
By

Samuel O. Akande
Olusola J. Ojo
Olabisi A. Adekeye
Department of Geology and Mineral Sciences, University of Ilorin, PMB 1515, Ilorin, Nigeria

Sven O. Egenhoff
Department of GeoSciences, Colorado State University, Fort Collins, Colorado, CO 80523, USA.

Nuhu G. Obaje
Department of Geology and Mining, Nassarawa State University, Keffi, Nigeria,

Bernd D. Erdtmann
Institut fur Geologie und Palaontologie, Technische Universitat Berlin, Sekr. ACK 14, Ackerstrasse 71-76, D-13355 Berlin, Germany.

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Abstract
The Nigerian Benue Trough is an intracratonic rift structure which evolution is related to the Early Cretaceous opening of the South Atlantic Ocean and the Gulf of Guinea. While exploration efforts for oil and gas have been concentrated on the adjacent Tertiary Niger Delta Basin, very little attention have been paid to the Cretaceous inland basins especially the southern segments of the trough with obvious stratigraphic continuity despite the commercial discoveries of the structural related rift basins of the Niger, Chad, Sudan and Cameroon within the same trend. Prior studies which included kerogen studies of the successions revealed a number of organic rich intervals capable of yielding significant quantities of hydrocarbons in the Cretaceous sections. Indeed stratigraphic continuity of these intervals suggest their potentials for hydrocarbons if suitable maturity levels were reached and both oil and gas can be generated.

The present study have expanded on some previously reported source rock data of the Cretaceous formations by detailed mapping of the source rock stratigraphic intervals on the basis of their structural setting, lithologic characteristics, sedimentology and depositional environments. Further characterization of the organic matter enrichments at the Cenomanian to Coniacian on one hand and the Campanian to Maastrichtian intervals were carried out to determine the geochemical character of the organic rich zones, their maturity and effectiveness to generate and expel hydrocarbons.

In the Lower Benue Basins, mature facies of the Cenomanian to Turonian Eze-Aku Formation with a predominance of Types II to III kerogen, the Turonian to Coniacian Type III dominated Awgu Formation and the Type III dominated Lower Maastrichtian sub-bituminous coals of the Mamu Formation have proven potentials as oil and gas source rocks. In the Middle Benue Basin, the preserved mature intervals of the Awgu Formation shales and coals, are good gas source rocks with some oily units in view of the predominating Type III nature of the organic matter. Targets for hydrocarbons generated at these stratigraphic intervals should be sought on the non-emergent Cretaceous reservoirs with respect to the Pre-Santonian successions whereas, the mature equivalents of the sub-bituminous coals facies would generate and charge both Upper Cretaceous reservoirs and possibly the sub- Niger Delta successions in the sub-surface.

Introduction
The Benue Trough in Nigeria consists of a series of rift basins which form a part of the Central West African Rift System of the Niger, Chad, Cameroon and Sudan (Fig. 1). Basement fragmentation, block faulting, subsidence and rifting accompanying the opening of the South Atlantic Ocean led to the deposition and accumulation of sediments ranging between 4000 to 6000m in the greater Benue Trough along the 800km axis over a width of ca.120km from the northern parts of the Niger Delta Basin in the south west to the fringes of the Chad Basin on the north east (Fig. 2). The trough, is divisible geographically into the Lower, Middle and Upper Benue basins with the Lower Benue consisting of the Abakaliki and Anambra Basins and the Middle Benue Basin occupying the region

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north of the Gboko regional fracture system i.e. the Gboko Line (Fig.2). Localized geological factors controlled the basins development and are reflected in the lithostratigraphy and ages of the facies associations. Previous work have laid emphasis on the geology of the petroliferous Anambra Basin because of the good exposures of the Cretaceous successions and exploratory wells drilled by oil companies compared with the Abakaliki Basin and the adjoining Middle Benue Basin. Recent exploration activities in the rift basins concentrated on the north side of the Upper Benue Trough where three exploratory wells; the Kolmani River -1, Kuzari -1 and Nasara -1 were drilled in the Gongola Basin while the Lower and Middle Benue Basins with obvious stratigraphic continuity were avoided despite the substantial thicknesses of the Cretaceous –Tertiary sediments in these basins. The presence of up to 8000m of Cretaceous – Tertiary sediments in the Lower Benue Anambra Basin with substantial thicknesses of proven potential source rock facies, seals and traps and the stratigraphically controlled occurrences of High volatile to Medium volatile and sub-bituminous coals in both the Lower and Middle Benue Basins having enormous potentials for both liquid and gaseous hydrocarbons support the need for a more serious attention to the Lower and Middle Benue Basins in all ramifications of frontier exploration. Previous drilling activities indicate both oil and gas finds in the Anambra Basin at various stratigraphic intervals including the antecedent and interconnected Abakaliki and Middle Benue Basins where oil seeps and pyrobitumens were reported2. Investigations of the Cretaceous Formations and their prospectivity in the Upper Benue Gongola and Yola Basins have illustrated the peculiarities of the geology and paleoenvironmental settings of these basins and the reflections on the hydrocarbon source rock characteristics3 which could be compared with the Lower and Middle Benue Basins.

The present paper attempts to fill the gaps and update the knowledge on the structural setting, paleoenvironments, sequence stratigraphic relations including the thermal and burial history of the successions of the Lower and Middle Benue Basins to interpret the time-space relationships of the source rock facies. The positioning of the potential source rocks are discussed in the context of the viable petroleum systems to emphasize the need for future exploration in the basins.


Figure 1. The Central West African Rift System showing the trends of rift basins. Notice the positions of the Benue Trough and the East Niger, Doba, Muglad and Melut basins (Adapted from Schull, 1988).
Tectono-stratigraphic setting

The zipper-like separation of the South American and African plates was consequent to crustal uplift, doming, subsidence and development of rift valleys flanked by stable cratons in the Late Jurassic to Early Cretaceous. This Mesozoic event led to the initial opening of the South Atlantic Ocean with the associated basins dominated by extensional processes. Recent studies suggest the importance of sinistral wrenching as an important process for the structural readjustment and geometry of the different sub-

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basins. Cretaceous successions in the Lower and Middle Benue Basins consist of over 5000m of sediments ranging from Aptian /Albian to Maastrichtian. The sediments constitute three unconformity bounded sedimentary cycles ranging from Albian- Cenomanian, Turonian – Coniacian and Campanian – Maastrichtian sedimentary cycles (Fig. 3).

