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Comparative Study of Local and Commercial Polymer Viscosities Effect on Enhanced Oil Recovery in Sandstone Formation

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Abstract
This work focuses on the experimental comparative study of local and commercial polymer injection fluid viscosity effects on reservoir recovery performance under flooding on sandstone formation. A sandstone reservoir core flooding aparatus was used in this work for experimental recovery assessment, with core sample holders which bears the sandstone consisting 40ml original oil in place (OOIP) exist at 30.34 cp oil viscosity. Cassava peels local polymer was also produced in this work, and assessed comparatively with commercial polymer on their recovery efficiency in an Enhanced Oil Recovery system, at variant viscosities 11.45cp, 15.56cp, 19.5cp, 23.54cp, and 27.65cp, as well been injected seperately at 300ml volume into a 0.45m long reservoir. Results achieved from the study was able to identified that the recovery rate of the two polymers are a little bit the same when injected as same operating conditions and viscosities, such that 34.85 ml, 29.18 ml, 19.48 ml, 10.79 ml, and 4.47 ml oil volume were recovered from the use of 11.45cp, 15.56cp, 19.5cp, 23.45 cp, and 27.65 cp viscos local polymers, while 41.54 ml, 36.72 ml, 22.63ml, 10.51 ml, and 5.19 ml oil volumes were recovered over injection of same viscosity cormart commercial polymer, in a 0.45m long reservoir of 40ml OOIP and 30.34 cp oil viscosity. Also, the commercial polymer was identified to be of higher fingering efficiency (FE): 65.39%, 55.34%, 32.12%, 16.65%, and 6.02%. While that of the local polymer was identified to be 53.79%, 46.05%, 38.61%, 15.13%, and 4.97%, over the increase in the fluid viscosities respectively. Using the analysis of variance (ANOVA), the relationship between the local and commercial polymers in the reservoir recovery system shows a strong significance relationship of F_{cal}= 281.081, 237.968, 264.0366, 192.4262, and 1445.1 for the respective viscosities, with a fingering nature of the polymers both agree to the fact that injected fluid fingers through the reservoir frontline in a wavelike motion, forming peaks, such that the magnitude and number of peaks defines the recovered oil volume, which is satisfactory to the Saffman- Taylor Instability (STI) principle for reservoir recovery under fluid injection . Conclusively, it's deduced from the study that viscosity influences reservoir recovery performance, hence polymer and other fluids of lower viscosities are best recommended for effective reservoir recovery performance under flooding. Also, local polymers such as that of the cassava peels are effective substitutes of some commercial polymers, hence should be used in areas where commercial polymers are scarce or expensive to afford for oil recovery purposes.

Keywords: Enhanced Oil Recovery, Viscosity, Cassava Peels, Polymer, Sandstone Formation, Core Flooding, Fingering Efficiency.

I. INTRODUCTION

The petroleum industry faces persistent challenges in maximizing oil recovery from reservoirs with significant hydrocarbon deposits, particularly as conventional reserves continue to decline. Primary recovery methods, which rely on natural reservoir pressure, typically extract only 20–25% of the original oil in place (OOIP). Secondary recovery techniques, such as water flooding and gas injection, can increase recovery to 30–50%, yet still leave a substantial portion of hydrocarbons unrecovered [2], [3]. This has necessitated the adoption of Enhanced Oil Recovery (EOR) technologies, which represent advanced methods designed to unlock previously inaccessible reserves and extend the productive lifespan of oil fields [7].

Among EOR techniques, polymer flooding has emerged as a promising chemical method. By injecting viscous polymer solutions, the mobility ratio between displacing fluids and reservoir oil is improved, leading to enhanced sweep efficiency and reduced fingering effects [8], [9]. Commercial polymers such as Hydroxyethyl Cellulose (HEC) and polyacrylamides have been widely used; however, their high cost and dependence on imports limit large-scale application, particularly in developing economies [15], [16]. In Nigeria, where local content initiatives are prioritized, attention has shifted toward exploring cost-effective alternatives derived from indigenous resources. Cassava peels, an agricultural waste product, have shown potential as a source of water-soluble biopolymers capable of controlling fluid mobility in reservoirs [10], [11].

The theoretical framework of this study is grounded in the Saffman-Taylor Instability (STI) principle, which explains the behavior of fluid interfaces during displacement. When a low-viscosity fluid is injected into a medium saturated with a higher-viscosity fluid, instability at the interface can lead to fingering, turbulence, and bypassing of oil. Achieving stable flood fronts is therefore critical to maximizing recovery efficiency [12], [13], [14]. This research investigates whether locally produced cassava peel polymers can match the recovery and fingering efficiency of commercial polymers across varying viscosities (11.45 cp to 27.65 cp) in sandstone reservoirs, using a core flooding apparatus.

The study is guided by the following objectives:

- To compare recovery rates of local cassava peel-based polymers and commercial polymers at different viscosities.
- To evaluate fingering efficiency under varying polymer viscosities.
- To determine statistical relationships between local and commercial polymer recovery efficiencies using Analysis of Variance (ANOVA) at a 5% significance level.
- To quantify percentage changes in oil recovery across viscosity ranges.

