Available online at
https://journal.uitm.edu.my/ojs/index.php/MJCET

e-ISSN: 2682-8588

Malaysian Journal of Chemical Engineering & Technology 8(2) 2025, 26–38

Malaysian Journal of Chemical Engineering and Technology

Effect of salinity and alkalinity on dynamic adsorption of anionic surfactant and oil recovery in alkaline-surfactant-polymer flooding using a sand pack model

Nur Sarah Mohd Noor[1], Tengku Amran Tengku Mohd[2*], Mohd Zaidi Jaafar[3]

[1,2]*Faculty of Chemical Engineering, Universiti Teknologi MARA, 40450 Shah Alam, Selangor, Malaysia.*
[3]*Faculty of Chemical and Energy Engineering, Universiti Teknologi Malaysia, 80150 Johor Bahru, Malaysia.*

ARTICLE INFO

Article history:
Received 18 September 2024
Revised 9 May 2025
Accepted 17 June 2025
Online first
Published 31 October 2025

Keywords:
Anionic surfactant
Surfactant adsorption
ASP flooding
Oil recovery
Salinity
Alkaline

DOI:
10.24191/mjcet.v8i2.3517

ABSTRACT

Alkaline-surfactant-polymer (ASP) flooding is a widely used enhanced oil recovery (EOR) method, but it has reliability issues, particularly surfactant adsorption that reduces efficiency. Surfactant adsorption becomes complex in the presence of alkaline and polymer, which exhibit uncertain behaviour at varying salinity and alkalinity. This study investigates the impact of brine and alkaline concentrations on the adsorption of anionic surfactant and the corresponding oil recovery in ASP flooding. The ASP formulation consisted of 2,000 ppm sodium dodecyl sulphate (SDS), 500 ppm partially hydrolysed polyacrylamide (HPAM) and 10,000 to 30,000 ppm sodium carbonate (Na_2CO_3) as the surfactant, polymer and alkaline, respectively. Sodium chloride (NaCl) was prepared at concentration 10,000 to 30,000 ppm to investigate the effect of salinity. Quartz sand (150 to 250 µm) was packed into a sand pack model for dynamic adsorption and oil recovery tests. The critical micelle concentration (CMC) of SDS was determined to be 2,200 ppm using the Du Noüy ring method. Adsorption was measured using a UV-Vis spectrophotometer. In dynamic adsorption, as salinity increases from 10,000 ppm to 30,000 ppm, surfactant adsorption increases as much as 10% from 0.69 mg/g to 0.76 mg/g. Meanwhile, surfactant adsorption decreases as much as 22% from 0.69 mg/g to 0.54 mg/g with increasing alkalinity from 10,000 to 30,000 ppm, respectively. The highest oil recovery of 75% original oil in place (OOIP) was achieved at 10,000 ppm brine and 30,000 ppm alkaline, which also exhibited the lowest adsorption. In conclusion, alkaline concentration has been the most determining factor, which has significant impact in minimising the surfactant adsorption, while enhancing the oil recovery in ASP flooding.

[2*] Corresponding author. *E-mail address*: amran865@uitm.edu.my
https://doi.org/10.24191/mjcet.v8i2.3517

1. INTRODUCTION

Due to the increasing demand for crude oil, ASP flooding has been adopted in 87 fields worldwide for enhanced oil recovery (EOR) purposes (Laben et al., 2021). The amount was affected by factors like geology, reservoir conditions and economy. In addition, the use of chemicals in ASP flooding is economic and effective, thus is a better choice for the fields. ASP flooding involves the injection of alkaline agents, surfactants, and polymers into the oil reservoir to improve oil displacement (Sun et al., 2020). This technique is sustainable because it uses environmentally friendly chemicals such as Sodium Dodecyl Sulfate, Hydrolysed Polyacrylamide, and Sodium Carbonate (Al-Jaber et al., 2023). According to Petroliam Nasional Berhad, who oversees activities related to oil and gas sector in Malaysia, they set policies and regulations to ensure sustainable development in EOR which has ASP flooding. The environmental impact of oil and gas operations would be reduced to have a balance energy development.

ASP flooding works on three key components which are alkali, surfactant, and polymer. Behrang et al. (2021) has demonstrated that when alkali component reacts with acidic crude oil components, interfacial tension will be reduced, and rock surface wettability will be altered. The surfactant speeds up the emulsification of oil droplets, thus facilitating their mobilisation in the reservoir. In terms of polymer, when injected, it improves the oil mobility by increasing the viscosity of the injected water. This will reduce the bypassing of injected fluids and improve the sweep efficiency (Zhu et al., 2020). Sweep efficiency refers to the fluid effectiveness in displacing the oil from the porous rocks. ASP flooding also offers several advantages over traditional EOR techniques, including the simultaneous action of alkali, surfactant, and polymer addresses the heterogeneity of reservoirs and improves displacement efficiency (Olajire, 2014). The alkali-surfactant interaction enables a more favourable mobility ratio, leading to enhanced microscopic and macroscopic sweep efficiency. Moreover, the use of polymers enhances the volumetric sweep efficiency by reducing the channelling effect and improving fluid conformance (León et al., 2018). Despite its advantages, ASP flooding has some weaknesses too. The high cost associated with the procurement and injection of alkali, surfactant, and polymer poses economic challenges (Uzoho et al., 2015). Additionally, reservoir heterogeneity may limit the effectiveness of the technique, leading to uneven fluid distribution and reduced recovery factors in certain regions of the reservoir (Wang et al., 2016).

