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# Potential of a Locally Made ASP Formulation Ogbonor (Irvingia Gabonensis) in Enhanced Oil Recovery Processes

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**Abstract:** The quest for techniques to recover the remaining 60–80% of the original oil in place (OOIP) left upon conventional oil recovery methods has become imperative. Alkaline–surfactant–polymer (ASP) flooding has emerged as one of the most promising and widely applicable techniques due to its significant improvement on the displacement and sweep efficiency. A number of the attempts has been devoted to investigating the combination of up to three substances to form the appropriate ASP system for a given application, which has been without a number of technical challenges. This paper reviews the possibility of employing an appropriately engineered synthesis of an ASP substance which incorporates all the three components in one. Research has been conducted into the suitability of an ASP system formulated using locally available and thus economically viable raw materials (Ogbonor seeds, *Irvingia gabonensis*, potash, and salt). The study shows the best level of salinity needed for the retention of the polymer gel viscosity is 30g/l and the maximum viscosity of the polymer solution is 1.086, in the absence of additives. This brought to a conclusion that the chosen additive (potash) does not have a significant effect on the polymer solution that will result in highest viscosity which enhances a good percentage of oil recovery. Polynomial models relating the resulting polymer viscosity with concentration and salinity have been developed, applicable for predicting polymer viscosity at different concentrations of salt and additive.

**Keywords:** Alkaline, Surfactant, Polymer, Oil Recovery, Viscosity, Ogbonor, Salinity, Modeling

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## 1. Introduction

Alkaline–surfactant–polymer (ASP) is a combination process in which alkali, surfactant, and polymer are injected in the same slug which outrightly affects oil flow behavior in the reservoir. Because of the synergy of these three components, ASP offers a considerable potential in chemical enhanced oil recovery (EOR). The success of this process depends on the proper combination of alkali, surfactant, and polymer and their compatibility with a reservoir.

In the ASP process, Chemicals used are an alkali (NaOH or Na<sub>2</sub>CO<sub>3</sub>), a surfactant and a polymer. Surfactants are chemicals used for the reduction of interfacial tension between the involved fluids, making the immobile oil mobile. Alkali reduces adsorption of the surfactant on the rock surfaces and reacts with acids in the oil to create natural surfactant. Polymer improves the sweep efficiency. ASP in a system gives rise to, oil mobility, diminishing of interfacial tension, and

increase in sweep. The process can also change the pH of the system depending on surfactant introduced and the alkali concentration [1]. The ASP method can be applied as an improved waterflooding with large slug of low surfactant concentration. The objective of the ASP flooding process is to reduce the amount of chemical consumed per unit volume of oil required and invariable a reduction in cost.

ASP floods in the world were commercially successful and were seen as an important technology for EOR; however, the projects were generally small. Difficulties in applying large reservoir scale surfactant flooding are due to the evaluation of potential recoveries mainly because reservoir modeling is not available yet. The production rates of the 100 largest oilfields in the world are all declining from plateau production. The challenge is to develop EOR methods that ensure an economical tail end production from these fields. Field practice has shown that more than 20% OOIP incremental recoveries can be obtained with the ASP process. Better ASP

systems need to be developed with more cost-effective surfactants in weak alkaline systems [2]. This study is aimed at investigating the suitability of a locally available and cost effective materials for ASP processes.

*Previous Works*

Liu et al. in 2008 [3] presented an ASP experiments in silica and dolomite sand packs for a system with a particular surfactant blend (Ni blend) and a West Texas crude oil. The alkali used was sodium carbonate, and experiment was conducted at ambient temperature. ASP experiment showed excellent recovery of waterflood residual oil (>95%).

Hongyan and Brian more recently [4] reported a development of a new surfactant-polymer system. The SP formulation in this work exhibits the efficient diffusion-adsorption properties of ionic surfactants as well as the high surface activity of nonionic surfactants. An excellent synergistic effect was obtained between the primary surfactant (SLPS) and secondary nonionic surfactant. The finalized S-P flooding formulation used in the pilot field trial was capable to improve the oil recovery by 18.1% in laboratory oil displacement tests. Since the injection of the main slug of the S-P flooding system in June 2004, the field trial has demonstrated tremendous decrease of water cut and enhancement of oil production. It has been reported that the accumulative oil-production increase had reached  $17.8 \times 10^4$  t in July 2008. The increase rate of oil recovery and decrease rate of water cut from S-P flooding are clearly higher than those using single polymer flooding.

Martin [5] used aluminium citrate process consisted at the injection of HPAM polymer solution slug AL3+ and citrates ions and a second polymer and acted as a bridge to the second polymer layer. The process was repeated until a desired layering was achieved. The disadvantage in his work was that the transport of AL3+ through the reservoir may be limited to near well bore, which needed another treatment further than that.

