Open Journal of Geology, 2023, 13, 504-535
https://www.scirp.org/journal/ojg
ISSN Online: 2161-7589
ISSN Print: 2161-7570

Biostratigraphy, Palynofacies and Organic Geochemical Characterization of Three Wells, Western Offshore Niger Delta Nigeria

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How to cite this paper: Ogunsanya, O.G., Asere, J.B., Boboye, O.A., Bosikun, K.S. and Adegboye, G.A. (2023) Biostratigraphy, Palynofacies and Organic Geochemical Characterization of Three Wells, Western Offshore Niger Delta Nigeria. *Open Journal of Geology*, **13**, 504-535.
https://doi.org/10.4236/ojg.2023.135023

Received: March 21 2023
Accepted: May 28, 2023
Published: May 31, 2023

Abstract

Ditch samples from AP-4, ER-51 and UK-2 offshore Niger Delta were subjected to biostratigraphic and organic geochemical analyses which entail foraminiferal, palynological, Spore Colour Index (SCI), Rock-Eval Pyrolysis and Fourier Transform Infrared Spectroscopy (FTIR) analyses. The results have established N19, N18 and N17; N17, N16 and N15; and N9 and N8 biozones; and P600 and P700 palynological zones. The dominance of palynomaceral (PM) I and II suggests Type III kerogen. PM III and IV (Type II and IV) were recorded. SCI ranges from 3/4 to 5/6 suggesting an early to mature liquid hydrocarbon generation phase. Rock-Eval Pyrolysis shows that the Total Organic Carbon (TOC), Hydrogen Index (HI), Pyrolysis temperature (T_{max}), and Vitrinite Reflectance (VR_o) range from 2.48 wt% - 6.37 wt%, 78 - 258, 411˚C - 431˚C and 0.26% - 0.69% respectively suggesting high TOC of Type II/III kerogen. FTIR indices show Type I kerogen in all the wells. VR_o results range from 0.4 - 0.5 indicating an immature source. High concentrations of aliphatic saturates in identified functional groups indicate a low biodegradation. The abundance and diversity of recovered assemblages and dominance of PM I and II suggest shallow depositional environments with an age range of late Miocene to early Pliocene. Palynomaceral, SCI, and Rock-Eval inference contradict FTIR kerogen type suggesting that IR spectroscopy might not be suitable for kerogen typing and origin. The geochemical and biostratigraphical inferences must be corroborated for a successful evaluation. However, the source rock in the study area has adequate organic matter with the prospect to generate both oil and gas at appropriate maturity.

Keywords

Biostratigraphy, Rock-Eval, Palynofacies, Infrared Spectroscopy,

Palynomaceral

1. Introduction

Biostratigraphy provides the transient transitioning of different rock units based on the fossil content, paleoenvironmental reconstruction enables the interpretation of the depositional environment in which source and reservoir rocks were formed. Palynofacies studies can also help identify depositional habitats, making them valuable to petroleum geologists as well, thus enhancing the overall assessment of a sedimentary basin's hydrocarbon potential [1]. Integrating palynofacies analysis in petroleum exploration is quite significant since it offers details on the type, quantity, and maturation of organic matter in a penetrated rock sequence.

In petroleum exploration, organic geochemistry is a major tool during the early stages of exploration, when source rocks are identified, and the later stages, when these rocks are classified into their various groups, and this is Hydrocarbon accumulation and basin analysis [2] [3]. Petroleum geochemistry is a branch of organic geochemistry that studies the origin, generation, migration, accumulation, and alteration of petroleum using chemical principles. This knowledge is then applied to the search for and production of oil and gas [4] [5] [6]. Therefore, it is anticipated that petroleum exploration and the development of previously explored areas would adopt a new and well-defined course in response to the rising demand for fossil fuel energy globally and the necessity to avoid the impending energy crisis.

This research is hinged on providing the information needed to optimize exploration and exploitation of petroleum in the Niger Delta region of Nigeria, by establishing the age and paleoenvironment, and to infer the thermal maturation and source rock potential of the penetrated wells to facilitate exploration activities in the region and complement the previous research on the basin.

2. Location of Studied Wells

The wells from which the ditch cuttings utilized for this study were obtained are located on offshore southwestern Niger Delta. The wells coded AP-4, ER-51 and UK-2 are located under the Oil Mining License (OML) 132, 133 and 134 fields respectively (**Figure 1**). The Niger Delta basin, one of the world's most productive petroleum provinces, is noteworthy for its hydrocarbon resources. The basin has seen a lot of exploration activity, which has allowed for the development of a thorough stratigraphy of the basin through a comparatively substantial amount of data from exploration wells. The diminishing oil recovery rate from the basin has prompted various approaches to be employed in search of hydrocarbon. Although several foraminifera and palynological investigations have dealt with the age and paleoenvironmental interpretations of the Niger Delta basin, there is still

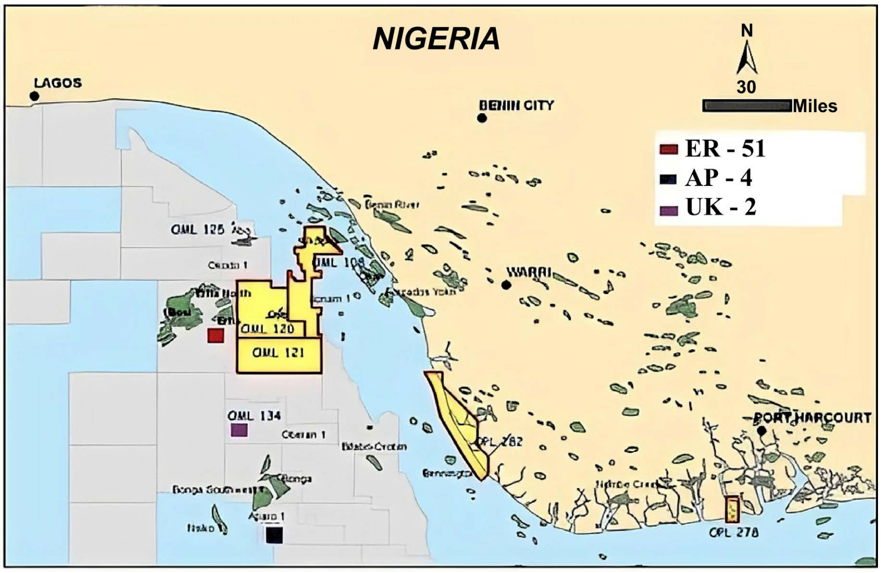

Figure 1. Map of Niger Delta showing study area (modified from AOGR, 2018).

paucity in use of detailed palynofacies analyses in interpreting paleoenvironmental settings especially in the offshore region.

3. Geotectonic Setting

The Niger Delta basin is situated on the continental margin of the Gulf of Guinea (**Figure 2**) in the equatorial West Africa, between latitude 3˚ and 6˚N and longitude 5˚ and 8˚E [7]. In the late Cretaceous, the separation of the African from the South American plates was responsible for the basin's development [3] [8] [9]. A failed rift that resulted from the separation of the South American and African plates gave rise to this basin during the Early Cretaceous. The onshore portion of the Niger Delta Province is delineated by the geology of southern Nigeria and southwestern Cameroon [10]. The northern boundary is the Cretaceous Anambra basin and the Benin flank (an east-northeast trending hinge line south of the West Africa basement massif). The northeastern boundary is defined by outcrops of the Cretaceous on the Abakaliki high, and further east-southeast by the Calabar flank (a hinge line bordering the adjacent Precambrian). The offshore boundary of the province is defined by the Cameroon volcanic line to the east, and by the eastern boundary of the Dahomey basin (Okitipupa basement high) to the west. Its southern limit rests on the Atlantic Ocean in the Gulf of Guinea.

From the Eocene to the present, the delta has prograde southwestward, forming depobelts that represent the most active portion of the delta at each stage of its development. The delta is the largest in Africa extending more than 300 km from apex to mouth and covers an area of about 75,000 km^2 with a clastic fill of about 12 km [3] [7]. The basin one of the world's most prolific petroleum producing Tertiary deltas that together account for about 5% of the world's oil and gas reserves, and for about 2.5% of the present-day basin areas on earth [7].

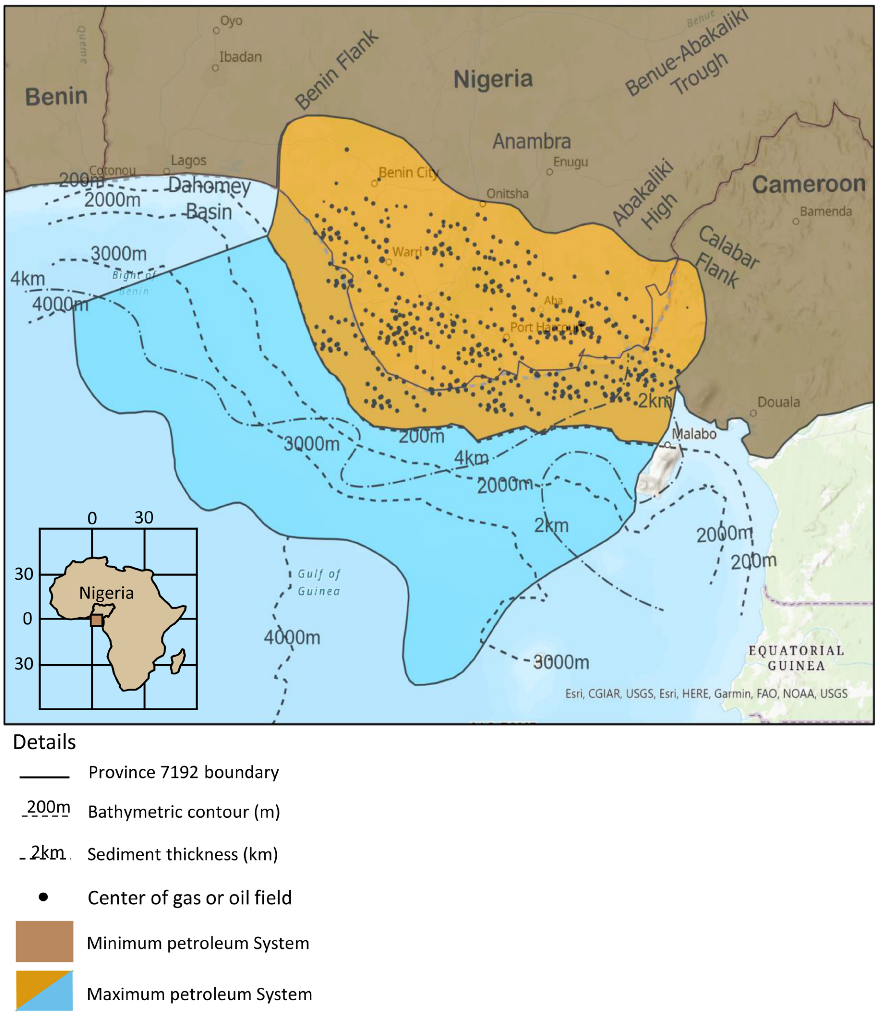

Figure 2. Index map of Nigeria and Cameroon. Map of the Niger Delta showing Province Outline (Maximum Petroleum System); Bounding structural features; Minimum petroleum system as defined by oil and gas field center points (Data from Petroconsultants 1996a); 200, 2000, 3000, and 4000 m bathymetric contours; and 2 and 4 km sediment Thickness [11].

The Niger Delta is divided into three formations, representing prograding depositional facies that are distinguished mostly on the basis of sand-shale ratios. The type sections of these formations are described in Short and Stäuble [12] and summarized in a variety of papers ([3] [7] [13] [14]). An upper delta-top lithofacies, the Benin Formation consists of massive continental sands and gravel, and unconformably grades into the delta-front lithofacies, the Agbada Formation which comprises mostly shoreface and channel sands with minor shales in the upper part, and an alternation of sand and shale in equal proportion in the lower part. The pro-delta marine shales and the Akata Formation forms the base of the delta (**Figure 3**).

