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Oil Recovery through Spontaneous Imbibition in Niger Delta Reservoirs

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***Abstract*— Spontaneous imbibition is of crucial importance to oil recovery from reservoirs. Spontaneous imbibition involves the displacement of the non-wetting fluid by the wetting fluid in a porous medium by capillary forces. The measurements of volume of liquid imbibed versus time are usually used to predict oil recovery**

This paper presents experimental data for cocurrent spontaneous imbibition into cores with different porosity and permeability. Experiments were performed using Niger Delta sandstone core samples. Core samples were initially saturated with brine. Two types of Synthetic reservoir brine were used as the wetting phase: A high salinity and a low salinity brine. Crude oil samples of different viscosities were then injected into the core samples. Oil recovery from the low salinity brine was about 30% higher than that of high salinity brine.

The Correlation of the experimental data for imbibition of brine into porous media was achieved through a semi-empirical scaling group and an analytical scaling group which include permeability, porosity, interfacial tension (IFT), viscosity of oil and brine, the size, shape and boundary conditions of the rock sample. The semi-empirical model could not scale the entire experimental data obtained at different interfacial tensions and permeabilities rather it could only scale the experimental data at a particular IFT and permeability. The analytical scaling group gave a satisfactory correlation of the experimental data at different IFT and permeability.

***Index Terms*— Spontaneous Imbibition, Low salinity, Oil Recovery, Relative Permeability, Displacement**

I. INTRODUCTION

The recovery of oil from reservoirs which are subjected to waterflooding or increase in the water/oil contact is governed by spontaneous imbibition phenomena (Cuiec *et al*., 1994). Water flooding can be an efficient method in many reservoirs, since it provides pressure support and oil displacement. However, the efficiency is dependent on the ability of the water front to access all parts of the reservoir and displace the oil uniformly towards the producing wells. The injected water will typically be more mobile than the oil and concentrate into a path with least resistance, where the pressure loss is very small. In a uniform reservoir this path will be a straight line between injector and producer, while heterogeneities will move the path towards areas with higher permeability (Andersen *et al*., (2013). The water-flooding performance works well with the water-wet condition, and imbibition can lead to significant recoveries, while poor recoveries and early water breakthrough occur with oil-wet condition. Imbibition is defined as displacement of the nonwetting phase (oil) by the wetting phase (water) with dominant effect of the capillary force in porous media (El-Amin and Sun, 2011). Imbibition can occur in both countercurrent and cocurrent flow modes, depending on the fracture network and the water injection rates. In cocurrent imbibition, water pushes oil out of the matrix thus, both water and oil flows are in the same direction. Countercurrent imbibition is whereby a wetting phase imbibes into a porous matrix rock, displacing the nonwetting phase out from one open boundary (El-Amin and Sun, 2011; Makhanov, 2013; Kerunwa *et al*., 2016). Cocurrent imbibition is faster ((Pooladi- Darvish and Firoozabadi, 2000; Unsal *et al*., 2006; Karimaie *et al*., 2006) and more efficient than countercurrent imbibition. Countercurrent imbibition is often the only possible displacement mechanism for cases where a region of the matrix is completely surrounded by water (Bourblaux and Kalaydjian, 1990; Pooladi-Darvish and Firoozabadi, 2000; Tang and Firoozabadi, 2001). Cocurrent spontaneous imbibition has been studied by many authors as a mechanism for oil production (Zhang *et al*., 1996; Ma *et al.,* 1997; Hamida and Babadagli, 2007; Hatiboglu and Babadagli 2010; Mason *et al*., 2010; Haugen *et al*., 2014).

In this work, we studied the behavior of core samples from three reservoirs in the Niger Delta of Nigeria when subjected to cocurrent spontaneous imbibition.

