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A Preliminary Investigation Of Petroleum Source Rock Potential Of The Ameki Shales, In The Niger Delta Basin, South Eastern Nigeria

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ABSTRACT
A geochemical analysis was carried out on Ten shale samples from the Eocene-Recent Ameki Formation Shales which lies between Latitude 7^0 30N and 8^0 00S and Longitude 6º 00E and 5^0 30W in the Niger Delta Basin, South-east, Nigeria. The aim and objectives of the study was to investigate the Petroleum potential of the formation in terms of quantity and quality of organic matter, organic richness, maturity status and to infer the environment of deposition. The indices used for the petroleum source rock evaluation include: Total Organic Carbon (TOC), Soluble Organic Matter (SOM), and Carbon Preference Index (CPI). The TOC values +vary from 1.98 wt. % -3.60wt. % with an average of 3.126wt%. The analytical data reveals that the shales can generate hydrocarbon as TOC values was above the threshold value of 1.5wt%. The results of SOM (ppm) also indicate a very good source rock as value range between 300ppm-600ppm with the mean of 1887ppm. The CPI which is the ratio of SOM to TOC gave values ranging from 0.03-0.234 with an average of 0.06293, suggesting a mature formation. The result of the above analyses confirms that the formation is organically rich and mature and thus has good hydrocarbon potential. However, this formation can be described as one that has prospect to generate and expel significant quantity of hydrocarbon.

Keywords: Geochemical, Petroleum Potential, Maturity, Total Organic Carbon, Soluble Organic Matter, source rock evaluation

INTRODUCTION
Petroleum source rocks are rocks that have the capacity to generate and expel enough hydrocarbons to form an accumulation of oil and gas (Hunt 1995). This definition or explanation covers every characteristic meant to be exhibited by source rocks which are permeable, porous, cap rock etc. Source rocks in terms of petroleum generation could either be immature (little or no generation) mature (principal generation) or post-mature (beyond generation).

The mechanism of the transformation of the sedimentary organic matter (kerogens) into oil and gas is known as pyrolysis. This transformation takes place in a sedimentary rock usually called a source rock. Four types of kerogens are recognized. Type I is algal- dominated and deposited in lacustrine environment and it has a high oil and gas potential (oil shale). Type II consists of degraded aquatic organisms, reworked and laid down in marine environment under anoxic conditions. Terrestrial plants are the principal contributors to type III and IV kerogen which are principally gas producers with much less oil potential than type I and II. On the basis of petroleum potential, source rocks can also be defined, a potential source rock is one that is too immature to generate Petroleum in its natural setting but will form significant qualities when heated in the laboratory or during deep burial. An effective source rock on the other hand is one that has already formed and expelled Petroleum to a reservoir which could be active (currently expelling) or inactive (due to uplift with erosion and cooling). (Hunt 1995).

The area of study lies within the Niger Delta Basin, which is located on the continental margin of the Gulf of Guinea in equatorial West Africa between latitudes 3^0N and 6^0N and longitude 5^0E and 8^0E and the area has received a lot of attention; example of works includes, Reyment (1965); Short and Stauble (1967), Nwajide (1979); Nwajide *et. al*. (1996); Reijer *et.al*. 1997; Nwajide and Hoque (1972); Dessauvaque (1974); Whiteman (1982), but very few have dealt with source rock potential of the surface equivalents of the subsurface of the Niger Delta.

Therefore, the present work is aimed at evaluating shale from the Ameki Formation, whether they could serve as source rocks. To determine their thermal maturity of the organic matter in the shale's and be able to use the above data to predict source rock potential of shales in the formation.

Some significant parameters used in this present study to evaluate the petroleum potential of the shale in Ameki Formation includes the Total Organic Carbon (TOC), Soluble Organic Matter (SOM) and Carbon Preference Index (CPI), to determine if the shale in this formation are in good condition to generate oil and gas.

Location Of The Study Area

The area of study is located in Ameki, a town in Abia state of Nigeria between latitude $7^0$30N and $8^0$00S and longitude $6^0$00E and $5^0$30W. The depth interval is between 8.76m – 90.19m, Ameki Formation is located in the Niger Delta Basin, South-east of Nigeria. Fig 1.

