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Influence of Crude Oil Components on Recovery by High and Low Salinity Waterflooding

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ABSTRACT: This study presents an investigation on the effects of various polar components of a crude oil on its recovery by high and low salinity waterflooding and correspondingly on some of the suggested mechanisms in the literature. Coreflooding experiments were performed on several Berea core plugs aged in four different variants of the same crude oil with relative amounts of acids, bases, and asphaltenes. The oils labeled as acid-free, base-free, asphaltenes-free (deasphalted), and original or normal crude oil were expected to initiate varying wetting conditions during aging. The results of high salinity waterflood showed that the plug aged with base-free oil provided the highest whereas that with acid-free oil provided the lowest final oil recoveries. A reduction in residual oil saturation (S_{orw}) by 1.4% to 2.9% PV for normal, base-free, and asphaltene-free crude oils after low salinity waterflooding (LSW) in tertiary recovery mode was observed. For the case of acid-free crude oil, the S_{orw} was reduced marginally. A 2−3-fold increase in differential pressure was observed during injection of low salinity brines. The effluent brine pH was also increased by 1 pH unit during LSW. The observations from the present work indicate that different oil components initiate varying wetting conditions and that the initial wetting conditions influence the performance of a tertiary low salinity flood. In particular, a low salinity flood seems favorable when the initial wetting conditions are not water−wet.

■ INTRODUCTION

Laboratory investigations and a few field observations conducted over the past few years reveal that injecting brine with low salinity improves oil recovery significantly. Literature so far has shown mixed results for LSW as a tertiary recovery process. The actual incremental recoveries measured indicated large variations on different reservoir cores and outcrops. Bernard[1] first provided an evidence of improved oil recovery along with increased pressure by injecting fresh water as compared to conventional high salinity waterflooding. Recent laboratory studies[2−5] also reported improved oil recovery with decreased brine salinity. Few field trials also reported improved recovery by LSW.[6−8] However, recently reported laboratory and field pilot results in a North Sea field showed poor response to the injection of low salinity brine.[9]

Based on experimental observations, researchers have proposed various phenomena/mechanisms to explain the cause of increased oil recovery by low salinity water injection. Tang and Morrow[10] proposed a mechanism of fines migration during LSW. They proposed that mixed−wet clay particles get detached from the pore walls during injection of low salinity brines. This results into release of associated oil droplets and increases the oil recovery along with production of fines. Lager et al.[11] proposed a mechanism of cation exchange between mineral surfaces and invading brine as the primary mechanism for improved oil recovery during LSW. They also concluded that pH induced interfacial tension (IFT) reduction[7] or emulsification and fines migration may not always occur in LSW. The theory of electrical double layer (EDL) expansion during LSW has also been argued by Berg et al.[12] and Ligthelm et al.[13] and supported by Lee et al.[14] Recently, Austad et al.[15] suggested a chemical mechanism related to a local increase in pH by LSW, while Skrettingland et al.[9] suggested that initial wetting conditions are important and attributed the poor response of LSW in the Snorre field to the near optimal wetting conditions for waterflooding.

There is, however, no consensus on a particular dominant mechanism although it has been shown that injection of low saline water may result in a wettability alteration toward a more water-wet behavior.[13] It is also widely accepted that the presence of clay minerals and crude oil containing polar components in the reservoir are important to observe benefits of LSW.[15,16] However, the effect of the presence of various crude oil components such as acids, bases, and asphaltenes on incremental oil recovery by LSW is not yet well understood. Recent work by Sandengen et al.[17] has shown core flooding results whereby the injection of low saline water was interpreted as yielding more oil-wetting conditions. They also reviewed the ion exchange mechanisms suggested by Lager et al.[11] to explain that injection of low salinity brines can alter wettability in both directions: either more oil-wetting or more water-wetting, depending on the oil and rock properties.

The adsorption of polar components can alter the initial water−wetness.[18−23] The wettability of reservoir rocks plays a vital role in deciding the performance of waterflooding and other EOR processes. It has been reported that the presence of small amount of asphaltenes in the crude oil can change the wettability of originally water−wet surfaces.[24,25] However, Skauge et al.[26] showed that the acidic and basic components also play a major role for wettability alteration. Researchers

