

Lithofacies and Organic Geochemical Studies of Akinside 1582 Well, Eastern Dahomey Basin Southwestern Nigeria

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Abstract

Subsurface samples from the Akinside 1582 well, located within the eastern Dahomey Basin were evaluated to determine the lithofacies, depositional environment, and hydrocarbon potential of the basin. The sediments within the interval 138-197m consist of limestones, shales, mudstone and glauconite; thus representing sediments belonging to the Ewekoro and Akinbo Formations.

The limestones are greyish, highly indurated, partly recrystallised and reveal six microfacies notably biosparite, shelly biomicrite, biomicrite, pel-biosparite, sandy-pelmicrite and sandy-biomicrite. The presence of gastropods, pelecypods, echinoderm, coralline algae, foraminifera and other skeletal debris indicate a shallow marine environment of deposition for the limestone.

Total organic carbon (TOC) for the sediments range from 0.10 to 0.58wt% and 0.59 to 0.62wt% for the Ewekoro and Akinbo Formations respectively while soluble organic matter (SOM) are correspondingly 392ppm and 887 to 2472ppm. These suggest a poor through moderate to adequate organic matter. Plot of HI versus OI indicates Type III and IV kerogens. Tmax values range from 362 to 467°C and cross plot of HI versus Tmax points to mainly immature to early mature sediments. The terpanes and sterane distributions indicate a marginally mature status for the sediments.

Pristane/phytane ratio ranges from 0.13 to 0.24 and 1.88 for the Akinbo and Ewekoro Formations respectively, thus indicating both anoxic and oxic conditions of deposition. The abundance of pentacyclic triterpane of oleanane and hopane skeletons and C₂₇ to C₂₉ regular steranes in the bitumen, indicate mixed source rocks (marine and terrestrial) for the sediments. However, ternary plot of C₂₇, C₂₉ and C₃₀ steranes strongly amplify terrestrial organic matter with prospect to generate gas rather than oil in the basin at appropriate maturation.

Introduction

The Dahomey Basin is one of the sedimentary basins on the continental margin of the Gulf of Guinea and extends from southeastern Ghana in the west, to the western flank of the Niger Delta (Fig 1). The genesis of the basin is associated with the separation of the African and South American landmasses as a result of the continental drift and subsequent opening of the Atlantic Ocean during the Mesozoic Era (Burke et al., 1972). Several hypotheses have been developed as to the origin/evolution of the Dahomey basin, but the rift hypothesis is widely supported (Omatsola and Adegoke, 1981).

The basin contains extensive wedge of Cretaceous sediments, up to 3,000m, which thicken from the onshore margin (where the predominantly clastic Cretaceous sediments rest on the basement) to the offshore. Within the offshore area, thick, fine-grained, Cenozoic sediments cover the basin (Whiteman, 1982; Schlumberger, 1985). The axis of the basin and the thickest sediments occur slightly west of the border between Nigeria and the Republic of Benin (Slansky, 1962; Billman, 1992).

The eastern Dahomey basin has proved to be of great geological interest, particularly because of extensive occurrences of limestones, phosphorites, glass sands and tar sands (Nton, 2001). Exploration activity for tar sands commenced in this sector of the basin in 1908, near Okitipupa, east of Lagos, where bituminous sands outcrop. Such investigations were later abandoned and the wells termed "dry". With the discovery of oil in the Niger Delta in 1956, focus shifted from this basin to the Niger Delta. It is relevant to note that conventional hydrocarbons in commercial quantity have been discovered offshore in the Republic of Benin (Billman, 1992). However, in comparison with the adjacent Niger Delta, few studies have been conducted in the eastern Dahomey basin in terms of hydrocarbon potential.

This study evaluates lithofacies and organic geochemical characterization of the associated limestones and shales of the Akinbo and Ewekoro Formations as penetrated by the Akinside 1582 well, located within the eastern Dahomey basin.

LOCATION OF STUDY AREA AND GEOLOGY

The study well, Akinside 1582, lies between latitudes 6° 45'01" to 6° 55'N and longitudes 3° 00' to 3° 15'E and falls

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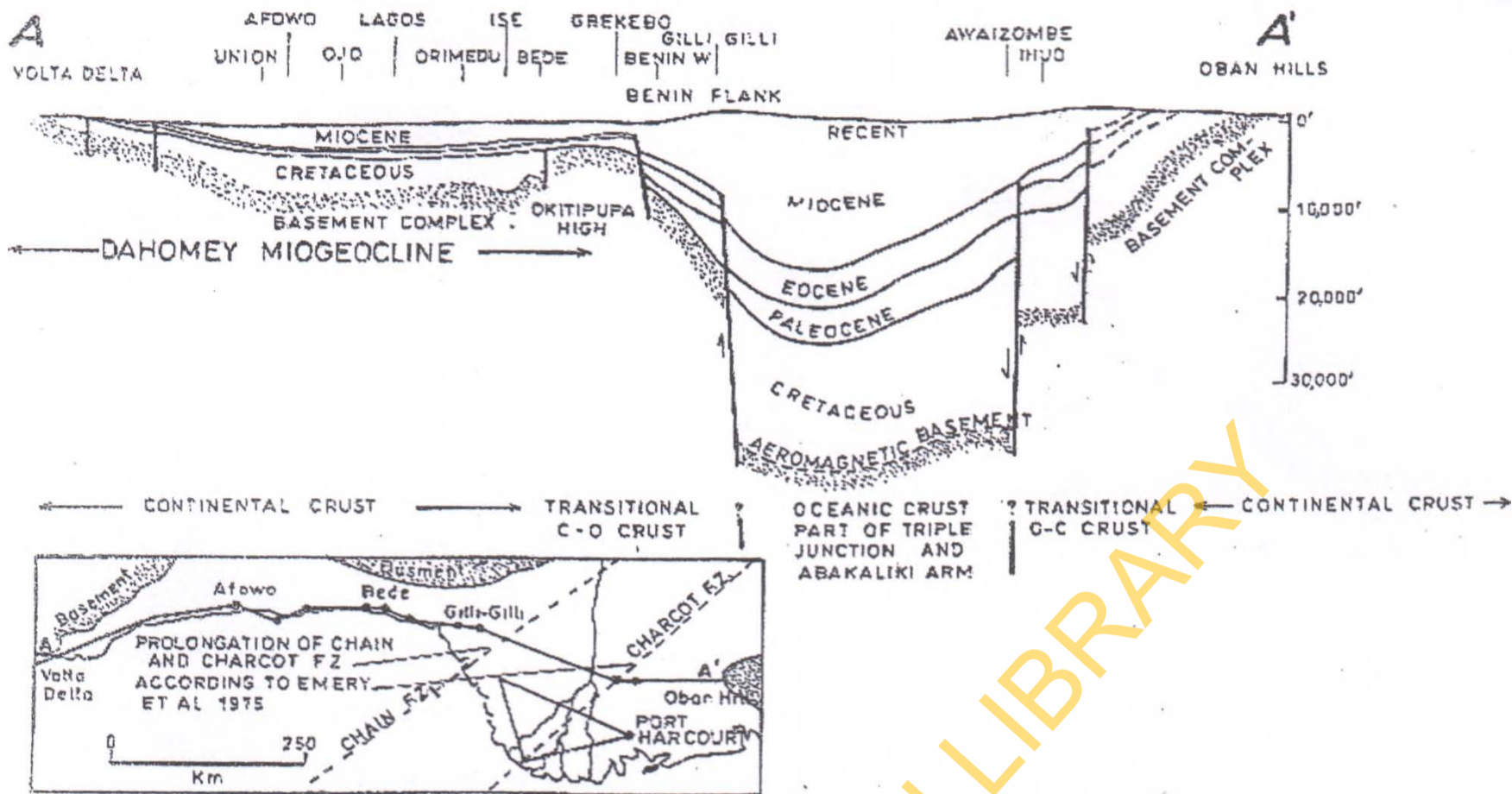


