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Sustainable Enhanced Oil Recovery in the Niger Delta Using Polymer Flooding and Alkaline Flooding

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ABSTRACT

The increasing demand for environmentally sustainable enhanced oil recovery (EOR) technologies has stimulated interest in replacing conventional synthetic chemicals with naturally occurring materials. Natural alkaline and polymeric substances are increasingly recognised because of their biodegradability, local availability, low cost, and reduced environmental impact. The potential of using mangrove wood ash as a natural source of alkaline material and Caladium bicolor starch as a biodegradable polymer to enhance oil recovery from Niger Delta sandstone reservoirs was investigated in this experiment. To evaluate their effectiveness, core flooding experiments were conducted using ten sandstone cores obtained from Niger Delta. In these experiments, the effect of salinity levels on oil recovery by both flooding agents was investigated. Additional rheological analyses were performed to determine the influence of temperature, concentration, wetting behaviour, and shear stress on the flooding agents. The mineralogical composition of the reservoir rocks was also determined using X-ray diffraction (XRD). The results showed that salinity strongly influenced the performance of both flooding agents. The rise in salinity decreased oil production despite a marginal increase in viscosity of the solution. For mangrove wood ash, the maximum oil displacement efficiency was attained at 1000 ppm with a value of 57.8%, while the lowest efficiency value was 51.0% at 5000 ppm. Likewise, for Caladium bicolor starch, the maximum efficiency value was 57.2% and the minimum value was 47.8%. The lowest water cut was also observed at 1000 ppm, recording 32% for Caladium bicolor flooding and 42% for mangrove ash flooding, whereas the highest water cuts occurred at elevated salinity levels. Unlike many previously reported natural EOR materials that are edible agricultural products, the materials investigated in this study are non-edible and readily available as local waste resources. Their use thus eliminates competition for food sources and decreases reliance on foreign-made chemicals. The results have shown that the use of mangrove wood ash and Caladium bicolor starch will greatly increase oil recovery at low salinity and provide environmental alternatives to chemical EOR in the Niger Delta oilfields.

Keywords: Enhanced oil recovery; alkaline flooding; polymer flooding; mangrove wood ash; Caladium bicolor; salinity; rheology.

1. INTRODUCTION

Enhanced Oil Recovery is an oil recovery technique that is typically employed after

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secondary and primary oil recovery. Primary recovery involves producing oil with the natural energy of the reservoir with no man made energy input. Secondary recovery is generally only started after the natural energy of the reservoir has been used up, and is by such means as injection of water or gas. The dispersion of the reservoir in terms of porosity and permeability values further contributes to low sweep efficiency of the waterflooding leading to increased water production and viscous fingering. However, sweep efficiency can be increased remarkably if the right injection process is used along with appropriate chemicals (Abbas et al., 2023). There are two broad classes of EOR processes - thermal and non-thermal oil recovery techniques. Thermal oil recovery technique heat the oil for the recovery, which will cover mostly heavy oil, extra-heavy oil, and tar sands (Gbadamosi et al., 2022). It is the non-thermal EOR which consists of gas EOR, chemical EOR, and microbial EOR used for reducing the viscosity, reducing the interfacial tension, increasing sweep efficiency, increasing oil recovery. Chemical Enhanced Oil Recovery (CEOR) primarily involves polymer flooding, surfactant flooding, alkaline flooding and now flooding with nanoparticles. The first alkaline and caustic flooding was in 1925 when Na_2CO_3 solution was injected in the reservoir in Bradford field, Pennsylvania. Alkaline flooding is a CEOR technique which involves in-situ surfactant formation as a result of the reaction between the alkaline and acid in crude oil (Sheng, 2015). This includes neutralisation of the organic acid in the crude oil, which allows the production of oil by reducing the Oil-Water Interfacial Tensions (OWIT), altering wettabilities, creating emulsions, lowering the mobilities, and improving the sweep efficiencies (Alade et al., 2022; Kumar et al., 2016). Most alkaline agents are relatively inexpensive, and alkaline flooding is also a more cost effective than other methods of CEOR (Abdelaziz et al., 2022). In the presence of salt, the interfacial tension between salt solution and alkaline solution becomes higher with respect to the interaction between the original salt solution and oil and the oil recovery is poor (Abdelaziz et al., 2022). The conventional synthetic alkaline used in CEOR is comprised of ammonium and sodium hydroxides, sodium and ammonium carbonates, sodium orthosilicate and metasilicate (Akpoturi & Ofesi, 2017). Synthetic alkaline is not being used as much due to its impact on the environment.

