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Laboratory Data for Oil Recovery by Injecting Low-Salinity Water into Sandstone from Brazilian Campos Basin Reservoir

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Abstract

The enhanced oil recovery method by low-salinity water flooding in sandstones has had promising results. When two immiscible phases are in contact with a solid surface, one is generally more strongly attracted by the solid than the other, called the wetting phase. The ability of different polar compounds to change the rock wettability depends on the rock type. In sandstone reservoirs, the electrostatic attraction between the positively charged surface of the oil and the negatively charged basal plans of the rock controls the oil adhesion on the rock surface. It is well known that typically lowering the injection brine salinity can enhance oil recovery, however, the effects of low-salinity water injection in sandstones are probably the result of several mechanisms acting in conjunction, highlighting the need to execute experimental tests. Moreover, this study aimed to evaluate the effect of brines with different compositions and salinity on the oil recovery factor of reservoir sandstone cores by carrying out core flooding experiments. In addition, reservoir cores were very friable, so sandpacks were produced to facilitate manipulation and make it possible to carry out the water flooding tests. Furthermore, they were used in four core flooding tests. Also, results indicated a potential low-salinity water effect, with an average incremental oil recovery of around 5.8%. The injectivity was analyzed using differential pressure during the experiments, and significant alterations were not observed due to the change in salinity of injected brines. Ultimately, the mineralogical analysis suggests that even sandstones with no clay content might show additional oil recovery due to low-salinity water injection, bespeaking the need to conduct more experiments for further investigation of the impact of the injected brine, the mineralogical composition of the rocks and the acting mechanisms.

Keywords: Low-Salinity Water Injection, LSWI in Sandstones, Oil Recovery.

Introduction

The production cycle of an oil reservoir is generally separated into three recovery modes. The first oil recovery method is called primary oil recovery, which uses natural reservoir energy to drive the oil through the pore network to produce wells. While the pressure on the fluid in the reservoir is great enough, the oil flows into the well and goes up to the surface. Moreover, oil moves out of the porous media into the well by one or more of three processes: dissolved gas drive (the propulsive force is the gas in solution in the oil; the gas tends to come out of solution because of the pressure release), gas cap drive (when there is gas above the oil, in the top of the trap), and water drive (the pressure of the water forces the oil out of the reservoir into the producing wells).

In secondary recovery, operations involve pumping or injecting water or gas to maintain the reservoir pressure and move the oil to the producing well.

The tertiary mode, also called Enhanced Oil Recovery (EOR), is the production of the ultimate oil, which remains trapped. In addition, the processes use thermal (heating the oil), injection of chemicals (polymers or surfactants), gases (carbon dioxide, hydrocarbons, or nitrogen), steam, or water with controlled concentration into the reservoir. The technique intends to reduce or eliminate the capillary forces that trap oil within pores or improve mobility. The International Energy Agency [1] estimates that roughly 500,000 oil barrels will be produced daily using chemical EOR methods in 2040. Efficient action in the primary and secondary recovery

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methods results in recoveries of around 35% to 45% of OOIP [2]. Therefore, depending on the economic feasibility studies and the characteristics of the field, an EOR method can be implemented to increase oil production.

Water injection with controlled salinity is an EOR method that is extremely advantageous because of its low cost and easy application in the field compared to other chemical addition techniques. Moreover, sandstones and carbonates have proved the method's potential [3,4]. Furthermore, low-salinity water flooding (LSWF), often called smart water or modified composition water, consists of changing the composition of seawater, produced water, or water from other sources for injection in the reservoir [5].

Among the EOR methods, low-salinity water injection does not produce enormous increments in the oil recovery factor. Still, it is an effective method since it can generate additional recovery with very low implementation and operational costs if low-salinity water injection is compared to other methods [5].

Several laboratory studies [6-9] have demonstrated the potential of LSWF in sandstones, either in secondary or tertiary mode. The secondary mode consists of the injection of low-salinity water after natural depletion of the reservoir, that is, directly in the connate water. The tertiary mode consists of the infusion of low-salinity water after injecting another type of water, e.g., seawater [10]. The researches were made in the literature [11] and authors compiled the frequency of LSWF recovery factors in sandstones showing it varies from 0 to 20% in secondary mode, and from 0 to 8% in tertiary mode. The low-salinity water injection potential was not recognized until the nineties when some researchers started investigating the effect of the water composition on the oil recovery. Since then, several works on the theme have been conducted by some companies and teams to understand the relationship between water salinity and oil recovery.

In many reservoirs, water is injected to increase the oil recovery, maintaining the reservoir pressure and displacing the oil towards the producing wells [12]. Moreover, the injected water can be from formation, production, aquifer, sea, or any other viable source. However, not all reservoirs have the potential for LSWF application since many properties must be analyzed and comprehended to classify a reservoir as promising for LSWF, such as oil and water composition [11]. Furthermore, the necessary conditions for the occurrence of the low-salinity effect in sandstones are [9]: significant clay content or negatively charged surface; the presence of formation water; exposure to oil with acid or basic polar components to create oil-wet or mixed wet conditions; significant reduction of the injection water salinity; and presence of multivalent ions in the formation water. The composition, salinity, and saturation of formation water can significantly affect the initial state of the rock wettability and, consequently, the method's efficiency as it depends on the interaction of water-oil-rock [5].

The presence of the calcium cation (Ca^{2+}) in the composition of the formation water is essential since it establishes an interaction between the rock, the brine, and the oil, called ion-binding, in which the multivalent ions act as bridges connecting oil and clay minerals. The presence of calcium is important [13,14]. The initial pH of the formation water can also be a decisive factor as the adsorption of the oil organic material onto the rock is intensified with pH reduction [15]. The basic components of the oil are identified as aromatics linked to nitrogen atoms. They are quantified by the base number (BN), while the acid components are identified by the carboxylic material and quantified by the acid number (AN). In addition, both components are found in heavy oil fractions and play an important role in the rock`s initial wettability [5]. These characteristics, such as AN, BN, and API degree, are fundamental parameters to indicate, qualitatively, the influence of the oil in the wettability state reached with the rock aging process [13]. Moreover, oils with high API are not good asphaltene solvents. Thus, they cause wettability alteration due to the precipitation of these compounds; oil with high AN and low BN, or vice-versa, interact with the silica surface through acid/base reactions and intensify the oil-wet state.

Core flooding experiments [16] were conducted in two sandstone cores: the first aged in crude oil and the second aged in "white" oil (a mixture of kerosene and mineral oil). Only the first core sample had additional oil recovery due to LSWF, which indicates the effect of oil composition on the oil/rock surface bond and associated wettability. As pointed out by the authors, the white oil does not have acidic components, and thus, it could not establish an oil-wet state. This explains why no incremental oil recovery was observed after the low-salinity water injection, which has, as its primary goal, the wettability shift from oil-wet to water-wet.

