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Injection of emulsions into cores packed with Ottawa sand and Berea sandstone as a method for enhanced oil recovery

Inyección de emulsiones en núcleos empacados de arena Ottawa y arenisca Berea como método de recuperación mejorada de petróleo

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Abstract

The use of preformed emulsions in enhanced oil recovery (EOR) processes is a novel technique in the Oil Industry aimed at, by means of the flow of injected water, increasing the sweeping volume and improving the efficiency of oil displacement. Oil-in-water (O/W) emulsions have shown good EOR performance, for they can better the water injection profile through the selective plugging process. In the present work, two O/W emulsion systems with drop size less than 6 μm were evaluated to be used as part of an enhanced oil recovery method. Oil recovery tests were run through a forced imbibition study simulating secondary and tertiary oil recovery processes in porous media such as packed cells with Ottawa sand and Berea sandstone cores. The results show that the emulsions exhibited higher recovery percentage in Berea sandstone than the one obtained with Ottawa-sand-packed cores. The crude-oil-based emulsion showed recovery efficiency above 18.1 % in Berea sandstone at a flow rate of 0.16 cm^3/min at 80 ºC.

Keywords: EOR, Emulsion flooding, Packed cell, Sandstone core.

Resumen

El uso de emulsiones preformadas en procesos de recuperación mejorada de petróleo (EOR) es una técnica novedosa en la industria petrolera que pretende, a través del flujo de agua inyectada, incrementar el volumen de barrido y mejorar la eficiencia de desplazamiento de petróleo. Las emulsiones de aceite en agua (O/W) han mostrado buen rendimiento en el proceso de EOR debido a que pueden mejorar el perfil de inyección de agua por medio del proceso de taponamiento selectivo. En este trabajo se evaluaron dos sistemas de emulsión O/W con un tamaño de gota inferior a 6 μm para utilizarlos como parte de un método de recuperación mejorada de petróleo. Las pruebas de recuperación de petróleo se llevaron a cabo mediante un estudio de imbibición forzada que simulaba los procesos de recuperación secundaria y terciaria de petróleo en medios porosos tales como celdas empacadas con arena Ottawa y núcleos de arenisca Berea. Los resultados muestran que las emulsiones exhibieron un mayor porcentaje de recuperación en la arenisca Berea que el obtenido con núcleos empacados con arena Ottawa. La emulsión basada en petróleo crudo mostró una eficiencia de recuperación superior al 18.1 % en los núcleos de arenisca Berea con un flujo de 0,16 cm^3/min a 80 ºC.

Palabras clave: EOR, Inundación con emulsión, celda empacada, núcleo de arenisca.

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1 Introduction

Despite the important and cutting-edge scientific advances related to sustainable energy sources, oil is still the most important energy source. The oil recovery process consists of three phases: primary, secondary and tertiary. In the first and secondary recovery phases, the reservoir natural pressure is used along with the injection of water or steam into the injection wells, respectively (Nazar *et al*., 2011). The microscopic displacement within the pores of natural geological formations has yielded recovery percentages from 20 to 50 % of original oil-in-place (OOIP) at the first and secondary recovery stages (Baldygin *et al*., 2014; Kamal *et al*., 2017; Karambeigi *et al*., 2015; Park *et al*., 2015; Shafiee Najafi *et al*., 2017). As for the tertiary oil recovery, also known as enhanced oil recovery (EOR), different methods involving thermal and biological processes, and the injection of gases and/or chemical substances are employed to produce a change in the mobility of stagnant oil trapped in a porous medium, mainly of mature reservoirs (Ahmadi *et al*., 2019; de Farias *et al*., 2016; Nazar *et al*., 2011; Shang & Hou, 2019; Suarez-Suarez *et al*., 2019; Vahdanikia *et al*., 2020; Zhao & Pu, 2020) and it has been reported that by means of this stage, between 20 and 40 % of additional OOIP recovery has been achieved (Li *et al*., 2020).

