ORGANIC PETROLOGY OF CAMPANO-MAASTRICHTIAN SEDIMENTS IN THE AGBOGUGU-LERU AXIS, ANAMBRA BASIN, SOUTHEASTERN NIGERIA.

BY

OBIUKWU EMENIKE ONYEDIKACHI

20085633438

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CERTIFICATION

This is to certify that this work, "Organic Petrology of Campano-Maastritchian Sediments in the Agbogugu-Leru Axis, Anambra Basin, Southeastern Nigeria", was carried out by **OBIUKWU EMENIKE ONYEDIKACHI** (**20085633438**) in partial fulfillment of the requirements for the award of the Degree of Master of Science (M.Sc.) in Sedimentary/Petroleum Geology in the Department of Geology of the Federal University of Technology, Owerri.

PROF. S.O ONYEKURU (Principal Supervisor)	8/12/21 DATE
PROF. C.J IWUAGWU (Co-Supervisor)	8/12/21 DATE
PROF. A.I. OPARA (Head of Department)	09-12-21 DATE
PROF. C.C.Z AKAOLISA (Dean, School of Physical Science)	13/12/21 DATE
PROF C.C EZE (Dean, School of Postgraduate)	DATE
PROF. A.E EDET (External Examiner)	19-02-2015 DATE

DEDICATION

This piece of work is dedicated to the Almighty God for His mercies and favours upon me.

ACKNOWLEDGMENT

There were many factors that contributed to the success of this work, the most important being the wisdom, patience and understanding given to me by God. He saw me through even when I had no steam left.

My special thanks go to my supervisors Prof. S. O. Onyekuru and Prof. C. J. Iwuagwu for carefully going through my work and advising me adequately. To the lecturers of the department of Geology (FUTO), I say thank you for all the knowledge I acquired. I also want to use this opportunity to express my heartfelt gratitude to all the Lecturers and staff of Geology Department, thank you

This section of work will not be complete without mentioning Mr. Bode, Mr. George and other staff of Getamme Laboratories Ltd. Port-Harcourt for carefully analyzing my samples.

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ABSTRACT

Ten rock (n=10) samples were subjected to various geochemical analyses to determine organic petrology and paleoenvironment of early Cretaceous sediments in parts of the southern Anambra Basin. The procedure for the determination of the Total Organic Matter content and Rock Eval pyrolysis were achieved using LECO 600 analyzer with a TOC module. Extractible Organic Matter was determined by the use of Soxhlet Extractor while the biomarker distribution was ascertained with the Gas Chromatography. The results reveal that the Total Organic Content (TOC) of shale samples recovered from the Enugu Shale ranged from 0.72 to 4.94 wt % with an average of 2.64 wt %. Samples recovered from the Mamu Formation have TOC values ranging between 0.76 to 2.11 wt % with an average value of 1.49 wt %. These values essentially exceeded the threshold value of TOC $\geq$ 0.5 wt % requirements for shale rocks to qualify as petroleum source rocks. The values are therefore, suggestive of good to very good sources rocks. The Hydrogen Index (HI) values of sediments from Enugu Shale ranged between 43 to 547 mgHC/gTOC with an average value of 185.65 mgHC/gTOC, while those recovered from sections of the Mamu Formation have HI value of 27 to 54 mgHC/gTOC with an average value of 39.45 mgHC/gTOC. The corresponding Oxygen Index (OI) values ranging between 15 to 106 mgCO$_2$/gTOC was recorded for Enugu Shale sediments with an average value of 59.2 mgCO$_2$/gTOC. The analyzed sediments of the Mamu Formation on the other hand, revealed values of the range of 26 to 86 mgCO$_2$/gTOC, with average of 49.4 mgCO$_2$/gTOC. These results showed that the Enugu and Mamu Formation sediments are dominated by type III kerogen and mixed type II/III kerogens. The maximum Temperature (Tmax) ranged from 424 to 439^0C with an average of 432^0C and 417 to 441^0C with an average of 431^0C for sediments from the Enugu and Mamu Formations, respectively. These temperature values are indicative of immature to transitionally early mature source rocks. The dominant vitrinitemaceral group in the analyzed shale samples ranged between 39 to 59 %; Inertnites, between 11 to 18 % while the liptinites ranged between 9 to 21 %. These biofacies in the shale samples from the Enugu and Mamu Formations were derived from the structural parts of plants that are deficient in hydrogen. The sediments are thus deposited in a suboxic but low PH paleo-depositional environment containing moderately to fairly rich organic matter. This source rock has the potential to generate gas rather than oil given sufficient maturity.

Keyword: Biofacies, Organic, Geochemical, Source Rock, Maceral, Maturity

CHAPTER ONE

INTRODUCTION

1.1 Background Information

Agbogugu – Leru area is located in the southern part of the Anambra Basin. The Anambra Basin is located south of the regionally extensive northeast-southeast trending Benue Trough. The basin has a 5km thickness of Cretaceous – Tertiary sediments characterized by enormous lithologic heterogeneity in both internal and vertical extension which were derived from a range of paleoenvironmental settings (Akaegbobi, 2005).

The favorable stratigraphic setting of interbedded shales and sandstones with occasional limestones seen in outcrops and subcrops in the basin aroused the interest of oil and gas companies to explore for Oil in Southeastern Nigeria in the 1940's. Initial efforts were unrewarding and this led to the neglect of the basin in favor of the prolific Niger Delta Basin. The recent policy of the Nigerian Government to encourage active exploration activities for hydrocarbons in marginal oil fields and inland lakes has led to a renewed interest in the Anambra Basin.

The basin's estimated reserve of about 1 billion bbl and 10 trillion standard cubic feet of oil and gas respectively could be a gross under estimation (Iheanacho, 2010). Of the less than 50 wells drilled in the basin, only three discoveries: Anambra River 1, Ihadiagu 1 and Aguleri-Otu have all produced oil (Nwajide, 2005). These occurrences present the great potential for hydrocarbon exploration and production in the basin. However, the very scanty 2-D seismic and minimal subcrop information shows that the Anambra Basin is clearly under explored. With improved 3-D seismic information and more geochemical data, the hydrocarbon resource of the basin will further be highlighted. It is against this background that the present study was embarked on in order to contribute to sustainable development of resource in the basin.

1.2 Problem Statement

Recent exploration techniques use modern understanding of organic petrology of sediments to identify source rocks, estimate its quality, type and maturation level of accompanying organic matter. It is also able to fingerprint the source rocks in a petroleum system (Margoon,1994) inorder to improve the success rate of petroleum exploration.

In the quest to finding more petroleum, numerous organic petrological techniques are used to identify the source rock and to determine the amount, type and maturation level of the organic matter. These techniques will evaluate the migration of petroleum from source rock in order to assess the possible migration and accumulation pathways.

Evidence of hydrocarbon occurrence abound in the Anambra Basin. Oil seeps have been known to occur in bituminous shale outcrops of the Ezeaku Formation, Awgu and Nkporo Shales. Some wells drilled in the basin encountered a number of oil shows (Nwajide, 2005; Ekweozor, 2005).

There may be other deposits that may be potentially profitable that have not been discovered in the basin. Hence, hydrocarbon potential of the Anambra Basin is still a matter that deserves consideration and in-depth evaluation for possible greater profitability and sustainability. Twenty-one exploratory wells have been drilled in the Anambra Basin since 1952. Five of these wells (Akukwa -l, Alo-l, Amansiodo - l, Igbariam -l and Ihandiagu - l) encountered gas while only three wells encountered oil. Based on these reported occurrences of hydrocarbons in the Anambra Basin, it is very likely that it is largely a gas-condensate basin (Ekweozor, 2005). Thus more work is required to assess the petroleum potential of the sediments in the Anambra Basin and other frontier basins for the sustainable development of petroleum resources in Nigeria.

1.3 Justification of study

In order to improve the success rate of petroleum exploration in the country, it is necessary to seek for more source rocks and re-assess the explored areas for additional oil and gas pool, using organic geochemistry.

The Anambra Basin has been known to produce hydrocarbon, in this study, evaluation of the source rocks in the basin requires detailed organic geochemical analysis to determine the quantity, quality and thermal maturation of the source rock especially in the study areas.

Thus, the Campano-Maastritchain deposits along the Agbogugu axis were assessed using geochemical techniques such as; Rock-Eval Pyrolysis and Total Organic Carbon (TOC) values to determine their hydrocarbon potential

1.4 Objectives of the Study

The main objective of the study is identifying pods of source rocks that form a part of the element of the petroleum system in the southern Anambra Basin.

The specific objectives of this study include the following:

i. Description of lithologic sections that crop out in the Leru-Agbogugu axis, chemical, physical and biogenic characteristics of the units.
ii. Facies analysis of units
iii. Determination of the quantity and quality of the organic facies.
iv. Evaluation of the thermal maturity and hydrocarbon generation potential of identified organic rich sediments using organic petrological methods.

1.5 Scope of study

The study area covers the Agbogugu-Enugu axis of the Anambra Basin. Two outcrop locations were used in this study. The locations involve the deposits derived from Mamu Formation and Enugu Shales, in Agbogugu-Enugu axis. The geochemical analysis is limited to TOC and Rock Eval pyrolysis only. Assessment of hydrocarbon potential is limited to quantity (TOC), quality and thermal maturation of organic matter (Rock Eval pyrolysis), for the shale.

CHAPTER TWO

LITERATURE REVIEW

2.1 Theoretical Review

2.1.1 Organic matter accumulation

The accumulation of organic matter in sediments is controlled by a limited number ofgeological conditions (Tissot & Welte, 1984). The main factors that control the accumulationof organic matter include the production of the biomass, the degradation processes andtransport of the organic matter. The quantity and quality of the organic matter accumulatedin sediment are basically the result of the combined influence of the biomass productivity,biochemical degradation and of the organic matter depositional processes. Theaccumulation is practically restricted to sediment deposited in aquatic environments, whichmust receive a certain minimum amount of organic matter. In subaerial sediments, organicmatter is easily destroyed by chemical or microbial oxidation. This organic matter can be supplied on theform of particulate organic matter (in particles) or as dissolved organic matter(Joao et al, 2012).

2.1.2 Organic matter transformation

Among the liberation of biological products in the adjacent environment and its incorporationto the sediments, occurs the intervention of a number of biologicalfactors, which will influence its chemical structure and will determine its space distribution inthe deposits. Organic matter consists of a diverse variety of compounds, which are subjected to microbial attack. The composed biomolecules in living tissues is thermodynamicallyunstable. When such molecules are secreted or excreted by the organisms, or even after thedeath of the organism, they tend to lose their integrity and they can be transformed in simplestable components such as CO_2, CH_4, NH_3, H_2S, and H_2O. This process of degradation can beaccomplished by the physicochemical processes (oxidation, photolysis and thermolysis(Joao et al, 2012).

2.1.3 Biomarkers

Biomarkers are organic compounds used in assessing sources of bitumen Organic matter derived from biochemical precursors by mainly reductive but also oxidative alteration processes with chemical structures which can be related back to their precursor compounds in contemporary or extract biota (Simonert, 2004; Tissot and Welte, 1984).

Biomarkers are present in both oil and source rock extracts; they provide a method to relate the two and can be used to interpret the characteristics of the source rocks (Grimalt et al., 2002). In addition, biomarkers can provide information on the organic source materials; environmental condition during its deposition; the thermal maturity experienced by a rock or oil and the degree of biodegradtion (Peters et al., 2005; El gayes et al., 2002).

Murray et al., (1997) reported that hopane (C_{29}, C_{30}) have microbial origin and some are derived from higher plants and oleananes is from terrestrial plants. Tricyclics are formed by partial aerobic oxidation of bacterial membrane.

2.2 Empirical Review

Geological investigations started in Nigeria with the establishment of the Mineral Surveys of Northern Nigeria in 1904 and Mineral Surveys of Southern Nigeria in 1930. Much geological information became available following the discovery of several industrial minerals especially coal and limestone in the early 1900s.

Reyment (1965) recognized only one large southern Nigerian Basin, which incorporates the Anambra Basin. Murat (1972) noted that sedimentation in southern Nigeria was controlled by three main tectonic phases and by epi-orogenic movements which resulted in major transgressive - regressive cycles.

The geology of the Anambra Basin has been documented in the geological maps of the Geological Survey of Nigeria, 1:250,000 (Reyment 1965; Murat 1972).

Agagu and Ekweozor (1982) worked on the source rock characteristics of the Senonian shales in the Anambra syncline and concluded that the shales have good organic matter richness with maturity increasing significantly with depth.

Ekweozor (1982) in his report on the application of petroleum geochemistry to exploration in Nigerian sedimentary basins, carried out preliminary geochemical investigations of the concentration and thermal maturity of the sedimentary organic matter isolated from certain sections of Imo, Nkporo, Awgu, and Ezeaku Formations of the Anambra Basin and Benue Trough. He reported that the organic matter was deposited under an oxic condition. Earlier Agagu (1978) had carried out a comprehensive study on the geology and petroleum potential of the Senonian to Maastrichtian sediments in the Anambra Basin and recorded that the sediments are organically rich but immature. All these preliminary reports confirmed the presence of abundant organic-rich shales as source rocks with organic carbon ranging from 0.22 to 4.16% within the Anambra basin, (Agagu and Ekweozor, 1982).

According to Petters (1978), a possible increase in organic richness from older to younger shales could have been due to a decrease in the preponderance of planktonic foraminifera. The idea was substantiated by Agagu and Ekweozor (1982) who reported an increase in the abundance of coarse terrigenous clastic particles and coal beds (a tendency towards less marine conditions). Agagu and Ekweozor (1982) pegged the Threshold of Intense Hydrocarbon Generation (TIGH) at about 1900m in southern Anambra basin. The threshold temperature was inferred to be 60^0C. They further ascertained that the onset of it is in the southern onshore and western offshore of the producing Niger Delta Basin.

Tebo (2000), while evaluating the geochemical characters of the Nkporo Shale reported that the shales were probably deposited under a strong anoxic (euxinic) water condition. Short and Stauble (1966) outlined the geology of the Anambra Basin and inferred that subsidence in the Santonian resulted in the deposition of the Nkporo/Enugu Shale and the coaliferous Mamu Formation, Ajali Formation and Nsukka Formation. The marine influence in these deposits is however, restricted to the Nkporo Formation and the lowermost part of the Mamu Formation and becomes insignificant in higher levels (Reyment, 1965).

Several workers including but not limited to Avbovbo and Ayoola (1981); Ehinola (1995); Njumbe and Onuoha (2002); Akaegbobi (2005) reviewed exploratory drilling results from the Anambra Basin and proposed that, but for the deeper unexplored sub-delta parts of the Cretaceous strata, most parts of the basin probably contain gas-condensates due to abnormal geothermal gradients.

Unomah (1989) evaluated the quality of organic matter in the Upper Cretaceous shales of the Lower Basin Trough as the basis for the reconstruction of the factors influencing organic sedimentation. He deduced that the organic matter and shales were deposited under a low rate of deposition. Specific references to the organic richness, quality and thermal maturity in the Mamu Formation and Nkporo Shales have been reported by Unomah and Ekweozor (1993), Akaegbobi and Schmitt (1998), Obaje et.al. (1999), Akaegbobi (2005), Ekweozor (2006) and Ajayi (2006). They reported that the sediments are organic-rich but of immature status.

Unomah and Ekweozor (1993) proposed that the shale in the Anambra basin and Afikpo syncline contain mainly terrestrial derived organic matter and essentially gas prone. They equally stated that the outcrops and near surface sections of Nkporo Shale are immature while the lower section is overcooked.

Latter, Akaegbobi and Schmitt (1998) observed that the Campanian and Maastichtain Nkporo Shale is a good example of mixed terrestrially marine source rock within the Anambra Basin. They recorded that the relationship between the hydrogen index (HI) and oxygen index (OI) in the said Nkporo Shale and other episodes of suboxic and anoxic conditions for the deposition of Nkporo/Enugu Shale.

Obaje et al. (1999) investigated the source rock potential of various formations in the Benue Trough and Anambra Basin. They proposed the Nkporo/Enugu Shale to be the source rock for the petroleum system in the Anambra Basin, having TOC values ranging from 1.1 to 4.2wt% and vitrinite reflectance values ranging from 0.44 to 0.65%. Later, Obaje et.al. (2004), while viewing the hydrocarbon prospectively of Nigeria's inland basins, proposed that the coal beds of the Mamu Formation have total organic carbon (TOC) content of as much as 60.8wt%, mean hydrogen index (HI) of 364 mgHC/g TOC, vitrinite reflectance (RO) of 0.54 to 0.56% and Tmax of 430 to 433^{0}C. They reported that the Mamu Formation is capable of expelling hydrocarbon given sufficient maturity.

Schmidt (1998) evaluated the economic potential of the Mamu Formation and Nkporo Group units and gave a detailed comparative analysis of the geochemical qualities of the shaly facies. The shale members of the Nkporo Group Shale presented better evidence of organic matter preservation and petroleum generation potential. On the basis of available geochemical and organic Petrographic data, he also identified only one petroleum system (upper Cretaceous – Lower Paleocene petroleum system) which consists of type II and III/II (gas/oil prone) kerogen. Schmdt (1998), therefore put the total volume of oil generated by the Nkporo Shale and the lower Mamu Formation at 7790 million bbl of oil or 5.08×10^{13} ft^3 of gas which is of the threshold value of 50 million bbl, required for expulsion of oil.

Akande (2004) reported that the coal sequences in the Mamu Formation are dominated by huminites with fewer amounts of liptinites and inertinites. The vitrinite reflectance ratio and Tmax values show that the coals are immature to marginally mature and proposed gas generative potential for coal. Akande et al. (2007) concluded that the associated coals in the Mamu Formation have the capability to generate and expel liquid hydrocarbons given sufficient maturity and may have generated an unknown volume of liquid hydrocarbons and gases as part of an active Cretaceous petroleum system.

Boore (2007) evaluated the hydrocarbon potential of shales from Mamu Formation and deduced that the shales have fair to moderate gas to minor oil-gas prone source potential at low thermal maturity. Emmanuel (2008) also assessed the petroleum potentials of the Post-Santonian sedimentary units in the Anambra basin and revealed that the possible zones of abnormal formation pressures within specific formations are the Santonian Nkporo Shale and Maastrichtian Mamu Formations. He concluded that the formations are the most stratigraphically important for any hydrocarbon search targeted at the upper-Cretaceous sediments in the Anambra Basin.

The paleoenvironments, biostratigraphy and petroleum geology of sediments in the Anambra Basin have attracted the attention of many authors. Agagu and Ekweozor (1982) reported that the Nkporo Shales constitute the main source and seal rocks in the Anambra Basin. Ekweozor and Gormly (1983) described the Nkporo Shale as an example of a marine source rock composed of Type II/III kerogens with low but consistent contribution from marine organic matter. The work of Unomah and Ekweozor (1993) revealed that the organofacies of the Nkporo Shale are provincial with the Calabar Flank having the highest oil potential whereas those in the Anambra Basin and Afikpo Syncline are gas prone. According to Akande et al. (1992), the lower Maastrichtian Coals of the Mamu Formation are characterized by moderate to high concentrations of huminite and some minor amounts of inertinites and liptinites.

