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Liquid and Gas Corrected Permeability Correlation for Heterogeneous Carbonate Reservoir Rocks

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ABSTRACT

Permeability is considered as an efficient parameter for reservoir modelling and simulation in different types of rocks. The performance of a dynamic model for estimation of reservoir properties based on liquid permeability has been widely established for reservoir rocks. Consequently, the validated module can be applied into another reservoir type with examination of the validity and applicability of the outcomes. In this study the heterogeneous carbonate reservoir rock samples of the Tertiary Baba Formation have been collected to create a new module for estimation of the brine permeability from the corrected gas permeability. In addition, three previously published equations of different reservoir rock types were evaluated using the heterogenous carbonate samples. The porosity and permeability relationships, permeability distribution, pore system and rock microstructures are the dominant factors that influenced on the limitation of these modules for calculating absolute liquid permeability from the klinkenberg-corrected permeability. The most accurate equation throughout the selected samples in this study was the heterogenous module and the lowest quality permeability estimation was derived from the sandstone module.

1. INTRODUCTION

Permeability is an essential parameter for the evaluation of reservoir potentiality and production rate estimation of a specific field. In addition, this parameter can be used in reservoir simulation of particular rock type [1, 2, 3, 4, 5]. The liquid permeability only measure for a specific rock interval and from a limited number of core samples. This restriction is derived from the experiment cost consideration and time consuming of measurement in laboratory. The magnitude of the measured liquid permeability has a limitation and does not cover the entire drilled core rocks and entire reservoir intervals [6, 7]. Consequently, the values of this parameter usually obtain from the integration of the experimental measurements of liquid and apparent gas permeabilities with using empirical equation and correlations that encouraged by inputting extra parameters [8, 9]. The magnitude of apparent gas permeability is commonly greater than the amount of brine permeability of the same sample with an average of one to three orders of magnitude of permeability [10; 11]. The result contrast between single point gas permeability and liquid permeability is derived from gas slippage criteria [12, 13, 14, and 15].

A number of mathematical equations have been established and improved for calculation of Klinkenberg corrected permeability which is equivalent to the brine permeability for different types of reservoir rocks. Each equation has a restricted application and its applicability varies for different types of reservoir rocks as the magnitude of permeability varies based on rock microstructure, pore system, diagenetic modifications and fracture impactions [16, 17, 18]. However, the dominant equation used for predicting Klinkenberg-corrected gas permeability from apparent gas permeability is North Sea method which is widely applied and considered as an efficient module in petroleum production and development planning. In addition, several modules have been established and improved for prediction the liquid permeability from the corrected gas permeability [6, 8, 9].

The objective of the current research is to examine a relationship between the magnitude of Klinkenberg-corrected gas (nitrogen) permeability and liquid (formation water) permeability using a heterogenous carbonate core samples from the Tertiary Baba Formation from Bai Hassan oil filed in the Kirkuk embayment zone. The Baba Formation is characterized by heterogenous lithology intervals in the studied field and especially throughout the selected wells. The rock fabrics are dominantly consists of dolomite, dolomitic limestone and limestone [19, 20]. In addition, nodules of anhydrite have been recorded from the drilled cutting samples. This reservoir rock has the most potential oil producing intervals throughout the tertiary petroleum system in Kirkuk oil fields [20]. Furthermore, establish the empirical equation from the correlation between apparent gas permeability and the Klinkenberg-corrected gas permeability to predict the brine or corrected gas permeability from single point gas permeability for different types of carbonate reservoir rocks. The outcomes of this work can be applied for estimating permeability for the Baba Formation in the neighboring fields and other carbonate reservoir rocks throughout the region.

2. METHODS AND MATERIALS

The rock samples for this study have been selected based on drilled core availability from the Tertiary reservoir rock interval of Baba Formation in Bai Hassan oil field within Kirkuk embayment zone. The Bai Hassan oilfield is one of the several elongated, asymmetrical, double plunnging anticlines that characterize the Foothills region of the Unstable Shelf Zone in northern and eastern Iraq, Figure (1). The northwest-southeast trending structure has 40 km length and 3.5 km width. The dips of the beds on the flanks are approximately 40 degrees while the noses plunge at approximately 5 degrees [21, 22]. The field is one of Iraq’s giant oil fields that contain multiple pay zones similar to most of the northern Iraq oil fields [21]. The Bai Hassan anticline lies between longitudes (43º 50´ to 44º 10´) East and latitudes (35º 30´ to 35º 45´) North. The field is located geographically about 37 km northwest of Kirkuk city which is parallel to the Avanah dome of the Kirkuk oil field [23]. The Khabaz and Jambur oil fields located in the south-east of the Bai Hassan field and Qarachuq structure in the north-west. The surface structure differs from the subsurface structures because of the effect of the faults [22]. The field is of a very complex nature with several major faults and minor faults spreading in the field. In term of structure component, the oil field consists of two different size domes named Daoud in the northwestern part of the structure and Kithke dome in the southeastern part of the field. The field has been discovered in 1953 by the Iraqi Oil Company (IPC) and having come on production in 1960. The data sets have collected from three wells including well BH-50 in Daoud dome, BH-20 and BH-78 in Kithke dome, Figure (2).

