Boletim de Geociências da Petrobras

Paleoenvironmental characterization and evaluation of source rock potential of the Cunga Formation in the Cabo de São Braz Area, Kwanza Basin, Angola

Caracterização paleoambiental e avaliação do potencial gerador de hidrocarbonetos da Formação Cunga na área de Cabo de São Braz, Bacia do Kwanza, Angola

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ABSTRACT

The Cunga Formation is a geological formation from Eocene, located in the onshore of Kwanza Basin, consisting predominantly of shale, black mudstone, marl, limestone, siltstone and sandstones. With the aim of characterising the paleoenvironment, and hydrocarbon generation potential of the Cunga Formation in the Cabo de São Braz area, X-ray diffraction (XRD - 24 samples), geochemical analyses were carried out (Total Organic Carbon - TOC 47 samples and Pyrolysis Rock-Eval - 49 samples), and palynomorphs evaluation - 2 samples. It was possible to identify the mineral associations, with the predominance of quartz, albite, microcline, muscovite, and orthoclase. The analysis of palynomorphs revealed the presence of marine palynomorphs, represented by dinoflagellates and foraminifers, and continental palynomorphs, represented by fungi and spores. The TOC values range between 0.14% and 7.52%. The pyrolysis analysis shows the presence of kerogen types II, II/III, and III. The parameter Tmax was used to evaluate the thermal maturity of the samples, with values ranging between 417 °C and 431 °C. These results indicate that the organic matter of the Cunga Formation in the Cabo de São Braz area, although deposited in a favourable coastal to neritic marine environment with good potential to generate oil and gas, has not reached sufficient thermal maturation and therefore has not acted as an effective source rock.

Keywords: Cunga Formation, Kwanza Basin, organic geochemistry, source rocks, Rock-Eval pyrolysis, thermal maturity.

RESUMO

A Formação Cunga é uma formação geológica localizada na porção onshore da Bacia do Kwanza, data do Eoceno e é composta predominantemente por folhelhos e argilitos castanhos a preto, margas, calcários, siltitos e arenitos. Com vista à caracterização paleoambiental e avaliação do potencial gerador de hidrocarbonetos da Formação Cunga na Região do Cabo de São Braz, foram realizadas análises de difração de raios X (DRX - 24 amostras), análises geoquímicas (Carbono Orgânico Total - COT, e Pirólise Rock-Eval) e avaliação dos palinomorfos. A partir das análises de DRX, foi possível identificar as associações minerais, tendo sido encontrados, com predominância, quartzo, albita, microclina, muscovita e ortoclásio nas amostras analisadas. A análise das lâminas palinológicas revelou a presença de palinomorfos marinhos, nomeadamente dinoflagelados e foraminíferos, bem como palinomorfos continentais, tais como fungos e esporos. A análise de COT permitiu quantificar a matéria orgânica, apresentado valores entre 0,14% e 7,52%. A análise de pirólise Rock-Eval forneceu informações sobre a qualidade da matéria orgânica presente nas amostras, revelando a ocorrência dos querogênio tipos II, II/III e III. Adicionalmente, o parâmetro Tmax foi utilizado para avaliar o grau de maturação térmica das amostras, registando-se valores entre 417 °C e 431 °C. Da interpretação dos resultados, determinou-se que a Formação Cunga na Zona de Cabo de São Braz foi depositada em um ambiente sedimentar marinho costeiro a nerítico. A Formação Cunga apresenta um bom potencial para a geração de gás e petróleo; contudo, devido à maturação térmica insuficiente, não se tem revelado uma rocha geradora eficaz.

Palavras-chave: Formação Cunga, Bacia de Kwanza, geoquímica orgânica, rocha geradora, pirólise Rock-Eval, maturação térmica.

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1. INTRODUCTION

The petroleum sector of Angola occupies a strategic position in both the national and regional economy, reflecting its substantial contribution to revenue and energy supply (Mohammed, 2018), and is underpinned by the presence of hydrocarbons within its sedimentary basins (Rodrigues et al., 2017). Previous studies of Angolan petroleum systems have emphasised the importance of integrated analyses that combine stratigraphy, depositional environment characterisation, and source rock assessment to improve understanding of hydrocarbon generation and accumulation (Brownfield et al., 2006; Pereira et al., 2021; Rodrigues et al., 2021). Despite these efforts, key formations within the Kwanza Basin remain poorly characterised, particularly regarding their stratigraphic framework, depositional paleoenvironment, and source rock potential. Therefore, Geo Research and Agostinho Neto University have joined efforts to carry out a study on the Cunga Formation in a specific portion of Cabo de São Braz.

The Cunga Formation, located in the onshore sector of the Kwanza Basin (Figure 1), has been highlighted in previous research as having significant source rock potential (Brownfield and Charpentier, 2006; Brognon and Verrier, 1966). However, its geological characteristics are still insufficiently understood, and there is a notable lack of integrated studies combining stratigraphy, depositional environment analysis, and source rock potential evaluation. These steps are essential for a comprehensive understanding of petroleum systems and for accurately evaluating the hydrocarbon potential of the basin.

The tectono-sedimentary evolution of the Kwanza Basin is closely linked to the rifting of the African and South American plates during the fragmentation of Gondwana (Rodrigues et al., 2017). This rifting, which resulted in the opening of the South Atlantic Ocean between the Late Jurassic and Late Cretaceous (Rabinowitz and La Brecque, 1979; Fairhead, 1988; Scotese et al., 1988), generated distinct tectonic episodes, each characterised by specific stratigraphy and structural styles, commonly classified as pre-rift, syn-rift (I and II), post-rift, and regional subsidence (Baptista, 2001). These tectonic phases strongly influenced sedimentation patterns and source rock development, shaping the present-day petroleum potential of the basin (Brownfield and Charpentier, 2006; Fort et al., 2004).

By focusing on the Cunga Formation, this study provides a more detailed assessment of its geological and geochemical characteristics while highlighting the current limitations in understanding its stratigraphy, depositional environment, and generative capacity, which remain crucial for refining petroleum system models in the Kwanza Basin.

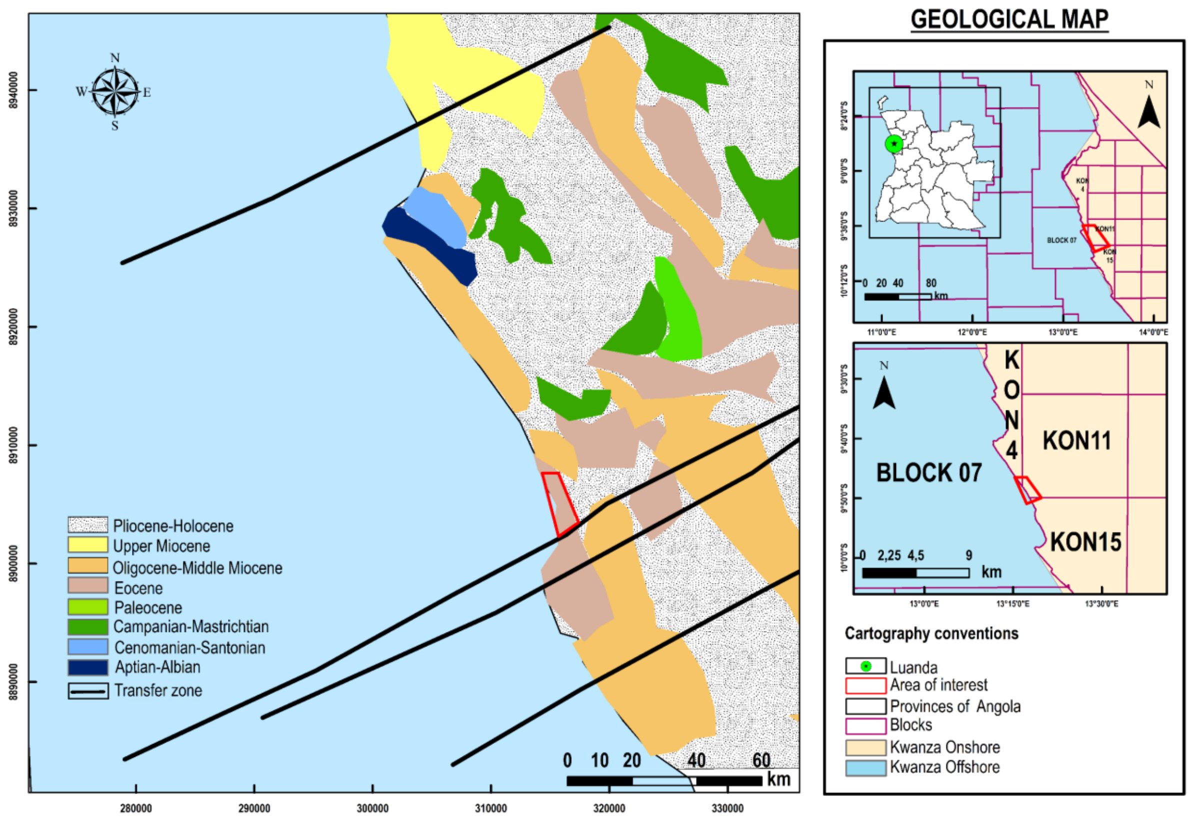

Figure 1. Geological framework of the study area (Modified from the Geological Map of the Kwanza Sonangol Basin (Total-Sonangol, 1987).

The specific objectives of this work include:

(1) To characterize the sedimentary environment of the Cunga Formation at both regional and local scales (Cabo de São Braz).

(2) To identify, quantify, and characterize the organic matter preserved in the collected samples.

(3) To determine the thermal maturity stages experienced by the Cunga Formation in the study area.

