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Experimental and theoretical investigation of low salinity water injection timing in high water cut sandstone reservoirs for enhanced oil recovery

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ABSTRACT

In this research, low salinity water flooding was used to investigate its low salinity effect in a high water cut sandstone reservoir to improve oil recovery. The application was done to five different sandstone cores in high water cut levels of 70%, 75%, 80%, 85% and 90% by injecting low salinity brines of 2000mg/L – 20,000mg/L NaCl concentrations. These Cores chosen for research had 27%-28% porosity and 280mD – 300 mD permeability. Different brine injection rates were considered from 0.5cm^3/s to 3cm^3/s in each experiment. The results showed that low salinity flooding can be used to harness more oil from high water cut reservoirs. However, water should be injected earlier to avoid porous particle dislodge by continuous flooding. Brines of 200mg/L-5,000mg/L NaCl yielded the highest Oil recovery compared to higher salinities of 10,000mg/L-20,000mg/L. This was partly due to increased jamin effect created as fluids flow at high water cut levels. Three water cut rising model levels were discussed for better timing to avoid porous particle detachment from the sandstone matrix. Early injection timing was discussed to be critical for low salinity injection to avoid the mentioned Particles phenomena and hence high water cut levels and low oil recovery.

1. Introduction

Due to global energy demand increase resulting from dwindling energy resources, maximizing oil recovery from previously exploited matured oil fields have become exceedingly crucial to meet the ever-increasing energy demand[1], [2]. Processes of oil recovery are majorly classified into three categories namely: primary, secondary and tertiary. However, the application of primary and secondary oil recovery techniques approximately leaves two-third of the original oil in place (OOIP) trapped in reservoirs. This is as a result of oil trapping by capillary forces or being bypassed during initial oil recoveries of primary and secondary production. To enhance the overall oil displacement efficiency, numerous enhanced oil recovery (EOR) methods have been devised and utilized. During oil recovery, the overall oil displacement efficiency is a combination of macroscopic (volumetric sweep) and microscopic (pore scale) displacement efficiency. Macroscopic displacement efficiency which is the measure of the effectiveness of injected fluids to contact with the oil zone with respect to the total reservoir volume well us microscopic displacement efficiency is related to the ability of the displacing fluid(s) to mobilize oil trapped at the pore scale when it contacts the oil[3].

Water flooding has been known for some time as an established essential practice in petroleum industry injected in the secondary mode to maintain reservoir pressure and produce some oil. It has been observed. However, the injection of low brine in tertiary mode increases oil recovery as compared to high salinity water injection [4]–[7]. Extensive laboratory studies have been done and more still in progress to understand this vital area of research which is regarded as a potential EOR method clearly. The low salinity water flooding (LSWF) has been tested in many oil reservoirs and showed promising results in agreement as a promising EOR technique[8]–[10]. Besides the earlier known water flooding which supplemented the in-built reservoir natural energy to expel crude oil to the production well, LSWF also interact with crude oil-brine-rock (COBR)

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system and create favorable conditions for oil recovery. This results in reduction in interfacial tension (IFT), reduction in viscosity, wettability alteration, oil swelling and favorable phase behavior change [11]–[13]. Wide range of suggestions have been put forward concerning the mechanisms of low salinity effect(LSE) which yields improved oil recovery[14]–[17], with a wide range of research findings and many suggested mechanism(s). This has been attributed to the complexity of crude oil brine (COBR) system interactions that do vary with rock type heterogeneities and crude oil composition[8], [18], [19]. Scholars however, generally accept wettability alteration as the cause of increased oil recovery in both sandstone and carbonate reservoirs. Besides this, other mechanisms causing LSE have been suggested as attributed to increase in the ionic double layer between the clay and oil interfaces, which facilitate the release of crude oil from the pores, fines migration, PH effect, Multicomponent Ionic Exchange (MIE), and Osmosis [8], [20], [21].

