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PRODUCTION CAPACITY ASSESSMENT OF THE HOFFELL LOW-TEMPERATURE GEOTHERMAL SYSTEM, SE-ICELAND

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ABSTRACT

Recently a new geothermal well named HF-1 was drilled for the purpose of space heating in the low-temperature geothermal field at Hoffell, Nesjar, in southeast Iceland. To evaluate the production capacity of the geothermal system a conceptual model of the system was established and a volumetric assessment performed. Based on the analysis of the conceptual model and the volumetric assessment, together with the Monte Carlo method, the total energy in the system is estimated as 46.9 TJ (most likely), the recoverable energy as 9.4 TJ (most likely) and the thermal power for 50 and 100 years is estimated as 6.0 and 3.0 MW_{th}. (most likely), respectively. Well test data from two step-rate tests were analysed with WellTester to estimate the parameters of the system. Permeability was, thus, estimated to be around 4.8-7.0 mDarcy. The well's skin factor was around -0.1 after the well was deepened. Lumped parameter modelling was consequently used to simulate the behaviour of the reservoir to exploitation during a long-term test from April 9 to September 8, 2013. A two-tank closed model and a two-tank open model (using Lumpfit) could simulate the monitoring data very well. The parameters resulting from the Lumpfit and WellTester evaluations are quite comparable, with the permeability thickness of the reservoir around Well HF-1 estimated to be in the range of 2-5 Darcy·m. Finally, future water level predictions were calculated to estimate the probable response of the reservoir to different production scenarios for the next 10 years, both with a conservative and an optimistic model. It seems that if the system is closed, Well HF-1 can only sustain around 10 l/s for the next 10 years and if it is open, Well HF-1 will sustain around 30 l/s for 10 years. It is unlikely that the system is completely closed so 15-20 l/s seems to be the most likely production range. If the system is closed, reinjection will be necessary to increase and maintain the production capacity.

1. INTRODUCTION

Recently a new deep geothermal well, HF-1, was drilled in the Hoffell area in the Nesjar region of Skaftafellssýsla in southeast Iceland. The area is characterised by a large outlet glacier from Vatnajökull, Hoffellsjökull, and gabbroic rock, which is very uncommon in Iceland but was originally formed deep in the earth's crust. The gabbroic rock is now visible due to uplift of the area and glacial erosion. The Hoffell area is 15 km from the town of Höfn (Figure 1).

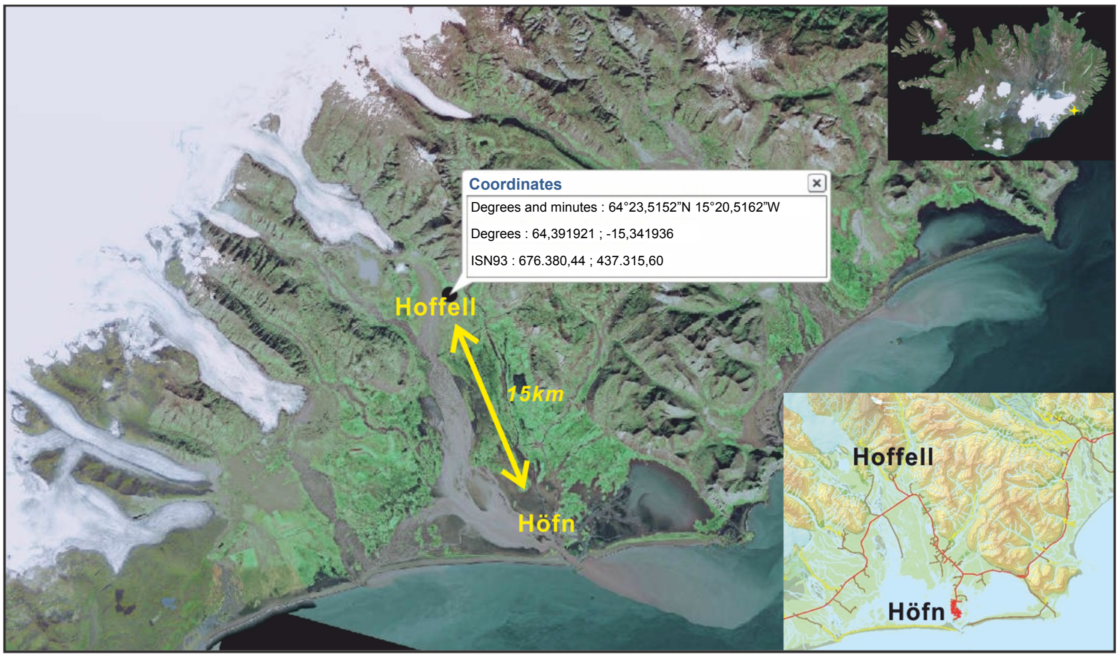

FIGURE 1: Location of the Hoffell area in SE-Iceland (modified from Landmaelingar Íslands, 2012)

Systematic geothermal exploration in this area began in 1992. The results of the exploration, which consisted of surface geology, magnetic measurements, chemical analysis of the water and geothermal gradient exploration drilling, showed that there is good likelihood of exploitable low-temperature geothermal resources. The temperature gradient of eastern Skaftafellssýsla is generally low, but at Hoffell and Midfell it shows abnormal values of up to 186°C/km (Figure 2), and chemical composition of the water indicated a 70-80°C temperature deep in the water system (Stapi Geological Services, 1994).

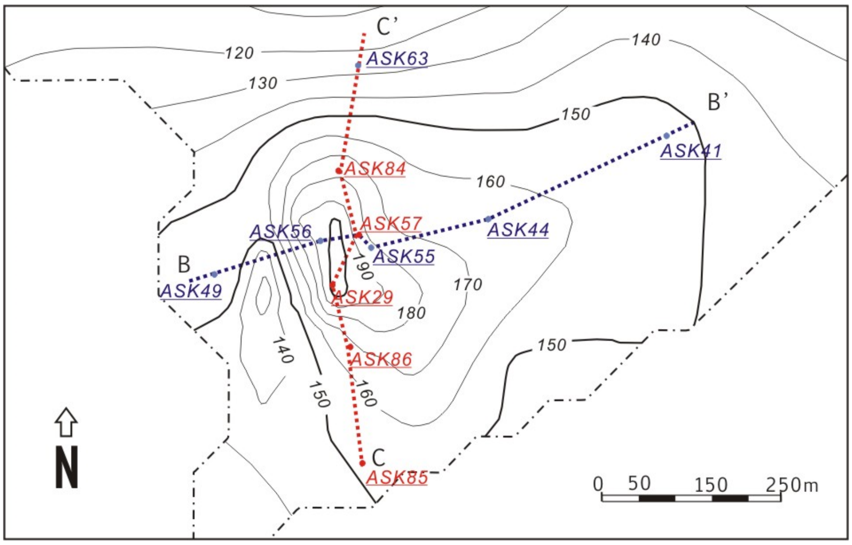

FIGURE 2: Temperature gradient map (°C/km) for the Hoffell area, showing locations of cross-sections in Figures 4 and 5 (modified from Árnadóttir et al., 2013)

RARIK (Iceland State Electricity) drilled Well HF-1, but before the well was drilled in 2012 there were already 33 boreholes in the area with a cumulative total drilling depth of 3594 metres (Figure 3). Most of the wells (20 holes) are shallow, actually shallower than 60 m, but four of the wells are over 300 m in depth.

The drilling of the borehole HF-1 (B73061) at Hoffell in Nesjar started in early November 2012 and lasted until 11 January 2013. The hole was first drilled down to 1208 m depth. However, ÍSOR experts met with the representatives of RARIK and suggested deepening the hole by at least 200 m to see further down into the approximately 80°C hot geothermal system. Following this the hole was deepened twice before 19 February 2013, first to 1404 m and finally to 1608 m depth (Kristinsson et al., 2013a, 2013b; Kristinsson and Ólafsson, 2013).

To estimate the parameters of the aquifers intersected by the well, well tests were performed by air-lifting with the drill-string in the well, blowing out air at different depths, on three occasions. Two of these are evaluated her. The first of these was conducted on January 12-13, lasting around 10 hours with temperature of 68-69°C, and the second one on February 19-20 lasting around 12 hours with temperature of 72-73 °C (Kristinsson et al., 2013a, 2013c).

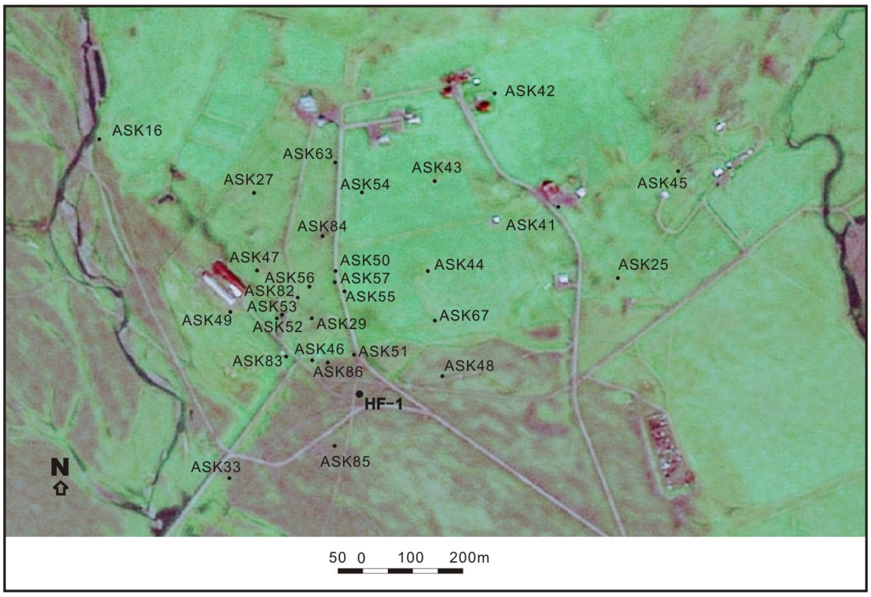

FIGURE 3: Location of borehole HF-1 and some of the exploration wells (Hjartarson et al., 2012)

After drilling was completed, long term production testing was performed to understand the reservoir behaviour and to estimate its production potential. The test started April 9, 2013. Water-level drawdown, production flow rate and temperature were monitored and recorded continuously. By September 8, 152 days of monitoring data had been collected.

This report presents the results of an assessment of the production capacity of the Hoffell low-temperature geothermal system. After a simple conceptual model was established, based on the geological background and the temperature distribution in the system, a volumetric assessment was performed to estimate the total energy and thermal power of the system, using the Monte-Carlo method. And then, well test interpretations were carried out to estimate the parameters of the reservoir. Finally, lumped parameter modelling was used to simulate the behaviour of the reservoir to exploitation and to predict the probable response of the reservoir to different production scenarios, including scenarios with reinjection.

2. CONCEPTUAL MODEL

Mountain-belt strata, which tilt steeply to the northwest, extend to the southeast of Vatnajökull glacier. The Hoffell area is located on the southern margin of the mountain belt. According to borehole and geological exploration, the bedrock of Hoffell and Midfell are mostly composed of basalt and gabbro. Several dykes, veins, cracks and faults exist in the area, but most of them are unclear. Magnetic surveying shows some small faults and cracks, which are not clearly related to the boundary of the geothermal system.