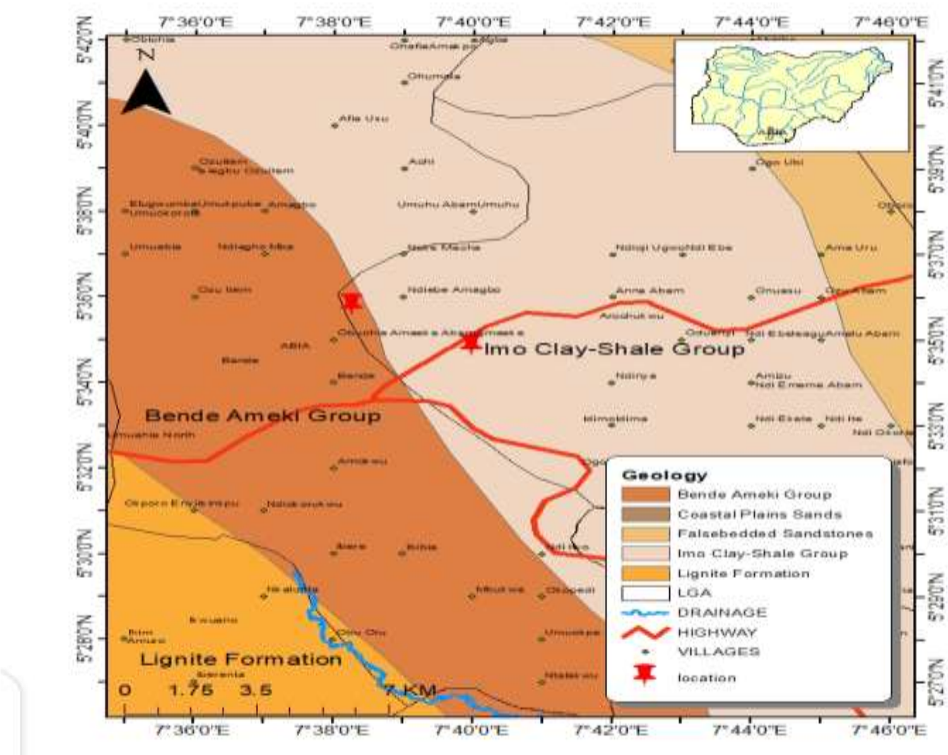

Figure 1: Location Map of Study Area

Geology of the Study Area

The Ameki Formation is overlying the Imo Formation considered as the basal unit of the Tertiary Niger Delta Basin (Whiteman 1982 and Kogbe, 1989) which overlies the Nsukka Formation of the Anambra Basin and its subsurface equivalent is the prodelta Akata Shale. Ameki Formation has been described as consisting essentially of grey- green sandy clays, sandy claystones and sandstones. Two main lithological units have been recognized; a lower with fine to coarse sandstones with intercalations of calcareous shale and thin shelly limestones, limestone nodules, and an upper with coarse grey-green sandstone and sandy clay (Whiteman, 1982)

The origin of the Niger Delta Basin is intimately related to the development of the Benue Rift. The Benue Rift was installed as the failed arm of a trilate fracture (rift) system, during the breakup of the Gondwana supercontinent and the opening of the southern Atlantic and Indian Oceans in the Jurassic. The initial syn rift sedimentation in the embryonic trough occurred during the Aptian to early Albian and comprised of alluvial fans and lacustrine sediments of the Mamfe Formation in the southern Benue Trough. Two cycles of marine transgressions and regressions from the middle Albian to the Coniacian filled this ancestral trough with mudrock, sandstones and limestones with an estimated thickness of 3,500 m. These sediments belong to the Asu River Group (Albian), the Odukpani Formation (Cenomanian), the Ezeaku Group (Turonian) and the Awgu Shale (Coniacian). During the Santonian, epeirogenic tectonics, these sediments underwent folding and uplifted into the Abakaliki- Benue Anticlinorium with simultaneous subsidence of the Anambra Basin and the Afikpo Sub- Basins to the northwest and southeast of the folded belt respectively.

