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Re-Evaluation of the Petroleum Potential of Bornu Basin, Nigeria

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Abstract

Bornu Basin is the southwestern Chad Basin in N.E. Nigeria. It has both structural and stratigraphic similarities with the proven petroliferous portions of the Chad Basin in Niger and Chad Republics. Its shales meet the minimum TOC requirement for oil generation. In spite of these favourable oil accumulation factors, only non-commercial gas was found in two out of twenty - three wells drilled in Bornu Basin. The petroleum potential of the basin is re-evaluated by using the Lopatin method to estimate its shales' organic maturation level and thereby determine the shales' petroleum generation status. The highest estimated cumulative Time Temperature Index and vitrinite reflectance values attained by Gongilla Formation are 4.26 and 0.56 % respectively. The corresponding values for Fika Shale are 0.28 and 0.3 %. These values are in the thermal immaturity interval. They reflect that the shales neither witnessed catagenesis nor attained the threshold of intense hydrocarbon generation. The highest estimated paleotemperature experienced by Fika Shale is about 48 °C, which is much lower than the minimum temperature requirements for entering into the oil window. These results agree with interpretations of earlier workers based on n- alkane fraction of shales, low values of SOM, SHC and SOM / TOC. Oil found in the Bima Formation in other portions of the Chad Basin, must have been generated in the underlying Pre-Albian shales. By virtues of their age and stratigraphic position, these Pre-Albian shales must have witnessed catagenesis. Pre- Albian shales may be present in deeper portion of Bornu Basin. These portions can be delineated by combined analysis of aeromagnetic and aerogravity maps.

The non-commercial gas found appears to be biogenically generated by the action of anaerobic bacteria on organic rich marine Fika Shale.

Introduction

The Bornu-Basin is the Nigeria portion of the Chad Basin, and is situated east of the Northern Nigerian Massif in N.E Nigeria [fig 1].

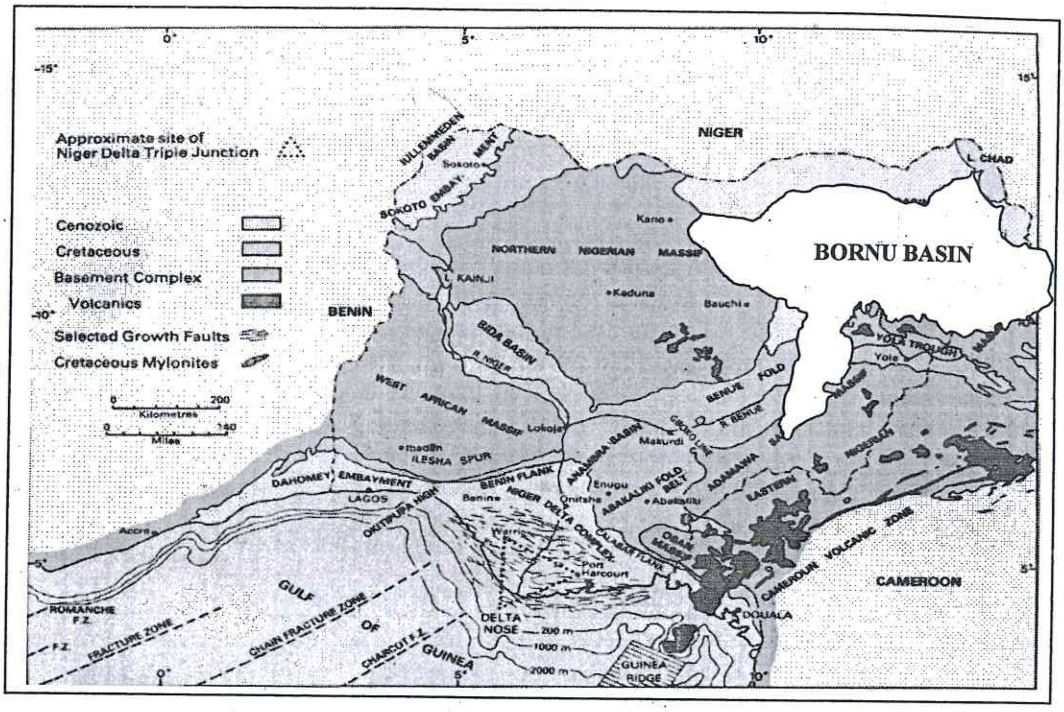


Fig 1: Location map of Bornu Basin and other sedimentary basins in Nigeria [After Whiteman, 1982].

Other portions of the Chad Basin are in eastern Niger, Chad and northern Cameroon [Fig. 2]

