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HYDROCARBON POTENTIAL OF THE UPPER CRETACEOUS COAL AND SHALE UNITS IN THE ANAMBRA BASIN, SOUTHEASTERN NIGERIA

Jude E. Ogala

Department of Geology, Delta State University, Abraka, Nigeria

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Abstract

The hydrocarbon potential of the Upper Cretaceous units (Maastrichtian Mamu Formation) of the Anambra Basin, Southeastern Nigeria was assessed by Rock-Eval pyrolysis. The total organic carbon (TOC) values range from 0.07 to 61.42 wt. % (averaging 8.54 wt. %). The genetic potential (GP) and hydrogen index (HI) values range from 0.05 to 332 mg HC/g rock and 40 to 771 mg HC /g respectively. These values indicate that the sediments have gas and oil generating potential. The organic matter is predominantly gas prone (mostly type III and mixed type III/II). The level of thermal maturity deduced from the production index (0.02 to 0.63), calculated vitrinite reflectance of 0.47 to 0.78 %Ro and T_{max} values between 338 and 441^{o}C suggest that the coal and shale samples are thermally immature to marginally mature with respect to petroleum generation.

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

1. Introduction

The Cretaceous Anambra Basin (SE Nigeria) consists of rhythmic clastic sequences of sandstones, shales, siltstones, mudstones, sandy shales with interbedded coal seams. It covers an area of about 40,000km^2 (Fig. 1). The Cretaceous sediments in the basin reaches a thickness of 6,000m; approximately 2,000m of this sediment was deposited in the Anambra Basin [1, 31] during the Campanian-Maastrichtian. The Anambra Basin has been a major geological area for coal exploration since 1909. The coal in this basin is subbituminous and occurs principally at two levels, the lower coal measures (Mamu Formation) and the upper coal measures (Nsukka Formation). The Lignite deposits occur in the Oligocene-Miocene Ogwashi-Asaba Formation [32]. Coal and Lignite resources have an estimated reserve of 1.5 billion tons and 300 million tons respectively [27,30] discussed the petroleum geology of the Benue Trough and south-eastern Chad Basin based on a revised stratigraphy and organic geochemical analyses of outcrop samples [12] investigated the petroleum geochemistry of Late Cretaceous and Early Tertiary Shales penetrated by Akukwa-2 well in the Anambra Basin, Southern Nigeria. They concluded that the deepest section of the Asata/Nkporo Shale may be very good source beds in the Anambra Basin [5] investigated the aromatic hydrocarbon distribution in Post-Santonian Shale and Coal in the Anambra Basin [6] presented data from source rock evaluation of coals from the lower Maastrichtian Mamu Formation. They concluded that the coals in the Mamu Formation have the capacity to generate and expel liquid hydrocarbons and gases as part of an active Cretaceous petroleum system.

Coal beds are now accepted as a potentially significant source of liquid hydrocarbons [7, 16, 23] and increasingly are becoming exploration targets in many parts of the world Examples of coal-derived petroleum have been reported from the Kutai Basin (Mahakam Delta), Indonesia [11]; Junggar, Tarim and Turpan Basins, Northwestern China [15]; Cooper Basin, Australia; Taranaki Basin, New Zealand [11] and Karoo Basin, Tanzania [21].

*corresponding author: etunimogala@yahoo.comm

This study attempts to employ standard geochemical methods in order to evaluate the hydrocarbon-generative potential and thermal maturity of shales and coals in the Maastrichtian Mamu Formation of the Anambra Basin. This will in turn provide additional information on their potential for liquid and gaseous hydrocarbons.

