Petroleum and Coal

Article Open Access

GEOCHEMICAL EVALUATION OF NKPORO FORMATION FROM NZAM-1 WELL, LOWER BENUE TROUGH

Mutiu. A. Adeleye[1], Adetola. J. Abiodun[1] and Liao. Yuhong[2]

[1] Department of Geology, University of Ibadan, Ibadan, Nigeria
[2] State Key Laboratory of Organic Geochemistry, Guangzhou Institute of Geochemistry, China

Received May 3, 2016; Accepted June 14, 2016

Abstract

Ditch cutting samples belonging to Nkporo Formation obtained from depth range of 2462m to 2717m in the Nzam-1 well, Lower Benue Trough were subjected to Total Organic Carbon (TOC) content and Rock-eval Pyrolysis to evaluate their source rock potential for hydrocarbon generation. The samples are made up of shales, sandy shales, mudstone and sandstone. The shales are fissile, fine grained and dark grey in colour while the sandy shales consist of fine grained, fissile and dark grey shales with significant appearance of fine to medium grained, whitish sands. The mudstone is fine grained, grey in colour and blocky (non fissile), while the sandstone is fine grained, compacted and white in colour. The TOC ranges from 0.08 to 1.45 wt. %, indicating that the samples contain appreciable proportion of organic matter that can generate hydrocarbon. Hydrogen Index and Tmax range from 14 mg/g to 37 mg/g and 436°C to 516°C respectively. Genetic Potential (GP), Production Index (PI) and Calculated Vitrinite reflectance (% Ro) range from 0.32 to 0.59 mg/g rock, 0.35 to 0.43 and 0.69 to 2.13 respectively. Rock-eval data indicate that the sediments contain poor to fair source rock for hydrocarbon with kerogen type III as the predominating organic matter, which is capable of generating dry gas. Tmax and other pyrolysis data suggest that the organic matter in the Nkporo Formation is at the peak of thermal maturity to post maturity with respect to hydrocarbon generation. It is concluded that the heat energy generated from post mature part of the studied section together with the thermal maturity peak to late maturity generally observed for the sediments may have resulted in the dry gas prospect.

Keywords: Organic matter; Kerogen type; Thermal maturity; Nkporo Formation; Lower Benue Trough.

1. Introduction

Increasing energy demand has necessitated the need for a review of several exploration data from many basins with hydrocarbon potentials around the world. In Nigeria, data generated from many inland basins including Benue Trough were reviewed with respect to their potential for hydrocarbon generation and subsequent production. The Benue Trough has been reported to contain large accumulation of hydrocarbon in addition to economic deposits of coal previously reported and exploited from the basin [1-4]. Since only few discoveries have been made from several exploration wells drilled in lower Benue Trough with dominance of gas over oil [5-6], exploration activities in the basin has been consistently low. Relatively recent incentives to oil companies from government and efforts from research institutes and universities formed part of the increasing exploration activities in the Lower Benue Trough and other inland basins in Nigeria.

The Benue Trough and other rift basins belonging to the West and Central African Rift System (WCARS) began to form in Early Cretaceous during the opening of South Atlantic Ocean [7]. The structural bifurcation of the Benue Trough into lower, middle and upper Benue Troughs played significant role in the trapping mechanism, while the stratigraphic configuration of the Benue Trough has also provided the essential components required for hydrocarbon play. The discovery of oil seepage prompted the need for hydrocarbon exploration in the Lower Benue Trough. Hydrocarbon exploration studies in the Lower Benue Trough by Shell (formerly Shell Darcy) and other companies in 1950s resulted in drilling of several exploration wells. Researches emanating from generated samples and data by oil companies and academia have indicated good hydrocarbon prospects in the Lower Benue Trough. However, hydrocarbon production from the Lower Benue Trough is still not achievable despite available data on the prospect.

Assessment of generative potential and characteristics of source rocks is fundamental in hydrocarbon exploration and its success depends largely on the employed organic geochemical method [8-9]. The evolution of organic matter from the time of deposition to the beginning of metamorphism is tightly linked with burial of source rock and ultimately on the history of hydrocarbon formation [10]. Therefore, organic matter richness, type and thermal maturity are the three fundamental geochemical parameters for evaluating prospective source rock [8].

Several studies have identified hydrocarbon source rocks in the Lower Benue Trough [6,11-22]. The Eze-Aku and Awgu Formations, and the Nkporo, Mamu and Imo Formations were identified as the hydrocarbon source rocks in the Abakaliki Anticlinorium and Anambra basin respectively. However, thermal maturity of the source rocks and type of hydrocarbon generated has not been consistent from one study to another. This calls for further research in order to clarify the ambiguity with respect to hydrocarbon prospect of the Lower Benue Trough. The Campano-Maastrichtian Nkporo shale has been described as one of the prolific source rocks in the Lower Benue Trough [5-6,13-14,17-18]. An attempt is therefore made in this study to evaluate the source rock potential for hydrocarbon generation of the Nkporo Formation from Nzam-1 well in the Lower Benue Trough.

