Flow Rate Influence in Relative Permeability Curves: Dependence with Oil Viscosity

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***Abstract*-- This work aims to evaluate the influence of the flow rate in relative permeability determination, also considering the effect of oil viscosity.**

Many researchers have focused on flow rate influence in relative permeability curves without obtaining agreement. One of the reasons for that discrepancy is the possible influence of other forces like viscous, capillary and gravitational that can affect the results.

Unsteady state displacement experiments were carried out in carbonate core samples, in order to obtain water and oil productions, differential pressure histories. Three different flow rates were used for each oil. Those rates guaranty to balance the forces affecting the flow. Flow rate values were varied in two different sequences, from maximum to minimum and vice versa, to observe if the order of the flow rate variations influences relative permeability curves. Data obtained from the experiments were analyzed using the JBN (Johnson-Bossler-Naumann) method to calculate the relative permeability curves.

Under the studied circumstances of this work, it was verified that oil and water relative permeability changes with the flow rate. Residual saturations and permeability corresponding to them also varied with the flow rate. Relative permeability curves showed that flow rate dependency is different according to the oil viscosity used, and this effect generates the different results obtained in the literature.

***Index Term*-- Relative permeability, transient analysis, experimental procedures, carbonate rock.**

I. Introduction

The storability of hydrocarbons in the reservoir is dependent upon the rock formation and the pore structures [26], and the success in recovering those hydrocarbons depends on the rock permeability.

The permeability is a property of porous materials that determines the ease of fluids, such as water, gas or oil, to flow through the interconnected pores. When a fluid flows in the presence of another fluid, the permeability of the flowing phase is called effective permeability. The ratio between the effective permeability of the flowing phase and the total permeability is called relative permeability. The relative permeability depends on rock type, fluids involved, rock-fluid interactions and flow conditions [11]. This work focuses on flow rate influence of oils with different viscosities.

The methods of measuring relative permeability highlights steady state [1], [14], [35] and unsteady state flows [4], [17], [21], [28], [29], [30]. The unsteady state methods are more used in industry because it demands less time, even its numerical analysis is more complex. According to the literature, the unsteady state methods can be subdivided into linear displacement tests [4], [17], [21], [29], [30] and centrifuge, [12], [33], [37].

Unsteady state experimental data can be processed using history matching method or analytical methods: Johnson-Bossler-Naumann - JBN (1959) [18], Jones and Roszelle - JR (1978) [19], and Hagoort [37].

Many researchers studied the flow rate influence on relative permeability without an agreement. Honarpour et al. [16] found no dependence on flow rate and water-oil relative permeability. Owens et al. [34] and Sandberg et al. [38] limited the flow rate to not disturb the measurements by inertial forces. Leverett et al. [23] attributed the variations to an end-effect. Labastie et al. [22] performed imbibition tests in water-wet sandstone and oil-wet carbonate cores. They found that both relative pemeabilities were dependent upon the flow rate near residual oil saturation and also, the residual oil tends to decrease with the increase in flow rate.

Odeh e Dotson [32] graphically corrected the flow rate effect of oil-water displacement tests using JR method. Qadeer et al. [36] showed the dependence of strongly water-wet sandstones using oil and water. They found that, in a drainage process, the end-point of the relative permeability for non-wetting phase and the saturation increased with the flow rate increase. The wetting phase does not have influence neither on drainage or imbibition processes. Mohanty and Miller [27] studied the influence of capillary number, heterogeneities, fingering and flow rate on the relative permeability by unsteady-state methods using mixed-wet sandstones and a 47 cP oil. They concluded that, when the flow rate increases, the residual oil saturation decreases and the relative permeability to water increases. Those changes were more pronounced for lower water saturations. In 2001, Chen and Wood observed no-dependence when water or oil was injected in steady state regime through mixed-wet and water-wet sandstones. Nguyen et al. [31] studied the influence of the increase in flow rate and contact angle in the relative permeability of low permeable heterogeneous samples. Those increases resulted in an augmentation of imbibition relative permeability curves and a decrease in residual oil saturation. They also found out that the increment is higher when the core contains large pores and small throats, being independent when dimensions are similar.

The majority of hydrocarbon reserves are present in carbonate reservoirs and the results for sandstones could not be suitable for this rock due to its different type of pores and presence of fractures [6], [7], [26], 0. Therefore, the study of the flow rate influencing the relative permeability of carbonate reservoir is important. Alizadeh et al. [2] studied Iranian carbonates and found that the relative permeability to water is not function of the flow rate. Considering imbibition process, at low water saturation, the relative permeability to oil decreased with higher flow rates and in a drainage process no-dependence trend was found. They also observed that the hysteresis effect increased for water curves and decreased for oil curves when the flow rate was increased. Keller et al. [20] observed that an increment in the flow rate correspond to higher contact angles just in viscous oils, and no dependence was found with low viscosity oils.

