The impact of low salinity on oil recovery from a carbonate reservoir

Silva, Diana Sofia; Pereira, Maria João; Rodriguez, María Rosario; Blin, Nicolas

Email address: diana.s.p.silva@ist.utl.pt

Instituto Superior Técnico

Avenida Rovisco Pais, 1

1049-001 Lisboa

Abstract: The work developed aims to study the impact of salinity and anions on the wettability and oil recovery in a carbonate reservoir rock, in Abu Dhabi.

It is already comproved that injecting brine with low salinity increases the oil recovery and some of the ions present, like sulphate, calcium and magnesium are the responsible. When the concentrations of non-active ions are reduced, these active ions have easier access to the carbonate surface, improving the oil recovery, through wettability alteration.

The work consists in an EOR core flooding experiment with the purpose of reproducing the reservoir conditions. To achieve this goal, four limestones cores were saturated with synthetic water, saturated with oil until reach the irreducible water saturation, aged at the reservoir temperature, injected with oil to measure the oil permeability and finally aged again to make the fluids adhere to the rock and restore wettability.

After the reached initial reservoir conditions, water with different salinity was injected, to analyse the effect of this method in the oil recovery.

Keywords: Carbonates, Low Salinity, Wettability, Enhanced Oil Recovery

1. Introduction

The work developed took place at the Research center of CEPSA, in Exploration and Production (E&P) department. CEPSA, Compañía Española de Petróleos, S.A.U. is a Spanish multinational oil and gas Company.

The Exploration and Production (E&P) department aims in their work to maximize the percentage of oil recovery in the fields, and to do that, the company is developing techniques for Enhanced Oil Recovery (EOR) applicable to current and future assets. Due to the high presence of carbonate reservoirs around the world, is important to study the carbonate behaviour.

Its mineralogy is formed principally by calcite, dolomite and minor clay, but this type of rocks is quite complex because of its heterogeneity. Carbonates are characterized by different types of porosity and complex pore size distributions which result in wide range of permeability.

Besides, it is estimated that 80 - 90 percent of the world's carbonate reservoirs are preferentially oil-wet and they exhibit negative capillary pressure, which leads to low oil production. All these reasons make important to study carbonate reservoirs and their production.

The work developed aims to study the impact of salinity and anions on the wettability of a carbonate reservoir rock and oil recovery in an Abu Dhabi oil field. Literature data show that Ca^{2+}, Mg^{2+}, and SO_4^{2-}, present in brine, are active ions in the wettability alteration process to water-wet, due to the strong affinity of sulphate, it can be adsorbed on the carbonates surface and it reduces the positive charge density.

During this study EOR core flooding experiments were performed in four cores. In these experiments, it is important to reproduce, as much as, possible the initial conditions of the rock, such as fluids saturation and wettabilit. Therefore, each core must be exposed during the right time to the various stages of the experiments.

Thus, the objectives of this work are to investigate the effect of salinity on the wettability of a carbonate reservoir rock, in order to analyse the productivity of carbonate rocks.

2. Oil Field details

The carbonate reservoir under study is located in Abu Dhabi, with reservoir temperature of 120 °C, and reservoir permeability of 10 mD. The reservoir geology type is Carbonate and the target formation geology type is Limestone.

Oil details

Data from a well:

Crude oil API gravity: 35.6° at 15.5 °C

Crude oil viscosity: 1.07 mPa.s at 120 °C

Crude oil density: 0.8292 kg/l at 37.8 °C

Brine details

The brine composition is given in Table 1. The data represents the average concentration of 6 brine analyses from one well:

Table 1- Brine details

Composition	Brine from the oil field (mg/L)
Choride	114363.17
Sulphate	273.33
Carbonate	NL
Bicarbonate	368
Calcium	16666.67
Magnesium	1570
Iron	135
Sodium	52235.67

3. Experimental methodology

3.1. Core preparation methodology

An EOR core flooding experiment at reservoir temperature has three principal steps: the core cleaning, core saturation and core flooding.

In order to perform an experiment of EOR core flooding is important to reproduce the reservoir conditions in the core, like fluids saturation and wettability. For this purpose, initially the core should be carefully cleaned of any rest of oil, perforation fluids, water, salts, or any other additives that the core may contain. Afterwards, different measurements can be done in order to characterize the rock to be used during the experiments. In the saturation step, the core is saturated with the original fluids, crude oil and reservoir brine, and then submitted to ageing process.

Before all these procedures, the core is placed in a coreholder, this equipment is used to confine the core and simulate the reservoir conditions.

