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Aspects of Hydrocarbon Potential of the Tertiary Imo Shale Formation in Anambra Basin, Southeastern Nigeria.

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Abstract: *The Tertiary Imo Shale Formation, a lithofacies equivalent of marine Akata Formation (prolific source rock) in subsurface Niger Delta, requires proper evaluation of its hydrocarbon generative potentials to complement organic geochemical data in Anambra Basin. This study attempts to evaluate aspects of the source rock potential for hydrocarbon generation of the Imo Shale Formation penetrated by the Akukwa-II and Nzam-I wells in Anambra basin. The sediments encountered at depth range of 120 to 240 m and 550 to 650 m in Akukwa-II and Nzam-1 wells respectively, are made up of shales, sandy shale and mudstones. The shales are fine grained, fissile and light to dark grey in colour, the sandy shale is medium grained and grey in colour while the mudstones are fine grained and brownish grey in colour. The Total Organic Carbon (TOC) values of the samples range from 0.39 to 0.94 wt. % (av. 0.60 wt. %) in Akukwa-II well and 0.39 to 2.07 wt. % (av. 0.70 wt. %) in Nzam-I well indicating that the sediments contain appreciable quantity of organic matter that can generate hydrocarbon. Hydrogen Index, Oxygen Index and Tmax of the samples range from 11.0 to 28.0 mg HC/g TOC, 53.0 mg/g to128 mg/g and 409 to 430 ^{o}C respectively in Akukwa-II well and 14.0 to 48.0 mg HC/g TOC, 45.0 to 294.0 mg HC/g TOC and 421 to 497 ^{o}C respectively in Nzam-I well. Genetic Potential (GP), Production Index (PI) and Calculated vitrinite reflectance (% Ro) in Akukwa-II and Nzam-I wells are 0.10 to 0.34 mg/g, 0.22 to 0.50, 0.202 to 0.580 and 0.08 to 0.73 mg/g, 0.04 to 0.32, 0.418 to 1.786 respectively. Rock-eval data suggest that the sediments are poor to fair source rock for gaseous hydrocarbon and the organic matter is predominantly type IV kerogen sourced from terrestrial materials which does not yield significant amounts of hydrocarbon. Thermal maturity derived from Rock-eval data revealed that the Imo Formation samples are immature with respect to hydrocarbon generation. The sediments may generate very little dry gas at appropriate maturity due to inert nature of type IV kerogen.*

Keywords: *Hydrocarbon potential, Imo Shale Formation, kerogen type, source rock, thermal maturity*

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I. Introduction

Anambra basin has attracted interest for about one century starting from the time of coal discovery in Enugu though the time of intensive coal exploitation in Enugu to the early time of hydrocarbon exploration in the basin and currently in the time of renewed exploration or re-evaluation of acquired data. Increasing energy demand has necessitated evaluation and re-evaluation of many inland basins in Nigeria. Most of the hydrocarbon exploration efforts in Anambra basin have indicated abundance of gas or condensates with little oil (1-3). Anambra basin is characterized by undeformed and non tectonised sediments with relatively moderate temperature regime which is suitable for generation and accumumulation of hydrocarbon when compared to the tectonised and deformed sediments of the pre Santonian Abakaliki folded belt (4). The stratigraphy and structural configuration of Campano-Maastrichtian Anambra basin has positioned it to be a petroliferous basin with all the elements of petroleum system (5). Among the highlighted source rocks in Anambra basin, Imo Shale has received little attention despite fact that the stratigraphy of the southern sedimentary basins showed strong resemblance in sediments of Imo Shale Formation and Akata Formation in Anambra basin and Niger Delta respectively (6-8). Murat (4) also highlighted the structural relationships between the evolution of the Anambra basin and Niger Delta with respect to the NE-SW trending Benue Trough. Assessment of hydrocarbon potential of a basin is not complete until all the elements of the petroleum system have been evaluated. Since Imo Shale has been reported to be an outcropping lithofacies equivalent of marine Akata Formation (a prolific source rock) in subsurface Niger Delta (7, 9, 10), geochemical evaluation of Imo Shale with respect to its hydrocarbon generative potential in the Anambra basin would therefore complement existing geochemical data on hydrocarbon prospectivity of the basin. Studies by (1-3, 5, 11-21) among others have identified hydrocarbon source rocks in Anambra basin. Most of these studies have documented Nkporo, Mamu and Imo Shale Formations as source rocks for hydrocarbon in the basin. A greater proportion of these studies were concentrated on Nkporo and Mamu Formations with emphasis on quality of organic matter, thermal maturity, organic matter source input and paleoenvironment. This may be due to the stratigraphic position of the formations in the Anambra basin coupled with the fact that they were penetrated by many exploration wells and their surface exposures were also rich in organic matter. Though quite a number of studies (7, 8, 22-25) have been done on age and paleoenvironment of Imo Shale Formation, however limited studies (13, 14, 26) were carried out on hydrocarbon potential of Imo Formation, possibly because it was proposed to be suitable seal or caprock (1) and the fact that it has only been encountered in few exploration wells while some outcrops of the formation were characterised by clays and siltstones which often diverts attention from it. This study therefore attempts to evaluate the source rock potential for hydrocarbon generation of the Imo Shale Formation penetrated by the Akukwa-II and Nzam-1 wells.

