Journal of Energy Policy, Research and Development
Vol. 1, No1, pp (18-49), March, 2011.

Evaluation of the Petroleum Potentials of the Northeastern Nigerian Sedimentary Basins

Abubakar, M. B.
National Centre for Petroleum Research and Development, Abubakar Tafawa Balewa University, P.M.B. 0248, Bauchi. Nigeria.

ABSTRACT

Petroleum exploration in the northeastern Nigerian sedimentary basins (the Gongola and Bornu Basins) dates back to 1970's. Although no commercial discovery is made to date, petroleum evaluation of these basins suggests similarity with the contiguous basins of Chad and Niger Republics and Sudan, where commercial oil discovery have been made. Three potential petroleum systems have been identified and could prove very effective in planning future exploration campaigns. The evaluation of the petroleum potentials of these basins also reveals numerous exploration challenges that require effective and dynamic strategies, and new perspectives and exploration concepts away from those applicable to the Niger

1.0 INTRODUCTION

The northeastern Nigeria includes two main sedimentary basins: the Upper Benue Trough and the Borno Basin.

The Upper Benue Trough is the northeastern geographical subdivision of the Benue Trough and covers an area extending from the Mutum Biyu-Bashar line in the southwest to the Dumbulwa-Bage high in the northeast as shown in Fig. 1. Most authors see the Upper Benue Trough as made up of two basins: an east – west trending Yola arm (Yola Basin) and north – south trending Gongola arm (Gongola Basin) also shown in Fig. 1. These two basins are separated by a structural high area dissected by four major NE-SW trending sinistral strike-slip faults as shown in Fig. 1 (the Gombe, Bima-Teli, Kaltungo-Wuyo and Shani faults) termed the "Zambuk Ridge" by Carter et al, 1963 or "Wuyo-Kaltungo high" by Zaborski, 1998. The Gongola Basin is controlled by numerous N-S and NNE-SSW trending faults while the Yola Basin appears to have been characterized by E-W trending faults Maurin and Guiraud, (1990).

The Bornu Basin (Chad Basin sector of Nigeria) lies further to the northeast of the Upper Benue Trough. It extends from the "Dumbulwa-Bage high" northeasterly to the Lake Chad and occupies an area of about 23,000km^2. Structural trends in the Bornu Basin are generally NE-SW.

The northeastern Nigerian basins are part of a megarift system termed the West and Central Africa Rift System (WCARS). The WCARS includes the Termit Basin of Niger and western Chad, the Bongor, Doba and Doseo Basins of southern Chad, the Salamat Basin of Central African Republic and the Muglad Basin of Sudan as shown in Fig. 2. The WCARS is linked to rifting followed by the opening of the South Atlantic Ocean during the Early Cretaceous and was subsequently modified strongly by transcurrent (strike-slip) faulting at its central axis. Several commercial oil and gas discoveries have been made as shown in at several stratigraphic horizons in Niger, Chad and Sudan sectors of the WCARS, except in the Upper Benue Trough and Bornu Basin.

In this article therefore, evaluation of the petroleum potentials of these basins will include regional synthesis with contiguous basins of Chad and Niger Republics and Sudan. For the Upper Benue Trough, the evaluation will concentrate on the Gongola Basin because of its thick sedimentary succession (up to 6000m) and presence of post-Santonian sediments that played an important role of enhancing maturity and. sub-cropping potential structures generated by the Santonian tectonic inversion. The Yola Basin is relatively of less interest because it lacks the post-Santonian sediments, and the Santonian tectonic structures have been unroofed by erosion as well.

2.0 EXPLORATION HISTORY

2.1 THE BORNU BASIN

The first permit for hydrocarbon exploration in the Bornu Basin was granted to NAPIMS, a subsidiary of Nigerian National Petroleum Corporation (NNPC), in early 1970's. Exploration started with the acquisition of aeromagnetic and gravity data. In 1977, NAPIMS through IDSL (another subsidiary of NNPC) acquired a total of 13,378.09km of 2-D seismic using thumper energy source, and in 1983 additional 20,266.91km of 2-D seismic was acquired using dynamite technique. Earlier interpretation of generated seismic data was done on a regional scale (map scale of 1:100,000) to provide better understanding of the general basin configuration, major fault trends and general structural and stratigraphic controls in the basin. Later interpretations were on a scale of 1:25,000 for the purpose of identifying specific trends and structural highs considered significant in the evaluation of hydrocarbon reserves. The interpretation of the seismic data identified three tectono-sedimentary sub-basins (areas) (Nwaezeapu, 1992):

(a) Block-faulted and folded area with thick sedimentary cover of up to 10,000m (Avbovbo et al., 1986).
(b) Gentle-slope area associated with listric faulting
(C) Platform area with relatively thin sedimentary pile associated with low relief anticlinal features.

Exploration in the Bornu Basin mainly targeted volcanic plugs wrongly interpreted from seismic lines as anticlinal plays in Fika and top Bima Formation (Nwaezeapu, 1992). Between 1981 to 1997 a total of 23 unsuccessful wells (except two with non-commercial gas quantity) with an average depth of 3,263m were drilled, mainly for these plays. Subsequently NAPIMS demobilized from the basin in 1997. Presently there is a renewed interest on the basin and NNPC engaged the services of a consultant company (Mosunmolu Ltd.) to assess the results and data gathered, thus far. From the last quarter of 2009 to date, NAPIMS contracted IDSL in joint venture with United Geophysical for additional seismic acquisition.

2.2 THE UPPER BENUE TROUGH (GONGOLA BASIN)

The first permit for petroleum exploration in the Upper Benue Trough (Gongola Basin) was given to three multinational companies (Shell, Chevron and Elf) in 1992, on a production sharing contract. Geological mapping of acquired acreages and aeromagnetic and gravity data acquisition and interpretation were done in 1995 to 1996. Between 1996 to 1999, a total of 4638.91km 2-D seismic was acquired using both vibroseis and dynamite energy sources. Between 1999 to 2000, the Shell, Chevron and Elf drilled the wells Kolmani River-1, the Nasara-1 and the Kuzari-1 to the total depth (TD) of 2785m, 1905m and 1665m respectively. Only well Kolmani River-1 encountered 43m Net gas sands with estimated reserve of 33BCF. Consequently, the three multinationals relinquished their acreages.

3.0 REGIONAL TECTONICS, STRUCTURES AND TRAPS

3.1 REGIONAL TECTONICS

The origin of the northeastern Nigerian sedimentary basins (the Gongola and Bornu Basins) and the entire WCARS is attributed to the break-up of Gondwana and the opening of the South Atlantic and the Indian Oceans (Benkhelil and Guiraud, 1980) and reflects an aborted break-up within the African plate as shown in fig. 2. Their location and trends appear to have been directly controlled by the reactivation of pre-existing steeply dipping Pan-African strike-slip lineaments (Maurin and Guiraud, 1990; Bumby and Guiraud, 2005).

Generally, basins within the WCARS are

divided into two subsystems: the NW-SE trending West African rift sub-system (WARS) mostly situated in Niger Republic (e.g. Termit Basin) and the E-W trending Central African rift sub-system (CARS) that includes basins of the southern Chad Republic, Salamat Basin of the Central African Republic and the Sudanese basins. While the WARS basins are characteristically rift basins (half-grabens), the CARS counterparts were strongly affected by strike-slip (transcurent) faulting associated with the Central African Shear Zone (CASZ). In this classification, the Bornu and Gongola Basins of Nigeria are considered part of the WARS, representing southwestern extension of the Termit Basin of Niger into Nigeria. The Gongola Basin, however, was highly affected by transcurrent faulting at different times of its evolutionary history such that it developed strong similarity with the Doba and Bongor Basins of the CARS than it does with the contiguous Bornu Basin of WARS. Therefore, the Gongola Basin may be structurally more complex and is expected to develop structures peculiar to both the WARS and CARS.

The tectonostratigraphic framework of WCARS owns its origin to three major rift phases and two non-rift phases shown in Fig. 3. These are:-

(a) Pre-Rift Phase

Prior to the beginning of rifting, the areas underlain by the Gongola and Bornu Basins and other WCARS basins were stable and mostly emergent platforms with no definitive rifting but straddled, from place to place, by thin wedges of continental sediments termed the "pre-rift" (Guiraud et al., 1987; Genik, 1993) as shown in Fig. 3. In the Gongola and Bornu Basins, the pre-rift sediments are referred to as "pre-Bima" deposits and may be as old as Late Jurassic (Guiraud, 1993).

(b) Lower Cretaceous Rift Phase I

The WCARS began to open as a rift from Late Jurassic – Early Cretaceous (Avbovbo et al., 1986). By the late Barremian time active rifting ceases and was followed by a regional unconformity especially in the WARS basins shown in Fig. 3. In the Bornu and Gongola Basins this phase of rifting is controlled mainly by NE-SW trending major faults.

A short-lived rifting phase was re-established in the Early Aptian and was followed by a thermotectonic sag stage of basin development which subsequently was closed with yet another regional unconformity at the close of the Early Cretaceous (Albian). In the northeastern Nigerian basins however, the Albian regional unconformity is questionable, except perhaps in the Bornu Basin.

During the Phase I rifting, up to 5000m of subsidence accompanied by the deposition of syntectonic Lower Cretaceous sediments were reported to have taken place (Genik, 1993).

(c) Upper Cretaceous Rift Phase II

The rift Phase II began with a short-lived period of late Albian – Cenomanian followed by a long period of thermotectonic subsidence shown Fig. 3 (Genik, 1993) The thermotectonic sagging had the effect of deepening and widening existing sedimentary basins. This corresponded with a general sea level highstand (Haq et al, 1987), and together, these resulted in a widespread marine transgression into the sagged rifts during the Late Cretaceous. In particular, there was marine incursion southwards from the Neotethys through Mali and Algeria and into Niger, and northeastwards from the Gulf of Guinea through Nigeria and into Chad and Niger. This culminated into the merger of the two seas over the Upper Benue Trough of Nigeria (Kogbe, 1972; Petters and Ekweozor, 1982; Reyment and Dingle, 1987; Bumby and Guiraud, 2005).

Regression began due to epeirogenic uplift coupled with a sharp basin modifying NW-SE compressional tectonic pulse termed the "Santonian event" (Guiraud and Bosworth, 1997). This event is believed to be associated with a change in the spreading direction/rate within the Atlantic Ocean (Bumby and Guiraud, 2005) and N-S compression between the African and European plates (Guiraud et al., 1987; Guiraud and Bosworth, 1997). Generally, this compressional event manifests in the form of hiatuses and unconformities shown in Fig. 3, and folding and strike-slip faulting leading to the development of transpressional flower structures within the strata of the WCARS basins. An unconformity related to this event was identified from seismic profiles of the Bornu Basin. Although arguments exist with regards to the presence or absence of the "Santonian event" in the Gongola Basin (Guiraud, 1993; Cratchley and Jones, 1965; Benkhelil, 1988, 1989), growing evidences tend to support its presence. Hiatuses on the pre-Santonian strata especially in the Gombe inlier and consistent discrepancies in beds attitude shown by pre and post-Santonian strata in the Gongola Basin suggest the Santonian compression event.

The "Santonian event" had wide-ranging effects significant for hydrocarbon exploration in the WCARS. It created hydrocarbon trapping folds in southern WARS and CARS (Genik, 1993), folded the northeastern Nigerian Basins (Avbovbo et al., 1986; Benkhelil, 1989), and produced hydrocarbon trapping folds in the Muglad Basin of Sudan (Giedt, 1990).

After the Santonian compression, mild uplift continued until about end Cretaceous (end Maastrichtian) and the rift Phase II was terminated by a regional unconformity brought about by yet another NW-SE terminal Cretaceous compression (Maastrichtian event) (Zaborski, 2000). This event also created additional hydrocarbon trapping structures within the WCARS (including the northeastern Nigerian basins).

During rift Phase II, 3000 – 6000m of subsidence was recorded in Upper Cretaceous marine to continental sediments of the WCARS (Genik, 1993).

(d) Palaeogene Rift Phase III

The Palaeogene rifting affected mostly the WARS basins with an estimated rift and thermotectonic subsidence of up to 2000m and 3000m respectively (Genik, 1993). The contained sediments are continental except for a marine sag interval deposited in middle Eocene as shown Fig. 3 (Genik, 1993). In the northeastern Nigerian basins, the deposited sediments were exclusively continental.

In contrast to the WARS, the CARS basins were generally emergent during this phase with recorded subsidence of not more than 200 – 300m in places (Genik, 1993).

By the close of Oligocene, rift Phase III was terminated by a regional unconformity.

(e) Post-Rift Phase

This is a non-rift phase associated with subsidence and continental sedimentation in the early Neogene (Miocene – Pliocene). Subsequently, uplift and volcanism followed (Grant et al., 1972; Genik, 1993). Continental sediments of Pliocene - Pleistocene were deposited in the Bornu Basin. In the Gongola Basin however, this phase was marked by uplift and erosion. Miocene to Holocene volcanism also affected the two basins (Grant et al., 1972).

4.0 STRUCTURES AND TRAPS

The WARS basins in Niger and Chad including the Bongor and Doba Basins in CARS and the Nigerian Bornu Basin are essentially extensional basins (rifted basins) composed of half-grabens, some of which exhibit reversed structural polarities (Bosworth, 19885; Genik, 1993).

The structural style in these dominantly extensional basins are typically tensional and transpressional. The tensional style is characterized by rotated synthetic fault blocks, antithetic fault blocks, horsts and grabens, compactional anticlines draped over basement horst blocks, and hanging-wall rollover anticlines along normal faults. Several of these structures are traps for hydrocarbons in the Termit Basin. Areal closures in fault structures are commonly $12.14 \times 10^6 m^2$ (3000 acres; Genik, 1993). Transpressional structural style is in the form of compressional anticlines whose areal closure range from about $4.05 \times 10^6 m^2$ (1000acres) to $>40.47 \times 10^6 m^2$ (>10,000 acres). These anticlines can be traps for hydrocarbons in the Termit Basin. They are considered to have originated by sinistral transpression during the mid-Santonian event (Genik, 1993).

In the Bongor and Doba Basins, and the Gongola Basin, these mainly extensional structural styles were strongly modified by strike-slip movements during the Santonian. This resulted into numerous transpressional anticlines which form the best oil-trapping structures in the Doba Basin (Genik, 1993). Their areal closure is commonly $<12.14 \times 10^6 m^2$ (<3000acres), but can be as large as $72.84 \times 10^6 m^2$ (18,000acres) (Genik, 1993).

The CARS basins, on the other hand, excluding the Bongor and Doba Basins, are dominantly transtensional (Genik, 1993). Structures in these basins are complex depicting mixture of extensional, transtensional and transpressional features. Some of the structures are rotated fault blocks, listric faults with rollover anticlines, compressional anticlines, upthrown blocks and negative and positive flower structures. Faulted compressional anticlines of mainly Santonian age are hydrocarbons traps in the Doseo Basin. Areal closure of these anticlines may reach up to $60.70 \times 10^6 m^2$ (15,000acres;) (Genik, 1993).

5.0 STRATIGRAPHY

The stratigraphy of the northeastern Nigerian sedimentary basins (the Gongola and Bornu Basins) including the Termit and Muglad Basins of Niger Republic and Sudan is shown on Figure 4.

Borrowing from Zaborski and Abubakar (2010), the sedimentary successions in the northeastern Nigerian basins can be categorized into four major assemblages divided on the basis of sequence boundaries (i.e. the presence of unconformity bounding surfaces). These assemblages from the oldest to the youngest are:

a) Assemblage 1: Pre-Rift and part of Lower Cretaceous Rift Phase I sequence consisting of the “pre-Bima” and lower part of the Bima Formation deposits.
b) Assemblage 2: upper part of the Lower Cretaceous Rift Phase I and the lower part of the Upper Cretaceous Rift Phase II sequence consisting of the middle and upper parts of the Bima Formation, the Yolde Formation and the Pindiga Formation (Kanawa, Deba Fulani/Dumbulwa/Gulani and Fika Members) in the Gongola Basin and the Gongila and Fika Formations in the Bornu Basin.
c) Assemblage 3: upper part of the Upper Cretaceous Rift Phase II sequence consisting of the Gombe Formation.
d) Assemblage 4: Palaeogene Rift Phase III and Post rift sequence consisting of the Kerri-Kerri and Chad Formations

Assemblage 1

This assemblage comprises of the Pre-Rift and the lowermost part of the synrift Lower Cretaceous Rift Phase I deposits. The assemblage consists of the so-called “pre-Bima” and the lower part of the Bima Formation sediments. This assemblage generally overlies the crystalline basement in both the Gongola and Bornu Basins with age range of Late Jurassic to Barremian.

The distribution of the “pre-Bima” in the Gongola Basin may be spatially restricted but seems to be ubiquitous in the Bornu Basin where it was described as indicative of continental sedimentation composed of conglomeratic facies of alluvial fans developed at the bases of fault scarps followed by interbedded sandstones and terrigenous mudstones. The interbedded sandstones and mudstones were considered to have accumulated within meandering/braided river channels and as overbank floodplain sediments respectively (Simon Robertson report, 1991).

