Prediction of Relative Permeability from Resistivity Index and Capillary Pressure Data

Hassan M. Sbiga,
Libyan Petroleum Institute (L.P.I)
Tripoli-Libya
hasanespiga@yahoo.com hasanespiga@gmail.com

Saber Elmabrouk
School of Applied Science Engineering
Libyan Academy
Tripoli-Libya
saber.elmabrouk@academy.edu.ly

Walid Mohamed Mahmud
Department of Petroleum Engineering
University of Tripoli
Tripoli-Libya
walidt@hotmail.com

Abstract

Relative permeability data are used to predict the most effective hydrocarbon displacement mechanisms in a reservoir and how to deplete most of the oil or gas out of the reservoir as quickly and cheaply as possible. Determination of capillary pressure and relative permeability are traditionally conducted in laboratory. However it is expensive, difficult, and time-consuming to measure capillary pressure and relative permeability in many cases. Models representing such relationships show that capillary pressure and relative permeability could be inferred from resistivity data using analytical mathematical models derived theoretically. In fact two parameters out three (capillary pressure, relative permeability or resistivity) could be inferred using these models if only one of the parameters is known. In this paper, laboratory measurements of resistivity index, capillary pressure with different techniques, and relative permeability were conducted on samples from two fields representing Libyan sandstone and carbonate reservoirs in order to review analytical mathematical models correlating resistivity index, capillary pressure and relative permeability. The results of relative permeability calculated using these models are analyzed and compared with data obtained from laboratory experiments. This paper shows that the three flow distribution functions, resistivity index, capillary pressure and relative permeability and also shows that relative permeability can be calculated from experimental data of both resistivity index and capillary pressure. Good matching between relative permeabilities calculated from models and with experimental data.

Keywords :   Capillary pressure, models, relative permeability, distribution function

1. Introduction

It is known that the three important parameters: resistivity, capillary pressure, and relative permeability, are all function of fluid saturation in porous medium. This implies that there maybe a correlation among the three parameters. Models representing such relationships show that capillary pressure and relative permeability could be inferred from resistivity data using analytical mathematical models derived theoretically. Literature on the relationship between capillary pressure and resistivity index has been scarce. Szabo [1] proposed a linear model to

correlate capillary pressure with resistivity by assuming the exponent of the relationship between capillary pressure and water saturation is equal to that of the relationship between resistivity and water saturation. Longeron et al. [2] measured resistivity index and capillary pressure under reservoir conditions simultaneously, however, no attempt was made to correlate the two parameters. Li and Williams [3] developed a correlation between resistivity and capillary pressure theoretically. The model was derived according to the fractal modelling of porous media. As mentioned previously, it is difficult to measure both capillary pressure and relative permeability. However, it is relatively easier to measure capillary pressure, especially when mercury-intrusion approach is applied. It maybe because of this that several mathematical models have been proposed to infer relative permeability from capillary pressure data. Purcell [4] developed a method to calculate permeability using capillary pressure curves measured by mercury-injection. Later, Burdine [5] introduced a tortuosity factor in the model. Corey [6] and Brooks and Corey [7] summarized the previous work and modified the method by representing capillary pressure curve as a power law function of the wetting-phase saturation. The modified model was known as the Brooks and Corey relative permeability model. However, literature on the relationship between relative permeability and resistivity index has also been scarce. Pirson et al. [8] proposed an empirical model to calculate relative permeability from resistivity data. Li [9] derived a model to infer relative permeability from resistivity index and verified the model using experimental data.

2. Procedures

In order to compare with experimental results, ten similar high porosity samples from two carbonate and sandstone oil fields were selected. Core samples were initially selected to study petrophysical parameters and their effect on resistivity. One and a half inch diameter core plugs were cut from full diameter core in the horizontal direction using a diamond core bit with water as bit coolant and lubricant. The samples were extracted of hydrocarbons using toluene, leached of salt using methanol and oven dried at 80 ^{O}C for a period of 48 to 72 hours, and then left to cool to room temperature before conventional core analysis commenced. Routine core analysis porosity and permeability measurements were first conducted on the plugs in core laboratory at the Libyan Petroleum Institute (L.P.I) and the results shown in Table 1.