II. Geology

The evolution of the Southern sedimentary basins began in the Early Cretaceous with the formation of the Benue-Abakaliki Trough as a failed arm of the rift triple junction associated with the separation of the African and south American continents and subsequent opening of the South Atlantic (27-29). The exact areal definition of the Benue Trough as a whole has been controversial, however it is clear that it originated from a \`pull-apart\` basin associated with the opening of the Atlantic Ocean which ended in the Early Tertiary with the development of the Tertiary Niger Delta (30). The Benue Trough is made up of three regions; the lower, the middle and the upper Benue Troughs. The northern limit of the Lower Benue Trough corresponds to the Gboko transform fault that was recognized by (12) while the eastern limit covers the Lokpanta area. The Santonian deformational episode fragmented the Lower Benue Trough into the Abakaliki Anticlinorium and the flanking Anambra and Afikpo Synclines. Murat (4) reported that prior to the Santonian period, the main depocentre was the Abakaliki Trough while a stable broad area (Anambra platform) was identified to the west. Consequent upon the Santonian folding, the Abakaliki Trough was inverted to produce the main surface structural feature, the Abakaliki Uplift. The Anambra platform now subsided strongly to become the main depocentre, with a subsidiary depocentre (Afikpo Syncline) developing simultaneously to the southeast of the Abakaliki Uplift (4). Agagu and Adhigije (31) also reported a division of the Anambra basin into southern Onitsha basin and circular northern Ankpa basin separated by the NW-SE trending Nsukka High. The tectonic evolution, structures, sedimentation and stratigraphy of the Anambra basin have been described by (4, 6, 11, 29-38) and others. The stratigraphy of the Campano-Maastrichtian Anambra basin consists of the Nkporo Group (Nkporo/Enugu/Owelli Formation), Mamu Formation, Ajali Sandstones, Nsukka Formation, Imo Formation and Ameki/Bende Formation (Table 1).

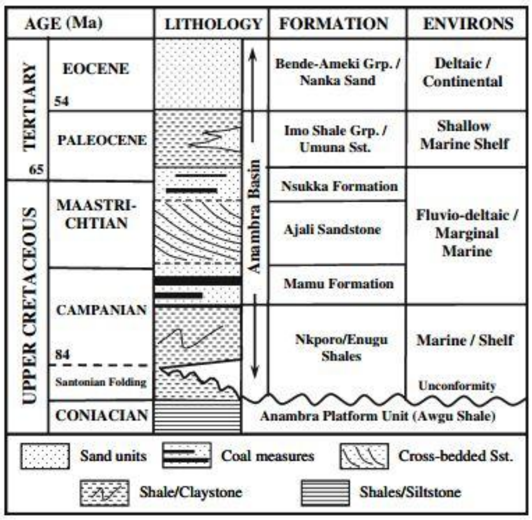
The Imo Formation was formerly referred to as Imo-Anambra Shales (39) and Imo Clay-Shales (40, 41). The Imo shale overlies the Nsukka Formation. It is essentially a mudrock unit consisting of thick, fine textured, dark grey or bluish grey shale, with occasional admixtures of clay, ironstone and thin sandstone bands and limestone intercalations. The Formation becomes sandier towards the top where it consists of alternation of sandstone and shale (42). Imo Shale represents a stratigraphic unit widely distributed over several hundreds of kilometers from the southeast boundary of Nigeria across the Niger Delta to the western boundary (23). Murat (4) reported that Imo Shale was deposited during Paleocene when transgressive conditions returned back to the Anambra basin. Nwajide and Reijers (10) interpreted the Imo shale to reflect shallow marine shelf in which foreshore and shoreface were occasionally preserved. Nwajide and Reijers (10) also inferred that the subsurface Paleocene deposits in the Niger Delta which are essentially of deep marine origin are equivalent of the Imo shale of the Anambra basin. The Imo Shale is dated Paleocene on the basis of foraminiferal (6), while Berggren (43) reported Lower Eocene age for upper part of the formation. Oloto (23) also reported Late Paleocene to Early Eocene for Imo Shale. Durugbo (26) reported Middle Paleocene to Early Eocene age for Imo Shale and inferred a near shore to marginal marine paleoenvironment.

