# Investigation of Combined Polymer Flooding and Low Salinity Water for Enhanced Oil Recovery in Dolomite Reservoir using Okro (*Abelmoschus esculentus*)

Omoniyi Omotayo Adewale<sup>1\*</sup>; A. Dodo Ibrahim Sulaiman<sup>2</sup>; Surajudeen Abdulsalam<sup>3</sup>; Mohammed Adamu Bello<sup>4</sup> Abubakar Tafawa Balewa University Bauchi, Bauchi State, Nigeria.

> Corresponding Author: Omoniyi Omotayo Adewale<sup>1\*</sup> e-mail: aoomotayo@atbu.edu.ng

Abstract:- The major objective of the present investigation was to study combined polymer flooding with low salinity water for enhanced oil recovery in dolomite reservoirs using okro (Abelmoschus esculentus) with the formulation of saline water and synthetic sea water, to conduct displacement experiments on six (6) dolomite core samples as well as studying the effect of concentration of Okro polymer, HPAM and saline water on oil recovery. It becomes imperative to ensure that residual or trapped oil are not left abandoned but are recovered from the reservoir in order to improve recovery. Recent studies have shown that local materials capable of acting as biopolymers have high potentials in enhancing oil recovery. This has attracted more interest due to their low cost, availability and environmentally friendly nature. Therefore, this research was conducted to study the effect of low salinity waterflooding on improving oil recovery in six dolomite cores. In addition a combined low salinity and polymer slugs injection was carried out by comparing a certain local polymer okro (Abelmoschus esculentus) and a commonly used synthetic polymer Partially Hydrolyzed Polyacrylamide (HPAM) in tertiary mode to determine and optimize its effectiveness in increasing oil production. Synthetic sea water and low salinity water were prepared in the laboratory to simulate actual formation brine. The Density and certain rheological property; viscosity of the polymers were determined at varying temperature range  $(20^{\circ}C - 26^{\circ}C)$ . Out of the six cores, two cores (D1, D2) were unaged and tested for effect of reducing salinity of injected brine in both secondary and tertiary mode while the remaining four cores (D3, D4, D5, D6) were aged for four weeks at 85 °C in order to observe the effect of wettability alterations on oil recovery. Using dolomite core plug, an oil displacement test was conducted to determine the oil recovery factor. The results indicate that the density and viscosity of brines and oils decrease with increase in the temperature. Core D1 was flooded with synthetic sea water while core D2 was flooded by 22 times DSSW (Diluted Synthetic Sea Water). Core D1 gave a recovery of 41.54% OIIP (Oil Initially In Place) which is higher than that of core D2 which gave 40.96%. The unaged cores showed a strongly water-wet behavior. The four aged cores D3, D4, D5, and D6 were flooded by low salinity brine which was 3000 ppm NaCl brine as a secondary mode. Cores D3, D4, D5, and D6 gave recoveries of 61.20, 60.02, 57.62, and 55.68% OIIP respectively. Low salinity water flooding gave an improvement in oil recovery with aged cores compared with unaged cores flooded with synthetic sea water. The aging period altered wettability of the cores to less waterwet state. Low salinity polymer slugs injection was conducted in all the six cores using okro and HPAM polymers. Cores D1, D2, D3, D4, D5, and D6 gave 1.21, 11.84, 2.3, 3.6, 11.21, and 4.79% OIIP respectively when okro was injected, while cores D1, D2, D3, D4, D5, and D6 gave 1.02, 8.56, 1.55 2.52, 8.9, and 4.3% OIIP respectively when HPAM polymer was injected. Overall, the results of low salinity and polymer slugs injection in all six cores showed that the slug injection has mobilized and produced different amount of oil from the cores. The oil recoveries for both okro and HPAM polymers from the aged cores were higher than those of the unaged cores which indicate the effect of initial wettability state on performance of low salinity waterflooding. In comparison, okro polymer gave higher recovery than HPAM polymer.

**Keywords:-** Reservoir, Natural Polymer, Abelmoschus Esculentus (OKRO), Partially Hydrolyzed Polyacrylamide (HPAM)., Wettability Alteration, Low Salinity Water.

# I. INTRODUCTION

More than half of the world's oil reserves are stored in carbonate reservoirs (Al-Shalabi *et al.*, 2014). Due to heterogeneity, the complexity of minerals (limestone, chalk, and dolomite), low permeability, and wettability condition, enhanced oil recovery (EOR) methods for such reservoirs are challenging. Because of the inherent oil-wet nature of the carbonate rock, a large volume of oil remains in the matrix with injected water failing to flush most of the oil from the pore spaces (Shehata and Nasr-El-Din, 2014). Hence, it is necessary to increase the potential of oil production through wettability alteration by EOR methods such as additive chemicals, nano-materials, and low-salinity water.

Water injection to improve the oil recovery has been employed for many years. The effect of injection brine composition and concentration on the displacement efficiency has been ignored in the design of water flooding in the past. Historically, avoiding formation damage by making sure no interaction between injected brine and indigenous brine will take place during water flooding was the main design parameter of water flooding (Abdulrazagy and Zaid, 2015). Morrow *et al.* (1996) concluded that oil recovery optimization during water flooding requires alteration of injection water brine composition. Tang and Morrow (1999) and McGuire *et al.* (2005) concluded that decreasing brine salinity results in an improvement of oil recovery.

Polymer flooding is an EOR method that uses polymer solutions to increase oil recovery by decreasing the water/oil mobility ratio thus increasing the viscosity of the displacing water. Polymer flooding is used under certain reservoir conditions that lower the efficiency of a regular waterflood, such as fractures or high-permeability regions that channel or redirect the flow of injected water, or heavy oil that is resistant to flow. Adding a water-soluble polymer to the water flood allows the water to move through more of the reservoir rock, resulting in a larger percentage of oil recovery.

It is a well acknowledged fact that the use of polymer increases the viscosity of the injected water and reduces permeability of the porous media, allowing for an increase in the vertical and areal sweep efficiencies, and consequently, higher oil recovery (Samanta *et al.*, 2011). The main objective of polymer injection is for mobility control, by reducing the mobility ratio between water and oil. The reduction of the mobility ratio is achieved by increasing the viscosity of the aqueous phase. Another main accepted mechanism of mobile residual oil after water flooding is that there must be a rather large viscous force perpendicular to the oil-water interface to push the residual oil. This force must overcome the capillary forces retaining the residual oil, move it, mobilize it, and recover it (Guo and Huang, 1990).

Low salinity waterflooding process involves injecting brine with a lower salt content or ionic strength. The ionic strength is typically in the range of 1000–5000 ppm which is much lower than that of the formation water or seawater. The low salinity waterflooding causes a shift in the thermodynamic equilibrium between crude oil, brine and rock system that has been established during the geologic time which tends to favor improved oil recovery. Several laboratory studies demonstrated the potential of low salinity water-flooding to improve oil recovery where the core flood experiments showed increase in oil recovery in both secondary and tertiary mode (Filoco and Sharma, 1998; Zhang and Morrow, 2006; Yildiz *et al.*, 1999). In addition, field trial of low salinity water-flooding has been carried out and showed significant success (Lager *et al.*, 2008).

# A. Problem Statement

Primary recovery can recover from zero to over 50% of the original oil in place (OOIP), and the secondary recovery can recover from 30 to 50 % of the original oil in place. Since

oil production grows at a rate greater than reserve addition, there is a need to boost the reserve, and this lies with the application of tertiary recovery (EOR) which targets what is left (>50 % OOIP).Hence there is need for the use of natural polymer.

https://doi.org/10.38124/ijisrt/IJISRT23MAY1178

Most of the polymers used in the EOR applications are imported from other countries; as such it takes a lot of time. Also, increased temperature and the presence of divalent ions result in mechanical degradation of these synthetic polymers thereby reducing their sweep efficiency (Obuebite *et al.*,2023). However, recent studies have shown that local materials capable of acting as biopolymers have high potentials in enhancing oil recovery. This has attracted more interest due to their low cost, availability and environmentally friendly nature.

In this research, investigation of combined polymer flooding and low salinity water for enhanced oil recovery in dolomite reservoir using okro (*Abelmoschus esculentus*), polymer flooding tests were systematically performed using polymer concentrations less and higher than 300 ppm (Shiran, 2014). The effect of this was examined on increased oil recovery at lower residual oil saturations similar to the cases in Shiran's work (Shiran, 2014) in which 300 ppm was used.

# B. Scope and Limitations

This experimental research was devoted to studying the combined effect of low salinity water flooding with polymer injection while comparing local and synthetic polymers. This research was limited to preparation of polymer solutions (okro and HPAM), synthetic sea water and low salinity water, preparation of six dolomite core samples, permeability measurements, drainage, aging, low salinity (LS) water flooding in aged and unaged cores, comparison between the synthetic sea water (SSW) and low salinity (LS) water flooding as secondary mode, oil recovery of low salinity waterflooding, wettability state of the crude oil/brine/rock (COBR) system, Pressure and production profiles of low salinity- polymer (LS-P) flooding in the six cores were compared using okro and HPAM polymers.

