COMPARATIVE ASSESSMENT OF HYDROCARBON POTENTIAL OF CRETACEOUS COALS FROM THE BENUE TROUGH, NIGERIA.

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ABSTRACT

Rock-Eval pyrolysis has been widely accepted as a standard method of analyzing sedimentary rocks especially coals for hydrocarbon prospectiveness. This method was used to analyse twenty-one samples from the Benue Trough of Nigeria. Four samples from the Mamu Formation, fourteen samples from the Agwu Formation, Two samples from the Lamja Sandstone, and one sample from the Gombe Sandstone within lower, middle and upper Benue Trough respectively. The four samples from the Mamu Formation have an average TOC of 44.03wt.%, an average S_1 of 2.14mg/g, an average S_2 of 133 mg/g and an average Tmax of 431ºC. The HI is very high, ranging from 266 to 327 mgHC/gTOC. The mean HI from S_2 versus TOC plot is about 363 (r^2 = 0.9877) mgHC/gTOC. This figure places these coals into type II organic matter that can generate oil and gas. The Tmax values suggest an onset of oil generation. The fourteen samples from the Agwu Formation have an average TOC of 46.23 wt.%, S_1 of 172 mg/g and Tmax of 452ºC. Agwu 1, Agwu 6 and Agwu 7 show exceptionally low HI, S_1 and S_2 but the Tmax values for these samples fall within the optimal temperature for hydrocarbon generation. HI for the rest of the samples ranges from 120 to 267 mgHC/gTOC. All the samples from the Agwu Formation have an average HI of 280 mgHC/gTOC from S_2 versus TOC diagram. On HI versus OI plot, the samples plotted on all the organic matter types' tracks. The HI value of 182 mgHC/gTOC from S_2 versus TOC plot implies that coals from the Upper Benue Trough have type III organic matter with gas and oil source potential. The Tmax of 438ºC indicates that the samples from the Lamja Sandstone are within early to middle oil window while the Tmax of 423ºC from sample of the Gombe Sandstone implies immaturity.

Keywords: Coal, Hydrogen Index, Organic matter, Maturity, Petroleum, Benue Trough.

INTRODUCTION

The location and position of various parts of the Benue Trough is in Figure 1. Coal is by definition a rock containing a greater proportion of preserved organic matter (OM) than the mineral matters (Boreham and Powell, 1993). Stach et al. (1982); Hatcher et al. (1983) and Schobert and Teichmüller (1989) believed that coal is largely a macromolecular organic rock derived from the burial and compaction of peat deposited under various wetland conditions. Levine (1993) used five genetic stages to describe the evolution of coal as a hydrocarbon source material and he related these stages to describe the diagenesis, catagenesis and metagenesis of Tissot and Welte (1984) and to American Standard Testing Material (ASTM) rank range. The transformation of vegetable matter into peat and coal is commonly regarded as proceeding in two stages, called the biochemical and physicochemical stages of coalifications. During biochemical coalification, organicsms initiate and assist in the chemical decomposition of vegetal matter and its convsersion into peat and brown coal. The results of this process depend on the phytogenic input and environmental condition under which it is transformed into peat (Diessel, 1992).

Humification results in the hydrolytic decomposition of dead vegetable matter, which affects the soft cell contents first followed by the cellulose and hemicellulose of the cell walls and eventually the more resistant compounds, such as lignin (Diessel, 1992). Levine (1993) described humification as a selective chemical process (es) during which fresh plant material alters to form humic substances having characteristics similar to vitrinite. He also described gelification as a process by which a colloidal solution is formed from original organic precursors. This subsequently dehydrates to form a hydrogel. The physically altered gel can be completely structureless or can be contain a highly degraded, swollen remnant cell structure.

Biochemical coalification begins with the accumulation of dead vegetable matter and ends with the polymerization of humic colloids at the rank of sub-bitiminous coal. The interaction of its many different physical, chemical and biological processes leads to the development of a diverse range of degradation products of vegetable matter which appear as macerals in coal. The biochemical stage of coalification is therefore one during which from the same source material can produce a fusinite consisting of almost pure carbon and a vitrinite containing only 79% carbon may result (Mackowsky, 1953).

The physic-chemical stage of coalification is initiated and maintained by deep post-depositional subsidence of the seam. Since all components contained in a seam are affected by the same

