

# PETROLEUM POTENTIAL OF CAMPANO-MAASTRICHTIAN SHALES OF ANAMBRA BASIN, SOUTH ASTERN NIGERIA

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## ABSTRACT

Over 6,000 meters thick terrigenous sediment (mainly shale/ siltstones/lithologies) of campano – Maastrichtian age has been recorded in the Anambra basin. These shale/siltstones lithologies have been reported to be rich in organic matter and had fulfilled other relevant condition for hydrocarbon source rock potential. However, only few patches of hydrocarbon shows have been documented elsewhere in the basin. This work attempts to critically evaluate the hydrocarbon source potential of the organic rich shale sediments in the basin.

A sample set of 40 ditch cuttings of manly shale lithologies retrieved at different depths intervals from 2 well were subjected to standard geo-chemical and organic petrography investigations. The samples were analyzed for the total carbon content (TOC), extract yield, organic matter types and organic maturity level.

As screening criteria, all the sample set were subjected to TOC measurement (LECO). The TOC values range from 0.81-1.40% (AKU2) and from 0.82-1.81% (AMA.1) most of the samples meet up with minimum required TOC value (.5%) for a siliciclastic sediments to be hydrocarbon prone. Extract yield range from 30.0 to 180.5 ppm (AKU2) and 30.0 to 128ppm (AMA 1). The Rock-Eval Pyrolysis data HI vs OI revealed that the samples fall within types II & III kerogen. This corroborates with the results of the maceral analysis. The maceral composition is mainly vitrinitic and liptinitic of terrestrial origin, which are over 65 volume percent.

The shales are moderately rich in organic matter. Extract yields and the bitumen ratio (mg HC/g TOC) revealed that these samples are at immature stage of Hydrocarbon generation. This is also supported by Tmax values of between 430-490°C.

**KEY WORDS:-** Terrigenous, Campano – Maastrichtian, Vitrinit, Liptinite, Rock-Eval.

## INTRODUCTION

Anambra basin is a cretaceous depocenter containing thick sequences of elastic sediment ranging from bituminous shales lignites through sandstone and marl and it's Paleo-geographical strategic positioning as the proto-Niger Delta provides and ideal ground for geo-chemical evaluation of shales as oil/gas prone source rock. Various published work e.g Ekweozor and Gormly [1983] Petters and Ekweozor (1982) have revealed that the Campano-Maastrichtian Nkporo shale exhibit characteristics of potential hydrocarbon source system for a series of oil/gas and condensate shows found within Ajali sandstone

The study area is roughly a triangular Sedimentary basin. It covers about 40,000 sq km. the southern boundary coincides with the Northern boundary of the Niger Delta basin. Anambra Basin extends northward beyond lower Benue River, but this view deals chiefly with the southern portion of the basin.

The two well studied are located within Enugu, southeastern part of Nigeria. The studied area is within Anambra basin, it covers an area of approximately 218 square kms bounded by Latitudes 5.5<sup>o</sup> and 6.5<sup>o</sup> north and longitude 6.5<sup>o</sup> and 7.5<sup>o</sup> east. Fig1

Since the discovery of petroleum in Niger Delta by Shell Petroleum Company of Nigeria in 1956, an increase in commercial exploration and exploitation have been going on with focus on the detection of suitable reservoir rocks and location of structural traps using geophysical methods. Recently, efforts are now on source rocks and their maturity.

There are a good number of research and geological studies in Niger Delta and Anambra Basin. Most of these works were carried out by oil companies operating in the area, but with only very few publication on source rock which have proved to be great geological interest and controversial Akaegbobi (1995). It was also observed that

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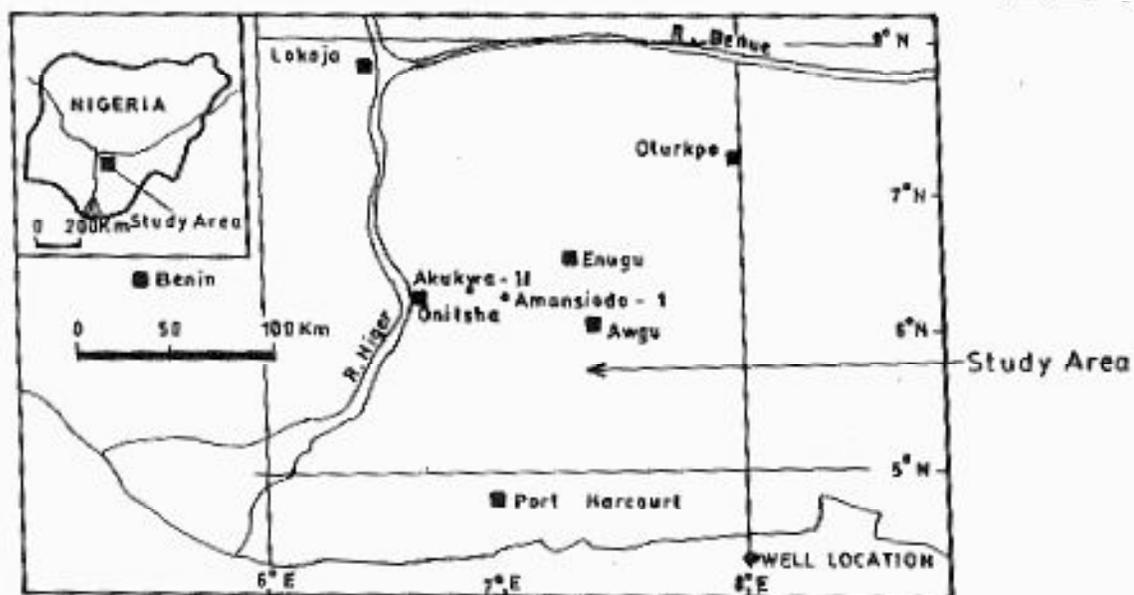


Fig-1: Location Map of the Study Area Showing the position of Akukwa-II and Amansiado-I wells.

some sediment sample in the Anambra Basin show very low vitrinity reflectance, Ekweozor & Gormly (1983). This allows the assumption that the formation of the petroleum hydrocarbon took place under low temperature condition. It could also be possible that the migration effect (Impregnation) of the petroleum hydrocarbon might have influenced the low vitrinity reflectance.

The Tectonic conditions of Anambra Basin make it ideal for study. In this respect, the organic geochemical investigation could be used to:

- Determine the Organic richness of the shale sediments
- Determine the quality of the kerogen.
- Determine the sediment maturity and finally.
- Evaluate the hydrocarbon potential of the basin sediments.

The two wells basic for selection because they both penetrated through the entire sediments of Anambra basin and located within the basin, in particular the Akukwa-II and Amansiado-I wells fig 2. The sediments selected are organic-rich. They are Nkporo shale sediments at various depths ranging from 1,400meters to 4,000 meters fig3 and fig 4.

