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Hydrocarbon Potential of the Lithostratigraphic Units in Late Cenomanian-Early Paleocene Shale, Southwestern Chad Basin

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Abstract: The Chad Basin is the largest intracratonic basin we have in Africa. About one tenth of its surface area lies in the northeastern part of Nigeria. Organic geochemical studies (pyrolysis) have been carried out on late Cenomanian to early Paleocene shale retrieved from the Bima, Gongila and Fika Shale Formations. The samples are from *Tuma* and *Sa* exploratory wells, which are located about 50 km apart in the northeastern fringe of Nigeria. The organic matter is predominantly gas prone (Type III kerogen). The assessed thermal maturation indices indicate that the Gongila Formation and basal section of the Fika Shale Formation are within the "oil window". The "oil window", deduced from the T_{max}, calculated % VRo and kerogen conversion T_{max}, occurs between 1,630m-2,215m in the *Tuma* well and 2,340-2,345 m in the *Sa* well respectively. The Fika Shale Formation and Gongila Formation have good source-rock potential in terms of its organic carbon content, but have low thermal maturity. The Gongila Formation (*Tuma* well) and the lower part of the Fika Shale Formation (*Sa* well) are poor in organic carbon and its hydrocarbon potential may already have been exhausted. The Bima Formation is not within the "oil window" and they have limited potential as a source rock, due to the presence of clastic and inert materials. However, the potential for gas accumulations do exists within the area.

Key words: Organic matter . thermal maturation . oil window . kerogen . source rock

INTRODUCTION

The Chad Basin is a sub unit of the large and connected chain of interior cratonic basins in Africa, whose origin are closely connected to the separation of the Gondwanaland during the Cretaceous [1]. The consensus among these workers is that the Chad Basin is the product of rifting, subsidence and sedimentation that accompanies the separation of the African and South American continents. In Nigeria, the Chad Basin has been the focus of exploratory drilling by the Nigerian National Petroleum Corporation (NNPC) since early 1980s. This project was based on the fact that this sector of the basin is a counterpart of the Sirte Basin of Libya which is producing [2], as well as the oil and gas indications in the eastern and western parts of the basin in the neighboring Republic of Chad and Niger within 1300m to 3450m depth range [1]. The pre-drilling investigations into the potential for hydrocarbon occurrences embarked upon by the NNPC have generated a lot of controversies. The present study attempt to assess the organic geochemistry (Rock-Eval II pyrolysis), to determine the organic and thermal maturity as well as the organic matter content of these exploratory wells. The two wells are located about 50 km apart (Fig. 1 and 2). This study is a preliminary evaluation of source rock potential and thermal maturation of this basin.

The geology and stratigraphic review of the study area: The Chad Basin is a broad intracratonic depression in Central West Africa containing buried rifts in the Niger Republic. The sedimentation of the Chad Basin commenced with the deposition of continental, poorly sorted, sparsely fossiliferous, medium to coarse grained, sandstone (Bima Formation) lying directly on the basement. This study revealed that the formation is composed of intercalation of shale (Heterolith) and sandstones, as reported by some authors [3, 4]. Overlying the Bima Formation is the Gongila Formation that is composed of sandstones and bluish black shale (calcareous) deposited in a shallow marine milieu. These deposits mark the onset of marine incursion into this basin. This transgression reached its pinnacle in the Turonian, (during which the Fika Shale Formation was deposited in an open marine milieu) and continue into Senonian after which a regressive phase of deposition occurred. In the Maastrichtian, estuarine and/or deltaic milieu prevailed which led to the deposition of the Gombe Sandstone in some part of the northeastern Nigeria. The formation constitutes intercalated shale, siltstones and ironstones.

