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An Experimental Investigation on Enhanced oil Recovery using Local Alkaline-Surfactant Solution for Niger-Delta Formation

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Abstract Ineffective methods of increasing oil recovery have been one of the challenges in the oil and gas industry, whose solutions are constantly sought after as the number of under-produced reservoirs increases daily. About 60% of crude Oil still lay trapped in the reservoir even after primary and secondary recovery process have been completed, hence the need for a method that further improves oil recovery. To mitigate these challenges and encourage the utilization of local contents, locally soured alkaline and surfactant were used in this research work as an Enhanced Oil Recovery (EOR) agent. Experimental flooding was conducted at the laboratory using the different concentrations of potash (0.5wt%, 1.0wt%, 1.5wt% and 2.0wt%) in equal volume of 100ml palm wine and brine. The locally sourced alkaline and surfactant materials used in this research work are Potash (Akanwu) and Palm wine. The efficiency of the formulated alkaline- surfactant solution was tested using different eight core samples for tertiary oil recovery process after primary and secondary flooding. The experimental result showed that the locally formulated alkaline - surfactant with different concentrations of potash in 100ml of palm wine give higher oil recovery with lower permeability change than those that contain same concentrations of potash in 100ml brine water. Samples -C3 and C2 with 1.5wt% and 1.0wt% potash in 100ml palm wine gave the highest cumulative oil recovery of80.77% and73.81% with lowest permeability change of 86.34 mD and 91.54 mD respectively. Samples- C6 and C7 that contains 1.0wt% and 1.5wt% potash in brine gave the cumulative oil recovery of 72.50% and 72% with the permeability change of 168.62 mD and 176.87mD respectively. The homogenous mixture of potash in both palm wine and brine water reduced the interfacial tension between oil water, alters rock wettability and hence increased oil displacement efficiency.

Keywords Brine, Enhanced Oil Recovery, Palm Wine, Permeability Alteration, Potash

1. Introduction

As the demand for energy keeps increasing, it becomes imperative to scoop the reservoir, thereby producing trapped and mobile oil to meet the increasing demand for energy. Chemical flooding is an aspect of enhanced oil recovery whereby chemicals like Alkaline, Surfactant and Polymer are injected into oil recovery for tertiary recovery. These chemicals are introduced into the reservoir to release and produce trapped and mobile oil that remained after primary or secondary recovery due to viscous, gravity and capillary forces. As the Niger Delta prepares for tertiary recovery stage, it becomes important to introduce local contents as substitutes for the high-cost chemicals for sustainability of the process. Research has shown that some local materials in Nigeria contain chemical compounds that can serve as Alkaline, Surfactant and Polymer when modified or refined [1]. Since these local materials are renewable and cheap, interest in their potential abilities will make their sustenance more achievable. Using EOR technique, about 30-70 percent or more of the reservoir original oil in place can be harvested as to compare with 20-40% using primary and secondary recovery. Different methods of EOR exists which are categorized into thermal, miscible, chemical, and microbial methods (Figure 1). All these different methods of enhanced oil recovery methods aimed at improving sweep efficiency, reduces capillary and interfacial force and reduces oil saturations below residual oil saturations (SOR) [2].

Oil recovery operations normally have been subdivided into three stages: primary, secondary, and tertiary (Figure 1). Primary recovery can recover from zero to over 50% of the original oil in place (OOIP); this depends on the hydrocarbon type and the reservoir drive mechanism. For instance, the primary recovery from oil sands is zero, whereas the recovery from a water drive and light oil reservoir can reach up to 50% or more in an effective gravity driven reservoir. When the reservoir energy is depleted, secondary recovery which is aimed at providing additional energy to boost or maintain the production level through injection of fluid is applied. Secondary recovery uses injections to re-pressurize the reservoir and displace oil to the producing well. Which is done through the injection of water or gas, water flooding is therefore referred to as secondary recovery [3].

The tertiary recovery which is also known as enhanced oil recovery(EOR) targets oil that is left after primary and secondary. It also involves the injection of fluids or gas into the reservoir but aimed at reducing the forces such as viscous, capillary, and interfacial forces holding the oil, to make it easy for production. The gases used in EOR process include nitrogen, hydrocarbon, carbon dioxide (CO_2), and fuel. Polymer is used to improve the sweep efficiency by changing the mobility ratio, the surfactant lowers the interfacial tension between the oil and displacing fluid [4].