Therefore, the main steps in the preparation of a core are:

• Gas permeability measurement at normal and reverse flow, at ambient temperature;

• Water saturation;

• Water permeability measurement at normal and reverse flow, at ambient temperature and at reservoir temperature;

• Dynamic pore volume measurement;

• Crude oil saturation;

• Irreducible water saturation measurement;

• Ageing at reservoir temperature;

• Crude oil injection at ambient temperature;

• Ageing at reservoir temperature;

• Injection of brines with different salinity.

This way, four Indiana limestone cores were prepared, passing through all this steps. At each core is assigned the code CC and a number between 1 and 4.

Table 2 - Characteristics of Limestone Cores

Core	Length (mm)	Diameter (mm)	Dry Weight (gr)
1	69.77	38.07	171.619
2	73.92	38.08	181.439
3	73.81	38.07	180.805
4	73.66	38.08	181.799

Measurement of rock permeability to gases

The first parameter usually measured in order to characterize a rock is the permeability. The permeability to gases is measured by monitoring the DP. Thus, the permeability was measured with a confining pressure of 20 bar in normal and reverse flow with Nitrogen (viscosity = 0.01777 mPa.s or cP).

The first step before starting the procedure is to dry the core. For this, the core is kept in an oven at 80 °C, overnight. The next step is to place the core in the coreholder and apply the confining pressure.

Then, at ambient temperature, the gas is injected. Using a gas meter the gas flow is monitored, as well as the differential pressure along the core, with the outlet at atmospheric pressure. The gas volume that went through the core during a specific time is used to calculate the gas flow rate.

The permeability was estimated using equation 1, after measuring the pressure produced in the core at different flow rates.

$$k(\,(mDarcy) = 2 * \frac{\mu\,(cP) * L\,(cm)}{S\,(cm^2)} * \frac{Q\,\left(\frac{cc}{h}\right) * P\,(bar)}{(P_1^2 - P_2^2)(bar^2)} * 1013 \qquad (1)$$

Where : k - permeability; μ - fluid viscosity; L - Lenght of the core; S - area of the core; Q - flow rate; P - absolute pressure for the flow rate measurement; P_1 - absolute pressure on the inlet and P_2 - absolute pressure on the outlet

Pore volume measurement

After the rock permeability to gases measurement, the core is removed from the coreholder to measure the PV.

The pore volume can be measured using two different procedures.

The first, is measured in bulk, calculating the difference between the core weight when it is saturated with degassed formation brine, and the core weight when it is completely dried. This value corresponds to the water that has gone into the core.

The second, dynamic PV, is measured through a tracer (naphthalene disulfonic), that is placed in the water injected in the core. Using online UV detectors, it is possible to know the time necessary for the tracer to travel through the entire core. Thus, knowing the flow rate applied and the time mentioned above, the pore volume can be calculated.

To do this measurement, the core was placed in a coreholder and saturated with water. Four different flow rates were used, 6 ml/hr, 12 ml/hr, 25 ml/hr and 50 ml/hr, and for each one the procedure was repeated two times.

To calculate, the pore volume value it is necessary to monitor the values recorded by the UV detector, convert them to absorbance and then normalize the values.

Therefore, knowing the specific time when the tracer is injected and when the peak of tracer takes place, it is possible to calculate the delay, which is the time between the moment when the tracer is injected until the moment when it comes out of the core. Once, the flow rate is known, as well as the delay, the volume can be calculated, multiplying the flow rate and the delay. Then, subtracting the dead volume (volume external to the core) we obtained the effective volume, in other words, the pore volume.

Measurement of rock permeability to water

After the pore volume measurement, the saturated core is placed back in the coreholder to measure the rock permeability to water.

The permeability is measured both in normal and back flow conditions using formation brine, with 30 bar of confining pressure, at 24 °C (viscosity = 1.183 mPa.s or cP) and at 120 °C (viscosity = 0.333 mPa.s or cP). For each experiment the DP was monitored for four flow rates, 10 ml/hr, 20 ml/hr, 30 ml/hr and 50 ml/hr, injected using an ISCO pump. The DP value is taken when the values are stable.

To measure the permeability at 120 °C the four coreholders were placed inside the oven at reservoir temperature.

Moreover, to evaluate the DP behaviour at different flow rates, for normal and back flow, a plot was made, where the two lines were compared, for quality control of the measurement. Then, if the two lines were very different the measurement should be repeated.

To measure the rock permeability using brine the DP was measured in the core, for different flow rates and different temperatures. The Darcy equation, equation 2, has been applied to calculate the permeability.

$$k(mDarcy) = \frac{\mu\,(cP) * L\,(cm)}{S\,(cm^2)} * \frac{Q\,\left(\frac{cc}{h}\right)}{\Delta P\,(bar)} * 1013 \qquad (2)$$

Where : k - permeability; μ - fluid viscosity; L - Lenght of the core; S - area of the core; Q - flow rate; and ΔP (bar) - pressure gradient across the core.

