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Petroleum systems and hydrocarbon potential of the Ruvuma Basin, Tanzania

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ABSTRACT

Ruvuma Basin is widely recognized across the world for large gas field discoveries, which indicate the presence of gas-prone sources. However, little is known about the basin's source rock's hydrocarbon generation potential, including the distribution of significant petroleum systems. Inferences are often drawn from Permo-Triassic and Jurassic source rocks in Mandawa Basin, Tanzania and Morondava Basin, Madagascar. As a result, knowledge of the basin's potential source rocks is not known. To constrain possible source beds including petroleum systems, this study thoroughly reviewed previous literature coupled with rock eval pyrolysis and vitrinite reflectance analysis on rock cuttings (n = 19) from the Ruvuma Basin's Permo-Triassic, Jurassic, and Cretaceous shales of Lukuledi-1 well.

The findings indicate variable petroleum systems with different generation potentialities in the Permo-Triassic, Jurassic, Cretaceous, and Cenozoic intervals. The Permo-Triassic plays sourced hydrocarbons from the matured Permo-Triassic shales of kerogen type II and I, with Total Organic Carbon (TOC) average of 40 %wt, Hydrogen index (HI) average of 286.5 mg HC/g TOC, vitrinite reflectance (Ro%) average of 0.81 with Tmax average of 436 °C capable of oil generation. The Jurassic play systems are charged from matured Jurassic kerogen type III and mixed type II/III shales with TOC~ 4 %wt, HI~54.25 mg HC/g TOC, Ro% ~0.6 and Tmax ~444 °C capable of gas generation. Cretaceous and the Cenozoic play systems, sourced hydrocarbon from deeper sources because their source rocks are thermally immature with kerogen type III, having TOC ~0.6 %wt, HI ~53.6 mg HC/g TOC, Ro% ~0.3 and Tmax <420 °C capable of gas generation.

These results indicate that the Cenozoic play system incorporates hydrocarbons from diverse sources/reservoirs, making it a potential exploration target for future discoveries. These findings necessitate more research to determine migratory patterns, which will result in new ground-breaking discoveries in the basin.

1. Introduction

A petroleum system is a pod of genetically related hydrocarbons containing key petroleum elements such as source rock, reservoir rock, and seal/cap rock (Magoon, 1992; Magoon and Beaumont, 1999). An active system is typically proven by a well-producing oil or gas, an oil or gas seep, or an oil or gas accumulation, regardless of how little (Magoon and Beaumont, 1999; Magoon and Dow, 1994). Petroleum systems analysis enhances the effectiveness of hydrocarbon exploration by significantly assisting in the comprehension of the underlying logic of where and how hydrocarbon accumulations develop in the subsurface (De Jager, 2020; Magoon and Beaumont, 1999). The key element used to define a petroleum system is the source rock such that the maturation and generation process must occur at the right place at the right time to produce a petroleum accumulation (De Jager, 2020; Magoon and Beaumont, 1999).

Ruvuma Basin is part of East Africa's passive margin system, which stretches from Tanzania to Mozambique along the continental coastline (Salman and Abdula, 1995; Smelror et al., 2008). The basin is 400 km long and 160 km wide, covering 64,000 km^2, located between the northeast of Mozambique and the southeast of Tanzania (Smelror et al., 2008, Fig. 1). The basin is known as the Rovuma Basin in Mozambique (Ledesma, 2013; Rego et al., 2019; Smelror et al., 2008). Hydrocarbon exploration in Ruvuma Basin started in the 1950s to shed light on the locations of thick sedimentary packages and assess the presence of components of active petroleum systems in the Basin (Mpanju and Philp,

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1994; Salman and Abdula, 1995). In 1982 the first gas discovery was reported in the basin from Mnazi Bay −1 well in the Oligocene and Miocene sands, making it Tanzania's second natural gas discovery after the Songo Songo gas field (Rego et al., 2019; Said et al., 2015). The Ruvuma Basin currently revealed the presence of roughly 240 trillion cubic feet (Tcf) of thermally mature dry gas (GeoPartners, 2020; Johnstone, 2016). However, the largest discovery of 200 trillion cubic feet (Tcf) was made offshore Mozambique, whilst the remaining 40 Tcf was made in Tanzania (Hydrocarbon technology, 2021; Rego et al., 2019). The presence of gas discoveries and multiple oil seeps reported in the onshore region of the basin provides indications of the presence of an active petroleum system and oil/gas-prone sources, although no potential oil or gas sources have yet been identified (Johnstone, 2016; Orsi, 2017).

The source rocks in the Ruvuma Basin are inferred from the nearby basin, the Triassic -Jurassic source rocks of the Mandawa Basin in Tanzania and the Jurassic source rock of Morondava Basin, southwest Madagascar (Zhang, 2014; Zhang et al., 2019; Zhou et al., 2013). The knowledge of what and where the prospective source rock intervals and potential petroleum systems in the Ruvuma Basin are hampered by a lack of a comprehensive analysis of the source rock's ability to generate hydrocarbons. Consequently, selecting a precise area for further exploration and drilling becomes increasingly challenging. To alleviate this situation, understanding the petroleum system and determining the potentiality of the basin's source rocks was unavoidable. As a result, this study intensively investigated the hydrocarbon generation potential of Permo-Triassic, Jurassic, and Cretaceous shales of Lukuledi-1 in the Ruvuma Basin. This was accomplished by the use of rock eval pyrolysis, and vitrinite reflectance, along with thorough reviews of previous works. The findings suggest the possibility of more discoveries in the basin, including oil accumulation, supporting the need for continued research and aggressive exploration.

1.1. Exploration history

Ruvuma Basin initiated exploration activities in the 1950s when a BP/Shell consortium acquired concession rights covering entire coastal Tanzania (Salman and Abdula, 1995). Three deep exploratory wells were drilled, two in Tanzania and one in Mozambique, as part of the initial seismic survey of both onshore and offshore locations (TPDC, 1992, Fig. 2). These wells include Mnazi Bay-1 (Tanzania), Lukuledi-1 (Tanzania), and Mocimboa-1 in Mozambique (Salman and Abdula, 1995, Fig. 2). Mnazi Bay-1 drilled to the Late Cretaceous interval and made the first commercial gas discovery in the basin (Rego et al., 2019; Salman and Abdula, 1995). Whereas, Lukuledi-l which was drilled to a depth of about 6368 ft (Macgregor, 2017; Macgregor et al., 2018; TPDC, 1992), cutting through the Permo-Triassic, Jurassic and Cretaceous shales, proved to be a dry well (Salman and Abdula, 1995). However, it was also discovered that the Mocimboa-1 well, which was drilled into the Lower Cretaceous, was also a dry well with a gas show (Salman and Abdula, 1995; TPDC, 1992).

The increased gas supply demand and the development of new geological techniques in the 2010's (Johnstone, 2016), resulted in the acquisition of the basin's 3D seismic data which was subsequently processed numerous times (Hydrocarbon Technology, 2021; Johnstone, 2016; Rego et al., 2019). The seismic processing led to the drilling of additional onshore and offshore wells both in Tanzania and Mozambique (Augé and Nakayi, 2014; Ledesma, 2013; Smelror et al., 2008). On the Tanzanian side, wells such as Likonde-1 (2010), Chaza-1 and Jodari (2010–2011), Ntorya-1 (2011), Ziwani-1 (2012) and Ntorya-2 (2016) were drilled (GeoPartners, 2020; Rego et al., 2019). During this time, substantial gas discoveries of 32 Tcf were made deep offshore of southern Tanzania (Augé and Nakayi, 2014; Johnstone, 2016; Rego et al., 2019). In Mozambique, the Mamba South-1 well drilled in 2011 (Ledesma, 2013), encountered approximately 300 m of gas pay in Eocene and Oligocene hybrid turbidite-contourite deposit reservoirs, making it the second gas discovery after Mnazi Bay-1 in 1984 (Brownfield and Schenk, 2016; Salman and Abdula, 1995). Following the success of Mamba South-1, an intensive drilling program was conducted from 2011 to 2014, resulting in the discovery and appraisal of the Mamba, Coral, and Agulha gas fields, which have an estimated gas of approximately 85 Tcf (Ledesma, 2013; Rego et al., 2019). The gas discoveries onshore and offshore in Ruvuma Basin indicate a prospective environment for additional discoveries since a comparable interval can be tracked both in Tanzania and Mozambique. Hence, calls for more research, new technology, and sufficient funding might result in

