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Comparative studies on hydrocarbon potential of Maastrichtian Mamu Formation on the western and eastern parts of Anambra Basin, Nigeria

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Abstract

Maastrichtian Mamu Formation outcropping at Uzebba was logged, sampled and analyzed for organic geochemical parameters. The results from the analysis were then studied and compared with organic geochemical parameters from Mamu Formation outcropping at Imiegba and Okobo. Total Organic Carbon contents of shale samples obtained from exposed outcrop sections around Uzebba range from 0.10 to 1.33 wt. %, hydrogen index ranges from 49-70 mg HC/g TOC, oxygen index ranges from 15-232 mg CO_2/g TOC, production index ranges from 0.17-0.64 while T_{max} ranges from 315-433^{0}C. The organic geochemical results of Uzebba when compared with Imiegba and Okobo show that the organic richness increases basinward (towards Okobo axis) and the organic matter becomes thermally mature basinward (towards the Okobo).

***Keywords**: Generative potential; Kerogens; Total organic carbon; Mamu Formation.*

1. Introduction

The Anambra Basin ranks almost next to the Niger Delta Basin in terms of richness in hydrocarbon reserves [1] Geological studies of the Anambra Basin continue to attract the attention of many geologists because of the proven hydrocarbon presence [1].

Ogungbesan and Adedosu [2] carried out detailed studies of the geochemical record of the Late Cretaceous Mamu Formation situated within the western flank of the Anambra Basin. Their findings indicated the presence of mostly terrestrial-derived organic matter (gas-prone Type III kerogen) mixed with minor marine organic matter deposited in suboxic to anoxic conditions. The shales were also found to be marginally mature, implying a low hydrocarbon source potential.

Akaegbobi *et al.* [3], also carried out research on Campano-Maastrichtian sediments in southeastern parts of the Anambra basin. Results from their research show that the Mamu For mation has TOC values ranging from 0.52 to 4.78 wt.% and HI values ranging from 10 to 226 mg HC/g TOC indicating that the organic matter in the Mamu Formation rest is mainly Type III and Type IV kerogens. This indicates that it is mainly gas prone.

A basin-wide comparative study on Mamu shale on western and eastern parts of Anambra Basin is limited hence there's a need for evaluation of organic richness, kerogens type, and thermal maturation of the Mamu Formation on the western flank in comparison with shales of Mamu Formation on the eastern flank. It is expected that this study would provide a basinal understanding of shales of Mamu formation as regards their hydrocarbon source potential in the Anambra Basin. Also, this study is expected to provide additional information for explorationists and researchers with an interest in organic geochemical studies of the Anambra basin as well as form a basis for further research work.

2. Geologic setting

The Anambra Basin is located at the southwestern extreme of the Benue Trough. Bounding the basin to west is the Precambrian Basement Complex rocks of western Nigeria, to the east is the Abakaliki Anticlinorium, and to the south, the northern portion of the Niger Delta petroleum province. It is bounded on the southwestern flank by the Niger Delta hinge line, northwest by the Benue flank and southeast by the Abakaliki Fold Belt. The Anambra Basin is one of the Cretaceous sedimentary basins of Nigeria. The basin is roughly triangular in shape and covers an area of about 40,000 square kilometers with sediment thickness of approximately 9km.

The basin is located between Latitudes 5^0 00' N to 8^0 00′ N and Longitudes 6^0 30' E to 8^0 00' E. The tectonic evolution of the sedimentary basins of southeastern Nigeria started with the breakup and separation of the African and South American plates in the Late Jurassic, which was initiated by the Y-shaped, RRR triple-junction ridge system [4-5]. Following midSantonian tectonism and magmatism, depositional axis in the Benue Trough was displaced westward resulting in subsidence of the Anambra Basin. The Anambra Basin, therefore, is a part of the Lower Benue Trough containing post-deformational sediments of Campanian-Maastrichtian to Eocene ages. It is logical to include the Anambra Basin in the Benue Trough, being a related structure that developed after the compressional stage [6].