Different results obtained over the years could be connected to the presence of capillary, viscous and/or gravitational forces. In order to balance those effects, dos Santos et al. [9] proposed some criteria to choose a range of injection flow rate. Three different injection rates were chosen according to this criteria and unsteady-state displacement tests were performed using oils with different viscosities.

II. Theory and Definitions

Effective permeability is the ability of a fluid present in the rock to flow in the presence of another one. Once normalized by a reference permeability it is then called relative permeability.

Wettability is the tendency of the fluid to adhere to the rock surface. If water fills the small pores and create a film around the big ones and oil fills the big pores, the porous media is characterized as water-wet.

The relative permeability to water or oil depends on the amount of mobile water or oil (saturation) and both depend on the pore size distribution. The normalization of the effective permeability by the gas absolute permeability eliminates the pore size distribution influence. Once two fluids do not flow at the same time in the same pore, one of the fluids blocks the pore to the other, reflecting on the pressure drop. In the case of a water-wet rock, the pressure drop is always higher for oil flooding than for water displacement. This behavior is a related to the difficult of the oil to flow through the rock. Craig [8] presented some rules to determine the wettability of the rock based on some experiments. 1) Irreducible water saturation for water-wet porous media is usually higher than 20-25% and for oil-wet rock lower than 10-15%. 2) Water saturation, in which oil and water relative permeability are equals, is higher than 50% for strongly water wet and lower than 50% for strongly oil wet. 3) Water relative permeability point at the maximum water saturation is smaller than 30% for strongly water wet and greater than 50% for oil wet.

Mobility is the ratio between relative permeability and viscosity of a fluid. Mobility is the ratio between the relative permeability and the viscosity of a fluid. The ratio between the mobility of the injected fluid over the displaced one is called mobility ratio. In the case of a water wet core sample imbibition correspond to water flood and drainage to oil flood. The mobility ratio equations for imbibition (I) and drainage (D) are shown in Equations (1) and (2) respectively:

$$M_I = \frac{k_w/\mu_w}{k_o/\mu_o} \quad (1) \qquad\qquad M_D = \frac{k_o/\mu_o}{k_w/\mu_w} \quad (2)$$

Considering the displacement tests, the flow rates chosen to run the experiments correspond to the minimum, maximum and an intermediate flow rate calculated by dos Santos criteria [9]. As said, those criteria are used in order to balance the influence of capillary, viscous and gravitational forces during the core flooding. It consists of four main equations, from (3) to (6), that have to be rearranged as a function of the velocity (U).

According to Equation 3, the capillary number, Nc, is the ratio between the viscous forces and the capillary forces on the pore scale, where U is the velocity, μ_o is the oil viscosity and σ is the interfacial tension (estimated as 0.03).

$$N_c = \frac{U\mu_0}{\sigma}\,; \sigma = 0.03 \tag{3}$$

The capillary-viscous ratio, ε_c, (Equation 4) is the ratio between the capillary pressure and the pressure drop on the core:

$$\varepsilon_c = \frac{\sigma\sqrt{k\Phi}}{\mu_0 LU};\ \varepsilon_c = 10^{-2} - 10^{-3} \tag{4}$$

where k is the absolute permeability, ϕ is the porosity and L is the length. Capillary-viscous ratio value is estimated to be between 10^{-2} and 10^{-3}.

The gravity viscous ratio, ε_g, evaluates the gravity segregation of the fluids according to Equation 5:

$$\varepsilon_g = \frac{(\rho_w - \rho_o) g 2 r k k_{ro}{}^0}{UL\mu_0}\,;\ \varepsilon_g < 1 \tag{5}$$

where ρ_w and ρ_o are the water and oil densities respectively, g is the gravity, r is the core radius and $k_{ro}{}^0$ is the relative permeability to oil at the maximum water saturation. This value should be lower than 1.

The sample representativity, ε_s, is guaranteed by the ratio between the sample volume and the pore volume (Equation 6).

This parameter has to be smaller than a given number α (0.01 – 0.1) as follows:

$$\varepsilon_s = \frac{U\pi r^2 \Phi \Delta t*}{\pi r^2 \Phi L} \ll \alpha;\ \alpha = 0.01 - 0.1 \tag{6}$$

where the maximum Δt is calculated according to Equation 7:

$$\Delta t = \frac{\alpha\ L}{U} \tag{7}$$

The equations are calculated for different rock lengths and plot to obtain a graphic as the example showed in Fig 1. That graphic is different for each rock sample because they have different properties and a different oil is used in each one. The range of flow rates to be used in flow experiments should be between the capillary-viscous ratio and the capillary number. An example of possible selected flow rate is also presented in Fig 1.

