OIL-WATER EMULSIONS INJECTION AS AN ENHANCED OIL RECOVERY METHOD

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Abstract. During the life of an oilfield, different oil recovery methods may be used to maintain the reservoir pressure and increase sweep efficiency. The method most commonly used is water injection. The efficiency of the method is limited due to the high mobility ratio between water and oil, that leads to water fingering. Mobility control agents can be used to minimize this effect. Among them, oil-water emulsions (O-W) present several benefits in cost, compatibility and efficiency. Several studies indicate a better sweep efficiency of the water phase with lower water-oil ratio in the production wells. If properly designed, the dispersed phase of the emulsion may block the pore throats and change the flow path at pore level, improving not only the sweep but also the displacing efficiency. The aim of this research is to study oil-water emulsion flooding and understand the mechanisms involving its use as a mobility control agent. The micro and macro effect of the emulsion injection is going to be evaluated experimentally by measuring the relative permeability curves of water-oil emulsions and oil in sandstone cores for different dispersed phase concentration, droplet size distribution and capillary number.

Keywords: emulsions, mobility control, enhanced oil recovery, sweep efficiency, displacing efficiency

1. INTRODUCTION

Water flooding is the most used method for increasing oil recovery. It was first tested in 1890 in Bradford field, Pennsylvania, and since then it has rapidly expanded as an effective method (Green et al, 1998). It is a relatively easy and cheap method to be implemented and usually presents a good efficiency in displacing oil (Craig, 1971). The availability of salt water is another advantage of this process in the case of offshore fields. Still, great amount of oil remains trapped in the reservoir. Due to the high mobility ratio between water and oil and due to the rock heterogeneities, viscous fingerings are formed, reducing the sweep efficiency of the method. The fingers anticipate the water breakthrough and, in a short period of time, the water-oil ratio (WOR) gets so high that the field is not economically feasible anymore. This way, the industry is always looking for new methods that can postpone the field depletion and, consequently, increase the oil recovery. Typically, 35 to 50% of oil is recovery by primary production followed by water flooding, according to Green et al (1998). That is, more than half the oil in place remains trapped in the pores or isolated in the reservoir.

Considering this amount of oil left in reservoirs, Enhanced Oil Recovery (EOR) methods have been successfully applied in the world. They are usually used in mature fields and have been largely studied since the oil prices reached higher levels. One of the focuses of the EOR studies is the mobility control processes. Their objective is to create a favorable mobility ratio between the injected fluid and the oil, acting on the mobility of the injected fluid (viscosity or effective permeability or both).

The most common method that controls the mobility ratio is polymer injection, which increases the viscosity of the injected liquid. The cost of this process is high, which may limit the economic feasibility of the method. Another mobility control method that is cheaper is the injection of oil-water (O-W) emulsions. Several studies have already proved this mobility control mechanism and make O-W emulsions an interesting candidate to be used as an EOR method in oil reservoirs. An important advantage of this method is that the water produced, which is actually an O-W emulsion, could be re-injected after treated in the reservoir and act as a mobility control agent. The objective of this method is to reduce the effective permeability of the injected fluid, reducing its mobility. In order words O-W emulsions is able to increase the recovery efficiency on the displacement of oil by the injected fluid.

This paper aims to provide a deeper understanding of the effects of emulsion flow in a porous media. It presents the relative permeability curve of O-W emulsions and oil in sandstone cores. The relative permeability curve is compared with the curve of aqueous phase and oil measured in the same condition and the effects of emulsions will be evaluated.

2. INJECTION OF O-W EMULSIONS: BACKGROUND

McAuliffe (1973) was the first to observe that O-W emulsions have properties that could improve the oil recovery factor. He concluded that an oil drop flowing through a pore throat would have to get deformed in order to pass through it. This way, the curvature radius of the leading portion of the drop decreases, while the radius of the drop still in the pore remains the same. Therefore, the capillary pressure, which is inversely proportional to the radius of curvature, increases in the front of the drop, creating resistance for the drop to flow. This phenomenon, known as Jamin effect, is able to reduce and even prevent the flow in a porous media when more than one phase is flowing (Rosa et al, 2006). The capillary pressure can cause the complete blockage of a pore throat, causing the flow to follow new paths. As this happens in more permeable zones, this permeable area becomes more restricted to flow and lower permeable zones may be reached by the injected fluids. Therefore, a new bank of oil will be able to be displaced in the reservoir.

