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The link to this publication is **https://ajoeer.org.ng/otn/ajoeer/qtr-2/2020/03.pdf**

African Journal of Engineering and Environment Research Vol.1(2) 2020 pp 37 - 51

ISSN: 2635-2974

GEOCHEMICAL AND GEOSTATISTICAL ASSESSMENT OF CRETACEOUS COALS AND SHALES IN SOME NIGERIAN SEDIMENTARY BASINS FOR THEIR HYDROCARBON PRONESS AND MATURITY LEVELS

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ABSTRACT:

*The Rock–Eval pyrolysis and LECO analysis for 9 shale and 12 coal samples, as well as, geostatistical analysis have been used to investigate source rock characteristics, correlation between the assessed parameters (*QI, BI, *S1, S2, S3, HI, S1 + S2, OI, PI, TOC) and the impact of changes in the Tmax on the assessed parameters in the Cretaceous Sokoto, Anambra Basins and Middle Benue Trough of northwestern, southeastern and northcentral Nigeria respectively. The geochemical results point that about 97% of the samples have TOC values greater than the minimum limit value (0.5 wt %) required to induce hydrocarbon generation from source rocks. Meanwhile, the Dukamaje and Taloka shales and Lafia/Obi coal are found to be fair to good source rock for oil generation with slightly higher thermal maturation. The source rocks are generally immature through sub-mature to marginal mature with respect to the oil and gas window, while the potential source rocks from the Anambra Basin are generally sub-mature grading to mature within the oil window. The analyzed data were approached statistically to find some relations such as factors, and clusters concerning the examination of the source rocks. These factors were categorized into type of organic matter and organic richness, thermal maturity and hydrocarbon potency. In addendum, cluster analysis separated the source rocks in the study area into two groups. The source rocks characterized by HI >240 (mg/g), TOC from 58.89 to 66.43 wt %, S1 from 2.01 to 2.54 (mg/g) and S2 from 148.94 to 162.52 (mg/g) indicating good to excellent source rocks with kerogen of type II and type III and are capable of generating oil and gas. Followed by the Source rocks characterized by HI <240 (mg/g), TOC from 0.94 to 36.12 wt%, S1 from 0.14 to 0.72 (mg/g) and S2 from 0.14 to 20.38 (mg/g) indicating poor to good source rocks with kerogen of type III and are capable of generating gas. Howeverr, Pearson's correlation coefficient and linear regression analysis shows a significant positive correlation between TOC and S1, S2 and HI and no correlation between TOC and Tmax, highly negative correlation between TOC and OI and no correlation between Tmax and HI.*

Keywords- Cretaceous, Geochemical, Statistical, Cluster, Factor analyses.

1. INTRODUCTION

Presently data set are being gathered through surveys to enable extensive appraisal of the oil and gas possibilities in the frontier basins of Nigeria by the Nigerian government through the Nigerian National Petroleum Corporation and other investors. These basins include the Anambra Basin, Benue Trough, Bida Basin, Chad Basin (Nigerian sector), Dahomey Basin and Sokoto Basins (Fig. 1). The oil and gas potency in the basins will depend on the fortune of the elements that make up the petroleum system. The elements include organically rich, mature source rocks and their volumes, porous and permeable reservoir rocks and seal lithologies, effective generation, expulsion and migration into reservoirs, availability of trapping mechanisms and timing of generation, expulsion and migration in relation to other events. At the centre of the petroleum system is the availability of organically rich, mature source rocks. Source rocks for petroleum generation are usually shales, carbonates and coals.

The northwestern Nigeria Sokoto Basin occupies the geographical Sokoto State, and parts of Zamfara and Kebbi State, covers about 20% of the northeastern region of Nigeria. It is considered as one of the promising basins in the country with good potential oil and gas deposits with area of about 60,000 km^2 and is also the least studied basin in Nigeria (Obaje et al., 2013, 2020a, 2020b). Potential hydrocarbon source rocks exposed in outcrops and stratigraphic sections in the Sokoto Basin, and a preliminary assessment of the hydrocarbon prospectivity using the organic geochemical tools (LECO and Rock-Eval pyrolysis analysis) had earlier been studied (Obaje et al., 2013, 2020a). They identified the source to be mainly the carbonaceous Dukamaje and/or Taloka shales. These methods are used in determining the thermal maturation of kerogen. Behar et al. (2001) defined the thermal parameters based on which maximum temperature (Tmax) can be used to model the proportions of the oil window. Thermal maturity of sediments can be ascertained with production of graph that plots Tmax values versus HI. In this study, we used both geochemical and statistical analyses for evaluating the source rocks in the northwestern Sokoto Basin.

In this study, both geochemical and statistical analyses were used for evaluating the source rocks and discriminate the maturity and hydrocarbon potentialities of the northwestern Lower and Middle Maastrichtian source rocks in the northwestern Sokoto Basin, the Campanian-Maastrichtian source rocks in the Anambra Basin and the Late Turonian – Early Santonian source rocks of the Middle Benue Trough. This work has studied the geochemical properties of organic material, thermal maturation and affluence of hydrocarbon in order to square up the petroleum potency of the source rocks. The intention of this study is to set up indices for a unified appraisal of organic material for petroleum potency evaluation and pivot on multivariate statistical analysis and cross-plots of TOC, and parameters of Rock-Eval pyrolysis. With speculative and analytical examination, we anticipate to uncover that the utility of nine (9) parameters (S1, S2, S3, S1+S2, HI, OI, PI, TOC, QI) increase as the thermal maturity of organic materials increase during the initial stage of thermal maturation. In addendum, this study is to style the affinities between organic material and thermal maturity.

2. GEOLOGICAL / STRATIGRAPHY SETTING

The discussion on the geological setting focuses on the Sokoto Basin being the south-eastern portion of the larger Iullemmeden Basin, the Anambra Basin and the Middle Benue Trough. This geological setting hosts the appraised carbonaceous shale and coal deposits (Fig. 1, 2, 3, 4).

2.1 The northwestern Sokoto Basin

Kogbe (1979, 1981) carried out a work on geology of the south-eastern (Sokoto) sector of the Iullemmeden Basin and produced a detailed geological map of the Sokoto Basin. Obaje (1987) worked on the Foraminiferal biostratigraphy and paleoenvironment of the Sokoto Basin of NW Nigeria. Obaje, 2009 in his book titled 'The Geology and Mineral Resources of Nigeria' give a detailed stratigraphic description of the formations within the basin. The main lithologies of the northwestern Sokoto Basin range in chronology from Pre-Maastrichtian to Eocene (Kogbe, 1981; Obaje, 1987, 2009; Obaje et al., 2020b) (Fig. 2). The stratigraphic rock units comprise continental and marine sediments (Fig. 2). The Pre-Maastrichtian part is represented by siliciclastics Gundumi-Illo Formation. This formation is wholly grits and clays that constitute the Pre-Maastrichtian 'Continental Intercalaire' which rest unconformably on the Pre Cambrian basement rocks of the northwestern Nigeria (Fig. 2). The Pre-Maastrichtian Gundumi-Illo Formation also unconformably underlies the Rima Group which comprise of the Taloka, Dukamaje and Wurno Formations. The Lower Maastrichtian Taloka Formation is composed mainly mudstone and friable sandstones and shales with coal seems, and is overlain conformably by Middle Maastrichtian marine Dukamaje Formation (Fig. 2) composed mainly of fossiliferous, calcareous and shales. The Dokamaje Formation is overlain conformably by Upper Maastrichtian Wurno Formation. The continental sandstone of the Wurno Formation are overlain unconformably by Paleocene units of Sokoto Group (Fig. 2). The Paleocene units comprise the Dange, Kalambaina and Gamba Formations. The Dange Formation (Lower Paleocene) composed of mainly marine shales. Kalambaina Formation represents a calcareous sequence. Gamba Formation consist of mainly marine shales, and it is uncoformably overlain by Eocene continental Gwandu Formation (Fig. 2) which forms the Eocene Continental Terminal.