4. Materials and Methods

The samples for the analysis of this study came in ditch samples from three (3)

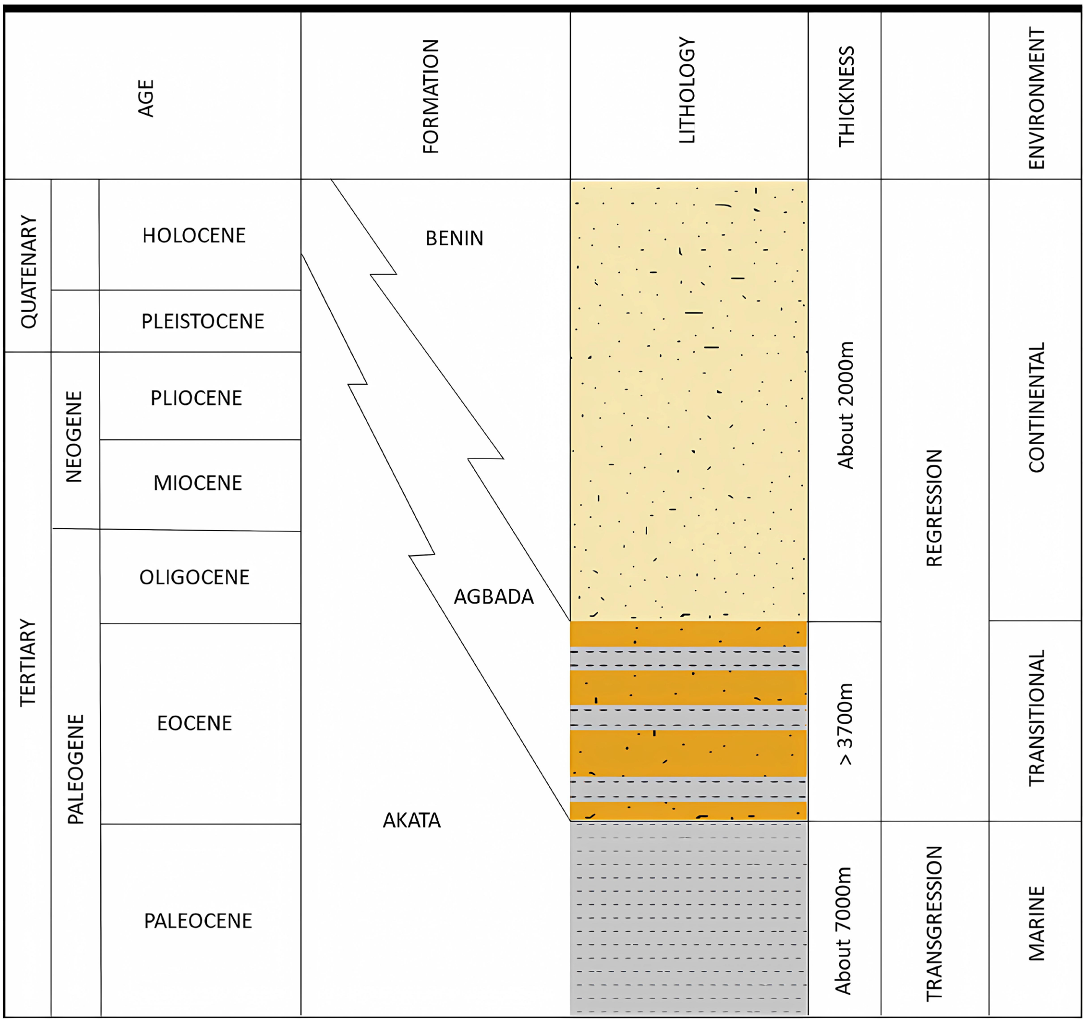

Figure 3. Stratigraphic column showing the three formations of the Niger Delta. Modified from [3] and [15].

wells in the offshore part of the southwestern Niger Delta basin. A total of Seventy-five (75) composite samples at approximately 18 m intervals were analyzed for wells AP-4, ER-51, and UK-2. Forty-three (43), twenty (20), and twelve (12) composite samples with a depth range of 1915 - 2682 m, 1027 - 1391 m, and 389 - 603 m were analyzed for wells AP-4, ER-51, and UK-2 respectively. These wells were logged and processed for biostratigraphical and organic geochemical analysis using standard preparation methods.

4.1. Biostratigraphical Analysis

Foraminiferal study

The samples were disaggregated in a solution of 10% H_2O_2 overnight and boiled in water with a pinch of soda ash and then washed through a 63 µm sieve. The recovered foraminifera were counted and studied under the microscope for generic classification.

Palynological Analysis

Standard procedure for slides preparation for palynological studies was employed. The hydrochloric (HCl) and hydrofluoric (HF) acids were added to digest and remove the carbonates and silicate from the rock samples. The residue was then sieved through a 5 μm and 10 μm mesh sieve for palynomorph recovery and the organic matter separation respectively. Slides were then prepared for light microscopy and photomicrography.

4.2. Rock-Eval Pyrolysis

A total of ten (10) ditch samples were subjected to pyrolysis via the Rock-Eval analyzer - 6 instruments. The pulverized organic-rich samples were heated in an inert environment to measure the yield of three groups of the free oil content, remaining generation potential, and the organic carbon dioxide yield. Samples were heated at 300˚C for 3 minutes, 300˚C to 650˚C at 25˚C/min then held at 650˚C for 3 minutes to obtain S_1, S_2 and S_3 respectively. The temperature was held here to ensure accuracy of the reading. The S_3 peak was measured between 300˚C and 400˚C.

4.3. Fourier Transform Infrared Spectroscopy (FTIR)

Six (6) ditch samples were subjected to the FTIR analysis, about 1/8" of each solid sample was taken on a micro-spatula and about 0.25 - 0.5 teaspoons of KBr. This was then mixed thoroughly in a mortar while grinding with the pestle. Just enough samples were placed to cover the bottom in the pellet die. The samples were then placed in a press and pressed at 5000 - 10,000 psi. The pressed sample was carefully removed from the die and placed in the FTIR sample holder and run in the Perkin Elmer FTIR instrument to record the Infrared spectrum.

5. Results and Discussion

5.1. Foraminiferal Biostratigraphy

The results show a diverse assemblage of planktonic and benthonic foraminifera, with ostracods and pelecypods as accessory microfauna. A total of one hundred and twenty (120) species were recorded from well AP-4, comprising hundred (100) species (83%) of calcareous and twenty (20) species of arenaceous forms. In ER-51; a total of forty-six (46) species were recorded. Twenty-two (22) of species recovered are calcareous (48%), with twenty-four (24) being arenaceous (52%). Of the calcareous forms, thirteen are benthic (59%) while nine (9) are planktic (41%). UK-2 well section comprises poor to fair recovery of both planktic and benthic species. Some of the species recovered include; *Globigerina bulloides*, *Globigerinata naparimaensis*, *Globoquadrine altispira*, *Hastigerina siphonifera*, *Turborotalia acostaensis*, *Ammonia beccarii*, *Bulimina* sp., *Cibicoides* sp., *Uvigerina* sp., *Trochammina* sp., *Oolina* sp., *Nodosaria* sp., *Dentalina* sp., *Gyroidina soldanii* (**Figure 4**).

Biozonation and Age Dating

Based on foraminifera abundance and diversity, the biozones and age dating of the wells under study were determined as follows.

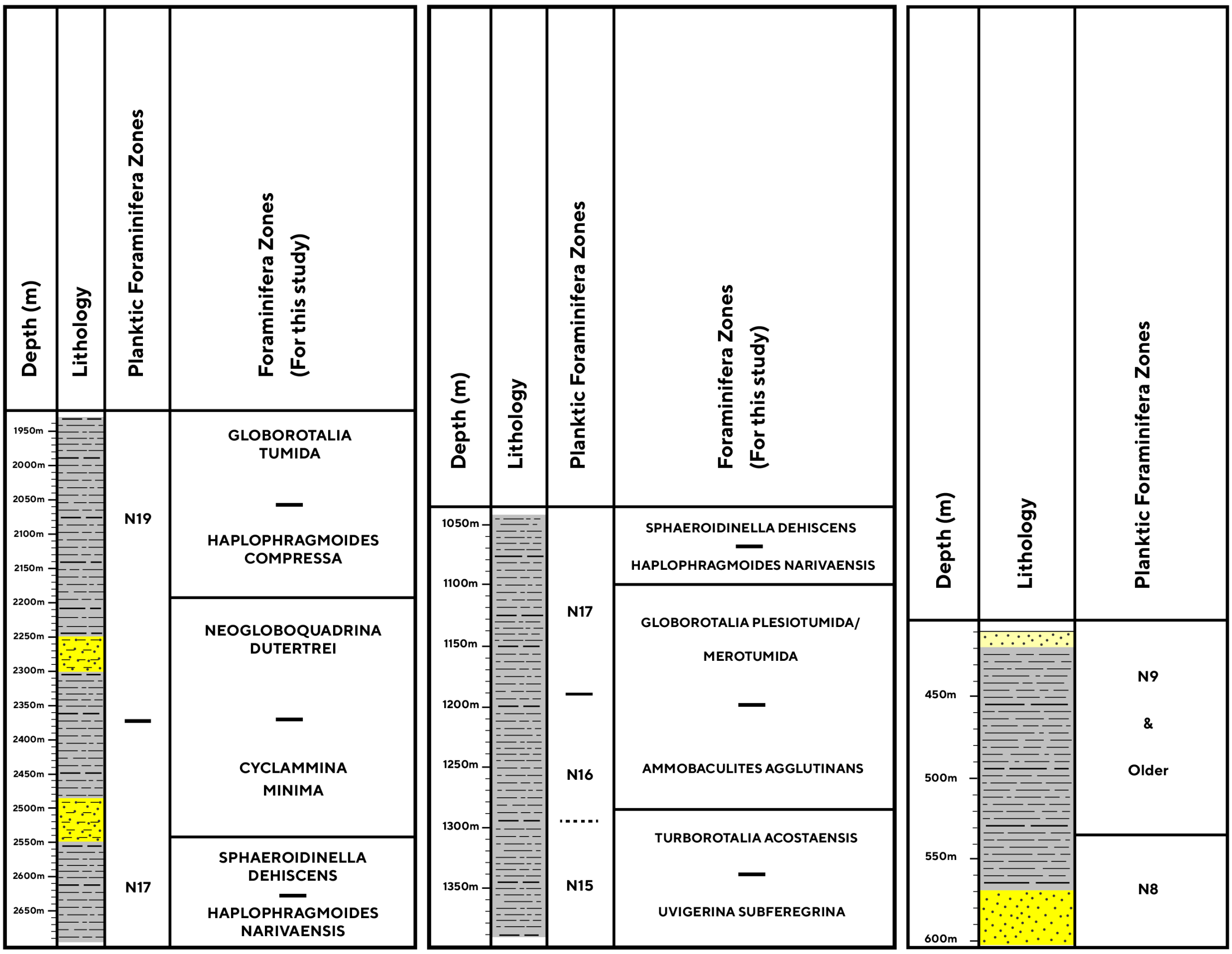

Figure 4. Summary of foraminiferal biostratigraphy.

Zone Description: *Globorotalia tumida*/*Haplophragmoides compressa Zone.*

Stratigraphic Interval: 1914 m - 2182 m (AP-4 well).

Equivalent Planktic Foraminifera Zone: Lower N19 - Upper N18.

Age: Late Miocene - Early Pliocene.

Zone description: *Neogloboquadrina dutertrei*/*Cyclammina minima* Zone.

Stratigraphic Interval: 2182 m - 2618 m (AP-4 well).

Equivalent Planktic Foraminifera Zone: Upper N18.

Age: Late Miocene.

Zone Description: *Sphaeroidinella dehiscens*/*Haplophragmoides narivaensis* Zone.

Stratigraphic Interval: 2618 m - 2673 m (AP-4 well); 1027 m - 1091 m (ER-51 well).

Equivalent Planktic Foraminifera Zone: Upper N17 - Lower N17.

Age: Late Miocene.

Zone Description: *Globorotalia plesiotumida*/*merotumida*/*Ammobaculites agglutinans* Zone.

Stratigraphic Interval: 1091 m - 1273 m (ER-51 well).

Equivalent Planktic Foraminifera Zone: "Lower" N17 - "Upper" N16.

Age: Late Miocene.

Zone Description: *Turborotalia acostaensis*/ *Uvigerina subperegrina* Zone.

Stratigraphic Interval: 1273 m - 1391 m (ER-51 well).

Equivalent Planktic Foraminifera Zone: "Lower" N16 - "Upper" N15.

Age: Late Miocene.

Partial Range zone: ?G*lobigerinoides bollii*/ *Orbulina universa.*

Stratigraphic Interval: 409 m - 536 m (UK-2 well).

Planktic Foraminifera Zone: N9 and Older.

Age: Early - Middle Miocene.

Zone Description: The top of this zone is tentatively placed at the first analyzed sample. Important Planktic foraminifera, G*lobigerinoides bollii* was also found within the interval. The base of the interval is placed at the last downhole occurrence of *Orbulina universa* at depth 536 m. *Uvigerina auberiana* was the only calcareous benthic species recorded within the interval. Arenaceous benthics are rare within the interval with the spot occurrences of *Haplophragmoides* spp*.* and *Textularia* spp*.*

Partial Range Zone: ?*Orbulina universa*/ *Uvigerina auberiana.*

Stratigraphic Interval: 536 m - 603 m (UK-2 well).

Planktic Foraminiferal Zone: N8.

Age: Early Miocene.

Zone Description: The top of this zone is marked by the LDO of *Orbulina universa* at 536 m depth while the base is tentatively placed at the last analyzed sample at 603 m. Planktic foraminiferal species that characterized this interval include *Globigerinoides obliquus obliquus*, *Globigerinoides ruber*, *Globigerinoides trilobus immaturus* and planktics indeterminate. Calcareous benthic species found with rare occurrences include *Uvigerina auberiana*, *Florilus ex. gr. costiferum*, *Ammonia tepida*, *Hoeglundina elegans*, *Quinqueloculina microcostata* and *Sphaeroidina bulloides.* Arenaceous benthics is rare within the interval with the spot occurrence of Saccammina Complanata.

Biozone Correlation

The N17 Zone was correlated for AP-4 and ER-51 wells suggesting an upper bathyal depositional environment based on the species recovered (**Figure 5**).

