Reservoir characteristics of some Cretaceous sandstones, North Western Desert, Egypt

Mohamed A. Kassab a,*, Abdou A. Abdou a, Nader H. El Gendy b, Mamdouh G. Shehata a, Abeer A. Abuhagaza a

a Egyptian Petroleum Research Institute (EPRI), El Zohour Region, Nasr City, Cairo 11727, Egypt
b Tanta University, Tanta, Egypt

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Abstract The present study aims to reveal diagenetic processes and reservoir characteristics of the subsurface Cretaceous (Upper and Lower) sandstones at the North Western Desert of Egypt at four wells namely Gibb Afia-1, Betty-1, Salam-1X and Mersa Matruh-1.

Petrographic observations and statistical analysis of petrophysical data of forty-five subsurface Cretaceous sandstone samples reflect good reservoir characteristics in some intervals due to high porosity (varies up to more than 27%) and permeability (varies up to more than 826 mD). In other intervals, they reflect fair to bad reservoir characteristics due to low porosity (reaches a value of 6.25%) and permeability (reaches a value of 0.01 mD), caused by matrix and diagenesis processes.

FZI (flow zone indicator) and R35 (pore aperture corresponding to the mercury saturation of 35% pore volume) were calculated from the measured porosity and permeability, by defining FZI and R35, four hydraulic flow units (HFU1, HFU2, HFU3 and HFU4) in a reservoir have been identified. HFU1 is distinguished by FZI values that lie between 3.71 and 8.11 m, meanwhile, the values of R35 are greater than 10 m. HFU2 is marked where the FZI values are between 1.32 and 3.70 m, while the values of R35 are between 2 and 10 m. HFU3 is noticed where FZI shows values between 0.40 and 1.31 m, while the values of R35 are between 0.5 and 2 m. The HFU4 is evaluated where FZI values are between 0.06 and 0.39 m, and the R35 values are less than 0.5 m.

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1. Introduction

The North Western Desert of Egypt has been recognized as a region of simple surface geological features, which conceal beneath it more complicated geological structures, in addition to different basins and sub-basins [1]. Many geological, as well as mineralogical and sedimentological researches...
have been carried out on the North Western Desert, [26,11,22,9,12,24,7,15].

The Cretaceous rocks in the study area (Fig. 2A and B) are divided into lower and upper units. The lower unit is made up of Lower Cretaceous clastics rocks, while the upper unit is composed mainly of carbonates rocks [24]. These rock units from base to top are Alam El Bueib Formation (Neocomian – Early Aptian), Alamein Formation (Early Cretaceous – Middle Aptian), Dahab Formation (Aptian – Early Albian), Kharita Formation (Early Cretaceous – Albian), Bahariya Formation (Early Cenomanian), Abu Roash Formation (Late Cenomanian – Santonian), and Khoman Formation (Santonian – Maestrichtian). A brief description of these units was mentioned by Kassab et al. [15].

The Cretaceous rocks (Aptian and Cenomanian–Turonian) deposited on Palaeo-highs under relatively high energy conditions are the main hydrocarbon reservoirs of the Western Desert [24]. The study of the subsurface Cretaceous sandstone rock samples at the northern part of the Western Desert is most interesting due to their high hydrocarbon potentiality. The present study aims to reveal the diagenetic processes and the reservoir characteristics of the subsurface Lower and the Upper Cretaceous sandstones at the North Western Desert, in terms of evaluate their hydrocarbon potentiality. The present work has been carried out for 45 samples belonging to four wells namely; Gibb Afia-1, Betty-1, Salam-1X and Mersa Matruh-1, which are located between latitudes 29° 37' 59" N & 31° 19' 43" N and longitudes 26° 20' 12" E & 27° 26' 45" E, (Fig. 1).

