Nigerian Journal of Technology (NIJOTECH)
Vol. 38, No. 4, October 2019, pp. **832 – 839**

Print ISSN: 0331-8443, Electronic ISSN: 2467-8821
www.nijotech.com
http://dx.doi.org/10.4314/njt.v38i4.3

DELINEATION OF FACTORS THAT CONTROL HYDROCARBON SOURCE ROCK MATURITY IN ANAMBRA AND ABAKALIKI BASINS SOUTH-EASTERN NIGERIA

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ABSTRACT
Outcrop information from Abakaliki and Anambra were used in this study to characterize the source and reservoir rocks in the two basins in order to give indication(s) for hydrocarbon generation potential in the basins to minimize uncertainty and risk that are allied with exploration and field development of oil and gas. Outrop mapping method was used to carry out geological, stratigraphical, geochemical, structural, petrographical, and sedimentological studies of rock units from outcrop sections within the two basins. Thirty-eight samples of shale were collected fromthese Basins in stratified mode of random sampling, and geochemical analysis (rockeval) was performed on the samples to determine the total organic content (TOC) and to assess the oil generating window. The results were analyzed, to properly characterize the potential source rock(s) and reservoir rock(s) in the basins, and factor(s) that can favour hydrocarbon traps. The results of the geological, stratigraphical, sedimentological, geochemical, and structural mapping were used to develop a new model for hydrocarbon generation in the Basins. The result of the geochemical analysis of shale samples from the Anambra Basin shows that the TOC values are $\geq 1wt\%$***, Tmax*** $\geq 431℃$***, Vitrinite reflectance values are*** $\geq 0.6\%$***, and*** S_1+S_2 ***values are*** $> 2.5mg/g$ ***for Mamu Formation while shale samples from other formations within Anambra Basin fall out of these ranges. The shale unit in the Mamu Formation is the major source rock for oil generation in the Anambra Basin while others have potential for gas generation with very little oil generation. The shale samples from Abakaliki Basin show that*** S_1+S_2 ***values range from*** $< 1 - 20mg/g$***, TOC values range from 0.31-4.55wt%, vitrinite reflectance ranges from 0.41-1.24% and Tmax ranges from*** $423℃ - 466℃$***. This result also shows that there is no source rock for oil generation in Abakaliki Basin; it is either gas or graphite.***

Key words: *Source rock, kerogen type, Abakaliki Basin, Anambra Basin, Oil generating window.*

1. INTRODUCTION

South-eastern Nigeria comprises Lower Benue Trough (Anambra Basin), Upper Benue Trough, Afikpo Basin and Abakaliki Basin. The basins overlap into one another in the geopolitical regions that boundary the south-eastern basins of Nigeria. Findings by authors that have worked in the region show that Abakaliki and Anambra Basin have prospects for hydrocarbon generation compare to other ones. Anambra Basin is located in the western part of southeast and extends to south-south part of Nigeria towards Edo and Delta States forming translational boundary with Niger delta (Fig. 1). It extends to the northern central in parts of Kogi and Benue States (Fig. 1). Abakaliki Basin is located in the eastern part of the southeast of Nigeria (Fig. 1). It boundary Anambra Basin, Afikpo Basin and Upper Benue Trough.

Petroleum generation within a basin is a function of the generative product of organic matter disseminated in the source rocks (shale) in the basin. The quantity of hydrocarbon in a basin is directly correlated with organic matter concentration of the potential source rocks within the basin [1]. Therefore, is very imperative to evaluate the potential source rocks in a

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basin in order to be able to evaluate the hydrocarbon generative potential of the basin. Under favourable condition of temperature, organic matter present in sedimentary rocks generates hydrocarbon. The generation of hydrocarbon and the type of hydrocarbon (oil or gas) that would be generated by a source rock in a basin solely depends on two major factors; temperature and time. Crude oil generation from source rock requires minimum temperature of 50°c while gas require minimum temperature range between 120°c-225°c [2], 225°c and above would generate graphite as carbon remains.

