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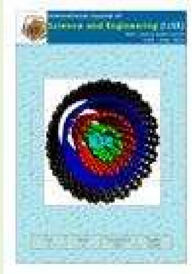

Organic Geochemical Characterization of "L-1" Well in the Anambra Basin, Southern Nigeria for Source Rock and Hydrocarbon Potential

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Abstract *- The Anambra basin of Nigeria harbours the largest deposit of sub-bituminous coal and lignite. There have been reports of oil seepages in parts the basin. Thepotential of the coal and other formations as source rock andhydrocarbon is yet to be fully understood. This study is aim at identifying the source rocks and the geochemical composition of the oil seepage. Forty eight shale and coaly samples comprising of twenty eight ditch cuttings, twelve sidewall core and eight conventional core samples from depths 550m to 2390m in L-1 Well in the Anambra Basin were subjected to organic geochemical investigation using Rock Eval, TOC, and Vitrinite Reflectance study. The Vitrinite reflectance valuesrangefrom 0.52% to 1.0 %, TOC range from 0.61% to 7.39%, while the T_{max} values range from 432 to 440. The Hydrogen index values ranges from 11mgHC/g to177mgHC/g. The catagenetic study show that the vitrinite reflectance slightly increase from 0.5 to 0.62% between depth of 850m to 1920m, which increases more sharply (in the top of Asata/Nkporo Shales) and reaches 1.0 at 2390m depth. The production indexes range from 0.04 to 0.33.The whole studied section of the well from the analyses iscomposed mainly of Kerogen Type III land derived organic matter with infinitesimal amount of Type IV and also it is evident from the study that the shaly and coaly intervals of the Lower Coal Measures are now in the oil generation zone and have already produced hydrocarbons.*

Keywords: Production index; Coal; Hydrocarbon; Rock-Eval pyrolysis; Vitrinite reflectance, Aulacogen

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INTRODUCTON

L-1 Well lies within the Anambra Basin, which is a roughly triangular structural Basin that was form during the separation of South America continent from Africa and it is the second most petroliferous Basin in Nigeria aside the Niger Delta Basin. The Basin occupies an area of 4,000km^2 and is bounded to the east by the undifferentiated Precambrian Basement Complex and Abakiliki anticlinorium to the west, but the Northern and Southern boundary are not well defined as shown in Figure 1 (Short and Stauble, 1967).

Hydrocarbon exploration started early within the basin but most of the wells were observed to be ungratifying and this discouraged most of the oil companies who then resorted to the very prolific Niger Delta. With increase in demand to meet the world's growing energy demand, dwindling reserves and discovering of inland petroleum reserves in Cameroun and Niger couple with increasing technology, attention has been moved to the Anambra Basin again for reevaluation. Research and exploration are been carried out in other to improve the available data on the Basin so as to discover new reserves and increase our production.

Organic geochemistry which is implored in this investigation is a very important tool in petroleum exploration both in the early stage in identifying the source rock and classifying crude oil into families (Ekweozor et al., 1979).

The objective of this research is to evaluate the hydrocarbon potential of the Anambra basin using geochemical and optical study of organic matter from L-1 well which penetrated the Early Tertiary and Late Cretaceous sediments of Imo Shale, Upper Coal Measures (Nsukka Formation), False Bedded Sandstone of Ajali Formation, the Lower Coal Measures (Mamu formation) and Asata/Nkporo Shale.

GEOLOGICAL SETTING

The Anambra basin is part of the Lower Benue Trough which is the southern section of the NE-SW aulacogen that developed as a failed arm of the triple radial rift system Grant (1971); and Olade, (1975). The Basin is in the form of a roughly triangular prism situated in the South-eastern part of Nigeria and covers about 4,000 km^2.

