Frontiers in Scientific Research and Technology

Online ISSN: 2682-2970
Print ISSN: 2682-2962
http://fsrt.journals.ekb.eg

FSRT J 9 (2024) 48 - 57 10.21608/FSRT.2024.288766.1128

The Geochemical Investigation of Fluid types by the Integration of Mud logs and Gas Chromatography, Shushan Basin, Egypt

Mariam Mohammed Reda[1*], Sherif Farouk[2], Saada Ahmed Saada[1], Ahmed M. Eldosouky[1], Mohamed Arafat[3]

[1]Department of Geology, Faculty of Science, Suez University, P.O. Box: 43221, Suez, Egypt

[2]Exploration Department, Egyptian Petroleum Research Institute (EPRI), 1 Ahmed El-Zomor Street, Nasr City, Cairo, Egypt

[3]Hurghada Faculty of Education, South Valley University, Egypt

ARTICLE INFO

Article history:
Received 11 May 2024
Received in revised form 14 June 2024
Accepted 23 June 2024
Available online 29 June 2024

Keywords
Shiffah and Safa reservoirs,
Condensates,
Shushan Basin,
Western Desert,
Egypt.

ABSTRACT

The Shushan Basin is the most important basins in the Western Desert. The main target of this study is the investigation of the fluid's types in the Shiffah and Safa reservoirs and studying the geochemistry of condensate of the upper part of Shiffah Formation (rich sand). The integration between wetness and balance curves indicated the fluid characterization, so Safa Formation and the upper part of Shiffah Formation show curves closer to each other, indicating the presence of condensate. Lower part of Shiffah and middle part of Shiffah formations show separation between the two curves, indicating the presence of oil. The condensate zone has a greater methane ratio and a wet C5 ratio than the oil zone. The C1/C4 ratio is higher than the C1/C3, suggesting that the oil and condensate zones are not wet-water zones. The examined condensates of the upper part of Shiffah Formation were derived from organic material associated with fluvio-deltaic environments. The Condensate of the upper part of the Shiffah Formation located in the more mature zone.

1. Introduction

Gas analysis during drilling plays a pivotal role in assessing well productivity and characterizing reservoirs (Kandel et al., 2001). By monitoring gas shows in drill fluid, valuable insights into hydrocarbon content can be gained, enabling better decision-making throughout drilling operations. Gas analysis not only helps ensure well stability and control but also provides essential information for understanding pore pressure dynamics. Moreover, the geochemical signatures of different hydrocarbon types and quantities in reservoirs can be identified through high-quality gas data, facilitating reservoir evaluation and characterization. Gas shows serve as indicators for locating important hydrocarbon contacts such as the Gas-Oil Contact (GOC) and the Oil-Water Contact (OWC), crucial for reservoir mapping and development strategies. Specialized ratios enhance the accuracy of these identifications, contributing to a more comprehensive understanding of the reservoir structure.

Beyond reservoir assessment, gas analysis contributes to advancing knowledge of geological formations encountered during drilling operations, enriching our understanding of subsurface environments. In essence, the comprehensive analysis of gas during drilling operations is indispensable for optimizing well productivity and maximizing the potential of hydrocarbon reservoirs (Dashti et al., 2016).

Gas shows monitoring during drilling operations are a crucial tool for well site geologists, offering valuable insights into reservoir properties, hydrocarbon potential, and wellbore stability. The wetness ratio (WR) and balance ratio (BR) are particularly significant metrics in this regard. The WR, and BR, are both influenced by hydrocarbon composition and gas density. As gas density increases, WR tends to increase as well, indicating a higher fraction of heavy gas components relative to lighter ones. Conversely, BR, the balance ratio, exhibits an inverse relationship with fluid density. As fluid density increases, BR decreases, reflecting the proportionality between BR and WR. BR is often used in tandem with WR for interpretation purposes (Pierson 2017; Arafat et al., 2024).

Exactly, the WR provides insight into the distribution of heavy and light gas components, with an increasing trend indicating a higher proportion of heavy components. On the other hand, the BR serves as a tool to evaluate gas

* Corresponding author at Suez University

E-mail addresses: mrmr.mohamed555@gmail.com (Mariam Mohammed Reda)

production potential, with higher values suggesting drier gas and rapid decrease indicating the presence of heavier hydrocarbons from a productive source.

By analyzing these ratios in conjunction, geologists can gain a comprehensive understanding of the composition and production potential of the gases in the wells under study. This information is invaluable for making informed decisions regarding drilling, production strategies, and reservoir management (Arafat et al., 2024).

Determining the types of fluids in the Shiffah and Safa reservoirs is the main goal of this study. These reservoirs contain three types of fluids (oil, condensate and gas). This study concentrates on the condensate in the upper part of the Shiffah Formation (Sand-rich) by studying its geochemistry.

2. Methodology

The study involves analyzing gas chromatographic data (C1–C5) from Geb-1x well. Gas peaks from reservoir sections are examined to derive wetness, balance, and character ratios using formulas derived from the work of Haworth et al. (1984, 1985) and Pierson (2017). These ratios help in understanding the composition and properties of the gas reservoir.

Wetness Ratio (WR) indicates the relative abundance of heavier hydrocarbons (C2-C5) compared to methane (C1) in the gas mixture. The wetness ratio formula, likely derived from Haworth et al. (1985) and Pierson (2017), quantifies this relationship.

Balance Ratio (WR) assesses the distribution of wet gases (methane) and dry gases (heavier hydrocarbons) in the gas sample. It provides insights into the composition and maturity of the gas reservoir.

Character Ratio (CR) evaluates the overall composition and characteristics of the gas, considering factors such as the presence of non-hydrocarbon gases and the relative proportions of different hydrocarbon components. It can help in distinguishing different gas types and understanding the reservoir's geochemical signature.

By combining gas chromatographic data with mud logs and applying these ratios, researchers can gain valuable insights into the composition, maturity, and quality of the gas reservoir, which is crucial for reservoir characterization and development planning.

