

Relative Permeability Measurements and Comparison to Field Data

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ABSTRACT

Laboratory experiments were made where two phase mixture of flashed geothermal brine was injected into a tube filled with porous material. Direct measurements of pressure gradient and mass flow were made and used for calculating the relative permeabilities of the two phases. The results were compared with relative permeabilities calculated from field data using the Shinohara method. The resulting relative permeabilities comply with known relative permeability curves to some extent, where the intrinsic permeability of the porous media accounts for the greatest error factor in the measurements.

1. INTRODUCTION

The flow of a geothermal fluid through a reservoir resembles flow through porous material using Darcy's law as one of the governing equations. In reality, the geothermal reservoirs normally consist of fractured rock with inhomogeneous permeability of a fractured matrix (Grant and Bixley, 2011). On a macroscopic scale, the porous media assumption seems appropriate (Chen et al., 2004) (Chen and Horne, 2006) and it is conventionally used to describe flow in geothermal reservoirs (Chen, 2005). In general, for the common type of liquid dominated reservoirs (Axelsson, 2008), the geothermal fluid exists either as a single liquid phase or a mixture of liquid and vapor. The geothermal fluid contains dissolved gasses and solids (Arnórsson et al., 2007), but is generally considered to be pure water or steam when its flow through the permeable matrix is simulated (O'Sullivan et al., 2001). The two phase flow of water and steam occurs under different conditions. If the reservoir is liquid dominated, boiling can occur and a two phase mixture is formed (Axelsson, 2008). Such a system as suggested by White (1967) can be described as a conceptual model, shown in Figure 1a. In the figure the heat source is assumed to be a magma intrusion at few kilometers depth, conducting heat through an impermeable layer to the porous and fractured matrix above. Another mechanism resulting in two phase flow is where production wells are used to extract fluid from the reservoirs for utilization. When the fluid is extracted through the wells, flashing occurs due to pressure drop in the well. The high enthalpy fluid reaches saturation through the pressure reduction and steam begins to form. The flashing horizon (the point where flashing starts) may either begin in the well or in the porous surroundings where the fluid is approaching the well (DiPippo, 2008). The geothermal reservoir and the well are shown in Figure 1b.

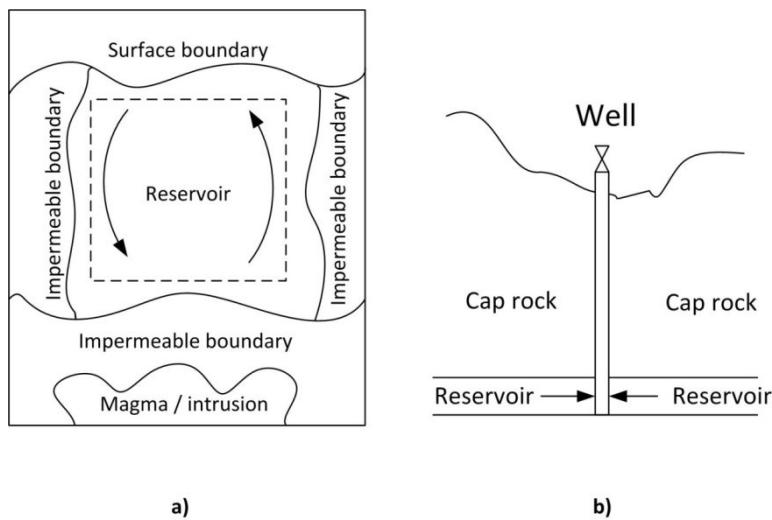


Figure 1 a) Convective system representing a volcanic geothermal reservoir. **b)** Geothermal well drilled into a reservoir, causing fluid to flow through the fractured reservoir into the well.

When two phase flow through a porous matrix has a very low velocity with low Reynolds numbers, Darcy's law is applicable (Todd and Mays, 2005). Note that Darcy's original law represents a single phase flow but an adaptation to a multiphase flow is possible by using the concept of relative permeability. Several relations for relative permeabilities are found in the literature (Pruess et al., 1999), (Kipp et al., 2008), normally showing them as functions of the water saturation, that is the portion of the total pore space in the flow channel occupied by water. These relations have been found experimentally and many of them originate from the oil and gas research and industry where the two phases are different immiscible substances rather than a single substance, but have also been adapted to geothermal reservoirs. The relative permeabilities are important parameters in reservoir modeling. They are not

only used to calculate the mass flux or the velocity of the phases but also for estimating thermodynamic and transport properties and can affect the parameters related to the reservoir performance significantly (Bodvarsson et al., 1980). A number of relative permeability functions used in the numerical reservoir simulator TOUGH2 (Pruess et al., 1999) are listed in Table 1 and indicate the wide range of relative permeability functions used in practice in such simulators. The relative permeability functions in Table 1 are presented as functions of the normalized water saturation, S_{wn} which defines the mobile region of the phases.

