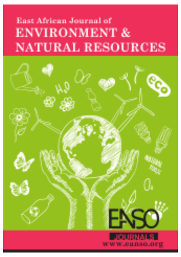

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Original Article

Identification and Characteristics of Source Rocks in LT-1 Well, Northern Kenya

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ABSTRACT

This study on the hydrocarbon source rocks identification of LT-1 well in a Tertiary rift basin, northern Kenya, which had oil and gas shows was based on the organic matter quantity, quality, and the thermal maturation generation capability of the organic matter disseminated in the analysed rock samples. 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 (HI and PI), temperature maximum (Tmax °C), porosities and other sedimentological parameters. This study involved a series of analytical geochemistry and petro-physical studies in ascertaining a number of effective source rock samples from the well cores which were then analysed in terms of TOC, PI, HI, S2, S1 and Tmax to determine oil/gas prone samples (resource areas) and distinguish them from strata with very high organic matter content. The samples with very high TOC were identified for possible source rock characterisations of the lithology pertaining to the well in terms of potential source-reservoir-seals associations. 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. In conclusion, after an in-depth comparison and study of organic carbon content, hydrogen and production indices, type of organic matter content and maturity of organic matter, we confirmed that the studied resource areas are favourably considered for medium- to large-size hydrocarbon discoveries.

APA CITATION

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INTRODUCTION

Petroleum source rock is defined as fine-grained sediment with a sufficient amount of organic matter, which can generate and release enough hydrocarbons to form a commercial accumulation of oil or gas [1]. Source rocks are commonly shales and mudstones, which contain a 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 [3]. Source rocks are classified according to oil generation into three classes as follows [3]:

- Immature source rocks that have not yet generated hydrocarbons.
- Mature source rocks that are in the generation phase.
- Post-mature source rocks are those which have already generated all crude oil-type hydrocarbons.

The petroleum source rocks are distinguished into potential, possible, and effective, as follows [2]:

- 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 [3]. 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 offer the advantages of the economic, ready availability of data, and continuity of sampling of vertically heterogeneous shale section [4].

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 Tertiary rift basin's LT-1 well (804-1290 m depths range), which had oil and/or gas shows, based on seismic and gamma-ray profiles, total organic carbon (TOC), maturity indices (HI and PI), porosities and other sedimentological parameters (*Tables 1, 2, 3* and *4*).

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Table 1: Petroleum Potential (Quantity) of an Immature Source Rock

Quality	TOC (wt. %)	S1 (mg HC/gm rock)	S2 (mg HC/gm rock)
Poor	0.0–0.5	0.0–0.5	0.0–2.5
Fair	0.5–1.0	0.5–1.0	2.5–5.0
Good	1.0–2.0	1.0–2.0	5.0–10.0
Very good	> 2	> 2	(>10)

Source: after, [2]

Table 2: Oil Potential in LT-1 Well

Depth(m)	S2>10 kg/g (mg/g)	S2>5 kg/g (mg/g)	Gamma Ray (API Units)
800-1164	Nil	Nil	60-120
1170-1300	17	2	140
1300-1500	9	15	140
1500-1650	9	3	60
1650-1800	1	2	120

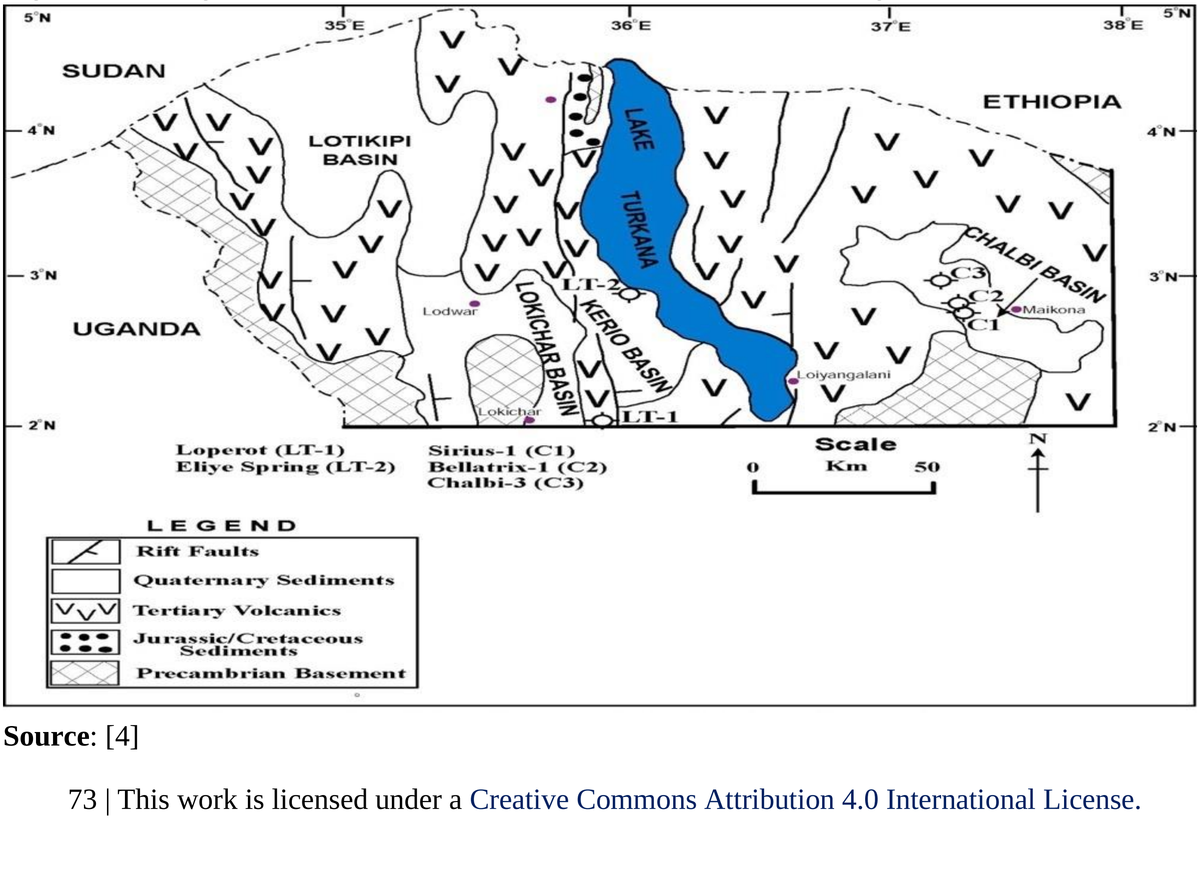
Source: modified after [4]

The characteristics of identified subsurface strata showing oil and gas indications augmented by geochemical analysis of the potential source rocks in terms of the total amount of organic carbon (TOC), maturity indices, and temperature maximum (Tmax) present conducive environments and implications for the generation of hydrocarbons. The section between 800 m and 1290 m depths was selected for rock pyrolysis because of the reported oil shows [4] and the abundance of rocks with high gamma-ray values (*Tables 2,3* and *4*). The aim was to measure the total amount of organic carbon (TOC) and identify the possible source rock characteristics in the LT-1 well.

Geological Setting and Depositional Environment

The local geology of the Tertiary Rifts Basins in northern Kenya is associated with a stupendous outpouring of volcanic lava flows which cover the old sedimentary rock sequences and Precambrian basement rocks (*Figure 1*) [4].

Figure 1: Geological map of the study area in northern Kenya showing LT-1 Well location



Source: [4]

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The asymmetric rifts or half-grabens are intracontinental and the gravity profiles reveal that they characteristically occur over the crests of regional arches of the basement and the mantle or only on the continental crust with a trough-like mantle profile [4]. The landscape and subsurface basin structures generally indicate that the tectonic activity, rifting and block faulting process, which was initiated in the Cretaceous time or prior, continued in pulses during the Tertiary and even during the Quaternary. The presence and thickness of sedimentary rock units have to be, however, confirmed further by well-drilling inventories and seismic data. Seismic characteristics reveal the physical characteristics like compactness, rigidity, porosity and permeability of the subsurface sedimentary units and density velocities [5]. The two wells LT-1 and LT-2 were drilled in the early 1990s by Shell Exploration and Production Kenya (SEPK) in the Lokichar-Kerio sub-basins to have penetrated chiefly the Palaeocene or younger strata.

The LT-1 well, in the north-south trending rift, penetrated a total depth of 2960 m. It was to penetrate the main objective reservoir rocks in a fault/dip closure, which had a high risk of trap failure due to unfavourable fault interposition. However, the well encountered a total of 13 m thin, shallow sandstone layers and two intervals of lacustrine shales, which were regarded as good to excellent source rocks. The main reservoir sandstone underlying the upper source rocks (1050-1390 m) also proved to be water-bearing and about 9.5 litres of oil and water was recovered [4]. It is located in the South Lokichar Basin (Loperot trough) some 30 km east of Lokichar trading centre, about 10 km northeast of Loperot Centre (*Figure 1*). It appears that the Tertiary faulting and rifting facilitated speedy erosion in the central part of the Lokichar basin, which deposited a thick succession of sedimentary sequences. Few of these surface sections or exposures of volcanic and sedimentary rocks have been scarcely exposed, usually lies between the basement and the volcanic deposits. They consist of over 200 m stacked, fining upward fluvial sequences with ‘coarse’ and ‘fine’ cycles [6] [7]. These sequences also contain considerable gastropods, freshwater algae and spores, intercalations of volcaniclastic sandstone beds, and reworked tuffaceous clasts [8]. The presence of freshwater algae and spores suggests a lacustrine environment for the Upper Oligocene to Lower Miocene sedimentation. The detailed lithology characteristics from the LT-1 Well were determined in the present study with respect to high organic matter deduced from subsurface geophysical and geochemical data, which further helped in characterising possible future prognostic targets and their implications for hydrocarbons prospecting and exploration in this northern Kenya rift basin according to their source-reservoir-seal associations [4].