One of the most employed EOR technologies is the flooding of oil reservoirs by means of chemical substances (chemical flooding) that are added to the injected water; these chemicals can be alkaline solutions (A), surfactants (S), polymers (P) and / or a combination of them (ASP). In the case of surfactant flooding, for instance, water containing a S (Nguele *et al*., 2017) and co-surfactants (Nordiyana *et al*., 2016) is injected with a pore volume (PV) interval ranging from 0.15 to 0.60 in order to reduce the interfacial tension and form an in situ emulsion (Z. Liu *et al*., 2019; Nazar *et al*., 2011; F. Yu *et al*., 2019; Zhou *et al*., 2020), which can be stabilized by the presence of asphaltenes, waxes, resins and naphthenic acids (Ahmadi *et al*., 2019; Ismail *et al*., 2020; Lee & Babadagli, 2020; Pang *et al*., 2019). When the emulsifier concentration is 0.4 or 0.5 %, pore-throat-scale emulsions with viscosity between 40-70 mPa·s can be formed and with the increase of emulsifier concentration, the storage modulus of emulsion increases related to the loss modulus, enhancing the viscoelasticity of formed emulsions compared to emulsions formed with 0.3 % or less surfactant (Zhou *et al*., 2017). Notwithstanding, both the emulsification and mobilization of crude oil by the injection of anionic S into oil reservoirs are affected significantly by high salinity and temperature (Goswami *et al*., 2018), producing precipitation and degradation phenomena and the possible plugging of pores by the S (Abdulredha *et al*., 2020; Ding *et al*., 2021; Goswami *et al*., 2018; Pang *et al*., 2019) as reported by Pang *et al*. in 2019 who stated that the viscosity and stability of in situ emulsions wind down with the salinity of synthetic reservoir water (Pang *et al*., 2019). In addition, the application of an S is not sufficiently efficient at the late stage of the secondary recovery because oil remains isolated within the reservoir and injected water formed preferential paths. The employment of an ASP solution is very expensive (Sun *et al*., 2020) and much more in reservoirs with high temperatures and salinity levels (Yang & Pu, 2020), which is the case of Mexican reservoirs (Birkle *et al*., 2009; Durán-Valencia *et al*., 2014).

In order to reconnect the isolated oil within the reservoir, the injection method of either preformed or outside-reservoir-formed emulsions with specific drop size in the dispersed phase (Vahdanikia *et al*., 2020) is used. As a consequence, the rock wettability is modified, for this action entails a new redistribution of fluids within the porous medium, widening the sweeping volume and improving the displacement by water injection (Zhou *et al*., 2020), even in the presence of divalent ions (Li *et al*., 2020). In addition, the emulsion blocking the formation can be easily removed and emulsions provide efficient well injectivity (Yu *et al*., 2018), which represents low risk in the application of the EOR process.

The type of preformed emulsion, oil/water fraction in the emulsion and the formation of dispersed droplets with desired size allow the monitoring of the additional oil displacement mechanism, which is complex (Ismail *et al*., 2020; F. Yu *et al*., 2019), based on the blocking of the porous medium and related to the capillary number, which is defined as the ratio of viscous to capillary forces, is more effective at low capillary numbers less than 10-4. (Guillen *et al*., 2012; Moradi *et al*., 2014).

Emulsions can be divided into three main groups: water in oil (W/O), oil in water (O/W) and multiple emulsions (Abdulredha *et al*., 2020). Preformed O/W emulsions, in which the dispersed phase is oil and the continuous phase is water, can be transported to the injection site and diluted with injection water, for they can improve the water injection profile through the selective plugging process (Bryan & Kantzas, 2009; Yang & Pu, 2020; Yazdani Sadati & Sahraei, 2019) as reported by Mandal *et al*. in 2010 who ran flooding experiments with O/W emulsions in sand pack holders with crude oil from the Ahmedabad oil field (India) and obtained additional OOIP recovery above 20 % (Mandal *et al*., 2010). Shupe & Maddox in 1981 and Cardenas *et al*. in 1981 patented O/W emulsions based on hydrocarbons such as diesel oil, naphtha, crude oil, and anionic and non-ionic surfactants for EOR in Berea cores with temperatures and salinity content up to 115 °C and 164,000 ppm, respectively, achieving additional recovery up to 19 % using 0.20 PV of emulsion (Cardenas *et al*., 1981; Shupe & Maddox, 1981). Likewise, Karambeigi *et al*. in 2015 employed diesel as hydrocarbon phase in an emulsion slug system. These authors varied the salinity and surfactant concentration and obtained 28 % of additional recovered oil, confirming that the use of hydrocarbons as hydrophobic phase is a viable alternative for the formulation of emulsions (Karambeigi *et al*., 2015). The oil phase can be represented not only by crude oil, but also by other oily chemical compounds such as silicone oils (Bousaid), triglycerides (Jeirani *et al*., 2013), etc., which helps control the hydrophobicity of the dispersed phase, emulsion stability, etc. In this sense, Demikhova *et al*. in 2014 and 2016 employed trioctylmethylammonium as emulsion dispersed phase and obtained remarkable results up to 26 % of additional recovery in Berea rock cores at 80 °C at 100,000 ppm (Demikhova *et al*., 2016; Demikhova *et al*., 2014).