The temperature gradient was measured in 33 gradient exploration holes. According to the results, an isoline map was plotted by ISOR. It shows that typically the temperature gradient of this area is high, or up to 150°C/km and, in the core of the area the gradient is up to 200°C/km and even more (Figure 2).

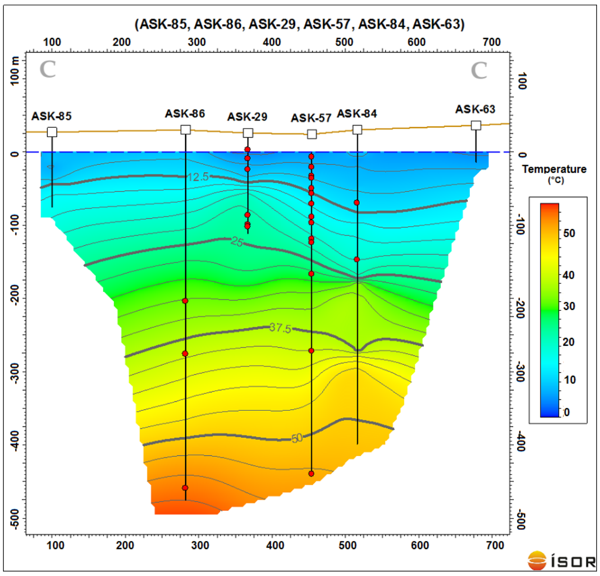

FIGURE 4: N-S temperature cross-section C-C´ (Árnadóttir et al., 2013)

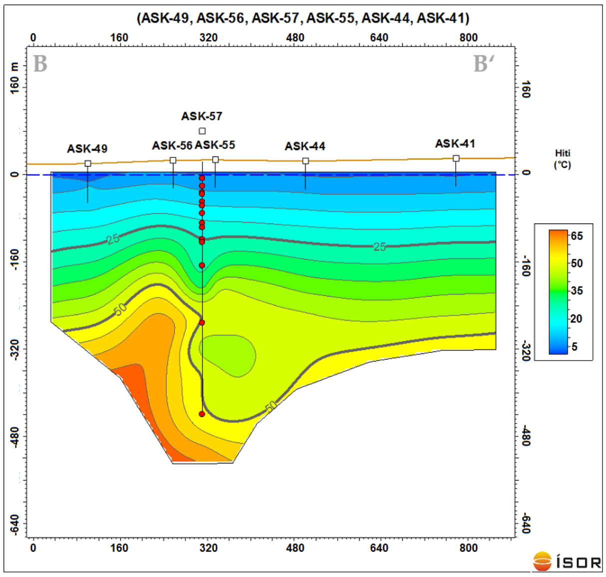

FIGURE 5: WSW-ENE temperaure cross-section B-B´ (Árnadóttir, et al., 2013)

Temperature cross-sections, also plotted by ISOR (Figures 4 and 5), show that the formation temperature is higher than 25°C under 100 m.b.s.l (metres below sea level), and it is higher than 50°C below around 400 m.b.s.l. The cross-sections do not reveal clearly the boundaries of the reservoir. The boundaries seem to be controlled by some geological structures at the outer edge of the geothermal system. They are likely controlled by diminishing permeability of fractures.

Temperature logs were measured in Well HF-1 from the beginning to the end of drilling (Figure 6). The estimated formation temperature of the well is about 80°C at 1000-1600 m depth. In addition, about 7.0 l/s free flow of 70°C hot water were delivered from the borehole after drilling. Considering the vertical distribution of the temperature versus depth, the main feedzones of the well must be confined above and the thermal water cools as it flows upward.

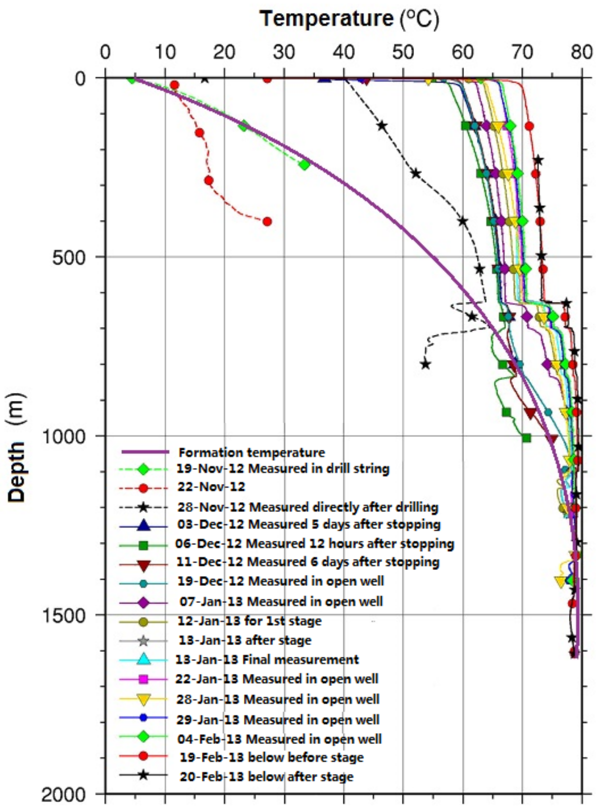

FIGURE 6: All temperature logs measured in Well HF-1 along with the deduced formation temperature profile

From the information above, a simple conceptual model of the Hoffell gothermal system could be established (Figure 7). It includes these main features: It is a liquid-dominated low-temperature geothermal system with about 80°C thermal groundwater in a deep confined aquifer below 600-1000 m depth. There seems to be 25-60°C thermal water in shallower layers, but it plays no major role. The reservoir seems to extend much deeper, and the boundaries of the system are still unknown. The main permeability of the system is provided by several near-vertical faults and/or fractures and the core of the system appears to be associated with the intersection of some of these.

3. VOLUMETRIC ASSESSMENT

3.1 Theoretical background

3.1.1 Volumetric method

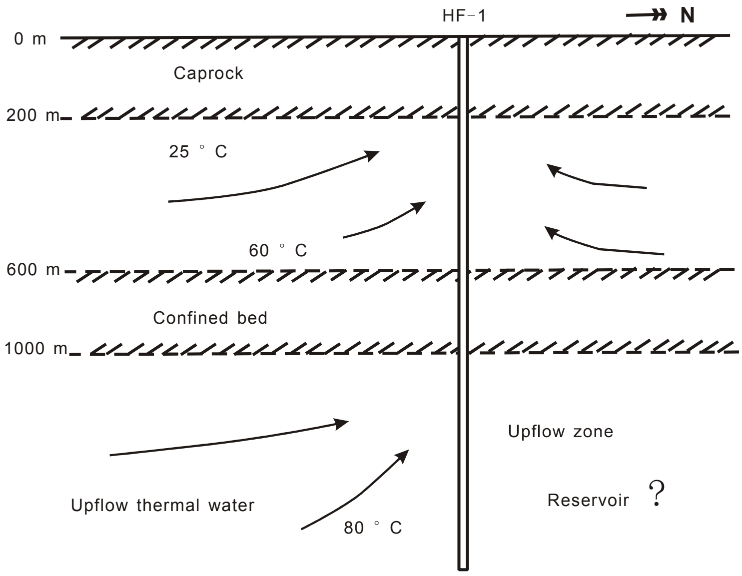

FIGURE 7: A sketch of the conceptual model of the Hoffell geothermal system

The volumetric method refers to the calculation of thermal energy in the rock and the fluid of a geothermal system, which could be extracted based on specified reservoir volume, reservoir temperature, and reference or final temperature. This method was originally patterned from the work applied by the USGS to the Assessment of Geothermal Resources of the United States (Muffler, 1979). In their work, the final or reference temperature is based on the ambient temperature, following the exhaust pressures of the turbines. Many, however, choose a reference temperature equivalent to the minimum or abandonment temperature of the geothermal fluids for the intended utilization of the geothermal reservoir. For space heating, as in the case under study here, the abandonment temperature is typically 30-40°C, but for electricity generation the reference temperature is usually up to 180°C for conventional power plants but lower for binary plants.

The equation used in calculating the thermal energy for a liquid dominated reservoir is as follows:

$$Q_T = Q_r + Q_w \tag{1}$$

and

$$Q_r = A \cdot h \cdot [\rho_r \cdot C_r \cdot (1-\varphi) \cdot (T_i - T_f)] \tag{2}$$

$$Q_w = A \cdot h \cdot \left[\rho_w \cdot C_w \cdot \varphi \cdot (T_i - T_f)\right] \tag{3}$$

where Q_T = Total thermal energy (kJ/kg);
Q_r = Heat in rock (kJ/kg);
Q_w = Heat in water (kJ/kg);
A = Area of the reservoir (m^2);
h = Average thickness of the reservoir (m);
C_r = Specific heat of rock at reservoir conditions (kJ/kg·K);
C_w = Specific heat of liquid (usually water) at reservoir conditions (kJ/kg·K);
φ = Porosity (dimensionless);
T_i = Average temperature of the reservoir (°C);
T_f = Abandonment /cut-off temperature (°C);
ρ_w = Liquid (usually water) density (kg/m^3); and
ρ_r = Rock density (kg/m^3).

The volumetric method can also incorporate equations for two-phase zones and for power generation capacity estimation. However, those equations will neither be explained nor used here.

The equations presented above only apply to the total thermal energy existing in the reservoir. But it is impossible to extract the total energy from the reservoir. In order to estimate the energy that can be extracted from the system, we need to introduce a recovery factor, R, which refers to the fraction of the stored heat in the reservoir that may be extracted to the surface. It depends on the fraction of the reservoir that is considered permeable and on the efficiency by which heat can be swept from these permeable channels, as well as on whether reinjection is applied during the utilization, and indirectly on the boundary conditions (open or closed) of the geothermal system. Using this factor, the thermal energy recoverable from the system can be calculated as follows:

$$Q_R = R \cdot Q_T \tag{4}$$

where Q_R = Recoverable thermal energy (kJ/kg); and
R = Recovery factor (dimensionless).

The recovery factor is a measure of how easily the heat contained in the system can be extracted. It depends mostly on permeability. For fractured reservoirs, the factor has a range of 2-25% (Williams, 2007). A linear correlation between porosity and recovery factor has been proposed where, for example, porosity of 10% responds to a recovery factor of 25% (Muffler, 1979). Such a relationship is not considered realistic for volcanic rocks.

3.1.2 Monte Carlo calculation

The variables used in the volumetric method are always uncertain. What we can estimate for the reservoir are often probable values of the variables rather than certain values. To deal with the uncertain situation, a numerical calculation technique, named Monte Carlo, can be used. It is a technique that uses a random number generator to produce and extract an uncertain variable from within a distribution model for calculation in a given formula or correlation. Monte Carlo simulation became popular with the advent and power of computers.

