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Hydrocarbon Potential of Some Afowo Shale Deposits in Part of South Western Nigeria

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Abstract
Six (6) core samples were collected at different depths from a borehole at a locality in part of Southwestern Nigeria at depth range of 92 – 112fts, 151 – 161fts, 210 – 220ft, 240 – 250ft, 250 – 260ft, 300 – 310ft. respectively and were subjected to Total Organic Content (TOC). Three samples with high TOC were equally subjected to Rock Eval Pyrolysis to evaluate the petroleum generative potential, organic richness, organic matter quality, origin of organic matter and thermal maturity of the rock.

The Rock-Eval Pyrolysis result showed total organic carbon content range of between 2.12 and 2.94wt% indicating organic –rich rock; hydrogen index (HI) ranged from 15 – 43 indicating increasing hydrocarbon potential with depth ; oxygen Index (OI) ranged from 121 – 177; Productive Index (PI) ranged from 0.19 – 0.26 with increase in depth and at depth 151-161ft it decreases indicating immature rock. $S_1 + S_2$ ranged from 0.59 - 1.37 indicating good hydrocarbon potential and Tmax range from 343^0C to 427^0C indicating thermal immaturity of the samples.

Hydrocarbon generative potential of the rock can be said to be poor. HI Vs OI plot indicates organic matter that belongs to Kerogen Type III and Type IV, which indicate gas prone source rock. The organic matter from the plots can also be deduced to be of terrestrial origin.

Key words- Hydrocarbon, Vitrinite, Kerogen, Shale and Rock-Eval-Pyrolysis.

1. Introduction.

The petroleum potential and source rock evaluation are basic problems to be solved in petroleum exploration. The increase in the demand of petroleum products has led to an increase in petroleum exploration in the world.

The surface area of Nigeria is 932,768km and it is covered in nearly equal proportions by crystalline and sedimentary rocks. In Nigeria, petroleum exploration has reached an advance level such that other basins are being explored apart from the conventional Niger Delta. One of these basins is the Dahomey basin which is an extensive sedimentary basin on the convential margin of the Gulf of Guinea extending from South-Eastern Ghana in the West to the Western flank of the Niger Delta (Omatsola & Adegoke, 1981). The eastern part of the basin falls within the Nigeria sector, with an overall thickness of 3000m, varying in thickness towards the offshore.

Several studies have been carried out on the Dahomey basin. The Eastern Dahomey basin has proved to be of great geological interest, particularly in the exploration for oil and gas. Generally, bitumen deposits occur in Southwestern Nigeria along a 5-8km wide belt that extends over 120km from Lagos to Ogun, Ondo and Edo States within the eastern margin of Dahomey (Benin) basin. Evaluation of the technical, economical and commercial feasibility studies on the exploration, development, transportation and refinement of tar sands in collaboration with Conoco Energy of the U.S.A. has been carried out.

Arising mainly from recent policies of the Nigeria authorities to encourage active exploration for hydrocarbons, there has been an upsurge of interest in the oil sands and heavy oil deposits availability of the conventional oil in the neighboring prolific Niger Delta. Its important to note that conventional hydrocarbons in commercial quantities have been found offshore in Republic of Benin (Billman, 1992).

The petroleum habitat is almost exclusively the Afowo Formation, a member of the Abeokuta Group of Omatsola and Adegoke (1981). This lithounit is of Turonian-Maastrichtian age and consists of interbeds of coarse-medium grained sandstones, siltstones and shale deposited in a transitional to marginal marine environment. The oil is found in the coarse-grained clastics with the formation in two discrete bands, each 30-40m thick and separated by 6-15m of carbonaceous shales. Origin of the Nigeria tar sands has been subject of controversy for quite some times, however attention has not been given to the source rock with the Dahomey basin, hence the need for this present project work which is aimed at determining the organic richness of the Afowo Formation.

2. Geology/ stratigraphy of the Dahomey Basin.

The study area falls within longitude 004 36 981 E and latitude 06 35 305N with an elevation of 139ft within the eastern Dahomey basin of southwestern Nigeria, Figure 1.

The Benin (Dahomey) Basin constitute part of a system of West African peri-cratonic (margin sag) basin (Klemme 1975; Kingston et al 1983) developed during the commencement of the rifting, associated with the opening of the Gulf of Guinea, in the Early Cretaceous to the Late Jurassic (Burke et al, 1971;Whiteman, 1982). The crustal separation, typically preceded by crustal thinning, was accompanied by an extended period of thermally induced basin subsidence through the Middle – Upper Cretaceous to Tertiary times as the South American and the African plates entered a drift phase to accommodate the emerging Atlantic Ocean (Storey, 1995; Mpanda, 1997).

