Petrophysical evaluation of sandstone gas reservoir using integrated well logs and core data for the Lower Cretaceous Kharita formation, Western Desert, Egypt

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Abstract

This study aims to evaluate Kharita gas reservoir to enhance the production. The increase in water-cut ratio reduces the left hydrocarbons' amount behind pipe. Accurate determination of pore throats, pores connectivity and fluid distribution are central elements in improved reservoir description. The integration of core and logging data responses is often used to draw inferences about lithology, depositional sequences, facies, and fluid content. These inferences are based on petrophysical models utilizing correlations among tools' responses as well as rocks and fluids properties. Upper Kharita Formation produces gas and condensate from the clastic sandstone in Badr-3 field, western desert of Egypt. It consists mainly of sandstone with shale intercalations. It is subdivided into three sub-units Kharita A, Kharita B and Kharita C that are in pressure communication. Hence, a new further investigation and review for the previously calculated GIIP (gas initially in place) was initiated. The results of this study yielded that the main uncertainty in the volumetric calculations was the petrophysical evaluation; subsequently, a new unconventional petrophysical evaluation approach was performed. The sands thickness in Upper Kharita Formation varies between more than 9 up and more than 61 m with average porosity values range between 0.08 and 0.17 PU while the average permeability values range between 1.89 and 696.66 mD. The average hydrocarbon saturation values range between 46 and 97%. The sands thickness in Upper Kharita Formation varies between more than 9 up and more than 61 m with average porosity values range between 0.08 and 0.17 PU while the average permeability values range between 1.89 and 696.66 mD. The average hydrocarbon saturation values range between 46 and 97%. Reservoir shale cutoff of 55% by using cross-plot between shale volume and porosity (Toby Darling concept) was utilized to discriminate the reservoir from non-reservoir sections. The porosity model was used to calculate reservoir porosity, using the density log. The Archie and saturation/height function models were used to calculate the water saturation and used to calibrate the water saturation in the transition zone. The porosity–permeability (POR-PERM) transform equation was used to estimate the reservoir connectivity (absolute permeability) for the four petrophysical facies (High Quality Reservoir, Moderate Quality Reservoir, Low Quality Reservoir and Highly Shale Reservoir). Core data have shown variations in reservoir quality parameters (porosity and permeability) from one well to the other. Integration of all the reservoir pressures indicated that there are different fluid types (oil, gas and water) in the Upper Kharita Formation level. The saturation/height function model was used to calibrate the saturation in the transition zone. The integration of geological core and geophysical log data helped to conduct a comprehensive petrophysical assessment of Upper Kharita Formation for a better estimation of the reservoir and to achieve a better understanding of the water encroachment in the Upper Kharita reservoir. The big challenge is the determination of the most correct model for calculating porosity, permeability and water saturation in this reservoir of different quality sand. The new petrophysical evaluation resulted in doubling the volumes in Upper Kharita reservoir and so a perforation campaign was performed to confirm the new volumetric calculations, which showed a good match with the model results. Hence, a new well was drilled targeting the low quality sand and found them with high pressure almost near virgin pressure.

Keywords Petrophysical modeling · Reservoir pressure · Capillary pressure · Upper Kharita · Western desert · Egypt

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Introduction

The Kharita reservoir consisted of two accumulations. The upper accumulations are main units (Kharita A, Kharita B and Kharita C) and lower accumulations are main units (Kharita D, Kharita E and Kharita F).

The current study aims to evaluate the petrophysical properties of Upper Kharita Formation in Badr-3 field, Abu El-Gharadig basin, Egypt. It covers the integration of both geological and reservoir data for formation evaluation. That was conducted through evaluating porosity, reservoir connectivity and hydrocarbon potentiality of the reservoir and their impact on field development plans. This study is required to build a better understanding of reservoir behavior to help in future reservoir development opportunities and act as a basis for reserves determination.

The production in Badr-3 field is from the Early Cretaceous Upper Kharita estuarine sandstones at a depth of about 4000 m. The current study is based on the data of four wells (BED3-4, BED3-6, BED3-7A and BED3-10A) in Badr-3 field (Fig. 1). Kharita Formation within the forest is folded into an asymmetrical anticline. Hydrocarbons' accumulations in Upper Kharita Formation consist of a large gas reservoir, with oil rim located only in the eastern side of the anticline which has been explained to be a result of the hydrocarbon migration from the East (El-Toukhy and Bakry 1988). Gas occupies the western side of the anticline as proved by logs and pressure gradients.

During the start of the field life around the year of 1983, only the clean sand stone was interpreted resulted in a calculated GIIP of 881 BCF (billion cubic feet of gas). Based on this calculated GIIP, new wells were drilled in this area targeting the clean sand stone of Upper Kharita Formation. Surprisingly, after more than 30 years of production, the cumulative production of this reservoir exceeded the calculated GIIP which proved that there is more volume than the initially calculated one. Therefore, a new study was initiated over the field and it started with performing a new petrophysical evaluation. The first result of this petrophysical evaluation was finding a lot of sand that was missed in the old one, but this sand was found to be in lower quality than the clean sand stone of Upper Kharita Formation in terms of both porosity and permeability.

The petrophysical characteristics deduced from well-log analysis are generally varied vertically through litho-saturation log plots and horizontally through iso-parametric maps (El-Khadragy et al. 2017). The integration between well logging and core data is a very important tool to evaluate the degree of heterogeneity and storage capacity properties as well as the zone of interest of productivity and perforation (Elnaggar et al. 2018).