This investigation aims to compare okro (*Abelmoschus esculentus*) and HPAM in low salinity water flooding for enhanced oil recovery in dolomite reservoir.

# II. LITERATURE REVIEW

Historically, avoiding formation damage by making sure no interaction between injected brine and indigenous brine will take place during water flooding was the main design parameter of water flooding. Morrow *et al.* (1996) concluded that oil recovery optimization during water flooding requires alteration of injection water brine composition. Tang and Morrow (1999) and McGuire *et al.* (2005) inferred that decreasing brine salinity results in an improvement of oil recovery. Jerauld *et al.* (2008) indicated that low salinity flooding of more than 20 sandstone cores at reservoir conditions in secondary and tertiary modes had been conducted as reported in the literature. They also reported an

improvement of recovery efficiency of 5 to 38 % and 3 to 17 % reduction of residual oil saturation as a result of low salinity flooding. Several laboratory studies demonstrated the potential of low salinity water-flooding to improve oil recovery where the core flood experiments showed increase in oil recovery in both secondary and tertiary mode (Filoco and Sharma, 1998; Zhang and Morrow, 2006; Morrow *et al.*, 1996). In addition, field trial of low salinity water-flooding has been carried out and showed significant success (Lager *et al.*, 2008).

McGuire *et al.* (2005) reported BP experience with low salinity flood. They indicated that BP tested four areas using water injection salinity ranges between 1500 to 3000 ppm and the benefits of its LoSal EOR ranged from 6 to 12 % OOIP, resulting in an increase in waterflood recovery of 8 to 19 %. It is well known that low salinity flood has the following advantages: high EOR potential, environmentally friendly, and combination with other recovery methods possible (such as polymers, alkaline, surfactant, etc.). Robertson (2007) showed that using data obtained from three oilfields, oil recovery increases as the salinity ratio of the waterflood decreases.

Kumar *et al.* (2010) concluded that oil recovery from Berea by traditional flooding is accompanied by fine migration in quantities sufficient to have some bearing on oilbrine interfacial stability, and that low salinity flooding increases this tendency. Wideroee *et al.* (2010) employed NMR relaxation/diffusion measurements and CryoESEM Imaging for detecting wettability changes during low salinity flooding of sandstone cores. They concluded that the responses in the data from low salinity flooding experiments may be attributed to wettability changes.

Wettability has in many papers been discussed as a key parameter for the LSE (Low Salinity Effect). However, the shift in wettability is not well documented. Wettability tests before and after shift in salinity are rare, and most indications are based on end point water relative permeability or the shape of the oil production curve. Tang and Morrow (1999) showed that properties of the crude oil and the rock and the presence of connate water all play an essential role in the sensitivity of oil recovery to brine composition.

Among other mechanisms that have been suggested for explaining LSE during the last 10 years, are in addition to fines migration, impact of alkaline flooding (McGuire *et al.* 2005), multicomponent ion exchange (Lager *et al.*,2007), microscopically diverted flow (Skauge, 2008), double-layer expansion (Ligthelm *et al.*, 2009) and pH driven wettability change (Austad *et al.*, 2010). Injection of low salinity brine can give rise to a moderate improvement in oil recovery compared to traditional high salinity water flooding.

According to Lager *et al.* (2008), a hydraulic unit was converted to inject low salinity brine into an Alaskan reservoir in 2005 by switching a single injection pad from high salinity produced water to low salinity water. An injector well and two close production wells were selected within a reasonably well constrained area. The detailed analysis of

# https://doi.org/10.38124/ijisrt/IJISRT23MAY1178

the production and the chemical composition of the produced water showed the effect of injection brine composition in improving recovery at reservoir scale. The salinity of the produced water used for injection was 16640 ppm of total dissolved solids, while the low salinity brine used has a salinity of 2600 ppm of total dissolved solids. The production data indicated that the process was successful where the oil production increased and the water cut dropped from 92 to 87 %.

# III. MATERIALS

### A. Sample Collection and Analyses

The crude oil sample was collected from the Research and Development Division of the Nigerian National Petroleum Corporation (NNPC). The characterization of the crude oil was done by analyzing the physical properties such as Color/appearance, Density, specific gravity, API Gravity, Cloud point, Pour point, Flash point, Kinematic and Dynamic viscosities. These oils were of two types. These oils were used either for displacement process or for aging. These oils are a high viscous crude oil sample X, and a medium crude oil sample Y.

### B. Core Preparation

Six dolomite cores were used in the course of this research, and these core samples were characterized in order to know their mineralogical composition. To avoid any experimental error, cores were prepared very carefully. The core restoration/mild cleaning were carried out using the technique in line with the procedure described by Springer et al. (2003) and Ivan et al. (2020) with a little modification. Before starting to carry out any measurement, the cores were cleaned with a brush to remove possible dust particles attached to the surface of the samples. Afterwards, they were inserted inside Soxhlet apparatus to be extracted with toluene for 24 h. The cores were put in the oven at temperature of 90 <sup>o</sup> C for couple of days to dry them properly and then the length and diameter of the cores were measured. The dead ends volumes were measured before mounting the core into the core holder to make correction for later calculations. Then a confining pressure of 27 bar was applied to the core and the pressure reading was checked for stabilization after half an hour to ensure there is no leakage in the core holder. Afterwards the core was connected to a computer-aided pump through a piston cylinder filled with synthetic sea water. Before starting to saturate the core, the pump was set to hold a pressure of 5 bar which was the pressure in the cylinder and lines as well. After the pressure was stabilized in the system, the inlet valve of the core-holder was opened and the brine was sucked into the core. The pump has to deliver more synthetic sea water to fill the pore volume of the core and to maintain the pressure of 5 bar. This was maintained until there was almost no change in the cumulative volume of added brine which represents the pore volume (VP), of the core used. The bulk volume  $(V_b)$  of the core was calculated based on the geometrical measurements done during the core preparation. The porosity of the core was then measured using equation 1.

$$\phi = \frac{V_P}{V_b} X \quad 100 \tag{1}$$

The core was put aside for one week after saturation to

allow synthetic sea water to attain ionic equilibrium with the core.



Fig 1: Porosimeter

The Porosimeter was used to measure the porosities of dolomite core samples. The core flooding was carried out using an experimental setup.

# IV. EXPERIMENTAL DESCRIPTION

### A. Permeability Measurements:

The permeability measurements were carried out using the Darcy's law equation. The absolute, effective and relative permeability measurements were conducted before aging, after aging, after low salinity flooding and polymer flooding.

# B. Drainage

The primary drainage process for the cores was established by using high viscous oil sample X. The process was done with the core oriented vertically to make use of the gravitational force.

# C. Aging:

After the primary drainage process the cores were aged using aging cell in an oven for 4 weeks at a temperature of 85 <sup>o</sup>C to alter the wettability of the cores. Cores D3, D4, D5, and D6 were aged for 4 weeks while cores D1 and D2 were not aged to watch the effect of aging on the performance of displacement experiments.

# D. Synthetic Sea Water and Low Salinity Water Flooding:

The effect of reducing salinity of the injected brine was inspected in the unaged cores in both secondary and tertiary mode. The synthetic sea water was injected first in core D1 as secondary mode then followed by 22 times diluted synthetic sea water as tertiary mode. Core D2 was flooded directly from the beginning by 22 times diluted synthetic sea water. The aged cores D3, D4, D5, and D6 were flooded by 3000 ppm NaCl brine (low salinity brine) as secondary injection. During the flooding experiments, all the cores were subjected to a confining pressure of 25 bar. Before starting the flooding in each core the system was pressurized to 8 bar by using the back pressure regulator to prevent the development of air bubbles.

The flooding process commenced with slow flow rate of 0.1 ml/min in order to forestall the fingering displacement that causes the early water break-through. When the oil production was stopped, the injection was continued at same rate for 2 more pore volume. After that the flow rate was increased in order to observe the effect of increasing the viscous force on the oil recovery. Also the injection continued for almost 2 pore volume after the oil production was ceased. The flow rates used in the experiments were 0.1, 0.5, and 1 ml/min. During the flooding, samples of production were collected using the fraction collector. The volume of oil and water produced in each tube was measured volumetrically and the calculations of the production profiles and saturations were carried out. The pressure profile during the displacement was continuously monitored.

### E. Samples Preparation

The fluid samples used in this study are described and presented in this section. In addition the chemical composition and the preparation procedures are explained for each fluid. These fluids were either used for displacement experiments or for other measurement during the study.

