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# Spatiotemporal Evolution of Potential Source Rocks in the Cretaceous Stratigraphic Units, Offshore Ghana

*Prosper Aduah Akaba[1], Judith Ampomah Owusu[2], Ebenezer Apesegah[2], Botwe Takyi[3], Frederick K. Bempong[3], Gordon Foli[1], Simon K. Y. Gawu[1]*

[1] Department of Geological Engineering, Faculty of Civil and Geo-Engineering, Kwame Nkrumah University of Science and Technology, Ghana
[2] Department of Geology, Ghana National Petroleum Corporation (GNPC), Tema, Ghana
[3] Department of Petroleum Geosciences and Engineering, School of Petroleum Studies, University of Mines and Technology, Tarkwa, Ghana

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**Abstract**

The marginal basins located offshore Ghana has been noted for their hydrocarbon potentials. Several studies have been carried out to evaluate the source rock potentials but most of these studies were localized for the stratigraphic interval studied. Thus, this study seeks to provide a better spatio-temporal overview of the organic-richness and maturation history of the source rocks in offshore Ghana from available well data. Geochemical analyzed source rock data in relation to organic-richness and thermal maturity (Tmax) from one hundred ninety (190) representative wells within the offshore Ghana, limited to the Cretaceous age, was plotted with the Geographical Information System (GIS). The results show that portions of the study area were covered with source rocks of varying degrees of high Tmax values (435$^0$C or above) and may have produced hydrocarbons. Also, TOC % results indicate all the stratigraphic units were adequate to generate hydrocarbons as well. However, the best source rocks are within the Albian, Cenomanian, Turonian and Santonian units and are concentrated in the western portion. Generally, there is no direct spatiotemporal qualitative correlation between levels of organic-richness to thermal maturity. The highest to lowest range of organic-matter zones did not necessarily commensurate to highest to lowest temperature regimes for the intervals studied.

***Keywords***: *Ghana; Total organic carbon content; Thermal maturity; Cretaceous; Source rocks.*

## 1. Introduction

A crucial exercise in hydrocarbon prospectivity analysis of every sedimentary basin is to establish the presence of a working petroleum system. A key element in a working petroleum system is establishing the presence of organic-rich and thermally mature source rocks which can produce substantial hydrocarbons [1-3]. Geochemical data are primarily used to ascertain or establish the petroleum potential of sedimentary basins. The parameters that are used in many studies are Total Organic Carbon Content (TOC), Vitrinite Reflectance (Ro), a maximum pyrolysis temperature (Tmax) and Hydrogen Index (HI). The amount of organic matter in source rocks is usually a measure of the total organic carbon content (TOC), expressed as a percentage (TOC %) of the dry rock [1-2]. Although, Peters *et al.*, [4] pointed out that TOC is a measure of the quantity and not the quality. Thermal maturity on the other hand, is the primary factor that determines whether the source rocks have been subjected to sufficient temperatures and pressures high enough to generate hydrocarbons and the resultant type of hydrocarbon to be produced, whether, oil, condensate or gas. For a potential source rock to be classified as excellent, it must have at least 4 % of TOC by weight [4]. According to Javie [5] even the smallest TOC values (poor to fair) can produce hydrocarbons, under the appropriate thermal maturity. Although there are models of expulsion that favor thermally induced diffusion and do not require a saturation threshold to be reached [6], the quantity of hydrocarbons expelled from a poor to fair source rock is unlikely to yield commercially viable accumulations.

Exploration for oil and gas in the offshore Ghana marginal Basins (Tano, Saltpond and Keta Basin) has lasted since 1896 [7]. The earliest exploration efforts commonly targeted areas where oil and gas naturally seeped or leaked to the surface and so pits in search for oil were dug in a town called Bonyere [8]. According to an unpublished report by the Ghana National Petroleum Corporation (GNPC), a marginal discovery was made in the Saltpond Basin in the 1970's by Signal- Amoco Consortium group with in place reserve estimated at 34.4 Mbbls of oil and 34.3 Bscf of gas. Commercial production commenced in October 1978 but declined in 1985 [9]. However, the period from 2001 to 2007 was noticeable by an intensive exploration carried out by exploration and production companies together with GNPC. Thus, the focus shifted from shallow to deep water, and, consequently in 2007, about 312 ft net column of high-grade oil in the Mahogany prospect (Jubilee field) in the West Cape Three Points License (Tano Basin) was discovered [10-11]. Following the success story of the Jubilee field discovery in 2007, more geologic studies are conducted to support and modify the current models and concepts used in offshore Ghana, particularly to understand the petroleum system. Studies have been done regarding source rock potentials in some of the offshore Marginal Basin in Ghana: Tano Basin [12-15], Keta Basin [16] and Saltpond Basin [17]. Most studies are confined to the Cretaceous Age; this is because it is currently the most prolific. However, having a broader picture of the spatial relation of some of the source rock parameters (TOC % and thermal maturity) obtained from wells drilled so far will enhance understanding how these parameters evolved through geologic ages. Thus, the study aims to examine the spatial relation and evolution of potential source rocks in the Cretaceous stratigraphic units in the offshore marginal basins of Ghana

## 2. Geologic setting of offshore Ghana

The offshore Ghana includes the Tano, Saltpond and Keta Basins constitute an array of basins making up the Gulf of Guinea Province. These Basins share common structural and stratigraphic characteristics, being wrench-modified Basins [18] and contain rocks ranging in age from Ordovician to Holocene [19]. The western boundary is the Tano Basin and the eastern boundary is the Keta Basin.

The bathymetry of offshore Ghana can be divided into the continental shelf, deepwater and ultradeep water. The continental shelf, deepwater and ultra-deepwater refers to present-day water depths less than 400 m, from 400 to 2 km and above 2 km respectively [20]. The term deepwater is used informally in the petroleum industry to refer to sediments deposited at water depths considered to be deep and located somewhere in the upper to middle slope region to the floor of a basin (Fig. 1), which is also equivalent to the present-day water depths more than 400 m [20].