The lower part of the Bima Formation in the Gongola Basin, on the other hand, is a highly variable unit ranging in thickness from 0 to over 1500m in places (Guiraud, 1990). It represents an active rift stage of basin development with lithofacies distribution strongly controlled by syndepositional tectonics which created a number of fault-bounded sub-basins. Syndepositional faulting seems to control the drainage pattern, making it internal, which developed into lakes at the axial regions of the sub-basins away from the source areas represented by uplifted basement horst blocks (Guiraud, 1990). This resulted into the deposition of coeval sedimentary sequences which started with fanglomeratic alluvial deposits close to the uplifted horsts passing laterally into braided river gravelly arkoses and into shally lacustrine deposits towards the centre of the sub-basins shown in Fig. 5. The lower Bima basal fanglomerates overlain by the lower Bima gravelly arkoses are characterized by 3-4m thick multiple fining upward sequences, each comprising at the base of channel pebbles lag capped by large scale trough crossbedded gravels to coarse grained sandstones grading into massive mottled sandstones as shown in Fig. 6 (Guiraud, 1990). In the Bornu Basin, dependable description of the lower part of the Bima Formation is not available due to the lack of outcrop sections, but it may represents the lower part of the “sand member” of the Bima Formation.

Assemblage 2

This assemblage is separated from the Assemblage 1 by a regional unconformity which corresponds to major land leveling phase that took place after the sedimentation and structuration of the lower Bima shown in Fig. 7. (Guiraud, 1990) It ranges from Aptian to Santonian and consists of the middle and upper parts of the Bima Formation of the Lower Cretaceous Rift Phase I, and the Yolde and Pindiga Formations of the Upper Cretaceous Rift Phase II in the Gongola Basin shown in Fig. 4. In the Bornu Basin however, the Yolde Formation may not be present and Gongila Formation is the correlative equivalent of the Pindiga Formation shown in Fig. 4. This assemblage was deposited mainly during a thermotectonic sag stage of basin development shown in Fig. 3, strongly influenced by eustatic transgressive and regressive episodes that ushered in by the Cenomanian age (Zaborski and Abubakar, 2010).

The middle part of the Bima Formation is represented by proximal braided river fining upward units of predominantly trough crossbedded coarse to very coarse grained sandstones composed of usually basal conglomerates with erosive under surfaces indicated in Fig. 6. Individual units are mostly capped with white to purple coloured clays that are thin and often not laterally extensive. Thicknesses of individual units range from 3 to 10m. The middle part of the Bima Formation was assigned Aptian to Albian age (Guiraud, 1990) and marks the transition from the active rifting to thermotectonic sag stage of basin development (Zaborski and Abubakar, 2010).

The upper part of the Bima Formation is composed of uniform fining upward units characterized predominantly by planar crossbedded coarse grained sandstones and thin parallel laminated sandstone units as shown in Fig. 6. Mostly, at the upper part of individual fining upward cycles are relatively thick white to pale-blue to purple coloured clays. The sandstones show commonly soft sediment deformation structures that include convolute bedding, overturned crossbedding and sand volcanoes (Samaila et al., 2006). The upper Bima is probably Albian in age and represent deposition in a distal braided river setting. In the Bornu Basin, the upper Bima is probably of Cenomanian age and may constitute the so-called “shale member” of the Bima Formation shown in Fig. 6.

Generally, the Bima Formation may have a total thickness of ≥3300m and is poorly sorted with degree of sorting showing progressive increase from the lower to the upper Bima. This attests to upward maturation which reflects the upward change from tectonic instability to stable periods of the basins development (Guiraud, 1990).

The Upper Cretaceous Series in the Gongola Basin begins with the Yolde Formation which lies conformably on the Bima Formation. The presence of this formation in the Bornu Basin is controversial, however, growing evidences tend to support that the so-called "Bima shale member" in the Bornu Basin may be the Yolde Formation as shown in Fig. 6. The Yolde Formation earlier interpreted as transitional marine (Carter et al., 1963) represents generally a retrogradational barrier island – lagoon depositional environment (Abubakar, 2006). It is also occasionally deltaic in places (Dike and Maigari, 2009). The base of the formation in the Gongola Basin is defined by the first appearance of marine shale while the top is defined by the disappearance of sandstones and the commencement of limestone-shale successions of the overlying Pindiga Formation (Carter at al., 1963). The formation represents the onset of the major late Cenomanian to Turonian transgression that affected the northeastern Nigerian basins and the entire Benue Trough and large parts of the Saharan region that culminated into the establishment of the transsaharan seaway (Zaborski, 2000). Lithologically, the formation is composed of a mixture of several coarsening and fining upward cycles that mainly involve coarse to medium to fine grained sandstones that are occasionally pebbly with erosive bases, bioturbated clays/shales (0.6-4m thick) with marls and thin limestone association, and interbedded silts/fine – medium grained sandstones/thin carbonaceous silts (Abubakar, 2006). Sedimentary structures of the sandstones are mainly planar crossbeddings, relatively few trough crossbeddings (mainly related to the pebbly coarse grained units) and occasionally herringbone crossbeddings and parallel laminations on the fine grained sandstones (Abubakar, 2006). The sandstones are generally moderately well sorted. The Yolde Formation in the Gongola Basin may reach a thickness of up to 200m or more.

The Pindiga Formation in the Gongola Basin and its lateral equivalent in the Bornu Basin (the Gongila Formation) make up the greater part of the Upper Cretaceous in the northeastern Nigerian basins shown in Fig. 6. The lower part of the Pindiga Formation is composed of interbedded limestone and shale (the Kanawa Member). It is predominantly sandy at the middle part (represented by the laterally equivalent Deba Fulani, Dumbulwa and Gulani Members, but shaly with some thin limestones at its upper part (the Fika Member). In the Bornu Basin, the Fika Member is of formational status (i.e. the Fika Formation).The Kanawa Member is upper Cenomanian to lower Turonian and may have a maximum thickness of up to 100m, the middle Pindiga Formation members are middle Turonian and may individually reach a maximum thickness of 180m and the Fika Member is Turonian to Santonian and may reach a maximum thickness of up to 250m (Zaborski, 2000). The lower parts of the middle members of the Pindiga Formation generally represent deposition in shoreface environments while the upper parts represent perhaps continental depositional setting, related generally to a short term regressive episode in middle Turonian times. These sandy members may be absent within the Pindiga Formation in the Kerri-Kerri Basin suggesting continued marine sedimentation in this part of the Gongola Basin.

The Gongila Formation of the Bornu Basin, on the other hand, is dominantly composed of terrigenous mudstones and argillaceous sandstones with subordinate clean sandstones (Nwaezeapu, 1992). Although the basal Gongila Formation of the Bornu Basin was assigned a Turonian age (Simon-Robertson report, 1991), the pollen (*Gnetaceaepollenites sp.*) upon which the age was deduced is a late Cenomanian index species (Lawal and Moullade, 1986; Abubakar, 2006; Abubakar et al., 2006). This misinterpretation, coupled with the established late Cenomanian age of the basal unit of the laterally equivalent Pindiga Formation in the Gongola Basin, strongly suggest late Cenomanian to Turonian age for the Gongila Formation. The Gongila Formation may reach a maximum thickness of up to 800m (Avbovbo et al., 1986). A thickness of up to

650m has been suggested for the overlying Fika Formation.

Assemblage 3

This assemblage is made up of the Gombe Formation and represents the topmost sedimentary unit of the Cretaceous succession in the Gongola Basin as shown in Fig. 4. Its presence in the Bornu Basin is debatable. The Gombe Formation is generally a coarsening upward sequence made up of several coarsening upward cycles. It has been described as "a sequence of estuarine and deltaic" sediments (Carter et al., 1963) as well as "a prograding linear clastic shoreline succession" (Zaborski, 2000). Recent study however, described the formation as typical of a prograding fluvially-dominated marine delta (Abubakar, 2006). The Gombe Formation unconformably overlies the Pindiga Formation and perhaps the Gongila Formation in the Gongola and Bornu Basins respectively. The formation is composed of predominantly silty micaceous shale interbedded with thin silts and minor very fine sandstones at the most basal part and at the base of each coarsening upward cycle as shown in Fig. 6. This forms the "prodelta facies" of Zaborski et al. (1997) and Abubakar (2006). It may reach a thickness of 20m (Abubakar, 2006). The "prodelta facies" transits into distributary mouthbars made up of very fine sandstones that are mostly rippled to parallel laminated and occasionally hummocky cross-stratified. This is capped occasionally by channel-filling planar to trough crossbedded and rippled sandstones interpreted as distributary channel sands. These sandstones constitute the "bedded sandstone facies" of Zaborski et al. (1997). The "bedded sandstone facies" may reach a thickness of 30m in places. Zaborski et al. (1997) reported the presence of a reddish coloured continental fining upward succession of channel-filling sandstones with intraformational conglomerates at the upper part of the Gombe Formation. This constitutes their "red sandstone facies". The Gombe Formation is also characterized by thin lignitic coal seams that could be up to 2m thick in places (Offodile, 1980). The formation is Campanian to Maastrichtian in age.

The Assemblage 3 was subsequently affected by the terminal Cretaceous compressional event (the Maastrichtian event) which uplifted, folded, faulted and deeply dissected all the Cretaceous sequences.

Assemblage 4

The Assemblage 4 comprises of sediments and volcanics associated with a renewed rifting at the beginning of Palaeogene (Palaeogene Rift Phase III) and Post Rift tectono-stratigraphic phase. It consists of the Kerri-Kerri and the Chad Formations accompanied by Neogene to Quaternary volcanic activity in the northeastern Nigerian sedimentary basinsas shown in Fig. 4. This assemblage unconformably overlies the Assemblage 3 and seems to be wholly continental in nature as shown Fig. 6.

The Palaeogene Rift Phase III was associated to an E-W extensional activity followed by a thermotectonic subsidence that resulted in the deposition of the grits, sands and kaolinitic clays of the Kerri-Kerri Formation in the western part of the Gongola Basin (Benkhelil, 1988; Zaborski, 2000). The deposition of the Kerri-Kerri Formation in the Bornu Basin was probably restricted to the southwestern portion of the basin. The Kerri-Kerri Formation represents mainly fluvial (braided river) sedimentation. The presence of lacustrine deltaic sediments at its basal part as reported by Adegoke et al. (1986), if any, is difficult to ascertain. The Kerri-Kerri Formation may reach a total thickness of 320m (Adegoke et al., 1986; Dike, 1993). It may be Palaeocene in age from palynologic data (Adegoke et al., 1978).

The Rift Phase III and the accompanying thermotectonic subsidence terminated at the beginning of the Neogene and was followed by the Post Rift Phase related to transtentional movements, minor subsidence and subsequent uplift to the present time (Genik, 1993). This resulted into the deposition of the continental Chad Formation unconformably on mostly the Cretaceous Fika Formation in the Bornu Basin indicated in Fig. 6, except at the southwestern margin of the basin where the Chad Formation overlies perhaps conformably the Kerri-Kerri Formation. No sedimentation was recorded in the Gongola Basin except normal faulting along the western margin of the Kerri-Kerri Basin (Adegoke et al., 1986).

The Chad Formation is Pliocene to Plaeistocene and consists of lacustrine mudstones and fluvial sandstones as shown in Fig. 6. The sandstone dominated intervals can be locally argillaceous, while the terrigenous dominated intervals are in parts arenaceous containing thin beds of sandstone and/or siltstone (Nwaezeapu, 1992). The formation may reach a maximum thickness of up to 800m (Simon-Robertson report, 1991).

Towards the end of the Cenozoic (Miocene), and until Recent times (Plaeistocene), widespread volcanic activities occurred in the southern and central parts of the Bornu Basin (Obaje et al., 2004) and the eastern part of the Gongola Basin. This resulted into the emplacement of several volcanic plugs in the Cretaceous to Cenozoic sedimentary sequences in the northeastern Nigerian sedimentary basins.

6.0 PETROLEUM POTENTIALS

The origin of the northeastern Nigerian basins has been shown to be related to rifting. Basin formed as rift and many rifted basins have high geothermal gradients and large traps for hydrocarbons (Avbovbo et al., 1986). Klemme (1980) showed that 35% of rifted basins contain giant oil fields. The discovery of oil in contiguous basins in Niger, Chad and Sudan (basins that share the same tectonostratigraphic history with the northeastern Nigerian basins) and particularly in the Chadian sector, the discovery of the 33BCF of gas in well Kolmani River-1 in the Gongola Basin (Abubakar et al., 2008) and non-commercial gas in two wells of the Bornu Basin (Nwaezeapu, 1992) attest to the presence of petroleum system(s) in the northeastern Nigerian basins. Petroleum system concept describes the genetic relationship between a pod of active source rock and the resulting oil and gas accumulations and encompasses four essential elements of source rock, reservoir rock, seal rock and overburden, and two processes of trap formation and generation-migration-accumulation of petroleum (Magoon and Dow, 1994). Source rocks generate the petroleum, reservoir rocks store it, seal rocks prevent further vertical migration of the petroleum to the surface where it can be lost, and the overburden (thickness of sedimentary pile above the source and the reservoir rocks) provides adequate temperature at the subsurface that will cook the source rocks to maturity so that they can generate and primarily migrate the oil to the reservoir rocks where it can be stored.

As part of the WCARS, it is instructive therefore to evaluate the petroleum potentials of the northeastern Nigerian basins within the context of the identified petroleum systems in the WCARS. In both the Gongola and Bornu Basins, sediments of over 6000m are abound as shown in Fig. 7. This is far more than the minimum overburden thickness of 1000m (Hunt, 1996) required for a basin to be prosperous when all other elements of a petroleum system are present.

7.0 PETROLEUM SYSTEMS

Three petroleum systems can be identified in the WCARS basins (Genik, 1993). These systems are related to the three major rift phases that affected the WCARS, hence mostly individually confined within the identified sequence bounded assemblages.

The identified petroleum systems, from oldest stratigraphic levels to the youngest, are:

(a) The Lower Cretaceous Petroleum System

This petroleum system is generally associated with the rift Phase I and the basal part (Cenomanian) of rift Phase II in the WCARS basins. Petroleum accumulations occur in sandstones of Aptian to Cenomanian alluvial/braided/meandering rivers, and coastal marine and lacustrine delta deposits see Table 1.

In the Muglad Basin of Sudan these sandy reservoirs constitute medium – coarse grained sandstones of the upper Albian – Cenomanian Bentiu Formation with porosity of up to 15-27% at depth interval of up to 3595m (Abdalla et al., 1999). In the Doba and Doseo Basins of the Chad Republic, the sandstones are fine to coarse grained, poorly – fairly sorted and sometimes conglomeratic. They were deposited predominantly in alluvial and braided river channels and as deltaic facies associated with lacustrine settings (Genik, 1993). Porosity ranges from 12-24% (ave. 18%) and permeability is 3-25md (ave. 15md) at depth range of 1500-2700m (Genik, 1993). In Termit Basin of Chad and Niger Republics, deltaic to tidal sandstones of Cenomanian Sedigi Formation constitutes the reservoir.

Source rocks of this system are the Lower Cretaceous (pre-Aptian to Albian) lacustrine shales deposited mainly at the axial part of the rift system in dysoxic to anoxic set-up as shown in Tabl1. They are generally rich in total organic carbon (TOC) and are composed of mainly type I (oil-generating) organic matter (OM). In the Muglad Basin, these source rocks constitute the Neocomian – Barremian Sharaf and Abu Gabra Formations consisting of lacustrine shales rich in amorphous kerogen (>80%) with TOC ranges of 1.5-2.3wt% and high values of hydrogen index (HI) of 338-546mgHC/gTOC (Mustapha and Tyson, 2002). This suggests mainly type I OM. These source rocks (e.g. Tefidet, Alaniara and Tegama Formations) in Niger and Chad Republics basins contain TOC that ranges from 1-14wt% with predominantly type I OM (HI >600mgHC/gTOC) derived from fresh water algae and bacteria (Genik, 1993).

Local seal rocks (3-5m thick) exist as interbedded Lower Cretaceous lacustrine shales while regional seals are provided by the Upper Cretaceous fluvial and lacustrine shales in the Muglad Basin (e.g. Aradeiba and Zarga Formations) and predominantly marine shales in Niger and Chad basins.

In the northeastern Nigerian sector of the WCARS, potential Lower Cretaceous Petroleum System includes sediments of the alluvial-braided-lacustrine Bima and the transitional (barrier island – lagoon and deltaic) Yolde Formations in both the Bornu and the Gongola Basins. As earlier mentioned, however, the presence of the Yolde Formation in the Bornu Basin is debatable. I strongly reserved that the Cenomanian marine part of the Bima Formation (Bima Shale Member) (Simon-Robertson report, 1991), which corresponds to the Seismic Sequence 2 (upper part of Bima Formation, shown in Fig. 8 of Avbovbo et al, 1986) is the representative Yolde Formation in the Bornu Basin.