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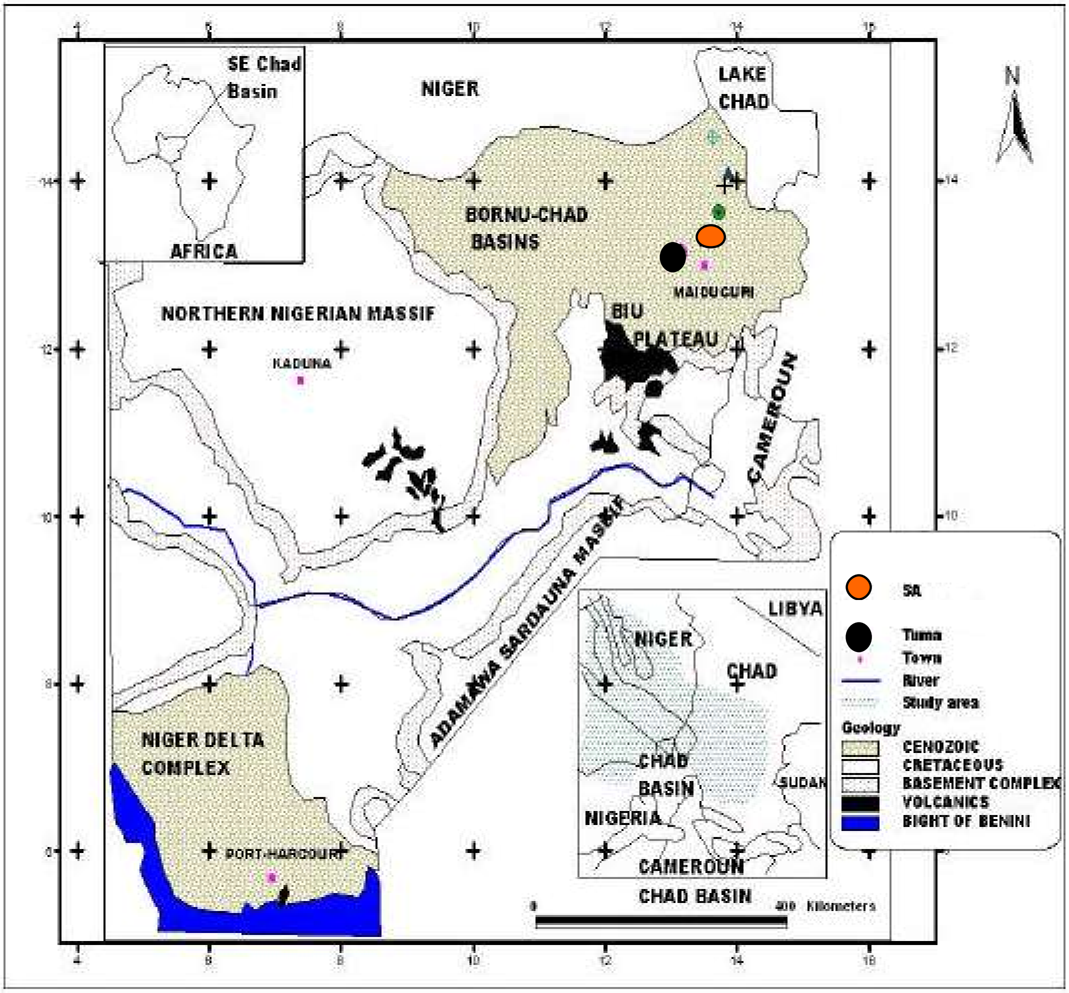

Fig. 1: Geological Map of Nigeria showing the Location of the Nigerian sector of the Chad Basin (Bornu Basin) and the studied wells [1, 15]

An extensional deformation that occurred in the Late Maastrichtian lasted to the end of the Cretaceous. This basin was later restructured into an elongate NE-SW graben system The sub basins that succeeded this deformation created space for the emplacement of the Tertiary Kerri-Kerri Formation, which overlies unconformably, the Cretaceous sediments [3]. In the Pleistocene via Pliocene, the continental Chad Formation was unconformably laid down over Kerri-Kerri and/or Gombe Sandstone Formations. However towards the end of the Tertiary up to Recent, there are widespread of volcanic activity occurrences in the southern and central part of the basin [5].

The lithostratigraphic successions observed in the studied wells and the sampled intervals are shown in Fig. 2. The *Tuma* and *Sa* wells penetrated the Bima, Gongila, Fika Shale and Chad Formations with a total depth of 3,630m and 2,460m respectively.