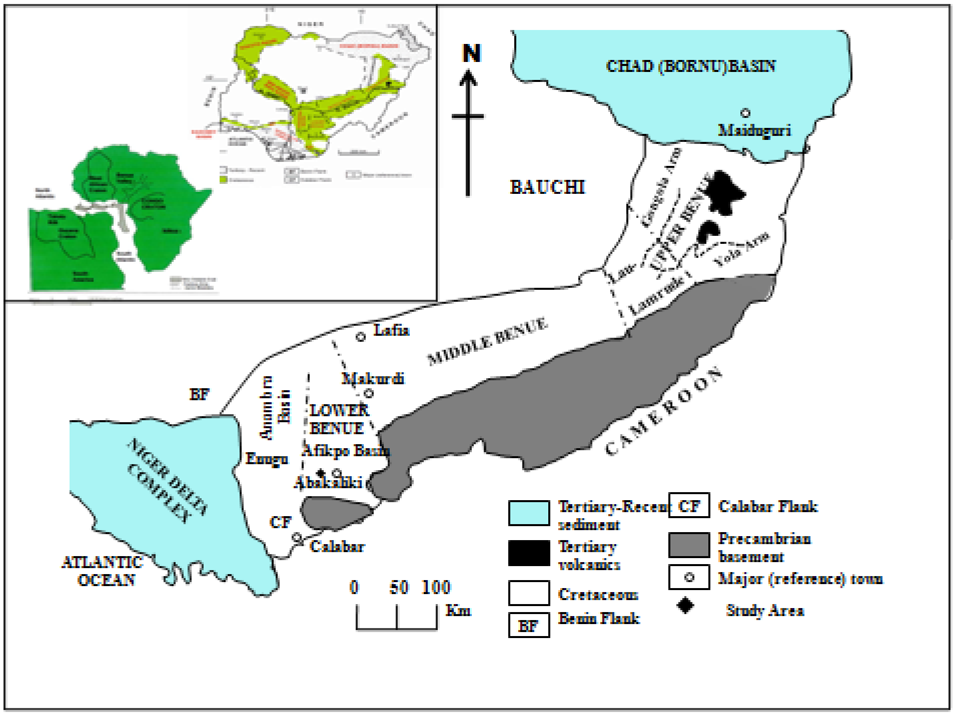

Fig. 1: Map showing the sedimentary basins of Nigeria. The map to the right is an enlarged outline geological map of Benue Trough showing the location of the Lower, Middle and Upper troughs.

pressure and temperature conditions, maceral properties begin to converge, in the course of which the initial chemical and physical difference between various coal macerals are cancelled (Diessel,1992). The bituminization process is possibly initiated at the boundary of sub-bituminous A and high-volatile bituminous coal (Teichmüller, 1989). Petroleum like hydrocarbons are generated and expelled from per hydrous vitrinite and liptinite macerals in turn causing aromatization and condensation of the remaining coal macerals (Mukhopadhyay and Hatcher, 1993).

Whereas coalification in the bituminous rank centers on changes to the molecular components, coalification at anthracite and meta-anthracite stages is principally related structural rearrangement of the matrix component. At high coal rank, the elemental composition of the coal changes very little and this involves the loss of hydrogen, with most of the molecular fraction been expelled or repolymerized (Levine, 1993).

This paper aims to identify some key organic geochemical indices and use the parameters to define quantity, quality and maturity of the coals from the Benue Trough, Nigeria.

REGIONAL STRATIGRAPHIC SETTING

The Benue Trough of Nigeria is a rift basin in central West Africa that extends NNE-SSW for about 800km in length and 150km in width (Fig. 1) (Simpson, 1954; Carter *et al*., 1963; Reyment, 1965; Murat, 1972 and Benkhelil, 1989). The trough contains up to 6000m of Cretaceous – Tertiary sediments of which those predating the mid-Santonian were compressionally deformed, faulted, and uplifted in several places (Petters and Ekweozor, 1982; Whiteman, 1982; Zaborski, 1998; and Benkhelil, 1989).

The Benue Trough geographically subdivided into Lower, Middle, and Upper Benue Trough is strictly a sedimentary basin extending from the Gulf of Guinea in the south to the Chad Basin in the north (Fig. 3) (Offodile, 1976; Dike, 1976a,b, 1993, 2002; Adeleye and Fayose,1978; Enu, 1987 and Petters, 1978, 1979b, 1980, 1982, 1991). The origin and tectonic history of the Benue Trough is associated with the break-up of the continents of Africa and South America. This break-up was followed by the drifting apart of these continents, the opening of the South Atlantic, and the growth of the mid-Atlantic ridge (Read and Watson, 1978; Freeth, 1990).

Wright (1981) presented a case for regarding the Benue Trough as having been a tensional feature throughout its entire history. His principal supporting evidence being the straight limbs of some folds structures discernible on ERTS (Earth Resources Technology Satellite) imagery. He briefly reviewed and dismissed the case for a seafloor spreading accompanied by subduction for the trough. Jones (1965) and Osazuwa et al. (1981) independently concluded that the Benue Trough is characterized by central gravity "highs" over Amar, Awe, Gboko in the Middle Benue Trough and the Kaltungo area in the Upper Benue Trough. Their results also revealed that the central gravity "highs" are flanked on both sides by gravity "lows". They interpreted the "lows" as areas of thickest Cretaceous sediments.

The Benue Trough is believed to be an aulacogen (a failed arm of a RRR triple junction) (Benkhelil, 1989). As pointed out by Petters (1982), in the Gulf of Guinea where bifurcating rift system become the site of a triple junction, two of the rifts opened into ocean with marginal basins underlain by half-grabens (e.g. the Dahomey Embayment). Along the third rift system in the Gulf of Guinea triple junction occurred only limited opening (Petters (1982). This was abandoned as a "failed arm" or juvenile aulacogen which today is the Benue Trough. This trough contains a thick folded sedimentary pile and an aulacogen delta (Niger Delta) at its re-entrant.

Detailed stratigraphic descriptions (Fig. 2) of the sediments in Benue Trough have been presented by Obaje et al. (1999,2004,2006), Obaje and Hamza (2000) and Pearsen and Obaje (2000).