The potential reservoirs are the alluvial fans and braided river channel sandstones, and perhaps lacustrine deltaic ssandstones of the Bima Formation, as well as, the barrier ridges and inlet channel sandstones and the flood and ebb deltas of the barrier island complex of the Yolde Formation. Sandstone thicknesses in the lower and upper Bima Formation are in the range of 3-10m and may be more than 100m where amalgamated. Sandstone thicknesses in the Yolde Formation ranges between 1-10m (Abubakar, 2006). Porosity and permeability data of these potential reservoirs are very scarce. Nwaezeapu, 1992 reported porosity of as low as 3% in the Bima Formation of the Bornu Basin. In the Gongola Basin, however, porosity varied from 5.58-29.22% and permeability is in the range of 10.67-89.27md (Samaila, 2007). The sandstones of Yolde Formation, on the other hand, are generally moderately well sorted and constitute very important aquifer in the Gongola Basin.

Potential source rocks of this system are the interbedded shales of the Bima and Yolde Formations. These shales are fluvial and perhaps lacustrine in the Bima Formation, and marine to lagoonal in the Yolde Formation. Although little is known on the distribution of the lacustrine facies in the Gongola Basin, Allix, 1983 and Guiraud, 1990 reported the presence of some 350m of alternating shales, silty shales, fine to coarse grained sandstones and minor carbonates in the core of Lamurde anticline. Allix, 1983 interpreted this succession as lacustrine-related shales and delta sandstones. Popoff, 1988 interpreted it as part of a regional lacustrine and perilacustrine succession that existed at depth over much areas of the the upper Benue Trough (including the Gongola Basin). Guiraud, 1991, however, regarded the lacustrine facies as strictly local to the Lamurde area. Source rock assessment (Table 2) indicates TOC range of 0.21-2.82wt% and an average of 0.79wt% for the Bima Formation of the Bornu Basin. 65.4% of samples from the studied data are ≥0.5wt% (the minimum threshold of OM quantity required for hydrocarbon generation). The HIs of these samples, however, range from 30-435mgHC/gTOC, shown in Table 2, with an average of 145.4mgHC/gTOC. This indicates the dominance of gas-generating type II OM. The source rock interval with HIs of as high as 435mgHC/gTOC, however, suggest the presence of localized type I (oil-generating) OM which may be related to lacustrine source rocks as reported from the contiguous basins of Sudan, Niger and Chad Republics. These may constitute important potential source rocks where thickly developed and laterally extensive. In the Bima Formation of the Gongola Basin, the TOC ranges from 0.10-0.87wt% with an average of mere 0.25wt% (Table 2). Only 19.0% of the samples from the studied data (excluding samples Nas 53, 54, 55 from the well Nasara-1) show TOC values ≥ 0.5wt%. HIs are equally low ranging from 21-160mgHC/gTOC shown in Table 2, with an average of 63.7mgHC/gTOC. This indicates the dominance of terrestrially derived type III OM capable of generating mainly gas. An exception to this interpretation, however, is the Rock Eval pyrolysis data of the samples Nas53, 54 and 55, representing a depth interval of 60ft (≈ 18m) from 4710ft (≈ 1436m) – 4770ft (≈ 1454m) in the well Nasara-1 drilled by Chevron in the Gongola Basin. At this depth interval, the TOCs and HIs are anomalously very high (52.10-55.20wt% and 564-589mgHC/gTOC respectively. This, coupled with the bimodality of the S_2 peak (pyrolysable hydrocarbon yield) of the Rock Eval pyrogram shown Fig. 9, high extract yield indicated in Table 3 and predominance of oil-related macerals (i.e. fluorinite and exsudatinite, in Plate 1 suggest the presence of reservoired migrated oil at the depth interval shown in Fig. 10. Very low extended hopane distribution of ≥ 0.27 (H31R/H30 ratios, indicated in Table 4 indicates that the oil was generated from lacustrine sediments (Abubakar et al., 2008). These sediments may be the lacustrine shales of the Bima Formation not yet penetrated by the well Nasara-1. Therefore, this may also attests to the presence of effective and mature type I (oil-generating) source rock of lacustrine origin at deeper stratigraphic levels in the northeastern Nigerian sedimentary basins. Potential source rocks from the Cenomanian Yolde Formation, on the other hand, show TOC values of 0.22-0.72wt% from the Bornu Basin (Table 2) and 0.10-12.90wt% in the Gongola Basin (Table 2). Up to 87.5% of samples from the Bornu Basin have TOCs ≥ 0.5wt% with an average of 0.60wt% as opposed to 40% from the Gongola Basin but with an average of 1.7wt%. HIs range from 11-113mgHC/gTOC in the Bornu Basin suggesting type III-IV (gas-generating to death) organic matter refere to Table 2. In the Gongola Basin, the HIs range from 26-171mgHC/gTOC with an average of 53.3mgHC/gTOC suggesting the predominance of type III organic matter but with localized presence of oil and gas generating type II organic matter. Generally, the potential source rocks of the Lower Cretaceous Petroleum System in both the Bornu and the Gongola Basins are mature for hydrocarbon generation showing Tmax values that are generally above the minimum threshold of as shown in 435°C Table 2.

Potential seal rocks of this system consist locally of the interbedded fluvial (floodplain) and lacustrine shales in the Bima Formation, and interbedded shallow marine and lagoonal shales in the Yolde Formation. The sealing shales within the Yolde Formation are occasionally laterally extensive and may reach thicknesses of up to 4m. Regional seal constitutes the marine shales of the lower Pindiga Formation in the Gongola Basin and the interbedded shales of the Gongila Formation in the Bornu Basin.

(b) The Upper Cretaceous Petroleum System

This system is restricted to the sediments of the Upper Cretaceous Rift Phase II which encompasses Assemblage 2 (except the Cenomanian Yolde Formation) and Assemblage 3. The formations involved are the Pindiga and Gombe Formations in the Gongola Basin and the Gongila and Fika Formations in the Bornu Basin indicted in Fig. 4.

This petroleum system is poorly developed and perhaps non-existing in the Muglad Basin of Sudan due to its little or none source rock potential. It is however well established in the Termit Basin of Niger and Chad Republics (Genik, 1993). The reservoirs are mainly deltaic – tidal marine clastics (e.g. Sedigi Formation) and fluvial sandstones of Senonian to Maastrichtian age with porosity in the range of 16-25% (ave. 20%) at depth of 2200-3500m and permeability of 35-82md (ave. 52md) at same depth interval (Genik, 1993). These sandstones are of limited thickness and areal extend but may stack up to 60-70m. The Maastrichtian fluvial sandstones may reach up to 400m thick and has porosities of 25-35% (Zanguina et al., 1998). Source rocks are shales of mostly shallow marine to deltaic depositional environment. They are composed of predominantly type III organic matter and have generated oil and gas in the Termit Basin. Average TOCs are in the range of 0.8-1.5wt% (Zanguina et al., 1998). Occasionally the TOCs may reach up to 30wt% (Genik, 1993), perhaps in coaly facies. The seals are the Upper Cretaceous marine shales, some of which are regional.

The potential source rocks of this possible petroleum system in the northeastern Nigerian basins are shales and limestones of the Pindiga, Gongila and Fika Formations, and perhaps the coals of the Gombe Formation shown in Fig. 4. TOCs from available data are in the range of 0.07-3.87wt% (ave. 0.81wt %) with 81.8% of samples $\geq$ 0.5wt% in the Gongila and Fika Formations of the Bornu Basin indicated in Table 5. HIs from these formations are 10-255mgHC/gTOC with an average of 55.2mgHC/gTOC as indicated in Table 5. This suggests the dominance of terrestrially-derived type III OM capable of generating mainly gas at adequate depth. Available data from the Pindiga Formation indicates 0.10-2.45wt% TOCs (ave. 0.59wt %) with 57.95% of samples having TOCs of $\geq$ 0.5wt%. HIs are very low (5-180mgHC/gTOC) suggesting poor generating potential, except in the upper part of the formation (Fika Member) where HIs are mostly above 150mgHC/gTOC shown in Table 5. The upper part suggests oil and gas generating type II organic matter. Shale and shaly coal samples of the Maastrichtian deltaic Gombe Formation show TOC ranges of 0.20-23.7wt% with 87.5% $\geq$0.5wt% as indicated in Table 5. Average TOC is 9.25wt% in the shaly coal facies and 0.79wt% in the shale facies. HIs range from 2-280mgHC/gTOC with an average of 19.17mgHC/gTOC in the shaly facies and 112.75mgHC/gTOC in the shaly coal facies. This suggests that the shaly coal facies are potential source rocks for gas and some oil locally, where HIs are more than 150mgHC/gTOC). The Tmax values of the Gongila and Fika Formations of the Bornu Basin are mostly above the minimum threshold, hence are generally mature and capable of hydrocarbon generation. The Pindiga and Gombe Formations of the Gongola Basin, on the other hand, show immaturity. Most of those areas from which the data in Table 5 is derived come from the less deeply buried parts of the Gongola Basin. In the Kerri-Kerri sub-basin, located in the western Gongola Basin shown in Fig. 1, these formations are overlain by the Kerri-Kerri Formation, hence may have been buried to greater depth to reach hydrocarbon generation maturity.

Possible reservoirs for this system are mainly mid-Turonian sandstones of the middle Pindiga Formation (the Deba Fulani, Dumbulwa and Gulani Members) and the Gombe Formation shown in Figs. 4 and 6. The limestones of the Gongila Formation in the Bornu Basin and the Kanawa Member of the Pindiga Formation in the Gongola Basin may also constitute local reservoirs where individual beds are stacked as in the Ashaka cement quarry (limestones reach thickness of 10m here) and where porosities and permeabilities are diagenetically and mechanically enhanced. Generally, the middle members of the Pindiga Formation include moderately well sorted, loosely cemented and thickly developed trough and planar crossbedded, as well as, hummocky cross-stratified medium to coarse grained sandstones that are occasionally pebbly and graded bedded (Abubakar, 2006). Granulestones are also present. These sandstones show coarsening upward cycles at the base, but are fining upward towards the top. The sandstones represent shoreface and fluvial sedimentation at the lower and upper parts of the members respectively (Abubakar, 2006). These sandstones may extend for over 10km and occur over the entire eastern Gongola Basin. The presence of this members in the sub-cropping part of the western Gongola Basin (Keri-Kerri sub-basin) is possible, but have not been proved. Although porosity and permeability data is lacking, these sandstones constitute excellently reliable aquifers that provide constant supply of a large volume of water needs of the Gombe town from semi-artesian wells at Kwadom. They form also highly productive aquifers in the Kumo area with water yield of 5.80-7.10l/sec. (Dike and Maigari, 2009). These indicate excellent reservoir qualities (high porosity and permeability) for the sandstones. The deltaic Gombe Formation, on the other hand, is made up of thickly developed and fairly extensive distributary mouthbars, and distributary and fluvial channel sandstones. These sandstones are moderately well sorted and mostly very fine grained. Porosity and permeability are likely to be highly variable. However, globally the porosities and permeabilities of deltaic sandstone reservoirs range from 11-35% and 250-8000md respectively (Morse, 1994). In the Bornu Basin, Nwaezeapu (1992) observed porosities of as high as 23% for the Gongila Formation.

The shales of the Fika Member could form effective seals for the reservoirs of the middle part of the Pindiga Formation shown in Fig. 4, and 6. The potential reservoirs in the Gombe Formation may be sealed by the intercalating silty shales of the formation, but may not be competently and laterally very effective. Fika Formation is the regional seal for the Upper Cretaceous system in the Bornu Basin.

(c) Palaeogene Petroleum System

This system is best developed in the Termit Basin of Niger Republic and is related to the Palaeogene Rift Phase III. There is little known on this system. The principal source rocks are lower Eocene shallow marine to paralic shales (200-500m thick) and the middle Eocene lacustrine shales (Genik, 1993). The lacustrine source rocks are of high quality type I organic matter, derived from fresh water algae and bacteria, and have generated and expelled mainly oil into middle to upper Eocene fluvial channels and lacustrine delta sandstones, as well as, "laterally" into fluvial sandstones of the Palaeocene shown in Table 1. (Genik, 1993) Oligocene lacustrine shales of up to 1000m thick provide regional seal while interbedded shales of the Eocene provide local seal potential (Genik, 1993).

This potential petroleum system may be absent in the Gongola Basin. In this basin, sedimentation ceased with the deposition of the Palaeocene continental Kerri-Kerri Formation followed subsequently by the Neogene to Quaternary volcanism shown in Fig. 4. The Kerri-Kerri Formation has, however, served to bury potential source rocks in the western Gongola Basin to greater depths than elsewhere and therefore has some relevance in terms of enhancing thermal maturity of the sub-cropping Cretaceous sediments (Zaborski and Abubakar, 2010).

In the Bornu Basin, however, potentials on the presence of the Palaeogene Petroleum System may exist. Here extensive deposition of the Eocene to Pleistocene fluvial – lacustrine Chad Formation on the Palaeocene continental Kerri-Kerri Formation took place as shown in Fig. 4. The Cretaceous Fika Formation may also act as a principal source rock for the system. Constraints to this system, however, may be in fundamentally inadequate thermal maturity of potential source rocks due to shallow levels of burial and perhaps absence of regional seals. Reservoirs at shallow depth levels may also be affected by meteoric water, hence becoming degraded.

8.0 HYDROCARBON TRAPS

Traps for hydrocarbons in the northeastern Nigerian basins are expected to mimic those identified in the WCARS basins of Termit, Doba, Doseo and Muglad. The position of the northeastern Nigerian basins at the confluence zone between the predominantly extensional WARS basins (e.g. Termit Basin, etc) and the predominantly transtensional CARS basins (e.g. Doseo Basin) shown in Fig. 2, suggests the possibility of mixed traps peculiar to both the WARS and CARS basins in the Nigerian sector. The fact that the northeastern Nigerian basins share the same tectonic origin and evolution of initial rifting, thermotectonic sagging, strike-slip faulting, and particularly mid-Santonian and end Cretaceous compressive phases with the other WCARS basins, also suggest that the structural traps may be of comparable volumes with those in the Termit, Doba, Doseo, etc. Rapid facies changes characterized the stratigraphic successions of the Bornu and Gongola Basins and this suggests the possibility of the presence of also stratigraphic traps.

Avbovbo et al, 1986 identified the existence of traps within horsts, in the drape or compaction structures over horsts, along normal faults, and along the flanks of horsts in the Bornu Basin of which Genik (1993) asserted are similar to those in the WCARS. Similar structures of E-W trending horsts and grabens related to tensional movements and controlled by synrift N60^{o}E trending fault system (generally parallel to sub-parallel to the length of the basin) have been reported from the upper Aptian and older sedimentary successions in the Gongola Basin (Popoff et al., 1983). In the Termit and Bornu Basins shown in Fig. 11, however, this pattern is superposed by NNW-SSE trending antithetic faults linked to latest Cenozoic movements (Genik, 1993). The NNW-SSE trends are also present in the Gongola Basin shown in Fig. 12.

These types of traps are expected to be dominant in the Lower Cretaceous Petroleum System of both the Bornu and the Gongola Basins. The block faulting that produced the horst and graben structures can also provide good migration pathways for generated hydrocarbons (Obaje et al., 2004).

The mid-Santonian and late Maastrichtian compressional events in the basins produced additional fracturing and folding that formed traps associated with large compressional anticlines with four-way dip or fault-assisted closures, and listric faults associated with flower structures (Nwaezeapu, 1992). These traps may be much prevalent in the Upper Cretaceous Petroleum System and are found to dominate the deeper central parts of the basins (Avbovbo et al., 1986, Fig. 13). The faults seem to die out at the end Maastrichtian unconformity that separates the Cretaceous from the Palaeogene sequences indicated in Fig. 14.

Stratigraphic traps may be in the form of onlap and truncational unconformities, buried channels and to a lesser extend pinchouts. The stratigraphic traps may be the dominant types in the Potential Palaeogene Petroleum System of the Bornu Basin. Structural traps will be scarce due to tectonic quiescence that accompany the deposition of the Palaeogene to Quaternary successions in the basin.

9.0 PETROLEUM GENERATION

Petroleum generation, its timing and expulsion in the Bornu and the Gongola Basins of the northeastern Nigeria are not known at present. Geothermal gradients, however, is in the range of 2.16-5.26^{o}C/100m in the Bornu Basin (Nwaezeapu, 1992) with the highest values in the region of the Neogene to Quaternary intrusive rocks which generally dominate shallow part (flanks) of the basin (Avbovbo et al., 1986). These geothermal gradient values compare well with values of 2.6-2.9°C/100m in the Muglad Basin of Sudan (Abdalla et al., 1999) and 2.5-3.0°C/100m in the basins of Chad and Niger Republics (Genik, 1993). Modeling for hydrocarbon generation in the Muglad Basin and the basins of Chad and Niger Republics using these geothermal gradients, suggests that presently oil-generation window lies at 2,300-5,000m depth in the Niger and Chad Republics basins (Genik, 1993), and at 3,500-4,000m in the Muglad Basin (Abdalla et al., 1999). Zanguina et al, 1998 indicated also that the top of "oil window" in east Niger grabens (e.g. the Termit Basin) is located at a depth of between 2,200 and 2,900m, and that the top of the "gas window" is between 3,600 and 4,000m. These geothermal gradient values and oil-generation windows could be extrapolated for the northeastern Nigerian basins. The most prospective areas may occur in the Central part of the basins where thicknesses of sedimentary cover are high. This constitutes the Kerri-Kerri sub-basin of the Gongola Basin shown in Fig. 1, 7 and central parts of the Maiduguri and Lake Chad sub-basins of the Bornu Basin shown Fig. 7.

