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Original Article

Petroleum Potential Prospectivity of Muglad Basin, South Sudan: A Case of Source Rocks Characterisation in the Drilled Kaikang West-1 Well

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ABSTRACT

This study focuses on Prospectivity of Petroleum Potential of Muglad basin, South Sudan, with the help of petroleum source rocks characterisation in the drilled Kaikang West-1 Well based on the organic matter quantity, quality, and the thermal maturation generation capability of the organic matter disseminated in the analysed rock samples. Muglad basin is a major petroliferous Western and Central African Rifts System (WCARS) member, with estimated reserves of 2,053 mm bbl. Muglad Basin comprises thick sandstones of Aradeiba and Bentiu Formations, considered to be the main petroleum prospectivity targets, with trapping mechanism being structural faults and lithological anticlines. The organic matter contents were determined directly from laboratory analyses of the source rock samples with the help of seismic and gamma ray profiles, total organic carbon (TOC wt %), maturity indices (OI, HI and PI), temperature maximum (Tmax °C), porosities and other sedimentological parameters. This study involved a series of analytical geochemistry and petro-physical studies to ascertain a number of effective source rock samples from the Well cores which were then analysed in terms of TOC, OI, PI, HI, S2, S1 and Tmax to determine oil/gas prone samples (resource areas). These were then distinguished from strata with very high organic matter samples as well as very high TOC to help identify for possible source rock characterizations within the lithology pertaining to the Well in terms of potential source-reservoir-seals combinations. The Rock-Eval pyrolysis data were useful in assessing and evaluating the type of organic matter, thermal maturity, and the generation capability of source rocks for hydrocarbon exploration rationale. The analyses revealed that some strata, within the sampled Well data, have high hydrocarbon generation potential with the existence of commercial hydrocarbon production.

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INTRODUCTION

Muglad basin is a major petroliferous Western and Central African Rifts System (WCARS) member, with estimated reserves of 2,053 mm bbl (*Figure 1*). The basin has been under intensive hunt for oil exploration activities since the early seventies (1970s) before Chevron overseas initiated the first oil and gas drilling in the basin in the 1980s. However, since then, significant achievements have been made to date; with many discoveries of giant oil fields such as Unity, Heglig, Toma South, Hamra, El Toor, Bamboo, and Munga in the Neem and Tharjiath oil fields.

The central part of the basin, Kaikang, however, remained unexplored due to several reasons, among them security concerns. This area is grossly underdeveloped and lies within a rugged and swampy terrain, with water flooding every year. The low human settlement here encourages keeping ranges of mainly animal husbandry as well as fishing grounds. Security issues due to marauding cattle rustlers have also been a challenge for quite a long time in the area [1].

The Muglad Basin comprises thick sandstones of Aradeiba and Bentiu Formations, considered to be the main petroleum prospectivity targets, with trapping mechanism being structural faults and lithological anticlines. Indeed, most of the petroleum generated by the Abu Gabra Formation source kitchen could have migrated to the upper Formations along these major basinal faults. Thus, sandstones within the Abu Gabra are generally thin, with poor permeability and porosity quality (*Table 1*), caused by compaction. Recently, new petroleum discoveries were identified within the Middle Abu Gabra rift, in the Abu Gabra Formation, which contained thick sedimentary piles with good petroleum accumulation capabilities [2].

Muglad Basin Configuration

The Muglad basin developed as deep block fault-bounded extensional basins of the NW-SE-trending Kenya’s Anza and South Sudan’s Abu Gabra rifts, which comprises Cretaceous and Tertiary non-marine sedimentary sequences [3], [4], [5]. These rifts system have been linked to the Central African rifts movement in Niger and Chad (*Figure 1*). The Basin development has similarly been linked to NE-SW tectonic rifting movements on the opening of the southern part of the Atlantic as well as the Indian Ocean. The Muglad Basin, therefore, is one of the largest of the NW-SE-oriented rift-related basins. In South Sudan, it extends across SE-oriented rift basins covering about 120,000 sq. km (approximately 200 km wide and over 800 km long). Periodic paleogeographic climatic shifts have been recorded in the clay minerals along the great East African Rift System (EARS) extending from Lake Malawi in southeastern Africa up to the Lake Turkana area in northwestern Kenya [1], [6] [9].

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Figure 1: Regional geological map of South Sudan [3]

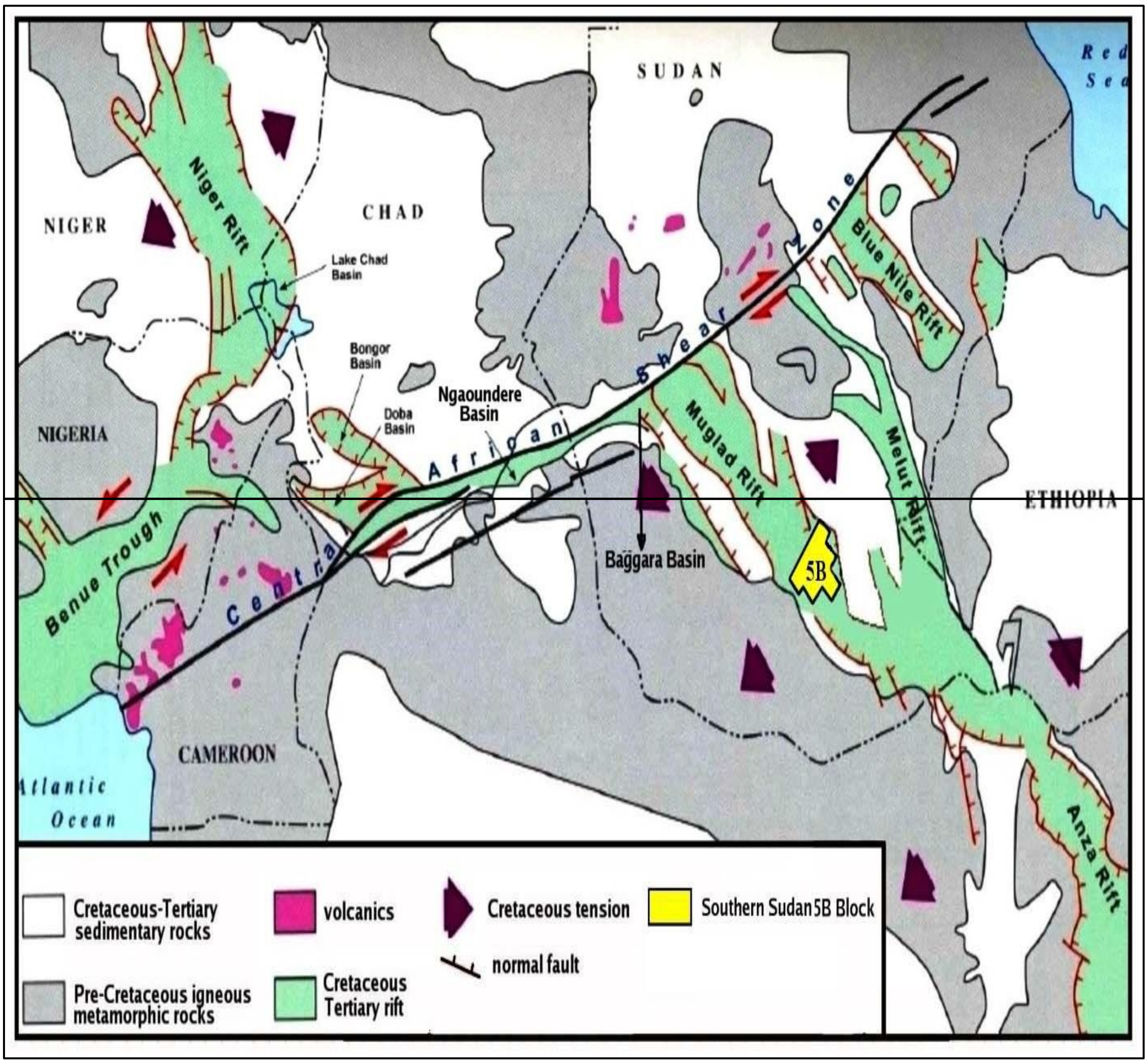
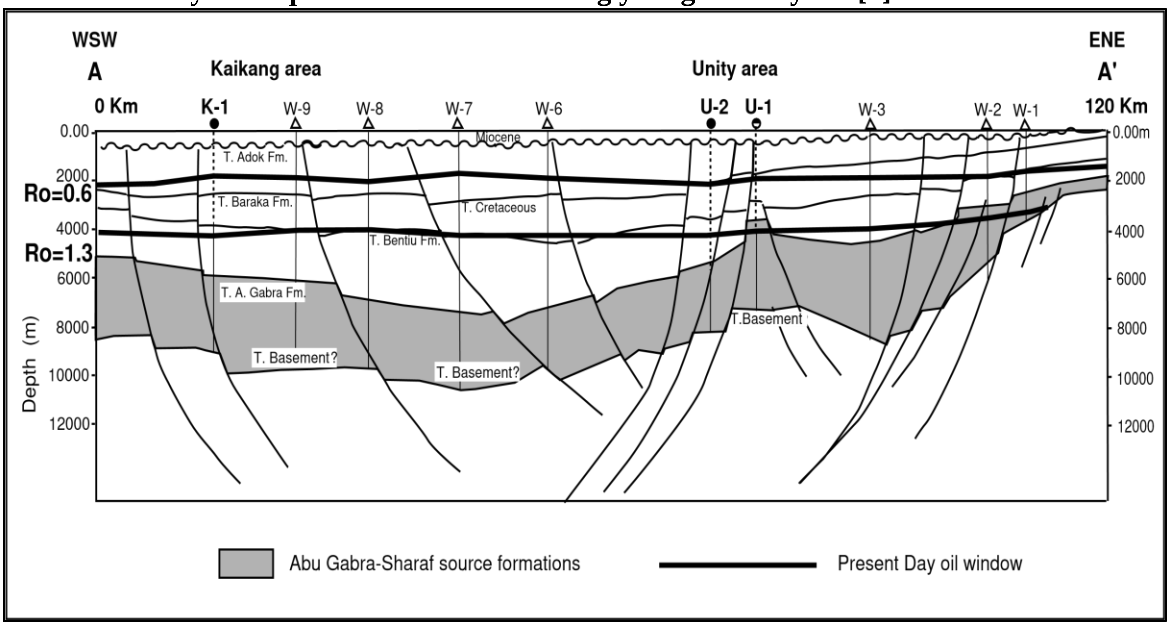


Figure 2: The sub-basins of Abu Gabra source rock typically have a half-graben geometry, which was modified by subsequent re-activation during younger rift cycles [3]



