PERMEABILITY PREDICTION FROM MERCURY INJECTION CAPILLARY PRESSURE: AN EXAMPLE FROM THE PERTH BASIN, WESTERN AUSTRALIA

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ABSTRACT

For shale gas reservoirs, permeability is one of the most important—and difficult—parameters to determine. Typical shale matrix permeabilities are in the range of 10 microdarcy–100 nanodarcy, and are heavily dependent on the presence of natural fractures for gas transmissibility. Permeability is a parameter used to measure the ability of a rock to convey fluid. It is directly related to porosity and depends on the pore geometry features, such as tortuosity, pore shape and pore connectivity. Consequently, rocks with similar porosity can exhibit different permeability.

Generally, permeability is measured in laboratories using core plugs. In some cases, however, it is difficult to obtain suitable core plugs. In these instances, other approaches can be used to predict permeability, which are chiefly based on mathematical and theoretical models. The approach followed in this peer-reviewed paper is to correlate permeability with capillary pressure data from mercury injection measurements. The theoretical and empirical equations, introduced in the literature for various conventional and unconventional reservoir rocks, have been used to predict permeability. Estimated gas shale permeabilities are then compared with results from transient and steady state methods on small pieces of rocks embedded in a resin disk. The study also attempts to establish a suitable equation that is applicable to gas shale formations and to investigating the relationship between permeability and porosity.

KEYWORDS

Permeability, shale, mercury injection capillary pressure (MICP), porosity, pore size distribution, steady state, unsteady state.

INTRODUCTION

Typical shale gas matrix permeabilities are in the range of 10 microdarcy—100 nanodarcy, and are heavily dependent on the presence of natural fractures for gas transmissibility. Permeability is a parameter used to define, or measure, the ability of a rock to convey fluid. It is directly related to porosity and depends on the pore geometry (Fredrich et al, 1993). Consequently, rocks with similar porosity can exhibit different permeability (Costa, 2006).

In reservoir rocks, the pores are connected by pore throats and each pore is accompanied by a certain range of throat sizes. A common technique in evaluating a number of petrophysical properties of a reservoir rocks is by measuring its capillary pressure. Capillary pressure and permeability are measured in laboratories using core plugs. In some cases, however, it is difficult to obtain suitable core plugs. In these instances, other approaches can be used to predict permeability and capillary pressure to provide an insight into the petrophysical properties; such approaches are based on empirical and theoretical models.

Core analysis, under ambient or reservoir conditions, is a common method for direct measurement of permeability. Because of their high costs, only a limited number of core analyses are done for any particular field, although cuttings are available in almost all wells. The mercury injection technique may be used with well cuttings, or chips (Jennings, 1987). As the reservoir properties—such as porosity and permeability—are controlled by the size and arrangement of pores and throats, the mercury injection method is commonly employed to characterise pore size distribution and permeability in porous media (Swanson, 1981b; Katz and Thompson, 1986; Pittman, 1992; Kale et al, 2010; Kamath et al, 1998; Shouxiang et al., 1991; Owolabi and Watson, 1993; Purcell, 1949). As most studies have been for sandstones, there is a lack of comprehensive studies for shale.

To bridge the information gap, this peer-reviewed paper will determine the applicability of the various models to estimate permeability from mercury injection measurements for shale gas samples. The authors assessed eight samples from one well, at various depths, in the Perth Basin. Predicted mercury injection capillary pressure (MICP) permeabilities are compared with those measured using transient and steady state techniques on small pieces of rock embedded in a resin disk. Models evaluated in this study include the Kozeny-Carman (Wylllie and Gregory,1955) and Swanson (1981), Winland (Kolodzie, 1980), Jorgensen (1988), Pape et al (1999), Rezaee et al (2006), Katz-Thompson (1986), Pittman (1992) and Dastidar et al (2007) methods.

The key objectives of the study are to compare the results of the MICP permeability prediction methods versus laboratory measured permeabilities, and to develop an improved relationship between permeability and pore throat size.