2.2 The Anambra Basin

The Anambra Basin is sometimes seen as an integral unit of the Lower Benue Trough (Figs. 1 and Fig. 3). During the Santonian, upheavals (epeirogenic) movements, these sediments experience flexure and uplifted into the Abakaliki-Benue Anticlinorium (Murat, 1972) with synchronous subsidence of the Anambra Basin and the Afikpo sub- basins to the northwest and southeast of the folded belt respectively (Murat, 1972; Mode and Onuoha, 2001; Adamu et al., 2017). The Abakaliki Anticlinorium later served as a sediment disbandment centre from which sediments were shifted into the Anambra Basin and Afikpo Syncline. The Cameroon basement complex, Oban Masif and southwestern Nigeria basement craton also served as sources for the sediments of the Anambra Basin (Nwajide and Reijers, 1996; Nwajide, 2014). Post-deformational sedimentation in the Lower Benue Trough, therefore, constitutes the Anambra Basin. After the development of the Anambra Basin following the Santonian epeirogeny, the Campanian-early Maastrichtian transgression deposited the Nkporo Group (i.e the Enugu Formation, Owelli Sandstone, Nkporo Shale, Afikpo Sandstone, Otobi Sandstone and Lafia Sandstone) as the basal unit of the basin, unconformably overlying the Awgu Formation. This was followed by the Maastrichtian regressive event during which the coal measures (i.e. the Mamu, Ajali and Nsukka Formations) were deposited. The Enugu and the Nkporo Shales represent the pro–delta fossiliferous facies of the Late Campano–Maastrichtian depositional cycle (Obaje, 2009; Nwajide, 2014). Deposition of the sediments of the Nkporo/Enugu Formations reflects a funnel-shaped shallow marine setting that graded into channeled low-energy marshes. The coal-bearing Mamu Formation and the Ajali Sandstone accumulated during this epoch of overall regression of the Nkporo cycle. The Mamu Formation occurs as a narrow strip trending north-south from the Calabar Flank, swinging west around the Ankpa plateau and terminating at Idah near the River Niger (Obaje, 2009; Nwajide, 2014; Adamu et al., 2018). The Ajali Sandstone marks the height of the regression at a time when the coastline was still concave. The converging littoral drift cells governed the sedimentation and are reflected in the tidal sand waves which are characteristic for the Ajali Sandstone (Adamu et al., 2017; Obaje et al., 1999; Nwajide, 2013; Adebayo et al., 2015; Adegbai et al., 2019; Dim et al., 2019).

2.3 The Middle Benue Trough

In the Middle Benue Trough, Obaje et al. (2004) and Abubakar et al. (2006) around the Obi/Lafia area, mapped six Upper Cretaceous lithogenic formations comprise the stratigraphic succession (Fig. 4). This succession is made up of Albian Arufu, Uomba and Gboko Formations (Asu River Group of Offodile, 1976; Nwajide, 1990). These are overlain by the Cenomanian – Turonian Keana and Awe Formations and the Cenomanian – Turonian Ezeaku Formation. The Ezeaku Formation is coterminous with the Konshisha River Group and the Wadata Limestone in the Makurdi area. The Late Turonian – Early Santonian coal-bearing Awgu Formation lies conformably on the Ezeaku Formation (Obaje, 2009).

3. SAMPLES AND METHODS

3.1 Geochemical analysis

Twenty-one (21) selected shale and coal rock ditch and field samples from Dukamaje and Taloka Formations of the northwestern Sokoto Basin, Enugu and Mamu Formations of the Anambra Basin and Awgu Formation of the Middle Benue Trough (Table 1) were analyzed for total organic carbon, and Rock–Eval pyrolysis. The LECO TOC content and Rock–Eval pyrolysis analyses were made partly in the laboratories of Geo-data GmbH Garbsen and partly at BGR Hannover, both in Germany through the instrumentality of the 2nd author (NGO). The Analyses were performed on 70 mg to 100 mg crushed whole rock samples, heated to 600^{o}C in a helium atmosphere, using a LECO and Rock–Eval 6 unit.

3.2 Statistical analysis

Multivariate statistical analysis was applied to evaluate the source rock potentiality and clarify the relationship between petroleum potential and maturity. The results obtained for studied samples were statistically analyzed using cluster analysis (hierarchical and K-means cluster analysis), Factor analysis, linear regression and Pearson's correlation by SPSS 15.0 (Zhang et al. 2007).

3.2.1. Cluster Analysis

Cluster analysis is based on a matrix measuring the differences between each parameter of each sample. Two basic types of cluster analyses are known: K-Means and hierarchical types. For K-means analysis, it is necessary to define the number of groups into which the samples/parameters are to be classified, while hierarchical cluster analysis enables the grouping of the samples or parameters without any previous classification (El-Nady and Lotfy, 2016). These differences are squared. By adding the individual matrices, a summed matrix is obtained. In the case when the values of the parameters are essentially different, they should preliminarily be standardized, in order that in the final matrix each parameter becomes an equal share. Based on the final matrix, a dendrogram is constructed, which involves all samples or parameters being classified into groups on the basis of all data taken into consideration (Golobocˇanin, 2004).

3.2.2. Factor Analysis

According to Joreskog, et al. (1978), the statistical method used for combining a large number of data into a considerably smaller number of factors, representing groups of initially mutually linearly dependent parameters containing the same amount of information as their constituent parameters is known as Factor analysis. The values of the coefficients preceding the parameters, marked as loadings, define the significance of a particular parameter in the characterization of an analyzed group of samples. The significance of a particular factor is defined by its characteristic value and percent of variance (Reimann, et al. 2000; Solevic, et al. 2008). In order to determine the relationship between the parameters for the sake of classification of the samples, an interdependence diagram of two factors may be constructed (Golovko and Pevneva, 2013). In the case when the parameters are defining factors reflecting certain types of reaction characteristic for the investigated group of samples, the course of these processes and their mutual agreement can be proven by constructing corresponding correlation diagrams of these factors (Golovko and Pevneva, 2013).

