RESEARCH PAPER

Petrophysical and gas chromatographic analysis integration for hydrocarbon identifications in Cretaceous reservoirs, Azhar Field, Beni Suef Basin, Egypt

Sherif Farouk, Saada A. Saada, Mohamed S. Fagelnour, Mohamed Arafat

Abstract

The petrophysical assessment of the Cretaceous succession from late Albian to Cenomanian (Upper Kharita, Bahariya formations, and Abu Roash ‘G’ Member) confirmed by gas chromatographic analysis utilizing well-log data and core data from the Azhar A-2 and Azhar E-1X wells located within the Beni Suef Basin, Western Desert of Egypt, was the aim of this work. The oil net pay zone of the Upper Bahariya Formation in the Azhar A-2 well is more effective and has a lower thickness than that of the Upper Bahariya Formation in the Azhar E-1X well. The gas chromatographic value analysis of the two wells (Azhar A-2 and Azhar E-1X) gives a good signature about the type of hydrocarbon content. The Abu Roash ‘G’ Member is characterized by the presence of oil in its lowermost part, and the C1/C2 ratio also confirmed the presence of oil, which ranges from 3 to 7, where 40 greater than wetness ratio greater than 17.5, character ratio greater than or equal to 0.5 with balance ratio less than 17.5. In the upper part of A/R, ‘G’ Member is characterized by the presence of oil/heavy oil because the wetness ratio is greater than 40 and the character ratio is greater than or equal to 0.5 with the balance ratio less than 17.5. The Upper Bahariya Formation is characterized by the presence of oil/heavy oil, where the wetness ratio is greater than 40, character ratio is greater than or equal to 0.5 with the balance ratio less than 17.5, and the C1/C2 ratio also confirmed the presence of oil/heavy oil that ranged from 2 to 5. The statistical analysis of the Upper Kharita Formation conventional core data indicated that the Upper Kharita Formation is characterized by fair-to-good porosity, fair permeability, and its gas chromatographic value analysis shows the presence of oil/heavy oil, where the wetness ratio greater than 40, character ratio greater than or equal to 0.5 with balance ratio less than 17.5, and C1/C2 ratio also confirmed the presence of oil/heavy oil, which ranged from 1.5 to 7.

Keywords: A/R ‘G’ member, Azhar field, Egypt, Gas chromatography, Petrophysical analysis, Upper Bahariya Formation, Upper Kharita Formation

1. Introduction

The Beni Suef Basin (BSB) is located in the northeastern corner of the African Plate. The basin developed during the Early Cretaceous period. The BSB is noted for its significant hydrocarbon potential. This implies that the subsurface geological formations within the basin may contain deposits of oil and gas. The basin is included in future exploration plans in the north-central region of Egypt. This suggests that there is ongoing interest or intention to explore and exploit the hydrocarbon resources in the
BSB. Rift basins often form in areas where the Earth’s crust is stretching and thinning, leading to the creation of depressions that can accumulate sediments and, potentially, hydrocarbons.2

The main reservoirs in a number of North Western Desert basins, including the basin under study, seem to be sandstone intervals found in the Cretaceous strata. Sandstone intervals within the Cretaceous sediments serve as the primary reservoirs in the North Western Desert basins. These sandstone intervals are laterally distributed across the majority of the North Western Desert basins, indicating a widespread presence. The Early Cretaceous Alam El-Bueib and Kharita formations, as well as the Late Cretaceous Bahariya and Abu Roash formations, are specifically mentioned as having reservoir sandstones.4–10 Given that these sandstone intervals are identified as main reservoirs, they likely hold significant hydrocarbon potential, and exploration and production activities may focus on these formations. Many previous works used the integration between gas chromatographic analysis and petrophysical parameters to assess the hydrocarbon potential.11 The wells under investigation, Azhar A-2 and Azhar E–1X, are situated in the western region of the BSB, specifically between latitudes 29° 08′–29° 08′ N and longitudes 30° 55′ and 29° 08′ E (Fig. 1). The present study appears to integrate geophysical (well-logging) and geochemical (gas chromatography) data to assess the reservoir properties and hydrocarbon content of several sandstone intervals within the A/R ‘G’ Member and Upper Bahariya Formation in the Azhar A-2 and Azhar E–1X wells. In addition, the petrophysical evaluation of Upper Kharita Formation in Azhar A-2 well using the conventional core data. Well logs can provide valuable information about subsurface properties such as porosity, permeability, and lithology. Gas chromatography data, a technique for analyzing the composition of gas samples, is used to gather information about the hydrocarbon content. Additionally, the petrophysical assessment includes the Upper Kharita Member based on core data from the Azhar A-2 well. A comprehensive assessment of the hydrocarbon potential in the selected sandstone intervals requires a comprehensive integration of gas chromatography data and well-logging information.12,13