It is especially in-demand to use eco-friendly alkaline (which occurs naturally) instead of synthetic alkaline. From the pH result, it shows that date palm ash is of alkaline with a pH range between 10–13. Alade et al. (2022) studied Greensome EOR from date palm ash obtaining a pH value between 10–13 which represents strongly alkaline. Mangrove Wood Ash (MWA) is alkaline fertiliser, by-product of wood burning, with pH ranging between 9 and 13. It is environmentally friendly as it is bio-degradable. It consists mostly of Potassium hydroxide and is applied in a number of uses including a fertilizer, liming agent, soap production and as a catalyst in biodiesel production (Sharma et al., 2012). According to Rahman et al. (2008) it was found that the pH of 6% wood is similar to 0.5% synthetic NaOH or in 0.75% Na_2SiO_3. Furthermore the interfacial effect on both synthetic alkaline and wood ash was similar. Akpoturi and Ofesi (2017) studied the application of palm bunch ash in alkaline flooding as against synthetic alkaline. They concluded that Potassium Hydroxide ash and ash of Palm bunch yielded 64% and 74% recovery respectively compared to the oil recovery of Na_2CO_3 ash which yielded 55% recovery. Palm bunch ash, plantain peel ash, Musa paradisiaca and Akanwu (Akpoturi & Ofesi, 2017; Uzoho et al., 2015; Izuwa et al., 2021; Tang et al., 2025) are other sources of ash used for Alkaline Flooding. Mangrove ash is composed of K^+, Na^+, Ca^{2+}, Mg^{2+}, Cl^-, SO_4, PO_4, NO_3, and total solids (Chuku & Chuku, 2016; Loto & Fakankun, 1989). Previously, Dadge and Umah (2018) had studied to use local raw material such as mangrove bark ash for the production of detergent. They found that ash obtained from mangrove barks yields high concentration of potassium hydroxide (58% equivalent to 12.546 mg/l), potash, and calcium with high concentration of sodium (7.862 mg/l) which is a good source of alkalinity. Based on the experimental analysis carried out by Loto and Fakankun (1989) they found that Mangrove ash has a pH which is approximately 11.44.

Chemical EOR method is one of the popular method and it includes polymer flooding, surfactant flooding and Alkaline-Polymer-Surfactant flooding. Chemical EOR results in a reduction in both the residual oil saturation (Sor) achieved and the water-oil mobility ratio (M) by polymer flooding between the water and the oil, which contributes to an increase in the volumetric sweep efficiency (Eb), Ahmed and Eman (2021). Usually, polymer flooding is implemented when the conventional waterflooding fails. The use of polymers is intended to thicken the displacing fluid to be able to displace the remaining oil. Water-based solutions are used and polymers added to improve the viscosity of the solution and the value of the mobility ratio. If mobility ratio is larger than 1, the phenomenon of viscous fingering can occur, in which the water being injected is not able to push the oil to the oil's production well and passes the oil ahead of it. One of the functions of polymer injection is to enhance the mobility ratio which results in increase in oil production when mobility ratio is less than one (Fakutsu, 2018). Polymers are chemicals made up of chemical chains of long and repeated small pieces of chemical called monomers which occurs in the process of polymerization (Nasiru et al., 2020). A polymer is a macromolecule – a large molecule – that is made up of many subunits. There are two types of polymers: Synthetic Polymers and Biopolymers. Cellulose, guar gum, xanthan gum are some of the natural polymers which have been studied for injection in the respective oil reservoirs (Gbadamosi et al., 2022). Natural polymers like guar, xanthan, cellulose, welan, scleroglucan, schizophyllan and gum tragacanth are gaining competition with synthetic polymers for EOR (Tyagi et al., 2025). Natural polymers give a higher viscosity to the displacing fluid and lowered the fluid permeability which has been seen to increase the mobility ratio. Possesses a hard composition and a long polysaccharide chain, thereby has the ability to endure extreme conditions in the reservoir (Abou-Alfitooh & El-Hoshoudy, 2023). Polymer flooding has been used in three ways that is effective to alter fractional flow, to decrease mobility ratio of water and oil, and for zonation of injected water (Alhuraishawy et al., 2018; Sun et al., 2018). This leads to above additional oil mobility in the reservoir and can further improve and enhance reservoir productivity by changing other reservoir and fluid properties (Saien & Gorji, 2017). Al-Jaber et al. (2023) studied the oil recovery using yams and cassava nanoparticles. Positive result that they reported was agglomerated purple yam nanoparticle that incredibly recovered the oil of 85%, and cassava nanoparticle up to 90.53%. North of Nigeria, Atiatobe and Mbachu (2023) investigated the application of plantain peel ash and corn starch in Alkaline-Polymer flooding. They had 70% and 78% oil recovery and they found that these materials can be used for improvement in oil recovery. In recent years, there have been some examples of other natural polymers used such as peel of banana plant *Mussacea paradisiaca* (Sowunmi et al., 2022; Fadairo et al., 2019). It can be noted that starch is a polysaccharide with two components, namely amylopectin and amylose that control behaviour of starch solution (Lemos et al., 2019). Edible purple yam and Cassava are used as biopolymer in EOR as reported by Al-Jaber et al. (2023). Abbas et al. (2022) derived macromolecular solution for EOR from *Abelmoschus esculentus* (okra) while Chilekwe and Adetila (2015) derived macromolecular solution from starchy materials and ogbono (*Irvingia gabonensis*) and natural polymer.