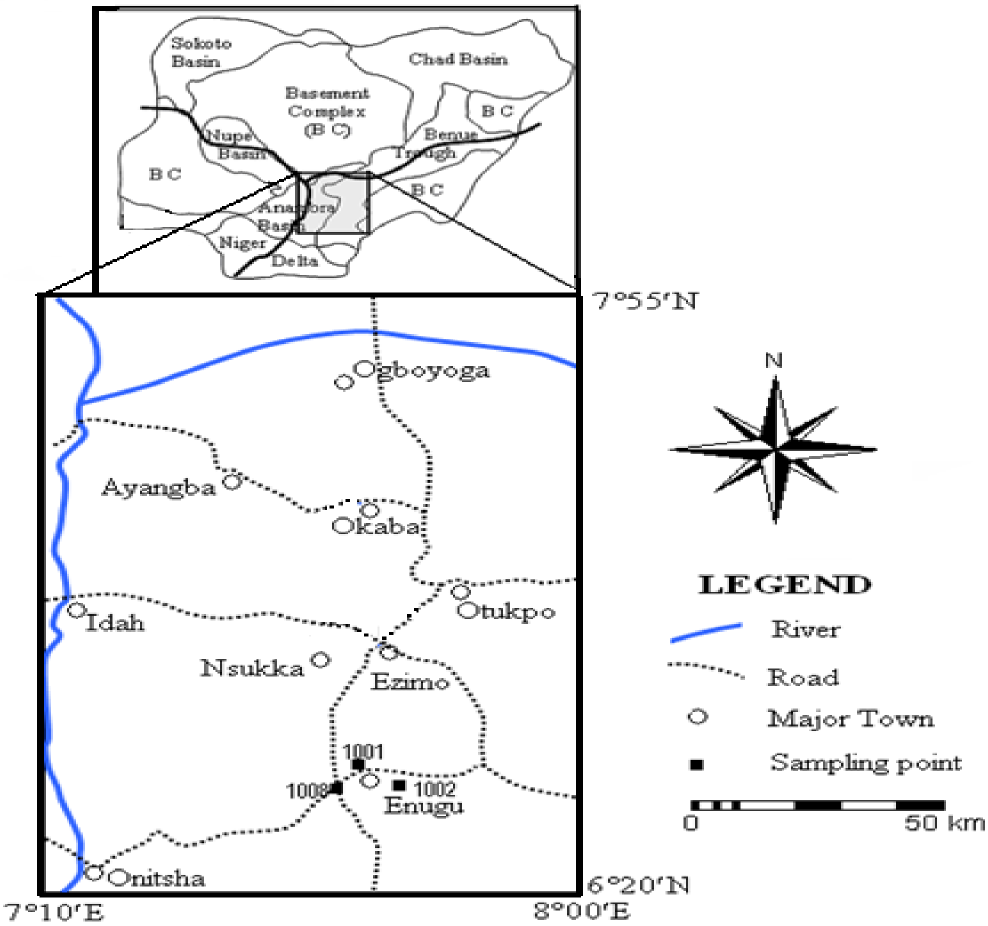

Figure 1 Map of the study area showing sample location

2. Geological setting

The structural setting and general geology of the Anambra Basin have been documented by various workers [2, 3, 24, 25, 26, 30]. The Anambra Basin is located in the south-western end of the Benue Trough of Nigeria (Figure 1).

The evolution of the Sothern sedimentary basin began in the Early Cretaceous with the formation of the Benue – Abakaliki Trough as a failed arm of the rift triple junction associated with the separation of the African and South American continents and subsequent opening of the South Atlantic [20]. The platform areas bordering the Benue Trough to the west (Anambra Platform) and to the east (Afikpo Platform) became downwarped due to the Santonian tectonism to form the Anambra Basin and Afikpo Syncline respectively [22]. The Anambra Basin contains about 6km thick Cretaceous/Tertiary sediments and is the structural link between the Cretaceous Benue Trough and the Tertiary Niger Delta [20].

The geologic strata of the Anambra Basin were deposited in a syncline initiated by the major folding episode in the Benue trough during Late Cretaceous times. During the Maastrich-tian, the Anambra Basin became silted up and extensive thickly vegetated swamps developed near sea level, on top of a broad delta fan built up by rivers bringing sediments from the hinterland [37]. Sedimentation in the Anambra Basin commenced with the Campano – Maastrichtian marine and paralic shales of the Enugu and Nkporo Formations. These basal units are overlain successively by the coal measures of the Mamu Formation, the Ajali Sandstone, and the Nsukka Formation. The marine shales of the

Imo and Nsukka Formations were deposited in the Paleocene, overlain by the tidal Nanka Sandstones (lateral equivalents the Ameki Formation) of Eocene age which constitute the Tertiary succession (Figure 2).

