Hydrocarbon Potential of the Lower Eocene Formations in Sabratah Basin, North West Offshore Libya*

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Abstract

The Lower Eocene Farwah Group (Jdeir and Bilal formations) represents a potential petroleum system in the western part of the Sabratah Basin, Offshore North West Libya. Many oil and gas fields were discovered in this area, for example, Bouri and Bar El Salam. Recently some dry exploration wells were drilled in the eastern part of the basin. In order to better understand the petroleum potential of the whole basin, geological and geochemical data from 40 wells were used. Five exploration wells that intersect the basin were selected for detailed petrophysical analysis (B330-NC41, E-001-NC35A, A1-18-ST2, L-001-NC41, and C3-NC41). The results suggest the best reservoir quality is within the Lower Eocene shallow platform Jdeir nummulitic shoals with an average porosity of 20% and reaches a thickness of 600 feet in the northwest at the Bouri Field area. Good reservoir quality is noted for the back-barrier lagoon Jirani Dolomite Member with an average porosity of 23%, reaches a thickness of 400 feet at the Bar El Salam Field area, and is mainly localized in the northwestern part of the basin. Reservoir quality of the Eocene is controlled by digenetic factors, with local variations in degree of calcite cementation and secondary porosity created by leaching of bioclasts and cements. Isopach maps generated show that thinning and thickening is controlled by paleotopography in the basin.

The geochemical analysis of the Lower Eocene (Ypresian) show the Bilal Formation is the principle source rock. At the northwestern part of the basin it has TOC contents ranging from 2% to 4%. Average hydrogen index values of 300 mg HC/g TOC indicate that organic matter is type II/III oil prone and average Tmax 450 °C. The TOC values decrease to the east and southern parts of the basin. An average TOC of 0.8 %, S2 values less than 1 mg HC/g rock, and hydrogen index values of 100 mg HC/g TOC indicate that organic matter is type III/IV poor potential. Few samples were analyzed for biomarkers. The results suggest the Ypresian source rock was deposited in a lagoonal anoxic depositional environment.

Introduction

Sabratah Basin is a Mesozoic-Cenozoic Basin, developed over a broad strain zone between the African and European plates during the Late Triassic-Middle Jurassic. It is filled with about 10 km thick succession of Triassic to Recent sediments (Bishop, 1975; Moody and Grant, 1989;

Mriheel, 2000). The Lower Eocene in offshore Libya and Tunisia represents a potential petroleum system (Jrad et al., 2015; Geochemical Labs Ltd, 1985). Many oil and gas fields were discovered in the study area, for example, Bouri and Bahr El Salam. Recently some dry exploration wells were drilled in the eastern part of the basin. In this study we have revaluated and reinvestigated the presence and potentiality of:

1. The reservoir Jdeir Formation and Jirani Dolomite Member.
2. The source rock Bilal Formation.

Methods

In order to better understand the petroleum potential of the Sabratah Basin, the geological data from 40 wells (Figure 1), including wire line logs (Gama Ray, Density, Neutron, Sonic, and Resistivity), formation tops, 35 final geological reports, core analysis reports, petrographic and geochemical reports were used.

Petrophysical analysis, were carried out using Techlog software for six wells (E-001-NC35A, B3-30-NC41, C3-NC41, L-001-NC41, J-001-NC41, and A1-18-ST2).

The geological data were reviewed and loaded into Petrel E&P.2013.2 software to generate maps and cross sections.

Results and Dissection

The results suggest the best reservoir quality is within the Lower Eocene shallow platform Jdeir nummulitic shoals with an average porosity of 20% and reaches a thickness of 600 feet (Figure 2) in the northwest at the Bouri Field area. Good reservoir quality is noted for back-barrier lagoon Jirani Dolomite Member with an average porosity of 23%, reaches a thickness of 400 feet at the Bar El Salam Field area, and is mainly localized in the northwestern part of the basin. Reservoir quality of the Eocene is controlled by digenetic factors, with local variations in degree of calcite cementation and secondary porosity created by leaching of bioclasts and cements (Figure 3). Isopach maps generated show that thinning and thickening is controlled by paleotopography in the basin as shown in cross sections (Figure 4a and Figure 4b).

