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Analysis of the Injection of Non-Ionic Surfactant in Cores of a Mature Field to Increase the Recovery Factor

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Abstract

Nonionic surfactant injection is the second most common chemical used as enhanced oil recovery technique. This paper analyses the effect of enhanced oil recovery technique by surfactant injection in cores through different rock- fluid properties at laboratory scale. A screening process was performed to find the most effective surfactant concentration on different water salinity. Thus, cores were saturated with brine and synthetic oil mixture. Afterward, the cores were desaturated using the Porous Plate equipment to measure capillary pressure, and spontaneous and forced imbibition test was applied to get recovery factor of each rock sample. The saturation process with different salinity, brines as well as, synthetic oil mixture is repeated twice. This process was performed for every surfactant concentration. The results showed that by surfactant injection into the rock samples, relative permeability values vary considerably in a way that improves oil recovery at different brine salinities. The oil recovery factor increased in a range of (1 - 6) % for a solution of 1% surfactant and 50000 ppm brine. On the other hand, when reducing brine salinity to 5000 ppm while keeping constant the chemical solution the recovery factor increases to around a range of 6 to 12%. After treating different rock samples with surfactant the results showed a significant volume of oil recovered after performing spontaneous imbibition test. The relative permeability curves of water and oil shifted to the right, decreasing residual oil saturation and changing rock wettability. (As a result, the optimum surfactant concentration is 1%wt. Additionally, as the surfactant concentration decrease, IFT increases).

Keywords*: Oil recovery factor; Relative permeability; Nonionic surfactant; Enhanced oil recovery; Mature oilfield; Salinity.*

1. Introduction

Surfactants have been considered since 1970 as a potent chemical since they can significantly reduce interfacial tension, alter the wettability of the rock, reduce capillary pressure, facilitate oil mobility and improve its recovery factor [1-9]. Surfactants are adsorbed at the oil-water interface resulting in an extremely low interfacial tension, which causes an increase in displacement efficiency; surfactants also help extract oil trapped in small pores in the reservoir rock [1,10-11].

The professional interest in the injection of non-ionic surfactants in cores samples is undoubtedly focused on improved oil recovery (EOR). The EOR is normally applied after secondary recovery to sweep all the remaining oil from the reservoir rock [12]. The EOR by chemical injection allows recovering the oil trapped in the finest pores of the reservoir rock even after applying a conventional water injection process; that is, it significantly improves the efficiency of oil recovery at the microscopic level [2, 13-14].

The academic interest is evidenced in several aspects of the properties and phenomena of the reservoir and its fluids. In one hand, the residual oil saturation (Sor) is altered by the use of non-ionic surfactants because they tend to replace the pore volume occupied by oil, that is, the amount of oil recovered increases [15]. Obviously the compatibility of the reservoir with the non-ionic surfactant should be considered [13,16]. On the other hand, the wettability of the rock is altered by the polar interactions of the different phases and the reservoir, consequently, the surfactants having different charges can alter the wettability of the reservoir [17-18]. One of the phases found in the reservoir is salt water and depending on its salinity can improve or worsen the adsorption of the surfactant at the oil-water interface, resulting in a reduction of the IFT [19-20].

The present research analysis examines the effects of the injection of a non-ionic surfactant with high and low salinity water into four rock samples of T sandstone oil reservoir of a mature field of the Ecuadorian Oriente basin. The fundamental characteristic obtained by adding a non-ionic surfactant in water with different salinities is the alteration of the interfacial tension (IFT) at the interface of the oil-water interface. To analyze this particularity, different surfactant concentrations with several salinity brines were injected with in sandstone rock samples with intermediate wettability.

The experimental procedure began with porosity, permeability and resistivity measurement of the four rock samples obtained from T sandstone reservoir of a mature field of the Ecuadorian basin. Next, the rock samples were saturated with salinity water of 54 g/L, which is identical as the real brine of T sandstone reservoir.

The next step was to measure the capillary pressure with a desaturation cell, so that as the water saturation in the core is reduced, a different capillary pressure is measured. This process ends with the saturation of irreducible water of each one of the cores. Consequently, the cores saturated with irreducible water are saturated with a synthetic mixture of petroleum and mineral oil (95% mineral oil and 5% petroleum with 22.5 API). These cores are subjected to a process of spontaneous imbibition in the Amott cell and forced imbibition in a centrifuge. The objective is to obtain the volume of oil recovered and the residual oil saturation of each of the cores, in order to obtain the relative permeability curves with the Corey method [21].

Then, a screening test is performed between different surfactant concentrations and different salinities of water. Typically, surfactant concentrations between 0.3 and 1% by weight are used for different formation water salinities. In this research, 1, 2, 3 and 4% by weight (wt.) of surfactant and salinities of 5, 10, 20 and 50 g/L were used. After measuring the interfacial tension (IFT) with the Nouy ring for all possible combinations of surfactant and salt water, the two combinations that gave the lowest value of IFT were chosen.

Finally, the cores must be washed and again saturated but this time with the two best combinations of surfactant and salt water, so that the process of measuring capillary pressure, saturation with synthetic oil, imbibition and application of the method of Corey.

The research shows a precedent in terms of experimental research since there are no previous studies on the feasibility of applying EOR by chemical injection in the eastern Ecuadorian basin. Consequently, what was done is; study the effectiveness of the EOR technique by injecting a non-ionic surfactant on a laboratory scale to increase the recovery factor; perform a conventional analysis that includes porosity and absolute permeability; Perform a special analysis of cores that includes capillary pressures and finally determine the relative permeability curves of the different cores.

2. Materials and methodology

The experimental methodology with the three general procedures applied for each of the four cores (core 2-4-8, core 2-3-6M, core 2-5 -12, core 3-6-20) of the sand T is in the flow chart of Fig. 1. The surfactant used is Enzurlan, which is a non-ionic ethoxylated alcohol type surfactant with a density of 1 g/cc and very easy to obtain in the market.

The most commonly used surfactants are synthetic sulfonates and sulfonates in the petroleum industry [22]. The advantages of using a surfactant in improved recovery processes are that they improve the displacement efficiency, reduce the saturation of residual oil, solubilize the oil dispersing it in the form of an emulsion, improve the wettability of the sandstones and can work at high temperatures. On the other hand, its disadvantages are its high costs and the precaution that must be taken when seeking compatibility with reservoirs.