3.2.3. Pearson's Correlation Coefficient and Linear Regression

El-Nady and Lotfy, (2016) described Pearson's correlation coefficient is as a statistical measure of the strength of a linear relationship between paired data. The correlation coefficient can range from -1 to +1, with -1 indicating a perfect negative correlation, +1 indicating a perfect positive correlation, and 0 indicating no correlation at all. (A variable correlated with it will always have a correlation coefficient of 1). Linear regression is the next step after correlation. It is used when we want to predict the value of a variable based on the value of another variable. The variable we want to predict is called the dependent or outcome variable. The variable we are using to predict the other variable's value is called the independent or the predictor variable (El-Nady and Lotfy, 2016).

4. RESULTS AND DISCUSSION

4.1. Geochemical methods

In order to examine the organic carbon content and source rock maturity different factors including quality and quantity of organic matter, generating potentialities, type of organic matter and thermal maturation were considered.

4.1.1. Quality and quantity of organic matter

The organic carbon richness of the rock samples (TOC %), is important in the examination of sediments as a source for petroleum. Tissot and Welte (1984), Peters and Cassa (1994), Peters (1986), Nton and Awarun (2011), Atta-Peters and Garrey (2014), Adilbi et al. (2019), El Nady et al. (2018), Koji et al. (2020) and Xiangxin et al. (2020) presented a scale for the assessment of source rocks potency, based on the TOC% and Rock–Eval pyrolysis data, such as S1 and S2. The procured data set in Table 1 show that the total organic carbon content values for the northwestern Sokoto Basin source rocks are between 0.94 and 7.00 wt% indicating fair to good source rocks, the values for the Anambra Basin source rocks are between 2.46 and 66.43 wt% indicating good to excellent source rocks. While the Middle Benue Trough source rocks are between 34.93 and 36.12 wt % indicating good to excellent source rocks. This assumption is validated by the plot of TOC (wt %) versus S2 (Fig. 5a). Also, the plot of S1 versus TOC (Fig. 5b) according to Ghori and Haines, (2007), can be used to discriminate between indigenous (autochthonous) and nonindigenous (allochthonous) hydrocarbons. This relation points that all of the studied rock samples for the Sokoto, Anambra Basins and Middle Benue Trough source rocks were characterized by autochthonous hydrocarbons showing that oil in the studied source rocks originate from within the studied basins.

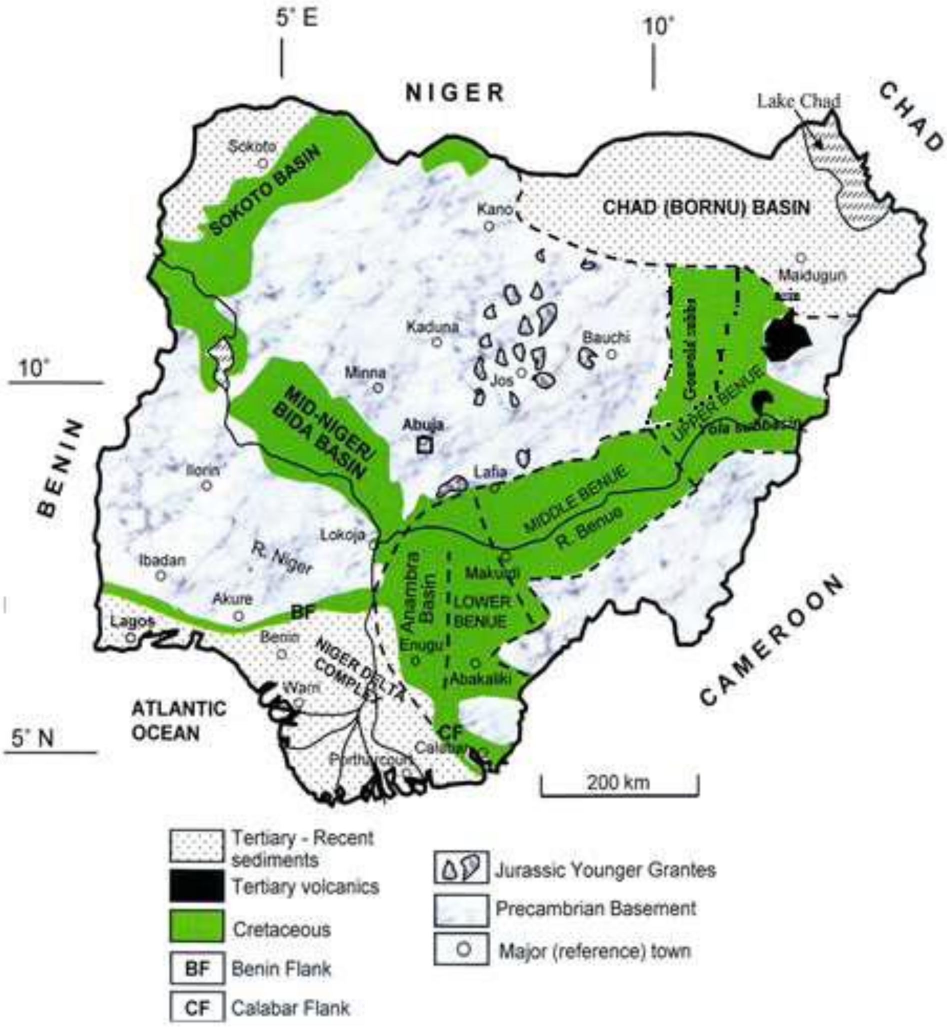

Figure 1 Generalized Geological sketch map of Nigeria showing the major geological components; Basement, Younger Granites, and Sedimentary Basins (Modified after Obaje, 2009)

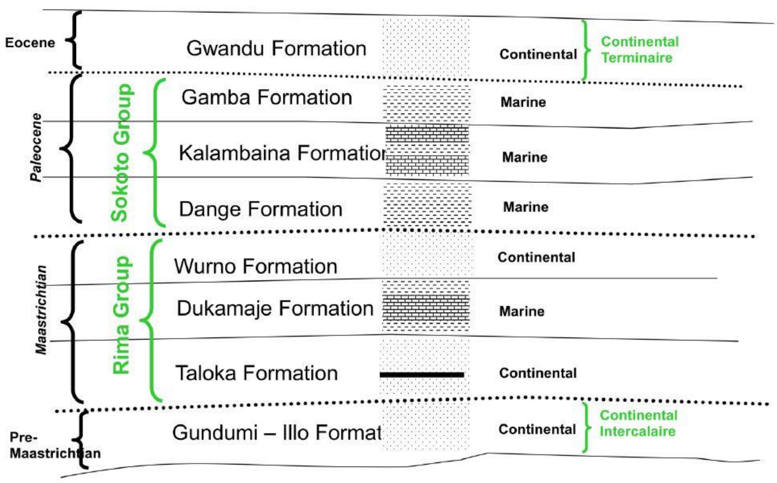

Figure 2 Stratigraphic successions in the Nigerian sector of the lullummeden Basin (Sokoto Basin) (Obaje, 2009)

