



## Integrated Organic Petrography and Rock-Eval Evaluation of the UDY Well Source Rocks, Niger Delta Basin, Nigeria

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### Abstract

This study integrates organic petrography and Rock-Eval pyrolysis to characterize kerogen type, thermal maturity, depositional environment, and hydrocarbon potential of the UDY well source rock interval (4050ft – 4250ft) in Utapate Oilfield, Niger Delta Basin. Petrographic analysis reveals vitrinite-dominated organic matter (74 -76.4 %), moderate liptinite enrichments (23.6 -25.2 %), trace inertinite (< 1%), suggesting a mixed terrestrial-algal organic matter source, typical of marginal marine or delta front settings. Rock-Eval results reveal high TOC (~3.8–4.0 wt.%), indicating good organic richness. S2 values (8–11 mg HC/g) and Hydrogen Index (HI) values (235–290 mg HC/g TOC) demonstrate good remaining generative potential and classify the kerogen as mixed Type II/III. Measured vitrinite reflectance (~0.58%) and Tmax values (427–430 °C) place the samples within the early oil window. High S1 values (8 to 10 mg/g), S1/TOC (>230 mg/g TOC) and elevated PI (0.44–0.47) suggest significant free hydrocarbon presence, likely due to migrated oil or early generation with limited expulsion. The combined results indicate that the UDY well sample interval is a high-quality source rock with considerable retained hydrocarbons and strong potential for both oil and gas generation during continued burial. This combined dataset provides a strong framework for evaluating hydrocarbon potential within the UDY stratigraphic interval and for regional petroleum systems modeling.

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## 1.0 Introduction

Accurate characterization of source rock potential is crucial for understanding petroleum systems and for forecasting hydrocarbon prospectivity in sedimentary basins. Source rock quality is typically assessed through Rock-Eval pyrolysis, TOC measurement, and organic petrography, each providing complementary insights into kerogen type, organic richness, and thermal maturity (Peters et al., 2005). Whereas organic petrography, including maceral identification and vitrinite reflectance measurements, provides direct optical evidence of organic matter source, preservation conditions, and thermal alteration (Taylor et al., 1998), Rock-Eval parameters such as S2 and Hydrogen Index (HI) quantify kerogen hydrogen richness and remaining generative capacity (Ehinola et al., 2005). The combined use of petrography and pyrolysis enhances reliability, especially where geochemical parameters alone may be ambiguous due to mineral matrix effects, bitumen presence, or mixed kerogen types.

Despite extensive research in other parts of the Niger Delta Basin, there remains notable paucity of organic geochemical and petrographic data from the southeastern sector of the coastal swamp depobelt, particularly within the Utapate oilfield. Besides, the geological complexity of the coastal swamp depobelt introduces additional uncertainties in source rock heterogeneity and depositional environment. This study will fill this crucial knowledge gap by generating new empirical data on the quantity, quality and maturity of organic matter, as well as the maceral composition and depositional environment of the shales. This study focuses on shale samples from UDY well (4050 - 4250 ft) located in the Utapate oilfield which falls within the Oil Mining Lease (OML) 13 (NPDC, 2020; Fig. 1). Two samples (UDY-2 and UDY-4) were subjected to maceral composition and vitrinite reflectance measurements, whereas rock-eval pyrolysis was conducted on six samples (UDY-

1 to UDY-6). The results will not only bridge the existing data gap on the organic geochemistry and petrography of the Utapate field but also provide a sturdy scientific basis for investment decisions and exploration strategies targeting marginal fields in the Niger Delta region.

## 2.0 Geologic Setting of the Niger Delta Basin

The Niger Delta Basin is one of the world's most productive petroleum provinces and represents a large Tertiary depocenter formed along the passive continental margin of West Africa. Its evolution began during the late Mesozoic as the South American and African plates separated, initiating the opening of the South Atlantic and creating a system of rift basins that subsequently linked to the modern delta (Burke, 1972; Evamy et al., 1978). The main phase of Niger Delta sedimentation commenced in the Paleocene and accelerated through the Eocene to Recent, driven by rapid subsidence and high sediment supply from the Niger River and its tributaries (Avbovbo, 1978; Ekweozor & Daukoru, 1994; Reijers et al., 1997; Nwajide, 2013). Differential subsidence across the margin facilitated the accumulation of an exceptionally thick sediment pile composed of three principal formations presented in Fig. 2. The uppermost Benin Formation (Miocene–Recent) representing continental sand-rich deposits representing subaerial delta plain facies. The Agbada Formation (Eocene–Pleistocene) comprising delta-front to coastal swamp alternations of sandstone and shale forming reservoir–seal pairs and the basal Akata Formation (Paleocene–Recent) consisting of pro-delta to deep marine shales believed to be the primary source rock for Niger Delta hydrocarbons (Ejedawe et al., 1984).

The delta's growth was accompanied by gravitational collapse and syn-depositional faulting above mobile, overpressured Akata shales. These processes created widespread listric normal faults, rollover anticlines, shale diapirs, and distal toe-thrust belts (Doust & Omatsola, 1990; Bilotti & Shaw, 2005).