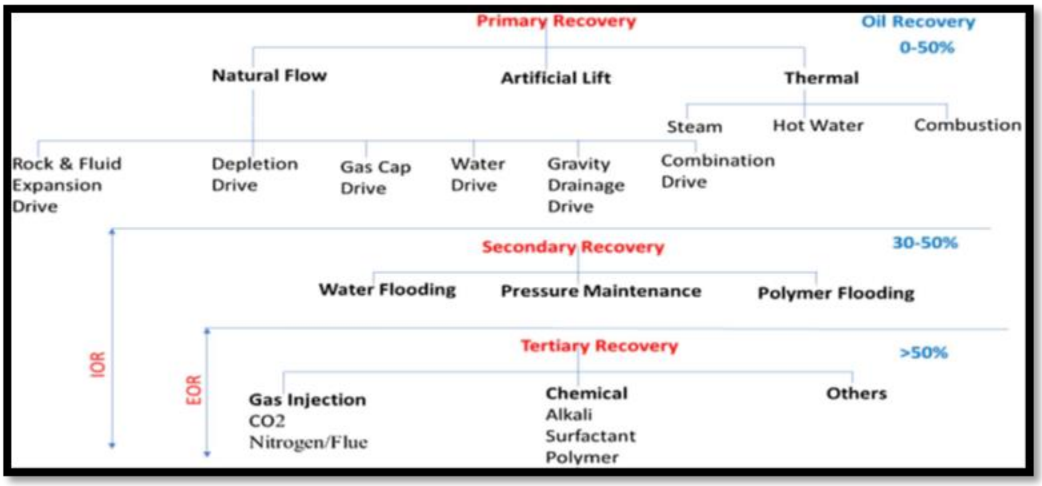

Figure 1: Summary of the hydrocarbon recovery stages, their estimated recovery efficiency, and techniques [5].

Recently, studies have proven that the use of locally sourced materials can be used to enhanced oil recovery ([6], [7], [8], [9], [10], [11]). [6] did a study on enhanced oil recovery using alcohol (palm wine), mixture of water and alcohol (palm wine) and starch mixtures in various ratios as to ascertain the best method for oil recovery. The experimental results showed that alcohol and starch mixture gave a better recovery as to compare with alcohol and water mixture. The authors observed that the mixture of alcohol and water increases oil recovery but there is an increase in alcohol content in the oil recovered. This could be attributed to interfacial tension reduction between oil and water. [7] did a work on analyzing and inspecting the effect of using locally sourced material (palm wine) to enhance oil recovery of hydrocarbons in a completed well. The researcher in his work succussed in using the alcohol to resolve the limiting capillary effects by lowering the interfacial tension which helped in mobilizing the residual oil left after water flooding. [8] Investigated on fourteen local materials for chemical enhanced oil recovery. They researched on Potash, Elaeis guineensis, Musa sapientum, Khaya ivorensis, Nkankan, Carica papaya's leaves, Cocos nucifera, Kai kai, Vernonia amygdalina, Abelmoschus esculentus, Brachystegia eurycoma, Detarium microcarpum, Irvingia gabonensis and Mucuna flagellipes. The authors reported that the best performing local alkaline, surfactant and polymer are potash, carica papaya leaves extract and Abelmosetus esculentus respectively. Abelmosetus esculentus gave the best performance than every other fourteen local materials screened without any negative effect to the formation.

[9] did a study on enhanced oil recovery using local alkaline (Palm bunch ash) – polymer (Abelmoshus esculentus) solution. The authors tested the efficiency of the Palm bunch ash and Abelmoschus esculentus

solution with different concentrations. The sand pack samples were individually flooded with brine for secondary recovery process and palm bunch and Abelmoschus esculentus mixture for tertiary recovery. The results obtained from the experimental work showed that the sample-A2 with concentration of 5g: 2g to 400ml with the PH value of 9.7 gave the highest oil recovery of 84.36% compared to other samples investigated. The authors concluded that the synergy effect of Alkaline – Polymer blend in improving oil recovery cannot be overemphasis. They concluded that local materials, alkaline and polymer gave better results when used separately than some blend of alkaline and polymer. [2] insisted that the injection of Polymer alone won't be able to alter the residual oil saturations, but the combined effect of both water flooding and alkaline flooding will result to a higher oil recovery. [12] demonstrated that when various chemicals are combined, they perform better and gave higher recoveries because of their synergy effect acting together in porous media, hence improves the sweeping efficiency.

[10] published a work on improving oil recovery using corn starch as a local polymer. The formulated cornstarch solution was injected into four different unconsolidated sand pack samples at different concentration of 500ppm, 1000ppm, 3000ppm, and 9000ppm. From the experimental work conducted, the authors reported that Cornstarch recovered an additional 25% of the residual oil after water flooding. Also, higher concentrations of cornstarch reduce the recovery factor due to polymer adsorption on the rock surfaces which alters the rock wettability. They recommended that the concentration of Cornstarch should be measured after the flooding experiments for a better understanding of the adsorption mechanism of cornstarch.[11] did a work on enhanced oil recovery using a local materials of plantain peel ash and corn starch. The core samples were individually flooded with brine (salt and water) for secondary recovery process and different concentrations of plantain peel ash and corn starch both in stand-alone and in combined form were used for tertiary recovery. The authors reported that at standalone corn starch solution increase recovery only at lower concentration but gives better recovery at higher concentration when mixed with plantain peel ash. At higher concentration there was an increase in viscosity of the corn starch solution which blocks the pore space and reduces the effectiveness of cornstarch solution change the rock wettability. They also reported that combining corn starch with plantain peel ash reduced formation damage drastically and gave a better recovery. The use of locally sourced materials for enhancing oil recovery is a highly welcome technology in the oil and gas industry globally because they are cost effective and environmentally friendly. This work aimed at studying the effectiveness of local alkaline (Potash) and surfactant (Palm wine) in enhancing oil recovery using the Niger Delta formation.

2. ENHANCED OIL RECOVERY METHODS AND MECHANISM

2.1Tertiary Oil Recovery Methods

Enhanced oil recovery is also known as tertiary oil recovery. There are four major classifications of enhance oil recovery: Thermal Flooding Process, Miscible flooding process, Chemical flooding process and Microbial flooding process.