The oldest Aptian – Cenomanian successions of the Asu River Group consists of arkosic sandstones, volcaniclastics, marine shales, siltstones and limestone which overly the Pre-Cambrian to Lower Paleozoic crystalline basement rocks. The arkosic sediments were derived principally from the extensive weathering of the basement rocks which were invaded by alkaline basaltic rocks prior to the initial rapid marine flooding of the Middle Albian times (Fig. 3). This first Albian – Cenomanian successions are overlain by the Eze-Aku and Awgu formations (Turonian- Coniacian) consisting predominantly of marine shales, calcareous siltstones, limestones and marls.

Pre-Santonian sediments of the first and second depositional cycle have been compressionally folded, faulted and uplifted in the Lower Benue basins and are clearly marked by major anticlinal and synclinal structures consequent to the Santonian tectonism. Major deformational structures as the Abakaliki anticline, the Anambra and Afikpo synclines (Lower Benue) the Keana anticline and Awe syncline (Middle Benue) are consequent to the Santonian tectonism (Fig. 4).

Figure 3. Generalized stratigraphic NE /SW framework from the Niger Delta through the Benue Trough to the Chad Basin illustrating the unconformity bound stratigraphic sequences of the basins.

The Post- Santonian collapse of the Anambra platform led to the emergence of several parts of the Lower and Middle Benue Basins during the Campanian – Maastrichtian and a shift in the depositional axis of sediments for the third transgressive cycle to the Anambra Basin. These sediments consist of the marine Nkpoko / Enugu Formations (lateral equivalents) overlain by the deltaic successions of the Mamu Formation and the marginal marine Ajali Formation in the Anambra Basin (Fig. 4). The Upper Cretaceous sediments are overlain by the transgressive Paleocene – Eocene shales, sandstones and siltstones of the proto -Niger Delta in the southern fringes of the Anambra Basin (Fig.5).

Figure 4. Generalized stratigraphy of the Lower Benue Anambra and Abakaliki Basins and the Middle Benue Basin.
Lithostratigraphy and Depositional Environments

The Asu River Group (Aptian – Albian)

This constitutes the oldest sediments in the Lower Benue Basins. Sediments of the Asu River Group consist of alternating shales and siltstones with occurrences of limestone and arkosic sandstones in these basins. Maximum thickness of the group was put at 1500m⁶ in the Abakaliki Basin. They are

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⁶ Shell BP 1957. Geological maps. 1: 250,000 sheets; Markudi (64); Ankpa (63); Enugu (72); Ogoja (73); Umuahia (79); Oban hills (80); Calabar (85). Geological Survey of Nigeria 1957 publications.; Simpsons, A., 1954. The Nigerian coalfield: the geology of parts of Owerri and Benue provinces. Bulletin Geol Survey of Nigeria 24, 85p.
frequently exposed on the core of anticlinal structures and lateral facies variations are composed of fine grained sandstones and siltstones interbedded with shales in the Middle Benue Keana anticline where a thickness of ca. 3000m was reported\(^7\). Stratigraphic studies suggest that sediments belonging to the Asu River were deposited mostly during the Albian in view of the prevalence of the Middle Albian Ammonites in the marine limestone facies\(^8\). However, microflora of the Upper Aptian to Lower Albian were reported in the Asu River Group and its lateral equivalents in the Upper Benue basin\(^9\). The terrains of the Asu River Group directly overlies the Pre-Cambrian to Lower Paleozoic basement rocks and the lithofacies and their lateral equivalents were derived from the weathering and erosion of the crystalline basement. The continental deposits were succeeded by marine shales of the first marine flooding into the Benue Trough in the Albian times during which the shales, limestone and the interbedded siltstone facies of the Asu River were deposited. Variation in thicknesses of the successions is indicative of the accommodation space created due to differential subsidence within the block faulted basins. The Asu River Group is interpreted as sediments of the first transgressive cycle into the Lower and Middle Benue Basins.

Figure 6. Geological setting in the Lower Benue Abakaliki Basin showing the position of Bende, Uturu and Ogbabu exploratory wells and the cross section AA’.


\(^{8}\) ibid

Eze-Aku / Awe / Keana Formations (Late Cenomanian – Turonian)
This consists of calcareous shales, siltstones, and silty shales overlying the Asu River sediments in the Lower Benue Basins. A flaggy, laminated oil shale member of this formation (the Lokpanta Shale) cropped out on the south side of the Abakaliki Basin. This marine oil shale member is traceable to the Calabar flank areas of southern Nigeria.

In the Middle Benue Trough, a regressive phase the Awe Formation consisting of transitional beds of sandstones and carbonaceous shales overlies the Asu River Group. This is overlain by continental fluvial sands of the Keana Formation (Figs 6 and 7). Both the Awe and the Keana Formations are succeeded by the marine strata of the Eze-Aku Formations consisting of calcareous shales, micaceous fine to medium grained sandstones and shelly limestones in the Middle Benue Basin. Locally, the shales grade into the predominantly fluvial cross bedded sandstones of the Markudi Formation (Fig.2).

Figure 7. Geological map of a part of the Middle Benue Basin showing all the Cretaceous units (modified from Offodile, 1976; Ajayi and Ajakaiye, 1981). A cross section AA’ is drawn up in Figure 15.
The Eze-Aku Formation is overlain by the Awgu Formation in the Lower and Middle Benue basins. This consists of a sequence of fossiliferous black shales and limestones in the Abakaliki Basin. In the Middle Benue Basin, the shales are interbedded with siltstone, sandstones, coals and subordinate limestone. The top parts of the Eze-Aku Formation and the marine successions of the Awgu Formation were deposited during the Late Cenomanian to Coniacian transgressive cycle. The Santonian was a period of non-deposition, folding and faulting. This was followed by uplift and erosion of the sediments.