2. TECTONOSEDIMENTARY EVOLUTION

The origin and evolution of Kwanza Basin resulted from the movement of the tectonic plates that caused the fracturing of the supercontinent Gondwana in the late Jurassic (Lundin, 1992; Hudec and Jackson, 2002; Karner et al., 2003; Jian-Ping et al., 2008; Rodrigues et al., 2017). The evolution of this basin occurred according to several distinct tectonic phases, each of them creating a specific stratigraphy and structural style. These phases are usually classified as: pre-rift, sin-rift (I and II), post-rift and regional subsidence (Horn, 1980; Hudec and Jackson, 2002; Brownfield and Charpentier, 2006). The stratigraphic sequences in the Kwanza Basin are represented by the pre-salt and post-salt sequences, separated by a salt sequence of variable thickness (Figure 2), marking the transition from continental deposition conditions to predominantly marine deposition conditions (Stark et al., 1991).

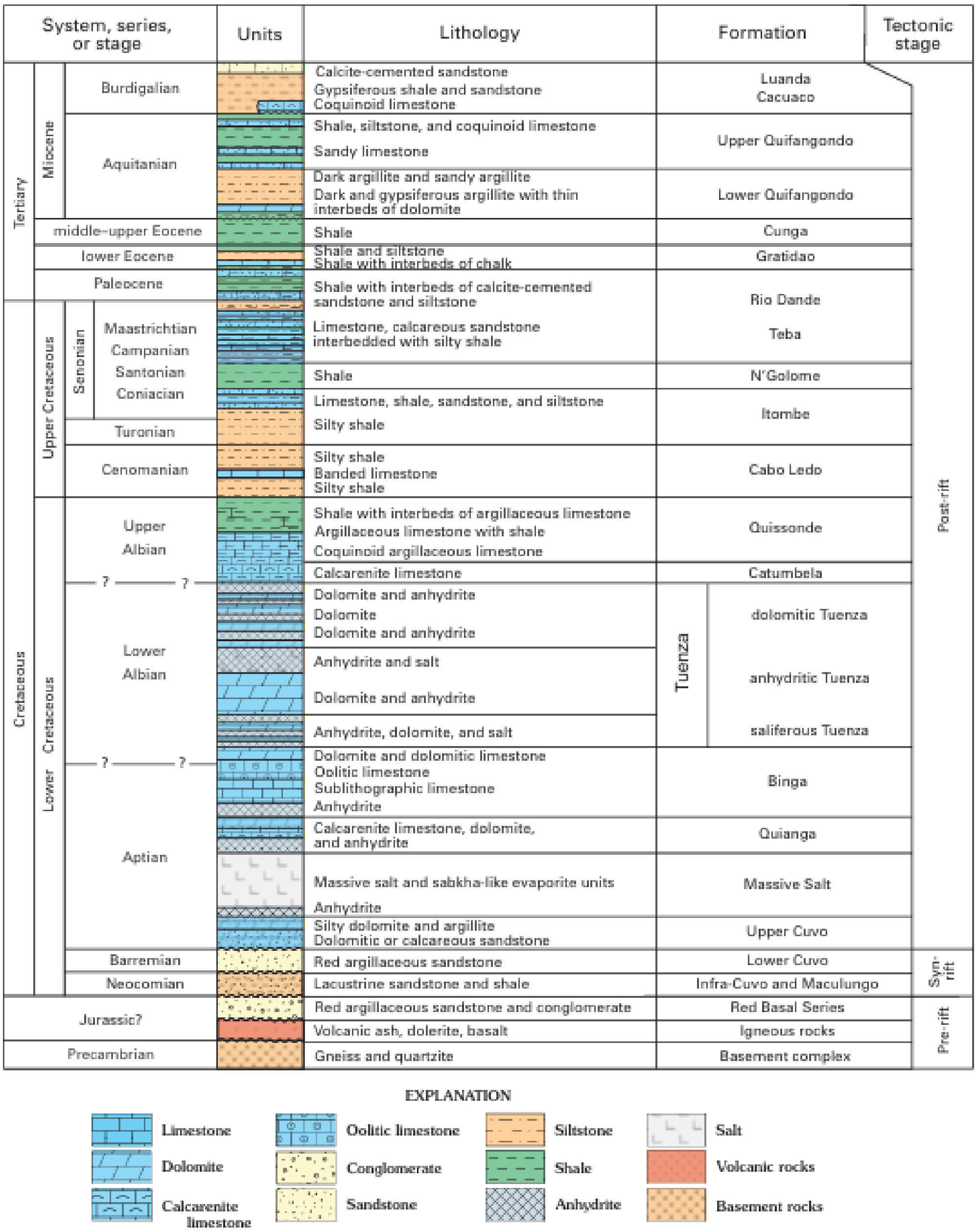

Figure 2. Stratigraphic column and summary of tectonostratigraphic events in Kwanza Basin (Brownfield and Charpentier, 2006).

As a result of gravity-induced deformation, an extension of thin layer was deposited on the Aptian salt in the Kwanza Basin (Wu et al., 1990; Duval et al., 1992; Demercian et al., 1993; Letouzey et al., 1995; Peel et al., 1995; Morley and Guerin, 1996). According to Fort et al. (2004), in passive margins, gravity-driven deformation above the salt usually leads to the development of extensional domains on the slope and contraction toward the base of the slope. The study carried out by Fort et al. (2004) establishes the existence of a structural zoning characteristic of the Angolan margin in which it is possible to identify comparable characteristics with three main structural domains, that is, ascending extensional domains and contractional domains towards the base of the slope separated by a transition domain, which is characterized by inverted extensional structures.

The ascending extensional domain is subdivided into three subdomains with (1) sealed slanted blocks, (2) growth failure systems and rollovers, and lastly, (3) extensional diapirs (Fort et al., 2004). The contractional domain toward the base of the slope is subdivided into three parts: (1) delayed compression of diapirs, (2) early onset of polyharmonic folds and push faults, (3) late stage folding and pushing. The results obtained by Fort et al. (2004) in studies based on seismic interpretation and on laboratory experiments, indicate that the overall structural zoning is mainly controlled by the basal slope angle, while the type of structures in the structural domains depends strongly on the sedimentation rate. In the extensional domain, structures and structural zoning depend on the coupling between brittle (sediments) and ductile layers (salt), while in the contractional domain, structures and structural zoning are mainly linked to contraction migration in time and space. Due to the structural similarity between the models and the Angolan margin, it is possible to say that the initial geometry of the salt basin was united both to the mainland and to the sea, and that the salt was entirely covered by sediments at the beginning of the gravity-driven deformation.

3. GEOLOGICAL AND PETROLEUM SYSTEM CONTEXT OF THE CUNGA FORMATION

3.1. Depositional framework of the Cunga Formation

At the regional scale, the Eocene Cunga Formation has traditionally been assigned to the post-rift stage and is considered part of the post-salt sequence, reflecting increasingly deep-marine conditions that prevailed in the Kwanza Basin (Brownfield and Charpentier, 2006). According to Stark et al. (1991) and Brownfield and Charpentier (2006), the formation is composed predominantly of pelagic limestones and mudstones containing planktonic organisms, together with shales, indicating deposition in a distal marine environment.

However, palynological data from the present study indicate a different depositional trend, pointing to a more proximal setting (Section 5.4). These findings challenge earlier interpretations and provide an opportunity to refine the understanding of the geodynamic environment of the Cunga Formation, highlighting potential lateral variability within the stratigraphic succession and the influence of local tectonic and sedimentary processes on depositional patterns.

3.2. The cunga formation within the petroleum systems of the Kwanza Basin

Four main regional petroleum systems have been recognised in the Kwanza Basin and are widely documented in the literature (Brognon and Verrier, 1966; Burwood, 1999; Schiefelbein et al., 1999): (1) the Pre-salt/Pre-salt Petroleum System, (2) the Pre-salt/Post-salt Petroleum System, (3) the Binga Post-salt Petroleum System, and (4) the Paleogene-Neogene Post-salt Petroleum System. The Paleogene-Neogene Post-salt Petroleum System is particularly relevant to the present study, as it comprises sedimentary packages that include fine-grained clastic lithologies such as shales and marls, together with interbedded carbonates and sandstones, which are favourable for organic matter accumulation and preservation (Cacama, 2021; Stark, 1991; Tissot and Welte, 1984). Within this framework, the Cunga Formation in the Cabo de São Braz area is regarded as a potential source rock unit of the Paleogene-Neogene Post-salt Petroleum System (Cacama, 2021). The formation is dominated by shales, mudstones and black marls (Cacama, 2021; Stark, 1991), lithologies that are widely recognised as favourable for organic matter preservation in post-salt stratigraphic successions (Al-Areeq and Albaroot, 2019; Chiaghanam et al., 2014; Tissot and Welte, 1984). The geochemical, petrographic, petrophysical, and structural characteristics of this petroleum system have been described in previous studies (Burwood, 1999; Brownfield and Charpentier, 2006; Serié et al., 2016; Beglinger et al., 2012).

Previous studies of the Eocene of the Kwanza Basin (Burwood et al., 1999; Kornpihl et al., 2024) have already indicated source rock maturation in the offshore domain. In this context and recognizing that a few works have addressed aspects of the onshore Kwanza Basin, the present study focuses specifically on the Cabo de São Braz area (Figure 1). This locality provides well-exposed outcrops of the Cunga Formation that allow for detailed stratigraphic and facies characterization. By documenting lithological variability, stratigraphic, and geochemistry characteristics in this marginal setting, the study contributes additional observations that may complement existing knowledge and support potential correlations with offshore data, thereby refining depositional models of the basin margin. The study area lies within blocks KON 4, KON 11, KON 15 and Block 07, which have been subject to past investigations and continue to receive investment through ongoing exploration initiatives, highlighting their relevance for future hydrocarbon assessment and development. In this initial phase, only outcrop samples were analysed. For subsequent stages, seismic and well data are expected to be incorporated to achieve greater precision and correlation, including depositional architecture, structural evolution, and salt tectonics since the Cunga Formation is not restricted to the southern sector of the Kwanza Basin. Furthermore, reinforcement of the paleoenvironmental analysis through palynological data will be essential, as in the present work this approach could not be explored in depth due to the limited availability of only two samples. Despite existing contributions, uncertainties remain regarding the depositional conditions, maturity, and source rock potential of this formation, particularly at the local scale.

