Communication in Physical Sciences, 2023, 9(2):80-92

Subsurface Lithologies and Rock Eval Pyrolysis Analyses of Amansiodo-I and Akukwa-1 Well Sections, Nkporo Formation, Southeastern Part of the Anambra Basin, Nigeria: Implication for Petroleum Source Rock Potentials

Azuka Ocheli*, Godwin Okumagbe Aigbado, Nkonyeasua Abanjo

Received: 12 February 2023/Accepted 18 April 2023/Published online: 05 May 2023

Abstract: *Subsurface lithologies and rock eval pyrolysis analyses were conducted on Amansiodo-I and Akukwa-1 well sections that penetrated the Nkporo Formation, located in the southeastern part of the Anambra Basin, Nigeria. A set of eleven ditch cuttings from the lithologies retrieved from depths 11500-2150 m were evaluated for their source rock viability, stage of hydrocarbon generation, and thermal maturity of the drilled well section. The lithofacies delineated in the Amansiodo-I well section were: greyish shale (low depositional process), compacted fissile shale and sandy (lower-medium depositional processes), and greyish shale, sandy, silty heterolithics (lower-medium depositional processes). The lithofacies delineated in the Akukwa-1 well section were sandstone and siltstone facies (medium energy of deposition) and shale lithofacies (lower energy depositional process). The environment of deposition in the studied wells is inferred to be a shallow marine environment with brackish-water incursions. Based on the total organic carbon, oxygen index, hydrogen index, genetic potential, kerogen types, and the various bivariate plots, the shale lithologies in the studied well sections are good sources with the potential for the production of oil and gas. However, some of the lithologic units were designated missing units because of the non-availability of their ditch cuttings.*

Keywords*: Ditch cuttings, hydrocarbon, heterolithics, kerogen, lthofacies, source rock*

Azuka Ocheli*,

Corresponding Author: Azuka Ocheli, Email: azuka.ocheli@unidel.edu.ng

Azuka Ocheli
Department of Geology, University of Delta, Agbor, Delta State, Nigeria
Email: azuka.ocheli@unidel.edu.ng
Orcid id: 0000-0003-3389-1236

Godwin Okumagbe Aigbadon
Department of Geology, Federal University Lokoja, Kogi State, Nigeria
Email: godwin.aigbadon@fulokoja.edu.ng
Orcid id: 0000-0001-6901-3123

Nkonyeasua Abanjo
Department of Geology, University of Delta, Agbor, Delta State, Nigeria
Email: nkonyeasua.abanjo@unidel.edu.ng
Orcid id: 0009-0003-6110-4903

1.0 Introduction

The thick sequence of the Anambra Basin is a cretaceous depocentre that covers about 40, 000 sq km in a nearly triangular form (Nwajide and Reijers, 1996). It has a total sedimentary pile of 9 km (Nwajide and Reijers, 1996) which reflects the breakup of the Gondwana supercontinent (Olade, 1975; Hoque and Nwajide, 1984). It is structurally linked to the Cretaceous Benue Trough (Lucas and Balogun 2015a,b) and the Tertiary Niger Delta Basin (Nwajide, 2022). The Santonianic folding instigated the second (Campanian-Eocene) sedimentary depositional cycle (Obi and Okogbue, 2001) and consequently upliftment of the Abakiliki Anticlinorium along the NE-SW axis with the final apportionment of the depocentre into the Anambra Basin on the Northwest and the Afikpo Syncline on the southeast. The Southern boundary of the

Anambra Basin is connected with the northern boundary of the present-day Niger Delta Basin (Ocheli, 2018). The northern boundary is connected with the lower Benue River (Oboh-Ikuenobi *et al*., 2003; Ola-Buraimo, 2013). It is bordered by the Abakiliki Anticlonorium in the east, the basement rock to the north, and the Benue hinge line to the northeast (Oboh-Ikuenobi *et al*., 2003; Ola-Buraimo, 2013). Several authors (Murat, 1972; Akande and Erdtmann, 1998) have discussed the stratigraphic succession of the basin and found that it ranges from Conancian-Santonian Awgu Shale, at the base, the Nkporo Group and its lateral equivalents (Nkporo Formation, Enugu Shale, and Owelli Sandstone), the Mamu Formation, the Ajali Formation, the Imo Formation, and the Ameki Formation and to the quaternary alluvium at the top (Lucas and Balogun, 2015a; b). The search for potential source rocks in the basin remains paramount in Nigeria since there is a decline in the production of oil and gas in recent times. Publications on the generation of petroleum from the source rocks in the Nkporo Formation on these well sections are very scanty since the companies carrying out exploration and exploitation hardly release information on the exploration wells for an appraisal because of reasons best known to the companies. This study intends to describe the depositional processes and environment and appraise the Amansiodo-I and Akukwa-1 well sections that penetrated the Nkporo Formation of the Anambra Basin using the ditch cuttings from the subsurface lithologies supplied by the Kaduna branch of the Geological Survey of Nigeria (GSN), Kaduna. Thus, this paper documents the variations in the lithologies, lithofacies, depositional processes and environment, kerogen types, thermal maturity, petroleum potential, and the extent to significant oil can be generated from the Amansiodo-I and Akukwa-1 well sections, Anambra Basin, Nigeria.

1.1 Location and geological setting

The geological settings and the surrounding hypotheses of the Anambra Basin have been well-investigated, and documented, by several sedimentary geologists (Ocheli *et al*., 2018; Okolo *et al*. 2020; Okoro *et al.*, 2020; Ocheli *et al*., 2021; Nwajide, 2013; 2022). According to Adeagbo (2010), the most accepted model is the plate tectonic episode which provides a more explanatory arrangement of transform feature zones in the Gulf of Guinea region (Adeagbo, 2010). The studied well sections penetrated the Nkporo Formation and is located within the southeastern part of the Anambra Basin, Nigeria (Fig. 1). The drilled well sections lie between longitude 7.00-8.00E and latitude 6.00-7.00N (Fig. 1).

2.0 Materials and Methods

The well lithologies were investigated at a depth ranging from 1150 to 2100 m. Fourteen (14) ditch cuttings collected from the Geological Survey of Nigeria (GSN) were subjected to lithological analysis and eleven (11) samples were subjected to rock eval pyrolysis analyses to ascertain the lithological units and kerogen type, and determine the extent to significant oil can be generated by the drilled Amansiodo-I and Akukwa-1 well sections. Standard sedimentological and rock eval pyrolysis procedures as described by Espitalie et al. (1977) and Akande *et al*. (2015) respectively were used in this study. Little quantity of each of the samples was heated between the temperature range of 250 and 550 °C without oxygen present. The quantity of free hydrocarbon (HC) is liberated by volatilization at the temperature of 250^0C which is recorded as SI-Peak. By further heating of the Kerogen, the quantity of hydrocarbon (HC) produced was recorded as S2 Peak. The quantity of Carbon (IV) oxide (CO_2) released from the kerogen at the end is recorded as S3 Peak.