2. Geological setting

The basin is situated in the Nile Valley at the beginning of the unstable shelf of Egypt. There have been two significant tectonic phases in the basin: the basin suffered syn-rift extensional tectonic activity throughout the Early Cretaceous. Rift basins are often characterized by extensional forces that lead to the creation of subsidence zones. In the latest Cretaceous, the basin was affected by a post-rift phase. The Santonian Syrian-arc compressional regime had an impact on this period.14–16 The post-rift phase in the latest Cretaceous was influenced by the Santonian Syrian-arc compressional regime. Compressional regimes are characterized by forces that lead to the shortening and folding of the Earth’s crust. The basin’s tectonic history involves both extensional and compressional phases, indicating a complex geological evolution.14,15,17,18

The Cretaceous–Paleogene periods are represented in the rather thick lithostratigraphic sequence found in the BSB. Thick siliciclastic rocks from the Kharita Formation, which date back to the Early Cretaceous, are deposited along rivers at the start of the succession. The Kharita Formation is followed by silica-dominated strata of the Cenomanian Bahariya Formation. The Abu Roash Formation is made up of

![Fig. 1. Location map showing Azhar Field, Beni Suef Basin, Egypt.](image-url)
clastic and carbonate unit intercalations and represents the Cenomanian–Santonian era. The succession changes to the Campanian–Maastrichtian Khoman Formation's carbonates and chalk as it moves upward4,17,18 (Fig. 2). The A/R Formation was divided into six members19 this study focused on the investigation of Abu Roash ‘G’ Member (A/R ‘G’ Member) that was located in Azhar A-2 well through the interval 6610–7044 ft and through the interval 6297–7364 ft in the case of Azhar E–1X well. The Bahariya Formation was divided into two parts (Upper Bahariya Formation and Lower Bahariya Formation)20 in Azhar A-2 well, the Upper Bahariya Formation is through the interval 7044–7450 ft and Lower Bahariya Formation is through the interval 7450–7815 ft, whereas in the case of Azhar E–1X well, the Upper Bahariya Formation is through the interval 7364–7840 ft and Lower Bahariya Formation is through the interval 7840–8212 ft.

3. Methodologies

Well-logging analysis and available core data that integrated with gas chromatographic analysis are used for identifying hydrocarbon-bearing zones. The method used is the Indonesian Porosity-Water Saturation method. Effective porosity (\(\phi_E\)), total porosity (\(\phi_T\)), water saturation (\(S_w\)), and identifying
hydrocarbon-bearing zone formation is called $V_{Sh}$. It shows what percentage of the rock's overall volume comprises shale and is given as a percentage. A rock formation's total porosity is expressed as $\Phi_T$. A rock's ability to hold fluids in its void spaces or apertures is measured by its porosity. Every kind of void space, whether connected or isolated, is included in total porosity. $\Phi_E$ is the effective porosity of a rock, representing the portion of the total porosity that contributes to fluid flow. It excludes isolated pores that are not connected to the larger pore network. These parameters are essential to understanding the characteristics of the reservoir.

