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Correlation and Mathematical Solution of Different Permeability Models to Derive and Assign New Appropriate Models (A Case Study: Egyptian Oil Reservoirs)

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Abstract

The present work aims to correlate different absolute and relative permeability models to obtain the suitable models that can be utilized to estimate the permeability values of Rudeis and Kareem formations of some subsurface samples (Lower-Middle Miocene), San El-Hagar 1 well, East Nile Delta, Egypt. For this purpose, the samples are prepared and cleaned for the porosity and capillary pressure measurements, then many approaches have been used to estimate absolute and relative permeability.

Petrographic investigation shows that the sandstones can be classified as Feldspathic Quartz Wackes, while the carbonates can be classified as Bioclastic Sandy Wackestone. Five absolute permeability models are compared depending on the porosity and displacement pressure to select the appropriate model for estimating the absolute permeability. The comparison revealed that Schlumberger and the Aigbedion models are the best.

Three relative permeability models were utilized to estimate the relative permeability from capillary pressure data and differentiate between wetting and non-wetting phases. These models are correlated to form the composite mathematical correlation to express the relative permeability curves by one curve for every sample. Based on these results the wettability of the sandstone rock samples is better than the carbonate rock samples. It is best described by the Corey relative permeability model, where its cross-point value is close to the average value (between 0.5 and 0.6).

Keywords: Absolute permeability; Relative permeability; Wettability; Rudeis Formation; Kareem Formation; East Nile Delta.

1. Introduction

San El-Hagar1well, which is located in the Eastern Desert at latitude 30° 29′ 13″ N and longitude 31° 50′ 53″ E as shown in Figure 1, was drilled by the Continental Delta Oil Company to a total depth of about 3772 m [1]. The Nile Delta, is one of the essential gas provinces globally, where many geological and geophysical surface and subsurface studies were carried out to determine the new hydrocarbon fields [2].

The source rocks in the Nile Delta are represented by the Early Miocene-Oligocene shales and mudstones [3]. The hydrocarbon generation (gas window) within the source rock in the Abu Madi/El Qar'a gas field, Nile Delta is started in the Middle to Upper Miocene. The peak of generation occurred through the Lower Pliocene [4].

The factors which affect the absolute permeability values are the amount and distribution of the clay minerals, rock matrix, size of matrix grains, and pore space characteristics. The proposed models [5, 6, 7, 8, and [9] are used to determine absolute values of permeability in reservoirs using porosity and irreducible water saturation. These parameters are significant factors in rock characteristics identification.

Petroleum and groundwater studies, soil science, and many other industries are based on determining of relative permeability. On the other hand, measuring relative permeability may be difficult in the cases of low permeability rocks and special fluid systems. Consequently, several mathematical models are proposed [10] to estimate relative permeability, where the comparison of experimental relative permeability measurements with the estimated results using five methods has been carried out, and the results demonstrate that these methods in their predictive capabilities are limited. Whereas, the pore-scale network models [11] were used to inspect the good correlation of the capillary pressure-saturation with

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the relative permeability relationships. These models confirmed that the curves of capillary pressure-saturation are matched with the curves of predicted saturation-relative permeability.

Fig. 1 The San El-Hagar 1 well located in the Eastern Desert at latitude 30° 29′ 13″ N and longitude 31° 50′ 53″ E.

Relative permeability is calculated by using three main approaches from capillary pressure measurements. The Purcell [12] approach doesn't consider the tortuosity factor in the estimation process. In contrast, the other two models [13 and 14] are based on the tortuosity factor during the calculation of relative permeability.

The relative permeability is coupled with the capillary pressure test [15] to develop models describing the relationships of relative permeability in two- or three-phase fluid flow with the capillary pressure measurements. As well, the study of the solutions for the passing flow in the unsaturated matrix by special correlation for relative permeability and capillary functions, is physically meaningful in many fluid flow solutions in porous media [16].

Permeability is usually measured experimentally utilizing basic core analysis that consumes cost and time. For that, the present study aims to assign and solve different models to achieve the appropriate models of absolute water-oil permeability and relative permeability from the measurements of porosity and capillary pressure for Rudeis and Kareem formations of some subsurface samples (Lower-Middle Miocene), San El-Hagar 1 well, East Nile Delta, Egypt. In addition to calculating the wettability from these newly derived models.