1.1 Effects of long-term flooding on reservoir matrix pore structure

Wen et al [22], studied flooded core samples with same high porosity and permeability, results showed that fractal dimension of pore structure gradually decreases as the water cut increases, [22] the micro heterogeneities in reservoirs after long term water flooding was seen with pore structure change resulting in water cut increase as shown in Fig.1 below. This is caused by long-term water flooding and washing of the microparticles in a reservoir and widening the pore spaces leading to water cut increase from 60% to 90%. The decomposed clay mineral fragment got scattered and migrated resulting into evenly distributed fluid with smooth crystal grain surfaces thus making throats more open to fluids flow[23]. This same scenario can be witnessed when LSF is done in a high water cut zone where fluid -rock interactions occur.

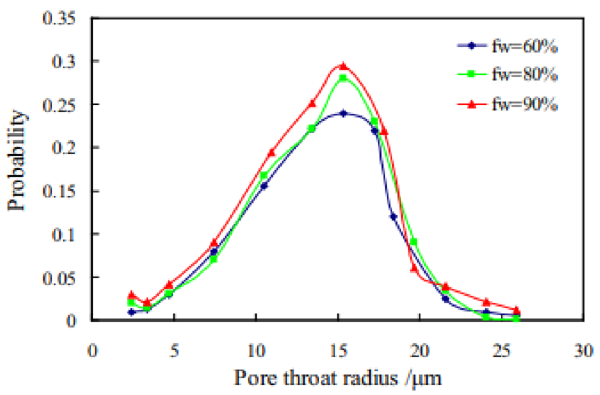


Figure 1. Relation between probability distribution of pore throat radius of core and water cut values[22]

1.2 Structure influence on fluids displacement in porous media

The fluids percolations in porous formations depend on the interpore sizes. The larger the average pore radius, the higher the oil displacement efficiency. The pore structure of rocks are changed greatly before and after water flood which closely correlate to the mineral compositions and occurrence[24]. This is described with Kozeny equation and relates the average pore radius has a significant correlation to permeability and porosity[25].

$$K = \frac{10^{15}\phi r^2}{8\tau^2}$$

Where ϕ ;Porosity, r; Radius, K; Permeability and τ ; Tortuosity.

From this equation, the fluids withdrawal efficiency has a good correlation to the oil displacement efficiency under the same wettability and fluid properties. This paper highlights how pore sizes influence fluids displacement in the reservoir rock. The oil displacement efficiency has been found to have a linear relationship with porosity and permeability by the equation below [25].

$$E_D = a\log\sqrt{8K/\phi} + b$$

Where E_D: Oil displacement efficiency, K; Permeability, ϕ ;Porosity, a and b Constants.

1.3 Contribution of reservoir fines in high water cut zones

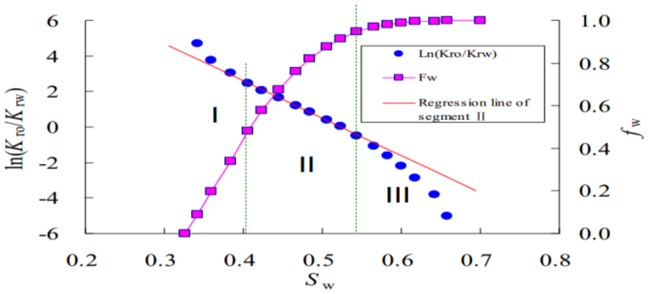
Clay particles have been generally suggested to play a key role in reservoir chemistry for creating a medium of attachment between the rock surface and the reservoir fluids. In reservoir rocks both sandstone and carbonate, a film layer is created resulting in electrostatic creation of charges both on the rock surface and on the intermediate ions in fluids. Both brine and polar compounds in crude oil [3], [26], [27]. Hydration of clay particles occur whenever clay is in contact with fresh water resulting to clay swelling issues. The low salinity water in sandstone rocks cause clay hydration and swelling unlike at high salt concentrations. This causes fines migration when the ionic strength of injected brine is less than a critical flocculation concentration which depend on the concentration of divalent cations[28]. The clay and silt dispersion flow along with water in the reservoir pores, which depend on the permeability of the reservoir[29]. While in fine pores, they cause blockage, allow fluids to accumulate, and trace an alternative pore while mobilizing oil in the reservoir[13], [30]. Therefore, this phenomenon allows water to be forced into low permeability zones and flow along with oil in the same path resulting in increased sweep efficiency and high oil recovery[31].