**GEOLOGICAL SETTING;** there are a lot of hypothesis about the origin of Benue Trough, but the most

acceptable model is that of the plate tectonic concepts which appears to account more satisfactorily for the present arrangement of transform features zones in the gulf of Guinea region. The Anambra basin (covering an area of about 2.18 Sqkm) is located in south central part of Nigeria. Extending northwards in the lower Benue River. The basin forms a boundary with tertiary Niger Delta basin to the south. As one of the component basin of the Benue Aulacogen, the Anambra basin reflects the features of the break-up of the Gondwana supercontinent. Olade (1975), Akaegbobi et al [2000]. The basin summary has been given by various workers, Agagu (1986), Agagu and Eweozor (1980), Agagu et al (1986) Ekweozor and Gormly (1983); Avbovbo (1978a). The sediment infill of the southern Nigeria Basin has been controlled by three main tectonic phases. The rift-like Benue Abakaliki trough was formed during the first tectonic phase (Albian) and filled by the sediment of three major cycles. The second phase resulted in the folding and in subsidence of the Anambra Basin which Subsequently was filled by second sedimentary cycles. The Nigeria Delta Basin was however formed during the third phase (upper Eocene). The cretaceous Anambra depositional site reflect a mega-facies region receiving sediments within two depositional cycles ranging from campanian to Eocene

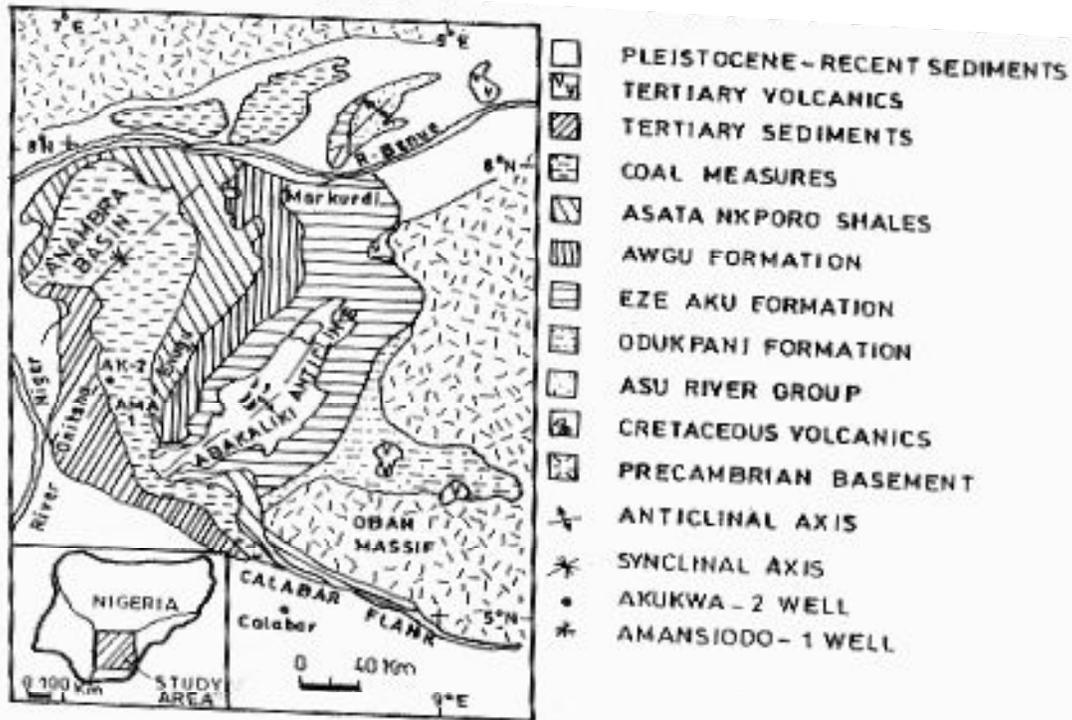


Fig. 2: GEOLOGICAL MAP OF THE LOWER BENUE TROUGH SHOWING THE POSITION OF AKUKWA - 2 AND AMANSIOSO - 1 WELLS ADAPTED FROM THE GEOLOGICAL MAP OF ENUGU .

Reyment, (1965). The sediments are mainly continental fluvio-deltaic and shallow marine sedimentation millieux. Azu river group, Odukpani Formation, Eze Aku shale group, Awgu shale, Nkporo shale, Mamu formation, Ajali sandstone, Nsukka formation, Imo shale and Ameki group. Fig;2.

**MATERIALS AND METHODS**

Anambra basin has received considerable geological interest since 1903, when exploration for coal deposits in the basin were published by Bain (1924 and 1930), Wilson and Bain (1928). Based on the fact that

geology and stratigraphy of the Benue trough has been well established and many works of the Anambra basin has been published. For this work, subsurface sample materials were selected for study. The samples are mainly ditch cuttings from two deep appraisal wells (Ama-1 and Aku-11) located at the south western part of the Basin, The samples are from the Geological survey Agency, Kaduna. These wells penetrated all the formations in the Basin; of interest are the capano-maastrichtian sediments. The depth examined for Amansiodo-I well is between 1,400meters to 2,000 meters and 3,330 meters to 3,900 meters for Akukwa-II well Fig 3 & 4. The

LITHOLOGIC LOG: AMANSIODO - I WELL

DEPTH (M)	AGE	FORM-ATION	LITHOLOGY	SAMPLE NO	LITHOLOGIC DESCRIPTION	INFERRED DEPOSITION ENVIRONMENT	
1.400	CAMPANO - MAASTRICHTIAN	MAMU FORMATION		AMOA04-01	SHALE: Clayish soft blue silty and sandy.	Low to medium energy depositional environment.	
1.450				AMOA04-02			
1.450				AMOA04-03	SHALE: dark-grey silty fissile and silty.	Low energy depositional environment.	
1.500			NKPORO SHALE	AMOA04-04	SHALE: dark-grey silty hard brittle silty and sandy.	Low to medium energy environment of deposition.	
1.500		AMOA04-05					
1.550				AMOA04-06	MISSING		
1.550				AMOA04-07	SHALE: Dark-grey hard brittle silty and sandy.		
1.600				AMOA04-08			
1.600				AMOA04-09			
1.650				AMOA04-10			
1.650				AMOA04-11	SHALE: dark-grey fissile very hard and highly compacted	Low energy environment of deposition	
1.700				AMOA04-12			
1.700				AMOA04-13			
1.750				AMOA04-14			
1.750				AMOA04-15			
1.750				AMOA04-16			
1.750				AMOA04-17	MISSING		
1.800					AMOA04-18	SHALE: grey fissile very hard and hilly compacted.	Low energy environment of deposition
1.850							
1.900					AMOA04-19	SHALE: dark-grey hard brittle silty and sandy.	Low to medium energy of deposition.
1.950			AMOA04-20				
2.000				MISSING			
					T.D. 2100m		

MissingShale

Fig.3: Lithostratigraphic log of Amansiodo - I Well .

LITHOLOGIC LOG: AKU -II WELL .