The scope of the research is limited to laboratory-scale experiments conducted under atmospheric conditions using a locally constructed core flooding apparatus. While this setup does not replicate high-pressure, high-temperature reservoir environments, it provides valuable insights into the fundamental displacement mechanisms and recovery efficiencies associated with polymer flooding. Limitations include the absence of standardized industrial specifications and undetermined maximum pressure and power tolerance of the apparatus.

The significance of the study lies in its contribution to reservoir engineering by experimentally validating the STI principle, demonstrating the direct impact of injection fluid viscosity on recovery performance, and introducing a methodology for calculating percentile fingering efficiency (PFE). Moreover, it supports Nigeria's local content policy by highlighting the economic and technical feasibility of utilizing agricultural waste-derived polymers as substitutes for costly imported products. Despite limitations in equipment specifications and experimental conditions, the findings underscore the potential of locally sourced polymers to enhance oil recovery, reduce operational costs, and promote sustainable energy practices [1], [4], [5], [6], [17], [21].

The petroleum industry has long employed secondary recovery techniques such as chemical methods, thermal methods, and gas injection to enhance production beyond primary recovery. In Nigeria, water injection remains the most widely used pressure maintenance technique, followed by gas injection, which dates back to 1863 and has since evolved from immediate productivity enhancement to ultimate recovery optimization [15,4]. The efficiency of gas injection depends on displacement and sweep efficiency, with studies highlighting the importance of injection volume, oil viscosity, and formation volume factor [7]. Recent advancements, such as NODAL analysis, have improved understanding of flow relationships and production optimization [22,9]. Gas re-injection has been proposed as a sustainable solution to reduce flaring in the Niger Delta, thereby improving recovery efficiency and minimizing environmental concerns [16]. Exergoeconomic optimization models have further demonstrated the importance of pressure maintenance during plateau and decline periods of reservoir performance [17,11,20]. These studies emphasize the need for integrated system design to sustain production.

NODAL analysis has been widely applied to evaluate well performance by analyzing pressure drops across system components [21], [24].. This approach ensures that inflow and outflow conditions are balanced, enabling optimization of production systems. Studies have shown that improper equipment sizing, such as oversized tubing, can reduce well deliverability and necessitate artificial lift systems prematurely [12],[11]. Proper system design, including tubing, casing, choke, manifold, and surface facilities, is critical for sustainable production [14], [3], [4].

Crude oil recovery is categorized into primary, secondary, and tertiary (enhanced) recovery methods [13]. Primary recovery relies on natural reservoir pressure or artificial lift systems such as pumps, gas lift, and hydraulic lift [15]. [21], [22]. Secondary recovery involves water or gas injection to maintain reservoir pressure, with water flooding being the most widely practiced method [14],[2] Enhanced Oil Recovery (EOR) techniques, including gas injection, thermal methods, and chemical flooding, can recover up to 65% of OOIP, making them vital for extending reservoir productivity [19], [20]..

Polymer flooding, a chemical EOR method, enhances sweep efficiency by increasing water viscosity. Both synthetic and bio-polymers have been applied, with local alternatives gaining attention due to cost-effectiveness.[5] demonstrated that locally sourced polymers such as okro and gum arabic can compete with synthetic polymers, achieving significant recovery rates with reduced permeability impairment. This supports the feasibility of local content initiatives, particularly in Nigeria, where high exchange rates make imported polymers expensive.

EOR processes are classified into thermal and non-thermal methods, with objectives including viscosity reduction, mobility control, and interfacial tension reduction [3], [19], [8]. Gas injection, particularly CO_2 flooding, is the most widely adopted due to its ability to reduce oil viscosity and improve miscibility [13]. Thermal methods, such as steam injection, are effective in heavy oil reservoirs, with superheated steam and horizontal wells offering improved recovery efficiency [15], [24], [14]. Chemical methods, including polymer flooding, remain essential for mobility control and cost reduction in EOR projects [13].

Key insights from the literature reveal that gas injection remains a cornerstone of secondary recovery, with modern applications focusing on sustainability and efficiency [16]. NODAL analysis provides a robust framework for optimizing production systems by balancing inflow and outflow conditions [21],[24]. Enhanced oil recovery methods can recover up to 65% of OOIP, highlighting their importance in meeting global energy demand [24]. Locally sourced polymers, such as cassava peel derivatives and okro, demonstrate competitive recovery performance compared to synthetic polymers, supporting cost reduction and local content policies [5].

In conclusion, while conventional recovery methods are limited, secondary and tertiary recovery techniques particularly polymer flooding offer significant potential for improving oil recovery efficiency. The integration of locally sourced polymers into EOR systems presents a viable pathway for reducing costs and promoting sustainability in Nigeria's petroleum industry. This merged introduction underscores the importance of system optimization, advanced recovery techniques, and local innovation in addressing the challenges of declining conventional reserves and rising global energy demand.

II. Materials and Method

The following material and methods were employed in the course of this investigation.