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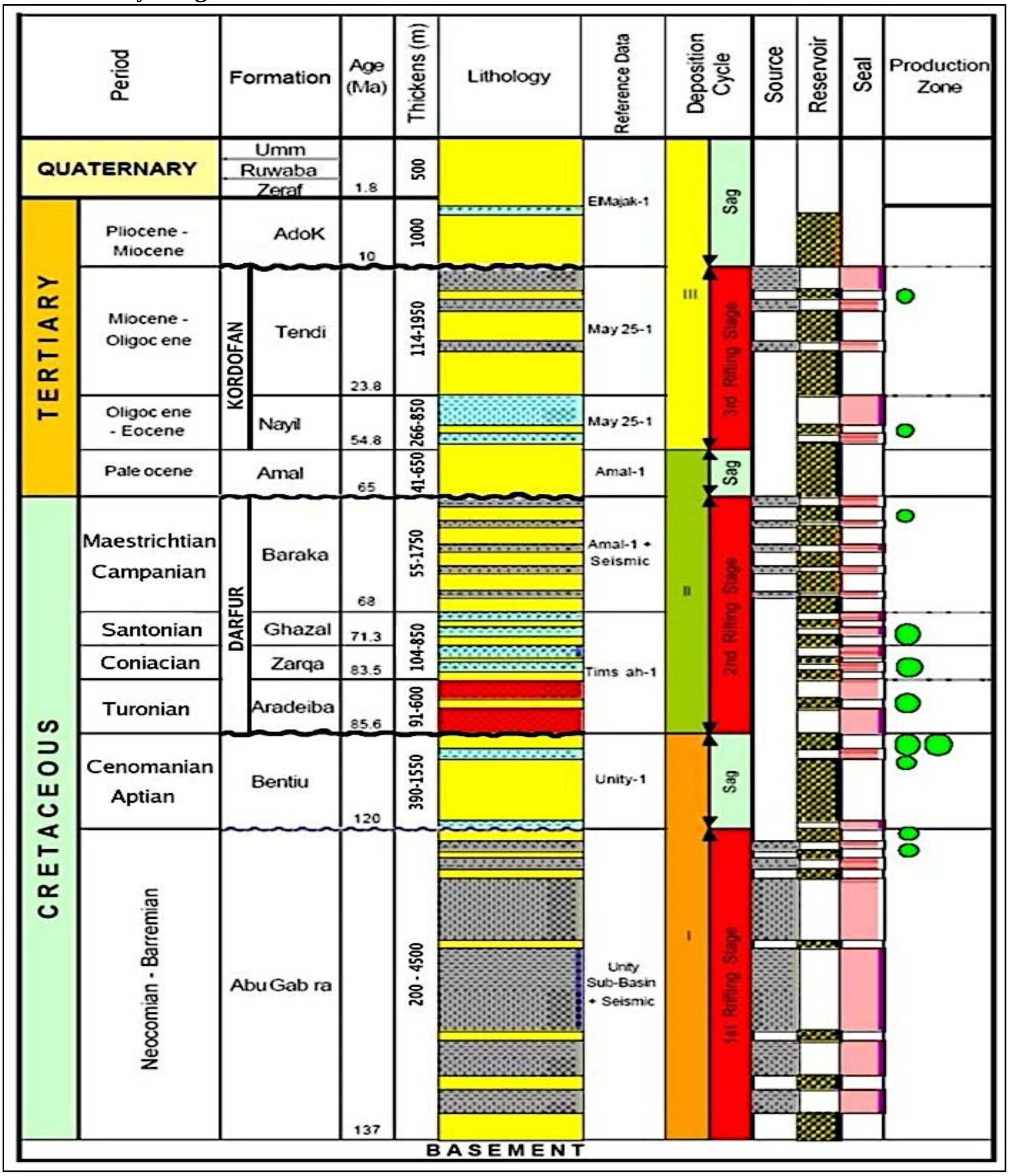
The Muglad basin consists of up to 13 km thick Cretaceous-Tertiary sediments. Three major episodes (phases) of extensional tectonism (rifting) recognized in the Muglad basin [3], [7] [9] include such structural and tectonostratigraphic features shown in *Figures 2* and *3* below.

- Phase 1 – Early Cretaceous, 140 - 95 million years
- Phase 2 – Late Cretaceous, 95 - 65 million years
- Phase 3 – Paleogene, 65 - 30 million years

Figure 3: The Three geological rift cycles of the Muglad Basin and Chrono-stratigraphic chart based on Palynological data of South Sudan



Source: modified from [3] and [7]

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The paucity of the most prospective potential source rocks in the southern part of the Abu Gabra Formation is caused by the limited Well intersections [3]. Thus, the trend analysis of sand versus shale obtained from Wells in Abu Gabra Formation, which is lithologically sandier, suggests less prospective areas towards the southern part of the basin. These units facilitated a better recognition of the petroleum system elements in the basin. Based on information obtained from drilled Wells' data and seismic features, the Abu Gabra Formation [8], [9] is informally divided into four stratigraphic units: AG-1, AG-2, AG-3, and AG-4. Of these units, two are similar to those of the Bentiu Formations (Beatiu-1 and Bentiu-2) which consist of interbedded sandstones and claystones as well as mainly massive blocky sandstones, respectively. The stratigraphic units AG-2 and AG-4 are also composed of interbedded sandstones and claystones but those of AG-3 consist of mainly massive blocky sandstones [3].

The characteristics of identified subsurface stratigraphic formations (*Figures 2* and *3*) namely; the Abu Gabra-Lower Bentiu Formation (Early Cretaceous), Baraka Formation (Late Cretaceous), and Nayil-Tendi Formations (Eocene-Early Cretaceous) showing potential petroleum prospectivity were augmented by geochemical analysis of the potential source rocks in terms of total amount of organic carbon (TOC) and temperature maximum (Tmax), present conducive environments and implications for the hydrocarbons generation [1], [3].

Source Rocks Potential

Source rocks are rocks that contain sufficient organic material to create hydrocarbons when subjected to heat and pressure over time [10]. The typical source rocks are shales and limestones. For a source rock to be productive it needs more time to mature, and hydrocarbons need to be able to migrate to a reservoir for storage. Hydrocarbon source rock evaluation is governed by organic matter content, quality and thermal maturation generation capability of organic matter present in the rock [[5], 11], [12].

The organic richness of a rock is expressed as the total organic carbon content [5]. The minimum acceptable TOC for clastic rocks that indicate good source rock potential is in the range between 1-0.5% [11]. Hence, TOC below 0.5% the source rock is deemed as poor and therefore it cannot yield significant hydrocarbons. The type of organic matter is the second most important parameter in evaluating source rock [12]. The three classes of organic matter already established are:

- Type I - oil prone organic matter
- Type II - mixed oil and gas organic matter
- Type III - gas prone organic matter

It was proposed that for mature source rock, Hydrogen index (HI) for gas-prone organic matter is less than 150, gas-oil organic matter is between 150 and 300. Thus, in an oil-prone organic matter HI is more than 300 [12] [17]. S1 represents the already generated hydrocarbon in the rock while S2 is the hydrocarbon generated through thermal cracking of non-volatile organic matter [13]. S2 usually decreases with burial depth >1 km. The greater the generative potential of S2 relative to the TOC, the greater the HI. As source rock matures, its HI decreases accordingly [5].

Petroleum source rock has been defined as the fine-grained sediment with sufficient amount of organic matter, which can generate and release enough hydrocarbons to form a commercial accumulation of oil or gas [10]. Source rocks are commonly shales and mudstones, which contain significant amount of organic matter. A petroleum source rock is also defined as any rock that has the capability to generate and expel enough hydrocarbons to form an accumulation of oil or gas [5], [12]. Source rocks are often classified into three classes [12] according to oil generation:

- Immature source rocks that have not yet generated hydrocarbons.
- Mature source rocks that are in generation phase.

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- Post mature source rocks are those which have already generated all crude oil type hydrocarbons.

The petroleum source rocks are similarly distinguished into three classes [11] as potential, possible, and effective:

- Potential source rocks are immature sedimentary rocks capable of generating and expelling hydrocarbons if their level of maturity were higher.
- Possible source rocks are sedimentary rocks whose source potential has not yet been evaluated, but which may have generated and expelled hydrocarbons.
- Effective source rocks are sedimentary rocks, which have already generated and expelled hydrocarbons.

The hydrocarbon source evaluation is generally based on the organic matter quantity (organic richness), quality (kerogen type), and the thermal maturation generation capability of the organic matter disseminated in the rock [12]. Organic matter content can be determined directly from laboratory analyses of the source rock samples (shale, limestone, or marl), and through indirect methods based on wireline data over the advantages of economic, ready availability of data, and continuity of sampling of vertically heterogeneous shale section [5].

The main objective of this study was to assess and evaluate the type of organic matter (kerogen/bitumen), thermal maturity (S1 and S2), and the generation capability of source rocks for hydrocarbon exploration rationale in the Muglad Cretaceous-Tertiary rift basin [3], [15] which has proven to have potential petroleum deposits, based on seismic and gamma ray profiles, total organic carbon (TOC), maturity indices (S1, S2, S1 +S2, OI, HI and PI), porosities and other sedimentological parameters. The majority of samples from the Tendi Formation in the Kaikang West-1 Well have proven to be mature with a Tmax ranging from 435-442^{o}C and this falls at the beginning of the oil generative window [5].

Here below, with the help of *Table 1*, the authors have attempted to interpret and examine some variations' parameters such as TOC, maturity indices, Tmax and depth (m) in order to identify possibility of having source rocks for hydrocarbons generation in the Kaikang West-1 Well, South Sudan.