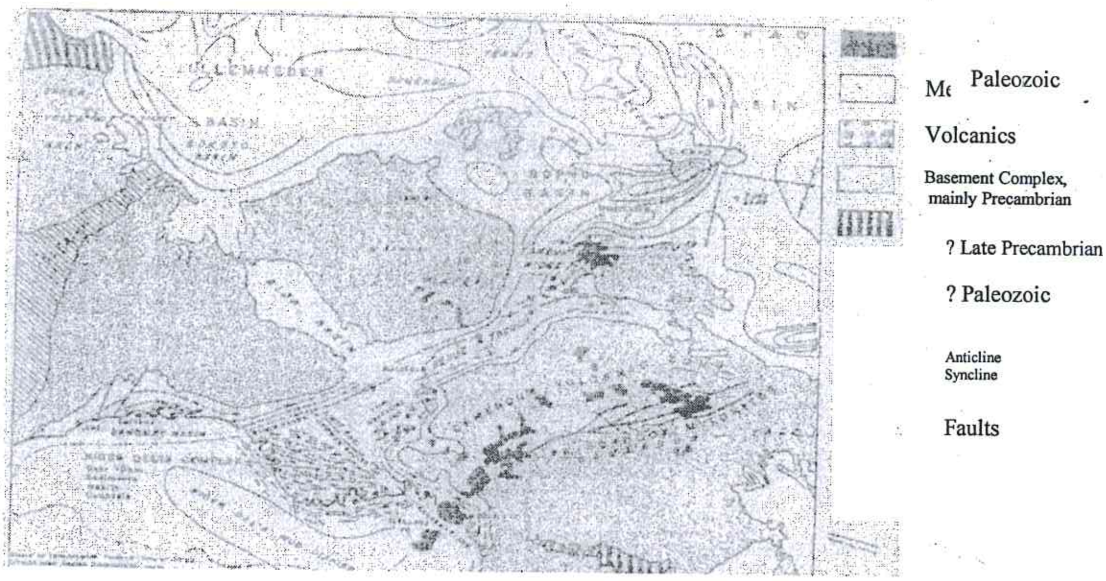


Fig. 2: Cartoon map showing portions of Chad Basin in Chad, Niger, Cameroun and Nigeria (After Whiteman, 1982)

The Bornu Basin is about a tenth of the Chad Basin. The established stratigraphic succession for Bornu Basin [Table1] is contained in

Avbovbo et al [1986] and Okosun [1995, 2002].

Table 1: Stratigraphic Succession for Bornu Basin.

AGE	FORMATION	LITHOLOGY	DEPOSITIONAL ENVIRONMENT
Pliocene- Pleistocene	Chad	Clay, sand, (unconformity)	Continental
Paleocene	Kerri-Kerri	Coarse sandstone, mudstones, (unconformity)	Continental
Turonian-Maestrichtian	Fika Shale	Blue black shales	Marine
Cenomanian – Turonian	Gongila	Sandstone and shale	Marine, Deltaic
Aptian- Albian	Bima	Sandstone (nonconformity)	Continental
Pre- Cambrian	Crystalline Basement		

Adapted from Avbovbo, 1986 and Okosun 1995, 2002.

The Pre-Albian sediments sandwiched between the Bima Formation and Basement in the Chad and Niger portion of the Chad Basin, are yet to be encountered in the Bornu Basin [Ayoola et al 1982). There is a correlation between the Chad Basin in Niger and Nigeria [Fig. 3].

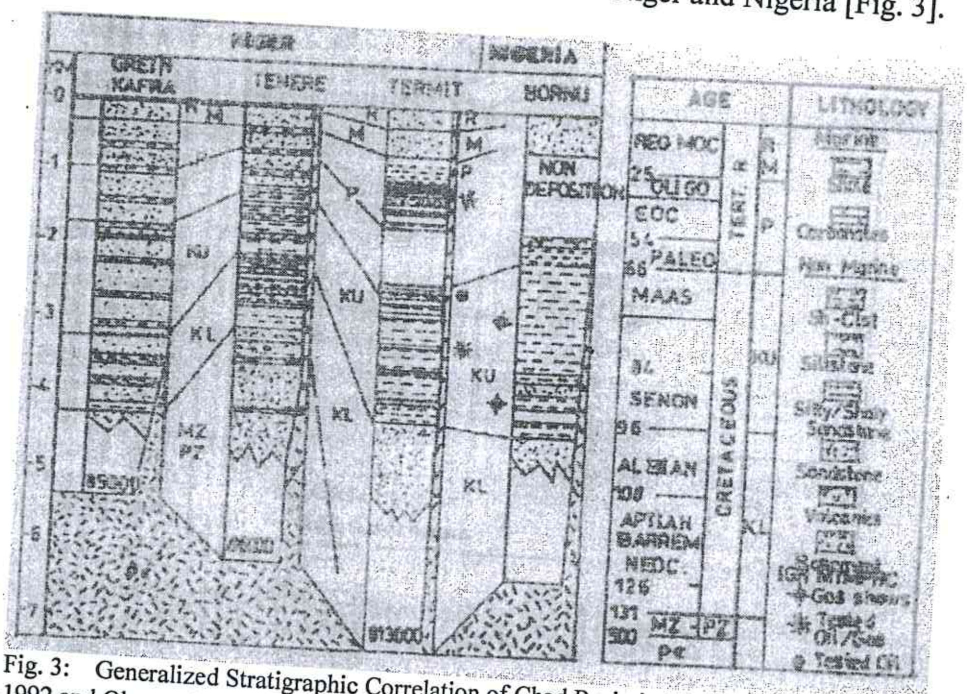


Fig. 3: Generalized Stratigraphic Correlation of Chad Basin in Niger and Nigeria (After Genik, 1992 and Okosun 2002)

Oil has been discovered in the Bima Formation equivalent in the Chad portion of the Chad Basin in the Lake Chad Syncline and around Fort Lamy.

Projected stratigraphic continuity of the proven petroliferous portions of the Chad Basin into the Bornu Basin, has continued to excite hope for oil discovery in the Bornu

Basin. NNPC has done much geophysical work and drilled twenty-three wells for oil in the basin [fig. 4].

