MODELING OF HYDROCARBON POTENTIAL AND THERMAL MATURITY OF GONGILA SHALE, CHAD BASIN, NORTHEASTERN NIGERIA

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Abstract. The Bornu Basin, which represents a part of the Chad Basin in Nigeria, makes one-tenth of the total area of the Chad Basin that extends to the Republic of Niger, Chad and Cameroun. This basin is a sediment-filled broad depression straddling northeastern Nigeria and adjoining parts of the Republic of Chad. The cumulative thickness of the sedimentary rocks exceeds 3,600 metres. The Nigerian share of the Chad Basin is supposed to be a potential hydrocarbon-producing basin. This is because commercial petroleum accumulations totalling over 120 billion barrels have been discovered in some parts of the basin outside Nigeria (largely in the Republic of Chad) in structurally related contiguous basins. The Gongila Formation (in the Chad Basin) is a transitional sequence between the underlying continental Bima sandstone and the overlying marine Fika shale.

Determining whether the shale beds present in the Gongila Formation are matured enough to generate hydrocarbons, nine wells were used and the petrophysical parameters such as total organic carbon (TOC) and total organic matter (TOM) were calculated for each of the wells. The heat flow history of the basin was calculated by establishing the relationship between the modeled thermal maturity curve and the equivalent observed maturity parameter (vitrinite reflectance). Thereafter this calculated heat flow is used to predict thermal maturity of source rocks and the timing of hydrocarbon generation.

The result obtained reveals that TOC and TOM of shale sequences in each well range from 3.58 to 27.48 wt% and from 1.15 to 8.79 wt%, respectively. Thus, TOC of the Gongila Formation exceeds the kerogen threshold of 0.5 wt% for the generation of hydrocarbons while TOM exceeds the kerogen threshold of 1 wt%. The heat flow was computed from the heat generation and was estimated to range between 33 and 75 mW/m^2. The modeled vitrinite reflectance ranges between 0.56 and 0.76%Ro.

It is concluded that the Gongila shale is a potential petroleum source rock. The temperature history is the factor controlling the maturation of organic compounds into fossil fuels. The Gongila Formation's thermal maturity,

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assessed on the basis of vitrinite reflectance, indicates that the shale sequences in this formation are within the early oil window and thermally matured for hydrocarbon generation.

1. Introduction

The Bornu Basin which represents the Chad Basin in Nigeria is one-tenth of the total areal of the Chad Basin that extends to the Republic of Niger, Chad and Cameroun. It is a part of the Western Central African Rift System (WCAS) that formed in response to the tectonic separation of the African crustal blocks in the Cretaceous [1]. This basin is a broad sediment-filled depression straddling northeastern Nigeria and adjoining parts of the Republic of Chad. The cumulative thickness of the sedimentary rocks exceeds 3,600 metres, and the rocks consist of a thick basal continental sequence of sandstone (Bima sandstone) overlaid by a transitional sequence of sandstone, shale and limestone beds (the Gongila Formation) followed by a thick succession of Quaternary limnic, fluviatile and eolian sands and clays (the Fika Formation). The Bima Formation is the oldest stratigraphic unit in the basin deposited under continental conditions. The formation consists of thin to thick beds of fine to coarse-grained sandstone of variable colour from white, brown, and reddish brown to grey. The coarse-grained textures are more common towards the bottom. Thin bands of clay and siltstone varying in colour from red to grey or brown occur as intercalations with the sandstone. The formation is feldspathic towards the bottom. Also, this formation lies unconformably on the Basement Complex; it derived from the degradation of the basement rocks and represents the upper part of the Continental Intercalaire in Nigeria. The formation is diachronous and probably of the Albian-Turonian Age. Furthermore, the Gongila Formation is a transitional sequence between the underlying continental Bima sandstone and the overlaying marine Fika shale [2]. The Gongila Formation is regarded as transitional deposits that accompanied marine incursions into the basin. The formation consists of a sequence of sandstones, clays, shales and limestone layers. It varies laterally in lithology and contains massive grey limestones overlaid by sandstones, siltstones, mudstones, shales, thin limestones (the limestone horizons are richly fossiliferous) and shales with shelly limestones. The sandstone texture varies from fine to coarse-grained. Volcanic intrusives which occurred as diorite sills are present at several horizons of the formation. The formation has been assigned to be of the Turonian Age [3].

According to [2], the marine transgression, which started in the late Albian, reached its peak in the Turonian, during which time the entire basin was inundated. However, during the Turonian bluish-black, ammonite-rich, open-marine shales (the Fika Formation) were deposited, and this sedimentation extended into the late Senonian. The Fika Formation is a fully marine

unit. This formation consists of blue-grey shale, occasionally gypsiferous, with intercalation of limestone horizons. Volcanic intrusives which occur as diorite sills are also present in several horizons of the formation. The formation is diachronous and has been assigned to be of the Turonian-Maastrichtian Age. The Turonian-Senonian was succeeded by a regressive phase.

The Nigerian area of the Chad Basin (especially the Gongila Formation) is supposed to be a prolific hydrocarbon-producing basin, because the Termit Basin in Chad and Niger republics, which has the same geology as that of the Bornu Basin, has been producing hydrocarbons for some time now.

Amongst the six stratigraphic units recognized in this basin, the Gongila Formation is a transitional sequence between the underlying continental Bima sandstone and the overlying marine Fika shale (Table 1). The formation consists of thin to moderately thick interbeds of shales, silty sandstone and sandstone. The shale is grey to dark grey while the sandstone is of variable color from brown, white, yellow, and purple to grey [3].

The Gongila Formation has been investigated using petrophysical techniques to estimate the hydrocarbon potential of the shales present in the formation.

A petroleum source rock is defined as a unit of rock that has generated or expelled oil or gas in sufficient quantity to form commercial accumulation. Source rocks are commonly shales and limestones that contain organic matter. The organic matter may be derived from aquatic organisms and bacteria [4], in which case it is commonly called kerogenous, or from land plants, in which case such material is referred to as humic [5]. The use of petrophysical techniques arises out of the need to assess source rocks for basin studies in various geological settings, where the database is restricted to basic log data and little or no geochemical information is available, and to provide an integrated "running" assessment of source capability for volumetric determinations [6]. In source rock analysis, total organic carbon (TOC) present in a potential source rock is very important because it significantly affects the response of various well logs. The factor controlling thermal maturation of organic compound into fossil fuels is temperature [3].

Source rock formations generally show a lower density, a lower sonic transit time, and a higher resistivity than other sediments of equal compaction and comparable mineralogy. This phenomenon can be used to identify source rocks on wireline logs (e.g. density (FDC), sonic, resistivity and gamma ray logs) provided the source rocks have a minimum thickness within the resolution of the sondes used and are sufficiently rich in organic matter [7].