Throughout the post Santonian to the Paleocene, the Anambra Basin was the center of deposition for several prodelta cycles, until a major northward marine transgression (Paleocene) took place leading to the deposition of Imo Shale followed by a regressive deposition of the Ameki Formation (Whiteman 1982; Kogbe, 1989; Ekweozor and Daukoru,1994).

The sedimentary cycles of southern Nigerian were controlled by three major tectonic phases which resulted in a complete depositional history (Short and Stauble, 1967; Murat, 1979; Whiteman, 1982).

The first phase during Albian time was characterized by movements along major NE – SW trending faults resulting in the formation of the rift-like Abakaliki-Benue Trough. To the northwest the limit of the basin was the Benin – Benue hinge line (fault zone). Between this hinge and the Abakaliki Trough shelf deposits were laid down on the Anambra platform.

The second phase (upper Santonian-lower Campanian) is characterized by compressional movements along the established North-east/South –west trend and resulted in the folding and uplifting of the basin that was displaced to a position south-west of the Benue folded belt and north-west of the Abakaliki uplift into a major depocenter for clastic infill.

The third phase (Eocene) resulted in the formation of a large deltaic complex in down dip of the basin (short Stauble 1967; Murat 1970).

Stratigraphy

The stratigraphy is as presented below:

Table 1: Stratigraphic Equivalencies between the outcropping and the Subsurface Niger Delta (Murat, R.C., 1972)

Age Span	Outcropping Units		Subsurface Formations
Oligocene- Present	Benin Formation		Benin Formation
Oligocene- Miocene	Ogwashi- Asaba Fm		Agbada Formation
Eocene- Early Oligocene	Ameki Gp	Nanka Fm	
		Nsugbe Fm	
		Ameki Fm	
Paleocene- Early Eocene	Imo Formation		Akata Formation

METHOD OF STUDY

Total organic carbon (TOC) content of sediment is a measure of the quality of organic matter present in a rock. It is a basic parameter and is required to interpret any other geochemical information obtained by

other methods. It is thus rated as the first screening parameter for source rock appraisal and serves as a witness of past potentials for already mature source rocks. It has been established from several studies that TOC of 0.5% is the threshold value for carbonate (Tissot and Welte 1978, Unomah and Ekweozor 1988). But for the generated petroleum to be expelled, a threshold of 1.5% is necessary for effective hydrocarbon expulsion from source rocks (Cools et. al., 1986).
It is noted that good source rocks have high TOC values. However, not all high TOC rocks have a good potential, thus other methods are necessary to appraise the source rock maturity, type of organic matter etc. (Lyne, 1982). Also, high TOCs are as a result of the preservation and transport of organic matter and not the organic productivity as strong currents and high CO_2 content of water and intensity of TOC is expressed as

$$\text{TOC (wt. \%)} = \frac{TX\ 0.2\ X\ 0.3}{Smaple}$$

The soluble organic matter (SOM) is used as a measure for the identification of hydrocarbon rich sediment. Thus, it gives the organic richness of source rock.
The calculation of SOM (ppm) is expressed as
SOM (ppm) = Absorbance X Gradient
The Carbon Preference Index (CPI) is also known as the transformation ratio which gives an indication of the maturity status of source rock or hydrocarbon generative potential of source rocks. It is expressed as the ratio of the soluble organic matter to the total organic carbon i.e., SOM/TOC.
This encompasses all the steps and procedures used in the determination of the Total Organic Carbon (TOC) content and the Soluble Organic Matter (SOM) content of the Ameki Shale as indices of investigating the petroleum potential of the formation.

Sample Preparation
Ten (10) selected shale samples (table 2) were bagged into transparent sample bags and properly labeled indicating the serial numbers and depth on each bag. After all these, the samples were oven dried at the laboratory after which were grind individual in a small mortar with a pestle to very fine grain size.

Table 2. Selected Sample Range [8.76M – 90.19M].

SAMPLE NUMBER	DEPTH RANGE (METERS)
1	8.76
2	10.12
3	22.52
4	46.08
5	65.10
6	66.62
7	68.66
8	73.64
9	85.76
10	90.19

The ten (10) samples of shale collected were subjected to a geochemical analysis in order to determine/characterized their potentials. The analytical methods involved are:
(a) Extraction and fractionation of soluble organic matter (SOM) from the samples.
(b) Determination of Total Organic Carbon (TOC) content

RESULTS

The data obtained from the analysis carried out to determine the TOC and SOM are presented below.

