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Aspects of the Source Rock Evaluation of the Organic Rich Intervals in Anambra Basin, Southeastern Nigeria

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ABSTRACT

Ditch cutting samples of organic rich intervals (Nkporo, Mamu, Nsukka and Imo formations) in Anambra basin from Oda River-1 and Anambra River-2 wells were subjected to Total Organic Carbon (TOC) and Rock-eval Pyrolysis analyses to evaluate their organic matter richness, organic matter type and thermal maturity. The samples comprised of shales, siltstones, lignites and claystones. The shales are dark coloured and moderately indurated with carbonaceous silt and dolomite stringers. The siltstones are fine to medium grained and dark grey to brown in colour. The lignites are grey to black coloured, medium grained, moderately hard to brittle and occurred as stringers. The claystones are grey coloured and medium grained. The TOC and Pyrolysis derived S2 results of the samples are 0.98-4.71 wt. % and 0.12-5.39 mg/g, respectively indicating poor to excellent source rocks. Hydrogen Index, Tmax, Genetic potential and measured vitrinite reflectance are 9-114 mg/g, 424 -471°C, 0.13-5.67 mg/g rock, and 0.41-0.88, respectively. Rock-eval data from the two wells indicated predominantly kerogen type IV kerogen with subordinate gas prone kerogen type III organic matter. Mamu Formation samples dominated kerogen type III and were abundant in Anambra River-2 well. Most samples from Anambra River-2 well are thermally mature while fewer samples from Oda River-1 well are thermally mature for hydrocarbon generation. However, majority of kerogen type III in Anambra River-2 well contained inert carbon.

Introduction

The recent discovery and the production of hydrocarbon from parts of Anambra basin has created renewed impetus for resurgence of hydrocarbon exploration in the basin. History has shown that Anambra basin came into limelight about a century ago when coal deposits (technically known as coal seams) were discovered across the basin The coals are originally referred to as the Lower and Upper Coal Measures (now Mamu and Nsukka formations, respectively) (Reyment, 1965). This came just few years after the commencement of the first oil exploration by the Nigerian Bitumen Corporation (a German company) sequel to the discovery of oil seepages at Araromi in Dahomey basin, southwestern Nigeria (Udosen et al., 2009). Coal exploitation was a major contributor to Nigerian economy at a time when coal was about the major source of energy. The total reserves of the sub-bituminous coals known in the different localities of Anambra basin was put at about 1.5 billion tones (Orajaka et al., 1990). The basin came into the second limelight with the commencement of hydrocarbon exploration by Shell BP (Shell Darcy) in 1950s in Anambra basin and underlying Abakaliki folded basin leading to drilling of several exploration wells. However, the wells have shown few discoveries with dominance of gas over oil (Ayoola & Avbovbo, 1981; Unomah & Ekweozor, 1993). Studies emanating from the samples and data generated from the exploration wells have highlighted the petroleum system with their source rocks and reservoirs in Anambra Basin (Ayoola & Avbovbo, 1981; Agagu & Ekweozor, 1982, Whiteman, 1982; Ekweozor & Gormly, 1983; Agagu et al., 1985; Nwachukwu, 1985; Unomah & Ekweozor, 1993).

Another phase of hydrocarbon exploration in Anambra basin was heralded by the initiation of Memorandum of Understanding (MOU) between the oil companies and Nigerian Government with suitable incentives about three or four decades ago. This led to resumption of exploration activities in several Nigerian inland basins including Abakaliki folded basin and Afikpo Syncline which are structurally associated with Anambra basin. The MOU became necessary at that time because hydrocarbon exploration gained wider acceptability due to increased energy demand in response to population explosion and the emergence of technological advancement in oil exploration and productions methods. The combined efforts of the industries and academia which had indicated good hydrocarbon prospect Anambra basin (Akaegbobi. & Schmitt, 1998; Obaje et al., 1999; Ehinola et al., 2005; Akande et al., 2007; Ogala, 2011; Adeleye et al., 2016; Akaeogbobi et al., 2017; Adebayo et al., 2018) has necessitated drilling of additional wells and ultimately resulted in the discovery and production of hydrocarbon from a section of the basin in the last few years. Therefore, there is a need for re-evaluation of the source rocks across the basin for additional hydrocarbon discovery and production.

Hydrocarbon exploration in Anambra basin had been sustained over the years because the basin had long been

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known to be composed of undeformed and non tectonised sediments with relatively moderate temperature regime which are suitable for hydrocarbon generation and accumulation (Murat, 1972). The structural connection between the evolution of the Anambra basin and the hydrocarbon prolific Niger Delta with respect to the NE-SW trending Benue Trough had also been highlighted (Murat, 1972). The stratigraphy and structural configuration of Campano-Maastrichtian Anambra basin has equally positioned it to be a petroliferous basin with all the elements of petroleum system (Obaje et al., 1999). Despite several studies on the different source rocks in Anambra basin from subsurface and surface samples, there are limited studies on the assessment of all the organic rich intervals from subsurface samples in the basin. This study was designed to evaluate some aspects of the source rock potentials of the organic rich intervals penetrated by Oda-1 River and Anambra-2 River wells in Anambra basin.