Thermal Flooding Process: This method involves introduction of heat into oil reservoir to recover heavy crude by reducing its viscosity with an increasing temperature. The heat could be in form of hot water or steam. Thermal recovery methods are not so advantageous for light crude reservoirs because of the viscosity of the crude.

Miscible Flooding Process: This process maintains reservoir pressure and improves oil displacement because the interfacial tension between oil and water is reduced due to the introduction of miscible gases into the reservoir. Miscible process can be categorized into two types such as single contact and multi contact miscible flooding. In single contact miscible flooding fluids such as LPG (liquefied petroleum gas or alcohols is injected. The injected fluid is miscible with residual oil immediately in contact. While in multiple contact or dynamic miscible process the injected fluids are usually methane, inert fluids, or an enriched methane gas supplemented with C_2-C_6 fractions [13].

Chemical Flooding Process: This involves addition of one or more chemical compounds to an injection fluid either to reduce the interfacial tension between the reservoir fluid and injecting fluid or to improve the sweep efficiency of the injected fluid. In chemical EOR the injected chemicals reduce the surface tension of the remaining oil and push the oil towards a producing well. Chemical Enhanced Oil Recovery includes Surfactant flooding, Alkaline flooding, Polymer flooding, Alkaline surfactant polymer flooding and Foam flooding.

Surfactant Flooding: They are generally used to overcome the immiscibility between water and oil by reducing the interfacial tension (IFT) between them and changing the wettability of the reservoir rocks to water wet. Surfactant can be classified into four major categories: Anionic surfactant, cationic surfactant, non-ionic surfactant, and zwitterionic (amphoteric) surfactant according to nature hydrophilic head.

Alkali flooding: Alkali flooding is an enhance oil recovery (EOR) technique that utilizes an alkali in improving oil recovery factor. Alkali is a basic compound which may be an ionic salt of an alkali metal or alkaline earth metal. During alkaline flooding, the alkaline reacts with the naphthenic acids in the reservoir to form surfactant (soap). Alkaline flooding method is distinct from other enhance oil recovery (EOR) methods on the basis that the chemicals that aid the oil recovery are generated in situ during the EOR process by saponification reaction. The organic acid is obtained from the acidic component of the crude oil. The generated soap acts as an in-situ surfactant to reduce (IFT) interfacial tension between oil and gas, reduce capillary pressure, alters wettability, and emulsify the crude oil, thereby, improving oil recovery. The injection of alkaline into the reservoir makes the reservoir more water wet, thus increasing the flood effectiveness [14].

Alkaline - Surfactant - Polymer Flooding: Alkaline Surfactant Polymer is a mixture of three reagents to flood the reservoir and recover more oil left after secondary flooding. It uses the benefits of the three flooding methods simultaneously and oil recovery is greatly enhanced by decreasing interfacial tension (IFT), enhancing sweep efficiency by extending the swept area in both vertical and horizontal directions and improving the mobility ratio. Secondary recovery technique is limited in oil recovery process. It leaves a significant amount of oil in reservoirs. Enhanced oil recovery (EOR), which is also called tertiary recovery, is an oil recovery technique by injecting a substance that is neither water nor gas into the reservoir. There are three main categories of EOR: Thermal, Gas injection (Miscible flooding) and Chemical methods. These methods are made up of technologies designed to increase oil recovery from the reservoirs. At the later stage of the life of a reservoir, a great amount of oil is still left behind unrecovered due to the constraint of the prevailing secondary recovery technique.

2.2 BASIC MECHANISM FOR ENHANCED OIL RECOVERY

Mobility Ratio: Mobility of a fluid is the ratio of effective permeability to viscosity of a fluid. Equation (1) gives the mathematical expression of mobility ratio.

$$M = \lambda = \frac{\kappa}{\mu} \qquad (1)$$

Where, M = Mobility Ratio, λ = Mobility, k = Permeability, μ = Viscosity

Mobility ratio is defined as the mobility of the displacing fluid divided by mobility of the displaced fluid Equation (2) gives the mathematical expression for mobility ratio.

$$M = \frac{mobility\ of\ displacing\ fluid}{mobility\ of\ displaced\ fluid} \qquad (2)$$

If mobility ratio, M is less than 1 mobility ratio is favorable. If M is greater than 1 mobility ratio is unfavorable. An unfavorable mobility ratio implies the displacing fluid-water moves more easily than the displaced fluid-oil and these leads to viscous fingering when the displacing fluid flow pass the displaced fluid. Thus, for effective displacement of fluid the mobility ratio is very important, and it can be improved by, reducing the viscosity of the displaced fluid, increasing the viscosity of the displacing fluid, increasing the effective permeability to oil and decreasing the effective permeability to displacing fluid [15].

The Capillary Number: Capillary number is defined as the dimensionless ratio between the viscous and capillary force. Equation (3) gives the mathematical expression for capillary number.

$$\mathrm{Nc} = \frac{\mu \upsilon}{\sigma} = \frac{\kappa \Delta p}{\sigma \iota} \qquad (3)$$

Where, Nc = capillary number, μ = viscosity of fluid, σ = interfacial tension, μ= displacement fluid viscosity, υ = pore velocity, κ = Effective permeability of the displaced fluid, $\frac{\Delta p}{t}$ = pressure gradient across distance.