The research on LSWF in sandstones is found in the literature [5,9,11], but field applications depend on the peculiarities and characteristics of the reservoir and fluids of each field. The success of the LSWF seems to be linked to the role of different mechanisms acting simultaneously, which are directly affected by the rock and fluid properties [17,18]. Some of the proposed mechanisms are fines migration [7], multi-ion exchange [19], pH increase [20], salting-in [21], and microdispersion [22].

Fines migration is the movement of small particles within the reservoir formation, involving both fine particle detachment and re-deposition along surfaces. This situation could either promote or prevent fluid flow through the pore throats. Carrying oil with the particles increases oil recovery. Blocking the paths reduces permeability. Both scenarios are possible.

In the multi-ion exchange, when oil droplets and rock particles come in contact with low-salinity water, some ions in the electrical double-layer around them migrate to the low-salinity water, reducing the charge density of this double-layer and resulting in its expansion.

During the LSWF, the multi-ion exchange removes organic polar compounds and organometallic complexes from the surface and replaces them with uncomplexed cations [19], which probably would result in a more water-wet surface, improving oil recovery. Data points, including secondary and tertiary flooding, were analyzed, showing that most effluent cation concentrations fall between the connate and injected concentrations, making it hard to draw any conclusions.

One mechanism that produces the low-salinity effect is the double-layer expansion at the interface water/mineral [14]. The influence of the injected water salinity in the zeta potential of the interface Berea sandstone/water [10] was analyzed, and the authors observed that the injection of the lower salinity water yielded the most negative potential. They explained this might have increased the negativity of the surface particles, strengthening the repulsive forces and, thus, expanding the double-layer. Such expansion makes the rock wetter, inducing oil recovery. Fines migration is another major mechanism for improved oil recovery [7]. Authors suggested that the mobilization of oil attached to the fines, with exposure to the water-wet surfaces beneath the stripped fines, yielded more water-wet behavior.

Moreover, the pH increase was also studied [20-23]. The adsorption of basic and acidic materials onto clay is very sensitive to changes in pH since the increase in the brine's pH reduces the interfacial tension between brine and oil, which works as an alkaline injection. In addition, the salting-in effect was proposed as another possible mechanism in which the solubility of organic material in water can be increased by removing salt from the water [21].

The mechanism behind the LSWI effect on oil recovery could also be analyzed through data matching [24]. The wettability alteration is probably the main contributor, from oil-wet to more water-wet. In this situation, the capillary pressure turns positive and begins spontaneous water imbibition into the rock matrix. Thus, a higher oil recovery occurs. A comprehensive study concluded that wettability alteration was caused by both change in surface charge and anhydrite dissolution [25]. The authors analyzed equilibrium process thermodynamics and geochemical models of two simulators, including water-sample checking, fluid and solid species comparison, and justification of LSWI application in carbonates.

Several researches describe the correlation between the presence of clay and the additional oil recovery in sandstones: results were obtained indicating better oil recovery from LSWF in sandstones with higher clay content [7]; the clay tends to reduce the water relative permeability, which might increase the oil production due to the occurrence of preferential flow, but the downside of clay presence in low permeability rocks saturated with oil is the swelling and subsequent permeability reduction [26]; LSWF is not effective in clay free rocks as it lacks cation exchange capacity [19]; the wettability transition to water wet occurs due to the increase in pH owing to the clay influence [27]. Nonetheless, studies in the literature report incremental recovery in clay-free sandstones, as indicated in the following compilation of results [11]. The relationship between tertiary recovery factor from LSWF and clay content showed that some rocks with different clay quantities (0 to 16%) had zero oil recovery, which suggests that even in rocks with clay in their composition, the low-salinity effect might not occur. For the rocks with 0% of clay, the recovery factor varies from 0 to 12% roughly, indicating that sandstones with no clay may have incremental oil recovery from LSWF.

Given the unexplained positive results of oil recovery due to low-salinity water injection in clay-free sandstones, the fluid-fluid interactions were analyzed to illuminate the discussion of the mechanism [28,29]. The microdispersion phenomenon could be associated with the success of low-salinity water injection (LSWI), which is explained as the formation of dark particles that are micro-emulsions of water in oil. When low-salinity water is injected into the porous media, the formation and growth of water droplets inside the oil phase occur, eventually resulting in a change in the oil distribution and displacement. Based on this proposed phenomenon, a screening method for LSWI projects was devised [22]. The authors analyzed several crude oils and their propensity to form micro dispersion when in contact with low-salinity water, which would result in better microscopic sweeping efficiency.

When clay is exposed to low-salinity water, fine detachment and migration occur due to multi-ion exchange and electrical double-layer expansion [30]. Acceptable migration due to low-salinity water enhances oil recovery while damaging injection and production wells. In low-clay samples, fines migrated only at high-rate injection. Generally, there is a trade-off between the intensity of acceptable migration and divalent cations concentration in flooding water. A high concentration of these cations prevents fines from movement, eradicating low-salinity flooding advantages. However, using medium concentrations results in partial fine migration, and the intensity depends on clay concentration and flooding rate. When the concentration of clay in the porous media is high, the possibility of the fine migration phenomenon also depends on fine-fine interparticle forces. Even so, when the concentration of clay particles is low, this phenomenon only depends on the interparticle forces in the matrix-fine system. The effect of surfactants on the possibility and intensity of acceptable migration in clay-rich sandstones was investigated [31]. Surfactants can cause wettability alteration toward water-wet conditions through adsorption in the stern layer, which results in oil desorption. Surfactant aqueous solutions were injected into various clay-rich sandstone sandpacks, increasing oil recovery [32]. Anyway, the mechanisms leading to enhanced oil recovery varied by surfactant type: altering the interparticle forces, reducing IFT, and changing wettability. The results suggested that the type of surfactant used should be carefully selected to achieve the desired recovery increase without affecting the permeability of the reservoir.

The lack of consensus on the primary mechanism for incremental oil recovery occurs due to the complexity of low-salinity water projects and the interactions between the displacing fluid and external factors such as crude oil, formation water, and rock type [33]. Additionally, experiments may yield conflicting observations between different mechanisms.

Oil recovery by low-salinity water flooding has generated relevant laboratory-scale results. The study of sandstones is evidenced in the literature [34-36]. Despite that, the application for each target field of study depends on the particularities and characteristics of both the reservoir and the existing and injected fluids.

The present study analyzed the effects of low-salinity water injection in a sandstone reservoir's secondary and tertiary modes. Core flooding experiments were conducted in reservoir samples to evaluate the oil recovery factor before and after the low-salinity water injection. The rock samples were chemically characterized by x-ray diffraction analysis to obtain the mineral composition of the cores and check for clay content.

