IOSR Journal of Applied Geology and Geophysics (IOSR-JAGG)
e-ISSN: 2321–0990, p-ISSN: 2321–0982.Volume 6, Issue 3 Ver. II (May. – June. 2018), PP 27-31
www.iosrjournals.org

Source Rock Evaluation of the Southwest Portion of the Bornu Basin, Nigeria

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Abstract: *Source rock evaluation in the Maiduguri area of south-western portion of the Bornu Basin was carried out with a view to assessing hydrocarbon generation potential in that part of the basin, where only three exploratory wells (13% of the wells drilled so far in the basin) have been drilled. Both bulk geochemical and vitrinite reflectance data were obtained from carefully selected shale samples from ditch cuttings of Ngor -1 well. The result was integrated with existing data of two other wells (Ngamma-1 and Gubio SW-1). The strata of the area is rich in organic matter with TOC well above 0.6 wt% and reaching up to 3.80 w.% and even 5.62 wt% in existing data of Gubio SW– 1 well. These organically rich beds fall within the oil generation window. The limiting factor observed in nearly all the samples (this study and previous ones) in the south-western portion of the Bornu Basin is the low hydrogen index of the organic matter that makes them gas prone with poor to fair or lean hydrocarbon generative potential.*

Keywords: *Bulk geochemistry, Bonu Basin, Vitrinite reflectance, source rock, hydrogen index.*

Date of Submission: 26-04-2018 Date of acceptance: 14-05-2018

I. Introduction

Few wells (three compared with nine in the south western portion of the basin) were drilled in search of hydrocarbon in the south-western portion of the Bornu Basin during the first intense exploration efforts in the Basin in the seventies. The three wells are Ngor 1, Ngamma -1 and Gobio SW -1. None of these three wells, just like other wells except two that encountered insignificant gas in the basin, is reported to be hydrocarbon bearing. This and other proprietary reasons may be responsible for a wary search for hydrocarbon in the area. Former source rock evaluation on one of the wells, Ngamma- 1, suggests very poor Hydrogen Index yield in the area in spite of availability of sufficient (0.76 – 1.04 wt.%) Total Oganic Carbon (TOC) that could generate hydrocarbon and the maturity level (> 440 $T_{max)}$ of the few samples studied (Alalade and Tyson, 2010). Alalade (2016) shows that out of the twenty samples from Ngamma-1 well studied only one has TOC of 0.38 wt.% while the rest are well above 0.5 wt% with values ranging between 0.56 and 1.05 wt.% which indicate a fair source-rock generative potential (Peters, 1986). Alalade (2016) put the oil window at depths 1785 – 3230 m in Ngamma as against 1556 – 3417 by Nwankwo and Ekine (.2009). Nwankwo and Ekine (op. cit.) put the oil window in Ngor – 1, which is the well under study in this work at 1806 – 3468 m.

This study therefore focuses on source rock evaluation of Ngor-1 well located within the south-western part of the basin. Source rock evaluation is a component that is central to the viability of any exploration venture because petroleum generating potential is directly related to it. The evaluation involves the determination of the amount, type and maturation level of organic matter in a fine grained rock. These parameters are interrelated and the indices for assessing them are well established (Hunt, 1979; Tissot and Welte, 1984; Peters, 1986; McCarthy et al. 2011).

The amount of organic matter in a sample is commonly measured in terms of the Total Organic Carbon (TOC) in it while the type of organic matters could be determined on the basis of the type of kerogen it contains. There are various methods, chemical and numerical, of determining the level of maturity of a source rock. Level of maturity is a measure of the thermal evolution of the rock. Commonly used indices include $T_{max,}$ and vitrinite reflectance, which is the amount of light reflected by vitrinite macerals in the sample. T_{Max} is obtained alongside other parameter during pyrolysis. It corresponds to the temperature at which residual hydrocarbon in the sample peaked during pyrolysis. The aim of this work is to assess the source rock status in the south western portion of the Bornu basin which can serve as a guide to a proposed new exploration campaign in the basin.

