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Investigation of Nanoparticles Assisted Surfactant Flooding for Enhanced Oil Recovery Using Different Salinity Range

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ABSTRACT: Enhanced oil recovery (EOR) techniques are important for increasing oil production as to meet global energy demands. Surfactant flooding is a commonly used EOR method, but it has issues with surfactant molecules adhering on the surface of the reservoir rock more especially at higher salinity range. The study compares 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.

KEYWORDS: Aluminium oxide, Enhanced Oil Recovery, Nanoparticle, Salinity, Sodium Dodecyl Sulfate

1. INTRODUCTION

Enhanced Oil Recovery (EOR) processes is divided into chemical, thermal, gas and microbial. Chemical EOR techniques are usually used as additives for hydrocarbon production due to its simplicity and relatively reasonable additional production costs ([1], [2]). Polymer, alkali and surfactant are the major chemical EOR agent normally used during tertiary flooding operations [3]. Surfactant flooding is one of the chemicals enhanced oil recovery (EOR) methods and has been proved to be suitable for EOR application globally. Surfactant flooding is one of the major enhanced oil recovery type that uses surfactant solutions to increase oil recovery by decreasing the water/oil mobility ratio thereby increasing the viscosity of the displacing water. In recent times, nanomaterials have played a significant role in oil and gas industries to recover more oil from the existing mature fields worldwide ([4], [5]).

The combination of nanoparticles with chemical during enhanced oil recovery processes helps to decrease oil viscosity, increase injected fluid density, wettability change, reduction in both interfacial tension, and surface tension between two liquids [6]. [3] showed that the application of only chemical EOR agents are not good enough to recover residual oil in both high temperature and high salinity reservoir. The Combinnation of nanoparticles with conventional chemicals shows promising results in enhanced oil recovery processes both for reservoirs with harsh conditions.

The introduction of nanoparticle and chemical hybrid aids to improve rheological properties of reservoir fluids, stabiliz emulsion and decrease interfacial facial tension. Nanoparticles like silica oxide, aluminium oxide, zinc oxide, titanium oxide, magnesium oxide and Copper oxide are used with brine or brine/chemicals to recover the residual oil after primary and secondary [7]. [8] showed the general types of nanoparticles which are organic, inorganic, metal oxides and non-silica nanoparticles as clearly illustrated in Fig. 1. Organic nanoparticles include carbon nanoparticles as well as carbon nanotube (CNT) nanoparticles. Silica oxide (S_iO_2) is of inorganic type while aluminum oxide (Al_2O_3), titanium oxide (T_iO_2) and iron oxide (Fe_2O_3/Fe_3O_4) are of metal oxides nanoparticles. Polymer nanoparticles and polymer-coated nanoparticles are examples for non-silica nanoparticles.

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Among the various types of conventional chemical EOR, surfactant is of the primary interest in this research study. It helps to reduce interfacial tension and other reservoir/fluids properties to improve the flow of oil to production wells. A surfactant molecule consists of a non-polar hydrophobic (lipophilic) tail and a polar hydrophilic (lipophobic) head It forms the micro-emulsion which helps to reduces the oil and water interfacial tension.

Recently, many researchers have demonstrated that combining nanoparticles and surfactants in the aqueous solution, will drastically reduce interfacial tension, permeability damage, wettability change as well as increasing capillary pressure in the reservoir ([9], [10], [11], [12], [13]). [9] 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.

[10] did a study on the role of electrostatic repulsion on increasing surface activity of anionic surfactants in the presence of hydrophilic Silica Nanoparticles. They proved in their work that the combination of the surfactant and nanoparticle in brine intensively reduce IFT and contact angle between the oil and the rock surface. [11] presented a research study on reducing surfactant adsorption on rock by silica nanoparticles for enhanced oil recovery. They used sodium dodecyl sulfate (SDS) surfactant and silica nanoparticles in distilled water as a dispersing agent for different nanoparticle concentrations of 0.1 – 0.5wt%. They concluded that the combination of SDS and silicon oxide reduced wettability and interfacial tension thereby improving oil recovery with 4.68% recovery factor.