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Table 1: The Rock-eval pyrolysis results from Kaikang West-1 Well, Muglad basin, South Sudan [15]

No	Depth (m)	Formation	TOC (wt%)	S1 (mgHC/ g rock)	S2 (mgHC/ g rock)	S3 (mg CO2/g rock)	S1+S2 (mgHC/ g rock)	Tmax (^{0}C)	HI (mgHC/ g TOC)	OI (mgHC/ g TOC)	TPI S1/ (S1+S2)	Quality
1	440	Adok	0.02	0.01	0.02	0.45	0.03	394	90	1842	0.26	poor
2	630		0.06	0.01	0.04	0.3	0.05	374	61	501	0.15	poor
3	840	Tendi	0.17	0.01	0.07	0.53	0.08	427	44	312	0.06	poor
4	980		4.5	0.06	26.82	0.94	26.88	435	596	21	0	v. good
5	1050		0.59	0.01	1.25	0.49	1.26	441	212	83	0.01	fair
6	1189		5.76	0.08	39.48	0.65	39.56	439	685	11	0	v. good
7	1245		0.81	0.01	1.28	0.76	1.29	442	158	93	0	fair
8	1295		6.85	0.08	49.78	0.75	49.86	438	726	11	0	v. good
9	1565		0.06	0	0.04	0.51	0.04	434	74	901	0.06	poor
10	1585		0.8	0.01	0.06	0.42	0.07	431	73	555	0.11	fair
11	1620		0.12	0.01	0.05	0.29	0.06	433	38	241	0.11	poor
12	1640		0.15	0.01	0.08	0.49	0.09	432	53	330	0.06	poor
13	1720	Amal	0.06	0	0.04	0.21	0.04	422	58	331	0.12	poor
14	1810		0.05	0	0.07	0.26	0.07	436	136	511	0.06	poor
15	1830		0.06	0.01	0.04	1.38	0.05	339	75	2434	0.15	poor
16	1895		0.06	0.01	0.05	0.22	0.06	431	83	378	0.12	poor
17	1990	Baraka	0.83	0.08	0.93	0.1	1.01	445	113	13	0.08	fair
18	2010		2.29	0.39	7.47	0.05	7.86	443	327	2	0.05	v. good
19	2040		0.52	0.03	0.83	0.1	0.86	445	161	19	0.04	fair
20	2060		5.92	1.63	23.29	0.05	24.92	438	393	1	0.07	v. good
21	2080		0.16	0.02	0.24	0.3	0.26	444	149	189	0.07	poor
22	2385		0.13	0	0	3.91	0	469	0	3016	0	poor

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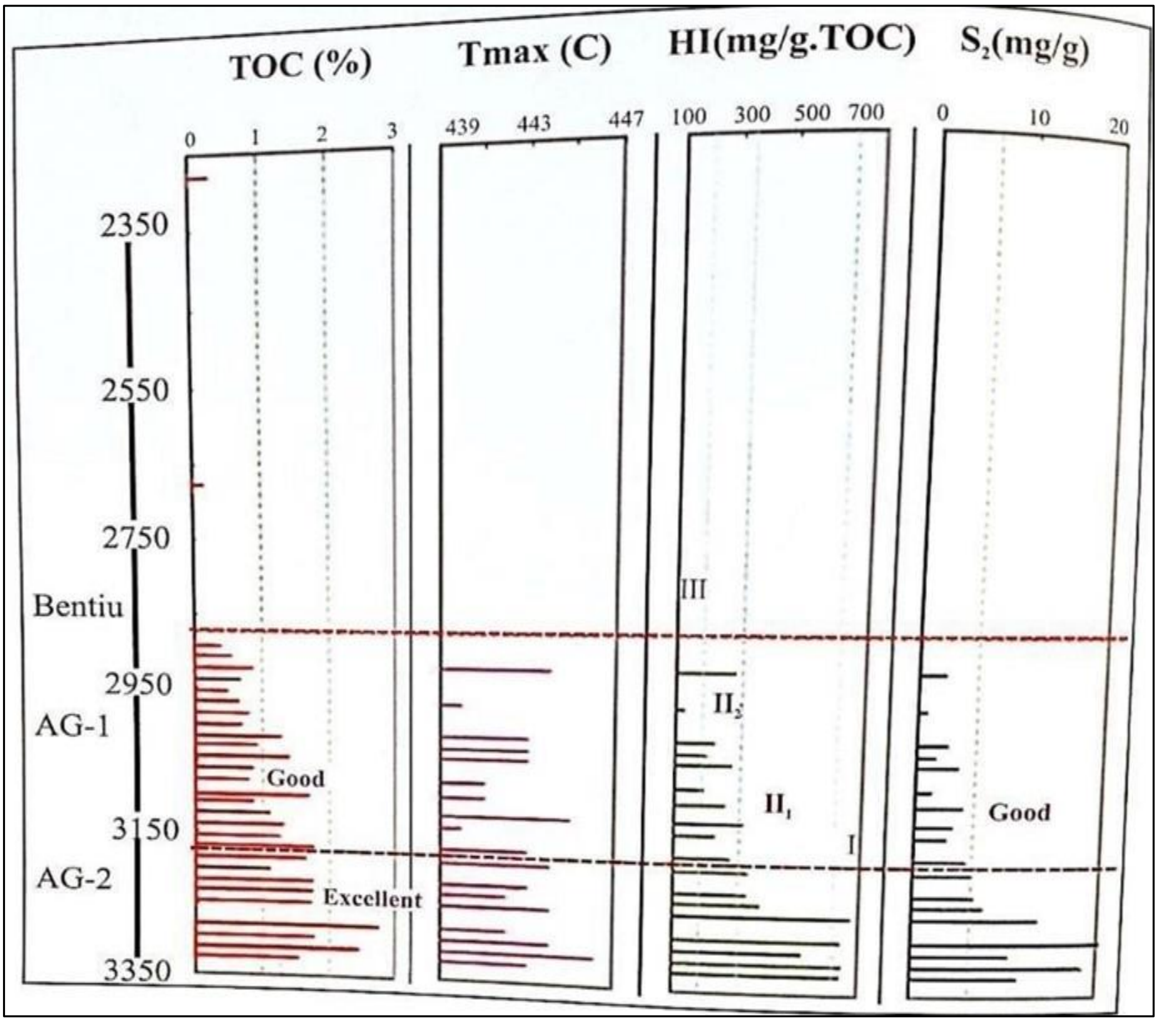
Figure 4: Geochemical profile of Abu Sufyan-1 Well, NW parts of the Muglad basin [9]



MATERIALS AND METHODS

From *Table 1*, some interpretation of possible petroleum prospectivity variations has been conducted using parameters like TOC, maturity indices (HI, OI and PI), Tmax (^{o} C) and depth (m) in order to identify the possible presence of source rocks for hydrocarbons generation from the samples that were subjected to Rock-Eval pyrolysis after drying (E.g., *Figure 5* below) [5]). The following variations' graphs from the given data (*Table 1*) were generated and then interpreted by characterising and recognising the source rocks potential of rock lithological sections in the drilled Kaikang West-1 Well, Muglad basin, South Sudan:

- S2 versus S1.
- S1 + S2 versus Depth (m).
- Oxygen Index (OI) versus Depth (m).
- Hydrogen index (HI) versus Depth (m).
- Production index (TPI= S1/ (S1 + S2) versus Depth (m).
- TOC (wt%) versus HI = (mgHC/gTOC).
- Production index (TPI) versus HI Tmax (degree C) versus Depth (m).
- TOC versus Depth (m).
- Tmax (degree C) versus TOC.

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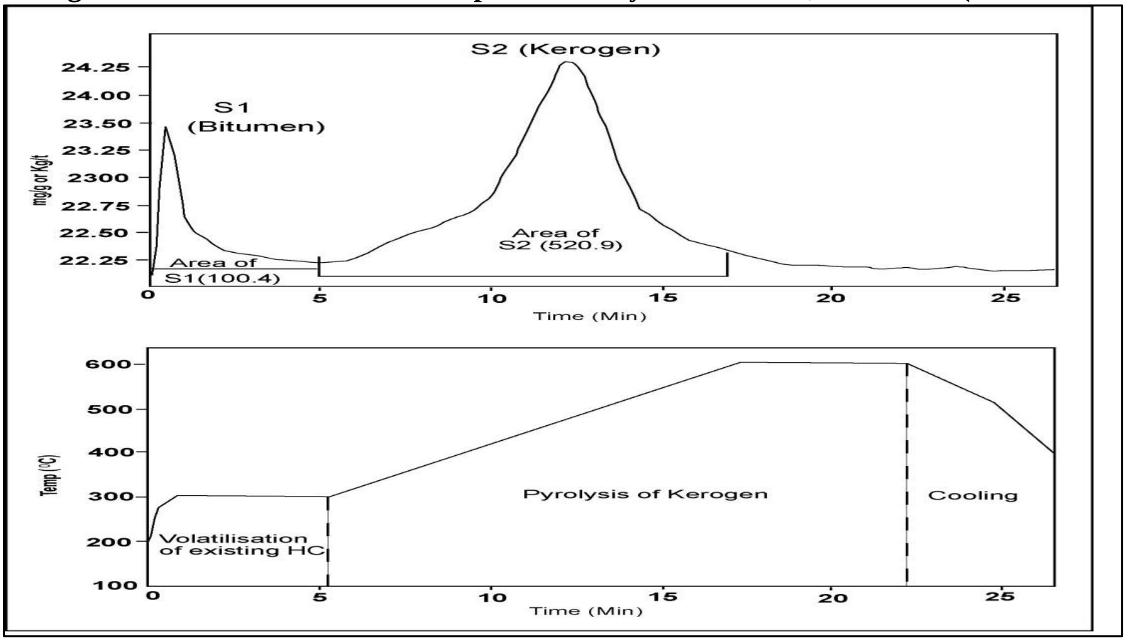
Figure 5: A Laboratory example of Rock-Eval pyrolysis sample [5] showing the effect of heating an organic-rich material at 1098 m depth in a Kenyan Rift Basin, LT-1 Well (at Tmax 435.3ºC)



Source: (Adopted from [5])

It has been suggested [17] that sedimentary rocks do not always initially contain petroleum. It is generated during burial and diagenesis of the organic matter (OM) they contain [12], [11]. In such intracontinental basins [10], like in the present Muglad basin case, the temperature gradient is often higher than the normal because of the process of formation of such depositional basins [5], [6]. It may sometimes reach a gradient even of 30–33ºC/km. Higher temperatures are also reached by the co-precipitations of radioactive elements [5] along the organic matter deposited such basins. It can be seen that the field of crude oil generation window could expand and reach a maximum between 2 and 3 km depth. In many cases where there is less generation of crude oil, there is still a possibility of finding gas. The most promising depths for gas, however, are beyond 2.8 km depth [5], [6].

In the case of the drilled Kaikang West-1 Well, in this present study area, some selected rock samples from 440 m up to 2385 m were analysed within the depth range. Of the four known types of kerogens, the present basin is expected to have either Type 1 or Type II or Type III, (e.g., those of Geochemical profile of Abu Sufyan-1 Well [15] located in NW parts of the Muglad basin – *Figure 4*), because the source of organic matter is lacustrine and fluvial [16]. Total organic carbon (TOC) is an indicative of a measure of carbon present in a rock in the form of kerogen and bitumen. The organic matter is usually converted into kerogen and the Type of kerogen depends upon the kind of organic matter that got buried in the subbasin or main basinal areas [5].