2. Literature review

The stratigraphy of the Miocene geological age in San El-Hagar-1 well was described [17 and 18] from base to top as Qantara, Kareem, Rudeis, and Qawasim formations (Figure 2), where the Kareem and Rudeis formations have consisted of shale with minor sandstone and limestone.

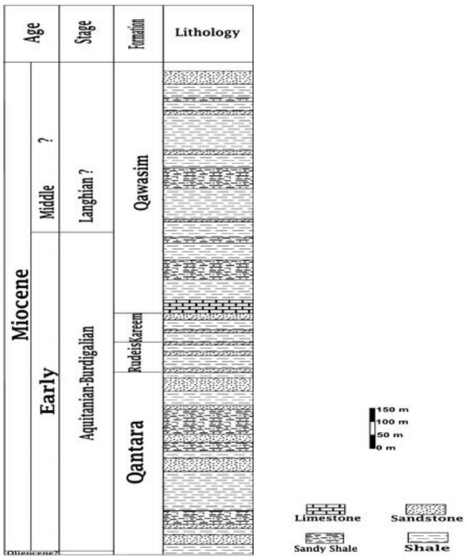

Fig. 2 The stratigraphy of the Miocene geological age in the San El-Hagar 1 well [22]. Red rectangle indicates the studied formations.

The Kareem Formation was first introduced [19] at the Gharib North-2 well (latitude 25° 25′ N and longitude 32° 54′ E), where the Kareem Formation measures about 260 m thick and recorded at depths ranging from 1310 m to 1571 m. The Kareem Formation belongs to the upper unit of Gharandal Group and its lithology is formed, in the lower part, of evaporites that turn out to be highly calcareous shale and grad into marl in the upper part.The Rudeis Formation which belongs to the lower unit of the Gharandal Group, is about 780 m thick in the Rudeis-2 well at the West Central Sinai (latitude 28° 53′ N and longitude 33° 10′ E). The lithology of this formation was described [20] as sandy shales and calcareous shales with hard sandstone beds and minor streaks of limestone.

The San El-Hagar 1 and the Boughaz-1 wells penetrated the Rudeis Formation with almost a thickness of 110 m. As well, the Rudeis Formation in the Boughaz-1 well is unconformably overlain by the Sidi Salem Formation and conformably overlies the Qantara Formation. Otherwise, this formation in the San El-Hagar-1 well conformably underlies the Kareem Formation and overlies the Qantara Formation.

The Middle Miocene Kareem Formation is dominated by sandstone facies (feldspathic quartz wacke) and consists mainly of fine (sometimes medium) and moderately to well-sorted quartz grains, whereas the Early Miocene Rudeis Formation is composed of carbonate facies (bioclastic sandy wackestone) that consist of very fine sand grains dispersed in microcrystalline carbonate groundmass [21 and 22]. The presence of the glauconite in the sandstone and the shallow forams in the carbonate samples indicate a shallow marine environment. The explanation of the core data of Kareem sandstone from ASHRAFI_SW_04 well indicates a suitable reservoir [23]; therefore, the hydrocarbon accumulation is another source of overpressure generation due to the accumulation of hydrocarbon fluids in the Kareem Formation [24].

Petrographically, thin sections of the studied rock samples from the Rudeis and Kareem formations are prepared and described petrographically using polarized microscope. The clastic samples are classified according to Pettijohn [25], whereas the carbonate samples are classified according to Dunham [26]. This study is carried out to determine the most representative microfacies for these samples in each formation and compare the results with the near facies description using the appropriate absolute permeability models [27].

The sandstone texture is a very influential factor that impacts the relationship between porosity and permeability. This concept was introduced [27] by discriminating between five types of sandstones; very coarse-grained, coarse and medium grained, fine-grained, silty, and clayey sandstone. The permeability and porosity trends are significant for studying the fluid flow in porous media. These relationships are based on pore size, pore throat distribution, specific surface area, irreducible fluid saturation, and the other petrophysical variables [28].

