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GEOLOGY

Petroleum Geochemical Assessment of Shale Samples from Well D, Southern Offshore Niger Delta Basin, Nigeria

Avaliação Geoquímica de Petróleo em Amostras de Folhelho do Poço D, Bacia do Delta do Níger Offshore Sul, Nigéria

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Abstract

This study evaluates the organic matter richness, hydrocarbon generative potential, and thermal maturity of sediments from Well D, located in the southern offshore Niger Delta Basin, using Total Organic Carbon (TOC) analysis, Rock-Eval pyrolysis, and kerogen classification. The TOC content of the analyzed samples ranges from 1.75 to 6.62 wt. %, with an average of 2.74 wt. %, indicating good to excellent source rock potential. S1 and S2 values, averaging 5.37 mg HC/g rock and 6.91 mg HC/g rock, respectively, further highlight the organic richness and hydrocarbon potential of these sediments. The S1/TOC ratio (average 1.97) suggests significant free oil presence and active hydrocarbon expulsion. Kerogen classification, based on a modified Van Krevelen diagram and Hydrogen Index (HI) versus Tmax plots, reveals predominantly Type II kerogen (oil-prone) with a minor mix of Type II/III (oil and gas-prone). Approximately 91% of the samples exhibit sufficient thermal maturity to generate hydrocarbons, while 9% remain immature. Genetic potential values ranging from 6.16 to 31.06 mg HC/g rock underscore the significant hydrocarbon potential of key intervals, especially those within the optimal oil window. The findings confirm that Well D sediments possess substantial potential for hydrocarbon generation, driven by favorable TOC levels, kerogen quality, and thermal maturity. These results align with previous studies of Niger Delta source rocks, providing valuable insights for future exploration and development in the region.

Keywords: Hydrocarbon generative potential; Thermal maturity; Kerogen classification

Resumo

Este estudo avalia a riqueza em matéria orgânica, o potencial gerador de hidrocarbonetos e a maturidade térmica de sedimentos do Poço D, localizado na porção offshore sul da Bacia do Delta do Níger, utilizando análise de Carbono Orgânico Total (COT), pirólise Rock-Eval e classificação de querogênio. O teor de COT das amostras analisadas varia de 1,75 a 6,62% em peso, com média de 2,74% em peso, indicando potencial de rocha geradora de bom a excelente. Os valores de S1 e S2, com médias de 5,37 mg HC/g rocha e 6,91 mg HC/g rocha, respectivamente, reforçam a riqueza orgânica e o potencial de hidrocarbonetos desses sedimentos. A relação S1/COT (média de 1,97) sugere presença significativa de óleo livre e expulsão ativa de hidrocarbonetos. A classificação do querogênio, baseada em um diagrama de Van Krevelen modificado e gráficos de Índice de Hidrogênio (IH) versus Tmax, revela predominantemente querogênio Tipo II (gerador de petróleo) com uma pequena mistura de Tipo II/III (gerador de petróleo e gás). Aproximadamente 91% das amostras exibem maturidade térmica suficiente para gerar hidrocarbonetos, enquanto 9% permanecem imaturas. Valores de potencial genético variando de 6,16 a 31,06 mg HC/g rocha destacam o significativo potencial de hidrocarbonetos de intervalos-chave, especialmente aqueles dentro da janela ótima de geração de petróleo. Os resultados confirmam que os sedimentos do Poço D possuem potencial substancial para geração de hidrocarbonetos, impulsionado por níveis favoráveis de COT, qualidade do querogênio e maturidade térmica. Essas conclusões estão alinhadas com estudos anteriores de rochas geradoras do Delta do Níger, fornecendo insights valiosos para futuras explorações e desenvolvimentos na região.

Palavras-chave: Potencial gerador de hidrocarbonetos; Maturidade térmica; Classificação de querogênio

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1 Introduction

The integration of petroleum geochemistry with geological and geophysical methods is crucial for reducing uncertainties in the elements and processes of petroleum systems, thereby improving exploration success (Sluijk & Parker 1986). Geochemical data serve as the foundation for evaluating source rock hydrocarbon potential and reconstructing the geohistory of the basin under investigation (Dembicki 2017; Hunt 1996; Tissot & Welte 1984).

The Niger Delta Basin, renowned for its substantial petroleum reserves, ranks among the world's premier hydrocarbon provinces (BP 2014; Tuttle *et al.* 1999; OPEC 2016). The basin's stratigraphy is composed of three major lithostratigraphic units: the Paleocene Akata Formation, the Eocene Agbada Formation, and the Oligocene Benin Formation. These formations represent a progressive depositional regression into the basin, characteristic of the delta's evolving clastic wedge (Doust & Omatsola 1990; Shannon & Naylor 1989). While there has been considerable debate regarding the primary source of hydrocarbons in the Niger Delta, many studies emphasize the role of the Akata Formation, composed predominantly of marine shales, as the principal source rock, enriched with organic material derived from terrestrial plants and characterized by Type III/II and III kerogen (Akaegbobi 2000; Akinlua & Torto 2010; Bustin 1988; Ekweozor & Okoye 1980; Nwachukwu & Chukwura 1986). Other studies also point to the Agbada Formation's shale interbeds within its sandy facies as contributors to hydrocarbon generation (Ekweozor & Daukoru 1984; Short & Stauble 1967; Weber & Daukoru 1975).

Despite extensive research on source rock potential in the Niger Delta Basin, most studies have focused on the northern and central regions (Akinlua *et al.* 2007; Akinlua & Ajayi 2009; Ekweozor & Daukoru 1984). In contrast, the southern part of the basin, particularly the area surrounding Well D, remains underexplored (Atoyebi *et al.* 2017; Akinlua *et al.* 2020). This lack of focus has created a gap in understanding the geochemical characteristics and hydrocarbon generation potential of source rocks in the southern basin. Since organic matter supply, preservation conditions, and thermal maturity can vary significantly across different sections of a basin due to changes in depositional environments, sedimentation rates, and geochemical conditions (Fadiya *et al.* 2020; Madhavaraju & Lee 2009; Nagarajan *et al.* 2007; Sabuni *et al.* 2022), it is essential to assess the source rock potential in this less-explored area to develop a comprehensive understanding of the basin's petroleum system.

This study seeks to fill these knowledge gaps by evaluating the hydrocarbon generation potential of sediments from Well D in the southern offshore Niger Delta Basin. The assessment will focus on the quantity and quality of organic material, including Total Organic Carbon (TOC) content, and the thermal maturity of the source rocks. By analyzing these factors, the study will provide insights into the hydrocarbon potential of the southern basin, contributing to a more complete understanding of source rock variability across the Niger Delta Basin. The findings will also inform future exploration strategies in the southern regions of the delta and offer valuable information regarding the geochemical processes influencing hydrocarbon generation in this part of the basin.

1.1 Location of Study Area

The Niger Delta is situated on the western coast of Africa, between latitudes 3°50′N and 6°50′N, and longitudes 3°25′E and 8°50′E (Figure 1). Well D, part of the study area, is located mainly in the southern offshore region of the Delta (Doust & Omatsola 1990). The Niger Delta is the delta of the Niger River, directly on the Gulf of Guinea along the Atlantic Ocean in Nigeria. It is commonly recognized to cover nine coastal states in southern Nigeria, including all six states from the South-South geopolitical zone, one state (Ondo) from the South-West geopolitical zone, and two states (Abia and Imo) from the South-East geopolitical zone (Maloney *et al.* 2010). The Tertiary Niger Delta spans approximately 211,000 km² and extends westward from the Anambra Basin and the Benue Trough (Tuttle *et al.* 1999). It is bordered by the West African Shield to the north, the Oban Massif to the east, and the Tertiary Cameroon Volcanic Line to the southeast (Agyingi *et al.* 2012).