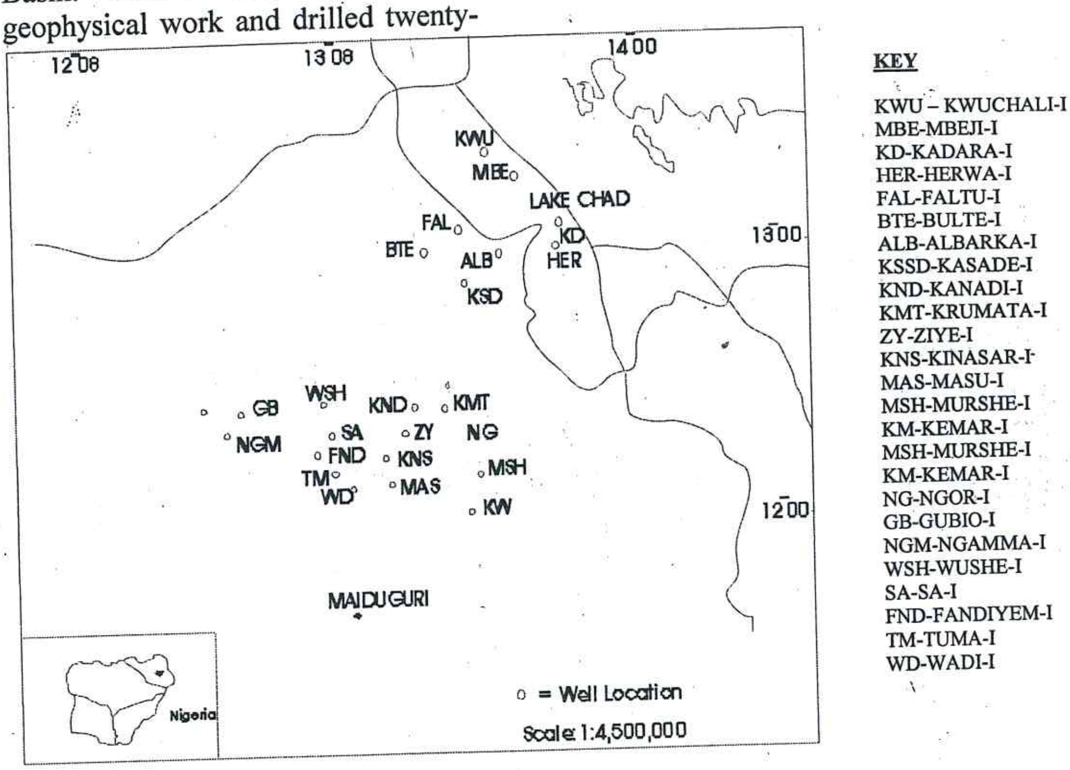


Fig. 4.: Location Map for wells drilled in Bornu Basin (NNPC in – house information)

In spite of the presence of shales with over minimum TOC [total organic content] and the presence of abundant potential structural and stratigraphic traps reported from the Bornu Basin, only non-commercial gas has been discovered in only two wells [Kinasar – 1 and Wadi – 1]. This necessitates a reevaluation of the basin's petroleum potential from the approach of determining the petroleum generation status of its organic rich marine shales. This is attempted in this work by estimating the shales' organic maturation level.

Evaluation Overview and Methodology

The original source of petroleum is the organic content in shales and lime mud deposited in low energy marine environments. As organic rich sediments are buried, their organic content undergoes maturation [also known as organic metamorphism] to generate petroleum in response to rising temperature and time. Organic maturation occurs in graded progression. It passes from diagenetic stage when 90% of the organic content is kerogen, through catagenic stage when oil and gas are produced, into metagenic stage when the eventual products are graphite and methane. The grade of organic maturation is source rock maturity, which can be estimated using and index called vitrinite reflectance [Ro] [Shagar, 2000; Yang et al, 2004]. Ro is initially 0.2% but the value rises steadily with increasing depth of burial and increasing maturity [Baker, 1999]. Oil – prone kerogen starts to generate at Ro of about 0.6%, with peak production being at 0.8 – 0.9%.

At 1.35 Ro, oil is no longer thermally stable and cracks to gas.

In this work, organic maturation level was estimated by the Lopatin method. This popular approach to organic maturation level estimate was introduced by Lopatin (1971) and popularized by Waples (1980). Its primary assumptions are:

{1} Time-temperature inter-relationship determines kerogen maturation, and

(2) Maturation rate is doubled every 10°C temperature rise.

Lopatin method estimates a sedimentary unit's maturation level at any point in it's burial history, using the cumulative sum of all its interval Time.-Temperature-Index values from initial burial to that point in time. It defines a sedimentary unit's interval TTI as the product of its residence times (Δt}within a 10° C temperature interval and the temperature interval's factor also known as the weightng factor].

Interval TTI = $\Delta t . r^{n}$ ------- Eqn 1

Every 10^{0} C temperature interval caries an index value (r^{n}) – Table2.

Table 2: list of temperature intervals, index values, and temperature factors for the calculation of TTI integrals

After Waples (1980).

$$\text{Cumulative TTI} = \sum_{n\,min}^{n\,max} \Delta t . r^{n} \text{ ------------Eqn 2}$$

Temperature Interval (°C)	**Index Value, n**	**Temperature Factors, r^{n}**
20 -30	-8	2^{-8}
30 – 40	-7	2^{-7}
40 – 50	-6	2^{-6}
50 – 60	-5	2^{-5}
60 – 70	-4	2^{-4}
70 – 80	-3	2^{-3}
80 – 90	-2	2^{-2}
90 – 100	-1	2^{-1}
100 – 110	0	1
110 – 120	1	2
120 – 130	2	2^{2}
130 – 140	3	2^{3}
	m	2^{m}

n max and n min on the summation symbol are the respective index values for the highest and lowest temperature intervals encountered.

The cumulative TTI values are converted to R_o using Fig5, which is a plot of Waples (1980) correlation between TTI and R_o derived from 402 worldwide samples.

