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Integrated Geochemical and Field Evaluation of the Fika Shale, Upper Benue Trough (NE Nigeria): Implications for Petroleum Source Rock Potential

Najib Abdullahi Yusuf¹, Bello Aliyu^{2,*}, Timothy Peter Bata³

¹ Teaching and Research Unit, Department of Physics, Engineering, Earth, Environment, and Mechanics, University of Grenoble Alpes, 38400 Saint-Martin-d'Hères, France

² State Key Laboratory of Oil and Gas Reservoir Geology and Exploitation, Chengdu University of Technology, Chengdu, China

³ Department of Applied Geology, Abubakar Tafawa Balewa University, Bauchi, Nigeria

*E-mail address: belloaliyukurya@yahoo.com

ABSTRACT

This study examines the Fika Shale in the Upper Benue Trough of north-eastern Nigeria to determine its petroleum source rock potential using a combination of field observations and laboratory analyses. Fifteen fresh shale samples were collected from the Pantami and Kundulun stream exposures and analyzed for Total Organic Carbon (TOC), Rock-Eval pyrolysis, and vitrinite reflectance. The TOC values (0.6–2.7 wt.%, average 1.67 wt.%) show that the shale contains fair to very good amounts of preserved organic matter. Rock-Eval results indicate Hydrogen Index values between 138 and 241 mg HC/g TOC, which point mainly to Type III kerogen with minor Type II/III influence in a few intervals. These kerogen types suggest that the shale can generate gas, with limited potential for mixed oil and gas. Most samples fall in the moderate source rock category based on their S₂ and genetic potential values, although the Liji Shale and PT-7 intervals stand out as better developed source horizons. Vitrinite reflectance values (0.77–1.34 %Ro) and Tmax readings (426–435 °C) show that the formation lies within the oil window and is approaching early wet-gas maturity in its more evolved sections. Field evidence, such as dark coloration, fine laminations, scattered pyrite, and the absence of bioturbation, supports deposition under low-energy, oxygen-deficient marine conditions that aided organic matter preservation. Altogether, the results indicate that the Fika Shale is an important contributor to petroleum generation within the Upper Benue Trough and forms a meaningful part of the basin's hydrocarbon system.

Keywords: Fika Shale, Upper Benue Trough, Rock-Eval pyrolysis, Kerogen type, Thermal maturity

1. INTRODUCTION

This study focuses on the applied geochemical evaluation of petroleum source rocks, with particular emphasis on the Fika Shale within the Upper Benue Trough, Nigeria. The research investigates the organic geochemical characteristics, hydrocarbon generation potential, and overall source rock quality of the formation. Through detailed analysis, the work aims to contribute to a better understanding of the petroleum system in the Upper Benue Trough and provide insights relevant to hydrocarbon exploration.

In recent years, Nigeria's search for new hydrocarbon resources has intensified, motivated by the dual imperative of boosting national reserves and diversifying exploration beyond the mature Niger Delta Basin, which remains the country's main producer with an output of approximately two million barrels of oil per day. Among the frontier basins currently attracting attention, the Upper Benue Trough stands out for its complex depositional history and proven stratigraphic intervals with source rock potential. Within this basin, the Fika Shale has been identified as a critical formation, widely regarded as a potential petroleum source rock.

Previous studies (e.g., Obaje et al., 2004; Adegoke et al., 2015; Sarki et al., 2017; Bata et al., 2017, 2025) have highlighted the organic richness and favorable maturity indicators of the Fika Shale, suggesting its capacity to generate hydrocarbons. However, most existing investigations are either spatially restricted or constrained by limited analytical integration, leaving gaps in the understanding of its regional source rock potential. Consequently, there is a strong need to re-examine the Fika Shale using modern, state-of-the-art geochemical techniques, coupled with field-based observations, to provide a more comprehensive assessment of its quality, maturity, and petroleum generation potential.

1. 1. Research question

The central research question guiding this study is:

What are the key source rock characteristics of the Fika Shale, specifically its organic matter quantity, quality, and thermal maturity, and how do these parameters collectively determine its effectiveness and potential for petroleum (oil and gas) generation?

1. 1. 1. Specific objectives

To address this research question, the study pursued the following objectives:

- 1) Quantify and analyze the distribution and variability of Total Organic Carbon (TOC) within sampled intervals of the Fika Shale.
- 2) Apply Rock-Eval pyrolysis to identify kerogen types and evaluate their implications for oil and gas generation potential.
- 3) Assess thermal maturity through vitrinite reflectance and Tmax parameters, and interpret their significance for hydrocarbon phase prediction (oil vs. gas).
- 4) Reconstruct depositional environments and redox conditions to understand the controls on organic matter preservation.

- 5) Integrate geochemical and field data to characterize the overall petroleum source rock potential of the Fika Shale.

2. REGIONAL GEOLOGY AND BRIEF LITERATURE REVIEW OF PREVIOUS WORKS

The Benue Trough of Nigeria is a prominent Cretaceous rift basin that formed in response to the separation of Africa and South America during the Early Cretaceous. Extending for more than 1,000 km in a northeast–southwest orientation, it is traditionally subdivided into the Upper, Middle, and Lower Benue Troughs (Nwajide, 2013). Within the Upper Benue Trough, the Fika Shale constitutes the uppermost marine unit of the Upper Cretaceous succession and has drawn considerable attention due to its dual role as a potential hydrocarbon source rock and an effective regional seal.

The stratigraphy of the Upper Benue Trough is well established (Figure 1). At its base, Precambrian basement rocks are unconformably overlain by the Albian Bima Formation, comprising dominantly continental sandstones. This is succeeded by the Cenomanian Yolde Formation, a sequence of sandstones and shales that also reflects continental to transitional settings. Above the Yolde Formation lie marine successions, including the Pindiga Formation and the Gongila/Fika formations.