Measurement of resistivity index was performed using fully saturated rock sample. Water saturation of rock sample is brought down from 100% using semi-permeable porous plate in a capillary pressure cell. A multiple sample desaturation cell enables to desaturate a set of core samples by the porous plate method. Humidified air at certain capillary pressure level is usually introduced to displace water. After capillary equilibrium, the water saturation is determined gravimetrically by using a high precision weighing balance and the resistivity of the partially saturated sample is measured. To further reduce the water saturation of the rock sample, the capillary pressure is increased to the next higher value, which further displaces more water, and water saturation and resistivity are re-measured. This process continued until irreducible water saturation is reached at 120 psig. There are three methods commonly used in laboratory to determine capillary pressure; mercury injection, porous plate and centrifuge. Capillary pressure of any two phase system can be converted to another provided the relevant interfacial tension and contact angle are known. The experimental data used in this study were obtained from porous plate and centrifuge methods which were conducted on ten core samples at the Libyan Petroleum Institute.

Relative permeability of a rock to oil, gas or water can be measured using core samples by either steady state or unsteady state methods [12]. In the former method, a fixed ratio of fluids is forced through the rock sample until pressure and saturation remain unchanged for a certain period of time. In the latter, only one fluid is injected into a sample that has already been prepared at initial reservoir conditions. This process of relative permeability determination is thought to closely represent water or gas flood in reservoir resulting in breakthrough of water or gas followed by an increase in water or gas saturation and finally residual oil saturation. The measurements of unsteady state can be made at constant injection pressure or constant flow rate. However, the latter is commonly used in most of core analysis laboratories. The core sample can be single plug, composite core made from a stack of plugs or a full diameter core is confined in a core holder. At the start of the experiment, oil is pumped through 100% saturated sample to establish the irreducible water saturation and to determine effective permeability to oil at irreducible water saturation (the base permeability) until no additional water is produced, then the injection of oil into the upstream end of the sample is stopped. Centrifuge maybe used to establish irreducible water saturation for relative permeability determination. Having established the irreducible water saturation and measured effective oil permeability at the irreducible water saturation, water is injected into the upstream end of the core sample at either constant flow rate or constant pressure. Oil and water are collected at the effluent end of the core using fraction

Proceedings of the International Conference on Industrial Engineering and Operations Management
Bandung, Indonesia, March 6-8, 2018

collector. Upstream and differential pressure are recorded versus time together with oil and water volumes until oil production ceases. At this point effective water permeability at residual oil saturation is measured.

Resistivity, capillary pressure and relative permeability have similar features. For example, all are function of fluid saturation in porous medium. This implies that there should be a correlation among the three parameters. The models representing such relationships are discussed in this section.

2.1 Relative Permeability Models from Resistivity Index

Li [9] derived the relationship between relative permeability and resistivity index:

$$Kr_w = Sw^* \frac{1}{RI} \tag{1}$$

krw is the relative permeability of the wetting phase, RI is the resistivity index. Sw* is the normalized saturation of the wetting-phase and is expressed as follows:

$$Sw^* = \frac{S_w - S_{wr}}{1 - S_{wr}} \tag{2}$$

where *Swr* is the residual saturation of the wetting phase.

The wetting-phase relative permeability can be inferred from the resistivity data based on Eq. 1. The computation of non wetting-phase relative permeability will be described as follows. The wetting-phase relative permeability can be calculated using the Purcell approach [4]:

$$Kr_w = (S_W^*)^{\frac{2+\lambda}{\lambda}} \tag{3}$$

where λ is the pore size distribution index and can be calculated from capillary pressure data. After the relative permeability curve of the wetting-phase is obtained using Eq.1, the value of λ can be inferred using Eq. 3. According to the Brooks-Corey model [7] , the relative permeability of the non wetting-phase can be calculated once the value of λ is available. The equation is expressed as follows:

$$Kr_{n_w} = (1 - S_W^*)^2 [1 - (S_W^*)^{\frac{2+\lambda}{\lambda}}] \tag{4}$$

One can see that the entire relative permeability set (both wetting and non wetting phases) can be inferred from resistivity index data using Eqs. 1 and 4.