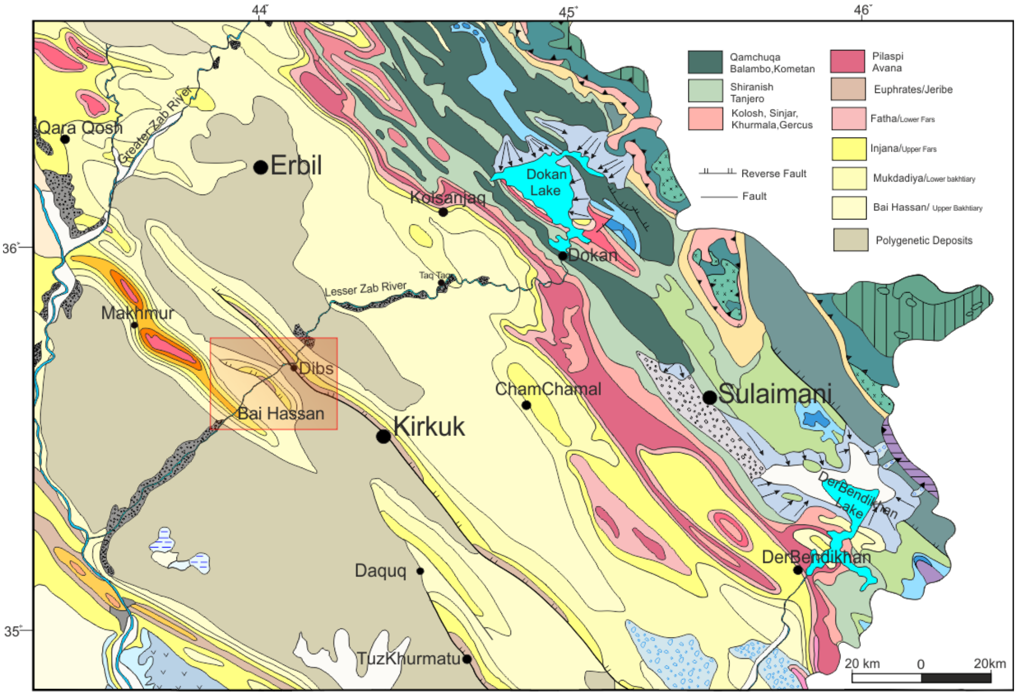

Figure 1: Geological map of the northeast of Iraq contains the dominant surface north-west and south-east trending structures. The highlighted structure is the position of the Bai Hassan anticline in the Kirkuk embayment zone of the Zagros basin.

In total 140 plug samples with 1.0 inch and 1.5 inch of diameter and different lengths were plugged on horizontally on the drilled core samples. Consequently, the samples were cut and the cleaned using dichloromethane liquid with applying Soxhlet procedure [24] to remove the remained hydrocarbon and consequently the samples were dried with temperature of 70 C° for 72 hours [25]. The plug sample bulk volume (V_B) and dry weight were measured before progressing petrophysical experiments. The value of grain volume (V_g), pore (V_p) volume, and effective porosity (Ø) were measured respectively based on gas expansion method of Bowel's law [26] using the equation number (1), (2), (3) and (4) with applying the initial pressure (P_1) 180 psi . The dry and clean samples were run in BLP-530 nitrogen porosimeter in Kurdistan institution for strategic study and scientific research laboratory, Figure (3).

$$V_g = V_2 - V_3 \tag{1}$$

V_2: constant of the porosimeter , cm^3

$$V_3 = \frac{P_1 V_1}{P_2} \tag{2}$$

P_1: initial pressure , psi
P_2: expansion pressure , psi
V_1: reference cell of the porosimeter , cm^3

$$V_p = V_B - V_g \tag{3}$$

$$\emptyset = \frac{V_p}{V_B} \tag{4}$$

V_p: pore volume of sample , cm^3
V_B: bulk volume of sample , cm^3
$\emptyset$: effective porosity , fraction