4. METHODOLOGY AND TECHNIQUES

This section outlines the steps and techniques used in conducting this study. The adopted methodology covers everything from the definition of the topic and objectives to the analysis of the obtained data and is divided into subsections that detail the specific procedures for each phase of the work and takes into consideration all the qualitative and quantitative aspects. The specifications related to data collection, sample analysis, and interpretation will be presented in subsections 4.1 to 4.3.

4.1. Fieldwork

Based on previous studies, the Geological Map of the Kwanza Basin (Total-Sonangol, 1987), topographic map-sheet No. 125, SC-33/ C-I of the IGCA (Scale 1/100 000, 1981) and aerial photographs (Google Earth), it was possible to select the profile to be studied. This profile is located along the coast of Cabo de São Braz, with a general NE-SW orientation, rises 95 meters high and extends 3 Km in length. It is divided into five distinct outcrops, labelled ML1, ML2, ML3, ML4, and ML5. In situ studies were conducted on the outcrops, allowing the observation and identification of variations in lithology, sedimentary structures, strata thickness, attitudes, and the intensity of weathering. This provided a reliable basis for the sampling process. The quality and quantity of the samples were critical, as they could influence the results of subsequent laboratory analyses. Given the specific focus of the study, preference was given to fine-grained, dark-coloured, and less weathered rocks, as these are more likely to preserve organic matter. A total of 49 samples were collected along the profile, with each sample weighing between 2 and 4 kg.

4.1.1. ML1 outcrop

The ML1 outcrop has a NW-SE spatial orientation (Figure 3) and exhibits an approximate thickness of 7 m with a lateral exposure of 15 m. The unit A is composed of interbedded shale and marlstone, displaying a progressive upward increase in marl content. Mudstones range in colour from greenish to grey and commonly exhibit parallel lamination. Individual beds vary in thickness between 5 and 15 cm, and the strata of this unit has a dip of approximately 7° to the NE. The unit B is composed of brown to black mudstone. A total of 15 stratigraphic levels were sampled in this outcrop (samples MCSB1 to MCSB15) within Unit A. The sampled lithologies consist of shale, black to grey mudstones.

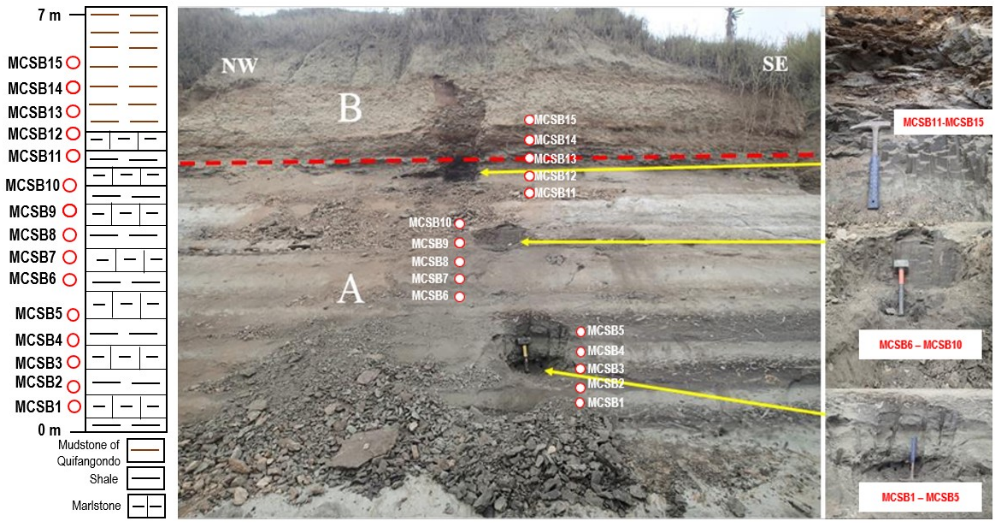

Figure 3. Outcrop ML1. Sedimentological profile of the ML1 outcrop located in the Cabo de São Braz region, Kwanza Basin.

4.1.2. ML2 outcrop

The ML2 outcrop is oriented SW-NE, with an estimated thickness of approximately 25 m and a lateral extent of around 50 m (Figure 4). These measurements were obtained using the Tangent method from compass, due to the challenges of staying close to the outcrop during the rapid tidal rise in the study area. Field measurements were therefore conducted at a safe distance, prioritizing sample collection. The stratigraphic succession consists of sedimentary packages with distinct lithologies. From the base to the middle portion of the section, the succession is dominated by interbedded shale to grey laminated mudstones and marlstone, and the upper portion of the outcrop is characterized by a thick limestone bed. A total of eight stratigraphic levels were sampled throughout the succession (MCSB1B to MCSB8B).

4.1.3. ML3 outcrop

The ML3 outcrop is oriented SW-NE and has an approximate thickness of 18 m, with a lateral exposure of around 18 m (Figure 5). The lower section of the succession (approximately the first 6 m) is primarily composed of interbedded black shale and marlstone with bioturbation, followed by a sequence of interbedded mudstone and siltstone. The upper portion of the outcrop is dominated by mudstone, with a 1 m thick limestone layer present. A total of 11 stratigraphic levels were sampled from this outcrop (MCSB9B to MCSB19B), which correspond to shale, brown to black mudstone, and silty mudstone.

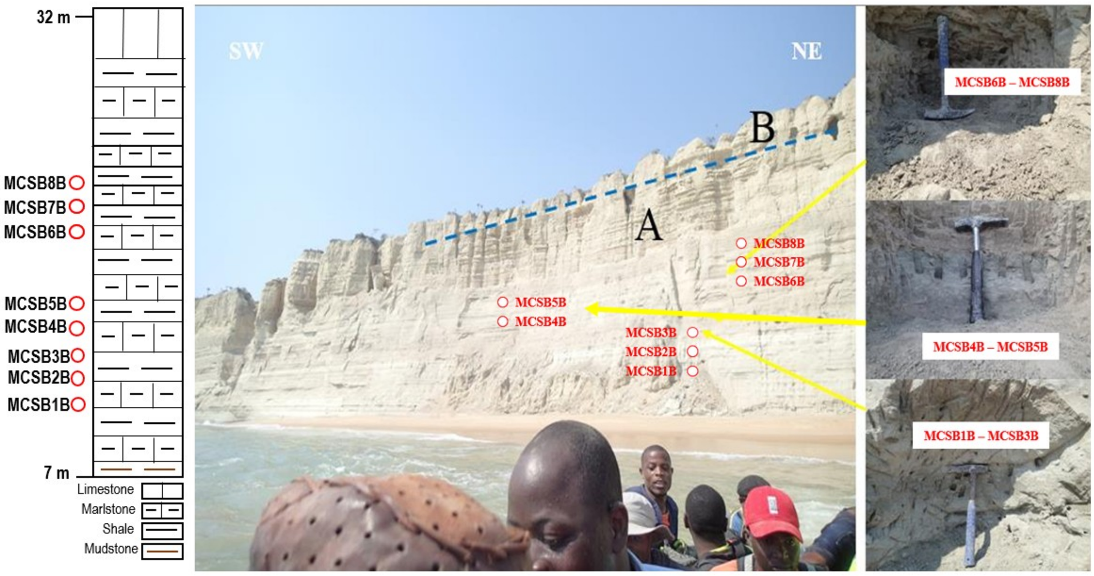

Figure 4. Outcrop ML2. Sedimentological profile of the ML2 outcrop located in the Cabo de São Braz region, Kwanza Basin.

Figure 5. Outcrop ML3. Sedimentological profile of the ML3 outcrop located in the Cabo de São Braz region, Kwanza Basin.

4.1.4. ML4 outcrop

The ML4 outcrop is oriented W-E and has an estimated thickness of approximately 18 m, with a lateral exposure of about 18 m (Figure 6). The lower portion of the succession (approximately 5 m) is dominated by interbedded shale, brown mudstone and marlstone, overlain by a sandstone bed approximately 1 m thick. The middle interval consists of intercalations of mudstones and siltstones, capped by a thicker limestone bed. The upper portion of the succession is characterized by a final intercalation of mudstone and siltstone at the top of the sequence. A total of eight stratigraphic levels were sampled (MCSB20B to MCSB27B) and the sampled lithologies correspond to mudstones and silty mudstones.

4.1.5. ML5 outcrop

The ML5 outcrop is oriented E-W and has an approximate thickness of 27 m (Figure 7). The succession shows a marked transition from predominantly clastic to more mixed lithologies. The lower portion is dominated by sandstone beds with significant silt and clay fractions. As the sequence progresses upwards, intercalations of sandstone with increasing amounts of siltstone and mudstone become more frequent. In the middle part of the outcrop, there is a greater proportion of interbedded siltstone and mudstone layers. However, compared to other outcrops in the region, the overall content of siltstone and sandstone is still predominant, particularly in the upper portion of the sequence. The uppermost section shows a further increase in the frequency of sandstone intercalations, reflecting a shift toward more siliciclastic deposition, with sandstone becoming the dominant lithology. Throughout the entire succession, the overall increase in sandstone content is notable, especially when compared to the other outcrops in the study area. A total of seven stratigraphic levels were sampled from this outcrop (MCSB28B to MCSB34B) and the sampled lithologies correspond to silty mudstones.