II. Scaling of Spontaneous Imbibition data

Empirical scaling laws have been proposed, to estimate the rates of oil recovery from matrix blocks of various sizes and shapes obtained from laboratory core samples (Zhang *et al.*, 1996; Ma *et al.*, 1997; Zhou *et al.*, 2002; Rezaveisi *et al.,* 2012). Mattax and Kyte (1962) and Rezaveisi *et al.,* 2012 posited that oil recovery for systems whose size, shape and fluid properties differ was a function of dimensionless time. Kazemi *et al.* (1992) proposed a shape factor that included the effect of size, shape, and boundary conditions of the matrix. Ma *et al.* (1997) and Zhang *et al.* (1996) modified the Mattax and Kyte (1962) derived expression to incorporate the effect of the nonwetting phase viscosity and boundary conditions. The applicability of these scaling models to imbibition data from unconsolidated porous media was investigated by Rezaveisi *et al.,* 2012

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The extent and rate spontaneous imbibition provides a measure of wettability which is totally dependent on surface energy. However, imbibition mechanism is very complex and many factors apart from wettability affect the rate of spontaneous imbibition and displacement efficiency (Xie and Morrow, 2010). The Ma *et al*.,(1997), semi-empirical scaling group for oil recovery from very strongly water-wet (VSWW) media is given as:

$$t_D = k\sqrt{\frac{K}{\phi}}\frac{\sigma}{\sqrt{\mu_w \mu_{nw}}}\frac{1}{L_c^2}$$

1

where where t_D is the dimensionless time, t is the imbibition time, k is the permeability of the rock, ϕ is the porosity of the rock,and $\sqrt{K/\phi}$ is proportional to microscopic pore space, σ is the interfacial tension existing between the oil and brine, $\sqrt{\mu_w \mu_{nw}}$ is the geometric mean of the viscosity of the wetting and nonwetting phase, L_c is the characteristic length that compensate for shape, sample size and boundary conditions

The above scaling correlation has been shown to correlate imbibition data with difference in porosity, permeability, boundary conditions, and liquid viscosity ratios efficiency (Xie and Morrow, 2010). This scaling group was developed and tested for oil recovery during counter-current spontaneous water imbibition in strongly water-wet media. The applicability of this correlation to porous sediments, other than those for which it was derived, depends on the representation of pore structure parameter $\sqrt{K/\phi}$ (Rezaveisi *et al.,* 2012).

The Li and Horne (2002) scaling model was also applied in this study to correlate the entire core samples (S1, S2 and S3) at different IFT and permeability. The dimensionless time defined by Li and Horne is given as:

$$t_D = \frac{KK_{re}^* P_c^* (S_{wf} - S_{wi})}{\phi \mu_e L_a^2} t$$

2

III. Core Material

Three rock samples collected from oil reservoir located in the Niger Delta depositional belt were used: Each sample from Northern Delta, greater Ughell and central swamp 1. These were among the seven fields that up make the Niger Delta belt. The rocks were homogeneous sandstone.

IV. Fluids

Two crude oil samples ('A' and 'B') from the Niger Delta with viscosities of 11.1012cp and 6.1212 measured using the cannon viscosimeter were used as the non wetting phase while the wetting phase was brine. The crude oils were filtered and vacuumed before use. The brine has a total dissolved solids (TDS) of 33,710 parts per million (ppm) with composition as shown in Table 1. The brine viscosity was also measured using cannon viscosimeter as 0.912cp. NaN3 was added to the brine to prevent bacterial growth. The interfacial tension (IFT) that exists between the brine and the crude oil samples were measured using fisher tensiometer as 24 dyne/cm and 20 dyne/cm respectively. A low salinity brine (1,698ppm) was produced from the first brine with composition shown in table 1 which was 20 times diluted. The interfacial tensions (IFT) that exists between the low salinity brine and the crude oil samples were measured as 14 dyne/cm and 10 dyne/cm respectively.

Table 1: Brine Composition (g/l)

Salt	**Composition (g/l)**
NaCl	27.66
KCl	0.87
$MgCl_2$	5.18
TDS	33.71

V. Experiment

Core samples of length 6.35cm and diameter 3.81 were used for the experiment. The dimensions represent the conventional laboratory scale in this study. Each core sample was 100% saturated of brine. We then, injected crude oil into each core sample at a constant rate of 3cc/sec. The samples were immersed in an imbibition tube filled with brine and exposed to co-current spontaneous imbibition with two-ends open (TEO) to imbibition. The cylindrical surface of the core samples were coated with epoxy resin to create the TEO boundary geometry. The volume of brine imbibed into the core plug was monitored against time until the imbibition had stabilized or the imbibition rate was extremely slow. The brine volume imbibed into the core plug against time is the oil recovery rate by spontaneous imbibition. At the end of the experiment each core sample was removed and measured to determine its weight. In this experiment, we recorded the oil recovery by co-current spontaneous imbibition in terms of fraction of the oil volume originally in place in the core sample. At the end of the experiment for the two crude samples, the experiment was repeated using the low salinity brine.