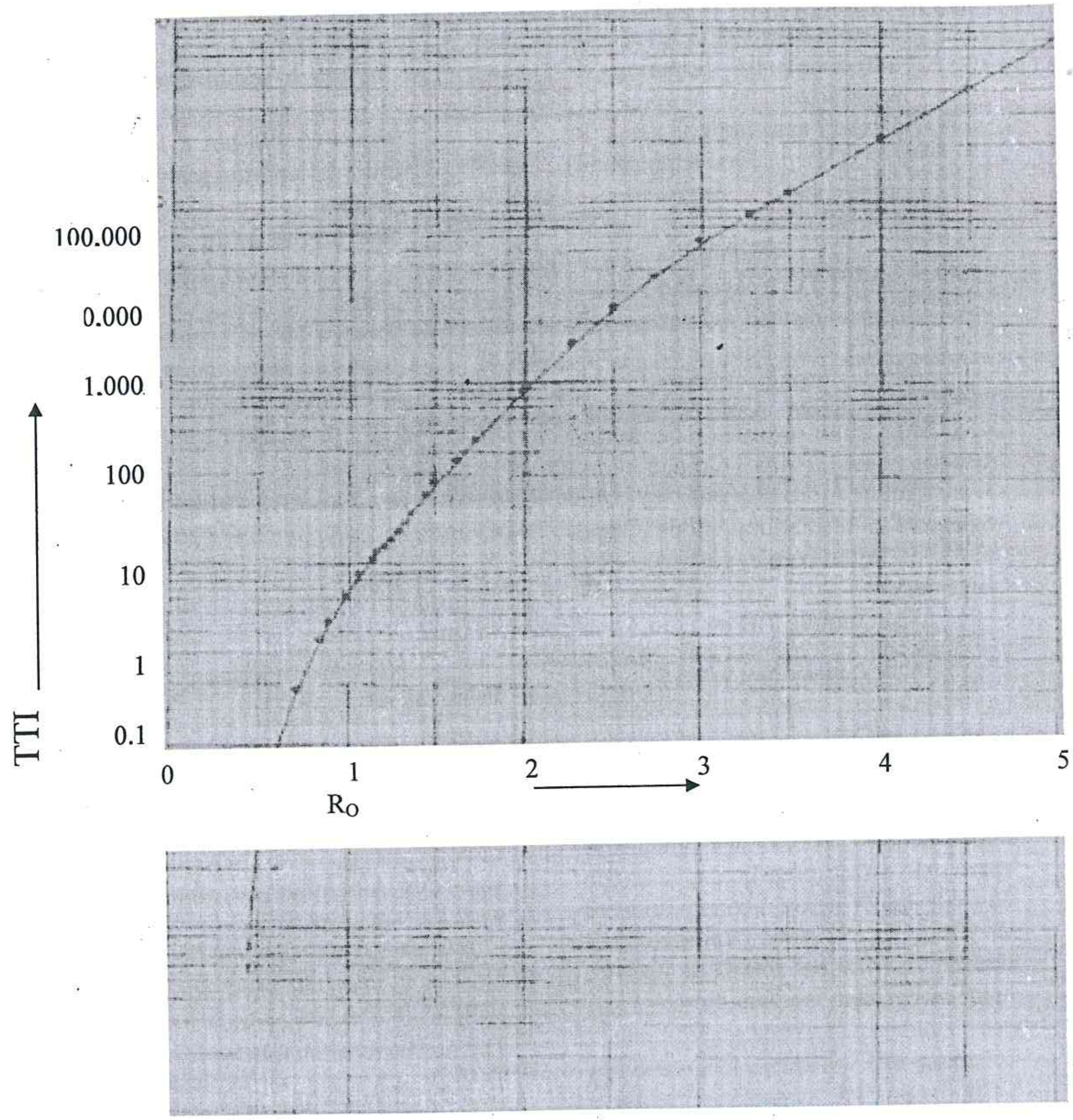


Fig. 5 Empirical relationship between TTI and Ro (After Waples 1980)

The cumulative TTI and R_o values are correlated with several important stages of oil generation, using table 3.

Table 3: Correlation of TTI with several important stages of oil generation (Waples, 1980)

STAGE	TTI	% Ro
Onset of Oil Generation	15	0.68
Peak Oil Generation	75	1.00
End of Oil Generation	160	1.30
Upper TTI limit for Occurrence of Wet Gas	6500	3.50

Δt and r^n were inferred from burial history plot and paleotemperature profile. The burial history plot was made by reconstructing the depth to the respective formation tops and basement top through past geologic time.

The burial history plot was corrected for compaction effects, using combined methods of Falvey and Middleton (1981), Middleton (1984), Onuoha (1985), Magara (1986) and Onouha and Ofoegbu (1988).

Falvey and Middleton (1981) states that if the present depth to top and bottom of a sedimentary unit are Z_1 and Z_2 respectively, depth to top of the unit Z_3 and bottom of the unit Z_4 at an earlier time is given by:

$$Z_4 - {}^1/C \ln [1+\phi_o CZ_4] = h_s + Z_3 - {}^1/C \ln [1+\phi_o CZ_3] \quad \text{- Equ 4}$$

Where $h_s = \int_{Z_1}^{Z_2} \left[1 - \phi_{[z]} \right] dz$ - Eqn 5

C is gradient of ϕ – Z [porosity – depth linear plot on a semi – log graph sheet] and ϕ_o is sediment's surface porosity. Knowing h_s, Z_3 is set to zero and Z_4 determined by iteration.

