



RESERVOIR PARAMETER ESTIMATION USING WELL LOGGING DATA AND PRODUCTION HISTORY OF THE KALDÁRHOLT GEOTHERMAL FIELD, S-ICELAND

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ABSTRACT

The Kaldárholt field is an important low-temperature geothermal fields located in S-Iceland. This field has been exploited from 2000, used mainly for heating purposes. Available well logging data (temperature profiles, dual neutron logs, natural gamma ray and caliper logs) as well as acoustic televiewer and production history data, were analyzed in an attempt to estimate reservoir parameters and identify possible fracture systems in the study area in relation to the different rock units and feed zones. The interpretation of temperature data shows that there is an oriented upflow of water with a temperature of 67°C.

Different petrophysical parameters were estimated like porosity, silica content and permeability. An inversion modelling technique was applied to derive the compressional velocity and density of the formation. Identification and typing of different rock units was also achieved through interpretation of synthetic seismograms and reflection coefficient as correlated with the geometrical pattern logs. The mechanical properties of the rocks were estimated and interpreted in relation to the different fractures and feed zones, as well as in matching with the main rock types. Televiewer amplitude and travel time data and breakout parameters were interpreted. Different fracture systems prevailing in the area were identified; their azimuth and dip directions were interpreted. A NNE-SSW dipping direction was assigned to these fractures, which exhibit high near-vertical dipping angles, more than 70°. The host rock of the Kaldárholt system is dominated by olivine tholeiit basalts of 12% porosity, 2.78 g/cm³ density and 0.18×10⁻¹⁰ Pa⁻¹ bulk compressibility. Tholeiit basalts follow with estimated 6% porosity, 60% silica content and 2.92 g/cm³ density. Also seen is a thin layer of acidic tuffs with 70% silica content and 2.65 g/cm³ density. Artificial neural networks (ANN) were also used to predict downhole porosity and silica content. A very good match was found between the predicted parameters and the log-derived ones.

Lumped parameter modelling was applied to simulate the production history of the field and estimate reservoir volume between 2 and 3 km³ and permeability near 100 mD. Monte Carlo simulation was also applied to estimate the geothermal power potential. It was found that the average thermal potential reserve in the Kaldárholt geothermal field corresponds to about 7.4 MWt.

1. INTRODUCTION

The geothermal resources in Iceland are closely associated with the country's volcanism and its location on the Mid-Atlantic Ridge. High-temperature resources are located within the active volcanic zone running through the country from southwest to northeast, while low-temperature resources are mostly in the areas flanking the active zone. There are over 600 hot water springs in 250 low-temperature fields and 26 potential high-temperature areas have been identified (Ragnarsson, 2003).

The relationship between tectonic activity and geothermal resources in Iceland is well known. Figure 1 shows a simplified tectonic and geological map of Iceland that includes the high- and low-temperature fields. The well-known S-Iceland seismic zone is indicated on the map by a rectangle, while the arrows denote the directions of spreading. The Laugaland and Kaldárholt geothermal fields are among numerous low-temperature fields which are located in the S-Iceland seismic zone.

The Laugaland-field is a small geothermal field used by the Hitaveita Rangaeinga district heating service. Production from the field started in 1982 and it serves two small towns, Hella and Hvalsövellur, with a total of 1200 inhabitants. Due to low permeability of the reservoir in the Laugaland field and continuously increasing drawdown of the water level, it was suggested that the reservoir could not sustain long-term production greater than about 17 l/s (Kristmannsdóttir et al., 2002). Therefore, a decision was taken to put the Kaldárholt geothermal field online in January 2000, to meet and satisfy the increasing demands of hot water utilization in the area, especially for space heating purposes.

The Kaldárholt geothermal field is located about 8.5 km north-northwest of Laugaland field (Figure 2). About 38 wells have been drilled in this field since 1982. The temperature gradient in most of these wells is relatively high. The interpretation of silica geothermometers based on the chemical analyses of available water samples from the hot springs in the area, show that the temperature of the deep reservoir is about 70°C. Exploration drilling started in the Kaldárholt geothermal field in 1998. The search for potential well sites, with both high permeability and relatively high temperature, was the main task. So, a number of wells were drilled to the north and northwest of the production well field (wells from KH-6 to KH-19) to explore the thermal state of the field in this direction, which at that time was believed to be the main area of hot water upflow. With the exception of well KH-17, which reached a depth of 405 m, all these wells are shallow and did not exceed 130 m in depth with actual formation temperatures of about 62°C.

During the drilling period, it was found that some of the wells were artesian with initial wellhead pressures of up to 0.5 bar. The latest wells drilled in the field are KH-35, KH-36 and KH-37. These wells were drilled in the east and southeast parts of the field with depths up to 550 m. All encountered deep and permeable feedzones, thus defining finally what is called here the production well field.

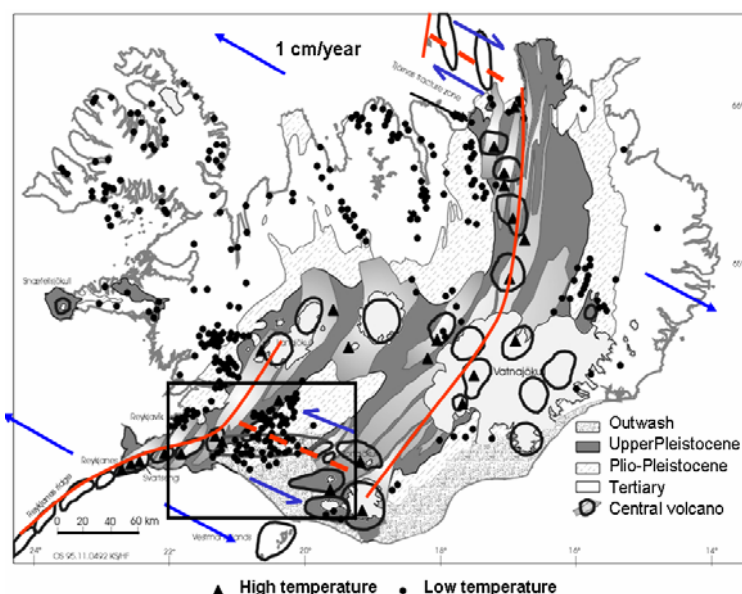


FIGURE 1: Simplified tectonic and geologic map of Iceland (after Björnsson et al., 2001)

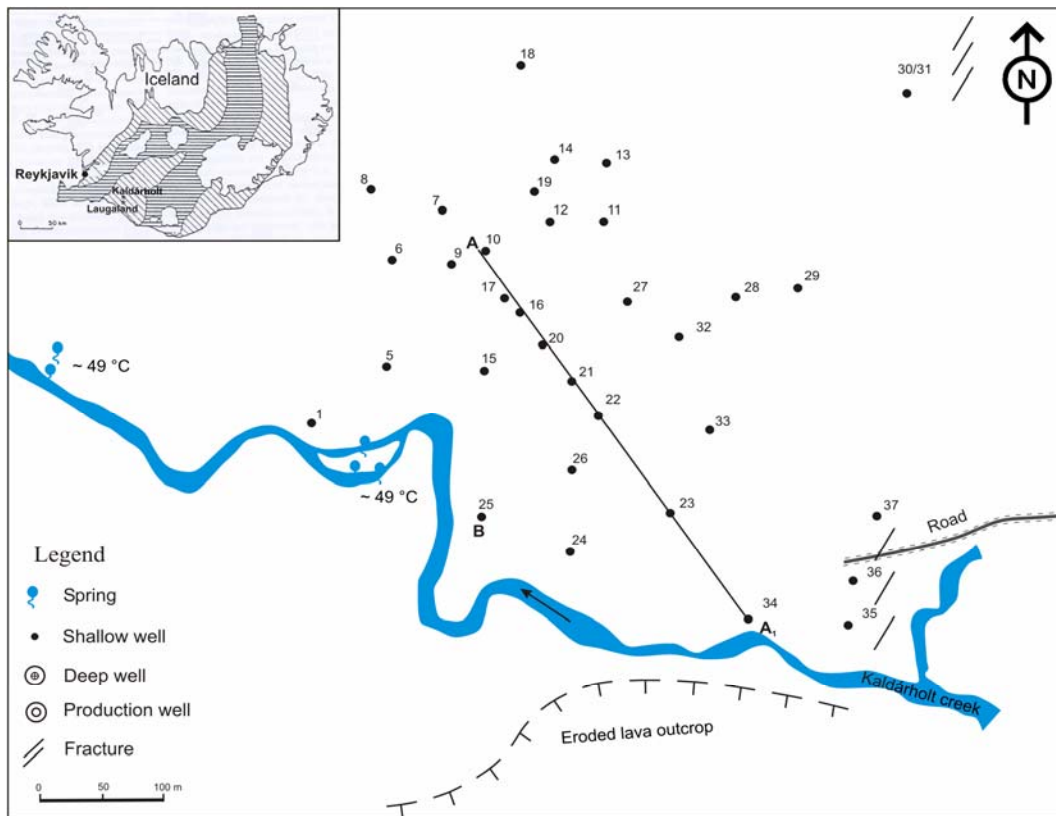


FIGURE 2: Location map of the Kaldárholt geothermal field

Well KH-36 is one of the three production wells in the field, yielding more than 30 l/s of 67°C hot water during seasonal space heating peaks. About 3-4 l/s of hot water from this well have been used for reinjection in the nearby Laugaland field since 2000. Due to good permeability at Kaldárholt field, the water level drawdown in the production well is less than 30 m for production of up to 33 l/s. Preliminary estimates based on well test analyses indicate that the geothermal field can supply at least 30 l/s of hot water in the long-term with an acceptable pressure drawdown (Zhang, 2003).

The purpose of the project was to estimate the main reservoir parameters in Kaldárholt and to analyze possible fracture systems affecting the area in relation with rock mechanics and feed zones. Lumped parameter modelling is used to simulate the production history and estimate the geothermal potential.

2. GEOTHERMAL AND TECTONIC ACTIVITY

Tectonic and geothermal activity are well known and closely related features in Iceland. The majority of the active subsurface geothermal reservoirs are oriented along structurally controlled fracture and fault systems. In addition, most of the warm springs which are detected at the surface are lined up along these fracture systems.

Two large (6.6) earthquakes occurred on 17 and 21 June 2000 in S-Iceland, with the former very close to the Kaldárholt field. They caused some major pressure changes in several geothermal reservoirs, especially those located within the S-Iceland seismic zone. The pressure changes correlate well with the focal mechanism of these earthquakes i.e. reservoir pressure increased in areas which underwent compression and decreased in areas where dilation took place (Björnsson et al., 2001).

Figure 3 shows a location map of some wells in S-Iceland in relation with the dominate seismic fractures mapped prior to the June 2000 quakes. The figure demonstrates the relationship between the

well sites and the fracture systems, which seem to be oriented north and north-northeast. Moreover, Figure 4 exhibits one of the most obvious pressure changes that happened in the Kaldárholt geothermal field during the June 21 quake. It shows the pressure change in well KH-35 around the time of the quake. A very sharp pressure drop of 0.35 bars accompanied the quake, immediately followed by 10 minutes recovery of 0.1 bar. It should be mentioned here that the wellhead pressure before the quakes was 0.5 bars but the June 17 quake had already compressed the reservoir dramatically. That led to the 2.35 bars pressure shown on Figure 4 prior to the June 20 quake. (Björnsson et al., 2001). A possible explanation for the increase in productivity in this area after the earthquake could be due to the fracture-opening pressure in relation to the minimum horizontal stresses prevailing in the area.

Therefore, the major tectonics prevailing in the area and their related features, in terms of the rock mechanics, the stress/strain state and the fracture pressure gradient seem to constitute the main factors controlling the whole geothermal system in this area. This was the standing point, from which the aim and idea of this study came.

3. ANALYSIS OF TEMPERATURE DATA

Temperature data obtained in boreholes serve as critical input to many fields of engineering, geothermal and hydrocarbon exploration, and in research for testing hypotheses concerning the evolution of the Earth's crust and tectonic processes. Temperature logs can detect thermal anomalies produced by temperature contrasts between the borehole fluid and the formation fluid or formation. A variety of information can be obtained from the identification and interpretation of these anomalies (Prensky, 1992).

Analysis of downhole temperature data is the main step required for quantitative assessment of geothermal reservoirs. Geothermal gradient and actual formation temperature are the simplest preliminary parameters which must be calculated first.

The geothermal gradient, or the rate at which the subsurface temperatures increase with depth, can be calculated from:

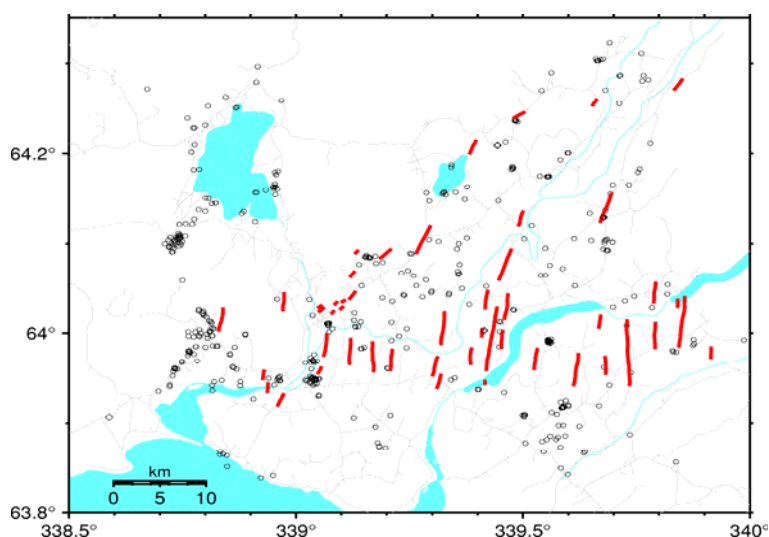


FIGURE 3: Location of water wells (circles) and active fracture systems (thick lines) in the S-Iceland seismic zone (Björnsson et al., 2001)

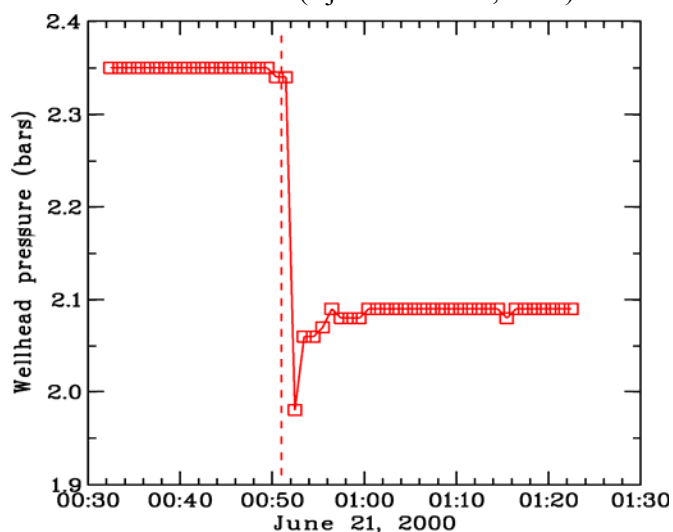


FIGURE 4: Pressure changes in well KH-35 around the June 21 quake, dashed lineshows time of the quake. (Björnsson et al., 2001)

$$GG = \frac{T_2 - T_1}{D_2 - D_1} \quad (1)$$

where T_1 = Formation temperature (°C) at depth D_1 (m);
 T_2 = Formation temperature (°C) at depth D_2 (m).