Table 3- Characteristics of Limestone cores, after PV measurement

Core	Length (mm)	Diameter (mm)	Dry Weight (gr)	PV (mL)	Bulk Porosity (%)
1	69.77	38.07	171.619	15.9	20.02
2	73.92	38.08	181.439	16.9	20.07
3	73.81	38.07	180.805	17.1	20.35
4	73.66	38.08	181.799	16.6	19.79

Crude oil saturation and irreducible water saturation measurement

The next step is to measure the oil saturation. For this, it is necessary to remove the water, saturate the core with oil, and measure irreducible water saturation *(Swi).*

In the beginning of this procedure the core is 100 % saturated with brine, and is placed in contact with a ceramic disc that is permeable to brine, but not to oil. Thus, when the pressure is applied to the oil and to the brine, it forces the brine out of the core, through the ceramic disc. The saturation is finished when no more water comes out of the core.

The procedure is performed at ambient temperature and different pressure steps are applied: ambient pressure, 0.5 bar, 1 bar, 2 bar, 4 bar, 6 bar, 8 bar and the last step 10 bar (the maximum oil pressure limit allowed). In each step an amount of water is produced, and the volume of water is measured in a burette placed in the coreholder outlet. The burette reading is made twice a day. Once the water produced value is known, the water saturation value can be calculated, as well as the oil saturation value.

In Fig. 1 is presented the capillary pressure evolution.
Analysing the shape of the capillary pressure curve, the water saturation evolution decrease fast, which means that the value of oil saturation increases fast during the first days, it might be induced by the oil that invade quickly the largest pores at first, and then the smallest pores.
The curve shape for core number 4 is similar to core number 3, this effect can be due the pressure steps duration were similar (the pressure was increased only when the value of water in the burette was constant during three or four readings), or core characteristics between both are similar. The curve shape for core number 2 is similar to core number 1, because the pressure steps duration were also similar, once the pressure was increased after a certain time.
The purpose to use the porous plate is to reach a low irreducible water saturation, and in this case the goal has been achieved.

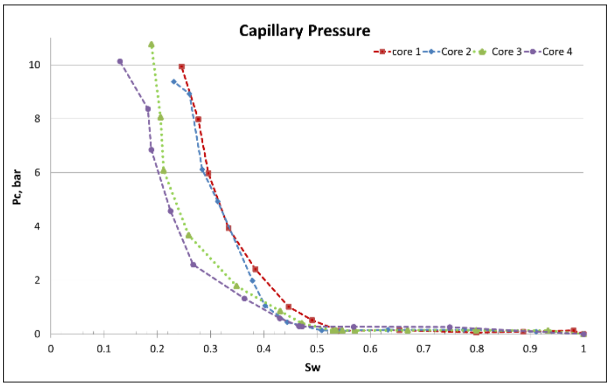

Figure 1 - Capillary Pressure evolution

Ageing at reservoir temperature

Once the core is saturated with oil until irreducible water saturation, the coreholder is placed in the ageing unit, where the core is aged at reservoir temperature and injected with oil, in order to measure the rock permeability to oil.

The purpose of this procedure is to make fluids adhere to the rock and restore the real wettability present in the field. For this, the time of ageing should be, at least, two weeks. However, for high temperature, such is the case where reservoir temperature is 120 °C, ageing may not affect the core wettability. During the ageing time the core is kept inside the oven at reservoir temperature, with confining pressure of 40 bar and pore pressure of 10 bar.

Relative rock permeability to oil is measured by injecting oil into the core, at different flow rates. In this case at 2 ml/hr, at 10 ml/hr, at 25 ml/hr, at 50 ml/hr, and at 100 ml/hr. The relative rock permeability to oil is measured approximately once a week, after each measurement, the valves are closed and the core is aged again.
Only cores number 1, 2 and 3 were submitted to ageing.

Analysing Figure 2, it is possible to conclude that the value of Kro was not constant for core number 3 and 2, however is constant for core number 1. Thus, the curve for core number 3 and 2 is irregular and have a drop, this can indicate alteration of core wettability, since the oil has more difficulties in pass through the core.

Some of the differences are due to the parameters that changed, for example the number of days during oil saturation, and ageing. And some of the differences are due to core characteristics.