3.0 Results and Discussion

3.1 Lithological result

The studied depth intervals, lithology, lithofacies, inferred depositional processes and environment of the Amansiodo-1, and Akukwa-1 well sections are displayed in the vertical lithological models (Figs. 2 and 3). Three lithofacies are delineated in the Amansiodo-1 well section with some missing lithologies and two lithofacies are delineated in the Akukwa-1 well section also with some units missing as discussed here under:

Amansiodo-1 well section:

Greyish shale lithofacies: These lithofacies were identified at depth intervals 1150- 1350 m, 1750-1875 m, and 2075-2100 m in Amansiodo-I well section (Fig. 2). It is made up of shale that is greyish. These lithofacies are inferred to be of low energy depositional process under shallow marine depositional environment.

Compacted fissile shale and sandy lithofacies: These lithofacies were identified at depth intervals 1475-1675 m. The base of the lithofacies is sandy (50m thick), overlain by the shale interval (1575-1675m) (Fig. 2), well laminated, fissile, and light to dark grey. This is overlain by moderately sorted sandstones, subrounded to rounded, and fine to medium-grain (100m thick). It is inferred to be lower-medium depositional processes under shallow marine to brackish water environments.

Shale, sandy, and silty heterolithics lithofacies: These lithofacies were identified at a depth interval of 2000-2100 m. The base of this lithofacies is greyish shale (50m thick), overlain by sandy (25 m thick) (Fig. 2). Next is the silty interval (20 m thick) and finally overlain by dark-grey shale (50 m thick) at the top of the lithofacies (Fig. 2). This lithofacies represent lower to medium energy depositional processes, belonging to shallow marine depositional setting with brackish water incursions.

Missing lithologic intervals: The ditch cuttings from depth intervals 1350-1475 m, 1725-1750, 1875-2000 m, and 2100-2150 m were not supplied and hereby designated as missing in this study (Fig. 2).

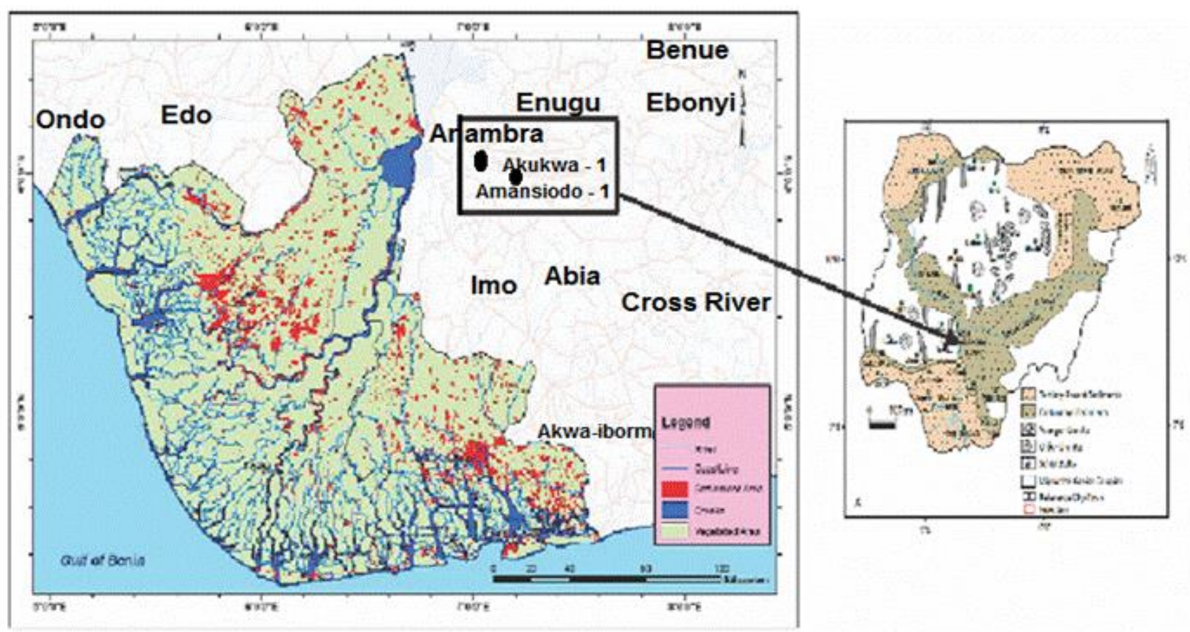

Fig. 1: Location map showing the site of the wells studied (Extracted from Geological Survey of Nigeria, 1984; Nwajide, 2022).

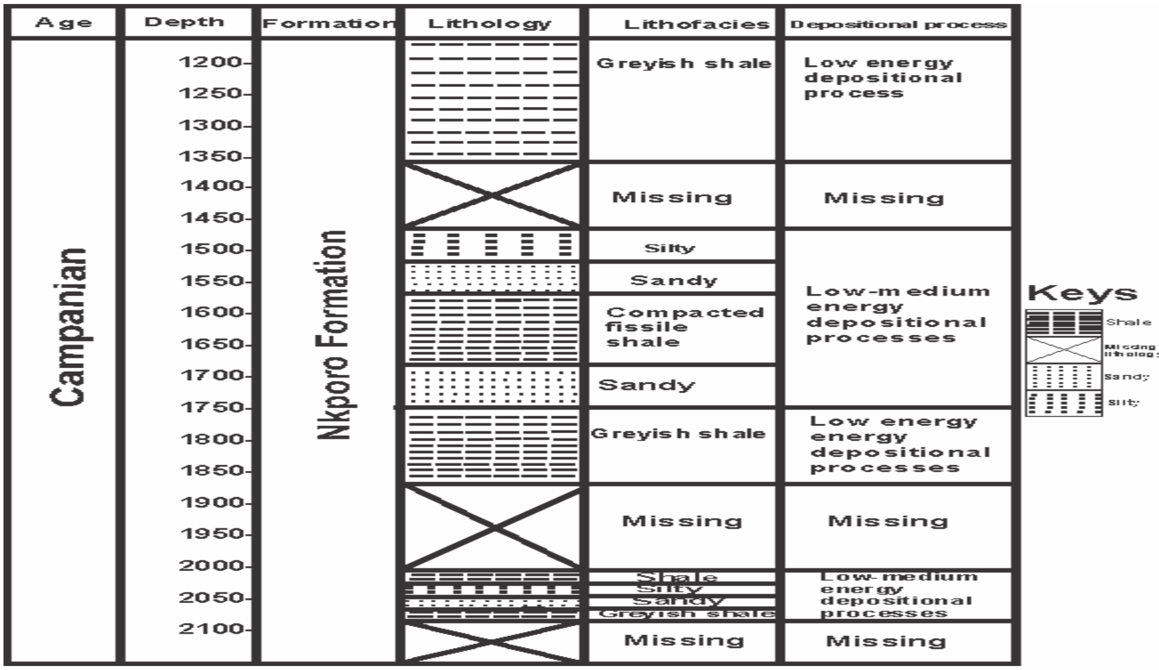

Fig. 2: Vertical lithological log of the Amansiodo-1 well section that penetrated the Nkporo Formation

