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PS High Impact Exploration Inventory in an Emerging Hydrocarbon Province, Morandava Basin, Offshore Madagascar*

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Abstract

Rifting of Madagascar from East Africa created a rich array of structural and stratigraphic traps in an area that has seen little sub-aerial erosion and extensive source rock deposition for more than 150 my. Recent gas discoveries on the conjugate Rovuma margin have ignited interest in the prospectivity of the Madagascan margin. Rovuma Basin wells have targeted a range of plays from onshore extensional (*Mecupa*), thrusted Tertiary traps (*Windjammer* discovery), Cretaceous stratigraphic traps (*Ironclad*) and Tertiary slope channels and fans (*Tubarao*, *Lagosta*, and *Barquentine* discoveries). In contrast, no wells targeting equivalent plays have been drilled in any of the western Madagascar basins. Onshore Madagascar, accumulations of more than 22 Bbbls of heavy oil and tar sands, frame the Central Mozambique Channel as a future hydrocarbon province with the possibility of a light oil 'sweet spot' midway between these two major proven accumulations of gas and heavy oil. However, the deep offshore currently represents an entirely undrilled frontier province.

2-D and 3-D data are used in this study with long distance 2-D well ties. As a frontier area for exploration, ages of the stratigraphy in the study area are largely unconstrained by well data. Interpretations were made primarily based upon the identification of seismic reflection terminations.

Key geologic surfaces mapped were Top Jurassic Maximum flooding (MFS), Intra- Cretaceous Sequence Boundaries (SBs), Upper Cretaceous SB, Top Maastrichtian SB, Top Oligocene MFS, and Top Miocene MFS. Two main erosive surfaces were interpreted, the Top Jurassic unconformity and the Upper Cretaceous unconformity. Stratigraphic interpretation using a combination of Variance/Coherency and Spectral Decomposition were used to support structural culminations.

The prospectivity of the offshore Madagascar study area is dominated by four-way dip closures at Cretaceous and Jurassic levels, Tertiary turbidite fans and slope channels, and possible Mesozoic reefs. Thermal model results as well as slick and seabed cores suggest possible oil prone source rocks that could be active in the offshore area. These range from Triassic through Lower Jurassic, Middle Jurassic, and Lower Cretaceous sequences. Similar Triassic source rocks are responsible for more than 20 billion barrels of exhumed hydrocarbons onshore Madagascar. The study area has significant source rock potential that is oil mature from Triassic through Jurassic with peak expulsion throughout the Miocene and Plio-Pleistocene.

Introduction

Madagascar is the third largest island in the world and covers an area of about 592,000 km^2. The study area (Morondava Basin) is located on the west coast of Madagascar in the South West of the Indian Ocean at a distance of about 400 km off the East coast of Africa and extends up to 300 km into the deep water (GETECH, 2009). The Belo Profond permit covers an area of nearly 13,800 km^2. It extends to the south both the exploration plays west of the Davie Ridge analogous to those of the Mozambique (Angoche/Rovuma Basins), as well as those exploration plays east of the Davie Ridge belonging to the Madagascan margin (Morondava Basin).

The subject of this paper covers an area of 700 km^2 and is a subset of much larger permits in the Mozambique Channel with water depths ranging from 1,800 m to 3,000 m (Figure 1). It is located at the eastern side of the Davie Fracture Zone (DFZ).

This paper is focused on evaluation of hydrocarbon prospectivity using preliminary basin/petroleum system modeling, 2D/3D Seismic stratigraphy framework interpretation, and integrating results from burial history (geohistory) curves, temperature (geothermal gradient), and information from surface geochemistry to establish the presence and preservation of source rocks within the basin.

As no wells have been drilled in the deep water offshore Madagascar, the nearest offset wells are situated in the shallow waters of coastal Madagascar, some 200 km or so to the east of the study area. As a consequence, there is significant uncertainty regarding subsurface control on all interpretations discussed herein. Vaucluse-1 and Heloise-1, which are located on 2D seismic lines, have been tied to the area of interest. A third well, Morondava-1 lies adjacent to the nearshore area of Madagascar (Figure 1).

Regional Geologic Framework

From the early Cambrian until the onset of the Gondwana break-up during the Middle Jurassic, Africa and Madagascar lay at the center of the Gondwana supercontinent, with South America to the west, Antarctica to the southeast, and India and Australia to the east (GETECH, 2009). From the Late Cambrian - Late Triassic, intra-continental East African Karoo Rift Basins were created as a result of an earlier failed attempt at Gondwana break-up (Schandelmeier et al., 2004). Additionally, the presence of Karoo sedimentary sequences in basins all over the continents that formally comprised Gondwana, including the intra-continental East African Karoo Rift Basins, further provides evidence of this earlier failed attempt at Gondwana break-up. The period of extension lasted intermittently for approximately 40 million years and only small amounts of extensions (50-100 km) occurred across the East Africa Rift Basins and no continental break-up occurred during this long-lived tectonic phase. In Mozambique, Tanzania, Kenya, and Madagascar, Karoo related crustal extension during the Karoo rifting can be split into three distinct regimes (Schandelmeier et al., 2004): (1) Early to Late Permian, when sinistral, strike slip movement formed NS trending pull-apart basins, (2) Latest Permian, sinistral strike-slip and normal extension formed transtensional basins, and (3) Early-Mid Triassic, NW-directed normal extension led to the formation of the NE trending half-grabens. Generally, the Karoo basins consist of depositional sequences delimited by tectonic events and consist mainly of continental, fluvial-deltaic and marginal marine sediments that are collectively called the Karoo Supergroup.

The break-up of East Gondwana (India, Antarctica, and Australia) and West Gondwana (Africa and South America) is widely accepted to have occurred during the latest Early-Mid-Jurassic (GETECH, 2009). Subsequent to the rift phase was the establishment of tectonically quiescent, stable conditions, and the thermal sag of the East African and western Madagascar basins from Early Cretaceous. Sea floor spreading continued between East Africa and both Antarctica and Madagascar. The relative motions of these various plates were accommodated by major fracture zones such as the Davie Fracture Zone (Figure 1). The Davie Fracture Zone (DFZ) is a major feature of the East African Margins that was generated during Gondwanan break-up (GETETCH, 2009). Today the DFZ is a 50 m-200 km wide N-S feature extending more than 1500 km with crustal fractures and diffuse deformation that extends from the SW corner of Madagascar to the intersection with the Kenyan coast. The final phase of basin development was the creation of the East African Rift System (EARS) in the Cenozoic (Figure 2). The chronostratigraphy of the area is shown on Figure 3.

Exploration History and Hydrocarbon Occurrence

In Madagascar eighty-eight exploration wells have been drilled, mostly onshore. The majority have encountered (mainly minor) oil shows or gas. Two giant fields, Bemolanga (tar sands) and Tsimiroro (heavy oil), both onshore western Madagascar (Figure 4), were discovered in the 1930s. The reservoir rock for these two fields is the Isalo I and II (Permian and Triassic) of the Karoo Supergroup.

In 1987, OMNIS/Petro Canada International Assistance Corporation (PCIAC) made a wet gas discovery (West Manambolo-1) in Cretaceous sandstones and Shell found light oil with its Manandaza-1 well.

Proven plays in the Morondava Basin are the Upper Cretaceous Sandstone Play, Middle Jurassic Sandstone/Carbonate Play (Bemaraha Formation), Upper Triassic to Lower Jurassic Sandstone/Carbonate Play (Isalo II Formation), and Middle-Upper Triassic Sandstone Play (Isalo I Formation). However, these plays are currently non-productive. Historically, hydrocarbon exploration in Madagascar has been high risk, with a chance of success (CoS) of only 4% (1 in 23). However, improved seismic acquisition shows that only 12 wells have been drilled on valid traps, such that the CoS may now be as high as 25% (Clark and Ramanampisoa, 2002). As yet untested, Tertiary-aged, deep-water, clastic reservoirs charged by Lower Cretaceous source rocks provide an exploration focus akin to the discoveries made on the Rovuma margin. It is currently unknown whether a Lower Cretaceous source rock has the potential to be as oil prone as the Jurassic and Triassic intervals responsible for the 22 Bbbls of heavy oil exhumed in western Madagascar.