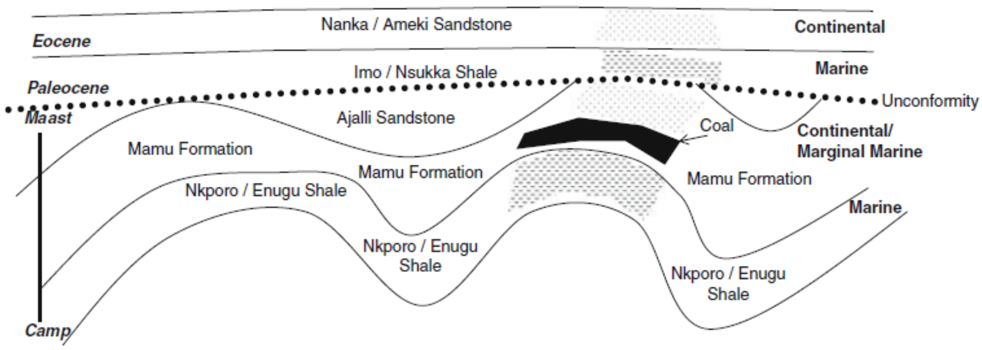

Figure 3 Stratigraphic successions in the Anambra Basin (After Obaje, 2009)

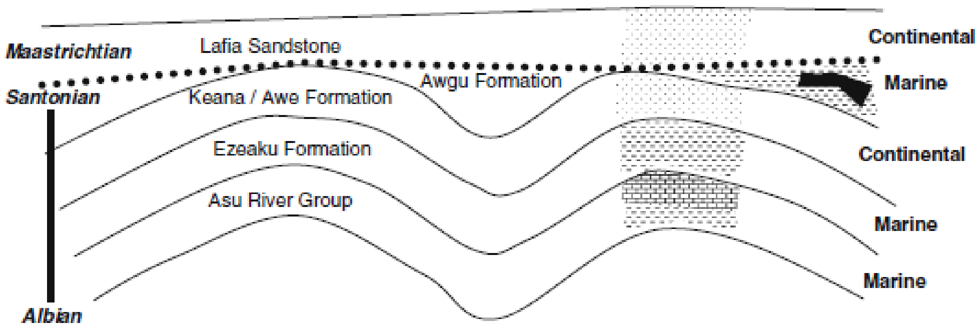

Figure 4 Stratigraphic successions in the Middle Benue Trough (After Obaje, 2009)

Table 1 Carbon determination (LECO) and Rock–Eval pyrolysis of the source rock samples from northwestern Sokoto and Anambra Basins, Nigeria

	DK1	DK2	DK3	DK4	DK5	TK1	TK2	IB1	IB1	OK1	OK2	OK3	ES1	ES2	ONY1	ONY2	LO1	LO2	LO3	LO4	LO5	LO6
TOC	3.24	2.46	2.52	0.98	2.89	6.63	1.38	61.79	60.98	59.21	60.36	61.58	2.46	2.54	66.72	68.75	35.99	34.76	36.12	35.78	35.89	34.93
S1	0.49	0.38	0.33	0.33	0.45	0.72	0.14	2.01	2.09	2.23	1.41	1.83	0.050	0.10	2.10	2.10	0.52	0.48	0.50	0.54	0.51	0.50
S2	3.32	2.59	1.11	0.33	2.93	3.02	0.13	148.71	143.99	151.92	166.04	168.47	0.973	1.17	162.49	168.11	19.59	18.99	19.71	20.11	19.12	20.38
S3	0.71	0.51	1.35	0.40	0.64	5.08	0.50	6.24	6.11	10.79	11.94	12.01	0.904	0.96	2.43	2.81	10.85	10.62	11.01	10.94	10.77	10.73
HI	102.47	105.28	44.05	33.67	101.38	45.55	9.42	2.40	236.13	256.58	275.08	273.58	39.55	46.06	243.54	244.52	54.43	54.63	54.57	56.20	53.27	58.35
OI	21.91	20.73	53.57	40.82	22.15	76.62	36.23	10.09	10.02	18.22	19.78	19.50	36.75	37.80	3.64	4.09	30.15	30.55	30.48	30.58	30.00	30.72
PI	0.13	1.13	0.23	0.50	0.13	0.19	0.52	0.01	0.01	0.01	0.008	0.01	0.05	0.08	0.01	0.01	0.03	0.02	0.02	0.03	0.03	0.02
Tmax	418	416	407	413	418	427	412	421	421	421	421	420	410	412	430	430	452	451	452	450	451	451
QI	1.18	1.21	0.57	0.67	1.17	0.56	0.20	2.44	2.40	2.60	2.77	2.77	0.42	0.50	2.47	2.48	0.56	0.56	0.56	0.58	0.55	0.60
B1	0.15	0.15	0.13	0.34	0.16	0.11	0.10	0.03	0.03	0.04	0.02	0.03	0.02	0.04	0.03	0.03	0.01	0.01	0.01	0.02	0.01	0.01
GP	3.81	2.97	1.14	0.66	3.38	3.74	0.27	150.72	146.08	154.15	167.45	170.30	1.023	1.27	164.59	170.21	20.11	19.47	20.21	20.65	19.63	20.88

S1: mgHC/g rock; S2: mgCO2/g rock; HI (hydrogen index): mgHC/g TOC; OI (oxygen index): mgCO2/g TOC;
PI (Production index) S1/(S1+S2)
QI (Quality index) (S1+S2)/TOC;
BI (Bitumen index) S1/TOC;
GP (Generating potential) S1+ S2.

