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Capillary desaturation curve: does low salinity surfactant flooding significantly reduce the residual oil saturation?

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Abstract

Different oil displacement experiments conducted on sandstone and carbonate samples show that low salinity water (LSW) injection can reduce the residual oil saturation (ROS). Recently, surfactant flooding (SF) in combination with low salinity water (known as low salinity surfactant (LSS) flooding) is proposed as a potentially promising hybrid enhanced oil recovery (EOR) process. A lower ROS is reported for a LSS process compared to that seen in SF or with LSW at the same capillary number. The capillary desaturation curve (CDC) is a well-known tool to study the effect of viscous and capillary forces on ROS for different EOR techniques. In this study, ROS data of various LSW, SF, and LSS flooding experiments at different capillary numbers are collected to develop a CDC to analyze the performance of the hybrid LSS method. This can help to analyze the effect of the hybrid method on an extra improvement in sweep efficiency and reduction in residual oil. A lower ROS is observed for LSS compared to LSW and SF in the same capillary number range. Our study shows different behaviors of the hybrid method at different ranges of capillary numbers. Three regions are identified based on the capillary number values. The difference in ROS is not significant in the first region (capillary number in the range of 10^{-7}–10^{-5}), which is not applicable in the presence of surfactant due to the low interfacial tension value. A significant reduction in ROS is observed in the second region (capillary number in the range of 10^{-5}–10^{-2}) for LSS compared to SF. This region is the most practical range for SF and LSS flooding. Hence, the application of LSS provides a noticeable benefit compared to normal EOR techniques. In the third region (capillary numbers greater than 10^{-2}), where the surfactant flooding is a better performer, the difference in ROS is negligible.

Keywords Capillary desaturation curve · Low salinity water flooding · Surfactant flooding · Residual oil saturation · Capillary number · Low salinity surfactant flooding

Abbreviations

CDC	Capillary desaturation curve
EOR	Enhanced oil recovery
IFT	Interfacial tension
LSS	Low salinity surfactant
LSW	Low salinity water
OOIP	Original oil in place
ROS	Residual oil saturation
SF	Surfactant flooding
Nc	Capillary number (dimensionless)
V	Darcy velocity (m/s)
μ	Dynamic viscosity (Pa.s)
σ	Interfacial tension between oil and water (N/m)
θ	Contact angle (degree

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Introduction

It is perceived that primary and secondary recovery mechanisms of oil recovery are incapable of fully draining the reservoir on account of domineering capillary forces or the deficient sweep efficiency of the injection fluid. This highlights the need for more effective and advanced approaches to move the remaining oil and increase drainage efficiency. As the most commonly employed secondary method of improved oil recovery (IOR), water flooding maintains the reservoir pressure and mobilizes the trapped oil.

In 1959, Martin examined the influence of injection brine composition, and the results displayed higher oil recovery because of salinity reduction, due to the migration of clay particles (Martin (1959)). The topic remained under-researched until 1967 when it was revived by Bernard's study, deploying laboratory investigations on Berea sandstone cores. The results highlighted the influence of salinity reduction on improving oil recovery (Bernard 1967). Consequently, a new line of research on active mechanisms during low salinity water (LSW) has flourished, considering fine migration (Fouladi et al. 2019; Tang and Morrow 1999), pH variation (Austad et al. 2010; McGuire et al. 2005; Morrow and Buckley 2011), multicomponent ion exchange (Al-Abri et al. 2019; Lager et al. 2008; Moradpour et al. 2020; Shabani and Zivar 2020), double-layer expansion (Mahani et al. 2015; Lee, et al. 2011), and water micro-dispersion (Darvish Sarvestani et al. 2019; Mahzari and Sohrabi 2015) as the most efficient mechanisms. These studies have been extensively performed at various scales such as molecular scale (Khosravi et al. 2020), pore level scale (Akai et al. 2020; Mirchi 2018), laboratory (Lager et al. 2008; Darvish Sarvestani et al. 2019), and field (Vledder et al. 2010) scales.

In spite of the beneficial impact of IOR methods regarding enhancing oil recovery, significant amount of original oil in place (OOIP) still remains unrecovered due to the low oil mobility and reservoir heterogeneity. Therefore, several enhanced oil recovery (EOR) techniques are applied to increase the microscopic/macroscopic oil sweep efficiency (Santoso et al. 2020). Chemical EOR techniques are among the most conventional ones as they are viable and cost-effective to be implemented in the fields (Druetta and Picchioni 2020). The chemicals are injected in various scenarios along with water and affect the interactions in CBR (carbohydrate, brine, rock) system favorably to increase the oil mobility and the displacement. Polymer, surfactant, alkali, foam, and nanofluids injections and different combinations of them are known as chemical EOR methods which improve oil recovery by lowering interfacial tension between oil and water, increasing the viscosity of the injected water, and modifying the rock wettability toward more water-wet status (Nwidee et al. 2016; Gbadamosi et al. 2019). Surfactants are amphiphilic (hydrophilic and hydrophobic simultaneously) agents that reduce the oil–water interfacial tension (IFT) and form water-in-oil or oil-in-water emulsions (Sheng 2015; Torrealba and Hoteit 2019). As a result, the trapped unrecovered oil is redistributed and mobilized leading to the incremental oil recovery of up to 30% OOIP (Massarweh and Abushaikha 2020). Surfactant injection is a widely used EOR method since there is a wide range of surfactant types each of which is suitable to use under desired criteria of water salinity, reservoir temperature, adsorption to reservoir rock, and operational costs.