3. Methods and Measurements

An irregular non-cylindrical nine subsurface rock samples (six samples from the lower part of Kareem Formation and three samples from the upper part of Rudeis Formation) are prepared and cleaned for the porosity and capillary pressure measurements; such as displacement pressure "*Pdi*, psi" and irreducible wetting phase saturation "*Swirr*, %" (Table 1). Remove hydrocarbon residues and salts using methanol and toluene, respectively, and then dried using a drying oven.

Table 1 Petrophysical parameters for nine samples from the capillary pressure test and porosity measurements.

Formation	Sample No.	Ø, %	Pdi, psi	Swirr, %	k, mD				
					Tixier (1949)	Timur (1968)	Coats & Dumanoir (1974)	Schlumberger (1991)	Aigbedion (2007)
Kareem	1	29.40	67.37	8.20	6002.56	5843.05	9363.69	7585.78	1015.40
	2	29.90	140.05	26.00	660.63	625.96	647.44	9549.93	1180.27
	3	27.70	55.02	5.20	10441.24	11180.04	19567.22	3467.37	608.78
	4	27.10	82.34	6.20	6440.39	7142.01	12345.24	2630.27	508.22
	5	28.40	55.02	13.90	1697.31	1746.26	2496.03	4786.30	751.53
	6	27.40	82.34	5.70	8140.17	8869.35	15426.80	3019.95	556.23
Rudeis	7	8.80	1411.32	4.10	17.27	115.80	328.10	0.58	2.06
	8	11.20	758.30	12.30	8.15	37.18	79.99	1.74	4.25
	9	12.90	939.89	14.00	14.69	53.44	104.50	3.80	7.08

The helium porosimeter of Heise Gauge-type is used for porosity determination through calculation of grain volume (V_g), as well mercury injection up to 30,000 psi is used to estimate the irreducible wetting phase saturation (*Swi*), which is the unsaturated fraction of the pore volume that can't be penetrated by mercury [29]. The pressure required for initial mercury saturation is called displacement pressure and is inversely proportional to permeability [21 and30].

The pore volume (V_p) and bulk volume (V_b) were utilized in the following equations for determining the porosity ($\emptyset$):

$$V_p = V_b - V_g (1)$$

$$\emptyset = \frac{V_p}{V_b} (2)$$

Many approaches have been used to estimate absolute and relative permeability, and various petrophysical models have been developed to enhance the estimation of permeability values of porous rocks. These models depend on porosity, irreducible wetting phase saturation, capillary pressure data, and different petrophysical attributes.

This study compares five permeability models to estimate the values of absolute permeability. The mathematical forms for these five models are as follows:

1. Tixier model [5]:

$$k^{0.5} = \frac{250 * \phi^3}{S_{wi}} \quad (3)$$

2. Timur model [6]:

$$k = 0.136 \frac{\phi^{4.4}}{S_{wi}^2} \quad (4)$$

3. Coates and Dumanoir model [7]:

$$k^{0.5} = 100 * \frac{(1-S_{wi}) * \phi^2}{S_{wi}} \quad (5)$$

4. Schlumberger model [8]:

$$k = 10^{(M * \phi + KC)} \quad (6)$$

5. Aigbedion model [9]:

$$Log\ k = -0.83565 + 13.069\ \phi \quad (7)$$

Where

M and *KC* are constant values (20 and -2, respectively) and were determined using a genetic algorithm with log-created data estimated from well log interpretation and core-estimated permeability data [8].

ϕ is porosity, fraction

k is permeability, mD

Swi Irreducible wetting phase saturation, fraction

The relative permeability is an essential factor for petroleum engineers, but it is difficult to change of pressure, there is a phase shift and mass transfer between the two phases. Accordingly, many mathematical models have been developed to calculate the relative permeability due to the difficulty of conducting direct experimental measurements.