Dataset and Methodology

The present study is based on analysis of 3-D seismic survey data. The survey was acquired from 2013-2014. Multiple angle stacks of Nears (5-15 deg), Mids (15-26 deg), Fars (26-37 deg), and Ultra Fars (37-48 deg) were also available. Several 2-D lines that overlap with the 3-D data at certain locations were also used. Well data include reports and wire line logs (mostly gamma ray, caliper, resistivity, and sonic). Other information such as geological reports, core photos, and biostratigraphic information for some of the wells were also integrated.

Due to this being a frontier area for exploration, ages of the stratigraphy in the study area are largely unconstrained by well data. In the assessment of the 2D/3D seismic data over the area, we made attempts to tie the seismic to two wells that are located on the shelf.

However, it should be noted that there remain large uncertainties in dating and in quality of the well ties, owing to the relatively poor seismic signal of the 2D lines over the shelf and were tied to the recently acquired 3D datasets where the 2D Seismic intercepts the 3D Survey. Where additional surfaces have been interpreted, notional age dates were assigned.

The workflows followed in our seismic interpretation were the concepts and methodologies outlined in Vail et al. (1977) and Mitchum et al. (1977). Interpretations were made based upon the identification of seismic reflection terminations and, to the greatest extent possible, facies associations and stratal stacking patterns. The paucity of well control in this dataset hinders the application of the latter two evidences; therefore in this case surface assignments are made primarily on the basis of reflection terminations.

In seismic data, sequence boundaries (abbreviated to "SB") are associated with truncation of seismic reflections beneath the surface and onlap of reflections above it (Mitchum et al., 1977). Truncation is associated with erosional processes, unconformity development, sediment bypass, and a basinward shift in facies during periods of reduced or negative accommodation. Typically, these periods may be associated with extensive deep-water slope and basin-floor fan deposition. Onlap results from the sedimentary fill that accumulates on recreation of accommodation. Accordingly, downlap surfaces represent the most landward shift in facies and are referred to as maximum flooding surfaces ("MFS"). The downlapping reflection terminations separate retrogradational stacking patterns of facies below from progradational stacking patterns above. In the clastic deep-water realm, this is typically manifest as the termination of slope and basin floor deposition. This practical application of this approach helped us in identification of petroleum system elements, notably source, reservoir and seal (ERCE, 2016).

Seismo-Stratigraphy and Structural Interpretation

Seven major regional horizons have been mapped for the study area namely Top Jurassic MFS, two Intra-Cretaceous SBs, Upper Cretaceous SB, Top Maastrichtian SB, Top Oligocene MFS, and Top Miocene MFS (Figure 5). Two main erosive surfaces were interpreted with a fair degree of certainty: the Top Jurassic unconformity and the Upper Cretaceous unconformity. The Cretaceous section presents an internal unconformity that delimits two seismic packages of very different character. The Maastrichtian horizon onlaps onto the Upper Cretaceous unconformity. This horizon represents the end of the Cretaceous and it is overlain by the Oligocene and the Miocene sections which are characterized by sub-parallel reflections. This area is characterized by pervasive volcanic intrusions. The intrusion of some of these volcanic features is directly related to the generation of structural highs in the section immediately above (Figure 6). Amplitude analysis on the seismic section is obscured by the strong amplitude values displayed by the volcanic features. Reservoir presence was more easily recognizable for the Cretaceous leads given the change in seismic character in this section which is interpreted as the Upper Cretaceous fluvial sandstones. The Upper Jurassic localized sands deposited in the eastern side of the Davie Fracture Zone also served as reservoirs. A potential seal is inferred in the section immediately above, the Maastrichtian, based on seismic character as well (Figure 7). In general, the Upper Jurassic/Base Cretaceous and Tertiary shales are interpreted as seals in this area (ERCE, 2016).

1D Petroleum System Modeling and Results

The models were calibrated using well data from shelfal close to the study area, since no wells exist in the deep offshore area. Calibration data used was from an analogue well off the coast of western Madagascar and the data types include vitrinite reflectance and bottom hole temperature data. The well was modelled and calibrated to its downhole observables. The basement and thermal history calibration information was applied to the pseudo wells Figure 1. Down hole observable data was adjusted to match pseudo well locations taking into consideration their water depths. Stretching episodes were also adjusted to give a best fit between modelled and measured parameters (Figure 8).

This Basin modelling study was undertaken in order to assess the potential for hydrocarbon charge in the offshore Morondava Basin. Included in this analysis is a characterization of known and postulated source rocks in the region in order to understand their distribution and potential efficacy. In addition, we had access to the information from hydrocarbon seepage, surface slick and shallow piston core geochemical studies previously carried out in this area, the detailed of which are beyond the scope of this paper. This data has been included in the study in order to analyze source rock potential in this as yet untested province. These inputs have been used to provide 1D thermal modelling control points that aid the identification of hydrocarbon kitchens, the determination of expulsion timing, and the determination of potential migration pathways (Figure 9, Figure 10, Figure 11, and Figure 12).

Implication of this Study

Evaluation of hydrocarbon source rock potential in the study area indicated that the area has good potential for hydrocarbon generation and expulsion as the source rock(s) is mature. The study has also highlighted a number of potential target features but there exist significant unknown with regard to these features as per the nature of their lithologies, and the possibility of high CO_2 contents due to the presence of volcanics.

Although there has long been interest in the petroleum prospectivity of offshore Madagascar, the study area as well as the Mozambique Channel as a whole constitutes a frontier area since a well is yet to be drilled. Consequently, to establish unequivocal evidence of an active petroleum system in this area a stratigraphic coring or exploration well must be drilled sooner or later. Achieving this would be of benefit in de-risking this uncalibrated basin in the following ways:

- Stratigraphic framework calibration: Absolute age determination using high resolution Biostratigraphy
- Identification of source rocks that are oil prone especially in the Jurassic and Cretaceous and other Elements of the Petroleum system

- Calibrate 3D interpretation with logs suites to be acquired; Seismic to Well tie
- Impact on Basin modeling-Thermal measurement and Inversion work as well
- Help unravel where the oil is; considering heavy oil has been found at the West coast of Madagascar and ENI/Anadarko have found gas in Mozambique

STOIIP and Resource Summary

Table 1

Table 2

Conclusions

The prospectivity of the study area has been characterized based on its position relative to the Davie Ridge. Seismic interpretation results show strong evidence in support of high prospectivity within the area of study based on the presence of structural, stratigraphic, and a combination of structural and stratigraphic traps (pinchouts/wedges, turbidites, channel fill deposits, and slope filled fans as well as amplitude anomalies).

Our study has shown that this area is dominated by four-way dip closures at Cretaceous and Jurassic levels. The nearest modeling point of MOF10 (Figure 1) of about 75 km north of the study area is Jurassic oil mature, with expulsion in Late Miocene to present. A wet gas-mature Triassic source rock capable of sourcing hydrocarbons also exists. Charge access via faults is considered a risk in this area. The calculations in Table 1 and Table 2 indicate a possible unrisked mean STOIIP of nearly 2.5 Bbbls for a single prospect – 'Meshach' at the upper Cretaceous level.