The Ghana Ridge, presumably and offset extension of the Romanche Fracture Zone, binds the basin to the west while the Benin Hinge Line, a Basement escarpment which separates the Okitipupa Structure from the Niger Delta basin binds it to the east. The Benin Hinge Line supposedly defines the continental extension of the Chain Fracture Zone, Figure 2.0.

The onshore part of the basin covers a broad arc-shaped profile of about 600 km 2 in extent. The onshore section of the basin attains a maximum width, along its N-S axis, some 130 km around the Nigerian – Republic of Benin border. The basin narrows to about 50 km on the eastern side where the basement assumes a convex upwards outline with concomitant thinning of sediments. Along the northeastern fringe of the basin where it rims the Okitipupa high is a brand of tar (oil) sands and bitumen seepages (Nwachukwu and Ekweozor, 1989).

The lithostratigraphic units of the Cretaceous to Tertiary sedimentary sequence of eastern margin of Dahomey basin according to Idowu et al.,(1993), are summarized in Table 1.

Fig. 1: Location map of the study area.

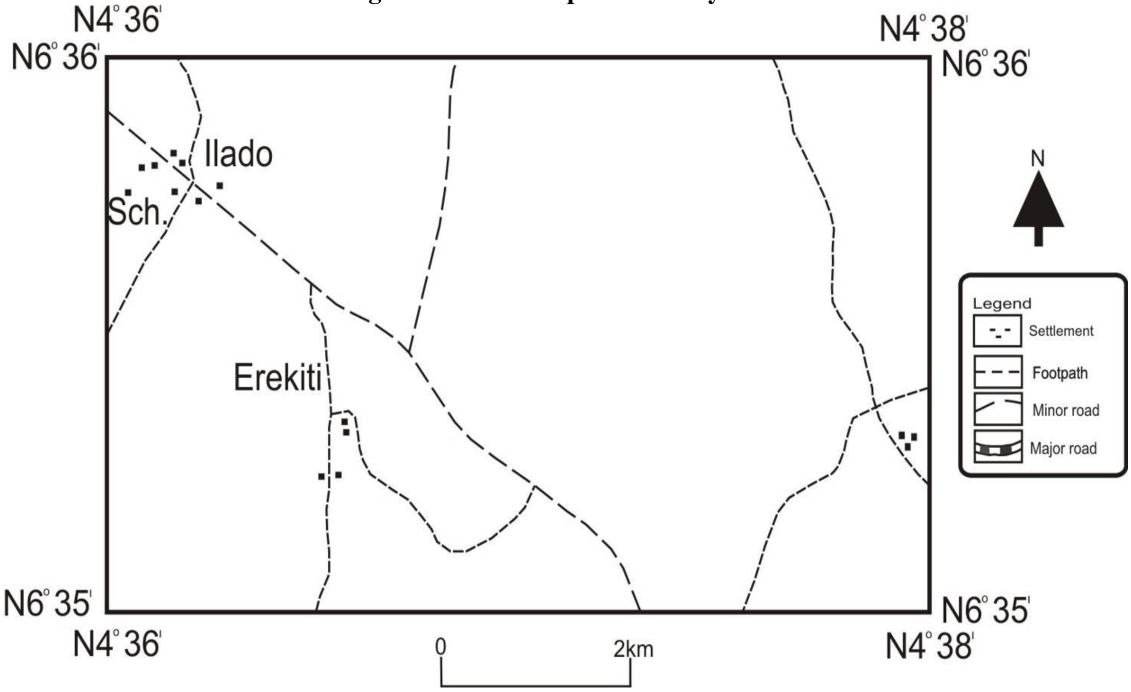

Table 1: Regional Stratigraphic Setting of the Eastern Dahomey Basin (After Idowu et al., 1993)

Age		Formation			Lithology
		Ako et al., 1980	Omatsola and Adegoke, 1981		
Tertiary	Eocene	Ilaro Formation	Ilaro Formation		Sandstone
	Paleocene	Oshosun Formation	Oshosun Formation		Shale
		Ewekoro Formation	Ewekoro Formation		Limestone
Cretaceous	Maastrichtian		Abeokuta Group	Araromi Formation	Shale.
	Turonian			Afowo Formation	Sandstone/ shale.
	Berremian			Ise Formation	Sandstone.