The Fika Shale directly overlies the Pindiga Formation (and locally the Yolde Formation) and is itself capped by the continental Gombe Sandstone. Younger successions include the Gongola Formation, deposited in lacustrine to deltaic environments, while the Paleogene Kerri-Kerri Formation, consisting of sandstones, siltstones, and shales, marks the final phase of sedimentation in the basin.

The petroleum system significance of the Fika Shale has been the subject of extensive research and exploration studies, including those by the Nigerian National Petroleum Company. Early geochemical investigations by Avbovbo et al. (1986) reported generally low total organic carbon (TOC) values (<1.0 wt.%) for outcrop samples, but higher and more variable values (1–3 wt.%) in subsurface equivalents. Based on these findings, the formation was initially regarded primarily as a regional seal overlying the sandstone and carbonate reservoirs of the Pindiga and Yolde formations. Subsequent studies, such as Akande et al. (1992), employed Rock-Eval pyrolysis on outcrop samples and documented gas-prone kerogens with hydrogen index (HI) values between 100 and 200 mg HC/g TOC.

Later assessments of thermal maturity revealed pronounced differences between surface and subsurface occurrences. Adegoke et al. (2015) showed that surface samples are largely immature, whereas deeper subsurface equivalents range from marginal to peak gas generation windows, with burial depth identified as the primary control on maturity. More recently, the Fika Shale has also been evaluated in the context of unconventional resources. Obaje et al. (2011) and Johnson et al. (2014) reported moderate TOC values but persistently low HI, which constrains its potential for shale gas and shale oil plays.

Compared with established unconventional shale systems globally, the Fika Shale is thus regarded as a relatively poor-quality unconventional reservoir, though its regional role as both a source rock and a seal remain significant within the petroleum system of the Upper Benue Trough.

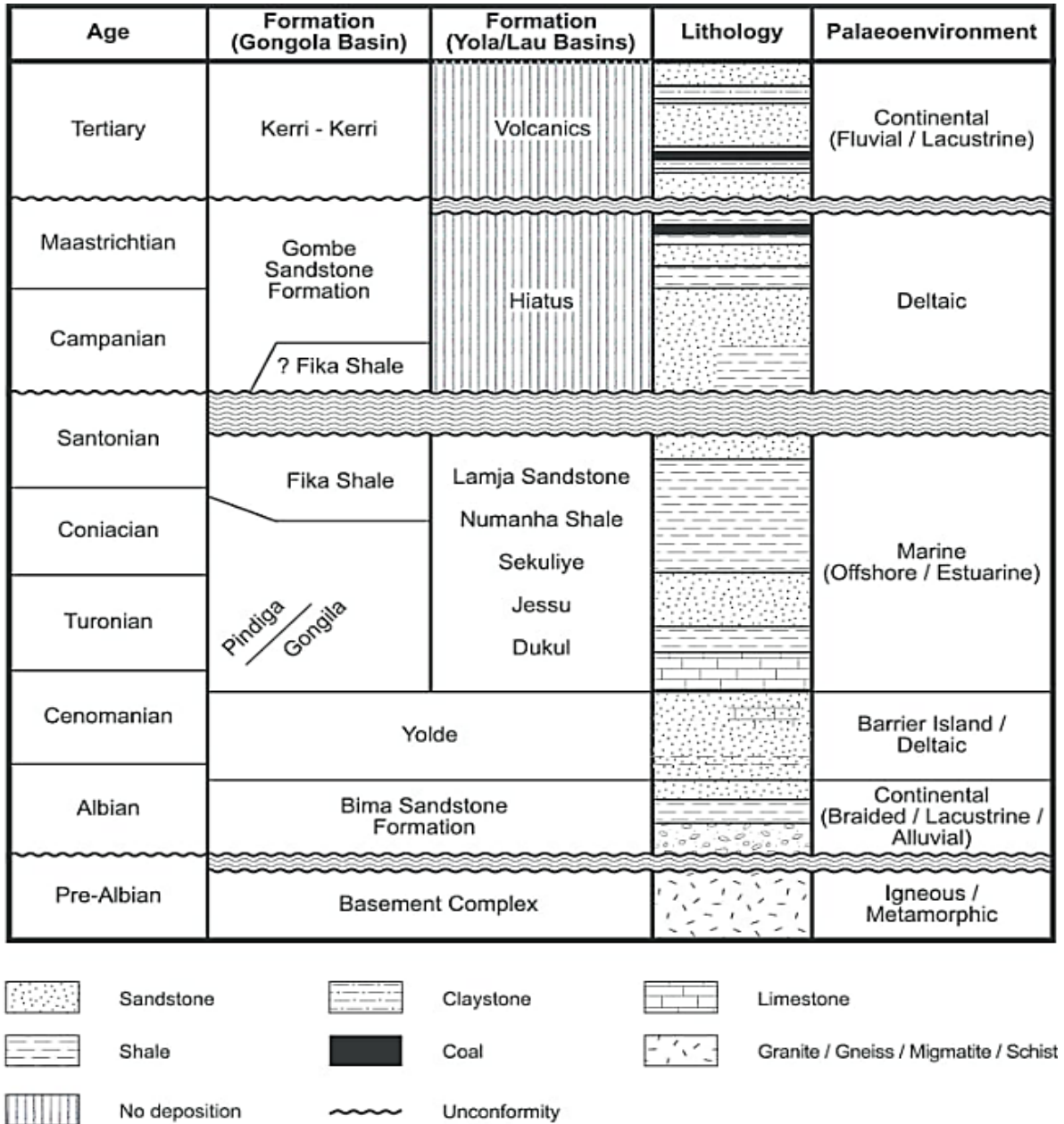


Figure 1. Stratigraphic successions in the Upper Benue Trough (After Nwajide, 2013).