**Enugu / Nkporo Formation: (Campanian – Maastrichtian).**

Following the intensive Santonian deformation and magmatism, a westerly displacement of the depositional axis of the Lower Benue Basins resulted from the collapse of Pre-Santonian Anambra platform consequent to continuous subsidence. Post deformational successions are represented by the Enugu / Nkporo Formation (lateral equivalents) which consists of a sequence of bluish to dark grey shale and mudstone locally with sandy shales, thin sandstones and shelly limestone beds. The shaly facies grade laterally to sandstones of the Owelli and Afikpo Formations in the Anambra Basin. The Enugu / Nkporo Formations are essentially marine sediments of the third transgressive cycle. These, in most parts of the Anambra Basin is overlain by the Lower Maastrichtian sandstones, shales, siltstones and mudstones and the interbedded coal seams of the deltaic Mamu Formation. The deltaic facies grade laterally into the overlying marginal marine sandstones of the Ajali and Nsukka Formations.

In the Middle Benue Basin, post Santonian sediments are represented by the continental beds of the Lafia Formation which comprises of ferruginised coarse to fine grained sandstones, flaggy mudstones and lignites bands within the fluvial successions.

**Imo Formation**

A major part of the Benue Trough was completely emergent at the end of the Cretaceous creating inverted basins with exposures of older sediments on the anticlinal structures.

However, records of marine incursions in the south western side of the Anambra Basin resulted in the deposition of the Paleocene to Eocene shales of the Imo Formation which succeeded the deltas of the Mamu Formation (Figs 4 and 5). The Imo Formation is overlain by the regressive sandstones succession of the Ameke Formation and the overlying sandstones, shales and lignite beds of the Oligocene / Miocene Ogwashi – Asaba Formation. These Tertiary units constitute the proto- Niger Delta Eocene to Recent sequences in the subsurface.

**Paleogeography**

The sedimentary fill of the Benue Trough in all the segmented basins were deposited within the accommodation space created by transcurrent fault systems which are the reactivated fault zones of the Pre-Cambrian to Lower Paleozoic basement. Movements along the transcurrent faults with translations into normal vertical faults formed the various sub-basins in which the initial
continental sediments were deposited\textsuperscript{10}. Although the sedimentary successions consist of three unconformity bounded sequences\textsuperscript{11} differential subsidence coupled with the eustatic sea level rise led to facies variations in basins. Consequent to the erosion and continental sedimentation of the Aptian and older time period (Fig.8a) the Albian marine transgression flooded the Lower and Middle Benue Basins leading to the deposition of thick shales of the Asu River Group at the basin centers and the carbonates and sandstone lateral equivalents at the basin margins. A regressive phase in the Late Cenomanian was represented by the transitional calcareous sandstones and shale beds of the Awe Formation and the fluvial to deltaic sandstones of the Keana Formation of the Middle Benue Basin (Fig. 8a).

The beginning of the second marine transgressive cycle in the Lower and Middle Benue Basins led to the deposition of laminated shales and calcareous siltstones of the Eze- Aku Formation which was succeeded by deposits of the transgressive maxima from the Turonian and Coniacian when thick black shales and limestones of the Awgu Formation were deposited (Fig. 8b). At this period, shales and carbonates were deposited on the Anambra platform, the Abakaliki Basin and the Middle Benue Basin at which time the whole of the Benue Trough was connected with shallow marine seas.

Figure 8a and b. Cretaceous paleogeography in the Benue Trough illustrating the interconnectivity of the Lower and Middle Benue Basins and the communication with the South Atlantic (modified from Benkhelil, 1989; schematic only, not to scale).

\textsuperscript{10} Op. cit

The second transgressive cycle maxima was followed by a regressive event in the Late Coniacian to Santonian and was succeeded by the compressional folding and faulting of the Mid Santonian when the Abakaliki Basin became emergent (Fig 8b). Since the emergence of the Abakaliki and Middle Benue Basins, sedimentation in the basins shifted to the Anambra Basin during the Campanian – Maastrichtian transgressive cycle at the time of deposition of the Enugu / Nkporo shales (Fig 8c). Regressive delta prevail for the deposition of the facies of the Lower Mamu Formation in a paralic environment which is partially inundated leading to the deposition of the marginal marine Ajali Sandstones in the Middle Maastrichtian and the fluvio-deltaic Nsukka Formation (Fig.8c). The sea has withdrawn from the Middle Benue Basin before the Santonian tectonism and only fluvio-deltaic sedimentation resulted in the formation of the Lafia Sandstone facies during the Campanian – Maastrichtian (Fig.8c).

Tertiary sedimentation in the Benue Basins were restricted to the southern Anambra Basin especially in areas where the proto- Niger Delta successions were deposited as a result of the Paleocene – Eocene transgression and deposition of the Imo Shale and the deltaic Oligocene – Miocene Ameki and Ogwashi – Asaba Formations as outcrop equivalents of the Niger Delta.

**Stratigraphic Distribution of Hydrocarbon Source Rock Facies**

The stratigraphic distribution of potential source rocks in the Lower and Middle Benue Basins reveal the regional continuity of lithofacies in these basins during their evolution.

Although prominent syn-rift sequences of paleo-rift systems are rare in outcrops compared to the Upper Benue and the East Niger, Chad and Sudanese Basins, arkosic sandstones, and finely
laminated mudstones of the Asu River Group are attributed to recycled sediments derived from the older basement rocks. However, the three unconformity bounded successions of sediments are recognizable in the basins with each cycle consisting of transgressive shales, marls, limestones and coals with source potentials.

In the older Abakaliki Basin, shales of the Asu River Group, the Eze-Aku and those of the Awgu Formation constitute the source rock facies of interest. Although the main axis of the Abakaliki Basin was emergent since the Santonian times, exposed successions of these shales are mappable in outcrops on the non-emergent areas and also in the synclinal areas adjacent to the main Abakaliki anticline.