The sedimentary succession in the Lower Benue Trough comprises the basal pre-Abian basement unconformably overlain by the Albian Asu River Group (3000m thick). The Asu River Group is overlain conformably by the Turonian-Early Santonian Cross River Group (2000m) (Petters, 1982; Petters and Ekweozor, 1982). A post-Santonian deltaic and coal measures sequence, about 2000m thick, rest unconformably on the Cross River Group (Fig. 2).

The Asu River Group comprises the oldest marine deposits in the Benue Trough. These are the shales, limestones and sandstone lenses of the Albian Abakaliki Shale, correlating with the Mfamosing Limestone, a lithostratigraphic unit introduced by Petters (1982). The Mfamosing Limestone is a 15m thick limestone sequence exposed along the Oban Massif on the Calabar Flank in the southeastern part of the Benue Trough (Petters, 1982; Ojoh, 1990; Akande et al., 1998; Dike and Onumara, 1999). The fossiliferous Arufu, Uomba, and Gboko

Formations in the Middle Benue Trough are the lateral equivalent of the Asu River Group (Petters, 1982).

Overlaying the Asu River Group is transgressive Cenomanian-Santonian lithogenetic unit; the Nkalagu Formation (black shales, limestones and siltstones) and interfingering regressive sandstones of the Agala, Amasiri and Agbani Formations (Petters, 1982). In the Middle Benue Trough, the Awe, Keana, and Makurdi Formations and the marine Ezeaku and Awgu Formations are the lateral equivalents of the Cross River Group (Obaje et al., 1999, 2004, 2006). Late Santonian-Early Campanian folding in the Benue Trough displaced the major depositional axis in the greater parts of the Benue Trough and was quite intense, producing over 100 anticlines and synclines (Benkhelil, 1989) (Fig. 2). Following the mid-Santonian tectonism (fold phase), depositional axis in the Benue Trough was displaced westward resulting in the subsidence of the Anambra Basin (Akande and Erdtmann, 1998). The Anambra Basin, therefore, is a part of the Lower Benue Trough containing post-deformational sediments of Campano-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 (Akande and Erdtmann, 1998).

In the Lower Benue, post-folding Campano-Maastrictian paralic shales of the Enugu and Nkporo Formations, coal measures of the Mamu and Nsukka Formations and sandstones of the Ajali

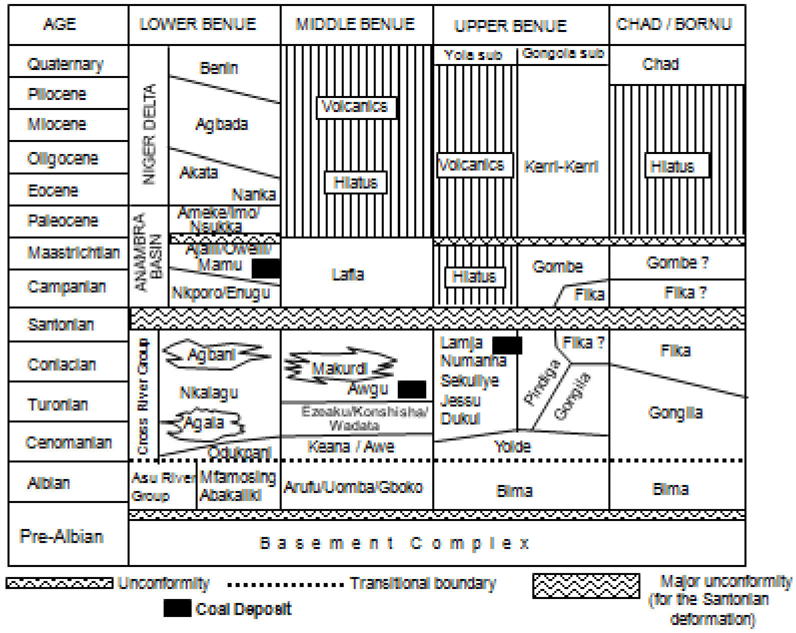

Fig. 2. Stratigraphic successions in the Benue trough and the relationship to the Chad basin and the Niger delta (After Obaje et al., 2004).

Formation was deposited (Akande and Erdtmann, 1998). In the Middle Benue Trough, only the Lafia Formation of continental fluvial depositional environment represents the lateral facies equivalent of post-Santonian sediments (Fig. 2). The outcropping Imo Shale and the Ameke Formation and their downdip equivalents, the Akata and Agbada Formations respectively are Paleogene paralic units in the Lower Benue Trough (Obaje et al., 2004). The Middle Benue Trough is barren of post-Cretaceous sediments.

In the Upper Benue Trough, Dike (2002) in Abubakar et al. (2008) agreed with the third basin ealier reported by Guiraud (1990) (NE-SW trending Lau Basin or Main Arm) (Fig. 1). The alluvial-fluvial-deltaic Bima Sandstone Formation occurs at the base of the stratigraphic sequence. The Albian sea apparently has not invaded the basin at the time (Benkhelil, 1989; Guiraud, 1990). Marine transgression started in the Cenomanian with transitional beds of the Yolde Formation and the overlying marine Pindiga and Gongila formations. The Pindiga and Gongila Formations are equivalent to the Nkalagu Formation in the Lower Benue Trough and Awe-Ezeaku –Awgu Formations in the Middle Benue (Obaje et al., 2004). These formations were deposited during Cenomanian- Early Turonian marine transgression. The limestones and shales of the Dukul Formation, the mudstones of the Jesu Formation, and the Sekuliye

Formation, the Numanha Shale, and the Lamja Sandstone are the facies equivalents of the Pindiga Formation (Obaje et al., 2004).