Reservoir description

The Perth Basin is a 100,000 km^2 area covering the Western Australian margin between Augusta and Geraldton. The Northhampton block is north of the basin, and the north-south trending of Darling Fault is east.

The samples in this study are from the Carynginia Formation and are classified as claystone. X-ray diffraction (XRD) analysis indicates a composition of 63% non-clays and 37% clays. Figure 1 summarises the average percentage of the minerals present in the samples.

Mercury porosimetry

The technique involves the intrusion of mercury (non-wetting liquid) at a high pressure into a porous material, through the use of a special assembly called a penetrometer. The pressure is

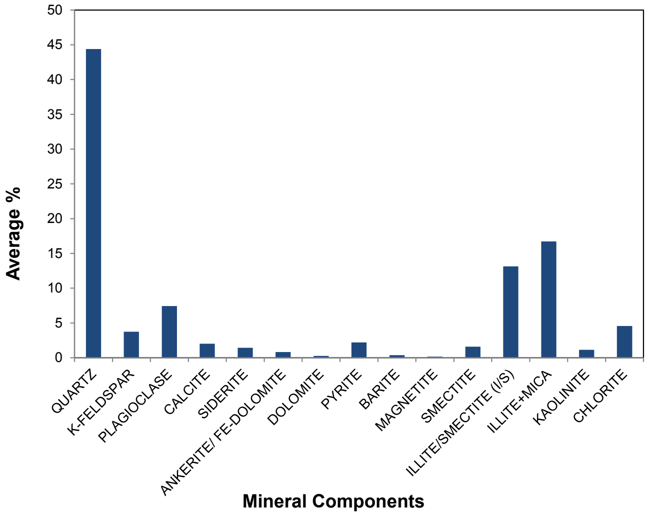

Figure 1. The average weight percentage of mineral composition of the samples in study.

applied at constant rate (pressure steps between 5–60,000 psi) and the volume of the injected mercury is measured at each pressure increment. The pore throat radius can be found from the entry pressure at the beginning of the sudden pressure drop using an equation derived by Washburn (1921):

$$P_c = \frac{-2\sigma \cos\theta}{r_c} \tag{1}$$

In Equation 1, P_c is the mercury entry pressure; σ is the mercury interfacial tension, θ the contact angle, and r_c is the radius of the pore that has been intervened by the mercury.

PERMEABILITY MEASUREMENTS

Liquid or gas can be used to measure permeability in laboratories on core plugs. Gas is usually preferred as the sample preparation is relatively simpler and the measurement duration much shorter; however, gas slippage occurs at low average pressure, causing Darcy's Law to produce high permeability values, requiring a Klinkenberg correction. The corrected permeability is then termed liquid permeability or Klinkenberg permeability.

Both steady and unsteady state methods are used as outlined by Luffel (1993). Permeability measurements are done using resin disks, where a piece of the rock is embedded in resin (Egermann et al, 2004; Egermann et al, 2006; Lenormand and Fonta, 2007; Lenormand et al, 2010). For rocks with permeabilities more than one millidarcy (mD), the initial coating is done with a high viscosity resin. This would prevent the resin from invading the pores. For lower permeabilities, a low viscosity resin allows partial invasion of a small distance and good sealing.

After the sample is embedded in the resin, the sample is cut into slices—with thicknesses ranging from 1–5 mm—and the surfaces polished. Samples with predicted low permeabilities are measured using a modified steady state method, with gas flow rate measured at the outlet; this minimises or eliminates any potential errors due to system leaks.

The resin disc is placed between two end pieces of the sample; the tightness is ensured by applying a load using a hydraulic press. The entry can be connected to several vessels of different volumes. The outlet is open to the atmosphere or closed on a small volume (Fig. 2). Inlet and outlet pressures are also measured. This set-up allows for unsteady and steady state gas flow experiments. The gas permeability is derived from pressure and flow rate.