Fig 1:

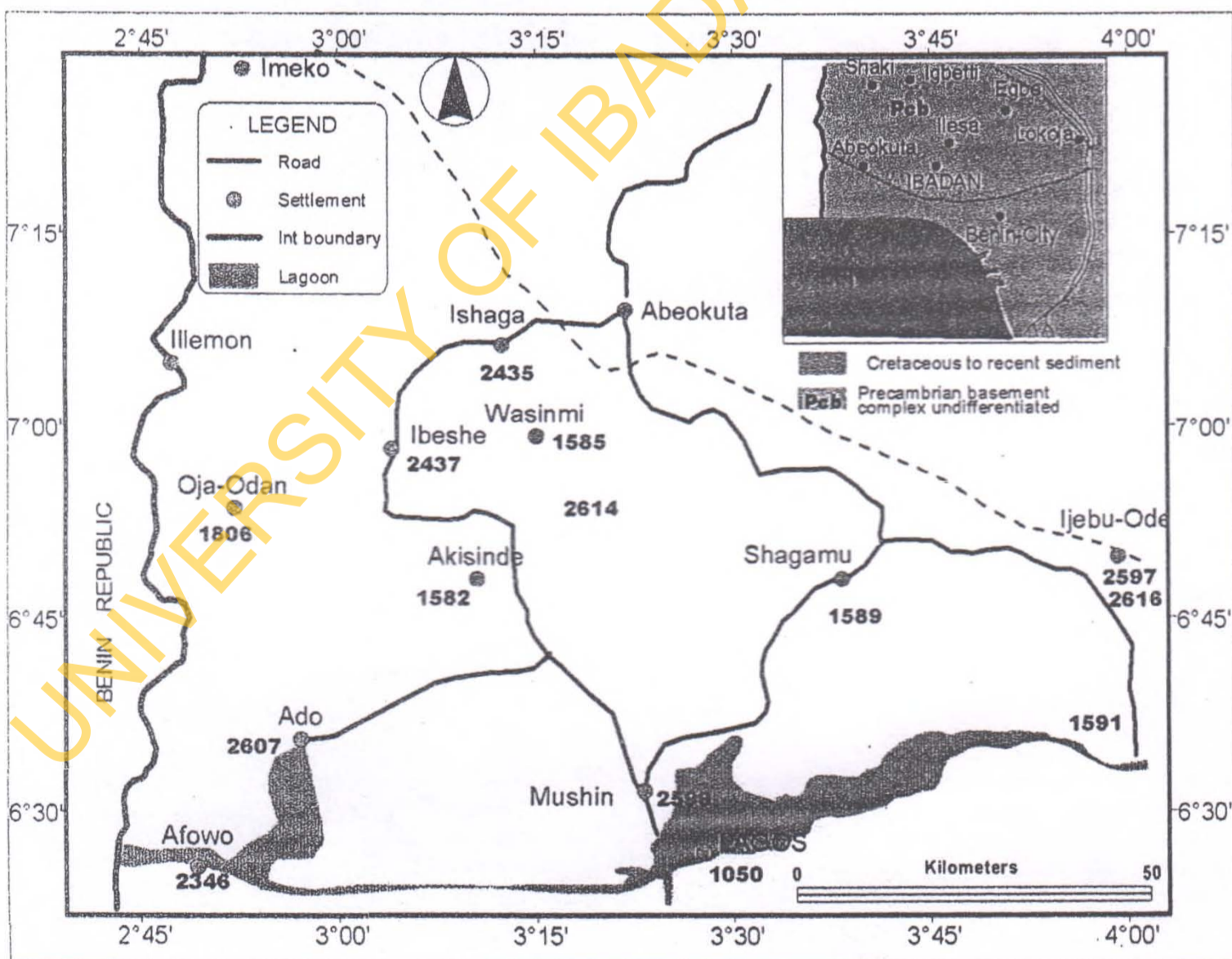


Fig 2:

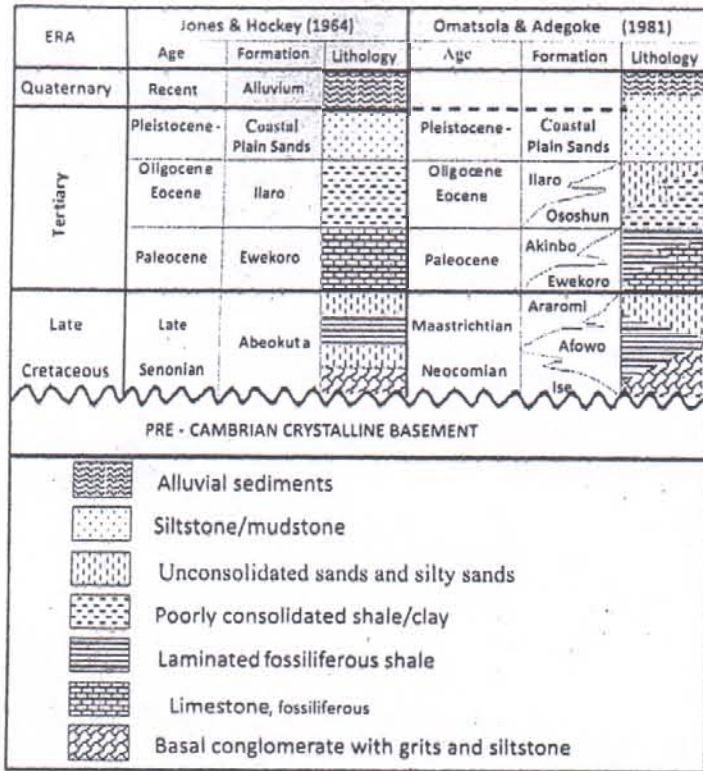


Fig 3: Stratigraphy of eastern Dahomey basin

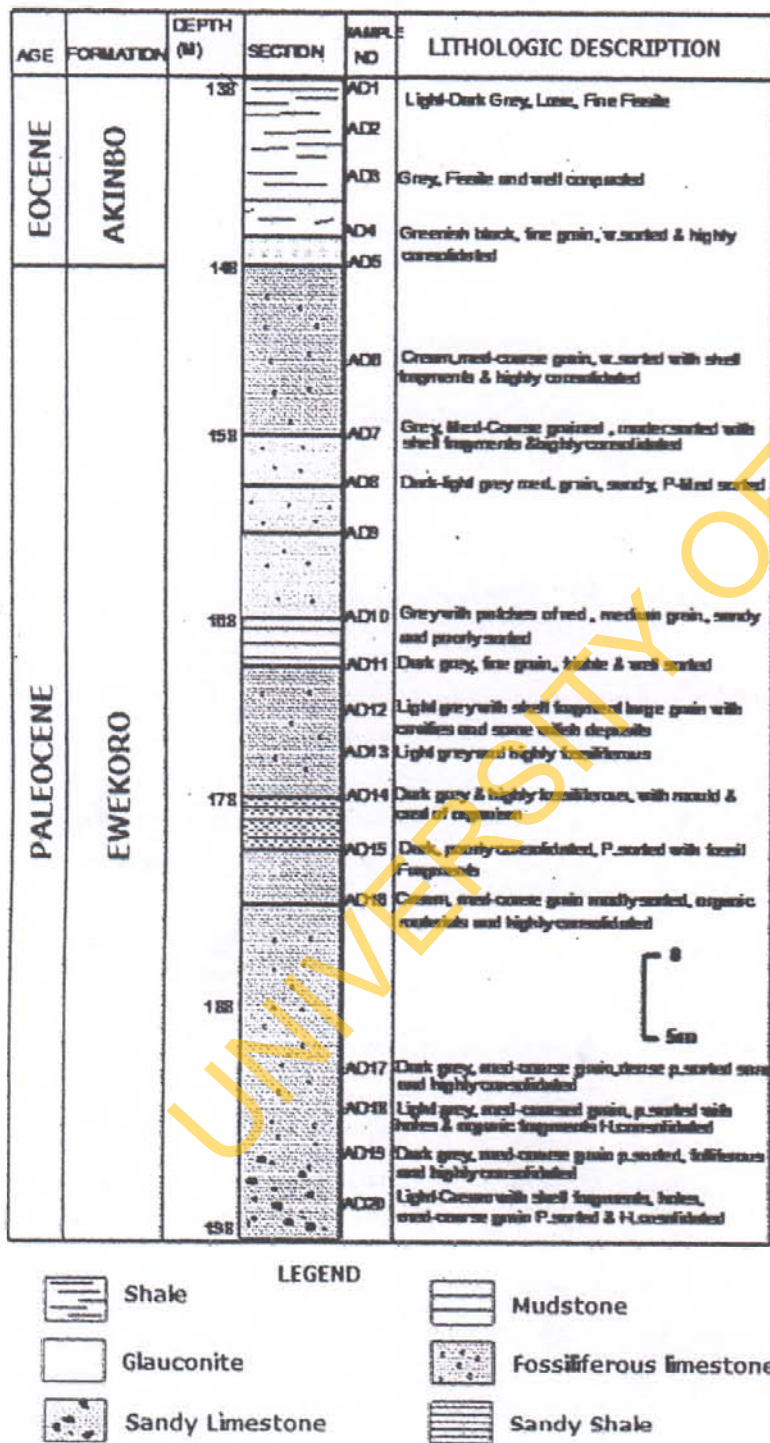


Fig 4:

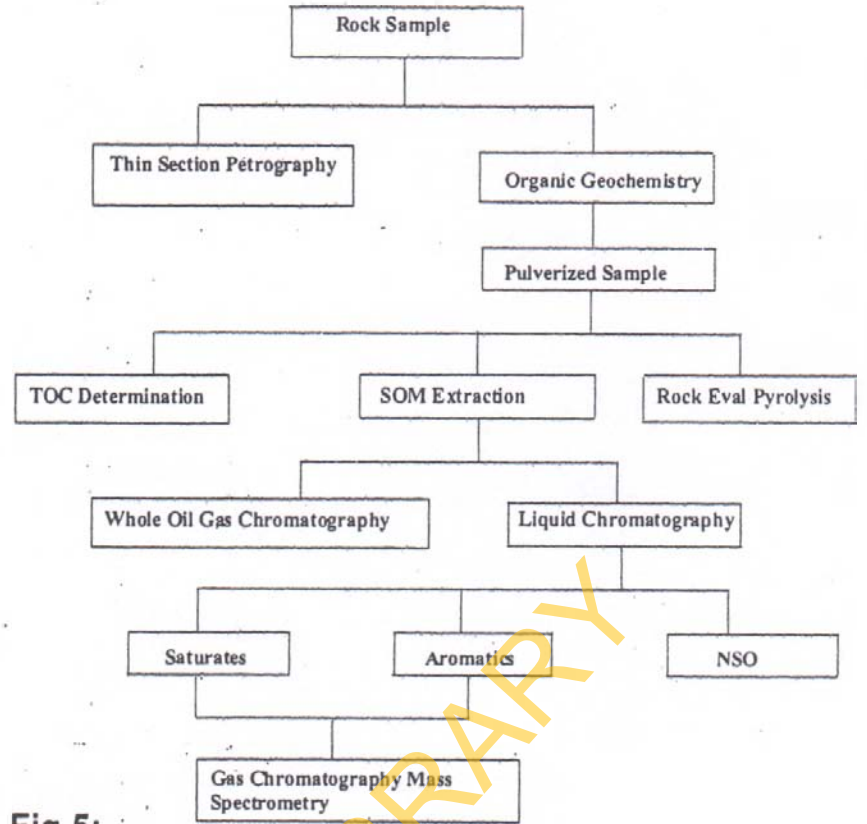


Fig 5:



Fig 6:

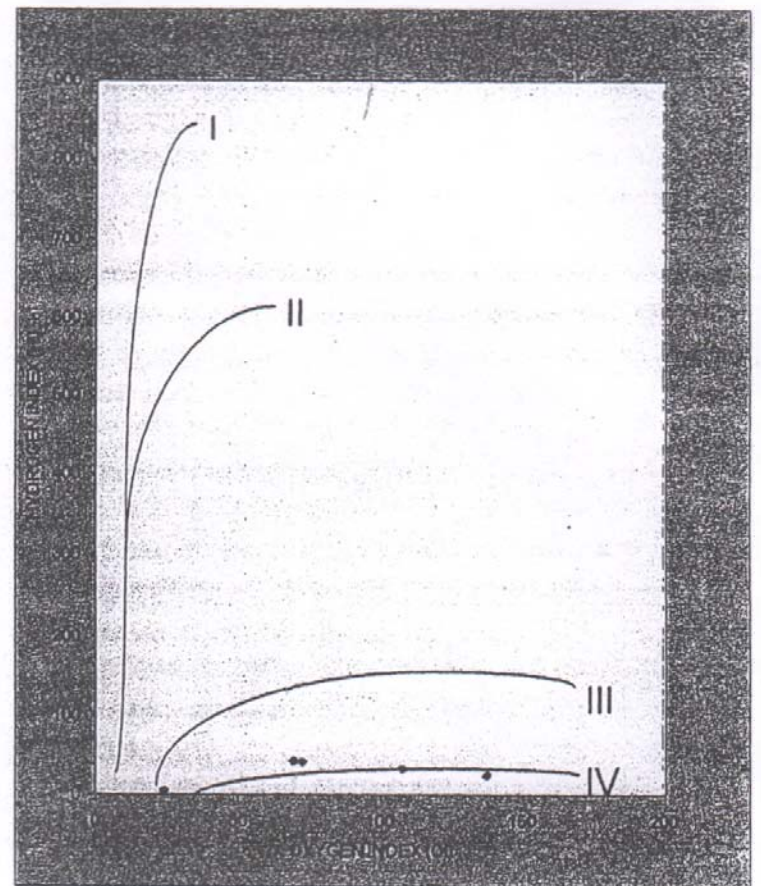


Fig 7:

within the eastern Dahomey Basin (Jones and Hockey, 1964) (Fig. 2). The stratigraphy of eastern Dahomey Basin, as described by different authors is shown in Fig 3. Omatsola and Adegoke (1981) proposed the Cretaceous sequence in the eastern Dahomey basin as beginning with the Abeokuta Group, made up of three formations from oldest to the youngest namely; the Ise, Afowo and Araromi Formations. The Ise Formation is the oldest Cretaceous unit in the eastern Dahomey Basin (Omatsola and Adegoke, 1981). This formation unconformably overlies the basement complex in southwestern Nigeria and consists of conglomerates and grits at base which are in turn overlain by coarse to medium grained sands with interbedded kaolinite. At the basement/sedimentary contacts, the conglomerates are unimbricated and at some locations, ironstones occur (Nton, 2001). The age of the Ise Formation is Neocomian to Albian.