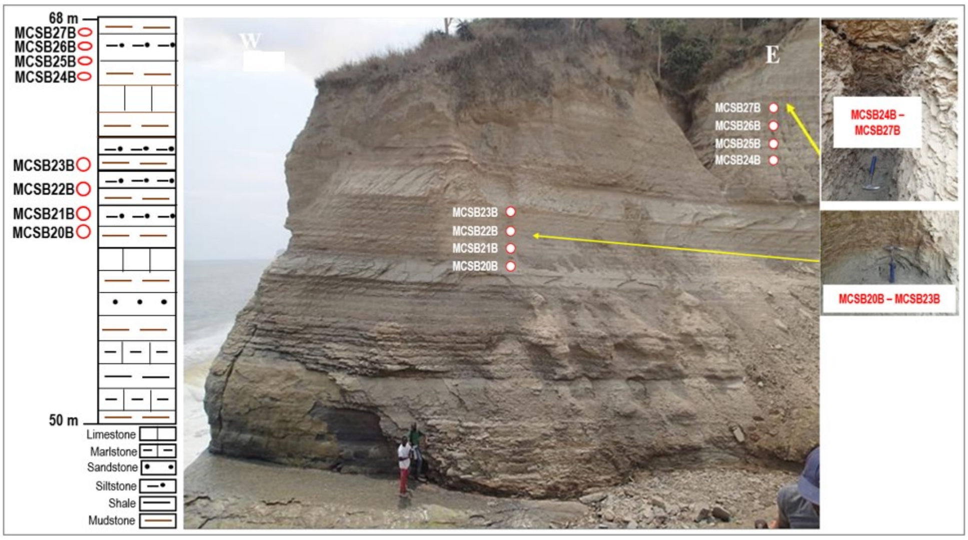

Figure 6. Outcrop ML4. Sedimentological profile of the ML4 outcrop located in the Cabo de São Braz region, Kwanza Basin.

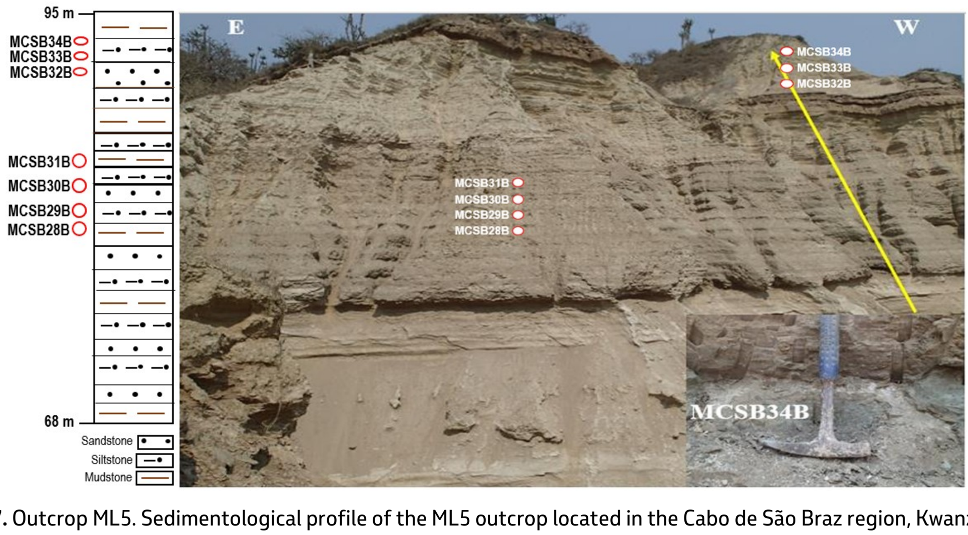

Figure 7. Outcrop ML5. Sedimentological profile of the ML5 outcrop located in the Cabo de São Braz region, Kwanza Basin.

4.2. Laboratory techniques

4.2.1. Preliminary preparation of samples

Initially, the samples were fragmented, followed by cleaning and the selection of fragments with potential for the desired analyses. Subsequently, 50 mg to 400 mg of each sample was accurately weighed using analogue scales for the respective analyses. The samples were then packaged in transparent plastic bags, clearly labelled with the identifiers MCSBn and MCSBnB.

4.2.2. X-ray diffraction (XRD)

This stage involved the preparation of the samples, which included several procedures: fragmentation, crushing, quartering, grinding, and homogenization. These steps were essential for reducing the samples to the appropriate particle size for X-ray diffraction (XRD) analysis (Silva, 2013). The analyses were conducted using the X'Pert PRO device from PANalytical, following the protocols outlined by Silva (2013). This analytical method enabled the acquisition of diffraction spectra, or diffractograms, for 24 samples, allowing for the identification, individualization, and quantification of the mineral species present. Consequently, this facilitated an assessment of the mineralogical composition of the rocks. The data are summarized in figures 4 and 5.

4.2.3. Total organic carbon (TOC)

The total organic carbon (TOC) analysis revealed the hydrocarbon-generating potential of 47 samples. The organic matter (OM) present in the sediments comprises both soluble (bitumen) and insoluble (kerogen) components in organic solvents (Tissot and Welt, 1984). To determine the TOC in the samples, inorganic carbon was first removed by reacting the samples with hydrochloric acid (HCl). Subsequently, the samples were combusted in a Leco® SC-144 analyser, which is equipped with an infrared detector. During this process, the samples were oxidized at a temperature of 1350 °C, allowing for accurate TOC quantification. The results are summarized in Section 5.2.

4.2.4. Rock-Eval pyrolysis

In the present work, 49 samples were submitted to Rock-Eval pyrolysis analysis, with a view to defining its hydrocarbon generating potential, as well as the degree of maturation. For this purpose, 250 mg of each previously ground sample was placed in the equipment at a temperature of 300º C to 600º C for 25 minutes for each sample, and throughout this period the parameters were read according to the procedures adopted by (Espitalié et al., 1977) combined with Van Krevelen diagram.

- **S1 (mg HC/g Rock):** This parameter quantifies the free hydrocarbons present in the samples, representing hydrocarbons that were generated naturally and are stored within the rock's pore space. In this study, S1 values were obtained following the vaporization of free hydrocarbons, providing an indication of the amount of hydrocarbons already present in the samples.
- **S2 (mg HC/g Rock):** S2 was measured between 300 °C and 600 °C, where the kerogen undergoes degradation, producing hydrocarbons. These hydrocarbons were quantified using a flame ionization detector, representing the generating potential of the organic matter within the rock. The S2 values obtained in this study reflect the potential for further hydrocarbon generation under optimal thermal conditions, offering insights into the rock's ability to generate hydrocarbons.
- **Tmax (ºC)**: Tmax, recorded during pyrolysis, indicates the temperature at which the maximum amount of hydrocarbons is generated (the peak of S2). This parameter was used to assess the thermal maturity of the organic matter in the samples. Based on the Tmax values, it was possible to classify the thermal maturity stage of the rock and determine whether the samples were in the oil or gas generation window.
- **S3 (mg CO_2/g Rock):** The amount of carbon dioxide (CO_2) produced during pyrolysis was measured as S3. This parameter is indicative of the loss of oxygenated functional groups in the organic matter, reflecting its composition. S3 was used to assess the presence and degradation of oxygenated compounds in the organic matter of the samples.
- **PI (Production Index):** The Production Index (PI) was calculated as the ratio of S1 to the sum of S1 and S2 (Equation 1). This index provides a measure of the maturity of the organic matter, where a low PI suggests immature organic matter, and a high PI indicates a more mature state with higher hydrocarbon generation.

$$(1)\quad PI = \frac{S1}{(S1 + S2)}$$

- **HI (Hydrogen Index, mg HC/g TOC):** The Hydrogen Index (HI) was calculated to characterize the type and origin of kerogen in the samples (Equation 2). HI values were derived from the ratio of S2 to total organic carbon (TOC) and were used to assess the hydrogen content, which indicates whether the kerogen is more oil-prone (marine type II) or gas-prone (terrestrial type III).

$$(2)\ \ HI = \frac{S2}{TOC}\ \times 100$$

- **OI (Oxygen Index, mg CO_2/g TOC):** The Oxygen Index (OI) was calculated to analyze the amount of oxygenated organic matter in the samples (Equation 3). This index was used alongside the HI to determine the kerogen type, with high OI values suggesting terrestrial organic matter (type III) and lower values suggesting marine, oil-prone kerogen (type II).

$$(3)\quad OI = \frac{S3}{TOC}\ \times 100$$

4.2.5. Palynological techniques

Two samples were processed for palynological analysis at the Geological Survey of Portugal (LNEG). A procedure using HCl and HF acids was used to extract and concentrate the organic matter (Wood et al., 1996; Riding and Warny, 2008; Rodrigues et al., 2021). The samples were not oxidized, and all residues were sieved with 7 µm and 10 µm meshes. The final residue was stained with safranin-O and mounted on microscope slides using Entelan®, a commercial resin-based mounting medium. The slides were examined under transmitted light, using an Olympus BX40 microscope equipped with an Olympus C5050 digital camera, as well as a Nikon eclipse Ci microscope. The analysis was carried out at LNEG, and to determine the relative abundance, the criterion of counting at least 150 palynomorphs using the 40x objective was established, a procedure adopted by Rodrigues et al. (2021) in recent studies. Based on the results of the microscopic observations, it was possible to group the palynomorphs into main classes, which comprise dinoflagellate cysts, foraminifera linings, terrestrial palynomorphs (spores and fungal remains) and other marine palynomorphs.