In the younger Anambra Basin, thinner shale successions of the Asu River Group, the Eze – Aku and the Awgu Formations are reported in oil exploratory wells and also in the marginal areas to the Abakaliki Basin. Apart from the source facies of the Pre-Santonian cycles, the Post Santonian sediments in this basin are represented by the marine Enugu / Nkporo Shale, succeeded by the shales and coal measures of the Mamu Formation. Proto Niger Delta successions of the Imo Formation belonging to the fourth cycle of sedimentation are exposed on the northern fringes of the Niger Delta.

Figure 9. Burial history reconstruction for the Bende well on the non-emergent outboard area of the Anambra Basin (Lower Benue) see Figure 6 for location. The burial history reflects the over-mature Asu River Group and the mature Awgu Formation. The bottom successions of the Mamu and Nkporo formations are considered mature to marginally mature at that location.
In the Middle Benue Basin, source rock facies are represented by the shales of the Asu River Group and are overlain by the regressive shales, siltstones and sandstones of the Awe and Keana Formations. This is succeeded by the Awgu shales, limestones and coal measures of the second transgressive cycle. Apart from the potential source facies of the first and second cycles, the third post Santonian cycle in the Middle Benue region consists of the non-source lithofacies of the continental Lafia Formation.

Although no exploratory well has penetrated the successions of rocks in the Middle Benue Basin except for the shallow coal core holes, exploration in the Lower Benue Abakaliki and Anambra Basins have reported oil and gas finds at certain stratigraphic intervals with good correlations with the occurrences of the source rock facies. The gas finds in the Late Cenomanian – Turonian Eze-Aku Shales and dry gas find at the Awgu Shale stratigraphic intervals plus the oil and gas finds at the Post–Santonian (Maastrichtian) intervals of the Anambra Basin suggest that these source rock facies reached maturity and have generated and expelled hydrocarbons at some stages of the basin history (Fig 9).

**Source Rock Evaluation**

**Analytical methods**

Samples of potential source rock facies i.e. shales, coals and mudstones were collected from mapped and logged sections of quarries, outcrop sections and exploration boreholes on specific traverses of the Lower and Middle Benue Basins (Figs 2, 6 and 7.)

**Organic petrography**

The shales and coal samples were crushed to a maximum particle size of 2mm, mounted in epoxy resin and then ground in the same procedure as coal samples are normally prepared for incident light microscopy. Rank (maturation) was determined by reflectance measurements of vitrinite particles and the composition of organic matter was determined by maceral analysis based on at least 50 counts in view of the sparse phytoclasts distribution especially in the shale. It is noted that some of the samples are coaly with discrete grains of vitrinite. The classification scheme that was applied here follows the interpretation of organic materials in coals and shales as used by Kalkreuth and McCauley. This is in line with the Stopes–Herlen classification of coals which defines three main groups of macerals termed: vitrinite, liptinite and inertinite. The studies were carried out on a Reichert Jung Polyvar Photomicroscope equipped with halogen and HBO (mercury) lamp.

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photomultiplier and a computer unit at the “Zentraleinrichtung fur Elektronenmikroskopie” (ZELMI) at the Technische Universitat Berlin, Germany. Mean random reflectance of vitrinite in oil (R_o m c.f. Bustin et al.)\(^{15}\) was calculated from the reflectance of at least 30 particles of vitrinite measured in random orientation using monochromatic (546nm) non-polarized light in conjunction with a x 40 oil immersion objective. R_o m as used by the authors is defined as the mean random reflectance in non-polarized light (see Bustin et al.).\(^{16}\) These authors recommend that in randomly oriented grains the random reflectance of vitrinite measured in non-polarised light is a true reflection of the average of the minimum and maximum reflectance expressed as R_o m = \(\frac{1}{2} (R_o \text{max} + R_o \text{min})\), where R_o max is the maximum reflectance and the R_o min is the apparent minimum reflectance.\(^{17}\)

The mean random reflectance R_o m is calculated from the mean reflectance values of a number of randomly oriented grains of vitrinite and has been so indicated in the present paper as used in Akande et al.\(^{18}\) Calibration of the microscope photometer was achieved using glass standards of known reflectance (1.23% and 3.16%) Measured R_o m values of the reflectance standards confirmed the photomultiplier to be consistently linear within the range of the measurements. Data collection and evaluation were performed using the coal programme by Reichert Jung Company, Austria. This programme reviews the total number of measurements over the selected class limits categorizing reworked vitrinites and other spurious measurements in histogram plots within selected boundary limits and macerals were identified through the use of white light and blue light excitation at 546nm and 460nm respectively. The mean reflectance as compared to the median or modal values appear to be an adequate measure of thermal maturity in this study.\(^{19}\)

**Total Organic Carbon**

Total Organic Carbon (TOC) analyses were carried out on crushed (powdered) rock samples. Approximately 100mg of each sample was weighed into oven sterilized crucibles. Approximately 1ml of hydrochloric acid (HCl) was added to the weighed sample in crucibles to remove carbonates. Samples in crucibles were then allowed to drain off the HCl for about 6 hours before being transferred into an oven set at 60°C and left overnight. Following the overnight drying, TOC were then measured using a LECO TOC analyzer instrument.

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15 Op. Cit
16 Op. Cit
**Rock-Eval pyrolysis**

The hydrocarbon generation potential, maturity, type of kerogen and hydrogen indices were determined using a Rock-Eval II instrument up to an elevated temperature of ca. 600°C. Pyrolysis of 30 – 40mg (up to 100mg where necessary) of samples at 300°C for 4 minutes was followed by programmed pyrolysis at 25°C/min to 550°C in an atmosphere of helium.

**Biomarker analysis**

Biomarker signatures of the high yielding shales and coals in the basins were assessed based on recent works and an on-going evaluation of the GC and GC-MS spectra of the n-alkanes and sterane components respectively of extracts and hydrocarbons expelled during hydrous pyrolysis experiments.

