VOL. 14, NO. 22, NOVEMBER 2019 ISSN 1819-6608
ARPN Journal of Engineering and Applied Sciences

www.arpnjournals.com

RELATIVE PERMEABILITY PREDICTED USING RESISTIVITY INDEX AND CAPILLARY PRESSURE DATA

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ABSTRACT

Capillary pressure and relative permeability are key parameters that govern the fluid flow in geothermal reservoirs. Relative permeability data are used to predict the most effective hydrocarbon displacement mechanisms and the most efficient methods for extracting oil or gas from the reservoir. Determination of capillary pressure and relative permeability are traditionally conducted in the laboratory; however, in many cases these measurements are expensive, difficult, and time consuming. Theoretical models show that capillary pressure and relative permeability could be inferred from resistivity data. In fact, if one of these three parameters is known, the other two can be determined. In this study, laboratory measurements of the resistivity index, capillary pressure, and relative permeability were conducted on samples from two oil fields representing Libyan sandstone (A) and carbonate (B) reservoirs in order to review the analytical mathematical models correlating these variables. The results of the relative permeability calculated using these models were analysed and compared with experimental data obtained in the lab. The results showed that permeability can be calculated from experimental data of either resistivity index or capillary pressure. Good matching was observed between relative permeabilities and those calculated from with experimental data.

Keywords: capillary pressure, models, relative permeability, distribution function.

1. INTRODUCTION

Three important parameters, namely; resistivity, capillary pressure, and relative permeability, are all functions of fluid saturation in porous media, which implies the parameters may be a correlated. Theoretical models representing such relationships show that the capillary pressure and relative permeability could be inferred from resistivity data. However, studies on the relationship between capillary pressure and the resistivity index, as well as those between the relative permeability and the resistivity Index, have been scarce

Longeron *et al.* [2] simultaneously measured the resistivity index and capillary pressure under reservoir conditions; however, no attempt was made to show correlation between the two parameters. 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. In another method Li and Williams [3] developed a theoretical method showing correlation between resistivity and capillary pressure according to the fractal modelling of porous media.

Regarding the relative permeability, Pirson *et al.* [8] proposed an empirical model for calculating relative permeability from resistivity data. Li [9] derived a model for inferring the relative permeability from the resistivity index and verified the model using experimental data.

Determination of capillary pressure and relative permeability are traditionally conducted in the laboratory. However, such measurements are difficult and time consuming. Measuring only the capillary pressure, especially using the mercury-intrusion approach, is easier than measuring both the capillary pressure and relative permeability. Therefore, several mathematical models have been proposed for inferring the relative permeability from only capillary pressure data.

In 1949, Purcell [4] developed a method to calculate the permeability using capillary pressure curves measured by mercury-injection. Later, Burdine [5] introduced a tortuosity factor in the model. Corey [6], Brooks, and Corey [7] further modified the method by representing capillary pressure curve as a power law function of the wetting-phase saturation in a model known as the Brooks and Corey relative permeability model.

2. Procedure

2.1 Sample preparation and Parameter Measurement

To compare the experimental results, a total of 10 samples chosen from two oil fields (carbonate and sandstone) with similar high porosity levels. Initially, the core samples were selected for studying the petrophysical parameters and their effect on resistivity. Core plugs (1.5-in diameter) were cut in the horizontal direction from full diameter cores using a diamond core bit with water as the bit coolant and lubricant. The samples were extracted of hydrocarbons using toluene, leached of salt using methanol, and oven dried at 80°C for a period of 48 to 72 hrs, and left to cool to room temperature before the conventional core analysis was performed. Routine core analysis porosity and permeability measurements were conducted on the plugs in the Core Laboratory at the Libyan Petroleum Institute (LPI) and the results are shown in Table-1.

The resistivity index was first measured using a fully saturated rock sample. The water saturation of the rock samples was reduced from 100% in a multiple sample desaturation cell, which utilized a semi-permeable porous plate in a capillary pressure cell. Then, humidified air at a

certain capillary pressure level was introduced to the desaturation cell to displace the water. After reaching capillary equilibrium, the water saturation was determined gravimetrically using a high precision weighing balance and the resistivity of the partially saturated sample was measured. To further reduce the water saturation of the rock sample, the capillary pressure was increased, and the water saturation and resistivity were re-measured. This process was repeated until the irreducible water saturation reached 120 psig.