III. Samples And Methods

Thirty-three (33) samples comprising of ditch cuttings and cores belonging to Imo Shale Formation in Akukwa-II and Nzam-I wells in the Anambra basin were obtained from the Nigerian Geological Survey Agency, Kaduna office. The samples were selected at 5 m interval from depth ranges of 120 m to 240 m and 550 m to 650 m in Akukwa-II and Nzam-1 wells respectively. Akukwa–II well is located on longitude $6^0 15^I$ N and latitude $7^0 10^I$ E (OPL 907) while Nzam-1 well lies in OPL 447 on longitude $06^o\ 28^I$ N and latitude $06^o\ 45^I$ E (Figure 1). The samples were examined for their lithology, colour, grain size among other features. The ditch cuttings samples were also checked for drilling mud and other impurities, and were subsequently removed where present.

All the samples were finely pulverized, stored in vials and labelled. The samples were treated with concentrated hydrochloric acid to remove carbonates and the total organic carbon (TOC) is measured on

Table 1: Stratigraphic sequence of the Anambra Basin



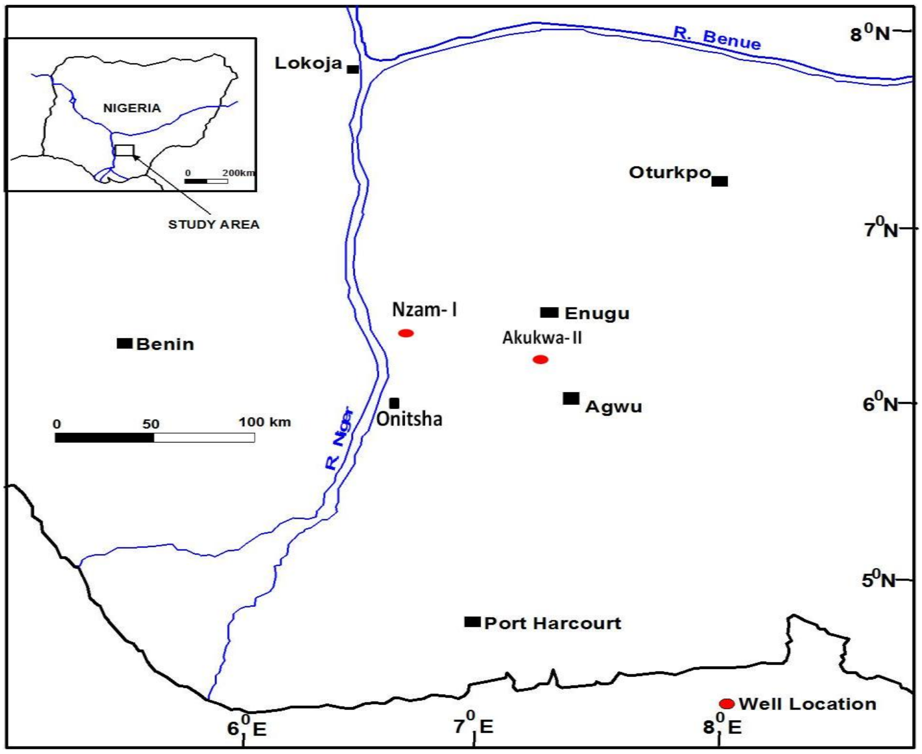


Figure 1: Map of southern Nigeria showing position of the studied wells

carbonate free samples using Elementar Vario EL III elemental analyser (Hanau, Germany). Using the threshold value of 0.5 wt. % TOC for the samples, twenty-eight (28) samples were further subjected to Rock-eval pyrolysis analysis using Rock-eval Pyrolyser II. Rock-eval data include Hydrogen Index (HI), Oxygen Index (OI), Genetic Potential (GP), Production Index (PI), maximum temperature (Tmax) etc. Calculated vitrinite reflectance (Calc. % Ro) was generated from Tmax using the formula: Calc. % Ro = 0.0180 × Tmax (44). The

Total organic carbon and Rock-eval pyrolysis analyses were carried out the State Key Laboratory of Organic Geochemistry, Guangzhou Institute of Geochemistry, China.