Other studies on paleoenvironments and biostratigraphy include Gebhardt (1998) who suggested that benthic foraminiferal assemblage from the lower Mamu Formation at Leru represents deposits of pro-delta to lagoon environments. Mode (1991) dated the Nkporo Shale, south of Leru, Maastrichtian. There are other outcrop based studies of the Anambra Basin that suggested the predominant influence of marginal marine in the Nkporo, Enugu and Mamu Formations (Ladipo, 1988; Nwajide and Reijers, 1996). Interpretation of depositional environments using lithofacies stacking pattern, sedimentary structures and biostratigraphic analyses inferred an estuarine/lagoonal to tidal delta to shallow, open marine depositional model for the Nkporo Shale and an estuarine to tidal delta to shallow marine paleodepositional model for the Mamu Formation (Onyekuru and Iwuagwu,2010).

The present study shall utilize a set of field operations, complimented with laboratory studies, to evaluate and infer the paleoenvironment and characterize the organic facies of potential source rocks in the study area for a better petroleum system study.

2.3 Location of the Study Area.

The study area lies within longitude $6^{0}35^{1}$E to $7^{0}45^{1}$E and latitude $5^{0}30^{1}$N to $7^{0}30^{1}$N within the Anambra Basin(Fig. 2.1).The area under study is located along the Enugu-Porthacourt express way.

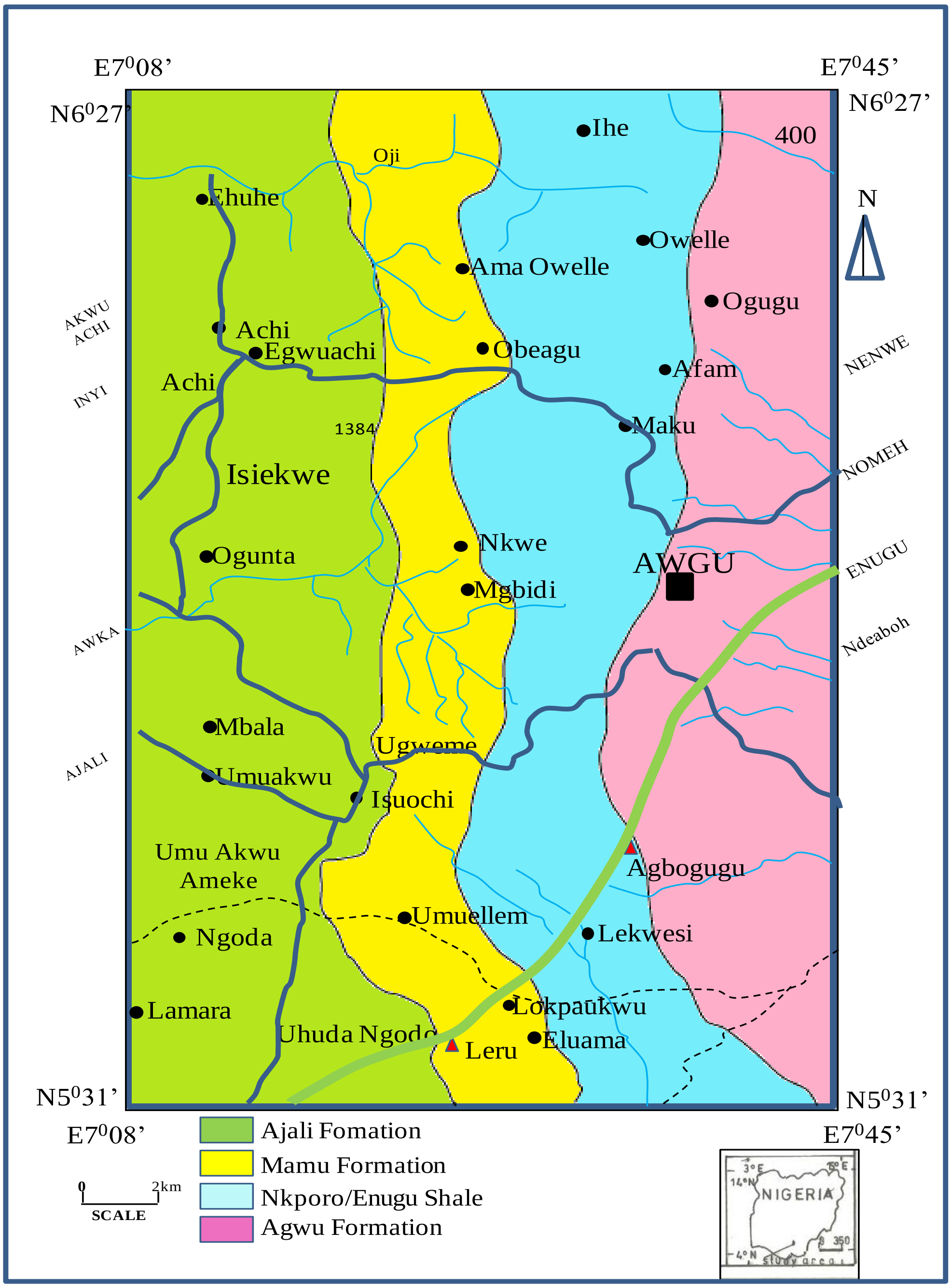


Fig. 2.1. Location and geologic Map of the study area

2.4 Geological Setting

2.4.1 Tectonic Evolution of the Anambra Basin

The tectonic evolution of the Anambra Basin may be traced back to the late Jurrassic when convention currents in the asthenosphere caused the break-up of the Gondwana Supercontinent. The separation of the African and South American plates left the Benue Trough as an aulacogen, a failed arm of an RRR Triple Junction (Burke, 1972; Olade, 1975). The Benue Trough is itself a part of the very expansive west and central Africa rift system in which it opened as anextensive sinistral wrench complex (Genik, 1993;). A reconstruction by Murat (1972) shows the southern part of the Benue Trough as longitudinally faulted, with its eastern half subsiding preferentially to become the Abakiliki depression. Basin subsidence in the southern Benue Trough was spasmodic. It was at a high rate in pre Albian time, low in Lower Cenomanian, and very high in Turonian; the latter was an important phase of platform subsidence (Ojoh, 1990). This is thought to be the actual time of initiation of the Anambra Basin creation a process that gained momentum in the Coniacian and climaxed during the Santonian thermotectonic event.

Following the Santonian Orogeny, the Abakiliki area became flexurally inverted to form the Abakiliki Anticlinorium, displacing the depocenter to the west, northwest and southwards (Fig. 2.2). This created the Anambra Basin dating back to 85 million years (Murat, 1972; Burke, 1972) Fig. 2.3.

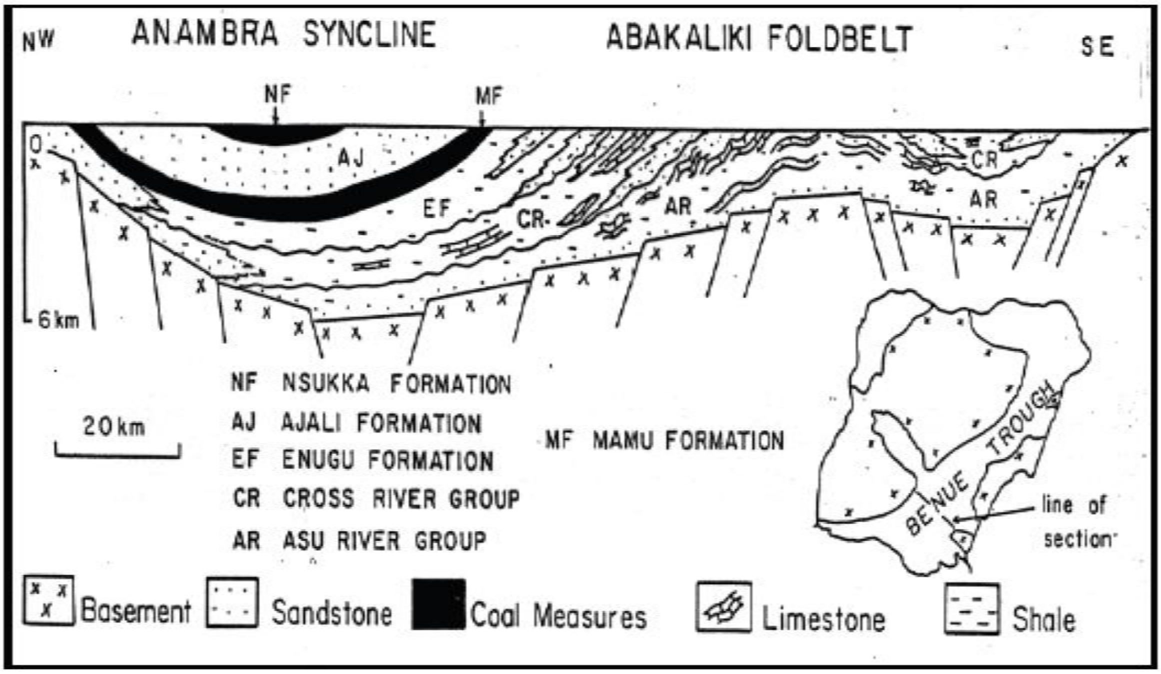


Fig. 2.2. Cross section of the Lower Benue Trough showing the synclinal Anambra Basin (After Petters and Ekweozor, 1982)

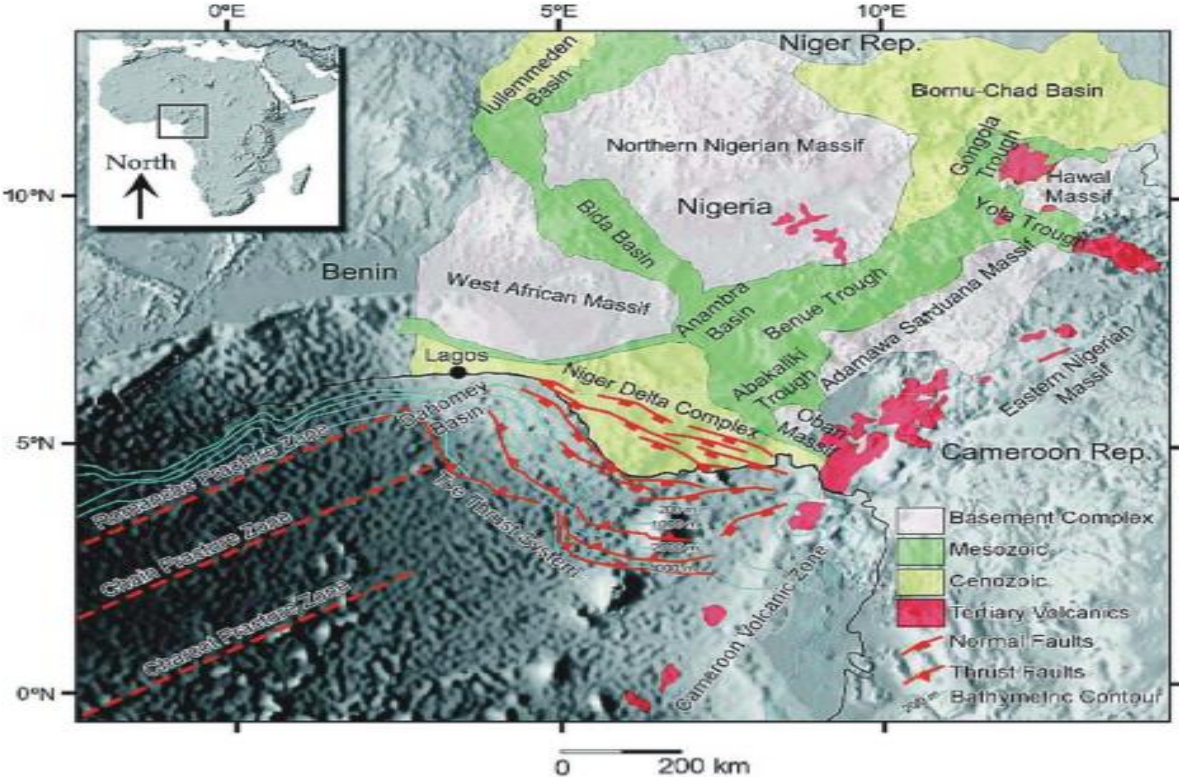


Fig. 2.3. Sedimentary Basin of Nigeria (After Corredor et al., 2005)

2.4.2 Stratigraphy

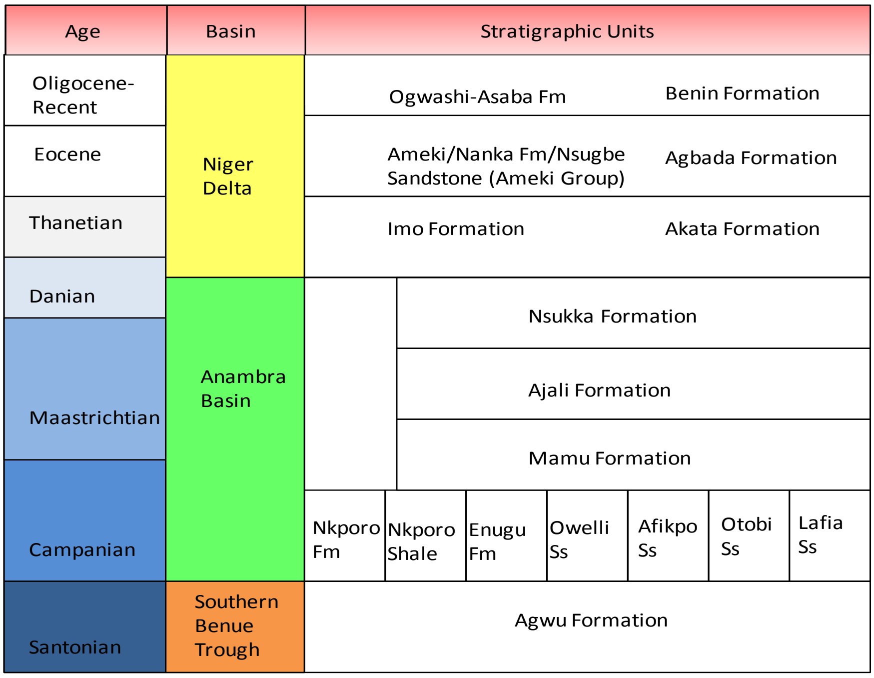
The formation of the Southern Nigerian sedimentary basin followed the break-up of the South American andAfrican continents in the Early Cretaceous (Murat, 1972; Burke, 1996). Various lines of geomorphologic, structural, stratigraphic and palaeontologic evidencehave been presented to support a rift model (King, 1950; Bullard et al., 1965; Reyment, 1969; Burke et al.,1971, 1972; Fairhead and Green, 1989; Benkhelil,1989; Guiraud and Bellion, 1995).

The stratigraphic history of the region is characterized by three sedimentary phases (Short and Stauble,1967; Murat, 1972; Obi and Okogbue., 2001) during which the axis of the sedimentary basin shifted. These three phases were: (a) the Abakaliki-Benue Phase (Aptian-Santonian),(b) the Anambra-Benin phase (Campanian-Mid Eocene), and (c) the Niger Delta phase (late Eocene-Pliocene). The more than 3000 meters of rocks comprising the Asu River Group and the Ezeaku and Awgu Formations, were deposited during the first phase in the Abakaliki-Benue Basin, the Benue Valley and the Calabar Flank (Table 2.1). The second sedimentary phase resulted from the Santonian folding and uplift of theAbakaliki region and dislocation of the depocenter into the Anambra Platform and Afikpo region. The resulting succession comprises the Nkporo Group, Mamu Formation, Ajali Sandstone, Nsukka Formation, Imo Formation and Ameki Group (Table 1). The third sedimentary phase credited for the formation of the petroliferous Niger Delta (Table 1), commenced in the Late Eocene as a result of a major earth movement that structurally inverted the Abakaliki region and displaced the depositional axis further to the south of the Anambra Basin (Obi and Okogbue., 2001).

The filling of the Anambra Basin occurred between the end-Santonian and the early Paleocene (Danian). There was one major marine transgression that initiated deposition in the new basin and a less extensive one, capping off depositions in the basin.

Depositions in the Campanian began with a short marine transgression followed by a regression in the Anambra Basin, the Nkporo Shale and its lateral equivalents, the Enugu Shale and Owelli Sandstone (Nkporo Shale Group), constitute the basal beds of the Campanian. The broad shallow sea gradually became shallower because of gradual subsidence, initiating regressive phase during the Maastritchtian that deposited deltaic foresets and flood plains (Lower Coal Measures: Mamu Formation). The Mamu Formation is overlain by the continental beds of Ajali Formation followed by a return to partially parallic conditions with the deposition of the Nsukka Formation, see Table 1 for the stratigraphic sequence in the Anambra Basin.

Table 2.1. Stratigraphic sequences in Anambra Basin, Benue Trough and Niger Delta (Nwajide, 2006).



<table>
<tr><th>Age</th><th>Basin</th><th colspan="7">Stratigraphic Units</th></tr>
<tr><td>Oligocene-Recent</td><td rowspan="3">Niger Delta</td><td colspan="4">Ogwashi-Asaba Fm</td><td colspan="3">Benin Formation</td></tr>
<tr><td>Eocene</td><td colspan="4">Ameki/Nanka Fm/Nsugbe Sandstone (Ameki Group)</td><td colspan="3">Agbada Formation</td></tr>
<tr><td>Thanetian</td><td colspan="4">Imo Formation</td><td colspan="3">Akata Formation</td></tr>
<tr><td>Danian</td><td rowspan="4">Anambra Basin</td><td rowspan="3"></td><td colspan="6">Nsukka Formation</td></tr>
<tr><td rowspan="2">Maastrichtian</td><td colspan="6">Ajali Formation</td></tr>
<tr><td colspan="6">Mamu Formation</td></tr>
<tr><td>Campanian</td><td>Nkporo Fm</td><td>Nkporo Shale</td><td>Enugu Fm</td><td>Owelli Ss</td><td>Afikpo Ss</td><td>Otobi Ss</td><td>Lafia Ss</td></tr>
<tr><td>Santonian</td><td>Southern Benue Trough</td><td colspan="7">Agwu Formation</td></tr>
</table>

The stratigraphic description of the sediments in the Anambra Basin is summarized below:

Nkporo/Enugu Shale (late Campanian-early Maastrichtian).

The Nkporo/Enugu Shalesre presents the brackish marsh and fosilliferous pro-delta facies of the Late-Early Maastrichtian depositional Nkporo Cycle (Nwajide and Reijers, 1996). They also interpreted the Formations of the Nkporo Cycles to reflect a funnel shaped shallow marine shelf that grade into channeled low-energy marshes.

This Shale has been extensively studied with respect to their fossil content (Mebradu, 1990; Nwajide and Reijers, 1996). Simpson (1954); Reyment (1965) and Mebradu, (1990) in their separate works miospores to suggested a Maastrichtian age for this formation based on miospores. Murat (1972) assigned an upper Senonian age, while Agagu et al. (1985) assigned a Campanian to Maastrichtian age to the Shales.

The Nkporo/Enugu Shales is overlain by the Ajali Sandstone, Mamu and Nsukka Formations. The Enugu Shale passes laterally into the Nupe Sandstone, Otobi Sandstone, Awgu Shale and Afikpo Sandstone. Enugu Shale is a lateral equivalent of Nkporo Shale (Nwajide and Reijers, 1996). The Owelli Sandstone is a regressive phase consisting of massive cross-bedded sands with occasional marly beds.

The Enugu Shale exposed at Agbogugu consists mainly dark grey to black shales which are very fissile and soft at the surface with occasional mudstones with thin beds of sandy shale. The Enugu Shale varies in thickness from 42 to 338m, and grades upwards into the Mamu Formation (Reijers, 1996). The shale is rich in micro fauna, mollusks and occasional fish remains. It was deposited mainly in the Anambra Basin and to a lesser extent in the Afikpo Syncline. The Shale was deposited as the basal lithostratigraphic unit in the Anambra basin.

