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Exploring the Dominant Factors of Chemical Adsorption in Enhanced Oil Recovery: An Analytical Investigation

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Abstract

Enhanced oil recovery (EOR) is a process for extracting oil that cannot be retrieved through the primary or secondary oil recovery techniques. A significant parameter that affects chemical (EOR) operations is chemical adsorption, which has a major impact on rock permeability, wettability, and the overall oil production.

Therefore, dynamic flooding experiments on an unconsolidated sand-pack model was conducted to investigate the chemical adsorption by calculating the amount of adsorption and the residual resistance factor at different injection conditions (injected chemical types and concentrations, salinity, temperature, flow rate, and additive nano-silica). Two chemicals, i.e., bio-polymer (xanthan gum, XG), and anionic surfactant (sodium dodecylbenzene sulphonate, SDBS) were used as displacement fluids in sandstone formations. Design Expert software was used to provide the number of experimental runs to each investigated factor, develop a predicted model for the amount of chemical adsorption and the residual resistance factor, and provide an optimum amount of chemical adsorption to enhance recovery. The results showed that increasing the biopolymer concentration from 500 to 1500 ppm in sandstone formation at different injection conditions (flowrate from 2 to 6 ml/min, salinities ranging from 0 to 10 wt%, and temperature from 20◦C to 70◦C) resulted in increasing chemical adsorption from an initial value of 0.2 mg/g to 1.15 mg/g after stabilized condition of chemical adsorption. Similar trend was observed in case of SDBS such that increasing the surfactant concentration from 2000 ppm to 5000 ppm resulted in increasing adsorption from an initial value of 0.11mg/g to 1.07mg/g at the same injection conditions. Using of nano-silica particles (NSP) as a co-injectant to the SDBS and XG enhanced the polymer adsorption by 67.8% and the surfactant adsorption by 60.2%. A previously proposed mechanism for the adsorption of XG/NSP and SDBS/NSP blends on sandstone was confirmed by the results obtained from the oil contact angle experiments. Finally, the adsorption optimization runs resulted in a recovery factor of 78.9% for the polymer folding, 67% for the surfactant, and 77% for the polymer-surfactant blend compared to 58% for the water flooding base case.

Keywords: Enhanced Oil Recovery; Polymer flooding; Surfactant flooding; Chemical adsorption; Rock wettability; Nanoparticle

1. Introduction

Up to two thirds of the crude oil remains trapped in the reservoirs after traditional recovery methods in an average oil reservoir, (Rosen, Wang, Chen, & Zhu, 2005). Enhanced oil recovery techniques have the potential to increase production rates and improve ultimate recovery, highlighting the critical importance of accurately predicting water saturation and areal sweep efficiency to ensure the success of these methods (Gomaa, Soliman, Nasr, Emara, El-Hoshoudy, & Attia, 2022) (Gomaa, Soliman, Mohamed, Emara, & Attia, 2022). One of the main methods of EOR is “chemical flooding”.

The chemicals of concern are the polymer xanthan gum (XG) bio-polymer and surfactant (sodium dodecylbenzene sulphonate, SDBS). Polymer flooding improves the recovery of the oil by increasing the water viscosity and enhancing the sweep efficiency and oil mobility ratio (Soliman, El-Hoshoudy, & Attia, 2020) (Elsaeed, Zaki, Omar, Soliman, & Attia, 2021) (El-hoshoudy, Gomaa, & Attia, 2019) (El-hoshoudy, El-Desouky, Attia, & Gomaa, 2018) (Mahran, Attia, & Saha, 2018), while

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the surfactant (sodium dodecylbenzene sulphonate, SDBS) acts as a miscible agent to recover the oil trapped as a discontinuous phase or continuous phase oil in unwept zones by changing the wettability and reducing the water/oil IFT

The (nano-Silica) improve oil recovery by enhancing the sweep efficiency and by changing the wettability into more water wet by being adsorbed on the rock surface (Attia & Musa, 2015). A recent mechanism of chemical flooding is the co-injection of nanoparticles with the chemicals (surfactant or polymer) to utilize the properties of each component to enhance the oil recovery (Suleimanov, Ismayilov, & Veliyev, 2011) (Mahmoudi, Jafari, & Javadian, 2019).