3. Geologic Setting

According to Said (1990), the north Western Desert is a portion of the unstable northern African shelf. It had witnessed several tectonic activity periods since the Paleozoic. Figure. 1a shows a regional map that shows the significant regional structural high (Sharib-Sheiba High and Qattara Ridge) that is trending E-W and was generated during the Hercynian Orogeny (EGPC, 1992; Guiraud et al., 2005). This structural ridge divided the coastal basins of Shushan, Matruh, and Dahab-Mireir in the north from the southern Abu Gharadig Basin. A significant thickness of mixed clastic and carbonate sediments that were produced during the Cenozoic and Mesozoic periods may be found in these northern basins. NE-SW trending faults divide the Shushan Basin from the Dahab-Mireir Basin in the SE and the Matruh Basin in the NW, and this study concentrates on that area (Figure. 1a). There are two primary fault trends that have been recorded from the Shushan Basin, which are boundary faults ranging NE-SW and dominant faults within the basin that trend NW-SE to E-W (Shalaby et al., 2012; El Diasty et al., 2016). From a structural point of view, the Paleozoic and Mesozoic interval is defined by a sequence of normal faults that form grabens, half-grabens, and horsts. The tectonostratigraphic settings of the region principally affect the deposition of the source and reservoir rock units. Because of both horizontal and vertical movements in the basement blocks, the Western Desert region's structural traps, including the Shushan Basin, developed during the Paleozoic.

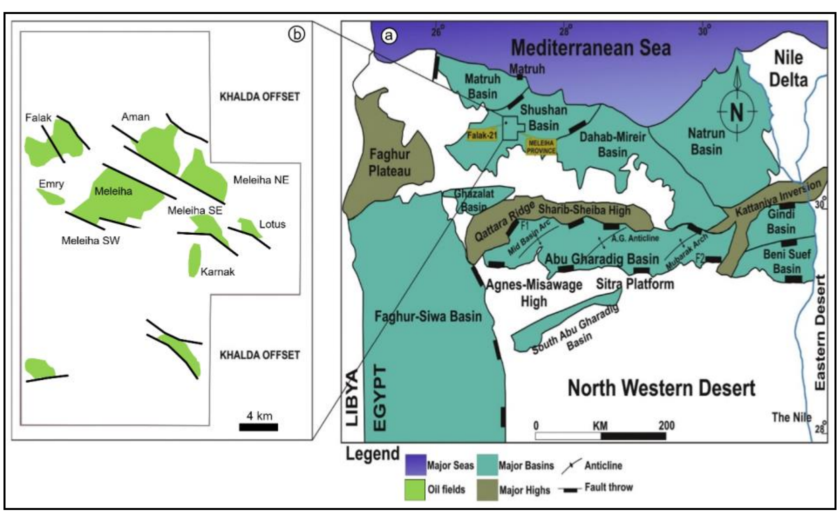

Figure 1: (a –b) Location map of the study area in the Shushan Basin in the north Western Desert, along with the structural trends (modified after EGPC, 1992).

Sultan and Abdelhalim (1988) provided a detailed description of how faulted anticlines and anticlines in general represent these structural traps. Although less common, compressional anticlines most likely resulted by drag folding, which is related to lateral movements along basement faults (Dolson et al., 2001a, b; Garfunkel, 2004; Guiraud et al., 2005). These traps kept developing during the Tethys opening and the Alpine Orogeny (Hantar, 1990). The main hydrocarbon reservoirs related to the NW-SE fault system that have been found in the Shushan Basin are shown in Figure. 1b.

Figure. 2 shows the Shushan Basin's lithostratigraphic succession.

Above the Precambrian crystalline basement is the unconformably deposited Cambro-Ordovician Shifah Formation. The Kohla to Safi formations are among the clastic deposits that make up the Silurian-Permian period. Source rock features can be found in the Dhiffah, Desouky, and Zeitoun formations' Devonian-Carboniferous shales (Reda et al., 2022). Mixed sediments are found in the Jurassic and Early Cretaceous, whereas carbonate deposition, which is primarily composed of chalk, argillaceous limestones, and dolomites with modest amounts of shales, dominates the Late Cretaceous to Miocene era (Mahmoud et al., 2019).