In the present work, it was decided to apply the injection of emulsion slug at the late stages of water injection, after water had already formed preferential paths within the porous medium and oil was isolated, to compare the effects of preformed O/W emulsions, in which the dispersed phase was represented by either crude oil or a hydrophobic chemical compound, on additional oil recovery. To do so, two emulsions were employed to modify the flow patterns formed after water flooding as part of an EOR study using packed Ottawa sand and Berea sandstone cores at different flow rates (0.16, 0.3 and 0.5 cm^3/min) and temperatures ranging from 25 to 80 ºC, respectively.

2 Experimental

2.1 Preparation of emulsions

A *crude-oil-based emulsion (COE)* was prepared by adding 70 g of hydrophobic phase, which was represented by crude oil (API gravity@20°C of 20.1 °API), to 30 g of aqueous phase, mixing with an Ultra-Turrax T25 Basic homogenizer at 16000 rpm for 8 min. The aqueous phase comprised 3 g of the Igepal CO 890 (Sigma-Aldrich) hydrophilic surfactant with HLB 17, and 29 g of distilled water. The diameter sizes of the 90 and 50 % dispersed phases, (D90) and (D50), were 2.9 and 2.0 μm, respectively. The diameter sizes were measured by using a laser diffraction piece of equipment Mastersizer 2000 Hydro2000S by Malvern. The prepared emulsion was diluted with distilled water before being used until obtaining 1 wt. % of the dispersed oil phase. The viscosity and density of the diluted emulsion were equal to those of water (1 cP and 1 g/ml, respectively).

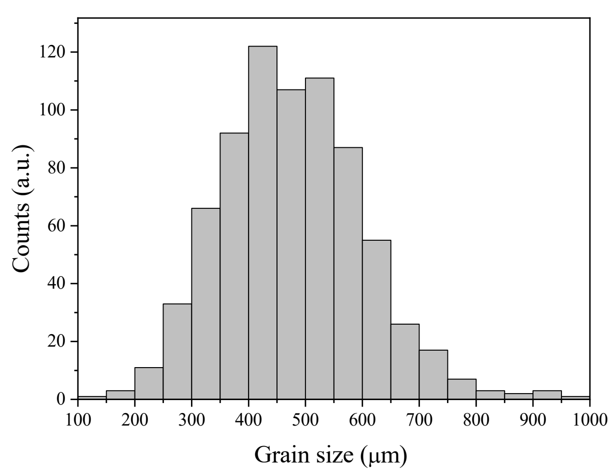

Fig. 1. Grain size distribution of Ottawa-type sand.

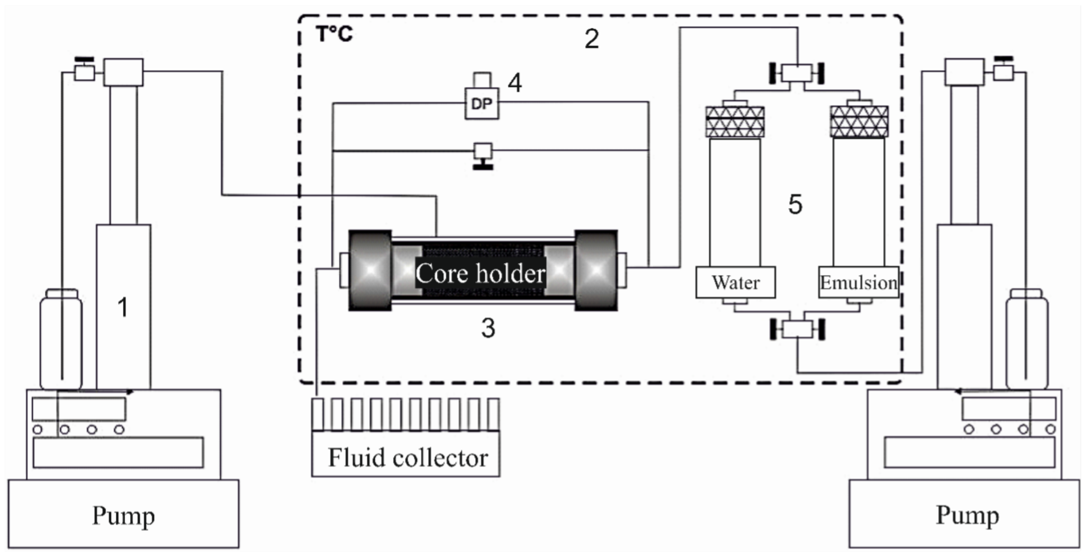

Fig. 2. Setup of the experimental flooding system: 1) pump for confining pressure, 2) experimental cell with controlled temperature, 3) core holder, 4) differential pressure transducer, 5) Quizix pump for injecting fluids.