Synthetic Sea Water (SSW)

ISSN No:-2456-2165

Synthetic sea water was used to saturate all the cores. The chemical composition of the synthetic sea water is listed in table 1. The brine was prepared by mixing distilled water and the salts. The brine was placed on a magnetic stirrer to dissolve the salts properly and then filtered using 0.45  $\mu m$  vacuum filter.

https://doi.org/10.38124/ijisrt/IJISRT23MAY1178

Table 1: Chemical Composition of Synthetic Sea Water (SSW)							
Salt	Formula	H2O, Mol kg <sup>-1</sup>	(g/kg) Solution	Producer			
Sodium Chloride	NaCl	4.504 x 10 <sup>-1</sup>	26.348	Sigma - Aldrich			
Potasium Chloride	KCl	9.022 x 10 <sup>-3</sup>	0.672	Sigma - Aldrich			
Sodium Hyrogen Carbonate	NaHCO3	1.979 x 10 <sup>-3</sup>	0.166	Sigma - Aldrich			
Pottasium Bromide	KBr	8.110 x 10 <sup>-4</sup>	0.096	Sigma - Aldrich			
Boric acid	H3BO4	3.186 x 10 <sup>-4</sup>	0.025	Sigma - Aldrich			
Sodium Fluoride	NaF	6.754 x 10 <sup>-5</sup>	0.003	Sigma - Aldrich			
Magnesium Chloride	MgCl <sub>2</sub> .6H <sub>2</sub> O	2.375 x10 <sup>-2</sup>	4.821	Quali-TechChem			
Calcium Chloride	CaCl2.2H2O	9.920 x 10 <sup>-3</sup>	1.458	Quali-TechChem			
Strontium Chloride	SrCl <sub>2</sub> . 2H <sub>2</sub> O	8.689 x 10 <sup>-5</sup>	0.017	Quali-TechChem			
Magnesium Sulphate	MgSO4. 7H2O	2.725 x 10 <sup>-2</sup>	6.704	Quali-TechChem			

The anhydrous salts were procured from Sigma-Aldrich (USA) and the hydrated salts were purchased from Quali-Tech Chem (Indian). The synthetic seawater was prepared using anhydrous and hydrated salts in accordance with the composition indicated in the work of Felix *et al.* (2020) and the concentration is similar to the study of Cuenca and Serna (2021). The synthetic sea water was diluted 22 times to make low salinity brine used for injection in the unaged cores according to the procedure of Saw and Mandal (2020) with little modification.

# Low Salinity Water (LSW):

The low salinity water used for secondary waterflooding in the aged cores was made by mixing distilled water and sodium chloride (NaCl). The brine contains 0.30 wt % of NaCl and the composition is listed in table 2.

Salt	(g/kg solution)	Producer
NaCl	3.000	Qualikems

The brine made was put on a magnetic stirrer to dissolve the salts properly and then filtered using 0.45  $\mu$ m vacuum filter.

# F. Crude Oils

During the drainage and flooding experiments, high viscous crude oil sample X was used to establish the minimum value of initial water saturation, Swi for all cores.

|--|

Oil Sample	AN	BN	Density	Viscosity	API	pН	Color
	Mg KOH/ g oil	Mg KOH/g oil	g/cm3	cP	gravity		
High viscous crude oil	3.91	1.29	0.9226	4.28	21.87	7.30	Black
Madium anda ail V	0.22	1 17	0.8054	2 15	26.52	7.60	Dorl
Medium crude on 1	0.25	1.17	0.8954	5.15	20.55	7.00	brown
							UIOWII

Crude oil densities and viscosities were measured at 20°C, 23 °C and 26 °C. Acid Number (AN) and Base Number (BN) were analyzed. Crude oil was also used in aging the cores before the main flooding experiments. Composition and some of the important properties of crude oil were noted. Table 3 shows the properties of the test fluids used for this experiment.

# G. Preparation of Okro (Natural Polymer) Sample

The Okro sample – natural polymer (*Abelmoschus* esculentus) was sliced, dried, pulverized and the powdered fruit was then passed through sieve no. #22 to obtain fine granules (Pratibha, 2020). A stock polymer solution with a

concentration of 20,000 mg/l was prepared by dissolving 10g of powdered okro sample in 0.5 liter of distilled water at 60 ° C and stirred vigorously for proper dissolution. However, the dissolution was incomplete as there were undissolved particles still floating in the solution. These particles were sieved out to obtain a clear solution. In determining the absorbance of the polymer at different concentrations, the stock polymer solution (20,000 mg/l) was further diluted to concentrations of 2200, 2000, 1600, 1200, 800, and 400 mg/l which was achieved by using 1.1, 1.0, 0.8, 0.6, 0.4 and 0.2 g of okro sample respectively in line with the procedure of Uzoho *et al.* (2022) with little adjustment.

# https://doi.org/10.38124/ijisrt/IJISRT23MAY1178

### H. Preparation of Polymer Solution (HPAM)

The type of polymer used in this study is the partially hydrolyzed polyacrylamide (HPAM). A 5000 ppm stock solution was prepared by measuring 0.30 wt% NaCl brine in a beaker. The beaker was placed on a magnetic stirrer and the speed was set to 150 rpm at 26 °C to create a vortex which extends about 75 % towards the bottom and to ensure full hydration of the polymer powder. An amount of 3 g of HPAM polymer weighted in a tray was added to the brine by carefully sprinkling the polymer powder just below the vortex shoulder. The speed of the magnetic stirrer was reduced to the lowest speed where polymer particles still float in the solution and the beaker was covered with perforated parafilm. The solution was left on the magnetic stirrer overnight and then transferred to Duran flask with a cork and sealed with parafilm. The polymer stock solution (5000 ppm) was further diluted to concentrations of 1000, 600, 300 and 100 ppm; and then filtered using 40 um filter and vacuum apparatus before using it for viscosity measurements and flooding process. This method was according to the procedures proposed by Lizcano et al. (2020) with slight modifications. In the work of Lizcano et al. (2020), a 5000 ppm stock solution using the magnetic stirrer vortex method was prepared, and from it, HPAM solutions of 2000, 1000, 500, 100, and 50 ppm were diluted, while in the current study, a 5000 ppm stock solution was prepared and diluted to concentrations of 1000, 600, 300 and 100 ppm; and then filtered using 40 µm filter and vacuum apparatus before using it for viscosity measurements and flooding process

# V. RESULT AND DISCUSSION

Below are presented the various measurements and displacement experiments conducted during this research, and they are discussed. The measured properties of different liquids used or prepared are stated and analyzed and these measured properties include density, and viscosity. The polymers concentration used for the tertiary injection was chosen on the basis of the viscosity measurements. Also the basic physical and petrophysical properties of the six dolomite cores used for displacement experiments are stated and discussed. These cores are assigned D1, D2, D3, D4, D5, and D6. Cores D1 and D2 were not aged while the remaining four cores were aged for four weeks at 85 °C.

Core D1 was first flooded with synthetic sea water, and then followed by 22 times diluted synthetic sea water. This was done in order to observe the effect of the low salinity waterflooding as tertiary mode. Core D2 was flooded directly by the 22 times diluted synthetic sea water as secondary mode and compared with core D1. The aged cores were flooded by low salinity brine which is 3000 ppm NaCl brine and the oil recovery and pressure profiles are presented. The wettability state as well as the recovery parameters of the cores are discussed and compared with the unaged cores to determine the effect of aging and low salinity waterflooding.

### A. Mensuration of Liquids Properties

In this section, the measured properties of the fluids used in this research are portrayed and discussed. The fluids were used during this investigation either for displacement experiments or for testing purposes.

### > Density:

The density measurements of the fluids used in this study are recorded in Appendix B. The measurements for brines and oils were carried out at three different temperatures. The results indicate that the density of brines and oils decreases with increase in the temperature.

### ➤ Viscosity

The viscosity measurements of brines and types of oil used in this study were conducted at three different temperatures and the results are shown in Appendix C. The fluid viscosity mainly depends on the temperature and the results demonstrate that the viscosity of brines and oils used decreased with increasing temperature. The displacement experiments in this study were conducted at room temperature and the measured temperatures during the experiments were between 20 and 26  $^{\circ}$ C.

The viscosity measurements of the polymer solutions were conducted at temperature of 20 °C, 23 °C, and 26 °C and they are depicted in Appendix C. The concentration of the polymer solutions used was chosen based on the viscosity measurements (see Appendix C). In the low salinity polymer slug injection which was the last flooding process, the concentration chosen for polymer slug was 600 ppm and that was in order to notice if any additional oil can be produced by further improving on the viscosity ratio between oil and polymer solution.

### B. Basic Physical and Petrophysical Properties of the Rocks

The six dolomite cores used in this research were assigned D1, D2, D3, D4, D5, and D6. The basic properties of these cores are presented in table 4. The Dolomite core samples were obtained from Oreke Ifelodun Local Government Area of Kwara State of Nigeria.