Mamu Formation (Late Maastrichtian sequence)

The Mamu Formation otherwise called the Lower Coal Measures overlies the Enugu shale without any evidence of a break in sedimentation(Nwajide and Reijers, 1996). Mamu Formation is referred to as the “Lower Coal Measures” and contains a distinctive assemblage of sandstone, shales, mudstone and sandy shales with coal seams at several horizons (Reyment 1965). The coal beds are of medium grade quality and are rich in resins and waxes which are often intercalated with carbonaceous shales and sparse arenaceous microfauna (Agagu et al. 1985). They have high ash content and display a rhythmic pattern of deposition. The sandstones which are fine to medium grained and white or yellow in color are normally well bedded although cross-bedding may be seen in places. The shales and mudstones are grey to black in color and frequently alternate with thin bands and lenses of limestone to form a characteristic stripped rock (Reyment 1965).

The sediments were deposited in shallow water, Cratchley and Jones(1965). Open strand plain, to coastal plain environment has been inferred for this formation by Agagu et al (1985), and Nwajide and Reijers (1996) respectively. The thickness of Mamu Formation is about 1300ft. (Cratchley and Jones, 1965).

Ajali Sandstone

The Ajali Sandstone was originally called the "White-Bedded False Sandstone" and the “White Sandstone" It is friable, white in colour and cross-bedded sandstone with thin beds of white mudstone near the base, it is very mature and well sorted and was deposited in a continental sequence (Benkheil, 1986; Amajor, 1987; Lapido, 1986, 1988; Adediran, 1991). A strand plain marsh environment with occasional fluvial incursions was inferred for this formation (Agagu et. al.. 1985). The thickness of the Ajali Sandstone is quite variable. Simpson (1954) gave a thickness range of 40 to 50ft. Between Enugu and Ekana, the formation is 250ft thick and along Enugu Escarpment north of the Oji River, it is 1500ft thick (Simpson, 1954). Northwest of Enugu, the Ajali Sandstone could be over 1700ft. The stratigaphic position of Ajali Formation as well as its field relations with the underlying Mamu and overlying Nsukka Formations suggested an Upper Maastrichtian age to the formation (Reyment, 1965).

Nsukka Formation

The Nsukka Formation, which overlies the Ajali Sandstone, begins with coarse- to medium-grained sandstones that grades upward into well-bedded blue clays ,fine-grained sandstones, and carbonaceous shales and thin bands of limestone (Reyment, 1965; Obi et al., 2001).

This Formation was originally regarded as being stratigraphically synonymous with the Upper Coal Measures (Murat, 1972; Dessauvagie, 1974). The name Nsukka Formation was proposed to replace this term (Reyment, 1965). There are few coal seams in the lower horizons of the Nsukka Formation (Reyment, 1965). The formation was deposited under parallic conditions, which prevailed during the second post-Santonian transgression cycle. Simpson, (1954), suggested a Maastrichtian to Paleocene age while Murat, (1974), suggested a Maastrichtian to Danian age for the formation. Also, Obi et al. (2001) used sedimentological evidence to suggest that the Nsukka Formation represented a phase of fluvio-deltaic sedimentation that began close to the end of the Maastrichtian and continued during the Paleocene.

2.4.3 Climate and Geomorphology

The study area lies within the equatorial monsoonal Climatic belts of Nigeria typified by the rainy to dry seasons (FMNAR, 1990). The rainy season last for about Eight months (March to October) while dry season lasts for four months (November to February) in the study area. Rainfall is not so heavy between the months of March and May while is heaviest between June and September. The driest period is between November and February.

The study area is drained by one main river system the Anambra-Mamu River System in the West. The role of tectonics and uplift in modifying drainage patterns and topography in Nigeria was earlier recognized by Falconer (1911). The drainage pattern of the Anambra Basin is dentritic with individual streams, which are often seasonal combining to form rivers. The Anambra-Mamu River drains extensive areas of Uzo-Uwani in the northwest and Awgu in southwest. For most of the rainy season the Uzo-Uwani lowlands in particular, is completely covered by floods. The impeded drainage of the soil provides fertile soil for planting of rice and yams as well as fish farming, according to Ofomata, (1981).

CHAPTER THREE

MATERIALS AND METHODS

The field study involved a detailed geological mapping of the area. It was aimed at identifying rock types, sedimentary structures, textural features and establishing the stratigraphic succession of rock units based on their field relationships. The thickness and lateral extents of beds were noted. Photographs of important features on outcrops were taken. Attitudes of the beds were taken with the compass clinometer while the thickness was measured with a tape. Lithologs were drawn right on the field and later modified using the computer.

Fresh samples were obtained using shovel for soft sections and chisel and hammer for undurated samples in the course of the field exercise. Badly weathered samples were discarded.

The collected representative samples were prepared for geochemical analysis.

3.1 Lithostratigraphic Study

This study involve review of different aspects of works done in the study area. Detailed geological mapping to examine outcrop sections and the lithofacies relationship in the outcropping profile, the sedimentary structures and sediment thickness. This was followed by sampling to cover the representative samples in a section. Finally, all sampled locations were referenced to the base map using a Geographical position system (GPS).

3.2 Laboratory Studies

Ten (10) representative fresh shale samples, made up of five (5) samples each from the exposures at Agbogugu and Leru/Isuochi junctions were subjected to organic geochemical analysis.

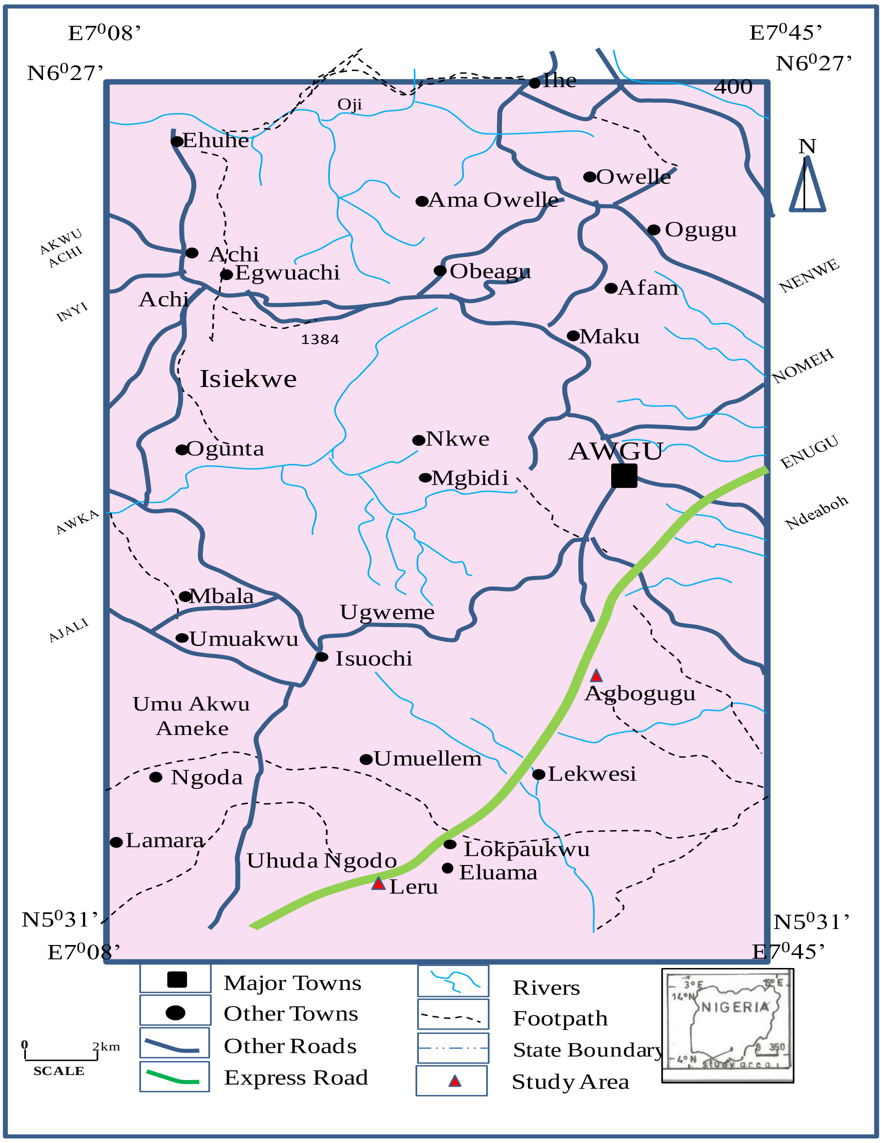


Fig 3.1. Sample location map of the study area

3.2.1 Sample Cleaning

The samples were initially cleaned by seeping and soaking in 100% dichloromethane. This was followed by decanting of the resulting solvent until the rocks were clean. After drying, the rock samples were washed with running tap water and oven-dried again at a pre-set temperature of 30^0 C.

3.2.2 Determination of Total Organic Carbon (TOC)

The determination of Total Organic Carbon (TOC) was done by Rock Eval Pyrolysis using the LECO C/S analyzer with TOC module at the Getamme Laboratories Ltd Port Harcourt.

The Total Organic Carbon(TOC)was determined on powdered samples pretreated with Hydrochloric acid (HCl) (for removal of carbonates) using LECO C/S Analyzer. 100mg of pulverized sample was weighed in a special porous crucible and placed on a cold sand bath; the weighed sample was then wetted with few drops of ethanol (to avoid sporadic reactions) and treated with some drops of 10% diluted Hydrochloric acid (HCl) until no further reactions occurred. The sample was left on the sand bath for 12 hours at a temperature of 80^oC in order to allow excess water to evaporate. Thereafter, the samples were transferred into a laboratory vacuum oven where it was kept for another 12 hours at a temperature of 50^oC. Before bringing the sample in the combustion chamber of the LECO Apparatus 1 g of copper chipping was added as catalyst. The sample was then burned in the LECO C/S Analyzer in the presence of oxygen at a temperature of 1300^oC. The evolved gases Carbon IV oxide (CO_2) and Tetraoxosulphate VI acid (H_2SO_4) were measured quantitatively and simultaneously by infra-red detectors and recorded as percent carbon and sulphur, respectively.

The samples in the instrument were calibrated with standards of known percent carbon and sulphur before analyzing in the LECO apparatus.

3.2.3 Rock-Eval Pyrolysis

The Rock-Eval Pyrolysis offers a rapid method for the characterization of kerogen types and for the determination of the maturity of organic matter. It does not require demineralization of samples and there is no other preparation other than pulverizing the samples into fine powder. However, the results can be adversely affected by drilling mud contamination, mineral matrix effects and low amount of kerogen. Maturation and source quality parameters derived from the peaks include Hydrogen Index (HI), Oxygen Index (OI), Total Organic Carbon (TOC), Production Index (PI), T_{max} and Potential Yield.

The Rock-Eval measurement was also carried out at the Getamme Laboratories Ltd, Port Harcourt. Ten screened samples were analyzed by Rock-Eval Pyrolysis to determine the hydrocarbon generation potential, kerogen types, maturity and hydrocarbon index (HI) using the Rock-Eval LECO C/S machine with TOC module.

The weight of the sample to be analysed was based on the TOC content of the sample. 100mg of sample was used for samples containing 0-4% TOC. The samples were weighed in a metal crucible that was previously burnt out at a temperature of 600^{o}C under nitrogen atmosphere. The crucible and contents were transported automatically into the oven room and flushed for 3 minutes with Helium to remove oxygen (O_2) and carbon IV oxide(CO_2). Subsequently the samples were placed in the oven for 3 minutes and heated to a temperature of 300^{o}C. During this process, free and absorptive hydrocarbons and hydrocarbon-like compounds were volatilized and quantitatively determined with the help of Flame Ionization Detector (FID). This was registered as S_1 peak.

The oven temperature was again increased to 550^{o}C at a programmed rate of 25^{o}C/minute and held constant for 1 minute. At this second temperature phase (300-550^{o}C) the solid organic matter was pyrolyzed and the mobilized hydrocarbons and hydrocarbon-like compounds were measured simultaneously and quantitatively with FID and registered as S_2 peak. The S_2 peak also provided information about the thermal maturity of the sample by means of the T_{max} parameter (the temperature at which the peak reaches its maximum. At the same time the CO_2 produced during the temperature interval (300-550^{0}C) was registered with the Thermal Conductivity Detector (TCD) as S_3-peak. The mobilized products of S_1 and S_2-peaks could be normalized to the weight of rock (mgHC/gRock) and to the Total Organic Carbon (TOC) as (mgHC/gTOC). The T_{max} value increases with increasing maturity.

Other parameters obtained from the instrument include the T_{max} that is the temperature corresponding to the temperature at which the pyrolytic yield of hydrocarbon (S_2-peak) reaches its maximum, hydrogen index (HI), Total Organic Carbon (TOC), Oxygen Index (OI), Production Index (PI), and Potential Yield.

The basic parameters obtained by pyrolysis (Wapples, 1985), are as follows:

S_1: this is the amount of free hydrocarbons measured in milligrams of hydrocarbon per gram of rock. If S_1>1mg/g, it may indicate an oil show. S_1 normally increases with depth also; contamination of sample by drilling mud can give an abnormally high value of S_1.

S_2: this is the amount of hydrocarbon generated by the thermal cracking of nonvolatile organic matter. S_2 indicate the quantity of hydrocarbons the rock has the potential to produce with increasing depth.

S_3: this is the amount of Carbon IV Oxide CO_2 (measured in milligrams of CO_2 per gram of rock) produced during pyrolysis of kerogen. S_3 indicates the amount oxygen (O_2) in the kerogen and it's used to calculate the oxygen index. Contamination of samples should be suspected if S_3 is abnormally high.

T_{max}: this is the temperature at which the maximum release of hydrocarbons from cracking of kerogen occurs during pyrolysis. T_{max} indicates the stage of maturation of organic matter.

The type and maturity of organic matter in petroleum source rock can be characterized from Rock Eval Pyrolysis data using the following parameters (Trans Le et al, 1993)

HI: Hydrogen Index (HI= 100 x [S_2/TOC]). It is used to characterize the origin of organic matter.

OI: Oxygen Index (OI= 100 x [S_3/TOC]). This parameter correlates the ratio of oxygen to carbon.

PI: Production Index (PI =S_1/[S_1 +S_2]). It is used to characterize the evolution level of the organic matter.

3.2.4 Extraction of Extractable Organic Matter (EOM)

The shale to be analysed was powdered and soxhlet-extracted in cellulose thimbles for a total of 36 hours in each case using 100% dichloromethane. The solvent from the resultant solution was removed by means of a rotary evaporator under vacuum (pressure not greater than 200 mbar) and finally by a flow of nitrogen at not more than a temperature of 30^0C to yield the Extractible Organic Matter (EOM).The EOM was analysed by capillary gas chromatography to produce gas chromatograms from which the values of the preliminary biomarker parameters, namely, Pristane/nC17, Phytane/nC18, Pristane/Phytane, etc were computed from peak heights.

$$\boldsymbol{EOM(ppm)} = \frac{Weig\,htofSOM\ (g)x10^6}{Weig\,htofsample\ \ (g)} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots.. \qquad (i)$$

From the values of the TOC (wt %) and SOM (ppm), the bitumen ratio can be calculated as follows:

$$\boldsymbol{BitumenRatio}\left(\boldsymbol{mg}\frac{\boldsymbol{ext}}{\boldsymbol{g}}\boldsymbol{TOC}\right)=\frac{EOM\ (ppm\,)}{TOC(wt\ \%)X10}\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \text{(ii)}$$

3.2.5 Gas Chromatography (GC)

Gas chromatography was conducted on a Varian 3400 GC fitted with 45m x 0.25mm fused silica column coated with a non-polar stationary phase (DB1). Both the injector and detector temperatures were set at 300^0C. The oven-heating programme was set at a temperature of 30^0C for an initial isothermal period of 2 minutes then heating up at the rate of 6^0C/min to 300^0C followed by final isothermal period of 13 minutes. The carrier gas was hydrogen and it was set at a flow rate of 2mL/min. Collection and processing of GC data was initially done with Atlas software via a Chromatographic Server. This process produced the respective gas chromatograms as well as the corresponding injection reports containing peak heights and areas.

3.2.6 Organic Petrology

Macerals are the remains of various types of plant and animal matter that can be distinguished by their chemistry and by their morphology and reflectance using a petrographic microscope (Sach et al, 1982).

In order to determine the maceral constituents. Representative samples collected from the sections were crushed to less than2mm and impregnated in epoxy resin, ground and polished for quantitative reflected light microscopy. MT9900 Series illumination model. Microscopic examination was carried out under X40 oil immersion objective.

CHAPTER FOUR

RESULT AND DISCUSSION

4.1 Results

4.1.1 Description of Lithologic Sections

4.1.1.1 Km 6, Agbogugu Junction, Portharcourt –Enugu Expressway.

The outcrop is located at Agbogugu Junction, along the Portharcourt –Enugu Expressway. It is precisely defined by Latitude and longitude N6^0 14’ and E7^0 28’ respectively. It stands at an elevation of 191m. The total logged section is about 45m (Fig. 4.1). The lowermost unit is a 25m thick highly pyritic shale, interbedded with thin beds of siltstone. Calcitic/Gypsum concretions are also evident. The unit dips at 6^0 in the direction of 180^0 Azimuth. Up-section, the unit is punctuated by a 1m thick clayey sandstone unit which in turn is overlain by a 15m thick Intervening bed of highly weathered homogenous pyritic shales and siltstones (Fig. 4.2). This unit is also laden with calcitic/gypsum concretions. A coarse-grained trough cross-bedded sandstone unit of 1m thick overlies the shale unit and a2m thick massive fine to medium-grained yellowish to white sandstone capped mud drapes overlain by the trough bedded unit. A ripple laminated 1.5m thick, yellowish and bioturbated sandstone unit with interlayering of siltstones capped with mudstones overlies the massive sandstone unit. Overlying this unit is a 1m thick ripple laminated yellowish white sandstone with intercalations of siltstone (Fig. 4.3) and exhibiting a sharp erosional contact with the overlying unit. The section is overlain by a 3m-thick fine to medium grained yellowish white cross-bedded sandstone dipping at 12^0 in the direction of 308^0 Azimuth (Fig. 4.4).