**Analytical results**

**Organic richness:**

*Lower Benue Abakaliki and Anambra Basins*

Shales of the Asu River Group exposed along the axis of the Abakaliki anticline are invaded by intrusive rocks and hydrothermal vein minerals (Fig.6) leading to very low grade metamorphism in places. The metamorphosed shales (with Rom between 2.46 and 4.53%) on the anticlinal axis (documented in the previous report of Akande and Erdtmann) were excluded in this study and not analyzed further due to their relatively high thermal maturity. Fluid inclusion studies of pyroboltenum associated vein minerals in the Asu River shales reveal formational temperatures range between 131 and 214°C confirming maturation in the gas generating stage. However, the Pre-Santonian shales of the Eze-Aku and Awgu Formations in the Abakaliki Basin were investigated. Tables 1a, 1b and 1c shows the Rock-Eval pyrolysis results from the Abakaliki and Anambra basins.

In the Eze-Aku shales, total organic carbon contents ranged from 0.24 to 5.47% with 90% of the sample population containing between 0.5 to 3.5%. TOC contents in the Awgu Formation ranged between 0.34 and 0.71% (Table 1a) with most values between 0.5 and 0.7%. The highest concentrations of organic carbon are present in the Lokpanta shale member of the Eze-Aku Formation with TOC frequently greater than 3.5%. This shale unit has been characterized as an “oil shale” member of the Eze-Aku Formation with proven TOC contents above 7% at depth.

In the Anambra Basin, kerogen studies of the Campanian – Maastrichtian shales of the Enugu / Nkpoto Formation indicate TOC contents between 0.54 and 3.0%. However, TOC contents in the overlying sub-bituminous coals of the Lower Maastrichtian Mamu Formation ranged from 60.97 to

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22 Akande 1989 Op. Cit
77.01% (Table 1b). As expected, the highest concentration of organic carbon are present in the sub-bituminous coal samples of this stratigraphic interval.

### Middle Benue Basin

Unlike in the Lower Benue Basins, investigations in the Middle Benue Basin was carried out only on Pre-Santonian shales in view of the absence of Post–Santonian successions in this region. TOC contents ranged from 0.12 to 0.31% in the Asu River Shales, 0.3 to 1.93 % in the Awe Shales and ranged from 0.1 to 0.19% in the Keana shale facies (Table 1c). Organic matter was more enhanced in the Turonian–Coniacian Awgu Formation with most samples having a range of 0.56 to 6.54 TOC except for one sample with a value of 0.2% TOC. The High Volatile A to Medium Volatile bituminous coals in the Awgu Formation are characterized by high TOC contents with a range from 18.6 to 79.1% marking a significantly enriched stratigraphic interval in the Awgu Formation.

Classification as a possible oil source rock requires a minimum of 1.0% TOC although a threshold as low as 0.5% TOC are however considered possible in gas prone systems.

It should be noted that variable organic richness may also control the generation of either oil and gas sufficient enough to saturate the pore network for adequate level of expulsion efficiency from a potential source rock, except in gas prone systems which are largely driven by diffusion at an adequate level of concentration gradient. The enumerated criteria will classify the Cenomanian Eze-Aku Formation including the Lokpanta Shale member, the Turonian to Coniacian Awgu Shales, the Campanian–Maastrichtian Enugu / Nkporo Shales and the Lower Maastrichtian sub-bituminous coals of the Mamu Formation with elevated levels of organic carbon as good to excellent oil and gas source rocks in the Lower Benue Basins.

Similarly, shales of the Cenomanian Awe Formation in the Middle Benue basin and the Turonian–Coniacian Awgu Shale including the interbedded coal measures are here considered as potential hydrocarbon source rocks.

### Hydrocarbon generation potentials

For the mere fact that organic carbon content alone cannot be used to establish the presence of potential and or effective petroleum source rocks in view of the constraints that different organic

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matter types have different hydrocarbon yields for the same organic carbon content\textsuperscript{30} a more direct measure of source rock capability to generate hydrocarbons is required for detailed assessment.

The Rock-Eval pyrolysis data set with the derivatives determined from the programmed heating of samples in inert atmosphere provide an added evidence by direct estimation of the hydrocarbons that evolved freely; considered as $S_1$; the generatable hydrocarbons directly from kerogen cracking known as $S_2$. The values of $S_1 + S_2$ herein represents the rocks total hydrocarbon generation potential comparable with the assessment criteria of Dymann et al\textsuperscript{31} with the suggestion of hydrocarbon yield $S_1 + S_2$ less than 2mg HC /g rock typifying little or no oil potential with some potential for gas; $S_1 + S_2$ from 2 to 6 mg HC /g rock indicating moderate or fair source rock potential and above 6 mg HC / g rock suggesting good to excellent source rock potential.

The threshold of $S_1 + S_2$ greater than 2.5 mg HC /g rock can be considered as a prerequisite for classification as a possible oil source rock\textsuperscript{32} and provide the minimum oil content necessary near the top of the main stage of hydrocarbon generation to saturate the pore network and permit expulsion. The total hydrocarbon yields $S_1 + S_2$ in the Abakaliki Basin samples range from 0.27 in the Awgu Formation to 26.46 mg HC /g rock in the Lokpanta Shale. Yields in the Enugu / Nkporo Shale range from 0.12 to 4.42 mg HC /g rock\textsuperscript{33}. The most elevated yields were observed in the sub-bituminous coals of the Mamu Formation (Anambra Basin) with a range from 139.97 to 199.28mg HC /g rock. $S_2$ (hydrocarbon yield) values of the successions have fair correlations with the organic richness expressed as the TOC values in the S2 versus TOC plot (Figs.10a and b).

In the Middle Benue Basin, hydrocarbon yields vary from a low 0.03 to 0.07 in the Asu River Shale; 0.07 to 0.43 in the Awe Shale with notable elevated yields from 0.12 to 5.20 in the Awgu Shale. Yield values as high as 81.4 mg HC /g rock was reported in the interbedded coal seams in this region\textsuperscript{34}. A good correlation exists between the $S_2$ and TOC values from the Awgu Shale assemblage (Figs.11a and b).