DEPTH (M)	AGE	FORM-ATION	LITHOLOGY	SAMPLE NO	LITHOLOGIC DESCRIPTION	INFERRED DEPOSITION ENVIRONMENT		
3,330	CAMPANO - MAASTRICHTIAN	NKPORO SHALE		AKDA04-01	SHALE: sandy highly compacted grey and silty.	Low energy depositional process		
				AKDA04-02				
				AKDA04-03				
3,400						AKDA04-04	MUDSTONE/SHALE Darkgrey silty and fissile	
3,400						AKDA04-05	SHALE: dark hard silty and sandy	
3,500						AKDA04-06	SANDSTONE: indurated dirty brown to brown fissile	High to medium energy all depositional process
3,500						AKDA04-07		
3,500						AKDA04-08	SHALE: dark grey plant fibre noticed	
3,600						AKDA04-09		
3,600						AKDA04-10		
3,600						AKDA04-11	SHALE: dark-grey dark medium grained	Low energy depositional process
3,700						AKDA04-12		
3,700						AKDA04-13	SHALE: sandy highly compacted fine to medium grained	Low energy depositional process
3,700						AKDA04-14		
3,800						AKDA04-15	SHALE: very hard dark grey	Low energy depositional process
3,800			AKDA04-16					
3,800			AKDA04-17	SHALE: grey dark colour, fissile, hard and sandy.	Low energy depositional process.			
3,800			AKDA04-18					
3,900				SANDSTONE: indurated whitish sand with clay-bands	High to medium energy depositional process			
					T.D. 4000m.			

Sandy ShaleMudstoneShaleSandstone

Fig.4: Lithostratigraphic Log of Akukwa -II Well .

well were drilled to evaluate the reservoir qualities of Ajali Sandstone and source rock qualities of Asaka/Nkporo shale.

**ANALYTICAL METHODS**

Evaluation of the source rock basically requires the measurement of three parameters which are, The quality, quantity and maturity of organic matter. In other to characterize organic matter disseminated in the sediments, the following organic geochemical methods were applied.

- Determination of total organic carbon (TOC) using Walkley Black oxidation method. (20)
- Rock – Eval pyrolysis, used to determine hydrocarbon potential as well as evaluating the kerogen type. (20) Espitalie et al (1977).
- Extraction of soluble organic matter using Soxhlet Extraction method.
- Maceral Analysis, was done using reflected light microscope quipped with white incident light and blue light irradiation.

**RESULTS AND INTERPRETATION**

- Source rock characterization:-This involve determination of the quantity, quality and

Thermal maturity (Temp) of the organic matter in the sediment.

- DETERMINATION OF THE QUANTITY OF ORGANIC MATTER. Using Black Oxidation method.
- TOC in a sediment is a function of fiz:-presence of Biogenic material, rapid sedimentation/burial and Redox reaction during deposition and diagenesis.
- The minimum TOC concentration necessary for petroleum generation according to Welte (1965) is 0.5%. good peteroleum source rocks usually have higher concentration of organic matter Hunt (1975).
- Table 1 ( a and b) Bitumen ratio Analysis. Ama-1 and Aku -11 wells.
- Interpretation: Ama-1 TOC range 0.81 – 1.42 Ave 1.3%  
Aku–11. TOC range 0.81 – 1.4% Ac1.0%
- TOC decreases with increasing depth.

**DETERMINATION OF THE MATURITY OF THE ORGANIC MATTER.**

- Maceral Analysis:- These were done to arrived at the maturity of the organic matter.

**Table 1a:** Bitumen Ratio Analysis, Amasiodo-1 well

Sample no	Depth (meters)	Lithology	TOC%	SOM (ppm)	BR MgExt/gTOC
AMOA-0404	1522	SHALE	0.90	32.2	3.58
AMOA-0406	1575	SHALE	0.82	30.0	3.66
AMOA-0408	1640	SHALE	1.81	128.0	7.07
AMOA-0409	1673	SHALE	1.18	44.8	3.79
AMOA-0410	1680	SHALE	1.70	47.2	2.78
AMOA-0413	1703	SHALE	1.08	60.0	5.56
AMOA-0415	1765	SHALE	1.07	68.0	6.36
AMOA-0417	1800	SHALE	1.81	30.0	3.31
AMOA-0420	1900	SHALE	1.34	80.0	5.97

**Table 1b:** Bitumen Ratio Analysis, Akukwa-II Well

Sample no	Depth (meters)	Lithology	TOC%	SOM (ppm)	BR MgExt/gTOC
AkOA-0404	3300	SHALE	1.02	96.4	9.45
AkOA-0406	3474	SHALE	1.02	80.2	7.86
AkOA-0408	3514	SHALE	1.81	180.5	22.28
AkOA-0409	3543	SHALE	1.12	75.2	6.71
AkOA-0411	3575	SHALE	0.81	55.4	6.84
AkOA-0413	3619	SHALE	0.94	30.0	3.19
AkOA-0414	3647	SHALE	1.18	47.5	4.03
AkOA-0415	3680	SHALE	1.40	3.00	2.14
AkOA-0416	3700	SHALE	0.86	47.2	5.49