The materials used in this study consisted of both locally produced and commercially available polymers, crude oil samples, and sandstone reservoir cores. The local polymer was derived from cassava peels, processed through hydrolysis and purification to obtain a water-soluble biopolymer suitable for flooding experiments. The commercial polymer employed was Hydroxyethyl Cellulose (HEC), a widely used synthetic polymer in enhanced oil recovery operations. The crude oil sample was obtained from a sandstone reservoir, with an original oil in place (OOIP) of 40 ml and a viscosity of 30.34 cP. Sandstone cores were prepared and mounted in core holders to simulate reservoir conditions during flooding experiments. These materials provided the basis for comparative analysis of recovery performance under varying polymer viscosities.

Equipment and Apparatus

1. Core flooding apparatus (locally constructed, 0.45 m reservoir length)
2. Measuring cylinders (50 ml, 100 ml)
3. Weighing balance
4. Thermometer
5. Stopwatch
6. Pycnometer for density measurement
7. Redwood viscometer for viscosity determination
8. Pressure gauges and injection pumps
9. Microscopes for flood front observation

Experimental Procedure

The experimental procedure was carried out in three stages. First, baseline characterization of the crude oil was performed to establish its physical properties, including density, viscosity, API gravity, flash point, cloud point, and pour point. These measurements confirmed the crude oil viscosity at 30.34 cP under atmospheric conditions.

The second stage involved the preparation of polymer flooding fluids. Cassava peel polymer was synthesized, dried, ground, and dissolved in brine to achieve viscosities of 11.45 cP, 15.56 cP, 19.5 cP, 23.54 cP, and 27.65 cP. Commercial polymer solutions were prepared at the same viscosity ranges to allow direct comparison. Each polymer solution was injected at a constant volume of 300 ml.

The third stage consisted of core flooding experiments. The sandstone reservoir model, measuring 0.45 m in length, was saturated with crude oil (40 ml OOIP). Polymer solutions were injected sequentially at the specified viscosities, and recovery volumes were measured at the outlet after breakthrough. Fingering efficiency (FE) was determined by observing flood front stability and turbulence at the fluid interface, in line with the Saffman–Taylor Instability principle.

Figure 1: Experimental Setup of an EOR Reservoir System Under Polymer Flooding (Source: RSU Laboratory)

Analytical Methods

Oil recovery efficiency was assessed by recording the recovered oil volumes for each viscosity and comparing the performance of local and commercial polymers. Fingering efficiency was calculated as the percentage of recovered oil relative to OOIP, with interface observations confirming the presence of instability patterns. Statistical analysis was conducted using Analysis of Variance (ANOVA) at a 5% significance level to determine the relationship between local and commercial polymer recovery efficiencies. F-calculated values were compared across viscosities to establish statistical significance.

Scope of Experiment

The study was conducted under atmospheric laboratory conditions using a locally constructed core flooding apparatus. The reservoir model length was 0.45 m, and each polymer solution was injected at a constant volume of 300 ml. Limitations included the absence of standardized industrial specifications for the apparatus and the undetermined maximum pressure and power tolerance. Despite these constraints, the experimental design provided valuable insights into the comparative performance of local and commercial polymers in enhanced oil recovery.

III. RESULTS AND DISCUSSION

3.1 EOR Flooding Assessment for 11.45 cp Viscous Local and Commercial Polymer Injection

Table 1: Sandstone reservoir flooding outputs over 11.45 cp local and commercial polymer injection

Q_{in}=300ml // OOIP=40ml // μ_{LP}= 11.45cp						
F-Period	Qout	Vo	Vp	Qout2	Vo2	Vp2
0	0	0	0	0	0	0
5	14.96	3.98	10.98	16.44	4.23	12.21
10	41.94	3.23	38.71	45.93	5.38	40.55
15	138.1	18.83	119.27	142.45	20.67	121.78
20	43	2.27	40.73	41,67	4.05	37.62
25	35	6.54	28.46	28.22	7.21	21.01
Total	273	34.85	238.15	274.71	41.54	233.17

The first flooding experiment evaluated the performance of 11.45 cp local and commercial polymers in a 0.45 m sandstone reservoir containing 40 mL of crude oil at 30.34 cp viscosity. The experimental results are presented in Table 1, which shows the fluid production at 5-second intervals up to 25 seconds. The results confirmed the presence of the fingering phenomenon, where the injected polymer advanced through the reservoir in a pseudopod-like pattern. This behavior, consistent with the Injected Fluid Fingering (IFF) concept, directly influenced both instantaneous and cumulative oil recovery. As shown in Figure 2, peak oil recovery occurred within the first 15 seconds for both polymers, with the local polymer recovering 18.83 mL of oil and the commercial polymer recovering 20.67 mL