A *hydrophobic-polymer-based emulsion (HPE)* was prepared by adding dropwise 30 mL of the aqueous phase, which was represented by the mixture of 1.5 g of Brij 30, 0.003 g of sodium lauryl sulfate, 0.18 g of polyvinyl alcohol and distilled water (up to 30 mL), to 10 mL of the hydrophobic phase, which was represented by 2 g of Luwax OA5 polymer dissolved in 10 mL of mineral oil at 80 °C, mixing with an Ultra-Turrax equipment T25 Basic homogenizer at 16000 rpm for 8 min. The diameter sizes of the 90 and 50 % dispersed phases, (D90) and (D50), were 5.6 and 4.8 μm, respectively.

The size of the particles was measured by using a particle size analyzer and counter PSS, model Accusizer 780, calibrated and verified with Duke Scientific certified standards with traceability to NIST. The prepared emulsion was diluted with distilled water before being used until obtaining 1 wt. % of the dispersed oil phase. The viscosity and density of the diluted emulsion were equal to those of water.

2.2 EOR in sand-packed acrylic cells

The forced imbibition tests using sand-packed cells were carried out with crude oil purchased from an oil field (33.6 °API, 12.5 mPa·s, and 867 kg/m^3 20 °C). Distilled water was employed as displacing fluid. The porous medium was Ottawa-type silica sand whose chemical composition (wt.%) was O (60.32 wt.%), Al (4.34 wt.%), Si (31.63 wt.%), Na (0.92 wt.%), Mg (0.38 wt.%), K (0.51 wt.%) and Fe (1.89 wt.%). The diameter size of the Ottawa-type sand ranged from 400 to 550 μm as shown in the particle size histogram in Figure 1.

The EOR experiments were performed using acrylic cells designed with an axial and radial diffusion system for a homogeneous distribution of displacing fluid. The cells had internal diameter of 4.4 cm (1.73 in), internal length of 13.6 cm (5.35 in) and cross-sectional area of 15.2 cm^2 (2.36 in^2) and were packed with silica sand by means of a compaction process, employing a vibrator for 20 min to ensure dense packing.

The EOR methodology consisted of three stages. At the first one, a saturation process was carried out with oil from the cells previously packed with Ottawa-type sand; then, the oil saturated core was placed in vertical position for 2 days by draining the system, until reaching irreducible oil saturation. At the second stage, secondary recovery was performed by injecting three PVs of distilled water through the porous medium, until reaching no more oil recovery. At the third stage, an emulsion slug equivalent to 10 % PV was injected into the packed cell. The concentration of the HPE and COE emulsions was 1.0 wt.% of the dispersed phase. After injecting the emulsion slug, water introduction was resumed immediately. The flow rates, both of water and emulsion, were 0.16, 0.3 and 0.5 mL/min, respectively, and the temperature in all the experiments was 25 °C. To be sure of the reproducibility of the results, each experiment was run in duplicate, and the average value of the oil recovery percentages was reported.

Table 1. Characteristics of the sand packs employed in the EOR experiments.

Emulsion	ID	PV[a] [cm^3]	ϕ [%]	Pore throats, r [μm]	K [D]
HPE	1-16	70	34	37.2	2.095
	1-30	75	35	36.7	2.140
	1-50	71	34	37.3	2.105
COE	2-16	69	33	37.8	2.053
	2-30	70	34	37.1	2.080
	2-50	69	33	37.7	2.045

[a]PV= pore volume, ϕ =porosity. PV and ϕ were calculated by the saturation method before starting the EOR tests.

Table 2. Characteristics of the Berea sandstone cores employed in the EOR experiments.

ID	Diameter [cm]	Length [cm]	Cross-sectional area [cm^2]	PV[a] [cm^3]	ϕ[a] [%]	Pore throats, r [μm]	K [D]
1-B16	5.12	10.09	20.55	37.76	18.2	6.1	0.056
2-B16	5.08	9.85	20.27	37.05	18.6	7.3	0.076

[a]PV= pore volume, ϕ =porosity. PV and ϕ were calculated by the saturation method before starting the EOR tests. Permeability (K) was calculated for water.

Figure 2 shows the oil recovery system employed during the secondary and tertiary stages for all the porous media.

The properties of the sand packs are reported in Table 1. The number of injected pore volume (N_{IPV}) was calculated for each experiment with Equation (1):

$$N_{IPV} = \frac{Qt}{A\phi L} \tag{1}$$

where t is the injection time, A is the cross-sectional area, ϕ is the medium porosity, Q is the flow rate (cm^3 s^{-1}) and L is the sand pack longitudinal distance. The computation of the oil tertiary recovery was employed as the emulsion efficiency criterion.