After further investigation for the studied sand, it was concluded that the clay content within it is considerably low resulting in the conventional porosity, permeability and water saturation models showed it to be non-reservoir. This derived us to implement new evaluation methods to enhance the reservoir quality which yielded more representative porosity, permeability and water saturation calculations for the field. Based on the new petrophysical evaluation, the initially calculated GIIP increased dramatically and that opened the window for both a perforation campaign to perforate more than 250 m of net gas-bearing sand in the existing wells and to drill further development wells in the field.

Geological setting

The stratigraphic column in the northern western desert (Fig. 2a) is thick and includes succession from recent to Pre-Cambrian basement complex. Total thickness, despite some anomalies, increases progressively to the north-northeast from about 1829 m in the south and reaches up to an estimated 7620 m of section along the coastal area. The stratigraphic section consists of alternating depositional cycles of clastics and carbonate rocks.

Five cycles have been recognized as follows (EGPC 1992):

- I. The clastic facies dominate the oldest sedimentary rocks and include the entire Paleozoic and Lower Jurassic formations.
- II. A carbonate section of Middle and Upper Jurassic formations.
- III. The cycle of clastic comprises the Lower Cretaceous up to the Upper Cretaceous Early Cenomanian.
- IV. From Upper Cenomanian and up to the Middle Eocene, carbonate deposits are again distributed throughout the northern western desert.
- V. The uppermost clastic includes the Upper Eocene–Oligocene, Miocene and younger section.

The Cretaceous mega-sequence is divided into Lower and Upper sequences. The Lower Cretaceous includes Alam El-Bueib, Alamein, Dahab and Kharita Formations, while the Upper Cretaceous sequence incorporates Bahariya, Abu Roash and Khoman formations (Hantar 1990).

The Alam El-Bueib Formation is composed mainly of sandstone with shale interbeds of Barremian–Early Aptian age (Hantar 1990). It is believed to be of continental origin with shallow marginal marine shales that may act as intra-formational seals.

The Alamein Formation is a widespread carbonate unit of Aptian age. It is composed of dolomite with shale and

Fig. 1 Location of Badr-3 field, western desert, Egypt (a) and four selected wells (b) for studying Kharita Formation (Bapetco, Internal Report 2017)

Fig. 2 Stratigraphy of the western desert, the main reservoirs (arrowed) in the Badr-3 field are in the Kharita Formation (Strating and Franssen 2006)

limestone interbeds. Dahab Formation consists of marine shale and channelized sandstone of Late Aptian age.

Kharita Formation is located in Abu El-Gharadig basin, it is one of the five members constituting the Early Cretaceous. This formation extends over most of the western desert. It consists of fine to coarse sandstone with interbeds of grayish green shale and some carbonates. The sandstone is colorless clean white to light gray medium to coarse grained with rounded grains slightly calcareous with traces of glauconite and pyrite (EGPC 1992).

Kharita Formation conformably rests on the Dahab Shale. In wells where the Dahab Shale is absent, it rests on the Alamein Dolomite or the Alam El-Bueib Formation. It underlies everywhere the widely spread Bahariya Formation at the easily recognizable contact provided by the limestone bed, which is persistently present at the base of the Bahariya Formation (Schlumberger 1984).

The average thickness of Kharita Formation is around 400 m with a maximum thickness of 1110 m. It must have accumulated in a local graben. The Kharita is assigned an

Albian to Cenomanian age. The unit was deposited in a high-energy shallow marine shelf. In the extreme north, the unit seems to have been deposited in deeper water, while in the south it was deposited under the influence of continental conditions (EGPC 1992).

During the Albian and earliest Cenomanian, the Kharita Formation (Fig. 2), an important reservoir in the Badr-3 field, was deposited in alluvial and coastal plain environments. Marine conditions returned to the Abu El-Gharadig basin during the early Cenomanian, evidenced by the reworking Kharita Formation sediments.

The Early Cenomanian Bahariya Formation was deposited. It consists mainly of fine-grained sandstones and shale with some thin streaks of limestone deposited in coastal to shallow marine environment.

Abu Roash Formation is divided from the oldest to youngest into Abu Roash G, F, E, D, C, B and A Members (Norton 1967). This formation is Santonian–Maastrichtian in age and is composed of chalky limestone deposited in a deep marine environment (Norton 1967). It is characterized by high porosity and low permeability.

The Mesozoic–Cenozoic tectonic evolution of the northern western desert involved four main phases of deformation. These are a phase of Jurassic–Early Cretaceous rifting, a phase of Cretaceous rifting, a phase of Late Cretaceous–Tertiary basin inversion and post-Dabaa normal faulting (Moustafa et al. 1998). Four different phases affected the area of Abu El-Gharadig basin are:

1. Jurassic rifting.
2. Cretaceous rifting.
3. Late Cretaceous–Tertiary inversion.
4. Post-Dabaa normal faulting.

Data and methods

To investigate the Upper Kharita reservoir rocks and to evaluate its hydrocarbon potential, four wells (BED3-4, BED3-6, BED3-7A and BED3-10A) from Badr-3 fields that were provided by Badr Petroleum Company have been selected. Besides, core data that exist in two wells out of four (BED3-4 and well BED3-6) were also examined.

There are a plenty of open hole logs (gamma ray (GR), resistivity (RES), neutron/density (Neu/Den), caliper (CALI) and sonic (DTC)) for the four wells. The available logs and core data were integrated to perform a dedicated petrophysical assessment of the reservoir.

The core data were utilized to provide the grain density, electrical properties (m, n) and geological description of the reservoir. The interpretation process was performed to obtain reservoir properties (porosity, permeability, water saturation

and net pay portion). The TechLog software was utilized to conduct the formation evaluation.