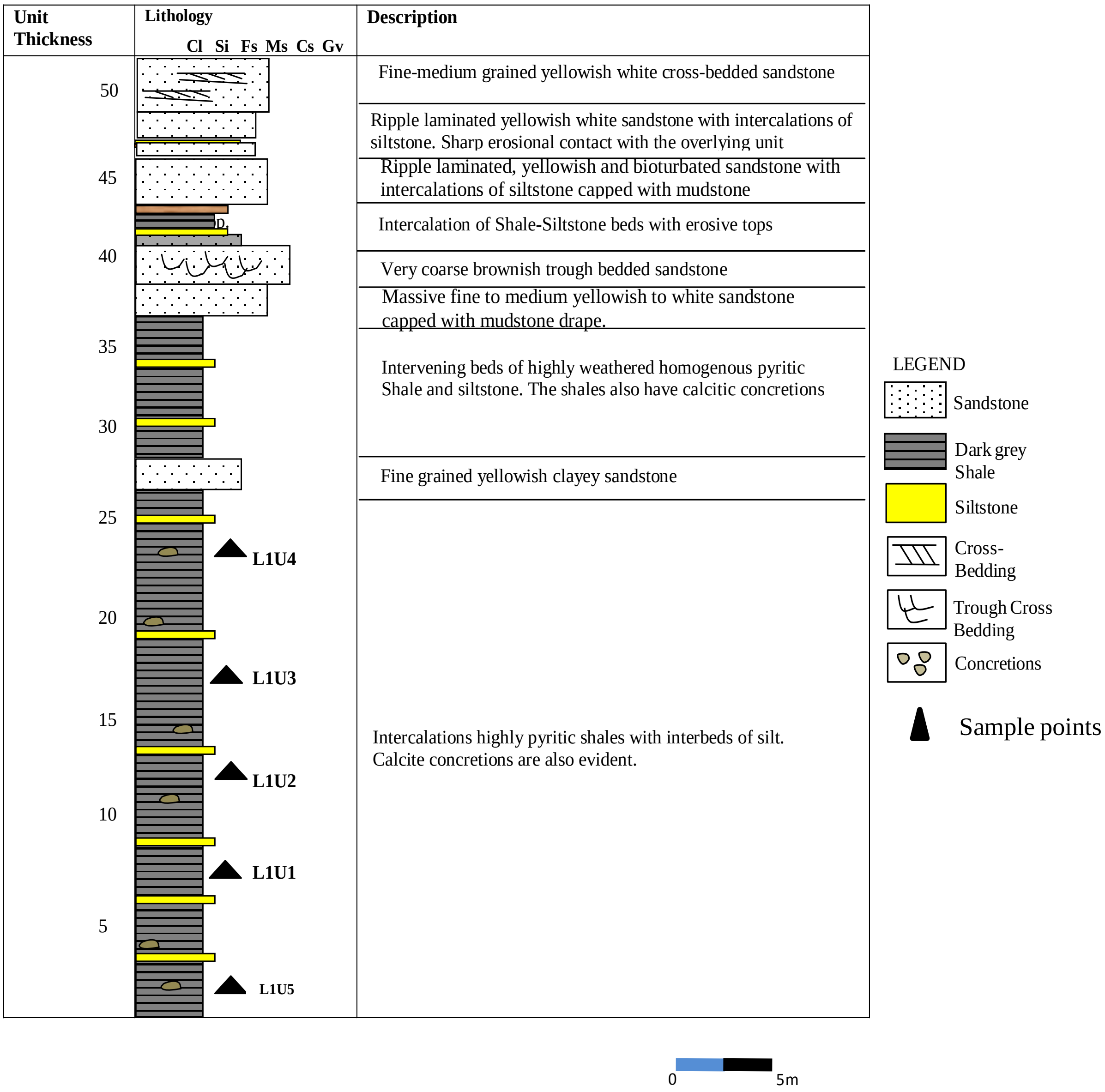


Fig. 4.1. Lithostratigraphic log of the Agbogugu Junction section along the, Ph/Enugu Expressway

Fig 4.2: Pyritic shale interbedded with thin beds of siltstone.

Fig 4.3: Ripple laminated sandstone at Agbogugu section

Fig 4.4: Cross bedded sandstone at Agbogugu section

4.1.1.2 Km 5 Leru/Isuochi junction along the Portharcourt/Enugu Expressway.

The outcrop is located at the Leru/Isuochi junction along the Portharcourt/Enugu highway. It is located within Latitude $5^0$54’N and Longitudes $7^0$26’E. The location stands at an elevation of 214m. The total logged section is about 17m thick (Fig. 4.5 and 4.6). The lowermost unit is comprised of dark grey, laminated and carbonaceous shale of about 4.5m thick, overlain by a 1.5m thick, laminated, dark grey shaly sandstone (Fig. 4.7). This in turn is succeeded by a 1m-thick yellowish brown clayey sandstone, the sandstone unit is fine grained in texture. A 2m-thick siltstone unit, yellowish white in colour and ripple laminated overlies the clayey sandstone unit. A moderately sorted fine to medium grained bioturbated sandstone unit of about 0.7m thick overflies the siltstone unit, this bed contains some identifiable trace fossil assemblage with horizontally inclined burrows of *Thalassinoides Paradoxicus* (Onyekuruand Iwuagwu, 2010). This unit is capped by a thin clayey siltstone unit. A 0.6m-thick greyish-white clayey sandstone, fine grained in texture overlie the bioturbated sandstone unit. Overlying this unit is a 0.7m thick coarse grained, Cross-bedded to herringbone, and poorly sorted sandstone. 1m thick fine grained, cross-bedded to herringbone sandstone overlie the coarse grained unit. it is overlain by a fine grained sandstone with intervening mud drapes. The cross-beds dip at 17^0 in the direction of 229^0 Azimuth. A fine grained yellowish brown highly weathered sandstone, 0.5m thick overlies this unit. The section is capped by a 1.5m thick medium-coarse grained, ferruginized sandstone, with a basal gravelly unit (Fig. 4.8). In the outcrop, the thickness of the silt and sand increases up-section while the shale unit thicken down section.

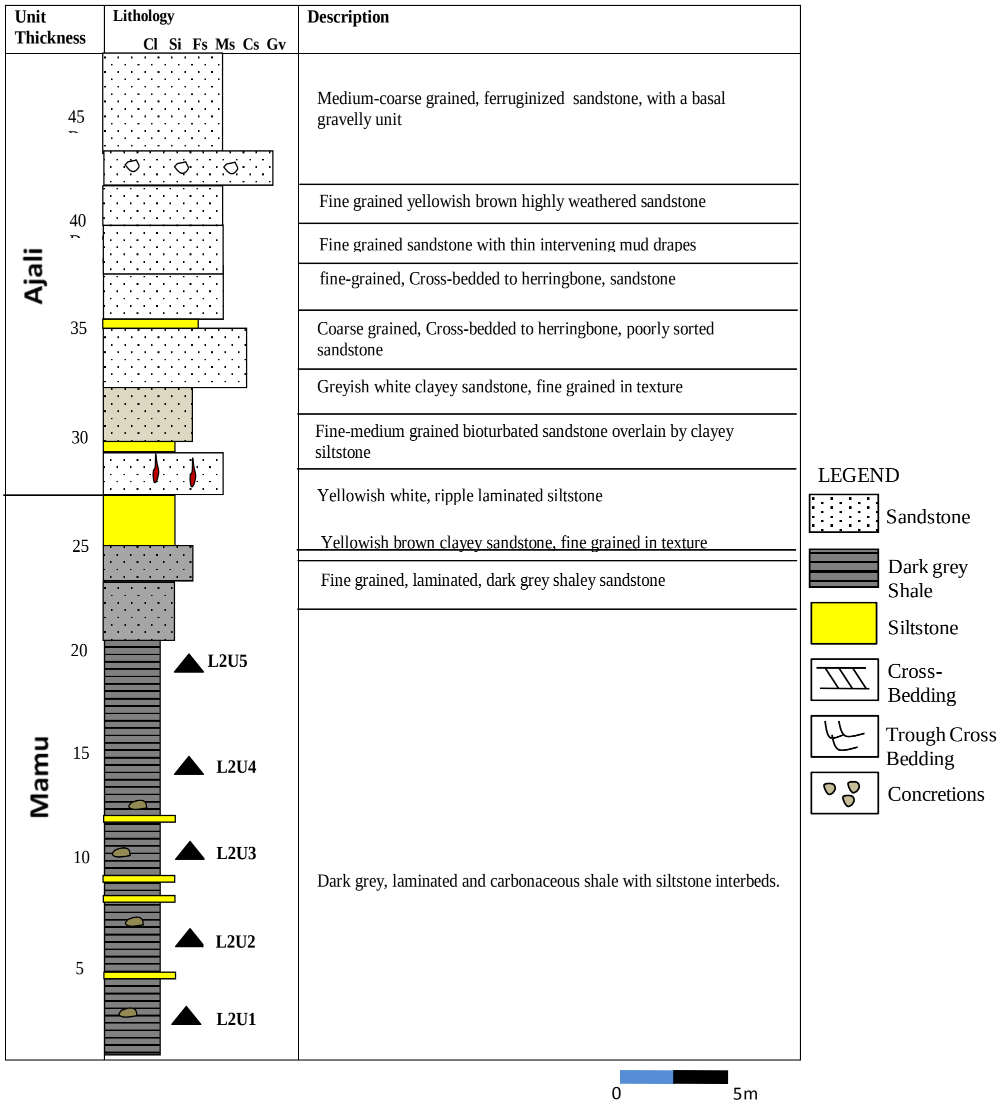


Fig.4.5. Lithostratigraphic log of outcrop at km 5 Leru/Isuochi Junction, Ph/Enugu Expressway

Fig. 4.6. The outcrop location outcrop at km 5 Leru/Isuochi junction, along PH/Enugu expressway

Fig. 4.7. Laminated, dark grey shaly sandstone at km 5 Leru/Isuochi junction, along PH/Enugu expressway

Fig. 4.8. Ferruginized sandstone with a basal gravelly bed at km 5 Leru/Isuochi junction, along PH/Enugu expressway

4.1.2 Organic Geochemistry

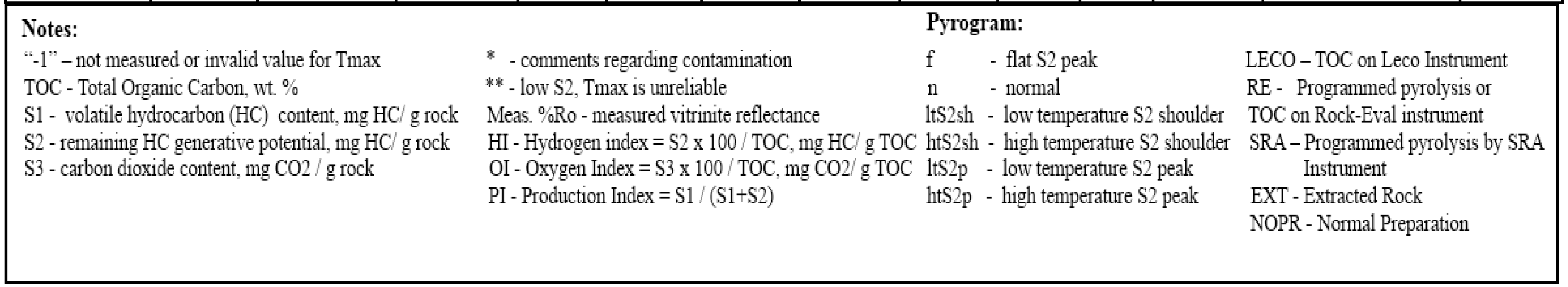
Evaluation of sedimentary rock as a possible source rock in research and development laboratories depends on the following source rock parameters:

1. Total amount of organic Carbon in a sample (TOC)
2. The quality of organic matter which is insoluble in organic solvents (Kerogen)
3. The quantity of soluble/extractable organic matter (SOM/EOM)

In this study, the quantity, quality and thermal maturity of the studied samples of Mamu and Enugu Formations were discussed based on Rock-Eval pyrolysis data (TOC, S_1, S_2, S_3, T_{max}, HI, PI and SP values). Measured Rock-Eval parameters include S_1 (mgHC/g rock), S_2 (mgHC/g rock), S_3 (mgCO_2/g rock), Tmax (^{0}C), and TOC (wt%). The parameters calculated from the measured values is shown in Table 2. The criteria for the assessment of hydrocarbon source rocks include quantity of organic matter, thermal maturity of organic matter and type of kerogen. (Peters, 1986; Baskin, 1997, Akande et al.,1998;Unomah and Ekweozor 1998; Schmidt, 1998; Akaegbobi and Schmitt ,1998; Ojo and Akande, 2000; Ugochukwu, 2010).

Table 4.1. Results of Organic Geochemical Analysis

S/N	ID	Client ID	Sample Type	TOC	S1	S2	S3	(°C)	HI	OI	S2/S3	S1/TOC*100	PI
1	9648	L1U1	Enugu Sh	4.94	0.19	7.00	2.98	437	142	60	2.3	4	0.03
2	9649	L1U2	Enugu Sh	2.46	0.16	1.74	0.82	424	71	33	2.1	7	0.08
3	9650	L1U3	Enugu Sh	0.72	0.04	0.31	0.59	439	43	82	0.5	6	0.11
4	9651	L1U4	Enugu Sh	0.80	0.07	1.00	0.85	435	125	106	1.2	9	0.07
5	9652	L1U5	Enugu Sh	4.32	2.49	23.63	0.63	428	547	15	37.5	58	0.10
6	9653	L2U1	Mamu Fm	0.76	0.05	0.28	0.65	441	37	86	0.4	7	0.15
7	9654	L2U2	Mamu Fm	1.36	0.04	0.37	1.08	434	27	79	0.3	3	0.10
8	9655	L2U3	Mamu Fm	2.11	0.06	1.14	0.55	429	54	26	2.1	3	0.05
9	9656	L2U4	Mamu Fm	1.92	0.06	0.78	0.54	434	41	28	1.4	3	0.07
10	9657	L2U5	Mamu Fm	1.28	0.06	0.49	0.36	417	38	28	1.4	5	0.11



Notes:

"-1" – not measured or invalid value for Tmax
TOC - Total Organic Carbon, wt. %
S1 - volatile hydrocarbon (HC) content, mg HC/ g rock
S2 - remaining HC generative potential, mg HC/ g rock
S3 - carbon dioxide content, mg CO2 / g rock

* - comments regarding contamination
** - low S2, Tmax is unreliable
Meas. %Ro - measured vitrinite reflectance
HI - Hydrogen index = S2 x 100 / TOC, mg HC/ g TOC
OI - Oxygen Index = S3 x 100 / TOC, mg CO2/ g TOC
PI - Production Index = S1 / (S1+S2)

Pyrogram:

f - flat S2 peak
n - normal
ltS2sh - low temperature S2 shoulder
htS2sh - high temperature S2 shoulder
ltS2p - low temperature S2 peak
htS2p - high temperature S2 peak

LECO – TOC on Leco Instrument
RE - Programmed pyrolysis or TOC on Rock-Eval instrument
SRA – Programmed pyrolysis by SRA Instrument
EXT - Extracted Rock
NOPR - Normal Preparation

4.1.2.1 Total Amount of Organic Content (TOC)

The aim of TOC is to determine the percentage by weight of the organic content in source rock. This is a measure of its potential to generate hydrocarbon. Based on percentage organic content, the following source rock ratings were applied as standards (Table 3)

Table 4.2. TOC standard rating for source rocks*(Tissot & Welte, 1984)*

% Organic Content	**Ratings**
< 0.5	Poor
0.5 – 1.0	Fair
1.0 - 2.0	Good
2.0 – 4.0	Very Good
> 4.0	Excellent

Table 4.2 shows the result of organic geochemical analysis carried out on the ten rock samples. The Total Organic Content (TOC) of the shale samples of Enugu Shale ranges from 0.72 to 4.94 wt % with an average of 2.64 wt%. Samples from the Mamu Formation, has TOC values ranging from 0.76 to 2.11 wt% with an average value of 1.49 wt%. The average value indicate very good and good TOC for Enugu and Mamu shales refspectively

4.1.2.2 Quantity of Organic Matter

The results of Extractable Organic Matter of shale samples in the study area is shown in Table 4.3, while the Plot of SOM (ppm) against TOC (wt %) (Jovancicevic et al, 2002) is shown in Fig. 4.9.

The bitumen content, also called Soluble Organic Matter (SOM) or Extractable Organic Matter (EOM)include organic matter that are soluble in organic solvent to obtain organic extracts. It is a function of the quantity, quality and maturity level of kerogen as well as the extent of the hydrocarbon expulsion (Tissot and Welte, 1984).Result of the SOM/EOM of the shale samples of the studied sections exceeds 500ppm. Samples from Enugu Shale has an average value of 3526ppm while those of Mamu Formation has an average value of 693ppm. The plot of TOC (%) against SOM (ppm) shows that most of the shale samples were clustered within the oil source rock field. Sample (L1U5) from Enugu Shale with a peculiar high SOM 14,900 (ppm) plotted within the migrated oil field (Fig. 4.9).

Table 4.3. Extractable Organic Matter of shale samples in the study area

S/No	Sample No	Formation	EOM (ppm)
1	L1U1	Enugu Shale	540
2	L1U2	Enugu Shale	708
3	L1U3	Enugu Shale	564
4	L1U4	Enugu Shale	872
5	L1U5	Enugu Shale	14,900
6	L2U1	Mamu Formation	576
7	L2U2	Mamu Formation	572
8	L2U3	Mamu Formation	1200
9	L2U4	Mamu Formation	568
10	L2U5	Mamu Formation	548

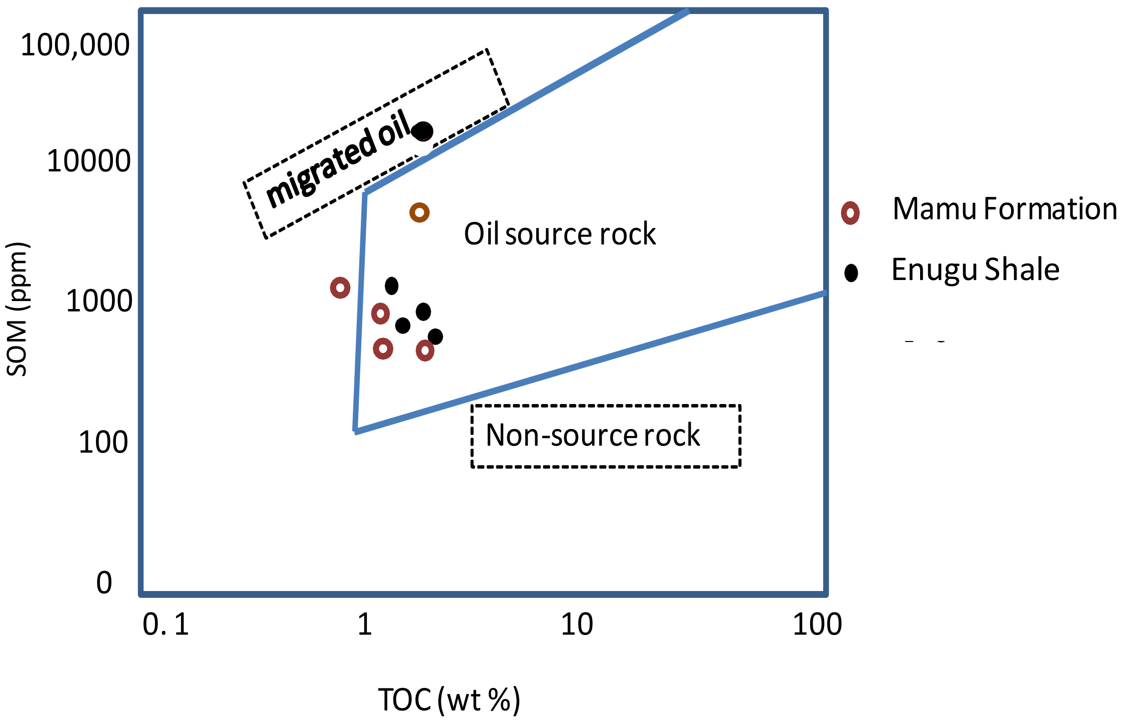


Fig. 4.9. Plot of SOM (ppm) against TOC (wt %) (Jovancicevic et al., 2002)

4.1.2.3 Insoluble Organic Matter (Kerogen) and Quality of Organic Matter.

Kerogen consists of insoluble organic debris found dispersed throughout sedimentary rocks. They consist of mixtures of macerals and other reconstituted degradation products of organic matters, while macerals are recognizable remains of different type of organic matters that can be differentiated under the use of microscope.