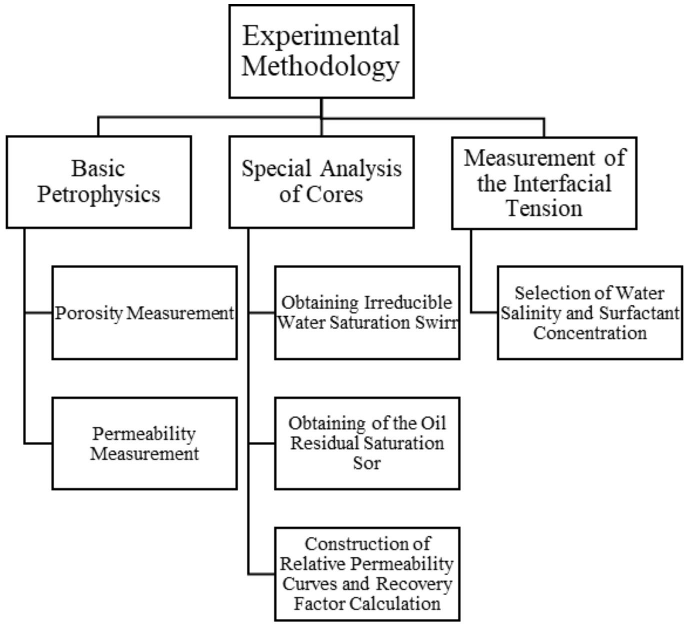

Figure 1. Flow diagram of the experimental methodology

In a surfactant injection process for EOR some considerations are taken into account Table 1. These considerations determined the effectiveness of the application of pilot tests of surfactant injection [23].

Table 1. Surfactant injection considerations

Considerations	Goodlett *et al.*, [23]	Lake & Walsh [?]
Gravity API	> 25	> a 23
Crude viscosity (cp)	< 40	< a 10
Crude composition	Light and intermediate	
Oil saturation (%)	> a 30	
Water salinity (ppm)	< a 140000	
Reservoir temperature (ºF)	< a 200	
Rock type	Preferable sandstone	
Permeability (mD)	> a 40	
Deep (ft)	< a 9000	> a 2500
Net thickness (ft)	Not critic	
Reservoir pressure (psi)		> a 1500
Porosity (%)	> a 20	

2.1. Basic petrophysics

The basic petrophysics consists in the measurement of the porosity and permeability properties of the four cores. The porosity was measured by two different procedures that are applied in the PORO PERM PRODUCTION equipment. The first one (procedure of the matrix cup) allows to measure in an approximate way the grain volume of the core and with the geometric measurements of the length and diameter of the core the porosity can be obtained; The equipment uses Boyle's law for gases to determine grain volume.

The second procedure (Core Holder procedure) directly determines the porous volume using the same Boyle law for gases but require the density of the rock determinated with the procedure of the matrix cup.

In the same way, the POROPERM PRODUCTION equipment is used to measure the permeability. The equipment allows to measure the permeability using the Darcy equation by flowing nitrogen gas through the porous space of the core. By means of the application of the Klinkenberg effect, the permeability of the liquid is obtained. The Klinkenberg effect consists of determining several permeabilities with gas flow (Kg) and through an extrapolation in a Kg vs. (1/Pm) graph where Pm is the average confining pressure of the core, we take the point of intersection of the Kg axis with the extrapolation line, this point is the permeability of the liquid.

2.2. Special analysis of cores

The special analysis of cores begins with the saturation of the four cores with water saturated with 54 g/L (54000 ppm) of potassium chloride. The procedure was carried out with a vacuum pump and a desiccator, see Fig. 2a. Subsequently, a desaturation process was carried out with the equipment known as Porous Plate, see Fig. 2b. The pressures that were applied to the desaturation were 1, 2, 5, 8, 15, 35, 75, 170 psi. and while the pressure increases, the water saturation in the cores is reduced. The saturation of water that can no longer be eliminated is known as saturation of irreducible water (Swirr). Each time the pressure is increased, the weight of the saturated core must be recorded so that, by difference with the weight of the dry core, the saturation of water at a new pressure is obtained.

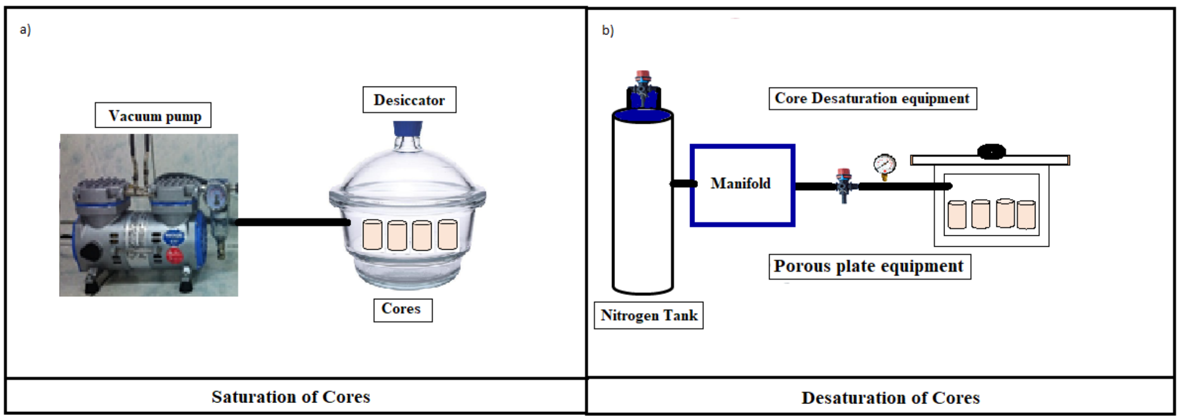

Figure 2. Saturation and desaturation of cores

The cores wetted with Swirr are saturated with a mixture of petroleum and mineral oil in a percentage of 5% by weight (wt.) And 95% wt respectively, see Fig. 3a [24]. The reason because a mixture of petroleum and mineral oil is used is that the original API of the petroleum of the reservoir where the cores were gotten was reduced for degradation. The mixture of petroleum and mineral oil has a severe API of 26 similar to that of the reservoir to which the cores belong. Subsequently the spontaneous and forced imbibition process is performed using the Amott cell and the centrifuge see Fig. 3b. Finally the saturation of residual oil (Sor) is determined after all the simulated oil of each core has been expelled. In this way both Swirr and Sor have been obtained.

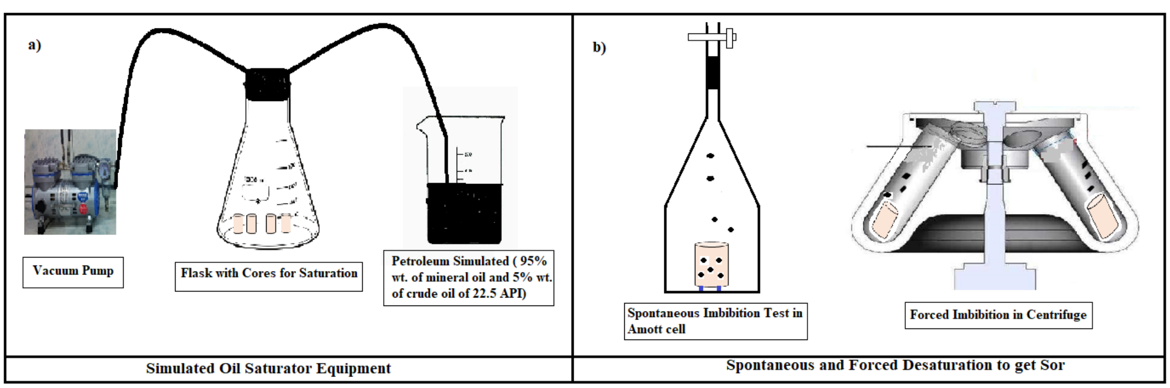

Figure 3. Saturation and desaturation of cores with simulated oil

Once the saturation of irreducible water is obtained, the relative permeabilities of oil and water with the Corey equations are determined:

$$Sw^* = \frac{Sw - Swirr}{1 - Swirr} \;.. \qquad (1)$$

$$krw = (Sw^*)^4 .... \qquad (2)$$

$$kro = (1 - Sw^*)^4 ... \qquad (3)$$

where Sw* is the water saturation for the Corey equation; Krw is the relative water permeability for each Sw*; and Kro is the relative oil permeability for each Sw*. The exponent 4 in the Corey equation is approximately four for consolidated rocks and it depends of the size and arrangement of the pores [25].