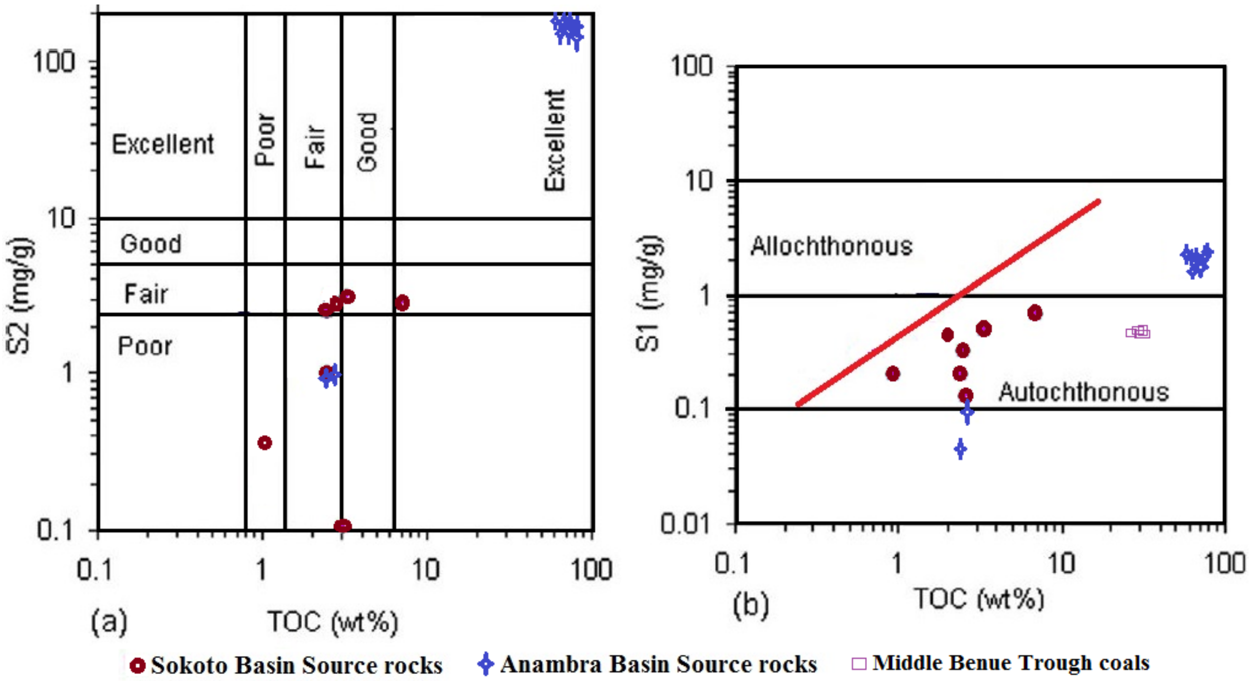

Figure 5 Quality and quantity of organic matter of Sokoto and Anambra Basin and Middle Benue Trough source rocks, Nigeria

4.1.2. Hydrocarbon generating potency

The generation potency of a source rock is identified using the results of pyrolysis analysis. The genetic potency (GP) is the sum of the values S1 and S2. According to Hunt (1996) source rocks with a GP <2, from 2 to 5, from 5 to 10 and >10 are considered to have poor, fair, good, and very good generation potence, respectively. The relationship between (S1+ S2) and TOC (Waples, 1985; El Nady and Lotfy, 2016). (Fig. 6a) shows that the Sokoto Basin (Dukamaje and Taloka shales) and the Middle Benue Trough source rocks are considered as fair to good source potential except few samples that are considered as poor source potential while the Anambra Basin source rocks are considered as good to excellent source potential. On the other hand, the plot of TOC (wt%) versus HI mg/g (Fig. 6b) shows that the Sokoto Basin and Anambra Basin source rocks are non-oil or gas source rocks.

4.1.3. Genetic organic matter

In petroleum prospectivity, the initial genetic type of organic matter of a particular source rock is essential for the prediction of oil and gas potential. Waples (1985); El Nady et al. (2018, 2016) and Koji et al. (2020) used the hydrogen index values (HI) to differentiate between the types of organic matter. Hydrogen indices <150 mg/g indicate a potential source for generating gas (mainly type III kerogen). Hydrogen indices between 150 and 300 mg/g contain more type III kerogen than type II and therefore are capable of generating mixed gas and oil but mainly gas. Kerogen with hydrogen indices >300 mg/g contains a substantial amount of type II macerals and thus are considered to have good source potential for generating oil and minor gas. Kerogen with hydrogen indices >600 mg/g usually consists of nearly type I or type II kerogen, they have excellent potential to generate oil.

In this study, we used Langford and Blanc-Valleron (1990) and; Bordenove et al., (1993) kerogen type diagram which represents the plot TOC versus S2 (Fig. 7a).This diagram shows that the Sokoto Basin and Middle Benue Trough source rocks are characterized by kerogen of type III, while the Anambra Basin source rocks are characterized by type II and type III. Based on pyrolysis data kerogen classification diagrams were constructed using the HI versus OI plot as opined by Van Krevelen (1961), popularly used to determine the kerogen type (Fig. 7b). The results show that the analyzed Sokoto Basin samples are generally plotted under type III kerogen, while the analyzed Anambra Basin samples are plotted in kerogen of type III and type II. Therefore, Anambra Basin samples contain mixed kerogen types II–III. These kerogen types are derived from land plants and preserved remains of algae (Peters et al. 1994). Mixed kerogen type characterizes mixed environment containing admixture of continental and marginal marine organic matter and has the ability to generate oil and gas accumulations (Hunt, 1996).

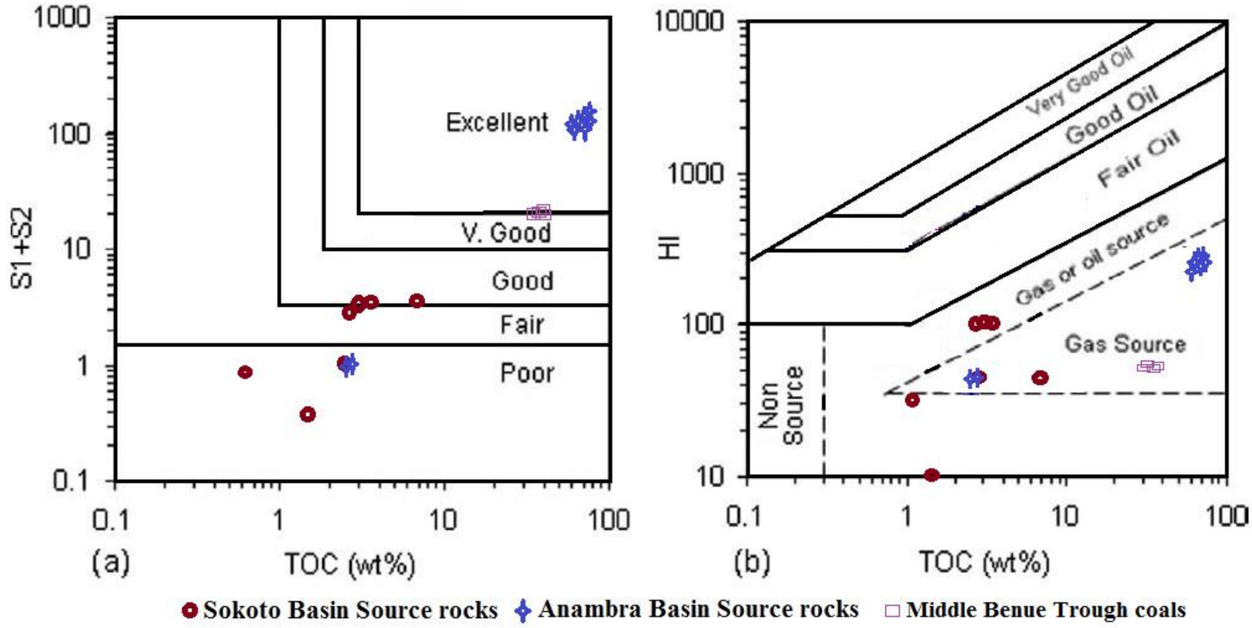

Figure 6 Generating potency of source rocks of Sokoto, Anambra Basins and Lower Benue Trough source rocks, Nigeria