1.4 Application of Low salinity brine in High water-cut level in mature oil reservoirs

As a result of field development in China and over the world, many oil fields have entered high water-cut stage which still contains large quantities of lucrative oil. Other oil fields are just about to enter this stage[32]. This remaining oil need to be extracted with a cheap and yet reliable technique. Furthermore, the application time is crucial in timing fluids flow before extra high water cut with dislodged pore crystals. Despite the great news of applying low salinity water flooding for improved oil recovery, there is need to time extra high early water production as this interferes with crude oil connectivity within the pores and also timing helps to create brine - rock interaction before crystal smoothening occurs. The objective of this work is to properly investigate the application of low salinity flooding effect in high water zone and the factors causing high water cut breakthrough. Loahardjo et al[33], carried out a number of waterflooding experiments on different types of cores, confirmed that sequential waterflooding, reduces residual oil saturation significantly from one flood to the next. Wen et al [22],conducted several waterflooding experiments with long cores taken from the production wells at ultrahigh water-cut period average water-cut 91.6% in the Shuanghe oilfield and found out that with the increase of flooding degree, the overall porosity and permeability of the reservoir became higher and the wettability changed to be more hydrophilic[34]**.** Though wettability alteration was achieved, there was no observable reduction in water cut suggesting that highest water breakthrough had been achieved and optimum time is needed to be investigated for low salinity injection.

1.5 A graph of water cut -relative permeability against water saturation characteristics curve.

The plot of logarithmic relative permeability against water saturation provides a decreasing trend as water saturation increases as well as water cut. These curves can be placed in three analytical stage regions of different water cut levels which are:



Based on the rock matrix behavior on long term exposure of water flooding, **Figure 2.** Curves of oil and water relative permeability with three water-cut zones[34].

The time for brine injection should be done before stage III. This serves as a guiding principle as shown in Fig.2 below.

$$\ln \frac{K_{rw}}{K_{ro}} = \alpha - \beta S_w$$

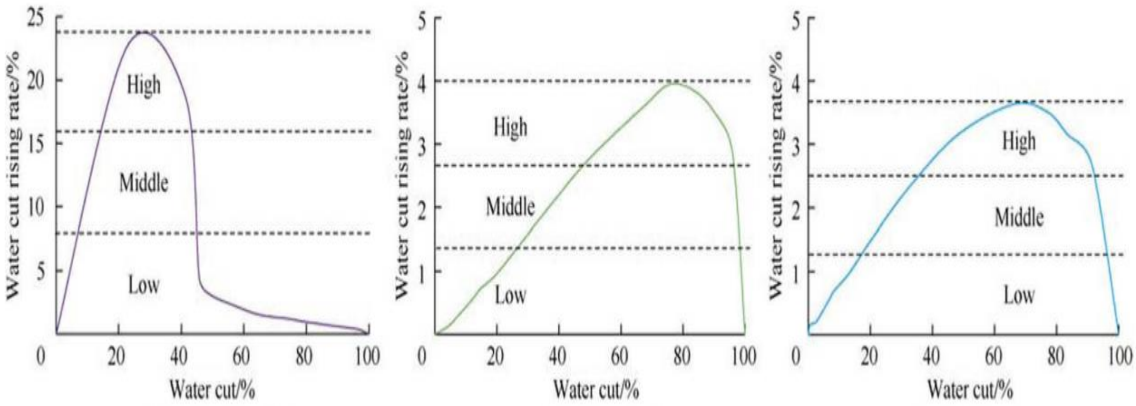
Alternatively shown as:

$$\frac{K_{rw}}{K_{ro}} = ne^{-mS_w}$$

Where K_{ro} is the oil relative permeability, K_{rw} is the water relative permeability, S_w is the water saturation at the outlet α, β are the slope, and the intercept, respectively; m and n are Kro/Krw and the constant of S_w at the outlet, respectively. The above equations have been analyzed by different scholars for new water drive curves for better interpretations on water cut prediction and delay in a given water reservoir [34], [35]. In 2017 Wen et al. showed that oilfields in ultra-high water cut stage, showed down warping trends and transformed from II linear relationship to III nonlinear relationship. These water drive curves show the up-warping trend showing that as water saturation increases, oil in the formation changes to partially continuous phase and non-continuous phase, causing the stronger Jamin effect with substantial reduction in oil permeability and increment of water permeability thus resulting in the down warping curve[34]. This is therefore not a good stage to apply low salinity water flooding, as this would not reverse the stronger jamin effect already caused. As a rule of thumb, low salinity injection should be applied before this step.