3. Methods of study.

Six (6) Core samples were collected from borehole **A**, in Southwestern Nigeria at depth range of 92 – 112 feet, 151 – 161 feet, 210 – 220 feet, 240 – 250feet, 250 – 260 feet, 300 – 330 feet respectively. The prepared samples were subsequently investigated for source rock properties by state- of – the –art techniques involving ROCK EVAL pyrolysis and some other measurements.

4. Result and Discussion.

Nwachukwu and Adedayo (1987), as well as Ekweozor and Nwachukwu (1989) have discussed the source-rock potential of interbedded shales in the tar sands sequence. Further analytical results on these shales from additional borehole A are shown in Table 2.

Total Organic Carbon (TOC):

The total organic carbon ranges from 2.12 to 2.94 wt% in the samples indicating that they have adequate organic matter for source rocks. The dark shale present within depth range of 92 – 112ft has the highest TOC wt% which is 2.94% while the lowest TOC of 2.12% is found in the dark shale also taken from depth range of 210-220ft.

Rock-Eval Pyrolysis

T_{max} from Rock-Eval pyrolysis (Table 2) ranges from 343-426°C indicating immature conditions of the shales. Rock-Eval pyrolysis data (Table 2) indicate poor hydrocarbon generating potential in most samples (S2= 0.46-1.33 mg/g). The Hydrogen Index values for the samples are also low in the range of 15-43 and characterize hydrogen deficient organic matter (type IV?).

Result equally shows that all the samples analysed contain Type lll Kerogen which is, vitrinite in nature. The samples are most likely to be land or terrestrial derived because of the organic matter type, Figure 2.

Hydrogen Jndex (HI) Vs. Tmax plot in Figure 3 indicates immature to marginally mature rock.

Table 2: Total Organic Carbon and Rock Eval pyrolysis result for selected core cuttings from borehole A.

Top depth (ft)	Bottom Depth (ft)	Median Depth (ft)	Description of sample	TOC	S1	S2	S3	Tmax (°C)	HI	OI	S2/S3	S1/TOC	PI
92	112	102	Dark grey shale	2.94	0.11	0.46	1.99	371	28	121	0.2	0.04	0.19
151	161	156	Dark grey shale	2.82	0.04	1.33	0.32	426	43	10	4.2	0.01	0.03
210	220	215	Dark grey shale	2.12	-	-	-	-	-	-	-	-	-
240	250	245	Dark grey shale	2.19	-	-	-	-	-	-	-	-	-
250	260	255	Dark grey shale	2.84	0.21	0.58	6.69	343	15	177	0.1	0.07	0.26
300	310	305	Dark grey shale	2.68	-	-	-	-	-	-	-	-	-

Tmax data not reliable due to poor S2 peak
TOC = weight percent organic carbon in rock
S1, S2 = mg hydrocarbon per gram of rock
S3 = mg carbon dioxide per gram of rock
Tmax = °C

HI = hydrogen Index = S2 x 100/TOC
OI = Oxgyen index = S3 x 100/TOC
S1/TOC = Normalised oil content = S1 x 100/TOC
PI = Production Index = S1/(S1 + S2)

