

Organofacies Characteristics of the Albian to Turonian Lower Post-Rift Sediments in the Orange Basin, South Africa: Insights into Type III Source Rock

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ABSTRACT

The present study describes the quantity, type, maturity, and petroleum generative potentials of potential source rock horizons using Rock-Eval pyrolysis for twenty-four (24) rock samples from the Orange Basin 4-K wells. The results showed an overall abundance of gas-prone organic matter. Since the HI value is generally less than 200mgHCgTOC in all the analyzed samples, it suggests type-III kerogen. Very low S₁ and S₂ yields indicate a low source rock generating potential in the lower post-rift deposits, which are probably more gas prone. Thermal maturity of the organic matter was predicted based on geochemical maturity indicators like Tmax (°C) and Production Index (PI). Tmax values vary from 425 to 476°C, signifying the presence of immature to early mature to late mature and post-mature source rocks. Meanwhile, the PI as a maturity indicator is between 0.10 and 0.27, containing early mature to peak mature source rocks. KH-1 well have PI values ranging from 0.18 to 0.24, with most of the samples at the peak of the oil window. This indicates that the KH-1 well organofacies are more likely to have good generative potential to produce oil.

Keywords: Rock-Eval; Orange Basin; organic matter; source rock; post-rift; organofacies.

1.0 INTRODUCTION

In spite of the quantity and quality of organic materials, a possible source rock also has the capacity to produce and eject thermally matured oil and gas accumulations that are buried in geological succession (Waples, 1994; Cavelan et al., 2020; Peters and Cassa, 1994; Abukova & Volozh 2021). Chen et al. (2020) and Waples (1994) grouped the source rocks into (1) effective source rock, (2) possible source rock, and (3) potential source rock. Generally, source rock evaluation is based on the quantity, composition, and degree of maturity of the organic materials present in the rock.

South Africa's largest offshore basin, the Orange Basin, is very little-studied (Figure 1; Adam & Opuwari 2024; Yelwa et al., 2024). With forty (40) wells being drilled, it is the most prolific basin and the broadest in South Africa, supporting sedimentary successions that flourish from the upper Jurassic to the Holocene (Broad et al., 2012; Yelwa et al., 2020; Yelwa et al., 2022). Prior research conducted in the region has included more than only sedimentological, geochemical, and geophysical

studies (van der Spuy 2003; Yelwa et al. 2022a; Yelwa et al. 2022b; Yelwa et al. 2024; Yelwa et al. 2025).

The organic content and producing capacity of the source rocks are described below. Additionally, some Rock-Eval data was used to determine the thermal maturity level of these rocks.

1.1 Geologic Setting

A distinct kind of passive margin, the Orange Basin was formed by Gondwana splitting and Triassic to Jurassic intracontinental rifting, resulting in a large number of graben and half-graben formations across the southwest boundary (Jungslager, 1999; Perez et al., 2019; Lovecchio et al., 2024; Yelwa et al., 2025). During the Cretaceous period, mountain-building activities were caused by volcanic eruptions that followed the separation of South America from Africa (Hartwig et al., 2012; Neukirchen, 2022). It is situated within the offshore Southwestern Africa Atlantic margin bounded by the Kudu arc northward and the Agulhas-Columbine arc southward (Figure 1). With a total deep-water licensing

area of over 43,000 km², the basin stretches up to Namibia's offshore southwestern volcanic rifted passive edge (Gerrard and Smith 1982; Yelwa et al., 2024). From the Late Jurassic to the Recent Era, the basin evolved (Brown, 1995; Gerrard and Smith, 1982; Maduna et al., 2022). It spans over 160,000 km² and extends aerially from the shelf to the deep offshore marine between latitudes 31° and 33.5°S and longitudes 16° and 17°E (Figure 1). Even though the Orange basin is the largest offshore basin in South Africa, less than 40 wells were drilled, equaling one well per 4,000 Km² (Broad et al. 2012; Adam & Opuwari 2024).

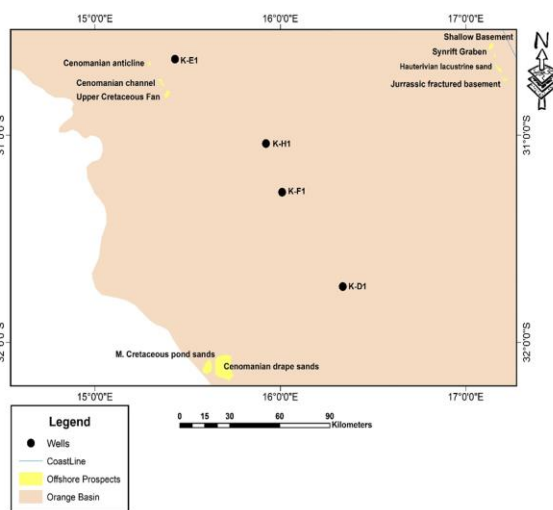


Figure 1. Location map of the Orange Basin, South Africa (Yelwa et al., 2022a)

2.0 Objectives and Methods

In this study, the TOC content and Rock-Eval pyrolysis approach (Espitalie et al., 1985; Uzoegbu et al., 2023) were used to describe the quantity, thermal maturity of organic matter, and relation to the petroleum generative potentials of the prospective organic sediments. Twenty-four chosen shale rock samples from the Cretaceous lower post-rift succession in the Orange Basin, South Africa, were subjected to this method. So, Rock-Eval pyrolysis data of the upper Turonian to Aptian stratigraphic framework was undertaken.