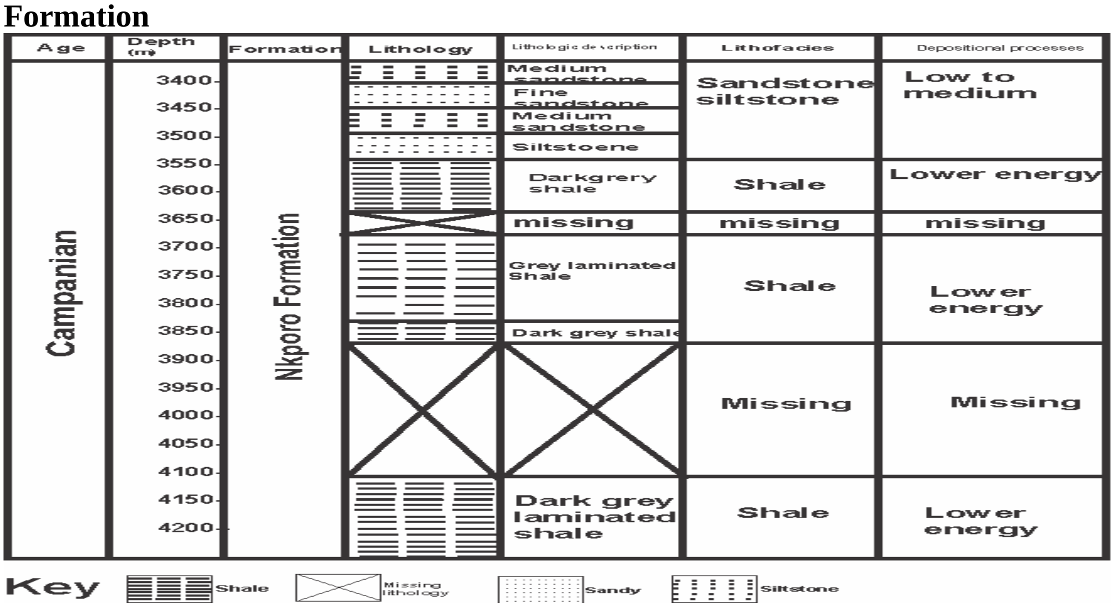

Fig. 3: Vertical lithological log of the Akukwa-1 well section that penetrated the Nkporo Formation

Akukwa-1 well section:

Sandstone and siltstone facies: These lithofacies are at depth intervals 3350-3550 m (Fig. 3). It consists of siltstone at the base (50 m thick), overlain by medium sandstone (50 m thick), succeeded by fine sandstone (50 m thick), and finally overlain by medium sandstone at the top (50 m thick) (Fig. 3). The sandstones are generally light brown and moderately to well sorted. It represents low to medium energy of deposition. This lithofacies is deposited in a shallow marine environment.

Shale lithofacies: Shale lithofacies intervals are at depth intervals 3550-3650 m, 3750-3900 m, and 4100-4250 m (Fig. 3). The shale is generally grey to dark grey colour and laminated. It is of lower energy depositional process under a shallow marine depositional environment.

Missing lithologic intervals: The ditch cuttings from depth intervals 3650-3700m and 3900-4100m from this well section were not supplied also and thus designated as missing lithologic intervals by this study (Fig. 3).

3.2 Rock eval pyrolysis results

Table 1 shows the result of the rock eval pyrolysis analysis of the ditch cuttings samples from the drilled Amansiodo-I well section that penetrated the Nkporo Formation, Anambra Basin, Nigeria. The total organic carbon (TOC) ranges from 0.64-16.48% with an average value of 1.58%. SI-peak values range from 0.09-0.39 mgHc/g rock with an average value of 0.21 mgHc/g rock, S2-Peak values vary from 1.14-3.46 mgHc/g rock with an average value of 2.69 mgHc/g rock; S3-peak values extend from 1.73-4.14 mgHc/g rock, with an average value of 3.14 mgHc/g rock. The hydrogen index (HI) varies from 21.00-442.00 mgHc/g rock, with an average value of 170.00 mgHc/g rock. The oxygen index (OI) ranges from 46-94 mgHc/g rock, with an average value of 69 mgHc/g rock. The Tmax ranges from 404-447^{0}C with an average value of 431 $^\circ$C. The production index (PI) ranges from 0.03-0.12, with an average value of 0.07. The genetic potential varies from 1.21-3.79 mgHc/g rock, with an average value of 2.90 mgHc/g rock. Table 2 shows the result of the rock eval pyrolysis analysis of the ditch cuttings samples from the drilled Akukwa-I well section that penetrated the Nkporo Formation, Anambra Basin, Nigeria. The total organic carbon ranges from 0.73-1.61% with an average value of 1.12%. SI-peak values range from 0.09-0.23 mgHc/grock with an average value of 0.23 mgHc/g rock, S2-Peak values vary from 0.73-16.08 mgHc/g rock with an average value of 3.85 mgHc/g rock; S3-peak values extend from 0.29-1.05 mgHc/g rock, with an average value of 0.69 mgHc/g rock. The hydrogen index (HI) varies from 153.00-456.00 mgHc/g rock, with an average value of 318.00 mgHc/g rock. The oxygen index (OI) ranges from 40-75 mgHc/g rock, with an average value of 61 mgHc/g rock. The Tmax ranges from 420-450^{0}C with an average value of 438^{0}C. The production index (PI) ranges from 0.04-0.12, with an average value of 0.08. The genetic potential varies from 0.82-16.75 mgHc/g rock, with an average value of 4.07 mgHc/g rock.