Using gamma-ray log (GR) readings as a base, the following formula can be used to get the shale volume:\cite{21,22}:

$$V_{Sh} = \frac{(GR_{\text{avg}} - GR_{\text{min}})}{(GR_{\text{max}} - GR_{\text{min}})}$$

*GR = the gamma-ray log value. *GRmin = the minimum gamma-ray log value within the analyzed data. *GRmax = the maximum gamma-ray log value within the analyzed data.

Total porosity ($\Phi_T$) can be computed using the following formula, which takes the average of density porosity ($\Phi_D$) and neutron porosity ($\Phi_N$)\cite{21,22}:

$$\Phi_T = \frac{(\Phi_N + \Phi_D)}{2}$$

*\Phi_T = the total porosity. *\Phi_N = the average neutron porosity. *\Phi_D = the average density porosity. The effective porosity ($\Phi_E$) can be calculated by multiplying the total porosity ($\Phi_T$) by a coefficient associated with the complement of the shale volume ($V_{Sh}$)\cite{21,22}:

$$\Phi_E = \Phi_T \times (1 - V_{Sh})$$

*\Phi_E = the effective porosity. *\Phi_T = the total porosity. *V_{Sh} = the shale volume.

Water saturation ($S_w$) for reservoir intervals is calculated with Archie's model.\cite{23} In the Archie model, the formula for water saturation is commonly represented as follows:

$$S_w = \left[aR_t/\Phi^mR_n\right]^{1/n}$$

*S_w = the water saturation. *$\Phi$ = the porosity. *R_t = the deep resistivity. *R_n = the connate water resistivity. a and m are empirical constants.

This investigation used two mudlogs from two wells. Two wells (Azhar-A-2, Azhar E-1X) had their mudlogs analyzed, and the reservoir sections' various gas peaks were chosen for additional study. Subsequently, the Pixler diagram was utilized to plot the gas chromatographic data (C1-C3) and the wetness, character, and balance ratios were calculated. Harworth et al. 1985,\cite{24} state that the following formulas were used to calculate these ratios.

The gas ratios are used to predict character, balance, and wetness ratios based on chromatography data. The values of these ratios can help determine the types of reservoir fluids and reveal information about the gas' composition.

Gas ratios: *Wh (Wetness Ratio): $\text{Wh} = \frac{(C_2 + C_3 + C_4)}{(C_1 + C_2 + C_3 + C_4 + C_5)} \times 100$ \cite{24,25} *Bh (Balance Ratio): $\text{Bh} = \frac{(C_4 + C_5)}{(C_1 + C_2 + C_3 + C_4 + C_5)}$ \cite{24,25} *Ch (Character Ratio): $\text{Ch} = \frac{(C_4 + C_5)}{C_6}$ (Haworth et al., 1985; Pierson, 2017)\cite{24,25} The wetness ratio (Wh), balance ratio (Bh), and character ratio (Ch) are key parameters derived from gas chromatography data of A/R ‘G’ Member and Bahariya Formation in Azhar A-2 and Azhar E-1X wells, and they are used to infer reservoir fluid types based on their estimated value ranges.

Furthermore, the accessible core data comprise a description of the lithology derived from core data and the whole set of conventional core data (for a 56-foot cored interval in the Azhar A-2). This includes bulk and grain densities ($\rho_b$ and $\rho_g$), helium porosity ($\phi$He), and vertical and horizontal air permeabilities ($k_V$ and $k_H$). Nabawy et al.\cite{26,26} have released a detailed description of measuring methodologies.\cite{27} The study involves core data from the Azhar A-2 well for deducing petrophysical parameters of the Upper Kharita Formation.