Results showed a Hydrogen Index (HI) value of 43 to 547 mgHC/gTOC for the Enugu Shale with an average value of 185.65mgHC/gTOC (Table 4.1).Again, sample L1U5 showed a remarkable value of 547mgHC/gTOC. Samples from Mamu Formation showed a HI value of 27 - 54mgHC/gTOC with average of 39.45mgHC/gTOC.

A corresponding Oxygen Index values of 15 - 106 mgCO_2/gTOC was recorded for Enugu Shale with an average of 59.2mgCO_2/gTOC. Mamu Formation on the other hand showed a value of 26 - 86 mgCO$_2$/gTOC with average of 49.4 mgCO$_2$/gTOC. A plot of Hydrogen Index (HI) against Oxygen Index (OI) showed that Enugu Shale and Mamu Formations are dominated by Type III kerogen and mixed Type II/III kerogen (Peters, 1986)(Fig. 13). Sample (L1U5) (Enugu Shale) plotted in the Type I zone. Samples from Mamu Formation are particularly low in HI (below 50mgHC/gTOC), and are inert (Type IV kerogen).

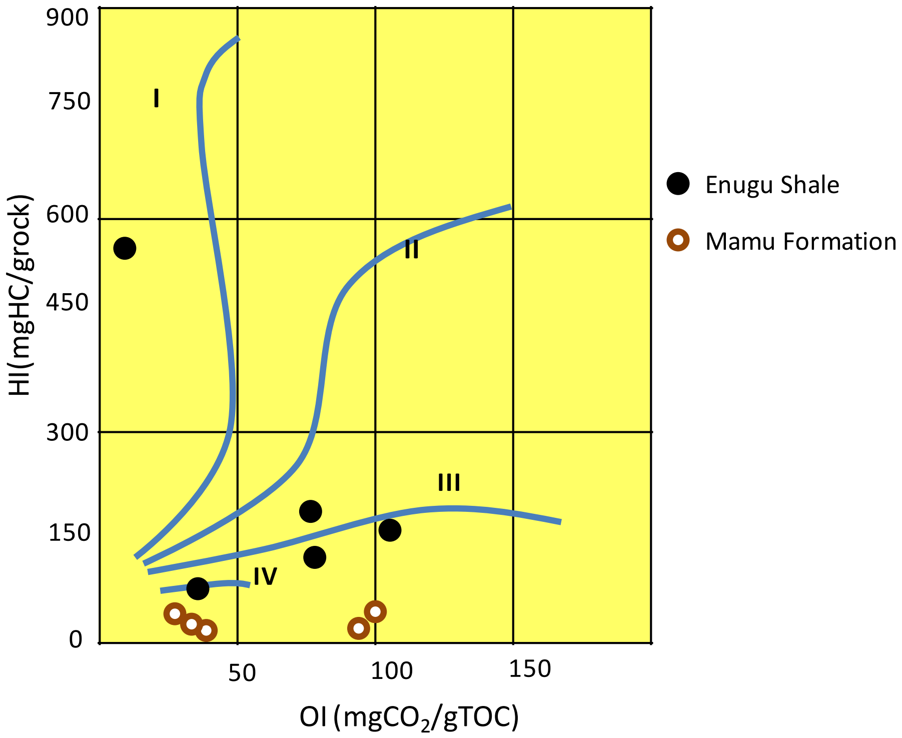


Fig. 4.10. Plot of hydrogen Index against Oxygen Index (Tissot and Welte (1984)

4.1.2.4 Maceral Analysis and Thermal Maturity Parameters

Result of Maceral analysis of the shale samples was applied to further assess the quality of the organic matter in the studied samples is shown in Table 4.4. The result indicates the prevalence of vitrinite maceral group.

The vitrinite maceral group in the analysed shale samples ranges between 39 to 59%. The inertnites ranged from 11 to 18% while the liptinites range from 9 to

21%. The vitrinite components are mainly desmocollinite, collinite and vitrodetrinite. The inertinites group consists of fusinites and semi fusinites whereas the liptinites components are mainly cutinites and sporinites.

Table 4.4. Result of Maceral analysis and vitrinite reflectance measurement.

Sample No	Formation	Vitrinite (%)	Liptinite (%)	Inertinite (%)	Mineral Composition	Pyrite (%)	Vitrinite reflectance
L1U1	Enugu Sh	57	11	14	8	10	0.49
L1U2	Enugu Sh	50	15	12	10	13	0.55
L1U3	Enugu Sh	56	11	14	11	8	ND
L1U4	Enugu Sh	49	14	16	11	10	ND
L1U5	Enugu Sh	39	21	13	14	13	0.49
L2U1	Mamu Fm	59	13	11	8	9	0.55
L2U2	Mamu Fm	56	11	14	12	7	0.59
L2U3	Mamu Fm	48	12	18	12	8	0.49
L2U4	Mamu Fm	55	9	11	17	8	0.55
L2U5	Mamu Fm	53	10	17	14	8	0.56

Thermal maturity refers to the extent of temperature-time driven reactions that convert sedimentary organic matter (source rock) to oil, wet gas, and finally to dry gas.

Thermal maturity in the study area has been assessed by the Rock-Eval, Tmax data and by the bitumen ratio. According to Peters (1986), variation in kerogen types affect Tmax values. At a thermal maturity that corresponds to a Tmax of 435^0C, source rocks with HI greater than 500mg HC/gTOC yield oil while those with HI value ranging from 250 to 500mgHC/gTOC yield oil and some gas. Rocks with HI of 50 to 250mgHC/gTOC produce gas while those with HI less than 50mgHC/gTOC are inert (Tissot et al., 1974).

In the present study, Tmax ranged from 424^0C to 439^0C with an average of 432^0C for sediments in the Enugu Shale and corresponding Hydrogen Index

(HI) values ranging from 43 to 547mgHC/gTOC with an average value of 185.65mgHC/gTOC. Mamu Formation sediments on the other hand showed a Tmax value of 417^0C to 441^0C with an average of 431^0C and a corresponding HI value of 26 to 86mgHC/gTOC with average of 39.45mgHC/gTOC).

The ratio of the bitumen content to the total organic content (bitumen ratio) can also be used as a maturation parameter for source rocks (Peters and Moldowan, 1993).

The calculated bitumen ratios for the Enugu Formation ranges from 35 to 1384.2 mgExt/gTOC with an aveage of 325.62 mgExt/gTOC while that of Mamu Formation ranges from 50 to 227.5 mgExt/gTOC with an average of 132.58 mgExt/gTOC. Aplot of HI versus Tmax (Fig. 14) show that the samples plot within the Type III kerogen zone confirming the predominance of Type III organic matter. The sediments from this plot are immature to transitional in term of their thermal maturity. Sample (L1U5) from Enugu Formation however plotted within the Type II kerogen zone.

Also, the ratio of extractable bitumen to total organic carbon (transformation ratio) can be used to determine sediment maturity, (Peters and Moldowan, 1993). This ratio varies from zero (0) in shallow sediments to 250mgExt/gTOC at peak oil generation then decreases at greater depth due to conversion of bitumen to gas. Oil prone source rocks and gas prone kerogens rarely exceed 50mgExt/gTOC at any level of maturity, thus, bitumen ratio as a maturity indicator(Mile, 1989). The bitumen ratio in the studied area ranges from 35to227.5mgExt/gTOC. This indicates that the sediments are immature, though Sample (L1U5) from Enugu Formation recorded a high value of 1384.2mgExt/gTOC which is indicative of mature source rock (Fig 4.11).

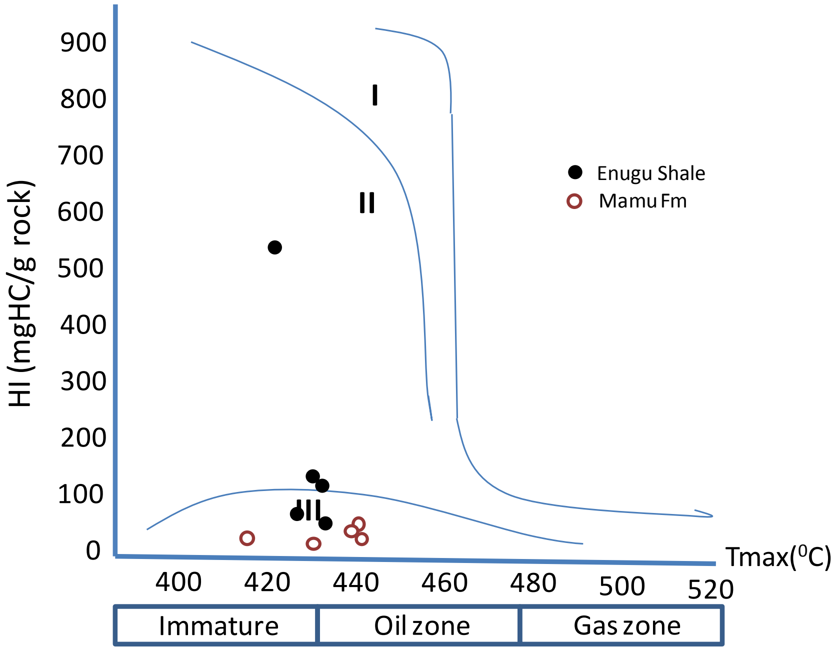


Fig.4.11 .Plot of HI against Tmax showing the Thermal Maturity and the OM type

The values for the production index (PI) ranges from 0.03 to 0.11 with an average of 0.195 for samples obtained in the Enugu Shale while those from the Mamu Formation ranges from 0.05 to 0.15 with an average of 0.24 (Tables 4.1 and 4.5). These values shows that the production index increases with increasing depth of burial of organic matter as expected (Barker 1974). This also implies that increase of production index is mainly due to cracking of the kerogen and to lesser extent, to thermal vaporization and cracking as asphaltenes which causes the S_2 signal to progressively transform to S_1. These values thus tell that the organic matter is immature (peter and Cassa, 1994). This is further highlighted by the plot of PI versus Tmax (Fig. 4.12).

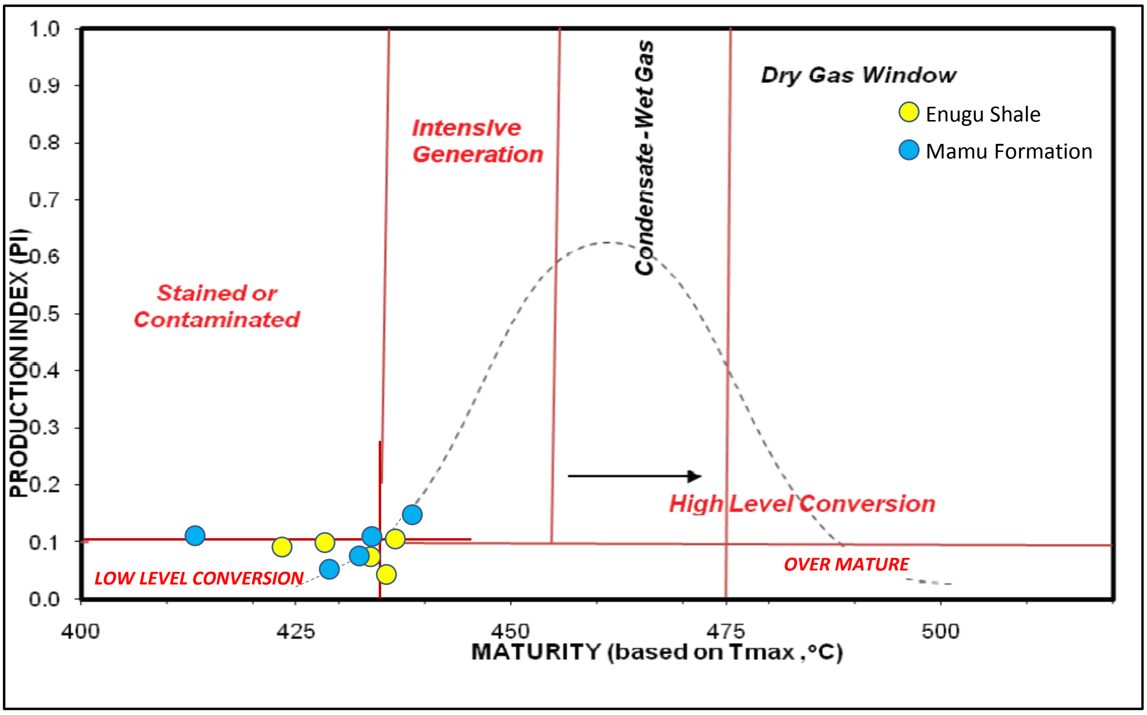


Fig. 4.12. A plot of Production Index (PI) against Tmax.

Table 4.5. Maturity Parameters from Tmax and Production Index.

FORMATION	Tmax (^{0}C)	PI
Enugu	424 – 439	0.03 - 0.11
Mamu	417 -441	0.05 – 0.15
REMARK	Immature	Immature

Vitrinite Reflectance is the method used to evaluate the maturation of kerogen and to establish the depth range associated with petroleum generation. This is an optical technique which measures the amount of incident/visible light from the polished surface of woody fragments/materials in kerogen. With increasing degree of thermal alteration, the fraction of incident light increases. Reflectance increases exponentially with depth (a straight line on a logarithmic scale) (Fig. 4.13). The oil window is generally accepted to be between the reflectance levels of 0.6% and 1.3% (Dow, 1977).

Zone of petroleum generation and destruction based on mean random reflectance are given below (Table 4.6).

Table 4.6. Vitrinite reflectance ranges of oil generation and destruction (After Dow, 1977)

% Ro	**Zone**
0.6	Incipient hydrocarbon generation
0.6-1.3	Main phase of oil generation
1.0	Peak oil generation
1.3	Major gas generation & Oil destruction
2.0	Peak dry gas generation per unit
3.2	Dry gas preservation

As shown in Table 5,the samples yielded a Vitrinite reflectance value in the range of 0.49 to 0.59 with an average of 0.53. Sample L1U3 and L1U4 of Enugu shale could not be determined by vitrinite reflectance and thus indicate purely marine origin.

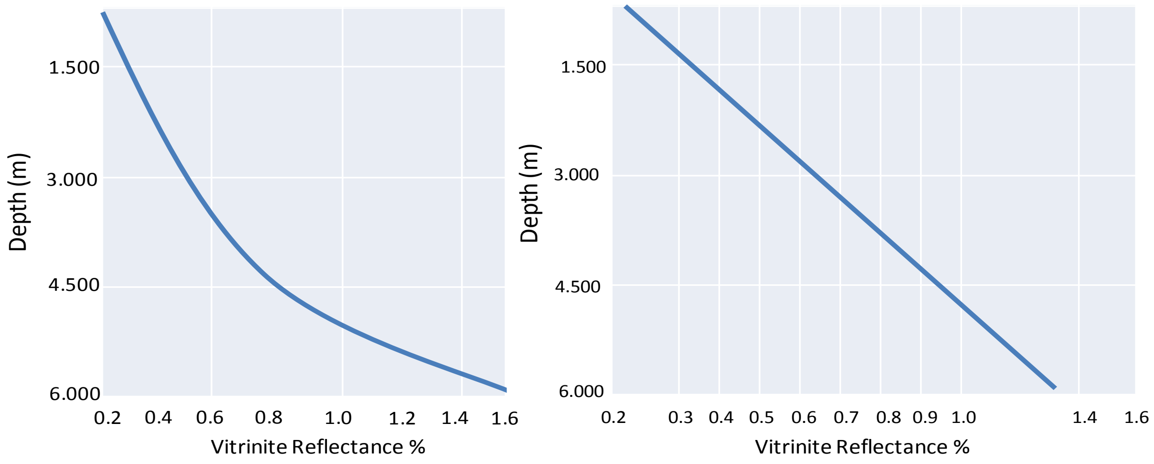


Fig. 4.13. Vitrinite Reflectance Plots – Linear and Logarithm scale *(Dow, 1977)*

4.1.2.5 Petroleum Generic Potential from Rock-Eval pyrolysis

The rock –Eval pyrolysis instrument produces three (3) peaks in the form of a pyrogram. S_1 peak represents the amount of free hydrocarbons (already generated) in a rock, S_2 peak represent the amount of hydrocarbons formed by the breakdown of kerogen due to heating to high temperatures and S_3 peak is the amount of carbon IV oxide (CO_2) formed from the thermal breakdown of the kerogen. S_1, S_2, and S_3 can be expressed in parts per million (ppm), parts per thousand (ppt), kilograms per ton of rock.

A guideline to the interpretation of rock-Eval pyrolysis is presented in (Table 4.7) below

Table 4.7. Parameters for petroleum generating potentials (After Tissot and Welte, 1984)

EVALUATION	PARAMETER	PARAMETER VALUE	RATING
Hydrocarbon Source Potential	$S_1 + S_2$ (ppm)	< 2000 2000 – 6000 > 6000	Poor Fair Good
Kerogen Type	S_1/S_3	< 5.0 5.0 – 10.0 > 10.0	Gas Prone Uncertain Oil Prone
Thermal Maturity	S_1/S_1+S_2	< 0.10 0.10 – 0.30 > 0.30 >>0.3	Immature Oil generation Gas generation Oil destruction
Thermal Maturity	Tmax (^{0}C)	< 430 430 – 465 > 465	Immature Oil generation Gas generation Oil destruction

The assessment is based on Tissot and Welte’s (1984) classification as follows: source rocks with Gas Potential (GP) less than 2mgHC/g rock (2000ppm) are suggestive of poor source rock, while rocks with GP of 2 to 6mgHC/g rock (2000 to 6000ppm) implies moderately rich source rock with fair oil potential.

Those with GP greater than 6mgHC/g rock(6000ppm) are considered as good or excellent petroleum source rocks (Tissot and Welte, 1984; Dymann et al., 1996; Akande et al., 2005). In the study area, the samples both from Enugu Shale and Mamu Formations exhibit average yields (4.01mgHC/g rock). This is further ascertained by the plot of Petroleum generic potential against TOC (%) as show below (Fig.4.14).

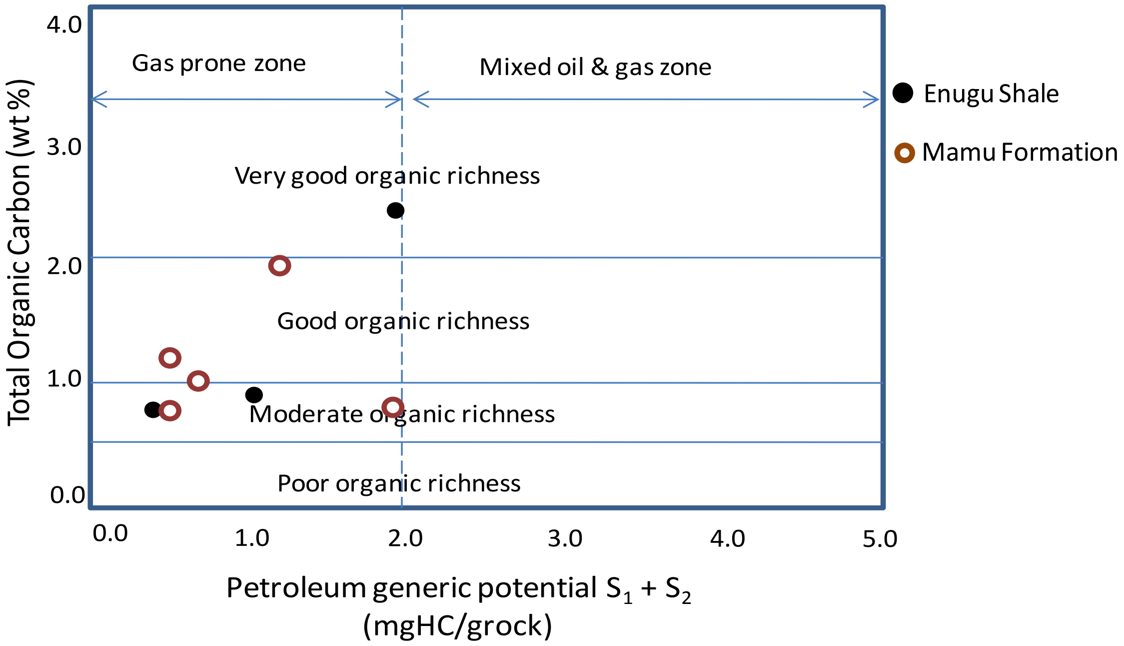


Fig. 4.14. Plot of TOC against Petroleum generic potential (Akande et al., 2005)

The plot of hydrocarbon yield or remaining hydrocarbon (S_2) against total organic carbon (Fig.18) classifies effective primary source rocks as those with S_2 greater than 5mgHC/g rock and Effective Non Source (ENS) rocks as those with S_2 less than 1mgHC/g rock. As shown in the figure 4.15, Enugu Shale and Mamu Formations are essentially secondary sources rocks with fair to very good hydrocarbon potential to generate gas and condensate. Sample (L1U5) from Enugu Shale showed a very high S_2 value of 23.6 and plotted in the Primary source rock field which implies potential to generate hydrocarbon without secondary enhancement.