The Monte Carlo method selects the occurrence of an unknown variable as through the random behaviour in a game of chance, for a single calculation. The calculation is repeated over and over again until the specified iteration cycle is completed. In playing dice, 1, 2, 3, 4, 5 or 6 are possible outcomes, but we don't know which outcome is the result of each roll. The same is true for the various parameters used in calculating the geothermal reserves (e.g. area, thickness, porosity, reservoir temperature, recovery factors). They all vary within a certain range of values that is uncertain for a particular sequence in the calculation. To produce the desired results, unknown variables for each reservoir property are fitted into a chosen model distribution (e.g. normal, triangular, uniform and log normal) based on predetermined conditions or criteria of the area being evaluated. The simulation then proceeds by extracting numbers representing the unknown variable and using these as input into the cells in the spread-sheet used until the process is completed (Sarmiento and Steingrímsson, 2007).

3.2 Volumetric assessment for the Hoffell geothermal system

3.2.1 Parameters and variables

The parameters used in the Monte Carlo volumetric assessment model for the Hoffell geothermal system are presented in Table 1.

Area (km^2)
Because of the lack of information on the boundaries of the geothermal system, we use the temperature gradient isoline of 150°C/km as the boundary. Thus, the area should be at least 0.1 km^2 in area. But the actual area is likely to be larger than this. In the Monte Carlo input cell, we use the most likely: 0.15 km^2; minimum: 0.1 km^2; maximum: 0.2 km^2.

Cut-off temperature (°C)
As the well will be used for space heating we use 25°C as the cut-off temperature.

TABLE 1: Parameters and variables used in the Hoffell Monte Carlo volumetric assessment

Input parameters	**Units**	**Minimum**	**Most likely**	**Maximum**	**Distribution**	**Random pick**
Surface area	km^2	0.1	0.15	0.2	Triangle	0.2
Thickness	m	1000	2000	2500	Triangle	1776
Rock density	kg/m^3	2700	2850	2900	Triangle	2824
Porosity	%	8	10	12	Triangle	8.1
Rock specific heat	J/kg°C	910	950	980	Triangle	953
Temperature	°C	70	80	90	Triangle	74
Fluid density	kg/m^3	958.1	971.6	977.7	Triangle	972.0
Fluid specific heat	J/kg°C		4200		Fixed	4200
Recovery factor	%	15.0	20.0	22.0	Triangle	18.5
Cut-off temperature	°C		25		Fixed	25

Reservoir temperature (°C)
The formation temperature of the well seems to be about 80°C in the 1000-1600 m depth-range. In the Monte Carlo input cell, we use the most likely: 80°C; minimum: 70°C; maximum: 90°C.

Thickness (m)
The formation temperature is higher than 25°C below 100 m.b.s.l., and it grows with increasing depth. The botton of the geothermal system is unknown. But with modern drilling techniques, at least 2500 m can be reached, and in Well HF-1 the thickness of the feedzone-interval is about 1000 m. In the Monte Carlo input cell, we use the most likely: 2000 m; minimum: 1000 m; maximum: 2500 m.

Rock density (kg/m^3)
The type of rock is mostly basalt, which has a density of around 2850 kg/m^3. Therefore, we use the most likely: 2850 kg/m^3; minimum: 2700 kg/m^3; maximum: 2900 kg/m^3.

Porosity (%)
The average porosity is assumed to be 10%, as is common for basaltic rocks in Iceland. In the Monte Carlo input cell, we use the most likely: 10%; minimum: 8%; maximum: 12%.

Rock specific heat (J/kg·°C)
Usually, it is about 950 J/kg°C. In the Monte Carlo input cell, we use the most likely: 950 J/kg°C; minimum: 910 J/kg°C; maximum: 980 J/kg°C.

Fluid density (kg/m^3)
Water density is 971.6 (most likely), 977.7 (maximum), and 958.1 kg/m^3(minimum) at 80°C, 70°C, and 90°C, respectively.

Fluid specific heat (J/kg·°C)
It is about 4200 J/kg°C for pure water at a temperature of 70-100°C.

Recovery factor (%)
According to Muffler´s research referred to above a porosity of 10% corresponds to a recovery factor of 25%, which seems to be a little large during actual utilization. In the Monte Carlo input cell, we use the most likely: 20%; minimum: 15%; maximum: 22%.

3.2.2 Results for Hoffell

The results obtained for Hoffell by the Monte Carlo method are presented in Table 2. According to the Monte Carlo volumetric assessment results, the total energy in the system is most likely 46.9 TJ (1 TJ = 10^{12} J) and the total recoverable energy is estimated to be most likely 9.4 TJ. If the heating system is used for 50 years, it would yield a most likely average thermal power of 6.0 MW_{th}. And if the heating system was used for 100 years, the thermal power is estimated to be most likely 3.0 MW_{th}.

The frequency distribution and cumulative frequency of the thermal power, as calculated by the Monte Carlo model, are presented in Figure 8. The mean thermal power, the median thermal power, the standard deviation, 90% upper limit, and 90% lower limit could also be extracted from the results, shown in Table 3.

TABLE 2: Most likely estimated results of the Monte Carlo volumetric assessment for Hoffell

Results	Units	Most likely	Random pick
Total Energy	TJ	46.9	38.6
Total Recoverable Energy	TJ	9.4	7.1
Thermal Power / 50 years	MW_{th}	6.0	4.5
Thermal Power / 100 years	MW_{th}	3.0	3.4

TABLE 3: Summarized results of the thermal power estimation for Hoffell according to the Monte Carlo volumetric assessment

Results	Units	Thermal power / 50 years	Thermal power / 100 years
Mean thermal power	MW_{th}	6.0	3.0
Median thermal power	MW_{th}	6.0	3.0
Standard deviation	MW_{th}	1.0	1.0
90% above (lower limit)	MW_{th}	3.3	1.7
90% below (upper limit)	MW_{th}	6.8	3.3

In addition to estimating the thermal power presented above, we need to know the corresponding average thermal water flow rate for well HF-01, which can then be compared with other results later in this report. As $Q = q \cdot c \cdot \Delta T$, where Q is the thermal power (W), c is specific heat of water (4200 J/kg·°C), ΔT is the difference between the water flow temperature and the cut-off temperature (75 – 25 = 50°C), we can estimate q, which is the average thermal water flow rate.

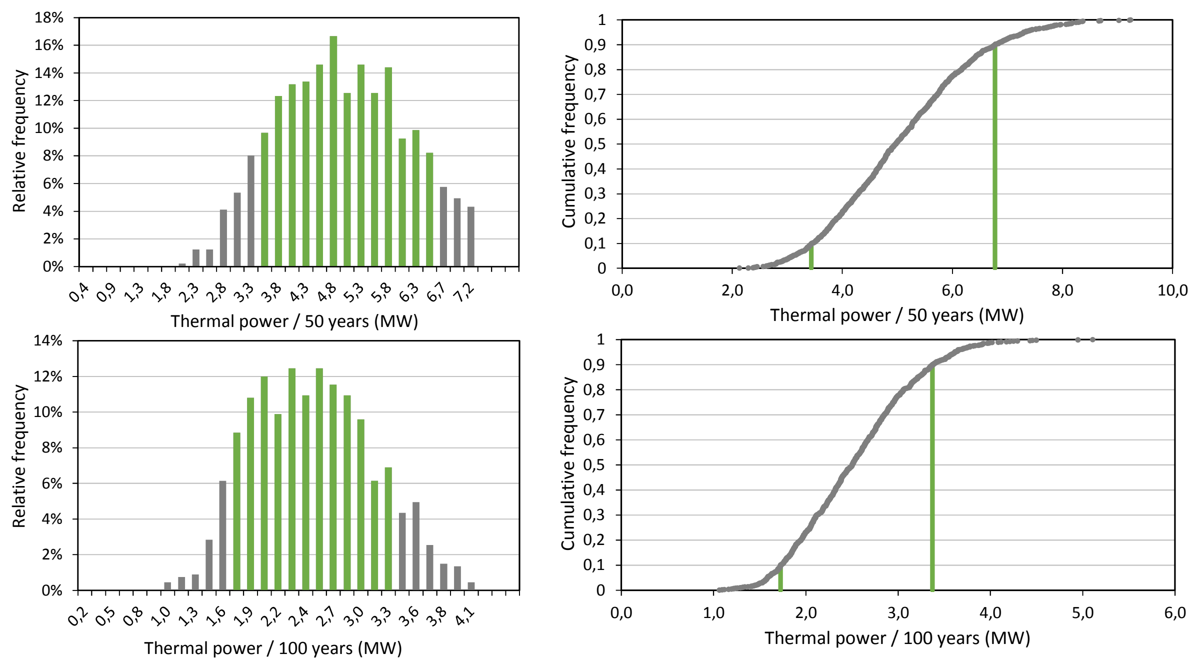

FIGURE 8: The outcome of the Monte Carlo volumetric assessment of the Hoffell system presented as probability and cumulative probability distributions for thermal power for 50 and 100 years utilization. The green columns on the left indicate the 90% probability range while the vertical green lines on the right indicate the 90% upper and lower limit of the cumulative distribution.

If the heating system will be used for 50 years with average thermal power of 6.0 MW_{th}, we need a thermal water flow rate of 28.6 l/s. And if the heating system will be used for 100 years with a thermal power of 3.0 MW_{th}, we need a thermal water flow rate of 14.3 l/s.

4. WELL TEST INTERPRETATION

4.1 Theoretical background

As an effective way to understand the hydrological conditions of a reservoir, well test analysis is, in fact, synonymous with pressure transient analysis. Pressure transients are caused by the changes in production or injection of fluids; hence, the flow rate is treated as a transient input and the pressure as a transient output (Horne, 1995). Usually, the traditional well test interpretation method does not consider the effect of temperature change during the test. On the other hand, the temperature often changes in reality due to variations in injection or flow rate, so the density of the water changes, therefore affecting the pressure. Under these conditions, a combination of the pressure response and the temperature change may give a more reasonable result (Liu, 2011).

4.1.1 Pressure diffusion equation

The basic equation of well testing theory is the pressure diffusion equation. The most commonly used solution of the pressure diffusion equation is the Theis solution, or the line source solution. Three governing laws are needed in deriving the pressure diffusion equation:

Conservation of mass inside a given control volume (in radial coordinates):

$$Mass\ flow\ in - Mass\ flow\ out\ = Rate\ of\ change\ of\ mass\ within\ the\ control\ volume$$

$$\rho Q - \left(\rho Q + \frac{\partial(\rho Q)}{\partial r}dr\right) = 2\pi r dr \frac{\partial(\varphi \rho h)}{\partial t}$$

or

$$-\frac{\partial(\rho Q)}{\partial r} = 2\pi r \frac{\partial(\varphi \rho h)}{\partial t} \tag{5}$$

Conservation of momentum, expressed by Darcy's law:

$$Q \ = \ -2\pi r h \frac{k}{\mu}\frac{\partial P}{\partial r} \tag{6}$$

where Q = Volumetric flow rate (m^3/s);
h = Reservoir thickness (m);
k = Formation permeability (m^2);
P = Reservoir pressure (Pa);
r = Radial distance (m); and
μ = Dynamic viscosity of fluid (Pa·s).

Fluid compressibility (at constant temperature):

$$c_f \ = \frac{1}{\rho}\left(\frac{\partial \rho}{\partial P}\right)_T \tag{7}$$

where c_f = Compressibility of fluid (Pa^{-1});
ρ = Density of fluid (kg/m^3); and
T = Temperature (°C).