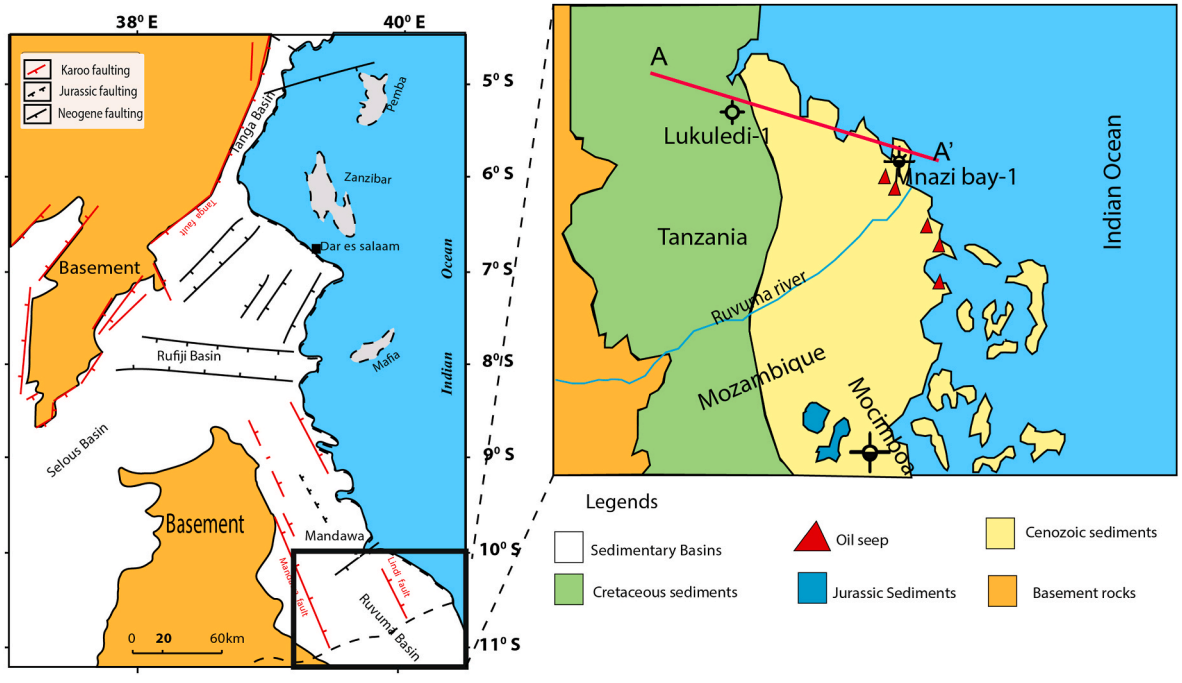


Fig. 1. Location and Geological map of Ruvuma basin, (modified from Kent et al.,1974) and (Salman and Abdula, 1995).

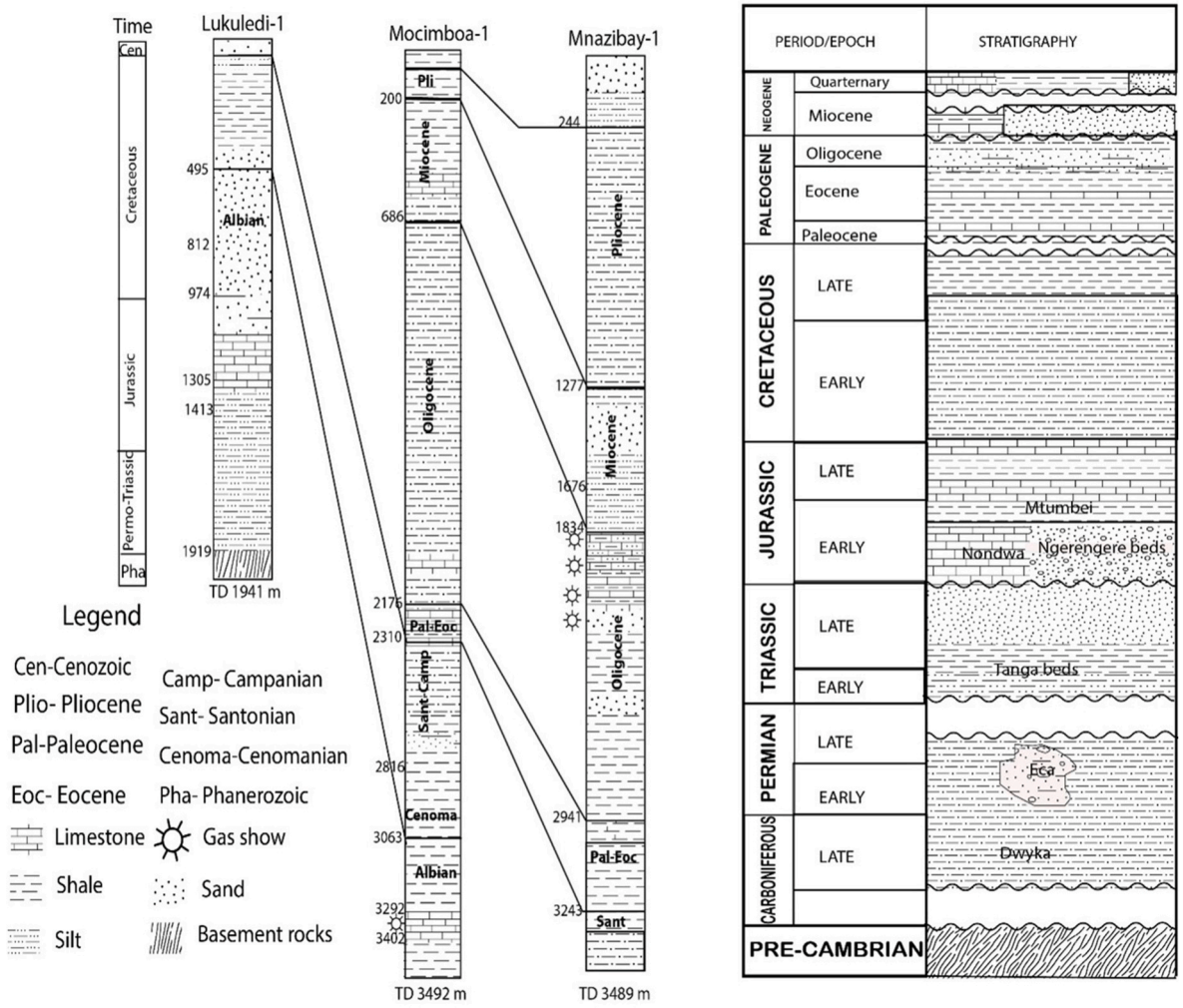


Fig. 2. Chronostratigraphic correlation of early drilled well in Ruvuma Basin between Lukuledi-1, Mnazi Bay-1 and Mocimboa-1 (left) with the general vertical stratigraphic section of Ruvuma Basin (right) modified after Salman and Abdula (1995).

amazing exploration success.