1.6 Low salinity water injection timing high before high water-cut production

The relationship between water production in high water cut reservoirs and oil recovery before water breakthrough time can be predicted. Yuan et al. in 2018[36] suggested injection



(a) Sub convex **(b) Sub concave** **(c) Sub S shape**

Figure 3. Optimized water injection timing to avoid high water cut ranges [36]

of water to producer relationship and proposed production intensity adjustment before water breakthrough to postpone the time.

Though in oil production, Water production cannot completely be eradicated, high water cut rising rates and excessive rapid water production is not desirable. Therefore, low salinity water injection should be done early to provide a fine migration control mechanism and control water cut before entering the stage of middle and higher water cut rising rate**.**

1.7 Model low salinity brine injection timing

This water injection paradigm illustrates the behavior curve of a reservoir whose characteristics are highly heterogeneous, the application criteria is highly unique from one reservoir to another. The fractal geometry theory and 3D pore network model play a significant role in quantitative characterization of microheterogeneity of reservoirs[37]–[39]. The relationship between water cut and water cut rising rate of three typical producers models namely: sub-convexity, sub-concave and sub-S illustrate the best timing of low salinity water injection percentwise to be done per water cut ranges. From 7%–15% for sub-convexity type, water cut between 28%–48% for sub-concave type, and water cut between 18%–36% for sub-S type. Which is different for each oilfield having their characteristic water cut curve and thus their oil production performance will be different. Therefore, careful study on when to inject tertiary water flooding in crucial since reservoirs are unique in physical properties, crude oil properties and show different dynamic characteristics [37], [40]–[42].

2. Results and Discussion

From Fig. 3 shown below, Generally the lowest brine concentration showed better recovery in all the five high water cut categories though with the overall low oil recovery. Various oil recovery curves at different water cut levels have been compared, the low sodium chloride concentrations were injected to determine its effect on oil recovery in different water cut percentages in synthetic sandstone cores. The maximum oil recovery was from 70% and 75% water cut levels with 2,000mg/l – 15, 000mg/L Na^+ concentration having the highest oil recovery range. While injected brine of 20,000mg/l yielded the least oil recovery of 33. 38% and 33.02% in the water cut levels shown in Fig. 3 and Fig.4. For 80% water cut, the oil recovery for both 2, 000mg/l and 5,000mg/l was 57.95% and 57.8% respectively. While for 85% and 90 water cut levels had both high and low oil recoveries for concentrations of 2000mg/l to 20,000mg/l.

2.1 Explanation for the trend

The low salinity brine application in high water cut reservoir studies provide an insight into fluid flow in micro pores, exposure time and its effects on the crystal surface. The crystals in sandstone cores get appreciable significant changes as fluids flow. Besides these mentioned conditions, the oil recovery was the highest in salinity ranges of 2,000-5,000mg/L. However, the highest recovery peaks in the five high water cut zones investigated ranges from 45% to 60%. This suggests a different explanation beyond brine concentrations.