The ability of polar compounds to alter rock wettability depends on the rock type. The sandstone's low-salinity effect is notably more complex than wettability alteration mechanisms in carbonates, likely resulting from the concurrent interaction of multiple mechanisms. In sandstone reservoirs, oil adhesion to the rock surface is influenced by electrostatic interactions between the positively charged oil surface and the negatively charged basal planes of the rock. Mechanisms associated with sandstone's low-salinity effect include fines migration, multi-ion exchange, pH increase, salting-in, and micro-dispersion. These processes are further influenced by the type and concentration of ions present in the brine, which interact with both the oil and the rock surface. Despite numerous studies on the mechanisms of oil recovery through low-salinity water injection in sandstones, questions remain about the optimal conditions required for the low-salinity effect to be observed and validated. Moreover, the variation in the recovery factor highlights the probable simultaneous action of multiple mechanisms. In addition, this study contributes to the ongoing investigation of enhanced oil recovery mechanisms and emphasizes the critical role of clay presence in sandstone reservoirs. Likewise, the increased oil recovery through low-salinity water injection in friable sandstone further supports this understanding. Additionally, using sandpacks in core flooding experiments provides a practical solution to challenges posed by fractured or friable core samples.

Materials and Methods

In this section, fluids and rock characteristics will be described, as well as the experimental procedures.

Brine Compositions

Using a magnetic stirrer, synthetic brines were prepared by adding the appropriate number of pure salts to the deionized water under agitation. The brines were then filtered using a 45 µm membrane and deaerated using a vacuum pump to remove any dissolved air. Table 1 shows the composition of formation water (FW). According to the geochemical simulation in the PHREEQC software, hydrochloric acid was added to the FW to avoid precipitation. Total dissolved solids (TDS) were also calculated.

Table 2 shows the composition of seawater (SW), produced water (PW), and a mixture of produced water and seawater (MW) used in the experimental tests. This mixture attempts to mimic the injection brine composition at the moment of the field production life when all the produced water must be injected into the reservoir. According to this, the mixture comprises 60% of produced water and 40% of seawater.

The low-salinity water (1000 ppm) used in the tests was prepared by diluting 1 g of NaCl in 1 L of distilled water. Table 3 shows the density and pH of all the brine solutions.

Table 1 Formation water composition.

Component	Initial Concentration [g/L]	Balanced Concentration [g/L]
NaCl	80.324	79.092
KCl	0.421	0.421
$MgCl_2.6H_2O$	2.760	2.760
$SrCl_2.6H_2O$	1.123	1.123
$CaCl_2.2H_2O$	1.552	1.552
$BaCl_2.2H_2O$	0.071	0.071
KBr	0.226	0.226
Na_2SO_4	0.004	0.004
Na_2CO3	2.632	2.173
HCl [ml/L]	0	1.83
TDS [mg/L]	86,798	85,107

Table 2 Brine composition.

Component	Seawater (SW)	Produced water (PW)	Mixture water (MW)
	Concentration [g/L]	Concentration [g/L]	Concentration [g/L]
NaCl	28.947	58.469	46.660
KCl	0.767	0.447	0.575
$MgCl_2.6H_2O$	0.610	2.450	2.914
$CaCl_2.2H_2O$	0.282	2.986	1.905
$SrCl_2.6H_2O$	-	0.968	0.581
$BaCl_2.2H_2O$	-	0.007	0.004
TDS [mg/L]	30,212	63,832	50,384

Table 3 Brine properties.

Brine	Density [g/ml]	pH
Seawater (SW)	1.018	8.69
Formation water (FW)	1.055	7.25
Low-Salinity water (LS)	0.998	9.51
Mixture water (MW)	1.031	7.25

Crude Oil

The crude oil was from a Brazilian reservoir. The oil homogenization procedure consisted of placing the oil vessel into an oven at 40ºC and stirring it every hour for 8 hours. Afterwards, 4 liters of oil were collected to be filtered. A 10 µm filter and a pump operating at a 300 ml/min flow rate were used. A mixture of dead oil and cyclohexane (87% dead oil and 13% cyclohexane) was prepared to mimic the viscosity condition in the reservoir (model oil) and, consequently, the water-oil mobility ratio. The values of specific mass and viscosity, measured for dead and model oil in atmospheric and reservoir conditions, are detailed in Table 4.

The Karl Fischer Volumetric Titrator - Mettler Toledo T50 determined the acid and basic oil numbers. The measurement was done in duplicate (ASTM D664, 2007). Table 5 shows the oil's measured molar mass, acid, and base numbers.

Table 4 Measured properties for dead and model oils.

Type	Atmospheric Conditions (14.7 psi / 25°C)		Reservoir Conditions (2000 psi / 54°C)	
Oil	Specific Mass [g/cm^3]	Viscosity [cP]	Specific Mass [g/cm3]	Viscosity [cP]
Dead	0.933	347	0.921	87
Model	0.915	110	0.901	33

Table 5 Properties of dead oil.

Parameter	Value
Molar Mass [g/mol]	259.65
AN [mg KOH/g]	2.2
BN [mg KOH/g]	0.082

Core Handling and Sandpacks

The sandstone reservoir core samples were extracted from a Brazilian offshore field located in the Campos Basin. Initially, the cores were characterized by measuring their basic petrophysical properties.

Numerous difficulties were encountered while handling the rock samples, primarily due to their friable nature and significant swelling capacity. Furthermore, the displacement of unstable particles within these rocks can block specific fluid pathways, reducing permeability. Moreover, in oil fields where water injection is employed, reduced injectivity often poses a significant challenge. Also, these handling problems are detailed in [37].

Thus, for this study, sandpacks were produced to obtain permeability values closer to the reservoir real data (around 1 and 3 Darcys) and, consequently, enable forced displacement tests.

Sandpacks provide an alternative porous medium to perform core flooding tests. Intact cores presenting friable characteristics made conducting forced displacement tests on these plugs impossible. Also, several different procedures were applied to obtain samples 100% saturated with water and under the condition of Swi, such as forced displacement, high-speed centrifuge, and the desiccator method, but without success. Furthermore, test results obtained with sandpacks should be carefully analyzed since their permoporosity properties are different from those of real reservoirs. In addition, experience with core flooding procedures and the assembly of sandpacks added value to studies on enhanced oil recovery and can be used to improve screening processes. Heat shrink tubes were shaped to assemble the sand packs, using a core as a cast and a hot air blower to form a cylindrical structure to wrap them. The friability of the rock samples made defragmentation of the cores relatively easy. The samples were removed from their metallic cover and put in airtight bags, two by two, according to their wells of origin, disintegrated, and transferred to the cylindrical wrap. The structure of the sand pack is composed of a base diffuser, steel mesh, 2 µm filter, rock grains, another 2 µm filter, and a top diffuser, respectively. After the assembly, the samples were weighed to measure the grain mass of each sand pack. Then, they were positioned in the inlet cover of the core holder, and, with the diffuser of the core holder located above, a new layer of heat-shrinking material was added to avoid the leak of rock powder during the maneuver. The careful assembling process of the sand packs can be seen in Fig. 1. The interior of the core holder is illustrated in Fig. 2.