[12] did a research work on experimental study of electromagnetic-assisted Zinc oxide Nanofluid flooding for enhanced oil recovery. The researchers used 0.1wt% Zinc oxide in Sodium dodecyl benzenesulfonate using brine as the dispersing agent to evaluates their effect on Tapis oilfield oil for IFT reduction. Their study reveals that the hybrid was able to reduce the interfacial tension with the recovery factor from 6.66 – 7.058%. [13] investigated the effect of sodium dodecyl sulfate (SDS) in 0.3% Aluminum oxide using crude oil from Iranian oilfield for ITF and wettability change. The authors reported that the mixture of surfactant in the right combination gave a positive alteration with the recovery factor of 15.18%. The literature proved that the hybrid of surfactant and nanoparticle helps to reduce wettability change, interfacial tension, permeability change and better oil recovery factor. Many studies have been conducted for the effect of surfactant and nanoparticles combination in improved oil recovery processes. However, very few studies have been done using Niger-Delta crude oil sample with different salinity range. Therefore, the research aimed to use different concentration ratios of sodium dodecyl sulfate (SDS) surfactant and Aluminum oxide nanoparticle in 30,000ppm and 60,000ppm brine using Niger Delta crude samples and formations.

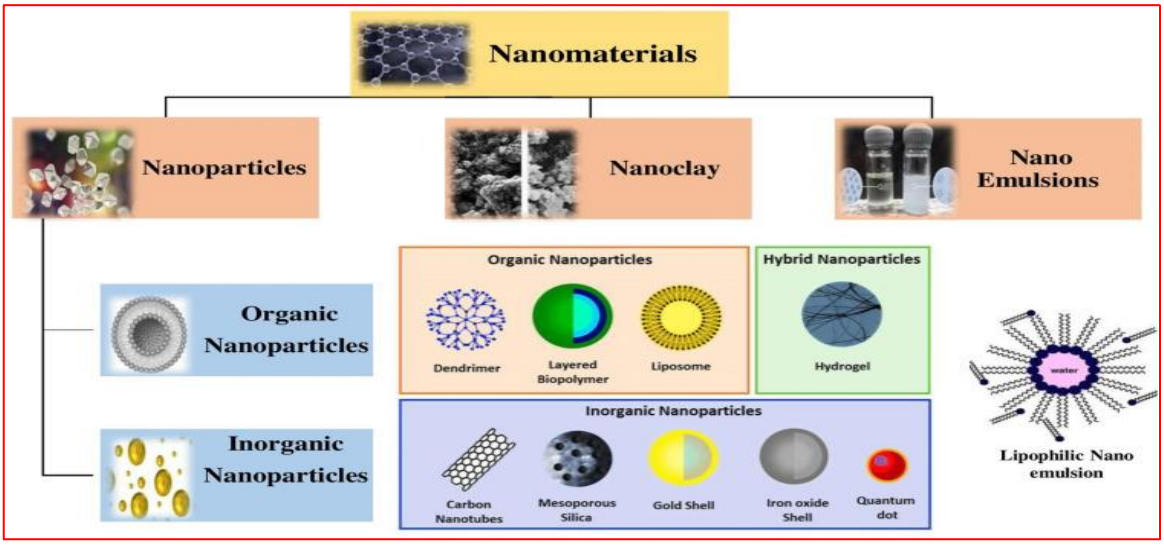

Fig. 1. Nanomaterials division breakdown [8]

2. Surfactant

Surfactants are added in small amounts of injection water to reduce the interfacial tension between oil and brine, helping to mobilize residual oil left behind during secondary recovery. Surfactants are also capable of altering the wettability of rocks by increasing the imbibition of water to the rocks [14]. However, the alteration of wettability by surfactants is more pronounced in carbonate formations as carbonate rocks are usually oil wet [15]. They can function as wetting agents, detergents, emulsifiers, dispersants and foaming agents. A surfactant molecule consists of a non-polar hydrophobic (lipophilic) tail and a polar hydrophilic (lipophobic) head.