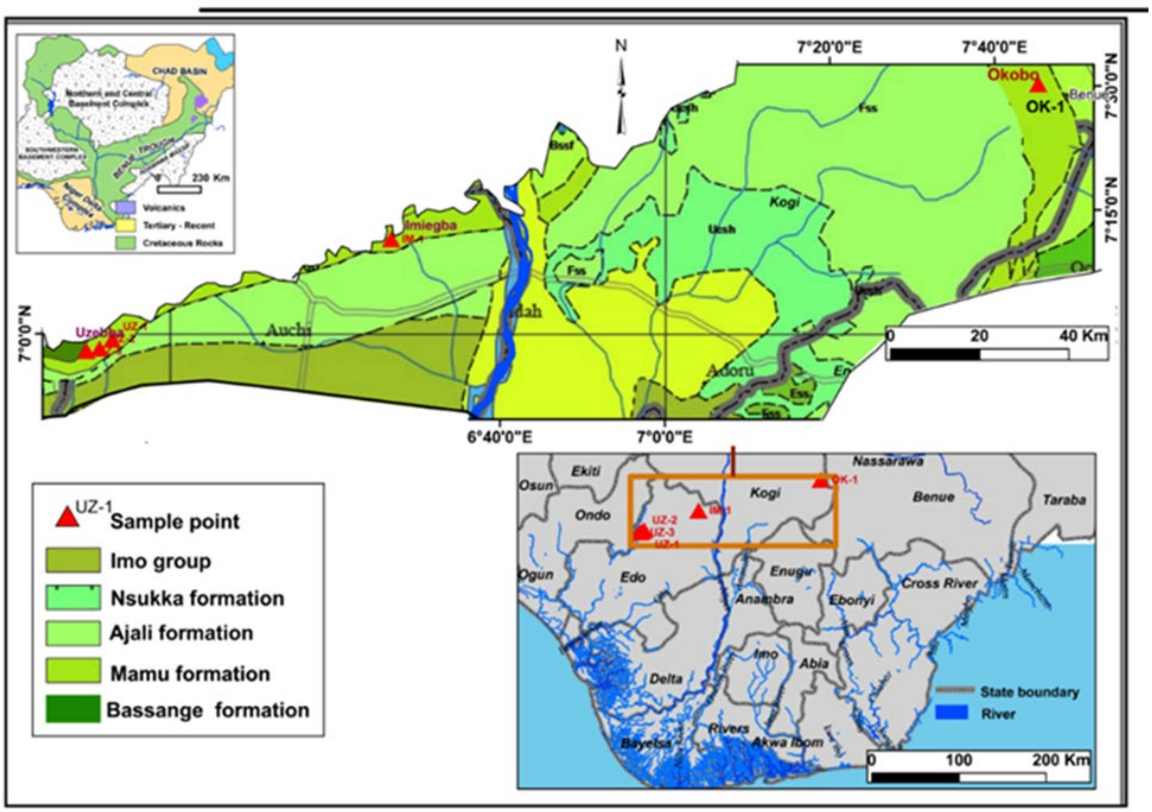

Figure 1. Geological Map of Nigeria showing the sample locations from Mamu Formation western and eastern Anambra Basin. Modified from [7]

3. Materials and methods

Three (3) outcrop sections of Mamu formation at Uzebba, within the western flank of the Anambra Basin were carefully logged, sampled and analyzed for organic geochemical attributes. The results were then compared with organic geochemical data published by [8] [9]from Mamu Formation exposed at Imiegba still within the western flank of the basin and Okobo at the eastern part of Anambra basin. The three (3) shale samples from exposed outcrop sections on the western flank of the Anambra Basin, were analysed for Total organic carbon content, kerogen type and thermal maturity. 40-50 mg of dried powdered samples were analysed using a Rock-Eval II/TOC pyrolysis. The quantity of organic carbon in three (3) shale samples was determined using LECO carbon analyzer. Thermal-maturity analyses of the three (3) shale samples was determined using a Rock-Eval II programmed pyrolysis.