Indicative index for source rock ability or potential in generating oil or gas is its attainment of oil generating window (OGW). OGW of a formation in a basin depends on the heat or geothermal gradient of the formation in the basin. Hence, it is very vital to know the tectonic history (subsidence history) of a basin in order to properly characterize the source rock and potential of the source rock for hydrocarbon generation. Several authors have worked in Anambra and Abakaliki Basins with various findings. Okeke *et al.*[3] carried out a biomarker evaluation of Nsukka Formation within the Anambra Basin and came out with a finding that Nsukka is immature and is predominantly of terrestrial origin. Akande *et al.* [4] did petroleum potential evaluation of both Abakaliki and Anambra Basin. They observed from their study that Eze-Aku Formation is of type II and III, Awgu Shale is of type III kerogen and is gas prone. They concluded in their work that hydrocarbon in the post Santonian succession (Anambra Basin) must have been sourced from the pre Santonian succession (Abakaliki Basin). Emujakporue and Ekine [5] did a regional work in the south eastern part of Nigeria. They observed that the geothermal gradient of the eastern Niger Delta from bottom hole temperature exploration for nineteen exploration wells vary from 13.46°c/km to 33.66°C/km with an average value of 23.56°C/km. They observed low value in the northeast-southeast direction and an increase in seaward. They finally concluded that the distribution of geothermal gradient across the basins in the eastern-south south Nigeria is directly related to the overburden thickness. This finding implies that Anambra Basin and Abakaliki Basin would not be able to generate hydrocarbon. However, this present research work is geared at characterizing the potential source rocks in the two basins in order to properly clarify mature source rocks in the two basins and as well identify the gas and the oil source, and those ones that have potential for oil or gas. Finally, this work is intended coming up with a new tectonic model for hydrocarbon maturation in Anambra and Abakaliki Basins in order to have basic knowledge about the basins in order to eliminate the uncertainties that are allied with exploration in the basins.

2. MATERIALS AND METHODS

Thirty-eight samples of shale were collected from the study area; thirteen samples were collected from Abakaliki Basin by a stratified ode of random sampling at various locations within the basin while twenty-five samples of shale were collected by a stratified mode of random sampling from outcrop sections in different locations in Anambra Basin during detailed geologic mapping.

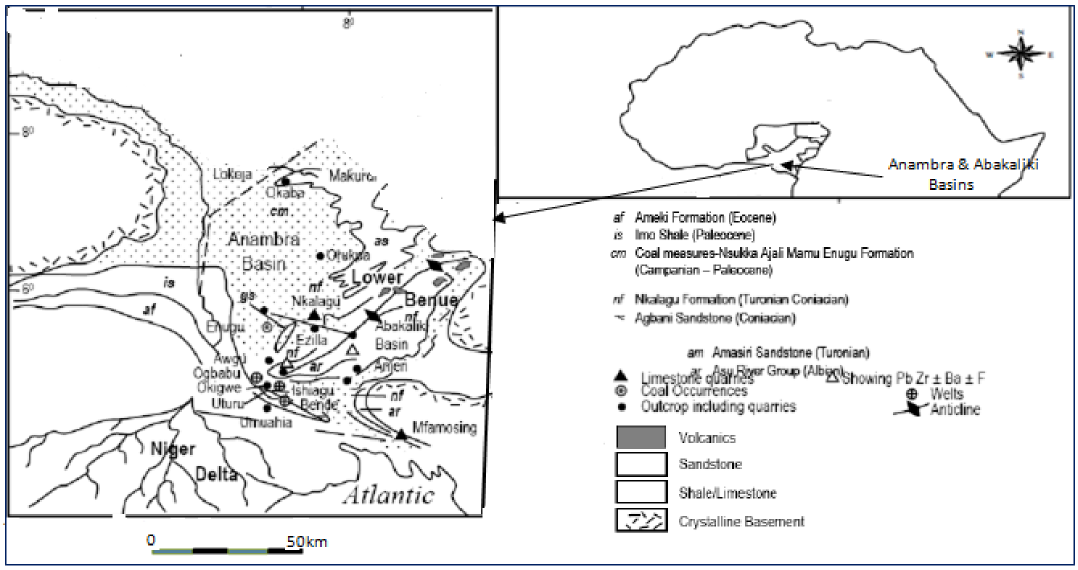

Fig. 1: Map of southeastern Nigeria showing Abakaliki and Anambra Basin

The shale samples were crushed. Representative samples of 100mg of each formation from both basins were weighed into oven and carbonate was removed by adding 1ml of HCl. 5hours was given to the samples to drain off the HCl and thereafter kept in an oven at temperature of 50°c and left overnight. In the following day, LECO device was used to measure the TOC of each sample. Rock-eval was done for each sample at elevated temperature of 600°c and rock pyrolysis was carried out simultaneously. Hydrocarbon already generated within the source rock (S_1), residual petroleum potential (S_2), gas (S_0), temperature at which maximum in S_2 response (Tmax), and the residual carbon content of each sample(S_4) were measured. The values of the measured Tmax were used to compute the vitrinite reflectance (%VRo) as well TOC with the equation below:

$$\%VRo = 0.01803Tmax - 7.16 \qquad (1)$$

Where %VRo = calculated vitrinite reflectance

$$TOC = \frac{(0.083(S_0 + S_1 + S_2) + S_4)}{10(wt\%)} \qquad (2)$$

The computed TOC values and measured S_1 and S_2 were used to compute hydrogen index (HI) and production index as follows:

$$HI = \frac{S_2}{TOC} \times 100 \qquad (3)$$

$$PI = \frac{S_1}{(S_1 + S_2)} \qquad (4)$$

The values of measured and computed parameters above were used to characterize the source rock. However, stratigraphical, sedimetological and petrographical studies of outcrops in the two basins were carefully carried out in other to get vital information about the geology and tectonic history of the basin in order to be able to integrate the information with geochemical information measured and computed using equations (1) to (4) above so as to properly model the tectonic model for hydrocarbon maturation for both Anambra and Abakaliki Basin. The results of the geological, stratigraphical, sedimentological, geochemical, and structural studies were integrated and used to develop a new model for hydrocarbon generation in the Basins.

3. RESULTS AND DISCUSSION

The result of the geological mapping of outcrops, sedimentological, stratigraphical, structural and petrological studies show that, Abakaliki Basin is filled with sediments that have high dip of over 35° (Fig. 2a) , baked shale (Fig. 2b) with slaty cleavage, and intrusion of syenite, trachyte, dolerite sill (Fig. 2c), gabbro dyke (Fig. 2d), lapili tuff, and pyroclastic intrusion. These intrusions form aureole (Fig. 2e) of various length ranging from 1.6m to 21m. They are folded and faulted. The formations within Anambra Basin have dip ranging from 2° to 8°. There are faults (Fig. 2f) cutting across some of the rock unit at local scale and trace of trace fossils within the sediments.

The results of the geochemical analysis for Abakaliki and Anambra Basins are given in Table 1 and 2 respectively.

3.2.1 Source Rock Characterization of Abakaliki Bain

The total organic content (TOC) result of Abakaliki Bain shows that Asu River Group is less than 0.5wt% (Table1). This suggests that the quality of Asu River Group source rock has poor quality (Table 3) according to Welte (1978) source rock quality characterization. However, other formation (Awgu and Eze-aku) in Abakaliki Basin have TOC values more than 0.5wt% (Table 1). It implies that the quality of these formations is fair to good (Table 3). The result of Tmax for Asu River Group is above 431°C (Table 1). It is an evidence that Asu River is thermally mature, which suggests rapid subsidence of the basin as at the time of deposition thus, given the required temperature for it to attain oil generating window (OGW). Despite it attainment of OGW, TOC values of Asu River Group indicate poor source rock quality (Table 3), it would not be able to generate hydrocarbon that can form pool in the reservoir. Hence, it is not adequate enough to generate enough hydrocarbon that can be trapped in a reservoir. This evidence is confirmed by the value of S1 which is zero throughout Asu River (Table 1), it shows that no hydrocarbon has been generated from the potential source rock. However, Awgu and Ezeaku Formations have some of their Tmax values above 431°C and bellow 431°C (Table 1). This observation suggests that some parts of the Abakaliki Basin where the source rocks were deposited experienced rapid subsidence thus paved way for thermal maturity while some parts of the basin did not experienced rapid subsidence thus they could not attain the depth at that time that was favourable for thermal maturity. The values of S_1+S_2 for Awgu and Ezeaku Formations in Abakaliki Basin are less than 2.5kgHC/t (Table 3) and the vitrinite reflectance values range between 0.6-1.25VR0% (Table 1).

