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Nonionic Surfactant to Enhance the Performances of Alkaline–Surfactant–Polymer Flooding with a Low Salinity Constraint

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Abstract: This paper presents a nonionic surfactant in the anionic surfactant pair (ternary mixture) that influences the hydrophobicity of the alkaline–surfactant–polymer (ASP) slug within low-salinity formation water, an environment that constrains optimal designs of the salinity gradient and phase types. The hydrophobicity effectively reduced the optimum salinity, but achieving as much by mixing various surfactants has been challenging. We conducted a phase behavior test and a coreflooding test, and the results prove the effectiveness of the nonionic surfactant in enlarging the chemical applicability by making ASP flooding more hydrophobic. The proposed ASP mixture consisted of 0.2 wt% sodium carbonate, 0.25 wt% anionic surfactant pair, and 0.2 wt% nonionic surfactant, and 0.15 wt% hydrolyzed polyacrylamide. The nonionic surfactant decreased the optimum salinity to 1.1 wt% NaCl compared to the 1.7 wt% NaCl of the reference case with heavy alcohol present instead of the nonionic surfactant. The coreflooding test confirmed the field applicability of the nonionic surfactant by recovering more oil, with the proposed scheme producing up to 74% of residual oil after extensive waterflooding compared to 51% of cumulative oil recovery with the reference case. The nonionic surfactant led to a Winsor type III microemulsion with a 0.85 pore volume while the reference case had a 0.50 pore volume. The nonionic surfactant made ASP flooding more hydrophobic, maintained a separate phase of the surfactant between the oil and aqueous phases to achieve ultra-low interfacial tension, and recovered the oil effectively.

Keywords: nonionic surfactant; heavy alcohol; low salinity; hydrophobicity; alkaline–surfactant–polymer; optimum salinity

1. Introduction

Alkaline–surfactant–polymer (ASP) flooding is a technique suitable for the many mature fields that have a low to moderate temperature and medium viscosity [1–4]. However, low salinity, similar to brackish water, hinders the application of ASP, and low-salinity reservoirs are dominant in onshore oil fields such as Meruap and Sukananti in Indonesia [5–7]. ASP flooding is an enhanced oil recovery (EOR) technology that involves injecting a mixture of alkaline, surfactant, and polymer materials that act together. The alkali forms an in-situ soap from its reaction with the acid content in the crude oil, and it also acts as a sacrificial agent to reduce the surfactant adsorption. The surfactant lowers the interfacial tension between the water and oil, and the polymer improves the displacement efficiency by increasing the viscosity of the solution.

Low-salinity environments (with salinity lower than that of seawater) in oil reservoirs are challenging for the design of ASP flooding, constraining the three phases of pre-flush, ASP flow, and polymer drive [8–10]. The surfactant should form a microemulsion in a separate phase between oil and water, i.e., a Winsor type III microemulsion, which generates an ultralow interfacial tension and allows effective recovery of the residual oil (Table 1). Achieving this type of microemulsion has required the salinity of alkaline–surfactant mixture to be near the formation salinity, with the available chemicals and combinations thereof being difficult to apply in low salinity environments.

Chemical reactions depend on several factors, including the characteristics of the crude oil, presence of formation water, salinity, temperature, and pressure. Many studies have concentrated on ASP design for mid-range temperatures and salinity to achieve wider applicability [10–14]. A few have investigated mixing chemicals applicable to specific temperatures and salinities [8,15–21]. Sagi et al. [16] recommended Tridecyl alcohol 13-polyoxypropylene (13PO) sulfate at a low temperature and a low-salinity carbonate reservoir. Gregersen et al. [8] suggested that blending 16–17 alcohol–13PO sulfate with internal olefin sulfonate (IOS) C_{20-24} was applicable in low-salinity conditions (less than 12000 ppm; parts per million; similar to 1.2 wt% NaCl) in the Minnelusa fields of Wyoming.

Enhanced oil recovery depends non-linearly on the detailed design of the ASP elements, including the concentrations of individual elements (alkaline, surfactants, and polymers), their combinations, surfactant mixture, availability of co-solvent, the selection of surfactants, co-solvent, and so on. Lately, the effects of an add-on co-solvent have been widely investigated [15,17–19,22,23]. Stoll et al. [15] discussed the performance of an ASP mixture through lab tests (including the phase behavior test and coreflooding test) and field pilot tests, with a system consisting of an alkali, two different types of surfactants and co-solvent, and a polymer. Shiau et al. [17] compared the performance of the surfactant/co-surfactant (binary) and surfactant/co-surfactant/co-solvent (ternary) mixtures in a high-salinity reservoir and showed that the ternary mixture could achieve a synergy to enhance ASP flooding. Tagavifar et al. [22] measured the microemulsion (oil, brine, surfactant, co-solvent, and polymer mixture) viscosity and showed that adding co-solvent to the surfactants could reduce the microemulsion/oil-viscosity ratio at the optimal salinity. Upamali et al. [23] found that replacing co-solvents into novel surfactants (short hydrophobe surfactants) produced a lower microemulsion viscosity, higher solubilization ratio, and reduced total chemical concentration. Yan et al. [18,19] characterized a ternary mixture consisting of nonionic, zwitterionic, and anionic surfactants and suggested that the ternary mixture decreased the interfacial tension more than the binary mixture. Their results were limited in that they characterized the surfactant features in a static condition without coreflooding tests.