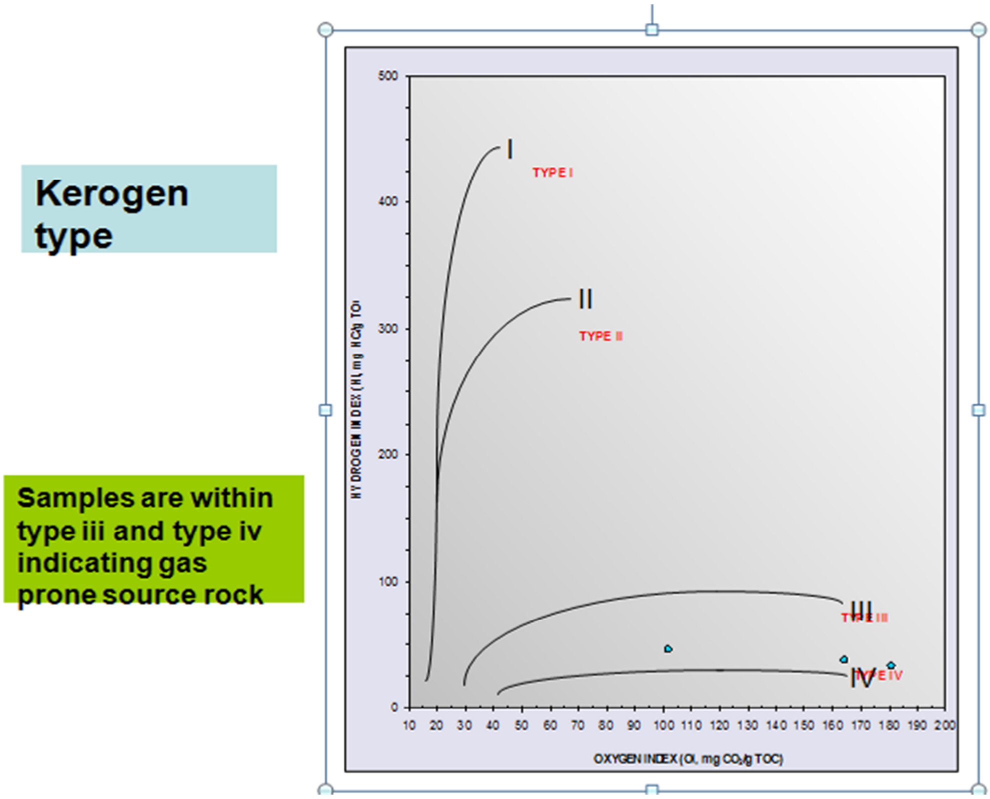

Fig. 2: plot of hydrogen index against Oxygen index (van krevelen plot)

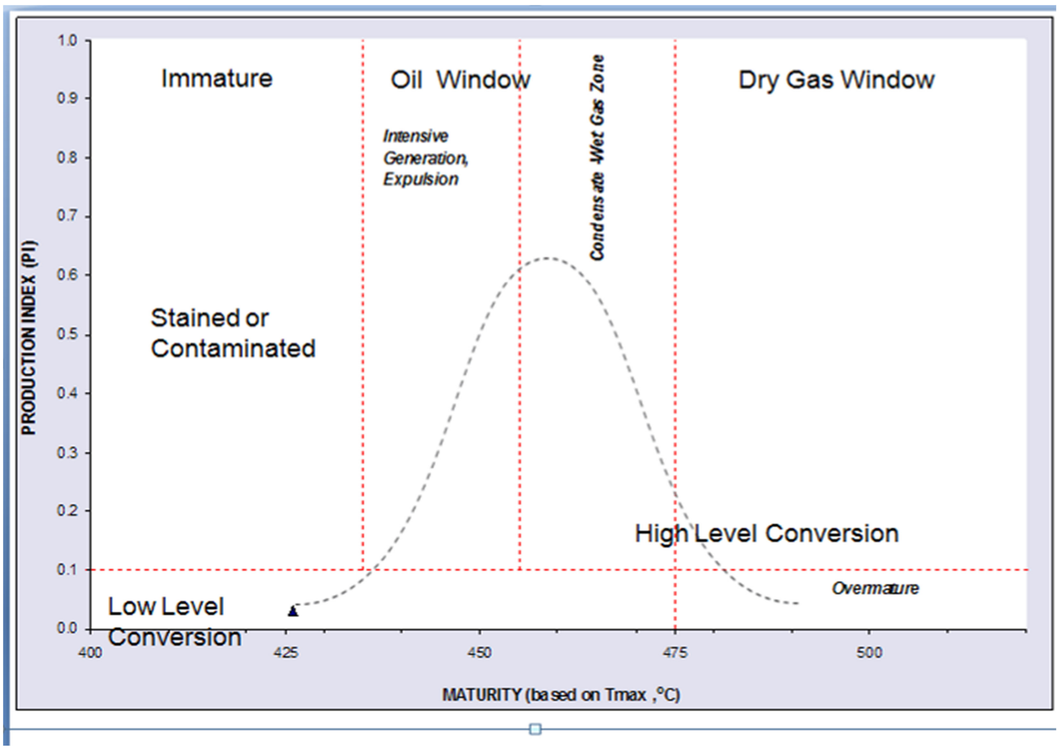

Fig. 3: Plot of production index against maturity (Tmax)

Figures 4, 5, 6, and 7 are logs showing the relationship between depth and TOC, depth and oil potential (S2), depth and hydrogen index, depth and normalised oil content.

Hydrocarbon Potential

The genetic or hydrocarbon potential (S1+ S2) of all samples analyzed falls within the range of 0.57 to

0.79mgHC/g rock indicating poor potential for generating commercial amounts of hydrocarbon.
Figures 4, 5, 6, and 7 show that organic richness and hydrocarbon potential of the shale samples increases with depth but the samples are gas prone.