Chemical adsorption can be viewed either an advantage or a drawback depending on reservoir type. The chemical adsorption results in chemical loss in the formation which causes a decrease in permeability and overall reduction in oil recovery (Attia, 2007), However these effects can be advantageous in certain cases; in the surfactant flooding the adherence of the molecules on the surface of the rock promotes wettability alteration which allows for increased recovery by changing the wettability into more water-wetting, while in case of polymer flooding in a heterogenous reservoir, the adsorption can redirect the polymer’s path from the high to low permeability zones where oil is trapped increasing the oil recovery, thus the optimization and management of the chemical retention is essential to the enhanced oil recovery.

(Zitha et al., 1998), and (Dang et al., 2011) determined that increasing the concentration of the polymer increases the retention and by controlling the concentration, the amount of adsorption can be controlled. As for the surfactant (Trogus et al., 1977) and (Ma et al., 2013) determined that increasing the surfactant concentration, increases the amount of adsorption till it reaches critical micelle concentration, at which point the adsorption stabilizes.

Increasing the solution salinity results in higher amount of polymer adsorption in the reservoir were determined by (Sarem, 1970), (Celik et al., 1991), (Shamsijazeyi et al., 2013) and (Dang et al., 2011). By investigating the influence of salinity on surfactant adsorption, it was determined that high salinity results in higher amount of adsorption (Verduzco et al., 2014).

Increasing the flow rate increases polymer retention for both HPAM and Xanthan gum polymers (Satken, 2021). (Idahosa, Oluyemi, Mufutau, & Prabhu, 2016) investigated the influence of injection rate on the dynamic retention of an anionic surfactant and determined that increasing the injection rate increases the rate of surfactant adsorption.

The effect of temperature on the Ad of anionic and non-ionic surfactants was studied by (Ziegler & Handy, 1981) and determined that at low concentration the temperature increase caused a decrease in the adsorption capacity while at high concentrations the temperature increase, increased the adsorption capacity. While (Belhaj, et al., 2020) stated that increasing the temperature results in higher amounts of adsorption in low adsorption density surfactants while the opposite is true for high adsorption density surfactants.

(Wiśniewska, 2012) determined that at higher temperatures the amount of adsorption is reduced and the creation of thicker adsorption layer of the polymer on the solid surface occurs.

(Doroszkowski, 1999) stated that increasing the temperature increases the amount of polymer adsorption such that the process is endothermic, however in case of physical adsorption the process is not endothermic, and the amount of polymer retention decreases with increasing the temperature.

It is the aim of the current study to investigate the adsorption behavior of SDBS and XG on sandstone surface at various concentrations, nano-silica concentrations, temperatures, flowrates, and salinities. Such that the previous work investigated the effect of each factor on the adsorption but not on the other factors, however the factors presented are compound variables meaning that their behavior is dependent on each other, therefore the design expert software is used to investigate the effect and significance of each factor on the Ad and Rrf as well as the interaction between the factors and each other. The design expert software is used to design the experimental work by generating the values of the factors for each experimental run, then it provides a model that can be used in response prediction and determines the significance of each factor and how it affects the Ad and Rrf. It also provides full analysis of the results. Oil contact angle calculations and relative permeability curves were employed to investigate the wettability of the SDBS/NSP and XG/NSP and to confirm the previously proposed mechanism which stated that the NSP addition increases the retention of XG and SDBS (Azmi, et al., 2022). Recovery experiments were done to verify the efficiency of the model and calculate the recovery factor for the optimal conditions generated by Design Expert.

2. Experimental

2.1. Materials

Xanthan Gum (XG), and nano-silica of size 20 nm were purchased from ITA Co. (Egypt). The anionic surfactant, sodium dodecylbenzene sulphonate (SDBS) 80% extra pure is provided by Loba Chemie PVT. LTD, (India).

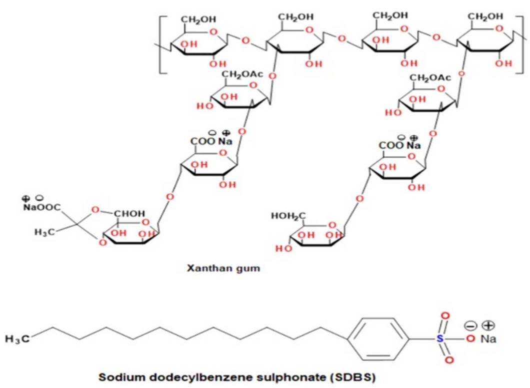

Figure 1: Chemical Structure of XG and SDBS (Azmi, et al., 2022).