Many researches have been done for its effects on the EOR chemicals dealing with their electrical charges on the rock surface including polymers, surfactant and nanoparticles. However, from their core flooding analysis under reservoir conditions it was determined that the surface of the sandstones is altered by low salinity resulting in a more negative oil-brine interface and consequently strong repulsive forces that causes the movement of the residual oil (Rahevar et al., 2023).

Oil recovery percentages, after using mangrove ash for alkaline flooding, and caladium bicolor tuber for polymer flooding, are compared. They are both natural materials and locally available. The locally sourced natural alkaline was used with polymer for the core flooding test to evaluate its effectiveness for oil-displacement.

2. MATERIALS AND METHODS

Ten sandstone core samples representing different reservoir depths were obtained from a producing reservoir within the Niger Delta Basin. Routine core analysis was carried out to determine the physical properties of the samples before flooding experiments commenced.

Porosity was determined using the gravimetric saturation method. Each dry core sample was weighed before saturation with formation brine under an overburden pressure of 500 psig. After complete saturation, the samples were reweighed, and pore volume was determined from the difference between the saturated and dry weights. The dimensions of each core plug were measured using a Vernier caliper to calculate bulk volume.

The porosity was calculated with the formula:

$$\text{Porosity} = \frac{Pore\ Volume}{Bulk\ Volume}$$

$$\text{Pore Volume} = \frac{Saturated\ weight - Dry\ weight}{Brine\ Density}$$

$$\text{Bulk Volume} = \frac{\pi}{4} LD^2$$

Where L = Length of core sample

D = Diameter of the core sample

Brine Density = 1.01g/cm^3

The core samples were cleaned of salt and hydrocarbon using methanol and toluene, respectively. Then, the routine core analysis was conducted as shown in Table 1.

Table 1. Petrophysical properties of the core samples

Core ID	Diameter, cm	Length, cm	Dry Weight, g	Saturated weight, g	Pore volume @ NOB 500psig	Porosity % @ 500psig NOB
1H	3.752	6.216	121.39	139.59	18.2	26.1
2H	3.739	5.899	115.40	133.00	17.6	23.9
3H	3.770	5.730	119.50	137.60	18.1	24.1
4H	3.791	6.821	127.42	143.92	16.5	25.4
5H	3.781	6.631	128.42	145.82	17.4	23.8
6H	3.802	5.810	130.20	149.40	19.2	24.9
7H	3.792	6.521	123.20	141.90	18.7	25.4
8H	3.772	6.432	121.22	141.32	20.1	26.6
9H	3.781	6.630	125.70	146.80	21.0	27.0
10H	3.720	6.451	127.65	149.75	22.1	28.0

The crude oil used was obtained from Niger Delta reservoirs, which have a density of 0.886g/cc, 28.2 °API, and viscosity of 8.692 cp. Mangrove ash, obtained from the combustion of mangrove, is a fuel for cooking or heating. It was sieved to remove particles before use, dissolved in deionized water, and stirred with a magnetic stirrer until homogeneous. The mixture was filtered to separate the liquid from the solid. This is then used as an alkaline solution for flooding.

A caladium bicolor tuber growing wildly was obtained from the bush in Emohua Local Government Area of Rivers State. It was harvested and taken to the laboratory, where it was thoroughly washed to remove dirt and mud. The was then cut into smaller pieces and oven-dried at 40 °C for 5 hours. It was then ground into a fine powder and sieved through a 100-micron sieve. The viscosities of both alkaline and polymer solutions were recorded over the temperature range 35 °C to 75 °C.

Thereafter, varying concentrations of saline water were added, and the mixture was stirred with a magnetic stirrer for about 5 hours to obtain a homogeneous solution.

Shear stress measurements were conducted using a Brookfield viscometer with spindle 4 at 12 RPM, corresponding to a shear rate of approximately 11.7 s^{-1}. Tests were performed at concentrations of 1000, 2000, 3000, 4000, and 5000 ppm over a temperature range of 35 °C – 75 °C.

Core flooding experiments were conducted on 5 core samples using alkaline flooding (mangrove ash solution) at varying salinities. Also, 5 additional core samples were subjected to polymer flooding with caladium bicolor starch at salinity concentrations ranging from 1000 to 5000 ppm. The hydrostatic core holder was used for the core flooding experiment. Oil displaced via flooding was recorded. The core samples saturated with crude oil were loaded into the Viton sleeve and placed in the hydrostatic core holder, which was connected to the Enerpac pump and pressurized to 500 psig. The constant-flow pump connected to the hydrostatic core holder was calibrated to a flow rate of 0.5 cc/minute. The caladium bicolor was injected into five core samples, and the volume of oil and water displaced was measured and recorded. Similarly, mangrove ash solution was injected into five additional core samples; the volumes of oil and water displaced were recorded.