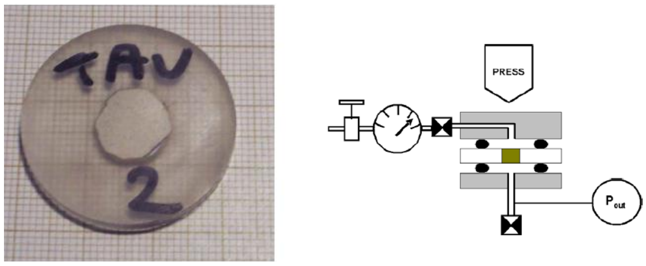

Figure 2. (Left) Sample embedded in a resin disk; (right) schematic diagram of sample setup (Lenormand, Bauget, and Ringot 2010).

The average pressure $<P> = (Pin+Pout)/2$ used was in the range of 14.5–101.5 psi through five pressure periods. The average gas (Klinkenberg) permeability $<Kg>$, at a single point steady state measurement, was found using Jones and Owens' technique (Jones and Owens, 1980). The measurements were conducted at a net confining pressure of 1015 psi. The microscopic flow can be described as average gas permeability:

$$K_g = k_1\left(1 + \frac{b}{<P>}\right) \tag{2}$$

In Equation 2, K_g is the average gas permeability, K_l is the Klinkenberg corrected permeability, determined from the intercept, and b is the gas slippage factor that is computed from the slope of the gas permeability versus the reciprocal average pressure plot (Fig. 3). The Klinkenberg plot is used to determine the liquid permeability and account for the gas slippage effects.

The gas slippage factor is given in Equation 3, where m is the slope:

$$b = \frac{m}{K_l} \tag{3}$$

Figure 4 is a plot of gas permeability and Klinkenberg corrected permeability versus porosity.

By definition, the minimum capillary entry pressure is the capillary pressure, where the non-wetting phase starts to displace the wetting phase, confined in the largest pore throat. From the capillary pressure equation (Equation 1), it is seen that the capillary entry pressure can be very large for shales with very small pore throats (Al-Bazali et al, 2005); the entry pressure is inversely proportional to the size of the pore the mercury will intrude (Webb, 2001). Figures 5 and 6 show capillary pressure (psi) versus mercury saturation (%), and pore volume (%) versus pore throat radius (um).

To ensure the sample is clean, it is first evacuated out to below 50um/hg. This will remove any moisture and adsorbed atmospheric gases on the surface and in the pores. The analysis proceeds when the system reaches this vacuum level. It is also important to note that when the system reaches this vacuum level it would become evident that there is no leak in the penetrometer and the sample is clean.

RESULTS AND DISCUSSION

Permeability comparisons

The generated data set consists of 10 samples from the Carynginia Formation in the Perth Basin. The dimensions of the core samples are either 2.5 or 3.8 cm in diameter at various cylindrical lengths. End trims of six samples with

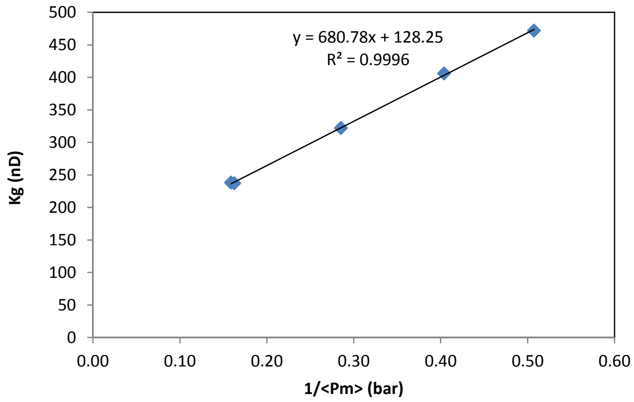

Figure 3. Sample 5—steady state Klinkenberg permeability.