Additionally, some simplifying assumptions are needed:

- Isothermal flow;
- Homogeneous and isotropic reservoir;
- Production well completely penetrating the reservoir thickness; and
- Reservoir completely saturated with single phase fluid.

Based on these equations and assumptions, the pressure diffusion equation can be expressed as (in radial coordinates):

$$\frac{1}{r}\frac{\partial}{\partial r}\left(\frac{r\partial P(r,t)}{\partial r}\right) = \frac{\mu c_t}{k}\left(\frac{\partial P(r,t)}{\partial t}\right) = \frac{S}{T}\frac{\partial P(r,t)}{\partial t} \tag{8}$$

where c_t = Total compressibility of rock and water, $\phi c_f + (1-\phi)c_r$, (Pa^{-1});
c_t = Compressibility of fluid (Pa^{-1});
c_r = Compressibility of rock (Pa^{-1});
ϕ = Porosity (-);
S = Storativity, $c_t h$, (m^3/(Pa·m^2));
T = Transmissivity, kh/μ, (m^3/(Pa·s));
h = Effective reservoir thickness (m);
k = Permeability of the rock (m^2);
μ = Dynamic viscosity of the fluid (Pa·s);
$P(r,t)$ = Reservoir pressure at a distance r and time t (Pa); and
t = Time (s).

4.1.2 Theis solution

The radial pressure diffusion equation is a partial differential equation. To solve this equation, initial and boundary conditions are required in addition to assumptions on the geometry of the reservoir (aquifer) in question. For an infinite acting, homogeneous reservoir of constant thickness, with a line-source at $r = 0$ simulating a production well, the initial and boundary conditions are (Liu, 2011):

a) Initial conditions

$$P(r,t) = P_i \quad for\ t = 0\ and\ for\ all\ r > 0 \tag{9}$$

where P_i = Initial reservoir pressure (Pa).

b) Boundary conditions

$$P(r,t) \to P_i \quad for\ r \to \infty\ and\ for\ all\ t > 0 \tag{10}$$

$$2\pi rh\frac{k}{\mu}\frac{\partial P}{\partial r} \to Q \qquad for\ r \to 0\ and\ for\ all\ t > 0 \tag{11}$$

The solution to the radial diffusion equation with these boundary and initial conditions is given by:

$$P(r,t) = P_i - \frac{Q\mu}{4\pi kh}W\left(\frac{\mu c_t r^2}{4kt}\right) = P_i - \frac{Q}{4\pi T}W\left(\frac{Sr^2}{4Tt}\right) \tag{12}$$

where $W(x)$ is the well function or the exponential integral function defined by:

$$W(x) = -E_i(-x) = \int_x^{\varphi}\left(\frac{e^{-u}}{u}\right)du$$

For small values of x, i.e. $x < 0.01$, $\mathrm{W(x)} \approx -\ln(\mathrm{x}) - \gamma \approx -\ln(\mathrm{x}) - 0.5772$, where γ is the Euler constant. Therefore, if (infinite acting period):

$$t > 25\frac{\mu c_t r^2}{k} = 25\frac{Sr^2}{T}$$

the Theis solution can be expressed as:

$$P(r,t) = P_i + \frac{2.303Q}{4\pi T}\left[log\left(\frac{Sr^2}{4Tt}\right) + \frac{\gamma}{2.303}\right] \tag{13}$$

Equation 13 is the most commonly used equation in well test analysis. It describes pressure at a distance r at time t when producing at constant rate Q with radial flow of single phase fluid in a homogeneous reservoir model.

4.1.3 Semi-logarithmic well test analysis

By monitoring pressure changes with time, it may be possible to fit the observed pressure history to the theoretical results and identify two important parameter groups, the permeability-thickness (kh) and the storage coefficient, or storativity-thickness, ($c_t h$). By rearranging Equation 9, the solution can be written as:

$$\Delta P = P_i - P(r,t) = \frac{2.303Q}{4\pi T}log\left(\frac{2.246T}{Sr^2}\right) + \frac{2.303Q}{4\pi T}log(t) \tag{14}$$

The above equation is in the form of $\Delta P = \alpha + mlog(t)$. Plotting ΔP vs. $log(t)$ gives a semi-log straight line response for the infinite acting radial flow period of a well, and this is referred to as a semi-log analysis. The line is characterized by the slope m and an intercept α, where

$$\Delta P = P_i - P(r,t), \qquad \alpha = \frac{2.303Q}{4\pi T}log\left(\frac{2.246T}{Sr^2}\right), \qquad m = \frac{2.303Q}{4\pi T}$$

By determining m, the formation transmissivity can be estimated by:

$$T = \frac{kh}{\mu} = \frac{2.303Q}{4\pi m} \tag{15}$$

If the temperature is known, then the dynamic viscosity μ can be found from steam tables, thus the permeability-thickness (kh) can be calculated as follows:

$$kh = \frac{2.303Q\mu}{4\pi m} \tag{16}$$

And the storage coefficient can be obtained by:

$$S = c_t h = 2.246\left(\frac{kh}{\mu}\right)\left(\frac{t}{r^2}\right)10^{-\frac{\Delta P}{m}} = 2.246T\left(\frac{t}{r^2}\right)10^{-\frac{\Delta P}{m}} \tag{17}$$

from any point on the semi-log straight line (t, Δp). 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 and the time at which the semi-log straight line begins (Horne, 1995).

Pressure propagation does not take place uniformly throughout the reservoir because it is affected by local heterogeneities. Usually, due to the ineffective pressure control during drilling or completion, some external fluids (such as mud, cement) invade into the original formation around the well and form a zone with lower permeability. Some methods (such as acidizing, hydraulic stimulation/fracturing) are often used to stimulate the reservoir next to a well so that during production a permeability improved zone can be formed. Such zones are called skin zones. It causes an additional pressure drop ΔP_s near the wellbore in addition to the normal reservoir pressure change due to production (Horne, 2010).

$$\Delta P_s = \frac{Q\mu}{2\pi kh} \times s \tag{18}$$

where s = Skin factor (dimensionless).

A negative skin factor indicates that the near-well permeability is improved while a positive skin factor indicates that the near well surroundings are damaged (reduced permeability). The skin due to a damaged zone of radius r_s and reduced permeability k_s can be calculated from:

$$s = \left(\frac{k}{k_s} - 1\right) ln \frac{r_s}{r_w} \tag{19}$$

where k = Permeability of undamaged zone (m^2);
k_s = Permeability of damaged zone (m^2);
r_s = Radius of damaged zone (m); and
r_w = Radius of wellbore (m).

Since the skin has a similar effect as changing the effective radius of the well, the effective well radius is r_{weff} given by:

$$r_{weff} = r_w e^{-s} \tag{20}$$

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

$$\Delta P = P_i - P(r_w, t) \approx \frac{2.303Q}{4\pi T}\left[log(t) + log\left(\frac{T}{Sr_w^2}\right) + 0.3514 + 0.8686s\right] \tag{21}$$

The skin effect does not change the evaluation of permeability-thickness in a semi-log analysis, but it does influence the evaluation of the storage coefficient, as shown in the following equation (the storage coefficient and skin are directly linked):

$$Se^{-2s} = 2.246T\left(\frac{t}{r^2}\right)10^{-\frac{\Delta P}{m}} \tag{22}$$

4.1.4 Derivative plot

A derivative plot is a useful diagnostic tool for examining the effects of wellbore storage, recharge and barrier boundaries, leakage, and delayed gravity response and fracture flow. The derivative plot provides a simultaneous presentation of $log(\Delta P)\ vs.\ log(\Delta t)$ and $log(tdP/dt)\ vs.\ log(\Delta t)$ and provides many separate characteristics in one plot that would otherwise require different plots. Selecting an appropriate calculating method of the derivative is very important when performing derivative analysis. A straightforward numerical differentiation using adjacent points will produce a very noisy derivative (Horne, 1995).

$$t\left(\frac{\partial P}{\partial t}\right) = t_i\left[\frac{(t_i - t_{i-1})\Delta P_{i+1}}{(t_{i+1} - t_i)(t_{i+1} - t_{i-1})} + \frac{(t_{i+1} + t_{i-1} - 2t_i)\Delta P_i}{(t_{i+1} - t_i)(t_i - t_{i-1})} - \frac{(t_{i+1} - t_i)\Delta P_{i-1}}{(t_i - t_{i-1})(t_{i+1} - t_{i-1})}\right] \tag{23}$$

Here t is the time, P is the pressure, and index $(i-1)$ and $(i+1)$ refer to the two adjacent points to i.

If the data are distributed in a geometric progression, then the numerical differentiation with the logarithm of time can be used to remove noise from the calculations (Horne, 1995).

$$t\left(\frac{\partial P}{\partial t}\right) = \left[\frac{ln(t_i/t_{i-1})\Delta P_{i+1}}{ln(t_{i+1}/t_i)ln(t_{i+1}/t_{i-1})} + \frac{ln(t_{i+1} \times t_{i-1}/{t_i}^2)\Delta P_i}{ln(t_{i+1}/t_i)ln(t_i/t_{i-1})} - \frac{ln(t_{i+1}/t_i)\Delta P_{i-1}}{ln(t_i/t_{i-1})ln(t_{i+1}/t_{i-1})}\right] \tag{24}$$

If this method still leads to a noisy derivative, the best method to reduce the noise is to use data points that are separated by at least 0.2 of a log cycle. Hence:

$$t\left(\frac{\partial P}{\partial t}\right) = \left[\frac{ln(t_i/t_{i-k})\Delta P_{i+j}}{ln(t_{i+j}/t_i)ln(t_{i+j}/t_{i-k})} + \frac{ln(t_{i+j} \times t_{i-k}/t_i^2)\Delta P_i}{ln(t_{i+j}/t_i)ln(t_i/t_{i-k})} - \frac{ln(t_{i+j}/t_i)\Delta P_{i-k}}{ln(t_i/t_{i-k})ln(t_{i+j}/t_{i-k})}\right] \tag{25}$$

$$ln(t_{i+j}) - ln(t_i) \geq 0.2 \tag{26}$$

$$ln(t_i) - ln(t_{i-k}) \geq 0.2 \tag{27}$$

The value of 0.2 (known as the differentiation interval) can be replaced by smaller or larger values (usually between 0.1 and 0.5), with consequent differences in the smoothing of the noise.

4.2 HF-1 well tests during drilling

Three production well tests were performed during, and at the end of, drilling. Two of them are used in the project to estimate the parameters of the reservoir intersected by the well. The testing was done by air-lifting, i.e. with the drilling string blowing out air at different depths. The first test used for interpretation was performed January 12-13 lasting around 10 hours with a water temperature of 68-69°C when the well was at depth 1214 m, and the second was done February 19-20 lasting around 12 hours with a water temperature of 72-73°C, when the well was 1608 m deep (Kristinsson et al., 2013b; 2013c).