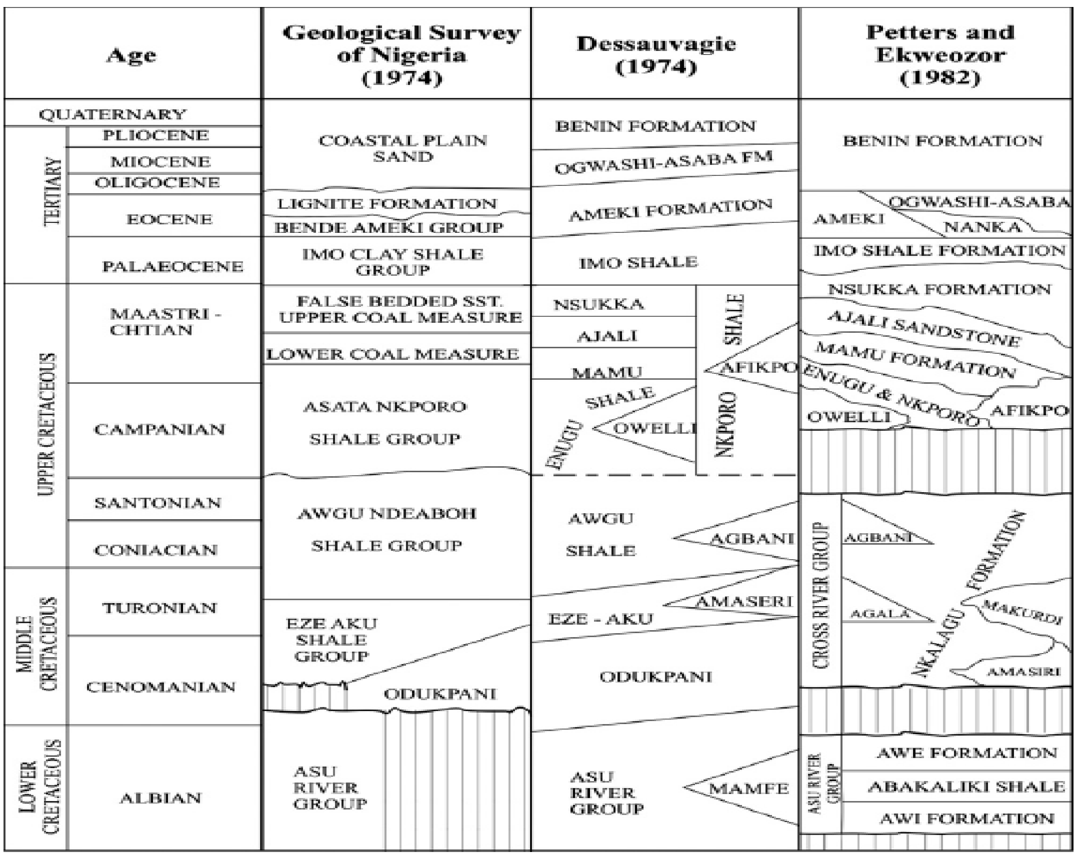
2. Geological Setting

The evolution of the Nigerian southern sedimentary basins began in the Early Cretaceous with the formation of the Benue-Abakaliki Trough as a failed arm of the rift triple junction which is associated with the separation of the African and south American continents and subsequent opening of the South Atlantic [23-25]. Although the exact areal definition of the Benue Trough as a whole has been an issue of controversy, however it is clear that it originnated from a `pull-apart` basin associated with the opening of the Atlantic Ocean which ended in the Early Tertiary with the development of the Tertiary Niger Delta [12,16]. The northern limit of the Lower Benue Trough (one of the three regions of Benue Trough) corresponds to the Gboko transform fault that was recognized by Whiteman [4] while the eastern limit covers the Lokpanta area. The Lower Benue Trough comprises of the tectonically inverted Abakaliki Anticlinorium and the flanking Anambra basin and Afikpo synclines to the west and east respectively [6].

The megatectonic framework was reported to have subdivided the Cretaceous history of the Lower Benue Trough into two main phases separated by the Santonian deformation [27]. Prior to the Santonian, the main depocentre was the narrow, NE-SW trending fault-bounded Abakaliki Trough. To the west and east, existed a broad stable area (Anambra platform) and relatively stable area (Ikpe platform) respectively [27]. Consequent upon the Santonian folding, the Abakaliki Trough was inverted producing the main structural feature of the Lower Benue Trough (Abakaliki Anticlinorium). The Anambra platform now subsided strongly to be become the main depocentre producing Anambra basin. A subsidiary depocentre, the Afikpo syncline, also developed simultaneously to the south east [27]. The sedimentation, structural framework and stratigraghy of the Lower Benue have been described [1-3,11-12,27-33]. The stratigraphy of the Lower Benue Trough is made of the Asu River Group, Eze-Aku Shales, Makurdi Sandstones, Awgu Shales, Nkporo Shales, Mamu Formation, Ajali Sandstones, Nsukka Formation, Imo Shales and Ameki Formation (Table 1).