The geochemical analysis of the Lower Eocene (Ypresian) show the Bilal Formation is the principle source rock. At the northwestern part of the basin it has TOC contents ranging from 2% to 4%. Average hydrogen index values of 300 mg HC/g TOC indicate that organic matter is type II/III oil prone and average Tmax 450 °C. The TOC values decrease to the east and southern parts of the basin. An average TOC of 0.8 %, S2 values less than 1 mg HC/g rock, hydrogen index values of 100 mg HC/g TOC indicate that organic matter is type III/IV poor potential (Figure 5).

Few samples were analyzed for biomarkers. The results suggest the Ypresian Bilal Formation source rock was deposited in a lagoonal anoxic depositional environment (Figure 6).

Conclusion

Petrophysical and sedimentological analysis results show that the Lower Eocene Jdeir Formation is the best reservoir potential. At its northwest Nummulitic “bank” facies has excellent quality with thickness of 200 feet at Bouri Field and an average porosity of 20%. Southeastwards “back-bank” facies is characterized mainly by lime grainstones and packstones, reaching a thickness of 155 feet, and an average porosity of 12%. Its southwards facies changes to the Taljah Formation and consists of dolomicrite with sand.

The geochemical analysis of the Lower Eocene (Ypresian) show the Bilal Formation is the principle source rock. At the northwestern part of the basin it has TOC contents ranging from 2% to 4%. Average hydrogen index values of 300 mg HC/g TOC indicate that organic matter is type II/III oil prone and average Tmax 450 °C.

The TOC values decrease to the east and southern parts of the basin. An average TOC of 0.8 %, S2 values less than 1 mg HC/g rock, hydrogen index values of 100 mg HC/g indicate that organic matter is type III/IV poor potential.

Few samples were analyzed for biomarkers. The results suggested that the Ypresian source rock was deposited in a lagoonal anoxic depositional environment.

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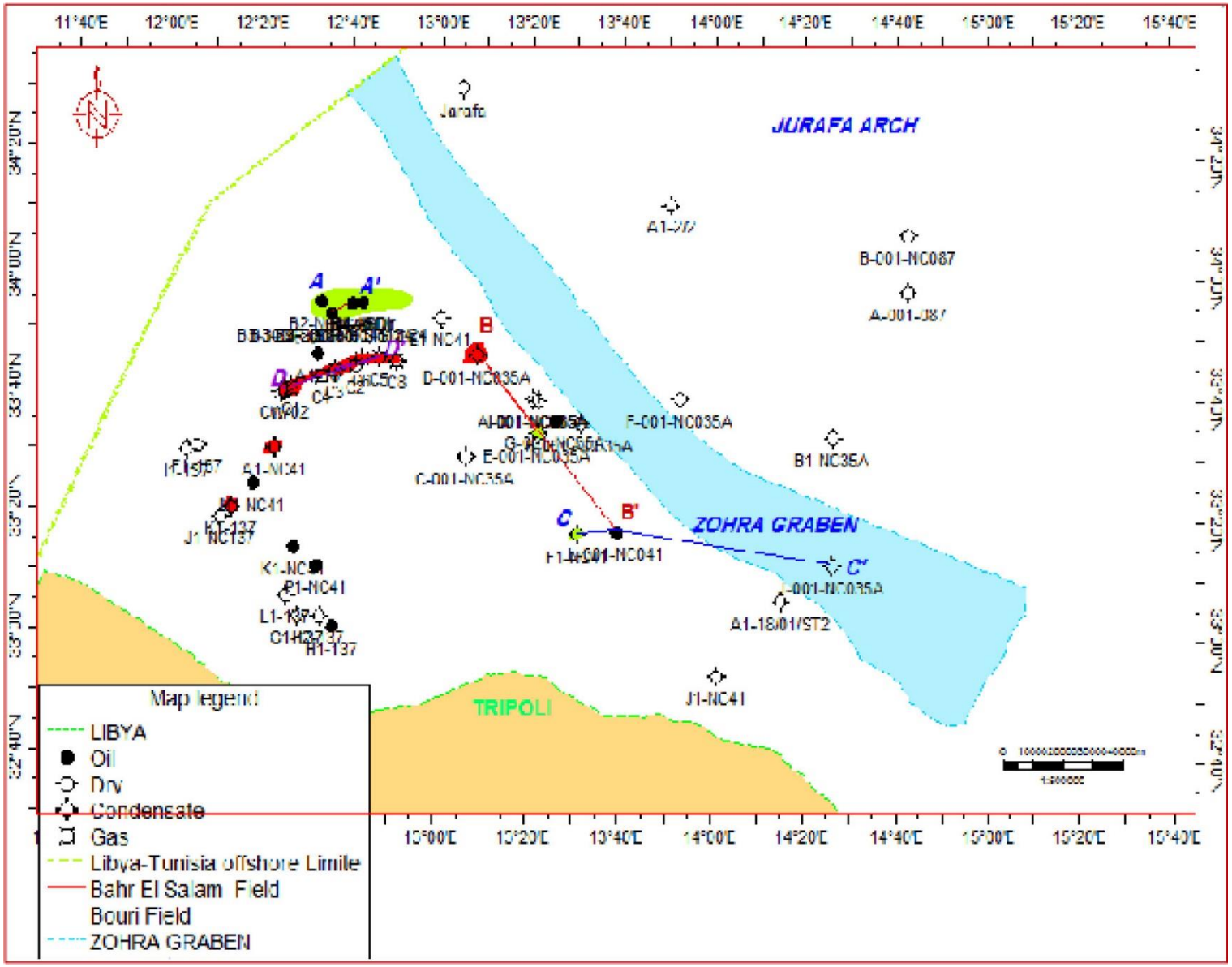