The volume of shale “Vsh” was used to evaluate the net reservoir lithology and can be calculated by using the following equation (Asquith and Krygowski 2004), and the calculated Vsh curves are illustrated in (Fig. 3)

$$V_{sh} = \frac{GR_{log} - GR_{sand}}{GR_{shale} - GR_{sand}} \quad (1)$$

where GR_{log} is the gamma-ray log reading in the zone of interest corrected for borehole size (API units). GR_{sand} is the gamma-ray log reading in 100% clean sand (API units). GR_{shale} is the gamma-ray log reading in 100% clean shale (API units). V_{sh} is the shale volume from gamma-ray log (Fractional).

The total porosity model was used to estimate the formation storage; porosity has been evaluated from the density logs in the Upper and Lower Kharita using the relationship (Dresser Atlas 1982).

$$\phi = \frac{(\rho_{max} - \rho_{log})}{(\rho_{max} - \rho_f)} \quad (2)$$

where ϕ is the formation porosity, fraction; ρ_{log} is the bulk density (Density log reading), g/cm³; ρ_{max} is the density of the rock matrix, g/cm³; and ρ_f is the density of the saturation fluid, g/cm³.

Average matrix density value of 2.66 g/cm³ was selected from core grain density histogram for Kharita A and 2.67 g/cm³ for Kharita B.

The apparent fluid density represents the density of the mixture of mud filtrate and formation fluid. Due to variations information fluid content (gas, oil and water), different apparent fluid densities were used. The western part has only gas reservoir, and the eastern part has gas and oil rim. The log bulk density versus in situ core porosity cross-plot was used to estimate the apparent fluid density for each case at 1PU on plot and fix the matrix density value on Y axis.

The lithology indicator logs (gamma ray, neutron, density and photo electric) per well indicate different petrophysical facies. The porosity–permeability transforms have been created; the stressed core porosity is plotted against core permeability at the ambient conditions from wells BED3-4 and BED3-6 to general formula per each petrophysical facies. A typical “characteristic relation” will use either power law or exponential models by (Siddiqui et al. 2008).

$$Perm = A * e^{B*Por} \text{ \{Power Law Model\}} \quad (3a)$$

$$Perm = A * e^{B*Por} \text{ \{Exponential Model\}} \quad (3b)$$

Fig. 3 A correlation panel showing calculated shale volume using GR log, Badr-3 field, western desert, Egypt

where Perm is the ambient air permeability in “mD.” Por is the stressed formation total porosity in fraction. A and B are variables.

Our motivation for this work is derived from our observation that many correlations of permeability, porosity and other variables can yield inconsistent and/or inaccurate results—especially for low permeability rock samples.

Archie’s model is used for water saturation calculation. Log-derived porosity and the deep resistivity are used as input for Archie’s models in the following equation (Archie 1942).

$$S_w = \sqrt[n]{\frac{R_w}{\emptyset^m \cdot R_t}} \quad (4)$$

where S_w is the water saturation, fraction; $\emptyset$ is the porosity, fraction; R_w is the resistivity of formation water, ohm.m; R_t is the resistivity of uninvited formation, ohm.m; m is the cementation exponent (usually near 2); n is the saturation exponent (also usually near 2).

The conventional determination of (a) and (m) is based on the following equation (Archie 1942).

$$FF = \frac{a}{\emptyset^m} \quad \text{Log } FF = -m \text{Log } \emptyset + \text{Log } a \quad (5)$$

A plot of log FF (Formation Factor) versus log $\emptyset$ is used to determine “a” and “m” for the core samples. Cementation factor “m” is determined from the slope of the least square fit straight line of the plotted points, while tortuosity factor “a” is given from the intercept of the line where $\emptyset = 1$.

The plot representing all plugs and the slope is “m.” One plug measures one FF and one $\emptyset$.

The classical process to determine saturation exponent (n) is based on the following equation (Archie 1942).

$$RI = S_w^{-n} \quad \text{Log } (RI) = -n \text{Log } (S_w) \quad (6)$$

A plot of log RI (resistivity index) versus log S_w is used to determine “n” for the core samples. Saturation factor “n” is determined from the slope of the least square fit straight line of the plotted points. Every plug measured different water saturation with different resistivity index to calculate on “n” value; all values by all plugs get saturation exponent “n.”

The plot representing just one plug and the slope is n. One plug measures more RI at more S_w values.

Archie’s parameters must be determined for each reservoir, depending on the rock heterogeneity and rock wettability conditions. In a carbonate reservoir as well as in a shaly sandstone reservoir, determination of Archie’s parameters is tedious work due to electrical heterogeneity in the case of carbonate rocks, which can be attributed to the complicated grain pattern distribution, and in the case of shaly sandstone, is mainly due to the local conductivity created by clay minerals. The conventional determination of Archie’s parameters can give acceptable values; however, the results are subjected to assumptions of full water saturation of the core samples in order to get the “a” and “m” parameters, and a homogeneous sample of the same porosity to get the saturation exponent “n” (Hamada 2017).

Capillary pressure reflects the interaction of rock and fluids, and is controlled by the pore geometry, interfacial tension and wettability. It is also employed to infer the free-water level (FWL) from oil transition zone saturation/height relation when validating pressure gradient data for both oil and water legs (Wardlaw and Taylor 1976).

$$P_c = \frac{2\sigma \cos \theta}{r} = (\rho_w - \rho_o)gh \quad (7)$$

where P_c is the capillary pressure; σ is the interfacial tension (fluid property); θ is the contact angle (related to wettability and rock fluid interaction); r is the pore radius (rock property related to permeability and porosity); ρ is the density for water and hydrocarbon (gas or oil); g is the gravitational acceleration; and h is the height above FWL (transition zone).