The Nkporo shales belonged to Asata Nkporo Shale Group [29] which is composed mainly of shales and sandstones overlying the Awgu shales [2]. The Nkporo shale consists of dark grey fissile shales and mudstones often pyritic or gypsum bearing, with occasional interbeds of sandy shales, shelly limestones, ripple-marked fine grained sandstones, coarse grained sandstones and chamositic or limonitic oolitic ironstones [16,34-36]. It is believed to be deposited as products of the first transgressive phase into the Anambra basin [37]. It rest conformably on Albian-Santonian formation of Abakaliki folded basin. An estimated maximum thickness of 1000 m is reported for the formation [2]. Its lateral equivalents are the Enugu shales and the Owelli sandstone (sandstone member). Stratigraphic position of Nkporo shale indicated a late Campanian age [2]. Upper Senonian [27] and Campanian to Maastrichtian [16] ages have been suggested for Nkporo Formation, while a Maastrichtian age was indicated for the formation based on miospores and *Libycoceras angolense* respectively [4]. The lithologies of Nkporo shales reflect a shallow marine offshore depositional environment over a shelf setting, shoaling upwards into lower to upper shoreface and even foreshore setting. A marine environment of deposition was reported for Nkporo shale [2,16], while a variety of environments including shallow open marine to paralic and continental settings was inferred for the Nkporo shale [38].

Table 1. Stratigraphic subdivision of the Lower Benue Trough, compiled from workers



3. Samples and Methods

Fifteen samples belonging to Nkporo Formation from Nzam-1 well in the Lower Benue Trough, comprising of ditch cuttings and cores were obtained from Kaduna office of the Geological Survey Agency of Nigeria. The samples were selected at 5 m interval, covering a depth range of 2462 m to 2717 m in the well. Nzam-1 well is located on longitude 06° 28^{I} N and latitude 06° 45^{I} E in OPL 447 (Figure 1) and it is one of deepest exploratory wells in the Lower Benue Trough that penetrated both the Anambra basin and Abakaliki Anticlinorium. The ditch cuttings samples were particularly checked for drilling mud and other impurities. The mud or impurities were removed where present. The lithological log of the sampled interval of the well is presented in Figure 2. Lithological description of the samples revealed that they are essentially composed of shales, sandy shales, mudstone and sandstone. The shales are fissile, fine grained and dark grey to grey in colour while the sandy shales consist of fine grained, fissile and dark grey shales with significant appearance of fine to medium grained, whitish sands. The mudstone is fine grained, grey in colour and blocky (non fissile), while the sandstone is fine grained, white in colour and compacted. The lithological log shows a dominance of shale units at the upper and middle parts, and sandy shale units at the lower part of the studied section. The shale unit at the upper part is capped with mudstone and sandstone units, while the shale units at the middle part are intercalated with sandy shale units. The sandy shale units at the lower part have small interval of shale unit between them.