IV. Results And Discussions

4.1 Lithology

The studied interval of Akukwa-II well (120-240 m) is essentially composed of light to dark grey shales. While that of the Nzam-1 well (550-650 m) is made up of shales, sandy shale and mudstones. The lithological logs of the sampled intervals of the Imo Shale from the two wells are presented in Figure 2. The shales are fine grained, fissile and light to dark grey in colour, the sandy shale is medium grained and grey in colour while the mudstones are fine grained and brownish grey in colour. In Nzam-I well, the shale unit is intercalated by sandy shale and mudstone units from the middle part to nearly the base of the section.

4.2 Organic Matter Richness

The results of the total organic carbon (TOC) and Rock-eval pyrolysis analyses are presented in Table 2. The quantity of organic matter expressed as total organic carbon is a measurement of the organic richness of sediments or rocks (44). The TOC values of the Imo shale samples ranges from 0.39 to 0.94 wt. % in Akukwa-II well and from 0.39 to 2.07 in Nzam-1 well. This shows an average TOC value of 0.60 wt. % and 0.70 wt. % in Akukwa-II and Nzam-1 wells respectively. Although, there are few samples with TOC values below 0.5 wt. % (threshold value for hydrocarbon generation), the average values and range of TOC values of the Imo shale samples from the two wells indicate that they contained appreciable quantity of organic matter with generative potential for hydrocarbon (45). The source rock quality of the sediments of Imo shale Formation from the wells was also assessed by the pyrolysis-derived hydrocarbon generative potential (GP = S1+S2) of the samples (Table 2). The GP values for the samples in Akukwa-II well range from 0.1 to 0.34 mg/g rock, while those of the samples from Nzam-I well range from 0.08 to 0.73 mg/g rock. Since the GP values for the samples in the two wells are less than 2 mg/g and the average TOC values are also less than 1.0 wt. %, the sediments are poor to fair source rock with possibility of gas generation (45, 46).

4.3 Quality of Organic Matter

The quality of organic matter encountered in shales and sandy shales of the Imo Formation in Akukwa-II and Nzam-1 wells was deduced from Rock-eval pyrolysis. Since petroleum is a generative product of organic matter disseminated in the sediments, therefore the quality of hydrocarbon is directly connected with the type of organic matter contained in potential source rocks (45). The quality of organic matter can be accessed by direct observation of some of the Rock-eval data and by several plots of these data. For instance, the HI values for Imo Shale ranging from 11.0 to 28.0 mg HC/g TOC and 14.0 to 48.0 mg HC/g TOC respectively in Akukwa-II and Nzam-I wells suggest that the sediments contained type IV kerogen (46). The plot of Hydrogen Index against Oxygen Index for Imo Shale in the wells (Figure 3) also suggests that the organic matter that makes up the sediments is essentially kerogen type IV sourced from terrestrial materials, known to be dominated by inertinite macerals which does not yield significant amounts of hydrocarbon (47). In addition, the plot of Hydrogen Index against Tmax (Figure 4) indicates type IV kerogen in the sediments from the two wells. Figure 4 further shows that the type IV kerogen in Akukwa-II well samples are essentially in the immature window while those of the Nzam-1 well are within the immature window with few samples in the oil and dry gas windows.

Similarly, the plot of Hydrogen Index against calculated vitrinite reflectance (Figure 5) suggests type IV kerogen as the main organic matter type in the samples from the wells. The type IV kerogen containing samples in Akukwa-II well are within the immaturity window with few marginally mature samples. While the type IV kerogen in Nzam-I well samples are within immaturity window with two samples in the oil window and one sample in the postmaturity or dry gas window. Also, the relevance of the S2 versus TOC plot in comparing the petroleum-generative potential of source rocks has been discussed by (48, 49) with the advantage that the slope lines radiating from the plot's origin are directly related to Hydrogen (HI= S2 × 100/TOC, mg HC/g TOC). The plot S2 versus TOC (Figure 6) however indicates that the sediments are generally dry gas prone and all samples from the two wells are organically lean with the exception of two samples from Nzam-I well.

4.4 Thermal Maturity of Organic Matter

Thermal maturity is the temperature at which the source rock attained its hydrocarbon generating window. This is influenced by the geothermal gradient and heat from magmatic intrusion. The degrees of thermal evolution of organic matter in Imo Formation sediments in the wells were deduced from Tmax, Production index (PI) and the calculated vitrinite reflectance (Calc. % Ro). Peters and Cassa (46) proposed that PI and Tmax values less than 0.1 and 435 ^{o}C indicate immature organic matter while PI and Tmax ranging from 0.1 to 0.4 and 435 to 450 ^{o}C respectively, indicate organic matter ranging from early maturity to the peak of maturity. PI value greater than 0.4 and Tmax of 450 to 470 ^{o}C indicate late maturity while Tmax greater than