3. METHODOLOGY

3. 1. Fieldwork and sampling

A comprehensive fieldwork exercise was conducted in the Upper Benue Trough Basin, where the Fika Shale are exposed. Fresh outcrop samples were systematically collected from exposed sections along road cuts and river channels, which were carefully mapped and logged at near-surface levels. Efforts were made to obtain unweathered and representative source rock samples from selected locations of interest.

The collected samples were stored in polythene bags, properly labelled, and subsequently transported to the petroleum geochemistry laboratory. In the laboratory, the samples were oven-dried at 110 °C and pulverised to fine powder. The prepared rock samples were then subjected to geochemical analyses, including Total Organic Carbon (TOC) determination and Rock-Eval pyrolysis.

3. 2. Total organic carbon and rock eval pyrolysis

A total of 15 potential source rock samples were selected, pulverized, and analyzed for total organic carbon (TOC), hydrogen index (HI), oxygen index (OI), and Tmax (temperature of maximum kerogen pyrolysis yield) using a Rock-Eval II instrument.

During analysis, the oven was held isothermally at ~300 °C for three minutes, allowing free hydrocarbons to volatilize and be measured as the S1 peak with a flame ionization detector (FID). Pyrolysis was then carried out between 300–600 °C at a heating rate of 25 °C/min. In this phase, higher molecular weight hydrocarbons (>C40) were volatilized and non-volatile organic matter cracked, with the resulting hydrocarbons measured as the S2 peak by FID.

Tmax, the temperature at which the S2 peak reached its maximum, varied depending on the type and thermal maturity of the kerogen. The hydrogen index (HI) was calculated from the ratio of S2 to TOC, reflecting the hydrocarbon-generating potential of the kerogen. The oxygen index (OI), determined from the CO₂ released at temperatures above 550 °C, provided insight into the oxygen content of the organic matter and its thermal maturity.

Sulphur content was also analyzed: residual samples were combusted at high temperatures in a LECO sulphur analyser, where sulphur was oxidized to SO₂ and quantified using infrared detection, expressed as a percentage.

3. 3. Vitrinite reflectance

Vitrinite reflectance is a widely used parameter for assessing the thermal maturity of organic matter in source rocks. In this study, it was measured on samples with TOC values greater than 2.0%. The samples were embedded in epoxy resin, and a section perpendicular to the surface was polished for analysis. Under a reflected light microscope, a photometer was used to measure the intensity of light reflected from vitrinite particles. The mean reflectance values obtained were recorded as Ro.

4. RESULTS AND DISCUSSION

4. 1. Field observations

Comprehensive fieldwork exercise was carried out along the Pantami Stream and Kundulun streams within Fika Formation, during which outcrop samples were systematically collected at intervals of at least 100 m from each sampling location. At each site, detailed lithological characteristics were recorded, including color, grain size, and mineralogical composition.

The shale along the stream exhibited notable variation in color, ranging from dark grey to light grey, reflecting differences in the organic matter content across the formation. The darker shale generally indicated higher concentrations of preserved organic matter, while the lighter grey shale suggested lower organic content or increased dilution by siliclastic minerals.

Grain size was very fine to fine, consistent with a low-energy depositional environment, and the rocks displayed high fissility, characteristic of well-laminated, clay-rich shale.

Mineralogically, the shale were dominated by clay minerals (such as illite and smectite), with subordinate quartz, feldspar, and occasional carbonate fragments. Disseminated pyrite was locally observed in some samples, further supporting deposition under reducing conditions.



Figure 2. Field photographs of dark and light grey shales of Fika Formation.

Table 1. Results from TOC and Rock-Eval Pyrolysis of the analysed samples.

Sample ID	TOC (%)	S (%)	S1 (mg/g)	S2 (mg/g)	HI (mg HC/g TOC)	OI (mg CO ₂ /g TOC)	Tmax (°C)
PT 7B	2.4	1.2	0.9	5.2	217	42	430
PT ST 1	1.8	0.9	0.4	2.9	161	56	425
PT ST 2	1.2	0.6	0.2	1.8	150	75	422

Pantami Stream 5	2.6	1.0	0.5	4.1	158	60	426
PT 5	1.0	0.5	0.1	1.5	150	70	420
PT ST 5	2.0	1.1	0.5	3.5	175	48	428
PT 7A	2.3	1.3	0.7	5.1	222	40	432
Sample 1 (Mile 3)	1.1	0.6	0.2	1.7	155	68	424
Pantami Stream 2	1.5	0.7	0.3	2.5	167	63	425
Sample 3	1.4	0.6	0.3	2.2	157	66	426
KD 2	1.3	0.5	0.2	2.0	154	70	423
Liji Oil Sand	0.6	1.4	1.5	0.5	—	—	—
KD-L-3	1.9	0.8	0.5	3.6	189	45	427
KD L -5	1.3	0.6	0.2	1.8	138	62	422
Liji Shales	2.7	1.6	0.8	6.5	241	35	435

4. 2. Organic matter richness/TOC analysis

The richness of organic matter in a potential source rock is most commonly assessed using Total Organic Carbon (TOC), which measures the total amount of organic material (kerogen) present in the rock, expressed as a weight percentage (TOC wt.%). Higher TOC values generally correspond to greater hydrocarbon generation potential. According to the classification proposed by Peters (1986), TOC values between 0.5–1.0 wt.% indicate *fair* source rock potential, 1.0–2.0 wt.% represent *good* potential, 2.0–4.0 wt.% reflect *very good* potential, and values exceeding 4.0 wt.% are considered *excellent*. This scheme remains one of the most widely applied benchmarks in petroleum geochemistry.