Core ID	Length (cm)	Diameter (cm)	PV (ml)	<b>Porosity</b> φ (%)	Absolute K (mD)	Swi (%)
D1	4.50	3.40	6.68	16.35	213.22	19.00
D2	4.26	3.40	6.32	16.34	217.30	20.50
D3	4.75	3.38	6.75	15.83	219.81	19.50
D4	4.20	3.50	6.30	15.59	219.17	22.00
D5	4.80	3.50	8.41	18.21	223.08	21.50

Table 4: Physical Properties of the Dolomite Core Samples

				_		
D6	4.80	3.38	7.81	18.13	221.39	23.00

As seen from table **4**, the dolomite cores have porosities ranging from 15.59 - 18.21 % while the absolute permeabilities vary between 213.22 and 223.08 mD. The mutation in the absolute permeabilities of the cores could be as a result of the interactions between the SSW used for measurement and the rock minerals during saturation. In addition, the differences in the pore structure of the cores could also conduce to the permeabilities variation. Initial parameters of the cores after the drainage process and also the permeability measurements conducted before and after the aging period are presented in table **5**.

https://doi.org/10.38124/ijisrt/IJISRT23MAY1178

Core ID	D1	D2	D3	D4	D5	D6
Swi[% PV]	18.70	19.00	19.50	22.50	21.50	23.00
Soi [%PV]	81.30	81.00	80.50	77.50	78.50	77.00
Keff [mD] before aging	262.26	268.27	273.05	282.80	287.85	287.52
Keff [mD] after aging	NA*	NA*	210.43	215.02	212.90	205.93

Table 5: The Initial Parameters of the Cores before Flooding F	rocess
----------------------------------------------------------------	--------

NA\* Implies not Aged

# The initial water and oil saturations of the unaged cores D1 and D2 are nearly the same as shown in table **5**. The other four cores that were aged for four weeks at 85 °C demonstrated a decrease in the effective permeability which indicates that the wettability of the cores has been altered during aging period. The diminution in permeability is more marked in cores D5 and D6 while cores D3 and D4 showed about 23 % and 24 % reduction in permeability respectively.

# C. Synthetic Sea Water (SSW) and Low Salinity (LS) Water Flooding in Unaged Cores:

In this procedure, the effect of decreasing the salinity of injected brine on the oil recovery of two unaged cores was first examined. The brines used were synthetic sea water and 22 times diluted synthetic sea water and the experiments were carried out in secondary and tertiary mode. Core D1 was flooded first with synthetic sea water; then followed by 22 times diluted synthetic sea water so as to observe the effect of low salinity waterflooding as tertiary mode. But core D2 was flooded directly by the 22 times diluted synthetic sea water and compared with core D1.

# > Production Profiles of Secondary Injection

The production profiles of secondary waterflooding of the unaged cores D1 and D2 are depicted in figure 2. Core D1 was flooded with synthetic sea water while core D2 was flooded by the 22 times diluted synthetic sea water.

# D. Comparison between the Synthetic Sea Water (SSW) and Low Salinity (LS) Water Flooding as Secondary Mode:

The production recovery parameters of synthetic sea water and low salinity water flooding were done as secondary mode water flooding in unaged cores D1 and D2 and the results are presented in table **6**. The flooding process in both cores was similar and the flow rate was increased when the oil production ceased so as to observe the effect of increasing the viscous force. It is apparent from the table that the two flooding cases gave almost same oil recovery where synthetic sea water gave 41.54% of oil recovery factor and 22 time diluted synthetic sea water gave 40.96% of oil recovery factor.



Fig 2: Production Profile of SSW and DSSW in Unaged Cores D1 and D2

Table 6: Production Recovery Parameters of SSW and Low Salinity (LS) Water Flooding as Secondary Mode

Core	D1 (Secondary SSW)	D2 (Secondary LS) (22DSSW)
PV Injected	9.7	7.0
RF (% of OIIP)	41.54	40.96
WBT (PV)	0.48	0.41
Sor (%PV)	31.92	31.74
Keffe at Sor	32.18	32.08

It was noticed in both experiments above that oil production was stopped or continued at a high water/oil ratio once the water break-through happened. This type of production shows that both cores have strongly water-wet conditions as observed in the work of Kakati *et al.* (2020). Besides, the high residual oil left after the flooding process which is 31.92 and 31.74 % PV for cores D1 and D2 respectively reflects that the cores are at strongly water-wet state.

Mamonov *et al.* (2019) and Mamonov *et al.* (2020) have demonstrated that low-salinity water injection (LSWI) has shown improved oil recovery in both sandstone and carbonate reservoirs. Although the mechanisms behind the success of LSWI in carbonates have been studied extensively, decoupling the specific underlying mechanisms remains a challenge. To tackle this challenge, a systematic study of the crude oil–brine–rock (COBR) interactions for each reservoir is critical. A stated essential condition for observing the effect of low salinity waterflooding is setting up the mixed wettability by exposing the rock to crude oil as observed in the work of Selem *et al.* (2021).

# E. Low Salinity (LS) Water flooding in Aged Cores:

Here, the secondary low salinity waterflooding process was conducted in the aged cores (aged for 4 weeks at a temperature of 80  $^{\rm O}$ C), and the results obtained are presented and discussed. The aged cores are D3, D4, D5, and D6 and the low salinity brine used for flooding is 3000 ppm NaCl brine. In this procedure the flow rate was increased when the oil production stopped so as to observe the effect of increasing the viscous force. The effect of aging period in modifying the wettability of the cores is discussed and the pressure profiles are shown below.

# > Oil Recovery of Low Salinity Water Flooding

The four aged cores were flooded with low salinity (3000 ppm NaCl) brine as secondary mode, and the recovery parameters of the cores are shown in Table 7. The results are also presented in Figure 3.

# International Journal of Innovative Science and Research Technology

ISSN No:-2456-2165

https://doi.org/10.38124/ijisrt/IJISRT23MAY1178

Table 7: The Recover	y Parameters of Low Salin	ity Waterflooding for th	e Aged Cores

Core ID	D3	D4	D5	D6
Swi (% PV)	19.50	22.50	21.50	23.00
Soi(% PV)	80.50	77.50	78.50	77.00
Pore volume injected([PV)	7.40	8.30	7.60	7.20
RF (% OIIP)	61.20	60.02	57.62	55.68
WBT([PV)	0.38	0.40	0.37	0.36
Sor,LS (% PV)	15.80	18.65	20.32	21.41
Keff @ Sor (mD)	60.83	72.92	61.00	70.53



Fig 3: Production Profiles of Low Salinity Waterflooding in Aged Cores



Fig 4: Recovery Profiles of Secondary Water Flooding for all Six Cores

# https://doi.org/10.38124/ijisrt/IJISRT23MAY1178

As presented in table 7, the recovery factors obtained for low salinity water flooding in the four aged cores are ranging between  $55.70 - 61.21 \pm 2$  % OIIP with highest recovery recorded in core D3. It was noted that the four cores have nearly the same initial oil saturations, Soi, in the range of 77.00 - 80.50 % PV, and the flooding processes were similar, the recovery factors and residual oil differ among the cores. The wettability of the cores could be modified during the aging period at different scale which led to this variation in oil recovery. The level of interaction between surface-active constituents in the oil and the rock surface in a crude oil/brine/rock (COBR) system is determined by many factors, such as fluid content, oil composition, rock mineral composition, brine composition, temperature, and pressure. The initial reservoir wettability is a result of the chemical equilibrium established between rocks and reservoir fluids, due to millions of years of contact. The disequilibrium of the crude oil-brine-rock (COBR) system induced by the injection of a low salinity or modified salinity brine can lead to an increase in oil recovery (Mohammadkhani et al., 2021).

Considering figure 4, the results of secondary injection in both aged and unaged cores clearly show that the low salinity (3000 ppm NaCl brine) injection in aged cores gives higher recovery when compared to injection of synthetic sea water and 22 times diluted sea water in the unaged cores. The obtained results reveal that the aging period of the cores had a positive effect in altering the wettability of the cores toward less water wet conditions which is evident in higher oil recovery. Literatures have it that both the aging time and aging temperature of cores affect the oil recovery where the oil recovery by waterflooding increases with increasing aging time and temperature (Jadhunandan and Morrow, 1995).

The noticed reduction in the oil permeability at initial water saturation before and after aging also could be a qualitative indication of alteration in the wettability of the aged cores to less water wet state compared to the unaged (strongly water wet) cores. In strongly water wet cores the oil occupies the large pores and therefore will flow easily with minimal resistance having high oil permeability. As the wettability changed towards less water-wet conditions the flow resistance of oil will increase leading to decrease in the oil permeability at initial water saturation. The cores D3, D4, D5, and D6 showed 24 - 28 % reduction in the oil permeability after aging, (see table 5). Similar result was observed in the studies of Shimokawara *et al.* (2019), where they found that ageing decreases the permeability because ageing turns the pore surface to oil wet and retards the water penetration particularly in large pores.

# F. Wettability

The fact that the original (restored or native state) wettability of an oil reservoir significantly impacts the waterflooding oil recovery has been widely acknowledged. However, the extent of this impact, the wettability state that results in the optimum oil recovery, and the underlying displacement mechanisms during waterflooding in systems of varying wettability states have been sources of controversy for many years. Some researchers have concluded that strong water-wetting preference of a rock sample leads to the most efficient oil displacement due to the associated capillary imbibition forces (Ekechukwu *et al.*, 2021).

A comparison of the oil recovery gotten from all the six cores used in this research flooded in secondary stage is depicted in Figure 4.

Low salinity waterflooding has proven to accelerate oil production at core and field scales. Wettability alteration from a more oil-wetting to a more water-wetting condition has been established as one of the most notable effects of low salinity waterflooding. To induce the wettability alteration, low salinity water should be transported to come in contact with the oil-water interfaces (Aziz *et al.*, 2019).