Total Organic Carbon (TOC) Content

From the analysis carried out on Total Organic Carbon (TOC), the following values or results were obtained (table 3).

Table 3: Showing Depth Range and Titre Value of The Samples

SAMPLE NO	DEPTH RANGE (M)	TITRE VALUE
Blank	-	6.3
Sample 1	8.76m	0.4
2	10.12m	0.3
3	22.52m	0.5
4	46.08m	1.6
5	65.10m	0.6
6	66.62m	0.5
7	68.66m	1.8
8	73.64m	0.9
9	85.76m	3.0
10	90.19m	1.3

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Using the formula

TOC (wt. %) = $\frac{T\ XB\ 0.2\ X\ 0.3}{sample\ wt.}$

Where T = Titre value of the blank – titre value of sample and sample wt. = 0.1g.

Calculation for each sample follows

For Sample 1 T = 6.3 – 0.4 = 5.9

TOC (wt. %) of sample 1 = $\frac{5.9\ X\ 0.2\ X\ 0.3}{0.1}$ = 3.54

The same calculation is done for the remaining nine samples i.e 2 – 10. This is represented in a tabular form as shown in Table 4 and fig. 2 show the plot.

Table 4: Showing the Results of TOC (wt. %) values

SAMPLE NO.	AGE	DEPTH (METERS)	WEIGHT TITRATE	TITRE VALUE	TOC VALUE (wt. %)	RESULTS
Blank		-	0.1g	6.3	-	-
1		8.76	0.1g	0.4	3.54	Good
2		10.12	0.1g	0.3	3.60	Good
3		22.52	0.1g	0.5	3.48	Good
4		46.08	0.1g	1.6	2.82	Good
5		65.10	0.1g	0.6	3.42	Good
6		66.62	0.1g	0.5	3.48	Good
7		68.66	0.1g	1.8	2.70	Good
8		73.64	0.1g	0.9	3.24	Good
9		85.76	0.1g	3.0	1.98	Good
10		90.19	0.1g	1.3	3.00	Good

Titre used – Barium Dipheny1

Indicator Used – FAS[$FeSO_4(NH_4)SO_4$]