For any given area, and in normal cases, the geothermal gradient is usually assumed to be constant. While the average gradient across normally pressured formations may be constant, geothermal and pressured formations exhibit abnormally high geothermal gradients. The geothermal gradient in Kaldárholt field is relatively high and ranges from 0.12 to 0.16°C/m.

Estimation of formation temperature in many cases depends on the conditions of a well. The presence of flow in a well screens the conditions in the formation and makes the determination of the formation temperature quite difficult. However, circulation during drilling also tends to cool and affect the temperature of a well, which begins to recover at end of drilling and eventually reaches equilibrium with the formation.

Two popular methods are available to estimate formation temperature from recovery data; the Horner plot and the Albright method. The Horner expression was originally developed for pressure build-up predictions for reservoir analysis, but was modified by Dowdle and Cobb (1975) to model temperature build-up.

In this study, the mathematical method which was proposed by Nwachukwu (1976) is used for estimating the true formation temperature. The method utilizes a modified Lachenbruch-Brewer equation, which states that if three temperature points are available, this can prove to be a useful cross-check with the Horner plot. Thus, a plot of T against $(t_c + t_L) / t_L$ on semi-log paper should be linear, and when extrapolated to a time ratio of unity, the result should be a close estimate of formation temperature. The equation must be solved for true formation temperature (T_f) as follows:

$$T = T_f - C \log \left(\frac{t_c + t_L}{t_L} \right) \quad (2)$$

where T_f = True formation temperature (°C);
 T = Measured temperature (°C);
 t_c = Circulation time at total depth, TD;
 t_L = Time since circulation stopped.

The mathematical algorithm, which solves for the three known temperature points, is:

$$\frac{T_f (t_2 - t_1) + [(T_1 t_1) - (T_2 t_2)]}{(T_2 - T_1)} = \frac{T_f (t_3 - t_1) + [(T_1 t_1) - (T_3 t_3)]}{(T_3 - T_1)} \quad (3)$$

where T_1 = Recorded BHT, log run1;
 T_2 = Recorded BHT, log run2;
 T_3 = Recorded BHT, log run3;
 t_1 = Time since circulation stopped, log run1;
 t_2 = Time since circulation stopped, log run2;
 t_3 = Time since circulation stopped, log run3;
BHT = Bottom hole temperature.

Figures 5 and 6 show the temperature profiles of wells KH-34 and KH-35. The temperature logs of these two wells are chosen as examples to demonstrate the behaviour of temperature in the whole Kaldárholt field. The maximum temperature of the reservoir is 68°C in both wells. The near vertical

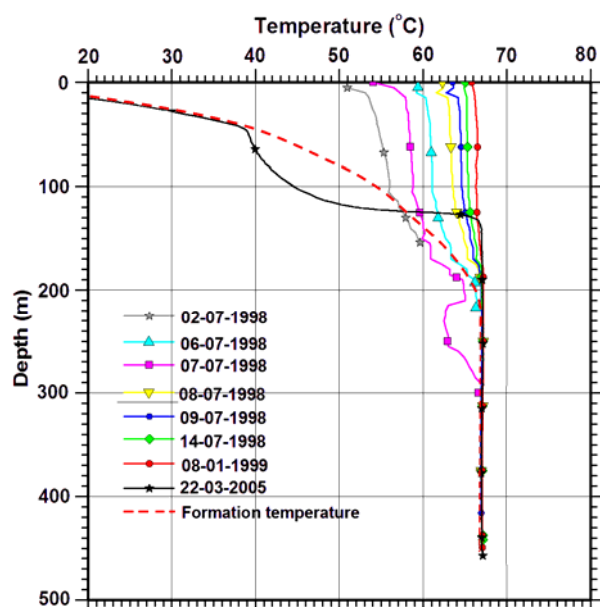


FIGURE 5: Temperature profiles of well KH-34 including the estimated formation temperature

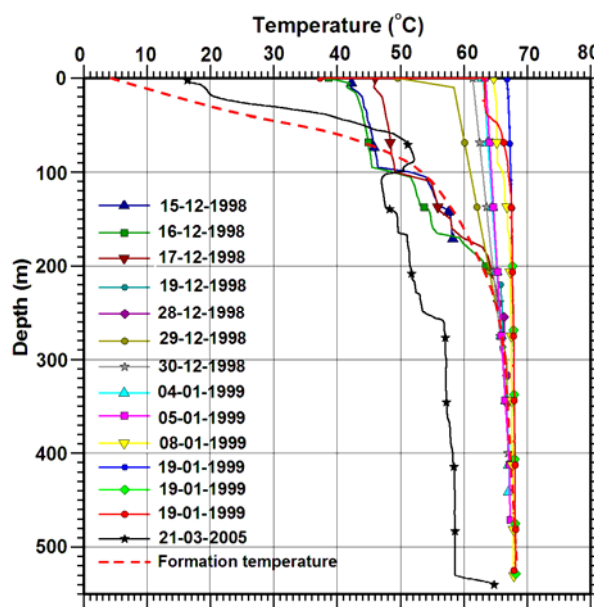


FIGURE 6: Temperature profiles of well KH-35 including the estimated formation temperature

profiles of temperature logs in the upper parts of the wells studied indicate the presence of artesian flow from the wells.

4. CONCEPTUAL RESERVOIR MODEL

Before setting up a more detailed computer-based quantitative model for a given geothermal field, a conceptual model must first be developed. A good understanding of the important aspects of the structure of the system and its most significant physical and chemical aspects is referred to as its conceptual model (O'Sullivan et al., 2001). A conceptual model is a descriptive or qualitative model of a geothermal system that incorporates essential physical features of the system and is capable of explaining the salient behaviour or characteristics of interest to the modeller. These models provide the basis for numerical models of reservoirs and guide in production drilling (Grant et al., 1982). In this study, a conceptual reservoir model for Kaldárholt field was constructed based on the different interpretations of the temperature data and the available geological information.

Figure 7 show a NW-SE temperature cross-section (A-A') constructed using the actual estimated formation temperatures. The cross-section shows that the main upflow of the hot water is more or less

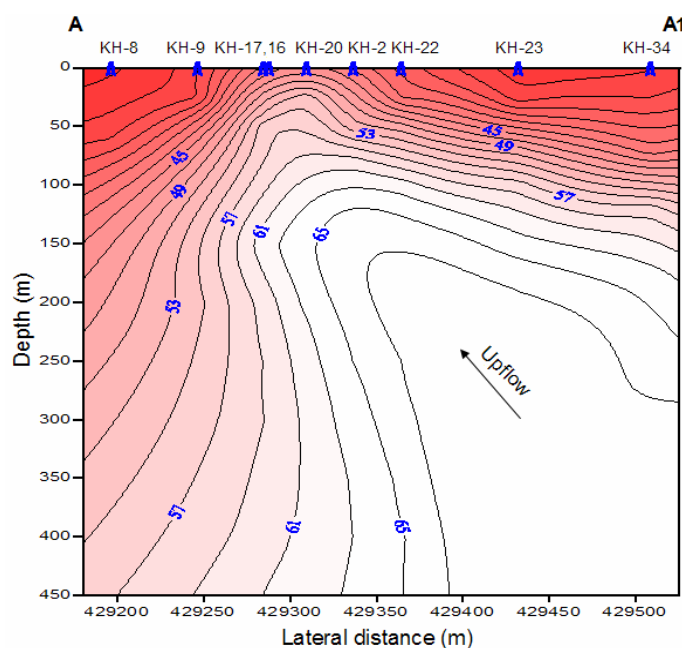


FIGURE 7: NW-SE temperature cross-section (A-A1) in the Kaldárholt geothermal field; location of cross-section is shown in Figure 2

oriented along a north-south direction. The subsurface orientation of the fracture system in the study area, and the possibility of the presence of some non-sealed faults cutting through the area, may act as the main pathways which control the general upflow direction. Therefore, the hot flowing water with temperature of about 67°C could reach the surface passing through shallower formations, where it forms some warm swamps and springs with an average temperature of 50°C. A more detailed information about the conceptual model of Kaldárholt geothermal field, as inferred from the interpretation of temperature profiles and their distribution in terms of subsurface lateral distribution maps and vertical temperature cross-sections, are enclosed in earlier work done by Zhang (2003).

It is worth mentioning here that the main upflow direction will be a matter for re-evaluation when a detailed fracture analysis is carried out, information which will be presented later on in this study.

5. WELL LOGGING ANALYSIS

5.1 Calibration, processing and correction of logging data

Calibrations play an important role in monitoring tool performance over time, so accurate calibrations of logging data are necessary before using them quantitatively. Also, processing and correction of logging data for lithological and environmental effects are very important to improve the quality of these data and to make them representative for actual petrophysical properties of the reservoir of interest.

The following are the main calibration and correction procedures which were conducted for the available logging datasets in the Kaldárholt geothermal field.

5.1.1 Calibration of gamma ray log

The natural gamma ray can be run in both open and cased holes either empty or fluid-filled. This log may be recorded in API units or counts per second units (CPS). The nature of gamma ray emission is statistical and must be averaged over time (Hearst and Nelson, 1985). The detector stability and the length of time required to obtain a stable count rate depend upon the radioactivity of the target and the efficiency of the detector. The primary calibration standard of gamma ray tools is the API units. So, when measured in CPS units, the gamma ray logs must be calibrated and converted to the API units.

Different statistical and probability distribution functions are used to model and calibrate the measured CPS radioactive count rate in a given time window (t). The most important parameter which affects the measurement, is the count rate error. Using the rules of propagation of error, the count rate error can be estimated as follows:

$$\sigma_r = \frac{\sqrt{n}}{t} \quad (4)$$

where σ_r = Standard deviation for the count per second (r);
 t = Time windows (t);
 n = Number of counts recorded during the counting time windows (t).

Taking the count rate error into consideration, the raw gamma ray count rate (CPS) can be converted and calibrated to API units as follows:

$$GR(API) = \frac{200}{\Delta_r} GR(CPS) \quad (5)$$

where Δ_r = Count rate difference.

5.1.2 Processing and matching of logging data

The processing of logging data is a very important step to remove unwanted signals and improve the quality and resolution of the raw data, especially for logs which deal with borehole geometry and fracture trace analysis in an imagery form. Acoustic televiewer log (HRAT) is one of the most important borehole-wall imagery logs, which is used mainly in this work to detect subsurface fractures and determine their orientations. Processing of HRAT logs includes; 1) the interpolation of the spirally distributed travel-time/amplitude data into a rectangular grid, 2) corrections of the magnetic anomalies and their corresponding sonde orientation data and 3) identification of borehole-wall irregularities (breakouts) and trajectory in 3-D space.

Matching and levelling of logging data is also a very important step before correction and interpretation techniques are applied. Two matching problems are encountered in this respect: The first is the linear vertical shift, which may occur due to the uncertainty of logging measurements and by using different depth markers during the log recording. The second results from using logging probes with different vertical resolutions that give simultaneous logging records at different depth increments for the same borehole. In this work, for example, we logged wells KH-34 and KH-35 using two probes with different vertical depth increments. The caliper log is measured using vertical depth increments of 0.5 m, while the dual neutron tool is logged using a 1 cm depth increment. A linear shift of 1.038 is also recognized between the acoustic televiewer log and other well logging data. Therefore, scaling and levelling of logging data, which are measured at different vertical depth increments, is very important before applying the interpretation techniques.

5.1.3 Environmental corrections

Environmental corrections are designed to remove any effect from the borehole (size, roughness, temperature, tool standoff) or the drilling fluids that may partially mask or disrupt the log response from the formation. For example, the natural gamma ray log response is affected by borehole size, weight and the salinity of the drilling fluid. So for accurate determination for the shale volume in sedimentary rocks or the silica content in igneous rocks, gamma ray logs must be corrected for bore hole size variations.

Borehole correction: In this work, the gamma ray readings are corrected for borehole conditions using GR-1 chart (Schlumberger Charts, 1991), based on laboratory work and Monte Carlo calculations to provide improved corrections of the gamma ray tools. Two correction parameters (t and CF') must be first determined. The first is the input parameter t , in g/cm^2 , which can be calculated as follows:

$$t = \frac{W_{fl}}{8.345} \left(\frac{2.54 (d_{hole})}{2} - \frac{2.54 (d_{sonde})}{2} \right) \quad (6)$$

The second is the correction for standoff, CF' :

$$CF' = CF'_m + (CF'_o - CF'_m) \cdot \left(\frac{S - S_m}{S_m} \right) \quad (7)$$

where W_{fl} = Weight of the drilling fluid;
 d_{hole} = Caliper log reading (mm);
 d_{sonde} = Diameter of gamma ray probe (mm);
 CF'_m = Correction factor for centered tools;
 CF'_o = Correction factor for ecentered tools;
 S = Actual standoff;
 S_m = Standoff with the tool centered.

Once we get the borehole and standoff correction factors, t and CF' , it is possible to get a good correction for the gamma ray reading (GR_{cor}).

5.2 Petrophysical analysis

5.2.1 Silica content estimation

Natural gamma ray tools detect gamma ray emissions from natural radioactive isotopes which reside in the formation. Good vertical resolution and the variations in response to the natural gamma ray log in correspondence to the variations in lithology with depth, serve as the basis of correlating formations in different wells.

In sedimentary rocks, the gamma ray log is used as a shale indicator as it exhibits higher radiation levels in front of shale and claystone, while much lower radiation levels are detected in front of sandstone, limestone, dolomites, anhydrite and halite. On the other hand, in volcanic rocks the log response is a function of the silica content rather than the shale volume. So it is common to use the gamma ray log for the detection of silica content and differentiation between the different rock types.

In the present work, silica content was estimated using different methods (Arason, 1993 and Stefánsson et al., 1982; 2000). Almost all the methods matched together and gave good representative silica content for the different rock units in the study wells. The most important of these is a new calibration method by Stefánsson et al., (2000) which relates the intensity of a gamma ray log with the chemical composition of Icelandic rocks as obtained from the chemical analysis of about 254 rock samples. The relation used is:

$$GR_{cor} (API) = (2.63) \times SiO_2 - (102) \quad (8)$$

Furthermore, a new mathematical term for silica content estimation was involved in this work. In its simple form, the term is a modification of the old conventional technique used for shale volume calculation in consolidated sedimentary rocks. It depends mainly on the index gamma ray (IGR). The later term is directly proportional to the concentration of radioactive materials, so it could be further used as an indicator for silica content estimation. The following liner relationship is established:

$$SiO_2 = 34 \times (SI + 1.206) \quad (9)$$

where SI = Silica indicator based on the calculation of index gamma ray and shale volume in old consolidated rocks.