Musharova [1] in his experiments proved the efficiency of introduction of the three chemicals such as alkali, surfactant, and polymer to the aqueous system. In particular, alkali and surfactant significantly drops interfacial tension of crude oil leading to increased oil mobilization and sweep efficiency. Polymer addition changes Newtonian fluid to non-Newtonian by increasing viscosity. Polymer greatly builds up an aqueous solution viscously. Addition of alkali to polymer system results in a shear thinning effect. For a successful Alkali-Surfactant-Polymer flooding, the investigation of crude oil and reservoir aqueous fluid must be done. Furthermore, all chemical should be tested for an assurance of a compatibility with the reservoir fluid and rock properties.

*Surfactants, Polymer and Alkali*

*Surfactants*

Surfactants or surface active agents when dissolved in water are substances that give a product the ability to remove dirt from surfaces. They are usually organic compounds that are amphiphilic, meaning they contain both hydrophobic groups and hydrophilic groups. Hence, a surfactant molecule contains either a water insoluble or oil soluble component and a water

soluble component depending on the nature of the hydrophilic group. Four classes of surfactants are (anionic, cationic, zwitterionic and nonionic) groups.

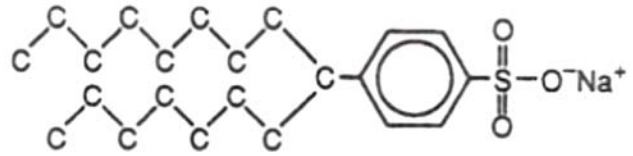


Figure 1. Surfactant molecule.

The active portion of anionic surfactants has a negative charge; they could be carboxylate (COO<sup>-</sup>), sulfate (SO<sup>-4</sup>) or sulfonate (SO<sup>-3</sup>). Cationic surfactants have a hydrophilic part bears a positive charge, e.g is cetyl ammonium bromide (C<sub>16</sub>H<sub>33</sub>N(CH<sub>3</sub>)Br). When this surfactant dissolves in water, the positive charge will be on the N-atom. Zwitterionic surfactants have both a positive and a negative charge, e.g. RN+H<sub>2</sub>CH<sub>2</sub>COO<sup>-</sup> (Long chain amino acid), C<sub>17</sub>H<sub>37</sub>NSO<sub>3</sub> (alkyldimethylpropanesultaine). Nonionic surfactants bear no apparent ionic charge. However the hydrophilic part is soluble in water because of polar groups [6].

Surfactants can be used to dissolve two immiscible fluids (e.g. oil and water) into each other. This is called an emulsion. To be able to do this, surfactants form micelles spontaneously water when the concentration of surfactants is high enough. A micelle can be spherical, cylindrical or a bilayer. The hydrophobic part dissolves in the oil phase, and the hydrophilic part dissolves in the water phase.

**2. Polymers**

Polymers are long chains of repeating units (monomers) linked by covalent bonds. There are two sets extensively used for enhancing oil recovery, namely synthetic polymers and biopolymers. The major field experience is with synthetic polymers. The most used polymer in field operations is polyacrilamide, PAM or hydrolysed polyacrilamide, HPAM etc. These are polymers where the monomeric unit is acrylamide. The chemical structure of HPAM is shown in Figure 2.

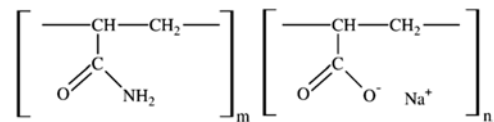


Figure 2. Molecular Structure of HPAM.

Two biopolymers are used for EOR purposes, named *xanthan* and *scleroglucan*. Both have a helical, rodlike structure and are extremely pseudoplastic with high viscofying effect. Polymer flooding gives significant increase in recovery when compared to conventional water flooding projects. It reduces the unfavorable effect of permeability variations. Hydrolyzed polyacrylamide (HPAM) is the only commonly used polymer in the field and can be used up to about 185 Ft depending on the brine hardness.

The addition of polymers to injected water can increase oil recovery not only by improving vertical and areal sweep but also by altering the water-oil fractional flow properties toward more efficient oil displacement. Polymers are used as a tool for mobility control to improve sweep efficient oil displacement increases with decreasing mobility (or increasing viscosity) of the displacing phase. This is also a basic principle of polymer flooding. For a given distance of viscous fluid penetration into a high permeability zone, the distance of penetration into less permeable zones becomes greater with increased viscosity or resistance factor of the injected fluid [7-10] (Seright et al. 2008). This concept is illustrated in Figure 3, demonstrating the distance of penetration in low permeability layers when the polymer penetrates 50ft in a high permeability layer. This effect must be considered while designing the polymer flooding, for the concentration and viscosities of the polymer should be elected accordingly.