3. Materials and methods

Thirty-seven (37) core samples from three boreholes (Figure 1) that penetrated the Maastrichtian Mamu Formation were collected from the Geological Survey Agency of Nigeria, Kadauna. The stratigraphic columns of the boreholes are shown in Figure 3.

Samples for TOC and Rock-Eval pyrolysis were ground, and material passing through a 60 mesh (250 micron) sieve was used for analysis. The samples were treated with concentrated hydrochloric acid to remove carbonates and total organic carbon (TOC) is measured on carbonate free samples using a LECO 230 analyzer. All samples were subjected to Rock-Eval pyrolysis, according to the procedures described by [13, 14, 34] using a Delsi Rock-Eval II instrument. The parameters obtained from this apparatus include: total organic carbon (TOC) content, S_1 (hydrocarbons released at temperatures of about 300^{0}C), S_2 (hydrocarbons generated by pyrolytic degradation of the organic matter in the rock samples at temperature of 300-550^{0}C), S_3 (CO_2 generated from the kerogen during thermal cracking of the kerogen) and T_{max} (temperature at which the maximum amount of hydrocarbons are generated, which is a measure of thermal maturity of the organic matter). Other parameters calculated from the pyrolysis data are hydrogen index (HI= S_2 × 100/TOC), oxygen index (OI = S_3 × 100/TOC), production index (PI= $S_1/(S_1 + S_2)$), normalized oil content (S_1 × 100/TOC), and calculated vitrinite reflectance (Calc. %Ro= 0.0180 × T_{max}, [12]). The laboratory analyses were performed at Humble Geochemical Services, Texas, USA.

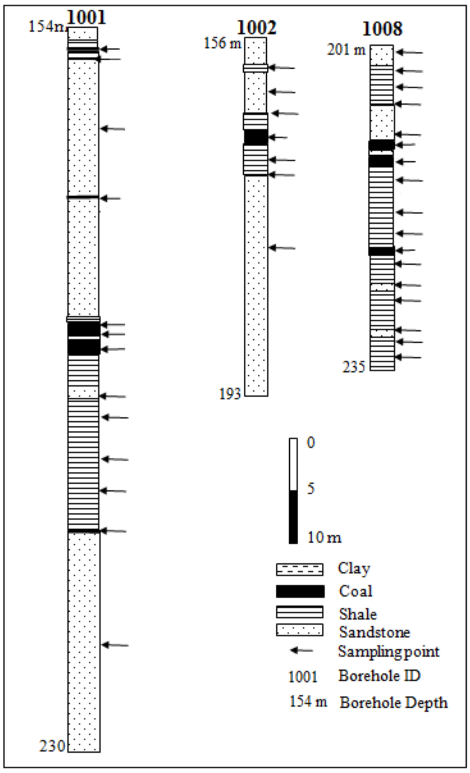

Fig. 3 Lithologic logs of boreholes

	PERIOD/AGE	FORMATION	BASIN
Tertiary	Eocene	Bende/Ameki Formation	Niger Delta Basin
	Palaeocene	Imo Shale Group	
Cretaceous	Maastrichtian - Palaeocene	Nsukka Formation	Anambra Basin
	Maastrichtian	Ajali Formation Mamu Formation	
	Campanian - Maastrichtian	Enugu/Nkporo /Owelli Formation	
	Santonian		

Major Unconformity

Fig. 2 Stratigraphic sequence of the Anambra Basin

4. Results and discussions

4.1 Organic matter richness

Total organic carbon content (TOC) and Rock-Eval analysis were performed on 37 potential source rock samples (Table 1). Total organic carbon in a source rock comprises three basic components: (1) organic carbon in a retained hydrocarbons as received in the laboratory; (2) organic carbon that can be converted to hydrocarbons, called convertible carbon (Jarvie, 1991a) or reactive or labile carbon [9]; and (3) a carbonaceous organic residue that will not yield hydrocarbons because of insufficient hydrogen commonly referred to as inert carbon [9, 17]. Adequate amount of organic matter is a necessary prerequisite for sediment to generate oil or gas [10].