2. Samples and methods

Forty-five (45) sandstone samples were collected from the studied two Cretaceous rock units (20 samples from the Upper Cretaceous and 25 from the Lower Cretaceous). Petrographic and petrophysical investigations have been conducted on these samples. Thin sections and scanning electron microscope of core samples are used to identify the mineralogical composition, diagenetic processes and depositional environments. Thin section preparation involved vacuum impregnation with blue epoxy to facilitate the recognition of porosity types. The petrographical study is based mainly on the microscopic examination of thin sections of the studied Cretaceous sandstone rock samples. The scanning electron microscopic analysis was performed on selected fifteen (15) samples by the scanning electron microscope (SEM) model (JEOL JSM – 5300) at the Egyptian Petroleum Research Institute.

Petrophysical measurements were carried out for forty-five (45) core samples at room temperature and ambient pressure at the Egyptian Petroleum Research Institute. The studied samples have been drilled into cylinders of about 2.54 cm in diameter and up to 3.00 cm length for the petrophysical measurements. These cylindrical samples were cleaned and then dried at a temperature of 85 °C for 10 h.

![Figure 1](http://dx.doi.org/10.1016/j.ejpe.2016.05.011)
Reservoir characteristics of Cretaceous sandstones

Figure 2  (A) A composite Lithostratigraphic Column of the Northern Part of the Western Desert (after Schlumberger, 1984 [23] and 1995 [24]). (B) Stratigraphic successions of Cretaceous in Betty-1, Gibb Afia-1, Salam-1X and Mesa Matruh-1 wells (after Kassab et al., 2013 [15]).
The bulk density \( (r_b) \) of rock samples was measured using direct methods for geometrical shapes (cylindrical plugs), where the bulk volume \( (V_b) \) and dry weight of the core samples \( (W_d) \) were measured using a precision caliper \((0.1 \text{ mm precision})\) and an electronic balance \((0.1 \text{ mg precision})\).

The measured rock bulk density \( (r_b) \) was calculated as:

\[
r_b = \frac{W_d}{V_b}
\]  

Helium prosimeter was used to determine the porosity. The rock porosity \( (\theta) \) has been determined using both matrix-cup
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helium prosimeter (Heise Gauge type) for grain volume estimation and DEB-200 instrument, which follows Archimedes law for bulk volume determination. The grain density (\( \sigma_g \)) was determined by the product of porosity measurements using the following equation:

\[
\sigma_g = \frac{W_a}{V_g}
\]

where \( V_g \) is the volume of rock grains, which can be calculated according to the following equation:

\[
V_g = V_b - V_p
\]

where \( V_b \) is the volume of the pores.

Permeability (K) was measured using Core Lab Permeameter. Permeability (K) was measured by the following equation:

\[
K = \frac{Q\mu L}{A\Delta P}
\]

where \( K \) is the permeability factor, milli Darcy, \( Q \) is the rate of flow, cm\(^3\)/sec, \( \mu \) is the viscosity, centipoises, \( P \) is the pressure gradient, atm./cm, \( A \) is the cross section area, cm\(^2\) and \( L \) is the length, cm.

Each distinct reservoir unit has a unique flow zone indicator (FZI), reservoir quality index (RQI) and normalized porosity index (NPI) values [2]. The combination of porosity and permeability data in terms of flow zone indicator, reservoir quality index and normalized porosity index is convenient to use with routine core analysis data. The concept of Amaefule, et al. [3] is based on the calculation of two terms, RQI and NPI as defined below:

\[
RQI = 0.0314 \times \sqrt{\frac{k}{\varnothing}}
\]

\[
NPI = \frac{\varnothing}{(1 - \varnothing)}
\]

\[
FZI = \frac{RQI}{NPI}
\]

\[
\log(RQI) = \log(FZI) + \log(NPI)
\]

where \( K \) is the permeability (mD), \( \varnothing \) is the effective porosity (fraction), NPI is the ratio of pore volume to grain volume and RQI & FZI are in microns.

R35 was calculated according to the Winland equation that was used and published by Kolodize [16], shown in equation below:

\[
\log R35 = 0.588 \log K_{air} - 0.864 \log \varnothing + 0.732
\]

where R35, \( \mu \)m is the pore aperture radius corresponding to the 35 percentile, \( K_{air} \) is the uncorrected air permeability (mD), and is porosity (%). Four petrophysical flow units (Megapor flow units, Macroport flow units, Mesoporth flow units and Microport flow units) with varying reservoir performances are distinguished by comparable ranges of R35 [17].

