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Normalize and De-Normalize of Relative Permeability Data for Mishrif Formation in WQ1: An Experimental Work

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Abstract

In many oil-recovery systems, relative permeabilities (kr) are essential flow factors that affect fluid dispersion and output from petroleum resources. Traditionally, taking rock samples from the reservoir and performing suitable laboratory studies is required to get these crucial reservoir properties. Despite the fact that kr is a function of fluid saturation, it is now well established that pore shape and distribution, absolute permeability, wettability, interfacial tension (IFT), and saturation history all influence kr values. These rock/fluid characteristics vary greatly from one reservoir region to the next, and it would be impossible to make kr measurements in all of them. The unsteady-state approach was used to calculate the relative permeability of five carbonate for core plugs from the Mishrif formation of WQ1. The relative permeability calculated by using Johnson, Bossler and Naumann (JBN) Correlation, which is, consider one of the unsteady-state approach where it found that the core plugs are water wet. A normalizing approach has been used to remove the effect of irreducible water and residual saturations, which would vary according on the environment. Based on their own irreducible water and trapped saturations, the relative permeabilities can subsequently be de-normalized and assigned to distinct sections (rock types) of the reservoir. The goal of this research is to normalize the relative permeability that was determined through water flooding.

Keywords: relative permeability, absolute permeability normalization, de-normalization.

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1- Introduction

In the laboratory, relative permeability (kr) is assessed using one of two methods: steady state or unsteady-state studies. The unsteady-state approach takes less time than the steady-state method, but it has a smaller range of saturation change. Measuring kr in mixed-wet rocks with low-IFT fluids is very difficult and necessitates specialized equipment [1].

A petroleum reservoir is a porous subsurface substance that traps oil, gas, or both structurally and stratigraphically. Fluid movement in such a porous media is a very difficult phenomenon to understand. The physical parameters of reservoir fluids must be learned in order to understand and forecast the volumetric behavior of oil and gas reservoirs as a function of pressure. Laboratory investigations on samples of actual reservoir fluids are frequently used to determine these fluid properties [2].

Studying and analyzing a reservoir's performance necessitates a knowledge of the rock's physical properties as well as the existing interaction between the hydrocarbon system and the formation.

Laboratory investigations of cores from the reservoir to be examined are used to determine rock attributes. The cores are taken out of the reservoir, causing changes in the core bulk volume, pore volume, reservoir fluid saturations, and, in some cases, formation wettability [2].

One of the key sources of data available to aid the reservoir engineer in appraising the economic viability of a hydrocarbon accumulation is special core analysis (SCAL) [1].

Special Core Analysis tries to extrapolate information from routine measurements to settings that are more indicative of reservoir conditions. In order to acquire a better knowledge of individual well and overall reservoir performance, SCAL data is used in conjunction with log and well test data. SCAL measurements, on the other hand, are more expensive and are often only performed on a small number of samples or when a challenging strategic reservoir management choice needs to be made (e.g. to gas flood, or not to gas flood). On intact core, tests are performed to determine fluid distribution, electrical properties, and fluid flow characteristics in two and occasionally three phase situations. Fig. **1** shows a schematic diagram of common SCAL measurements [1].

In general, relative permeability is defined as the ratio of a continuous phase's conductance in a linked passage occupied by that phase to the overall conductance of the porous material. As a result, relative permeability of one phase denotes the contribution of that phase's flow to the overall flow. However, some elements of existing phases are not mobile in most displacement processes, and thus

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do not contribute to flow until they join a continuous-flowing channel [2].

As a result, there are two types of saturations in any phase distribution: mobile and immobile saturations, with only the mobile fluids contributing to flow and production. Rock absolute permeability, wettability, IFT, and hysteresis are significant characteristics that affect relative permeability because they control fluid dispersion inside porous media. The immobile fluids in the pore space of the rock limit the path available for mobile fluids to move [3].