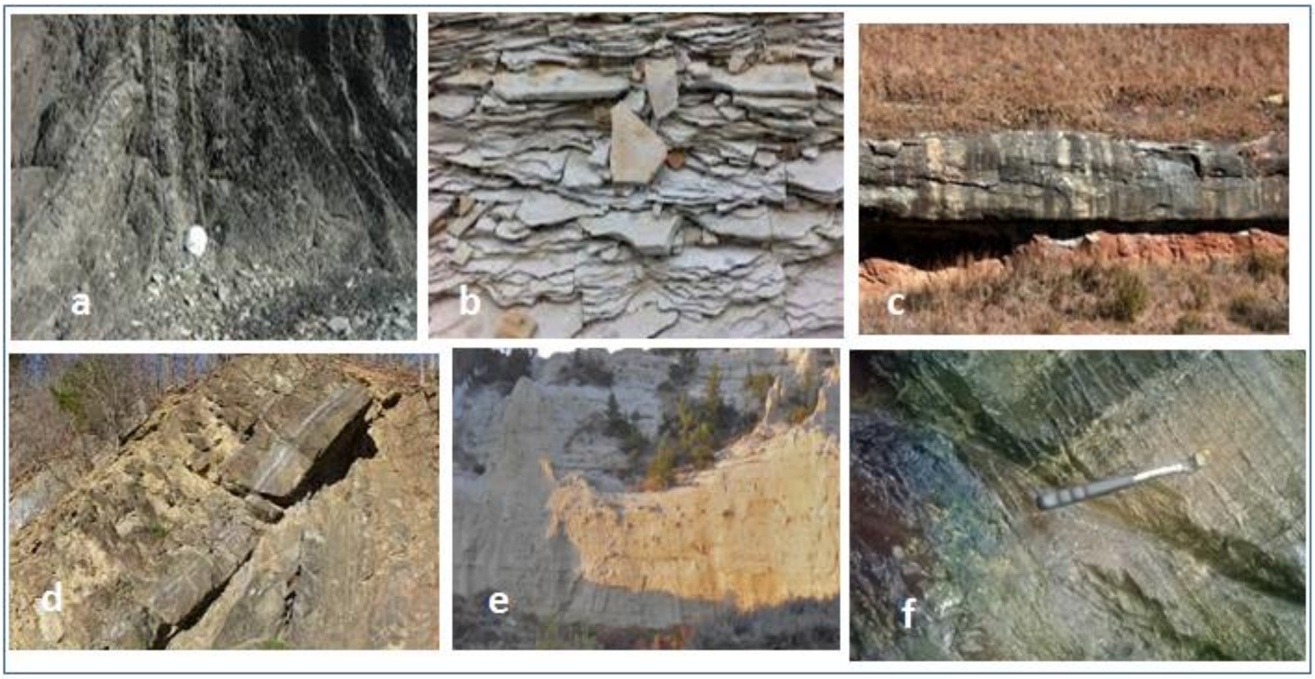

Fig.2: (a) Tilted Asu River Group (b) Baked shale unit within Bakaliki Basin (c) Dolerite sill intrusion within the sedimentary rock at Lokpatan (d) Gabbro dyke intusion (e) Aureole contact at Abakaliki within Asu River Group (f) Faulted unit of Imo Shale at the Edo State portion of Anambra State

Table 1: Geochemical Result of shale samples within Abakaliki Basin

S/N	Formations	TOC (wt%)	S_1(HC/t)	S_2(HC/t)	Tmax (°C)	%VRo	HI	PI
1	Awgu	1.49	0.11	1.63	423	0.46	109	0.04
2	Awgu	0.71	0.2	0.08	466	1.24	13	0.07
3	Awgu	0.51	0.2	0.17	435	0.68	33	0.54
4	Awgu	0.65	0.19	0.35	434	0.67	54	0.35
5	Ezeaku	1.88	0.59	10.30	422	0.45	548	0.05
6	Ezeaku	0.86	0.01	0.09	426	0.52	10	0.10
7	Ezeaku	1.59	0.33	6.94	426	0.52	435	0.05
8	Ezeaku	1.91	0.33	0.87	420	0.41	46	0.03
9	Ezeaku	0.76	0.01	0.39	432	0.6	52	0.03
10	Ezeaku	0.57	0.09	0.19	448	0.92	33	0.3
11	Asu River	0.31	0	0.03	464	1.2	9	0
12	Asu River	0.16	0	0.05	440	0.77	33	0
13	Asu River	0.22	0	0.06	441	0.79	23	0