Using the exponential relationship $[\phi_{[z]} = \phi_o e^{-cz}]$ between ϕ and depth,

h_s is solved for as follows:

Substituting for $\phi_{[z]}$ in Eqn 5,

$$h_s = \int_{Z_1}^{Z_2} \left[1 - \phi_o\, e^{-CZ}\right] dz \qquad - \quad Eqn 6$$

$$h_s = \int_{Z_1}^{Z_2} (1)\, dz - \int_{z_1}^{z_2} \phi_o\, e^{-CZ}\, dz \qquad - \quad Eqn\ 7$$

$$h_s = \left[Z\right]_{Z_1}^{Z_2} - \left[-\frac{\phi_O}{C} e^{-CZ}\right]_{Z_1}^{Z_2} \qquad - \quad Eqn\ 8$$

$$h_s = \left(Z_2 - Z_1\right) - \left[-\frac{\phi_o}{C} e^{-CZ_2} - \left(-\frac{\phi_O}{C} e^{-CZ_1}\right)\right] \qquad - \quad Eqn\ 9$$

$$h_s = \left(Z_2 - Z_1\right) - \left[-\frac{\phi_O}{C} e^{-CZ_2} + \frac{\phi_O}{C} e^{CZ_1}\right] \qquad - \quad Eqn\ 10$$

$$h_s = \left(Z_2 - Z_1\right) + \frac{\phi_O}{C} e^{-CZ_1} - \frac{\phi_O}{C} e^{-CZ_1} \qquad - \quad Eqn\ 11$$

$$h_s = \left(Z_2 - Z_1\right) + \frac{\phi_O}{C} \left(e^{-CZ_2} - e^{-CZ_1}\right) \qquad - \quad Eqn 12$$

Paleotemperature profile is a plot of the temperature attained by a sedimentary unit at different depths, as it is buried deeper and deeper through geologic time.

Falvey and Middleton (1981), Onuoha (1985) Magara (1986), and Onuoha and Ofoegbu (1988) estimated paeotemperature profile using:

T (t) = To + G (t) . Zs (t) - Eqn. 13.

T (t) represents a sedimentary unit's temperature at time t m.y. [in the past] when the sediment's top was Zs, and geothermal gradient and surface temperature were G(t) and T_o respectively.

In this work, 20°C was chosen T_o [Onuoha 1985, Onuoha and Ofoegbu 1988], 2..4°F/100 Ft [converted from 26.°C/km of Ali and Onuoha, 1998] was chosen for G(t), 0.55 was chosen for ϕ_o [Middleton, 1984; Onuoha and Ofoegbu, 1988] and 0.0006 chosen for C [Magara, 1986].

Data Presentation

The well-site stratigraphy observed at Kinasar – 1 is Fig 6 [Okosun, 1995 and 2002].

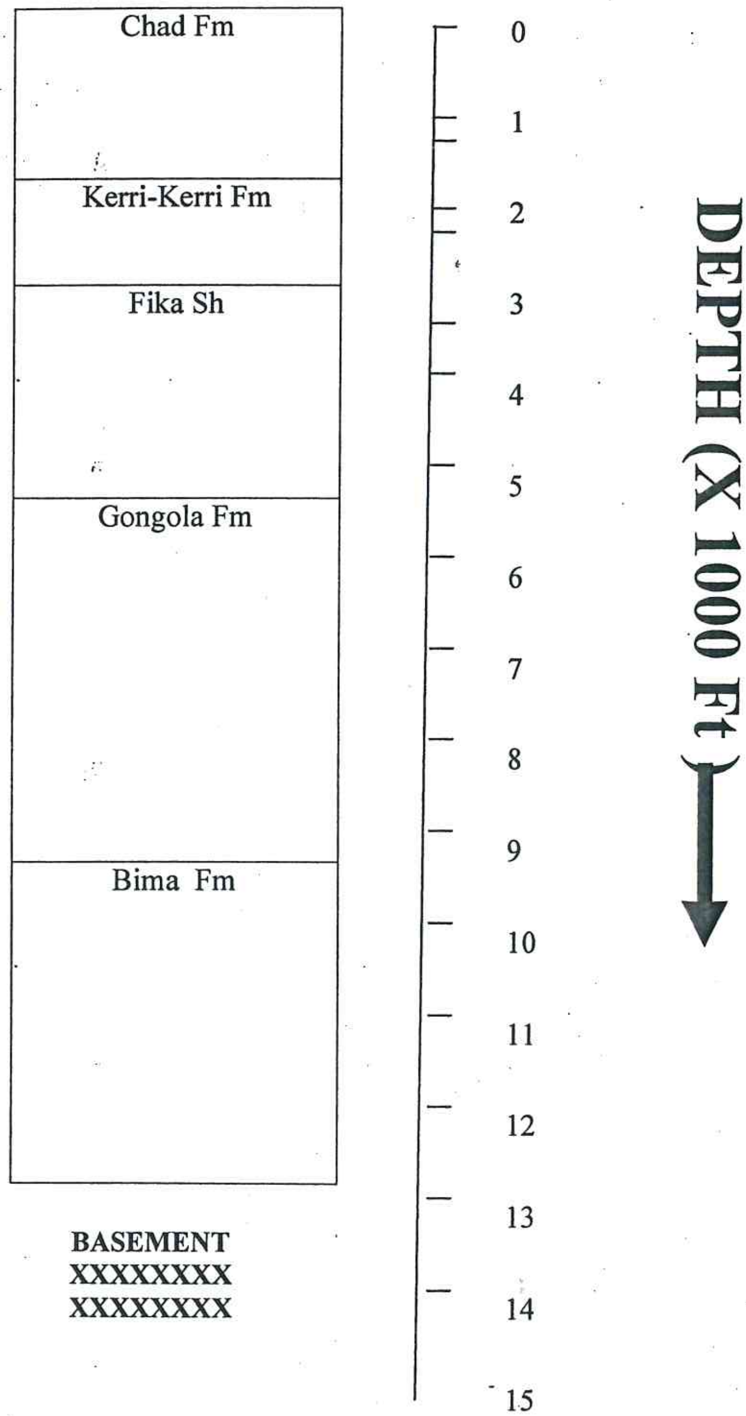


Fig 6: well – site stratigraphic profile at kinasar-1 (After Okosun, 1995 and 2002)

