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CHARACTERIZING THERMAL MATURITY AND HYDROCARBON POTENTIAL OF SOURCE ROCK USING ROCK-EVAL 6 PYROLYSIS TECHNIQUE: A CASE STUDY OF POLOGBENE-1 WELL, NORTHERN DELTA DEPOBELT, NIGER DELTA BASIN

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ABSTRACT

Organic geochemical evaluation of source rock within a petroleum system is important considering its role as the source of hydrocarbon. Subsurface samples at depth of 2361 m (outer shelf) and 2613 m (lower slope) from Pologbene-1 Well located within the northern delta depobelt were analysed using Rock-Eval pyrolysis analytical technique. This technique involves the temperature programmed heating of samples in an inert environment. Inference was drawn from Rock-Eval geochemical parameters, which include the already generated oil in the rock (S1), the amount of hydrocarbon generated through thermal cracking of nonvolatile organic matter (kerogen) (S2), Total Organic Carbon (TOC), and Maximum Temperature (T_{max}). Others are Hydrogen Index (HI), Oxygen Index (OI) and Production Index (PI). The results were compared with the inner shelf (1716 m) and the upper slope (2595m) of the same well. Two geochemical models were established; Hydrogen Index/Oxygen Index (HI/OI) and Hydrogen Index/Maximum Temperature (HI/T_{max}), for the outer shelf and upper slope source rock of Pologbene-1 Well. The two models were derived from Hydrogen Index (HI) values of 502 and 548, Oxygen Index (OI) value of 14 and 15 and Maximum Temperature (T_{max}) value of 429°C and 419°C (outer and upper slope respectively). The model indicate that the samples are oil and gas prone, are Type II source rock containing Type II kerogen. S1, S2 and Total Organic Carbon (TOC) values of 7.96 mg/g, 328mg/g and 65.36 wt. percentage for outer shelf and 7.51mg/g, 325mg/g, 59.37 percent for upper slope respectively indicate good to source capacity and high petroleum potential for Pologbene-1 Well.

1. INTRODUCTION

The relationship between the occurrence of organic compounds in sedimentary deposits and petroleum deposit has long been of interest. Studies of ancient sediments and rock provide insights into the origins and sources of petroleum geochemistry and the biochemical antecedents of life.

In petroleum geology, source rock refers to rock from which hydrocarbon have been generated or are capable of being generated. They are sedimentary rocks that are, or may become, or have been able to generate petroleum (Tissot and Welte, 1984). They are organic-rich sediments that may have been deposited in a variety of environments including deep water, marine, lacustrine and deltaic, and one of the necessary elements of a working petroleum system (Peters and Cassa, 1994).

Various methods have been employed over time to determine the petroleum potential of source rock, their stages of thermal maturation, type and class of inherent kerogen (Peters and Moldovan, 1993), (Agagu and Ekweozor 1982). The generative source potential and the main product expelled at peak maturity is also of basic interest.

The study well is located in the Northern Delta depobelt of the Niger Delta basin, which is the oldest of the depobelt in the Niger delta Basin. It lies along the northern perimeter of the Niger delta where the proximal parts of its lithostratigraphic units are exposed and partly grades into the lithofacies of the Anambra basin. Thus, it is geochemically and stratigraphically similar to the Southern end of the Anambra Basin (Evamy et al, 1978). Well sections through the Niger Delta generally display three vertical lithostratigraphic subdivisions: an upper delta top facies; a middle delta front lithofacies; and a lower pro-delta lithofacies. These lithostratigraphic units correspond respectively with the Benin Formation (Oligocene-Recent), Agbada Formation (Eocene-Recent) and Akata Formation (Paleocene-Recent). From the Eocene to the present, the delta has prograded southwestward, forming depobelts that represent the most active portion of the delta at each stage of its development. These depobelts form one of the largest regressive deltas in the world with an area of some 300,000 km^2 a sediment volume of 500,000 km^3 and a sediment thickness of over 10 km in the basin depocenter. The Niger Delta is framed on the northwest by a subsurface continuation of the West African Shield, the Benin Flank. The eastern edge of the basin coincides with the Calabar Flank to the south of the Oban Masif (Weber et al., 1987).

The stratigraphy, Sedimentology, structural configuration and paleo-environment in which the reservoir rocks accumulated have been studied by various workers (Short et al., 1965; Weber et al., 1987; Nwajide et al., 1996; Reijers et al., 1996). This study therefore seeks to determine the thermal maturity and petroleum generative potential of source rock in the northern delta depobelt of the Niger Delta Basin, using Rock-Eval pyrolysis approach.