In this study (Table 1), TOC values range from 0.6 to 2.7 wt.%, with an average of 1.67 wt.%. The lowest value (0.6 wt.%) was recorded in the Liji Oil Sand sample, classifying it as a *fair* source rock and marginally sufficient for hydrocarbon generation. The majority of samples—including PT ST-1, KD-2, PT-3, PT-5, PT ST-5, Sample 1 Mile 3, Pantami Stream-2, Sample-3, KDL-3, and KDL-5—fall within the 1.0–2.0 wt.% range, categorizing them as *good* source rocks with adequate organic richness to support petroleum generation. The highest TOC values (>2.0 wt.%), recorded in samples PT-7A, PT-7B, Pantami Stream-5, and the Liji Shales, fall into the *very good* category, indicating significant organic matter enrichment and strong source rock potential.

Overall, the analyzed shale samples exhibit fair to very good organic richness, consistently surpassing the minimum threshold of 0.5 wt.% required for a rock to qualify as a potential petroleum source rock.

4. 3. Rock-Eval pyrolysis

Rock-Eval pyrolysis is a widely applied geochemical technique that plays a critical role in petroleum exploration and source rock evaluation. It provides a rapid and reliable means of assessing the quantity, quality, and thermal maturity of organic matter within sedimentary rocks, particularly organic-rich shales. By simulating natural hydrocarbon generation under controlled heating, the method yields a suite of parameters that form the foundation of source rock characterization.

The S1 parameter (mg HC/g rock) quantifies the amount of free hydrocarbons already present in the rock, representing oil and gas that have been generated and retained. The S2 parameter (mg HC/g rock) measures the hydrocarbons released during the thermal cracking of kerogen, reflecting the remaining generative potential of the rock. From these values, the Hydrogen Index (HI; mg HC/g TOC) is derived as $(S2/TOC) \times 100$, providing insight into kerogen type and whether the source rock is predisposed to generate oil, gas, or a mixture of both.

Complementary to HI, the Oxygen Index (OI; mg CO₂/g TOC) is obtained from CO₂ released during pyrolysis and, when combined with HI, facilitates kerogen typing and assessment of organic matter origin, commonly displayed on Van Krevelen diagrams. Another key parameter, Tmax (°C), represents the temperature at which the maximum release of hydrocarbons occurs during S2. It serves as a reliable maturity indicator, distinguishing between immature, mature, and post-mature stages of hydrocarbon generation. The results of the Rock-Eval pyrolysis analysis for the studied Fika Shale samples are presented in Table X.

4. 3. 1. Kerogen Type (Organic Matter Type)

After establishing organic richness from TOC values, the next step in evaluating source rock potential is to determine the type of organic matter (kerogen type). This study used Hydrogen Index (HI) values obtained from Rock-Eval pyrolysis, supplemented by HI versus OI cross-plots (Van Krevelen diagram), to classify kerogen types and infer their hydrocarbon generation potential.

4. 3. 1. 1. Kerogen Classification Based on Hydrogen Index (HI)

The Rock-Eval pyrolysis results show HI values ranging from 138 to 241 mg HC/g TOC. According to the classification scheme of Peters et al. (2005), these values correspond to Type III and mixed Type II/III kerogen.

- Type II/III kerogen: Three samples—PT 7A, PT 7B, and Liji Shales—record HI values between 217 and 241 mg HC/g TOC, placing them in the transitional Type II/III field. This kerogen type reflects mixed organic matter input, capable of generating both oil and gas, although with lower oil potential than pure Type II kerogen. These samples therefore, represent the most prospective intervals within the dataset.
- Type III kerogen: The remaining eleven samples exhibit HI values between 138 and 189 mg HC/g TOC, classifying them as Type III kerogen. This hydrogen-poor kerogen is typically derived from terrestrial higher plant material rich in cellulose and lignin. Its hydrocarbon potential is dominantly gas-prone, with limited capacity for liquid hydrocarbon generation.

No samples displayed HI values high enough to indicate Type I (>600 mg HC/g TOC, algal-rich, highly oil-prone) or pure Type II kerogen (300–600 mg HC/g TOC, marine oil-prone), confirming the absence of algal-dominated organic matter in the analyzed intervals.

4. 3. 1. 2. Hydrogen Index (HI) versus Oxygen Index (OI) Correlation

To further refine kerogen classification, HI values were plotted against OI values on a Van Krevelen diagram (Figure 3). The cross-plot results confirm that the majority of samples fall within the Type III kerogen field, reinforcing their classification as gas-prone. Only three samples, PT 7A, PT 7B, and Liji Shales - plot in the Type II/III transitional field, consistent with the earlier HI-based interpretation.

This distribution suggests that the organic matter in the Fika Shale was predominantly derived from terrestrial inputs, deposited under conditions that favored preservation of gas-prone kerogen. The presence of transitional Type II/III kerogen in select intervals indicates localized contributions of mixed organic matter, likely reflecting variations in depositional settings from marine to lacustrine environments.

