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Hydrocarbon Generation Potential of the Campano-Maastrichtian Dark Mudstone Lithofacies, Benin Flank, South West Anambra Basin, Nigeria

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ABSTRACT: The dark mudstone lithofacies of Mamu Formation was deposited during the Campano-Maastrichtian flooding episode. It is laterally heterogeneous, and has been subdivided into marsh, bay and central basin sub-environments in order of proximality. Arising from recommendation from a previous study, we evaluated its hydrocarbon generating potential using multidisciplinary tools involving visual kerogen analysis, as well as bulk and isotope geochemistry. Seventy-seven sample materials were taken from 3-outcrop sites at Uzebba, Okpekpe and Imiegba locations, Benin flank, SW Anambra Basin, Nigeria. The results show that bulk of the samples have good organic richness. Kerogen quality is dominantly of gas prone Type III kerogen. However, visual kerogen analysis indicates the presence of an oil prone Type II/III kerogen in the central basin subenvironments. An immature thermal maturity is inferred based on spore colour index (SCI) of less than 6 on the SCI chart (thermal alteration index of <2.5). In addition, we hypothesize that the dark mudstone lithofacies possesses biogenic gas potential based on its organic richness, kerogen quality and thermal maturity. Shale gas prospectivity is further enhanced by the low dip of the Mamu Formation, shallow burial as well as high silica content. Worth mentioning is the proximal marsh mudstone (Uzebba location) with suitable microfabric, very high silica as well as >10m of combined (continuous) outcropping and subcropping thickness.

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Visual kerogen analysis complemented by bulk and isotope geochemistry have proven to be very useful tools in evaluating the hydrocarbon generation potential of fine-grained lithologic units (Tyson, 1995; Al-Ameri *et al.,* 1999; Chiaghanam, *et al.,* 2013; Gonçalves *et al.,* 2015). A clear advantage of visual kerogen analysis over other tools is that it provides valuable information on the nature of the particulate organic matter that constitute the kerogen, their characteristics, as well as the proportion of various organic matter constituents (Tyson, 1995). In addition, it is simple, relatively inexpensive yet very powerful (Thakur and Dogra, 2011; Mendonça Filho *et al.,* 2012). Renewed interest in hydrocarbon exploration of Nigeria's inland basins (especially the Benue Trough, Benin and the Anambra basins) in recent times have provided a strong impetus for a good understanding of its petroleum system elements. At the core of this is the understanding of the basins' Cretaceous source rocks. The source rock properties of the mudstone (shale) and coal of Campano-Maastrichtian Mamu Formation, Anambra Basin have been evaluated mostly in the eastern segment using programmed pyrolysis (Akaegbobi et al., 2000; Ogala 2011; Akande et al., 2012; Olatinpo et al., 2016; Faboya et al., 2019), whereas only a few studies exist in the southwestern segment (Edegbai and Emofurieta, 2015; Ogbamikhumi *et al.,* 2017 Maju-Oyovwikowhe and Malomi, 2019). Data from these findings have been used to characterize the Mamu Formation as having well to very good organic richness with thermally immature to early mature dominantly type III kerogen. Interestingly, some of the data suggest the occurrence of marine and mixed marine kerogen (Olatinpo *et al*., 2016; Faboya *et al.,* 2019), which is attractive to petroleum explorers. Hence, the need for kerogen / organic facies analysis to be undertaken on the dark mudstone. In our preliminary assessment of the source potential of the dark mudstone lithofacies of the Mamu Formation in the Benin flank of the Anambra Basin (Edegbai and Emofurieta, 2015), we recommended a detailed study of the dark mudstone unit. Following through with this, detailed studies with aimed at unraveling the prevalent paleodepositional and paleoceanographic conditions of the Maastrichtian seaway (Edegbai et al., 2019a, 2019b, 2020) was undertaken. This present effort embodies the findings of a detailed multidisciplinary evaluation (palynofacies, bulk geochemistry and carbon isotope geochemistry) of the dark mudstone lithofacies aimed at assessing the source rock potential of the dark mudstone unit outcropping at Uzebba, Okpekpe

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Imiegba locations, Benin Flank, western Anambra Basin, as well as its implication for shale gas development.

