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RESERVOIR ASSESSMENT OF THE ÓSABOTNAR LOW-TEMPERATURE GEOTHERMAL FIELD, SW-ICELAND

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ABSTRACT

In the year 2002, production began in the Ósabotnar low-temperature geothermal field to cover a decline in the capacity of wells in the Thorleifskot-Laugardaelir low-temperature system in SW-Iceland. Ósabotnar is a liquid-dominated convective system. A 10 year long series of production rates exists for the two production wells ÓS-01 and ÓS-02 and pressure data are available for well HT-24 for almost the entire production period. These data were simulated by lumped parameter modelling. By simulating various production scenarios, the maximum production potential was estimated. Accurate models predict the water level in the future, and this field looks promising. These results provide a good basis for management of the resource. It is hoped that, in the future, deeper wells in the Ósabotnar low-temperature geothermal field with deeper casings will provide a steady supply of thermal water for space heating in this district.

1. INTRODUCTION

In Iceland, geothermal energy plays an important role. The principal use of geothermal energy in the country is for space heating. Currently, about 90% of the space heating energy is supplied by geothermal energy (Axelsson et al., 2010b). The low-temperature geothermal systems, with a reservoir temperature below 150°C, are located outside the volcanic zone that passes through Iceland. The Ósabotnar geothermal field is one of the numerous low-temperature geothermal areas in Iceland. Many of them, like the Ósabotnar field, provide geothermal energy for space heating.

In a cold country like Iceland, home heating needs are greater than in most low latitude countries. The average temperature in Reykjavík is −1°C in January and 11°C in July. Due to the low summer temperatures, the heating season lasts throughout the year (Axelsson et al., 2010a).

There exists no stable system that can provide energy eternally. Geothermal systems should be used in a sustainable manner in order not to exhaust the system. Reservoir assessments for these geothermal fields are, therefore, very important. The system should be studied well, in order to efficiently manage the resource so that it can provide heating energy in the long term.

2. THE ÓSABOTNAR GEOTHERMAL FIELD

2.1 General

The Ósabotnar geothermal field is located in SW-Iceland, about 4 km north of the town of Selfoss (Figure 1). This low-temperature system, along with the Thorleifskot-Laugardaelir low-temperature system, is used by the Selfoss district heating company (Selfossveitur) for district heating in the Árborg community, which encompasses the towns of Selfoss, Eyrarbakki and Stokkseyri as well as the surrounding rural areas (Ólafsson et al., 2005).

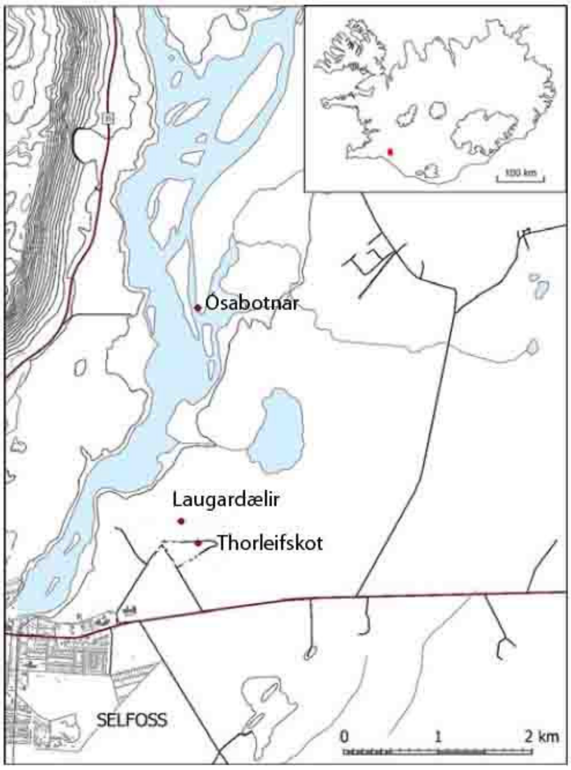

FIGURE 1: The Ósabotnar geothermal field and town of Selfoss (modified from Ólafsson et al., 2005)

Production drilling in the Ósabotnar geothermal field was begun in 2000 to address the potential decline in energy due to a decline in the output from wells in the Thorleifskot-Laugardaelir low-temperature system. The Thorleifskot-Laugardaelir low-temperature geothermal system is inside the South-Iceland seismic zone and is, therefore, highly permeable due to numerous fractures. At first, the thermal water production mainly depended on a few shallow wells, but these wells were abandoned, one by one, because of an inflow of cold groundwater through some of the open fractures. Later, Selfoss District Heating drilled deeper wells with deeper casings in order to stop the inflow of cold water from shallower feed zones. Still, many of these wells have been affected by the cooling (Tómasson and Halldórsson, 1981).

Drastic production temperature decline was observed in several wells in Thorleifskot-Laugardaelir geothermal field, with a maximum decline of about 35°C. For Selfoss district heating, this problem was resolved by drilling additional production wells in a nearby low-temperature geothermal system. In order to explore for new geothermal reservoirs in the neighbourhood of Árborg, Selfoss District Heating engaged in an extensive geothermal exploration program by drilling a number of shallow temperature gradient wells. This led to the discovery of the Ósabotnar reservoir, located 4 km north of the town of Selfoss with a reservoir temperature of approximately 90-100°C. It is hoped that, in the future, this deeper part of the system will provide more energy for Selfoss District Heating (Axelsson et al., 2010a). Production well ÓS-01 was drilled to 386 m in May 2000 and to the final depth of 804 m in January 2001 (Ólafsson et al., 2005). Well ÓS-02 in Ósabotnar was drilled in the summer of 2007, and reached a depth of 1717 m.

The importance of monitoring and assessing the effects of production on the geothermal system in Ósabotnar is twofold. On the one hand, in recent years the demand for hot water has increased significantly, as Table 1 shows, making the drilling of new production wells increasingly necessary. Total production has increased by approximately 25% over the last ten years in response to increased demand for geothermal water in the area of Selfoss District Heating.

On the other hand, cold water inflow from shallow, open fractures within the seismic zone in Thorleifskot-Laugardaelir has lowered the temperature of the extracted fluids; this cooling increased after the earthquakes in 2000 and 2008.

The Ósabotnar reservoir has a temperature of 90-100°C at 1000 m. The water is more dilute compared to the Thorleifskot and Laugardaelir reservoirs, with a chlorine content of 50-60 mg/l, a silica content of 70-75 mg/l, and pH around 9.8-9.9 (Table 2). Production from the Ósabotnar field started in early 2002 and the water was mixed with waters from production wells in the Thorleifskot and Laugardaelir fields. Soon, scaling problems were encountered in the central pump station where calcite was deposited in the pumps that feed the distribution system. Calculations showed that a mixture of the two water types, although rather similar in composition, became more supersaturated with respect to calcite than water from individual wells. To respond to this problem, experiments were performed in 2003 where water from the Ósabotnar well was acidified with sulphuric acid to lower the pH value before mixing (Ólafsson et al., 2005). The results were promising and today the water from Ósabotnar is acidified with concentrated sulphuric acid and mixed with waters from other production wells utilized by Selfoss District Heating without scaling problems.

TABLE 1: Annual average production in geothermal areas in Thorleifskot-Laugardaelir and Ósabotnar in the years 2001-2011 for Selfoss area (modified from Axelsson and Halldórsdóttir, 2012)

Year	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
Thorleifskot-Laugardaelir production (l/s)	98.3	74.9	83.7	78.3	85.3	78.8	92.2	89.4	102.0	78.8	82.2
Ósabotnar production (l/s)	1.7	22.6	13.2	22.1	21.6	29.7	15.1	31.5	21.4	46.3	42.8
Annual total prod. (l/s)	**100**	**97.5**	**97**	**100.4**	**106.9**	**106.5**	**107.3**	**120.9**	**123.4**	**125.1**	**125**

TABLE 2: Chemical composition of geothermal water from well ÓS-01 (mg/l unless otherwise noted) (modified from Ólafsson et al., 2005)

Sampling date	2004.02.04	B	0.19	SO_4	29.7
Temperature (°C)	79.5	Na	73.7	Al	0.097
Discharge (l/s)	38	K	1.24	Mn	0.001
pH / T (°C)	9.8 / 23	Mg	0.002	Fe	0.004
CO_2 (total)	9.9	Ca	7.13	TDS	285
H_2S	0.16	F	0.67	δD (‰)	-65.6
SO_2	71.0	Cl	70.0	δ18O (‰)	-9.65

2.2 Previous studies in the Ósabotnar geothermal field

The main production wells in Ósabotnar geothermal field are ÓS-01 and ÓS-02. Figure 2 shows the locations of these wells and of exploration wells that are nearby. Drilling of well ÓS-01 was completed at the end of January 2001 to a depth of 804 m. It is lined with a 10" pipe to 150 m depth, and all cold water feed zones above 360 m depth in the well were cemented closed. Immediately at the end of drilling, it was clear that the well was very productive. Well ÓS-02 in Ósabotnar was drilled in the summer of 2007; the well is 1717 m deep and lined with