Three models were chosen for calculating relative permeability and applied in this study to calculate relative permeability from capillary pressure data, where the mathematical equations of these models are as follows:

1. Purcell model [12]:

$$k_{rw} = (S_w^*)^{\frac{2+\lambda}{\lambda}} \quad (8)$$

$$k_{rnw} = [1 - (S_w^*)^{\frac{2+\lambda}{\lambda}}] \quad (9)$$

2. Corey model [31]:

$$k_{rw} = (S_w^*)^4 \quad (10)$$

$$k_{rnw} = (1 - S_w^*)^2 [1 - (S_w^*)^2] \quad (11)$$

3. Brooks and Corey model [32]:

$$k_{rw} = (S_w^*)^{\frac{2+3\lambda}{\lambda}} \quad (12)$$

$$k_{rnw} = (1 - S_w^*)^2 [1 - (S_w^*)^{\frac{2+\lambda}{\lambda}}] \quad (13)$$

The S_w^* is the normalized wetting phase saturation and can be represented as in Equation 14for the drainage case:

$$S_w^* = \frac{S_w - S_{wr}}{1 - S_{wr}} \quad (14)$$

Where

S_w^* is the normalized wetting phase saturation

S_{wr} is the residual saturation of the wetting phase

k_{rw} is the relative permeability of the wetting phase

k_{rnw} is the relative permeability of the nonwetting phase

λ is the pore size distribution index and equal 0.37

4. Results and Discussion

4.1. Petrographic investigation

The studied sandstone samples of the Kareem Formation (Middle Miocene) are classified as Quartz Wacke (Figure 3A and B).This sandstone is considered very fine to fine-grained with slightly medium-sized grains. The clay matrix is more than 10% of its composition, and the quartz is the main constituent, where it is dominated by monocrystalline with straight extinction. Potash and plagioclase feldspar varieties follow the quartz in quantity, besides, considerable amounts of glauconite are recorded. The sand grains are well cemented with carbonate, clay, and slightly iron oxides. These sandstones are characterized by textural and mineralogic immaturity.

The studied carbonate samples of the Rudeis Formation (Early Miocene age) are classified as Sandy Wackestone, which mainly composed of very fine sand grain size disseminated in microcrystalline carbonate groundmass, partially dolomitized with a considerable amount of foraminiferal tests and echinoids (Figure 3C and D).

The visual porosity in the studied sandstone of Kareem Formation is mainly primary intergranular porosity contributed with secondary porosity resulted from the leaching and dissolution of feldspars, calcite cement, and pore-filling detrital clay (Figure 3A). The sandstones were subjected to compaction as evidenced by the deformed feldspar grains, simple and complex fracturing of quartz grains, and the presence of convex and concave contacts.

4.2 Absolute permeability models

The absolute permeability is determined using five models, these models were compared according to porosity and displacement pressure to determine the suitable model for estimation of the absolute permeability for the studied samples. These models will be used to identify the near facies description of sandstone and carbonate samples that will be compared with the results of petrographic studies.

4.2.1 Porosity and absolute permeability models

The relationships between porosity (*Ø*) and absolute permeability (*k*) (Figure 4) that were determined using the five models of Tixier, Timur, Coats & Dumanoir, Schlumberger, and Aigbedion, for the nine samples, revealed that the relationships by using Schlumberger and Aigbedion models show the best correlation coefficient values which are greater than 0.9, whereas the other models of Tixier, Timur, and Coats & Dumanoir show correlation coefficient values less than 0.9. Therefore, Schlumberger and Aigbedion models are powerful models for determining absolute permeability that is highly correlated with porosity.

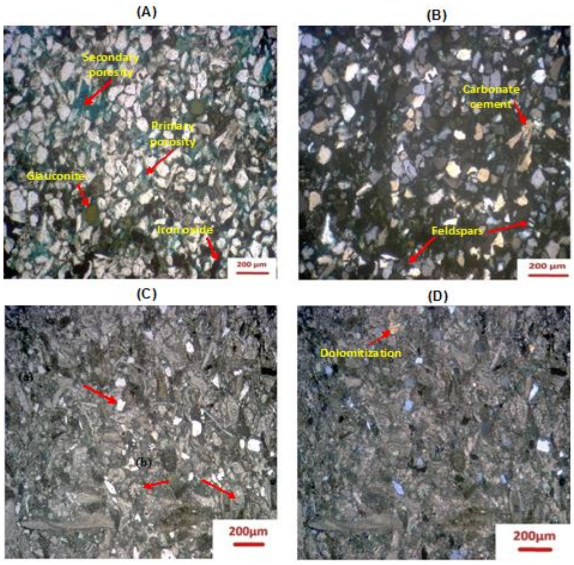

Fig. 3 The photomicrographs A) and B) show Quartz Wacke microfacies with K-feldspars (yellow stained), glauconite and partial cementation, Kareem Formation, PPL and XPL, respectively. The photomicrographs C) and D) show Sandy Wackestone microfacies with foraminiferal and echinoids tests, Rudies Formation, PPL and XPL, respectively