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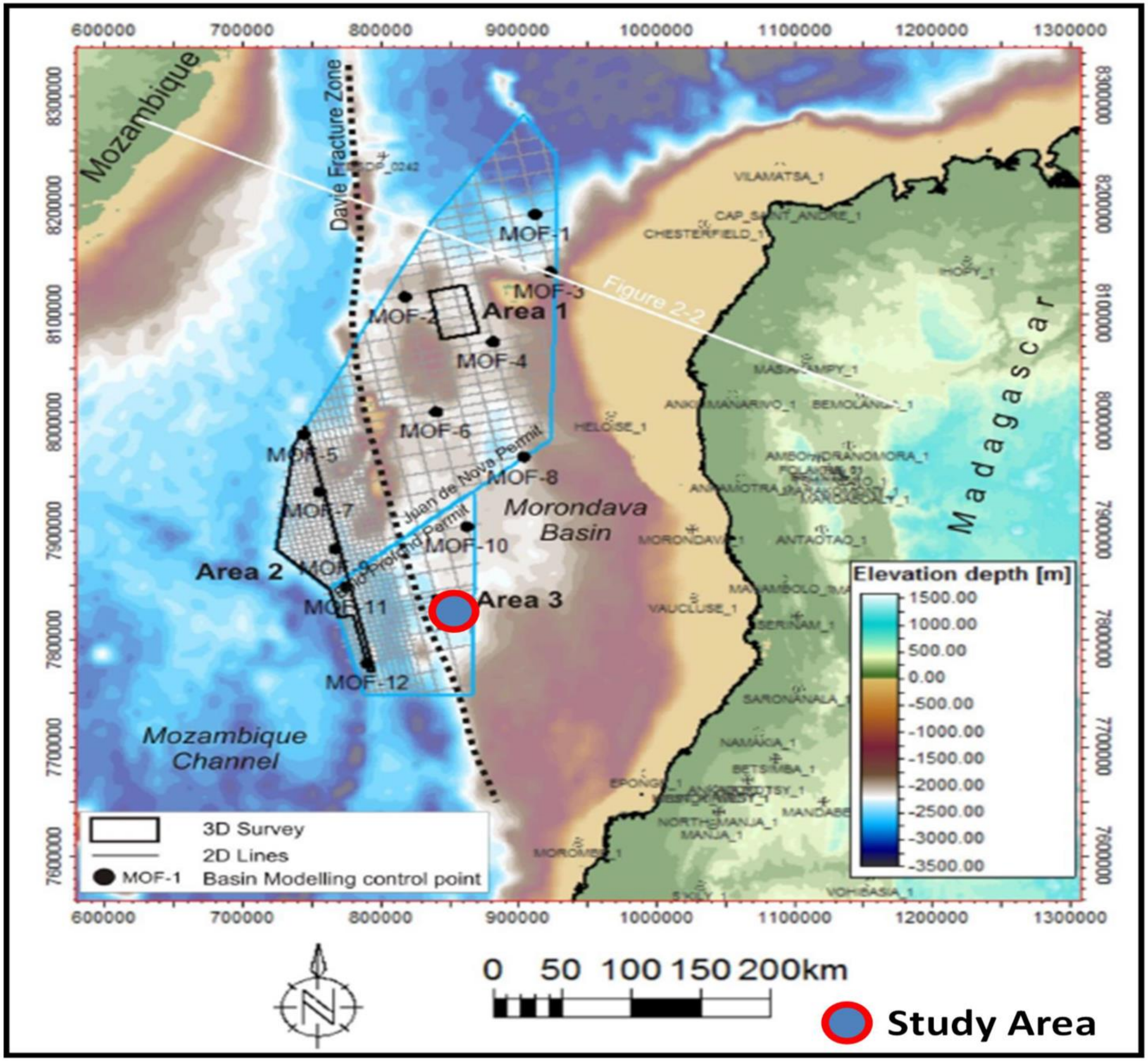

Figure 1. Location map of the study area, nearest wells, Basin modeling control points, 2D and 3D Survey datasets (Modified from ERCE, 2016).

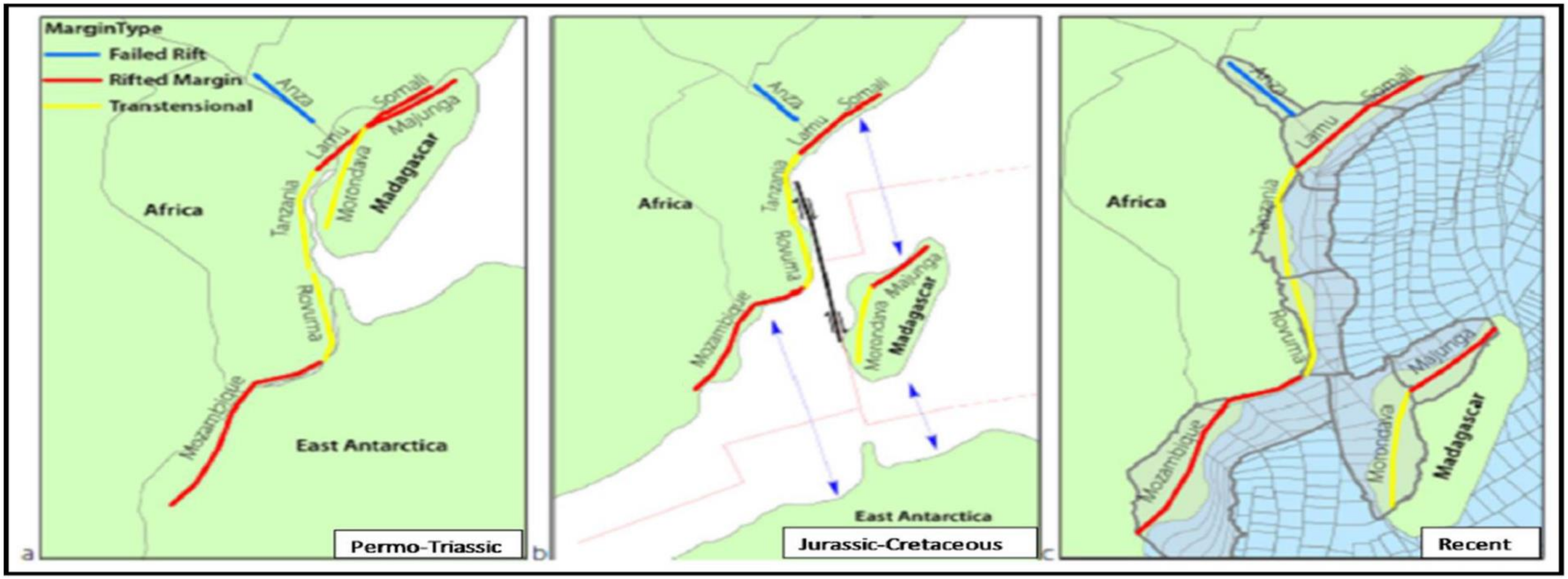

Figure 2. The development of the East African Coastal Basins (Modified from GETECH, 2009).