The TOC content for the lithostratigraphic columns of the wells 1001, 1002 and 1008 ranges from 0.22 to 61.42 wt. % (averaging 12.16 wt. %), 0.07 to 7.47 wt. % (averaging 2.22 wt. %) and 0.71 to 55.07 wt. % (averaging 8.37 wt. %) respectively (Table 1). These TOC values show that the sediments have comparable average TOC contents, which are greater than the 0.5 wt. % threshold value required for a potential source rock to generate hydrocarbons [35]. There is no clear trend of the TOC-values with depth (Figure 4).

The source rock quality of the coals and shales in the three wells (Figure 3) is confirmed by the pyrolysis-derived generative potential (G.P. = S1+S2) of selected samples (Table1). The hydrocarbon generative potential of wells 1001, 1002 and 1008 ranges from 0.16-332.22 mg/g rock, 0.05-34.84 mg/g rock and 0.35-295.28 mg/g rock respectively. Hydrogen index (HI) values for the studied samples ranges from 59 to 771 mgHC/g TOC for well-1001, 40 to 444 mgHC/g TOC and 44 to 527 mgHC/g TOC for wells 1002 and 1008 respectively. These values indicate a moderately good source rock with gas and oil generating potential (G.P. > 2 mg/g; [29, 35]).

4.2. Types of organic matter

The type of organic matter in sediments penetrated by the three wells (1001, 1002 and 1008) was assessed by Rock-Eval pyrolysis (Table1). Most of the studied rock units from the three wells are mainly of type III with subordinate type II-III. The plots Rock-Eval S_2 versus TOC (Figure 5) are useful to compare the petroleum-generative potential of source rocks [18, 28]. The slopes of lines radiating from the origin in Figure 5 are directly related to hydrogen index (HI= S_2 × 100/TOC, mg HC/g TOC). Hydrogen index values of greater 600, 300-600, 200-300, 50-200 and less than 50 mg HC/g TOC classifies organic matter as type I (very oil prone), type II (oil prone), type III (gas prone) and type IV (inert) respectively [28]. The relationship between the hydrogen index (HI) versus oxygen index (OI) (Figure 6), reveals kerogen of type III and mixed type II-III organic matter which are predominantly gas prone. Plots of HI versus Tmax (the maximum temperature of pyrolysis) (Figure 7) and HI versus calculated %Ro (Figure 8), also shows that the organic matter in the samples is mainly type III with subordinate type II/III. The above results are in agreement with the data obtained by earlier workers [4, 6, 33].

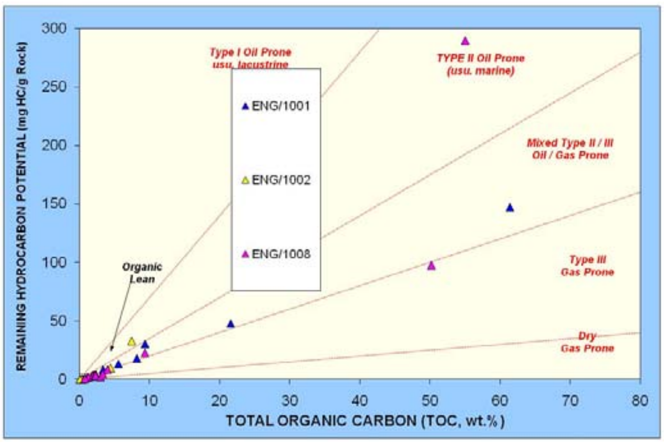

Fig. 5 Plots of Rock-Eval S_2 versus TOC [18]