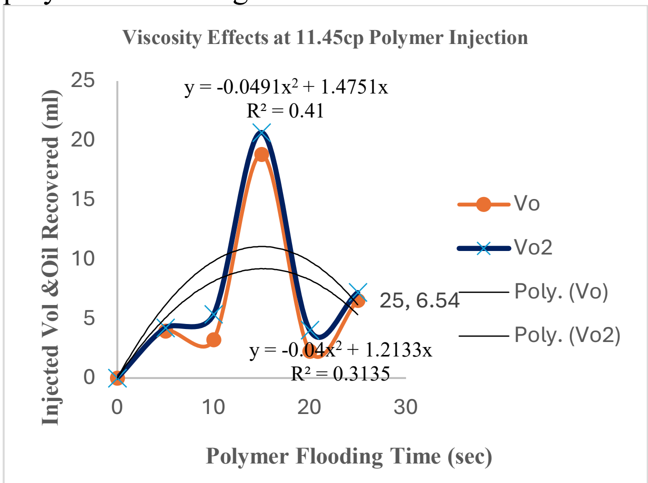

Figure 2: Viscosity Effects on Oil Recovery for 11.45cp Polymer Flooding EOR System

By the end of the 25-second flooding period, the local polymer system recovered 34.85 mL of oil, while the commercial polymer recovered 41.54 mL. Out of the 300 mL injected, 238.15 mL of the local polymer and 233.17 mL of the commercial polymer were regained, demonstrating that although the commercial polymer performed slightly better, the cassava-peel polymer delivered comparable results under identical conditions. Also, the reservoir performance was modeled from the experimental data and expressed by the fitted fingering-efficiency polynomials: for the local polymer, the model is

$y_{L-11.45} = -0.04x2 + 1.2133x$ (1)

$y_{F-11.45} = -0.0491x2 + 1.4751x$ (2)

These models yielded fingering efficiencies of 53.79% (local) and 65.39% (commercial). The fingering instability index (R^2) values were 0.3135 and 0.41, respectively. ANOVA results, shown in Table 2, revealed a strong statistical relationship (R^2 = 98.23%, F = 281.081), confirming the close performance similarity between both polymers.

Table 2: ANOVA and Regression result of 11.45cp local and commercial polymer relationship

Statistic	Value				
Multiple R	0.9929597				
R Square	0.9859689				
Adjusted R Square	0.9824611				
Standard Error	0.8910504				
Observations	6				
Source	df	SS	MS	F	Significance F
Regression	1	223.1704	223.170	281.081	7.42E-05
Residual	4	3.175883	0.79397		
Total	5	226.3463			
	Intercept	TENNER Variable 1			
Coefficients	-0.670067	0.9357342			
Standard Error	0.530701	0.055813			
t Stat	-1.26261	16.7655			
P-value	0.27532	7.42E-05			
Lower 95%	-2.14353	0.780772			
Upper 95%	0.80339	1.09069			
Lower 95.0%	-2.14353	0.78077			
Upper 95.0%	0.80339	1.09069			

The total fluid recovery assessment further clarifies system performance and is plotted in Figure 3 which shows the relationship between time and overall fluid recovery and highlights the instability of the system as the injected polymer fluids finger through the reservoir front-line, the overall fluid recovery totals were 273 ml for the local polymer system, composed of 34.85 ml crude oil and 238.15 ml local polymer recovered from 300 ml injected volume, and 274.71 ml for the commercial polymer system, composed of 41.54 ml crude oil and 233.17 ml cormart polymer recovered from 300 ml injected volume.

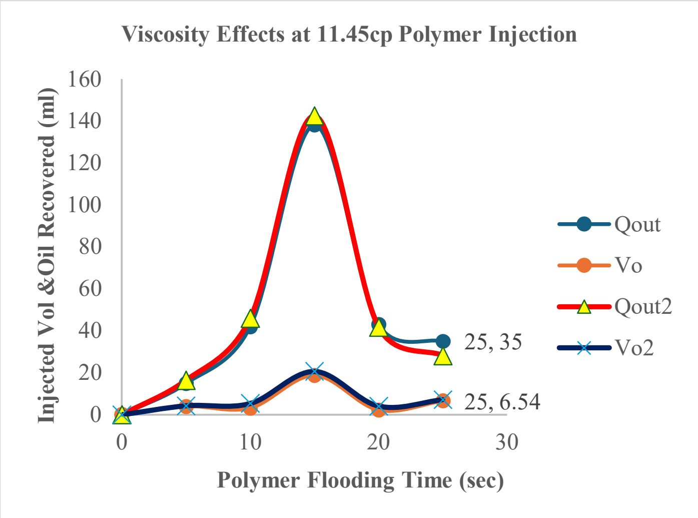

Figure 3: Viscosity Effects on Fluid Recovery for 11.45cp Local Polymer Flooding EOR System

These results conclusively demonstrate that both polymers are effective for oil recovery, with the commercial polymer exhibiting slightly higher efficiency while the marginal difference supports the viability of the locally produced cassava peel-based polymer for enhanced oil recovery applications.