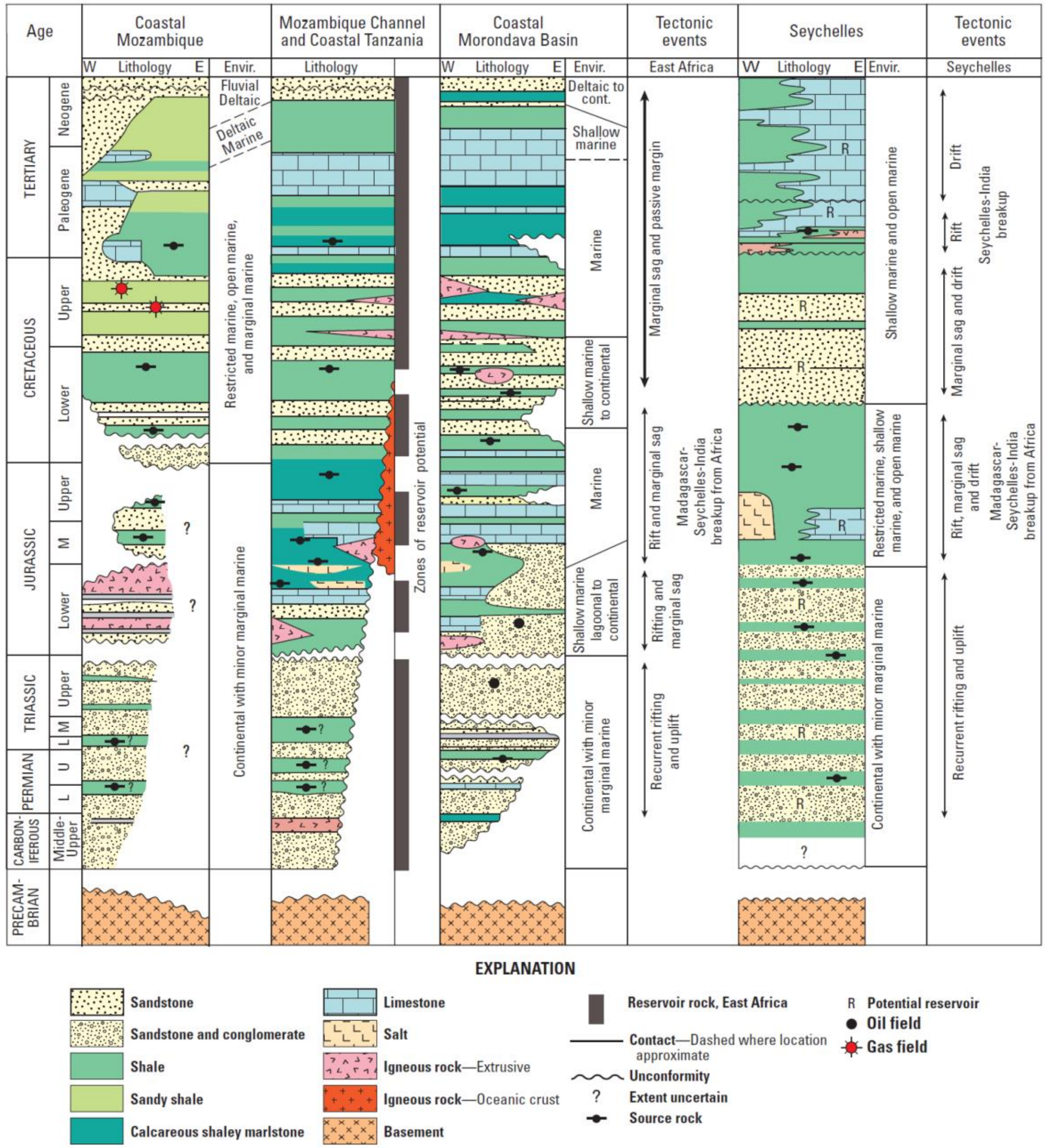

Figure 3. Generalized stratigraphic columns for Mozambique Coastal, the Mozambique Tanzania Coastal, and the Morondava and Seychelles Provinces along the east coast of Africa (U.S. Geological Survey, 2012).

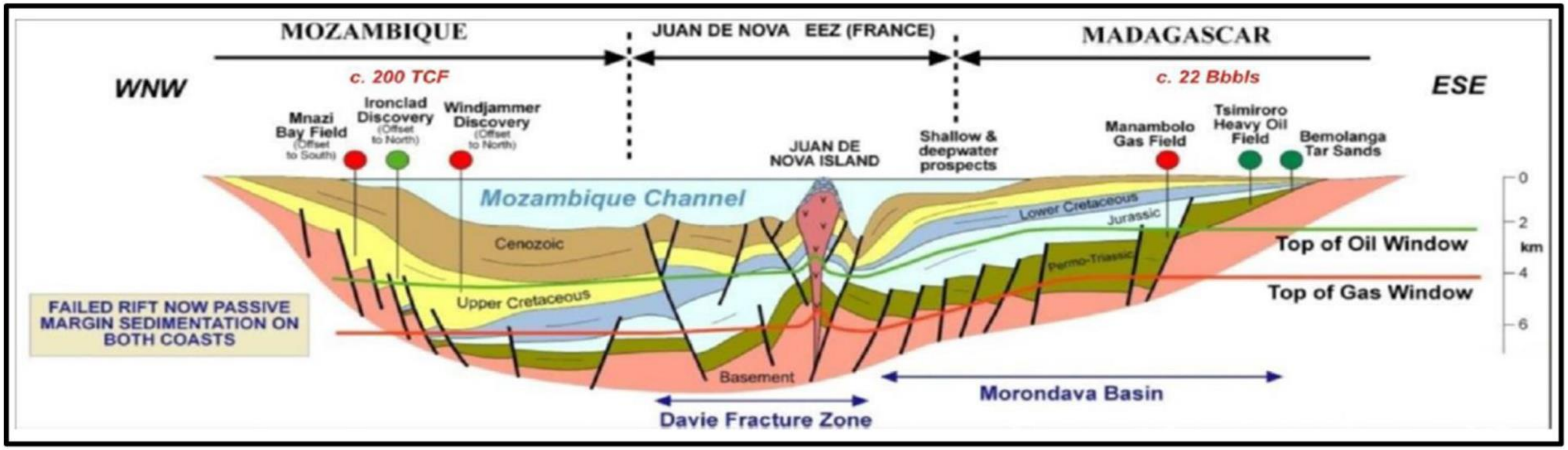

Figure 4. Cross section from the Rovuma Basin, Mozambique to onshore Madagascar, showing the context for recent discoveries on the Rovuma delta (Modified from Roberts et al., 2013).