Geological Setting

The evolution of the Southern sedimentary basins began in the Early Cretaceous time with the formation of the Benue-Abakaliki Trough as a failed arm of the rift triple junction which was associated with the separation of the African and south American continents and the subsequent opening of the South Atlantic (Burke et al., 1971; 1972; Burke and Whiteman, 1973). The Benue Trough is a linear NE-SW trending Anticlinorium stretching from the Chad basin in the North to the Gulf of Guinea through Niger Delta in the South (Avbovbo, 1980). 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 (Whiteman, 1982). The Benue Trough comprises 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 Whiteman (1982) while the eastern limit covers the Lokpanta area. The lower Benue Trough was fragmented by the Santonian deformational episode into the tectonically inverted Abakaliki Anticlinorium and the flanking Anambra and Afikpo Synclines (Murat, 1972).

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 (Murat, 1972). 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 (Murat, 1972). Agagu & Adhigije (1983) also reported that the Anambra basin is subdivided into a main 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 the focus of several studies (Reyment, 1965; Murat, 1972; Burke et al., 1972; Burke and Whiteman, 1973; Agagu, 1978; Petters, 1978; Agagu & Ekweozor, 1982; Petters & Ekweozor, 1982; Whiteman, 1982; Agagu & Adhigije, 1983; Agagu et al, 1985; Allix, 1987; Benkhelil, 1989; Ojoh, 1990; Nwajide, 1990; 2013). 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 Nkporo Formation (Asata Nkporo Shale) consists of dark grey fissile shales and mudstones often pyritic or gypsum bearing, with occasional interbeds of sandy shales, shelly limestones, ripple-marked fine grained sandstones, coarse grained sandstones and chamositic or limonitic oolitic ironstones (Reyment, 1965; Agagu et al, 1985; Arua, 1988; Okoro & Arua, 1989; Mode, 1991). It has an estimated maximum thickness of 1000 m and it is believed to be deposited as products of the first transgressive phase in the Anambra basin (Reyment & Morner, 1977)**.** The lateral equivalents are the Enugu shales and the Owelli sandstone. Stratigraphic position of Nkporo shale has indicated Campano-Maastrichtian age (Agagu et al, 1985), while the presence of miospores and *Libycoceras angolense* indicated a Maastrichtian age (Whiteman, 1982). Mamu Formation (Lower Coal Measures) is made up of laterally variable succession of fine to medium grained well bedded sandstones, siltstones, shales, mudstones, coal seams and frequently bioturbated sandy shales. Mamu Formation displays a repeated rhythmic pattern of deposition consisting of shale and sandy shale, coal occasionally with shale at the top, carbonaceous shale, sandstone with occasional shale and sandy shale or shale (Whiteman, 1982). The coal beds and carbonaceous shales are concentrated at the basal parts of the formation. The coal seams are generally laterally impersistent and vary in thickness from few cm to about 4 m (Agagu et al., 1985). The Maastrichtian Mamu Formation has been described as parallic sequence because of the alternating marine and continental sediments and the paleogeography of Anambra basin (Burke et al., 1972, Murat, 1972; Petters, 1978). Strandplain marsh or deltaic system was inferred as depositional environment of Mamu Formation (Agagu et al., 1985).

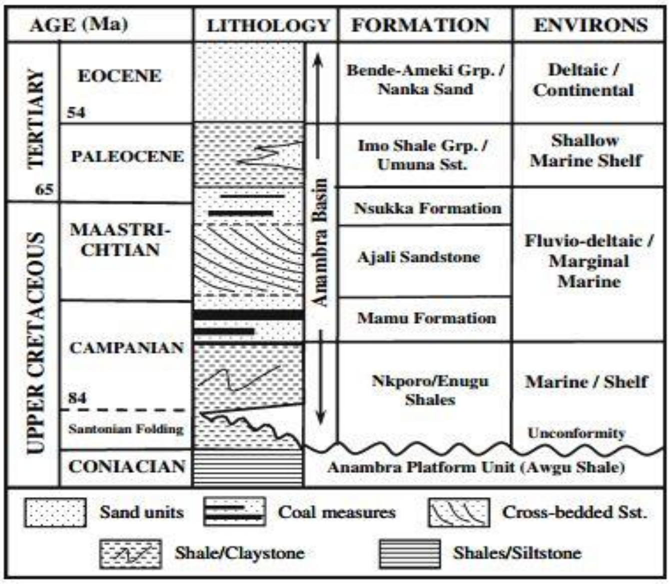

Table 1. Stratigraphic sequence of the Anambra basin.

The Nsukka Formation (Upper Coal Measures) is stratigraphically synonymous to the Mamu Formation except that it is generally less sandy with fewer coal seams (Reyment, 1965; Murat, 1972; Dessauvagie, 1974). The formation consists of alternating sequence of laminated, very fine grained sandstones and siltstones. There are also brown and grey shales, carbonaceous shales, sandy shales and mudstones with numerous coal seams (nearly 2 m thick) at various horizons (Agagu et al. 1985). Sections of the formation without coal seams are rich in fragmentary plant remains. The depositional environment inferred from the surface exposures is strandplain marsh with occasional fluvial incursions and it is dated Maastrichtian to Paleocene (Agagu et al. 1985). The Imo Formation (Imo-Anambra Shales) consists of thick, fine textured, dark grey or bluish grey shale, with occasional admixtures of clay, ironstone and thin sandstone bands and limestone intercalations (Nwajide 2013). Oboh-Ikuenbe et al. (2005) reported Imo shale as a stratigraphic unit that is widely distributed over several hundreds of kilometers from the southeast boundary of Nigeria across the Niger Delta to the western boundary. Imo Formation was deposited during Paleocene when transgressive conditions returned back to the Anambra basin (Murat, 1972). Nwajide & Reijers (1996) 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. Near shore to marginal marine paleoenvironment was inferred for Imo Shale and it is dated middle Paleocene to Early Eocene (Durugbo, 2013) and late Paleocene to Early Eocene (Oloto, 1992).