Table 2: Geochemical Result of shale samples within Anambra Basin

S/N	Formations	TOC (wt%)	S_1(HC/t)	S_2(HC/t)	Tmax (°C)	%VRo	HI	PI
1	Ogwashi	1.64	0.05	0.59	422	0.45	35.98	0.04
2	Ogwashi	1.76	0.07	0.14	414	0.30	7.95	0.33
3	Ameki	1.55	0.03	0.15	410	0.23	7.1	0.17
4	Ameki	1.5	0.04	0.65	416	0.34	43	0.06
5	Imo	1.6	0.01	0.26	420	0.41	16.25	0.04
6	Imo	1.5	0.04	0.52	426	0.52	35	0.07
7	Nsukka	0.5	0.03	0.21	421	0.42	42	0.13
8	Nsukka	0.85	0.03	0.26	430	0.58	31	0.1
9	Nsukka	1.6	0.07	0.74	430	0.58	64	0.09
10	Nsukka	1.05	0.07	0.71	432	0.62	68	0.09
11	Nsukka	18.67	0.43	18.25	431	0.6	98	0.02
12	Mamu	5.08	0.24	9.96	432	0.6	196	0.02
13	Mamu	1.45	0.09	153	432	0.62	106	0.06
14	Mamu	4.73	0.3	11.87	433	0.63	251	0.02

S/N	Formations	TOC (wt%)	S_1(HC/t)	S_2(HC/t)	Tmax (°C)	%VRo	HI	PI
15	Mamu	6.1	0.27	11.62	432	0.62	260	0.03
16	Mamu	3.79	0.33	9.86	433	0.63	251	0.02
17	Enugu	2.04	0.09	0.8	425	0.49	69	0.05
18	Enugu	0.74	0.07	1.18	428	0.54	159	0.1
19	Enugu	2.34	0.05	1.29	434	0.65	55	0.09
20	Enugu	2.95	0.07	1.29	427	0.53	42	0.04
21	Nkporo	3.21	0.01	3.56	434	0.65	111	0.03
22	Nkporo	0.97	0.07	0.3	439	0.74	31	0.03
23	Nkporo	2.29	0.03	1.18	424	0.47	48	0.04
24	Nkporo	1.07	0.03	1.1	425	0.49	36	0.07
25	Nkporo	5.75	0.38	18.91	432	0.62	294	0.07

These values suggest gas prone source rock (Table 3). Those ones that have S1+S2 values less than 2.5kgHC/t and vitrinite reflectance values less than 0.6VR0% indicate immature source rocks (Table 3).

A plot on hydrocarbon yield curve after (Fig.5) according to the method of Salufu and Ogunkunle [6] shows that the three formations in the Abakaliki Basin are between mature gas source rocks and immature source rocks. Similarly, a plot on kerogen curve (Fig. 6) after the method of Baskin [7] indicates kerogen type III and immature (Fig. 6). This suggests that Abakaliki Basin source rocks can only generate gas.

Table 3: Interpreted result of Rock-EvalPyrolyiss for shale samples in Abakaliki Basin

S/N	Formations	TOC (wt%)	Tmax (°C)	%VRo	S_1+ S_2	Source Rock	Maturity	%Maturity	Hydrocarbon yield
1	Awgu	1.49	423	0.46	1.74	Good	Immature		Gas potential
2	Awgu	0.71	466	1.24	0.1	Fair	Mature		Gas
3	Awgu	0.51	435	0.68	0.37	Fair	Mature	75%	Gas
4	Awgu	0.65	434	0.67	0.54	Fair	Mature		Gas
5	Ezeaku	1.88	422	0.45	10.89	Good	Immature		Oil potential
6	Ezeaku	0.86	426	0.52	0.1	Fair	Immature	33%	Gas potential
7	Ezeaku	1.59	426	0.52	7.27	Good	Immature		Oil Potential
8	Ezeaku	1.91	420	0.41	1.2	Good	Immature		Gas potential
9	Ezeaku	0.76	432	0.6	0.4	Fair	Mature		Gas
10	Ezeaku	0.57	448	0.92	0.28	Fair	Mature		Gas
11	Asu River	0.31	464	1.2	0.03	Poor	Mature		Gas
12	Asu River	0.16	440	0.77	0.05	Poor	Mature	100%	Gas
13	Asu River	0.22	441	0.79	0.06	Poor	Mature		Gas