A pycnometer (10mL) was used to calculate the API and the crude oil density. A rolling ball viscometer was utilized to calculate the viscosity of the oil; the results are shown in Table 1.

Table 1 Oil Properties

Properties	Values at 25°C
Density (g/mL)	0.85
API	31
Viscosity (cp)	3.8

2.2. Displacement apparatus

2.2.1. Sand pack apparatus

Figure 2 illustrates the displacement apparatus. The EOR experiments were performed using a sand pack to represent the reservoir rock. The sand pack is made of acrylic material, and it was fitted with two inlet and outlet chambers to establish uniform distribution of the fluid being injected. A nitrogen gas cylinder fitted with a pressure regulator was used to inject the chemicals into the model. Chemical tanks are used for storing the XG, SDBS, crude oil, and the brine solution. A graduated glass tube was used to collect effluent fluid samples. To control the temperature of the model, a water bath fitted with an electric heater, regulator, and thermometer was used.

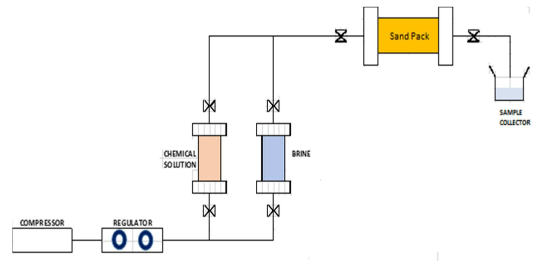

Figure 2: Displacement set-up

2.2.2. Sand pack preparation

The sand pack was prepared by using 0.3 mm unconsolidated sand. The inlet and outlet were fitted with filters and screens to prevent sand migration and provide efficient fluid distribution during fluid injection through the sand pack. Darcy's law was utilized to measure the absolute permeability, and the saturation fluid method was used to measure the porosity.

Table 2 shows the sand pack details

Property, unit	value/unit
Diameter, cm	5.2
Length, cm	21
Sand size, mm	0.3
Pore volume, mL	100
Bulk volume, mL	412.334
Area, cm2	19.635
Permeability, mD	500–532
Porosity, %	25

2.3. Experimental procedures

2.3.1. Adsorption and Residual resistance factor

The sand was packed into the model while saturating it with brine, then it was introduced to the water bath to control its temperature. The permeability was calculated using brine injection before the injection of the chemical, then the chemicals was injected into the sand pack to displace the brine, and samples of the chemical effluent were collected to calculate the concentration by using the viscosity correlation method (Lam, Martin, Jefferis, & Goodhue, 2014). The permeability is calculated again by re-injecting brine to displace the injected chemical to calculate the Rrf. All chemical solutions are prepared and continuously stirred using mechanical stirrer and sonicator prior to the experiments.

2.3.2. Oil Recovery Experiments

In order to verify the optimal solution provided by the software, recovery experiments were performed in the lab where the oil recovery and displacement efficiency were calculated.

2.3.2.1. Water Flooding

The water flood run was performed using 10 wt% brine solution, such that 2PV of brine was injected continually till no more oil was recovered from the model. The residual oil saturation and cumulative oil recovery were calculated by recording the effluent water and oil collected in the graduated glass cylinders, also the date was used to develop the relative permeability saturation curve, and to compare with the polymer and surfactant flooding for the optimal conditions.

2.3.2.2. Chemical Flooding

After the water flooding, the sand pack was injected with XG, XG/NSP, SDBS, SDBS/XG, XG/SDBS/NSP solutions with the optimal concentrations determined from the software at 10wt% salinity and 25 ° C.

2.3.3. Oil Contact Angle

A circular coin shaped core samples were saturated with brine fully (10 wt% NaCl) overnight at 25 °C and were introduced to the solution with optimum concentrations of XG, SDBS, XG/SNP blend, and SDBS/SNP blend. Then, an oil droplet was injected into the core sample's lower surface to measure the oil contact angle using the sessile drop method. (Gao, et al., 2020)

2.4. Design Expert use in chemical adsorption analysis:

The design expert software is used to design the experimental work by generating the values of the factors for each experimental run, then it provides a model that can be used in response prediction and determines the significance of each factor and how it affects the Ad and Rrf. It also provides full analysis of the results as well as analysis of variance (ANOVA) and diagnostic plots.

2.4.1. Design the experiment.

By entering the factors to be studied (concentration, NSP concentration, flowrate, temperature, salinity) and their limits as shown in table (3). The software designs the experimental runs suitable to study the factors.