Table 1: Sets of relations for relative permeabilities as functions of normalized water saturation (Pruess et al. 1999)

Name	k_{rw}	k_{rs}
X – Curves	$k_{rw} = S_{wn}$	$k_{rs} = 1 - S_{wn}$
Corey curves (1954)	$k_{rw} = S_{wn}^4$	$k_{rs} = (1 - S_{wn})^2(1 - S_{wn}^2)$
Grant's curves (1977)	$k_{rw} = S_{wn}^4$	$k_{rs} = 1 - k_{rw}$
Functions of Fatt and Klikoff (1959)	$k_{rw} = S_{wn}^3$	$k_{rs} = (1 - S_{wn})^3$
Functions of Verma et al. (1985)	$k_{rw} = S_{wn}^3$	$k_{rs} = 1.259 - 1.7615S_{wn} + 0.5089S_{wn}^2$

When results of steam and water flow are compared to nitrogen-water flow or air-water flow using the same experimental setup, the relative permeabilities for the steam phase seem to be higher than for the nonwetting phase at the same water saturation for the air water and nitrogen water experiments (Chen, 2005) (Chen et al., 2007). This indicates that the boiling mechanism induces the flow of steam where in absence of boiling the two phases seem to restrain the flow of each other to a greater extent. Thus more information is needed regarding the two phase flow of water and steam in porous medium. The purpose of this study is to address this need by designing an experiment where two phase mixture of a geothermal fluid is injected into relatively large tube filled with porous material. The dimensions of the tube were selected to reduce the end and wall effects of the device. The conditions may therefore to some extent resemble a geothermal reservoir better than in many of the previous experiments using smaller diameter tubes.

Previous results from steam water experiments have shown that there is no set of relative permeability curves which is applicable for all flow cases (Verma, 1986), (Sanchez and Schechter, 1990), (Piquemal, 1994), (Ambusso, 1996), (Satik, 1998), (Mahiya, 1999), (O'Connor, 2001). When modeling the two phase flow of water and steam, an arbitrary curve has to be selected for the relative permeability curves and in reservoir modeling tools like TOUGH2 and HYDROTHERM various relative permeability functions can be selected (Pruess et al., 1999), (Kipp et al., 2008). Furthermore, the relative permeabilities can not be determined directly since the water saturations are normally not known for the reservoirs. However, the relative permeabilities can be estimated by applying a method introduced by Shinohara (1978). That method uses the flow discharge and enthalpy from a well for a specific production history and the corresponding wellhead or downhole temperature to determine fluid properties that are used to evaluate the relative permeabilities for downhole two phase reservoir conditions. Another method by Grant (1977) was defined to determine the relative permeabilities from field data, using discharge and enthalpy measurements from the wellbores followed by improved analysis by Horne and Ramey (1978). Reyes et al. (2004) applied the Shinohara method on production data from two geothermal fields. They also used the method on laboratory results from Chen (2005) where the relative permeabilities for water and steam were calculated using two different methods. One where the water saturations were directly measured, and the other where the Shinohara method was applied. There was a very small difference between the values calculated using the two different methods.

In this paper, the Shinohara method for quantifying relative permeabilities is derived from Darcy's law and then applied to well data from geothermal fields in Iceland. The purpose of this study is also to use this method on field data and to derive the relative permeabilities of the reservoir fluid which flows to the wells located in the fields. The results are also compared to laboratory measurements. This method allows the relative permeabilities to be calculated without direct measurements of the water saturation and the results can be used for modeling the reservoir, using only information from wells.