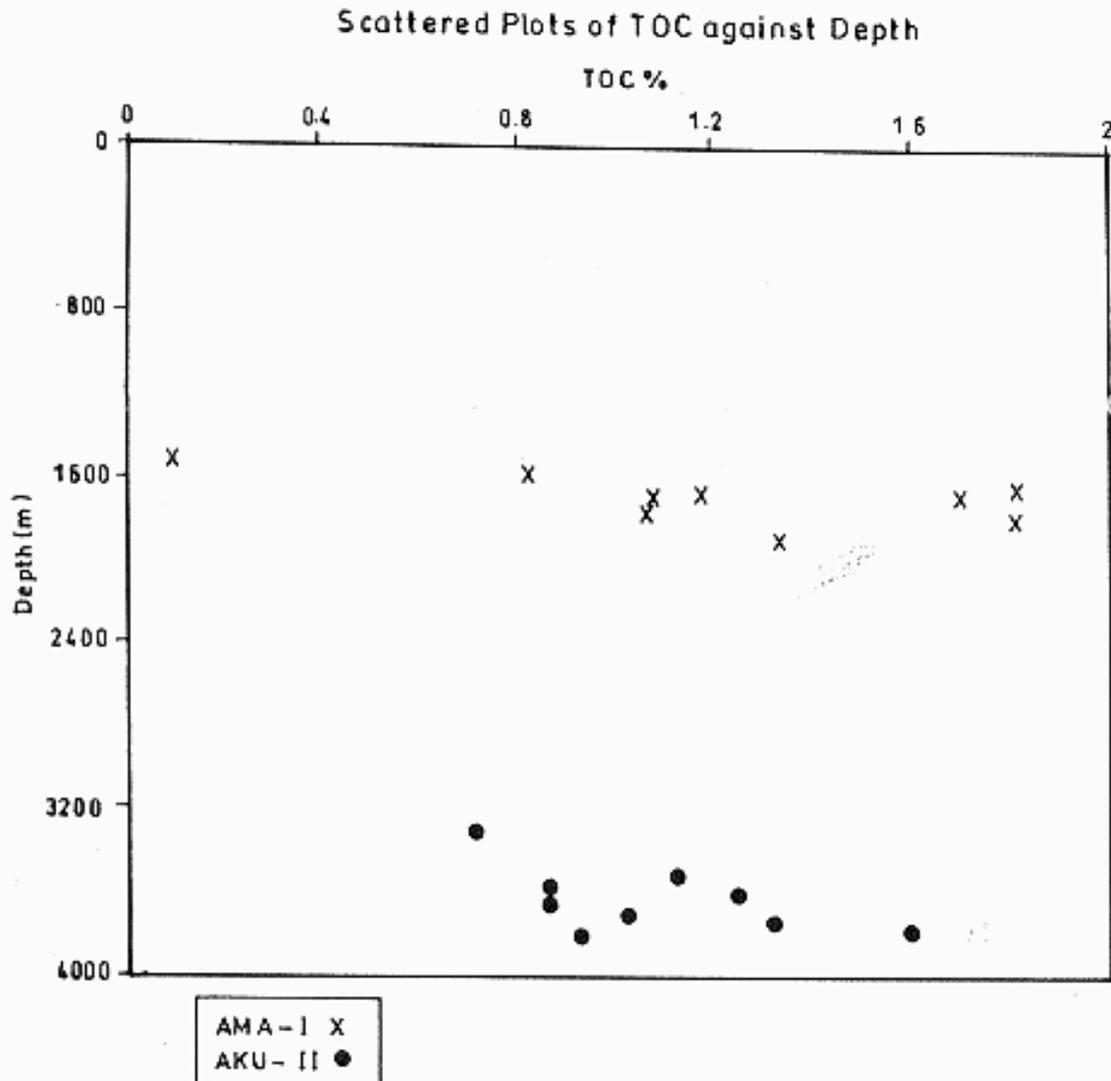


Fig.5: Plots of TOC against depth Amansiado-I and Akukwa II wells

- Three groups were classified: vitrinite, (collinite and tellinite mainly woody tissue such as stems, bark, root and twigs.
  - Liptinite group (Alginite, sporinite, resinite and cuticle) consist of material from algae and resins.
  - Intertinite group (macrinite, micrinite etc.). Similar to vitrinite but altered under oxidizing condition.
  - Interpretation
    - Liptinite-oil prone
    - Inertinite – has negligible HC but could generate gas.
- Table 2a and b Maceral Analysis Ama -1 and Aku -11 wells. Fig.6. piechart of maceral Analysis. The chart shows that vitrinite and inertinite percentage are higher than Liptinite percentage. This indicated mainly terrigenous plants and woody source which is prone to the generation of gas.

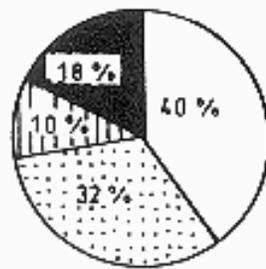
**Table 2a:** Maceral Analysis, Amasiado- I well

Sample No	Depth in meters	Formation	Lithology	Vitrinite	Liptinite	Inertinite	Mineral compound	Pyrite	Others
AMOA-0404	1,522	MAMU	SHALE	57	15	9	11	8	19
AMOA- 0406	1,575	MAMU	SHALE	34	28	10	23	5	28
AMOA- 0408	1,640	NKPORO	SHALE	48	15	12	18	7	25
AMOA-0409	1,673	NKPORO	SHALE	42	25	15	12	6	18
AMOA-0410	1,680	NKPORO	SHALE	40	32	10	12	6	18
AMOA-0413	1,703	NKPORO	SHALE	45	25	8	16	6	22
AMOA-0415	1,765	NKPORO	SHALE	50	20	9	12	9	21
AMOA-0417	1,800	NKPORO	SHALE	48	15	12	18	7	25
AMOA-0420	1,900	NKPORO	SHALE	53	18	9	12	8	20

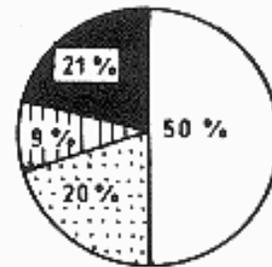
**Table 2b:** Maceral Analysis. Akukwa II well

Sample No	Depth in meters	Formation	Lithology	Vitrinite	Liptinite	Inertinite	Mineral compound	Pyrite	Others
AKOA-0405	3,360	NKPORO	SHALE	43	18	7	22	10	32
AKOA-0406	3,474	NKPORO	SHALE	50	20	10	14	7	21
AKOA-0408	3,514	NKPORO	SHALE	55	10	5	21	9	30
AKOA-0409	3,543	NKPORO	SHALE	40	32	10	12	6	18
AKOA-0411	3,576	NKPORO	SHALE	35	22	12	26	5	31
AKOA-0413	3,619	NKPORO	SHALE	38	29	5	19	9	28
AKOA-0414	3,647	NKPORO	SHALE	65	18	4	8	5	13
AKOA-0415	3,680	NKPORO	SHALE	30	25	15	25	12	37
AKOA-0416	3.700	NKPORO	SHALE	22	31	8	27	12	39

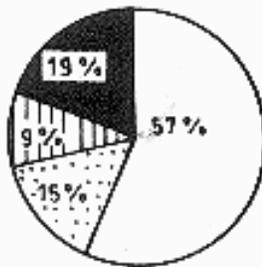
FIG. 6a - PIE CHART OF MACERAL ANALYSIS FOR AMANSIODO - 1 WELL