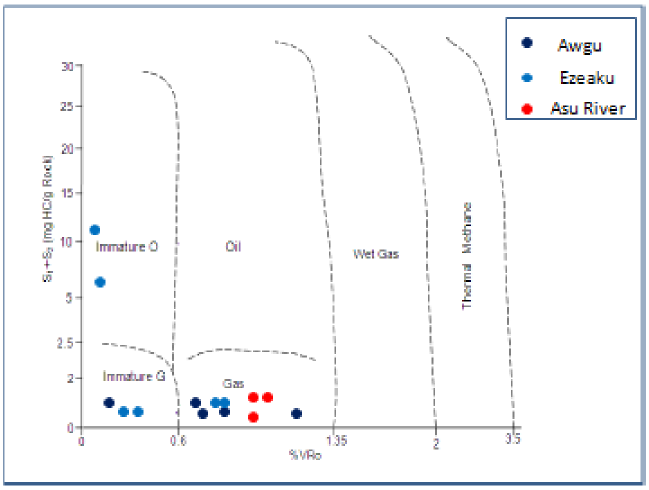

Fig. 5: Hydrocarbon yield curve for source rock in Abakaliki Basin

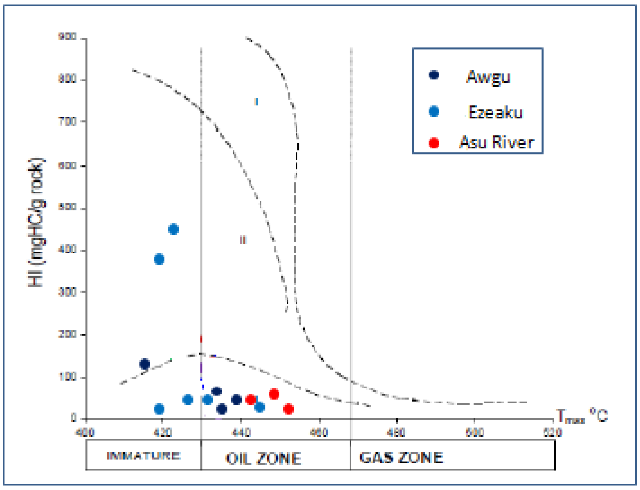

Fig. 6: Kerogen type curve for source rock in Abakaliki Basin

3.2.2 Source Rock Characterization of Anambra Bain

All the twenty four shale samples collected from Anambra Basin show TOC values range from 0.5wt% to over 5wt% (Table 2). These values suggest that the source rocks within Anambra Basin are fair to excellent in quality (Table 4) to generate enough hydrocarbon requires to form a pool in any available reservoir. All the Tmax values for Mamu Formations are above 431°C (Table 2). This shows that Mamu Formation has attained OGW, evidence of rapid subsidence as at the time of deposition. However, Two out of the Nkporo Formation have value lesser than 431°C (Table 2), which means those ones were deposited at the portion of the basin that experienced very low rate of subsidence thus, they could not reach the require depth that would have favour the generation of the minimum temperature for geothermal cooking of the organic matter within the source rock. Similar process gave rise to those portions of Ogwashi-Asaba, Ameki, Imo, Enugu, Nkporo, and Nsukka Formations that have TOC values below 431°C (Table 2).

The plot of the parameter on hydrocarbon yield curve (Fig. 7) after the method of Salufu and Ogunkunle (2015) shows that Mamu is mainly oil prone with very little gas (Fig. 7). Enugu, Nsukka, and Nkporo Formations are between immature and gas prone with little oil while Ogwashi-Asaba, Ameki, and Imo Formations are immature (Fig. 7). The plot of HI against Tmax shows that Mamu is mainly type II with very little type III kerogen while others fall within type III kerogen and at immature portion (Fig. 8).

3.2.3 Model for Hydrocarbon Maturation in Abakaliki and Anambra Bains

The breaking up of West African plate from South American plate in the Early Cretaceous led to the evolution of Abakaliki Basin as one of the basins within the Benue Trough. Atlantic Ocean was evolved as a result of the rift.

Table 4: Interpreted result of Rock-Eval Pyrolysis for shale samples Anambra Basin