McAuliffe (1973), Hofman and Stein (1991) have performed several experiments to prove this effect. While the first used Boise, Alhambra and Berea sandstone samples and prepared emulsions with an oil content of 0.5%, Hofman and Stein used a sample made by 40-60 μm glass spheres with an oil content of 1.0%. Both of them used drops between 1 and 12 μm. They observed that larger drops result in a stronger permeability reduction. While larger drops are getting deformed, the curvature radius ratio between the front and the back of the drop increases and the capillary pressure demands extra pressure to make the drop flow. In the other hand, with smaller emulsion drops, the deformation may not exist or be negligible, so the capillary pressure will not be high enough to block the throat and reduce the liquid mobility.

A pilot project using O-W emulsions as EOR was performed by Chevron (McAuliffe, 1973) during the 1970s in the Midway-Sunset oil field in California, United States. They have treated an area of the field only with water and another only with emulsions. As expected, the WOR of the emulsion treated area was much smaller than the water treated area. The oil production was 10% higher in the emulsion treated area as well. It indicates that the effect of the fingerings was diminished by the O-W emulsions and a larger area of the reservoir was reached by the injected fluid and, consequently, more oil was displaced by it.

Cobos et al (2009) measured the extra pressure required to deform a drop in a capillary tube throat with a diameter of 50 μm, which represented a pore throat. They have also visualized the deformation while the drop was passing the throat. Their results show that the extra pressure has increased 100% in some cases. The extra pressure is function of the ratio between the size of the pore and the size of the drops and also the Capillary Number, which relates the dynamic viscosity of the continuous phase (μ), the flow velocity (V) and the interfacial tension (σ). The Capillary Number (Ca) is defined by Equation (1):

$$Ca = \frac{\mu V}{\sigma} \, , \tag{1}$$

In other words, capillary driven mobility control depends on the ratio of viscous force and capillary forces, which is represented by the capillary number. When viscous forces predominate (high capillary number) the Jamin effect is negligible. On the other hand, when the flow is dominated by capillary forces (low capillary number), this effect must be considered and the capillary pressure plays an important role.

Therefore, the extra pressure measured by Cobos et al and the consequently block of the pores will only occur with low capillary numbers and large drops. If properly designed, the drops will not block pores near the injector well, where the velocity of the flow is higher, i.e. high capillary number, which means that emulsion will not affect the injectivity of the well. When the emulsions reach a certain distance of the well, where the velocity of the flow has decreased (low capillary number), the pores will be blocked and the flow path will be deviated to a less permeable zone, where oil remains trapped.

Guillen et al (2011) have also proved this capillary effect. They performed experiments with homogeneous sandstones showing that for low capillary numbers, 55% of oil can be recovered after water flooding followed by a O-W emulsions injection instead of 27% oil recovery for the same process in high capillary numbers. The experimental evidences show that emulsion injection not only improves sweep efficiency but also the microscopic displacement efficiency.

Figure 1 shows a sketch representing how the O-W emulsions act in a porous media. The black line represents the water path before the emulsions injection and the red line represents the water path after the pores get blocked by the emulsions injection.