2. MATERIALS AND METHODS

The major method employed for this study is the Rock-Eval 6 pyrolysis, whose aim is to identify the type and maturity of organic matter and to detect petroleum potential in sediments. The materials used are spectrophotometer, carthometer, chromatographic glass column, cuvette and temperature-programmed muffle furnace. Subsurface samples at depth of 2361m (outer shelf) and 2613m (lower slope) from Pologbene-1 Well were analysed using Rock-Eval pyrolysis analytical technique, which involves the temperature programmed heating of samples in an inert environment.

2.1. Determination of Direct Measurements

The parameters, which are a result of direct measurement from the Rock-Eval pyrolysis procedure, include S1, S2, S3 and T_{max}. As a standard, 25 g of the sample was prepared. It was crushed, disaggregated, and then passed through a 25µm sieve. The samples were placed in a temperature programmed muffled furnace, which is built to model an inert environment (an environment devoid of oxygen). The temperature was programmed at 100 ^{o}C with a steady rise of 25 ^{o}C per minute. Between 300 – 350^{o}C, the first reading for S1 was taken. S1 represent the already generated hydrocarbon (oil and gas) in the rock. Trapped CO_2 in the sample starts evolving when the temperature is increased slightly. Within the temperature range of 350 – 390 ^{o}C when CO_2 evolves, S3 was measured. S3 is the amount of CO_2

produced during pyrolysis of kerogen. It represents the amount of oxygen in the sample. With increase in the temperature of pyrolysis, S2 was measured within a temperature range of 300-600 ^oC. The maximum temperature, T_{max} is the temperature of maximum release of hydrocarbon during Rock- Eval pyrolysis. It occurs at top of the S2 peak between the temperature of 300 – 600 ^oC. Above 650^{o}C the value of S4 was measured. CO and CO_2 are both components of S4.

2.2. Determination of Derived Measurement

2.2.1. Hydrogen index (HI)

The ratio of S2 hydrogen (in mg HC/g dry rock) to total organic carbon (TOC) in grams. The hydrogen index is a measure of the hydrogen richness of the source rock, and when the kerogen type is known, it can be used to estimate the thermal maturity of the rock. When plotted against the oxygen index (OI), the HI can be used to provide a good assessment of the petroleum generative potential in a source rock (Peters and Moldowan, 1993).

$$HI = (S2/TOC) * 100 \quad (1)$$

2.2.2. Oxygen index (OI)

The ratio of S3 (mg CO2/g dry rock) to TOC (in grams). The parameter measures the oxygen richness of a source rock and was used in conjunction with the hydrogen index to estimate the quality and thermal maturity of source rocks. This index is unreliable in rocks with high carbonate content. High OI value (>50 mg/g) are characteristic of immature hydrogen.

$$OI = (S3/TOC) * 100 \quad (2)$$

2.2.3. Production index (PI)

The production index is the ratio of already generated hydrocarbon to potential hydrocarbons. Low ratios indicate either immaturity or extreme post mature organic matter. High ratios indicate the mature stage or contamination by migrated hydrocarbons or drilling additives. The PI increases steady with depth and associated hydrocarbon generation.

$$PI = SI/ (S1 + S2) \quad (3)$$

2.3. Determination of Total Organic Carbon (TOC)

To determine the values of TOC, the samples are pyrolysed to temperature greater than 850^{0}c in an oven. A process known as oxidation. This gives the organic carbon evolved above this temperature.

2.4 Determination of Total Percentage of Hydrocarbon (TPH)

The sample (10g) is placed on top a glass chromatographic column packed with activated silica gel. 100ml of xylene is poured through the column. Silica gel attracts and absorbs aromatics. Because of this strong through the column. The fraction of aromatics and non-aromatics are weighed and measured as A and B.

A = weight of aromatics recovered; B = weight of non-aromatics recovered

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$$\text{Aromatic fraction (wt \%)} = (A/(A+B)) * 100 \quad (4)$$

$$\text{Non-aromatic fraction (wt \%)} = (B/(A + B)) * 100 \quad (5)$$

3. RESULTS AND DISCUSSION

The result of the analysis of shale samples from Pologbene-1 Well in the northern delta depobelt of the Niger delta basin is as presented in Tables 1 and 2. The plot of hydrogen index (HI) against oxygen index (OI) on a modified Van Kreveleen diagram was used to provide a crude assessment of the petroleum generative potential of a source rock. Figure 1 is a HI/OI geochemical model of Pologbene-1 well (outer shelf and inner slope). High hydrogen content in kerogen corresponds to greater oil generation potential. When HI is plotted against T_{max}, which is a maturation parameter, it gives an indication of the source rock type (Peters and Moldowan, 1993).