S/N	Formations	TOC (wt%)	Tmax (°C)	%VRo	S_1+ S_2	Source Rock	Maturity	%Maturity	Hydrocarbon yield
1	Ogwashi	1.64	422	0.45	0.64	Good	Immature	0%	Gas potential
2	Ogwashi	1.76	414	0.30	0.21	Good	Immature		Gas potential
3	Ameki	1.55	410	0.23	0.18	Good	Immature	0%	Gas potential
4	Ameki	1.5	416	0.34	0.69	Good	Immature		Gas potential
5	Imo	1.6	420	0.41	0.27	Good	Immature	0%	Gas potential
6	Imo	1.5	426	0.52	0.56	Good	Immature		Gas potential
7	Nsukka	0.5	421	0.42	0.24	Fair	Immature		Gas potential
8	Nsukka	0.85	430	0.58	0.29	Fair	Immature	40%	Gas potential
9	Nsukka	1.6	430	0.58	0.81	Good	Immature		Gas potential
10	Nsukka	1.05	432	0.62	0.78	Good	Mature		Gas
11	Nsukka	18.67	431	0.6	18.68	Excellent	Mature		Oil
12	Mamu	5.08	432	0.6	10.10	Excellent	Mature		Oil
13	Mamu	1.45	432	0.62	153.09	Good	Mature		Oil
14	Mamu	4.73	433	0.63	11.9	Excellent	Mature	100%	Oil
15	Mamu	6.1	432	0.62	11.89	Excellent	Mature		Oil
16	Mamu	3.79	433	0.63	2.40	V. good	Mature		Gas
17	Enugu	2.04	425	0.49	0.17	Good	Immature		Gas potential
18	Enugu	0.74	428	0.54	1.25	Fair	Immature		Gas potential
19	Enugu	2.34	434	0.65	1.34	V. good	Mature	25%	Gas
20	Enugu	2.95	427	0.53	1.36	V. good	Immature		Gas potential
21	Nkporo	3.21	434	0.65	3.57	V. good	Mature		Oil
22	Nkporo	0.97	439	0.74	0.10	Fair	Mature		Gas
23	Nkporo	2.29	424	0.47	1.21	V. good	Immature	60%	Gas potential
24	Nkporo	1.07	425	0.49	1.13	Good	Immature		Gas potential
25	Nkporo	5.75	432	0.62	19.39	Excellent	Mature		Oil

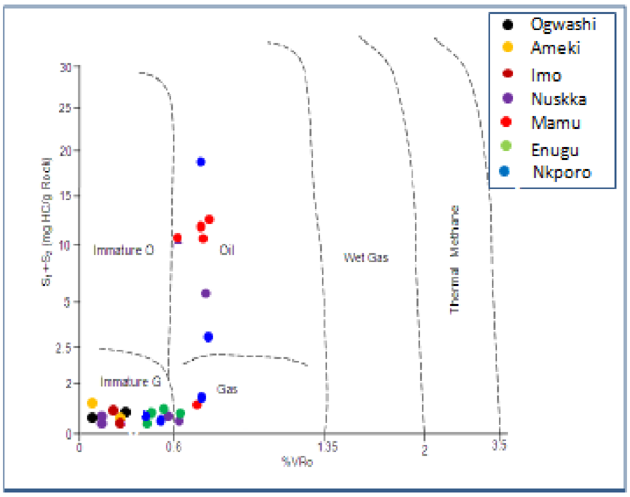

Fig. 7: Hydrocarbon yield curve for source rock in Anambra Basin

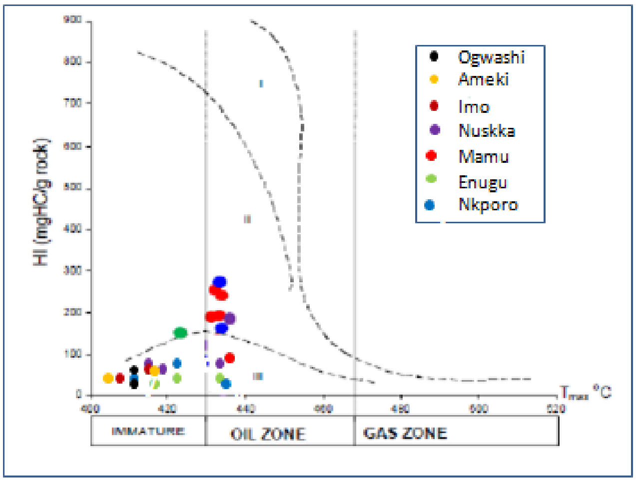

Fig. 8: Kerogen type curve for source rock in Anambra Basin

However, Benue Trough is the failed arm of the triple junctions that extends into Nigeria, passing through the south east. Further movement along the fault plane modified the basin into Abakaliki. As the basin opened up, there was no sedimentation immediately until Albian time set in, when marine transgression and sedimentation began. Sediments and organic materials were transported from both land and marine into the basin as Asu River Group and Ezeaku Group in the Albian-Turonian. Asu River Group was deposited in the aerated portion of the basin where oxidation was predominant thus caused starvation of organic matter contents in the shale unit of Asu River due to inadequate preservation as indicated by low TOC values less than 0.5wt% (Table 1). Ezeaku Formation was deposited in the portion of the basin where there was little or no oxidation thus; the shale unit was rich in organic matter as shown by the high TOC value greater than 0.5wt% (Table 1) due to good preservation.