2.2 Capillary Pressure Models

Brooks and Corey capillary pressure model [7] expressed as follows:-

$$P_{CD} = (S_W^*)^{\frac{-1}{\lambda}} \tag{5}$$

where P_{cD} is the dimensionless capillary pressure (*Pc/pe*); *pe* is the entry capillary pressure and λ is the pore size distribution index, therefore the dimensionless capillary pressure can be determined using Eq. 5 with the value of λ. The second approach to determining capillary pressure is the application of the model developed by Li and Williams [3] as follows:

$$P_{CD} = (I)^{\beta} \tag{6}$$

where β is the exponent in the relation between disjoining pressures and film thickness. One can see from Equation 6 that the dimensionless capillary pressure can be calculated from the resistivity index once the value of β is known. According to the above description, Eqs. 1, 3, 4, 5, and 6 constitute the interrelationship among resistivity index, capillary pressure, and relative permeability. This implies that if one of the three parameters (capillary pressure, relative permeability, and resistivity) is known, the other two could be inferred using these models.

3. Results and Discussion

In this section, results of relative permeability predicted using resistivity index and capillary pressure data are analyzed and compared with experimental data. Also relationships between resistivity index and capillary pressure are discussed.

3.1 Prediction of Relative Permeability from Resistivity Index and Capillary Pressure Data

The relationship between relative permeability and resistivity index (Eq. 1) was verified using the experimental data of resistivity and capillary pressure measured by L.P.I. in sandstone rocks with different permeability (Table 1). All of the experimental data used in this study were obtained in drainage process. Firstly, the values of oil/water relative permeability were predicted with the experimental data of resistivity index using Eqs. 1 and 4. Secondly, the oil/water relative permeability data were predicted using the experimental capillary pressure data. Finally the results of relative permeability predicted from resistivity index and capillary pressure data respectively were compared. Figure 1 shows the oil/water relative permeability data obtained from resistivity index and capillary pressure in Nubian sandstone for sample # 3 with a porosity of 17.05% and a permeability of 352.1 mD. As shown in Figure 1, water relative permeability data predicted from the resistivity index data are close to those predicted using experimental capillary pressure data. The oil relative permeabilities predicted from the resistivity index data are almost equal to those predicted from the experimental capillary pressure data.

Figure 2 shows oil/water relative permeability data obtained from resistivity index and capillary pressure in Nubian sandstone for sample # 9 with a porosity of 14.98% and a permeability of 222.2 mD. As shown in Figure 2, water relative permeability data from experimental resistivity index data using (Eq.1) are close to those predicted using the capillary pressure data. Oil relative permeability from experimental resistivity index data using (Eq.4) are almost equal to those predicted from the experimental capillary pressure data.
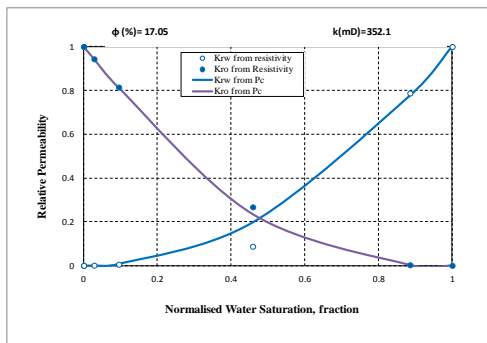

Fig 1. Relative permeability predicted from resistivity and capillary pressure data in Nubian sandstone sample # 3 at ambient conditions
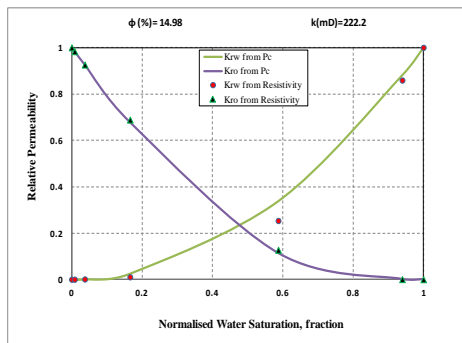
Fig. 2. Relative permeability predicted from resistivity and capillary pressure data in Nubian sandstone sample # 9 at ambient conditions

Figures 3 and 4 show oil/water relative permeability data obtained from resistivity index and capillary pressure in Nubian sandstone samples # 13 and 58 with a porosity of 14.94% and 15% respectively and a permeability of 630.2,

and 82.5 mD respectively. From the figures, water relative permeability data predicted from resistivity index data using (Eq.1) are close to those predicted using the capillary pressure data. Oil relative permeability predicted from resistivity index data using (Eq.4) are almost equal to those predicted from capillary pressure data.
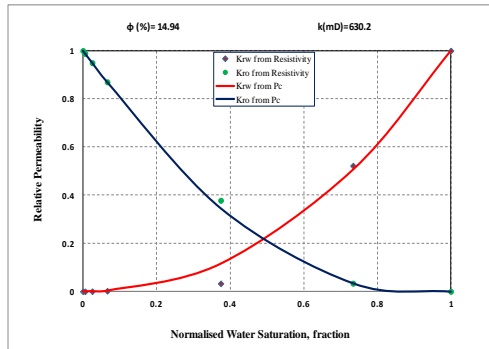