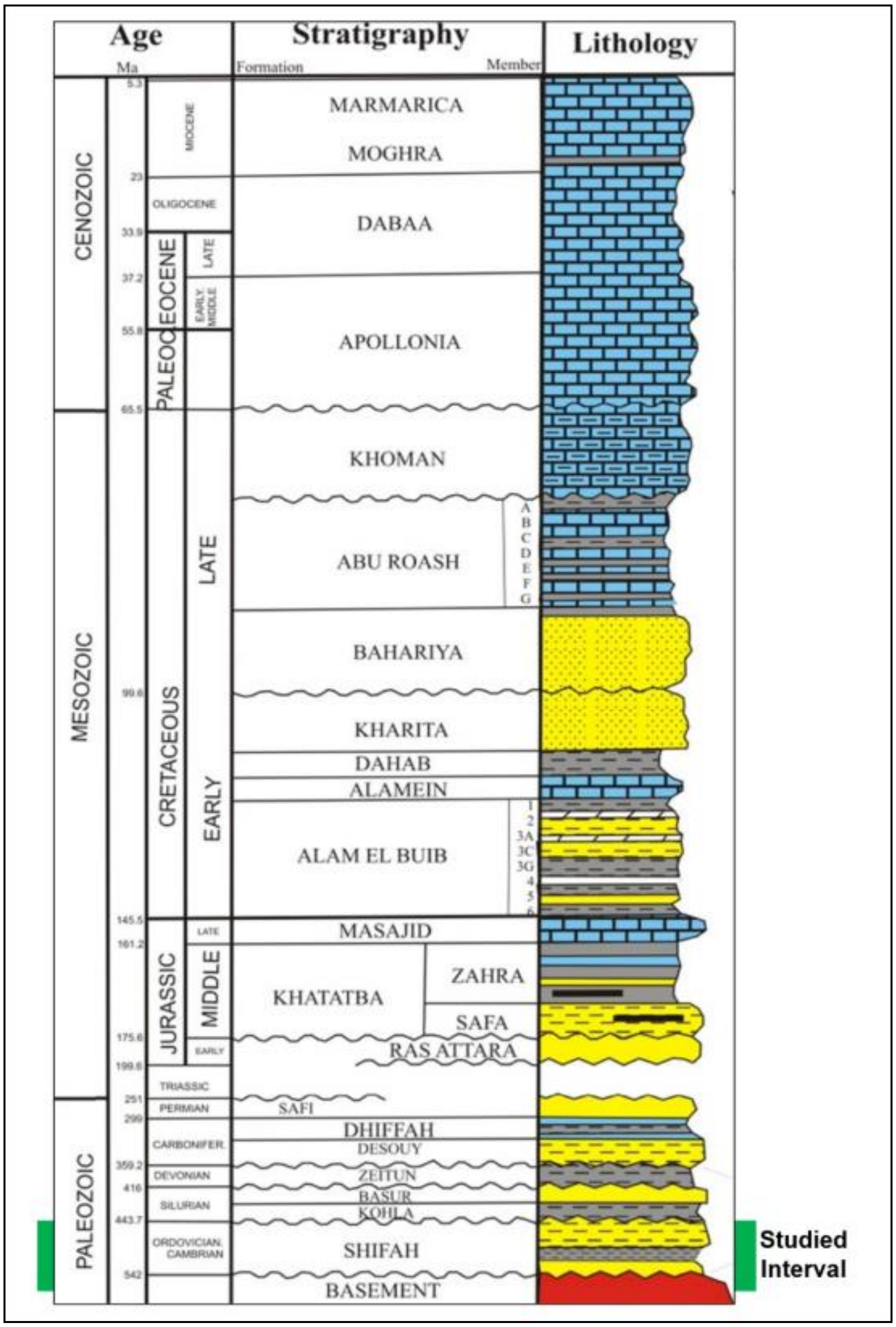

Figure 2: Regional stratigraphic succession of the Western Desert (after Keeley, 1994). The Lower Paleozoic interval is marked by green

4. Gas chromatographic analysis:

The significance of wetness and balance ratios determines the types of fluids encountered during drilling operations (Harworth et al., 1984). Wetness and balance ratios serve as indicators of the types of fluids encountered in the reservoir. Gas presence is anticipated when the balance ratio exceeds the wetness ratio. Conversely, oil presence is expected when the wetness ratio is higher than the balance ratio. Closer proximity of the wetness and balance ratio curves suggests denser gas and a higher probability of reservoir productivity (Harworth et al., 1984; Mode et al., 2014; Arafat et al., 2024). Conversely, wider separation between the curves may indicate lighter gas. Closer proximity of the curves indicates lighter oil, while wider separation suggests heavier oil. The crossover point of the curves defines the gas-oil contact (GOC), providing insights into the transition from gas to oil in the reservoir. Significant increases in the wetness ratio can indicate the presence of an oil-water connection (Harworth et al., 1984; Mode et al., 2014; Arafat et al., 2024; Farouk et al., 2024). This suggests the existence of heavier hydrocarbons along with residual oil traces. By comparing wetness and balance ratios and analyzing the patterns of their curves, operators can anticipate the presence of gas or oil and identify critical contacts such as oil-water and gas-oil contacts. These contacts are crucial for reservoir evaluation and production planning. The relationship between wetness and balance ratios provides a rapid evaluation method for assessing fluid types and contacts throughout the drilling operation. It offers insights into the changing composition of fluids encountered in the reservoir, helping operators make informed decisions during drilling and production activities. Overall, the wetness and balance ratios, along with the patterns of their curves, offer valuable information for characterizing reservoir fluids, identifying important contacts, and optimizing drilling and production strategies. Their rapid evaluation can enhance operational efficiency and aid in maximizing reservoir potential (Harworth et al., 1984; Mode et al., 2014; Arafat et al., 2024; Farouk et al., 2024).

The WR, BR, and CR ratios provide a framework for interpreting fluid types encountered during drilling operations. By analyzing these ratios and their relationships, operators can identify and characterize gas, oil, and residual oil, as well as differentiate between gas and oil shows. These interpretations aid in decision-making and optimization of drilling and production strategies. The interpretation of WR, BR, and CR ratios for characterizing fluid types encountered during drilling operations is as the following:

1. WR (Harworth et al., 1984; Mode et al., 2014; Arafat et al., 2024):

- WR < 0.5: Indicates very dry gas.
- WR = 0.5-17.5: Indicates gas, with increasing density as WR increases.
- WR = 17.5-40: Indicates oil, with increasing density as WR increases.
- WR > 40: Indicates residual oil.

2. BR (Harworth et al., 1984; Mode et al., 2014; Arafat et al., 2024):

- BRis nearly inversely related to WR and helps differentiate between coal bed anomalies and oil shows.
- BR > 100: Indicates very dry gas.
- BR > WR: Indicates gas, with gas density increasing as the curves become closer.
- BR < WR: Indicates gas/oil or gas/condensate, with oil density increasing as the curves separate.
- BR much less than WR when WR > 40: Indicates residual oil.

3. Ch Ratio (Harworth et al., 1984; Mode et al., 2014; Arafat et al., 2024):

- CR ratio helps interpret data and identify fluid characteristics.
- CR < 0.5: Accurately interprets gas based on WR and BR ratios.
- CR > 0.5: Associates oil with the gas character indicated by WR and BR ratios.

The integration between Wetness and Balance curves indicated the fluid characterization, so the Safa Formation and the upper part of Shiffah Formation (rich sand) shows curves closer to each other, where 10<WR <20, BR > WR, 30< BR <35 and CR < 0.5, indicating the presence of condensate (Dashti et al., 2016) (Figure. 3). Lower part of Shiffah and Middle part of Shiffah formations show separation between the two curves, where 20<WR <25, 10< BR <15 WR > BR and CR > 0.5, indicating the presence of Oil (Dashti et al., 2016; Farouk et al., 2024) (Figure. 3).

According to this study, the condensate zone has a greater methane ratio and a wet C_5 ($C_1/(C_1+C_2+C_3+C_4+C_5)$ ratio than the oil zone (Figure. 4). The C_1/C_4 ratio is higher than the C_1/C_3, suggesting that the oil and condensate zones are not wet-water zones (Figure. 5).

5. Geochemistry of Condensate:

5.1 Origin of Condensate:

Exactly, API gravity serves as a fundamental parameter for categorizing crude oils into different grades based on their density relative to water. Lighter oils, characterized by higher API gravity values, are less dense and tend to float on water (Tissot and Welte, 1978). These lighter oils usually contain fewer heavy compounds, making them easier to refine and often more valuable in the market. Dashti et al., 2016 classified the crude oils according to API gravity. If API less than 20, Crude oil is heavier. API 20-35, the Crude oil is moderate. API 35-45, the Crude oil is lighter. While, if API is more than 45, the crude oil is condensate. In this study, API is more than 45; the crude oil is condensate with low WR than BR (Mode et al., 2014).