3. Results

Petrographic and petrophysical investigations have been conducted on forty-five (45) Cretaceous sandstone samples. Petrographic observations and the statistical analysis of petrophysical data reflect good reservoir characteristics in some intervals due to high porosity and permeability, while in some other intervals they reflect fair to bad reservoir characteristics due to low porosity and permeability caused by matrix and diagenetic processes. Porosity decreases due to cementation and compaction caused by continuous deposition. However, porosity preservation may attribute to early partial carbonate and silica cementation [8] and the presence of clay coating, ([10,18]).

The emplacement of oil has been suggested to inhibit diagenesis by limiting both cementation and chemical compaction [21]. Moreover, enhancement of secondary porosity in sandstones occurs due to the dissolution of framework grains and cements ([6,25]).

3.1. Petrographic analysis

Petrographic examination of the studied Cretaceous sandstones [Plate 1 (PL.1) and Plate 2 (PL.2)] reveals an occurrence of the following types of sandstones: ferruginous quartz wacke (Pl.1-1), quartz arenite (Pl.1-2), ferruginous quartz arenite (Pl.1-3; Pl.1-6; Pl.2-5; Pl.2-8), ferruginous calcareous quartz arenite (Pl.2-1), quartz wacke (Pl.2-2), gypsiferous quartz arenite (Pl.2-3), ferruginous calcareous quartz wacke (Pl.2-4) and laminated quartz arenite/quartz wacke (Pl.2-6).

3.2. Factors controlling rock properties

Diagenetic processes “include all the processes which start immediately after the deposition of the loose sediments and continue till metamorphism”. From the petrophysical point of view, the diagenetic processes are of great importance due to its effect on the composition and texture of sedimentary rocks, i.e. due to its enhancing or reducing impacts on the pore volume, fluid flow efficiency, and petrophysical potentiality of the studied samples.

Porosity is affected to a great extent by diagenetic changes. Evidences of these changes were detected in the studied Cretaceous sandstones. The identified diagenetic processes have either resulted in a decrease or an increase in porosity and therefore diminished or improved the reservoir potentiality. Nabawy and Kassab [19] mentioned that dissolution and leaching out, as well as fracturing are the most important porosity-enhancing processes. On the other hand, cementation, compaction, pressure solution, authigenic clay minerals, and aggrading neomorphism are the most important porosity-reducing diagenetic processes.

Diagenetic processes that reduce porosity include filling of pore spaces with clays either infiltrated (Pl.1-1; Pl.2-2; Pl.2-4) and/or authigenic (Pl.1-4, Pl.2-7), quartz overgrowth (Pl.1-2) and authigenic calcite (Pl.1-5). The cementation includes patchy and uniform calcite (Pl.2-1); iron oxides as coatings, patches and fracture filling by ferrigenous material (Pl.1-6). The compaction is represented by concavo-convex and suture contacts of grains (Pl.1-2). On the other hand; porosity was enhanced by fracturing (Pl.2-6), leaching (Pl.2-2) and dissolution of grains (Pl.1-7, Pl.1-8, Pl.2-4).

From the resultant data of petrographic investigation and diagenetic processes, the Lower Cretaceous sandstones are characterized by a lesser degree of textural maturity, fracturing, leaching and oversize pores while Upper Cretaceous sandstones are more mature, dominated by dissolution and development of authigenic minerals. Based on these results,
it is expected that Lower Cretaceous sandstones are of better reservoir quality than Upper Cretaceous sandstones. The degrees of textural maturity of sands are based on roundness, grain size distribution (sorting) and percentage of detrital clay matrix [13].