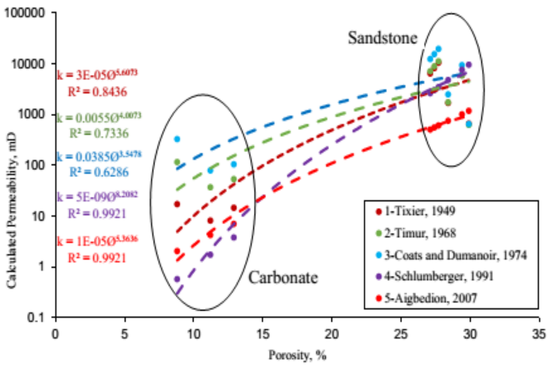

Fig. 4 Absolute permeability (k) and porosity (Ø) relationship for the five models.

4.2.2 Displacement pressure and absolute permeability models

The comparison between displacement pressure (*pdi*) for the nine samples and the calculated absolute permeability (*k*) using the five models of Tixier, Timur, Coats & Dumanoir, Schlumberger, and Aigbedion (Figure 5) showed that the inverse power relationships for Schlumberger and Aigbedion models are of excellent reliability (up to 0.92) followed by Tixier model, where the correlation coefficient value is 0.91. On the other hand, the absolute permeability values, that were determined by the other models are of lesser reliability (less than 0.9).

4.2.3 The lithology comparison and identification

The near facies description of the Kareem and Rudeis rock samples by plotting the results of absolute permeability that were calculated by Schlumberger and Aigbedion models on the Chilingarian chart revealed that; the sand stone rock samples of Kareem Formation can be described as clayey to silty sandstone lithofacies (Figure 6a), whereas the carbonate rock samples of Rudeis Formation can be classified as intercrystalline limestone and dolomite lithofacies (Figure 6b). These are highly compatible with the petrographic results which revealed that, the sandstone type of Kareem Formation is quartz wacke microfacies (Figure 3A and B), whereas the carbonate type of Rudeis Formation is sandy wackestone microfacies (Figure 3C and D).

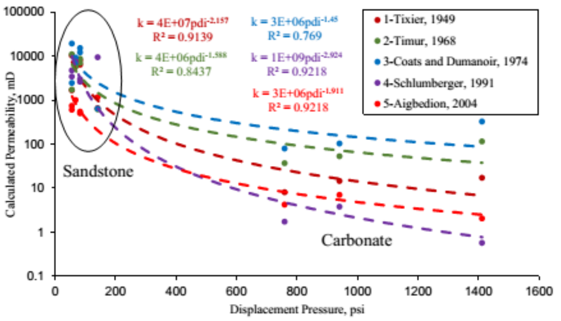

Fig. 5 Absolute permeability (k) and displacement pressure relationship for the five models.

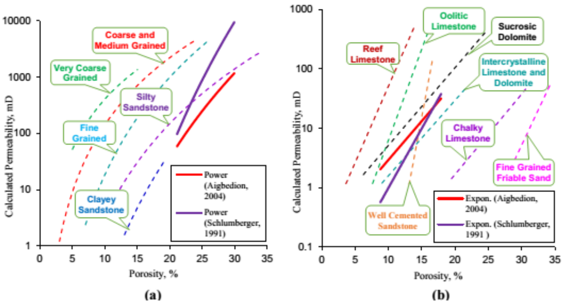

Fig. 6 The comparison of Schlumberger and Aigbedion models for: **(a)** Six sandstone samples to identify the sandstone type of Kareem Formation (solid lines), and **(b)** Three carbonate samples to identify the carbonate type of Rudeis Formation (solid lines)[27].

4.3 Relative permeability models

The relative permeability is estimated by using the Purcell model (Equations 8 and 9), the Corey model (Equations 10 and 11), and Brooks-Corey model (Equations 12 and 13). These models are also based on the experimental data of the capillary pressure test for the nine samples.