MATERIALS AND METHODS

A total of 21 outcrop carbonaceous coal samples were obtained from the Mamu Formation, Agwu Formation, Lamja Sandstone and Gombe Sandstones along road cuts and mining pits. Care was taking to avoid weathered portions of the outcrop and to obtain material sufficient for various geochemical analyses. In the laboratory, the samples were reshaped using a rotating steel cutter to eliminate surface that could be affected by alteration. Chips were cut from the samples and dried in an oven at 105°C for 24 hours. The dried sample was pulverized in a rotating disc mill to yield about 50 g of sample for analytical geochemistry. The TOC and inorganic carbon (TIC) contents were determined using Leco CS 200 carbon analyzer by combustion of 100 mg of sample up to 1600°C, with a thermal gradient of 160°C min^{-1}; the resulting CO_2 was quantified by an Infrared detector. The sample with known TOC was analyzed using a Rock-Eval 6, yielding parameters commonly used in source rock characterization, flame ionization detection (FID) for hydrocarbons thermal conductivity detection (TCD) for CO_2. The Zeiss standard universal reflected microscope was used for vitrinite reflectance.

RESULTS AND DISCUSSIONS

Total Organic Carbon

Total organic carbon (TOC) is the first primary factor to be considered in assessing the hydrocarbon generative potential of a sedimentary rock. A rock that is organic –lean is automatically excluded from further screening for hydrocarbon potentiality, no matter how thick the rock unit is. Judging by these statements, the average TOC of 44.04 wt.% for samples from the Mamu Formation, 46.23 wt.% for samples from the Agwu Formation and 50.90 wt.% for samples from the Lamja Sandstone and ranges from 30.80 to 60.80 wt.%, 17.40 to 79.10 wt.% and 50.70 to 51.10 wt.% respectively and a value of 20.20 wt.% for Doho samples (Table 1) show that these coals have satisfied the organic matter requirement for the generation of hydrocarbon as all the TOC results are far beyond the minimum threshold of 0.50 and 0.40 wt.% for shaly and carbonate materials.

Table 1: Rock-Eval Pyrolysis Data.

BENUE TROUGH	LOCALITY	SAMPLE NO.	TOC (wt.%)	S_1 (mg/g)	S_2 (mg/g)	S_3 (mg/g)	Tmax (^{o}C)	HI (mgHC /gTOC	OI (mgCO_2 /gTOC	PI S_1/S_1+S_2	SP S_1+S_2	S_2/S_3	S_1/TOC
Upper	Lamja	LAM-1	50.70	2.15	93.25	12.62	438.00	184.00	25.00	0.02	95.40	7.39	0.04
	"	LAM-2	51.10	1.47	91.70	14.15	438.00	179.00	28.00	0.02	93.17	6.48	0.03
	Doho	GOM-1	20.20	0.62	35.95	10.53	423.00	178.00	52.00	0.02	36.57	3.41	0.03
Middle	Jangwa	AGW-1	17.40	0.08	2.49	12.49	457.00	14.00	72.00	0.03	2.57	0.20	0.00
	"	AGW-2	66.70	4.38	164.29	1.33	452.00	246.00	2.00	0.03	168.67	123.53	0.07
	"	AGW-3	23.80	0.72	39.58	1.23	455.00	166.00	5.00	0.02	40.30	32.18	0.03
	"	AGW-4	18.50	0.38	22.18	5.32	444.00	120.00	29.00	0.02	22.56	4.17	0.02
	"	AGW-5	61.10	1.93	83.05	13.60	449.00	136.00	22.00	0.02	84.98	6.11	0.03
	"	AGW-6	43.10	0.19	10.81	18.12	445.00	25.00	44.00	0.02	11.00	0.60	0.00
	"	AGW-7	44.20	0.26	18.42	19.13	441.00	42.00	43.00	0.01	18.68	0.96	0.01
	"	AGW-8	27.00	3.93	41.20	1.65	452.00	153.00	6.00	0.09	45.13	24.97	0.15
	"	AGW-9	70.60	2.27	171.54	2.31	453.00	243.00	3.00	0.01	173.81	74.26	0.03
	"	AGW-10	79.10	3.16	207.30	2.50	459.00	262.00	3.00	0.02	210.46	82.92	0.04
	"	AGW-11	26.40	0.84	43.51	1.48	457.00	165.00	6.00	0.02	44.35	29.40	0.03
	"	AGW-12	76.30	3.04	203.84	2.52	452.00	267.00	3.00	0.01	206.88	80.89	0.04
	"	AGW-13	75.60	2.60	192.77	2.69	457.00	255.00	4.00	0.01	195.37	71.66	0.03
	"	AGW-14	17.40	0.41	21.76	5.37	444.00	125.00	31.00	0.02	22.17	4.05	0.02
Lower	Enugu	MAM-1	52.00	1.45	170.16	5.93	433.00	327.00	11.00	0.01	171.61	28.69	0.03
(Anambra	"	MAM-2	60.80	4.53	188.57	9.00	431.00	310.00	15.00	0.02	193.10	20.95	0.07
Basin)	"	MAM-3	32.50	1.61	92.36	4.84	431.00	284.00	15.00	0.02	93.97	19.08	0.05
	"	MAM-4	30.80	0.95	81.81	5.54	430.00	266.00	18.00	0.01	82.76	14.77	0.03