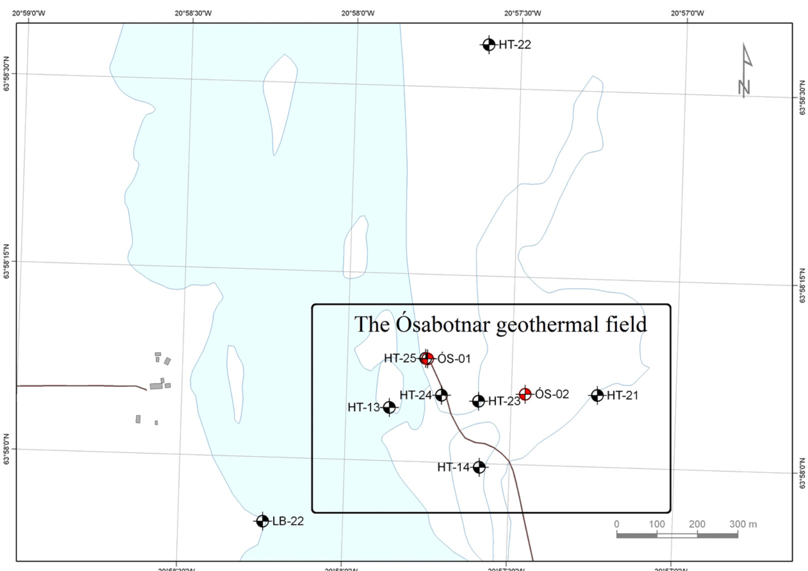

FIGURE 2: The Ósabotnar geothermal field and well locations

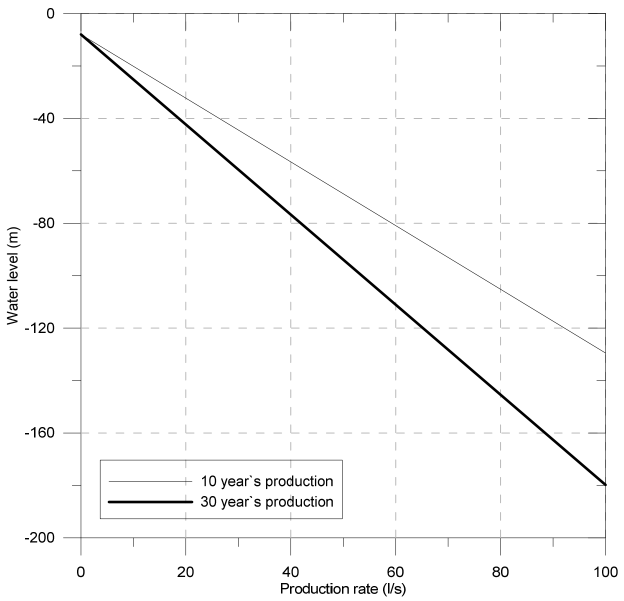

FIGURE 3: Water level forecasts for the geothermal system in Ósabotnar (modified from Gudni Axelsson and Magnús Ólafsson, 2006)

14" tube of 411 m. Because of loose strata, which were a problem during drilling, the well was lined with a 10¾" hanging casing from 364 down to 472 m depth. Testing of the well at the end of drilling showed further collapse in the well which also proved necessary to case off. Now there is an 8" perforated casing from 354 m depth down to 550 m. Below that the well is not cased.

An assessment, aimed to assess the capacity of the geothermal system in Ósabotnar, was made in the early years of exploitation of Ósabotnar as a production field (Axelsson and Ólafsson, 2006). It was based mainly on the examination of changes in water levels which was then used for forecasts of water level changes for different production scenarios. Figure 3 shows the results of the prediction calculations from 2006. It shows the water level forecasts for the geothermal system in Ósabotnar for a processing scenario that allows for three production wells in the area (Axelsson and Ólafsson, 2006), after 10 and 30 years of production. Variable production from wells is assumed so that the maximum production in winter is about 50% above the average production. The figure shows the position of the lowest water level as a function of total average production.

The Ósabotnar system is inside the S-Iceland seismic zone and is highly permeable, like the Thorleifskot-Laugardaelir system. This allows for the inflow of cold groundwater through some of the open seismic fractures at shallow depths. The temperatures are quite high in the deeper parts, and steadier than at shallow depths. Figure 4 shows a map of seismic activity and faults (black lines) mapped near the Ósabotnar geothermal field. The red star shows the location of the M_L>5 earthquake in this area in 2008.

2.3 Reservoir features

According to previous research, this low-temperature geothermal system is a liquid-dominated reservoir, which is in agreement with the temperatures encountered. At shallow depth there are many open fractures. Cold inflow through these faults causes cooling in the system making deeper casings necessary for the wells in this field. At greater depth, the temperature is steady and high, at around 95°C. The pH value of the water in this system is high; therefore, the produced water cannot be used directly. Through mixing of the water with fluids from the Thorleifskot-Laugardaelir field, this problem was solved.

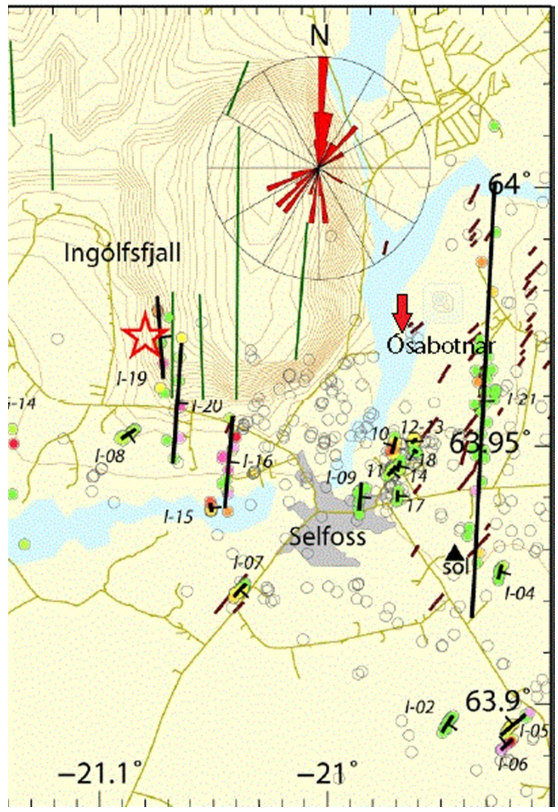

FIGURE 4: Seismic epicentres (grey circles) and mapped faults (black lines) near the Ósabotnar geothermal field (modified from Hjaltadóttir et al., 2009)

2.4 The purpose of the study

The main objective of reservoir engineering is to assess the production potential of a geothermal reservoir and to predict its response to future utilization. The main purpose of this report can be summarized by the following:

- Interpret the temperature logging data and obtain basic reservoir features;
- Find available data to do a volumetric assessment of the available energy in the Ósabotnar low-temperature geothermal system;
- Assess the production capacity of the Ósabotnar geothermal field by using the volumetric and the lumped assessment method; and
- Based on the modelling results, present several suggestions, which are important for the development of this geothermal field.

3. PRODUCTION DATA

Another study of Ósabotnar is currently underway to evaluate the capacity of the geothermal system on the basis of data on the reaction of the field to production, collected since 2005. In addition, detailed data were collected separately in 2011. This newer study is not complete, but the available data mostly confirm the previous findings. Figure 5 shows an example of water level data from well HT-24, which has the longest monitored history in the area. The data are consistent with the findings of the model calculations from 2006.

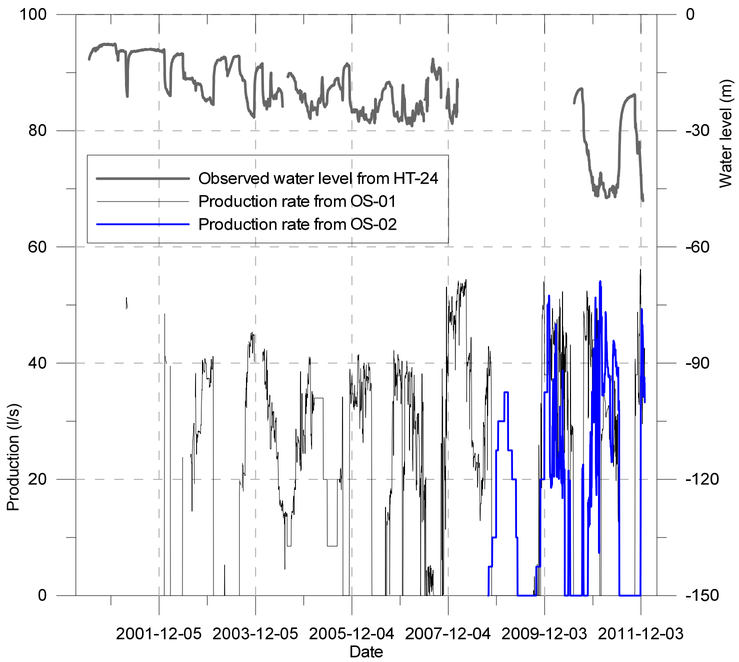

FIGURE 5: Production history of the geothermal system at Ósabotnar (wells ÓS-1 and ÓS-2) and water level data from a monitoring well (HT-24) in the región (modified from Axelsson and Halldórsdóttir, 2012)

It should be noted that there have been some problems with the use of well ÓS-1 after the earthquake of 2008. On one hand, there has been an increase in the amount of sand carried up the well which has disrupted pump operation. On the other hand, there are indications that the water level in the well will fall more sharply with pumping than first expected. This could indicate that the well is partially clogged, such that less water is obtained from deeper feed zones. At present, this reservoir provides 46.9 l/s on average.

4. TEMPERATURE MEASUREMENTS

Numerous temperature profiles were done in all eight boreholes in the Ósabotnar geothermal field. Focus was on the two wells, ÓS-01 and ÓS-02. The measurements were done at several stages after drilling. These profiles are the main basis of the analysis presented in this chapter. The profiles have been used to identify the main feed zones and to analyse the flow characteristics in the reservoir. By using these data, profiles about the distribution of temperature at different depths were drawn, and from the results, the area of this field was estimated.