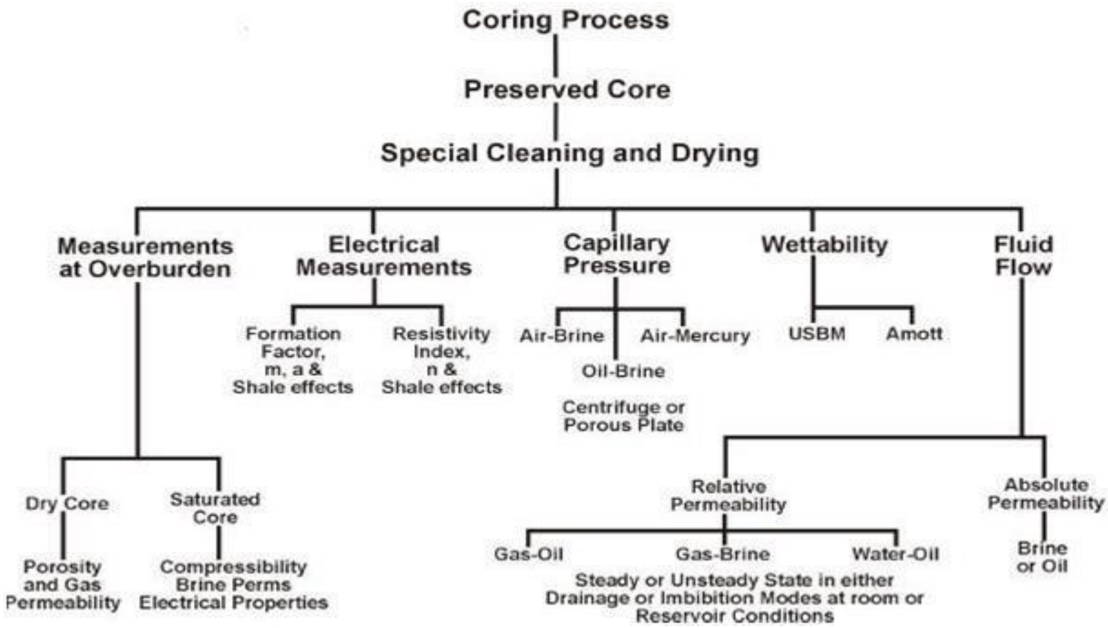

Fig. 1. Schematic Diagram of Common SCAL Measurements

As a result, immobile-fluid saturation is an important factor to consider when determining relative permeability. The immobile saturation of any fluid is given as a function of other fluid saturations, rock absolute permeability, wettability, IFF, and hysteresis behavior as shown in Equation 1:

Simmobile=Simmobile (S, K, wettability, IFT, hysteresis) (1)

To account for the influence of irreducible water and trapped saturations, which would vary depending on the conditions, normalization procedures have been proposed to described the classic normalization procedure as follows [4]:

Si normalize= (Si-Sir)/ (1-Swr-Sor-Sgr) (2)

i=oil, gas, water

Where Sin represents the normalized saturation for phase i, Si represents the phase saturation at any moment, and Sir represents the residual (immobile) saturation for each phase obtained at the end of displacement.

We presume that the kr under new conditions may be approximated from previous kr under different situations using the normalized saturation and the applicable irreducible and residual saturations.

We use relative permeability (Kr) normalization techniques on the experimental water-oil relative permeabilities in this paper.

In the world of petroleum technology, core analysis is a relatively new development. The first studies on this topic were conducted in the context of analyzing and planning secondary oil recovery via water flooding. The current examination of flush field sands necessitates new and independent interpretations of cored material data.
The development of quick, conventional methods for analyzing physical properties of sandstone, such as permeability, porosity, and grain size, and the fluid content of the sand, is a priority [5].

SCAL data, particularly capillary pressure (Pc) and relative permeability (Kr), are critical inputs to the reservoir simulation model, whose predictions are used to orient exploration and production decisions toward optimum productivity and maximum oil recovery [6].

In heterogeneous, fractured, and/or anisotropic rocks, whole core analysis is required to characterize porosity and directional permeability. For heterogeneous reservoirs, full core measurements are necessary because small-scale variability may not be effectively reflected by plug measurements. In heterogeneous rocks, whole core analysis (special core analysis) is also required for determining multi-phase flow parameters [1].

The findings of relative permeability testing on a large number of reservoir rock core samples are typically inconclusive. As a result, relative permeability data collected from different rock samples must be averaged. The relative permeability curves should be standardized before being utilized for oil recovery prediction to eliminate the effect of variable initial water and critical oil saturations. Based on the required fluid saturation for each reservoir site, the relative permeability can then be de-normalized and assigned to different regions of the reservoir [7].

According to L.P. Dake (1979) [8], effective permeability plots can be adjusted by dividing the scales by the absolute permeability k value to obtain relative permeability plots.

$$Kro(Sw)=Ko(Sw)/K \quad (3)$$

$$Krw(Sw)=(Kw(Sw))/K \quad (4)$$

The experimental calculations of relative permeability data and compare it with another correlation makes this work very important to reduce the cost of doing many experiments in the lab.

The important of relative permeability data in the simulation models makes the normalizing and de-normalizing methods very important where it can be used normalizing process to reduce the number of curves for relative permeability data that used in the models and to know the wettability of the field from the intersection between oil and water relative permeabilities.

The goal of this research is to normalize the relative permeability that was determined through water flooding.

2- Permeability

Permeability is assessed by flowing a viscous fluid through a core plug with defined dimensions (A and L) and measuring the flow rate q and Δp, as shown in Equation 5 [9]:

$$K = \frac{q\mu L}{A\Delta p} \quad (5)$$

Where: k = proportionality constant, or permeability, (Darcy's), μ = viscosity (cp), q = flow rate through the porous medium, (cm^3/sec), l = length of core, (cm), A = cross-sectional area, (cm^2).

When measuring permeability, the following conditions must be met:

- Laminar (viscous) flow.
- There is no response between the fluid and the rock.
- At 100% pore space saturation, only a single phase is present.

Permeability can be classified into:

2.1. Absolute permeability

The permeability measurement is sometimes referred to as specific or absolute permeability when the medium is totally saturated with one fluid. The steady-state flow Equation 5 is frequently used to compute absolute permeability [9].

2.2. Effective Permeability

The effective permeability is the permeability to a specific fluid when there are multiple fluids present in the rock pore spaces [9].