It is worth mentioning at this point, the effect of the end Cretaceous (end Maastrichtian) tectonic event and the Neogene to Quaternary volcanism vis-à-vis petroleum generation and preservation in the basins. The effect of the end Cretaceous event may be positive by enhancing trapping mechanisms if petroleum generation post-date it and may be negative, on the other hand, if generation pre-date it. The later may open up some of the earlier formed petroleum traps resulting into tertiary migration of the petroleum to high level traps or loss to the surface. The volcanism has also similar effect depending on whether generation occurs pre- or post-volcanism. If volcanism is pre-generation, it may enhance source rock maturity due to increase in geothermal gradient in adjacent areas, but otherwise it may burn up hydrocarbon accumulations that occur close to the volcanic plutons and sills.

10. EXPLORATION CHALLENGES

Exploration challenges in the northeastern Nigerian basins (the Bornu and Gongola Basins) are numerous but fundamentally they include:

(a) Wrong interpretation of seismic data: Analysis showed that 19 out of the 23 wells in the Bornu Basin were drilled off structure and targeted highly reflective "bright spots" (e.g. Wade-1, Albarka-1, etc; sown in Fig. 15 commonly used in the Niger Delta for hydrocarbon detection (Nwaezeapu, 1992). It is now understood that these imbricate-shape amplitude anomalies in the Bornu Basin are manifestations of volcanic plugs and sills embedded in the host rock rather than hydrocarbon presence as occur in the Niger Delta (Nwaezeapu, 1992). The remaining 4 wells targeted thick "reservoir sands" proximal to the identified structure building faults. Such proximal clastics often lack source and seal rocks in half-graben basins like the Bornu and the Gongola. Many discontinuous, low amplitude seismic reflections seen on some seismic profiles from the Bornu Basin, on the other hand, also posed serious interpretation problems (Nwaezeapu, 1992). These were given different interpretations ranging from massive clastics to homogenous limestone beds or shales. Consequent to these wrong interpretations, dry wells were drilled.

(b) Inadequate 2-D seismic density: Exploration in the Bornu and Gongola Basins, so far, utilized 2-D seismic. Structural resolution, using this method, requires shooting numerous seismic lines at relatively short intervals. The 2-D seismic density is grossly inadequate in the northeastern Nigerian basins when compared to what obtains in adjacent Termit Basin where hydrocarbons are discovered as shown in Fig. 16.

(c) Lack of proper grasps of the geology, stratigraphy, structure and architecture of the basins: The Bornu and Gongola Basins, unlike the Niger Delta, are rifted basins with mostly dissimilar structure and architecture, hence require new perspectives and exploration concepts away from that of the Niger Delta.

stratigraphy, structure and architecture of the basins: The Bornu and Gongola Basins, unlike the Niger Delta, are rifted basins with mostly dissimilar structure and architecture, hence require new perspectives and exploration concepts away from that of the Niger Delta.

(d) Over dependence on the prolificity of the Niger Delta: At the present production rate, the reserve of oil in the Niger Delta will last for decades. Therefore at the moment, multinational companies are not eager to make new discoveries in the Bornu and Gongola Basins, especially since additional production cost over that of the Niger Delta will be involved in the construction of long pipelines and flow stations to the sea for onward transportation to world markets.

11.0 FUTURE EFFECTIVE AND SUSTAINABLE EXPLORATION STRATEGIES

In view of the above challenges, it has become obvious that exploration in frontier basins like the Bornu and Gongola Basins will require effective and dynamic strategy and incentives to sustain efforts and make discoveries. From the technical (geologic) perspective, future strategies should include:

(a) Detail and proper understanding of the stratigraphy of the basins through detail geological and structural mapping preferably on a scale of 1:12500, incorporating GIS, radar imageries and aeromagnetic/gravity structural maps, and detail outcrop sections (composite and stratigraphic) and boreholes logs.

(b) Organic facies study employing the conventional elemental typing and bulk compositional study of first formed petroleum. Bulk compositional study is presently the best approach to organic facies characterization (di Primio and Horsfield, 2006), especially where phase, volume and kinetic modeling need to be performed without access to calibration data (this is normally the case in frontier basins like the Bornu and Gongola). It is the most useful research tool for understanding the processes of individual hydrocarbon generation and migration.

(c) Correlation study of the drilled wells with outcrop sections using lithology (lithofacies, potential source and reservoir rocks horizons), palaeontology (preferably palynology), radiometry in some favourable cases and organic facies.

(d) Integration of sequence stratigraphic ideas in petroleum system elements (source, reservoir and seal rocks only) appraisal.

(e) Shallow boreholes drilling at identified localities to test for possible lacustrine shales in the basins (the Gongola Basin in particular because of its good exposures of the Cretaceous formations).

(f) Basinal modeling for depth to hydrocarbon generation window and timing of generation vis-à-vis traps formation.

(g) Risk factor analysis and the development of risk segment maps.

12.0 SUMMARY AND CONCLUSION

Three potential petroleum systems may be abounding in the northeastern Nigerian sedimentary basins (the Bornu and the Gongola Basins). These petroleum systems are:

(a) The Lower Cretaceous Petroleum System related to the Pre-Rift and Lower Cretaceous Rift Phase I (including the Cenomanian of the Upper Cretaceous Rift Phase II) tectonostratigraphic sequences. This system may be characterized by mainly good quality (type I organic matter) lacustrine source rocks with high TOCs and adequate maturity. Reservoir rocks are alluvial-braided-lacustrine delta sandstones of Aptian to Albian Bima Formation, and the sandstones of the barrier-island complex of the Cenomanian Yolde Formation. Regional seal could be the shales of the Kanawa Member of the Pindiga Formation in the Gongola Basin and the interbedded shales of the Gongila Formation in the Bornu Basin. This perhaps could be the most promising petroleum system in the basins.

(b) The Upper Cretaceous Petroleum System restricted to the Upper Cretaceous Rift Phase II tectonostratigraphic sequences. The source rocks are marine composed of mostly type III terrestrially derived OM that is marginally mature to immature in the exposed Cretaceous rocks of the eastern Gongola Basin. These source rocks may be mature in the Kerri-Kerri sub-basin where they are buried by the Palaeocene Kerri-Kerri Formation. Good to excellent quality reservoirs are the sandy members of the Pindiga Formation and the sandstones of the deltaic Gombe Formation in the Gongola Basin. Limestones of the lower Pindiga Formation (the Kanawa Member) may form reservoirs where thickly developed and its porosities improved by diagenesis and fracturing. In the Bornu Basin, the reservoirs are mainly the sandstones of the Gongila Formation. Seals are the interbedded shales of the Gongila Formation and Fika Formation in the Bornu Basin, as well as, the shales of the Pindiga Formation in the Gongola Basin. Silty shales of the Gombe Formation may not be very effective.

Structures and traps in the northeastern Nigerian basins mimic those associated with the other basins of the WCARS where petroleum has been discovered.
Data on petroleum generation and timing is not available, but seem to be similar to what obtains in the Muglad Basin of Sudan and the Termit Basin of Niger/Chad Republics. In this basins, present-day depth to petroleum generation-window lies between 3,500-4,000m and 2,300-5,000m respectively.

Exploration challenges are very numerous and require new perspectives and exploration concepts if success is to be achieved.

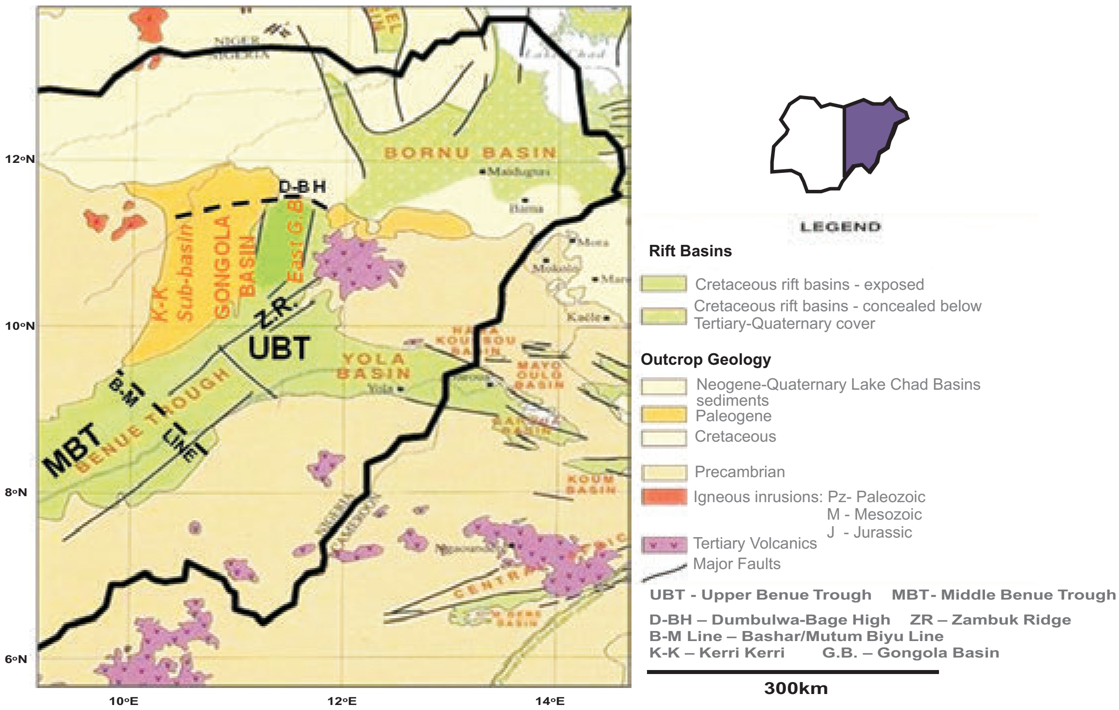


Fig. 1: Generalized Geology of the northeastern Nigerian sedimentary basins showing Gongola and Bornu Basins.

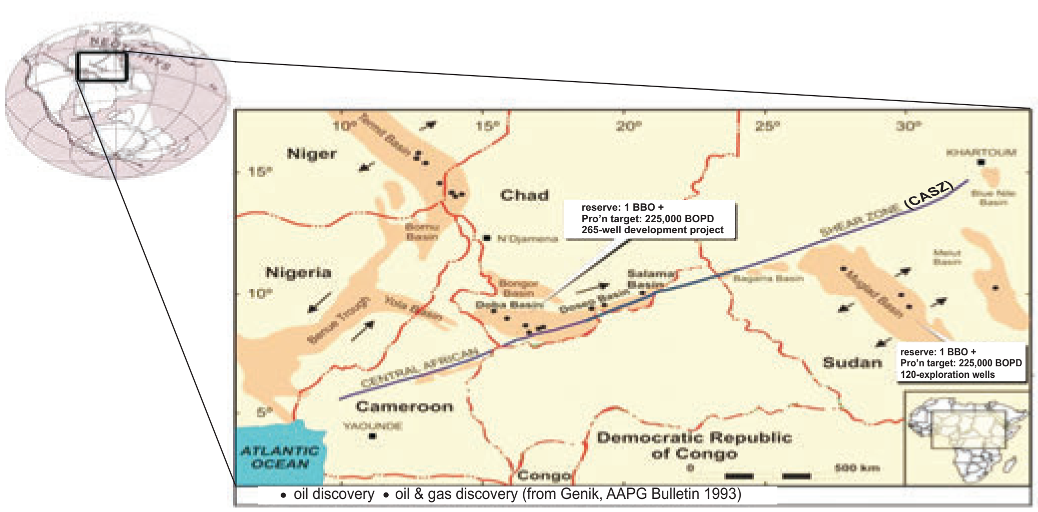


Fig. 2: West and Central African Rift System showing the locations of oil and gas discoveries (from United Reef Limited Report, 2004).

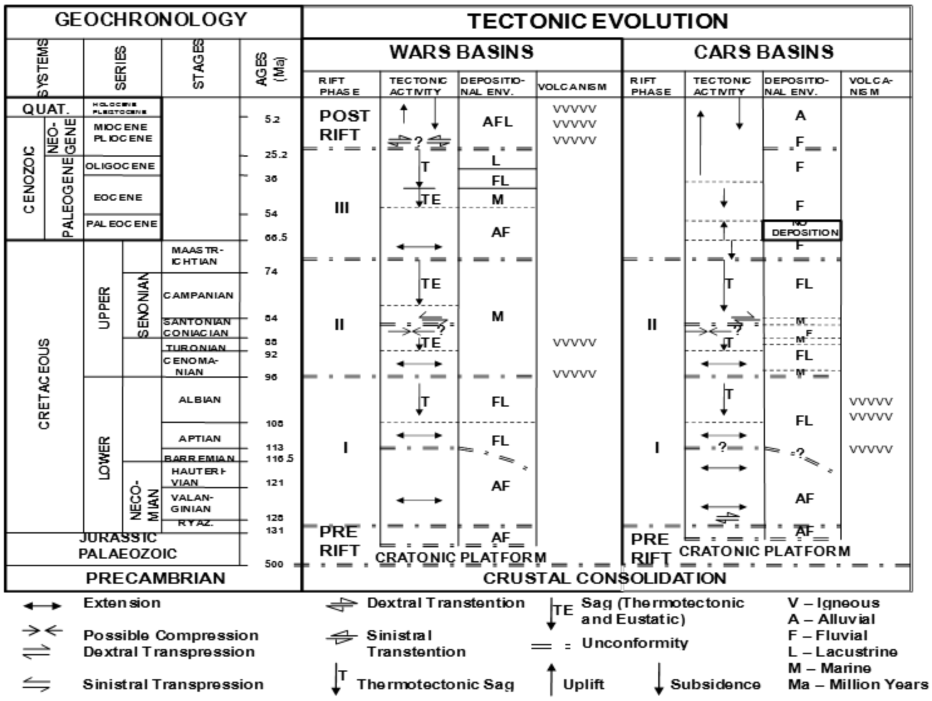


Fig. 3: Tectonic Framework of the WCARS basins (including the Gongola and Bornu Basins) (modified from Genik, 1993).

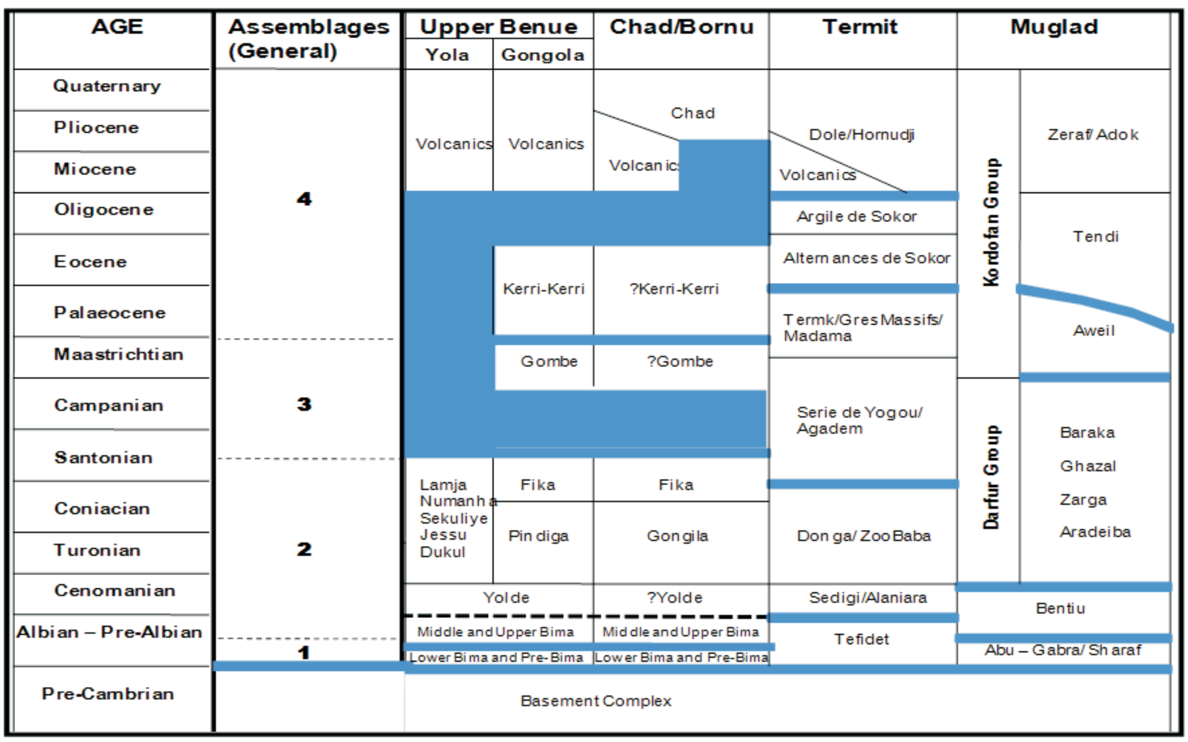


Fig. 4: Generalized stratigraphic successions in the Upper Benue Trough, Bornu, Termit and Muglad Basin.