4.3.1 Comparison of the three relative permeability models

The comparison between the three relative permeability models for the sandstone rock samples of Kareem Formation(sample number 1 as an example, Figure 7a) and the carbonate rock samples of Rudeis Formation(sample number 7 as an example, Figure 8a) revealed that, the studied samples are wetting phase wet according to the cross point values of the Corey (between 0.5 and 0.6) and Brooks-Corey (between 0.6 and 0.7) models where the latter one seems to be more deviated to the right (wetting phase-wet).On the other hand, the cross-point value of the Purcell model show nearly neutral wettability (around 0.5) for the sandstone and carbonate samples.

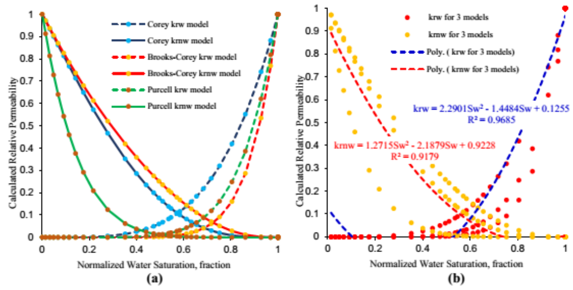

Fig. 7 Cross plots showing: **(a)** The comparison, and **(b)** The mathematical correlation, of the three relative permeability models for sandstone sample number 1 (as an example) of the Kareem Formation.

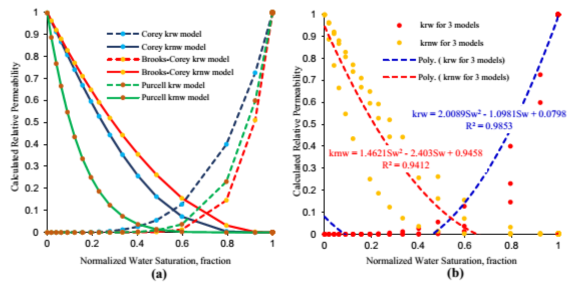

Fig. 8 Cross plots showing: **(a)** The comparison, and **(b)** The mathematical correlation, of the three relative permeability models for carbonate sample number 7 (as an example) of the Rudeis Formation.

4.3.2 Mathematical correlation of relative permeability models for each sample

The mathematical correlation of the three wetting non-wetting relative permeability models is utilized to represent the relative permeability curves by one curve for each non-wetting and wetting relative permeability. Therefore, the mathematical form, for the wetting and non-wetting phases, is described by two polynomial second order degree equations for each sandstone (sample number 1 as an example, Figure 7b) and carbonate sample (sample number 7 as an example, Figure 8b), in addition, the cross points became one average point which can be determined by solving the two polynomial equations (wetting and non-wetting) for each sample, where this cross point is an indication of the wettability of sample.

4.3.3 Composite correlation of relative permeability models for all samples

The composite correlation of the three relative permeability models as shown in Figure 9 a and b for the six sandstone samples and the three carbonate samples respectively, is achieved by mathematical solving of the polynomial functions for each sample to get the cross points (Table 2).The average cross point value of the sandstone samples is at 59% wetting phase saturation with correlation coefficient greater than 0.9, whereas for the carbonate samples is at 55% wetting phase saturation. Based on these results, the wettability and reservoir quality of the sandstone rock samples are better than the carbonate rock samples; in addition, the wettability is best described by the Corey relative permeability model, where its cross point value is close to the average value (between 0.5 and 0.6).

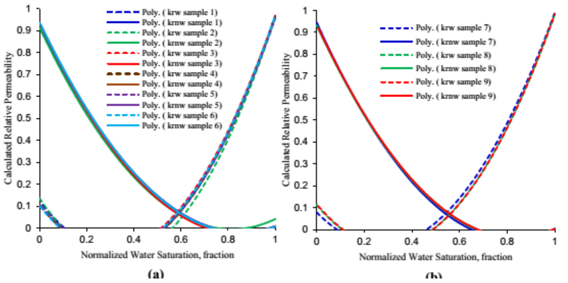

Fig. 9 The composite mathematical correlation of the three relative permeability models for: **(a)** Six sandstone samples of the Kareem Formation, and **(b)** Three carbonate samples of the Rudeis Formation.