Lower Benue Trough

The most important factor controlling the generation of oil and gas is the hydrogen content of the OM. The quantity of the petroleum generated and expelled increases as the atomic hydrogen-to-carbon (H/C) ratio of the OM increases. OM with HI values above 200mgHC/gTOC is considered capable of generating some liquid hydrocarbon (Hunt, 1996). Peters (1986a) suggested that OM at a thermal maturity equivalent to a vitrinite reflectance of 0.6Ro% with HI above 300mgHC/gTOC will produce oil, those HI between 300 and 150mgHC/gTOC will produce oil with some gas, those with HI between 150 and 50 mgHC/gTOC will produce gas and those with less than 50mgHC/gTOC are inert. Hunt (1996) believed that change over from oil-prone to gas- prone source rock is usually within 150-200 mgHC/gTOC. The HI from the Rock-Eval data ranges from 266 to 327mgHC/gTOC. On S_2 v. TOC plot, the average HI is about 363mgHC/gTOC (r^2 = 0.998) (Fig. 3). This result is relatively high compared to the calculated mean of 297mgHC/gTOC (Table 1) because S_2 v. TOC plot removes matrix effects the retention

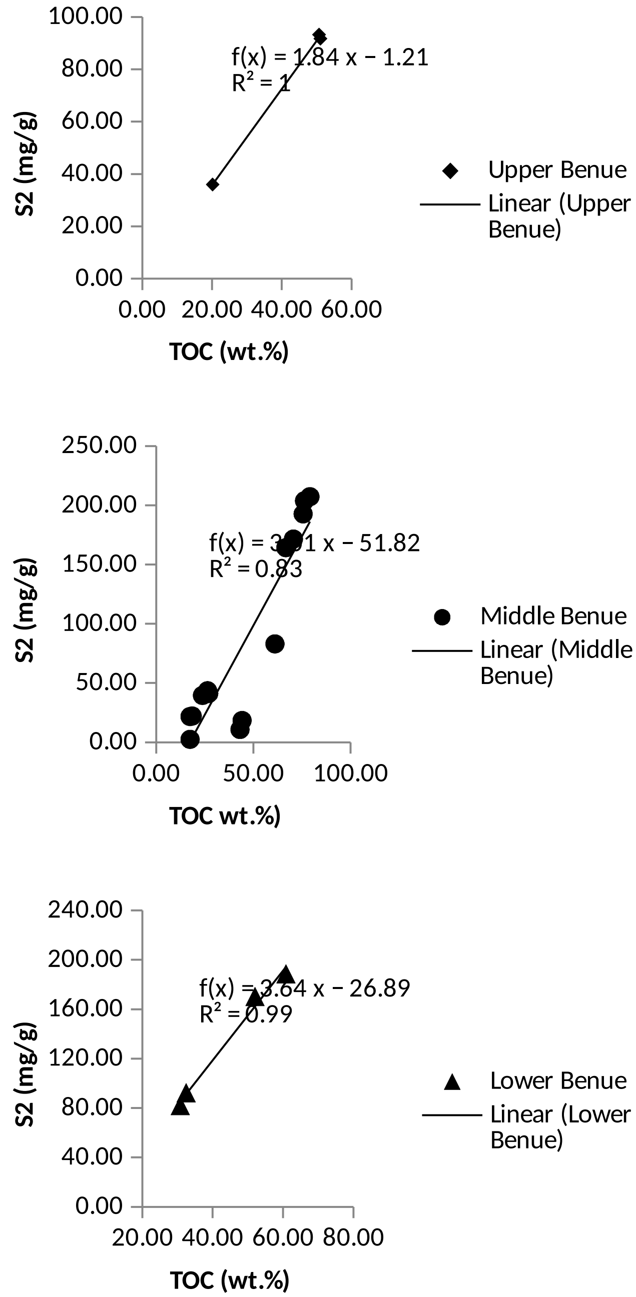

Fig. 3: S_2 vs. TOC plot of coal samples from the Benue Trough.

of pyrolysable (S_2) hydrocarbons on minerals (Langford and Blanc-Valleron, 1990). Based on the HI, these coals can be interpreted as an oil source rock. This is further confirmed by the kerogen type on HI vs.OI diagram (Fig. 4), which shows that all the samples plotted on type I track. However, on Tmax vs. HI diagram (Fig. 5) the samples show potentiality for both oil and gas.

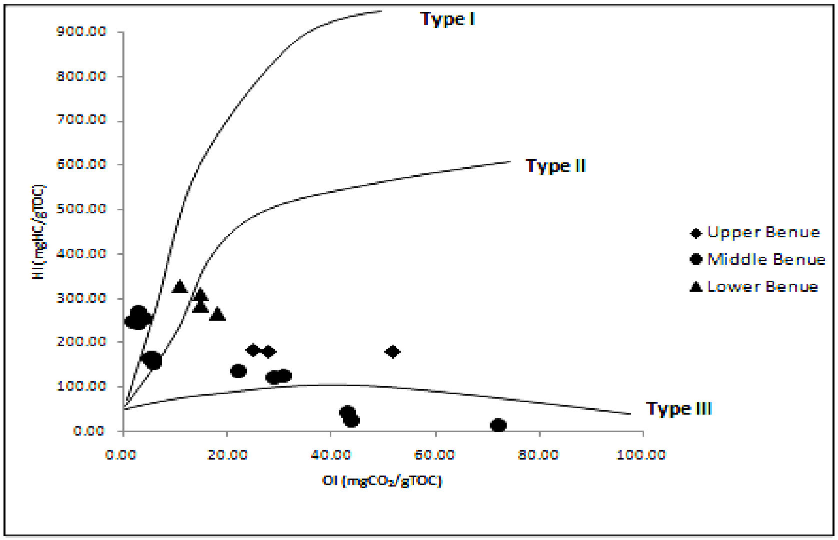

Fig. 4: HI vs. OI plot showing kerogen type of coal samples from the Benue Trough.