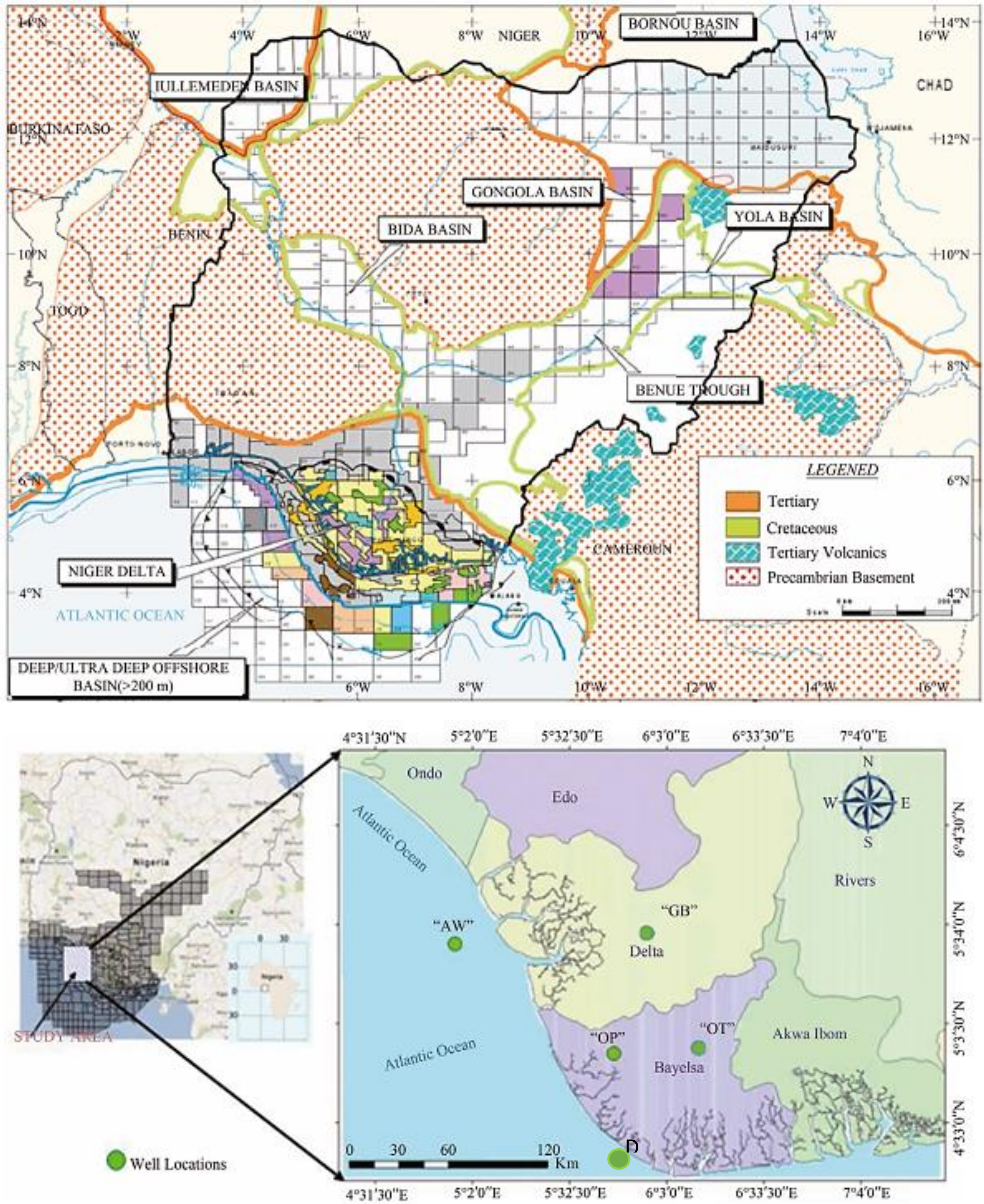

Figure 1 A. Simplified geology of the Niger Delta and other sedimentary basins in Nigeria (Modified after Aizebeokhai 2012; Ebong *et al.* 2019); B. Location map showing well D.

2 The Regional Geologic Setting and Stratigraphy of Niger Delta Basin

2.1 Regional Geologic Setting

The regional geological setting of the Niger Delta Basin has been thoroughly studied by various researchers over the years (Acha 2021; Doust & Omatsola 1990; Evamy *et al.* 1978; Short & Stauble 1967; Weber & Daukoru 1975). Amafulde (1988) and Tuttle *et al.* (1999) define the offshore boundaries of the basin, with the Cameroon Volcanic Line to the east, the Dahomey Basin's eastern limit to the west, and either the 2 km sediment thickness contour or the 4000 m bathymetric contour to the south and southwest (Figure 2). The province, covering 300,000 km², encompasses the geological extent of the Tertiary Niger Delta (Akata-Agbada) Petroleum System (Figure 2). Positioned in the Gulf of Guinea, the Niger Delta spans the region known as the Niger Delta Province, as defined by Klett *et al.* (1997).

Since the Eocene, the delta has prograded southwestward, creating dip belts that mark the delta's most active regions during various stages of its development (Figure 3). These dip belts together form one of the largest regressive deltas in the world, covering roughly 300,000 km², with a sediment volume of 500,000 km³ and sediment thickness exceeding 10 km in the basin's depocenter. The formation of the Niger Delta Basin began in the early to mid-Cretaceous period, coinciding with the separation of the African and South American continents (Figure 4). Delta growth progressed through several phases, leading to the deposition of three main formations within the offlapping siliciclastic sedimentation cycles that characterize the basin. Subsidence and sediment supply rates influenced the deposition of distinct dip belts that shifted seaward as subsidence continued. These dip belts exhibit syn-sedimentary faulting due to variations in subsidence and sediment deposition rates.

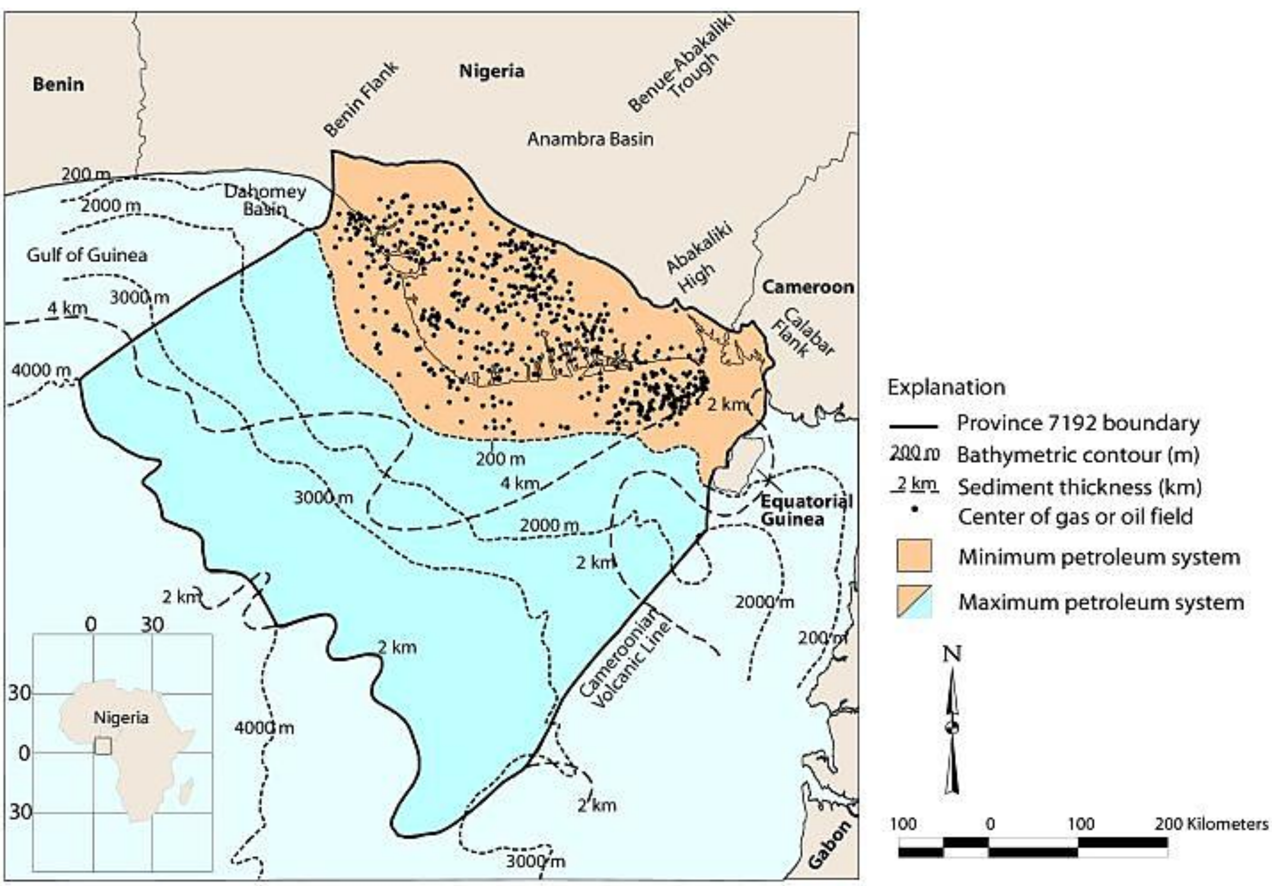

Figure 2 Index map of Niger Delta showing province outline (maximum petroleum system). Bounding structural features; minimum petroleum system as defined by oil and gas field center points (Short & Staluble 1967; Weber & Daukoru 1975).