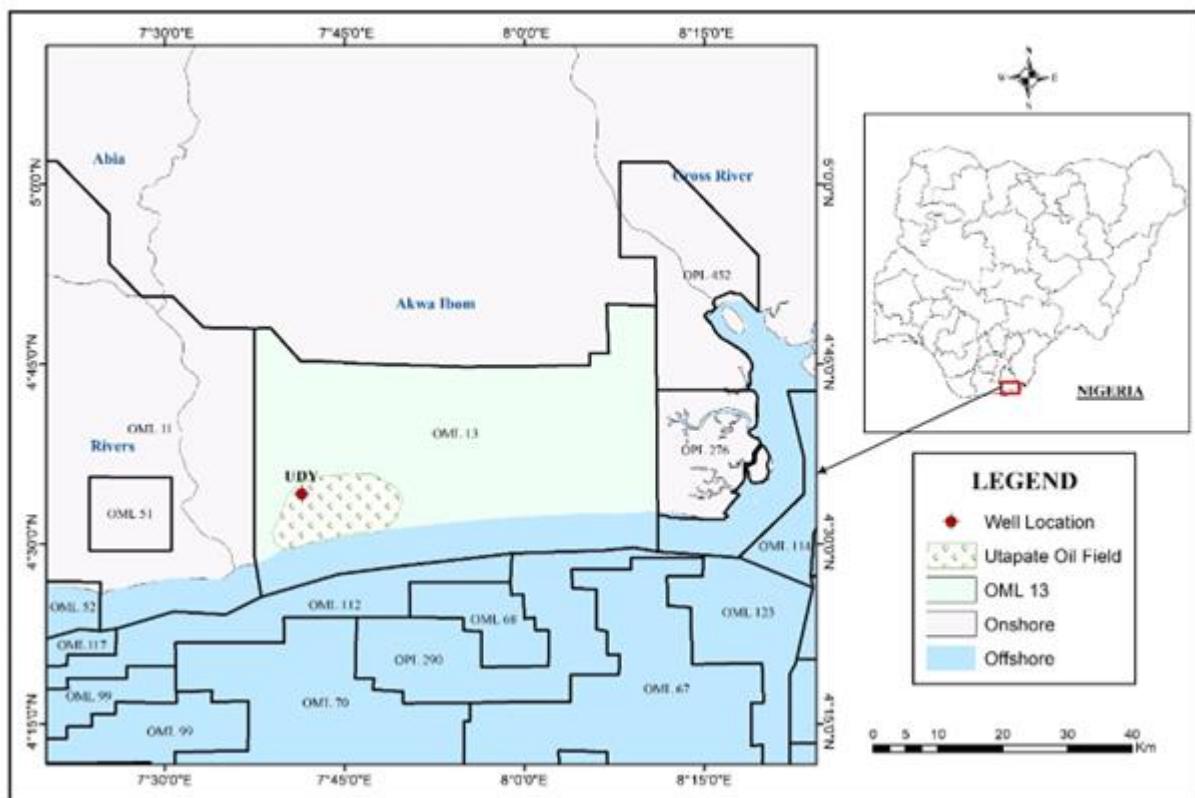


Fig. 1: Map of OML 13 showing Utapate Oilfield and well location

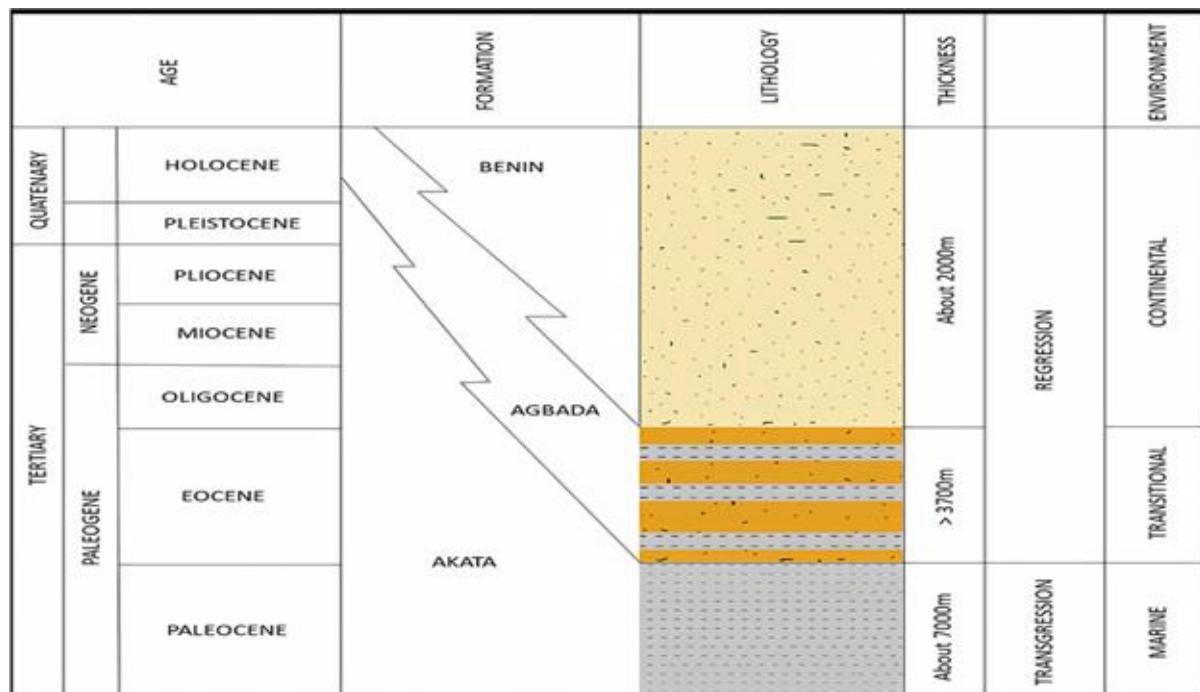


Fig. 2: Stratigraphic Units in the Niger Delta Basin (Adapted from Obaje, 2019)

These features create numerous structural and stratigraphic traps, making the basin one of the most structurally complex delta systems globally (Nwajide, 2013).

Due to its location in a tectonically active setting, the Niger Delta exhibits strong spatial

heterogeneity in sedimentation, redox conditions, and organic matter preservation, factors that exert first-order control on kerogen quality and hydrocarbon potential (Ekweozor & Udo, 1988; Doust & Omatsola, 1990; Udo & Ekweozor, 1990).

### 3.0 Materials and Methods

Six ditch cutting samples were collected from UDY well located in the southeastern Niger Delta Basin. Samples were washed with neutral detergent to minimize the influence of the drilling fluid on the rock samples, then sun-dried. Samples were disaggregated with a durable plastic mortar and pestle and neatly stored in labelled sample bags with reference to the depth from which they were taken. Six samples (UDY-1 to UDY-6) were selected for Rock-Eval pyrolysis to capture vertical geochemical variability. Two of these (UDY-2 and UDY-4) were chosen for petrographic analysis because they exhibited representative TOC values, and bracketed the central stratigraphic interval of interest. The samples for organic geochemical analysis were shipped via courier to the laboratory of GeoMark Research Limited in Houston, Texas, while those for organic petrography were shipped to the laboratory of the Kentucky Geological Survey at the University of Kentucky in Lexington, Kentucky, both in the United States of America.