The section below, therefore, attempts to examine some variations of such parameters like Total Organic Carbon (TOC) and Temperature maximum (Tmax º C) in respect with Depth (m), Hydrogen index (HI), Production index (PI), Maturity indices S1, S2, (S1 + S2), and Oxygen index (OI) in order to decipher and further identify possible presence of source rocks for hydrocarbons generation in the Kaikang West-1 Well. For example, intracratonic basin like this [5] does not usually attract marine organic matter (OM). The basin comprises mainly fluvial and lacustrine environments of deposition [3]. Therefore, the OM brought from the vegetation on the higher lands of the time (Lower Cretaceous and Early Tertiary) could have been buried along with the sediments in the mostly fluvial and lacustrine environments [6] and [19].

Selection of Samples for TOC Analysis

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Total organic carbon (TOC) is a measure of carbon present in a rock (not percent) in the form of kerogen and bitumen [5], [16] and [17]. As mentioned in sections above, the drilled Kaikang West-1 Well in Muglad basin, South Sudan, penetrated a thick petroliferous sedimentary pile in the Cretaceous-Tertiary reservoirs from mainly lacustrine/fluvial depositional environment. The lithology established through drill core samples showed no substantial presence of carbonaceous strata beyond 2385 m depths. Rock samples selected from 440 to 2385 m depth, showing some indications of the presence of organic matter, were analysed using Rock-Eval technique procedure. This section, between 440 m and 2385 m depth, was selected because of the reported oil shows prospectivity and abundance of rocks with high gamma ray values also. The objective was to measure the total amount of organic carbon (TOC) and identify the possible petroleum source rocks in the drilled Kaikang West-1 Well in the Muglad basin.

DATA INTERPRETATION, ANALYSIS, RESULTS AND DISCUSSIONS

Variations of S1 and S2 versus Depths (m)

Variations of S1 versus S2 values (440-2385 m)

From *Table 1*, the S2 versus S1 plots in *Figures 6A* and *6B*, obtained from the Rock-Eval pyrolysis results of the drilled Kaikang West-1 Well in Muglad basin, South Sudan, showed fair to good S2 kerogen potential at depths 1895 m to 2060 m (i.e. the basal parts of Amal and Baraka Formations). However, depths ranging from 2060 m up to 3500 m in the Abu Sufyan-1 Well in the NW parts of the Muglad basin of Bentiu Formation (*Figure 4*) show good to excellent TOC as well as good quality S2 values, while those of Baraka Formations are very poor (0.04-0.05 mgHC/g.TOC at points 9 to 10 in *Figure 6B*). The depths between 3200 m and 3350 m indicate fair to good S2 values (ranging from 0.5 to 20 mg/g) with corresponding excellent TOC (>1 % and <3 %) and an average Tmax of 440°C as well as high HI (300-700 mgHC/g.TOC), thus indicative of Types I and II kerogen potential.

Figure 6A: Variation of S1 versus S2 values (440 – 2385 m)

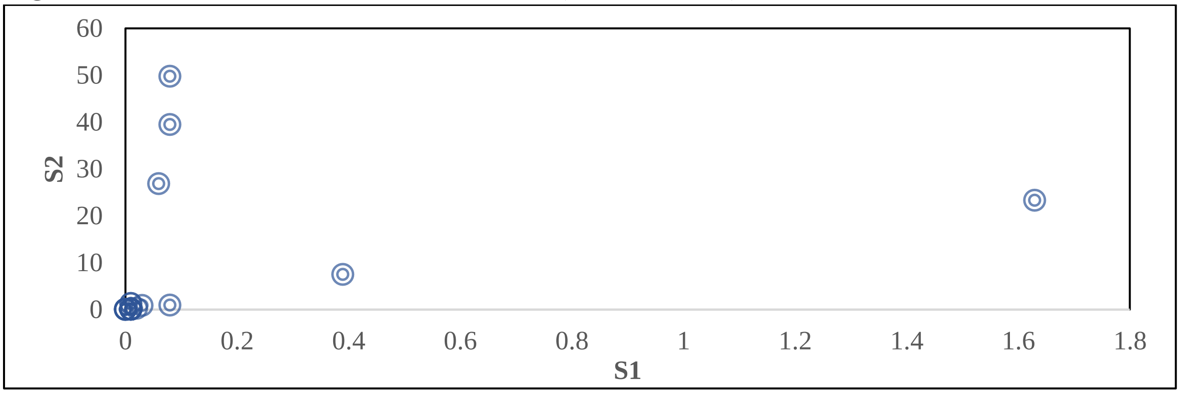
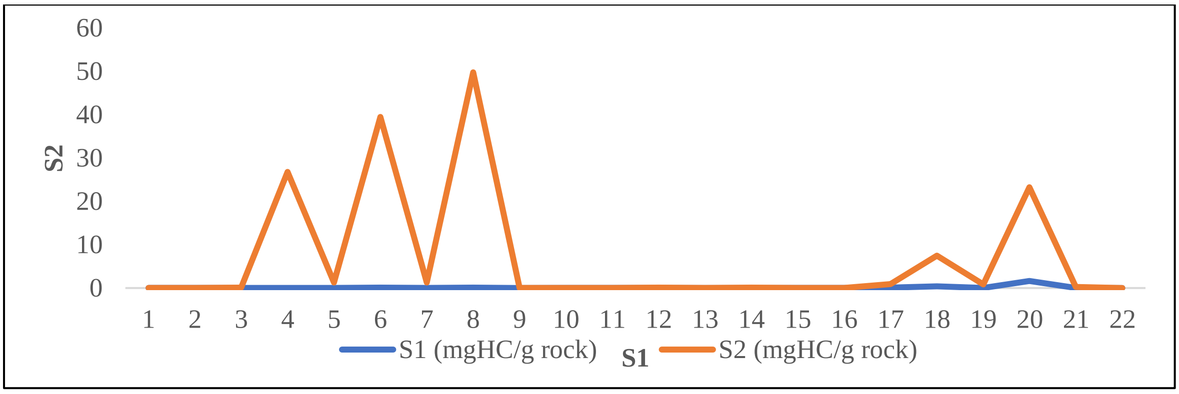
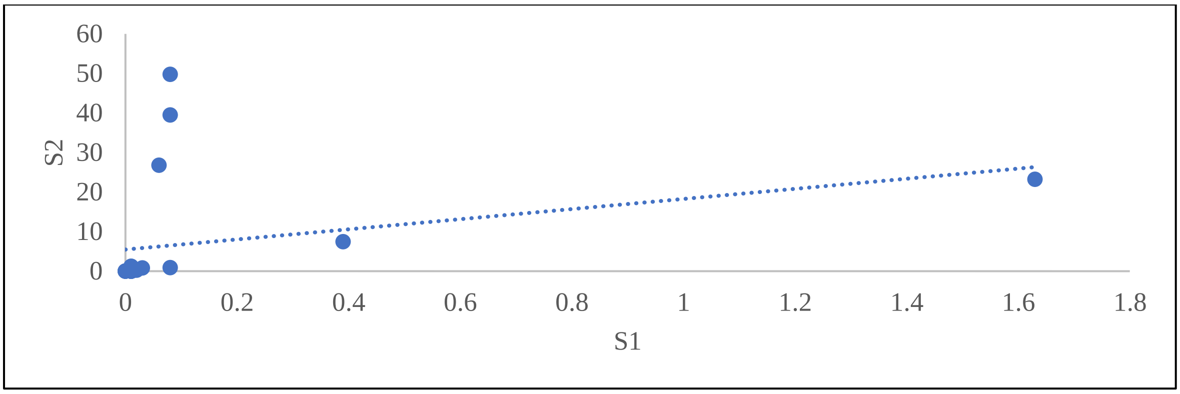


Figure 6B: Variation of S1 versus S2 values (440 – 2385 m)



In summary a plot of variation of S1 vs S2 which indicates a generalized linear relationship (*Figure 6C*) for Kaikang West-1 Well sample ranging from 440-2385 m depth showed that most of the samples had S2 values < 1.0 (mgHC/g rock). There are, however, very few samples which gives S1 greater than 0.2 (mgHC/g rock). Samples between 980-1295 m depth showed more S2 values greater than 10 (mgHC/g rock) with very few samples of S2 exceeded 20 (mgHC/g rock). In most cases, samples with S2 values > 5 (mgHC/g rock) are usually taken as good potential for hydrocarbon generation [5].

Figure 6C: Variation of S1 vs S2 for the Well



Variations of S1+S2 versus Depth (m)

Figure 7A: S1 + S2) versus depth (m)

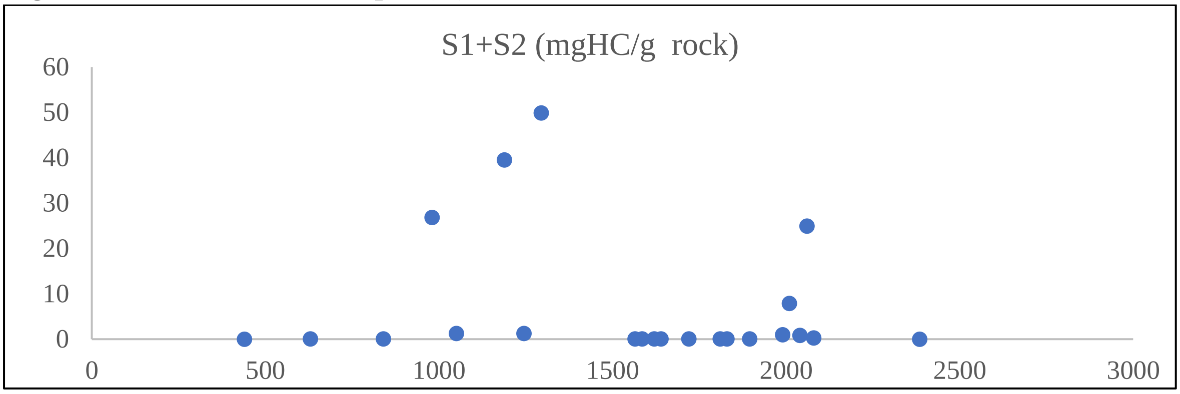
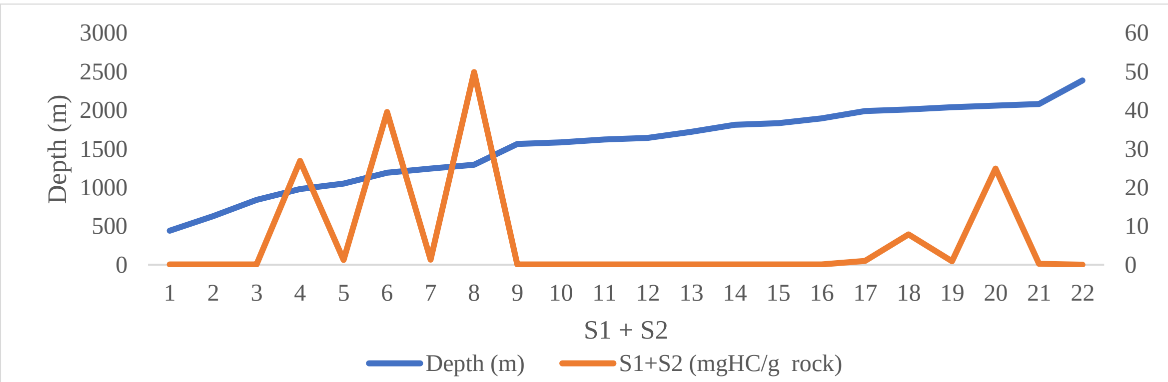