These Basins formed at the climax of the Late Jurassic to Early Cretaceous tectonism that characterized the drifting apart of the African and South American paleocontinents. According to Brownfield and Charpentier [21] block and transform faulting superimposed across an extensive Paleozoic basin characterized this break up. The area has undergone a complex history, which can be classified into three (3) periods of basin development, thus, pre-transform (Late Proterozoic to Late Jurassic), syn-transform (Late Jurassic to Early Cretaceous), and post-transform (Late Cretaceous to Holocene). Dumestre [22], Kjemperud *et al.*, [19], Tucker [23], and Chierici [18] refer to these 3 stages respectively as pre-rift (or intracratonic), syn-rift (or rift), and post-rift (or drift).

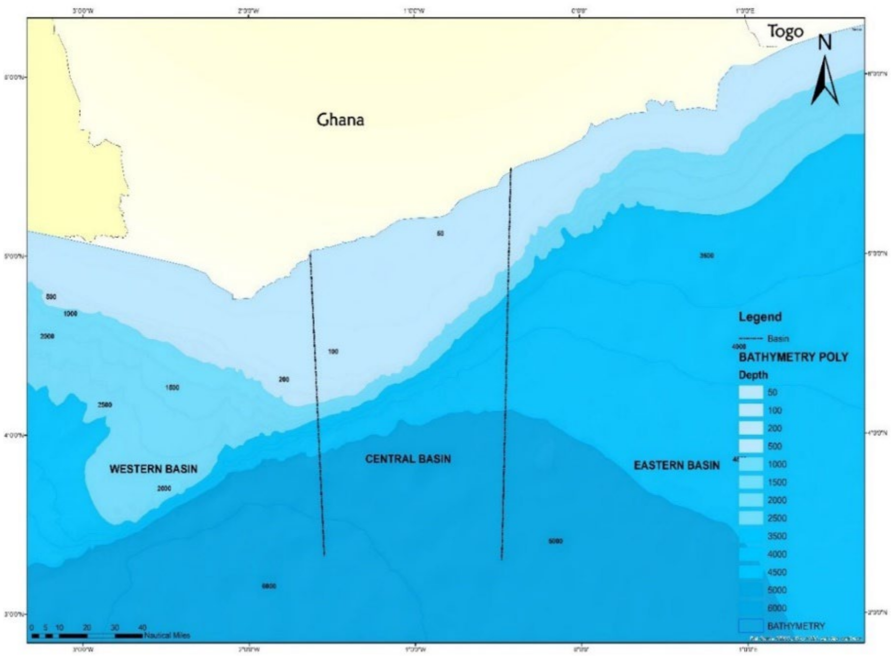


Fig. 1. The present-day bathymetry of offshore marginal basin Ghana

## 3. Methodology

The method adopted in this research was an approach designed to gain an overall understanding of the spatial variation of organic matter (organic-richness and thermal maturity) and consequent levels of hydrocarbon prospectivity in relation to source rock viability. Conditions that favor organic matter production and preservation must exist in an environment before TOC % values could be high. Geographic distribution maps of organic-richness and thermal maturity were generated for the Albian, Cenomanian, Turonian, Santonian, Campanian and Maastrichtian ages. The maps were characterized according to [1-3,24]. According to these afore-mentioned authors, the organic-richness and thermal maturity classifications are given in Table 1.

Table 1. Combined petroleum generation potential of source rocks based on Tmax, Vitrinite Reflectance (Ro) and TOC values

| Potential | TOC (wt %) | Maturation | | |
|---|---|---|---|---|
| Poor | <0.5 | Maturity | Ro (%) | $T_{max}$ (°C) |
| Fair | 0.5-1 | Immature | 0.20-0.60 | <435 |
| Good | 1-2 | Mature | | |
| Very good | >2-4 | Early | 0.60-0.65 | 435-445 |
| Excellent | >4 | Peak | 0.65-0.90 | 445-450 |
| | | Late | 0.90-1.35 | 450-470 |
| | | Postmature | >1.35 | >470 |

The classifications are based on maps generated by interpolations between data points, and for each stratigraphic interval, to provide a better spatio-temporal overview of the organic-richness and maturation history of the source rocks in the offshore Ghana than the more localized TOC and Tmax data from the wells. The ArcGis software was used to generate the maps.

## 4. Results and discussion

This section presents the maps that were generated from the well data and, thus, a discussion on the spatial variation and the evolution of the potential source rock from the Albian to Maastrichtian age.

### 4.1. Albian interval

#### *4.1.1. Organic-richness distribution*

Fig. 2 shows the spatial distribution of organic richness for the Albian stratigraphic interval. The highest and least values of TOC are 3.2 % and 0.3 % respectively, ranging from "Poor" (0-0.5 %) to "Fair" (0.5-1 %), to "Good" (1-2 %) to "Very Good" (4 % and above).