4. Results and discussion

4.1. Petrophysical assessment of the cretaceous succession (late Albian—Cenomanian)

Examination of the petrophysical parameters of the Cretaceous succession (late Albian—Cenomanian), where A/R ‘G’ Member and Upper Bahariya Formation is characterized by using well-logging data and we found that A/R ‘G’ Member is characterized by a very thin net pay zone but it shows gases. Upper Bahariya Formation contains the most important reservoir that contains the thickest net pay zone in the Cretaceous succession. Conventional core data are used for the Upper Kharita Formation. The Upper Bahariya Formation of the BSB contains limited sandstone streaks, which are thought to be less-effective pay zones,\cite{26} whereas the present study indicates that the Upper Bahariya Formation shows a more effective net pay zone. The presence of effective porosity within the specified range and the low shale volume indicate good conditions for the occurrence of hydrocarbons. The water saturation levels, on the other hand, suggest that the reservoir
contains a significant amount of water, which is a factor to consider when determining if extracting hydrocarbons from this formation is economically viable. More details about the sorts of hydrocarbons present and the permeability of the rock would give a more complete picture of the reservoir potential. The interpretation of the well-logging data of the Upper Bahariya Formation of Azhar A-2 well indicated that the interval of the oil reservoir zone is between 7360 ft and 7430 ft with 12 ft thickness of the net pay, which was characterized by 27% effective porosity and 44% $S_w$ (Fig. 3a), in the case of Azhar E-1X well, indicating that the interval of the oil reservoir zone is between 7550 ft and 7620 ft with 20 ft thickness of the net pay, which was characterized by 20% effective porosity and 22% $S_w$ (Fig. 3b).

The density-neutron cross-plot of Upper Bahariya Formation in Azhar-A-2 well shows that most of the formation is highly argillaceous (75–90 GAPI – green color points) with sandstone having calcareous cement (most points are clustered between the dolomite and limestone lines) (Fig. 4a), but in the case of Azhar-E-IX well, the Upper Bahariya Formation is highly argillaceous (60–90 GAPI – brown and green color points) with sandstone having calcareous cement (points clustered between the dolomite and limestone lines) (Fig. 4b).

4.2. Gas chromatographic analysis of A/R ‘G’ member and Upper Bahariya Formation

The wetness ratio (Wh), balance ratio (Bh), character ratio (Ch), and $C_1/C_2$ ratio are all parameters used in the analysis of oil and natural gas to recognize their composition and characteristics. The interpretation of well logs, including wetness and...
balance ratios, requires a sophisticated awareness of both geology and petrophysics. The relationship between these ratios is just one aspect of a larger analysis that is carried out during the exploration and drilling of hydrocarbon reservoirs. The assessment of reservoir productivity entails considering a variety of factors.

With an increase in gas density, the wetness ratio rises. Temperature, pressure, and the makeup of the gas mixture all have an impact on gas density. The fraction of heavy gas components increases relative to the lighter gases, so the behavior of natural gas mixes is consistent. Heavy hydrocarbons like butane and propane are referred to as ‘heavy’ components in natural gas, while methane is referred to as a ‘lighter’ component. A larger concentration of heavy components relative to lighter ones is indicated by the gas mixture becoming denser overall. Because these heavier components are more prone to condense into liquid phase under specific conditions (such as during cooling), this increased concentration of heavy components can result in an increase in the wetness ratio. Terms like Wh and Bh ratios can be used to characterize mixtures of hydrocarbons. When interpreting hydrocarbon data from various sources, including well logs, gas chromatography, and other analytical methods, these ratios are frequently utilized. When evaluating the quality and economic feasibility of hydrocarbon reservoirs, the results may be very important.

Fig. 4. Upper Bahariya Formation neutron-density cross-plot. (a) Azhar-A-2 well and (b) Azhar-E–IX well.
Predictions of gas are indicated if the Bh is higher than the Wh.\textsuperscript{25} If the curves are close to each other, it suggests a more consistent relationship between the two ratios, based on this comparison, it is most likely the case that the hydrocarbon mixture is heavier (denser gas composition) in gases than in liquids, which suggests that a reservoir with a denser gas composition is more likely to be productive.\textsuperscript{29} This could be because denser gases often contain more valuable hydrocarbons. The relationship between the balance ratio and the wetness ratio helps to predict the kind of hydrocarbon that will be found during drilling.\textsuperscript{29} It is possible that oil is being predicted if the wetness ratio is higher than the balancing ratio.\textsuperscript{25} This comparison probably shows that there is a greater proportion of liquids (oil) in the hydrocarbon mixture than gases.\textsuperscript{24} The interaction between balance and wetness ratios is as follows:\textsuperscript{25}:

1. If Bh greater than Wh: gas is predicted.
2. If Wh greater than Bh: oil is predicted.

A reservoir with a large separation between the Wh and Bh curves may be unproductive or contain residual oil. Residual oil refers to oil that remains in the reservoir after primary extraction methods have

![Fig. 5. (a) Gas analysis of A/R ‘G’ Member (6600–7044 ft), Azhar-A-2 well. (b) Gas analysis of A/R ‘G’ Member (6300–7300 ft), Azhar-E–1X well.](image)
been applied; the gas–oil contact is determined by these crossover points.\textsuperscript{29} The depth or location at which the curves cross over indicates the level in the reservoir where the transition from gas to oil occurs.\textsuperscript{29} Geologists and reservoir engineers can determine the oil–water contact by determining a sharp increase in the wetness ratio and the corresponding changes in hydrocarbon composition, which indicates the presence of water in the reservoir.\textsuperscript{29} Understanding the scope of oil-bearing zones and developing efficient production methods are made easier with the use of the oil–water contact (OWC), which is a vital parameter for reservoir management.\textsuperscript{24} The integration between Wh and Bh ratios shows separation between them, which indicates two possible oil shows in the Cretaceous succession (A/R ‘G’ Member and Upper Bahariya Formation). Based on petrophysical cutoffs, the net pay zones are extrapolated from mud logging data analyzed from Azhar A-2 well and Azhar E-1X well. The Wh in the lower part of A/R ‘G’ Member of Azhar A-2 well is between 17.5 and 40 and (Ch) greater than or equal to 0.5 with (Bh) less than 17.5, where Wh greater than Bh, indicating the presence of oil through the interval of 6725–7040 ft\textsuperscript{24} (Fig. 5a). The Wh in the upper part of A/R ‘G’ Member of Azhar A-2 well is greater than 40 and (Ch) greater than or equal to 0.5 with (Bh) less than 17.5, where
Wh greater than Bh, indicating the presence of oil/heavy oil through the interval of 6610–6720 ft$^{24}$ (Fig. 5a). The Wh in the lower part of A/R ‘G’ Member of Azhar E–1X well is between 17.5 and 40 and (Ch) greater than or equal to 0.5 with (Bh) less than 17.5, where Wh greater than Bh, indicating the presence of oil through the interval of 6560–7360 ft$^{24}$ (Fig. 5b). The Wh in the upper part of A/R ‘G’ Member of Azhar E–1X well is greater than 40 and (Ch) greater than or equal to 0.5 with (Bh) less than 17.5, where Wh greater than Bh, indicating the presence of oil/heavy oil through the interval of 6300–6550 ft$^{24}$ (Fig. 5b).

Based on petrophysical cutoffs, the net pay zones are extrapolated from mud logging data analyzed from Azhar A-2 well and Azhar E–1X well. The Wh of the Upper Bahariya Formation of Azhar A-2 well is greater than 40 and Ch greater than or equal to 0.5 with (Bh) less than 17.5, where Wh > Bh, indicating the presence of oil/heavy oil through the interval of 6300–6550 ft$^{24}$ (Fig. 5b).

Fig. 7. Gas analysis of Upper Bahariya Formation (7300–7850 ft), Azhar-E–1X well.
7044–7450 ft\textsuperscript{24} (Fig. 6). The Wh in Upper Bahariya Formation of Azhar E–1X well is greater than 40 and (Ch) greater than 0.5 with (Bh) less than 17.5, where Wh greater than Bh, indicating the presence of oil/heavy oil through the interval of 7364–7840 ft\textsuperscript{24} (Fig. 7).