Organic richness, organic matter type, and maceral composition were evaluated using methods and procedures outlined by (Tissot & Welte, 1984; Espitalie et al., 1985; Hunt, 1996; Hakimi et al., 2010; McCarthy et al., 2011; Egbobawaye, 2017; Ndip et al, 2019; Sih et al., 2023). Total organic carbon (TOC) was determined using LECO SC-832HT carbon analyser whereas Rock-Eval pyrolysis was done using HAWK pyrolysis instrument, and organic petrography was achieved using a Zeiss universal reflecting light microscope equipped with both white and fluorescent light sources. Identification of organic matter (macerals) was achieved using a Zeiss epiplan 40X oil immersion objective, in conjunction with a 1.6X magnification changer (final magnification of 640X). Quantification of the macerals was achieved by employing a counting device fitted to the microscope stage, in accordance with ASTM D7708-23a standards.

### 4.0 Results

#### 4.1 Organic petrography

Maceral composition provides key insights into the origin, preservation, and hydrocarbon-generation potential of sedimentary organic matter. The relative proportions of maceral groups are strongly diagnostic of kerogen type and, by extension, the quality of a source rock (McCarthy et al., 2011; Hunt, 1995). In addition, maceral assemblages are widely used to reconstruct paleo-environmental conditions and depositional settings (Liu et al., 2020; Gonclaves et al., 2021; Liu et al., 2022; Sih et al., 2023). Maceral analysis of samples UDY-2 and UDY-4 shows that both samples are strongly dominated by vitrodetrinite, comprising 74.0% and 76.4%, respectively (Table 1) and representative micrographs are shown in Figs. 3 and 4. Liptinitic components, mainly lamalginite, bituminite, amorphous organic matter (AOM), and minor sporinite, make up approximately 22.0% in UDY-2 and 18.8% in UDY-4. Solid bitumen occurs in both samples in similar amounts (3.6–4.0%). Inertinite is nearly absent, with values <1%.

Vitrinite reflectance (VRo) data from 85 measurements per sample show narrow distributions. Average VRo values are 0.57% (UDY-2) and 0.58% (UDY-4). Minimum reflectance values range from 0.51–0.52%, while maximum values range from 0.65–0.66% (Table 1). Standard deviations are low (0.034–0.039), indicating homogeneity of maturation within each sample.

#### 4.2 Rock-Eval Pyrolysis

The Rock-Eval pyrolysis results and other useful parameters are presented in Table 2. The UDY well samples have TOC values between 3.80 and 3.95 wt.% with a mean value of 3.87 wt. %. S1 (free hydrocarbons (mg HC/g rock) values range from 8.87 to 10.06 mg HC/g (mean = 9.41 mg HC/g rock), while S2 (remaining hydrocarbon potential (mg HC/g rock) values range between 10.30 and 11.29 mg HC/g, averaging 11.00 mg

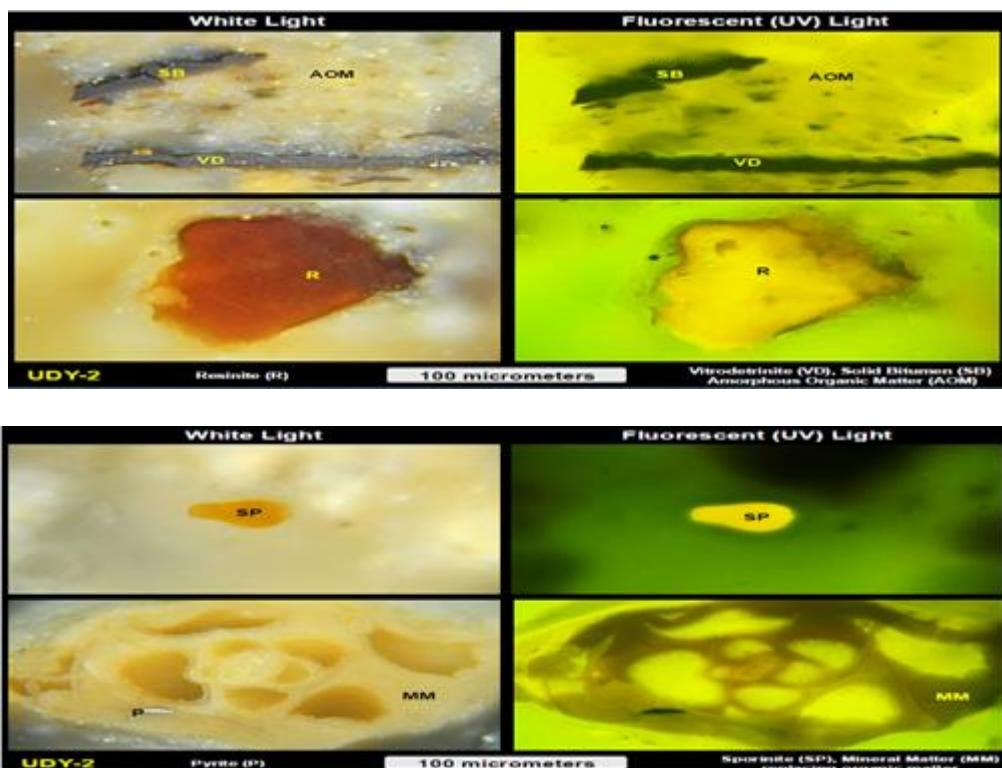
HC/g rock. S3 values (0.49–0.63 mg CO<sub>2</sub>/g) represent the amount of CO<sub>2</sub> produced during pyrolysis of kerogen.

Hydrogen Index (HI) values vary from 269 to 295 mg HC/g TOC and Oxygen Index (HI) values of 13–16 mg CO<sub>2</sub>/g TOC are used to