MATERIALS AND METHODS

Twenty-two shale ditch cutting samples of the late Cenomanian-early Paleocene age were carefully selected at regular intervals subject to the organic matter content. They are subjected to Rock-Eval II pyrolysis in the Activation Laboratories, Canada, according to the procedures described by [6, 7]. The parameters obtained from Rock-Eval II pyrolysis include Total Organic Content (TOC), Thermal maturity (T_{max}), Hydrogen Index (HI), Oxygen Index (OI), S1, S2 and S3 (Table 1). The Geochemical logs for the studied wells are represented in Fig. 3.

RESULTS AND DISCUSSION

The geochemical characterization results are presented in Table 1 and Fig. 4-8. The pyrolysis results show that TOC ranges from 1.06 % w/w at the base of

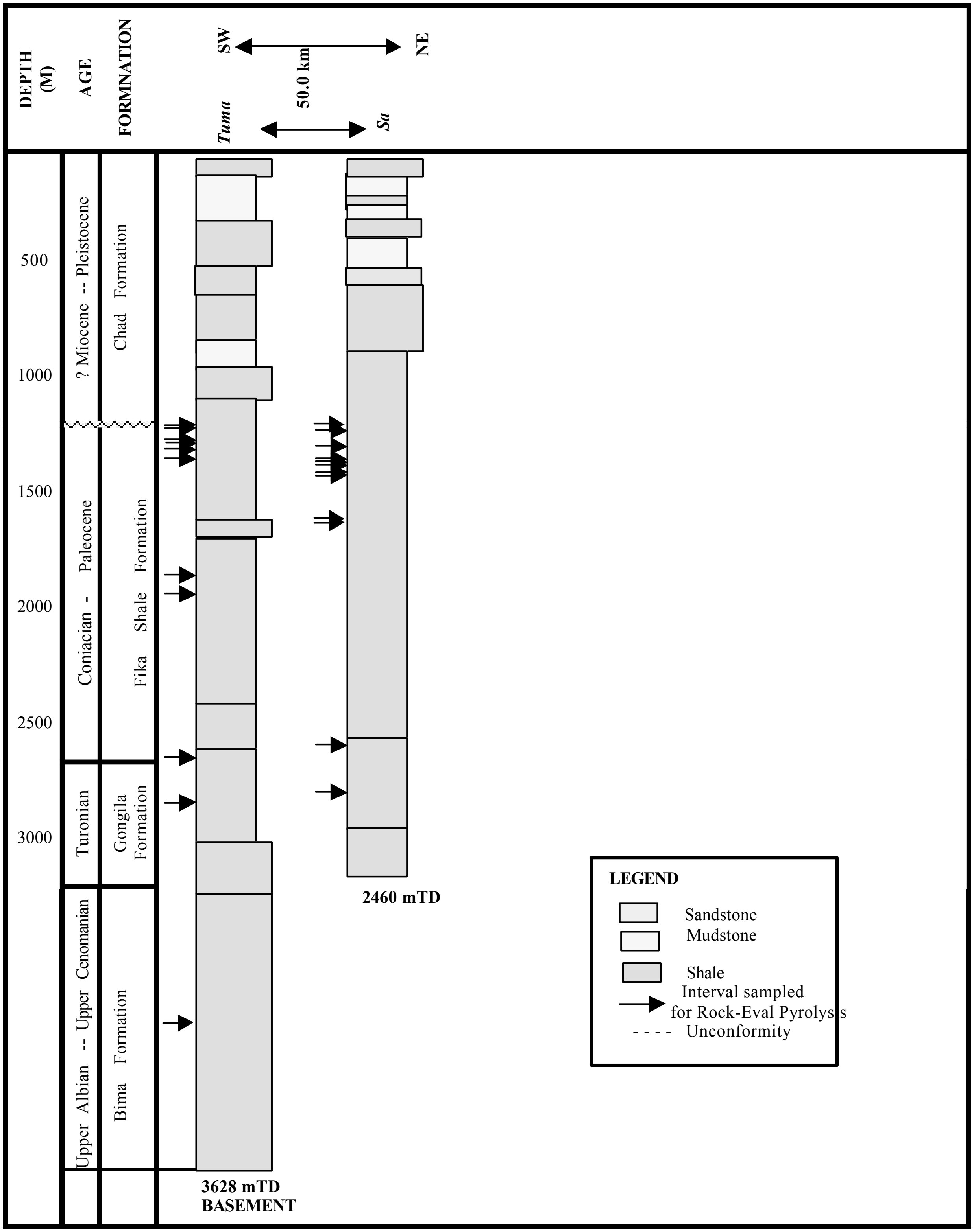

Fig. 2: Lithostratigraphic succession and sampled intervals in *Tuma* and *Sa* well