Table 2: Petrophysical parameters of the Niger Delta core samples used for the experiment

Core Sample	**Air Perm (md)**	**Liq. Perm (md)**	**Porosity**
1	2219	1177	0.2966
2	2106	1036	0.2803
3	2142	1082	0.2937

VI. Results and Discussion

Figs. 1-4 depict the experimental results of oil recovery (% OOIP) versus the imbibition time at different interfacial tension (IFT). Core samples (S1-S3) that produced oil (% OOIP) was separately collected from each open end face and recorded against time (minutes)**.** Production differs in various degree of asymmetry from rock sample to rock sample. The total production rate from the two end faces was not separately correlated to the degree of asymmetry observed during the measurement of production from each open end face as shown in Table 3. As can be seen from table 3, there was no symmetrical production from the three core sample during imbibition in both high and low salinity brine. In the TEO experiments (with vertical orientation, Fig. 4), the imbibition front was established from the top end face of the core, though the difference in density between brine and oil seriously opposed imbibition. The oil production ratios from the two end faces in the TEO experiments were as stated in Table 3. For example: Core sample 1 (S1) gave 76% at the top end and 24% at the bottom end for imbibition of high salinity brine while for low salinity brine, we had 88% at the top end and 12% at the bottom end.

Core samples 1 with higher permeabilities gave higher recoveries of crude sample 'A" at lower IFT than those with lower permeabilities (2 and 3). For low salinity brine, the recovery at low IFT was quite high. Core sample 1 (S1) gave an oil recovery of 73%, oil originally in place (OOIP), sample 2 gave 67%OOIP while sample 3 gave 63%OOIP for crude sample A (Fig. 3). Oil recovery by imbibition of low salinity brine produced on the average, about 30% OOIP more than the imbibition of high salinity brine (Figs. 1 – 4 and Table 3). The same trend was also observed at both high and low IFT for crude sample 'B'. Crude sample B yielded higher recoveries because the IFT was lower than those of crude sample A. Spontaneous imbibition of brine generally yielded higher oil production at lower IFT. This is because higher IFT brine imbibed very slowly than that of lower IFT. Li, (2011) posited that the underlying mechanism of high oil recovery with low salinity water imbibition is the mobilization of discontinuous oil, which takes place under a negative pressure gradient, higher than that of brine imbibition at the same flow velocity, due to water permeability reduction caused by blockage of the porous network by migrating clay crystals and particles or swelling clay aggregates.

VII. Scaling of the Spontaneous brine Imbibition Experiment

In this study, the scaling correlation of Ma *et al.* (1997) given by Equation 1 was used to scale
imbibition oil recovery data from the TEO experiment. Figures 5-8 show the scaling results obtained for the spontaneous water imbibition data at different interfacial tension. It is expected that all the experimental data points obtained at different interfacial tension should sit close to a single curve. From figures 5 – 8, for both high and low salinity brine, all the data points sit close to a single curve, but when the eqn. 1 was used to correlate the entire core samples (S1, S2 and S3) at the three different IFT and permeability, the data points could not sit close to a single curve. Figure 9 demonstrate that the experimental data points scatter significantly. This shows that the Ma *et al*., (1997) model failed to scale the experimental data obtained at the three different IFT and permeabilities. The model could only scale the experimental data individually at a particular IFT and permeability (figs. 5-8). Li and Horne, (2002) pointed out that the Ma *et al.*, (1997) model failed to scale the experimental data obtained at the three different IFT and permeabilities because of the following reasons:

A. decrease in IFT from 24dyne/cm to 20dyne/cm could result in significant increase in relative permeability of the oil and water. Ma et al., (1997) could not take into account the effect of relative permeability in the derivation of their model
B. Again, gravity could also be a key factor because of significant decrease in capillary pressure caused by lowering the IFT further. Thus gravity was not accounted for in the Ma *et al*., (1997) scaling law (Eqn. 1).

The Li and Horne (2002) scaling group was then used in this study to correlate the experiment data of the entire core samples (S1, S2 and S3) at the three different IFT and permeabilities. The data points sit close to a single curve. From figure 10, the experimental data points could not scatter.