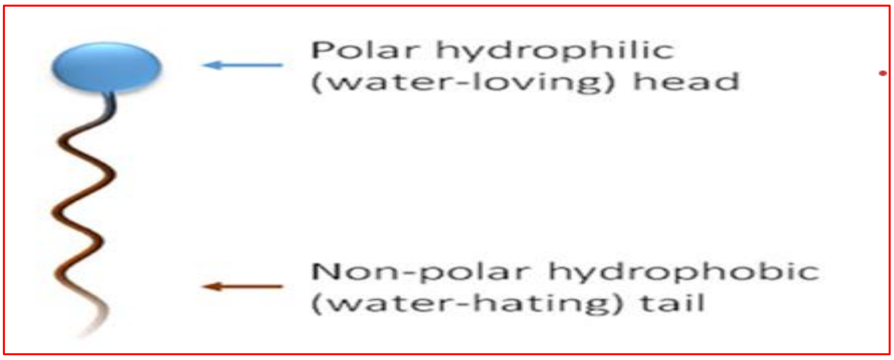

Fig. 2 General structure of a surfactant molecule

The hydrophobic tail has a higher affinity for oil, while the hydrophilic head has a greater affinity for water (Fig. 2). This structure makes surfactants soluble in both the water and oil phases. When the surfactants are injected into the oil phase, it causes a disruption in the original oil structure because of the hydrophilic group and increases the free energy in the system, the system tries to adjust for the presence of this surfactant by reducing contact with the hydrophilic. Likewise, when the surfactant is injected into the water phase, it causes a disruption in the original water structure due to the hydrophobic portion of the molecule and the system will also try to adjust for the presence of the hydrophones by reducing contact with the hydrophobics. These adjustments cause the surfactant molecules to be absorbed at the interface of the two fluids causing a reduction in the interfacial tension, [16]. The surfactants accumulate at the interface in the form of micelles [17].
The four classes of surfactants are Anionic surfactants, Cationic surfactants, Non-ionic surfactants and Zwitter-ionic surfactant [18]. However, cationic surfactants can be applied as co-surfactants. Generally, non-ionic surfactants have not provided satisfactory results for EOR. The success of a surfactant flooding process is a function of the type of reservoir rock, i.e. sandstone or carbonate. Most surfactant flooding treatments have been carried out on sandstone reservoirs because of its favorable characteristics. The mechanism behind this is to reduce the interfacial tension (IFT) between the oil and water in the pore spaces. When designed properly, a surfactant flooding scheme can reduce IFT by about 10–3 dynes/cm. It aids to recover an additional 60% of original oil in place left behind in the reservoir after water flooding

Screening criteria Surfactant screening is carried out in order to evaluate the performance a single surfactant or a combination of different surfactants under different reservoir conditions in order to ascertain suitability for a particular flooding scheme, Hirasaki et al. (2008). The following parameters were outlined by [15] as the important factors that affect the choice of surfactants:
- The type of formation, salinity of formation water and presence of divalent ions
- The depth and temperature of the reservoir
- Permeability of the formation
- Crude oil composition, API gravity and viscosity
- Residual oil saturation
- Storage capacity

3. METHODLOGY

3.1 Equipment and Materials

3.1.1 Equipment

The following equipment were used in carrying out these research: Venire caliper, Density bottle, PH meter, Hydrometer, Thermometer, Canon U-tube Viscometer, Electronic Weighing balance, Stopwatch, Retort Stand, Pump, Flooding Pump Setup, Core-holder, Sieve and Stirrer.

3.1.2 Materials

The materials used in conducting this research are Niger-Delta sand, twelve unconsolidated sand-packs, Aluminum oxide nanoparticles, aluminum foils, masking tape, industrial salt (NaCl), surfactant (Sodium Dodecyl Sulfate, SDS), laboratory prepared brine and crude oil. 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 0.87g/cm^3, viscosity of 13.03cP and ^{o}API gravity of 32 at the 28^{o}C.

3.1.3 Preparation of Laboratory Brine

The brine was prepared using 30g and 60g industrial sodium chloride (NaCl) in 1000 liters of distilled water. 30,000ppm and 60,000ppm brine concentrations were gotten and were used as dispersing agent. The density of the formulated brine was 1.0211g/cm^3 and 1.0312g/cm^3 for 30,000ppm and 60,000ppm respectively.