GEOLOGICAL SETTING.

The Nigerian sector of the Chad Basin is named the Bornu Basin (some authors such as Nwajide (2013) and Goni and Zarma (2015 prefer the Bornu sub-Basin). It is located in the northeastern part of Nigeria (Fig. 1). The Chad Basin is the largest intracratonic basin in the west central Africa and occupies an approximate area of 2,335,000 km^2 covering part of Chad, Nigeria, Niger Republic, Cameroon, and Central African Republic territories (Fig. 1; Obaje et al., 2004a; Guiraud et al., 2005). The basin is one the basins associated with the West and Central African rift system (WCARS) whose tectonostratigraphic evolution reflects a complex geologic history influenced by stretching and subsidence of the African blocks during the breakup of Gondwana and opening of the South Atlantic Ocean in the Early Cretaceous (Guiraud and Maurin, 1992; Genik, 1993, Brownfield et al., 2010; Fairhead et al., 2013). All the basins in the WCARS are genetically related and have similar structural settings. Nearly all except the Bornu basin is oil producing.

The stratigraphic framework of the Bornu Basin is divided into **six** major stratigraphic units (Fig. 2; Avbovbo et al., 1986; Olabode et al., 2015). Sedimentary fill in the basin started in the Early Cretaceous with the deposition of sediments of Bima Formation, composed of sparsely fossiliferous, poorly sorted, cross stratified, fine- to coarse-grained arkosic sandstones, during the late Aptian to Albian. The Bima sandstones directly overlie the Precambrian basement and are interpreted as fluvial and lacustrine deposits (Avbovbo et al., 1986). Regional extensional events of the Cenomanian (Genik, 1993) in the Chad Basin marked the onset of marine transgression and subsequent deposition of Gongila Formation sediments. These sediments consist of alternating sandstones and calcareous shales that are interpreted to be of shallow marine origin (Avbovbo et al., 1986; Olugbemiro et al., 1997). Marine transgression predominated throughout most of the Turonian and reached its peak in the late Turonian to Senonian during which sediments of Fika Formation were deposited. The Fika Formation consists essentially of thin- to thick-bedded shales with interbedded siltones and sandstones deposited in an open marine environment (Okosun, 1995; Obaje et al., 2004a). This was followed by deposition of alternating siltstones, shales, and sandstones, Gombe Formation, in an estuarine to deltaic environment during the Maastrichtian (Avbovbo et al., 1986; Obaje et al., 2004a). The last rifting phase in the Chad Basin in the late Maastrichtian to Paleocene (Genik, 1993) resulted in the development of series of block faulting horsts and grabens structures that are followed by a long period of non-deposition (Obaje et al., 2004). Gombe Formation was unconformably overlain by fine- to coarse-grained sandstones of Kerri-Kerri and Chad Formations which were probably deposited in a lacustrine environments in the Neogene and Pliocene respectively. The Chad Basin experienced widespread volvanic activities in the central and southern parts in the Tertiary (Obaje et al., 2004a).

Previous studies suggest that the main potential hydrocarbon source rocks in the Bornu Basin are some of the interbedded shales of the Fika and Gongila Formations (Obaje et al., 2004; Adekoya et al., 2015). The few interbedded sandstones of Fika Formation and the predominant sandstone of Gombe Formation have been identified as the possible reservoir rocks (Adepelumi et al. 2011; Adekoya et al., 2014). The total organic contents (TOC) of shale source rocks usually varies across the basin with values ranging from 0.54 to 1.25 wt.% while the organic matter is predominantly type III kerogen, suggesting a poor to fair gas prone hydrocarbon field (Obaje et al., 2004b; Adekoya et al., 2014). The geothermal gradient in the Bornu Basin ranges from 30 to 44 °C/km with a regional average of 34 °C/km (Nwankwo and Ekine, 2009).