When a porous media is saturated with more than one fluid, effective permeability is a measure of the fluid conductance capacity to that particular fluid.

Oil

$$Keo = \frac{q_o\mu_o L}{A\,\Delta p_o} \quad (6)$$

Water

$$Kew = \frac{q_w\mu_w L}{A\,\Delta p_w} \quad (7)$$

Gas

$$Keg = \frac{q_g\mu_g L}{A\,\Delta p_g} \quad (8)$$

2.3. Relative permeability

When two or more immiscible fluids are present in a formation, each fluid tends to obstruct the flow of the others. The relative permeability impact is the reduction in a fluid's ability to flow through a permeable medium. In other terms, it is the ratio of a phase's effective permeability. For the oil phase the effective permeability Ko and oil relative permeability Kro given by Equation 9 [9]:

$$K_{ro} = \frac{K_o}{K} \quad (9)$$

$$K_{rw} = \frac{K_w}{K} \quad (10)$$

$$K_{rg} = \frac{K_g}{K} \quad (11)$$

Where: K=the absolute permeability, kro, krw, krg is the relative permeability for oil, water, gas respectively, ko, kw, Kg Is the effective permeability for oil, water, gas respectively.

Effective and a number of factors influences Relative Permeability:

- Saturations of fluids.
- Rock pore space geometry and grain size distribution.
- Wettability of rocks as shown in Fig. **2**.
- History of fluid saturation (i.e., imbibition or drainage).

-Effect of wettability on relative permeability

The importance of relative permeability curves in reservoir evaluations stems from their capacity to predict fluid output during reservoir investigation. They found a connection between phase saturation and the rock's capacity to produce for a particular phase. These curves are determined through a sequence of standard measurements and calculations carried out in specialized core laboratories, typically utilizing specific forms of frontal advance theory.

The single most crucial stage in generating an accurate history match and properly projecting future performance is the production of realistic relative permeability curves. The engineer is frequently forced to seek analog data from offset rocks in the absence of relative permeability data, which will hopefully represent the fluid flow characteristics inside the reservoir of interest [9].

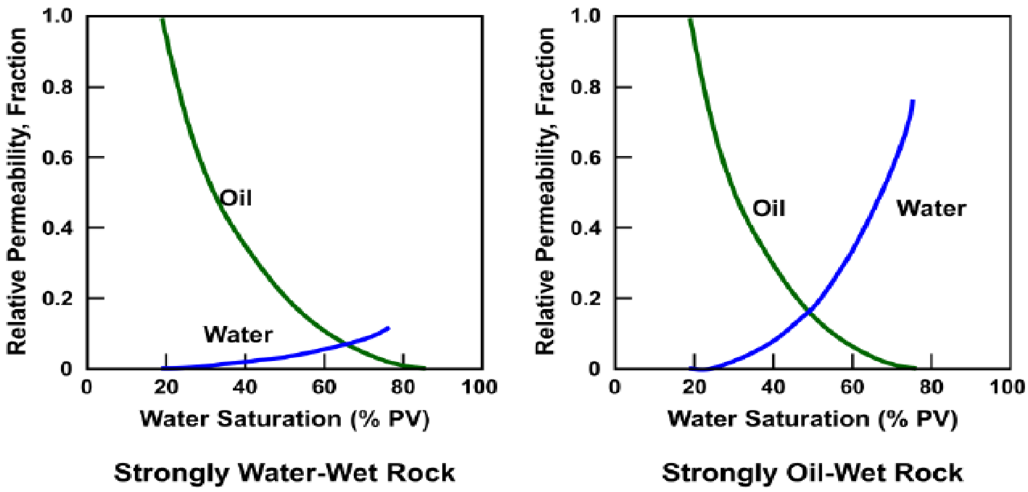

Fig. 2. Effect of Wettability on Relative Permeability

3- Permeability from the Core

For a fluid of known viscosity, all laboratory methods for estimating permeability rely on the measurement or interpretation of a flow rate through and a pressure drop across a sample of known length and cross sectional area. Darcy law is then used to examine the data. In principle, the type of the fluid should not matter; but, when the rock and fluid interact, the nature of the fluid is critical.

The permeability measuring method can be classified depending on the sample type (plug or complete Demeter core), the fluid employed (gas or liquid), and the procedure used (Steady or unsteady state conditions). Standard laboratory analysis processes will generally offer reliable data on permeability of core samples, but the sample type affects the amount and quality of information that may be obtained. If the rock is not homogeneous, whole core analysis, will most likely produce more accurate results than core plug analysis (small pieces cut from the core) [10].

Cutting the core with an oil-base mud is one procedure that has been utilized to improve the accuracy of the permeability determination. Using a pressure-core barrel and reservoir oil to conduct the permeability tests.

Overburden pressure affects permeability because it is an evaluation of the permeability of the reservoir rock in the system, which is an isotropic property of porous rock in some defined sections of the system, meaning it is directional. This factor should be taken into account in deep wells. Plug samples drilled parallel to bedding planes called Horizontal permeability (Kh) and perpendicular to the bedding plane called vertical permeability (Kv) [10].