There are three methods commonly used in the laboratory to determine the capillary pressure of reservoir rocks; mercury injection, the porous plate, and centrifuge. The capillary pressure of any two-phase system could be converted to another system provided the relevant interfacial tension and contact angle are known. The experimental data used in this study were obtained from measurements performed using the porous plate and centrifuge methods at Libyan Petroleum Institute (Core lab, LPI 1998, 2008) on ten core samples.

Finally, the relative permeability of a rock to oil, gas or water can be measured using core samples by either steady state or unsteady state methods. In the steady state method, a fixed ratio of fluids is forced through the rock sample until the pressure and saturation remain unchanged for a certain period of time. In the unsteady state method, one fluid is injected into a sample that has already been prepared at initial reservoir conditions. The unsteady state process of relative permeability determination is thought to closely represent a water or gas flood in the reservoir, resulting in breakthrough of water or gas followed by an increase in water or gas saturation and residual oil saturation. The measurements of the unsteady state can be made at constant injection pressure or constant flow rate. However, constant flow rate measurements are commonly used in most core analysis laboratories. The core sample can be single plug, composite core made from a stack of plugs or a full diameter core confined in a core holder. At the start of the experiment, oil is pumped through a 100% saturated sample until no water is produced, which establishes the irreducible water saturation and determines the effective permeability to oil at irreducible water saturation (the base permeability). A centrifuge may be used to establish the irreducible water saturation for relative permeability determination. Having established the irreducible water saturation and measured the effective oil permeability that saturation, water is injected into the upstream end of the core sample at either constant flow rate or constant pressure. A constant flow rate is usually used in core analysis laboratories. The oil and water are collected at the effluent end of the core using a fraction collector. The upstream and differential pressure are recorded together with the oil and water volumes with respect to time until oil production ceases. At this point, the effective water permeability at the residual oil saturation is measured.

2.2 Relative Permeability Models from Resistivity Index

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

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

Where K_{rw}indicates the relative permeability of the wetting phase, and RI is the resistivity index. Here S_{w*} is the normalized saturation of the wetting-phase:

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

Where S_w is the saturation of the wetting phase, and Swris the residual saturation of the wetting phase.

The wetting-phase relative permeability can be inferred from the resistivity data based on equation 1. The non-wetting-phase relative permeability can be computed as follows. First, the wetting-phase relative permeability can be calculated using the Purcell approach [4]:

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

Where λ is the pore size distribution index, which can be calculated from capillary pressure data. After the relative permeability curve of the wetting-phase is obtained using equation1, the value of λ can be inferred using equation 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.

$$\mathrm{Kr}_{n_w} = (1 - S_w^*)^2 [1 - (S_w^*)^{\frac{2+\lambda}{\lambda}}] \tag{4}$$

Thus, the entire relative permeability (both wetting and non-wetting phases) can be inferred from the resistivity index data using equations 1 and 4.

2.3 Capillary Pressure Models

The Brooks-Corey capillary pressure model [7] can be expressed as follows:

$$\mathrm{P}_{CD} = (S_w^*)^{\frac{-1}{\lambda}} \tag{5}$$

Where $P_{cD}$is the dimensionless capillary pressure (P_c/P_e) *for* entry capillary pressure P_c, and λ is the pore size distribution index. Therefore, the dimensionless capillary pressure can be determined using equation 5 with the value of λ from equation 3. The Li and Williams model [3] provides a second approach for determining capillary pressure.

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

Where β is the exponent in the relation between disjoining pressures and film thickness. Thus, the dimensionless capillary pressure can be calculated from the resistivity index once the value of β is known.

Equations 1, 3, 4, 5, and 6 describe the interrelationship among the resistivity index, capillary pressure, and relative permeability. As shown above, if one of the three parameters is known, the other two parameters could be inferred using these models.