After the low salinity waterflooding in the aged cores, these relative permeability values could indicate cores wettability. These values are compared with the values of the unaged cores D1 and D2 (strongly water-wet cores). The residual saturation after secondary waterflooding and the relative permeability values of the six cores are depicted in Table 8.

Core	D1	D2	D3	D4	D5	D6
Sor	31.92	31.74	15.80	18.65	20.32	21.41
Krw after LS	0.12	0.14	0.21	0.17	0.20	0.18

Table 8: Residual Saturation and Relative Permeability Values of All Cores

The Unaged Cores D1 And D2 Were Strongly Water Wet With Their Values Of Relative Permeabilities Being 0.12 And 0.14 Respectively. However The Typical Values Of The Relative Permeability For Strongly Water Wet System Is In The Range Of 0.05 To 0.1. In Their Works, Niu And Krevor (2020) Observed That Sufficient Dissolution Will Result In Structural Alterations To The Pore Structure Of The Rock That Control Fluid Flow. This Includes The Porosity, Absolute And Relative Permeability, Residual Trapping, And Mechanical Properties.

The Aged Cores Were Flooded By Low Salinity Brine, And Showed Relative Permeability Values Between 0.17 - 0.21 Which Are In The Range Of The Typical Weakly Water Wet Systems Of Relative Permeability Of 0.1 - 0.3. According To Craig's First Rule, Water Relative Permeability At Residual Oil Saturation Is Generally Less Than 0.3 In Water-Wet Systems, Whereas Its Value Is Greater Than 0.5 In Oil-Wet Porous Media (Faramarzi *Et Al.*, 2021).

Due To Aging, The Wettability Of Cores D3, D4, D5 And D6 Had Been Modified To Less Water Wet State, And This Was Reflected In The Reduction In Oil Permeability After The Aging. There Is That Tendency That During The

# ISSN No:-2456-2165

Low Salinity Water Flooding The Wettability Of The Cores Might Be Changed Toward More Water Wet Leading To The Release Of Oil From The Rock Surface And Hence Increased Recovery.

### > Pressure Profiles

The pressure and production profiles of the low salinity waterflooding in the aged cores have been combined, and are depicted in Figures 5-8. The pressure development of the cores had rather similar trends, as evident from these figures. The pressure profiles started increasing at the beginning of the low salinity injection until the peak values were reached just before the water break-through, and then decreased and leveled off. The flooding started with injection rate of 0.1 ml/min to obtain a stable displacement and avoid the fingering phenomena which cause early water break-through. The observed pressure peak at water break-through of the cores was in the range of 2-23 mbar and the volume of oil produced at the breakthrough were 0.38, 0.40, 0.37, and 0.36 PV from cores D3, D4, D5, and D6 respectively. The pressure stabilized at the breakthrough with minor perturbation in the profile. There was a slight increase in the differential pressure profiles of the cores D3, D4, D5, and D6 after about 2.5 PV injection occasioned by the increase in the injection rate.

After the oil production ceased, the injection rate was increased to 0.5 ml/min and then increased further to 1 ml/min as evident from the increase in the pressure profiles. There was no noticeable response of this increase in the injection rate in the production profiles of core D5; but cores

### D3, D4 and D6 produced more oil as the injection increased.

https://doi.org/10.38124/ijisrt/IJISRT23MAY1178

The increase in recovery resulting from the rising flow rate is one of the indications that the wettability of the core was less water wet. In some dolomite formations that contain fine particles; these could migrate in the porous medium and cause a reduction in the permeability of the formation by plugging the interconnecting pore throats. In addition, fine migration has been proposed to provide a mobility control to improve the performance of the waterflooding by diverting the flow from the water swept zones to un-swept zones. Till now, it is widely accepted that, when fine migrated, the clay particles will plug the smaller pores or pore throat, then the formation permeability is reduced, and the water is forced to take other flow paths. As a result, the sweep efficiency is improved (Xu, 2019). Fines migration occurs in pore space because the resultant force exerts the particle oppositely from the pore wall when a steady-state flow or other dominant factors are changed substantially, e.g. increase in flow velocity and decrease in injecting water salinity (Suparit et al., 2020).

Fine particles have not been visually noticed in this research in the produced effluent during the core flood experiments of secondary low salinity water flooding. As noticed in the pressure profiles of the cores shown in Figures 5-8, it seems to be stable during the low salinity injection and increased only as a response of raising the flow rate.



Fig 5: Production and Pressure Profiles of LS Waterflooding in Core D3.



Fig 6: Production and Pressure Profiles of LS Waterflooding in Core D4.



Fig 7: Production and Pressure Profiles of LS Waterflooding in Core D5.





# International Journal of Innovative Science and Research Technology

ISSN No:-2456-2165

### G. Low Salinity Polymer Slug Injection:

All the cores were flooded by 1 PV of polymer followed by continuous low salinity brine injection after the tertiary low salinity surfactant and polymer slugs injection to observe any further production. The concentration of the polymer solution used in this stage is 600 ppm. The recovery parameters of the cores are presented in tables 9 and 10.

https://doi.org/10.38124/ijisrt/IJISRT23MAY1178

Table 9: Recovery Parameters of Low Salinity Polymer Injection using Okro						
re ID	D1	D2	D3	D4	D5	
after LS	23.90	21.65	11.21	12.77	12.68	

Core ID	D1	D2	D3	D4	D5	D6
Sor after LS	23.90	21.65	11.21	12.77	12.68	15.00
PV inj	3.5	3.7	5.2	3.7	3.6	4.7
RF (Soi)	1.21	11.84	2.3	3.6	11.21	4.79
Sor after LS-P	23.48	20.68	10.00	9.91	10.00	13.92
ΔSor	0.42	0.97	1.21	2.86	2.68	1.08

Core ID	D1	D2	D3	D4	D5	D6
Sor after LS	27.95	24.15	11.94	15.74	14.80	17.50
PV inj	3.5	3.7	5.2	3.7	3.6	4.7
RF (Soi)	1.02	8.56	1.55	2.52	8.9	4.3
Sor after LS-P	26.98	22.15	10.42	11.21	12.70	13.99
ΔSor	0.97	2.00	1.52	3.59	3.04	3.51

# Table 10: Pacovery Parameters of Low Salinity Polymor Injection using HPAM

### Oil Recovery $\triangleright$

The oil recoveries from the six cores flooded by 1 PV of 600 ppm Okro and HPAM polymer solutions are depicted in Figures 9 and 10 respectively. The results clearly suggest that the polymer slugs injection have mobilized some oil from the cores. Nevertheless the amount of the produced oil varies among the cores as illustrated in Figures 9 and 10. Cores D1. D3, and D4 demonstrated oil production of less than 4 % of OIIP while core D2 and D5 showed a significant amount of oil recovery of 11.84 and 11.21 % of OIIP when okro was injected.

When HPAM was injected, Cores D1, D3, and D4 demonstrated oil production of less than 3 % of OIIP while cores D2 and D5 showed a substantial amount of oil recovery of 8.56 and 8.9 % of OIIP. These two cores with highest

recovery responded early to the polymer slug injection by starting oil production after injecting around 0.2 and 0.3 PV of polymer slug into cores D2 and D5 respectively during okro and HPAM injection.

The oil recovery from the cores does not show the effect of wettability on the performance of the polymer slug injection. The highest recovery was obtained from strongly water- wet core which is core D2 and on the other hand the lowest recovery obtained was from the other strongly water wet core D1during okro polymer injection. Besides, the aged cores have a much lower residual oil before the low salinity polymer slug injection compared to the unaged cores, (see tables 9 and 10). Thus the responses to the polymer slug injection might differ from the cores.



Fig 9: Oil recovery of Low Salinity Polymer Slug Injection of the Cores using Okro



Fig 10: Oil Recovery of Low Salinity Polymer Slug Injection of the Cores using HPAM.

# > Pressure Profiles

The pressure profiles of low salinity polymer slug injection performed in each of the six cores were deployed against the oil production profiles and the results are presented in Figures 11–22.

During the polymer slug injection, the pressure across the cores increased in reaction to increasing the viscosity of the injected brine. The pressure profiles in all the cores decreased during the low salinity brine injection that followed the polymer injection, and stabilized afterwards. All the cores commenced production of oil during the polymer slug injection and continued producing during low salinity flooding until the oil production stopped. Therefore, this indicates that the swelling of clay in the dolomite sample used was not pronounced, otherwise it would be observed as a noticeable increase in the pressure profile.

The consequence of polymer solution in improving oil recovery was mainly due to increasing the viscosity of the injected brine which conduces to improving the volumetric sweep efficiency and therefore affords lower residual oil, Sor.



Fig. 11: Pressure and Production Profiles of LS-P Flooding in Core D1 using Okro.



Fig 12: Pressure and Production Profiles of LS-P Flooding in Core D1 Using HPAM.



Fig 13: Pressure and Production Profiles of LS-P Flooding in Core D2 using Okro.



Fig. 14: Pressure and Production Profiles of LS-P Flooding in Core D2 Using HPAM.