The challenge to design an ASP formulation with an add-on co-solvent or co-surfactant is from the difficulties in using the ASP system in low-salinity environments. The performance can change according to reservoir conditions, the nonlinear relationship between the reservoir fluids and ASP mixture that is injected, and the degree of synergy with the co-solvent. The typical chemicals are manufactured for medium- or high-salinity conditions, and theoretically, a low-salinity environment requires a long-tail surfactant to achieve a higher solubilization in oil but widens the Winsor type II zone (water-in-oil emulsion in the oil) that leads to surfactant retention. The surfactant structure can be tailored by searching for surfactant candidates with respect to various reservoir characteristics [11] and mixing amphiphilic species would be an alternative solution, such as intermolecular or intramolecular mixtures [24,25]. To ensure the applicability of ASP flooding to a low-salinity environment, we have to decrease the optimum salinity to be near the formation salinity in order to generate a Winsor type III microemulsion (Table 1). As such, the optimum salinity is a guideline for the ASP slug that will show the same solubilization of oil and water.

Controlling the hydrophobicity has been a favorable mechanism used to decrease salinity to the optimum level. A hydrophobic surfactant tends to be more soluble in oil and to form water-in-oil microemulsions, which results in a shift in the middle phase microemulsion to a lower salinity level. The hydrophilic and lipophilic balance (HLB) and the solubilization ratio have been used to characterize surfactant types together with the critical micelle concentration, Kraft temperature, molecular packing parameter, and so on [26]. HLB indicates the relative tendency to form water-in-oil or oil-in-water emulsions by calculating the molecular mass, while the solubilization ratio comes from a phase behavior experiment that can incorporate crude oil, formation water, and reservoir conditions such as the temperature and pressure.

The phase behavior approach is a robust method to examine the ASP chemicals. It can provide an accurate evaluation of many chemical samples over a relatively short time [26,27]. If the oxypropylene chain is long enough, such as at about 15 or more PO groups, it becomes a hydrophobic surfactant [28]. Yada et al. [29] implemented PO chains as hydrophobic materials and modifiers for the polyoxyethylene (EO) chain. In addition, hydrophobic interactions between the tail of the surfactant and the adsorbed crude oil components alter the wettability [26]. Puerto et al. [30] showed that the length of hydrophobe chains and EO or PO chains influenced the solubilization parameters as well as the optimal salinities of the surfactant. A large hydrophobe alkoxy carboxylate surfactant that was chemically and thermally stable was applicable for crude oil with the equivalent alkane carbon number higher than 12 [31,32]. It can be tailored by modifying the number of carbons and the number of PO and EO groups (alkoxy groups) according to the specific needs of enhanced oil recovery. Barnes et al. [33] concluded that the important factors to match the surfactant with different compositions of crudes were controlled hydrophobe branching and molecular weight. Song et al. [34] demonstrated the use of EO to improve the solubility of the surfactant and to reduce the surfactant loss due to adsorption. Upamali et al. [23] emphasized the essential features of the type and structure of the surfactant molecule and that of the hydrophobe for the microemulsion formation, hardness tolerance, thermal stability, and favorable microemulsion rheology, respectively.

This paper describes our experimental investigation of the effects of a nonionic surfactant to modify the hydrophobicity and decrease the optimum salinity when constrained by a low salinity environment. It presents an optimal ASP formulation in a ternary mixture and evaluates the effects of a nonionic surfactant added into two anionic surfactant pairs with a comparison using heavy alcohol. The target reservoir is located in the South Sumatra basin in Indonesia, which has a low salinity of 6400 ppm (0.64 wt% NaCl). The experiments include an aqueous stability test, salinity scan, and coreflooding test to ensure field applicability.

Table 1. Summary of microemulsion types (Winsor types).

Winsor Types	Type I	Type II	Type III
Surfactant form	Oil-in-water emulsion in the aqueous phase	Water-in-oil emulsion in the oil phase	A separate phase between the oil and the aqueous phases
Features	Cannot achieve the ultralow interfacial tension	Lead to surfactant retention	Ideal to obtain the ultralow interfacial tension

2. Description of Chemicals, Brine, and Crude Oil

2.1. Alkali, Anionic Sufractant Pair, and Polymer

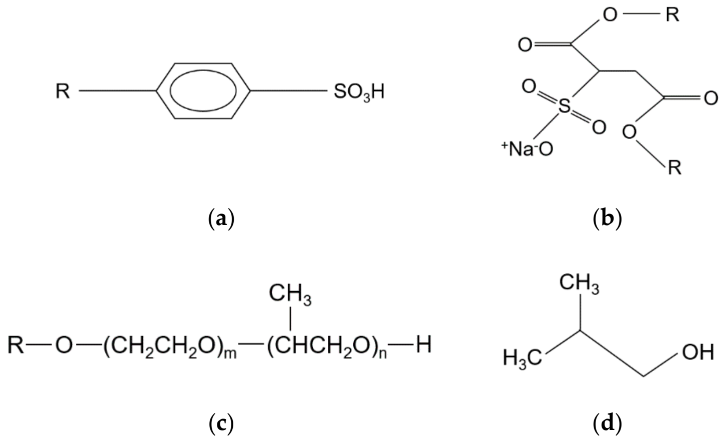
The alkali used was sodium carbonate (Na_2CO_3), which has been widely used and validated as a good alkaline material. The polymer was hydrolyzed polyacrylamide (HPAM). Two kinds of anionic surfactants were introduced: linear alkylbenzene sulfonate (C_{11}–C_{13}) (LAS) and Dioctyl sulfosuccinate (C_8–C_8) (DOSS). LAS, a sulfonate-type surfactant, has a high solubilization ratio in the water and oil system, but it also has a high optimum salinity, while DOSS can reduce the optimum salinity. Their mixture could result in a high solubilization, but the optimum salinity is much higher than that of the target reservoir (6400 ppm = 0.64 wt% NaCl), with the mixture of LAS and DOSS at 2.6 wt% NaCl at 25 °C, that is, much higher than that of the formation salinity and at which the Winsor type II would be made [20]. Thus, the extremely low salinity constraint requires a more hydrophobic condition with a reduction in the optimum salinity with LAS and DOSS as the surfactant pair.