II. Methodology

The only well yet to be subjected to bulk geochemical studies in the south western portion of the Bornu Basin forms the focus of this study. Fourteen ditch cutting samples were carefully selected to encompass a range of Cretaceous strata in the well after a detailed sedimentological study of two hundred and thirty (230) ditch-cutting samples taken at 5 metres interval (except where there were few missing gaps). The 230 cuttings were obtained from a depth range of 460 to 2745 m. From the initial detailed sedimentological analysis carried out, it was noted that the Tertiary sediments had no shale that could be source rock and were not considered adequate for this study.

The samples were sieve-washed under running water to remove drilling contaminants, dried and pulverized. One gram of powdered sample each was decarbonated with HCl and utilized for total organic carbon (TOC) analyses using a LECO-CS 244 carbon analyser. The result of the TOC analyses guided further selection of samples for the Rock-eval pyrolysis performed on each sample using 100 mg of powdered whole rock and GEO-IMT-2005 instrument. The Rock-eval method consisted of estimating the petroleum potential of rock samples by pyrolysis according to a programmed temperature pattern. A response curve for the instrument's FID detector was calibrated in mg (oil)/gram (rock) using known IFP standards to monitor the released hydrocarbons as S1 (thermo-vaporized free hydrocarbons) and hydrocarbons from cracking of organic matter (S2). The temperature at the S2 peak corresponds to the pyrolysis oven temperature during maximum generation of hydrocarbon (Peters and Cassa, 1994). This was recorded as the Tmax. In addition, CO and CO_2 released during pyrolysis were monitored in real time by means of an IR cell, giving information on the oxidation state of organic matter (S3). Key parameters derived from the pyrolysis results included: hydrogen index (HI), which is derived from the ratio of hydrogen to TOC (i.e. 100 x S2/TOC); oxygen index (OI), which is a reflection of the oxygen contained in the kerogen, useful in tracking kerogen maturation or type and is derived from 100 x S3/TOC; and Production Index (PI) that is used to characterize the evolution of the organic matter and defined as S1/ (S1+S2) (McCarthy et al., 2011).

III. Result

Majority of the samples analysed in the Fika Shale have TOC values between 0.91% and 1.83% (Table 1 and Fig. 3). An outlier TOC value of 3.80% was obtained in the upper part of the Fika Shale. Samples of the presumed Bima Formation are not rich in organic matter (Table 1). For this reason, pyrolysis data were not obtained for the section. In terms of thermal maturity of the organic matter, three samples within a section of 1600 m – 1810 m gave values above the 435^{o}C Tmax that marks the onset of hydrocarbon generation. One sample from Yolde Formation at a depth of 2000 m yielded a T_{max} value of 429 ^{0}C, which is close to maturity. All the samples analysed in Ngor – 1 revealed that HI values for 9 (nine) of the samples are less than 30 mgHC/gTOC while only one sample from the upper part of Fika Formation at a depth of 960 m had an HI value of 50 mgHC/gTOC. The HI values obtained from Ngor – 1 suggest dominant occurrence of inert organic matter (Type IV kerogen). T_{max} recorded for the organic rich sample at 960 m disappointedly falls within the immature zone (Fig. 4)