Table 3. Limits of Parameters

Limits of parameters	*Polymer Flooding*	*Surfactant Flooding*
Chemical concentration	500-1500 ppm	2000-5000 ppm
Nano-Silica concentration	100-2000 ppm	100-2000 ppm
Salinity	0-100000 ppm	0-100000 ppm
Temperature	25℃ - 75℃	25℃ - 75℃
Flowrate	2-6 ml/min	2-6 ml/min

2.4.2. Data Analysis

The software performs ANOVA analysis to show the statistical significance of each factor individually as well as the interaction between the factors. It also provides a variety of graphs that can be used to identify standout effects such as Interaction curves, 3D and contour graphs.

2.4.3. Prediction of Ad and Rrf

It establishes a correlation based on the acquired data that can be used to predict the Ad and Rrf based on the values of the factors inside the correlation.

2.4.4. Optimization of Ad and Rrf

The optimization feature searches for a combination of factor values that satisfy the criteria placed on each of the responses (Ad and Rrf) as well as the factors.

3. Results and Discussion

3.1. Adsorption and Residual resistance factor

The influence of operating parameters, i.e., concentration, nano-silica concentration, salinity, temperature, and flow rate in sandstone formation were investigated by measuring the amount of adsorption and the Rrf for the sodium dodycylbenzenesulphonate and Xanthan gum biopolymer. The amount of adsorption (Ad) is calculated using Equation 1 (Tay, et al., 2015). The resistance factor (Rf) of a given fluid is the mobility ratio of the brine and chemical being injected. Residual resistance factor (Rrf) of a given fluid refers to the ratio of the brine permeability before and after chemical solution flows through the sand pack. The (Rrf) is calculated using Equation 2 (Stahl, Moradi-Araghi, & Doe, 1988).

$$Ad = \frac{V}{M}(C_1 - C_2) \quad (1)$$

where M is the sand mass in g, V is the volume of solution in litre, C1 is inlet concentration in ppm, and C2 is the outlet concentration in ppm, such that the outlet concentration is determined from the viscosity values using a OFITE testing equipment (OFITE) model 800 8-speed electronic viscometer to establish a calibration curve then determine the effluent concentration. (Lam, Martin, Jefferis, & Goodhue, 2014).

$$Rrf = \frac{Kw1}{Kw2} \quad (2)$$

Where Kw1 is the permeability prior to the injection of the chemical and Kw2 is the permeability after the injection of the chemical.

3.2. Effect of concentration, nano-Silica, Temperature, Salinity, Flowrate, and their interactions

3.2.1. The effect of biopolymer and nano-Silica concentrations, Temperature, Salinity, Flowrate in sandstone formation on the Ad and Rrf

The influence of the individual variables for the biopolymer in sandstone formation on adsorption and Rrf are shown in figures 3 and 4.

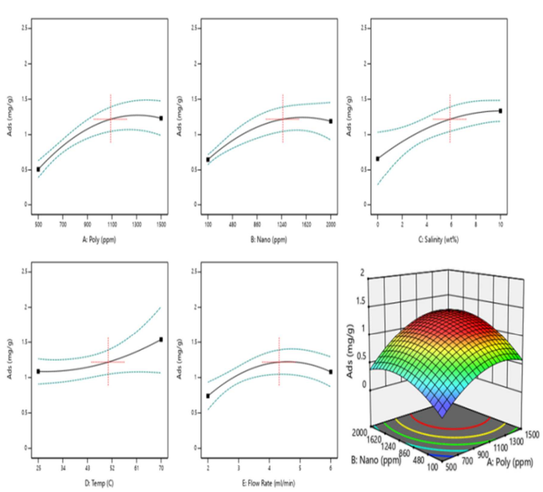

Figure 3: Effect of concentration, nano-Silica, Temperature, Salinity, Flowrate for the biopolymer on adsorption

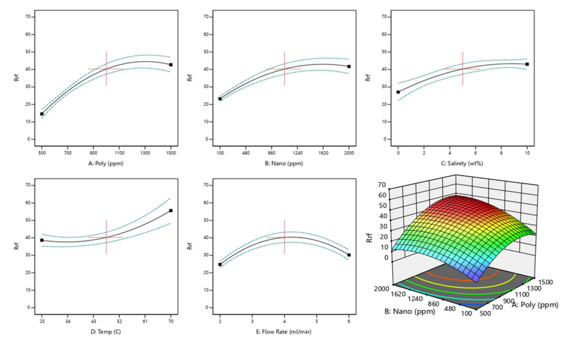

Figure 4: Effect of concentration, nano-Silica, Temperature, Salinity, Flowrate for the biopolymer on Rrf

All variables have positive effect on the responses, however some of the variables alter their trend after the midpoint.