3.3. Petrophysical properties

Petrophysically the studied samples can be classified into two petrophysical groups by taking the age of rocks into consideration; group 1 (Lower Cretaceous sandstones group) and group 2 (Upper Cretaceous sandstones group). The variety of petrophysical measurements, which were carried out on the studied samples are compiled in Table 1. Numbers of petrophysical relationships are introduced to follow up the impacts of diagenetic processes on petrophysical behavior of the studied sandstone rock samples.

3.3.1. Bulk density (\(\rho_b\)) – porosity (\(\varnothing\)) relationships

In the present study, bulk density–porosity relationships for the studied samples of the Lower and the Upper Cretaceous sandstones are shown in Fig. 3. These relationships are excellent inverse relations characterized by high and reliable coefficient of correlations of \(r = 0.99\) and 0.98, respectively. This linear relationship may be due to similar mineralogical composition, grain shape, packing and fabric; therefore the pore framework is expected to be uniform and homogeneous. The bulk density–porosity relationships in these figures are linear and controlled by the following equations

\[
\rho_b = 2.712 - 2.969 \varnothing, \text{ for Lower Cretaceous sandstones}
\]

(10)

\[
\rho_b = 2.766 - 3.164 \varnothing, \text{ for Upper Cretaceous sandstones}
\]

(11)

3.3.2. Permeability (k) – porosity (\(\varnothing\)) relationships

Permeability-porosity cross plot for the studied samples are shown in Fig. 4. The data points in the figure show different positive trends between the porosity and permeability, which are characterized by correlation coefficients of \(r = 0.59\) and 0.83 respectively. The equations representing these relations are

**Plate 1** Upper Cretaceous Sandstones. (1) Ferruginous quartz wacke, showing very fine to medium, subrounded to rounded, ill sorted quartz grains. Betty-1 well, depth 1047 m, core 10, S.No 14, (PPL). This is an immature sedimentary texture (sample contains > 5% detrital clay matrix) with bi-modal grain size distribution. In addition, coarser grains are poor sorted and angular [13]. (2) Quartz arenite, showing medium, point, elongated and concavo-convex contacts of quartz grains and silica overgrowth. Salam-1X well, depth 1884 m, core 2, S.No. 13, (CN). It is a mature rock (no clay matrix, subrounded to rounded, well sorted quartz grains). (3) Photomicrograph showing very fine-grained quartz with some glauconite cemented by calcite and iron oxide and porosity is mainly intergranular. Salam-1X, depth 1879 m, core 1, S.No. 19, (PPL). (4) SEM photomicrograph, showing, authigenic kaolinite booklets Salam-1X, depth 1878 m, core 1, S.No. 21. (5) SEM photomicrograph showing quartz grain with calcite, Salam-1 X, depth 1873 m, core 1, S.No. 27. (6) Photomicrograph showing fracture filling by ferruginous material. Mersa Matruh-1 well, depth 1465 m, core 11, S.No. 17, (PPL). (7) SEM Photomicrograph, showing quartz dissolution. Salam-1X, depth 1892 m, core 2, S.No. 8. (8) SEM Photomicrograph, showing microcline alteration. Salam-1X, depth 1878 m, core 1, S.No. 21.
Plate 2  Lower Cretaceous Sandstones. (1) Photomicrograph of ferruginous calcareous quartz arenite, showing subangular quartz grains, point, elongated, and concavo–convex contacts and the calcite cement corroded quartz grains. Gibb Afia-1 well, depth 1389 m, core 24, S.No. 3, (CN). (2) Quartz wacke showing silty size and good porosity formed due to leaching of detrital clays. Gibb Afia-1 well, depth 1284 m, core 21, S.No. 5, (PPL). (3) Gypsumiferous quartz arenite, showing rounded quartz grains, and gradation in size from medium to fine grains. Betty-1 well, depth 3014 m, core 29, S.No. 1, (CN). (4) Ferruginous calcareous quartz wacke, showing very fine to coarse quartz grains, well rounded in clay matrix and good porosity (oversize and intragranular) caused by porosity due to voids within the rock grains. Porosity due to dissolution of detrital grains. Betty-1 well, depth 2755 m, core 27, S.No. 4, (PPL). (5) Photomicrograph showing quartz grains cemented with clay and ferruginous material, microporosity was detected. Betty-1 well, depth 2535 m, core 25, S No. 8, (PPL). (6) Laminated quartz arenite/quartz wacke showing very fine sandstone and siltstone, clay matrix with channel and fracture porosities. Mersa Matruh-1 well, depth 2497 m, core 21, S.No. 8, (PPL). (7) SEM Photomicrographs, showing illite in sandstone, it occurs as elongated filaments growing in pore spaces, Betty-1 well, depth 2758 m, core 28, S.No. 3. (8) Photomicrograph of ferruginous calcareous quartz arenite, showing fine rounded quartz grains and glauconite cemented with calcite. Iron oxides are coating the quartz grains. Mersa Matruh-1 well, depth 1590 m, core 12, S.No. 16, (PPL).