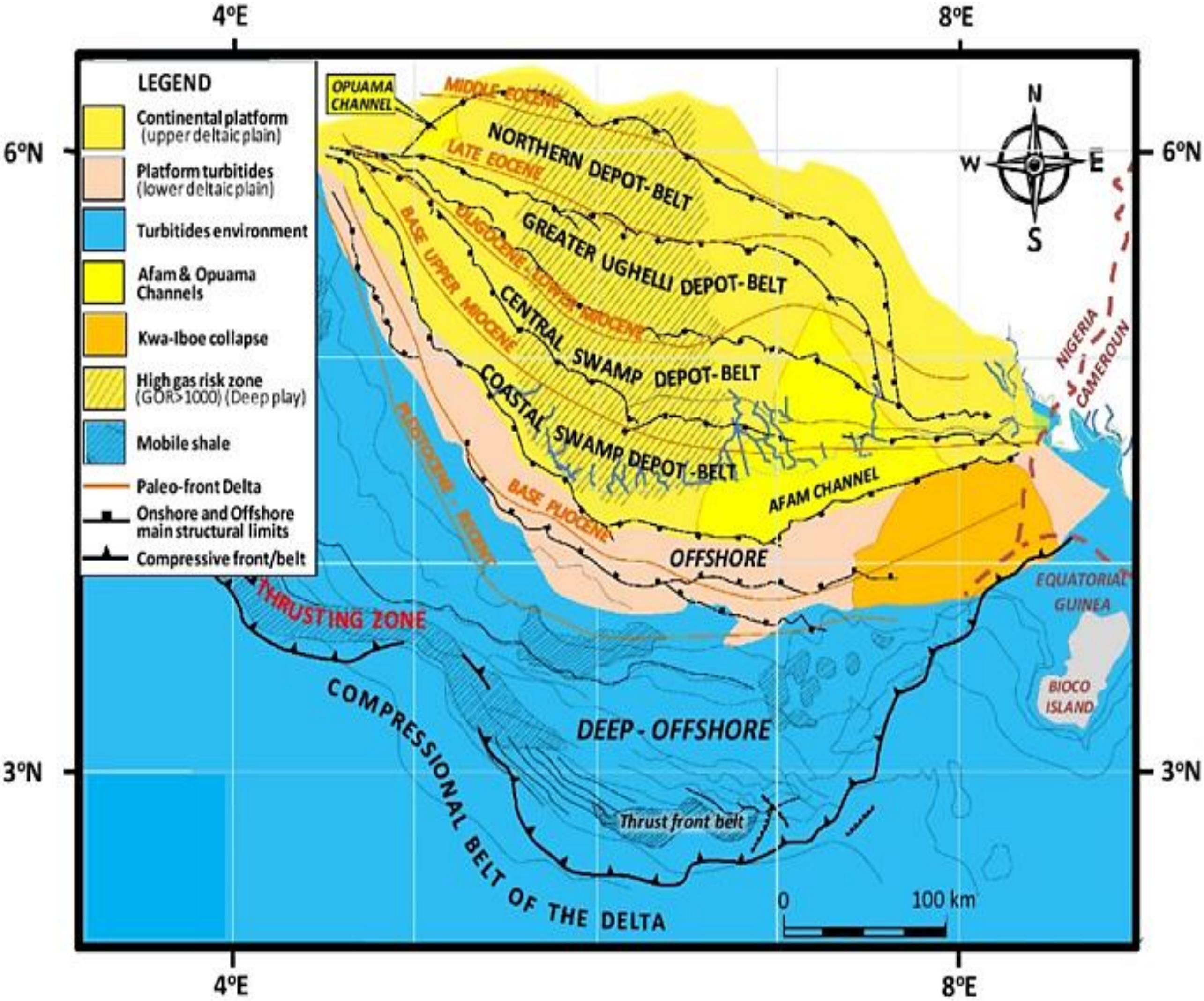

Figure 3 Map of Niger Delta showing depobelts (after Ebong *et al.* 2019).

Doust and Omatsola (1990) divided the basin into three structural provinces: the Northern Delta Province, the Central Delta Province, and the Distal Delta Province. Each of these provinces displays distinct structural characteristics associated with gravity tectonics and depositional patterns (Figure 4). The Niger Delta's clastic wedge was formed along a failed arm of a rift system during the Jurassic breakup of the South American and African plates. Sediment deposition occurred throughout the Cretaceous to Tertiary periods, characterized by alternating transgressive and regressive phases. The delta's morphology and evolution have been shaped by tectonic activity, sedimentation rates, and sea-level fluctuations over time. Its geological history is preserved in its stratigraphy, fault systems, and structural complexities, which have been the subject of extensive research.

2.2 Stratigraphy of Niger Delta Basin

The stratigraphic framework of the Tertiary Niger Delta and its underlying Cretaceous sequences, as described by Short and Stauble (1967), reveals a complex evolutionary process driven by regressive depositional forces across the basin. In the subsurface, the Niger Delta features three primary lithostratigraphic units—Akata, Agbada, and Benin Formations—that become progressively younger toward the basin, reflecting a progradational clastic wedge as depositional environments migrated seaward (Figure 5). This stratigraphy shows a coarsening-upward pattern, indicative of the transition between marine, deltaic, and fluvial depositional settings (Weber & Daukoru 1975; Weber 1986).