2.2. Add-On Chemical: Nonionic Surfactant Versus Heavy Alcohol

This paper compared the effects of the addition of a nonionic surfactant in ASP flooding to those of adding heavy alcohol. We selected polyoxyethylene polyoxypropylene alkyl ether (C_{12} 60PO:40EO) as the nonionic surfactant, since it is neutral and does not result in significant adsorption. This nonionic surfactant, referred to as LB-95, is an (EO–PO) alkyl ether type in which a PO chain has been introduced between the EO chains. In addition, the alkyl chain of the EO type surfactant has been used as a solubilizer because it displayed excellent emulsification and solubilization for various oily substances with different polarities. As the reference material, a heavy alcohol (alcohol with larger than three carbon atoms [35]) was chosen. Iso-butanol (IBA; $C_4H_{10}O$) is an aliphatic alcohol that is used as a solvent in chemical reactions and as a starting material for organic synthesis. Table 2 summarizes the chemicals used in the experiments, and Figure 1 describes their chemical structures. The base mixture consisted of 0.25 wt% 1:4 (weight ratio; wt/wt) of LAS and DOSS anionic surfactant pair, 0.2 wt% Na_2CO_3 as the alkaline, and 0.15 wt% HPAM as the polymer. The proposed formulation added 0.2 wt% of nonionic surfactant (LB-95), while the comparison added the same amount of IBA instead of LB-95.

Table 2. Summary of the chemical materials as the alkaline–surfactant–polymer (ASP) components used in this study. LAS: linear alkylbenzene sulfonate; DOSS: dioctyl sulfosuccinate; HPAM: hydrolyzed polyacrylamide.

ASP Element	**Name**	**Trade Name (Abbreviation)**	**Concentration (wt%)**
Alkaline	Sodium carbonate (Na_2CO_3)	Sodium carbonate (Na_2CO_3)	0.2
Polymer	Hydrolyzed Polyacrylamide	A-430PB (HPAM)	0.15
Anionic surfactant pair	Linear alkylbenzene sulfonate (C_{11}–C_{13})	ASCO96 (LAS)	0.05
	Dioctyl sulfosuccinate (C_8–C_8)	ASCODOSS (DOSS)	0.2
Nonionic surfactant (control group)	Polyoxyethylene polyoxypropylene alkyl ether (C_{12} 60PO:40EO)	Hannong Koremul-LB-95 (LB-95)	0.2
Heavy alcohol (comparison group)	Isobutyl alcohol ($C_4H_{10}O$)	Iso-butanol (IBA)	0.2



(**a**) (**b**)
(**c**) (**d**)

Figure 1. Chemical structures: (**a**) LAS; (**b**) DOSS; (**c**)> LB-95; (**d**) IBA.

2.3. Brine and Crude Oil Samples

The target sandstone reservoir for ASP flooding is located in the South Sumatra basin, Indonesia, and it has low-salinity formation water at 6400 ppm. The reservoir has a moderate temperature of 60 °C (degrees Celsius) and an initial reservoir pressure of 58.8 bar (=853 lb/in^2 gauge pressure). The average porosity was 15%, and the permeability was 68.5 md (millidarcy). The productive zone was located at 871.2 m (=2860 ft) of true vertical depth and the net payzone thickness was 5.5 m (=17.99 ft). The crude oil was categorized as a light oil. Table 3 describes the composition of the formation water and the produced oil.

Table 3. Properties of the reservoir fluids.

Reservoir Fluid	Property	Value or Amount
Formation water (brine)	Magnesium	0.12 wt%
	Barium	0.005 wt%
	Chloride	0.31wt%
	Sodium	0.04 wt%
	Sulfate	0.01 wt%
	Calcium	0.00202 wt%
	Bicarbonate	0.16 wt%
Crude oil	API gravity (°API) [1]	42.8
	Viscosity (cp)	0.85 at 25 °C and 1 atm

[1] American Petroleum Institute gravity.

3. Experimental Procedure

The experiments consisted of phase behavior tests (aqueous stability test and salinity scan) and a coreflooding test. The phase behavior tests examined the effects of the nonionic surfactant and salinities (in the range of 0.1 and 2.5 wt% NaCl) at an equilibrium condition while the coreflooding test evaluated the field applicability of the proposed ASP mixture of the sandstone rocks.

3.1. Phase Behavior Test

The phase behavior test was divided into an aqueous stability test and a salinity scan. The former used an alkali, surfactant mixture, and polymer solution without crude oil, while the latter included crude oil. Synthetic brines (deionized water containing NaCl), ASP (alkaline surfactant polymer mixture with nonionic surfactant or heavy alcohol for the aqueous stability test), and AS (alkaline surfactant mixture with nonionic surfactant or heavy alcohol for the salinity scan) solutions were prepared in advance. Since the prepared synthetic brine was highly concentrated, it was first introduced into a 5 mL DIFFICO borosilicate pipette (Witeg Diffico, Wertheim, Germany), followed by deionized water to reach the desired salinity, and the ASP solution was added afterwards. We used a pipette from Pipetman (Gilson, USA), to ensure an accurate volume of the solution. The top end of the pipette was secured with silicone (Shin-Etsu, Japan). The aqueous solution mixture in the pipette was mixed by inverting and reverting the pipettes several times. It was placed in an oven to be visually inspected for any precipitation or phase separation at the reservoir temperature (60 °C) and atmospheric pressure for seven days of equilibrium time.