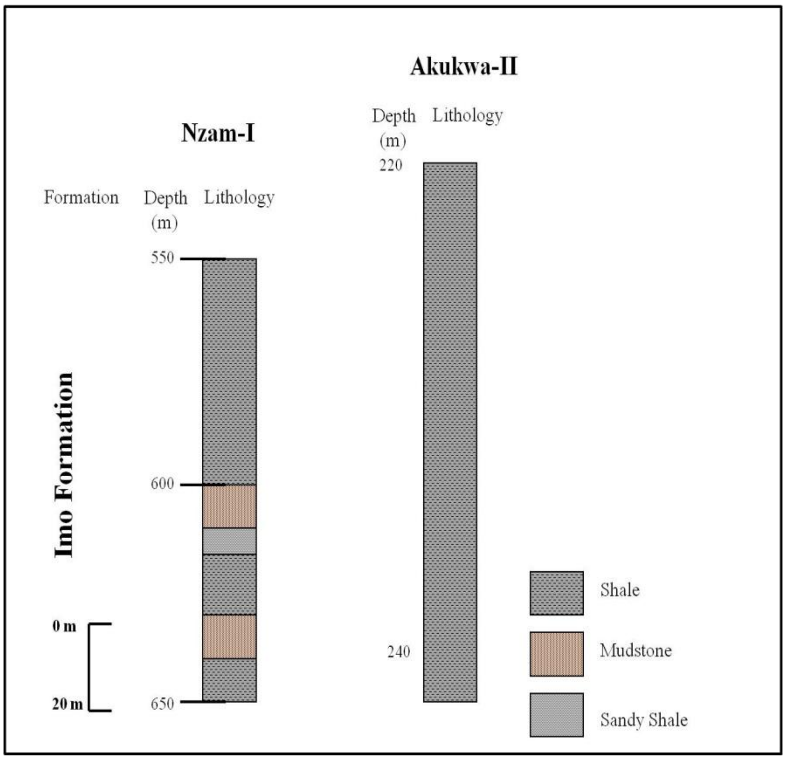


Figure 2: Lithological logs of the studied sections of the wells

Table 2: TOC and Rock-eval Pyrolysis Results of the Imo Shale Formation from Akukwa-II and Nzam-1 wells

Sample I.D	Depth (m)	TOC Wt.%	S1 (mg/g)	S2 (mg/g)	S3 (mg/g)	GP (mg/g)	Tmax (^{O}C)	Calc %Ro	HI mg/g	OI mg/g	PI	PC (%)
AK 01	120-125	0.39	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
AK 02	125-130	0.94	0.08	0.26	0.61	0.34	409	0.202	28	65	0.24	0.06
AK 03	140-145	0.54	0.03	0.08	0.5	0.11	428	0.544	15	93	0.25	0.03
AK 04	145-150	0.64	0.05	0.17	0.82	0.22	430	0.58	27	128	0.23	0.05
AK 05	150-155	0.61	0.13	0.13	0.64	0.26	423	0.454	21	105	0.5	0.05
AK 06	160-165	0.77	0.03	0.1	0.56	0.13	426	0.508	13	71	0.25	0.04
AK 07	170-175	0.63	0.04	0.09	0.49	0.13	425	0.49	14	78	0.32	0.03
AK 08	175-180	0.64	0.03	0.09	0.44	0.12	427	0.526	14	69	0.22	0.03
AK 09	180-185	0.50	0.04	0.06	0.3	0.10	423	0.454	12	60	0.37	0.03
AK 10	185-190	0.48	0.04	0.06	0.37	0.10	425	0.49	12	77	0.44	0.02
AK 11	195-200	0.69	0.05	0.11	0.53	0.16	427	0.526	16	77	0.29	0.04
AK 12	200-205	0.52	0.06	0.09	0.43	0.15	418	0.364	17	83	0.41	0.03
AK 13	205-210	0.56	0.04	0.07	0.39	0.11	423	0.454	12	70	0.34	0,03
AK 14	210-215	0.70	0.04	0.07	0.37	0.11	423	0.454	12	70	0.34	0.03
AK 15	225-230	0.59	0.03	0.07	0.42	0.10	423	0.454	12	71	0.31	0.03
AK 16	230-235	0.61	0.05	0.07	0.42	0.12	425	0.49	11	64	0.42	0.03
AK 17	235-240	0.46	0.04	0.07	0.45	0.11	423	0.454	15	98	0.36	0.03
NZ 01	550-555	0.5	0.01	0.12	0.7	0.13	428	0.544	24	140	0.07	0.13
NZ 02	560-565	0.5	0.01	0.12	0.44	0.13	427	0.526	25	92	0.07	0.13
NZ 03	565-570	0.5	0.01	0.1	0.66	0.11	427	0.526	21	138	0.08	0.11
NZ 04	570-575	0.5	0.01	0.12	0.7	0.13	428	0.544	24	140	0.07	0.13
NZ 05	575-580	2.07	0.16	0.57	0.78	0.73	448	0.904	28	38	0.22	0.73
NZ 06	580-585	0.5	0.01	0.1	0.66	0.11	427	0.526	21	138	0.08	0.11
NZ 07	585-590	1.69	0.14	0.3	0.76	0.44	497	1.786	18	45	0.32	0.44
NZ 08	590-595	0.50	0.05	0.24	1.47	0.29	421	0.418	48	294	0.17	0.29
NZ 09	595-600	0.44	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
NZ 10	605-610	0.34	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
NZ 11	610-615	0.83	0.02	0.26	0.52	0.28	437	0.706	31	63	0.07	0.28
NZ 12	615-620	0.42	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
NZ 13	620-625	0.51	0.02	0.17	0.62	0.19	426	0.508	33	122	0.09	0.19
NZ 14	625-630	0.39	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
NZ 15	635-640	0.5	0.01	0.07	0.48	0.08	428	0.544	14	98	0.04	0.07
NZ 16	645-650	0.5	0.01	0.1	0.45	0.11	427	0.526	22	98	0.08	0.11