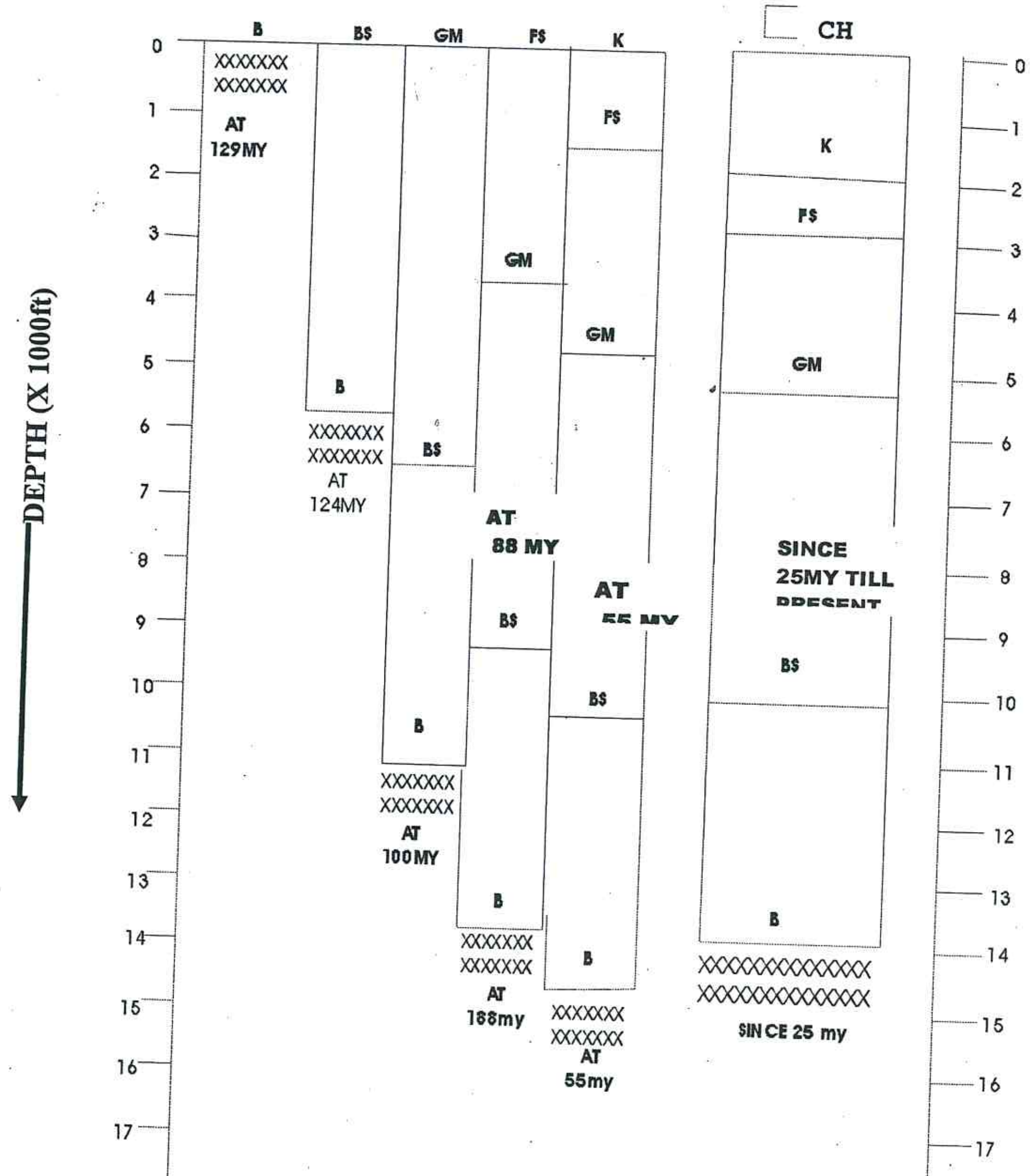


Fig. 7: Compaction – corrected burial depth history for KINASAR - 1

KEY

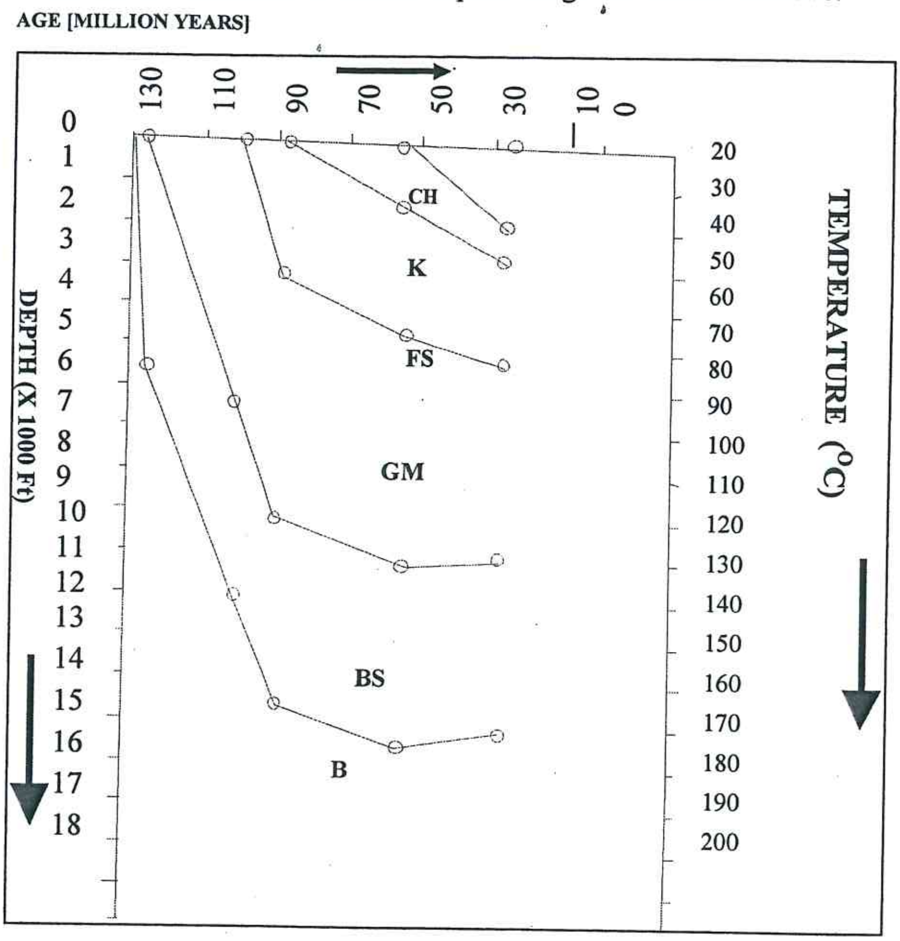
B:	BASEMENT	BS: BIMA FORMATION	GM: GONGILA FORMATION
FS:	FIKA SHALE	K: KERRI-KERRI FORMATION	
CH:	CHAD FORMATION	MY:	MILLION YEARS

The compaction – corrected burial depth history of the well –site formations, from the time the basement was at the surface in the Aptian to when the Chad Formation has been at surface [since the Oligocene] is Fig 7 above.

Table 4: Paleotemperature Estimates

Depth (Ft)	Paleotemperature Estimate
1469	103.3°F [39.59°C]
3623	155°F [68.31°C]
4676	180°F [82.35°]
5661	203.9°F [95.48°C]
6527	224.7°F [107.03°C]
9271	290.5°F [143.61°C]
10206	313°F [156.08°C]

The paleotemperatures estimated at various depths are given in table 4 above.



KEY

B: BASEMENT BS: BIMA FORMATION GM: GONGILA FORMATION
FS: FIKA SHALE K: KERRI-KERRI FORMATION