Table 1: Results of rock-eval pyrolysis for *Tuma* and *Sa* wells

Sample No	Depth (m)	Formation	TOC (wt %)	T_{max} (°C)	HI (mgHc/gTOC)	OI (mgCO$_2$/gTOC)	S_1 (mg/g)	S_2 (mg/g)	S_3 (mg/g)	S_1+S_2 (Kg^{-1}t^{-1})	S_1/TOC (mgHC/gTOC)	S_2 /S_3	PI (S_1/S_1+S_2)	SOM (Ppm)	SHC (Ppm)	AHC (ppm)
Tuma WELL																
TS 1	995-1000	Fika formation	1.23	424	132	31	0.17	1.60	0.36	1.77	0.14	4.44	0.10	2150	1245	810
TS 2	1005-1010	Fika formation	1.58	428	27	17	0.20	0.41	0.25	0.43	0.01	1.64	0.05	*	*	*
TS 3	1075-1090	Fika formation	1.47	431	61	15	0 40	0.87	0.20	1.27	0.27	4.35	0.04	*	*	*
TS 4	1095-1100	Fika formation	1.41	427	36	13	0.03	0.49	0.17	0.52	0.02	2.88	0.10	*	*	*
TS 5	1275-1280	Fika formation	2.18	427	91	24	1.03	1.96	0.50	2.99	0.47	3.92	0.34	3000	1640	780
TS 6	1500-1510	Fika formation	1.35	428	53	48	1.57	0.70	0.63	2.27	1.16	1.11	0.69	945	555	850
TS 7	1630-1635	Fika formation	1.11	441	28	22	0.16	0.30	0.23	0.46	0.14	1.30	0.35	*	*	*
TS 8	2200-2215	Gongila formation	1.23	482	10	10	0.60	0.11	0.11	0.71	0.49	1.00	0.35	*	*	*
TS 9	2485-2495	Bima formation	1.22	413	27	25	0.20	0.31	0.17	0.51	0.16	1.82	0.39	*	*	*
TS 10	3105-3120	Bima formation	1.06	*	59	46	1.20	0.61	0.47	1.81	0.13	1.30	0.66	2200	1465	830
Sa WELL																
SS 21	920-925	Fika formation	1.09	427	89	44	0.47	0.97	0.48	1.44	0.43	2.02	0.33	*	*	*
SS 22	980-985	Fika formation	1.18	421	69	21	0.18	0.80	0.23	0.98	0.15	3.48	0.18	*	*	*
SS23	1085-1090	Fika formation	1.20	424	79	26	0.13	0.95	0.31	1.08	0.11	3.06	0.12	*	*	*
SS 24	1100-1105	Fika formation	1.58	425	95	24	0.20	1.49	0.37	1.69	0.13	4.03	0.12	*	*	*
SS 25	1140-1145	Fika formation	1.43	426	68	41	0.16	0.95	0.57	1.11	0.11	1.67	0.14	*	*	*
SS 26	1160-1165	Fika formation	1.31	418	60	36	0.17	0.79	0.47	0.96	0.13	1.68	0.18	*	*	*
SS 27	1200-1205	Fika formation	1.31	429	60	25	0.11	0.77	0.32	0.88	0.08	2.41	0.13	*	*	*
SS 28	1220-7225	Fika formation	1.72	426	101	21	0.19	1.71	0.34	1.90	0.11	5.03	0.10	*	*	*
SS 29	1300-1305	Fika formation	1.03	430	14	24	0.06	0.13	0.23	0.19	0.06	0.57	0.32	*	*	*
SS 30	1340-1343	Fika formation	1.02	429	59	27	0.16	0.60	0.26	0.76	0.16	2.31	0.21	*	*	*
SS 31	2180-2185	Fika formation	1.45	494	09	12	0.10	0.12	0.16	0.22	0.07	0.95	0.45	525	360	749
SS 32	2340-2345	Gongila formation	1.02	446	23	22	0.15	0.22	0.21	0.37	0.15	1.05	0.41	240	140	690