Table 3: Ratio of oil production from each open end face during asymmetric oil recovery

	High Salinity Brine			Low Salinity Brine		
Core Sample Total	S1	S2	S3	S1	S2	S3
[%OOIP]	0.45 .	0.43	0.38.	0.84 .	0.78	0.73.
Low Prod [%]	24%	29%	35%	12	18	20
High prod [%]	76%	71%	65%	88	82	80

Figure 4: Experimental setup for imbibition occurring spontaneously in a system of oil/brine/reservoir rock

Conclusions

The following conclusions are drawn from this study:

1. The oil recovery was higher in the low salinity brine than in the high salinity brine.
2. In the two-end open experiment, oil production was asymmetrical, no symmetrical productionwas observed
3. The analytical scaling group gave a satisfactory correlation for all the cases tested at different interfacial tensions while the semi-empirical model could not satisfactorily scale theexperimental data at different interfacial tensions

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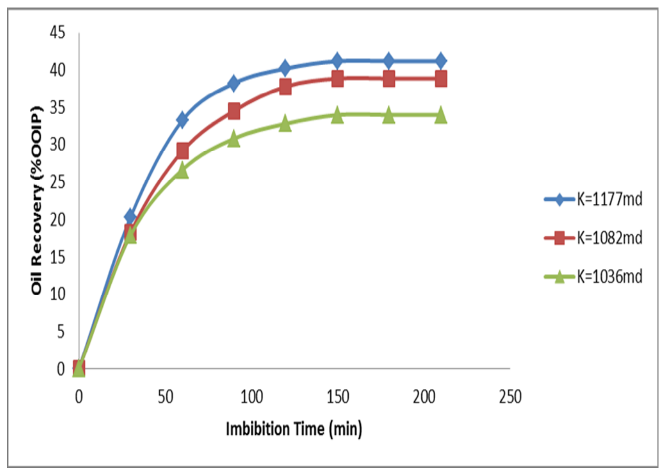

Fig. 1: Relationship between oil recovery and imbibition time for Niger Delta Core at IFT = 24dyne/cm.

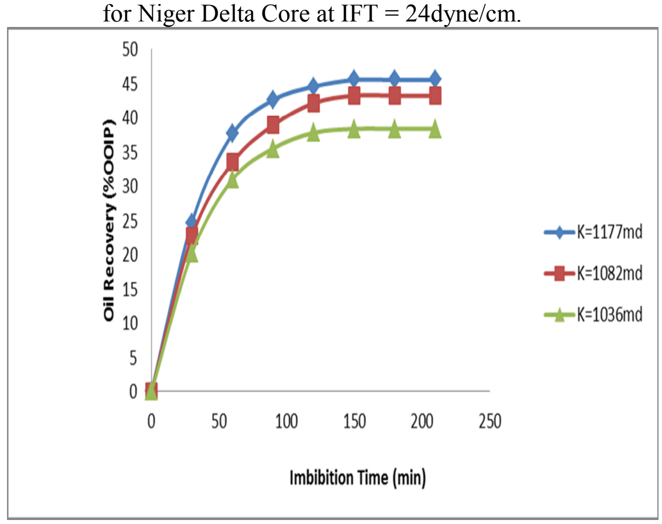

Fig. 2: Relationship between oil recovery and imbibition time for Niger Delta at IFT = 20dyne/cm

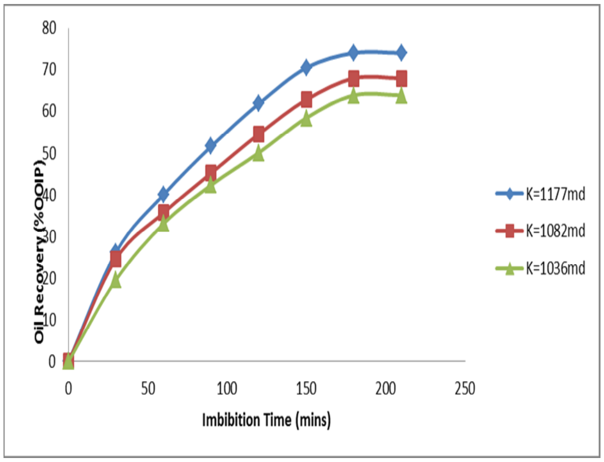

Fig. 3: Relationship between oil recovery and the square root of imbibition time for Niger Delta at IFT = 14dyne/cm