Figure 7B: S1 + S2 versus depth (m)



Similarly, the same patterns (*Figures 7A* and *7B*) of plots of variations between $S_1 + S_2$ versus depth graphs recorded high values > 10 mgHC/g rock (26.88, 39.56 and 49.86 at points 4, 6 and 8, respectively) in the shallow Denti Formation (980 – 1295 m depth) which indicate high potential of

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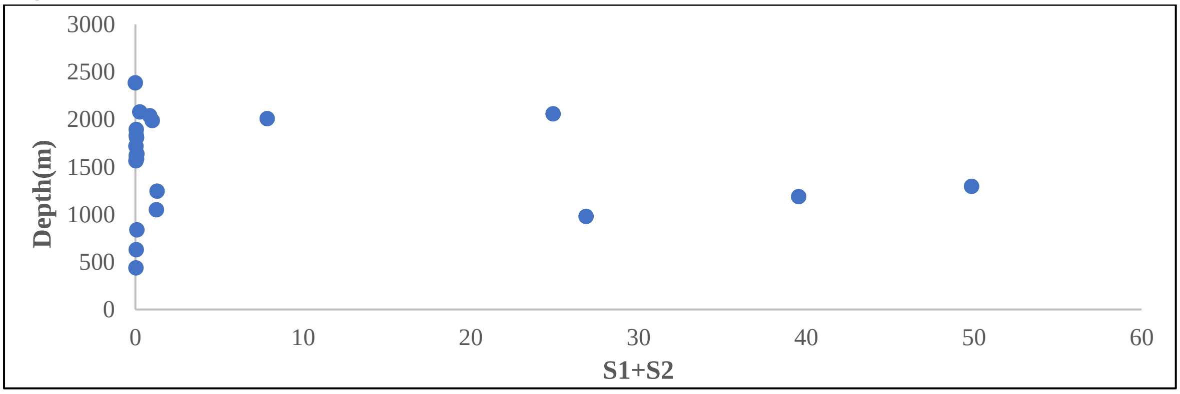
source rock for hydrocarbons generation. Some source rocks from depth range 1990 m – 2060 m in Baraka Formation have also recorded high values (7.86 and 24.92 mg/g at points 18 and 20 respectively, in *Figure 8B*). There is an apparent gradual increase of S1 + S2 with depth (from 440 m to 2385 m) showing some increase in indications and/or variations of the presence of rich organic matter (OM) that could generate petroleum prospectivity in the basinal area.

In summary samples with S1+S2 values < 2 mgHC/g rock (*Figure 8*) are not considered potential source rocks for hydrocarbon generation [5]. Source rocks with values of S1+S2 > 10 mg/g are considered rich for sufficient oil generation/expulsion. The upper Tendi Formation has S1+S2 values > 10 mgHC/g rock, therefore it's considered best for oil expulsion. It can be seen from that the number of samples showing S1+S2 > 10 mgHC/g rock fall in depth range (980-1295 m) as seen in *Figures 7A, 7B* and *8*).

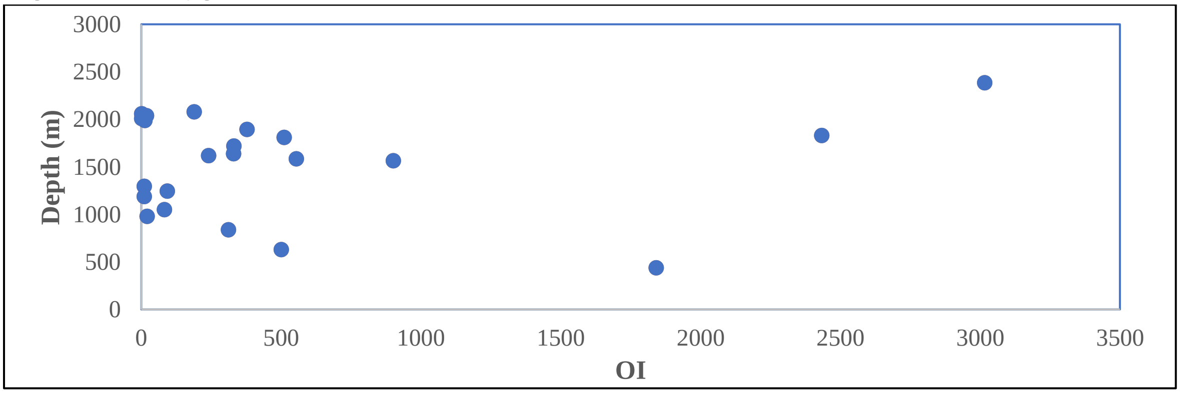
Figure 8: S1+S2 vs Depth (m)



Similarly, the same pattern (*Figures 9A & B*) of plots showing variations between depth versus oxygen index (OI) graphs, which recorded low OI values (11 to 93 mgHC/g rock) between depth range 980 m to 1295 m, in the shallow Denti Formation, is also indicative of anaerobic condition conducive for high potential of source rocks for hydrocarbons generation.

Variations of Oxygen Index (OI) versus Depth (m)

Figure 9A: Oxygen Index (OI) versus Depth (m)



There is, however, exceptionally high OI between 1565 m and 1896 m depths, which reveal poor quality source rocks (*Table 1*) with low TOC (0.05-0.15 %), HI (53-75) and PI {S1/(S1+S2)} – averaging 0.09.

In summary Oxygen index (OI) is a measure of amount of oxygen relative to amount of organic carbon content present in a sample [18]. High OI in source rock is indicative of gas prone, terrigenous -sourced, kerogen type III and hence considered undesirable quality for a good oil-

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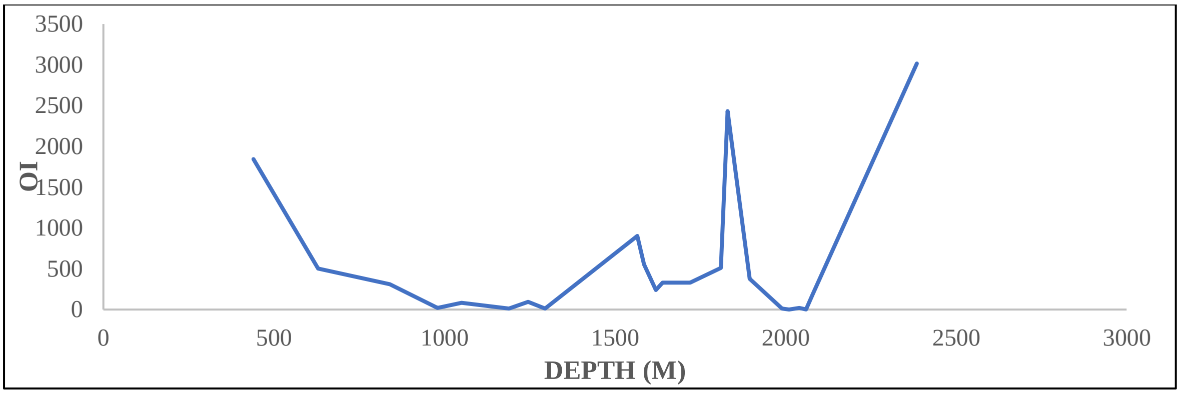
prone source rock [5]. Oxygen index for Tendi Formation ranges from 11-901 indicating that the Formation has Type II, mixed Type II-III and Type III kerogens. Thus, from *Figure 9B*, we can observe that the variations of OI with depth is not uniform, with high OI of over 400 between depths 565 and 1990 m, and exceptionally higher OI of 2434 at 1830 m and 3016 at 2385 m depths, respectively.

Figure 9B : OI vs Depth (m)

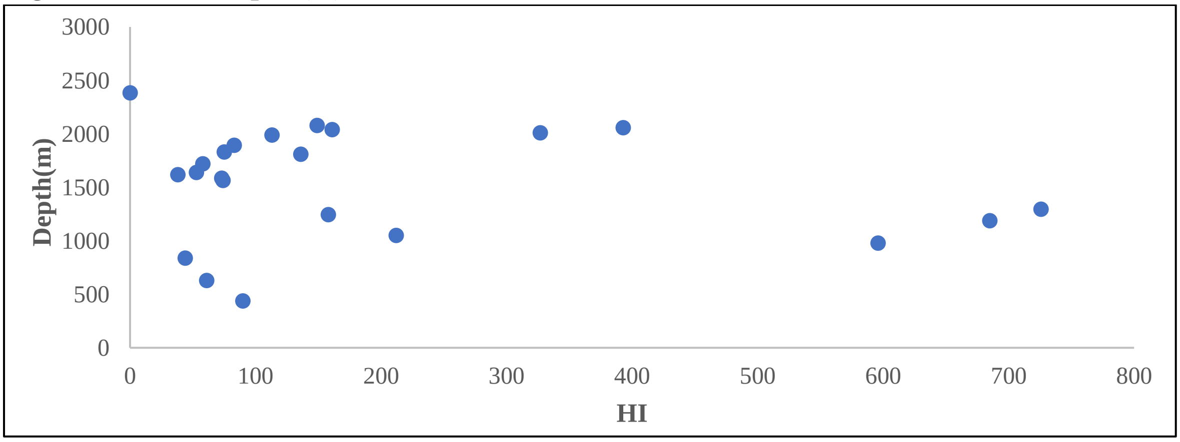


Variations of Hydrogen index (HI) versus Depth (m)

Figure 10 which is a plot of Hydrogen index (HI) versus depth, clearly shows high values of HI (about 392 to 726) within same depth ranges (at shallow depth 980–1295 m and deeper depths beyond 2060 m, respectively). Similarly, TOC wt % values (4.5% - 6.85%) appear to increase within the same lower part of these depths (1189–1295 m) and even intermittently towards 1800 m depth as seen in *Figure 10*. It can be seen in *Figure 4* that there are many levels of low and high HI intermittently present, even in sediments that occurred at the deeper regions of the Well. This indicates that there is no uniform variation in maturity of the organic matter with depth (up to even 1800 m) as well as variations in H/C ratio.