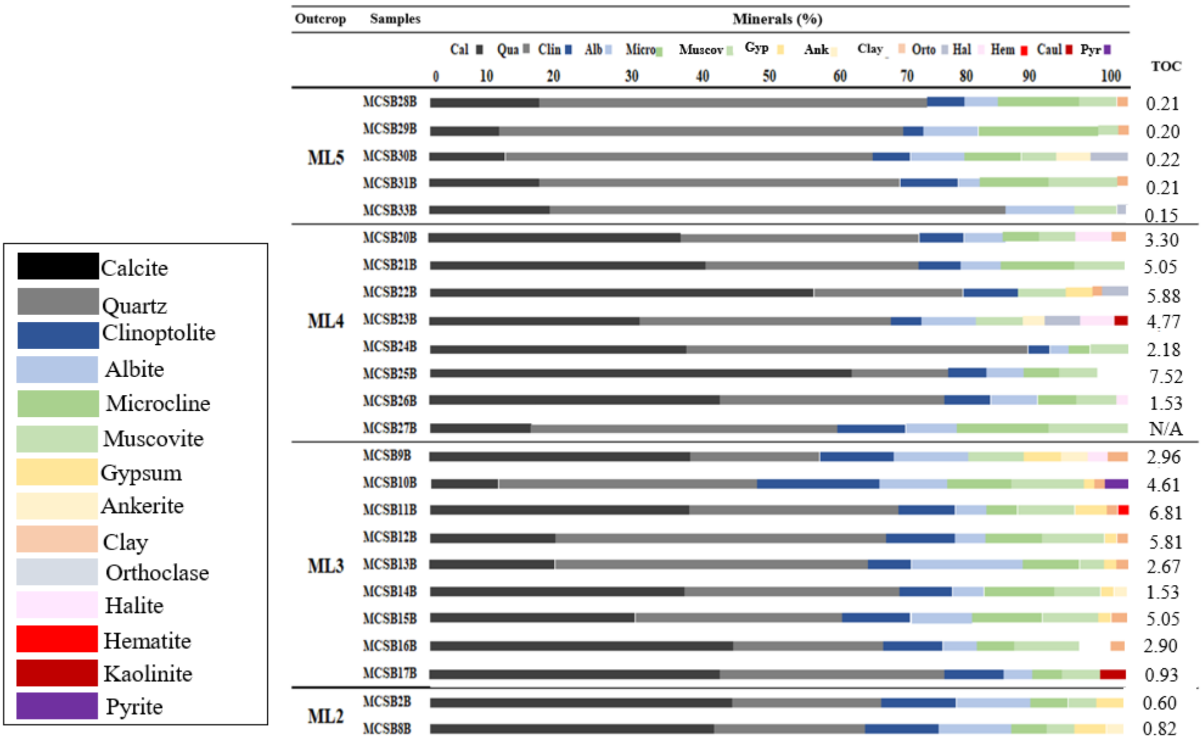

Figure 8. Distribution of TOC values versus mineralogical composition, highlighting trends in organic matter preservation across the samples.

5. RESULTS

5.1. X-ray diffraction (XRD)

The X-ray diffraction (XRD) analyses produced diffractograms that enabled the identification of the mineralogical assemblages present in the investigated samples. These results were subsequently used to construct a diagram illustrating the distribution of mineral phases per sample and, consequently, per outcrop (Figure 8). XRD analysis was conducted exclusively on samples collected from outcrops ML2, ML3, ML4, and ML5. All analysed samples exhibit compositions containing more than one mineral phase, with calcite and quartz identified as the dominant minerals in each sample (Figure 8). These primary phases are commonly accompanied by feldspars and clay minerals, with kaolinite being particularly abundant, indicating a predominantly detrital composition with significant carbonate and clay contributions. In outcrop ML2, two samples were analysed, both displaying a similar mineralogical signature characterised by the dominance of calcite and quartz, together with clinoptilolite, albite, microcline, muscovite, gypsum, and ankerite. In outcrop ML3, where nine samples were examined, the mineral assemblages follow the same general trend as in ML2 but additionally contain halite, pyrite, hematite, and kaolinite, suggesting a greater mineral diversity and potential influence of evaporitic processes. Outcrop ML4 (eight samples analysed) retains the same dominant mineralogical pattern, with calcite and quartz prevailing and occasional occurrences of evaporitic minerals. Finally, the five samples analysed from outcrop ML5 exhibit mineralogical assemblages consistent with those observed in ML4, confirming the continuity of the mineralogical framework across the studied succession (Figure 9).

5.2. Total organic carbon (TOC)

Total organic carbon (TOC) analyses were performed on 47 samples collected from outcrops ML1 to ML5 (Table 1) to quantify the organic matter content of the studied sedimentary succession. TOC values range from 0.14 to 7.52 wt.%, with an average of 2.65 wt.% for the entire dataset.

In outcrop ML1, 15 samples were analysed, corresponding mainly to shale and marl lithologies. TOC values vary between 0.88 and 5.59 wt.%, with a mean value of 3.17 wt.%. Outcrop ML2 comprises 7 samples, also dominated by shale and marl lithologies, displaying a relatively narrow TOC range of 0.51 to 0.82 wt.% and an average of 0.60 wt.%. Outcrop ML3 includes 11 samples of predominantly clayey siltstone lithologies, with TOC values ranging from 0.93 to 6.81 wt.% and an average of 3.32 wt.%. In outcrop ML4, 7 samples were analysed, mainly consisting of claystone and clayey siltstone lithologies; TOC values vary from 1.35 to 7.52 wt.%, with an average of 4.29 wt.%. Finally, outcrop ML5 comprises 7 samples of clayey siltstone lithologies, which exhibit low TOC values ranging between 0.14 and 0.22 wt.%, with an average of 0.18 wt.%.

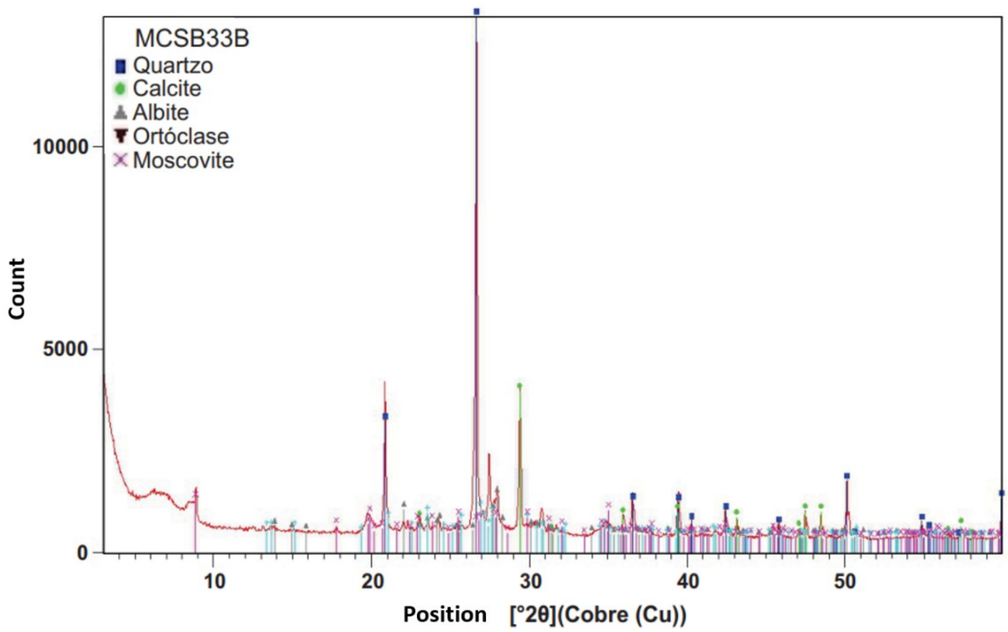

Figure 9. Diffractogram of Sample MCSB33B, representative of the mineralogical composition from the ML5 outcrop, Cabo de São Braz region, Kwanza Basin.

Table 1. Rock-Eval Pyrolysis and TOC analysis data, showing key parameters for each sample.

Rock	Sample	TOC (%)	S1 (mg HC/g rock)	S2 (mg HC/g rock)	S3 (mg CO_2/g rock)	Tmax (°C)	HI (mg HC/g TOC)	OI (mg CO_2/g TOC)	PI
ML5	MCSB 34B	0.14							
	MCSB 33B	0.15							
	MCSB 32B	0.14							
	MCSB 31B	0.21							
	MCSB 30B	0.22							
	MCSB 29B	0.20							
	MCSB 28B	0.21							
ML4	MCSB 26B	1.35	0.10	2.96	4.05	427	219	300	0.03
	MCSB 25B	7.52	0.40	31.09	4.75	424	413	63	0.01
	MCSB 24B	2.18	0.11	5.56	4.23	429	255	194	0.02
	MCSB 23B	4.77	0.26	17.62	3.88	428	369	81	0.01
	MCSB 22B	5.88	0.35	18.68	3.74	429	318	64	0.02
	MCSB 21B	5.05	0.20	15.01	3.48	429	297	69	0.01
	MCSB 20B	3.30	0.24	10.76	2.85	422	326	86	0.02
ML3	MCSB 19B	1.10	0.03	0.80	1.18	428	73	107	0.04
	MCSB 18B	2.19	0.14	6.61	4.42	428	302	202	0.02
	MCSB 17B	0.93	0.07	1.73	2.62	430	186	282	0.04
	MCSB 16B	2.90	0.18	10.24	3.97	429	353	137	0.02
	MCSB 15B	5.05	0.49	18.08	3.17	424	358	63	0.03
	MCSB 14B	1.53	0.11	3.49	2.08	428	228	136	0.03
	MCSB 13B	2.67	0.34	7.87	2.44	426	295	91	0.04
	MCSB 12B	5.81	0.47	25.08	2.34	426	432	40	0.02
	MCSB 11B	6.81	0.32	16.93	2.05	421	249	30	0.02
	MCSB 10B	4.61	0.36	16.57	2.30	427	359	50	0.02
	MCSB 9B	2.96	0.31	10.62	2.41	429	359	81	0.03
ML2	MCSB 7B	0.82							
	MCSB 6B	0.53							
	MCSB 5B	0.66	0.10	0.23	2.21	426	186	335	0.30
	MCSB 4B	0.53	0.10	0.55	2.46	417	104	464	0.15
	MCSB 3B	0.51	0.12	0.60	2.30	417	118	451	0.17
	MCSB 2B	0.60	0.12	0.82	1.85	421	137	308	0.13
	MCSB 1B	0.57	0.11	0.75	1.45	420	132	254	0.13
ML1	MCSB 15	1.13	0.15	9.83	2.21	424	314	71	0.02
	MCSB 14	5.59	0.57	20.70	3.01	422	370	54	0.03
	MCSB 13	2.66	0.41	6.55	2.66	426	246	100	0.06
	MCSB 12	3.78	0.47	13.25	3.63	425	351	96	0.03
	MCSB 11	4.78	0.52	17.88	2.61	426	374	55	0.03
	MCSB 10	4.44	0.47	13.62	3.81	424	307	86	0.03
	MCSB 9	1.42	0.30	4.18	2.15	430	294	151	0.07
	MCSB 8	1.38	0.30	2.85	3.27	427	207	237	0.10
	MCSB 7	2.36	0.50	7.51	2.29	426	318	97	0.06
	MCSB 6	0.88	0.20	1.31	1.70	422	149	193	0.13
	MCSB 5	1.36	0.23	2.13	2.36	424	157	174	0.10
	MCSB 4	4.30	0.34	16.20	3.06	426	377	71	0.02
	MCSB 3	2.27	0.17	6.27	3.11	428	276	137	0.03
	MCSB 2	4.67	0.25	16.02	2.99	431	343	64	0.02
	MCSB 1	4.67	0.48	14.44	4.21	429	309	90	0.03