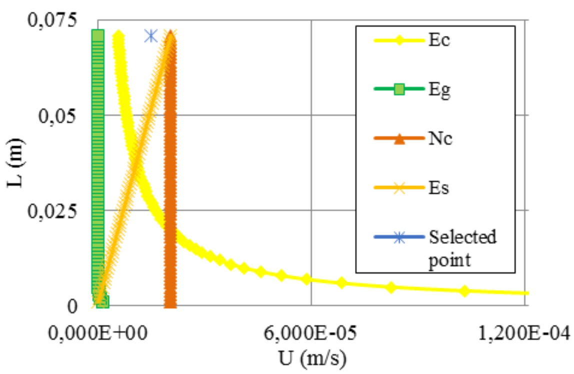

Fig 1. Dos Santos criteria. [24] [24]

Johnson-Bossler-Naumann [18] proposed an analytical method to calculate relative permeability from laboratory measurements during imbibition process. The equations are analogous when drainage process are considered, Lucia and Moreno [24], and are presented as follows from Equation 8 to 18.

- Amount of water injected, W_{inj}, based on the experimental water flow rate, Q_w, and the elapsed time:

$$\left(W_{inj}\right)_j = \sum_{j=0}^{n} Q_w.\left(t_j - t_o\right) \tag{8}$$

- Injected pore volume (VP_{inj}):

$$\left(VP_{inj}\right)_j = \frac{\left(W_{inj}\right)_j}{VP} \tag{9}$$

- Average water saturation, $(\overline{S_w})_j$ according to the irreducible water saturation after oil flooding (drainage), S_{wi}, and the ratio between oil produced and pore volume (Np/VP).

$$(\overline{S_w})_j = S_{wi} + \frac{\left(N_p\right)_j}{VP} \tag{10}$$

- Water saturation at the outlet, S_{w2}:

$$(S_{w2})_j = \overline{S_w} - \left(VP_{inj}\right)_j \left.\frac{d(\overline{S_w})}{d\left(VP_{inj}\right)}\right|_j \tag{11}$$

- Oil (f_{o2}) and water (f_{w2}) fractional flow at the outlet face:

$$f_{o2} = \frac{(\overline{S_w})_j - (S_{w2})_j}{\left(VP_{inj}\right)_j} \tag{12}$$

$$f_{w2} = 1 - f_{o2} \tag{13}$$

- Oil and water relative permeability, k_{ro}^* and k_{rw}^*, for imbibition using the injectivity, I_r, which is the ratio between the flow rate and the differential pressure at the current time to the initial time:

$$(I_r)_{\mathrm{j}} = \frac{\left({}^{q}/_{\Delta P}\right)_{t=t_j}}{(q/\Delta P)_{t=0}} \tag{14}$$

$$(k_{ro})_{\mathrm{j}} = \frac{(f_{o2})_j}{(dI_r)_j} \tag{15}$$

$$(k_{rw})_j{}^* = \frac{(f_{w2})_j}{(dI_r)_j}\frac{\mu_{w\,j}}{\mu_o} \tag{16}$$

$$k_{ro} = (k_{roL})_{\mathrm{j}}{}^* \frac{k_{o@Swi}^{(1D)}}{\mathrm{k_{abs}}} \tag{17}$$

$$k_{rw} = (k_{rwL})_{\mathrm{j}}{}^* \frac{k_{o@Swi}^{(1D)}}{\mathrm{k_{abs}}} \tag{18}$$

where k_o and k_w are the effective permeability to oil and water, correspondent to the end of the first (1) or second (2), drainage (D) or imbibition (I), k_{abs} is the absolute permeability to gas.

III. EXPERIMENTAL PROCEDURES

Fifteen displacement tests were performed at constant temperature in three different cores from the same sample of carbonate. Different oil viscosity was used in each core sample. The tests consisted of the injection of a fluid in order to displace the resident one. Once the porous media used was water-wet, the oil injection corresponds to a drainage process, because it does not wet the rock surface, and the water flooding corresponds to imbibition process.

Carbonate samples were taken from an Eocretaceous carbonate block of Morro do Chaves Member in the Alagoas Basin. That geologic formation was originated by bivalves deposition in shallow water, [10], [13]. Those core samples presented interparticle porosity and non-touching vugs according to Lucia [26] classification. They were chosen to avoid fractures or faults; they just showed some calcite crystals as a result of precipitation of calcium ions and evaporation of carbon dioxide.

Procedures started with the measurement of the mean properties, shown in TABLE 1, such as length and diameter, porosity and absolute permeability to gas using a pachymeter, a gas porosimeter, and a gas permeameter respectively.

TABLE 1.