3.3 Depositional processes and environments

Based on the greyish shale lithofacies, compacted fissile shale and sandy lithofacies, and the shale, sandy, and silty heterolithics lithofacies, the depositional processes have been inferred to be of low-medium energy depositional under a shallow marine setting with brackish water inputs for the lithofacies from the Almansiodo-1 well section. The sandstone and siltstone lithofacies and shale lithofacies delineated from the Akukwa-1 well section indicate low-medium energy processes of sediment deposition in a shallow marine setting. The depositional environments of some units within the studied wells were not inferred as a result of the non-availability of the depth ditch cuttings for the study and hence designated in this study as missing lithofacies. The kerogen types revealed that the studied wells were marine and terrestrial under a paralic depositional environment.

The kerogen types that are capable of generating petroleum (oil and gas) are thought to have been derived from marine and terrestrial sources (Petters, 1986; Maju-oyovwikowhe and Malomi, 2009; Kouadio *et al*., 2020).

Table 1: Result of the rock eval pyrolysis of the Amansiodo-1 well section

Sample No.	Depth (m)	Tmax (^{0}C)	TOC (%)	S1	S2	S3	P1	HI	OI	GP
A-1	1200.00	432	3.73	0.09	2.46	1.72	0.04	66.00	46	2.55
A-2	1250.00	426	0.68	0.26	3.01	0.50	0.08	442.00	74	3.27
A-3	1300.00	418	1.40	0.20	2.86	1.32	0.07	204.00	94	3.06
A-4	1350.00	437	12.40	0.18	3.10	8.31	0.06	25.00	67	3.28
A-5	1500.00	441	16.48	0.11	3.46	10.05	0.03	21.00	61	3.57
A-6	1550.00	439	2.59	0.28	2.77	1.89	0.09	107.00	73	3.05
A-7	1600.00	421	5.32	0.17	3.62	3.46	0.05	68.00	65	3.79
A-8	1700.00	440	1.02	0.07	1.14	0.55	0.06	112.00	54	1.21
A-9	1750.00	438	1.03	0.16	1.38	0.80	0.10	134.00	78	1.54
A-10	1800.00	447	1.11	0.39	3.17	0.91	0.11	286.00	82	3.56
A-11	2100.00	404	0.64	0.36	2.62	0.38	0.12	408.00	59	2.98
Average	1554.55	431	1.58	0.21	2.69	1.09	0.07	170.00	69	2.90
Range	1200-2100	404-447	0.64-16.48	0.09-0.39	1.14-3.46	0.38-8.31	0.03-0.12	21-442	46-94	1.21-3.79

Units of S1, S2, S3, PI, HI, and OI are measured in mgHC/grock, Tmax represent thermal maturity, S1 represent free ion content, S2 represent hydrocarbon yield, S3 represent peak, HI represent hydrogen index, OI represent oxygen index and GP represent genetic potential.

Table 2: Result of the rock eval pyrolysis of the Akukwa-1 well section

Sample No.	Depth (m)	Tmax (^{0}C)	TOC (%)	S1	S2	S3	P1	HI	OI	GP
B-1	3550.00	420	1.61	0.12	0.88	1.05	0.12	201	65	1.00
B-2	3600.00	435	0.73	0.16	2.13	0.29	0.07	452	40	2.29
B-3	3750.00	440	1.06	0.23	2.65	0.58	0.08	350	55	2.88
B-4	3800.00	450	1.33	0.14	1.03	0.77	0.12	456	58	1.17
B-5	3850.00	445	0.92	0.09	0.73	0.65	0.11	153	71	0.82
B-6	4150.00	440	0.75	0.67	16.08	0.56	0.04	225	75	16.75
B-7	4200.00	435	1.45	0.18	3.42	0.91	0.05	390	63	3.60
Average	3842.86	438	1.12	0.23	3.85	0.69	0.08	318	61	4.07
Range	3550.00-4200.00	420-450	0.73-1.61	0.09-0.23	0.73-16.08	0.29-1.05	0.04-0.12	153-456	40-75	0.82-16.75

****Units of S1, S2, S3, PI, HI, and OI are measured in mgHC/grock, Tmax represent thermal maturity, S1 is the free ion content, S2 represents hydrocarbon yield, S3 represents peak, HI represents hydrogen index, OI representd oxygen index and GP is the genetic potential.**

Kerogen Types

Accordingly, kerogen types 1, 11, 111, and 1V have been recognized based on their optical and elemental compositions (Maju-oyovwikowhe and Malomi, 2009). Kerogen with high hydrogen contents corresponds to a higher oil-generating potential (Maju-oyovwikowhe and Malomi, 2009). It has also been revealed that Type 1 kerogen is oil-prone, Type II is also oil-prone, Type II/III is oil-gas-prone, Type III is gas-prone, and Type IV is neither oil nor gas (Agagu and Ekweozor, 1982; Akaegbobi and Schmitt, 1998; Adeagbo, 2009; Babatunde, 2010). Hunt (1996) suggested that the amount of petroleum generated and expelled from source rock increases with the atomic hydrogen-to-carbon H/C ratio of the organic matter. Type III is terrestrial (Petters, 1986). Hydrogen index <50mgHc|grock indicates an absence of a significant quantity of oil-generated lipid materials and confirms the kerogen Type IV. Values from 50-250 mgHc/grock indicate that the shale contains kerogen Type III. Values above 250 mg Hc/grock indicate a very significant quantity of oil/gas that can be generated from kerogen Type II. Therefore, the values of HI for the studied wells indicate that the shale lithologies are dominant of kerogen Types II, III, and mixed Types II/III kerogens. binary plots showing the hydrogen index (HI) versus Tmax revealed the kerogen types to be Type II and Type III kerogen (Fig. 4) and HI versus OI shows that the Almansiodo-1 well section are dominant of Type III, Type II, and mixed TypeII/III kerogens (Fig. 5). It further revealed the extent of the thermal effect on the organic matter and that the hydrogen index (HI) varies with the depth in which the ditch cuttings were recovered. The plotted samples are above 450 ^{0}C. The low concentration of hydrogen index (HI) value depicts that the kerogen Types 11 and 111 organic matter are deposited in an oxidizing environment. Type II/III kerogen referred to as mixed kerogen from the modified diagram of the Krevelen (Fig.4) (Tissot *et al*., 1974). Types II/III is capable of generating gas and gas oil respectively at the required depth temperature (Fig. 4). It indicates the transition between Types II and III signifying a combination of marine and terrigenous organic matter deposited under a paralic marine depositional environment (Kouadio et al., 2020) which is in line with this study. In another development, the high value of the oxygen index (01) can be attributed to the low content of carbonate minerals. It authenticated immature to non-viable source rocks potentials. It also revealed kerogen Types 11 and 111.