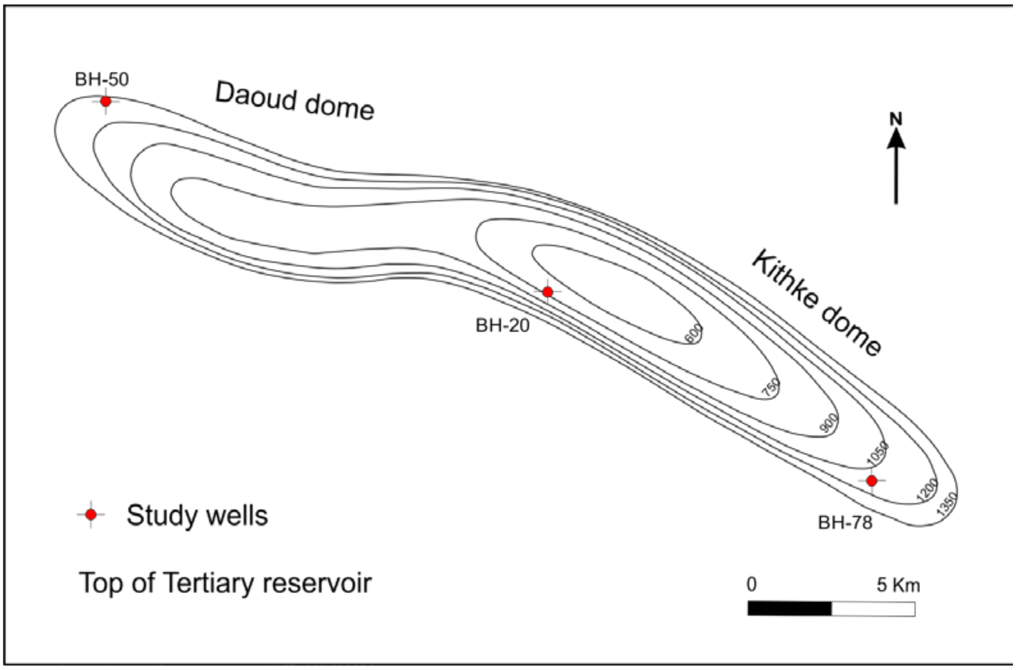

Figure 2: Contour map on the top of the Tertiary reservoir rocks of Bai Hassan field structure, modified from [27]. The anticline composes of two dominant domes; Daoud, and Kithke. The studied wells including BH-20, BH-50 and BH-78 were drilled in different positions of the field.

The permeability was measured for the all core plug samples using the conventional steady state method with injecting of nitrogen gas through the plug samples with known viscosity of the applied gas, Figure (4). All measurements were run at an equivalent reservoir pressure of confining pressure, zero back pressure and 25 Cº of temperature. The magnitude of permeability was recorded from the Darcy law, equation number (5) using reservoir permeability tester in Kurdistan institution for strategic study and scientific research petroleum laboratory.

$$K = \frac{14700\mu QL}{A\Delta P} \qquad (5)$$

K: permeability, mD

Q: flow rate, cm^3/sec

A: surface area of the sample cm^2

ΔP : differential pressure, psi

μ: dynamic viscosity of the fluid, centipoises

L : length of the sample, cm

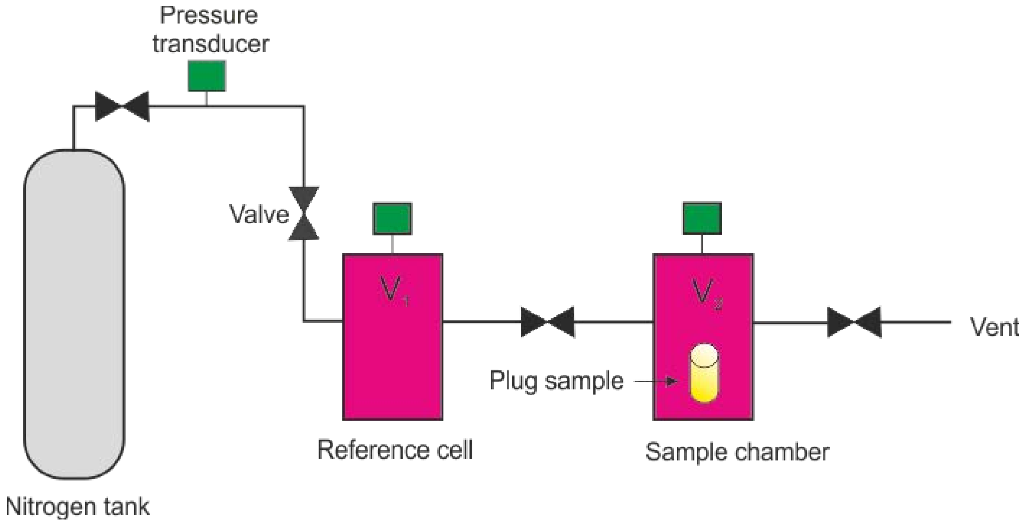

Figure 3: Schematic diagram of nitrogen gas porosimeter set up was used to measure effective porosity of the carbonate plug samples. The volume of reference cell is 53.17 cm^3 and the volume of sample cell is 154.45 cm^3 [28].

The gas permeability for all samples were run with five points of mean pore pressure including (150,175,200, 225,250) psi respectively. The results of gas apparent permeabilities of each sample were plotted with the inverse of applied pore pressure for each permeability measurement, as shown in Figure (5). A straight line is interconnected all points and intersects the y-axis (apparent) permeability where inverse of pore pressure equal to zero presents the mean pore pressure tends to infinity[29]. The intersected permeability is called the Klinkenberg permeability and its value close to the brine permeability of the sample [30].