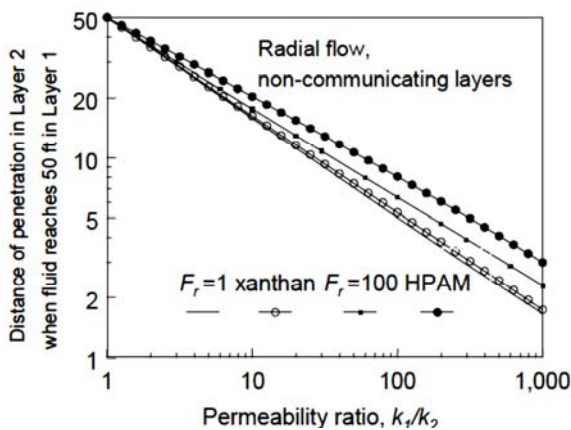


Figure 3. Rheology effect on penetration [11].

A commonly accepted technique for evaluating polymer flood potential for a particular reservoir is by simulation of water flood and polymer floods under varying conditions and comparison of resulting oil recoveries. For the simulations to realistically portray reservoir response to polymer, it must include all significant properties of polymer reservoir system.

### 3. Alkaline

Alkalis are all Arrhenius bases, which form hydroxide ions ( $\text{OH}^-$ ) when dissolved in water. Common properties of alkaline aqueous solutions include: Moderately concentrated solutions (over 10<sup>-3</sup> M) have a pH of 10 or greater. Concentrated solutions are caustic (causing chemical burns). Alkaline solutions are slippery or soapy to the touch, due to the saponification of the fatty acids on the surface of the skin. Most basic salts are alkali salts, of which common examples are: sodium hydroxide (often called "caustic soda"), potassium hydroxide (commonly called "caustic potash"), lye, calcium carbonate, magnesium hydroxide is an example of an atypical alkali since it has low solubility in water. Nowadays, instead of sodium hydroxide (NaOH), sodium bicarbonate ( $\text{NaHCO}_3$ ) or sodium carbonate ( $\text{Na}_2\text{CO}_3$ ) is used to reduce

emulsion and scale problems.

Alkali reacts with the petroleum acids during the alkaline flooding in the reservoir. To form a surfactant hydroxide ion reacts with a pseudo-acid component which is known Hydrolysis reaction. Alkaline flooding like surfactant flooding improves oil recovery by lowering the interfacial tension (IFT) between the crude oil and the displacing water. The surfactants for alkaline flooding are generated in-situ when alkaline materials react with crude oil. This is possible if the crude oil contains sufficient amount of organic acids to produce natural surfactant or emulsification of the oil for the alteration in the preferential wettability of the reservoir rock surfactant flooding involves the mixing of the surface active agent with other compounds as alcohol and salt in water and injected to mobilize the crude oil. Polymer thickened water is then injected to mobilize the crude oil.

The alkaline chemicals react with organic acids in certain crude oil to produce surfactant in-situ that dramatically lower the IFT between water and oil. The alkaline agent also reacts with reservoir rock surfaces to alter the wettability from oil-wets to water-wets or vice versa. Other mechanisms include emulsification and entrainment of oil to aid mobility control. The Slug size of alkaline solution is often 10-15% Pv. The concentrations of alkaline chemically are normally 0.2 to 5%, dosage a pre-flush of fresh or softened water often proceed the alkaline slug and a drive fluid, which is water or polymer solution after the slug [12].

#### ASP Process and Mechanism

ASP is the process where high concentration of Alkali with a low concentration of Surfactant and Polymer is injected in to the reservoir. In some cases, Alkaline and surfactant are first injected followed by Polymer slug for mobility control. Upon completion of the ASP and polymer injection, regular water flooding behind the ASP wall can be resumed.

This process uses a very low concentration of the surfactant to achieve ultra low interfacial tension between the trapped oil and the injection fluid/formation water. The ultra low interfacial tension also allows the alkali present in the injection fluid to penetrate deeply into the formation and contact the trapped oil globules. The alkali then reacts with the acidic components in the crude oil to form additional surfactant in-situ, thus, continuously providing ultra low interfacial tension and freeing the trapped oil. In the ASP Process, polymer is used to increase the viscosity of the injection fluid, to minimize channelling, and provide mobility control.