Figure 1. Location of the wells studied and cross sections.

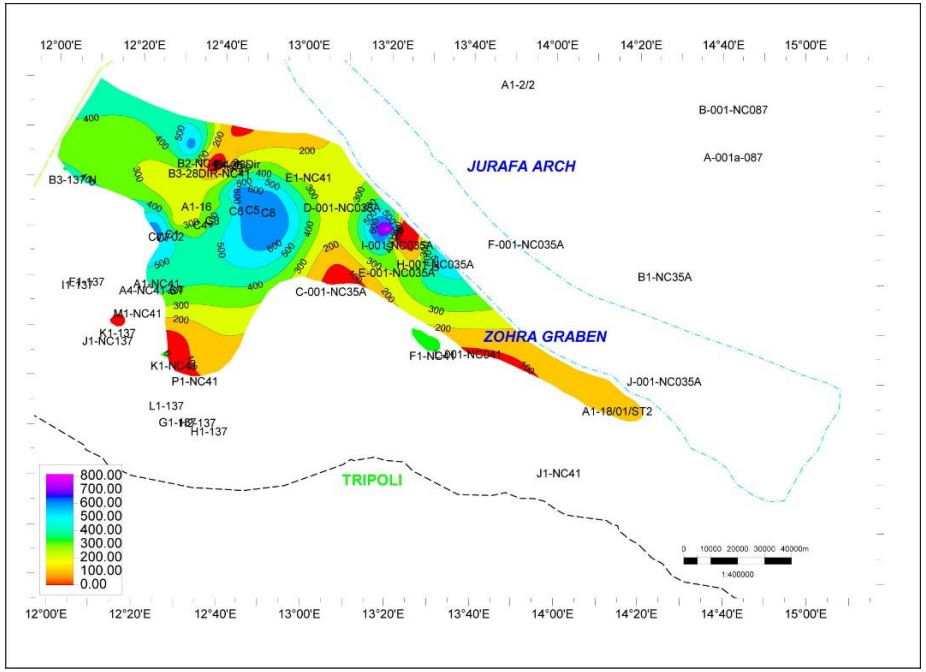

Figure 2. Isopach Map of Lower Eocene Jdeir Formation.