Geologic Setting: The Anambra Basin (Fig. 1) marks the next to last stage of the Benue Trough's tectonostratigraphic evolution in Southern Nigeria (Edegbai et al., 2019a). It is generally believed to be a continental sag basin formed after thermal induced subsidence which followed the widespread Santonian inversion episode. However, recent schools of thought suggest an interior fracture basin (Ladipo pers. Comm., 2019) or a faulted passive margin (Omatsola, 2019). The wedge-shaped outline of the lithic fill, the presence of synsedimentary deformation structures (Obi and Okogbue, 2004) as well field evidences of normal faults (Dim et al., 2020) are evidences for fault-controlled subsidence. The Anambra Basin has a Campanian to Danian stratigraphic fill which is composed of the Nkporo Group, the Mamu Formation, the Ajali Formation and the Nsukka Formation in stratigraphic order (Fig. 1, Table 1). *Lithostratigraphy of the Mamu Formation in the Benin Flank:* The Mamu Formation in the Benin flank comprises of 7-lithofacies, which were combined into marsh, bay, barrier, beach, and washover fan lithofacies association as well as meandering fluvial-tidal channel lithofacies association Edegbai et al (2019b). *Dark mudstone lithofacies:* The dark mudstone is one of the 7-lithofacies identified in the western flank. At the Imiegba and Uzebba outcrops (Fig. 3), thicknesses of up to 6 m exist. Texturally, it shows poor sorting and varies from fine mudstone to sandy mudstone with fabric characterized by laminations, which may be planar, lenticular, wavy, or curved. It is weakly to moderately bioturbated, which is a function of proximality and water depth (Edegbai, et al., 2019b). Mineralogically, it is devoid of calcite, and has a composition that varies between 100% quartz and clay (mainly kaolinite) (Edegbai, et al., 2019b). In addition, geochemical microfabric, paleontological characterization show that the dark mudstone is laterally heterogeneous, which led to the identification of 3-subenvironments: marsh, bay and central basin (Edegbai, et al., 2019b) in order of proximality.

MATERIALS AND METHODS

Kerogen analysis: Kerogen slides were prepared for 74 (7 composite) samples (Fig. 2) following standard procedures (Traverse, 2007). Subsequently thereafter, palynofacies characterization, which involved identification of the kerogen constituents, grouping of palynological organic matter (using a simple scheme that comprises of aquatic amorphous organic matter, phytoclast, and palynomorph) and point counting a minimum of 300 constituents before normalizing to 100%.

Total organic carbon, Total nitrogen, and stable organic carbon isotope measurements: Seventy-four samples were analyzed for total organic carbon (TOC), and total nitrogen (N_t) at the Stable Isotope Mass Spectrometry Laboratory, University of Florida (UF), USA, as well as at the Organic and Isotope Geochemistry Departmental Laboratory at Kiel University (CAU), Germany (Fig 3). For quality assurance a few samples were measured in both laboratories to check for data consistency (see Table 2). In addition, 50 samples were selected for stable organic carbon isotope ($\delta^{13}C_{org}$) measurements at UF (Table 2). The experimental procedures employed both laboratories are detailed in Edegbai et al. (2020).

RESULTS AND DISCUSSION

A summary of the results of palynofacies and geochemical analyses is presented in Table 3.

Organic richness: The TOC vary from 0.24 to 2.96%, with the mean TOC for the central basin, bay and marsh sub-environments are 1.09 %, 1.39 % and 1.21 %, respectively (n = 27, 23, and 27, respectively). The organic richness is more variable in the bay sub-environment (SD = 0.91%), than in the marsh (SD = 0.34%) and central basin sub-environment (SD = 0.27%), which is a reflection of the interplay of productivity and preservation consequent upon relative sea level fluctuations. The organic richness of the samples varies from poor to very good (Peters and Cassa, 1994). On the average, all samples from three sub-environments have good organic richness, whereas only 11 % of all the samples possess very good organic richness (predominantly in the bay sub-environment). The TOC reported is commonplace with realms where significant clastic dilution is prevalent (Tyson, 1995).

Kerogen Quality: The phytoclast group is the most dominant organic matter group with relative abundances varying from 37.22% to 100% (Table 3). The mean phytoclast proportion for the central basin, bay and marsh sub-environments are 60.86% (n = 21; SD =14.95), 93.42% (n = 22; SD = 6.88) and 88.59% (n = 27; SD = 4.94), respectively. The mean palynomorph relative abundances for the central basin, bay and marsh sub-environments are 34.29% (n = 21; SD =16.20), 6.27% (n = 22; SD = 6.77) and 10.13% (n = 27; SD = 4.81), respectively. Finally, the mean aquatic amorphous organic matter percentages for the central basin, bay and marsh sub-environments are 4.85 % (n = 21; SD = 4.60), 0.08% (n = 22; SD = 0.19) and 1.28% (n = 27; SD = 0.95), respectively. There is lateral variability in relative abundance of particulate organic matter, with the central basin recording the greatest variability. The Nt values are very low, ranging from 0.03 (at low TOC) to 0.1% (Table 2).