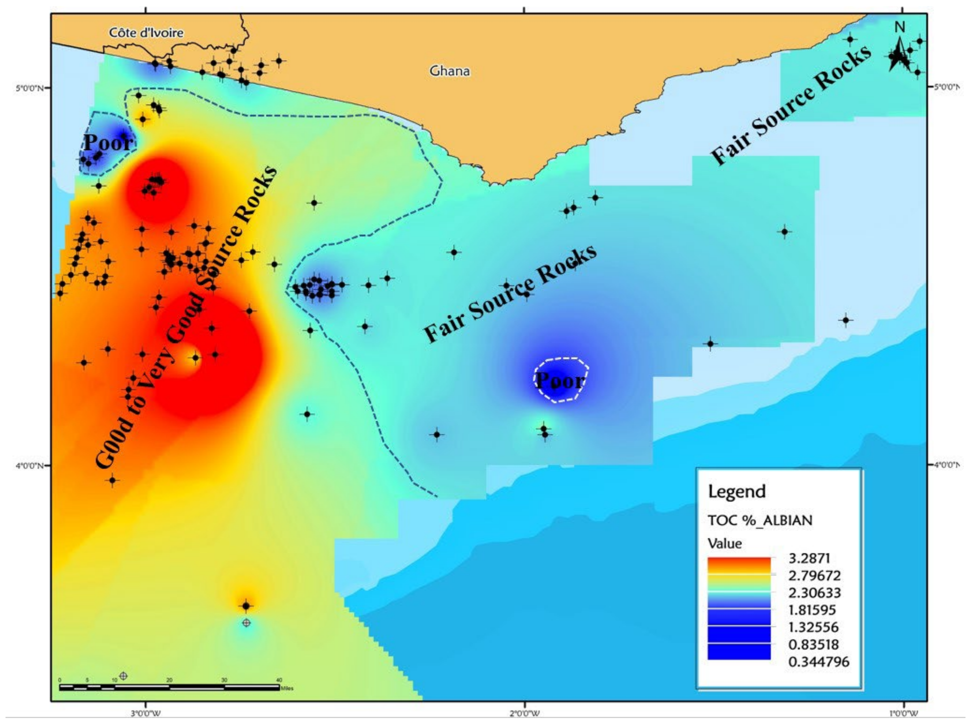


Fig. 2. Lateral distribution of organic richness in the Albian interval

The best source rocks in the range of "Good" to "Very Good" are situated in the western portion as marked in Fig. 4. This explains why more of the discoveries were encountered in the western portion, particularly Tano Basin. "Poor" source rocks occurred in relatively small areas within the central and northwestern portions, whilst "Fair" source rocks occupy the rest of the area. TOC % values range from 0.34 % to 3.3 %, making almost the entire Albian interval a favorable organic-rich unit. Source rocks with enough TOC % were deposited under conditions that favored organic-matter production and preservation.

#### *4.1.2. Thermal maturity distribution*

Fig. 3. shows the geographic distribution of the thermal maturation regime of source rocks in offshore Ghana for the Albian interval. The highest and lowest values of Tmax are 451°C and 427°C respectively.

The map indicates that a greater portion of the area is covered by source rocks with Tmax above the oil maturation window (435°C). The likely source kitchen where rocks have been subjected to enough baking by requisite temperatures and pressures (enough to generate both oil and gas, as the case may be), is situated in the mid-portion of the western end of the study area. This likely source kitchen is also host to "Good" and "Very Good" source rocks as it corresponds to the organic-richness map in Fig. 3. There is no sharp geographic boundary between the mature and immature zones. Rocks with the least Tmax values (427°C) are still close to the oil maturation window (435 °C). Also, the slightly immature zones will be mature and begin to produce hydrocarbons with further burial, and if oil-prone kerogens are present

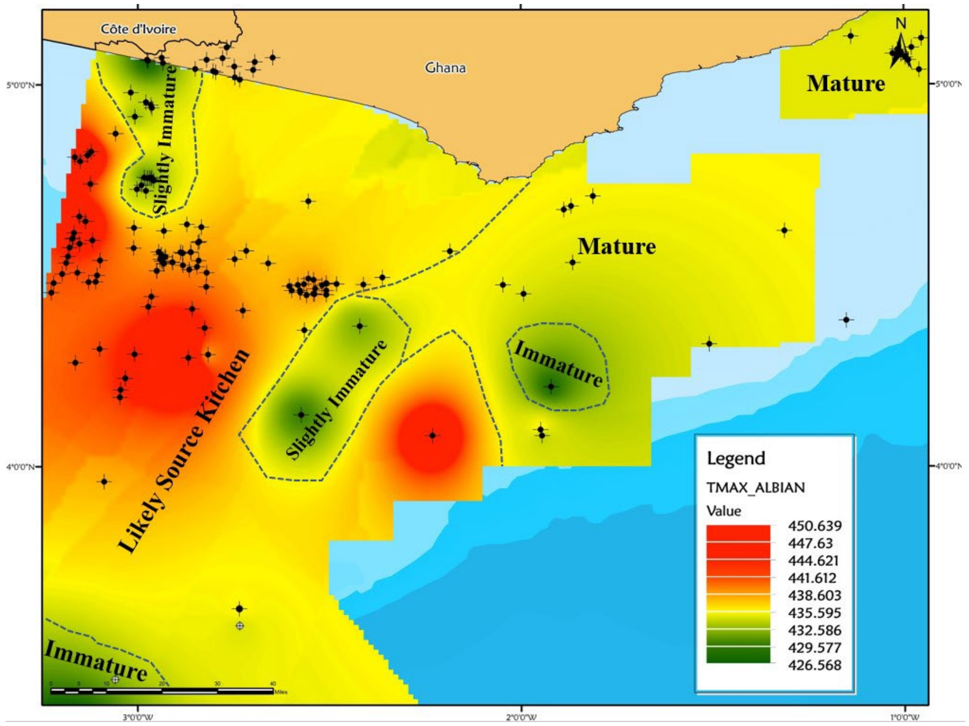


Fig. 3. Lateral distribution of thermal maturity in the Albian interval

## 4.2. Cenomanian interval

### *4.2.1. Organic-richness distribution*

The organic-richness map for the Cenomanian showed that the concentration of TOC is well distributed within the interval. Fig. 4 showed the spatial distribution of TOC % concentration.