In the present study, the pore throats in both core types, Ottawa sand and Berea sandstone, were determined approximately by means of the following empirical equation obtained from a multiple linear regression analysis, which was proposed by Windland and Pittman (Rezaee *et al*., 2006):

$$\log r = \frac{\log k + 1.221 - (1.415 \log \phi)}{1.512} \tag{2}$$

The pore throat values for the Ottawa sand and Berea sandstone packed systems are reported in Tables 1 and 2, respectively.

2.3 EOR in Berea sandstone cores

The porosity and permeability characterizations, as shown in Table 2, were carried out using distilled water considering a density value of 998 kg/m^3, where it can be observed that the porosity of the cores is 18 %. Every sandstone core was placed horizontally and flooded at 80 °C; after measuring the permeability of the sandstone core, the porous space was fully saturated with brine, which was displaced by injecting crude oil until reaching the residual water saturation. The brine solution was prepared by using well-produced water whose salinity (NaCl) was 266881 ppm, total water hardness ($CaCO_3$ and $MgCO_3$) was 63300 ppm, Fe^{2+} concentration was 0.41 ppm, density@20 °C was 1176.4 kg/m^3, pH value of 5.95 and Stiff&Davis stability index equal to 1.62191, which was diluted three times with distilled water (Demikhova *et al*., 2016). The secondary oil recovery was carried out with brine at least at 5 PV, the flow rate was kept at a constant inlet flow rate of 0.16 cm^3/min, when the oil production fell to zero; all the oil inside the pore space was static and a slug of 0.1 PV with 1 wt.% of emulsion concentration was injected into the rock core, followed immediately by another brine injection cycle. The calculated cumulative tertiary oil recovery was used as the criterion for the emulsion efficiency. More details about the emulsion flooding process in Berea cores can be found in (Ge *et al*., 2020; Karambeigi *et al*., 2015).

