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Experimental assessment of surfactant and silicon oxide nanoparticle hybrid for enhanced oil recovery using Niger delta formation

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Abstract

Due to the inconveniences experienced by the injection of surfactants, in which there are a low reduction in interfacial tension, high technical costs and large amounts of surfactant adsorbed on the rock; new technologies have been proposed to optimize surfactant injection processes, where the application of nanoparticles is seen as a proposal to improve the technique performance. Surfactant enhanced oil recovery (EOR) technology has received much attraction due to its excellent capability to increase the displacement efficiency by altering the wettability, and mobilizing the remaining oil. However, surfactant systems are widely acknowledged to have high adsorption on solid (rock/clay/sediment) surfaces most especially at higher salinity and temperature levels. In this research catanoic cetyltrimethyl ammonium bromide (CTAB) and anionic Sodium dodecyl sulfonate (SDS) surfactants were evaluated in hybrid with silicon oxide nanoparticle against oil recoveries and permeability change for 30000ppm and 60000ppm salinity and temperature of 29°C and 60°C. The study compares the effect of stand- alone catanoic cetyltrimethyl ammonium bromide (CTAB) and anionic Sodium dodecyl sulfonate (SDS) surfactants for salinity range 30,000ppm and 60,000ppm. The efficiency of the formulated fluids was tested using twelve core samples of Niger - Delta sand and the flooding was done at the temperatures of 29°C and 60°C. The result revealed that formulations with nanoparticle gave higher recovery than standalone fluids. 0.1% SDS/0.1%wt SiO_2 concentration gave the highest cumulative recovery of 86.36% as to compare with 0.1% SDS standalone fluid and 0.05wt% SDS/0.05wt% CTAB concentrations which has cumulative oil recoveries of 80.95% and 69.57% respectively at 29°C. The anionic SDS fluids gave higher recovery than cationic CTAB fluids with better permeability change. The use of silicon oxide nanoparticle homogenously mixed with SDS surfactant altered the properties of hydrocarbons that aided in easy sweeping of the reservoir pore throats and reduces formation damage.

Keywords: Enhanced Oil Recovery; Sodium Dodecyl Sulfonate; Surfactant; Silicon Oxide; Permeability Damage

1 Introduction

Enhanced Oil Recovery (EOR) techniques stand as a transformative frontier in the oil and gas industry, representing innovative methods deployed to extract additional hydrocarbons (about 75%) from reservoirs beyond the capabilities of conventional extraction techniques. As global energy demands surge and easily recoverable oil reservoirs diminish, the significance of EOR techniques intensifies in maximizing oil production [1]. By implementing enhanced oil recovery approach, the petroleum industry can effectively address the energy demand concerns and maximize oil production [2]. Enhanced oil recovery processes are implemented to increase the flow of oil to the well by injecting water, chemicals or gases into the reservoir all by changing the physical properties of the oil and the rock surface [3] and [4]. Thermal, chemical, gas injection and biological are the main types of Enhance oil recovery processes [5].

Among the four aforementioned enhanced oil recovery type, chemical flooding which include polymer, alkaline and surfactant is the most suitable choice for reservoirs containing light oil. Chemical enhanced oil recovery (CEOR)

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methods involve mobility control of the injected fluid using polymer, wettability alteration and interfacial tension (IFT) reduction using surfactant and combination of polymer and surfactant and nanoparticles [6], [7]. Rock and fluid properties and interactions are among the most important criteria in selecting an EOR method. The purpose of EOR is to modify the physical and chemical properties of minerals and fluids in the reservoirs, to increase the oil recovery factor [8]. Surfactants has an excellent capability to reduce the oil-water interfacial tension and alter rock wettability are common in EOR application lately, and laboratory studies have shown their effectiveness to unlock the residual oil. However, their commercial scale applications are always restrained by excessive surfactant loss due to surfactant adsorption and interactions with formation fluids especially at some incompatible conditions.

Nanotechnology has gained considerable interest in recent decades and gradually developed into the leading-edge EOR technology for oil and gas industry. Nanomaterials usually have a size of 1-100 nm, which is much smaller than the typical pore size of 5-50 μm, thus, ensuring their applicability in low-permeable reservoirs with small pores and narrow pore throats. Commonly-used nanomaterials include metal oxide nanomaterial, carbon-based nanomaterial, and silica-based nanomaterial. Silica-based nanomaterial has long been the most popular one because of its superiority in great marketing potentiality, broad availability, low cost for fabrication, low toxicity and simplicity in surface modification. However, pure silica nanoparticles hardly have any impacts on IFT and in most cases relatively high particle concentration (≥ 1.0 wt.%) is required to induce noticeable wettability alteration [9]. [10] reported that even when the applied nanomaterials have super good disparity in the dispersant, the permeability reduction caused by nanomaterial adsorption and straining was huge, and the adverse effects were observed to increase with increasing nanomaterial concentrations. Surfactant-nanoparticle augmented systems have been a research focus in recent years because of their synergistic effects, such as increased particle stability, reduced particle dosage, reduced surfactant adsorption loss and enhanced recovery efficiency [11].

Nanoparticle such as silicon oxide (SiO_2) has been widely investigated in combination with surfactant for enhanced oil recovery lately. In recent studies, many researchers like [12], [13], [14], [15], [16], [17], [18], [19], [20], [21], [22] have proved the efficiency of surfactant nanoparticles hybrid in EOR processes. [13] researched on the blending of silica nanoparticles and surfactants for improved stability and controllable mobility for low permeability reservoir. The author concluded that the SiO_2-surfactant gave a great potential in low permeability reservoirs. [15] showed in their work that due to the similar charge which exist between anionic surfactant and silicon oxide, this aids the hybrid to show an increase in stability of Silicon oxide nanoparticle through supercharging effect. In the work done by [12] and [16] the authors mentioned that more attention should be paid to silicon oxide nanoparticle-surfactant concentration ratios as to get a stable and applicable formula. The concentration of surfactant is very important because sometimes when surfactant concentration is higher than its critical micelle concentration there will be adverse effects on the osmotic depletion.