When the capillary number is increased, the residual oil saturation is decreased by either a reduction in oil viscosity or an increase in pressure gradient butt of more importance is a decrease in the interfacial tension (IFT)

[16]. However, for a meaningful residual oil to be produced, the critical value of $\frac{\Delta p}{L}$ must be exceeded by an increase in water flooding rate.

Interfacial Tension (IFT): It is generally defined as the accumulation of energy and the imbalance force at the interface of two different phases such as liquid–solid Interfacial tension is the force of attraction between the molecules at the interface of two fluids. At the air–liquid interface, this force is often referred to as surface tension. The surface tension of petroleum product, together with its viscosity, affects the rate at which an oil spill spreads. Air/oil and oil/water interfacial tensions can be used to calculate a spreading coefficient which gives an indication of the tendency for the oil to spread. It is defined as:

Spreading Coefficient = SWA: SOA: SWO (4)

SWA is water/air interfacial tension, SOA is oil/air interfacial tension, and SWO is water/oil interfacial tension. Unlike density and viscosity, which show systematic variations with temperature and degree of evaporation, interfacial tensions of crude oils and oil products show no such correlations [15].

Permeability and relative permeability: They describe flow of a particular fluid in a particular rock type. If the fluid system changes or the rock type changes, the appropriate values of permeability and relative permeability must be measured. Permeability measurements for a gas flood would not be consistent with the waterflood system. The permeability distribution and relative permeability curves used in reservoir engineering calculations need to reflect the type of processes that are expected to occur in the reservoir. Relative permeability data are often measured and reported for laboratory analysis of several core samples from one or more wells in a field. The set of relative permeability curves should be sorted by lithology and averaged to determine a representative set of curves for each rock type. Several procedures exist for normalizing or averaging relative permeability data [15].

Wettability Concept: It is defined as the tendency of one fluid to spread on or adhere to a solid surface in the presence of other immiscible fluids. It is quantified by contact angle [17]. Wettability of the pore surface is one of the important factors influencing the distribution and transport of various fluid phases in petroleum-bearing formations. The wettability of rocks is altered by the rock and fluid interactions and variations of the reservoir fluid conditions, prediction of its effects on formation damage is a highly complicated issue. Although mineral matters forming the reservoir rocks are generally water-wet, deposition of heavy organic matter, such as asphaltenes and paraffins, over a long reservoir lifetime may render them mixed-wet or oil-wet, depending on the composition of the oil and reservoir conditions.

3. MATERIALS AND METHODS

3.1 Materials and Equipment

Materials

The materials used in this study are Crude oil, Brine (mixture of industrial salt and water), Potash as Alkaline and Palm wine as surfactant.

The crude oil sample was obtained from a field from Niger Delta of Nigeria and has the following properties: specific gravity of 0.912, density of 0.8718g/cm3, viscosity of 8.2858cP and API gravity of 23.65 at the 29ºC. The sand pack was prepared using sand grain size between 65 to 205 macrons. The sand packs were saturated with brine and its bulk volume, porosity and permeability were calculated using Equations 5 to 7.

$$PV = \frac{W_{sat.plug} - W_{dry\ plug}}{P_{NaCl}} \qquad (5)$$

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

$$Porosity, \emptyset = \frac{P.V}{B.V} \times 100\% \qquad (6)$$

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

$$K = \frac{Q\mu_{NaCl}L_{plug}14700}{A_{plug}\Delta P} \qquad (7)$$

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

Brine Formulation: The brine was formulated by using industrial salt which has 99.9% pure NaCl with molecular weight of 58.44. The salt was dissolved in water and properly stirred using a stirrer so as to get homogenous solution. Its concentration was 10grams of NaCl in 1000ml of distilled water. The concentration is considered as moderate salinity for sea water. The brine has the density of 1.0105g/cm^3.

Alkaline-Surfactant Fluids Preparation: The potash used in this research was gotten from oil-mill market Port Harcourt, River's state, Nigeria. 0.5g, 1.0g, 1.5g and 2,0g of potash were dissolved in equal volume of 100ml of brine and palm wine respectively to give a homogeneous mixture of different enhanced oil recovery agents.

Equipment

Encapsulated plug sample (unconsolidated Sand-packs), Vernier caliper, Density bottle, PH meter, Hydrometer, Thermometer, Canon U-tube Viscometer, Electronic weighing balance, stopwatch, Retort stand, Pump, Flooding Pump Setup, Core-holder, Sieve and stirrer.

3.2Experimental Procedure

i. The eight unconsolidated Niger - Delta core (plug) samples labeled S1 to S8 were cleaned and fully dried in an oven.
ii. The weight, length and diameter of different core plugs were measured, and the results are showed in Table 1.
iii. The core plugs were totally saturated in a laboratory brine water as to measure the saturated weight of the individual core samples.
iv. The pore volume of each core sample was calculated using Equation 5, by subtracting the saturated weight from dry weight and was divided by the density of the brine solution and result is shown in Table 2.
v. The result obtained from bulk volume as shown in Table 1 and pore volume in Table 2 with Equation 6 was used to determine porosity (Table 2).
vi. The formation permeability was calculated using Darcey's law at a constant flow rate of 0.9091cm^3/s using Equation 7.
vii. The laboratory experiment core flooding started by injecting crude oil into the core to displace the brine water solution. It is important to know that not all the injected brine was displaced, and the remaining brine water in the core is known as connate water.
viii. The same quantity of oil that entered the unconsolidated core is equivalent to brine solution displaced from the core sample at constant flow rate.
ix. The brine was injected (secondary recovery) into the core to displace crude oil and the amount of oil recovered was measured and recorded. The laboratory brine water injection was a control experiment.
x. Other laboratory experiments were carried out following the above procedures. The water breakthrough time was recorded.