Usage of alkaline, surfactant and polymer together in EOR has been recognized to be one of the major techniques due to its large reduction in the quantity of surfactant compared to when it is used alone. Also typical alkali can be used which is much cheaper than surfactant. Therefore, it is the most economical process. Implementation of ASP requires a thorough research to be conducted to determine the most suitable alkali, surfactant and polymer as well as conditions of reservoir, oil.

#### Conditions for good EOR using ASP processes

The design of an alkaline/surfactant/polymer process according to Shunhua et al. [6] requires knowledge of the

amount of soap formed under alkaline conditions from naphthenic acids in the crude oil. He demonstrated in his experiment that for several crude oil, when substantial acid is present, the acid number determined by nonaqueous-phase titration which is approximately twice of what is found by hyamine titration of a highly alkaline aqueous phase used to extract soaps from the crude oil. The acid number by crude extraction should provide a better estimate than nonaqueous-phase titration because the extracted soap interacts with the injected surfactant to form surfactant films and microemulsion droplets during an ASP processes.

The knowledge of salinity and interfacial tension is also important. In his work, Liu et al [3] stated that an unusually wide range of salinities of ultralow oil/water interfacial tensions (IFTs) was found for one alcohol-free crude oil / anionic surfactant system under alkaline conditions where naphthenic soaps were present [6].

**Appropriately Engineered Design of ASP Systems**

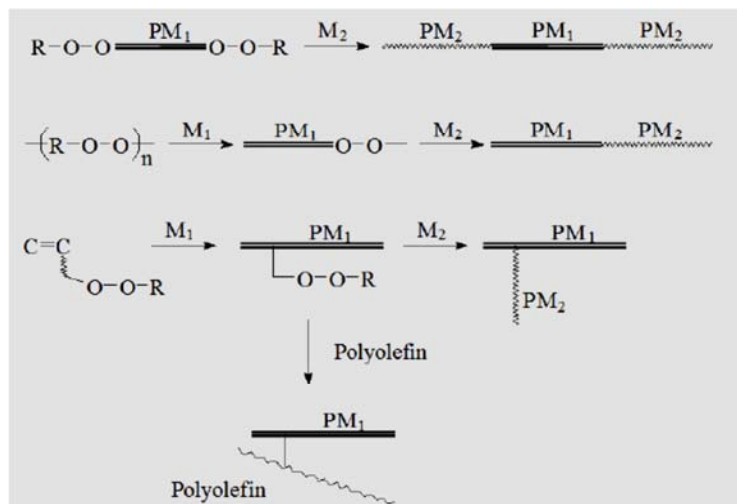
The introduction of alkali to surfactant flooding some decades back led to the reduction in the amount of surfactant required and the process became known as alkaline surfactant polymer flooding (ASP). This was followed up by the discovery that the adsorption of anionic surfactants on calcite and dolomite could be significantly reduced by employing sodium carbonate as the alkali, thereby making the process applicable for the formation of carbonates. These same substances can also alter the wettability of carbonate formations from strongly oil-wet to preferentially water-wet. This wettability alteration in combination with ultra-low interfacial tension (IFT) makes it possible to displace oil from preferentially oil-wet carbonate matrix to fractures by oil-water gravity drainage.

The alkaline surfactant process co-injects alkali and synthetic surfactant. The alkali generates soap in situ by reaction between the alkali and naphthenic acids in the crude oil. It was recently recognized that the local ratio of soap/surfactant determines the local optimal salinity for minimum IFT. Recognition of this dependence makes it possible to design a strategy to maximize oil recovery with the least amount of surfactant and inject polymer with the

surfactant without phase separation. An additional benefit of the presence of the soap component is that it generates an oil-rich colloidal dispersion which produces ultra-low IFT over a much wider range of salinity than in its absence [13].

Khaled et al. [14] presented a new alkaline–surfactant (AS) flooding formulation that replaces and improves the traditional alkaline–surfactant–polymer (ASP) flooding slug. This was achieved through the design of a cost-effective AS slug, wherein a new series of polymeric surfactants was produced on the basis of agriculture material by employing a graft polymerization process using several surfactant-to-acrylamide ratios. This surfactant was specially designed to graft the sulfonated group to the polymer backbone as one component system for interfacial tension (IFT) reduction and viscosity control, which are necessary for an effective ASP EOR process. As a consequence, a combination of alkali and surfactant with a concentration of 0.8 and 0.4% was found to significantly reduce the IFT while maintaining the desired viscosity of the solution.