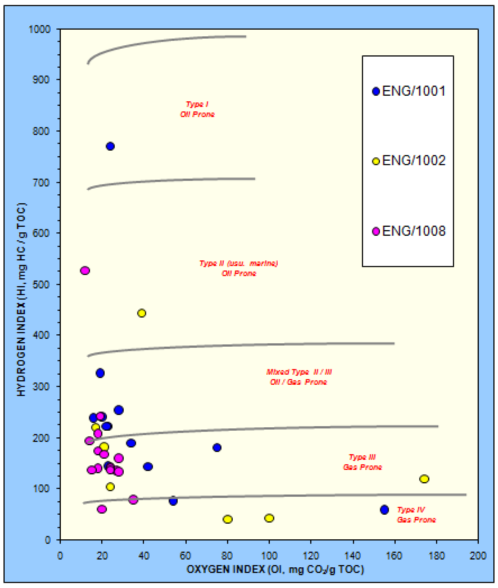

Fig.6 Plot of hydrogen index (HI) versus oxygen index (OI) for the coal and shale units from the Mamu Formation

4.3. Thermal maturity of organic matter

Thermal maturity provides an indication of the maximum paleotemperature reached by a source rock. The thermal maturity of the shales and coals of the Anambra Basin have been discussed by several authors [4, 5, 36].

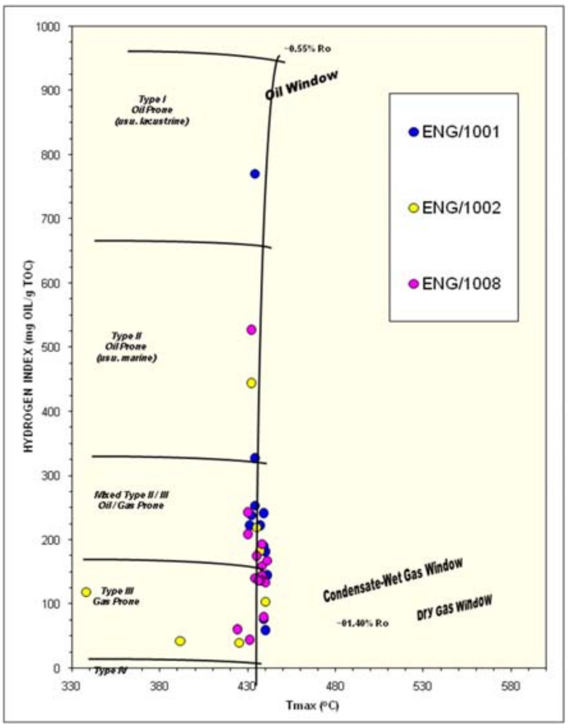

Fig. 7 Plot of HI versus Tmax for characterization of the organic matter for wells-1001, 1002 and 1008 from the Mamu Formation

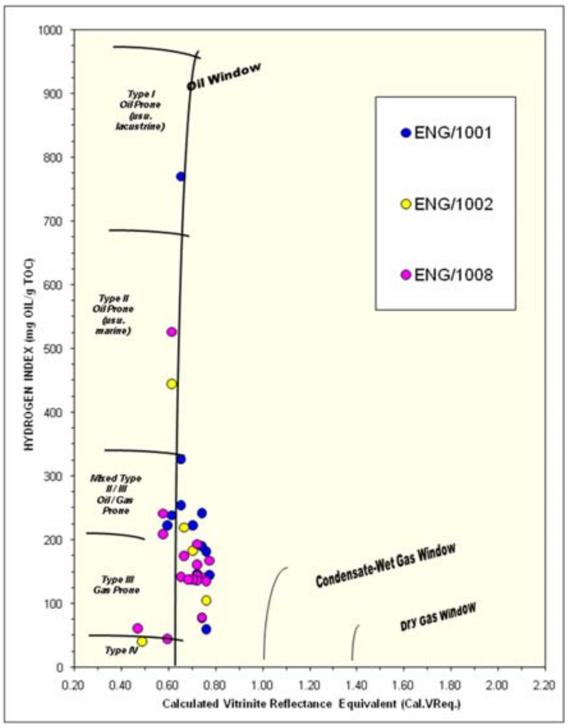

Fig. 8 Plot of HI versus calculated vitrinite reflectance (Calc.%Ro)