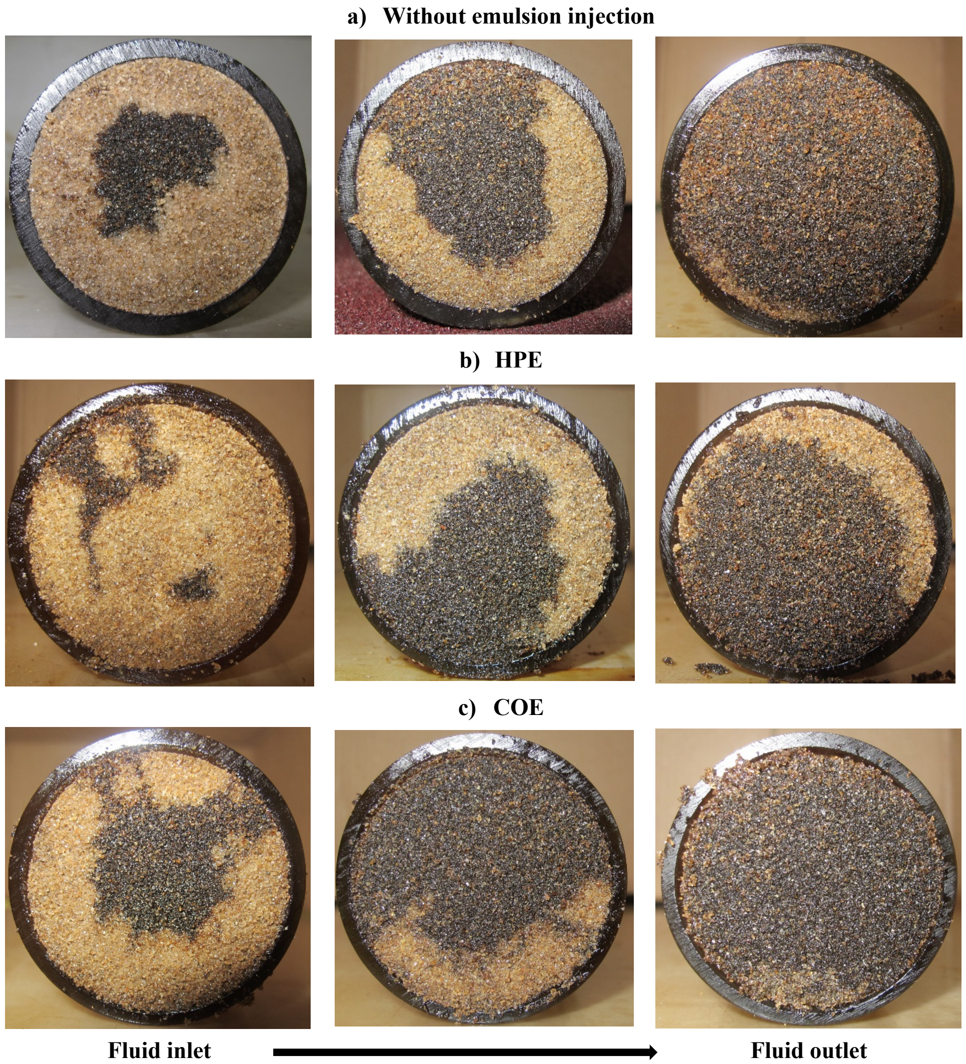

Fig. 3. Images of sand-core cross-sections after oil recovery at a flow rate of 0.5 mL/min a) without emulsion injection, b) with HPE emulsion injection and c) with COE emulsion injection. The fluid flows from left to right.

2.4 *Results and discussion*

2.5 *EOR using emulsions in Ottawa-sand-packs*

The average porosity of the Ottawa-sand-pack cells was equal to 33.8 ± 0.75 %, Table 1, indicating a homogeneous distribution of grains as a consequence of a successful vibration-packing process. These porosity results are similar to those obtained by Baldygin *et al*. in 2014 (34.63±1.069), de Farias *et al*. in 2016 (39.3) and Liu *et al*. in 2017 (31.83±0.739).

Figure 3 shows the images obtained from sand-packed-core cross-sections after carrying out the oil recovery process at a flow rate of 0.5 cm^3/min a) without emulsion injection, b) with HPE emulsion injection and c) with COE emulsion injection. It is observed that in the zones close to the displacing fluid injection, the oil amount is lower than at the exit of cores in all the experiments, i.e. most residual oil is segregated and accumulated at the core outlet. In the packed cell, where the injection of the HPE emulsion was performed, a different fluid redistribution phenomenon at the inlet and outlet ends was provoked by the injection of emulsion. In contrast, a difference using the COE emulsion with water injection was not so remarkable; only in the center of the sand pack there was a wider redistribution of oil in the COE system.

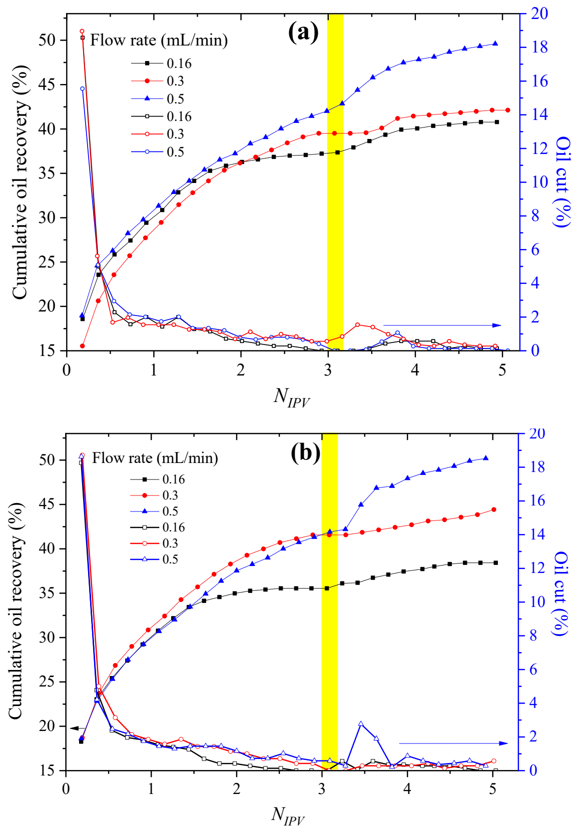

Fig. 4. Oil recovery variation with respect to the NIPV in packed-Ottawa-sand cores by using (a) HPE and (b) COE.

Figures 4 (a) and (b) show the cumulative oil recovery profiles with the corresponding percentage of oil cut using the HPE and COE emulsions, respectively. In the cumulative oil recovery curves plotted as N_{IPV} functions, an inflexion point is observed, which corresponds to the emulsion injection stage after 3 PVs of water injected. After the emulsion injection and subsequent reactivation of water injection at flow rate of 0.5 cm^3/min, an additional oil recovery stage is observed through a sudden increase in the slope of the cumulative oil recovery curves, which is more evident for the COE emulsion. The increase in the oil recovery percentage occurred in all the experiments independently of the displacing fluid flow rate, which evidenced the efficiency of the employed emulsions. In addition, it is observed that the increase in the flow rate augments the additional recovered oil percentage since a higher flow rate provokes stronger oil pushing through the pore throats.