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Table 1. Physical Properties and Initial Conditions of Core Plugs with Respective Type of Crude Oil

plug	length (cm)	diameter (cm)	PV (mL)	porosity (%)	K_{brine} (mD)	S_{wi} (% PV)	oil type
A	9.82	3.75	15.1	13.9	15.9	20.4	original (NCO)
B	9.81	3.80	16.7	15.0	17.2	19.5	ashphaltene-free (AsFO)
C	9.81	3.77	15.3	13.9	16.8	22.7	base-free (BFO)
D	9.80	3.79	16.3	14.8	16.5	18.6	acid-free (AFO)

have also studied the implications of acid/base content on wettability alteration of different surfaces.[18,24,26,27] Denekas et al.[18] selectively removed the acidic and basic compounds from the crude oil and found that the wettability of sandstone was altered by both the acidic and basic components of the crude oil. Somasundaran[28] noted that the quartz surfaces are more sensitive to the basic components in the crude oil. Crude oil with high acid numbers resulted in more water–wet surfaces, while higher base numbers gave more oil–wet behavior.[24,26,27] Tweheyo et al.[29] showed alteration of wetting behavior for sandstone core plugs from two oil fields in the North Sea when acids and bases were added to a mineral oil.

Recently, Ashraf et al.[4] investigated the effect of adding acidic and basic components in n-decane on the rock wettability and performance of LSW on Berea core plugs. They found that the addition of o-toluic acid and hexadecylamine in n-decane resulted in neutral–wet and oil–wet conditions, respectively. The coreflooding results also showed that the neutral–wet cores provided the highest whereas oil–wet cores provided the lowest oil recoveries by high and low salinity waterflooding. Farooq[30] measured interfacial tensions (IFTs) for acid-free, base-free, and asphaltene free oils under high and low salinity environments and found that the base-free and acid-free oils provided lower and higher IFTs, respectively. He also investigated the wettability alteration of the quartz surfaces by adsorption of crude oils of high and low total acid number (TAN). He found that for the surface adsorbed with high TAN crude oil, the high salinity brine did not alter the wettability. However, the low salinity brine altered the wettability of the surface from neutral–wet to water–wet. For the case of low TAN crude oil, the high salinity brine altered the wettability from neutral–wet to water–wet. No further wettability alteration was observed by low salinity brine.

The present work is an extension of the work by Ashraf et al.[4] Different reservoirs contain crude oils of widely varying TANs, TBNs, and asphaltene content, and hence they exhibit different interactions between the fluids and the rock minerals. In the present study, a crude oil of high TAN and reasonably high TBN has been selected, and then the acids, bases, and asphaltenes were selectively removed to investigate the effects of their absence on oil recoveries with injection of high and low salinity waterflooding and, where possible, be used to further verify on some of the suggested recovery mechanisms. In particular, the work was interested in finding out whether the various oil components initiate different wettabilities and if the various initial wetting conditions are important in enhancing a tertiary low salinity waterflood. The findings would be discussed based on classic wettability theory especially with reference to adsorption and oil production before and after water breakthrough.

■ EXPERIMENTAL

The experimental work involved core and fluid preparations, determining the basic parameters, and core flooding.

Core Material and Preparation. Four Berea sandstone core plugs were cut from a sandstone block and designated as A, B, C, and D. The plugs were first cleaned with methanol and dried in a heating oven at 60 °C for three days when there was no further change in the weights. The saturation porosities and brine permeabilities were then measured. Irreducible water saturation (S_{wi}) was established first by porous plate followed by crude oil injection to achieve homogeneous saturation distribution. Lastly, the plugs were aged at 80 °C in the respective oils for three weeks and then mounted into the flooding rig. The core properties and oil used in each experiment are listed in Table 1.

Mineralogy. The mineralogy was characterized by X-ray diffraction (XRD) analysis which was carried out on a small sample taken from the block. The XRD results for the whole rock are given Table 2. It was then assumed that the obtained mineralogy is representative for all the core plugs. It can be observed that the Berea block contains kaolinite as the main clay mineral and some dolomite.

Table 2. XRD Analysis of the Representative Core Samples (% Mass)

mineral	quartz	K–feldspar	albite	kaolinite	dolomite
% mass	80.0	6.0	6.5	6.5	1.0

Table 3. Composition of Connate and Injection Brines

ion	connate brine (mol/m^3)	HS (mol/m^3)	LS1 (mol/m^3)	LS2 (mol/m^3)
Na^+	642.0	598.9	65.3	15.2
Ca^{2+}	3.0			
Mg^{2+}	137.7			
K^+	7.7			
Ba^{2+}	0.5			
Sr^{2+}	0.4			
Cl^-	654.9	598.9	65.3	15.2
total	1446.2	1197.8	130.6	30.4
TDS[a] (ppm)	38522	35000	3813	890
pH @ 21 °C/80 °C	8.71/7.48	8.61/7.39	7.28/6.58	6.97/6.63
viscosity[b] (mPa·s)	1.037	1.033	1.000	0.985
density[b] (g/cm^3)	1.050	1.046	1.023	1.022

[a]Total dissolved solids. [b]Measured at room temperature.