Table 1  Compilation of minimum, maximum, average values, and standard deviation of petrophysical parameters of some Cretaceous sandstone samples.

<table>
<thead>
<tr>
<th>Petrophysical parameters</th>
<th>Lower Cretaceous sandstones</th>
<th>Upper Cretaceous sandstones</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Min.</td>
<td>Max.</td>
</tr>
<tr>
<td>σb</td>
<td>1.92</td>
<td>2.54</td>
</tr>
<tr>
<td>σg</td>
<td>2.61</td>
<td>2.76</td>
</tr>
<tr>
<td>Ø%</td>
<td>6.25</td>
<td>27.57</td>
</tr>
<tr>
<td>K, mD</td>
<td>0.01</td>
<td>826.52</td>
</tr>
<tr>
<td>RQI</td>
<td>0.01</td>
<td>2.02</td>
</tr>
<tr>
<td>NPI</td>
<td>0.07</td>
<td>0.38</td>
</tr>
<tr>
<td>FZI</td>
<td>0.06</td>
<td>8.11</td>
</tr>
<tr>
<td>R35</td>
<td>0.05</td>
<td>21.10</td>
</tr>
</tbody>
</table>

Where; 
K is the permeability (mD), Ø is the porosity (%), σg is the grain density (g/cm³) σb is the bulk density (g/cm³), RQI is the reservoir quality index (μm), NPI is the normalized porosity index, FZI is the flow zone indicator (μm) and R35 is the pore aperture corresponding to the mercury saturation of 35% pore volume.
3.3.3. Reservoir quality index (RQI) – porosity (Ø) and permeability (k) relationships

The reservoir quality index (RQI, μm) values of the studied Cretaceous sandstone samples are directly related to the porosity (Fig. 5). Porosity and reservoir quality index relationship for the Lower Cretaceous sandstones has a fair correlation coefficient ($r = 0.51$), while for the Upper Cretaceous sandstones it has a good correlation coefficient ($r = 0.80$), the equations representing these relations are:

$$\ln(RQI) = 14.790 \cdot Ø - 4.367, \text{ for the Lower Cretaceous sandstones}$$

$$\ln(RQI) = 20.899 \cdot Ø - 5.759, \text{ for the Upper Cretaceous sandstones}$$

The reservoir quality index is directly related to the permeability (Fig. 6) with excellent correlation coefficient ($r = 0.996$ and $0.998$), respectively. These relations are closed relationships, the equations representing these relations are

$$\ln(RQI) = 0.468 \ln(K) - 2.498, \text{ for the Lower Cretaceous sandstones}$$

$$\ln(RQI) = 0.457 \ln(K) - 2.524, \text{ for the Upper Cretaceous sandstones}$$

3.3.4. Flow zone indicator (FZI) – porosity (Ø) and permeability (K) relationships

Fig. 8, displays Flow zone indicator (FZI) and porosity relationships for the studied sandstone samples as a direct proportional relationship, which is described by the equation

$$\ln(FZI) = 1.012 \ln(Ø) + 1.646, \text{ for the Lower Cretaceous sandstones}$$
Flow zone indicator and permeability relationships (Fig. 9) are direct proportional relationships and can be described by the equations

\[
\ln(FZI) = 0.393 \ln(K) - 0.744, \text{ for the Lower Cretaceous sandstones}
\]