2.3. Measurement of the interfacial tension

The effects of cationic, anionic and nonionic surfactants on the interfacial tension between oil and water in the presence of an amine resulted in extremely low interfacial tensions [1]. On the other hand, the presence of salt can alter the distribution of the active components on the surface of the oil phase to the water phase [1]. The salts can also accelerate the diffusion of the active components of the surface of a solution towards the interface and therefore improve the adsorption of the surfactants at the interface, decreasing the IFT [1]. From this point of view, it is quite clear that the interaction between the surfactants and the different salinities of the reservoir water generate a clear alteration in the IFT. For this reason, in order to effectively study the surfactant Enzurlan, a selection process of the best combination of surfactant and salinity is carried out. Four different combinations of surfactants were made for each salinity, see Fig. (4).

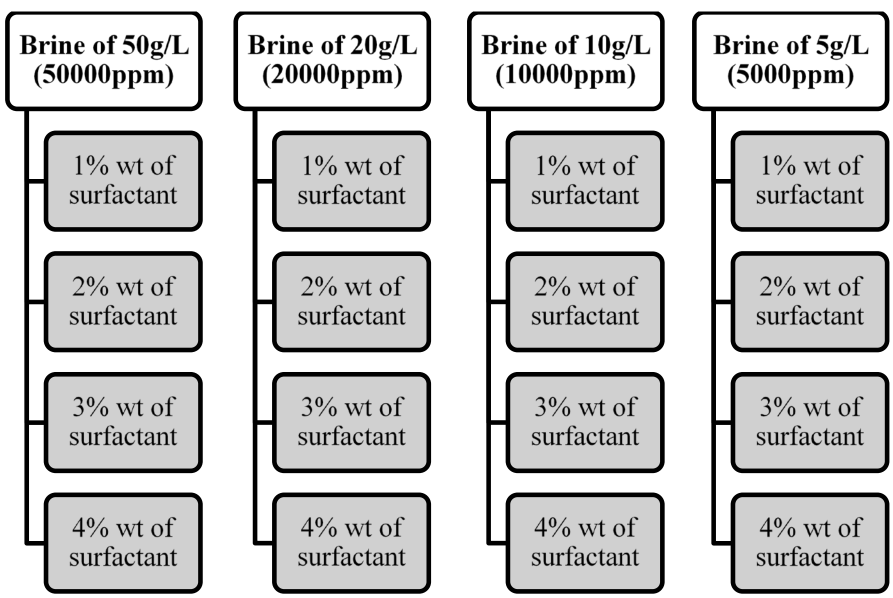

Figure 4. Flow diagram of the screening of surfactant and brine

In order to measure the interfacial tension, the Nouy ring method was used, which basically consists of placing a ring in the interface of the fluids and measuring the force of the tension that is generated [26]. The measurement of this tension can be done using a dynamometer or a digital balance of good precision.

Once the best combinations of surfactant concentration with salinity are obtained, the special cores analysis process is repeated, that is, obtaining the irreducible water saturation Swirr, residual oil saturation Sor and the relative permeability with the Corey method, but this time considering that the water will have a new salinity different from that of the reservoir and with the increase of a certain amount of surfactant depending on the selection process. In this case the best combinations were: salinity 50 g/L with 1% wt and 5 g/L with 1% wt.

3. Results

Throughout the research process, basic petrophysical results, interfacial tension measurements, capillary pressures, relative permeability curves and, finally, recovery factors at the laboratory level were obtained by spontaneous and forced imbibition. The results of the measurement of the porosity by two methods and the permeability obtained are (Table 2).

Table 2. Porosity and permeability results

Core	Weight (gr)	Length(mm)	Diameter (mm)	Vt (cc)	Vp (cc)	Grain Density (g/cc)	Ø matrix (%)	Ø Core Holder (%)	KL (mD)
No. 2-4-8	52.542	45.3	25.22	22.63	2.686	2.65	12.384	11.84	38.315
No. 2-3-6M	51.826	42.208	25.16	22.97	3.104	2.64	14.524	13.54	89.521
No. 2-5-12	51.64	46	25.22	22.98	2.89	2.65	15.194	12.568	131.150
No. 3-6-20	43.68	40.04	25.14	19.88	3.824	2.65	17.072	19.23	701.810

Table 3. Interfacial tension results

Surfactant %	Initial IFT (mN/m)	Simulated formation water (Brine)			
		5 g/L (5000ppm)	10 g/L (10000ppm)	20 g/L g/L(20000ppm)	50 g/L (50000ppm)
1	16.61	6.42	7.75	12.01	11.24
2	16.61	8.66	8.59	13.40	12.15
3	16.61	11.73	15.08	14.17	14.24
4	16.61	12.08	17.87	15.57	16.68

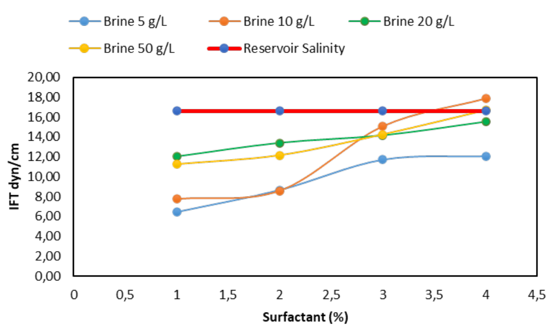

Figure 5. Interfacial tension curves for different surfactant and salinity concentration and brine

The results obtained from the interfacial tension in the screening process of the best combination of surfactant concentration and salinity are presented in Table 3 and Fig. 5. Fig. 6 and Fig. 7. show the results of the capillary pressures and the Swirr that were obtained in the 4 cores that were analyzed. These results were represented in In each figure. the capillary pressure curves of the saturated cores were placed with formation water. water with salinity of 50 g/L and 1% wt. of surfactant and water with salinity of 5 g/L and 1% wt. of surfactant.

After the spontaneous and forced inbibition. the results of the saturation of residual oil Sor were obtained see Table 6. The spontaneous imbibition with Amott's cell allowed to determine factors of recovery Fig. 8 and Fig. 9.

On the other hand. cores were subjected to forced imbibition where the following recovery factors were obtained Fig. 10 and Fig. 11.