Organic peroxides are products of important technological applications, and they play a vital role in biological processes. This accounts for the ever-increasing interest in such substances for more than a century. As a result of years of investigation in this direction, a separate branch of organic chemistry – chemistry of organic compounds has appeared and gained a fruitful elaboration. Despite the fact that rich experimental and theoretical material exist, a large variety of well-known and characterized peroxide compounds, whose production and application have reached industrial levels, the implementation of research work into the synthesis, property studies and search for applicability of novel peroxides have gained an intensive development all over the world [15, 16]. This is due to the fact that peroxides have ceased to be merely initiators of radical processes, but transformed to a powerful instrument for the modification of polymers, tailoring the surface properties of materials, creation and improvement of the qualities of adhesives, gums, composite materials amongst others, which requires peroxide products with a certain complex of properties [17, 18].



**Figure 4.** Application of Peroxide Moieties for Polymer Functionalization.

Thermal stability, capability to homolytical or heterolytical decomposition, initiating and other features of peroxide substances (including surface-activity, adhesiveness, solubility in various media) could be purposefully altered by incorporating into their molecules substitutes of various polarity, nature and electronic effects: halogens, hydroxyl, carbonyl, carboxylic, nitro-, amino- functionalities, etc. Moreover, the presence of other functionalities alongside with peroxide groups in the organic peroxide molecules opens the door to new possibilities of their utilization during the synthesis and modification processes of macromolecular compounds, for activation of mineral surfaces, creation of multicomponent polymer systems including composite materials [19-21]. For this reason the application of multifunctional peroxide substances has gained the increasing attention of scientists and industrialists, therefore further investigations in this direction toward the formulation of uniquely distinct and cost-effective substances combining the needed characteristics inherent in typical ASP formulations for EOR applications are indeed exceedingly pressing and promising. Future research is geared toward creating unique ASP formulations involving a single substance incorporating all the three features of ASP in one with the sole advantage of ensuring maximum compatibility and synergy of the required actions during technological applications for enhanced oil recovery. Particularly in this work, a local formulation including a local polymer (Ogbonor seeds, *Irvingia gabonensis*) has been investigated for suitability as a component of the ASP EOR formulation, and the additive composition that gives the highest viscosity for EOR has been determined.

## 4. Methodology

### *Brine, Polymer and Additive Preparation*

For the preparation of brine of various concentrations ranging from 0 – 60 g/L, appropriate amounts of salt was weighed in a volumetric flask or measuring cylinder, and distilled water was added with subsequent mixing. Dried Ogbonor seeds (*Irvingia gabonensis*) were obtained locally, grounded to a very fine powder. In all cases, local polymers (powder) of different concentrations were dissolved in corresponding brine solution. The polymer was added slowly while stirring to allow for quick dispersion of polymer particles. The viscosity was measured with glass viscometer at a laboratory temperature of 27°C and polymer concentration ranging from 0g/l to 10g/l.

Potash was obtained and grounded to a fine powder. Depending on the concentration, it was mixed with the already prepared brine and agbono solution with their corresponding concentrations. To achieve this, the required grams of polymer, additive and salinity were measured with a weighing balance, then added with sporadic stirring so as not to produce agglomerate of froth until the polymer was clear. The solution was kept and closely observed to know when the polymer dissolved. The solution was then filtered to remove the

particles that may have settled. The filtered solution was heated to 27°C and The fluid viscosity taken. This procedure was repeated with the mapped concentrations of the salt, polymer and additive. The viscosity of the solution used was determined by the Ostwald glass viscometer.

### *Calibration of Density Bottle*

$$\text{Weight of empty density bottle} = W_{1(g)}$$

$$\text{Weight of bottle + distilled water} = W_{2(g)}$$

$$\text{Volume of distilled water recovered from density bottle} = V(cc)$$

$$\text{Density} = \frac{\text{Mass}}{\text{Volume}} = \frac{(W_2 - W_1)(g)}{V(cc)} \quad (1)$$

$$\text{Temperature of solution} = 27^\circ\text{C}$$

$$\text{Time for liquid to flow through viscometer capillary} = t_{\min}$$

$$\text{Viscometer constant at } 27^\circ\text{C} = K$$

### *Viscosity of Agbono, Additive and Salinity Solution*

$$\text{Weight of empty density bottle} = W_1$$

$$\text{Weight of density bottle + solution} = W_2$$

$$\text{Weight of solution} = W_2 - W_1$$

$$\text{Volume of solution in the density bottle} = V$$

$$\text{Density} = \frac{W_2 - W_1}{V} \quad (2)$$

$$\text{Viscosity of solution} = \text{Fluid density} \times \text{time (sec)} \times \text{Viscosity constant}$$