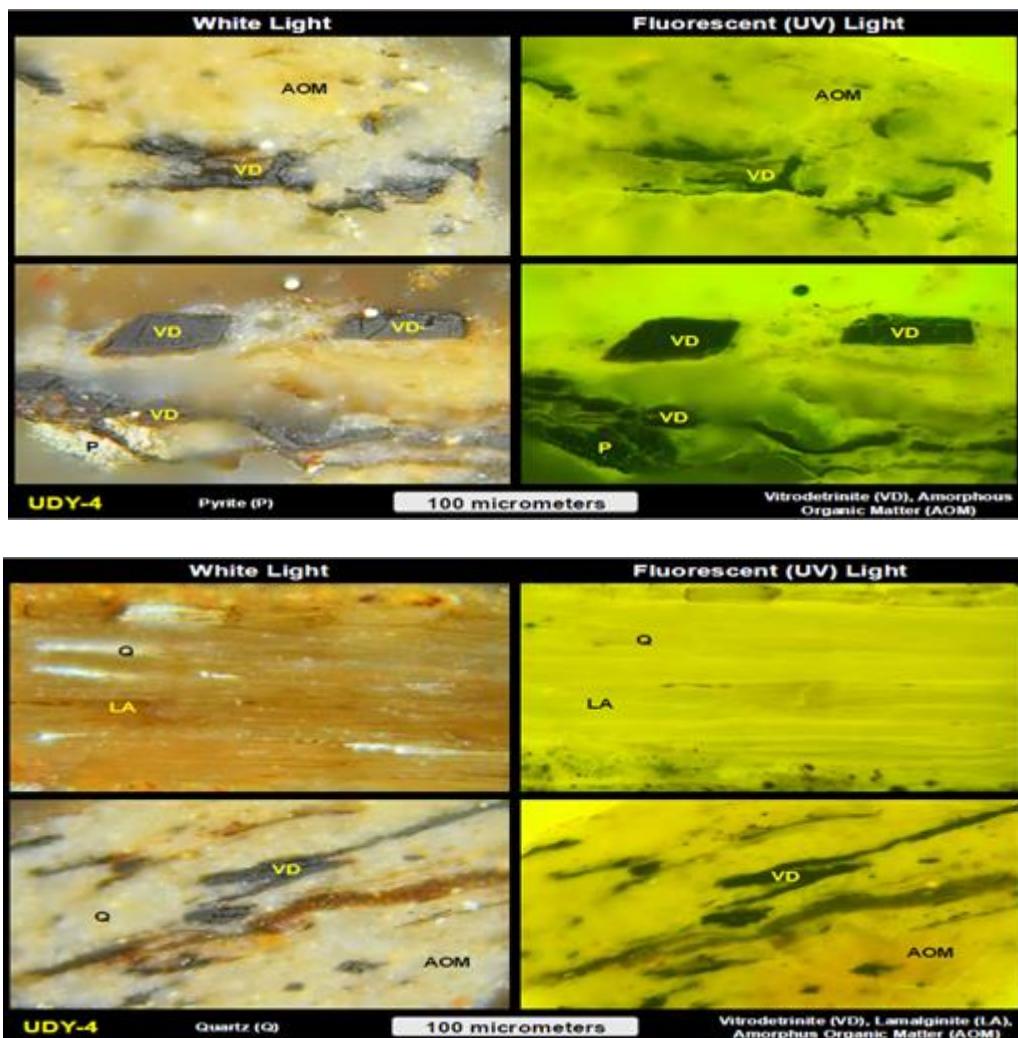
classify the type of kerogen in source rocks. Tmax, temperature of maximum S2 release, varies from 427°C to 430°C while calculated VRo values range from 0.53–0.58%. PI values of 0.44–0.47 are used to characterize the evolution of organic matter.

**Table 1:** Organic Petrographic Results

Sample ID	UDY	UDY
	2	4
Vitrodetrinite	74.0	76.4
Sporinite	0.4	0.0
Lamalginite	12.4	10.0
Bituminite	4.8	3.6
solid bitumen	3.6	4.0
AOM	4.4	5.2
inertodetrinite	0.0	0.4
semi-inertodetrinite	0.4	0.4
Avg. VRo random	0.57	0.58
Max. VRo random	0.66	0.65
Min. VRo random	0.51	0.52
St. Deviation	0.039	0.034
Measurements	85	85



**Fig. 3:** Photomicrographs of UDY-2 showing resinite, sporinite, vitrodetrinite, solid bitumen, amorphous organic matter, mineral matter replacing organic matter.



**Fig. 4:** Photomicrographs of UDY-4 well samples showing pyrite, quartz, vitrodetrinite, lamalginite and amorphous organic matter

**Table 2:** TOC and Rock-Eval pyrolysis results and other derived parameters of the studied shale samples from UDY well, Utapate oilfield, Niger Delta Basin

Rock	Upper		HAWK	HAWK	HAWK	HAWK	Calculated	Hydrogen	Oxygen	S2/S3	S1/TOC	Production	Genetic
ID	Depth (m)	TOC (wt%)	S1 (mg HC/g)	S2 (mg HC/g)	S3 (mg CO <sub>2</sub> /g)	T <sub>max</sub> (°C)	%Ro (RE TMAX)	S2x100/TOC	S3x100/TOC (mg HC/mg CO)	Conc.	Norm. Oil Content	Index (S1/(S1+S2))	Potential (S1 + S2)
UDY-1	4,100.00	3.80	8.87	11.21	0.56	428	0.54	295	15	20	233	0.44	20.08
UDY-2	4,115.00	3.89	9.71	11.29	0.62	427	0.53	290	16	18	250	0.46	21
UDY-3	4,130.00	3.83	8.79	10.30	0.59	428	0.54	289	15	17	230	0.46	19.09
UDY-4	4,145.00	3.88	9.23	10.88	0.49	430	0.58	281	13	22	239	0.46	20.09
UDY-5	4,160.00	3.85	10.08	11.20	0.63	428	0.54	284	16	18	255	0.47	21.28
UDY-6	4,175.00	3.87	9.82	11.14	0.52	428	0.54	288	13	21	254	0.47	20.96

## 5.0 Discussion

### 5.1 Organic Petrography

#### 5.1.1 Type of organic matter and hydrocarbon potential

The dominance of vitrinite maceral (Table 1) signifies substantial woody, terrestrial humic input and supports the presence of Type III

kerogen, capable of generating gas (Stach et al., 1982; Tissot & Welte; 1984; Hunt, 1996; Mastalerz et al., 2018; Sih et al., 2023). Moderate liptinite macerals reflect contributions from hydrogen-rich algal and microbial organic matter, supporting the presence of Type II kerogen, which is more oil-prone (Hunt, 1996; Mastalerz et al., 2018; Ndip et al. 2019). Trace

inertinite suggests limited oxidative degradation before burial, implying relatively stable depositional conditions with intermittent anoxia. Thus, the overall maceral assemblage confirms the presence of mixed Type II/III kerogen, implying a source rock with the potential to generate both oil and associated gas (Tissot & Welte; 1984; Hunt, 1996; Mastalerz et al., 2018).