Brines. The composition and properties of the connate and injection brines are listed in Table 3. The connate brine used to establish the initial water saturation is typical formation water and contains both divalent and monovalent ions. This was intended to avoid any compromises related to wettability arising from formation of organometallic complexes or binding on the mineral surface. However, the injection brine contains only NaCl in both high and low concentrations viz., HS (35000 ppm of total dissolved solids (TDS)), LS1 (3813 ppm TDS), and LS2 (890 ppm TDS). All the brines were filtered with 0.45 μm filter papers before use.

Oils. Four different variants of a stock tank crude oil were used as the displaced phase. The crude oil was made "free" from its acid, basic, and asphaltene components using the extraction procedure reported by Farooq.[30] The oils are designated as NCO, AsFO, BFO, and AFO to represent normal crude oil, asphaltene-free (deasphalted), base-free, and acid-free oils, respectively. These components were not completely extracted, but the amounts were significantly reduced when compared with the original crude oil. Then the TAN and total base number (TBN) were measured according to ASTM standards[31,32] for NCO. Due to limited quantity of other three oil types, either TAN or TBN were measured, and the other parameter was assumed to be the same as that of NCO. The TAN and TBN of AsFO were assumed to be the same as that of NCO. The oil properties are listed in Table 4. For AFO in particular, the TAN was reduced significantly from 2.680 to 0.398 after extraction, and hence the TAN and TBN are comparable. As expected, the viscosity of AsFO was measured to be much lower than the rest of the oil types because of the absence of heavier components. The asphaltene content in NCO was 0.66 ± 0.1 (wt%),[30] while BFO showed the highest viscosity.

Table 4. TAN and TBN for Original and Fractionated Crude Oils

oil type	TAN	TBN	TAN/TBN ratio	viscosity @22 °C/80 °C (mPa·s)	density @22 °C (g/cm^3)
NCO	2.680	0.746	3.59	22.3/5.03	0.86
AsFO	2.680	0.746	3.59	5.16/1.89	
BFO	2.680	0.062	43.23	36.5/5.73	
AFO	0.398	0.746	0.53	21.4/4.00	

Coreflooding. The flooding experiments were performed horizontally in a standard core flooding rig at 80 °C and 20 bar, while a back pressure of 10 bar was maintained to avoid gas liberation at high temperature. Figure 1 shows a schematic drawing of the apparatus for the coreflooding experiments. A positive displacement pump (Quizix pump from Chandler Engineering, USA) displaces fluid (brine or oil) from reservoirs to the core plug inside a Hassler core holder. A flooding rate of 9 *ml/h* was chosen in order to approximate typical reservoir velocities. A differential pressure transmitter was connected to the inlet and outlet ends of the core holder to measure the pressure drop across the core during fluid injection. The data from the differential pressure transmitter were continuously logged into the computer. The waterflooding followed sequential injection of HS as the high salinity brine, LS1 as the first low salinity brine, and last LS2 as the second low salinity brine. The pH was monitored with an inline pH meter at the outlet.

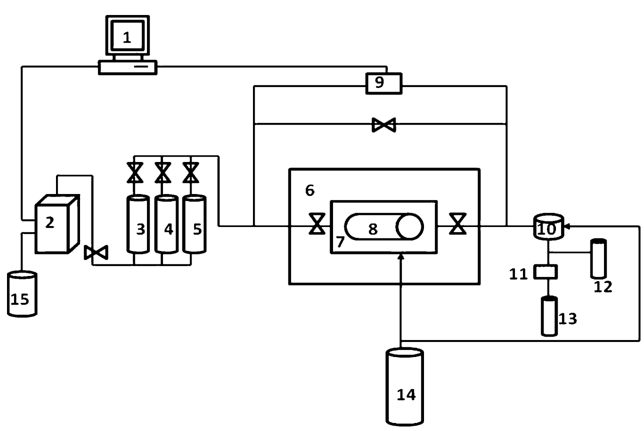

Figure 1. Schematic of apparatus for coreflooding experiments: 1. computer, 2. Quizix pump, 3−5. brine cylinders, 6. heating cabinet, 7. Hassler core holder, 8. core plug, 9. differential pressure transmitter, 10. back pressure regulator, 11. pH meter, 12. effluent collector, 13. effluent collector, 14. high pressure nitrogen cylinder, 15. pump inlet.