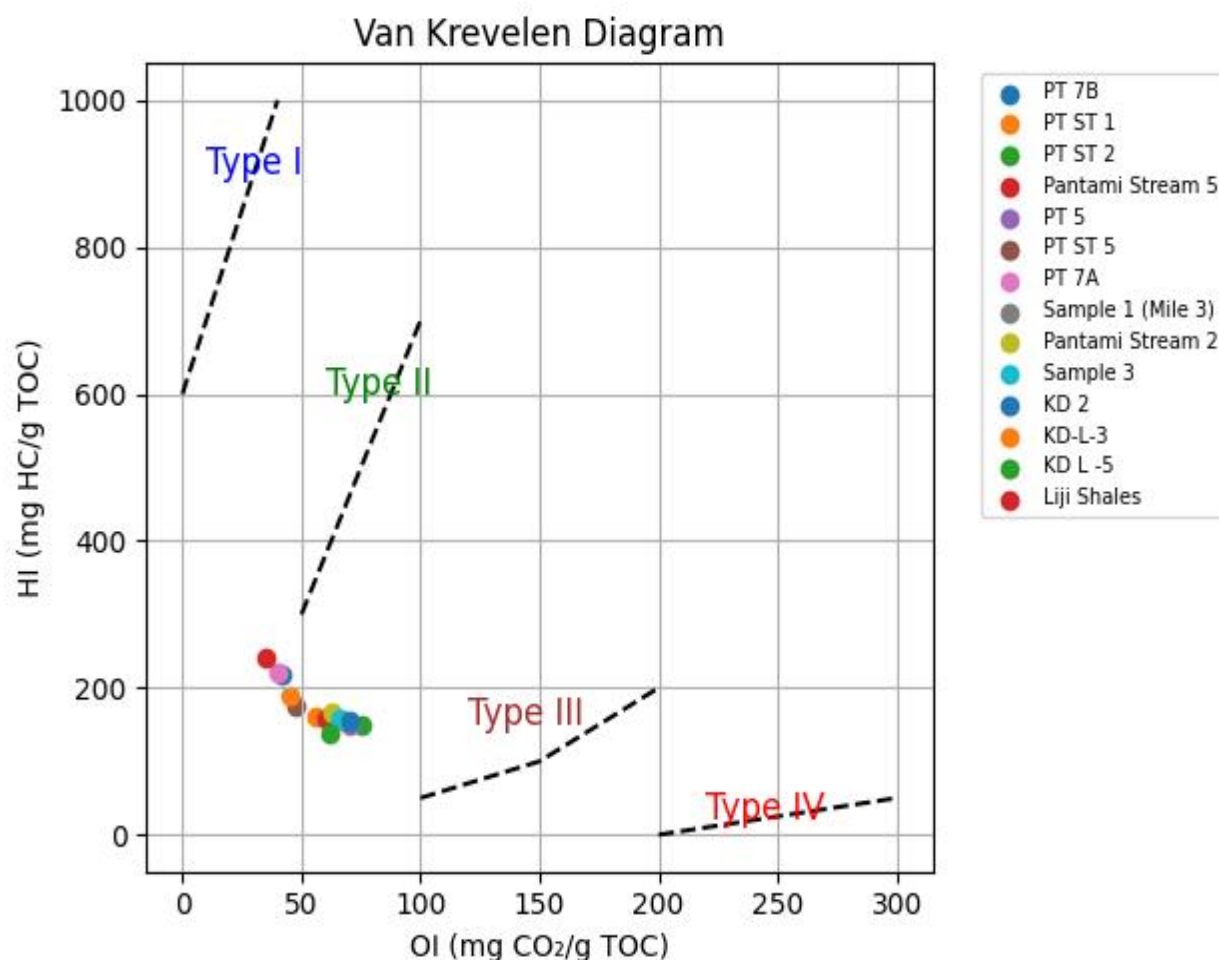


Figure 3. Plot of HI vs OI determining the types of Kerogens present (Pseudo Van Krevelen Diagram).