ROCK SAMPLE MEAN PROPERTIES Adapted from [24]

		CARBONATE CORES		
		2c	1a	1b
Length	[cm]	7.09	7.21	7.14
Diameter	[cm]	3.77	3.77	3.77
Porosity	[fr]	18.1	21.0	17.3
Absolute permeability to gas	[mD]	129.5	150.1	92.2
Pore volume	[cm^3]	12.1	14.0	11.8

A brine with 80000 ppm of NaCl was used as water phase. The oil phase was different for each sample, i. e.: Emca was used in the sample 2c, Nujol was used in the sample 1a and a mixture of Emca and Nujol (30/70 in weight) was used in the sample 1b. In Fig 2 and 3 are presented the densities and viscosities of the used fluids.

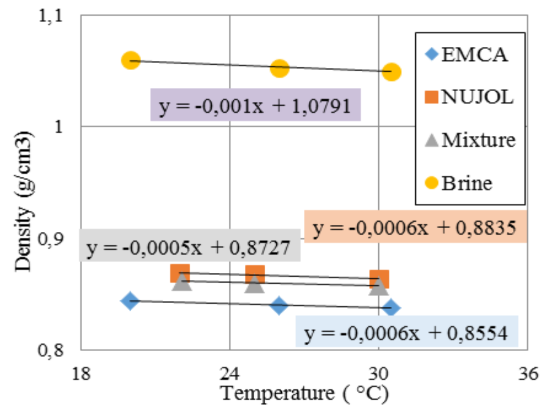

Fig 2. Fluid densities. Adapted from [24]

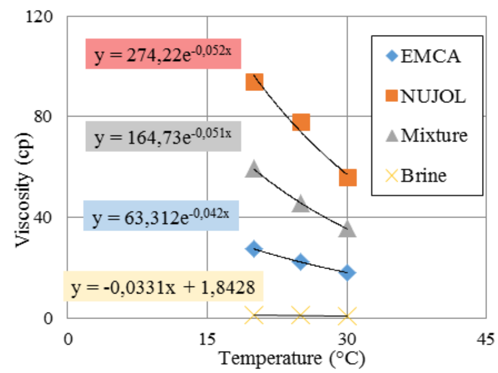

Fig 3. Fluid viscosities. Adapted from [24]

After the measurement of the mean properties, the rock samples are saturated with brine (water phase). The sample is submitted to vacuum, brine is admitted, and it is left to stabilize for twelve hours. After that, the plug is introduced into a core holder and assembled in the experimental setup. A confining pressure of 600 psi is applied to guarantee an one-directional flow.

The experimental apparatus is presented in Fig 4 and consists of three manometers that withstand 20, 80 and 320 psi, a core holder in horizontal position, two different cylinders containing each one of the fluids to be injected, a pump to keep the flow rate constant and a balance to control the mass produced over the time.

Fig 4. Experimental device [24] [24]

Once the rock is assembled the displacement starts. Briefly, brine is injected to measure the absolute permeability to water, followed by the oil injection until it reaches the connate water saturation. The relative permeability to oil at connate water saturation is calculated and then another water flood was performed, followed by another oil and water injections respectively. The steps are seen in TABLE .

TABLE II
Experimental measurement in each step. Adapted from [24]

STEP	MEASUREMENT OBTAINNED
1st imbibitions	Water absolute permeability
1st drainage	$k_{oef@Swi}$
2nd imbibition	$k_{wef@Sor\_2E}$
2nd drainage	$k_{oef@Swi\_2D}$
3rd imbibition	$k_{wef@Sor\_3E}$

The permeabilities shown in the TABLE II correspond to the effective permeabilities to oil or water, k_{oef} and k_{wef}, at the end of the test, i.e., at the irreducible water saturation, S_{wi}, or residual oil saturation, S_{or}. They are calculated according to Darcy´s law, which is shown in equation (19) for a fluid j.

$$k_j = \frac{\mu_j\, qL}{A\, \Delta P} \qquad (19)$$

μ_j is the viscosity of the fluid, q is the flow rate, L is the length, A is the area and ΔP is the pressure drop.

Those procedures allow knowing the production of both fluids over time and the permeability of a fluid when the other one is immobile.

Three water imbibition floods, (1E, 2E and 3E), and two oil drives drainages (1D and 2D) were carried out alternately in all core samples for each flow rate, as shown in Fig 5.