The salinity scan test identified potential surfactants compatible with crude oil. The criteria included a high oil solubilization ratio in general and a low optimum salinity in the current reservoir condition. The solubilization ratio of oil or water was determined using Equation (1):

$$\sigma_i = \frac{V_i}{V_s}, \tag{1}$$

In Equation (1), σ_i (mL/mL) is the solubilization ratio of i liquid phase, i.e., 'o' for oil and 'w' for water. V_i (mL) represents the volume of oil or water solubilized in the microemulsion at equilibrium state, and V_s (mL) is the volume of the surfactant obtained from the multiplication of aqueous volume and surfactant concentration [36]. The interfacial tension at the optimum salinity can be estimated using Equation (2):

$$\gamma = \frac{0.3}{(\sigma^*)^2} \tag{2}$$

where γ (mN/m) denotes the interfacial tension and σ^* (mL/mL) is the solubilization ratio at the optimum salinity [37]. The same pipette as in the aqueous stability test was used to ease the observation of the formed microemulsion [20]. The order of different solution placements into the pipettes were as follows: synthetic brine, AS solution, and crude oil. The volume ratio between the aqueous phase and oleic phase was 50:50. The fluid level was recorded, and the crude oil was then added to the pipette. The top opening of the pipette was sealed using silicone. The pipettes were shaken a few times, placed in the oven at 60 °C, and allowed to equilibrate within seven days.

3.2. Coreflooding Test

The epoxy-molded Berea sandstone was prepared for a core size of 15 cm in length and 3.81 cm of diameter. The epoxy was hardened for 20 h, and a leak test was performed. One core was prepared for each coreflooding test (proposed and comparison formulas). The consolidated core sample was connected to the pump, the pressure transducer, and the fraction collector (Figure 2). The absolute permeability was determined in the brine-saturated sample. The brine had the same salinity as the formation water (0.64 wt% NaCl). The crude oil flowed downward into the brine-saturated sample until reaching 1% of the watercut, and then the initial oil and water saturations were determined.

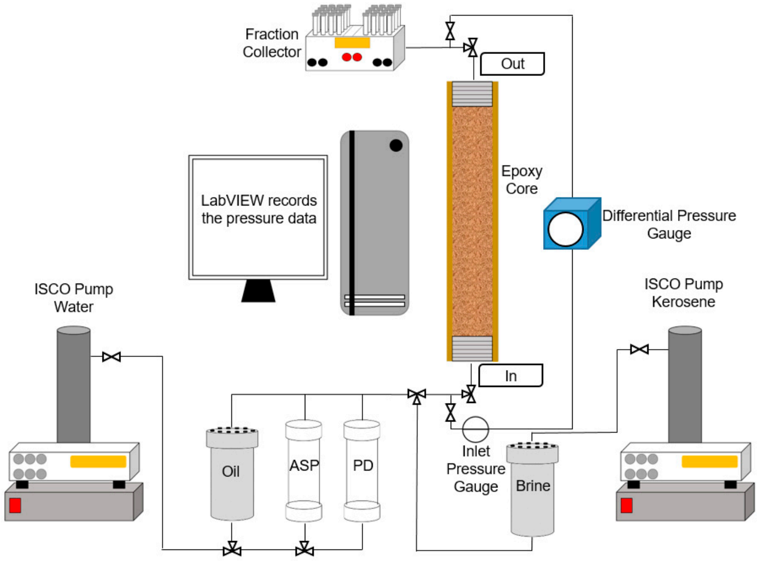


Figure 2. Schematic diagram of the experimental apparatus for the coreflooding test. 'ASP' stands for alkaline–surfactant–polymer and 'PD' represents the polymer drive.

A pre-flush using brine was carried out until 1% of oilcut, i.e., extensive waterflooding. The pressure was stabilized to determine the flow rate and the oil production rates to calculate the residual oil saturation. The ASP mixture flowed 0.4 pore volume (PV), and then 1.6 PV of polymer followed. Two ASP cases were compared: one adding the nonionic surfactant, and the other adding heavy alcohol into the anionic surfactant pair (LAS and DOSS). The residual oil saturations and oil recovery were determined by the material balance from the effluent samples. The effluent salinity was measured to track the progress of the varying slugs. The cumulative residual oil recovery (f_{op}) was defined as:

$$f_{op} = \frac{\sum V_o}{V_{orw}} \tag{3}$$

In Equation (3), V_o (mL) is the produced-oil volume and V_{orw} (mL) represents the residual-oil volume after waterflooding. To evaluate the ASP efficiency, the cumulative ASP oil ratio (CAOR) was introduced with Equation (4):

$$CAOR = \frac{\sum V_o}{\sum V_{ASP}} \tag{4}$$

where V_{ASP} indicates the volume of the ASP injected into the sandstone core. The injection volumetric velocity was maintained at 0.24 mL/min (approximately 1 ft/day superficial velocity).