5.2. Palynology

Palynological studies were utilized for age dating, paleoenvirnmental deductions and palynomorph abundance and diversity. Inferences obtained revealed well preserved and moderate recovery of palynomorphs such as *Zonocostites ramonae*, *Monoporites annulatus*, *Psilatricolporites crassus*, *Pachydermites diederixi*, *Cyperaceacepollis* spp., *Sapotaceae*, *Pteris* spp., *Laevigatosporites* spp., *Magnastriatites howardi*, *Verrucatosporites* spp*.* and *Acrostrichum aureum.* Dinoflagellate cysts such as *Polyshaeridium zoharyi*, *Leiosphaeridium spp.*, and *Lingulodinium machaerophorum* were also recorded in well AP-4; in wells ER-51 and UK-2 marine indicators such as: microforaminiferal wall linings and *Leiosphaeridia spp.* were also recorded.

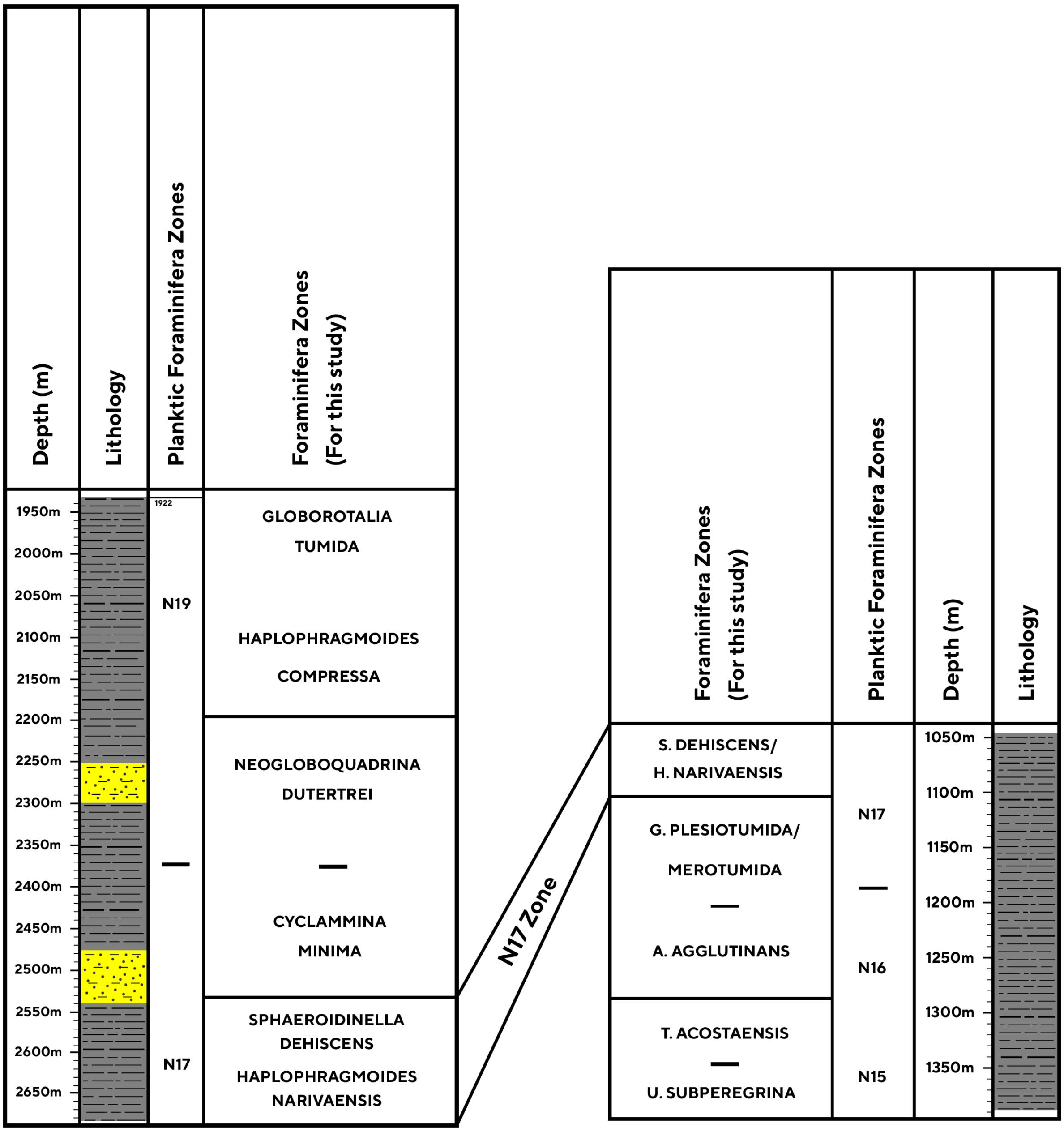

Figure 5. Foraminifera biozone correlation for ER-51 and AP-4 wells.

Palynozone and Age Dating

The biozones present in the wells studied were classified based on [16] and correlated with [17] (**Figure 6**). These zones and corresponding subzones are;

Zone: *Monoporites annulatus* Zone (well AP-4).

Subzones: P670 and P650 subzones (*Magnastriatites howardi*).

Age: Early Miocene.

Zone: *Echitricolporites spinosus* Zone, (well ER-51 and UK-2).

Subzones: P770 (well ER-51) and P780 (well UK-2).

Age: Middle Miocene.

Palynozone Correlation

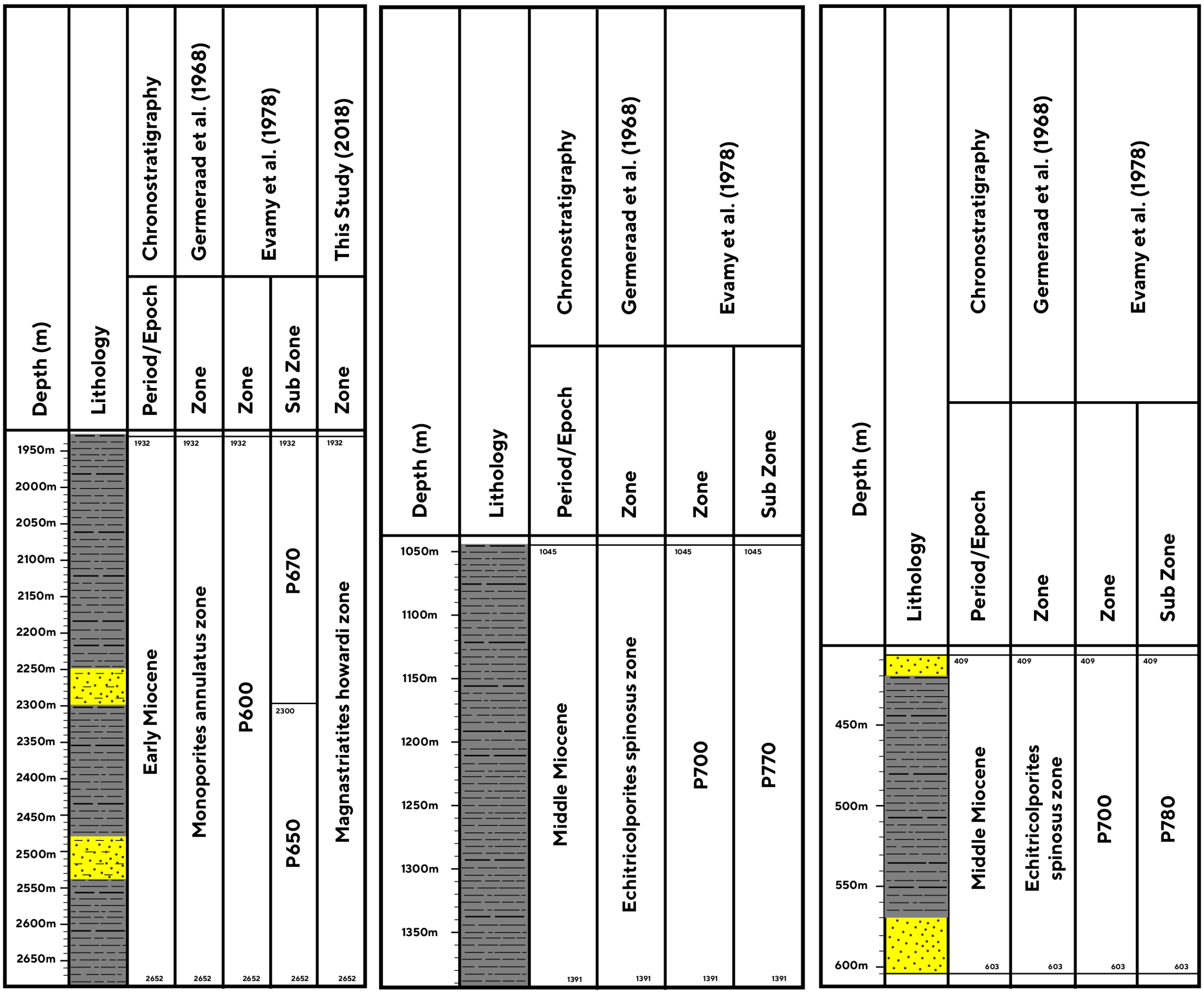

Figure 6. Summary of palynology.

The *Echitricolporites spinosus* Zone was correlated and established for ER-51 and UK-2 wells (Figure 7). This occurs at 1050 m - 1391 m in ER-51 well and 400 m - 603 m in UK-2 well. This is indicative of a shallow marine depositional environment.

Palynofacies

The palynofacies analysis across the three (3) wells revealed that the samples are dominated by resinous cortex, structureless material (Palynomaceral (PM) I) and the platy-like structured plant material (PM) II). The large to medium sized dead carbon black equidimensional lath/needle shaped plant material (PM IV) were also recorded in appreciable quantity, while the stomata bearing aqueous plant material (PM III) were recorded in small amount. PM I and II ranges from large-medium size for ER-51 and UK-2 wells but medium to small size for AP-4 well. PM IV ranges from large to medium in size for wells UK-2 and AP-4 but medium to small size for ER-51 well. The above deduction reveals a shallow marine environment of deposition across the three (3) wells [18].

Figure 7. Palynozone correlation for ER-51 and UK-2 wells.

5.3. Kerogen/Thermal Maturation Analysis

Spore Colouration/Degree of Maturation

The results of the kerogen analysis for the studied wells revealed that the spore colour ranges from light to medium brown 4/5 transiting to medium to dark brown 5/6 (well AP-4) and orange to orange brown 3/4 transiting to medium brown 4 (wells ER-51 and UK-2). This shows that the samples vary from medium degree of maturation to late degree of maturation and early degree of maturation respectively in the wells of study [19] [20] (**Table 1**).

Geochemical Deductions

The sediments from the studied wells are dominated by Palynomacerals I and II (vitrinite) which are source materials for kerogen type III which is gas prone [18] [21]. Palynomaceral III (cutinite) which falls under kerogen type II (oil and gas prone) was found in negligible quantity, while Palynomaceral IV (Inertinite) is purely dead carbon [18] [21]. Geochemically, it can be inferred that the studied well sections are predominantly *Gas prone* based on the dominance of organic materials that are responsible for gas generation.

Table 1. Spore color index of wells (modified after: [22]).

Organic Thermal Maturity	Spores/Pollen Colour	Spores Colour Index (SCI)	
Immature		1	
		2	
Mature Main Phase of Liquid Petroleum Generation		3	ER-51 & UK-2
		4	AP-4
		5	
		6	
Dry Gas or Kerogen		7	
		8	
		9	
		10	

5.4. Paleoenvironment

Paleoenvironmental deduction from foraminifera study was made primarily on the assemblage, abundance and diversity of benthic species. The presence or absence of planktic foraminifera also serves as a determining factor. The abundance of deep water foraminifera such as *Uvigerina subperegrina*, *Cibicidoides mundulus*, *Karreriella siphonella*, *Trochammina globigeriniformis*, and *Bathysiphon* sp. for AP-4 and ER-51 conform to a marine depositional environment. These wellsare interpreted to have fluctuated between outer neritic and upper bathyal [23] [24] [25]. UK-2 well is characterized by little occurrence of both calcareous benthic foraminiferal species and arenaceous benthic suggestive of an outer neritic to inner neritic environment of deposition. The assemblage includes *Uvigerina auberiana*, *Haplophragmoides* spp., *Textularia* spp., *Florilus ex. gr. costiferum*, *Ammonia tepida*, *Hoeglundina elegans*, *Quinqueloculina microcostata*, *Sphaeroidina bulloides* and *Saccammina complanata*.The paleoenvironmental interpretations were guided by varied micropaleontological criteria including the occurrence of environmental diagnostic benthic foramaniferal species [26] [27] [28].

