6	865	2793	1051	5.03	8.89	861.3	8.3	120	Sl
200	18.2	207.8	8.6	888	2795	1052	4.26	7.47	855.5	9.2	120	Sl
300	20.3	213.2	7.4	913	2798	1053	3.5	6.09	848.8	10.2	120	Sl
400	22.8	219.2	6.1	940	2800	1054	2.8	4.82	841.4	11.5	120	Sl
500	26.0	226.1	4.5	972	2801	1055	2.12	3.6	832.5	13.0	120	Sl
600	30.7	235.1	2.3	1014	2802	1056	1.39	2.32	820.4	15.4	120	Sl
700	37.5	244.0	0	1057	0	1057	0.82	0	808.1	0	120	1p
800	45.5	244.2	0	1058	0	1058	0.82	0	808.7	0	120	1p
900	53.5	244.4	0	1059	0	1059	1.46	0	809.3	0	90	1p
1000	61.5	244.6	0	1060	0	1060	1.46	0	809.8	0	90	1p
1100	69.5	244.8	0	1061	0	1061	1.45	0	810.4	0	90	1p
1200	77.5	245.0	0	1062	0	1062	1.45	0	811.0	0	90	1p
1300	85.7	219.0	0	941	0	941	0.19	0	847.1	0	90	1p
1400	94.0	219.2	0	942	0	942	0.19	0	847.6	0	90	1p
1500	102.3	219.4	0	943	0	943	0.19	0	848.1	0	90	1p
1600	110.7	219.5	0	944	0	944	0.19	0	848.6	0	90	1p
1700	119.0	219.7	0	945	0	945	0.19	0	849.1	0	90	1p

5. PRODUCTION TEST

A production test is conducted by flowing the well through an orifice to a silencer. Measurements are taken to evaluate the total flow rate, enthalpy and chemical characteristics of the fluids. The output from a geothermal production well indicates how successful the exploration, siting and drilling of the well has been. Furthermore, a production test is necessary for developers of geothermal projects to give an idea of the best utilization schemes for each production well, and how the reservoirs should be managed in the future.

In order to analyse flow from wells, several measurements and flow tests are carried out. The most important flow parameters determined are

1. The total mass flow;
2. The discharge enthalpy;
3. The non-condensable gas content and dissolved solids;
4. The wellhead pressure during discharge;
5. The pressure drop (drawdown) from the reservoir to the well during discharge;
6. The long-term variations in all the parameters in monitoring the flow character of the wells and the pressure drawdown in the reservoir, supplies the fundamental data for predicting future response of the reservoir.

The main parameters to be determined are the mass flow rate, the wellhead pressure and the enthalpy of the produced fluid. An important assumption is normally made in determining enthalpy. The assumption is that flow in geothermal wells is isoenthalpic, that is, any heat transfer due to thermal conduction between the wellbore and the surrounding formation is negligible. Thus, the enthalpy of the discharge is the sum of the enthalpy of the fluids entering at the feed zones. For high flow rates and long discharge time this approximation is fairly accurate, but at low flow rates heat transfer (usually cooling) can be considerable as the fluid flows up the wellbore towards the wellhead. (Steingrímsson, 2002).

5.1 Production test of HE-4

A long-term production test was performed in well HE-4 in the year 2002. The method used to measure the flow rate and the enthalpy was the critical lip pressure and water flow rates method that is the common way for measuring two-phase discharge from geothermal wells. The method is based on a formula empirically deduced by Russell James in 1970, assuming that there is a fairly large amount of steam or steam and water mixture flowing at sonic velocity through an open-ended pipe to the atmosphere. The absolute pressure at the extreme end of the pipe is then proportional to the mass flow rate and enthalpy. The formula that Russell James deduced empirically is

$$Q = 1835000 \times A \frac{P_c^{0.96}}{H^{1.102}} \tag{32}$$

where
Q = Mass flow rate in kg/s;
P_c = Critical pressure at the end of the lip pipe in bar-a;
A = Areal cross-section of the lip pipe in m^2;
H = Fluid enthalpy in kJ/kg.