Table 1: Showing Result from Rock-Eval pyrolysis (direct measurement)

Depositional Environment	Depth (m)	S1 (mg/g)	S2 (mg/g)	S3 (mg/g)	S4 (mg/g)	T_{max} (oC)
Pologbene-1 well (Outer shelf)	1716	8.81	271	4	0.58, 0.31	453
Pologbene-1 well (Inner shelf)	2361	7.96	328	9	0.58, 0.13	429
Pologbene-1 well (Upper slope)	2595	7.43	321	8	0.57, 0.17	419
Pologbene-1 well (Lower slope)	2613	7.51	325	9	0.56, 0.18	420

Table 2: Showing Result from Rock-Eval pyrolysis (derived measurement)

Depositional Environment	Depth(m)	TOC (wt %)	THC (wt %)	HI	OI	TPH (wt %)
Pologbene-1 well (Outer shelf)	1716	0.751	1797	361	5	71.9
Pologbene-1 well (Inner shelf)	2361	0.654	1576	502	14	63.1
Pologbene-1 well (Upper slope)	2595	0.602	1524	533	14	61.03
Pologbene-1 well (Lower slope)	2613	0.594	1504	548	15	60.24

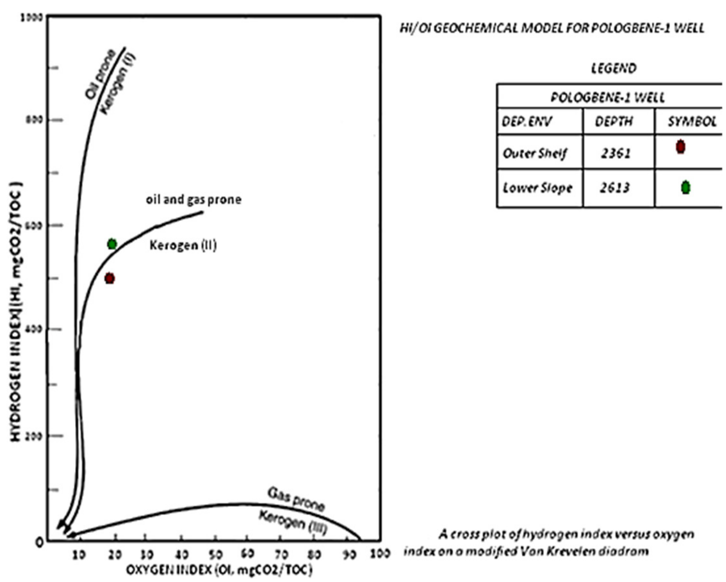

Figure 1: HI/OI model for Pologbene-1well derived from the modified van Krevelen diagram

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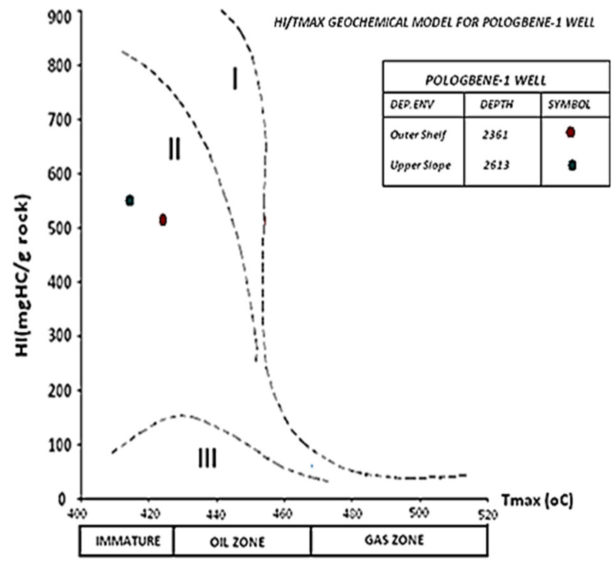

Figure 2: HI/T_{max} Model for Pologbene-1 well

The outer and lower slope from the benchmark shows value of S1 greater than 4. This implies that the shale sample at depth interval 2361 m and 2631m of Pologbene-1 well have excellent source potential. A comparison of the value of S1 at depth interval 2361m and 2613m (outer shelf and lower slope respectively), with the value of S1 at depth 1716m and 2595m (inner shelf and upper slope respectively) of Pologbene-1 well, shows a decrease in S1 value from the inner shelf to the out shelf (8.81-7.96mg/g) and an increase in value from the upper slope to the lower slope (7.43-7.51mg/g). Pologbene-1 well however has excellent petroleum potential. S2 values give an indication of amount of hydrocarbon generated through thermal cracking of organic matter (kerogen).