5.2.2 Porosity estimation

Porosity is among the most important petrophysical properties, which must be carefully determined for a good evaluation and assessment for the reservoir of interest. In the present study, porosity was determined using the compensated dual neutron log (CNL). This tool determines the formation porosity by measuring the intensity of thermal neutron radiation produced by bombarding the formation with fast neutrons. Collisions with formation elements, most notably hydrogen, reduce the energy of the fast neutrons to the thermal level (Schlumberger Interpretations, 1989).

The tool employs a chemical source of neutrons and two thermal neutron detectors. The actual measurement consists of the calibrated ratio of the far-detector to near-detector count rates (Mod-8 ratio to porosity transform). The far/near ratio is related to the hydrogen content of the formation. When hydrogen is associated with liquid-filled pore space, this ratio can be used to determine the classic NPHI porosity. Use of the count-rate ratio measurement effectively compensates for variations

in borehole and formation salinity. It also minimizes the effects of changes in borehole size (caliper corrected).

The following is the ratio-to-porosity transform which is used for fraction porosity estimation:

$$Ratio = \frac{\text{Far detector (CPS)}}{\text{Near detector (CPS)}} \quad (10)$$

Having the porosity ratio, the environmentally uncorrected apparent limestone porosity can be estimated using a special user function for the dual neutron probe provided by Robertson Geologging as follows:

$$\phi_{app} = (M \cdot \text{Cali}) + C \quad (11)$$

where ϕ_{app} = Apparent limestone porosity (%);
 Cali = Caliper log reading (mm);
 M and C = Slope and intercept for the calibrated porosities at borehole diameters 214 mm and 150 mm.

5.3 Inversion modelling of logging data

5.3.1 Inversion of porosity and gamma ray for velocity estimation

The sonic log is a very important tool, which when available can be used for detailed fracture analysis and geo-pressuring estimation. In this study, an attempt was made to invert the neutron porosity and the natural gamma ray into sonic acoustic velocities. Another transform (Porter transform), which relates the two aforementioned parameters with sonic time, is also used. In its simple form, the transform states:

$$\phi = \frac{A(\Delta t_{log} - C)}{GR_{cor} + B} \quad (12)$$

where ϕ = Porosity (%);
 Δt_{log} = Sonic transit time for each interval ($\mu\text{s/m}$);
 A, B and C = Constants.

For this transform, to give a good approximation of the sonic velocities of basaltic rocks, good input parameters must be available. Furthermore, it is assumed to be more likely related to the lithological content of the rock rather than any other parameters. The silica content is calculated from the response of the natural gamma ray log. Then inversion of the gamma ray and the neutron porosity logs will together give a good approximation for the sonic transit time (Δt_{log}) and hence the velocity of sonic waves. Having the sonic transit time, it is straight forward to derive the formation bulk density (ρ_b) of the rock.

5.3.2 Calibration with actual petrophysical core data

The neutron porosity and gamma ray intensity, when inverted, can give a good approximation for the sonic acoustic velocities, assuming that these values are calibrated with actual core analyses. To do that, the sonic time (Δt) measured in some wells in the vicinity of the investigated area or the velocity measurements of some core samples with the same rock composition and petrophysical characteristics must be used in the calibration. Sigurdsson et al., (2000) carried out extensive laboratory analyses of more than 500 rock samples representing formations in active low- and high-temperature geothermal

systems in Iceland. The rock samples were collected in such a manner that they represent most Icelandic rock type compositions, from basaltic to rhyolitic, including lavas, hydroclastites, intrusions and some sedimentary rocks of volcanic origin. The results indicate that the average grain densities of crystallized basaltic rocks (2.90 g/cm³) decrease to glassy hydroclastites and reach about 2.70 g/cm³ in acidic rocks. Some core samples, especially those taken from olivine-tholeiitic basalt, exhibit low sonic P-wave velocity in the range of 2200-2700 m/s, while the remainder of the samples shows velocities in the range of 4000-4600 m/s which is a normal velocity range for dense-crystalline basalt.

In terms of composition of the analysed samples and the range of rock types that they cover, these laboratory results can be used in Kaldárholt geothermal field to calibrate the inverted petrophysical parameters of the studied rock units (sedimentary rocks overlying un-conformably different varieties of basaltic rocks), especially those parameters dealing with velocity and density.

Figure 8 shows the formation analysis log of well KH-34. This well is presented as an example to exhibit the different lithological and rock units encountered in the study area as correlated with the estimated petrophysical parameters. The analysis log illustrates that olivine tholeiite is the dominant rock unit in the study area. It exhibits an average porosity of 12%, which is relatively high compared with the porosity of other rock units, while it shows low gamma ray and in doing so low silica content associated with an average rock density of 2.78 g/cm³. The second dominant rock unit is tholeiite basalt. This rock unit is characterized by its dense nature, medium to high silica content and low porosity. Average values of 2.92 g/cm³, 60% and 6% were recorded for the density, silica content and porosity, respectively. A very high gamma ray count rate of more than 125 API was recorded at a depth interval between 292 and 310 m, associated with a very high silica content of more than 70% and low density response on the order of 2.65 g/cm³ or slightly less. These were interpreted as typical petrophysical characteristics of acidic tuff.

Some thin rock units of mixed lava and crushed materials with a high pore system were encountered at different depth levels of the well and with different thicknesses. In general, these rock units exhibited high porosities of up to 18%. A well-recognized thin rock unit of breccia was indicated at a depth interval of 264-253 m and was characterized by high pore space volume (24%) and very low rock density (2.58 g/cm³). In addition, small rock units of icelandite, basalt and very thin streaks of sandstone were also encountered in the study well. Furthermore, a relatively thick unconsolidated sand unit (25 m) with a very high porosity was detected at the uppermost part of the well, just capping the unconformity surface which separates this sedimentary rock unit from the underlying basaltic rocks.

5.4 Rock types identification

5.4.1 Synthetic seismograms

This study uses of synthetic seismograms as a tool for rock typing and as a feed zone indicator. These synthetic seismograms can differentiate between different rock types and detect different possible reflectors in relation with the fracture system in the area. To construct synthetic seismograms, a reflection coefficient (R_c) had to be calculated at each boundary of successive layers using the velocity and density data, assuming that the incidence was near to vertical, as follows:

$$R_c = \frac{AI_2 - AI_1}{AI_2 + AI_1} \quad (13)$$

where AI_1 = Acoustic impedance of the first layer ($\rho_1 V_1$);
 AI_2 = Acoustic impedance of the second layer ($\rho_2 V_2$);
 R_c = Reflection coefficient.

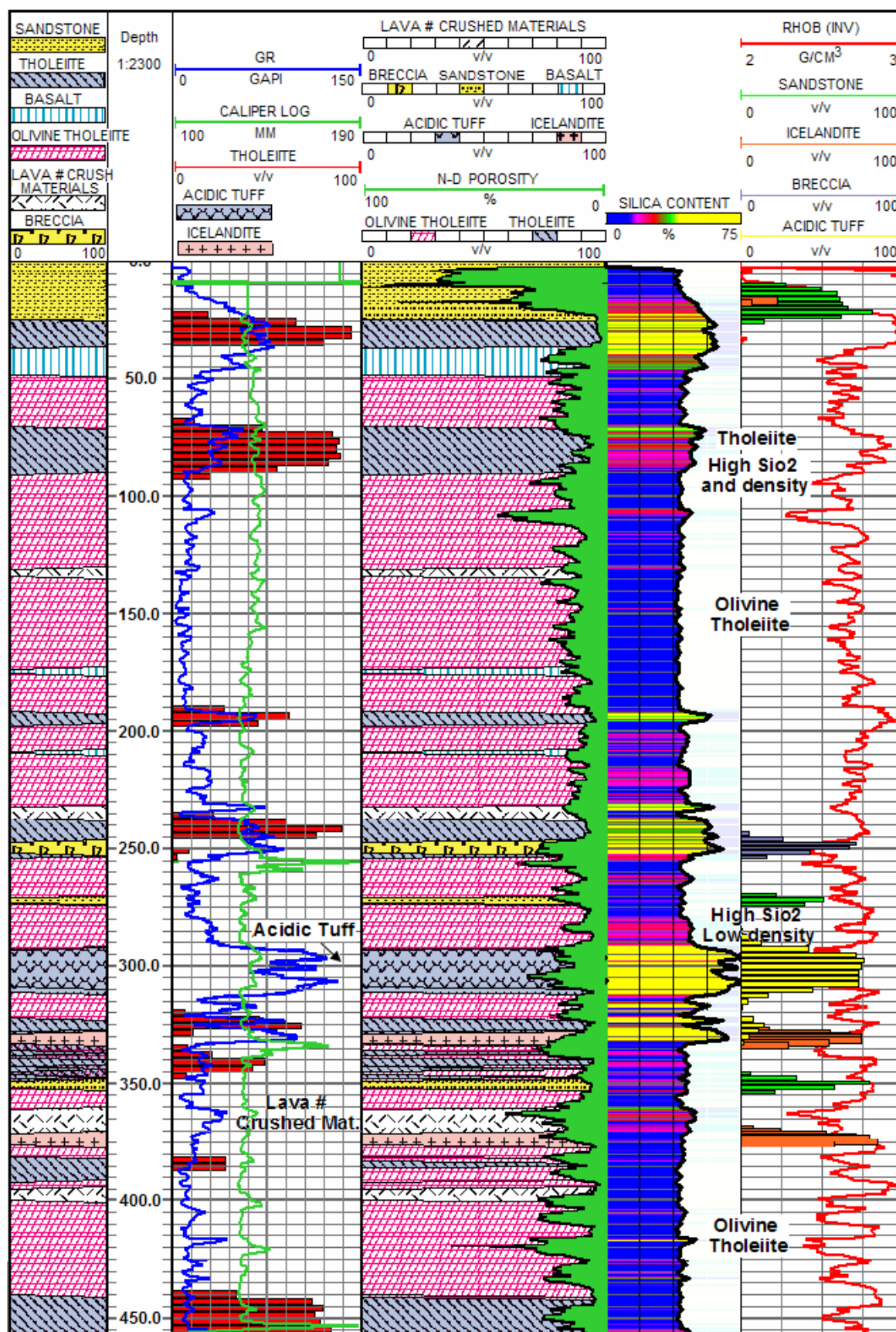


FIGURE 8: Formation analysis log of well KH-34

In the absence of a density log, synthetic seismograms can be calculated more simply from the velocity model based on well log traces. The converted sonic transit time ($\Delta t_{\log}$) can be used to create the synthetic seismic traces as follows:

$$R_c = \frac{V_2 - V_1}{V_2 + V_1} \quad (14)$$

where V_1 and V_2 = Acoustic velocities for two successive layers (m/s).

Figure 9 illustrates the different rock-typing techniques used for characterization of different rock units encountered in well KH-34 as correlated with the possible feed zones and fracture systems, which were either detected during drilling and/or from the interpretation of temperature and caliper logs. Four rock-typing techniques, namely the synthetic seismic trace, the reflection coefficient, the filtered gamma ray and the stack log geometrical pattern, are incorporated and used together to figure out the different rock units in the study area. The synthetic seismic trace and the reflection coefficient are generated using the calculated velocity and density. The gamma ray log is filtered and represented in a variable density mode in order to delineate slight differences between different rock units in terms of intensity increase and/or decrease.

The stack log pattern is another rock typing technique which depends mainly on the differentiation of rock units according to variation in their petrophysical properties in a geometrical-based form. The datasets used in the stack pattern logs are two-dimensional array of floating point values. The depth represents one dimension of this array where each depth segment is defined by certain top and bottom depth values. The other dimension can be any other log which is believed to match with the different rock units. This dimension consists of normalised log data values with certain widths at the top and bottom of any detected thin rock unit.

Regarding Figure 9, a number of thin units is indicated in the stack log associated with very sharp decrease in the velocity to less than 1500 m/s. An obvious anomaly is recorded at a depth of 108 m where a clear feed zone is indicated from the temperature logs (Figure 5). A very strong negative synthetic seismic trough and negative reflection coefficient are recorded at this depth, which means that there is a velocity transform from the high-velocity layer above the feed zone to much lower velocity within the fracture system of the feed zone. Another strong velocity anomaly, that matched with a temperature and caliper-interpreted feed zone is indicated at a depth of 333 m. The filtered gamma ray exhibits strong anomaly with high silica content, meanwhile the reflection coefficient is obviously negative in front of this depth level. The synthetic seismic trace is not so strong in front of this depth level.

At a depth of 253 m there is a strong velocity inversion from the high-velocity tholeiite to the underlying low-velocity breccia bed. The caliper log indicates the presence of a well identified fracture system in front of this depth. Some other thin units of low velocities are indicated from the stack model at depths of 308, 363 and 421 m. High filtered gamma ray radiation is recorded for the thin unit indicated at the depth of 308 m, but with a weak and low amplitude synthetic seismic trace. Meanwhile, very strong negative synthetic seismic traces are recorded in front of the other two depth levels.

It is very important to notice that at a depth below 400 m, there is not a great variation in the lithology of this well. Only two rock units (olivine tholeiite and tholeiite) are indicated from the interpretation of well cuttings and from the low silica content indicated by the filtered gamma ray. Despite this homogeneity, the reflection coefficient and the synthetic seismic trace are telling something more. These two physical properties fluctuate more functionally in front of this depth range, giving rise to more successive peaks and troughs of high amplitude; which reveals the presence of successive bedding of different petrophysical characters, even if there is no lithological change.