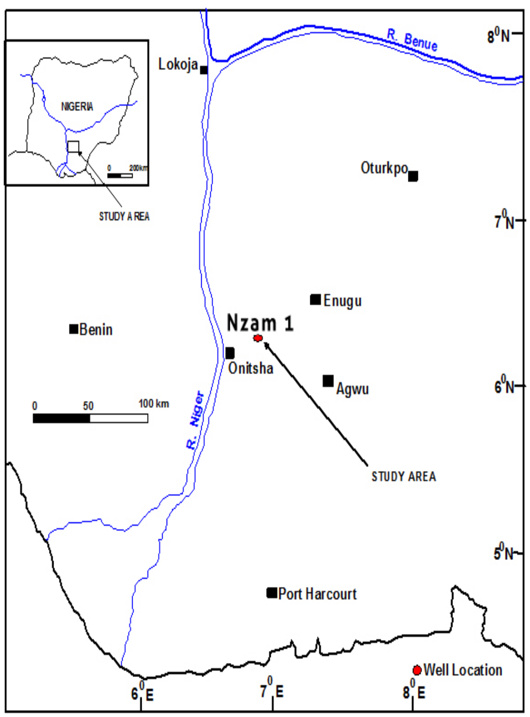


Fig. 1. Map of southern Nigeria showing the location of Nzam-1 well

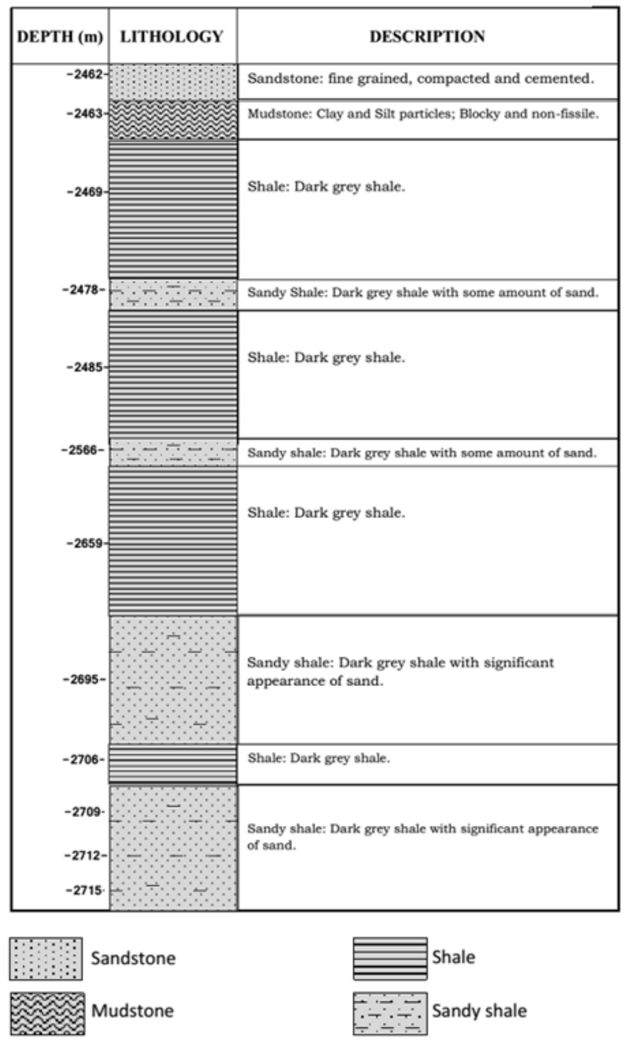


Fig. 2. Lithological log of the studied section of Nzam-1 well

All samples were pulverized, stored in vials and labeled. The samples were treated with concentrated hydrochloric acid to remove carbonates and total organic carbon (TOC) was measured using Elementar Vario EL III elemental analyzer (Hanau, Germany). Using minimum value of 0.5 wt. % TOC for the samples, thirteen (13) samples were further subjected to Rock-eval pyrolysis analysis using Rock-eval Pyrolyser II. Calculated vitrinite reflectance was generated from Tmax using the formula: Calc. % Ro = 0.0180 × Tmax [39]. The Total organic carbon and Rock-eval pyrolysis analyses were carried out at the State Key Laboratory of Organic Geochemistry, Guangzhou Institute of Geochemistry, China.

4. Results and discussions

4.1. Organic Matter Richness

The results of the total organic carbon (TOC) and Rock-eval pyrolysis are presented in Table 2. The TOC is a measure of the organic richness of the sedimentary rocks [39]. The TOC values of the samples belonging to Nkporo Formation in Nzam-1 well range from 0.08 to 1.45 wt. %, indicating that the samples contained appreciable organic matter except for two samples with TOC values below 0.5 wt. %. Since adequate organic matter is a pre-requisite for hydrocarbon generation from sediments [40], the Nkporo shale could be regarded as potential hydrocarbon source rock because it's average TOC value (1.17wt. %) is above 0.5 wt. % considered as the threshold value for hydrocarbon generation [41].

Table 2. TOC and Rock-eval Pyrolysis Results of the Nkporo Formation.

Depth (m)	TOC wt.%	S1 (mg/g)	S2 (mg/g)	S4 (mg/g)	S1+S2 (mg/g)	Tmax (^{O}C)	Calc %Ro	HI mg/g	PI	PC (%)
2462-2467	1.12	0.16	0.24	10.90	0.40	439	0.742	21	0.4	0.03
2472-2477	0.99	0.14	0.24	9.54	0.38	446	0.868	24	0.37	0.03
2477-2482	1.03	0.21	0.38	9.83	0.59	444	0.832	37	0.36	0.05
2482-2487	1.09	0.22	0.36	10.43	0.58	442	0.814	33	0.38	0.05
2487-2492	1.07	0.18	0.24	10.37	0.42	440	0.76	22	0.43	0.03
2642-2647	1.16	0.17	0.31	11.23	0.48	448	0.904	27	0.35	0.04
2647-2652	0.08	NA	NA	NA	NA	NA	NA	NA	NA	NA
2652-2657	1.40	0.21	0.31	13.57	0.52	516	2.128	22	0.4	0.04
2657-2662	1.25	0.18	0.25	12.11	0.43	503	1.894	20	0.42	0.04
2672-2677	1.14	0.14	0.25	11.05	0.39	436	0.688	22	0.36	0.03
2687-2692	1.08	0.15	0.23	10.53	0.38	448	0.904	21	0.39	0.03
2697-2702	1.12	0.13	0.24	10.93	0.37	451	0.958	21	0.35	0.03
2702-2707	1.03	0.13	0.24	9.99	0.37	446	0.868	23	0.35	0.03
2707-2712	1.45	0.12	0.20	14.20	0.32	440	0.76	14	0.38	0.03
2712-2717	0.08	NA	NA	NA	NA	NA	NA	NA	NA	NA

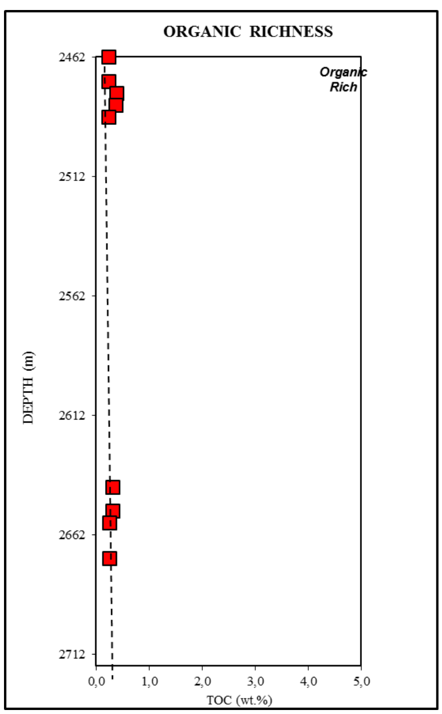


Figure 3. Plot of TOC against depth showing organic matter richness in studied section of Nzam-1 well

The organic matter content in the samples is fairly constant with depth with only slight increase towards the middle of the studied section (Figure 3). The source rock quality of the Nkporo shales from Nzam-1 well determined by the pyrolysis-derived generative potential (GP=S1+S2) is shown in Table 2. The hydrocarbon generative potential (GP) and Hydrogen index (HI) values of the samples range from 0.32 to 0.59 mg/g rock and 14.0 to 37.0 mg HC/g TOC respectively. The GP and TOC values (<2 mg/g and av. 1.17 wt. %) indicate poor to fair source rock, possibly with gas potential [41-42].