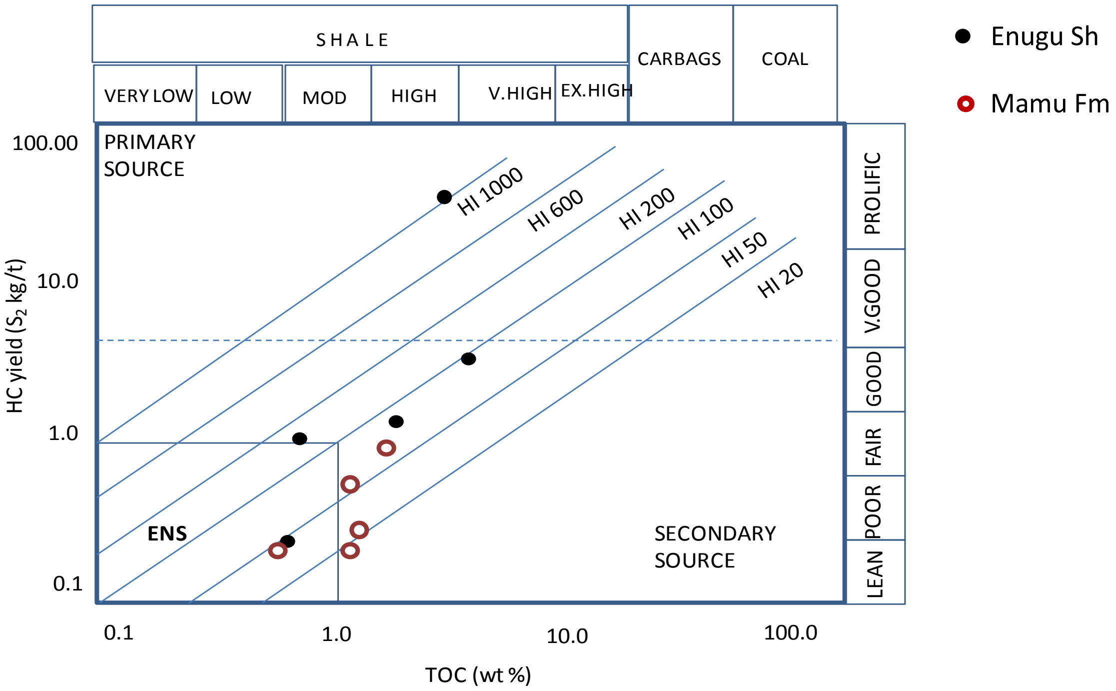


Fig.4.15 .Plot of hydrocarbon yield against TOC (Burwood, 1995)

4.1.2.6 Gas Chromatography

The peak identities of both the high molecular and low molecular carbon are shown in Fig. (4.16 to 4.25).The pristane (nC17), phytane (nC18), CPI and OER values are also shown in Table 4.8.