Mean of TOC (wt. %) = $\frac{31.26}{10}$ = 3.126 ≈3.13

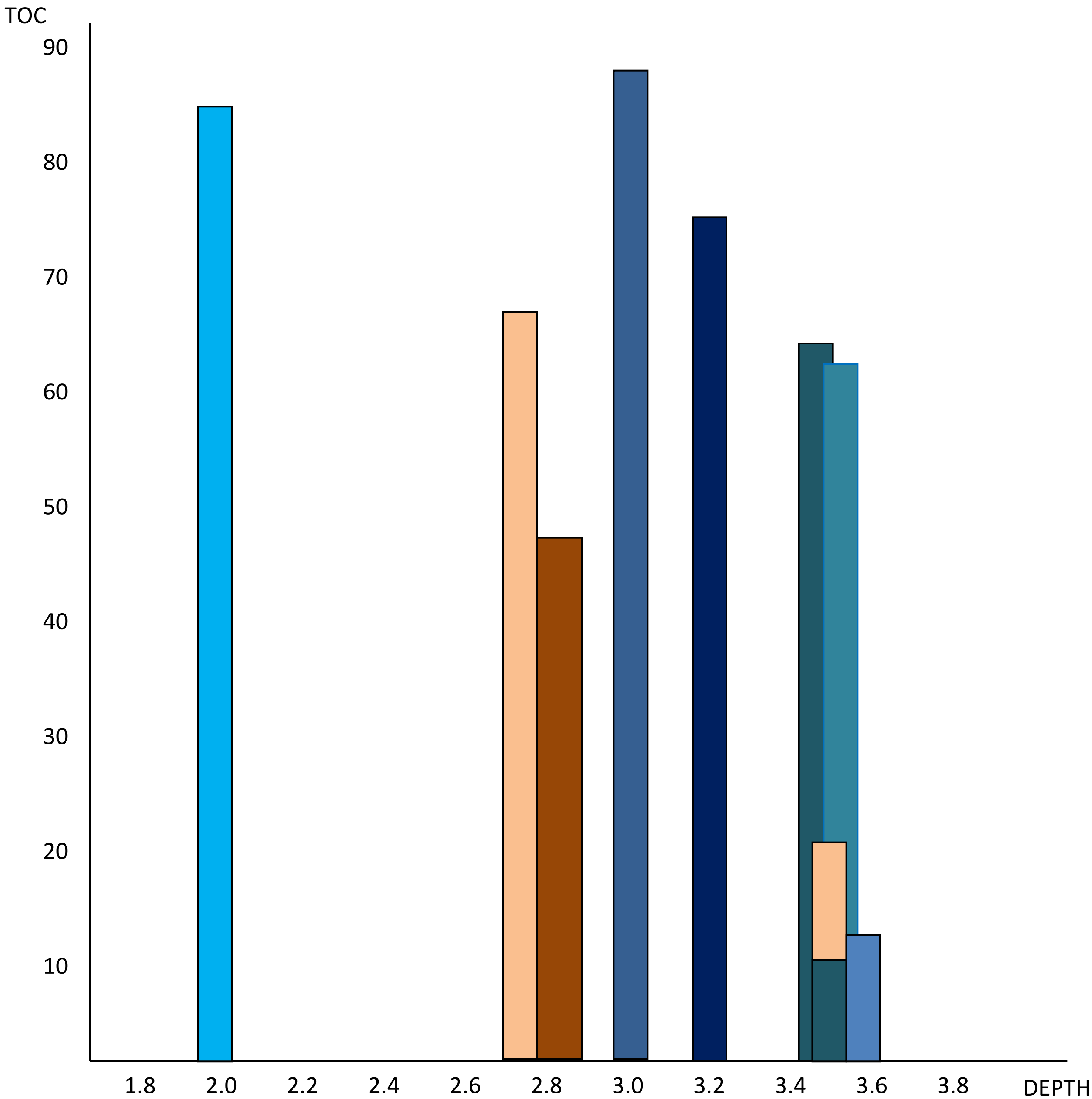

Figure 2: Plot of TOC vs Depth of Burial

Soluble Organic Matter (SOM) Content

From the study or analysis carried out on SOM, the following values (absorbance) were obtained. This is represented in a tabular form showing in table 5

Table 5: Results of analysis carried out on SOM

SAMPLE NO	DEPTH (METERS)	SOM VALUE (ABDSORBANCE)
1	8.76	0.03
2	10.12	0.03
3	22.52	0.01
4	46.08	0.22
5	65.10	0.029
6	66.62	0.06
7	68.66	0.02
8	73.64	0.03
9	85.76	0.02
10	90.19	0.18

The results were obtained using the formula
SOM (ppm) = Abs. X Gradient
Where Gradient = 6000x
Calculation for each sample will be as follows;
Sample 1
2.0g shale was extracted with 10m of Chloroform (CCl_3)
Absorbance got = 0.03
Standard booming light and medium calibrated graph has a gradient of 6000x.
SOM = Abs of soil extracted X Gradient of standard graph.
6000x X 0.03
= 180ppm
But 180ppm SOM = 200g soil
10ml CCl_3 = 2.0g soil
1000ml $CCl_3 = \frac{2.0}{10} \times \frac{1000}{1}$
=200g
∴ 200g soil = 180 mg/1 SOM
1g soil = $\frac{180}{200}$
1000g or 1kg soil = $\frac{180}{200} \times \frac{1000}{1}$
The remaining nine samples is calculated in the same way.
Sample 1 SOM = 900ppm

Table 6: A comprehensive SOM Table is computed below

SAMPLE NO	AGE	DEPTH (Meters)	WEIGHT OF SAMPLE	SOM VALUE (ABS)	SOM (ppm)	RESULTS
1		8.76	2g	0.03	900	Good
2		10.12	2g	0.03	900	Good
3		22.52	2g	0.01	300	Good
4		46.08	2g	0.22	6600	Good
5		65.10	2g	0.029	870	Good
6		66.62	2g	0.06	1800	Good
7		68.66	2g	0.02	600	Good
8		73.64	2g	0.03	900	Good
9		85.76	2g	0.03	600	Good
10		90.19	2g	0.18	5400	Good