3. RESULTS AND DISCUSSIONS

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

The relationship between relative permeability and resistivity index (equation 1) was verified using the experimental resistivity and capillary pressure (Core lab, LPI 1998, 2008) in sandstone rocks with different permeability (Table-1). All of the experimental data used in this study were obtained in drainage process. First, oil/water relative permeability were predicted with resistivity index using data using equations 1 and 4. Then, the oil/water relative permeability was predicted using the experimental capillary pressure data (Core lab, LPI 1998, 2008). Finally, the relative permeabilities predicted from the resistivity index data and capillary pressure data were compared. Figure-1 shows the oil-to-water relative permeability data obtained from the resistivity index and capillary pressure in Nubian sandstone sample # 3 with a porosity of 17.05% and a permeability of 352.1 md (Well A-01). As shown in Figure-1, the water relative permeabilities predicted from the resistivity index data using equation 1 were close to those predicted using experimental capillary pressure data, and the oil relative permeabilities predicted from the resistivity index data using equation 4 were almost equal to those predicted from the experimental capillary pressure data.

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

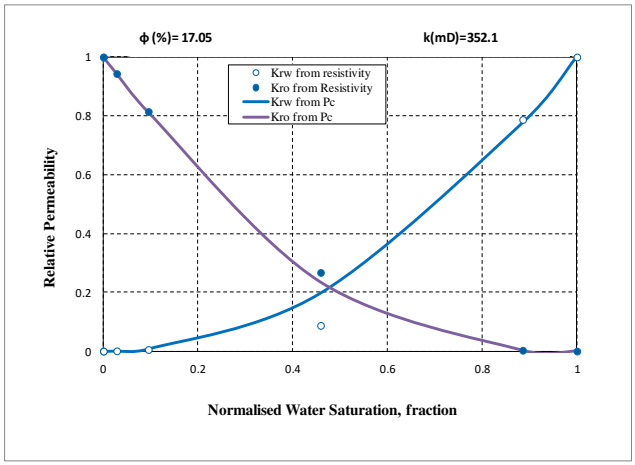

Figure-1. Relative permeability predicted from resistivity and capillary pressure data in Nubian sandstone sample# 3 at ambient conditions.

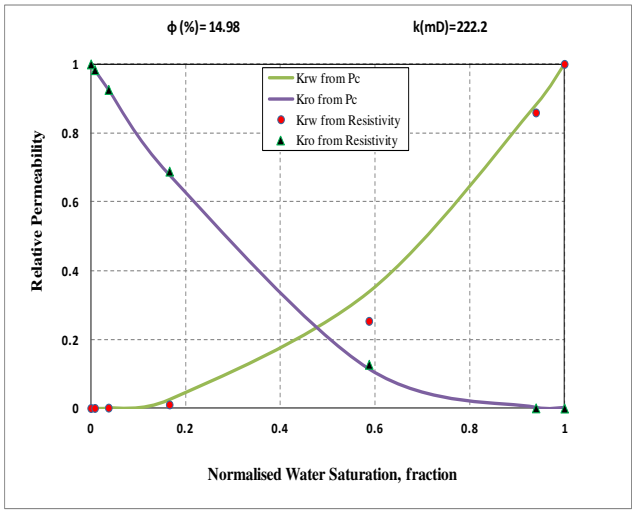

Figure-2. Relative permeability predicted from resistivity and capillary pressure data in Nubian sandstone sample# 9 at ambient conditions.

Figures 3, and 4 show the oil/water relative permeabilities data obtained from the resistivity index and capillary pressure in Nubian sandstone samples # 13and 58, respectively, which have respective porosities of 14.94%, and 15% and a permeabilities of 630.2 and 82.5 mD. As show, the water relative permeabilities data predicted from the resistivity index data using (equation 1) were close to those predicted using the capillary pressure data. Likewise, the oil relative permeabilities predicted from the resistivity index data using (equation 4) are almost equal to those predicted from capillary pressure data.

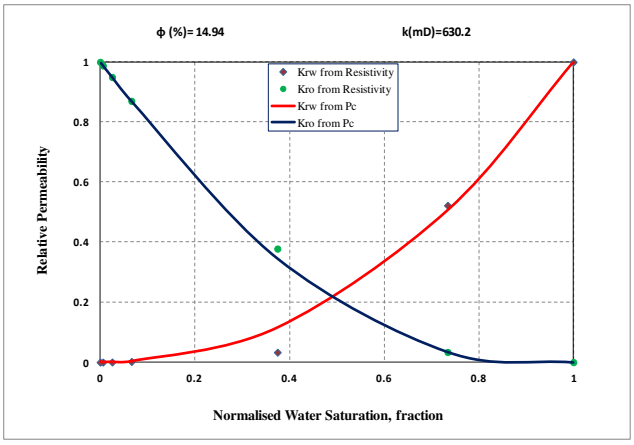

Figure-3. Relative permeability predicted from resistivity and capillary pressure data in Nubian sandstone sample# 13 at ambient conditions.