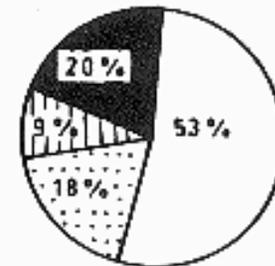
AMOAO410



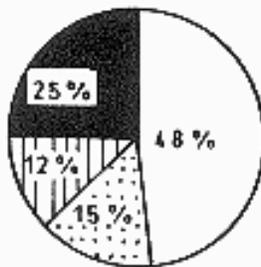
AMOAO415



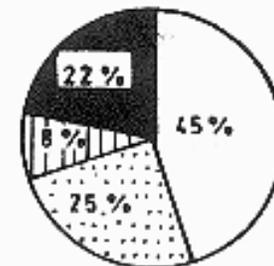
AMOAO414



AMOAO420

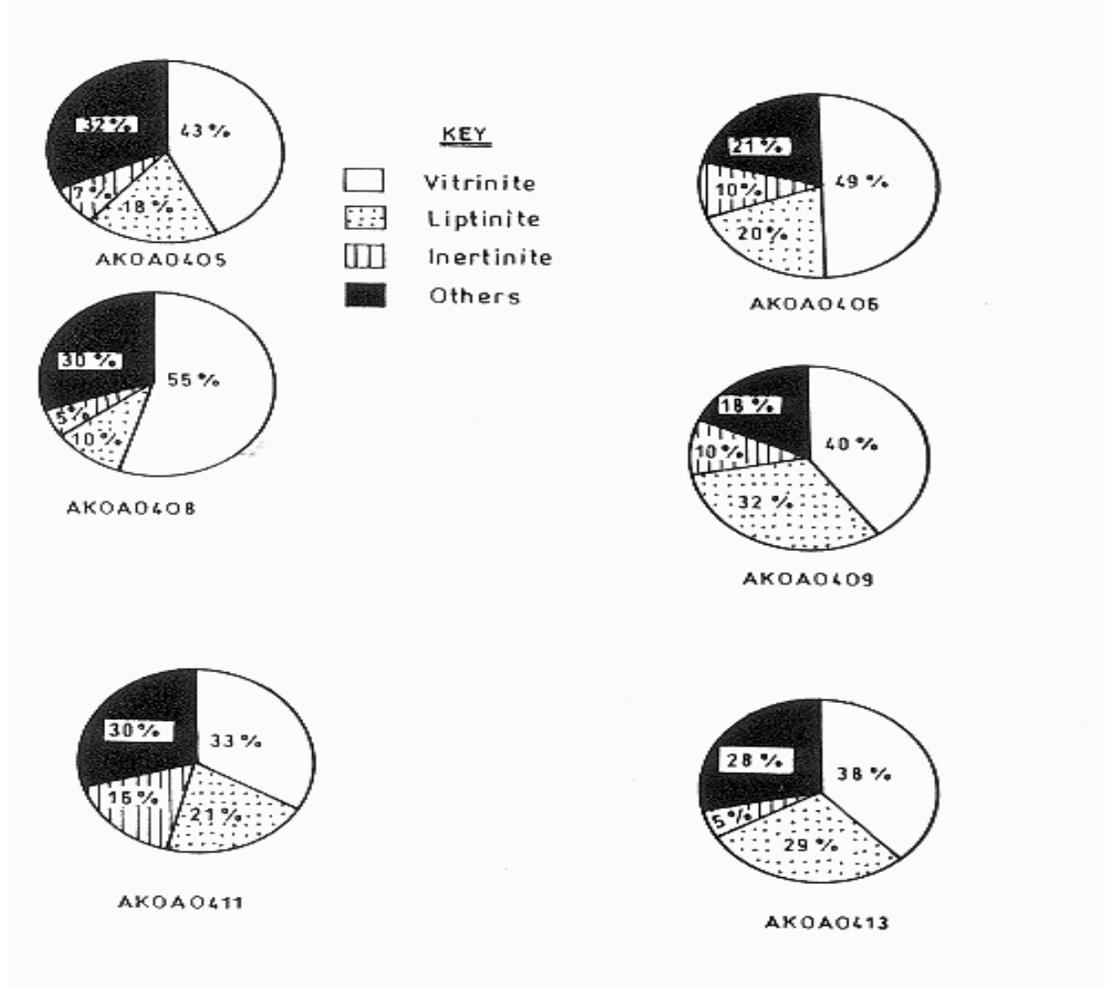


AMOAO417



AMOAO413

FIG. 6b: PIE CHARTS OF MACERAL ANALYSIS FOR AKUKWA - II WELLS



**DETERMINATION OF THE KEROGEN TYPE**

**EVAL PYROLYSIS METHOD**

**ROCK-Eval Pyrolysis (Analysis)**

Table; 3a and b Rock Eval Analysis. Ama -1 and Aku - 11 wells

- This involves heating small amount of sample between 250°C and 550°C in the absence of oxygen (Thermal decomposition reaction).
- S1 – Peak: quantity of free hydrocarbon (HC) Librated by volatilization at 250°C. (mgHc/g rock).
- S2 – peak: quantity of HC produced by further hearing of kerogen. (mgHc/g rock). Present day ability of the kerogen to generate HC.

- S3 – peak – CO2 released from the kerogen at the end.
- Dymann et al (1996) gave the following classification
- Lower than 2mgHc/grock (2000ppm) – Little or no source potential but some potential for gas.
- 2 to 6 mgHC/grock (2,000 – 6,000ppm) = moderate or fair source rock potential.

**Interpretation**

- The Rock-Eval Analysis of both wells (Ama-1 and Aku-11) revealed the following values of S1 peak; Ama-1 (0.03 to 0.28)

**Table .3 a:** Roc k-Eval Analysis, Ama-I Well

Sample no	Depth meters	Formation	TOC (%)	T <sup>o</sup> C	S1	S2	S3	PI	HI	O1
AMOA-04-04	1522	MAMU	0.09	426	0.04	0.053	1.62	0.07	59	180
AMOA-04-06	1575	MAMU	0.82	443	0.03	1.12	7.28	0.03	137	888
AMOA-0408	1640	NKPORO	1.81	440	0.17	4.14	2.24	0.04	229	124
AMOA-0409	1673	NKPORO	1.18	437	0.28	5.39	2.29	0.05	451	228
AMOA-0410	1680	NKPORO	1.70	438	0.15	3.34	2.45	0.04	196	144
AMOA-0413	1703	NKPORO	1.08	450	0.10	1.23	1.48	0.08	114	137
AMOA-0415	1765	NKPORO	1.07	471	0.12	0.32	1.42	0.27	30	133
AMOA-0417	1800	NKPORO	1.81	442	0.04	1.25	1.24	0.03	69	105
AMOA-0420	1900	NKPORO	1.34	428	0.13	0.45	1.36	0.22	34	102

**Table 3b:** Rock-Eva Analysis, Aku-II Well

Sample no	Depth meters	Formation	TOC (%)	T <sup>o</sup> C	S1	S2	S3	PI	HI	O1
AMOA-04-05	3300	NKPORO	0.69	467	0.04	2.55	1.80	0.02	370	261
AMOA-04-06	3474	NKPORO	1.02	487	0.10	4.01	2.45	0.02	393	240
AMOA-0408	3514	NKPORO	0.81	478	0.10	2.37	2.40	0.06	293	296
AMOA-0409	3543	NKPORO	1.12	480	0.20	3.30	2.30	0.07	395	205
AMOA-0411	3572	NKPORO	0.81	493	0.26	3.41	2.74	0.07	421	338
AMOA-0413	3619	NKPORO	1.94	496	0.10	3.77	3.08	0.04	401	328
AMOA-0414	3647	NKPORO	1.18	434	0.20	4.01	3.22	0.05	340	273
AMOA-0415	3680	NKPORO	1.40	415	0.15	1.03	2.99	0.12	114	207
AMOA-0416	3700	NKPORO	0.86	484	0.21	3.15	2.95	0.06	366	343

mgHc/g rock) Ave 0.12mgHc/grock. Aku – 11 (0.04-0.26mgHc/g rock) Ave 0.15 mgHc/g rock.