3.1.4 Surfactant- Nanofluids Preparation

The Aluminum oxide nanoparticles and Sodium Dodecyl Sulfate (SDS) surfactant used in this research was gotten from JoeChem Chemical Shop Port Harcourt, River's state, Nigeria. The hybrid of the surfactant and nanoparticle was formulated using different concentrations ratios of 0.1wt% and 0.3wt% for 30,000ppm and 60,000ppm brine concentrations. 0.1wt% standalone SDS surfactant and Aluminum oxide nanoparticles were also formulated with 30,000ppm and 60,000ppm brine concentrations

3.2 Experimental Procedure

- Twelve unconsolidated Niger - Delta core (plug) samples were prepared, cleaned, and fully dried in an oven.
- The measurement of weight, length and diameter of different prepared cores were done, and the result was 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 plug samples.
- 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. (Equation 1 and Table 2).
- Porosity determination was done 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. 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 procedures. The water breakthrough time was recorded.
- The different concentrations of Sodium Dodecyl Sulfate (SDS) surfactant, Sodium Dodecyl Sulfate (SDS)/Aluminum oxide hybrid and Aluminum oxide nanofluid at different concentrations ratios (Table 4) were injected into the core until no oil could be recovered at the residual oil saturation.
- 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)

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

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

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

4.1 Petrophysical Properties of the Formation

The result of bulk volume for each core sample are represented in Table 1. The plug samples with identities of A31, A32, A33, A34, A35 and A36 are saturated with 30,000ppm brine while those with A61, A62, A63, A64, A65 and A66 identities are saturated with 60,000ppm as indicated in (Table 1). Bulk volume is the total sand volume used to form the core sample excluding the volume of the screen. The grain size of the sieved formation used in preparing the encapsulated plug is between 465μm-675μm. The results obtained from measurement of bulk volume for the plug samples of 30,000ppm brine concentration ranges from 55.42 to 64.97cm^3 and 57.06 to 65.91 cm^3 for 60,000ppm brine concentration are (Table 1).

Table 1. Bulk Volume of Encapsulated Plug

Sample Plug ID	Saline Concentration	Total Length of Plug	Plug Diameter	Plug Radius	Bulk Volume
ID	**PPM**	**(cm)**	**(cm)**	**(cm)**	**(cm3) πr2h**
A31	30,000	7.88	3.24	1.62	64.97
A32		7.40	3.06	1.53	55.42
A33		6.83	3.32	1.66	59.13
A34		6.62	3.3	1.65	56.62
A35		7.65	3.2	1.6	61.52
A36		7.26	3.32	1.56	62.80
A61	60,000	7.83	3.22	1.61	63.76
A62		7.72	3.2	1.61	62.08
A63		7.8	3.28	1.64	65.91
A64		6.53	3.3	1.65	60.43
A65		7.56	3.1	1.55	57.06
A66		7.61	3.2	1.6	61.20

The pore volume is the total volume of small openings/spaces in the bed of the adsorbent particle. It's an indication of the volume of fluid that can be occupied by the pore space. The higher the pore volume /porosity the higher the volume of fluid that can be contained in the core and the better the reservoir formation. The results of the calculated pore volume of the core samples varies from 20.56 to 27.42cm^3 for 30,000ppm brine concentration and 21.59 to 27.48 cm^3 for 60,000ppm brine concentrations (Table 2). The porosity of the porous medium (Sand pack) was calculated from the bulk Volume (Table 1) and pore volume of the samples using Equation 2. The porosity result is shown in Table 2.

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Table 2. Pore Volume and Porosity of the Plug Samples

Sample Plug ID	Saline Concentration	Wt of Dried plug + screen + foil	Wt of Sat. plug + screen + foil	Wt of fluid within the pores	Density of Sat. Fluid	Pore Volume	Bulk Volume	Porosity
ID	PPM				(g/cm^3)		(cm^3) $\pi r^2 h$	(%)
A31	30,000	152.9	180.8	27.93	1.0188	27.42	64.97	42.72
A32		156.7	177.6	20.95	1.0188	20.56	55.42	37.79
A33		133.8	159.1	25.28	1.0188	24.81	59.127	41.96
A34		130.4	154.6	24.17	1.0188	23.72	56.62	41.89
A35		134.7	157.0	22.34	1.0188	22.34	61.52	36.31
A36		140.2	163.6	23.33	1.0188	23.33	62.8	37.15
A61	60,000	146.9	173.7	26.75	1.0188	26.25	63.76	41.18
A62		145.9	171.7	26.21	1.0188	25.72	62.08	41.44
A63		154.2	182.4	28.12	1.0188	27.48	65.91	41.70
A64		118.8	140.8	22.45	1.0188	21.59	60.43	38.66
A65		128.6	151.9	23.35	1.0188	23.35	57.06	40.92
A66		135.5	157.9	22.46	1.0188	22.46	61.2	36.69

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 flow rate 0.90 cm^3/sec and the pressure difference was recorded for every experiment. 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 3.