The degree of thermal maturity of the shales and coals of the Maastrichtian Mamu Formation was assessed by pyrolysis-derived indices, such as Rock-Eval T_{max}, production index and calculated %Ro (Table 1). According to [28], PI and T_{max} values less than about 0.1 and 435^{0}C respectively, indicate immature organic matter while Tmax greater than 470^{0}C points to the wet-gas zone. The T_{max} values of the coal and shale samples in wells 1001, 1002, and 1008 ranges from 431 to 441^{0}C (averaging 437^{0}C), 425 to 440^{0}C (averaging 414^{0}C) and 424 to 441^{0}C (averaging 435^{0}C) respectively. The calculated vitrinite reflectance values range between 0.60 to 0.78 %R_o (well-1001), 0.49 to 0.76 %R_o (well-1002) and 0.47 to 0.78 %R_o (well-1008). Both values indicate that the samples are thermally immature to marginally mature with respect to petroleum generation. Plots of PI versus T_{max} (Figure 9), PI versus calculated vitrinite reflectance (Figure 10) also show that the coal and shale sediments are partly within the oil window. The production index (PI=S1/S1+S2) values > 0.1 (Table 1) observed on few core samples indicate possible impregnation by migrated bitumen or contamination by mud additives [8]. Other samples with PI-values ranging from 0.02 to 0.09 correspond to the expected results.

5. Conclusion

This study has shown that the coals and shales of the Maastrichtian Mamu Formation in the Anambra Basin, SE Nigeria has a total organic carbon (TOC) contents of up to 61.42wt.%. The hydrogen index (HI) and generative potential (GP) of the shale and coal samples in this study are above the minimum values required for a potential source rock, suggesting that the sediments have gas and oil generating potential. The organic matter is predominantly gas prone (mostly Type III and some mixed Type II/III). The level of thermal maturation derived from the Rock-Eval data show that the shale and coal sediments are partly within the oil window.

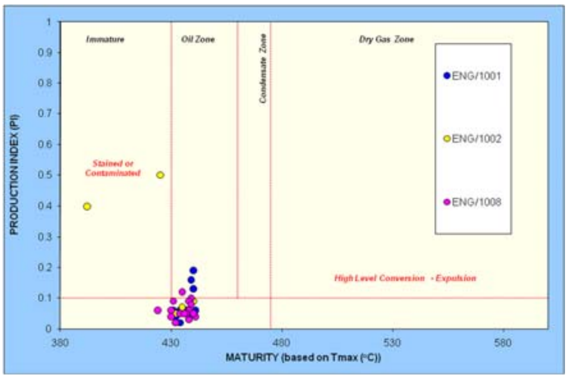

Figure 9: Plot of production index (PI) against T_{max} of the studied rock samples from the Mamu Formation

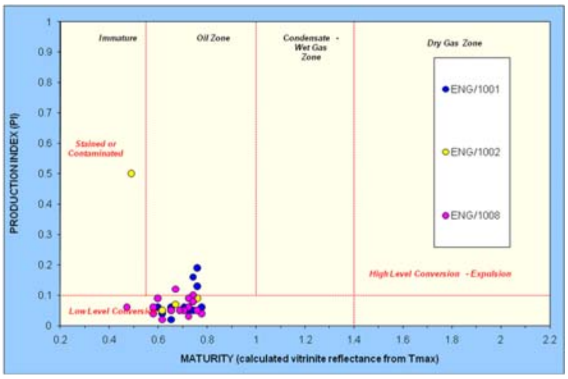

Figure 10: Plot of production index (PI) versus calculated vitrinite reflectance (Calc. %Ro)

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Table 1: TOC and Rock-Eval pyrolysis results of the studied samples