2. METHODS AND MATERIALS

2.1 Darcy's Law and Relative Permeabilities

Darcy's law was first discovered empirically by the French hydrologist Henry Darcy in 1856 (Darcy, 1856). It is applicable to laminar flow with low Reynolds numbers and is given by Eq. (1) for flow of a single phase fluid.

$$\vec{q} = -\frac{k}{\nu}(\nabla p - \rho \vec{g}) \quad (1)$$

where \vec{q} is the fluid mass flux (mass flow per unit area), k is the intrinsic permeability of the porous matrix, ν is the kinematic viscosity of the fluid, ∇p is the pressure gradient, ρ is the fluid density and \vec{g} is the gravitational acceleration. The intrinsic permeability is usually determined experimentally and then it can be more convenient to use the mass flow definition, \dot{m} , where Eq. (1) becomes:

$$\dot{m} = -\frac{k}{\nu} A \vec{n}(\nabla p - \rho \vec{g}) \quad (2)$$

where \vec{n} is the unit normal to the cross sectional area A of the permeable flow channel. When two phases are present and flowing simultaneously, as is the case of water and steam in high enthalpy geothermal reservoirs, the intrinsic permeability alone is not sufficient to describe the flow in the porous matrix. An area reduction factor is applied in the Darcy's law and two versions of Eq. (2) are presented, one for each phase. Then, the concept of relative permeabilities, k_r is introduced as shown in Eqs (3) and (4):

$$\dot{m}_w = -\frac{k k_{rw}}{v_w} A \vec{n} \cdot (\nabla p - \rho_w \vec{g}) \quad (3)$$

$$\dot{m}_s = -\frac{k k_{rs}}{v_s} A \vec{n} \cdot (\nabla p - \rho_s \vec{g}) \quad (4)$$

where the subscripts w and s specify the water and steam phase respectively. The relative permeabilities are usually presented as functions of local water saturations, which are defined as the following volume fraction in Eq. (5).

$$S_w = \frac{V_w}{V_w + V_s} \quad (5)$$

where V_w and V_s are the volumes occupied by water and steam respectively. In real geothermal applications, it can be difficult to determine the local water saturation in the flow channel. Nevertheless, the flowing saturation can be defined as in Eq. (6).

$$S_{w,f} = \frac{\dot{V}_w}{\dot{V}_w + \dot{V}_s} = \frac{(1-x)v_w}{(1-x)v_w + x v_s} \quad (6)$$

where \dot{V}_w and \dot{V}_s are the volumetric flow rates of water and steam respectively and v_w and v_s are the specific volumes of water and steam respectively and x is the steam fraction as defined in Eq. (7).

$$x = \frac{\dot{m}_s}{\dot{m}_s + \dot{m}_w} \quad (7)$$

When the local water saturation, S_w , is not known the relative permeabilities can be determined experimentally by using Eqs (3) and (4). Then the mass flow needs to be measured experimentally as well as the fluid's thermodynamic state (pressure, enthalpy) and the pressure gradient through the porous sample with the known intrinsic permeability k . The relative permeability can then be determined from Eqs. (8) and (9).

$$k_{rw} = -\frac{\dot{m}_w v_w}{k A \vec{n} (\nabla p - \rho_w \vec{g})} \quad (8)$$

$$k_{rs} = -\frac{\dot{m}_s v_s}{k A \vec{n} (\nabla p - \rho_s \vec{g})} \quad (9)$$

In real applications like when fluid flows to wells, the water saturation used to determine the relative permeabilities in Eqs (8) and (9) as well as the pressure gradients are unknown quantities. For determining the relative permeabilities for such cases, the so called Shinohara method can be applied as described in the following section.

2.2 The Shinohara Method

A method introduced by Shinohara (1978) is presented here, which enables the determination of the relative permeabilities of water and steam in a geothermal reservoir using production history and enthalpy measurements for a geothermal well. Using Eqs (10) and (11) (assuming one dimensional, horizontal flow, neglecting gravity effect and rearranging terms) we get the following:

$$k_{rw} = -\frac{\dot{m}_w v_w}{k A \nabla p} = \frac{\dot{m}_w v_w}{Q^* v_s} \quad (10)$$

$$k_{rs} = -\frac{\dot{m}_s v_s}{k A \nabla p} = \frac{\dot{m}_s}{Q^*} \quad (11)$$