4. Results and Discussion

4.1. Phase Behavior Test

Figure 3 presents the results of the aqueous stability test. The test group included the nonionic surfactant (LB-95), while the reference group had heavy alcohol (IBA) added into the base the ASP mixture (0.25 wt% 1:4 (wt/wt) of the LAS and DOSS anionic surfactant pair, 0.2 wt% Na_2CO_3 as the alkali, and 0.15 wt% HPAM as the polymer). The amount of chemical added was 0.2 wt%. The proposed mixture (nonionic surfactant) did not show any precipitation until 2.5 wt% NaCl (Figure 3b) while the reference mixture (heavy alcohol) started precipitation from 2.0 wt% NaCl (see the solid-like white materials at 2.0 and 2.5 wt% NaCl in Figure 3a). This aqueous stability test showed that to compare the two cases, we have to maintain a salinity below 2.0 wt% NaCl, and thereby the proposed nonionic surfactant could apply up to 2.5 wt% NaCl, but the applicability of heavy alcohol would be limited below 2.0 wt% NaCl.

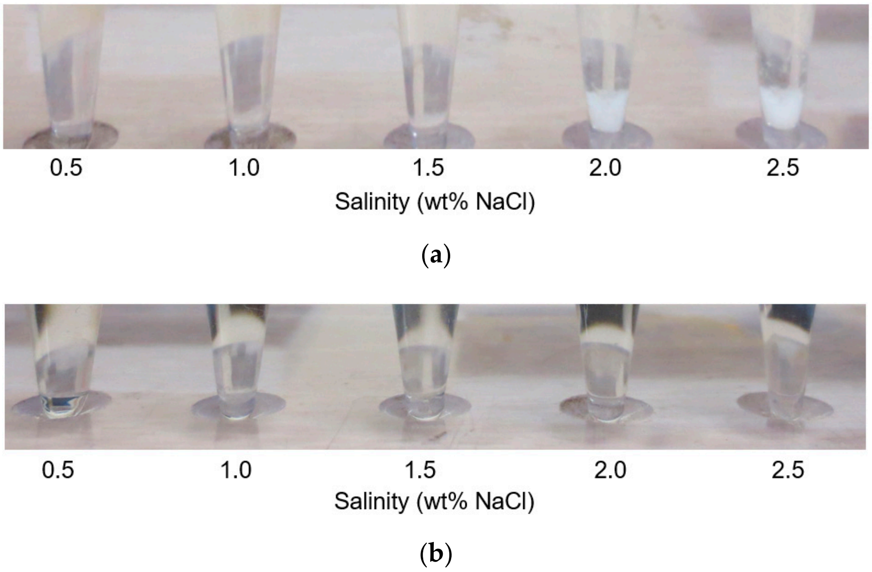
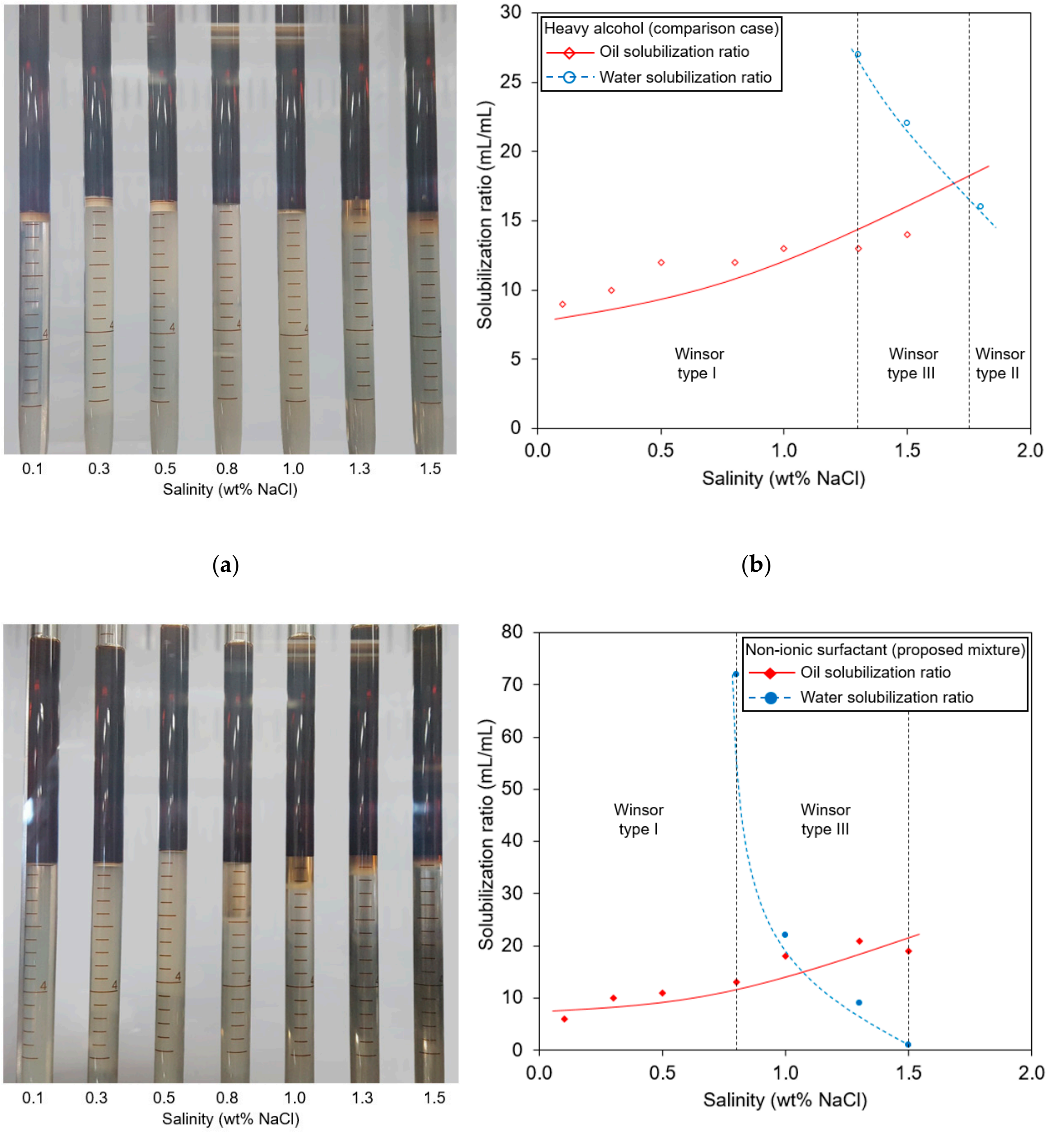