The results of the relative permeability curves are shown in Fig. 12 and Fig. 13 for the comparison of the relative permeability curves for the saturated core with simulated water from the reservoir and water with salinity of 50 g/L and 1% wt. of surfactant. And Fig. 14 and Fig. 15 for the comparison of the relative permeability curves for the saturated core with simulated water from the reservoir and water with salinity of 5 g/L and 1% wt. of surfactant.

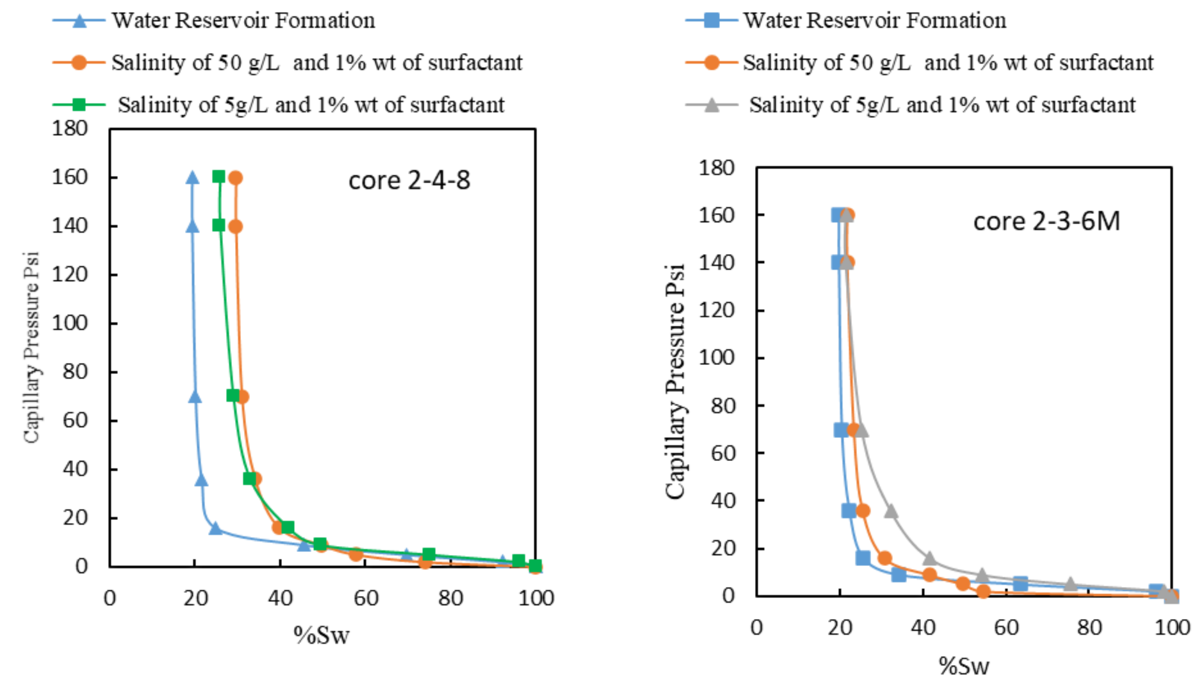