5.3. Rock-Eval pyrolysis

Following the determination of total organic carbon (TOC), Rock-Eval pyrolysis was performed to obtain geochemical parameters related to the organic matter present in the samples (Table 1). A total of 40 samples from outcrops ML1 to ML4 were analysed, and the pyrolysis parameters S1, S2, S3, Tmax, Hydrogen Index (HI) and Oxygen Index (OI) were determined. The ML5 outcrop was not included in this analysis because the low TOC values of its samples did not allow for the reliable determination of Rock-Eval parameters.

In outcrop ML1, 15 samples (MCSB1-MCSB15) were analysed. The S1 values range from 0.12 to 0.57 mg HC g^{-1} rock, whereas S2 values vary between 1.31 and 20.70 mg HC g^{-1} rock. S3 values range from 1.70 to 4.21 mg CO_2 g^{-1} rock, and Tmax spans 421-430 °C. The Hydrogen Index (HI) ranges from 149 to 377 mg HC g^{-1} TOC, while the Oxygen Index (OI) varies between 54 and 237 mg CO_2 g^{-1} TOC (Table 1).

In outcrop ML2, seven samples were analysed (MCSB1B-MCSB8B), excluding sample MCSB7B. S1 values range from 0.10 to 0.12 mg HC g^{-1} rock, and S2 values vary between 0.55 and 1.23 mg HC g^{-1} rock. S3 values are between 1.45 and 2.46 mg CO_2 g^{-1} rock, and Tmax ranges from 417 to 427 °C. HI values vary from 104 to 186 mg HC g^{-1} TOC, while OI values range from 218 to 464 mg CO_2 g^{-1} TOC (Table 1).

Outcrop ML3 comprises 11 analysed samples (MCSB9B-MCSB19B). S1 values range from 0.03 to 0.49 mg HC g^{-1} rock, and S2 values span 0.80-25.08 mg HC g^{-1} rock. S3 values range from 1.18 to 4.42 mg CO_2 g^{-1} rock, with Tmax values between 421 and 430 °C. HI values vary from 73 to 432 mg HC g^{-1} TOC, whereas OI ranges from 30 to 282 mg CO_2 g^{-1} TOC (Table 1).

In outcrop ML4, seven samples (MCSB20B-MCSB26B) were analysed. S1 values range from 0.10 to 0.35 mg HC g^{-1} rock, while S2 values vary between 2.96 and 31.09 mg HC g^{-1} rock. S3 values are between 2.85 and 4.75 mg CO_2 g^{-1} rock, and Tmax ranges from 422 to 429 °C. HI values vary from 219 to 413 mg HC g^{-1} TOC, and OI values range from 63 to 300 mg CO_2 g^{-1} TOC (Table 1).

5.4. Palynomorph analysis

Two samples (MCSB6 and MCSB9) from outcrop ML1 were analysed for palynomorph content. Both samples contain organic matter of continental and marine origin, although the relative proportions differ between them. In general, marine palynomorphs dominate in both samples. In sample MCSB6, a total of 18 palynomorphs were counted. Continental elements represent 16.70% of the assemblage and are exclusively composed of fungi. The remaining 83.30% are marine palynomorphs. Sample MCSB9 yielded 145 palynomorphs, of which 4.12% are of continental origin, represented by spores (2.06%) and fungi (2.06%). The remaining 97.94% are marine palynomorphs (Table 2).

Table 2. Palynological data for MCSB6 and MCSB9 samples.

			Distribution per sample (%)		
Environment	Group	Family		MCSB6	MCSB9
Continental	Palynomorphs	Fungi	Fungi	16.70	2.06
		Spores	*Cicatricosiorites sp.*		2.06
Marine	Palynomorphs Dinoflagellates	Palynomorphs	*Impagidinium sp.*	5.55	2.06
			Spiniferites spp.	5.55	7.58
			Selenopemphixnephroides	5.55	1.37
			Homotrybliumtrenuispinosum		3.44
			Homotryblium sp.		3.44
			Hystrichosphaeridium sp.		1.37
			Impagidinium dispertitum		2.06
			Nematosphaeropsis sp.		0.68
			Spiniferites pseudofurcatus		1.37
			Dynocist sp. B		3.44
			Deflandrea phosphoritica		2.75
			Deflandrea sp.		3.44
			Trinovantenidium sp.		6.20
	Zoomorphs		*Radiolaria*	27.77	22.90
			Foraminiferous linings	38.88	32.41
	Palynomorphs	Other marine palynomorphs			1.37
				100	100

6. DISCUSSIONS

Following the acquisition of laboratory data, the results were interpreted in terms of paleoenvironmental conditions, source rock potential, and thermal maturity. The integration of field observations, mineralogical data (XRD), palynological assemblages, and geochemical parameters (TOC and Rock-Eval pyrolysis) provides a comprehensive framework for reconstructing depositional environments and assessing the hydrocarbon generation potential of the Cunga Formation in the Cabo de São Braz area.

6.1. Paleoenvironmental interpretation

The paleoenvironmental reconstruction of the Cunga Formation (Cabo de São Braz area) is based on the combined analysis of outcrop facies, mineralogical assemblages, palynomorph distribution, and geochemical indicators. This multi-proxy approach is essential because the texture, sedimentary structures, mineralogy, fossil content, and organic geochemistry of sedimentary rocks directly record the physical, chemical and biological processes active during deposition and early diagenesis (Boggs, 1987).

6.1.1. Facies and sedimentary processes

The succession is dominated by fine-grained lithologies, mainly shale, mudstone and marlstone, with intercalations of limestones, siltstones, and, in the uppermost part of the sequence, sandstones (Figure 10). The predominance of fine-grained sediments and frequent planar lamination indicate deposition primarily by suspension settling under low-energy hydrodynamic conditions, typical of quiet neritic environments (Boggs, 1987). Recurrent and locally intense bioturbation provides evidence of benthic activity and episodic oxygenation at the seabed, suggesting fluctuations in bottom-water conditions during deposition.

Vertical facies variations, marked by alternations between clay-rich, marly and carbonate-rich levels, together with the upward increase in silt and sand content, reflect relative sea-level changes that controlled detrital input, carbonate production and depositional energy (Boggs, 1987). The occurrence of pyrite and calcite points to specific diagenetic processes, including early fluid circulation and later overprinting, which accompanied these stratigraphic changes.

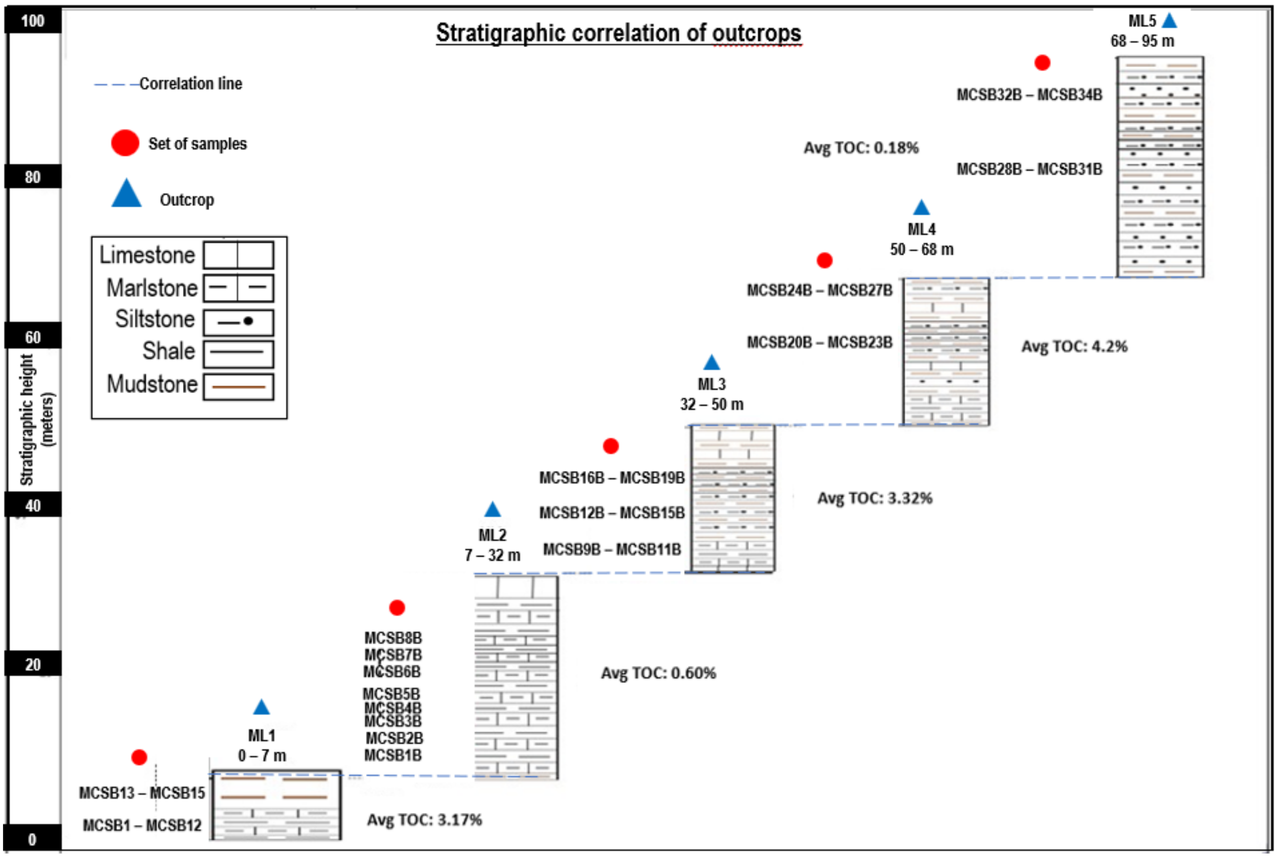

Figure 10. Stratigraphic correlation of outcrops.