Fig. 15: Pressure and Production Profiles of LS-P Flooding in Core D3 Using Okro.



Fig. 16: Pressure and Production Profiles of LS-P Flooding in Core D3 Using HPAM.



Fig. 17: Pressure and Production Profiles of LS-P Flooding in Core D4 Using Okro.



Fig. 18: Pressure and Production Profiles of LS-P Flooding in Core D4 Using HPAM.



Fig. 19: Pressure and Production Profiles of LS-P Flooding in Core D5 Using Okro.



Fig. 20: Pressure and Production Profiles of LS-P Flooding in Core D5 Using HPAM.



Fig. 21: Pressure and Production Profiles of LS-P Flooding in Core D6 Using Okro



Fig.22: Pressure and Production Profiles of LS-P Flooding in Core D6 Using HPAM.

Low salinity polymer slugs injection was conducted in all the six cores using okro and HPAM polymers. Cores D1, D2, D3, D4, D5, and D6 gave 1.21, 11.84, 2.3, 3.6, 11.21, and 4.79% OIIP respectively when okro was injected, while cores D1, D2, D3, D4, D5, and D6 1.02, 8.56, 1.55, 2.52, 8.9, and 4.3% OIIP respectively when HPAM polymer was injected.

In comparison, okro polymer gave higher oil recovery

# https://doi.org/10.38124/ijisrt/IJISRT23MAY1178

ISSN No:-2456-2165

than HPAM. This may be due to the suggestion made by Obuebite and Okwonna (2023) in their studies, that HPAM is susceptible to high salinities and high temperatures, thus at higher temperatures and salinity, the viscosity of HPAM is grossly reduced, thereby reducing its efficiency to improve recovery.

However, the effectiveness of several natural polymers such as Okro, Ogbono, and Gum Arabic in improving sweep efficiency was investigated by Uzoho *et al.* (2019) where they all reported that Okro gave the best recovery.

# VI. SUMMARY

It was anticipated in this investigation that lowering the salinity of the injected brine could conduce to increasing oil recovery from dolomite cores. Conditions necessary for improving oil recovery by low salinity waterflooding include significant clay fraction, initial formation water which contains divalent cations, crude oil which contains polar components, and exposure of the rock to crude oil to create mixed-wet conditions. The experiments carried out on the two unaged cores established the fact that reduction in salinity has little effect on oil recovery in unaged cores either in secondary or tertiary mode.

The secondary low salinity waterflooding in the aged cores gave a recovery factor of  $55.68 - 61.21 \pm 2$  % which is higher than the recovery factors of secondary synthetic sea water flooding and low salinity water-flooding of the unaged cores which are 41.54 % and 40.96 % respectively. This emphasizes the importance of initial wettability state of the core to observe the effect of low salinity waterflooding.

The low salinity polymer slugs injection was conducted in all the six cores using okro and HPAM polymers. Cores D1, D2, D3, D4, D5, and D6 gave 1.21, 11.84, 2.3, 3.6, 11.21,and 4.79% OIIP respectively when okro was injected, while cores D1, D2, D3, D4, D5, and D6 1.02, 8.56, 1.55, 2.52, 8.9,and 4.3% OIIP respectively when HPAM polymer was injected. These results validate the use of okro polymer as an alternative to synthetic polymers under reservoir conditions for enhanced oil recovery (EOR) applications in the oil industry.

# VII. CONCLUSIONS

The demand to transform petroleum-based polymer usage on a large scale into a green polymer is unequivocal. The natural chemicals from plants provide sustainability and cheaper sources of chemicals, and could be tailored to be compatible with the field specification.

The current experimental investigation was performed to improve the oil recovery and extraction of residual oil from highly abundant oil-wet carbonate rocks. Core flooding experiments were carried out in six dolomite cores to investigate the effect and different aspects of low salinity waterflooding followed by polymer slugs injection. Low salinity water, synthetic sea water, okro and HPAM polymer solutions were formulated and used for injection in the dolomite cores. Two out of the six cores were unaged (D1, D2) and were tested for effect of reducing salinity of injected brine in both secondary and tertiary modes. Core D1 was flooded with synthetic sea water while core D2 was flooded by the 22 times diluted synthetic sea water. Core D1 gave a recovery of 41.54% OIIP while core D2 gave 40.96%. The unaged cores showed a strongly water-wet behavior. These results indicate that reduction in salinity has little effect on oil recovery in unaged cores.

The four aged cores D3, D4, D5, and D6 were flooded by low salinity brine which is 3000 ppm NaCl brine as a secondary mode. Low salinity water flooding gave an improvement in oil recovery with aged cores compared with unaged cores flooded with synthetic sea water. The aging period altered wettability of the cores to less water-wet state which was corroborated by reduction in the oil permeability after aging, and this is responsible for the improved recovery.

Overall, the results of low salinity polymer slugs injection in all six cores showed that the slug injection has mobilized and produced different amount of oil from the cores. The oil recoveries for both okro and HPAM polymers from the aged cores were higher than those of the unaged cores which indicate the effect of initial wettability state on performance of low salinity waterflooding. Fines particles were not observed in the effluent during the coreflooding experiments and the pressure profiles were stable and increased only as a response of rising the flow rate. The low salinity polymer slug injection performed at the end with higher concentration resulted in producing additional oil from the cores. However the performance of this injection varied because of different residual oil obtained in the six cores before the low salinity polymer slug injection.

The results showed that natural polymer performed better than the synthetic polymer during the low salinity polymer slugs injection under reservoir conditions for enhanced oil recovery (EOR) applications in the oil industry. Experimental results show that natural polymers can recover additional oil from the reservoir. The okro polymer will serve as a good replacement to the HPAM due to its availability, cheapness, biodegradability; it does not cause any adverse effect to the reservoir and its fluids. Besides, there are some environmental issues associated with the use of HPAM such as solid waste, waste water pollution which can contaminate ground water aquifer.

# FURTHER WORK

Large Sor is normally recorded in water-wet reservoirs due to increased capillary entrapment of oil. By optimizing the ion composition, it may be possible to find a brine composition that modifies the reservoir wettability toward less water-wet conditions than what was obtainable in this investigation, thus effecting further Sor reduction. The comprehension of aspects behind the effect of low salinity waterflooding in increasing the oil recovery demands extensive researches to ascertain the different variables that conduce to the performance of the process.

# ISSN No:-2456-2165

Quantitative methods such as USBM and Amott-Harvey should be employed in the determination of initial wettability state and the changes in the wettability of the cores during the low salinity water flooding, as this will assist in describing the improvements in the recovery. The consequence of reducing salinity of the injected brine should be conducted in aged cores where the initial wettability of the cores reflects the reservoir wettability and the experiments should be performed in both secondary and tertiary mode. There is tendency that during the low salinity flooding the wettability of the cores might be changed toward more water wet leading to the release of oil from the rock surface and increase recovery. However, due to the current high oil price, the application of polymer flooding will become profitable by causing incremental oil recovery on an economic scale.

The cultivation of okro (*Abelmoschus Esculentus*) should be encouraged to provide new avenues and market for agriculture, thereby creating job opportunities in the sector and to produce enough seeds feed stocks for okro powder production for constitution as natural polymer for EOR application.

• Funding: Self-Funded.

# REFERENCES

- [1]. Abdulrazagy Z., Zaid A., An Experimental Investigation of Low Salinity Oil Recovery in Carbonate and Sandston Formation, International Journal of Petroleum and Petrochemical Engineering (IJPPE) Volume 1, Issue 1, June 2015, PP 1-11
- [2]. Al-Shalabi P.E., Emad & Sepehrnoori, Kamy & Delshad, Mojdeh. (2014). Mechanisms behind low salinity water injection in carbonate reservoirs. Fuel. 121. 11–19. 10.1016/j.fuel.2013.12.045.
- [3]. Austad, Tor & Rezaeidoust, Alireza & Puntervold, Tina. (2010). Chemical Mechanism of Low Salinity Water Flooding in Sandstone Reservoirs. SPE Improved Oil Recovery Symposium. 1. 10.2118/129767-MS.
- [4]. Aziz, R., Joekar-Niasar, V., Martínez-Ferrer, P. J., Godinez-Brizuela, O. E., Theodoropoulos, C., & Mahani, H (2019). Novel insights into pore-scale dynamics of wettability alteration during low salinity waterflooding. Scientific reports, 9(1), 9257. https://doi.org/10.1038/s41598-019-45434-2
- [5]. Cuenca, E.; Serna, P (2021). Autogenous Self-Healing Capacity of Early-Age Ultra-High-Performance Fiber-Reinforced Concrete.Sustainability, 13, 3061. https://doi.org/10.3390/su13063061
- [6]. Ekechukwu, Gerald & Khishvand, M. & Kuang, Wendi & Piri, Mohammad & Masalmeh, Shehadeh. (2021). The Effect of Wettability on Waterflood Oil Recovery in Carbonate Rock Samples: A Systematic Multi-scale Experimental Investigation. Transport in Porous Media. 138. 10.1007/s11242-021-01612-3.
- [7]. Faramarzi, Mohsen & Mirzaei-Paiaman, Abouzar & Ghoreishi, Seyyed Ali & Ghanbarian, Behzad. (2021).