1.2. Geological setting of Ruvuma basin

Ruvuma Basin is part of the Coastal Tanzania Basin (CTB), which is located on the passive margin south of the western Indian Ocean (Brownfield and Schenk, 2016; Mbede, 1991). The basin is bounded by basement highs to the north (separating it from the Mandawa Basin) and south, extending eastward to the Indian Ocean (Nicholas et al., 2006; Salman and Abdula, 1995). The basin's formation is associated with continental rifting and drifting in the Permo-Triassic through Jurassic, and Cenozoic times (Mbede, 1991; Reeves, 2014; Zhou et al., 2013). Rifting in the Permo-Triassic records the first tectonic event known as "Karoo rifting" that resulted in the formation of karoo rift basins (Catuneanu et al., 2005; Rabinowitz et al., 1983; Wopfner and Kaaya, 1991). The karoo deposits in Ruvuma Basin which are substantial accumulations of fluvial and deltaic systems are indicative of this occurrence (Geiger et al., 2004; Hankel, 1994; Key et al., 2008). They are mainly found in the Palma Embayment and Lukuledi-1 well, dominated by the sandstones, siltstones and shales of the delta plain (Kapilima, 2004; Macgregor, 2017; Salman and Abdula, 1995). Specifically, the Permo-Triassic period is known for coal deposits worldwide with thin organic-rich algal (oil-prone) shales generating hydrocarbons trapped in the karoo sandstone (Catuneanu et al., 2005; Kreuser et al., 1990). The majority of the potential structures were created early in the basin's rifting in Permo-Triassic (Davison and Steel, 2018), including the structural Trap formation of the Permo-Triassic which coincided with the structural evolution of the basin prior to the generation, migration and accumulation of hydrocarbons (Brownfield and Schenk, 2016). The karoo deposits are succeeded by Jurassic limestone evidencing restricted marine conditions (Nicholas et al., 2007; Salman and Abdula, 1995). This limestone occurs as arenaceous bioclastic limestone with Kimmeridgian-Tithonian fossils discovered on the Mozambique side (Salman and Abdula, 1995). Gondwana's drift during the Middle Jurassic rifting caused Madagascar to move away from the coast of East Africa along the Davie fracture (Fossum et al., 2021; Hankel, 1994; Reeves, 2018), causing the rift basin to slowly filled with water forming an Indian ocean (Geiger et al., 2004; Reeves, 2018; Zhou et al., 2013). As a result of continued water filling, the full ocean's development occurred, leading deposition of marine shales on top of limestones (Mahanjane and Franke, 2014; Rego et al., 2019). The thickening of the marine shale (probable seal for underlying reservoir and source rock) deposits over the shallow marine limestones (Nhabanga and Ringrose, 2019), suggests reactivation of the earlier karoo basins structures that created faults-Jurassic faults-acting as migration pathways (Coffin and Rabinowitz, 1987; Kent et al., 1971; Schandelmeier et al., 2004; Wopfner and Kaaya, 1991). The rifting and drifting slowed during the Late Cretaceous, creating a passive margin (Fossum et al., 2021; Reeves, 2018). This was caused by the cessation of the seafloor spreading due to the cooling of the lithosphere (Coffin and Rabinowitz, 1987; Fossum

et al., 2021). The cessation of the spreading center caused major subsidence in Ruvuma Basin, with the influx of sand sheets from the exposed rift shoulders (Coffin and Rabinowitz, 1987; Sansom, 2018; Zhou et al., 2013). Onshore delta systems were developed as a result of the sand supply while supplying more sand in offshore locations (Brownfield and Schenk, 2016; Nicholas et al., 2007; Salman and Abdula, 1995). The transgression (shales) and regressive marine sandstone, such as the slope-turbidite channel and basin-floor fan sandstone, which are all similar to the Kipatimu formation, characterize the delta-systems formed seaward (Brownfield and Schenk, 2016; Mahanjane and Franke, 2014; Salman and Abdula, 1995). These offshore turbidite sand deposits are indicative of the synchronous interaction of northeasterly, along-slope moving contour currents and eastward-flowing turbidity currents (Hancox et al., 2002; Lu et al., 2021; Sansom, 2018). They are drilled onshore by the Mocimboa-l well on the Mozambique side of the basin (Mahanjane and Franke, 2014; Salman and Abdula, 1995). These Cretaceous sand form the reservoir of the gas discovered in Ntorya wells. The East African Rifting during Cenozoic, supplied a thick pile of sands, Mikindani formation, a potential reservoir of Mnazi Bay gas fields (Acosta et al., 2015; Kent et al., 1971; Mbede, 1991). Additionally, they are responsible for creating structures, the Cenozoic faults, that assisted in charging the Cenozoic reservoirs from deeper source rocks and reservoirs (Key et al., 2008; Zhou et al., 2013). Following the rifting, significant uplift and erosion have been reported from southern Tanzania and Mozambique (Mahanjane and Franke, 2014; Nicholas et al., 2007), supplying sediments to adjacent offshore areas (Geiger et al., 2004; Key et al., 2008; Mahanjane and Franke, 2014).

1.3. Structural architecture

Ruvuma Basin, structurally is separated from other basins by the Kitere and Makonde basements (McDonough et al., 2018; Salman and Abdula, 1995; Wen et al., 2015, Fig. 3). The basin's architecture generally owes its development to the tectonic activities (faulting) that occurred throughout the Permian-Triassic (karoo), Jurassic, and Cenozoic times defining its present trend (Fuhrmann et al., 2020; Geiger et al., 2004; Lu et al., 2021, Fig. 4). In Mozambique, the main faults run N–S to NNW-SSE, whereas in Tanzania, they mostly run NE-SW (Franke et al., 2015; Kapilima, 2004). These faults appear to be parallel to the Davie fracture which is a NW-SE trending feature that corresponds to Madagascar's strike-slip southward drift (Mahanjane, 2014; Mpanda, 1997; Rabinowitz et al., 1983; Reeves, 2020). The Davie fracture is characterized by basement high dipping gently to the East and sharply to the West (Coffin and Rabinowitz, 1987; Franke et al., 2015; Mahanjane and Franke, 2014). The steep side of the Davie fracture where Most of the Ruvuma Basin's hydrocarbon discoveries have been made (Franke et al., 2015; Mahanjane and Franke, 2014; Rego et al., 2019), warrants further research due to the likelihood of future discoveries.

1.4. Hydrocarbon occurrence

The world-class gas fields are known to occur in the Ruvuma Basin, Northern Mozambique, and offshore Tanzania, providing information on the region's and the Western Indian Ocean's overall prospectivity (Augé and Nakayi, 2014; Rego et al., 2019; Wen et al., 2015). The deep-water province of the Oligocene, Eocene, and Paleocene sands is where the majority of the gas in northern Mozambique has been discovered (Cenozoic play system). Contrarily, the gas in Tanzania is from the Early Cretaceous (Cretaceous play system) and Miocene turbidites sands, Cenozoic play system (Brownfield and Schenk, 2016; Rego et al., 2019; Sansom, 2018; Zhou et al., 2013). Oil seeps reported in the basin from Tanzania and Mozambique (Fig. 5), suggest the existence of oil-prone sources and the basin's potential for oil accumulation (Boote and Machete, 2019; Mpanju and Philp, 1994; Pereira et al., 2013). However, no oil has yet been discovered in the region despite the condensates produced with gas in the Mnazi Bay-1 and Ntorya wells (Brownfield and Schenk, 2016; Mpanju and Philp, 1994). Condensate analysis reveals an oil-based source rather than a gas-prone source (Mpanju and Philp, 1994; Pereira et al., 2013). Although the investigation of the oil seeps established a Jurassic carbonate source distinct from other seeps along the Tanzanian coast (Boote and Machete, 2019; Brownfield and Schenk, 2016; Pereira et al., 2013). Hydrocarbon generation models identified numerous hydrocarbons discovered to date were generated by matured source rock from the Permo-Triassic, Jurassic, and Cretaceous shales of comparable play systems (Brownfield and Schenk, 2016; Key et al., 2008, Fig. 6). The Jurassic and Cenozoic faults served as entry points for the generated hydrocarbons from deeper sources into the Cretaceous and younger strata (Pereira et al., 2013; Wen et al., 2015; Zhou et al., 2013). Mudstones and shales