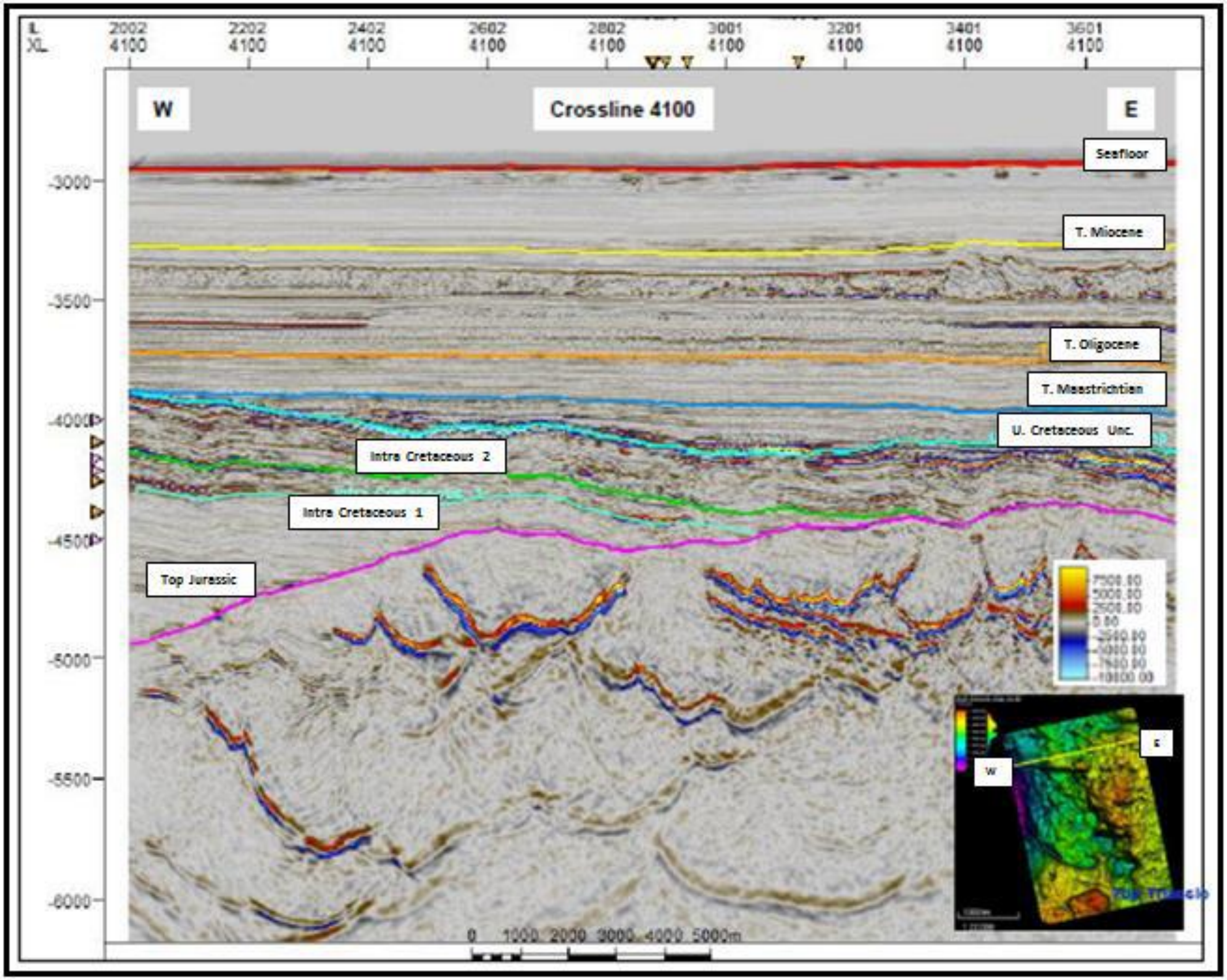

Figure 5. Seismic section showing the seven interpreted surfaces at the eastern side of the Dave Fracture Zone. Depocentre shifts from west to east between Upper Jurassic and Cretaceous unconformity. Evidence of possible uplifting and tilting.

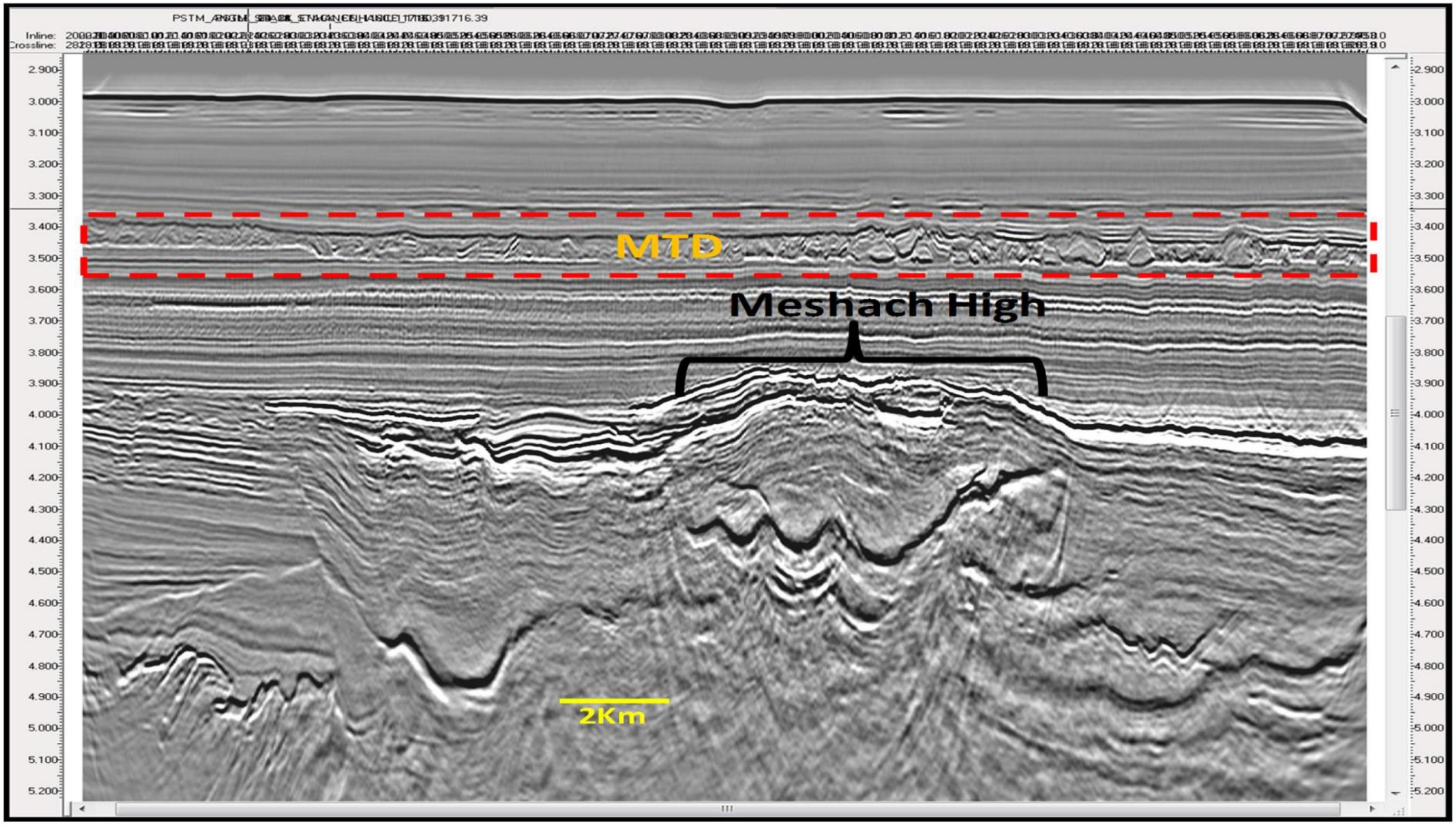

Figure 6. Mass transport deposit (MTD) located in the study area. The system is closely related to regional tectonic events/uplifts, volcanism, and associated with variations in sedimentation rate in the Miocene.