The J-Leverett function was used for the data averaging at the reservoir conditions. No stress correction has been applied, as the porosity–permeability relationships will be almost the same under the stress conditions, where 0.95 is the porosity stress correction factor (Leverett 1941).

$$S_{wr} = S_w - S_{wi} = aJ^b \quad (8)$$

$$J = \frac{P_c}{\sigma \cos \theta} \sqrt{\frac{\text{Perm}}{\phi}} \quad (9)$$

where P_c is the Capillary pressure; S_w is the Core water saturation; S_{wi} is the irreducible water saturation; S_{wr} is the reducible water saturation; J is the J-Leverett function; Perm is the permeability; $\emptyset$ is the porosity; σ is the surface tension; θ is the contact angle; and a and b are the variables.

The standard values of $\sigma \cos \theta$ for the existing oil/brine system equals 26, while for gas/brine system equals 50.

To measure the current water saturation and the current contact behind the casing run the thermal decay time (TDT) log, which is record of the rate of capture of thermal neutrons in a formation, to measure the captured cross section (SIGMA) ($\Sigma = 4.545/\tau$) ranges between 75 and 450 micro-seconds. The unit for Σ is capture unit (C.U.), which is high in water and low in oil or gas (Olesen et al. 1989).

$$\Sigma = \Sigma_{ma}(1 - \emptyset) + \emptyset \Sigma_w S_w + \emptyset \Sigma_h (1 - S_w) \quad (10)$$

where S_w is the water saturation, fraction; $\emptyset$ is the porosity, fraction; Σ_{ma} is the SIGMA of rock matrix, capture units (C.U.); Σ_w is the SIGMA of formation water, capture units (C.U.); Σ_h is the SIGMA of hydrocarbon, capture units (C.U.).

Results and discussion

Archie model

The values of GR log reading for zones that have been involved in the Archie model are tabulated (Table 1). The calculated Vsh curves for the four wells are illustrated in Fig. 3. Variations in GR derived Vsh value (last green curve) can be noticed. The average values of shale volumes for

Table 1 The actual parameters used to evaluate Vsh of GR log reading

Well name	Zone	GRsand (API)	GRshale (API)
BED 3–4	Kharita A	19	89
	Kharita B	20	86
	Kharita C	27	103
BED 3–6	Kharita A	21	97
	Kharita B	17	78
	Kharita C	22	108
BED 3–7A	Kharita A	21	107
	Kharita B	11	90
	Kharita C	28	108
BED 3–10A	Kharita A	13	87
	Kharita B	15	70
	Kharita C	24	105

different zones are illustrated in (Table 2) together with tops and bottoms of these zones. The shale volume cutoff was calculated using the volume of shale versus porosity cross-plot (Darling 2005) to give a clear distinguish of shales and sands. A shale volume cutoff of 55%, due to the increase of shale, reveals no change in porosity (Fig. 4).

Porosity model

Log-derived porosity values were calibrated to stress core porosity ones, where the data were available. All the available core porosity values were corrected to the in situ conditions, using a correction factor of 0.96, based on special core analysis (SCAL) data from BED3-4 and BED3-6 wells. The stress factor which is used to correct the core porosity values

for reservoir conditions under the overburden pressure was used here to correct the core porosity for Kharita A and B. Special core analysis (SCAL) for BED3-6 covered Kharita A and B includes measurement of porosity and permeability at overburden pressure (Table 3). Correlating the full logs with the cores' porosity and permeability shows a clear difference in the behavior of points on the plot. Correlation panels in Fig. 5 show a perfect match between the calculated porosity values represented by the porosity curve (colored in blue) and the core-derived porosities (red dots). It also shows an excellent match between permeability curves (colored in black) and core-derived permeability values (brown dots). The average porosity value of clean sand (Kharita B) is relatively higher than that of the shaly sand (Kharita A), where it shows about 17% compared to 9% of the later. Similarly, the average permeability value of clean sand (Kharita B) is relatively higher than that of the shaly sand (Kharita A), where it shows about 700 mD compared to 10 mD of the later.

The following grouping (High Quality, Medium Quality, Low Quality and Highly Shale Reservoir) was achieved by correlating the full logs with the core porosity and core permeability as shown in Fig. 5. The relationships between porosity and permeability (Fig. 6) are characterized by correlation coefficients values of $R^2 = 0.51, 0.77, 0.71$ and 0.10 for High Quality, Medium Quality, Low Quality and Highly Shale Reservoir, respectively, and provided the following equations:

$$\text{For High Quality Reservoir, Permeability} = 5.4753 * e^{\theta * 27.223} \quad (11)$$

$$\text{For Medium Quality Reservoir, Permeability} = 0.0836 * e^{\theta * 50.855} \quad (12)$$

Table 2 The average values for volume of shale per unit

Well	Zones	Top (m)	Bottom (m)	Average values of shale Volume
BED3_4	Kharita A	3483.772	3552.616	0.268
BED3_4	Kharita B	3552.616	3619.998	0.226
BED3_4	Kharita C	3619.998	3724.529	0.154
BED3_6	Kharita A	3596.99	3663.863	0.144
BED3_6	Kharita B	3663.863	3718.992	0.11
BED3_6	Kharita B-WATER	3718.992	3736.249	0.101
BED3_6	Kharita C-WATER	3736.249	3795.244	0.178
BED3_7A	Kharita A	3574.86	3648.805	0.254
BED3_7A	Kharita B	3648.805	3714.152	0.087
BED3_7A	Kharita C-WATER	3714.152	3786.047	0.247
BED3_10A	Kharita A	3607.411	3667.688	0.246
BED3_10A	Kharita B	3667.688	3704.979	0.226
BED3_10A	Kharita B-WATER	3704.979	3739.277	0.129
BED3_10A	Kharita C	3739.276	3795.277	0.208