The bio-polymer concentration (A) has a positive effect on Ad and Rrf, these findings agree with (Mishra, Bera, & Mandal, 2014), however the increase rate of the values is slower at higher chemical concentrations indicating stabilization of the adsorption(i.e., approaching saturation) at high concentrations. This can be attributed to the high amount biopolymer molecules retained on the surface of the rock by hydrogen bonding between negatively charged sandstone surface (SR) and the hydroxyl groups in the polymer.

The nano-Silica concentration (B) has a positive effect on Ad and Rrf which can be due to the adsorption of the silica gel on the rock and hydrogen bonds formation through the hydroxyl groups on the silica, then XG polymer retention took place on the surface of the rock (Bracho, Dougnac, Palza, & Quijada, 2012), also multi-layer adsorption can take place as the nano-Silica particles act as the cross linker between polymer chains through hydrogen bonds (Potanian, 2019) (Nassau & Raghavachari, 1988).

The Salinity (C) has a positive effect on Ad and Rrf, the increase in the adsorption and Rrf value with increasing solution salinity can be due to the salting out effect by decreasing the polymer solubility leading to XG “sedimentaion” onto the rock surface (Braga, Azevedo, Marquis, Menossi, & Cunha, 2006).

The Ad and Rrf increase by increasing the flow rate (D) due to hydrodynamic retention in which the polymer molecules gets trapped due to the hydrodynamic drag forces which increase at high flow rates (Chauveteau & Kohler, 1974) (Sorbie, 2013). The second mechanism is polymer trapping due to its shape changing from coiled to elongated at high shear rates which facilitates its adsorption in smaller pores (Dominguez & Willhite, 1977) (Huh, Lange, & Cannella, 1990) (Marker, 1973).

The temperature showed a monotonic increase in Ad and Rrf. The amount of adsorption decreases with increasing the temperature because the polymer solubility increases as the temperature rise (Wisniewska, 2012), However the polymer layer thickness showed an increase as the temperature rise due to the straightening the adsorbed polymer macromolecules. The effect of the adsorbed layer was more profound during this study thus the temperature had a positive effect on the Ad and Rrf.

3.2.2. Effect of concentration, nano-Silica, Temperature, Salinity, Flowrate for the surfactant in sandstone formation

The influence of the individual variables for the surfactant in sandstone formation on adsorption and Rrf are illustrated in figures 5 and 6 respectively.

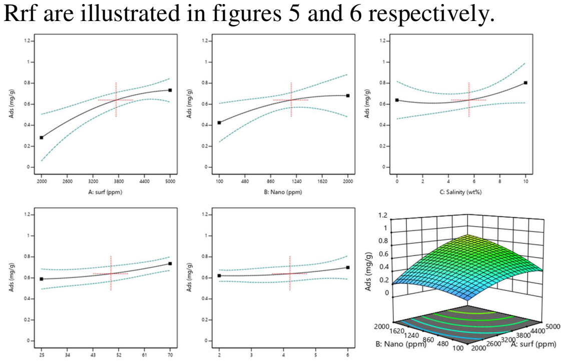

Figure 5: Effect of concentration, nano-Silica, Temperature, Salinity, Flowrate for the surfactant on

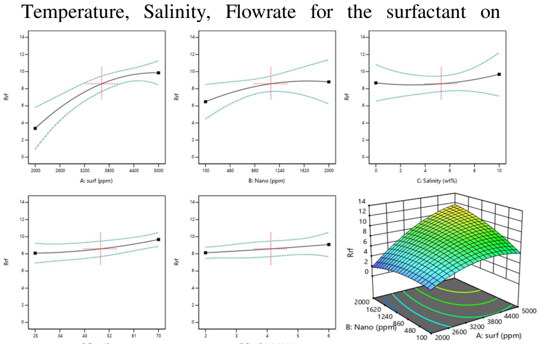

Figure 6: Effect of concentration, nano-Silica, Temperature, Salinity, Flowrate for the surfactant on Rrf

The concentration (A) has a positive influence on the Ad and Rrf, this can be attributed to the formation of miscellas at higher concentrations, such that at low concentration the adsorption occurs as single monomer but at higher concentrations the monomers aggregate forming miscellas which increases the adsorption density, the adsorption then stabilizes when the CMC is reached (Adak, Bandyopadhyay, & Pal, 2005) (Budhathoki, Barnee , Shiau, & Harwell, 2016) (Kamal, Hussein, & Fogang, 2017).