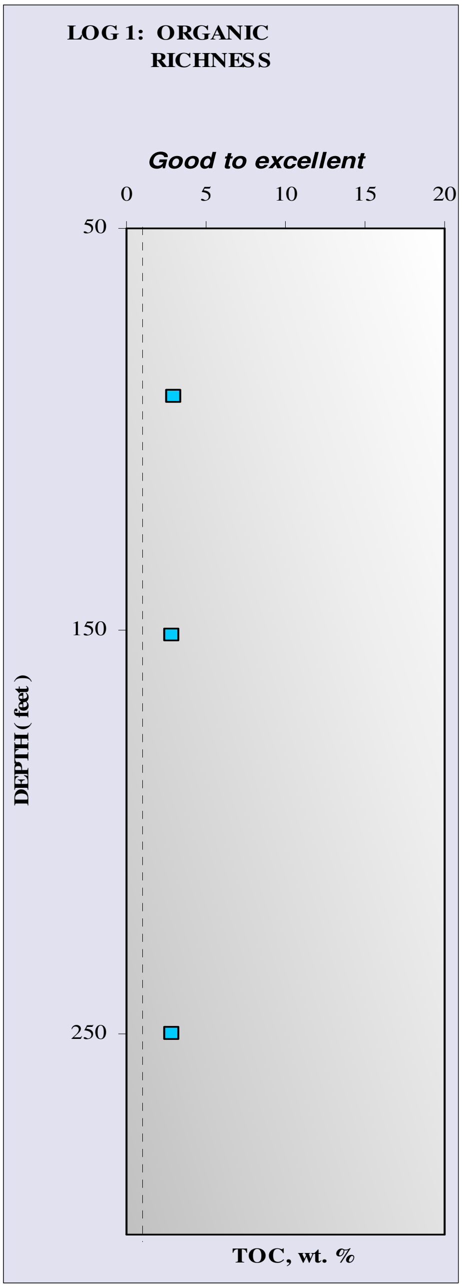

Fig. 4: plot of depth against Total Organic Contents (geochemical log of TOC)

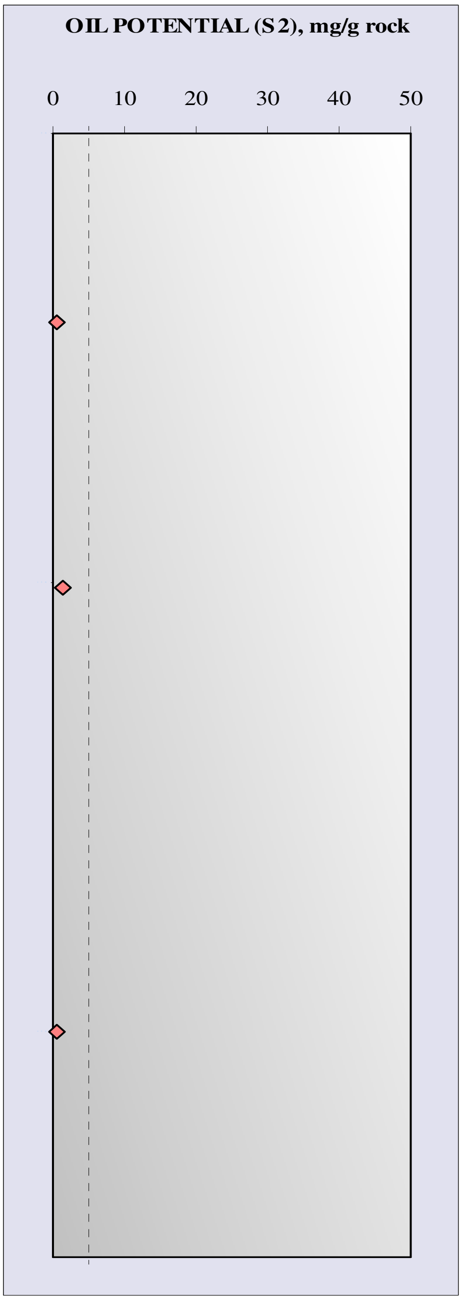

Fig. 5: Plot of Depth against Oil Potential (Geochemical Log Of Remain Potential (S2)