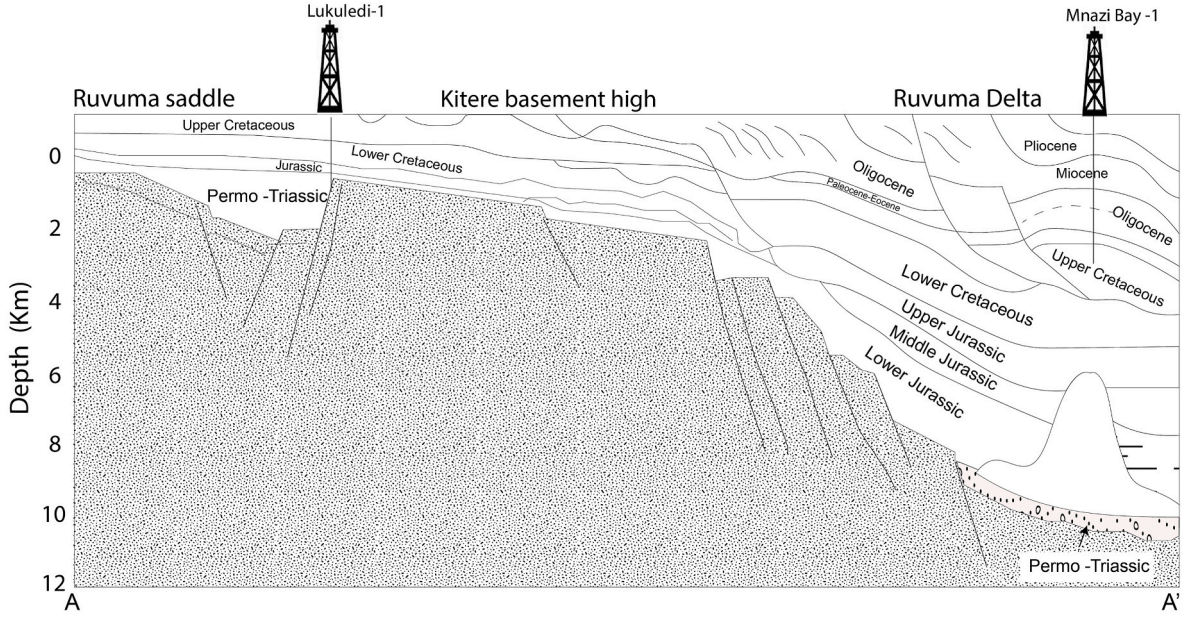


Fig. 3. Schematic cross-section of Ruvuma Basin, showing the structural framework from Onshore to Offshore with major geological strata from A-A′ in Fig. 1 (Modified after TPDC, 1992).

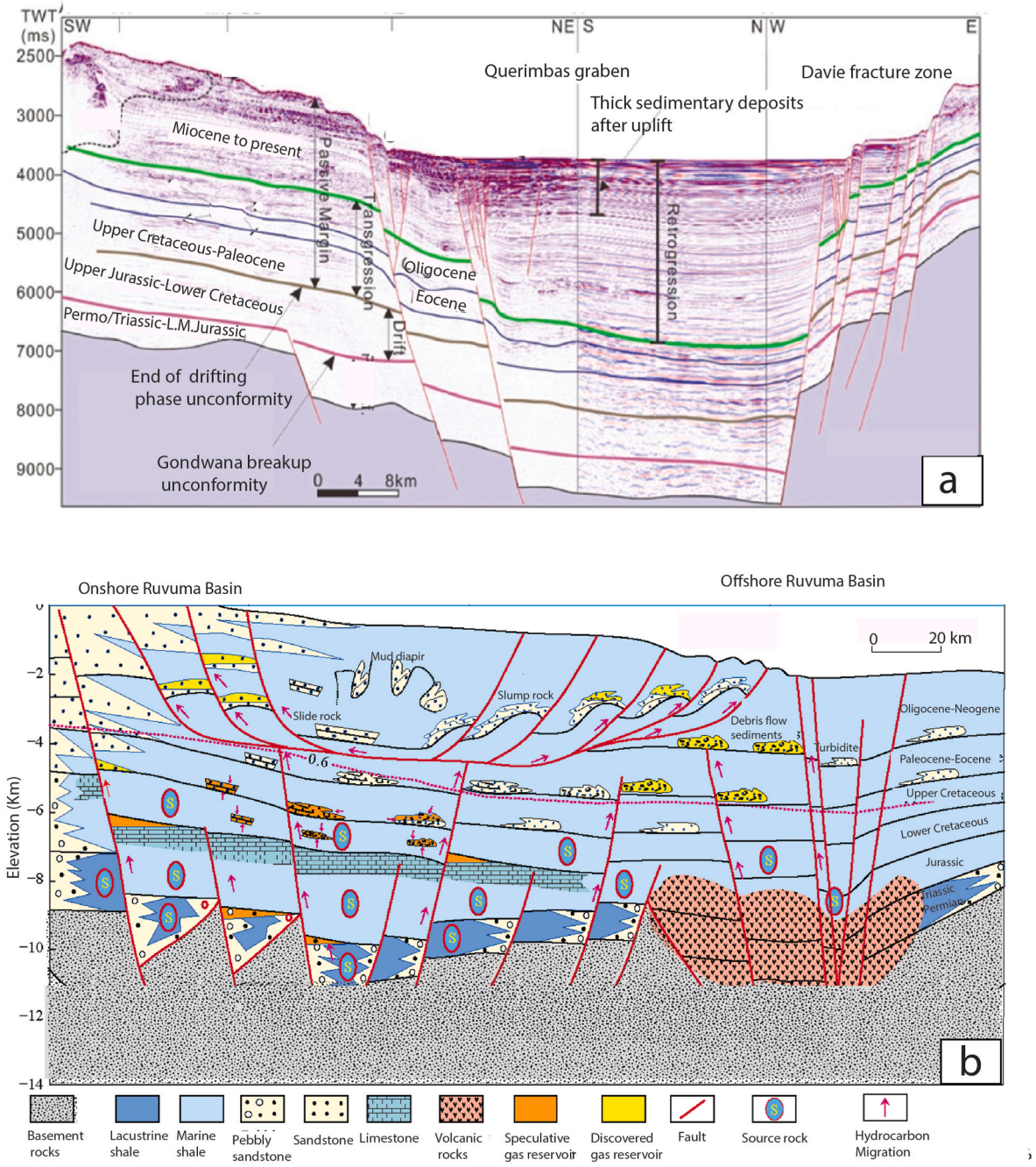


Fig. 4. (a) Regional seismic profile of west-east direction showing the stratigraphy of Rovuma Basin, Querimbas Graben, Davie Fracture Zone (modified after Luan et al., 2021); (b)Hydrocarbon accumulation model of a delta-changing type of Ruvuma Basin from Onshore to Offshore (Modified after Wen et al., 2015).

from the Cretaceous, Paleogene, and Neogene sealed and trapped hydrocarbons in structural and stratigraphic units (Cameron and Rego, 2020; Nairn et al., 1991; Zhou et al., 2013).

2. Materials and methods

A total of 19 drill cuttings samples were selected from Lukuledi −1 well in the depth between 240 ft and 6052 ft encompassing the Permo-Triassic, Jurassic and Cretaceous shales based on visible organic matter richness. All selected shale samples were washed and dried at 35°C for 24hrs to remove drilling mud and carefully prepared for vitrinite reflectivity analysis and Rock-Eval pyrolysis following the standard procedure described by ((Espitalie et al., 1977; Hunt, 1996; Peters, 1986; Tissot and Welte, 1984).

2.1. Rock-Eval pyrolysis and vitrinite reflectance

Rock eval pyrolysis was employed to determine source rock richness, organic matter type (kerogen) and maturity to asses hydrocarbon generation potential. The selected thirteen samples were grided to a powder and 70 g of each were placed in the pyrolysis oven for heating. The recorded results from pyrolysis were TOC- total organic carbon (%wt), S1- free hydrocarbons available in the sample, S2- the hydrocarbons generated through thermal cracking of nonvolatile organic matter, S3- the amount of CO2 produced during pyrolysis of kerogen, Tmax - the temperature at which the maximum release of hydrocarbons from cracking of kerogen occurs during pyrolysis, the hydrogen index (HI) and the Oxygen index (OI).

Vitrinite reflectance (Ro %) analysis was applied to evaluate the



Fig. 5. Examples of natural oil seeps at Ruvuma Basin, Msimbati-Tanzania (A) Makukwa-1 sand consisting of heavy bitumen saturated oil sand (B) Makukwa-2 oil stained sand found nearby Makukwa-1.