Well ÓS-01. Seven temperature profiles were measured in well ÓS-01 (Figure 6a). Four main feed zones can be observed for it, 90 to 150 m b.s.l. (feed zone 1), 270 to 320 m b.s.l. (feed zone 2), 410 to 480 m b.s.l. (feed zone 3) and, 520 to 560 m b.s.l. (feed zone 4). Below -600 m, the temperature profiles are stable and vertical. The heat convection below this depth plays an essential role because of the free cross-flow and high permeability.

Well ÓS-02. Fourteen temperature profiles were measured in well ÓS-02 (Figure 6b). Three main feed zones can be observed for this borehole at 350 to 400 m b.s.l. (feed zone 1), 460 to 490 m b.s.l. (feed zone 2) and at 780 to 850 m depth (feed zone 3). Below -600 m, the temperature profiles are stable and vertical. This indicates a convective heat flow in the temperature profiles taken during the warm up period.

Well HT-13 and HT-25. Sixteen temperature profiles were measured in well HT-13 (Figure 6c). Ten temperature profiles were measured in well HT-25 (Figure 6d). At shallow depth, cross flow is evident in the wells. The profiles show that there are many open fractures at shallow depth.

Well HT-14 and HT-24. Five temperature profiles were measured in HT-14 (Figure 6e). Six temperature profiles were measured in HT-24 (Figure 6f). The temperature increases linearly with depth and therefore the measurements show that heat conduction is dominant in the wells.

Contour maps. According to the temperature profiles and contour maps (Figures 6 and 7), the temperature in the reservoir is around 95°C. The thickness of the reservoir is assumed to be 1200 m, derived from the temperature profiles. By using the program Steamtable, water properties in this reservoir can be estimated as follows: The average density of the water is 0.962 kg/m^3 and the dynamic viscosity is 297.3 $\times 10^{-6}$ Pa·s.

5. WELL TESTS

WellTester is a program that was written at Iceland GeoSurvey (ÍSOR) to handle data manipulation and the analysis of well tests (mainly multi-step injection tests) in Icelandic geothermal fields (Júlíusson et al., 2007). This program deals with the analysis of well testing data in six steps from setting initial conditions to modeling and finally generating a report. WellTester uses a Windows based graphical user interface that offers a good deal of user friendly processing of the well testing data. The flow models in WellTester are based on single-phase flow through homogeneous or dual porosity reservoirs. The reservoir fluid is assumed to be slightly (and only slightly) compressible, which further limits the applicability to single-phase liquid reservoirs and well tests where the fluid stays as a single-phase liquid throughout the test. WellTester offers three types of boundary models (infinite boundary, constant pressure boundary and no flow boundary) to make the inverse estimtions of different reservoir parameters (transmissivity, storage coefficient, etc). The parameters are calculated by iterations of some initial input values in this step.

The pressure diffusion equation is used to calculate the pressure (p) in the reservoir at a certain distance (r) from an injection (or production) well at rate (Q) after a given time (t). Several simplifying assumptions are used with the pressure diffusion equation:

a) Darcy's Law applies;
b) Porosity, permeability, dynamic viscosity and compressibility are constant;
c) Fluid compressibility is very small;
d) Pressure gradients in the reservoir are small;
e) Single-phase flow; and
f) Gravity and thermal effects are ignored.

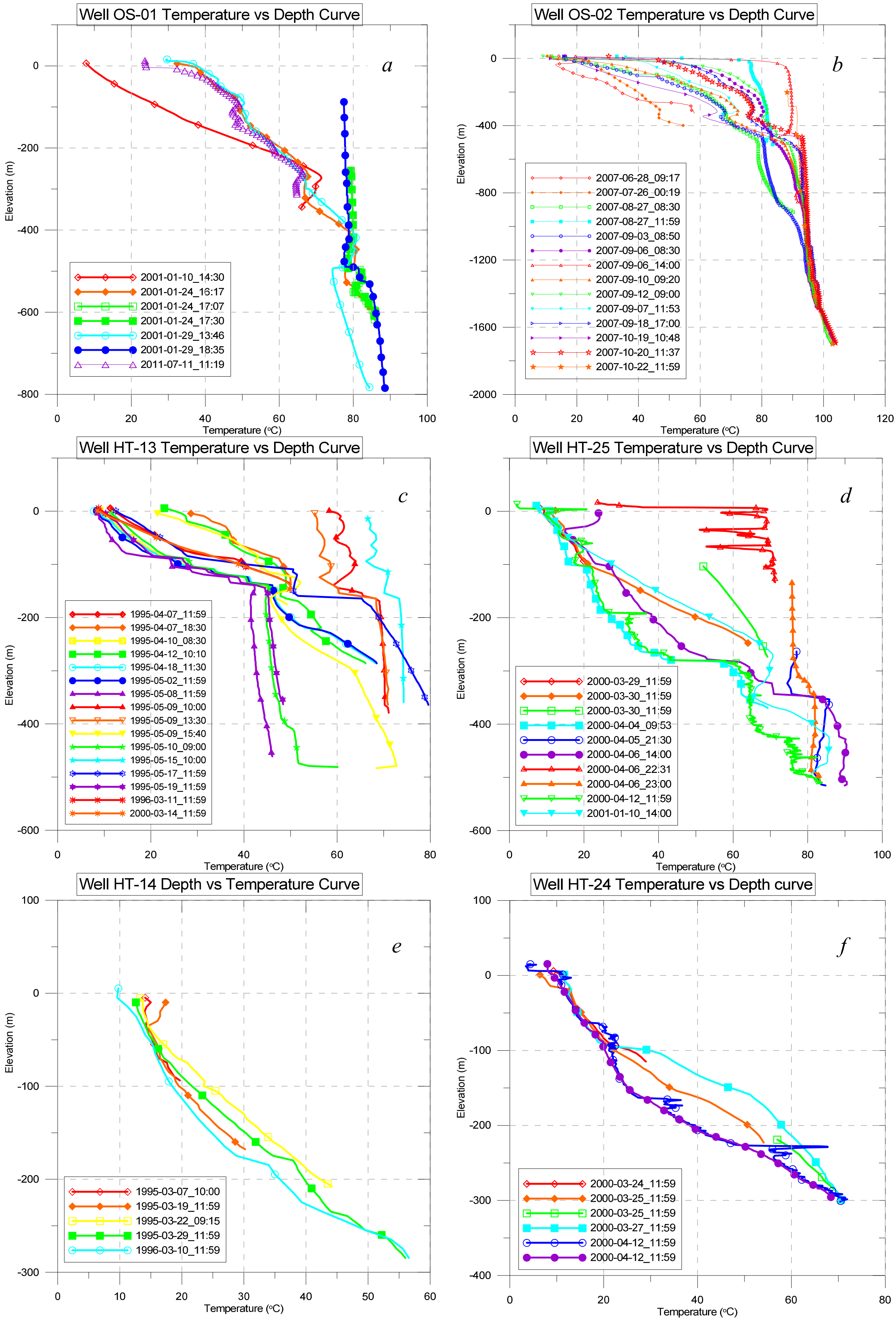

FIGURE 6 : Temperature profiles of the Ósabotnar geothermal field

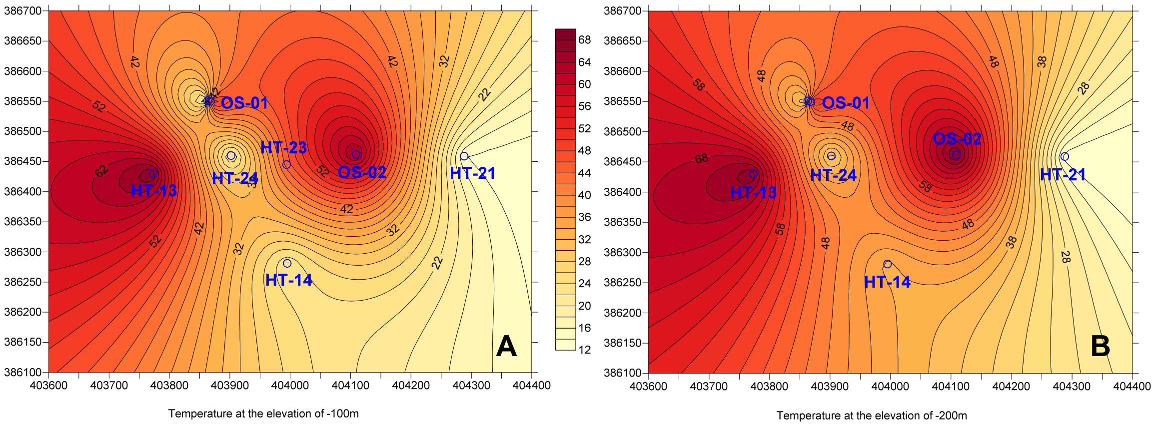

FIGURE 7: Contour maps at different depths, a) 100 m depth; b) 200 m depth

The pressure diffusion equation is:

$$\frac{1}{r}\frac{\partial}{\partial r}\left(r\frac{\partial p}{\partial r}\right)=\frac{\mu c_t}{k}\frac{\partial p}{\partial t}=\frac{S}{T}\frac{\partial p}{\partial t} \qquad S=c_t h \; and \; T=\frac{kh}{\mu} \tag{1}$$

or

$$\frac{\partial^2 p}{\partial r^2}+\frac{1}{r}\frac{\partial p}{\partial r}=\frac{\mu c_t}{k}\frac{\partial p}{\partial t}=\frac{S}{T}\frac{\partial p}{\partial t} \qquad S=c_t h \; and \; T=\frac{kh}{\mu} \tag{2}$$

where ρ = Density (kg/m^3);
c_t = Total compressibility (Pa^{-1});
c_r = Rock compressibility (Pa^{-1});
c_w = Water compressibility (Pa^{-1});
T = Transmissivity (m^3/(Pa·s));
S = Storage coefficient (m/Pa = m^3/(m^{2}Pa) = m^3/N);
μ = Dynamic viscosity (Pa·s);
k = Permeability (m^2); and
h = Reservoir thickness (m).