Surfactant flooding (SF), as a chemical EOR method, is utilized to obtain higher levels of oil extraction by reducing the IFT and adjusting wettability, which leads to the movement of capillary trapped oil. The application of surfactants in EOR goes back to the 1920s, where laboratory investigations by Uren and Fahmy (1927) signaled increased oil recovery efficiency due to the injection of different solutions of water-soluble agents. A reduction in IFT was introduced as the main reason for the observed EOR (Uren and Fahmy 1927). After introducing the surfactant as an effective agent, further studies on multiphase flow phenomena during SF led to the recognition of the corresponding parameters, resulting in the optimization of the ultimate oil recovery factor (Glover et al. 1979; Healy et al. 1976; Hirasaki et al. 1983; Nelson and Pope 1978). In between, Fathi and Ramirez (1984) tried to determine the best injection strategy for a tertiary SF to maximize the amount of oil produced and minimize the surfactant cost by using the distributed parameter control theory. The results showed that the mentioned theory was able to optimize the SF operation for two different trends of IFT variation in the core scale (Fathi and Ramirez 1984). Schilling et al. (1995) studied the drainage-imbibition mechanisms that lead to mobilization of residual oil saturation (ROS) during tertiary SF in two homogeneous and heterogeneous glass micromodels. In the reported results, the values of ROS after SF were similar, but microscopic sweep and recovery efficiency were higher for the homogeneous model compared to the heterogeneous model. This was due to the fact that surfactant in the heterogeneous model finds the path with lower resistance resulting in early breakthrough and lower sweep efficiency (Schilling et al. 1995).

Abeysinghe et al. (2012a) studied oil recovery mechanisms using unsteady state and steady state SF on mixed-wet Brea core samples. A low ROS was observed due to the presence of the surfactant and its IFT reduction ability. The capillary desaturation curve (CDC) was used to interpret the results, where a slow decline in ROS was observed with capillary number increment. In addition, no plateau of ROS and no critical value for capillary number were reported by the researchers (Abeysinghe et al. 2012a). In another study by Abeysinghe et al. (2012b), 4 core samples were flooded by formation water followed by SF to study the ROS for two water- and mixed-wet states of wettability. The results showed a higher recovery factor during the SF flooding in the case of the mixed-wet wettability compared to the water-wet. It was also shown that the reduction of ROS in mixed-wet core samples depends on the values of the injected pore volumes (Abeysinghe et al. 2012b).

The efficiency of the surfactant can be influenced by the active ions in brine and its salinity. Decreasing the IFT using a surfactant agent is dependent upon various factors, including brine concentration. Accordingly, a mixture of surfactant and low salinity water flooding was deployed as a new hybrid method for EOR known as low salinity surfactant (LSS) flooding (Pourafshary and Moradpour 2019). The main idea of a LSS process is to alter the wettability of the porous media and simultaneously reduce the IFT between the water and oil phases. The LSS process could be cost-effective and commercially available compared to other EOR methods, because at lower salinity, the adsorption and consequently retention of surfactant is less, which helps to reduce the costs of the operation (Glover et al. 1979). In addition, when the salinity of the environment is low, more surfactant systems are commercially available. Alagic and Skauge (2010) first introduced the LSS process, where 3 LSW/SW flooding experiments followed by LSS were conducted on Brea sandstone cores. The obtained results showed significant enhancement in the ultimate oil recovery, up to 33% of original oil in place (OOIP) (Alagic and Skauge 2010). After that, further investigations in the core scale were employed by researchers to study the effect of the initial wettability state of the core samples (Alagic et al. 2011), evaluate the performance of the optimum salinity during LSS (Johannessen and Spildo 2013; Khanamiri et al. 2015), study the effect of concentration of cations (Na^{+}, Ca^{2+}, and Mg^{2+}) and salinity in the composition of brine (Hosseinzade Khanamiri et al. 2016a,2016b) and to assess the effect of removing alkali associated with surfactant on either high salinity and LSS flooding (Zhang et al. 2015). In addition, in a study in the microscopic scale by Mirchi (2018), it is visually demonstrated that LSS shows higher performance compared to LSW or high salinity water flooding in carbonate core samples. In the mentioned study, fluid distribution and in situ contact angle distribution in the porous media were shown for the oil-wet system (Mirchi 2018).

The main target of different methods of EOR, such as LSW, SF, and LSS, is to reduce the ROS, and this can be done by increasing the capillary number in the system. The competition between capillary and viscous forces, which are the controlling forces in a two-phase flow at the pore level, is known as the capillary number (Eq. 1). The magnitude of viscous forces is affected by permeability, applied pressure, and viscosity. The affecting parameters on the capillary force are IFT, state of wettability, pore size distribution (PSD), and geometry of the pores.

$$N_c = \frac{V\mu}{\sigma} \tag{1}$$

where N_c stands for the capillary number, μ is the dynamic viscosity of the displacing fluid, V is the Darcy velocity, and σ is the interfacial tension between oil and water.