[21] did a study on effect of surfactant and nanoparticles in low salinity water on interfacial tension and contact angle. The authors used anionic surfactant sodium dodecyl sulfate (SDS), silica nanoparticles and brine to investigate their performance on the interfacial tension and contact angle at different conditions and concentrations in low salinity water. Their result proved that using the hybrid of nanoparticles, surfactant and brine in low salinity provided the best positive effect on IFT reduction, than using the surfactant and brine alone. They concluded by presenting the optimal surfactant of 2,000 ppm in the presence of 750 ppm nanoparticles gave the best effect of interfacial tension and contact angle reduction for the field they studied.

[22] in their study compared the effect of Sodium Dodecyl Sulfate (SDS) surfactant and Aluminum oxide (Al_2O_3) nanoparticle hybrid at different salinity concentration ratios, stand-alone Sodium Dodecyl Sulfate surfactant and Aluminum oxide nanoparticle on viscosity, salinity ranges of 30,000ppm and 60,000ppm, permeability change and oil recovery. The efficiency of the formulated fluids was tested through flooding experiment using different twelve core samples of Niger - Delta sand formation. The results showed that the surfactant-nanoparticle hybrid solution enhanced the viscosity of fluids, gave better permeability change and higher oil recovery for both 30,000ppm and 60,000ppm salinity change examined. Concentration ratio of 0.1 wt%Al_2O_3 and 0.3wt% SDS gave the highest cumulative oil recovery of 82.61% using 30,000 ppm and 78.26% for 60,000ppm brine concentration at the same fluid concentration ratio brine followed by 0.2 wt%Al_2O_3/0.3wt%SDS concentration ratio. The hybrid with 0.1 wt%Al_2O_3 and 0.3wt% SDS concentration ratio gave lower permeability change of 52.30md than every other concentration investigated. The combination of Aluminum oxide nanoparticle and Sodium Dodecyl Sulfate surfactant enhances surfactant properties as to improve displacement efficiency, reduce surfactant adsorption and permeability damage. Having gone through the literature, it can be observed that few study has been done regarding Sodium Dodecyl Sulfate (SDS) surfactant, cetyltrimethyl ammonium bromide and silicon oxide nanoparticle using crude oil sample and formation from Niger

Delta. This study then aimed to investigate the effect of these surfactants with silicon oxide nanoparticles hybrid using sandstone from Niger Delta for different salinity and temperature ranges for Enhanced oil recovery.

2 Surfactant

Surfactant is a chemical that is used in chemical systems that contains surface actives agents, which are polymeric molecules that can lower the IFT between the liquid and the oil in the reservoir. The most used structural form of surfactant is one that has nonpolar parts, hydrocarbon tail, and polar ionic parts. Surfactants are also referred to as amphiphile molecules because they contain a nonpolar 'tail' and a polar 'head'-group within the same molecule. Due to the balance that surfactant has between its components of the hydrophilic and hydrophobic part which give the surfactant, it's the active agent. In EOR our topic the surfactant flooding the hydrophobic tail interacts with residual oil and the other part of the hydrophilic head interacts with the water as shown also in the last figure. Typically contribute to a highly significant reduction in interfacial forces between (water and oil) and (oil and rock). The four classes of surfactants are Anionic surfactants, Cationic surfactants, Non-ionic surfactants and Zwitter-ionic surfactant (Table 1).

Table 1 Types of Surfactant and Their Chemical Structures

Anionic	
Sodium dodecyl sulfate (SDS)	$CH_3(CH_2)_{11}SO_4^- Na^+$
Sodium dodecyl benzene sulfonate	$CH_3(CH_2)_{11}C_6H_4SO_3^- Na^+$
Cationic	
Cetyltrimethylammonium bromide (CTAB)	$CH_3(CH_2)_{15}N(CH_3)_3^+ Br^-$
Dodecylamine hydrochloride	$CH_3(CH_2)_{11}NH_3^+Cl^-$
Non-ionic	
Polyethylene oxides	$CH_3(CH_2)_7(O.CH_2CH_2)_8OH$

The classification of surfactant: This material can be classified on its ionic base of each group as follows (Table 2) Anionic Sodium dodecyl sulfate (SDS), Sodium dodecyl benzene sulfonate, Cationic Cetyltrimethylammonium bromide (CTAB) Dodecylamine hydrochloride Non-ionic the Anionic type of surfactant is negatively charged and is commonly for industrial usage like detergents. The Cationic type is the one that has a positively charged head and this type of surfactant dissociate in water to form amphiphilic cations and anions. The nonionic surfactant is the type that has no charge and mainly is used in EOR as a co-surfactant to enhance the surfactant process. The most commonly used surfactant in EOR can be sulfonated hydrocarbons like alcohol prepopulate sulfate. That is used to achieve the maximum surfactant flooding for any oil reservoir to enhance the oil recovery after the end of natural recovery and the end of secondary recovery the EOR which surfactant flooding one of its branches. The idea for using surfactant flooding in EOR is based on the ability of surfactant to lower the surface energy which was described by the Gibbs adsorption isotherm equation:

3 Methodology

The experiment aimed to evaluate petro-physical properties of a porous formation, formulate EOR fluids using cetyltrimethyl ammonium bromide (CTAB) and Sodium dodecyl sulfonate (SDS) surfactant with silicon oxide nanoparticle hybrid as to measure the increased oil recovery and permeability damage. Twelve (12) core encapsulated plug samples were prepared for the experiment with the grain sizes of 600μm. The dimension of plug samples (length and diameter) were measured and defined with samples identification number ranging from A1 to A12 for easy recognition. The EOR fluid were prepared using the at constant 0.1wt% concentration of surfactants with 0.1wt% of nanoparticles respectively in solution with dispersing agent (brine) of 30,000 and 60,000ppm salinity (alkaline). The core flooding was done under different temperature range of 29^{o}C and 60^{o}C. The hybrid of the surfactants, surfactant-nanofluid, standalone surfactants and nanoparticle were also evaluated with a dispersing agent (brine) of 30,000 and 60,000ppm salinity (alkaline).

3.1. Equipment and Materials

3.1.1 Equipment

Encapsulated plug sample (unconsolidated Sand-packs), Venire caliper, Density bottle, PH meter, Hydrometer, Thermometer, Canon U-tube Viscometer, Electronic Weighing balance, Stopwatch, Retort Stand,Sieve, Stirrer and flooding loop (displacement loop, flow meter, core holder, stem heads (2), Valve (2), accumulator and pressure gauge.

3.1.2 Materials

Preparation of Brine: Two laboratory brine solutions were formulated in this study. The brine solutions were prepared with 30g and 60g of sodium chloride (NaCl) in 1000ml of water. The density of the formulated brine using different 30000ppm and 60000pm are 1.021g/dm^3 and 1.039 g/ dm^3.

Preparation of Nanofluids: The silicon oxide nanoparticles, cetyltrimethyl ammonium bromide (CTAB) and Sodium dodecyl sulfonate (SDS) used in this study were acquired from JoeChem Chemical Shop Port Harcourt, River's state, Nigeria. 0.1g silicon oxide nanoparticle and 0.1g Sodium dodecyl sulfonate (SDS) were dissolved in equal volume of 200ml of brine from the different concentrations of 30g/L and 60g/L. The ratio of the formulated fluids can be found in Table''''

Crude Oil Properties: The crude oil sample was obtained from a field from Niger Delta of Nigeria and has the following properties: specific gravity of 0.860, density of 0.8958g/cm^3, viscosity of 43.022cP and ^{o}API gravity of 33.99 at the 29^{o}C.

3.1.3 Experimental Procedure

Twelve core (plug) samples were prepared for the experiment with the grain sizes of 600µm, the length and diameter were measured, cleaned and were fully dried in an oven. The plug samples were well defined with samples identification number (A1 to A12) for easy identity. The EOR fluid prepared consist of silicon oxide nanoparticle and surfactants (Sodium dodecyl sulfonate and cetyltrimethyl ammonium bromide) with a constant concentration of 0.1wt% for both nanoparticles and surfactants at 30000ppm and 60000ppm salinity.

The weight, length and diameter of each prepared core was measured, and the result is presented in Table 1. The twelve core samples were fully saturated in a brine water of the different 30,000ppm and 60,000ppm concentrations as to measure the saturated weight of various core samples. The Pore volume of each core sample was estimated by removing the saturated weight from dry weight and the outcome was divided by the density of the different brine solution of 30,000ppm and 60,000ppm using Equation 1 as represented in Table 2. The porosity was determined by using the bulk volume result (Table 1) and pore volume result (Table 2) using Equation 2.

The flooding experiment started by injecting crude oil into the core to displace the brine solution at 29^{o}C temperature. It should be noted that not all the brine solution was displaced, and the remaining water is known as connate water. The same quantity of oil that entered the unconsolidated core is equivalent to brine solution displaced from the core samples at constant flow rate of 0.9091cc/sec. The brine was injected (secondary recovery) into the core to displace crude oil and the amount of oil recovered was measured and recorded. The laboratory brine water injection was a control experiment. Other laboratory experiments were carried out following the above stated procedures. The water breakthrough time was recorded. The different concentrations of Sodium dodecyl sulfonate, Sodium dodecyl sulfonate /silicon oxide hybrid and Sodium dodecyl sulfonate/ cetyltrimethyl ammonium bromide hybrid at constant 0.1wt% concentrations were injected into the core until no oil could be recovered at the residual oil saturation. The temperature was increased 29^{o}C to 60^{o}C for the final flooding as to evaluate the effect of relatively high temperature on formulated EOR fluids in cumulative oil.

Finally, the unconsolidated core was removed from the core-holder and re-weighted, the recovered oil was measured and change in permeability was determined using Equation 3.

Pore Volume Equation: $PV = \frac{W_{sat.plug} - Weight_{dry\ plug}}{P_{NaCl}}$ (1)

Where; $W_{sat.plug}$ = weight of saturated plug, $Weight_{dry\ plug}$ = weight of dry sample, P_{NaCl} = density of Brine

Porosity: $Porosity, \emptyset = \frac{P.V}{B.V} \times 100\%$ (2)

Where, P.V = pore volume, B.V = bulk volume

Permeability: $K = \frac{Q\mu_{NaCl/KCl}L_{plug}14700}{A_{plug}\Delta P}$ (3)

Where, Q = flow rate, μ_{NaCl} = viscosity of NaCl/KCl (Brine), L_{plug} = length of plug, A_{plug} = cross section area of plug, ΔP = differential pressure and K = permeability

4 Results and discussion

After performing the secondary and tertiary oil recovery, results obtained from the laboratory experiments using SDS alone, SDS- SiO_2 nanoparticle and SDS-CTAB hybrid using 30000ppm and 60000ppm brine and temperatures of 29°C and 60°C are showed in the Table 4.8. The percentage of oil recovered during the secondary flooding process (water flooding) ranges from 45% to 55% indicating that up to 35% - 50% oil is remaining in sand pack, hence, the need to employ tertiary recovery. It was observed that recovery was high for 30000ppm salinity and at 29°C temperature for all the EOR fluids formulated as to compare to 60000ppm salinity and 60°C temperature.