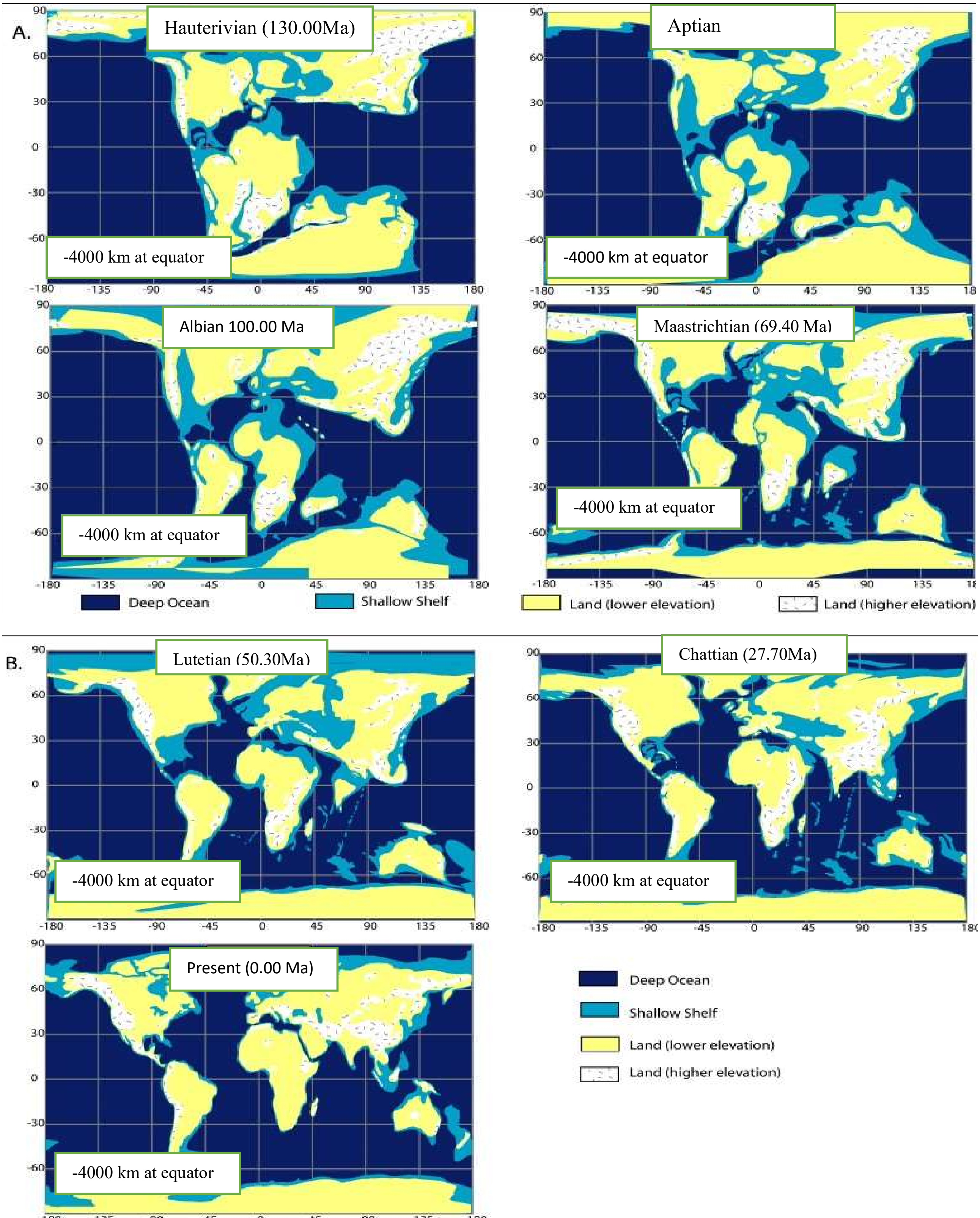

Figure 4 Paleogeography showing the opening of the South Atlantic, and development of the region around Niger Delta: A. Cretaceous (130.0-69.4ma) paleogeography; B. Cenozoic (50.3ma to present) paleogeography (Tuttle et al. 1999).

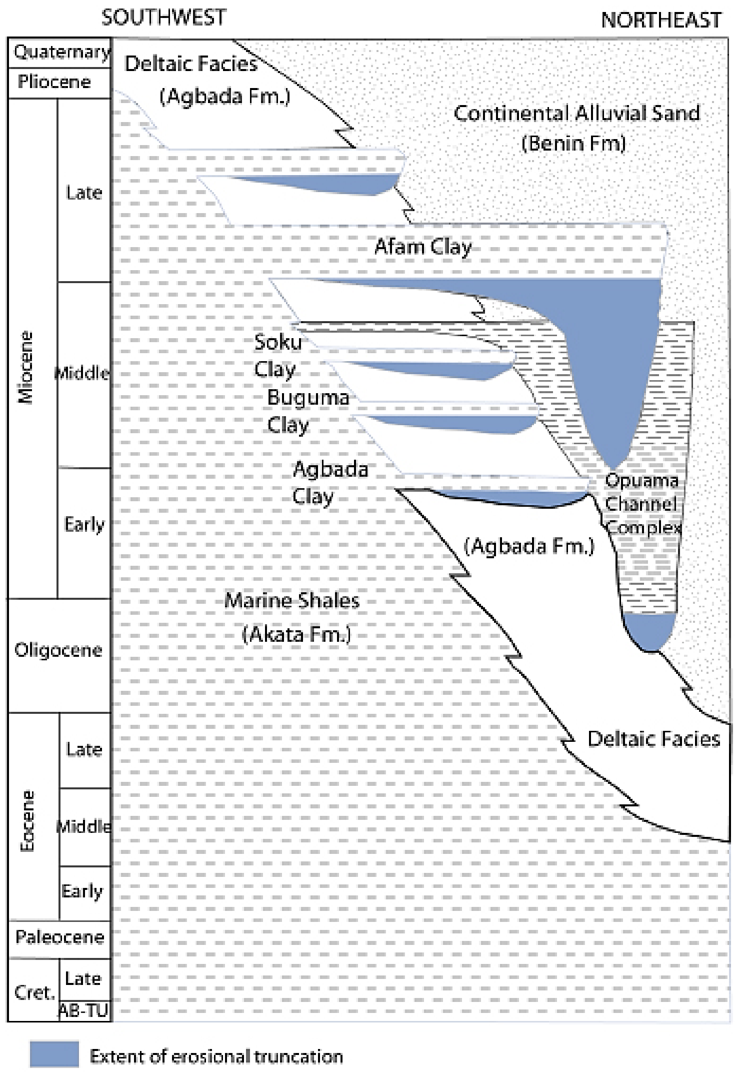

Figure 5 Stratigraphic column showing the three formations of the Niger Delta. Adapted from Shannon and Naylor (1989) and Doust and Omatsola (1990).

At the base, the Akata Formation consists of marine-deposited shales, which are considered the primary source rocks for hydrocarbons, along with turbidite sands that offer potential deepwater reservoir targets. Occasional interbeds of clay and silt are also present. This formation spans the Paleocene to the Holocene, representing the deep marine sedimentary environments that characterized the early development of the basin. Overlying the Akata is the Agbada Formation, which is the main hydrocarbon-bearing unit. It comprises paralic siliciclastic deposits that record deltaic sedimentation from the Eocene to the Pleistocene. This formation's complex siliciclastic sequence reflects the intricate depositional environment of a delta system advancing over time. The uppermost Benin Formation, a non-marine unit dating from the Oligocene to Recent, consists of fluvial gravels and sands deposited in the upper delta plain. Due to its terrestrial nature, the Benin Formation contains limited hydrocarbon potential.

These formations were deposited in cyclical, off-lapping siliciclastic sequences, strongly influenced by syndepositional faulting caused by fluctuations in subsidence rates and variations in sediment supply. The interaction between tectonic forces and sedimentary processes during deposition contributed to the stratigraphic and structural configuration of the delta, as highlighted by Short and Stauble (1967), Weber and Daukoru (1975), and subsequent researchers such as Acha (2021), Avbovbo (1978), Burke *et al.* (1972), Doust and Omatsola (1990), Omoboriowo *et al.* (2012), Reyment (1965), Stacher (1995), Weber (1986) and Whiteman (1982). This dynamic relationship between depositional patterns and tectonic controls has played a crucial role in shaping the hydrocarbon potential of the Niger Delta, resulting in a highly complex yet productive petroleum system.

3 Methods

The analysis for this study adhered to the methodologies outlined by Espitalié *et al.* (1977), Peters (1986), and Tissot and Welte (1984). The calculation of parameters such as the Oxygen Index (OI), Hydrogen Index (HI), and Production Index (PI), as well as their interpretations, followed guidelines established by Espitalié *et al.* (1977), Tissot and Welte (1984), and Vandenbroucke and Largeau (2007).

Forty shale ditch cuttings from Well D, located in the southern offshore Niger Delta Basin, Nigeria, were carefully selected for geochemical analysis. These samples were retrieved from depths ranging between 2650 m to 3645 m. To prepare them for analysis, the samples were air-dried and then pulverized to achieve uniform consistency. A solution of dichloromethane and methanol was applied to the samples, followed by a rinse with distilled water to eliminate any potential contaminants, thereby preserving the samples' organic integrity for accurate geochemical assessment. The processed samples were properly labeled and stored in secure bags for laboratory analysis.

Rock-Eval pyrolysis and Total Organic Carbon (TOC) analysis, well-established techniques in organic geochemistry (Espitalié *et al.* 1977), were used to evaluate the organic matter of each sample. During the pyrolysis process, key parameters were recorded, including S1 (free hydrocarbons), S2 (remaining hydrocarbon-generating potential), S3 (CO_2 yield), and T_{max} (the temperature at which S2 reaches its maximum yield). Additionally, the Hydrogen Index (HI) was calculated as (S2/TOC) × 100 (mg HC/g TOC), and the Oxygen Index (OI) as (S3/TOC) × 100 (mg CO_2/g TOC). The potential yield (PY) or generation potential of hydrocarbons is quantified as the sum of S1 and S2 (mg HC/g rock). The hydrocarbon type index, S2/S3, is calculated to identify the nature of hydrocarbons (oil or gas-prone) within the rock sample. These metrics are critical in evaluating the hydrocarbon-generating capability and type of source rocks. These geochemical indices provided a detailed evaluation of the organic matter content, thermal maturity, and hydrocarbon generation potential of the shale samples, offering crucial insights into the petroleum potential of the studied interval.

4 Results

The results of the Total organic carbon (TOC) and Rock–Eval pyrolysis of the sediments retrieved from well D are presented in Table 1.