Usually, among the geophysical methods used in the exploration of hydrocarbons, gravity and seismic methods have been more effective in delineating prospective subsurface structures. The LT-1 well was drilled in the early 1990s by SEPK for hydrocarbon in the Lodwar South Lokichar (Loperot) sub-basin as well as to provide stratigraphic control in the Tertiary rift basin (*Figure 1*). The sedimentary pile consists of Tertiary, terrestrial sediments with chiefly fluvial and fluvio-lacustrine deposits. Well-developed lacustrine deposits occur at intervals between 1058-1380 m and 2540-2960 m and also between 176-207 m. Due to a fault cut-out at around 1650 m, some 150 m of the lower part of the main lacustrine sequence was found missing. The lack of diagnostic Tertiary palynological data makes age determination difficult. The section being overlain by volcanic rocks (Miocene?), the entire sequence has been considered to be Lower to Middle Miocene (?) in age. The sedimentary sequence between 100-258 m was characterised by p-wave values ranging from 2.2 to 2.3 km/s and high gamma-ray values averaging 120 API units (*Tables 2,3* and *4*) [4].

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Table 3: Source Rocks and Reservoir Rocks in LT-1 Well

Depth (M)	Lithology	(API Units)	Vp (Km/s)	Porosity (Φ)
800-850 **RES**	Sandstone	75	2.6	12-40%
900-980 **RES**	Sandstone	120	2.65	—
1400-1500 **RES**	Sandstone	60	2.9	9-19%
1500-1620 **RES**	Sandstone/shale	60	2.95	—
1760-1800 **SR**	Sandstone/shale-More of shale	75	3.1-3.2	5-10%

RES *= Reservoir Rocks;* ***SR*** *= Source Rocks*

Source: [4]

RESEARCH METHODS

Petroleum Source Rocks Evaluation Using Geochemical Data

The source rock evaluation within any study area involves the recognition of petroleum source, which depends on the determination of its proportion of organic matter (organic matter quantity) is usually expressed as total organic carbon (TOC wt%). It also depends on the type (or quality) of organic matter (kerogen) preserved in the petroleum source. The total organic carbon, S2 and genetic potential from Rock-eval pyrolysis and extractable organic matter (bitumen) from selected rock samples were used to identify the source-richness in terms of quantity and generation potential. Rock-eval Tmax (C°) was used to evaluate the source rock maturity stage in conjunction with the vitrinite reflectance pattern as a maturity tool.

One of the requirements needed for source rocks to generate commercial amounts of oil is that they must contain a sufficient quantity of organic matter enough to generate and expel hydrocarbons. The type of organic matter has an important influence on the nature of generated hydrocarbons. According to [9], organic richness alone may not suffice to evaluate source rocks, where the organic matter is mainly inertinite (i.e., oxidised or biodegraded), and is not capable of generating hydrocarbons, even if present at high concentrations. Thus [2] presented a scale for the assessment of source rocks used on a wide scale and is applied in this work; a content of 0.5 wt% TOC as a poor source, 0.5–1.0 wt% as a fair source, 1.0–2.0 wt% as a good source, and more than 2.0 wt% TOC as a very good source rock, and also based on the rock-eval pyrolysis data, such as S1 and S2 (*Tables 1* and *2*).

The organic matter richness and hydrocarbon generative potential of the source rocks in the LT-1 well that was drilled in a lacustrine/fluvial environment can be evaluated by bulk geochemical data such as TOC content and pyrolysis S1 and S2 yields. The organic richness of a rock is usually expressed as the total organic carbon content (wt. % TOC). The minimum acceptable TOC value for clastic-type rocks indicating good source potential is 1.0-0.5 % [3]. The section below examines some variations of some of the parameters like Total Organic Carbon (TOC) and Tmax (°C) with respect to depth in order to identify the possible presence of source rocks for hydrocarbon generation in the LT–1 Well. For example, intracratonic basins like the one under study do not attract marine OM [10]. The basin has had fluvial and lacustrine environments of deposition [4]. Therefore, the organic matter brought from the vegetation on the higher lands of the time (? Cretaceous and Early Tertiary) was buried along with the sediments in the mostly lacustrine and fluvial environments.

The type of organic matter (kerogen) is considered the second most important parameter in evaluating the source rock. The kerogen type can be differentiated by optical microscopic or by physicochemical methods. The differences among them are related to the nature of the original organic matter. The organic matter in potential source rocks must be of the type that is capable of generating petroleum. It has been established that organic matter is classified into three classes [2]:

- Type I: mainly oil-prone organic matter with minor gas.

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- Type II: mixed oil and gas-prone organic matter.
- Type III: mainly gas-prone organic matter.

The organic matter type is an important factor for evaluating the source rock potentiality and has an important influence on the nature of the hydrocarbon products [2]. He proposed that, for mature source rock, HI for gas-prone organic matter is less than 150, gas-oil-prone organic matter is between 150 and 300, whereas oil-prone organic matter is more than 300 HI [2]. Hence, it is very important to determine the kerogen types in order to detect the hydrocarbon products. The pyrolysis results can be used for the determination of the organic matter types.

There are, however, some practical drawbacks to these analytical strategies, which can be solved through a combination of the results of different analyses, such as thermal maturity, TOC, and Rock-Eval analysis that formed the main reason behind implementing different strategies in this study. The rock samples from LT-1 well were analysed in terms of TOC, PI, HI, S2, S1, and Tmax to determine oil/gas-prone samples (resource areas) from strata that had high organic matter content [1] [2]. These predictions are often quite crucial to the exploration, development, and production (E&P) stage of hydrocarbon exploitation as they will lead to solid predictions and thus avoid spending substantial expenses and eliminate uncertainties.

Selection of Rock Samples and Analysis

The selected LT-1 well samples were first treated with organic solvents (Chloroform, Dichloromethane, Menthol Acetone, etc.) to remove bitumen. Bitumen content (TOC) also represents the oil content that can be dissolved from a rock. Subsequently, they were subjected to pyrolysis (Rock-Eval) after drying. The dried sample (~100 mg) was put inside a flame ionisation detector (FID) and heated in a stream of helium at a relatively low temperature (up to 300^{o}C) for the first five minutes in order to remove free or absorbed hydrocarbons (bitumen) that were present in the rock sample before pyrolysis (*Figure 2*).

The analysis records two peaks, representing the volumes of two components of the organic matter (volumes proportional to the areas below the peaks). The expelled hydrocarbons, which usually volatilise below 300 ^{o}C are represented by peak S1, which provides a measure of already generated hydrocarbons – bitumen [10].

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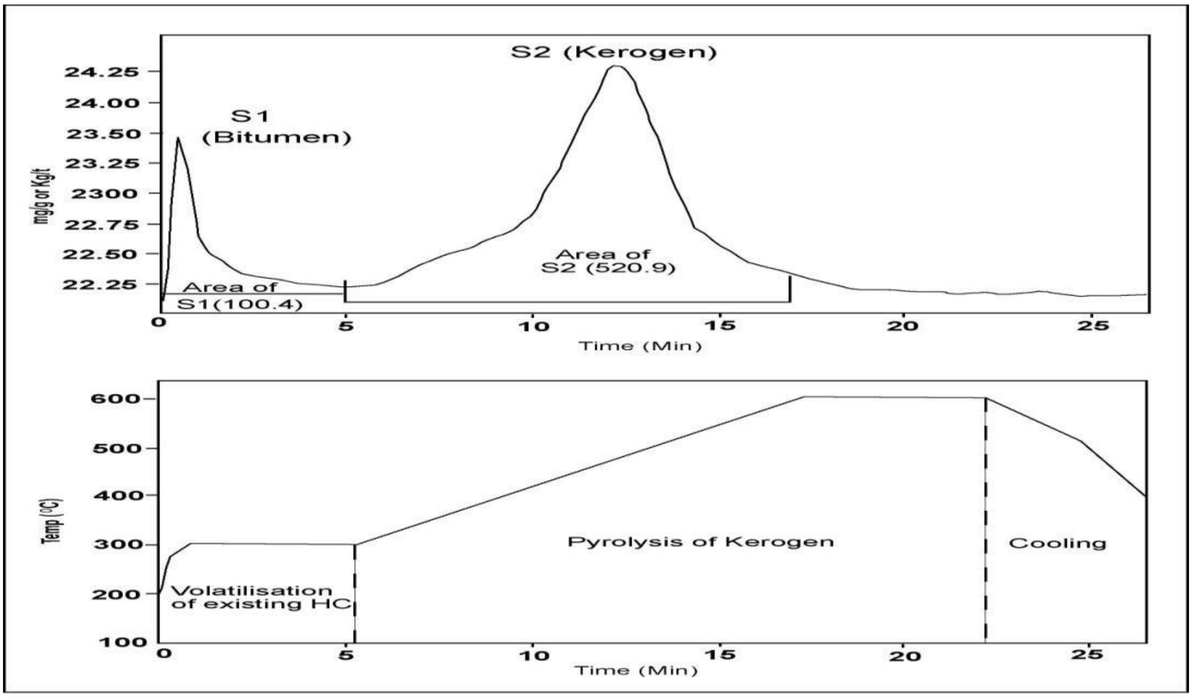
Figure 2: Laboratory rock pyrolysis showing the effect of heating an organic-rich sample at 1098 m depth of the LT-1 Well (Tmax 435.3 ºC)



Source: (after [4])

Figure 2 shows peaks of S1 and S2, where S1 represents the already generated oil in the rock. These are the hydrocarbons already present in the sample, and they are distilled out of the sample at the initial heating of the sample to a temperature of 350°C [2]. These values may be anomalously high from migration and contamination by drilling fluids and mud. S1=1.0 mg HC/g dry rock—minimum value for good source rocks, where S2 is the number of hydrocarbons generated through thermal cracking of non-volatile organic matter.