In ASP flooding, brine and alkaline concentration plays a big role in oil recovery. Abdel-Wali (1996) has observed that the salinity of the injected brine can affect the solubility of the surfactants and alters the interfacial tension at the oil-water-rock interfaces. When interfacial tension between oil and brine has been reduced, the oil will detach and mobilize easily. In this case, optimal brine salinity is crucial to achieve an effective oil mobilisation (Sukee et al., 2022). For alkaline concentration, the success of ASP flooding depends on its ability to neutralize acidic components in the crude oil, thus altering interfacial tension and affecting the wettability of the reservoir rocks too. It is important to have optimal alkaline concentration in ASP flooding process, same as brine. An insufficient concentration of alkaline agents may hinder the neutralisation of acidic species within the crude oil, limiting the desired reduction in interfacial tension. Meanwhile, excessive alkaline concentration may yield smaller or less returns on oil recovery. The cost associated with procuring and injecting alkaline agents escalates with higher concentrations, posing economic challenges to the overall feasibility of ASP flooding projects (Al-Jaber et al., 2023). All in all, having a balance between achieving optimal oil recovery and managing operational costs is a critical consideration in the determination of brine and alkaline concentrations.

Adsorption in general is a surface phenomenon where atoms, molecules or ions from gas or liquid adhere to a surface. It is influenced by adsorbate and adsorbent that will determine the efficiency of the adsorption. One of the major mechanisms in adsorption is electrostatic interactions. It involves the attraction or repulsion of the charged particles at the interface of an adsorbate and adsorbent material. Opposite charges will form a bond on surface. The strength of the bond will be affected by the charge's magnitude and the distance between them. The complex interactions between the surfactant molecules and reservoir rock surfaces have made the utilisation of surfactants more difficult. Surfactant adsorption occurs when

https://doi.org/10.24191/mjcet.v8i2.3517

surfactant molecules adhere to the solid surfaces of reservoir rocks, thus altering the mobility of the oil. The extent of surfactant adsorption is influenced by various factors such as rock mineralogy, reservoir temperature, alkalinity and salinity of the injected fluids (Belhaj et al., 2019; Mohd et al., 2019). Excessive surfactant adsorption will diminish the surfactant concentration in the displacing fluid and alter the interfacial tension between oil and water. This case will reduce the ability of surfactants to create and stabilize oil-in-water emulsions. The use of anionic surfactants for adsorption in sandstone formations has been widely studied and proven effective for EOR. Wettability of the surfaces were improved, leading to increase in anionic surfactant adsorption (Herawati et al., 2022; Wang et al., 2016). In addition, ASP flooding field application using anionic surfactant has shown increase in oil recovery, making it preferable option for sandstone formations (Zhong et al., 2019; Li et al., 2020).

In the context of EOR through ASP flooding, understanding the adsorption of anionic surfactant onto reservoir rocks is crucial. There are uncertain adsorption behaviours when surfactant interacts with the reservoir rock in the presence of alkaline and polymer (Amran et al., 2022; Mohd et al., 2023). While several studies have explored the role of surfactants, there remains a lack of clarity on how variation of salinity and alkalinity concentration individually affect dynamic adsorption of ASP flooding in unconsolidated sandstone media. This study addresses the gap by focusing specifically on salinity and alkalinity concentration because they can be readily controlled and adjusted in field applications. Unlike temperature and rock mineralogy that were often difficult to modify, salinity and alkalinity can be optimised to reduce surfactant loss and improve cost-efficiency in ASP flooding. Due to that, this study was presented to investigate the effect of salinity and alkaline concentration on the adsorption of anionic surfactant and the corresponding oil recovery in a sand pack model.

2. METHODOLOGY

2.1 Material

Sodium dodecyl sulfate (SDS) surfactant was obtained from Sigma-Aldrich, while partially hydrolysed polyacrylamide (HPAM) used as polymer was acquired from Vchem. Sodium carbonate (Na_2CO_3) used for preparation of alkaline solution and sodium chloride (NaCl) for brine preparation were obtained from QReC. Quartz sand was the mineral used in adsorption tests, obtained from Pantai Port Dickson, Malaysia, sieved at desired range of size (150 to 250 μm). Sand was packed in the sand pack model, ensuring uniform packing density.

The concentration range for salinity and alkalinity (10,000 to 30,000 ppm) was selected based on practical laboratory constraints and commonly tested ranges in chemical flooding systems. Lower concentrations were excluded due to their limited effect on fluid interactions, while higher values were avoided to minimize risks such as surfactant instability and precipitation.

2.2 Methods

CMC determination

Tensiometer (KRUSS K20 EasyDyne) was used in this test to measure the surface tension and critical micelle concentration (CMC) by plotting surface tension values against surfactant concentrations. Du Noüy ring method was used to measure surface tension at atmospheric pressure at different SDS surfactant concentrations. It ranges from 0 to 6,000 ppm. Acetone was used for each measurement to clean the ring before flame-dried during the experiment. CMC can determine the minimum value of surfactant that can reduce the maximum surface tension in water (Ramesh & Sakthishobana, 2021). In the curve plotted, CMC was identified from the concentration at the inflexion point.

https://doi.org/10.24191/mjcet.v8i2.3517

Porosity and permeability test

For sand pack model preparation, the sand was filled and packed into the cylindrical perspex to represent solid particles to meet the specification as presented in Table 1. At the inlet and outlet, mesh screens were placed so that during injection, porous media did not pass through and come out from the sand pack model. The experimental set-up for porosity and permeability measurement is shown in Fig. 1. From the figure, pressure gauge measured the pressure drop across the model. Collector at the end is for effluent fluid measurement. The porosity of the sand pack model was determined from the pore volume of the sand occupied in the model relative to the bulk volume. It can be calculated using Eq (1):

$$\Phi = \frac{V_{in} - V_{out}}{V_{bulk}} \tag{1}$$

Where V_{in} (ml) is the volume of water injected, V_{out} (ml) is the volume of effluent collected and V_{bulk} is the bulk volume of the porous media. Permeability was measured using Darcy's Law as in Eq (2):

$$k = \frac{Q\mu L}{A\Delta P} \tag{2}$$

Where k (Darcy) is permeability, Q (cm^3/sec) is flow rate of injection, μ (cp) is viscosity of fluid, L (cm) is length of the linear model, A (cm^2) is cross section area of the linear model and ΔP (atm) is pressure difference.