Figure 3. Results of the aqueous stability test of (**a**) 0.2 wt% heavy alcohol (IBA; the reference case); (**b**) 0.2 wt% nonionic surfactant (LB-95; the proposed case) mixing with 0.25 wt% 1:4 (wt/wt) of LAS and DOSS anionic surfactant pair, 0.2 wt% Na_2CO_3 as the alkali, and 0.15 wt% HPAM as the polymer.

Figure 4 shows a salinity scan test with Winsor type III microemulsion and solubilization ratio to determine the optimum salinity. The proposed mixture with a nonionic surfactant showed a lower optimum salinity and wider range of the type III zone than the reference case. The optimum salinity with the same solubilization ratio of oil and water was 1.1 wt% NaCl for the proposed mixture and

1.7 wt% NaCl for the reference case. The figures on the left side of Figure 4 (Figure 4a,c) revealed that the add-on of the nonionic surfactant resulted in a larger amount of Winsor type III than the reference case, which could be effective in making the residual oil moveable. The solubilization ratio at the optimum salinity was 16 mL/mL for the proposed mixture and 18 mL/mL for the reference. They were over the criterion to obtain an ultralow interfacial tension, i.e., 1.17 × 10^{-3} mN/m and 0.93 × 10^{-3} mN/m (Table 4; [20,36]). Table 4 summarizes the results of the salinity scan test; a notable result is the difference of optimum salinity. The proposed case (AS with nonionic surfactant) showed the reduced value of optimum salinity favorable at the low salinity environment. The coreflooding test is required to evaluate the difference of solubilization ratios, as well as the optimum salinities influencing residual oil recovery.



(**a**) (**b**)

(**c**) (**d**)

Figure 4. Salinity scan test: (**a**,**b**) as the reference case (heavy alcohol); (**c**,**d**) as the proposed mixture (nonionic surfactant). The left-hand side (**a**,**c**) shows microemulsions with the Winsor type III and the right-hand side (**b**,**d**) describes the solubilization ratio with the salinities. 'ME' stands for microemulsion.

Table 4. Summary of the salinity scan test.

Cases	Solubilization Ratio (mL/mL)	Optimum Salinity (wt% NaCl)	Interfacial Tension (mN/m)
Reference case	18	1.7	0.93×10^{-3}
Proposed case	16	1.1	1.17×10^{-3}

The hydrophobicity was deemed to be the reason why the nonionic surfactant produced a reduction in the optimum salinity. Theoretically, PO units broadened the ultralow interfacial tension and made the surfactant mixture more hydrophobic. The optimum condition with hydrophobic surfactant would increase the dispersing tendency of the surfactant in water by decreasing the salinity. The hydrophobicity was not quantitatively validated using an HLB value, but the hydrophobicity was indirectly estimated from the solubilization ratio and the optimum salinity. The nonionic surfactant contributed to making the ASP and oil system more hydrophobic, and it reduced the optimum salinity. Riswati et al. [20] showed that a single anionic surfactant such as LAS and DOSS failed to reach the equilibrium condition and was not suitable as a surfactant for low salinity conditions. The mixture of the two with glycol ethers solvent produced an optimum salinity higher than 2 wt% NaCl at 25 °C. Increasing the temperature will increase the interfacial tension and the optimum salinity [38,39].

4.2. *Coreflooding Test*

Table 5 summarizes the design of the ASP coreflooding tests. The proposed mixture used 1.1 wt% NaCl, while the comparison implemented 1.7 wt% NaCl as the salinity of the ASP slug, as the results of the phase behavior tests. The other elements of the ASP flooding, such as the preflush and polymer drive, were set to a salinity that was the same as the formation salinity to demonstrate field applicability. The microemulsion types would be the Winsor types I–III–I estimated by the phase behavior tests (Figure 4). Figure 5 depicted the pressure drop during the coreflooding tests. The test group showed less of a pressure drop than the reference case, so the nonionic surfactant helped to have less restricted flow and a reduction in pore plugging.

Table 5. Detailed design of the coreflooding test (ASP flooding).