S2 is also an indication of the quantity of hydrocarbons that the rock has the potential to produce should burial and maturation continue. This parameter normally decreases with burial depths >1 km, and S2 >= 5.0 mg HC/dry rock is usually taken as the minimum value for good source rocks.

Pyrolysis is the thermal decomposition (cracking) of organic matter with increasing heat in the absence of oxygen. Rock-Eval pyrolysis is an analytical tool where the oil within the rock is thermally distilled (S1) and the convertible kerogen within the rock is cracked or pyrolysed to oil and gas (S2) in order to quantify the remaining generative potential (quality) of the source rock [3] [10]. The greater the generative potential (S2) relative to the TOC, the greater the Hydrogen Index (HI). As a source rock matures, its HI decreases; thus, HI can be used as a relative maturation parameter. Temperature maximum (Tmax ºC) is the temperature at which the S2 peak crests and is also a relative maturation indicator. The higher the Tmax temperature, the greater the thermal maturity of the source rock [11].

The transformation ratio is a ratio based on present-day convertible kerogen that remains in the rock relative to the original convertible kerogen in the rock [3]. As S2 decreases, or more organic matter has been converted to oil and gas, the transformation ratio increases. However, the hydrogen index (HI) is a measure of how much of the convertible kerogen has converted, which is a maturation proxy—not a measure of that PLUS any high boiling oil in the rock [12]. Thus, the S2 and TOC can be measured accurately, whereas the measurement of Tmax is made by an algorithm within the instrument software.

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Figure 3: Variations of S1 versus S2 Values (804 m to 1290 m depths)

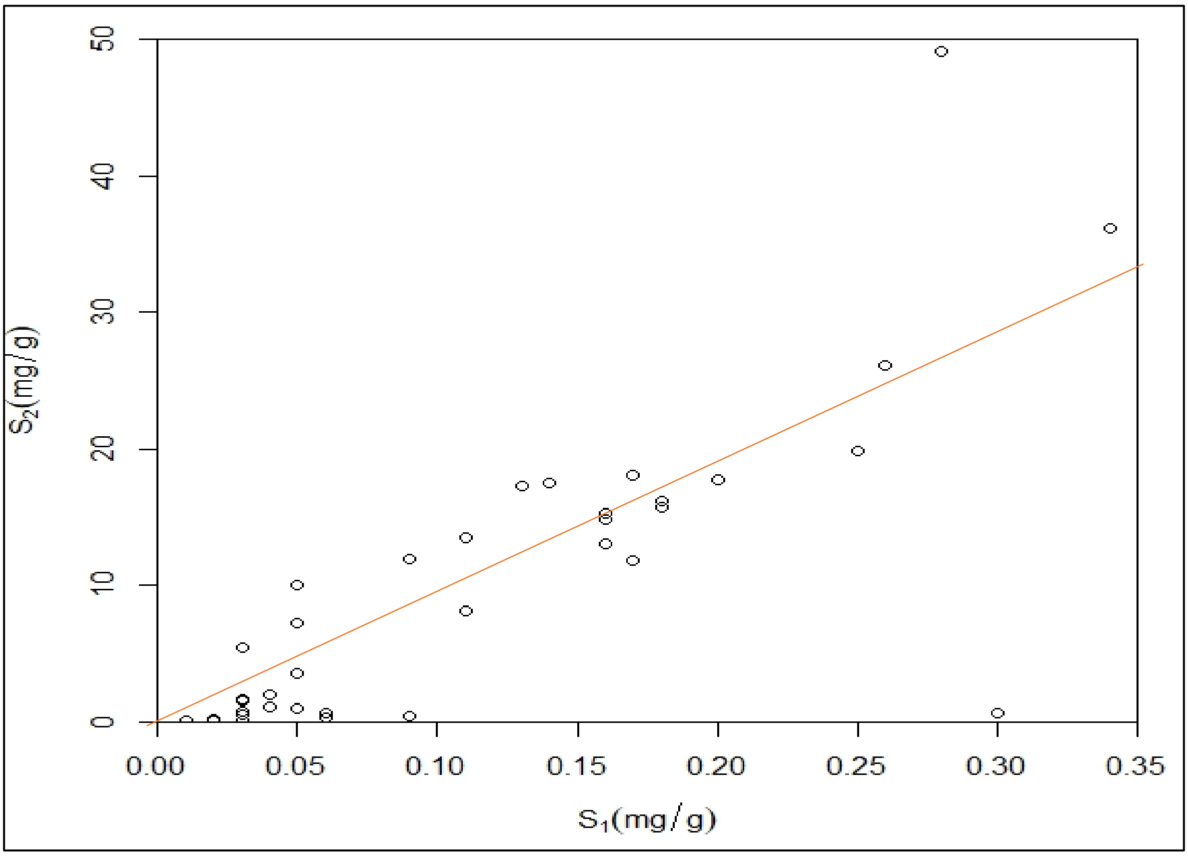

Figure 3 is a graph plot of variations of S1 versus S2, which indicates a generally linear relationship. The S2 versus S1 diagram for LT-1 well samples range from 804 m to 1290 m depths. Most of the samples showed S2 values <20 mg/g. There are not many samples which give higher S1 values (>0.2). However, most of the samples showed S2 values (averaging 10 mg/g) with few up to even 20 mg/g or even more, and low S1 values (< 0.2). The low S1 values indicate the paucity of hydrocarbons (bitumen) generated below 300 °C. S2 values >10 mg/g are supposed to be more potential for hydrocarbon (kerogen) generation (*Tables 1, 2* and *4*). Those with S2 values > 5 mg/g are similarly good potential for hydrocarbon generation.

RESULTS AND DISCUSSION

On further heating the sample at the rate of 25°C per minute up to 600 °C, the main pyrolytic thermal breakdown of kerogen occurs and is represented by peak S2 (*Figure 2*). The measure of the S2 area, produced at higher temperatures (550–600°C), decides the actual potential for the generation of hydrocarbons by the sample. The area S2 is a measure of the remaining hydrocarbon-generating ability of the organic matter. Oxygen–bearing volatile compounds (CO_2 and H_2O) are usually passed to a separate (thermal conductivity) detector, which produces an S3 response [4]. However, this procedure was not conducted in the case of LT–1 Well samples.

The two areas of S1 and S2 are used to determine the maturation level of kerogen in the source rock. They are expressed in milligrams per gram of original rock (mg/g) or kilograms per ton (kg/ton). *Figure 3* shows the samples with S1 and S2 values in different ranges. From *Tables 2, 3* and *4* data, the following summary could be drawn. It is seen that the maximum number of samples showing S1+S2>10 kg/t fall in the depth range of 1175 m to 1290 m. There are no samples which give S2 even less <5 kg/t in the depth range 800 m up to 1164 m (*Table 2*).

Rocks with S1 + S2 values < 2 kg/ton are not considered potential source rocks for hydrocarbon generation (*Figure 4* and *Table 2*). Between 2 and

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5 kg/ton, a significant amount of petroleum may be generated but it would be too small to result in expulsion. Source rocks with S1 + S2 values between 5 and 10 kg/ton have the potential to expel some portion of the generated oil. Only source rocks with values >10 kg/ton are considered rich for sufficient oil expulsion [13]. Thus, these rocks had the potential for oil generation as well as expulsion (*Table 4*). The actual oil and gas generation can take place only when the threshold temperature (60 ^oC) is reached. It also depends on the maturity level of kerogen, given by the temperature maximum – Tmax (^oC).

The Tmax at which the S2 generation peak occurs is also recorded in degree Celsius (^oC) and is an indicator of source maturity (a function of the degree of maturation). Perhaps the temperature did not reach the threshold of 60^oC considering the shallow depth range of these samples (804–1290 m). Or whatever hydrocarbon that was generated has been expelled and/or migrated (increasing HI of over 200 from 1179–1290 m depth as shown in *Figure 5* below). For expulsion to occur, the source rocks must get saturated first, a condition which is reached only on maturity of kerogen and temperature.