Table 1. Details of sand pack model specification

Details	Specification
Model Shape	Cylinder
Model Length (cm)	20
Inner Diameter (cm)	2
Bulk Volume (cm^3)	62.83
Porous Media	Sand
Model Material	Acrylic Perspex

Source: Authors' own data

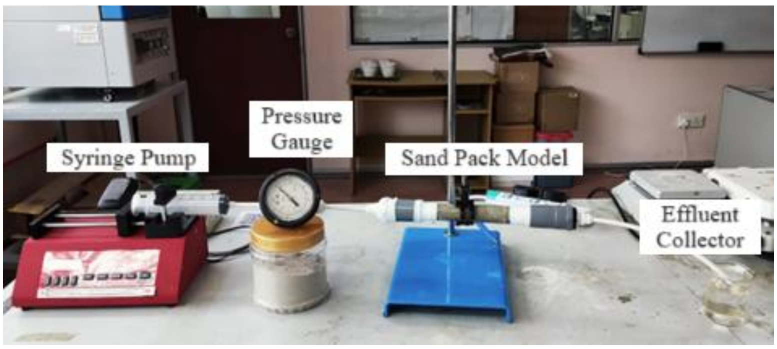

Fig. 1. Porosity and permeability measurement set-up for sand pack model.

Source: Authors' own data

https://doi.org/10.24191/mjcet.v8i2.3517

Dynamic adsorption test

The experimental set-up for this test is the same as Fig. 2. Firstly, the sand pack model was saturated with brine. Then, under constant flow rate, it was pumped with alkaline, anionic surfactant, and polymer solution. The effluent then was collected at every pore volume (PV) and the sample was analysed using UV-Vis spectrophotometer to determine the surfactant concentration for measuring adsorption. The procedures were repeated with ASP formulation at varying brine concentrations (10,000 to 30,000 ppm) and alkaline concentrations (10,000 to 30,000 ppm). To ensure that the effects observed were solely due to salinity and alkalinity only, all other variables including temperature, surfactant and polymer concentrations, injection rate, and sand pack properties, were kept constant throughout the experiments. As shown in Table 2, any change in adsorption at different formulations was observed and analysed.

Table 2. Parameters investigated for surfactant adsorption and ASP flooding

Chemical	Concentration (ppm)
Alkaline (Na_2CO_3)	10,000 to 30,000
Surfactant (SDS)	2,000
Polymer (HPAM)	500
Brine (NaCl)	10,000 to 30,000

Source: Authors' own data

Adsorption measurement

Calibration of UV-Vis spectrophotometry is a must to ensure accurate results. A calibration curve will be generated from a linear plot of absorbance and surfactant concentration with concentration ranges from 0 to 2,000 ppm. The adsorption of surfactant onto sand particles can be determined from the curve. To calibrate, one cuvette was filled with distilled water and another one with sample and place it in the instrument's slot as a blank reference. A calibration curve was prepared by measuring the UV absorbance of SDS surfactant solutions at 265 nm, as determined from the wavelength scan (Abdulhameed et al., 2022). Absorbance readings were taken for various concentrations, and a plot of absorbance versus concentration (ppm) was constructed. In this study, absorbance was measured for sample at varying brine concentrations (10,000 to 30,000 ppm) and alkaline concentrations (10,000 to 30,000 ppm). The absorbance of each sample at different formulation were observed and analysed to determine adsorption rate. The value of adsorbed surfactant can be determined by using Eq. (3) (Wu et al., 2017):

$$\delta = \frac{C_o V_o - \int_{i=1}^{n} C_i V_i}{m} \tag{3}$$

Where δ is dynamic adsorption amount, m (g) is dry weight of the sand pack model, C_o (wt%) is initial surfactant concentration, V_o (mL) is total volume of ASP formulation being injected, C_i (wt%) is concentration of surfactants from collected effluents at varying period and V_i (mL) is volume of effluent's sample.

Oil recovery test

The oil recovery tests were performed for water flooding and following ASP flooding as the secondary recovery and EOR methods, respectively. The original oil in place (OOIP) was first determined before conducting the water flooding. 10,000 ppm of brine was injected and saturated the sand pack at 1 ml/min flow rate, followed by injection of paraffin oil. During the injection of paraffin oil, when oil collection in the sample becomes constant, the OOIP can be determined during this stage. Next, water flooding started with injection of 10,000 ppm brine and the oil recovered at the effluent was collected at every 2 pore volume

https://doi.org/10.24191/mjcet.v8i2.3517

(PV) interval. The procedure was repeated for 30,000 ppm brine water flooding. For this stage, oil recovery achieved was evaluated using Eq. (4).

$$\text{Oil Recovery (\%)} = \frac{\text{Recoverable Oil}}{\text{OOIP}} \text{ x } 100\% \tag{4}$$

When no more oil was recovered at the effluent, the test was stopped. After that, ASP flooding proceeded to obtain incremental oil recovery. ASP formulations using 10,000 ppm alkaline, 2000 ppm SDS and 500 ppm HPAM at 10,000 ppm brine were injected into the sand pack at 1 ml/min flow rate. The incremental oil recovery was assessed for ASP flooding implemented after water flooding. When there was no oil drop in the sampling, the injection stopped. To evaluate the effect of salinity and alkaline, the procedures were repeated with various ASP formulations at 30,000 ppm brine and 30,000 ppm alkaline. Any change on oil recovery at different formulation were observed and analysed.