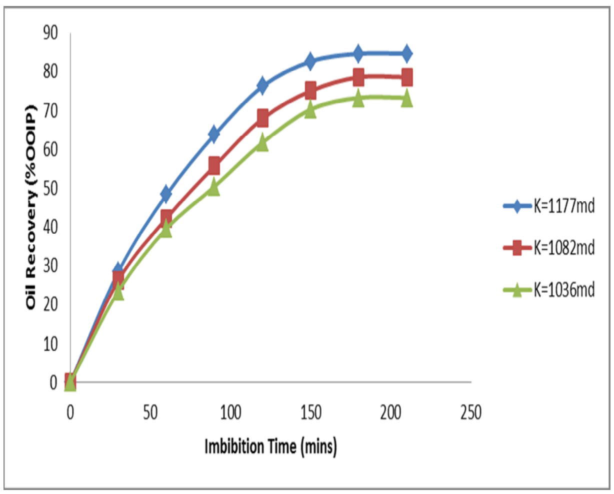

Fig. 4: Relationship between oil recovery and the square root of imbibition time for Niger Delta at IFT = 10dyne/cm

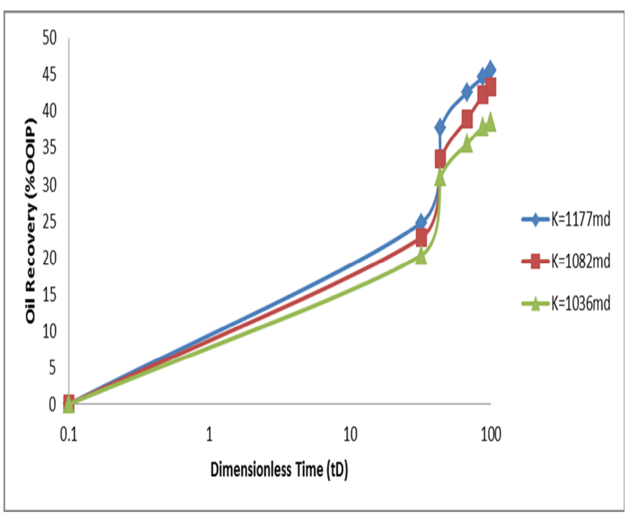

Fig. 5: Relationship between oil recovery and Dimensionless time (Ma *et al.*, 1997) for Niger Delta rocks at IFT = 24dyne/cm

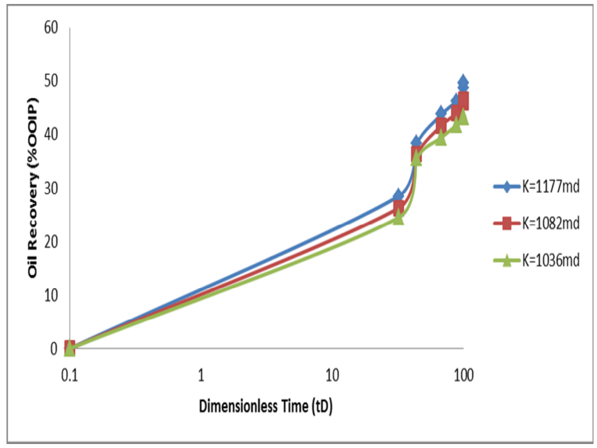

Fig. 6: Relationship between oil recovery and Dimensionless time (Ma *et al.*, 1997) for Niger Delta rocks at IFT = 20dyne/cm

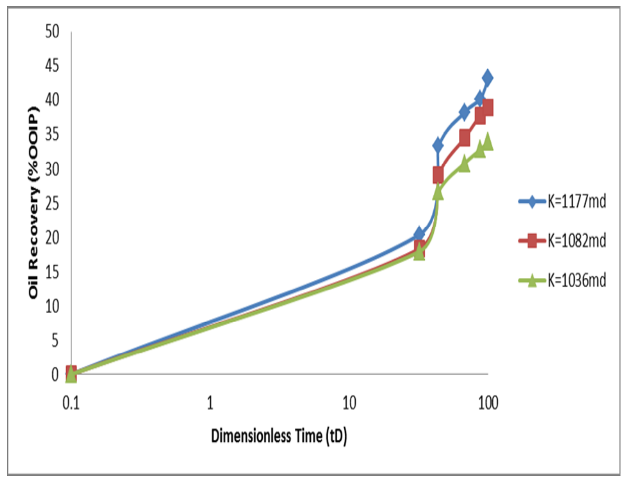

Fig. 7: Relationship between oil recovery and Dimensionless time (Ma *et al.*, 1997) for Niger Delta rocks at IFT = 14yne/cm