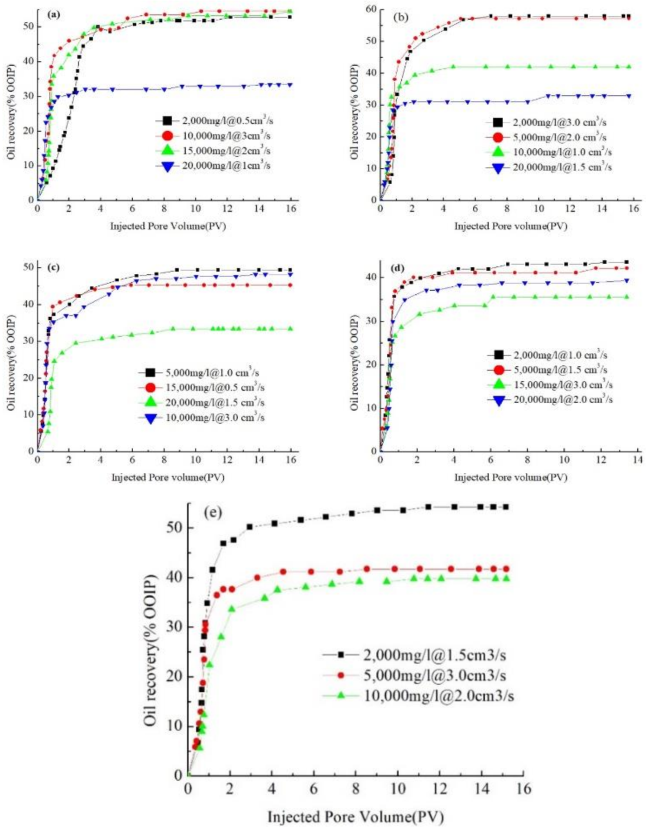


Figure 4. Graphic representation of oil recovery against pore volume injected at different water cut levels: (a) at 70%, (b) 75%, (c) 80% (d) 85% and (e) 90%.

The fines and clay removal by the long-time exposure of the flowing fluids in the pores could have contributed to the opening of the pore throats and creating an easy breakthrough for the brine flow in a short time. The removal of clay from rock pores was found to have an effect on oil recovery[13], [43], [44]. LSWF in the clay-coated porous media with swelling clay led to pore-plugging, which causes two phenomena: (1) oil trapping; (2) sectional sweeping and a sharp rise in the interstitial velocity in some of the pore-paths and finally full washing of the pore-paths[45]. Thus, improvement in oil recovery can be attributed to early brine injection for better timing before this happens. clay migration block also pore throats resulting in decrease in permeability, increase in pressure change and oil mobilization for residual oil recover [46], [47]. Na^+ ions also helped in detaching the charged clay particles from rock surfaces and higher-pressure drop occurrence with the monovalent ion injection which happen in some sections of the core[48]. This is because the monovalent cations such as Na^+ always lead to repulsive electrostatic contribution to the total disjoining pressure and hence to near-zero contact angles [12], [49]. Furthermore, general decrease in oil recovery above 80% water cut is attributed to stronger jamin effect attained in the fluids flow mode[34], the pores of the core are water wet and occupy tinny pores trapping oil in big pores and making it more permeable to water[24]. Application of low salinity in such a zone could not reverse the already attained flow paradigm. The extension of the electrical double layer concept resulted in ionic double layer conductivity in the reservoir rock, which depended on the sodium chloride ions in the electrolyte as well as concentration. The negatively charged clay porous rock structure of an oil reservoir containing connate water, created an electrical double layer around it whose thickness depended entirely on the sodium ion concentration. However, high-salinity brine contained more ions which make the double layer more compact, but with injection of low-salinity water, the double layer tends to expand bring about the differences in recovery curves in Fig. 3 above whose oil recovery trends increase with decrease in salinity.

2.2 The effect of variation of sodium chloride salinity on overall oil recovery

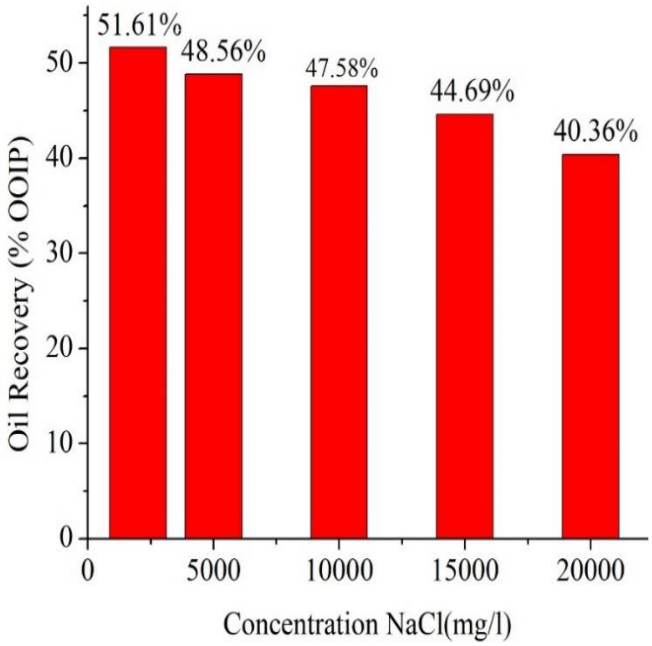


Figure 5. Histogram representation of average oil recovery Concentration of NaCl mg/l