3. RESULTS AND DISCUSSION

Mineralogical Characterization of the Core Samples

The mineralogical composition of the reservoir rocks was determined using X-ray diffraction (XRD) analysis to evaluate the suitability of the sandstone formation for chemical enhanced oil recovery. Mineral composition plays an important role in fluid-rock interactions because alkaline solutions may react with carbonate minerals, while polymer adsorption is influenced by the mineral surface characteristics.

The XRD analysis of the ten core samples for the core flooding analysis are represented in Table 2. The table demonstrates that the composition of cores varies with depth and of the cores, the majority are found to be predominantly quartz with a slight trace of calcite. Porosity and permeability alteration can be the result of alteration caused by the dissolution of quartz and calcite, due to the alkalinity of the mangrove ash which may lead to alteration tendency (Tang et al., 2021; Sheng, 2022). According to (Hezekiah-Braye & Abu, 2024) the important properties of the cores which include porosity and permeability might also be different because of the adsorption nature of caladium bicolor starch. The formation investigated indicates that it is quartz rich sandstone.

Table 2. XRD characterization of the core samples

		Whole Rock Composition (%)									
S/N	Sample	Quartz	Calcite	Dolomite	Rutile	Witherite	Lizardite	Microcline	Kaolinite	Halite	Total % (Whole Rock)
1	1H	91	4	5	–	–	–	–	–	–	100
2	2H	97	3	–	–	–	–	–	–	–	100
3	3H	86	–	–	–	10	4	–	–	–	100
4	4H	84	8	–	–	–	8	–	–	–	100
5	5H	92	8	–	–	–	–	–	–	–	100
6	6H	72	–	–	–	–	–	22	6	–	100
7	7H	85	–	–	–	13	–	–	–	2	100
8	8H	75.4	7.9	9.8	–	–	–	–	–	6.9	100
9	9H	80	9	11	–	–	–	–	–	–	100
10	10H	78	10	12	–	–	–	–	–	–	100

The mineralogical analysis therefore confirms that the selected core samples provide a suitable representation of Niger Delta sandstone reservoirs for evaluating the performance of locally sourced alkaline and polymer flooding agents.

Salinity Effect on the Viscosity

The salinity of caladium bicolor and wood ash has effect on the viscosity of it, increasing salinity concentration from 1000 ppm to 5000 ppm, they are correspondingly vis (0.8752 cp, 0.8922 cp and 0.8751 cp, 0.8954 cp). Since mangrove ash contains sodium and calcium ions, it can cause flocculation which will increase its viscosity. Previous research results (Shafiei et al., 2023) showed that the influence of cations on emulsion stability increases with the increase in viscosity up to 10 000 ppm. This is because of the presence of microscopic images, concentrations of up to 10000 ppm salt and a smaller droplet size and a higher viscosity.

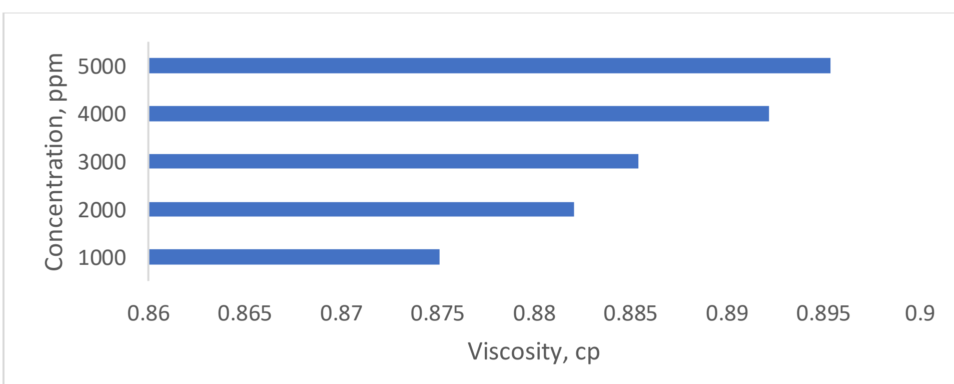

Figure 1. Salinity Effect on Viscosity

The result achieved also agrees with the work of Ghannam (2005) about the effect of salinity on oil water emulsions. From his findings, it was concluded that with the increase of NaCl concentration, the average droplet size decreased, the emulsion stability increased and also the viscosity increased as there is a direct relationship between the emulsion stability and the viscosity. The salinity effect on the viscosity of mangrove is presented in Figure 1.

Concentration On Oil Recovery Factor

Figure 2 displays the oil recovery factor at varying salinity concentrations during oil recovery. The results showed that each core sample exhibited varying recovery factors across concentrations from 1000 to 5000 ppm. Mangrove ash flooding displayed a higher oil recovery factor of 57.8%, while Caladium bicolor had 57.2%, and the least recovery factor of 50.8% and 47.8%, respectively. Mangrove ash exhibited a better recovery factor, which may be due to its alkalinity, which increases pH and reacts with organic acids in the crude oil to form a surfactant that reduces interfacial tension, alters wettability, and mobilizes residual oil (Sharma et al., 2012; Akpoturi & Ofesi, 2017).