Comparing S2 value with standard S2 indicator range for petroleum potential clearly shows that the sample at this depth (2361m and 2631m) in Pologbene-1 well have excellent petroleum potential. Comparing the value of TOC for outer shelf and lower slope with the standard range indicates that the sample at this depth for Pologbene-1 well has good to excellent source capacity since both values are greater than 2. Comparing TOC values in the outer shelf and lower with values in the inner shelf and upper slope (1716m and 2595m respectively) of Pologbene-1 Well shows a steady decrease in TOC with depth (from 75.11wt% in the upper shelf to 59.37wt% in the lower slope) thus indicating lesser source capacity with increasing depth. Pologbene-1 well has good to excellent source capacity.

Comparing value of T_{max} and PI with standard range clearly shows that the samples analysed at depth of 2361m and 2613m (outer shelf and lower slope respectively) of Pologbene-1 well are both immature. The implication of this is that though the samples have good to excellent source capacity and excellent petroleum potential as inferred from S1, S2 and TOC values, it cannot produce hydrocarbon. This may be due to the fact that, the samples at this particular depth of burial have not undergone the appropriate thermal maturation or prolonged extent of burial heating as to attain peak maturity. Though the amount of organic matter may be sufficient and the right quality and type of organic matter may be present, no hydrocarbon can be produced. At peak maturity however, this same sample will generate sufficient hydrocarbon.

A comparison of T_{max} value at depth 2361 m (outer shelf) and 2613 m (lower slope) to depth of 1716 m (inner shelf) and 2595 m (upper slope) of pologbene-1 well shows a steady decrease in maturity with depth from T_{max} value of 453

^{o}C in the inner shelf (1716 m) to 420 ^{o}C in the lower slope. Peak maturity however occurred within the inner shelf at a depth of 1716 m. The main stage of thermal evolution is diagenesis.

The hydrogen index (HI) gives an indication of the hydrogen richness of source rocks. Hydrogen rich samples have higher hydrocarbon production potential. The hydrogen index (HI) also gives insight to the type of kerogen present in the sample (Peters and Cassa, 1994). Comparing result obtained from Rock-Eval pyrolysis with standard range by (Peters and Cassa, 1996) shows that the samples at this depth are of Type II source rock. In addition, a cross plot of HI /T_{max} on a modified Van Krevelen plots into the kerogen Type II region thus confirming the same inference from HI. The sample could be either of the several type of Type II kerogen which include exinite (formed from the casings of pollen and spores), cutinite (formed from terrestrial plant cuticle), resinite (formed from terrestrial plant resins and animal decomposition resins) and liptinite (white are formed from terrestrial plants lipids and marine algae). Type II kerogen are formed from lipids deposited in a reducing condition. The sample, having Hydrogen to Carbon ratio (H:C) of <1.25 and Oxygen to Carbon ratio (O:C) range of 0.03 to 0.58, can be inferred to be typical of type II kerogen source rocks. They all have great tendencies to produce petroleum. The HI/T_{max} Geochemical Model for Pologbene - 1 Well model was established by plotting value of HI from Rock-Eval against OI on a modified Van Krevelen diagram to deduce the type of source rock the analysed sample belong.

The cross plot marker fell within the region of Type II source rock on the geochemical model therefore, it can be inferred that the analysed samples are possibly Type II source rocks. It therefore means that the analysed sample contains marine planktonic remains preserved under anoxic condition in a marine environment. Type II source rocks produce both oil and gas when thermally cracked during deep burial.

4. CONCLUSION

From the geochemical evaluation of ditch cutting samples from Pologbene-1 well at depth of 2361m (outer shelf) and 2613m (lower shelf) and further comparison with results of similar studies on the same well at depth of 176m (inner self) and 2595m (upper slope), it can be concluded that Pologbene-1 well is oil and gas prone. The TOC, S1 and S2 geochemical parameter indicated samples that have good to excellent source capacity and excellent petroleum potential. The T_{max} and Production Index (PI) value shows that the source rocks are immature. Thermally immature source rocks have been affected by diagenesis without any pronounced effect of temperature. Immature source rocks do not produce hydrocarbon. Hydrogen Index (HI) and HI/OI geochemical model indicated kerogen type II for these samples while it was deduced from HI/OI geochemical model that the samples are type II source rock capable of producing a mixture of oil and gas. It can therefore be said that the samples have the right quality (type) and quantity (amount) of organic matter with excellent source potential, but it is immature. However, at peak maturity the samples will generate a mixture of oil and gas.

5. ACKNOWLEDGMENT

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6. CONFLICT OF INTEREST

There is no conflict of interest associated with this work.

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