3.4 Thermal maturity

The thermal maturity of organic matter is indicative of the maximum paleo-temperature reached by a source rock of any sedimentary formation in a basin (Petters, 1986). Source rock is generally said to be matured if it reaches the level of generating petroleum (Kouadio, 2020), immature if it does not reach the level of generating petroleum, and over-mature if it passed the time of significant petroleum generation and expulsion (Kouadio, 2020). Tmax of 430^{0}C is the threshed boundary (Tissot and Welte, 1984; Babatunde, 2010; El Nady *et al*., 2018). Values below the 430 ^{0}C threshed limit indicate thermally immature kerogen to generate oil and gas and are also linked with maximum hydrocarbon pyrolitic yield. Values equal to or greater than 430 ^{0}C Tmax indicate thermally matured to generate oil and gas. The Tmax values of the subsurface lithologies in the study area ranging from 404-496 ^{0}C indicate that the kerogen Types 11 and 111 determined in the ditch-cutting confirmed that the kerogen Types 11 and 111 are thermally matured to generate oil and gas. A source rock is said to mature when it is capable of generating petroleum. Samples A-2, A-3, and A-7 are thermally immature to generate petroleum at 430 ^{0}C as the value of Tmax is below while others are thermally mature to generate petroleum. Early mature source rock is 430- 432 ^{0}C. The thermal maturity of organic matter is dependent on Tmax. (Tissot *et al*., 1974) and the kinetics of the organic matter cracked in the kerogen (Akaegbobi, 1995;

Akaegbobi *et al.* 2000). The oil-generating window for Type 111 kerogen is 430-470 ^{0}C. The oil-generating window for Type 11 kerogen is 430-455 ^{0}C. Tmax varies with the geothermal gradient and the temperature.

3.5 Petroleum genetic potential and TOC

Petroleum genetic potential is the arithmetic sum of S1 and S2 values obtained from the rock eval pyrolysis (Maju-oyovwikowhe, 2019). S1 is a measure of the free oil content and thus accounts for the mineral in the C7-C12 (Maju-oyovwikowhe, 2019). S2 is the remaining non-extractable hydrocarbon potential produced as kerogen is been cracked (Maju-oyovwikowhe, 2019). S2 indicates the measure of the potential for source rock organic matter to generate further hydrocarbons (Maju-oyovwikowhe, 2019). A total organic carbon < 0.5% indicates poor source rock, 0.5< 1.0% indicates fair, 1.0<2.0% indicates good, 2.0<4.0% indicates very good, and 4.0% and above indicates excellent source rock (Petters and Cassa, 1994). Therefore the total organic carbon of the shale lithologies in the Amansiodo-I well section ranging from 0.64-16.48% with an average value of 1.58% indicates fair to excellent source rock and on average, the well is generally good. The total organic carbon ranges from 0.73-1.61% with an average value of 1.12%, the shale lithologies from the Akukwa-1 section indicate fair to good and on average the shale lithologies are generally good. Total organic carbon (TOC) is used to determine the potential source rock. It reflects the presence of biogenic material that was formed under rapid sedimentation, and oxidation processes that have taken place during deposition and diagenesis (Adeagbo, 2010). According to Welte (1965), Hunt (1975), and Tissot and Welte (1984), the lowest value of TOC required for petroleum generation from a potential source rock is 0.5%. Therefore, The TOC of the shale lithologies within the two studied wells indicates that the shale lithologies are capable of generating petroleum since their total organic carbon concentration is greater than 0.5%. The high values of the S2 peak show that the well section liberated a high quantity of carbon (IV) oxide CO_2.