The Ise Formation is overlain by the Afowo Formation and comprised coarse to medium grained sandstones with variable but thick interbedded shales, siltstones and claystones. Intense pyritization of the clayey horizon is common. The lower part contains an alternation of brackish marginal marine strata with subrounded clean well sorted loose fluvial sands (Billman, 1992). The sandy facies are tar-bearing around Okitipupa, while the shales are organic-rich. The formation has been dated Turonian to Maastrichtian based on palynomorphs and foraminifera contents (Billman, 1992; Omatsola and Adegoke, 1981).

The Araromi Formation overlies the Afowo Formation and has been described as the youngest Cretaceous sediment in the eastern Dahomey basin (Omatsola and Adegoke, 1981). It comprised fine to medium grained sandstones at base, overlain by shales, siltstone with interbedded limestone, marl and lignite. This Formation is highly fossiliferous, containing abundant planktonic foraminifera, ostracods, pollen and spores. Omatsola and Adegoke (1981) assigned a Maastrichtian to Palaeocene age to this formation based on faunal content.

Overlying the Araromi Formation in the eastern Dahomey Basin is the Ewekoro Formation. The Ewekoro Formation is made up of an extensive limestone body, which is traceable over a distance of about 320km from Ghana in the west, towards the eastern margin of the Dahomey basin in Nigeria (Jones and Hockey, 1964). The limestone body shows an increase in arenaceous materials at the base. The Formation is Palaeocene in age and is associated with shallow marine environment based on the presence of gastropods, pelecypods, echinoid fragments and other skeletal debris (Elueze and Nton, 2004).

The Akinbo Formation overlies the Ewekoro Formation and consists of shale -clayey sequence. The claystones are concretionary and are predominantly kaolinite (Nton and Elueze, 2005). The base of the formation is defined by the presence of glauconitic band with lenses of limestones (Ogbe, 1972; Nton, 2001). The formation is Palaeocene to Eocene in age.

The Oshosun Formation overlies the Akinbo Formation and consists of greenish – grey or beige clay and shale with interbeds of sandstones. The shale is thickly laminated and glauconitic. According to Okosun (1998), the basal beds consist of any of the following facies; sandstones, mudstones, claystones, clay-shale or shale. This formation is phosphate-bearing (Jones and Hockey, 1964; Nton, 2001).

The Ilaro Formation overlies the Oshosun Formation in the eastern Dahomey Basin. It consists of a sequence of predominantly coarse sandy estuarine, deltaic and continental beds, which display rapid lateral facies changes. This formation was temporary assigned a Leutatian age (Slansky, 1962).

The youngest stratigraphic sequence in the eastern Dahomey basin is the Benin Formation. It is also known as the Coastal Plain Sands (Jones and Hockey, 1964) and consists of poorly sorted sands with lenses of clays. The sands are in parts cross bedded and show transitional to continental characteristics. The age is from Oligocene to Recent.

MATERIALS AND METHODS

Sampling

Subsurface samples from Akinside 1582 well (Figs. 2 and 4), were obtained from the Nigerian Geological Survey Agency (NGSA), Federal Ministry of Solid Minerals, Kaduna, Nigeria. With an overall thickness of 207m for this well, the interval between 135 to 196.6m was investigated for this study (Fig. 4). A total of 20 samples made up of thirteen (13) limestones, five (5) shales and two (2) glauconite/ mudstones were used for this study. The lithologic sequence (Fig.4) is made of highly consolidated limestone ranging in depth from 181.7 to 196.6m at the base. The limestone belongs to the Ewekoro Formation and is sandy, fossiliferous and cavernous with color ranging from light to dark grey.

Overlying this unit is a sandy shale unit of 1.6m thick. It is dark, poorly laminated and contains some fossil fragments. Above this unit is a middle limestone sequence (174.9 to 178.9m) which in turn is overlain by mudstone unit. The limestone ranges in color from light grey to dark grey, containing mostly shell fragments. The mudstone is dark grey, fine grained and friable.

Successive lithologies are sandy and fossiliferous limestone, glauconite band, overlain by well laminated shale sequence. The glauconite band is greenish to black, medium grained, well sorted and very consolidated. This upper sequence belongs to the Akinbo Formation.

Thin Section Petrography: The limestone samples were thin sectioned by standard methods and examined under the petrological microscope Model Brunel, at the Petrological Microscope Laboratory, Department of Geology, University of Ibadan. The classification of the limestone is based on the concept of Folk and Ward, (1957). Photomicrographs of features of interests were taken and described.

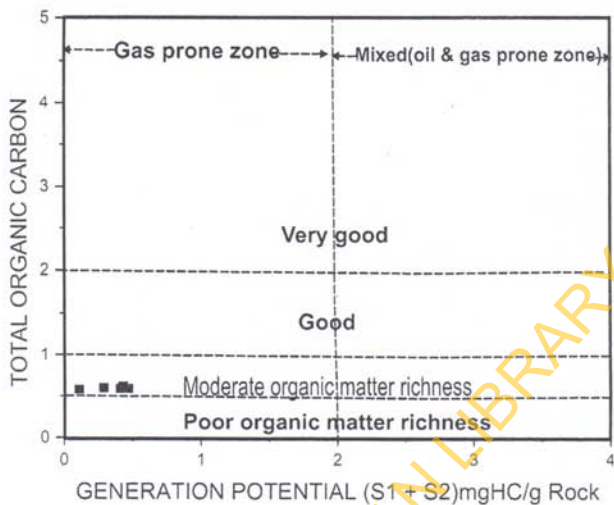


Fig 8:

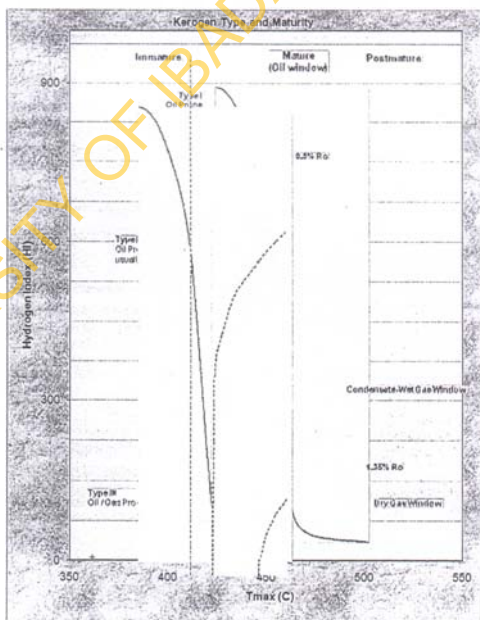


Fig 9:

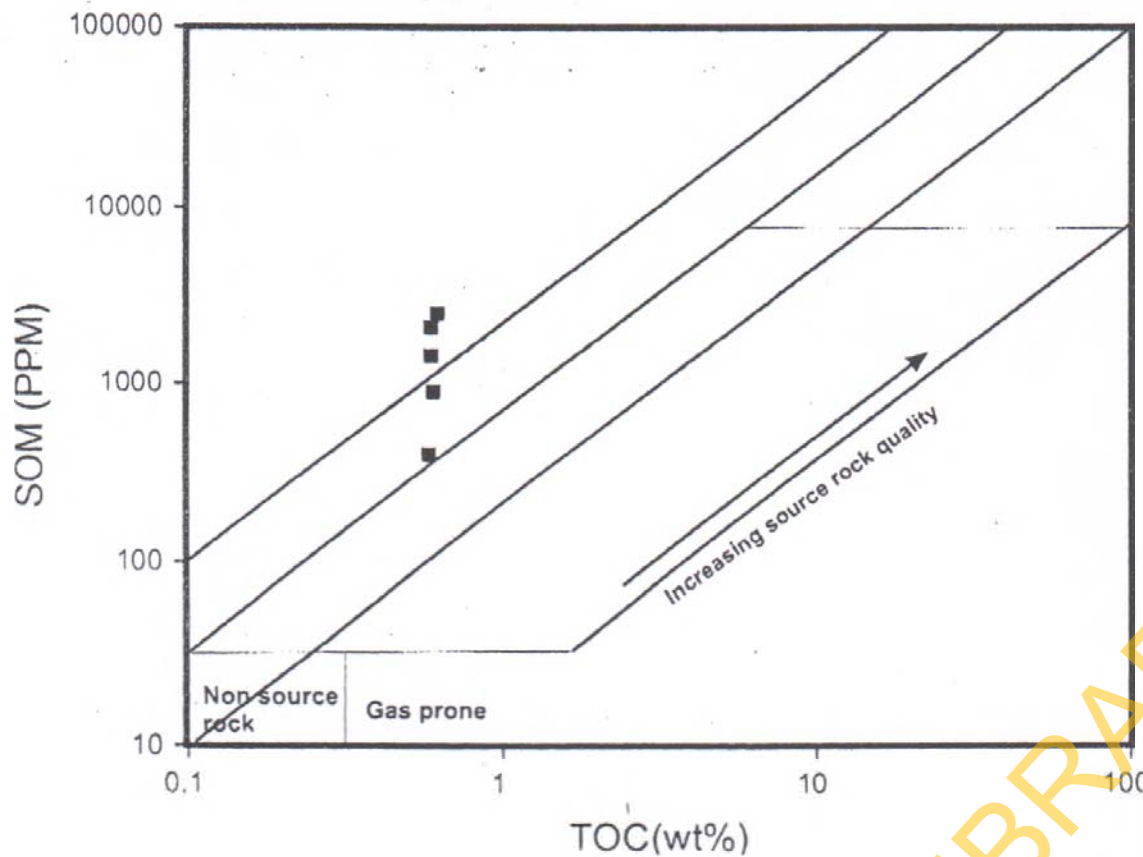


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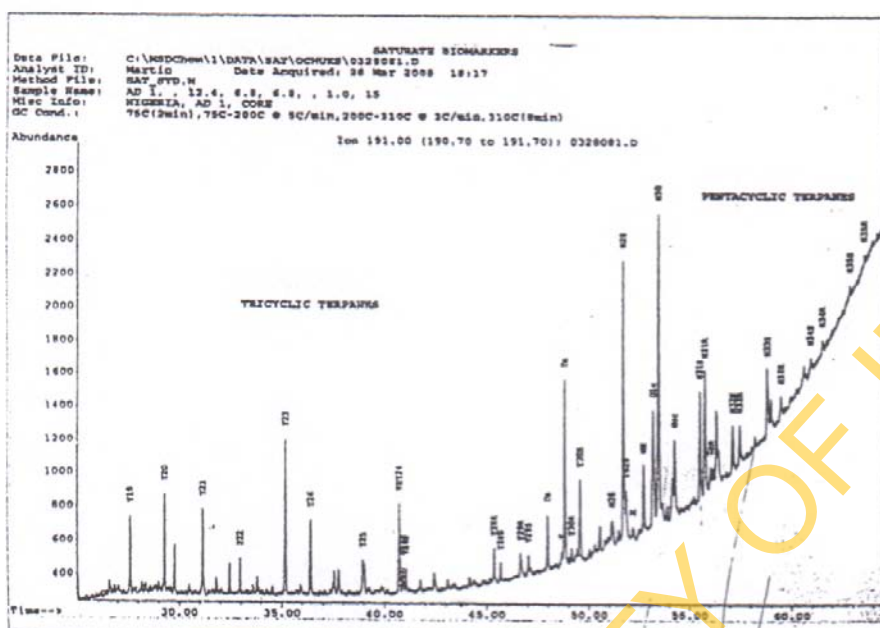


Fig 11a:

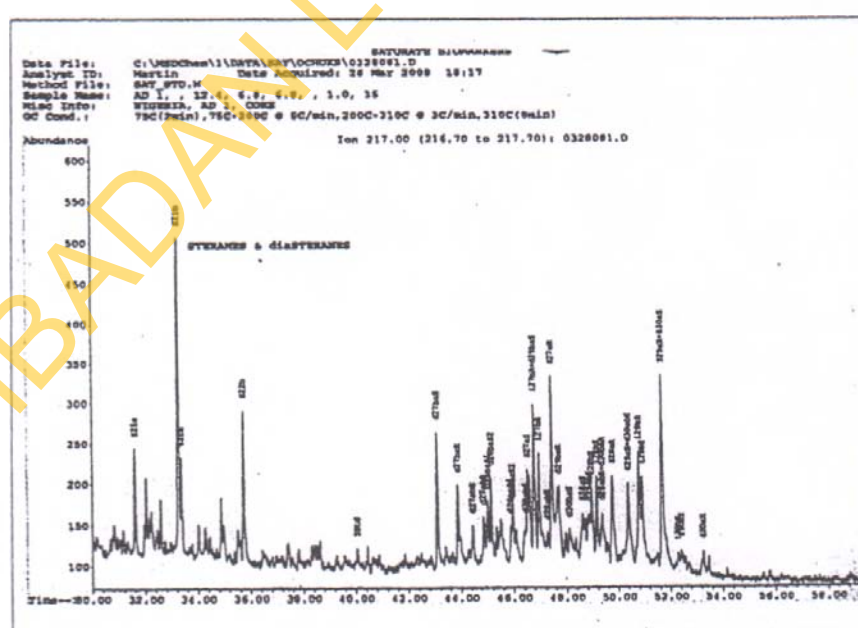


Fig 11b:

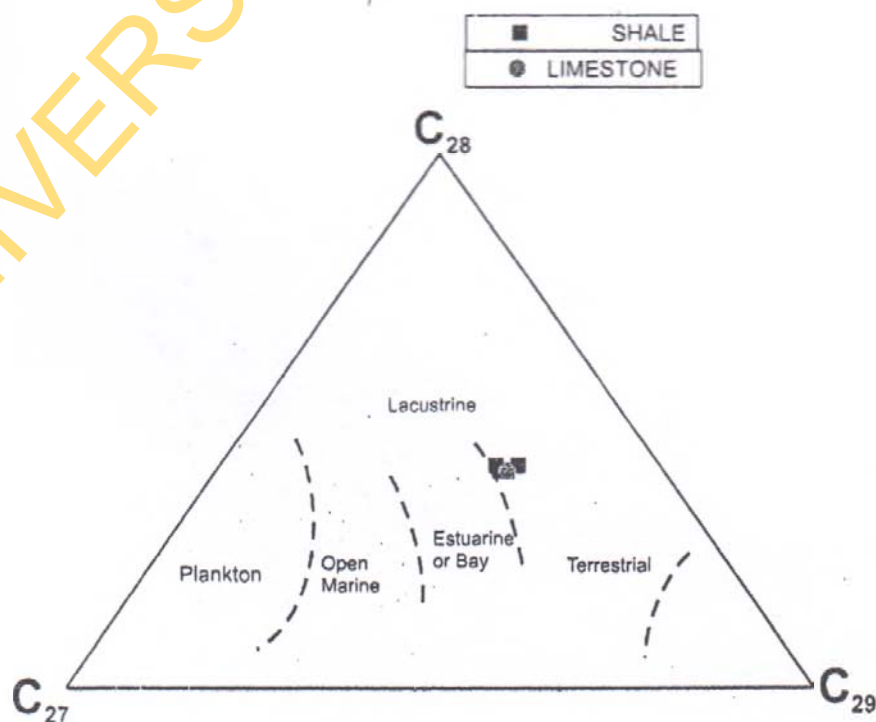


Fig 12:

Table 1: Toc And Rock Eval Parameters Data Of Selected Samples

	SOM/TOC mgextr/TOC	TOC Wt. %	S1 mg/g	S2 mg/g	S3 Mg/g	Tmax	HI	OI	S1/ TOC	PI	GP
2064	350	0.59	0.22	0.25	0.43	467	42	73	36	0.46	0.47
1426	242	0.59	0.16	0.25	0.41	464	42	69	27	0.39	0.41
887	148	0.60	0.14	0.15	0.83	436	25	137	23	0.48	0.29
2472	399	0.62	0.22	0.21	0.67	443	34	108	35	0.51	0.43
392	68	0.58	0.08	0.03	0.14	362	5	24	13	0.72	0.11

Notes:

TOC=weight percent organic carbon in rock

S1, S2=mg hydrocarbons per gram of rock

S3= mg carbon dioxide per gram of rock

S1/TOC=normalised oil content=S1 X 100/TOC

HI=hydrogen index= S2 X 100/TOC

OI=oxygen index= S3 X 100/TOC

Tmax=°C

PI= production index= S1/ (S1+ S2)

Table 2. Source and Thermal Maturity Parameters from the Pentacyclic Triterpane and Sterane Distribution

Sample No.	Depth (m)	Formation	Source Parameters						Maturity Parameters				
			A	B	C	C ₂₇	C ₂₈	C ₂₉	D	E	F	G	H
AD1	138	Akinbo	0.58	0.10	0.52	37	22	41	0.23	0.18	0.56	0.37	0.39
AD2	141	Akinbo	0.28	0.10	0.51	39	21	40	0.24	0.19	0.55	0.36	0.42
AD3	144	Akinbo	0.22	0.09	0.51	40	19	41	0.21	0.19	0.52	0.36	0.40
AD4	147	Akinbo	0.36	0.07	0.51	38	22	40	0.16	0.18	0.53	0.27	0.37
AD20	197	Ewekoro	0.42	0.18	0.50	39	21	40	0.29	0.18	0.58	0.49	0.44

A= Oleanane/ $\alpha\beta$ C₃₀ Hopane (Oleanane index)B= Gammacerane/ $\alpha\beta$ C₃₀ Hopane (Gammacerane index)C= $\alpha\alpha$ C₂₉(S+R)/ $\alpha\alpha$ C₂₉(S+R) + $\alpha\alpha$ C₂₇(S+R)

D= Ts/ Ts+Tm

G= 20S/20S+20R

E= $\beta\alpha/\beta\alpha+\alpha\beta$ C₃₀hopaneH= $\beta\beta$ (S+R)/ $\beta\beta$ (S+R) + $\alpha\alpha$ (S+R) C₂₉F= 22S/22S+22R C₃₂ Hopanes

Table 3. Chromatographic Data showing Values of Isoprenoid ratios

Sample No.	Formation	Pr/ph	Pr/nC ₁₇	ph/nC ₁₈
AD1	Akinbo	1.13	N/D	0.37
AD2	Akinbo	0.16	N/D	0.73
AD3	Akinbo	0.24	N/D	0.75
AD4	Akinbo	0.37	N/D	0.71
AD20	Ewekoro	1.88	N/D	1.18

N/D= Not Determined

Organic Geochemical Analyses

Total organic carbon

The total organic carbon (TOC) determination afforded a preliminary screening of potential source rocks based on acceptable threshold of 0.3wt% and 0.5wt% TOC required for carbonates and shales respectively (Tissot and Welte, 1984). Each of the twenty (20) rock sample was pulverized and sieved through a 40 mesh sieve. 50 mg of each sample was combusted in a LECO model C230 combustion furnace and CO₂ generated was quantitatively measured using an infrared detector.

Rock-Eval Pyrolysis

Arising from TOC adequacy, six (6) samples, made up of five (5) shales and one (1) limestone were selected for Rock-eval pyrolysis. 100mg of each sample was dried, pulverized and sieved. Each sample was loaded into the Rock-Eval crucible with an auto sampler into an oven, where it was purged to remove oxygen and carbon dioxide. The sample was then raised into a 300°C oven to elute the S₁ peak (free hydrocarbons). The oven temperature was then ramped at 25°C, up to 600°C to crack and elute the S₂ (kerogen) peak. CO₂ was collected and quantified from 300°C to 390°C to give the S₃ peak.

S₁, S₂, and Tmax values were determined with the flame ionization detector (FID) while the S₃ was measured with a thermal conductivity detector (TCD). The instrument was calibrated with Eagleford shale, which has a Tmax of 412°C and S₂ of 16.91 mg/g. Both the total organic carbon and Rock-eval pyrolysis were conducted at the Baseline Resolution Analytical Laboratory, INC. Shenandoah, Texas.

Bitumen Extraction

Based on TOC adequacy, six (6) selected samples were pulverized and 20 gms of each was taken into cellulose thimbles and extracted in a standard Soxhlet apparatus using 100mls of methylene chloride: methanol solution. The extracts were dried in a rotary evaporator and weighed. This analysis was carried out at the Exxon Mobil Geochemical Laboratory, Qua Iboe Terminal (QIT) Eket., Nigeria

Gas Chromatography of Whole Oil

Each bitumen extract was diluted with a few drops of carbon disulphide while agitating until sample is dissolved. A limited volume was placed in a labelled auto-sampler vial which was transferred to the auto-sampler tray for the analysis to run. 1.0ul of the diluted extract was rapidly injected into the gas chromatograph in split mode, using a graduated Hp 10ul injection syringe.

Gas Chromatography was carried out in a Hewlett Packard 6890A gas chromatograph equipped with dual flame ionization detectors. The chromatograph was fitted with Hp-1 capillary column (30m x 0.32mm

1.Dx0.52microns) using helium as the carrier gas. The column temperature was programmed at 35°C to 300°C/min with a flow rate of 1.1mls/min.