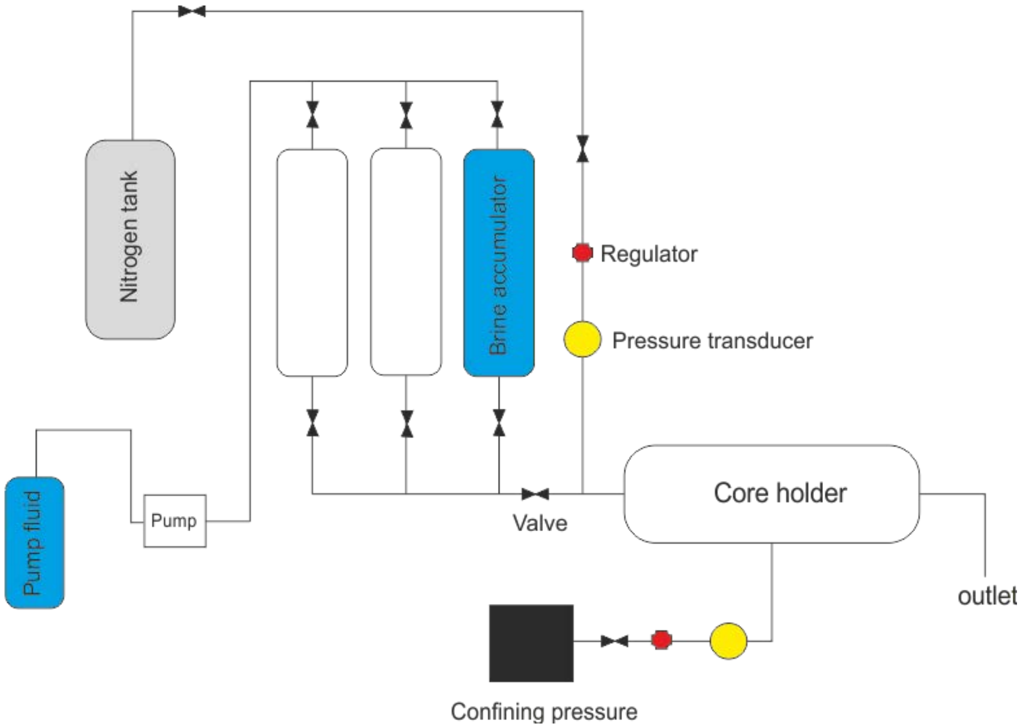

Figure 4: Simplified diagram of gas and liquid reservoir permeability tester has been used in this study, modified from [31]. In this set up, liquid and gas permeability measurements were progressed separately but all the chambers and valves allocated in one instrument.

Besides of the gas permeability, 7 plug samples have been selected for measuring liquid permeability with injecting a constant flow rate of the brine (0.10 cm^3/sec) to pass through the plug samples, table 1. The differential pressure (ΔP) derived from the inlet and outlet pressures have been recorded with continuous measuring of the liquid permeability in each sample as far as the fluid flow reaches to the steady state. At the stable fluid flow condition, the permeameter gives the actual value of the liquid permeability. In this paper we have selected 7 plug samples for measuring the liquid permeability based on the variation of the magnitude of the measured porosity and klinkenberg-corrected permeability distributions throughout the collected plug samples.