- Since the values of S1 peak for both wells is less than 2mgHC/g rock. This revealed little or no source potential for oil but some potential for gas.
- Values of S2 peak – revealed high amount of CO<sub>2</sub> released after the whole reaction, this is equivalent to the amount of oxygen in the sample.

Fig. 7; plots of HI vs T max. Ama-1 and Aku -11 wells.

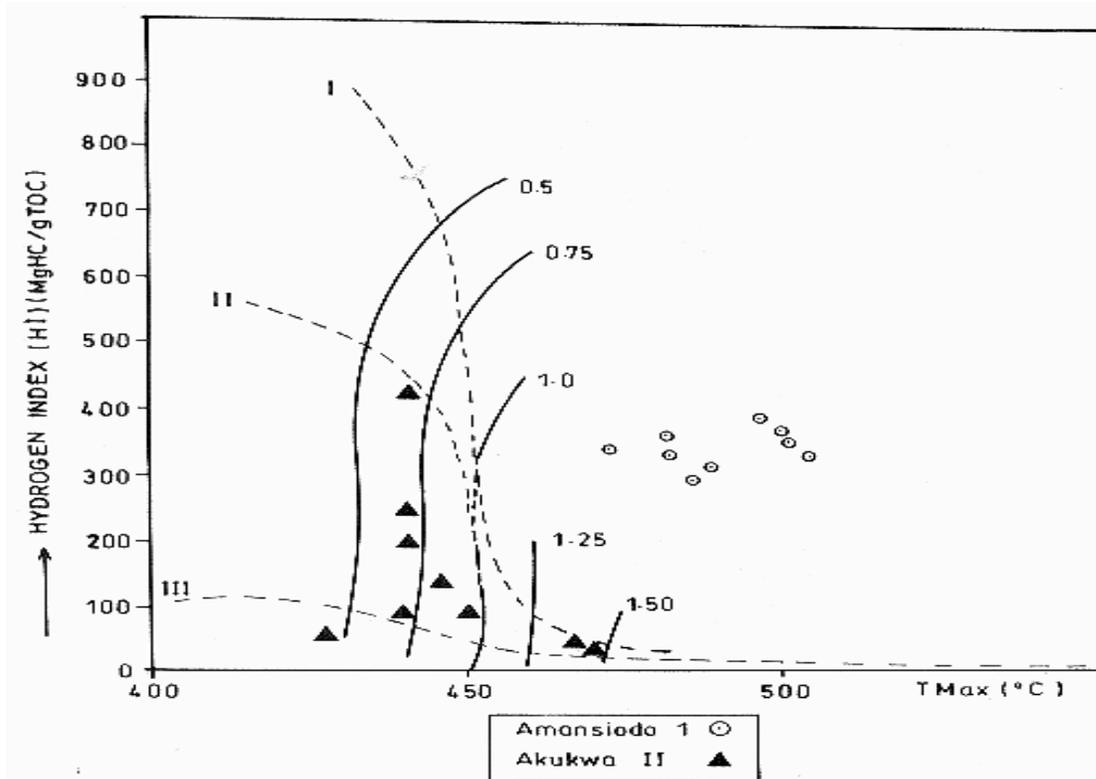


Fig-7: Plot of HI Vs TMax for Ama-I and Aku-II Wells.

Ama-1 well plots within Type II and III kerogene. That of Aku – II well is outside the field, this may be due to the contamination of the samples.

Fig. 8; plots of HI vs OI for Ama-1 well and Aku-II wells. Ama-1 plots within Type II and III. That of Aku – II well is outside the field.

Fig. 9; plot of HI vs TOC, Ama-1 and Aku-11 wells. The plots revealed increase TOC with increasing HI for both wells.

Fig. 10; plot of Bitumen ratio (mgExt/gTOC) vs depth for Ama-1 and Aku –II wells.

The plots show. a decrease in BR(Bitumen ratio) with increasing depth for both wells.

Fig 7. is an evolution diagram drawn to assess the extent of thermal effect on the organic matter and to cross check the validity of the hydrogen index (HI) of the kerogens as a function of T-max. Most of the samples from Amansiodo-1 well plot along the type II kerogen evolution pathway except one which follow the type III kerogen pathway.

The Aku – II well samples plotted outside the field this may be due to sample contamination. Most of the samples of Ama-1 well are relatively immature plotting below and around 0.5% Rm boundary line and majority having T-max value quite below 450°C.

Fig 8:- The samples from Ama –1 well have very low values of HI and high values of OI and plot

mainly along the type III and II kerogen evolutionary pathway. The low hydrogen index HI values point to type II and III organic matter deposited perhaps in an oxidizing environment. The high values of OI may equally be due to relatively high content of carbonate minerals with lower TOC values (<2%). It must be noted that all the samples are relatively immature and are no source rocks. The plots of Akukwa – II are generally outside the field, this may be due to sample contamination.

Fig 9:. A plot of HI against TOC for both Ama –1 and Aku –II wells. The values for Ama-I is (0.09%-1.8%) with only a sample having value less than 0.5%. Aku –II values range from (0.69% to 9.94%). The HI of Ama-I well were found to be lower than that of Aku-II well this is due to the depth of burial.

Fig 10:. The plot of Bitumen ratio against depth Show no variation in the extractable organic matter (EOM) or bitumen from the samples. The bitumen ratio in Ama-I well vary from 2.78 to 7.07 and Aku-II from 2.14 to 9.45 with a point having a value of 22.28. There is no clear or definite trend of the extractable yield with depth which is of course a function of geothermal gradient and temperature. However there is a slight increase of the value at depth 3,514 meters in Aku-II well.