Since the most complete and readily available well data is the suite of logs comprised of density, sonic, resistivity and gamma ray logs, it seemed desirable to investigate the possibility that source rocks might be recognizable from these logs. In this work, the relation between rock density, gamma

Table 1. Stratigraphic Sequence of the Bornu Basin [modified from 2 and 3]

PERIOD/ EPOCH	FORMATION	LITHOLOGY	AVERAGE THICKNESS (m)	THICKNESS FROM SEISMIC DATA (m)	OUTCROP DESCRIPTION	SUBSURFACE INTERPRETATION FROM SEISMIC DATA
QUATERNARY	CHAD		400	800 (Average)	Variegated clays with sand interbeds	
TERTIARY	KERRI-KERRI		130		Iron-rich sandstones and clays covered by laterite plinths.	
MAASTRICHTIAN	GOMBE		315	.. ..	Sandstone + siltstones + clay with coal seams. Fossils: bivalve impressions and criziana	
SENONIAN	FIKA		430	0 – 900	Dark grey to black gypsiferous shale with limestone interbeds	
TURONIAN	GONGILA		420	0 – 800	Alternating sequence of sandstone and shale with limestone	
CENOMANIAN	BIMA		3,050	2,000	Poorly sorted gravelly to medium-grained highly feldspathic sandstone	
ALBIAN	??UNNAMED		3,600			Seismically transparent sequence. [A mono-lithological sequence is inferred].
	??UNNAMED		0 – 3,000			Piedmont alluvial fans and early rift sediments.
PRECAMBRIAN	BASEMENT COMPLEX					

LITHOLOGY LEGEND: Sandstone   Shale   Igneous and metamorphic rocks

ray and rock porosity logs as established by Schmoker [6] for determining the TOC value of a unit was employed for the investigation of the total organic matter (TOM) and TOC content of some intercalations of shale in the Gongila Formation, which is suspected to produce hydrocarbons in commercial quantity. The minimum concentration of organic carbon content required for a source rock to become a source of commercial hydrocarbon accumulations has frequently been stated to be 0.5 wt% [8].

Burial history and thermal maturity models of possible source rock sequences were obtained by using well logs to estimate heat generation. The best logs for estimating heat generation are derived from the natural gamma spectrometer (NGS) tool. Rybach [9] developed a simple relationship between heat generation and the natural gamma log (GR (API units)), to be used in case when electric well logs are available. Thermal maturity of source rock is modeled basing on heat flow and is expressed in terms of vitrinite reflectance. Vitrinite reflectance is an indicator of the cumulative time and temperature history of the sediments. Vitrinite reflectance can indicate whether hydrocarbon generation could have been occurred and suggest the types of hydrocarbons that may have been formed. Maturity inferences from vitrinite reflectance can help to identify which source rocks are potential contributors to a petroleum system. In addition, vitrinite reflectance can be used in basin modeling to tell whether the modeled thermal history is reasonable [10].

The success of any exploration activity depends on proper assessment of the presence of effective source rock and of the hydrocarbon volume generated and expelled in an area. Thus, modeling of the petroleum system is an effective way to examine the dynamics of sedimentary basins and of the fluids in them, as well as past conditions suitable for hydrocarbons' generation and expulsion. In addition to understanding these phenomena, thermal maturity modeling can address questions relating to maturation timing, transformation, migration and accumulation of hydrocarbons by considering geologically plausible range of thermal and geochemical parameters [11–13].

2. Geology of the Chad Basin

The Nigerian sector of the Chad Basin, known locally as the Bornu Basin, is one of Nigeria's inland basins occupying the northeastern part of the country. The Bornu Basin is a part of the Western Central African Rift System (WCAS) [10]. Gravimetric studies carried out on the Benue Trough and the Bornu Basin [14–16] have shown the presence of a NE-SW striking positive gravity anomaly.

The Bornu Basin is a sediment-filled broad depression straddling Northeastern Nigeria and adjoining parts of the Republic of Chad (Fig. 1). It is separated from the upper Benue Basin by the Zambuk Ridge. Cumulative

thickness of the sedimentary rocks is over 3,600 meters, and rocks consist of a thick basal continental sequence overlaid by transitional beds followed by a thick succession of Quaternary limnic, fluviatile and eolian sands and clays. Outcrops of older beds are rare, as they are in most parts covered with desert-blown sediments. The oldest rocks in the Bornu Basin belong to Bima sandstone and the youngest to the Chad Formation (Table 1). The dominant folds in the Bornu Basin are the Dumbulwa anticline and the Mutwe syncline of NW-SE trend. The Nigerian National Petroleum Corporation (NNPC) has shot several kilometers of seismic lines and also drilled many wildcat wells for the exploration of hydrocarbons in the basin.
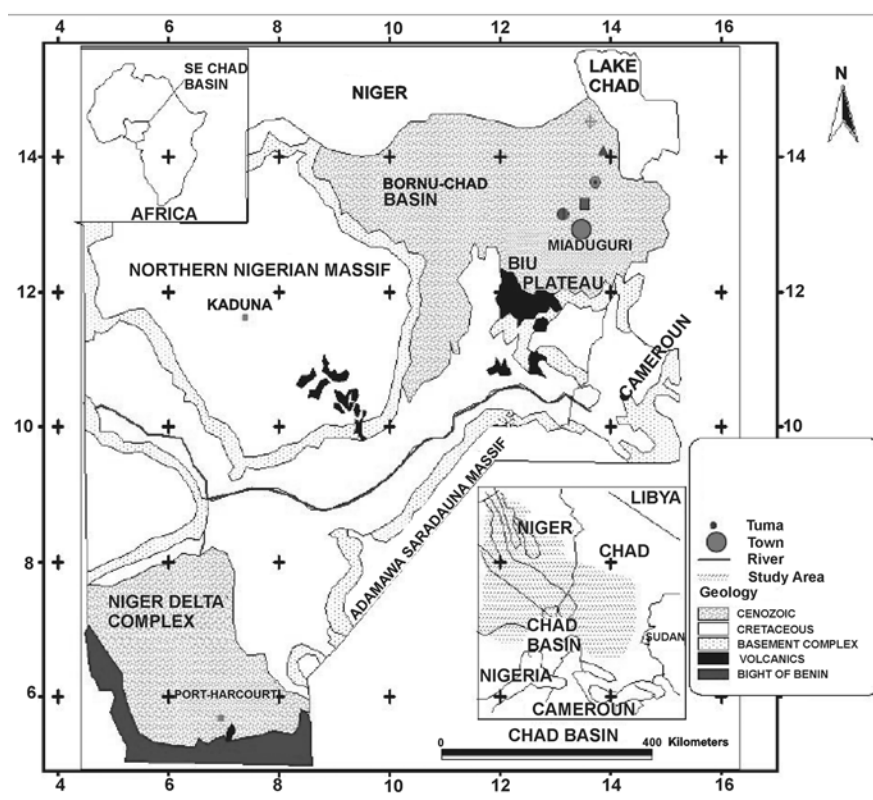

Fig. 1. Geological map of Nigeria showing the location of the Nigerian sector of the Chad Basin (Bornu Basin).

3. Methodology

This work is the first attempt to model thermal maturity of the Gongila Formation. It is aimed at reconstructing temporal evolution of the Bornu sedimentary basin in order to make quantitative assumptions of possible

geological phenomena leading to hydrocarbons' accumulation in the basin. For this purpose, 1-D modeling algorithm was used to simulate the thermal history and the maturation of the organic matter and the content of the Gongila Formation. In the context of a sedimentary basin, the 1-D approach is satisfactory for these purposes because thermal transfers were considered to be mostly vertical and thermal convective transfers are assumed to be negligible.

The correlation of the shale intervals across the selected wells and the computation of relevant petrophysical parameters needed for calculation of TOC were done using the Landmark Geographix software. TOM was then computed from TOC using a correction factor of 0.32 [17].