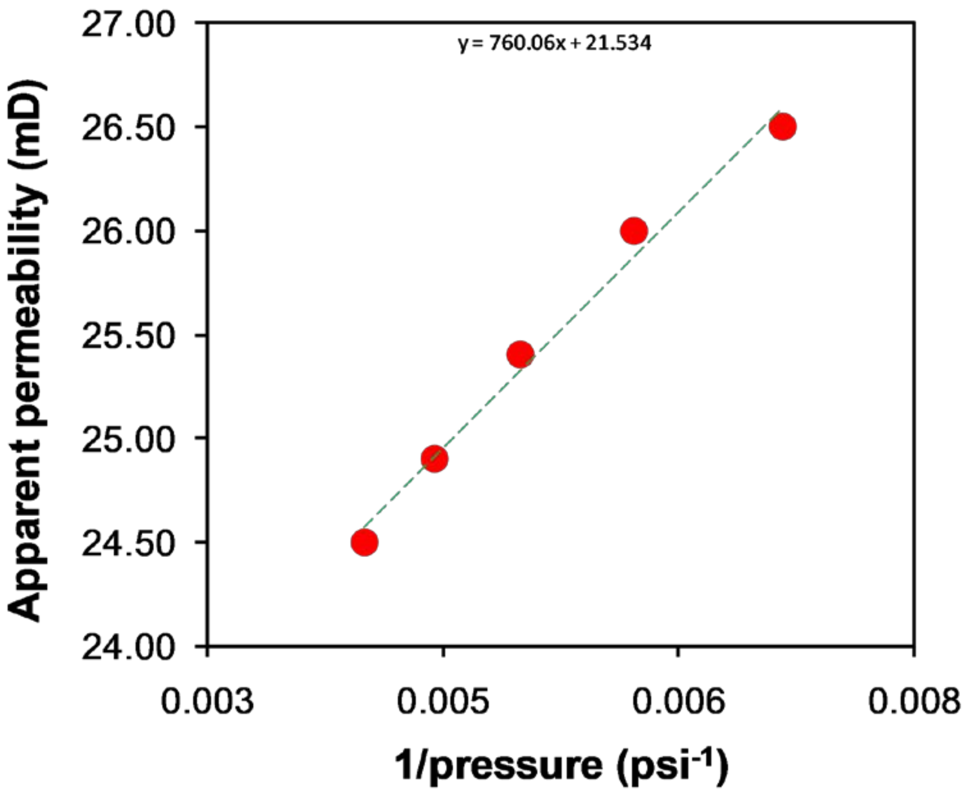

Figure 5: Apparent permeability as a function of mean pore pressure for achieving the klinkenberg-corrected gas permeability of typical sample from Baba Formation in Bai Hassan field. The pore pressure and permeability were reordered using nitrogen gas as applied fluid.

Table 1: Depth and dimensions information of the selected samples for measuring brine permeability

Sample	Well	Depth (m)	Diameter (cm)	Length (cm)	Brine permeability (mD)
B-1	BH-20	1381	2.54	5.72	0.50
B-2	BH-20	1387	2.54	2.54	12.0
B-3	BH-20	1397	2.54	4.60	256.54
B-4	BH-50	1447	2.54	2.54	44.0
B-5	BH-50	1490	2.54	2.54	23.0
B-6	BH-78	1687	2.54	2.54	0.90
B-7	BH-78	1716	2.54	5.60	2.10

3. RESULTS

The measured gas porosity and corrected gas permeability relationship is shown in semi-log diagram for 140 plug samples in Baba Formation, Figure (6). The presented statical data of the measured porosity and permeability in this work are derived from the current available plug samples and probably its distribution will be changed with adding extra samples specifically fracture core samples. The magnitude of the measured porosity and permeability are varied within the measured plug samples and widely distributed throughout the studied intervals. The value of the measured effective matrix porosity started from 0.010 to 0.37 with an average of 0.20. The magnitude of the measured matrix klinkenberg-corrected gas permeability has five orders of magnitudes. The minimum measured permeability is 0.009 mD and 879.023mD is the maximum measured permeability, the average measured permeability is 123.52 mD. The poroperm relationship in carbonate reservoir rocks consistently crucial to achieve especially when the carbonate fabric consists of intercalation of dolostone, limestone and a mixture of both. A non-linear trend of enhancing the magnitude of the corrected gas permeability can be observed with increasing the amount of porosity throughout the measured samples. The plotted corrected gas permeability as a function of the gas porosity has power law relationships with a coefficient of determination (R^2=0.67) and this correlation can be presented on the empirical module as shown in equation (6). Furthermore, the magnitudes of the measured liquid permeability of 7 samples were plotted as a function of the klinkenberg-corrected gas permeability in log-log plot, Figure (7). The mathematical relationship between these two experimental parameters can be explained by a power law relationship (equation 7) with a coefficient of determination (R^2=0.99).

$$K_K = 11129\emptyset^{3.521} \tag{6}$$

$$K_L = 0.9823K_k^{1.0292} \tag{7}$$

K_K: Klinkenberg-corrected gas permeability, mD

K_L: Liquid (brine) permeability, mD

The differences between liquid and Klinkenberg-corrected gas permeability throughout the measured samples started from 0.0 % for the tightest sample to 23.69% in the most permeable sample, Figure (8). The highest difference is coincided with the highest measured permeability specifically higher liquid permeability value. Three established equations for predicting the liquid permeability from the corrected gas permeability in sandstone, limestone and dolomite rocks have been examined in this study for appraising validation and applicability of these equations in heterogenous carbonate reservoir rocks using equation number (8),(9) and (10). The estimated liquid permeability based on the correlation with the corrected gas permeability in this research and other equations are presented in Figure (9).