Fig. 4 Shale volume versus porosity cross-plot (0.55 cutoff), Badr-3 field, western desert, Egypt

$$\text{For Low Quality Reservoir, Permeability} = 0.0052 * e^{0.68.567} \quad (13)$$

$$\text{For High Shale Reservoir, Permeability} = 0.0541 * e^{0.18.308} \quad (14)$$

The reservoir permeability values can be calculated for uncored intervals in all wells in the study area using the previous equations. Four porosity–permeability equations were used per different log response by lithology indicator logs (gamma ray, neutron, density and photo electric) per well.

The reservoir water saturation values can be calculated by Archie equation, cementation exponent “m” was calculated from formation resistivity factor (FF) (Table 4), and saturation exponent “n” was calculated from resistivity index (RI) (Table 5). The cementation exponent “m” and the saturation exponent “n” are available in BED3-6 of the Kharita A and Kharita B, where in Kharita A, the average “n” equals $n = 2.12$ and the average “m” equals $m = 1.94$. In Kharita B, the average “n” equals 2.02 and the average “m” equals 1.8 (Fig. 7); the formation water resistivity ($R_w = 0.015$ Ohm.m) was calculated, based on 180–200 Kppm of NaCl water salinity and down hole temperature of 245 F°, by using the RDT pressure tool by using (Schlumberger charts 2013).

In water intervals (Fig. 8) in wells BED3-6 and BED3-10A, the Pickett plot was performed over the intervals (3725–3730 m) and

(3755–3760 m), respectively, by using a fixed $R_w = 0.015$ Ohm.m. The estimated “m=2.4” value from the Pickett Plot was recommended for Archie water saturation (Fig. 8).

Table 6 shows the minimum, average and maximum for porosity, permeability and water saturation for four wells per reservoirs. The sands thickness in Upper Kharita Formation varies between more than 9 up and more than 61 m with average porosity values range between 0.08 and 0.17 PU while the average permeability values range between 1.89 and 696.66 mD. The average hydrocarbon saturation values range between 46 and 97%.

Saturation/height modeling

Using all permeability ranges (model 1)

Figure 9 shows capillary pressure versus water saturation for Kharita Formation in BED3-6. In this method, all the available capillary pressure data are used. Core samples are divided into two groups, based on the permeability ranges above and below 100 mD. Two different values of $Sw_i = 0.035$ and 0.14 are substituted in Eq. 8 to calculate the reducible water saturation (Sw_r) for higher and lower permeability groups respectively. Figure 10 shows the fitting parameters for the J-function, where “a” equals 0.32 and “b” equals −0.91 for the best fitting (Skelt and Harrison 1995).

Table 3 Porosity and permeability at overburden pressure for SCAL data of BED3-6 well

BED3-6 porosity/permeability at overburden			Overburden pressure (psi)				
			0	1000	2000	4000	5500
Sample	Reservoir	Depth (m)	Porosity at overburden (Frac)				
5	Kharita A	3602.4	0.142	0.14	0.139	0.138	0.137
8		3603.6	0.134	0.133	0.131	0.129	0.128
18		3606.86	0.119	0.116	0.115	0.113	0.113
34		3613.13	0.117	0.115	0.114	0.113	0.112
50	Kharita B	3618.9	0.109	0.107	0.106	0.104	0.102
137		3679.05	0.186	0.184	0.182	0.18	0.18
170		3689.9	0.161	0.159	0.158	0.157	0.157
186		3695.93	0.177	0.174	0.172	0.171	0.169
190		3696.97	0.178	0.174	0.172	0.171	0.17
199		3700.25	0.147	0.145	0.144	0.143	0.142
210		3703.58	0.149	0.146	0.145	0.144	0.144
216		3705.65	0.163	0.161	0.16	0.159	0.159
Sample	Reservoir	Depth (m)	Permeability at overburden (mD)				
5	Kharita A	3602.4	100	98	97	94	93
8		3603.6	69	67	64	61	58
18		3606.86	47	44	43	42	40
34		3613.13	12	11.4	11.1	10.7	10.2
50	Kharita B	3618.9	11.2	10.8	10.4	10	9.8
137		3679.05	835	800	785	770	750
170		3689.9	305	290	280	275	270
186		3695.93	1210	1110	1070	1040	1020
190		3696.97	1000	960	925	905	890
199		3700.25	160	155	150	145	145
210		3703.58	250	245	240	235	225
216		3705.65	575	545	535	520	520

$$Sw_{cap} = sw_i + 0.32 * \left[\frac{(FWL - TVDSS) * (RHOW - RHOH) * 3.281}{\sigma \cos \theta} * \sqrt{\frac{Perm_{mD}}{\phi_{frac}}} \right]^{-.91} \quad (15)$$

where Sw_{cap} is the water saturation in fraction. FWL is the free-water level, m; TVDSS is the true vertical depth sub see, m; RHOW is the water gradient, (psi/ft); PHOH is the hydrocarbon gradient, (psi/ft); Perm is the permeability, mD; ϕ is the porosity, fraction.