Still, the literature lacks of more studies and researches on O-W emulsions injection. Macro scale experiments are necessary to understand the flow behavior of emulsions in a reservoir and some results from the laboratory are needed to be implemented in a more accurate simulation model. The measurement of the relative permeability curve of O-W emulsions displacing oil, which is the objective of this work, is an attempt of evaluating the micro and macro effect of the emulsion injection and, also, collecting important information about the injection of emulsions in order to provide them to a reservoir scale emulsion injection simulation study.
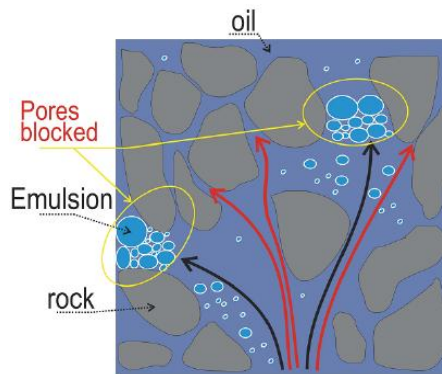
Figure 1 – Sketch of O-W emulsions as an EOR process

3. EXPERIMENTAL PROCEDURE

The relative permeability curve of emulsion displacing oil in a sandstone core was measured using an adaptation of the TEMCO Core Flooding System model CFS-830-SS at a temperature of 44°C. Due to the simple calculation and implementation, the steady state method is used to measure the relative permeability curves. In other words, the aqueous phase and oil phase were injected at constant flow rates until the equilibrium is reached and the pressure drop measured. The effective permeability of each phase is then calculated using Darcy's law.

The tests were conducted using two cylindrical cores of Bentheimer sandstone measuring both 3.80 cm in diameter and 8.86 and 8.30 cm in length each. The porosity was approximately 22.0% in the two cores. Both ends of the core holder were equipped with flow distributors so the injected fluid enters the core in a uniform way. In this work, Morlina 150 mineral oil, from Shell, was used. The oil viscosity and density was respectively 104 cP and 0.87 g/mL at the experimental conditions. Tests were performed with different surfactants and the stabilization of O-W emulsions was examined during a few days in order to find the best surfactant for the selected oil.

The continuous phase of the emulsion (the aqueous phase) was made of distilled water with 15 g/l of sodium chlorate (NaCl) and 0.6 g/l of the selected surfactant, Ultrol L80 from Oxiteno. This concentration is higher than the Critical Micelle Concentration (CMC) for this surfactant. Tests were made to confirm the stability of emulsions for the time needed to measure one curve. The surfactant was added to the aqueous solution in order to isolate the effect of the emulsions on the relative permeability curve. In other words, any change to the relative permeability curve is not due to the surfactant, but only due to the O-W emulsions. The concentration of salt, according to Bernard (1967), is more than enough to avoid clay swelling and a possible increase in pressure gradient. The viscosity and density of the aqueous phase are 0.64 cP and 1.00 g/ml, respectively. The rock sample was placed in a recipient filled with the chosen solution. Then, a vacuum pump was used to saturate the core, whose weight was measure before and after this procedure to calculate the rock porosity.

Three cylindrical accumulators (pistons) filled with oil, water and emulsion and two pumps are responsible for injecting fluids in the core. Figure 2 shows the sketch of the system used to measure the relative permeability curves. During all the work, the constant flow rate condition is used. The flow rates vary from 0.06 ml/min to 2.00 ml/min.
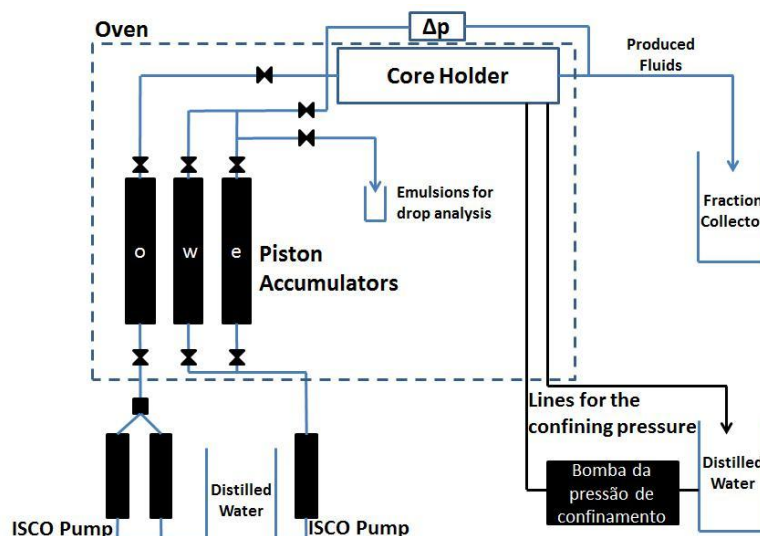