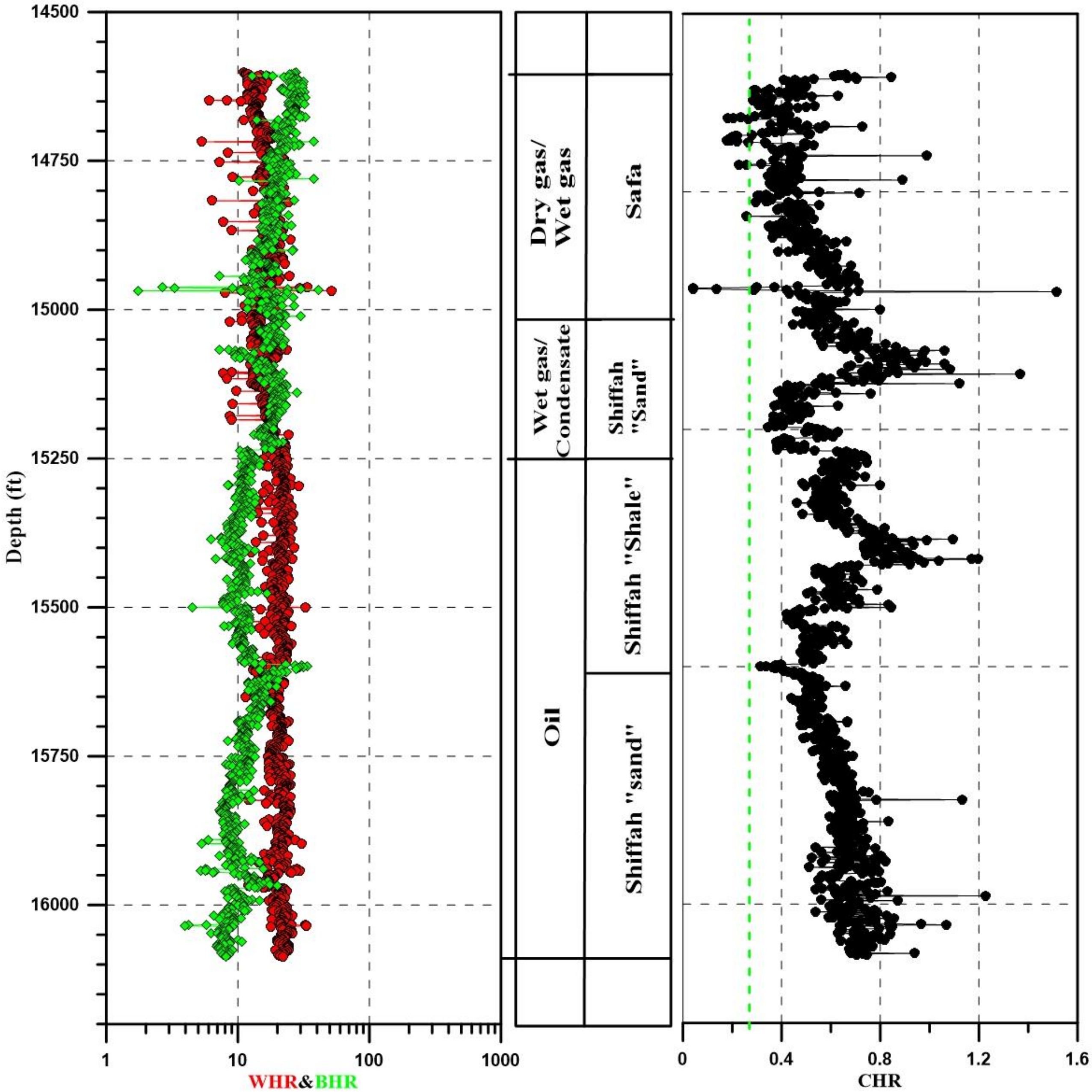

Figure 3: Geb-1x well mud gas diagnostic ratio log. The diagnostic ratios, CR, BR, and WR, as established by Haworth et al. (1985)

Assessing the origin and source of condensate is crucial for understanding its composition and potential applications. Using multiple geochemical indicators, including biomarkers, is a robust approach to determine the origin of condensate. The ratios of phytane/n-C18 and pristane/n-C17 can provide further information about the environmental conditions and thermal maturity during deposition (Farouk et al., 2023). The observation that pristane has a greater value than phytane, along with pr/phytane (Pr/Ph) ratios exceeding 3, indicates that terrigenous organic matter is likely the primary source of the studied condensates of the upper part of the Shiffah Formation (Sand-rich). In environments dominated by terrestrial input, such as riverine systems or coastal regions influenced by terrestrial runoff, pristane tends to be more abundant than phytane. This imbalance in pristane and phytane concentrations leads to Pr/Ph ratios greater than 1. A Pr/Ph ratio exceeding 3 suggests a significant contribution from terrestrial organic matter. The ratios indicate that mixed organic materials were deposited under suboxic to somewhat oxic environments (El Diasty et al., 2022) (Figure. 6).