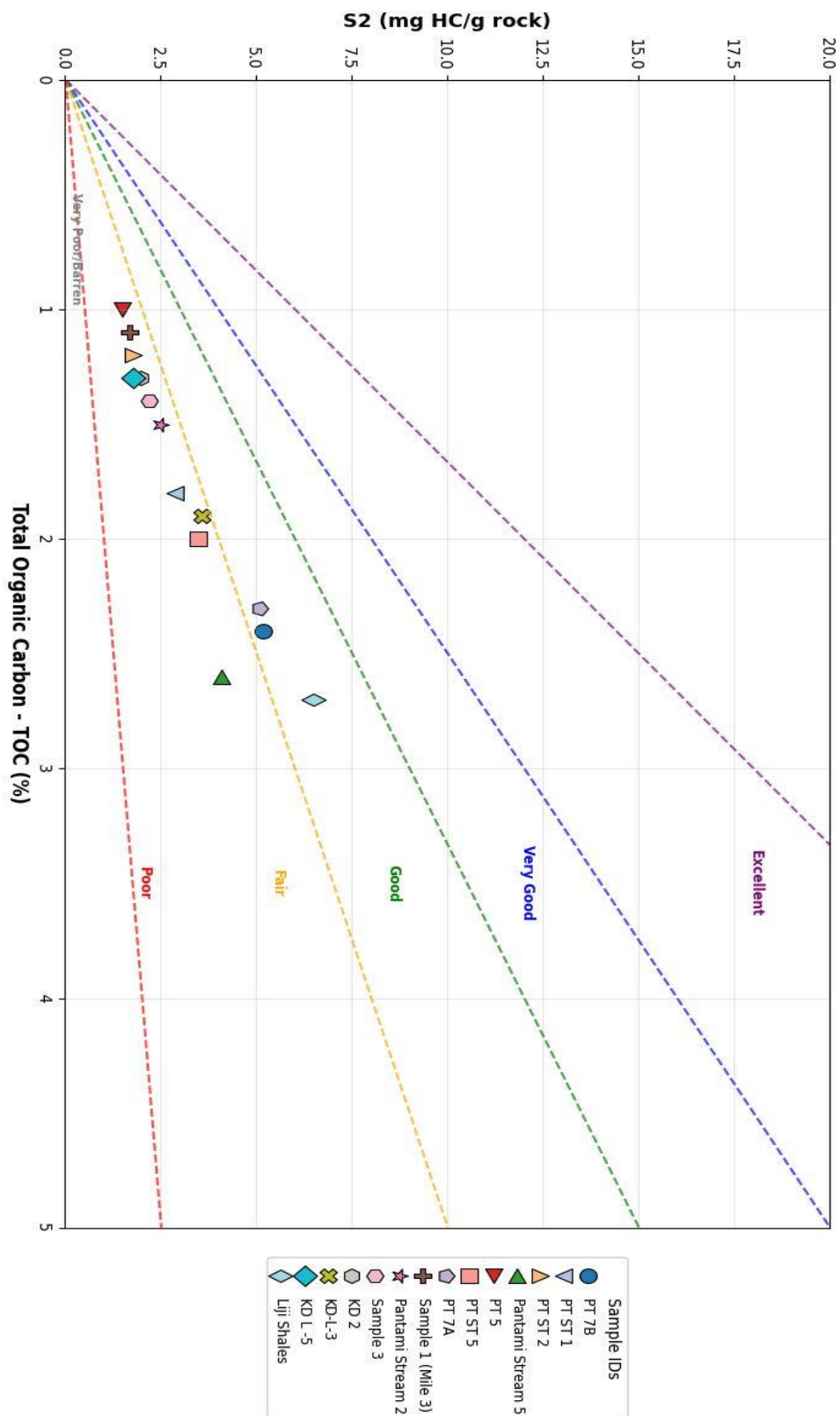


Figure 4. Plot of S2 vs TOC.

4. 3. 2. Source rock potentials

Jackson et al. (1985) and Ehinola et al. (2005) proposed the use of S2 versus TOC cross-plots as a reliable approach for evaluating source rock quality. This method compares the quantity of organic matter (TOC) with its hydrocarbon-generating capacity (S2), thereby providing a robust measure of petroleum potential.

In the present study, TOC values range from 0.6 to 2.7 wt.%, while S2 values vary between 0.5 and 6.5 mg HC/g rock (Table 1). Three samples—the Liji Shale (TOC 2.7 wt.%, S2 6.5 mg HC/g rock), PT-7A (TOC 2.3 wt.%, S2 5.1 mg HC/g rock), and PT-7B (TOC 2.4 wt.%, S2 6.5 mg HC/g rock)—fall into the *good source rock* category (Peters, 1986). These are characterized by both high organic richness and strong generative capacity, representing the most promising intervals within the dataset.

A second group, including Pantami Stream-5, PTST-5, and KDL-3, records TOC values of ~2.0 wt.% with S2 values between 3.5 and 4.1 mg HC/g rock. These are classified as *moderate to fair quality source rocks*, with adequate but lower hydrocarbon generation potential compared to the first group.

In contrast, samples such as PTST-1, PTST-2, Sample-3, KDL-2, and KDL-5 yield TOC values of 1.0–1.8 wt.% and S2 values of 1.8–2.9 mg HC/g rock. These represent *fair to poor quality source rocks*, reflecting limited organic richness and weak generative capacity.

Overall, the S2 versus TOC plot (Figure 4) reveals a positive correlation between TOC and S2, confirming that hydrocarbon generation potential in the studied Fika Shale samples is primarily controlled by the quantity of preserved organic matter.

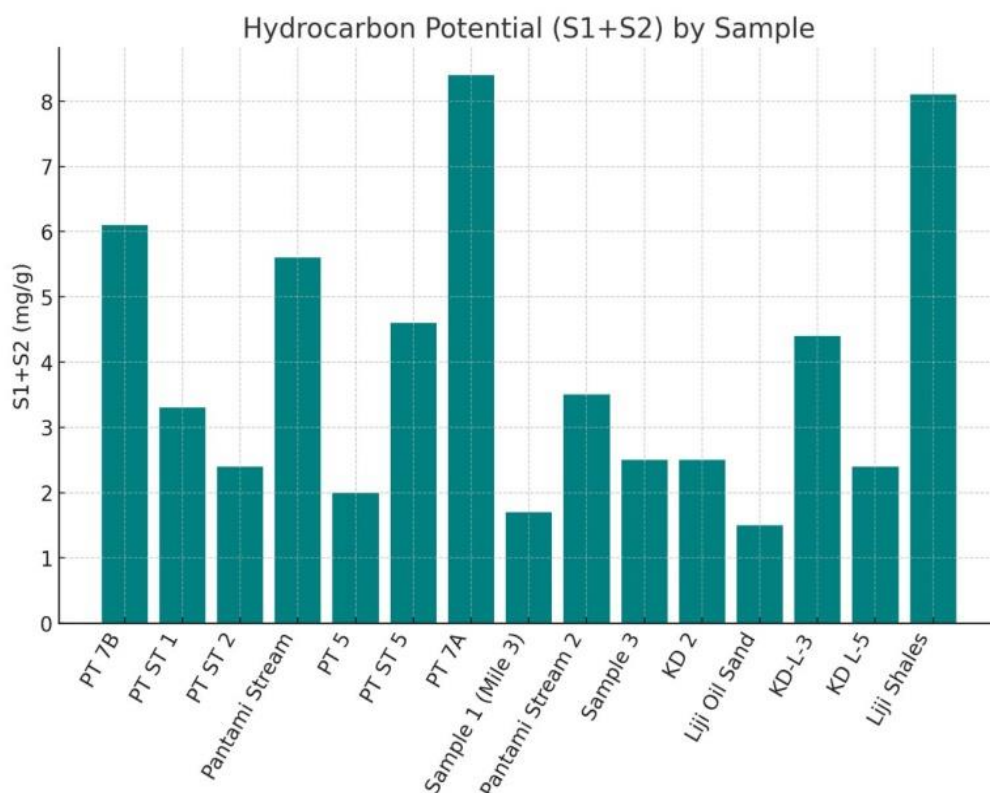


Figure 5. Results of Pyrolysis S1+S2.