Figure 2 - Sketch of the experiment

The core sample is confined with water at a pressure of approximately 2300 psi. The first step is to inject the aqueous solution and measure the absolute permeability. The solution is injected with several flow rates and, in each case, the stationary regime is reached and the pressure drop measured. The slope of a line drawn in a graph $\triangle P \times Q$ is used to calculate the absolute permeability of the core sample, considering the Darcy's Law for a Cartesian one-dimensional flow.

The following step was to inject oil until no more aqueous phase is being produced. At this point, the oil saturation is maximized and, consequently, the connate water saturation is reached. The mass balance is used to calculate all the saturations during this and the following stages. For this reason the control of the produced and injected fluids is carefully examined. Then, the oil flow rate is varied and the same procedure described above is used to calculate the relative permeability of oil with its maximum saturation.

Lowering the oil flow rate and increasing the aqueous phase flow rate make possible to have different saturations of oil in the core sample and, meanwhile, the pressure drop is measured and their relative permeability is calculated. The Ca is kept constant at all curves, i.e. the total flow rate remains the same (0.40 or 2.00 ml/min depending of the curve). Still, mass balance is necessary to calculate the saturations and Darcy's Law is used to calculate the effective permeability of both fluids. The capillary pressure is not considered in this experiment.

Similar procedure was performed to measure the relative permeability curve of O-W emulsions displacing oil. First only oil is injected, so the connate water saturation is reached. The next step was to vary the oil flow rate and start to inject O-W emulsions so the relative permeability curve can be measured. O-W emulsions were created using shear force. Then, these emulsions were put in a specified cylinder with a magnetic stirrer so the oil drops will not separate by density. The drop size distribution was measured before and after each curve to confirm that the size does not change and that the drops do not coalesce. This way, O-W emulsions and oil are injected at different flow rates and their effective permeability can be measured at each rate (the total flow rate remains constant).

Some parameters like oil concentrations, drop diameter and cappilary number (change of the total flow rate) will be varied in order to check their effect in the relative permeability curve. Table 1 presents all the curves measured in this work. Sample 1 was used to measure cases *a* to *d*; in all these cases the total flow rate was 2.0 ml/min and the Cappilary number 6.1×10^{-7} (the viscosity and the surface tension remained constant at all curves). These curves aim to verify the effect of the emulsion itself, the oil concentration and the drop size. It is important to notice that the d[0.9] (means 90% of drop size is below) is getting higher in each curve measured. Cases *e* to *g* have lowered the total flow rate to 0.4 ml/min (Ca = 1.2×10^{-7}) and were measured using the second sample. These curves verify the effect of the Cappilary number and drop size. Cases *a* and *e* aim to compare the effect of emulsion with the aqueous phase in the rest of curves. They will be presented along with all the curves with the respective Cappilary number.

Table 1 – The curves measured and their parameters

Case	Curve	Cappilary number	Oil Concentration (%)	d[0.9] (μm)
a.	aqueous phase and oil	6.1×10^{-7}	-	-
b.	emulsion and oil		3.0	37.8
c.	emulsion and oil		1.5	53.1
d.	emulsion and oil		3.0	231.7
e.	aqueous phase and oil	1.2×10^{-7}	-	-
f.	emulsion and oil		3.0	43.7
g.	emulsion and oil		3.0	357.3

4. EXPERIMENTAL RESULTS AND DISCUSSION

Both samples have their absolute permeability measured at approximately 2 Darcy.