Mean SOM (ppm) = $\frac{18,870}{10}$ = 1887

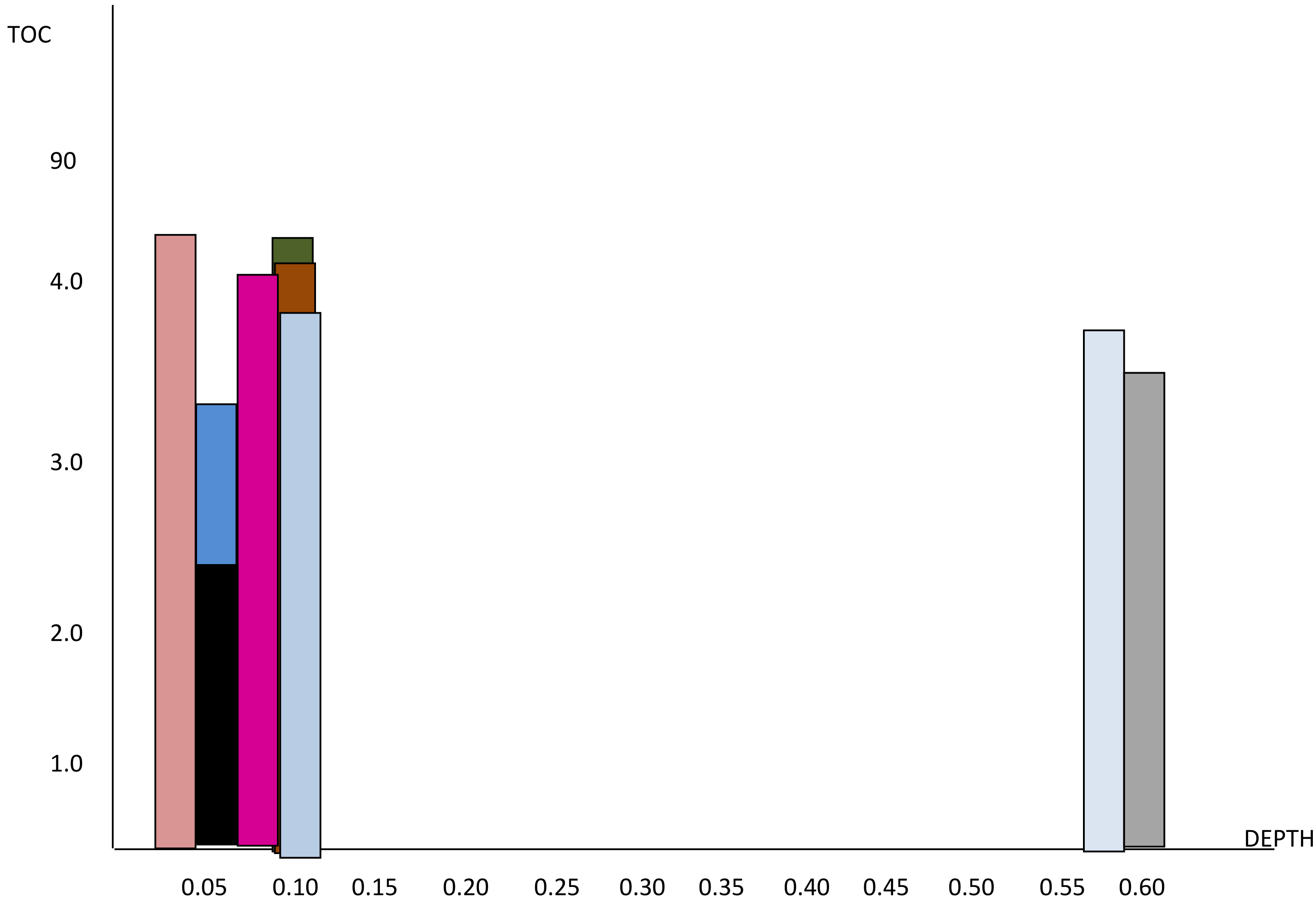

Figure 3: Plot of TOC vs SOM

Carbon preference index (CPI)