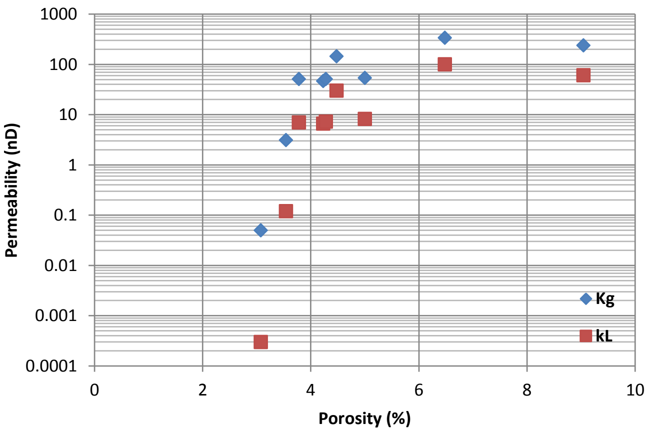

Figure 4. The measured porosity and gas permeability of the samples in the study.

various sizes were used for MICP measurements, and a total of 10 samples were used for permeability measurements. The results are displayed as log-log plots of measured permeability versus the predicted permeability (Fig. 7).

Generally, for gas shale formations, the accuracy of the mercury injection capillary pressure-based permeability methods is expected to be low. As a quantitative comparison, the authors rank the mean square error (MSE) and the standard detion (σ) in ascending order, and coefficient of determination (R2) in descending order. The final ranking of the suitable model is done through a cumulative rank of each MSE, σ and R2.

Table 1 summarises the ranking of each MICP permeability method. The authors stress that the comparisons made are indefinite, but serve as an indication of the method that would perform better in evaluating the permeability of a gas shale formation. The assessment of the best performer, done through statistical analysis, shows that none of the models work well for shales.

Pore throat size and permeability relationship

Porosity and permeability relationships are qualitative in nature; particular rocks may exhibit high porosity, but ultra-low permeability. Figure 8 is a cross-plot between the porosity and measured permeability of the samples in the study, showing a weak correlation. This is not unexpected, given that the porosity symbolises the pore volume and the permeability reflects the pore throat size in the system. The authors have tabulated R2 in increments of five (pore throat radius is 15%–75% mercury saturation) to obtain the best throat size and permeability correlation

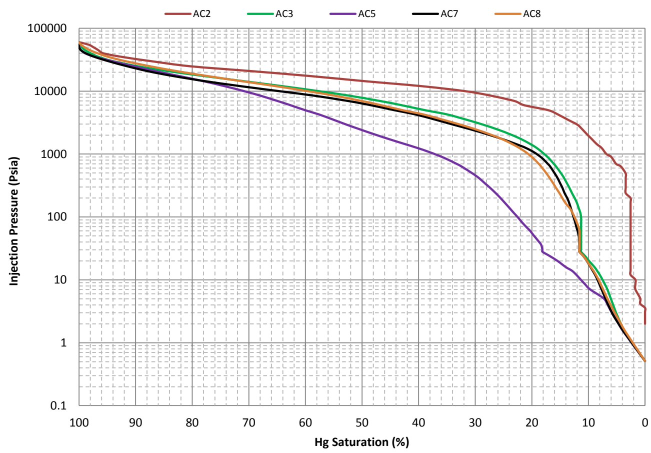

Figure 5. The capillary pressure curves of the samples used in the study.