AK: AKUKWA-II Well NZ: NZAM-I Well

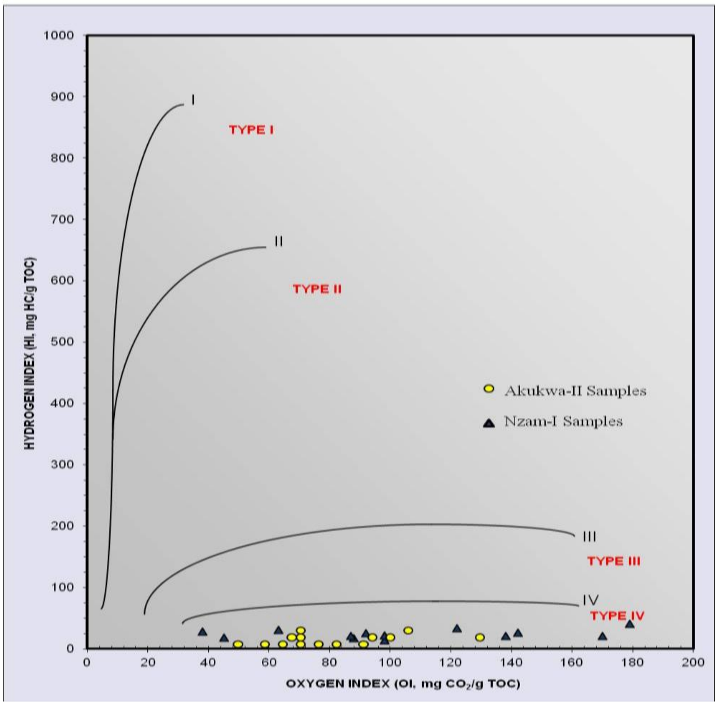


Figure 3: Plot of Hydrogen Index (HI) against Oxygen Index (OI) indicating type kerogen in Imo Formation sediments.

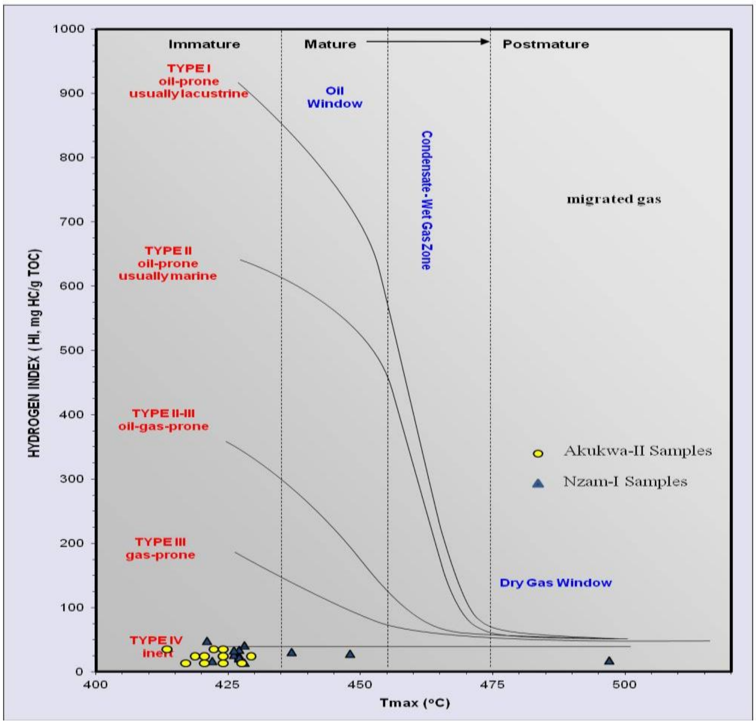


Figure 4: Plot of Hydrogen Index (HI) against Tmax showing kerogen type IV organic matter within immature, oil and dry gas windows