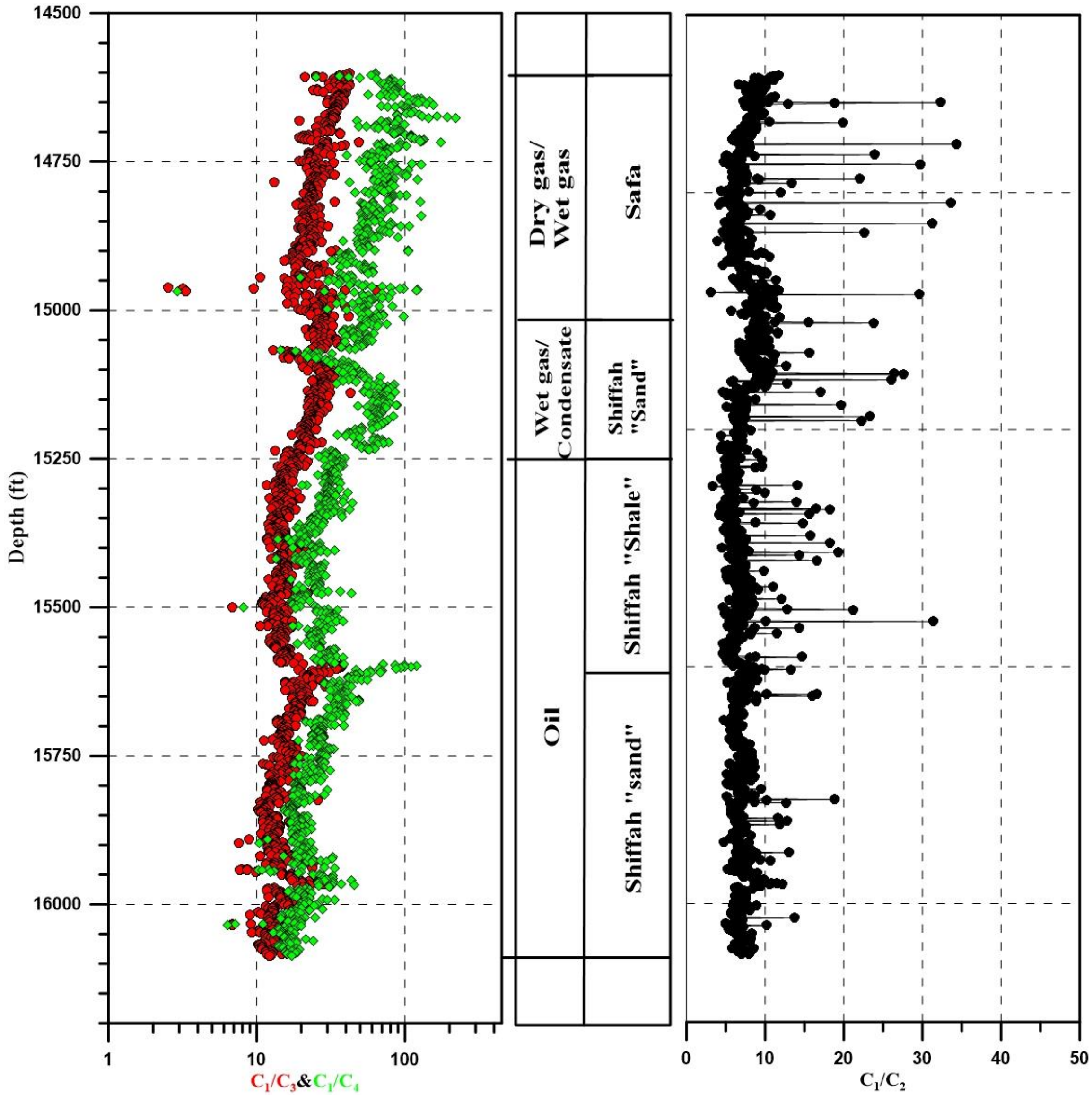

Figure 4: shows the relationship between the mud gas ratios for the Geb-1x well (C_1/C_2, C_1/C_3, and C_1/C_4).

The relationship between Dibenzothiophene (DBT)/Phenanthrene and pr/ph ratios was employed to deduce the depositional environment of the analyzed condensates of the upper part of the Shiffah Formation (Sand-rich) (Hughes et al., 1995). The findings suggest that the majority, if not all, of the studied condensates of the upper part of the Shiffah Formation originated from organic matter formed in a fluvio-deltaic environment (El Diasty et al., 2022) (Figure. 7). In such an environment, characterized by the interaction of river systems and deltaic sedimentation, the organic material is primarily derived from terrestrial sources like land plants and soil organic matter. This environment often results in the preservation of certain biomarkers, such as high molecular weight compounds and sulfur-containing compounds like dibenzothiophene (DBT) (Hughes et al., 1995). Additionally, the pr/ph ratio reflects the dominance of terrigenous organic matter, further supporting the conclusion that the studied condensates were sourced from organic material associated with fluvio-deltaic environments (Hughes et al., 1995).

5.2 Maturity of Condensate:

The use of heptane (H) and isoheptane (I) values, along with sterane maturity parameters, can provide insights into the thermal maturity of hydrocarbons or source rocks. Heptane and isoheptane values are often employed in assessing the thermal maturity of organic matter (El Diasty et al., 2016). These values are based on the ratio of specific hydrocarbons (heptane and isoheptane) and how they change with increasing thermal maturity. Generally, as maturity increases, the ratio of isoheptane to heptane tends to decrease (Farouk et al., 2023). Sterane maturity parameters involve the analysis of specific sterane compounds, which are organic molecules derived from sterols during the burial and thermal alteration of organic matter (Thompson, 1983; Peters et al., 2005). Two common sterane maturity parameters are C29αα(S)/αα(S) + αα(R) and C29ββ(R)/ββ(R) + αα(R). These parameters focus on the ratios of different sterane isomers, reflecting changes in their composition as a result of thermal maturation. As the organic matter matures thermally, these ratios tend to change in predictable ways. By combining these various parameters, analysts can gain a more comprehensive understanding of the thermal maturity of the studied hydrocarbons or source rocks (Thompson, 1983; Peters et al., 2005). In this study, Figure. 8 and Figure. 9 illustrate that condensate of the upper part of the Shiffah Formation located in the more mature zone.