$$= \left( \frac{W_2 - W_1}{V} \right) \times (t \times 60) \times K \quad (3)$$

$$\text{Volume of bottle} = 50\text{ml}$$

$$\text{Weight of bottle} = 19.048\text{g}$$

$$K = \text{Viscosity constant @ } 27^\circ\text{C} = 0.00361381$$

## 5. Results and Discussion

The dependence of the viscosity of the resulting mixture as a function of the polymer concentration and salinity are presented in Tables 1 to 3 as well as Figures 5 to 7 at various additive concentrations ranging from 0 g/L to 10 g/L. Clearly evident from Table 1 is the fact that for 0g/L concentration of additive the least viscosity was 0.0951 and maximum viscosity of 1.086 was observed at 30g/L salt concentration. Figure 5 shows that for 2g/L concentration of additive the least viscosity was 0.0962 and maximum viscosity of 0.1804 was observed at 40g/L salt concentration. The polymer viscosity is a key parameter to improve the mobility ratio between oil and water and adjust the water intake profile. As injection viscosity increases, the effectiveness of polymer flooding increases. The viscosity can be affected with increased polymer weight [21-25]. Secondly, increased polymer concentration leads to higher viscosity and increased sweep efficiency.

At 4g/L concentration of additive the least viscosity was 0.0975 and maximum viscosity of 0.2347 was observed at

0g/L salt concentration (Table 2). Figure 6 shows that for 6g/L concentration of additive the least viscosity was 0.0975 and maximum viscosity of 0.2249 was observed at 0g/L salt concentration. Evident from Table 3 is the same trend for 8g/L concentration of additive, with the least viscosity being 0.0974 and maximum viscosity of 1.0717 observed at 10g/L salt concentration. Upon 10g/L concentration of additive the least viscosity was 0.0966 and maximum viscosity of 0.1518

was observed at 50g/L salt concentration (Figure 7).

The graphs showing the relationship between concentration of Ogbonor and salt given a particular concentration of additive have all been fitted to a polynomial equation with a sufficiently high coefficient of determination ( $R^2$ ). The coefficients of the model equations for variation of viscosity at various salt concentrations (0g/L of additive) are presented in Table 4.

**Table 1.** Variation of viscosity at different concentrations of Ogbonor and salinity given 0g/L Additive.

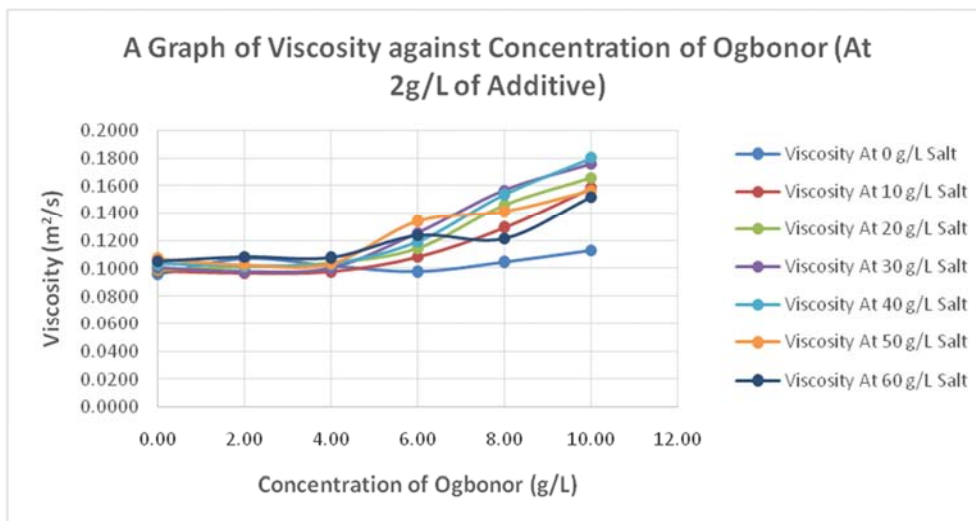
0g/L Additive							
Salinity	0	10	20	30	40	50	60
<b>Ogbonor</b>							
0	0.0951	0.0957	0.0996	0.1003	0.1094	0.1045	0.1002
2	0.2068	0.1061	0.1065	0.1086	0.1106	0.1135	0.1067
4	0.1389	0.1247	0.1271	0.1208	0.1312	0.1255	0.1183
6	0.2019	0.1666	0.1656	0.1657	0.1609	0.1527	0.1662
8	0.2059	0.1941	0.1879	0.1918	0.1878	0.1950	0.1699
10	0.3920	0.1957	0.1755	0.1890	0.2068	0.1961	0.1994