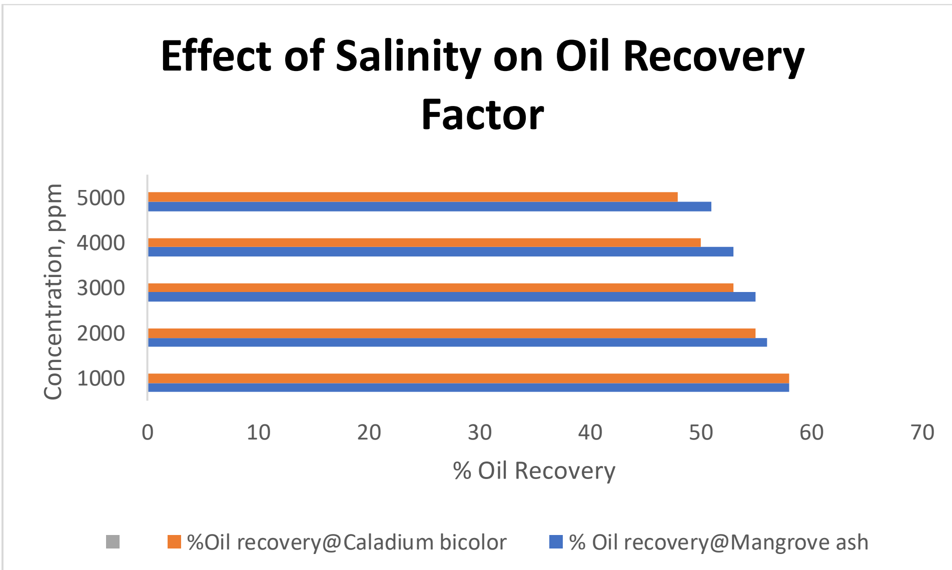

Figure 2. Percentage Oil Recovery Factor of Mangrove ash and Caladium bicolor starch

The effect of varying level of salinity on alkaline flooding (mangrove ash) and polymer flooding (Caladium bicolor) is shown in the figure 2. It was noticed that the best recovery was obtained with the lowest concentration (1000ppm) and the lowest oil recovery obtained with the highest concentration (5000ppm). This suggests the importance of salinity on oil recovery, being seen that higher salinity (from 1000 to 5000 ppm) reduces the oil recovery. If the level of salinity is high, precipitates may form and this will cause poor recovery of oil. This result agrees with that in (Nyah et al., 2024) concerning the effect of salinity concentration on oil recovery. Mangrove ash and caladium bicolor recover 58% of the oil at the concentration of 1000 ppm. As a result of their investigation, the optimum value of salinity for oil recovery is around 1000–6000 ppm. Besides, the mangrove ash with low salinity can lower the oil-water boundary interfacing tension by reacting with the organic acids in the crude oil which reduce the capillary force and thus improve the recovery of oil. Tang et al. (2025) reported that a combination of low-salinity water and alkali can increase oil recovery by altering the activity of divalent ions, such as calcium and magnesium. Hezekiah-Braye and Abu (2025) in them researching work demonstrated the effectiveness of caladium bicolor in comparison to synthetic polymer (Hydrolyzed polyacrylamide) and other biopolymers. From their experimental results, Caladium bicolor had an oil recovery of 46.9% while hydrolyzed polyacrylamide had an oil recovery of 46.6%. The results show that mangrove ash and caladium bicolor can sweep oil which improves oil recovery.

Statistical Analysis of Oil Recovery

The effect of salinity on oil recovery during flooding experiments was evaluated using descriptive statistics and one-way analysis of variance (ANOVA). Mean oil recovery and standard deviation was calculated for each salinity level. Mean oil recovery and standard deviation were calculated for each salinity level.

The assumptions of independence, normality, and homogeneity of variance were assumed for the ANOVA analysis. The results showed a progressive decline in oil recovery with increasing salinity. The mean oil recovery values were 61.76±5.93%, 59.45±4.82%, 57.28 ±5.09%, 55.37±4.85%, and 53.50 ±4.91% for salinities of 1000, 2000, 3000, 4000, and 5000 ppm respectively as shown on Table 3. Table 4 which shows that a One way ANOVA was performed to check whether there were statistically significant differences between the oil recovery of these different salinity levels. The F-statistic resulted from the analysis is 4.03 with a p value of 0.007. As p-value is less as compared to the significance level 0.05, it indicates that the null hypothesis that salinity has no effect on oil recovery is rejected. These results showed that there was statistical significance effect of salinity on recovery. This decrease in recovery as the salinity increases could be explained by the variation in fluid-rock interaction that can happen, the decrease in sweep efficiency that can occur, and the flooding agents (which recovery they give out) may not work as well during high salinity conditions. From the overall results obtained, it was concluded that lower salinity conditions would result in better recovery of oil from the reservoir analysed, being a Niger Delta sandstone reservoir.