The TOC map over the study area was generated using the Surfer^{TM} software. The gamma ray log was used to compute heat generation (A) in the formation, which was then converted to heat flow (Q). The computed heat flow values were used as input parameters to model the Gongila Formation using the PetroMod^{TM} 1-D Express software. In this particular study, the EASY %Ro was used to compute profiles of the percentage of vitrinite reflectance (%Ro) with depth for all the well data and to optimize the thermal history models of the Gongila Formation. Because of its use as an indicator of thermal maturity, vitrinite reflectance has become a widely used tool in integrated basin analysis and in the exploration for oil and gas [5]. The Surfer ^{TM} software was further used to generate the map of maturity index of the area using the computed vitrinite reflectance maturation algorithm called EASY %Ro. The EASY %Ro may be applied over a range of vitrinite reflectance values (%Ro) of about 0.3 to 4.5%.

The data used for this study was obtained from the Nigerian National Petroleum Corporation database available in the Department of Geology, Obafemi Awolowo University, Ile-Ife. This data include a suite of well log data available from twenty-three (23) wells in the Bornu Basin, out of which nine wells – Kinasar, Kuchali, Faltu, Wadi, Ngamma-East, Tuma, Murshe, Krumta and Ziye – were selected for this study. These nine wells were selected because this research focused on the Gongila Formation located in the southern and northeastern part of the investigated area.

The composite logs used for this study consist of the following logs: lithologic logs (spontaneous potential and gamma ray), resistivity logs (induction and electrode logs), porosity logs (bulk density, neutron and sonic logs) and caliper logs. An example of the log is shown in Fig. 2.

The total organic carbon present in selected shale intervals in the Gongila Formation was calculated using the Schmoker and Hester's equation [18] as follows:

$$TOC(wt\%) = \left(\frac{154.497}{p_b} \right) - 57.261, \tag{1}$$

where

TOC is the total organic carbon percent weight, wt%,
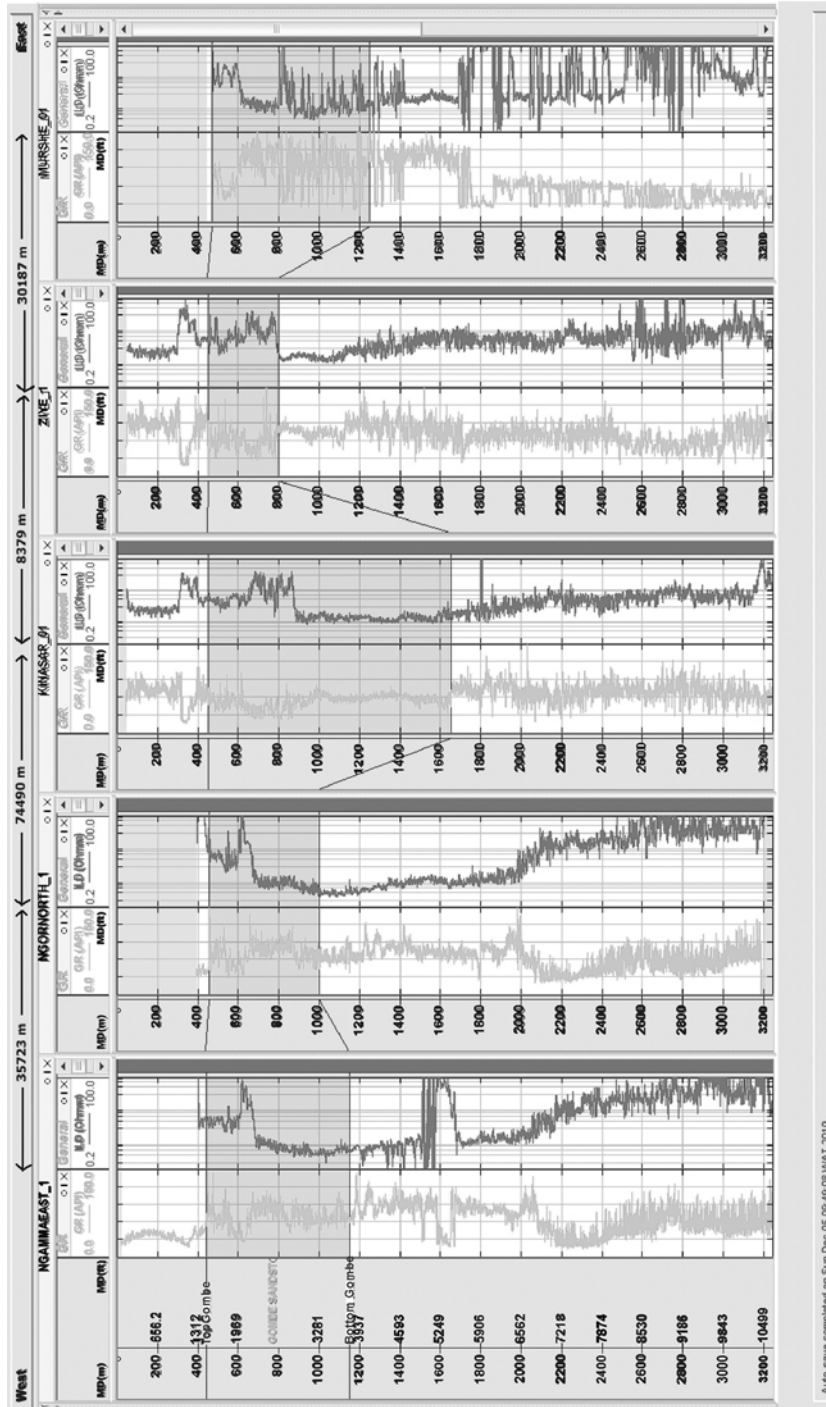p_b is the bulk formation density as measured by density logs.

Fig. 2. Typical well logs used for this study showing the gamma ray and resistivity logs.

The result obtained for TOC was then converted to TOM values by means of a correction factor of 0.32 (for ancient sediments), that is, the obtained TOC values were multiplied by 0.32 to give the TOM values for the points of interest. This methodology was proposed by Schmoker [6] and has been successfully applied for various sedimentary basins of the world.

Peters [8] classified the potential of source rocks on the basis of organic carbon content, as shown in Table 2 below:

Table 2. Interpretation of source richness basing on weight percent of TOC [8]

Richness	TOC, wt.%
Poor	0.0–0.5
Fair	0.5–1.0
Good	1.0–2.0
Very good	>2.0

3.1. Heat generation and heat flow

Generally, high heat generation results in a decrease in heat flow with the depth – a result similar to poor compaction modeling [19]. Till date, heat generation within sediments is poorly constrained, not well understood and not extensively investigated. Ryback [9] derived an empirical relationship between the fractional proportion of quartz in the matrix (FQ) and heat generation (A) measured in sedimentary rocks from the Labrador Shelf whose heat generation (A) equation is given as

$$A = -0.96(FQ) + 1.29, \tag{2}$$

where A is heat generation, μWm^{-3}.

Thus, in order to determine the applicability of Eq. 2 to the Bornu Basin, A was plotted against RHOB $\times$ GR. Figure 2 shows a good linear fit between three parameters plotted. This presumes a good correlation between heat generation (A), a product of the formation bulk density (RHOB) in g/cc and the natural gamma log (GR) in the API unit. The cross-plot of A versus RHOB $\times$ GR of the Bornu Basin (Fig. 2) indicated that the gradient ($m =$ 0.006) was relatively constant for all the wells. Therefore, heat generation equation for the Chad Basin can be re-written as Eq. 3 instead of the generalized Eq. 2:

$$A = 0.006 \times RHOB \times GR. \tag{3}$$

Since the cross-plot yields gradients very similar to East Yeeda 1, it supports the assumption that the relationship holds across the regional scale in the Bornu Basin.