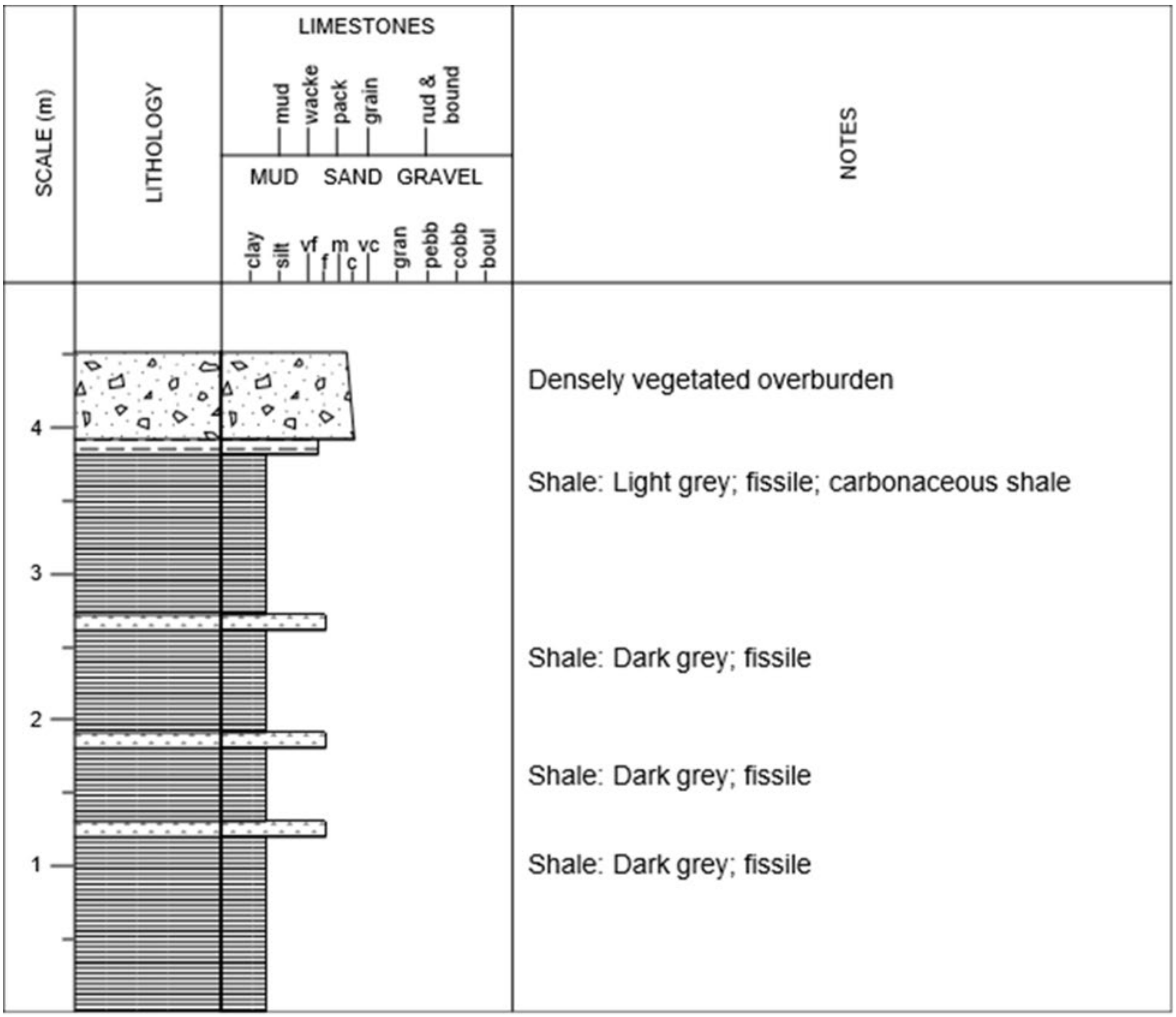

Figure 2. Lithologic log of Mamu Formation outcropping at Uzebba

4. Results and discussion

4.1. Hydrocarbon generation potential

The Rock-Eval pyrolysis provided four measured parameters: S1, S2, S3 and Tmax [10]. The Hydrogen Index (HI), Oxygen Index (OI), Generative Potential (GP), Production Index (PI) and vitrinite reflectance (Ro) was subsequently calculated from the measured parameters to provide information about quantity, type and thermal maturity of organic matter in the source rock [10-11].