Figure 6. Capillar pressure curves results for cores 2-4-8 and 2-3-6M

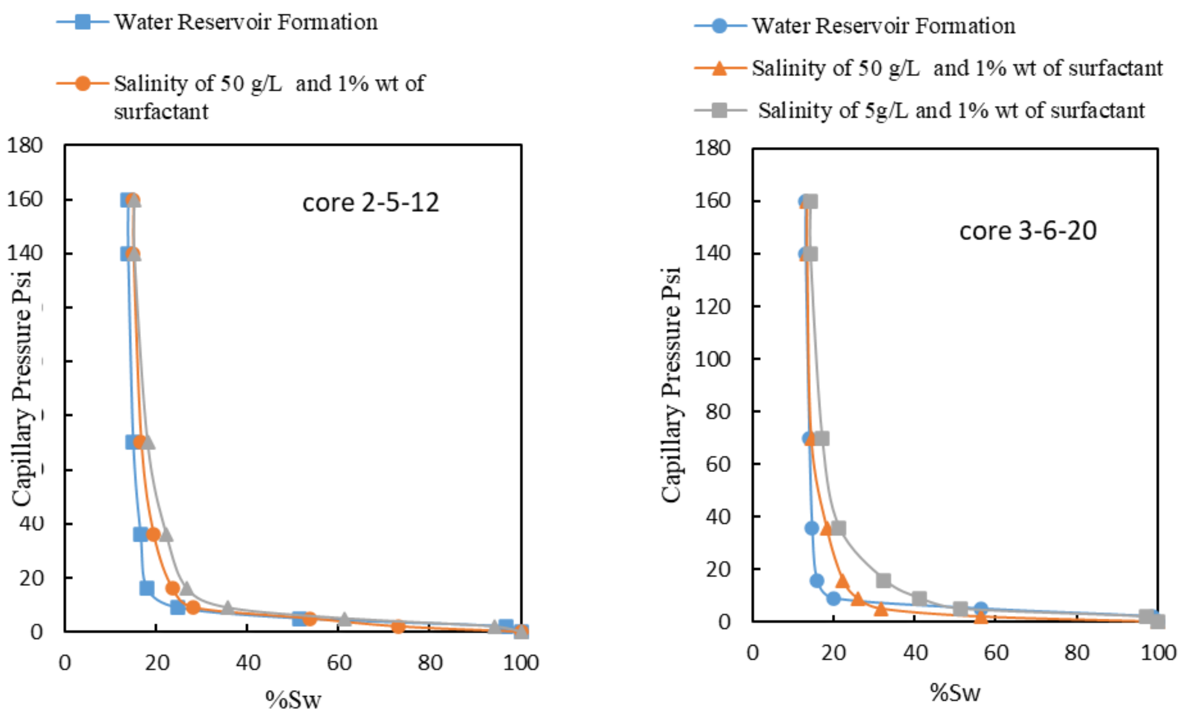

Figure 7. Capillar pressure curves results for cores 2-5-12 and 3-6-20

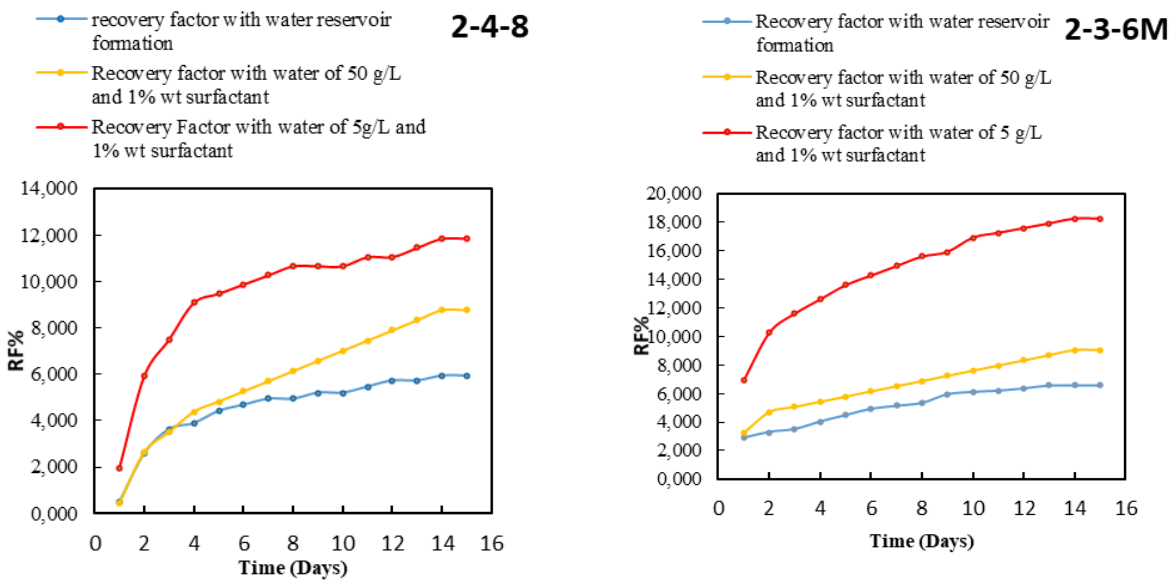

Figure 8. Recovery factor in cores 2-4-8 and 2-3-6M

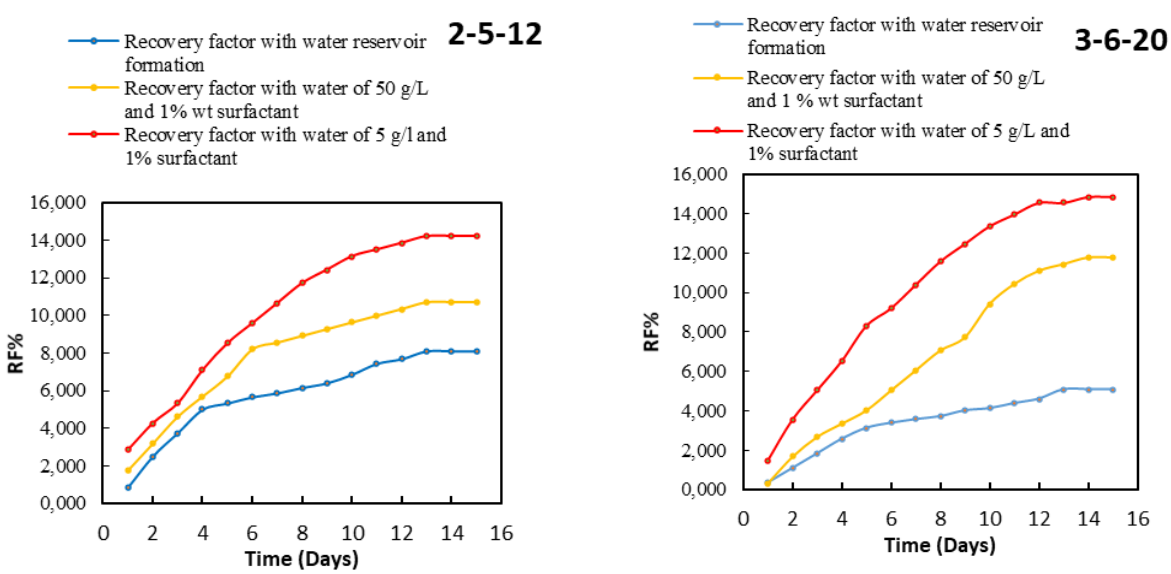

Figure 9. Recovery factor in cores 2-5-12 and 3-6-20M

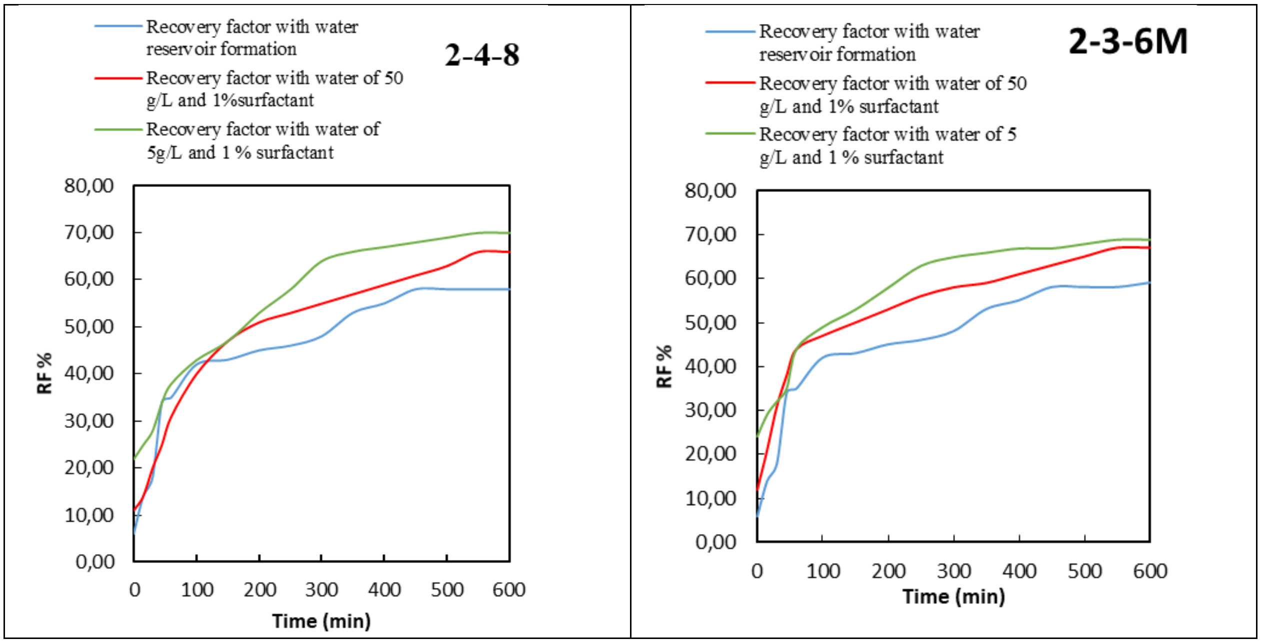

Figure 10. Recovery factor for forced imbibition in cores 2-4-8 and 2-3-6M

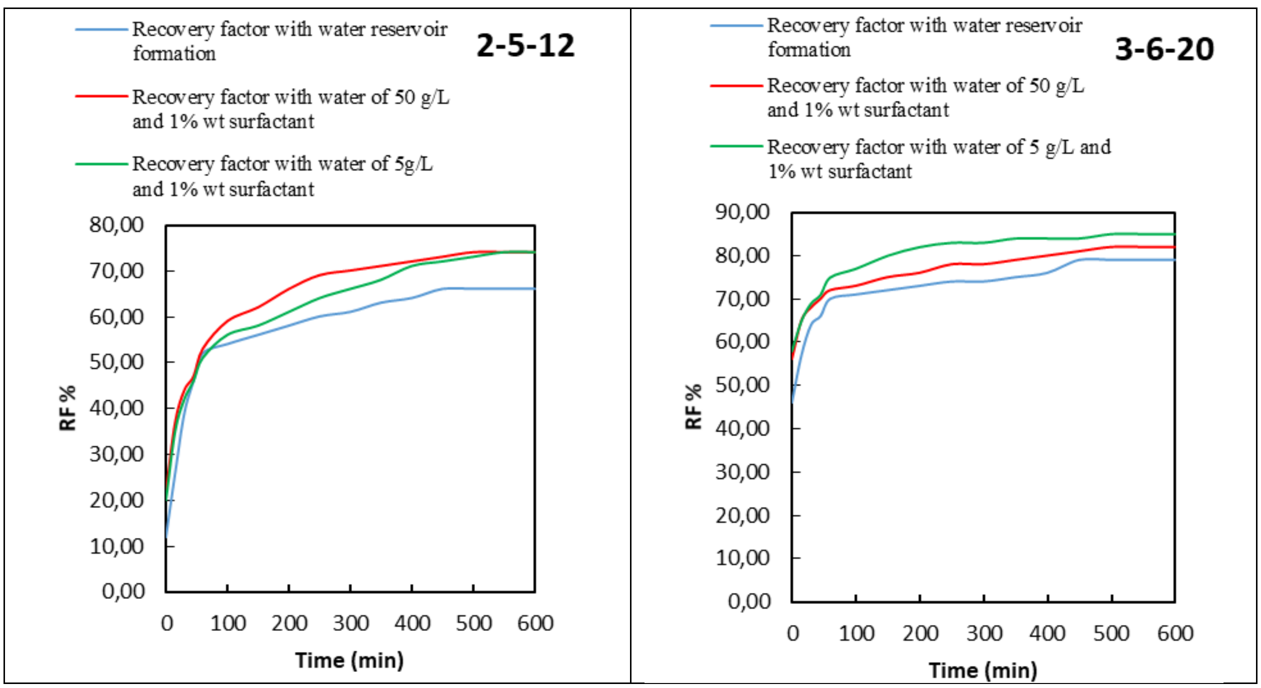