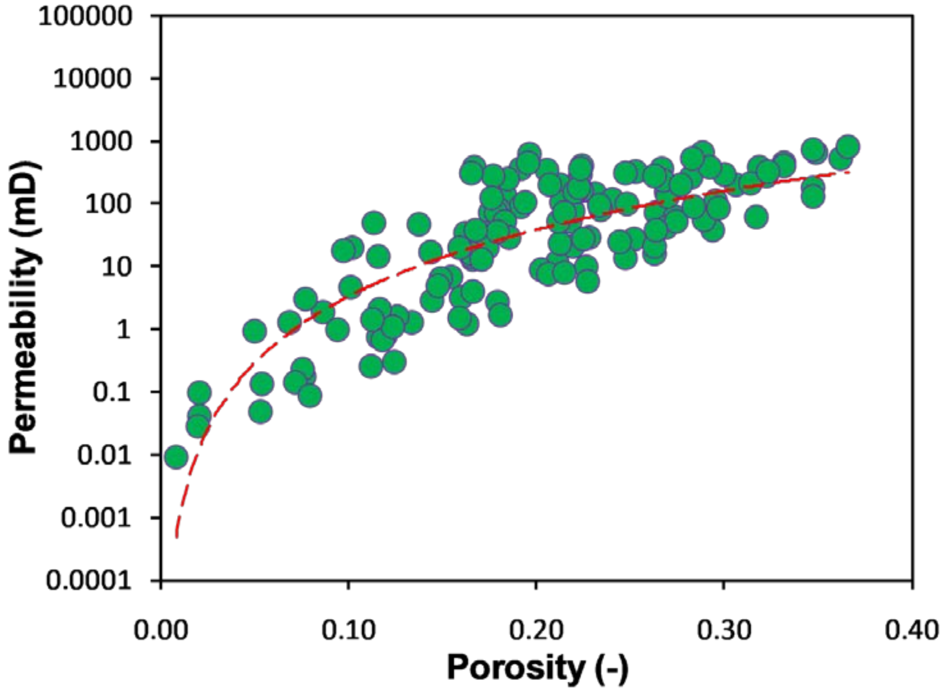

Figure 6: The measured klinkenberg-corrected gas permeability as a function of the measured gas porosity for the achieved plug samples of Baba Formation in Bai Hassan field (n=140).

An average absolute error was used as an index for validity checking of all applied modules using the measured liquid permeability in the laboratory and calculated liquid permeability from the equations as two input variables. The highest percentage of the average absolute error between the two results is relevant with highest discrepancy between the measured and calculated permeabilities. In contrast, the lowest percentage of the error means the identical match between the measured and calculated permeabilities. In comparison with the measured liquid permeability of the selected samples the absolute error percentage with applying equations (7), (8), (9) and (10) the error was 3.22% for the current study established equation and 10.5% was observed from limestone equation. The absolute error percentage increased to 21.52 with applying dolomite equation and the maximum error was recorded once the sandstone equation has been used, 36.89%.

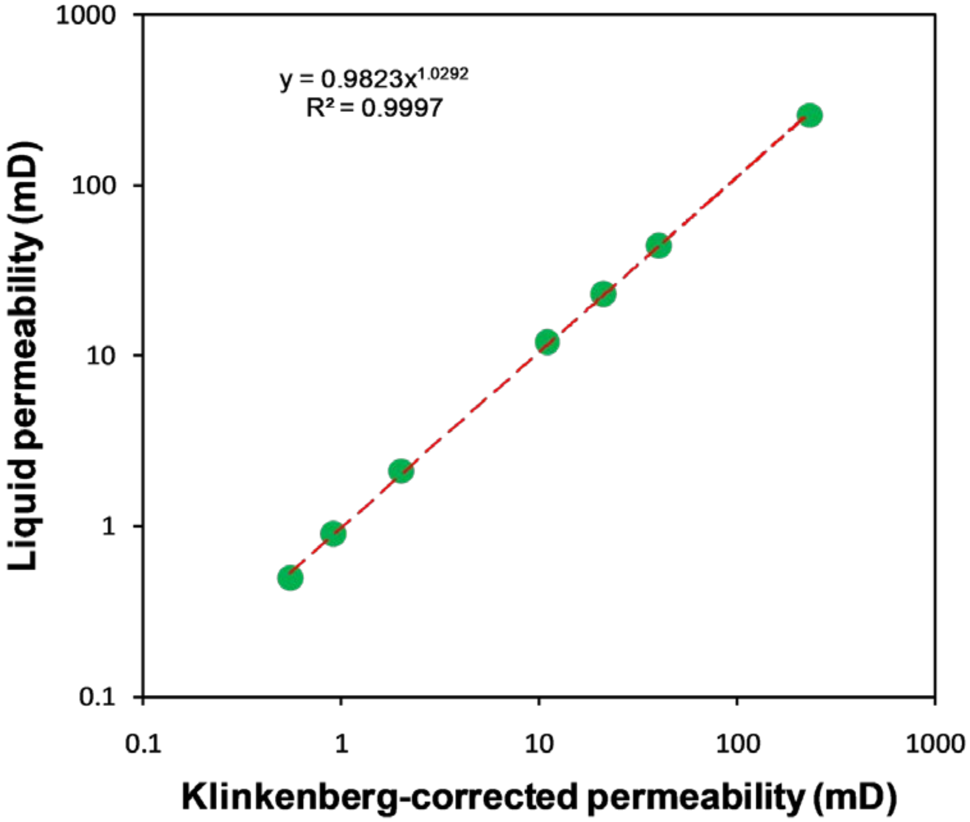

Figure 7: Liquid permeability as a function of klinkenberg-corrected permeability of the selected samples in Baba Formation (n=7).