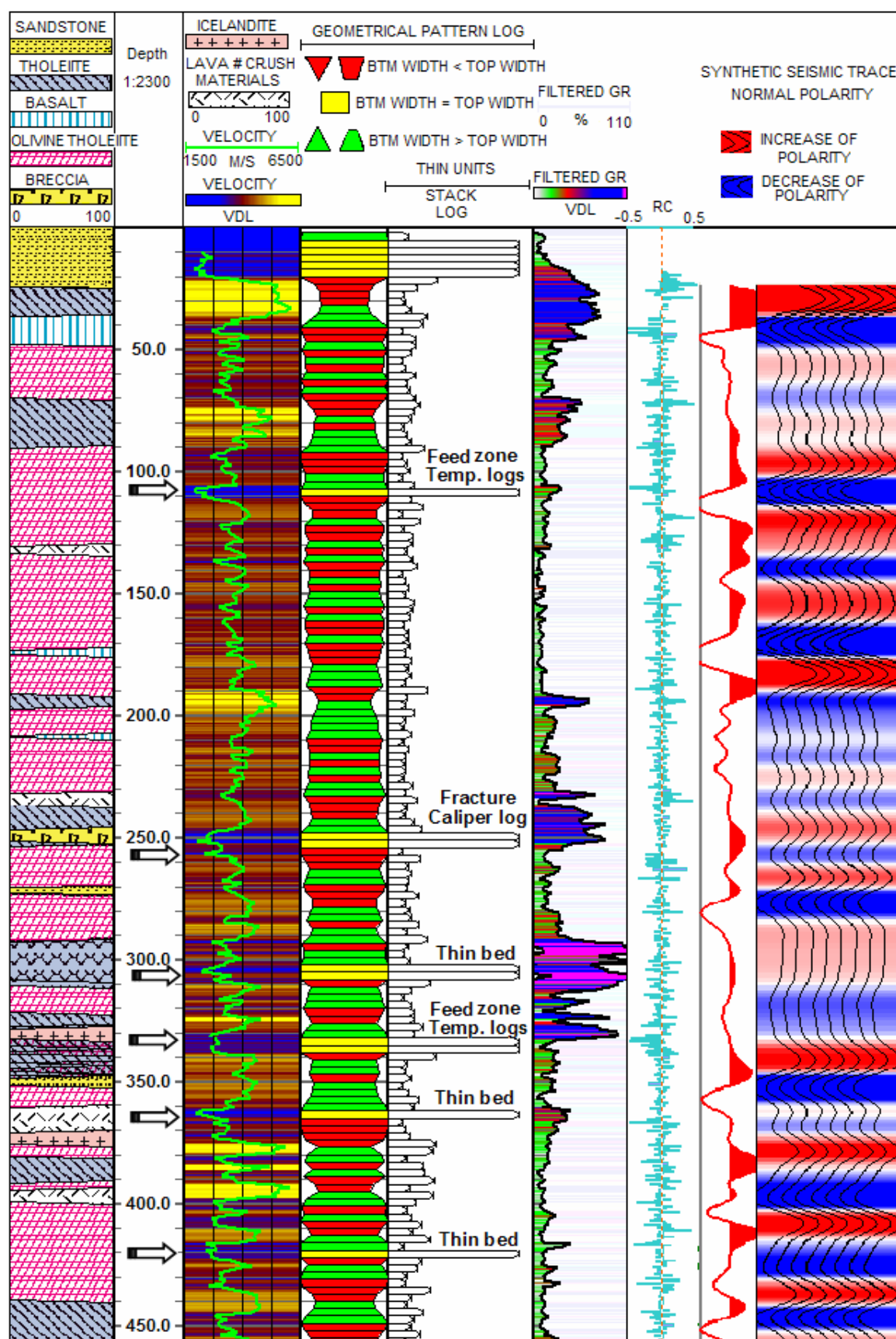


FIGURE 9: Rock units identification in relation with fractures and feed zones of well KH-34

5.5 Artificial neural networks (ANN)

5.5.1 Application of artificial neural networks for predicting porosity and silica content

In the last few years, artificial intelligence has been involved in solving many problems in different fields of science. Many authors have dealt with the application of neural networks in solving fundamental problems in geophysical and petroleum engineering like: Fu, 1994; Haykin, 1994; Mohaghegh et al., 1994 a,b; Mohaghegh, 2000, 2005; and Lim, 2005.

Artificial intelligence is generally divided into two basic categories: rule-based expert systems and adaptive neural systems. By definition, a neuron is a nerve cell with all of its processes. The main interest in neural network comes from the recognition that the human brain processes information in a different manner than conventional digital computers (Mohaghegh and Ameri, 1995). Neural networks can address some important problems which conventional computing has been unable to solve. While the conventional computer systems work on a sequential process, the neural networks work in a parallel distributed information processing system. So, unlike the sequential computer system which works with a central processor that can address an array of memory locations, the neural network stores knowledge in the overall state of the whole network, hence the accuracy of these systems.

The idea of artificial neural networks is to input a number of parameters related to each other by certain features and try to use these features to predict another one or two output properties. To develop a neural network model, two groups of data are very important. The first is the training group, which contains all the input parameters, while the other is the application group, which will be used in the final prediction.

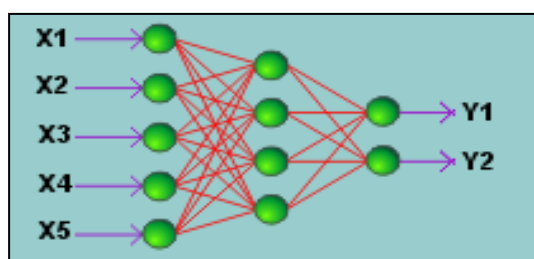


FIGURE 10: Design of a simple artificial neural network

The importance of a training group stems from the fact that neural networks can only predict data using information provided during the training phase. So, this group is very important for training the network to predict certain phenomenon. To design a simple neural module (Figure 10), it is very important first to define the number of input parameters in the training group which will be used in the prediction. This number is very important as it controls many other parameters, especially the number of the hidden layers. Another important parameter is the committee option, which

tells the neural network the number of simultaneous iterations, which will be used in the predictions.

Once a good training group is established for certain input parameters of a given well, this group can be further used as an application group for prediction in other wells whose data are scarce, missed or of bad quality.

In this study, a simple model of an artificial neutral network (ANN) using the standard technique was designed to predict some important petrophysical parameters of the reservoir, especially the porosity and silica content. Figure 11 shows two crossplots for the neural-derived porosity and silica content against the log-derived ones. Good matching is recognized between the estimated parameters using both methods in both plots. The correlation coefficient is more than 98% in the case of the porosity crossplot (Figure 11a) with a very low standard of error of 0.018. A few datapoints marked as selections 1 and 2 shifted from the best-fit line. These poorly fitting datapoints are characterized by a high gamma ray content ($GR < 52\%$) and low to medium Young's modulus (0.75-4), as indicated by the assigned colour legend of both parameters. The silica content crossplot (Figure 11b) also exhibits a very good matching between the results of both methods especially for datapoints with high silica ($SiO_2 > 60\%$). Poor matching is observed for a low range of silica content ($SiO_2 < 42\%$).

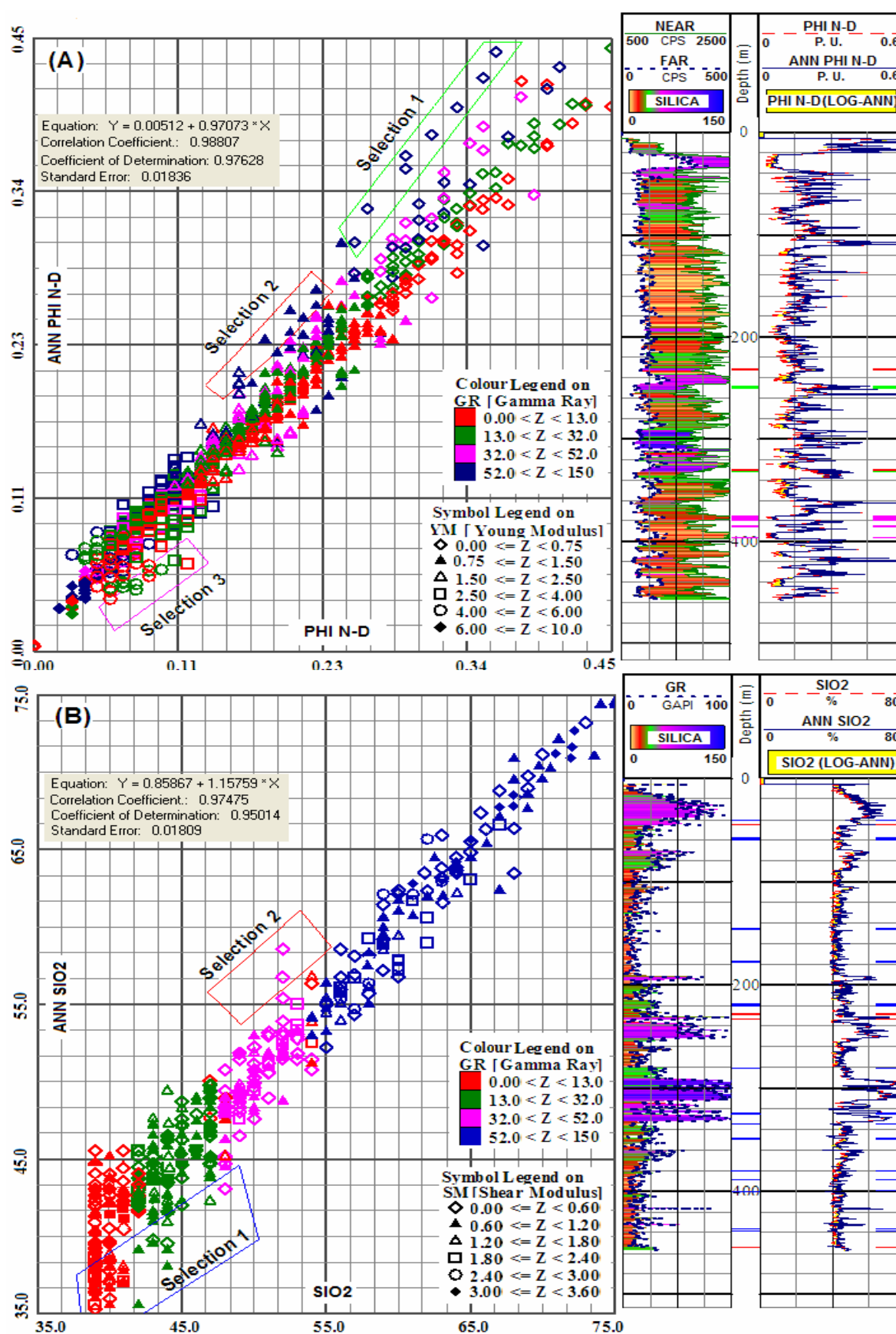


FIGURE 11: Crossplots of a) porosity and b) silica content of well KH-34, as deduced from normal logging techniques and artificial neural networks (ANN)

Despite this poorly fitting range, only a few clusters shifted from the fit line. The colour legends indicate that these clusters are characterized by low to medium gamma ray radiation and low shear modulus.

It is worth mentioning here, that the gamma ray is used along with the Young's and shear modulus as multi-Z parameters, to set up the necessary limitations for using this model in further predictions. However, more details about the different elastic constants used in this study, including Young's and shear moduli, will be discussed in the next part.

5.6 Fracture system identification

Logging tools are designed to respond to the petrophysical properties of the formation as well as to the different characteristics of the wellbore environment. Determining the mechanical properties of rocks and identifying the presence of effective fractures are among the most important purposes and are necessary to better understand the geometry and continuity of the reservoir of interest.

Naturally fractured rocks are very important as possible feed zones because of the extra drainage and the considerable increase of permeability that they provide. Although fractures can have a very significant effect on the total permeability of a rock, they have very little effect on the porosity, saturation and other petrophysical characteristics of the rock (Schlumberger Interpretations, 1989).

In the present study, the identification of possible fracture systems is performed through two procedures. The first is a quantitative determination of mechanical properties of the different rock units through studying their elastic constants and the stress/strain ratio acting on them, while the second is the qualitative characterization of orientation and breakouts, along with the dip and azimuth, of the indicated fractures through analysing acoustic televiewer data.

5.6.1 Mechanical properties and velocity analysis

The compressional and shear velocities are very important physical properties of rocks, which, when known in-situ, will provide information on the mechanical properties of the rocks. Integrating the analysis of the elastic wave velocities, in conjunction with the bulk density of rocks and their elastic moduli relationships, proved to be the most effective technique for studying the mechanical properties of rocks with any fractures which may occur. Among the most important and well-known elastic constants, are: Poisson's ratio, shear modulus, Young's modulus, bulk modulus, bulk and rock compressibilities, tensile strength and Biot elastic constant.

Poisson's ratio and shear modulus can be determined directly from the log data, and their values are used to calculate bulk modulus and Young's modulus. The following are the different mathematical expressions used to estimate these elastic moduli;

- Poisson's ratio (ν):
$$\nu = \frac{0.5 \left(\frac{\Delta t_c}{\Delta t_s} \right)^2 - 1}{\left(\frac{\Delta t_c}{\Delta t_s} \right)^2 - 1} \quad (15)$$

- Shear modulus (G):
$$G = \frac{\rho_b}{\Delta t_c \nu} a \quad (16)$$

- Young's modulus (E):
$$E = 2G (1 + \nu) \quad (17)$$

- Bulk modulus (K_b):

$$K_b = \rho_b \left(\frac{1}{\Delta t_c^2} - \frac{4}{3\Delta t_s^2} \right) a \quad (18)$$

- Bulk compressibility (C_b):

$$C_b = \frac{1}{K_b} \quad (19)$$

- Rock compressibility (C_r):

$$C_r = \rho_g \left(\frac{1}{\Delta t_{c_{ma}}^2} - \frac{4}{3\Delta t_{s_{ma}}^2} \right) a \quad (20)$$

- Biot elastic constant (α):

$$\alpha = 1 - \frac{C_r}{C_b} \quad (21)$$

where Δt_c = Compressional transite time (m/s);
 Δt_s = Shear transit time (m/s);
 $\Delta t_{c_{ma}}$ = Compressional transite time of the matrix (m/s);
 $\Delta t_{s_{ma}}$ = Shear transite time of the matrix (m/s);
 a = Constant for adjusting units.

Figure 12 represents the different estimated mechanical parameters of well KH-34 in relation with the compressional and shear velocities. A very strong match between the shear and bulk moduli and the type and composition of the different rock units is observed. The bulk modulus increases remarkably and reaches a maximum value of 9.2×10^6 psi (6.3×10^{10} Pa) in front of the tholeiite. Moreover, the tensile strength behaves in the same manner, a phenomenon which reflects the brittle and dense nature of these rock units, which usually extrude along the fissures of pre-existing formations. On the other hand, a reverse behaviour is observed in front of the breccia and the icelandite, where the bulk modulus exhibits a minimum value of 1.2×10^6 psi (8.3×10^9 Pa).

The Biot elastic constant shows a positive response in front of some depth levels, associated with sudden increase in the velocity ratio (V_s/V_p) and a marked decrease in the tensile strength. This suggests the presence of open feed zones and/or the presence of more permeable rock units with high pore volume. Two depth levels marked with sharp increase in the velocity ratio and positive response of the Biot elastic constant, are detected. The first is found at a depth of 108 m where a well-defined feed zone is indicated from the interpretation of temperature logs, while the other is indicated at a depth of 256 m in front of a thin breccia rock unit intercalated between tholeiitic and olivine tholeiitic rock units above and below, respectively. The caliper log read a very high values up to 205 mm at this level indicating the presence of a good fracture zone. Another level of positive Biot elastic constant and high velocity ratio is observed in front of the lava and crushed materials at a depth of 362 m. This depth level, together with the other levels which share the same mechanical characteristics, represent zones of possible lateral flow.

The bulk compressibility curve shows an average value of 0.26×10^{-10} Pa⁻¹ in front of the olivine tholeiite a value which becomes slightly higher in front of the tholeiite basalt (0.18×10^{-10} Pa⁻¹). Meanwhile, it increases remarkably in front of zones of possible lateral flow, recording a maximum value of 0.92×10^{-10} Pa⁻¹.