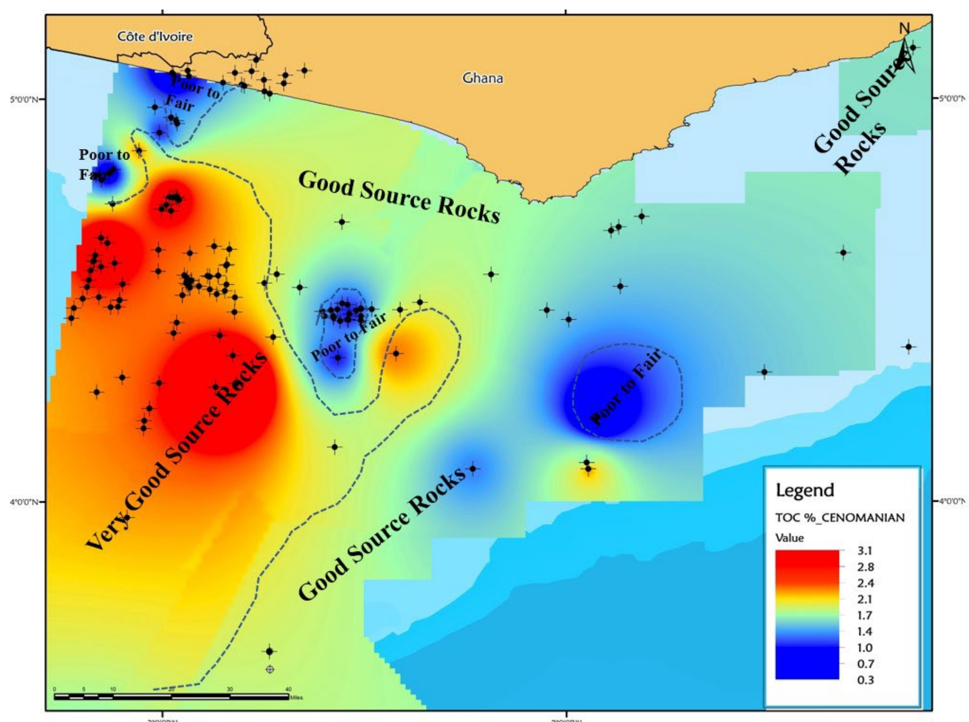


Fig. 4. Lateral distribution of organic richness in the Cenomanian interval

The highest organic-rich rocks, in the range of "Very Good" source rocks (2-4 TOC %), are dominant in the western portion trending north- south north, whilst the lowest organic-rich rocks, in the range of "Poor to Fair" are found localized in the mid-portion and in the north-western portion as indicated in Fig. 4. TOC % values range from 0.3 % to 3.1 %, making almost the entire stratigraphic interval a favorable organic-rich unit. The results confirm the existence of the anoxic conditions of the Cenomanian that favored organic matter production and preservation [20].

#### *4.2.2. Thermal maturity distribution*

Fig. 5 showed the spatial distribution of the maturity status of the source rocks within the Cenomanian interval. The map indicates that most of the area is characterized predominantly by immature source rocks.

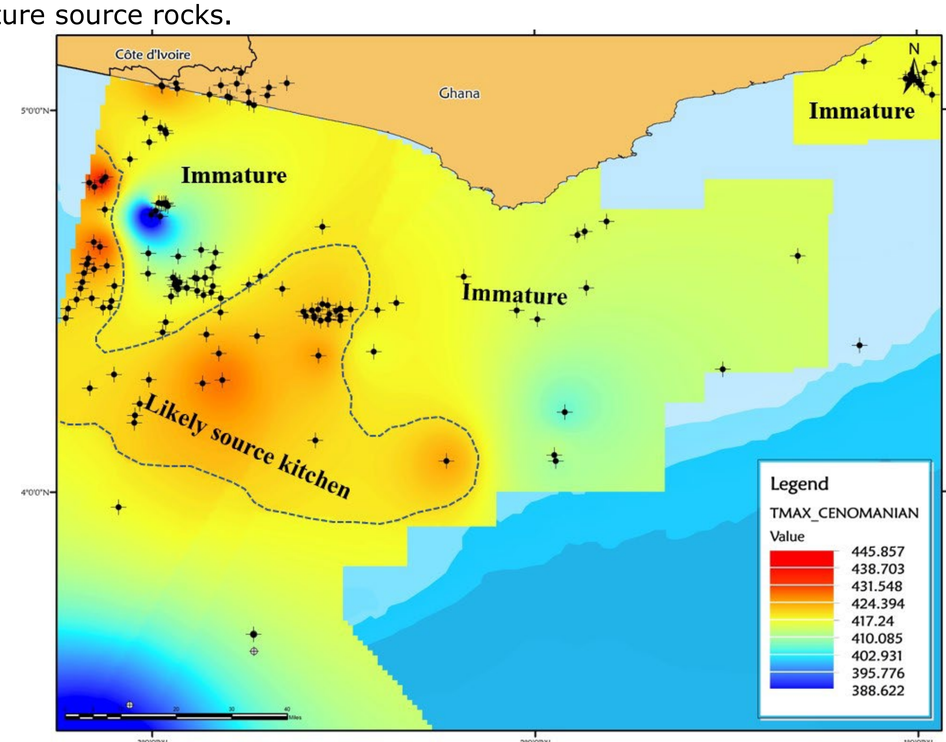


Fig. 5. Lateral distribution of thermal maturity in the Cenomanian interval

Tmax values range from lowest (389°C) to highest (446°C) within this interval. Values around or above 435°C are seen in the area marked out from the mid portion to western boundary (Ghana-Ivory Coast boundary). It can be observed that portions of this marked out area fall within the "Very Good" organic-rich source rocks (Fig. 5) and therefore is the likely source kitchen for the Cenomanian in offshore Ghana.

### 4.3. Turonian interval

#### *4.3.1. Organic-richness distribution*

The organic-richness map for the Turonian shows that the concentration of TOC is well distributed within the interval. Fig. 6 shows the lateral distribution of TOC % concentration.

The highest organic-rich rocks, in the range of "Good to Very Good" source rocks (1-2, 2-4 TOC %), are found in the mid-portion to the south and southwestern flank, and in the north-eastern part of the study area. The lowest organic-rich rocks, in the range of "Poor to Fair" occupy the northeastern corner as indicated in Fig. 6. TOC % values range from 0.012 % to 3.3 %, making a greater part of stratigraphic interval a favorable organically rich unit. The results show that the worldwide anoxic conditions that favor organic matter production and preservation also existed in the Turonian age in the western portion of offshore Ghana.