4.1. Result for Petrophysical Properties for Various Core Samples

Bulk volume is a vital parameter in enhanced oil recovery, governing the storage capacity and fluid flow dynamics within the reservoir, thereby influencing the efficiency of recovery techniques, fluid mobility, oil saturation, and ultimately, the amount of hydrocarbons that can be extracted from the formation. The plug samples ranges from A1 to A12 for easy identification. The bulk volumes of the individual plug samples listed in Table 2 were calculated using Equation1. The bulk volume of core plugs varies from 74.12 to 65.29cm^3 with plug sample of A12 having the highest followed with plug A11 and plug A5 has the smallest value. It can observe generally that samples with lower bulk volumes have shorter lengths with slightly smaller radii. The bulk volumes of the individual plug samples are presented in Table 2 were calculated using Equation1.

Table 2 Bulk Volume of Encapsulated Plug

Sample	**Length**	**Diameter**	**Radius**	**Bulk Vol.**
plugs ID	(cm)	(cm)	(cm)	(cm^3)
A1	7.40	3.38	1.69	66.43
A2	7.39	3.4	1.7	67.12
A3	7.95	3.34	1.67	69.68
A4	8.05	3.34	1.67	70.56
A5	7.36	3.36	1.68	65.29
A6	7.89	3.34	1.67	69.16
A7	7.50	3.36	1.68	66.56
A8	8.04	3.38	1.69	72.17
A9	7.89	3.4	1.7	71.66
A10	7.56	3.38	1.69	67.86
A11	8.09	3.38	1.69	72.62
A12	8.16	3.40	1.70	74.12

Pore volume plays a pivotal role in enhanced oil recovery, as it directly influences the storage capacity, fluid saturation, and sweep efficiency of the reservoir, thereby impacting the effectiveness of recovery techniques and ultimately determining the number of hydrocarbons that can be extracted from the formation. The pore volumes of the individual plug samples listed in Table 3 were calculated using Equation 2. From Table 2 and 3, Plug Sample A1 has a bulk volume of 61.94 cm^3 and a pore volume of 24.91 cm^3. This indicates that Plug Sample A1 has a storage capacity of 24.91 cm^3, which can accommodate gas, oil, and water. Table 3 also presents the encapsulated plug's porosity, which ranges from 38.89% to 41.97%, indicates that it is highly porous.

Table 3 Pore Volume and Porosity of the Plug Samples

	Dried Wt. (g)	**Saturated. Wt. (g)**	**Fluid Wt. (g)**	**Sat. fluid density g/cm3**	**Pore vol. cm³**	**Porosity (%)**
A1	147.05	171.30	24.25	1.0248	23.6632	35.62
A2	148.78	173.63	24.85	1.0248	24.2486	36.13
A3	164.17	190.10	25.93	1.0248	25.3025	36.31
A4	161.41	186.76	25.35	1.0248	24.7365	35.06
A5	138.67	162.21	23.54	1.0248	22.9703	35.18
A6	161.78	186.41	24.63	1.0248	24.0339	34.75
A7	147.40	171.09	23.69	1.0248	23.1167	34.75
A8	166.41	193.88	27.47	1.0248	26.8052	37.14
A9	160.40	186.74	26.34	1.0248	25.7026	35.87
A10	143.84	167.82	23.98	1.0248	23.3996	34.48
A11	157.27	182.68	25.41	1.0248	24.7951	34.14
A12	140.75	165.11	24.36	1.0248	23.7705	32.07

Permeability is the ability of the core sample to allow fluid to flow through it. It was measured by injecting water into core at a uniform flow rate of 0.9091 cm^3/sec and the pressure difference was recorded for every experiment. The viscosity of the brine was 1.0224cp which was also uniform. The permeability(K) of the sand packed was estimated using Darcy's law equation as shown in Equation 3. Permeability of the core samples were measured before and after flooding with different EOR dispersing agents as shown in Table 4 as to measure the formation damage after the recovery. As illustrated in Table 4 the formulated encapsulated plug samples exhibit a permeability range of 100-1000 mD, indicating that they are from a highly permeable sandstone formation. Table 4 also demonstrated how permeable each sample plug is before flooding operation was carried out, meaning sample plug A1 will allow more fluid flow compare to sample A5 due to the permeability difference which are 369.79mD and 342.13mD respectively.