Figure 3 presents the relative permeability curve of emulsion and oil (case *b*) and the curve of aqueous phase and oil (case *a*). This emulsion has an oil content of 3.0% and 90% of oil drops are smaller than 37.8 μm. In the two curves, Ca valued 6.1×10^{-7} and the connate water saturation was measured in 9.70%. The residual oil saturation for case *a* is 65.52% and for case *b* is 58.80%.
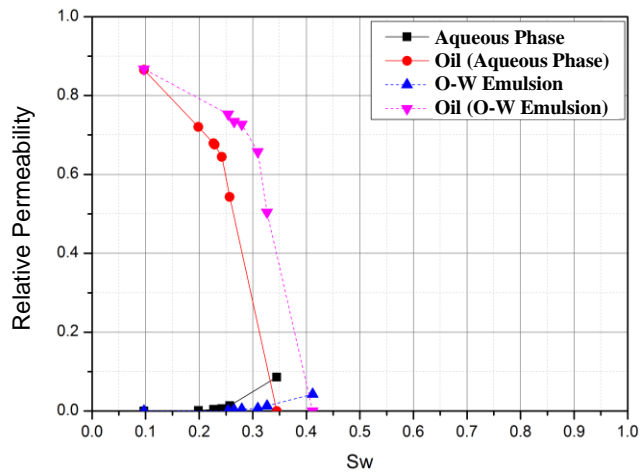
Figure 3 - Relative permeability curves measured of cases *a* and *b*

The results show a decrease of approximately 7% of the residual oil saturation and an increase of the oil permeability when injecting O-W emulsions. The emulsions were able to block the more permeable zones in the sample so a new bench of oil is displaced in the core. After the last point measured, 34.9% of the oil in place was displaced when injecting emulsions; this is 27.1% higher than case *a* (27.4% of oil displaced). The aqueous phase mobility has also diminished meanwhile the oil mobility has increased making a more favorable ratio and increasing the sweep efficiency of the oil recovery.

Another evidence of the emulsions effect is the pressure drop. It stabilized in 1.44 psi when injecting only aqueous phase (last point of case *a*). When injecting emulsions (case *b*), the pressure drop doubled in the last point (the flow rate was the same). This indicates that the oil drops were blocking the easiest ways and the injecting fluid was flowing through zones that were originally less permeable.

Still with the same Capillary number, case *c* was measured in order to determine the effect of oil concentration in the relative permeability curve. The drop size is slightly higher than case *b*, but this should not make any change in the curve; and even if it does, such change would be to increase the effect of emulsion, which did not happen. Case *d* repeated the oil concentration of case *b*, but the drop size was increased in one order of magnitude. Its objective was to verify the effect of an increase in the drop size and, also, prove that the effect seen in case *c* was not due the slightly increase in the drop size.

Figure 4 presents the cases *c* (left) and *d* (right), both compared to case *a*. As the laboratory ran out of energy, it was not possible to measure the last point of case *c*. For this reason, the residual oil saturation could not be determined.
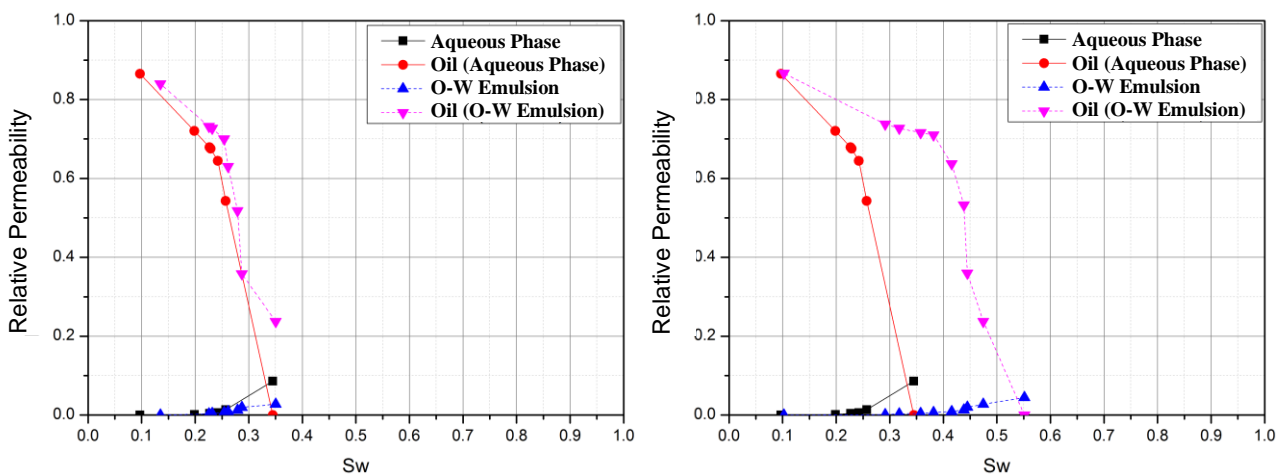