Where:

$$Q^* = -\frac{k A \nabla p}{v_s} \quad (12)$$

The total mass flow, \dot{m}_t of the two phase mixture according to Eqs (3) and (4) is:

$$\dot{m}_t = \dot{m}_w + \dot{m}_s = -k A \nabla p \left(\frac{k_{rw}}{v_w} + \frac{k_{rs}}{v_s} \right) = -k A \nabla p \left(\frac{k_{rw}}{v_w} \frac{v_s}{k_{rs}} + 1 \right) = Q^* k_{rs} \left(\frac{\dot{m}_w}{\dot{m}_s} + 1 \right) \quad (13)$$

When applying the Shinohara method on the well data from a geothermal field, the total discharge \dot{m}_t has to be known. Furthermore to determine the mass flow ratio \dot{m}_w/\dot{m}_s at downhole conditions the enthalpy of the fluid h_t has to be known. The steam fraction of the two phase mixture is determined by Eq. (14).

$$x = \frac{h_t - h_w}{h_s - h_w} \quad (14)$$

where h_w and h_s are the saturation enthalpies of water and respectively. The steam fraction in the two phase reservoir from Eq. (7) can then be used to determine the mass flow of each phase in the reservoir to the well using the total flow rate \dot{m}_t as seen in Eqs (15) and (16).

$$\dot{m}_w = (1 - x)\dot{m}_t \quad (15)$$

$$\dot{m}_s = x\dot{m}_t \quad (16)$$

Now if $\dot{m}_w = 0$ then $k_{rs} = 1$ and according to Eq. (13) Q^* can be found plotting \dot{m}_t against \dot{m}_w/\dot{m}_s and noting that Q^* is the intercept to y-axis of the regression line. The assumptions made for using the Shinohara method on a geothermal well to determine the relative permeabilities of the two phases in the reservoir, are the following (Shinohara, 1978):

- The pressure gradient is constant for a short time for each well
- The product of permeability and flowing area, kA is constant for each well
- Wellhead steam and water discharges are the same as downhole values, thus neglecting flashing of fluid in the wellbores
- Fluid flows in the reservoir according to Darcy's law
- Flashing in the reservoir is neglected

Also, it is assumed that the flow in the two phase reservoir is horizontal, that is without effect from gravity. If the downhole properties (that is the temperature and therefore the fluid viscosity and density) are known, a correction can be made for applying the downhole conditions by estimating the steam fraction, x , at the bottom of the well at the given enthalpy h , which is assumed to be constant in the well. Thus a better approximation for the mass flow ratio is gained for the downhole conditions based on the estimated steam fraction. By obtaining Q^* from Eq. (12) and plotting \dot{m}_t against \dot{m}_w/\dot{m}_s as well as knowing the total flow and the mass fraction (which can be determined if the total enthalpy of the flow is known), k_{rw} and k_{rs} can be determined according to Eqs (10) and (11). For the laboratory data obtained by (Chen, 2005) the water saturations, S_w and the flowing water saturations $S_{w,f}$ were both known and the correlation in Eq. (17) was gained (Reyes et al., 2004).

$$S_w = 0.1152 \ln(S_{w,f}) + 0.8588 \quad (17)$$

By using Eq. (17) it is possible to estimate the local water saturation from the flowing water saturation and to compare the values to known relative permeability curves.

2.3 Laboratory Measurements

The relative permeabilities from the field data were compared to data collected from laboratory experiments. In those experiments the relative permeabilities were determined for a two phase flow of water and steam flowing through porous material. The device used for the experiment consisted of a steel pipe with 10 inch diameter and 4 m length. Two types of porous filling material were used, each which had different intrinsic permeability. The fluid used for the experiments was of geothermal origin, and was separated water from Reykjanes Power Plant in Iceland. By using geothermal fluid instead of pure water, conditions of the geothermal reservoirs could be resembled to some extent. The experimental setup is shown in Figure 2.