3.2 EOR Flooding Assessment for 15.56 cp Viscous Local and Commercial Polymer Injection

Table 3: Sandstone reservoir flooding outputs over 15.56 cp local and commercial polymer fluids

As illustrated in Figure 3, maximum oil recovery again occurred within the first 15 seconds. The local polymer recovered 16.05 mL of oil, and the commercial polymer 17.67 mL during this period. Total oil recovery decreased to 29.18 mL for the local polymer and 36.72 mL for the commercial polymer, representing reductions of 16.3% and 11.6%, respectively, compared to the 11.45 cp experiment. The decline in recovery confirms the inverse relationship between injection viscosity and displacement efficiency. Higher viscosity reduced the mobility contrast between the injected polymer and the reservoir oil, weakening the fingering effect and lowering overall recovery.

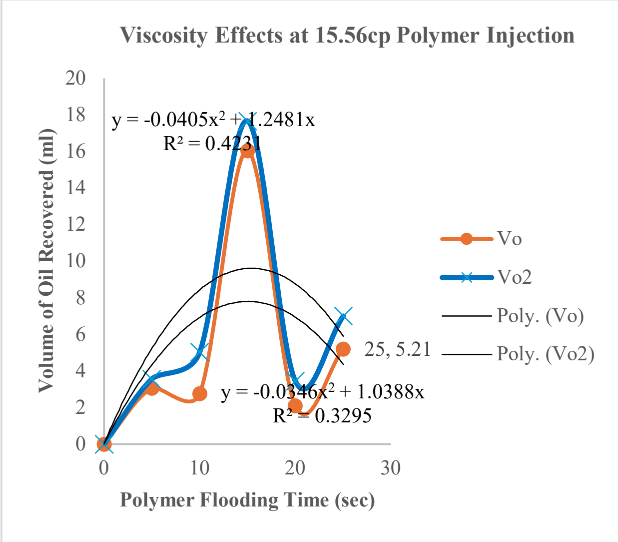

Figure 4: Viscosity Effects on Oil Recovery for 15.56cp Local Polymer Flooding EOR System

$$y_{L-15.56} = -0.0346x2 + 1.0388x \quad (3)$$

$$y_{F-15.56} = -0.0405x2 + 1.2481x \quad (4)$$

Reservoir performance models achieved from the EOR system over the injection of 15.54cp viscos local and commercial polymer as seen defined as equation (3) and equation (4) determined the fingering efficiency (FE) of 15.56cp viscos local polymer in a sandstone reservoir to be 46.05% (local) and 55.34% (commercial).The fingering instability index ratio ($R^2 = 0.3227$ local, 0.4167 commercial) again showed slightly better performance for the commercial polymer. ANOVA results in Table 4 confirmed a strong correlation between both polymer systems ($R^2 = 98.35\%$, $F = 237.968$), reinforcing the conclusion that the local cassava-peel polymer performs comparably to the commercial polymer.

Q_{in}=300ml // OOIP=40ml // μ_{LP}= 15.56cp						
F-Period	Qout	Vo	Vp	Qout2	Vo2	Vp2
0	0	0	0	0	0	0
5	18.96	3.06	15.9	17.62	3.56	14.06
10	47.94	2.76	45.18	39.85	5.03	34.82
15	105.1	16.05	89.05	112.08	17.67	94.41
20	33	2.1	30.9	34.78	3.45	31.33
25	25	5.21	19.79	26.33	7.01	19.32
Total	230	29.18	200.82	230.66	36.72	193.94

Table 4: ANOVA and Regression result of 15.56 cp viscus local and commercial polymer relationship

Statistic	Value
Multiple R	0.9917
R Square	0.983469
Adjusted R Square	0.979336
Standard Error	0.823838
Observations	6

Source	df	SS	MS	F	Significance F
Regression	1	161.511	161.511	237.968	0.000103
Residual	4	2.71484	0.67871		
Total	5	164.226			

	Intercept	TENNER Variable 1
Coefficients	-0.83162	0.930548
Standard Error	0.499407	0.055813
t Stat	-1.66521	15.42621
P-value	0.171201	0.000103
Lower 95%	-2.2182	0.763066
Upper 95%	0.554957	1.09803
Lower 95.0%	-2.2182	0.763066
Upper 95.0%	0.554957	1.09803

The overall fluid recovery assessment, shown in Figure 5, revealed total recoveries of 230 ml for the local polymer and 230.66 ml for the commercial polymer. Compared with the 11.45 cp experiment, total recovery decreased by 43 ml for the local polymer and 44.05 ml for the commercial polymer. These reductions, together with the similar recovery patterns observed, confirm that increasing polymer viscosity adversely affects reservoir recovery efficiency during flooding operations.