Figure 4: (S1+S2) versus depth

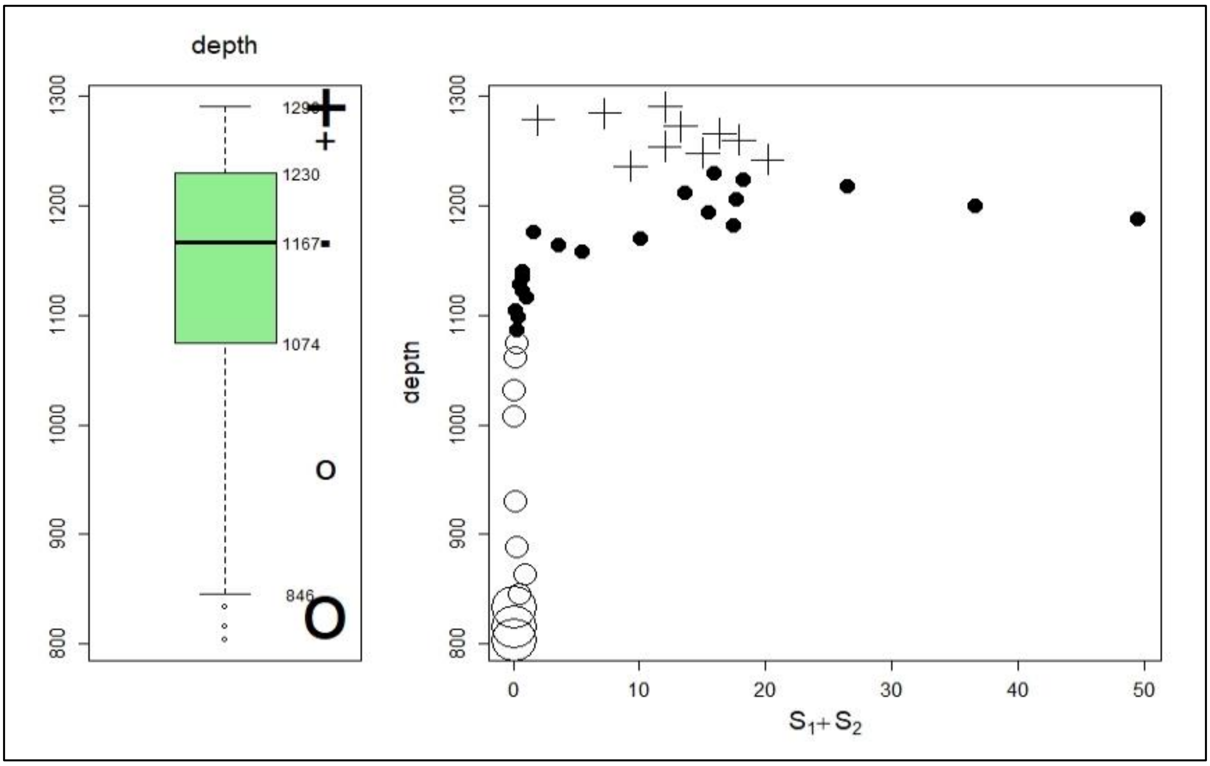

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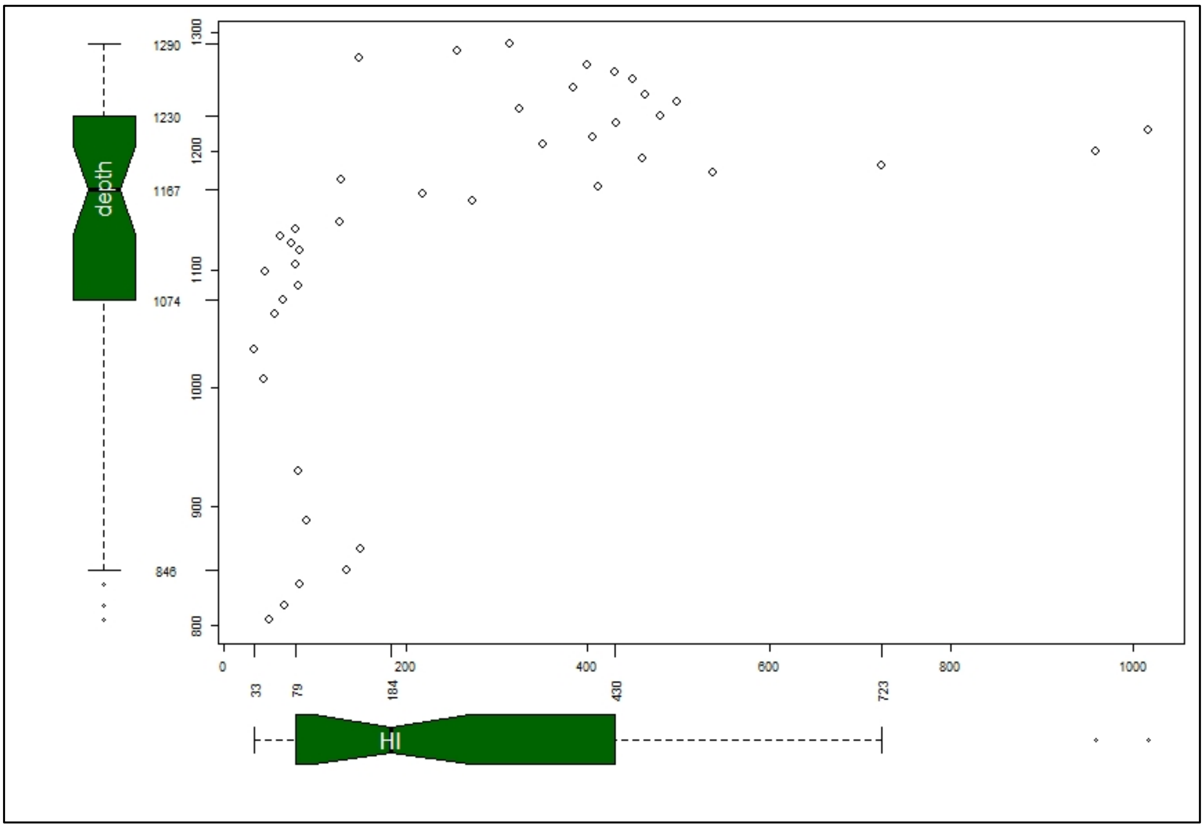
Figure 5: Hydrogen index (HI) versus depth for samples from LT-1 well



Detection and Measurement of Source Rocks

This study applied a range of geochemical techniques such as TOC, maturity indices and Tmax, which have been developed to identify and measure the potential of source rocks for the generation of hydrocarbons.

Hydrogen Index (HI)

Figure 6 is a plot of HI versus TOC from the LT-1 well. It shows most of the samples lie between type I and type III and less in type II based on its kerogen (*Table 4*). The hydrogen index (HI) represents the amount of hydrogen relative to the amount of organic carbon present in the rock at the formation depth. Gross trends of hydrogen indices (HIs) can be used as a maturation indicator. The hydrogen index is calculated from Rock-Eval data using the following formula: HI=(S2x100)/TOC. Plots of HI versus TOC also give useful characteristics in determining the maturity of hydrocarbon-generating rock ([3], pp.2). The HI is said to decrease with maturity. A generalised linear relationship between TOC and HI is shown in *Figure 6*. It can be seen that 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 4* shows variations of high HI with depth, especially from 1140 to 1290 m.

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Figure 6: Variations of TOC versus HI