Samples and Methods

Ditch cuttings samples of organic rich intervals from two wells in Anambra basin (Oda River-1 and Anambra River-2) obtained from Kaduna office of Nigerian Geological Survey Agency (NGSA) were used for this study. The two wells, 15km apart in the basin (Figure 1) are parts of exploration wells drilled by Elf Petroleum Nigeria Limited in the basin. Oda River-1 has a total depth of 2390 m while Anambra River-2 was terminated at a depth of 2180 m. The wells penetrated the argillaceous and clastic sequences of the upper Cretaceous to early Tertiary age. Ditch cutting samples from the 2 wells were described with the lithological properties including textures, colour etc. Twenty-four (24) organic rich argillaceous sediments consisting of 11 samples from Oda River-1 and 13 samples from Anambra River-2 well were selected. The selected samples are made up of Asata/Nkporo Shale (ANS), Mamu Formation (LCM), Nsukka Formation (UCM) and the Imo Shale (IMS). The samples were checked for drilling mud and other impurities, and were removed where present. The lithological description of the samples (Figure 2) indicated a sequence of shales, siltstones, lignites and claystones.

The shales are moderately indurated and grey to black in colour with carbonaceous silt and stringers of dolomites and carbonates. The siltstones are fine to medium grained and dark grey to brown in colour. The claystones are medium grained and light grey in colour. The lignites are black to dark brown coloured, fine to medium grained and moderately hard to brittle. The lignites occur mostly as stringers in the two wells. Minor stringers of grey coloured and silty limestones or otherwise calcareous siltstone were also observed in the two wells at varying proportions.

Selected samples were finely pulverized, stored in glass vials and labeled in preparation for the geochemical analyses. A portion of the pulverized samples were treated with concentrated hydrogen chloride acid to remove carbonates for Total organic carbon (TOC) determination. The TOC and Rock-eval Pyrolysis were performed on the selected samples using a LECO Olympus binocular camera Carbon-Analyzer IR 112 and Weatherford Source Rock Analyzer-TPH/TOC (SRA) instruments, respectively. For the measurements of vitrinite reflectance of the samples, polished blocks of whole rock samples were prepared following the procedures in the published guidelines of Taylor et al. (1998). The mean random vitrinite reflectance (Ro %) was measured on the samples with a Windows-based DISKUS Fossil software in the microscope previously calibrated using standard sapphire (0.589% refractive index) and immersion oil (ne = 1.518; 23°C). The percentage of incident light reflected from the vitrinite particles in the samples was measured in comparison to the known standard of 0.589%.

Results and Discussions

Organic Matter Richness

Geochemical results (TOC, Rock-eval Pyrolysis and vitrinite reflectance data) of the samples from the two wells are presented in Table 2. Organic richness and hydrocarbon potential of rock samples are commonly evaluated from the TOC and Pyrolysis derived S2 (Jarvie, 1991; Waples et al., 1992). The guidelines for interpreting source rock quantity, quality and maturation (Table 3) has shown TOC values of 1-2%, 2-4% and >4% for good, very good and excellent source

Table 2.Geochemical Results of studied samples from Oda River-1 and Anambra River-2 wells.

Well Name	Depth (m)	Formation	TOC Wt%	Tmax (^{O}C)	S1 (mg/g)	S2 (mg/g)	S3 (mg/g)	GP (S1+S2)	HI mg/g	OI mg/g	PI	S1/TOC *100	VRE
ODA RIVER-1	850-855	IMS	1.61	430	0.01	0.14	0.36	0.15	9	22	0.07	0.62	0.75
	900-905	IMS	1.2	427	0.01	0.12	0.42	0.13	10	35	0.07	0.83	NA
	960-965	IMS	1.16	425	0.01	0.14	0.52	0.15	12	45	0.06	0.86	NA
	1000-1005	UCM	2.68	424	0.04	0.59	1.56	0.63	22	58	0.06	1.49	0.65
	1020-1025	UCM	3.28	430	0.17	1.66	2.56	1.83	51	78	0.09	5.18	0.62
	1500-1505	LCM	0.98	430	0.06	0.53	0.89	0.59	54	91	0.1	6.12	NA
	1600-1605	LCM	1.01	430	0.06	0.58	0.66	0.64	57	65	0.09	5.94	NA
	1750-1755	LCM	3.09	431	0.03	3.05	0.98	3.33	99	32	0.08	9.06	0.73
	2000-2005	LCM	1.92	440	0.28	0.96	3.46	1.03	50	180	0.07	3.65	0.88
	2200-2205	LCM	1.74	447	0.07	0.51	0.44	0.58	29	25	0.12	4.02	0.78
	2300-2305	ANS	2.17	434	0.1	0.49	0.97	0.59	23	45	0.17	4.61	0.79
	2385-2390	ANS	1.78	442	0.07	0.65	1.13	0.72	37	63	0.1	3.93	0.81
	3390-3395	ANS	2.02	441	0.11	0.58	0.89	0.69	29	44	0.16	5.45	0.71
ANAMB-RA RIVER-2	560-565	IMS	1.51	426	0.04	0.53	1.62	0.57	35	107	0.07	2.65	0.65
	620-625	UCM	2.77	443	0.03	1.12	7.28	1.15	40	263	0.03	1.08	0.41
	1550-1555	LCM	4.17	443	0.17	4.14	2.24	4.31	99	54	0.04	4.08	0.69
	1555-1560	LCM	4.71	440	0.28	5.39	2.69	5.67	114	57	0.05	5.94	0.78
	1600-1605	LCM	3.81	437	0.15	3.34	2.45	3.49	88	64	0.04	3.94	0.71
	1750-1755	LCM	2.94	438	0.1	1.23	2.26	1.33	42	77	0.07	3.4	0.75
	1890-1895	LCM	1.67	450	0.01	0.32	1.48	0.33	19	89	0.03	0.6	NA
	1900-1905	ANS	2.5	437	0.12	1.25	1.81	1.37	50	72	0.08	4.8	NA
	2055-2060	ANS	1.83	471	0.04	0.43	1.42	0.47	24	78	0.08	2.19	NA
	2130-2135	ANS	3.6	442	0.13	0.63	1.24	0.76	18	34	0.17	3.61	NA
	2145-2150	ANS	2.02	444	0.02	0.31	1.54	0.33	15	76	0.06	0.99	NA