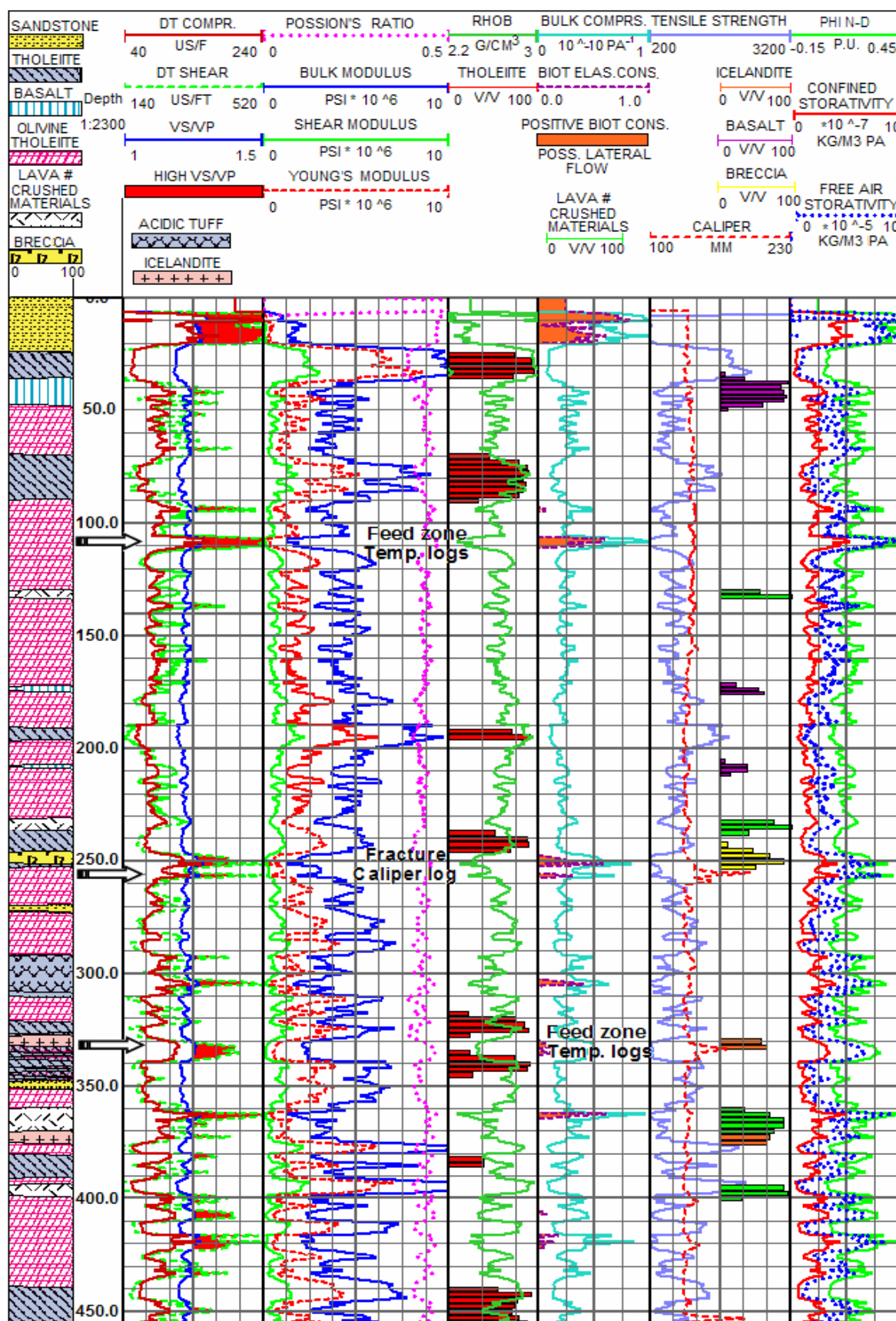


FIGURE 12: Mechanical properties and velocity analysis of the rock units of well KH-34

Knowing the rock compressibility and having the rock porosity from the petrophysical analysis, it will be easy to estimate the rock storativity providing that the water density is estimated at the actual reservoir temperature. In this work, the storativity is estimated for the two reservoir cases; the confined and unconfined supposing that the exact behaviour of the reservoir, in terms of its volume, recharge area and the storativity of its capacitors is not well known. The information which will be confirmed at a later stage of this study through simulating the production history of the field using lumped modelling. An average confined storativity value of $2.46 \times 10^{-7} \text{ kg}/(\text{m}^3\text{Pa})$, which increases remarkably in front of the fractures and the zones of possible lateral flow, is recorded in this well. Meanwhile, the free-surface storativity shows a much higher average value of $3.1 \times 10^{-5} \text{ kg}/(\text{m}^3\text{Pa})$, with marked increase in front of some rock units like; the breccia, lava and crushed materials.

5.6.2 High resolution acoustic televiewer (HRAT)

The borehole televiewer is an acoustic scanner, which scans the borehole wall and gives an image as if it was split vertically and laid flat. Vertical fractures will appear as straight lines, while dipping fractures appear as sinusoidal traces.

The high resolution acoustic televiewer probe (HRAT) used in this study is made by Robertson Geologging. This probe uses a fixed acoustic transducer and a rotating acoustic mirror to scan the borehole walls with a focussed ultrasound beam. The amplitude and travel time of the reflected acoustic signal are recorded simultaneously as separate image logs. Features such as fractures reduce the reflected amplitude and often appear as dark sinusoidal traces on the log. The travel-time log is equivalent to a high-precision 360-arm caliper and shows diameter changes within open fractures and breakouts.

Most of the geothermal fields in Iceland (high- and low-temperature fields) are producing from wells cutting through igneous rocks, mainly basaltic in composition. The feed zones in most cases are open fractures which are sometimes difficult to detect either in position and/or in orientation without detailed logging analysis. The high resolution acoustic televiewer is used mainly for picking up fractures, delineating their orientation (dip and azimuth), locating possible thin beds as well as giving a detailed information about the borehole geometry.

Analysis of amplitude and travel time data

Televiewer travel time and amplitude data for each depth level in a well can be separated in such a manner that every group of curves corresponding to one quarter of the borehole cross-section can be represented together according to their actual positions on a circle. Such type presentations are very powerful enabling us to handle breakout effects in each part of the borehole cross-section separately as a function of depth. Furthermore, the geometrical change in the shape of any irregular geological structure can be figured out qualitatively.

The amplitude and the travel time data of the deeper section of well KH-35 is shown in Figure 13. Each of the amplitude and travel time data is re-arranged in unrolled four tracks. Each track represents one quarter of the borehole cross-sectional area. For example, the first travel time track represents the first quarter of the borehole cross-sectional area which extends from the north to the east (0° to 90°). For each track, only nine curves are selected either for the travel time or for the amplitude data. Each of these curves is selected at an order of 10° degrees difference. Regarding Figure 13, two distinctive geologic features with different breakout characteristics are indicated. The first (A) is observed between depths of 496 and 498 m, while the second (B) is detected at a depth range of 521-524 m.

Feature A is characterized by a high travel time associated with a marked regular decrease in the amplitude. More wide fluctuation of the travel time is observed in the first and third travel time tracks, suggesting the presence of more breakouts extending along a northeast-southwest direction. It should be mentioned here that the presence of travel time curves in track 3 with different magnitudes, indicates that two possible geologic features are dipping in different manners in the southwest

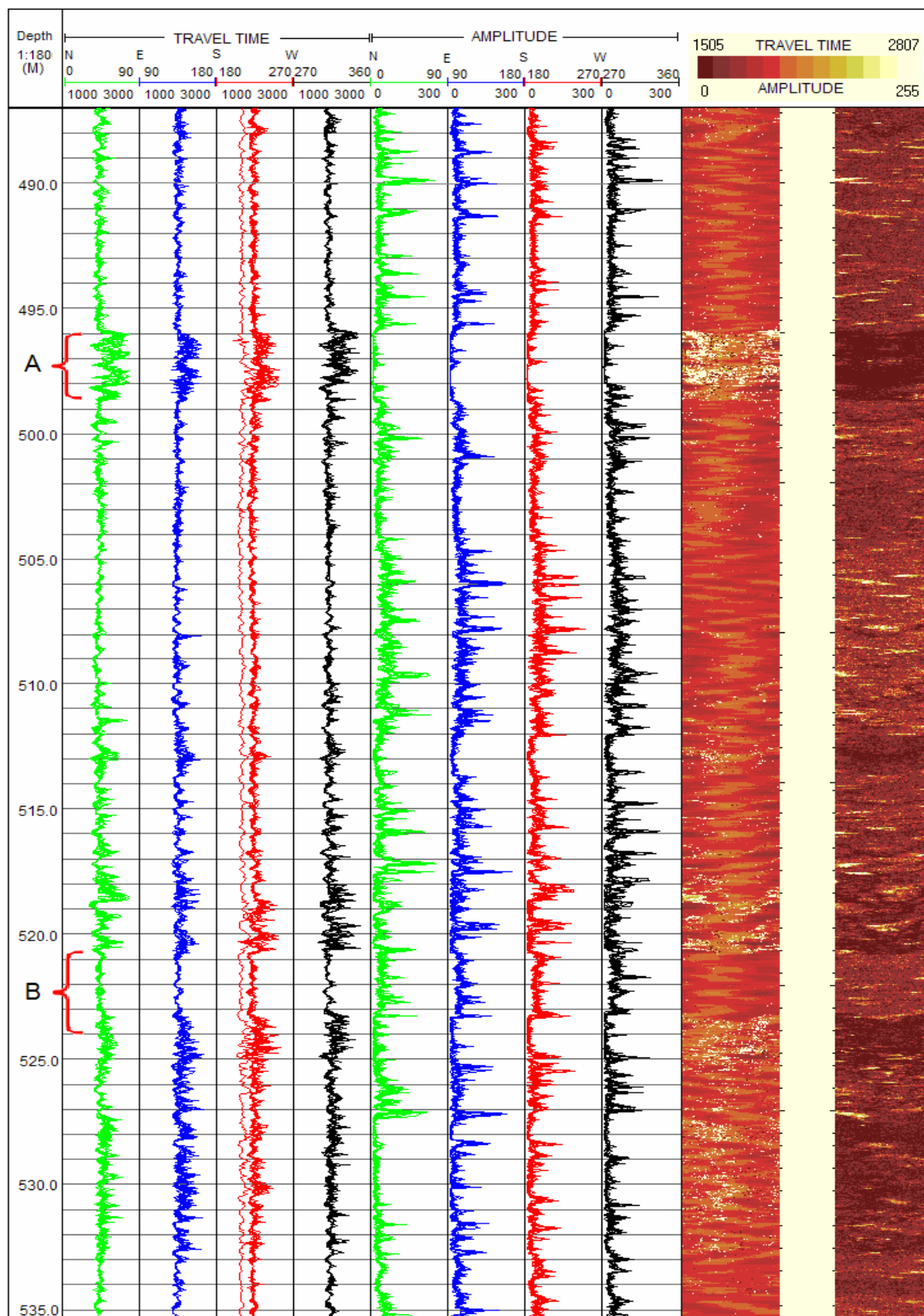


FIGURE 13: Interpretation of the travel time and the amplitude data for the lower section (487 - 535.5 m) of well KH-35

direction, even though they have the same dipping attitude in the northeast direction. By interpreting the caliper and neutron logs at the same depth interval, it is found that values of up to 240 mm and 50% are given for both of these two curves, respectively. This indicates that at this depth interval there is an open fracture system trending NE-SW and exhibiting many dipping directions.

On the other hand, feature B, and in contrast to that of A, is characterized by low regular travel time and high irregular amplitude. The caliper and neutron log show no characteristic behaviour in front of this rock unit which seems to be dense and mineralized and most probably is an igneous intrusion.

Analysis of breakout data

The relationship between the different breakout parameters (alpha, beta, alpha/beta and psi) are studied and interpreted together with the other deviation and borehole radius data. The different borehole radii as extracted from the televiewer data, are represented in a four-track unrolled arrangement in the same manner as in the interpretation of the travel time and amplitude data. Figure 14 shows the borehole cross-sectional and breakout parameters at depth ranges between 260 and 450 m in well KH-35.

At depth levels of 344, 370.4, 381.5 and 439.4 m, very big borehole radii associated with high alpha readings and high alpha/beta ratios are indicated. These depth levels represent the zones most affected by the breakout parameters and indicate possible feed zones. Out of these four depth levels, only three borehole cross-sections are constructed to illustrate the effect of the breakouts and identify the possible fractures and their orientation. The most obvious breakout is recognized at a depth of 439.8 m, where an extensive fracture system dominates. A very high alpha/beta ratio of 1.06 is recorded in front of this depth level.

Identification of fractures

Picking the different fracture and structure systems encountered in the Kaldárholt study area is of prime importance due to the role they play in controlling the direction of main upflow of the geothermal water. The final corrected amplitude images for sonde decentralization and magnetic anomaly are used for this purpose. The sinusoidal trace is picked up from the borehole televiewer image by converting the amplitude image to a binary, amplitude-gradient image by edge detection.

Figure 15 represents an example of a number of picked fractures and structures, their dip and azimuth at different depth intervals in well KH-35. The figure shows that all the fracture systems are dipping mainly along a NNE-SSW direction. The dip angles are very high and in most cases exceeds 70° in a steep near-vertical attitude.

The tadpoles in the right side of the amplitude image illustrate the magnitude of the different encountered dips. Some of the detected fractures are in fresh and open condition, meanwhile others are filled and closed. A few planar low-angle intrusions were also detected and analyzed in terms of their dip angles and azimuth directions.

Table 1 exhibits azimuth and dip values of the different fractures and structures picked up in the depth range 340 - 535 m in well KH-35. The data represented in the table emphasizes the NNE-SSW dipping direction of the fracture system. Some other minor fractures are also oriented in the NW-SE direction.