It can be seen from the Fig. 4 that different degrees of salinity have a very large impact on the final recovery factor. In this study, as the degree of salinity decreases, the final recovery factor increases compared with the recovery factor of 20,000 mg/L, the recovery factor of 2000 mg/L is increased by 11.25%. The change in wettability of rocks from oil-wet to water-wet is considered to be the main mechanism for low-salinity water flooding to increase oil recovery. Related to this is electrical double layer (EDL) at the oil-brine and the brine-rock interface, and EDL interaction energy is one of the major contributions to the interfacial tension. The interface of solid and oil will be charged when in contact with water, due to the ionization and dissociation of surface groups on solid or oil surface or due to adsorption of ions from the solution. The net charge on the surface will attract ions of the opposite polarity in the solution, forming another layer close to the surface equally but opposite to the charge to balance the charged surface layer. Furthermore, the charge distribution will be altered and the total free energy will be changed, leading to a pressure between the oil-brine and the brine-rock interface. The rock and the oil surfaces both are usually negatively charged in brine thus a repulsive force presents due to EDLs overlapping and resulting in increased oil recovery[27].

2.3 Oil recovery trend with increase in water cut percentage

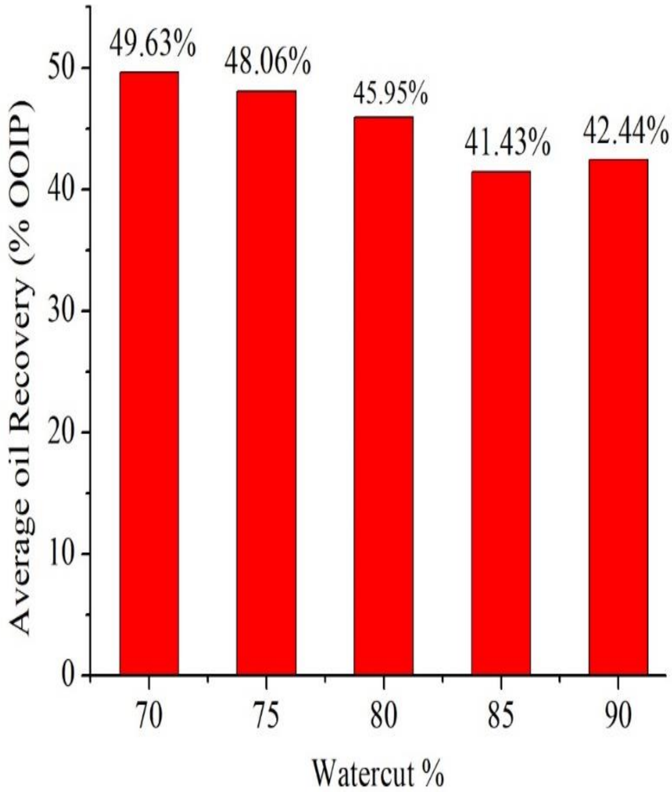


Figure 6. Graphical representation of oil recovery against water cut time zone during low salinity injection

From Fig. 5 above, generally oil recovery decreases with increase in water cut. The earlier low-salinity water injection would give better results of improved oil recovery before high water breakthrough which leaves behind trapped oil ganglia. The average recovery factor of 70% water cut into low salinity water is 7.19 % different from the average recovery factor of 90% water cut into low salinity water. From the slopping trend of oil recovery from left to right, it suggests that earlier water cut values would give higher oil recoveries. Low ionic strength of NaCl solutions resulted in a stronger negative charge of the brine/oil interface compared to high ionic strength which would be more effective in oil removal when low salinity is injected earlier[27].

water flooding conditions, the oil displacement efficiency may be also different as seen with the obtained results.