Sample No	Top Depth(m)	Bottom Depth(m)	Lithology	TOC (wt.%)	S1 (mg HC/g rock)	S2 (mg HC/g rock)	S3 (mg CO2/g rock)	Tmax (°C)	Calc. %Ro	HI (mg HC/g TOC)	OI (mg CO2/g TOC)	S2/S3	S1/TOC (mg HC/g TOC)	PI (S1/S1+S2)
ENG/1001	157		Shale	9.34	1.88	30.53	1.79	434	0.65	327	19	17	20	0.06
ENG/1001	157		Coal	21.57	3.00	47.86	4.97	431	0.60	222	23	10	14	0.06
ENG/1001	157	159	Shale	0.48	0.07	0.37	0.26	439*	0.74	77	54	1	15	0.16
ENG/1001	159	163	Shale	0.32	0.09	0.58	0.24	440	0.76	181	75	2	28	0.13
ENG/1001	163	172	Shale	1.68	0.12	2.44	0.39	438	0.72	145	23	6	7	0.05
ENG/1001	172		Coal	8.17	1.14	18.15	1.82	437	0.71	222	22	10	14	0.06
ENG/1001	172	173	Shale	0.22	0.03	0.13	0.34	440*	0.76	59	155	0	14	0.19
ENG/1001	184	186	Coal	61.42	5.90	147.03	10.06	432	0.62	239	16	15	10	0.04
ENG/1001	186		Shale	5.54	1.19	13.35	1.11	439	0.74	241	20	12	21	0.08
ENG/1001	186	187	Coal	42.04	8.23	323.99	10.15	434	0.65	771	24	32	20	0.02
ENG/1001	187	193	Shale	2.01	0.20	3.79	0.68	439	0.74	189	34	6	10	0.05
ENG/1001	197	205	Shale	1.95	0.18	2.81	0.82	441	0.78	144	42	3	9	0.06
ENG/1001	205		Coal	3.35	0.46	8.52	0.94	434	0.65	254	28	9	14	0.05
ENG/1002	156	159	Shale	4.45	0.75	9.78	0.76	435	0.67	220	17	13	17	0.07
ENG/1002	159	160	Shale	0.31	0.64	0.37	0.54	338*	-1.00	119	174	1	206	0.63
ENG/1002	160	165	Shale	0.07	0.02	0.03	0.07	392*	-1.00	43	100	0	29	0.40
ENG/1002	165	166	Shale	0.10	0.04	0.04	0.08	425*	0.49	40	80	1	40	0.50
ENG/1002	166	167	Coal	2.33	0.24	4.25	0.49	437	0.71	182	21	9	10	0.05
ENG/1002	167	178	Shale	7.47	1.68	33.16	2.92	432	0.62	444	39	11	22	0.05
ENG/1002	178	193	Shale	0.84	0.09	0.87	0.20	440	0.76	104	24	4	11	0.09
ENG/1008	201	202	Shale	1.75	0.42	3.05	0.32	435	0.67	174	18	10	24	0.12
ENG/1008	202	203	Shale	1.05	0.17	1.47	0.19	439	0.74	140	18	8	16	0.10
ENG/1008	203		Coal	50.24	3.28	97.63	6.95	438	0.72	194	14	14	7	0.03
ENG/1008	203	205	Shale	1.07	0.15	1.53	0.26	438	0.72	143	24	6	14	0.09
ENG/1008	205	206	Shale	0.71	0.05	0.56	0.25	439	0.74	79	35	2	7	0.08
ENG/1008	206	210	Shale	1.25	0.11	1.70	0.34	438	0.72	136	27	5	9	0.06
ENG/1008	210	211	Coal	3.97	0.52	8.24	0.72	430	0.58	208	18	11	13	0.06
ENG/1008	211		Shale	1.87	0.19	3.00	0.53	438	0.72	160	28	6	10	0.06
ENG/1008	211	213	Shale	2.17	0.15	3.65	0.46	441	0.78	168	21	8	7	0.04
ENG/1008	213		Shale	2.24	0.15	3.00	0.62	440	0.76	134	28	5	7	0.05
ENG/1008	213	214	Shale	2.36	0.17	3.32	0.57	434	0.65	141	24	6	7	0.05
ENG/1008	214	220	Shale	2.28	0.15	3.12	0.55	437	0.71	137	24	6	7	0.05
ENG/1008	220	221	Coal	55.07	5.30	289.98	6.48	432	0.62	527	12	45	10	0.02
ENG/1008	221		Shale	2.96	0.12	1.77	0.60	424	0.47	60	20	3	4	0.06
ENG/1008	221	225	Shale	0.72	0.03	0.32	4.91	431*	0.60	44	682	0	4	0.09
ENG/1008	228	230	Shale	3.29	0.23	4.51	0.48	436	0.69	137	15	9	7	0.05
ENG/1008	233	235	Shale	9.32	1.04	22.53	1.73	430	0.58	242	19	13	11	0.04