The pressure diffusion equation is the essential equation for well test analysis. And some important reservoir parameters that are calculated using injection well testing data are listed and described as follows:

Transmissivity (T) is an important characteristic of reservoirs and is a measure of the ability of reservoirs to transmit fluid, determining how fast the pressure changes between the well and the reservoir;

The injectivity index (II) is defined as the change in the injection flow rate divided by the change in stabilized reservoir pressure. It is often used as a rough estimate of the connectivity of the well to the surrounding reservoir.

Storage coefficient (S) is another important reservoir parameter that is defined as the volume of fluid stored in the reservoir, per unit area, per unit increase in pressure. Hence, it has great impact on how fast the pressure wave can travel within the reservoir.

Skin factor (skin) is a unitless variable used to quantify the permeability of the volume immediately surrounding the well.

Radius of investigation (r_e) is the approximate distance (m) at which the pressure response from the well becomes undetectable. Hence, this radius defines the area around the well being investigated.

Production well tests are conducted to analyse the flow characteristics of a well. These discharge tests are done by measuring the fluid flow from a discharging well at different wellhead pressures (or lip pressures). Grant et al. (1982) stated that during production well tests a well is opened up and allowed to discharge fluid to the surface. The main parameters measured during such tests are total flow rate, wellhead pressure, enthalpy of the fluid and the steam/water fraction. Temperature of the fluid discharged, non-condensable gas content, and depth to water level are also monitored. There are two main methods commonly applied for determining these parameters: the separator method and the lip pressure method. A brief explanation of these two methods is given below (Grant et al., 1982).

The separator method is the most reliable method for measuring flow. A separator is used to separate steam and water at a specific separator pressure so that the flow rate of each component of the flow can be measured with an orifice plate (for water) and a differential pressure sensor (for steam). The flow rate of water, W (kg/s), through an orifice is given by:

$$W = C\sqrt{\Delta P/v} \tag{3}$$

where C = The orifice constant, depends on setup and units;
ΔP = Differential pressure (bar); and
v = Specific volume of fluid (m^3/kg).

The lip pressure method is based on an empirical formula developed by Russell James (James, 1970). This method is not as accurate as the separator method but offers the advantages of minimum instrumentation requirements for flow measurements. In the lip pressure method approach, the steam-water mixture from the well is discharged through a pipe into a silencer to separate the steam and water at atmospheric pressure. The lip pressure (the pressure of the fluid passing at the extreme end of the pipe) is measured with a gauge and the water flow from the silencer is measured using a sharp-edged weir near the silencer outlet (Grant et al., 1982). James's formula, which is practically tested over enthalpy ranges of 400-2800 kJ/kg, is given by:

$$\frac{GH_t^{1.102}}{P_{lip}^{0.96}} = 1680, \qquad G = W/A \tag{4}$$

where P_{lip} = The lip pressure (MPa - if the unit of P_{lip} is bar-a then the constant 1680 on the right of Equation 4 should be 1,835,000);
G = The mass flow per unit area in kg/(s cm^2); and
H_t = Total enthalpy (kJ/kg).

The water flow rate (W_w (kg/s)) from the silencer is related to the total mass flow by:

$$\frac{W_w}{AP_{lip}^{0.96}} = \frac{1680}{H_t^{1.102}}\frac{H_s - H_t}{H_s - H_w} \tag{5}$$

where H_s and H_w = Steam and water enthalpies evaluated at separator or atmospheric pressure (kJ/kg).

If separation is at atmospheric pressure of 100 k Pa (near sea level):

$$\frac{W_w}{AP_{lip}^{0.96}} = Y = \frac{0.74(2675 - H_t)}{H_t^{1.102}} \tag{6}$$

where A = The cross sectional area of the discharge pipe (cm^2);
P_{lip} = The lip pressure (MPa); and
W_w = Water flow rate (kg/s).

Equation 6 can be solved for total enthalpy as:

$$H_t = \frac{2675 + 365Y}{1 + 3.1Y} \tag{7}$$

The total mass flow can also be calculated by:

$$X = \frac{H_t - H_w}{H_{sw}}, W = \frac{W_w}{1 - X} = \frac{W_w H_{sw}}{H_s - H_t} \tag{8}$$

where $H_{sw} = H_s - H_w$.

Production well test analysis was done for ÓS-02 in three different phases (Figure 8). The well test models used for the production analysis of the three phases are summarised in Table 3. The results of the analysis are presented below for phases a and b, leaving out phase c due to bad results. This is followed by a common overview of the results. The production well test analysis for the two phases was simulated with different boundary conditions and reservoir models. Several iterations of the models were done for different reservoir parameters. Interestingly, constant pressure boundaries with homogenous reservoir models returned the best fits for almost all of the phases. In a constant pressure boundary condition, the pressure changes in the well stabilize and the measured pressure becomes constant. In other words, the time rate of pressure change approaches zero. This phenomenon happens when the injection or production to or from the well equals production from or recharge to the reservoir. Constant pressure boundaries are a result of the presence of factors like injection wells and flowing fractures that cause the pressure response to reach steady state (Jónsson, 2010).

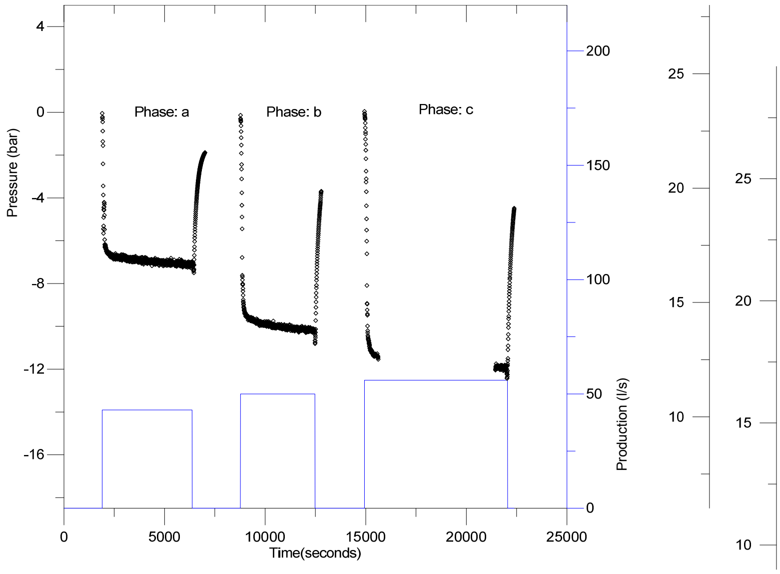

FIGURE 8: Three phases used in the well test analysis for well ÓS-02

TABLE 3: Summary of model selected for well test analysis of ÓS-02

Reservoir	Homogeneous
Boundary	Constant pressure
Well	Constant skin
Wellbore	Wellbore storage

WellTester requires the input of some initial parameters that are used to calculate deduced parameters, such as reservoir thickness and effective permeability. The initial parameter values need not be accurate values of the reservoir being modelled; rough estimates are usually good enough. The initial parameter values used for this analysis are shown in Table 4.

TABLE 4: Summary of initial parameter values for WellTester analysis of the Ósabotnar geothermal field

Parameter	Value	Unit
Estimated reservoir temperature (T_{est})	95	°C
Estimated reservoir pressure (P_{est})	100	bar
Wellbore radius (r_w)	0.11	m
Porosity (φ)	0.1	-
Dynamic viscosity of reservoir fluid (μ)	297×10^{-6}	Pa·s
Total compressibility (c_t)	6.4×10^{-10}	Pa^{-1}

The estimated reservoir temperature values considered in this analysis are taken from the temperature logging data for well ÓS-02. The porosity, dynamic viscosity and total compressibility values are based on parameters summarized in Table 4. The program performed a non-linear regression analysis to find the parameters that best fit the production test data which consists of pressure versus time at a specific depth and ΔQ, i.e. the change in flow rate. The results of the analysis along with brief discussions are presented below.

Phase a:
The model response from the non-linear regression analysis of the observed data for "phase a" is presented in Figure 9. The model fits the data well and can be taken as representative of reservoir response to production. Based on this model, the different reservoir parameters that were calculated are presented in Table 5.