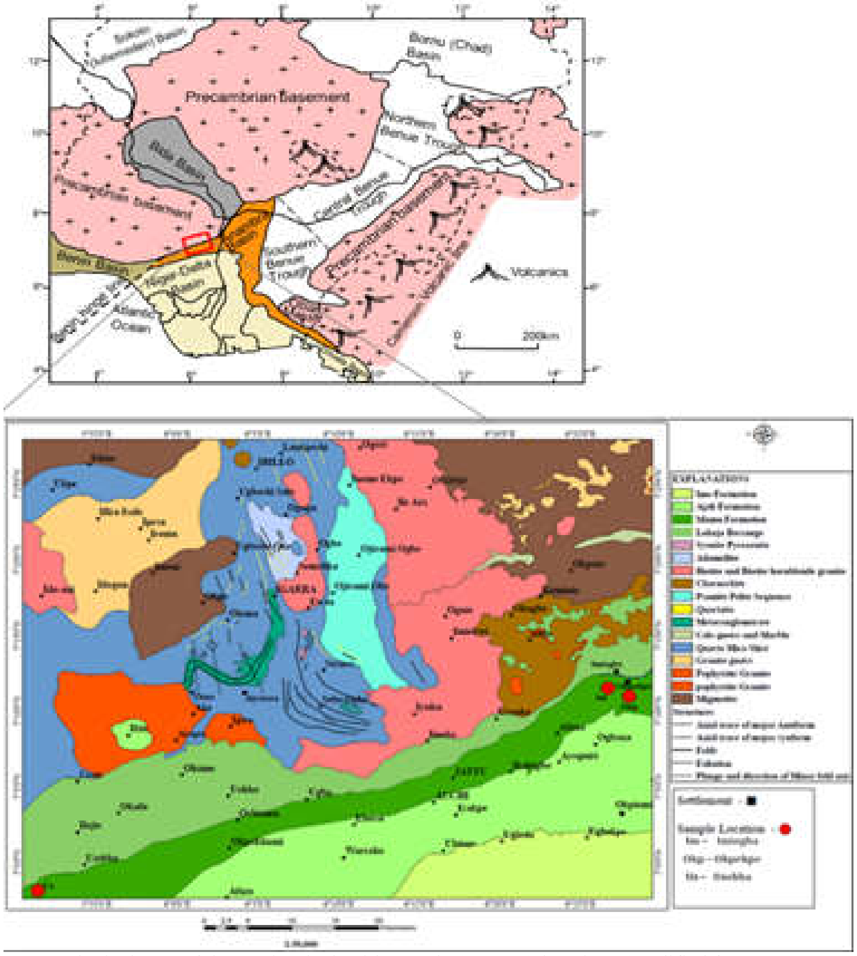
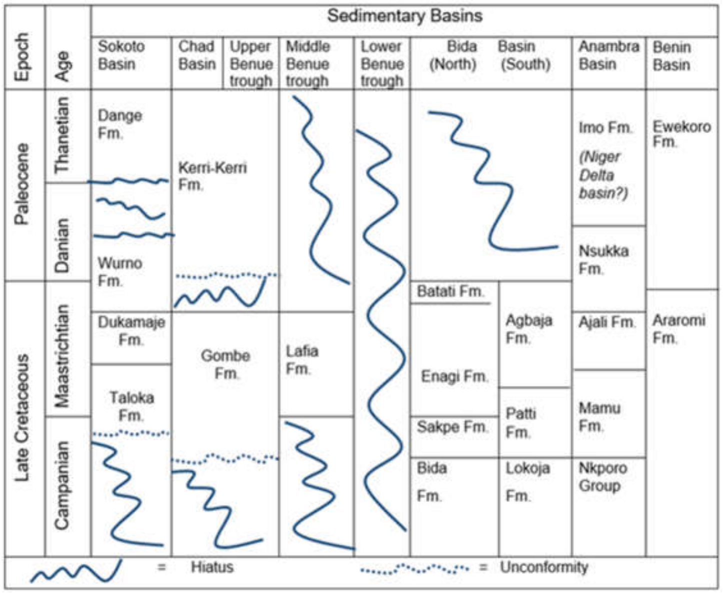


Fig. 1. Geological map of the Benin Flank with sample (outcrop) locations (modified from NGSA, 2006)

Table 1. *Summary of Late Cretaceous to Paleocene stratigraphy of Nigerian basins*