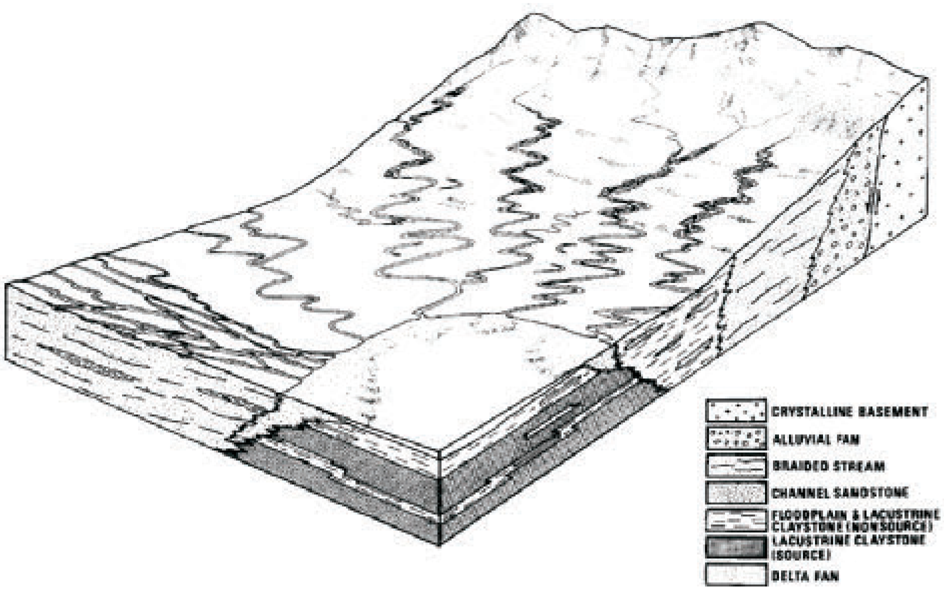


Fig. 5: Generalized depositional model of the lower part of the Bima Formation (adapted from Schull,1988).

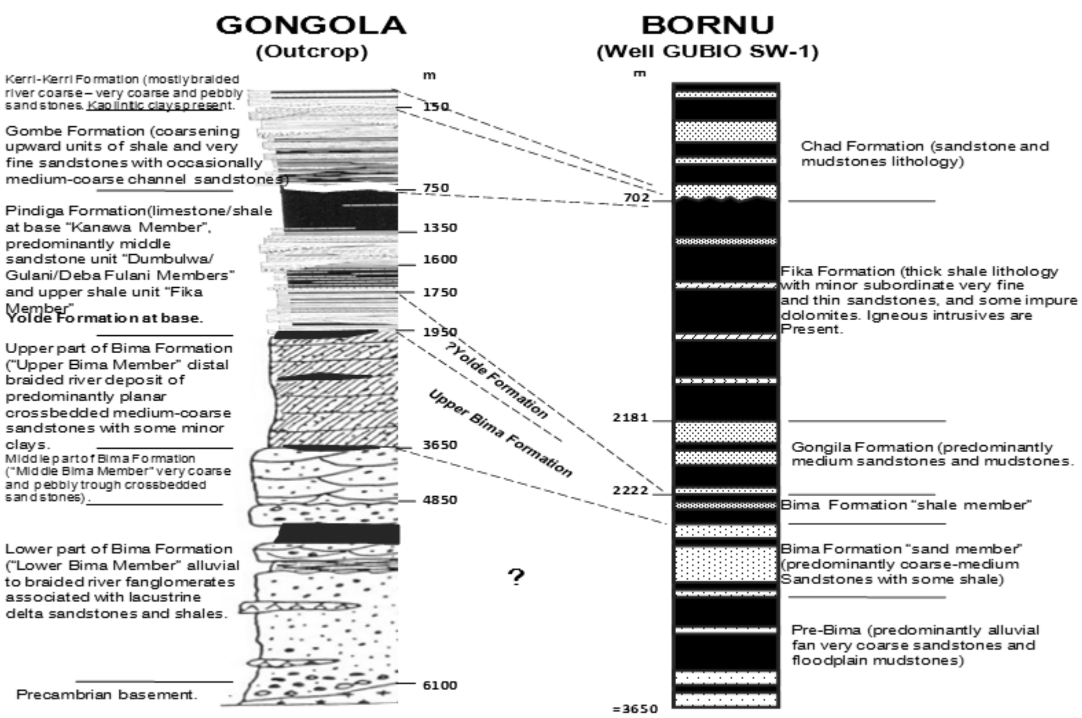


Fig. 6: Composite stratigraphic sections of the Gongola and Bornu Basins showing correlations (Gongola section modified from Zaborski, 2003 and Rebelle, 1990).

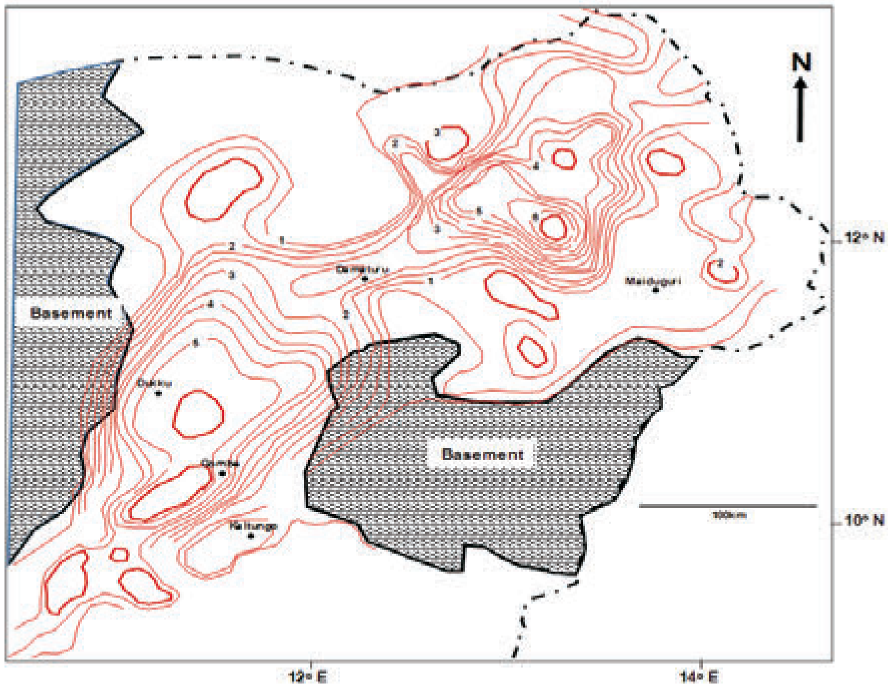


Fig. 7: Isobath map (contours in Km below sea level) in the Gongola and Bornu Basins deduced from magnetic data (modified from Benkhelil et al.,1989).

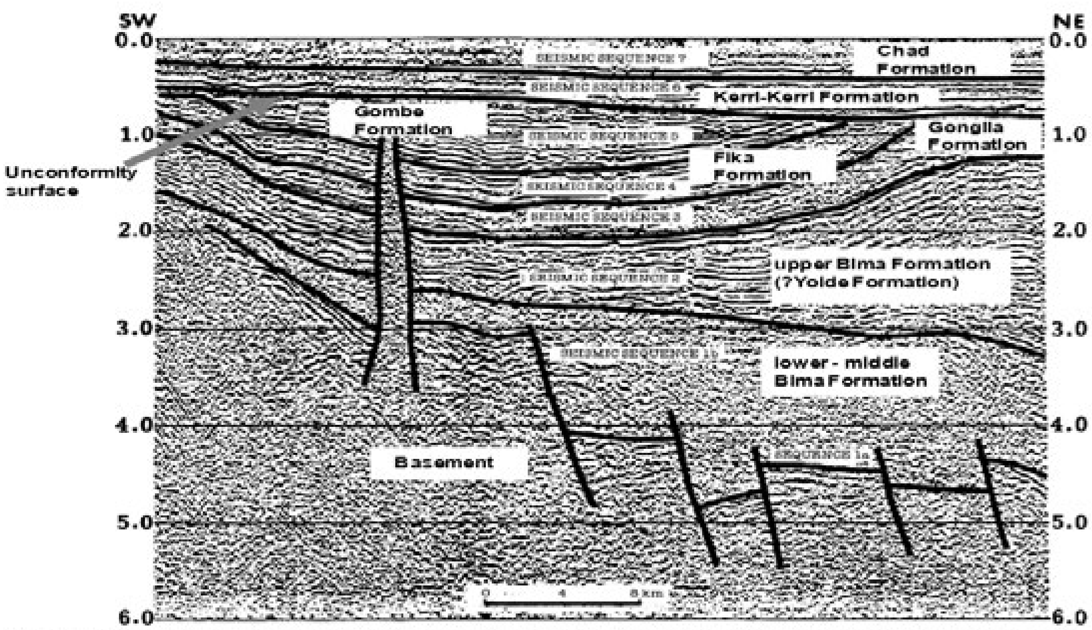


Fig. 8: Typical seismic section showing various stratigraphic intervals in Bornu Basin. Note the unconformity beneath the Kerri-Kerri Formation (from Avbovbo et al., 1986).

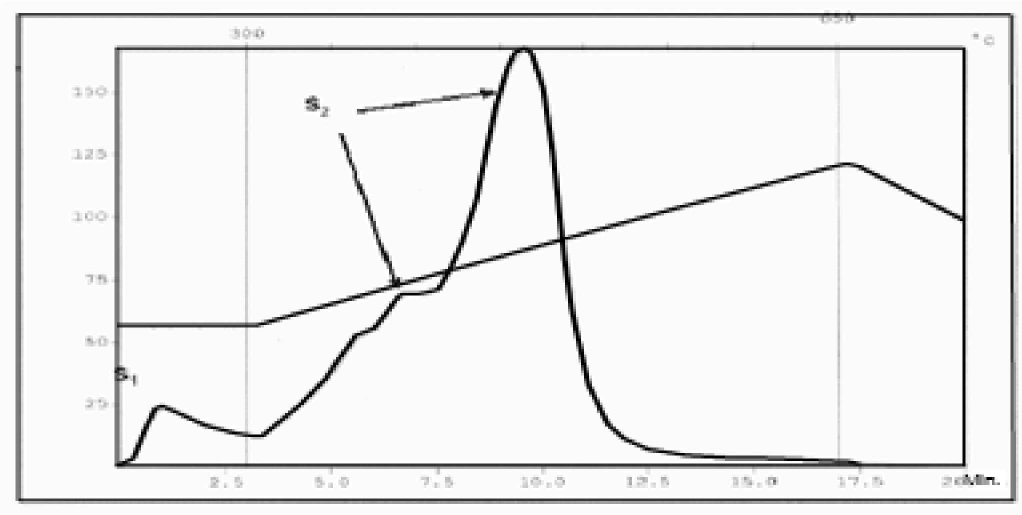


Fig. 9: A pyrogram of sample NAS 53 showing bimodal S_2 peak

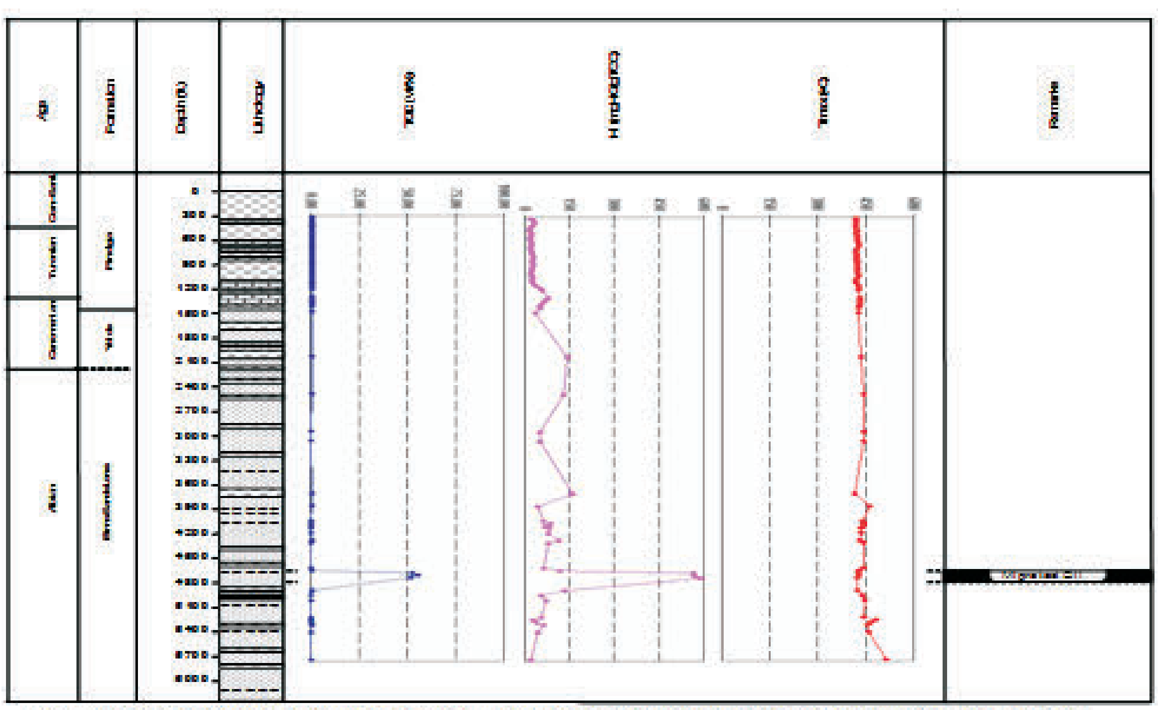


Fig. 10: The stratigraphy of the well Nasara-1 showing TOC, HI and Tmax variation with depth and the interval of possible migrated oil.

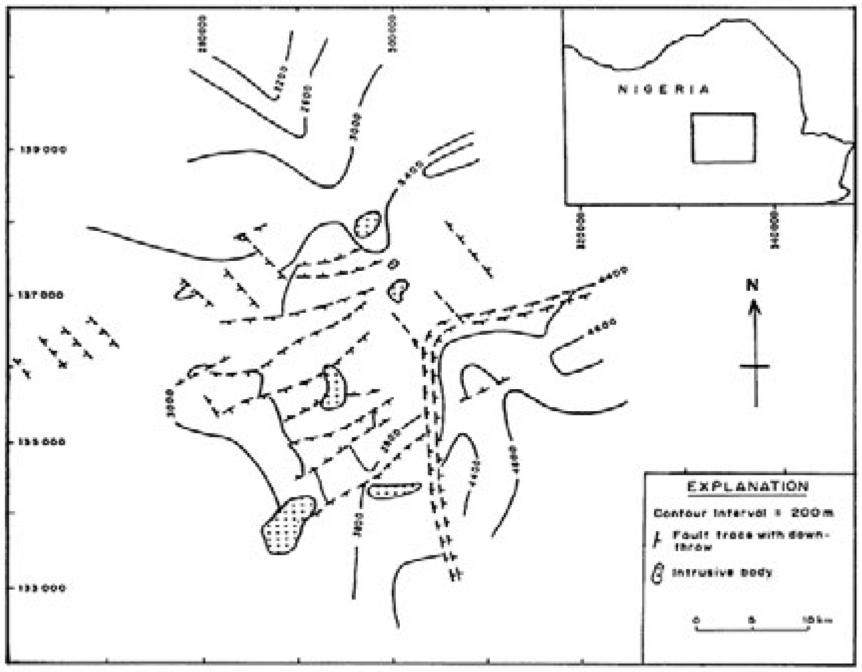


Fig. 11: Major NE-SW and associated NNW-SSE structural trends in the Bornu Basin (from Avbovbo et al., 1986).