(20)

\[
\ln(FZI) = 0.352 \ln(K) - 0.828, \text{ for the Upper Cretaceous sandstones}
\]

(21)

3.3.5. R35 – porosity (\(\Phi\)) and permeability (\(K\)) relationships

R35 and porosity relationships (Fig. 10) for the studied sandstone samples are direct proportional relationships, which is described by the equation:

\[
\ln(R35) = 15.588(\Phi) - 2.546, \text{ for the Lower Cretaceous sandstones}
\]

(22)

\[
\ln(R35) = 22.925(\Phi) - 4.210, \text{ for the Upper Cretaceous sandstones}
\]

(23)

Fig. 11, displays R35 and permeability relationships as direct proportional relationships, with very high coefficients of correlation (\(r = 0.99\) and \(r = 0.99\)) of both the Lower and the Upper Cretaceous sandstones.

\[
\ln(R35) = 0.533 \ln(K) - 0.629, \text{ for the Lower Cretaceous sandstones}
\]

(24)

\[
\ln(R35) = 0.513 \ln(K) - 0.674, \text{ for the Upper Cretaceous sandstones}
\]

(25)

3.3.6. Flow zone indicator (FZI) – R35 relationships

FZI and R35 relationship (Fig. 12) for the studied sandstone samples are direct proportional relationships, with very high coefficients of correlation (\(r = 0.98\) and \(r = 0.98\)) of both the Lower and the Upper Cretaceous sandstones.

\[
\ln(FZI) = 0.761 \ln(R35) - 0.282, \text{ for the Lower Cretaceous sandstones}
\]

(26)

\[
\ln(FZI) = 0.700 \ln(R35) - 0.363, \text{ for the Upper Cretaceous sandstones}
\]

(27)
4. Discussion

The results of polarizing microscope and scanning electron microscope (SEM) investigations show that the diagenetic signatures that have been observed in the studied sandstones include compaction, cementation, grain fracturing, leaching and dissolution. The diagenetic processes enhancing the porosity are leaching and dissolution of framework silicates. The diagenetic processes reducing the porosity are the effect of detrital clay minerals (Pl.1-1; Pl.2-2; Pl.2-4) and/or authigenic clay minerals (Pl.1-4, Pl.2-7), quartz overgrowth (Pl.1-2) and authigenic calcite (Pl.1-5), compaction and pressure solution.

The porosity evaluation from the petrographical study is mainly primary porosity (intergranular porosity Pl. 1-1; Pl. 1-3) and secondary porosity due to leaching and dissolution of detrital grains and framework silicates [channel, oversize, intragranular and fractures porosities (Pl. 2-2; Pl. 2-4; Pl. 2-5; Pl. 2-6, respectively)] were microscopically identified in the studied Cretaceous sandstone samples. It is obvious that most of the primary porosity was destroyed during the diagenetic history.

The bulk density decreases with increasing porosity, the relationship between the two indicates that the bulk density values are highly affected by the porosity values and the porosity can be predicted from the bulk density with high precision. Fig. 3 shows excellent relationships, with very high coefficients of correlation between the bulk density and rock porosity of both the Lower and the Upper Cretaceous sandstones.

The permeability of most studied rock samples increases with increasing the porosity. The Upper Cretaceous sandstones have low permeability value (52.69 mD) than those of Lower Cretaceous sandstones (123.24 mD), while both of the Upper and the Lower Cretaceous sandstones have approximately the same porosity values (17.03% and 16.90%, respectively). The porosity and permeability are reduced to some extent due to compaction and the presence of quartz overgrowths, clay minerals (kaolinite and illite), and calcite minerals as cement materials.