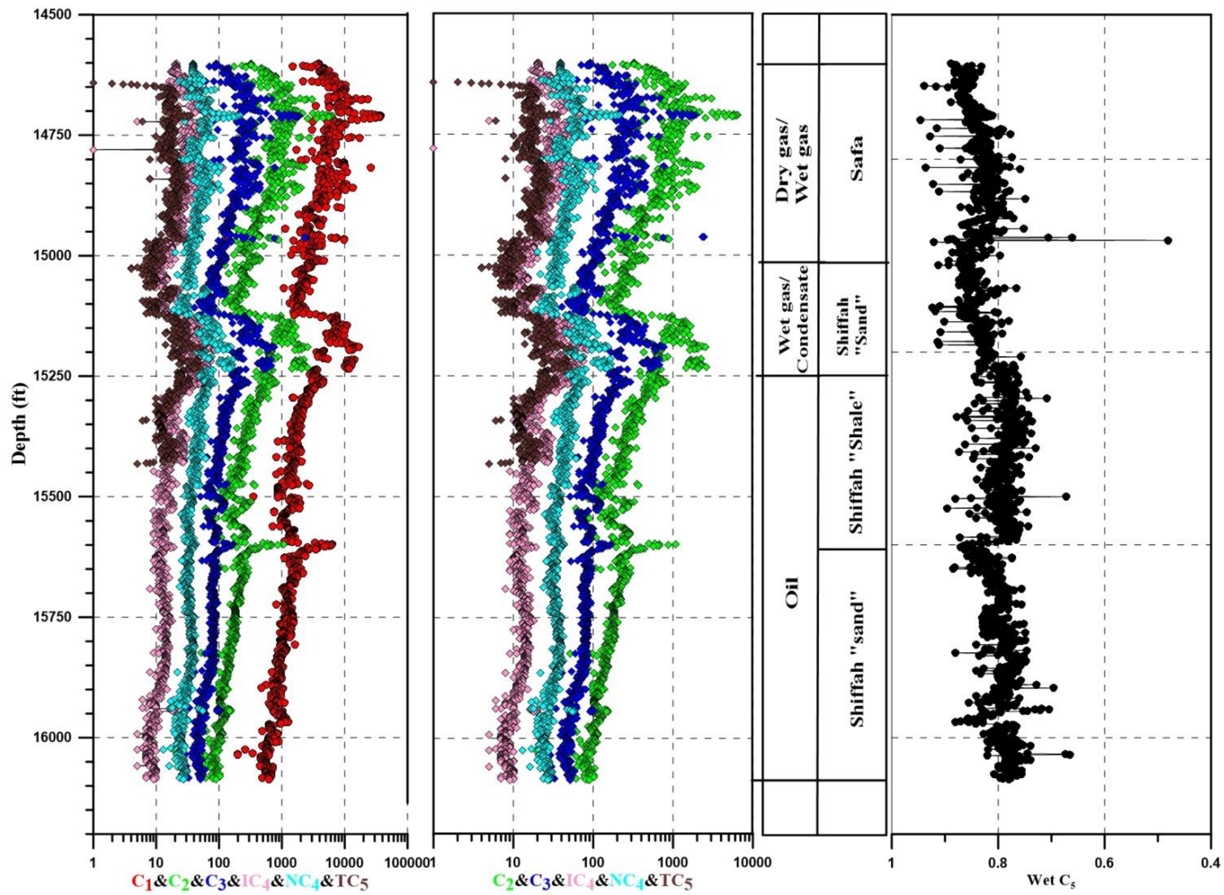

Figure 5: Mud Gas concentration Log for Geb-1x well.

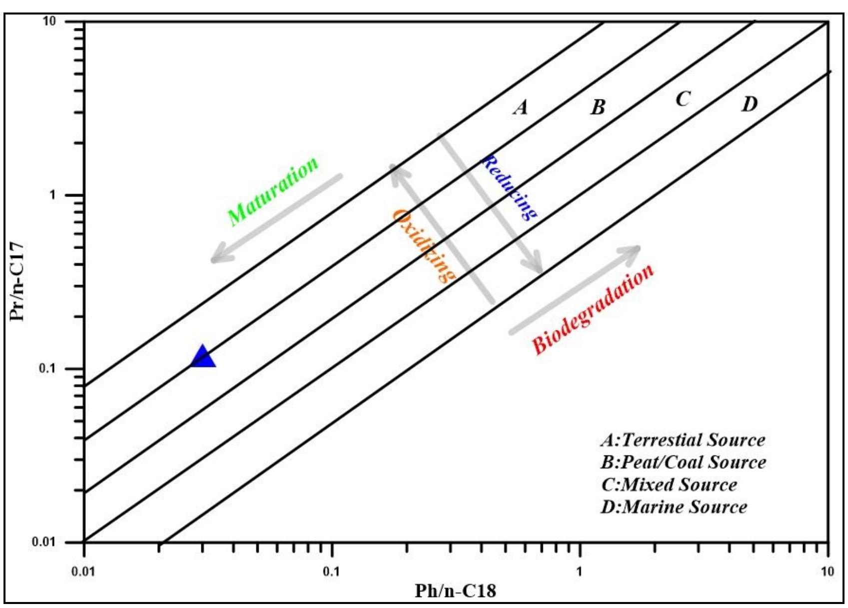

Figure 6: Plot of the Pristane/n-C17 against Phytane/n-C18 ratios shows how the source rocks of the condensate samples under study were deposited.

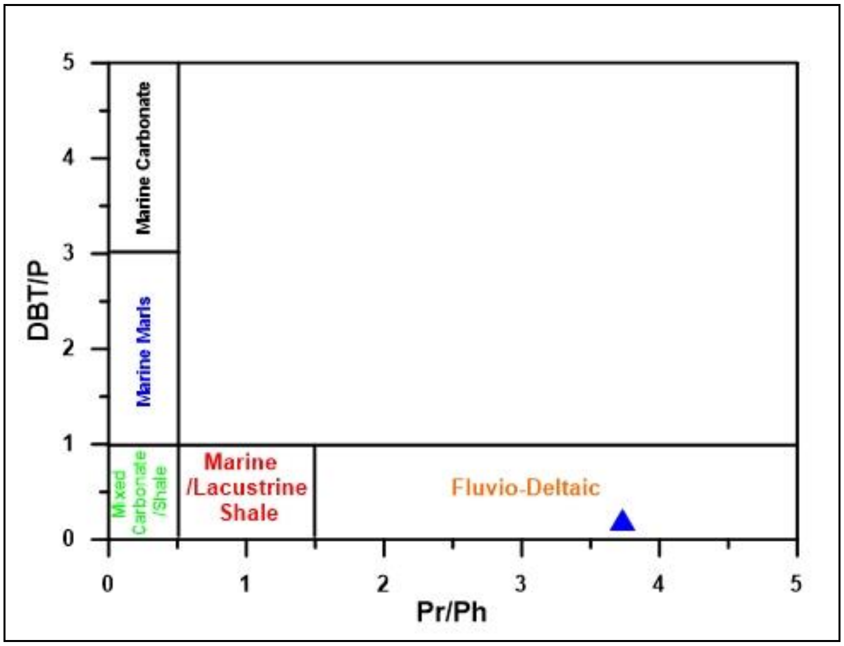

Figure 7: shows the correlation between aromatic compound (DPT/P) and pr/ph.