It has been shown that the capillary number and ROS are related such that a greater capillary number leads to a lower ROS. Considering Eq. 1, increasing the capillary number can be carried out in 3 theoretical ways, which are: (1) increasing the displacement velocity, (2) increasing the viscosity of the displacing fluid, or (3) decreasing the IFT. Practically, it may not be possible to increase the velocity or viscosity by such a value, regarding the required or created injector-producer significant pressure difference. Such an excessive pressure difference may result in severe formation damage. To conclude, the most practical technique of increasing the capillary number is the reduction of the IFT.

The CDC is a plot of ROS versus the capillary number, where it is one of the most important input parameters in reservoir simulation software for EOR (Oughanem et al. 2013) and is influenced by the wettability and the PSD of the porous medium. Figure 1 presents a schematic of the CDC, where the logarithmic x-axis is representative of the capillary number, and the normal y-axis shows the residual saturation of the non-wetting phase. In this figure, there is a normal range of capillary numbers for water flooding, where the ROS is usually high in this range. After passing the critical capillary number using an EOR method,

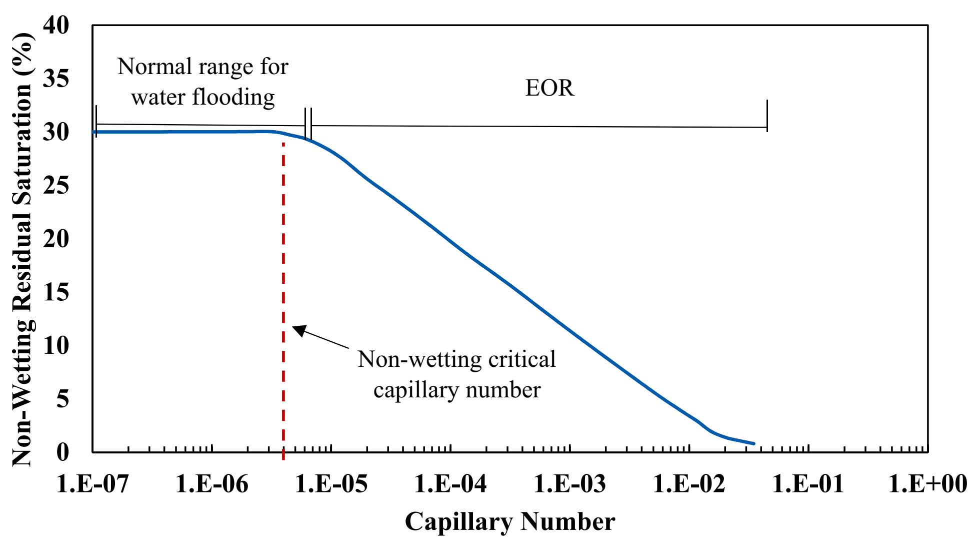

Fig. 1 Schematic of the capillary desaturation curve (Lake 1989 adapted from Lake (1989))

a reducing trend can be observed for ROS. Garnes et al. (1990) reported 4×10^{-6} as the critical capillary number of water-wet Berea sandstones (Garnes et al. 1990). Since the capillary number has a significant impact on the amount of trapped fluid, the ROS is commonly measured experimentally as a function of the capillary number to obtain the CDC (Sahimi 1993). On the other hand, a large change in the capillary number is required to significantly change the ROS due to the logarithmic x-axis of CDC.

LSW is able to reduce the ROS by altering the wettability of the rock, which is known to be the most effective mechanism in this method. It can also redistribute the remaining oil inside the pores because of rock/oil/brine interactions, but it cannot bring all the redistributed oil saturation into production due to the high governing capillary force. This is due to the fact that to bring the trapped redistributed oil inside the pores into production, we need to overcome the capillary force by reducing the IFT. SF, on the other hand, is able to reduce the IFT but does not work efficiently as a wettability modifier. Therefore, taking advantage of both LSW and SF could help to significantly reduce the ROS. The objective of this study is to investigate the ROS at different capillary numbers by using the CDC, which is a useful tool to investigate the performance of each mode of EOR, for various LSW, SF, and LSS flooding experiments.