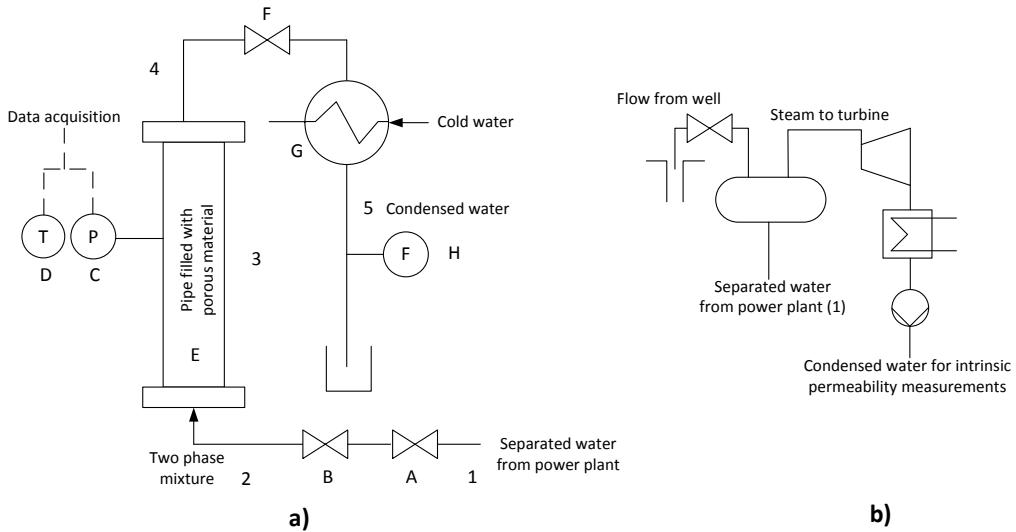
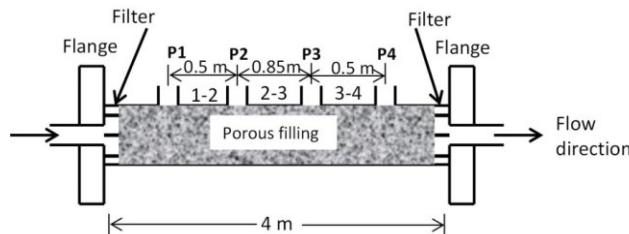


Figure 2: a) A simplified process diagram showing the main components and fluid states in the measurement device designed and constructed for this study. The components are described in Table 2. b) A simplified process diagram of the power plant where fluid was extracted from for the measurements

The separated geothermal water was flashed before entering the inlet to the pipe thus creating a two phase mixture of water and steam. The enthalpy of the fluid was determined using the Lovelock method (Lovelock, 2001). By measuring the pressure at several locations in the flow channel (see Figure 3) and the total mass flow and knowing the total enthalpy and thereby the steam fraction, the relative permeabilities could be calculated from Eqs. (8) and (9). In all those calculations thermodynamic data from the IAPWS database was used (IAPWS, 2007) to determine the fluid properties. The geothermal fluid contains dissolved gasses and minerals which might affect the thermodynamic properties of the fluid. However, in geothermal modeling, the properties of pure water are generally used as properties for the fluid (O'Sullivan et al., 2001).

Table 2: Description of the components of the measurement device referring to Figure 2. D: diameter, t:thickness, L:length

Component	Component name	Description
A	Stop valve	D=1 inch
B	Throttle valve	D=1 inch
C	Pressure sensor	tecsis, Type P3276B078001
D	Temperature sensor	Thermocouple
E	Pipe filled with porous material	D=10 inch, t=5mm, L=4 m
F	Back pressure valve	D=1 inch
G	Condenser/cooler	Heat exchanger
H	Flow meter	Mass and time measurement

**Figure 3: Location of pressure sensors on the measurement device**

2.4 Field Data

The Shinohara method was applied to data from three Icelandic geothermal fields. Reykjanes, Nesjavellir and Hellisheiði. Available data on well discharge and enthalpy were used to calculate the relative permeabilities for the downhole two phase reservoir flow for each well used in the study. The enthalpy measurements were made with tracer analysis (Hirtz et al., 2001) (Lovelock, 2001). The mass flow and enthalpy were known from the wellhead condition and downhole temperature was determined from temperature profiles from the wells. It is important for this method to use as accurate temperature values as possible for the reservoir fluid since the relative permeabilities depend on the viscosities (see Eqs (10) and (11)) which can be highly temperature dependent.

3. RESULTS

Direct measurements of pressure and mass flow were made for flow of two phase water and steam as described in Section 2.3. Before being able to calculate the relative permeabilities in Eqs (8) and (9), the intrinsic permeability, k , was calculated from the measured values of water phase only. Figure 4 shows the resulting relative permeabilities for water and steam from the measurements described in Section 2.3 when the relative permeabilities for both phases are plotted on the same graph. The measurements were made for horizontal and vertical flow directions and for two types of filling material, sand and sand/gravel mixture. Different flow cases are indicated with different legends in Figure 4.