5.6.3 Neutron signature of fractures in relation to velocity and televiewer data

The neutron log responds mostly to the hydrogen index of the formation, which in its turn is proportional to the quantity of the hydrogen per unit volume. The effects of borehole parameters are greatly reduced by taking the ratio of the two counting rates. The neutron tool is very sensitive to some elements like boron and rare earth elements which have a particularly high thermal neutron capture cross-section. When the borehole is irregular with many breakouts, which is the case of the

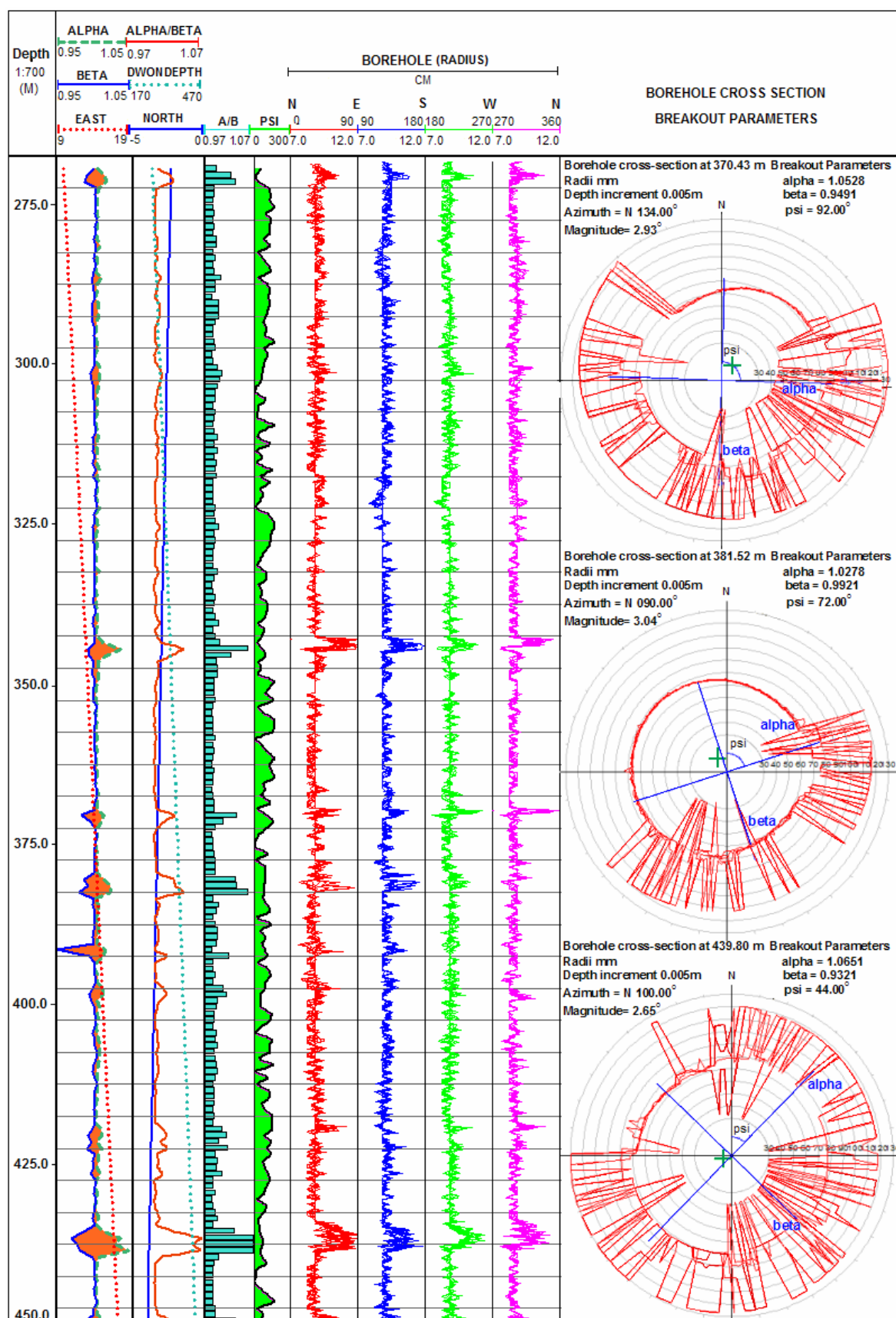


FIGURE 14: Borehole cross-sectional and breakout parameters at a depth range of 260-450 m in well KH-35

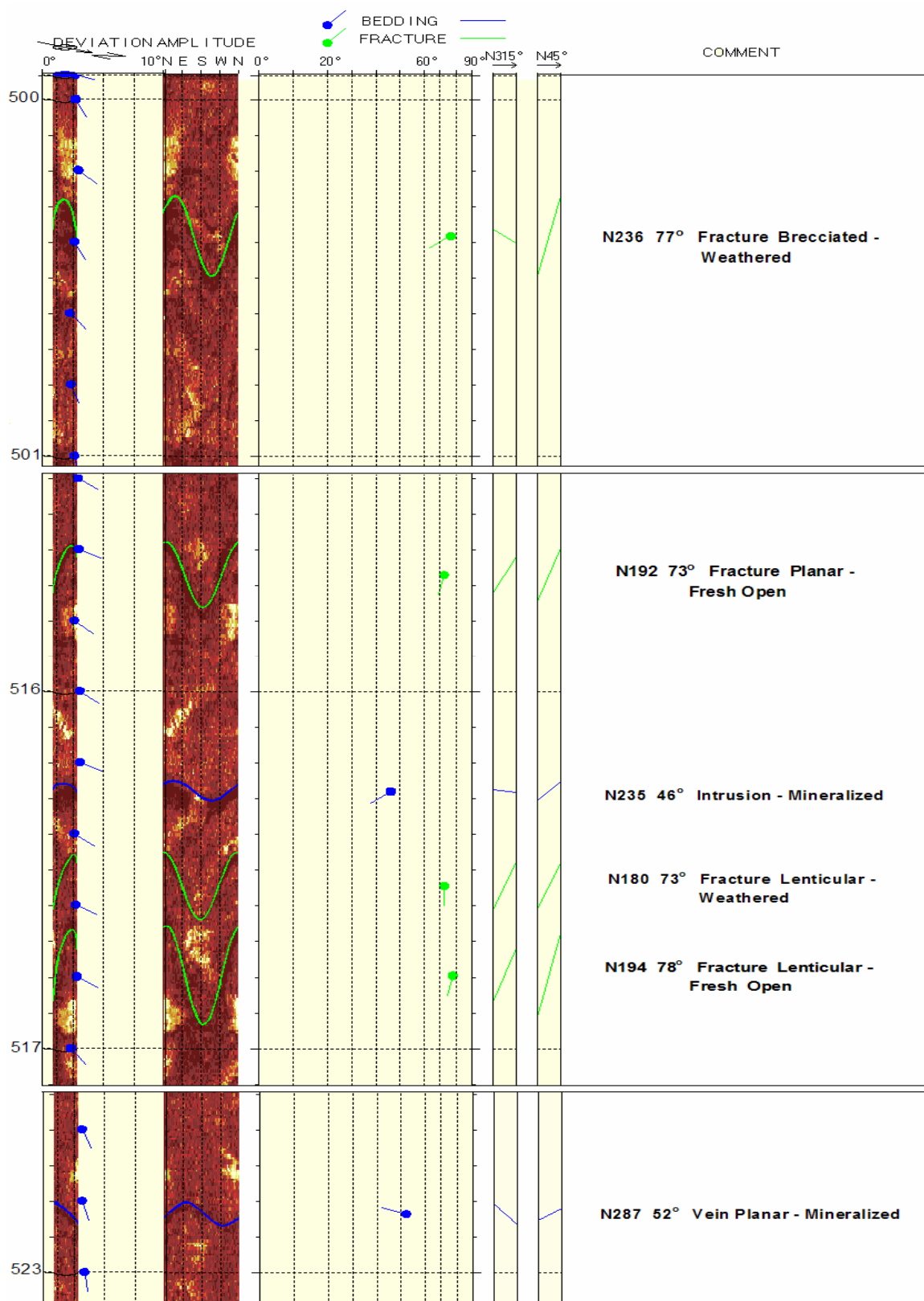


FIGURE 15: Unrolled amplitude image corrected for a magnetic anomaly and sonde decentralization, showing number of picked fractures and structures at different depth intervals of well KH-35

TABLE 1: Azimuth and dip values of fractures and structures picked up at depth interval between 340 and 535 m in well KH-35

No.	Depth (m)	Azimuth (°)	Dip (°)	Fracture/ Structure	Description
1	350.54	190	74	Hairline fracture	Near vertical– Mineralized
2	405.93	234	85	Vein	Planar – Mineralized and high angle
3	406.36	198	78	Hairline fracture	Vertical fractures – Thermal cracking
4	409.15	174	74.6	Fracture	Lenticular – Fresh open fracture
5	410.52	192	81	Fracture	Lenticular – Vertical and high angle
6	413.23	94	46.6	Fracture	Planar – Low angle
7	413.86	200	79	Hairline fracture	Vertical fractures – Thermal cracking
8	419.76	169	77	Fracture	Lenticular
9	429.89	229	78	Fracture	Planar – Intermediate angle
10	430.78	198	75	Fracture	Lenticular
11	439.63	153	84	Fracture	Lenticular – Fresh open fracture
12	452.56	177	84	Fracture	Lenticular – Fresh open fracture
13	487.67	188	84.7	Primary structure	Planar bedding
14	499.77	126	81	Fracture	Lenticular – Weathered
15	500.46	236	76.5	Fracture	Brecciated – Weathered fracture zone
16	507.19	184	77	Fracture	Brecciated – Weathered fracture zone
17	508.60	161	80	Fracture	Brecciated – Weathered fracture zone
18	509.64	166	82	Hairline fracture	Lenticular – Mineralized
19	509.89	176	76.8	Hairline fracture	Mineralized
20	511.50	212	73.8	Hairline fracture	Crushed – Mineralized
21	511.80	243	77	Fracture	Crushed – Mineralized fracture zone
22	515.59	192	72.7	Fracture	Planar – Fresh open fracture
23	516.26	235	46	Intrusion	Planar – Mineralized bedding
24	516.55	180	72.6	Fracture	Lenticular – Weathered – Hairline
25	516.80	194	78.1	Fracture	Lenticular – Fresh open fracture
26	517.62	173	82	Fracture	Lenticular – Fresh open fracture
27	518.01	236	82	Fracture	Fresh fracture zone
28	518.44	209	77.6	Fracture	Lenticular – Fresh open fracture
29	521.76	183	73.4	Intrusion	Mineralized – Irregular
30	522.01	287	52.1	Vein	Planar – Mineralized

basaltic rocks in many localities in Iceland, these inter-veining fractures may act as feed zones along which inflow to the well may take place. Being filled with water, these fractures will contain more dissolved salts, most probably sodium chloride (NaCl) which will take up more space on the expense of the hydrogen, thereby reducing the hydrogen density. As the slowing of thermal neutrons emitted from the source depends on the amount of hydrogen in the formation, this means that the far thermal neutrons will travel greater distance in the fracture zone until they find the hydrogen nucleus to collide with. In so doing, a much lower count rate will be recorded by the far neutron detector which will lead to a low porosity ratio. As a result, much higher uncorrected porosity will be indicated in front of these fractured zones.

In the Kaldárholt field, most of the neutron logs exhibit high uncorrected neutron porosity, which correlates well with the different fractures present. Therefore, the uncorrected neutron porosity can be used as a quick look indicator for the identification of the fracture system by matching with the caliper and other logs. Figure 16 shows a neutron porosity-silica content crossplot with the caliper and velocity logs as multi-Z parameters. The crossplot shows that the majority of datapoints are ranged between 40 and 60% in terms of their silica content and between 4 and 36% in terms of the uncorrected neutron porosity. The velocity of these datapoints ranges from 2500 m/s to 5000 m/s as

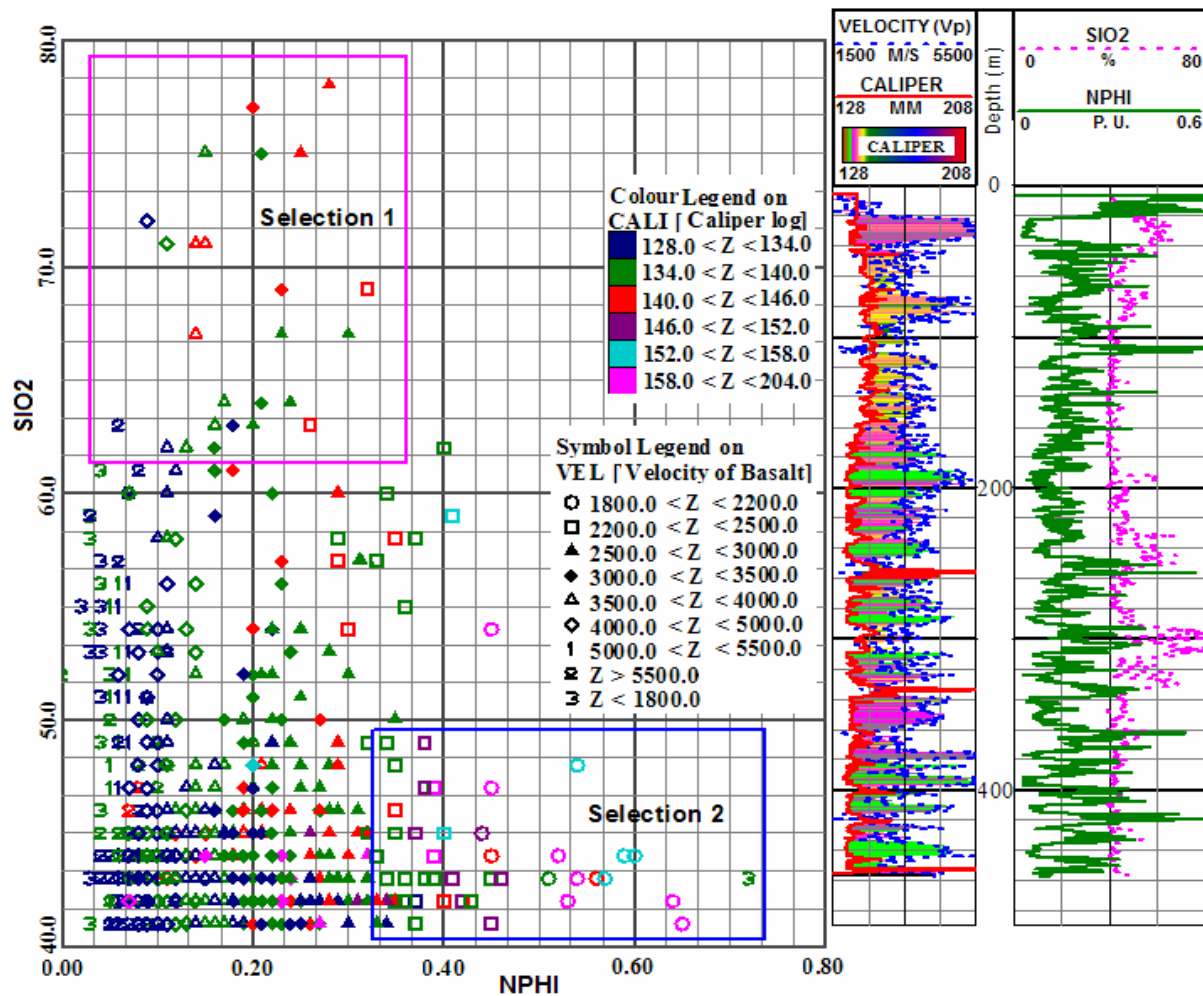


FIGURE 16: Neutron porosity - silica content crossplot of well KH-34

indicated from the velocity symbol legend, while the caliper log readings give normal range between 134 and 152 mm.

Selection 1 shows that, although some clusters are located in the area of high silica content, still these clusters almost share the petrophysical characteristics of the main datasets. Only the caliper log readings become much more restricted between 134 and 146 mm. Selection 2, on the other hand, contains the most important group, which demonstrates the relationship between the high-recorded neutron porosity and the high caliper log readings. This group contains the clusters which have much higher neutron porosity (>36%) and much lower velocity range (1800-2500 m/s) as represented by the open-shaped circles and some open-shaped squares in the velocity symbol key. The caliper log colour legend assigns much higher values for these clusters or more than 152 and up to 204 mm.

Relation with amplitude and core televiewer data

The televiewer image can give meaningful geological information if compared with other logging data. Figure 17 shows the travel time and amplitude data image for a depth interval between 390 and 395 m to the left, as compared with the caliper and neutron logging data in the middle, and the four-side core view image of the televiewer data on the right side of the figure.