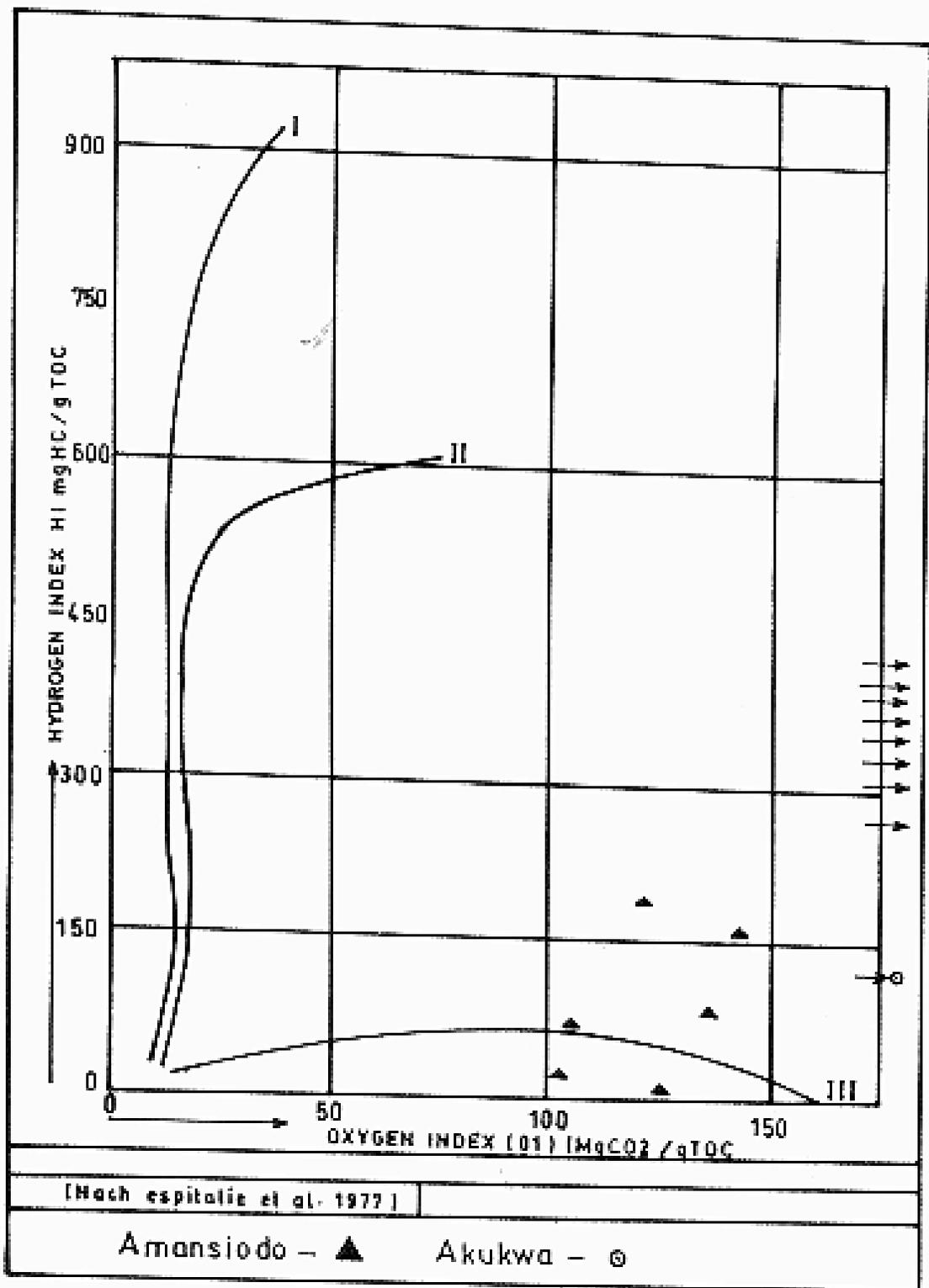


Fig. 8: Plots of HI Vs OI for Ama-I and Aku-II Wells

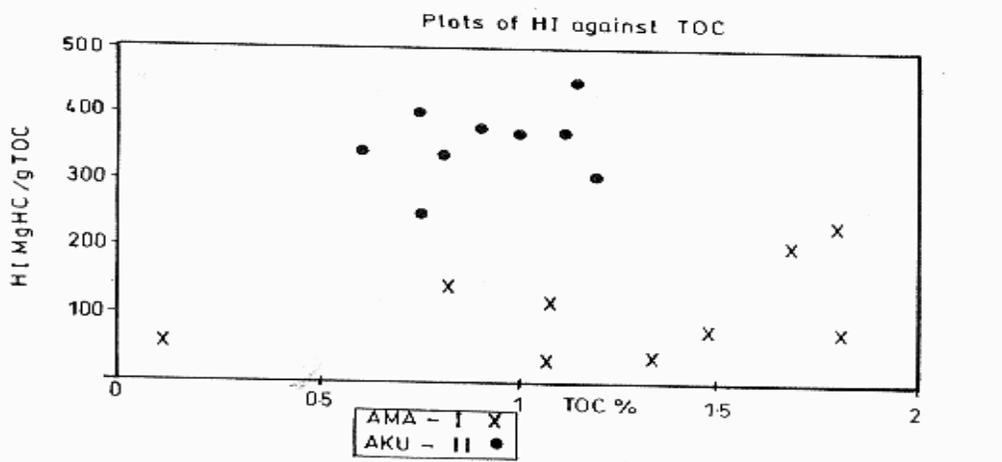


Fig. 9: Plots of HI against TOC, Ama-I and Aku-II Wells

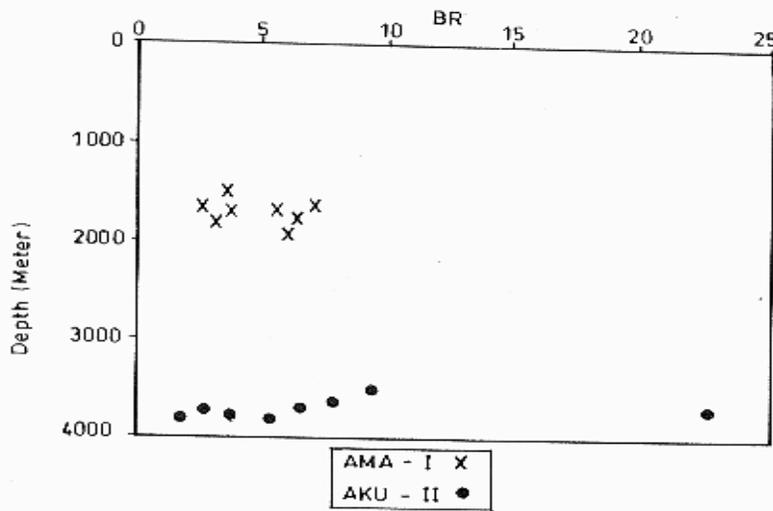


Fig. 10: Plots of Bitumen ratio against depth Amansiodo - I and Akukwa - II Wells.

Fig 11: The plot of SOM against depth. In Ama-I well, the values of SOM range from (30.0 to 80.0ppm) with a high value of 128ppm at a depth of 1,640 meters. The same variation was in Aku-II well with values ranging from 30.0ppm to 96.4ppm with a high value of 180.5ppm at a depth of 3,514 meters. The plots of Ama-I well show a slight increase with increasing depth which shows that it is a function of geothermal gradient and temperature, on the contrary the plot of Aku-II show also a slight decrease in SOM values with increasing depth this is also a function of geothermal gradient and temperature.

Fig 12:- The T-max ( $^{\circ}\text{C}$ ) is a pyrolysis parameter that respond to the thermal maturity of kerogen, it is the temperature corresponding to the maximum hydrocarbon pyrolytic yield i.e maximum of  $\text{S}_2$  peak in the Rock-Eval Pyrogram. The T-max varies as a function of the thermal maturity of organic matter (TISSOT and ESPITALIE 1974). T max is also linked to the kinetics of the cracking of the organic mater contained in the kerogen (AKAEGBOB 1995).