Table 1. Summary of results from TOC and Rock-eval analysis of samples from Uzebba, Imiegba and Okobo, Anambra Basin Nigeria

Sample no.	TOC (wt. %)	S_1 (mg HC/g)	S_2 (mg HC/g)	S_3 (mg CO_2/g)	T_{max} (°C)	GP	HI	OI	PI
Data from Western flank									
UZ-1	0.77	0.13	0.54	0.29	433	0.67	70	38	0.19
UZ-2	1.33	0.13	0.65	0.20	431	0.78	49	15	0.17
UZ-3	0.10	0.09	0.05	0.23	315	0.14	50	232	0.64
IM-1	0.09	0.04	0.23	0.36	431	0.27	26	40	0.15
IM-2	1.13	0.04	0.33	0.44	435	0.37	29	39	0.11
IM-3	1.30	0.05	0.36	0.24	426	0.41	28	18	0.12
Data from Eastern flank									
OK-1	0.78	0.05	0.45	0.47	435	0.50	56	60	0.09
OK-2	4.77	0.19	9.46	1.32	433	9.65	198	27	0.02
OK-3	2.76	0.18	2.52	1.25	437	2.70	91	45	0.07
OK-4	1.72	0.13	1.66	1.01	439	1.79	96	58	0.07

Abbreviations

TOC: total organic carbon, wt. %; S_1: free oil content (mg HC/g rock); S_2: remaining generation potential (mg HC/g rock); S_3: organic carbon dioxide yield (mg CO_2/ g rock); HI: Hydrogen Index S_2/TOC x 100 (in mg HC/g TOC); OI Oxygen Index: S_3/TOC x 100 (in mg CO_2/g TOC); PI Production Index: S_1/ (S_1+S_2); GP Generative Potential: S_1+S_2 (in mg HC/g TOC); T_{max}: temperature at max evolution of S_2 hydrocarbons (°C)

4.2. Organic richness

One of the conditions for source rocks to produce commercial quantities of oil is that they contain sufficient organic matter to generate and expel hydrocarbons [12-13], also reported that "clastic rocks, which are known as petroleum sources, contain a minimum of 0.5 wt. % of the total organic carbon (TOC wt. %), while good source rocks contain an average of about 2.0 wt. % of TOC. Total Organic Carbon (TOC) contents of the Mamu Shale vary from 0.10 to 1.33 wt. % within the Uzebba area, 0.90-1.30 wt. % within the Imiegba area and 0.78-4.77 wt. % within Okobo at the eastern region of the Anambra basin. This shows that TOC values (organic richness) increase basinward as the depth of burial increases; suggesting that we have excellent source rocks with greater potential to produce hydrocarbon basinward (Table 1). The Hydrogen Index (HI) values range from 49 to 70 mgHC/gTOC at Uzebba, 26 to 29 mgHC/gTOC at Imiegba and 56-198 mgHC/gTOC at Okobo. The lower Hydrogen Index (HI) values of shale of Mamu Formation reflects lower percentages of autochthonous organic matter [14]. The HI values are also seen to be increasing basinward.

Table 2. Mean values of TOC from Uzebba, Imiegba and Okobo and their respective locations

	Location	TOC (wt. %)
UZEBBA	0	0.73
IMIEGBA	7.5	1.11
OKOBO	24.2	2.51

NOTE: The red circle represents TOC values between 0-0.99 wt.%, blue represents TOC values between 1-1.99 wt.% while the green circle represents TOC values above 1.99

4.3. Type of organic matter

The quality of hydrocarbon is directly related to the type of organic matter contained in any potential source rocks [13]. The kerogen type of the Mamu shale samples from Uzebba, Imiegba, and Okobo was identified using HI versus OI cross plots (Figure 5A). The type of organic matter identified from the cross plot shows the presence of terrestrial organic matter. Therefore, it can be inferred that the Mamu sediments from the western flank, of Anambra Basin are of type IV but as we go basinward towards the eastern region of the basin we have type III kerogen with the potential to produce gas.