Datasets

The idea of taking advantage of both the LSW and SF methods and establishing a hybrid method, known as LSS, has made researchers eager to study the performance of the LSS method through laboratory and modeling studies. Although the LSS method shows promising performance in core flooding experiments, only a few studies have been done on this method in the laboratory. In this section, we have tried to summarize the LSS experiments conducted by researchers in order to establish a dataset. The dataset consists of ROS and capillary number data. The ROS is calculated based on the reported ultimate recovery and OOIP of the core samples for each method. Figure 2 shows an example of the oil recovery and its corresponding ROS for an LSW flooding followed by LSS (Alagic and Skauge 2010). The capillary number is also calculated using the rock properties, fluid properties, and operational conditions, such as viscosity, porosity, injection rate, and IFT between brine solution and oil through Eq. 1. It should be mentioned that different definitions of the capillary number are presented in the literature. Each of them includes a specific parameter to capture the related phenomenon. For example, cos θ uses in the denominator of the Eq. 1 to include the effect of wettability. However, using such a definition may cause a mathematical error because of the contact angles with values equal or close to 90 degrees, which is the normal contact angle range in the mixed-wet media (Mirchi 2018; Lin et al. 2019). Therefore, this study uses the capillary number formula in the format of Eq. 1, while all of the literature listed in Table 1 and Table 2 used the same definition.

In addition, the ROS and capillary number data of the LSW and SF methods are calculated/collected to compare with the LSS method.

It is worth noting that all the used data for LSW and LSS methods were achieved by core flooding experiments of synthetic/native core samples in the laboratory. The rock mineralogy of the used core samples is sandstone. The porosity and permeability of the core samples are in the range of

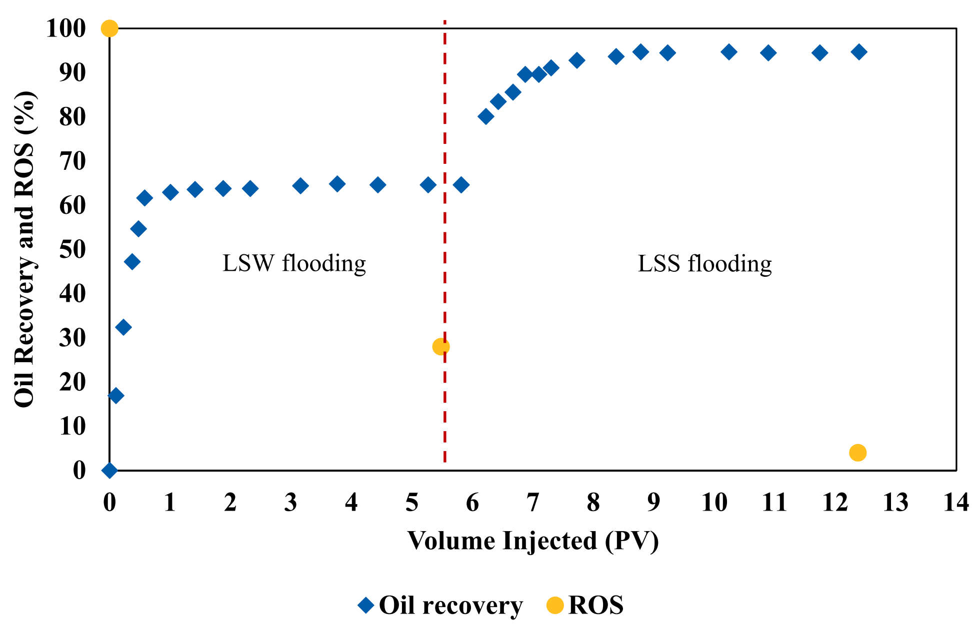

Fig. 2 Oil recovery and corresponding ROS for a LSW flooding followed by LSS (Alagic and Skauge 2010)

Table 1 Literature survey of the used datasets for the LSW and LSS methods

Author	Scenario	Finding	Surfactant
Alagic and Skauge (2010)	3 LSW flooding experiments followed by LSS	Low ROS (as low as 4%) was obtained by surfactant injection after stabilizing a low salinity environment	Internal olefin sulfonate Enordet 0242L (23.4% active matter) received from shell chemicals
Alagic et al. (2011)	4 LSW flooding experiments followed by LSS for aged and unaged Brea sandstone	Continuous injection of LSS solution resulted in lower ROS from both aged and unaged cores	Internal olefin sulfonate Enordet 0242L by shell chemicals
Spildo et al. (2012)	3 LSW flooding experiments followed by LSS	An intermediate wet state showed better performance during the LSS The tested homogeneous and heterogeneous core samples showed an insignificant response to LSW but heterogeneity affected the LSS performance significantly	S13D, an isotridecyl alcohol 13PO sulfate surfactant (83.5% active matter) by Tiorco
Riisøen (2012)	4 LSW flooding experiments followed by LSS in aged Bentheimer	Insignificant reduction in ROS reported for LSW, while a 6–22% reduction in ROS was reported for LSS compared to LSW	Sotridecyl alcohol 13PO sulfate surfactant (83.50% active matter) by Stepan
Johannessen and Spildo (2013)	5 LSS flooding experiments, each of them experienced LSW or seawater or optimum salinity before LSS	The tested Berea cores, both homogeneous and heterogeneous, showed insignificant response to LS injection alone LSS was able to reduce the ROS significantly, which was lower than what the capillary number predicts The ROS during optimum salinity surfactant flooding was in line with what the capillary number predicts	APS and IOS1518 blend butanol (SBA) as a cosolvent. All of the by Shell
Tavassoli et al. (2016)	Simulation of LSS process using UTCHEM-PHREEQC (the data are taken from Alagic and Skauge (2010))	A high salinity surfactant was introduced as a method, which was able to reduce the ROS to 0%. Hybrid methods were introduced as a method to reduce the uncertainty associated with LSW or SF. Pre-flood reduced the effectiveness of the process	Internal olefin sulfonate Enordet 0242L (23.4% active matter) received from Shell Chemicals
Hosseinzade Khanamiri et al. (2016)	5 LSW flooding experiments followed by LSS	There was an optimum Ca^{2+}/Na^{+} ratio, which could increase the performance of LSW and LSS.LSW and LSS made the core sample more water-wet than high salinity water and high salinity surfactant (HSS) At low surfactant concentration, the LSS recovered as much oil as the HSS	Sodium dodecylbenzenesulfonate (SDBS), Sigma-Aldrich