The pyrolysable hydrocarbons range from 81.81 to 188.57 mg/g and average of 133 mg/g. These values classed these samples as excellent source rock. Based on the standard procedure of source rock pyrolysis analysis, the concentrations of free hydrocarbons (Table 1) can be interpreted as moderate, good and excellent. The free hydrocarbon for these samples ranges from 0.95 to 4.53 mg/g and therefore supports the above conclusion. The Tmax values are either on or higher than the birth line temperature (430ºC) for hydrocarbon generation. It ranges from 430 to 433ºC, therefore, based on these Tmax values transitionally to early maturity can be assumed for these samples. Obaje et al. (1999a) gave vitrinite reflectance (%Ro) values ranging from 0.40 to 0.54%Ro for coal samples from the Mamu Formation.

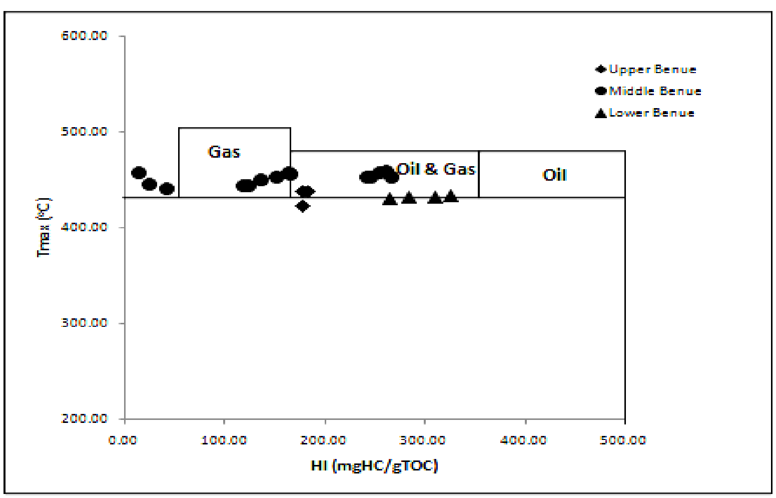

Fig. 5: Tmax vs. HI plot of coal samples from the Benue Trough.

The kerogen content of 44.03 mgHC g^{-1}TOC was described as good, with an S_2/S_3 of 20.87 indicative of gas-prone organic matter is consistent with its T_{max} of 430 to 433ºC, indicative of early maturity to maturity while the S_1/TOC of 0.05 indicates early generation of petroleum.

The production index (PI) is used to assess the generation status of source rocks but is often useful when homogeneous source rocks of different rank are compared, in which case it is characterized as the transformation ratio (Bordenave et al., 1993). Hunt (1996) suggested that a PI from 0.00 to 0.40 is characteristic of source rocks in the oil window. The value of 0.02 of this coal is consistent with its T_{max} of 431.25ºC. This maturity is also consistent with the fairly well fluorescing organic matter as well as Rock Eval T_{max} of 430ºC, reaching the 430-435ºC for low sulphur immature source rocks containing Type III (Bordenave et al., 1993; Hunt, 1996).

A Plot of the SOM (extract yield) against TOC (Fig. 6) as proposed by Landis and Connan (1980) in Jovancicevic et al. (2002) for the coal samples indicates migration of oil has taken place on the shale samples from Mamu Formation, Anambra Basin. This is supported by the diagram of $S_1 + S_2$ vs TOC (Fig. 7) characterizing the coal samples from the Anambra Basin as good to excellent source rocks with TOC and $S_1 + S_2$ above 1.0wt% and 5.0mg/g respectively.