In the real sense, no laboratory analysis was carried out for this parameter; its values/results can be obtained from the results of TOC and SOM that have already been ascertained. As calculated as the ratio of SOM to TOC which is expressed as

CPI = $\frac{SOM\ (wt.\%)}{TOC\ (wt.\%)}$

Where SOM (wt. %) = $\frac{SOM\ (ppm)}{10000}$

Table 6: Calculated Ratio of SOM to TOC

SAMPLE NO.	Depth (METERS)	TOC VALUE (wt. %)	SOM (ppm)	SOM VALUE (wt. %)	CPI SOM TOC	RESULTS
1	8.76	3.54	900	0.09	0.025	Mature
2	10.12	3.60	900	0.09	0.025	Mature
3	22.52	3.48	300	0.03	0.0086	Immature
4	46.08	2.82	6600	0.66	0.234	Mature
5	65.10	3.42	870	0.087	0.025	Mature
6	66.62	3.48	1800	0.18	0.0517	Mature
7	68.66	2.70	600	0.06	0.022	Mature
8	73.64	3.24	900	0.09	0.028	Mature
9	85.76	1.98	600	0.06	0.03	Mature
10	90.19	3.00	5400	0.54	0.18	Mature

Calculation for each sample will be as follows
For sample 1
SOM (ppm) = 900ppm
TOC (wt. %) = 3.54

But SOM (wt. %) = $\frac{SOM\ (ppm)}{10000} = \frac{900}{10000}$

$=0.09$

$\therefore$ CPI = $\frac{SOM\ (wt.\%)}{TOC\ (wt.\%)} = \frac{0.09}{3.54}$

$= 0.025$

The same calculation is done for the remaining nine samples i.e. 2-10. After calculating the under listed, Table was drawn i.e., Table 6.

Mean CPI = $\frac{0.6293}{10}$

$=0.06293.$

DISCUSSION OF RESULTS

Hydrocarbon source rock evaluations of the ten samples were carried out to determine whether they are good or poor source rocks. In the study, two criteria were used, namely; organic richness and degree of maturation.

Determination of organic richness and maturation was based on the amount of total organic carbon content (TOC), extractable/soluble organic matter (SOM) and carbon preference index (CPI).

Total Organic Carbon (TOC)

The total organic carbon content of the shale's samples analyzed varies from 1.98wt% to 3.60wt% with an average TOC value of 3.12wt% with reference to studies of Tissot and Welte (1978), Unomah and Ekweozor (1988), Okoye (1985) which states that for an elastic source rock like shale to generate petroleum, a threshold value of 0.5% TOC (wt%) must be attained.

Therefore, an average TOC value of 3.126wt for samples studies is well above the minimum threshold for hydrocarbon generation as shown above in table 3.

Ronov (1958) states that the ability of a rock to generate and expel hydrocarbon is dependent on the quantity of organic matter. The quantity of organic matter present in a rock can be evaluated and classified using the TOC content (Philip et al, 1986) as indicated below

TOC (wt %)	Grade of Source Rock
<0.5%	poor
0.55-0.1.05	fair
>1.0%	good

Form the data above, it can be inferred that the analyzed samples which yielded organic carbon values are greater than the threshold values of 0.5%.

From my results, it could be seen that the shales in this formation do not just meet the required threshold but exceeds the value. This confirms that the Ameki Formation shales have reached a stage of (effective) oil generation and thus could be referred to as good source rocks.

Form the results obtained for TOC (Table 3) which clearly shows that values ranging from 1.98wt%-3.60wt% with an average TOC value of 3.126% it can be deduced that the Ameki Formation shales are organically rich.

Soluble Organic Matter (SOM)

The soluble organic matter SOM showed a pattern similar to that of the total organic carbon (TOC) content (Table 4)

The table above indicates that SOM (ppm) values range between 300-6600ppm with a mean of 1887ppm.