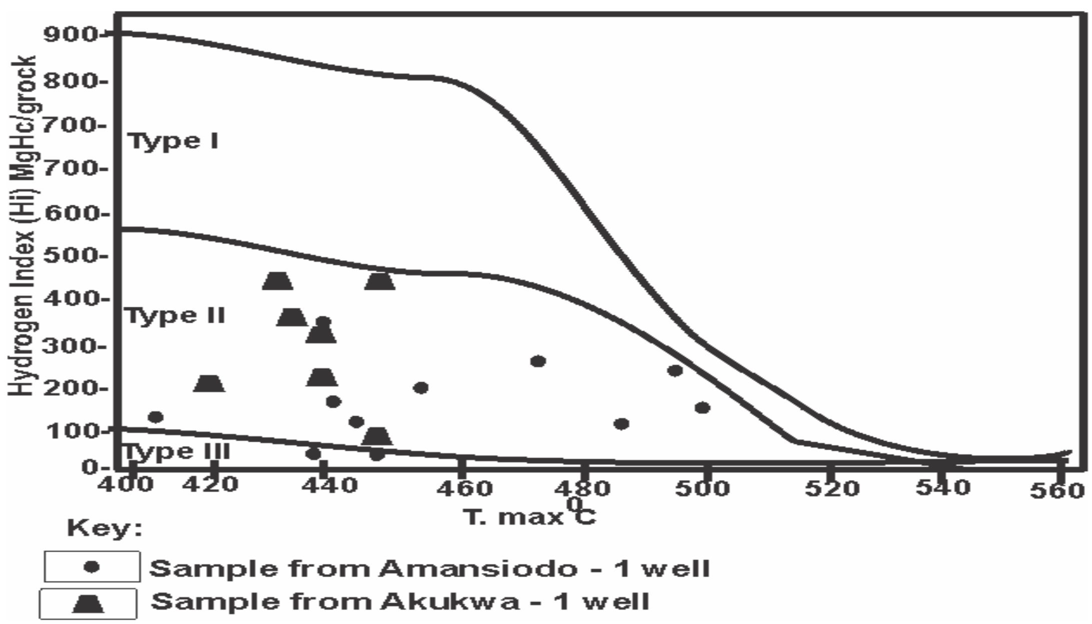

Fig. 4: Binary plot involving Hydrogen Index (HI) versus Tmax

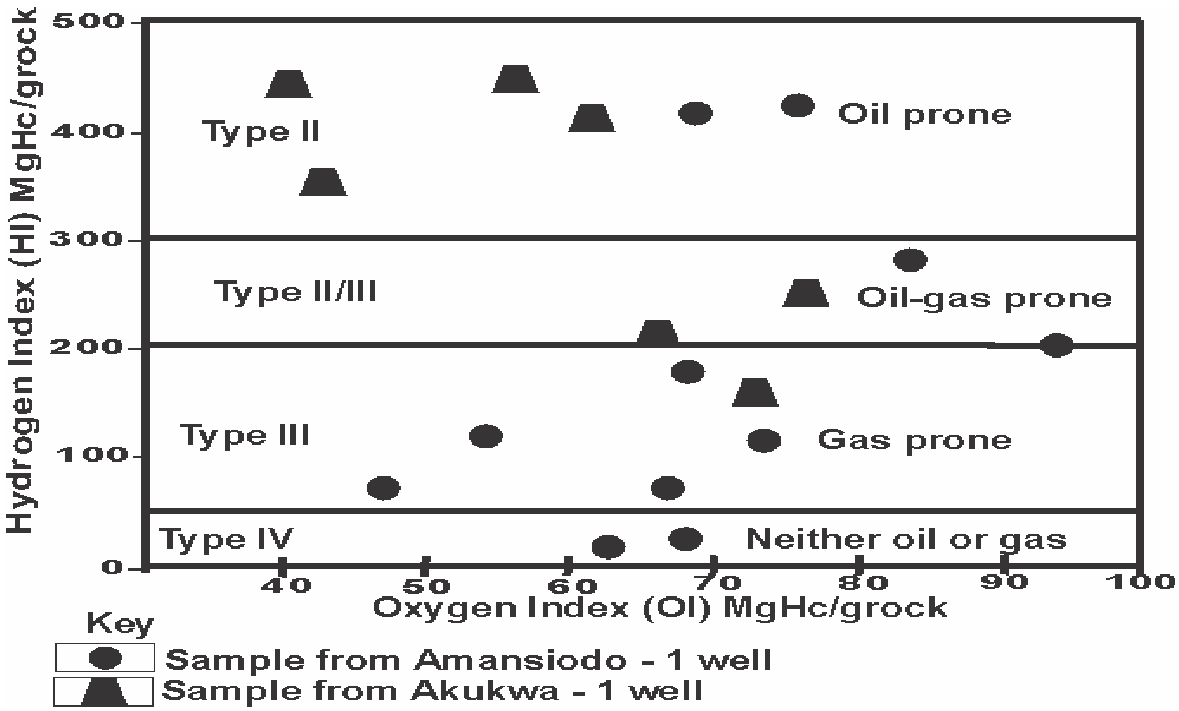

Fig. 5: Binary plot involving hydrogen index (HI) versus oxygen Index (OI)