Table 4 Experimental Results of Samples Plug Permeability

Sample	**Length**	**Radius**	**Q 1**	**Viscosity of brine**	**Plug Area**	**ΔP B/4**	**K1*14500**
plugs ID	cm	Cm	cm3/sec.	Cp	cm2	EOR {psi}	md
A1	7.40	1.69	1.23	1.0224	96.56	3.00	465.79
A2	7.39	1.700	1.20	1.0224	97.13	3.00	451.16
A3	7.95	1.67	1.07	1.0224	100.98	4.00	312.20
A4	8.05	1.67	1.10	1.0224	102.03	3.50	367.59
A5	7.36	1.68	1.17	1.0224	95.46	3.50	382.08
A6	7.89	1.67	1.17	1.0224	100.35	4.00	340.93
A7	7.50	1.68	1.17	1.0224	96.94	3.50	383.41
A8	8.04	1.69	1.17	1.0224	103.36	4.00	337.30
A9	7.89	1.7	1.20	1.0224	102.48	3.50	391.34
A10	7.56	1.69	1.17	1.0224	98.26	4.00	333.62

A11	8.09	1.69	1.17	1.0224	103.89	4.00	317.46
A12	8.16	1.7	1.13	1.0224	105.36	4.00	324.35

4.2. Results of Fluid Properties (PH, Density, Viscosity)

Density plays a crucial role in the Enhanced Oil Recovery (EOR) performance. It influences viscosity, mobility, sweep efficiency, and oil displacement efficiency in saline reservoirs. The density EOR fluids using the hybrid of cetyltrimethyl ammonium bromide (CTAB) and Sodium dodecyl sulfonate (SDS) with silicon oxide nanoparticle are shown in Table 5.

As shown in Table 5, the densities of the formulated fluids using 30000ppm salinity have IDs of F31 to F36 while for 60000ppm have ID of F61 to F66. The density measurement is important because it will be used to determine the fluid kinematic viscosity. Kinematic viscosity is a ratio of dynamic viscosity to density and dynamic viscosity is the measure of fluid's internal resistance to flow. It is observed that the viscosity of the surfactant's standalone with surfactant-surfactant hybrid are relatively the same but the surfactant- nanoparticle are relatively higher most especially for 30000ppm salinity. In Enhanced Oil Recovery (EOR) operations, salinity substantially influences the viscosity of surfactant-based fluids. Elevated salinity levels reduce viscosity by screening charges and decreasing hydrodynamic volume.

Table 5 Result for Density /Viscosity of the Flooding Sample and Crude

Fluid ID	Dispersing fliud Conc.	Salinity (PPM)	Efflux time (sec)	Kinematics viscosity	Density (g/cm3)	Dynamic viscosity (cp)
B3	Brine	30000	27.92	1.0165	1.0247	28.612
F31	0.1% SDS		26.59	0.9681	1.0196	27.112
F32	0.1% CTAB		26.36	0.9597	1.0186	26.850
F33	0.05% SDS/0.05% CTAB		28.91	1.0526	1.0172	29.407
F34	0.1% SDS/0.1%wt SiO_2		27.22	0.9910	1.0211	27.794
F35	0.1% CTAB/0.1%wt SiO_2		28.31	1.0307	1.0521	29.785
F36	0.05% SDS/0.05% CTAB/0.1%wt SiO_2		30.11	1.0963	1.0713	32.256
F61	0.1% SDS	60000	28.54	1.0391	1.0375	29.611
F62	0.1% CTAB		26.60	0.9685	1.0351	27.534
F63	0.05% SDS/0.05% CTAB		27.12	0.9874	1.0385	28.166
F64	0.1% SDS/0.1%wt SiO_2		26.44	0.9626	1.0631	28.108
F65	0.1% CTAB/0.1%wt SiO_2		28.54	1.0391	1.0711	30.569
F66	0.05% SDS/0.05% CTAB/0.1%wt SiO_2		29.42	1.0711	1.0911	32.100

4.3. Recovery of Crude Oil by Water and Tertiary Methods

Table 6 show the percentages of cumulative oil recovered using 0.1wt% concentration of SDS standalone, SDS-nanoparticle hybrid and SDS-CTAB-nanoparticle at 29°C temperature for brine salinity of 30,000ppm and 60,000ppm and with temperature range 29°C and 60°C. It can be observed from Figures1 and 2 that flooding at lower temperature relatively gave higher recovery for both 30000ppm and 60000ppm salinity for all the enhanced oil recovery fluids studied. For all the EOR fluids evaluated, fluid with $S33_{29}$ ID (0.1% SDS/0.1%wt SiO_2) concentration gave the highest cumulative recovery of 86.36% as to compare with 0.1% SDS standalone and 0.05wt% SDS/0.05wt% CTAB concentrations which has cumulative oil recovery of 80.95% and 69.57% respectively at 29^{s}C. The standalone SDS performed better than SDS-CTAB hybrid for both salinity ranges researched. The formulation with nanoparticles performed better than those without nanoparticles. Figure 4.3 presented the cumulative oil recovered using different salinity of 30000ppm and 60000ppm for temperature ranges of 29^oC and 60^oC. The good performance of anionic SDS and silicon oxide nanoparticle is because the synergy effect of SDS which has negative charge in the polar head hence is repelled by the clays and sandstones from the reservoirs, reducing its retention in the porous medium [23].

Table 6 Oil Recoveries Using Secondary and SDS /Silicon Oxide hybrid

Fluid ID	OIIP (ml)	Secondary Rec. (ml)	Break Thur. (ml)	Salinity (ppm)/°c	Temp. (°c)	Tertiary Oil Rec. (ml)	Residual Oil (ml)	Cumulative Oil (ml)	Cumulative Oil (%)
$S31_{29}$	21	12	38	30,000	29	5.0	4.0	17.0	80.95
$S32_{29}$	23	13	40			3.0	4.2	16.0	69.57
$S33_{29}$	22	13	43			6.0	4.0	19.0	86.36
$S34_{29}$	22	12	37			3.8	3.7	15.8	71.82
$S61_{29}$	21	11	36	60000		4.5	3.5	15.5	73.81
$S62_{29}$	21	12.5	35			4.0	3.5	16.5	78.57
$S63_{29}$	23	12	39			2.8	4.0	14.8	64.35
$S64_{29}$	21	12	43			3.3	3.0	15.3	72.86
$S31_{60}$	21	12	36	30000	60	3.4	4.0	15.4	73.33
$S32_{60}$	21	12	35			2.0	4.5	14.0	66.67
$S33_{60}$	22	13	38			3.8	4.2	16.8	76.36
$S34_{60}$	22	12	42			2.5	3.5	14.5	65.91
$S61_{60}$	20	11	38	60000		2.8	3.7	13.8	69.00
$S62_{60}$	21	11.5	43			1.8	4.0	13.3	63.33
$S63_{60}$	24	13.5	36			3.8	4.0	17.3	72.08
$S64_{60}$	21	11	42			2.4	5	13.4	63.81