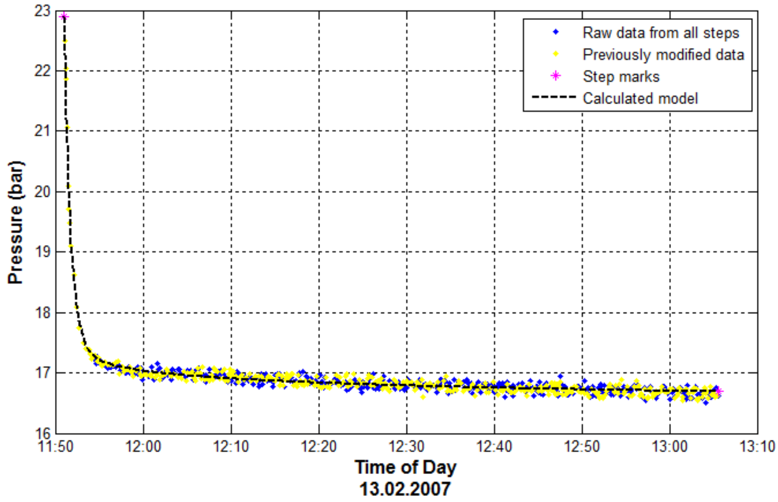

FIGURE 9: Fit between model and collected data for Phase a

The fit between the model and collected data for Phase a (Figure 9) shows how well the model simulates the observed pressure responses. Figure 10 shows the fit between the model and selected data on a log-linear scale (1) and a log-log scale (2). The derivative shown on the right plot is commonly used to determine the most appropriate type of model. The derivative plot in Figure 10 (2) is basically a time derivative of the change in pressure multiplied by time. The fact that it tends to drop to zero is typical of constant pressure boundary models. In such models, pressure approaches steady state and the changes in the pressure in the well approaches zero, hence, the derivative plot tends to zero.

TABLE 5: Reservoir parameters and confidence intervals (CI) estimated using nonlinear regression model for Phase a

Parameter	Parameter value	Lower boundary 95% CI	Upper boundary 95% CI	Unit
Transmissivity (*T*)	1.27×10^{-7}	1.21×10^{-7}	1.34×10^{-7}	$m^3/(Pa \cdot s)$
Storage coeff. (*S*)	1.12×10^{-11}	-3.09×10^{-12}	2.54×10^{-11}	$m^3/(Pa \cdot m^2)$
Skin factor (skin)	0.65	0.46	0.84	-
Wellbore storage (*C*)	2.68×10^{-6}	2.54×10^{-6}	2.83×10^{-6}	m^3/Pa
Injectivity Index (*II*)	6.59			(l/s)/bar

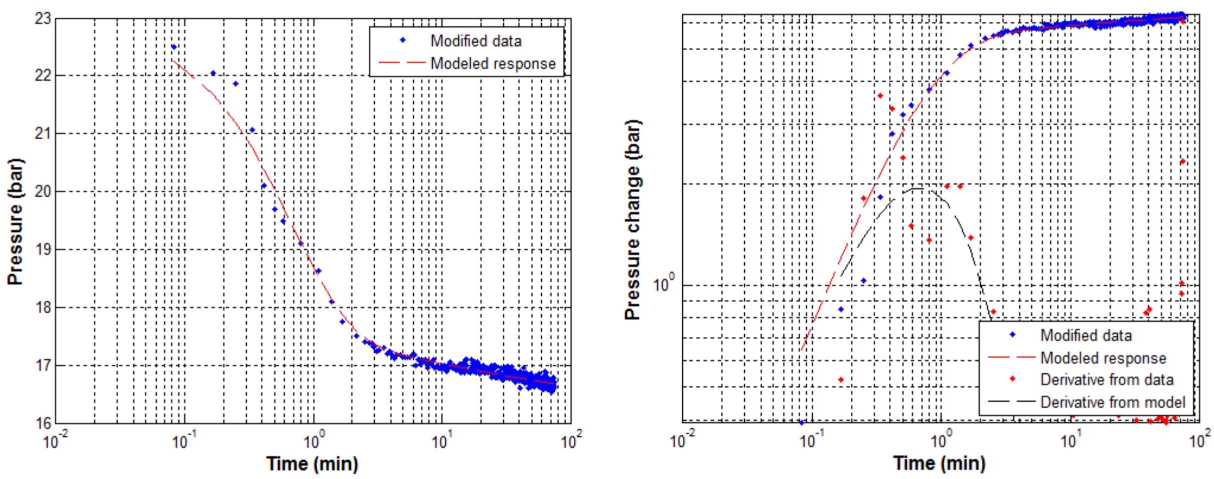

FIGURE 10: Fit between model and selected data of Phase a; (1) log-linear scale; (2) log-log scale

Phase b:
The model response from a non-linear regression analysis of the observed data for Phase b is presented in Figure 11. The model fits the data well and can be taken as representative of reservoir response to production. Based on this model, the different reservoir parameters that were calculated are presented in Table 6.

TABLE 6: Reservoir parameters and confidence intervals estimated using nonlinear regression model for Phase b

Parameter	Parameter value	Lower boundary 95% CI	Upper boundary 95% CI	Unit
Transmissivity (*T*)	1.71×10^{-7}	1.69×10^{-7}	1.72×10^{-7}	$m^3/(Pa{\cdot}s)$
Storage coeff. (*S*)	1.00×10^{-11}			$m^3/(Pa{\cdot}m^2)$
Skin factor (skin)	0.20	0.12	0.28	-
Wellbore storage (*C*)	3.41×10^{-6}	3.33×10^{-6}	3.48×10^{-6}	m^3/Pa
Injectivity Index (*II*)	9.11			(l/s)/bar

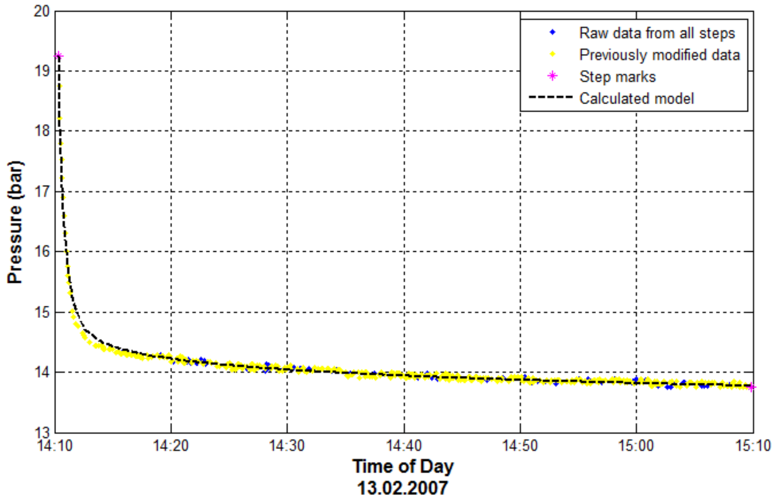

FIGURE 11: Fit between model and collected data for Phase b

The fit between the model and collected data for Phase b (Figure 11) shows how well the model simulates the observed pressure responses. Figure 12 shows the fit between the model and selected data on a log-linear scale (1) and a log-log scale (2).

From the results of the analysis, it can be observed that well ÓS-02 is characterised by high transmissivity and low storage coefficient, with good values of the injectivity index. The transmissivity of this system was estimated 1.27-1.71×10^{-7} $m^3/(Pa{\cdot}s)$, which is fairly high. The storage coefficient was estimated 1.00-1.12×10^{-11} $m^3/(Pa{\cdot}m^2)$, a very low value. The permeability-thickness of the system was found to be 5.12×10^{-11} m^3, or 51.2 Darcy-m, which is comparable to previous estimates of 50-60 Darcy-m (Axelsson et al., 2007).

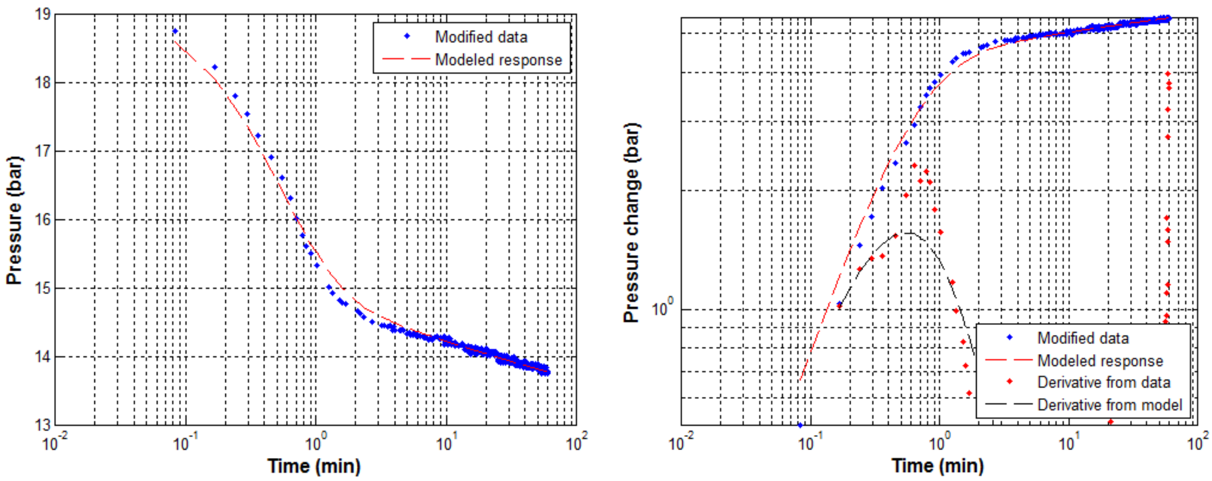

FIGURE 12: Fit between model and selected data of Phase b; (1) log-linear scale; (2) log-log scale

6. LUMPED PARAMETER MODELLING

6.1 General

Many methods have been used during the last several decades to assess geothermal reservoirs in both exploration and exploitation phases. Different geothermal models play essential roles in geothermal resource development and management. The most important purpose of a geothermal model is to obtain information on a geothermal reservoir as well as on the nature and properties of the system. Currently, quite a few model approaches are in use by geothermal reservoir specialists. Geothermal models involve a mathematical model being developed that simulates some of the data available on the geothermal reservoir. This ranges from basic volumetric resource assessment and simple analytical models to fit the results of a short well test to detailed numerical modelling of a complex geothermal system, simulating an intricate pattern of changes resulting from long-term production. The three main types of models are (a) simple analytical models, (b) lumped parameter models and (c) detailed numerical models. Numerous examples are available on the successful role of modelling in geothermal resource management. Also, through modelling, one can predict the response of the reservoir to future production and estimate the production potential of the system as well as estimate the outcome of different management actions (Axelsson, 1989).