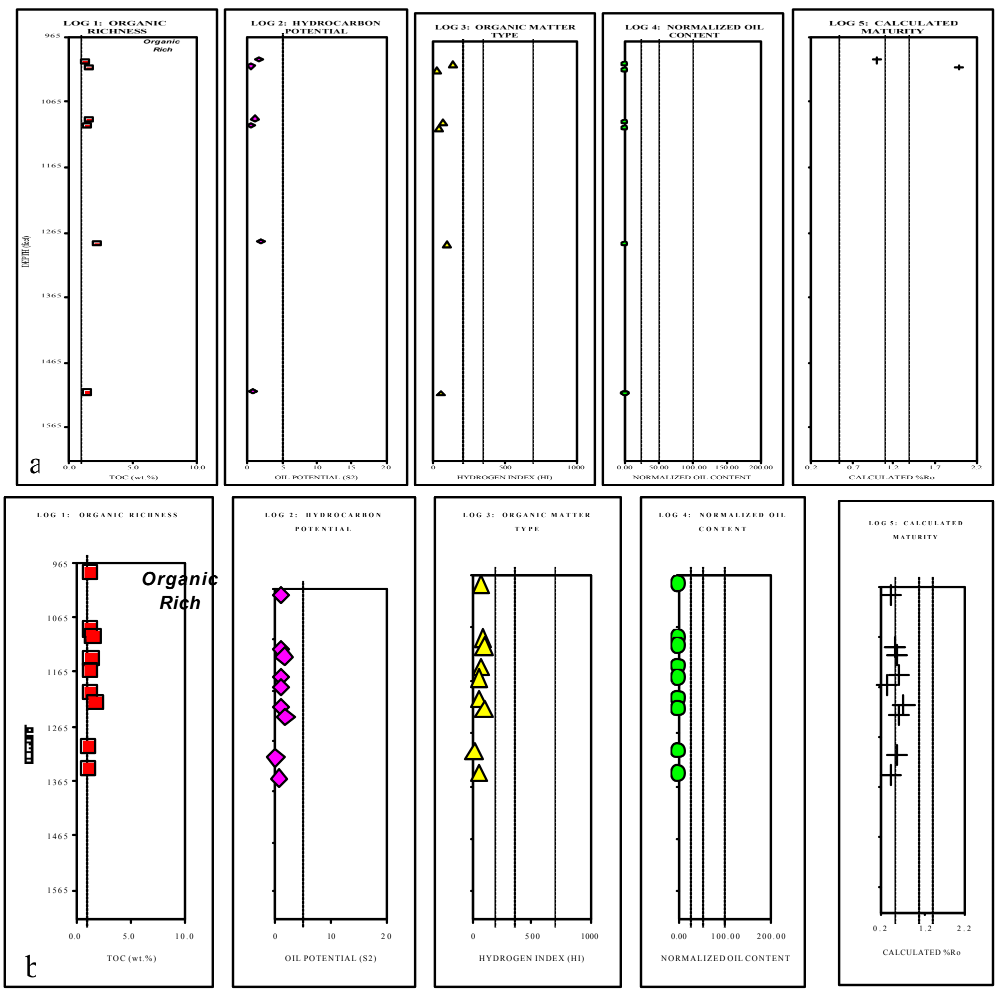

Fig. 3: Geochemical logs of (a) *Tuma* and (b) *Sa* wells

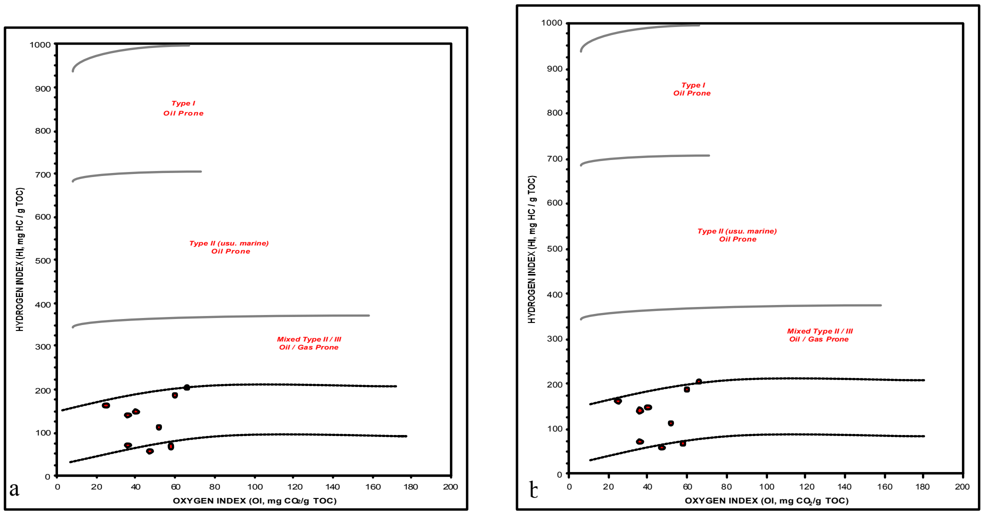

Fig. 4: Kerogen Type for (a) *Tuma* and (b) *Sa* wells

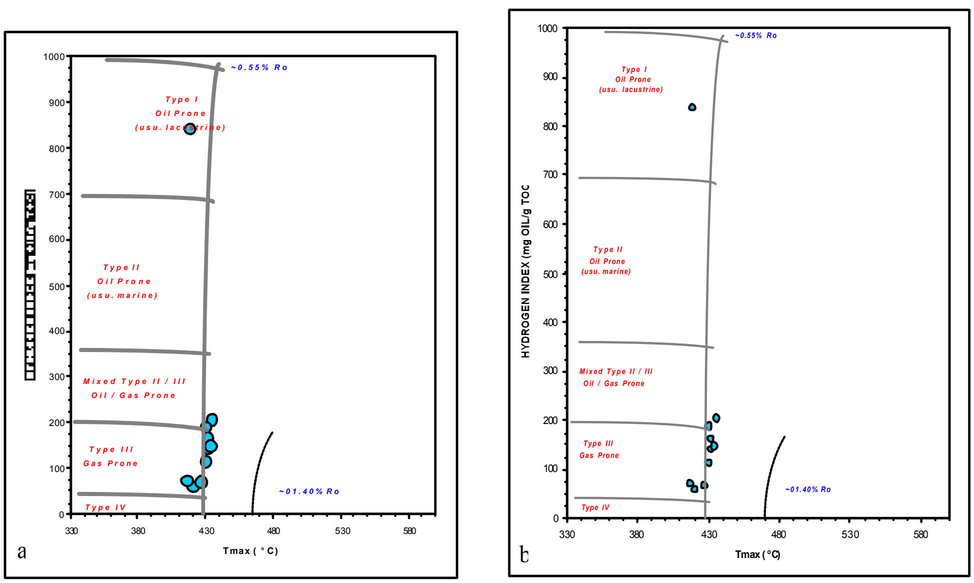