When calculating reservoir permeability, various factors must be addressed as possible sources of inaccuracy. These are the factors:

- Because of reservoir variability, a core sample may not be typical of the reservoir rock.
- It's possible that core recuperation isn't complete.
- When the core is cut or dried in preparation for analysis, the permeability of the core may be altered. When the rock contains reactive clays, this problem is more likely to arise.
- The sampling procedure could be skewed. There is a strong tendency to analyze only the best portions of the core.

4- Experimental Materials and Setup

4.1. Materials

All investigations used reservoir crude oil from the Mishrif formation in the WQ1 field. To eliminate any possible solid particles, the oil was filtered using a 5.0-lm filter paper (using a vacuum pump). At room temperature of 25 ºC, the oil density and viscosity are 0.9 g/cc and 10 cp, respectively. The high viscosity of crude oil making the experiments are difficult. The dead oil diluted by gas oil with percentage 80 % to decrease the viscosity where the viscosity and density of the new oil prepared are 4.5 cp and 0.82 g/cc.

Formation water taken from the field that used to saturate core plugs and to make water-flooding experiments. The salinity of formation water is 180 Kppm. The composition of formation water as shown in Table **1**.

For the experiments, five core samples were used. XRD (X-Ray Diffraction) examination revealed that samples were primarily composed of calcite, which accounted for more than 97 percent of the rock's mineralogy. The permeability of the cores ranged from (6.02-143 mD), with porosities ranging from 15 to 25%. Table **2** shows the petrophysical parameters of the core. Each core is 1.5 inch (3.81 cm) in diameter and varies in length between (7.09-7.3 cm).

Table 1. The Analysis Composition of Formation Water

Example	Column(A)
Water injected component	Formation water ppm
Cl	96205
So4	650
Na	50089
Ca	12390
Mg	3736

Table 2. Core Dimensions and Petrophysical Properties

sample	Length(cm)	Pore volume,cm3	Porosity,%	Permeability ,mD
1	7.3	12.91	16.06	7.597
2	7.25	13.28	16.62	143.7
3	7.3	17.71	22.01	8.583
4	7.09	18.22	23.39	6.02
5	7.25	17.83	22.42	6.375

XRD was test before injection for limestone core sample as shown in Fig. **3** for the plug 4. From XRD test we notice that the mineral composition for limestone plug 4 is $CaCO_3$ (calcite) with percentage 97% and SiO_2 (Quartz) with percentage 3%.

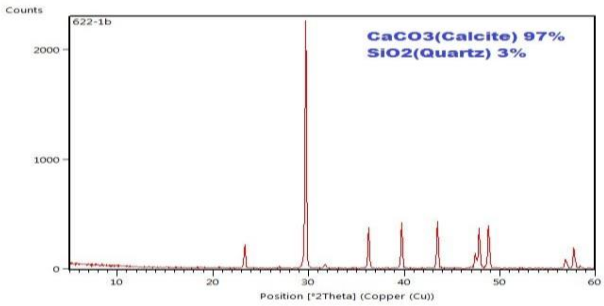

Fig. 3. XRD for the Plug 4

4.2. Core Saturation Procedure

The following procedure applied to saturate the core plugs and calculate the absolute permeability:
1. Cleaning the core plugs by using toluene or methanol in the soxhlet extraction device [11].
2. After placing the cores in the desiccator, a vacuum was applied for one hour to eliminate any remaining air.
3. In the desiccator, drops of formation brine were administered until the formation brine filled the cores inside the beaker.
4. Set the vacuum pump to remove all potential air from the core for 6 to 8 hours.
5. The cores were vacuum-sealed and kept in the desiccator for two days.
6. The pore volume was calculated using the weight difference (wet weight -dry weight) and brine density. At this point, the porosity may be computed. The computed pore volume and porosity are presented in Table **2**.

5- The Methodology

- Relative Permeability Calculations

Following the completion of the flooding sequence and operations, the following approach was used to collect all of the necessary data for relative permeability estimates [12].

- Johnson, Bossler and Naumann (JBN) Correlation

A three-step process may be summarized as follows: Equation 12 provides the injection of pore volume

$$PVinj = \frac{Wi}{PV} \qquad (12)$$

Where: $PVinj$ = Pore volume injection, Wi = Water injected in total, cc.

Equation 13 of the Welge technique calculates average water saturation at the outlet face of rock samples.

$$SWavg = SWi + \frac{NP}{PV} \qquad (13)$$

Where: Np = Oil production through time, Swi= Initial saturation with water, fraction, Sw avg= the average water saturation of the rock samples' outflow face, fraction.

Welge demonstrated that displacing phase saturation downstream at the core's end (Sw2) is related to average displacing phase saturation (SWavg), fractional flow of the displaced phase (oil), and injected pore volume as in Equation 14.

$$Sw2 = SWavg - (fo * Wi) \qquad (14)$$

Where: Sw_2 = End-of-core saturation, fraction, fo = the displaced phase's fractional flow (oil), fraction.