The density, viscosity, and P^H for different concentrations of alkaline-surfactant EOR agents formulated fluids are measured and the results are shown in Tables 3 and 4. These EOR agents were injected into the individual core until no oil could be recovered at the residual oil saturation.

4. RESULTS AND DISCUSSION

The results of the experimental designed on the effect of alkaline and surfactant locally sourced agents on enhanced oil recovery are presented in this section. The local alkaline and surfactant used are potash and Palm wine respectively.

4.1 Petrophysical Properties of the Formation

The bulk volume for each plug sample as indicated in Table 1 represents the entire sand volume used to form the plug sample excluding the volume of the screen. The encapsulated plug prepared uses a sieved formation having a grain size of about 600 µm. The results for the measurement of the bulk volume of the plug samples ranges from 61.59 to 69.78 cm^3.

Table 1: Bulk Volume of Encapsulated Plug

Plug ID	Thickness of the Screen (cm)	Total length of plug (cm)	Actual plug length (cm)	Plug diameter (cm)	Plug radius (cm)	Bulk Volume (cm^3)

S1	0.03	7.11	7.08	3.36	1.68	62.78
S2	0.03	7.14	7.91	3.34	1.67	69.30
S3	0.03	7.98	7.95	3.34	1.67	69.65
S4	0.03	7.89	7.86	3.34	1.67	68.87
S5	0.03	7.73	7.70	3.36	1.68	68.27
S6	0.03	7.05	7.03	3.34	1.67	61.59
S7	0.03	7.84	7.81	3.34	1.67	68.43
S8	0.03	7.90	7.87	3.36	1.68	69.78

The pore volume is the total volume of small openings/spaces in the bed of the adsorbent particle. It's an indication of the volume of fluid that can be occupied by the pore space. The higher the pore volume /porosity the higher the volume of fluid that can be contained in the core and the better the reservoir formation. The results of the calculated pore volume of the core samples varies from 25.99cm^3 to 29.65cm^3 (Table 2). The porosity of the porous medium (Sand pack) was calculated from the bulk Volume (Table 2) and pore volume of the samples using Equation 2. The porosity results as determined from Table 2 and Equation 2 is also represented in Table 2.

Table 2: Pore Volume of the Plug Samples

Plug ID	wt.of screen + foil (g)	wt. of screen + foil + dry plug	wt. of dry plug (g)	wt. of screen + foil + saturated plug (g)	wt. of saturated plug (g)	Density of Fluid (g/cm^3) 10,000 ppm	Pore Volume (cm^3)	Porosity
S1	29.76	136.86	107.1	164.17	27.31	1.0216	26.73	42.56
S2	33.88	153.37	119.497	182.82	29.45	1.0216	28.83	41.60
S3	32.37	156.24	123.87	280.11	30.18	1.0216	29.54	42.41
S4	32.10	149.81	117.71	177.87	28.06	1.0216	27.47	39.89
S5	31.62	148.32	116.70	176.32	28.00	1.0216	27.41	40.15
S6	28.69	133.95	105.26	160.51	26.56	1.0216	25.99	42.19
S7	31.76	150.27	118.51	178.58	28.31	1.0216	27.71	40.44
S8	32.27	156.62	124.35	186.91	30.29	1.0216	29.65	42.49

Density is the mass of object per unit volume. It measures how dense a fluid can be. The results of density of the formulated fluids using different concentrations of potash in both palm wine and brine are showed in Table 3. The density measurement is important because it will be used to determine the fluid kinematic viscosity. Table 3 also shows the PH values of various concentrations of alkaline- surfactant used in this study. The presence of potash increases the PH values for both palm wine and brine.

Table 3: Experimental Result for Density and PH for Formulated Alkaline- Surfactant solutions.

Fluid sample	Fluid concentration	wt. of density of bottle (pynometer) (g)	wt. of density bottle + sample (g)	wt. of fluid (g)	Volume of density bottle (cm^3)	PH	Density of fluid (g/cm^3)
C1	0.5wt% Potash/100ml palm wine	23.30	79.45	56.15	56.10	8.3	1.0010
C2	1wt% Potash/100ml palm wine	23.30	79.57	56.27	56.10	8.5	1.0030
C3	1.5wt% Potash /100ml palm wine	23.30	79.67	56.37	56.10	8.9	1.0048

C4	2wt% Potash /100ml palm wine	23.30	79.74	56.44	56.10	9.1	1.0061
C5	0.5wt% Potash /100ml brine	23.30	79.38	56.08	56.10	7.2	0.9996
C6	1wt% Potash /100ml brine	23.30	79.51	56.21	56.10	7.5	1.0019
C7	1.5%wt Potash /100ml brine	23.30	75.30	52.00	56.10	7.8	0.9209
C8	2wt% Potash /100ml brine	23.30	79.11	55.61	56.10	7.9	0.9913
C_{brine}	30.000ppm	23.30	80.61	57.31	56.10	4.7	1.0216

The measure of fluid's internal resistance to flow is dynamic viscosity while kinematic viscosity is a ratio of dynamic viscosity to density. The higher the fluid's viscosity the more it's resistance to flow. One of the characteristics of a good EOR agent is one that can increase the viscosity of the brine. The results of kinematic and dynamic viscosities of the formulated fluids used in this study are showed in Table 4. The crude oil sample has the viscosity of 49.1060cp, brine has 5.1082cp, the viscosity of different concentration of the formulated fluids ranges from 7.6077 to 26.3387cp. It was also observed that the viscosity of fluids formulated with potash and palm wine a has higher viscosity than those formulated with brine.