The flowing saturations were calculated and the relative permeabilities plotted as function of them. Figure 5 shows the relative permeabilities from Figure 4 when the calculated flowing water saturations have been inserted into Eq. (17) to estimate the actual water saturation.

Figure 6 to Figure 8 show the results of relative permeability calculations for the wells at the three geothermal fields in Iceland. Figure 6 shows the results for Reykjanes, Figure 7 for Hellisheiði and Figure 8 for Nesjavellir.

Figure 9 shows the results of the field relative permeabilities as calculated using the Shinohara method together with the calculated relative permeabilities from measurements shown in Figure 4. Figure 10 shows the relative permeabilities for both the measured values and the field data when the actual water saturation was calculated using Eq. (17).

4. DISCUSSION

The results from the laboratory experiments do not show clearly which relative permeability curve is the most suitable but rather form a cluster of data points as shown in Figure 4. The reason for this variance can be due to variations in intrinsic permeability. This variation is larger for the material containing larger grain size (sand and gravel). The variance in the intrinsic permeabilities may be due to the fact that some of the smaller particles in the filling were washed out through the filter holding the porous material in place, thereby increasing the intrinsic permeability between runs. Another factor affecting the intrinsic permeabilities is the silica content of the fluid, since the silica precipitates with decreasing pressure. That effect could have resulted in a decrease in intrinsic permeabilities in some cases. However, from Figure 5 it is clear that the relative permeabilities show curvilinear behavior to the water saturation. This applies both for the laboratory data as well as the field data as seen in Figure 10. The relative permeabilities from the Reykjanes wells show better correlation to known relative permeability curves than the Hellisheiði wells which are scattered. In Figure 6 and Figure 7 the results divide into two groups, one group following the Verma curve to some extent and the other follow the Corey curve to some extent. From that it can be concluded that the wells in the same geothermal systems can follow different relative permeability curves.

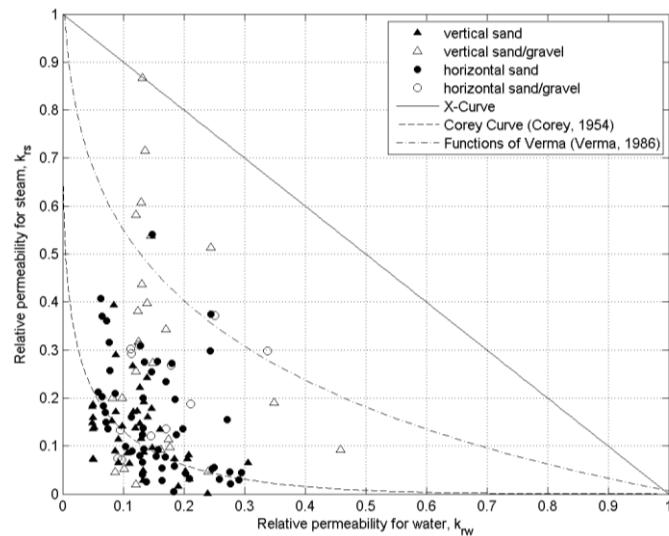


Figure 4: The calculated relative permeabilities from measurements

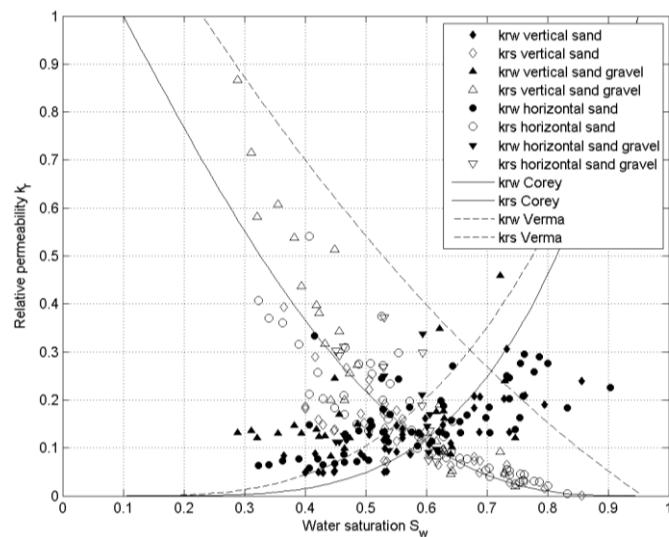


Figure 5: The calculated relative permeabilities as functions of the local saturation, gained from Eq. (17) for all four flow cases. For the Corey and the Verma Curves, $S_{wr}=0.1$ and $S_{sr}=0.05$