Wettability of Carbonate Reservoir Rocks: A Comparative Analysis. Applied Sciences. 12. 131. 10.3390/app12010131

https://doi.org/10.38124/ijisrt/IJISRT23MAY1178

- [8]. Felix F., Gion JS., Shehadeh KM., Ali M.A (2020).,An experimental and numerical study of low salinity effects on the oil recovery of carbonate rocks combining spontaneous imbibition, centrifuge method and coreflooding experiments,,Journal of Petroleum Science and Engineering,190,2020,107045,ISSN 0920-4105,https://doi.org/10.1016/j.petrol.2020.107045.
- [9]. Filoco P.R. and Sharma, M.M. (1998). "Effect of BrineSalinity and Crude Oil Properties on Relative Permeabilities and Residual Saturations", SPE 49320.
- [10]. Guo, S. P., & Huang, Y. Z. (1990). Physical Chemistry Microscopic Seepage Flow Mechanism (pp. 100– 102). Beijing: Science Press
- [11]. Iván, P.T., Tina, P., Skule, S., Paul, H., Panos, A., Hae, Y. & Magnus, K.. (2020). Core wettability reproduction: A new solvent cleaning and core restoration strategy for chalk cores. Journal of Petroleum Science and Engineering. 195. 107654. 10.1016/j.petrol.2020.107654.
- [12]. Jadhunandan, P. P. and Morrow, N.R. (1995). "Effect of Wettability on Waterflood Recovery for Crude-Oil/Brine/Rock Systems ", SPE Reservoir Engineering, February
- [13]. Jerauld, Gary & Webb, Kevin & Lin, Cheng-Yuan & Seccombe, James. (2006). Modeling Low-Salinity Waterflooding. 10.2523/102239-MS.
- [14]. Kakati, A., Kumar, G., & Sangwai, J. S.(2020). Oil Recovery Efficiency and Mechanism of Low Salinity-Enhanced Oil Recovery for Light Crude Oil with a Low Acid Number. ACS omega, 5(3), 1506– 1518. https://doi.org/10.1021/acsomega.9b03229
- [15]. Kumar M., Fogden, A. Norman R. Morrow, N.R. and Buckley, J.S.(2010):"Mechanisms Of Improved Oil Recovery From Sandstone By Low Salinity Flooding" Being a paper prepared for presentation at the International Symposium of the Society of Core Analysts held in Halifax, Nova Scotia, Canada, 4-7 October, 2010.
- [16]. Lager A., K.J. Webb, and C.J.J. Black, (2007). " Impact of Brine Chemistry on Oil Recovery ", Paper A24 presented at the 14th European Symposium on Improved Oil Recovery, Cairo, Eygpt, 22-24 April.
- [17]. Lager A., K.J. Webb, I. R. Collins, and D.M. Richmond, (2008). " LoSalTM Enhanced Oil Recovery: Evidence of Enhanced Oil Recovery at the Reservoir Scale ", SPE 113976.
- [18]. Ligthelm, Dick & Gronsveld, Jan & Hofman, Jan & Brussee, Niels & Marcelis, Fons & Linde, Hilbert. (2009). Novel Waterflooding Strategy By Manipulation Of Injection Brine Composition. 10.2118/119835-MS.
- [19]. Lizcano Niño, J. C., De Sousa, V. H. & Moreno, R.
  B. Z. L (2020). Less-Concentrated HPAM Solutions as a Polymer Retention Reduction Method in CEOR. Revista Fuentes: El reventón energético, 18(1), 75-

https://doi.org/10.38124/ijisrt/IJISRT23MAY1178

92

- [20]. Mamonov, A.; Kvandal, O.A.; Strand, S.; Puntervold, T. Adsorption of polar organic components onto sandstone rock minerals and its effect on wettability and enhanced oil recovery potential by smart water. Energy Fuels 2019, 33, 5954-5960.
- Mamonov, A.; Puntervold, T.; Strand, S.; Hetland, B.; [21]. Andersen, Y.; Wealth, A.; Nadeau, P.H. Contribution of Feldspar Minerals to pH during Smart Water EOR Processes in Sandstones. Energy Fuels 2020, 34, 55-64.
- [22]. McGuire, P. L., Chatham, J. R., Paskvan, F. K., Sommer, D. M, and F. H. Carini. "Low Salinity Oil Recovery: An Exciting New EOR Opportunity for Alaska's North Slope." Paper presented at the SPE Western Regional Meeting, Irvine, California, March 2005. doi: https://doi.org/10.2118/93903-MS
- [23]. Mohammadkhani, S.; Anabaraonye, B.U.; Afrough. A.; Mokhtari, R.; Feilberg, K.L. (2021). Crude Oil-Brine-Rock Interactions in Tight Chalk Reservoirs: An Experimental Study. Energies 2021, 14, 5360. https://doi.org/10.3390/en14175360.
- Morrow N.R., Valat M. and Yildiz HEffect of Brine [24]. Composition On Recovery of an Alaskan CrudeOil By Waterflooding»-Paper SPE 9694. - presented at Annual Technical Meeting, Jun 10-12, 1996, Calgary, Alberta.
- [25]. Niu, B., Krevor, S (2020). The Impact of Mineral Dissolution on Drainage Relative Permeability And Residual trapping Trapping in Two Carbonate Rocks. Transp Porous Med 131, 363–380 (2020). https://doi.org/10.1007/s11242-019-01345-4
- [26]. Obuebite, A. A. & Okwonna, O. (2023). Performance assessment of a novel bio-based polymer for enhanced oil recovery in high salinity sandstone reservoirs. GSC Advanced Research and Reviews. 14. 129-143. 10.30574/gscarr.2023.14.2.0061.
- [27]. Pratibha (2020). Extraction and Characterization of Okra Mucilage as a Pharmaceutical Aid by)-Research gate, International Journal of Scientific Development and Research (IJSDR), April 2020, 5, Issue 4, 189.
- Robertson, Eric. (2007). Low-Salinity Waterflooding [28]. to Improve Oil Recovery-Historical Field Evidence. 10.2523/109965-MS.
- Samanta, Abhijit & Ojha, Keka & Sarkar, Ashis & [29]. Mandal, Ajay. (2011). Surfactant and Surfactant-Polymer Flooding for Enhanced Oil Recovery. 2. 1-6. 10.3968/j.aped.1925543820110201.608.
- [30]. Saw, R K. and Mandal, A. (2020). A mechanistic investigation of low salinity water flooding coupled with ion tuning for enhanced oil recovery. The Royal Society of Chemistry. Vol.10, 69, pp.42570-42583. doi 10.1039/D0RA08301A
- Selem, A.M., Agenet, N., Gao, Y. et al.(2021). Pore-[31]. scale imaging and analysis of low salinity waterflooding in a heterogeneous carbonate rock at reservoir conditions. Sci Rep 11, 15063 (2021). https://doi.org/10.1038/s41598-021-94103-w
- Shehata A.M., Nasr-El-Din H.A., Reservoir Connate [32]. Water Chemical Composition Variation Effect on

Low-Salinity Waterflooding, SPE Journal., SPE 171690 (2014).DOI http://dx.doi.org/10.2118/171690-MS

- Shimokawara, M., Yogarajah, E., Nawa, T., [33]. Takahashi, S., (2019). Influence of Carbonated Water-rock Interactions on Enhanced Oil Recovery in Carbonate Reservoirs: Experimental Investigation and Geochemical Modeling. Journal of the Japan Petroleum Institute. 62. 19-27. 10.1627/jpi.62.19.
- [34]. Shiran BS. Enhanced Oil Recovery by Combined Low Salinity Water and Polymer Flooding. [Ph.D. dissertation]. Bergen: University of Bergen; 2014.
- [35]. Skauge, A. [2008]: Microscopic diversion - A new EOR technique. In: The 29th IEA Workshop & Symposium Beijing, China, 2008
- [36]. Springer, N., Korsbech, U., & Aage, H. K. (2003). Resistivity Index Measurement without the Porous Plate: A Desaturation Technique Based on Evaporation Produces Uniform Water Saturation Profiles and More Reliable Results for Tight North Sea Chalk. In Abstract volume Society of Core Analysts.
- Suparit T., Alexander S., Cheowchan L., Muhammad [37]. Y., Azim K., Fines (2020). Migration and permeability decline during reservoir depletion coupled with clay swelling due to low-salinity water injection: An analytical study, Journal of Petroleum Science and Engineering, Vol.

194, https://doi.org/10.1016/j.petrol.2020.107448.