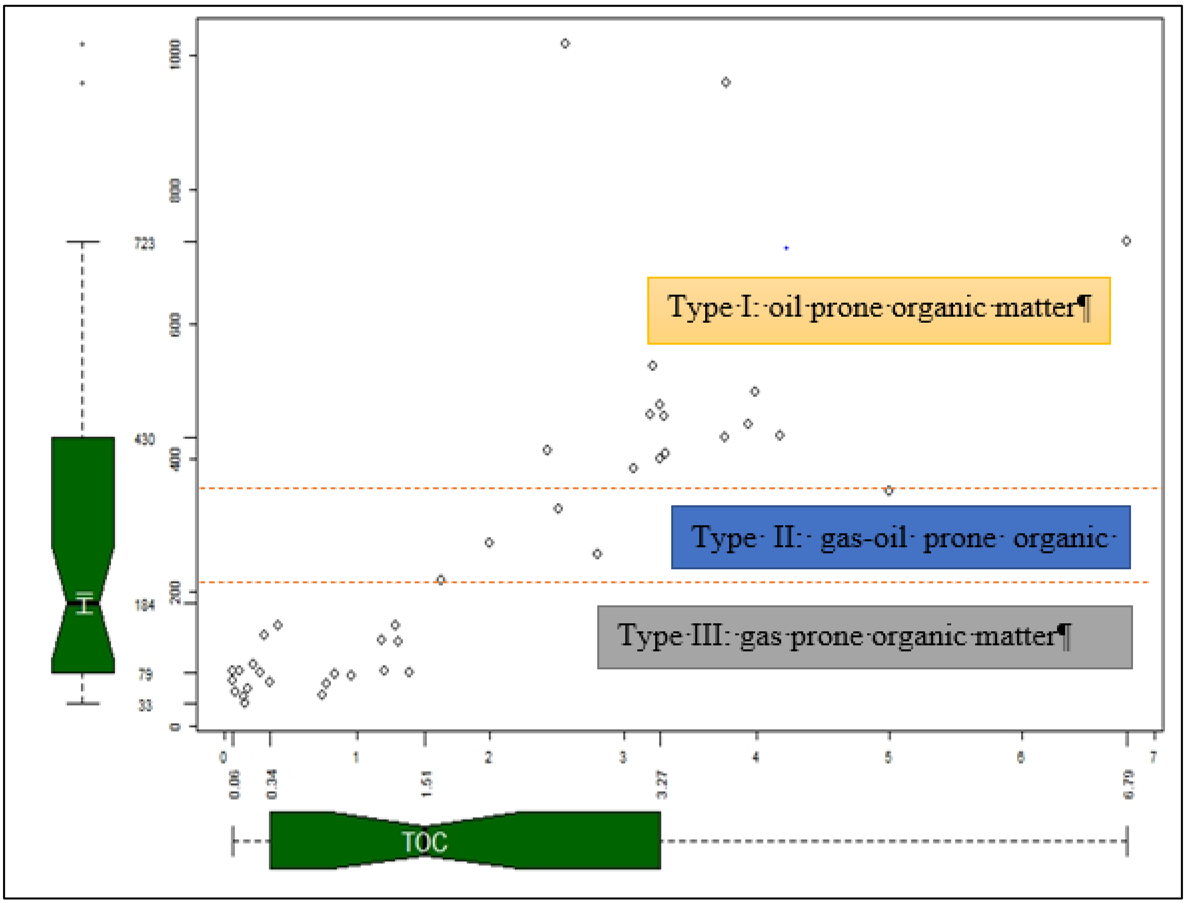

Figure 7: Hydrogen index (HI) versus depth for samples from LT-1 well

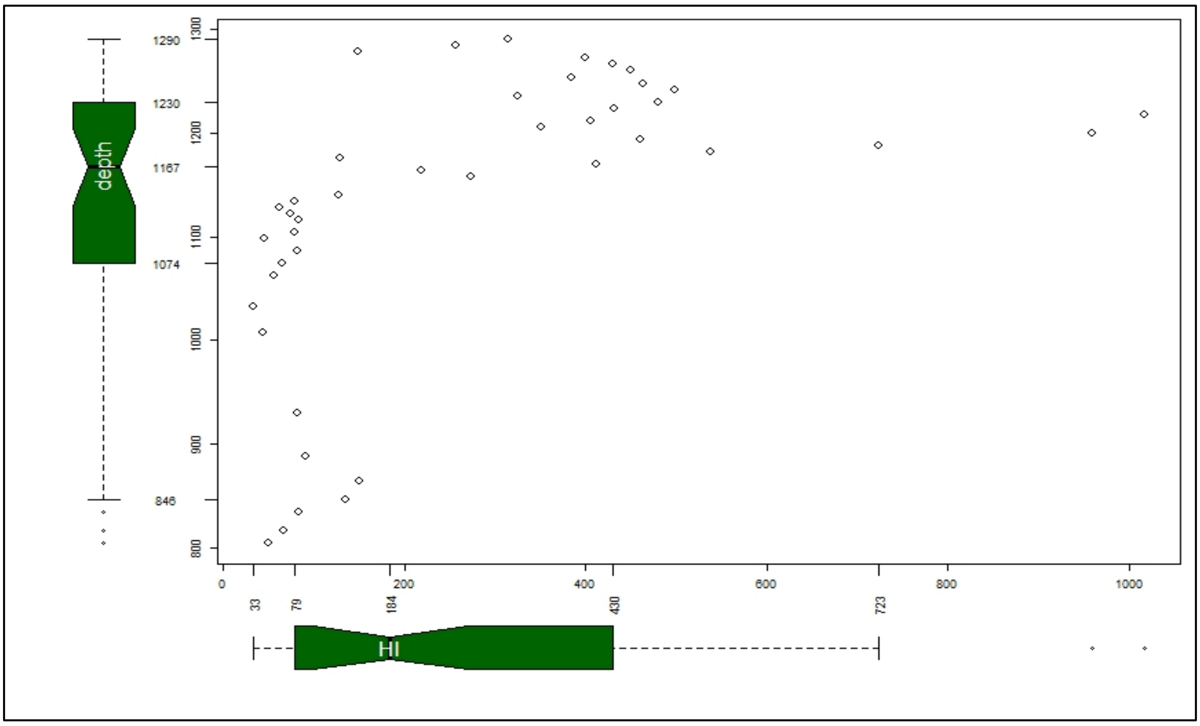

Figure 7 is a plot of the Hydrogen index (HI) versus depth for samples from LT-1 well clearly shows these high values of HI (about 200 up to 500, with few even up to 1000) within the same

depth range. Similarly, TOC wt % values appear to increase within the same lower part of these depths range (1140—1290 m). It can be seen that there are many levels of low and high HI intermittently present even in sediments that occurred at the deeper regions of the LT-1 well (*Table 4*). This indicates that there is no uniform variation in the maturity of the organic matter with depth (up to 1290 m) and there is a variable H/C ratio.

Therefore, the HI of the LT-1 well appears to intermittently increase with depth between 1150 m to 1290 m, thus indicating a decrease in the organic content in the rock formation. At this depth range, the HI values are greater than 200 while those samples with HI less than 100 are not many though those less than 200 are obtained in many levels too. It is only in the samples at depths 1200 m and 1218 m that showed HI > 900. The high HI values (*Figure 7*) correspond to the high S1+S2 values of *Figure 4*. Therefore, the increase in the depth corresponds to the decrease in hydrogen index (HI) values of the organic content in the rock formation.

Figure 8: Production index (PI) versus Hydrogen index (HI)

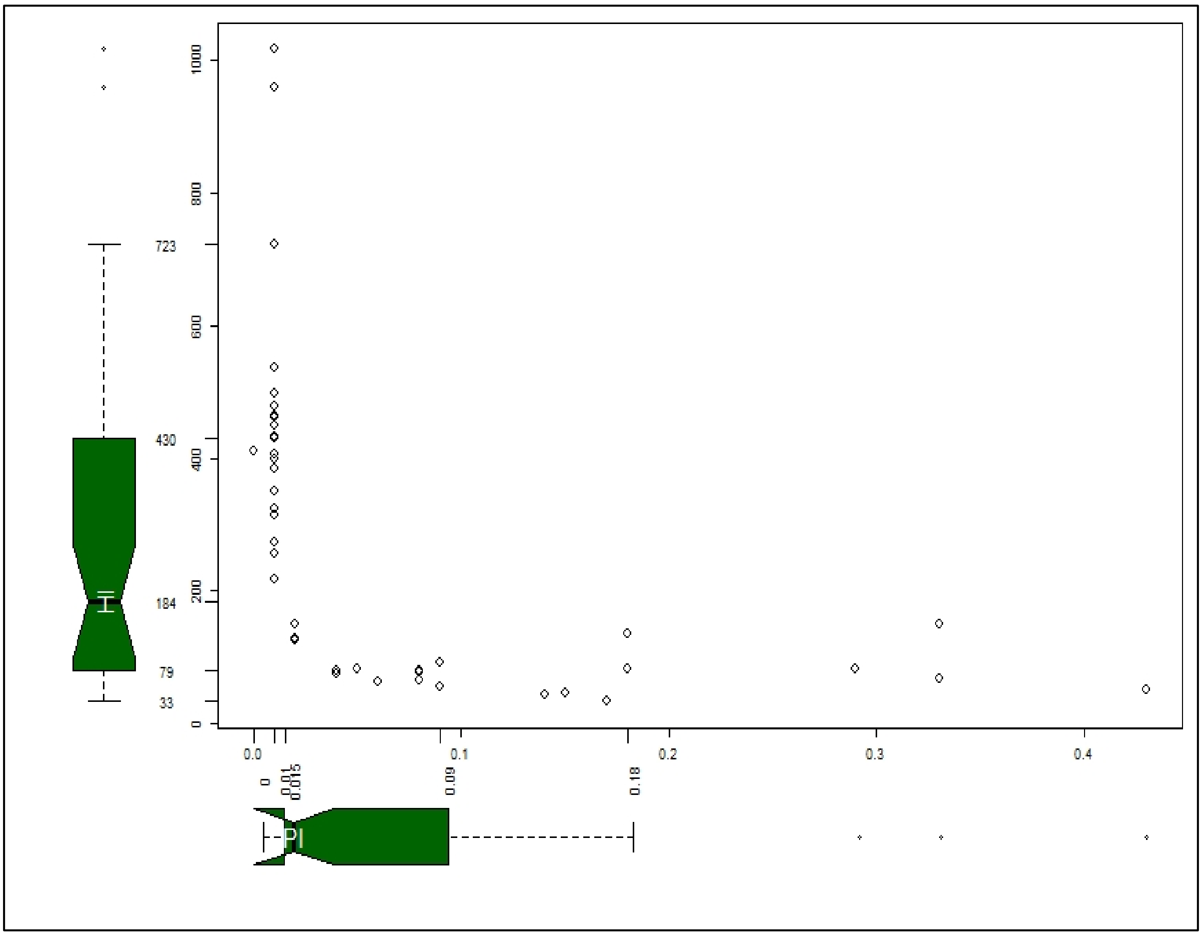

Figure 8, which is a plot of HI versus PI, indicates that samples with higher HI have lower PI and those with lower HI have comparatively higher PI. This confirms the interpretation of migration and accumulation of hydrocarbons in the ranges of depths described above (1140 to 1290 m).

Production Index (PI)

The transformation ratio S1/(S1+S2), also known as production index (PI) or petroleum potential, represents the level of thermal maturation. It measures the progress in the generation of hydrocarbons and shows the level of thermal maturation. The S2/S3 values indicate the type of organic matter for low maturation contents,

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hydrocarbons that can be indicated in the HI data for a uniform source section when HI increases with depth and with a decrease in production index (PI).

The inconsistencies (or rather intermittent values observed in PI) due to changes in organic facies or the chemistry of the source rock can produce shifts in the HI data, which are not indicative of maturation trends of the hydrogen index. If there was no mobilisation and migration of hydrocarbons from samples analysed, the PI should have increased smoothly with depth (fig. 2.22 of [12], p.67). In our present case, PI suddenly changed from increasing at a depth of 1140 m. *Figure 5* indicates that it is not the case in the LT-1 well from 1140 m to 1290 m depths. Though beyond 1290 m and even up to about 1800 m, the PI shows very high values, thus indicating thereby the dominance of accumulation of bitumen. This is also inferred by the low values of S2 (*Tables 1, 2* and *Figures 4, 7* and *8*).