The sediments deposited in the Anambra Basin are generally considered to be Upper Cretaceous – Lower Tertiary descendant of the Southern Benue trough and the stratigraphic history is characterized by three sedimentary phases (Short and Stauble, 1967). The Aptian - Santonian Abakaliki - Benue Phase which resulted in the deposition of the Asu River Group and the Eze-Aku and Awgu Formations in the Abakaliki-Benue Basin, the Benue valley and the Calabar Flank, Campanian-Mid Eocene Anambra-Benin phase resulting from the Santonian folding and uplift of the Abakaliki region and dislocation of the depocenter into the Anambra platform and Afikpo region leading to the deposition of the Nkporo Group, Mamu Formation, Ajali Sandstone, Nsukka Formation, Imo Formation and Ameki Group (Table 2)., and the Late Eocene-Pliocene Niger Delta phase characterizes the stratigraphy of Anambra Basin. Due to earth movement the southern position of the basin is down warped and overlapped by thick Tertiary deposits of the Niger Delta (Short &Stäuble, 1967; Murat, 1972). Nwajide and Reijer (1997) observed that the regressive offlap sequence began to develop in the Campanian times and prograded into the Maastrichtrian and the delta development ended in the Paleocene when the Imo shale Paleocene transgression phase occurred. This is a pointer to the fact that the main source, reservoir and cap rocks which are related to the petroleum potentials of the basin are diagnostic in these sequences particularly in the Coal Measure facies, the AwguShale's and Agbani Sandstones.