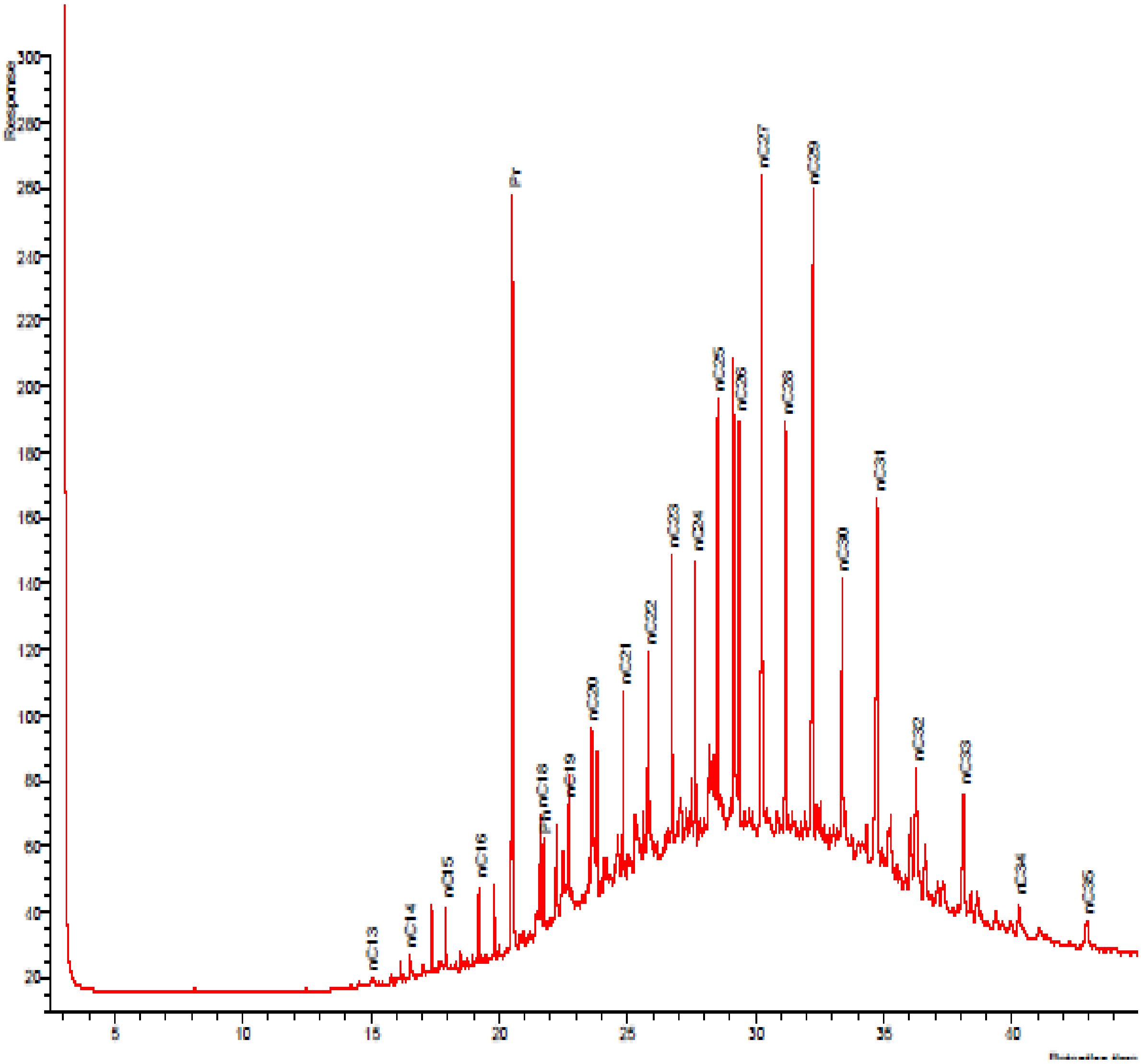


Fig. 4.16.Gas Chromatogram of Sample L1U1

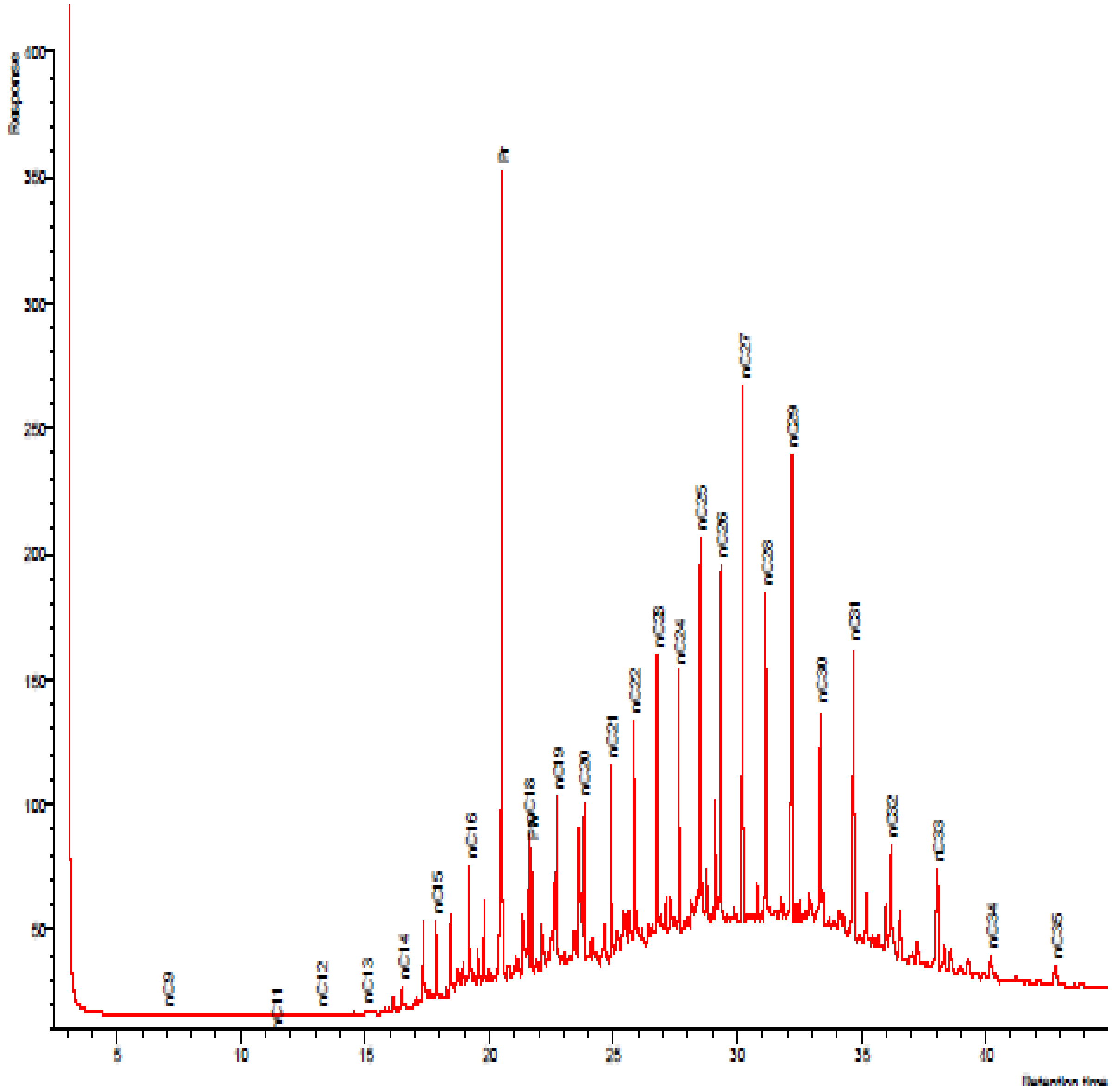


Fig. 4.17 Gas Chromatogram of Sample L1U2

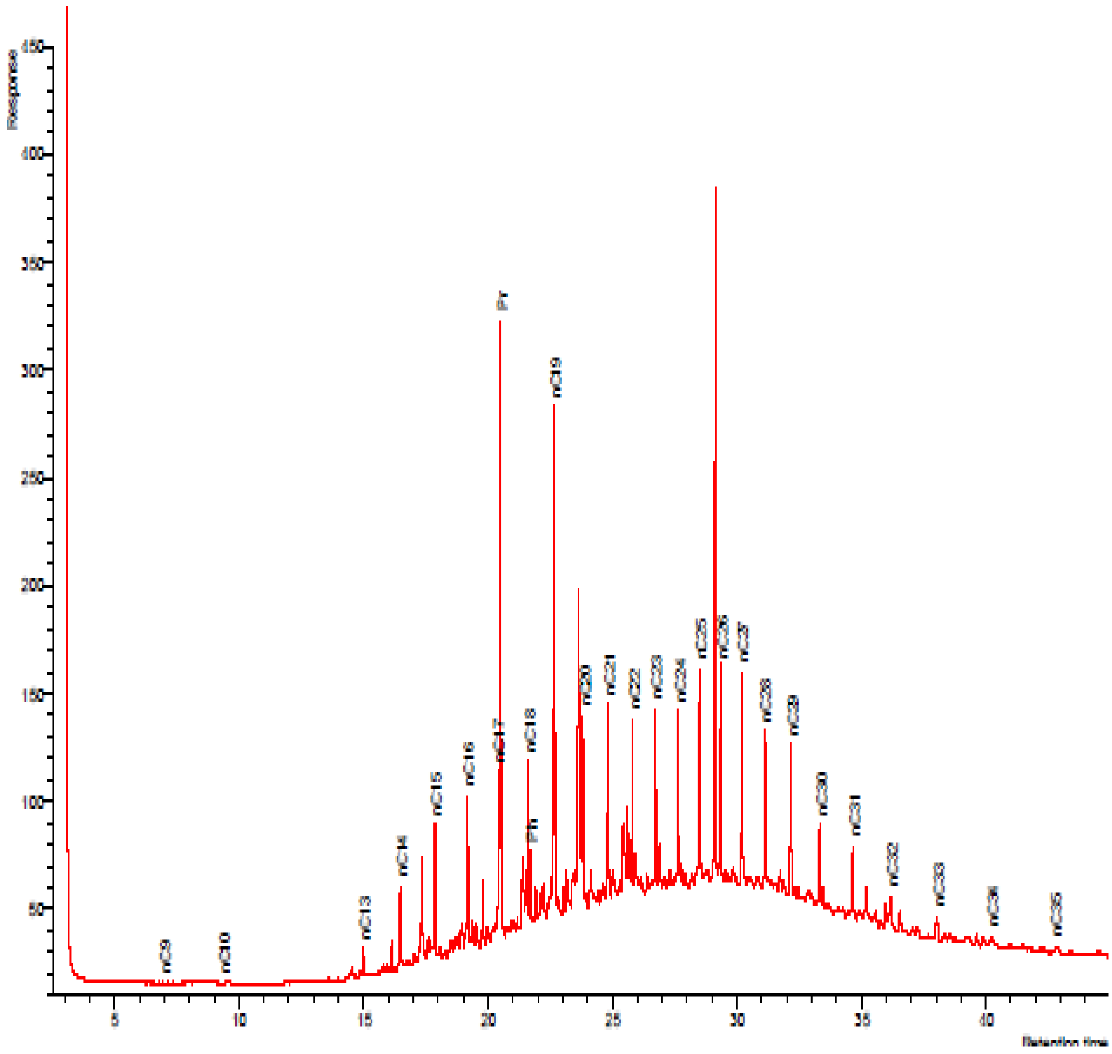


Fig. 4.18.Gas Chromatogram of Sample L1U3

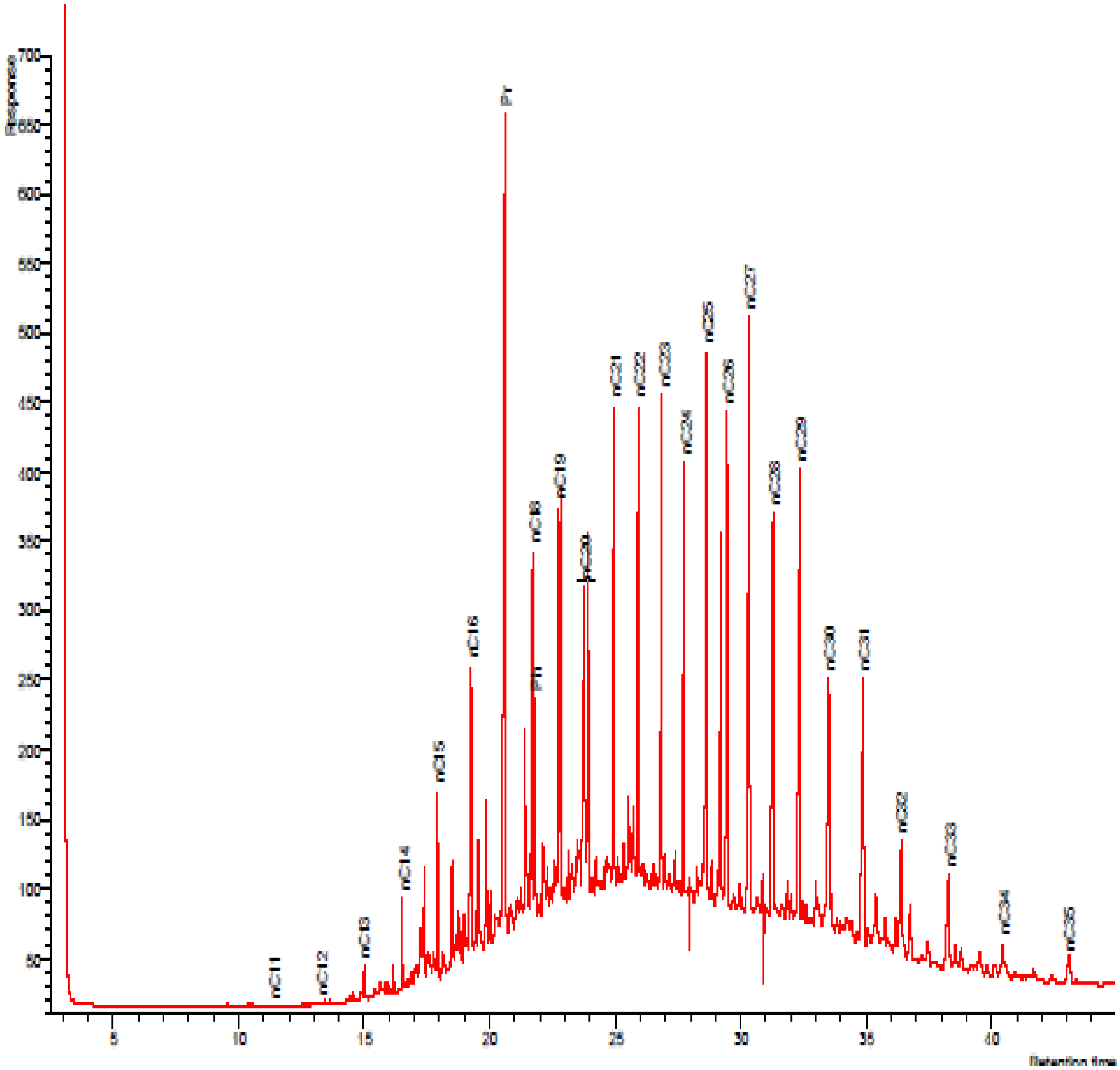


Fig. 4.19.Gas Chromatogram of Sample L1U4

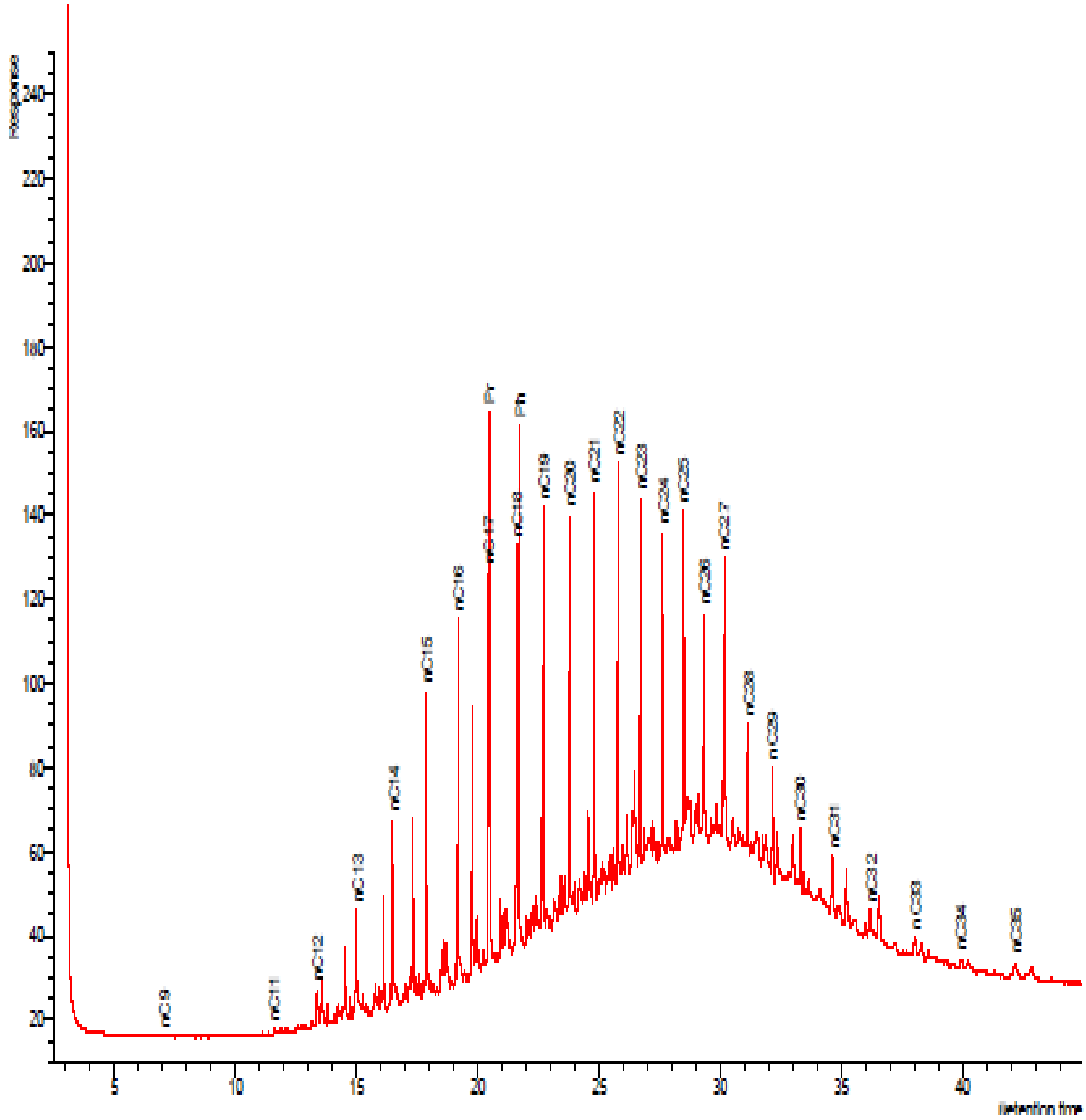


Fig. 4.20.Gas Chromatogram of Sample L1U5

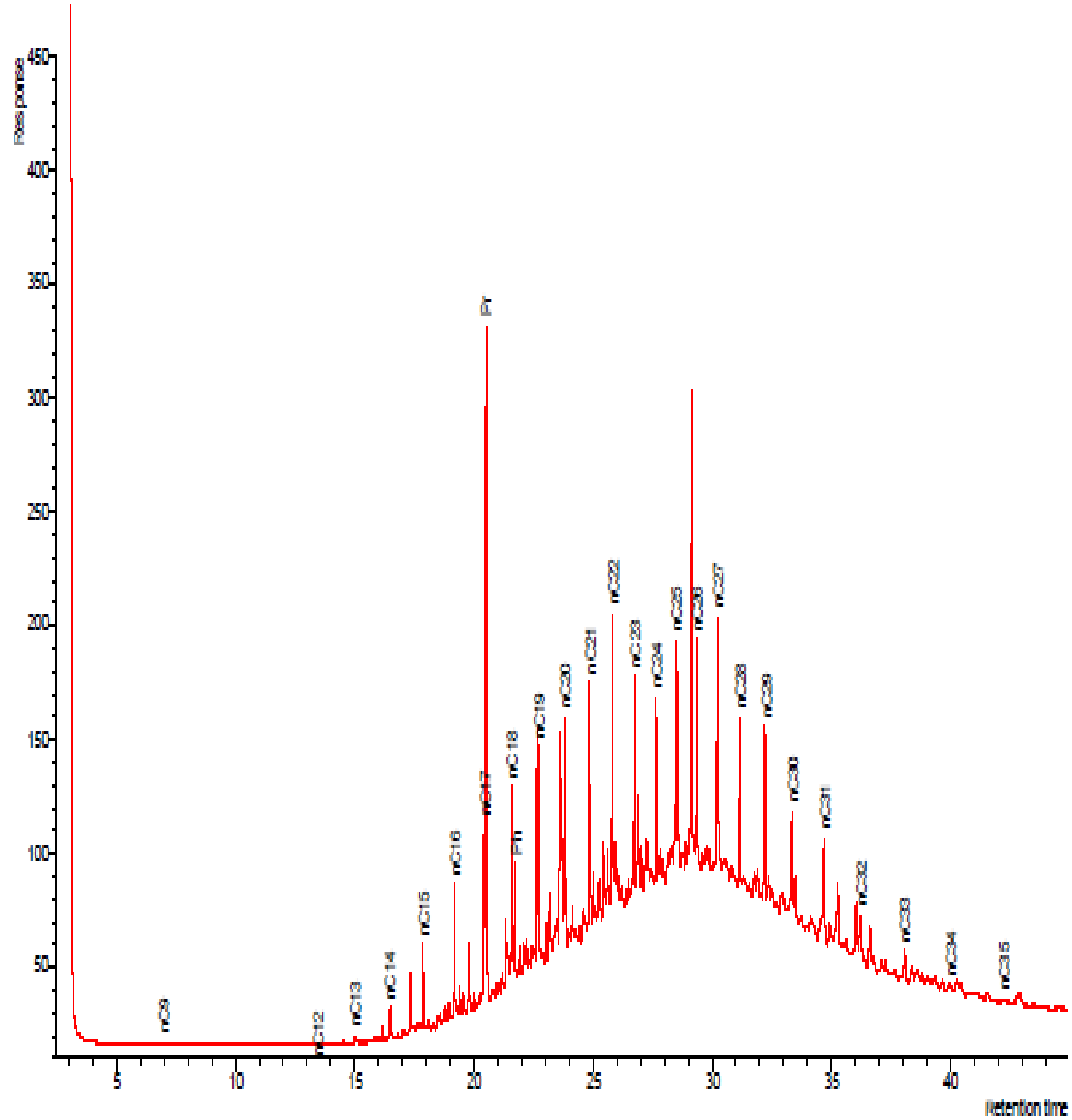


Fig. 4.21.Gas Chromatogram of Sample L2U1

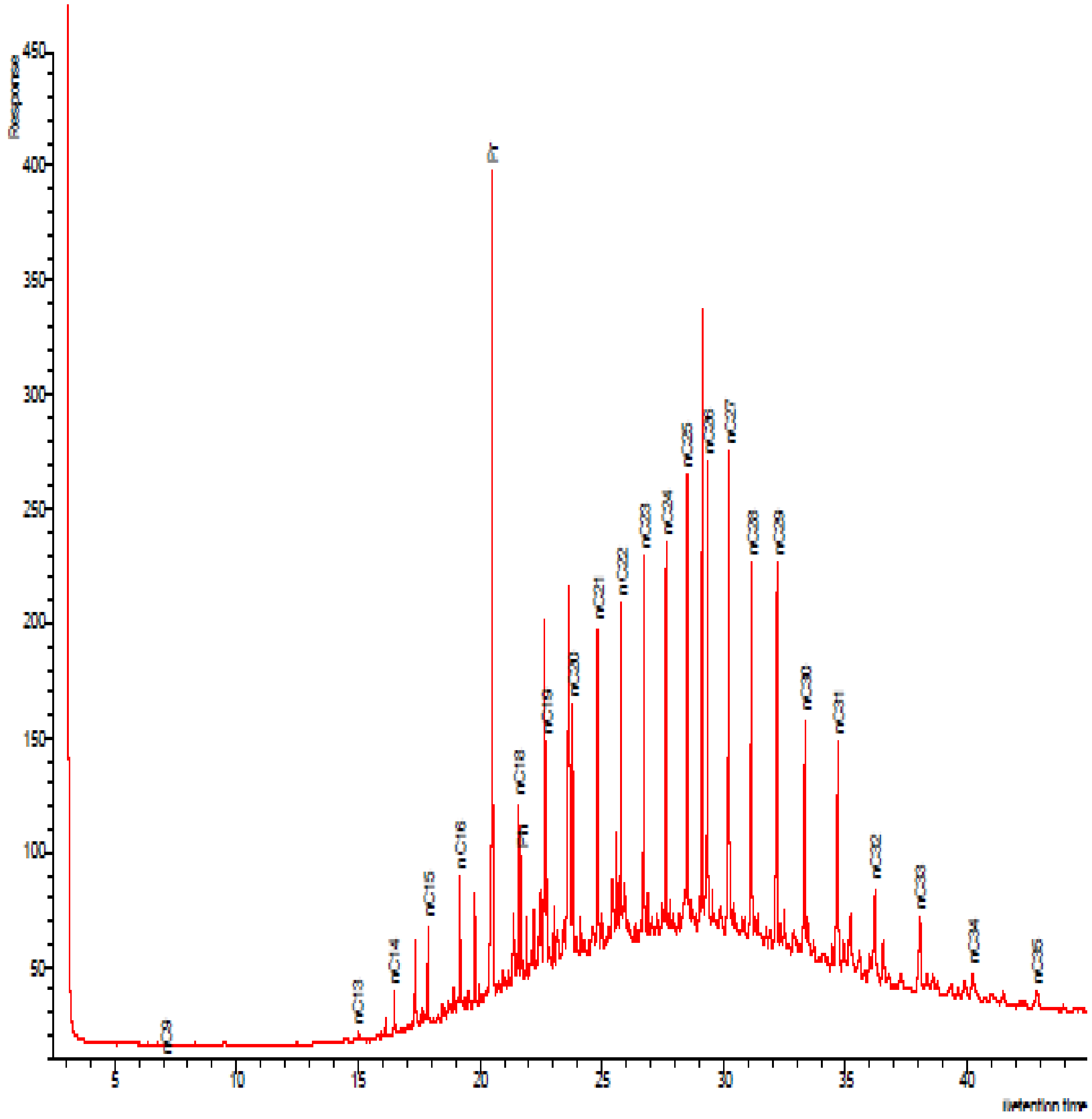


Fig. 4.22.Gas Chromatogram of Sample L2U2

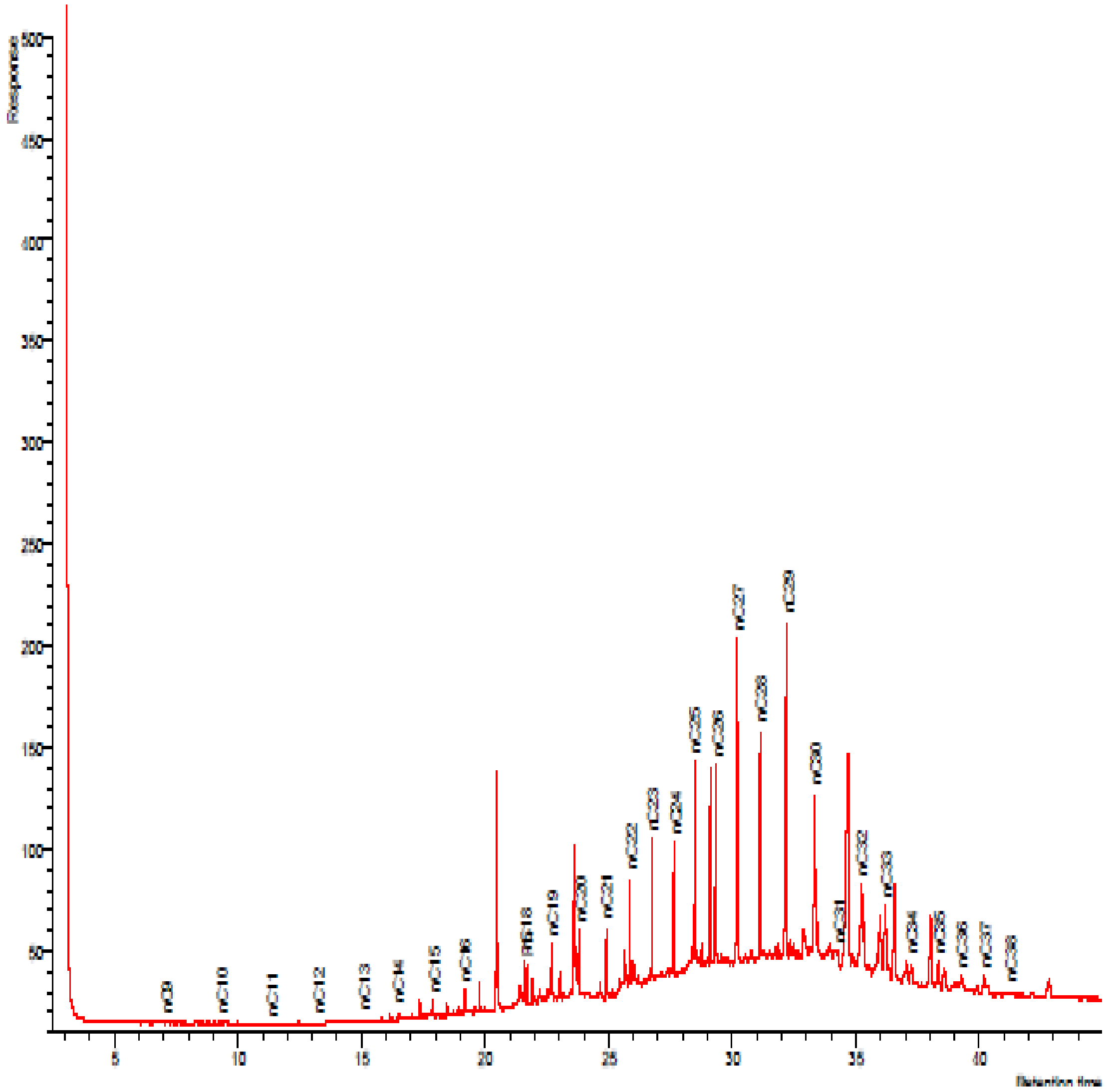


Fig. 4.23.Gas Chromatogram of Sample L2U3

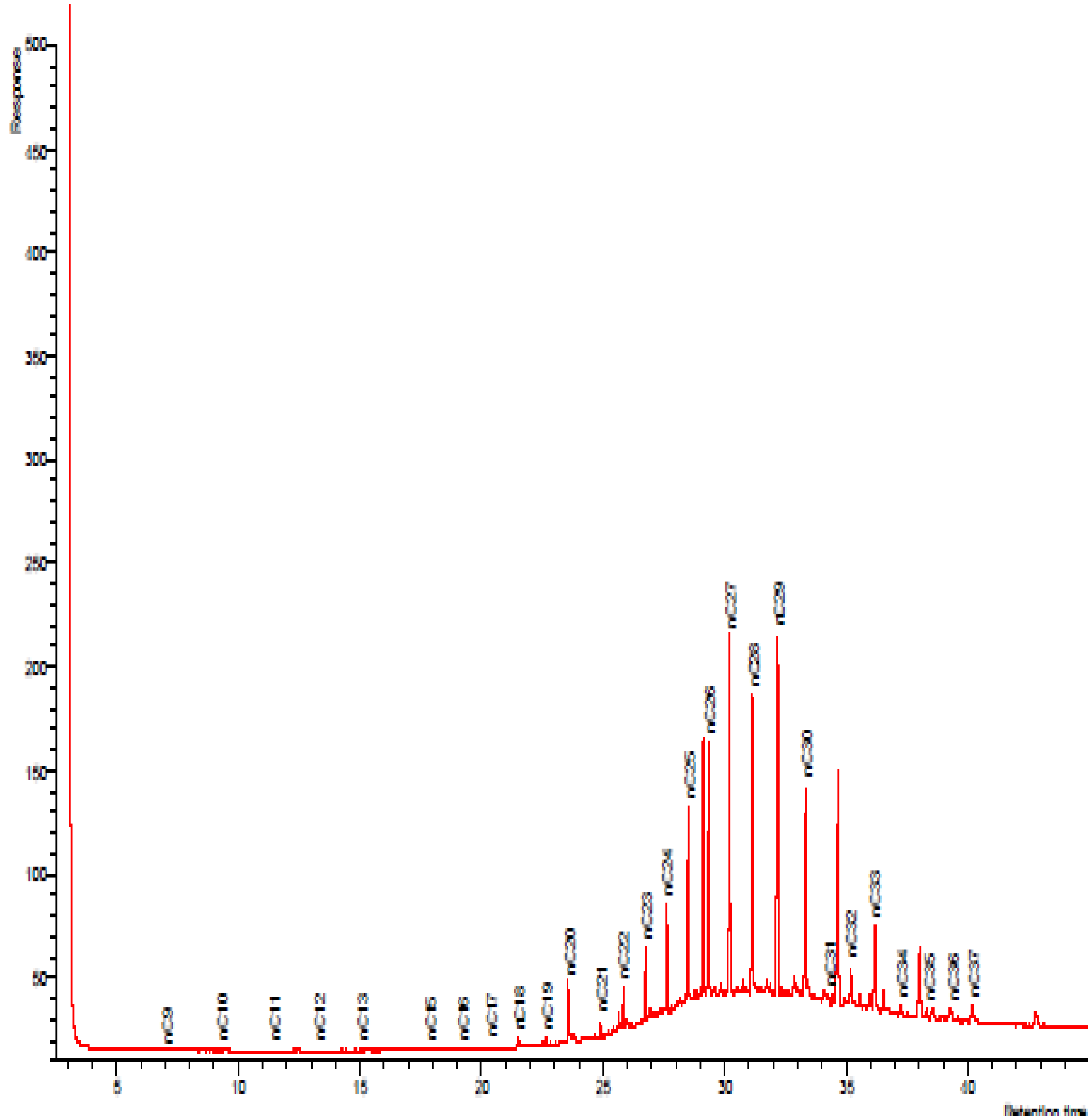


Fig. 4.24.Gas Chromatogram of Sample L2U4

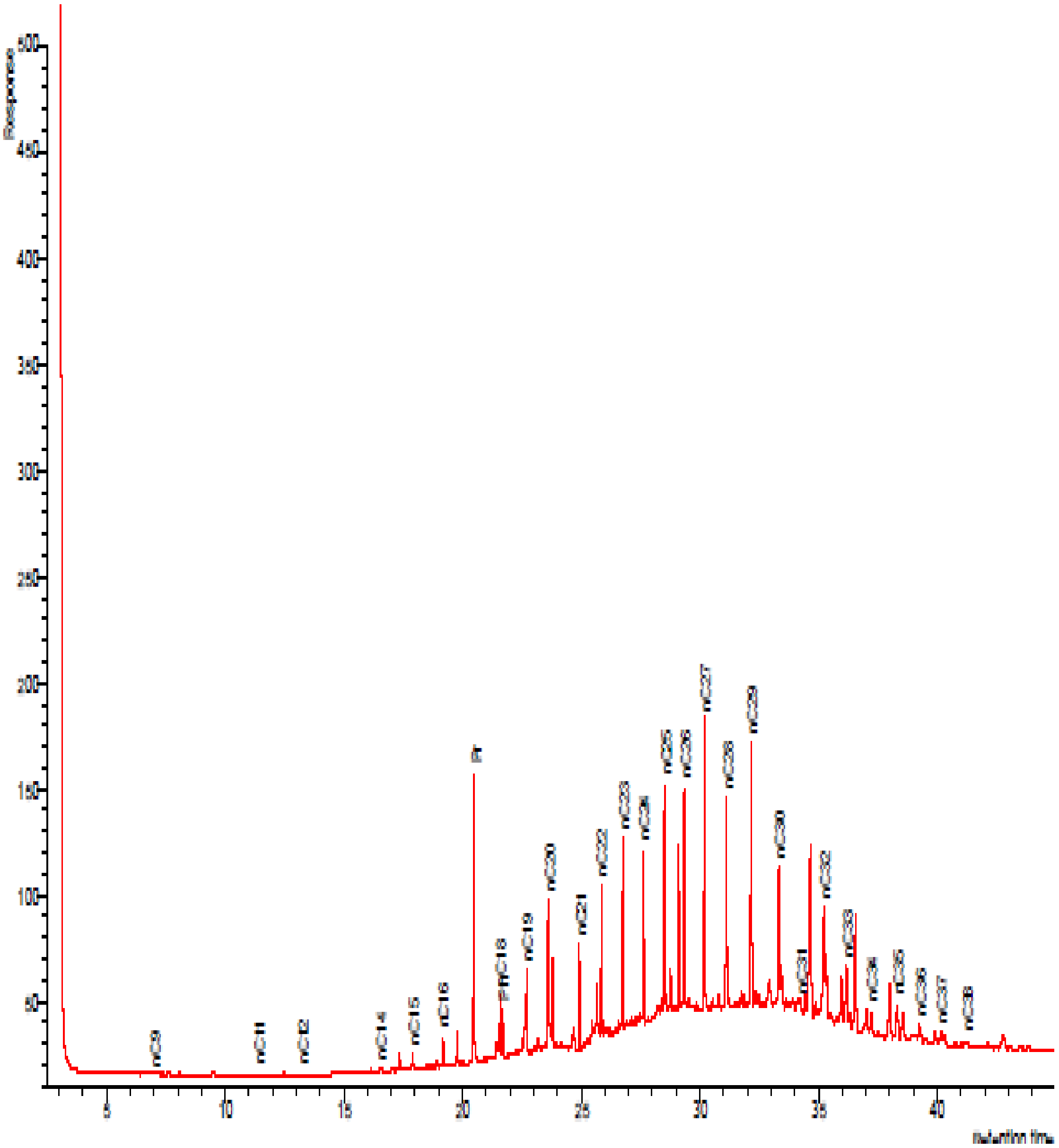


Fig. 4.25.Gas Chromatogram of Sample L2U5

Table 4.8.Values of paraffin parameters

Sample No	Pristane/nC17	Phytane/nC18	Pristane/Phytane	OER	CPI
L1U1	9.36	0.83	6.38	0.83	1.73
L1U2	9.55	0.88	6.59	1.62	1.30
L1U3	3.30	0.56	5.63	1.20	1.27
L1U4	NA	0.66	3.03	1.34	1.07
L1U5	1.38	1.27	1.03	1.05	1.08
L2U1	3.55	0.65	4.60	1.19	1.06
L2U2	6.94	0.74	5.64	1.22	1.07
L2U3	NA	0.89	NA	1.70	1.14
L2U4	NA	NA	NA	1.40	1.01
L2U5	NA	0.76	6.01	1.43	1.00

4.1.2.8 N-Paraffin/Isoprenoid Ratios

Pristane/phytane[Pr(n17)/Pr(n18)] ratio of sediments can be used to determine depositional environment (petters et al, 2005). Pr/ph ratio < 1 indicates anoxic depositional environment, while pr/ph > 1 indicates oxic conditions. Pr/ph < 2 indicates marine sourced organic matter and pr/ph > 3 indicates terrigenous organic matter input. Petters and Moldowan (1993) stressed that high pr/ph (>3) indicates terrigenous input under oxic conditions and low pr/ph (<0.8) indicates anoxic hypersaline or carbonate environment.

The studied samples pr/ph value > 3 (Table 9) typical of sediments deposited in Oxidising, terrestrial and peat environment (Fig. 4.26). This is consistent with the geology of the study area as the Enugu Shale and parts of the Mamu Formation are known to be coal bearing (Reyment, 1965).High concentration of high molecular weight n-alkanes (C23-C30) compared to low molecular weight n-alkanes (C15-C21) present indicates organic matter from terrestrial higher plants.

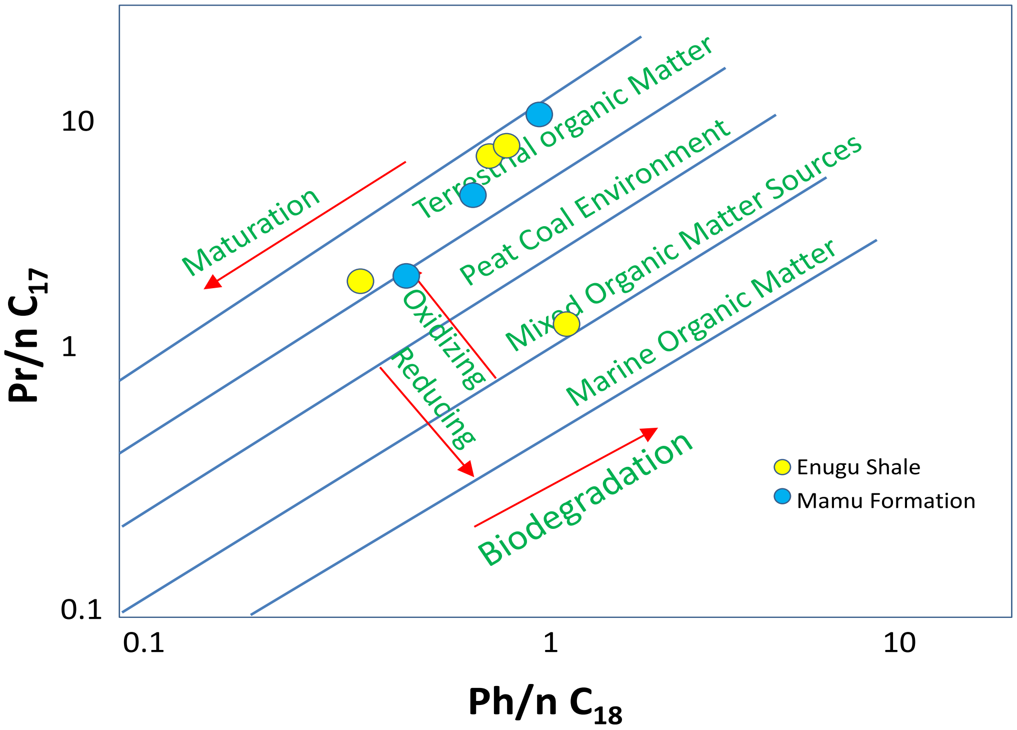


Fig. 4.26. Plot of Pristane(n17) versus Phytane(n18) (After Moldowan et al., 1994)

4.1.2.7 Carbon Preference Index (CPI) and Odd-Even Carbon Ratio(OER)

This is the relative abundance of Odd versus Even carbon numbered N-Paraffins;it can also be used to estimate thermal maturity of organic matter. The CPI values in the studied sediments (Table 4.8) range from 1.0 to 1.73. Maxwell et al., (1971), showed that when this value is greater than 1, the sediments are immature with terrestrial organic input. He also showed that strong odd/even bias of heavy n-alkanes indicates sediments immaturity. From the studied samples, the odd numbered n-alkane are more abundant than the even numbered alkanes, this indicates the sediments are immature. The Carbon Preference Index (CPI) from the studied area suggests that the sediments analysed are thermally immature for oil generation.

4.2 Discussion

4.2.1 Quality, Quantity and Generic Potential of Organic Facies

The Total Organic Content (TOC%) of the shale samples from Enugu Shale ranges from 0.72 to 4.94 wt % with an average of 2.64 wt%. Samples from the Mamu formation, has TOC values ranging from 0.76 to 2.11 wt% with an average value of 1.49 wt%. These values exceed the threshold value of 0.5wt% required for a sedimentary rock to be regarded as a petroleum source rock (Table 3)(Hunt, 1979 and Tissot and Welte, 1984). The TOC values suggest that the shales of the Enugu Shale and Mamu Formations are good to very good sources rocks (Peters, 1986).

The total amount of heavy hydrocarbon (C_{15+}) Extractable Organic Matter (EOM) is the total amount of heavy hydrocarbon and non-hydrocarbon present in a source rock in parts per million (ppm). The total amount of extractable organic matter ina source rock is a direct measure of its oil source possibility, because oil is related to its source. The SOM/EOM of the shale samples of both Mamu and Enugu shales exceeds 500ppm. Samples from Enugu Shale has an average value of 3526ppm while those of Mamu Formation has an average value of 693ppm. Furthermore, plot of TOC (%) versus SOM (ppm) from the present study shows that the sediments can be classified as fair to good source rocks based on the quality definition by Hunt and Meinert (1954), Baker (1972).

A plot of Hydrogen Index (HI) against Oxygen Index (OI) showed that Enugu Shale and Mamu Formations are dominated by Type III kerogen and mixed Type II/III kerogen (Peters, 1986) (Fig 13). Sample L1U5 (Enugu Shale) plotted in the Type II zone. Samples from Mamu Formation are particularly low in HI (below 50mgHC/gTOC), and are inert (Type IV kerogen). Type III kerogen implies gas prone source rocks, mixed Type II/III indicates oil to gas prone source rocks while Type IV kerogen is inert. Type III kerogen usually contain mainly polyaromatic structure formed from the lignin of vascular plants and some linear carbon chains derived from cuticular waxes (Akande et. al., 2005).

The Source Potential (S_1 + S_2) based on the assessment of Tissot and Welte's (1984) classification shows that source rocks with Gas Potential (GP) less than 2mgHC/g rock (2000ppm) are suggestive of poor source rock, while rocks with GP of 2 to 6mgHC/g rock (2000 to 6000ppm) implies moderately rich source rock with fair oil potential. Those with GP greater than 6mgHC/g rock(6000ppm) are considered as good or excellent petroleum source rocks (Tissot and Welte, 1984; Dymann et al., 1996; Akande et al., 2005) . In the study area, Enugu Shale and Mamu Formations samples exhibit average yields (4.01mgHC/g rock) consistent with moderate to fair source rock potential and are gas prone to mixed oil and gas prone, theyalso have good to very good organic richness.

Finally, the plot of hydrocarbon yield (S_2) against total organic carbon (Fig.18) classifies effective primary source rocks as those with S_2 greater than 5mgHC/g rock and Effective Non Source (ENS) rocks as those with S_2 less than 1mgHC/g rock. As shown, Enugu Shale and Mamu Formations are essentially secondary sources rocks with fair to very good hydrocarbon potential to generate gas and condensate. Sample L1U5 from Enugu Shale showed a very high S_2 value of 23.6 and plotted in the Primary source rock field.

Maceral analysis of the shale samples to further assess the quality of the organic matter in the rock studied samples indicates the prevalence of vitrinite maceral group. The vitrinite maceral group in the analysed shale samples ranges between 39 to 59%. The inertnites ranged from 11 to 18% while the liptinites range from 9 to 21%. The vitrinite components are mainly desmocollinite,

collinite and vitrodetrinite. The inertinites group consists of fusinites and semi fusinites whereas the liptinites components are mainly cutinites and sporinites. The vitrinite maceral which dominated the studied Enugu Shale and Mamu Formation sediments are derived from structural part of plants and are deficient in hydrogen. They correspond to type III kerogen (Tissot et al., 1974; Van Krevelen, 1961, Akande et al., 1992). According to Akande et al., (1992), the lower Maastrichtian coals of the Mamu Formation are characterized by moderate to high concentration of huminite and some minor amounts of inertinites and liptinites. Akaegbobi and Schmitt (1998) supported the earlier reports; that the Nkporo shale is dominated by Type III/II kerogens with dominance of terrestrially derived organic matter in the study area.