The standard relationship between heat flow (Q), and heat generation (A_o) proposed by Rybach [9] for the petroliferous sedimentary basins around the

world was adopted for this study and used to compute heat flow (Q) for the studied area in the Bornu Basin. This relationship is given as

$$Q = q + A_o D, \tag{4}$$

where Q – is heat flow, A_o – heat generation, q and D – constant components of heat flow.

Globally, q averages about 27 mWm^{-2} and ranges from 18 to 33 mWm^{-2}. D averages about 10 km and ranges from 4.5 to 16 km according to [9, 19, 20]. For all the wells investigated in this study, the heat generation (A_o) values obtained for each well using Eq. 3 were used as input into Eq. 4 to derive heat flow (Q), while the average values of $D = 10$ km and $q = 27$ mWm^{-2} were assumed for this study.

4. Results and discussion

4.1. Modeling of thermal maturity and burial history

The heat flow history of a basin is calculated by establishing an agreement between a calculated (or modeled) maturity curve and the equivalent determined maturity parameter (such as vitrinite reflectance). This calculated heat flow can then be used to presume thermal maturity of source rocks and timing of hydrocarbon generation (Table 3). Heat generation as well as heat flow were determined from the gamma ray log using Eq. 3 which is the modified version of the empirical relationship given by Bucker and Rybach [20]. The values of density from the RHOB log, and the gamma ray readings at the point of interest, multiplied by the proportionality constant, which is 0.006 for this study, gives the heat generation value for a specific point. The computed heat flow values which range from 47.95 to 65.64 mWm^{-2} were used as the input parameters for the PetroMod modeling software to model thermal maturity of the Gongila Formation and to ascertain the level of maturity of the shale intercalations present in the Gongila Formation as well as to determine the hydrocarbon generating potential of the formation.

The gamma-ray log was used to identify the shale interval present in the Gongila Formation and the intervals in the nine wells were compared to give an idea of the possible continuity of the potential source rocks at different

Table 3. Vitrinite reflectance and hydrocarbon generation [13]

Oil-prone generation		Gas-prone generation	
Generation stage	Ro, %	Generation stage	Ro, %
Immature	<0.6	Immature	<0.8
Early oil	0.6–0.8	Early gas	0.8–1.2
Peak oil	0.8–1.0	Peak gas	1.2–2.0
Late oil	1.0–1.35	Late gas	>2.0
Wet gas	1.35–2.0		
Dry gas	>2.0		

depths in the area. Petrophysical parameters were calculated for each shale interval in each selected well (Tables 4–12).

Table 4. Average petrophysical parameters for the well Faltu-1

Shale intervals	Depth range	Thickness, m	I_{GR}	V_{sh}	$Ø_d$	TOC, wt%	TOM, wt%
Shale 1	1894–1959	65	0.504	0.230	0.221	10.935	3.499
Shale 2	2066–2103	37	0.595	0.285	0.200	10.193	3.261
Shale 3	2343–2353	10	0.696	0.509	0.194	9.168	2.933

Table 5. Average petrophysical parameters for the well Kinasar-1

Shale intervals	Depth range	Thickness, m	I_{GR}	V_{sh}	$Ø_d$	TOC, wt%	TOM, wt%
Shale 1	1807–1828	21	0.392	0.147	0.186	9.148	2.927
Shale 2	1844–1874	30	0.350	0.129	0.103	5.119	1.638
Shale 3	2148–2170	22	0.225	0.066	0.174	8.189	2.620

Table 6. Average petrophysical parameters for the well Krumta-1

Shale intervals	Depth range	Thickness, m	I_{GR}	V_{sh}	$Ø_d$	TOC, wt%	TOM, wt%
Shale 1	1408–1440	32	0.350	0.135	0.186	9.638	3.084
Shale 2	1520–1609	89	0.421	0.162	0.103	5.097	1.631
Shale 3	1804–1847	43	0.534	0.254	0.237	11.658	3.73

Table 7. Average petrophysical parameters for the well Kutchali-1

Shale intervals	Depth range	Thickness, m	I_{GR}	V_{sh}	$Ø_d$	TOC, wt%	TOM, wt%
Shale 1	2167–2200	33	0.5422	0.2783	0.2308	11.553	3.697
Shale 2	2225–2261	36	0.5322	0.2454	0.1805	8.513	2.724
Shale 3	2409–2414	5	0.5454	0.2722		–	–

Table 8. Average petrophysical parameters for the well Wadi-1

Shale intervals	Depth range	Thickness, m	I_{GR}	V_{sh}	$Ø_d$	TOC, wt%	TOM, wt%
Shale 1	1923–2008	85	0.4383	0.1861	0.1151	5.739	1.836
Shale 2	2048–2106	58	0.5048	0.2308	0.2417	11.642	3.725
Shale 3	2221–2258	37	0.5172	0.2378	0.2189	10.823	3.463

Table 9. Average petrophysical parameters for the well Ngamma-East-1

Shale intervals	Depth range	Thickness, m	I_{GR}	V_{sh}	$Ø_d$	TOC, wt%	TOM, wt%
Shale 1	1865–1950	85	0.6593	0.3898	0.1499	4.980	1.593
Shale 2	1972–2066	94	0.6547	0.3914	0.065	7.114	2.276
Shale 3	2084–2097	13	0.6279	0.3754	0.1542	5.251	1.680

Table 10. Average petrophysical parameters for the well Murshe-1

Shale intervals	Depth range	Thickness, m	I_{GR}	V_{sh}	$Ø_d$	TOC, wt%	TOM, wt%
Shale 1	2499–2554	61	0.55713	0.2856	0.2446	12.875	4.120
Shale 2	2599–2621	22	–	–	0.482	27.485	8.795
Shale 3	2831–2865	34	0.5549	0.2836	0.1268	6.201	1.984

Table 11. Average petrophysical parameters for the well Ziye-1

Shale intervals	Depth range	Thickness, m	I_{GR}	V_{sh}	$\varnothing_d$	TOC, wt%	TOM, wt%
Shale 1	1987–2057	70	0.5829	0.2987	0.2506	12.064	3.860
Shale 2	2087–2103	16	0.3259	0.1097	0.1495	7.210	2.307
Shale 3	2505–2517	12	0.3331	0.1271	0.1336	6.407	2.050

Table 12. Average petrophysical parameters for the well Tuma-1

Shale intervals	Depth range	Thickness, m	I_{GR}	V_{sh}	$\varnothing_d$	TOC, wt%	TOM, wt%
Shale 1	2682–2706	24	0.6317	0.3802	0.1164	6.087	1.947
Shale 2	2715–2743	28	0.6498	0.3806	0.1103	5.588	1.788
Shale 3	3060–3075	15	0.3671	0.1414	0.0648	3.589	1.148

Three shale intervals labeled Shale 1, Shale 2, and Shale 3 were picked according to their relative thickness across the wells. These shale beds in the wells were compared, and formation tops and bottoms were assigned to these beds (Fig. 2 and 3). The correlation was based on their log signatures indicative of shale zone and gross thickness (Fig. 3).

Nine wells were analyzed and studied. Petrophysical parameters such as TOC content, TOM, density-derived porosity ($\varnothing_d$), volume of shale (Vsh), and gamma ray index (I_{GR}) were calculated for the three identified shale units in the Gongila Formation. Only the average values of the parameters for each studied well are displayed in Tables 4 to 12.