4.2. Type of Organic Matter

It is a known fact that organic matter in a sedimentary rock among other conditions influences the type and quality of generated hydrocarbon because of different convertibility property of organic matter type [41]. Organic matter type disseminated in sediments may be determined by plots of data from Rock-eval pyrolysis as proposed by Peters [8,42]. The cross plot of Hydrogen Index against Tmax (Figure 4) suggests that organic matter in the Nkporo shale is gas prone kerogen type III (sourced from terrestrial material) within the oil window and condensate to wet gas window.

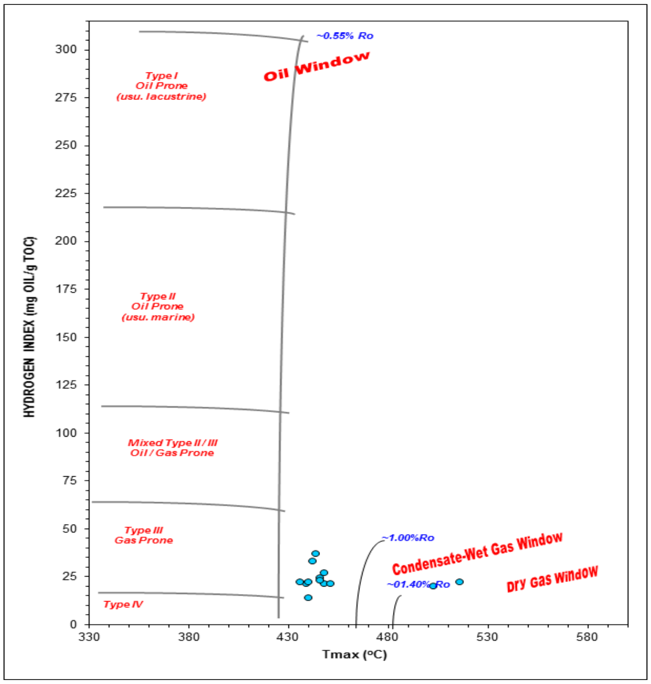


Fig. 4. Plot of Hydrogen Index against Tmax showing gas prone kerogen type III within the oil and condensate to wet gas windows

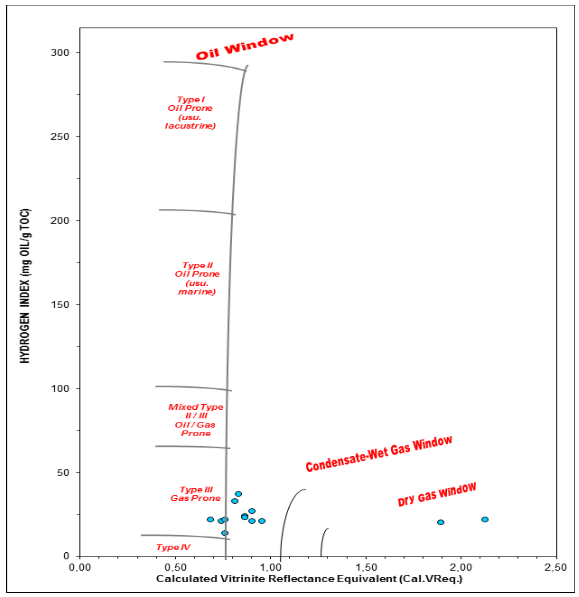


Fig.5. Plot of Hydrogen Index against Calculated Vitrinite Reflectance indicating gas prone kerogen type III organic matter within the oil window and dry gas windows

The plot of Hydrogen Index against Calculated Vitrinite Reflectance (Figure 5) also suggests that the organic matter in the samples is gas prone kerogen Type III within the oil and dry gas windows. The cross plot of S2 against TOC has become a useful tool for comparing the petroleum-generative potential of source rocks [8,43], the slopes of the lines radiating from the origin in the plot are directly related to hydrogen index (HI= S2 × 100/TOC, mg HC/g TOC). The plot of S2 against TOC (Figure 6) shows that the sediments of Nkporo Formation are essentially dry gas prone.

4.3. Thermal Maturity of Organic matter

The thermal maturity of source rock (contained organic matter) corresponds to its maximum pyrolytic yield and S2 peak in the rock evaluation process [44]. Also, the thermal maturity variation of different kerogen types is a function of their thermal evolution with vitrinite reflectance (% R_o) [45]. The thermal evolution of sedimentary organic matter in this study was determined from Tmax, Production Index (PI) and Calculated Vitrinite Reflectance (% Ro). Although, Tmax values may be affected by lower organic matter content, presence of heavy or free hydrocarbons in the S2 peak which may cause the Tmax value to be anomalously low (less than 400°C). Tmax is dependent upon kerogen type, which is a reflection of the kinetics of oil generation. Thus, Tmax should be interpreted in light of kerogen type.