3. RESULTS AND DISCUSSION

3.1 CMC of SDS surfactant

CMC of surfactant was found using surface tension measurement by plotting surface tension versus surfactant concentration as seen on Fig. 2. As the concentration of surfactants increases, the surface tension decreases. This kept happening until it reached the inflexion point where the curve started to deflect. Thus, the CMC for SDS was found at 2200 ppm. This is because as the concentration increases towards 2200 ppm, there are more SDS molecules at the surface which then becomes overcrowding, thus energetically unfavourable (Kawai et al., 2005). To avoid this issue, at 2200 ppm, the excess SDS molecules start clustering together in the bulk solution to form micelles (Šarac & Bešter-Rogač, 2020). This is why adding more SDS would not further reduce the surface tension.

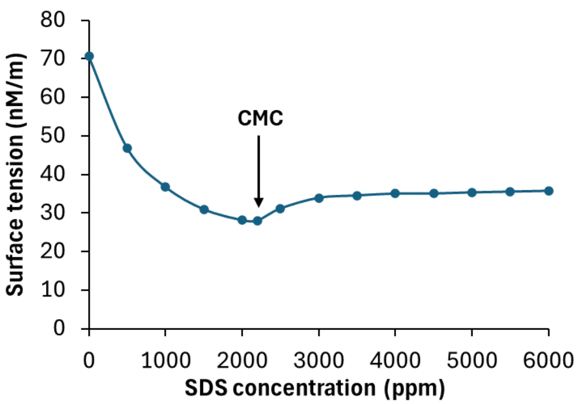

Fig. 2. CMC of SDS surfactant

Source: Authors' own data

https://doi.org/10.24191/mjcet.v8i2.3517

3.2 Porosity and permeability measurement

The porosity of the sand pack model was measured at 0.395, while the permeability was 1.75 D thus implying that 39.5% of the sand pack model was a void space that can be filled with fluids like distilled water, brine and ASP formulation solutions. Permeability of 1.75 D, which was more than 1 Darcy indicated a moderate capacity to transmit fluids. These results mean that the physical characteristics of the sand pack model were high porosity with significant amount of void space and well connected.

3.3 Dynamic adsorption of SDS

Dynamic adsorption tests of SDS surfactant in ASP flooding were conducted by injecting ASP formulation into the sand pack model. Fig. 3 illustrates the adsorption of SDS surfactant in ASP flooding for varying brine and alkaline concentrations ranging from 10,000 to 30,000 ppm. The data of surfactant adsorption for the effect of salinity and alkaline concentration are tabulated in Tables 3 and 4, respectively. In all cases, the amount of SDS adsorbed increased initially with increasing pore volume until it reached a plateau at 2 PV which indicated the adsorption sites have become saturated with SDS molecules. The highest SDS adsorption (0.76 mg/g) was observed at 30,000 ppm brine and 10,000 ppm alkaline, while the lowest adsorption (0.54 mg/g) was found at 10,000 ppm brine with 30,000 ppm alkaline. From the Fig. 3, SDS adsorption increased with increasing salinity. This means that higher salinity conditions promote greater adsorption of SDS surfactants in the sand pack model. This observation aligned with the findings of Zhong et al. (2019) and Nieto-Alvarez et al. (2023), who reported that elevated ionic interactions contribute to increased surfactant adsorption density and subsequently raise the CMC. In addition, the results indicated that surfactant adsorption decreased as the alkalinity increased. This means that lower alkalinity conditions promoted greater SDS adsorption in ASP flooding. The observed reduction in adsorption at higher alkalinity was consistent with the electrostatic repulsion mechanism described by Koparal et al. (2021), wherein elevated pH conditions increased the negative surface charge of minerals, thereby repelling the negatively charged SDS molecules and resulting in decreased adsorption.

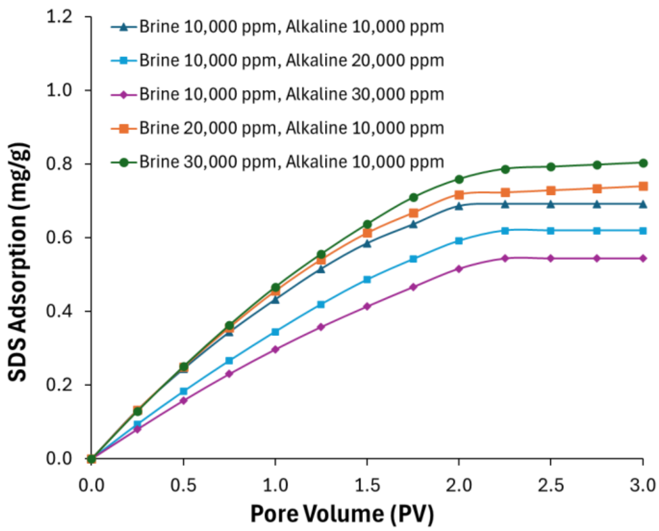

Fig. 3. Salinity and alkalinity effect on SDS adsorption in ASP flooding using 2000 ppm SDS surfactant.