Table 3 shows the results of the EOR process by both emulsions. At the end of the water flooding stage, it is observed that the cumulative recovered oil percentages are ~ 36.6, 40.6 and 42.0 % for flow rates of 0.16, 0.3 and 0.5 cm^3/min, respectively. As for the tertiary recovery stage, the additional recovered oil percentage intervals ranged up to 8 % by using the emulsions; the recovered-oil percentages reached by employing both emulsions are similar. Emulsion flooding would cause modest efficiency losses around the inlet flow zone, but as the emulsion penetrates deeper into the reservoir (Moradi *et al.*, 2014), the drops get trapped at sufficient distance within the rock nucleus and therefore act as a plug, bringing on the sweep efficiency of the displacing fluid.

Table 3. EOR results by using emulsions in packed-Ottawa-sand cores.

Emulsion		HPE			COE	
Identification number	1-16	1-30	1-50	2-16	2-30	2-50
Secondary oil recovery						
Flow rate, Q (cm^3/min)	0.16	0.3	0.5	0.16	0.3	0.5
N_{IPV}	3	3	3	3	3	3
Recovered oil (%)	37.70	39.53	42.00	35.53	41.60	41.92
Residual oil saturation (-)	0.623	0.605	0.580	0.645	0.584	0.581
Tertiary oil recovery						
Flow rate, Q (cm^3/min)	0.16	0.3	0.5	0.16	0.3	0.5
Recovered oil (%)	3.00	2.61	7.59	2.88	2.86	8.29
Total oil recovery (%)	40.70	42.14	49.59	38.41	44.46	50.21
Residual recovered oil* (%)	4.82	4.31	13.09	4.47	4.90	14.27

*is the ratio between the oil recovered during the tertiary oil recovery and residual oil saturation after the secondary oil recovery.

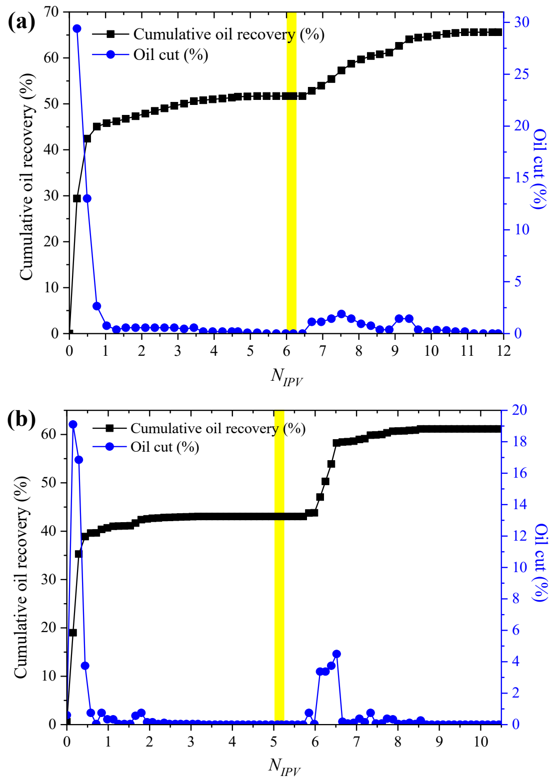

Fig. 5. Oil recovery variation with respect to the N_{IPV} in Berea sandstone by using (a) HPE and (b) COE.

By comparing the oil recovery efficiency percentages through the ratios between the oil recovered during the tertiary oil recovery (emulsion injection) and the residual oil saturation after the secondary oil recovery (water flooding), the HPE and COE emulsions present very similar results, where COE presents slightly better results than HPE at faster flow rates (0.30 and 0.50 cm^3/min), reaching up to 14 % of residual recovered oil.

2.6 EOR using emulsions in Berea sandstone cores

Figures 5 (a) and (b) display the variations of the cumulative oil recovery and oil cut percentages as functions of the N_{IPV} at a flow rate of 0.16 cm^3/min using the HPE and COE emulsions, respectively. The observed recovery behavior pattern is like the one witnessed with Ottawa sand packs; however, the recovery percentages of the secondary and tertiary stages are higher as observed in Table 4. The slightly higher secondary recovery in the rock cores can be attributed to the brine being slightly denser than distilled water, so the displacement is a bit more efficient.