A well-defined lenticular-shaped fracture is observed at a depth of 391.20 m in the amplitude image. This fracture is assumed to be closed due to the low travel time trace it exhibits as recognized from the travel time data. This fracture is underlain by another well-recognized vertical or more definitely near vertical hair-line fracture system. This system is indicated as a vertical anomaly of low-travel time in the middle of the travel time image, which suggests an open system. The caliper and neutron logs

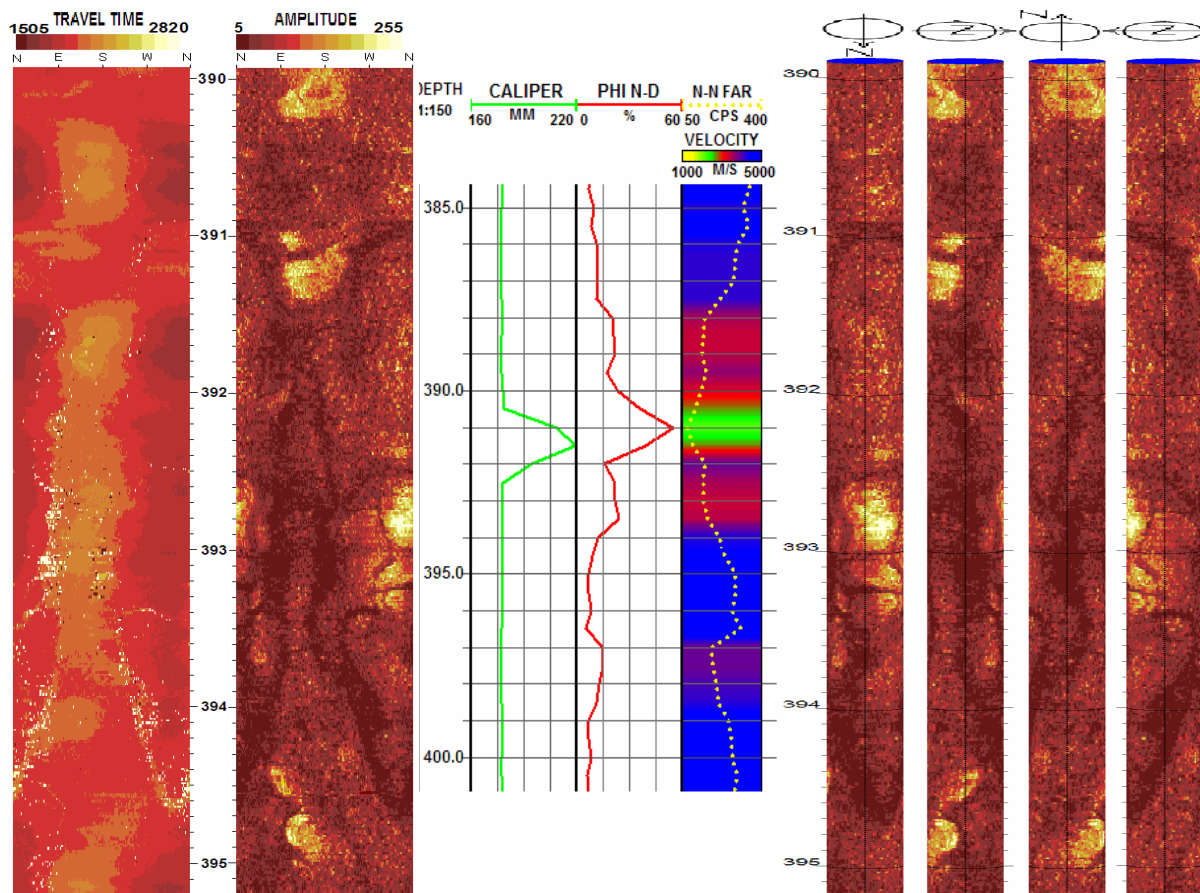


FIGURE 17: Well-identified lenticular-shaped fracture underlain by vertical hair-line fracture system as indicated by comparing the well logging data with the other televiewer time, amplitude and core data in well KH-35

show a very sharp increase up to 210 mm and 55%, respectively, for the same depth interval. Moreover, the far neutron detector reads a very low value of less than 100 cps associated with a strong low velocity anomaly of less than 2100 m/s as indicated in the variable velocity log. The four-side core image reveals that the vertical continuity of the open vertical fracture system is well developed in the northern and easterly directions rather than the other directions.

Relation with breakout data

Another powerful correlation between the televiewer and logging data is presented in Figure 18. The 3-D borehole televiewer image shows extensive breakouts at a depth interval between 439 and 443.8 m in well KH-35.

Two borehole cross-sections are constructed at two different depth levels to demonstrate the effect of the breakout and to clarify the directions of the possible fracture system. The first is taken at a depth level of 441.81 m where the extensive breakout dominates.

It appears clear that the smoothed breakout aperture for the main fracture system seems to extend along a northeast-southwest axis. The major axis (alpha) of the best-fit elliptical cross-section is oriented N032.0° (psi). Meanwhile, the second borehole cross-section is taken at a depth of 443.6 m away from the fractured zone. No fractures are indicated in this cross-section which is more regular and circular in shape. The sonde decentralization is negligible in this cross-section. The caliper and neutron logs correlate well with the breakout data at this depth interval (439-443 m) giving rise to much higher values. The neutron log records a value of 46%, while the caliper reaches more than 215 mm. Furthermore, a much higher increase in the sonic transit time is recorded in front of this depth level.

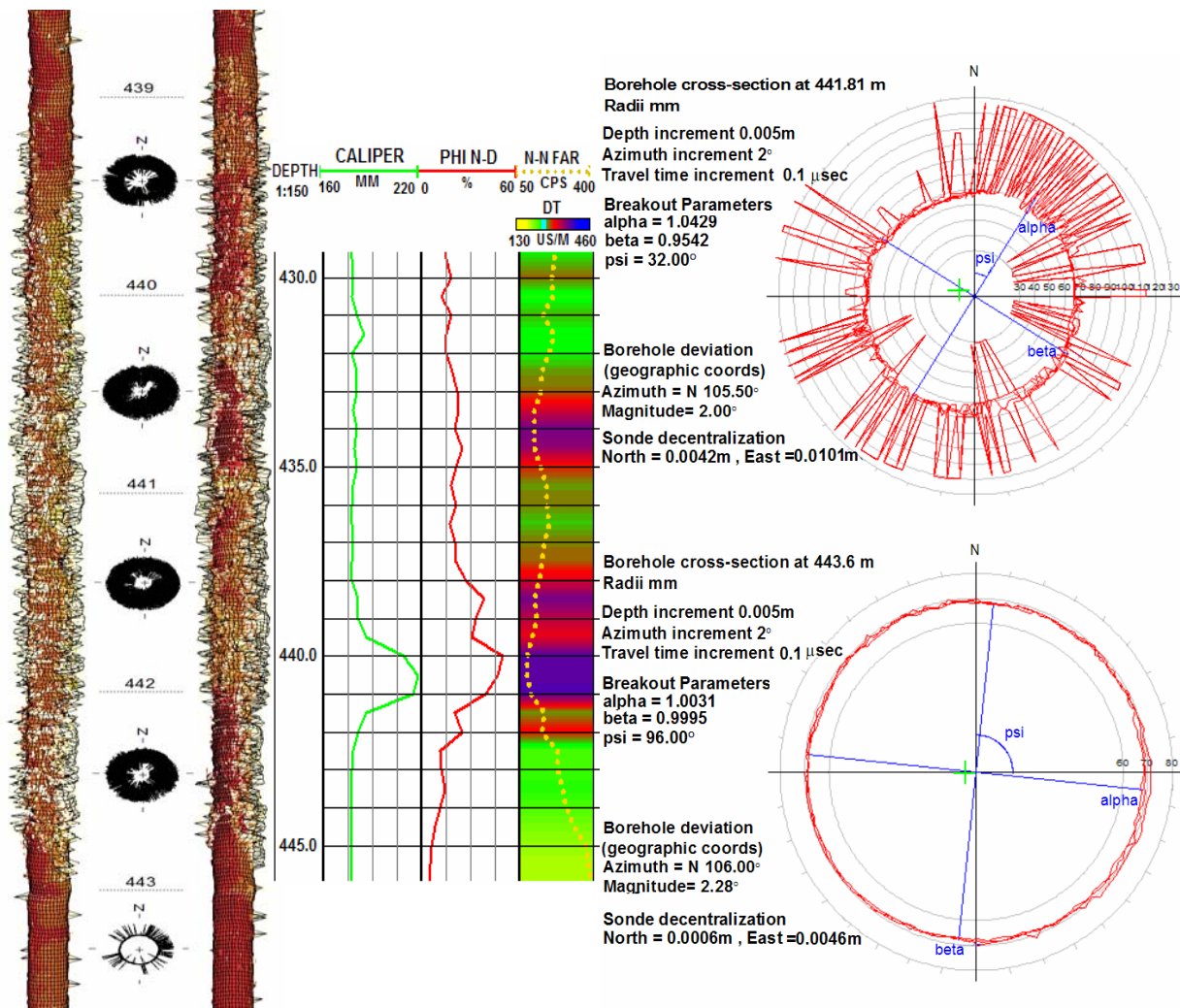


FIGURE 18: 3-D borehole televiewer image, well logging data and cross-sectional area of well KH-35 showing extensive breakout between depths 438.7 and 443.8 m

6. RESERVOIR MODELLING

Modelling of geothermal systems has become a mature technology, applied to many geothermal fields around the world. Large complex three-dimensional models having computational meshes with thousands of blocks are now used routinely (O'Sullivan et al., 2001). Modelling of geothermal reservoirs, as well as other hydrological reservoirs, is used extensively as a tool for resource assessment. Rapid advances are being made in the development of numerical simulators for detailed and complex modelling of such systems. Simulation models compute flows, pressure, water quality, and other parameters based upon physical laws and conceptual relationships. These models are calibrated by comparing computed results to observed values with subsequent adjustments to mathematical coefficients to attain closer agreement.

Many authors have dealt with using computer modelling in the planning and management of the development of geothermal fields. Among these, the following are some of the most important: Bödvarsson et al., 1986; O'Sullivan et al., 1990; Williamson, 1990; Menzies et al., 1991; Pritchett et al., 1991; Axelsson and Arason, 1992; Strobel, 1993; Sakagawa et al., 1994; Todesco, 1995; Boardman et al., 1996; Antics, 1997; Battistelli and Nagy, 2000; Trew, et al., 2001; Mazur et al., 2002; Yasukawa et al., 2003; McKenna and Blackwell, 2004; and White and Hunt, 2005.

In the present study, simple lumped parameter models are used to give some insights into the reservoir properties of the Kaldárholt geothermal field, especially its volume and permeability.

6.1 Lumped parameter modelling

Lumped parameter model simulators have been developed and successfully applied to many geothermal reservoirs all over the world. They can be used as an alternative to the detailed numerical modelling of complex fluid rock systems (Axelsson, 1989). LUMPFIT, a lumped model simulator included in the ICEBOX software package, has been widely used for low- to medium-temperature geothermal resource assessment and management in Iceland, China, Turkey, Central America and other countries (Axelsson, et al., 2005). In lumped models, the hydrological properties of a reservoir are lumped together in one or two quantities for several sub-volumes of a reservoir. Axelsson (1989) presents the basic system equations, which describe the behavior of the general lumped parameter model as well as giving a general solution for the pressure response to variable production.

6.1.1 Model description

In its simple form, a lump parameter model can either be open or closed and consists of a few tanks and few resistors. The tanks simulate the storage capacity of different parts of a geothermal system and the water level or pressure in the tanks simulates the water level or pressure in corresponding parts of the system. A tank has storage coefficient (capacitance) κ when it responds to a load of liquid mass

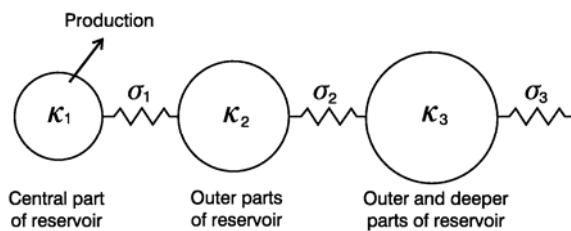


FIGURE 19: A simple open lump parameter model (Axelsson, 1989)

m with a pressure increase $p = m/\kappa$. The resistors (conductors) simulate the flow resistance in the reservoir. The mass conductance (inverse of resistance) of a resistor is σ when it transfers $q = \sigma \Delta p$ units of liquid mass, per unit time, at the impressed pressure differential Δp (Axelsson et al., 2005).

Figure 19 shows a simple open lumped parameter model with no connection to a constant pressure source (closed model).

6.1.2 Modelling results

A 60 month history of water level and production data of well KH-36 is used in the simulation. Different lumped parameter models were used to simulate the water level response data for this well from January 2000 to February 2005. The simulations were carried out automatically using different guesses for the expected model of the reservoir. Initial guess of the lumped model parameters was made using a one-tank closed model, and then the parameters were changed by an iterative process until a satisfactory fit was obtained between the observed and calculated data.

It was found that a two-tank closed model is the most reliable physical model that gives, to a certain degree, a convenient correlation and matching between the observed and calculated data. It should be mentioned here that a two-tank open model could not be reached in this simulation nor the three-tank models. Table 2 summarizes the different parameters obtained from the Lumpfit simulation for one-tank (closed and open) and two-tank closed models.

Figure 20 exhibits a comparison between the observed and simulated water level data for well KH-36, where reasonable matching is observed between the two dataset curves.

TABLE 2: Model parameters obtained by Lumpfit simulations of the production history of the Kaldárholt geothermal field

Parameters	One-tank closed	One-tank open	Two-tank closed
A_1	-	0.03884	0.53937
L_1	-	0.04742	1.47309
A_2	-	-	-
L_2	-	-	-
B	0.01669	-	0.00686
κ_1 (kg/Pa)	16102	6909.14	491.25
κ_2 (kg/Pa)	-	-	38605
σ_1 (kg/Pa-s)	-	0.1243×10^{-3}	0.2712×10^{-3}
σ_2 (kg/Pa-s)	-	-	-
Coff. of determ. (%)	31%	41.6%	59%

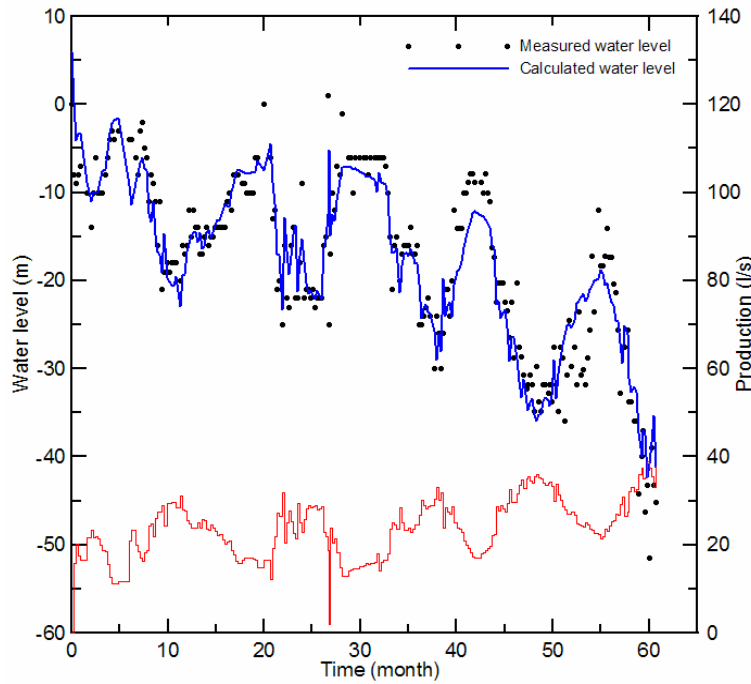


FIGURE 20: Water level changes in well KH-36 simulated by LUMPFIT with a two-tank closed model

6.1.3 Reservoir properties

Some average reservoir properties of the Kaldárholt geothermal field can be estimated using parameters derived from lumped parameter modelling (Table 2). Based on these parameters, the volume of reservoir tanks and their surface area can be estimated using the following equations;

$$V = \frac{\kappa}{\rho_w c_t} \quad (22)$$

$$A = V/h \quad (23)$$

Assuming two-dimensional (2-D) radial flow, an average permeability can be estimated using the following equation:

$$K = \frac{\sigma \ln(r_2 / r_1) \nu}{2\pi h} \quad (24)$$

where V = Reservoir volume (km^3);
 ρ_w = Water density (kg/m^3);
 C_t = Total compressibility (Pa^{-1});
 A = Surface area (km^2);
 r_1, r_2 = Inner and outer radii of the tanks;
 κ, σ = Capacitance and conductance of a resistor;
 ν = Kinematic viscosity (m^2/s);
 h = Thickness of the reservoir (km).