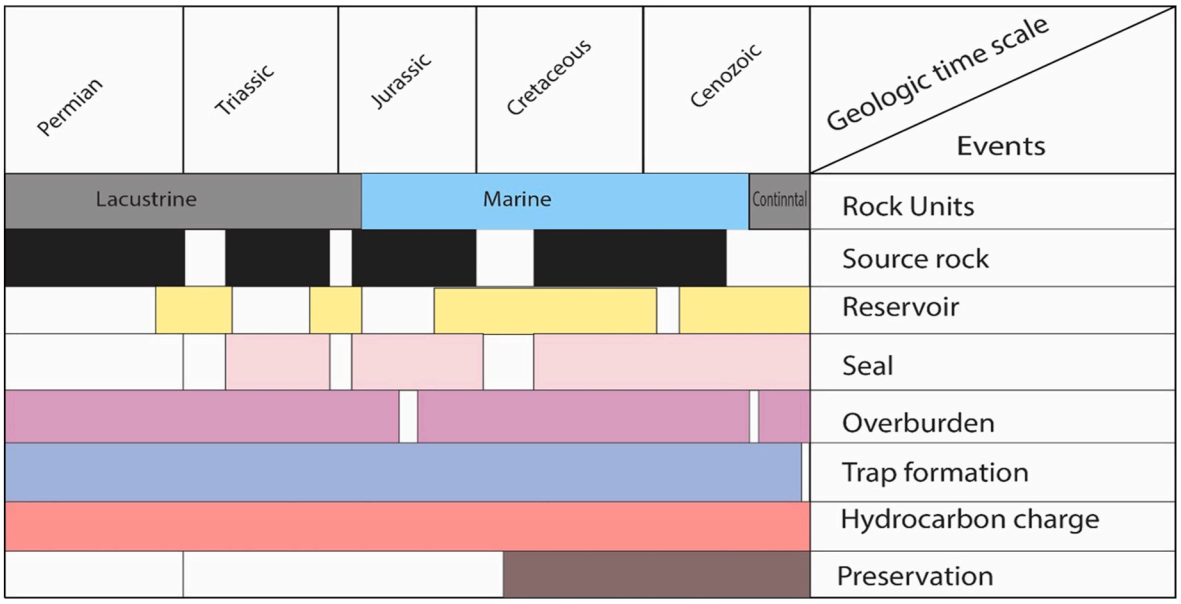


Fig. 6. Events chart for the petroleum elements of the Ruvuma Basin.

thermal maturity of six samples by measuring the percentage of incident light reflected from a polished surface of vitrinite. The kerogen of selected samples was isolated from shales, embedded in resin blocks, and polished. The reflectance was measured using a Zeiss Universal microscope with a total visual magnification of 400× (equipped with an Epi 40X Pol oil immersion objective and 10.0× eyepieces) at a wavelength of 546 nm. The two standards used are Spinel (Ro% = 0.588) and Gadolinium–Gallium-Garnet (Ro% = 1.696). The measurement was taken 50 times in each sample where feasible depending on the amount of organic matter available.

3. Results

3.1. Rock-Eval pyrolysis and vitrinite reflectance

The rock eval pyrolysis results of the Ruvuma Basin shale intervals of the Permo-Triassic, Jurassic and Cretaceous sequences are presented in table −1. The results demonstrate the Permo-Triassic shales had TOC values ranging from 7.53% wt to 78.74% wt with an average of 40 % wt. The HI values vary from 187 mg HC/g TOC to 386 mg HC/g TOC with an average of 286.5 mg HC/g TOC yielded at the Tmax between 432 °C and 442 °C. The computed generation potential (GP) ranges from 29.8 to 206 mg HC/grock, with an average of 108.4 mg HC/grock.

The Jurassic shales demonstrated to contain the TOC values ranging from 1.39 % wt to 9.73% wt with an average of 4 % wt. The HI values vary from 33 to 69 mg HC/g TOC with an average of 54.25 mg HC/g TOC yielded at the Tmax between 445 °C and 443 °C. The computed generation potential (GP) varies between 1.1 and 3.58 mg HC/grock, with an average of 1.9 mg HC/grock.

The Cretaceous shales yield TOC (wt) values between 0.52% wt to 0.67% wt with an average of 0.6%wt. The HI value range from 35 mg HC/grock to 162 mg HC/g TOC at Tmax of <420 °C.

The results of the vitrinite reflectance demonstrate that the Cretaceous shales have the lowest Ro%, which is 0.3 at a depth of 1220 ft. Whereas Ro% in Jurassic shales ranges from 0.5 at 3142 ft to 0.7 at 4035 ft with an average of 0.6. The Permo-Triassic shales, on the other hand,

show an increasing Ro% value, rising from 0.72 at 5737 ft to 0.9 at 6052 ft with an average of 0.81.

4. Discussion

4.1. Petroleum systems

Ruvuma Basin contains active petroleum systems which are directly related to the structural evolution of the basin throughout its rifting in the Permo-Triassic, Jurassic and Cenozoic (Davison and Steel, 2018). These petroleum systems are from Permo-Triassic, Jurassic and Cenozoic periods (Key et al., 2008; Salman and Abdula, 1995). Reviewing the stratigraphy, structural development, and petroleum geochemistry of the basin reveals the timing of the hydrocarbon generation, migration, and accumulation is in place with trap and seal formation (Hollebeek et al., 2015; Key et al., 2008; Salman and Abdula, 1995; Wen et al., 2015). However, the Permo-Triassic and Jurassic prospective systems were affected by the latest rifting, Cenozoic rifting (Boote and Machete, 2019). As a result, large quantities of oil and gas find their way to the surface and younger strata of the Cenozoic (Boote and Machete, 2019; Davison and Steel, 2018; Mpanju and Philp, 1994). To comprehend the prospective petroleum systems presented in the basin and the role source rocks played in the discovered hydrocarbon, a thorough review is discussed below and substantiated by the geochemical finding of the source rocks analysis.

4.1.1. Source rocks

The source rock richness varies with the time interval of the Ruvuma Basin's shale deposits. For example, the Permo-Triassic shales have the highest organic richness, excellent generation potential with a TOC of