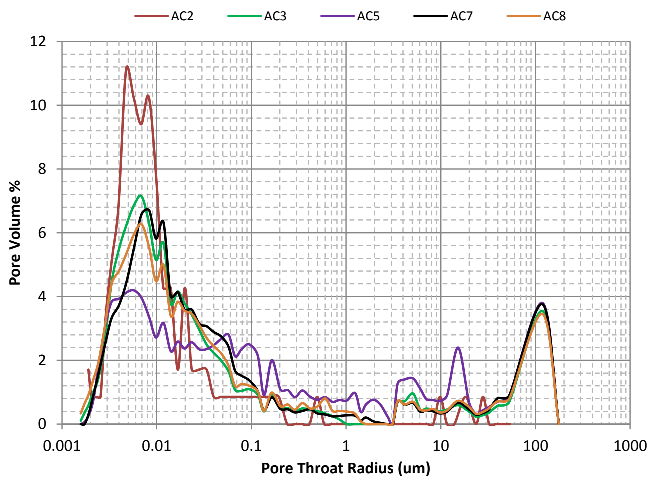

Figure 6. The pore size distribution from MICP.

(Table 2). R75 shows a stronger influence on permeability (Fig. 9). The equation found to be suitable for the area in the study is:

$$LogK = 37.255 - 6.345\,Log\varnothing + 15.227\,LogR_{75} \quad (4)$$

In Equation 4, K is in nanodarcy, porosity is in percentage and R is in micrometer. Most of the permeability estimations from the capillary pressure data are based on a single point on the curve or the full range of the data points. Additionally, the majority of the techniques were based on conventional reservoirs, while this study examines extremely low permeability rocks—gas shales.

DISCUSSION AND CONCLUSIONS

The Winland equation is based on a simple assumption for a simple pore network, such as sandstone (interparticle porosity). In other words, there is a linear relationship between the pore throat size at 35% mercury saturation, porosity and permeability. Similarly, Rezaee et al (2006) suggested a throat size of 50% mercury saturation is ideal for carbonates. For gas shale rocks, it is evident higher injection pressure is required for mercury to invade the smaller pores.

The permeability values estimated here show that most of the theoretical and empirical values overestimate the permeability of shale rocks. This is expected as most of the models are based on sandstone, carbonates and tight sand, and these rocks have pore throat radiuses larger than shale.