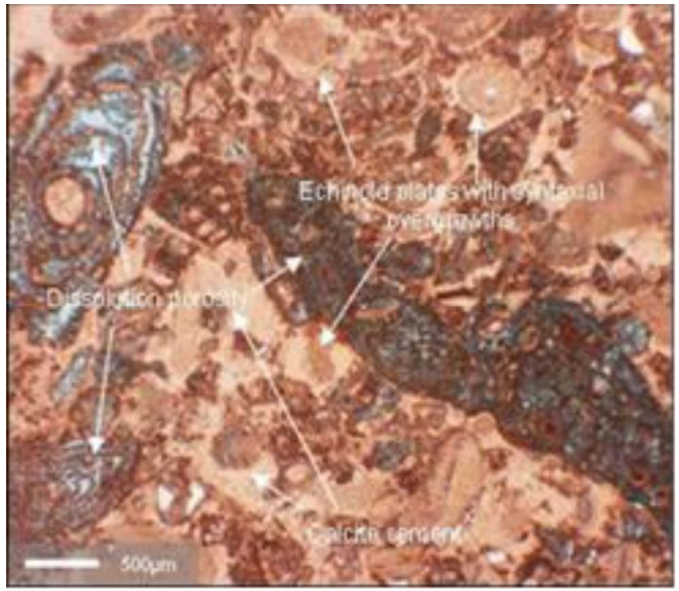

Figure 3. Thin section sample from Jdeir Formation at depth 7,553 feet in the well E-001-NC35A.

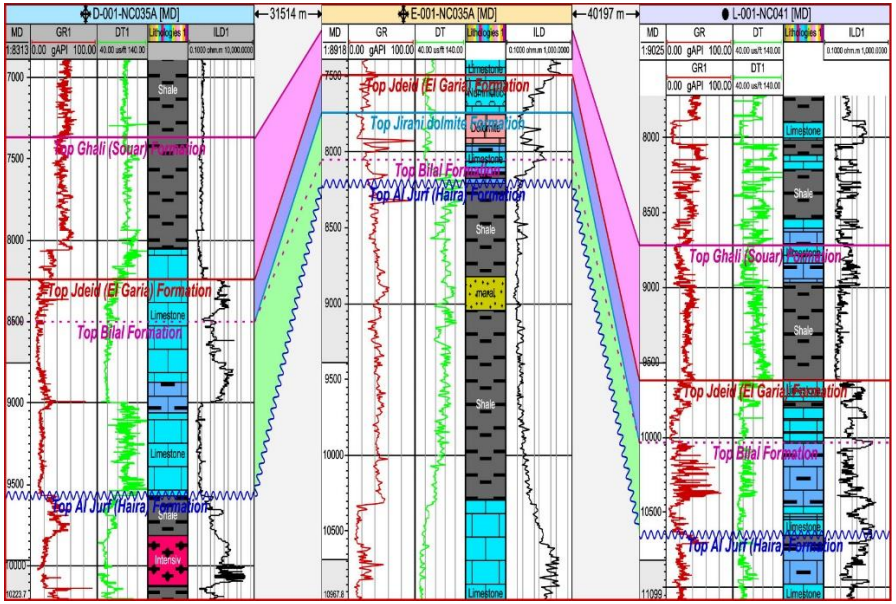

Figure 4a. The cross section (B-B'), shows Jdeir Formation and Jirani Member varies in thickness and is controlled by paleogeography.

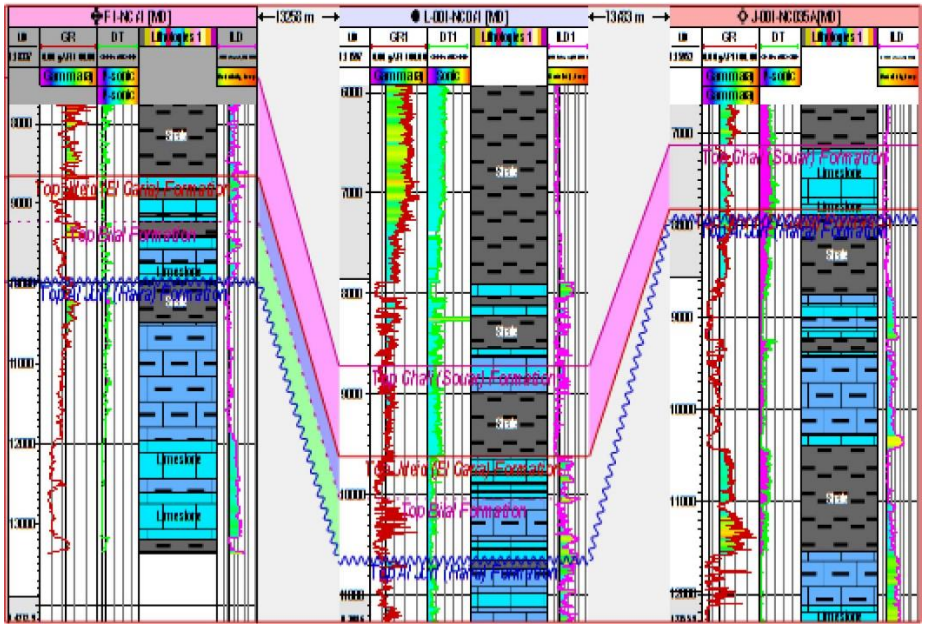

Figure 4b. The cross section (C-C'), passes through the southeastern part of the Basin , note Jdeir Formation and Jirani Member section is present in some wells and in others does not developed as back bank environment.