The relations between permeability and porosity (Fig. 4) are fair and very good for the Lower and the Upper
porosity and permeability (Figs. 5 and 6, respectively) show spaces radii. Due to the effect of the isolated porosity and differences in pore are scattered above and below the best fit lines, this may be and/or increasing the pore throat sizes. A few data points the rock, and means decreasing the amounts of fine contents pathways to flow and therefore increases the permeability of ability. Higher porosity will contain larger pore and connected loci of the Upper Cretaceous sandstones (r = 0.59) means that, the porosity is not the main contributor for the rock permeability values. Also, the presence of fine contents and/or differences in pore throat sizes can reflect such cases of low correlation between them. The very good correlation coefficient of the Upper Cretaceous sandstones (r = 0.83) means that the porosity has a strong influence on the permeability. Higher porosity will contain larger pore and connected pathways to flow and therefore increases the permeability of the rock, and means decreasing the amounts of fine contents and/or increasing the pore throat sizes. A few data points are scattered above and below the best fit lines, this may be due to the effect of the isolated porosity and differences in pore spaces radii.

The relations between the reservoir quality index and both porosity and permeability (Figs. 5 and 6, respectively) show that, the reservoir quality index (RQI) depends mainly on permeability. The reservoir quality index (RQI) average values of the Lower Cretaceous sandstones and the Upper Cretaceous sandstones are 0.46 and 0.30 μm, respectively. The average values of porosity are 16.6 and 16.7 %, respectively, and the average values of permeability are 123.24 and 52.69, respectively. These indicate that, the sandstones of the Lower and the Upper Cretaceous are characterized by high to moderate reservoir quality, respectively.

Core porosity and permeability values were used to calculate RQI, NPI and FZI values for each core sample using Eqs. (5)–(7), respectively.

Flow zone indicator (FZI), a unique parameter for each hydraulic unit, was used to characterize each rock type. The number of hydraulic flow units and mean values of FZI for each HFU were calculated from the measured porosity and permeability. Flow zone indicator (FZI) is an effective parameter in correlating rock and fluid properties and (HFU) technique classified more homogenous areas in the reservoir than other ones [5]. Rocks containing pore lining, pore filling and pore bridging clays as well as fine-grained, poorly-sorted sands tend to exhibit high surface area and high tortuosity, hence low FZI. While, clean, coarse-grained and well-sorted sands exhibit lower surface areas, lower shape factor, lower tortuosity, and higher FZI values [3].

FZI values allow representing the reservoir by subdividing it into hydraulic flow units with specified flow zone indicator. FZI petrophysical classifications can be used to subdivide the reservoir rock into layers; within a layer, the variation of the permeability at a given porosity is small [28]. The HFU method was first defined by Bear [4] as the representative elementary volume of the total reservoir rock within which the geological and petrophysical properties of the rock volume are the same. Hear et al. [14] defined flow unit as a reservoir zone that is laterally and vertically continuous, and has similar permeability, porosity, and bedding characteristic. Flow units are resultant of the depositional environment and diagenetic process [27].

Hydraulic units are related to geological facies distributions [3]. Rock samples with similar FZI values are observed to fall on one line on a log–log plot of RQI and NPI. A clear distinction between clean and argillaceous sand can be obtained through FZI index calculation as clay rich, poorly sorted, fine grained sedimentary rocks have a lower FZI value whereas less argillaceous, coarse grained and well sorted sands have high FZI value. A petrophysical flow unit is defined as an interval of sediment with similar petrophysical properties such as porosity, permeability, water saturation, pore throat radius, storage and flow capacity, that are different from the intervals immediately above and below the reservoir intervals [20].

The FZI for the Lower Cretaceous sandstones ranged from 0.06 to 8.1 μm with a mean value of approximately 1.98 μm and standard deviation value of 2.62. For the Upper Cretaceous sandstones ranged from 0.14 to 4.07 μm with a mean value of approximately 1.12 μm and standard deviation value of 1.27.

In this study, the log–log plot of RQI versus NPI (Fig. 7), yields a straight line with unit slope and its intercept when (NPI = 1) is termed as Flow zone indicator (FZI). FZI petrophysical classifications can be used to subdivide the reservoir rock into layers, the variation of the permeability at a given porosity within in each layer is very small. The FZI values allow representing the reservoir by subdividing it into four hydraulic flow units with specified flow zone indicator.