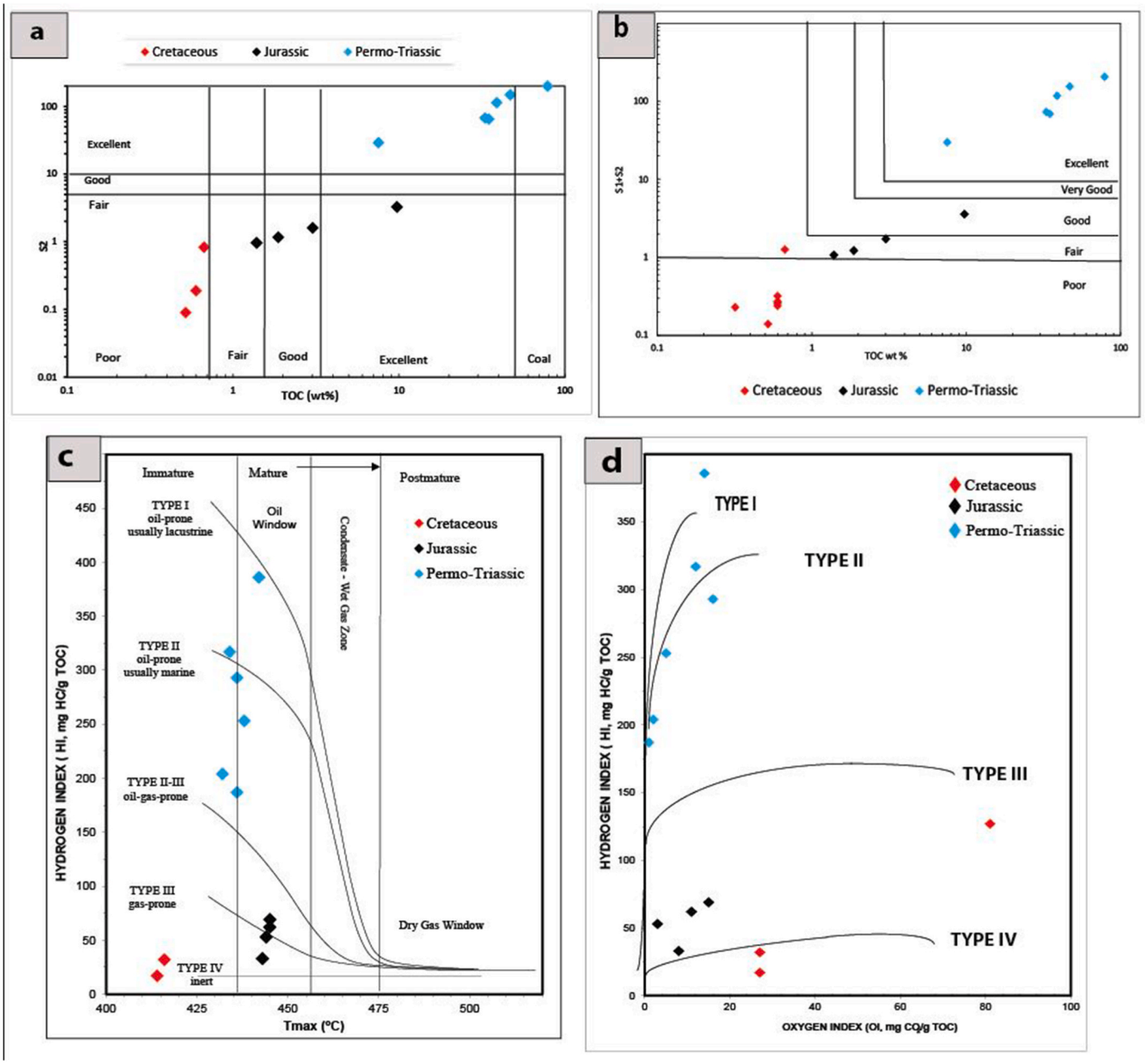


Fig. 7. Results of Hawk pyrolysis plotted on: (a) S2 versus TOC presenting source rock richness: (b) S1+S2 plot against toc and HI versus TOC showing hydrocarbon generation potential: (c and d) HI versus Tmax and HI versus Oxygen index (OI) classification diagram presenting maturity and kerogen type. These plots indicate the existence source rocks capable of generating hydrocarbons.

about 78 %wt (Fig. 7a and b), whilst Jurassic shales, which are similarly organically rich, have TOC levels of approximately 9 %wt. The Cretaceous shales are biologically lean (Fig. 7a and b), which implies they have an exceptionally low organic matter content, as indicated by TOC values of 1 % wt. (McCarthy et al., 2011; Peters, 1986). The variations in the richness of the Ruvuma Basin, Lukuledi-1 shales are attributable to the depositional environment, the supply of organic matter and the basin's preservation (Espitalie et al., 1977; Tissot and Welte, 1984). In particular, the Permo-Triassic period is acknowledged for coal deposits worldwide (Catuneanu et al., 2005; Hazra et al., 2019; Hunt, 1991; Kreuser et al., 1990). Their existence suggests humid conditions with relatively heavy rainfall and river systems which are responsible for both luxuriant vegetational development and poor drainage (Rafferty, 2010; Wopfner, 2002). Consequently, swamps served as depositional basins for decomposing plant material, which progressively changed into peat and finally coal (Kreuser et al., 1990b; McCabe, 1985; Wopfner, 2002). Indeed, the Permo-Triassic period in Tanzania is distinguished by subsequent rifting dominated by fluvial and lacustrine conditions, which explains the occurrence of coal not only in the Ruvuma Basin but also in inland basins such as the Rukwa and Ruhuhu (Catuneanu et al., 2005; Kapilima, 2004; Kreuser et al., 1990; Wopfner, 2002).

Plots of the hydrogen index (HI) vs the oxygen index (OI) on a modified van Krevelen diagram and a plot of the hydrogen index versus Tmax (Fig. 7c & d), demonstrate that most Permo-Triassic shale intervals are characterized by kerogen type I, II, and mixed type II/III demonstrating oil proneness and might be capable of producing modest gas (Fig. 7c and d). The Jurassic and Cretaceous shale intervals exhibit gas proneness evidenced by kerogen types III and IV (Fig. 7d). Type III kerogens are typically gas sources (Tissot and Welte, 1984; Peters, 1986), whereas Type IV kerogens are often considered inert, having little or no hydrocarbon source potential (Espitalie et al., 1977; Hunt, 1996; Peters, 1986). The presence of coal in Permo-Triassic shales (Fig. 7a) is typically thought to be a "gas-prone" source bed (Hunt, 1991). However, these shales exhibit oil proneness comparable to the Permo-Triassic shales of Madagascar's Morondava Basin, which produced heavy oil discovered in Tsimiroro (Schandelmeier et al., 2004; Zhou et al., 2013). Coal-derived oil is also known to induce economic accumulations in places like New Zealand's Taranaki Basin, Gippsland Basin in south Australia, Songliao Basin in China and Kutei Basin, Indonesia (Bishop, 2000; Lee, 1986; Petersen, 2005; Sykes et al., 2014). As a result, the existence of oil-prone Permo-Triassic shales in the Ruvuma Basin suggests the possibility of future oil discoveries in the basin.

Thermal maturity is variable within Ruvuma Basin spanning from immature, oil to a gas window. The Cretaceous shale intervals exhibit immaturity with Tmax <420 °C and Ro% of 0.3 (Table 1), suggesting that these rocks are incapable of hydrocarbon generation at present maturity (Al-Areeq, 2018; Mukhopadhyay and Dow, 1994; Tissot and Welte, 1984). Jurassic shales are in the mature stage within the oil generation window with Tmax >430 and Ro% > 0.6. On the other hand, the Permo-Triassic also shows thermal maturity in the gas window as indicated with higher Ro% values of about 0.9 (Table 1). The maturity of Permo-Triassic and Jurassic in the basin is proven by the existence of about 240 Tcf of thermally mature dry gas discovered offshore northern Mozambique and southern Tanzania (Rego et al., 2019). It is still unclear whether the gas in the Ruvuma Basin comes from the initial gas-prone source or overmature oil-prone sources (Davison and Steel, 2018; Pereira et al., 2013). This is because the Permo-Triassic shales of eastern Africa are thought to be overmature, which means they are in the gas window and any oil generated would be converted to gas (Kreuser et al., 1988, 1990; Pereira et al., 2013; Rego et al., 2019).

4.1.2. Reservoir

The identified prospective reservoirs in the Rovuma Basin are found throughout the Permo-Triassic, Jurassic, Cretaceous, and Cenozoic intervals (Davison and Steel, 2018; Zhou et al., 2013, Fig. 8). They are mostly made up of deltaic sediments and turbidites with high porosity and permeability (Lu et al., 2021; Palermo et al., 2021; Rego et al., 2019). For example, Permo-Triassic reservoirs in the Lukuledi-1 well constitute sandstone with a porosity of 25% and a permeability of 5630 Md (Zhou et al., 2013). Jurassic reservoirs are made of carbonates with a porosity of 19.9% and a permeability of 201 Md (Davison and Steel, 2018; Salman and Abdula, 1995). Cretaceous reservoirs are made of sandstone with a porosity of 34.9% and a permeability of 1730 Md (Augé and Nakayi, 2014; Davison and Steel, 2018; Rego et al., 2019). And the Cenozoic reservoirs are made of turbidites with porosities of about 15–25% and permeabilities of up to 560 Md (Salman and Abdula, 1995; Zhou et al., 2013). However, it is only the Cretaceous and Cenozoic reservoirs producing in the basin. The Cretaceous reservoirs led to major discoveries of gas produced by the Ntorya wells (GeoPartners, 2020; Rego et al., 2019; Zhou et al., 2013). They were tested and flowed at a maximum rate of 20.1 million standard cubic feet of gas a day (mmscfd), producing 139 barrels of oil a day and 53° API condensate (Zhou et al., 2013). Indeed, the Cretaceous period is a prospective reservoir because the Songo Songo gas field was discovered in a comparable interval (Sabuni et al., 2022; Zhou et al., 2013). The Cenozoic reservoirs form the majority of well-known producing hydrocarbon fields (Augé and Nakayi, 2014; Mahanjane, 2014; Mahanjane and Franke, 2014), such as the gas fields of Mnazi Bay and Msimbati in Tanzania and Coral and Mamba in Mozambique (Mahanjane and Franke, 2014; Palermo et al., 2021).