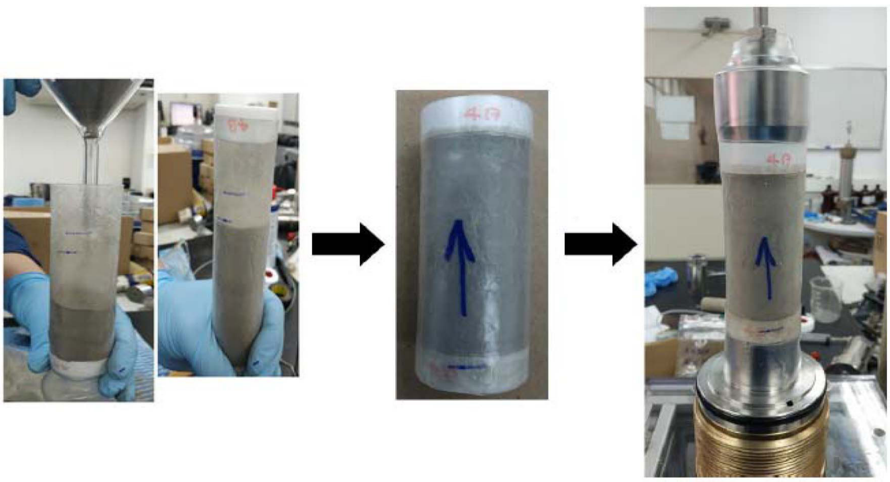

Fig. 1 Process of molding the rock grains and assembling the sand pack onto the core holder.

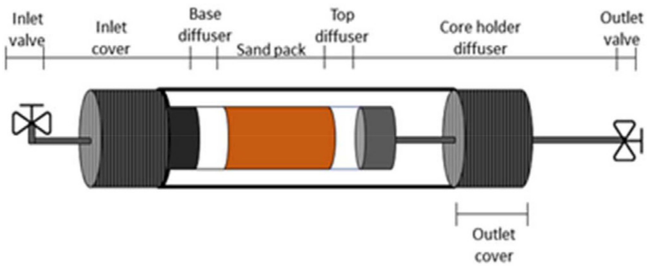

Fig. 2 Illustration of the core holder interior and its components.

After that, the rock samples were cleaned by the core flooding procedure. First, aviation kerosene was injected until clean effluent was observed. Then, heptane was injected to displace kerosene and remove any residual oil. Finally, the cores were dried with air injection at 50 psi for at least 24 hours. This cleaning procedure was adapted from that presented elsewhere [38,39]. After the cleaning process, the gas permeability and porosity of the sandpacks were measured. Table 6 shows the gas permeability values for each sample and the assembled sand pack. Three sandpacks, denominated SP1, SP7, and SP8, were chosen for experiments. SP1 and SP7 were composed of rocks from well Y, while SP8 was composed of rocks from well Z. Fantasy names were assigned to the wells in compliance with the company's privacy rules.

Experimental Procedure

To re-establish the initial water saturation (Swi), a vacuum was applied to the sandpacks for 5 hours. Then, approximately 5 porous volumes (PV) of FW were injected at an initial flow rate of 0.1 ml/min. After that, the differential pressure was measured to calculate the rock's absolute permeability to water. The initial flow rate was 0.5 ml/min, followed by 1.0 ml/min and 1.5 ml/min. Then 1.0 ml/min again and finally 0.5 ml/min. Each flow rate was maintained for one injected pore volume. The differential pressure values, recorded by the logger connected to a transducer, were applied in Darcy's law equation for linear flow to calculate the permeability of the samples.

To achieve the condition of initial water saturation, 4PV of model oil was injected into the saturated samples at a flow rate of 0.1 ml/min.

After determining initial water saturation, the core holders containing the sandpacks were placed inside the oven at reservoir temperature (54°C) for fifteen days to simulate a static aging process. The sandpacks were kept inside the core holders to avoid disintegration during assembly and disassembly.

The forced displacement apparatus used in the experimental tests is illustrated in Fig. 3.

Table 6 Permeability and porosity of rock samples and sandpacks.

-	Permeability [mD]			Porosity [%]
-	Rock Sample A	Rock Sample B	Sand pack	Sand pack
SP1	761.7	1688.6	388.2	36.0
SP7	833.3	1237.2	862.5	35.3
SP8	1020.6	121.7	985.0	36.3

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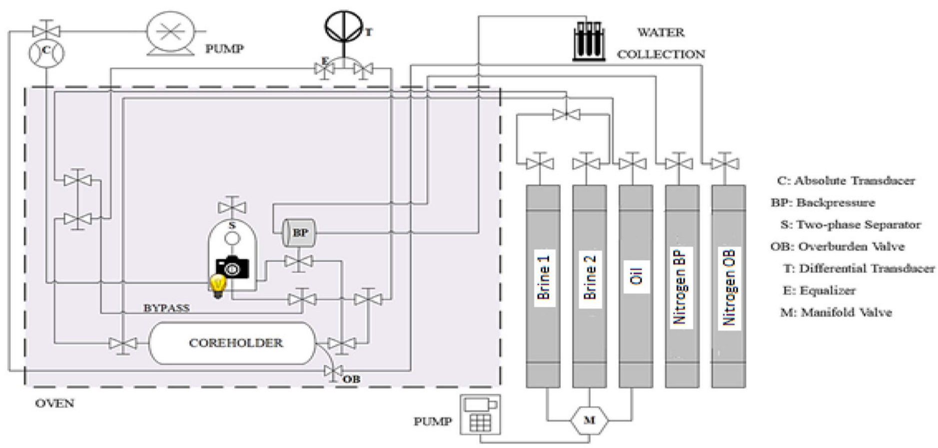

Fig. 3 Schematic illustration of the forced displacement apparatus.

The setup comprises the core holder, two bottles containing brines of different compositions, one bottle of model oil, and two bottles containing nitrogen gas used as a lung to maintain the desired overburden pressure of the core holder and the backpressure. Confinement pressure was monitored throughout the test by an absolute transducer connected to the overburden valve and a hand pump. The transducer was also connected to the output of the separator to monitor the fluids' production pressure. Furthermore, a differential transducer was connected to the inlet and outlet valves of the core holder to enable the recording of the differential pressure throughout the injection test.