It is worth mentioning here, that the log-derived parameters are incorporated with the other parameters derived from the Lumpfit simulation, and integrated together while trying to characterize and interpret the reservoir properties of the Kaldárholt geothermal field.

From the previous well logging analyses and the interpretation of the different temperature data with respect to reservoir thickness, values of 11% and 500 m are used for the reservoir porosity and thickness, respectively. In addition, the rock compressibility and storativity for the reservoir (confined and unconfined), as concluded from studying the mechanical properties of the rocks, are directly involved in the interpretation. Average values of $0.26 \times 10^{-10} \text{ Pa}^{-1}$, $2.46 \times 10^{-7} \text{ Kg}/(\text{m}^3 \text{ Pa})$ and $3.1 \times 10^{-5} \text{ Kg}/(\text{m}^3 \text{ Pa})$, are used for the rock compressibility, confined and free-surface storativities, respectively. These values are assumed to be representative for the olivine tholeiite, which is the main rock unit prevailing in the study area. Table 3 summarizes the different reservoir properties obtained from Lumpfit modelling.

TABLE 3: Primary reservoir properties as estimated from lumped parameter simulation of the Kaldárholt geothermal field (Table 2)

Model	Property	First tank		Second tank	
		Storativity model		Storativity model	
		Confined	Unconfined	Confined	Unconfined
Two-tank closed model	Volume (km^3)	1.99	0.016	156.93	1.286
	Surface area (km^2)	4.18	0.034	328.11	2.69
	Permeability (m^2)	9.19×10^{-14}	9.19×10^{-14}	-	-

Considering the results in Table 3 and from a quick look interpretation of Figure 20, it is evident that although the Lumpfit model gives a fairly good match for the first and second tanks between the observed and calculated datasets, there are considerable differences between the estimated reservoir properties, based on the two storativity models. For example the volume of the first tank based on the unconfined storativity model is unrealistically small while the volume of the second tank assuming the confined storativity model is very large. From this information, it is concluded that the confined model of the first tank with a volume of 1.99 km^3 and surface area of 4.18 km^2 is reasonable. For the second tank, and according to the simulation results, the assumption was made that the storativity of this tank is controlled by a free-water surface, with a volume of 1.286 km^3 and surface area of 2.69 km^2 . So, it is believed that this tank represents the outer part of the reservoir which is connected to a free water surface and represents the main recharge area in the field. As a whole, the permeability appears to be high and in the order of $9.19 \times 10^{-14} \text{ m}^2$.

7. VOLUMETRIC HEAT RESOURCE ASSESSMENT

7.1 Volumetric analysis

Volumetric analysis of a reservoir involves computation of the total heat energy stored in a volume of rock as compared to a certain reference temperature. This will be the sum of the thermal energy stored in the rock matrix and the thermal energy of the fluid (water and/or steam) in the rock pore spaces. Beside the temperature and its related parameters, other important reservoir parameters (volume, porosity and density of both rock and water) must be determined first before assessing a thermal potential of the reservoir. The total stored heat energy in a reservoir volume can be estimated using the following equations:

$$E = E_r + E_w \quad (25)$$

$$E_r = V(1 - \phi) \rho_r C_r (T_i - T_o) \quad (26)$$

$$E_f = V \phi \rho_w C_w (T_i - T_o) \quad (27)$$

where E = Total thermal energy in the rock, E_r , and fluid, E_f (J);
 V = Reservoir volume (m^3);
 ϕ = Reservoir porosity (%);
 $\rho_{r,w}$ = Densities of rock and water (kg/m^3);
 $C_{r,w}$ = Heat capacities of rock and water ($J/kg^\circ C$);
 T_i = Initial reservoir temperature ($^\circ C$);
 T_o = Reference temperature ($^\circ C$).

Some principal reservoir parameters which are derived from the analyses of temperature and well logging data, and which can be used in thermal energy estimation, are represented in Table 4. According to these parameters, the stored heat energy of the Kaldárholt geothermal reservoir is estimated to be 1.16×10^{17} J.

TABLE 4: Reservoir parameters used for geothermal reserve estimation

Property		Unit	Value
Reservoir	Volume	km^3	2
	Porosity	%	11
Density	Rock	kg/m^3	2900
	Water	kg/m^3	980
Heat capacity	Rock	$J/kg^\circ C$	1000
	Water	$J/kg^\circ C$	4200
Temperature	Initial	$^\circ C$	68
	Reference	$^\circ C$	50

With the thermal energy of the reservoir, at hand, it is possible to calculate its thermal power potential as follows:

$$\text{Reservoir reserve (MWt)} = \frac{\text{Heat energy} \times \text{Recovery factor} \times \text{Conversion efficiency}}{\text{Plant life} \times \text{Load factor}} \quad (28)$$

By using the above equation, the thermal power potential of the Kaldárholt geothermal reservoir is found to be 7.4 MWt, assuming a recovery factor of 0.2, heat conversion efficiency of 0.5, plant life of 50 years and load factor of 0.95.

7.2 Monte Carlo simulation (probability method)

Computer simulation using the Monte Carlo method provides a powerful tool for analysis of parameters used in the volumetric analysis, not possible using traditional analytical approaches. The origin of the modern Monte Carlo methods stems from work on the atomic bomb during the Second World War where they were mainly used for numerical simulation of the neutron diffusion in fissile material, which is a probabilistic problem. Later on, it was realized that the Monte Carlo methods could also be used for deterministic problems (Sambridge and Mosegaard, 2002).

The use of Monte Carlo simulation in reserve estimation of a certain reservoir has become highly important, due to the uncertainties in determining some rock properties and the difficulties in measuring these parameters when the datasets are poor, incomplete and/or of poor quality. The

individual reservoir parameters, which are used for reservoir assessment and total thermal energy estimation, are further simulated in order to get more accurate distributions which should be representative for the reservoir model.

Monte Carlo is a random sampling method and requires a large sampling number N for accurate estimation. The algorithm relates and controls the uncertainty distributions of the individual parameters by a random number function (between 0 and 1) which performs numerous random iterations for each distribution. To generate a random real number between two parameters (a and b), the general RAND function is:

$$\text{RAND}() \times (b-a) + a \quad (29)$$

where a = Minimum value of certain reservoir property;
 b = Maximum value of certain reservoir property.

Using the RAND function, a matrix of $7 \times 10,000$ was constructed for the computation of the thermal reservoir reserves for the Kaldárholt geothermal field. Table 5 shows the parameters which are used in the calculation with their minimum and maximum values.

TABLE 5: Parameters of the Monte Carlo analysis for the Kaldárholt geothermal field, with the best guess values and their probability distributions

Property	Unit	Best guess model	Probability distribution		
			Type	Minimum	Maximum
Reservoir volume	km ³	2	square	1	3
Rock density	kg/ m ³	2900	triangular	2700	3100
Water density	kg/ m ³	980	square	950	1000
Porosity	%	11	triangular	4	20
Rock heat capacity	J/kg°C	1000	constant	-	-
Water heat capacity	J/kg°C	4200	constant	-	-
Reservoir temperature	°C	68	square	66	72
Reference temperature	°C	50	constant	-	-
Recovery factor	%	0.20	constant	-	-
Conversion efficiency	%	0.5	constant	-	-
Plant life	Year	50	constant	-	-
Load factor	%	0.95	constant	-	-

Two randomness methods are assigned in this study; the first is the squared distribution (normal) which is used to describe the possible distribution of a certain parameter within defined limits. The second is the triangular distribution which describes the distribution within a range or limits (high and low). Then, the best guess values of the different reservoir parameters are further used for calculating the thermal reservoir reserve using Equations 27 and 28.

Figures 21 and 22 represent the histogram probability distribution and the cumulative occurrence of the power potential production in the Kaldárholt geothermal field. The histogram shows that the range of the probability is between 3 to 13 MWt. It appears clear that a value from 6.5 to 8.5 MWt is the most likely range for the reserve (chance > 24 %) and that there is a 7% chance for the reserve being less than 5 MWt and 5% chance for the reserve to be more than 11 MWt. The cumulative occurrence curve shows a range of 32-82% for the most likely range of the reserve (6.5 to 8.5 MWt).

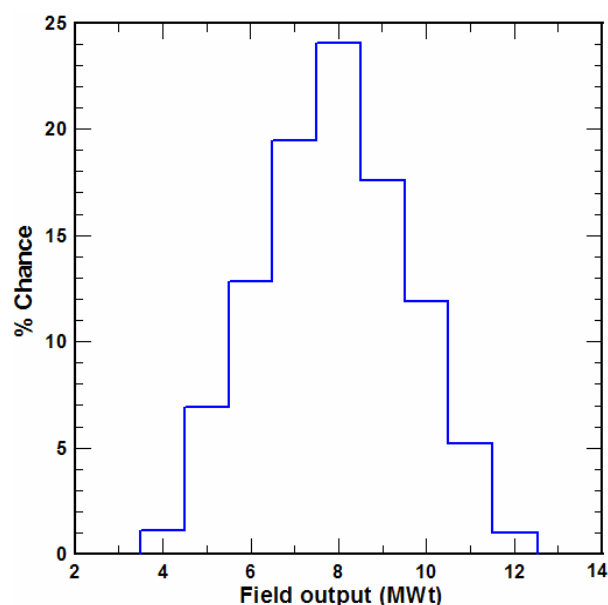


FIGURE 21: Histogram distribution of the available power potential in the Kaldárholt field

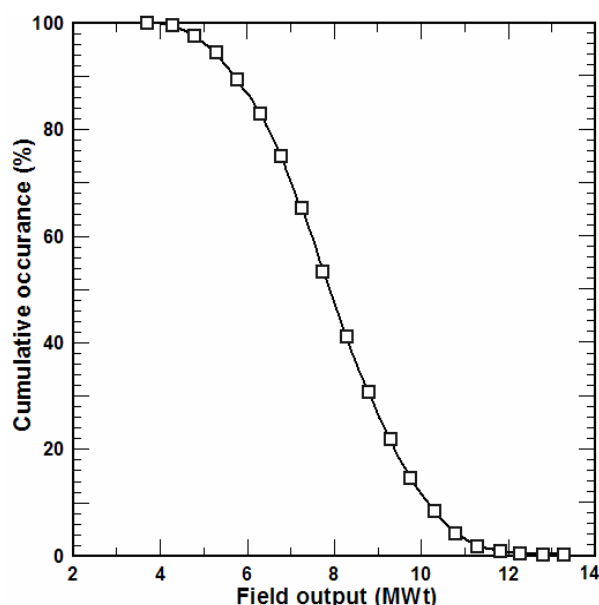


FIGURE 22: Cumulative occurrence curve for the available power potential in the Kaldárholt field

8. SUMMARY AND CONCLUSIONS

The Kaldárholt field is among the most important low-temperature geothermal fields located in S-Iceland. The aim of this study was to estimate reservoir parameters using well logging data and production history of the field.

For this purpose, complete analyses of available temperature, logging and production history data are carried out using different approaches. An inversion modelling technique (calibrated with actual petrophysical core data) is applied to detect and predict sonic travel time and rock density, the parameters necessary for estimating the mechanical properties of the rocks. In addition, acoustic televiewer data are interpreted in order to locate different fractures and identify their dip and azimuth.

The interpretation of temperature logs and drawing of cross-sections indicates that the temperature of the upflowing water is about 67°C. The geothermal gradient is relatively high in this area and ranges between 0.12 and 0.16°C/m.

From the well logging analyses, it is found that the porosity in the Kaldárholt system ranges from 5% to 20%. The density increases in tholeiite rock units reaching more than 2.90 g/cm³, while in acidic tuff it decreases to less than 2.70 g/cm³. Rock unit identification in relation to fractures and feed zones is performed through different rock typing techniques. Synthetic seismic trace (normal and reverse polarities), reflection coefficient, filtered gamma ray and stack log pattern, are the most useful rock type indicators.

In most cases, a well-recognized negative synthetic seismic trace is observed in front of feed zones, identified from temperature logs and the possible fracture systems. This phenomenon can be further used to differentiate between the open and closed nature of these fractures. The stack log pattern assigns thin rock units in front of these zones, while the reflection coefficient gives negative values. This means that there is a velocity transform from high-speed layers above to a low-speed fracture or feed zone below. Furthermore, artificial neural networks (ANN) are applied to predict porosity and silica content. Two small models are designed using standard techniques. The predicted values fit

very well with the results obtained from conventional well logging analyses, with a correlation coefficient of more than 98%.

The possible fracture system in the study area is investigated using two different techniques. The first is conducted by analyzing the stress/strain ratios acting on the different rock units and their effect on the mechanical properties of the reservoir rocks. The second employs detailed analyses of acoustic televiewer data. In this respect, the different elastic constants are estimated and interpreted in conjunction with other logging and lithological data. It is found that bulk modulus correlates well with the different rock units especially for tholeiite, where it exhibits very high values or up to 9×10^6 psi (6.3×10^{10} Pa). Biot elastic constant tends to be positive for breccia, lava and crushed materials, which means a very good chance for the lateral flow of fluids. A relative increase in the velocity ratio (V_s/V_p) is observed at these zones, a sensible result if compared with the negative synthetic seismic trace.

From the analysis of the amplitude, travel time and breakout data, it is noticed that the majority of the fracture and structure systems encountered in the study area are oriented along an NNE-SSW direction with high near-vertical dip angles for the fractures and low dipping in the bedding and intrusions.

Lumped parameter modelling is used to simulate the changes in the water level and production history of the field. A two-tank closed model is considered the “best” model, giving the most reliable estimation of the reservoir volume and permeability. The modelling results indicate that the permeability is very good and the storativity of the reservoir is relatively high compared with other low-temperature systems in S-Iceland. In addition, a geothermal resource assessment was carried out using the volumetric method and Monte Carlo simulation. The volumetric calculations give an average value of 7.4 MWt, while the probability method gives a range of 6.5-8.5 MWt for the most likely value for the reserve (with a probability of more than 24%).

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