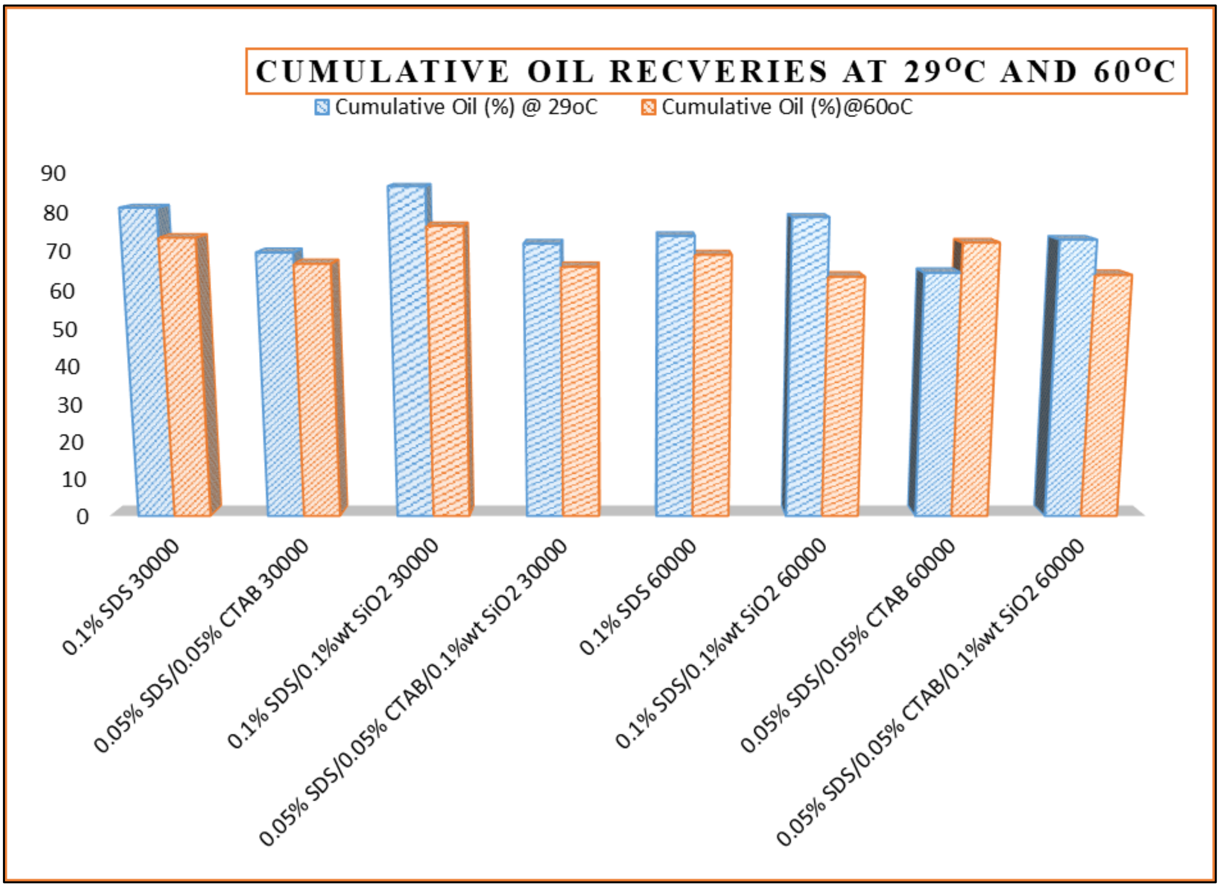

Figure 1 Cumulative recovery against Fluid Concentrations Using SDS Surfactant/Nanoparticles hybrid for 29°C and 60°C

Figures 1 and 2 shows recovery performance against different concentration with varying temperature (29°C and 60°C) and constant salinity of 30,000ppm and 60,000ppm. These Figures showed that recovery using 30000ppm salinity performed generally better than 60000ppm salinity. This is attributed to the reduction of the repulsive forces between the negative heads of the SDS and the surface sandstone formation (also negatively charged), due to the electrolytes (Na +), allowing the SDS molecules to adhere with easier on the surface of the sand grains. In Figures 1and 2 the deterioration of the EOR fluid due to high temperature and high salinity was reduced on addition of silicon oxide nanoparticle to SDS. It can also be observed from the Figure 2 that 0.1% SDS/0.1%wt SiO_2 concentration gave the highest oil recovery of 86% for 30000ppm salinity as to compare with at 60000ppm that gave cumulative recovery of 72.08%. The positive effect of silicon oxide in improving oil recovery in high salinity and temperature can also be observed from Figures 1 and 2 because all the fluid combined with nanoparticle performed well both for the two salinity ranges investigated. The surfactant- nano fluid performed better due to the synergy between the SDS and Silicon oxide nanoparticle. Figure 4.5 showed the summary of cumulative recovery at different salinity for the surfactant and the hybrid studied.