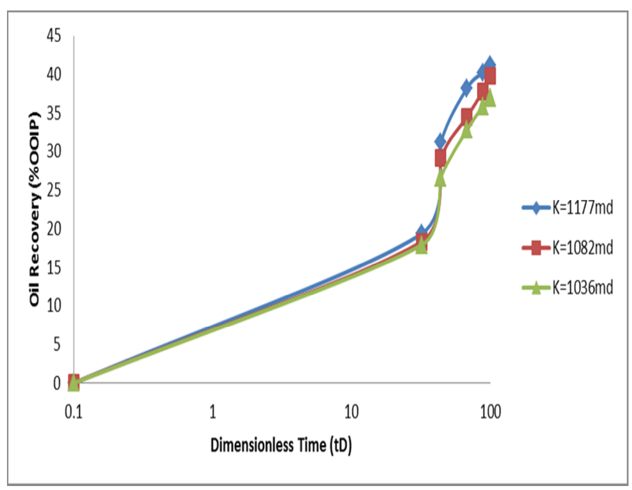

Fig. 8: Relationship between oil recovery and Dimensionless time (Ma *et al.*, 1997) for Niger Delta at IFT = 10dyne/cm

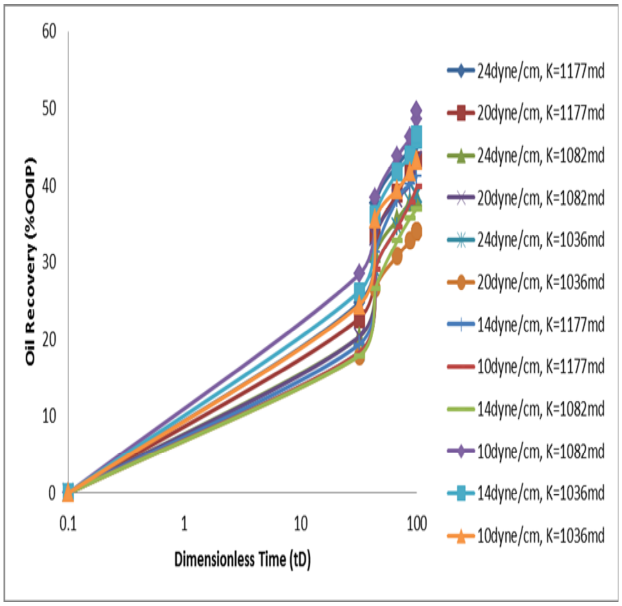

Fig. 9: Scaling Result with the Ma *et al*., (1997) Dimensionless time for different Niger Delta Rocks at different interfacial Tensions (IFT)

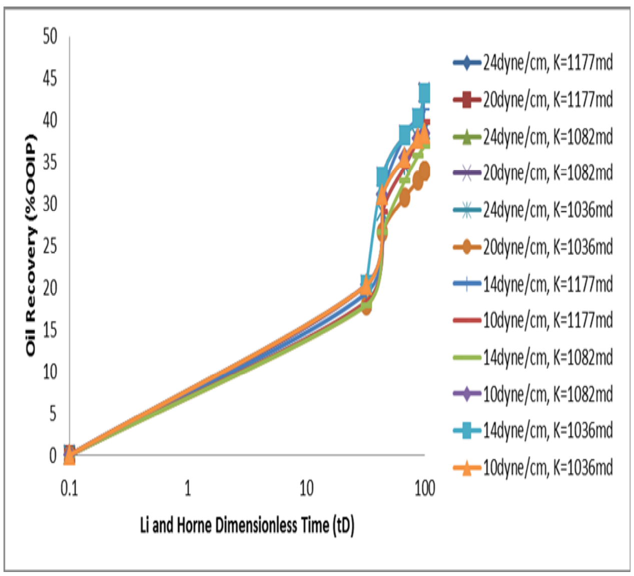

Fig. 10: Scaling Result with the Li and Horne (2002) Dimensionless time for different Niger Delta Rocks at different interfacial Tensions (IFT)