For any given injection, the fractional flow of oil may be determined by determining the average and intercept saturations:

$$fo = \frac{\Delta Sw}{\Delta Pvinj} \qquad (15)$$

Also,

$$fw = 1 - fo \qquad (16)$$

Where: fw= the displacing phase's fractional flow of water, fraction.

Darcy's Law was used to calculate the average oil viscosity for each pressure drop:

$$\mu o = \frac{Ko * A * \Delta Pinj}{q * L * 14700} \qquad (17)$$

Where: μ_0= obtained average oil viscosity, cp, Ko = Permeability of oil, mD, Q = Flow rate, cc/sec.

The average oil viscosity and the injected pore volume affect the effective viscosity:

$$\lambda = \mu avg - \left(\frac{\Delta \mu avg}{\Delta Pvinj}\right) * Pvinj) \qquad (18)$$

Where: λ = Effective viscosity, cp. Finally, the following equations are used to calculate the relative permeabilities:

$$Kro = \mu o * \frac{fo}{\lambda} \qquad (19)$$

$$Krw = \frac{\mu o * fw}{\lambda} \qquad (20)$$

6- Results and Discussion

Because absolute permeability is a significant aspect in the calculations of relative permeability, the absolute permeability for the five core plugs discovered after the saturation process with varying flow rates for larger pore volumes.

6.1. Absolute permeability calculations

After the core plugs saturated with formation water by vacuum pump, the liquid permeability for the core plugs are calculated by injection the brine [13].

Pore volume for core plug 1 is 12.91 cm^3 as shown in Table **2**. Therefore, we injected more than 1.5 pore volumes from the brine with injection rate 2 cm^3/min to calculate the absolute permeability where the pressure stabilizes at 50 psi as shown in Fig. **4** after applying Darcy law the absolute permeability found 7.14 md.

The absolute permeability for plug 2, calculated by injection various rates and record pressure drop as shown in Fig. **5**. By applying Darcy law and taking the average value for the absolute permeability, we calculate it 143.7 md.

The same procedure for the other plugs where more than one pore volume injected to calculate the absolute permeability before relative permeability water flooding experiments. The absolute permeability for the plug 3, 4 and 5 as seen in Table **3** and Fig. **6** and Fig. **7**.

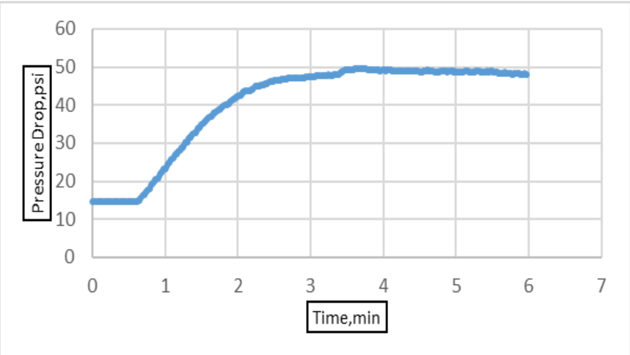

Fig. 4. Absolute Permeability for Plug 1

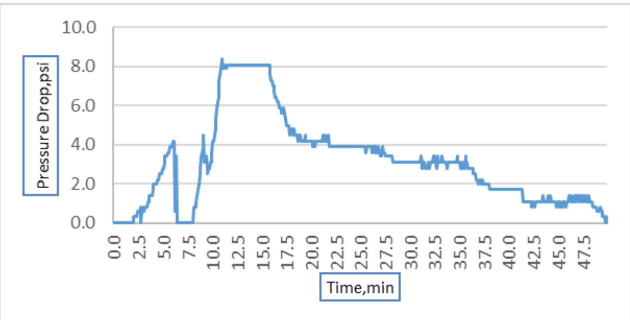

Fig. 5. Time Versus Pressure to Calculate Absolute Permeability for Plug 2

6.2. Oil injection experiment

The oil injected with flowing rate 0.5 cm3/min for all core-flooding experiments to calculate the oil relative permeability and residual water saturation where the results seen in Table **3**. The high value of residual water saturation for plug 2, which is 44% and low value for the plugs 1 and 3, which is 20%.

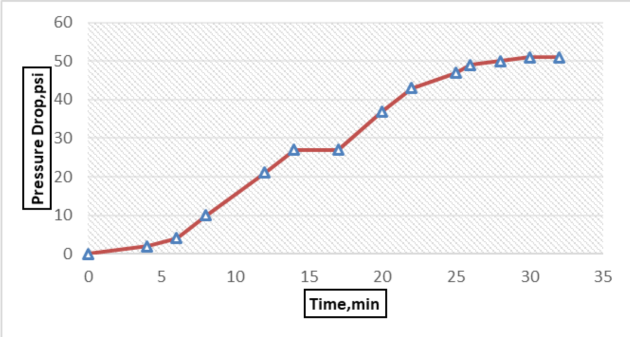

Fig. 6. Time Versus Pressure to Calculate Absolute Permeability for Plug 3

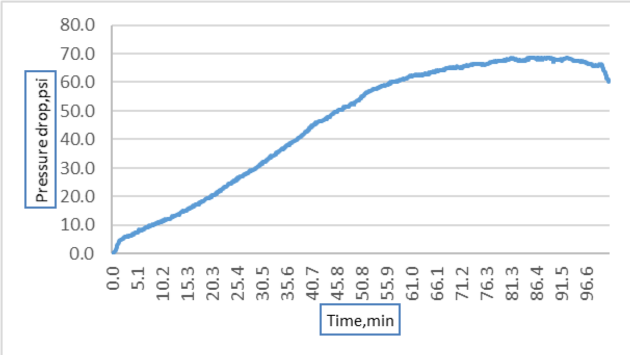

Fig. 7. Time Versus Pressure to Calculate Absolute Permeability for Plug 4

6.3. Coreflood experiments

After the cores flooded with oil, the final pressure of oil injected recorded and stopped the injection process [14].