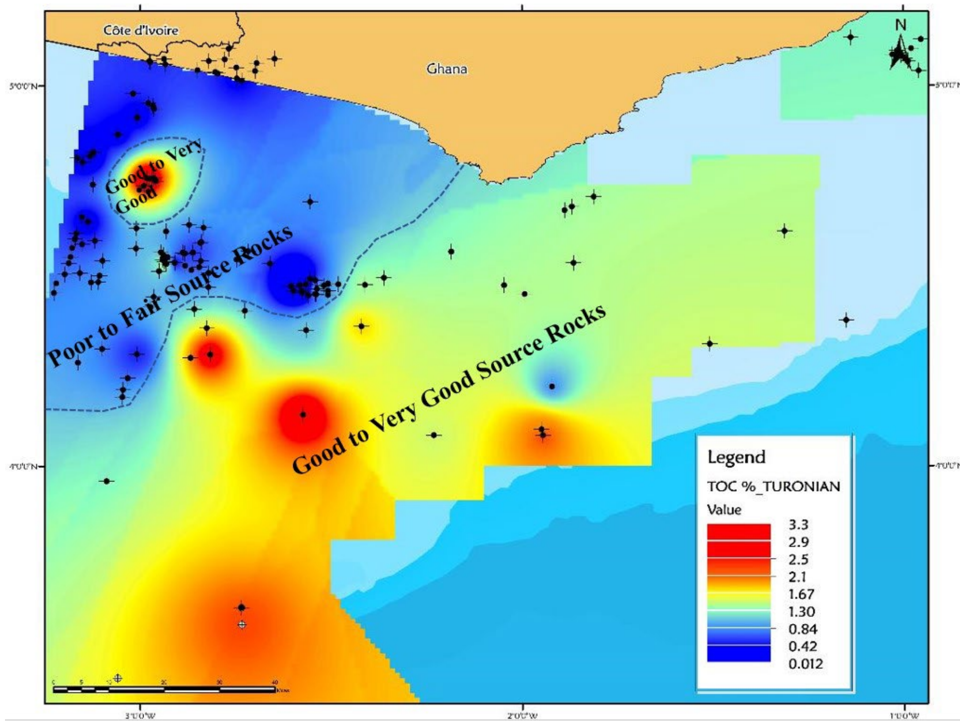


Fig. 6. Lateral distribution of organic richness in the Turonian interval

### *4.3.2. Thermal maturity distribution*

Fig. 7 shows the geographic distribution of the thermal maturation regime of the offshore Ghana source rocks for the Turonian interval. The highest and lowest values of Tmax are 446°C and 3°C respectively.

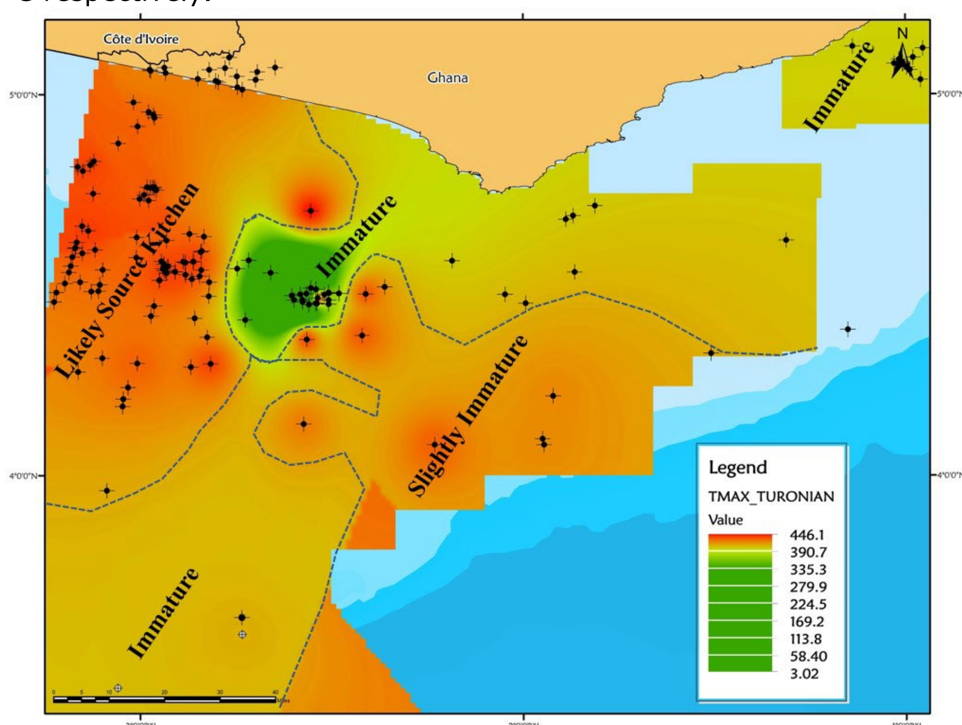


Fig. 7. Lateral distribution of thermal maturity in the Turonian interval

Fig 7. indicates source rocks with Tmax within and/or above the oil maturation window (435°C or above) are at the northeastern corner of the study area. There are slightly immature source rocks around the southwestern portions and the rest of the area is covered with immature source rocks (Fig. 7). However, there is a sharp boundary of the maturation regime towards the northeastern part where the likely source kitchen (435°C and above) is in close contact with a highly immature zone with Tmax as low as 3°C. This could be attributable to an uplift that brought the Turonian rocks in the highly immature zone to shallow depths, or it is an outlier caused by an error in data analysis or recording. The likely source kitchen where rocks have been subjected to sufficient baking by requisite temperatures and pressures (enough to produce both oil and gas), is situated in the northwestern end of the study area. This likely source kitchen is also host to "Poor to Fair" and "Good to "Very Good" source rocks as it corresponds to the organic-richness map in Fig. 7. The slightly immature portions with further burial can produce oil as the organic-richness in the rocks is high enough to produce the requisite saturation to expel hydrocarbons, and if oil prone kerogen is present.

### 4.4. Santonian interval

#### *4.4.1. Organic-richness distribution*

Fig. 8 shows the distribution of organic-richness in the Santonian age. The results indicate that the entire unit has source rocks with sufficient organic-matter capable of generating hydrocarbons, with the least and highest TOC values being 0.6 % and 5.4 % respectively.