4.1 Total Organic Carbon (TOC) and Pyrolysis Parameter Results

The TOC values of the studied samples in well "D" varied between 1.75 and 6.62 Wt. % with an average value of 2.74 Wt. % (Table 1). The ditch cuttings from well "D" had an S1 minimum value of 2.4 mg HC/g rock and a maximum value of 13.46 mg HC/g rock (average 5.37 mg HC/g rock). Sediments retrieved from well "D" offshore Niger Delta Basin had an S2 minimum value of 2.38 mg HC/g rock and a maximum value of 17.up6 mg HC/g rock (ave.= 6.91 mg HC/g rock). The S1/TOC values ranged from 0.88 to 3.76 with an average value of 1.97. The S1/TOC maximum value is 3.76 at a depth of 3570 m and 3750 m for the top and bottom depth respectively and minimum value of 0.88 at a depth of 3260m and 3265m for the top and bottom depth respectively with an average value of 1.97. The depth plots of TOC in well D (Figure 6) showed that the organic richness of the shales ranges from good to excellent.

4.2 Kerogen Type

The type of organic matter in a source rock is crucial for predicting its hydrocarbon potential, whether it will generate oil or gas. In this study, the sediments displayed a hydrogen index (HI) ranging from a minimum value of 99 mgHC/gTOC to a maximum of 386 mgHC/gTOC, with an average of 482.54 mgHC/gTOC. The oxygen index (OI) of the ditch cuttings (shales) varied between 26 mgCO2/gTOC and 56 mgCO2/gTOC, averaging at 37.57 mgCO2/gTOC (Table 1).

Table 1 TOC and Rock-Eval Pyrolysis results of ditch cuttings from well D.

Serial No.	Sample Type	Depth (m)	TOC	S1	S2	S3	T_{max}	HI	OI	S1/ TOC	PI	S1+S2	S2/S3
1	rcs	2650	2.23	6.37	3.51	0.9	430	157	40	2.86	0.64	9.88	3.9
2	rcs	2690	1.83	3.63	3.49	0.72	429	191	39	1.98	0.51	7.12	4.85
3	rcs	2720	1.77	3.5	4.08	0.71	431	231	40	1.98	0.46	7.58	5.75
4	rcs	2750	2.16	4.65	5.27	0.58	429	244	27	2.15	0.47	9.92	9.09
5	rcs	2780	2.18	3.94	4.22	0.70	431	194	32	1.81	0.48	8.16	6.03
6	rcs	2810	2.71	4.25	2.67	0.76	422	99	28	1.57	0.61	6.92	3.51
7	rcs	2840	2.09	3.43	3.6	0.82	424	172	39	1.64	0.49	7.03	4.39
8	rcs	2880	2.74	5.14	3.99	0.91	424	146	33	1.88	0.56	9.13	4.38
9	rcs	2910	1.77	3.78	2.38	0.90	430	134	51	2.14	0.61	6.16	2.64
10	rcs	3010	6.62	13.46	17.6	1.37	428	266	21	2.03	0.43	31.06	12.85
11	rcs	3040	3.00	6.73	7.66	1.02	433	255	34	2.24	0.47	14.39	7.51
12	rcs	3060	2.85	4.86	4.88	1.01	432	171	35	1.71	0.5	9.74	4.83
13	rcs	3080	2.36	4.96	6.15	0.83	429	261	35	2.10	0.45	11.11	7.41
14	rcs	3100	2.39	4.4	3.84	0.7	431	161	29	1.84	0.53	8.24	5.49
15	rcs	3120	2.12	3.41	4.65	0.66	430	219	31	1.61	0.42	8.06	7.05
16	rcs	3140	2.4	3.94	4.20	0.68	427	175	28	1.64	0.48	8.14	6.18
17	rcs	3160	2.17	4.00	4.78	0.7	434	220	32	1.84	0.46	8.78	6.83
18	rcs	3180	2.01	3.28	3.66	0.7	430	182	35	1.63	0.47	6.94	5.23
19	rcs	3200	1.93	4.76	5.2	0.53	431	269	27	2.47	0.48	9.96	9.81
20	rcs	3220	1.75	3.32	4.34	0.68	430	248	39	1.90	0.43	7.66	6.38
21	rcs	3240	2.08	3.19	4.05	0.83	433	195	40	1.54	0.44	7.24	4.88
22	rcs	3260	2.72	2.40	5.97	0.82	436	219	30	0.88	0.29	8.37	7.28
23	rcs	3280	1.81	2.58	5.23	0.75	430	289	41	1.43	0.33	7.81	6.97
24	rcs	3310	2.25	3.85	5.6	0.82	432	249	36	1.71	0.41	9.45	6.83
25	rcs	3330	2.28	4.69	6.47	0.79	428	284	35	2.06	0.42	11.16	8.19
26	rcs	3350	3.06	4.63	6.64	1.21	430	217	40	1.51	0.41	11.27	5.49
27	rcs	3370	3.45	6.54	8.32	1.39	436	241	40	1.90	0.44	14.86	5.99
28	rcs	3390	3.01	5.2	7.06	1.17	430	235	39	1.73	0.42	12.26	6.03
29	rcs	3410	5.17	5.09	8.03	0.95	430	155	18	0.98	0.39	13.12	8.45
30	rcs	3450	2.76	7.08	8.71	1.05	432	316	38	2.56	0.45	15.79	8.3
31	rcs	3470	3.87	8.51	14.39	1.95	433	372	50	2.20	0.37	22.9	7.38
32	rcs	3490	2.65	7.63	10.02	1.36	433	378	51	2.88	0.43	17.65	7.37
33	rcs	3510	3.19	5.4	11.09	1.64	433	348	51	1.69	0.33	16.49	6.76
34	rcs	3530	3.43	3.32	11.00	1.25	436	321	36	0.97	0.23	14.32	8.8
35	rcs	3550	3.98	6.88	14.26	1.61	436	358	40	1.73	0.33	21.14	8.86
36	rcs	3570	3.38	12.71	10.89	1.51	434	322	45	3.76	0.54	23.6	7.21
37	rcs	3590	3.12	9.28	11.02	1.73	435	354	56	2.98	0.46	20.3	6.37
38	rcs	3600	3.51	6.8	10.26	1.88	434	292	54	1.94	0.4	17.06	5.46
39	rcs	3630	2.31	8.02	8.91	0.98	432	386	42	3.47	0.47	16.93	9.09
40	rcs	3640	2.31	5.08	8.45	1.06	433	366	46	2.20	0.38	13.53	7.97

TOC total organic carbon (wt%), *S1* mgHC/grock, *S2* hydrocarbon generated from the thermal breakdown of kerogen (mgHC/grock), *S3* CO_2 value (mgCO2/gTOC), *Tmax* the temperature at which the maximum release of hydrocarbons from the cracking of kerogen during pyrolysis (°C), *HI* Hydrogen index (mgHC/gTOC), *OI* oxygen index (mgCO2/gTOC), *PI* production index (mgHC/gTOC), *PY*(*S*1+*S*2) potential yield (mg HC/ grock) and *S*2/*S*3 hydrocarbon-type index, rcs = rock cuttings