- [38]. Tang, G.Q. and Morrow, N.R. (1999) Influence of Fines Migration and Brine Composition on Crude Oil/Brine/Rock Interaction and Oil Recovery. Journal of Petroleum Science and Engineering, 24, 99-111. https://doi.org/10.1016/S0920-4105(99)00034-0.
- [39]. Uzoho CU, Onyekonwu MO, Akaranta O. (2019). Chemical Flooding Enhanced Oil Recovery Using Local Alkali- Surfactant-Polymer. World Journal of Innovative Research.; 7(1):16-24.
- Uzoho, Chidinma & Ade, Enaanabhel & Onyekonwu, [40]. M.O.. (2022). Investigation of Permeability Impairment Using Local Polymers for Enhanced Oil Recovery. 10.2118/211922-MS.
- [41]. Wideroee1 ,H.C., Rueslaatten, H., Boassen1, T., Crescente, C,M., Raphaug,M., Soerland,G.H. and HegeUrkedal, H." Investigation Of Low Salinity Water Flooding By Nmr And Cryoesem:", Being a paper prepared for presentation at the International Symposium of the Society of Core Analysts held in Halifax, Nova Scotia, Canada, 4-7 October, 2010.
- Xu, Dawei, ((2019). Review and data analysis of low [42]. salinity water effect through induced fine migration"MastersTheses.7927.https://scholarsmine. mst.edu/masters theses/7927
- Yildiz, H.O., Valat, M., and N.R. Morrow. "Effect of [43]. Brine Composition On Wettability And Oil Recovery

of a Prudhoe Bay Crude Oil." J Can Pet Technol 38 (1999): No Pagination Specified. doi: https://doi.org/10.2118/99-01-02

[44]. Zhang, Yongsheng & Morrow, Norman. (2006). Comparison of Secondary and Tertiary Recovery With Change in Injection Brine Composition for Crude-Oil/Sandstone Combinations. Proceedings -SPE Symposium on Improved Oil Recovery. 2. 10.2118/99757-MS.

# https://doi.org/10.38124/ijisrt/IJISRT23MAY1178

# APPENDIX A

Table A1: Drainage Data of Cores D1 and D2.						
Core	Volume of high viscous oil Injected X	Volume of produced water	Swi	Soi		
ID	( <b>PV</b> )	( <b>ml</b> )	(%)	(%)		
D1	15.00	2.61	17.4	82.6		
D2	18.00	3.44	19.1	80.9		

# Table A2: Drainage Data of Core D3.

Rate	Volume of high viscous oil Injected X	Volume of produced	Swi (%)	Soi (%)
(ml/min)	( <b>PV</b> )	water (ml)		
0.1	2.0	0.41	20.70	79.30
0.5	2.0	0.44	22.13	77.87
1.0	4.0	1.38	34.58	65.42
1.5	3.0	0.93	31.00	69.00
2.0	3.5	0.96	27.53	72.47

# Table A3: Drainage Data of Core D4.

Rate (ml/min)	Volume of high viscous oil Injected X (PV)	Volume of produced water (ml)	Swi (%)	Soi (%)
0.1	2	0.44	21.96	78.04
0.5	1.5	0.38	25.62	74.38
1.0	4	1.33	33.17	66.83
1.5	3	0.90	30.00	70.00
2.0	4	1.13	28.32	71.68

# Table A4: Drainage Data of Core D5

Rate	Volume of high viscous oil Injected X	Volume of produced water (ml)	Swi (%)	Soi (%)
(ml/min)	( <b>PV</b> )			
0.1	2	0.38	19.01	80.99
0.5	2	0.38	18.73	81.27
1.0	2	0.38	19.16	80.84
1.5	4	0.99	24.75	78.25
2.0	3	0.86	28.50	71.50

### Table A5: Drainage data of core D6.

Rate	Volume of high viscous oil Injected X	Volume of produced water (ml)	Swi (%)	Soi (%)
(ml/min)	( <b>PV</b> )			
0.1	2	0.40	20.00	80.00
0.5	2	0.39	19.70	80.30
1.0	3.5	0.82	23.28	76.72
1.5	2.5	0.47	18.94	81.06
2.0	5	1.55	31.00	69.00

Volume 8, Issue 5, May – 2023 ISSN No:-2456-2165

# **APPENDIX B**

# Table B: Density Measurements of Fluids with Uncertainty of +/- 0.0001.

Density (g/cm3)					
Temperature [ <sup>O</sup> C]	20 °C	23 °C	26 <sup>o</sup> C		
Fluids					
Synthetic sea water	1.0472	1.0310	1.0192		
Low salinity water	0.9987	0.9901	0.9835		
High viscous Sample X crude oil	0.9418	0.9305	0.9226		
Medium crude oil	0.9039	0.9008	0.8954		
3000 ppm NaCl brine	1.003	0.8901	0.7950		
C12TAB	0.9989	0.9921	0.9830		

Table C1: Viscosity Measurements of Brines and Oils.

Temperature [ <sup>O</sup> C]	20 °C	23 °C	26 <sup>o</sup> C	
Fluids	Viscosity (cP)			
Synthetic sea water	1.09	1.02	0.98	
Low salinity water	1.02	0.93	0.87	
High viscous Sample X crude oil	4.37	4.31	4.28	
Medium crude oil	3.40	3.27	3.15	
3000 ppm NaCl brine	0.96	0.84	0.79	
C12TAB	1.02	0.86	0.81	

Table C2: Concentration of OKRO Polymer Solutions: Viscosity Measurements.

Polymer solution	Concentration, mg/l	Viscosity (cP)		
	(ppm)	20 °C	23 °C	26 <sup>o</sup> C
Stock polymer solution	20.000	72.32	69.14	57.26
Diluted polymer solution	2200	64.63	60.21	50.98
Diluted polymer solution	2000	50.05	43.53	38.72
Diluted polymer solution	1600	42.97	40.22	31.54
Diluted polymer solution	1200	39.01	32.68	23.82
Diluted polymer solution	800	33.52	27.21	18.30
Diluted polymer solution	400	28.30	21.73	14.61

# Table C3: Concentration of HPAM Polymer Solutions.

	<i>v</i>			
Polymer solution	Concentration, mg/l	Viscosity (cP)		
	(ppm)	20 °C	23 °C	26 <sup>o</sup> C
Stock polymer solution	5000	40.00	37.08	30.75
Diluted polymer solution	1000	33.41	23.91	18.90
Diluted polymer solution	600	24.57	16.25	11.53
Diluted polymer solution	300	15.16	12.08	9.03
Diluted polymer solution	100	11.28	9.24	6.76

Viscosity (mPa.s)	Shear rate (1/S)					
	100 ppm	300 ppm	600 ppm	1000 ppm	5000 ppm	
0	23.09	159.56	618.98	1546.05	10482.69	
10	17.32	116.42	459.49	1282.02	9620.67	
20	15.39	104.78	306.32	964.01	7696.54	
30	11.54	69.99	229.75	769.21	6413.78	
40	7.70	52.50	183.80	641.01	5497.53	
50	5.77	42.91	153.16	549.44	4810.34	
60	4.62	34.93	131.28	480.76	4275.85	

International Journal of Innovative Science and Research Technology

https://doi.org/10.38124/ijisrt/IJISRT23MAY1178

ISSN No:-2456-2165

Table C5: Shear Rate of Polymer Solution for Okro

Viscosity (mPa.s)	Shear Rate (1/s)						
	1200 ppm	1600 ppm	2000 ppm	2200 ppm	20,000 ppm		
0	47.21	186.34	634.15	1210.62	11675.38		
10	18.74	76.59	226.84	603.54	4891.79		
20	10.80	37.27	105.69	201`.77	1459.42		
30	9.44	31.06	90.59	151.33	11297.26		
40	7.87	26.62	79.27	134.51	1167.54		
50	6.74	23.29	70.41	121.06	1061.40		
60	5.90	20.70	63.42	110.06	973.20		





Fig. 23D1: Viscosity of Synthetic Sea Water Measured at Different Temperature.



Fig 24D2: Viscosity of Low Salinity Water Measured at Different Temperature



Fig. 25D3: Viscosity of High Viscous Crude Oil Sample X Measured at Different Temperature.



Fig 26D4: Viscosity of Medium Crude Oil Measured at Different Temperature



Fig 27D5: Viscosity of 3000 Ppm NaCL Brine Measured at Different Temperature.



Fig 28D6: Viscosity of 400 ppm Okro Polymer Solution Measured at Different Temperature.



Fig. 29D7: Viscosity of 800 ppm Okro Polymer Solution Measured at Different Temperature



Fig 30D8: Viscosity of 1200 ppm Okro Polymer Solution Measured at Different Temperature



Fig 31D9: Viscosity of 1600 ppm Okro Polymer Solution Measured at Different Temperature



Fig. 32D10: Viscosity of 2000 ppm Okro Polymer Solution Measured at Different Temperature.



Fig. 33D11: Viscosity of 2200 ppm Okro Polymer Solution Measured at Different Temperature.



Fig. 34D12: Viscosity of 20000 ppm Okro Polymer Solution Measured at Different Temperature.



Fig. 35D13: Viscosity of 300 ppm HPAM Polymer Solution Measured at Different Temperature.



Fig. 36D14: Viscosity of 600 ppm HPAM Polymer Solution Measured at Different Temperature.



Fig. 37D15: Viscosity of 1000 ppm HPAM Polymer Solution Measured at Different Temperature.



Fig. 38D16: Viscosity of 5000 ppm HPAM Polymer Solution Measured at Different Temperature.