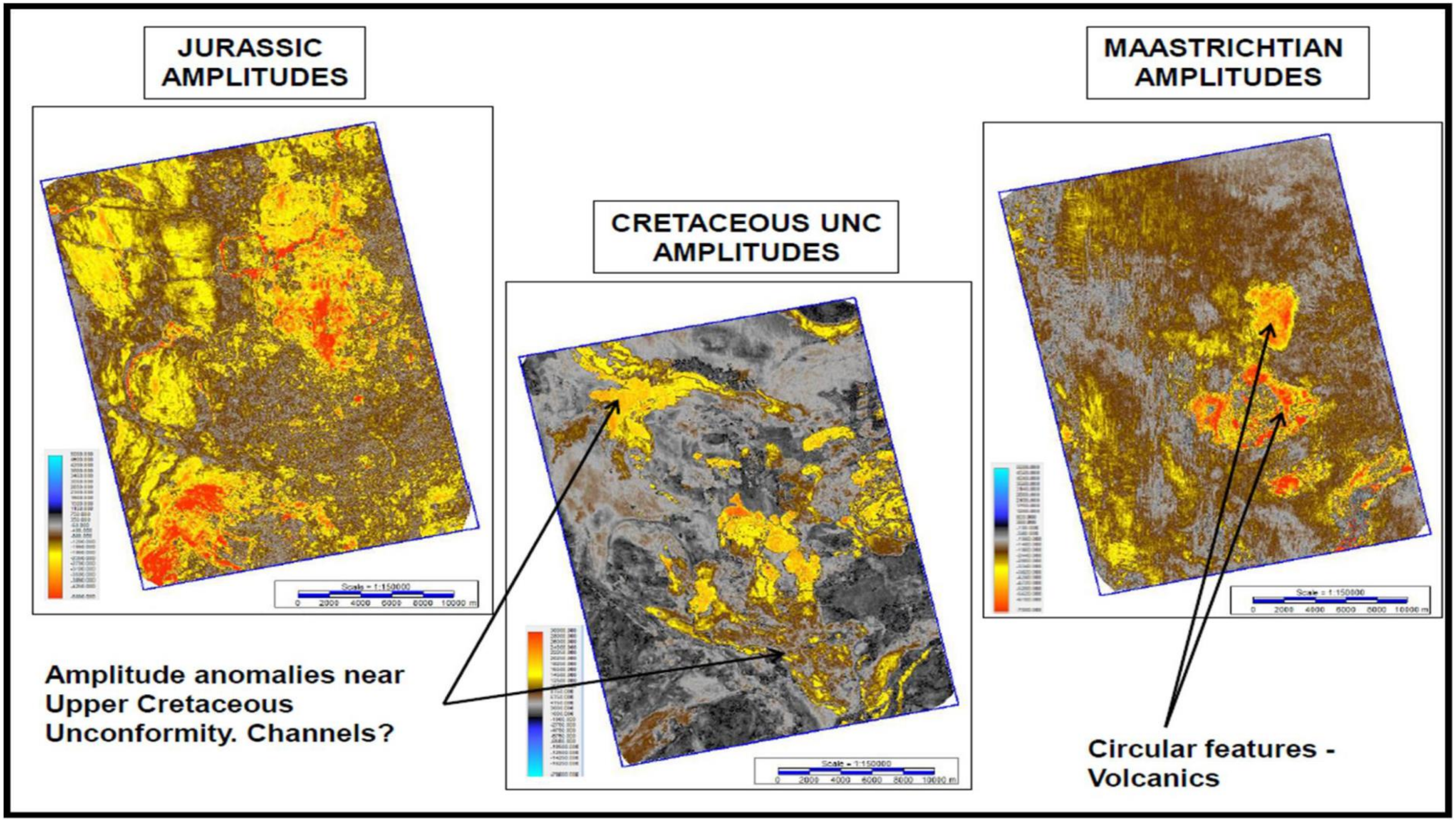

Figure 7. Amplitude Maps of Jurassic, Cretaceous, and Maastrichtian surfaces with expressions of Channels, Volcanics, and possible Reefs. The amplitude anomaly is associated with closures above volcanic intrusion especially at the Upper Jurassic surface.

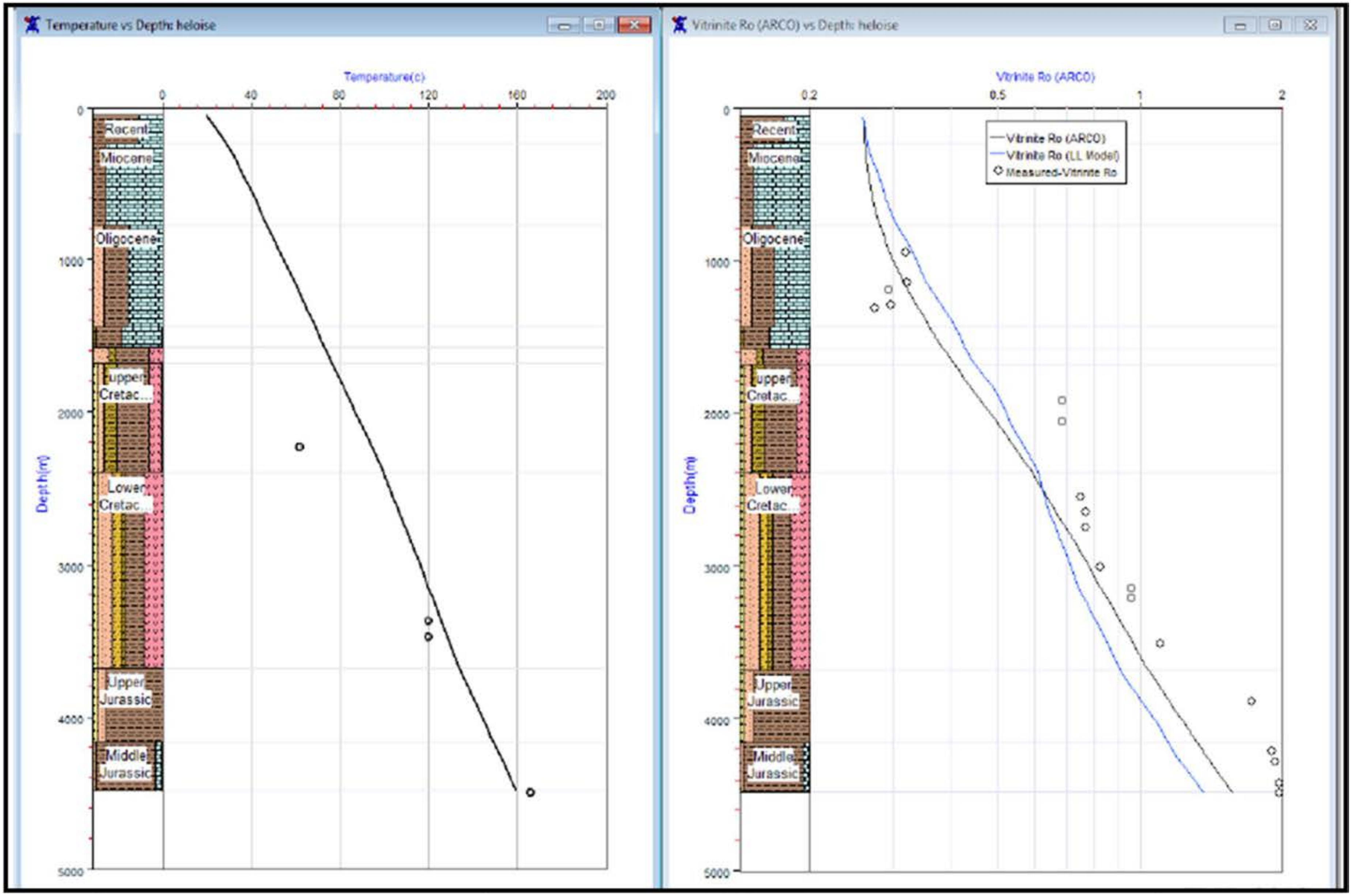

Figure 8. Modelled Trends in Temperature (left) and Vitrinite Reflectance (right) calibrated against measured well data.