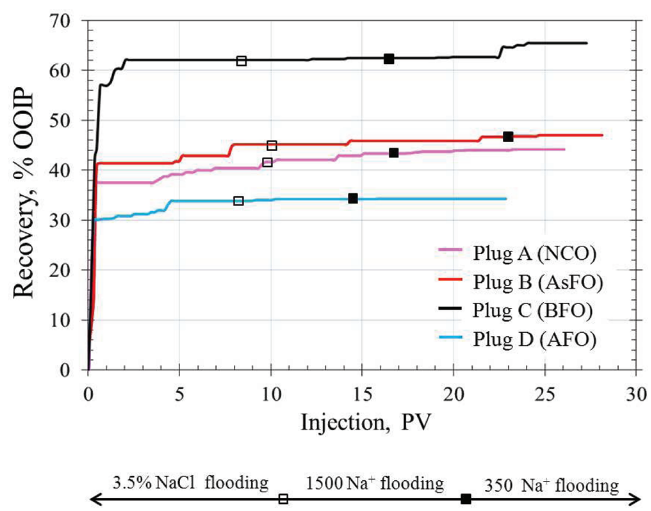

Figure 2. Comparison of oil recoveries for plugs A to D with high and low salinity brines. □ mark indicates the end of the HS injection and the start of the LS1 injection; ■ mark indicates the end of the LS1 injection and the start of the LS2 injection.

■ RESULTS AND DISCUSSION

The core flooding results showing oil recovery, water-cut, pH of effluent brine, and differential pressure are given in Table 5 and in Figures 2−5. Since no separate wettability measurements were done on the plugs, basic classic wettability theory will be used in the discussions to qualify the wetting behavior of the plugs. The four plugs behaved differently during waterflooding, indicating direct influence of oil components on wettability, fines migration, and eventual oil recovery by high and low salinity brines.

The plugs aged in NCO showed the earliest water breakthrough (BT) and a tail-end production during injection of HS brine (Figure 2). Additional 23% OOIP was recovered after breakthrough (ABT), somewhat indicating typical of oil-wet or intermediate-wet behavior. The subsequent recovery from the two low salinity brines was highest at 4% OOIP. The scattering in the pressure data is most likely due to blocking and bursting of pore throats by internal fines migration especially during LS injection (Figure 3). In certain cases, the process can contribute to incremental oil production by stripping the oil-wet clays and/or by water diversion mechanism.

The plug aged in BFO showed similar behavior to the plug aged in NCO but with relatively shorter tail production whereby additional 20% OOIP was produced after breakthrough. The corresponding recovery from the low salinity brines was also close at 3.5% OOIP. Most of the LSW recovery in the NCO-aged plug was from LS1, while that in the BFO-aged plug was from LS2. Some fines were observed at the oil−water interface of the effluent from the BFO-aged plug, while no such fines were observed in the effluent from the NCO-aged plug, although that does not rule out internal fines movement.

Except BFO which was significantly deprived of its basic components, the presence of acids and asphaltenes in both BFO and NCO appeared to have resulted in oil-wet behavior in

Table 5. Summary of Coreflooding Experiments

					recovery (% OOIP)			S_{orw} (% PV)			
plug	oil type	S_{wi} (% PV)	BT[a] recovery (% OOIP)	BT[a] PV	HS	LS1	LS2	HS	LS1	LS2	total recovery (% OOIP)
A	NCO	20.4	26.7	0.25	40.4	2.9	0.8	47.4	46.8	44.5	44.1
B	AsFO	19.5	41.0	0.38	45.2	1.5	0.2	44.1	43.9	42.7	46.9
C	BFO	22.7	42.6	0.36	62.1	0.4	3.0	29.3	27.0	26.7	65.5
D	AFO	18.6	30.1	0.29	33.8	0.1	0.4	53.9	53.6	53.5	34.3

[a]Breakthrough.