well are at peak of maturity to postmaturity while those of the Nzam-I well are immature with only two samples at early to peak of maturity. The Tmax and Calc. % Ro values range from 409 to 430 ^{o}C and 0.20 to 0.58 respectively in Akukwa-II well, and 421 to 497 ^{o}C and 0.418 to 1.786 respectively in Nzam-1 wells. The Tmax and Calc. % Ro values suggest that the samples in Akukwa-II are immature while those of Nzam-I well are also immature except three samples at early maturity to postmaturity.

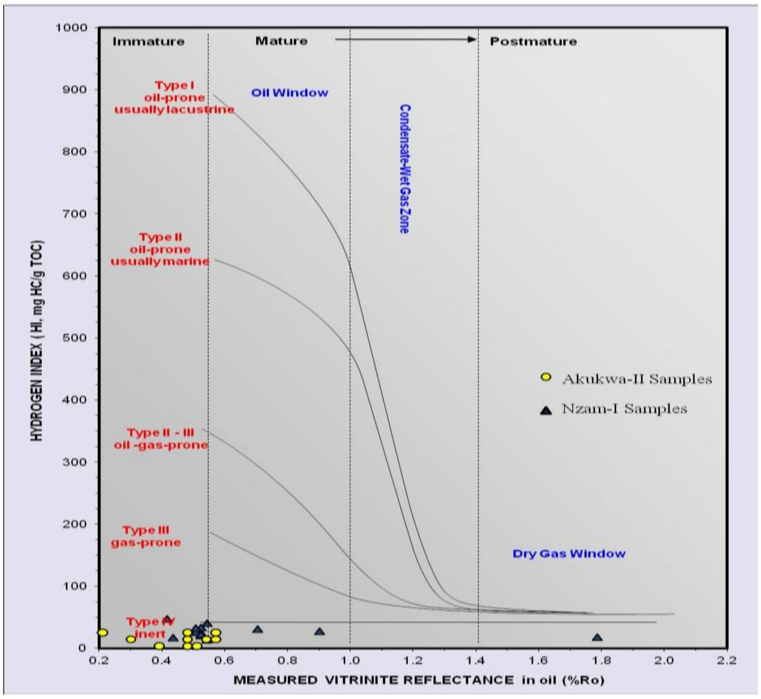


Figure 5: Plot of Hydrogen Index (HI) vs Calculated vitrinite reflectance (Calc % Ro) indicating type IV organic matter in immature window with few samples in oil to dry gas windows.

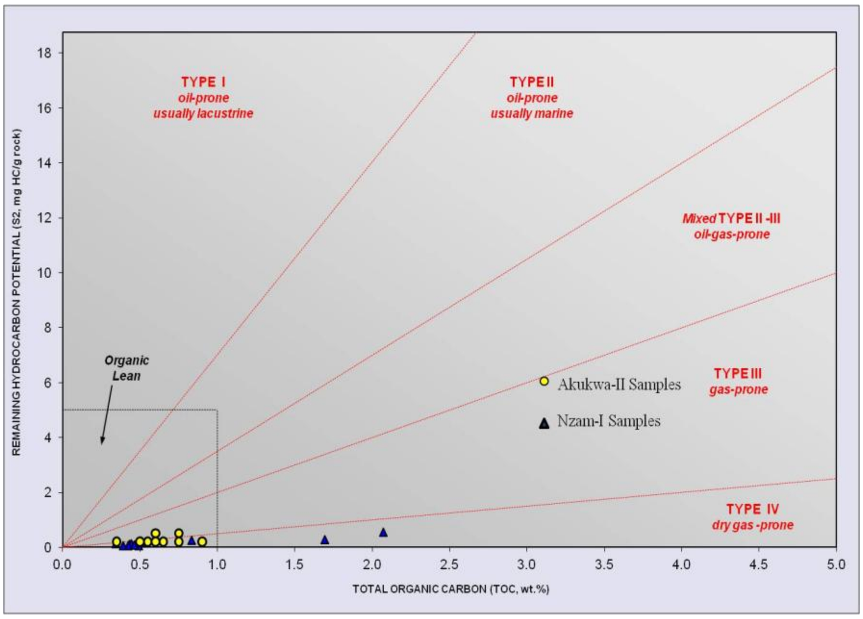


Figure 6: Plot of S2 against TOC showing lean organic matter with few good organic matter and dry gas as the main hydrocarbon type.