To measure the oil and water relative permeabilities, the formation water injected with rate 0.5 cm3/min after the system pressure raised to the last pressure value from the oil experiment. For plug 1, the oil and water relative permabilities as shown in Fig. **8**. Where the intersection between Kro and Krw is more than 50%, which mean this plug is water wet.

The same procedure for the other plugs as shown in Fig. **9** to Fig. **12** for the plugs 2, 3, 4, and 5. Table **3** summarize the relative permeability calculations.

Table 3. Summarize of special core analysis data

parameters	Plug 1	Plug 2	Plug 3	Plug 4	Plug 5
Swi,%	20	44	20	28.1	27.12
IOIC,cc	10	7.92	13	13.11	13.64
KL,md	7.514	143.7	8.45	6	6.23
Ko,md	4.35	36.27	4.56	2.98	5.39
Kw,md	2.46	34.92	4.16	1.87	3.19
Krw	0.327	0.642	0.492	0.311	0.512
Kro	0.579	0.667	0.540	0.497	0.865
Sor,%	18	24	19.95	37.37	13.87
NP,cc	8.311	6	10.65	8.1	11.775
RF,%	83.11	75.76	81.92	61.78	88.71
RF at bt,%	40	37.87	58.46	38.14	66
wettability	Water-wet	Water-wet	Water-wet	Water-wet	Water-wet

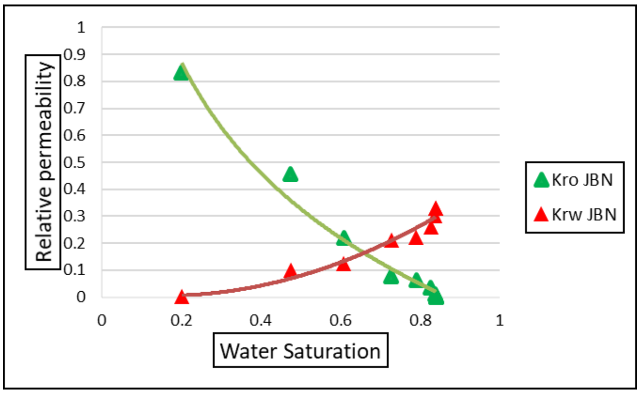

Fig. 8. Relative Permeability Curve for Plug 1

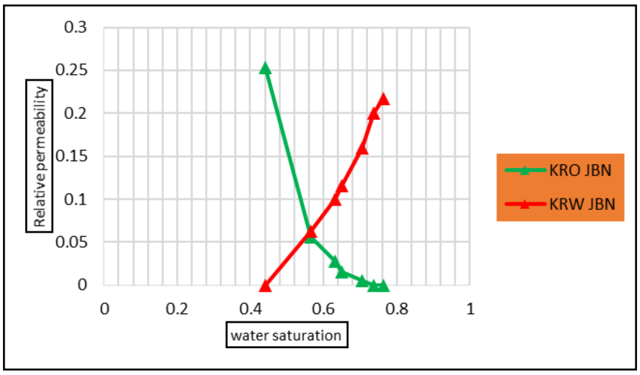

Fig. 9. Relative Permeability Curve for Plug 2

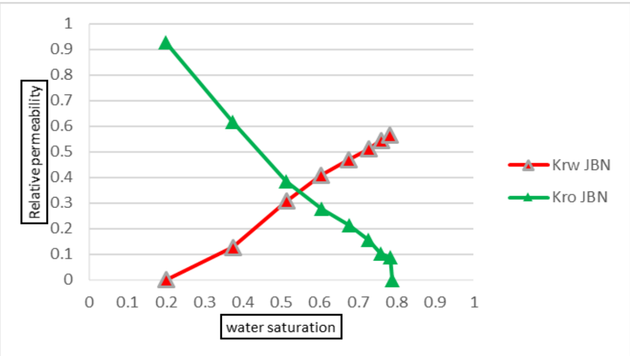

Fig. 10. Relative Permeability Curve for Plug 3

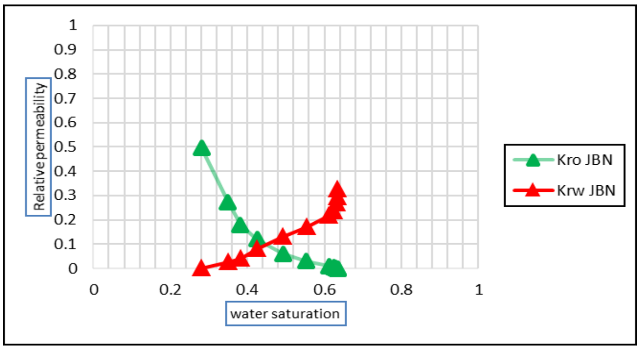

Fig. 11. Relative Permeability Curve for Plug 4

6.4. Normalization and averaging relative permeability data

The procedure for normalize relative permeability data.
Step 1. Calculate the normalized water saturation Sw* for each core sample by using Equation:

$$Sw *= \frac{Sw-Swc}{1-Swc-Soc} \tag{21}$$

Step 2. Determine the relative permeability of oil [(Kro)swc] and relative permeability to water [(Krw)sor] from the experiments as shown in Table **4**