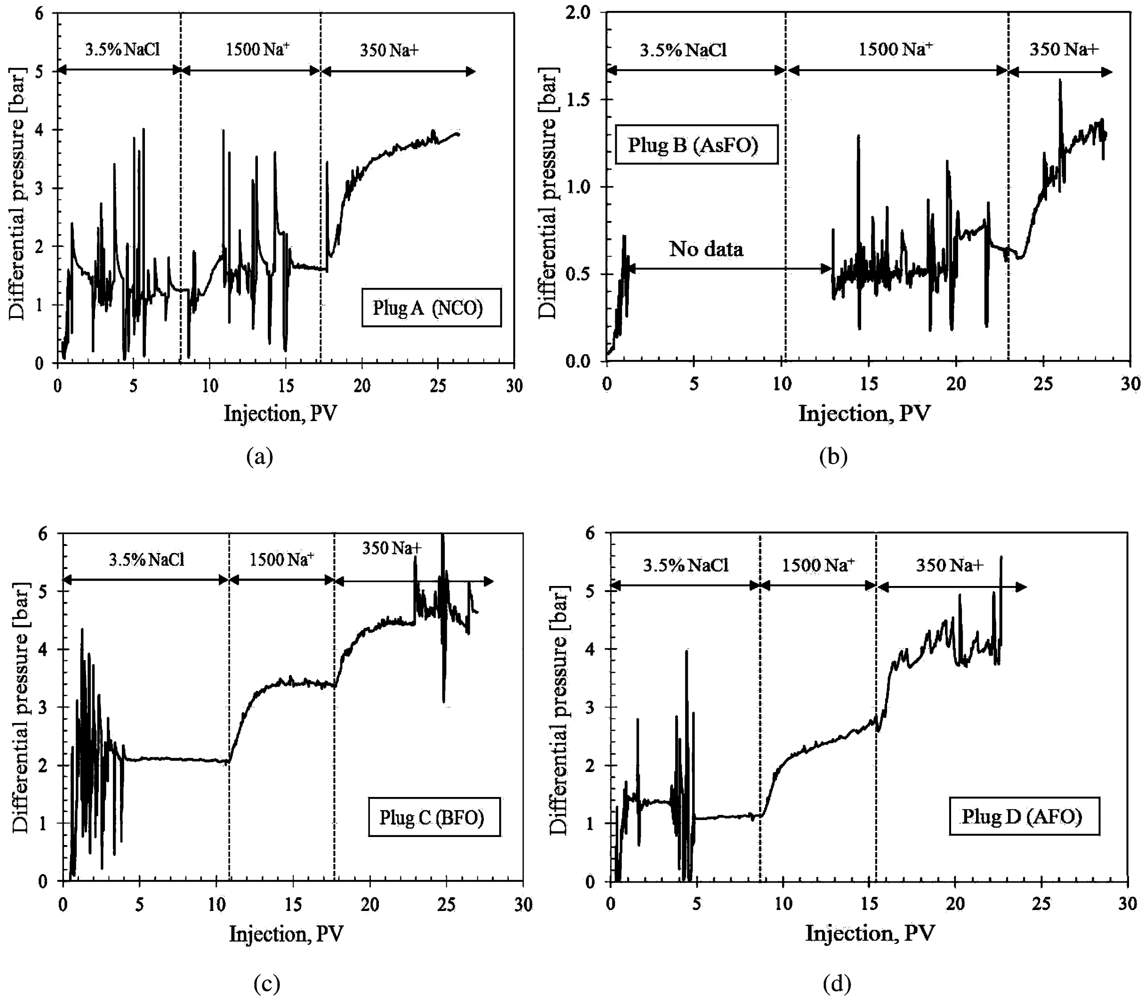

Figure 3. Differential pressure profiles for (a) plug A saturated with normal crude oil, (b) plug B saturated with asphaltene-free oil, (c) plug C saturated with base-free oil, and (d) D saturated with acid-free oil and coreflooded with sequential injection HS, LS1, and LS2 brines.

the two plugs. This is possible by an ion-binding mechanism within pH limitations. It is therefore likely that wettability alteration away from oil-wetness due to migration of the oil-wet fine particles contributed to further incremental oil by low salinity, at least in the BFO-aged plug. Also, the ultimate recovery was highest in the BFO-aged plug which had the highest TAN/TBN ratio. Core flooding was most efficient in the BFO-aged experiment, and the optimal recovery is typical of neutral (or intermediate) wetting behavior. Tweheyo et al.[29] and Ashraf et al.[4] showed that when an acidic additive (o-toluic acid) was added to n-decane with no basic components, the resulting wettability on reservoir and Berea sandstone plugs was typically intermediate. Jadhunandan and Morrow[33] proposed that the optimal recovery was because the trapping forces are minimal at intermediate wet conditions in both reservoir and Berea sandstones. The explanation is that the acidic additive generates a negatively charged oil–water interface, and since the rock surface was considered negatively charged, no wettability alteration was expected due to the developed electrostatic repulsive forces. However, the BFO was not completely deprived of the basic components besides still containing a lot of asphaltenes and acids.

The plugs aged in oils deprived of asphaltenes (AsFO) and acidic components (AFO) showed similar behavior toward oil recovery after breakthrough. The rather insignificant oil production by HS after breakthrough is typical of water-wet behavior, particularly so with the oil deprived of the asphaltenes (AsFO) which showed more delayed water breakthrough. The AsFO-aged plug still contained both basic and acidic components, but it has been shown that asphaltenes play an important role in establishing oil-wet character.[20] Hence strong oil-wet behavior was not expected in the AsFO-aged plug, and the rather mild response from LSW could be a result of limited internal fines migration rather than wettability alteration. The differential pressure was lowest in this experiment during injection of LS probably due to limited internal fines migration (Figure 3b). In addition, AsFO had lower viscosity due to the absence of the heavier components, a fact that contributed to reduced differential pressure. The pressure data during HS injection was lost due to logging problems.