Source: Authors' own data

https://doi.org/10.24191/mjcet.v8i2.3517

Table 3. Surfactant adsorption in ASP flooding at varying salinity for 2000 ppm SDS surfactant.

Brine Concentration (ppm)	**Na_2CO_3 Concentration (ppm)**	**Maximum Adsorption (mg/g)**
10,000	10,000	0.69
20,000	10,000	0.72
30,000	10,000	0.76

Source: Authors' own data

Table 4. Surfactant adsorption in ASP flooding at varying alkalinity for 2000 ppm SDS surfactant.

Brine Concentration (ppm)	**Na_2CO_3 Concentration (ppm)**	**Maximum Adsorption (mg/g)**
10,000	10,000	0.69
10,000	20,000	0.62
10,000	30,000	0.54

Source: Authors' own data

As salinity increases, electrostatic interactions are altered. SDS has a negatively charged head group since it is an anionic surfactant. Initially, the charged head group of the surfactant interacts electrostatically with the surface, creating electrostatic repulsion that prevents adsorption (Vatanparast et al., 2018). However, when NaCl is added, it increases the ionic strength in the solution. The additional salt ions tend to surround the charged head group of the surfactant and the charged surface, forming an "ionic cloud" (Kumar et al., 2004). The ionic cloud increases the electrostatic attraction between surfactant molecules and surface, thus increasing adsorption (Carpenter et al., 2021). Although the ionic cloud reduces electrostatic repulsion, this increased adsorption is undesirable to ASP flooding effectiveness. It reduces the amount of surfactant available in the fluid phase, which negatively affects oil mobilisation, ultimately lowering overall oil recovery.

As the alkalinity increases, the surface tends to lose its positive charges and becomes more negative (Zhang et al., 2023). This is due to the SDS surfactant nature which possesses negatively charged head group. Since both surface and SDS molecules have become like-charged, thus both will repel, hindering their adsorption. Low adsorption of SDS surfactant is favourable in EOR to prevent reduction in concentration, thus becoming ineffective and less efficient (Bera et al., 2013). This is why 10,000 ppm salinity with adsorption 0.69 mg/g and 30,000 ppm alkalinity with 0.54 mg/g were desired because it gives the lowest adsorption based on Table 3.

3.4 Oil recovery measurement

Fig. 4 shows the percentage oil recovery achieved from water flooding and following ASP flooding using 2000 ppm SDS at varying salinity and alkalinity ranging from 10,000 ppm to 30,000 ppm. The summary of oil recovery obtained during water flooding, ASP flooding and total recovery is presented in Fig. 5. Both water flooding and ASP flooding show similar trends in which the oil recovery increased steadily as pore volume increased and then became constant at PV 1.5 to 2 and at PV 3.5 to 5 respectively. For water flooding, the oil recovery obtained at 10,000 ppm brine was 42% OOIP, but as salinity increased to 30,000 ppm, the oil recovery reduced to 38% OOIP. Meanwhile, the following ASP flooding achieved an incremental oil recovery of 28% OOIP with total recovery of 70% OOIP at 10,000 ppm brine and 10,000 ppm alkaline. However, at increasing salinity to 30,000 ppm, oil recovery decreased to 67% OOIP, which in turn increased to 75% OOIP with increasing alkalinity to 30,000 ppm.

https://doi.org/10.24191/mjcet.v8i2.3517

The results suggested that alkalinity played a stronger role than salinity in influencing oil recovery during ASP flooding. In cases where salinity was high, adding more alkali still improved recovery, likely because it helped lower surfactant adsorption and supported better emulsification. These effects seemed to help balance out the downsides of high salinity. These findings highlight the importance of optimising alkaline concentration rather than salinity control when formulating an effective ASP flooding strategy.

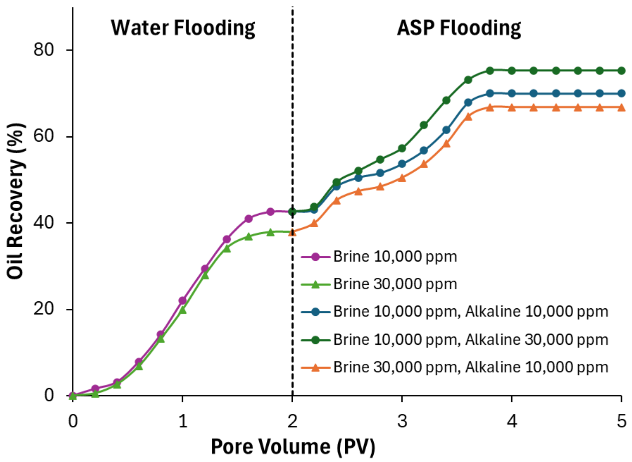

Fig. 4. Salinity and alkalinity effect on oil recovery in ASP flooding using 2000 ppm SDS surfactant

Source: Authors' own data

In water flooding phase, increasing salinity reduces the oil recovery. The increasing ionic strength increases the IFT between the oil and water phases, making it harder for the water to displace the oil. Meanwhile, lower salinity resulted in higher oil recovery. Also, due to the IFT, but has reduction between oil and water (Villero-Mandon et al., 2024). Lower IFT facilitates the oil mobilisation due to the water effectively pushing the oil through the reservoir rock. In terms of wettability, lower salinity can alter the wettability of the rock surface, making it more favourable for oil recovery. The low ionic strength reduces the electrostatic forces that make the rock surface water-wet (Gopani et al., 2021). This condition lets water adhere to the rock surface more strongly than oil.