Epoch	Age	Sokoto Basin	Chad Basin	Upper Benue trough	Middle Benue trough	Lower Benue trough	Bida (North)	Basin (South)	Anambra Basin	Benin Basin
Paleocene	Thanetian	Dange Fm.	Kerri-Kerri Fm.						Imo Fm. *(Niger Delta basin?)*	Ewekoro Fm.
	Danian	Wurno Fm.							Nsukka Fm.	
Late Cretaceous	Maastrichtian	Dukamaje Fm. Taloka Fm.	Gombe Fm.		Lafia Fm.		Batati Fm. Enagi Fm.	Agbaja Fm.	Ajali Fm. Mamu Fm.	Araromi Fm.
	Campanian						Sakpe Fm. Bida Fm.	Patti Fm. Lokoja Fm.	Nkporo Group	

= Hiatus = Unconformity

The mean Nt for the central basin, bay and marsh sub-environments are 0.06% (n = 26; SD = 0.02), 0.07% (n = 23; SD = 0.02) and 0.06% (n = 24; SD=0.01), respectively. The central basin, bay and marsh sub-environment have mean TOC/ Nt values of 18.44, 19.06 and 21.04, respectively (Table 2). The variability around mean TOC/ Nt values is greatest in the marsh and bay sub-environments (SD = 9.59 and 7.60 respectively) and lowest in the central basin sub-environment (SD = 6.22). The δ^{13}Corg values of the samples vary in the range of -23.85 0/00 (central basin mudstone) to -27.87 0/00 (bay mudstone) (Table 3). Mean δ^{13}Corg are -25.75 0/00 (n = 15, SD = 0.61), -25.97 0/00 (n = 16, SD = 0.95) and -26.48 (n = 19, SD = 0.24) for the central basin, bay and marsh mudstones, respectively.

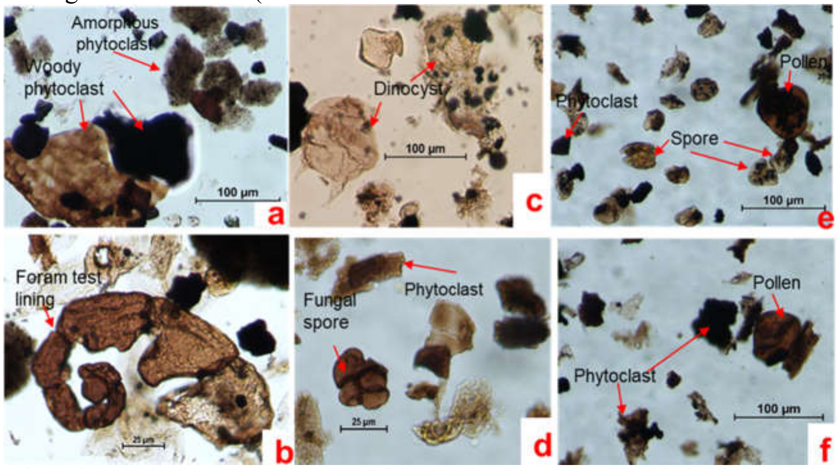


Fig. 2. Photomicrographs showing various types of dispersed organic matter identified (Edegbai et al., 2019b)

Visual kerogen analysis by means of the relative percentages of aquatic amorphous organic matter, phytoclasts and palynomorphs (APP) reveal two palynofacies groups: PF-A and PF-B. The PF-A is defined by a high proportion of phytoclasts predominating over the other organic matter groups, whereas PF-B, is defined by moderate relative abundance of phytoclasts, and palynomorphs, as well as a low percentage of aquatic amorphous organic matter (Figs. 4-5). We deduct that the PF-A group is congruent with the organic facies C and CD (Jones *in* Tyson, 1995) with gas prone type III kerogen, which is unique to regions proximal to fluvial sources (marsh and bay) (Gonçalves et al., 2015).