Taken together, the ML1-ML5 outcrops demonstrate alternating phases of quiet-water deposition, intervals of carbonate development, and episodes of siliciclastic progradation (Embry and Johannessen, 1992; Posamentier and Allen, 1999). This stratigraphic variability records cycles of relative sea-level change and shifts in depositional energy, consistent with mixed depositional systems commonly observed in marginal basins (Einsele, 1992). Comparable successions, where fine-grained mudstones and marlstones are overlain by limestones and sandstones, have been interpreted as transgressive-regressive sequences in similar tectono-sedimentary settings (Catuneanu, 2006; Embry and Johannessen, 1992; Posamentier and Allen, 1999). The observed facies transitions in the Cabo de São Braz area therefore reflect the interplay between accommodation space and sediment supply, highlighting the dynamic stratigraphic evolution of the Kwanza Basin margin.

6.1.2. Mineralogy and sediments provenance

XRD analysis reveals mineral assemblages dominated by quartz, feldspars (albite, microcline/orthoclase), micas (muscovite), and clay minerals, together with diagenetic and authigenic phases such as calcite, gypsum, ankerite, halite and hematite (figures 8 and 9). The presence of feldspar and mica suggests a proximal source area, since these relatively unstable minerals tend to alter to more stable phases during long-distance transport, increasing chemical maturity (Boggs, 1987). The mineralogy is compatible with a provenance dominated by low-grade metamorphic and granitoid plutonic rocks, consistent with the adjacent continental basement.

6.1.3. Palynological evidence

Palynological data show the coexistence of continental elements (fungi and spores) and marine components (dinoflagellates, and foraminiferal linings), with a clear dominance of marine organisms (Table 2). The combined presence of these groups indicates marine deposition with a significant continental influence, consistent with sediment supply from nearby terrestrial sources (Mulanda, 2021; Pereira, 2021). The high proportion of marine palynomorphs rules out a purely continental environment, while the consistent presence of terrestrial elements excludes a deep marine setting. Therefore, the palynological assemblage supports deposition in a coastal to neritic environment (Tahoun et al., 2017; Rodrigues et al. 2021), in agreement with facies observations.

6.1.4. Geochemical indicators and organic matter preservation

Geochemical data (TOC and Rock-Eval parameters) integrated with facies and paleoenvironmental evidence indicate that depositional conditions favoured the preservation of organic matter in specific intervals of the succession (Table 1). Fine-grained sediments, together with variations in redox conditions and sedimentation rates, contributed to enhanced organic matter preservation, particularly in the more clay- and marl-rich intervals (Hunt, 1996; Tissot and Welt, 1984).

6.2. Organic matter quantity

In terms of hydrocarbon generation potential, a sedimentary rock is generally considered to have source-rock potential when its TOC exceeds a minimum threshold, although this threshold can vary with lithology. For siliciclastic rocks, TOC values above approximately 0.5-1.0% are typically used as the lower limit for potential hydrocarbon generation (Albriki et al., 2021), while for carbonate rocks a lower TOC threshold (often around ~0.3-0.5%) may be appropriate due to differences in organic matter preservation and hydrocarbon yield. Accordingly, based on TOC values and lithology, source rocks can be classified into different petroleum potential categories, as presented in Table 3.

Table 3. Classification of source rocks by TOC content (wt %), following the criteria of Peters and Cassa (1994) with foundational context from Tissot and Welte (1984).

Source rock potential category	TOC (%)
Poor	0 - 0.5
Fair	0.5 - 1.0
Good	1.0 - 2.0
Very good	2.0 - 4.0
Excellent	>4.0

In the present study, 47 samples were analysed across the stratigraphic succession, with TOC values ranging from 0.14% to 7.52% (Table 1). This variability reflects significant differences in OM production, deposition, and preservation along the succession.

From the total analysed outcrop assemblages, ML1 contains samples ranging from poor to very good in source-rock quality, with a predominance of values in the fair to very good categories, indicating a generally favourable organic richness and hydrocarbon generation potential. In contrast, the samples from ML2 are dominantly poor in TOC content and hence display low source-rock potential. The ML3 outcrop includes one sample with poor TOC and one with fair TOC, but most analyses are concentrated in the good to very good range, signifying a relatively robust source-rock quality overall. Finally, the assemblage of samples from ML4 spans from good to excellent TOC values, reflecting strong organic richness and high potential as source rock (Figure 11).

6.3. Organic matter quality

Organic matter (OM) quality, controlled by its biochemical composition of lipids, proteins, carbohydrates, and lignin, governs both hydrocarbon generation potential and the type of hydrocarbons produced (Tissot and Welte, 1984; Hunt, 1996). Because terrestrial plants are dominated by carbohydrates and lignin, whereas marine phytoplankton is richer in proteins and lipids, the relative proportions of these compounds provide insights into OM origin and depositional conditions. In this study, OM quality was evaluated using Rock Eval pyrolysis, focusing on the Hydrogen Index (HI) and the S2/S3 ratio (Table 1), complemented by a modified van Krevelen diagram where HI and OI values discriminate kerogen types (Peters and Cassa, 1994). These parameters directly reflect the biochemical composition of the original OM and its transformation during early diagenesis, allowing classification into kerogen types. From the S2/S3 ratios and HI values, as well as the projection of HI and OI onto the van Krevelen diagram (Figure 12), the samples were classified as containing kerogen types II, II/III, and III (Table 4). The predominance of type II/III and III kerogens, with subordinate type II, therefore, reflects a mixed organic matter input with strong continental influence (type III) and moderate marine contribution (type II). Type II kerogen, derived from hydrogen-rich, lipid-dominated marine OM, is generally oil prone, while type III kerogen, linked to lignina and cellulose-rich terrestrial plants, is more gas prone and has limited oil-generating capacity (Tyson, 1995; Peters and Cassa, 1994). Considering the average TOC of 2.65% and the coexistence of these kerogen types, the Cunga Formation represents a potential source rock capable of generating oil, oil-gas mixtures, and gas depending on thermal maturity.

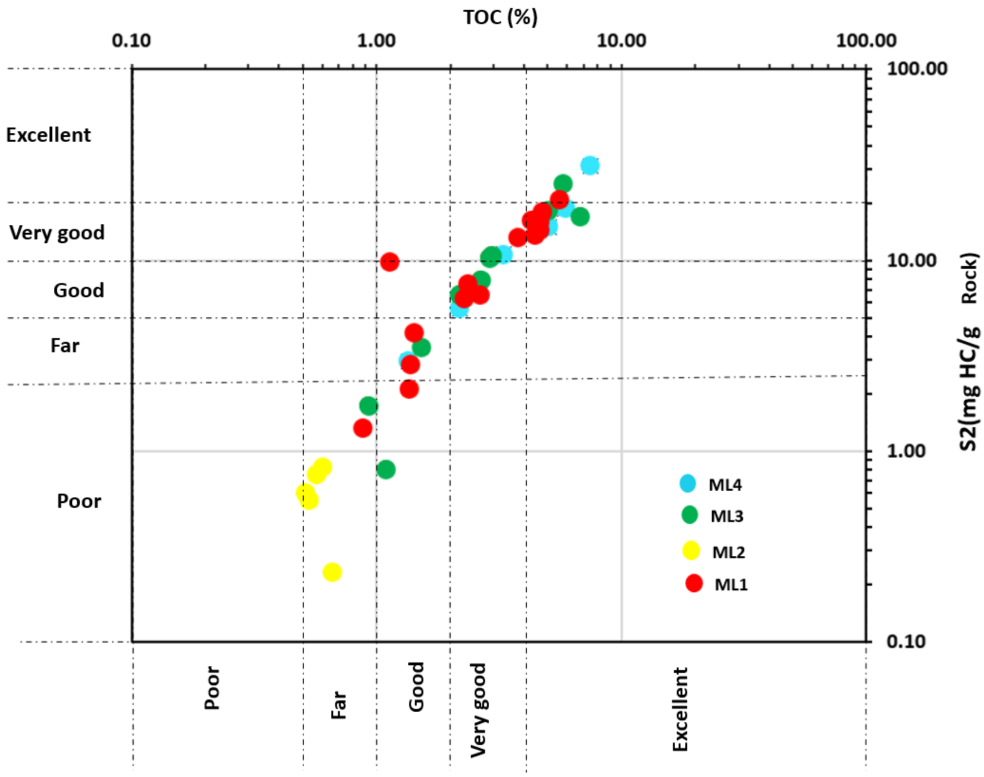

Figure 11. Cross-plot of total organic carbon (TOC) vs. remaining hydrocarbon potential (S_2) showing organic matter richness and source-rock generative potential (based on Rock-Eval pyrolysis data).