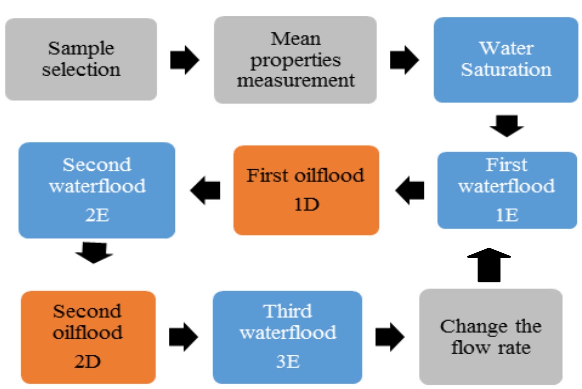

Fig. 5. Test protocol

The three used flow rates correspond to the minimum, maximum and intermediate values estimated according to dos Santos' criteria [9]. Each flow rate test was performed twice, starting from maximum to minimum and vice versa. The flow rates chosen for each rock sample are shown in TABLE:

TABLE III
Flow rates for each rock sample Adapted from [24]

	Rock sample 2c	Rock sample 1a	Rock sample1b
Maximum	1.5	0.4	0.43
Intermediate	1.1	0.3	0.33
Minimum	0.7	0.2	0.23

IV. Results

Fifteen displacement tests were performed: three tests using the EMCA oil ($\mu_{@23°C}$=24.10 cp), six tests using NUJOL ($\mu_{@23°C}$=82.92 cp) and other six run using a mixture of of Emca and Nujol 30/70 in weight ($\mu_{@23°C}$=50.97 cp). For the EMCA tests, the displacement sequences were performed increasing the flow rate from the minimum to the maximum (The three used flow rates correspond to the minimum, maximum and intermediate values estimated according to dos Santos' criteria [9]. Each flow rate test was performed twice, starting from maximum to minimum and vice versa. The flow rates chosen for each rock sample are shown in TABLE:

TABLE); and , for the two last oils, each sequence of tests was run decreasing the flow rate from the maximum to the minimum and, subsequently, in the opposite succession (The three used flow rates correspond to the minimum, maximum and intermediate values estimated according to dos Santos' criteria [9]. Each flow rate test was performed twice, starting from maximum to minimum and vice versa. The flow rates chosen for each rock sample are shown in TABLE:

TABLEIII).

Connate (irreducible) water saturation is greater than 20% of porous volume and the relative permeability at maximum water saturation is very small TABLE, It means that the core samples are strongly water wet according with the first and third Craig´s rule [8]. The increment in pressure drop explained in Item 0 is a consequence of the difficult of the oil flow through the rock, can be shown in

It is also reflected in the time before the breakthrough, the moment when the injected fluid starts to produce, which usually is greater for the oil than for the water.

Displacement efficient depends on the mobility ratio, as smaller is the mobility ratio, most efficient is the displacement, [39]. A higher oil viscosity involves greater difficulty for the oil imbibeand reflects in higher mobility ratio for Nujol, intermediate for the mixture of oils and lower for Emca, Therefore, based on our results, grey columns in

TABLE, smaller flow rates leads to more efficient displacements for Nujol and the mixture of oils and higher flow rates for Emca oil, since the value is between indicative interval provided by dos Santos criteria [9].

In the following table, results for drainage are in red and results for imbibitions are in blue, flow rate is in green and mobility in grey. Each color is darker for the highest value obtained in each group of tests, in the case of Nujol and the mixture of oils, the first three tests are considered a group and the last three another.

TABLE IV
Residual saturations, its effective permeabilities and mobility ratio

		S_{wi-1D}	$k_{oef@Swi-1D}$	S_{or-2E}	$k_{wef@Sor-2E}$	$M_{\_2E}$	S_{wi-2D}	$k_{oef@Swi-2D}$	$M_{\_2D}$	S_{or-3E}	$k_{wef@Sor-3E}$	$M_{\_3E}$
Rock	Q	[fr]	[mD]	[fr]	[mD]		[fr]	[mD]		[fr]	[mD]	
2c Emca	0.70	0.35	57.82	0.29	2.42	0.94	0.31	36.73	0.69	0.25	1.61	1.04
	1.10	0.40	27.16	0.16	1.35	1.11	0.42	18.58	0.63	0.14	0.99	1.18
	1.50	0.46	36.63	0.10	1.37	0.88	0.49	18.37	0.61	0.06	0.96	1.25
1a Nujol	0.40	0.37	48.04	0.25	2.89	4.83	0.42	47.49	0.21	0.18	2.35	3.75
	0.30	0.45	47.62	0.16	2.03	3.17	0.51	41.70	0.28	0.11	1.88	3.31
	0.20	0.58	40.22	0.04	1.47	2.72	0.62	41.18	0.33	0.09	1.33	2.75
	0.20	0.56	36.26	0.07	1.34	2.88	0.62	34.26	0.35	0.09	1.31	2.89
	0.30	0.53	37.67	0.08	1.47	3.13	0.46	36.86	0.34	0.18	1.39	2.86
	0.40	0.48	35.47	0.13	1.85	3.98	0.43	37.57	0.25	0.21	1.56	3.37
1b Mixture	0.43	0.22	59.58	0.40	2.89	2.04	0.25	56.73	0.42	0.34	2.34	1.94
	0.33	0.30	47.62	0.30	2.03	2.11	0.29	41.93	0.45	0.29	1.87	2.04
	0.23	0.39	46.30	0.24	1.47	1.46	0.42	41.18	0.60	0.21	1.33	1.49
	0.23	0.46	36.93	0.17	1.36	1.68	0.45	30.50	0.49	0.16	1.24	1.89
	0.33	0.50	33.53	0.11	1.77	2.53	0.54	31.97	0.40	0.08	1.91	2.62
	0.43	0.56	31.24	0.05	1.99	2.85	0.63	32.99	0.36	0.01	2.11	2.52