Fig. 3. Relative permeability predicted from resistivity and capillary pressure data in Nubian sandstone sample # 13 at ambient conditions
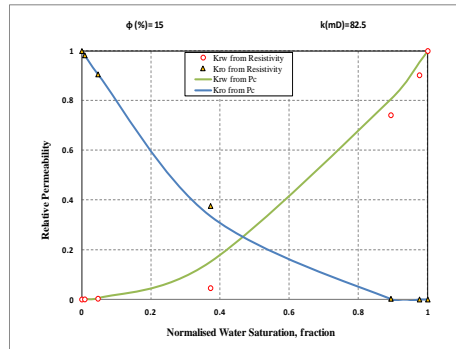
Fig. 4. Relative permeability predicted from resistivity and capillary pressure data in Nubian sandstone sample # 58 at ambient conditions

3.2 Comparison of Predicted Relative permeability from Resistivity with Experimental Data

In the last section, relative permeability data calculated from resistivity index are compared with those computed from capillary pressure instead of experimental data of relative permeability. Thus, relative permeability data were predicted from resistivity index and compared directly with experimental data. Experimental data of resistivity and gas/water relative permeability measured by L.P.I. for five limestone core samples with different permeabilities were used to test the models (Eqs. 1 and 4). The permeability of the core samples ranged from 9.6 to 113.4 mD. Porosity, permeability, and initial water saturation (*Swi*) are listed in Table 1.

Table 1: Porosity and permeability values of two different oil fields.

Sandstone Formation				Carbonate Formation (limestone)			
Sample #	Ø (%)	K(mD)	Swi (f)	Sample #	Ø (%)	K(mD)	Swi (f)
3	17.05	352.1	0.0962	2	25.65	82.71	0.041
9	14.98	222.2	0.0927	6	32.29	68.29	0.0846
13	14.94	630.2	0.0751	7	33.88	113.45	0.1012
58	15.00	82.50	0.238	15	21.21	11.320	0.1909
59	12.93	48.5	0.235	24	16.60	9.67	0.1971

Nitrogen was the non wetting-phase and brine with salinity OF 80,000 ppm was the wetting phase. The resistivity and relative permeability were measured simultaneously at ambient conditions. Results of relative permeability predicted from resistivity index data using Eqs. 1 and 4 were compared with experimental data. Figure 5 shows the comparison of gas and water relative permeability predicted from resistivity index with experimental data in core sample #2. Both gas and water relative permeabilities data predicted from resistivity index data using the mathematical models (Eqs. 1 and 4) were almost equal to the experimental data at the same water saturation.
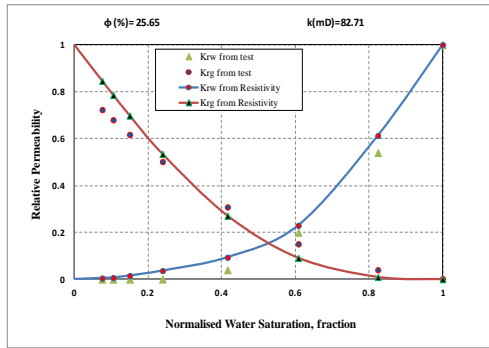
Fig. 5. Comparison of relative permeability predicted from resistivity with experimental data (sample # 2, Ø = 0.26, K=82.71md, swi = 0.041)
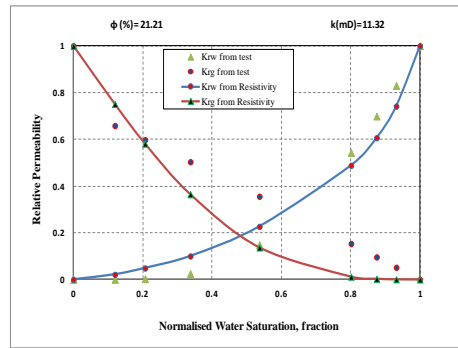

Fig. 6. Comparison of relative permeability predicted from resistivity with experimental data (sample # 15, Ø = 0.21, K=11.32 md, swi= 0.1909)

For core sample #15, results are plotted in Figure 6. Water relative permeability data calculated using Eq. 1. are approximately equal to the experimental data. However, for the gas phase, the predicted relative permeability is smaller than the experimental data.