The map of TOC in the studied area is shown in Fig. 4. The map shows a tight closure towards the south-eastern part of the map thus indicative of increasing maturity in that direction. Also, the observed closure might be related to the sparse data selection that was obtained mainly in the south-eastern corner of the basin. The TOC and TOM values calculated from density log indicate that the TOC of Gongila shale exceeds the kerogen threshold of 0.5 wt% (for a potential source rock) for generation of crude oil [5 21]. The result also shows that the TOM of the Gongila Formation exceeds the kerogen threshold of 1 wt%.

The cross-plots of heat generation *versus* the product of the bulk density (RHOB) and the gamma ray log values (GR) for all the wells (Fig. 5) show a similar gradient of 0.006, and this confirms that the region of interest contains sediments derived from the same source, thus showing the applicability of the equation presented in [20] for the Gongila Formation.

Heat production and heat flow were computed for each well studied. The data are given in Table 13.

From the given heat generation and heat flow values, it is obvious that the quantitative estimation of heat generation and heat flow for the nine wells studied yielded values that are slightly higher than given in [5, 22, 23] for sedimentary rocks. It will suffice to suggest that observed by us relatively high heat values may be due to widespread volcanic activity in the southern and central parts of the basin. Besides, the presence of ubiquitous intrusive
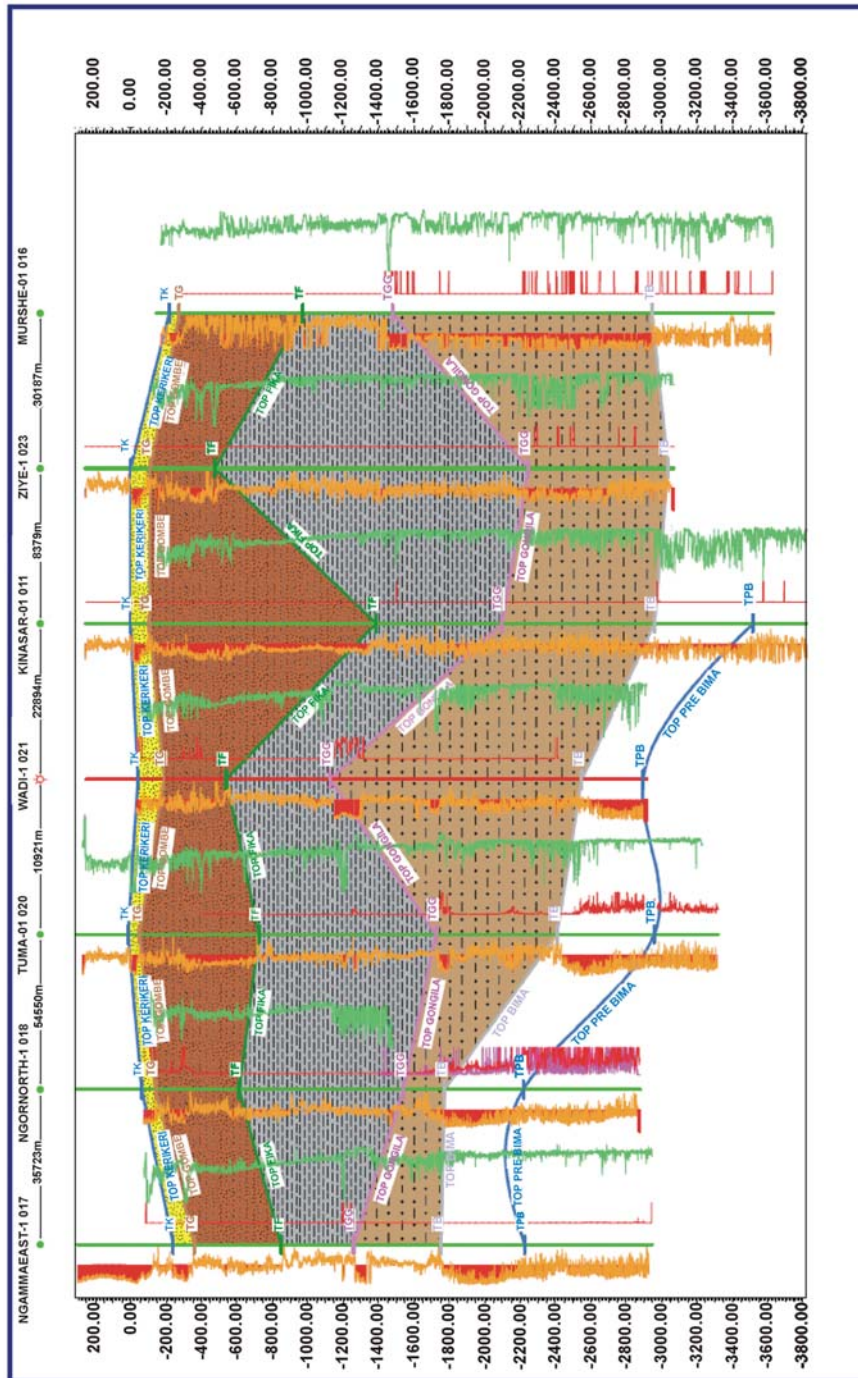
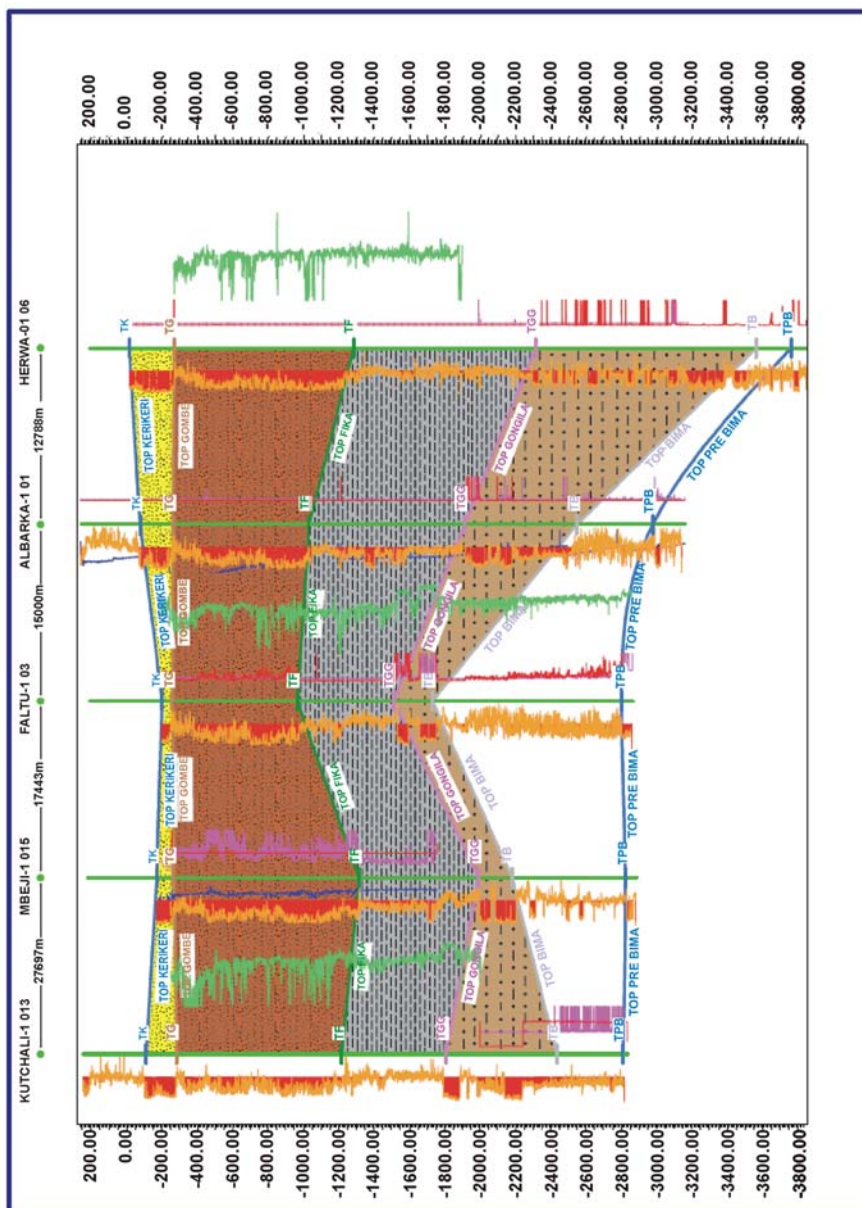Fig. 3. Correlation of Gongila shale intervals (N-S) across the studied wells in the Bornu Basin.