In the Earth’s crust, organic matter generally changes into hydrocarbons when it is heated and compressed. You could observe a larger C\textsubscript{1}/C\textsubscript{2} ratio at lower thermal maturity levels, which indicates that methane predominates over ethane.\textsuperscript{30} The C\textsubscript{1}/C\textsubscript{2} ratio decreases as thermal maturity increases because there is usually a greater conversion of organic matter into heavier hydrocarbons.\textsuperscript{31} When discussing oil and gas, the ratio of methane (C\textsubscript{1}) to ethane (C\textsubscript{2}) in the hydrocarbon composition is commonly referred to as the C\textsubscript{1}/C\textsubscript{2} ratio. In geochemistry and petroleum exploration, this ratio is important for understanding the properties of the hydrocarbons present in reservoirs.\textsuperscript{32} This ratio is widely used by the oil and natural gas sectors as a diagnostic tool to identify the kind and maturity of organic matter responsible for producing hydrocarbons in a particular geological formation. It is possible to determine from the ratio whether the hydrocarbon in a specific reservoir originates from a source rock that underwent high or low thermal maturity. The hydrocarbon composition’s methane (C\textsubscript{1}) to ethane (C\textsubscript{2}) ratio, or C\textsubscript{1}/C\textsubscript{2} ratio is less commonly used in the study of crude oil, the C\textsubscript{1}/C\textsubscript{2} ratio is more frequently associated with natural gas.\textsuperscript{24} When discussing crude oil, the distribution of different hydrocarbon compounds, like aromatic hydrocarbons, cycloalkanes, and alkanes, is frequently more important than an accurate C\textsubscript{1}/C\textsubscript{2} ratio. An understanding of the geological conditions of the hydrocarbon’s formation and the thermal maturity of the source rock can be derived from the C\textsubscript{1}/C\textsubscript{2} ratio.\textsuperscript{24} Methane typically makes up the majority of the composition of natural gas reservoirs; this percentage can range from roughly 70–90\% or more. These percentages, however, may differ depending on a number of variables, including the reservoir’s geology, the source rock’s thermal maturity, and the existence of other hydrocarbons and nonhydrocarbon gases.\textsuperscript{33} A lower C\textsubscript{1}/C\textsubscript{2} ratio in natural gas indicates higher thermal maturity of the source rock. This implies that the hydrocarbons originated from organic matter that has been subjected to greater heat and pressure. Ethane (C\textsubscript{2}) is a heavier hydrocarbon than methane (C\textsubscript{1}), and its presence in higher proportions relative to methane indicates a greater level of thermal maturity.\textsuperscript{24} When the C\textsubscript{1} is slightly higher than the C\textsubscript{2} where the higher percentage of C\textsubscript{1} is slightly due to the biodegradation processes. Because the C\textsubscript{2}–C\textsubscript{5} hydrocarbon gases dissolve more readily in oil, the gas phase is enriched in C\textsubscript{1} and less so in C\textsubscript{2} and C\textsubscript{3}. Therefore, high C\textsubscript{1} content does not always imply a high maturity or a biogenic origin; this high

![Fig. 8. Statistical analysis of the Upper Kharita Formation core data in Azhar-A-2 well: (a) helium porosity, (b) fluid porosity, (c) horizontal permeability, (d) vertical permeability.\textsuperscript{27}](image)
percentage of $C_1$ gives a misinterpretation about the gas origin.\textsuperscript{33}