6.2 Method description

Because of its many benefits, including time and cost effectiveness, high precision, and their basis being easily grasped, lumped parameter models have been used extensively 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, The Philippines, Turkey and many other countries during the past few decades. They can simulate such data very accurately, if the data quality is sufficient (Axelsson et al., 2005). The principal purpose of this method is, of course, as mentioned above, to estimate the production potential of geothermal systems through pressure response predictions and to estimate the effects of various production scenarios.

Figure 13 shows a sketch map of a lumped parameter model used to simulate the observed water-level changes resulting from long-term production history of wells (Axelsson, 1989; Axelsson and Arason, 1992). The innermost tank in both models, which has a mass storage coefficient, κ_1, simulates the volume of the production part in the geothermal system. This tank is connected by a conductor σ_1 to a second tank, κ_2, which simulates the outer and the deeper parts of the reservoir. The conductor simulates the rock conductivity (permeability) between those two parts. In an open model, the second tank is connected to a constant pressure recharge source representing the boundary conditions). In a closed model the second tank is connected to a third tank which probably simulates both the deeper parts of the reservoir and the overlying groundwater system.

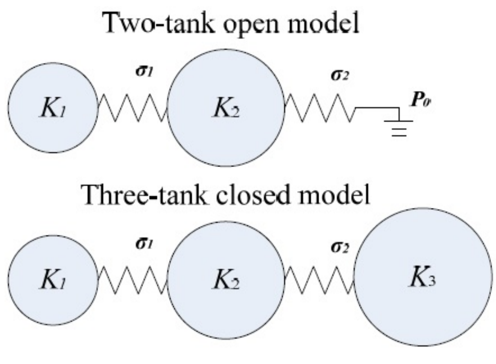

FIGURE 13: Examples of lumped parameter models used to simulate water level or pressure changes in a geothermal system (Axelsson, 1989)

The program LUMPFIT (included in the ICEBOX package) solves the simulation problem as an inverse problem and will automatically fit the analytical response functions of lumped models to the observed data by using a nonlinear iterative least-squares technique for estimating the model parameters (Axelsson, 1989).

The procedure for finding the best fitting parameters for a specific model, which could best fit the observed data, is as follows: First, begin with a one-tank closed model, then turn to a one-tank open model. After that, a two-tank closed model and a two-tank open model follows. Each previous model will give suggestions on the initial guesses of the model coefficients for the next more complex model. In this way, it should be continued step by step until it is expanded to a three tank open model, which is the most complicated model allowed by the program and often is sufficient for most systems. The pressure response (Δp) of a general open lumped model with N tanks, to a constant production (Q), since time t = 0, is given by the equation:

$$\Delta p(t) = -\sum\nolimits_{i=1}^{N} Q\frac{A_i}{L_i}[1 - e^{-L_i t}] \tag{9}$$

The pressure response of an equivalent N-tank closed model is given by the equation:

$$\Delta p(t) = -\sum\nolimits_{i=1}^{N-1} Q\frac{A_i}{L_i}[1 - e^{-L_i t}] - QBt \tag{10}$$

The coefficients, A_i, L_i and B are functions of the storage coefficients of the tanks (κ_i) and the conductance coefficients of the resistors (σ_i) of the model (Axelsson, 1989).

By using these parameters, the main reservoir properties of the Ósabotnar geothermal system can be estimated. Water compressibility c_w was estimated to be 10×10^{-10} Pa^{-1}, and the compressibility of the rock matrix c_r, composed of igneous rock, is approximately 0.2×10^{-10} Pa^{-1}. The storativity of a liquid-dominated confined geothermal system can then be estimated using

$$s \ = \ \Delta m/\Delta pV \ = \ \rho w[\varphi cw + (1-\varphi)cr] \tag{11}$$

Then the value of reservoir storativity can be used to estimate the principal properties and characteristics of the reservoir by assuming two-dimensional flow (Figure 14). In accordance with the following series of equations, using the volume of different parts of the reservoir, their area and permeability can be deduced based on the two dimensional flow model (Guo, 2008). The capacitance of each tank can be written as:

$$\kappa_1 = V_1 s; \quad \kappa_2 = V_2 s; \quad \kappa_3 = V_3 s \tag{12}$$

where V_1, V_2, V_3 = The volumes of different tanks; and
s = The storativity of the reservoir.

Also

$$R_1 = \sqrt{\frac{V_1}{\pi H}}; \quad R_2 = \sqrt{\frac{V_1 + V_2}{\pi H}}; \quad R_3 = \sqrt{\frac{V_1 + V_2 + V_3}{\pi H}} \tag{13}$$

where R_1, R_2, R_3 = The radii of different tanks; and
H = The thickness of the reservoir.

Furthermore:

$$r_1 = \frac{R_1}{2}; \quad r_2 = R_1 + \frac{(R_2 - R_1)}{2}; \quad r_3 = R_2 + \frac{(R_3 - R_2)}{2} \tag{14}$$

where r_1, r_2, r_3 = The half radii of different tanks.

Then, the permeability of each tank can be expressed as:

$$k_i = \sigma_j \frac{ln\left(\frac{r_{i+1}}{r_i}\right) v}{2\pi H} \tag{15}$$

where r_i = The half radius of tank *i*;

σ_j = The conductance between tank i and tank i+1; and
υ = The viscosity of geothermal fluid.

6.3 Lumpfit modelling of the Ósabotnar geothermal system

The production potential of a geothermal system is predominantly determined by the pressure decline due to production. If the energy supply is sufficient, the drawdown becomes the unique influence on the production capacity of a geothermal system. In order to evaluate the potential of the Ósabotnar geothermal field, lumped parameter models were used to simulate and predict pressure variations in this report. The parameters obtained from the simulations were used to calculate reservoir properties, such as reservoir volume and average permeability.

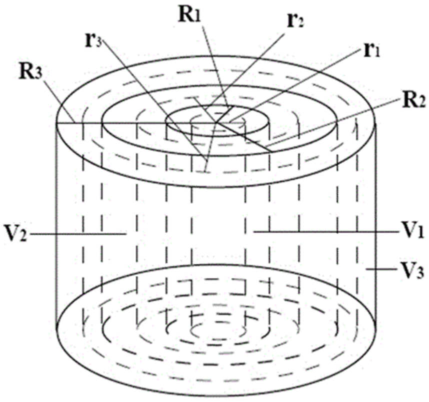

FIGURE 14: Three-tank model with two-dimensional flow

Well HT-24 is located 100 m south of well ÓS-01 (Table 7). The well is mainly used for observing the water level during operation; the initial water level was 8 m below the surface. The average temperature was 15°C at depths between 0 and 100 m, and from this value the density of water at this depth was 999.1 kg/m^3. The water level data from June 2008 to June 2010 were not recorded because the equipment broke down during an earthquake in 2008. Unfortunately, when a new sensor was installed, it was installed at a different depth. There is, therefore, a discrepancy between the data series from 2001-2008 and the more recent one from 2010-2011. In order to tackle this issue, we simulate the water level data according to the earlier production data series (from the beginning to February 2008). Then the model constructed with the old data series is used to simulate the more recent data (from February 2008 to July 2010). Next the simulated water level is added to the data which was used to run the Lumpfit program. After that we could simulate the water level from July 2010 to December 2011, according to the production rate during this period. Through comparison of the results with the observed water level data, finally the relationship between the simulated data and the observed data was found; the error was 54.13 m (5.3 bar). Then we obtained a whole series of data which contained all the water level and production rates from the very beginning up until December 2011. The model developed using this data series was then used to predict the water level in the future for several production scenarios. The two-tank open model and the three-tank closed model were found to be best for simulating the variation of the water level. Figure 15 shows good agreement between the observed data and the calculated data for well HT-24. The parameters of the two models are listed in Tables 8 and 9 for comparison.