Currently, no hydrocarbons have been recovered in the Permo-Triassic and Jurassic reservoirs in the basin, except those of Tsimiroro heavy oil found in the Morondava Basin Madagascar (Schandelmeier et al., 2004; Zhou et al., 2013). The scarcity of Permo-Triassic and Jurassic reservoirs in the Ruvuma Basin is intricately linked to Cenozoic rifting (Nairn et al., 1991; Rego et al., 2019; Zhang et al., 2019). It is

Table 1
Rock eval pyrolysis and vitrinite reflectance results from Lukuledi-1 well.

Interval	Depth (ft)	TOC	S1	S2	S3	HI	OI	Tmax	S2/S3	S1+S2	Ro%
Cretaceous	240	0.67	0.43	0.8	0.54	127	81	379	0.5	1.26	
	540	0.52	0.05	0.1	0.14	17	27	414	0.6	0.14	
	1120	0.6	0.08	0.2	0.16	32	27	416	0.4	0.27	0.3
Jurassic	3142	9.73	0.31	3.3	0.81	33	8	443	0.1	3.58	0.5
	3908	3.02	0.12	1.6	0.1	53	3	444	0.1	1.72	
	3971	1.87	0.06	1.2	0.2	62	11	445	0.1	1.22	
	4035	1.39	0.11	1	0.21	69	15	445	0.1	1.1	0.7
Permo-Triassic	5207	7.53	0.68	29.1	1.05	386	14	442	0.02	29.8	
	5737	33	5.68	67.5	0.62	204	2	432	0.1	73	0.72
	5989	78.74	6.76	199	3.98	253	5	438	0.03	206	
	5992	38.78	3.8	114	6.12	293	16	436	0.03	117.4	
	5994	46.83	6.56	149	5.74	317	12	434	0.04	155.1	
	6052	34.77	3.98	65	0.54	187	1	436	0.1	68.95	0.9

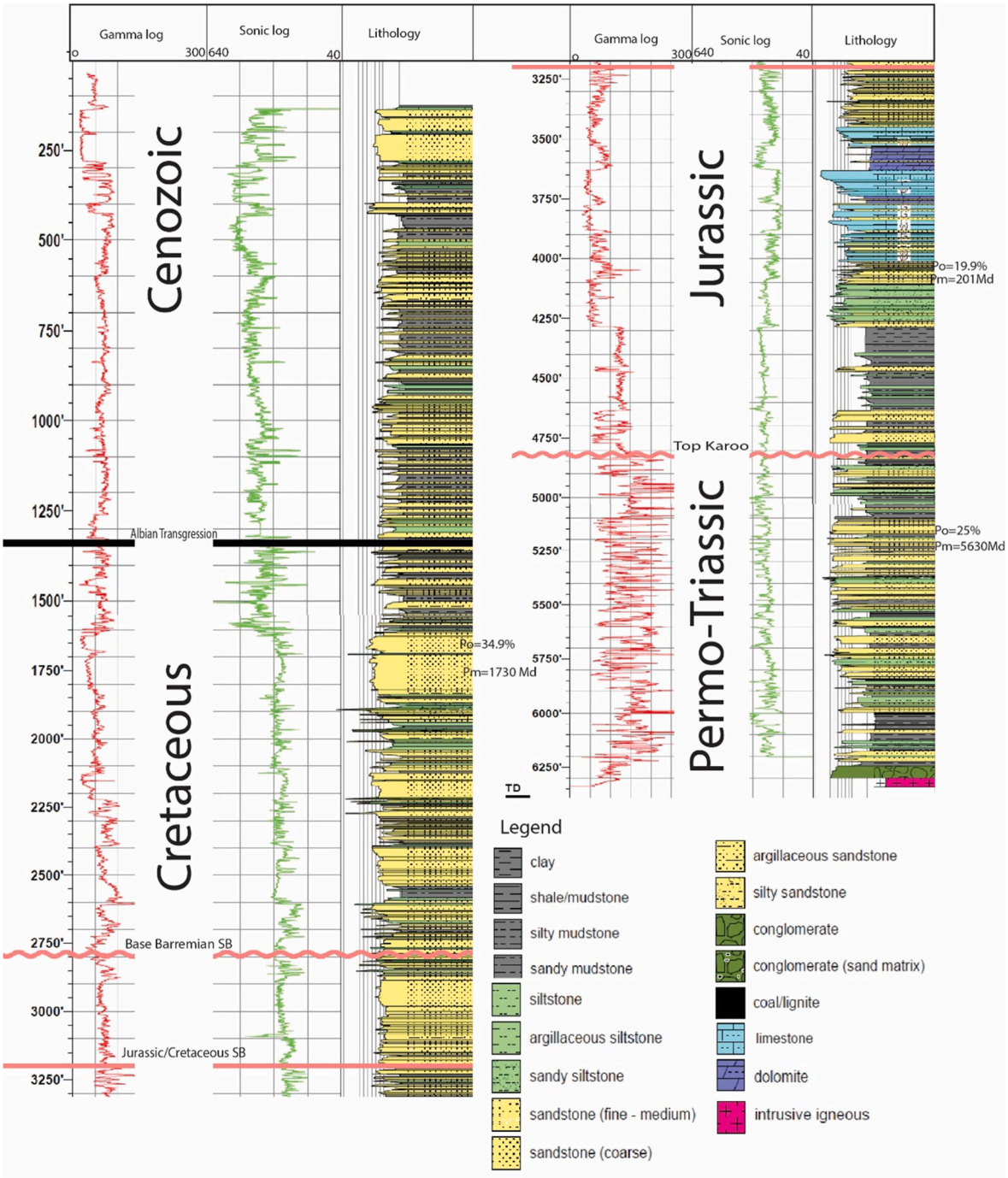


Fig. 8. Chronostratigraphic well plot of Lukuledi showing encountered lithologies including porosity (po) and permeability (pm).

claimed that the rifting created several faults, including breaching the accumulated hydrocarbons in the reservoirs (Davison and Steel, 2018; Macgregor et al., 2018; Rego et al., 2019). Consequently, triggered the upward migration of accumulated hydrocarbons into younger reservoirs (Davison and Steel, 2018; Rego et al., 2019; Zhang et al., 2019). Indeed, the Cretaceous and Cenozoic reservoir deposits have a substantial influence on the petroleum prospectivity of the Ruvuma Basin. As a result, hydrocarbon exploration must strive to prolong these sections offshore and in adjacent basins.

4.1.3. Traps

The Ruvuma Basin's trapping mechanism comprises structural and stratigraphic traps (Brownfield and Schenk, 2016; Mahanjane, 2014). The structural traps predominate the Permian and Jurassic intervals whilst the Cretaceous and Cenozoic intervals are dominated by both structural and stratigraphic traps (Dolson, 2018; Sansom, 2018). The principal traps include anticlinal structures (rollover), fault sealing blocks, turbidites, and pinched-out sandstones (Dolson, 2018; Lu et al., 2021; Zhou et al., 2013, Fig. 9). Pinch-out sands and fault sealing predominates the Cretaceous reservoirs where Ntorya and Ziwani gas were discovered (Rego et al., 2019; Salman and Abdula, 1995; Zhang et al., 2019). Whereas rollover anticlines and turbidites dominate the gas fields of Cenozoic intervals in Mnazi Bay and offshore both in Mozambique and Tanzania (Augé and Nakayi, 2014; Davison and Steel, 2018; Mahanjane, 2014). More gas discoveries were made in Cenozoic stratigraphic traps, and clastic turbidite plays than in any other trap type in