Figure 11. Recovery factor for forced imbibition in cores 2-5-12 and 3-6-20M

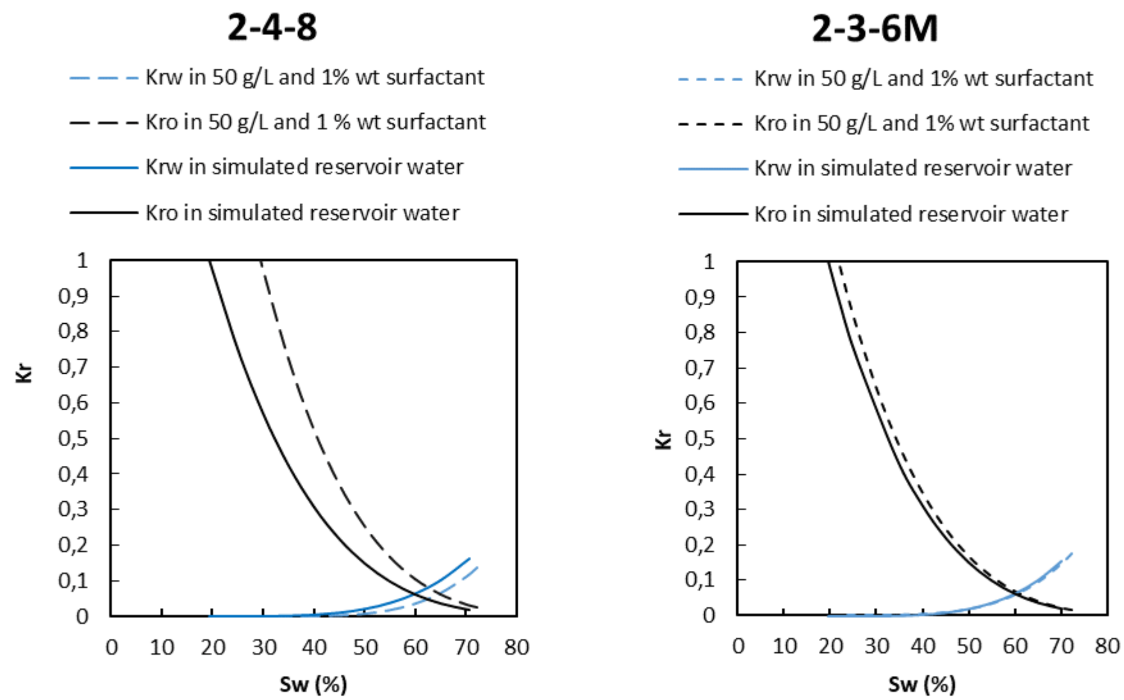

Figure 12. Comparison of the relative permeability curves for simulated reservoir water and salinity water 50g/L with 1% of surfactant for cores 2-4-8 and 2-3-6M

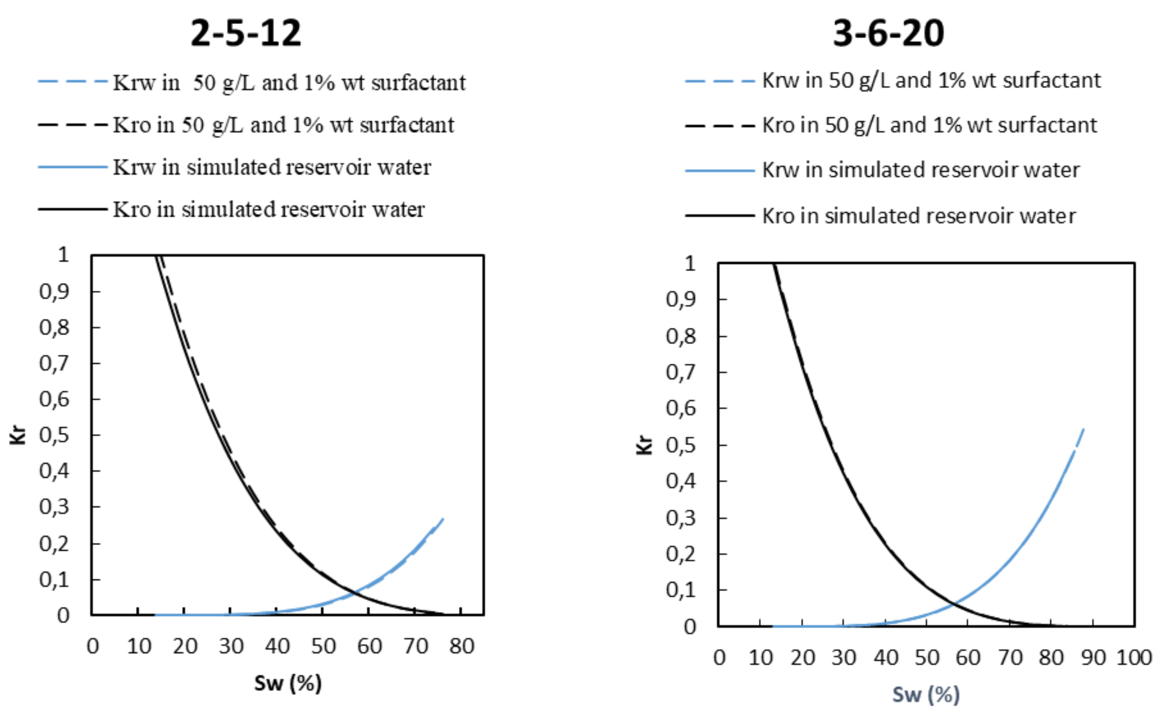

Figure 13. Comparison of the relative permeability curves for simulated reservoir water and salinity water 50g/L with 1% of surfactant for cores 2-5-12 and 3-6-20