3.2 Comparison of predicted Relative Permeability from Resistivity Index with Experimental Data

In section 3.1, the relative permeabilities data calculated from the resistivity index are compared with those computed from capillary pressure. In this section, the relative permeabilities predicted from the resistivity index are directly compared with the experimental data. The resistivity index and gas/water relative permeability were measured (Core lab, LPI 1998, 2008) in five core samples (limestone) from well B-01 with different permeabilities. The permeabilities of the core samples ranged from 9.6 to 113.4 md.

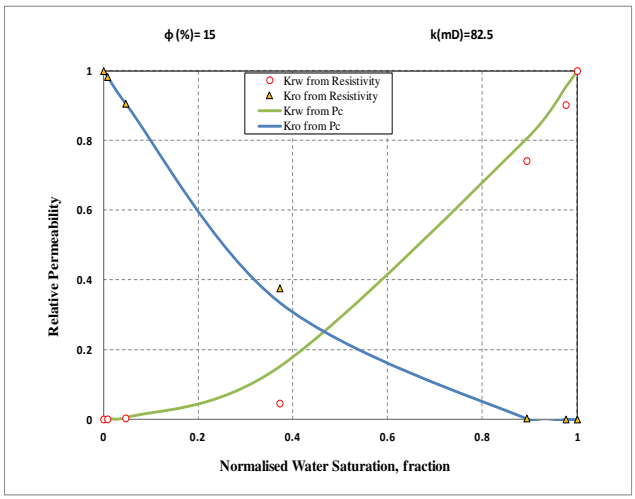

Figure-4. Relative permeability predicted from resistivity and capillary pressure data in Nubian sandstone sample# 58 at ambient conditions.

Table-1. Porosity and permeability values of two different oil fields (wells A-01, and B-01).

Sandstone Formation (Well A-01)				Carbonate (limestone)Formation (Well B-01)			
Sample #	Ø (%)	K(mD)	S_{wi} (f)	Sample #	Ø (%)	K(mD)	S_{wi} (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 80,000-ppm salinity was the wetting phase. The resistivity and relative permeability were simultaneously measured at ambient temperature. The relative permeabilities predicted from the resistivity index data using equations 1 and 4 were compared with the experimental data. Figure-5 shows the comparison of gas and water relative permeability predicted from resistivity index with experimental data for core sample #2. Both the gas and water relative permeabilities predicted from the resistivity index data using (equations 1 and 4 respectively) were almost equal to the experimental data at the same water saturation.

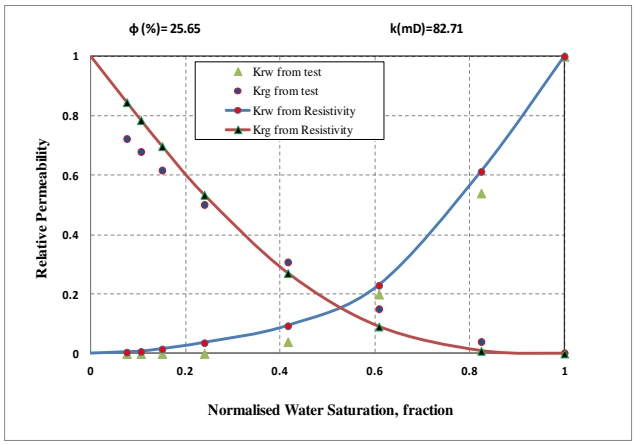

Figure-5. Comparison of relative permeability predicted from resistivity with experimental data (sample # 2, Ø = 0.26, K=82.71md, S_{wi}= 0.041).