### 5.1.2 Thermal maturity based on organic petrography

Vitrinite reflectance values between 0.57–0.58% VRo indicate that both samples lie within the early oil window (Taylor et al., 1998; Peters et al., 2005). The presence of solid bitumen confirms that early hydrocarbon generation has begun, consistent with reflectance values approaching or slightly surpassing the onset of oil generation (~0.55% VRo) (Mastalerz et al., 2018). Solid bitumen forms during the transformation of thermally labile organic constituents as kerogen begins to generate hydrocarbons (Teichmuller & Durand, 1983; Tissot & Welte; 1984; Hunt, 1996; Mastalerz et al., 2018). The narrow reflectance ranges and low standard deviations suggest a consistent thermal history without significant thermal overprinting or mixing of organic matter populations (Taylor et al., 1998; Liu et al., 2019).

### 5.1.3 Depositional environment

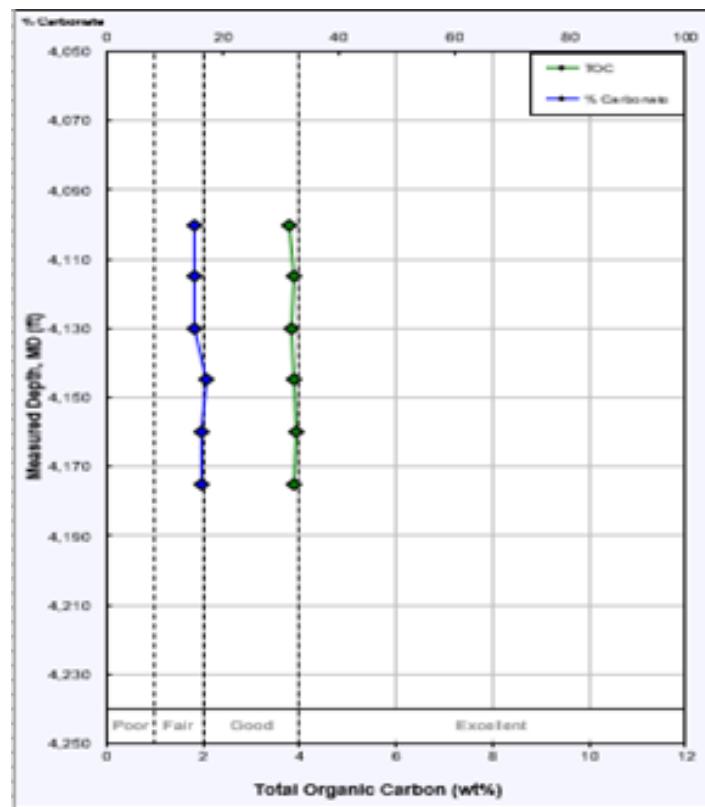
High vitrinite maceral contents in UDY-2 and UDY-4 samples indicate substantial influx of terrestrial organic matter, typical of deltaic or paralic depositional environments whereas low inertinite points to minimal oxidation. The presence of lamalginite, bituminite and AOM suggests intervals of algal productivity and reduced oxygen conditions, implying deposition in a fluctuating redox system, possibly within

marginal marine, delta-front, or lagoonal settings (Diessel, 1992; Tyson, 1995). These mixed terrestrial-aquatic signatures are characteristic of environments capable of preserving both humic and hydrogen-rich organic matter.

## 5.2 Rock-Eval Characterization

### 5.2.1 Quantity of organic matter

The quantity of organic matter in source rocks, comprising soluble bitumen and insoluble kerogen, is conventionally assessed using total organic carbon (Conford, 1986; Peters, 1986; Peters & Cassa, 1994; Shalaby et al., 2012b; Gilbert et al., 2021; Asuaiko et al., 2024). TOC, therefore, provides a direct measure of source-rock richness and forms the basis for evaluating the petroleum generative capacity of shale successions. In this study, TOC data were obtained for six shale samples collected from UDY well located in the southeastern Niger Delta Basin (Table 2). The TOC values range from 3.80 to 3.95 wt.%, with a mean of 3.87 wt.%, indicating that all samples contain abundant organic matter. All TOC values exceed the widely accepted minimum threshold of 0.5 wt.% required for source rocks to be considered capable of generating hydrocarbons (Jarvie, 1991; McCarthy et al., 2011; El-Nady, 2016; Shalaby et al., 2019b; Fadiya et al., 2021; Kouadio et al., 2022; Asuaiko et al., 2022). Peters & Cassa, (1994) noted that TOC of 2 to 4 wt. % indicates a very good source rock. Thus, TOC values of UDY well samples (3.80-3.95 wt.%), therefore, classify as “very good” in terms of organic richness. This conclusion is further corroborated by depth vs. TOC cross-plots (Fig. 5), which illustrate that the samples lie consistently within the field of good to very good source-rock potential.