NA: Not available

Table 3. Guidelines for interpreting source rock quantity, quality, maturation (Espitalié et al., 1984; Peters 1986; Traverse 1988; Peters et al., 1994; Flowler et al., 2005)

Quantity	**TOC**	**S1(mg HC/g rock)**	**S2 (mg HC/g rock)**
Poor	< 0.5	< 0.5	<2.5
Fair	0.5 -1	0.5-1	2.5-5.0
Good	1-2	1-2	5-10
Very Good	2-4	2-4	10-20
Excellent	>4	> 4	>20
Quality	HI (mg HC/g rock)	S2/S3	Kerogen Type
None	<50	<1	IV
Gas	50-200	1-5	III
Gas and Oil	200-300	5-10	II/III
Oil	300-600	10-15	II
Oil	>600	>15	I
Maturation	Ro (%)	Tmax (°C)	TAI
Immature	0.2-0.6	<435	1.5-2.6
Early Mature	0.6- 0.65	435-445	2.6-2.6
Peak Mature	0.65-0.9	445-450	2.7-2.9
Late Mature	0.9-1.35	450-470	2.9-3.3
Post Mature	>1.35	>470	>3.3

rocks respectively, while their corresponding S2 values are 5-10 mg/g and 10-20 mg/g and >20 mg/g, respectively (Espitalié et al., 1984; Peters, 1986; Traverse, 1988; Peters et al., 1994; Fowler et al., 2005). The geochemical results showed that the TOC values of the samples from the two wells ranged from 0.98 to 4.71 wt. % (0.98 to 3.28 wt % for Oda River-1 well and 1.51 to 4.71 wt. % for Anambra-2 well). These TOC results indicated that the samples contained appreciable organic matter that can generate hydrocarbons because all TOC values are above the 0.5 wt. %, which has been adopted as threshold value for hydrocarbon generation in source rocks (Tissot & Welte, 1984). The S2 values for the samples also ranged from 0.12 to 5.39 mg/g for the two wells (0.12 to 1.66 mg/g for Oda River-1 well and 0.31 to 5.39 mg/g for Anambra-2 well). When considering the adequacy of organic matter, an important pre-requisite for hydrocarbon generation (TOC) and S2 values, the sediments are therefore regarded as fair to good hydrocarbon source rocks (Conford, 1986; Tissot & Welte, 1984). Specifically, the TOC values indicated that the samples are fair to excellent source rocks while the S2 values showed that the samples are mostly poor to fair source rocks.

The quality of the source rocks in the organic rich intervals from the wells was also evaluated by the Pyrolysis derived hydrocarbon generative potentials (GP= S1 + S2) (Table 2). The hydrocarbon generative potentials (GP) and hydrogen index (HI) values of the samples in the wells ranged from 0.13 to 5.67 mg/g rock and 9.0 to 114.0 mg HC/g TOC, respectively. The GP values ranging from 2.00-6.00 mg/g and HI values < 200 mg HC/g TOC) indicated poor to fair source rocks, possibly with gas potential (Conford, 1986; Tissot & Welte, 1984).

In addition, cross plot of S2 versus TOC (Figure 3) has indicated that the samples from Oda River-1 well are poor to very good source rocks, while samples from Anambra River-2 well are fair to excellent source rocks. The cross plot of GP and TOC (Figure 4) has also shown that Oda River-1 well contained fair to very good source rocks, while Anambra River-2 well are composed of fair to excellent source rocks. Cross plot of S1 versus TOC (Figure 5) was used to differentiate between the migrated and non-migrated hydrocarbons. The dividing line on the plot shows S1/TOC = 1.5. Values belonging to non-indigenous hydrocarbon generation are above the line while indigenous hydrocarbon values emerge below it (Hunt, 1996). The figure shows that the samples from the two wells contained indigenous organic matter which has undergone diagenesis with the sediments.