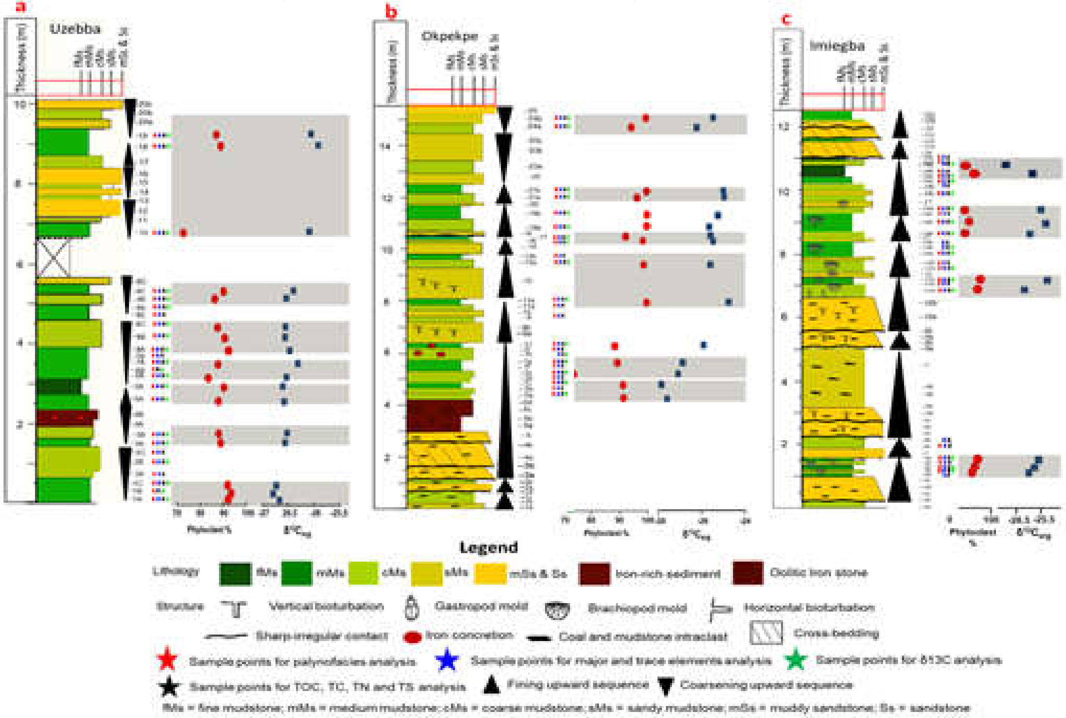


Fig. 3. Graphic logs of the measured sections with sample points. Note the heavier $\delta^{13}C_{org}$ values corresponding with high phytoclast abundance (adapted from Edegbai et al., 2020).

Table 2. Raw data used for quality checks

x = data from University of Florida; y = data from Kiel UniversityS/N	N_t (wt. %)	TOC (wt. %)	S/N	N_t (wt. %)	TOC (wt. %)
U1-5B (x)	0.07	1.27	Im-2E (x)	0.06	1.09
(y)	0.08	1.14	(y)	0.04	0.45
Mean	*0.08*	*1.21*	*Mean*	*0.05*	*0.77*
SD	*0.01*	*0.09*	*SD*	*0.01*	*0.45*
U1-6B (x)	0.07	1.04	IM 2B (x)	0.06	1.09
(y)	0.08	1.29	(y)	-	0.92
Mean	*0.08*	*1.17*	*Mean*		*1.01*
SD	*0.01*	*0.18*	*SD*		*0.12*
U1-8B (x)	0.07	1.24	OK 7E (x)	0.08	2.82
(y)	0.06	1.15	(y)	0.11	3.10
Mean	*0.07*	*1.20*	*Mean*	*0.10*	*2.96*
SD	*0.01*	*0.06*	*SD*	*0.02*	*0.20*
U1-10 (x)	0.07	2.12	OK 11B (x)	0.05	0.42
(y)	0.04	2.56	(y)	-	0.43
Mean	*0.06*	*2.34*	*Mean*		*0.43*
SD	*0.02*	*0.31*	*SD*		*0.01*

Whereas, PF-B group is congruent with the organic facies BC and C (Jones *in* Tyson, 1995) with gas and oil prone type II/III kerogen, which is characteristic of realms remote from fluvial sources (central basin sub-environment). In addition, clastic dilution is supported by the low $N_{t,,}$ Good positive covariation observed in the TOC *vs.* N_t binary plot, as well as the clustering of bulk of the data around the TOC/ $N_t \geq 20$ line, which indicate the dominance of land derived biomass (Meyers, 1994) (Fig 6). In Cretaceous strata it has been shown that there is an enrichment of $\delta^{13}C_{org}$ in land derived biomass over marine biomass, which is attributable to C-isotopic fractionation (Arthur et al., 1985). $\delta^{13}C_{org}$ data ranges of -29 to -27 and -25 to -24 have been reported for marine and land derived biomass respectively (Arthur et al., 1985). The $\delta^{13}C_{org}$ data (Table 3) show the dominance of terrestrial biomass, which is congruent with the findings of Faboya et al (2019) on the eastern segment, as well as bulk geochemistry, palynofacies data as well as hydrogen index data generated in preliminary studies (Edegbai and Emofurieta, 2015).