Table 2 Literature survey of the used datasets for the SF method

Author	Scenario	Finding	Surfactant
Fathi and Ramirez (1984)	One-dimensional surfactant flooding problem when considering two different types of IFT behavior	The optimal injection strategy was not unique for the IFT behavior of type A, while a unique optimal injection strategy was observed for the type B	Not available
Abeysinghe et al. (2012a)	Steady and unsteady state of surfactant flooding in mixed-wet Brea sandstones	The additional oil production was observed due to the increase in oil relative permeability at higher capillary numbers	Anionic surfactant, sodium C6–10 alcohol ether sulfate
Abeysinghe et al. (2012b)	Water flooding of the mixed-wet and water-wet Brea sandstones followed by surfactant flooding	Higher oil recovery was observed in mixed-wet core samples compared to water-wet core samples, while more pore volumes needed to be injected to achieve a plateau in mixed-wet core samples	Anionic surfactant, sodium C6–10 alcohol ether sulfate

15.3–24.4% and 85–2040 mD, respectively. Table 1 presents a literature survey of the data used for LSW and LSS methods. It is worth noting that flooding of the LSS was conducted after injection of the LSW for all experiments (tertiary recovery).

Table 2 presents a literature survey of the data used for the SF method. It should be mentioned that both laboratory and modeling studies were nominated for the data collection. The rock mineralogy of the used core samples is sandstone. The porosity and permeability of the samples are in the range of 22–25% and 418–657 mD, respectively.

Results and discussion

As mentioned, the ROSs and capillary numbers are calculated using the published data in the studies presented in Table 1 and Table 2, in order to create a dataset. The calculated ROSs and capillary numbers for the LSW, SF, and LSS methods are plotted in the form of the CDC in Fig. 3. This figure discusses the values of ROS at different capillary numbers for the mentioned methods. To do so, the CDC is divided into three regions, and each region is discussed in detail.

The first region stands for the capillary numbers in the range of less than 10^{-5}. In this region, the capillary number is low, and consequently, ROS is high (usually more than 30%). This region can stand for the normal range of water flooding but covers higher capillary numbers compared to the reported critical capillary number (4×10^{-6}) by Garnes et al. (1990) (Garnes et al. 1990). As presented in Fig. 3, all the LSW data are placed in this region and more specifically in the range of 10^{-7} and 10^{-6}. All the data used in this study come from core flooding experiments, where the affecting parameters on the viscous force (viscosity and Darcy velocity) are in the same range. In addition, the range of the IFT between different types of brine and oil is not wide. It is worth mentioning that the use of different ions alters the brine-oil IFT values by only a few units, which is reported and confirmed in the literature (Bartels et al. 2019). Thus, the density of the LSW data in this region is high.

The use of the CDC for interpretation of the LSW data is a controversial question, which is still under investigation. It is mentioned in the literature that CDC is not an appropriate tool for the LSW method because of two reasons. The first reason is low changes in capillary number parameters when HSW changes to LSW, as mentioned above. The second reason is that the injection of LSW results in a more water-wet condition and higher ROS, which is in contradicts with observations (Bartels et al. 2019; Jadhunandan and Morrow 1995; Christensen and Tanino 2018). Although this question has not been answered yet, we believe CDC is applicable in our study because this research compares conducted and