Therefore, the plot of HI vs Depth shows that Baraka Formation lies between kerogen Types I and II. Tendi Formation, similarly lies between kerogen Types I and III. Thus, the Hydrogen index (HI) represents the amount of hydrogen relative to the amount of organic carbon (OM) present in the rock at the formation depth. The graph reveals that HI decreases with maturity. It can also be seen that HI increases from 440-980 m depth. But from depth 1050 m, there is no uniform variation of HI with depth. It is only observed in the samples at depth range 980-1295 m which indicate HI > 500. The higher HIs values correspond to high (S1+S2) values.

Figure 10: HI vs Depth (m)



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Variations of Production index (TPI= S1/ (S1 + S2) versus Depth (m)

Figures 11A and *B***,** which are plots of PI versus Depth (m), indicate that samples with higher HI have lower PI and those with lower HI have comparatively higher PI. This confirms the interpretation of generation, migration and accumulation of hydrocarbons in the depth ranges described above (the shallow 1189–1295 m and deeper 2010–2060 m, respectively).

Hence, Production index (PI) is the measure of the progress in the generation of hydrocarbon [5] and this shows level of thermal maturation. Thus, from these plots we can see that variation of PI with depth is not uniform. PI decreases from 0.26 to 0 between depth range 440-1295 m.

Figure 11A: Production index (PI) versus Depth (m)

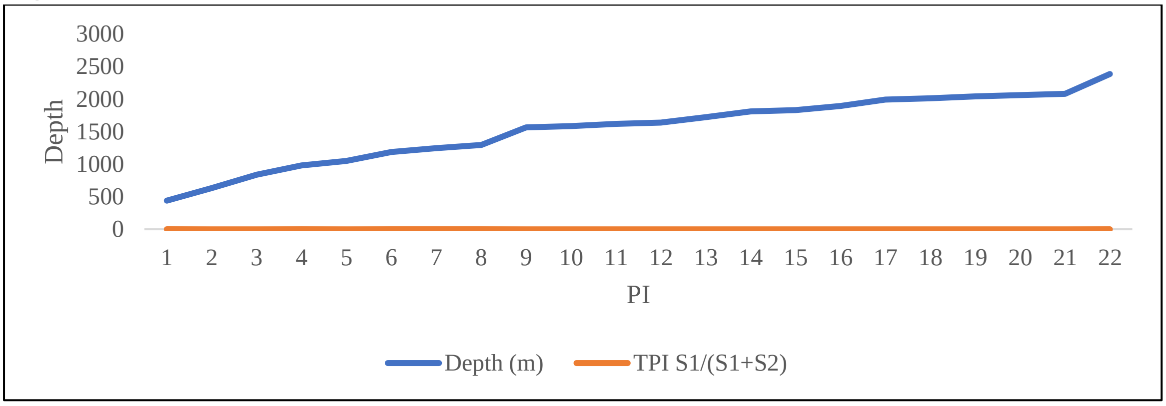
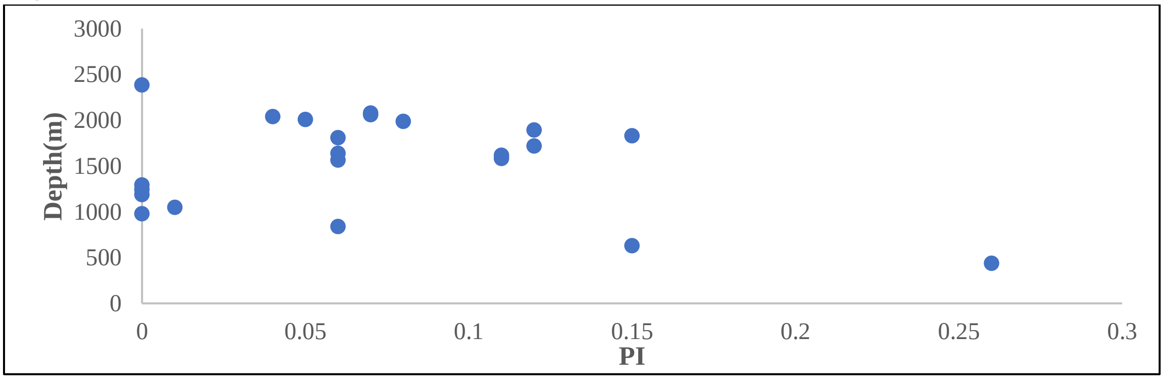


Figure 11B: Production index (PI) vs Depth (m)



Variations of TOC (wt%) versus HI (mgHC/gTOC)

The Hydrogen index (HI) is calculated from Rock-Eval data [5]. *Figures 12A* and *12B* are plots of HI versus TOC from the samples. This shows that most of the samples belong between Type I and Type III, but less of Type II, based on its kerogen. The Hydrogen index (HI) represents the amount of hydrogen relative to the amount of organic carbon present in the rock at the Formation depth [5]. Gross trends of Hydrogen indices (HIs) can be used as a maturation indicator.

Plots of HI versus TOC (*Figure 12A*) also give useful characteristics in determining the maturity of hydrocarbon generating rock. The HI is said to decrease with maturity [5]. A generalized linear relation between TOC and HI is shown in the shallow depths (980–1295 m) of *Figure 12B*. The samples with high TOC do not necessarily show high HI. Samples showing high HI indicate a narrow range of TOC. Samples with higher HI do not necessarily show high TOC. Table 1 shows variations of high HI with depth, especially from shallow depth range of 980 to 1295 m, even up to 2060 m depth.

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Thus, the plot of TOC versus HI (*Figure 12B*) gives useful linear characteristic in determining the maturity of hydrocarbon generating rock. HI is said to decrease with maturity. From the graph it can be seen that the samples showing high HI indicate a narrow range of TOC. Samples with higher HI do not necessarily show high TOC, though as earlier noted, samples with TOC greater than 2 % are generally good for hydrocarbon generation [5] and [15].

Figure 12A; TOC (wt%) versus HI = (mgHC/gTOC)

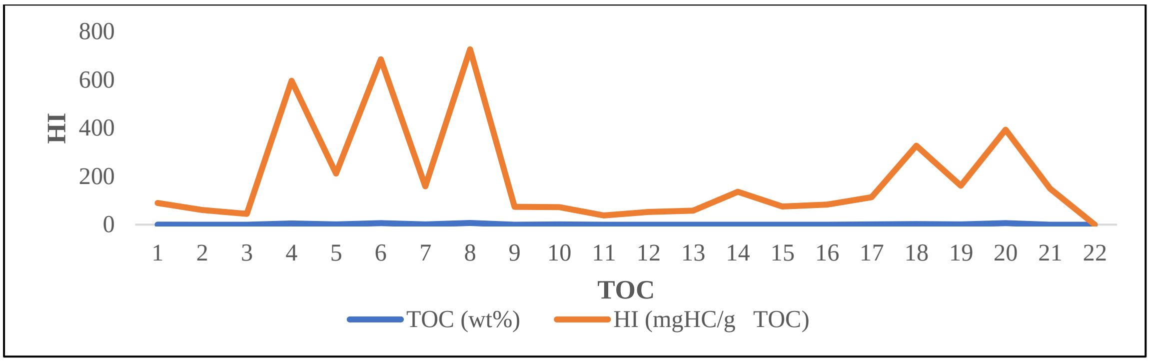
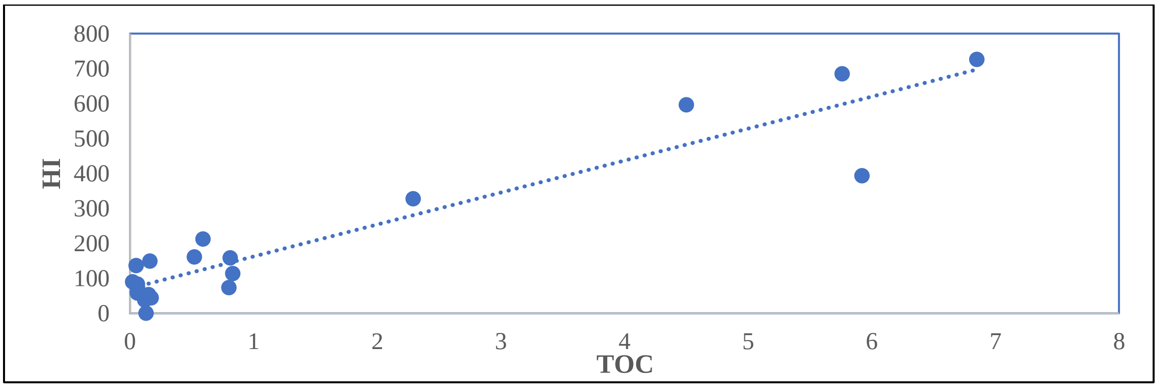


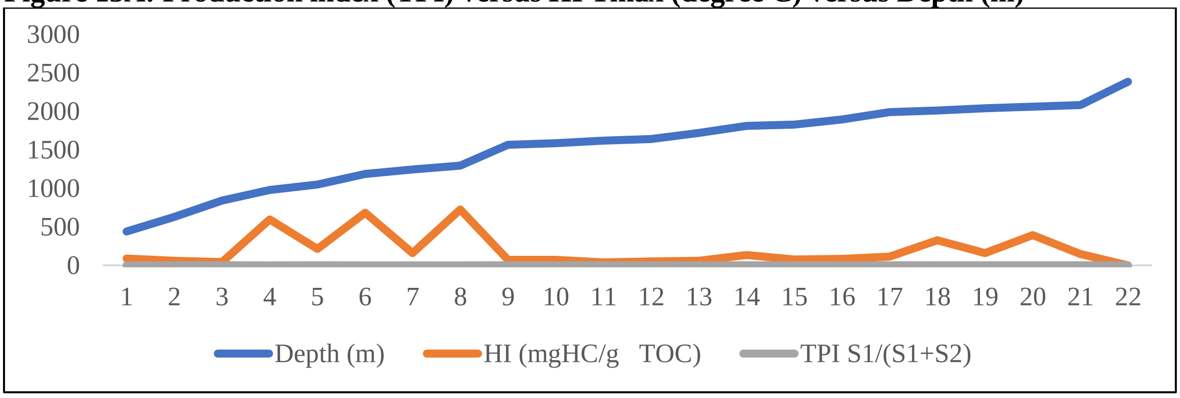
Figure 12B: TOC vs Hydrogen index (HI)



Variations of Production index (TPI) versus HI Tmax (degree C) versus Depth (m)

Figure 13A are plots of Production index (PI), versus HI/Tmax (ºC) versus depth, as shown in the *Table 1*. From this graph, Production index (PI) has recorded low values which are very good, and thus correspond to the high values of Hydrogen index (HI), ranging from (596 – 726 mgHC/gTOC), and a Tmax ranging from (435 – 442ºC). This mainly depends on maturation level of the organic matter. As a rule, Tmax (ºC) increases with maturity of organic matter [5], [18]. *Figure 13B* indicates the trend of maturity levels with depth. Tmax increases with increasing burial from the depth range 1189 m to 1295 m.