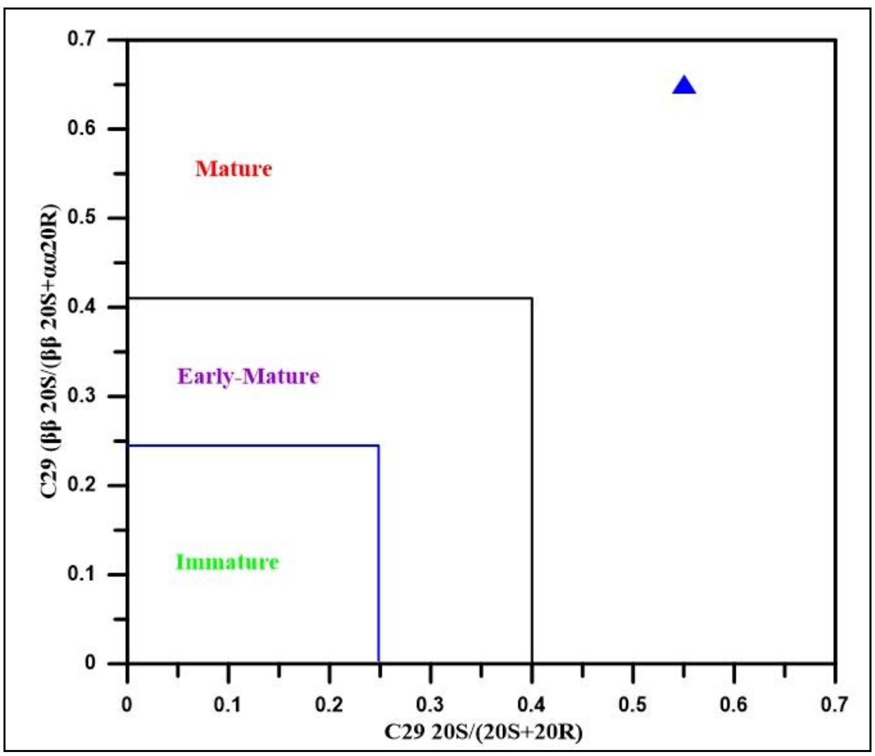

Figure 8: shows a plot of the Sterane C29 20S / (20S + 20R) ratio against the C29 ββ / (ββ + αα) ratio.

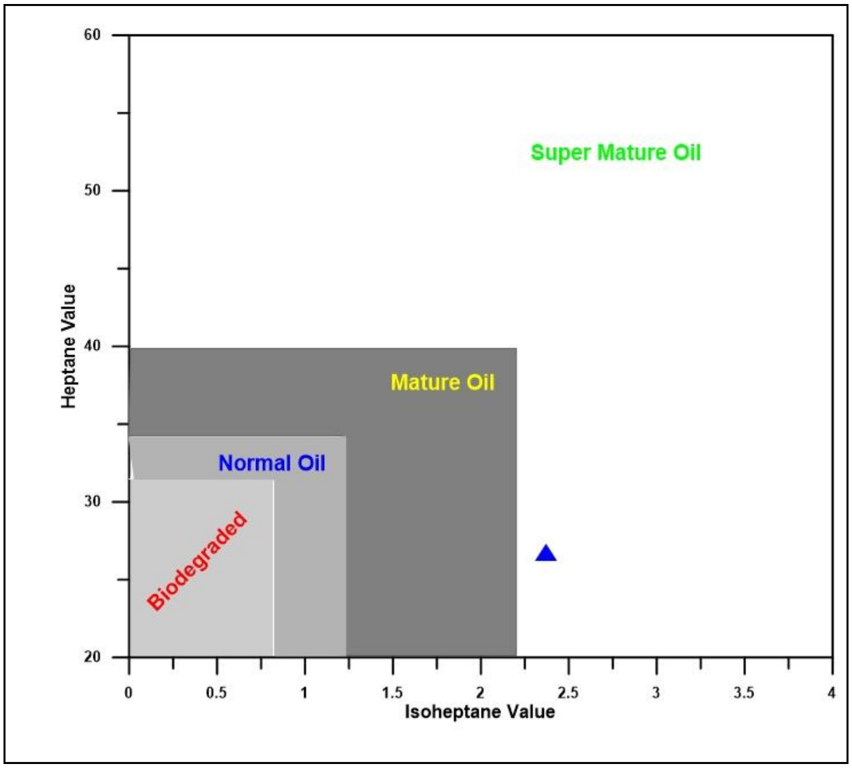

Figure 9: Thompson's (1983) diagram showing Heptane and Iso-Heptane values.

Conclusion

- The WR, BR, and CR ratios provide a framework for interpreting fluid types encountered during drilling operations. By analyzing these ratios and their relationships, operators can identify and characterize gas, oil, and residual oil, as well as differentiate between gas and oil shows.
- In the Safa Formation and the upper part of the Shiffah Formation, the wetness (WR) and balance (BR) curves are closer to each other, with specific ranges: $10 < WR < 20$, $BR > WR$, $30 < BR < 35$, and $CR < 0.5$. This pattern indicates the presence of condensate.
- On the other hand, in the lower and the middle parts of Shiffah Formation, there is a separation between the two curves. In this case, the ranges are $20 < WR < 25$, $10 < BR < 15$, $WR > Bh$, and $CR > 0.5$. These characteristics suggest the presence of oil.
- In the condensate zone, the methane ratio and the wet C5 ratio are both higher compared to the oil zone, as depicted in Figure 4. Additionally, the C_1/C_4 ratio is higher than the C_1/C_3 ratio. These observations collectively suggest that both the oil and condensate zones are not wet-water zones.
- The higher Methane ratio in the condensate zone implies a greater proportion of Methane relative to other hydrocarbons, which is characteristic of condensate-rich formations. Similarly, the higher wet C_5 ratio in the condensate zone indicates a higher proportion of heavier hydrocarbons compared to the oil zone.
- The C_1/C_4 ratio being higher than the C_1/C_3 ratio further supports the differentiation between the oil and condensate zones. This could indicate a higher concentration of lighter hydrocarbons relative to butanes in the condensate zone compared to the oil zone.
- A higher pr/ph ratio of the condensate in the upper part of the Shiffah Formation indicates a dominance of Pristane over Phytane, suggesting a higher contribution of terrigenous organic matter. This ratio aligns with the characteristics of fluvio-deltaic environments, where terrestrial organic material is prevalent.
- Therefore, the pr/ph ratio provides supporting evidence that the condensates of the upper part of the Shiffah Formation were formed from organic material associated with fluvio-deltaic environments.
- According to Heptane and Iso-Heptane and C29αα(S)/αα(S) + αα(R) & C29ββ(R)/ββ(R) + αα(R) plots, condensate of the upper part of the Shiffah Formation is more mature.

References

Arafat, M., Farouk, S., Saada, S. A., & S Fagelnour, M. (2024). Hydrocarbon gas chromatography as indicator of fluids types: A case study of Azhar field, Beni Suef Basin, Egypt. Frontiers in Scientific Research and Technology.