Fig. 5: Kerogen Type and Maturity (T_{max}) for (a) *Tuma* and (b) *Sa* well

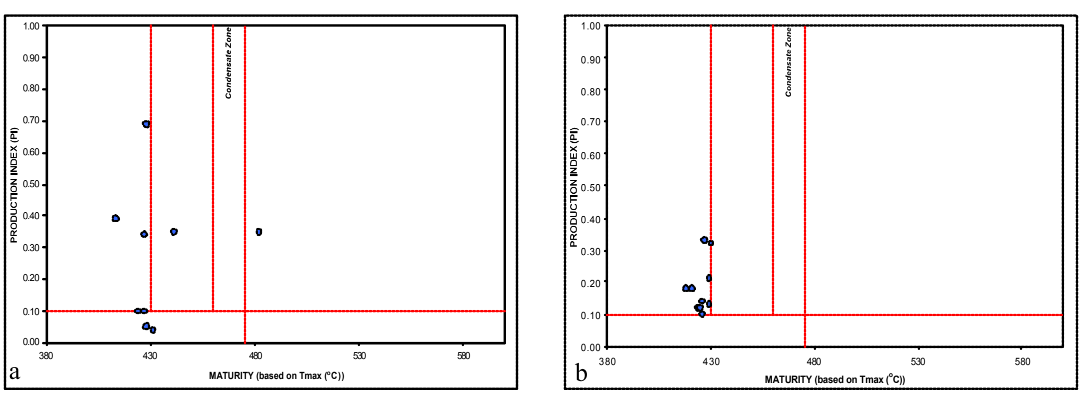

Fig. 6: Kerogen conversion and maturity for (a) *Tuma* and *Sa* wells (based on T_{max})