2.4 Explanation for decrease oil recovery despite increase in wettability at water cut levels

Generally, the factors which affect oil displacement efficiency include reservoir heterogeneity wettability, micro-pore structure, PV of injected water, injection rate, and oil water viscosity ratio. However, under the same Therefore, the oil displacement efficiency at the high water cut stage levels get changed, because the pore structure characteristics of the original reservoir get changed significantly as the mineral particles get washed and migrated at very high-water levels and clay film falls off after long-term water injection[25]. The results are porosity and permeability are changed this will have a negative impact on oil recovery by having a shorter breakthrough.

2.5 The influence of water injection rate on recovery factor

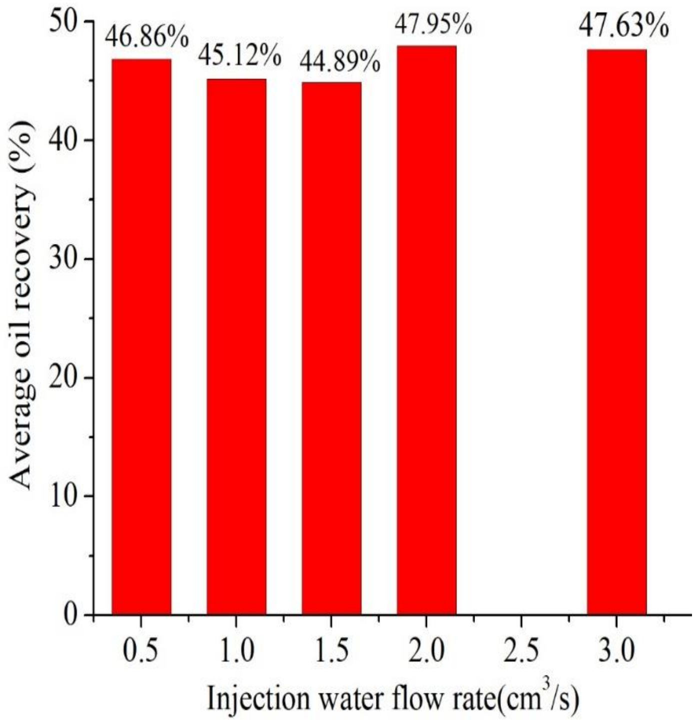


Figure 7. Graphical representation of average oil recovery against fluid injection rate for the entire flooding process

Fig. 6 shows the variation of average percentage oil recovery against brine injection rate is almost the same. The increase in the injected rate causes an improvement of recovery factor, due pressure maintenance in the reservoir. Nevertheless, the recovery factor of these five zones show slightly different profiles in improving oil recovery, with increasing oil recovery of 46.86% for 0.5cm3/s and 47.63% for 3.0cm3/s. It must be emphasized that with the increase in injected brine flow rate, water production consequently increased, which is a negative aspect of the water injection method since the water produced raises the cost of producing for treatment and disposal. When the low salinity brine is injected in already high water cut state reservoirs, it flows through the established paths created by crystal dislodge resulting in no effect on oil recovery.

3. Experimental

3.1 Materials

Materials used in this experiment include synthetic sandstone cores, crude oil sample M-01, synthetic formation water, and LSW of different salinities. The Oil used for the experiment has the composition and physical properties shown in Table 1. The low salinity water used for the experiment is of the following concentrations: 2,000, 5,000, 10,000, 15,000, 20,000 mg/L. The compositions of this low salinity water is listed in Tables 3. Formation water used initial flooding is 21,692mg/L in Table 2.

Table 1. Components and physical properties of crude oil

Crude Oil sample	M-01	
Components/wt%	Saturated hydrocarbon	36.12
	Aromatic hydrocarbon	31.13
	Resins	22.42
	Asphaltene	10.33
Viscosity/mPa s @ 60°C	Reservoir	22,500

Table 2. Composition of Formation water (mg/L)