The rig was assembled inside an oven, and the temperature was maintained at 54 °C. To start the recovery test, all the lines were saturated with the lower salinity brine, and the system pressure was gradually increased in sync with the confining pressure of the sand packs. Due to the sandpacks' susceptibility to deformation, the injection and overburden pressures were 320 and 520 psi, respectively.

A small amount of oil was injected through the top valve of the separator to establish the interface and test the image quality of the separator ruler captured by the camera. Then, the first brine was injected at a flow rate of 0.1 ml/min until it reached the oil production plateau, i.e., until there was no more visible oil production on the separator scale after 1 additional PV injected. After that, lower salinity brine was also injected at 1 ml/min until the production plateau. From there on, the valves were closed, and the injection stopped.

The rock minerals were identified by X-ray diffraction analysis via the total powder method and quantified through Rietveld modeling. Data were collected in a diffractometer (D2 Phaser, manufactured by Bruker).

Results and Discussion

The results obtained from experimental tests are described in this section.

Only 3 sand packs were available for the 4 planned experiments, so the sand pack SP8 was chosen to undergo 2 core flooding experiments (tests 2 and 3). Therefore, after Test 2, the sand pack SP8 was cleaned with aviation kerosene and heptane, and all physical properties were measured again to conduct Test 3. The permeability reduction observed in the sand pack SP8 for Test 3 was ascribed to fines migration caused by the repetition of the cleaning process.

The experimental plan considering sandpacks involves four core flooding laboratory tests that can be summarized as follows:

1. First core flooding: Formation Water followed by Low-Salinity Brine (1000ppm).
2. Second core flooding: Low-Salinity Brine.
3. Third core flooding: Formation Water, Seawater, and Low-salinity Brine.
4. Fourth core flooding: Seawater, Mixtured Water (Produced 60% and Seawater 40%), and Low-Salinity Brine.

Saturation Data

During the saturation of samples SP1, SP7, and SP8 with formation water, a history of differential pressure was obtained. Then, the absolute water permeability (KFW) was calculated from the differential pressure history (ΔP), shown in Fig. 4 to 7 for each experiment. Darcy's law was used, assuming negligible capillary effects. To obtain reliable results, variation in the injection rate was performed after the injection of 4 PVs of formation brine and the data were collected. The absolute permeability was calculated from the recorded pressure values on the transducer, and the different flow rates applied.

During the delta P measurements of the sand pack SP1 (Fig. 4), a slight increase in the delta P values was observed for the different flow rates evaluated. This behavior can be attributed to the sample's permeability, which is the lowest among the investigated samples. If lower flow rate values had been used, the delta P values acquired would have been more constant. Therefore, in this case, the average of the delta P values was used in the permeability calculation.

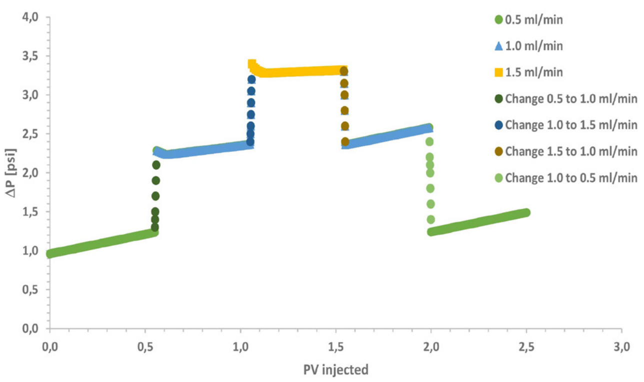

Fig. 4 Differential pressure versus Pore Volume injected - Sample SP1– First core flooding test.

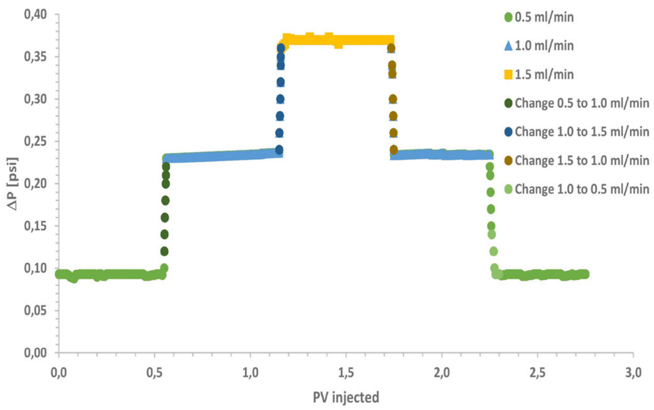

Fig.5 Differential pressure versus Pore Volume injected - Sample SP8– Second core flooding test.

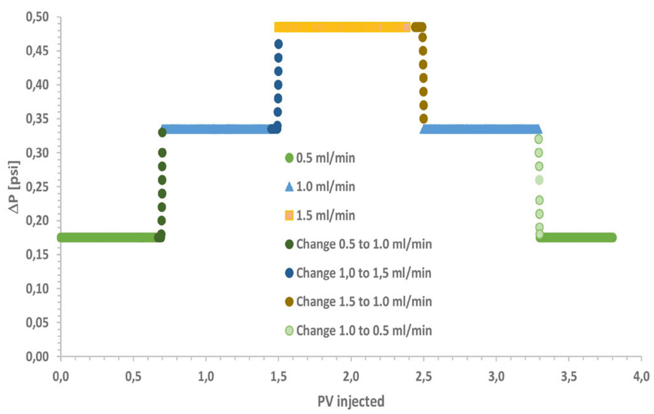

Fig. 6 Differential pressure versus Pore Volume injected - Sample SP8– Third core flooding test.

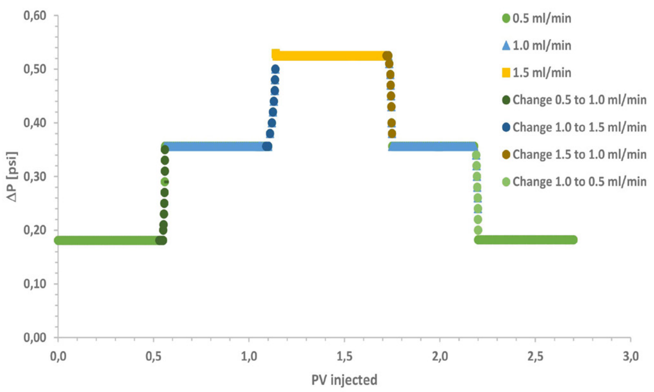

Fig. 7 Differential pressure versus Pore Volume injected - Sample SP7– Fourth core flooding test.