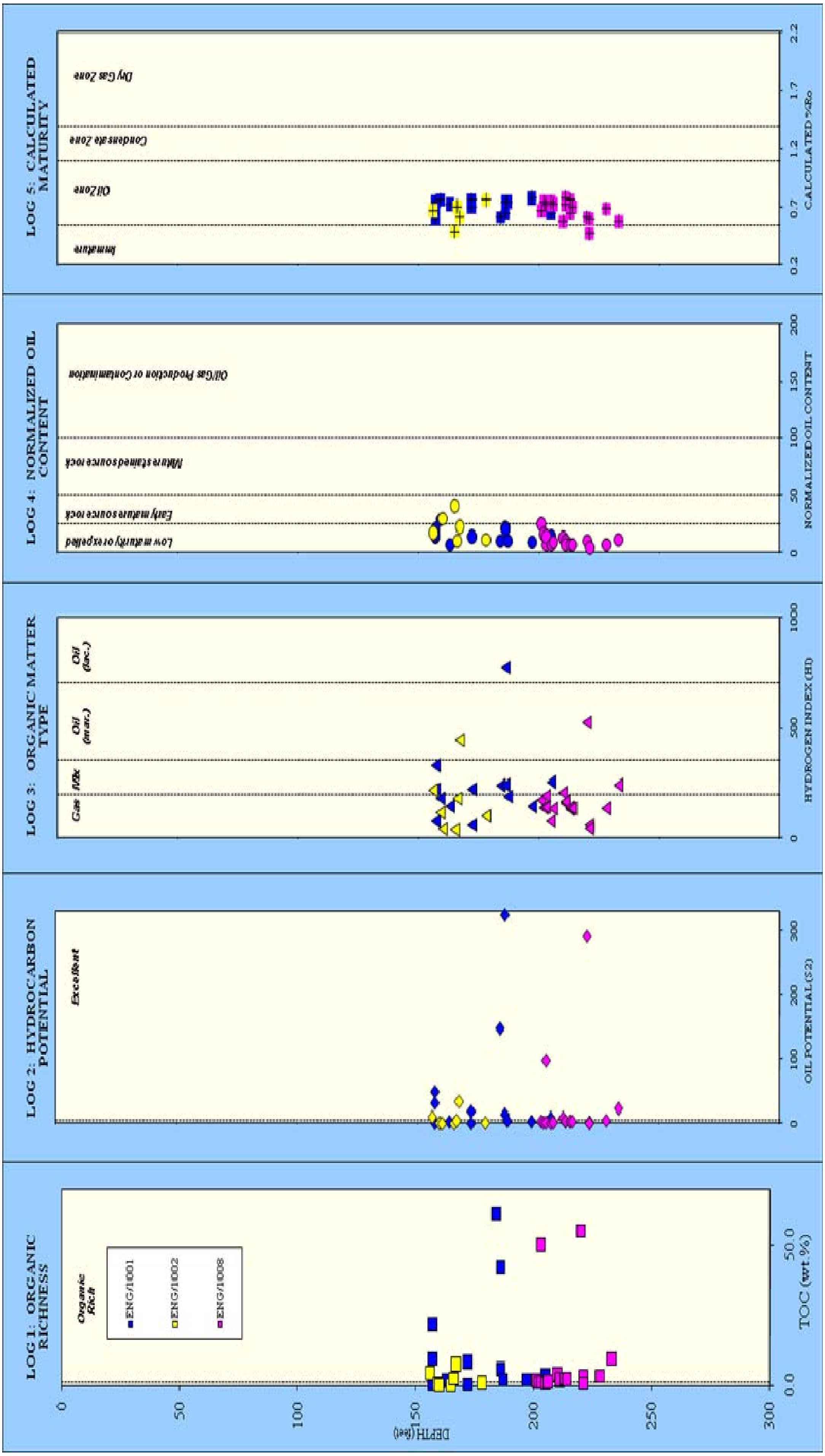

Figure 4: Geochemical logs of studied wells