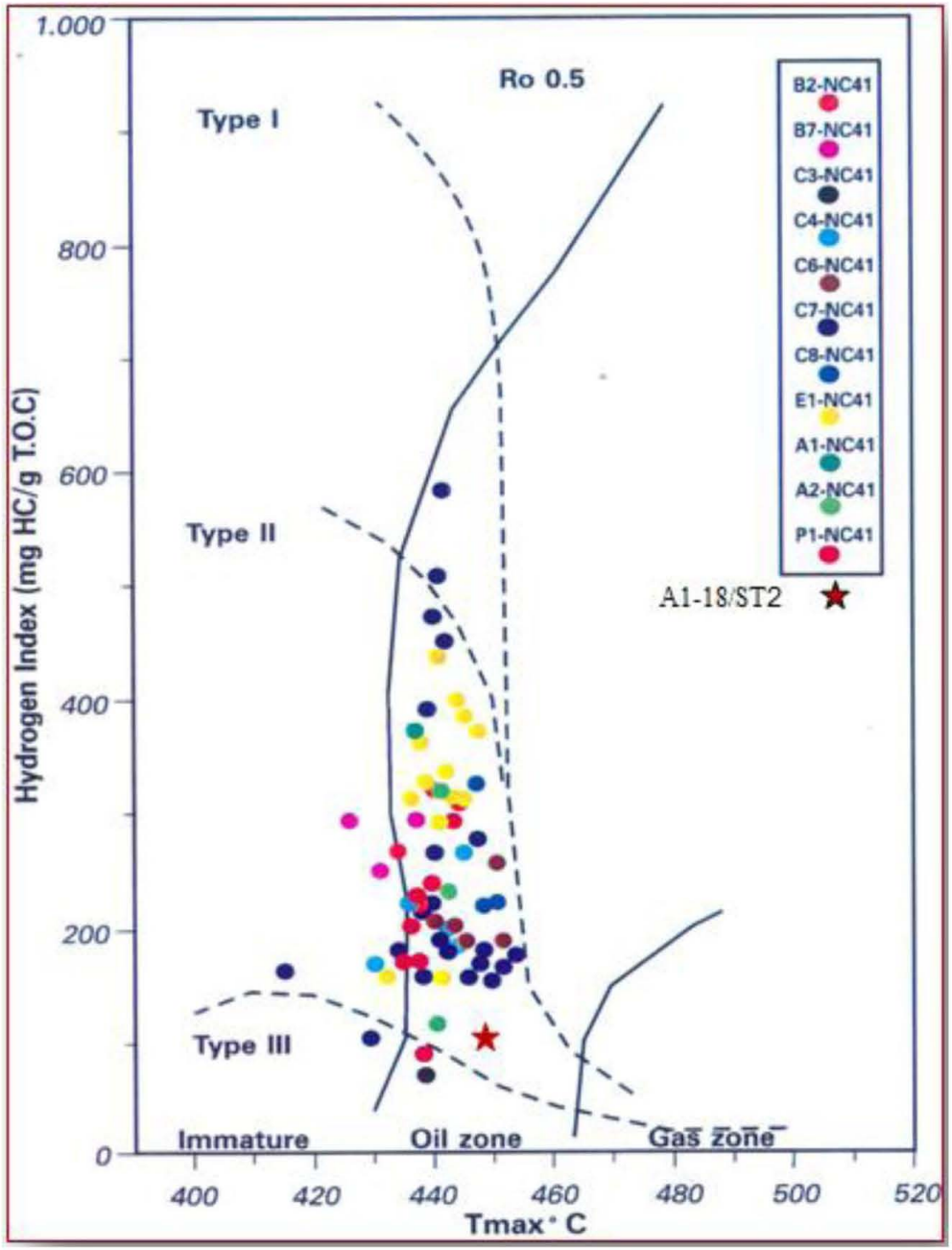

Figure 5. Hydrogen index versus Tmax ºC for samples from Bilal Formation.