In the A/R ‘G’ Member and Upper Bahariya Formation, the wetness ratio is higher than balance ratio that indicates oil shows. We used the $C_1/C_2$ ratio as a rapid indicator to format the oil net pay.\textsuperscript{12–24} According to,\textsuperscript{13} the $C_1/C_2$ ratio in the lower part of the A/R ‘G’ Member of Azhar A-2 well and Azhar E–1X well is between 3 and 7, indicating the presence of oil,\textsuperscript{24} meaning that if the $C_1/C_2$ ratio is lower than 10 indicating oil and if $C_1/C_2$ ratio is higher than 10, it indicates on gas presences.\textsuperscript{13} The $C_1/C_2$ ratio in the upper part of the A/R ‘G’ Member of Azhar A-2 and Azhar E–1X well is between 2 and 5, indicating the presence of oil/heavy oil (Fig. 5a–b), this differentiation between the $C_1/C_2$ ratio of upper and lower A/R ‘G’ parts indicates that the more maturity increases, the more the $C_1$ decreases and $C_2$ increases, so the $C_1/C_2$ ratio decreases (Fig. 5a–b). The $C_1/C_2$ ratio in Bahariya Formation of Azhar A-2 and Azhar E–1X wells is between 2 and 7.7, indicating the presence of oil (Figs. 6 and 7). These results confirmed by $Ch$ that is greater than or equal to 0.5. The contact between oil and heavy oil to be indicated perfectly, we should use measurements of formation pressure and fluid gradient changes.\textsuperscript{13} Both A/R ‘G’ Member and Bahariya Formation in the studied two wells show that $C_1/C_3$ ratio is higher than $C_1/C_2$ ratio, which assured that both A/R ‘G’ Member and Bahariya Formation are not wet-water (Figs. 5–7).

### 4.3. Statistical analysis of Upper Kharita Formation core data

Upper Kharita Formation characterization (7835–7900 ft) deduced by the relationship between porosity and permeability and its statistical analysis, which indicated that Upper Kharita Formation in Azhar-A2 well has helium porosity values of maximum frequency (63%) in the histogram of fair porosity and minimum frequency (21%) in the histogram of good porosity, which has a 10.9% value of the mean and 4.46% value of the standard deviation (Fig. 8a).\textsuperscript{27} The fluid porosity has a value of maximum frequency (63%) in the histogram of negligible porosity and a value of minimum frequency (41% in the histogram of poor porosity), which has a 9.4% value of the mean and a 5.4% value of the standard deviation. According to porosity measurements, the Upper Kharita Formation is an inhomogeneous reservoir with fair-to-good porosity (Fig. 8b).\textsuperscript{27}

The horizontal permeability has values of maximum frequency (54%) in the histogram of fair permeability and minimum frequency (1%) in the histogram of excellent permeability, which has a 103.8 mD value of mean and 217.15 mD value of standard deviation (Fig. 8c).\textsuperscript{27} The vertical permeability has values of maximum frequency in the histogram of fair permeability with minimum frequency in the histogram of very good permeability, which has a 53.24 mD value of mean and 92.82 mD...
value of standard deviation (Fig. 8d). The statistical analysis of permeability data depicts that the Upper Kharita Formation is an inhomogeneous reservoir with fair permeability.

4.4. The helium porosity–horizontal permeability cross-plot

The helium porosity–horizontal permeability cross-plot shows an increasing trend for the sandstone, shaly sandstone, sandstone, and shale facies (Fig. 9a). These facies have a very strong correlation coefficient (0.89) that shows that the permeability can be calculated using the least-squares method, where

\[ K_{\text{horizontal}} = 10.3739 \times \log \Omega_{\text{helium}} + 10.6638 \]

The values of helium porosity and horizontal permeability for the shaly siltstone and siltstone/shale interbed are scattered, with no direct relation to the 52 main sandstone facies’ trend. This indicates that both the shaly siltstone and siltstone/shale interbed facies are nonreservoirs.

4.5. The grain density–helium porosity cross-plot

The grain density–helium porosity cross-plot shows that the sandstone, shaly sandstone, sandstone, and shale facies have grain density values around 2.65 gm/cc with helium porosity value greater than 9% (0.09 decimal) (Fig. 9b). The shaly siltstone and siltstone/shale interbed facies have grain density values higher than 2.65 gm/cc with helium porosity value lower than 9% (0.09 decimal). It can be concluded that the value of 9% (0.09 decimal) porosity is considered the cutoff for reservoir facies in the Upper Kharita Formation.

4.6. Helium- and fluid porosity cross-plot

The integration between helium and fluid porosities in the Upper Kharita Formation is indicated by the positive increasing trend. The helium porosity of our samples is higher than its fluid porosity because of the effectiveness of fractures and bedding pores, which indicate a variety of pore spaces in core samples (micropores and macropores). Because of the high correlation coefficient (0.76) of each parameter, it indicates the high quality of the reservoir (Fig. 9c).