3.0 RESULTS AND DISCUSSIONS

3.1 Quantity of Organic Matter

The organic geochemistry of the examined 24 samples within 4 wells was independently assessed according to total organic carbon (TOC) values (Peters and Cassa, 1994; Cappuccio et al., 2021). The TOC values of the examined shales show good yield between 1.12 and 1.89 wt%, averaging up to 1.44 wt%, proving favorable petroleum potential with a rich organic matter type. The

TOC values in the KD-1 well range from 1.19 to 1.7 wt%, with an average of 1.49 wt%, implying good petroleum potential. In this well, TOC content increases with depth. KE-1 TOC content ranges from 1.2 to 1.89 wt%, having an average of 1.41 wt%. The KE-1 hosts the highest TOC value of 1.89 wt% at the Lower Albian 3340 m. In KF-1 well, TOC content is between 1.12 and 1.8 wt%, with an average of 1.50 wt%, also of good petroleum potential. In KH-1, the well TOC content is between 1.20 and 1.48 wt%, with an average of 1.35 wt% with increasing depth as in KD-1 samples which is also of good generative potential.

3.2. Quality of Organic Matter

Determination of the quality of kerogen input in the shales was examined through HI and OI (Peters and Cassa, 1994; Bansal et al., 2019). S₃ peak, HI and OI were generally adapted for kerogen-type determinants in the examined samples. The overall lower post-rift HI values are between 33.33 and 150 mgHCgTOC, with an average of 85.43 mgHCgTOC, suggesting the abundance of gas-prone organic matter. In all the samples examined from various wells, KH-1 shales have higher HI values, implying higher quality source rocks than the other well samples. The oxygen index of the 24 samples examined ranges between 43.23 and 460.20 mg CO₂/g TOC, with an average up to 108.45 mg CO₂/g TOC. Since the HI value is generally less than 200 mg HCg TOC in all the analyzed samples, it suggests type III kerogen (Peters and Cassa, 1994; Hazra et al., 2022). A plot of S₂ versus TOC and HI versus OI has abundant type III with some type IV kerogen (Figures 2 and 3). This organofacies shows high contribution from terrigenous higher plants.

The Orange Basin is predominantly composed of type III kerogen (Figure 3). This may be due to Orange Basin sediment input from the Orange River having abundant terrestrial remains, particularly around the Northern and Central units of the basin (vander Spuy, 2003; Ncube et al., 2024).

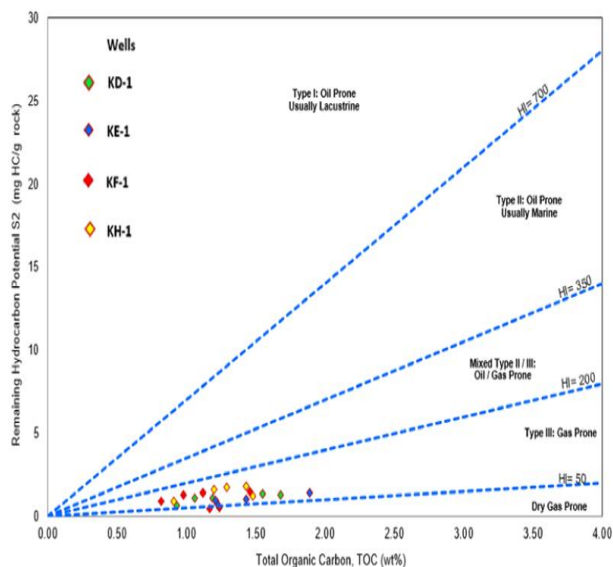


Figure 2: S_2 versus TOC showing prevalence of type III kerogen in the study area

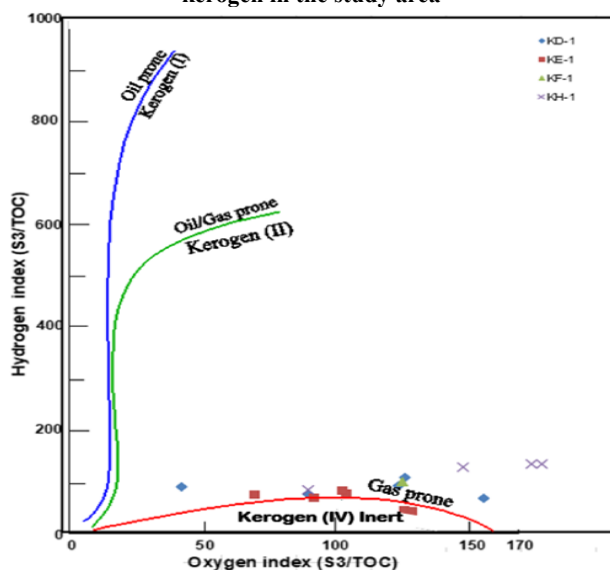


Figure 3: Pseudo van Krevelen plot of hydrogen index against oxygen index (Yelwa et al., 2025) illustrates 90% of the examined samples are gas prone, whereas 10% are possibly inert. This was also true in Figure 2 above.