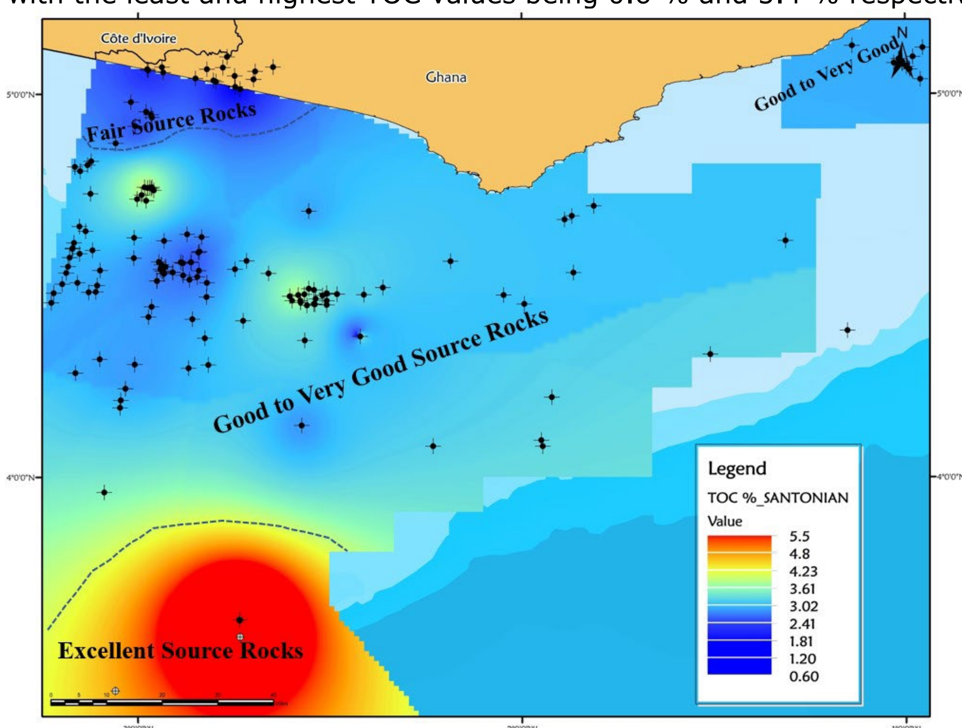


Fig. 8. Lateral distribution of organic richness in the Santonian interval

"Excellent" source rocks (TOC 4 %) occur in the southwestern part of the study area whilst "Fair" source rocks (TOC 0.5-1 %) are seen at the northwestern corner. The rest of the area is characterized by "Good" to "Very Good" source rocks (TOC 1-2 % to 2-4 %).

#### 4.4.2. Thermal maturity distribution

Fig. 9 shows the spatial distribution of the thermal maturation regime of source rocks for the offshore Ghana for the Santonian interval. The highest and lowest values of Tmax are 549°C and 100°C respectively.

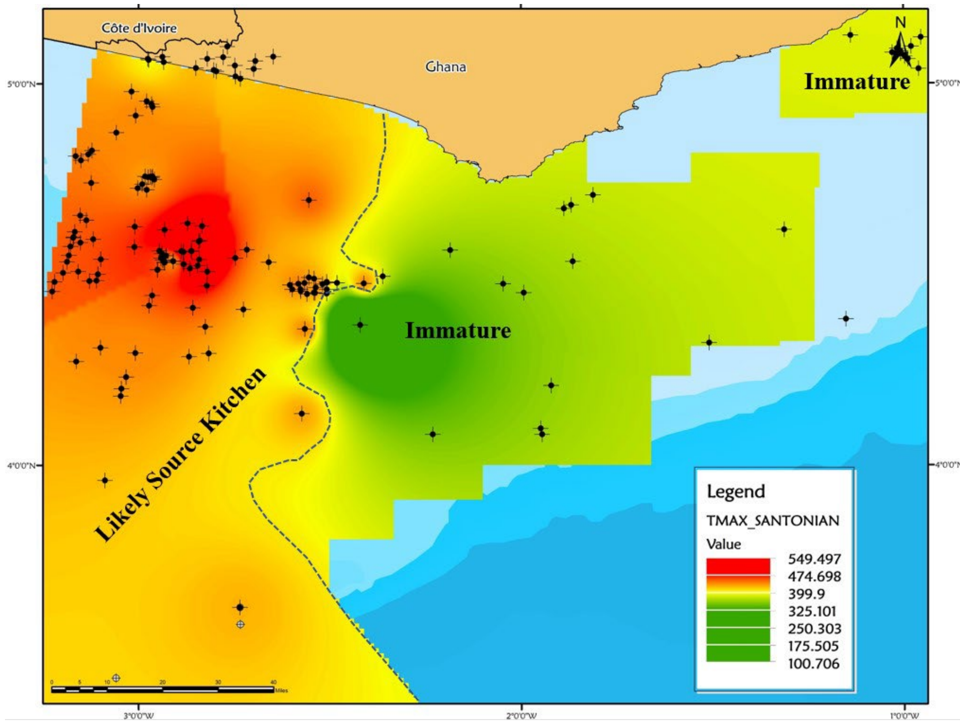


Fig. 9. Lateral distribution of thermal maturity in the Santonian interval

The map indicates that a substantial portion of the offshore Basin is covered by source rocks with Tmax values above the oil maturation window (435°C). However, there is a sharp geographic boundary between some mature and immature zones. Rocks with Tmax values as low as 100°C lie in close proximity and or share boundary with rocks of Tmax values as high as 450°C. This could be possibly attributable to an uplift that brought the Santonian rocks in the immature zone to shallow depths, or it is could an outlier caused by errors in data analysis. The likely source kitchen where source rocks have been subjected to sufficient baking by the requisite temperatures and pressures (enough produce both oil and gas), is situated in the western end of the study area. This likely source kitchen is also a host to "Good", "Very Good" and "Excellent" source rocks as it corresponds to the organic-richness map in Fig. 9. The immature portions with further burial can produce oil as the organic-richness in the rocks is high enough to produce the requisite saturation to expel hydrocarbons.

### 4.5. Campanian interval

#### *4.5.1. Organic-richness distribution*

Fig. 10 shows the lateral distribution map of organic-richness for the Campanian interval. The results show the source rocks within the unit are from "Fair" to "Excellent" in TOC % content.

The highest and least TOC values are 0.9 % and 4 % respectively. The best source rocks are within the range of "Very Good" (TOC 2-4 %) to "Excellent" (TOC 4 % or above) which occur in the mid-portion to the western part as shown in Fig. 10. Also, "Fair" source rocks are situated at the northwestern corner, whilst "Very Good" source rocks occupy the rest of the study area. The results show that conditions that favor organic matter production and preservation prevailed in the Campanian age.