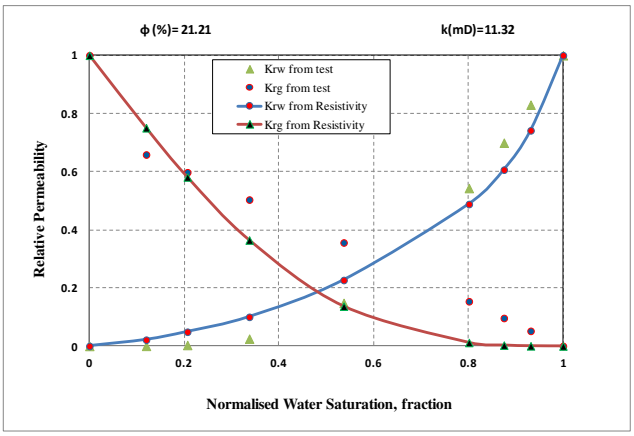

Figure-6. Comparison of relative permeability predicted from resistivity with experimental data (sample # 15, Ø = 0.21, K=11.32 md, S_{wi}= 0.1909).

The results for core sample # 15 are plotted in Figure-6. The water relative permeability data calculated using equation 1 were approximately equal to the experimental data, but for the gas phase (computed using equation 4), the predicted relative permeability was smaller than the experimental data.

The results for the remaining three core samples are shown in Figures 7 to 9. The models (equations 1 and 4) work better for core samples with higher permeabilities than those with lower permeabilities. The predicted gas phase relative permeability was smaller than experimental data in core samples with low permeabilities, which One of the possible reason may be a result of gas slippage in the two phase flow or to pore geometry. As gas saturation increases, the larger pores dominate the resistivity. At this stage, the water saturation is still high because micro-pores hold a large water volume, which causes high resistivity. However, as the increasing gas saturation drains water from the micro-pores, water saturation decreases sharply with little influence on resistivity, [10]. However, the gas slip effect in two-phase flow was not considered in the experimental relative permeability data. Therefore, gas slippage is greater in core samples with low permeabilities than in those with high permeabilities.

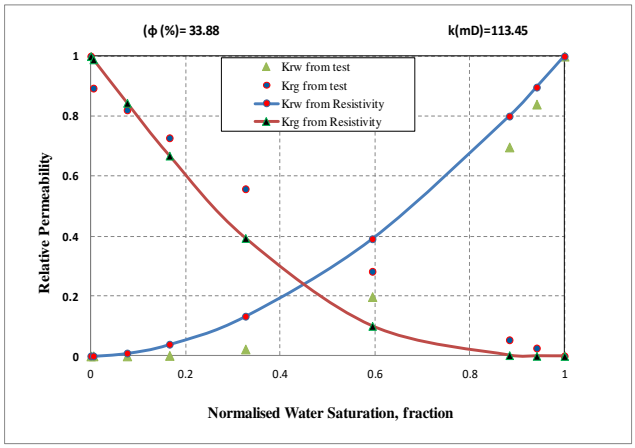

Figure-7. Comparison of relative permeability predicted from resistivity with experimental data (sample # 7; Ø = 0.34, K=113.5 mD, S_{wi}= 0.1012).

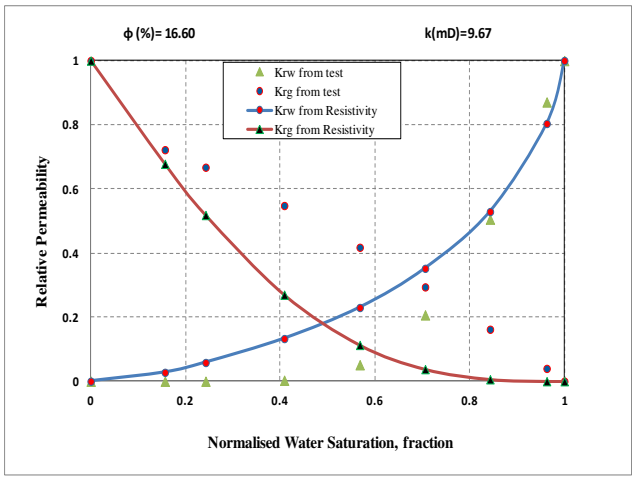

Figure-8. Comparison of relative permeability predicted from resistivity with experimental data (sample # 24; Ø = 0.16, K=9.7 mD, S_{wi}= 0.1971).