$$K_{LS} = 0.479 K_K^{1.14} \quad (8)$$

$$K_{LL} = 0.864 K_K^{1.039} \quad (9)$$

$$K_{LD} = 0.930 K_K^{0.9708} \quad (10)$$

K_{LS}: Klinkenberg-corrected gas permeability using North Sea equation, mD

K_{LL}: Klinkenberg-corrected gas permeability using limestone equation, mD

K_{LD}: Klinkenberg-corrected gas permeability using dolomite equation, mD

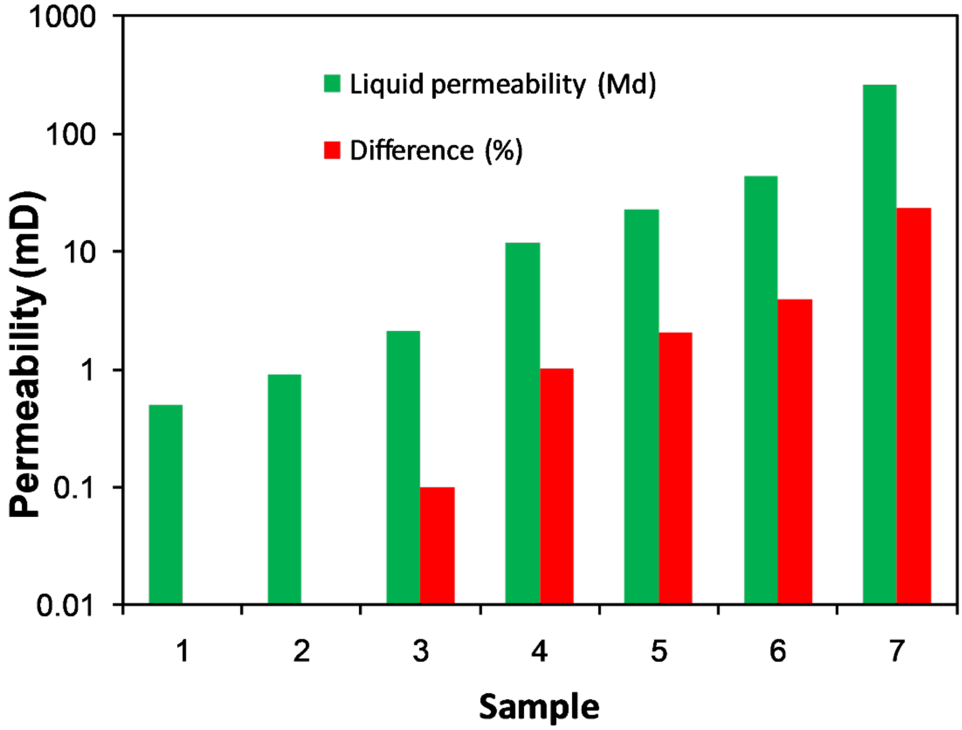

Figure 8: Difference between the liquid permeability and klinkenberg-corrected permeability as a function of the liquid permeability of the same sample set.

4. DISCUSSION

The single point measured gas permeability usually higher than the liquid permeability of the same sample because gas slippage criteria and this diversity between the apparent gas permeability and liquid permeability can be reduced by applying high pore pressure. The measured permeability of all samples in this study is klinkenberg-corrected permeability and the gas slippage effect has been corrected, as a result the gas slippage impaction is out of the consideration.

The reservoir properties of the studied intervals are characterized by heterogeneous rock fabric components and anisotropic petrophysics parameters including porosity and permeability. The magnitude of the measured permeability in the selected samples provide a wide range distribution and has five orders of magnitude of matrix permeability started from microdarcy scale (0.009 mD) to greater than 820 mD and contain greater than 2 Darcy in fractured core samples which is excluded in this study. This diversity in permeability distribution derived from the fact that the reservoir permeability does not depend on porosity alone in carbonate rocks. The magnitudes of permeability are sufficiently influenced by the rock microstructure and pore system [32, 33, 34, 35]. Furthermore, this heterogeneity in rock components and reservoir properties reduce the appropriateness of the established equation for estimation liquid permeability in different types of reservoir rocks.

The absolute error percentage of the calculated liquid permeability using the current study module (equation 7) has the lowest value (3.22%). The value of calculated liquid permeability locates in the same range of the measured liquid permeability. The similarity of the permeabilities distribution is derived from the fact that the calculated permeability achieved from the correlation between two experimental inputs including the measured liquid permeability and measured gas permeability of the same rock samples. However, these empirical relationships provided an acceptable outcome for this type rock and can be applied within another carbonate rock types, but it possibly needs scale correction because of the influence of reservoir rock heterogeneity in carbonate rocks.

The highest error percentage was recorded from the application of sandstone equation (36.89%) because the equation was originally designed for sandstone reservoir rocks that were characterised by homogenous petrophysical distribution and uniform pore system which are obviously different with carbonate reservoir rock properties [36,37]. The integration of pore system with rock matrix homogeneity in clastic rocks gives porosity dependence of the permeability while this phenomenon is rare or absent in carbonate reservoir rocks. The results of error from the dolomite equation are quite high and cannot be accepted for predicting the liquid permeability in heterogenous carbonate reservoir samples in comparison of the newly proved equation in this study. The dolomite module even for individual core sample which mainly consists of dolomite minerals has error percentage greater than 20% and higher. This contrast between the measured and calculated permeabilities from the dolomite equation is related to the permeability distribution in dolomite module rock samples which has two orders of the magnitude permeability while the magnitude of permeability in studied samples originally have five orders of magnitude permeability distribution. However, both modules are achieved from the dolomite rock types but the closeness and similarity between the measured and predicted permeabilities are low. This diversity probably relates to the rock fabric of dolomite mineral especially shape and type of dolomite crystals that control permeability variation in dolomite reservoir rocks [38].In addition, pore system including pore size is another sufficient factor needs to be considered for permeability modelling [39]. The pore structures probably in the dolomite module samples have different scale of sizes in comparison to the current study samples that made them higher distinction between the calculated and measured permeabilities [40].