The tertiary recovery stage presented additional recovered oil percentages of 13.92 and 18.11 for the HPE and COE emulsions, respectively; from these results, it seems that the COE emulsion is more efficient than HPE. As the nature of the dispersed phase of the COE emulsion is the same as that of the displaced oil, COE forms an oil bank within the core, becoming evident through high oil cut at the fluid outlet after post-injection of 1 PV of water (Figure 5 (b)). However, the HPE emulsion blocked the water flow and redistributed the fluids within the core in a gentler way, making the additional oil cut not as high but the oil output took longer injection time. Notwithstanding, if the ratio between the tertiary recovery and residual saturation percentages after water flooding is considered, the residual oil recovery is of 28.82 and 31.77 % for the HPE and COE emulsions, respectively. Then, the difference between the recovery percentages is minimal and in good agreement with the tests run in Ottawa-sand-packs; furthermore, it should be kept in mind that the permeability of the core 2-B16 (76 mD) in the experiment with COE is a little higher than that present in the experiment with HPE (56 mD). The efficiency of the emulsions in the core tests is practically similar due to their retention in the pore throats, thus favoring the pore blocking through size exclusion. The injection of emulsions with oily dispersed phases alters the preferential water paths, forming a movable oil bank (Demikhova *et al*., 2016).

Table 4. EOR results using emulsions in Berea sandstone.

Emulsion	HPE	COE
Identification number	1-B16	2-B16
Secondary recovery		
Flow rate, Q (cm^3/min)	0.16	0.16
N_{IPV}	6	5
Recovered oil (%)	51.70	43.04
Residual oil saturation (-)	0.483	0.570
Tertiary recovery		
Flow rate, Q (cm^3/min)	0.16	0.16
Recovered oil (%)	13.92	18.11
Total oil recovery (%)	65.62	61.15
Residual recovered oil* (%)	28.82	31.77

*is the ratio between the oil recovered during the tertiary oil recovery and the residual oil saturation after the secondary oil recovery.

It has been reported that the emulsion droplet size plays a major role in the oil sweeping process, and in this sense, a droplet size above 10 μm could provoke the plugging of the pore throats in a core, thus generating a deficient additional oil recovery process. When a drop is trapped in the pore throat, smaller than the drop size, the curvature of the drop tip is increased, which leads to higher capillary pressure at the front, and if the continuous phase viscous gradient is insufficient to overcome the high capillary pressure at the drop tip, consequently, the drops can remain trapped in the pores (Moradi *et al*., 2014). In all the systems, it is observed that the pore throat values are higher than the droplet sizes in both emulsions. The ratio between the pore throats and emulsion droplet size (D50) in the Berea rock core is 2.5 for HPE and 7.3 for COE, which indicates that the COE droplets can better penetrate the porous cores, while HPE drops are retained in the vicinity of the injection area, whereby their penetration into the core is less effective than that of the COE emulsion; in this way, the HPE emulsion affects less area within the cores to perform the modification of the preferential water flow patterns compared to the COE emulsion. On the one hand, unlike the Berea sandstone cores, the packed sand systems present a pore throat size that is much higher than the droplet size in the emulsions, which could reduce the efficiency of the additional oil recovery performed by the emulsions, because a lower size could affect the retention process of the emulsion droplets in the pores and consequently affect the modification of the preferential water flow patterns through the pore throats, presenting very similar additional recovery performances for the COE and HPE emulsions. Because the flow of emulsions throughout the cores on pore scale changes the mobility of the flow patterns generated by the water flow, pores that had not been displaced during the secondary recovery stage get reached, thus accomplishing the reduction of additional residual oil.

Conclusions

The injection of two emulsions, with 1 wt.% of dispersed oily phase at different flow rates, produced additional oil recovery from two porous media: sand packs and sandstone cores. The COE emulsion presented additional oil recovery above 18.1 % in the Berea sandstone core and 8.3 % in the Ottawa sand pack at a flow rate of 0.5 cm^3/min, while the HPE emulsion presented additional oil recovery of 13.9 and 7.6 %, respectively. However, by adjusting the oil recovery data in terms of residual recovery for the Berea rock cores, the results were 28.8 and 32.7% for HPE and COE, respectively. A third of residual oil was recovered due to the capacity of the synthesized emulsions to alter the preferential water paths, redistributing fluids within the core, and forming a movable oil bank. The crude oil-based emulsion (COE) facilitated the oil bank formation, while the hydrophobic compound-based emulsion (HPE) redistributed gradually fluids within the core, achieving the recovery of a third part of residual oil by injecting only one slug of 10 % of PV. The injection of the manufactured emulsions made possible the recovery of discontinued oil at the late stages of the water injection process with high water cut in the producing wells by only injecting a small slug of chemical without stopping the waterflooding process before employing more complicated processes like ASP.

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