A weak to fair relationship between FZI and rock porosity (Fig. 8), with a very low and fair coefficients of correlation (r = 0.26 and r = 0.61) for the Lower and the Upper Cretaceous sandstones, respectively. These directly proportional relationships indicate that porosity has slight to moderate effect on FZI for both the Lower and the Upper Cretaceous sandstones, respectively. The FZI depends mainly on permeability, where the coefficients of correlations are 0.94 and 0.96 for the Lower and the Upper Cretaceous sandstones, respectively as shown in Fig. 9.

The relationships between porosity and R35 (Fig. 10) are weak to good relationships with a very low to fair coefficient of correlations (r = 0.47 and r = 0.78) of both the Lower and the Upper Cretaceous sandstones, respectively. This directly proportional relationship indicates that porosity has effect on R35 to some extent. The permeability depends mainly
on R35 (Fig. 11), while the FZI values are directly related to R35 and depend mainly on it.

Petrophysically, the studied sandstones revealed novel classifications of hydraulic flow units (HFUs) based on R35 and FZI values. Four hydraulic flow units (HFU1, HFU2, HFU3 and HFU4) have been distinguished by comparable ranges of R35 and the FZI values. HFU1 is represented by megaport flow units (approximately 11% represent of the reservoir), where the production of medium-gravity crude can readily attain tens of thousands of only a few barrels per day if the zonal thickness and other factors are constant. HFU2 is represented by macroport flow units (approximately 29% of the reservoir), with other constraints held constant, are capable of thousands of barrels of oil production per day. The HFU3 is represented by mesoport flow units (about 13% of the reservoir), which allow only hundreds of barrels of oil per day with the other factors held constant. The HFU4 is represented by microport flow units (about 47% of the reservoir), are decidedly non-reservoir. Key wells with mostly microport flow units make at best only a few barrels of oil per day through pumping.

The flow unit’s properties of the Lower Cretaceous sandstone samples were distributed as in the following table:

<table>
<thead>
<tr>
<th>Number of samples</th>
<th>Megaport flow unit</th>
<th>Macroport flow unit</th>
<th>Mesoport flow unit</th>
<th>Microport flow unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>Percentage (%)</td>
<td>9</td>
<td>11</td>
<td>11</td>
<td>24</td>
</tr>
</tbody>
</table>

The flow unit’s properties of the Upper Cretaceous sandstone samples were distributed as in the following table:

<table>
<thead>
<tr>
<th>Number of samples</th>
<th>Megaport flow unit</th>
<th>Macroport flow unit</th>
<th>Mesoport flow unit</th>
<th>Microport flow unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>Percentage (%)</td>
<td>2</td>
<td>18</td>
<td>2</td>
<td>23</td>
</tr>
</tbody>
</table>

5. Conclusions

1- The studied Cretaceous sandstone samples reflect good reservoir characteristics in some intervals due to high porosity and permeability, while in some other intervals they reflect fair to bad reservoir characteristics due to low porosity and permeability. High reservoir quality in the Lower Cretaceous sandstones is due to diagenetic processes (grain fracturing, leaching and dissolution) that enhanced both the porosity and permeability. On the other hand, the poor reservoir quality in the Upper Cretaceous sandstones is a result of the prevalence of compaction (concavo–convex and suture contacts) and cementation by iron oxides, quartz overgrowths, calcite and detrital and authigenic clays.

2- Four hydraulic flow units (HFU1, HFU2, HFU3 and HFU4) in a reservoir have been identified by defining FZI and R35. HFU1 is distinguished by FZI values that lie between 3.71 and 8.11 μm, meanwhile, the values of R35 are greater than 10 μm. HFU2 is marked where the FZI values are between 1.32 and 3.70 μm, while the values of R35 are between 2 and 10 μm. HFU3 is noticed where FZI shows values between 0.40 and 1.31 μm, while the values of R35 are between 0.5 and 2 μm. The HFU4 is evaluated where FZI values are between 0.06 and 0.39 μm, and the R35 values are less than 0.5 μm.

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