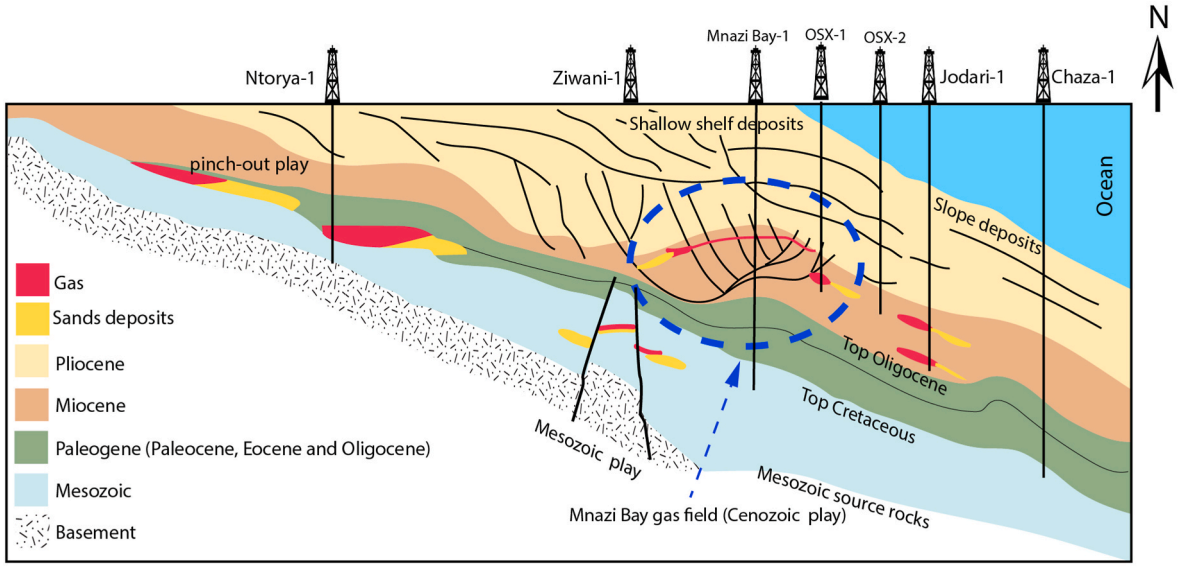


Fig. 9. Simplified structural cross sections of onshore to offshore Ruvuma Basin, presenting the distribution of wells, petroleum plays and trapping mechanism. The sections illustrate the structural architecture of coastal Tanzania and the Ruvuma Basin with hydrocarbon occurrences and drilled wells (Modified after Rego et al., 2019).

the basin, outperforming structural trap exploration (Key et al., 2008; Rego et al., 2019). This means that if high-resolution 3D and 4D seismic acquisition are carried out to better subsurface strata imaging, the turbidites of the Ruvuma Basin promise more prospective discoveries.

4.1.4. Seal

The principal seals identified in the Ruvuma Basin include Permo-Triassic, Jurassic, Cretaceous, and Cenozoic seals (Cameron and Rego, 2020; Rego et al., 2019; Zhou et al., 2013), which are largely composed of grey marl, mudstones, and shales (Key et al., 2008; Luan et al., 2021). The presence of fault seals has also been proven in the basin's Permo-Triassic and Jurassic intervals (Davison and Steel, 2018). They are, however, only found in faulted areas, in a contrast to the Jurassic, Cretaceous, and Cenozoic seals that are found across the basin (Sansom, 2018). According to hydrocarbon generation models of Ruvuma Basin, substantial seal capacity was achieved, sufficient to store a large amount of hydrocarbons prior to Cenozoic rifting (Brownfield and Schenk, 2016; Macgregor et al., 2018; Nairn et al., 1991; Rego et al., 2019). The rifting is thought to have breached previous seals, allowing the contained hydrocarbons to enter Cenozoic reservoirs, where a tiny percentage of the hydrocarbon was released to the surface (Johnstone, 2016; Mpanju and Philp, 1994). This is demonstrated by oil seeps in the Ruvuma Basin, which have been documented in both Tanzania and Mozambique (Mpanju and Philp, 1994). The Cenozoic seals are mostly Miocene and Pliocene mudstones and shales that have resulted in world-class gas discoveries containing migratory hydrocarbons both onshore and offshore (Sansom, 2018; Wen et al., 2015; Zhou et al., 2013).

4.2. Hydrocarbon plays

A hydrocarbon play is a collection of oil and gas reservoir zones controlled by similar processes of hydrocarbon generation, migration, and accumulation (Sabuni et al., 2022). A comprehensive review of the petroleum system has shown that Ruvuma Basin's potential plays include; the Permo-Triassic, Jurassic, Cretaceous, and Cenozoic plays (Brownfield and Schenk, 2016; Rego et al., 2019; Sansom, 2018). The Permo-Triassic play was discovered on the northern edge of the Ruvuma Basin near the Lukuledi-1 well (Salman and Abdula, 1995). The hydrocarbons in this play are derived from Permo-Triassic source rocks, which are primarily coal-rich and have a TOC of up to 78%wt, with Jurassic shales serving as caprock (Brownfield and Schenk, 2016; Cameron and Rego, 2020; Zhou et al., 2013). The Jurassic play, on the other hand, was discovered near the Tanzania-Mozambique border (Mikindani) within the basin (Mpanju and Philp, 1994). The hydrocarbons in Jurassic reservoirs are derived from Jurassic source rocks, which are predominantly shales and organically rich limestone, with Cretaceous shales acting as a seal (Davison and Steel, 2018; Zhang et al., 2019; Zhou et al., 2013). The biomarker fingerprints of the oil seep encountered in the basin revealed the contribution of these Jurassic sources to oil formation (Mpanju and Philp, 1994). The existence of Cretaceous play has been detected in the Ntorya gas fields (Pereira et al., 2013; Rego et al., 2019; Zhou et al., 2013). Hydrocarbons are sourced from the Lower Cretaceous organic-rich source rocks charging the Upper Cretaceous sandstones, capped by upper Cretaceous and Cenozoic shales (Davison and Steel, 2018; Fossum et al., 2021). Furthermore, the Cenozoic play represents the offshore Ruvuma gas discoveries (Brownfield and Schenk, 2016), where hydrocarbon sourced from broken seals of older formations such as Permo-Triassic, Jurassic and Cretaceous through Cenozoic faults (Brownfield and Schenk, 2016; Key et al., 2008). Herein, the hydrocarbons are sealed by Late Miocene shales and Pliocene mudstone (Davison and Steel, 2018; Zhang et al., 2019; Zhou et al., 2013). Onshore and offshore, petroleum plays from the Cretaceous and Cenozoic periods are now extremely promising, with a larger supply of gas in place offering the strongest prospectivity.

5. Conclusions

Based on comprehensive reviews and the results of the geochemical evaluation of shale source potential by Rock-Eval pyrolysis and vitrinite reflectance measurements from the Permo-Triassic, Jurassic, and Cretaceous intervals of the Lukuledi-1 well in the Ruvuma Basin, the following conclusions were drawn:

The Permo-Triassic and Jurassic shales are matured and organically rich, whereas the Cretaceous is organically lean and immature. The Permo Triassic has the highest richness and excellent hydrocarbon generating potential for oil generation with kerogen Type I and II whilst the Jurassic has fair organic matter richness, poor hydrocarbon yields, kerogen type III giving a poor source for gas. On the other hand, Cretaceous shales which are immature exhibit gas potentiality with the dominance of kerogen type III and IV. Hence, the Permo-Triassic

interval of the Ruvuma Basin constitutes a potential source bed that increases the basin's prospectivity.

The review of the play systems identified the major four play systems, namely Permo-Triassic, Jurassic, Cretaceous, and Cenozoic. These plays were filled by the hydrocarbons from the mature Permo-Triassic, Jurassic and Cretaceous source rocks. The Cenozoic play is the basin's most promising play, having acquired hydrocarbons from deeper sources following secondary migration triggered by Cenozoic tectonic activity.

Exploration results to date have been phenomenal, with natural gas discoveries considerably exceeding expectations in the Ruvuma Basin. Given the location of these recent discoveries and worldwide energy demands, many more discoveries are predicted in the near future. A more extensive analysis of source rock relationships to oil and gas must be tested and correlated to produce a complete understanding of the basin's hydrocarbon generations, as the Ruvuma Basin offers a competitive fiscal regime in comparison to other petroleum-rich countries in eastern Africa.

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Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Data availability

Data will be made available on request.

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