3.3 Source Rock Generative Potential

The source rock generative potential was evaluated using Rock-eval S_1 , S_2 parameters based on Peter & Cassa, 1994. This is achieved by plotting remaining HC generative potential (S_2 mgHC/grock) versus TOC (wt%). Similarly, free hydrocarbon (S_1 mgHC/grock) is plotted against remaining hydrocarbon generative potential (S_2 mgHC/grock). The analyzed samples have very low S_2 yield between 0.4 and 1.81 mg HC/g rock. The very low S_1 and S_2 yields signify low source rock potential that is likely more gas prone. The extractable hydrocarbon

content (S_1) of KD-1 shales ranges between 0.12 and 0.28 mg HC/g rock. Its average is 0.21 S_2 mgHC/grock. Similarly, S_2 ranges from 1.08 to 1.8 mgHC/g rock, averaging 1.38 mgHC/g rock, signifying poor source rock quality.

The petroleum potential of the KE-1, KF-1, and KH-1 well shales is also poor, with the least abundance at the KE-1 samples, having an average S_1 content of 0.14, 0.35, and 0.42, respectively. Based on the poor S_1 and S_2 contents, it is ascertained that the source rock generative potential of the examined lower post-rift sediments within the 4 wells is mostly potentially gas dominated. Oil-prone resources may be at the deeper portion of the basin (vander Spuy, 2003; Fielies & Africa 2022; Opuwari, 2021; Adam & Opuwari 2024). This refers the source rock quality is likely greater towards the deeper distal environments of the orange basin (Yelwa et al., 2022).

3.4 Thermal Maturity of Organic Matter

The appraisal of maturity level is significant in depicting the hydrocarbon generation in source rocks for petroleum exploration (Espitalie et al., 1986; Hazra et al., 2019; Xia et al., 2019; Adeoye et al., 2020; Fangzheng et al., 2020). In this analysis, thermal maturity of the organic matter was predicted based on geochemical maturity indicators like T_{max} ($^{\circ}C$) and Production Index (PI). The measured T_{max} values range from 425 to 476 $^{\circ}C$. This indicates that the upper Turonian to Aptian shales contain immature to postmature organic matter. This is shown by the van Krevelen diagram of HI and T_{max} values (Figure 3). KD-1 well sediments' T_{max} is between 425 and 454 $^{\circ}C$, thus containing immature to late mature source rocks for oil generation. KE-1 well sediments range from 427 to 441 $^{\circ}C$, reflecting immature to early mature source rocks. KF-1 well samples are at the late stage of thermal maturation (452-464 $^{\circ}C$). The measured T_{max} values for KH-1 source rocks, on the other hand, are between the immature and post-mature stages of maturation (430-476 $^{\circ}C$). The postmature shale is at 4232 m, which is the deepest analyzed source rock. This proves that deeper successions are the most mature source rocks, as T_{max} directly increases with depth. It suggests a high paleo-geothermal gradient, an attribute of low sedimentation rate. Some samples, even though at appreciable depth, are still immature, possibly due to maturity increasing at a low rate.

The PI as a maturity indicator is between 0.10 and 0.27 (Abubakar et al., 2023), containing early mature to peak mature source rocks. KD-1 well samples have PI values between 0.10 and 0.16, signifying an early stage of thermal maturation, as in KE-1 shales (0.10-0.23). The

Lower Albian shale at 3,340 m corresponds with Tmax and its PI early maturation of the source rocks. S₁ and S₂ values are relatively low, though increasing with depth. Thus, using PI and VR for KE-1 source maturation is greatly encouraged. Its calculated and measured vitrinite reflectance corresponds to early maturity for oil. The KF-1 shale production index ranges from 0.16 to 0.27, thriving from the early to the peak of oil generation. KH-1, well, on the other hand, has PI values ranging from 0.18 to 0.24, with most of the samples at its peak of oil window.

4.0 CONCLUSION

Rock-Eval pyrolysis data of the upper Turonian to Aptian stratigraphic framework depicts type III kerogen with low generative potential. The source rock generative potential of the investigated lower post-rift package shows poor potential. Rock-Eval Tmax of analyzed samples ranges between immature to late mature source rocks for KD-1 samples; immature to early mature source rocks for KE-1 sediments; late stage of maturation for KF-1; and immature to post-mature source rocks for oil generation in KH-1 well.

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