Behar, F., Kressmann, S., Rudkiewicz, J. L., & Vandenbroucke, M. (1992). Experimental simulation in a confined system and kinetic modelling of kerogen and oil cracking. Organic Geochemistry, 19(1-3), 173-189.

Dashti, J., Al-Awadi, M., Al-Ajmi, B., Rao, S., Shoeibi, A., Estarabadi, J., ... & Nadiminti, A. (2016, November). Use of Advanced Mud Gas Chromatography for Reservoir Quality Prediction While Drilling. In International Petroleum Technology Conference (p. D011S009R005). IPTC.

Dolson, C., Shaan, V., Matbouly, S., Harwood, C., Rashed, R., Hammouda, H., 2001a. The petroleum potential of Egypt. In: Downey, W., Threet, C., Morgan, A. (Eds.), Petroleum Provinces of the Twenty -First Century, vol. 74. American Association of Petroleum Geologists, pp. 453 –482.

Dolson, J. C., Shann, M. V., Matbouly, S. I., Hammouda, H., Rashed, R. M., 2001b. Egypt in the twenty -first century: petroleum potential in offshore trends. GeoArabia 6 (2), 211 –230.

EGPC (Egyptian General Petroleum Corporation), 1992. Western Desert, Oil and Gas Fields. A Comprehensive Overview. 11th EGPC Petrol. Exploration and Production Conference Cairo, Egypt, pp. 1 –431.

El Diasty, W. S., El Beialy, S. Y., Littke, R., & Farag, F. A. (2016). Source rock evaluation and nature of hydrocarbons in the Khalda Concession, Shushan Basin, Egypt's Western Desert. International journal of coal geology, 162, 45-60.

El Diasty, W. S., Moldowan, J. M., Peters, K. E., Hammad, M. M., & Essa, G. I. (2022). Organic geochemistry of possible Middle Miocene–Pliocene source rocks in the west and northwest Nile Delta, Egypt. Journal of Petroleum Science and Engineering, 208, 109357.

El Diasty, W. Sh, El Beialy, S.Y., Littke, R., Farag, F.A., 2016. Source rock evaluation and nature of hydrocarbons in the Khalda concession, Shushan Basin, Egypt’s Western Desert. Int. J. Coal Geol. 162, 45 –60.

Farouk, S., Khairy, A., Shehata, A. M., Uguna, C. N., El Sheennawy, T., Salama, A., ... & Meredith, W. (2023). Geochemical evaluation and hydrocarbon generation potential of the upper Cretaceous–Pliocene succession, offshore Nile Delta, Egypt. Journal of African Earth Sciences, 205, 105004.

Farouk, S., Saada, S. A., Fagelnour, M. S., & Arafat, M. (2024). Petrophysical and Gas Chromatographic Analysis Integration for Hydrocarbon Identifications in Cretaceous Reservoirs, Azhar Field, Beni Suef Basin, Egypt. Egyptian Journal of Petroleum, 33(1), 7.

Garfunkel, Z., 2004. Origin of the eastern mediterranean basin: are -evaluation. Tectonophysics 391, 11 –34.

Guiraud, R., Bosworth, W., Thierry, J., Delplanque, A., 2005. Phanerozoic geological evolution of northern and central Africa: an overview. J. Afr. Earth Sci. 43, 83 –143.

Hantar, G., 1990. North Western Desert. In: Said, R. (Ed.), the Geology of Egypt. Balkema, Rotterdam, pp. 407 –438.

Haworth, J., Sellens, M., & Whittaker, A. (1984). Interpretation of Hydrocarbon Shows Using Light (C1-C5) Hydrocarbons. AAPG Bulletin, 68(4), 484-485.

Hughes, W. B., Holba, A. G., & Dzou, L. I. (1995). The ratios of dibenzothiophene to phenanthrene and pristane to phytane as indicators of depositional environment and lithology of petroleum source rocks. Geochimica et Cosmochimica Acta, 59(17), 3581-3598.

Hughes, W. B., Holba, A. G., & Dzou, L. I. (1995). The ratios of dibenzothiophene to phenanthrene and pristane to phytane as indicators of depositional environment and lithology of petroleum source rocks. Geochimica et Cosmochimica Acta, 59(17), 3581-3598.

Keeley, M. L., 1994. Phanerozoic evolution of the basins of Northern Egypt and adjacent areas. Geol. Rundsch. 83 (4), 728 –742.

Mahmoud, M. S., Deaf, A. S., Tamam, M. A., Khalaf, M. M., 2019. Revised (miospores -based) stratigraphy of the lower cretaceous succession of the minqar -IX well, Shushan Basin, north Western desert, Egypt: biozonation and correlation approach. J. Afr. Earth Sci. 151, 18 –35.

Mode, A. W., Anyiam, O. A., & Egbujie, B. C. (2014). The application of chromatographic gas ratio analysis in reservoir fluid evaluation of “Beta” field in the Congo basin. Journal of the Geological Society of India, 84, 303-310.

Peters, K. E., Walters, C. C., & Moldowan, J. M. (2005). The biomarker guide (Vol. 1). Cambridge university press.

Reda, M., Fathy, M., Gawad, E. A., 2022. Comprehensive 3D reservoir modelling and basin analysis: an insight into petroleum geology to re-evaluate the hydrocarbon possibilities in the Siwa Basin, North -Western Desert, Egypt. Geol. J. 57 (4), 1600 –1616.

Said, R., 1990. Cretaceous paleogeographic maps. In: Said, R. (Ed.), The Geology of Egypt. pp. 439 –449. Balkema, Rotterdam.

Shalaby, M.R., Hakimi, M.H., Abdullah, W.H., 2012. Organic geochemical characteristics and interpreted depositional environment of the Khatatba Formation, northern Western Desert, Egypt. American Association of Petroleum Geologists Bulletin. 96 (11), 2019–2036.

Sultan, N., Abdelhalim, M. A., 1988. Tectonic framework of northern Western Desert, Egypt, and its effect on hydrocarbon accumulations. In: Egyptian General Petroleum Corporation 9th Exploration and Production Conference . pp. 1 –23. Cairo, Egypt, Nov 20 -23.

Thompson, K. F. M. (1979). Light hydrocarbons in subsurface sediments. Geochimica et Cosmochimica Acta, 43(5), 657-672.

Tissot, B. P., Welte, D. H., Tissot, B. P., & Welte, D. H. (1978). Sedimentary processes and the accumulation of organic matter. Petroleum Formation and Occurrence: A New Approach to Oil and Gas Exploration, 55-62.