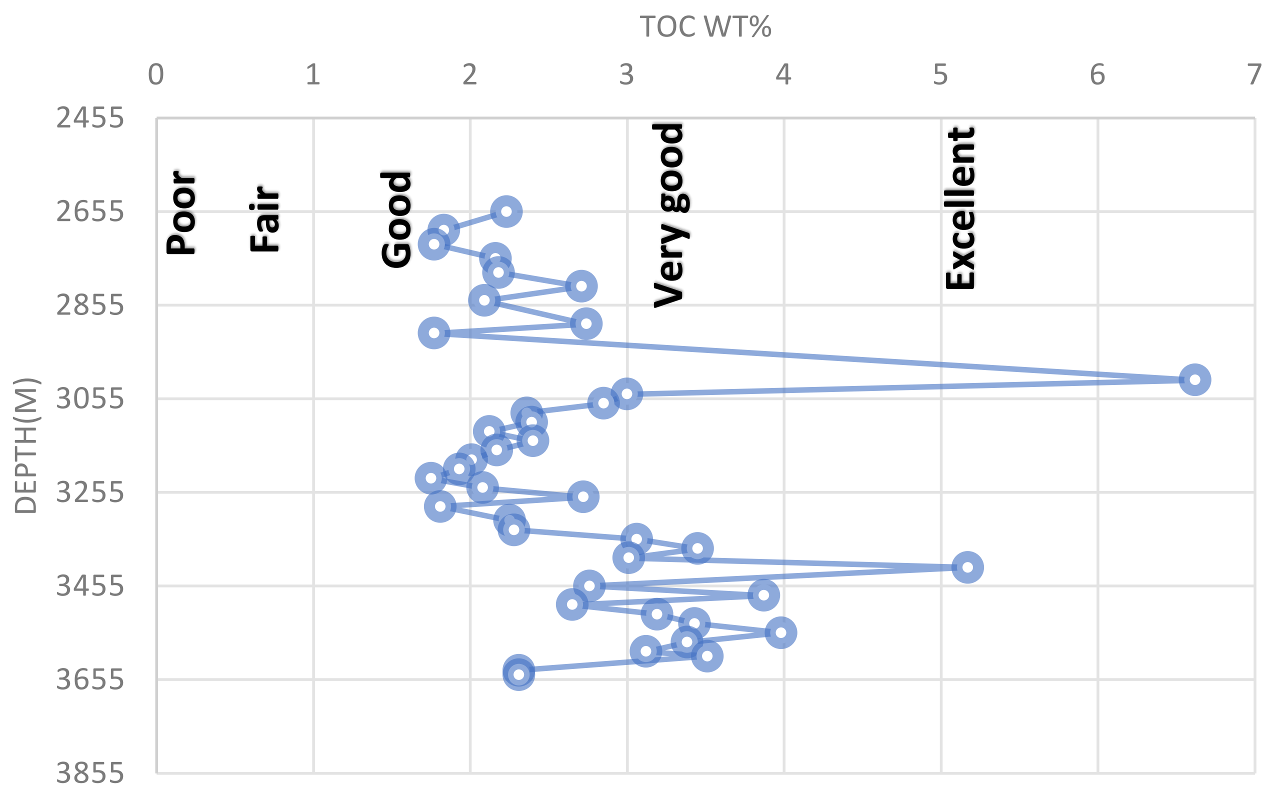

Figure 6 Depth (m) plots of total organic carbon (TOC, Wt. %).

A modified Van Krevelen diagram (Figure 7) was used to plot the hydrogen index (HI) against the oxygen index (OI) and interpreted following the guidelines of Tissot and Welte (1984) and Peters and Cassa (1994). The diagram identified different kerogen types present in the organic matter, including Type I, and Type III kerogens, which indicate the potential for generating oil and gas. Additionally, HI versus Tmax was plotted to minimize the influence of the oxygen index (OI) when determining the kerogen type and it indicated that the organic matter contained Type I, Type II and mixed Type II/III, following Hunt (1996), as shown in Figure 8. The findings were further investigated by the S2 versus TOC plot (Figure 9), according to the methods of Langford *et al.* (1990) and Bordenave *et al.* (1993) and the results indicates Type oil prone and Type II/III gas prone organic matter for the studied sediments.

4.3 Maturation

The analyzed samples from Well "D" in the offshore Niger Delta Basin exhibit a Tmax range between 422°C and 436°C, with an average of 431°C. The production index (PI) varies from 0.23 to 0.64, with an average value of 0.45. A plot of HI versus Tmax (Figure 8) illustrates the types of kerogen present and the maturity levels of the cuttings from Well D. Additional plots, such as depth versus Tmax (Figure 10) and PI versus Tmax (Figure 11), further support the finding that the samples range from immature to early maturity, indicating minimal hydrocarbon generation potential. The S2/S3 ratios, which are greater than 1, suggest the presence of immature to mature Type II to Type III organic matter, capable of generating both oil and gas. This interpretation is consistent with the S2 versus TOC plot (Figure 9), which also indicates that the samples are predominantly composed of Type II and Type III organic matter. The total hydrocarbon yield (PY), calculated as the sum of S1 and S2, ranges from 6.16 to 31.06 mgHC/g rock, suggesting a fairly hydrocarbon generation potential in the analyzed samples from Well D.

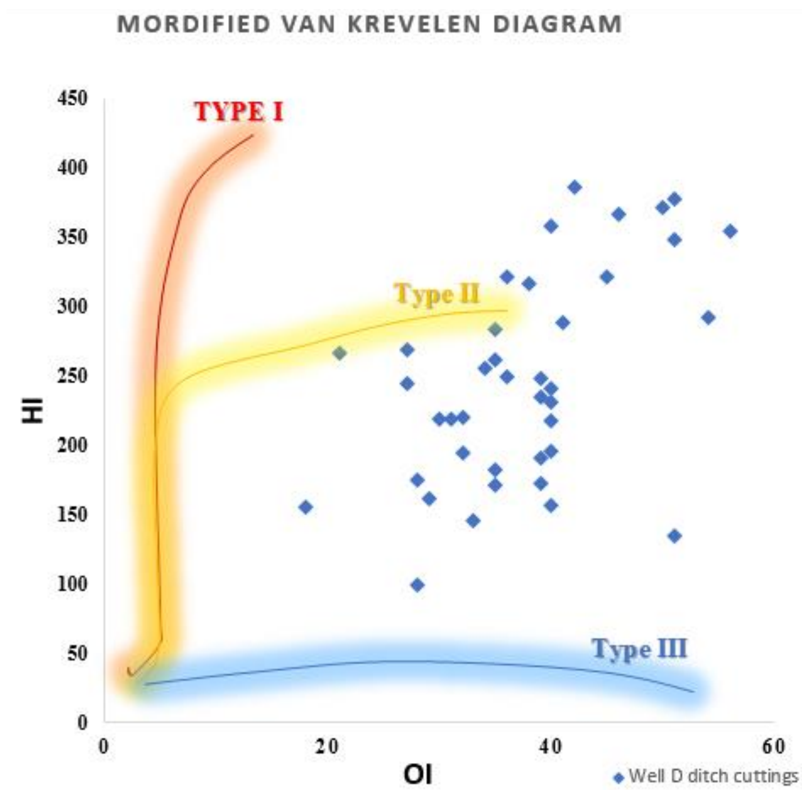

Figure 7 Modified Van Krevelen Diagram of HI *vs.* OI for Well D Samples.

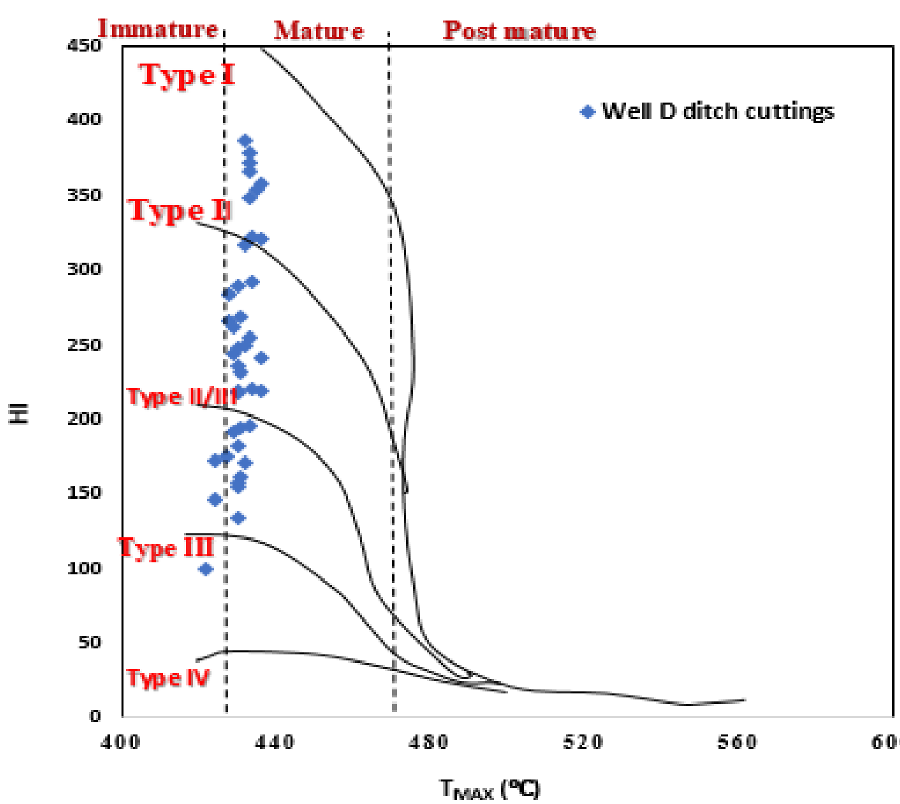

Figure 8 Plot of the relationship between Hydrogen Index (HI) and Oxygen Index (OI), showcasing the kerogen type.