\32 Bissada, Op. Cit
\33 Ehinola et al. 2005 Op. Cit
\34 Ehinola et al. 2002 Op.Cit
Figure 10. a. Summary source rock quality information on the basis of Rock-Eval parameters where primary source field is ascribed to sediments with S2 greater than 5kg / ton rock; ENS refers to effective non source field. The Lokpanta Shale and the Mamu Formation sub-bituminous coals are prolific source facies.

b. Plot of the Tmax against HI for the shales and coals in the Lower Benue Basins. The plot confirms the best producer of oil and gas is the Lokpanta Shale while the sub-bituminous coals have adequate capability to produce oil and gas.
A comparison of the similarities in the yield of hydrocarbons in the data set indicate that highest yields are restricted to the Cenomanian Eze – Aku Shale of the Abakaliki Basin and the Maastrichtian sub-bituminous coals of the Anamba Basin. In the Middle Benue Basin, significant yields are confined to the Turonian to Coniacian Awgu Shale and the outlined intervals above are significant from the standpoint of petroleum exploration in the two regions.

Figure 11. a. S2/TOC plot for the source rock quality in the Middle Benue Basin. Most values for shales in this basin (e.g. the Asu River, Awe and Awgu shales) plot in the secondary source fields probably as a reflection of the high level of maturity with VRom greater than 0.7%.

b. Plot of Tmax/ HI for the Middle Benue Basin shales; the Awgu Shale have greater potential for gas generation and could have produced some gas at the maturity level established for the samples.
**Kerogen Typing**

Characterization of organic matter in source rocks can be accomplished through a number of parameters of which the Rock-Eval pyrolysis measurements and their derivatives could serve as important criteria. These basic kerogen types could be identified from hydrogen indices\(^{35}\). Type I organic matter is hydrogen rich (HI greater than 600mg HC/g TOC) and this is considered to be predominantly oil-prone. Type II organic matter is characterized by HI between 350 and 600mg HC/g TOC and this could generate both oil and gas at the appropriate level of maturity. Type III organic matter is characterized by low to moderate HI of between 75 and 200mg HC/g TOC and could generate gas at the appropriate level of thermal maturity. Type IV organic matter normally exhibit very low HI less than 50mg HC/g TOC; are produced under very oxic environment and are generally inert\(^{36}\). However, Peters\(^{37}\) suggested that at a thermal maturity of vitrinite reflectance of 0.6\% (Tmax 435°C) rocks with HI above 300mg HC/g TOC will produce oil; those with HI between 300 and 150 will produce oil and gas; while those with HI between 150 and 50 will produce gas and those with HI less than 50 are inert.

![Figure 12. Kerogen classification of the Lokpanta, Eze-Aku, Awgu shales and the Mamu Formation coals on a plot of HI versus Tmax in the Lower Benue Basins.](image)

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\(^{35}\)Tissot et al. 1974, Op. Cit


Considering the present data set in the light of the recommendations of Tissot and Welte (1984) and Peters (1986) the best oil prone source rocks in the Lower Benue Basins appear to be restricted to the Cenomanian Lokpanta shale stratigraphic interval with Type II oil prone assemblage while the larger parts of the Eze-Aku Formation and the Turonian to Coniacian Awgu Shales plotting in the Type III gas prone kerogen field could be considered as gas producers at the appropriate maturation levels (Fig.12). The sub-bituminous coals of the Lower Maastrichtian stratigraphic interval contain oil and gas prone kerogens plotting on the upper band of the Type III field of the HI / Tmax diagram (Fig.12).

Despite some enhanced TOC values in the Turonian – Coniacian Awgu Shale of the Middle Benue Basin, the hydrogen indices are generally low varying between 26mg HC /gTOC to 77mg HC/g TOC and plotting in the Type III gas prone kerogen field (Fig.13). The low values of hydrogen indices may reflect the higher level of maturity generally within the oil window and or higher proportions of reworked vitrinites and inertinites in the Awgu Shales in this geographical region. Hydrogen indices generally decrease at higher maturation levels due to the generated hydrocarbons and this could explain the low level recorded at this stratigraphic interval in the Middle Benue Basin.

Indeed the organofacies of the Awgu Formation show substantial contribution from terrestrial sources as indicated on the HI / Tmax plots where all the samples, including the Awe Shale and the Asu River Shale plot in the Type III (gas prone) kerogen field (Fig.13).

Figure 13. Kerogen classification of the Asu River, Awe and Awgu shales on the HI / Tmax plot in the Middle Benue Basin.

**Thermal Maturity**

38 Op. Cit
In this study, the Tmax values from pyrolysis experiments are considered as a simple measure of the sample level of thermal maturity at least where the total organic carbon reached the minimum threshold of 0.5% expected for clast source rocks with adequate hydrocarbon yields. Apart from this criterion, the vitrinite reflectance measurements are considered as an adequate estimation of the thermal maturity of the investigated samples. Although transformation ratios or the production indices i.e. S1 / S1 + S2 can provide an estimation of thermal maturity, these indices can only be considered as reliable thermal maturity indicators when hydrocarbon yields are significantly above background levels. As that was not the case for most of the samples investigated, the transformation ratio parameter was not applied as a measure of maturity in this study. Thermally mature sediments in this study are thought to display values of Tmax of at least 430°C and greater with Vitrinite reflectance VRom values between 0.6 and 1.3%. This is in line with minimum maturity threshold of 420°C suggested for hydrocarbon generation in coaly source rocks.

Based on these parameters, contrasting levels of maturity was attained in the Abakaliki and Anambra Basins (see section in Fig.14).