The nano-Silica concentration (B) increase causes an increase in the Ad and Rrf, this can be due to the formation of hydrogen bond between the hydrophobic surfactant tail and the sandstone rock surface caused by the addition of nano-Silica which results in attracting more surfactant molecules to the rock surface (Ahmadi & Shadizadeh, 2013) (Li, An, Gong, & Cheng, 2007). The Salinity (C) has a positive effect on the Ad and Rrf which can be attributed to the decrease of the repulsion forces between the sandstone surface and the oppositely charged ionic surfactant head as the salinity increases which increases the Ad and Rrf (Belhaj, et al., 2020) (Koopal, Lee, & Bohmer, 1996).

The Temperature (D) has a positive effect on Ad and Rrf , these results agree with (Ziegler & Handy, 1981) where it was reported that the amount of adsorption increase as the temperature rise for surfactants with low adsorption density.

The flow rate (E) also has a positive effect on Ad and Rrf, these results agree with (Kwok, Hayes, & Nasr El Din, 1994) which reported that increasing the flow rate results in a decrease in the mass transfer resistance near the rock surface due to increasing the shear rate.

4. Optimization

4.1. Optimum Conditions

The optimization module searches for a combination of factor levels that simultaneously satisfy the criteria placed on each of the responses (Ad and Rrf) and factors (chemical concentration, nano-silica concentration, salinity, flow rate, and temperature). To include a response in the optimization criteria it must have a model fit through analysis.

First, for each factor, a goal is set which is to maximize, minimize or keep it in range with specifying that range. Second the importance is specified either low, fair, or high importance. Third, after the model is analyzed, the responses will be included in the optimization section, where the goal and importance can be set for each response. i.e. if the goal is to have low adsorption in the reservoir, the goal will be set to minimize adsorption and the importance will be high and vice versa if the goal is to increase adsorption.

These steps are repeated for each factor based on the goals and conditions desired for the Enhanced Oil Recovery operation. After the optimization is complete, the software provides multiple solution that satisfies the desired criteria in order to choose the most suitable solution for the operation.

Table 3 shows the numerical optimization for the Biopolymer and surfactant in sandstone formation where the goal is set to minimize the amount of adsorption and Rrf and the importance is set to high while all factors are kept in range except for the nano-Silica concentration which is set to low to avoid high cost. The most suitable solution is selected as shown in the table.

Table 4. Numerical Optimization for the Biopolymer and Surfactant in Sandstone Formation

	Polymer Flooding	*Surfactant Flooding*
Chemical concentration	501.78 ppm	2242.9 ppm
Nano-Silica concentration	108.58 ppm	208.109 ppm
Salinity	100000 ppm	100000 ppm
Temperature	25ºC	25ºC
Flow-rate	2.23 ml/min	4.75 l/min

4.2. Experimental

4.2.1. Recovery

Utilizing the optimal conditions generated by the software, recovery experiments were performed to determine the oil recovery and the displacement efficiency of XG, SDBS, XG/NSP, SDBS/NSP, and XG/SDBS/NSP solutions and compare it to the base case (water flooding) to verify that the optimal conditions achieve enhanced recovery at the lowest adsorption and Rrf values.

First the Ad and Rrf were calculated experimentally for the optimal conditions selected and the values were: Ad: 0.3 mg/g and Rrf: 6 for the polymer, while the surfactant resulted in Ad: 0.177 mg/g and Rrf: 2. This shows that the optimal conditions resulted in low adsorption and residual resistance factor values.

Then the recovery experiment results show that, the oil recovery in the water flooding base case is 58%, compared to 78.9% in XG/NSP flooding and 67% in SDBS/NSP flooding, while the XG flooding resulted in 75% and the SDBS resulted in 64%. While the injection of a surfactant slug (0.2PV) followed by the injection of a polymer slug (0.2PV) resulted in 77% Recovery.

The results show that the addition of nano-silica improved the recovery of the oil by 4% in case of polymer and 3% in case of the surfactant which can be attributed to the improved wettability alteration caused by the adsorption of the nano silica on the rock surface.