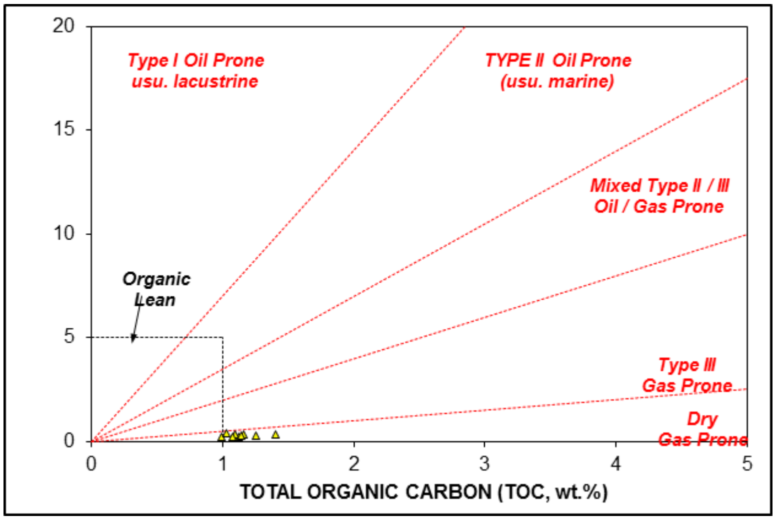


Fig. 6. Plot of S2 against TOC showing high level of thermal maturity of the organic matter and dry gas as the main hydrocarbon type

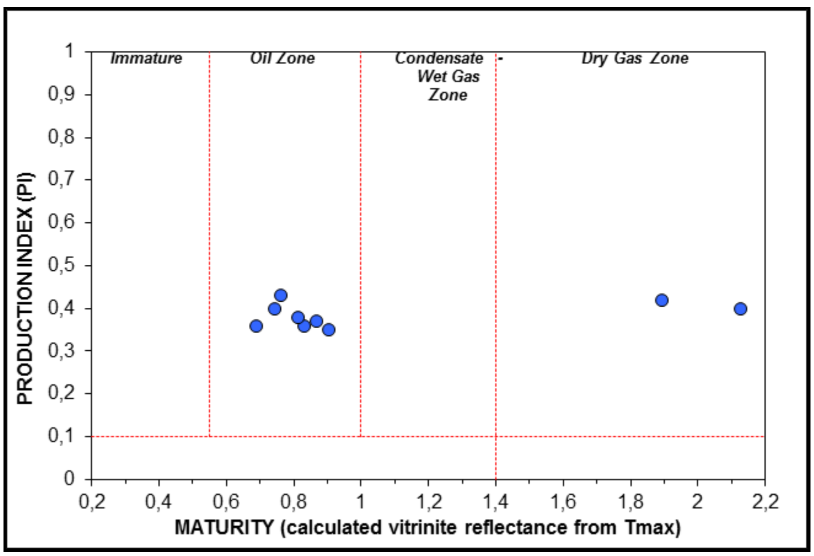


Fig. 7. Plot of Production Index against calculated vitrinite reflectance showing optimum maturity to post maturity of organic matter and oil with little dry gas zones

It was proposed that PI and Tmax values less than about 0.1 and 435°C respectively, indicate immature organic matter while PI and Tmax ranges 0.1 to 0.4 and 435 to 450°C respectively, indicate organic matter from early to the peak of maturity respectively. PI of greater than 0.40 and Tmax of 450 to 470°C and greater indicates late maturity to post maturity [42]. The PI values of the shales of Nkporo Formation range from 0.35 to 0.43 while the Tmax values range from 436°C to 516°C (averaging 454°C). The PI suggests that the samples are at the peak of maturity to late maturity, while the Tmax suggests that they are mature to post mature. The average Tmax (454°C) suggests that the samples are at late maturity with respect to hydrocarbon generation. The calculated vitrinite reflectance values also range between 0.69 to 2.13 % Ro, indicating that the thermal maturity of the samples range from the peak of maturity to post maturity. Averagely, the samples could be described to be at peak of maturity to late maturity with respect to petroleum generation except for samples ranging from 2647 m to 2662 m that are within the dry gas window (post mature) because they have undergone high level conversion.

Furthermore, cross plot of Production Index against Calculated Vitrinite Reflectance (Figure 7) also indicates that the samples belonging to Nkporo Formation are at optimal thermal maturity to post maturity. This is because two samples are within the dry gas zone and the remaining samples are within the oil window. This implies that the expected hydrocarbon type is dry gas. The Production Index is generally expected to increase with increasing depth of burial of organic matter [46]. The Production Index (PI=S1/S1+S2) values of > 0.1 (Table 2) generally observed for the samples indicate possible impregnation by migrated bitumen or contamination by mud additives [47].

4. Conclusions

The lithologies of the Nkporo Formation from Nzam-1 well in the Lower Benue Trough are composed of fine grained and dark grey shales, dark grey sandy shales, fine grained and blocky grey mudstone and fine to medium grained whitish sandstone. The TOC values of the samples range from 0.08 to 1.45 wt. % (av. 1.17 wt. %) indicating that they are potential source rocks for hydrocarbons. Generative potential and TOC suggest poor to fair source rocks with gas potential. The organic matter type is predominantly type III kerogen which is essentially dry gas prone. Thermal maturity derived from Rock-eval data indicated that the samples belonging to Nkporo Formation are at the peak of thermal maturity to post maturity with respect to hydrocarbon generation. It may therefore be summarized that higher thermal condition (post maturity) recorded within a small section (2647-2662 m) of the studied interval together with peak thermal maturity to late maturity in the sediments could be responsible for the dry gas. Despite having good proportion of organic matter in oil window, a dry gas prospect from thermal maturity indicator emphasizes the relevance of thermal maturity to hydrocarbon generation in sedimentary basins.