Tissot and Welte (1984) introduced the concept of Genetic Potential ($GP = S1 + S2$) as a quantitative basis for classifying source rock quality. According to their classification scheme, source rocks with $GP < 2$ mg HC/g rock are considered *non-generative or gas-prone*, those with GP between 2 and 6 mg HC/g rock are regarded as *moderate source rocks*, and rocks with $GP > 6$ mg HC/g rock are classified as *good source rocks*.

In this study, Samples PT-5 and 1 Mile 3 yield GP values below 2 mg HC/g rock, indicating that they are non-generative to gas-prone in character. A majority of the samples—PT ST-1, PT ST-2, Pantami Stream-5, PT ST-5, PT-7A, Pantami Stream-2, Sample-3, KD-2, Liji Oil Sand, KDL-3, and KDL-5—fall within the 2–6 mg HC/g rock range, placing them in the *moderate source rock* category. In contrast, PT-7B and Liji Shales exhibit GP values exceeding 6 mg HC/g rock, which classifies them as *good-quality source rocks* with stronger hydrocarbon generation potential (Figure 5).

Overall, the genetic potential values corroborate findings from TOC and S2 analyses, highlighting that while most Fika Shale intervals are moderate in generative capacity, select horizons (PT-7B and Liji Shales) stand out as the most prospective within the studied succession.

4. 4. Thermal maturity assessment

The thermal alteration of organic matter provides a robust and widely accepted indicator of source rock maturity. The concentration of organic matter within source rocks, together with the extent of hydrocarbon generation, is primarily governed by both the type of organic matter present and the degree of thermal transformation it has undergone (Tissot and Welte, 1984). These authors proposed well-structured guidelines for interpreting thermal maturity using vitrinite reflectance (%Ro) values: rocks with $Ro < 0.5\%$ are classified as immature, with no significant hydrocarbon generation; values of 0.5–0.7% correspond to the early oil window; 0.7–1.0% to the main oil window; 1.0–1.3% to the late oil window; and 1.3–2.0% to the wet gas/condensate window. In the present study, thermal maturity was evaluated using temperature-sensitive parameters such as vitrinite reflectance (%Ro) and Rock-Eval Tmax. Four samples with the highest total organic carbon (TOC) contents were selected for detailed assessment. Vitrinite reflectance analyses yielded mean values of 1.22% (PT 7B), 0.77% (Pantami Stream-5), 1.02% (PT 7A), and 1.34% (Liji Shales). These results reveal a progressive maturity trend across the sampled locations.

- **Pantami Stream-5** ($Ro = 0.77\%$, $T_{max} = 426$ °C): The Ro value places this sample in the early to mid-oil window. However, the relatively low Tmax may indicate suppression effects, possibly associated with surface weathering. At greater depths, higher Tmax values would be expected. Overall, this sample represents the incipient to active oil-generation phase.
- **PT 7A** ($Ro = 1.02\%$, $T_{max} = 432$ °C): Both vitrinite reflectance and Tmax place this sample firmly in the late oil generation stage. These results suggest that the source rock has already undergone significant transformation, with hydrocarbons actively expelled into the system.
- **PT 7B** ($Ro = 1.22\%$, $T_{max} = 430$ °C): This sample also lies within the late oil window, confirming extensive petroleum expulsion. The slightly lower Tmax compared to PT 7A may reflect subtle variability in kerogen type or depositional history, but the Ro value strongly supports late-stage oil generation.

- **Liji Shales** ($R_o = 1.34\%$, $T_{max} = 435\text{ }^{\circ}\text{C}$): These values indicate thermal evolution beyond the late oil window, entering the early gas-generation (wet gas/condensate) phase. This suggests that the Liji Shales represent the most thermally mature source rocks in the dataset.

Collectively, the results demonstrate that the studied samples range from early oil window to early gas generation, highlighting the progressive maturity of organic matter within the investigated section. This maturity variation has direct implications for hydrocarbon generation, expulsion, and preservation across the basin.

Table 2. Results of vitrinite reflectance measurements on selected rock samples.

Sample	Vitrinite Reflectance (RO)	TMAX
PT7B	1.22	430
Pantami Stream 5	0.77	426
PT7A	1.02	432
Liji shale	1.34	435