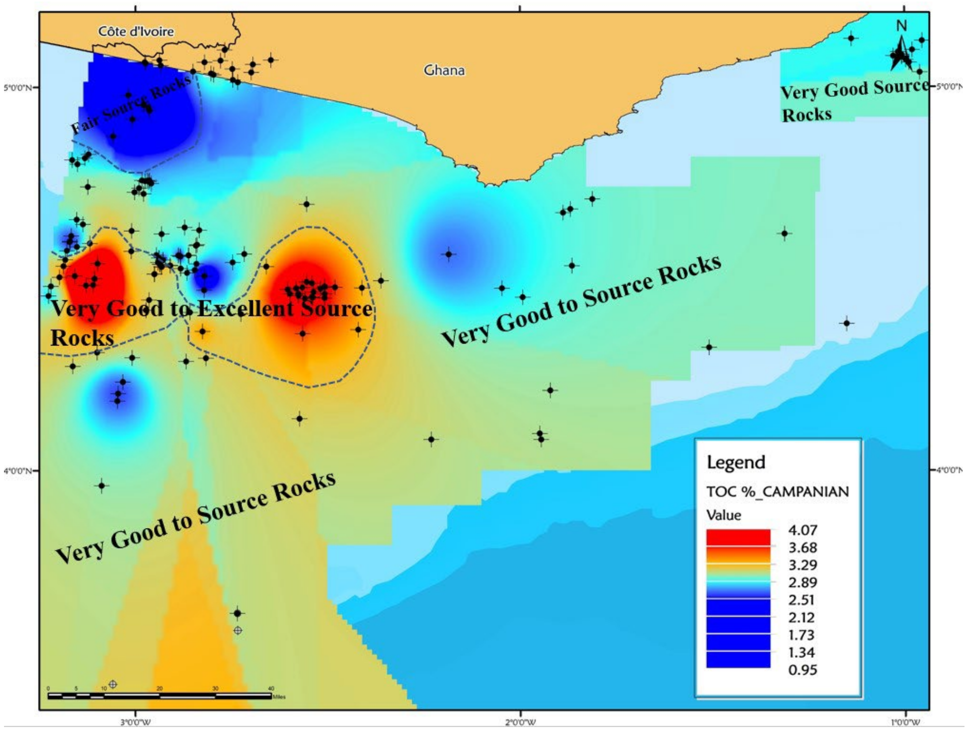


Fig. 10. Lateral distribution of organic richness in the Campanian interval

#### *4.5.2. Thermal maturity distribution*

Fig. 11 presents the spatial distribution of the maturity regime of source rocks in the study area during the Campanian. The highest and least values of Tmax are 435°C and 404°C respectively.

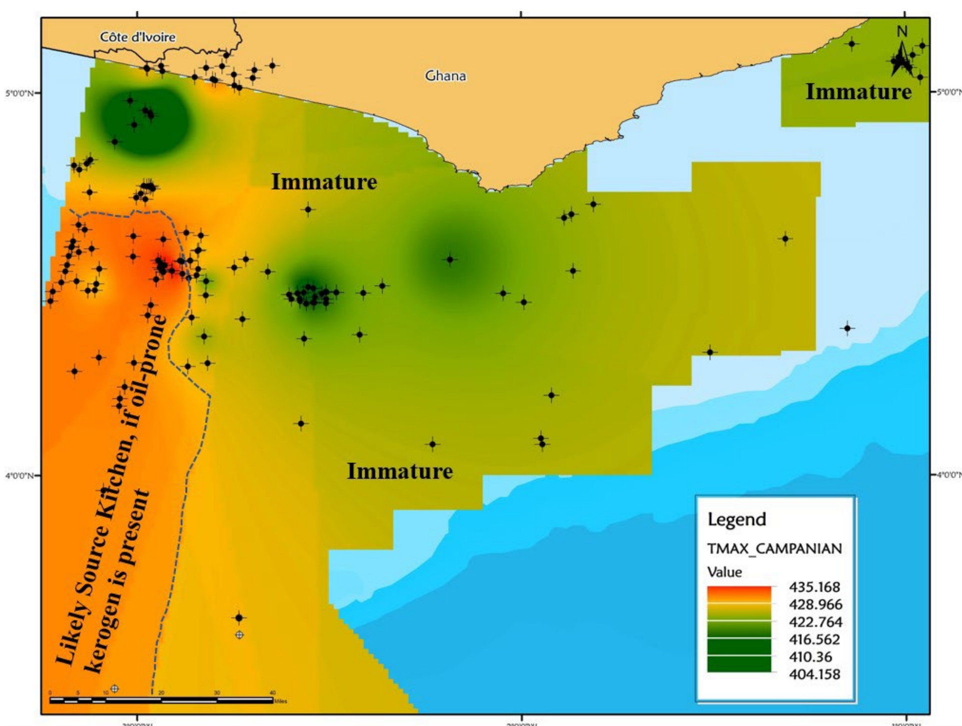


Fig. 11. Lateral distribution of thermal maturity in the Campanian interval

The highest and least Tmax values indicate that the maturity regime is not significantly different across the study area. The likely source kitchen is situated in the western part as marked out by region of highest Tmax values. The source rocks within this region can generate hydrocarbons if they are oil-prone. The source rocks, however, may require further burial with time for gas generation to be achieved.

## 4.6. Maastrichtian interval

### *4.6.1. Organic-richness distribution*

Fig. 12 shows a spatial distribution of the organic richness of source rocks in Maastrichtian time. The highest and least values of TOC are 3.5 % and 0.55 % respectively.