Type of Organic Matter

The type of organic matter in a sedimentary rock among other factors is an important parameter for evaluating the source rock potential and ultimately the nature of hydrocarbon produced or generated (Tissot & Welte, 1984). Organic matter type encountered in the sediments or sedimentary rocks is often determined by the plots of Rock-eval pyrolysis data (Peters, 1986; Peters & Cassa, 1994). The modified Van krevelen diagram of hydrogen index (HI) versus oxygen index (OI) for the samples from the two wells (Figure 6) showed that they contain predominantly kerogen type IV with subordinate kerogen type III organic matter. The kerogen type III is gas prone and terrestrially sourced, while the kerogen type IV is inert (may not generate oil or gas) because it originated from degraded organic matter. The kerogen type III was observed to have been contributed mostly by Mamu Formation (LCM) sediments and the proportion was higher in Anambra River-2 well than in Oda River-1 well.

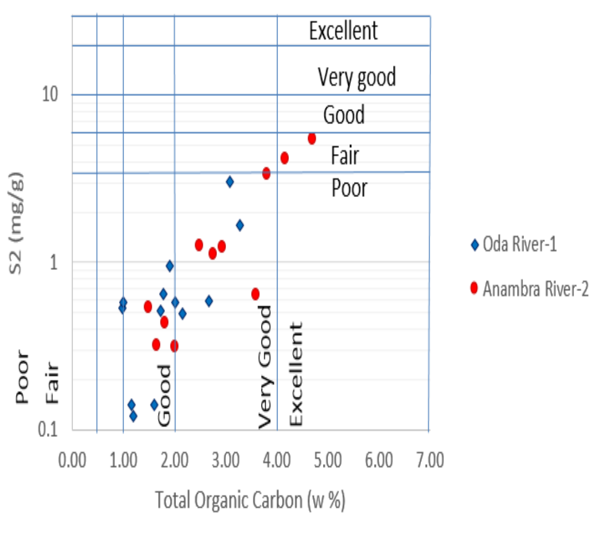

Fig 3. Plot of S2 against TOC indicating hydrocarbon potential of the studied samples.

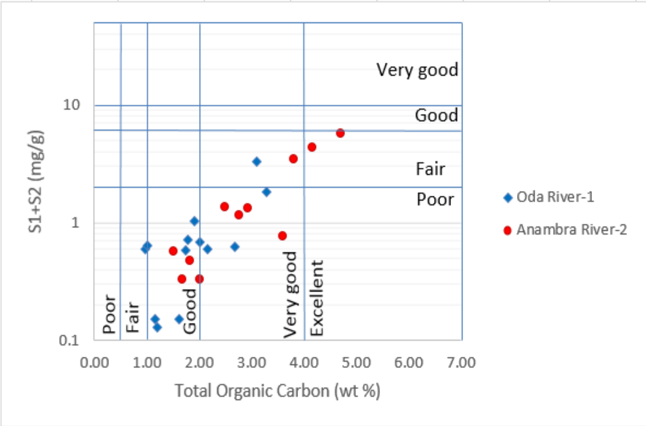

Fig 4. Plot of S1+S2 against TOC showing the genetic potential of the studied samples.

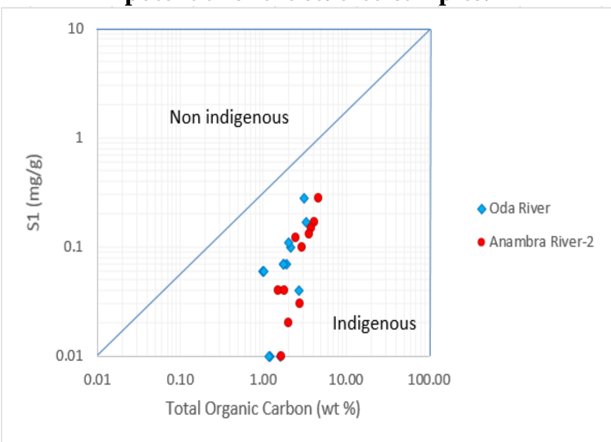

Fig 5. Plot of S1 against TOC showing the precursor of the organic matter in the studied samples.

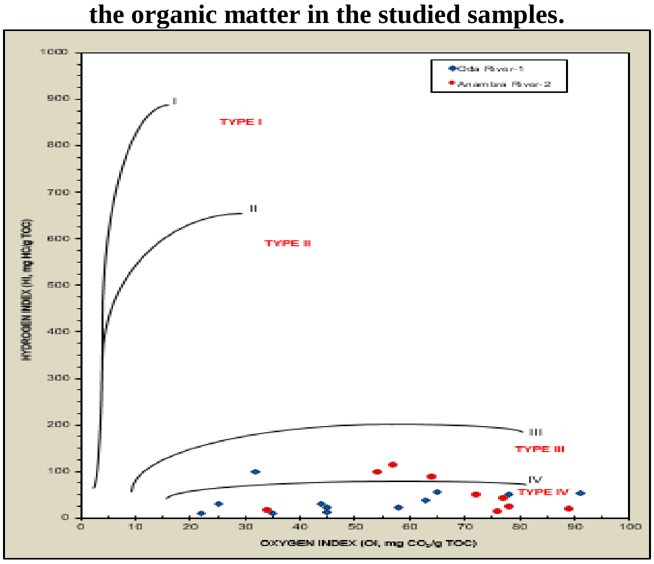

Fig 6. Modified Van Krevelen's diagram (HI vs OI plot) for the studied samples.