Gas chromatography – Mass Spectrometry

The bitumen extract was separated into saturate, aromatic, resin and asphaltene fractions using liquid chromatography. About 50mg of the extract was weighed into labelled centrifuge tubes to precipitate the asphaltenes, leaving the samples at room temperature for 4 hrs and then centrifuged for 30mins at 1500rpm. The solvent was then decanted into a 20mls pre-weighed vial and dried with nitrogen at 40°C. This procedure yielded the pentane soluble fraction which was weighed and recorded. Surrogate and approximately 2mls of pentane was added to the pentane soluble fraction and mixed. 14gms of activated silica gel was poured into a liquid chromatography column and tapped to pack. 5mls of hexane was added to the column as pre-wet. As the pre-wet entered the gel, the pentane soluble fraction was added followed by additional 5mls of hexane which was collected in a 50mls evaporator tube as the saturates. The pentane in the vial was rinsed with 20mls aliquots of hexane and then added to the liquid chromatography column as previous addition entered the gel. Likewise, the aromatics and the NSO were recovered using methylene chloride and methylene chloride/methanol respectively. The bitumen extraction, whole oil GC and GC/MS analyses were conducted at Exxonmobil Geochemistry Laboratory, Qua Iboe Terminal (QIT), Eket, Nigeria. Detailed analytical procedures can be consulted in Oloba, (2009).

The work flow for this study is shown in Fig. 5.

RESULTS AND DISCUSSION

Petrography

The major microfacies of the limestone are made up of biomicrite, shelly biomicrite, biosparite and sandy biomicrite. The biomicrite contains bioclasts of echinoderms, bivalve, gastropods, ostracods and foraminifera. Some of the bioclasts have recrystallised into microspar and sparry calcite cement. Transverse section of foraminifera, echinoid spine and pelecypod are visible (Fig.6). The sandy biomicrite is exemplified by the presence of sand size quartz. The presence of quartz is associated with terrigenous input which constitutes the basal part of the Ewekoro Formation. The biosparite consists of shell fragments of gastropods, bivalves, some quartz component in sparry calcite. The allochems are set in a matrix that was originally micrite and later re-crystallised to sparry calcite. Majority of these fragments have undergone mineralogical changes leading to obliteration of their original wall structure during inversion from aragonite to calcite or by replacement by spar, which is indistinguishable from the cement occurring between the grains. In the shelly biomicrite, some of the fossils have undergone intense recrystallization.

Organic Matter Richness

The result of total organic carbon (TOC) in wt % is shown in Table 1. It is known that adequate amount of organic matter, measured as percentage total organic carbon (TOC) is a pre-requisite for sediments to generate oil or gas (Conford, 1986) and a measure of the organic richness of sedimentary rocks (Jarvie, 1991). Out of a total sample of twenty (20), only five samples had adequate organic matter. The TOC values for the shale samples of the Akinbo Formation range from 0.59 to 0.62 with an average of 0.60. The lone limestone sample from Ewekoro Formation has a TOC value of 0.58 wt %. This indicates that the shales of the Akinbo Formation satisfy the required threshold value for clastic rocks to generate petroleum though not rich. The limestones are generally lean in organic matter in eastern Dahomey basin (Nton, 2001; Elueze and Nton, 2004, Nton et al., 2009). The shales are thus classified as moderate (having a capacity to yield petroleum) while the limestone generally has low TOC, with only one sample having organic matter above the threshold of 0.3wt% for non clastic rocks to generate petroleum (Dow, 1977; Tissot and Welte 1984).

The soluble organic matter (SOM) of selected shale samples range from 887 to 2472ppm, with an average of 1712 (Table 1). Arising from quality definition of Baker (1972), the shales have adequate bitumen yield while the limestone, with a value of 392ppm, can be termed inadequate and poor.

The free hydrocarbon (S_1) values for the shales range from 0.14 to 0.22 with an average of 0.19 while the limestone has a value of 0.08 (Table 1). According to Peters, (1986); Miles, (1989), the yield is poor. The source rock potential (S_2) for the shales show a range of 0.15 to 0.25 with an average of 0.22; and 0.03 for the limestone. This is also interpreted as poor source rock based on the concept of Peters and Cassa, (1994).

Organic Matter Type

The hydrogen index (HI) for the shales ranges from 25 to 45 with an average of 36 while that of the limestone is 5 (Table 1). Cross plot of HI versus OI (Fig. 7) indicate types III and IV kerogens for the sediments with majority falling in type III. Type IV kerogen indicate inert source rock with no potential for hydrocarbon generation, while Type III kerogen points to an organic matter having prospects to generate gas at appropriate maturation (Dow, 1977, Peters 1986). Peters (1986), suggested that at thermal maturity equivalent to a vitrinite reflectance of 0.6% (T_{max} 435°C), rocks with HI > 300mgHC/gTOC produce oil; those with HI between 150mgHC/gTOC and 300mgHC/gTOC produce oil and gas; those with HI between 50mgHC/gTOC and 150mgHC/gTOC produce gas; and those with HI < 50mgHC/gTOC as applied to the values obtained from this study are inert. The Generic Potential (GP) is generally lower than 2kgHC/ton of rock expected for good source rock (Dymann et al. 1996). This suggests little or no oil source rock potential but some gas potential (Tissot and Welte, 1984; Dymann et al. 1996). Plot of TOC versus GP further supports the gas

prone of the sediments with moderate organic richness (Fig. 8).

Organic matter Maturity

The degree of thermal evolution of sedimentary organic matter can be deduced from T_{max} (°C), production index, bitumen ratio and biomarker parameters. The T_{max} values (Table 1) range from 436 to 467°C with an average of 453°C for the shales and 362°C for the limestone. These indicate that the shales range from transitionally late mature to early peak mature (oil window), but on the average, lie within the early peak mature while the limestone is immature. Cross plot of Hydrogen Index (HI) against T_{max} (Fig.9) further supports type III organic matter/ gas prone and with immature status.

The production index (PI) ranges from 0.39 to 0.51 (average; 0.46) for the shales and 0.72 for the lone limestone sample (Table 1). These values show that the production index increases expectedly with increasing depth of burial of organic matter (Barker 1974). Arising from this study, it can be interpreted that the organic matter is early mature to mature.

The ratio of soluble organic matter to total organic carbon, sometimes called transformation ratio, can be used in determining sediments maturity (Peters and Moldowan, 1993). This ratio varies from near zero in shallow sediments to about 250mg/g TOC at the peak of oil generation and decreases because of conversion of bitumen to gas at greater depths. According to Miles (1989), oil-prone source rocks and gas prone kerogen rarely exceeds 50mg/g TOC at any level of maturity. Thus the anomalous high values for the sediments; 148-399 mgextr/gTOC; (av 285) for the shales and 68 mgextr/gTOC, for the limestone are indications of contamination by migrated oil or man-made products, particularly for the shales. These corroborate an earlier findings by Elueze and Nton (2004) and the report of Peters and Moldowan, (1993). To further highlight the source rock potential of the sediments and ascertain possible levels of contamination, the plot of SOM against TOC (Fig. 10) shows that most of the sediments fall within the field of oil impregnation. However, two samples plot outside this region having, less than 1000ppm extract yield, and is indicative of increasing source rock quality.