Table 3. Result for Permeability of the Plug Sample

Sample Plug ID	Saline Concentration	Length	Radius	Plug Area	Diff.Press. B/4	K1*14700	Diff.Press. A/F	K2*14700
ID	PPM	cm	cm	cm^2	EOR {psi}	md	EOR {psi}	md
A31	30,000	7.88	1.62	96.70	3	366.11	3.5	313.8
A32		7.40	1.53	85.85	3	387.27	3.5	331.9
A33		6.83	1.66	88.55	3	346.52	4.0	259.9
A34		6.62	1.65	85.74	3	346.89	4.0	260.2
A35		7.65	1.6	93.00	3	374.14	4.0	319.3
A36		7.26	1.6	89.08	3	369.86	4.0	301.9
A61	60,000	7.83	1.61	95.49	3	368.38	3.5	315.8
A62		7.72	1.6	93.69	3	370.18	3.5	317.3
A63		7.80	1.64	97.27	3	360.25	4.0	270.2
A64		6.53	1.65	84.8	3	345.94	4.0	259.5
A65		7.56	1.55	88.73	3	386.66	4.0	322.9
A66		7.61	1.60	92.60	3	372.96	4.0	270.9

4.2 Recovery of Crude Oil by Water and Tertiary Methods

Density is the mass of object per unit volume. It measures how dense a fluid can be. The results for both density and viscosity using formulated EOR agents of Sodium Dodecyl Sulfate (SDS) and Aluminum oxide nanoparticle for different concentrations of 30000ppm and 60,000ppm brine are shown in Table 4. 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. The higher the fluid's viscosity the more it's resistance to flow. One of the characteristics of a good EOR agent is one that can increase the viscosity of the brine. The results of kinematic and dynamic viscosities of the surfactant - nanoparticles hybrid as formulated with different concentrations ratios of 0.1wt% and 0.3wt% in different salinity range, are presented in Table 4. It was observed that the viscosity of surfactant- nanofluids slug using 60,000ppm brine concentration is slightly higher than those formulated with 30,000ppm. The fluids samples of F31 which is the sample with 0.1wt% of Aluminuim oxide and 0.1wt% of SDS has the lowest viscosity while the nanofluid with 0.3wt% Al_2O_3 and 0.1wt% of SDS has the highest viscosity 1.4752cp. The pH of the formulated EOR agents varies from 5.6 to 6.8 but generally, the pH of 60,000 ppm brine concentration are higher than those formulated with 30,000ppm.

Table 4. Result for Density /Viscosity of the Flooding Sample and Crude

Fluid Sample	**Fluid Concentration**	**Saline Concentration**	**Efflux Time**	**Viscometer constant**	**Density of fluid g/cm3**	**Dynamic viscosity**	**Kinematic viscosity**	**PH**
ID		**PPM**	**sec**	**150/60lb**			**(cp)**	
F31	0.1 wt%Al_2O_3/0.1wt%SDS	30,000	28.12	0.036415	1.0188	1.0203	1.0015	6.1
F32	0.3 wt%$A_{l2}O_3$/0.1wt%SDS		29.27	0.036415	1.0193	1.0438	1.0241	6.0
F33	0.1 wt%$A_{l2}O_3$/0.3wt%SDS		28.87	0.036415	1.0202	1.0874	1.0659	5.6
F34	0.2 wt%$A_{l2}O_3$/0.3wt%SDS		28.93	0.036415	1.1229	1.0244	1.0962	5.9
F35	0.1wt% SDS/Brine		29.54	0.036415	1.0123	1.0121	1.0002	6.2
F36	0.1 wt% Al_2O_3/Brine		30.10	0.036415	1.0244	1.0962	1.1229	5.9
F61	0.1 wt%Al_2O_3/0.1wt%SDS	60,000	31.26	0.036415	1.0396	1.1835	1.1384	6.0
F62	0.3 wt%Al_2O_3/0.1wt%SDS		38.95	0.036415	1.0399	1.4752	1.4185	6.6
F63	0.1 wt%Al_2O_3/0.3wt%SDS		37.23	0.036415	1.0407	1.3746	1.3208	6.8
F64	0.2 wt%Al_2O_3/0.3wt%SDS		36.27	0.036415	1.0395	1.3593	1.3077	6.7
F65	0.1wt% SDS/Brine		33.45	0.036415	1.0276	1.1543	1.1233	6.1
F66	0.1 wt% Al_2O3/Brine		35.91	0.036415	1.0394	1.3077	1.3593	6.3