For Ama-I well the T-max values range is from  $426^{\circ}\text{C}$  –  $471^{\circ}\text{C}$ , for Aku-II well T-max values range is from  $415^{\circ}\text{C}$  –  $496^{\circ}\text{C}$ . In both well the T-max was found to vary slightly with depth; it increases with increasing depth, this show that the T-max is a function of the geothermal gradient and the temperature. From the diagram of the relationship between T-max, kerogen types and oil and gas windows (after BORDENAVE et al 1993), the oil generating window for a type III kerogen is from  $430^{\circ}\text{C}$  to  $470^{\circ}\text{C}$  and for a type II kerogen is from  $430^{\circ}\text{C}$  to  $455^{\circ}\text{C}$ .

The T-max results of the two wells vary from one sample to the other. The T-max values of up to  $471^{\circ}\text{C}$  were observed for the Ama-I well and up to  $496^{\circ}\text{C}$  for Aku-II well. Since the threshold of hydrocarbon generation (THG) for kerogen II and III is  $430^{\circ}\text{C}$  T-max the samples from both well are thermally

matured to generate oil and gas.

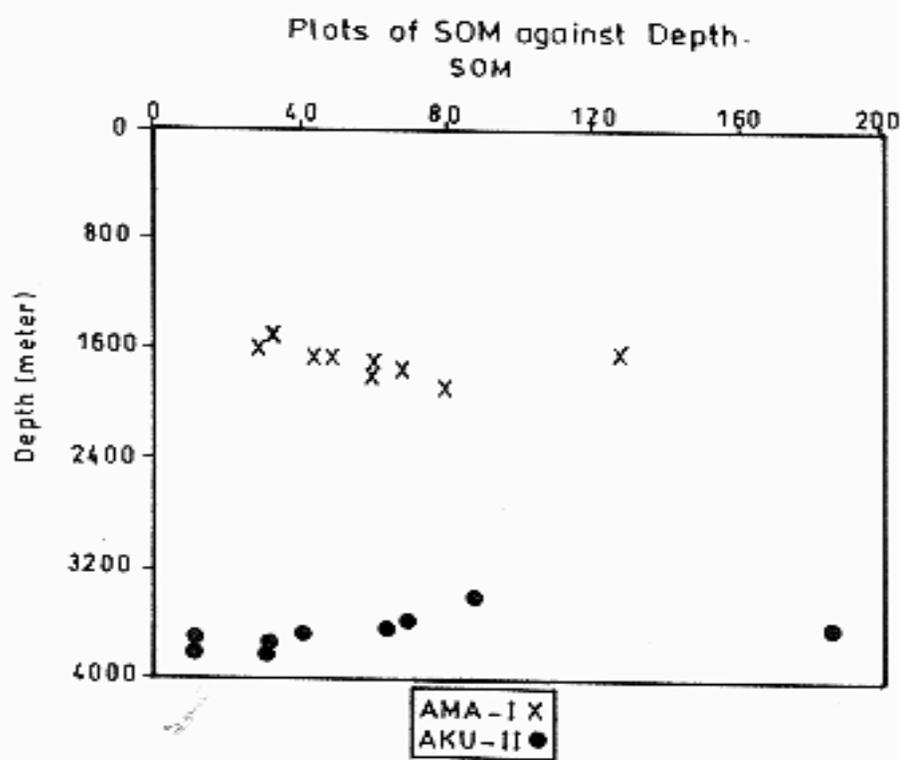


Fig.11: Plots of SOM against depth Amansiodo-I and Akukwa - II wells.

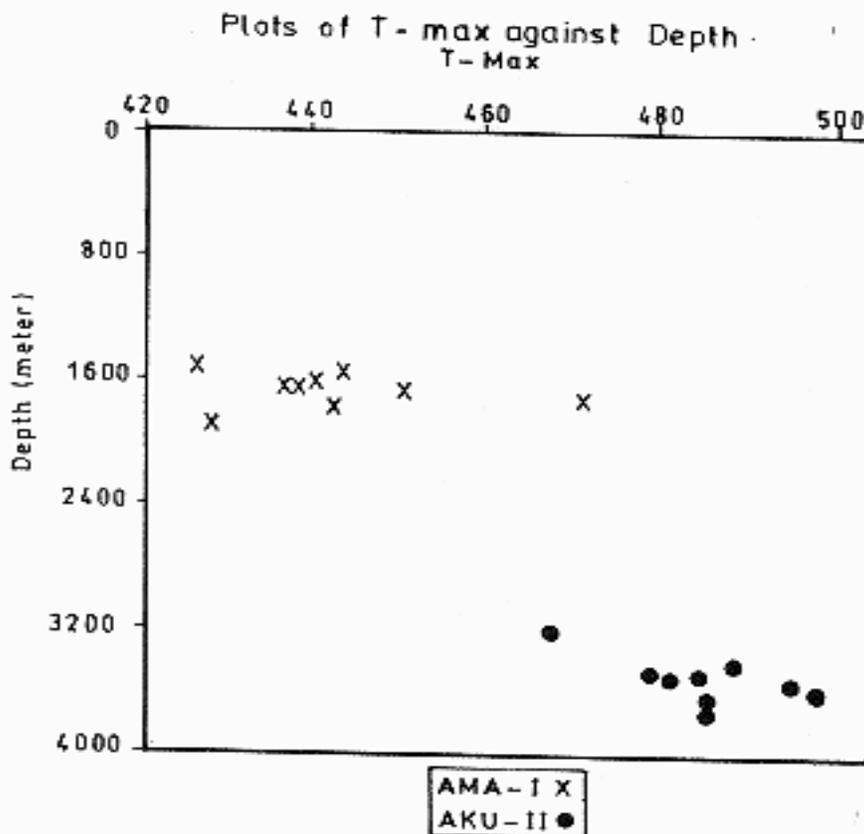


Fig.12: Plots of T- Max against Depth Amansiodo-I and Akukwa - II wells.

**CONCLUSION**

The Shales were found to contain enough total organic carbon (TOC) and enough extractable organic matter to generate enough hydrocarbon (HC)

The result of Maceral analysis as indicated by the pie-chart revealed high vitrinite and inertinite values to Liptinite in both wells; since the percentage of vitrinite is high there is tendency for the shale to generate gas. The plot of Hydrogen index against temperature maximum (T-max), which gives the vitrinite reflectance measure indicate that the shale samples could only generate dry-gas.

Rock-Eval pyrolysis results revealed that shales of Nkporo has Hydrogen index of more than 200 which implies that significant oil can be generated from the shale. The cross plot of Hydrogen index and oxygen index revealed that the shale can only generate Type II and Type III kerogens. The T max value of 430°C to 490°C also revealed that the source rocks are matured enough to generate oil and gas since the threshold of hydrocarbon generation (THG) for kerogen II and III is 430 T-max

The Rock-Eval and T-max values give relatively good results especially for TOC-rich samples which is the case of the basins of sedimentary rocks with predominantly terrestrial organic matter, this is also revealed by the organic matter to be mainly type II and III kerogen which also suggest derivation mainly from terrestrial higher plants, these results reflects immature to early mature stages of organic matter (OM).

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