Table 2 Polynomial functions of relative permeabilities, correlation coefficients and cross point values for the Kareem sandstone and the Rudeis carbonate samples.

Formation	Sample No.	krnw		krw		Cross Point values	
		Relationship	R^2	Relationship	R^2	x	y
Kareem	1	$krnw = 1.2715\ Sw^2 - 2.1879\ Sw + 0.9228$	0.92	$krw = 2.2901\ Sw^2 - 1.4484\ Sw + 0.1255$	0.97	0.59	0.07
	2	$krnw = 1.3823\ Sw^2 - 2.2545\ Sw + 0.9138$	0.80	$krw = 2.4497\ Sw^2 - 1.6209\ Sw + 0.1355$	0.96	0.61	0.05
	3	$krnw = 1.3477\ Sw^2 - 2.2737\ Sw + 0.9347$	0.92	$krw = 2.2018\ Sw^2 - 1.3377\ Sw + 0.1049$	0.97	0.58	0.07
	4	$krnw = 1.3049\ Sw^2 - 2.2353\ Sw + 0.9375$	0.93	$krw = 2.2627\ Sw^2 - 1.4029\ Sw + 0.1071$	0.97	0.59	0.07
	5	$krnw = 1.304\ Sw^2 - 2.2303\ Sw + 0.935$	0.92	$krw = 2.2147\ Sw^2 - 1.366\ Sw + 0.11$	0.96	0.59	0.07
	6	$krnw = 1.3078\ Sw^2 - 2.2393\ Sw + 0.9383$	0.93	$krw = 2.2297\ Sw^2 - 1.3616\ Sw + 0.1011$	0.97	0.59	0.07
Rudeis	7	$krnw = 1.4621\ Sw^2 - 2.403\ Sw + 0.9458$	0.94	$krw = 2.0089\ Sw^2 - 1.0981\ Sw + 0.0798$	0.98	0.54	0.07
	8	$krnw = 1.3952\ Sw^2 - 2.3239\ Sw + 0.9328$	0.92	$krw = 2.1412\ Sw^2 - 1.2717\ Sw + 0.113$	0.98	0.56	0.07
	9	$krnw = 1.3916\ Sw^2 - 2.3247\ Sw + 0.9371$	0.92	$krw = 2.1586\ Sw^2 - 1.2916\ Sw + 0.1173$	0.98	0.56	0.07

5. Conclusions

The petrographic investigation shows that the studied sandstones (clastic samples) can be classified as Quartz Wackes, while the carbonates (non-clastic samples) can be classified as Sandy Wackestone. The petrographic studies used to confirm the lithology composition of Kareem and Rudeis formations and compared with suitable permeability models.

As relative permeability has important implications for the flow of reservoir fluids, a number of models have been developed to relate relative permeability to other reservoir properties. The main objective of this study is based on solving different absolute and relative permeability models to achieve the best models. Also, the three relative permeability models are handled for making composite correlations of these models by using mathematical solving.

The Schlumberger and the Aigbedion models for absolute permeability estimation give excellent reliability. These models are used to determine the nearest facies description of the sandstone and carbonate samples where the results are highly compatible with the petrographic results.

The comparison between the three relative permeability models revealed that the studied samples are wetting phase wet according to the cross point values of the Corey and Brooks-Corey models; on the other hand, the cross point value of the Purcell model show nearly neutral wettability for the sandstone and carbonate samples.

The wettability of the sandstone rock samples (about 59%) of Kareem Formation is better than the carbonate rock samples (about 55%) of Rudeis Formation; in addition, the wettability is best described by the Corey relative permeability model.

Since this study aims to assign and derive new models that can be used for permeability calculations and wettability of rock samples, where permeability is usually measured experimentally utilizing basic core analysis that consumes cost and time, so further studies are required to compare between the results of wettability from measured and calculated permeability values, in addition to the possibility of applying this technique that was utilized in this study on other reservoirs.

6. Conflicts of interest

In accordance with our policy on Conflict of interest please ensure that a conflicts of interest statement is included in your manuscript here. Please note that this statement is required for all submitted manuscripts. If no conflicts exist, please state that “There are no conflicts to declare”.

7. Formatting of funding sources

List funding sources in a standard way to facilitate compliance to funder's requirements.

8. Acknowledgments

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