Acknowledgements

The authors are grateful to the Nigerian Geological Survey Agency for providing the samples. This work benefited from research linkage made during the visit of first author to China few years ago. The visit was supported by the Chinese Academy of Sciences, Third World Academy of Sciences, University of Ibadan and Prof Ran Yong of the Guangzhou Institute of Geochemistry, China.

References

[1] Simpson A. 1954: The Nigeria Coalfield, the Geology of Parts of Onitsha, Owerri and Benue Provinces, Geol. Survey of Nig. Bulletin, 24.

[2] Reyment RA. 1965: Aspect of the Geology of Nigeria. Ibadan University Press, 145p.

[3] Geological Survey of Nigeria. 1974; Geological map of Nigeria. Scale 1:2,000,000. Geological Survey of Nigeria, Kaduna.

[4] Whiteman AJ. 1982: Nigeria; Its Petroleum Geology, Resources and Potentials: London, Graham and Trotman, 394p.

[5] Avbovbo AA and Ayoola O. 1981: Petroleum prospects of the southern Nigeria's Anambra Basin. Oil and Gas Journal, p 334-347.

[6] Unomah GI and Ekweozor, CM. 1993: Petroleum source-rock assessment of the Campanian Nkporo Shale, Lower Benue Trough, Nigeria. NAPE Bull. Vol. 8 (2), 172-186.

[7] Fairhead JD and Green CM. 1989: Controls on rifting in Africa and the regional tectonic model for the Nigeria and East Niger rift basins. J. Afri. Earth Sci. 8: 231-249.
[8] Peters KE. 1986: Guidelines for evaluating petroleum source rock using programmed pyrolysis, AAPG Bull. 70 (3), 318-329.
[9] Baskin DK. 1997; Atomic H/C Ratio of Kerogen as an estimate of Thermal maturity and Organic matter conversion. AAPG Bull. Vol. 81, pp. 1437-1450.
[10] Tissot, BP and Welte DH. 1978; Petroleum Formation and Occurrence. Springer-Verlag, Berlin, 538p.
[11] Agagu OK and Ekweozor, CM. 1982: Source rock characteristics of Senonian shales in the Anambra Syncline, Southern Nigeria. Jour. of Mining and Geology, Vol. 19, 52-61.
[12] Petters SW and Ekweozor CM. 1982: Origin of Mid-Cretaceous Black shales in the Benue Trough, Nigeria. Paleogeography, paleoclimate, Vol. 40, pp 311-319.
[13] Ekweozor CM. (1982): Petroleum Geochemistry: Application to Petroleum Exploration in Nigeria's Lower Benue Trough. Nig. Jour. of Mining and Geology, Vol. 19, pp 122-131.
[14] Ekweozor CM and Gormly JR. 1983: Petroleum Geochemistry of Late Cretaceous and Early Tertiary Shales penetrated by the Akukwa-2 Well in the Anambra Basin, Southern Nigeria. Jour. Pet. Geol. Vol. 6, No. 2, pp 207-216.
[15] Nwachukwu JI. 1985: Petroleum prospects of Benue Trough, Nigeria. AAPG Bull. Vol. 69 (4) pp 601-609.
[16] Agagu OK Fayose EA and Petters SW. 1985: Stratigraphy and Sedimentation in the Senonian Anambra Basin of Eastern Nigeria. Jour. of Mining and Geology, Vol. 22, p.25 – 36.
[17] Akaegbobi IM and Schmitt M. 1998: Organic facies, hydrocarbon source potential and the reconstruction of depositional Paleoenvironment of Campano-Maastrichtian Nkporo shale in the Cretaceous Anambra Basin, Nigeria NAPE Bull. 13(1), 1-19.
[18] Obaje NG, Ulu OK and Petters SW. 1999; Biostratigraphic and geochemical controls of hydrocarbon prospects in the Benue Trough and the Anambra Basin, Nigeria. NAPE Bull. 14(1): 18-54.
[19] Ehinola OA, Badejoko TA, Ekweozor CM and Adebowale KO. 2004: Organic facies in the Middle Cretaceous black shales of the Abakaliki Fold Belt, Southeastern, Nigeria. NAFTA. 55 (12): pp 505-515.
[20] Ehinola OA, Sonibare OO, Falode OA, and Awofala BO. 2005: Hydrocarbon potential and thermal maturity of Nkporo Shale from Lower Benue Trough, Nigeria. Journal of Applied Sciences, 5 (4): pp 689-695.
[21] Ogala JE. 2011: Hydrocarbon potential of the upper Cretaceous coal and shale units in the Anambra basin, southeastern Nigeria. Petroleum & Coal, 53 (1) 35-44.
[22] Adeleye AM, Adeigbe EO and Yuhong L. 2014: Source rock evaluation of the Awgu Formation from Nzam-1 well, Lower Benue Trough, Nigeria. NAPE Bull. Vol 26, No 1, pp 87-100.
[23] Burke KC, Desauvagie TFJ and Whiteman AJ. 1971: Opening of the Gulf of Guinea and geological history of the Benue depression and Niger Delta. Nature, 233, 51-55.
[24] Burke KC, Desauvagie TFJ and Whiteman AJ. 1972: Geological history of the Benue valley and adjacent areas, in T.F.J. Desauvagie and A.J. Whiteman eds. African Geology, Ibadan, Nigeria. Ibadan University Press, pp 187 – 205.
[25] Burke KC and Whiteman AJ. 1973: Uplift, rifting and break-up of Africa. In Implications of continental drift to the earth sciences, (D. H. Tailing and S. K. Runcorn eds), pp. 735-755. Academic Press, London.
[26] Ekweozor CM and Unomah GI. 1990: First Discovery of Oil Shale in the Benue Trough, Nigeria. Fuel, Vol. 69, pp 502-508.