In ASP flooding, higher salinity leads to lower oil recovery. This is because increased salinity not only raises the interfacial tension between oil and water but also promotes more surfactant adsorption onto the rock surface (Maiki et al., 2024). When salinity increases, the ionic strength of the solution rises as well, causing a screening effect that weakens the repulsion between the negatively charged SDS molecules and the rock. As a result, more surfactant molecules attach to the rock, leaving fewer in the injection fluid to do their job, mainly to reduce interfacial tension and forming micelles. With less surfactant at the oil–water interface, oil displacement becomes less effective, and overall recovery drops.

Increasing alkalinity can improve oil recovery in ASP flooding. As alkali concentration rises, it helps to stabilize emulsions and keeps surfactant molecules from precipitating, which makes the oil displacement process more effective (Obuebite & Okwonna, 2023). A higher pH also develops with increased alkalinity, causing the rock surface to become more negatively charged (Koparal et al., 2021). Since SDS also carries a negative charge, this creates a repelling force between the surfactant and the rock, which lowers the chances of adsorption. With less surfactant sticking to the rock, more stays in the solution to reduce interfacial tension and move trapped oil. On top of that, high alkalinity may cause slight changes in the rock's pore structure, which can further limit how much surfactant gets adsorbed, supporting better oil displacement overall.

https://doi.org/10.24191/mjcet.v8i2.3517

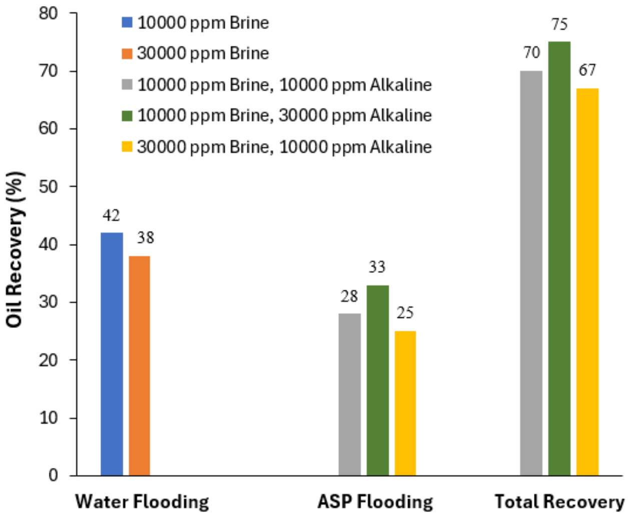

Fig. 5. Summary of oil recovery in ASP Flooding using 2000 ppm SDS surfactant

Source: Authors' own data

4. CONCLUSION

In conclusion, comprehensive experimental approach was successfully conducted to investigate the adsorption of ionic surfactant in ASP flooding and the corresponding oil recovery for EOR application. ASP was formulated using Na_2CO_3, SDS and HPAM, while NaCl brine was selected to investigate the effect of salinity and simulate the real reservoir conditions. CMC of SDS surfactant was found at the inflexion point of 2200 ppm. Thus, lower concentration of 2000 ppm SDS, which was close to the CMC value was selected for further adsorption and oil recovery tests to ensure adsorption occurs, while achieving high oil recovery. From the dynamic adsorption and oil recovery tests, SDS adsorption and the corresponding oil recovery in ASP flooding using 2000 ppm SDS were observed at varying salinity and alkaline concentrations. It was found that lower salinity at 10,000 ppm with high alkalinity at 30,000 ppm exhibited the lowest SDS adsorption at 0.54 mg/g, while yielding the highest total oil recovery of 75% OOIP. It means that SDS surfactant can be sustained longer by having this formulation. Alkaline concentration was also discovered as the most determining factor, which has significant impact on the SDS adsorption and oil recovery in ASP flooding. Overall, this comprehensive experimental design seeks to contribute valuable insights into adsorption behaviours of SDS surfactant with the presence of alkaline and polymer at varying salinity and alkaline concentration, as well as the corresponding oil recovery in the context of ASP flooding for EOR application. For future improvements, replacing sand packs with reservoir core samples may be considered for a realistic assessment of the interaction between the rock, brine and surfactant under reservoir conditions. Besides that, investigating other types of surfactants such as cationic and non-ionic surfactants can improve understandings on the surfactant adsorption behaviours in ASP flooding for different charged surfactants. This adsorption behaviours can also be analysed with different minerals such as calcite and clay minerals. Lastly, the adsorption and oil recovery tests can be conducted at high pressure and temperature to simulate and mimic the real reservoir conditions.

https://doi.org/10.24191/mjcet.v8i2.3517

ACKNOWLEDGEMENTS

The authors would like to thank the Faculty of Chemical Engineering, Universiti Teknologi MARA for the facilities and support provided. This research was funded by the Ministry of Higher Education (MoHE) through Fundamental Research Grant scheme (FRGS) with code (FRGS/1/2023/TK05/UITM/02/1).

CONFLICT OF INTEREST STATEMENT

The authors agree that this research was conducted in the absence of any self-benefits, commercial or financial conflicts and declare the absence of conflicting interests with the funders.

AUTHORS' CONTRIBUTION

Author 1: Conceptualisation, methodology, formal analysis, investigation, and writing-original draft; **Author 2**: Project administration, conceptualisation, data analysis and validation; supervision, writing-review and editing, and validation; **Author 3**: supervision, editing, and validation.