The composition and distribution of certain diagnostic chemical fossils can therefore indicate the maximum thermal stress experienced by the rocks or petroleum in which the compounds are found Ekweozor and Strausz, (1982). A typical representative gas chromatogram (Gc-Ms) of pentacyclic triterpane (m/z 191) and steranes (m/z 217) are shown in Figs 11a and 11b. Arising from the chromatograms, an assessment of the thermal maturity level were generated based on maturity parameters (D, E, F, G and H; Table 2). The values show little or no variation to differentiate the degree of thermal evolution. This limited variation probably indicates that the sediments were formed at the same general level of thermal

evolution or that the parameters are not sensitive enough to differentiate the sediments based on their level of thermal maturity. Similar views have been expressed by Sonibare and Ekweozor (2001).

Parameter D (T_s/T_s+T_m ratio) for the shales and limestone are generally less than 0.50; 0.16 to 0.24 for the shales and 0.29 for the limestone and further shows that the samples are immature (Peters and Moldowan, 1993). Parameter F ($22S/22S+22RC32$ ratio) rises from 0 to about 0.6 (0.57 to 0.62=equilibrium during maturation; Seifert and Moldowan, 1986) during maturation. Samples showing $22S/22S+22R$ ratios in the range 0.50 to 0.54 (AD3 and AD4, Table 2.) have barely entered oil generation, while ratios in the range 0.57 to 0.62 indicate that the main phase of oil generation has been reached or surpassed. The values obtained for the samples AD1, AD2 and AD20 (0.56, 0.55, 0.58 correspondingly) indicate that they are marginally mature (Peters and Moldowan, 1993). The values obtained for $\beta\alpha/\beta\alpha+\alpha\beta C30$ hopane (parameter E) indicate thermally immature status for the sediments. This corroborates the findings of Peters and Moldowan, (1993).

The sterane ratios are lower than the values expected for high matured oils derived from source rock that has undergone complete sterane isomerisation as pointed out by Granthman, (1986). High matured oil/bitumen is expected to have $20S/20S+20R$ (parameter G) and $\beta\beta/\beta\beta+\alpha\alpha C29$ (parameter H) sterane ratios of about 0.5 and 0.7 respectively (Seifert and Moldowan, 1986). However the studied samples have values ranging from 0.27 to 0.49 and 0.39 to 0.44 respectively. These low ratios probably indicate that majority of the extracts were of relatively low maturity or that time/temperature constraint on the source rocks had not allowed complete isomerisation of sterane to take place. These views have been expressed by and Sonibare and Ekweozor (2001).

The normalized GC data for the n-alkanes are given in Table 3. In this study, the CPI and isoprenoid/n-paraffin ratios could not be calculated due to depletion of the n-paraffins as a result of biodegradation. The effects of biodegradation and immature status of the organic matter are exemplified by the presence a hump of unresolved complex mixture (UCM) in a typical diffractogram. This corroborates the findings of Ekweozor and Nwachukwu, (1989), Killops and Al-Juboori, (1990) and Elueze and Nton, (2004).

PALAEODEPOSITIONAL ENVIRONMENT

The limestone petrography shows the abundance of gastropods, coralline algae, echinoid spines, pelecypods, and other skeletal debris. These point to a shallow marine environment (Black, 1970; Elueze and Nton, 2004). The matrix supported limestones show deposition in quiet water and low energy environment.

The pristane/phytane (pr/ph) ratios have been used to deduce the redox potential of the source sediments (Didyk et. al, 1978). Arising from this study, pr/ph ratios range from 0.24 to 1.13 (average; 0.48) for the shales

and 1.88 for the limestone (Table 3). These indicate anoxic to oxic conditions for the shales while the limestone is associated with oxic conditions. The relatively high concentration of high molecular weight n-alkanes from the gas chromatograms imply organic matter contributed from predominantly terrestrial plants (Hunt, 1979). In addition, the prevalence of types III and IV kerogens connote terrestrial organic matter thus favouring continental environment, where oxic conditions prevail.

The abundance of pentacyclic triterpane of oleanane and hopane skeletons indicate bitumen extracts derived from source rock of mixed origin (marine and terrestrial). Oleanane has been linked mainly with terrestrial source (Phillip and Gilbert, 1986). The precursors of Oleanane are presumed to be oleanoid triterpenoids, which are associated with highly specialised terrestrial plants such as angiosperm. Hopane type triterpane precursors are widely distributed among bacteria and cyanobacteria (blue-green algae) found in marine environments (Peters and Moldowan, 1993).

The ratios of oleanane to $\alpha\beta$ hopane, otherwise known as oleanane parameter (Parameter A; Table 2) ranges from 0.22 to 0.58 and further permits the grouping of the bitumen extracts into three families depending on the contribution of terrestrial relative to marine organic matter (Sonibare and Ekweozor, 2001). Gammacerane, a C-30 triterpane shows values ranging from 0.07 to 0.18 and indicate source rocks deposited under normal salinity conditions. The presence of C_{27} - C_{29} regular steranes in the bitumen supports a mixed origin of the source rock. C_{27} steranes are believed to be derived from marine source while C_{29} steranes have been linked to higher plant source (Haung and Meinschein, 1979). $C_{29}/C_{28} + C_{27}/\alpha\alpha\alpha$ sterane ratio, which is a mixture of terrestrial relative to marine input ranges from 0.50 to 0.52. This distribution lacked sufficient variation to allow for classification of the bitumen source, suggesting that the bitumen were derived from source rock of similar organic facies or that the parameter is not sensitive enough to differentiate between organic facies within the basin. The cluster percentages of $C_{27}/\alpha\alpha\alpha$ ($20R+S$), $C_{28}/\alpha\alpha\alpha$ ($20R+S$) and $C_{29}/\alpha\alpha\alpha$ ($20R+S$) of the extracts plots (Fig. 12) within terrestrial environment.

SUMMARY AND CONCLUSION

Selected core samples penetrated by the Akinside 1582 well in the eastern Dahomey basin, were investigated to ascertain the different lithofacies, hydrocarbon potential and palaeodepositional environment of the sediments. Petrographic study of the limestones revealed microfacies namely; biosparite, shelly biomicrite, biomicrite, pel-biosparite, sandy pel-micrite and sandy biosparite. Gastropods, brachiopods, bivalves, echinoderm, algae, foraminifera and other skeletal debris represent the main bioclastic components while quartz, peloids, few ooids, intraclasts and glauconite constitute the non-bioclastic grains.

The organic matter quantity suggests a poor to moderate content and strongly supports type III kerogen which is gas prone. Thermal maturity parameters such as Tmax, plot of HI versus Tmax and biomarker parameters indicate immature to early peak maturity for the samples. Fossil assemblages associated with the limestone and the presence of abundant lime mud supported microfacies indicates a shallow marine, quiet water and low energy environment for the carbonates. The abundance of pentacyclic triterpane of oleanane and hopane skeletons and C₂₇ to C₂₉ regular steranes in the bitumen, indicate that they were formed from source rock of mixed origin (marine and terrestrial) while the cluster percentages of C₂₇ to C₂₉ steranes on ternary diagram indicates predominantly terrestrial precursor for the organic matter which is further supported by the relatively high concentration of high molecular weight n-alkanes from the gas chromatographic data.

Further work will entail sampling deeper horizon with increased sampling density for a thorough understanding of source rock potential as well as observe the trends at deeper horizon. This will allow for more making more definite may deductions.

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