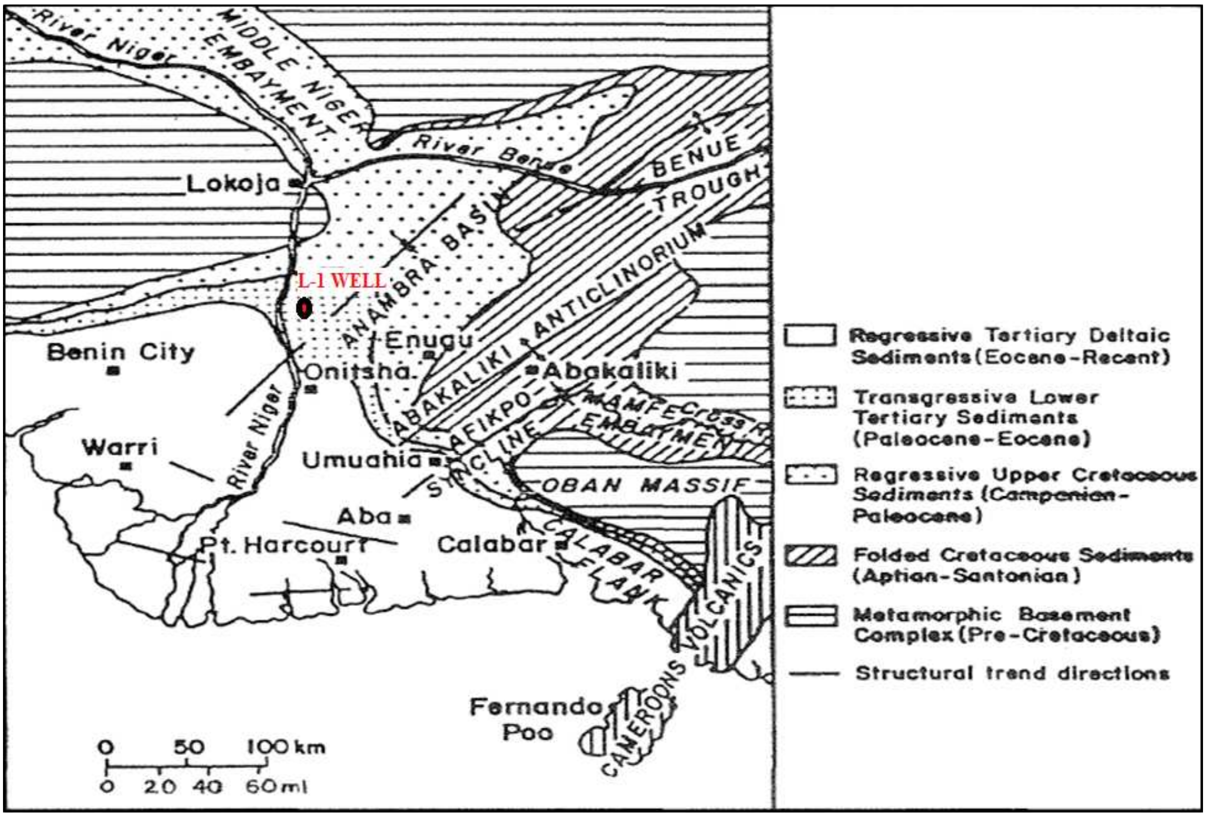

Figure 1. Position of the Anambra Basin in the tectonic framework of Southern Nigeria (after Short and Stauble, 1967)

Table 1. Stratigraphy of Southern Benue Trough / Anambra Basin

AGE		SOUTHERN BENUE/ ANAMBRA BASIN	CYCLE OF SEDIMENTATION
TERTIARY	EOCENE	AMEKI/NANKA FORMATION	3RD CYCLE OF SEDIMENTATION
	PALEOCENE	IMO SHALE	
	MAASTRICHTIAN	NSUKKA FORMATION	
		AJALI FORMATION	
		MAMU SHALE	
	CAMPANIAN	ENUGU/NKPORO FORMATION	
	SANTONIAN-CONIACIAN	AGWU FORMATION	2ND CYCLE OF SEDIMENTATION
	TURONIAN	EZE-AKU GROUP (KEANA, MAKURDI,AGALA AND AMASERI FORMATION)	
	CENOMANIAN	ODUKPANI FORMATION	
LOWER CRETACEOUS	ALBIAN	ASU RIVER GROUP	1ST CYCLE OF SEDIMENTATION
	APTIAN		
PRECAMBRIAN		BASEMENT COMPLEX	

METHODOLOGY

Forty eight shale and coaly samples comprising of twenty eight ditch cuttings, twelve sidewall core and eight conventional core samples were collected from stratigraphic depth ranging from 550 to 2930m (TD) cutting across five formations from Imo Shale to Asata / Nkporo Shales within **L1-Well.**

Samples preparation was done according to Espitalie*et al*., 1977, standard organic geochemical sample preparation procedure and Stach et al 1982; Obaje, 1994; organic petrologic sample preparation procedure. The Analysis was carried out with LECO 230 analyzer and Delsi Rock Eval II instrument and the following were obtained:

a) Total organic carbon (TOC) determination to estimate the quantity of organic matter in each sample.

b) Rock-Eval pyrolysis to determine the hydrocarbon generative potential of the organic matter (S1, S2, S3, Tmax, and the derivatives: Hydrogen Index (HI), Oxygen Index (OI), and Production Index (PI).

c) Vitrinite reflectivity (Ro %) to determine the source rocks maturity.

RESULTS AND DISCUSSIONS

The results of the geochemical analyses are shown in Table 2, fromwhich profiles weregenerated to represent the degree and level of maturity of the organic matter in the sediment.