(Sw_i) values for these samples are plotted versus permeability (Fig. 11), to extrapolate Sw_i at lower permeability zones (perm < 100 mD) and to result in smoothed water saturation model from the resulted sat/height model. Figure 12 shows the fitting parameters for the J-function, where “a” equals 0.303 and “b” equals −1.225 for best fitting, (Skelt and Harrison 1995).

$$Sw_{cap} = (0.346 * Perm^{-0.302}) + 0.303 * \left[\frac{(FWL - TVDSS) * (RHOW - RHOH) * 3.281}{\sigma \cos \theta} * \sqrt{\frac{Perm_{mD}}{\phi_{frac}}} \right]^{-1.225} \quad (16)$$

Using the high permeability ranges > 100 mD (model 2)

In this method, the capillary pressure data for high permeability samples (perm > 100 mD) are used. Irreducible water saturation

Figure 13 shows the log plots for BED3-6 and BED3-10A wells in the eastern and western flanks, respectively. The water saturations from models 1 and 2 are presented in

The results show that Leverette-J saturation/height models 1 and 2 show good match at the transition zones (water–oil in BED3-6 and water–gas in BED3-10A). For permeability less than 10 mD, the difference between Archie and Sat/H model saturations become significant

in model 1 and this was overcome by using variant Swi in model 2. Saturation/height model 2 gives good saturation match at low and high permeability ranges, which could replace model 1 at low permeability ranges. Saturation/height model 2 is recommended to be used for all permeability ranges of Kharita Formation.

Fig. 6 POR-PERM transform to estimate the permeability, Badr-3 field, western desert, Egypt, in **a** high quality sand, **b** medium quality sand, **c** low quality sand and **d** highly shale

Air/brine was used to fit the Leverett-J at the laboratory condition. Oil/brine was used in the oil rim and the gas/brine was used in the western flank, where no oil rims.

Formation fluid type and fluid contacts

In virgin reservoirs, the static reservoir pressures are not affected by the fluid withdrawal and the observed gradients therefore reflect the density of the original fluids. The “breaks,” where the slope changes in the gradient, reflect the original fluid contacts (Dowdle and Cobb 1975).

Formation fluid type and fluid contacts have been discussed by many authors, e.g., Attia et al. 2015; Abudeif et al. 2016a; Abudeif et al. 2016b; Abudeif et al. 2018; Radwan et al. 2020.

All the available formation pressure data have been analyzed. The pressure data show almost consistent gas, oil and water pressure trend lines of the average gradient, 0.11 psi/ft, 0.29 psi/ft and 0.47 psi/ft, respectively. The fluid contacts and fluid types in the virgin pressure wells at the time of data acquisition are interpreted as follows.

Eastern flank

The eastern flank wells are BED3-4, BED3-6 and BED3-7A. BED3-4 well is shallower than BED3-6 and BED3-7A, which penetrated all Kharita interval gas columns (Fig. 14a). BED3-6 and BED3-7A present an oil rim from the formation pressure cross-plots (Fig. 14b and c). BED3-7A well penetrated the gas column and oil rim, and did not penetrate the water leg. BED3-6 well penetrated the gas column, oil rim and penetrated the water leg. Pressure data from BED3-6 and BED3-7A, in the gas column, were used to get the gas–oil contact (GOC) in Badr-3 eastern flank.

Western flank

BED3-10A has penetrated the gas column and the water leg in the far west of the field, where it penetrated the hydrocarbon column and the water leg. Successful pressure data were acquired in both the hydrocarbon and water intervals. Formation pressure data were plotted versus true vertical depth subsea (TVDSS), to establish the fluids’ gradients and to define the hydrocarbon type. The hydrocarbon interval

Table 4 Porosity and formation resistivity factor (FF) at overburden pressure for SCAL data of BED3-6 well

BED3-6 porosity/FF at overburden			Overburden pressure (psi)				
			0	1000	2000	4000	6620
Sample	Depth (m)	Permeability (mD)	Formation resistivity factor (FF)				
11	3604.5	15	53.1	65.5	72.1	80.3	85.4
37	3614.05	6.1	54.9	70.4	80.1	94.2	105.9
39	3615.55	46	40.9	48.7	52	56	58.3
58	3621.85	62	35.2	43.5	46.3	49.7	51.9
114	3667.09	125	30.4	37.4	39.8	42.1	43.4
138	3679.35	325	24.7	33.2	35.2	37.2	38.2
159	3686.25	1220	17.2	21.3	21.9	22.6	22.8
167	3688.92	570	21.1	23.6	24.3	24.9	25.2
173	3690.72	245	24.8	27.6	28.8	30	30.6
187	3696.13	380	24	26.1	27.1	27.9	28.5
208	3703.12	195	26.6	29.8	31	32	32.7
222	3708.37	625	19.3	21.3	21.9	22.4	22.7
Sample	Depth (m)	Permeability (mD)	Porosity (Frac)				
11	3604.5	15	0.111	0.108	0.106	0.104	0.103
37	3614.05	6.1	0.105	0.103	0.101	0.099	0.098
39	3615.55	46	0.126	0.122	0.121	0.119	0.118
58	3621.85	62	0.135	0.132	0.13	0.129	0.127
114	3667.09	125	0.145	0.142	0.14	0.139	0.138
138	3679.35	325	0.148	0.144	0.141	0.139	0.138
159	3686.25	1220	0.18	0.175	0.173	0.17	0.169
167	3688.92	570	0.168	0.165	0.164	0.162	0.161
173	3690.72	245	0.156	0.152	0.151	0.15	0.148
187	3696.13	380	0.161	0.158	0.156	0.154	0.153
208	3703.12	195	0.151	0.147	0.145	0.143	0.142
222	3708.37	625	0.176	0.173	0.172	0.17	0.169