Results of the remaining three core samples are shown in Figures 7 to 9. It can be seen that the models (Eqs. 1 and 4) work better in core samples with higher permeabilities than in those with lower permeabilities. The predicted gas phase relative permeability is smaller than experimental data in core samples with low permeabilities. This might be due to gas slippage in two phase flow or maybe due to pore geometry of samples with low permeability. As gas saturation increases, first the larger pores dominate the resistivity. At this stage, water saturation is still high because micro-pores hold up a large water volume, which causes a high resistivity. As gas starts to drain water from micro-pores, water saturation decreases sharply with little influence on resistivity, Swanson, [10]. The gas slip effect in two phase flow was not considered in the experimental data of relative permeability. The gas slippage is greater in core samples with low permeabilities than in those with high permeabilities.
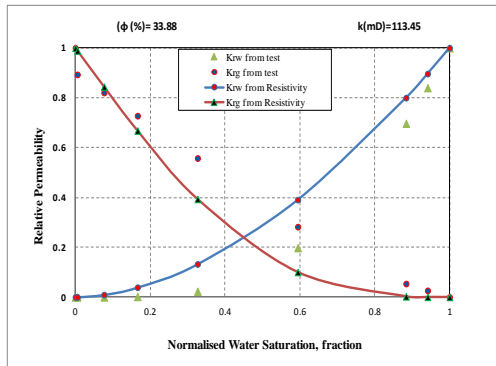

Fig.7. Comparison of relative permeability predicted from resistivity with experimental data (sample # 7, Ø = 0.34, K=113.5 md, swi= 0.1012)
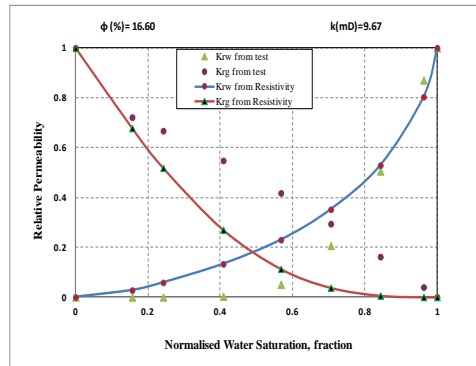

Fig. 8. Comparison of relative permeability predicted from resistivity with experimental data (sample # 24, Ø = 0.16, K=9.7 md, swi= 0.1971)
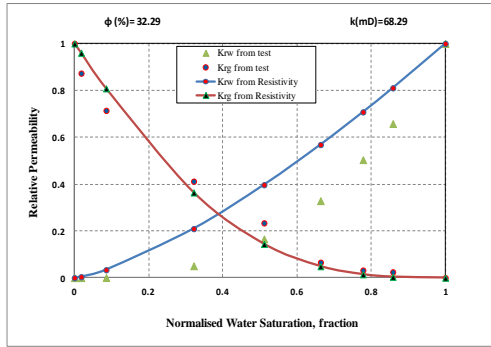
Fig. 9. Comparison of relative permeability predicted from resistivity with experimental data (sample # 6, Ø = 0.32 K=68.3 md, swi= 0.0846)

3.3 Validation of Relationship Between Capillary Pressure and Resistivity Index With Experimental Data

Experimental data of gas-water capillary pressure and resistivity measured simultaneously by L.P.I. were used to test the relationship between capillary pressure and resistivity index (Eq. 6). Experiments were conducted at ambient conditions on sandstones obtained from two oil reservoirs but different formations. Group I core samples were from one formation with high permeability and Group II were from another formation with low permeability. Permeability in Group I ranged from 76.6 to 953 mD; permeability in Group II ranged from 3.35 to 37.1 mD as shown in Table 2.

Table 2: Properties of rock samples, L.P.I.