Palynological analysis reveals fair to moderate records of land-derived pollen and spores with few marine indicators. AP-4 well consists of moderate records of land-derived pollen and spores including *Zonocostites ramonae*, *Monoporites annulatus*, *Retitricolporites irregularis*, *Psilatricolporites crassus*, *Sapotaceae*, *Cyperaceaepollis* spp., *Retibrevitricolporites protrudens*, *Laevigatosporites* spp., *Verrucatosporites* spp., *Pteris* spp., and *Acrostichum aureum*, and few dinoflagellate cysts, particularly *Polysphaeridium zoharyi*, *Lingulodinium machaerophorum* and *Leiosphaeridia* spp. which is indicative of a Shallow Marine environment of deposition. ER-51 also has moderate records of land-derived forms which include: *Monoporites annulatus*, *Zonocostites ramonae*, *Psilatricolporites crassus*, *Crassoretitriletes vanraadshooveni*, *Sapotaceae*, *Pteris* spp., *Acrostichum aureum*, *Laevigatosporites* spp., and *Verrucatosporites* spp. Few marine indicators, microforaminiferal wall linings and*Leiosphaeridia* spp. were also recorded. The above assemblage is indicative of a Shallow Marine environment of deposition. A coastal deltaic, near shore environment of deposition is proposed for UK-2 well due to few records of land-derived palynomorphs including *Monoporites annulatus*, *Zonocostites ramonae*, *Psilatricolporites crassus*, *Laevigatosporites* spp., *Acrostichum aureum* and *Verrucatosporites* spp. and a single record of *Leiosphaeridia* spp.

The data show that intervals of the studied wells are dominated terrestrial environment with marine influence. Thus, a predominant fluvial to shallow marine deposit is suggested for the wells as PMI values are <100 (**Tables 2-4**). Occurrence of *Botrycoccus braunii* in AP-4 (Samples 28, 29, 30, 39, 40) and UK-2 (sample 12) which is freshwater algae also suggest freshwater source near marine environment marginal marine environment. Therefore, paleoenvironment that fluctuate between continental and shallow marine environments is suggested for AP-4 and UK-2 wells.

Palynofacies studies reveal the dominance of AOM and PM II across the studied well sections. The high percentage of AOM in organic rich sediments indicates enhanced preservation in reducing conditions and increased stability of water column, resulting in dysoxic or anoxic bottom conditions ([21] [29] [30]). In oxygen deficient basins, with high AOM preservation, allochtonous terrestrial material is dominant in the immediate vicinity of fluvio-deltaic sources or within turbidites ([29] [31]). The phytoclast contents of this facies suggest the proximity to a fluvio-deltaic source [32]. Equal proportions of AOM, opaque and translucent phytocalsts suggest a non-marine (marginal marine) environment under dysoxic condition. Based on this, a shallow marine environment was inferred.

Table 2. Paleoenvironment interpretation from P.M.I. value of the palynomorphs distribution (AP-4 Well).

Depth (m)	Pollen	Spore	DC	Algae	Total	PMI	Pollen (%)	Spore (%)	Microplankton (%)
1914 - 1932	-	5	-	-	5	0	0	100	0
1932 - 1950	5	19	-	-	24	0	20.8	79.2	0
1950 - 1968	2	2	-	-	4	0	50	50	0
1968 - 1986	1	1	-	-	2	0	50	50	0
1986 - 2005	1	1	1	-	3	33.3	33.3	33.3	33.3
2005 - 2023	2	5	-	-	7	0	28.6	71.4	0

Continued

2023 - 2041	1	16	-	-	17	0	5.9	94.1	0
2041 - 2050	1	16	3	-	20	16.7	5	80	15
2050 - 2064	3	5	-	-	8	0	37.5	62.5	0
2064 - 2082	3	6	-	-	9	0	33.3	66.7	0
2082 - 2100	7	21	1	-	29	3.4	24.1	72.4	3.4
2100 - 2118	3	8	-	-	11	0	27.3	72.7	0
2118 - 2136	7	33	-	-	40	0	17.5	82.5	0
2136 - 2155	6	15	-	-	21	0	28.6	71.4	0
2155 - 2173	3	30	-	-	33	0	9.1	90.9	0
2173 - 2191	3	7	-	-	10	0	30	70	0
2191 - 2209	-	11	-	-	11	0	0	100	0
2209 - 2227	2	13	-	-	15	0	13.3	68.7	0
2227 - 2245	1	21	-	-	22	0	4.5	95.5	0
2245 - 2264	3	15	-	-	18	0	16.7	83.3	0
2264 - 2282	2	7	-	-	9	0	22.2	77.8	0
2282 - 2300	3	13	-	-	16	0	18.8	81.2	0
2300 - 2318	2	9	-	-	11	0	18.2	81.8	0
2318 - 2336	5	8	-	-	13	0	38.5	61.5	0
2336 - 2355	6	22	-	-	28	0	21.4	78.6	0
2355 - 2373	3	7	-	-	10	0	30	70	0
2373 - 2391	1	10	1	-	12	8.3	8.3	83.3	8.3
2391 - 2409	3	17	1	3	24	19	12.5	70.8	16.7
2409 - 2427	3	6	2	2	13	40	23.1	46.2	30.8
2427 - 2445	3	6	2	1	12	30	25	50	25
2445 - 2464	-	13	-	-	13	0	0	100	0
2464 - 2482	2	3	-	-	5	0	40	60	0
2482 - 2500	-	2	-	-	2	0	0	100	0
2500 - 2518	1	11	-	-	12	0	8.3	91.7	0
2518 - 2536	4	5	-	-	9	0	44.4	55.6	0
2536 - 2554	2	6	-	-	8	0	25	75	0
2554 - 2573	-	6	3	-	9	42.9	0	66.7	33.3
2573 - 2591	3	5	-	-	8	0	37.5	62.5	0
2591 - 2609	-	5	-	1	6	16.7	0	83.3	16.7
2609 - 2627	-	2	1	1	4	66.7	0	50	50
2627 - 2645	4	3	-	-	7	0	57.1	42.9	0
2645 - 2664	2	13	-	-	15	0	13.3	86.7	0
2664 - 2682	3	6	-	-	9	0	33.3	66.7	0

Table 3. Paleoenvironment interpretation from P.M.I. value of the palynomorphs distribution (ER-51 Well).

Depth (m)	Pollen	Spore	DC	Algae	Total	PMI	Pollen (%)	Spore (%)	Microplankton (%)
1027 - 1045	-	7	-	-	7	0	0	100	0
1045 - 1064	3	1	1	-	5	20	60	40	40
1064 - 1082	1	2	-	-	3	0	33.3	66.7	0
1082 - 1100	2	5	-	-	7	0	28.6	71.4	0
1100 - 1118	2	2	-	-	4	0	50	50	0
1118 - 1136	2	4	-	-	6	0	33.3	66.7	0
1136 - 1155	2	6	-	-	8	0	25	75	0
1155 - 1173	1	2	-	-	3	0	33.3	66.7	0
1173 - 1191	1	6	-	-	7	0	14.3	85.7	0
1191 - 1209	2	1	-	-	3	0	66.7	33.3	0
1209 - 1227	3	5	1	-	9	11.1	33.3	55.6	11.1
1227 - 1245	1	1	-	-	2	0	50	50	0
1245 - 1264	1	3	-	-	4	0	25	75	0
1264 - 1282	1	1	1	-	3	33.3	33.3	33.3	33.3
1282 - 1300	-	4	-	-	4	0	0	100	0
1300 - 1318	1	3	-	-	4	0	25	75	0
1318 - 1336	-	2	-	-	2	0	0	100	0
1336 - 1355	1	13	-	-	14	0	7.1	92.9	0
1355 - 1373	3	3	-	-	6	0	50	50	0
1373 - 1391	3	6	1	-	10	10	30	60	10

Table 4. Paleoenvironment interpretation from P.M.I. value of the palynomorphs distribution (AP-4 Well).

Depth (m)	Pollen	Spore	DC	Algae	Total	PMI	Pollen (%)	Spore (%)	Microplankton (%)
389 - 409	-	2	2	-	4	0	0	50	50
409 - 427	1	3	-	-	4	0	25	75	0
427 - 445	2	3	2	-	7	33.3	28.6	42.9	28.6
445 - 464	1	3	2	-	6	40	16.7	50	33.3
464 - 482	3	5	-	-	8	0	37.5	62.5	0
482 - 500	2	8	-	-	10	0	20	80	0
500 - 518	2	6	-	-	8	0	25	75	0
518 - 536	2	3	-	-	5	0	40	60	0
536 - 555	6	2	-	-	8	0	75	25	0
555 - 573	2	4	-	-	6	0	33.3	66.7	0
573 - 591	-	7	-	-	7	0	0	100	0
591 - 603	2	2	-	1	5	20	40	40	20

5.5. Source Rock Evaluation

Identifying the source bed in petroleum exploration cannot be over emphasized, this is done by means of organic geochemical modelling to determine the concentration, type, and thermal maturation of the organic matter presumed to exist in the source rock [33].

The quantity, type, and quality of petroleum generated by the wells of interest were determined from Rock-Eval analysis. The hydrocarbon type generated from any source rock is dependent on the quality or type of organic matter deposited in the source rock [33]. Hydrocarbon potentials and parameters such as the hydrogen index (HI), Oxygen Index (OI), Generative Potential (GP), Production Index (PI), Ratio of source rock potential to organic carbon dioxide yield S_2/S_3, Cross plots of HI against OI; and Cross plots of S_2 against TOC were utilized in the identification of the type and quality of the hydrocarbon, thermal maturity was also determined from T_{max} inference (**Table 5**).

Organic Matter Quantity

This is the quantity of organic matter present in a rock and is a percentage of total organic carbon (TOC), which is a measure of the organic matter richness expressed as the percentage weight of dry rock sample [33]. Petroleum is a generative product of organic matter disseminated in the source rock. For a source rock to expel oil, the minimum organic matter necessary must range between 0.5% to 1.4% TOC [34] [35].

TOC values obtained from well ER-51 values range from 3.0 - 3.6 wt% with an average of 3.39 wt%. The TOC values here are consistent between 2 - 4 which is indicative of a very good petroleum potential [35]. In well AP-4, TOC values range from 4.47 - 6.37 wt% with an average of 5.39 wt%, which is indicative of

Table 5. Results of geochemical analyses.

Well	Sample ID	Upper depth (M)	Lower Depth (M)	Median Depth (M)	MINC (%)	TOC (wt%)	S_1 (mgHC/g)	S_2 (mgHC/g)	S_3 (mgHC/g)	Tmax (°C)	Calculated %R_o RE Tmax	HI (S_2x100/TOC	OI (S_3x100/TOC)	S_2/S_3 Conc. (mgHC/mgCO$_2$)	S_1/TOC Norm Oil Content	PI ($S_1/(S_1 + S_2)$)	GP ($S_1 + S_2$)
ER-51	S1	1027	1087	1057	0.69	3.60	7.64	2.82	2.58	431	0.60	78	72	1	212	0.73	10.46
	S2	1117	1177	1147	0.38	3.55	9.87	2.59	1.73	430	0.58	73	49	1	278	0.79	12.46
	S3	1207	1297	1252	0.25	3.41	6.33	1.81	1.53	412	0.26	53	45	1	186	0.78	8.14
	S4	1327	1391	1359	0.69	3.00	5.21	5.06	2.94	436	0.69	169	98	2	174	0.51	10.27
AP-4	S1	1914	2024	1969	0.72	5.94	27.99	5.42	3.08	432	0.62	91	52	2	471	0.84	33.41
	S2	2254	2304	2279	0.51	6.37	27.30	7.54	2.83	430	0.58	118	44	3	429	0.78	34.84
	S3	2544	2682	2613	0.63	4.47	35.03	11.54	1.75	430	0.58	258	39	7	784	0.75	46.57
UK-2	S1	389	419	404	0.48	2.73	7.91	5.59	3.27	431	0.60	205	120	2	290	0.59	13.50
	S2	419	569	494	0.30	2.73	13.07	2.95	2.95	415	0.31	108	113	1	479	0.82	16.02
	S3	569	603	586	0.43	2.48	8.75	6.15	6.15	430	0.58	248	122	2	353	0.59	14.9

an excellent source potential [35]. For well UK-2, TOC values range from 2.48 - 2.73 wt% with an average value of 2.64 wt%. This inference according to [36] is of a very good generative potential.

Free Oil Content (S_1)

This is the measure of the thermally extractable hydrocarbons present in the whole rock accounted for by the materials in the C_7 - C_{32+} range, depending on the S_1 hold time, excluding the heavy molecular weight resin and asphaltene fractions which are liberated during higher temperatures of the S_2 cycle [37]. The S_1 values for Well ER-51 range from 5.21 - 9.87 mmHC/g rock (average 7.26 mmHC/g rock), suggesting a very good free oil content. In well AP-4 and UK-2, S_1 range from 27.30 to 35.03 mmHC/g rock (average 30.11 mmHC/g rock) and 7.91 mmHC/g rock and 13.07 mmHC/g rock (average 9.91 mmHC/g rock) respectively which is an excellent free oil content. It can therefore be interpreted that the values of S_1 obtained in each well that free oil content is very good to excellent [38].

Source Rock Potential (S_2)

This is the magnitude of pyrolysate yield obtained from the cracking of Kerogen. It represents the present-day source rock potential [39]. The S_2 values for this study in wells ER-51, AP-4 and UK-2 range between 1.81 to 5.06 mmHC/g rock (average 3.05 mmHC/g rock); 5.42 - 11.54 mmHC/g rock (average 8.17 mmHC/g rock); and 2.95 - 6.15 mmHC/g rock (average 4.89 mmHC/g rock) respectively. These values are fair to good in well ER-51, good to excellent in AP-4 and fair to excellent in UK-2 potentials for generating oil and gas [38].