Temperature Maximum - (Tmax ºC)

The temperature maximum (Tmax) mainly depends on the maturation level of the organic matter (OM). As a general rule, Tmax (ºC) increases with the maturity of OM.

Figure 9, a plot of T_{max} versus depth, indicates the trend of maturity levels with depth. T_{max} increases with increasing burial. The samples show that the organic matter (OM) has reached or passed the onset of the main oil generation stage T_{max} (435-465 ºC). The highest values of Tmax are obtained only from samples at deeper levels (1140 to 1290 m), but the variation is not uniform.

The gamma-ray range (60–120 API units) in these deeper depths of LT-1 (*Tables 2, 3* and *4*) with good porosity (12–40%) and p-wave seismic velocity (about 2.65 km/s [5]) showing uniform and frequent varying Tmax do not coincide with either the plots of S1+S2 (*Figure 4*) or with HI (*Figure 7*) but has similarity with the variation of PI (*Figure 8*). The similarity between PI and Tmax graphs (plots) in these depth regions is indicative of a kind of difference between the hydrocarbon type (bitumen or kerogen) on one side and a difference in the temperature that could be attained on the other.

Usually, the kind of kerogen that shows a lower Tmax range (<435 °C) is the simpler type (possibly Type I), while those samples in the 1140m to 1290 m depths range (*Figures 9* and *10*) had more complex type of kerogen (maybe Type III). The kerogen breakdown depends not only on the temperatures attained but also on the time that it takes for the breakdown; given sufficient time and temperatures in the range of 1000–1500ºC, kerogen breakdown is facilitated. The more complex kerogen, however, takes a higher temperature and greater time for the cracking process. The time perception, of course, is in the range of thousands of years or even millions of years.

Achieving a level of maturity of kerogen (within the organic matter in the source rocks) is vital for petroleum exploration. With immature kerogen, no petroleum is generated, but with increasing maturity, the first oil and then gas is expected to be generated (*Tables 1, 2* and *4*). Tmax is an indicator of maturity; the higher the Tmax, the higher would be the degree of maturity. It is also to be considered that more complex kerogen requires higher temperatures for breaking (possibly in the deeper parts of LT-1 well, even up to 1800 m, which was not covered here).

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Table 4: Potential Reservoirs and Source Rocks

Depth (m) of LT-1 Well	G.Ray (API)	Vp (Km/s)	TOC (wt %)	HI (mg HC/g)	PI	Porosity (φ)	Tmax (^{0}C)	Age (time)	OM Type	Oil / Gas	Lithology
830-1057	-	-	-	-	0.2-0.4	16%	330-440	Lower/Middle Miocene	-	Oil	Sandstone/shale
1100-1170 (690 m thick)	110AV	2.8-3.8	4.1-17	83-1600	0.01-0.05	9-19%	441-537	Oligocene/Lower/ Miocene		Oil/gas	Sst/ shales
1000-1386	120	1.8-1.9	-	300-600	-	-	445-500		III/II	Oil/gas	Black shales
2256-2286	75	3.4	2.9	115-137	3.4	>5%	336-442		III	-	Black shales
2628-2960	75	3.7	1.4	44-70	2.6		460		III	-	Shales/ Sst.

***Sst** = Sandstone*

(**Source**: After [4])

Tmax (°C), which is the temperature at which the rate of hydrocarbon generation is at its maximum during pyrolysis (25 °C/min), from 300–600 °C (*Figure 2*), is used mainly as a thermal maturity parameter. Therefore, the increase in the depth represents the linearly build-up of temperature (geothermal gradient) at its peaks or regions to generate (kerogen) hydrocarbons.

When drilling the LT-1 Well, oil and gas shows were encountered at depth levels between 800–1000 m and 1400–1600 m. The first level is above the sequence showing moderate TOC values (*Figures 11*) and high HI (*Figure 7*) and very low PI (*Figure 8*).

Thus, the oil show represents the migrated oil from the depths which have low PI. The TOC value of 0.5% is frequently taken as the maximum organic content for a source rock. Below this is not enough hydrocarbons can possibly be generated to saturate the source rock (*Tables 3* and *4*). The LT-1 well sequence consists mainly of sandstones and siltstones with few clays. The LT-1 Well showed good seals provided by lacustrine shales at depths where the oil shows have been found (*Figure 11*).