The plug aged in the oil deprived of the acidic components (AFO) showed similar water-wet behavior to the AsFO-aged plug in terms of oil recovered after breakthrough, but no additional oil was recovered by the LS brines. Addition of an organic additive (hexadecylamine) to n-decane resulted in an oil-wet character of reservoir sandstone samples.[29] The plug had a TAN/TBN ratio of less than unity, and the overall recovery was the lowest. Neither does the pressure variation in Figure 3(d) indicate rigorous internal fines migration during LSW. The oil is relatively basic, and it is likely to get even more strongly adsorbed on the rock surface especially clays at low saline environments. Injecting LS brine in such a system could therefore alter the wettability toward more oil-wet and effectively stop any further oil production. Sandegen et al.[17] showed through experimental evidence and a cation exchange model that injecting LS brine in an apparent water-wet plug containing basic oil can shift the wettability to oil-wetness. They further illustrated that oil production can cease if the LS brine is introduced in the early stages of flooding. The shift to oil-wetness was attributed to both the type of oil and the mineralogy.

Rigorous fines migration was not expected under HS flooding, yet the pressure fluctuations resemble those under LS flooding. This could indicate possible loosening of fine particles within the porous medium even at a high concentration of monovalent NaCl solution brine. Furthermore, during LS1 injection, significant pressure fluctuations associated with internal fines movements were observed only in plugs containing both acidic and basic components (NCO and AsFO) but not in the base- or acid-free oils (Figure 3(a),(b)). In both NCO- and AsFO-aged plugs, internal fines migration was initiated at relatively higher salinity (LS1), which was a more efficient EOR brine than LS2. There is minimal indication of fine particle migration during the LS2 flood, and one explanation could be that all particles likely to be moved did so during the LS1 flood.

On the other hand, there was no pressure scattering or additional oil recovery in the BFO- and AFO-aged samples by the LS1 flood (Figure 3(c)(d)). Instead, the pressure data indicate that internal fines migration was initiated at a much lower salinity (LS2), and in the case of the BFO-plug, LS2 was more efficient than LS1. The AFO-aged plug did not indicate pressure variations by LS1 and only minor variations by LS2 (Figure 3(d). The subsequent LSW recovery was similarly negligible. Injection of such low salinity brines may not be practical in reality.

It is claimed that the type of crude oil, as characterized by the acid and base numbers, does not affect the oil recovery by lowsal injection.[11,14] The observations from this work seem to support this claim as long as the base/acid interactions remain undisturbed, which was the case for NCO and AsFO. Processes which may deprive the original crude oil of acidic or basic components appear to impact negatively on the LS performance. This is because of limited fines production or the migrating fine particles are not oil-wet. However, how the type of crude oil influences LSW EOR requires further investigation, whereby the oil is better characterized than basing conclusions on the acid and base numbers.

Wettability of the reservoir rock is highly dependent on the crude oil/brine/rock (COBR) interactions. Buckley and Liu[21] suggested that polar interactions, surface precipitations, acid/base interactions, and ion−binding are the main mechanisms of interactions. They pointed out that acid/base interactions are the most important when a water film is present between rock mineral and the crude oil. McLean and Kilpatrick[34] showed that acidic components in crude oils have the greatest tendency to accumulate at interfaces. Oil with a high base number and low acid number should have ample positively charged interfacial sites to enable strong interactions between oil components and the negatively charged rock surface, especially when pH is low.[21] Zheng and Powers[35] hypothesized that protonation of the basic functional groups lead to a positively charged NAPL (nonaqueous phase liquid)−water interface, thus resulting in an electrostatic attraction to the mineral−water interface. The presence of clay minerals is considered important in the performance in low salinity EOR. While the majority of studies on fluid-rock interactions in the literature used high salinity brines, different oil components and clay types preferentially interact when the brine chemistry is changed. Hedges and Hare,[36] Wang and Lee,[37] and Greenland et al.[38] studied the adsorption of amino acids and aliphatic amines on clays (kaolinite, smectite, and Illite) at high and low salinity conditions at discrete pH values. They observed that the basic (positively charged) amino acids and amines were strongly adsorbed onto the clay minerals in fresh water than in high salinity environments such as seawater. Hedges and Hare[36] further showed that in salt-free aqueous solutions, only kaolinite slightly adsorbed the acidic (negatively charged) amino acids but not neutral (uncharged) amino acids.