Table 4. Experimental Result of Viscosity of the Alkaline - Surfactant Solution and Crude Oil.

Fluid Sample of Crude oil	Temp ^0C	Efflux time (sec)	Viscometer Constant 150/601B	Density of Fluid (g/cm^3)	Kinematic Viscosity (cp)	Dynamic Viscosity (cp)
C1	29	224	0.036415	1.0216	8.1569	8.3331
C2	29	412	0.036415	1.0216	15.0029	15.3270
C3	29	597	0.036415	1.0216	21.7397	22.2093
C4	29	708	0.036415	1.0216	25.7818	26.3387
C5	29	209	0.036415	1.0216	6.9274	7.6077
C6	29	395	0.036415	1.0216	9.3419	9.5437
C7	29	109	0.036415	1.0216	12.3862	12.6538
C8	29	121	0.036415	1.0216	15.0208	15.3452
C_{brine}	29	140	0.036415	1.0216	5.0981	5.1082
C_{oil}	29	1320	0.036415	1.0216	48.0677	49.1060

Permeability is the ability of the core sample or plug sample to allow fluid to flow through it. The higher the permeability of the reservoir formation the more oil will be displaced from the pore. It was measured by injecting water into core at a flow rate of 0.9091cm^3/sec and the pressure difference was recorded for every experiment. The permeability(K) of the sand packed was estimated using Darcy's law equation as shown in Equation 7 and Table 5.

Table 5: Result for Permeability of the Plug Sample

Plug ID	Flow rate (cm^3/sec)	Viscosity of Brine (cp)	Actual Length of Plug (cm)	Plug Radius (cm)	Area (cm^2)	Differential Pressure (psi)	Permeability (k)
S1	0.9091	5.2053	7.08	1.68	92.79	2.5	2122.68
S2	0.9091	5.2053	7.91	1.67	100.84	3.0	1818.39
S3	0.9091	5.2053	7.95	1.67	100.94	3.0	1825.74
S4	0.9091	5.2053	7.86	1.67	99.99	2.5	2187.36
S5	0.9091	5.2053	7.70	1.68	99.01	3.0	1803.29
S6	0.9091	5.2053	7.03	1.67	91.29	2.5	2142.73

S7	0.9091	5.2053	7.81	1.67	99.47	3.0	1820.59
S8	0.9091	5.2053	7.87	1.68	100.81	3.0	1810.19

4.2 Results of Oil Recovery Using Tertiary and Secondary Methods

Results obtained from the laboratory experiments after performing the secondary and tertiary oil recovery using brine, local alkaline-surfactant solution of Potash in both Palm wine and brine respectively as the flooding agents are showed in Table 6 and Figure 2. The percentage of oil recovered during the secondary flooding process (water flooding) ranges from 50% to 60% indicating that up to 35% - 50% oil is remaining in sand pack, hence, the need for EOR process. The result from tertiary recovery showed that sample C-3 that contains 1.5%wt% of potash in 100ml of palm wine gave the highest cumulative recovery of 80.77% as to compare to sample C-7 which contain 1.5wt% of potash in brine which has the cumulative recovery of 72% (Figures 2 and 3). It was generally observed that the solution with dispersing surfactant of palm wine give better recovery than those formulated with brine. This is due to synergy effect of both potash in reducing the interfacial tension between oil and water as well as palm wine in reducing the viscosity of the crude oil. From this experimental study, it can be found that the presence of potash in palm wine and brine has a big effect on hydrocarbon properties and reservoir rock formation. (Figures. 2 and 3).

Table 6: Summary of Oil Recovery Using Different EOR formulated Fluids

Plug samples ID	OIIP	Break thru. Time (sec)	Δρ at drainage (psi)	Secondary. Recovery (ml)	Conc. of fluid for tertiary recovery (%)	Tertiary recovery (ml)	Cumulative recovery (ml)	Residual oil (ml)	Percentage Recovery (%)
S1	21.00	39.00	7.50	13	C1	2.50	15.50	5.5	73.81
S2	25.00	45.00	8.50	16	C2	3.00	19.00	6.00	76.00
S3	26.00	49.00	8.50	17	C3	4.00	21.00	5.00	80.77
S4	24.00	43.00	8.00	14	C4	3.00	17.00	7.00	70.83
S5	24.00	43.00	8.00	14	C5	2.50	17.00	7.50	68.75
S6	20.00	38.00	7.50	12	C6	2.50	14.50	5.5	72.50
S7	25.00	45.00	8.50	16.0	C7	2.00	18.00	7.00	72.00
S8	26.00	49.00	8.50	17	C8	2.50	18.50	7.50	71.15