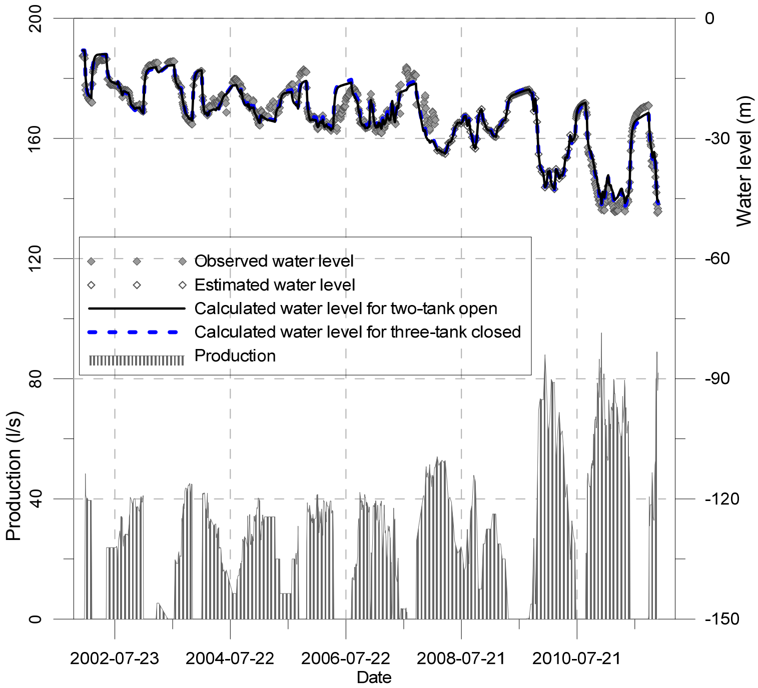

FIGURE 15: Simulation results for the Ósabotnar geothermal field by using two-tank open model and three-tank closed model (observation well HT-24)

The coordinates of the observed well

HT-24, from which water level data were used in the lumped model, and the coordinates of the two production wells OS-01 and OS-02 are listed in Table 7. The distances from well HT-24 to the two production wells are also listed in this table. The distances were so small that the water levels in the three wells were only several meters different. In other words, we could use the prediction from well HT-24 as the situation in the two production wells.

TABLE 7: Coordinates of wells used for lumped parameter modeling of the Ósabotnar reservoir

	HT-24	**OS-01**	**OS-02**
Coordinate X	403902	403868	404109
Coordinate Y	386460	386550	386462
Distance from HT-24 to well (m)	0	96.2	207.0

6.4 Discussion of modelling results

The properties of the conductors of the lumped model can be used to estimate the reservoir permeability by assuming a given reservoir geometry (Table 8). The value of the reservoir thickness was estimated to be 1200 m, which is roughly the distance from the shallowest to the deepest hot water feed-zone in wells ÓS-01 and ÓS-02. Based on calculations, which assume cylindrical geometry of the reservoir as shown in Figure 14, the permeability is estimated 0.029 D (Table 9). It should be pointed out that the permeability calculated from the simulation results is the mean permeability because the lumped model assumes that the entire Ósabotnar system is one homogenous reservoir.

TABLE 8: Parameters of a lumped model for observation well HT-24

Parameter	**Two-tank open model**	**Three-tank closed model**
A_1 (data units)	0.00318	0.00346
L_1 (data units)	0.119	0.133
A_2 (data units)	0.0000678	0.0000788
L_2 (data units)	0.00155	0.00264
B (data units)	0	0.00000527
κ_1 (kg/m^{3}Pa)	256	234
κ_2 (kg/m^{3}Pa)	12300	10000
κ_3 (kg/m^{3}Pa)	----	148000
σ_1 (kg/sPa)	0.000346	0.000351
σ_2 (kg/sPa)	0.000226	0.000294
Initial water level (m)	-8	-8
The past average production (l/s)	0	0
Root mean square misfit	0.211	0.207
Estimate of standard deviation	0.212	0.207
Coefficient of determination	93.8%	94.1%

TABLE 9: Reservoir properties according to lumped parameter models for the Ósabotnar reservoir

Model	**Properties**	**First tank**	**Second tank**	**Third tank**	**Total**
Two-tanks open	Reservoir volume (km^3)	0.761	36.6		37.4
	Area (km^2)	0.635	30.5		31.2
	Permeability, k (D)	0.029			
Three-tanks closed	Reservoir volume (km^3)	0.697	29.8	439	469
	Area (km^2)	0.581	24.9	366	391
	Permeability, k (D)	0.0292	0.0175		

6.5 Prediction

In order to reassess the production potential of the Ósabotnar geothermal field, lumped parameter models were used to predict future water-level variations for several long-term production scenarios. A conjectured production period of 20 years was added to the input file for the models. The study process can be described as follows: First of all, the best fitting lumped parameter models, which can best represent the actual situation of the geothermal system, were selected as prediction models. Then, different production scenarios were assumed as input files. Fives scenarios (listed in Table 10) were assumed for this study. The first scenario maintains the mean production of the last two years, without any change, during which two wells provided thermal water instead of only well ÓS-01. It predicts what will happen in the next 20 years if the present production behaviour is continued. The second scenario also maintains the mean production of the last two years, but with 30% of the total production injected back into the reservoir. This has the same effect as decreasing the production by 30%. The third scenario increases production by 30%. The forth scenario increases production by 50%, which is based on the average increase of the past ten years (25% per decade). The fifth scenario increases production by 2.5% per year, which is also based on the average increase of the past ten years (25% per decade). Here, both the open model and the closed model are used for predicting the reservoir response. The results of the predictions for the closed and open models represent two extreme conditions for the lumped parameter modelling and the geothermal reservoir. The real behaviour of the reservoir will be somewhere between these two simulated responses. The difference between the predictions of the open and closed models is noteworthy and reflects the uncertainty in the predictions. Table 11 lists a few comparisons between several scenarios over the next 20 years. Figures 16-18 show the predictions of different scenarios for the future.

TABLE 10: Net mass production in scenarios used in this study to predict water level changes in the Ósabotnar geothermal field (production in l/s)

Current production maintained	**Current production with 30% injection**	**Production increased by 30%**	**Production increased by 50%**	**Production increased by 2.5% per year**
46.9	32.8	61.0	70.4	$Q_{2011}\times(1+ n_i \times 0.025)$

Note: $n_i = i - 2011$ ($2011 < i < 2031$)

TABLE 11: Comparison between average water level predictions for open and closed models, and different scenarios, at the end of the 20th year

Parameter	**Cu.prod. w. 30% inject.**	**Curr. prod.**	**Cu. prod. incr. 30%**	**Cu. prod. incr. 50%**	**Production increased by 2.5% per year**
Average production rate (l/s)	32.8	46.9	61.0	70.4	$Q_{2011}\times(1 + n_i\times0.025)$
Production rate changing (%)	-30%	100%	+30%	+50%	2.5% per year
A: Predicted water level from two-tank open modelling (m)	-32.1	-42.4	-52.7	-59.5	Dynamic water level, minimum at -90 m
B: Predicted water level from three-tank closed modelling (m)	-46.3	-60.3	-74.3	-83.6	Dynamic water level, minimum at -110 m
Water level difference (A-B) (m)	14.2	17.9	21.6	24.0	

Note: $n_i = i - 2011$ ($2011 < i < 2031$)

The two-tank open model and the three-tank closed model proved to be the best lumped parameter models for the Ósabotnar geothermal field. This field has had an average production of 46.9 l/s over the last year. The prediction was done assuming that this flow rate would continue. As shown in Figure 16, the open model gives a more optimistic forecast than the closed model. The water level in well HT-24 is maintained at -42.36 m at the end of 2031, but the water level is predicted to decline to about -60.27 m for the case of a closed model in 20 years, which is equivalent to a water level decline of 1.11 m per year.

The other three scenarios involved decreasing production by 30% or increasing it by 30% or 50%, resulting in 32.8, 61.0 and 70.4 l/s production, respectively. The prediction results are presented in Figure 17. The three-tank closed model with 70.4 l/s gives the most pessimistic prediction with the water level declining to about -83.6 m in well HT-24. As the production rate increases, the difference between the water levels predicted by the open and closed models becomes greater.

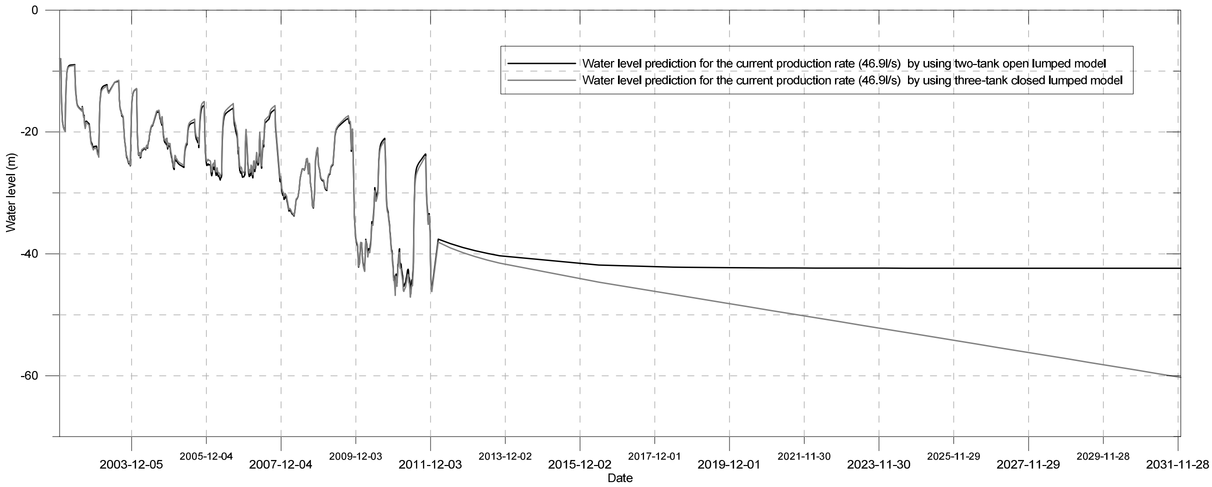

FIGURE 16: Comparison between predictions of the closed and open models for current average production (46.9 l/s) for the Ósabotnar geothermal field (observation well HT-24)

