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Geochemical characterization of Afikpo Basin, Arochukwu Area, South East, Nigeria

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ABSTRACT

Geochemical analyses were carried out on shale samples obtained from a well in the Arochukwu Area, Afikpo Basin, to determine the TOC and SOM values. The TOC values varied from 0.85wt% - 1.15wt% with an average of 1.03wt%, while the SOM values ranged from 20ppm – 480ppm with an average of 120.5 ppm. The above results show that the TOC values fall above the minimum threshold for hydrocarbon generation potential. The minimum threshold value for TOC is 0.5%. The average SOM value of 120.5 ppm which is higher than the minimum value which is 50 ppm is also indicative of good source rock potential for the studied samples. The transformation ratio which serves as a quantitative analysis to determine the level of maturity shows an average value of 12.4 which indicate that studied samples of the area are immature . The implication, therefore, is that the sediments from the studied depth slice can be regarded as immature sediment in predominantly gas prone enviroment.

Keywords: source rock, pyrolysis, ditch cuttings, Formation, Arochukwu.

INTRODUCTION

Most people now believe that oil and gas are formed when the remains of dead animals and plants are mixed with sediments, buried and formed into rocks and then heated deep underground. The oil and gas then seep out through porous rocks where they may or may not collect in an oil or gas field. Geochemistry, particularly organic geochemistry tries to find if the rocks in an area are of the right sort and the right amount to form oil or gas.

The mechanism of the transformation of the sedimentary organic matter into oil and gas is known as pyrolysis. These transformations take place in a sedimentary rock usually called a SOURCE ROCK. It is important, therefore, to recognize these rocks in the early stages of petroleum exploration, for their evaluation. The presence of more than one source rock in an area makes it more attractive. An estimate of how prolific the source has been and some indication of the nature of the hydrocarbon products (oil or/and gas) is valuable for effective exploration of petroleum.

It is in this regard, that the present work is aimed at evaluating the source rock qualities of the study area , with a view to further understanding the petroleum prospects of the Afikpo Basin.

LOCATION OF STUDY AREA

The studied samples were recovered from an interval of an appraisal well in Arochukwu Area in Afikpo Basin, southeastern Nigeria which lies within Latitude 5^0 28' and Longitude 7^0 .57' in southeastern Nigeria .

AIM OF THE STUDY

The aim of this research work is to carry out geochemical characterization of a sedimentary section of Arochukwu Area in Afikpo Basin. The Characterization involves analysis and interpretation of source rock parameters in order to determine the hydrocarbon source potential of the studied sediments

GEOLOGY OF AFIKPO BASIN

The Study area, Arochukwu Area lies within Afikpo Basin in the Lower Benue Trough, Reyment [16] and has the following lithostratigraphic divisions:

Asu River Group: This is a sequence of marine shales occupying the core of the Abakaliki Anticlinorium. It has a thickness of about 6000ft, embedded with shale and micaceous sandstone and the shales are deeply weathered and contains radiolarian echinoids, pelecypods and gastropods . The Age is Albian.

Eze-Aku Shale Group: The Eze Aku Shale group consist of hard grey to black shale having thick flaggy calcareous and non-calcaroeus shale. The Eze-Aku Formation represents a shallow water deposit. The fossils consist of mainly pelecypods, gastropods, echinoids, e.t.c which indicate basal Turonian age .

Agwu Shale: The Agwu Shale overlies the Eze Aku shale conformably and is between Agwu and Ndeaboh in Southern eastern Nigeria.The lithology is a bluish-grey well-bedded shale interbedded with fine yellow calcareous sandstone and shaly limestone with a total thickness of 900m,the strata are greatly folded and contain oil seeps.

Nkporo/Enugu shale and Owelli sandstone: Nkporo shale of Late Campanian age is the basal facies of the late Cretaceous sedimentary cycle in the Anambra basin. Exposures are poor, bearing coarsening upward deltaic sequences of shales interbedded with sands. This interpretation is supported by the vertical association of distributary channel sands (basal Mamu formation) and the lateral equivalents of lower flood plain carbonaceous shales (Enugu shales) towards the central and northern parts of the basin. The lithology of Enugu shales consists mainly of carbonaceous shales and coals within the upper half deposited in lower flood plain and swampy environments. The sediments are normally associated with siderites and pyrites which are early diagenetic minerals. The Owelli sandstone is the major sand member of the Enugu shale formation and forms and elongate shoestring sand body elongated to the NE defining a meander belt of a fluvial/distributary channel system. Sedimentary structures of the channel sand exposed at the junction, for instance demonstrates possible tidal processes coupled with a few gastropod shells recovered, suggesting marine incursions into these distributary channel systems .

Mamu Formation: The Mamu Formation overlies the upper Campanian lateral facies associations described above. The age ranges from lower to middle Maastrichtian from south to north. Both vertical and lateral facies changes are observed, formation thickness ranges from 100m to 1000m across the basin and lithology includes shales and sandstones, with some limestones in the south and coal seams in the central to upper parts of the basin. Depositional environments include distributary/estuarine channels, barrier foot, swamp and tidal flats,.