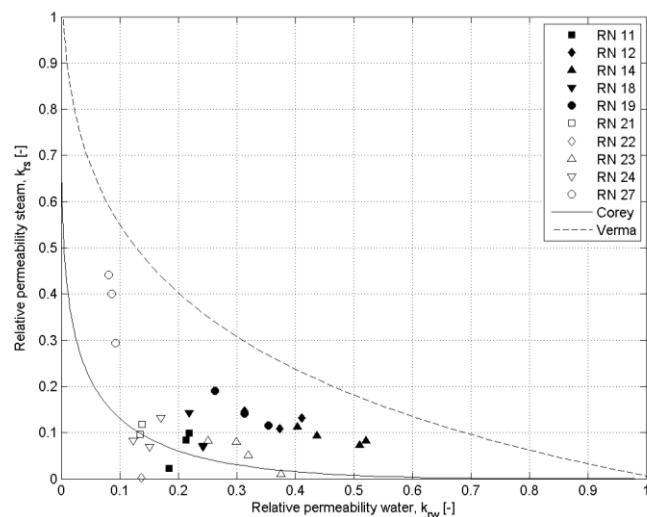


Figure 6: Relative permeabilities from Reykjanes wells calculated with the Shinohara method as well as the Corey curve (Corey, 1954) and Functions of Verma (Verma, 1986)

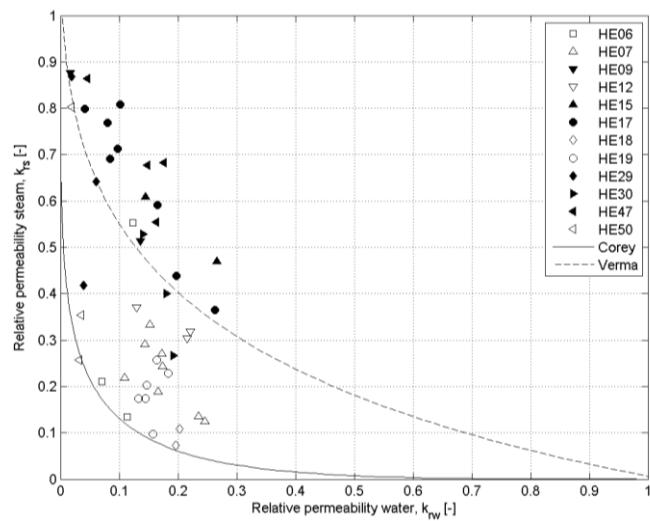


Figure 7: Relative permeabilities from Hellisheiði wells calculated with the Shinohara method as well as the Corey curve (Corey, 1954) and Functions of Verma (Verma, 1986)

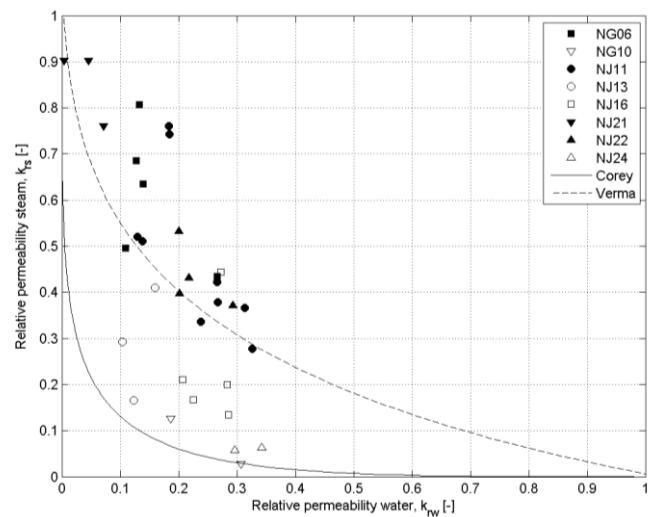


Figure 8: Relative permeabilities from Nesjavellir wells calculated with the Shinohara method as well as the Corey curve (Corey, 1954) and Functions of Verma (Verma, 1986)