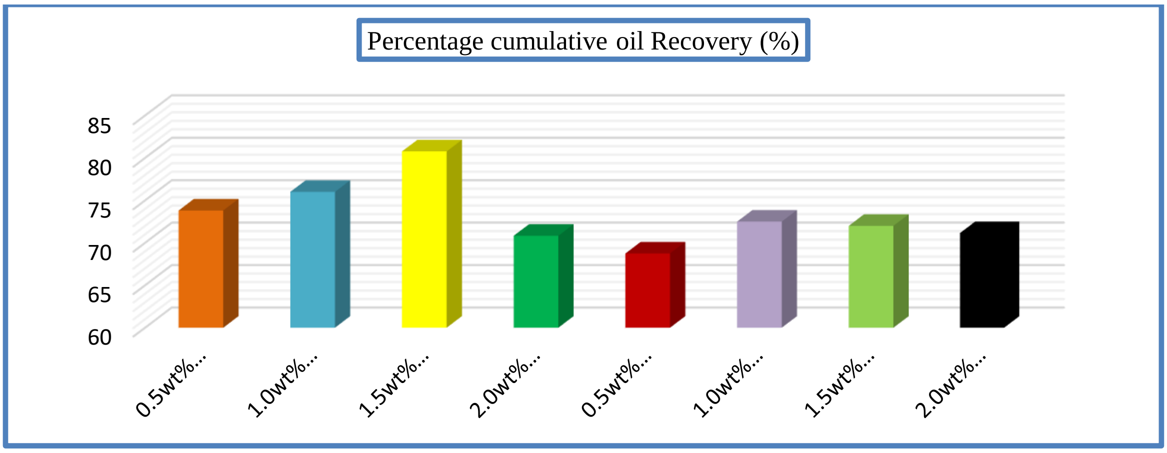

Figure 2: A Plot of Percentage oil Recovery at Different Concentration

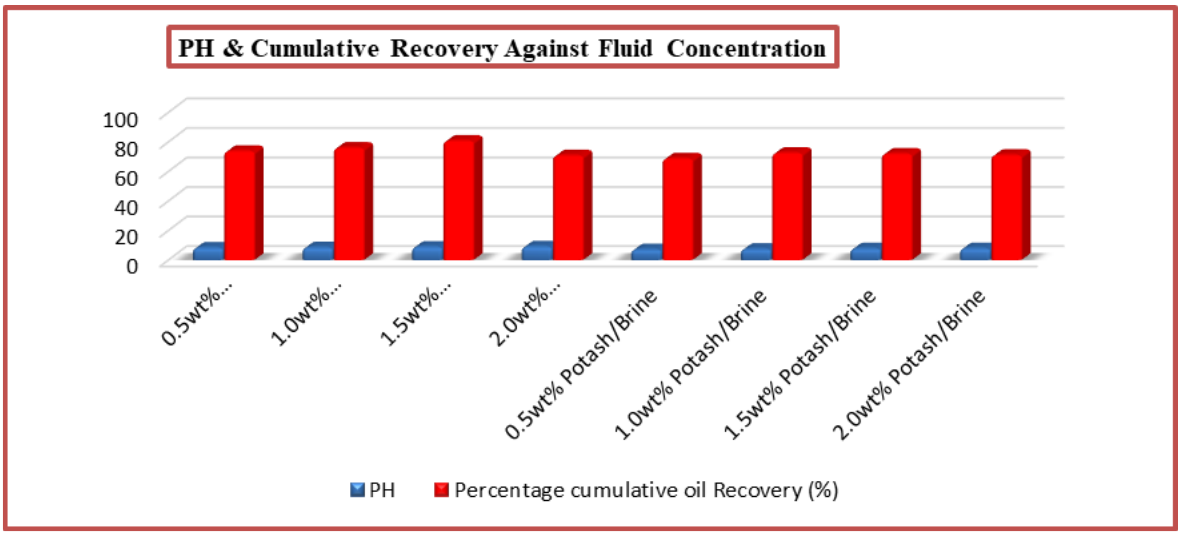

Figure 3: Percentage recovery against Fluid concentrations

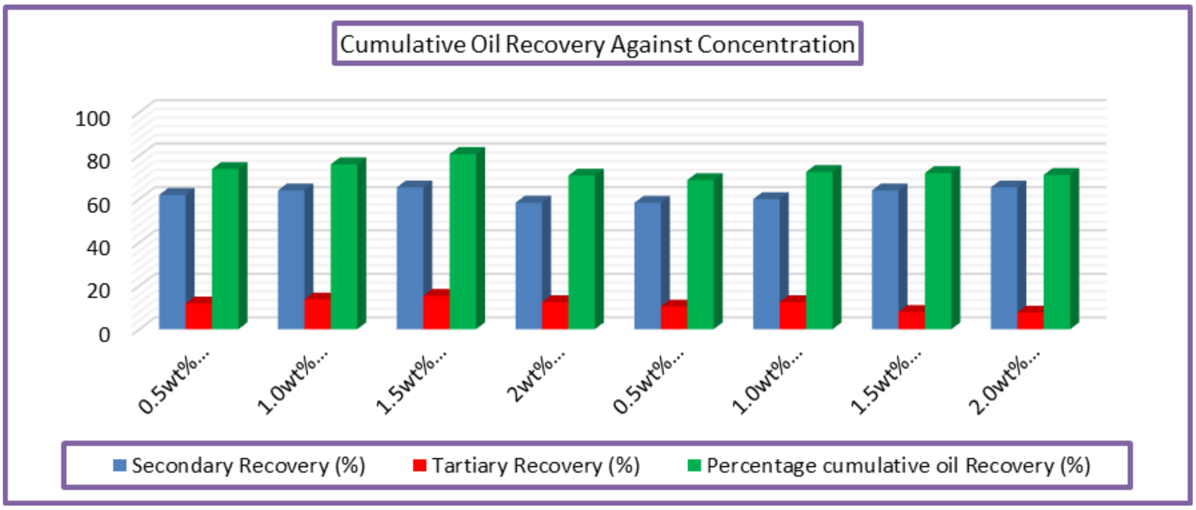

Figure 4: Secondary, Tertiary, Cumulative recovery against Fluid concentrations

4. 3 Result for Permeability Change

The core's permeability change was determined after the secondary and tertiary flooding, as to evaluate or check the extent of formation damage caused by the different formulated fluids. There is no significant decrease in permeability of the plug's formation after flooding with different fluids. The potash in palm wine generally has reduced permeability change as to compare with potash in brine. Table 7 and Fig. 5 presents the alteration in permeability for all the EOR agents studied. Permeability alteration for all the formulated fluids concentrations evaluated ranges from 80.23 md to 188.56 md. The lowest value of 80.23 md permeability change was gotten from concentration of 0.5wt% of potash in palm wine and the highest permeability change 188.56 md value was gotten from 2.0wt% of potash in brine. It was generally observed that alkaline in surfactant does not generally affect the reservoir formation negatively as has been observed by using polymer.

Table 7. Permeability Change with Difference Concentrations of Formulated Fluids

Formulated Fluids Concentrations	$k_{i\,(mD)}$	$k_{i\,(mD)}$	$\Delta K = K_i - K_{f\,(mD)}$	Percentage Recovery (%)