Figure 13A: Production index (TPI) versus HI Tmax (degree C) versus Depth (m)



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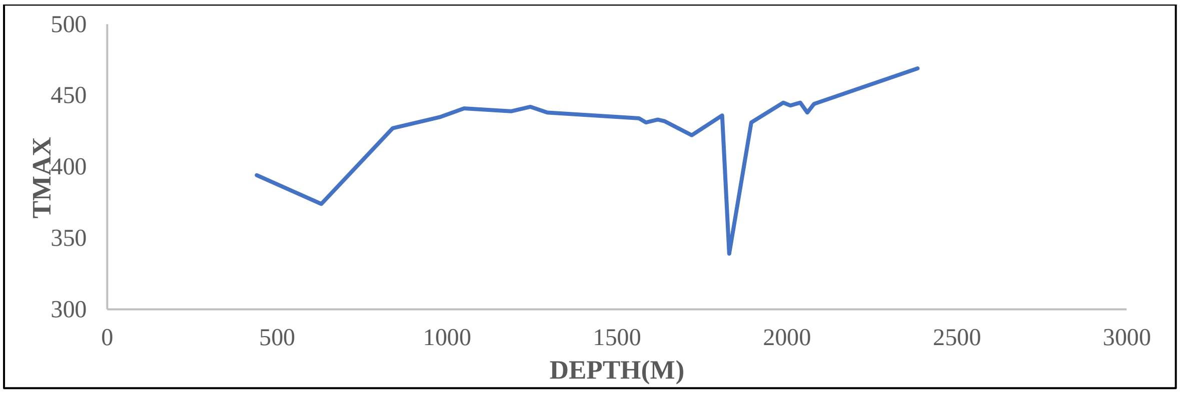
Tmax depends on the maturation level of the organic matter (OM). From the general rule, Tmax increases with level of maturity of OM [15], hence the plot of Tmax vs depth (*Figure 14* A) increases with depth though the variation is not uniform. The highest values of Tmax (440-469ºC) are obtained at deeper levels (1050-2385 m). Samples at depth range 1990-2060 had more complex Type of kerogen, possibly type III, because Tmax was > 435ºC. However, [15], noted that the majority of samples from the Tendi Formation in the Kaikang West-1 Well are mature with a Tmax ranging from 435-442ºC, and this falls at the beginning of the oil generative window.

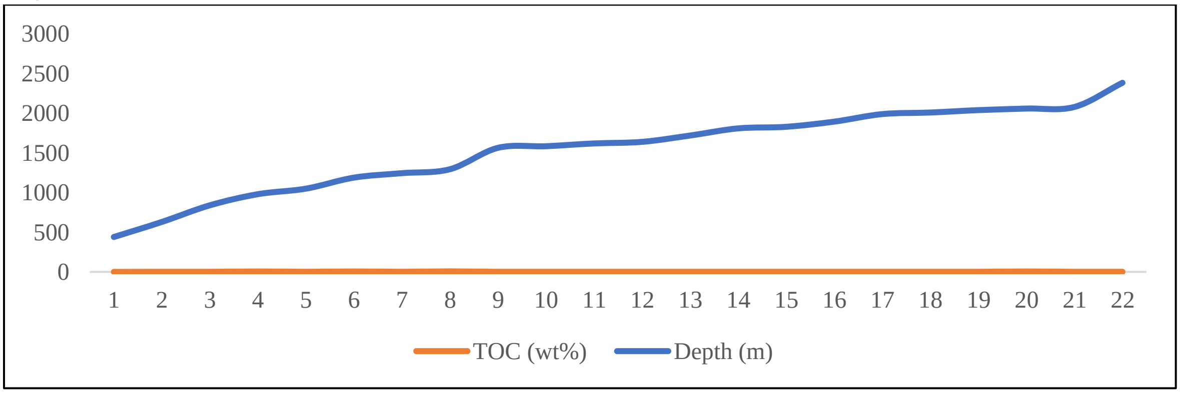
Figure 14A: Tmax vs Depth (m)



Variations of TOC (%) versus Depth (m)

Figure 15A shows plot of TOC versus Depth (m). With the increase in the depth range, there is decreasing Hydrogen index (HI) values of the organic content in the rock formation. Similarly, there is increased TOC with depths. The samples with high TOC do not necessarily show high HI. Samples showing high HI indicate a narrow range of TOC. Samples with higher HI do not necessarily show high TOC. *Table 1* shows variations of high HI with depth, especially from shallow range of 980 m to 1295 m, even up to 2085 m depth shown at point 22 of the graph.

Figure 14A : TOC (%) versus Depth (m)



From *Figure 15B* graph of TOC vs Depth, it can be seen that the variation of total organic carbon with depth is not uniform. Thus, as a general requirement TOC of less than 0.5% implies that the source rock is of poor quality and cannot be able to generate hydrocarbons. The upper part of Baraka Formation between depths 1990-2060 m, a fair to good source rock with TOC ranges from 0.83-5.92% indicating the potential to yield hydrocarbons was encountered. Also, at depths between 980-1295 m, the TOC is ideal for generation of petroleum. Thus, the Adak and Amal Formations have TOC < 0.5% which is insufficient to yield significant hydrocarbons.

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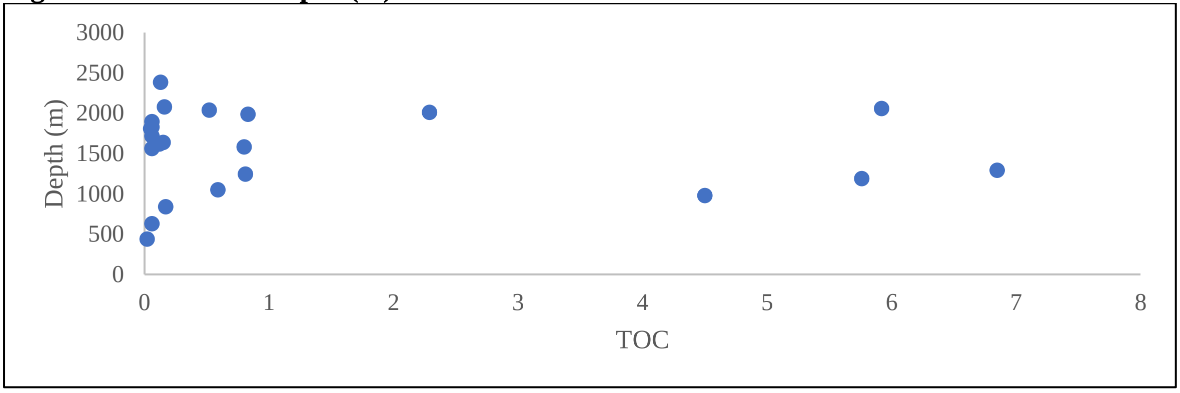
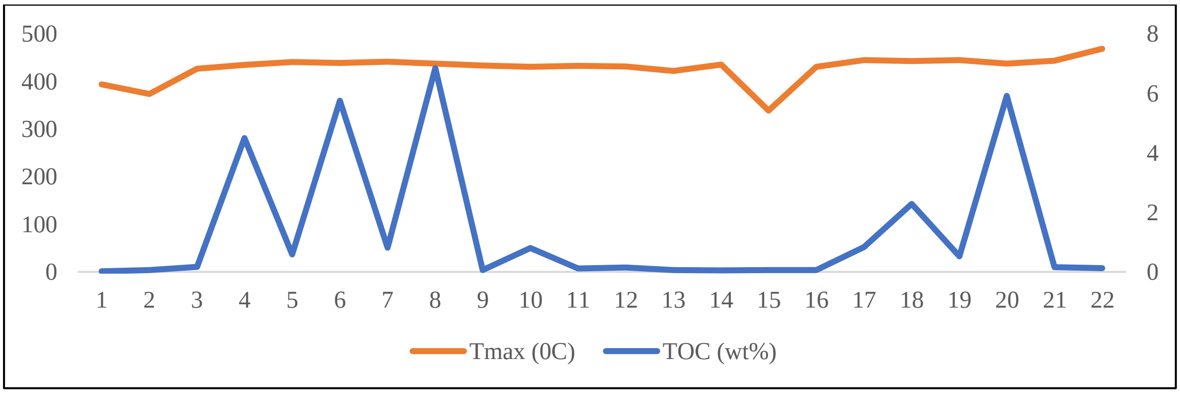
Figure 15B: TOC vs Depth (m)



Variations of Temperature maximum - Tmax (ºC) versus TOC (%)

The temperature maximum (Tmax) mainly depends on maturation level of the organic matter (OM). As a general rule, Tmax (ºC) increases with maturity of OM [15]. *Figure 16A* gives the plot variations of Tmax/TOC with depth. As a rule, Tmax (ºC) increases with maturity of organic matter, which indicates the trend of maturity levels with depth. Tmax increases with increasing burial. The samples shown in *Table 1* apparently indicate that the organic matter (OM) has reached or passed the onset of the main oil generation stage [18] whose Tmax usually range from 435-465ºC. In this scenario, the Tmax values ranging from 435–442ºC can generate Types II and III kerogen, herein tallies with the high values of TOC ranging from 4.5-5.76 TOC (%) in *Table 1*.

Figure 16A: Tmax (degree C) versus TOC (%)



The highest values of Tmax (469ºC at point 22) are obtained only from samples at deeper levels but the variation is not uniform (*Figure 16A*). Achieving a level of maturity of kerogen (within the organic matter in the source rocks) is necessary for petroleum exploration. With immature kerogen no petroleum is generated but with increasing maturity at depth, first oil and then gas is expected to be generated [5]. Tmax being an indicator of the maturity, the higher the Tmax the higher would be the degree of maturity. It can also be considered that more complex kerogen requires higher temperatures for breaking.

Thus, Tmax is an indicator of maturity, the higher the Tmax the higher the degree of maturity of organic matter [12], [15]. It should be known that the more complex kerogen requires higher temperature for breaking as seen in the plot of Tmax vs TOC (*Figure 16B*).