Fig. 5, 6, and 7 show that delta P values are stabilized for the flow rates applied in each sample. It was also possible to see that, in some cases, the effect of the new flow rate in the transducer presents a time delay and can only be seen after around 0.1 PV injected. The calculated water permeability values with the data shown in these graphs are presented in Table 7.

The results showed considerably lower water absolute permeability than the data obtained from a permeabilimeter. The differences are mainly related to the permeabilimeter's limitations in terms of pressure, temperature, and type of fluid used.

Also, the irreducible water saturation index is shown.

Table 7 Comparison between gas permeability and water absolute permeability.

Core Flooding Test	Sample	K_{N2} [mD]	K_{FW} [mD]	Swi [%]
First	SP1	388	74	18
Second	SP8	985	725	16
Third	SP8	914	502	24
Fourth	SP7	862	500	30

The samples were 100% saturated with formation water and then, saturated with model oil to obtain the Swi condition. The initial water saturation of the sand pack samples varies between 16 and 30%, showing a good sweep of the formation water by the oil in the working conditions, compared to the Swi in the reservoir (15%).

Core Flooding

After aging, the sand pack SP1 was subjected to core flooding test 1, which injected around 9 PVs of FW, followed by approximately 9 PVs of LS. The plateau of oil recovery by FW was reached before the brine exchange. Furthermore, the accumulated oil recovery and differential pressure curves can be seen in Fig. 8, where, as well as in the following plots in this section, the blue dashed vertical lines represent the moment when the brine swap happens. The yellow dashed vertical lines indicate when the new brine gets in contact with the rock inlet face. The incremental recovery factors between the moment of brine swap and the moment that it arrives at the rock inlet are displayed near the yellow lines. Plots with no incremental recovery factor shown near the yellow line indicates 0% additional recovery.

The injection of formation water resulted in the recovery of 17.5% of OOIP. After the stabilization of oil production, low-salinity water was injected, generating an additional recovery of 8.9%. A similar oil recovery increase in Berea sandstone, about 6.9% of the OOIP, switching the injection brine from formation water to 5000 ppm NaCl brine, was presented in the literature [40]. Additional oil recovery by low-salinity was attributed to Na+ ions' exchange and/or wettability alteration to more water-wet [41]. The authors also used Berea outcrop samples and performed a displacement-imbibition and core flooding test using three brine concentrations of NaCl (1.0, 0.1, and 0.01 wt% NaCl). The results show that low-salinity resulted in a higher oil recovery factor in both tests. A tertiary recovery of 2.24% OOIP with low-salinity water injection in clay-free unconsolidated Ottawa sand pack cores was also reported [42].

Some experimental complications did not allow the measurement of the differential pressure at the beginning of the test (up to 0.9 PV injected) and between 11.0 and 13.8 PV injected. After an apparent stabilization between 0.9 and 1.6 psi during the FW injection, an increase in the differential pressure is noticed with the brine exchange, which may be associated with the brine/oil/rock interaction.

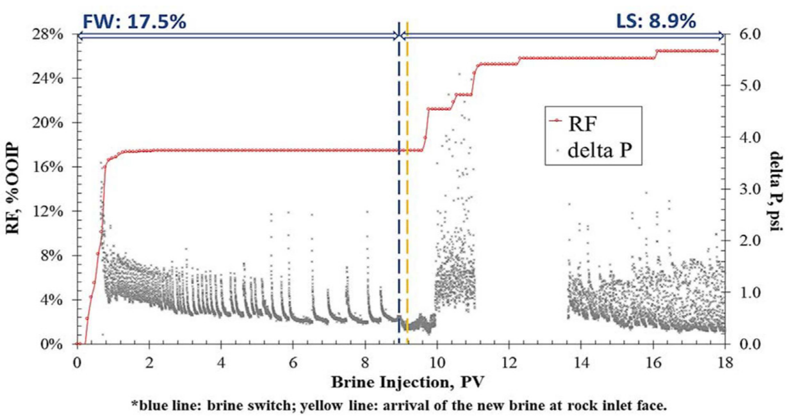

Fig. 8 Oil recovery factor and differential pressure curve, first core flooding test (sand pack SP1).

This behavior coincides with the beginning of LS's additional oil recovery. Also, the increase in the differential pressure associated with oil production may be related to scanning new pores and paths. However, it is impossible to prove which mechanisms are responsible for the additional recovery and could be associated with the performance of several mechanisms in conjunction. Moreover, the differential pressure measurements are very important in core flooding tests. Furthermore, the pressure transducers must be capable of sensing little differences at high local pressure values. Also, when differential pressure reduces, the flow is facilitated, meaning better conditions for the flux. On the other hand, if the value increases, the path is obstructed, or at least, the pressure drop is higher. Small values (1 or 2 psi) of differential pressure indicate high permeability of the porous media.

In the second core flooding test, about 8 PV of LS were injected into the sand pack SP8 in secondary mode resulting in a 32% recovery of OOIP, as shown in Fig. 9. The behavior of the differential pressure curve was as expected, considering the single injection test. Also, a decline in the delta P curve could be seen around 3.5 PV injected and subsequent stabilization by the end of additional oil production.

After this test, sample SP8 was submitted to the cleaning process, and subsequent saturation was made to be used in experimental test 3. The results of the third core flooding test are shown in Fig. 10. The oil recovery and differential pressure curves are presented in the plot. The first brine injected was formation water, representing the first standard water injected in reservoirs as a secondary recovery method. The FW brine yielded a recovery factor of 34% of OOIP during the injection of 6.8 PV. After such injection volume, it was decided to change the brine injection to the seawater. At the beginning of the SW injection, it is possible to see an increment of 0.6 % of OOIP, which it cannot be attributed to SW, once it happened before the dead volume injection, shown by the yellow dashed line. In addition, the oil recovery attributed to the SW is around 1.4%, considering 9.4 PV injected. Finally, around 13.8 PV of LS was injected. Likewise, with the SW injection, it is possible to see an increase in oil recovery before the dead volume injection. However, in this case, the recovery was stable for around 3 PV before the brine change. In this case, the abrupt recovery in the first moment of LS injection was associated with the manipulation of valves during the brine change, which it could release the oil confined inside the lines or even the system's valves. Furthermore, the oil recovery promoted by LS was around 4.5%, which can be considered a good increase in oil recovery by LS water effects.

The differential pressure declined until 12 PV was injected, followed by a stabilization. When the LS started to be injected, an increase between 0.2 and 0.4 psi in delta P was observed. Moreover, this increase indicates that the LS caused interaction reactions in the porous medium that can also be observed in the additional oil recovery. Also, it is important to emphasize that the second and the third core flooding tests were performed with the same sand pack rock, and it is possible to see that the recovery in secondary mode using LS and FW was very similar, 32% with LS and 34% with FW for around 7 PV injected. No evidence of the LS effect was shown in the secondary mode for this sample. The last experimental test was carried out using sample SP7. The results of the fourth core flooding test are shown in Fig. 11.