470 °C indicate postmaturity. The PI values of the shales and sandy shales of Imo shale Formation range from 0.22 to 0.50 in Akukwa-II well and 0.04 to 0.32 in Nzam-I well. These suggest that the samples from Akukwa-II

In addition, plot of Production index against Tmax (Figure 7) shows that the generality of Imo Shale samples are immature with respect to hydrocarbon generation and are either within the low level conversion or the stained or contaminated zone except a sample each at oil and postmaturity windows respectively. The sediments of Imo Formation may therefore generate very little dry gas at appropriate maturity. The figure further shows that all the samples from Akukwa-II well are immature, though they are above the low level conversion but are essentially confined to the stained or contaminated zone. All the samples from Nzam-I well are also immature except two samples distributed between oil window and postmaturity window. Another sample that happens to be at the early maturity of oil window is also at low level conversion. However, it was observed in this study that the thermal maturity deduced from plots of PI against Tmax and PI versus Calc. % Ro corresponds with those deduced directly from Tmax and Calc. % Ro, but at variance with that of PI. This implies that caution must be exercised when interpreting thermal maturity directly from Rock-eval data.

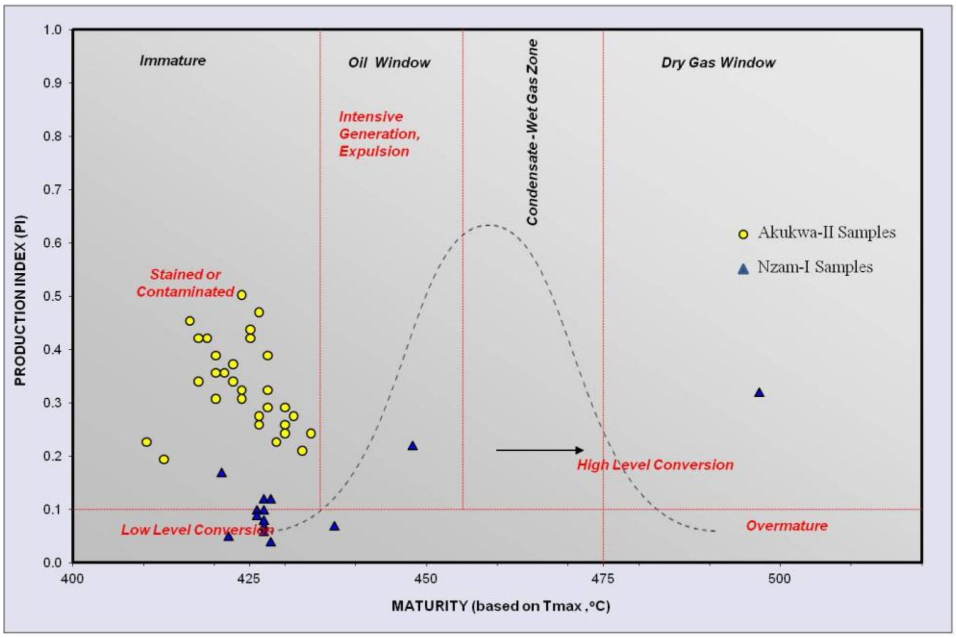


Figure 7: Plot of Production Index against Tmax showing thermal immaturity with respect to hydrocarbon generation.

V. Conclusions

The sediments of Tertiary Imo Shale Formation encountered at depth ranges of 120-240 m and 550-650 m in Akukwa-II and Nzam-1 well respectively are made of shales, sandy shale and mudstones. The shales are fine grained, fissile and light to dark grey in colour. The sandy shale is medium grained and grey in colour while the mudstones are fine grained and brownish grey in colour. The TOC values of the samples ranges from 0.39 to 0.94 wt. % (av. 0.60 wt. %) and 0.39 to 2.07 wt. % (av. 0.70 wt. %) in Akukwa-II and Nzam-1 wells respectively, indicating that they have potential for hydrocarbon generation. Generative potential with TOC suggest poor to fair source rock with possibility of gas. Organic matter contained in the sediments is predominantly type IV kerogen sourced from terrestrial materials which does not yield significant amounts of hydrocarbon. Thermal maturity derived from Rock-eval data revealed that the Imo Formation samples are immature with respect to hydrocarbon generation. The sediments are therefore capable of generating very little dry gas at appropriate maturity because of the inert nature of type IV kerogen.

Acknowledgements

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