Fig. 4. Correlation of Gongila shale intervals (W-E) across the studied wells in the Bornu Basin.
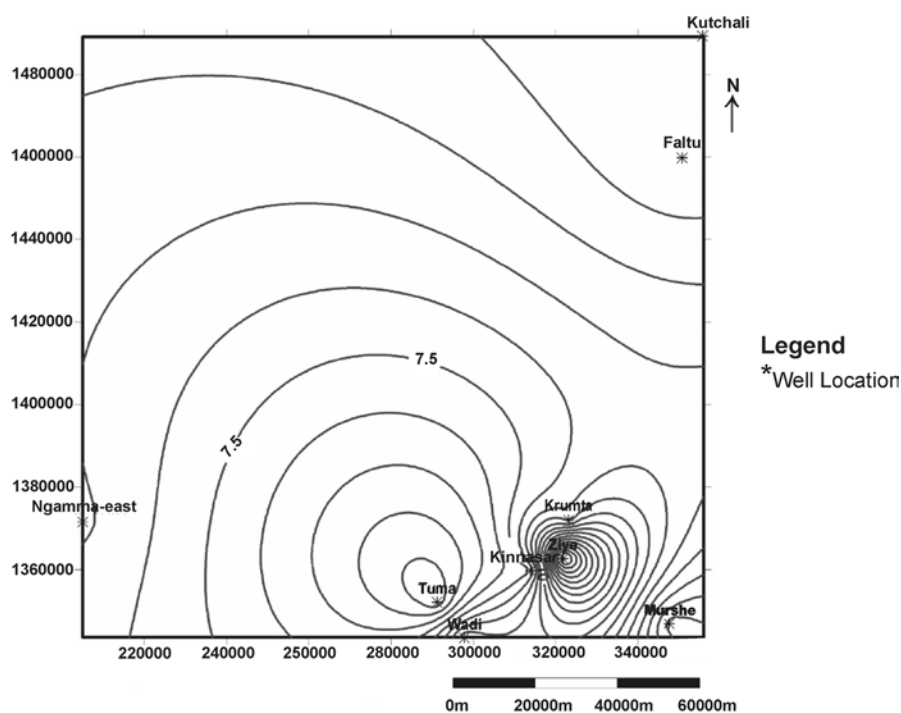
Fig. 5. Map of TOC values (wt%) distribution in the studied area.

Table 13. Heat production and heat flow of wells

Well	Heat production, μWm^{-3}	Heat flow, mW/m^2
Faltu-01	0.8–3.7	35–64
Kinasar-01	0.8–4.4	35–71
Krumta-01	0.9–4.8	36–75
Kutchali-01	0.6–3.5	33–62
Murshe-01	0.9–2.5	36–52
Ngamma-East-01	0.9–3.8	36–65
Tuma-01	0.6–3.6	33–63
Wadi-01	0.8–3.3	35–60
Ziye-01	0.9–2.4	36–51

bodies that are either doleritic or gabbroic has been delineated in the Bornu Basin by Carter et al. [3] coupled with the fact that the basin is rimmed by crystalline basement rocks mainly of granitic and gneissic composition.