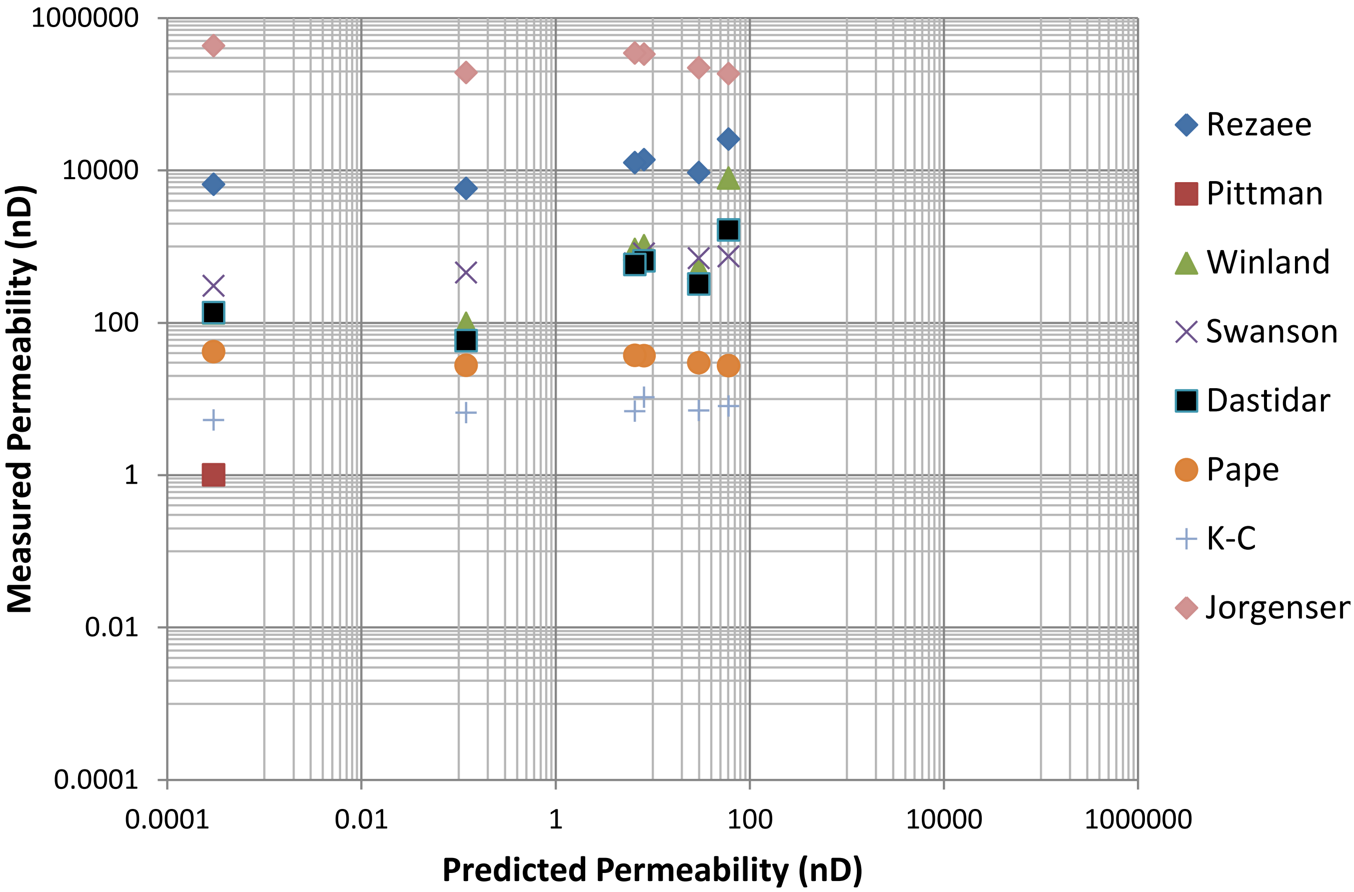

Figure 7. Measured permeability vs porosity for samples from Carynginia Formation.

Table 1. Ranking of the MICP permeability methods.

Rank	Method	MSE	Std Devi.	R2	SUM
1	Rezaee R50	2	1	4	7
2	Pittman R25	3	4	1	8
3	Winland R35	5	3	2	10
4	Dastidar	6	2	3	11
5	Pape	7	6	5	18
6	Kozney-Carman	1	5	8	14
7	Swanson	4	8	7	19
8	Jorgensen	8	7	6	21

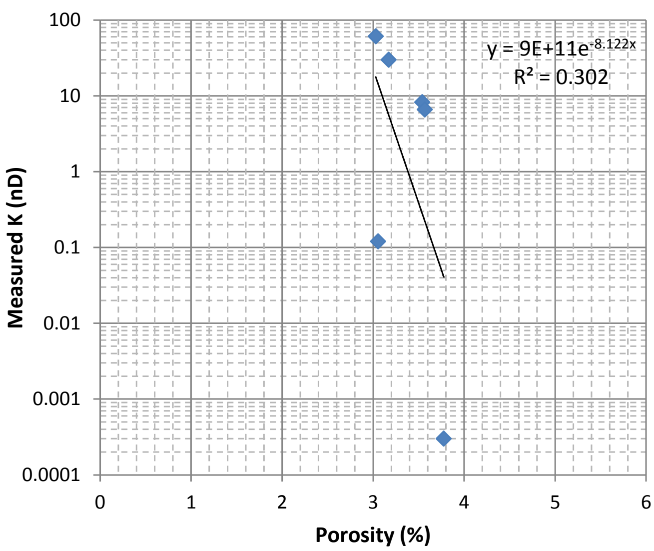

Figure 8. Cross plot of MICP porosity versus measured gas permeability showing a weak correlation.

The authors have performed comparisons between measured permeability values and those estimated from MICP data for a number of gas shale samples from the Carynginia Formation in the Perth Basin. The authors have predicted permeability from published mercury injection capillary pressure methods and ranked them relative to measured permeability. It has been found that the permeability models produce unsatisfactory results as they are not exclusively developed for gas shale reservoirs and most of the methods are developed for rocks with permeabilities more than 0.1 mD.