![Figure 14. Vitrinite reflectance (VRom) distribution along profile AA’ from Enugu (Anambra Basin) to Enyigba (Abakaliki Basin). Line of section as shown in Figure 6. Note the effect of intrusives on the structural axis and the maximum reflectance values.](image)

This is reflected on the northwest-southeast section AA’ from Enugu area (Anambra Basin) to Enyigba (Abakaliki Basin) which indicates that the maturity of the Cretaceous sediments increase with their ages from the Anambra Basin into the Abakaliki Basin. The oldest (Albian) Asu River Group shales exposed on the core of the Abakaliki anticline is over-mature (VRom 2.46 to 4.53%) with notable intrusive and hydrothermal effects on the AA’ section especially in the Abakaliki area (Fig.14). VRom values of the overlying Eze-Aku Shale vary from 0.71 to 0.93% indicating maturity comparable with the measured Tmax value of 448°C except for the value 394°C for EZ-05 which reflects the low TOC for this sample. The sharp contrasts in reflectance values between the Eze-Aku Formation and the underlying Asu River Shale suggest that the un-eroded Turonian sediments were not subjected to the thermal effects recognized in the Asu River sediments on the Abakaliki anticline. The Lokpanta shales with Tmax varying from 424 to 430°C and VRom between 0.43 to 0.55% indicate immature to marginal maturity. The overlying Awgu Shale in the Abakaliki Basin with Tmax from 434 to 467°C and VRom between 0.81 to 1.07% is mature. In the Anambra Basin, sub-bituminous coals are notably immature to marginally mature on the basis of the Tmax values from 417°C to 428°C and VRom between 0.41 to 0.63%.  

Unlike the pattern shown in the Lower Benue Basins, thermal maturity levels appear to be elevated in the successions of the Middle Benue Basin as reflected in both the Tmax values and the vitrinite reflectance measurements. VRom in the Albian Asu River shales vary from 0.66 to 1.1% (Tmax 438 to 464°C) and the overlying Awe Formation have VRom measurements from 0.89 to 1.12% (Tmax 444 to 450°C). The overlying Awgu Shale considered as the most important stratigraphic interval with source potential have VRom between 0.52 and 1.13% (Tmax between 444 to 459°C) is mature with respect to petroleum generation. A value of Tmax 481°C for the sample S1 is considered anomalous and reflects the presence of inert or recycled organic matter in the sample. 

Maturity variations in the Middle Benue Basin succession reflects both stratigraphic and geographic position in the context of vitrinite reflectance values of the core holes investigated for this study and the surface outcrops as shown in the northwest – south east section AA’ from Obi to Ortesh areas of study (Fig.15). The three shallow core holes (108, 123 and 137) investigated penetrated only the Turonian – Coniacian Awgu shales and coals. Considering the obvious similarities in the maturation of the Asu River Group shales compared with the organic rich Awgu shales at the outcrop level (see section AA’ it is expected that Albian Asu River shales will attain a higher maturity at the deeper non – emergent levels of the basin. Indeed given the maturity level of the Awgu shales in the shallow bore holes and outcrops with a range from 0.5 to 1.1% VRom, this will give a maximum temperature estimate of heating between 60 and 145°C based on the

plots of VRo and temperature\textsuperscript{42}. Assuming a maximum geothermal gradient of 30°C, about 2200 to 4800m (average of 3250m) of sediments would have been removed\textsuperscript{43} above the exposed sections of the Awgu Formation in the areas of study. This suggests that exploration should obviously be focused on the non-emergent deeper sections of the basin where the Awgu shale has been buried to considerable depths.

\textbf{Biomarker analysis}


![Diagram of geological section with labels such as Lafia, Awgu, Keana, and Awe, showing exploratory coreholes and a cross-section profile.](image-url)
Few authors have reported the analysis of biomarker assemblages of lipid extracts of individual units exposed in the study areas most especially the shales and coals that were geochemically characterized as having elevated TOC and hydrocarbon yield values in these basins. In the Cenomanian Lokpanta Shale, Ekweozor and Unomah (1990) reported low levels of pristane/phytane of ca. 0.9 and the predominance of the nC27 steranes in this shale unit hence confirming its deposition in a marine anoxic environment coinciding with the global Late Cenomanian - Coniacian Oceanic Anoxic Event (OAE) associated with great development of carbonaceous shales.

Figure 16. GC – MS chromatogram of n-alkanes in the saturated fractions of the hydrous pyrolysed sub-bituminous coal extracts (Mamu Formation). At 330 – 345°C the n-alkane distributions are similar to early mature to mature terrestrially – sourced oils.
This marine influence deposited Kerogen Types I and II oil prone Types on a global scale and the Abakaliki Basin deposit compares closely with the event which peaked at the end of Coniacian global sea level rise and connection of the Atlantic and Tethys seaway. A scenario with restricted circulation of the seawater in faulted basinal blocks created the favourable euxinic conditions for marine hydrocarbon source rocks\(^{44}\).


Figure 17. Evolution of (A) Bitumen index and (B) Production Index in the hydrous pyrolysed sub-bituminous coals of the Mamu Formation. Both indices illustrate significant increase above 300°C.
Recent studies of lipid extracts from the Lower Maastrichtian sub-bituminous coals from the Anambra Basin e.g. Obaje et al.\textsuperscript{45} and Akande et al.\textsuperscript{46} reported biomarkers with a dominance of long chain aliphatics and obvious odd – even predominance pointing to high input of terrigenous organic matter deposited under oxic conditions. The high pristane / phytane ratios and high nC29 sterane components in the regular sterane distribution all confirm a considerable input of terrestrial Type III gas prone organic matter and the high levels of aerobic environment of deposition of the sub-bituminous coals.\textsuperscript{47} Furthermore, the geochemical characteristics of the sub-bituminous coals exemplified through catalytic oxidation procedures\textsuperscript{48} indicate liberation of aliphatic compounds adhered to the fatty acids with significant proportions of long chain aliphatics above nC19 up to nC35 in the GC – MS chromatograms (Fig. 16 c.f. Akande et al. 2007; Akande et al. 2008).