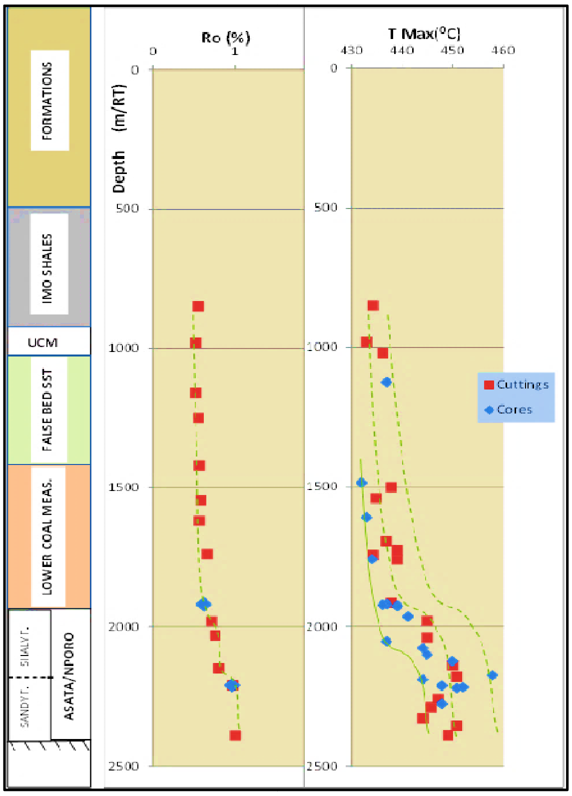

Fig. 2. Synthetic Catagentic Profile

Imo Shales

Six Imo shale samples were subjected to Rock Eval analysis. The average organic matter of the samples is fair with TOC range of0.61 to 1.08%.

The hydrogen index (HI = S2/TOC) vs. oxygen index (OI=S3/TOC) plot on the van Krevelendiagram (Van Krevelen, 1984; Tissot and Welte, 1984), indicates the predominance of organic matter of types III kerogen **(Fig. 3).** The genetic potential (S_1+S_2) of the samples is less than 0.2 mg HC/g of rock hence it source rock potential is negligible

Upper Coal Measure

One sample was analyzed and studied within this formation. It is characterized by a type III kerogen and has a TOC of 1.02% and the genetic potential (S_1+S_2) of the samples is 0.22 mg HC/g of rock hence it is negligible

Table 2. Results of organic geochemical data

DEPTH (m)	SAMPLE REF	FORMATIONS	IR, %	VR %	TOC %	EOM %	EOM/ TOC, %	S_1	S_2	S_3	HI	OI	Tmax ^{0}C	PI (S_1/S_1+S_2)
550.0	#01	IMO SHALES	90.31		0.61					0.57		93		
650.0	#02	“	89.60		0..93			0.2	0.1	0.45	11	48		
700.0	#03	”	92.04		0.65				0.1	0.40	15	62		
800.0	#04	“	92.20		0.66					0.31		47		
850.0	#05	“	91.77	0.57	1.08	0.0152	1.4		0.2	0.42	19	39	(434)	
900.0	#06	IMO SHALES	86.65		0.75			0.01	0.1	0.45	13	60		
980.0	#07	UPPER COAL M.	75.28	0.52	1.02	0.0354	3.5	0.02	0.2	1.33	20	130	(433)	
1020.0	#08	F B SANDSTONE	79.19		3.22	0.2266	7.0	0.58	3.7	1.67	115	52	436	0.14
1124.0	#09	“	94.82		3.25			0.19	4.3	0.58	132	18	437	0.04
1160.0	#10	“		0.52										
1250.0	#11	“		0.54										
1425.0	#12	F B SANDSTONE		0.56										
1484.5	#13	LOWER COAL M.	91.81		2.32			0.21	1.4	0.90	60	39	432	0.13
1500.0	#14	”	87.71		0.82	0.0657	8.0	0.09	0.6	0.49	73	60	438	
1540.0	#15	“	91.09	0.57	1.36			0.12	1.3	1.19	96	87	435	
1608.5	#16	“	95.66		7.39			0.85	14.1	0.78	191	11	433	0.06
1625.0	#17	“		0.56										
1695.0	#18	“	92.85		1.58			0.16	1.8	0.75	114	47	437	0.08
1725.0	#19	“	84.70		1.35	0.0668	4.9	0.08	1.1	1.35	81	100	439	
1745.0	#20	“	89.44	0.66	3.20			0.62	5.1	1.22	159	38	434	0.11
1758.5	#21	“	90.92		6.67			0.79	11.8	1.47	177	22	434	0.06
1760.0	#22	“	91.98		2.26	0.0937	4.1	0.28	3.0	0.75	133	33	439	0.09
1915.0	#23	“	91.06		1.27			0.20	1.3	2.28	102	180	438	0.13
1927.0	#24	“	94.70		2.18	0.1352	6.2	0.22	3.1	3.38	142	155	439	0.07
1920.2	#25	“	92.97	0.62	1.71	0.1346	7.9	0.14	1.9	2.07	111	121	437	0.07
1922.6	#26	“	95.13		1.62			0.19	1.9	1.94	117	120	436	0.09
1926.8	#27	LOWER COAL M.	95.10		1.75	0.2740	15.7	0.23	2.2	2.02	126	115	439	0.09
1965.0	#28	ASATA/NKPORO SH. SHALY	94.72		2.54			0.21	1.6	1.31	63	52	441	0.12
1980.0	#29	“	85.78	0.70	2.14			0.19	1.4	4.52	65	211	445	0.12
2040.0	#30	“	74.26	0.75	1.95	0.1342	6.9	0.19	1.4	5.26	72	270	445	0.12
2054.0	#31	“	94.28		1.38			0.09	0.4	0.50	29	36	437	0.18
2078.0	#32	“	93.10		1.65			0.14	1.0	1.07	61	65	444	0.12
2101.0	#33	“	93.52		1.63			0.27	1.3	0.55	80	34	445	0.17