Organic Matter (*Kerogen*) *Type and Quality*

The kerogen type and quality are an important parameter in source rock evaluation potential due to its influence on the nature of the hydrocarbon products [33] [40] [41]. The organic geochemical modelling based on kerogen type and quality can be estimated using the following parameters which are obtained from Rock-Eval Pyrolysis analysis; Hydrogen and Oxygen Indices (HI and OI); Ratio of source rock potential to organic carbon dioxide yield S_2/S_3, Cross plots of HI against OI; and S_2 against TOC.

Hydrogen and Oxygen Indices (*HI and OI*)

Hydrogen index (HI) represents the hydrogen richness and oxygen index (OI) depicts the oxygen content of the kerogen, both relative to the total organic carbon content [42]. [38] suggested the HI values required as baselines for gas prone organic matter, gas-oil prone organic matter and oil prone organic matter in mature source rocks. It is very important to determine the Organic matter types and quality present in source rocks as they primarily influence the type of hydrocarbon produced at maturation.

In this study, results obtained from well ER-51 shows that HI values range between 78 and 169 which is indicative of gas prone organic matter. In well AP-4 and UK-2, HI values range between 91 and 258; and 108 and 248 respectively, indicating that the wells are oil and gas prone is in the mixed organic matter zone.

Pseudo Van Krevelen diagram (**Figure 8**) generated to deduce organic matter (kerogen) type (HI vs OI) of the studied wells in this research show that organic matter from well ER-51 are Type III kerogen and in well AP-4 as well as UK-2 the kerogen type present are Type III/II kerogen which generate oil and gas with appropriate maturity.

The kerogen quality determined from Rock-Eval inferences can be deduced by plotting the source rock potential against Total Organic Carbon (TOC). The environment of origin of the sediments can be inferred from the kerogen quality plot (**Figure 9**) which is a plot of hydrocarbon generation potential (S_2) against the Total Organic Carbon (TOC).

Kerogen quality plots show that well ER-51 is Type III which are gas prone and are of terrestrial origin; well AP-4 is within Type II and Type III with about 66.66% of the well gas prone (Type III) and the remaining 33.3% of the well, being Type III/II (gas-oil-prone). 33.33% of the sediments here are of mixed (marine and terrestrial) origin with the remaining 66.66% being terrestrial derived

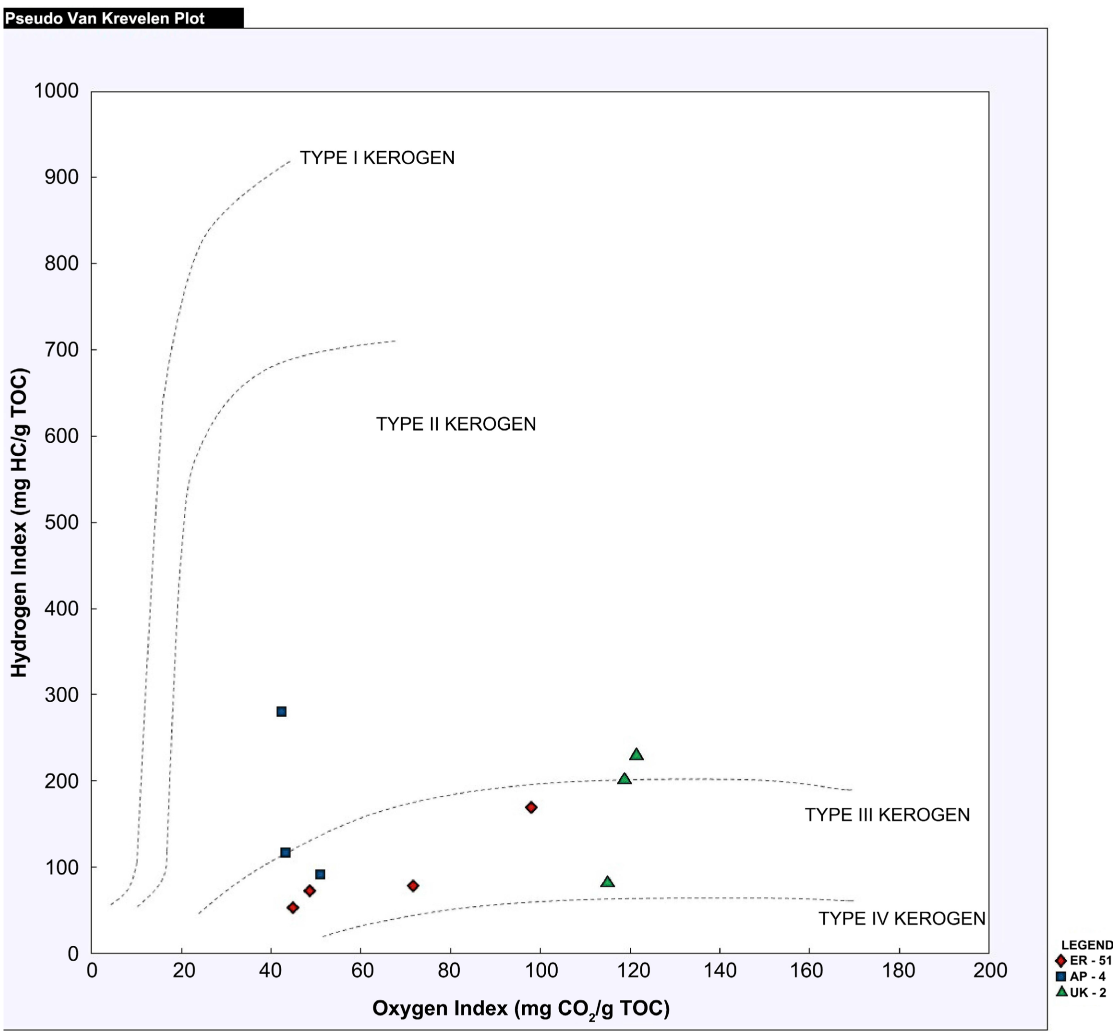

Figure 8. Modified Van Krevelen diagram showing that organic matter is mainly Type III and some Type II (after [43]).

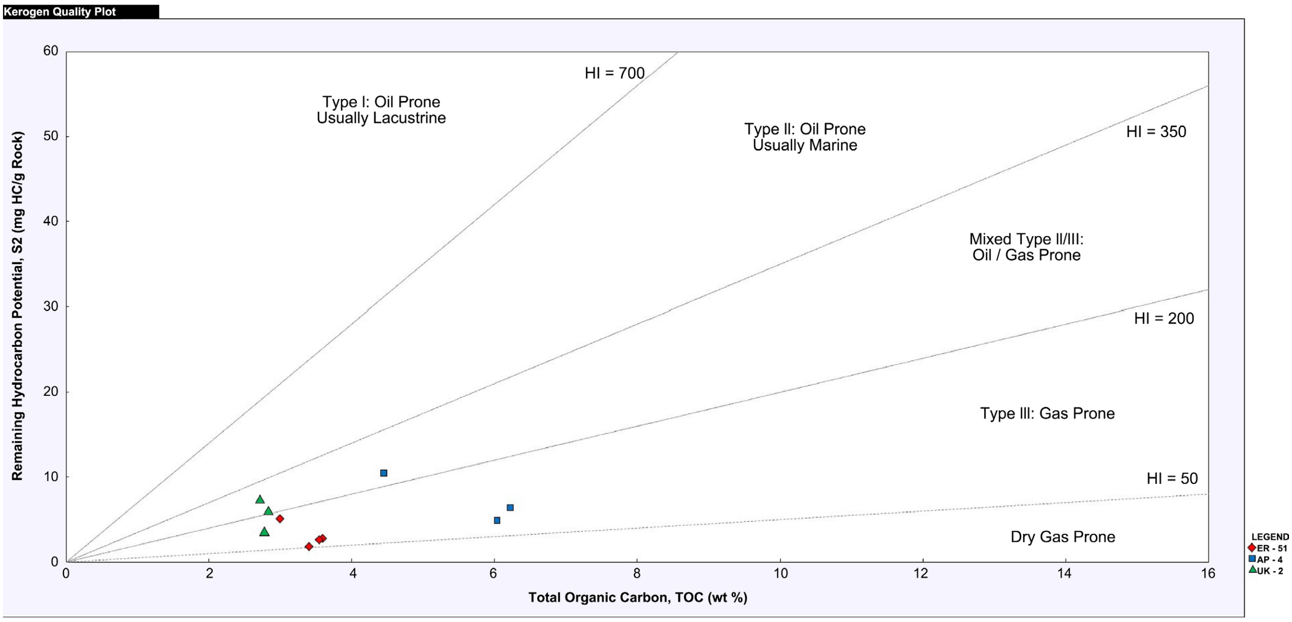

Figure 9. Plot showing the Kerogen Type and sediment origin in the wells of study (mainly marine and terrestrial in origin (after [44]).

organic matter; Kerogen quality in UK-2 shows that about 33.33% of the well fall into Type III which is gas prone and is of terrestrial origin while the remaining 66.66% are Type III/II which are gas-oil-prone and are of terrestrial and marine formed organic matter.

Maturity of Organic Matter

Thermal maturity of organic matter is the extent of the heat driven reactions involved in converting organic rich sediments into petroleum [45]. To determine the maturity of source rock organic matter, many parameters are employed such as the Pyrolysis temperature (T_{max}), Vitrinite Reflectance (R_o) and Production Index (PI).

Pyrolysis temperature (T_{max})

The pyrolysis temperature (T_{max}) is used often as an indicator for rate of maturity of the source rock organic matter. This is due to the fact that as the temperature of maximum rate of pyrolysis increases within the source rock, maturity of kerogen present also increases. The temperature at which S_2 peak reaches maximum (T_{max}) has over time become an important part of Rock – Eval parameters necessary for geochemical modelling. The values of T_{max} obtained in this study show that wells ER-51, AP-4 and UK-2 have values ranging from 412 to 436, 432 to 450, and 415 to 430 respectively. These values obtained are indicative of organic matter in immature to early mature window, early mature window, and an immature to early window respectively.

When the Hydrogen Index (HI) is plotted against the T_{max} (**Figure 10**), results obtained show that; in well ER-51, 25% of the well is in the immature area and the remaining 75% falls in the early oil generation window; in well AP-4, 66.6% is early mature and 33.3% is in the early part of the oil generation window, just

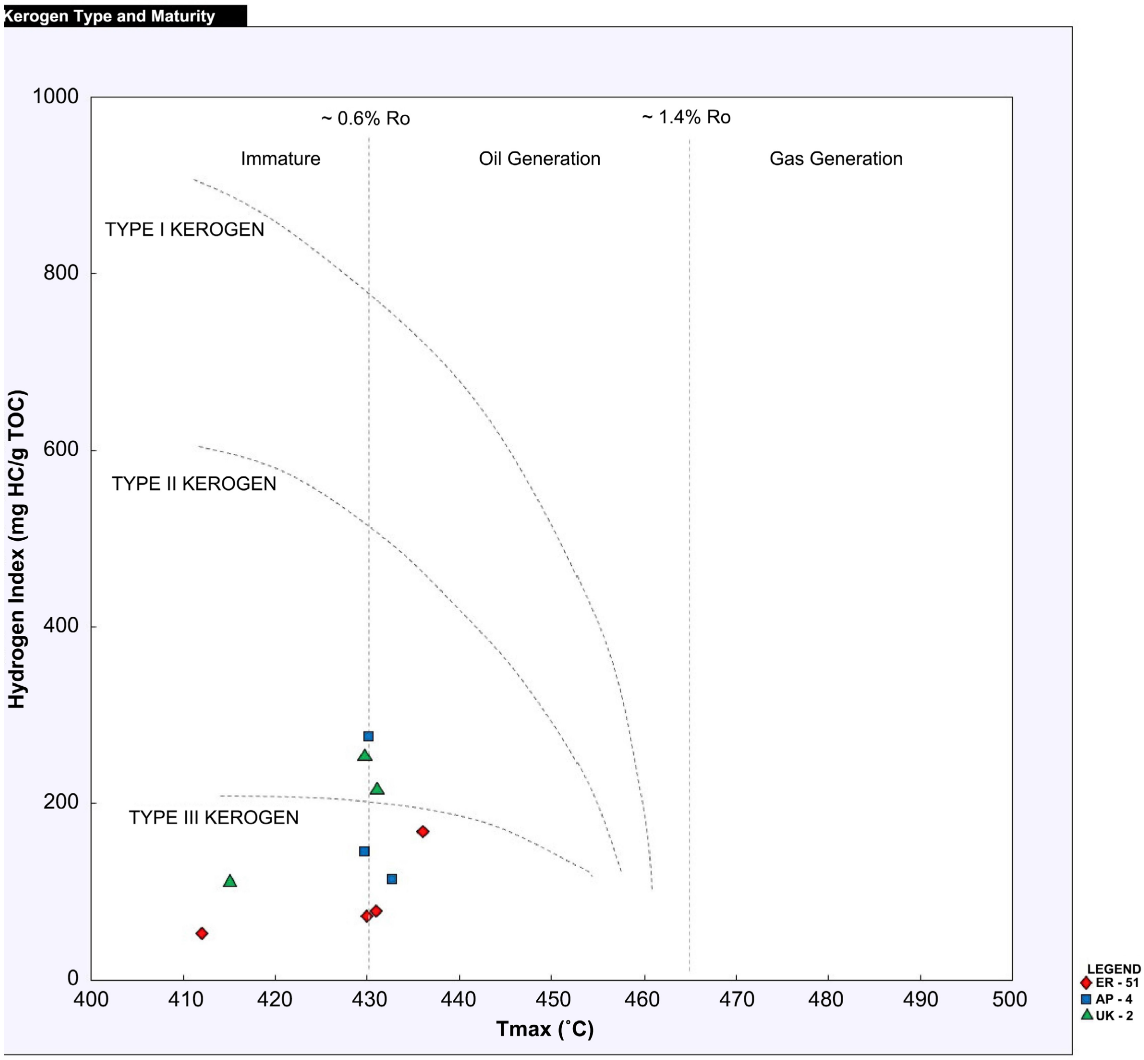

Figure 10. Plot of HI vs T_{max} showing that the Kerogen in the wells of study are in the immature to early oil generation window (after [44]).

above the ~0.6%R_o line of maturity in the oil generation window showing that the well is marginally mature; and in UK-2, 33.3% is in the immature window and 66.66% of the well is in the oil generation window having really low R_o values which is indicative of early maturity.