Artificial maturation of the coals by stepwise hydrous pyrolysis from 270 to 345\textdegree C / 72hours indicate changes in the Rock-Eval parameters with the obvious reductions in the hydrogen indices corresponding to increase in hydrocarbon yields, production indices and bitumen indices confirming oil and gas generation potential of the coals (Figs.16 and 17). The decrease in bitumen index of the pyrolysed samples after stabilization indicate that some quantity of hydrocarbons was expelled (Fig. 17b).

In the Middle Benue basin, lipid extracts of the coals and the interbedded shales of the Awgu Formation show biomarkers with unimodal distributions of short and long chain n-alkanes with no obvious odd over even predominance and a dominance of nC29 regular steranes.\textsuperscript{49} This observation suggest that organic matter was contributed from both algal Type II oil prone and terrigenous Type III gas prone higher plants. The high values of pristane / phytane ratios and the predominance of nC29 steranes support the prevalence of diverse oxic environments with interchanges of continental, marine and lacustrine environments\textsuperscript{50} (Obaje et al. 2004).

**Discussion**

The present study have outlined the overall source potential of the Middle Cretaceous sequences in the Lower and Middle Benue Basins of the larger Benue Trough in relation to stratigraphic evolution of the successions. The evaluation and stratigraphic relations suggest that the oil and gas potentials of the basins are restricted to discrete intervals which in the Lower Benue Basins include the oil prone Lokpanta Shale member of the Eze-Aku Formation, the oil and gas prone Awgu Formation and the oil and gas prone Lower Maastrichtian sub-bituminous coals of the Mamu Formation. Based on the immature to the marginally mature status of source rocks at these stratigraphically separated intervals, it is expected that the timing of hydrocarbon generation and expulsion would differ, considering the fact that the Pre-Santonian Asu River Group, Eze-Aku and Awgu Formations could have commenced hydrocarbon generation at the time of maximum burial ca. 85Ma in the non-emergent areas before the Santonian tectonism and uplift (see Fig.9). Based on the burial history plot of the Bende well located in

\textsuperscript{45} Op. Cit
\textsuperscript{46} Op. Cit
\textsuperscript{47} Obaje, et al, Op Cit
\textsuperscript{48} Petersen, H.I., Nytoft, H.P., 2006. Oil generation capacity of coals as a function of coal age and aliphatic structure. Organic Geochemistry 37, 558 – 583.
\textsuperscript{49} Obaje, et al, Op Cit
\textsuperscript{50} Ibid
the non emergent area of the Anambra Basin, it is inferred that the Cenomanian to Coniacian sequences reached maturity and could have generated and expel hydrocarbons into the Pre-Santonian reservoirs before the deposition of the Campanian – Maastrichtian successions. This is reflected in the presence of oil seepages and gas shows in the Eze-Aku and Awgu Formation intervals in the Abakaliki and Anambra Basins.

Although the samples from the Lower Maastrichtian sub-bituminous coals are thermally immature at the level of sampling, the data to date on biomarkers and hydrous pyrolysis experiments have provided some very useful insights with respect to their oil and gas proness and their proven capabilities to generate and expel oil and gas at maturity. Basal parts of the coal bearing Mamu Formation could therefore be considered as important oil and gas source rocks for the Cretaceous petroleum system in the non-emergent parts of the basin and could represent a component for hydrocarbon generation and expulsion in the sub-delta intervals of the Niger Delta outboard and deep water regions.

The mature shales of the Awe Formation is organically lean in the Middle Benue Basin, however, the overlying Awgu Formation shales in this region with the interbedded coals are considered as having both oil and gas generating potential. The trimaceritic (vitrinite, liptinite and inertinite) coal facies and some parts of the interbedded shaly facies of the coal measures with large proportions of liptinites at this stratigraphic intervals are believed to have adequate oil generation potential at the level of maturity attained whereas the associated vitrinite –fusinite coal facies with its high content of humic organic matter (vitrinite and inertinite) could have generated wet and dry gas at maturity. The present study considers the Lower and Middle Benue Basins as related both stratigraphically and in the developmental stages consequent to the rifting processes and sedimentation compared to the Upper Benue Trough systems which though structurally related evolved differently in time and space.

Conclusions

The present study has addressed the need to re-evaluate the oil and gas potential of the Lower and Middle Benue Basins in the context of the stratigraphic successions and their interconnected lateral equivalents in the two regions. Although no exploratory well has been drilled in the Middle Benue Basin, it is noteworthy that the stratigraphic relations of the interconnected basins and thicknesses of the sediments deserve more detailed exploration to unlock the oil and gas potentials.

In the Lower Benue Basins, the Cenomanian to Turonian interval i.e. the Eze-Aku Formation, the Turonian to Coniacian interval of the Awgu Formation and the Lower Maastrichtian sub-bituminous coals have proven potentials for oil and gas prone source rocks. Whereas generated hydrocarbons in the Pre-Santonian sequences must have been expelled into the older Pre-Santonian reservoirs, the mature equivalents of the Lower Maastrichtian coaly source rocks could have generated and expel hydrocarbons into the post-Santonian reservoirs in the Anambra Basin and into the sub-delta sequences in the outboard areas of the Niger Delta.

The Middle Benue Basin contain predominantly gas prone source facies within the Turonian – Coniacian Awgu Formation and the associated coal measures. These sequences contain both oily and gaseous facies intervals of coals which have capability to generate gaseous hydrocarbons including coal bed methane and some oil at the level of maturity attained even at the outcrop level. Reservoirs and traps for hydrocarbons generated at this Pre-Santonian interval will likely be proximal to the outlined potential source beds in view of the major break in sedimentation accompanying Santonian tectonism and uplift.

Acknowledgement

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Table 1a Rock-Eval pyrolysis data of the Cenomanian – Turonian Eze- Aku Formation and the Turonian – Coniacian Awgu Formation in the Abakaliki Basin.
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Table 1b. Rock-Eval pyrolysis data of the Lower Maastrichtian sub-bituminous coals, Anambra Basin.
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Table 1c. Rock-Eval pyrolysis data of the Asu River Group, the Awe, Keana and Awgu Formation in the Middle Benue Basin.