DEPTH (m)	SAMPLE REF	FORMATIONS	IR, %	VR %	TOC %	EOM %	EOM/ TOC, %	S_1	S_2	S_3	HI	OI	Tmax ^0C	PI (S_1/S_1+S_2)
2125.0	#34	"	86.63		1.32			0.05	0.3	1.78	23	135	(450)	
2140.0	#35	"	88.74	0.80	1.59	0.1667	10.5	0.10	0.8	1.43	50	90	450	
2175.0	#36	"	87.78		2.33			0.39	0.8	1.09	34	47	458	0.33
2180.0	#37	"	78.18		1.50	0.0875	5.0	0.19	0.9	1.59	60	106	451	0.17
2190.0	#38	"	83.50		2.29			0.30	0.6	1.91	26	83	444	0.33
2221.0	#39	ASATA/NKPORO SH. SANDY	96.64	0.95	3.68	0.9160	2.5	0.73	3.0	1.02	82	28	451	0.20
2212.2	#40	"	96.00		2.79	0.1484	5.3	0.53	2.0	0.69	72	25	448	0.21
2218.1	#41	"	95.74		2.13	0.1761	8.3	0.38	1.4	0.03	66	39	452	0.21
2218.6	#42	"	98.72		0.11	0.0192	17.5		0.1	0.09	91	82		
2260.0	#43	"	90.41		1.27			0.19	0.9	1.61	71	127	447	0.17
2277.5	#44	"	94.69		3.51			0.55	2.4	0.70	68	20	448	0.19
2290.0	#45	"	90.66		1.92			0.30	1.5	2.14	78	111	446	0.17
2330.0	#46	"	90.48		1.44			0.22	1.0	1.95	69	135	444	0.18
2356.0	#47	"	89.94	0.97	1.74	0.0940	5.4	0.14	1.0	1.99	57	114	451	
2390.0	#48	"	89.47	1.00	1.77			0.34	1.2	1.63	68	92	449	0.22