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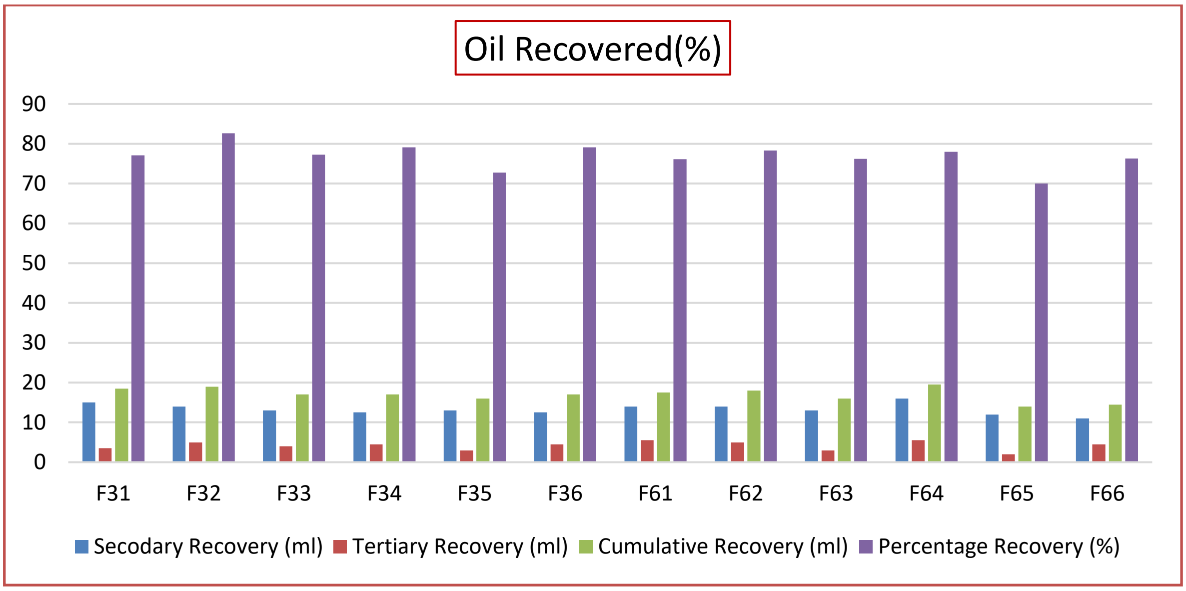

4. 3 Permeability Change Result

After the secondary and tertiary flooding, the core's permeability change was determined as to evaluate the extent of formation damage caused by formulated EOR fluids. There was a significant decrease in permeability of the reservoir formation generally after flooding with different nanofluid concentration ratio. The nanofluid with 30,000ppm brine dispersing agent has high reduction in permeability as to compare to the nanoparticle dispersed in 60,000ppm brine. Fig. 5 shows the change in permeability for all the EOR agents studied. Permeability alteration for all the nanofluids concentrations evaluated ranges from 52.03 md to 90.06 md. The lowest value of 52.03 md permeability change was gotten from concentration ratio of 0.1 wt%Al_2O_3 and 0.1wt%SDS in 30,000ppm brine as to compare to the concentration ratio with 60,000 ppm brine which has 90.06 md. The concentration ratio of 0.3 wt%Al_2O_3 and 0.1wt%SDS in 60,000 ppm has the highest permeability damage as to compare with other concentrations ratio and standalone aluminum oxide nanoparticle and Sodium Dodecyl Sulfate surfactant both in 30,000ppm and 60,000ppm. It was also observed that the concentration with the highest nanoparticle concentration gave the highest permeability damage both for 30,000ppm and 60,000ppm brine solution. The result is expected because some authors have proved that Surfactant flooding is economically unfeasible due to surfactant molecules adsorption on the reservoir rock surface but works better when mixed with nanoparticle.