Table 3A. Summary of data from palynofacies and geochemical analyses (composite samples are indicated with thick borders)

Sample No.	Lithofacies	Palynofacies data (%)			Geochemistry data			
		Phytoclasts	Palynomorphs	AOM	TOC	Nt	TOC/ Nt	$\delta^{13}C_{org}$ (permil, vs VPDB)
U1 IA	L1 Marsh	92.31	5.71	1.99	1.35	0.06	22.5	-26.69
U1 1B		92.74	6.05	1.21	1.33	0.06	22.17	-26.79
U1 1C		91.22	7.43	1.35	1.19	0.05	23.8	-26.71
U1 2A		83.66	15.18	1.17	1.22	0.07	18.27	-
U1 2B		86.11	13.54	0.35	0.99	0.05	19.8	-26.73
U1 2C		82.49	16.50	1.01	1.17	0.06	18.90	-
U1 3A		88.93	10.42	0.65	1.24	0.06	20.67	-26.53
U1 3B		88.20	11.15	0.66	1.2	0.06	20	-26.51
U1 5A		88.49	10.20	1.32	1.78	0.08	22.25	-26.56
U1 5B		90.29	9.06	0.65	1.20	0.07	16.20	-26.59
U1 6A		83.62	15.87	0.48	1.09	0.06	18.17	-26.54
U1 6B		83.62	15.87	0.48	1.04	0.08	13.59	-26.46
U1 7A		87.83	9.54	2.63	1.12	0.06	18.67	-26.32
U1 7B		87.83	9.54	2.63	1.03	0.06	18.29	-
U1 8A		92.05	5.96	1.99	1.16	0.06	19.33	-26.49
U1 8B		90.61	8.74	0.65	1.20	0.06	19.05	-26.67
U1 8C		90.61	8.74	0.65	0.97	0.05	19.4	-26.57
U1 8D		89.91	8.83	1.26	1.07	0.06	17.68	-
U1 9A		89.91	8.83	1.26	1.2	0.06	20	-26.55
U1 9B		86.58	11.82	1.60	1.09	0.06	18.17	-26.52
U1 9C		90.23	7.82	1.95	0.8	0.06	13.33	-26.39
U1 10		72.36	25.47	2.17	2.55	0.04	64.58	-26.08
U1 18		89.61	7.47	2.92	0.98	0.05	19.6	-25.89
U1 19		87.54	8.85	3.61	1.23	0.06	20.5	-26.05

In addition, an increase in the proportion of phytoclast is directly proportional to enrichment of $\delta^{13}C_{org}$ (Fig. 3), which underscores the influence of relative sea level flux and organic facies development.

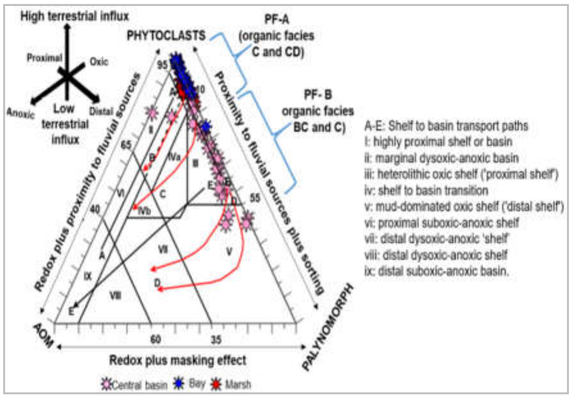


Fig. 4. APP plot showing different palynofacies groups (Edegbai et al., 2020)

Thermal maturity: Maturity assessment based on spore colour index chart was employed. Our findings show that the colour of the spores recovered from all 3-subenvironments is less than 6.0 on the SCI chart (Pearson, 1984). This is equivalent to a thermal alteration index (TAI) of <2.5, indicating a thermally immature kerogen. This concurs with thermal maturity estimates from SCI and Tmax data obtained from our preliminary studies (Edegbai and Emofurieta, 2015), as well as from other studies (Olatinpo et al., 2016; Ogbamikhumi et al., 2017, Maju-Oyovwikowhe and Malomi, 2019; Faboya et al., 2019).

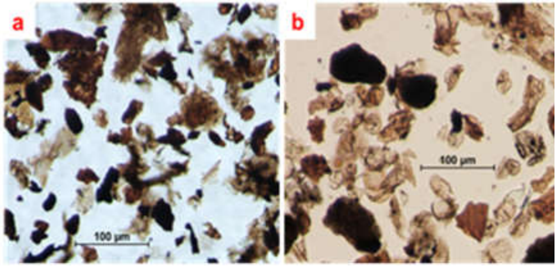


Fig. 5.a, PF-A palynofacies group (Organic facies C and CD) characteristic of the marsh and bay sub-environments. b, PF-B group (organic facies BC and C) characteristic of the central basin sub-environment

Shale gas potential: Following guidelines for geological characterization of shale gas plays (Bouhlel et al., 2012), we can assess the shale gas potential of the dark mudstone lithofacies. The organic richness, which is mostly < 2 wt.% fall short of 2 wt.% which is the preferred minimum for shale gas plays (Troudi *et al.,* 2012). Based on insight from kerogen quality and thermal maturity assessment observed in this study, we infer a biogenic gas potential for the dark mudstone lihofacies. In addition, the gentle dip and shallow burial as well as the silica content > 30% of large proportion of the dark mudstone lithofacies (especially the marsh sub environment) are desirable attributes for shale plays (Burns *et al.,* 2012).