When observing the residual saturations, TABLE, two different tendencies have to be explained.In the less viscous fluid (Emca), when the flow rate is increased the irreducible water saturation increases too and the residual oil saturation (S_{or}) decreases. That phenomenon occurs in the opposite direction for Nujol oil. In the mixture of oils, the first group of tests shows the same flow rate dependence as Nujol oil and the second group as Emca oil. It means that amount of fluid that cannot be produced depends on fluid used. So the flow rate is not the only factor affecting the residuals saturations, i. e., the oil viscosity is important too. It shows a change in the tendency for the intermediate viscosity (mixture of oils), and because of that, results for the first three tests match with Nujol results and the other three with Emca results.. Residual oil saturations for Emca and the second group of the mixture of oils showed the same tendency obtained by Labastie et al. [22]. While residual oil and water saturations for Nujol oil tests match with Qadeer et al [36] results.

In the case of the oil and water effective permeability at residual saturations, the flow rate is not the single parameter involved. Pressure drops have to be analyzed at the same time we analyze the flow rate, as they are inverse in the equation. Variations in pressure drop depend on the flow rate and the viscosity of the oil. Both, oil and water effective permeabilities, tend to decrease with an increment in the flow rate for Emca oil, and the opposite effect happens for the Nujol oil. The mixture of oils in the first group of tests acts as Nujol and in the second as Emca. The first drainage and second imbibition of the experiment with Emca oil and flow rate equals to 1.1 cm^3/min did not behave as explained, because the growth in pressure drop was really high and counteract flow rate effect as they are inverse in the equation, (19). In the case of Nujol oil, the first and the second drainage for the last test (q= 0.4) did not behave as explained because of a decrease in the ambient temperature. Consequently, viscosity increased, causing an increment in pressure drop and, as a result, a reduction in the permeability according to the equation (19), TABLE .

TABLE V
Injected fluid viscosity and pressure drop at the breakthrough instant

		T_{1D}	μ_{1D}	P_{BT_1D}	T_{2E}	μ_{2E}	P_{BT_2E}	T_{2D}	μ_{2D}	P_{BT_2D}	T_{3E}	μ_{3E}	P_{BT_3E}
Rock	Q	°C	cp	psi	°C	cp	psi	°C	cp	psi	°C	cp	psi
2c Emca	0.70	25.0	22.15	48.48	25.0	0.99	48.48	25.5	21.69	88.32	27.5	0.91	70.4
	1.10	25.0	22.15	181.76	25.0	0.99	141.44	25.5	21.69	261.12	25.0	0.99	192.64
	1.50	24.0	23.10	179.20	25.0	0.99	108.60	25.5	21.69	348.20	25.0	0.99	255.40
1a Nujol	0.40	24.0	78.72	103.68	25.5	0.98	35.36	24.5	76.70	111.36	24.5	1.01	54.88
	0.30	25.5	72.82	105.6	25.5	0.98	87.68	25.5	72.82	119.04	25.0	0.99	45.76
	0.20	24.5	76.70	82.56	24.0	1.03	37.60	22.0	87.35	88.96	24.5	1.03	38.40
	0.20	24.0	78.72	87.68	24.5	1.01	38.40	22.2	86.45	88.32	25.0	0.99	39.68
	0.30	24.0	78.72	125.44	25.5	0.98	49.60	25.5	72.82	120.96	25.5	0.98	52.32
	0.40	22.2	86.45	158.72	25.5	0.98	63.04	22.2	86.45	163.84	25.8	0.97	73.60
1b Mixture	0.43	23.5	49.68	49.76	24.0	1.03	32.48	24.0	48.43	67.68	24.0	1.03	35.36
	0.33	23.0	50.96	67.84	24.0	1.03	38.08	24.5	47.21	74.24	23.0	1.06	40.64
	0.23	24.5	47.21	56.64	23.5	1.05	34.72	24.0	48.43	56.64	25.0	0.99	36.64
	0.23	25.0	46.02	49.44	24.5	1.01	38.72	25.0	46.02	73.92	25.0	0.99	41.6
	0.33	24.0	48.43	101.12	25.0	1.01	49.92	25.0	46.02	99.84	23.50	1.06	59.94
	0.43	25.0	46.02	125.44	24.0	1.03	58.88	24.5	47.21	128.64	24.2	1.04	63.33

Results obtained for Nujol and the first group of the mixture of oils water effective permeability and Emca residual oil saturation match with Mohanty and Miller [27] results. Oil effective permeability of Nujol and the first group of the mixtures of oils also match with Qadeer et al [36] results.