Table 3. Statistical Summary of Oil Recovery at Different Salinity Levels

Salinity (ppm)	Mean Oil Recovery (%)	Standard Deviation (%)
1000	61.76	5.93
2000	59.45	4.82
3000	57.28	5.09
4000	55.37	4.85
5000	53.50	4.91

Table 4. One-Way ANOVA Results for Oil Recovery

Source of Variation	F-value	p-value	Significant
Salinity Effect	4.03	0.007	0.05

One-Way ANOVA performed on recovery data from ten core samples showed that salinity exerted a statistically Significant effect on oil recovery (F=4.03, P=0.007). Mean recovery decreased from 61.76% at 1000 ppm to 53.50% at 5000 ppm, indicating that increasing salinity adversely affected flooding efficiency.

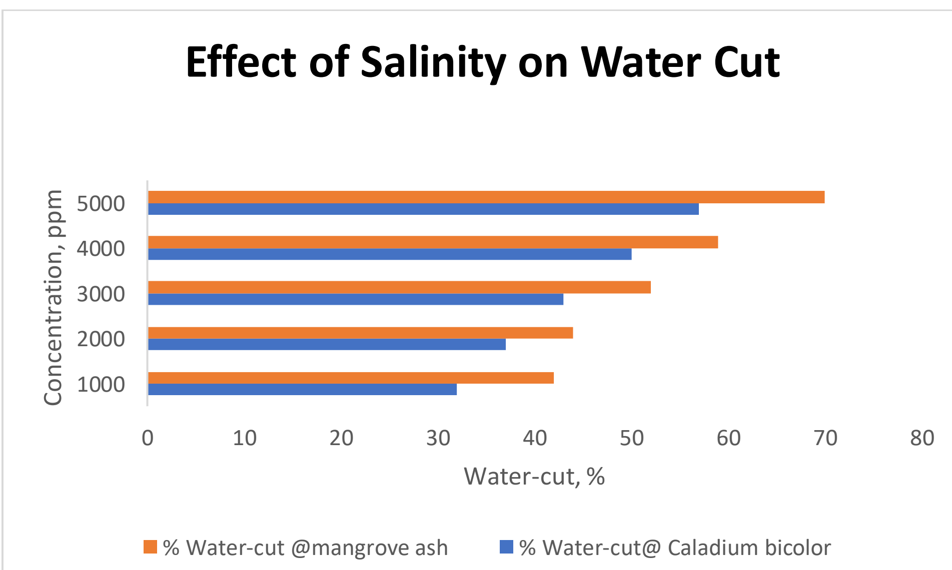

Figure 3. Percentage Water-cut

Water Cut

The differences in Both Flooding techniques in terms of water cut percentage is presented in Figure 3. Based on the results, it can be concluded that Caladium bicolor was able to generate less volume of water compared to mangrove ash. The mobilisation of the displacing fluid was significantly affected by the addition of caladium bicolor that increased the viscosity of the water, therefore the mobility of the displacing fluid in the core flooded with caladium bicolor would be expected to be less than the core flooded with mangrove ash resulting in a lower water-cut and/or delayed water breakthrough time for the core flooded with caladium bicolor. High water-cut corresponds with low oil production, high lifting, higher handling costs, corrosion, scaling and erosion, higher produced water treatment costs and represents a higher environmental impact. Further, a high water-cut may result in foreclosure of the well. It was obvious that polymer flooding and alkaline flooding had a great difference in water-cut. At 1000ppm, the percentage water-cut of caladium bicolor was 32% while that of mangrove wood ash was 42%. With increasing salinity, the water cut was increasing. Maximum water-cut was found to be 70% obtained from the mangrove wood ash. This implies that the polymer has more reducing viscous fingering.

The effect of temperature on the rheological properties of Caladium bicolor was analyzed at a temperature range of 35 °C to 75 °C, as shown in Table 3. The apparent viscosity increases with an increase in temperature from 3.533 mPas at a temperature of 35 °C to 7.021mPas at 75 °C, implying a non-Newtonian fluid behavior of shear thickening effects.

Effect of Temperature on the Rheological Behaviour of *Caladium bicolor*

The rheological properties of polymer solutions determine their ability to maintain favourable mobility control during chemical flooding. Temperature is particularly important because many polymers experience viscosity loss at elevated reservoir temperatures.

The rheological analysis of *Caladium bicolor* starch demonstrated that the apparent viscosity increased with increasing temperature over the investigated range of 35–75°C**.** Apparent viscosity increased from 3.533 mPa·s at 35°C to 7.021 mPa·s at 75°C, indicating that the starch exhibited non-Newtonian behaviour with shear-thickening characteristics under the experimental conditions. The temperature – viscosity of Caladium bicolor is summarized in Table 5.