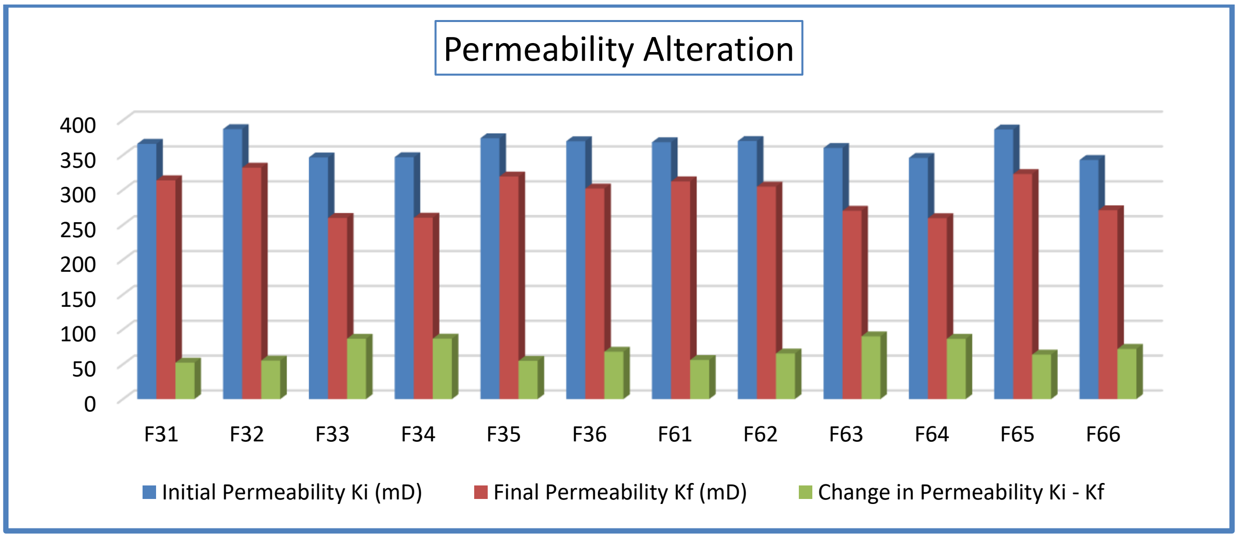

Fig. 5. Permeability Alteration for different concentration of EOR agents

5. CONCLUSION

The results from the experimental tests have proved the effectiveness of the synergy of the Aluminium oxide (Al_2O_3) nanoparticles and Sodium Dodecyl Sulphate (SDS) surfactant in improving oil recovery in both 30,000ppm and 60,000ppm brine concentrations. The brine concentration of 30,00ppm generally performed better than 60,000ppm concentration. The presence of Aluminium oxide nanoparticle in Sodium Dodecyl Sulphate in different concentration ratios improved the viscosity of the enhanced oil formulated fluid, which reduced the mobility ratio between the injected fluids and the oil in the reservoir. The synergised surfactant-nano-aluima solution reduced the permeability damage of the formation from 90.06 md to 53.03 md. which led to higher oil recovery but can block formation pores at higher concentration. The concentration ratios formulated with 30,000ppm has the cumulative oil recovery ranging from 77.08% to 82.61% while those concentrations formulated with 60,000ppm has the cumulative oil recovery ranging from 76.087% and 78.00%. For both 30,000ppm and 60,000ppm, concentration ratio of 0.1 wt%Al_2O_3 in 0.3wt% SDS gave the highest cumulative oil recovery. All the various formulated hybrid ratios in both 30,000ppm and 60,000ppm performed better than standalone surfactant and aluminium oxide Nano-fluids. The right combination of Sodium Dodecyl Sulphate and Aluminium oxide in brine improved oil recovery based on viscosity, permeability change, and oil recovery. This study also showed that the presence of nanoparticle in surfactant improve recovery in relatively high salinity reservoir. Reservoir engineers should consider the concentration ratio when designing enhanced oil project as to get best optimum results of high recovery and less formation damage

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