Vitrinite Reflectance (R_o%)

Another parameter utilized in assessing organic matter maturity is Vitrinite Reflectance (R_o%). In this study, calculated Vitrinite Reflectance range from 0.26 - 69 in ER-51 which indicates that the well is immature to marginally mature. In AP-4, R_o range from 0.58 - 0.62 which is indicative of marginally mature source rocks. In UK-2, R_o values range from 0.31 - 0.60 which suggests immature to early mature source rocks. It is observed that Vitrinite reflectance readings obtained from each well supports deductions made from T_{max} values obtained in each well.

Production Index

Source rock maturity can also be assessed from the Production Index (PI) which is the ratio of free oil content (S_1) to the sum of free oil content (S_1) and source rock potential (S_2) [46]. PI of organic matter increases with maturity and indicates the presence of epigenetic hydrocarbons.

Mathematically, the Production Index is given as; PI = $S_1/(S_1 + S_2)$.

Production index values obtained in Wells ER-51, AP-4 and UK-2, range from 0.51 - 0.73, 0.75 - 0.84 and 0.59 - 0.82 respectively. These values are greater than 0.30, indicating gas generation/oil cracking window. Cross plots of PI against T_{max} inferences show that organic matter in well ER-51 is 25% immature in the stained or contaminated zone and the remaining 75% is marginally mature in the oil zone; in AP-4 the plots show that the well is within the oil zone and is marginally mature; in UK-2, the plots show that 33.33% of the well is immature and is in the contaminated or stained zone, while 66.66% of the well is in the marginally mature window in the oil zone (**Figure 11**).

5.6. Fourier Transform Infrared (FTIR) Spectrometry Analysis

Fourier transform infrared spectroscopy analysis carried out on six (6) ditch samples from the three wells (AP-4, UK-2 and ER-51) revealed crucial information on the molecular structure of organic components of the source rock of study which was important for extensive chemical characterization of geochemistry and thermal maturation of organic matter rich source rock of the Niger Delta. The infrared (IR) spectra displayed distinct peaks for the aliphatic (CH_2 and CH_3), carboxyl/carbonyl and aromatic compounds needed for organic matter maturation, Kerogen typing and organic matter characterization studies. The IR spectra as obtained from FTIR spectroscopy for the studied wells are shown in **Figures 12-17**.

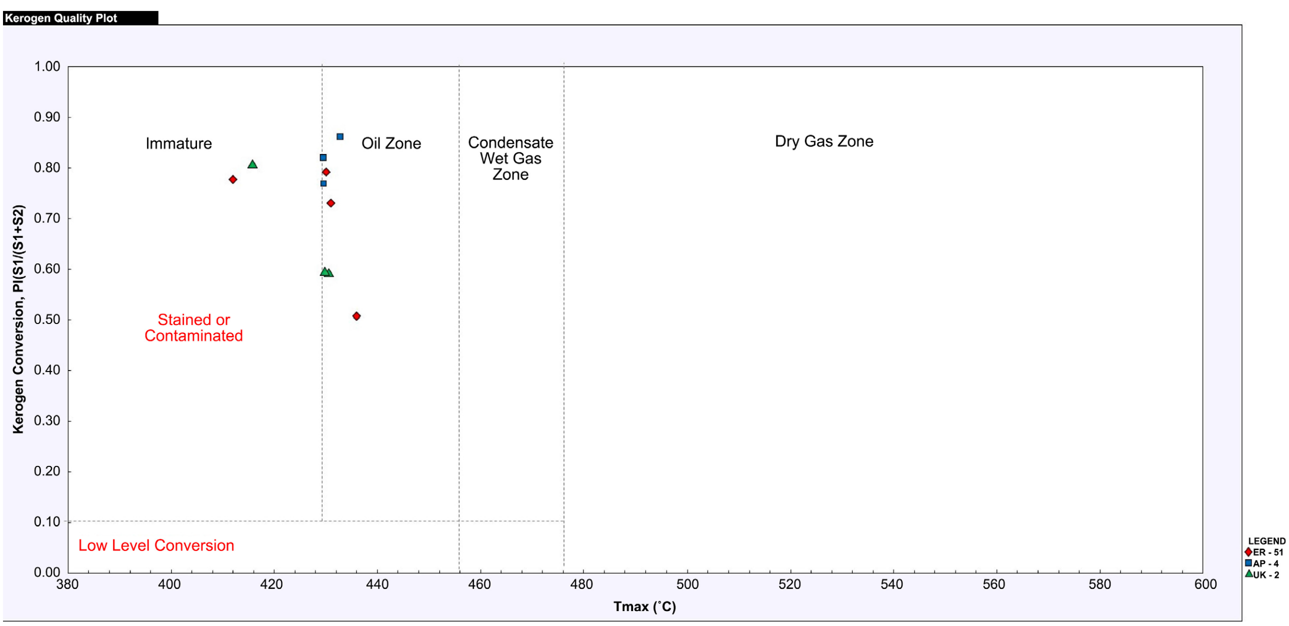

Figure 11. Kerogen quality of the studied wells (after [44]).

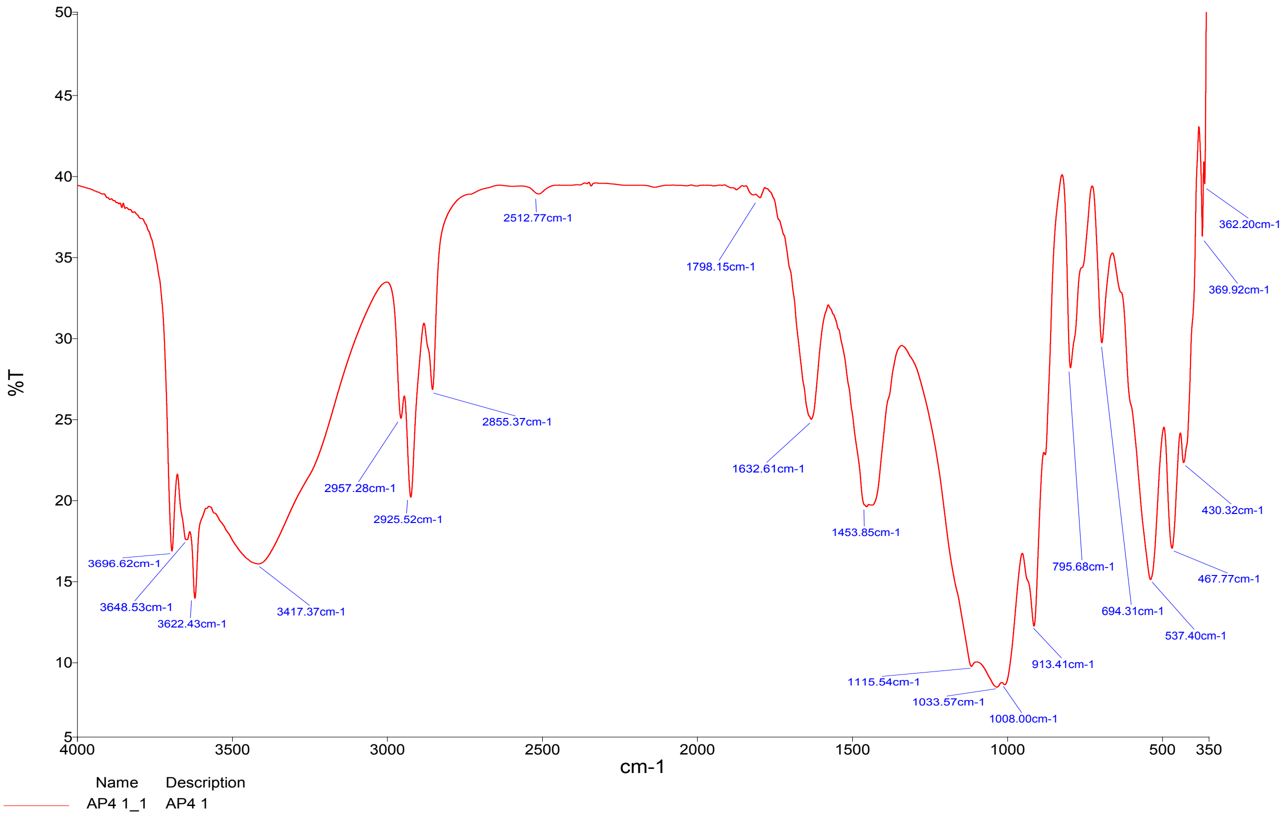

Figure 12. IR spectrum for well AP-4 (sample G1).

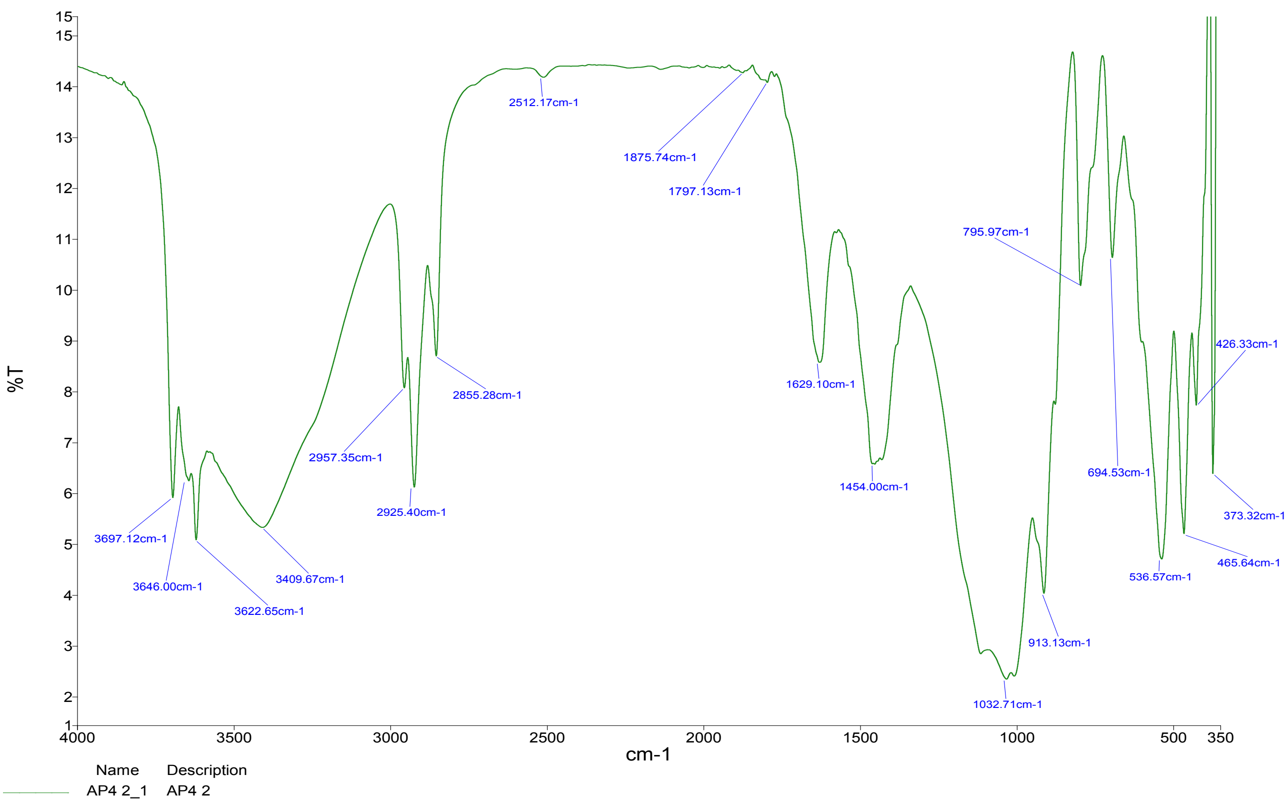

Figure 13. IR spectrum for well AP-4 (sample G2).