Table 5. Temperature -Viscosity Analysis of Caladium biocolor

S/N	Temperature, °C	Spindle	RPM	Dial Reading, (% Torque)	Viscosity, (mPas)
1	35	4	12	92.1	3.533
2	45	4	12	88.7	3.682
3	55	4	12	91.3	3.833
4	65	4	12	90.9	5.157
5	75	4	12	89.6	7.021

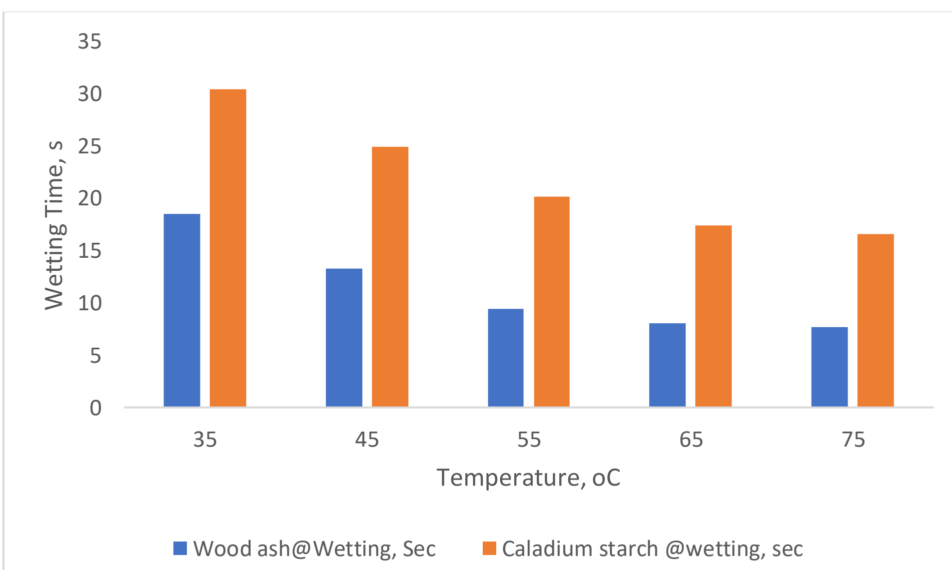

Figure 4. Temperature Vs Wetting Time of Mangrove Wood Ash and Caladium bicolor

Wetting Behaviour of Mangrove Wood Ash and *Caladium bicolor*

Wetting time can be used as a short-range measure of the rate at which a fluid will wet the surface of a rock. The shorter in the wetting time indicates better alteration toward the water wetting of wettability. In EOR it is helpful to change the sandstone from oil wet to water wet to release the trapped oil. Mangrove wood ash ever surpasses Caladium bicolor at any temperature. The Mangrove wood ash takes 7.66 s and Caladium bicolor takes 16.51 s to wet at 75 °C. The ash from the mangrove is alkaline and has a pH of 11-12. In situ surfactant is created by the reaction of alkali with the acidic materials present in crude, which creates them. Caladium bicolor (a polysaccharide polymer) affects viscosity, but not the primary parameter, working on the surface tension—in other words, wettability changes more slowly than viscosity changes. From the results obtained in figure 4, it is seen that as the temperature is increased, the wetting time decreases. This means at high temperature there will be speedier proliferation and wetting.

Effect of Concentration on Shear Stress of Caladium bicolor

The effect of the concentration on the shear stress of Caladium bicolor was studied. The effect of concentration on shear stress is shown in figure-5. Since a 5 fold increase in Caladium bicolor concentration resulted in a 35.6% increase in shear stress, this suggests that the concentration is affecting the shear stress. Non-linear relationship shows a pseudo-plastic behaviour of the Caladium bicolor. When polymer concentration is low, the polymer chains are separated and, behave independently. The apparent rise in shear stress with temperature (and concentration) strengthen the claim that there is no thermal degradation of Caladium bicolor up to 75 °C.

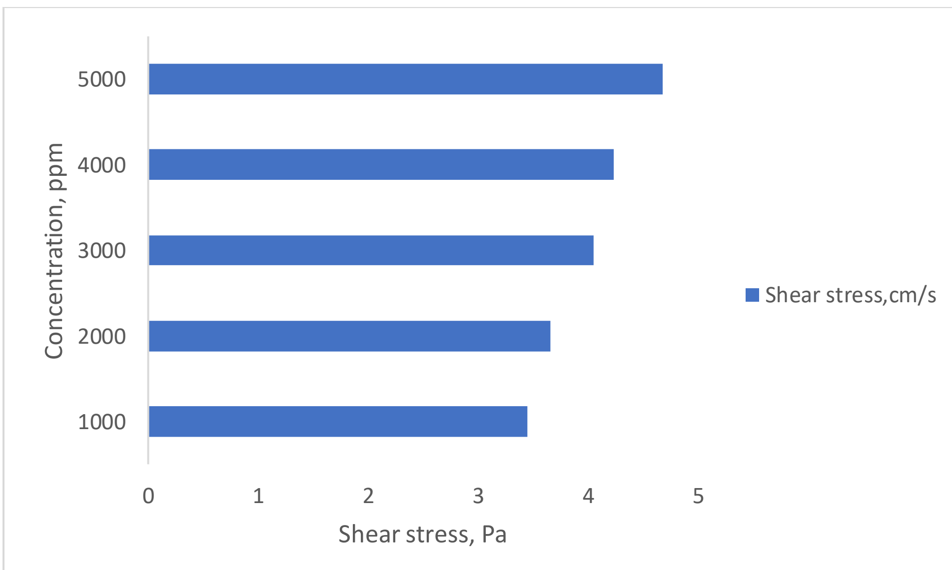

Figure 5. Effect of Concentration on Shear Stress of *Caladium bicolor*

Economic Evaluation of Mangrove Wood Ash and *Caladium bicolor*

Data obtained from the core flooding experiment at varying concentration of 1000 – 5000 ppm of mangrove ash and caladium bicolor was used.