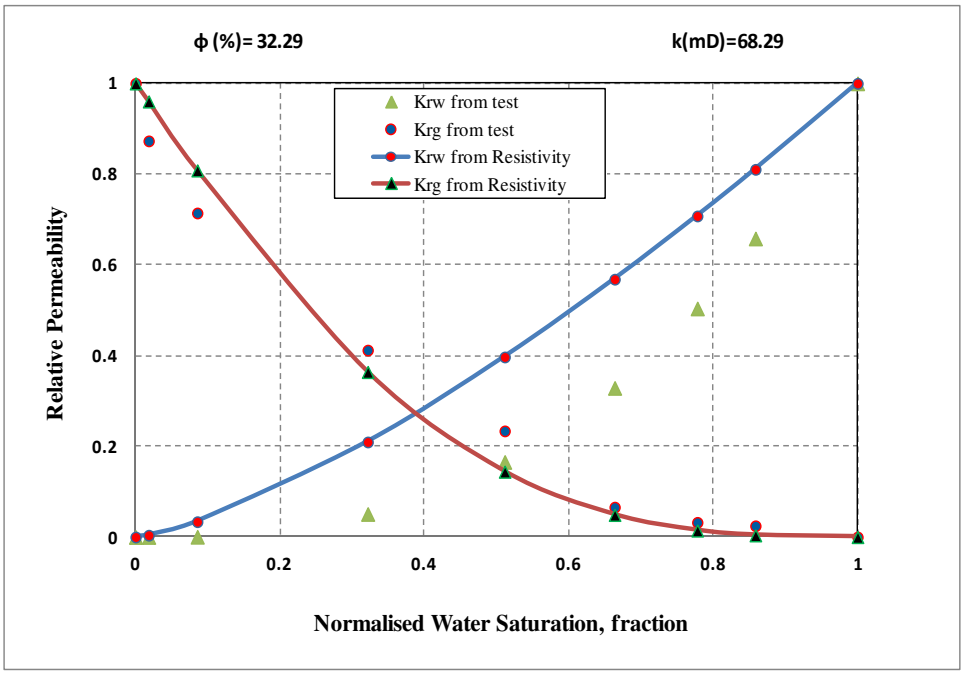

Figure-9. Comparison of relative permeability predicted from resistivity with experimental data (sample # 6; Ø = 0.32, K=68.3 mD, S_{wi}= 0.0846).

3.5 Validation of the Capillary Pressure and Resistivity Index Relationship using Experimental Data

Experimental data for the gas-water capillary pressure and resistivity (Core lab, LPI 1998, 2008) was used to validate the relationship between the capillary pressure and resistivity index (equation 6). The experiments were conducted at ambient conditions. The sandstone core samples were obtained from two oil reservoirs with different formations: Group I core samples were from a high permeability, while the Group II samples were from a low permeability formation. The permeability in Group I ranged from 76.6 to 953 mD, the permeability in Group II ranged from 3.35 to 37.1 mD (see Table-2).

Table-2. Properties of rock samples (Core lab, LPI 1998, 2008).

	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

The relationships between the capillary pressure and resistivity index of the Group I samples are shown in Figure-10. On the log-log plot, straight-line fitting is accurate for samples with high values of capillary pressure and resistivity index (corresponding to samples with small water saturations), as predicted by the model (equation 6).

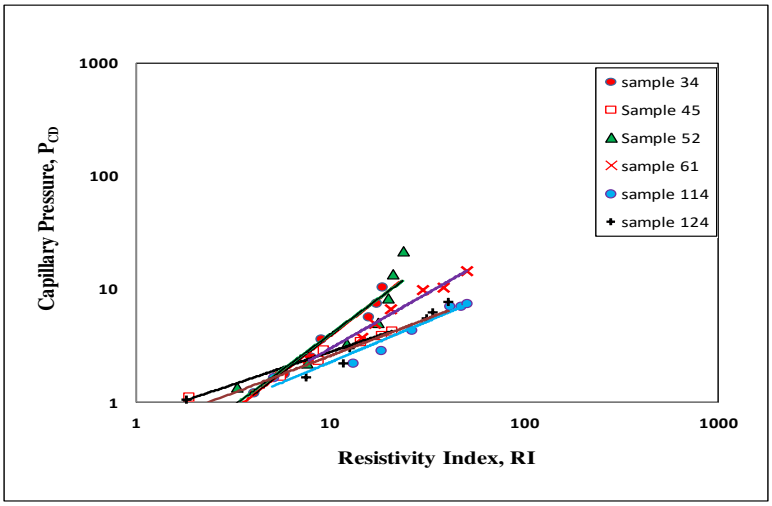

Figure-10. Relationship between capillary pressure and resistivity index for the Group I core sample (high permeability).