	Sample #	Ø (%)	K (md)	Swi (f)
Group I	34	9.3	115	0.170
	45	8.43	76.6	0.161
	52	12.03	225	0.212
	61	13.98	953	0.132
	114	15.42	602	0.095
	124	14.79	231	0.134
Group II	21	15.71	6.35	0.516
	156	11.65	8.70	0.403
	190	11.27	37.1	0.214
	226	7.74	6.87	0.262
	396	8.95	9.41	0.271
	447	14.13	3.35	0.695

Relationships between capillary pressure and resistivity index of Group I are shown in Figure 10. On log-log plot, a straight line exists in the range with great values of capillary pressure and resistivity index (corresponding to small water saturations), as predicted by the model (Eq. 6). Figure 11 shows relationships between capillary pressure and resistivity index of Group II core samples with low permeability. The results shown in Figure 11 demonstrate the

validity of Eq. 6 in low permeability core samples. Comparing Figure 11 with Figure 10, it can be seen that the model (Eq. 6) works better in core samples with low permeabilities than those with high permeabilities.
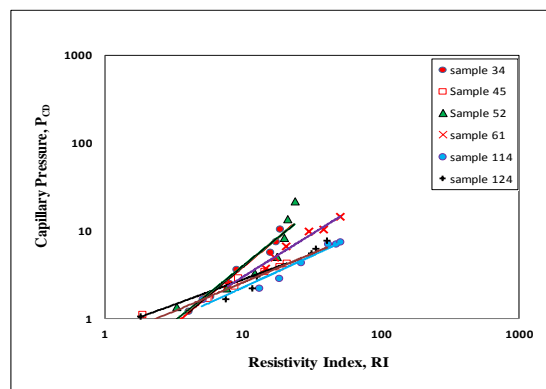

Fig. 10. Relationship between capillary pressure and resistivity index in the core sample (Group I, high permeability)
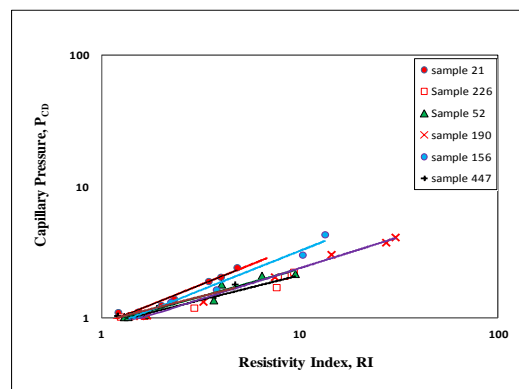
Fig.11. Relationship between capillary pressure and resistivity index in the core sample (Group II, low permeability)

As demonstrated in Figure 10, Eq. 6 works properly for high values of capillary pressure and resistivity (corresponding to low values of water saturations) in core samples with high permeabilities. At high water saturations, experimental data deviate the power law model. This maybe because water saturation distribution is consistent at high water saturations. In this case, water (wetting phase) remains in both small and large pores. In the case of low permeability core samples, the number of data points that deviate the power law model is less than in high permeability. This maybe due to the irregular surface of core samples with low permeability or due to existence of micro-pore type system. In low permeability rock, most of the pores are small and the pore system maybe irregular. As gas saturation increases, first the larger pores dominate the resistivity. At this stage, water saturation is still high because micro-pores hold up a large water volume, which causes high resistivity. As gas starts to drain water from micro-pores, water saturation decreases sharply with little influence on resistivity, Swanson [10].

4. Conclusions

The following conclusions may be drawn according to the present study:

- The three saturation functions, resistivity index, capillary pressure and relative permeability, are coupled and can be inferred from each other using mathematical models described in this paper if one of the three parameters is known.

- Relative permeability can be calculated from experimental data of both resistivity index and capillary pressure.

- Good matching between relative permeability predicted from models and that one obtained from experimental work directly especially for wetting phase in samples with high permeability.

- A power law model applies to the relationship between capillary pressure and resistivity index. Ability of fitting to experimental data is greater in low permeability rocks than in high permeability rocks.

Nomenclature

kr$_{nw}$ = relative permeability of non wetting phase.
kr$_w$ = relative permeability of wetting phase.
Pc   = capillary pressure.
pe   = entry capillary pressure.
S$_w$ = wetting phase saturation, fraction
S$_w$*   = normalized wetting phase saturation, fraction
S$_{wr}$ = residual wetting phase saturation.
Sw (f) = water saturation (fraction)
λ   = pore size distribution index.
RI   = resistivity index
K   = permeability , mD

Acknowledgment

References

[1] Szabo, M.T.: New Methods for Measuring Imbibition Capillary Pressure and Electrical Resistivity Curves by Centrifuge, *SPEJ* (June, 1974), 243-252.