**Fig. 5:** Plot of depth versus TOC, revealing the organic richness of the samples

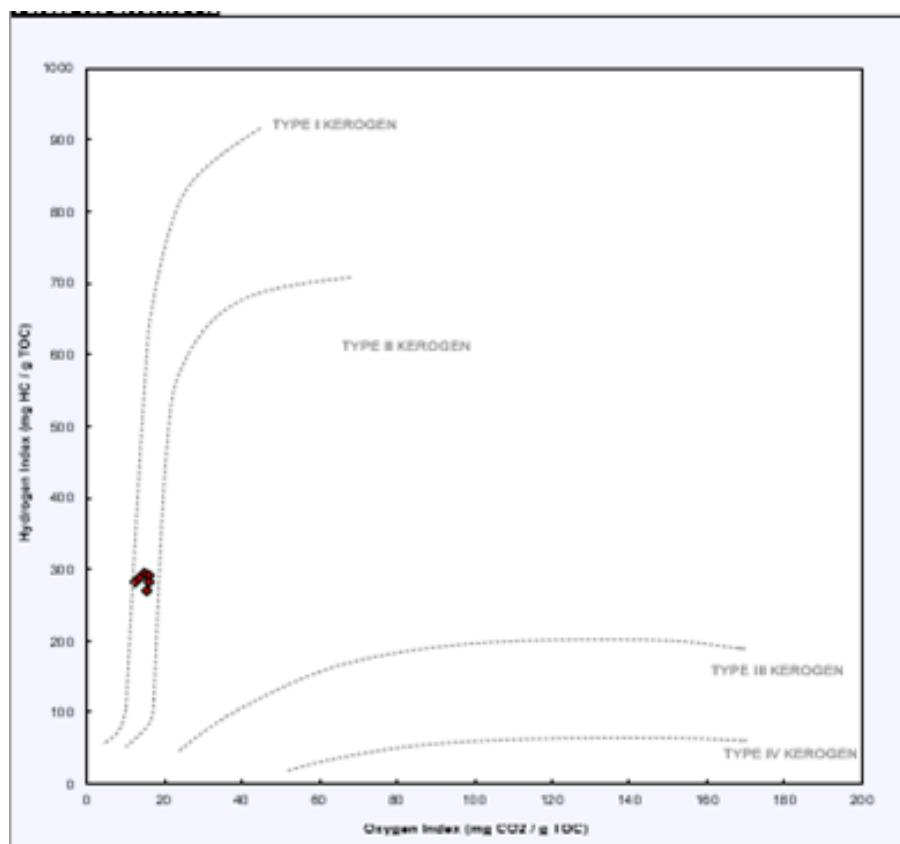
### 5.2.2 Quality of organic matter

In this study, Rock-Eval pyrolysis parameters  $S_2$  and  $S_3$  were converted to Hydrogen Index ( $HI = S_2/TOC \times 100$ ) and Oxygen Index ( $OI = S_3/TOC \times 100$ ) (Table 2), and plotted on a pseudo-Van Krevelen diagram (Fig. 6) to assess kerogen type. The  $HI-OI$  relationships show that UDY samples fall predominantly within the Type II evolution pathway. This kerogen type is characterized by relatively high  $HI$  values (269–295 mg HC/g TOC; mean 284.50 mg HC/g TOC) and low  $OI$  values (13–16 mg  $CO_2$ /g TOC; mean 14.67 mg  $CO_2$ /g TOC). This combination indicates organic matter derived from mixed marine and terrestrial sources, but with a strong algal/marine contribution typical of oil-prone systems.

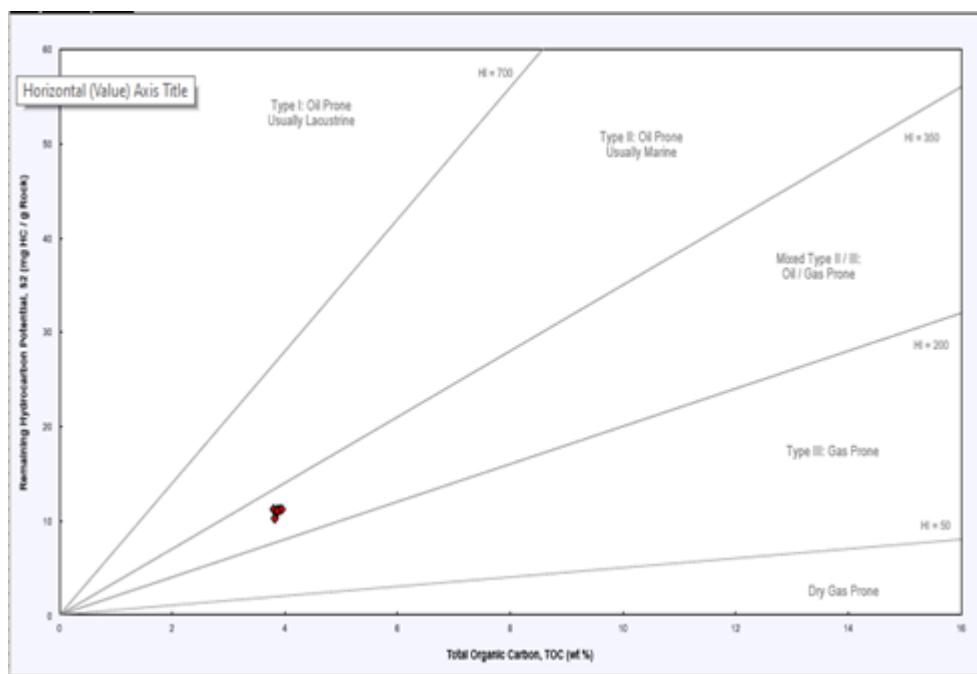
To further evaluate organic matter quality, a kerogen-type diagram based on  $S_2$  versus TOC (Jackson et al., 1985; Langford & Blanc-Valleron, 1990; Bordenave et al., 1993; Shalaby et al., 2020; Ahmed et al., 2022; Uzoegbu & Ugwueze, 2023) was constructed (Fig. 7). This diagram corroborates the Van Krevelen

interpretation: UDY samples plot within the mixed Type II/III field, suggesting oil and gas generative potential resulting from combined marine and terrestrial inputs.

Hunt, (1996) records that hydrogen content is widely regarded as the strongest geochemical control on petroleum type and yield. Also, Martinelli, (2009) affirms that high hydrogen enrichment generally corresponds to enhanced oil-generative potential. Based on established  $HI$  thresholds (Waples, 1985; Peters & Cassa, 1994; Gilbert et al., 2021; Ombati et al., 2023), kerogen classification is as follows: Type IV (non-generative):  $HI < 50$ ; Type III (gas-prone):  $HI = 50-200$ ; Type II/III (mixed oil and gas):  $HI = 200-300$ ; Type II (oil-prone):  $HI = 300-600$ ; Type I (highly oil-prone):  $HI > 600$ . The UDY samples exhibit  $HI$  values between 269 and 295 mg HC/g TOC, falling entirely within mixed Type II/III kerogen field, reflecting both oil and gas generative tendencies. This interpretation is fully consistent with the  $S_2$  versus TOC plot (Fig. 7), which shows clear clustering in the Type II/III field.



**Fig. 6:** Plot of HI versus OI, determining the type of kerogen present in the source rock



**Fig. 7:**  $S_2$  versus TOC cross plot to identify kerogen type of organic matter

Further confirmation is provided by the Hydrocarbon Type Index ( $S_2/S_3$ ), which evaluates whether kerogen is predisposed to generating oil, gas, or both (Peters & Cassa, 1994). According to this classification: <1 – Type IV (non-generative); 1–5 – Type III (gas-

prone); 5–10 – Type II/III (mixed oil & gas); 10–15 – Type II (oil-prone); >15 – Type I (highly oil-prone). The UDY shale samples show  $S_2/S_3$  ratios ranging from 17 to 22 (mean 19.33), exceeding the threshold of >15 associated with Type I oil-prone kerogen. Although the HI and

Van Krevelen data classify the kerogen primarily as mixed Type II/III, the high  $S_2/S_3$  ratios indicate highly oil-generative potential, probably reflecting the dominance of hydrogen-rich, marine-derived organic precursors.