Figure-11 shows the relationships between the capillary pressure and resistivity index of the low permeability Group II core samples. These results validate the relationship given in equation 6 for low permeability core samples. Comparing Figure 11 with Figure-10, the model in (equation 6) works better for core samples with low permeability than those with high permeability.

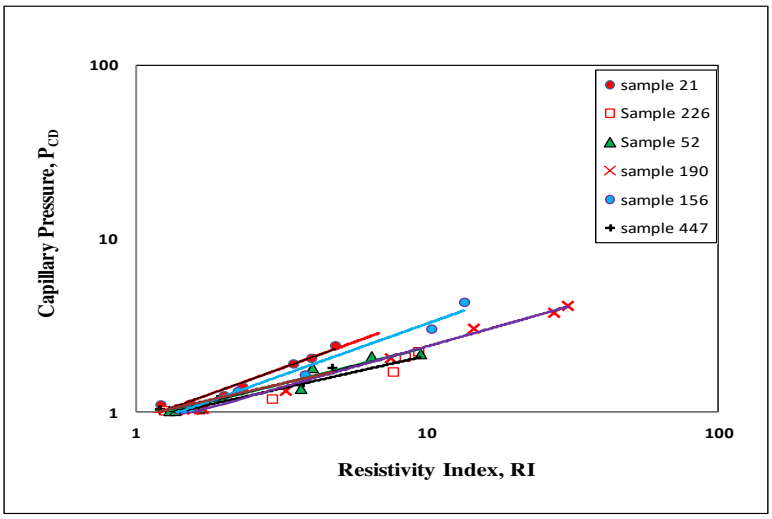

Figure-11. Relationship between capillary pressure and resistivity index in the core sample (Group II, low permeability).

As demonstrated in Figure-10, equation 6 works properly for high values of capillary pressure and resistivity (corresponding to low water saturations) in core samples with high permeability. However, at high water saturations, the experimental data deviate from the power law model, possibly because the water saturation distribution may be more consistent at high water saturations. In this case, water (wetting phase) remains in both the small and large pores. On the other hand, in low permeability core samples, fewer data points deviate from the power law model, possibly due to the irregular surface of low permeability or due to existing micro-pore type systems. In low permeability rock, most of the pores are small, and the pore system may be irregular.

As described above, when gas saturation increases, larger pores dominate the resistivity; however,as the gas starts to drain water from micro-pores, the water saturation decreases sharply with little influence on resistivity [10].

CONCLUSIONS

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

- The three saturation functions, namely the resistivity index, capillary pressure and relative permeability, are coupled and can be inferred from each other using the mathematical models described in this study.

- Relative permeability can be accurately calculated from experimental data of either the resistivity index or the capillary pressure.
- Good matching between the relative permeability predicted from models and that directly obtained from experimental work was observed, especially for the wetting phase in high permeability samples.
- A power law model applies to the relationship between the capillary pressure and resistivity index. The goodness of fit to the experimental data is better for low permeability samples than for high permeability samples.

Nomenclature

K_{rnw}	relative permeability of non-wetting phase.
K_{rw}	relative permeability of wetting phase.
P_c	capillary pressure.
P_e	entry capillary pressure.
S_w	wetting phase saturation.
S_{w*}	normalized wetting phase saturation.
S_{wr}	residual wetting phase saturation.
λ	pore size distribution index.
RI	resistivity index

ACKNOWLEDGMENTS

The authors would like to thank Libyan Petroleum Institute for their permission to publish this work and to all colleagues in the Reservoir Rock Section for their help in providing the necessary data. We would also like to thank United Arab Emirates University who supported the study with any kind of help, ideas, and advice during this project.

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