Results obtained from the experimental procedures for forced water imbibitions and drainages are shown in the following figures. The curves for lower normalized water saturation are obtained during drainage tests and for higher saturations during imbibition.

In all experiments, water relative permeability values were very low, however always showing the same dependence of oil permeability.

In the Fig 6 it is observed that the relative permeability curves increase with lower flow rate.. That dependence is bigger at the early part of the test and at almost not appreciated at the end, which was the same observed by Mohanty and Miller [27].

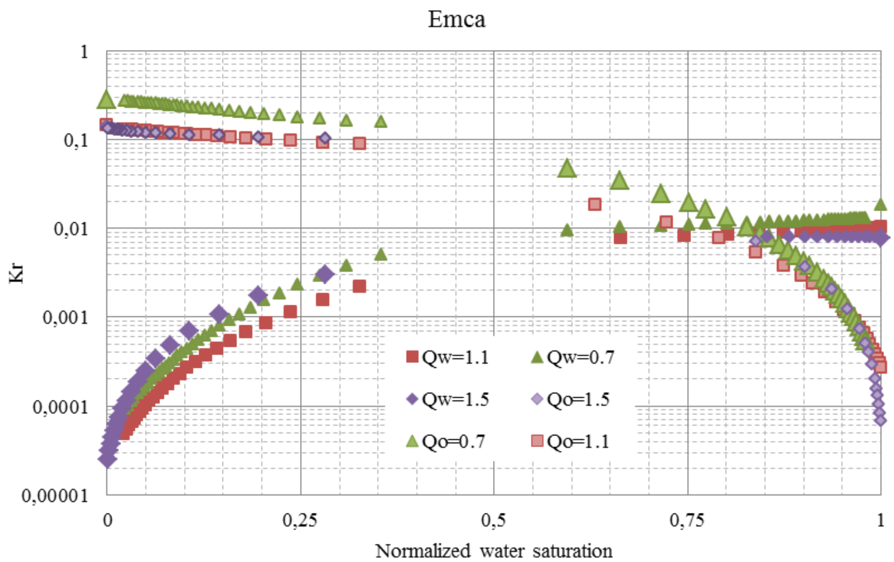

Fig 6. Relative permeability curves for Emca oil

In the Fig 7 the curves for the mixture of oils are shown. One can observe that, highest values of relative permeabilities result of highest flow rate and curves for the medium and lowest flow rates are almost the same.

That shows a change in the relationship between relative permeability and flow rate for the tested oil with an intermediate viscosity.

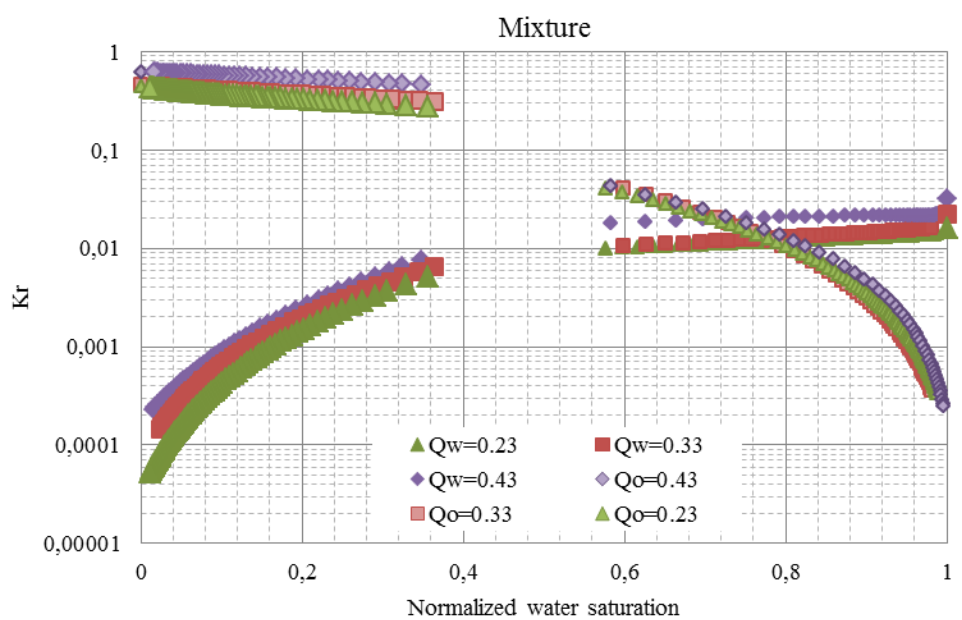

Fig 7. Relative permeability curves for the mixture of oils

Fig 8 shows the curves for the Nujol oil where the flow rate dependence is the opposite that for Emca oil, as we already observed in the mixture of oils. Therefore, if the flow rate increases, the relative permeability curves increase too.