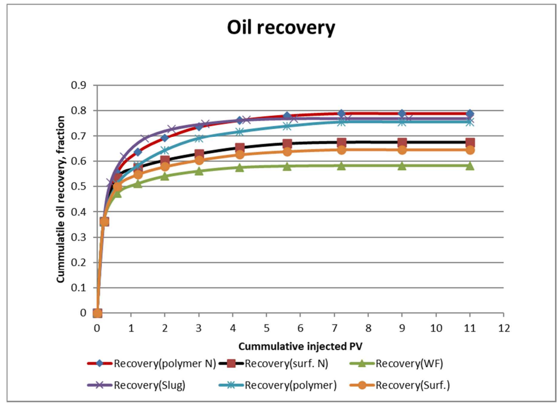

Figure 7: Oil Recovery for water, XG, SDBS, XG/NSP, SDBS/NSP, and mixture slugs flooding in sandstone formation

4.2.2. Wettability

4.2.2.1. Relative permeability curve

The rock wettability is monitored through the construction of relative permeability curves and the displacement efficiency was calculated for each case as shown in figures 8, 9, and 10. As shown in the figures; the SDBS/NSP, XG/NSP and the XG/SDBS/NSP slug mixture at optimum conditions enhanced the rock water wettability compared to the base case (water flooding).

The displacement efficiency was calculated using equation 3, where the SDBS/NSP, XG/NSP, and the XG/SDBS/NSP slug mixture flooding improved the displacement efficiency at optimal conditions as shown in table 5.

$$Ed = \frac{S_w^{-} - S_{wi}}{1 - S_{wi}} \qquad \text{(Tarek, 2006)} \quad (3)$$

It was also found that NSP improved both the wettability into more water wet and the displacement efficiency compared to the XG and SDBS flooding without NSP, this can be due to the adsorption of the NSP on the rock surface altering the rock wettability, thus enhancing the overall displacement efficiency.

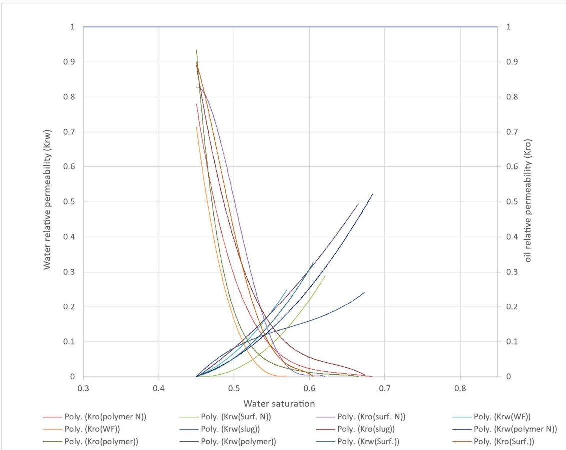

Figure 8: Relative permeability for water, polymer, surfactant, and mixture slugs flooding in sandstone formation in secondary recovery

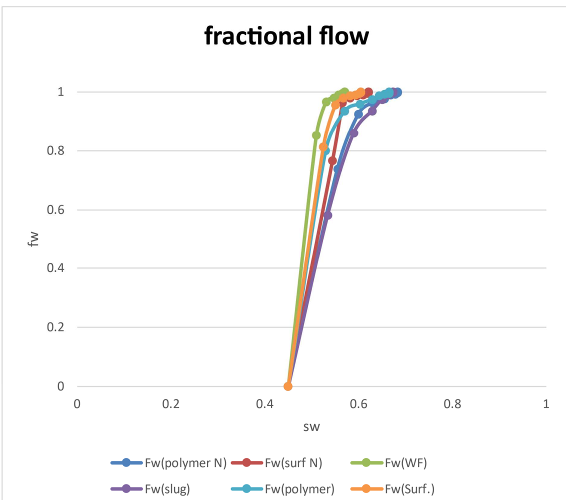

Figure 9: Fractional flow for water, polymer, surfactant, and mixture slugs flooding in sandstone formation in secondary recovery

4.2.2.2. Oil contact angle

Figure 10 shows that the addition of the NSP decreased the oil contact angle by 10◦ for the XG and by 6◦ for the SDBS, which indicated that the NSP has the ability to change the rock wettability into more water wet. These results are in line with the previously proposed mechanism which stated that the addition of NSP in oil wet rock enhances the recovery of oil increases, such that in the displacement fluids, the nano-silica bonded to XG, SDBS through hydrogen bonds. Then, the SDBS/NS and XG/NS got adsorbed on the rock surface thus altering the rock wettability as shown in figure 11 (Azmi, et al., 2022). Also the results obtained agree with and confirm the results obtained from the relative permeability curves as shown in table 5, where the highest permeability alteration to more water wet occurred during SDBS/NSP flooding as seen from the values of *Sw @Kro=Krw* and oil contact angle, followed by SDBS flooding, XG/NSP flooding, XG flooding, and the least water wet was experienced during water flooding.