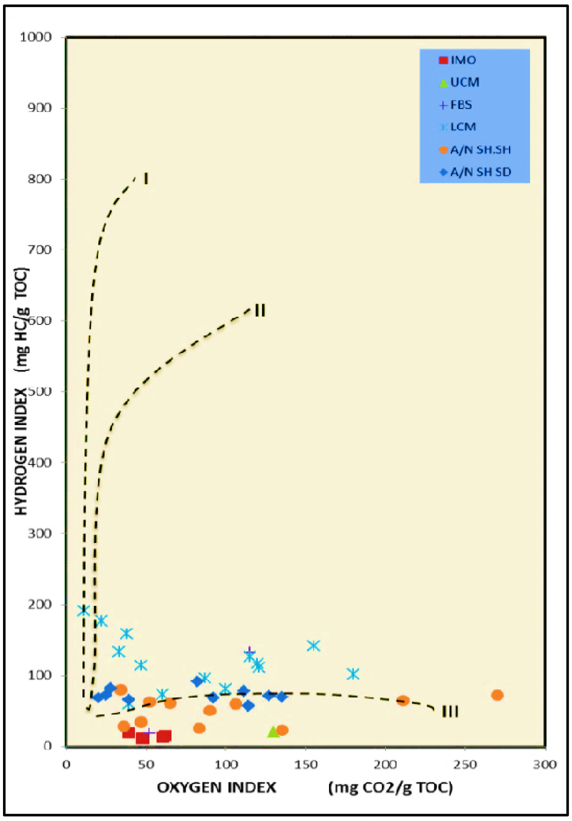

Fig. 3. L-1 Well Plot of HI versus OI for kerogen type assessment

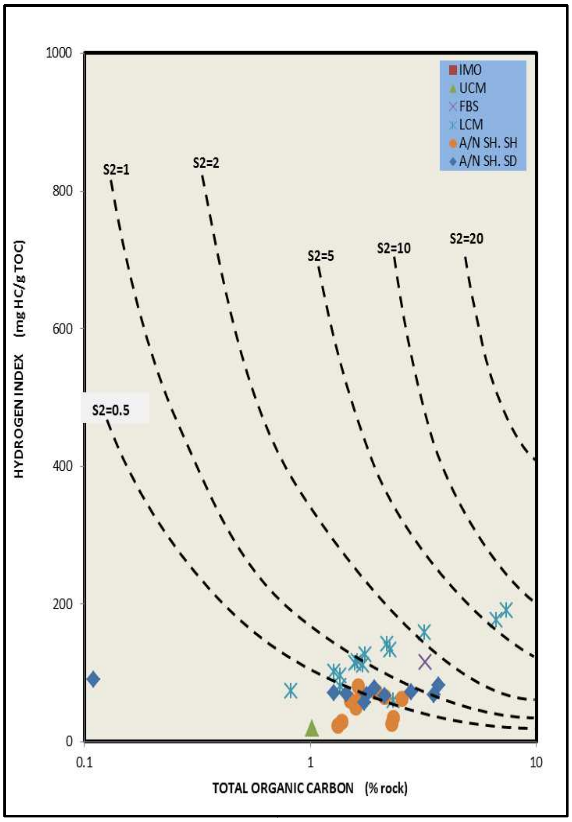

Fig. 4. L-1 Well Plot of HI versus Tmax showing the potential for oil and gas phase