Table 3B. Summary of data from palynofacies and geochemical analyses (composite samples are indicated with thick borders)

Sample No.	Lithofacies		Palynofacies data (%)			Geochemistry data			
			Phytoclasts	Palynomorphs	AOM	TOC	Nt	TOC/Nt	$\delta^{13}C_{org}$ (permil, vs VPDB)
IM 2B	L1	Central Basin	58.61	38.74	2.65	1.01	0.06	16.76	-25.97
1M 2C			62.87	34.53	2.61	0.93	0.06	15.5	-25.82
1M 2D			54.85	41.21	3.94	1.02	-	-	-
1M 2E			71.33	25.33	3.33	1.09	0.05	21.34	-25.62
IM 4A			83.17	15.18	1.65	1.51	0.03	43.95	-
IM 11A			67.65	31.05	1.31	1.17	0.06	19.5	-26.17
IM 11B			50.50	46.18	3.32	1.40	0.07	19.39	-
IM 11C			73.63	23.47	2.89	0.94	0.06	15.67	-25.50
IM 13A			75.49	19.61	4.90	1.21	0.07	17.29	-25.74
1M 13B			80.39	17.32	2.29	1.28	0.08	16.08	-
IM 14A			58.50	37.91	3.59	1.22	0.06	20.33	-25.37
IM 16A			39.76	60.24	0.0	1.18	0.04	29.12	-26.01
IM 16B			48.46	45.06	6.48	1.51	0.09	16.78	-25.60
1M 16C			40.69	51.74	7.57	1.34	0.10	13.18	-
1M 16D			37.22	52.37	10.41	1.1	0.07	15.71	-25.75
IM 18A			79.55	0.65	19.81	0.32	0.03	10.67	-23.85
IM 18C			66.34	30.39	3.27	0.61	0.04	15.25	-26.14
IM 19A			62.46	36.57	0.97	0.83	0.06	13.83	-25.84
IM 19B			37.46	60.59	1.95	0.8	0.05	16	-26.48
IM 19D			50.83	42.57	6.60	1.03	0.07	14.89	-
IM 19E			78.25	9.42	12.34	1.15	0.06	17.99	-
IM 2A			-	-	-	1.10	0.05	21.06	-
IM 4B			-	-	-	0.83	0.04	18.79	-
IM 14B			-	-	-	1.14	0.07	16.29	-26.41
IM 14C			-	-	-	1.25	0.08	16.59	-

IM 18B			-	-	-	1.10	0.06	18.87	-
IM 19C			-	-	-	1.40	0.07	18.82	-
OK 7A	L1	Bay	90.72	9.28	0.0	2.52	0.09	28.0	-27.59
OK 7B			90.72	9.28	0.0	0.95	0.06	16.58	-
OK 7C			90.86	6.58	0.0	2.35	0.09	26.11	-27.87
OK 7D			90.86	6.58	0.0	2.86	0.12	24.02	-
OK 7E			71.38	28.44	0.19	2.96	0.10	30.90	-27.14
OK 7F			85.11	14.89	0.0	2.19	0.09	25.26	-
OK 7G			88.34	11.66	0.0	2.48	0.09	27.56	-26.77
OK 7H			-	-	-	2.59	0.09	28.78	-26.35
OK 7I			88.40	11.11	0.49	1.78	0.07	24.51	-
OK 7J			88.40	11.11	0.49	1.82	0.07	26.0	-25.92
OK 9			96.79	3.21	0.0	0.24	0.05	4.76	-
OK 11A			99.39	0.61	0.0	0.70	0.07	9.72	-
OK 11B			99.77	0.23	0.0	0.42	0.05	8.50	-24.73
OK 13A			98.86	1.14	0.0	0.92	0.05	17.32	-25.57
OK 13B			98.66	1.34	0.0	1.30	0.08	15.85	-
OK 15			98.79	1.21	0.0	0.38	0.03	12.67	-25.47
OK 17			91.56	8.44	0.0	1.04	0.06	17.33	-25.51
OK 19A			99.36	0.64	0.0	1.16	0.06	19.33	-25.65
OK 19B			100.0	0.0	0.0	0.68	0.05	13.60	-25.17
OK 21A			93.79	6.21	0.0	0.27	0.03	9.0	-24.95
OK 21B			100.0	0.0	0.0	0.40	0.04	10.0	-25.01
OK 24A			94.12	5.29	0.59	1.37	0.06	22.83	-26.26
OK 24B			99.35	0.65	0.0	0.59	0.03	19.67	-25.48