Furthermore, cross plot of HI versus Tmax is commonly used to avoid the influence of OI on kerogen typing (Hunt, 1996). The cross plot of HI against Tmax (Figure 7) for the studied samples has shown that the samples in the Oda River-1 and Anambra River-2 wells are composed of both kerogen type IV and kerogen type III organic matter, but with a slight dominance of kerogen type IV. It was also observed that a greater portion of gas prone kerogen type III organic matter are from the Mamu Formation (LCM), and with higher contribution from Anambra-2 well than Oda River-1 well. The cross plot of S2 against TOC (Figure 8) is one of the best method for analyzing the true average HI and the adsorption of hydrogen by the rock (Peters, 1986; Langford & Blanc-Valleron, 1990). The figure shows that the samples from the two wells are composed mostly of kerogen type IV and type III organic matter. It was also noted that the two wells (Anambra River-2 and Oda river-1) had nearly equal contributions to the kerogen type III organic matter, while a greater portion of the kerogen type IV organic matter is associated with Anambra River-2 well.

Thermal Maturity of Organic matter

The degree of thermal alteration of organic matter provides an indication of source rock maturity. Thus, the thermal maturity is the temperature at which the source rock attained its hydrocarbon generating window. Thermal maturity is influenced by the geothermal gradient, heat from magmatic intrusion, organic matter type, presence of excess free hydrocarbon and other factors like mineral matter content, depth of burial and age (Tissot & Welte, 1984). The phenomenon is related to nature of chemical reaction that occurs through thermal cracking of source rocks. The stronger bonds survive until higher temperature in the late stage while weaker bonds break up in the early stage

(Whelan & Thomson, 1993). The thermal evolution of sedimentary organic matter from this study was deduced from Tmax, Production index (PI) and vitrinite reflectance (% Ro). Studies conducted by Peters & Cassa (1994) had proposed that PI, Tmax and Ro values: < 0.1, < 435 ^{o}C and 0.2 - 0.6, respectively, indicate immature organic matter while PI, Tmax and Ro ranges of 0.1 - 0.4, 435 - 450 ^{o}C and 0.6 - 0.9 respectively, indicate organic matter from early to the peak of maturity respectively. Tmax of 450 - 470 ^{o}C and greater as well as Ro of 0.9 - 1.35 and greater, indicate late maturity and overmaturity respectively.

Geochemical results (Table 2) showed that PI values of the samples from the two wells ranged from 0.03 to 0.17. The fact that virtually all the samples have PI values below 0.1 and approximately 0.1 except few samples (1 ANS sample in Anambra-2 well, 2 ANS samples and 1 LCM sample in Oda River-1 well), implied that all samples in the two wells are thermally immature except few thermally mature samples. Table 2 also showed that the Tmax for the samples in the two wells ranged from 424 to 471 ^{o}C (424 to 447°C in Oda River-1 and 426 to 471°C in Anambra River 2). This shows a slightly higher Tmax in Anambra River-2 than Oda River-1 well. And it thus indicated that most of the samples in Oda River-1 well are thermally immature with only few thermally mature samples (2 samples each of LCM and 1 ANS sample). However, all samples from Anambra River-2 well are thermally mature except one IMS sample. A sample of ANS in the well is observed to be overmature because its Tmax is 471 ^{o}C (Peters & Cassa, 1994).

Furthermore, Dow (1997) and Waples (1985) gave an overview of maturity distribution with respect to vitrinite reflectance (Ro) data, and it is considered to be one of the most reliable and most commonly used maturity indicators. Therefore, measured Ro values of samples from Anambra River-2 well ranging from 0.41 to 0.78 indicate samples at the peak of maturity to late maturity with respect to hydrocarbon generation except for a thermally immature sample. The measured Ro values of samples from Oda River-1 well also ranges from 0.47 to 0.88, this indicate that some samples are thermally immature while others are at early maturity to the peak of thermal maturity with respect to hydrocarbon generation. Cross plot of HI and Tmax for the samples (Figure 7) was also used to access the thermal maturity and it thus showed that most samples from Oda-River-1 well are thermally immature with few thermally mature samples within the oil window. For Anambra River-2 well, greater proportion of the samples are thermally mature at early to late stage of oil generation window except a thermally immature sample.

The cross plot of Tmax and vitrinite reflectance (Figure 9) for the samples in the two wells showed that most samples from Anambra River-2 are at the peak of maturity at oil window with only one thermally immature sample. While, majority of the samples from Oda River-1 are thermally immature with fewer thermally mature samples at early maturity to peak of maturity. In addition, cross plot of Tmax against Production index (Figure 10) for the samples from the two wells showed that virtually all samples from Anambra River-2 well that are thermally mature samples are within the inert carbon window except one ANS sample in the hydrocarbon generation window. The figure also shows that Oda River-1 well is characterised by immature samples, while the remaining samples are marginally mature to thermally mature. However, nearly all the thermally mature samples from Oda River-1 well are within the hydrocarbon generation window with a sample in inert carbon window.