Figure 4 - The picture on the left presents the results of cases *a* and *c*. The one in the right side presents the results of cases *a* and *d*.

With the decrease of oil concentration, the effect of the emulsion has reduced. Even though, the oil mobility is higher than case *a* and the aqueous phase mobility is lower.

Case *d* shows an increase of the effect of the emulsion with the increase of drop size. The relative permeability of oil increases for a fixed saturation whereas the aqueous phase has its permeability decreased. The residual oil saturation reduced to 44.87%. It means that, after the last point measured, 50.0% of the oil initially located in the pores was displaced. This is 82.5% higher than case *a*. The O-W emulsions with a higher drop size were able to increase even more the sweep efficiency and, as consequence, the oil displaced. As the rock sample is relatively homogeneous, the

displacement efficiency has also been improved. The pressure drop measured when injecting only emulsion was 2.59 psi which was also higher than case *a*.

The next step was to verify the effect of the Capillary number. A decrease in the total flow rate was performed for the following curves, so Ca values now 1.2 x 10^{-7}. Therefore, case *e* is necessary so the emulsions could be properly compared to the aqueous phase with the respective Capillary number. As the surface tension and viscosity remained constant, Ca reduced in 5 times by reducing the flow rate at the same ratio (the diameter of the cores are the same).

Case *f* tries to repeat case *b*, but with a lower Capillary number; the oil concentration did not change and the oil drop sizes was approximately the same. Case *g* only shows again the effect of the drop size, which increased in one order of magnitude again, and can be also compared to case *d*.

Figure 5 presents on the left the comparison of cases *f* and *e* and, on the right, case *g* compared to case *e*.
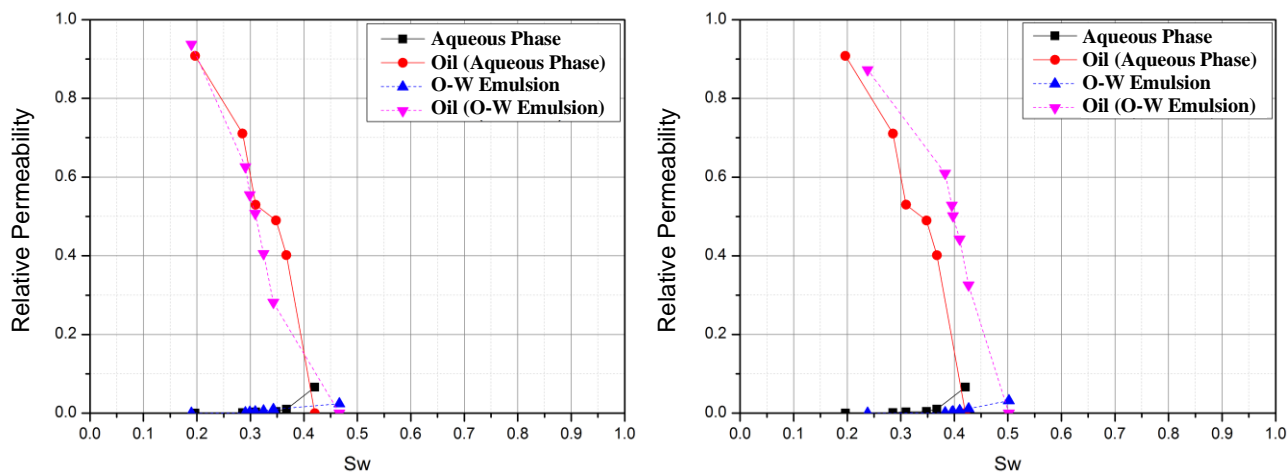