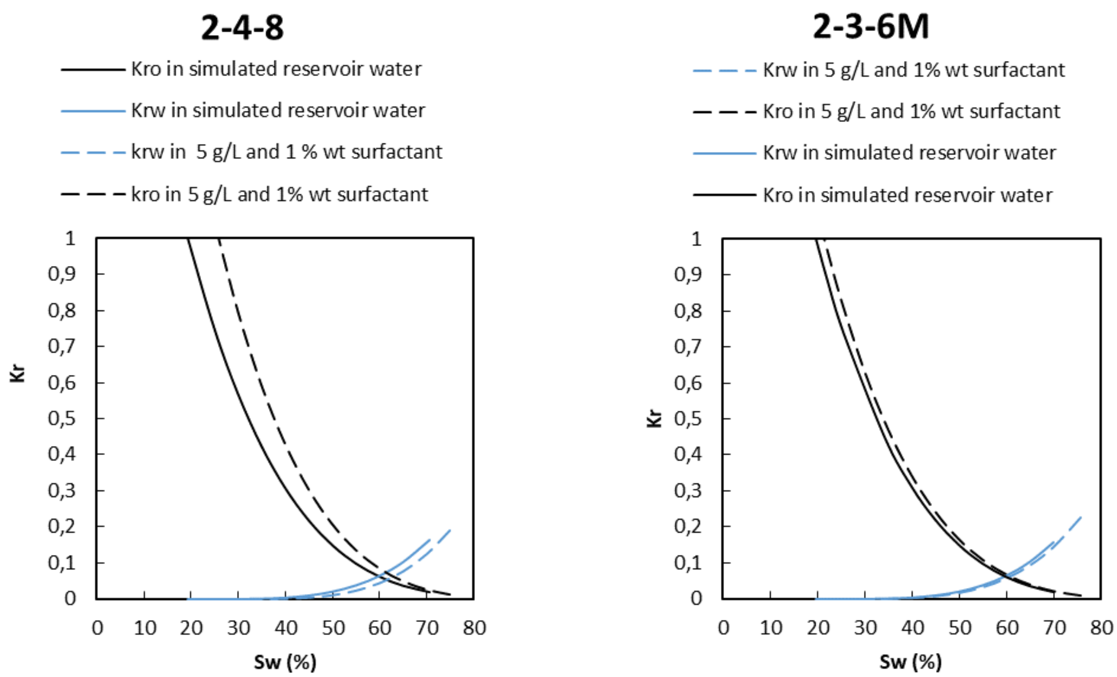

Figure 14. Comparison of the relative permeability Curves for simulated reservoir water and salinity water 5g/L with 1% of surfactant for cores 2-4-8 and 2-3-6M

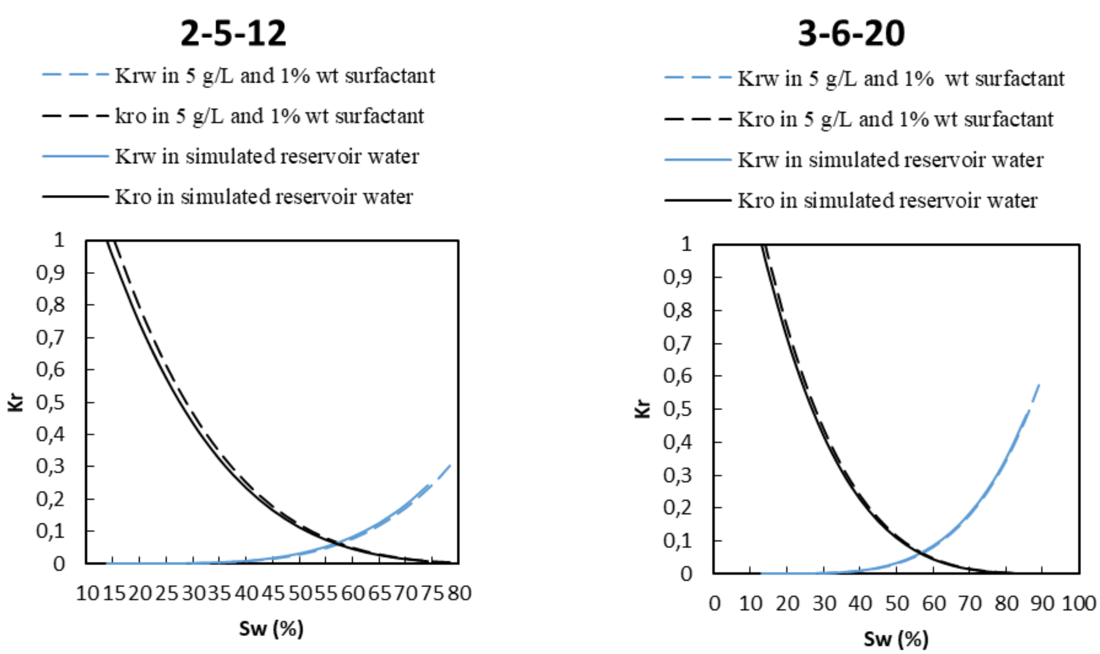

Figure 15. Comparison of the relative permeability curves for simulated reservoir water and salinity water 5g/L with 1% of surfactant for cores 2-5-12 and 3-6-20

4. Discussion of results

The results obtained determined that. the rock samples from T sandstone reservoir have different permeability and porosity values. (Table 2) By highlighting it can be seen that the lowest permeability was recorded for core No. 2-4-8 with 38.315 mD and the highest permeability for core N ° 3-6-20 with 701.810 mD. On the other hand. porosity values that vary from 11.84% to 19.23% for cores No. 2-4-8 and 3-6-20 respectively were recorded. Therefore. it is determined that the core with better petrophysical properties is No. 3-6-20; and the core with the least favorable petrophysical properties for oil recovery is No. 2-4-8.

Regarding the interfacial tension. it was evident (Table 3) that the interfacial tension IFT was reduced both by the use of the commercial surfactant (Enzurlan) and by variations of salinity. The most remarkable aspect is that the initial interfacial tension of the surfactant was a value of approximately 16.61 mN/m and was modified to 6.42 mN/m after using brine with 5g / L salinity and 1% wt. surfactant treatment. The synergistic action of the surfactant and the salt generated this interfacial tension reduction. On the other hand. there is a limit between the amount of surfactant that is added to a fluid. concentration. and the reduction of the interfacial tension. this is corroborated in the bibliography [1.27]; in this case. for the surfactant Enzurlan. from 4% wt. of concentration. an unfavorable effect was generated increasing the IFT. In the Oil Stimulation Matrix Manual of C. Islas [28] it is mentioned that in order to prevent skin. non-reactive matrix stimulations are performed with surfactant concentrations lower than 1%. Enzurlan is a non-ionic alcohol-ethoxylated surfactant which possess an hydrophilic component and a hydrophobic one that is a polyether chain component; Enzurlan does not ionize. but is bound by its functional groups.