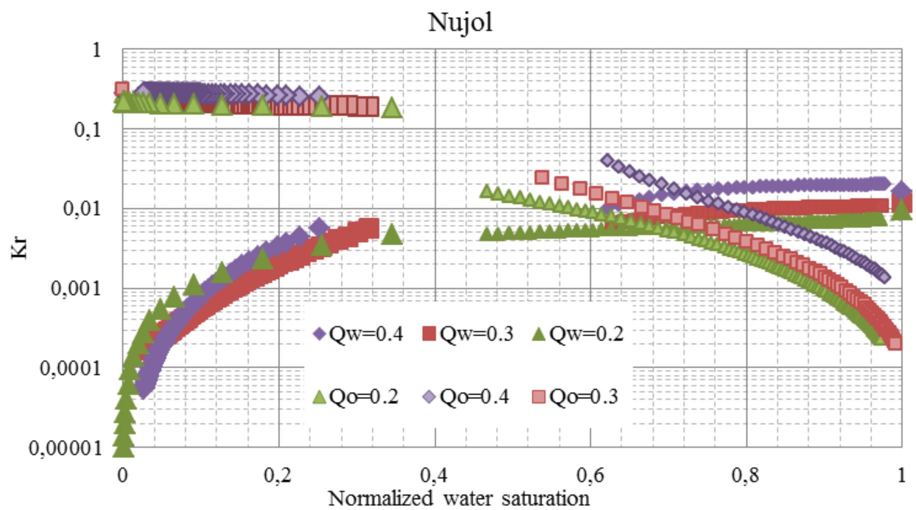

Fig 8. Relative permeability curves for Nujol oil

Saturation at which oil and water relative permeabilities are equal is always greater than 50%, confirming the strong water wettability of the rock, second Craig´s rule [8].

Relative permeability curves for both processes, imbibition and drainage, increases with the flow rate for viscous oils, Nujol and the mixtures of oils, and decreases for non-viscous oils, Emca.

Those differences with the oil viscosity can be explained according to Keller et al [20] and Nguyen et al [31]. Keller et al [20] found that, in high viscous oils, the contact angle increases with flow rate. Nguyen et al [31] proved that an increment in contact angle and/or in flow rate refers to higher imbibition relative permeability. Therefore, in the mixture of oils and Nujol oil with an increase in the flow rate contact angles are increased, obtaining higher relative permeability curves, as a result. Higher contact angles correspond to higher interfacial tensions and, consequently, lower capillary number with an increment in flow rate. Emca oil has low viscosity, so no variations in the contact angle happen and capillary number increase with the flow rate, because of that the tendency is different from Nujol oil.

Relative permeability curves show the capability of the liquid to flow in the presence of another fluid, so higher oil relative permeability is desirable because it refer to easily displacement of the oil over the water. Under the studied circumstances, higher flow rates are preferable for viscous oils such as Nujol and the mixture of oils and, for non-viscous oils like Emca, low flow rates are better. Residual saturations also depend on the flow rate and on the viscosity of the oil. If the flow rate increases, the residual oil saturation decreases and the irreducible water saturation increases for both, Nujol and the mixture of oils. Nevertheless, an opposite tendency is obtained for Emca oil. Results obtained for Emca oil in water flood (imbibition) match with what Alizadeh et al. [2] obtained for kerosene, which also is low viscosity oil. Oil relative permeability results for Nujol oil and the mixture agree with Nguyen [31]. Further studies can be found in Lucia and Moreno [24].

V. CONCLUSION

Considering the results obtained in the present work, it can be affirmed for the carbonate samples used and the experimental applied conditions, that relative permeability curves depend on the flow rate and that relationship is different according to the oil.

Because of this conclusion, we can point out that oil viscosity is a very important factor to take into account for selecting displacement flow rate aiming to obtain the highest oil production.

Relative permeability curves increases with the flow rate for viscous oils and decreases for less viscous ones. Differences on the dependence of the flow rate are consequence of the increment in the contact angle in the cases of more viscous fluids. This effect leads to increments in relative permeability curves. In the case of water relative permeability curves, these effects are very tiny.

It was found that flow rate also influences the oil and water residual saturations and the effective permeability corresponding to them. Results obtained for those parameters depend on the viscosity of the oil too. When displacing Emca oil (low oil viscosity) during imbibition process, higher residual oil saturations was obtainned, while during the drainage (Emca injection), lower irreducible water saturations were derived with lower flow rate . Opposite dependence was found for Nujol (high oil viscosity) and both relationships were observed in the displacement tests involving the mixture of oils.

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