The foregoing results led going into vitrinite reflectance studies of five of the samples obtained at depths of 2550 m, 2850 m, 3400 m, 4000 m and 4550 m because of favourable TOC values and shaly physical appearance of the samples. The analysed samples were predominantly composed of mudstone and few carbonate fragments. Generally mudstone and carbonate fragments had low organic matter content but the latter occasionally exhibited areas of bitumen streaking. The histogram plots of the organic matter particles of the analysed samples (Fig. 5) showed dominance of phytoclasts, which had been degraded and exhibited high reflecting solid bitumen. Recycled vitrinite and inertinite were common. There were areas in the samples that were rich in hematite, indicating oxidation perhaps owing to sample storage. Distinguishing recycled vitrinite from primary vitrinite was sometimes difficult. However, there were several fair quality lenses of primary vitrinite while low to moderate liptinite was present. Degraded high reflecting solid bitumen occurred in moderate amounts. There was no matrix bitumen staining. Liptinite was present mostly as yellow fluorescing algal cysts. Cavings were present and tentatively assigned thin light orange spores were present in caved fragments. Most samples did not show convincing fluorescence indigenous organic matter, although mineral fluorescence was present. Few samples exhibited convincing spore fluorescence of mid-orange with very weak intensity and was considered to be primary. Generally, a vitrinite reflectance value (> 0.6 Ro%) that is more reliable suggests a mature bed, indicating thermal maturation of early oil window, peak oil window, late oil window to early wet gas condensate zone. A plot of HI against TOC shows a clustering of the results at the margin of immature to mature source rock in the strata penetrated by the Ngor – 1 well (Fig. 4).

IV. Source Rock Evaluation In The Southwestern Part Of The Bornu Basin.

Organic richness of sediments

In source rock evaluation, the organic richness (TOC) of the sediments is directly related to the petroleum-generating potential of the rock and constitutes the first primary factor to be ascertained. Prior to this report, two of the wells (Ngamma and Gubio) out of the three wells drilled in the south western part of the Bornu Basin have been examined for TOC availability (Alalade and Tyson, 2010; Alalade, 2016). The two wells are very rich in organic matter, particularly within the Fika Shale and the Gongila Formations. Specifically, out of the 20 samples studied by Alalade (2016) and another 3 by Alalade and Tyson (2010) only one sample recorded a value of 0.38 wt% of TOC while others gave values that are predominantly more than 0.8 wt%, with a few values being above 2 wt%. McCarthy et al. (2011) considered any sediments having TOC values greater that 2 wt% as having a good potential for hydrocarbon generation. In the Gubio well, the TOC is predominantly above 0.9 wt% with a good number in the range of 0.64 and 5.72 wt%, which is considered as good to very good in terms of organic richness for hydrocarbon generation (McCarthy et al. (2011). According to Peters (1986), any rock with TOC values above 4 wt% has an excellent generative potential. In Ngor well (Table 1) within the Fika Formation and upper part of Gongila Formation a fair to good organic source rock is recorded. All these suggest that within the south western portion of the Bornu Basin sufficient amounts of organic matter for hydrocarbon generation are available.

Thermal Maturity of Organic Matter

Thermal maturity refers to exposure of source rock to heat over time (McCarthy et al., 2011) resulting in generation of hydrocarbon from organic matters. Commonly used tools for characterizing the level of organic matter maturation is the pyrolysis temperature (Tmax) at the S2 peak that marks the maximum kerogen and heavy hydrocarbons yield. Most of the Tmax data in Ngor – 1 well cluster around the point marking the onset of hydrocarbon generation while three samples are fully within the oil generation window (Fig. 4). On the contrary, the vitrinite reflectance data, which fall in the range of 0.63 – 1.22 %Ro, suggest that the section of the Ngor 1 well studied falls within the oil generation window (Fig.5). Vitrinite reflectance values for the samples at shallow depths are higher than 0.6 %Ro (Fig. 5). For example 0.63 %Ro was obtained at a depth of 960 m suggesting an onset of oil generation at shallower depth than the 2000 m estimated by Genik (1993) for the whole basin and 1806 m by Nwankwo and Ekine (2009) for Ngor-1 well. Similarly in the other two wells in the south western portion of the basin, Alalade and Tyson (2010) have estimated that the onset of hydrocarbon generation occurs at depths of 1700 m and 1785 m in Gubio and Ngamma wells, respectively. However we consider the result of this study that suggests the commencement of oil generation window at a shallow depth of 960 m plausible because the depth falls below the intra-Maastrichtian unconformity and is within the Fika Shale (Adekoya et al., 2014). Our knowledge of the Bornu Basin indicates that it is only the Tertiary sediments that are not within the oil generation window (Adekoya et al., 2014).