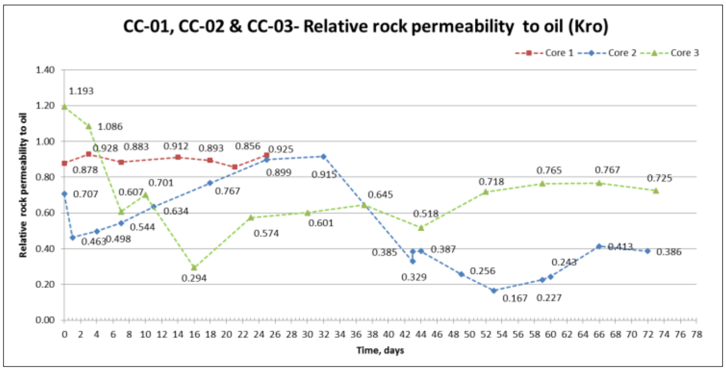

Figure 2 - Relative rock permeability to oil, for core number 1, 2 and 3

Injection of brines with different salinity

During the experiment different brines were prepared such as: Formation Brine (FB), Synthetic Seawater (SSW), Synthetic Seawater diluted 10 times (SSW 1/10), Synthetic Seawater diluted 25 times (SSW 1/25) and Synthetic Seawater modified (SSW mod). The salts used to prepare the fluids included: NaCl, $CaCl_2$:$2H_2O$, $MgCl_2$:$6H_2O$, $NaHCO_3$, Na_2SO_4 and KCl. KCl was only used for the following brines SSW, SSW 1/10, SSW 1/25 and SSW mod. The necessary weight of the different types of salts were added to tap water, once the amount of salt present in this water was negligible. The salts were added one by one, beginning with the salt that had the biggest amount and ending with the salt in smallest amount. Once added the first salt, the water with the salt was stirred with magnetic stirrer, and when the mixture was homogeneous another salt was add, until all the brine composition was complete. Then, the brine was filtered through a 0,22 µm filter to removing possible particles that were undissolved.
For each one, except for SSW mod the viscosity and density were measured at different temperatures and at reservoir temperature and the pH, to monitored if the water characteristics are not changed after injection.

Table 4 – Brine characteristics

Ions	FB	SSW	SSW 1/10	SSW 1/25	SSW mod
Chloride, mg/L	108186.2	19466.46	2060.13	813.68	16278.63
Sulphate, mg/L	281.02	2756.76	289.41	109.56	13303.44
Calcium, mg/L	16798.84	499.71	45.34	18.28	619.6
Magnesium, mg/L	1586.08	1363.19	127.16	64	1539.62
Sodium, mg/L	57542.42	10951.09	1054.71	493.69	12495.31
Potassium, mg/L	-	373.09	35.49	18.28	516.33
TDS, g/L	229	42	4.2	1.7	42.4
pH	6.5	6.3	6.3	7.8	7.9
Viscosity, mPa.s	0.333	0.2	0.151	0.172	-

3.2. Core flooding methodology

Before performing a core flooding some calculations need to be made, for each core and for each case. It is important to know the volume of oil present in a core, that corresponds to the maximum of volume that can be produced.

Therefore, since the pore volume and irreducible water saturation are known, it is possible to know the oil saturation and consequently the oil and water volume present in the core. The oil saturation, So, is given subtracting the Swi to 1. And the volume of oil present in the core, was calculated applying equation 3.

$$Volume\ of\ oil\ (ml) = PV * S_o \qquad (3)$$

Where: PV - pore volume (ml) and So - Oil saturation.

A different sequence of brines were injected in each core. Here, it will be only described the core flooding procedure for CC-01 and

CC-02. The first injection was always formation brine, that was used as a reference in terms of oil recovery. Afterwards SSW was injected, SSW is easily available in the field and the salinity is around 5 times lower than FB, and after SSW, the brine injected varies according to the core used.

It is important to monitor pressure and conductivity during all the experiment. The conductivity, is variable with salinity and both variables are directly proportional. This means that when salinity increases the conductivity increases, and when salinity decreases conductivity decreases. Thus, it is expected that during FB injection the values of conductivity is high and decreases with the following injections. It is also expected that when oil passes through conductivity cell, the conductivity value is zero.

The DP should increase in same proportion that the flow rate increases, which means that if the flow rate increase four times, for example since 3 ml/hr until 12 ml/hr, the value of DP should increase also four times. It is also expected that the values of DP decrease when a brine with less salinity is injected, as a result of the lower viscosity. Generally low salinity brines have a lower viscosity than formation brine.

The oil recovery factor was calculated using the equation 4.

$$Oil\ recovery\ (\%) = \frac{V_{prod}}{OOIP} * 100 \qquad (4)$$

Where : V_{prod} - Volume of oil produced (ml) and OOIP - Original oil in place (ml)

4. Results and discussion

In this chapter the results of two core floodings will be presented, the core flooding performed for core number 1, CC-01 and the core flooding performed for core number 2, CC-02. The formation brine was used in both core flooding, as a reference in terms of oil recovery. The Formation brine injection was followed by Synthetic Sea Water injection and finally a dilution of the SSW or a modified SSW. For each core, at least 3 brines were tested at two flow rates, 3 ml/hr and 12 ml/h.