Conclusions

Organic rich intervals penetrated by Oda River-1 and Anambra River-2 wells in Anambra basin comprised of the Asata Nkporo shales (ANS), Mamu (LCM), Nsukka (UCM) and Imo (IMS) formations. The lithological units making up the formations in the two wells are shales, siltstones, lignites and claystones, with minor stringers of grey coloured and silty limestones or calcareous siltstones. The grey to black coloured, medium grained and moderately hard to brittle lignites occur as stringers in the two wells. The total organic carbon of the samples ranging from 0.98 to 4.71 wt. % suggested that they are hydrocarbon source rocks. Hydrogen Index and Generative Potential indicated poor to fair source rocks, possibly with gas potential. The sediments contained predominantly inert type IV kerogen with subordinate gas prone type III kerogen organic matter. The kerogen type III organic matter is mostly associated with the sediments of Mamu Formation (LCM) with inputs from other formations and they are abundant in Anambra River-2 well. Thermal maturation derived from Rock-eval data revealed that virtually all the samples from Anambra River-2 well are thermally mature at the peak of maturity, while those of Oda River-1 well are immature with respect to hydrocarbon generation except few samples at early maturity to peak of maturity. The cross plot of Tmax and PI indicated a predominance of the associated organic matter in inert carbon window with fewer samples in hydrocarbon generation window. This study has shown that the Nkporo (ANS) and Mamu (LCM) formations are the source rocks with capacity for hydrocarbon generation in the two wells from Anambra basin as reported from a number of previous studies. The study emphasizes the importance of quality organic matter in hydrocarbon generation and these are often assessed from PI and S2 of Rock-eval data. Thus, this study has shown that good proportion of organic matter constituting the organic rich intervals in the studied wells are composed of inert carbon which can neither generate oil nor gas.

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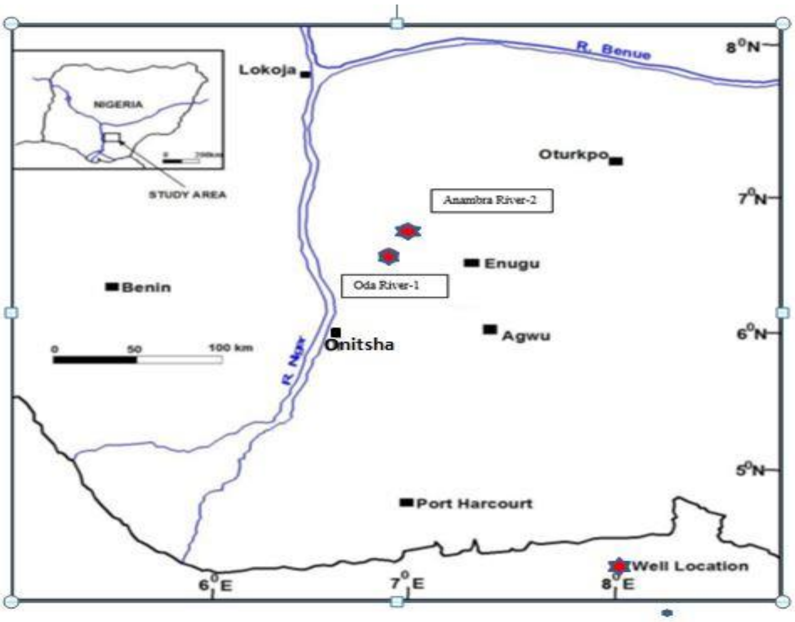

Figure 1. Map of southern Nigeria showing position of the studied wells.

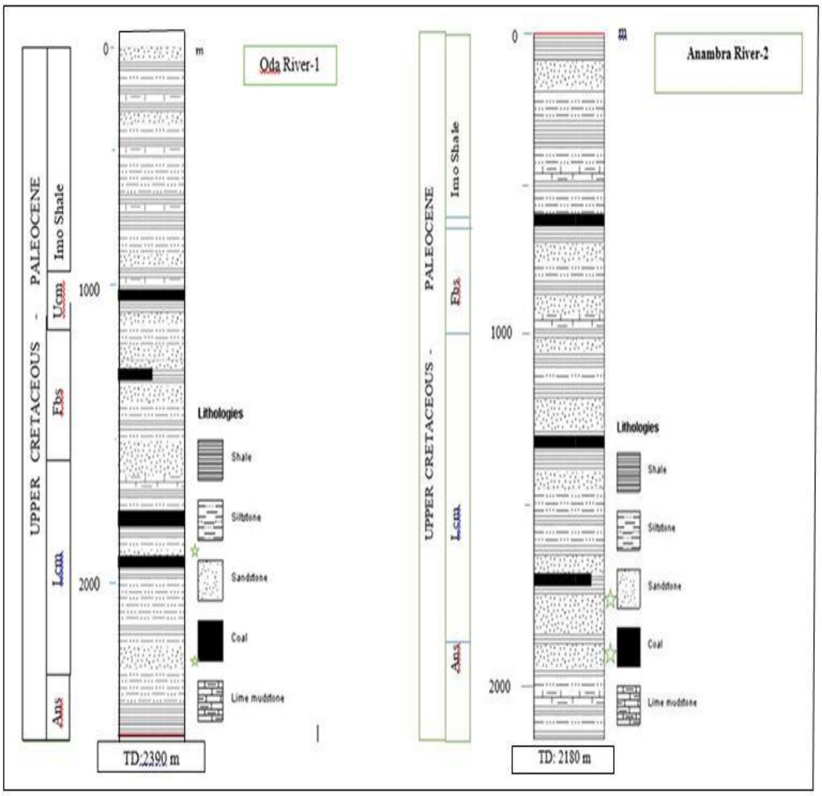

Figure 2. Lithological logs of the studied wells.