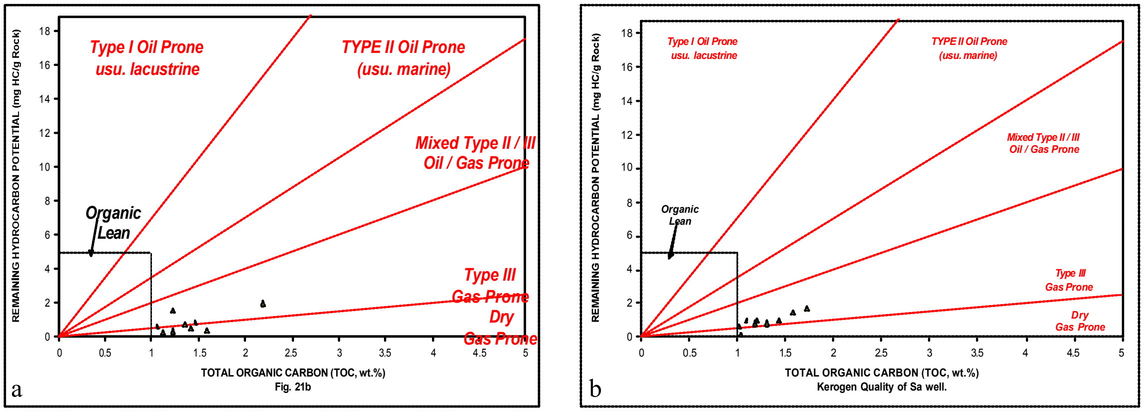

Fig. 7: Kerogen Quality of (a) *Tuma* and (b) *Sa* wells

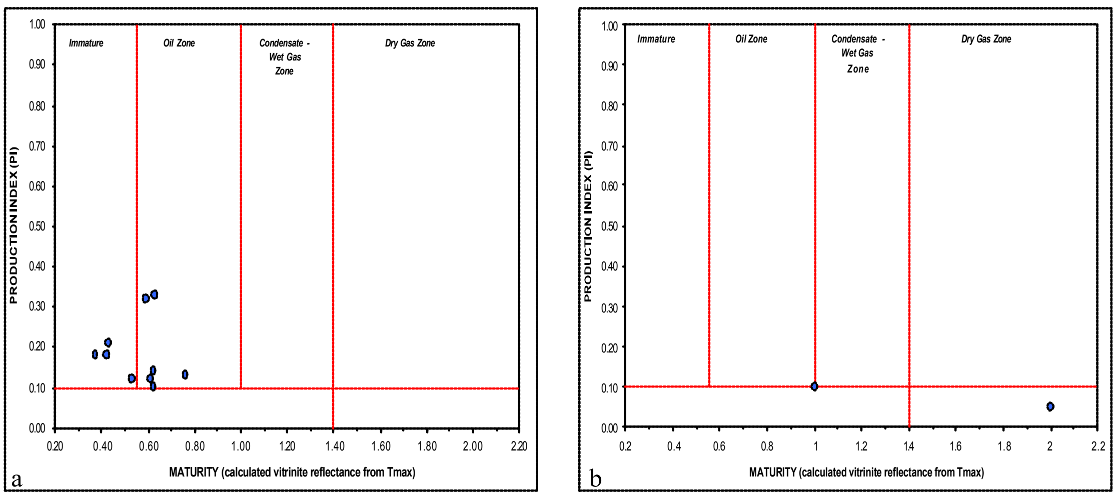

Fig. 8: Kerogen conversion and maturity (calculated %VRo from T_{max}) for (a) *Tuma* and (b) *Sa* wells