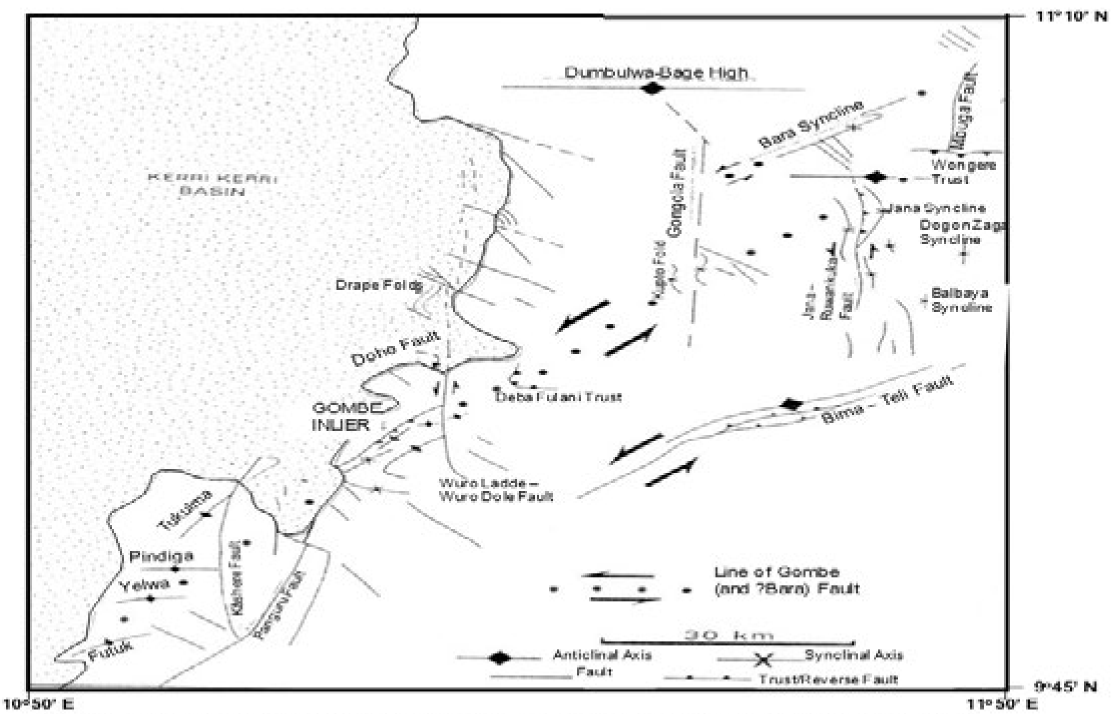


Fig. 12: Major NE-SW and associated NNW-SSE structural trends in the Gongola Basin (from Zaborski, 1998)

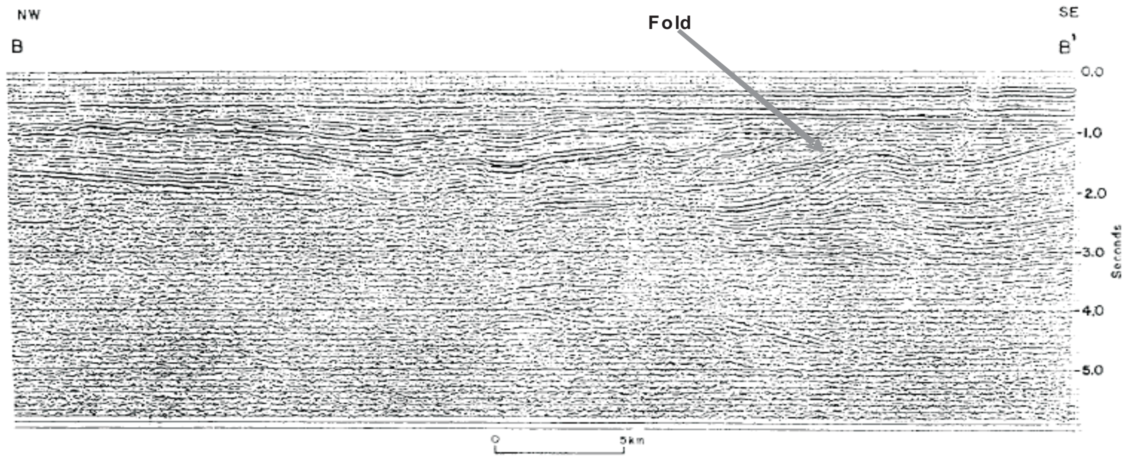
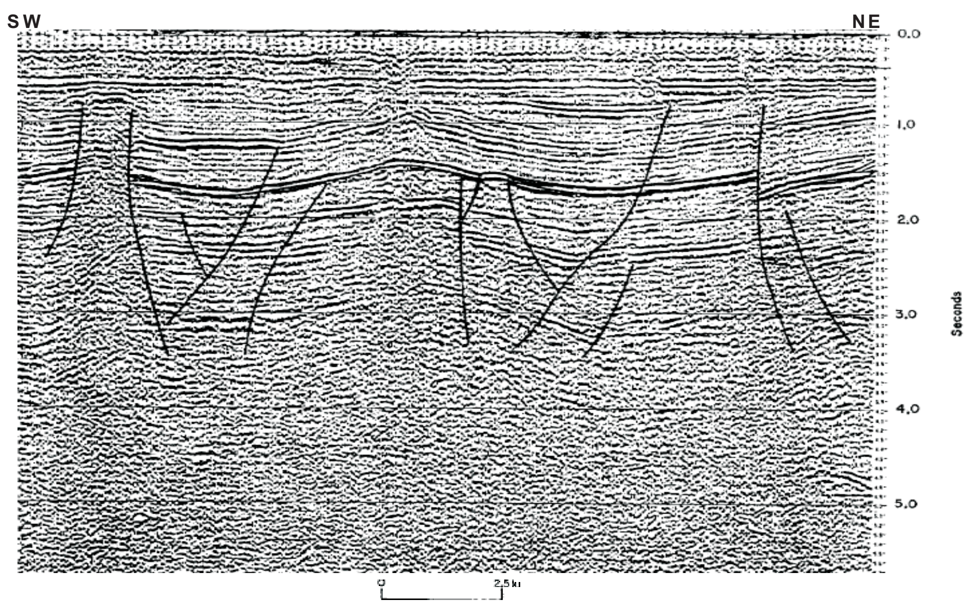


Fig. 13: Seismic section from the Bornu Basin showing amplitude of folds increasing basinward (towards the central part) (from Avbovbo et al., 1986).



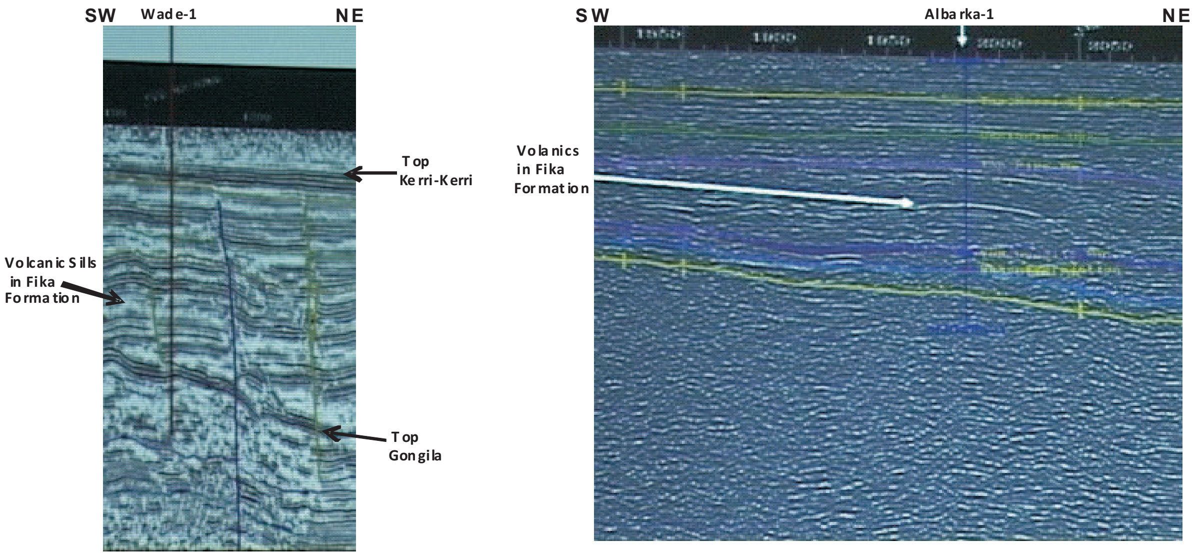


Fig. 15: Seismic sections from Bornu Basin showing wells targetting "Bright Spots" related to volcanic plugs and sills.

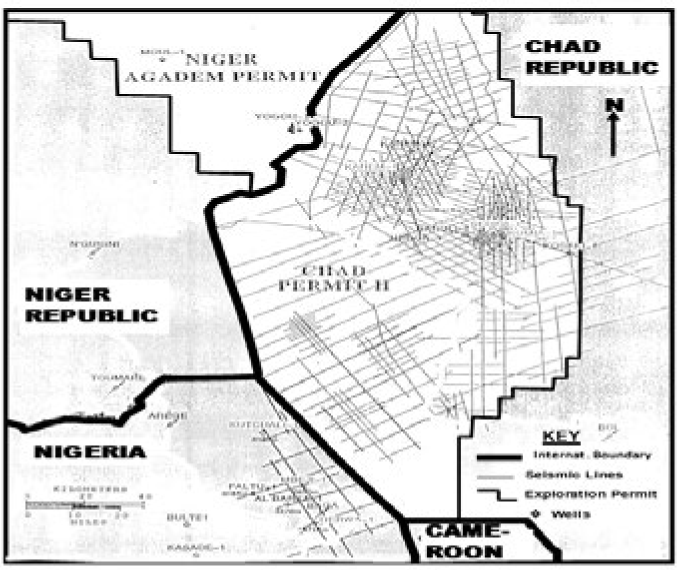


Fig. 16: 2-D Seismic Density in Bornu Basin, Nigeria and Termit Basin, Chad Republic (from Lake Chad Data Trade).

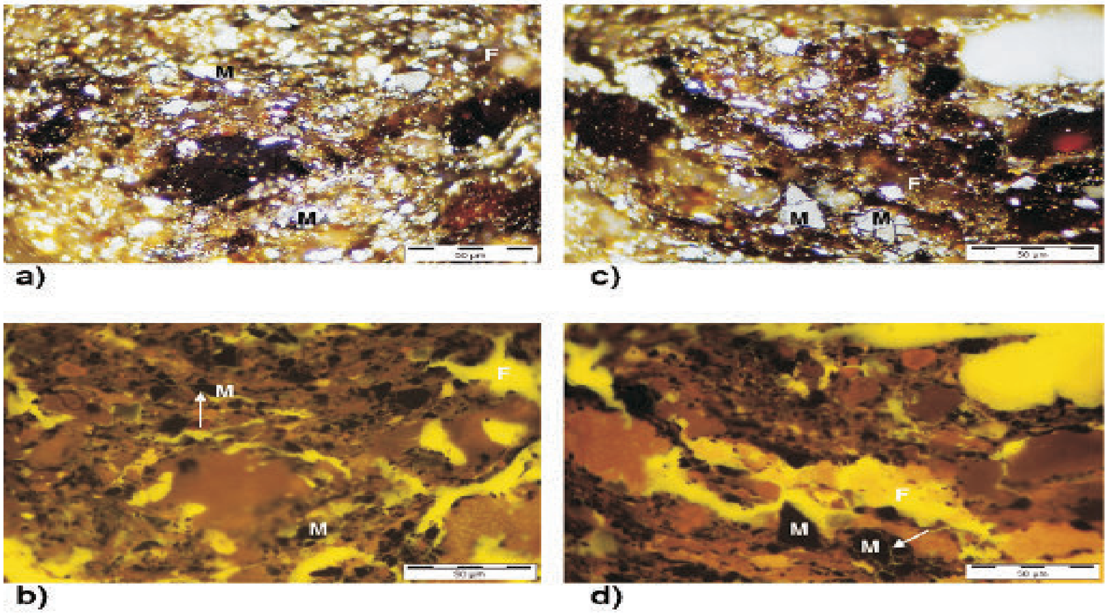


Plate 1: Maceral composition of sample NAS 53 under reflected white light (upper) and fluorescent light (lower). (F) Fluorinite perhaps associated with exsudatinite; (M) mineral matter, mainly quartz and clays. Note the infilling (arrow) of the fractures of the mineral matter by fluorinite in (c) and (d).

Table 1: Petroleum discovery wells in Niger and Chad Republics showing stratigraphic levels and rock types of reservoirs and the associated petroleum system (data from Genik, 1993).

Country	Basin	Well Name	Year Drilled	Total Depth (TD) (m)	Age at TD	Rock Type	Results	Petroleum System
Niger	Termit	Sokor-4	1984	1870	Eocene	Continental Clastics	Oil	Palaeogene
"	"	Sokor-2	1983	1895	"	"	"	"
"	"	Goumeri-1	1990	3280	Palaeocene	Continental Sandstone	Oil and Gas	"
"	"	Sokor-1	1982	2470	Maastrichtian	"	Oil	Upper Cretaceous
"	"	Madama-1	1975	3810	Santonian	Marine Clastics	"	"
Chad	"	Sedigi-2	1989	3048	Senonian	Marine Sandstone	Oil and Gas	"
Niger	"	Yogou-1	1979	3995	Coniacian	Marine Clastics	Oil	"
Chad	"	Kanem-1	1974	3726	"	Marine Sandstone	"	"
"	"	Sedigi-1	1975	3682	Cen. - Tur.	Marine Clastics	Oil and Gas	Lower Cretaceous
"	Doba	Kome-4	1989	1981	Cenomanian	Continental Sandstone	Oil	"
"	"	Kome-3	1989	3657	Albian	Continental Clastics	"	"
"	"	Kome-2	1985	1981	"	"	"	"
"	"	Kome-1	1976	3055	"	Continental Sandstone	"	"
"	Termit	Kumia-1	1976	4272	Albian-Aptian	Continental Clastics	"	"
"	Doba	Miandoum-1	1974	3572	"	Continental Sandstone	"	"
"	"	Bolobo-1	1989	4095	Aptian	"	"	"
"	Doseo	Kibea-1	1986	3112	"	Continental Clastics	"	"
"	"	Maku-1	1985	2056	"	"	Oil and Gas	"
"	"	Tega-1	1979	3356	"	"	Oil	"
"	Doba	Belanga-1	1978	3574	"	"	"	"
"	"	Mangara-1	1978	3234	"	Continental Sandstone	"	"

Table 2: Rock Eval pyrolysis data of samples from Lower Cretaceous - Cenomanian sediments of the northeastern Nigerian Basins.