Table 5 Water saturation and resistivity index (RI) at overburden pressure for SCAL data of BED3-6 well

BED3-6 porosity/RI at overburden								
Sample	Depth (m)	Permeability (mD)	Porosity (Frac)	FF	S _w Min	S _w Max	RI Min	RI Max
11	3604.5	15	0.111	53.1	14.1	91.4	1.21	47.36
37	3614.05	6.1	0.105	54.9	24.5	89	1.28	17.85
39	3615.55	46	0.126	40.9	19	76.1	52.69	1.91
58	3621.85	62	0.135	35.2	18.5	92.3	1.2	43.87
114	3667.09	125	0.145	30.4	7.2	85.3	209.28	1.38
138	3679.35	325	0.148	24.7	5.2	33.1	9.56	407.74
159	3686.25	1220	0.18	17.2	3.8	35.6	6.34	550.63
167	3688.92	570	0.168	21.1	5.5	70	2.22	688.69
173	3690.72	245	0.156	24.8	6.2	84.3	1.42	303.76
187	3696.13	380	0.161	24	6.5	72.4	1.84	201.34
208	3703.12	195	0.151	26.6	8.5	88.5	1.24	85.95
222	3708.37	625	0.176	19.3	4.9	70.4	981.88	2.19

Needs to be in simple form I prefer min, max, average and stander deviation

Fig. 7 Saturation exponent “n” and cementation factor “m” of Kharita A and Kharita B where: **a** Saturation exponent “n” of Kharita A from BED3-6 SCAL. **b** Cementation factor “m” of Kharita A from

BED3-6 SCAL at reservoir pressure 5500psi. **c** Saturation exponent “n” of Kharita B from BED3-6 SCAL. **d** Cementation factor “m” of Kharita B from BED3-6 SCAL at reservoir pressure 5500 psi

shows pressure gradient of 0.15 psi/ft, which indicates a gas-bearing formation. The gas–water FWL was estimated at 3705 m TVDSS. The plot also shows the absence of oil rim in the western part of the field (Fig. 14d).

Hence, the pressure data in the four wells divided the Upper Kharita reservoir into two flanks. The eastern flank which penetrated the oil column with the free-water level was estimated at 3719 m TVDSS and the gas–oil contact (GOC) at 3682 m TVDSS. The western flank which penetrated only the gas and the free-water level was estimated at 3705 TVDSS.

Figure 15 shows a cross section from west to east along Badr-3 field showing the distribution of fluid types and contacts for Upper Kharita. The source rocks for the western desert are typically shale sequences associated with the transgressive front of Upper Jurassic and Upper Cretaceous carbonates. The hydrocarbons of the Abu El-Gharadig basin are a multi-sourced from Cretaceous, Jurassic and possibly Carboniferous rocks. The main recognized source rocks for the Abu El-Gharadig area include the “F” Member of the Abu Roash Formation and the shales of the Jurassic Khatatba Formation. The Abu Roash “F” Member provided much of the oil generated in the Abu El-Gharadig basin, including the oil rim present in the Badr-3 field. The presence of charge

has been proven by the well-log sand pressure points in this study. Oil charge is interpreted to be from Abu Roash “F,” which is mature to generate oil in (eastern flank). Gas charge is from Khatatba, which is mature to generate gas (western flank). Access to charge from the kitchen area to Badr-3 field by migration through faults so in the study area there is no problem of source rock.

There is an oil rim of initially 42 m thickness in the eastern flank. The oil–water FWL (OW-FWL) and the gas–water FWL (GW-FWL) are used to calculate the effective capillary pressure over the hydrocarbon column, with the associated fluid gradient. There is no oil rim in the western flank and the GW-FWL was used to calculate the effective capillary pressure over the entire reservoir at this part (Fig. 16).

In the current study, two models have been performed. Model 1 used all the available capillary pressure data with different irreducible water saturations (S_{wi}) to high and low permeability ranges 0.14 with permeability less than 100 mD and 0.035 with permeability more than 100 mD. Model 2 used the high permeability ranges and utilized S_{wi} as a function of permeability instead of fixed number. The water, gas and oil gradients deduced from formation

Fig. 8 Correlation panel for BED3-6 and BED3-10A showing the water bearing interval (a), and Pickett plot (b) of this water leg to estimate the cementation factor (m), Badr-3 field, western desert, Egypt

Table 6 The minimum, maximum and average values for porosity, water saturation and permeability per unit