For two-phase application, the enthalpy of the two-phase mixture is used; which is the case for well HE-4, instead of steam enthalpy. Therefore, in order to quantify the discharge from the two-phase well HE-4, the following observations were measured or calculated:

a) Total flow rate of steam and water, Q in kg/s;
b) Water flow rate, W in kg/s;
c) Steam flow rate, S in kg/s;
d) Lip pressure, P_c in bar-a;
e) Enthalpy, H in kJ/kg;
f) Mass ratio of steam to the total flow, X_s.

The relationship of the total flow rate Q, to the water flow rate W, and the two-phase enthalpy H, is given by:

$$Q = W \frac{H_s - H_w}{H_s - H} \tag{33}$$

The enthalpies of steam H_s, and water H_w, are taken from steam tables at atmospheric pressure, the pressure at which the two phases are separated in the silencer. Inserting these values for the specific enthalpy, the equation becomes:

$$Q = W \frac{2256}{2676 - H} \tag{34}$$

During the production test, well HE-4 was discharged through a lip pressure pipe into a silencer. Thereafter; wellhead pressure, critical pressure at the lip pipe and the separated water at the weir box flowing from the silencer were measured. Thus, the enthalpy of the two-phase flow was given by

$$\frac{1835000\, AP_c\, 0.96}{H^{1.102}} = W \frac{2256}{2676 - H} \tag{35}$$

The enthalpy H, is the only unknown variable in the above equation and is determined by iteration of the equation. After the enthalpy was determined, the total flow rate was calculated. Measured and calculated values from the production test are given in Table 6. The flow history of the well for 147 days is shown in Figure 13.

TABLE 6: Measured and calculated parameters of the production test of HE-4

Time	WHP, P_0 (bar)	Lip pipe diameter (mm)	Lip press. (bar)	Wat. height in weir box (mm)	Water flow (kg/s)	Total flow (kg/s)	Enthal. (kJ/kg)	Separat. pressure (bar)	High-press. steam (kg/s)	Low-press. steam (kg/s)	Water in weir box (kg/s)	Comm.
3/4/2002 11:14	14.5	155	2	220	31.29	43.5	1121	7	8.5	4.7	30.3	
3/4/2002 11:18	13	155						7				
3/4/2002 11:24	12.5	155	2	210	27.87	40.6	1193	7	9.4	4.2	27.1	
3/4/2002 11:30	11.5	155	1.7	205	26.25	37.6	1167	7	8.2	3.9	25.5	
3/4/2002 11:47	11.3	155	1.7	205	26.25	37.6	1167	7	8.2	3.9	25.5	
3/4/2002 12:30	10.5	115	1.7	205	26.25	37.6	1167	7	8.2	3.9	25.5	
4/4/2002	10.2	155	1.3	180	18.99	29.3	1275	7	7.9	2.9	18.5	
5/4/2002	10.5	155	1.25	190	21.72	31.3	1177	7	7	3.3	21.1	
6/4/2002	11	155	1.3	190	21.72	31.6	1190	7	7.2	3.3	21.1	
7/4/2002	11.1	155	1.35	190	21.72	31.9	1203	7	7.5	3.3	21.1	
9/4/2002	11	155	1.3	190	21.72	31.6	1190	7	7.2	3.3	21.1	
11/4/2002	11.2	155	1.3	190	21.72	31.6	1190	7	7.2	3.3	21.1	Sample
16/4/2002	12.2	155	1.65	190	21.72	33.5	1275	7	9.1	3.3	21.2	
21/4/2002	13	155	1.7	190	21.72	33.8	1286	7	9.3	3.3	21.2	
30/4/2002	13.8	155	1.7	195	23.17	35.0	1246	10	8.1	4.3	22.6	
7/5/2002	14.2	155	1.75	195	23.17	35.3	1257	10	8.4	4.3	22.6	
13/5/2002	14.6	155	1.9	200	24.68	37.4	1249	10	8.7	4.6	24.1	
23/5/2002	14.5	155	2	195	23.17	36.7	1309	10	9.7	4.3	22.6	
27/5/2002	14.5	155	1.9	195	23.17	36.1	1289	10	9.2	4.3	22.6	
10/6/2002	14.5	155	2	200	24.68	37.9	1269	10	9.3	4.6	24.1	
14/6/2002	14.3	155	2.05	195	23.17	36.9	1319	10	9.9	4.3	22.7	
14/6/2002	14.3					49.3	1226	10	11	6.2	32.2	Tracer flow unit
5/7/2002	15.8	155	2.1	195	23.17	37.2	1329	10	10.2	4.3	22.7	
2/8/2002	15	155	2.15	195	23.17	37.5	1339	10	10.5	4.3	22.7	
14/8/2002	15.2	155	2.2	200	24.28	39.0	1308	10	10.3	4.6	24.1	
29/8/2002	15.5	155	2.2	190	21.72	36.5	1390	10	11.1	4.1	21.3	
10/9/2002	15	155	2.25	195	23.17	38.0	1358	10	11	4.3	22.7	Sample