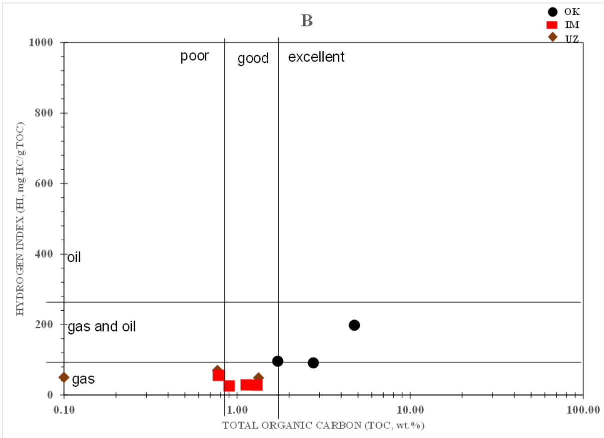

Figure 3. (A) Rock–Eval pyrolysis S2 against Total organic carbon (TOC), showing source rock potential of Mamu formation from Uzebba to Okobo (B) Hydrogen Index against Total organic carbon (TOC) showing generative potential; OK – Okobo, IM – Imiegba, IU – Ifon-Uzebba

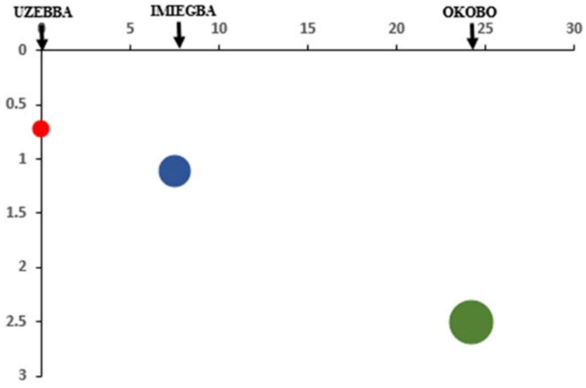

Figure 4. Schematic diagram of mean TOC against location showing the increase in TOC basinward

4.4. Thermal maturity

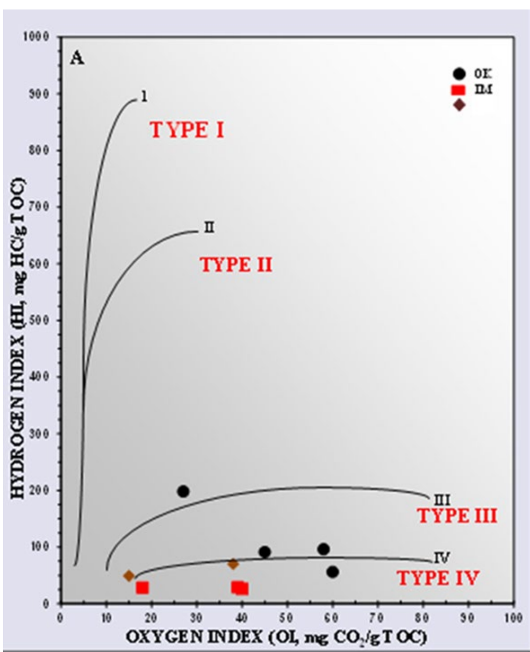

Figure 5. (A) Plot of HI versus OI indicating the kerogen types [15] (B) Cross plot of HI versus T_{max} indicating maturity [16]

In this study, Tmax values ranges from 315- 433°C, 426 - 435°C and 433 - 439°C for Uzebba, Imiegba and Okobo respectively while PI ranges from 0.17 - 0.64, 0.11 - 0.15 and 0.02 - 0.09 respectively. The cross plot of HI against Tmax, indicates that the organic matter becomes mature basinward (Figure 5B).

5. Conclusions

Organic geochemical studies, to assess the petroleum generation potential of the Mamu Formation on the western and eastern parts of the Anambra Basin allows for the following conclusions;

1. The kerogen contents of the Maastrichtian Mamu Shales are classified as type III, with total organic carbon (TOC) content ranging from 0.10 to 1.33 wt. % within the Uzebba area, 0.90-1.30 wt. % within the Imiegba area and 0.78-4.77 wt. % within Okobo at the eastern region of Anambra basin. This suggests that the shale samples range from poor to excellent source

rock basinward. The hydrogen index (HI) values of the shale samples range from 26-198 mgHC/g TOC, reflecting mainly terrigenous source.
2. The pyrolysis temperature (Tmax) values of the analyzed shales range from 315- 433°C, 426 - 435°C, and 433 - 439°C for Uzebba, Imiegba and Okobo respectively while PI ranges from 0.17 - 0.64, 0.11 - 0.15 and 0.02 - 0.09 indicating that the organic matter becomes thermally mature basinward.

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