Well	Zones	Top, (m)	Bottom, (m)	Gross, (m)	Net, (m)	Net to gross, (m)	Porosity			Permeability			Water saturation		
							Min. Phi, (Frac)	Av. Phi, (Frac)	Max. Phi, (Frac)	Min. k, (mD)	Av. K, (mD)	Max. K, (mD)	Min. Sw	Av. Sw	Max. Sw
BED3_4	Kharita A	3483.77	3552.62	68.84	45.89	0.67	0.02	0.10	0.20	0.03	29.79	856.78	0.06	0.17	0.66
BED3_4	Kharita B	3552.62	3620.00	67.38	57.55	0.85	0.05	0.12	0.24	0.04	140.86	1029.49	0.01	0.07	0.24
BED3_6	Kharita A	3596.99	3663.86	66.87	23.77	0.36	0.04	0.11	0.19	0.19	78.03	382.35	0.04	0.12	0.98
BED3_6	Kharita B	3663.86	3718.99	55.13	46.73	0.85	0.04	0.14	0.21	0.03	297.34	974.03	0.02	0.05	0.15
BED3_6	Kharita B-WATER	3718.99	3736.25	17.26	16.04	0.93	0.06	0.15	0.21	0.11	298.62	1052.12	0.12	0.47	0.90
BED3_6	Kharita C-WATER	3736.25	3795.24	59.00	5.03	0.09	0.02	0.09	0.12	3.14	1.89	17.26	0.24	0.54	0.99
BED3_7A	Kharita A	3574.86	3648.81	73.95	44.42	0.60	0.03	0.09	0.17	0.05	10.78	198.49	0.02	0.17	0.97
BED3_7A	Kharita B	3648.81	3714.15	65.35	61.58	0.94	0.03	0.17	0.25	0.03	696.66	3091.61	0.01	0.03	0.10
BED3_7A	Kharita C-WATER	3714.15	3786.05	0.00	9.73		0.03	0.10	0.18	0.88	6.65	29.42	0.20	0.40	0.97
BED3_10A	Kharita A	3607.41	3667.69	60.28	37.08	0.62	0.02	0.09	0.16	0.15	27.86	148.90	0.04	0.15	0.90
BED3_10A	Kharita B	3667.69	3704.98	37.29	32.17	0.86	0.01	0.10	0.22	2.29	89.85	829.29	0.03	0.10	0.69
BED3_10A	Kharita B-WATER	3704.98	3739.28	34.30	30.41	0.89	0.03	0.12	0.17	0.32	144.68	530.34	0.22	0.42	0.72
BED3_10A	Kharita C	3739.28	3795.28	0.00	16.58		0.03	0.08	0.14	0.14	4.76	26.65	0.13	0.28	0.97

Min is minimum; Max is maximum; Av is average; Phi is the porosity (in fraction); k is the permeability (mD); and Sw is water saturation %

Fig. 9 Capillary pressure versus water saturation for Kharita Formation in BED3-6 well, Badr-3 field, western desert, Egypt

Fig. 12 J-function fitting for the high permeability core samples, Badr-3 field, western desert, Egypt

Fig. 10 J-function fitting parameters plot, Badr-3 field, western desert, Egypt

Fig. 11 Irreducible water saturation (Swi) as a function in permeability, Badr-3 field, western desert, Egypt

pressure analysis are 0.47 psi/ft, 0.11 psi/ft and 0.29 psi/ft respectively.

Water saturation changes with time due to the water-cut increase with the production. To measure the current water saturation and the current contacts behind the casing, TDT (thermal decay time) log was run. Water saturation changes, with time due to the water-cut increase with the production and the ranges of captured cross section (SIGMA) are 7–12 C.U. lithology, 21 C.U., fresh water, 120 C.U., salt water, 14–22 U.C., oil and 0–12 C.U., gas.

The water saturation was calculated by the TDT log in BED3-4 well, to determine which layer increases the water cut in the production. Kharita B was found to be responsible for that increase in water cut (Fig. 17).

Conclusions

- New cutoffs increase the net sand in Kharita A which is low quality than Kharita B. Build porosity and permeability models are based on cores and wire line logs by recognizing the different facies and genetic units and mitigating the uncertainty ranges.
- The evaluations of the petrophysical modeling study were carried out to improve the understanding of the future reservoir development opportunities of Badr-3 field. Leverette-J saturation/height models 1 and 2 show good match at the transition zones (water–oil in BED3-6 and water–gas in BED3-10A). For permeability less than 10 mD, the difference between Archie and saturation/height (Sat/H) model saturations become significant in model 1 and this was overcome by using variant Swi in model 2. Saturation/height model 2 gives good saturation match at low and high permeability ranges, which could replace

Fig. 13 BED3-6 (a) and BED3-10A (b) logs plot comparing water saturation from Archie and sat/H models-1&2, Badr-3 field, western desert, Egypt

Fig. 13 (continued)

Fig. 14 Pressure plots for upper Kharita, Badr-3 field, western desert, Egypt to show: **a** Gas in BED3-4, **b** Gas, oil and water in BED3-6, **c** Gas and oil in BED3-7A, **d** Gas and water in BED3-10A

Fig. 15 A cross section along Badr-3 field showing the distribution of fluid types and contacts, Badr-3 field, western desert, Egypt

Fig. 16 A pressure plots compared with saturation height for the eastern flank (gas and oil) and western flank (gas zone), Badr-3 field, western desert, Egypt

- model 1 at low permeability ranges. Saturation/height model 2 is recommended to be used for all permeability ranges of Kharita Formation.
- The pressure data proved that the eastern flank contains oil and gas, while the western flank contains only gas, due to the different charging system. Achieving better understanding of the water encroachment in the Upper Kharita reservoir by running the TDT is able to understand that the water filled the Kharita B unit and judged the water encroachment.
- Due to its geological and dynamic complexity (consisting of an oil rim and large gas cap with water drive) confirmed with the pressure plots and established gas, oil and water gradient. Combining the results of the studied four wells provides a comparison across the Abu El-Gharadig basin of the generation potential.
- This study is recommended to focus on Badr-3 area for Kharita A because it has been low intervals perforated. Isolate all Kharita B intervals due to highly water production and add perforation in Kharita A for all intervals.

Fig. 17 BED3-4 log plot comparing the current hydrocarbon saturation versus the original saturation, Badr-3 field, western desert, Egypt

Declarations

Ethical Approval This manuscript has not been submitted to more than one journal for simultaneous consideration. The submitted work is original and not has been published elsewhere in any form or language (partially or in full). Results are presented clearly, honestly, and without fabrication, falsification or inappropriate data manipulation (including image-based manipulation).

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