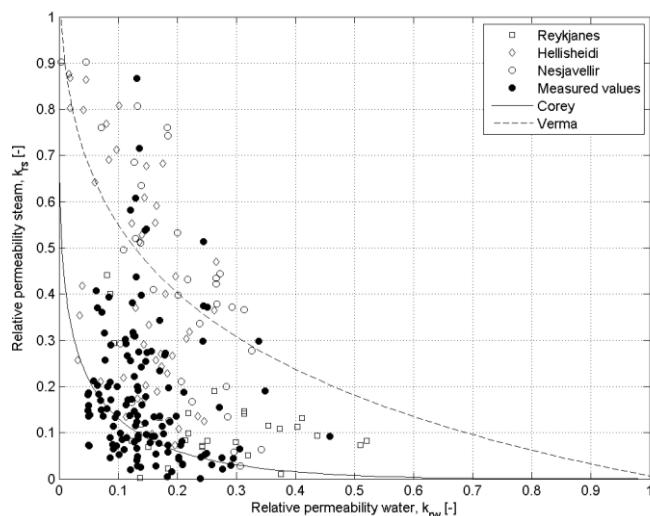


Figure 9: Comparison of measured values from laboratory measurements and data from geothermal wells as well as the Corey curve (Corey, 1954) and Functions of Verma (Verma, 1986)

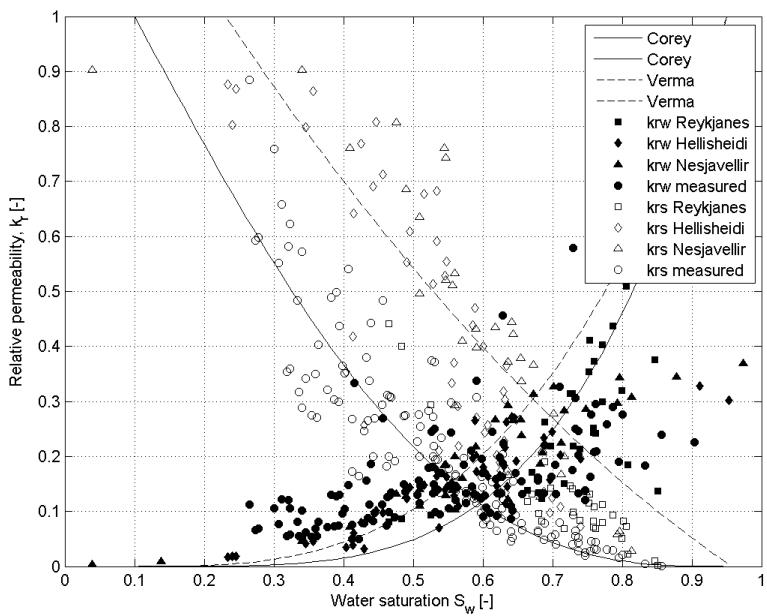


Figure 10: The relative permeabilities as functions of the actual water saturation together with the Corey curve (Corey, 1954) and Functions of Verma (Verma, 1986)

5. CONCLUSIONS

Darcy's law and the relative permeability theory have been applied both to field data and to data from laboratory measurements. The objective of this study was to calculate the relative permeabilities from measured values and to use the Shinohara method to estimate relative permeabilities of field data without information about the water saturation needed. The following conclusions can be drawn from this study:

- The conditions in the experiments are likely to resemble the flashing of geothermal fluid from water phase to steam phase as occurs in liquid dominated systems
- The Shinohara method could be applied using data from the three geothermal under consideration, since all the relevant data was available
- The relative permeabilities for water of both the laboratory and the field data show less interaction than the Corey curves do at low water saturation, but more interaction for higher water saturations
- The Hellisheiði and the Nesjavellir wells do follow different curves, indicating that wells within the same geothermal reservoir can follow different relative permeability curves
- When modeling geothermal reservoirs, a careful selection of the relative permeability curves has to be made, since according to the calculations for Hellisheiði and Nesjavellir, the wells within the same system can follow different relative permeability curves
- The relative permeabilities calculated from measured values and field data show smaller values than the linear curves do, therefore they indicate an interaction between the two phases
- In real geothermal reservoirs, the intrinsic permeabilities can hardly be considered constant, therefore reservoir behavior resembling the results shown for the laboratory values might be expected for real geothermal cases

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