REFERENCES

Abdel-Wali, A. (1996). Effect of simple polar compounds and salinity on interfacial tension and wettability of Rock/Oil/Brine system. *Journal of King Saud University: Engineering Sciences*. *8*(2), 153–162. https://doi.org/10.1016/s1018-3639(18)30655-x

Abdulhameed, A., Abdul Halin, I., Mohtar, M. N., & Hamidon, M. N. (2022). Optimization of Surfactant Concentration in Carbon Nanotube Solutions for Dielectrophoretic Ceiling Assembly and Alignment: Implications for Transparent Electronics. *7*(4). https://doi.org/10.1021/acsomega.1c06323

Amran, T., Mohd, T., Bohairah, T.A., Jaafar, M.Z. (2022). Characterization of Quartz Sand as an Adsorbent for Anionic Surfactant Adsorption with Presences of Alkaline and Polymer. *Chemical Engineering Transactions*, 95, 283-288. https://doi.org/10.3303/CET2295048

Al-Jaber, H. A., Arsad, A., Bandyopadhyay, S., Jaafar, M. Z., Tahir, M. N., Nuhma, M. J., Abdulmunem, A. R., Abdulfatah, M. Y., & Alias, H. (2023). Relation between Conventional and Starch-Assisted ASP Injection and Impact of Crystallinity on Flood Formation. *Molecules*, *28*(18), 6685. https://doi.org/10.3390/molecules28186685

Behrang, M., Hosseini, S., & Akhlaghi, N. (2021). Effect of pH on interfacial tension reduction of oil (Heavy acidic crude oil, resinous and asphaltenic synthetic oil)/low salinity solution prepared by chloride-based salts. *Journal of Petroleum Science and Engineering*, *205*, 108840. https://doi.org/10.1016/j.petrol.2021.108840

Belhaj, A. F., Elraies, K. A., Mahmood, S. M., Zulkifli, N. N., Akbari, S., & Hussien, O. S. (2019). The effect of surfactant concentration, salinity, temperature, and pH on surfactant adsorption for chemical enhanced oil recovery: a review. *Journal of Petroleum Exploration and Production Technology*, *10*(1), 125–137. https://doi.org/10.1007/s13202-019-0685-y

Bera, A., Kumar, T., Ojha, K., & Mandal, A. (2013). Adsorption of surfactants on sand surface in enhanced oil recovery: Isotherms, kinetics and thermodynamic studies. *284*. https://doi.org/10.1016/j.apsusc.2013.07.029

Carpenter, A. P., Foster, M. J., Jones, K. K., & Richmond, G. L. (2021). Effects of Salt-Induced Charge Screening on AOT adsorption to the planar and nanoemulsion Oil–Water interfaces. *Langmuir*, *37*(29), 8658–8666. https://doi.org/10.1021/acs.langmuir.0c03606

Gopani, P. H., Singh, N., Sarma, H. K., Negi, D. S., & Mattey, P. (2021, April 10). A Zeta Potentiometric Study on Effects of Ionic Composition and Rock-Saturation on Surface-Charge Interactions in Low-Salinity Water Flooding for Carbonate Formation. https://doi.org/10.2118/200804-MS

Herawati, I., Permadi, P., Rochliadi, A., & Marhaendrajana, T. (2022). Adsorption of anionic surfactant on sandstone reservoir containing clay minerals and its effect on wettability alteration. *Energy Reports*, *8*, 11554–11568. https://doi.org/10.1016/j.egyr.2022.08.268

Koparal, G. B., Sharma, H., Liyanage, P. J., Panthi, K. K., & Mohanty, K. (2021). Adsorption of anionic surfactants in sandstones: impact of sacrificial agents. *SPE Western Regional Meeting*. https://doi.org/10.2118/200883-MS

Kumar, S., Khan, Z. A., & Din, K.-. ud . (2004). Clouding phenomenon in ionic micellar solutions: Role of the counterion. *7*(4). https://doi.org/10.1007/s11743-004-0320-z

Laben, A. B., Kayiem, H. H. A., Alameen, M. A., Khan, J. A., Belhaj, A. F., & Elraies, K. A. (2021). Experimental study on the performance of emulsions produced during ASP flooding. *Journal of Petroleum Exploration and Production Technology*, *12*(7), 1797–1809. https://doi.org/10.1007/s13202-021-01409-6

León, J. M. B., Izadi, M., Castillo, A.., Zapata, J. F., Chaparro, C., Jiménez, J., Vicente, S., & Castro, R. H. (2018). Use of Cross-Linked Polymer Systems to Improve Volumetric Sweep Efficiency and Alternative Full Field Development Strategy for a Mature Waterflooding Optimization Processes - Dina Cretaceous Field Case. *SPE Improved Oil Recovery Conference, Tulsa, Oklahoma, United States of America*. https://doi.org/10.2118/190313-ms

Li, Y., Kong, B., Zhang, W., Bao, X., Jin, J., Wu, X., Guo, Y., Liu, Y., Wang, Y., He, X., Zhang, H., Shen, Z., & Sha, O. (2020). Field Application of Alkali/Surfactant/Polymer Flood with Novel Mixtures of Anionic/Cationic Surfactants for High-Temperature and High-Water-Cut Mature Sandstone Reservoir. *SPE Reservoir Evaluation & Engineering*, *23*(03), 1093–1104. https://doi.org/10.2118/195056-PA

Maiki, E. P., Sun, R., Ren, S., & AlRassas, A. M. (2024). Experimental and Molecular Dynamics Simulation to Investigate Oil Adsorption and Detachment from Sandstone/Quartz Surface by Low-Salinity Surfactant Brines. https://doi.org/10.1021/acsomega.4c00562

Mohd, T. A. T, Bohairah, N. A., Mat Shayuti, M. S., Nik Ab Lah, N. K. I., Shahruddin, M. Z., & Jaafar, M. Z. (2023). Minimizing Adsorption of Anionic Surfactant in Alkaline-Surfactant-Polymer System: Effects of pH and Surfactant Concentration. *Key Engineering Materials, 939,* 75–82. https://doi.org/10.4028/p-0huhs2

Mohd, T.A.T., Jaafar, M.Z. (2019). Adsorption of Anionic Sodium Dodecyl Sulfate Surfactant on Local Sand and Kaolinite Surfaces: The Prospect of Alkaline and Salinity. *International Journal of Recent Technology and Engineering, 7*(6), 972–979.