Deroo et al (1977 and 1979) have classified sediments in terms of their chloroformic extracts as follows:

<50ppm	-	poor source rock
50-100ppm	-	fair source rock
>100ppm	-	good source rock

From my data, it can be clearly seen that the value so far obtained falls in the category of “above 100ppm” which is indicative of good source rocks. Therefore, the shales in this formation can be rated as good source rocks with respect to the above classification.

The values of SOM (wt. %) range from 0.03wt%-0.66wt% with an average of 0.1887wt%.

Derroo *et al*, 1977, have shown that soluble organic matter content in the 0.15% - 3.36% is high. The average SOM values for analyzed samples fall within the range and is interpreted to be high.

These data also indicate that the shales are organically rich.

Carbon Preference Index (CPI)

As shown in the table 5 above, carbon preference index (CPI) value range between 0.03-0.234 with a mean of 0.06293.

According to Derroo *et. al.*, (1977), carbon preference index (CPI) in range 0.013 – 0.160 is characteristics of organic matter in sediment which are meant to reach the main phase of oil generation, thus, are not matured. Therefore, for the sediments to be classified as matured, it must exceed this range which is 0,016.

From Table 5 above, the average carbon preference index (CPI) value for the ten samples is 0.06293; this is far above the standard threshold value required for hydrogen generation. This implies that the sediments are good source rocks.

Although from the Table 5 above, sample 4 has CPI value less than the required range i.e. 0.014, thus sample four could be said to be as a result of some errors encountered during the analysis or degradation effect. The remaining nine samples have CPI values that exceed the required range.

However, since the mean (CPI) value (0.06293) which comprises of the ten samples exceeds the required range (0.016), it can be interpreted that the shales in the Ameki formation are matured to generate hydrocarbons hence, very good source rock.

The environment of deposition of source rocks can be inferred from both geological and geochemical perspectives.

However, from the geochemical point of view the Ameki Formation Shales depositional environment can be inferred from the analysis of TOC content. As already stated, values of TOC exceeded the threshold values of generating petroleum which is 0.5%. this indicates that the Ameki Formation shale were deposited in an anoxic (Oxygen deficient) environment, as this environment favour the accumulation of organic matter and thus the generation of petroleum.

From the above discussion, it is obvious that both geological and geochemical evaluations are in alignment confirming that the Ameki Formation shale was deposited in a reducing environment.

A petroleum potential of a formation can be investigated in terms of the quality of total organic carbon (TOC), organic richness (SOM) and the maturity status (CPI) of the formation.

Therefore, the petroleum formation of the Ameki Formation shales can thus be described as a formation that has a significant quantity of organic matter, organically rich and matured based on results of TOC, SOM, and CPI respectively

CONCLUSION

The results of the various geochemical analysis carried out within the Ameki Formation shales shows the samples exhibited the qualities of good source rock. This geochemical analysis carried out on ten shale samples with the aim of investigating the quantity of organic matter present, organic richness, maturity status and infers the petroleum potentials of Ameki formation shales. Source rock evaluation indices such as total organic carbon (TOC), soluble organic matter (SOM) and the carbon preference index (CPI) were used to achieve the above-mentioned objectives.

The TOC values range from 1.98wt.% - 3.60wt% with an average of 3.126wt%. According to Bordenave et al (1993), the TOC of sediment is the basic parameter which is required to interpret any given geochemical information obtained by other methods. Therefore, good source rocks have good TOC values. The average TOC value for the studied sample is in agreement with the 0.4 – 4.44wt% range reported by Ekweozor and Okoye, (1985), Tissot and Welte (1978). Unaomah and Ekweozor (1988). Therefore, it is reasonable to conclude that the sample section has required Kerogen concentration to produce petroleum.

Again, it shows that these shales are organically rich as SOM (ppm) values which range between 300ppm-6600ppm indicating very good source rocks. Some good source rocks are classified to have SOM (ppm) values greater than 100ppm. The ratio of the SOM to TOC i.e. (SOM/TOC) known as the carbon preference index (CPI) gave values ranging from 0.03 – 0.234 with a mean of 0.06293 suggesting a mature formation as values exceeds this threshold which is 0.016.

In conclusion it can be deduced that despite the limiting factors, the Ameki shale can generate and expel significant quantity of hydrocarbon, since results of TOC, SOM and CPI are of standard value.

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