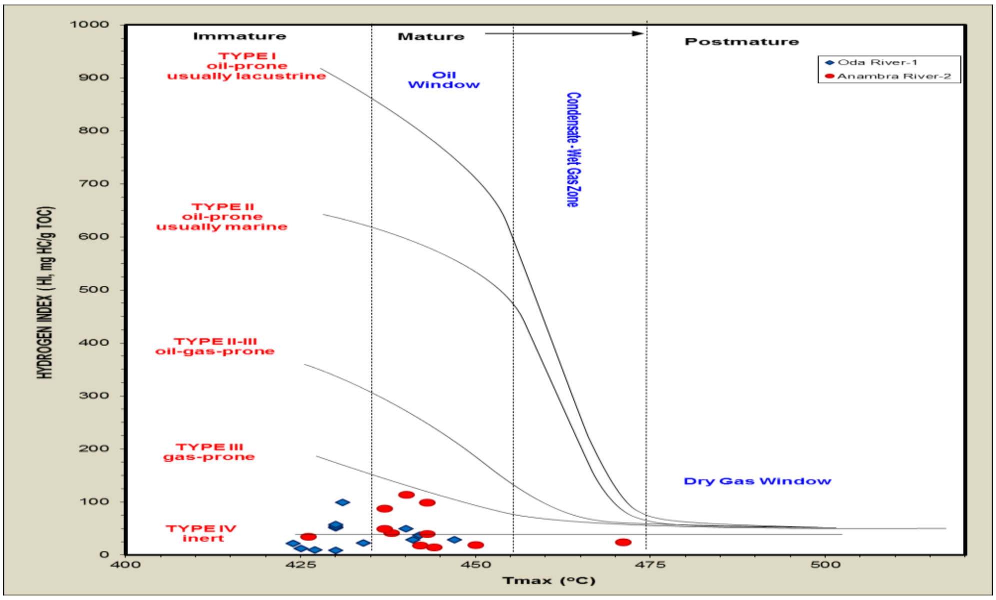

Fig 7. Plot of HI against Tmax showing organic matter and thermal maturity of the studied samples.

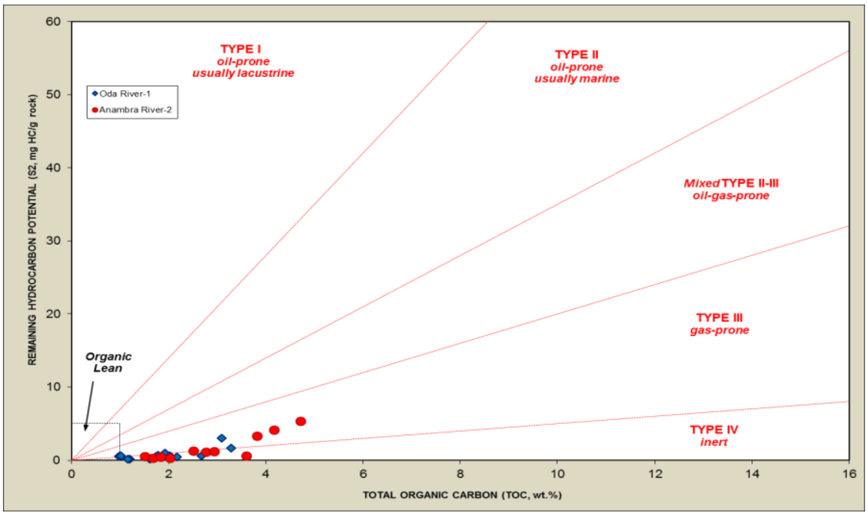

Fig 8. Plot of S2 against TOC showing kerogen type in the studied samples.

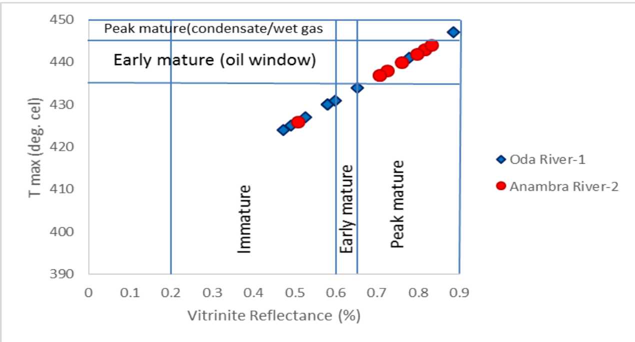

Fig 9. Plot of Tmax against measured Vitrinite reflectance indicting thermal maturity of the studied samples

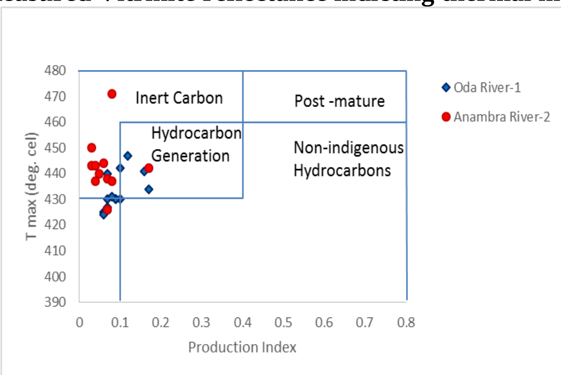

Fig 10. Plot of Tmax against Production Index showing zone of hydrocarbon generation

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