The heat flow was used to model thermal maturity of the Gongila Formation. Interpretations of thermal maturity modeling for each well are shown in Fig. 6, and the generated maturity (EASY%Ro) maps of the shale beds present in the Gongila Formation, the Bornu Basin, are shown in Figures 7–9. One can see that the results of thermal maturity and the maturity index (EASY%Ro) obtained in this study depend on the distribution of the selected wells.
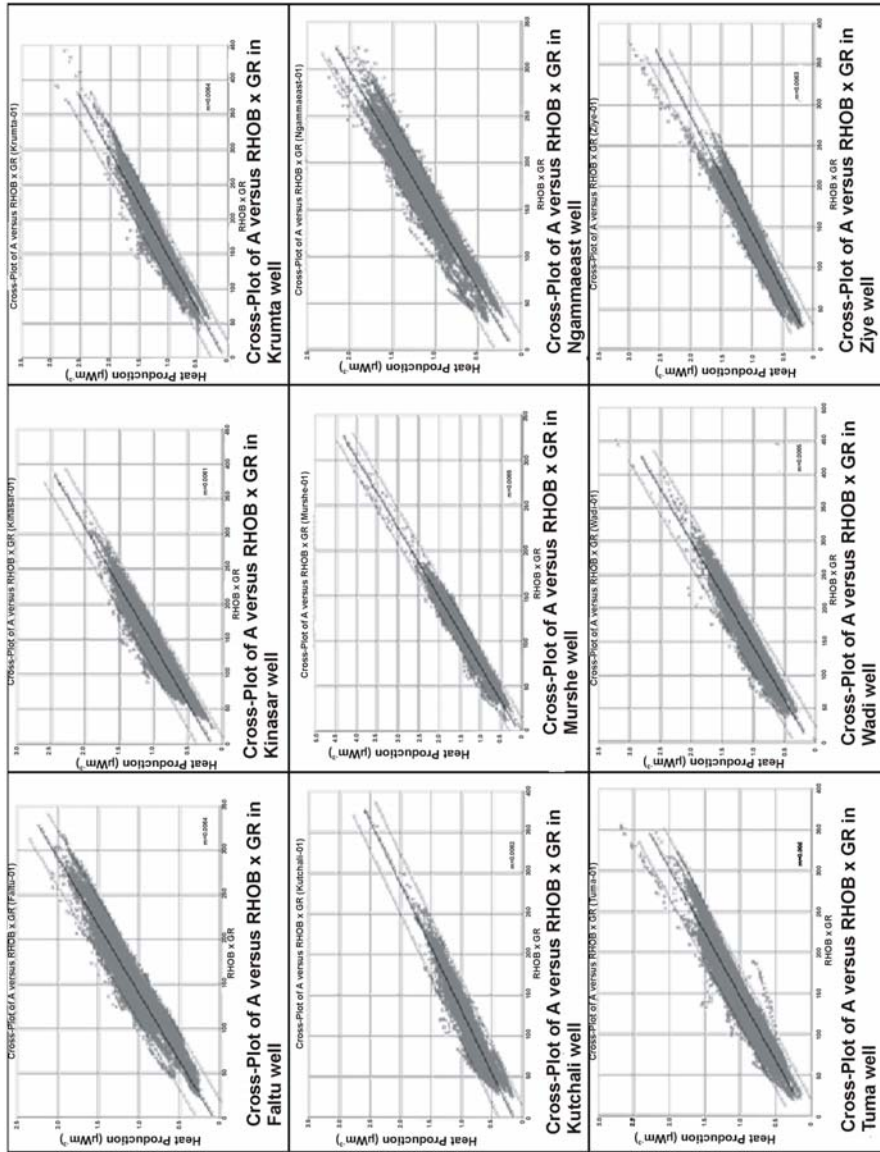
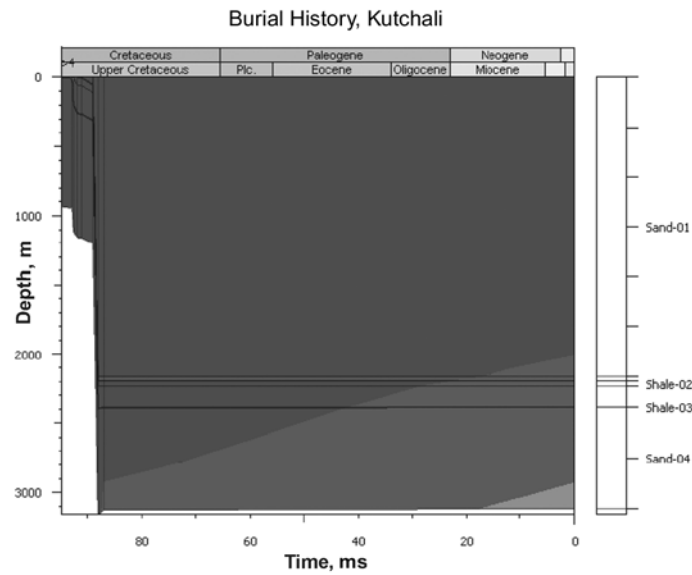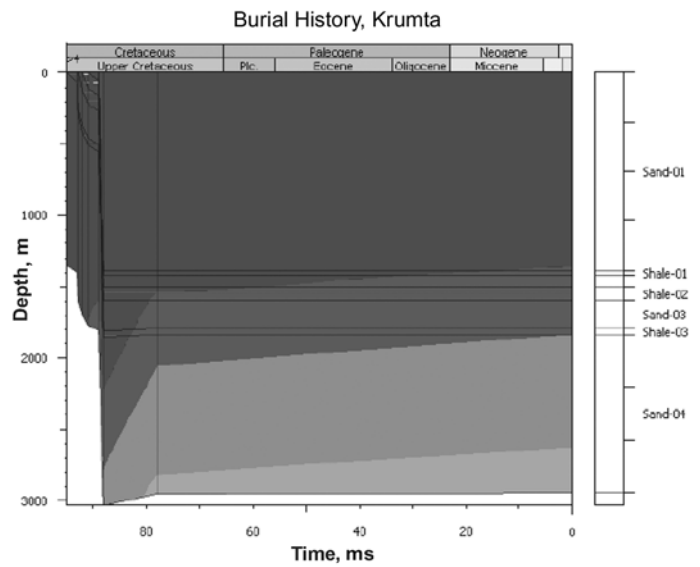Fig. 6. Cross plots of *A versus* RHOB x GR for all nine wells used for the study.
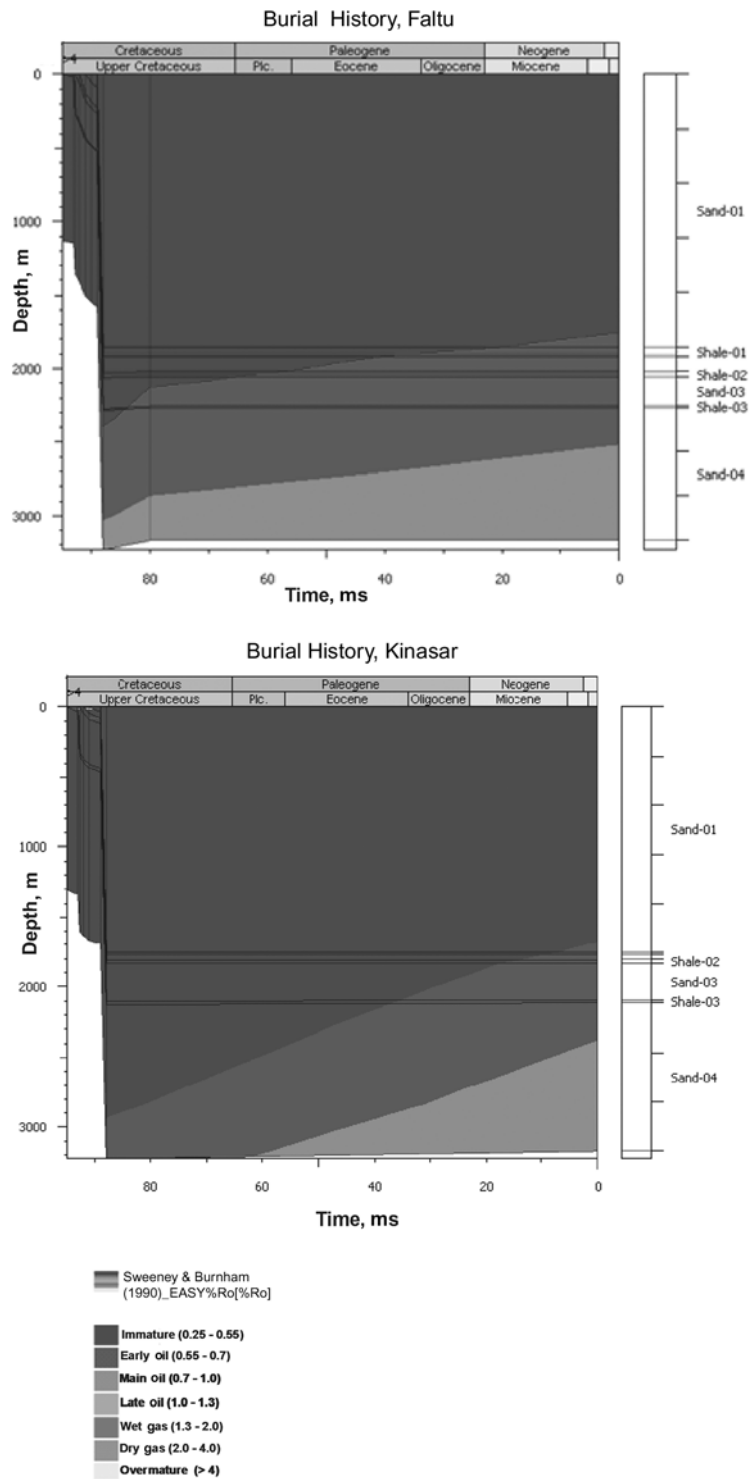
Fig. 7. Thermal history of some of the wells in the study area.
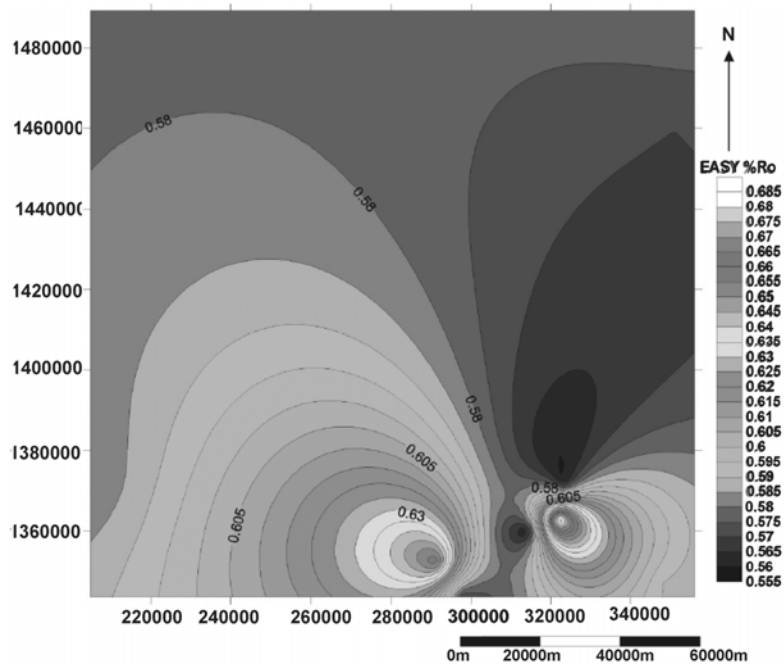
Fig. 7. Continues.