Furthermore, due to its proximity to provenance and shallow depth the microfabric and degree of bioturbation (Edegbai *et al.,* 2020), the marsh sub-environment possesses better petrophysical properties in comparison to the bay and central basin sub-environments. In terms of thickness, the Uzebba and Imiegba locations (marsh and central basin sub-environments) have up to 6m of (continuous) outcropping thicknesses of the dark mudstone unit. We estimate the thickness at the Uzebba location to be up to 15 m inclusive of the subcrop thickness.

Conclusion: This multidisciplinary study has shown that the dark mudstone unit possess good organic richness, whose variability is affected by proximality to provenance as well as relative sea level changes. The dark mudstone unit possess thermally immature kerogen, whose quality is predominantly of gas prone Type III. Nonetheless, visual kerogen analysis indicates the presence of Type II/III kerogen with oil generation potential in the distal central basin sub-environment. The outcropping dark mudstone unit have potential for biogenic gas.

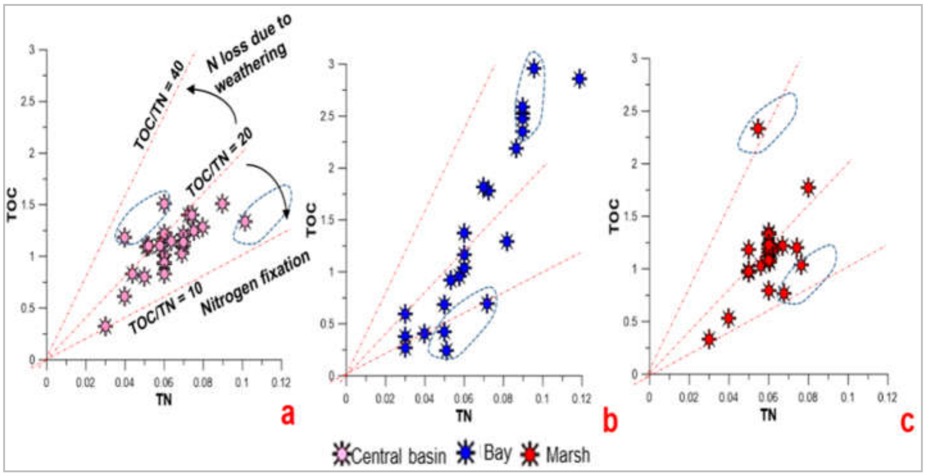


Fig. 6. TOC vs. Nt binary plots for dark mudstone subenvironments (adapted from Edegbai et al., 2020)

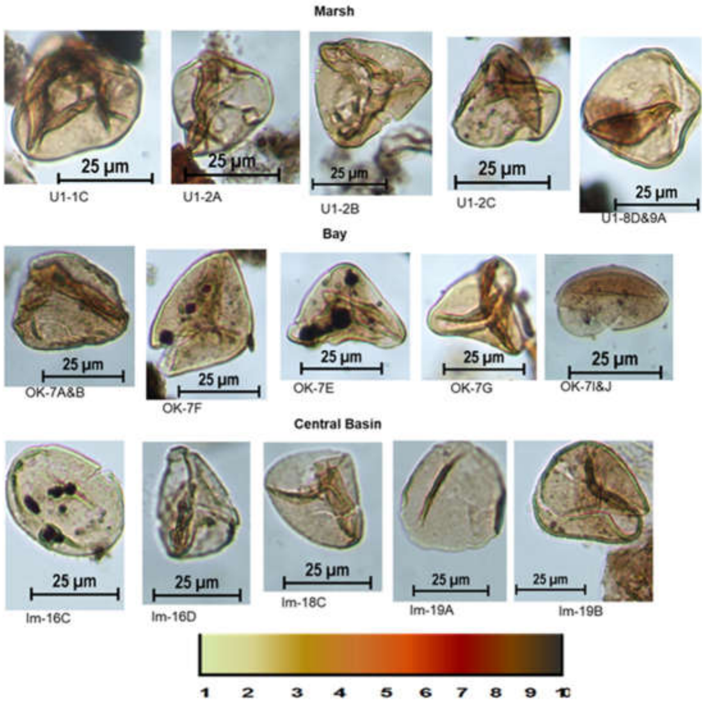


Fig. 7. Spores recovered from the dark mudstone samples. Spore colour index chart adapted from Pearson (1984)

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