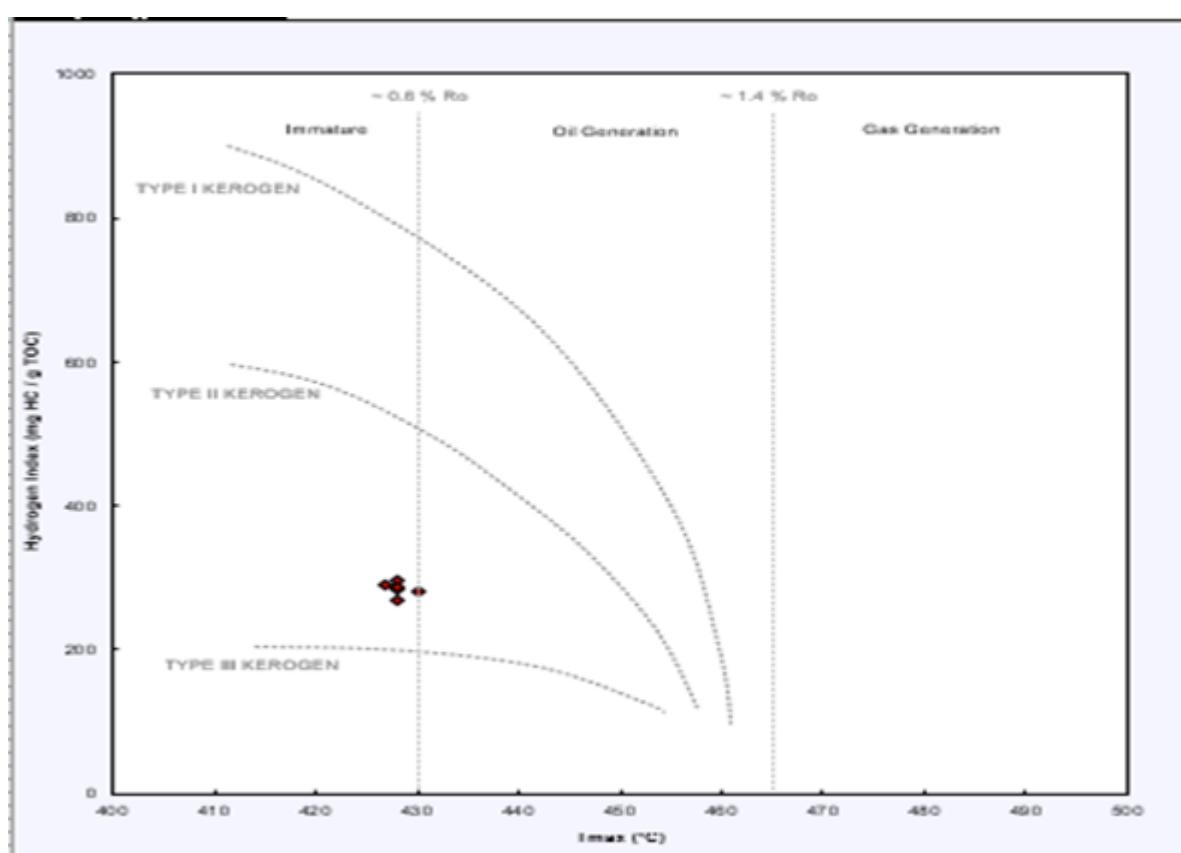
### 5.2.3 Thermal maturity of organic matter

Thermal maturity reflects the extent to which organic matter has been altered by burial, heating, and pressure through geologic time, ultimately governing its capacity to generate hydrocarbons (Tissot & Welte, 1984; Jarvie et al., 2001; Shalaby et al., 2019b; Ombati et al., 2023; Asuaiko et al., 2024). Progressive thermal alteration modifies the physical and chemical characteristics of kerogen; these changes are quantifiable through Rock-Eval pyrolysis and vitrinite reflectance parameters.

$T_{max}$ , the temperature at which maximum hydrocarbon generation occurs during pyrolysis, is one of the most widely applied maturity

indices. The analyzed UDY shale samples exhibit  $T_{max}$  values ranging from 427°C to 430°C (mean 428.17°C) (Table 2). According to established thresholds (Hunt, 1996; Ehinola et al., 2015; Osli et al., 2019; Shalaby et al., 2019b; Uzoegbu et al., 2022; Uzoegbu & Ugwueze, 2023; Oriakhi & Okosun, 2025), the oil-generation window broadly spans 430–450°C. Thus, the observed  $T_{max}$  values place the samples within the immature to marginally mature stage for petroleum generation.

Vitrinite reflectance ( $Ro$ ), calculated from  $T_{max}$  using the Jarvie, et al., (2001) empirical relationship ( $CVRo = 0.0180T_{max} - 7.16$ ), ranges from 0.53 to 0.58%  $Ro$  (mean 0.55%  $Ro$ ). The  $T_{max}$ – $Ro$  cross-plot (Fig. 8) likewise positions the samples within the immature to early-mature transition zone, consistent with the lower end of the oil window (Peters & Cassa, 1994; ASTM, 2023).



**Fig. 8:** Plot of HI versus  $T_{max}$  to indicate maturity evolution of UDY well samples

The Production Index ( $PI = S_1 / (S_1 + S_2)$ ) provides additional insight into maturity by

expressing the proportion of free hydrocarbons relative to total hydrocarbon-generative

capacity. PI values for the UDY samples range from 0.44 to 0.47 (mean 0.46), which, based solely on PI thresholds (Peters & Cassa, 1994), would suggest peak to late maturity. However, these PI values are anomalously high given the low Tmax and calculated Ro values. Peters, (1986), Hunt, (1996) and McCarthy et al., (2011) noted that PI values exceeding 0.20 frequently indicate contamination by oil-based

drilling muds or migrated hydrocarbons, rather than true maturity advancement. In this study, all samples exceed this contamination threshold, and all exceed Hunt's upper limit of 0.40 for indigenous oils in the main oil window. The Tmax–PI cross-plot (Fig. 9) corroborates this disparity, reinforcing the likelihood of non-indigenous (migrated) hydrocarbons contributing to elevated  $S_1$  values.