The Ajali Sandstones: The Ajali sandstone consists of mineralogically much matured, medium to coarse grained, moderately well sorted quartz grains, and intercalations of thin laterally extensive clay beds of normally less than 1m also occur. The formation thickness is about 300m extending across the entire basin and into the middle Niger Basin and slightly diachronous, ranging from Middle to Late Maastrichtian from south to north.

Nsukka Formation : The Nsukka Formation (Upper Coal Measure) lies conformably on the Ajali Sanstone. It occurs from the north of Awka to the Upper Ankpa sub-basin, with lithology of mainly shales, siltstones, sands and coals and lateritic cover. Age of the formation is from upper Masstrichtian to Danian, and depositional environment is similar in many respects to the Mamu Formation (lower coal measures), consisting of transitional/shoreline, mudflats and swamps, deposited during a largely regressive phase of sea level changes.

MATERIALS AND METHODS

Sample Preparation: Selected sample interval (Table 1) the samples were oven dried properly after which they were ground individually.

Table 1: Selected sample interval

Sample no	Depth (metres)
1	0-3
2	3-6
3	6-9
4	9-12
5	12-15
6	15-18
7	18-21
8	21-24
9	24-27
10	27-30

Evaluation techniques: The Ten shale samples were subjected to a geochemical analysis in order to characterize their petroleum generation potential

The analytical methods involves are:

(a) Extraction and Fractionation of soluble organic matter (SOM) from the samples and
(b) Determination of total organic carbon (TOC) content

Total Organic Carbon (TOC): TOC determination is done to estimate the quantity of organic matter in each sample. The basic principle behind this is that organic carbon is determined by a mixture of hydrogen tetraoxosulphate (iv) acid and aqueous potassium dichromate ($K_2Cr_2O_7$).After complete oxidation from the heat of solution and external heating, the unused or residual $K_2Cr_2O_7$ (in oxidation) is titrated against ferrous ammonium sulphate. The used $K_2Cr_2O_7$, the difference between added and residual $K_2Cr_2O_7$ gives a measure of organic content of sediment.

Soluble Organic Matter (SOM): To determine source rock potential, maturity and depositional environment. The significance of this is that extraction and the determination of yield of soluble organic matter (SOM) allow for identification of hydrocarbon rich sediments, while the ratio of soluble organic matter (SOM) to the total organic carbon (TOC) gives an indication of the maturity status of hydrocarbon generative potential of the source rock,Ejedawe et al, [5] and [6].

RESULTS

The total organic *carbon content* (TOC) of the ten (10) analyzed samples varied from 0.85wt% - 1.15wt%, with an average of 1.03%. Table 2, shows the end point and TOC values obtained.

It has been established from various studies that TOC of 0.5% is the standard minimum threshold value for source rock to generate hydrocarbon, Frankyl [18].

Table 2: Total organic carbon content of the study area

Sample number	End point values	Rating	TOC	Depth (metres)
1	1.66	Good	1.15	0-3
2	1.20	Good	1.52	3-6
3	1.70	Good	0.95	6-9
4	1.80	Good	0.93	9-12
5	2.20	Good	0.90	12-15
6	2.30	Good	0.85	15-18
7	1.60	Good	1.12	18-21
8	1.70	Good	0.97	21-24
9	1.80	Good	0.95	24-27
10	1.90	Good	0.94	27-30

Therefore an average TOC value of 1.03 wt% for samples studied is well above the minimum threshold for hydrocarbon generation.

Ronov [17] states that the ability of a rock to generate and expel hydrocarbon is dependent on the quantity of organic matter present. The quantity of organic matter present in a rock can be evaluated and classified using the total organic carbon content as indicated below, Ekweozor et al [7].

TOC (WT %)	Grade of Source Rock
< 0.5%	Poor
0.5% - 1.0%	Fair
> 1.0%	Good

From the data above, it can be inferred that the analyzed samples which yield organic carbon values are greater than the threshold value (0.5%). The organic carbon rating of the source rock can be said to be good, Evamy et al [9].
***Extractable Soluble Organic Matter (SOM)*:** The samples were subjected to extractable soluble organic matter analysis (SOM), the values were shown (see Table 3)

Table 3: Values obtained for the soluble organic matter (SOM) of well samples by Soxtec extraction method

S/N	Depth(M)	Wt of sample (g)	Wt of extract	SOM (wt %)	SOM (ppm)	TOC
1	0-3	10	0.015	0.02	20	1.15
2	3-6	10	0.036	0.05	50	1.52
3	6-9	10	0.028	0.04	40	0.95
4	9-12	10	0.085	0.12	120	0.93
5	12-15	10	0.018	0.188	188	0.90
6	15-18	10	0.019	0.042	32	0.85
7	18-21	10	0.068	0.08	80	1.12
8	21-24	10	0.290	0.48	480	0.97
9	24-27	10	0.075	0.105	105	0.95
10	27-30	10	0.078	0.09	90	0.94

The extractable soluble organic matter (SOM) showed a pattern similar to that of the total organic carbon content. The SOM values increases from depth interval 0-3m to 12-15m with depth of burial and then flunctuate for the rest of the depth interval (see Table 3).