An alternative method for determining permeability from MICP measurements has been established. The relationship takes into account both porosity and pore throat size at 75% mercury saturation. The pore throat radius does not display exclusivity at some definite mercury saturation levels, and every rock may vary in R values depending on its pore structure and geometry.

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Table 2. Correlation coefficient (R2) for permeability and throat radius at various mercury saturation.

	r15	r20	r25	r30	r35	r40	r45	r50	r55	r60	r65	r70	r75
R2	0.660	0.584	0.618	0.664	0.692	0.692	0.648	0.680	0.762	0.799	0.752	0.861	0.889

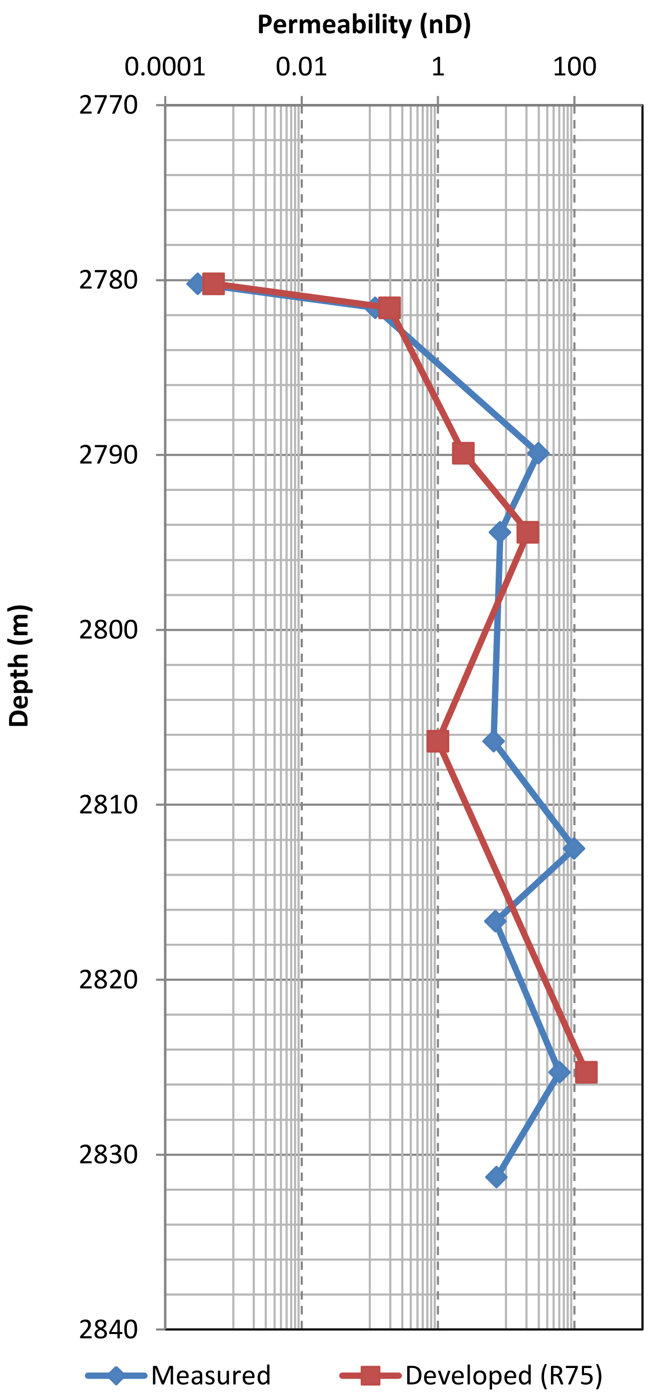

Figure 9. Comparison of measured permeability and developed prediction equation vs depth of the analysed samples.

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