Maturation in Abakaliki Basin was as a result of burial and heat flow. At the time of deposition of the Asu River and Ezeaku Groups in Abakaliki there was low rate burial of sediments as indicated by the presence of slatycleavge among the backed shale associated with the two formations, then, the organic matter in the shale units could not attain the required temperature for hydrocarbon maturation. The inception of Santonian paved way for hydrocarbon maturation in Abakaliki Basin by heat flow in the basin by igneous bodies intrusions (Fig. 9), evidence from the syenite, trachyte, dolerite, lapili tuff and pyroclastic intrusions that are associate with the Asu River and Ezeaku sediments. The heat flow resulted to high Tmax values observed in some of the shale samples of Asu River, Ezeaku, and Awgu Shale while those one with Tmax value less than 431°C (see Table 1) is as a result of variation in heat flow due to the fact that some area experienced intensive igneous intrusions and heat flow was very intense while those areas that experience mild or no igneous intrusion have very low or no heat flow (Fig. 9). The heat flow heat up the little oil in Abakaliki during the Santonian tectonism thus converting it to gas because of high heat flow.

Santonian tectonism caused uplift that created Anambra Basin. In the Late Campanian marine transgression caused both marine and terrestrial sediments to be deposited into the basin as Nkporo Group. Fluctuation in sea level caused other formations to be deposited in sequential other, Mama overlies Nkporo Group, and Mamu passes upward unto Ajali, Nsukka, Imo, Ameki, and Ogwashi–Asaba Formations. The sediments were deposited laterally across the Anambra Basin and overlap each other at some part of the basin in vertical succession. Hydrocarbon maturation in Anambra Basin is due to rapid subsidence rate that occurred in variation laterally across the basin. Mamu Formation was deposited in the portion of the basin that experienced rapid subsidence (Fig. 9) at the time of deposition, that is why the whole formation was able to attain depth range that favoured maturation (Table 4). However, the remaining formations that have both mature and immature source rock is as a result of their lateral deposition in both the portions of the basin that experienced rapid subsidence and that portion that did not (Fig. 9). Some overlaps into active part and they were able to attain maturation while the part the fall out of the active part remain immature. Formations that were deposited in the Late Paleocene to Eocene in the basin (Imo Shale, Ameki, and Ogwashi-Asaba) were deposited at the time the basin was not experiencing rapid subsidence (Fig. 9) again thus, they could not attain the depth that would have favour Imo Shale, Ameki, and Ogwashi-Asaba Formations to attain hydrocarbon maturation. That is why all the Tmax values of these formations are below 431°C (see Table 2).

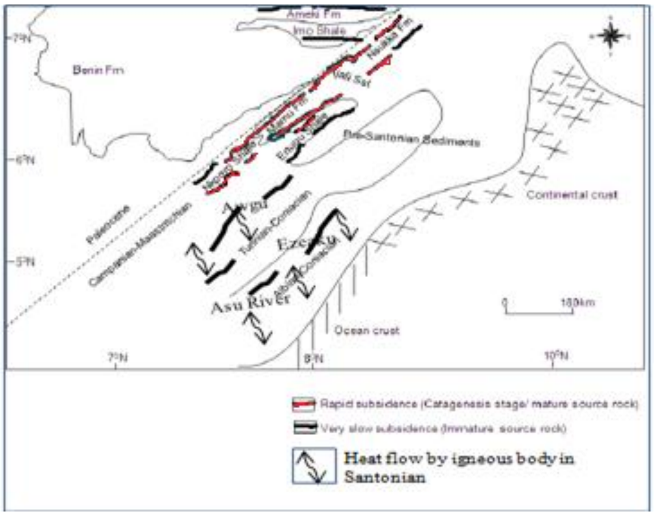

Fig. 9: Model for hydrocarbon Maturation in Abakaliki and Anambra Basin

4. CONCLUSION

This study has shown that there are indications for oil and gas generation from the source rocks in the Anambra Basin while only gas can be generated from the source rocks within Abakaliki Basin. Hydrocarbon maturation in the Abakaliki Basin was by burial and heat flow while rapid subsidence caused hydrocarbon maturation in the Anambra Basin.

The presence of localized structures (faults and folds) within the Anambra Basin and regional faults and folds by Santonian tectonism within Abakaliki Basin give evidence of structural traps occurrence within the two basins respectively to trap hydrocarbon that must have been generated from the source rocks in the two basins. However, effort should be geared toward identifying these traps at deep depth in order to effectively explore for the hydrocarbons within these basins using sophisticated 2D and 3D seismic.

5. REFERENCES

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