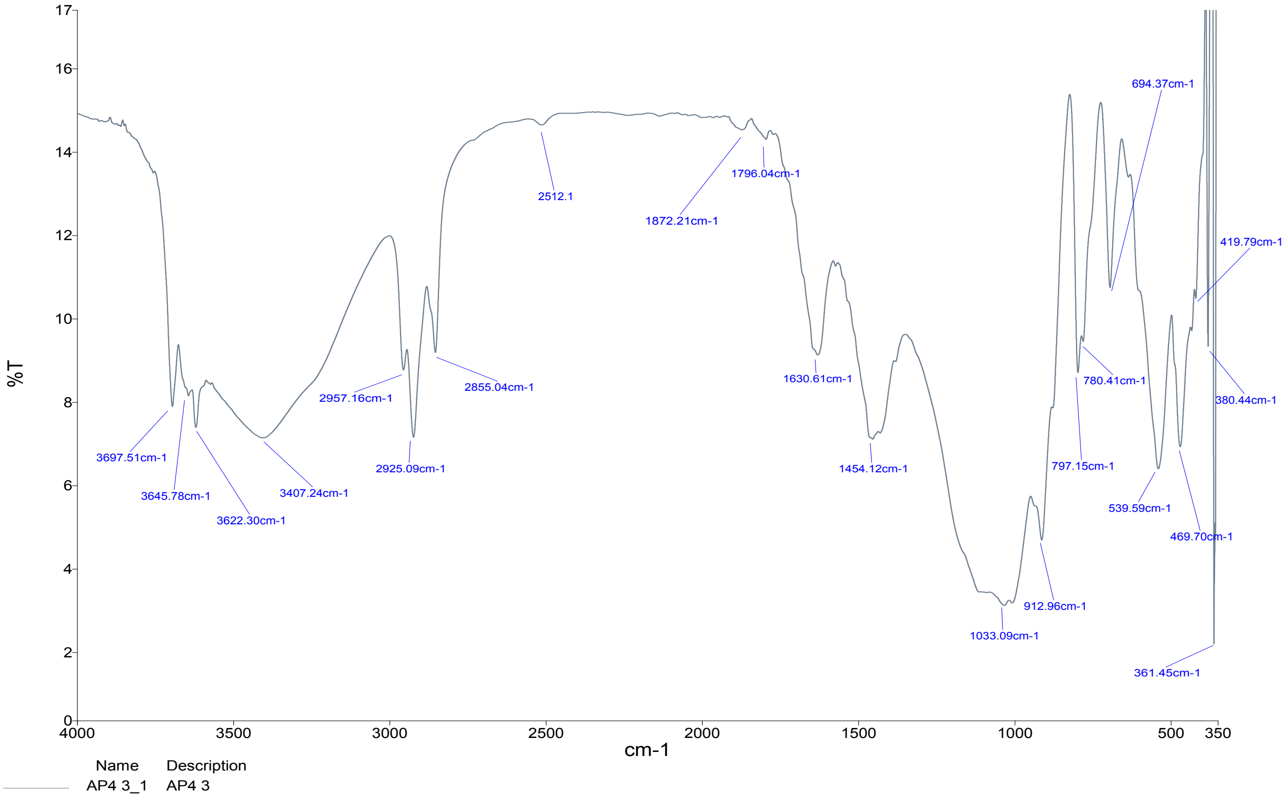

Figure 14. IR spectrum for well AP-4 (sample G3).

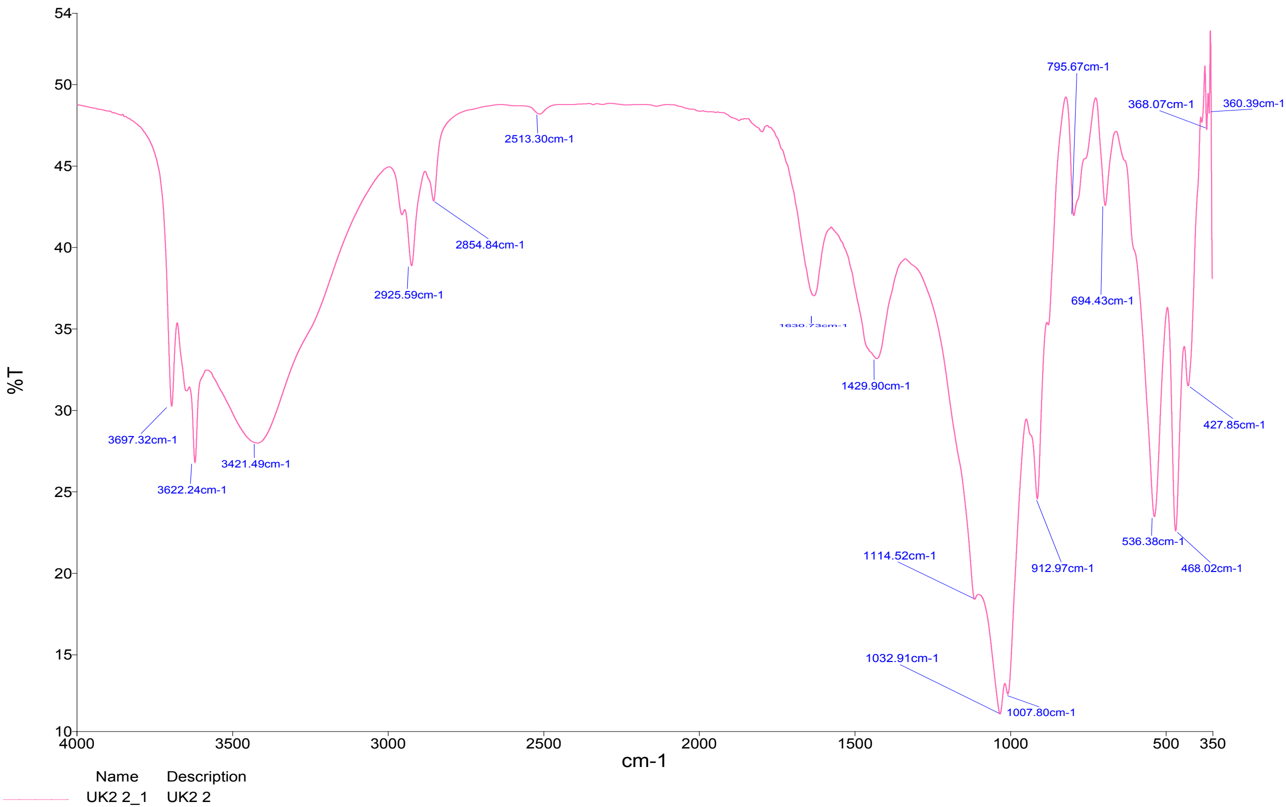

Figure 15. IR spectrum for well UK-2 (sample G1).

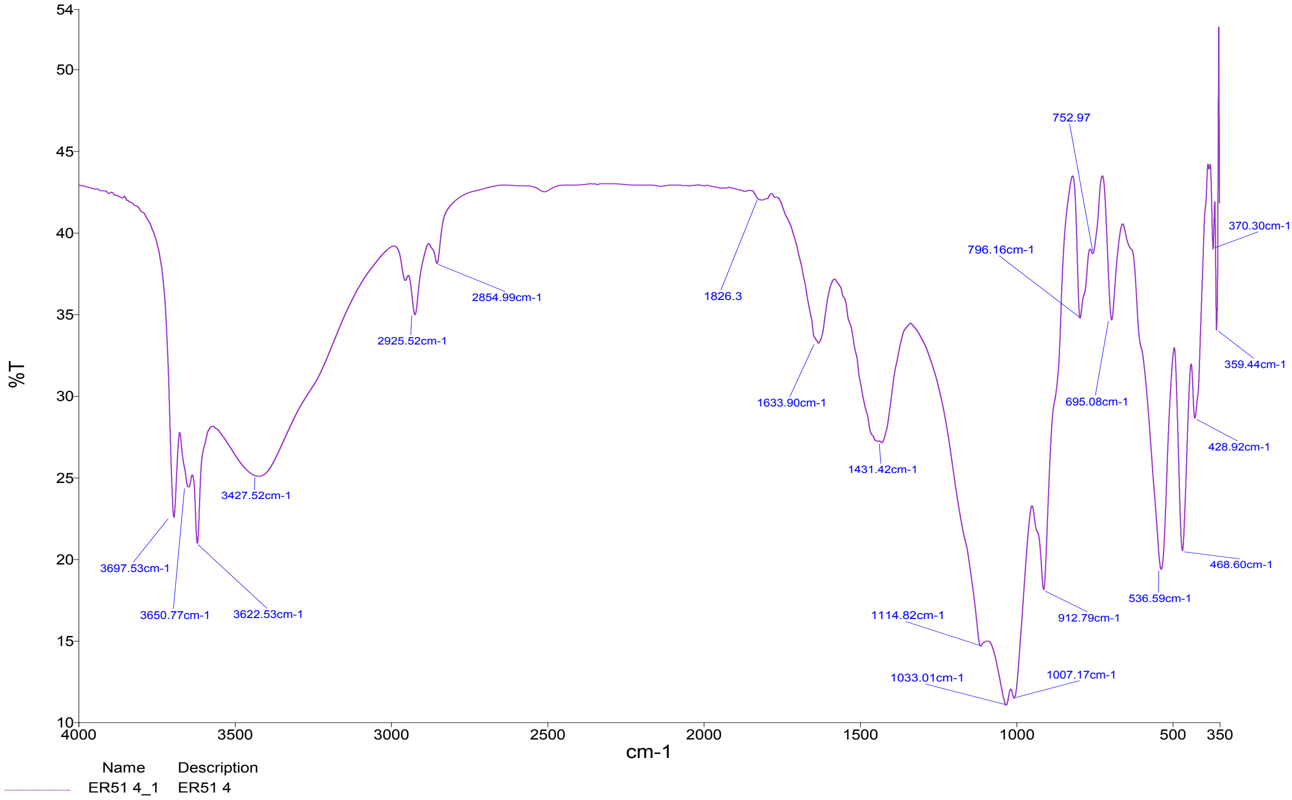

Figure 16. IR spectrum for well ER-51 (sample G1).

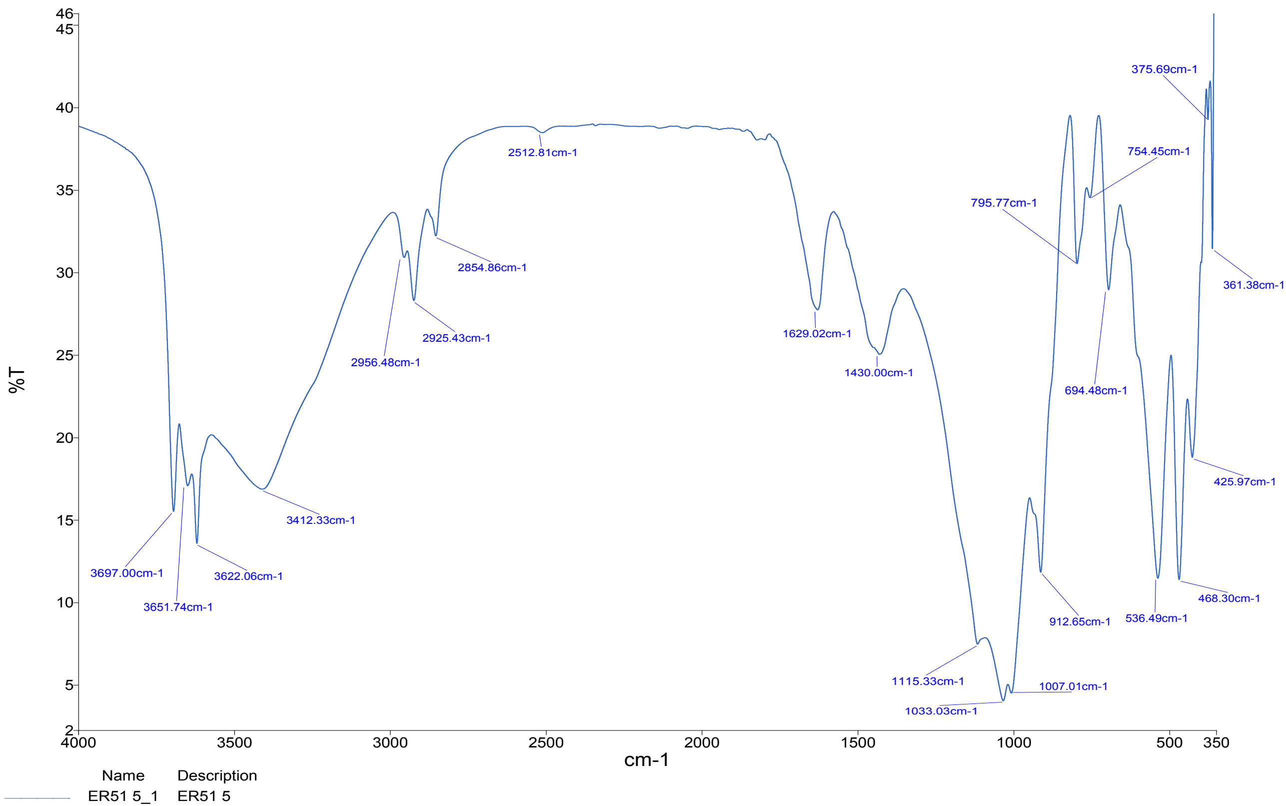

Figure 17. IR spectrum for well ER-51 (sample G2).