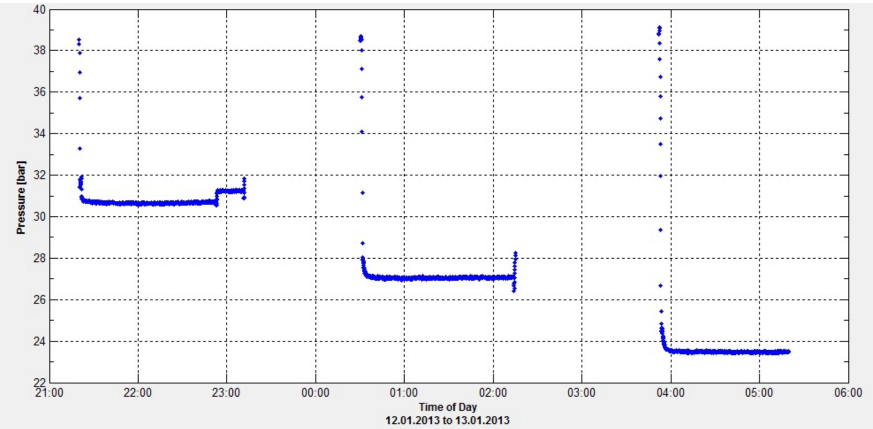

FIGURE 9: Pressure transients measured at 400 m depth in well HF-1 during the first well test, January 12 - 13, 2013

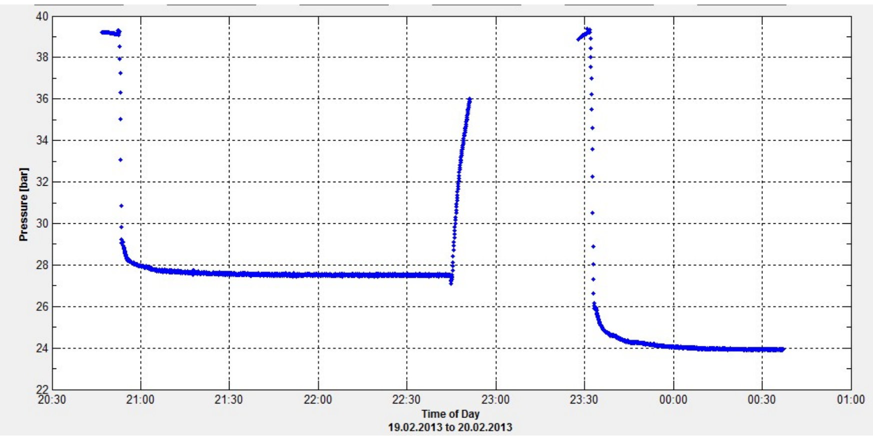

FIGURE 10: Pressure transients measured at 400 m depth in well HF-1 during the second well test, February 19 - 20, 2013

The first production test included 3 effective drawdown steps (Figure 9). Step 1 lasted from 21:20 to 23:12 on January 12, 2013, with an average production rate of 13 l/s. Step 2 lasted from 00:30 to 02:15 on January 13, 2013, with an average production rate of 15.5 l/s. Step 3 lasted from 03:52 to 05:20 on January 13, 2013, with an average production rate of 19 l/s. What should be mentioned is that the well had a free flow rate of 4.6 l/s before testing. The pressure transients in the well were measured with a pressure sensor at 400 m depth.

The second production test included 2 effective drawdown steps (Figure 10). Step 1 lasted from 20:47 to 22:44 on February 19, 2013, with an average production rate of 25 l/s. Step 2 lasted from 23:28 February 19 to 00:37 February 20, 2013 with an average production rate of 29 l/s. The pressure was also measured with a sensor at 400 m depth. But the free flow rate of the well was 7 l/s before this test.

4.3 Well test interpretation and results

Computer software, WellTester, which was developed by ISOR (Júlíusson et al., 2007), was used for the well test interpretation. To obtain a better fit between the data and theory with WellTester, each step of the two production tests was interpreted separately.

4.3.1 The first production well test

The initial parameters given in WellTester are values that are assumed to be known approximately. It is not essential for all of these parameters to be correct (with the exception of the wellbore radius) to get meaningful results from the well test analysis, but having good estimates helps in deducing information from the well test beyond the standard output. The initial parameter values used for this analysis are shown in Table 4.

The 3 steps were modelled separately to estimate the parameters of the reservoir. By trying different flow models to fit each of the steps with WellTester, the best model appeared to be a dual porosity reservoir model, with a constant pressure boundary, constant skin and wellbore storage.

TABLE 4: Summary of initial parameters used for analysis of the first production well test with WellTester

Parameter Name	Values	Unit
Estimated reservoir temperature (T_{est})	69	°C
Estimated reservoir pressure (P_{est})	38	bar
Wellbore radius (r_w)	0.14	m
Porosity (φ)	0.10	-
Dynamic viscosity of reservoir fluid (μ)	$4.09\cdot10^{-4}$	Pa·s
Compressibility of reservoir fluid (c_w)	$4.45\cdot10^{-10}$	Pa^{-1}
Compressibility of rock matrix (c_r)	$2.44\cdot10^{-11}$	Pa^{-1}
Total compressibility (c_t)	$6.65\cdot10^{-11}$	Pa^{-1}

In order to obtain realistic results, the reservoir thickness was set between 500 and 1000 m, the storativitiy was set between $3.33\cdot10^{-8}$ and $6.65\cdot10^{-8}$ m3/ (Pa·m2), the skin factor was set between -1 and 1, and the radius of investigation was set between 75 and 80 m, because there is no effect in other wells, except a slight effect in Well ASK-86 which is 75 m north of HF-1 (Kristinsson et al., 2013b). A summary of the output from WellTester, i.e. the estimated reservoir and well parameters, is listed in Table 5 and the output plots for each step with sampled data and model results are shown in Figures 11-13.

TABLE 5: Summary of the WellTester results for the first HF-1 well test of Well HF-1 January 12-13

Parameters	Step 1	Step 2	Step 3	Units
Transmissivity (T)	$1.19\cdot10^{-8}$	$1.04\cdot10^{-8}$	$0.99\cdot10^{-8}$	$m^3/(Pa\cdot s)$
Storativity (S)	$5.81\cdot10^{-8}$	$5.65\cdot10^{-8}$	$5.65\cdot10^{-7}$	$m^3/(Pa\cdot m^2)$
Radius of investigation (r_e)	75	75	75	m
Skin factor (s)	0.60	0.67	0.67	-
Reservoir thickness(h)	873.11	849.89	850.00	m
Wellbore storage (C)	$4.52\cdot10^{-7}$	$2.55\cdot10^{-7}$	$4.24\cdot10^{-7}$	m^3/Pa
Effective permeability (k)	5.57	5.00	4.76	mD

4.3.2 The second production well test

Initial parameters used for the analysis of this production well test are shown in Table 6.

The two production steps were modelled separately to estimate the parameters of the reservoir. By trying different flow models to fit each of the steps with WellTester, the best fitting model also turned out to be the dual porosity reservoir model with a constant pressure boundary, constant skin and wellbore storage, as in the case of the first well test interpretation. The ranges of reservoir thickness, storativity, skin factor and radius of investigation were set the same as in the first test. The resulting parameter estimates are listed in Table 7 and the output plots for each step with sampled data and model results are shown in Figures 14-15.

Based on the results of the two interpretations, transmissivity (T) can be assumed to be in the range of $0.99 \cdot 10^{-8}$ - $1.45 \cdot 10^{-8}$ $m^3/(Pa \cdot s)$; storativity (S) is in the range of $5.36 \cdot 10^{-8}$ - $5.81 \cdot 10^{-8}$ $m^3/(Pa \cdot m^2)$; permeability is in the range of 4.76-7.04 mD, which is quite low compared to other geothermal systems in Iceland. Skin factors changed from around 0.60 - 0.67 to -0.03 ~ -0.09 from the first well test to the second. This shows that the well is improved after deepening between the two tests.

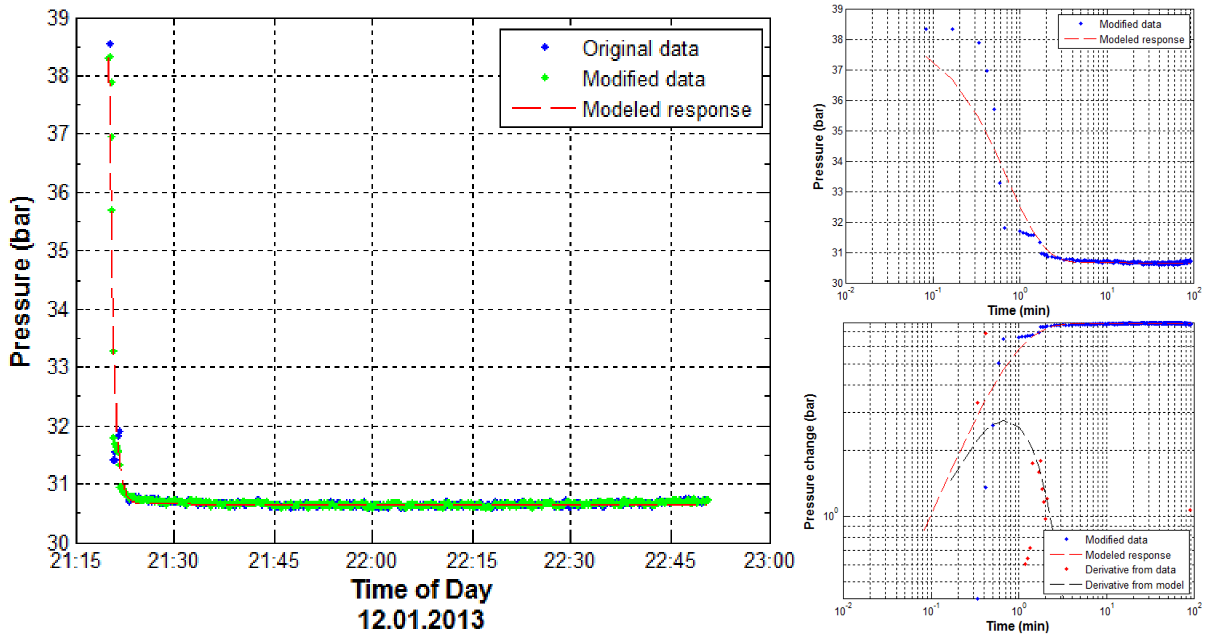

FIGURE 11: Fit between model and collected data for step 1 in the first well-test of HF-1; Left: Linear time-scale; Upper right: Logarithmic time scale; Lower right: Log-log scale