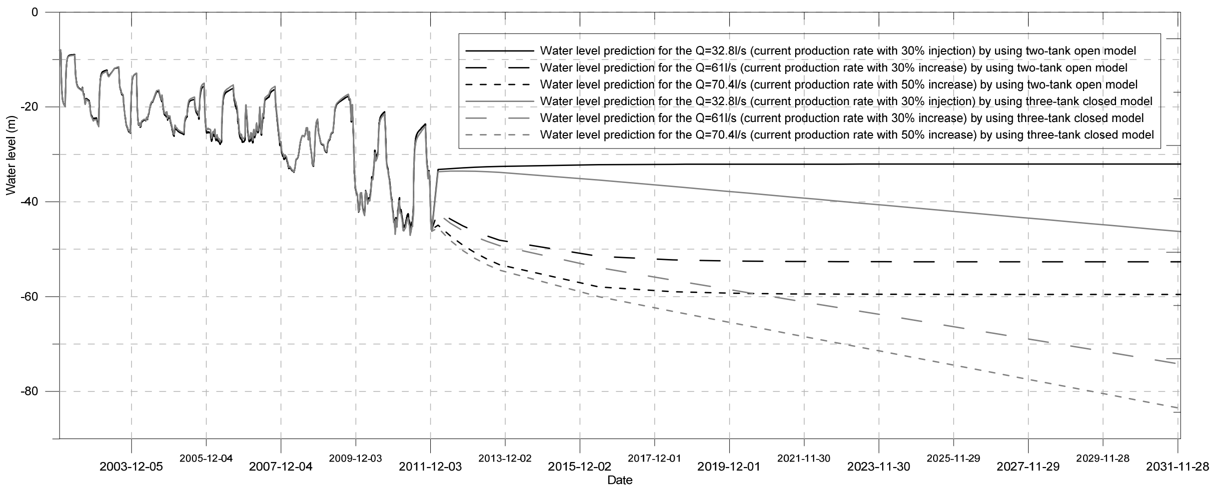

FIGURE 17: Comparison between predictions of the closed and open models for 32.8 l/s (current production with reinjection 30%), 61.0 l/s (130% of current production) and 70.4l/s (150% of current production) for the Ósabotnar geothermal field (observation well HT-24)

Figure 18 shows the results of a simulation run where an average increase rate of 2.5% per year for the next 20 years is assumed for the production from the Ósabotnar field. The increase rate is estimated from the last ten years‘ increase rate. The annual variations of the production rate were simulated based on the last year (2011). The dynamic prediction shows that the possible lowest water level could be -110 m at the end of 2031. This value is not the average value, but indicates that the depth of the pump should be lower.

Overall, the results indicate that all the prediction scenarios are realistic, both from the point of view of the open and the closed model. This is because the predicted maximum drawdown of the reservoir water level is about -102 m (initial water level was -8 m) since the beginning of utilization. This should be easily manageable. Increased production may require lowering the pumps in the two prediction wells as well as lowering the water level sensor in the observation well.

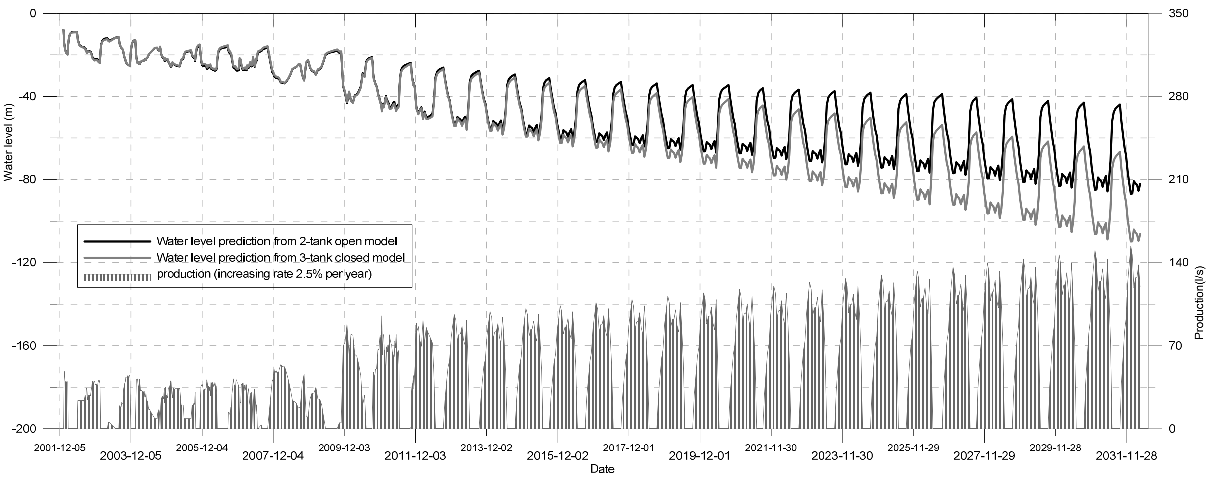

FIGURE 18: The prediction of the open and closed models for 2.5% increasing rate, based on the current production (46.9 l/s) for the Ósabotnar geothermal field (observation well HT-24)

7. VOLUMETRIC METHOD FOR THE ÓSABOTNAR GEOTHERMAL FIELD

The total heat energy contained within a geothermal system can be estimated by different methods. The volumetric method is often the method of choice in the first stages of exploitation due to its simplicity. This method ignores the dynamic pressure response to production and the exact geometric structure of the system. Consequently, it requires only limited information on the properties of a reservoir and is, therefore, suitable for systems that are in the initial stages of research. The energy contained within the system can be expressed by:

$$Q = VC(T_R - T_0) \tag{16}$$

where V = The volume of the reservoir (m^3);
T_R = Uniform reservoir temperature (°C);
T_0 = Rejection temperature (°C); and
C = The average volumetric heat capacity (J/(m^3°C)).

By assuming a homogenous reservoir, the heat capacity can be written:

$$C = (1-\varphi)\rho_r \beta c_r + \varphi \rho_w \beta_w \tag{17}$$

where φ = The porosity of the rock;
ρ = The density (kg/m^3); and
β = The specific heat (J/(kg°C)).

It is impossible to extract all the energy contained within the system, so we define a factor called the recovery factor R, which is an estimate of how easily the heat contained in a geothermal system can be extracted. The recoverable heat from a geothermal system can then be written:

$$Q_R = RQ \tag{18}$$

The parameters were set as in Table 12 for the volumetric calculations. The value of the reservoir thickness was 1200 m, which was calculated from the shallowest to the deepest hot water feed-zone in wells ÓS-01 and ÓS-02. The area was calculated from the results of the lumped model. In the lumped model the volume of the reservoir was estimated as 0.729 km^3 (the average of 0.761 and 0.697).

TABLE 12: Parameters used for a volumetric resource assessment for the Ósabotnar geothermal reservoir

Parameter	Values
Porosity of reservoir (%)	10
Area (km^2)	0.61
Average reservoir thickness (m)	1200
Average reservoir temperature (°C)	95
Cut-off temperature (°C)	10
Density of basalt (kg/m^3)	2850
Density of water at 95°C (kg/m^3)	962
Heat capacity of basalt (J/(kg°C))	950
Heat capacity of water at 95°C (J/(kg°C))	4210
Recovery factor (%)	25

Based on the method and equations presented above, the geothermal fluid volume and energy content of the reservoir in Ósabotnar area are estimated below:

TABLE 13: Result of the volumetric geothermal assessment for the Ósabotnar geothermal field

Parameter	Value
Volume of geothermal fluid (10^9 m^3)	0.729
Heat in the reservoir (10^{12} J)	177
Recoverable heat (10^{12} J)	44.2

8. DISCUSSION AND CONCLUSIONS

The results of the successive assessments described in this report show that the potential of the Ósabotnar geothermal field is promising. In the future, this field could provide more thermal water than is being extracted at present. According to the results from simulations, if the Selfoss district heating company maintains the current average production over the next 20 years , the water level will drop to between -42.36 m (open model) and -60.27 m (closed model). If, however, the production is increased to 150% of the current average production, the three-tank closed model gave the most pessimistic prediction with the water level declining to about -83.57 m. By assuming that the production increases by the current average increase rate, which is 2.5% per year, the model gave the deepest water level of -110 m during the peak production period in winter.

The main conclusions of this work can be summarized as follows:

- The Ósabotnar geothermal field is a liquid-dominated low-temperature geothermal reservoir, which is located in SW-Iceland, about 4 km north of the town of Selfoss. The initial water level was -8 m at the beginning of production.

- The results of a production well test indicate that this reservoir has a constant pressure boundary, homogeneous porosity and constant well skin. A lumped parameter model of the reservoir has a volume of 0.729 km^3, and the permeability is about 0.029 Darcy (in the first tank, which represents the innermost part of the system).

- Both the two-tank open and three-tank closed lumped models were used to simulate the monitored production data and pressure. The two models were also used to predict different production scenarios. In the case of an open model, the water level in this reservoir will drop to -32.05, -42.36, -52.66 or -59.53 m for a future production of 70%, 100%, 130% or 150% of the current average production, respectively. In the case of a closed model, the water level in this reservoir will drop to -46.29, -60.27, -74.25 or -83.57 m for the same production scenarios, respectively. Finally, in the case of a continuous increase in production of 2.5% per year, the deepest water level was predicted to be -110 m at the end of the forecasted period.

- Using the volumetric method, the estimated thermal energy in this field is 176.8×10^{12} J, and a total of 44.2×10^{12} J can be extracted, by assuming a recovery factor of 25%.

These results indicate that the Ósabotnar low-temperature geothermal field will be a steady and sufficient source of geothermal water for the Selfoss district heating company.

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