Fig. 8: Combined burial history and paeotemperature plot for well-site at KINASA-1

The combination of paleotemperature profile with burial history plot is given in Fig 8 above.

Tables 5 and 6 are tabulations of temperature interval, temperature factor, resident times, interval TTI and cumulative TTI for Gongila Formation and Fika Shale respectively.

Table 5 [Gongila Formation]

Temperature Interval (°C)	Temperature factor (r^n)	Residence Times (Δt)	Interval TTI ($\Delta t_n r^n$)	Cumulative TTI
20 - 30	2^{-8}	3.5	0.01367	
30 – 40	2^{-7}	3.5	0.02734	
40 – 50	2^{-6}	4	0.0625	0.10351
50 – 60	2^{-5}	19	0.59375	0.09726
60 – 70	2^{-4}	33	2.0625	2.75976
70 – 80	2^{-3}	12	1.5	4.26
				[Ro = 0.56%]

Table 6 [Fika Shale]

Temperature Interval (°C)	Temperature factor (r^n)	Residence Times (Δt)	Interval TTI ($\Delta t_n r^n$)	Cumulative TTI
20 – 30	2^{-8}	23	0.0898	
30 – 40	2^{-7}	22.5	0.17578	
40 – 50	2^{-6}	18.5	0.28906	
				0.55464
				Ro=0.3 %.