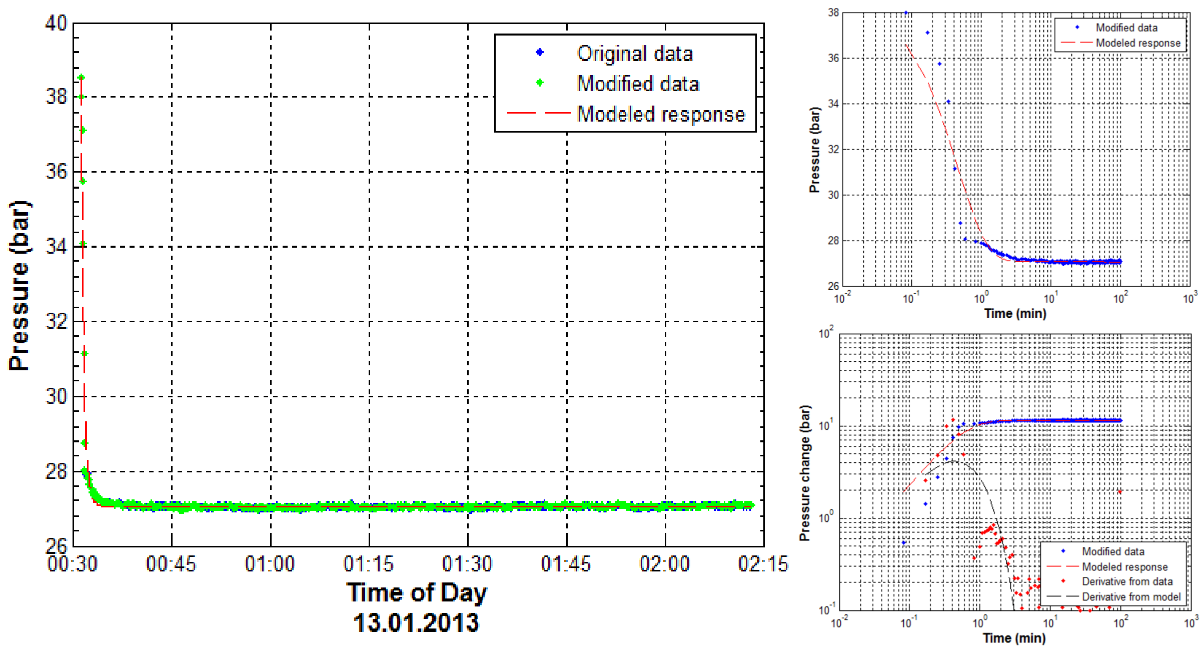

FIGURE 12: Fit between model and collected data for step 2 in the first well-test of HF-1; Left: Linear time-scale; Upper right: Logarithmic time scale; Lower right: Log-log scale

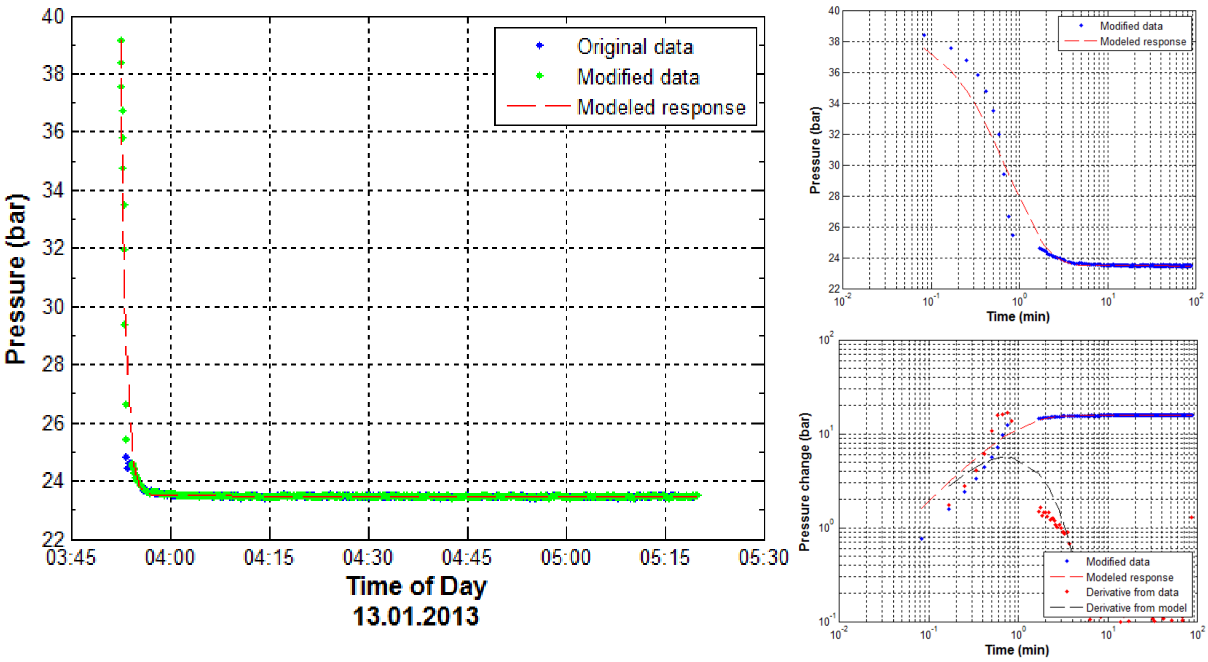

FIGURE 13: Fit between model and collected data for step 3 in the first well-test of HF-1; Left: Linear time-scale; Upper right: Logarithmic time scale; Lower right: Log-log scale

TABLE 6: Summary of initial parameters used for analysis of the second production well test with WellTester

Parameter name	Values	Unit
Estimated reservoir temperature (T_{est})	73	°C
Estimated reservoir pressure (P_{est})	39	Bar
Wellbore radius (r_w)	0.14	M
Porosity (φ)	0.10	-
Dynamic viscosity of reservoir fluid (μ)	$3.89 \cdot 10^{-4}$	Pa·s
Compressibility of reservoir fluid (c_w)	$4.48 \cdot 10^{-10}$	Pa^{-1}
Compressibility of rock matrix (c_r)	$2.44 \cdot 10^{-11}$	Pa^{-1}
Total compressibility (c_t)	$6.68 \cdot 10^{-11}$	Pa^{-1}

TABLE 7: Summary of the WellTester results for the second HF-1 well test, February 19-20

Parameters	Step 1	Step 2	Units
Transmissivity (T)	$1.45 \cdot 10^{-8}$	$1.28 \cdot 10^{-8}$	$m^3/(Pa \cdot s)$
Storativity (S)	$5.36 \cdot 10^{-8}$	$5.49 \cdot 10^{-8}$	$m^3/(Pa \cdot m^2)$
Radius of investigation (r_e)	75	75	m
Skin factor (s)	-0.03	-0.09	-
Reservoir thickness(h)	801.74	822.10	m
Wellbore storage (C)	$5.82 \cdot 10^{-7}$	$9.55 \cdot 10^{-7}$	m^3/Pa
Effective permeability (k)	7.04	6.06	mD

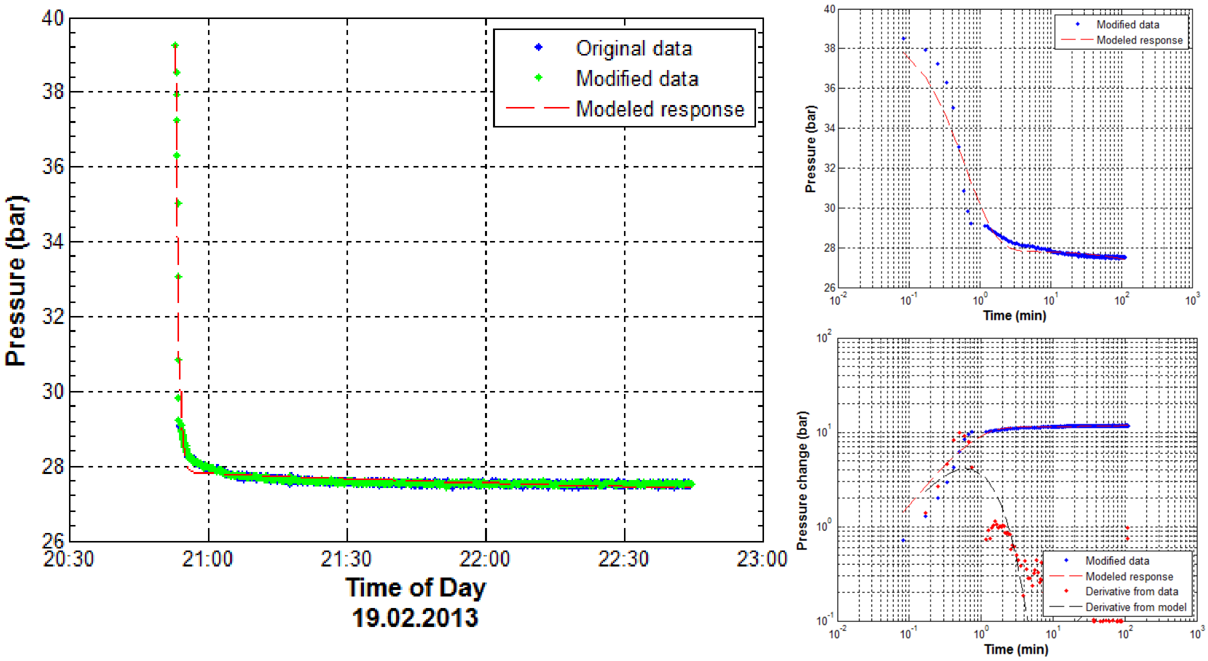

FIGURE 14: Fit between model and collected data for step 1 in the second well test of HF-1; Left: Linear time-scale; Upper right: Logarithmic time scale; Lower right: Log-log scale

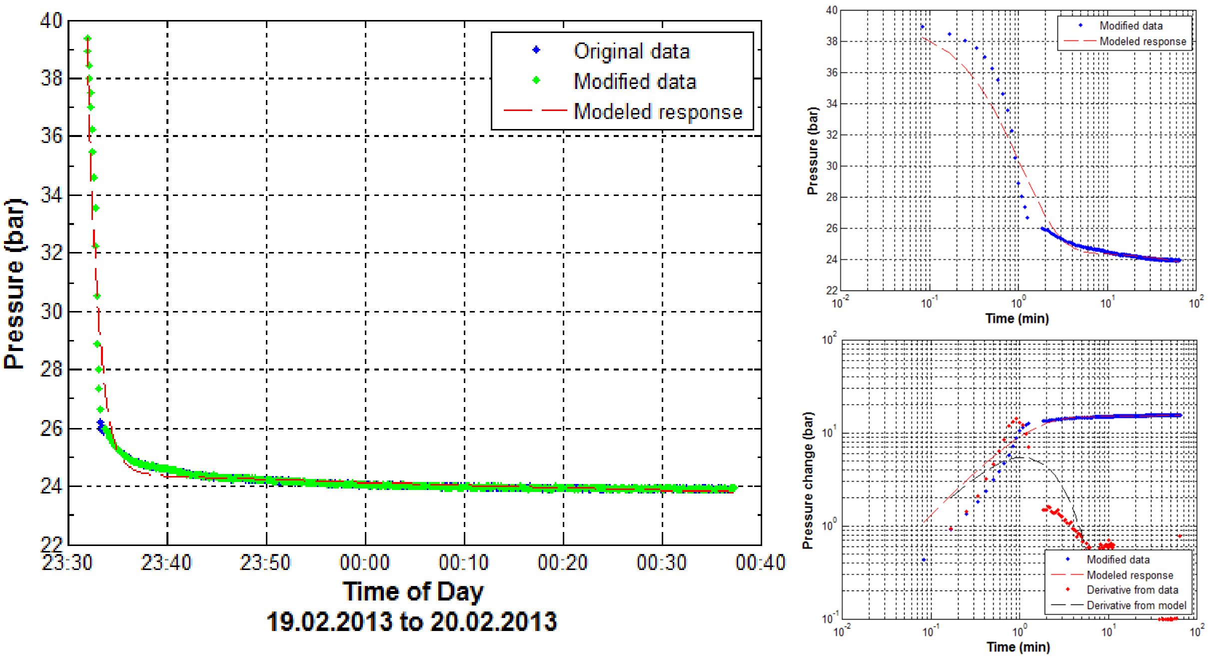

FIGURE 15: Fit between model and collected data for step 2 in the second well test of HF-1; Left: Linear time-scale; Upper right: Logarithmic time scale; Lower right: Log-log scale

5. LONG-TERM PRODUCTION TEST AND FUTURE PREDICTIONS

5.1 Theoretical background

To estimate production capacity of geothermal systems based on the prediction of changes in reservoir conditions (chiefly pressure and temperature), reservoir modelling needs to be brought in to help.