In the present work, the rock contained about 6.5 wt % kaolinite as the dominant clay, hence oil-wet behavior was expected after aging at low pH conditions. However, the rock also contains the same amount of albite ($NaAlSi_3O_8$) as kaolinite. Albite belongs to the plagioclase feldspar group and is a typical example of anionic polysilicates which can give an alkaline solution of 7.5 to 9.5. The increase in pH due to albite-brine interaction can be expressed in eq 1

$$NaAlSi_3O_8 + H_2O \rightarrow HAlSi_3O_8 + OH^- + Na^+ \tag{1}$$

The pH of the connate brine was slightly above 7 (Table 3), which means more adsorption of polar components onto clay or strong oil-wet behavior. In such a situation, significant low salinity effect due to wettability alteration is expected and has been observed in related studies by Reinholdtsen et al.[39] It is therefore the reason we suggest in this work that the incremental oil observed from the LS flooding is mainly due to internal fines migration as manifested from the differential pressure data.

Figure 3 signifies that low salinity waterflooding may result in a decrease in the absolute permeability of reservoir significantly. In the present investigation, the absolute permeabilities have been reduced considerably by injection of low salinity brines. However, it may be possible to have a critical salinity of injection brine above which a decrease in permeability may not be that significant.

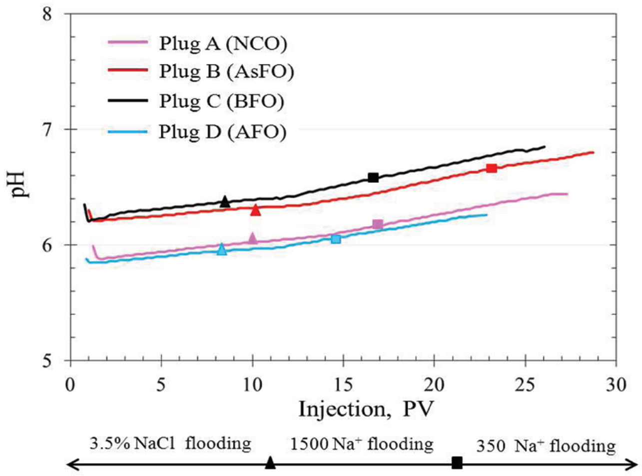

Figure 4. Comparison of effluent pH profiles for plugs A to D with sequential injection of HS, LS1, and LS2 brines. Filled triangles (▲) indicate the end of HS and the start of LS1 injection; filled squares (■) indicate the end of LS1 and the start of LS2 injection.

Figure 4 shows the pH of effluent brines where the pH increased during low salinity waterflooding for all the experiments although the overall increase was less than 1 pH unit. The mineralogy given in Table 2 shows 1 wt % dolomite. It is therefore likely that an increase in pH was due to dissolution of dolomite during low salinity flooding. It should be noted, however, that in the absence of a buffering system like CO2 buffering of the injected brines, an increase in the pH during experiments performed at low pressure conditions could be a potential artifact. Hence care must be given when analyzing core flooding results performed without buffering systems. This is not a problem in oil field reservoirs because, usually, CO2 controls the pH, but probably more important in this work is the fact that the rock contained albite, 6.5 wt %, which gives an alkaline solution even in the presence of CO2 buffering.[39] Another explanation for the increase in the pH could be due to desorption of cations from the clays by low salinity water according to eq 2. Oil bound on the clays through ion-binding mechanism could be manifested as increased oil produced by low salinity water as these ions are desorbed

$$Clay - Ca^{2+} + H_2O = Clay - H^+ + Ca^{2+} + OH^- \quad (2)$$

Lowering the salinity is not expected to reduce the interfacial tension (IFT) by more than 1 order of magnitude. However, altering the oil composition can, depending on the pH. Farooq[30] measured the oil−brine IFT using similar oils used in this study and found that the oils which had the acids extracted generally had lower IFT. The IFT varied with the brine pH. Still, the variation was within 1 order of magnitude. It is therefore unlikely that IFT plays a major role in the mechanisms of low salinity water.

Figure 5 shows watercut profiles during coreflooding experiments. It can be observed that watercut reached to about 1 after water breakthrough during injection of HS brine. Subsequent injection of low salinity brines (LS1 and LS2) reduced the watercut slightly for all the plugs except plug D. This finally provided 2−4% OOIP of additional oil recovery.