ASP Flooding	Pre-Flush	ASP Slug	Polymer Drive
Salinity (wt% NaCl)	0.64	1.1 (the proposed case) 1.7 (the reference case)	0.64
Pore volume injected	2.0	0.4	1.6

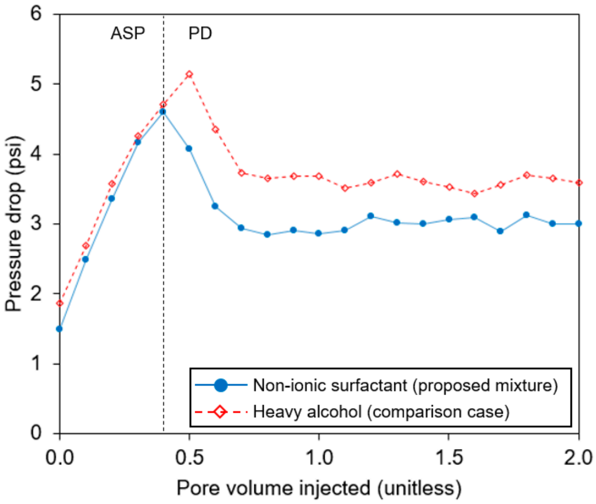
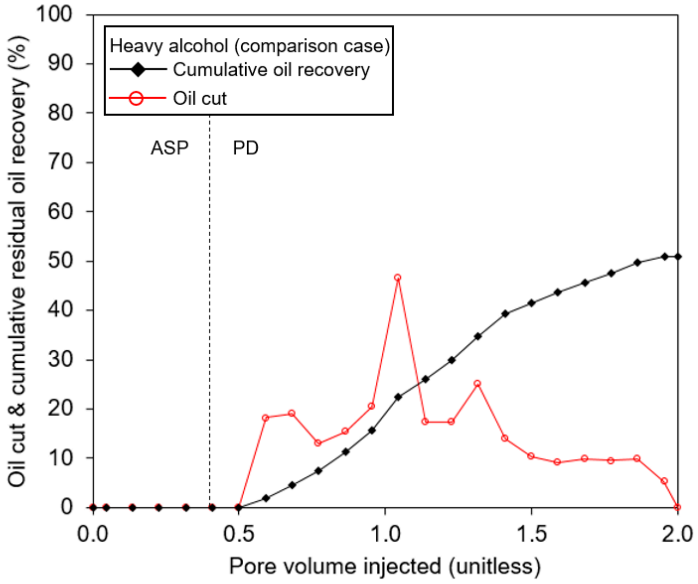
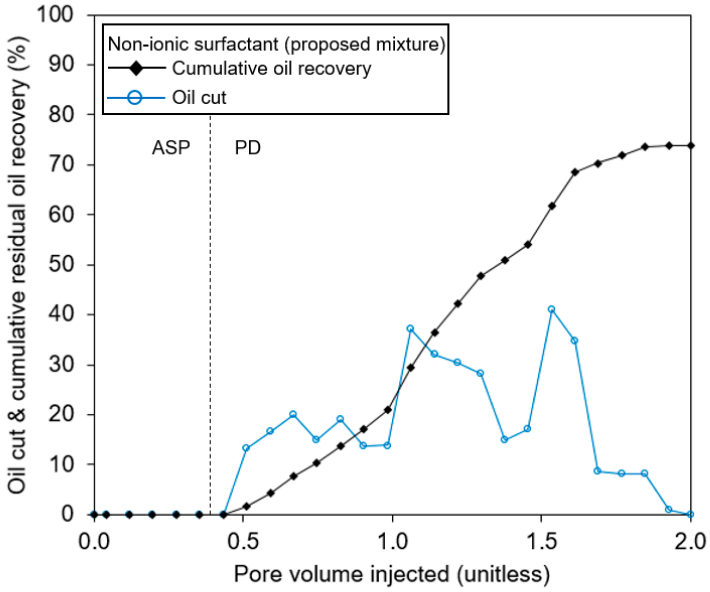


Figure 5. Plot of the pressure drop measured during the coreflooding tests.

Figure 6 compared the oil cut and the cumulative oil recovery after pre-flush. The cumulative oil recovery of the nonionic surfactant addition was about 74% of the residual oil after waterflooding, while that of the comparison remained at 51%. The oil cut of the proposed mixture showed a late-time recovery while that of the comparison case showed one highest peak and then a sharp decrease. The trajectories in the proposed mixture confirmed the effectiveness of the polymer drive. Figure 7 depicted CAOR to examine the efficiency of the ASP flooding. The CAOR of the nonionic surfactant addition was much higher than that of the heavy alcohol, and, thereby, the nonionic surfactant helped to recover the residual oil with better efficiency (Figure 7).



(**a**)



(**b**)

Figure 6. Oilcut and cumulative oil recovery after pre-flush: (**a**) the reference case (heavy alcohol); (**b**) the proposed case (the nonionic surfactant) mixing with 0.25 wt% 1:4 (wt/wt) of LAS and DOSS anionic surfactant pair, 0.2 wt% Na_2CO_3 as the alkali, and 0.15 wt% HPAM as the polymer.

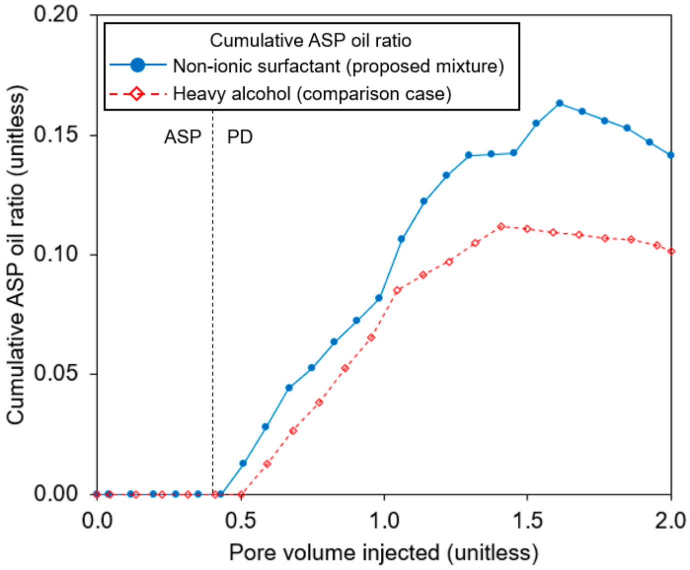


Figure 7. Comparison of cumulative ASP oil ratio (CAOR) to evaluate the efficiency of ASP flooding.