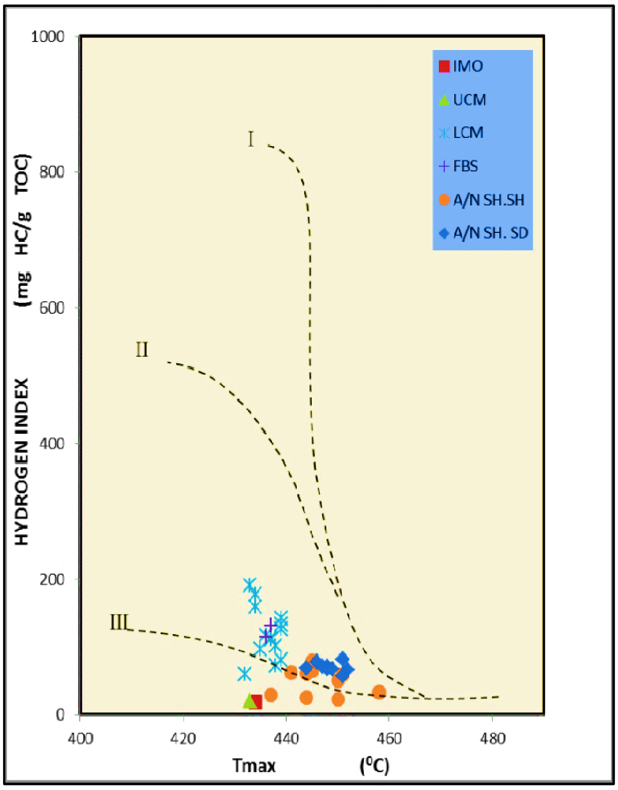

Fig. 5. L-1Well Plot of HI versus TOC

False Bedded Sandstone

Two shale samples interbedded within sandstone of the formation was studied and an average TOC of 3.2% recorded. The genetic potential was very high with an average of 4.38 mg HC/g rock (Table 1). The Tmax values for the section was 436 and 437 this reflect an early mature stage of maturation and in combination with the type III kerogen observed from the hydrogen index of 115 and 132 which falls within 150 to 50 (Peter, 1986). It indicates that the organic matter is predominantly gas prone.

Also it mustn't be forgotten that this shale levels are very scarce and that false bedded sandstone is a reservoir and not a source rock.

Lower Coal Measure

The average organic content of the fourteen analyzed samples from this formation is high to locally high (1.2 to 7.4% TOC) due to frequent presence of coaly particles. Sample #16, 20, and 21 is composed of oil prone type II kerogen with $S_2/S_3>5$ while sample #13, 14, 15, 18, 19, 20, 21, 22, 23, 24, 25, 26, and 27 indicates gas prone type III kerogen with $S_2/S_3<2$.

The genetic potential ranging from 1.2 to 15mg/g is the highest recorded of all the formations crossed within the borehole. The production Indices [PI= $S_1/(S_2+S_3)$] of the samples ranging from 0.6 to 0.13 reflects an immature level and Tmax values ranging between 432 to 439, coupled with vitrinite reflectance 0.6% indicating that the samples are within oil window but the low hydrogen index and moderate maturation reveals minor hydrocarbon potential.

Asata/Nkporo Shale

This formation was divided into two facies for this study and they are the Shaly upper part where eleven samples were analyzed and the Sandy lower part where ten samples were analyzed.

The organic content of the samples seems quite good and homogenous in the formation, though the lower sandy part is slightly better with a TOC and genetic potential [GP= S_1+S_2] ranging 1.3 to 3.5% and 1 to 1.8 respectively compared to 1.5 to 2.5% and 1 to 3.7 at the Shaly upper part reflecting a moderately good source rock. Hydrogen index versus oxygen index plot indicates type III kerogen.

The production index is relatively high ranging from 0.12 to 0.33 **(Table 2)** which is compatible with the generation of hydrocarbons. The T_{max} value which range from 441 to 452 combined with a vitrinite reflectance of 1% reflects mature stage of maturation. The PI values of the studied samples of Asata/Nkporo formation which are greater than 0.1 (Table 2) also reveals possible impregnation by migrated oil or contamination by mud additives (Clementz, 1979).

CONCLUSIONS

The organic geochemical study of L-1 Well revealed a land derived type III organic matter throughout the section. The from the study, the kerogen is predominantly gas prone. The catagenetic study assessed from the $T_{max}$and vitrinite reflectance gently increases from 0.5 to 0.65% VRo between the depths of 850m and 1944 m, and then increases more sharply at the top of the Asata – Nkporo Shales and reaches 0.95 – 1% VRowhich at 2390m depth it is therefore at the early to mature stage of maturation. Juxtaposition of the geochemical and petrologic results reveal that the shaly and coaly intervals of the coal measure present a good genetic potential and the Asata / Nkporo shales which has a genetic potential of 3 - 4 mgHC/ g of rock reflects a medium potential for hydrocarbon sourcing and this is further buttressed by PI values which are greater than 1 an indication possible impregnation by migrated oil.

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