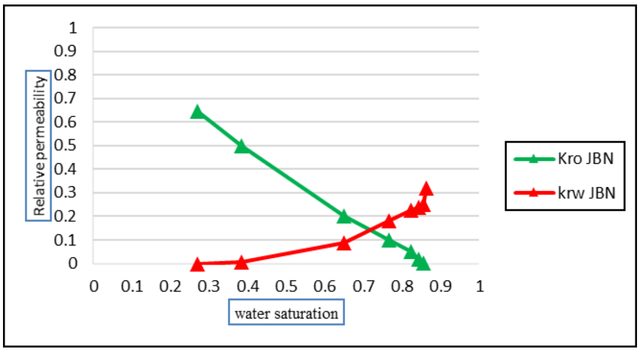

Fig. 12. Relative Permeability Curve for Plug 5

Table 4. The Relative Permeability Values at Critical Saturation [12]

Plug no	Plug 1	Plug 2	Plug 3	Plug 4	Plug 5
Kro(Swc)	0.831	0.254	0.926	0.497	0.647
Krw(Sor)	0.327	0.217	0.564	0.324	0.319

Step 3. Calculate the normalized Kro* and Krw* for all core samples as shown in Table **4** from the following equations:

$$Kro *= \frac{Kro}{(Kro)Swc} \tag{22}$$

$$Krw *= \frac{Krw}{(Krw)Soc} \tag{23}$$

Where: kro =relative permeability of oil at different Sw, Kro(Swc)= relative permeability of oil at connate water saturation, Kro* = normalized relative permeability of oil, (krw)Soc is the relative permeability of water at the critical oil saturation.

The normalized water saturation and relative permeability shown in Table **5**.

Table 5. Normalized Water Saturation and Relative Permeability [12]

Plug no	5		Plug no	6	
Sw*	Kro*	Krw*	Sw*	Kro*	Krw*
0	1	0	0	1	0
0.433321	0.54837	0.291199	0.392409	0.222224	0.288452
0.643981	0.264407	0.42	0.59791	0.458341	0.458341
0.831976	0.0937	0.699048	0.658771	0.535723	0.535723
0.930373	0.04815	0.634664	0.826436	0.021732	0.737022
0.94	0.036113	0.7	0.928106	0.000233	0.920774
0.96	0.001204	0.909685	1	0	1
0.98	0.00000012	0.999308			
1	0	1			

Step 4: Calculate the average normalized relative permeability for the oil and water from the following equations:

$$(Krw *)avg = \frac{\sum_{i=1}^{n}(hk\,Krw*)i}{\sum_{i=1}^{n}(hk)i} \tag{24}$$

$$(Kro *)avg = \frac{\sum_{i=1}^{n}(hk\,Kro*)i}{\sum_{i=1}^{n}(hk)i} \tag{25}$$

Where: n=total number of core samples, hi= thickness of sample I, Ki=absolute permeability of sample i.
Step 5. Plot the normalized values of kro* and krw* versus Sw* for each core on a regular graph paper as shown in Fig. **13**.

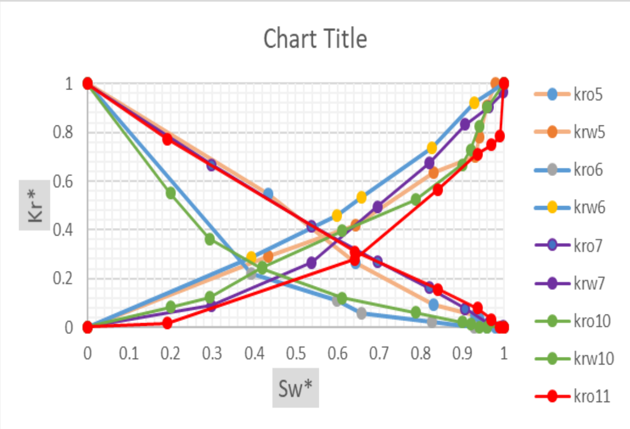

Fig. 13. The Normalized Values of Kro* and Krw* vs Sw*

Step 6. Select arbitrary values of Sw* and calculate the average kro* and krw* by applying Equations 24 and 25 as shown in Table **6** and Fig. **14**.