During the experiment, oil production, pressure, conductivity, ions concentrations and pH were monitored.

CC-01

The first core flooding was performed over core number 1, knowing the pore volume and irreducible water saturation it is possible to know the oil saturation and consequently the oil and water volume present in the core, in this case, the pore volume is 15.9 ml and *Swi* is 0.245. Oil saturation value is given subtracting the *Swi* to 1, this way *So* is 0.755. The volume of water in the core is 3.9 ml and the volume of oil 12 ml, given by equation 3.

In this core four different brines were injected:
- First injection: FB
- Second injection: SSW
- Third injection: SSW 1/10
- Fourth injection: SSW 1/25

The first injection was formation brine that was used as a reference in terms of oil recovery. After the FB, was injected SSW, since SSW is easily available in the field and the salinity is around 5 times lower than FB, after SSW, was injection SSW diluted 10 times, and after, SSW diluted 25 times. During all the experiment is important to monitor pressure and conductivity.

Is expected that SSW would change the core wettability, because the SSW is 5 times less salty than the formation brine, and also because the sulphate concentration in this brine is around 10 times greater than in the formation brine.

In Fig. 3 are presented the oil recovery results for each brine, the conductivity and DP results also for each brine and the flow rate.

Formation brine was first injected at 3 ml/hr and then when the oil production was stable increased to 12 ml/hr. This injection produced 55 % of the original oil in place. 275 ml of FB were injected, which means 17.30 PV. During this injection the high salinity damaged the pump, which lead to irregular DP data and conductivity, however it is possible to see that during this injection the conductivity presents high values as a result of the high salinity level.

Later, injection was switched to SSW at 3 ml/hr and after 12 ml/hr. This injection showed extra 4.2 % oil production, which is an indication of wettability alteration to less oil-wet. Were injected additional 27 PV of SSW, which means 429 ml. It is possible to see that the conductivity for this brine is lower than for FB, due to low salinity. However in the first moments of SSW injection conductivity values were high because FB is flowing out of the core. In this case, the DP is more stable than comparing with formation brine DP. After the oil production stopped, the flow rate was switched to 1 ml/hr, to keep the core in stand-by. During this time, no extra oil was produced, however the outlet was clean, and the oil trapped went out, due to this action is possible to observe oil production at 1 ml/hr. During the injection of both brines the high pressure burette was used. The oil produced was kept in the upper part and the oil volume was measured daily.

After the oil production by SSW injection was stopped, SSW diluted 10 times was injected to study if the injection of a brine with low salinity can give extra oil production, compared to previous brine. Similar to previous brines, the first flow rate was 3 ml/hr and then 12 ml/hr. The SSW 1/10 injection did not show any extra oil production, which means that this salinity was not capable to change the core wettability to less oil-wet. Were injected additional 32 PV of SSW 1/10, which means 561 ml. It is possible to see that the conductivity for this brine is lower than for SSW, due to lower salinity. However in the first moments of SSW 1/10 injection conductivity values were high because SSW and FB are flowing out of the core. The DP is stable and lower than for SSW. After the oil production stopped, the flow rate was switched to 1 ml/hr, to keep the core in stand-by until next injection.

The last injection was SSW 1/25, first at 3 ml/hr and then 12 ml/hr, with the objective to examine if this brine with low salinity, 1.7 g/L, can produce extra oil compared to the previous brines. With the SSW 1/25 injection no extra oil was produced, which means that this brine was not capable to change the core wettability to less oil-wet. Were injected additional 26.6 PV of SSW 1/25, which means 423 ml.

It is possible to see that the conductivity for this brine is lower than for SSW 1/10, due to lower salinity, however in the first moments of SSW 1/25 injection conductivity values were high because previous brines are flowing out of the core. The DP is stable and lower than for SSW 1/10. After the oil production stopped, the flow rate was