S/N	Sample Name	Sample Locality	Basin/Sub-basin	Formation/Lithology	Age	TOC	S1	S2	S3	Tmax	HI	OI	PI	Source
1	KAN-22	Kanadi Well	Chad	Bima (?Gongila/?Yolde)/Shale	?Albian-Cenomanian (?Middle)	0.62	0.05	0.07	0.39	467.00	11.00	63.00	0.42	Olugbemiro, 1997
2	KAN-23	"	"	"	"	0.72	0.16	0.30	0.62	472.00	41.00	86.00	0.35	"
3	KAN-24	"	"	"	"	0.71	0.08	0.15	0.44	475.00	21.00	62.00	0.35	"
4	KAN-25	"	"	"	"	0.55	0.18	0.22	0.34	477.00	40.00	61.00	0.45	"
5	KAN-26	"	"	"	"	0.71	0.35	0.24	0.43	480.00	34.00	61.00	0.59	"
6	KAN-27	"	"	"	"	0.68	0.32	0.36	0.45	482.00	52.00	66.00	0.47	"
7	KAN-28	"	"	"	"	0.56	0.28	0.35	0.43	485.00	62.00	76.00	0.44	"
8	KAN-29	"	"	"	"	0.22	0.23	0.25	0.59	488.00	113.00	272.00	0.48	"
9	KIN-24	Kinasar Well	"	Bima (?Yolde)/Shale	"	0.51	0.15	0.22	0.19	517.00	43.00	37.00	0.41	"
10	KIN-25	"	"	"	"	0.27	0.11	0.08	0.06	522.00	30.00	22.00	0.58	"
11	KIN-26	"	"	"	"	0.45	0.61	0.58	0.57	526.00	129.00	127.00	0.51	"
12	KIN-27	"	"	"	"	0.35	0.68	0.48	0.37	530.00	137.00	106.00	0.59	"
13	KIN-28	"	"	"	"	0.45	0.67	0.60	0.58	532.00	133.00	129.00	0.53	"
14	KIN-29	"	"	"	"	1.00	0.93	1.00	0.70	538.00	100.00	70.00	0.48	"
15	KIN-30	"	"	"	"	0.21	0.45	0.38	0.14	542.00	181.00	67.00	0.54	"
16	KIN-31	"	"	"	"	0.28	0.40	0.40	0.22	548.00	143.00	79.00	0.50	"
17	KIN-32	"	"	"	"	0.58	0.96	0.71	0.73	555.00	122.00	126.00	0.57	"
18	KIN-33	"	"	"	"	2.09	3.27	9.09	0.37	556.00	435.00	18.00	0.26	"
19	KIN-34	"	"	"	"	0.34	1.37	0.46	0.30	560.00	135.00	88.00	0.75	"
20	KIN-35	"	"	"	"	0.42	1.29	0.57	0.42	564.00	136.00	100.00	0.69	"
21	KIN-36	"	"	"	"	0.61	2.36	0.88	0.58	571.00	144.00	95.00	0.73	"
22	KIN-37	"	"	"	"	0.67	2.11	0.95	0.60	575.00	142.00	90.00	0.69	"
23	KIN-38	"	"	"	"	1.23	2.28	2.12	1.59	578.00	172.00	129.00	0.52	"
24	KIN-39	"	"	"	"	1.18	3.08	1.76	1.25	581.00	149.00	106.00	0.64	"
25	KIN-40	"	"	"	"	0.72	2.88	1.04	0.81	586.00	144.00	112.00	0.73	"
26	KIN-41	"	"	"	"	2.82	4.01	4.03	3.71	591.00	143.00	132.00	0.50	"
27	NA10	N. Borehole (GSN1612)	UBT/Gongola	Yolde/Shale	Pre-to M. Cenomanian	0.56	0.03	0.24		442.00	48.00		0.89	Akande et al., 1998
28	NA12	"	"	"	"	12.90	4.48	22.00		438.00	171.00		0.83	"
29	NA17	"	"	"	"	0.33	0.01	0.09		437.00	27.00		0.90	"
30	NA22	"	"	"	"	0.89	0.06	0.49		437.00	55.00		0.89	"
31	NA23	"	"	"	"	0.58	0.02	0.28		438.00	48.00		0.93	"
32	NA25	"	"	"	"	0.39	0.01	0.20		442.00	55.00		0.95	"
33	NA27	"	"	"	"	0.10	0.00	0.11		0.00	30.00		1.00	"
34	NA29	"	"	"	"	0.21	0.02	0.09		0.00	42.00		0.82	"
35	YOLD2	Futuk	"	"	"	0.35	0.01	0.11	0.12	438.00	31.00	34.00	0.92	Obaje et al., 2004a
36	YOLD4	"	"	"	"	0.30	0.01	0.08	0.19	437.00	26.00	63.00	0.89	"
37	Nas-35	Well Nasara-1	"	Bima/Shale	"	0.59	0.02	0.31	0.52	427.00	52.00	88.00	0.94	Abubakar et al., 2008
38	Nas-36	"	"	"	"	0.69	0.02	0.24	0.52	428.00	35.00	75.00	0.92	"
39	Nas-37	"	"	"	"	0.87	0.05	1.23	0.44	437.00	142.00	51.00	0.96	"
40	Nas-38	"	"	"	"	0.55	0.02	0.70	0.52	442.00	128.00	95.00	0.97	"
41	MYS3	Gombe	"	"	"	0.21	0.01	0.13	0.51	424.00	62.00	242.00	0.93	"
42	Nas-39	Well Nasara-1	"	"	"	0.24	0.01	0.12	0.48	445.00	50.00	201.00	0.92	"
43	Nas-40	"	"	"	"	0.25	0.00	0.13	0.39	445.00	52.00	156.00	1.00	"
44	Nas-42	"	"	"	"	0.38	0.07	0.61	0.76	414.00	160.00	199.00	0.90	"
45	Nas-43	"	"	"	"	0.49	0.02	0.21	0.41	463.00	43.00	84.00	0.91	"
46	Nas-44	"	"	"	"	0.17	0.01	0.11	0.45	441.00	63.00	259.00	0.92	"
47	Nas-45	"	"	"	"	0.30	0.02	0.26	0.55	442.00	86.00	182.00	0.93	"
48	Nas-46	"	"	"	"	0.23	0.02	0.15	0.62	443.00	65.00	270.00	0.88	"
49	Nas-47	"	"	"	"	0.21	0.01	0.17	0.49	435.00	81.00	233.00	0.94	"
50	Nas-48	"	"	"	"	0.21	0.02	0.17	0.43	437.00	79.00	201.00	0.89	"
51	Nas-49	"	"	"	"	0.35	0.02	0.39	0.52	432.00	113.00	151.00	0.95	"
52	Nas-50	"	"	"	"	0.13	0.02	0.10	0.35	444.00	78.00	273.00	0.83	"
53	Nas-51	"	"	"	"	0.13	0.01	0.08	0.30	444.00	61.00	229.00	0.89	"
54	**Nas-52**	"	"	"	"	0.33	0.06	0.39	0.48	426.00	119.00	146.00	0.87	"
55	**Nas-53**	"	"	**Bima/Sand**	"	**52.70**	20.56	297.44	10.13	**427.00**	**564.00**	19.00	0.94	"
56	**Nas-54**	"	"	**"**	"	**55.20**	22.60	314.29	11.18	**428.00**	**569.00**	20.00	0.93	"
57	Nas-55	"	"	**"**	"	**52.10**	18.10	306.91	10.87	**423.00**	**589.00**	21.00	0.94	"
58	Nas-56	"	"	Bima/Shale	"	0.51	0.04	0.68	0.48	425.00	134.00	94.00	0.94	"
59	Nas-57	"	"	"	"	0.18	0.01	0.10	0.45	440.00	56.00	253.00	0.91	"
60	Nas-58	"	"	"	"	0.30	0.01	0.21	0.37	446.00	70.00	124.00	0.95	"
61	Nas-59	"	"	"	"	0.15	0.00	0.08	0.36	444.00	54.00	242.00	1.00	"
62	Nas-60	"	"	"	"	0.25	0.00	0.07	0.36	484.00	28.00	145.00	1.00	"
63	Nas-61	"	"	"	"	0.21	0.00	0.08	0.38	466.00	38.00	182.00	1.00	"
64	Nas-62	"	"	"	"	0.37	0.06	0.23	0.43	456.00	62.00	116.00	0.79	"
65	Nas-63	"	"	"	"	0.10	0.01	0.04	0.38	457.00	42.00	399.00	0.80	"
66	Nas-64	"	"	"	"	0.29	0.00	0.06	0.30	514.00	21.00	104.00	1.00	"

Table 3: TOC and extract composition of oil stained samples from the Bima Formation in well Nasara-1.

Sample Name	Sample Type	Locality	Formation	Lithology	TOC (wt%)	Extract (mg/g)	Extract (ppm)	Extract (mg/gTOC)	Saturate (%)	Aromatics (%)	Heteropolar (%)
NAS53	Oil Stained Sand	Nasara-1 Well	Bima	Sands	52.70	235.74	235740	239.86	14.90	5.70	74.90
NAS54	"	"	"	"	55.20	237.19	237190	447.33	16.30	5.10	78.70
NAS55	"	"	"	"	52.10	187.58	187580	429.70	13.20	5.50	81.30
NAS56	Borehole Cuttings	"	"	Shales	0.51	0.69	690	360.04	n.i.	n.i.	n.i.

NOTE: n.i. = not investigated

Table 4: Extended hopane distribution of samples from 4710-4770ft in well Nasara-1

Sample Name	Sample Type	Locality	Formation	Lithology	H31R/H30
NAS53	Oil stained cuttings	Well Nasara-1	Bima	Sands	0.19
NAS 54	"	"	"	"	0.25
NAS53	"	"	"	"	0.27

Table 5:Rock Eval pyrolysis data of samples from Uower Cretaceous sediments of the northeastern Nigerian Basins.

S/N	Sample Name	Sample Locality	Basin/Sub-basin	Formation/Lithology	Age	TOC	S1	S2	S3	Tmax	HI	OI	PI	Source
1	KM3	K/Borehole (GSN4041)	UBT/Gongola	Gombe/Shale	Campanian - Maastrichtian	1.46	0.03	0.96		433.00	65.00		0.97	Akande et al., 1998
2	KM4	"	"	"	"	1.20	0.01	0.27		422.00	22.00		0.96	"
3	GMC1	H/Gari	"	"	"	0.55	0.02	0.10		418.00	18.00		0.83	Obaje et al., 1999
4	GMC7	"	"	"	"	0.25	0.01	0.10		418.00	0.00		0.91	"
5	GMC14	"	"	"	"	0.20	0.01	0.00		418.00	0.00		0.00	"
6	UBHJ1	"	"	"	"	0.92	0.01	0.03	0.47	282.00	3.00	51.00	0.75	Obajeet al., 2004a
7	UBHJ2	"	"	"	"	0.83	0.01	0.03	0.47	300.00	4.00	57.00	0.75	"
8	UBHJ3	"	"	"	"	0.96	0.01	0.03	0.43	502.00	3.00	45.00	0.75	"
9	UBHJ4	"	"	Gombe/Coaly Shales	"	1.05	0.01	0.03	0.37	310.00	3.00	35.00	0.75	Abubakar et al., 2008
10	UBWJ1	W/Sale	"	"	"	1.26	0.01	0.05	0.67	515.00	4.00	53.00	0.83	Obajeet al., 2004a
11	UBWJ2	"	"	"	"	2.63	0.01	0.06	2.60	511.00	2.00	99.00	0.86	"
12	UBDJ1	D/Borehole	"	"	"	6.84	0.13	12.01	5.08	429.00	176.00	74.00	0.99	Abubakar et al., 2008
13	MGMC3	"	"	"	"	3.43	0.08	9.62	1.58	432.00	280.00	46.00	0.99	"
14	UBDJ2	"	"	Gombe/Shaly Coal	"	20.20	0.62	35.95	10.53	423.00	178.00	52.00	0.98	"
15	CP8	G. Maiganga/Borehole	"	"	"	14.90	0.79	18.19	11.30	435.00	122.08	75.84	0.96	"
16	CP13	"	"	"	"	23.70	0.80	32.60	14.77	423.00	137.55	62.32	0.98	"
17	FKS5	Nafada	UBT/Gongola	U.Pindiga/Shale	Cenomanian(Upper) - Santonian	0.05	0.03	0.09		591.00	180.00		0.75	Obaje et al., 1999
18	FKS9	"	"	"	"	0.05	0.04	0.09		586.00	180.00		0.69	"
19	FKS11	"	"	"	"	0.04	0.03	0.06		584.00	150.00		0.67	"
20	FKS14	"	"	"	"	0.39	0.02	0.02		445.00	5.00		0.50	"
21	KM9	K/Borehole (GSN4041)	"	Pindiga/Shale	"	2.45	0.02	1.88		435.00	76.00		0.99	Akande et al., 1998
22	KM11	"	"	"	"	1.63	0.01	0.22		415.00	13.00		0.96	"
23	KM13	"	"	"	"	1.56	0.01	0.31		416.00	19.00		0.97	"
24	KM16	"	"	"	"	0.60	0.00	0.09		423.00	15.00		1.00	"
25	KM17	"	"	"	"	0.74	0.02	0.10		422.00	13.00		0.83	"
26	KM18	"	"	"	"	0.39	0.00	0.04		426.00	10.00		1.00	"
27	KM19	"	"	"	"	0.28	0.01	0.04		0.00	14.00		0.80	"
28	KM21	"	"	"	"	0.65	0.00	0.09		425.00	13.00		1.00	"
29	KM23	"	"	"	"	0.54	0.01	0.05		419.00	9.00		0.83	"
30	KM25	"	"	"	"	0.21	0.01	0.11		0.00	0.00		0.92	"
31	GB 1	G/Borehole(GSN1504)	"	"	"	0.57	0.01	0.09		426.00	15.00		0.90	"
32	GB 3	"	"	"	"	0.60	0.02	0.10		423.00	24.00		0.83	"
33	GB 6	"	"	"	"	0.35	0.00	0.08		428.00	22.00		1.00	"
34	GB 8	"	"	"	"	0.46	0.03	0.08		421.00	17.00		0.73	"
35	GB 10	"	"	"	"	0.47	0.01	0.08		422.00	23.00		0.89	"
36	GB 13	"	"	"	"	0.49	0.02	0.18		424.00	36.00		0.90	"
37	GB 14	"	"	"	"	0.45	0.01	0.07		419.00	16.00		0.88	"
38	GB 16	"	"	"	"	0.32	0.01	0.07		425.00	21.00		0.88	"
39	GB 17	"	"	"	"	0.48	0.01	0.14		419.00	29.00		0.93	"
40	GB 19	"	"	"	"	0.43	0.01	0.07		419.00	16.00		0.88	"
41	GB 21	"	"	"	"	0.42	0.02	0.08		425.00	19.00		0.80	"
42	GB 22	"	"	"	"	0.40	0.00	0.15		420.00	37.00		1.00	"
43	GB 26	"	"	"	"	0.38	0.01	0.15		423.00	39.00		0.94	"
44	GB 28	"	"	"	"	0.46	0.02	0.14		424.00	30.00		0.88	"
45	GB 31	"	"	"	"	0.40	0.01	0.11		424.00	27.00		0.92	"
46	AS1	AshakaQuarry	"	"	"	0.41	0.00	0.10		423.00	24.00		1.00	"
47	AS2	"	"	"	"	0.26	0.00	0.04		431.00	15.00		1.00	"
48	DA 7	Pindiga	"	"	"	2.13	0.07	0.73		424.00	34.00		0.91	Obaje et al., 1999
49	DA 11	"	"	"	"	2.08	0.07	0.63		423.00	32.00		0.90	"
50	DA 12	"	"	"	"	1.94	0.05	0.32		419.00	16.00		0.86	"
51	GGS3	AshakaQuarry	"	"	"	0.52	0.01	0.09		418.00	17.00		0.90	"
52	GGS12	"	"	"	"	0.50	0.02	0.10		419.00	20.00		0.83	"
53	GGS13	"	"	"	"	0.51	0.02	0.07		418.00	14.00		0.78	"
54	GGL16	"	"	"	"	0.10	0.01	0.02		483.00	20.00		0.67	"
55	GGS17	"	"	"	"	0.57	0.04	0.19		417.00	33.00		0.83	"

S/N	Sample Name	Sample Locality	Basin/Sub-basin	Formation/Lithology	Age	TOC	S1	S2	S3	Tmax	HI	OI	PI	Source
56	GGS21	AshakaQuarry	UBT/Gongola	Pindiga/Shale	Cenomanian (Upper) - Santonian	0.46	0.02	0.05		416.00	11.00		0.71	Obaje et al., 1999
57	PIND10	Pindiga	"	"	"	0.71	0.02	0.22	0.36	418.00	31.00	51.00	0.92	Obaje et al., 2004a
58	GONG1	AshakaQuarry	"	"	"	0.59	0.02	0.12	0.35	419.00	20.00	60.00	0.86	"
59	GONG2	"	"	"	"	0.52	0.01	0.09	0.26	420.00	17.00	50.00	0.90	"
60	GONG3	"	"	"	"	0.53	0.01	0.08	0.32	417.00	15.00	61.00	0.89	"
61	GONG4	"	"	"	"	0.55	0.02	0.14	0.33	421.00	26.00	61.00	0.88	"
62	Nas-1	Well Nasara-1	"	"	"	0.67	0.01	0.12	0.40	419.00	18.00	60.00	0.92	Abubakar et al., 2008
63	Nas-2	"	"	"	"	0.87	0.02	0.29	0.67	420.00	33.00	77.00	0.94	"
64	Nas-3	"	"	"	"	0.65	0.01	0.20	0.31	420.00	31.00	48.00	0.95	"
65	Nas-4	"	"	"	"	0.63	0.01	0.14	0.41	420.00	22.00	65.00	0.93	"
66	Nas-5	"	"	"	"	0.55	0.01	0.08	0.34	421.00	15.00	62.00	0.89	"
67	Nas-6	"	"	"	"	0.51	0.01	0.08	0.34	423.00	16.00	67.00	0.89	"
68	Nas-7	"	"	"	"	0.64	0.01	0.16	0.36	421.00	25.00	57.00	0.94	"
69	Nas-8	"	"	"	"	0.58	0.01	0.11	0.34	423.00	19.00	59.00	0.92	"
70	Nas-9	"	"	"	"	0.66	0.01	0.10	0.25	424.00	15.00	38.00	0.91	"
71	Nas-10	"	"	"	"	0.58	0.01	0.11	0.38	424.00	19.00	65.00	0.92	"
72	Nas-11	"	"	"	"	0.46	0.01	0.10	0.36	427.00	22.00	78.00	0.91	"
73	Nas-12	"	"	"	"	0.45	0.00	0.08	0.37	426.00	18.00	82.00	1.00	"
74	Nas-13	"	"	"	"	0.51	0.01	0.10	0.34	424.00	20.00	67.00	0.91	"
75	Nas-14	"	"	"	"	0.56	0.01	0.13	0.57	420.00	23.00	102.00	0.93	"
76	Nas-15	"	"	"	"	0.57	0.01	0.14	0.44	421.00	24.00	77.00	0.93	"
77	Nas-16	"	"	"	"	0.55	0.01	0.15	0.56	424.00	27.00	102.00	0.94	"
78	Nas-17	"	"	"	"	0.59	0.01	0.15	0.39	420.00	26.00	66.00	0.94	"
79	Nas-18	"	"	"	"	0.53	0.01	0.13	0.57	424.00	25.00	108.00	0.93	"
80	Nas-19	"	"	"	"	0.48	0.01	0.14	0.47	423.00	29.00	98.00	0.93	"
81	Nas-20	"	"	"	"	0.50	0.01	0.14	0.47	423.00	28.00	93.00	0.93	"
82	Nas-21	"	"	"	"	0.44	0.01	0.10	0.35	424.00	23.00	79.00	0.91	"
83	Nas-22	"	"	"	"	0.44	0.01	0.11	0.46	424.00	25.00	104.00	0.92	"
84	Nas-23	"	"	"	"	0.45	0.01	0.09	0.31	425.00	20.00	69.00	0.90	"
85	Nas-24	"	"	"	"	0.40	0.01	0.09	0.37	426.00	22.00	92.00	0.90	"
86	Nas-25	"	"	"	"	0.54	0.01	0.14	0.55	422.00	26.00	102.00	0.93	"
87	Nas-26	"	"	"	"	0.59	0.01	0.14	0.31	419.00	24.00	53.00	0.93	"
88	Nas-27	"	"	"	"	0.59	0.01	0.17	0.51	420.00	29.00	86.00	0.94	"
89	Nas-28	"	"	"	"	0.46	0.01	0.16	0.51	426.00	35.00	110.00	0.94	"
90	Nas-29	"	"	"	"	0.50	0.02	0.26	0.48	429.00	52.00	96.00	0.93	"
91	Nas-30	"	"	"	"	0.53	0.02	0.30	0.55	427.00	57.00	104.00	0.94	"
92	Nas-31	"	"	"	"	0.75	0.03	0.58	0.40	430.00	77.00	53.00	0.95	"
93	Nas-32	"	"	"	"	0.71	0.03	0.48	0.53	433.00	68.00	75.00	0.94	"
94	Nas-33	"	"	"	"	0.58	0.03	0.33	0.63	432.00	57.00	108.00	0.92	"
95	Nas-34	"	"	"	"	0.59	0.01	0.29	0.45	433.00	50.00	77.00	0.97	"
96	MPS20	Pindiga water borehole	"	"	"	0.30	0.06	0.08	0.31	421.00	26.00	102.00	0.57	"
97	MPS50	"	"	"	"	0.57	0.02	0.20	0.34	421.00	35.00	60.00	0.91	"
98	MPS63	"	"	"	"	0.52	0.02	0.20	0.27	417.00	38.00	52.00	0.91	"
99	MPS70	"	"	"	"	0.47	0.01	0.15	0.28	419.00	32.00	59.00	0.94	"
100	MPS72	Gombe	"	"	"	0.64	0.02	0.21	0.33	421.00	33.00	52.00	0.91	"
101	MPS77	Balbaya	"	"	"	0.23	0.01	0.02	0.32	476.00	9.00	139.00	0.67	"
102	MGS5	AshakaQuarry	"	"	"	0.42	0.01	0.06	0.34	421.00	14.00	81.00	0.86	"
103	MGS2	"	"	"	"	0.50	0.01	0.11	0.22	423.00	22.00	44.00	0.92	"
104	MGS1	"	"	Pindiga/Calcareous Shale	"	0.37	0.01	0.15	0.64	425.00	40.00	171.00	0.94	"
105	KIN-3	Kinasar Well	Chad	Fika/Shale	Cenomanian (Upper) - Santonian	0.95	0.04	0.47	0.61	429.00	49.00	64.00	0.08	Olugbemiro, 1997
106	KIN-4	"	"	"	"	0.75	0.05	0.42	0.72	428.00	56.00	96.00	0.11	"
107	KIN-5	"	"	"	"	0.77	0.04	0.19	0.48	429.00	25.00	62.00	0.17	"
108	KIN-6	"	"	"	"	1.14	0.08	0.77	0.42	434.00	67.00	36.00	0.09	"
109	KIN-7	"	"	"	"	0.92	0.07	0.46	0.49	432.00	50.00	53.00	0.13	"
110	KIN-8	"	"	"	"	0.54	0.04	0.14	0.46	435.00	25.00	85.00	0.22	"
111	KIN-9	"	"	"	"	1.57	0.45	1.67	0.62	440.00	106.00	39.00	0.21	"
112	KIN-10	"	"	"	"	1.01	0.23	0.85	0.64	443.00	84.00	63.00	0.21	"