[2] Longeron, D.G., Argaud, M.J., and Bouvier, L.: Resistivity Index and Capillary Pressure Measurements under Reservoir Conditions using Crude Oil, SPE 19589, *Proceedings* of the 1989 SPE Annual Technical Conference and Exhibition, San Antonio, TX, USA, October 8-11, 1989.

[3] Li, K. and Williams, W.: Determination of Capillary Pressure Function from Resistivity Data, *Transport in Porous Media* (2006), DOI 10.1007/s11242-006-0009- 9.

[4] Purcell, W.R.: Capillary Pressures-Their Measurement Using Mercury and the Calculation of Permeability, *Trans. AIME*, (1949), 186, 39.

[5] Burdine, N. T.: Relative Permeability Calculations from Pore Size Distribution Data, *Trans. AIME*, (1953), 198, 71.

[6] Corey, A. T.: The Interrelation between Gas and Oil Relative Permeabilities, *Prod. Mon.*, (1954), 19, 38.

[7] Brooks, R. H. and Corey, A. T.: Properties of Porous Media Affecting Fluid Flow, *J. Irrig. Drain. Div.*, (1966), 6, 61.

[8] Pirson, S.J., Boatman, E.M., and Nettle, R.L.: Prediction of Relative Permeability Characteristics of Intergranular Reservoir Rocks from Electrical Resistivity Measurements, *Journal of Petroleum Technology* (May 1964), 561-570.

[9] Li, K.: A New Method for Calculating Two-Phase Relative Permeability from Resistivity Data in Porous Media, *Transport in Porous Media* (2007), DOI 10.1007/s11242-007-9178-4.

[10] Swanson, B. F., 1985, "Microporosity in Reservoir Rocks: Itis Measurements and Influence on Electrical Resistivity" Trans. SPWLA,26th Ann.Logg.Symp., June,17-20.p42-52.

[11] Core lab section Manual, LPI.

[12] Mahmud, W. M, Elmabrouk, S. and Ben Mahmud, H. K., 2017, "Investigating Relative Permeability Measurements using Unsteady-State Core Flooding Method" International Journal of Petroleum and Petrochemical Engineering (IJPPE), Volume 3, Issue 4, 2017, PP 54-64

Biography

Hassan Sbiga is received his B.SC in petroleum engineering from Tripoli University - Libya in spring1992; and Master degree in petroleum engineering from Heriot-Watt University, Edinburgh-UK in 2005; and Doctor of Philosophy (PhD) in Petroleum Engineering from Heriot Watt University, Edinburg UK in 2013. Mr. Sbiga has 20 years experience in oil field and he is a member of SPE. His experience covered Routine and special core analysis, and participated in several joint venture studies concerning Libyan oil Reservoirs. He joined recently to reservoir simulation studies section at LPI, and worked a Lecturer as a co-operator in different Universities and institutes in Libya giving Reservoir Rock Properties Course, Introduction to petroleum engineering, and others. He was selected by HWU as a staff to teach Formation Evaluation course in HWU School Branch in Libya in 2008. Mr. Sbiga also participated , presented, and published papers in national and international conference and journals in petroleum industry.

Saber Kh. Elmabrouk received his Ph.D. degree in reservoir and oilfield management from the University of Regina, Saskatchewan, Canada. He earned his Master's and Bachelor's degrees in Petroleum Engineering from the University of Tripoli, Libya. Dr. Saber is currently a faculty member at the School of Applied Science and Engineering, The Libyan Academy, Tripoli, Libya. He teaches graduate courses in both Petroleum Engineering and Engineering Management departments. His research interests include uncertainty analysis and risk management, modeling, optimization, big data analysis, artificial intelligence, and oilfield management. His research experience and teaching career spans twenty-five years.

Walid Mohamed Mahmud is currently an Assistant Professor at the Department of Petroleum Engineering, University of Tripoli, Libya. In addition to teaching several undergraduate and postgraduate petroleum engineering courses, Dr. Mahmud has supervised numerous undergraduate and postgraduate graduation projects. Dr. Mahmud is the Department Quality Control and Assurance Coordinator. Dr. Mahmud's main research interests include, but not limited to, multiphase flow in porous media, network modeling and relative permeability laboratory measurements.