Kerogen Maturity and Typing

The parameters obtained from the IR spectra (Table 6) were used to deduce the kerogen type and maturity via A-factor against C-factor plotting [47], (Figure 18). These factors are determined by comparing the ratios of changes in intensity of aliphatic peaks and carboxy/carbonyl peaks relative to aromatics peaks

Table 6. A and C-factors generated from IR spectra.

WELL	SAMPLE No	CH_2	CH_3	CARBOXYL/ CARBONYL	AROMATICS	A-FACTOR	C-FACTOR	KEROGEN TYPE
AP-4	G1	2855.31	2925.52	1798.15	1632.61	0.780	0.520	Type I
	G2	2855.28	2925.40	1797.13	1629.10	0.779	0.525	Type I
	G3	2855.04	2925.09	1796.04	1630.61	0.779	0.524	Type I
ER-51	G1	2854.99	2925.52	1826.30	1633.90	0.779	0.528	Type I
	G2	2854.86	2925.43	1820.4	1629.02	0.780	0.528	Type I
UK-2	G1	2854.84	2925.52	1790.40	1630.73	0.780	0.523	Type I

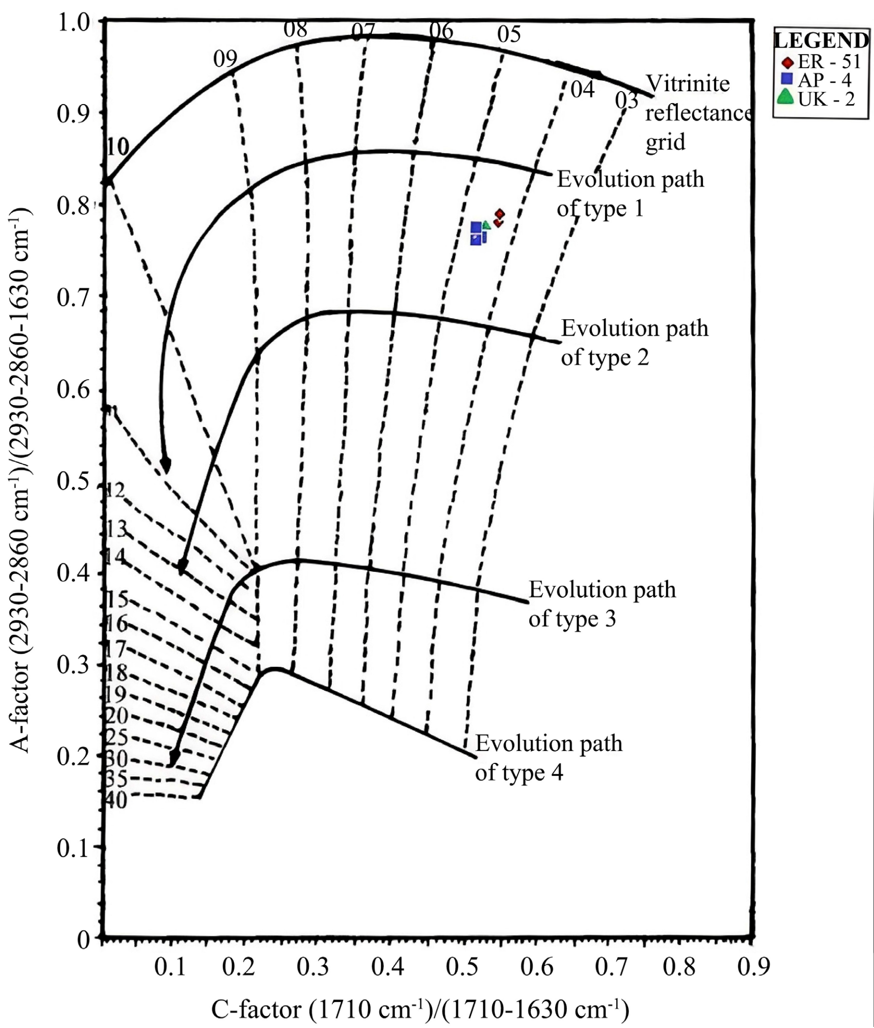

Figure 18. Plot of A-factor versus C-factor on the IR-chart (after [47]).

[48] as observed from the spectra. The A-Factor and C-Factor were calculated using the equation:

$$\text{A-Factor} = \text{Aliphatic} + \text{Aromatic}$$

where Aliphatic = $CH_2 + CH_3$

$$\text{C-Factor} = \text{Carboxyl/Carbonyl} + \text{Aromatic}$$

A-factor versus C-factor plot shows that all samples plotted along the Kerogen Type I evolution pathway which are oil prone sediments sourced from algal materials in a lacustrine environment. This results, however, contradicts the Type II/III results already obtained from Rock-Eval/Pyrolysis.

The Vitrinite Reflectance (VR_o) equivalent obtained from the A-factor versus C-factor plot (**Figure 18**) is between 0.4 - 0.5 and indicates that the source rock is an immature source rock. The results of VR_o obtained from the FTIR analysis supports assertions from the results of T_{max} and VR_o obtained from Rock-Eval/Pyrolysis.

The hydrocarbon source potential (HSP) given by A-factor X TOC X 10, which is influenced by the presence of aliphatic hydrocarbons in the kerogen was determined from the IR spectral and indicates that the source rock would provide an excellent yield of hydrocarbons. This result correlates with results obtained from genetic potential ($S_1 + S_2$) obtained from Rock-Eval studies.

Organic Geochemical Characterization

The prominent functional groups present in the organic matter of the wells of study are shown in **Table 7**. These functional groups were obtained from the IR spectra of the wells under study (**Figures 12-15**). The major functional groups observed from the IR spectrum includes; O – H stretching of free alcohol with wavelength between 3700 - 3600 cm^{-1} (e.g. stigmasterol), N – H stretching of primary amine (e.g. 2-amino-5-nitrothiazole, 4-nitro aniline) having wavelength of 3500 - 3400 cm^{-1}, C – H stretching of alkanes with wavelength of 2957 - 2855 cm^{-1} (e.g. paraffin oil, docosane, dodecane octadecane), C – H bending of the methyl group some of which includes 3-methyloctane, isopropyl cyclohexane with wavelength of 1453 - 1430 cm^{-1}, C = C bending of monosubstituted alkane

Table 7. Functional groups of peaks obtained in the IR spectrum of wells studied.

PEAK	WAVELENGTH (cm^{-1})	MODE OF VIBRATION	FUNCTIONAL GROUP
P1	3700 - 3600	O - H Stretching	Free Alcohol
P2	3500 - 3400	N - H Stretching	Primary Amine
P3	2957 - 2855	C - H Stretching	Alkane
P4	1453 - 1430	C - H Bending	Methyl Group
P5	915 - 912	C = C Bending	Monosubstituted Alkane
P6	796	C - H Bending	Substituted Benzene
P7	537 - 500	C - Br Stretching	Halo Compound
P8	468 - 425	C - I Stretching	Halo Compound

e.g. 1-octadecane with wavelength of 915 - 912 cm^{-1}, C - H bending substituted benzene with wavelength of 796 cm^{-1}, C - Br and C - I stretching of halo compound having wavelengths of 537 - 500 cm^{-1} and 468 - 425 cm^{-1} respectively, example of these compounds includes bromo triphenyl methane and 1-Iodoheptane.

Biodegradation of Organic Matter

The functional groups present also serve as an indication of the biodegradability of the source rock hydrocarbons. Biodegradation involves the aerobic or anaerobic consumption of organic matter by bacteria in an oil reservoir [49]. As maturation of the organic matter increases, the aliphatic peaks increase while carboxyl/carbonyl peaks decrease, a further increase in maturation will decrease aliphatic peaks with no observable change in peaks of aromatic C=C bonds [18]. The presence of aliphatic saturates such as dodecane, tetradecane, hexadecane, heptadecane, 2-methyl octadecane, 4-methyl pentadecane, 2-methyl octane in the cuttings samples is an indication that the hydrocarbon is not biodegraded due to the high amount of aliphatic saturates in the samples the lower the level of biodegradability [50].

6. Conclusion

Foraminifera analysis reveals that samples from AP-4 and ER-51 wells are characterized by three (3) biozones each. AP-4 comprises the *Globorotalia tumida*/*Haplophragmoides compressa* Zone, *Neogloboquadrina dutertrei*/*Cyclammina minima* Zone and *Sphaeroidinella dehiscens*/*Haplophragmoides narivaensis* Zonewhile *Sphaeroidinella dehiscens*/*Haplophragmoides narivaensis* Zone, *Globorotalia plesiotumida*/*merotumida*/*Ammobaculites agglutinans* Zone and *Turborotalia acostaensis*/*Uvigerina subperegrina* Zone make up the ER-51 well. The wells are dated Late Miocene to Early Pliocene and Late Miocene respectively based on the constructed biozones. An Upper Bathyal depositional environment was inferred due to the abundant record of deep water foraminifera. Two biozones (N9 and N8) were established for UK-2 well. This well is characterized by a few occurrences of both calcareous benthic foraminiferal species and arenaceous benthic, suggesting an outer neritic to inner neritic environment of deposition. The moderate recovery and distribution of palynomorph enabled the establishment of two palynozones and four subzones across the three wells. *Monoporites annulatus* (P600) Zone was established in AP-4 well with *Magnastriatites howardii*/*Psilatricolporites crassus*/*Monoporites annulatus* (*P670*) and *Magnastriatites howardii*/*Praedapollis flexibilis*/*Pachydermites diederixi* (*P650*) as Subzones, all dated *Early Miocene*. *Echitricolporites spinosus* (*P700*) Zone was established for ER-51 and UK-2 wells, with *Verrutricolporites rotundi*/*Crassoretitriletes vanraadshooveni* (*P770*) and *Multiareolites formosus*/*Racemonocolpites hians* (*P780*) as Subzones dated *Middle Miocene.* A Shallow Marine environment of deposition was inferred for AP-4 and ER-51 well based on the recovery of land-derived pollen and spores while a coastal deltaic, near shore environment of deposition is proposed for this well due to few records of land-derived palynomorphs. Results from palynofacies analysis reveal that the samples were dominated by PM I and PM II which are equivalence of Types II and III kerogen, respectively. PM III (Type II kerogen) and PM IV (Type IV kerogen) were recorded in minute and moderate quantity respectively. The Spore Colour Index for the well samples ranges from 3/4 - 4 for UK-2 and ER-51 wells, and 4/5 - 5/6 for AP-4 well revealing that the sediment falls within the mature main phase of liquid hydrocarbon generation. The dominance of PM I and II is indicative of a shallow marine environment, and also the potential of higher gas hydrocarbon generation due to the high percentage of organic matter which acts as parent material for gas.

Organic geochemical inferences reveal that the TOC values of the samples from the section range from 2.48 - 6.37 wt% indicating that the source rock has a high organic matter richness ranging between very good to excellent hydrocarbon generation potential domain. These TOC values suggest that the prevailing conditions obtainable during deposition of sediments and organic matter favored organic matter production and preservation.

About 80% of the samples subjected to analyses were observed to contain Type III Kerogen which are gas prone since they are sourced from terrestrially derived organic matter, while 20% of the samples are made up of Type II Kerogen which are oil and gas prone made up of marine and terrestrially sourced organic matter. Pyrolysis Temperature (T_{max}) values range from 412˚C to 436˚C showing that the organic matter is in the Immature to Early mature window. Cross plots of HI vs T_{max} show that about 60% of the samples are within the immature area of the plot while the remaining 40% of the samples are within the early maturity window. The calculated Vitrinite reflectance (R_o) range between 0.26 to 0.69 indicating an immature to early mature source rock. This corroborated the T_{max} values. The plot of T_{max} and R_o against depth further confirms that the source rocks are in the immature to early maturity window. The PI values obtained from the area of study range from 0.51 - 0.84 which shows that the wells will readily generate gas. The cross plot of Production Index (PI) against T_{max} further shows that the samples are within the immature to early matured zone.

FTIR spectroscopy results when applied for kerogen typing and maturity levels, showed that the wells under study are of Type I kerogen, contradicting results obtained from Rock-Eval pyrolysis as well as already established works done in the area of study as the source rock of the Niger Delta is of Type II/III kerogen. This suggests that IR spectroscopy might not be a suitable tool in source rock characterization in terms of Kerogen typing and origin. The results obtained from VR_o however, supports deductions from Rock-Eval earlier made in this study, suggesting that IR spectroscopy can be a valuable tool in thermal maturity studies. FTIR spectroscopy despite being an important tool in petroleum geochemistry should be integrated with other organic geochemical analysis for better source rock Kerogen characterization.

Functional groups present in the study area were identified from FTIR spectroscopy, identified functional groups from the spectra peaks in the wells of study includes: halo compounds, alkanes, amines, methyl group, alcohols, monosubstituted alkanes and substituted benzene. The characterization of these functional groups is important in assessing the quality of the hydrocarbon. The extent of biodegradation as seen from functional groups identified in the IR spectra, shows that the wells ER-51, AP-4 and UK-2 are not biodegraded due to the high concentration of aliphatic saturates in the ditch samples analyzed.

This study has shown that the studied wells have adequate organic matter with the prospect to generate both oil and gas at appropriate maturity

Conflicts of Interest

The authors declare no conflicts of interest regarding the publication of this paper.

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