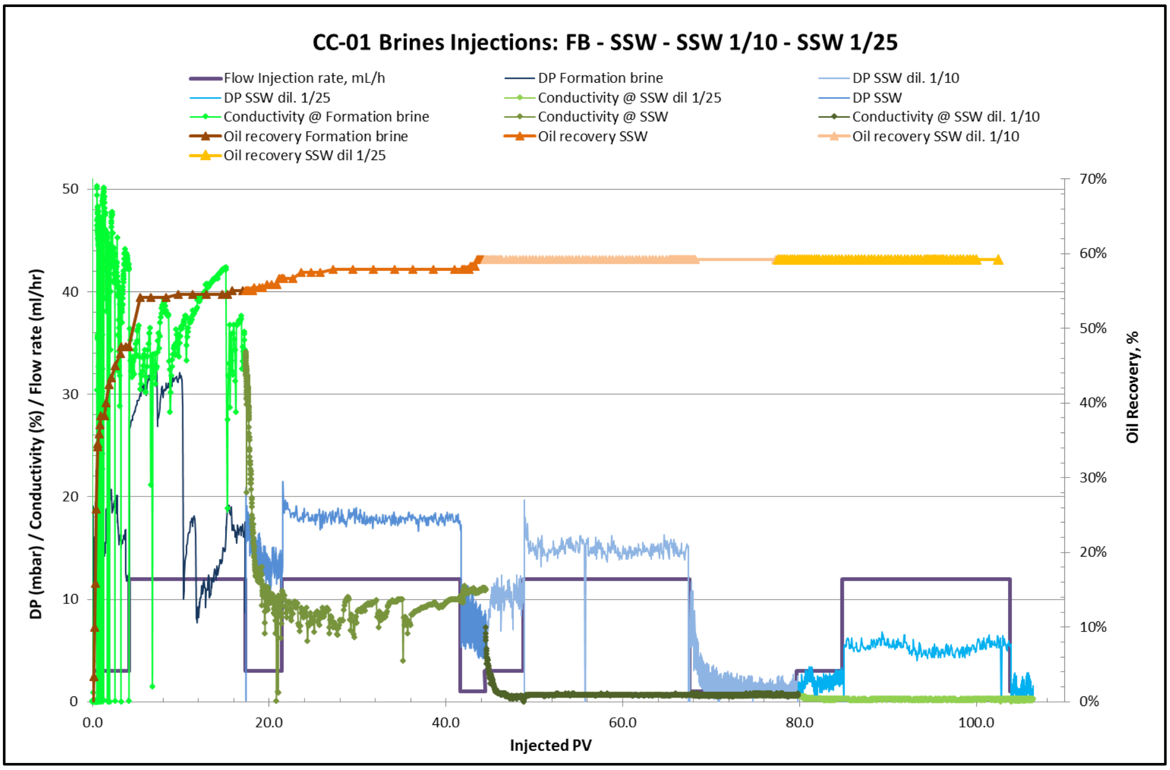

Figure 3 - Brines injection results for core number 1

switched to 1 ml/hr, to keep the core in stand-by until next step.
During the injection of both brines the sample collector was used, and the fluids produced were kept in test tubes. In this case just water was produced, however this water was kept to future analyses.

Thus, during the experiment were injected 106.26 PV, which means 1689 ml of different brines, leading to the production of 7.1 ml of oil, 59.17 % of the original oil in place (12 ml).

In the end of injections, the water kept in the test tubes was submitted to analyses, that allow a better understanding of what happens inside the core. The effluent ionic composition, calcium, magnesium, potassium, chloride, sodium and Sulphur was analysed.

In Fig. 4 it is possible to see the values of calcium (Ca^{2+}) in the effluent, as well as the level of calcium in both initial solutions, SSW 1/10 and SSW 1/25. Each dot in the plot corresponds to a sample analysed. No samples were analysed between 65 PV and 77 PV, because during this period of time the flow rate was 1 ml/hr.

Analysing the results of calcium (Ca^{2+}) composition it is possible to see that the effluent values were above the level of initial solution. This may indicate the core dissolution or previous brines production. At the first moments it is possible to see high concentration of this ion, due to production of FB and SSW trapped inside the core and pushed by new brines. The rock dissolution can happen due to the lower calcium concentration present in the injected brine, which causes dissolution of the calcium

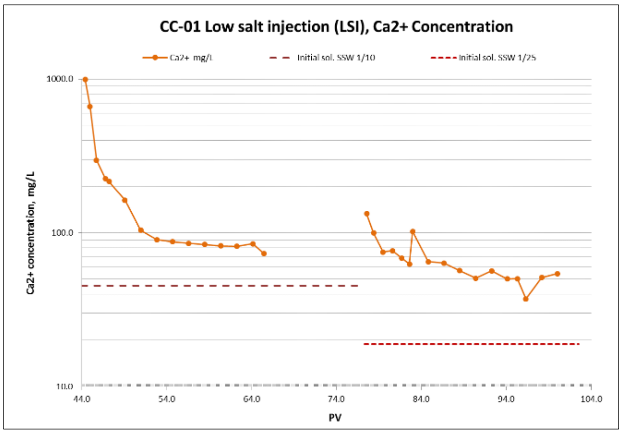

Figure 4 - Results of analyses performed to the effluent to measure the Calcium concentration

carbonate from the rock and establishes equilibrium with the brine.