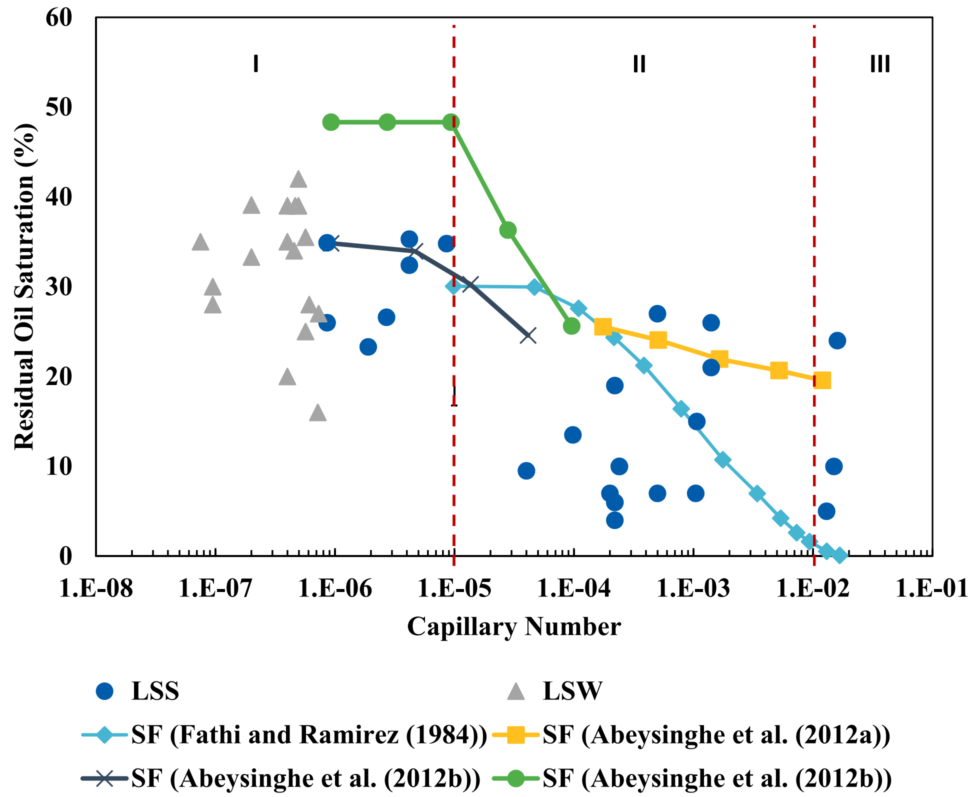

Fig. 3 Capillary desaturation curve for LSW, SF, and LSS methods

stabilized LSW experiments with LSS and SF. Therefore, the CDC does not have to explain the active mechanisms during the injection of a LSW.

In region I, the ROS of the LSW data is in the range 16–42% of OOIP, with an average of 32%, which shows that a considerable amount of oil is left in the porous media. It is believed that large pores are contributing to the production and this amount of oil is trapped in the smaller pores and/or in the corners of the porous media (Mirchi 2018). This is due to the fact that although the reduction of the salinity (or engineering the ions) of the water during LSW flooding can change the wettability of the porous media, it cannot significantly reduce the oil-brine IFT. Therefore, the LSW cannot invade into the small pores and/or remove the trapped oil in the corners, resulting in capillary trapping. Adding a surfactant into the injected LSW highlights the benefit of lowering the IFT. In order to discuss in more detail, one experiment from each of the nominated studies has been chosen to compare the LSW data and the corresponding LSS data, as presented in Fig. 4.

The presented CDC in Fig. 4 shows that the cooperation of surfactant with LSW can increase the capillary number and subsequently significant reduction in ROS. The capillary number changes show up to 3 orders of magnitude increment, while the magnitude of ROS is decreased by up to 30%. The high increment of capillary number leads to the production of a higher volume of OOIP. For instance, Fig. 2 shows the oil recovery of the core sample B2 of the Alagic and Skauge (2010) study, and the corresponding ROS and capillary numbers for the two steps of LSW and LSS flooding are presented in Fig. 4. The injection of the LSS solution after flooding with LSW caused a significant increase in the recovery factor. It is believed that the significant reduction in ROS (higher oil recovery) observed could be due to two main reasons. The first reason is that surfactant is able to reduce the IFT, which causes invasion of the brine solution into smaller pores, results in bringing trapped oil into production. The second reason is that the redistributed oil and/or destabilized oil layers by LSW injection because of rock/oil/brine interactions and it is swept by the LSS as a result of capillary force reduction.

Some data of the SF are observed in this region because of the role of surfactant in the IFT reduction process, which leads to the higher capillary numbers. In addition, the reduction of ROS for SF data in this region is insignificant because the increment of the capillary number is insufficient and/or ineffective to mobilize the trapped oil in the pores. The data related to the LSS method are also limited to a few data, and show less magnitude of ROS.

The second region stands for the capillary numbers in the range of 10^{-5} and 10^{-2}. In this region, the LSW data are absent, but the majority of the LSS data are scattered. Generally, the LSS data show lower ROS compared to the LSW data (appeared in the first region of CDC) due to the