The limestone module for calculating liquid permeability was originally applied for samples with 4 orders of permeability distribution [41] which is close to the permeability distribution of the current work samples. This coincidence of the permeability distributions motivated the limestone module to be applicable for the heterogeneous carbonate reservoir samples. Besides of the permeability distribution the pore structure parameter including pore size and pore throat size ratio [42] has sufficient impact on the permeability in carbonate rocks. The limestone module based on the porosity-permeability relationship has the pore to pore throat size ratio possibly similar or within the same range of the pore and throat scale within this study core plug samples.

The measurement techniques are another point probably has an impaction on the correlation between measured permeability and calculated permeability modules. The applied confining pressure and flow rates are the two dominant parameters which have role in the designing of permeability estimation in reservoir rocks [25, 43]. The liquid permeability for the selected samples was measured with applying reservoir pressure while other modules have not mentioned the confining pressure condition of the permeability measurements to conduct the best correlations between the measured and predicted permeabilities. Furthermore, each designed approach for estimation permeability derived from a specific applied fluid flow to measure the magnitude of permeability which eventually causes a wider error when the proved module applies to another reservoir rock.

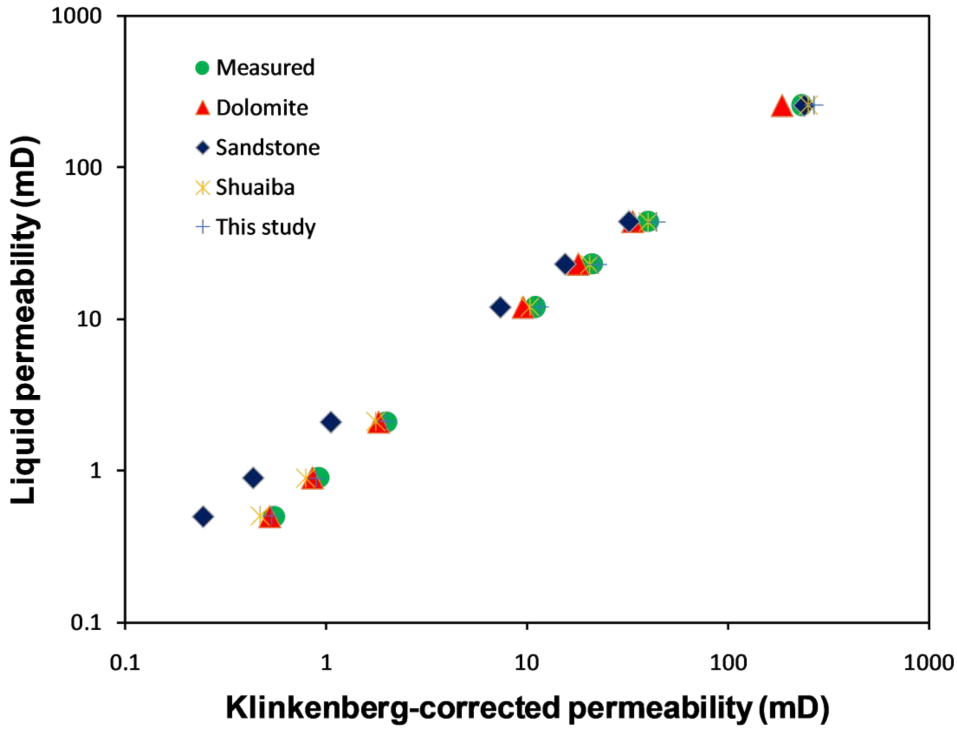

Figure 9: Comparison of the liquid permeability estimated from different modules with the measured liquid permeability. The klinkenberg-corrected permeability of the plug samples was used as an input parameter.

5. CONCLUSION

- The power law relationship between the measured porosity and klinkenberg-corrected permeability in the heterogenous carbonate reservoir rock samples are dominantly influenced by the heterogeneity of the rock microstructure and anisotropic pore system.
- An empirical equation was established (equation number 7) from the correlation between the measured liquid permeability and gas corrected permeability from the selected plug samples of the heterogenous carbonate reservoir rocks in Baba Formation.
- The applicability and validation of three different liquid permeability estimation and this study modules have been examined with the measured liquid permeability of 7 core plug samples. The absolute error percentage of this study has the lowest percentage (3.22%) and the sandstone module has the highest error percentage (36.89%).
- The permeability distributions, rock microstructure and pore system are the dominant factors that influenced on the appropriateness of the established permeability modules using the heterogenous carbonate samples.

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