**Table 2.** Variation of viscosity at different concentrations of Ogbonor and salinity given 4g/L Additive.

4g/L Additive							
Salinity	0	10	20	30	40	50	60
<b>Ogbonor</b>							
0	0.0975	0.0982	0.0982	0.0997	0.1023	0.1048	0.1029
2	0.1022	0.0981	0.0992	0.1051	0.1051	0.1077	0.1115
4	0.1007	0.1020	0.1037	0.1029	0.1070	0.1064	0.1057
6	0.1099	0.1122	0.1174	0.1120	0.1163	0.1431	0.1179
8	0.1987	0.1586	0.1597	0.1709	0.1591	0.1470	0.1622
10	0.2347	0.2067	0.1697	0.1715	0.1849	0.1534	0.1462

**Table 3.** Variation of viscosity at different concentrations of Ogbonor and salinity given 8g/L Additive.

8g/L Additive							
Salinity	0	10	20	30	40	50	60
<b>Ogbonor</b>							
0	0.0974	0.0998	0.0998	0.1012	1.002	1.0411	0.1038
2	0.1049	1.0717	0.1081	0.1104	0.1134	0.1143	0.1165
4	0.1221	0.1174	0.1121	0.1158	0.1153	0.1169	0.1185
6	0.1358	0.1279	0.1179	0.1250	0.1261	0.1308	0.1349
8	0.1892	0.1613	0.1669	0.1547	0.1729	0.1723	0.1623
10	0.1552	0.1273	0.1256	0.1333	0.1437	0.1407	0.1319



**Figure 5.** Variation of viscosity with concentration of Ogbonor at different salt concentrations given 2g/L of additive.

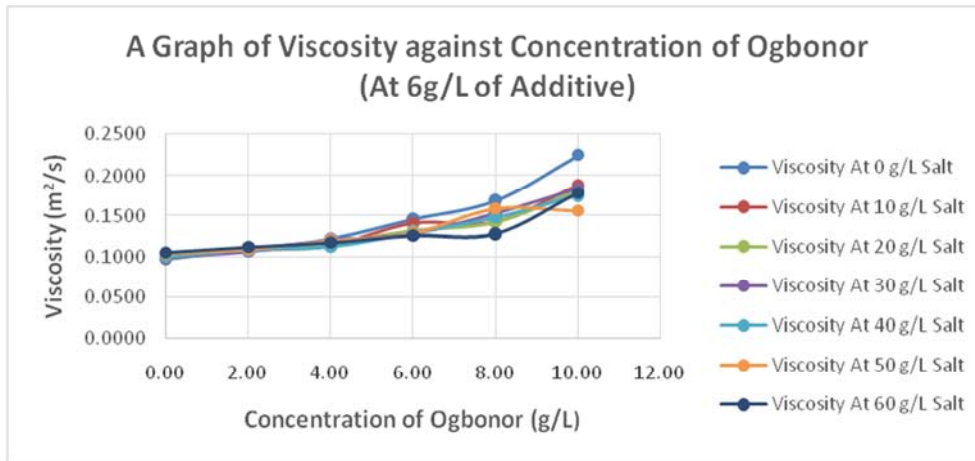


Figure 6. Variation of viscosity with concentration of Ogbonor at different salt concentrations given 6g/L of additive.

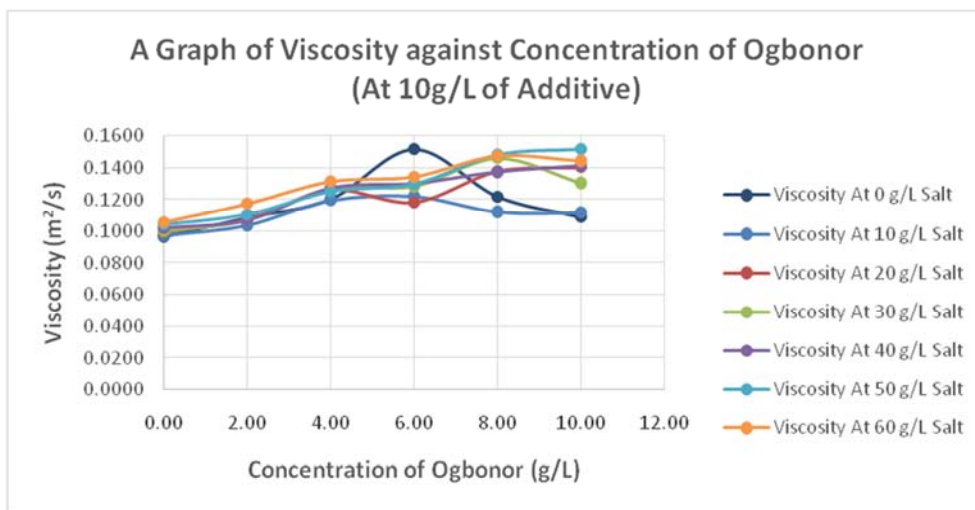


Figure 7. Variation of viscosity with concentration of Ogbonor at different salt concentrations given 10g/L of additive.