Table 4: Source Rock Classification scheme (After Deroo et al,1977)

SOM	Source Rock Potential
50ppm	Poor source rock
50ppm-100ppm	Fair source rock
100ppm	Good source rock

The value of SOM ranges from 20ppm to 480ppm with an average of 120.5ppm. Deroo et al [4] Table 4 have shown the Source rock classification scheme of the soluble organic matter (SOM). The average SOM value for analyzed well samples falls within this range, and is interpreted to be good source rock. However, the concentration of soluble organic matter of less than 7000PM as in the case of the study area, is incomparable to the prolific petroleum source rocks of the world.

Transformation Ratio: The transformation ratio, Table 5 which serves as a quantitative analysis is an index of maturity. It is investigated as a comparative measure between the values of SOM and those of TOC.

Table 5: Average transformation Ratio (TR)

Sample number	Depth (M)	TR=SOM/TOC	SOM (wt %)	TOC(wt%)
1	0-3	1.7	2.0	1.15
2	3-6	3.3	5.0	1.52
3	6-9	4.2	4.0	0.95
4	9-12	12.9	12.0	0.93
5	12-15	20.9	18.8	0.90
6	15-18	3.8	3.2	0.85
7	18-21	7.1	8.0	1.12
8	21-24	49.5	48.0	0.97
9	24-27	11	10.5	0.95
10	27-30	9.5	9.0	0.94

Average transformation ratio is 12.4
According to Deroo et al [4] values of transformation ratios between 1.7-49.5 indicate that the sediments are immature, see table 6, base on these immature status the estimated vitrinite reflectance values of most of the samples are indicative of an immature bed that may be capable of generating oil and gas when matured, the resultant maturity status is confirmed by relatively low vitrinite reflectance. The initial oil generation begins in sedimentary rocks at vitrinite reflectance value (VR_O) : 0.6% while oil generation terminate at vitrinite reflectance value (VR_O)= 1.3%, Frankyl [10], and this concides with the beginning of maximum gas generation . According to Reyment [16] ,

the Anambra/Afikpo basins has sediments that are within the gas generating range. From the table, the average TR value for the samples is 12.4 which indicates that sediment in the study area are immature.

Table 6: Classification of Source Rocks Maturity based on transformation ratio (After Miles,1989).

Status	Extract/TOC	Estimated Vitrinite reflectance
Immature	<70	<0.5
Early mature	70-100	0.5-0.65
Peak mature	>100	0.65-0.9
Late mature	100-500	0.9-1.3
Post mature	>500	>0.3

DISCUSSION

Hydrocarbon source rock evaluation of the samples from study area was 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.

The determination of organic richness was based on the amount of organic carbon content and extractable organic matter.

The total organic carbon content ranges from 0.85w% 1.15wt% with an average of 1.03%. This implies that they are very good, and they exceed the minimum threshold value for a petroleum source rock (0.5wt%). The extractable organic matter also tends to increase initially and then flunctuate as the depth of burial increases. The values obtained is interpreted as an indicative of good source rock (SOM values of 20ppm- 480ppm, average of 120.5ppm).

The level of maturity of the sediment to produce hydrocarbon was determined using the transformation ratio (TR). This is a ratio of the extractable soluble organic matter to total organic content (SOM/TOC). The values tend to fluctuate. The highest being 49.5. The ratio of SOM/TOC contained in sediments is a measure of the transformation of kerogen into hydrocarbon. It is low in immature sediments, but increases sharply in mature ones ,Cavaliere,[3]. In this study,. Deroo et al [4] has stated that values of less than 70(<70) indicate no hydrocarbon generation. The average value of TR 12.4 for the studied samples does not exceeds this threshold. Therefore, the samples can be said to be immature.

CONCLUSION

The result of the various geochemical analyses carried out within the studied sedimentary section shows that the samples indicates that the study area is predominantly gas prone.

The TOC values range from 0.85wt% -1.15wt% with an average of 1.03wt%. According to Bordenave et al [2], the TOC of a sediment is the basic parameter which is required to interprete any other geochemical information obtained by other methods. Therefore, good source rocks have high TOC values The maturity status of the sediments is an indicative of immature source rocks It is generally accepted that good shaly source rock of liquid petroleum should normally have a minimum average TOC of 1 – 2wt%. Therefore, it is reasonable to conclude that the level of organic richness as indicated by TOC and extractable organic matter as measured by SOM and as well as maturity assessment that the study section consist of immatured sediments in a predominantly gas prone environment.

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