Figure 8 depicts the salinities and the regions of the type III microemulsion. The mixing effect with the formation salinity and the ASP slug increased the salinity at an early time and then eventually decreased when the polymer drive with a lower salinity arrives, following the desired transition. A steep inclination in the cumulative oil recovery profile intersected the type III region. The nonionic surfactant lasted in the type III region more than the reference case, as indicated with the type III effluent salinity, with the nonionic surfactant addition showing the larger PV of 0.85 (from 0.75 PV to 1.6 PV). The cumulative residual oil recovery when type III occurred at the proposed mixture was 61%, whereas 30% occurred for the reference case.

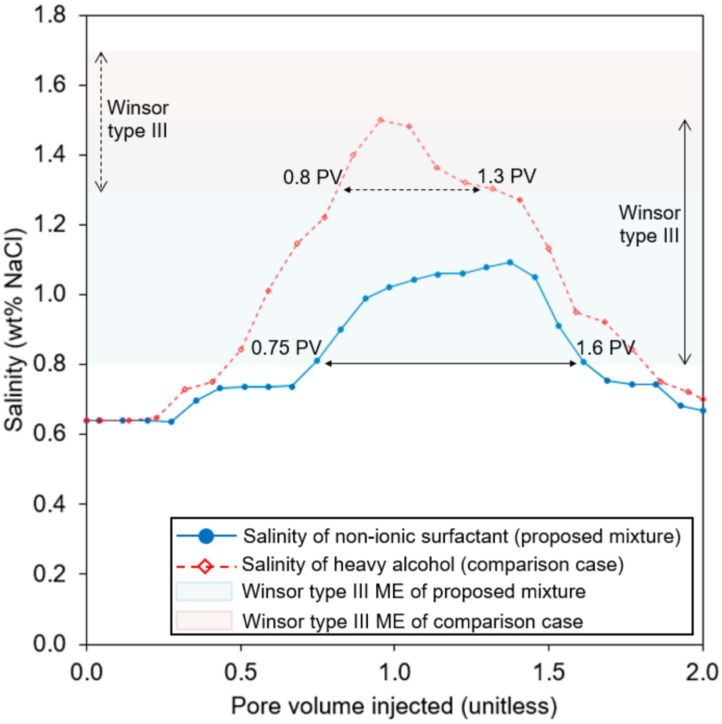


Figure 8. Plot of the effluent salinity and cumulative oil recovery versus pore volumes to investigate the importance of the type III occurrence. 'ME' stands for microemulsion.

The oil recovery would be optimized when the type III region of the ASP formula approached the formation water closely, i.e., 0.8 to 1.5 wt% (Figure 8). As the salinity reached the type III and flowed through the core sample, the type III microemulsion was formed. This microemulsion type solubilized oil and water equally, and hence an ultralow interfacial tension was attained. It was apparent from the experimental results that the introduction of a nonionic surfactant effectively improved the performance of the anionic surfactant pair in a low salinity condition by modifying the hydrophobicity to obtain a lower optimum salinity.

These findings provide an insight into the surfactant screening and formulation processes for ASP flooding where assigning a nonionic surfactant with a PO group into an anionic surfactant pair might work well in sandstone oil reservoirs with low salinity formation water and light oil. It was expected to reduce the trial and error time during the surfactant screening stage for cases similar to the reservoir characteristics in this work. Mixing different PO number nonionic surfactants and other heavy alcohol types into the anionic surfactant pair could be a useful way to reach more conclusive results. Future work should include an in-depth economic analysis of the feasibility of the project to determine the best surfactant mixture and an injection scenario that are economically promising.

5. Conclusions

This paper presented positive effects of a nonionic surfactant mixed with an anionic surfactant pair to overcome the low salinity constraint. The low salinity limits the design of an optimal ASP flooding method to recover residual oil, and thus it is important to reduce the optimum salinity to be near or less than the formation salinity to obtain the desired ultralow interfacial tension. The nonionic surfactant addition to the anionic surfactant pair was effective in making the ASP mixture more hydrophobic, in order to recover the residual oil. The phase behavior and the coreflooding tests confirmed the efficiency of using a nonionic surfactant compared to a heavy alcohol. The nonionic surfactant contributed to a reduction in the optimum salinity of the anionic surfactant pair. The suggested ASP formulation was 0.25 wt% 1:4 (wt/wt) of LAS and DOSS anionic surfactant pair, 0.2 wt% Na_2CO_3 as the alkali, 0.15 wt% HPAM as the polymer, and 0.2 wt% LB-95 as the nonionic surfactant. It had 1.1 wt% NaCl, which is higher than the formation salinity. The proposed ASP mixture could recover up to 74% of the residual oil, even though extensive waterflooding was conducted. The nonionic surfactant helped enlarge the Winsor type III regions to generate hydrophobic conditions, and thus recover the oil effectively.

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