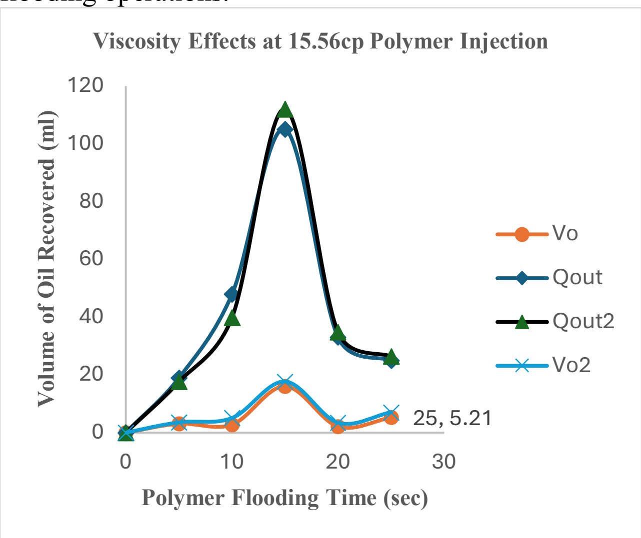

Figure 5: Viscosity Effects on Fluid Recovery for 15.56cp Local Polymer Flooding EOR System

3.3 EOR Flooding Assessment for 19.5 cp Viscous Local and Commercial Polymer Injection

The third flooding experiment evaluated the performance of 19.5 cp local and commercial polymers under the same reservoir conditions. The experimental data are presented in Table 5, showing the progressive decline in oil and polymer recovery as viscosity increased.

Q_{in}=300ml // OOIP=40ml // μ_{LP}= 19.5cp						
F-Period	Qout	Vo	Vp	Qout2	Vo2	Vp2
0	0	0	0	0	0	0
5	12.89	0.98	11.91	13.65	1.78	11.87
10	48.34	2.65	45.69	42.22	3.39	38.83
15	87.56	9.95	77.61	93.09	11.48	81.61
20	26.88	3.21	23.67	28.34	2.87	25.47
25	19.34	2.69	16.65	21.09	3.11	17.98
Total	195.01	19.48	175.53	198.39	22.63	175.76

Table 5: Sandstone reservoir flooding outputs over 15.56 cp local and commercial polymer fluids

As illustrated in Figure 5, both polymers continued to exhibit the characteristic fingering pattern observed at lower viscosities, but with noticeably reduced displacement strength. The local polymer recovered 19.48 mL of crude oil and 175.53 mL of polymer (195.01 mL total), while the commercial polymer recovered 22.63 mL of oil and 175.76 mL of polymer (198.39 mL total).

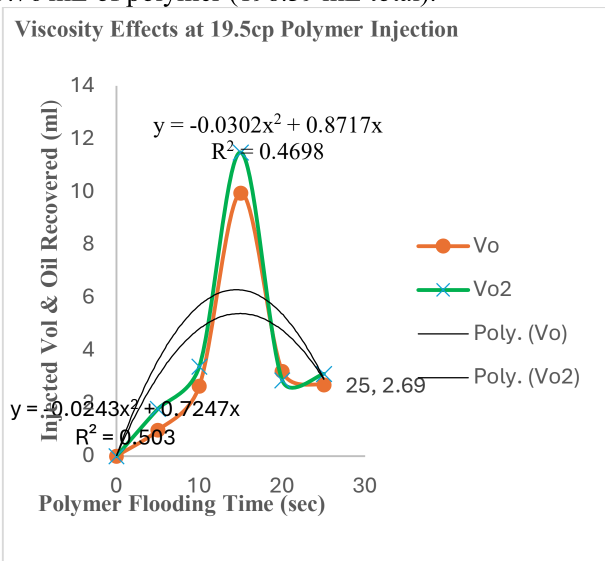

Figure 6: Viscosity Effects on Oil Recovery for 19.5cp Local Polymer Flooding EOR System

The decline in recovery confirms the inverse relationship between injection viscosity and recovery efficiency. As viscosity increases, the mobility contrast between the injected polymer and the reservoir oil decreases, weakening the fingering mechanism that drives displacement.

$$y_{L-19.5} = -0.0243x2 + 0.7247x \quad (5)$$

$$y_{F-19.5} = -0.0302x2 + 0.8717x \quad (6)$$

Reservoir performance models achieved from the EOR system over the injection of 19.5cp viscos local and commercial polymer as seen defined as equation (5) and equation (6) determined the fingering efficiency (FE) of 15.56cp viscos local polymer in a sandstone reservoir to be of 32.12% (local) and 38.61% (commercial). The fingering instability index ratio ($R^2 = 0.4775$ local, 0.4698 commercial) was slightly higher than those at lower viscosities, indicating a shift in flow behavior as the viscosity ratio between the injection fluid and reservoir oil narrows. ANOVA results in Table 6 showed a strong statistical relationship ($F = 264.0366$), confirming that both polymers maintained similar performance characteristics despite the reduced recovery.