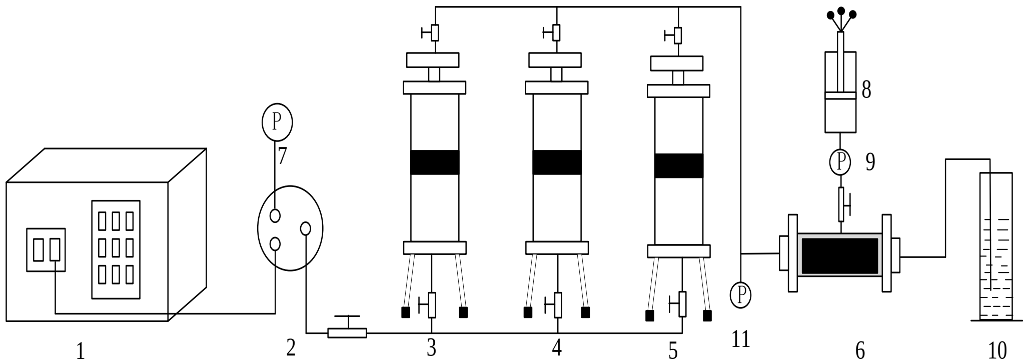
Na^++K^+	Ca2+	Mg^{2+}	Cl^-	Salinity
7,144	403.6	45.9	11,525	21,692

Table 3. Composition of (mg/L) used in low salinity water injection

No	Na^+	K^+	Mg^{2+}	Cl^-	Salinity
1	2,000	200	200	2,200	4,800
2	5,000	500	500	5,500	12,000
3	10,000	1,000	1,000	11,000	24,000
4	15,000	1,500	1,500	16,500	36,000
5	20,000	2,000	2,000	22,000	48,000

3.2 Experimental setup:

The LSW flooding equipment used is shown in Figure 4. It consists of a water injection pump, core holder, and fluid cylinder. The fluid injection pump can maintain a constant flow rate for the injection of various fluids in sequence with pressure data being monitored.



1- Pump, 2- six-way valve, 3- crude oil vessel, 4- low salinity water vessel, 5- Formation water vessel

2- 6-core holder, 7,9,11-pressure sensor, 8-hand pump, 10-Cylinder gauge

Figure 8. Flow chart of water flooding experiment

The experiment procedure

The sandstone cores saturation with formation water:

1. The cores were put in a vessel and a vacuum pump used to extract air from them until negative pressure is obtained.
2. These emptied cores were then connected to the formation water for complete saturation followed by crude oil saturation and kept for three days to mature in crude oil.
3. Cores were singly selected and formation water was pumped (connect valve 1 and Valve 5) to displace crude oil from matured core until a required water cut percentage was reached while recording exiting fluids, time and pressure variation.
4. Low salinity water flooding was performed (connect valve 1 to valve 4) to continue with the flooding and displace further crude oil and water from the core. The recording was continued from the interchange until no more oil flows to at least 10PV.
5. The procedures 3 and 4 were repeated with a new water cut value.

The design scheme in table below was adopted in the study and three factors were investigated: injection rate, brine salinity and water cut percentage.

Table 4. Low salinity injection arrangement scheme

Parameters	1	2	3	4	5
Water-cut (%)	70	75	80	85	90
Salinity(mg/L)	2000	5000	10000	15000	20000
Injection rate (cm3/s)	0.5	1.5	3	2	1

Table 5. Porosity and permeability of selected sandstone cores for experiment

Core number	Length/cm	Porosity /%	Permeability K/mD
3-B	5.135	27.1818	280.13845
1-2	5.585	27.6906	281.21903
2-2	5.727	25.7208	285.18013
4-III	5.544	31.227	285.18013
4-4	5.487	29.3777	307.34945
9	5.023	29.8424	272.62050

4. Conclusion

(1) Low salinity water flooding generally improves oil recovery but knowledge of the reservoir properties, fluids and type of brine to apply needs to be understood.

(2) Low salinity water flooding generally improves oil recovery but knowledge of the reservoir properties, fluids and type of brine to apply needs to be understood.

(3) Proper timing before application of low salinity water flooding should be done to avoid a late ultra-high water cut zone with dislodged crystal particles and also understanding the reservoir fluids flow characteristics which are necessary since reservoirs are very heterogeneous.

(4) Several recovery mechanisms have been proposed by various researchers with no consensus existing as to which mechanisms are dominant in improving oil recovery during low-salinity water injection. Prior to any field-scale application, extensive laboratory

studies need to be conducted on the representative rocks and fluid samples to investigate the potential of LSW to increase oil recovery.

(5) The low salinity injection application field can be synergistically used with other EOR processes such as alkaline/surfactant/polymer flooding with the potential for greater incremental recoveries.

Acknowledgements

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