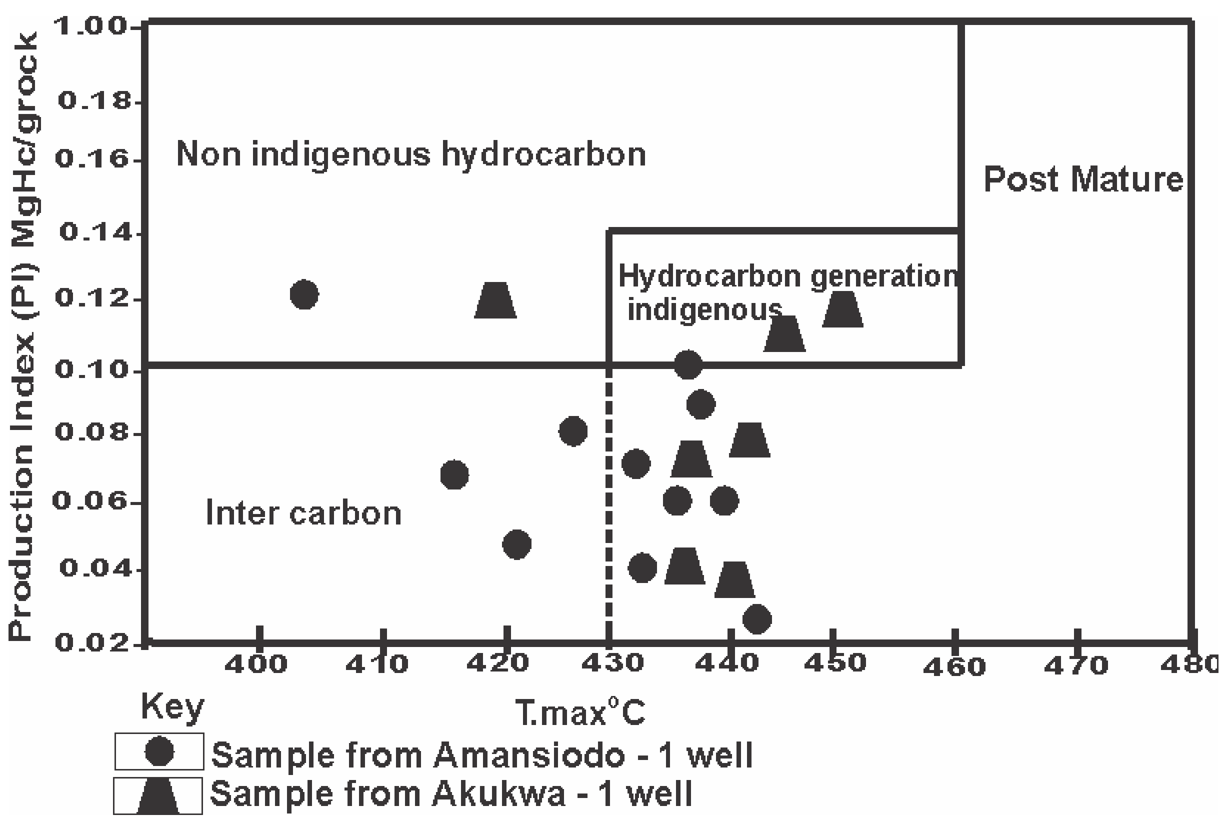

Fig. 6: Binary plot involving Production Index (HI) versus Tmax

The S2 peak is a measure of the potential for source rock organic matter to generate further hydrocarbons (Dymann et al. 1996; Akande et al. 2005). A source rock with a genetic potential (GP) less than 2mgHc/grock (2000ppm) indicates infinitesimal oil but could also produce gas (Tissot and Welte, 1984; Dymann et al. 1996; Akande et al. 2005; Maju-oyovwikowhe, 2019), while a source rock with a genetic potential (GP) ranging from 2-6 mgHc/grock (2000-6000 ppm) indicate moderately rich source rock with fair oil potential, and source rock with a genetic potential (GP) greater than 2 mgHc/grock (6000 ppm) indicate good source rock (Tissot and Welte, 1984; Dymann *et al.* 1996; Akande *et al*. 2005; Maju-oyovwikowhe, 2019). Therefore, the GP values of the samples A-8 and A-9 from the Amansiodo-I well section less than 2mmHc/grock reflect non-viable source rock potential but are still viable for gas potential while other samples greater than 2mgHc/grock reflects moderately rich source rocks for oil and gas. This is equivalent to the quantity of oxygen in each of the ditch cuttings. In another development, the high value of the oxygen Index (01) can be attributed to the low content of carbonate minerals. From the plot of PI versus Tmax in the Amansiodio-1 well section (Fig. 6), sample A-11 is grouped as non-indigenous hydrocarbon, samples A-2, A-3, and A-7 are grouped as inter-carbon, and sample A-10 belongs to the boundary between post mature and hydrocarbon generation indigenous. From the plot of HI versus OI (Fig. 5), the kerogen is dominantly Type II and mixed Type II/III. Two of the samples A-4 and A-5 belong to Type IV kerogen that produces neither oil nor gas (Figs. 4-6) From the plot of HI versus Tmax, the shale is dominantly Type II with a few Type III kerogen (Figs. 4-6). From the plot of PI versus Tmax in the Akukwa-1 well section (Fig. 6), sample B-1 is grouped as non-indigenous hydrocarbon, samples B-4 and B-5 are grouped as hydrocarbon generation indigenous, and samples B-2, B-3, B-6, and B-7 are grouped as post mature. From the plot of HI versus OI, the kerogen is dominantly Type II and mixed Type II/III (Fig. 5). From the plot of HI versus Tmax, the shale belongs to Type II kerogen (Fig. 4). Kerogen Types II, III, and mixed Types II/III which are terrestrially derived and dominant in the two wells are capable of generating hydrocarbons.

4.0 Conclusions

Subsurface lithological and rock eval pyrolysis analyses of the Amansiodo-I well section have been undertaken in the Anambra Basin, Nigeria. Three lithofacies were identified in the Amansiodo-1 well section and two lithofacies were identified in the Akukwa-1 well section. The lithofacies delineated in the Amansiodo-I well section were: greyish shale (low depositional process), compacted fissile shale and sandy (lower-medium depositional processes), and greyish shale, sandy, silty heterolithics (lower-medium depositional processes). The lithofacies delineated in the Akukwa-1 well section were sandstone and siltstone facies (medium energy of deposition) and shale lithofacies (lower energy depositional process). The environment of deposition in the studied wells is inferred to be a shallow marine environment with brackish-water incursions. Rock eval pyrolysis revealed that a significant quantity of oil can be generated from the studied shale samples. The binary discriminant plots of HI versus OI and HI versus Tmax revealed the generation of kerogen types II and III, and that the source rocks are thermally matured to generate oil and gas. Furthermore, the kerogen types II and III are suggested to have been derived from terrestrial high plants. The shale lithologies from the studied wells have the potential to generate petroleum based on the total organic carbon, the kerogen types, hydrogen index, oxygen index, and the genetic potential. The shale lithologies are thermally immature to mature.

5.0 References

Adeagbo, O. A. (2010). Petroleum potential of Campano-Maastricthian shales of

Anambra Basin, southeastern Nigeria. *Global Journal of Geological Sciences, Nigeria*, 1, pp. 65-79.

Agagu, O. K. & Ekweozor, C. M. (1980). Petroleum geology of Senonian sediments in Anambra syncline, southeastern Nigeria (abs.). *Bull. Assoc. Petrol. Geol*. Tulsa 64 pp.

Agagu, O. K. & Ekweozor, C. M. (1982). Source rock characteristic of Senonian Shales in the Anambra Syncline, Southern Nigerian. *Journal of Mining and Geology, Nigeria*, 19, pp. 132-140.

Akaegbobi, I. M. (1995). The Petroleum province of Southern Nigeria-Niger Delta and Anambra Basins: Organic geochemical and organic petrographic approach. Ph. D Diss. *TU Berlin (Berliner Geowissenschaftliche Abahhandlungen Reihe A)*, 182pp.

Akaegbobi, I. M., Nwachukwu, J. I. & Schmitt, M. (2000). Aromatic hydrocarbon distribution and calculation of oil and gas volumes in Post Santonian shale and coal, Anambra Basin, Nigeria, in Mello M. R. & Katz, B. J. (eds.), Petroleum systems of South Atlantic margins: *AAPG memoir* 73, pp. 233-245.

Akaegbobi, M. I. & Schmitt, M. (1998). Organic facies hydrocarbon source potential and the reconstruction of the depositional paleoenvironment of the Campano-Maastrichtian Nkporo Shale in the Cretaceous Anambra Basin, Nigeria. *NAPE Bull.*13, 1, pp. 1-19.

Akande, S. O, Erdtman, B. D, Hetenyi, M. (2005). Paleoenvironments, organic petrology, and rock-eval studies on source rock fade of the Lower Maastrichtian, Patti Formation, southern Bida Basin, *Nigeria. J. Afr. Earth Sc*. 49. Pp. 394 – 406.

Akande, S. O. & Erdtmann, B. D. (1998). Burial metamorphism (thermal maturation) in Cretaceous sediments of the southern Benue Trough and Anambra Basin, Nigeria. *American Association of Petroleum Geologists Bulletin*, 82, 6, pp. 1191-1206.

Akande. S. O, Erdman, B. D. & Hetenyi, M. (2005). Paleoenvironments, organic petrology, and rock-eval Maastrichtian Patti Formation, southern Bida Basin, Nigeria. *J. Afr. Earth Sc.*, 49, pp. 394-406.

Babatunde, O. L. (2010). The main oil source formations of the Anambra Basin, Southern Nigeria. *AAPG International Convention and Exhibition*, September, 15.

Dymann, T. S, Palacos, J. G. Tysdal, R. G, Perry, W. J, & Pawlewicz, M. J. (1996). Source rock potential of middle cretaceous rocks in southwestern Montana. *AAPG Bull.*, 80, pp. 1177 – 1184.

Espitalie. J., Madec, M., Tissot, B. & Leplat, P. (1977). Source rock characterization method for petroleum exploration offshore Tech no. Confer. *OTC 2935, 439-41 Houston.*

GSN, (1984). Federal Geoloigical Survey of Nigeria.

Hoque, M. & Nwajide, C. S. (1984). Tectono-sedimentological evolution of an elongated intracratonic Basin (Aulacogen): The case of the Benue Trough of Nigeria. *Journal of Mining and Geology*, 21,1-2, pp. 19-26.

Hunt, J. M. & Jamieson, G.E. (1965). Oil and organic matter in source rock of petroleum: *Amer. Assoc. Petroleum Geologists Bull.*, 40, pp. 477-488.