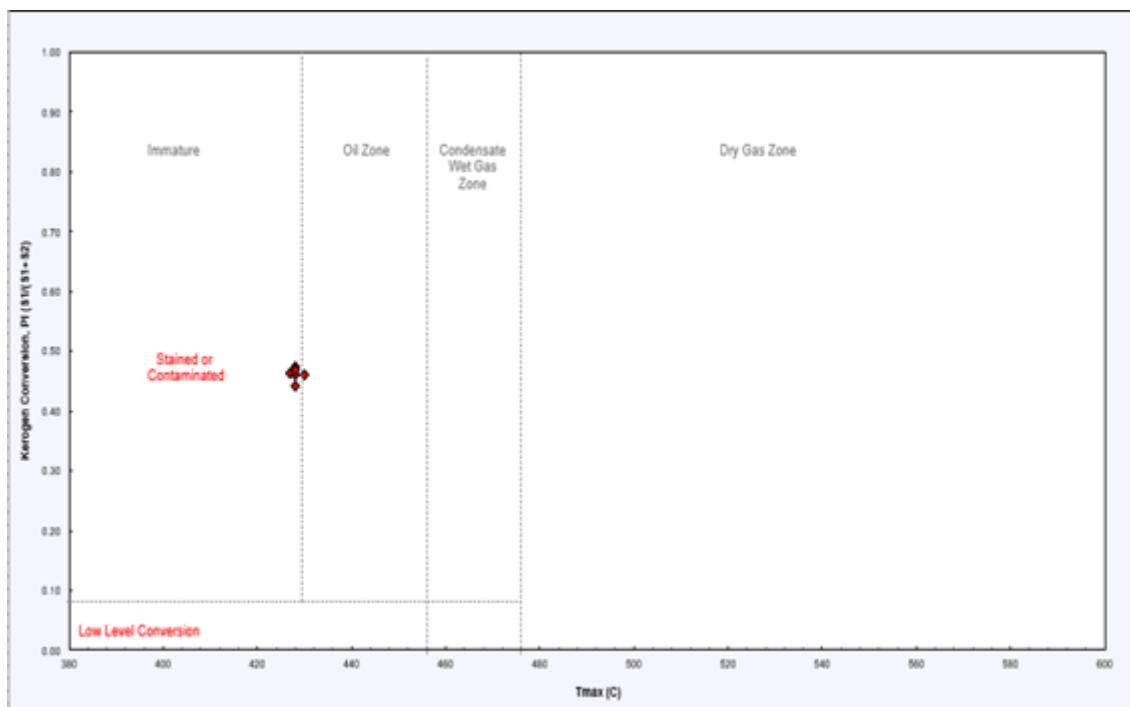


Fig. 9: Kerogen conversion and maturity indicators of the UDY well samples

#### 5.2.4 Source Rock Potential for Hydrocarbon Generation

Source rock generative potential is evaluated by the content of organic carbon,  $S_1$  values,  $S_2$  values and the sum of  $S_1$  and  $S_2$  values. Peters & Cassa, (1994) classifies source rock generative potential into poor (< 0.5 wt.%), fair (0.5 – 1.0 wt.%), good (1.0 – 2.0 wt.%), very good (2.0 – 4.0 wt.%) and excellent (> 4.0 wt.%). The TOC of the studied samples (2.35 – 3.95 wt.%) infers a very good potential to generate hydrocarbons.

The Rock–Eval  $S_1$  and  $S_2$  parameters provide insights into the free hydrocarbons present in the rock and the amounts of hydrocarbons that can be generated from kerogen, respectively (Peters & Cassa, 1994; Kouadio et al., 2020; Wotanie et al., 2022; Kumar et al., 2024). In the studied

shales,  $S_1$  values span 8.87 – 10.06 mg HC/g rock (mean 9.41 mg HC/g rock), while  $S_2$  values range from 10.30 – 11.29 mg HC/g rock (mean 11.00 mg HC/g rock) (Table 2). According to the classification of Peters & Cassa, (1994),  $S_1$  values greater than 4 mg HC/g rock indicate excellent generative potential, while  $S_2$  values from 10 – 20 mg HC/g of rock infer very good petroleum potential. The measured  $S_1$  data fall within excellent petroleum potential while  $S_2$  values fall within the very good category. These results reaffirm the interpretation that the UDY well samples contain an appreciable volume of thermally reactive kerogen capable of yielding significant hydrocarbons. The Genetic Potential ( $GP = S_1 + S_2$ ) provides a comprehensive measurement of the total hydrocarbons (oil +

gas) that may be generated upon sufficient thermal exposure (Hunt, 1996; Ehinola et al., 2015; Qadri et al., 2016; Osli et al., 2019; Kouadio et al., 2021; Wotanie et al., 2022; Oriahki & Okosun, 2025). Hunt, (1996) evaluated GP values <2, 2–5, 5–10, and >10 kg HC/ton as indicative of poor, fair, good, and very good generative potential, respectively. The GP values obtained for the UDY well samples range from 19.09 to 21.28 kg HC/ton (average 20.42 kg HC/ton), placing them unequivocally within the very good generative potential category. This result is entirely consistent with the patterns displayed on the S<sub>2</sub>–TOC plot (Fig. 7), where all samples plot within the field of good to very good source rocks.

## 6.0 Conclusions

Although petrography was performed on only two samples, Rock – Eval pyrolysis was conducted on six samples. All six Rock-Eval datasets show highly consistent TOC, HI, and Tmax values, indicating that UDY-2 and UDY-4 are valid representatives of the organic facies and maturity state of the entire sampled interval. The studied UDY samples reveal that:

1. The organic matter (comprising 74 -76% vitrinite, 18 -22% liptinite and negligible inertinite < 1%) is a mixture of terrestrial and algal inputs, forming a Type II/III kerogen assemblage.
2. The source rock is organically rich and possesses excellent hydrocarbon generative potential, with TOC ranging from 3.80 to 3.95 wt.% and high S<sub>2</sub> values varying between 10.30 and 11.29 mg HC/g of rock.
3. Tmax values of 427 -430°C and calculated vitrinite reflectance values (0.53 to 0.58% Ro) place the interval at the onset of the oil generation window.
4. High S<sub>1</sub> (8.87 -10.06 mg HC/g rock), PI (0.44 – 0.47) and S<sub>1</sub>/TOC (230 -255) values reveal abundant free hydrocarbons, suggesting migrated oil charge or strong retention capacity.

5. The depositional environment was paralic–deltaic with fluctuating redox conditions conducive to organic preservation.
6. The UDY interval is a highly prospective source rock with both oil and gas generation potential.

These findings provide a solid scientific foundation for further exploration decisions and petroleum systems modeling in the region.

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## Conflict of interest

The authors have no conflict of interests.

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