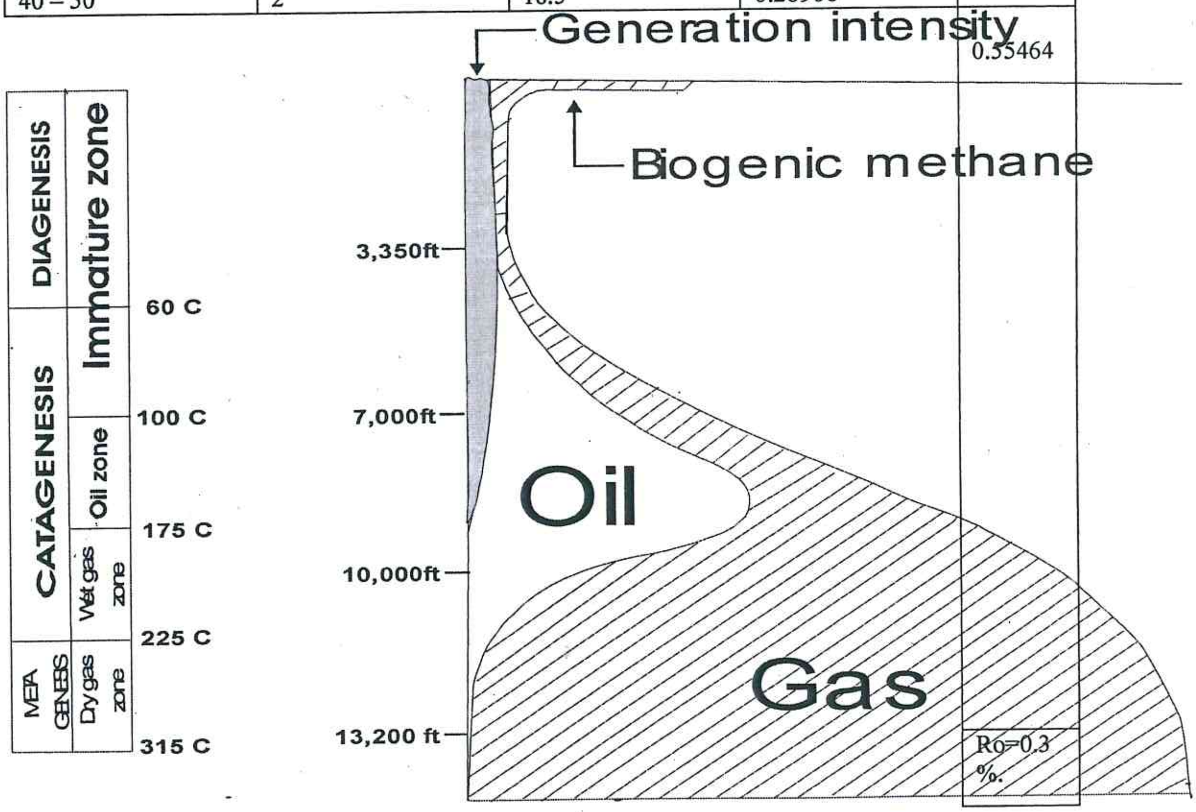


Fig. 9: Petroleum generation in relation to temperature and depth. (Adapted from Tissot and Welte 1978)

Data Analysis and Discusion

The highest value of cumulative TTI for Gongila Formation is 4.25976 [Table 5]. This is far below the minimum cumulative TTI of 15 (Lopatin, 1971; Waples,1980; Onuoha,1985; Magara,1986 ; Shagar,2000) required to reach the onset of oil generation – table 3. The corresponding estimated Ro value is 0.56% [Fig 5], which is far below the minimum 0.65% (table 3)required to initiate oil generation. The maximum paleotemperature attained by the Gongila Formation is 74°C [Fig 8]. It spent only 45 M.Y. [out of its 96 M.Y .age] between 60 and 75°C [Fig 8 and table 4] in the lowest portion of the oil window temperature interval [Fig 9].

It never met the 100°C temperature requirement for vigorous or peak oil generation. Thus the Gongila Formation shows thermal immaturity of its organic content.

The highest cumulative TTI value for Fika shale is 0.3546 [table 6]. This is much lower than the minimum requirement for initiating oil generation. The corresponding estimated Ro [0.3%] is also below the oil generation minimum. It is obvious from Fig 8 that the Fika Shale never attained the minimum temperature requirement for oil generation, its maximum paleotemperature being about 48°C. Thus Fika Shale is also marked by thermal immaturity of its organic content.

Idowu and Ekweozor (1993) reported low values of SHC/TOC [ratio of saturated hydrocarbons to total organic content], low values of SOM/TOC [ratio of soluble organic matter to total organic carbon content], and n – alkane distribution pattern that reflect thermal immaturity for Gongila Formation and Fika Shale. They reported that the n- alkane fraction of the shales shows an odd – even predominance in the range of 1.3 to 1.5, which is an unequivocal evidence for low maturity status. Petters and Ekweozor (1982) also observed low SOM/TOC values for the Gongila Formation and Fika Shale. This they interpreted as indicators of thermal immaturity.

Thermal immaturity indicates that the shales were never opportune to attain TIHG [the threshold of intense hydrocarbon generation]. This accounts for the non-discovery of oil in the twenty-three wells that have been drilled in the basin. There is no indication that the shales experienced catagenesis [the thermochemical transformation of kerogen into oil and gas].

The non – commercial gas discovery in Kinasar – 1 and Wadi – 1 could be biogenic gas generated by anaerobic bacteria activity at depths at temperature below 60%. With the entire organic – rich marine Fika Shale unable to attain 60°C, anaerobic bacteria had field day transforming the organic matter into biogenic gas. The biogenic gas migrated into and accumulated in sands interbedded with shales in the Fika Shale and in the overlying Kerri – kerri Formation. Baker (1999) reported that commercial accumulations of biogenic gas are known from parts of the world.

The oil found in Bima Formation in the Chad and Niger portions of the Chad Basin (the Lake Chad Syncline) must have been generated from the marine shales of the underlying Paleozoic sediments. Stratigraphically positioned between Bima Formation and basement, the Paleozoic sediments are at depths that must have attained paleotemperatures that supported catagenesis.

It is obvious from Eqn 1 that even where geothermal gradient is low, several hundred millions of years of passing time [such as with the Paleozoic sediments of Chad Basin] will force organic rich sediments into catagenesis. Thus oil exploration in Bornu Basin should be dictated by the search for Paleozoic sediments in its subsurface. This could be achieved by delineating the deeper portions of the basin through combined analysis of aeromagnetic and aerogravity maps, followed with seismic stratigraphic analysis of seismic sections from the delineated portions. Most of the wells already drilled in the basin [Wadi-1,SA-1,Kanadi-1, Albarka-1,Mbeji-1] bottomed in Gongila Formation, while a few others bottomed in Fika Shale [for example Wushe1]. Efforts should be made to penetrate the entire stratigraphic succession of the basin.

Conclusions

The discovered non-commercial gas in Bornu Basin is biogenic gas generated by anaerobic bacteria action on organic rich marine Fika Shale. The Fika Shale and the Gongila Formation have not gone through the catagenic phase of organic matter transformation. The oil found in Lake Chad Syncline results from catagenesis of Paleozoic sediments underlying the Bima Formation coeval strata. The Paleozoic or Pre-Albian sediments are yet to be found in Bornu Basin. Their search is thus crucial to the search for oil in the Bornu Basin.

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