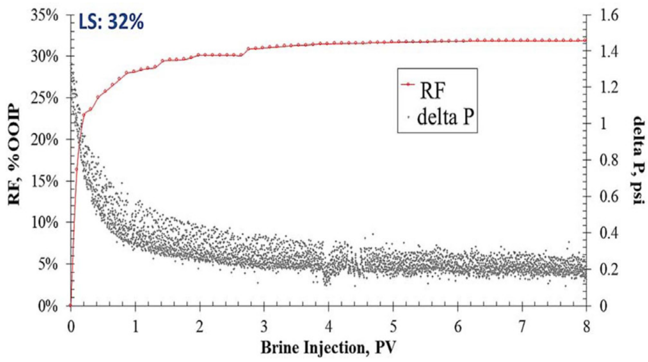

Fig. 9 Oil recovery factor and differential pressure curve, second core flooding test (sand pack SP8).

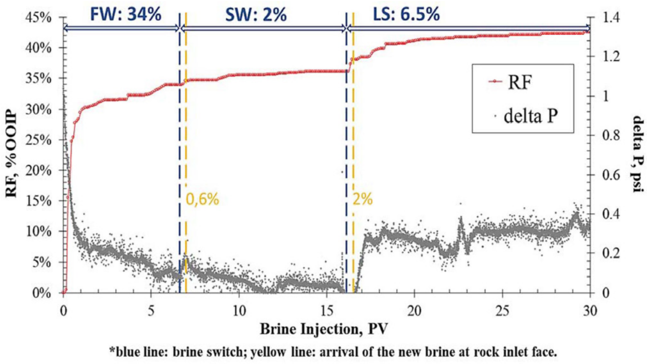

Fig. 10 Oil recovery factor and differential pressure curve, third core flooding test (sand pack SP8).

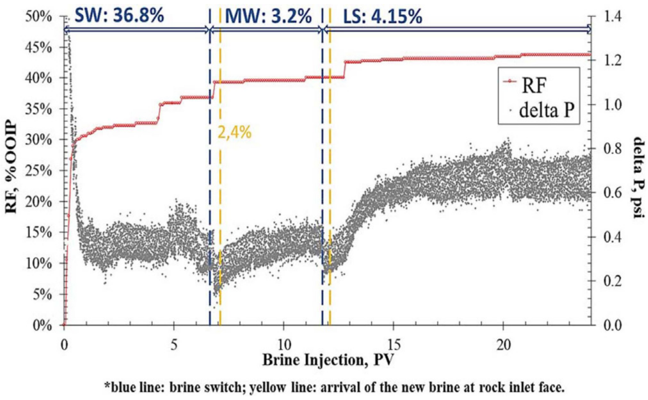

Fig. 11 Oil recovery factor and differential pressure curve, fourth core flooding test (sand pack SP7).

The first brine injected was seawater, as the actual scenario of the studied reservoir was considered. Around 6.6 PV of this brine was injected, promoting recovery of 35% OOIP. The second brine evaluated was mixed water (60% produced water and 40% seawater), assuming the reinjection of all produced water in the reservoir. At the beginning of MW injection, it is possible to see an increase of about 2.4% in oil recovery that cannot be associated with an effect of the brine itself. The increase in oil recovery promoted by the injection of 5 PV of MW was around 0.8% of OOIP, which could not be considered a positive result of MW injection. Furthermore, low-salinity brine rose of around 4%, even as injected in the last mode. In addition, the oil production stabilized after the injection of 9 PV of LS. However, the most considerable amount of oil was produced around the first porous volume injected.

Regarding the differential pressure, it can be seen that the curve maintained a constancy between 0.2 and 0.5 psi until the change of brines from MW to LS. At the beginning of MW injection, a decrease in delta P is observed, typical in water exchange moment; however, the value grows until the stabilization is around 0.4 psi. With the injection of low-salinity water, it is noticed that the measured values increase and remain in a range between 0.55 and 0.8 psi, which, again, indicates the triggering of brine/oil/rock reactions as the migration of fines. These results show positive perspectives for injecting this new water composition (produced water + seawater) into the reservoir. According to the recovery factor, it is expected that injecting all produced water into the reservoir does not promote significant changes in the recovery factor. However, considering the variation of delta P, no events were observed that could indicate a decrease in the reservoir's injectivity with the use of a higher salinity brine (MW) subsequently to the injection of SW.

The first core flooding test used sand pack SP1 from well Y, with Swi equal to 18%, showing a final Recovery Factor (RF) near 26%, the lowest value of the four core floodings. This result should probably be related to the lowest permeability of 388.2 mD. The second and third core flooding tests employed sand pack SP8 from well Z, with similar Swi and permeability of 985.0 mD, achieving a final RF of about 32 and 43% respectively. The fourth core flooding test, with sand pack SP7 from well Y, presented the highest RF (47%), even though it had the lowest amount of oil (Swi=30%), but permeability equal to 862.5 mD.

Injection of low-salinity water promoted an increase in recovery factor, from 4 to 9 %.

The review of data-driven analyses of low-salinity water flooding [36] found a tertiary recovery factor of up to 10 % when the samples presented no clay content. Moreover, clay is generally referred to as kaolinite, illite, chlorite, and smectite groups. Its content and composition can vary from one place to another. When there is no clay in the rock, low-salinity water could promote an incremental oil recovery due to the interaction between oil and brine, forming micelles that move along the flux. No additional production is observed if the brine composition contains only ions that do not interact with oil. Another hypothesis is that low-salinity water could change wettability towards more water.

In core flooding experiments, border effects are related to the flow near the boundaries or interfaces of the rock plug. Such phenomena could influence the results because of non-uniformities in the flow patterns and concentration profiles. Capillary end effects may trap fluids, impacting the overall displacement process. Larger plugs should be used to minimize border effects. Another technique employs a porous plate with wettability and porosity adjusted for the test. In the present work, border effects could explain the slight differential pressure variation observed between the blue and yellow dashed lines in the recovery factor graphics. Images from computed tomography could help to analyze this research.

Rock Mineral Composition Discussion

X-ray diffraction analysis was carried out on some reservoir core samples to identify the mineral composition and explain their permeability and behavior when submitted to low-salinity water injection. Moreover, such analysis showed the compositional diversity of the samples of this sandstone field. The results are shown in Table 8.

Table 8 Mineral composition of sandpacks SP1, SP7, and SP8 (mass %).