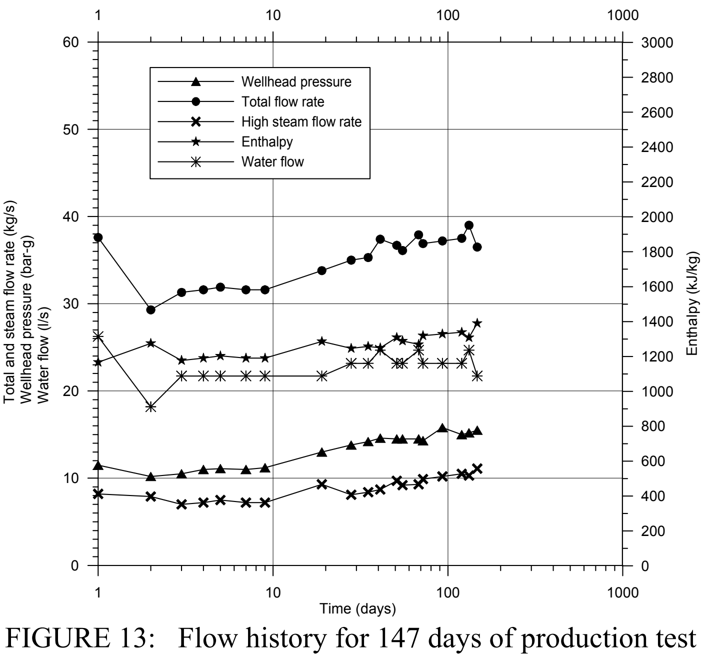

FIGURE 13: Flow history for 147 days of production test of well HE-4

Comparison of the simulated enthalpy, using the Hola wellbore simulator program, and the enthalpy calculated from the production test shows a difference in values. The HOLA simulated enthalpy is less than that of the production test by a factor of about 200 kJ/kg. This difference is accounted for by the precision in the measured parameters during the production test. Either the critical lip pressure values are too high or, which is more likely, the separation of water and steam in the silencer was not complete, and some water was lost to the atmosphere through the top of the silencer. Consequently, the amount of water measured in the weir box was a minimum value. As a result, the enthalpy obtained by the HOLA wellbore simulator should be taken as the output enthalpy of well HE-4.

6. RESULTS AND CONCLUSIONS

Wellbore parameters evaluated from the step injection test of HE-4, using semi-log analysis and the Lokur program, are reliable and are close in their values. Therefore, these parameters are considered to represent the response of well HE-4 to the step injection test. The type curve analysis in this case was useful only in refining the wellbore storage and skin effects from the straight line that represents the infinite acting radial flow in the semi-log analysis.

The warm-up, injection and dynamic temperature profiles revealed three main feed zones located at about 1150, 1400 and 1550 m measured depth in the well. Furthermore, two minor feed zones, located at 1720 m measured depth and at the bottom of the well, were also identified from the temperature and pressure logs. The warm-up temperature profiles indicate that the well is approaching thermal equilibrium, also reflected in the formation temperature evaluated using the Horner plot method. However, the Albright method and the alteration temperature seem to over-estimate the formation temperature of the well. The bottom hole formation temperature is determined by the dynamic temperature profile.