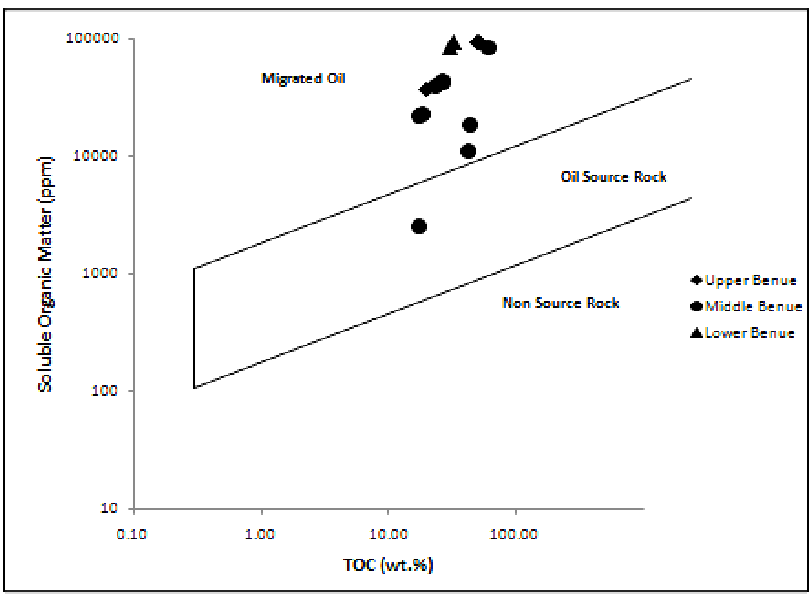

Fig. 6: A diagram showing the characterization of organic matter SOM. vs TOC (based on Landais and Connan in Jovancicevic et al., 2002) of samples from the Benue Trough indicated migration of oil in the area.

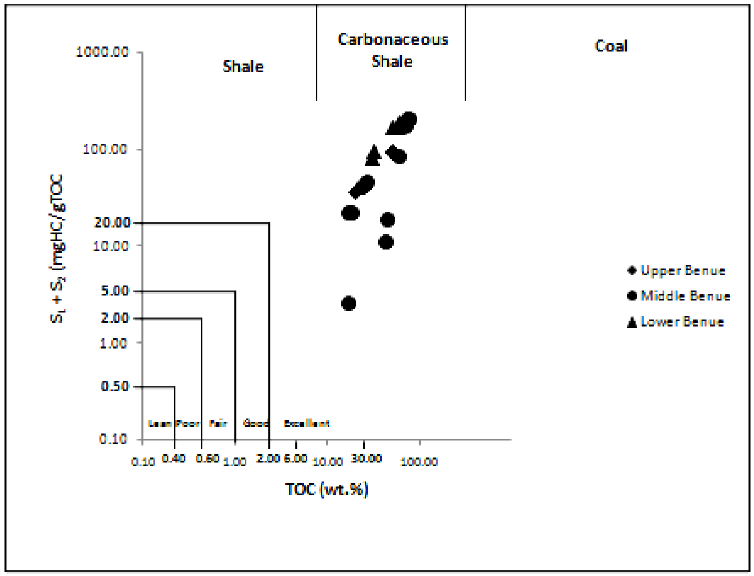

Fig: 7: A diagram indicating the quality of different source rocks, $S_1 + S_2$ vs TOC of coal samples from the Benue Trough.

Middle Benue Trough

The samples from the Agwu Formation have HI ranging from 14 to 267 mgHC/gTOC. Eleven of the fourteen samples studied have HI that fall within the range of 72 to 156 mgHC/gTOC. Such a range was recorded by Garcia-Gonzalez et al. (1997) from the Almond coals, which have both oil and gas in place. The other three samples have very low HI falling into type IV OM with negligible hydrocarbon source potential. On S_2 vs. TOC plot (Fig. 3), the HI is around 280 mgHC/gTOC ($r^2 = 0.8281$). This classified the middle Benue coals as type III OM, as such it can generate oil and gas. This contradicts the kerogen typing and Tmax vs. HI plot (Fig. 5). The latter indicates that these coals can generate oil and gas. This could be due to high the OI of some of the samples (Table 1, Fig. 4). Mukhopadhyay and Hatcher (1993) observed a trend of increasing HI with liptinite content of coals. Liptinites are derived from hydrogen-rich plant organs as well as algal and bacterial substances (Obaje, 1994). The relatively high HI observed in some of the samples could be attributed to the liptinite contents in the coal reported by Obaje and Hamza (2000). On a mineral matter free basis, Obaje et al. (1994) showed that the liptinite contents in a trimaceritic coal facies of these coals can go as high as 25.60% and is always more than 15%. The Lower Tertiary Latribe coals and coaly shales in the Gippsland Basin of southeastern Australia "which have produced" an initial reserve of 3bbls of oil, 8tcfs of gas and

800mbls of condensate have liptinite contents of around 25% with an average of around 15% (Hunt, 1996). This shows correlation with the figures cited above for the Agwu coals.

The eleven samples that have high HI, also recorded high S_1 and S_2 while the three samples with low HI show low S_1 and S_2 but on a general note, all the samples show moderate, good to excellent source rock potential (S_1 range from 0.08 to 3.97 mg/g and S_2 range from 2.49 to 207.30 mg/g) 50% of the samples has S_1 above 2 mg/g, 14% has S_1 of 0.72 to 0.84 mg/g and 365 has S_1 of less than 0.50 mg/g. The source rock potential of these samples has very high S_2 values representing excellent source rock potential.

All the samples have Tmax values above 435ºC, which Peters (1988) said indicates an upper limit of immature organic matter and less than 470ºC which he regarded as representing the wet-gas zone. Tmax is supposed to increase steadily with maturity, with the oil generation window between Tmax values of 435 and 470ºC. Usually it does, but sometimes it oscillates back and forth as much as 20ºC because of changes in the OM's hydrogen content. A high –hydrogen OM generally has low Tmax and a low-hydrogen OM has high Tmax (Hunt, 1996). The Tmax that ranges from 441 to 459ºC indicates that these coals fall within the early to peak oil window. Obaje et al. (1999) gave %Ro values for these coals that range from 0.76 to 1.25%Ro and suggested a maturity of middle to late oil window.