Table 6: ANOVA and Regression result of 19.5cp viscus local and commercial polymer relationship

Q_{in}=300ml // OOIP=40ml // μ_{LP}= 23.45cp						
F-Period	Qout	Vo	Vp	Qout2	Vo2	Vp2
0	0	0	0	0	0	0
5	10.56	0.57	9.99	11.04	0.78	10.26
10	38.23	0.86	37.37	39.11	1.04	38.07
15	55.65	5.89	49.76	60.09	5.33	54.76
20	24.78	1.78	23	26	1.33	24.67
25	11.77	1.69	10.08	15.09	2.03	13.06
Total	140.99	10.79	130.2	151.33	10.51	140.82

Statistic	Value
Multiple R	0.99251
R Square	0.985077
Adjusted R Square	0.981346
Standard Error	0.47815
Observations	6

Source	df	SS	MS	F	Significance F
Regression	1	60.36602	60.36602	264.0366	8.39E-05
Residual	4	0.91451	0.228627		
Total	5	61.28053			

	Intercept	TENNER Variable 1
Coefficients	-0.05016	0.874104
Standard Error	0.281549	0.053794
t Stat	-0.17817	16.2492
P-value	0.867249	78.49E-05
Lower 95%	-0.83187	0.724749
Upper 95%	0.731541	1.023459
Lower 95.0%	-0.83187	0.724749
Upper 95.0%	0.731541	1.023459

The overall fluid recovery profile in Figure 7 further demonstrates the viscosity-dependent decline in mobility and displacement efficiency.

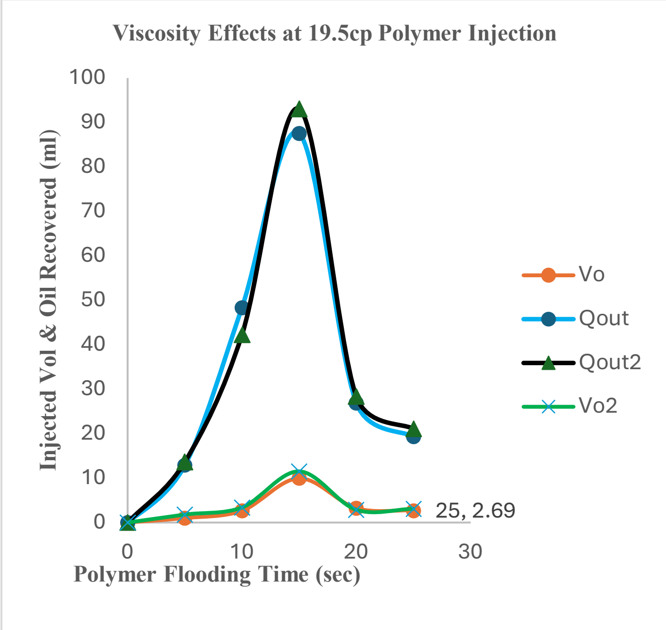

Figure 7:Viscosity Effects on Fluid Recovery for 19.5cp Local Polymer Flooding EOR System

3.4 EOR Flooding Assessment for 23.54 cp Viscous Local and Commercial Polymer Injection

The fourth experiment assessed polymer flooding performance at 23.54 cp, a viscosity approaching that of the reservoir oil (30.34 cp). The results, shown in Table 7, reveal a substantial drop in recovery efficiency.

Table 7: Sandstone reservoir flooding outputs over 23.45 cp local and commercial polymer fluids.

oil recovery decreased sharply to 10.79 mL for the local polymer and 10.51 mL for the commercial polymer. This represents reductions of 69% and 75%, respectively, compared to the 11.45 cp experiment. As shown in Figure 8, peak recovery still occurred within the first 15 seconds, but at significantly lower volumes.

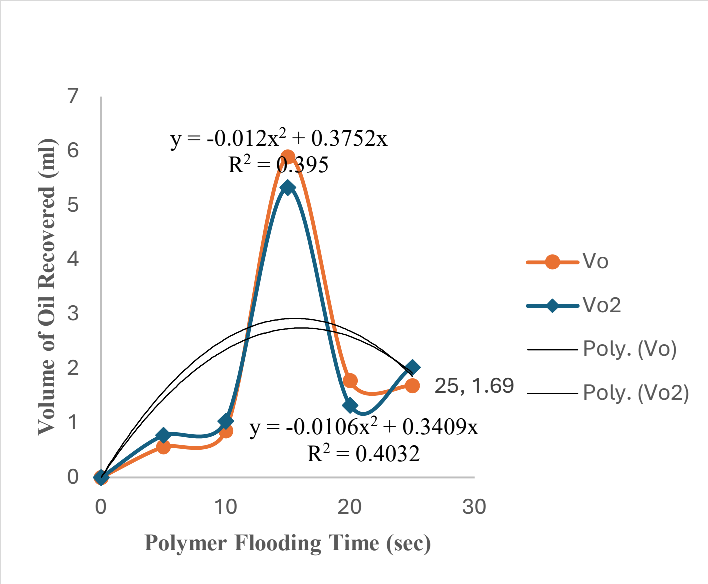

Figure 8: Viscosity Effects on Oil Recovery for 23.54cp Local Polymer Flooding EOR System

A notable observation at this viscosity level was a delayed fingering onset of approximately 8 seconds, attributed to the reduced viscosity contrast between the injection fluid and reservoir oil. This delay weakened the displacement front and reduced both oil and polymer recovery. Instability index values ($R^2 = 0.4032$ local, 0.395 commercial) were nearly identical, indicating similar flow behavior for both polymers at this viscosity. Performance models were:

$$y_{L\text{-}19.5} = -0.0106x2 + 0.3409x \quad (7)$$

$$y_{F\text{-}19.5} = -0.012x2 + 0.3752x \quad (8)$$

Fingering efficiencies dropped to 15.13% (local) and 16.65% (commercial), confirming the strong influence of viscosity on fingering strength. ANOVA results in Table 8 showed a significant relationship (F = 192.4262), reinforcing the similarity in performance between both polymers at this viscosity level.