CC-02

The second core flooding experiment was performed over core number 2. In this case, the pore volume is 16.9 ml and *Swi* is 0.231. Oil saturation value is given subtracting the *Swi* to 1, this way *So* is 0.769, The volume of water in the core is 3.9 ml and the volume of oil 13 ml, given by equation 3.

In this core three different brines were injected:
• First injection: FB
• Second injection: SSW
• Third injection: SSW mod

In Fig. 5 are presented the oil recovery results for each brine, the conductivity and DP results also for each brine and the flow rate.

Formation brine was first injected at 3 ml/hr and then when the oil production was stable increased to 12 ml/hr, and in the end of production decreased to 1 ml/hr, to keep the core in stand-by until next injection. This first injection produced around 45.38 % of the original oil in place. Were injected 23.04 PV of FB, which means 389.4 ml.

Later, the injection was switched to SSW at 3 ml/hr and after 12 ml/hr, this injection did not showed extra oil production. Were injected additional 25.44 PV of SSW, which means 430 ml. It is possible to see that the conductivity for this brine is lower than for FB, since in the first moments of SSW injection conductivity values were high because FB is flowing out of the core. After a long time injecting without oil production the flow rate was switched to 1 ml/hr, to keep the core in stand-by.

After SSW injection stopped, SSW modified was injected to study if the injection of a brine with same salinity, but different ionic composition can produce extra oil, compared to previous brine. Similar to the previous brines, the first flow rate was 3 ml/hr and then 12 ml/hr. The SSW mod injection showed extra 3 % oil production. However, the quantity was difficult to quantify, and to know the exact time and quantity produced. Thus, in Fig. 5 the line correspondent to SSW mod oil recovery is an approximation. This means that, this ionic composition was capable to change the core wettability to less oil-wet. Were injected additional around 47 PV of SSW mod, which means 794 ml. It is possible to see that the conductivity for this brine is in the same level than for SSW, once both brines have the same salinity, with TDS around 42 g/L. The DP was not stable, since it increase since the first flow rate, this can indicate core damaged, or obstruction. In a carbonate reservoir the rock surfaces have a positive charge while the acidic components of oil have a negative charge, causing the rock to be oil-wet or mixed-wet. If the active anions in the water, for example SO_4^{2-}, the rock surface than the acidic oil components, the anions are adsorbed and the oil is desorbed. This process explains the extra oil production with SSW mod.

Thus, during the experiment were injected 95.7 PV, which means around 1617 ml of different brines, leading to the production of 6.29 ml of oil, 48.38 % of the original oil in place (13 ml).

In the end of injections, similar to core number 1, the water kept in the test tubes was submitted to analyses. The composition of calcium, magnesium, potassium, chloride, sodium and sulphur were analysed for SSW injection and for SSW mod injection.

The results of calcium (Ca^{2+}) composition showed that the effluent values are below the level of initial solution, the opposite of what happened to core number 1. Which means that in this case did not happen core dissolution, possibly because the brine injected was not a low salinity brine with no need to establish equilibrium with calcium carbonate from the rock. This difference between calcium concentration can indicate that some calcium precipitate.

5. Conclusion

The main objective of the experiment was to modify the salinity and the ionic composition of sea water to improve the oil recovery in oil wet cores. To achieve this goal four cores were prepared to perform core flooding, however in this work just two core flooding experiments are described, due to time frame.

The conclusion about this study can be briefly summarized as:

• The oil recovery by formation brine injection was 55 % of OOIP for core number 1, CC-01. At the first flow rate, 3 ml/hr, 47.5 % of OOIP was produced.

• In core number 1 when injected SSW the oil recovery increased 4.2 %. At the first flow rate, 3 ml/hr, 1.67 % of OOIP was produced.