4.1.4. Thermal maturation

According to Tissot and Welte (1984); Xiangxin et al. (2020); Lai et al. (2018); Zhao et al. (2014); Zou et al. (2019); Han et al. (2017) and Hakimi et al. (2016), the generation of petroleum from the organic matter during its burial history is a part of the overall process of thermal metamorphism of organic matter. The concentration and distribution of hydrocarbons inhibited in a particular source rely on both the type of the organic matter and its degree of thermal alteration (Tissot and Welte, 1984; Nton and Awarun, 2011; Adilbi et al. 2019; Koji et al. 2020; Xiangxin et al. 2020 and Langford and Blanc-Valleron, 1990). In the present study, the thermal maturity level of the source rocks has been unraveled by the examination of the geochemical parameters as Rock–Eval pyrolysis ‘‘Tmax’’, production index ‘‘PI’’ (Hunt, 1996; Espitalie et al., 1985). Peters (1986); Espitalie et al. (1985); El Nady and Hammad, (2015) and Pitman and Rowan, (2012) reported that oil generation from source rocks began at Tmax = 435–465 ºC. Production index ‘‘PI’’ between 0.2 and 0.4, the organic matters are in immature stage when ‘‘Tmax’’ has a value less than 435 ºC, and ‘‘PI’’ less than 0.2 and the gas generation from source rocks began at ‘‘Tmax’’ 470 ºC, and production index ‘‘PI’’ more than 0.4. Based on pyrolysis data kerogen classification diagrams were constructed using the HI versus Tmax plot as carried out by (Espitalie et al.,1985; Nunn, 2012) which is used to determine the kerogen type and maturity (Fig. 7a). The results show that the analyzed Sokoto Basin and Middle Benue Trough samples are generally plotted in the immature zone of type III kerogen, while the analyzed Anambra Basin samples are plotted in the immature zone grading to marginally mature zone with kerogen of type III and type II. The plot of Tmax versus PI diagram (Peters, 1986; Waples, 1985; Nunn, 2012) (Fig. 7b) indicates that the Sokoto Basin and Middle Benue Trough source rocks are immature source rocks while, the Anambra Basin source rocks grade from immature to marginally mature.

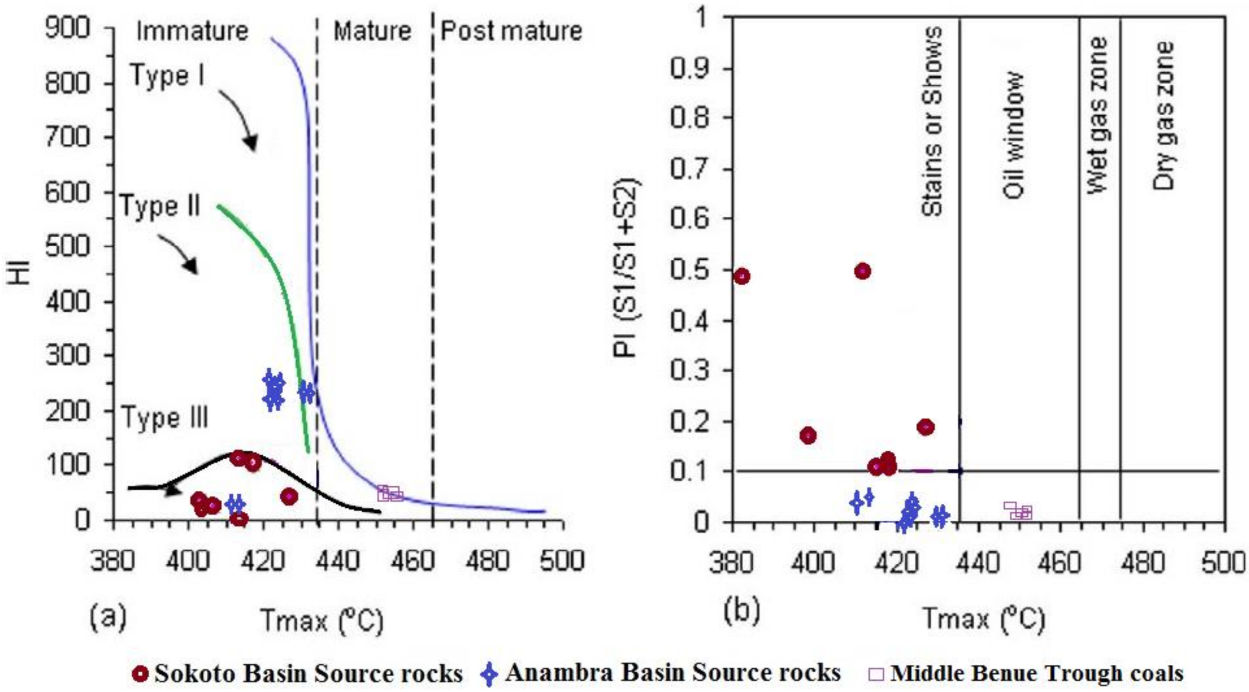

Figure 7 Thermal maturation and genetic type of organic matter of Sokoto, Anambra Basins and Lower Benue Trough source rocks, Nigeria

4.2. Statistical methods

The multivariate statistical analysis is the construction of cluster analysis (hierarchical and K-means cluster analysis), Factor analysis, linear regression and Pearson's correlation.

4.2.1. Cluster analysis

The set of 9 source parameters (Tmax, HI, OI, PI, S1, S2, S3, TOC, S1 + S2) were subjected to hierarchical cluster analysis using the standard method, which was proven to be the most reliable according to the up-to-date organic geochemical investigations (El-Nady and Lotfy, 2016; El Nady et al. 2018; Koji et al. 2020; Xiangxin et al. 2020). Based on the different HI values, the samples were distinguished into two main clusters. The first one (cluster I) of high HI values greater than 240 mg/g and the second (cluster II) of HI values lower than 240 mg/g. However, the samples of cluster II of comparable HI values have showed variability in other parameters like TOC, S1, S2 and Tmax. The resulting dendrogram (Fig. 8) showed two types of clusters which reflect two types of source rocks. Cluster I that represents Anambra Basin source rock is found to be a fair source rock for oil generation with slightly higher thermal maturation and characterized by HI ranging from 241 to 258 mgHC/g. TOC reflecting that these source rocks were characterized by kerogen type II and III. Cluster II mainly represents Dukamaje Formation with subordinate Taloka Formation of the Sokoto Basin, Enugu Shale of the Anambra Basin and the Lafia Obi coal of the Lower Benue Trough which are characterized by HI ranging from 9 to 105 mgHC/g. TOC reflecting kerogen type III. By applying K-means cluster analysis on the same set of source parameters, the results showed that 71.40% of all samples belong to cluster II while 28.60% of the samples belong to cluster I (Fig. 8).