4.7. Vertical and horizontal permeability

The cross-plot of vertical and horizontal permeability in the Upper Kharita Formation shows a positive increased trend (Fig. 9d). The horizontal permeability of the samples is higher than the vertical permeability, which indicates a variety of pore spaces in core samples (micropores and macropores) and indicates that the reservoir is inhomogeneous. The relationships between horizontal and vertical permeabilities show a high correlation coefficient of 0.89.
4.8. Neutron density for the determining lithology of the Upper Kharita Formation

The cross-plot of neutron density can be used to define the lithology of the Upper Kharita Formation in the Azhar-A2 well. The Upper Kharita Formation is a slightly clean to slightly argillaceous sandstone reservoir. Neutron and density values indicated that reservoir facies exist along the sandstone lithology trend, with shifting in the southeast direction toward the limestone–dolomite direction because of the high shale content (Fig. 10).

4.9. Gas chromatographic analysis of the Upper Kharita Formation

Based on petrophysical cutoffs, the net pay zones are extrapolated from mud logging data analyzed from the Azhar A-2 well. The wetness ratio of the Upper Kharita Formation of Azhar A-2 well is greater than 40 and character ratio is greater than or equal to 0.5 with a balance ratio less than 17.5, where Wh greater than Bh, indicating the presence of oil/heavy oil through the interval of 7835–7900 ft (Fig. 11). In the Upper Kharita Formation, the wetness ratio is higher than the balance ratio that indicates oil shows. We used the \( \frac{C_1}{C_2} \) ratio as a rapid indicator to format the oil net pay\(^{12-24} \) (Fig. 11). According to\(^{13} \) the \( \frac{C_1}{C_2} \) ratio of Upper Kharita Formation in Azhar A-2 well is between 1.5 and 7, indicating the presence of oil\(^{24} \) (Fig. 11). Upper Kharita Formation in the studied Azhar A-2 well shows that the \( \frac{C_1}{C_4} \) ratio is greater than \( \frac{C_1}{C_3} \) ratio, which assures that Upper Kharita Formation is not wet-water.

4.10. Conclusions

The petrophysical assessment of Cretaceous succession (late Albian–Cenomanian) indicated a presence of three reservoirs (A/R ‘G’ Member, Upper Bahariya, and Upper Kharita formations). We petrophysically studied A/R ‘G’ Member and Upper Bahariya Formation by using the well-logging implications and Upper Kharita Formation is petrophysically studied by using conventional core data.

A/R ‘G’ Member showed a very thin net pay zone, but the mud logging analysis shows gases indicating the presence of oil in its lower parts and showing the presence of oil/heavy oil in its upper part in the two wells (Azhar A-2 and Azhar E–1X). Upper Bahariya Formation is the most important effective reservoir in the Cretaceous succession where the net pay zone is characterized by 12 ft thickness, 27% effective porosity, and 44% \( S_w \) in Azhar A-2 well, whereas in the case of Azhar E–1X well, the net pay zone is characterized by 20 ft thickness, 20% effective porosity, and 22% \( S_w \). The gas chromatographic analysis of the hydrocarbon content of the Upper Bahariya Formation indicated the presence of oil/heavy oil.

The Upper Kharita Formation using core data analysis is characterized as an inhomogeneous
reservoir with fair-to-good porosity and with fair permeability, where the gas chromatographic analysis of the hydrocarbon content of the Upper Kharita Formation indicates the presence of oil/heavy oil.

Authors contribution

All authors were equally contributed.

Funding

The authors extend their appreciations to Hurghada Faculty of Education, South Valley University for funding the present work.

Conflicts of interest

There are no conflicts of interest.

Acknowledgment

The authors would like to thank the EGPC and Khalda Petroleum Company for allowing them to use the geochemical and petrophysical data for the wells that are being investigated for this study.

References