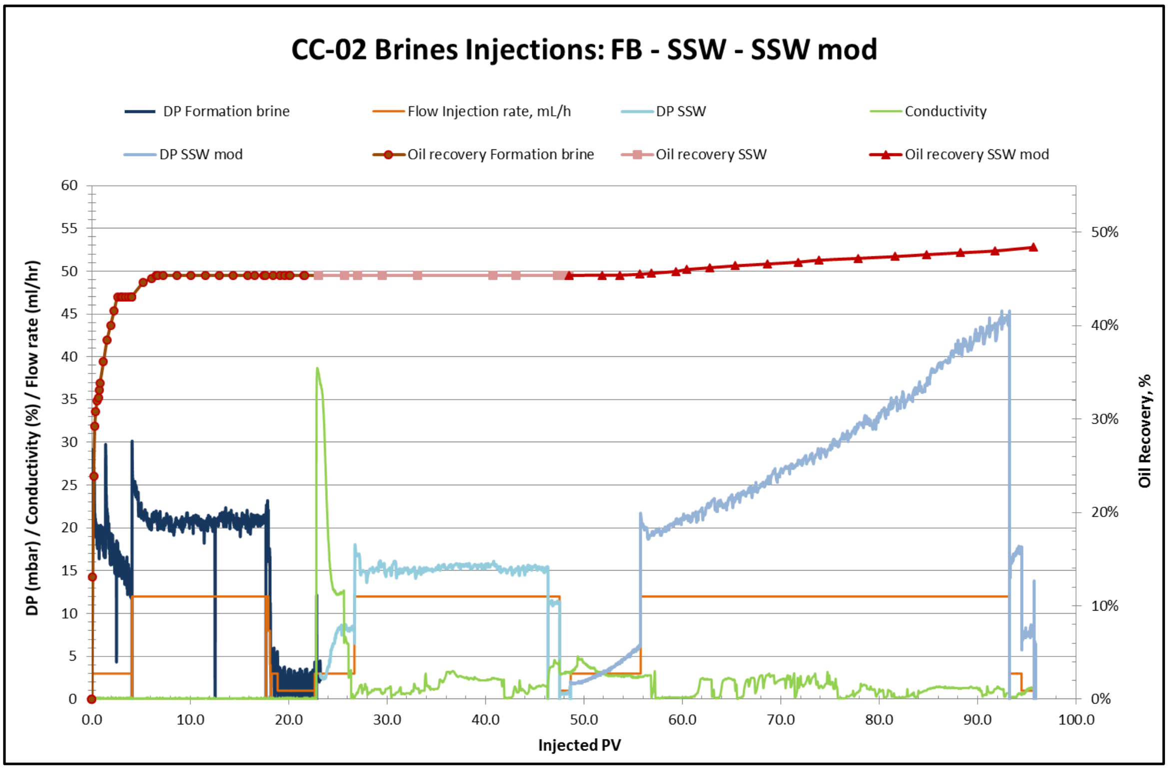

Figure 5 - Brines injection results for core number 2

• No increased oil recovery was observed when injecting SSW diluted 10 times and 25 times, in core number 1.
• The oil recovery by formation brine injection was 45.4 % of OOIP for core number 2, CC-02. At the first flow rate, 3 ml/hr, 43.1 % of OOIP was produced.
• No increased oil recovery was observed when injecting SSW in core number 2.
• In core number 2, when injecting SSW modified the oil recovery increased around 3%.
Despite the preparation of the cores was equal, the conditions were not equal. The 10% difference of oil recovery during FB injection may indicate that the core number 2 is more oil wet than core number 1, and is more difficult to produce oil.
It is important to emphasize that the injection of low salinity brine, SSW diluted, did not show favorable results, however the injection of SSW modified with more concentration of SO_4^{2-} showed favorable results. This means that not only the salinity is important, but also the ionic composition.

This four experiments are not enough to keep or discard a process, is important to perform more experiments with different brines, with different salinities and ionic composition.

5.1 Future Work

To improve the oil recovery it is suggested as future work to inject a surfactant, Surface Active Agent. A surfactant can be injected to lower the Interfacial tension (IFT) or capillary pressure that do not allow the oil to move through the core, and be produced. Oil recovery improvement occurs by reducing both IFT and capillary forces in the formation.

Surface active agents are usually organic compounds with a chemical structure that consists of two different molecular components, the hydrophilic group and the hydrophobic groups. A hydrophilic group is a water-soluble component, and a hydrophobic group is a water insoluble component. The soluble component, or hydrophilic group, is called the "head", and the hydrophobic group is called the "tail", as The head and tail surfactants attack the interface between two immiscible surfaces, thus decreasing the interfacial forces between the two surfaces.

Surfactants are frequently classified into four main categories, in accordance to the ionic nature of the head group, a surfactant can be anionic, cationic, nonionic or zwitterionic. Each type have certain characteristics depending on how the surfactant molecules ionize in aqueous solution.
When a surfactant is injected the hydrophilic head interacts with water molecules and the hydrophobic tail interacts with the residual oil. By this, the surfactant can form water-in-oil or oil-in-water emulsions.

Surfactant molecules are amphiphilic, once they have both hydrophilic and hydrophobic groups.
A surfactant can be sensitive to high temperature and high salinity, therefore surfactants that can resist to these conditions should be used.

Thus, in this experiment a surfactant may be injected to reduce the IFT, and try to improve the oil recovery, making the oil move inside the core. Given the reservoir conditions, this surfactant should be resistant to high temperature and high salinity and anionic.

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