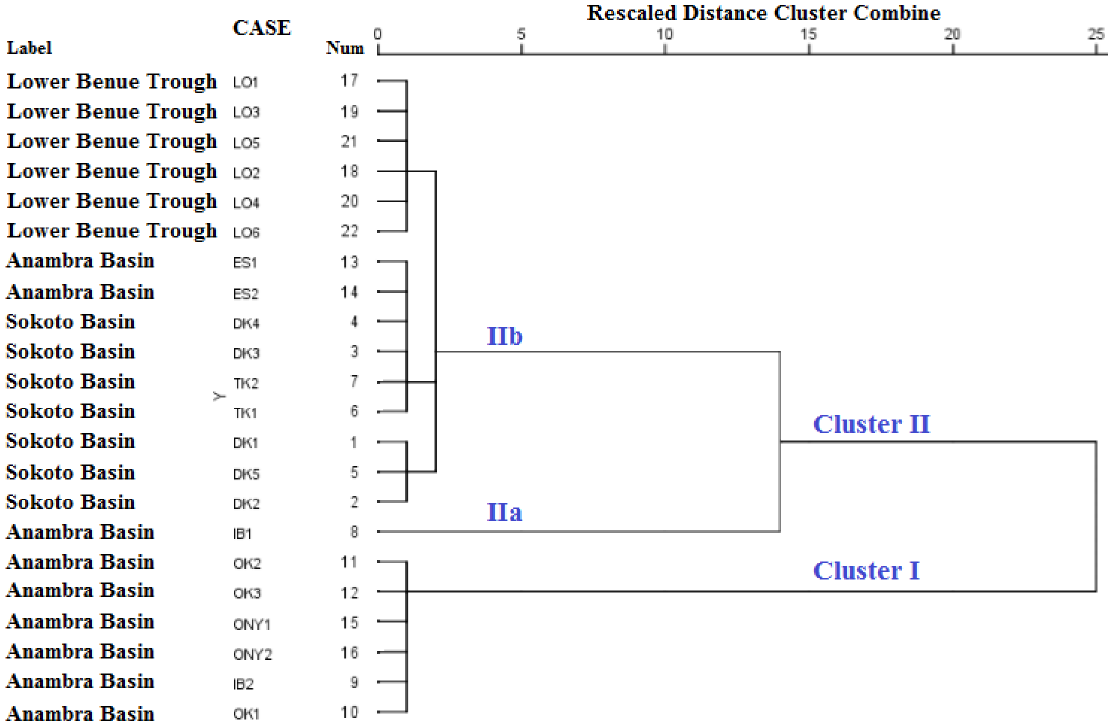

Figure 8 Hierarchical cluster analysis dendrogram using average linkage (between groups)

4.2.2. Factor analysis

To get a more detailed classification of the source rock potential in the study area, a factor analysis of the source parameters was carried out using principle component analysis (Table 2). According to up-to-date organic geochemical investigations, this method has been shown to be the most convenient (Espitalie et al., 1985; Wilhelms et al. 1998). Factor analysis showed that there are two factors affecting the source rocks evaluation potentiality in the study area, factor 1 includes (TOC, S1 and S2) which determine the quantity of the organic matter and (Tmax and PI) which determine the thermal maturity of the organic matter.

On the other hand, factor 2 includes (HI, QI and BI) which determine the quality of the organic matter. The results of the factor analysis shows two distinct groups of source rocks. Group 1 represented Anambra Basin except sample (ES1, ES2 and IB1) and Group II was classified into two subgroups: IB1 (Anambra Basin) and Sokoto Basin and Middle Benue Trough samples. In totality, factor analysis shows that evaluating the source rocks rely on determining hydrocarbon potency, organic richness, type of organic matter, and thermal maturity. Correlating the results derived by application of factor and cluster analyses methods; corroborate the existence of two distinct source rock types.

Table 2 Factor analysis of the measured parameters in the study area.

Variable	Factor 1	Factor 2
TOC	0.960	-0.206
S1	0.935	0.210
S2	0.968	0.198
S3	0.482	-0.741
HI	0.824	0.291
OI	-0.734	-0.186
PI	-0.521	0.544
TMAX	0.133	-0.881
Q1	0.909	0.380
B1	-0.534	0.651
GP	0.969	0.198
Eigen value	6.520	2.474
Of Variance%	59.270	22.487
Cumulative%	59.270	81.758

4.2.3. Pearson's correlation coefficient and linear regression analyses

To investigate the relation between the assessed parameters (S1, S2, S1 + S2, HI, QI, BI, PI, TOC) of petroleum potentiality and to investigate the impact of changes in the Tmax and Ro% on these parameters, we applied Pearson's correlation (Table 3) and linear regression analysis (Table 4). The Pearson's correlation analysis shows a strong positive correlation between TOC and S1 and S2 (Table 3, Fig. 9a and 9f) indicates the contribution of S1 and S2 from TOC. Furthermore, highly positive correlation between TOC and HI (Fig. 9d), highly negative correlation with oxygen index (Fig. 9b) and little to no correlation between TOC and Tmax (Fig. 9e) and PI indicate that the maturity of source rocks is independent of the amount of organic matter (Reimann et al. 2002). Highly positive correlation between S1 and S2 (Fig. 9f) and also between S2 and HI in addition to no correlation between Tmax and HI (Fig. 9c) illustrate that the highest HI occurs at certain maturities and does not occur in stages of less maturity or over maturity. Highly negative reverse correlation between HI and OI was also shown (Fig. 9b). The values of BI and QI showed an increase in their values at the early stage of maturity and then gradually declined with increasing maturity.

Table 3 Correlation matrix of the parameters in the studied source rocks

	TOC	S1	S2	S3	HI	OI	PI	TMAX	Q1	B1	GP
TOC	1	0.877**	0.901**	0.615**	0.685**	-0.677**	-0.557**	0.356	0.784**	-0.610**	0.901**
S1	0.877**	1	0.959**	0.283	0.775**	-0.650**	-0.380	-0.040	0.930**	-0.322	0.960**
S2	0.901**	0.959**	1	0.329	0.823**	-0.687**	-0.402	-0.071	0.955**	-0.389	1.000**
S3	0.615**	0.283	0.329	1	0.241	-0.117	-0.520*	0.716**	0.201	-0.628**	0.328
HI	0.685**	0.775**	0.823**	0.241	1	-0.596**	-0.247	-0.126	0.857**	-0.237	0.823**
OI	-0.677**	-0.650**	-0.687**	-0.117	-0.596**	1	0.184	-0.061	-0.711**	0.306	-0.687**
PI	-0.557**	-0.380	-0.402	-0.520*	-0.247	0.184	1	-0.387	-0.258	0.620**	-0.402
TMAX	0.356	-0.040	-0.071	0.716**	-0.126	-0.061	-0.387	1	-0.219	-0.521*	-0.071
Q1	0.784**	0.930**	0.955**	0.201	0.857**	-0.711**	-0.258	-0.219	1	-0.213	0.955**
B1	-0.610**	-0.322	-0.389	-0.628**	-0.237	0.306	0.620**	-0.521*	-0.213	1	-0.388
GP	0.901**	0.960**	1.000**	0.328	0.823**	-0.687**	-0.402	-0.071	0.955**	-0.388	1

**. Correlation is significant at the 0.01 level (2-tailed).

*. Correlation is significant at the 0.05 level (2-tailed).