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Figure 9: Tmax versus depth

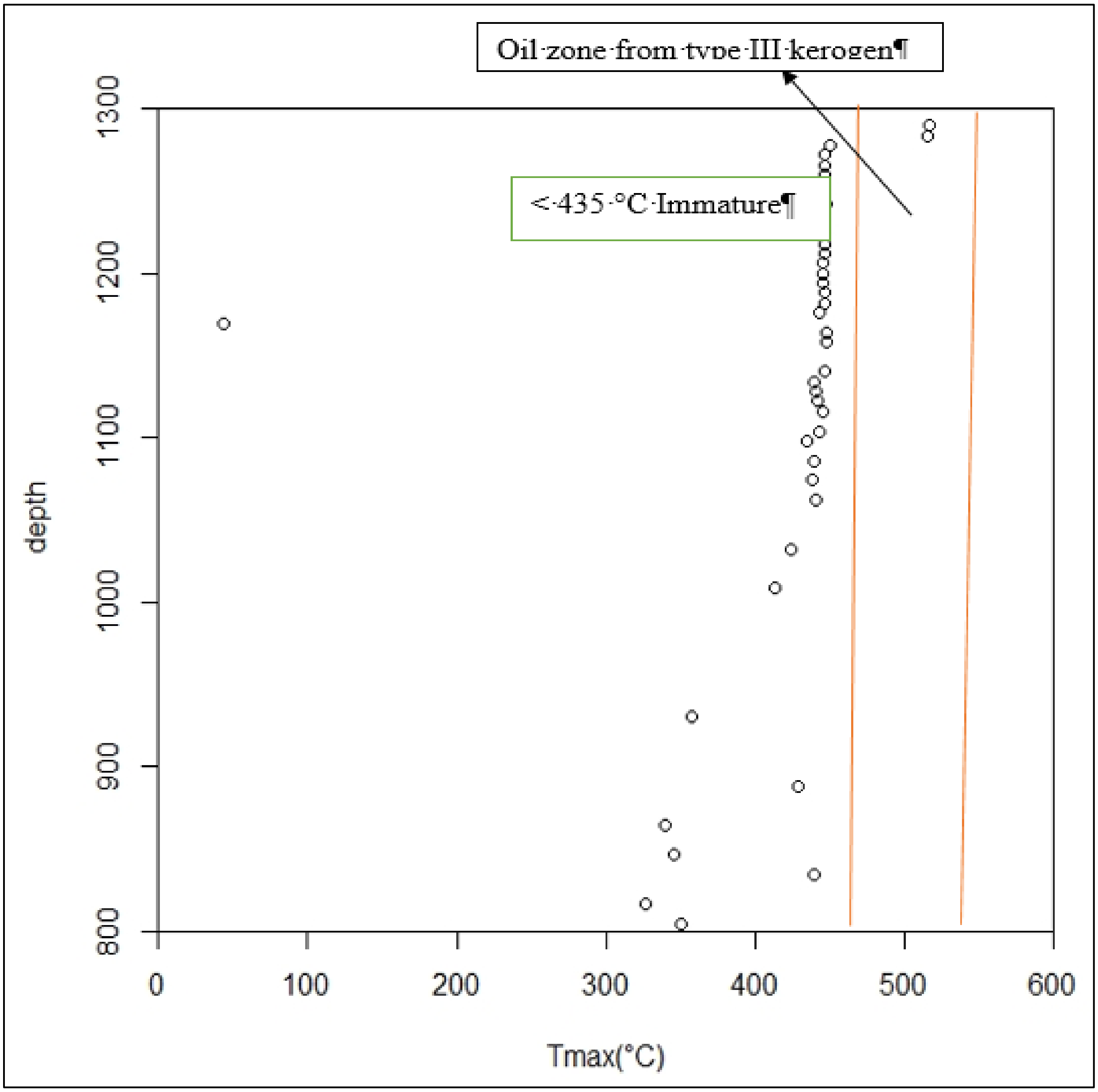

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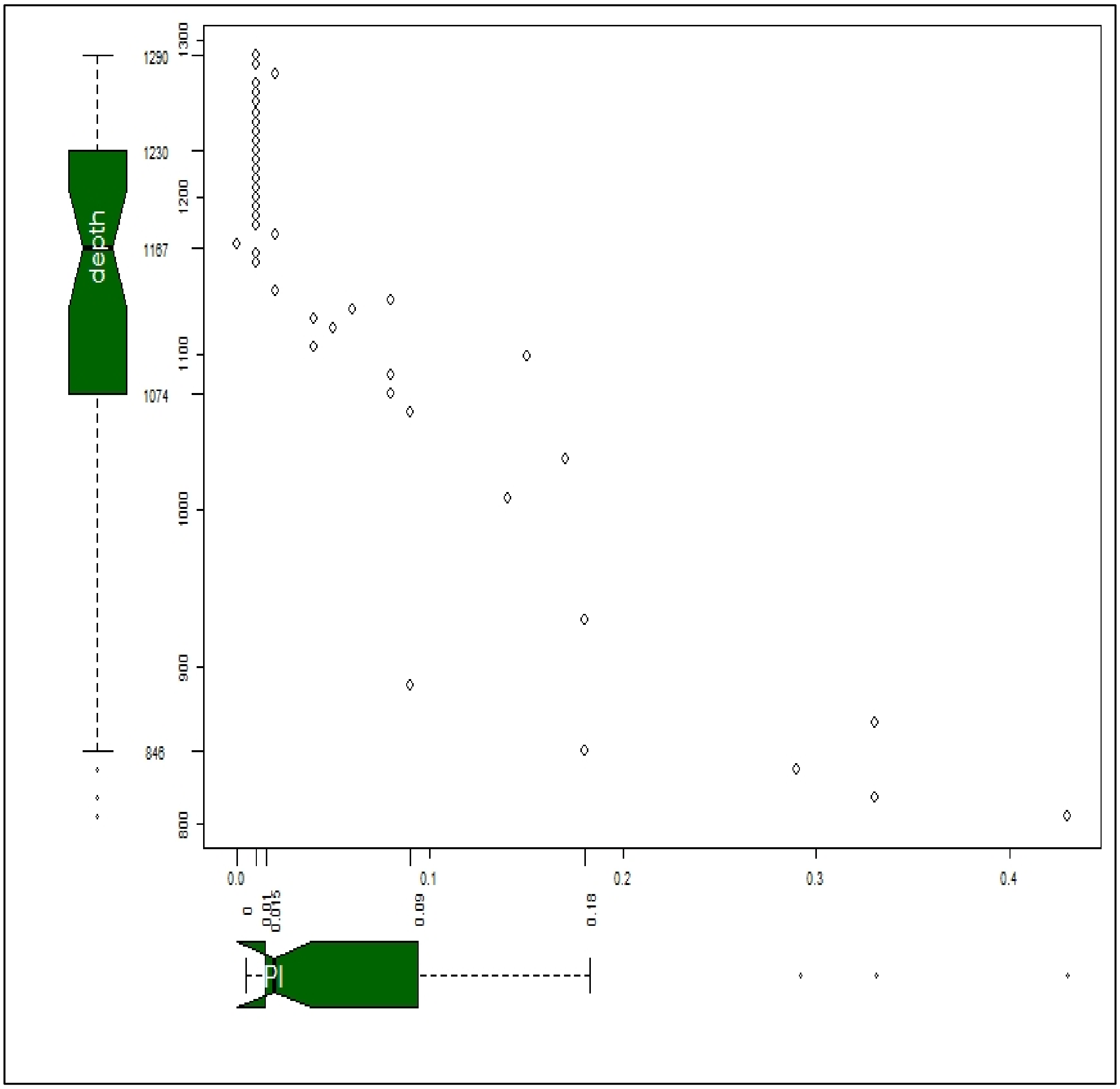
Figure 10: Production index (PI) versus depth



The reported sections [4] in which oil and gas indications were encountered at depths between 800–1000 m and 1400–1600 m (during drilling in LT-1 well) belong to the Upper Oligocene–Lower Miocene as well as the lower part of the Lower–Middle Miocene (*Figure 11* and *Tables 3* and *4*).[4]. The LT-1 well sequence consists mainly of sandstones and siltstones with few clays. The LT-1 showed good seals provided by lacustrine shales at depths where the oil shows have been found (*Figure 11*). The black shales have high gamma-ray log values (120 API units) and low porosity (<5%). They intermittently were encountered in LT-1 well at 850–900 m, 980–1057 m and 1360–1420 m depths (*Table 4*).

However, the numerous interpreted and intrabasinal N-S-trending faults in basin where LT1 was drilled (*Figure 11*) could have caused the escape of whatever hydrocarbons generated. Thus, even if the good sandstones were of good reservoirs and quality, as intermittently seen between depths 800–1760 m, with good porosity (9–40%), no oil accumulation took place, perhaps due to lack of fault closures. The sandstones show decreasing porosity with depth (12–40% up to 1000 m and 9–19% below 1386 m) and low permeability.

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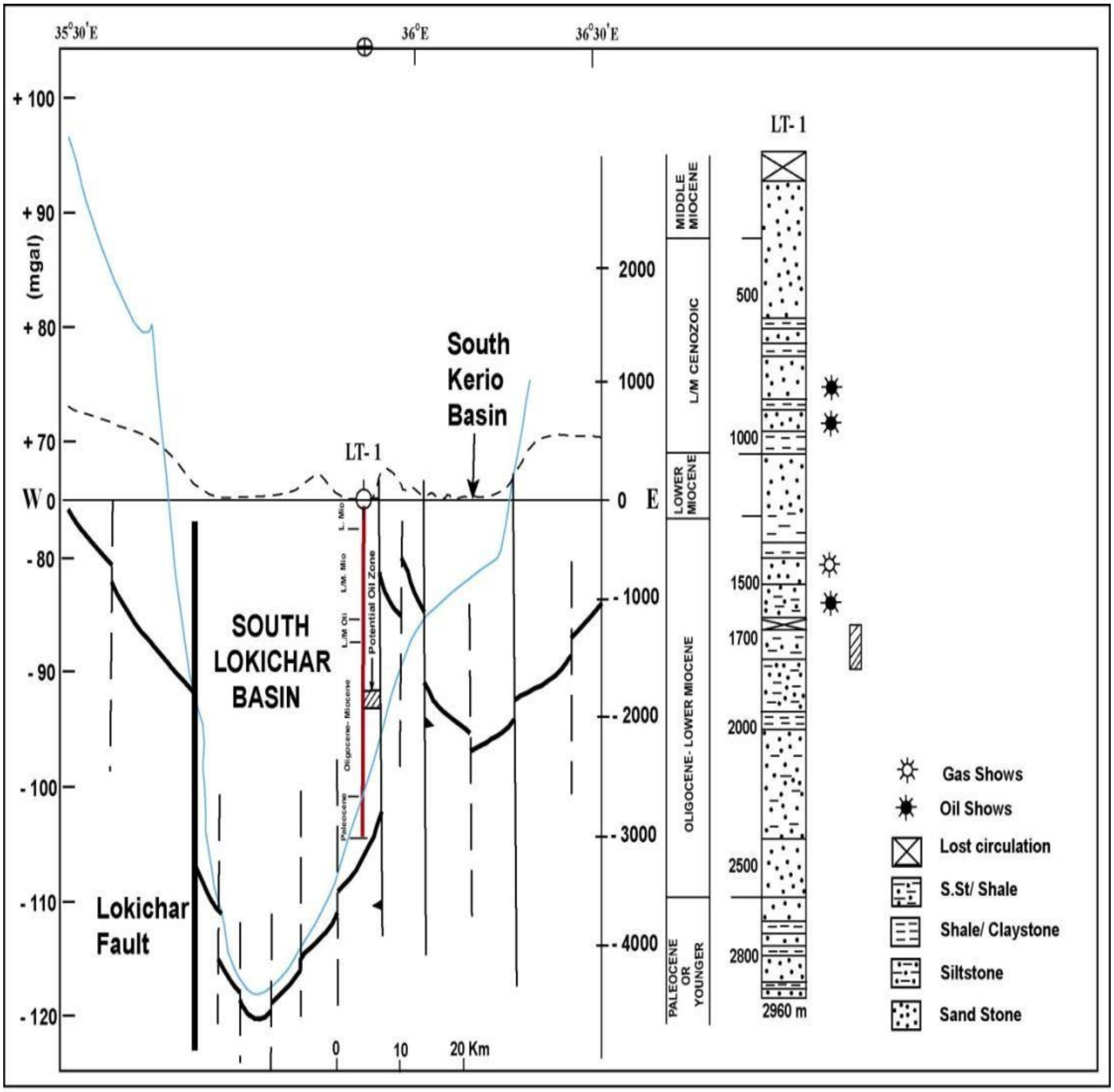
Figure 11: Cross-section of LT-1 Well showing basement depth and Bouguer gravity curves



Source: [4].

It is possible that there are distinctive variations in reservoir characteristics from one basinal graben to another within the northern Tertiary rift basins of Kenya. The maturation of organic matter (*Table 4*) in these source rocks (lacustrine) was consequent to high heat flow associated with mantle upwelling and rifting [4]. The proximity of volcanic dykes locally enhanced the maturation temperature. The LT-1 well was drilled close to the eastern margin of the Deep South Lokichar Basin, perhaps on a tilted fault block. Further east of the LT-1 well location is a small Horst-like structure, represented by the basement ridge forming the western part of the South Kerio Basin. To the west of the LT-1 well, numerous N-S intrabasinal faults have been interpreted, which extend to the basement (*Figure 11*). Thus, the South Lokichar basin is deeper in this part along the marginal N–S trending Lokichar fault [4].