A simplified cash flow model was applied for 1 MMbbl reservoir with 0.3 PV chemical slug injection.

Fluid volume injected	= 300, 000 bbl
Chemical mass	= Concentration × Fluid volume ×0.1198kg/bbl
Chemical cost	= Mass × Unit cost
Incremental oil	= STOIIP× Recovery factor
Revenue	= Incremental oil× Oil price
Net revenue	= Revenue -Chemical cost

Assumptions

Unit costs were estimated from local market surveys and laboratory -scale procurement costs in Rivers State, Nigeria.

a. Oil price = $75/bbl, constant

b. Unit cost: Caladium bicolor =$1.00/kg
c. Unit cost Mangrove wood ash =$0.15/kg
d. No discounting, CAPEX or operational costs included
e. 100% chemical utilization

Recovery Performance

Recovery decreased with concentration for both agents. Caladium bicolor showed maximum recovery of 23% at 1000 ppm, declining to 17% at 5000 ppm. Mangrove wood ash alkaline peaked at 24% at 1000 ppm and maintained 22% at 4000 ppm. The economic evaluation is captured in table 6.

Table 6. Economic Evaluation

Concentration	Chemical Cost	Incremental Oil, bbl	Revenue @ $75/bbl	Net Revenue
Caladium Polymer				
1000 ppm	$36,000	230,000	$17,250, 000	$17, 214,000
4000 ppm	$144,00	190,000	$14,250,000	$14, 106,000
Mangrove wood ash				
1000 ppm	$5,400	240,000	$18,000, 000	$17,994,600
4000 ppm	$21,600	220,000	$16, 500, 000	$16, 478, 400

Net revenue is maximized at 1000 ppm for both chemicals. Mangrove ash provides $780, 600 higher net revenue than caladium bicolor at 1000 ppm, and maintains a $2.37M advantage at 4000 ppm.

Economic Sustainability

The use of Caladium bicolor polymer and Mangrove wood ash alkaline as medium which chemically treated in the EOR is technically viable with the best economic performance at 1000 ppm. Based on the concept of sourcing from agricultural waste which allows them to be relatively free of foreign exchange, stable recovery performance and the consistency with local content and waste valorization, Mangrove ash has proven itself to be superior economically.

4. CONCLUSION

The experimental study of mangrove ash and caladium bicolor show that recovery factor of oil reduces due to increase in salinity, from 1000 ppm to 5000 ppm. Both caladium bicolor and mangrove ash resulted in maximum recovery percentage at the lowest salinity (1000 ppm) which were 57.2% and 57.8%, respectively. Well performance in terms of oil recoveries was diminished at high salinity, and this may have been caused by negative fluid/rock reactions and flooding efficiencies. The effects of alkaline flooding using mangrove ash and polymer flooding using caladium bicolor were compared overall, alkaline flooding with mangrove ash had higher oil recovery factor than polymer flooding with caladium bicolor since starch is sensitive to salts such as (Ca^{2+}, Mg^{2+}, Na^{+}). The reduced salinity of 1000 ppm yielded very high oil recovery which may be attributed to the caladium bicolor viscosity and sweep efficiency medium. The results showed that both mangrove ash and caladium bicolor had high oil recovery factor and oil displacement efficiency indicating excellent potential for oil recovery. In this experiment, it is manifested that these natural materials could do well be an alternative for EOR. Caladium bicolor is one of the non-edible plants that could be explored for biopolymer production as an EOR. The future study should be done by the mixture of two materials, mangrove ash and starch of caladium bicolor in an alkaline polymer flooding as an effective method to collect oil and the economy of the materials. Future work should focus on pilot -scale field trials and full lifecycle cost analysis including CAPEX.

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Author Contributions

Oritom Hezekiah-Braye: Conceptualization, methodology, experimental design, laboratory investigation, data analysis, interpretation of results, manuscript drafting, and supervision.

Godloves T. Nonju: Experimental investigation, data collection, statistical analysis, literature review, manuscript preparation, editing, and revision.

Both authors read and approved the final version of the manuscript.

Informed consent

Not applicable.

Conflicts of interests

The authors declare that they have no conflicts of interest, competing financial interests or personal relationships that could have influenced the work reported in this paper.

Ethical approval & declaration

Not applicable. Ethical approval was not required for this study because it did not involve human participants, animals, or clinical specimens.

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Data and materials availability

All data generated and analysed during this study are presented within this manuscript. Additional information supporting the findings of this study will be made available by the corresponding author upon reasonable request.

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