Nieto-Alvarez, D. A., Marín-León, A., Luna-Rojero, E. E., Servín-Nájera, A. G., Soto-Castruita, E., Cisneros-Dévora, R., Cerón-Camacho, R., Hernández-Altamirano, R., Mena-Cervantes, V. Y., & Zamudio-Rivera, L. S. (2023). Static and dynamic adsorption of supramolecular surfactant for oil recovery in high temperature and salinity conditions. *Journal of Surfactants and Detergents*, *26*(6), 817–826. https://doi.org/10.1002/jsde.12678

Obuebite, A. A., & Okwonna, O. O. (2023). Design of salinity tolerant in alkaline surfactant systems for high salinity reservoirs. *14*(3). https://doi.org/10.30574/gscarr.2023.14.3.0076

Olajire, A. A. (2014). Review of ASP EOR (alkaline surfactant polymer enhanced oil recovery) technology in the petroleum industry: Prospects and challenges. *Energy*, *77*, 963–982. https://doi.org/10.1016/j.energy.2014.09.005

Ramesh, M., & Sakthishobana, K. (2021). Significance of biosurfactants in oil recovery and bioremediation of crude oil. In *Elsevier eBooks*, 211–226. https://doi.org/10.1016/b978-0-12-822696-4.00006-1

Šarac, B., & Bešter-Rogač, M. (2020). The Influence of Ionic Liquids on Micellization of Sodium Dodecyl Sulfate in Aqueous Solutions. *67*(3). https://doi.org/10.17344/ACSI.2020.6052

Sukee, A., Nunta, T., Fongkham, N., Yoosook, H., Jeennakorn, M., Harbottle, D., Santha, N., & Tangparitkul, S. (2022). Effects of brine valency and concentration on oil displacement by spontaneous imbibition: An interplay between wettability alteration and reduction in the oil-brine interfacial tension. *Journal of Molecular Liquids*, *365*, 120089. https://doi.org/10.1016/j.molliq.2022.120089

Sun, C., Guo, H., Li, Y., Jiang, G., & Ma, R. (2020). Alkali effect on alkali-surfactant-polymer (ASP) flooding enhanced oil recovery performance: Two large-scale field tests' evidence. *Journal of Chemistry*, 1–22. https://doi.org/10.1155/2020/2829565

Uzoho, C. U., Onyekonwu, M., & adnAkaranta, O. (2015). Formulation of local Alkaline- Surfactant-Polymer (ASP) for enhanced oil recovery in Niger Delta: a review. *All Days*. https://doi.org/10.2118/178300-ms

Vatanparast, H., Shahabi, F., Bahramian, A., Javadi, A., & Miller, R. (2018). The Role of Electrostatic Repulsion on Increasing Surface Activity of Anionic Surfactants in the Presence of Hydrophilic Silica Nanoparticles. *8*(1). https://doi.org/10.1038/S41598-018-25493-7

Villero-Mandon, J., Pourafshary, P., & Riazi, M. (2024). Oil/Brine Screening for Improved Fluid/Fluid Interactions during Low-Salinity Water Flooding. https://doi.org/10.3390/colloids8020023

Wang, Z., Yu, T., Lin, X., Wang, X., & Su, L. (2016). Chemicals loss and the effect on formation damage in reservoirs with ASP flooding enhanced oil recovery. *Journal of Natural Gas Science and Engineering*, *33*, 1381–1389. https://doi.org/10.1016/j.jngse.2016.06.048

Wu, Y., Chen, W., Dai, C., Huang, Y., Li, H., Zhao, M., He, L. and Jiao, B. (2017). Reducing surfactant adsorption on rock by silica nanoparticles for enhanced oil recovery. *Journal of Petroleum Science and Engineering*, *153*, 283– 287. https://doi.org/10.1016/j.petrol.2017.04.015

Zhang, Z., Ispas, S., & Kob, W. (2023). Surface properties of alkali silicate glasses: Influence of the modifiers. *158*(24). https://doi.org/10.1063/5.0155497

Zhong, H., Yang, T., Yin, H., Lu, J., Zhang, K., & Chen, F. (2019). Role of alkali type in chemical loss and ASP-Flooding enhanced oil recovery in sandstone formations. *SPE Reservoir Evaluation & Engineering*, *23*(02), 431–445. https://doi.org/10.2118/191545-pa

Zhong, X., Pu, H., Zhou, Y., & Zhao, J. X. (2019). Static adsorption of surfactants on bakken rock surfaces in high temperature, high salinity conditions. *SPE International Conference on Oilfield Chemistry*. https://doi.org/10.2118/193589-MS

Zhu, S., Shi, L., Wang, X., Liu, C., Xue, X., & Ye, Z. (2020). Investigation into mobility control mechanisms by polymer flooding in offshore high-permeable heavy oil reservoir. *Energy Sources, Part A: Recovery, Utilization, and Environmental Effects*, 1–14. https://doi.org/10.1080/15567036.2020.1797941

https://doi.org/10.24191/mjcet.v8i2.3517