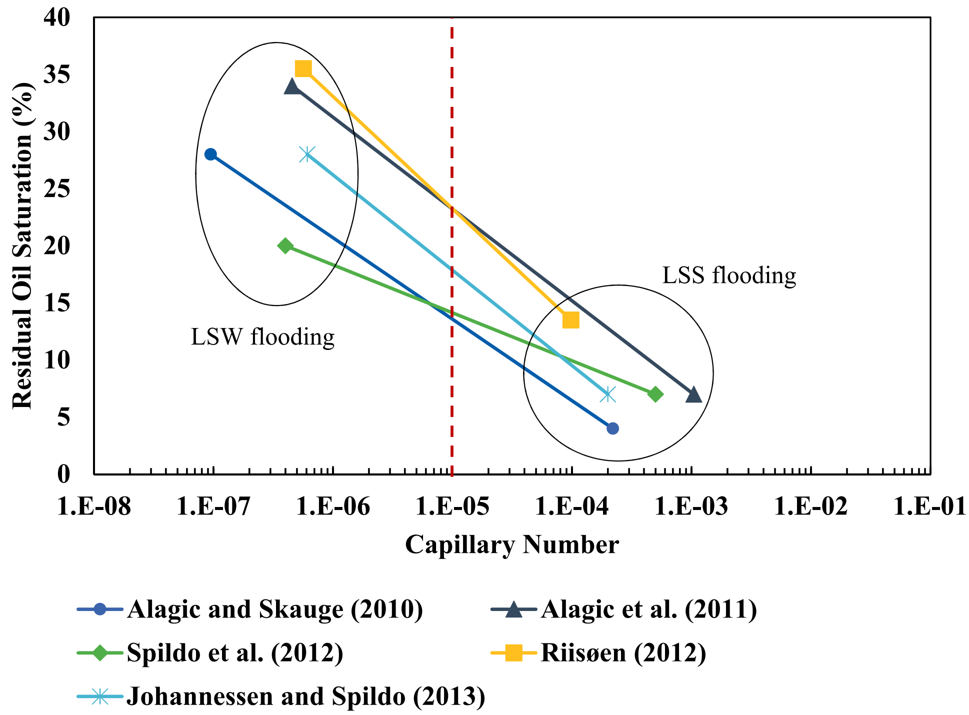

Fig. 4 Capillary desaturation curve for nominated LSW experiments and their corresponding LSS experiments

assistance of the surfactant. Different types and volumes of surfactants were used in the LSS experiments by researchers, which leads to different responses of rock-fluid (see Table 1 and Table 2). On the other hand, the PSD varies in different samples, resulting in the different potential of the EOR for each core sample. Therefore, LSS data are more scattered compared to LSW data.

The majority of the SF data are also located in this region. SF data show an average of 5% higher ROS compared to LSS data. In addition, the reduction in ROS for the SF method is less than the LSS method at the same increment of capillary number. This observation is in line with Spildo et al. (2012), where it was concluded that reduction of IFT in LSS floods generates an increase in oil recovery, which exceeds the expected performance of injecting a surfactant solution with the same reduction in IFT but without the low salinity contribution (Spildo et al. 2012). To deeply investigate the mentioned statement, the nominated data for SF and LSS experiments were compared in terms of IFT reduction and differential of ROS. Table 3 presents the nominated SF and LSS experiments for further investigation. It should be mentioned that the same data are used in this section as were used for Fig. 4, except for Riisøen's experiment, which is excluded as the IFT data were not available.

Figure 5 shows the IFT ratio and differential of ROS for the experiments presented in Table 3.

In this figure, the IFT ratio presents the ratio of the brine-oil IFT when the surfactant is absent to when the surfactant is present in the brine. The term "differential ROS" is representative of the differential of ROS values before and

Table 3 Nominated SF and LSS experiments for analysis of their performances

Number of scenario	Author(s)	Method
1	Abeysinghe et al. (2012a)	SF
2	Abeysinghe et al. (2012b)	SF
3	Abeysinghe et al. (2012b)	SF
4	Alagic and Skauge (2010)	LSS
5	Alagic et al. (2011)	LSS
6	Spildo et al. (2012)	LSS
7	Johannessen and Spildo (2013)	LSS

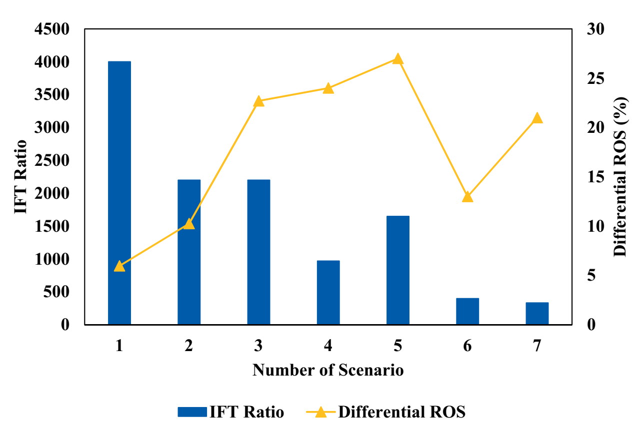

Fig. 5 Performance comparison between LSS and SF methods

after the SF/LSS processes. The IFT ratio of the SF method (Average of 2800) is higher than the LSS method (Average of 837), which means that the added surfactant could reduce the IFT between brine-oil for SF more than LSS. The values of the differential ROS compared to the magnitude of the IFT ratio for SF are lower than with LSS. It can be inferred that, although the higher IFT ratio of the SF method caused lower capillary trapping, the LSS method could be more effective in terms of ROS reduction. This figure supports the mentioned statement that by using LSS, much less ROS can be achieved compared to using SF.

Another arguable phenomenon is capillary end-effect. This phenomenon causes oil to remain in the core sample due to the discontinuity of the wetting phase (Huang and Honarpour 1998). Adding surfactant to the injection stream (brine and/or LSW) during SF or LSW flooding may reduce the capillary end-effect, which leads to incremental oil production at the same ROS. The effect of capillary end-effect can be minimized/eliminated by applying a series of high injection rates, called bump floods, or choosing the appropriate length of the core samples and injection rate, which have been applied in all experiments. Therefore, the observed incremental oil recovery can be attributed to the abovementioned reasons but not a reduction in capillary end-effect.