Reservoir modelling plays such an important role in geothermal assessment and management, because a lot of information can be obtained through it. It is an effective tool not only in obtaining information on physical conditions and properties of a reservoir, but also in simulating and predicting its response to exploitation.

Various modelling methods are used in geothermal research such as simple analytical modelling, lumped parameter modelling and detailed numerical modelling. Among these the lumped parameter modelling methods, which ignore geometry and integrate all the properties into lumped values, have been extensively used to simulate data on pressure (water-level) changes in geothermal systems in Iceland as well as in the P.R. China, Central America, Eastern Europe, Philippines, Turkey and many other countries during the past few decades (Axelsson, 2005). They can simulate such data very accurately, if the data quality is sufficient. Compared to other simple models, lumped parameter modelling can be the most precise. And compared to detailed numerical modelling, it is not very time consuming and does not require such comprehensive field data.

A general lumped parameter model is shown in Figure 16. It consists of a few tanks (capacitors) that are connected by flow resistors (conductors). The tanks simulate the storage capacity of different parts of the reservoir and the resistors, or conductors, simulate the permeability. A tank in a lumped model has a storage coefficient (capacitance) κ when it responds to a load of liquid mass m with a pressure increase, $\mathrm{p} = \mathrm{m}/\kappa$. The resistors (conductors) simulate the flow resistance in the reservoir, controlled by the permeability of the rocks. The mass conductance (inverse of resistance) of a resistor is σ when it transfers $\mathrm{Q} = \sigma\Delta\mathrm{p}$ units of liquid mass per unit time at the pressure difference, $\Delta\mathrm{p}$. The pressures in the tanks simulate the pressures in different parts of the reservoir, whereas production from the reservoir is simulated by withdrawal of water from only one of the tanks (Axelsson, 1989).

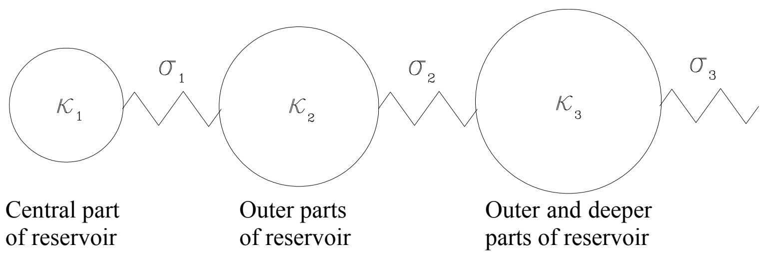

FIGURE 16: A general lumped parameter model used to simulate water level or pressure changes in a geothermal system (Axelsson et al., 2005)

Lumped models can be either open or closed. Open models are connected by a resistor to an infinitely large imaginary reservoir which maintains a constant pressure, and it can be considered optimistic since equilibrium between production and recharge is eventually reached and the water level will stabilize during long term production. On the other hand, closed lumped models are isolated from any external reservoir and can be considered pessimistic since no recharge is allowed for such models and the water level declines steadily with time during long term production. Actual reservoirs can most generally be represented and simulated by two- or three-tank closed or open lumped parameter models (Axelsson, 1989). The pressure response, $\Delta p(t)$, of a single-tank open model for production Q, assuming a step response since time $t = 0$, is given by the following equation (Axelsson and Arason, 1992):

$$\Delta p(t) \;=\; -\left(\frac{Q}{\sigma_1}\right)\left(1 - e^{\frac{\sigma_1 t_i}{\kappa_1}}\right) \tag{28}$$

The pressure response of a more general open model with N tanks, to Q, assuming a step response, from time $t = 0$, is given by:

$$\Delta p(t) = -\sum_{j=1}^{N} Q\left(\frac{B_j}{L_j}\right)\left(1 - e^{-L_j \times t_i}\right) \tag{29}$$

The pressure response of a general closed model with N tanks is given by:

$$\Delta p(t) = -\sum_{j=1}^{N} Q\left(\frac{B_j}{L_j}\right)\left(1 - e^{-L_j \times t_i}\right) + Q \times C \times t_i \tag{30}$$

Coefficients B_j, L_j and C are functions of the storage coefficients of the tanks (κ_j) and the conductance coefficients of resistors (σ_j) of the model, and can be estimated by the LUMPFIT program which uses an iterative non-linear inversion technique to fit a corresponding solution to the observed pressure or water level (Axelsson, 1989).

After developing a model which matches the observed data very well with LUMPFIT, the size and properties of the different parts of the reservoir can be estimated by the conductance and capacitance coefficients obtained from the model (Vitai, 2010).

The surface area of the different parts of the system A_j can be calculated by the following equation:

$$A_j = \frac{\kappa_j}{s \cdot h} \tag{31}$$

where κ_j = Storage coefficient or capacitance (kg/Pa) or ($m \cdot s^2$);
s = Storativity of the reservoir ($kg/(Pa \cdot m^3)$) or (s^2/m^2);
h = Reservoir thickness (m); and
j = 1, 2, 3, referring to the innermost, the deeper or outer and the recharge part of the reservoir, respectively, (this is valid only for a 3-tank model; for a 1-tank model, $j = 1$ and for a 2-tank model $j = 1, 2$).

Conductance σ_j can be used to estimate the permeability k_j (or permeability thickness $k_j h_j$) of the different parts of the reservoir. For 1-dimensional flow, it can be calculated as:

$$k_j = \left(\sigma_j L_j \upsilon\right)/A_{\perp j} \tag{32}$$

where k_j = Permeability of the reservoir (m^2);
υ = Kinematic viscosity of the geothermal fluid (m^2/s);
σ_j = Conductance coefficients of resistor ($m \cdot s$) or ($kg/(Pa \cdot s)$);
$A_{\perp j}$ = Area of the reservoir perpendicular to the flow path (m^2); and
L_j = Length of the flow path between adjacent reservoir parts, of the outermost part of the system and the surroundings (m).

For 2- dimensional flow, the permeability can be expressed as:

$$k_j = \left(\sigma_j \upsilon ln \frac{r_{j+1}}{r_j}\right)/2\pi h_j \tag{33}$$

where r_j = Defined in Table 8; and
h_j = Thickness of the reservoir (m).

The radius of each tank and the equations for calculating distances from the centre to the relevant edge are listed in Table 8. The tanks in LUMPFIT may be thought of as concentric volumes where R_1 is the radius of the innermost one, R_2 the radius of the second one and R_3 of the outermost one. In the formulas in Table 8, r_1, r_2, r_3 and r_4 are the distances from the centre of a tank to the outside of the relevant edge.

TABLE 8: The radius of each tank and equations to calculate distances from the centre to the relevant edge for different lumped parameter models, for 2-dimensional flow (Liu, 2011)

Model type	Equations
1-tank open model	$r_1 = R_1/2; r_2 = 3\,R_1/2$
2-tank closed model	$r_1 = R_1/2; r_2 = R_1 + (R_2 - R_1)/2$
2-tank open model	$r_1 = R_1/2; r_2 = R_1 + (R_2 - R_1)/2;\ ;\ r_{2+1} = R_2 + (R_2 - R_1)/2$
3-tank closed model	$r_1 = R_1/2; r_2 = R_1 + (R_2 - R_1)/2; r_3 = R_2 + (R_3 - R_2)/2$
3-tank open model	$r_1 = R_1/2; r_2 = R_1 + (R_2 - R_1)/2; r_3 = R_2 + (R_3 - R_2)/2; r_4 = R_3 + (R_3 - R_2)/2$
	$V_1 = \kappa_1/S;\ V_2 = \kappa_2/S; V_3 = \kappa_3/S;\ R_1 = (V_1/\pi h)^{0.5};$ $R_2 = [(V_1 + V_2)/\pi h]^{0.5}; R_3 = [(V_1 + V_2 + V_3)/\pi h]^{0.5}$ where V_j is the volume of the j-th tank (m^3) and R_j is the radius of the first j tanks combined (m).

5.2 Lumped parameter modelling for the Hoffell geothermal system

After drilling of Well HF-1 was completed, a long term production test with a down-hole pump was started on April 9, 2013. The test is was still on-going at the time of writing of this report. Water-level drawdown, production flow rate and water temperature have been monitored and recorded simultaneously. Up until September 8, 152 days of monitoring data had been collected. These data provide the basis for lumped parameter modelling of the geothermal system and interpretation.

During the 152 day production process, production started with a flow rate of 20 l/s, and was later changed to 15 l/s (on August 2, 2013). The water level in the well varied in the range of -80 to -140 m depth (below surface level) while the water temperature was constant at 72°C. As was referred to in Section 4.2, Well HF-1 had a free flow rate of 7.0 l/s when it was measured on February 19, 2013. Considering this background condition, the production test/process can be assumed to be extended from 49 days to 201 days in total, from February 19 to September 8, 2013. The flow rate of the test was assumed to be 7.0 l/s with a water level of 0 m, constantly from February 19 to April 9, 2013.

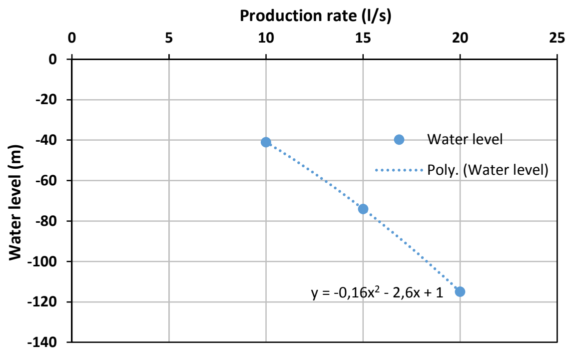

FIGURE 17: Relationship between water level and production rate during a step-rate test of Well HF-1

During the long time production test, a step rate test was performed on May 7-8, 2013 to estimate the relationship between the water level and the production rate. According to the plot of the results (Figure 17), a trend line and its equation were calculated which show that the well has a turbulence coefficient of 0.16 $m/(l/s)^2$.

Two lumped parameter models, a two-tank closed model and a two-tank open model, were used to simulate the long term monitoring data from Well HF-1, assuming an initial water level of 85 m above surface. The modelling results are shown in Figure 18. The coefficient of determination for the fit of the two-tank closed model is 98.7% while that of the two-tank open model is 99.3%. The parameters of the two models are listed in Table 9.