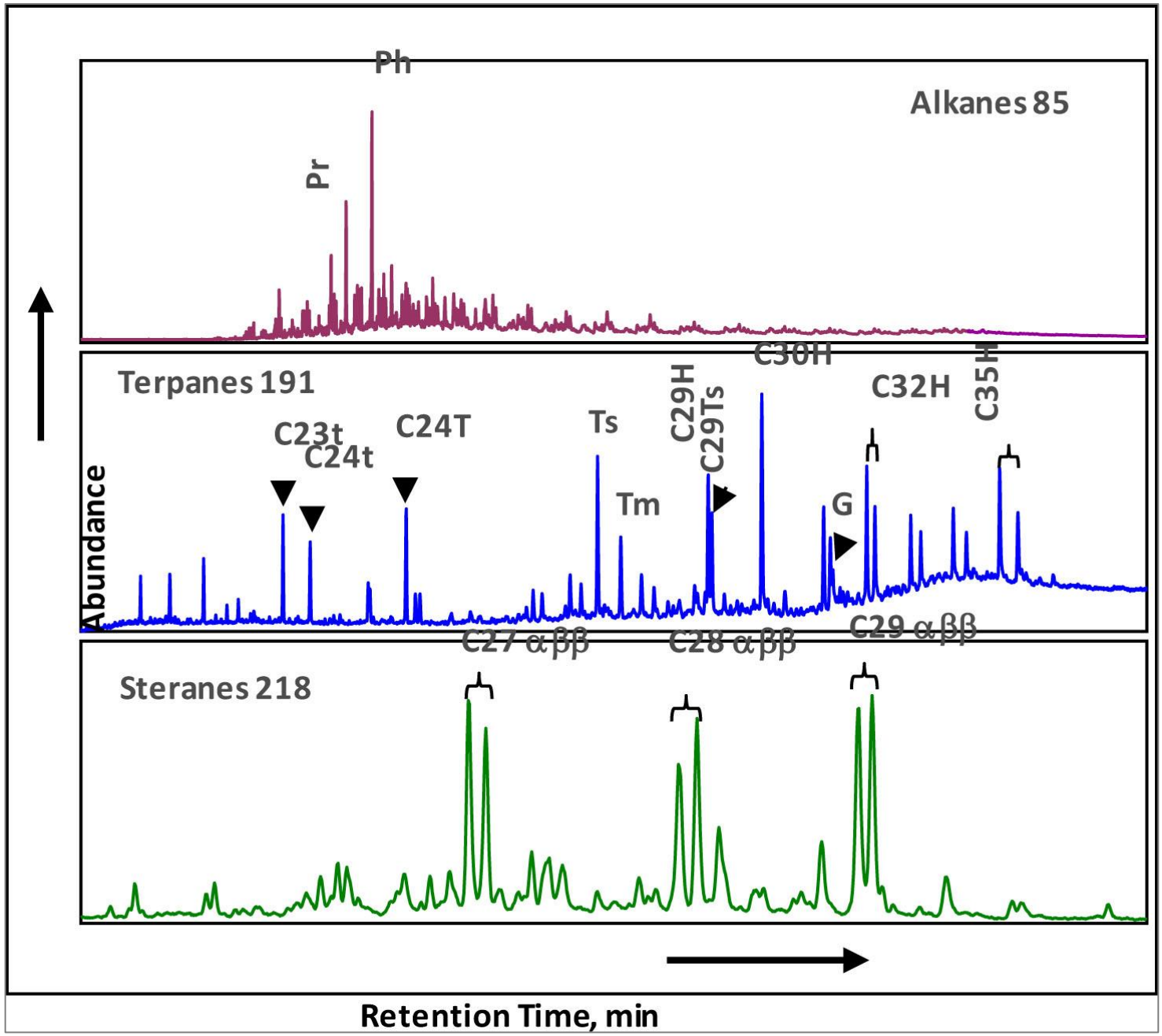

Figure 6. Data suggest Extracts were generated from a very anoxic, restricted circulation carbonate depositional environment.