[27] Murat RC. 1972: Stratigraphy and paleogeography of the Cretaceous and Lower Tertiary in Southern Nigeria. In T.F. J. Dessauvigie and A.J. Whiteman eds. African Geology, University of Ibadan press, pp.635 - 648.
[28] Cratchley CR and Jones GP. 1965: An interpretation of the Geology and gravity anomalies of the Benue Trough, Overseas Geological survey, paper 1, 25p.
[29] Desauvagie TFJ. 1974; Geological map of Nigeria (scale 1;1,000,000). Nigerian Mining Geological and Metallurgy Society, Ibadan, Nigeria.
[30] Agagu OK. 1978; Geology and petroleum potentials of the Senonian to Maastrichtian sediments in the Anambra Basin, Eastern Nigeria. Unpublished Phd Thesis, Universisty of Ibadan, Nigeria, 214p.
[31] Agagu OK and Adighije C. 1983: Tectonic and Sedimentation framework of the Lower Benue Trough, Southeastern Nigeria. Jour. African Earth Science, 1, 267-274.
[32] Agumanu AE. 1989; The Abakaliki and Ebonyi Formations: subdivision of the Albian Asu River Group in the southern Benue Trough, Nigeria. J. Afri. Earth Sci. 9, 195-207.
[33] Ojoh KA. 1990; Cretaceous geodynamic of the southern part of the Benue Trough (Nigeria) in the equatorial domain of the South Atlantic. Stratigraphy, basin analysis and paleo-oceanography. Bull. Cent. Rech. Explor.-Prod. Elf-Aquitaine 14, 419-442.
[34] Arua I. 1988; Episodic sedimentation: an example from the Nkporo shale (Campano- Maastrichtian), Nigeria. J. Afri. Earth Sci. 7, 759-762.
[35] Okoro AO and Arua I. 1989; Reconstruction of paleowaveand paleodepth regimes of the Nkporo sea (Campano-Maastrichtian) using wave –formed ripple marks. J. Min. Geol. 25, 75-79.
[36] Mode AW. 1991; Assemblage zones, age and paleoenvironment of the Nkporo shale, Akanu area, Ohafia, southeastern Nigeria. J. Min. Geol. 27, 107-114.
[37] Reyment RA and Morner NA. 1977; Cretaceous Transgressions and Regressions exemplified by the South Atlantic. Palaeontological Society of Japan, Special Papers, No.21, pp.247-261.
[38] Nyong EE. 1995; Geological Excursion Guide book to Calabar Flank and Oban Massif. In the 31st Annual conference of the Nigerian Mining and Geosciences Society, Calabar, March 12-16.
[39] Jarvie DM. 1991: Total organic carbon (TOC) analysis. In: Merril, R.K., (ed.), Treatise of petroleum geology: Handbook of petroleum geology, source and migration processes and evaluation techniques. AAPG Memoir, 113 – 118.
[40] Cornford C. 1986; Source rocks and hydrocarbons of the North Sea. In: Glennie, K.W., (ed.), Introduction to the Petroleum Geology of the North Sea, Oxford, U.K., 197-236.
[41] Tissot BP and Welte DH. 1984: Petroleum Formation and occurrence. 2nd ed., Springer-Verlag, Berlin, 699p.
[42] Peters KE and Cassa MR. 1994: Applied source rock geochemistry. In: The Petroleum System, From Source to Trap (L.B. Magoon and W.G. Dow, eds.), AAPG Memoir, 60, Tulsa, OK, pp. 93-117.
[43] Langford FF and Blanc-Valleron MM. 1990: Interpreting Rock-Eval pyrolysis data using graphs of pyrolyzable hydrocarbons versus total organic carbon. AAPG Bull. 74, 799-804.
[44] Espitalie J, Laporte JL, Madec M, Marquis F, Leplat P, Paulet J and Boutefeu A. 1977: Methode rapide de caracterisation des roches meres, de leur potential petrolier et de leur degre d'evolution. Rev. Inst. Fr. Petr. 32, 23-42.
[45] Espitalie J and Bordenave ML. 1993; Rock-Eval pyrolysis. In: M.L.Boordenave (ed.). Applied Petroleum Geochemistry, pp. 237-261.

[46] Barker C. 1974; Pyrolysis techniques for source rock evaluation. AAPG Bul., Vol. 58, pp. 2354-2361.
[47] Clementz DM. 1979; Effect of oil and bitumen saturation on source-rock pyrolysis. AAPG Bull., 63, 2227-2232.

Correspondence Author Email: mutiuadeleye@gmail.com, Telephone: +234 805 575 1954