Table 6. The Average Relative Permeability Versus sw*

Sw*	Kroavg	Krwavg
0	1	0
0.2	0.603367	0.134923
0.4	0.4215	0.314
0.6	0.312	0.4125
0.8	0.156	0.699048
1	0	1

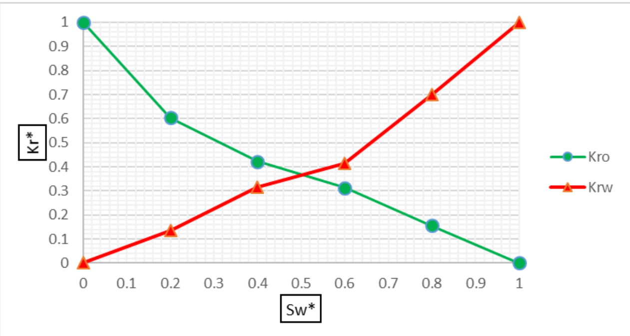

Fig. 14. Average Relative Permeability Versus Average sw

6.5. De-normalizing the relative permeability data

Taking the average connate water saturation and residual oil saturation for the five core plugs where (Swc)avg=0.226 and (Sor)avg=0.278, de-normalize the data to generate the required relative permeability data as shown in Table **7** and Fig. **15**.

Table 7. Average Relative Permeability and Water Saturation

Sw	Kro	Krw
0.2782	0.630796	0
0.377294	0.380602	0.047298
0.476388	0.265881	0.110075
0.575481	0.196808	0.144605
0.674575	0.098404	0.245057
0.773669	0	0.350558

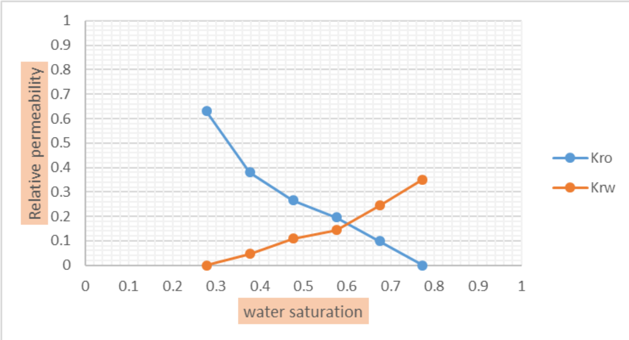

Fig. 15. Average Relative Permeability Versus Average sw

After normalize all relative permeability data we noticed that the intersection between oil and water relative permeabilities at water saturation 0.6 which means that the Mishrif formation in West Qurna-1 is water wet.

7- Conclusions

- We apply normalize technique to remove the effect of variable irreducible water saturation in the relative permeability calculations.
- The absolute permeability is important factor in the calculations of relative permeability, therefore it must be known for different flow rates and record different pressure drop.
- After applying de-normalize technique for carbonate core plugs of Mishrif formation, we found that Mishrif formation is water-wet where the intersection of relative permeability for the oil and water versus water saturation more than 50%.
- The relative permeability curves should be adjusted before being used for oil recovery prediction to eliminate the effect of variable initial water and critical oil saturations. Based on the essential fluid saturation for each reservoir location, the relative permeability can then be de-normalized and given to distinct regions of the reservoir.

From relative permeability data, we noticed that the higher values of oil and water relative permabilities are 0.865 and 0.642 respectively.

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تعديل وتسوية لبيانات النفاذية النسبية لتكوين طبقة المشرف في حقل غرب القرنة ١:عمل تجريبي

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الخلاصة

في الكثير من انظمه استخلاص النفط, النفاذية النسبية هي عامل مهم في الجريان التي تؤثر على انتشار المائع وتنتج من المصادر النفطية. تقليدياً تم اخذ نماذج صخرية من المكمن واجراء دراسات مختبرية للحصول على خواص المكمن المهمة. بالرغم من حقيقة ان النفاذية النسبية هي دالة لتشبع المائع فانه توزيع شكل المسامات, النفاذية المطلقة, التبللية, الشد البيني, وتاريخ التشبع جميعها تؤثر على قيم النفاذية النسبية. هذه خصائص الصخرة/المائع تتغير بصورة كبيرة من منطقة الى اخرى وهذا يجعل من غير الممكن قياس جميع قيم النفاذية النسبية لهذه المناطق. طريقة الحالة غير المستقرة استخدمت لحساب النفاذية النسبية لخمسة نماذج صخرية كاربونيت من طبقة المشرف لحقل غرب القرنة-١. النفاذية النسبية المحسوبة بواسطة معادلة Johnson, Bossler and Naumann (JBN) التي تعتبر احد طرق النفاذية غير المستقرة وجدت ان النماذج الصخرية هي مبللة بالماء. مبدا تعديل استخدم لازالة تاثير تشبع الماء غير قابل للازاحة والتشبعات المتبقية التي تتغير من صخرة الى اخرى. اعتماداً على تشبع الماء غير قابل للأزاحة فان النفاذية النسبية يتم تسويتها وتعيينها للمقاطع الواضحة (نوع الصخرة) من المكمن. الهدف من هذا البحث تعديل النفاذية النسبية التي تم ايجادها خلال تجارب حقن الماء.

الكلمات الدالة: النفاذية النسبية, النفاذية المطلقة, التعديل, التسوية.