REFERENCES

Abubakar, M.B. (2006). "Biostratigraphy, palaeoenvironment and organic geochemistry of the Cretaceous sequences of the Gongol Basin, Upper Benue Trough, Nigeria." Unpubl. Ph.D Thesis, Abubakar Tafawa Balewa University, Bauchi, Nigeria, 294pp.

Abubakar, M.B., Obaje, N.G., Luterbacher, H.P., Dike, E.F.C., Ashraf, A.R. (2006). "A Report on the occurrence of Albian – Cenomanian elater-bearing pollen in Nasara-1 well, Upper Benue Trough, Nigeria: biostratigraphic and palaeoclimatological implications." Jour. Afr. Earth Sci. 45, 347–354.

Abubakar, M. B., Dike, E. F. C., Obaje, N. G., Wehner, H. and Jauro, A. (2008). "Petroleum prospectivity of Cretaceous formations in the Gongola Basin, Upper Benue Trough, Nigeria: an organic geochemical perspective on a migrated oil controversy". Journal of Petroleum Geology, v. 31(4), 387-408.

Abdalla, M.Y., Pearson, M.J., Ashcroft, W.A, Iliffe, J.E. and Whiteman, A.J. (1999). "Modeling petroleum generation in southern Muglad rift basin, Sudan." AAPG Bull., 83(12), 1943 – 1964.

Adegoke, O.S., Jan du Chene, R.E., Agumanu, A.E. and Ajayi P.O., (1978). "Palynogy and age of the Kerri- Kerri Formation, Nigeria." Rev. Espan. Micropaleont., 2 : 267-283.

Adegoke, O.S., Agumanu, A.E., Benkhelil, M.J. and Ajayi, P.O., (1986). "New stratigraphic, sedimentologic and structural data on the Kerri-Kerri Formation, Bauchi and Borno States, Nigeria." Journal of African Earth Sciences, 5(3): 249-277.

Akande, S.O., Ojo, O.J., Erdtmann, B.D., Hetenyi, M. (1998). "Paleoenvironment, source rock potential and thermal maturity of the Upper Benue rift basins, Nigeria: implications for hydrocarbon exploration." Org. Geochem., 29(1 – 3): 531 – 542.

Allix, P. (1983) Environments Mésozoïques de la partie nord-orientale du fossé de la Bénoué (Nigéria): stratigraphie, sédimentologie, évolution géodynamique. In: Popoff, M., Wiedmann, J. and Klasz, I. (1986). "The Upper Cretaceous Gongila and Pindiga Formations, Northern Nigeria: subdivisions, age, stratigraphic correlation and paleogeographic implications." *Eclogae Geol. Helv*., 79, 343-363.

Avbovbo, A.A., Eyoola, E.O. and Osahon, G.A. (1986). "Depositional and structural styles in Chad Basin of northeastern Nigeria." AAPG Bull., 80, 1787 – 1798.

Benkhelil, J. and Guiraud, R. (1980). "The Benue (Nigeria), an intracontinental chain with Atlantic style." Comptes Rendus de l'Academie des Sciences, serie D, 290, 1517 – 1520.

Benkhelil, J. (1988). "Structure et évolution géodynamique du bassin intracontinental de la Benoué (Nigeria)." Bull. Des Centres de Recherches Explor.-Prod. Elf-Aquitaine, 12, 29 – 128.

Benkhelil, J. (1989). "The origin and evolution of the Cretaceous Benue Trough (Nigeria)." *J. African Earth Sci*., 8, 251 - 282.

Benkhelil, J., Guiraud, M., Ponsard, J.F. and Saugy, L. (1989). "The Bornu – Benue Trough, the Niger Delta and its offshore: tectono-sedimentary reconstruction during the Cretaceous and Tertiary from geophysical data and geology". In: Kogbe, C.A. (2nd Ed.) Geology of Nigeria. Rock View Nig. Ltd. (publ.), Jos, Nigeria, 277 – 310.

Bosworth, W. (1985). "Geometry of propagating continental rifts." Nature, 316(6029), 625 – 627.

Carter, J. D., Barber, W. and Tait, E. A. (1963). "The geology of part of Adamawa, Bauchi and Bornu provinces in Northeastern Nigeria. *Geol." Survey Nig. Bull*., 30, 1 - 109.

Bumby, A.J. and Guiraud, R. (2005). "The geodynamic setting of the Phanerozoic basins of Africa." Jour. Afr. Earth Sci., 43, 1 – 12.

Cratchley, C.R. and Jones, G.P. (1965). "An interpretation of the geology and gravity anomalies of the Benue Valley, Nigeria." Overseas Geol. Surveys Geophysical Paper, 1, 1 – 26.

di Primio, R. and Horsfield, B. (2006). "From petroleum-type organofacies to hydrocarbon phase prediction." Aapg Bull., 90(7), 1031 – 1058.

Dike, E.F.C., 1993. Stratigraphy and structure of the Kerri-Kerri Basin, NE Nigeria. Jour. of Mining Geology, 29 (2): 77-93.

Dike, E.F.C. and Maigari, A.S. (2009). "Reservoirs of the north-east and future of petroleum exploration." Proceedings of two day symposium on sustainable fossil fuel and renewable energy in the northeast and other related regions of Nigeria, NCPRD Bauchi, 50 – 62.

Genik, G.J. (1993). "Petroleum geology of Cretaceous-Tertiary rift basins in Niger, Chad and Central African Republics". AAPG Bull., 77(8), 1405 – 1434.

Giedt, N.R. (1990). Unity field Sudan, Muglad rift basin, Upper Nile province. AAPG Treatise Petrol. Geol. Atlas Oil and Gas Fields, 177 – 197.

Grant, N.K., Rex, D.C. and Freeth, S.J. (1972). "Potasium-argon ages and strontium isotope measurements from volcanic rocks in northeastern Nigeria." Contrib. Mineralogy and Petrology, 35, 277 – 292.

Guiraud, M. (1990). "Tectono-sedimentary framework of the Early Cretaceous continental Bima Formation (Upper Benue Trough, NE Nigeria)." Jour. Afr. Earth Sci. 10, 341–353.

Guiraud, M. (1991). "Mécanisme de formation du basin crétacé sur décrochements multiples de la Haute-Bénoué (Nigéria)". Bull. Des Centres de Recherches Explor.-Prod. Elf-Aquitaine, 15, 11 – 67.

Guiraud, M. (1993). "Late Jurassic rifting - Early Cretaceous rifting and Late Cretaceous transpression inversion in the Upper Benue Basin (NE Nigeria)." Bull. Des Centres de Recherches Explor.-Prod. Elf-Aquitaine, 17, 371 – 383.

Guiraud, R., Bellion, Y., Benkhelil, J. and Moreau, C. (1987). "Post Hercynian tectonics in northern and western Africa." Geol. Jour., 22, 433 – 466.

Guiraud, R. and Bosworth, W. (1997). "Senonian basin inversion and rejuvenation of rifting in Africa and Arabia: synthesis and implications to plate-scale tectonics." Tectonophysics, 282, 39 – 82.

Haq, B.U., Hardenbol, J. and Vail, P.R. (1987). "The new chronostratigraphic basis of Cenozoic and Mesozoic sea level changes. Cushman Foundation for Foraminiferal." Research Special Publication, 24, 7 – 13.

Hunt, J.M., 1996. "Petroleum geochemistry and geology," 2nd Edition. Freeman, W.H. and Co., New York.

Klemme, H.D. (1980). "Petroleum basins – classifications and descriptions." Jour. Petrol. Geol., 3, 187 – 207.

Kogbe, C.A. (1972). "Geology of the Upper Cretaceous and Tertiary sediments of the Nigerian sector of the Iullemmeden Basin (West Africa)." Geologische Rundschau, 62, 197 – 211.

Lawal, O., Moullade, M. (1986). "Palynological biostratigraphy of Cretaceous sediments in the Upper Benue Basin." Rev. Micropaleontologie 29, 61–83.

Magoon, L.B. and Dow, W.G. (1994). "The petroleum system." AAPG Memoir, 60, 3 – 24.

Maurin, J.-C. and Guiraud, R. (1990). "Relationships between tectonics and sedimentation in the Barremo-Aptian intracontinental basins of northern Cameroon." Jour. Afr. Earth Sci., 10, 331 – 340.

Morse, D.G. (1994). "Siliciclastic reservoir rocks." AAPG Memoir, 60, 121 – 140.

Mustapha, A.A. and Tyson, R.V. (2002). "Organic facies of Early Cretaceous syn-rift lacustrine source rocks from the Muglad Basin, Sudan." Jour. Petrol. Geol., 25(3), 351 – 366.

Nwaezeapu, A.U. (1992). "Hydrocarbon exploration in frontier basins: the Nigerian Chad Basin experience." A paper presented at NMGS Annual Conf., PortHarcourt, Nigeria, 17pp.

Obaje, N.G., Pearson, M.J., Suh, C.E., Dada, S.S. (1999). "Organic geochemical characterization of the potential hydrocarbon source rocks in the Upper Benue Trough." Jour. Min. Geol., 35(2): 137 – 152.

Obaje, N.G., Wehner, H., Scheeder, G., Abubakar, M.B. and Jauro, A. (2004). "Hydrocarbon prospectivity of Nigeria's inland basins: from the viewpoint of organic geochemistry and organic petrology." AAPG Bull., 88(3), 325 – 353.

Offodile, M.E. (1980). "A mineral survey of the Cretaceous of the Benue Valley, Nigeria." Cretaceous Research, 1, 101 – 124.

Olugbemiro, O.R. (1997). "Hydrocarbon potentials, maturation and paleoenvironments of the Cretaceous (Cenomanian – Santonian) series in the Chad Basin, NE Nigeria." Tubinger Mikropalaontologische. Mitt. 14: 1-169.

Petters, S.W. and Ekweozor, C.M. (1982). "Petroleum geology of Benue Trough and southeastern Chad Basin." AAPG Bull., 66, 1141 – 1149.

Popoff, M., Benkhelil, J., Simon, B. and Motte, J.J. (1983). "Approche géodynamique du fossé de la Bénoué (N. Nigeria a partir des données de terrain et de télédètection." Bull. Des Centres de Recherches Explor.-Prod. Elf-Aquitaine, 7, 323 – 337.

Popoff, M. (1988). “Du Gondwana à l'Atlantique sud: connexions du fossé de la Bénoué avec les basins du nord-est brésilien jusqu'à l'ouverture du golfe de Guinée au cretace inférieur.” Jour. Afr. Earth Sci., 7, 409 – 431.

Rebelle, M. (1990); “The marine transgression in the Benue Trough (NE Nigeria): a paleogeographic interpretation of the Gongila Formation.” Jour. Afr. Earth Sci., 10, 643 – 655.

Reyment, R.A. and Dingle, R.V. (1987). “Paleogeography of Africa during the Cretaceous Period.” Palaeogeogr., Palaeoclimatol., Palaeoecol., 59, 93 – 116.

Samaila, N.K., Abubakar, M.B., Dike, E.F.C. and Obaje, N.G. (2006). “Description of Soft-Sediment Deformation Structures in the Cretaceous Bima Sandstone from the Yola Arm, Upper Benue Trough, Northeastern Nigeria.” Journal of African Earth Science, 44(1), 66 – 74.

Samaila, N.K. (2007). “Reservoirs potentials of the Upper Bima Sandstone in the Yola and Lau-Lamurde Basins, Upper Benue Trough, NE Nigeria.” Unpl. Ph.D thesis, Abubakar Tafawa Balewa University, Bauchi, Nigeria, 201pp.

Simon-Robertson Report (1991). “The stratigraphy, sedimentoloy and geochemistry of the NNPC Ngamma East-1 and Gubio SW-1, drilled in the Nigerian Chad Basin, Bornu State, Nigeria, and correlation with the previously studied Tuma-1, Kanadi-1 and SA-1 wells.” Report submitted to NNPC (NAPIMS), Nigeria, 46pp.

Schull, T.J. (1988). “Rift basins on interior Sudan: petroleum exploration and discovery.” AAPG Bull., 72(10), 1128 – 1142.

United Reef Limited Report (2004). “Report on the petroleum potential of the RSM Production Corporation oil and gas permit area in the northeastern portion of the Central African Republic.” 27pp.

Zaborski, P., Ugodulunwa, F., Idornigie, A., Nnabo, P. and Ibe, K. (1997). “Stratigraphy and structure of the Cretaceous Gongola Basin, Northeast Nigeria. *Bull. Centre Rech. Elf Expl.” Prod.*, 21(1), 153 - 185.

Zaborski, P.M. (1998). “A review of the Cretaceous system in Nigeria.” African Geoscience Rev., 5, 385 – 483.

Zaborski, P.M. (2000). “The Cretaceous and Paleocene transgressions in Nigeria and Niger.” Jour. Min. Geol. 36(2), 153–173.

Zaborski, P.M. (2003). “Guide to the Cretaceous System in the upper part of the Upper Benue Trough, northeastern Nigeria.” Afr. Geosci. Rev., 10(1&2), 13 – 32.

Zaborski, P.M. and Abubakar, M.B. (2010). “Evaluation of the Gongola Basin. A report submitted to National Frontier Exploration Service, NNPC, 37pp.

Zanguina, M., Bruneton, A. and Gnnard, R. (1998). “An introduction to the petroleum potential of Niger.” Jour. Petrol. Geol., 21(1), 83 – 103.