Kouadio. K. E., Abrakasa, S., Ikiensikimama, S. S. & Botwe, T. (2020). Source rocks characterization of Agbada and Akata Formations in the Niger Delta, Nigeria. *European Journal of Environment and Earth Sciences*, 1, 4, pp. 1-6. DOI: https://dx.doi.org/10.24018.ejgeo.2020.1.4.38

Lucas, F. A. & Balogun, F. O. (2015a). Palynology and palynomorphs abundance pattern in Amansiodo-1 well, Anambra Basin, Nigeria. *Nigerian Journal of Applied Science, Benin*, 33, pp. 129-136.

Lucas, F. A. & Balogun, F. O. (2015b). Lithofacies evaluation of Amansiodo-1 well section, Anambra Basin, Nigeria. *Nigerian Journal of Applied Science, Benin*, 33, pp. 166-165.

Maju-oyovwikowhe, G. E. & Malomi, B. P. (2019). Evaluation of hydrocarbon potential, quality of source rock facies, and delineating of their depositional environment in Mamu Formation of Anambra Basin, Nigeria. *Journal of Appl. Sci. Environ. Manage*, 23, 3, pp. 383-388.

Murat, R. C. (1972). Stratigraphy and paleogeography of the Cretaceous and Lower Tertiary in Southern Nigeria. In: Dessauvagie, T.F.J. & Whiteman, A. (eds.), 1972. *African Geology, University of Ibadan*, pp. 251-266.

El Nady, M. M, Ramadan, F. S., Hammad, M. M, Mousa, D. A. & Lotfy, N. M. (2018). Hydrocarbon potentiality and thermal maturity of the Cretaceous rocks in Al Baraka oil field, Komombo Basin, South Egypt. *Egyptian Journal of Petroleum*, 27, pp. 1131-1143. https://doi.org/10.1016/j.ejpe.2018.04.003

Nwajide, C. S. (2013). Geology of Nigeria sedimentary basins. *CSS Bookshops Limited, Lagos*, 565p.

Nwajide, C. S. (2022). Geology of Nigeria sedimentary basins. *CSS Bookshops Limited, Lagos*, 693p.

Nwajide, C. S. & Reijers, T. I. (1996). The Geology of the Southern Anambra Basin, In Reijers, T. J. A. (ed.), 1996. Selected chapters on Geology: Sedimentary geology and sequence stratigraphy of the Anambra Basin. *SPDC Corporate Reproghraphics Services, Warri, Nigeria*, pp. 133-148.

Obi, G. C. & Okogbue, C. O. (2004). Sedimentary response to tectonism in the Campanian-Maastrichtian Anambra Basin succession, Southeastern Nigeria. *Journal of Africa Earth Sciences*, 38, pp. 99-108.

Oboh-Ikuenobe, F. E., Obi, C. G., & Jaramillo, C. A. (2005). Lithofacies, palynofacies, and sequence stratigraphy of Paleogene strata in Southern Nigeria. *Journal of African Earth Sciences*, 41, pp. 79-102.

Ocheli, A., Okoro, A. U., Ogbe, O. B. & Aigbadon, G. O. (2018). Granulometric and Pebble Morphometric Applications to Benin Flank Sediments in Western Anambra Basin, Nigeria: Proxies for Paleoenvironmental Reconstruction. *Journal of Environmental Monitoring and Assessment, Springer International Publishing AG, Part of Springer Nature*, 190, 5, pp. 1-17. https://doi.org/10.1007/s10661-018-6637-z

Ocheli, A, Ogbe, O. B. & Aigbadon G. O. (2021). Geology and geotechnical investigations of part of the Anambra Basin, Southeastern Nigeria: implication for gully erosion hazards. *Environmental Systems Research, Springer Nature, Switzerland*, 10, 23, pp. 1-16. https://doi.org/10.1186/s40068-021-00228-2

Okolo, G. C., Emedo, O. C., Obumselu, A. C., Madukwe, F. C. & Ulasi A. N. (2020). Lithofacies, particle size analysis, and paleodepositional environment of the Eze-Aku Group (Cenomanian–Turonian) in the Itigidi-Ediba area, Afikpo Synclinorium, southeastern Nigeria. *Journal of Sedimentary Environment, Springer Nature, Switzerland*, pp. 1-24. https://doi.org/10.1007/s43217-020-00012-9

Okoro, A. U., Igwe, E. O. & Umo, I. A. (2020). Sedimentary facies, paleoenvironments, and reservoir potential of the Afikpo Sandstone on Macgregor Hill area in the Afikpo Sub basin, southeastern Nigeria. *SN Applied Sciences, Springer Nature Switzerland*, 1-17pp. https://doi.org/10.1007/s42452-020-03601-5

Ola-Buraimo, A. O. (2013). Palynological stratigraphy of the Upper Cenomanian-Turonian Eze-Aku Formation in Anambra Basin, Southeastern Nigeria. *Journal of Biological and Chemical Research* 30, 10, pp. 54-67.

Olade, M. A. (1975). Evolution of the Nigeria Benue Trough – a tectonic model. *Geol. mag*. 112, pp. 575-583.

Peters, K. E. (1986). Guidelines for evaluating petroleum source rocks using programmed pyrolysis. *AAPG Bull*., 70, 329 p.

Peters, K.E. & Cassa, M. R. (1994). Applied source rock geochemistry in Magoon, L.B, and Dow, W.G. (1994) (eds.), the petroleum system-from source to trap: *AAPG Memoir 60*.

Tissot, B. P, Welte, D. H. (1984). Petroleum formation and occurrence, *2nd ed Springer Verlag, Berlin*, 699 p.

Welte, D. H. (1965). Relation between petroleum and source rock. AAPG Bulletin, 49, 12, pp. 2246-2268. https://doi.org/10.1306/A663388C-16CO-11D7-8645000102C1865D

Acknowledgments

The authors happily thank the Geological Survey of Nigeria, Kaduna branch for providing the ditch-cutting samples used for this research study. The authors also thanked the Chief editor for the editorial work done on this manuscript and the anonymous reviewers.

Ethical

Not applicable

Funding

This study is a self-sponsored research work.

Data availability

Data is readily available on request.

Consent for publication

Not Applicable

Availability of data and materials

The publisher has the right to make the data public

Competing interests

The authors declared no conflict of interest.

Funding

There is no source of external funding

Authors' contributions:

Azuka Ocheli: The first author developed the conceptualization, data administration, investigation, analysis, interpretation, original draft, and proof reading of the manuscript.

Godwin Okumagbe Aigbadon: The second author contributed to the conceptualization, investigation, and proof reading of the manuscript.

Nkonyeasua Abanjo: The third author assisted in the data analysis, investigation, and proof reading of the manuscript.