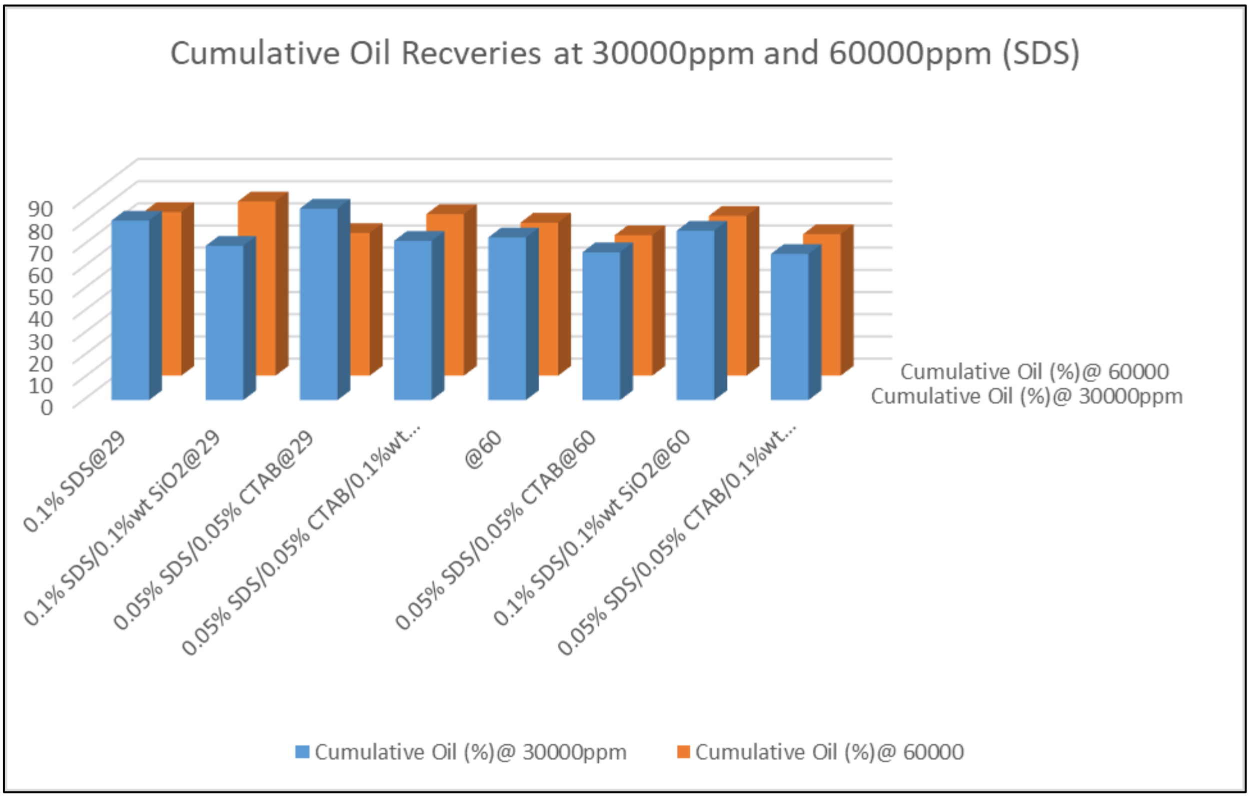

Figure 2 Cumulative recovery against Fluid Concentrations Using SDS Surfactant/Nanoparticles hybrid for 30000ppm and 60000ppm

4.4. Result for permeability change of plug samples

After the secondary and tertiary flooding, the core's permeability change was determined as to evaluate the extent of formation damage caused by EOR fluids and nanoparticles. There is a significant decrease in permeability of the reservoir formation after the tertiary flooding (Table 7 and Figure 3). Table 7 and Figure 3 show the permeability alteration using different SDS and nanoparticle hybrid for salinity concentrations of 30000ppm and 600000ppm at of 29°C and 60°C with their individual cumulative recovery factor. It was generally observed that permeability alteration is relatively lower at temperature of 29°C and 30000ppm salinity as to compare to temperature of 60°C and salinity of 60000ppm and their cumulative recovery is also higher. Figure 3 shows the change in permeability for all the EOR agents studied using SDS surfactant which ranges from 100.21md to 30.12 md. The lowest value of 30.12 md permeability change was gotten from concentration of 0.1% SDS/0.1%wt SiO_2 30000ppm at 29°C and the highest permeability change was gotten from 0.05% SDS/0.05% CTAB/0.1%wt SiO_2 60000ppm @60 °C. It was observed that the reduced permeability changes for SDS and nanoparticle hybrid gives a higher oil recovery, meaning that there is good synergy between the surfactant and nanoparticles most especially in lower concentration which helps to reduce the adsorption of surfactant on the formation surface.

Table 7 Permeability Alteration for different concentration of EOR agents using SDS Surfactant and Nanoparticle

Conc. Of EOR Fluids	K_1 B/4 EOR (md)	K_2 A/F EOR (md)	K Alt (K_1-K_2) (md)	Cumulative Oil Recovery (%)
0.1% SDS 30000ppm @29 °C	379.00	293.47	85.53	80.95
0.05% SDS/0.05% CTAB 30000ppm @29 °C	331.52	283.086	48.434	69.56
0.1% SDS/0.1%wt SiO_2 30000ppm @29 °C	381.49	351.37	30.12	86.36
0.05% SDS/0.05% CTAB/0.1%wt $SiO_2$30000ppm @29 °C	337.15	299.973	37.177	71.82