the Bima Formation to 2.18% in the Fika Shale Formation (*Tuma*) and 1.02.% w/w at the Gongila Formation (SS 32) to 1.72% w/w (SS 28) of Fika Shale Formation (Sa). The analyzed samples in these wells have values above the required threshold (0.5 %w/w) showing the enrichment in the organic carbon. The top of the Fika Shale Formation of the wells have the highest TOC, HI and S_2 values indicating the pinnacle of anoxic depositional milieu, while the Bima Formation is representing oxic milieu as evident in high OI values.

The HI is used to characterize the kerogen type and the maturation level in conjunction with the OI [8]. HI values range from 10 to 132mgHC/gTOC in the *Tuma* well and 0.9 to 101mgHC/gTOC in *Sa* well, while OI range from 10 to 48mgHC/gTOC (*Tuma*) and 12 to 44mgHC/gTOC (*Sa*) respectively (Table 1). These values are within the typical range of Type III organic matter [8-12]. It is evident from these values that they are typical of gas prone kerogen type.

Tmax values are generally inconsistent in the wells. Tmax increases with depth except where faults, unconformities and contamination (migrated oils and bitumen) cause variations [9, 11]. Mud additives (bitumen and lignite) are responsible for the extenuated Tmax values.

Inasmuch that the Chad Basin has been characterized by complex faulting systems as well as the extensive inversion uplifts [4], the irregular Tmax pattern is expected. These extenuated values could also be as a result of hydrocarbon migration [7]. Depressed Tmax values also show direct relationship to bitumen content [13].

The Production Index (PI) shows a decrease in the Bima Formation of the wells relative to other values in the Fika Shale and Gongila Formations. The PI inconsistency in *Tuma* and *Sa* wells may reflect the lithofacies and matrix contrast between the Bima Formation and the overlying Fika Shale Formation and Gongila Formation. The arenaceous nature of the

Bima Formation is responsible for the low PI measurement [9].

The genetic potential (S_1+S_2) values follow the trend of TOC and S_2. It expresses the potential of a source rock to generate hydrocarbons. These values range from 0.43 to 2.99 (*Tuma*) and 0.19 to 1.9 kg/ton (*Sa*), which are well above the minimum value (>2) of a potential hydrocarbon source rock [14]. This is attributed to the upper sequence of the Fika Shale Formation; hence hydrocarbon generative capacity is high. The HI and OI indices indicate that the organic matter is Type III kerogen which is gas prone. The HI versus T_{max} relationships show that most of the samples (Fika Shale) clustered around 435°C which is the oil window boundary (434-470°C) wh iles the Gongila and Bima (Shale) samples are within the oil zone.

CONCLUSIONS

The recent discoveries of petroleum (Oil and gas) in the neighboring basins (Republics of Chad and Niger) have buttressed the concept that the source rocks in the Nigerian sector of Chad Basin are thermally and organically matured to generate commercial quantity of hydrocarbons haven fulfilled all the petrophysical parameters.

The reservoir potential is good, the Bima Formation (continental) and the Gombe Sandstone (estuarine/deltaic) are the possible reservoirs. Even exploratory wells in the Nigerian sector of the Chad Basin has located dissipated gas "show" at diverse depths in a number of wells.

This study has confirmed that the Fika Shale Formation is a good source rock which has not reached the "oil window". The Gongila Formation which represents the transitional shallow-marine depositional phase is poor in organic carbon content and of reduced thickness. The Bima Formation is not within the oil and gas generation and they have limited potential as a source rock, due to the presence of clastic and inert materials. However, the potential for gas accumulations do exists within the area.

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