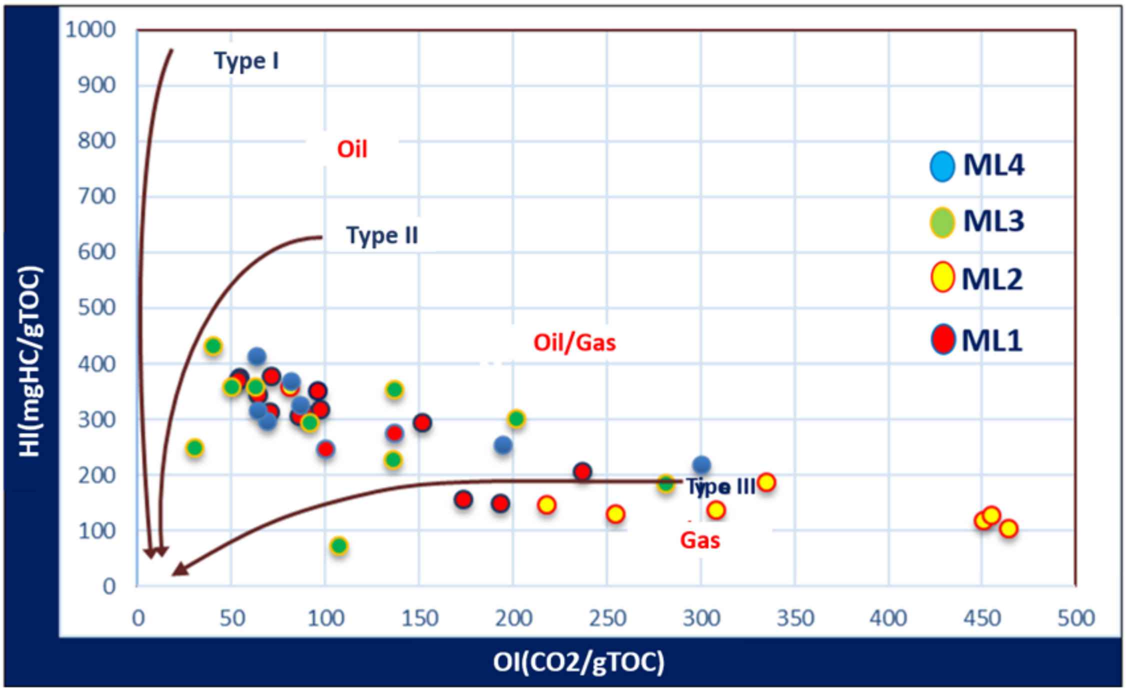

Figure 12. Determination of kerogen types based on the Hydrogen Index (HI) and Oxygen Index (OI) using a modified van Krevelen type diagram, showing fields for kerogen types II, II/III and III.

Table 4. Organic matter quality, kerogen type, and hydrocarbon generation potential based on Rock-Eval pyrolysis parameters. Following the criteria of Peters and Cassa (1994) with foundational context from Tissot and Welte (1984).

Kerogen type	HI (mg HC/g TOC)	S2/S3	H/C	Type of Hydrocarbon generated
I	>600	>15	>1.5	Oil
II	300-600	10-15	1.5-1.2	Oil
II/III	200-300	5-10	1.0-1.2	Oil and gas mixtures
III	50-200	1-5	0.7-1.0	Gas
IV	<50	<1	<0.7	None

Additionally, the integration of IO values, DRX, and facies associations refines this interpretation. In facies association ML2, authigenic minerals exceed 45%, and IO values cluster between 200-300 mg CO_2/g TOC and 450-470mg CO_2/g TOC, reflecting alternation between moderate preservation and significant oxidation of organic matter in a lithological context dominated by shales, marls, and siltstones. In ML3, authigenic minerals surpass 30%, but IO values remain predominantly low (20-100 mg CO_2/g TOC, rarely up to 300 mg CO_2/g TOC), pointing to enhanced preservation under reducing conditions in fine-grained sediments. By contrast, outcrop ML4 is characterized by more than 50% authigenic minerals, increased siltstone content, and thick limestone beds, suggesting a more open carbonate setting with greater circulation and oxygenation, favouring intense oxidation of organic matter. Taken together, Rock-Eval pyrolysis (Tissot and Welte, 1984; Hunt, 1996), IO, DRX, and facies analysis confirm that the Cunga Formation records both substantial terrestrial input and variable redox conditions in the water column, meaning that oxygen availability during deposition was not constant. At times the water column was more oxygenated (oxidizing conditions), which promoted organic matter degradation, while at other times it was depleted in oxygen (reducing conditions), favouring preservation (Ader et. al., 2009; Adegoke et al., 2014; Tribovillard et al., 2006; Deng et al., 2023).

6.4. Thermal maturation

Thermal maturity of organic matter was assessed using Rock-Eval pyrolysis parameters, specifically Tmax and the Production Index (PI). Tmax represents the temperature at which maximum hydrocarbon generation occurs (S2 peak) and is widely used to estimate the thermal maturity of source rocks (Peters and Cassa, 1994). The PI also correlates with thermal evolution and is commonly employed as a maturation indicator. The criteria used for maturity assessment are summarized in Table 5.

Table 5. Thermal maturity stages and corresponding hydrocarbon generation characteristics, showing the progression from immature through early, peak, late, and overmature stages (Peters and Cassa, 1994).

Tmax (°C)	PI	Thermal maturity stage
<435	0,1	Immature
435-445	0,10 0,15	Early mature
445-450	0,25-0,40	Peak mature
450-470	>0,40	Late mature
>470		Overmature

Results from Rock-Eval pyrolysis (Table 1) indicate that all analysed samples exhibit Tmax values consistent with low thermal maturity, falling within the immature range (Figure 13). Accordingly, no significant hydrocarbon generation through thermal cracking was observed. When the data are evaluated by outcrop, the thermal immaturity is further reinforced. Across all studied outcrops (ML1-ML4), Tmax values consistently remain below 435 °C and PI values are low, indicating that the organic matter is thermally immature and has not entered the catagenesis window.

Despite the quality of the organic matter, the rocks of the Cunga Formation in the Cabo de São Braz area have not been exposed to the appropriate combined factors (sufficient temperature, time, and burial conditions) required to generate oil; consequently, under the studied burial and thermal history, these rocks remain thermally immature and have not generated hydrocarbons.

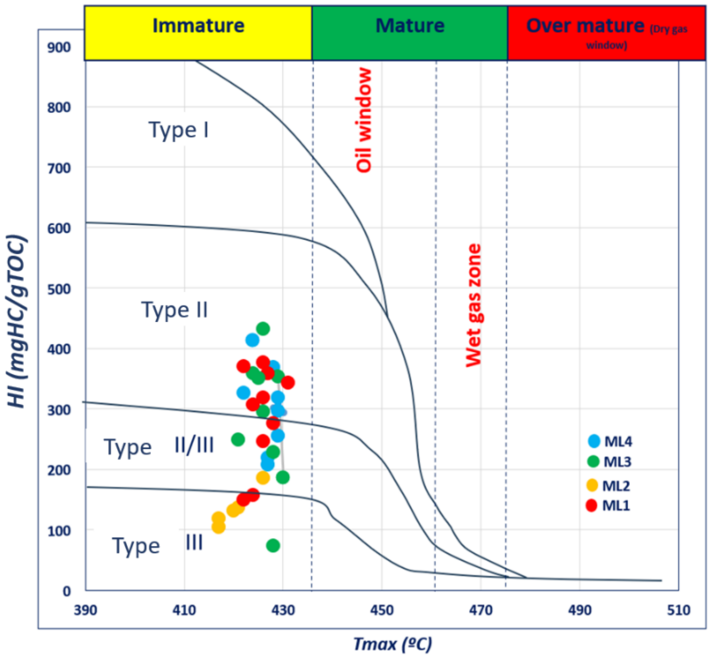

Figure 13. Cross-plot of Hydrogen Index (HI) vs. Tmax illustrating organic matter thermal maturity and hydrocarbon generation trends based on Rock-Eval pyrolysis data.

Table 6. Summary of the geochemical characteristics of the sequence under study.

utcrop	High (m)	TOC (average) %	Kerogen	Potential for HC generation	Tmax (average) ºC	Maturation	Stage
ML5	68 m - 95 m	0.18					
ML4	64 m - 68 m	4.29	III	Mixture of oil and gas, gas and oil	427	Immature	Diagenesis
	59 m - 64 m		II				
	50 m - 59 m		II/III				
ML3	45 m - 50 m	3.32	II	Mixture of oil and gas, gas and oil	427	Immature	Diagenesis
	41 m - 45 m		II/III				
	32 m - 41 m		III				
ML2	7 m - 32 m	0.60	III	Gas	421	Immature	Diagenesis
ML1	5 m - 7 m	3.17	II/III	Mixture of oil and gas, gas and oil	426	Immature	Diagenesis
	4 m - 5 m		II				
	0 m - 4 m		III				

7. CONCLUSIONS

Based on the results obtained, the following conclusions can be drawn:

1. In the Cabo de São Braz area, the Cunga Formation was deposited in a proximal marine setting, specifically within the coastal to neritic zone. This interpretation is supported by the predominance of marine palynomorphs, particularly radiolarians and foraminiferal linings, which are commonly associated with shallow marine environments.
2. The sedimentary dynamics of the basin varied during deposition, affecting the production, accumulation, and preservation of organic matter. This variability is reflected in the lithological alternations observed across the sequence, as well as the dispersion of TOC values and the diversity of kerogen types identified in the analysed samples.
3. The Cunga Formation in the study area exhibits an average TOC of 2.31%, indicating a generally good potential for hydrocarbon generation. The kerogen is predominantly Type II/III and Type III, suggesting that the organic matter is capable of generating gas and oil-gas mixtures, with only limited potential for significant oil generation in intervals where Type II kerogen is present. However, the average Tmax of 425 °C indicates that the formation remains thermally immature and within the diagenetic stage. As a result, under the current burial and thermal conditions, the rocks have not been exposed to the appropriate combined factors (temperature, time, and burial history) required to enter the oil-generation window and thus have not generated significant hydrocarbons despite the favourable organic matter characteristics in this part of the basin.

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