Considering that the salinity of reservoir formation water is 54 g/L. it was decided to choose the concentration of 50 g/L and 1% wt. of surfactant to proceed with the investigation. It is because in addition giving a low value of IFT. is easier to use the same production fluid for EOR processes.

Regarding the capillary pressures and saturations of irreducible water Swirr can be observed (Fig. 6 and 7) that the Swirr for the water of simulated formation was always lower than the Swirr of the water with salinity of 5 and 50 g/L with 1% wt. of surfactant; This demonstrates that water with different salinity and surfactant occupies the space that would occupy the oil when we do not use surfactant. The most notorious Swirr change case is for core No. 2-4-8 which increases its Swirr from 19.4% to 29.6% for salinity water 50 g /L and 1% wt. of surfactant and 25.9% for saline water of 5g /L and 1% wt. of surfactant see Table 4. It is important to mention that the least favorable core in its petrophysical characteristics is the one that increased the most in the Swirr.

The capillary pressure curves obtained (Fig. 6 and Fig. 7) correspond to an intermediate wettability rock with a drainage process applied with the desaturator equipment see Fig. 2. With respect to the residual oil saturation Sor for all cores it was reduced. The largest reduction was achieved in core No. 2-4-8 from 29.41% to 25.15% with salinity water 5 g /L and the lowest reduction was achieved in core No. 2-5-12 from 25.76% to 23.78 % with salinity water of 50 g/L; see Table 4. In the same line after having applied spontaneous and forced inbibition. the recovery factor for all the cores was increased; In addition. the best result was obtained with salinity water of 5 g/L and surfactant at 1% wt; the only case where the highest recovery factor was obtained with 50 g /L and 1% surfactant was for the core N ° 2-5-12 Fig. 12. The final recovery factor can be observed in Table 5 and It is generally seen that when using water with salinity of 50 g/L and 1% of surfactant. this factor increased by around 3%. while when using water of salinity of 5 g/L and 1% of surfactant. the factor increased in 6%; as an example you can see in Table 7 in No. 2-4-8 the initial recovery factor is 5.9%. which increases to 8.8% with water with salinity 50 g/L and 1% surfactant and then increases to 11.8% with salinity water of 5 g/L and 1% of surfactant.

Table 4. Residual oil saturation results

Core	Sor with water reservoir formation	Sor with salinity of 50 g/L and 1% wt of surfactant	Sor with salinity of 5g/L and 1% wt of surfactant
	%	%	%
N° 2-4-8	29.41	27.71	25.15
N° 2-3-6-M	29.89	27.68	24.36
N° 2-5-12	25.76	23.78	21.8
N° 3-6-20	14.38	12.88	11.08

Table 5. Recovery factor results

Core	Initial RF (%)	Surfactant 1% 50 g/L Final RF (%)	Surfactant 1% 5 g/L Final RF (%)
No. 2-4-8	5.9	8.8	11.8
No. 2-3-6M	6.6	9.1	18.3
No. 2-5-12	8.1	10.7	14.2
No. 3-6-20	5.1	11.75	14.8

The relative permeability curves obtained are typical of rocks with intermediate wettability. this can be corroborated by the saturation of critical water. which in most cases is between 20 and 15% see Fig. 12. 13. 14. 15 and in the Sw at the point Kro=Krw. According to Ken Sorbie *et al.* [29] for a reservoir to be wetted by water or oil. it must meet the following requirements see Table 6.

Table 6. Typical characteristics of water-wet and oil-wet relative permeabilities

	Water wet	Oil wet
Swc	mostly >20%	< 15% (often <10%)
Sw where Krw=Kro	Sw>50%	Sw<50%
Krw at Sro	Krw<0,3	Krw>0,5

Table 7. Analysis of the rock humectability

	N° 2-4-8		N° 2-3-6M		N° 2-5-12		N° 3-6-20	
	Water wet	Oil wet	Water wet	Oil wet	Water wet	Oil wet	Water wet	Oil wet
Swc	X	X	Uncertain	Uncertain	X	√	X	√
Sw Where Krw=Kro	√	X	√	X	Uncertain	Uncertain	Uncertain	Uncertain
Krw At Sro	Uncertain	Uncertain	Uncertain	Uncertain	Uncertain	Uncertain	X	√

An analysis of the relative permeability curves obtained for each core showed that no core meets the three factors. concluding that the wettability of the cores is intermediate. see Table 7.

Considering the absolute permeability obtained in the petrophysical analysis (Table 2) and the relative permeability obtained for the four cores saturated with formation water and water with salinity of 50 g/L and 1% of surfactant (Fig. 12 and Fig. 13); It can be observed that the less favorable the characteristics of the rock or core. the greater the effect will be on the change of salinity and the use of surfactant.

Another important aspect to mention is that the relative permeability curves of Kro and Krw for all cores move to the right. this can be justified since water always tends to occupy the less favorable porous spaces and oil occupies the pore spaces more favorable. To understand it better. an example is enough; If we analyze Fig. 12 for core No. 2-4-8 we can say that the critical water saturation for water without surfactant is around 19.4% and after using the surfactant goes up to 29.6% this is an indication that when the water without surfactant was used. 19.4% of the less favorable porous space was occupied by the water. whereas when the surfactant was used. 29.6% of the less favorable porous space was occupied by the water. that is to say. there was oil that was released because of water with surfactant.

5. Conclusions

The surfactant Enzurlan which is a non-ionic surfactant allows to improve the recovery of oil in the sand T of the fields of the Ecuadorian east. but it is necessary to carry out a study to reservoir conditions since all the experimentation carried out in this work was carried out at laboratory conditions. This surfactant does not ionize in contact with the fluids but. due to the presence of its functional groups. it accommodates in the interfaces and generates this effect in the interfacial tension. Then the best combinations obtained were 50 g/L of salinity with 1% wt of surfactant and 5 g/L with 1% wt of surfactant.

The synergy of the non-ionic surfactant with the changes of salinity generated changes in the relative permeability curves. this allows us to conclude that the salinity solutions of 50 and 5 g/L both with 1% wt of surfactant occupy the less favorable porous space and that allowed to increase the oil recovery factor see Table 7.

Reservoir rocks with less favorable petrophysical characteristics have better results when using surfactants. see Fig. 12. 13. 14 and 15. which corroborates the previous statement that the surfactant in the water solution tends to occupy the less favorable porous spaces That is. the application in unconventional reservoirs with very low porosities and permeabilities will have better effects. On the other hand. an issue that remains unknown is the application of this surfactant in rocks of wettability to water or oil because in that case the results may vary.

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