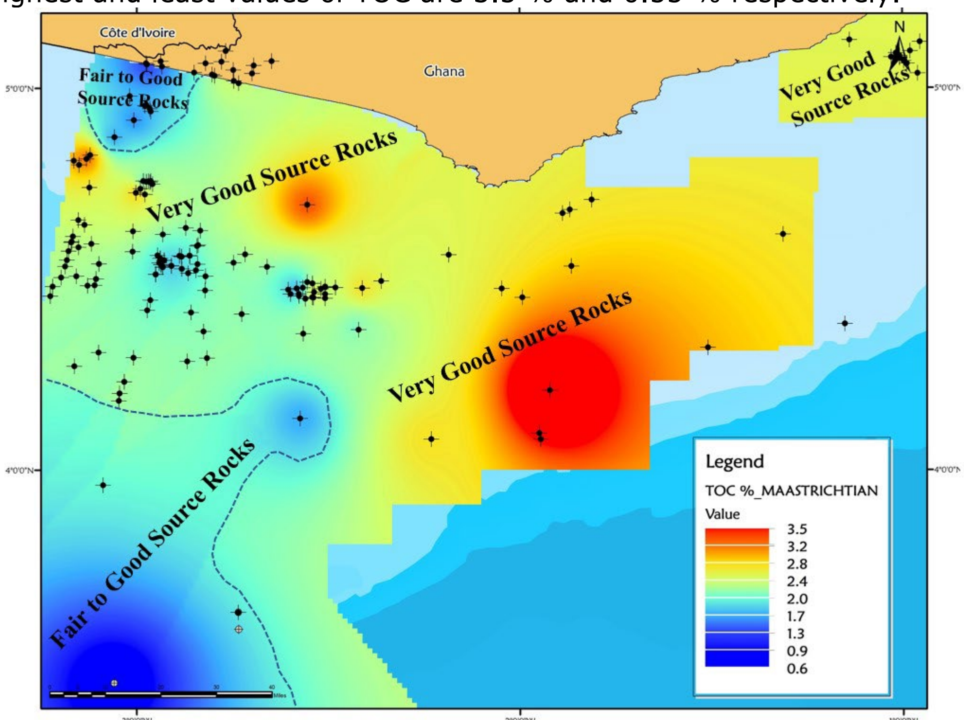


Fig. 12. Lateral distribution of organic richness in the Maastrichtian interval

The results show that the source rocks in the stratigraphic interval range from 'Fair" (0.5-1 %), "Good" (1-2 %), "Very Good" (2-4 %). "Fair to Good" source rocks are seen in the southwestern corner of the study area, whilst the rest of the area is covered by "Very Good" source rocks.

### *4.6.2. Thermal maturity distribution*

Fig. 13. shows the lateral distribution of the maturation regime of source rocks within the Maastrichtian interval. The highest and least values are 433 $^{0}$C and 99 $^{0}$C respectively.

The results showed that Tmax values all lie below the oil maturation window of 435 $^{0}$C. This is probably because the Maastrichtian interval is the youngest in the sequence and, relatively, has not been buried deeply enough to be subjected to sufficient pressure and temperature conditions. Perhaps, if oil-prone source rocks are present they might be slightly mature and in the early stage to produce hydrocarbons.

According to Chierici [17], MacGregor *et al.*, [25] and Atta-Peters and Garrey, [12], regional kerogen quality data from the offshore indicate there are predominantly types I, II, II/III and III kerogen showing a potential to generate both oil and gas, deposited in fluvial, deltaic, and marine environments. Also, vitrinite reflectance data show some stratigraphic intervals record reflectance of vitrinite (Ro) up to 0.8 %. This value is within the oil generation window [1-2] and corroborates the instances of spatio-temporal thermal maturity revealed by the Tmax maps.

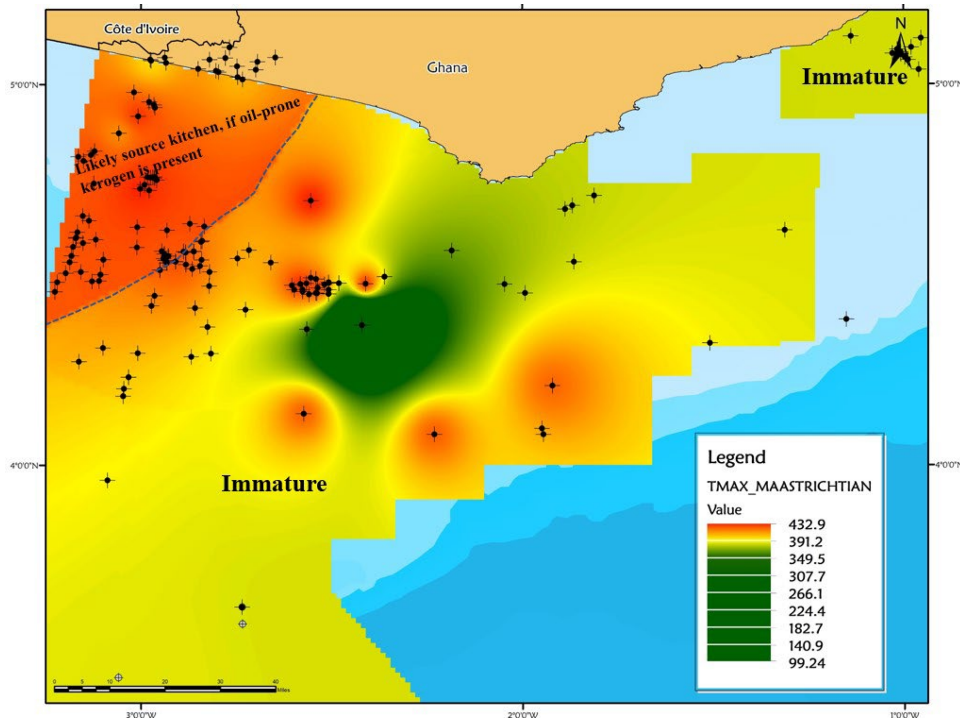


Fig. 13. Lateral distribution of thermal maturity in the Maastrichtian interval

## 5. Conclusions

An attempt to have an evolutionary discussion of some critical geochemical parameters (Tmax and TOC) that are used to characterize the quality of source rocks has been carried out for the offshore marginal basins of Ghana using the GIS tool. The results show that favorable conditions prevailed in the time of deposition of sediments that favored organic-matter production and preservation. The TOC % results in all the stratigraphic units were high enough to generate and produce the requisite saturation for the expulsion of hydrocarbons from source rocks. Most of the data lie above 0.5 % up to the "Excellent" range in Santonian and Campanian. The least TOC value of 0.3 % occurred in Albian and Cenomanian intervals, which is still capable of being classified as "Fair". Furthermore, the results also show that portions of the study area were covered with source rocks of varying degrees of thermal maturity (Tmax 435 $^0$C or above) and must have produced hydrocarbons in those portions with, probably, subsequent migration to other areas. The slightly immature source rocks in older sequences (Albian and Cenomanian) may have generated hydrocarbons given the longer exposure periods, and especially if oil-prone source rocks are present.

The source rocks have good hydrocarbon generation potential based on the results. The best source rocks are within the Albian, Cenomanian, Turonian and Santonian intervals and are distributed at the western portion of the study area, particularly around the Ghana-Ivory Coast boundary where relatively high organic-richness coincided with relatively high thermal maturity. Generally, there is no direct spatiotemporal correlation between levels of organic-richness to levels of thermal maturity. The highest to lowest range of organic-matter zones did not necessarily experience commensurate highest to lowest temperature regimes for all the Cretaceous intervals studied.

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*To whom correspondence should be addressed: Dr. Prosper Aduah Akaba, Department of Geological Engineering, Faculty of Civil and Geo-Engineering, Kwame Nkrumah University of Science and Technology, Ghana,*
*E-mail: prosperous1000@yahoo.com*