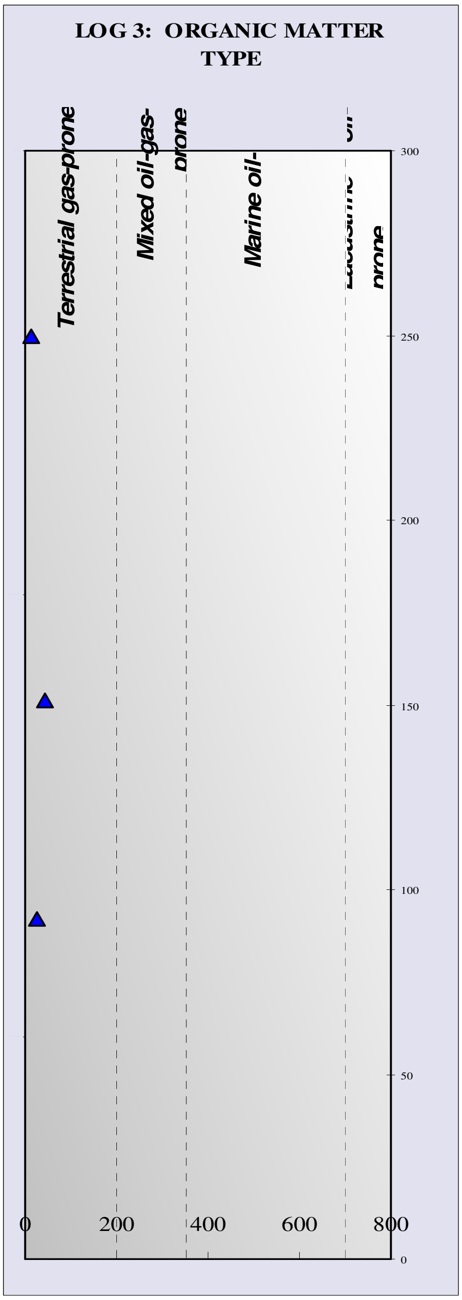

Fig. 6: plot of depth against hydrogen index (Geochemical log of kerogen type (HI).

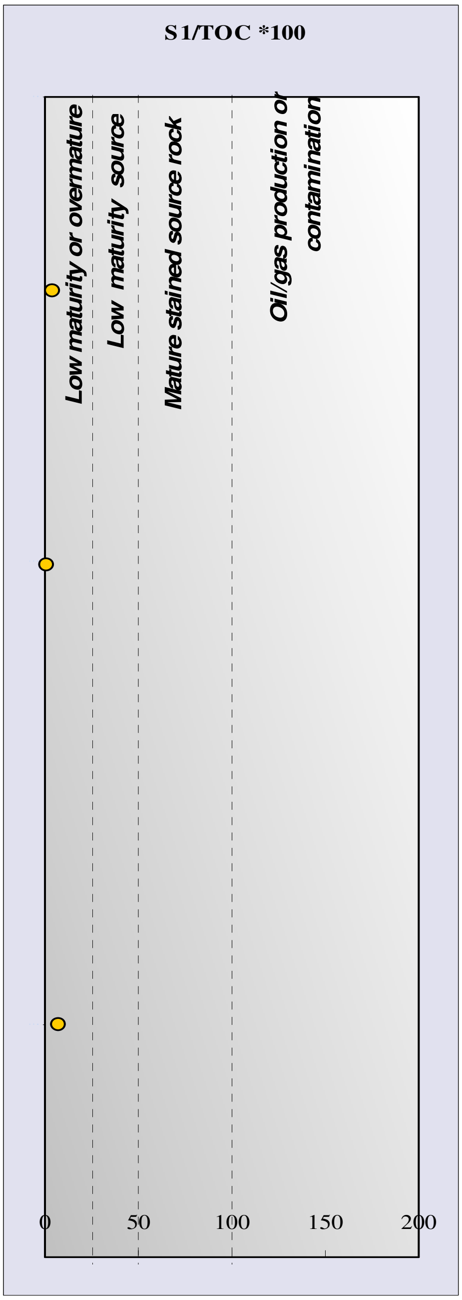

Fig. 7: Plot of depth against normalized oil content (geochemical log of normalized oil content.

5. Conclusion.

From Rock-Eval pyrolysis, it can be deduced that the shale in borehole A is a potential source rock varying from immature to marginally mature with prospects to generate gas rather than oil but at a greater depth and appropriate thermal maturity, there is likelihood of the shale generating oil. Production index (PI) indicates immature to marginally mature rock. Hydrocarbon potential from SI +S2 indicates poor potential with the organic materials being terrestrial.

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