Figure 6 shows a comparison of breakthrough (BT), after breakthrough (ABT) by high salinity and additional oil recovery by LSW. 1.4% to 2.9% PV of reduction in S_{orw} was observed for normal, base-free, and asphaltene-free crude oils

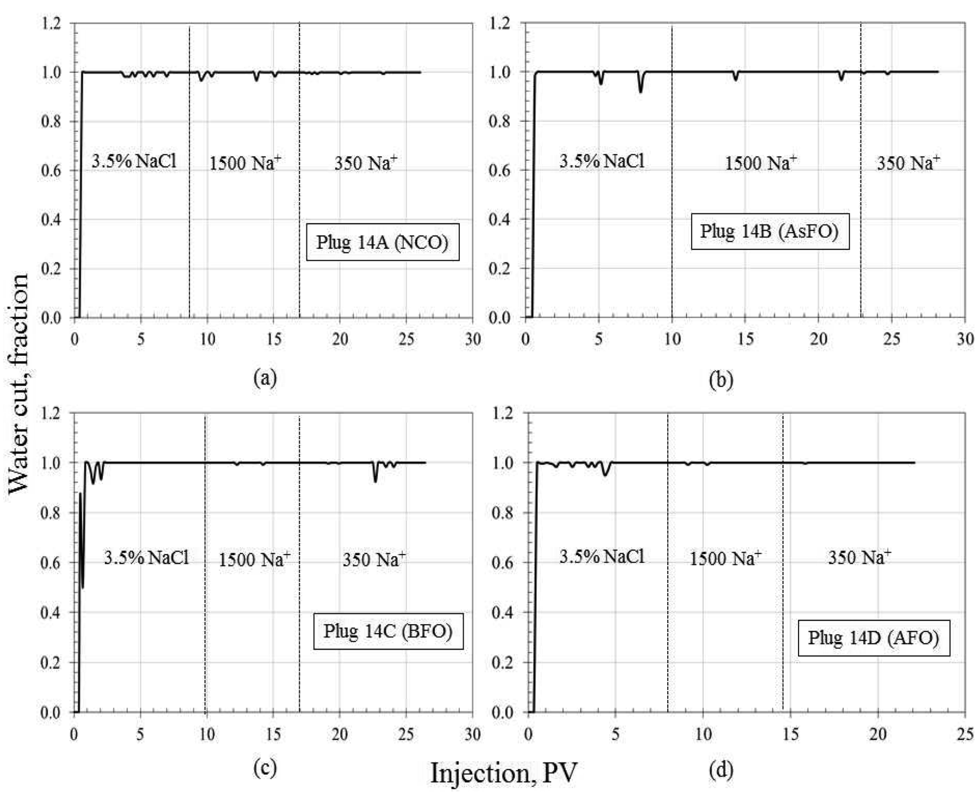

Figure 5. Watercut profiles for plugs for (a) plug A saturated with normal crude oil, (b) plug B saturated with asphaltene-free oil, (c) plug C saturated with base-free oil, and (d) D saturated with acid-free oil and coreflooded with sequential injection of HS, LS1, and LS2 brines.

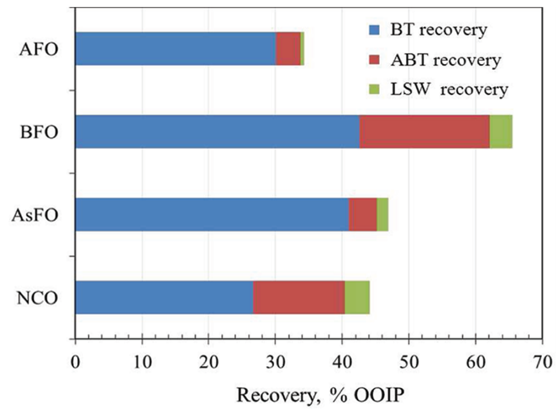

Figure 6. Comparison of oil recoveries after sequential injection of high salinity and low salinity brines. BT: breakthrough; ABT: after breakthrough.

by LSW in tertiary injection mode. For the case of acid-free crude oil, the S_{or} was reduced marginally.

■ CONCLUSIONS

An experimental study has been carried out to study the influence of relative amounts of crude oil components on wetting behavior, fines migration, and subsequent oil recovery by flooding with high and low salinity brine in Berea sandstone. The production behavior during the high salinity flooding indicated that the different oil variants established different wetting conditions. The oils where aphaltenes and acidic components were extracted showed typical water-wet character. The oil with reduced basic components showed oil-wet or intermediate-wet properties, similar to the original crude oil. Incremental oil recovered by low salinity was associated with both the initial wetting conditions and internal migration of fine particles. Two trends in fines migration were observed: a) release of the particles in systems with similar acid/base interactions, i.e. the same TAN/TBN ratio occurred at a relatively higher salinity (LS1), and b) release of the particles needed much lower salinity (LS2) in systems where crude oil was deprived of acidic or basic components. Generally, however, the presence of acidic components (higher TAN/TBN ratio) seem to provide a more favorable environment for low salinity tertiary flooding.

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Notes

The authors declare no competing financial interest.

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