Table 4 Linear regression coefficients of the parameters in the studied source rocks

Model		Unstandardized Coefficients		Standardized Coefficients	t	Sig.	Correlations		
		B	Std. Error	Beta			Zero-order	Partial	Part
1	(Constant)	-64.731	74.113		-.873	.401			
	TOC	-.005	.362	-.021	-.014	.989	.463	-.004	-.001
	S1	-4.464	3.871	-.533	-1.153	.273	.043	-.328	-.101
	S3	-.022	.350	-.016	-.062	.952	.660	-.019	-.005
	HI	.013	.013	.196	1.030	.325	.011	.297	.091
	OI	-.077	.095	-.195	-.816	.432	-.163	-.239	-.072
	PI	-3.309	2.992	-.135	-1.106	.292	-.569	-.316	-.097
	TMAX	.202	.186	.496	1.088	.300	.811	.312	.096
	Q1	-9.348	4.603	-1.355	-2.031	.067	-.115	-.522	-.178
	B1	-13.407	11.994	-.166	-1.118	.287	-.736	-.319	-.098
	GP	.139	.133	1.558	1.050	.316	.108	.302	.092

a. Dependent Variable: Sample_ID

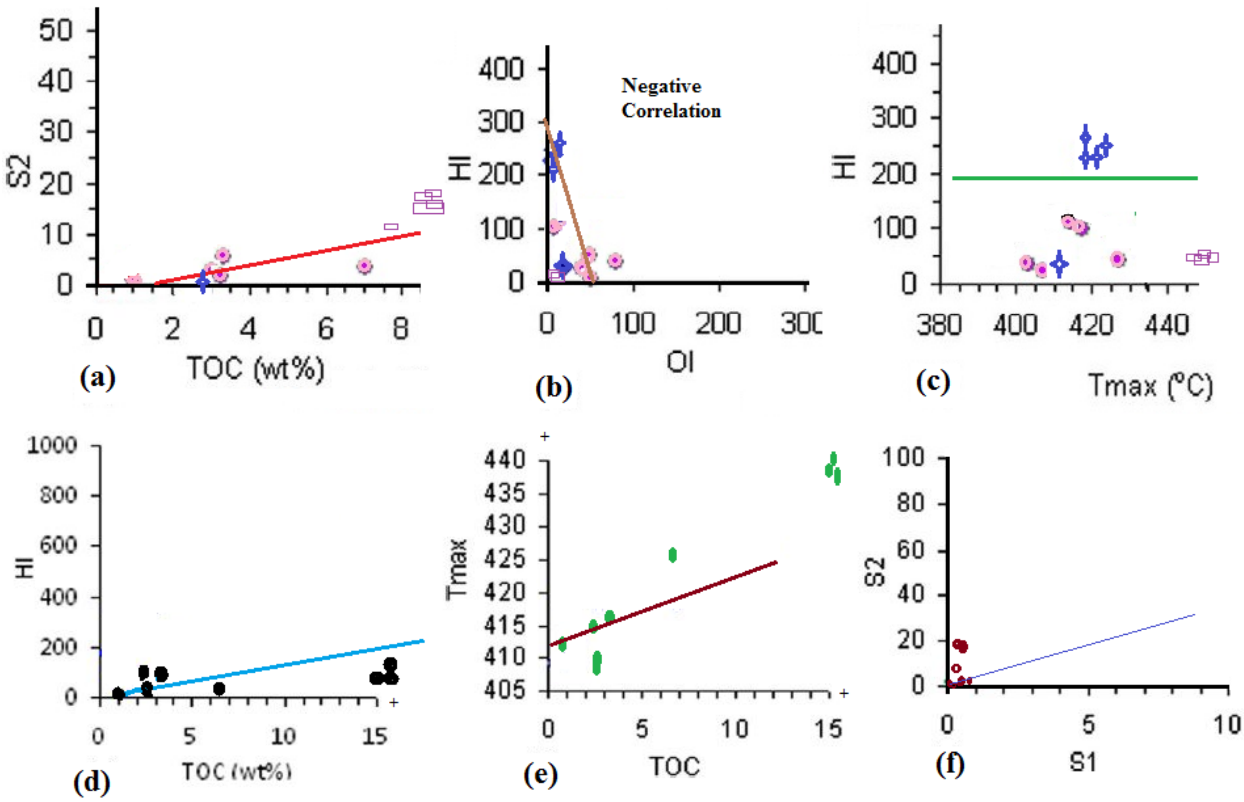

Figure 9 Pearson's correlation coefficient of the studied samples.

5. CONCLUSIONS

Integrated LECO, Rock–Eval pyrolysis and multivariate statistical analysis are examined to investigate the level and time of hydrocarbon generation and expulsion of shale and coal successions in northwestern Sokoto, Anambra Basins and Middle Benue Trough, they showed that the northwestern Sokoto Basin and Middle Benue Trough source rocks are poor to good source rocks with kerogen of type III and are capable of generating gas. The Anambra Basin source rocks are good to excellent source rocks with kerogen of type III and type II and are capable of generating oil and gas. Employing Hierarchical cluster analyses on the studied samples shows two clusters reflecting two types of source rocks. Cluster I are source rocks characterized by HI >240 (mg/g), TOC from 58.89 to166.43 wt %, S1 from 2.01 to 2.54 (mg/g) and S2 from 148.94 to 162.52 (mg/g) indicating good to excellent source rocks with kerogen of type III and type II and are capable of generating oil and gas. Cluster II are source rocks characterized by HI <240 (mg/g), TOC from 0.94 to 36.12 wt %, S1 from 0.14 to 0.72 (mg/g) and S2 from 0.14 to 20.35 (mg/g) indicating poor to good source rocks with kerogen of type III and are capable of generating gas. Employing factor analysis on Rock–Eval pyrolysis variables indicates that there are three factors affecting the evaluation of source rocks. Factor 1 includes variables TOC, S1, S2 which determine the organic richness and hydrocarbon potentiality of source rocks and also HI which determine the type of organic matter that characterizes source rock. Factor 2 include variables PI and Tmax which reflect the maturity of source rocks. Pearson's correlation analysis shows a strong positive correlation between TOC and S1 and S2 indicates the contribution of S1 and S2 from TOC. Furthermore, highly positive correlation between TOC and HI, highly negative correlation with oxygen index and no correlation between TOC and Tmax and PI indicate that the maturity of source rocks is independent of the amount of organic matter. Highly positive correlation between S1 and S2 and also between S2 and HI in addition to, no correlation between Tmax and HI illustrate that the highest HI occurs at certain maturities and doesn't occur in stages of less maturity or over maturity. Highly negative reverse correlation between HI and OI was also shown.

ACKNOWLEDGEMENTS

Great acknowledgments goes to the Nigerian National Petroleum Corporation through the office of the NNPC Chair in Basinal Studies, Ibrahim Badamasi Babangida University, Lapai, Nigeria and the Sokoto State Government for supporting different aspects of the Sokoto Basin hydrocarbon prospectivity evaluation.

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