Mineral-	SP1	SP7	SP8
Calcite	-	8.1	17.1
Quartz	63.9	43.9	38.7
Sanidine	17.5	37.8	13.2
Oligoclase	18.7	10.2	30.5
Dolomite	-	-	0.5

Sandpacks SP1, SP7, and SP8 from wells Y and Z, contained high quartz concentrations and varied in sanidine, oligoclase, and calcite concentration. Sample SP8, the only one from Well Z, had the highest concentration of oligoclase among the analyzed samples.

Each type of clay has a specific layer structure and chemical composition; which results in a different cation exchange capacity, a parameter that indicates the number of positive ions the clay can retain [43]. Therefore, the higher the cation exchange capacity, the higher the possibility of expanding the interlayer gaps and swelling the clay structure, which might cause undesired permeability decrease.

Sandpacks SP1, SP7, and SP8 showed a high concentration of quartz and a low concentration of phyllosilicates and carbonate, which can explain the good permeability of the original samples (Rock Sample A and Rock Sample B ~ 1 Darcy). This composition implies the presence of sediments with high compositional maturity, referring to the degree to which chemical characteristics are so mature that grains are more in equilibrium with Earth's surface conditions [44].

According to these analyses, the increase in oil recovery obtained during the low-salinity water injection could not be attributed to the rock's clay content. Recent research suggests that fluid-fluid interactions, particularly the formation of oil-injected brine micro dispersions, have emerged as another mechanism for low-salinity water flooding, and it has also been noted that clay is not an influencing factor in LSWF [45]. The impact of clay content on low-salinity water flooding performance in sandstone reservoirs was reported and it concluded that there is no direct relation between the total clay content and oil recovery during low-salinity water flooding [46]. The authors also point out that sandstone rock quality and minerals distribution, other than the clay content, appear to play a key role in the success of low-salinity injection.

The key mechanism behind the low-salinity effect cannot be easily identified [47]. The experiments performed by the authors do not confirm the models that require the presence of the clay but do not exclude them. They observed a clear low-salinity effect on cleaned, oxidized silicon wafers (SiO_2), similar in composition, but not in structure, to the quartz that dominates sandstone reservoirs. The authors point out the role of the electrical double-layer at mineral surfaces.

The electric double-layer force is always part of the low-salinity effect [48]. They demonstrate that the electrical double-layer affects oil release from quartz surfaces, even when the oil molecule is uncharged. However, they predict that the ionic strength effect is at least one order of magnitude greater on clay surfaces than on quartz due to the much higher surface charge on the type of clay minerals usually observed in sandstone.

These results and studies show the complexity of the mechanism that involves an increase in the recovery factor in sandstone reservoirs by injecting low-salinity water. However, the experimental tests on these sandstone reservoir samples showed LSW injection potential for increasing oil production.

Conclusions

The present study experimentally investigated the effects of low-salinity water injection on the oil recovery factor at pressure and temperature similar to those of the reservoir. A forced displacement test was performed with an injection of formation water followed by low-salinity water.

Due to the challenges associated with oil injectivity in Brazilian sandstone reservoir samples, alternative methodologies were used to prepare the samples for the aging process. Moreover, the methodology applied to solve the problems inherent in the preparation of reservoir rock samples was the construction of sandpacks with the grains of the samples, maintained in a recipient with diffusers at the ends.

The sandpacks from wells Y and Z were used in the forced displacement tests. Ultimately, the results indicate a potential effect of low-salinity water with an average incremental oil recovery of around 4%, evidencing the need for further tests to investigate the effect of injection water salinity in more detail. In addition, regarding the injection of the brine mixture, the results indicated that the injection of the produced water into the reservoir would not affect the oil recovery.

The injectivity was analyzed by the differential pressure measured along the tests, and significant changes were not observed due to the variation in salinity of the injected brines. Even with the increase in salinity, test 4 (MW injection after SW injection), significant changes were not observed in the variation of delta P.

The forced displacement test performed in the sand pack SP1 with purer mineralogical composition, i.e., formed only by quartz and feldspathic minerals, showed the highest additional oil recovery factor after low-salinity water injection. The others sandpacks have calcite in their composition and it is estimated that the dissolution of this carbonate material may have masked the effect of the ion exchange that occurred in the porous medium and, thus, resulted in a lower recovery.

The absence of clays in the reservoir samples suggests that the mechanism involving the increase in the recovery factor in sandstone reservoirs through the injection of low-salinity water may be more complex than the mechanisms already proposed in the literature. Moreover, the experimental results with the reservoir samples indicated a potential effect of low-salinity water on oil recovery.

Finally, the data obtained are essential for application in reservoir engineering. From a simulation model, a history-matching process could be applied to find the relative permeability curves that best fit the experimental results. In this way, the relative permeability curves for each injected brine can be generated to assist in simulating the indicators of oil field management.

Forward-looking Statements

Future research directions for this study suggest several approaches to expand understanding and address existing gaps. One potential area of investigation involves modifying the composition of low-salinity water to analyze how specific ions contribute to wettability changes and oil recovery enhancement. Additionally, conducting forced displacement experiments in sand packs under reservoir-like pressure and temperature conditions could provide a more accurate representation of real-world processes.

Another important direction is to incorporate bump flow techniques during forced displacement tests. This approach would help ensure that any observed additional oil recovery is solely due to changes in brine composition while minimizing edge effects. Further, X-ray micro-CT analysis could provide valuable insights into fluid distribution within the rock matrix and identify pore blockages caused by fine particles, which might explain permeability damage observed in some cases. Effluent analysis also plays a critical role in refining experimental precision. Collecting effluent samples directly at the core holder outlet would allow immediate pH measurement, reducing the risk of fluid contamination and improving the reliability of results. Additionally, chromatographic analysis of effluents could reveal the presence of divalent ions, offering evidence of desorption processes that may be essential for achieving enhanced recovery through low-salinity water injection.

Simulating fluid flow within porous media using data and outcomes from experimental tests could provide a theoretical framework to support experimental observations. Together, these recommendations pave the way for a deeper understanding of the mechanisms underlying low-salinity water injection and its potential to optimize oil recovery.

Nomenclatures

AN: Acid Number [mg KOH/g]
BN: Basic Number [mg KOH/g]
EOR: Enhanced Oil Recovery
FW: Formation Water
LS: Low-Salinity Water (1000 ppm)
LSWF: Low-Salinity Water Flooding
LSWI: Low-Salinity Water Injection
MW: Mixture of Produced Water and Seawater
OOIP: Original Oil in Place
PV: Pore Volume
PW: Produced Water
RF: Recovery Factor
SP: Sand Pack
SW: Sea Water
Swi: Initial Water Saturation [%]
TDS: Total Dissolved Solids [mg/L]

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