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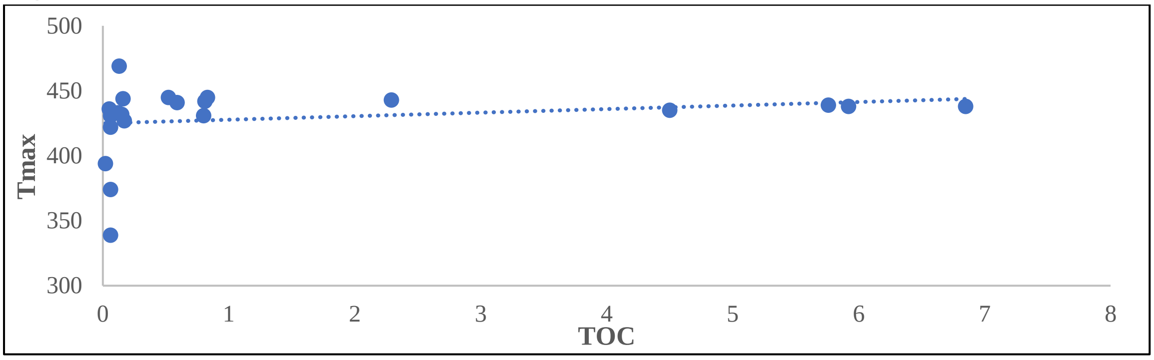
Figure 16B: Tmax vs TOC

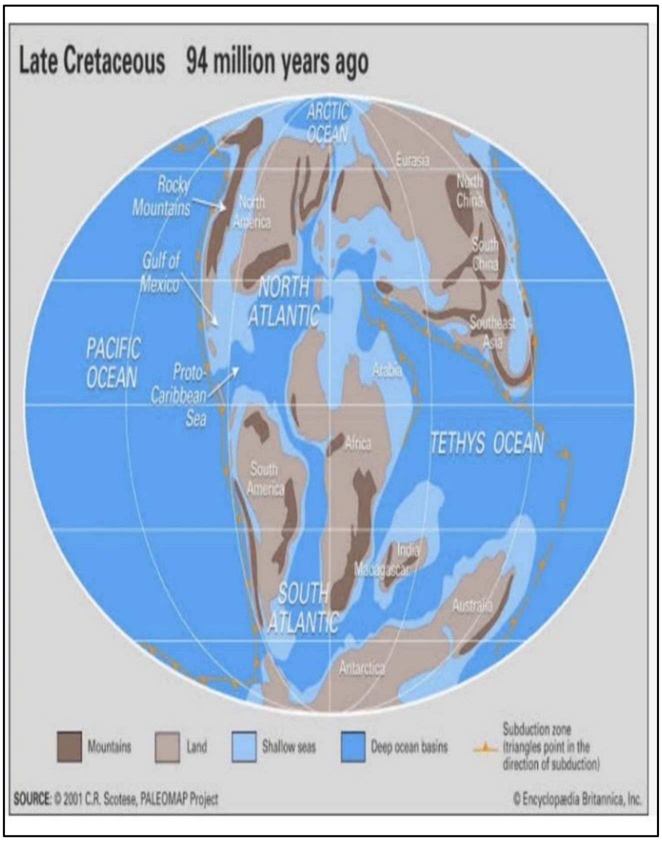


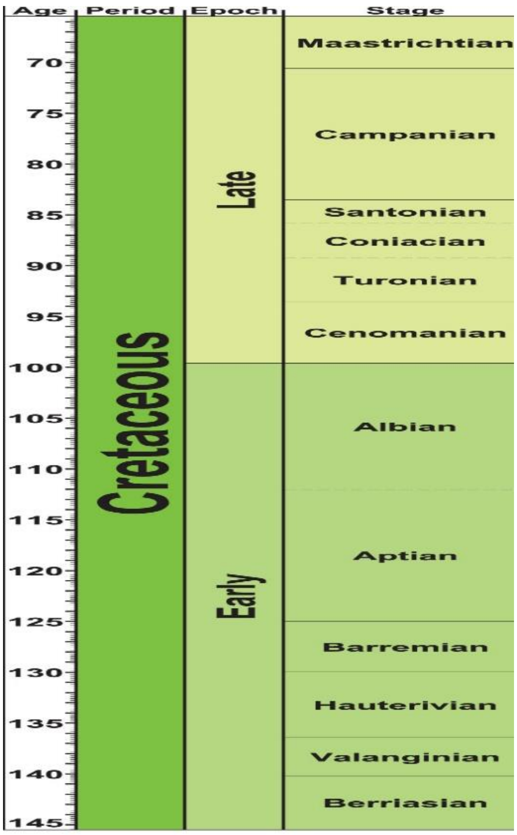
Paleogeographic Position of South Sudan Rifts

It is interesting to note that the prevailing paleogeographic position of this depositional rift region (what is presently northern Kenya's and Sudan's Abu Gabra/Muglad extensional rifts) was much to the south of the Equator (*Figure 17*) during the Early Cretaceous time [19]. Luxuriant vegetation on land, swampy grounds, humid climate, and good rainfall were some of the then prevailing environmental conditions [5], [6].

With such a source, the organic matter (OM) that got buried could only generate the Types I, II or Type III kerogens whose initial product could be waxy crude or gas [12], [18]. The radiogenic heat from OM-rich sediments adds further to the temperature gradient, which is otherwise also higher than the normal geothermal gradient in the intracratonic rift basins [5].

Figure 17: Paleogeographic position of Kenya in Late Cretaceous time





Source: Encyclopaedia Britannica, Inc. 2001

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PROGNOSTIC SOURCE ROCKS EVALUATION IN MUGLAD BASIN

The hydrocarbon potential of the subsurface Cretaceous-Tertiary sedimentary rock sequences of the Muglad basin has been interpreted using some selective geochemical analysis of rock samples in the drilled Kaikang West-1 Well. The distinctive geological setting features caused by tectonic rifting and block faulting, which affect sediment deposition and distribution of rock formations [2]. The main source rocks in the Muglad Basin are represented by interbedded lacustrine fine-grained siliciclastic sediments containing Type I Kerogen, with TOC values ranging from 1 to 5 wt. % (averaging 1.3 wt. %), which were deposited in freshwater lakes (lacustrine) within the distal depositional environmental and geological settings [11], [12]. It has been noted that the majority of samples from the Tendi Formation in the Kaikang West-1 Well are mature with Tmax ranging from 435 to 442^{o}C and this falls at the beginning of the oil generative window [15].

The paucity of the most prospective potential source rocks in the southern part of the Abu Gabra Formation is caused by the limited Well intersections. Thus, the trend analysis of sand versus shale obtained from Wells in Abu Gabra Formation, which is lithologically sandier, suggests less prospective areas [9] towards the southern part of the basin. The paleocurrent directions are apparently toward the north [20]. According to tectonic cycles and sedimentary facies studies in the Muglad Basin, five reservoir assemblages [7], [21] were predicted in the Cretaceous and Palaeocene/Neogene assemblages. The Cretaceous assemblages comprise the Abu Gabra Formation (reservoir/cap rock), Bentiu Formation (reservoir rock), Aradeiba Formations (seal/cap rock), and Darfur Group (reservoir and/or cap rock). The Paleogene/Neogene assemblages include the Amal Formation (reservoir rock), and Nayil-Tendi (cap rock) as one assemblage in addition to the Nayil-Tendi reservoir and cap rocks [22], [23].

In the Muglad basin, the rift extensional tectonism has created four major structural trap styles (*Figures 2 and 3*): UP-thrown fault blocks (horst and tilted fault blocks), faulted anticlines, roll-over anticlines, and down-thrown fault blocks. Stratigraphic traps comprising fluviatile sand distribution and flooding shale are expected when structural deformations are absent, but pinch-out traps caused by the numerous unconformities all over the basin may also form potential traps [3]. The organic matter (OM) is usually converted into kerogen and the type of kerogen depends upon the kind of OM that gets buried in the depositional basin [5], [7]. Therefore, the OM brought from the vegetation on the higher lands of Muglad Basin at that time (Cretaceous and Early Tertiary) was buried along with the sediments in the mostly lacustrine and fluvial environments [4]. Thus, the Abu Sufyan sub-basin (*Figure 2*), did provide the kerogen types generated during the burial and digenesis of the organic matter (OM) they contained based on the Hydrogen index (HI). However, [24] noted that the highest TOC values of 7.5 wt. % exist in the rift basin.

Higher oil generative potential is found in AG-2 (mainly Type I and Type 11, kerogens), while AG-1 is mainly Type III (*Figure 4*). Likewise, in the Suf C-1 Well the kerogen types are mainly Type III and partly Type II for the Darfur Group, while the underlying AG-1 unit has mainly Type II kerogen, and minor Type III kerogen, while AG-2 is mainly Type II, and less of Type III kerogen. In Well Suf C-1, just south of the previous Well, the kerogen type of the Darfur and Bentiu Formations are of Type III, with similar hydrogen index (HI) data results of kerogen macerals, which is indicative of the original organic matter of the Abu Gabra source rocks that were mainly derived from an aquatic land source [20].

CONCLUSION

The surface lithological characteristics give a clear indication that sedimentation, if at all has taken place during the Cretaceous-Tertiary, or older times within Muglad basin, should have been restricted to smaller subbasins which can be

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demarcated only by geophysical data. Seismic survey is a useful tool for exploration as it helps in covering large areas and in mapping the subsurface rock stratigraphic units bringing out also the physical characteristics like the degree of compactness, rigidity, porosity, and permeability. The analysis helped in determining the proportion and frequency of the shale horizons within the otherwise sandy sections, as well as the variations in grain size within the sandstone beds. Marine sediments, if present with higher gamma ray (uranium content) values, are of course considered to be better source rocks than those deposited in fluvial/lacustrine and freshwater conditions.

Fluvial and Lacustrine sedimentary deposits like the present ones have typically low gamma ray radioactivity. The radioactive heat from organic matter rich sediments adds further to the temperature gradient which is otherwise also higher than the normal geothermal gradient in such intracratonic rift basins. Black shales rich in carbon (2 percent weight TOC) as well as syngeneic uranium (up to 400 ppm) though more common to marine sediments, could also have been deposited in other environments which are biologically productive and anoxic. Speedy sedimentation along with rapid basin subsidence prevents the oxidation of organic matter and preserves it for potential hydrocarbon generation rationale.

In conclusion, after in depth comparison and study of organic carbon content, oxygen, hydrogen and production indices, type of organic matter content and maturity of organic matter, the study confirmed that the studied resource areas in Muglad basin are favourable to be considered for future medium- to large-size hydrocarbon discoveries. Moreover, the source rock of the Abu Gabra Formation in NW Muglad Basin shows good kerogen (Types I or Type II and less of Type III), which reveal large hydrocarbon potential. It has been seen that the then paleogeographic position of this region was much to the south of the equator and hence possibly had luxuriant vegetation on land, swampy grounds, humid climate, and good rainfall as then prevailing environmental conditions. The organic matter (OM) could have generated only Types I, II and III kerogen in the Muglad basin of South Sudan.

CONFLICTS OF INTEREST

The authors declare no conflicts of interest regarding the publication of this paper.

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