The pressure pivot point is located at about 1400 m measured depth and is the controlling feed zone of the well. The pivot point, along with over-pressure at about 500 m measured depth and a regional cold groundwater level are considered to be the controlling points in evaluating initial pressure, using the PREDYP program. These points represent the main geothermal reservoir zone (700 m - bottom), geothermal over-pressurized zone (300 - 700 m) and groundwater reservoir zone, respectively.

The enthalpy, simulated using the HOLA wellbore simulator program from the dynamic temperature and pressure profiles, is reliable. This simulated enthalpy is less than the enthalpy obtained from the production test by a factor of about 200 kJ/kg, because of inaccuracy in the measuring of weir box water flow rate during the production test due to poor water/steam separation in the silencer.

ACKNOWLEDGEMENTS

I wish to thank my supervisors, Benedikt Steingrímsson and Ómar Sigurdsson, for their continuous supervision and valuable discussions during my work. I am grateful to Dr. Ingvar Birgir Fridleifsson, Lúdvík S. Georgsson and Gudrún Bjarnadóttir for their successful administration, assistance and guidance given during the training period. I would like to thank all the reservoir-engineering instructors for their keen interest in passing their skill to others. My special appreciation goes to all 2002 fellows for their friendship and fellow feeling. Finally, this paper is dedicated to my younger sister, Tsigeweini Tareke Beyene, who died the day I heard that I was awarded this training.

REFERENCES

Arason, P., and Björnsson, G., 1994: *ICEBOX*, 2nd edition. Orkustofnun, Reykjavík, 38 pp.

Árnason, K., Karlsdóttir, R., Eysteinsson, H., Flóvenz, Ó.G., and Gudlaugsson, S.Th., 2000: The resistivity structure of high-temperature geothermal systems in Iceland. *Proceedings of the World Geothermal Congress 2000, Kyushu-Tohoku, Japan*, 923-928.

Björnsson, A., Hersir, G.P., and Björnsson, G., 1986: The Hengill high-temperature area SW-Iceland: Regional geophysical survey. *Geoth. Res. Council, Transactions, 10,* 205-210.

Björnsson, G., 1993: Program PREDYP. In: Arason, P., and Björnsson, G. (collected in 1994), *ICEBOX, 2nd edition, user's guide.* Orkustofnun, Reykjavík, 38 pp.

Björnsson, G., 2002: *Using temperature and pressure logs to determine reservoir conditions and well status*. UNU, Geothermal Training Programme, Iceland, unpublished lecture notes.

Björnsson, G., Arason, P., Bödvarsson, G.S., 1993: *The wellbore simulator HOLA. Version 3.1. User's guide*. Orkustofnun, Reykjavík, 36 pp.

Bödvarsson, G., 1961: Physical characteristics of natural heat resources in Iceland. *Jökull, 11,* 29-38.

Hjartarson, A., 2002: *Pressure transient analysis (well testing theory)*. UNU, Geothermal Training Programme, Iceland, unpublished lecture notes

James R., 1970: Factors controlling borehole performance. *Geothermics, Sp. issue, 2-2,* 1502-1515.

Pálmason, G., 1973: Kinematics and heat flow in a volcanic rift zone, with application to Iceland. *Geophysical Journal Royal Astron. Soc., 33,* 451-481.

Pálmason, G., and Saemundsson K., 1974: Iceland in relation to the Mid-Atlantic Ridge. *Annual Review Earth Planet. Sci., 2,* 25-50.

Saemundsson, K., 1995: *Geothermal and hydrothermal map of the Hengill area, 1:25,000.* Orkustofnun, Reykjavík.

Stefánsson, V., and Steingrímsson, B.S., 1990: *Geothermal logging I, an introduction to techniques and interpretation, 3rd edition.* Orkustofnun, Reykjavík, report OS-80017/JHD-09, 117 pp.

Steingrímsson, B., 2002: *Discharge measurements and injection tests*. UNU, Geothermal Training Programme, Iceland, unpublished lecture notes.

Steingrímsson, B., Franzson, H., Magnússon, I.Th., Árnason, K., Saemundsson, K., Thordarson, S., Thórhallsson, S., 2001: *Wells HE-3 and HE-4 at Hellisheidi. Siting and design of the wells*. Orkustofnun, Reykjavik, report OS-ROS-01/01 (in Icelandic), 17 pp.