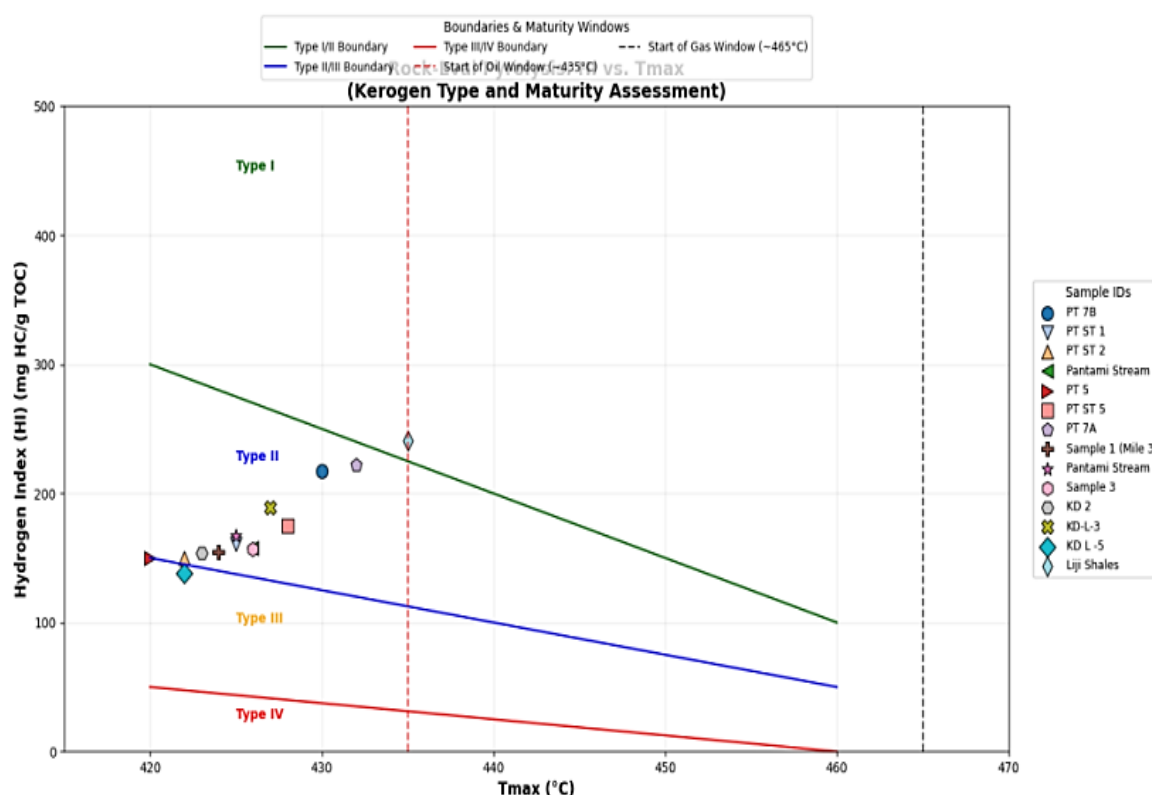


Figure 6. Plot of HI vs Tmax indicating source rock thermal maturity.

A cross-plot of kerogen type against thermal maturity, based on Hydrogen Index (HI) and Tmax values (Figure 6), was employed to further evaluate the relationship between organic matter maturity and hydrocarbon generation potential in the analyzed samples. The plot reveals that Type II oil-prone kerogen is predominant, with a subordinate contribution from mixed Type II/III kerogen, consistent with observations from Figure 3. Importantly, all data points fall within the established maturity zone.

In summary, the results demonstrate that all analyzed samples lie within the oil window, confirming favorable thermal maturity conditions for effective hydrocarbon generation.

4. 5. Depositional environment from field and geochemical evidence

Field observations indicate that the Fika Shale is typified by its black to dark-grey coloration, fine lamination, and absence of bioturbation—features that strongly suggest deposition under an anoxic environment (Joseph et al., 2022). The dark coloration of shale is generally associated with enhanced preservation of organic matter. In contrast, under oxygen-rich (oxic) conditions, organic matter is typically degraded; thus, the preservation of organic material in the Fika Shale points to oxygen-deficient bottom waters at the time of deposition.

The presence of fine laminations and the absence of bioturbation further support this interpretation. Laminations are best preserved in environments with minimal benthic disturbance, a condition favored by anoxic or dysoxic bottom waters. Similarly, the lack of bioturbation, which is usually linked to oxygenated conditions and benthic activity, indicates that oxygen levels were insufficient to sustain a diverse benthic community.

Geochemical data corroborate these field-based inferences. The total organic carbon (TOC) contents of the shale exceed the minimum threshold of 0.5 wt.% for organic richness, confirming appreciable preservation of organic matter. Likewise, the consistently low sulfur contents (<1%) in the analyzed samples (Table 1) are in line with deposition under oxygen-deficient conditions, where limited sulfate availability restricts pyrite formation.

Taken together, these sedimentological and geochemical characteristics strongly suggest that the Fika Shale was deposited in a quiet, low-energy marine setting, where oxygen deficiency not only inhibited benthic activity but also facilitated the accumulation and preservation of organic matter.

5. CONCLUSIONS

The petroleum source rock evaluation of the Fika Shale in the Upper Benue Trough demonstrates that it constitutes a source rock of fair to very good quality. Total Organic Carbon (TOC) values consistently exceed the minimum threshold required for hydrocarbon generation, confirming adequate organic matter enrichment. Rock-Eval pyrolysis results further reveal a predominance of Type III kerogen with contributions from mixed Type II–III kerogens, suggesting a dual potential for oil and gas generation.

Thermal maturity assessments based on vitrinite reflectance and Rock-Eval Tmax indicate that the Fika Shale lies predominantly within the oil to early gas generation window, with certain intervals already advancing into the late oil phase. This maturity spectrum signifies that active hydrocarbon generation and expulsion have likely taken place in the deeper subsurface, enhancing the petroleum system potential of the formation. The depositional environment, characterized by anoxic and low-energy marine conditions, strongly favored the

preservation of organic matter. These paleoenvironmental conditions, combined with the geochemical characteristics, underscore the Fika Shale's role as an effective source rock within the Upper Benue Trough. Nevertheless, the variability in TOC and generative capacity across different localities, coupled with the predominance of Type III and mixed kerogen assemblages, suggests that while the formation is capable of generating and expelling hydrocarbons, its potential is more moderate compared to highly oil-prone kerogen systems.

In summary, the Fika Shale can be regarded as a significant contributor to the petroleum prospectivity of the Upper Benue Trough. Its maturity profile, kerogen composition, and depositional attributes collectively affirm its role in regional hydrocarbon generation, with implications for both oil and gas exploration strategies.

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