Table 5. Wettability, Displacement Efficiency, and Oil contact angle for water, polymer, surfactant, and mixture slugs flooding in sandstone formation in secondary recovery

Type	*Sw @Kro=Krw*	*Displacement Efficiency*	*Oil Contact Angle(^{0})*
Water Flooding	*0.51 (waterwet)*	*0.64*	*65*
Surfactant Flooding	*0.54 (waterwet)*	*0.68*	*48*
Polymer Flooding	*0.525 (waterwet)*	*0.72*	*60*
Surfactant (nano) Flooding	*0.56 (waterwet)*	*0.7*	*42*
Polymer (nano) Flooding	*0.537 (waterwet)*	*0.745*	*55*
Slug Mixture Flooding	*0.544 (waterwet)*	*0.726*	*-*

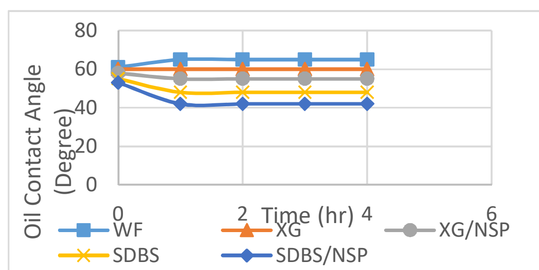

Figure 10: Oil contact angle vs. time

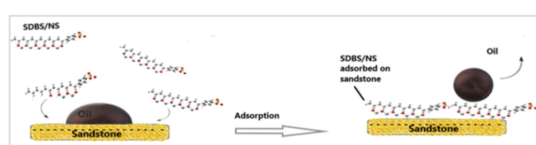

Figure 11: Mechanism for NSP/SDBS adsorption on sandstone that improves the oil recovery by increasing water wettability. (Azmi, Saada, Shokir, Attia, & Omar, 2022)

5. Conclusions

(1) With increasing the salinity, concentration, and flow-rate, the adsorption on the sandstone rock surface increases, such that, increasing the XG concentration from 500 to 1500 ppm at salinities ranging from 0 to 10 wt%, and flowrate from 2 to 6 ml/min resulted in adsorption increase from 0.2mg/g to 1.15mg/g after which the adsorption stabilized, while increasing the SDBS concentration from 2000ppm to 5000ppm resulted in adsorption increase from 0.11mg/g to 1.07mg/g.

(2) The Temperature increase from 20oC to 70oC resulted in an increase in XG adsorption by 39.6% and SDBS by 22.9% in sandstone formation.

(3) The adsorption optimization runs resulted in a recovery factor of 75% for the XG flooding, 64% for the SDBS, 79% for the XG/NSP, 67% for the SDBS/NSP, and 77% for the XG/SDBS/NSP blend compared to 58% for the waterflooding base case. This shows that the optimal conditions provided by the design expert software enhanced the oil recovery while reducing the Ad and Rrf.

(4) The use of nano-silica particles (NSP) as a co-injectant to the SDBS and XG increased the polymer adsorption by 67.8%, while the surfactant adsorption increased by 60.2%.

(5) The nano silica increases the Ad of XG and SDBS thus alter the wettability to more water wet as evident from the oil contact angle results and the relative permeability curves, such that the addition of the nano-silica decreased the oil contact angle by 10 ◦ for XG and by 6 ◦ for SDBS. These findings are in line with the previously proposed mechanism which states that the nano-silica bonded with SDBS, and XG through hydrogen bonds. Then, the SDBS/NS and XG/NS got adsorbed on the rock surface, thus changing the wettability into more water wetting.

2. Conflicts of interest

In The authors report no conflicts of interest. The authors alone are responsible for the content and writing of this article.

- The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.
- The authors declare the following financial interests/personal relationships which may be considered as potential competing interests.

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