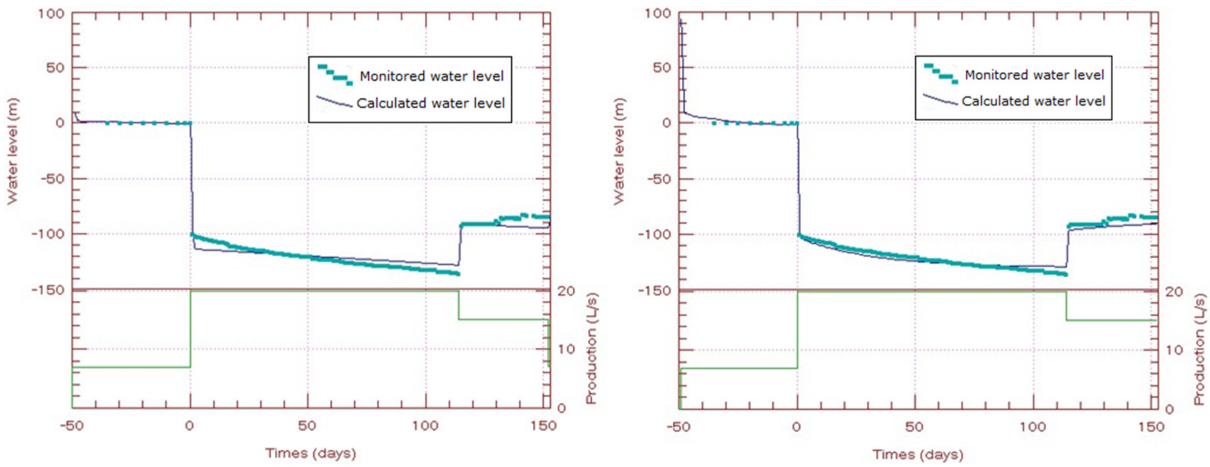

FIGURE 18: Monitored and calculated water level of Well HF-1 during the long-term production test; calculated values are those of the lumped parameter models (Left: Two-tank closed model; Right: Two-tank open model); Time t = 0 corresponds to April 9, 2013

Assuming a confined liquid-dominated geothermal system with 2-dimensional flow, storativity of 5.43×10^{-8} and reservoir thickness of 810 m (average of the second well test), the surface area and permeability thickness of different parts of the reservoir could be estimated according to the theoretical background. The results are listed in Table 10.

Based on the results, it is reasonable to conclude that the permeability thickness of the reservoir around Well HF-1 is around 1.9 - 2.2 D·m. This is further supported by the fact that this range is quite similar to that estimated for the short-term test analysed by WellTester.

TABLE 9: Parameters of lumped parameter models for Well HF-01

Parameters	Two-tank closed model	Two-tank open model
A_1 (data units)	32.3	52.9
L_1 (data units)	2.49	4.40
A_2 (data units)	-	0.0596
L_2 (data units)	-	0.0315
B (data units)	0.00645	-
κ_1 (kg/m^{3}Pa)	0.273	0.166
κ_2 (kg/m^{3}Pa)	1370	150
σ_1 (kg/sPa)	0.00000784	0.00000845
σ_2 (kg/sPa)	-	0.0000547
Root mean square misfit	5.30	3.80
Estimate of standard deviation	5.35	3.85
Coefficient of determination	98.7%	99.3%

TABLE 10: Reservoir properties of the lumped parameter models for the Hoffell reservoir

Properties	Two-tank closed model	Two-tank open model
Reservoir volume V_1 (km^3)	0.00502	0.00306
Reservoir volume V_2 (km^3)	25.2	2.76
Surface area A_1 (km^2)	0.00620	0.00378
Surface area A_1 (km^2)	31.1	3.41
Permeability thickness k_1h_1 (D·m)	2.2	1.9
Permeability k_1 (mD)	2.7	2.3

5.3 Future water-level predictions

Based on the lumped parameter models established above, future predictions could be calculated to estimate the response of the water level (reservoir pressure) to exploitation. The monitoring period was relatively short, only 201 days, which is not long enough to make accurate long term predictions. However, 10 year predictions were calculated to help gain an understanding of the general water-level changes for different production flow rates.

As estimated in Chapter 3, the average thermal water flow rate was estimated to be 28.6 l/s if the heating system was used for 50 years and 14.3 l/s if the heating system was used for 100 years. These results form the basis for the prediction production scenarios; the production rates were set as 28.6 l/s, 21.4 l/s, 14.3 l/s and 7.15 l/s.

Since we do not know whether the geothermal system is closed or open, i.e. with no recharge or with recharge equilibrating with the production, two models were adopted for the predictions. The two-tank closed model was used to get conservative predictions while the two-tank open model was used to get optimistic predictions. The prediction results of the two models are shown in Figure 19.

The results (Figure 19, Table 11) show that the water level behaves quite differently in the two models. Over the next 10 years, the water level is predicted to decline very sharply in the closed system while in the open system it reaches equilibrium. With an increasing production rate, the difference between the two becomes more obvious. The difference between the two models varies from 180 m to 658 m after 10 years with the production rates changing from 7.15 l/s to 28.6 l/s. The water level in a closed system had a greater response to large production rates than that in an open system. A large production rate (e.g. 21.45 and 28.6 l/s) would lead to a very great water level decline, if the geothermal system was a closed system. A large rate such as 28.6 l/s would cause the water level to drop down to -841 m after 10 years, which is not realistic.

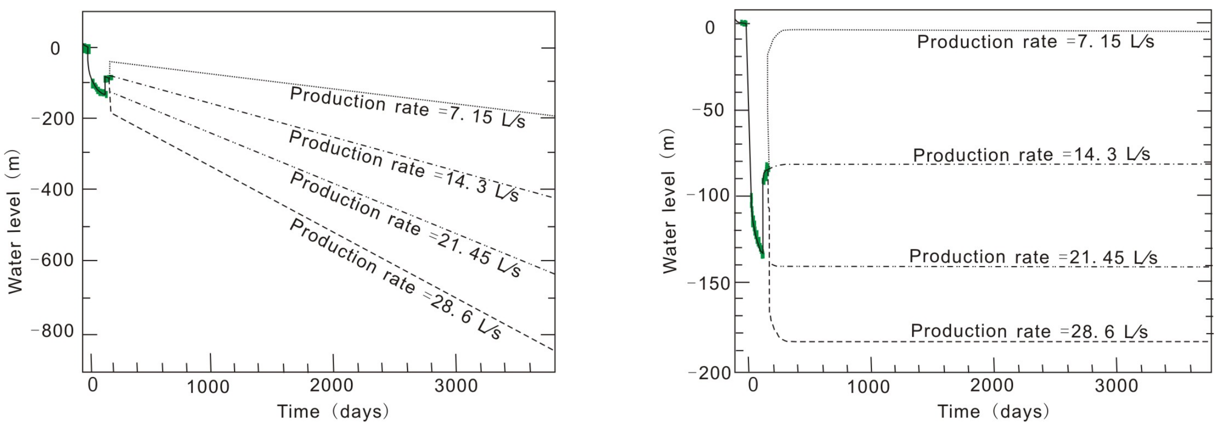

FIGURE 19: Predicted water levels in Well HF-1 for the next 10 years for different production rates (Left: Conservative predictions using two-tank closed model; Right: Optimistic predictions using two-tank open model)

TABLE 11: Predicted water levels in Well HF-1 after 10 years production (m)

Production flow rate (l/s)	Conservative model (closed system)	Optimistic model (open system)	Difference between the two models
7.15	-187	-6.5	180
14.3	-421	-81.6	339
21.45	-639	-140	499
28.6	-841	-183	658

Based on the results, it seems that if the system is open, Well HF-1 will sustain around 30 l/s for 10 years; if the system is closed, the well can only sustain around 10 l/s for the next 10 years (pump at depth of about 200 m). It is also very unlikely that the system is completely closed; maybe its behaviour will be somewhere in-between the two models, which means 15 to 20 L/s is the most likely production range. However, to reduce negative influence, reinjection will be necessary, especially for large production rates if the system turns out to be relatively closed.

6. CONCLUSIONS

The purpose of this research project was to perform a production capacity assessment for the Hoffell low-temperature geothermal system in SE-Iceland, using three different reservoir engineering research methods. The conclusions of the work can be summarized as follows:

- Based on the geological background and subsurface temperature distribution of the system, a simple conceptual model was established. The system is a liquid-dominated low-temperature geothermal system with about 80°C thermal groundwater existing in deep confined aquifers below 600-1000 m depth, with flow controlled by near-vertical fractures.

- A volumetric assessment was performed using the Monte Carlo method. The total energy of the system was estimated to most likely be 46.9 TJ and the total recoverable energy was estimated to most likely be 9.4 TJ. If the energy was used for a heating system for 50 years or 100 years, it corresponds to a most likely thermal power of 6.0 MW_{th} or 3.0 MW_{th} with a production flow rate of 28.6 l/s or 14.3 l/s, respectively.

- Interpretation of two well tests performed in Well HF-1 was carried out with the software WellTester to estimate the parameters of the reservoir. The transmissivity (T) was estimated to be in the range of $0.99 \cdot 10^{-8} - 1.5 \cdot 10^{-8}$ $m^3/(Pa \cdot s)$ and the permeability in the range 4.8 – 7.0 mDarcy. The skin factor of the well improved from around 0.6 to -0.1 from the first well test to the second. This shows that the well was obviously improved by deepening between the two tests.

- Lumped parameter modelling was used to simulate the behaviour of the reservoir to exploitation, based on the results of a 5 month production test, using the software Lumpfit. A two-tank closed model and a two-tank open model were used to simulate the long term monitoring data from Well HF-1, and a good fit between the data and the models was achieved. Permeability, estimated on the basis of the Lumpfit-results and from WellTester, was quite comparable, indicating that the permeability thickness of the reservoir around Well HF-1 was about 2 – 5 Darcy·m.

- Predictions were calculated to estimate the probable response of the water level in Well HF-1 to different production rates for the next 10 years. It seems that if the system is open, Well HF-1 will sustain around 30 l/s for 10 years. If the system is closed, the well will only sustain around 10 l/s for the next 10 years, according to the present predictions. It is very unlikely that the system is completely closed, however; maybe the behaviour will be between the two possibilities, which means that 15 – 20 l/s is the most likely production range. Reinjection will be necessary if the system turns out to be relatively closed.

- It should be noted that the future predictions are quite uncertain, as witnessed by the great discrepancy between the open and closed predictions. As more production experience is gained, this discrepancy will diminish. It may also be mentioned that an unusually great turbulence pressure-drop occurred in well HF-1, corresponding, for example, to about 65 m at 20 l/s production. If more successful production wells are drilled in the area, the production capacity of the system would likely increase as the turbulence pressure loss would decline as production was distributed among more wells.

- Further research is highly necessary in the Hoffell area as the geothermal system needs to be described in more detail for a more accurate assessment and with precise locations of new wells. The sustainable production capacity of the reservoir should be revealed if more wells are drilled in the future. Once exploitation starts, monitoring and comprehensive management of this valuable resource should be performed carefully and scientifically.

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