Table 8: ANOVA and Regression result of 23.45 cp viscus local and commercial polymer fluids

Statistic	Value				
Multiple R	0.989766				
R Square	0.979636				
Adjusted R Square	0.974545				
Standard Error	0.337522				
Observations	6				
Source	df	SS	MS	F	SignificanceF
Regression	1	21.9214	21.9214	192.4262	0.000157
Residual	4	0.455684	0.113921		
Total	5	22.37708			
	Intercept	TENNER Variable 1			
Coefficients	-0.15777	1.116711			
Standard Error	0.197159	0.080502			
t Stat	-0.80023	13.87178			
P-value	0.468407	0.000157			
Lower 95%	-0.70517	0.893201			
Upper 95%	0.389628	1.340222			
Lower 95.0%	-0.70517	0.893201			
Upper 95.0%	0.389628	1.340222			

The overall fluid recovery profile in Figure 4.8 highlights the delayed fingering and reduced displacement efficiency.

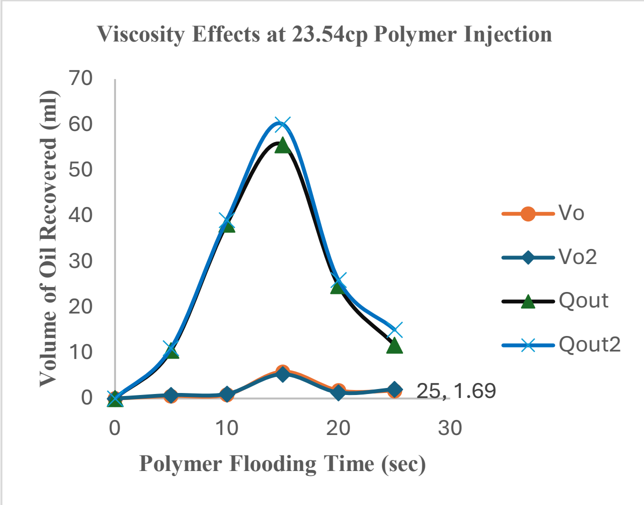

Figure 9: Viscosity Effects on Fluid Recovery for 23.54cp Local Polymer Flooding EOR System

4.0 Conclusion and Recommendation

This study examined the performance of a cassava-peel–derived polymer as a locally sourced and compares the alternative to commercial polymer for enhanced oil recovery in sandstone reservoirs. Core-flooding experiments conducted across four viscosity levels showed a clear inverse relationship between polymer viscosity and oil recovery efficiency. At the lowest viscosity (11.45 cp), both polymers achieved their highest displacement performance, with the local polymer recovering 34.85 mL of oil and the commercial polymer 41.54 mL. As viscosity increased toward the reservoir oil viscosity (30.34 cp), recovery declined sharply, accompanied by delayed fingering onset and reduced mobility contrast. Fingering-efficiency trends and early-time recovery behavior aligned with Saffman–Taylor Instability, confirming that favorable mobility ratios dominate effective displacement. ANOVA results ($R^2 > 97\%$) further demonstrated that the cassava-peel polymer performs comparably to the commercial polymer under controlled laboratory conditions. Overall, the findings indicate that cassava-peel polymer is a technically viable, cost-effective, and environmentally sustainable

EOR agent, particularly within the 11.45–15.56 cp viscosity range. Its strong performance correlation with commercial polymer highlights its potential for deployment in regions where synthetic polymers are costly or difficult to obtain.

Based on these results, field applications should prioritize injection viscosities below 20 cp to maintain favorable mobility ratios. Standardized production and quality-control protocols are needed to ensure consistent polymer properties, and pilot-scale testing in sandstone reservoirs with similar characteristics is recommended to validate injectivity and sweep efficiency. Further research should investigate polymer behavior under reservoir temperature and pressure, long-term stability, adsorption characteristics, and potential synergy with surfactant or alkaline flooding. Developing local production capacity for cassava-peel polymer would support Nigeria's EOR supply chain while advancing circular-economy and sustainability goals.

controlled laboratory experiments, that locally sourced Niger Delta clays (Oboburu, Egamini, and Afam) can be processed into nanoparticles capable of enhancing the petrophysical properties of heavy crude oil. The study establishes measurable impacts of clay nanoparticle oxides on crude oil viscosity, density, and API gravity, confirming their potential to improve oil mobility and recovery efficiency.

Furthermore, this work closes an existing knowledge gap by providing experimental evidence that clay despite already existing in reservoir formations can function effectively as an enhanced oil recovery (EOR) agent when processed to nanoscale dimensions. The findings offer a cost-effective and locally available alternative to conventional EOR additives and lay a scientific foundation for scaling laboratory results into field-level petroleum recovery applications.

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