4..2.2 Thermal Maturity

Thermal maturity refers to the extent of temperature-time driven reactions that convert sedimentary organic matter (source rock) to oil, wet gas, and finally to dry gas.

Thermal maturity in the study area has been assessed by the Rock-Eval, Tmax data and by the bitumen ratio. According to Peters (1986), variation in kerogen types affect Tmax values. At a thermal maturity that corresponds to a Tmax of 435^0C, source rocks with HI greater than 500mg HC/gTOC yield oil while those with HI value ranging from 250 to 500mgHC/gTOC yield oil and some gas. Rocks with HI of 50 to 250mgHC/gTOC produce gas while those with HI less than 50mgHC/gTOC are inert (Tissot et al., 1974).

In the present study, Tmax ranged from 424 to 439^0C with an average of 432^0C for sediments in the Enugu Shale and corresponding Hydrogen Index (HI) values ranging from 43 to 547mgHC/gTOC with an average value of 185.65mgHC/gTOC. Mamu Formation sediments on the other hand showed a

Tmax value of 417 to 441^{0}C with an average of 431^{0}C and a corresponding HI value of 26 to 86mgHC/gTOC with average of 39.45mgHC/gTOC.

These values suggest that the shales of Mamu and Enugu Formations are immature to transitionally early mature source rocks. As shown in figure 13, the low values of hydrogen index imply that the Enugu Shales and Mamu Formations are dominated by Type III kerogen and mixed Type II/III kerogen of terrestrial origin (Peters, 1986). Type III kerogen implies gas prone source rocks, mixed Type II/III indicates oil to gas prone source rocks while Type IV kerogen is inert.

The ratio of the bitumen content to the total organic content (bitumen ratio) can also be used as a maturation parameter for source rocks (Peters and Moldowan, 1993).

The calculated bitumen ratios for the Enugu Formation ranges from 35 to 1384.2 mgExt/gTOC with an average of 325.62 mgExt/gTOC while that of Mamu Formation ranges from 50 to 227.5 mgExt/gTOC with an average of 132.58 mgExt/gTOC. From these values, it can be deduced that the shales of Enugu Shales and Mamu Formations are immature to early mature source rocks (Miles, 1989).

A plot of HI versus Tmax show that the samples plot within the Type III kerogen zone confirming the predominance of Type III organic matter. The sediments from this plot are immature to transitional in term of their thermal maturity. Sample L1U5 from Enugu Formation however plotted within the Type II kerogen zone.

4.2.3 Depositional Environment

Pristane/phytane ratio of sediments can be used to determine depositional environment (petters et al, 2005). Pr/ph ratio < 1 indicates anoxic depositional environment, while pr/ph > 1 indicates oxic conditions. Pr/ph < 2 indicates marine sourced organic matter and pr/ph > 3 indicates terrigenous organic matter input. Petters and Moldowan (1993) stressed that high pr/ph (>3) indicates terrigenous input under oxic conditions and low pr/ph (<0.8) indicates anoxic hypersaline or carbonate environment.

From the studied shale samples, Pristine/Phytane ratios are greater than 3 (Table 8). This is typical of sediments deposited in Oxidising, terrestrial or peat environment. This is consistent with the geology of the study area as the Enugu Shale and parts of the Mamu Formation are known to be coal bearing (Reyment, 1965).High concentration of high molecular weight n-alkanes (C23 to C30) compared to low molecular weight n-alkanes (C15 to C21) (Fig. 19 to 28) present indicates organic matter from terrestrialhigher plants.

The presence of depositional structures such as planar cross-bedding, wave ripple lamination and parallel lamination as observed in the field data suggest a shallow marine shoreface with low depositional energy condition for the Enugu Shale. The presence of extraformational clast within the Enugu shale indicates that there was fluvial influence during the period of deposition of Enugu Shale within the Anambra Basin (Agagu et al., 1985).

The fine to medium grained sandstone, siltstone and fissile shale, mud clasts and burrows that dominate the Mamu Formation succession as observed from field relationships suggest that the unit was deposited in an environment where there was little or no existence of tidal or wave action i.e. quite environment where low energy favoured deposition of fine to medium size sediments. The presence of coal beds that alternate the shale, siltstone and sandstone units within Mamu Formation sequence indicates that Mamu Formation was deposited in an estuary environment similar to the observation of Reyment (1965) and Nwajide and Reijers (1996).

CHAPTER FIVE

CONCLUSION AND RECOMMENDATIONS

5.1 Conclusion

The investigated sections of the Mamu and Enugu formations exposed along Enugu – Okigwe – Port Harcourt expressway consists of coarsening upward sequences with thick carbonaceous shale at the base, passing through siltstone into thin texturally mature sandstone. They are interpreted as prodelta (open marine) to tidally influenced shoreface (shallow marine deposits).

A total of ten (10) outcrop samples (shales) were obtained from road cuts along Port Harcourt–Enugu expressway. These samples were subjected to geochemical analyses in order to characterize the source rock potential and investigate the environment of deposition of the sediments.

Rock-Eval pyrolysis and maceral analysis data reveal that Type III kerogen are prevalent, indicating contribution from terrestrial source and their potential to generate gas.

Organic richness of the samples was deduced from plot of $S_1 + S_2$ and TOC, SOM and TOC as fair to excellent. Plots of TOC against petroleum genetic potential and hydrogen index against oxygen index show mainly type III (gas prone) with minor amounts of mixed Type II/III (oil to gas prone kerogen). The values of Tmax and bitumen ratio suggest immature to early mature thermal status of the source rocks.

Other parametes such as CPI, OER were used to estimate maturation level as immature. The presence of Oleanane, dominance of high molecular n-alkanes over low molecular n-alkanes, the high pr/ph ratio suggest terrestrial source input.

5.2 Recommendations

i. It is suggest that further studies should use deeper samples from bore holes and other drilling programs to be able to obtain more more samples for studies a deeper depths.

ii. At present level, liquid hydrocarbons have not been generated. The studied areas are therefore considered to be of good petroleum potential particularly gaseous hydrocarbon. Therefore, improved 3-D seismic information and more petroleum geological research work in the basin, the hydrocarbon resource of the basin is recommended which will be enhanced and these will provide information to oil and gas companies operating in the region to optimize the development in exploration and exploitation of petroleum in the basin

5.2 Contributions to Knowledge

i. The study has shown that the sediments under study were deposited in a partial/normal marine (under sub-oxic to sub-anoxic water condition)

ii. The sediments at the moment posses about 70% of what it takes to be economic, though largely gas, they present fair prospect in terms of economic viability.

iii. The environment of deposition and kerogen types has also be ascertained to aid other research studies in the area.

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