Hydrocarbon Generation Potential.

Hydrocarbon generation potential is a measure of the ability of organically rich, thermally matured argillaceous rock to generate oil, oil and gas or gas only. The major factors controlling their formation are the type of organic matter present and the thermal evolution of the rock. In this study, a plot of Hydrogen Index against Tmax and van Krevelen diagram were used to assess the hydrocarbon potential in Ngor-1 well. While the organic matter is predominantly type III with two samples falling at the verge of Type II (Fig. 4B), all the values except one suggest immature sediments (Fig. 4A). The genetic potential of Type III kerogen is gas (Hunt, 1979; Peters, 1986, McCarthy et al., 2011). The only sample within the mature section has TOC value of 1.11 wt.% and occurs at a depth of 1810 m within the Fika Shale. This suggests occurrence of source rock within the section and calls for further exploration work targeting the section.

Thermal Evolution and Tectonism

Hunt (1979) pointed out that the presence of unconformity could be supported by an offset in the depth trends of Tmax. On the basis of Hunt's finding, two periods of cooling are inferred from the thermal evolution (as recorded in the Tmax values) of the strata penetrated by Ngor – 1 well (Fig.3). The periods of cooling are most probably caused by exhumation which indicates occurrence of unconformities. These unconformities occur prior to the folding, uplifting and erosion recorded in all the basins in the WCARS as a result of the Santonian squeeze (Genik 1992, 1993; Fairhead, 2013). The exhumation periods are reflected on the electrofacies controlled stratigraphy (Adekoya et al. 2014) of the well (Fig. 3a). The older cooling event occurred after the regression that led to the deposition of the Gongila Formation, suggesting either erosion of part of the formation or period of non-deposition before the subsequent Coniacian transgression that led to the deposition of the Fika Shale. The second cooling event is reflected by a sharp-based gamma ray log motif (Fig. 3a) and it occurs within the Fika Formation.

V. Conclusions

All the samples analysed from Ngor – 1 well were obtained from Fika, Yolde/Gongila and Upper Bima Formations. Three of the samples are mature (within the oil window) with T_{max} values between 435°C and 438°C. The remaining six samples cluster around the level of the onset of hydrocarbon generation with T_{max} values that vary from 427°C to 433°C. The vitrinite reflectance data, which unfortunately do not support the inference from the Tmax data, suggests that the well section studied falls within the oil generation window. Based on Tmax results, two periods of cooling totally different from the one after the Santonian squeeze were identified. The first one marks the boundary between the Gongila and the Fika Formations and the second falls within the Fika Formation. Fika Formation has relatively higher quantity of organic matter in the Maiduguri SW part of the basin. Owing to very low Hydrogen Index, the section of the Ngor well studied does not hold any significant potential for hydrocarbon generation. In spite of this general conclusion, it would appear that part of the strata studied could generate insignificant hydrocarbon.

Acknowledgement

The original research forming the source of the data used for this study was sponsored from the 2010 PTDF Research Competition funded by Petroleum Technology Development Fund (PTDF), Abuja, Nigeria. This is acknowledged with thanks. The authors are particularly grateful to Prof. R.W. Brown and Dr. K. Dobson of the University of Glasgow, UK for facilitating the geochemical analysis. Prof. C. M. Ekweozor's advice on how to go about the analysis is also appreciated.

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IOSR Journal of Applied Geology and Geophysics (IOSR-JAGG) is UGC approved Journal with Sl. No. 5021, Journal no. 49115.

Ola, Peter Sunday. " Source Rock Evaluation of The Southwest Portion of The Bornu Basin, Nigeria." IOSR Journal of Applied Geology and Geophysics (IOSR-JAGG) 6.3 (2018): 27-31.