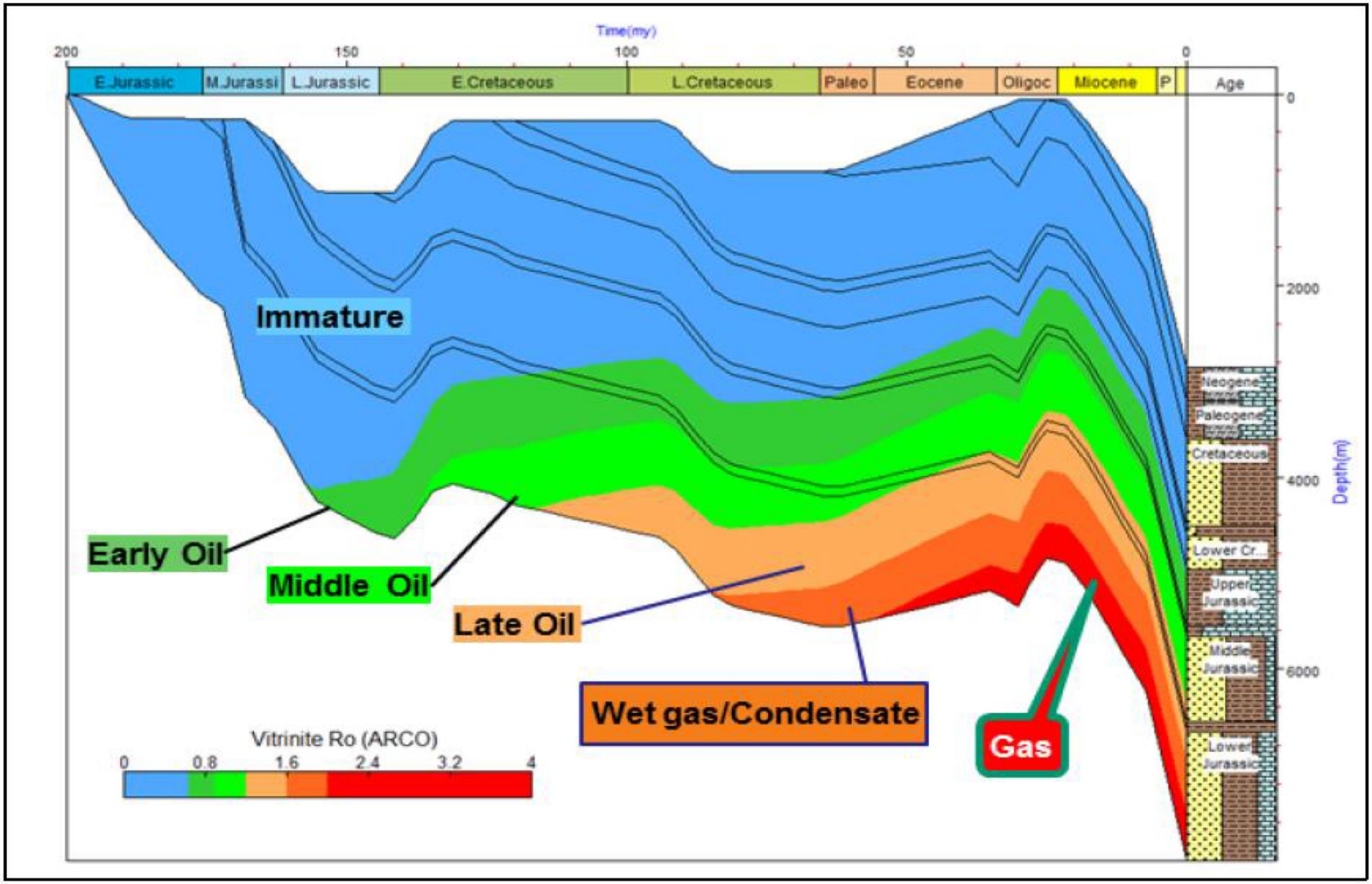

Figure 9. 1D Thermal Maturity Geo-history and Maturity window for Offshore Morondava Basin.

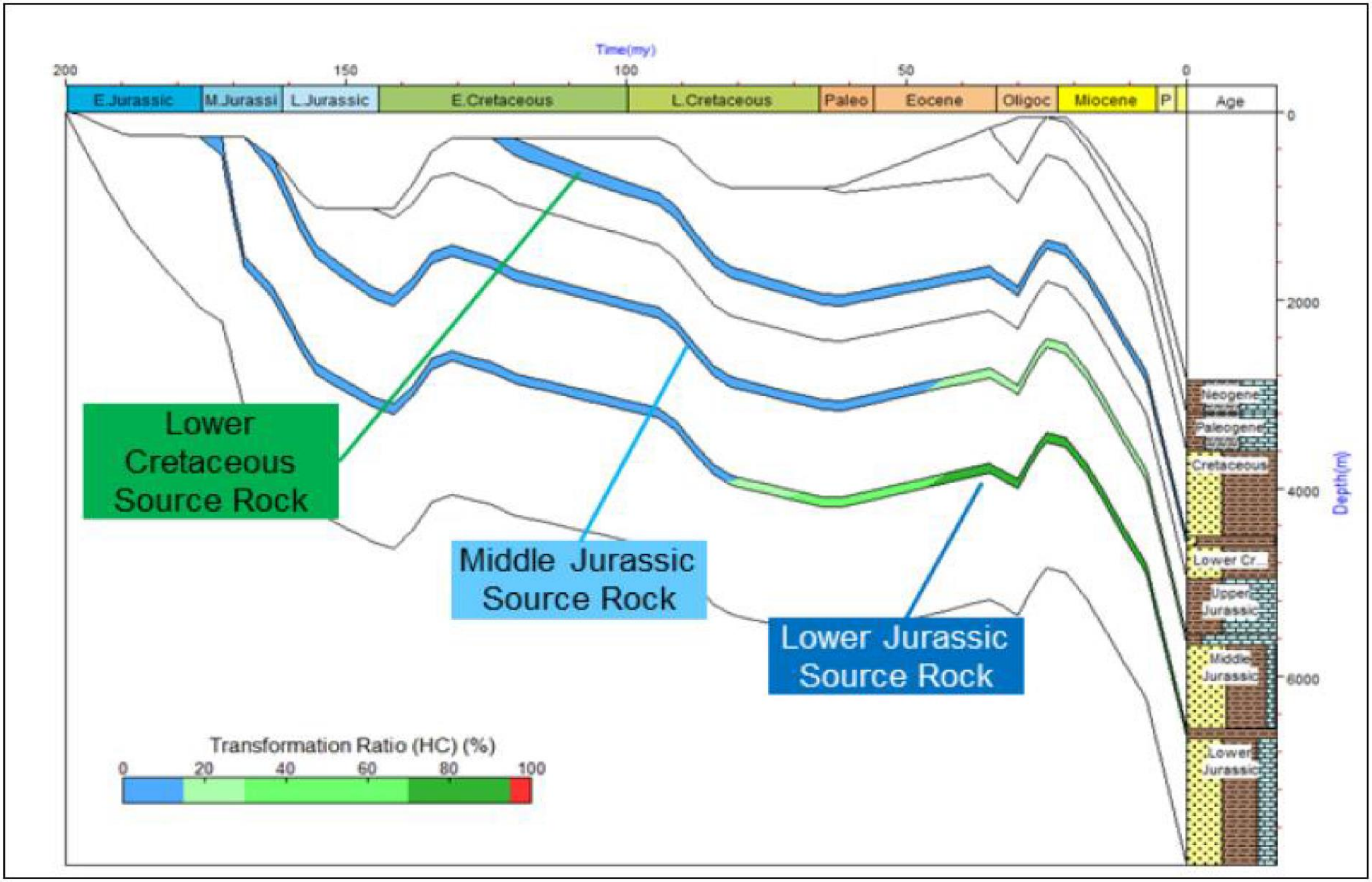

Figure 10. 1D Thermal Maturity Geo-history and Transformation per Source rock of the Morondava Basin.