Figure 5 - The picture on the left presents the results of cases *e* and *f*. The one in the right side presents the results of cases *e* and *g*.

As the Capillary number was reduced, the effect of emulsions has also reduced. However, this was not expected. According to the references – McAuliffe (1973), Cobos et al (2009) and Guillen et al (2011) – a decrease in Ca would bring a stronger blockage effect of oil drops, i.e. the mobility of oil would increase. In case *f*, the residual oil saturation was 53.35%, which is lower than case *e* (57.96%). But the oil mobility in case *f* was equal or slightly lower than case *e*. Whereas the pressure drop in the last point of case *e* was 0.37 psi, the same point for case *f* was 1.01. As expected, the pressure drop has also increased when injecting only O-W emulsions. In case *f*, 34.2% of oil was displaced after the last point; this is higher than case *e*, where only 27.4% of oil was displaced. This values were equivalent to those obtained in cases *a* and *b*. Case *f* also showed a lower mobility for the injecting phase, which reduces the mobility ratio and increases the sweep efficiency.

As the drop size increases, the effect of emulsion is stronger. This was observed for the two Capillary numbers used in this work. However, the lower Ca did not represent the stronger effect again. Case *g* showed a residual oil saturation of 49.81%, a pressure drop of 0.77 psi in the last point and a percentage of 34.6% of oil displaced after the same point. This is still below the expectations as comparing to case *d*.

5. FINAL REMARKS

This work measured the relative permeability curves of O-W emulsions and oil for different oil concentration, drop size and Capillary number and compared them to the curve of aqueous phase and oil. In all cases, the emulsions have reduced the residual oil saturation and the mobility of the injecting phase (the emulsion itself). The mobility of the oil phase has also presented some improvement as the emulsions were injected. These effects were stronger with the higher oil concentration and the bigger drop size. On the other hand, a lower Capillary number, which would supposedly increase the blockage of the porous by oil drops, did not result exactly as expected. The mobility of the oil did not even increase when comparing cases *e* and *f*. This can be explained by the fact of Ca being too low for the two values used in this work and, for some unknown reason, there could exist some sort of limit for too low Ca. Another possible reason is the formation of emulsions when injecting only aqueous phase as the Ca has reduced. It is already known that two fluids flowing in a porous media can form emulsions (Miranda, 2010); and reducing the Ca may have facilitated the formation of emulsions.

The pressure drop when injecting only emulsion (last point of cases *b*, *c*, *d*, *f* and *g*) is always higher than the cases where only aqueous phase was injected. This is explained by the oil drops that have blocked the more permeable zones forcing the injecting phase to look to zones that were originally less permeable. The fact of having a higher value of pressure for smaller oil drops can be explained by the higher value of oil saturation that difficult the flow of the injected fluid.

As conclusion, the injection of O-W emulsion is able to increase the oil recovery factor. A possible loss of injectivity may happen as the pressure required to inject fluids in the reservoir would increase. Anyway, if properly designed, this problem can be controlled by reducing the flow rate and such a project can be effectively implemented as an Enhanced Oil Recovery method. An interesting possibility would be an alternate injection of emulsions and water. This could improve the sweep and displacement efficiency and, as consequence, increase the oil recovery factor. Another possibility is to use as O-W emulsion the produced water of a mature field. The oil recovery could be improved by re-injecting the produced water in the field. The oil droplets present is this water would produce the same effects viewed in this work and, not only the oil recovery would increase, but also a part of the problem of management of produced water would be solved.
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