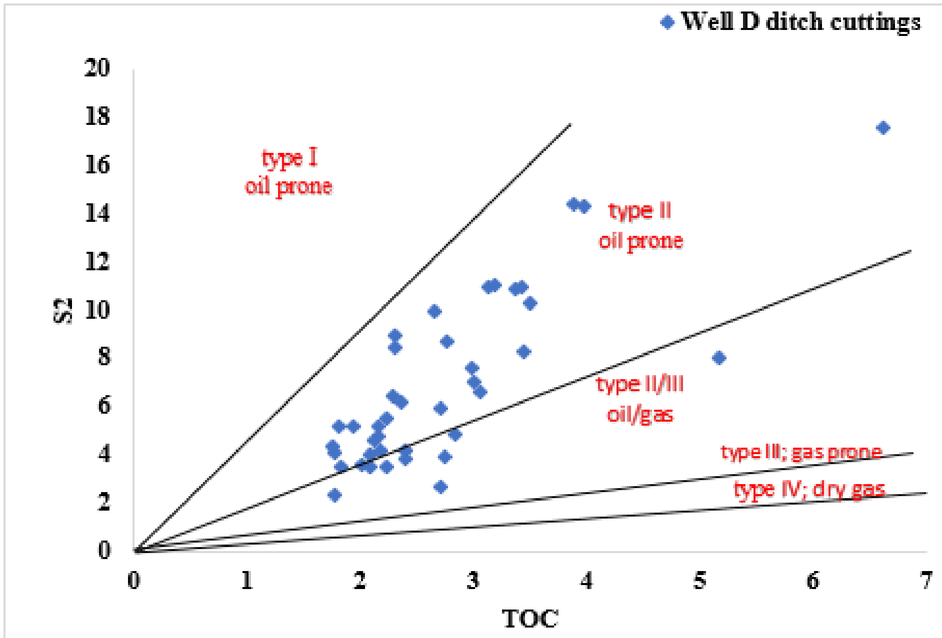

Figure 9 Plot of the kerogen affinity of the offshore Niger Delta basin's source rocks after Bordenove *et al.* (1993) and Landford *et al.* (1990).

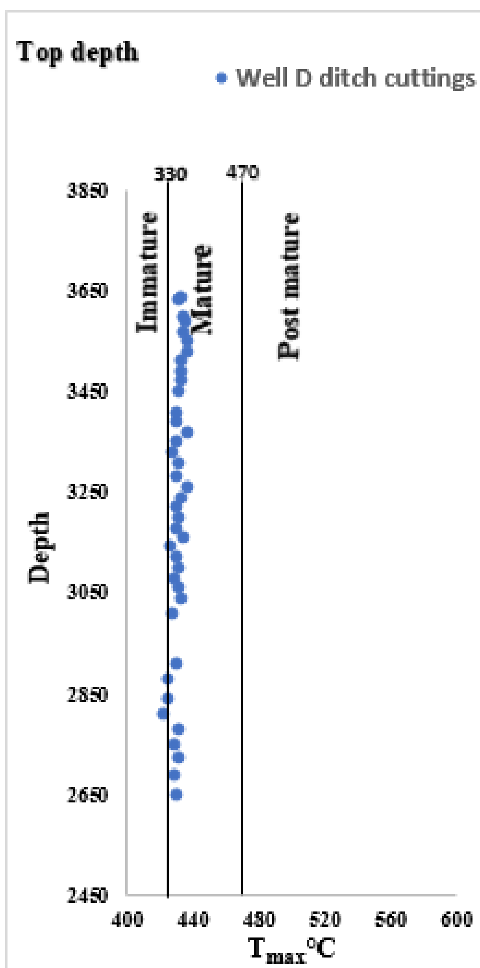

Figure 10 Plot of depth versus T_{max} showing the thermal maturity of shales.

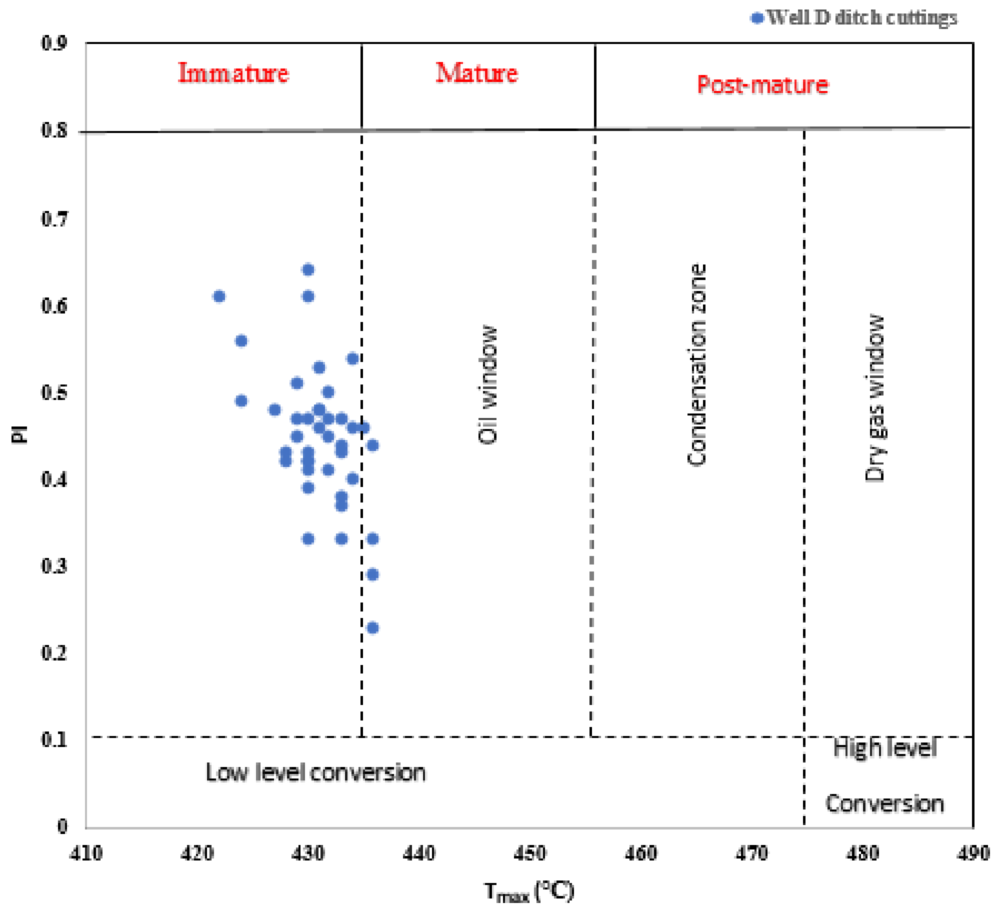

Figure 11 Plot of PI versus T_{max} for evaluating the thermal maturity of the sediments retrieved from well "D" offshore Niger Delta Basin. After Hamdy *et al.* (2020).

5 Discussion

5.1 Organic Matter Richness and Hydrocarbon Generative Potential

For a shale to qualify as a source rock, the minimum Total Organic Carbon (TOC) content generally ranges between 0.5% and 1.0% (Al-Musawi 2010; McAuliffe 1977). Tissot and Welte (1978) proposed a lower threshold of 0.5% for detrital rocks and about 0.3% for carbonate and evaporite rocks. This study follows TOC-based source rock classification criteria outlined by Peters (1986) and Peters and Cassa (1994).

TOC analysis of samples from Well D in the offshore Niger Delta Basin revealed an average TOC value exceeding 1 wt. %, which is consistent with Tissot and Welte (1984) assertion that clastic source rocks with TOC values above 0.5 wt. % are capable of generating petroleum. Nwachukwu *et al.* (2000) reported that Niger Delta shales typically have an average TOC of 1.2 wt. %, while the samples in this study averaged 2.74 wt. %. These findings suggest that the shales from Well D possess potential as hydrocarbon source rocks.

The average values of S1 (5.37 mg HC/g rock), S2 (6.91 mg HC/g rock), and TOC (2.74 wt.%) suggest that the source rocks from Well "D" possess good to very good organic richness, as classified by Peters (1986) and Peters and Cassa (1994). The S1/TOC ratio further indicates a significant presence of free oil, with 98% of the samples showing an S1/TOC ratio greater than 1. According to Hunt (1996) and Smith (1994), oil expulsion typically begins when the S1/TOC ratio ranges from 0.1 to 0.2. In this study, all samples exceeded this threshold, with an average S1/TOC ratio of 1.97, indicating active hydrocarbon expulsion.