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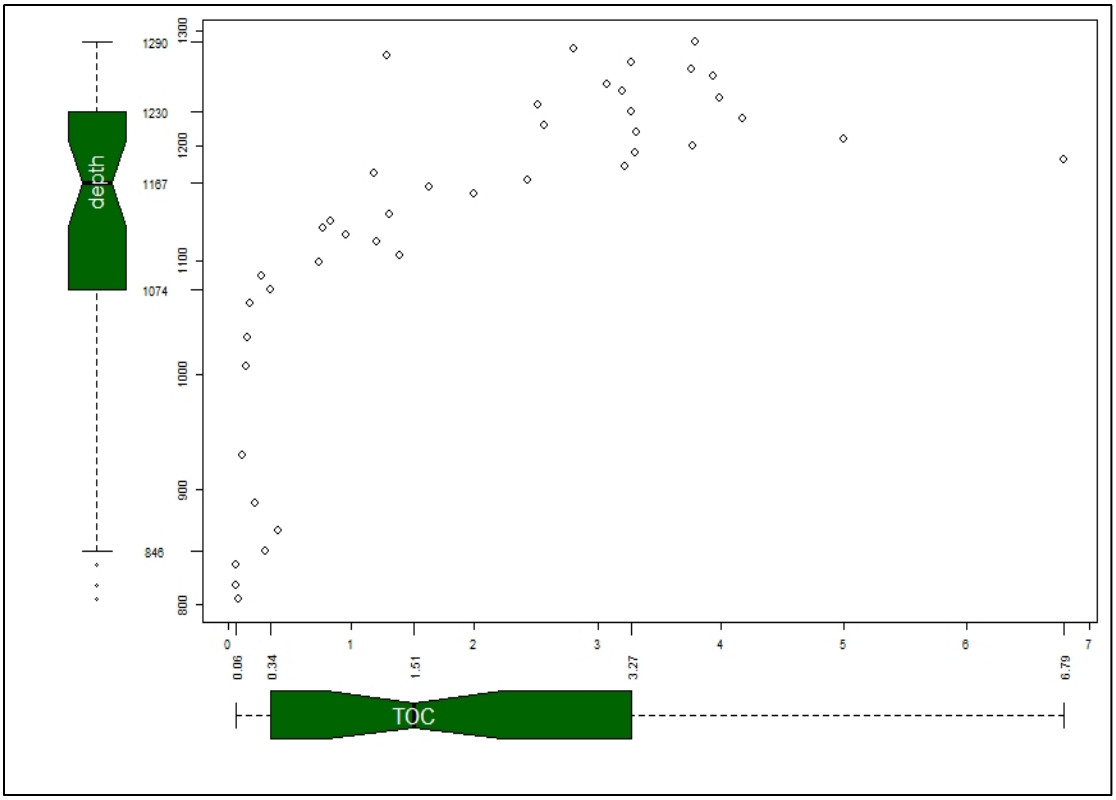
Total Organic Matter (TOC wt %)

Figure 12 is a plot of total organic carbon (TOC) versus depth for core samples taken from the LT-1 well. Based on the TOC contents (*Tables 1, 2, 3,* and *4*) 50 % of the samples can be classified as (very good) source rock quality (>2%), 30% of the samples had poor source rock quality (0-0.5%), 15% of the samples had good source rock quality (1-2%), and 5% of the samples got fair source rock quality (0.5-1%).

Figure 12: Plot of total organic carbon (TOC) versus depth



Nevertheless, the TOC value of 0.5% and above is frequently taken as the maximum organic content for a source rock (*Tables 1, 2* and *4*). Below this, not enough hydrocarbons can possibly be generated to saturate the source rock. The second level of the oil window, which was beyond the scope of this study area, could possibly be within the depth range of samples that could indicate uniform Tmax, as well as low PI, higher TOC, and maybe moderately high HI.

Obviously, a normal geothermal gradient in such rift-related basins will lead to threshold temperatures of 65–150°C at greater depths of this LT-1 well. Hence, it is expected that the kerogen type at those deeper depths in the present case, which represents the frequently maximum ranges of Tmax was the principal level for oil formation (*Table 4*). Most of the reported oil and gas shows are above this level and are within rocks with suitable porosity (*Table 4*). It is seen from *Table 2* as well as *Figures 3* and *4* that in the depth range 1179–1290 m there are as many as ten samples, and even over, with S1+S2>10 kg/t (mg/g).

Paleogeographic Position

It is interesting to note that the prevailing paleogeographic position of this region (what is presently northern Kenya) was much to the south of the Equator (*Figure 13*) during the Triassic-Jurassic/Cretaceous time [4]. Luxuriant vegetation on land, swampy grounds, humid climate, and good

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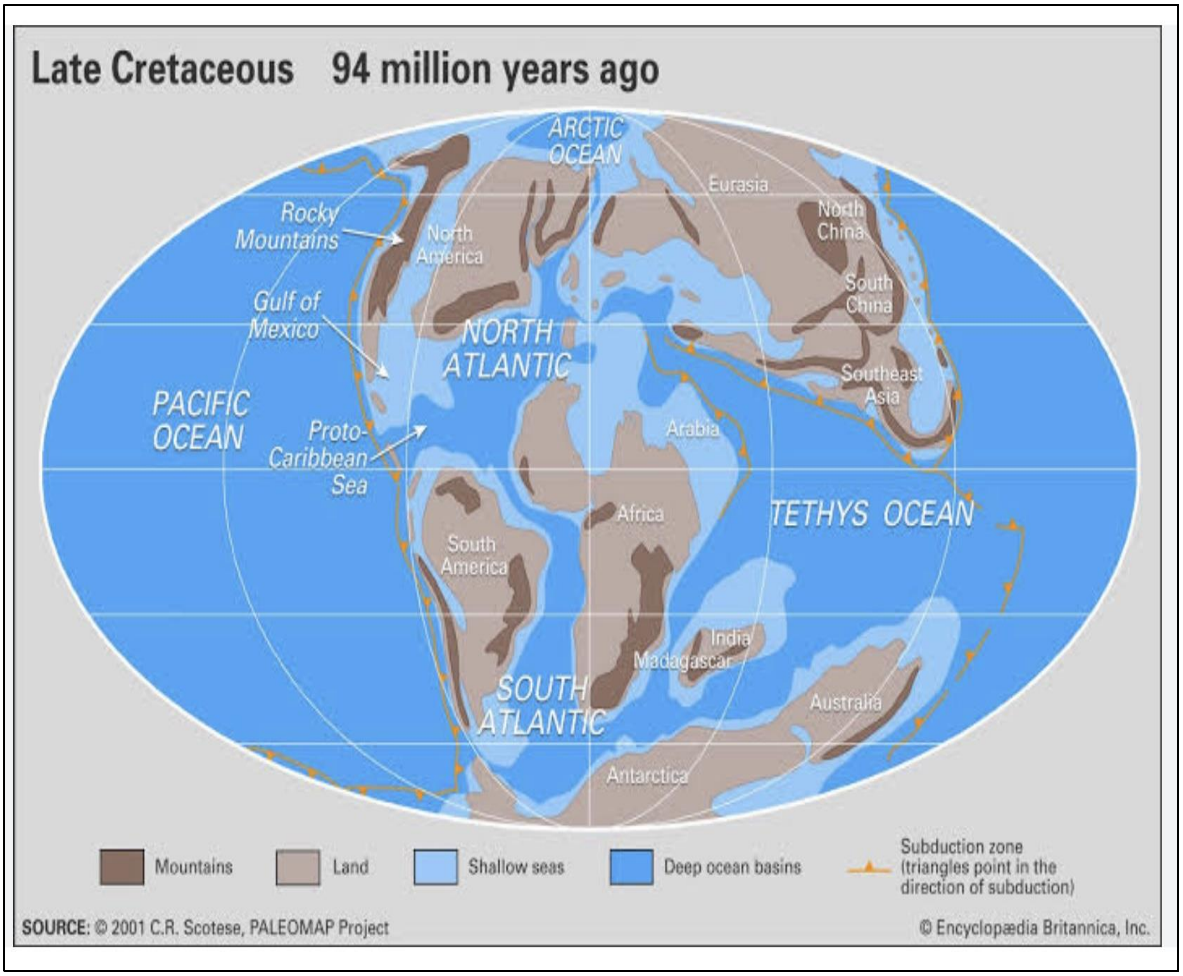
rainfall were some of the then prevailing environmental conditions [15]. With such a source, the organic matter (OM) that got buried could only generate the Type I or Type III kerogen whose initial product could be waxy crude or gas [4]. The analysis helped in determining the proportion and frequency of shale horizons within the otherwise sandy sections, as well as the variations in grain size within the sandstone beds.

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. Black shales rich in carbon (2 per cent weight TOC) as well as syngenetic uranium (up to 400 ppm) though more common to marine sediments, can also be deposited in other (lacustrine) environments which are biologically productive and anoxic [16]. Speedy sedimentation, along with basin subsidence, prevents the oxidation of organic matter and preserves it for possible hydrocarbon generation.

Figure 13: Paleo graphic position of Kenya in Late Cretaceous time



Source: Encyclopaedia Britannica, Inc. 2001

The sedimentation in these intracratonic rift basins was controlled by intrabasinal and marginal faults, some of them also reaching the basement (*Figure 11*). Intracratonic basins of these types are poor prospects for hydrocarbon exploration, but they contain adequate potential reservoir rocks, which can trap whatever hydrocarbons that were generated by the chiefly continental organic matter buried with the sediments. There are a few examples (1.5 per cent of the world's proven reserves) of hydrocarbon-generating intracratonic basins of this type [9][4].

CONCLUSION

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

From the seismic profiles, it was revealed that the frequency of the shaley rocks and compact sandstones increased with depth. These rocks were further distinguished by the gamma-ray logs to demarcate black shales with organic matter, coaly beds and sediments with radioactive elements. 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 with higher gamma ray (uranium content) values are of course considered to be better source rocks than those deposited in lacustrine and freshwater conditions.

Lacustrine sediments like the present ones typically have low gamma ray radioactivity. The radioactive 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. Black shales rich in carbon (2 per cent weight TOC) as well as syngenetic uranium (up to 400 ppm) though more common to marine sediments, can also be deposited in other environments which are biologically productive and anoxic. Speedy sedimentation, along with basin subsidence prevents the oxidation of organic matter and preserves it for possible hydrocarbon generation.

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Conflicts of Interest

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

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