Fig. 8. Generated maturity (EASY%Ro) map of Shale 1 interval in the Gongila formation, the Bornu Basin, Nigeria.
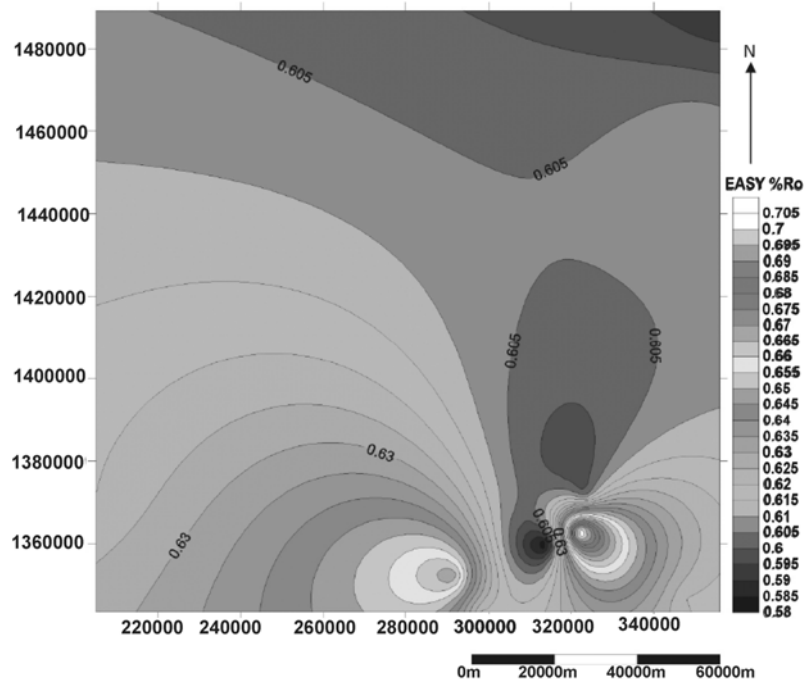

Fig. 9. Generated maturity (EASY%Ro) map of the Shale 2 interval in the Gongila Formation, the Bornu Basin, Nigeria.
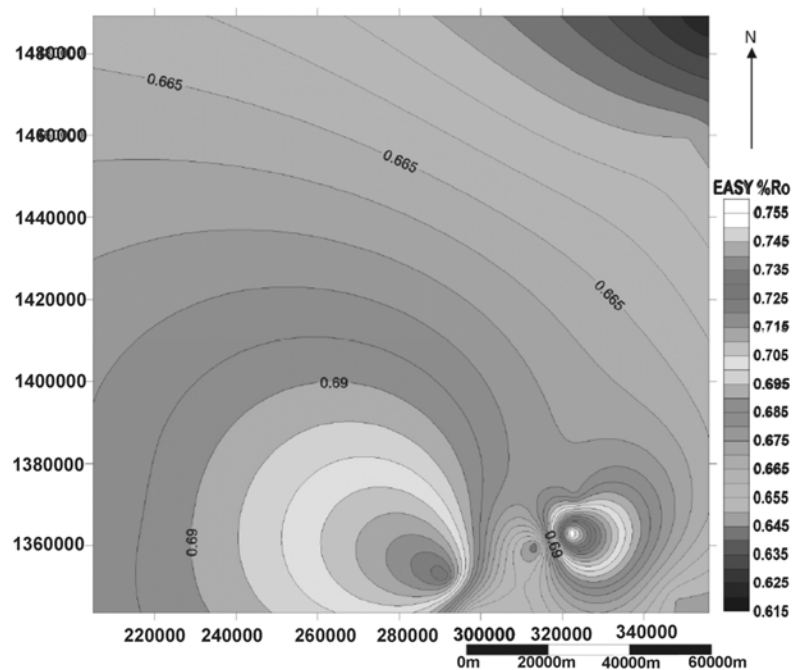
Fig. 10. Generated maturity (EASY%Ro) map of the Shale 3 interval in the Gongila Formation, the Bornu Basin, Nigeria.

They are not evenly distributed over the Bornu Basin but are concentrated in its north-eastern and south-western parts. Thus, if a greater number of wells more evenly distributed over the whole basin had been selected, a slightly refined and different contour distribution pattern would have been obtained.

5. Conclusion

The correlated well and borehole data for the Chad Basin area provide insights into the petrophysical evaluation of the Gongila Formation thus enabling to determine the potential of hydrocarbon generation in this area. The TOC and TOM values were calculated for shale intervals in each well; they range between 3.58 and 27.48 wt%, and 1.15 and 8.79 wt%, respectively. The results indicate that the TOC values of the Gongila shale exceed the kerogen threshold of 0.5 wt% (for a potential source rock) for generation of crude oil [5, 21]. They show also that the TOM values of the Gongila Formation exceed the kerogen threshold of 1 wt% as well. Combining this information, it could be suggested that the Gongila shale might be a good potential source rock for petroleum. This demonstrates that the shale intervals investigated within the Gongila Formation fall well within the "early oil window" according to [13].

Also, the areas that could possibly serve as a good source for hydrocarbon generation were delineated basing on the TOC results obtained. It is inferred that maturity of the organic matter increases from the south-central part towards the north-east of the investigated area. Furthermore, for all the wells investigated, the cross-plots of heat generation *versus* RHOB × GR show that the gradient for the Bornu Basin is generally the same – 0.006. This value probably suggests that the basin contains sediments derived from the same source.

Quantitative estimation of heat generation and heat flow for the nine wells studied yielded values that are slightly higher than those observed by Tissot and Ulrich [5, 22] for sedimentary rocks. The only plausible explanation for these high heat values may be the occurrence of widespread volcanic activity in the basin coupled with the presence of intrusive bodies that are ubiquitous in the Bornu Basin as suggested earlier by Carter and others [3].

Generally, the combined result basing on maturity modeling and thermal maturity derived from the vitrinite reflectance varies from 0.56Ro% to 0.76Ro% for the Gongila Formation; these values possibly imply that the shale intervals studied within this formation are mature enough for hydrocarbon generation as suggested by Senftle and Landis [13].

Acknowledgements

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