Table 4. Coefficients of the model equations for variation of viscosity at various salt concentrations (0g/L of additive).

Salt concentration, g/L	$y = a_5x^5 + a_4x^4 + a_3x^3 + a_2x^2 + a_1x + a_0$						$R^2$
	$a_5 \times 10^4$	$a_4 \times 10^4$	$a_3 \times 10^3$	$a_2 \times 10^2$	$a_1 \times 10^2$	$a_0$	
0	2.00	-0.62	0.56	-21.56	30.82	0.9510	0.999
10	0.10	-5.00	4.80	-1.51	2.02	0.0957	1.000
20	0.10	-4.00	3.20	-0.89	1.09	0.0996	0.999
30	13.00	-365.00	369.00	-159.29	247.37	0.1003	0.999
40	0.00	0.07	-0.3	0.43	-0.69	0.1094	1.000
50	-0.10	2.00	-1.0	0.2	0.29	0.1045	1.000
60	0.70	-17.00	13.7	-4.34	4.74	0.1002	1.000

*Effect of salinity and additive on Ogbonor solution*

Experimental results confirmed that on addition of salt to Ogbonor solution, its viscosity increases with increasing salinity,, thereby indicating polymer stability at high salinity. The same is the case with the blending of additive with the Ogbonor solution at different salt concentration, the viscosity alternates between minimum and maximum value as the salinity increases.

In the absence of any additive the maximum viscosity of Ogbonor solution is 1.086 which takes place at 30g/L concentration of salt solution. This is followed by a viscosity of 1.0717 when the Ogbonor solution is mixed 8g/L of

additive and 10g/L of salt.

It is significantly to note that Ogbonor is not totally decomposed at high concentrations of salt. Overall maximum viscosity has been observed at 30g/L of salt with 0g/L of additive. Furthermore, maximum viscosity in the presence of additive occurs at a lower salt concentration of 10g/L. Therefore, in oil reservoirs with high salinity, this polymer (Ogbonor) could act as water shut off upon its application in ASP EOR processes [23, 24].

The maximum viscosity of the polymer solution (Ogbonor) is 1.086, this occurred at 30g/l concentration of salinity, in the absence of additive (i.e. 0g/l additive. This brought to a

conclusion that the chosen additive (potash) does not have an effect on the polymer solution that will result in highest viscosity which enhances good percentage of oil recovery [26-28].

At 0g/l additive, the maximum viscosity of the polymer solution was observed and lower concentration of 10g/l, because of this, the polymer solution can be used as water shut off in oil reservoir.

The models developed can be used to predict polymer viscosity at different concentrations of salt and additive and the solution of the model varies between minimum and maximum value as the salinity increases, this is same with the blending of additive to the polymer solution at different salt concentrations.

Addition of polymer to increase the displacing fluid viscosity leads to improved sweep efficiency in the reservoir. Through thorough research, it was also observed that polymer viscosity decreases with increase in temperature. Polymer injection is for mobility control by reducing the mobility ratio between water and salt.

## 6. Conclusion

The various techniques being applied to achieve optimal recovery of crude oil has been briefly presented, with special emphasis on the alkaline–surfactant–polymer flooding, which has emerged as one of the most promising and widely applicable techniques due to its significant improvement on the displacement and sweep efficiency.

The result of the experiment shows that upon the addition of salt to ogbonor solution, its viscosity does not only decrease with increasing salinity, but increases and therefore shows that the local polymer (Ogbonor) will be stable at high salinity.

The study shows the best level of salinity needed for the retention of the polymer gel viscosity is 30g/l and the maximum viscosity of the polymer solution (Ogbonor) is 1.086, in the absence of additive (i.e. 0g/l additive). This brought to a conclusion that the chosen additive (potash) does not have a maximum effect on the polymer solution that will result in highest viscosity which enhances good percentage of oil recovery.

The models developed in this research can be used to predict polymer viscosity at different concentration of salt and additive and the solution of the model varies between minimum and maximum values as the salinity increases.

Addition of polymer to increase the displacing fluid viscosity leads to improved sweep efficiency in the reservoir. The majority of the attempts have been devoted to investigation of the combination of up to three substances technical challenges encountered in ASP processes have been highlighted and these have led to the idea of developing potential alternatives from locally available raw materials. A way to approach this objective which is a subject for future research is to employ a recently developed technique of polymer modification which may involve the application of certain peroxide oligomers capable of interface modification and compatibilization of various alkaline/polymer surfactant

systems as well as creation of appropriately engineered designed formulations.

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