On Tmax vs. HI plot (Fig. 5) three samples (Agwu 1, Agwu 6 and Agwu 7) show signs of not generating either oil or gas. Six samples show the potential for gas generation, and four samples indicates oil and gas potential. This spatial distribution of the possible types of hydrocarbons is a clear reflection of the kerogen types (Fig. 4) and further reflects the petrographic diversity of these coals, and in general the diversity of possible hydrocarbons from coals of the Benue Trough (Figs 5, 6). Obaje et al. (1994) identified the macerals; vitrinite, liptinite and inertinite in different proportion but without any particular trend in shaly coal facies of coals from the Agwu Formation of the Middle Benue Trough.

The kerogen content of 46.23 mgHC g^{-1}TOC was described as good, with an S_2/S_3 of 38.28 indicative of gas-prone organic matter is consistent with its T_{max} of 441 to 457ºC, indicative of maturity while the S_1/TOC of 0.04 indicates early generation of petroleum.

The PI value of 0.02 of this coal is consistent with its T_{max} of 451.51ºC. This maturity is also consistent with the fairly well fluorescing organic matter as well as Rock Eval T_{max} of 430ºC, reaching the 430-435ºC for low sulphur immature source rocks containing Type III (Bordenave et al., 1993; Hunt, 1996).

A Plot of the SOM (extract yield) against TOC (Fig. 6) as proposed by Landis and Connan (1980) in Jovancicevic et al. (2002) for the coal samples indicates migration of oil has taken place on the shale samples from Agwu Formation, Cross River Group. This is supported by the diagram of $S_1 + S_2$ vs TOC (Fig. 7) characterizing the coal samples from the Cross River Group as good to excellent source rocks with TOC and $S_1 + S_2$ above 1.0wt% and 5.0mg/g respectively.

Upper Benue Trough

Petrographic and geochemical data on these coals is very scarce to non-existent. Therefore, interpretation of their hydrocarbon generation potential needs to be based on the present data. As mentioned above the TOC's for both the Lamja and Gombe coals have satisfied the OM needed for source rocks. The free hydrocarbon per milligram of gram of rock is relatively high for both coals. The pyrolysable hydrocarbon shows that the coals have excellent source rock potential. The HI of 184 mgHC/gTOC, 179 mgHC/gTOC and 178 mgHC/gTOC with an average of 182 mgHC/gTOC (r^2 = 0.994) from S_2 vs. TOC diagram (Fig. 3) placed these coals into type III OM, therefore both can generate gas and probably little oil. The Tmax of 438ºC suggests the early to middle oil window. On Tmax vs. HI plot (Fig. 5), the coals plotted at the boundary of gas and oil zones, and on HI vs. OI plot (Fig. 4), the samples clustered between type II and III tracks in confirmation of the conclusion above. The Gomco 1 has Tmax of 423ºC, which is below the lower threshold limit (430ºC) for effective thermal stress to occur. The Cretaceous sub-bituminous coal of Pakistan has a similar Tmax value and sub-bituminous coals equate to diagenetic level in the stages of coalification process. Therefore, this sample indicates immaturity.

The kerogen content of 46.23 mgHC g^{-1}TOC was described as good, with an S_2/S_3 of 5.76 indicative of gas-prone organic matter is consistent with its T_{max} of 423 to 438ºC, indicative of maturity while the S_1/TOC of 0.03 indicates early generation of petroleum.

The PI value of 0.02 of this coal is consistent with its T_{max} of 433ºC. This maturity is also consistent with the fairly well fluorescing organic matter as well as Rock Eval T_{max} of 430ºC, reaching the 430-435ºC for low sulphur immature source rocks containing Type III (Bordenave et al., 1993; Hunt, 1996).

A Plot of the SOM (extract yield) against TOC (Fig. 6) as proposed by Landis and Connan (1980) in Jovancicevic et al. (2002) for the coal samples indicates migration of oil has taken place on the shale samples from Lamja and Gombe sandstones of Yola and Gongola sub-basins. This is supported by the diagram of $S_1 + S_2$ vs TOC (Fig. 7) characterizing the coal samples from the Yola and Gongola sub-basins as good to excellent source rocks with TOC and $S_1 + S_2$ above 1.0wt% and 5.0mg/g respectively.

CONCLUSION

Twenty-one coal samples from the lower, middle and upper parts of the Benue Trough have been examined for hydrocarbon source rock potential. Based on the HI, the coals from the Mamu Formation of the lower Benue Trough showed type II OM that has a potential to generate oil and gas. The coals from the middle and upper Benue Trough have type III OM with a potential of oil and gas generation. The samples from the Mamu Formation have Tmax values, which suggest an on set of hydrocarbon generation. The Agwu coals are within the early to peak oil window. For the Lamja samples, the Tmax suggest an early to middle oil window. While in the sample from Gombe Sandstone the Tmax indicates immaturity.

The coals from middle and lower Benue Trough may constitute good source rocks. Apart from favourable geochemical indices, rhythmic sedimentation that characterized the OM, the deposition of these formations has contributed in the multiplicity of the coal seams, which on individual basis are very thin but on aggregate represent a very thick rock unit.

The one sample studied from the Gombe Sandstone is not enough to permit solid conclusion on the hydrocarbon potential of the coal, therefore, it's here suggested the feature studies should include many samples covering the lateral extent and if possible subsurface of the formation.

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