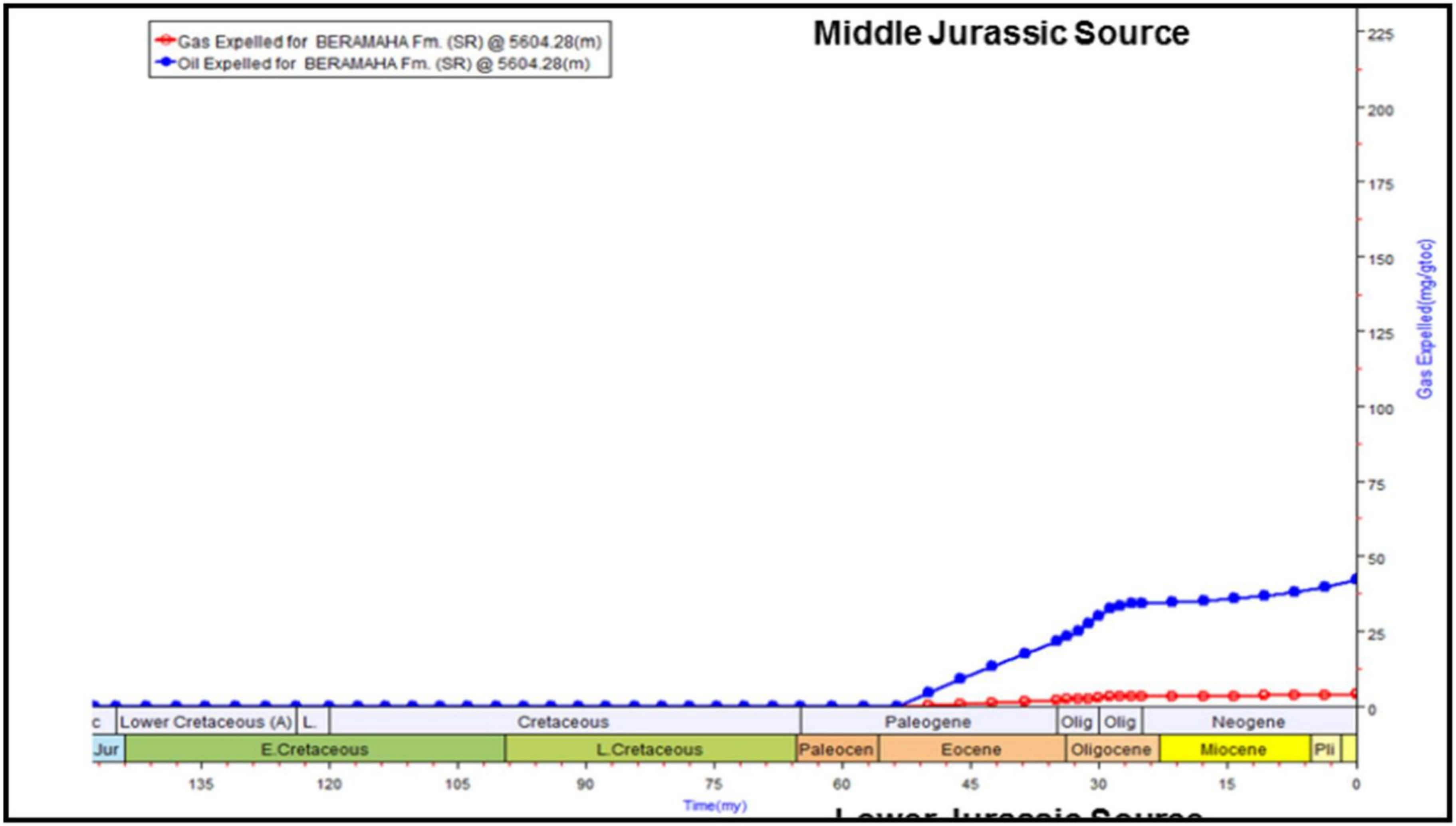

Figure 11. Interpretive graph of Volumes of expelled oil and gas with Time for Middle Jurassic Source Rock.

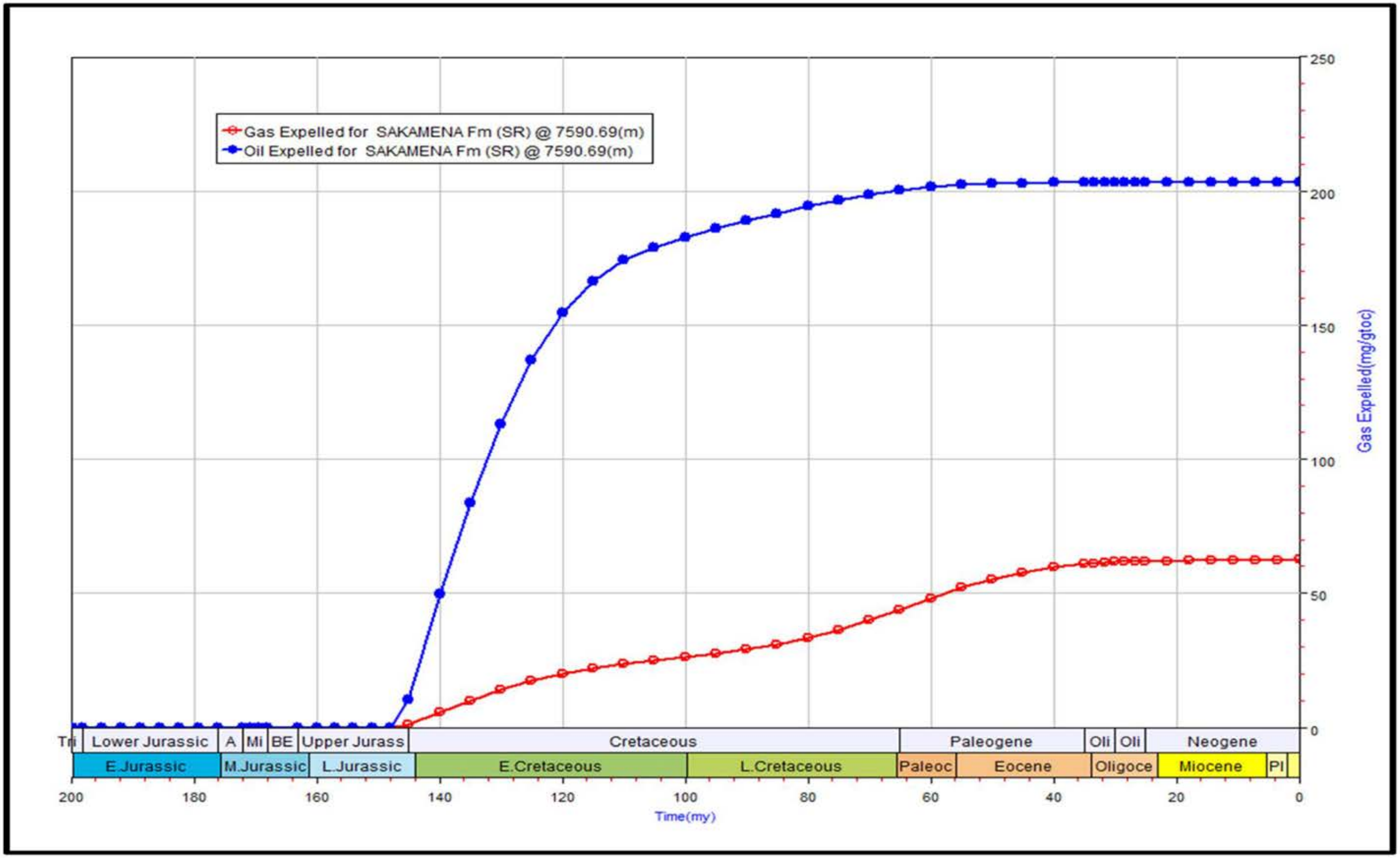

Figure 12. Interpretive graph of Volumes of expelled oil and gas with Time for Lower Jurassic Source Rock.

Parameter	Low	High	Distribution	P90/P10 or Min/Max
Area (sq-km)	74.97	107.96	Lognormal	P90/P10
Reservoir Thickness (m)	100.00	200.00	Normal	P90/P10
N/G	0.30	0.70	Triangular	P90/P10
Porosity (frac)	0.25	0.41	Triangular	Min/Max
HC Saturation (frac)	0.60	0.80	Normal	P90/P10

Table 1. Volumetric Input Parameters.

Low	Med	High	Mean
1304.84	2334.22	3726.30	2446.20

Table 2. Unrisked STOIIP (MMstb).