The TOC versus depth plot (Figure 6) reveals a random distribution, which reflects variations in depositional timing and organic content. Maximum TOC values (6.62 wt.%) were recorded at depths of 3010 m to 3015 m, while minimum TOC values (1.75 wt.%) occurred between 3220 m and 3225 m, suggesting that the shales contain organic matter richness ranging from good to excellent, making them capable of hydrocarbon generation. The specific depths at which TOC peaks and troughs occur indicate varying levels of hydrocarbon productivity, with some hydrocarbons likely expelled (Hunt 1996; Tissot and Welte 1984).

The S2 versus TOC plot (Figure 9) further confirms the organic richness and hydrocarbon-generating potential of the shales. Approximately 95% of the samples exhibit good to very good organic richness, consistent with findings from Ekweazor and Okoye (1980) and Fadiya *et al.* (2021) in the same region. About 5% of the samples demonstrate excellent organic richness, further indicating that the sediments from Well "D" have the potential for significant hydrocarbon generation.

The high TOC and S2 values observed in the deposits suggest a substantial input of organic matter, likely sourced from fluvial processes and deposited in a marine setting (Zhou *et al.* 2013). This period was marked by the formation of sedimentary basins and significant sedimentation from both terrestrial and marine sources, influenced by the evolving rift system (Ebinger & Scholz 2012; Morley *et al.* 1999; Macgregor 2015).

5.2 Quality of Organic Matter

Kerogen, the organic material found in sediments, consists of high-molecular-weight compounds that are insoluble in aqueous alkaline solvents and common organic solvents (Tissot & Welte 1984; Whelan & Thompson-Rizer 1993). Initially, organic matter deposited in unconsolidated sediments is not classified as kerogen; it undergoes conversion into kerogen during diagenesis (Hunt 1996; Peters *et al.* 2005; Sardar 2014). Therefore, kerogen is a mixture of organic matter in sedimentary rocks that remains insoluble in non-oxidizing acids, bases, and organic solvents (Hunt 1996).

Identifying kerogen types in source rocks is essential, as different organic matter types exhibit varying potentials for hydrocarbon generation (Tissot & Welte 1978; 1984). In this study, we used Rock-Eval pyrolysis data and total organic carbon (TOC) content to classify kerogen types. We employed a modified Van Krevelen diagram (Figure 7) and validated the results further by plotting Hydrogen Index (HI) against Tmax (Figure 8) to reduce the influence of oxygen index (OI) anomalies (Hunt 1996).

From the modified Van Krevelen diagram (Figure 7), the samples from well "D" in the offshore Niger Delta Basin show that approximately 35% of the kerogen is Type I (oil-prone), and around 65% is Type II (capable of generating both oil and gas) (Peters *et al.* 2005). The S2 versus TOC plot (Figure 9) accounts for the influence of the oxygen index, revealing that roughly 70% of the samples fall within the mixed Type II kerogen category, 30% fall within the Type II/III oil and gas zone, and none fall into the Type III or Type IV categories. This indicates that the source rocks from well "D" predominantly contain Type II and mixed Type II/III kerogens.

The Tmax versus HI plot (Figure 8) further corroborates the thermal maturity and kerogen types in well "D," showing that the kerogens are predominantly Type II (oil-prone) and mixed Type II/III (oil/gas). These results suggest that the shales (source rocks) from well "D" contain kerogens ranging from Type II to Type III, aligning with the findings of Fadiya *et al.* (2021) in the same region.

5.3 Thermal Maturation and Genetic Potential

The thermal alteration of organic matter due to heating, referred to as maturity, is a critical factor in hydrocarbon generation (Peters & Cassa 1994). This study employed Rock-Eval Pyrolysis data, focusing on the Production Index (PI) and Tmax to evaluate the thermal maturity of source rocks, using the classification systems of Bacon *et al.* (2000) and Peters and Cassa (1994). Additionally, a plot of Hydrogen Index (HI) versus Tmax (Van Krevelen 1950) was used to further assess the maturity of kerogen.

The HI versus Tmax cross-plot was chosen to determine kerogen quality and maturity, as it reduces the impact of anomalies in the Oxygen Index (OI) (Hunt 1996). Elevated OI values can result -from impurities, solid solutions, and the pyrolytic formation of organic acids that produce CO_2 from carbonates below the trapping temperature of 390°C (Peters 1986). Approximately 91% of the samples analyzed fall within the mature zone, indicating sufficient thermal maturation for hydrocarbon generation. Around 9% of the samples remain immature, suggesting they have not yet reached the required maturity to generate significant hydrocarbons. Importantly, no samples were found in the post-mature zone, which indicates that none of the source rocks have been exposed to the extreme temperatures that would lead to excessive gas generation.

These results align with previous studies by Ekweazor and Okoye (1980) and Nyantakyi (2014) in the Niger Delta Basin, suggesting that the maturity range for well "D" spans from immature to mature. Similar findings were also reported by Fadiya *et al.* (2021) for sediments from the same region.

The PI versus Tmax plot provides further insights, showing that 90% of the samples fall within the immature zone, while 10% are classified as mature. This suggests that the source rocks in well "D" primarily range from immature to mature in terms of thermal maturity. The average PI value of 0.45 indicates a degree of post-thermal maturity in some samples, as per the Bacon *et al.* (2000) scale. This post-maturity is likely influenced by localized thermal conditions or variations in the basin's thermal history.

Both the HI versus Tmax and PI versus Tmax plots offer a thorough understanding of the thermal maturity of the source rocks in well "D." The high percentage of mature samples (91%) points to significant potential for hydrocarbon generation. In contrast, the presence of immature samples (9%) indicates that some portions of the source rocks have not yet reached the thermal maturity necessary for hydrocarbon generation. The absence of post-mature samples suggests that the source rocks have not been subjected to extreme temperatures that would result in the predominance of gas-prone kerogens.

The genetic potential values provided, ranging from 6.16 mg HC/g rock to 31.06 mg HC/g rock, indicate a variation in the hydrocarbon-generating potential across the sampled interval. Higher PY (S1 + S2) values > 10 mg HC/g rock generally reflect source rocks with greater potential for hydrocarbon generation (Peters 1986), while lower values (< 5 mg HC/g rock) correspond to sections with less potential. The intervals with higher genetic potential values are likely in the early to peak maturation stages, suggesting substantial potential for both oil and gas generation. Conversely, sections with lower values may have reached the over mature stage, particularly in the upper part of the well or near the upper limits of the oil window, where hydrocarbon generation would predominantly shift towards gas production.

The well sections with high genetic potential values, such as 22.9, 23.6, and 31.06 mg HC/g rock, represent promising targets for hydrocarbon exploration (Peters 1986). These intervals are likely to be more productive in generating oil and gas, especially if they are within the optimal maturation window. The findings from this study reinforce the significant hydrocarbon potential of well D southern offshore the Niger Delta Basin, offering valuable insights for future exploration and development in the region.

6 Conclusion

The sediments from well D, located in the southern offshore region of the Niger Delta Basin, exhibit a high organic matter content, indicating their classification as good to excellent source rocks for hydrocarbon generation. This assessment is supported by several key indicators, including an average Total Organic Carbon (TOC) content of 2.74 wt. %, S1 values averaging 5.37 mg HC/g rock, and analysis from TOC versus S2 and TOC versus depth plots. The TOC values, which range from 1.75 to 6.62 wt. %, are in line with previous studies on Niger Delta source rocks (Adekoya *et al.* 2014, Ekweozor and Okoye 1980; Nwachukwu *et al.* 2000), further confirming their potential for hydrocarbon generation.

Rock-Eval pyrolysis results reveal the presence of predominantly Type II kerogen (oil-prone), with a mix of Type II/III (oil/gas-prone) and minor Type III (gas-prone) kerogen. These findings are consistent with the kerogen types identified by Fadiya *et al.* (2021) in their research on the Niger Delta Basin.

In terms of thermal maturity, the sediments in well D range from immature to early-mature, suggesting their ability to generate hydrocarbons at various stages of maturation. This maturity range shows some variation when compared to previous studies by Adekoya *et al.* (2014), Ekweozor and Okoye (1980), Fadiya *et al.* (2021), and Nwachukwu *et al.* (2000) which typically observed maturity levels ranging from immature to mature within the same Niger Delta Basin.

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