0.1% SDS 60000ppm @ 29 °C	387.29	316.87	70.42	73.81
0.1% SDS/0.1%wt SiO260000ppm @29 °C	333.62	297.98	35.64	78.57
0.05% SDS/0.05% CTAB 60000ppm @29 °C	322.89	277.66	45.23	64.35
0.05% SDS/0.05% CTAB/0.1%wt SiO_2 60000ppm @29 °C	323.52	283.48	40.04	72.86
0.1% SDS 30000ppm @60 oC	379.00	290.89	88.11	73.33
0.05% SDS/0.05% CTAB 30000ppm @60 °C	391.52	309.66	81.33	66.67
0.1% SDS/0.1%wt SiO_2 30000ppm @60 °C	381.49	346.22	35.27	76.36
0.05% SDS/0.05% CTAB/0.1%wt SiO_2 30000ppm @60 °C	337.15	288.35	48.79	65.91
0.1% SDS 60000ppm @60 °C	387.29	295.75	91.54	69.00
0.05% SDS/0.05% CTAB 60000ppm @60 °C	333.62	273.30	60.32	63.33
0.1% SDS/0.1%wt SiO_2 60000ppm @60 °C	322.89	282.57	40.32	72.08
0.05% SDS/0.05% CTAB/0.1%wt SiO_2 60000ppm @60 °C	323.52	223.31	100.21	63.81

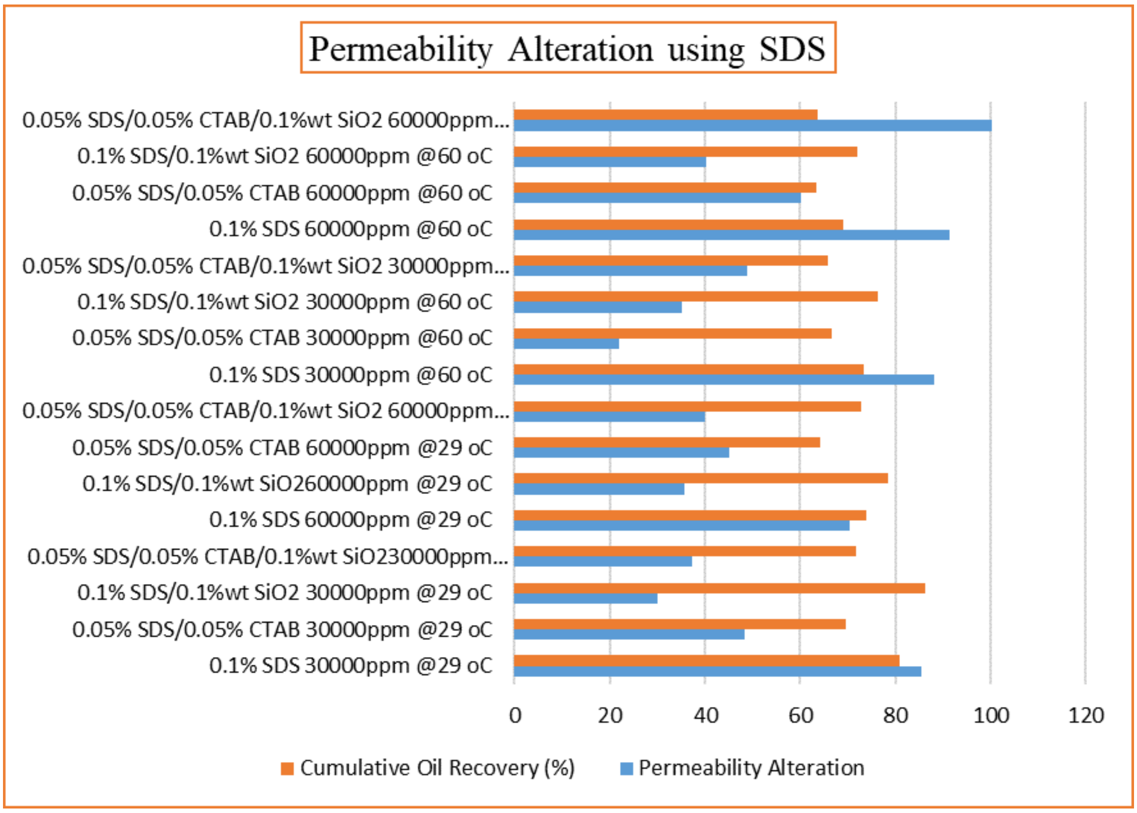

Figure 3 Permeability Alteration for different concentration of EOR agents using SDS Surfactant at Temperature of 29°C and 60°C for Salinity of 30000ppm and 60000ppm.

5 Conclusion

The results from the experimental tests have proved the effectiveness of the synergy of the aluminum oxide nanoparticles and guar gum polymer in improving oil recovery in both 30,000ppm and 60,000ppm brine concentrations. The presence of aluminum oxide in guar gum improved the viscosity of polymer solution, which reduced the mobility ratio between the injected fluids and the oil in the reservoir. Secondly, this synergized polymer-nano-alumina solution reduced the permeability damage of the formation. Among the hybrid compositions studied, the least altered permeability values were observed in S35 (67.05md), S36 (88.63md), S65 (67.59md), and S66 (86.37md). These compositions which when compared to those with the highest permeability alteration values such as samples S63 (117.72md) gives the best recovery percentage. Generally, the guar gum/ silicon oxide hybrid in both 30,000ppm and 60,000ppm gave higher oil recovery than standalone polymer and silica nanofluids for the different brine concentrations examined. All the concentrations that are based on 30,000ppm brine performed better than 60,000ppm based on viscosity, rheological, permeability change, and oil recovery.

Compliance with ethical standards

Disclosure of conflict of interest

No conflict of interest to be disclosed.

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