0.5wt% Potash /Palm Wine	2122.68	2042.45	80.23	73.81
1.0 wt%Potash /Palm Wine	1818.39	1732.05	86.34	75.76
1.5wt% Potash/Palm Wine	1825.74	1734.2	91.54	80.77
2.0wt% Potash/ Palm Wine	2187.36	2.091.91	95.45	70.83
0.5wt%Potash/Brine	1803.29	1652.43	150.86	68.75
1.0wt%Potash / Brine	2142.73	1974.11	168.62	72.50
1.5wt%. Potash /Brine	1820.59	1643.72	176.87	72.00
2.0wt%. Potash /Brine	1810.19	1621.63	188.56	71.15

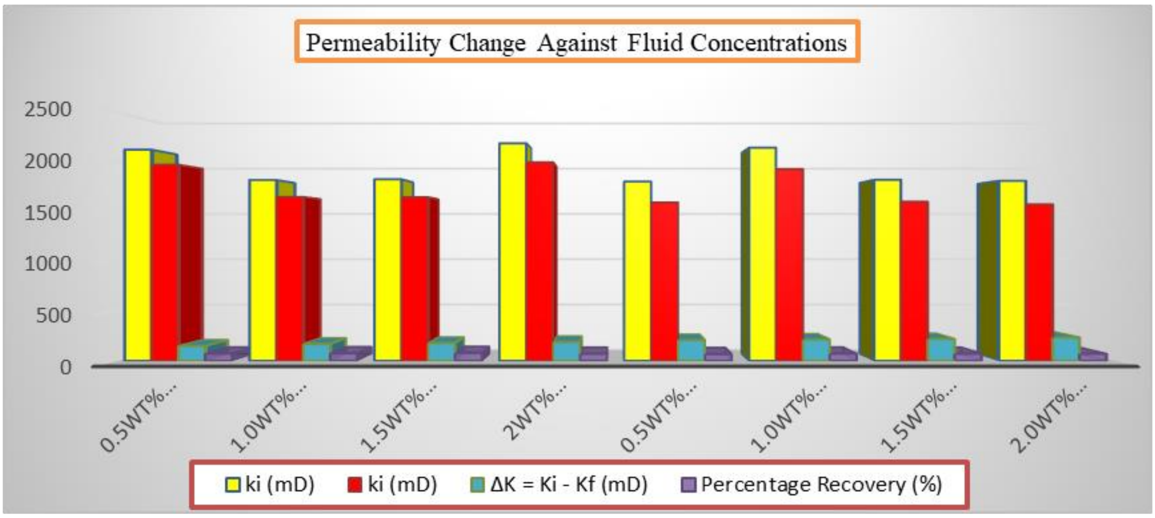

Figure 5: Permeability Change against Recovery against Different formulated alkaline-polymer solution

4. CONCLUSION

Based on the experimental results obtained from this study, the following conclusions are reached.

- The use of potash increased recovery both in palm wine and brine.
- The EOR fluids formulated with potash and palm wine gave higher recovery than those fluids formulated with potash and brine.
- The formulated fluid that contains 1.5wt% of potash in 100ml of palm wine gave the highest oil recovery of 80.77% and with the lowest permeability change of 91.54mD
- The formulated fluid that contains 1.5wt% of potash in 100ml of brine gave the recovery of 72% and the permeability change 176.87.
- Generally, from the permeability alteration results, the locally formulated EOR fluids applied in this study did not affect the formation negatively.
- Reservoir engineers should encourage the use of local material in enhancing oil recovery because they are environmentally friendly, cheap and renewable.

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