As mentioned, 2 reasons (reduction of capillary force and redistribution of the oil and/or destabilized oil layers) might be responsible for the stunning performance of LSS flooding when LSW was already flushed into porous media. The second mentioned reason, redistribution of the oil and/or destabilized oil layers because of rock/brine/oil interaction as a result of LSW flooding, does not contribute to the SF method. Therefore, in SF, the IFT reduction due to the added surfactant causes the invasion of the brine solution into smaller pores and results in bringing trapped oil into production, but there is no redistributed oil and/or destabilized oil layers to be brought to the production. Figures 6 and 7 schematically illustrate this hypothesis. Figure 6 shows the configuration of the fluids in a pore after SF, for both water-wet and oil-wet mediums. Regarding this figure, a layer of oil is sandwiched between formation brine and surfactant solution. This amount of oil can be the target of the LSW flooding follow by LSS flooding, where the interactions between rock/oil/brine can redistribute the volume of oil left and/or destabilize the oil layers, as shown in Fig. 7.

The third region stands for the capillary numbers 10^{-2} and greater. A few data of LSS and SF are observed in this region, which shows that it is difficult to reach capillary numbers of 10^{-2} and greater. The LSS data in this region show high ROS values with an average of 13%, which illustrates that the performance of the LSS method is not prominent. Flooding a surfactant could be more effective when the capillary number is within the third region, where the average ROS is 6.7% for the SF method. Therefore, the SF method is recommended to achieve lower ROS when

Fig. 6 Microscopic analysis of surfactant flooding in left water-wet medium and right oil-wet medium. The deep blue is representative of the formation brine, the brown represents the oil, and the white represents the surfactant solution (Yadali Jamaloei and Kharrat 2009 adapted from Yadali Jamaloei and Kharrat (2009))

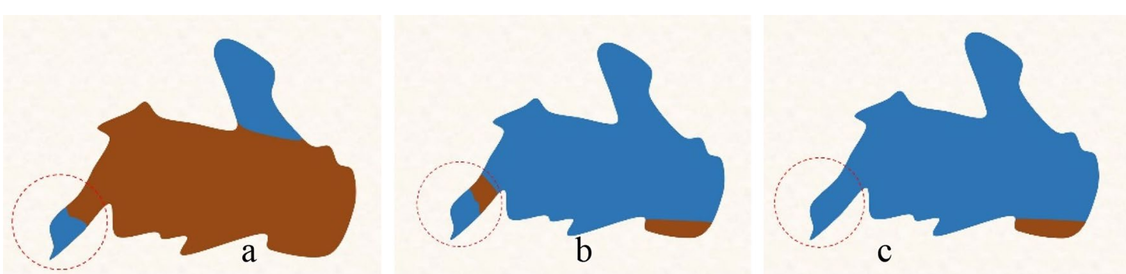

Fig. 7 Displacement of trapped oil: **a** initial water saturation, **b** residual oil saturation after LSW flooding, and **c** residual oil saturation after LSS flooding. Red represents the oil, and blue represents the brine phase (Mirchi 2018 adapted from Mirchi (2018))

operating within this region. It should be mentioned that the capillary numbers within this range could be reached by using the optimum salinity of water or a high portion of the surfactant. This way, the challenge of high rate of surfactant retention may arise which results in environmental damages and/or economically impractical operations.

Conclusion

In this study, the performance of the hybrid low salinity surfactant method is compared with low salinity water and surfactant flooding. For this purpose, a dataset consisting of residual oil saturation and capillary number values is established using data presented by scholars.The capillary desaturation curve was used to study the effective mechanisms on residual oil saturation at different capillary numbers for the mentioned EOR techniques. Based on the three identified regions in the capillary desaturation curve, it is concluded that:

- A high density of the low salinity water data is observed in the first identified region, with an average of 32% of residual oil saturation.
- A stunning performance of low salinity surfactant flooding is observed in the second identified region (capillary numbers in the range of 10^{-5} and 10^{-2}) in terms of residual oil saturation compared to the low salinity water method and surfactant flooding as a result of taking advantage of both methods.
- The low salinity surfactant method is able to increase the capillary number by up to three orders of magnitude and decrease the magnitude of ROS up to 30%, which highlights its advantages over the SF method.
- Residual oil saturation of the low salinity surfactant method shows an average of 5% lower values compared to the surfactant flooding method.
- Although a higher IFT ratio of surfactant flooding caused lower capillary force, flooding of low salinity water could be more effective in terms of the reduction in the magnitude of residual oil saturation.
- The redistribution of the oil and/or destabilization of the oil layers are known as a reason behind the better performance of low salinity water flooding.
- The surfactant flooding is found to be more effective in high capillary numbers (third identified region).

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Compliance with ethical standards

Conflict of interest On behalf of all the co-authors, the corresponding author states that there is no conflict of interest.

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