Reservoir Characterization Of Kareem Formation Along The Central Trough Of The Southern Gulf Of Suez, Egypt.

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ABSTRACT

The Kareem Formation is considered as one of the most significant hydrocarbon reservoirs in the Gulf of Suez. About one quarter of the Gulf of Suez oil production comes from this formation. In this study, we used the available geophysical and geological data for seven wells distributed along the central trough of the Southern Gulf of Suez to detect the main geologic and petrophysical characters of the Kareem Formation. This study indicates that the facies and thickness of the Kareem Formation show noticeable variation throughout the studied area. Such variation could be attributed basically to the synsedimentary prevailing tectonics and the sea level subtopography. The Kareem Formation consists mainly of sandstone and shale intercalations. The sandstones tend to develop on the down thrown sides of the bordering faults toward the center of the fan lobe, whereas more pelagic sediments had the chance to develop on the upthrown ones. Subsequent diagenetic processes, such as dolomite cementation and feldspar alteration could result in a great reduction of the reservoir quality. The Kareem Formation can be divided into two sequences. The lower sequence consists of low stand system tract, while the upper sequence consists of lowstand, transgressive and high stand system tracts. The main hydrocarbon production comes from the sandstones of the basin floor fan, as the main constituent of the lower sequence, as well as the lower shoreface sandstone of the transgressive system tract. The Kareem reservoir quality is graded from good to poor, depending on the degree of the post – sedimentation diagenetic processes, and can be subdivided into seven hydraulic flow units.

Key words: Kareem Formation – Gulf of Suez – reservoir characterization – sequence stratigraphy.

Introduction

The Kareem Formation was introduced by the EGPC Stratigraphic Committee (1964) to describe the uppermost rock unit of the Lower to Middle Miocene Gharandal Group, as a part of the stratigraphic column of the Gulf of Suez Province. The Kareem Formation is bounded by two unconformities separated it from the underlying open marine Rudeis Formation and the overlying greatly fluctuating depositional environments Belayim Formation. The above mentioned Stratigraphic Committee (op. cit) divided the Kareem Formation into two members. The lower Markha Member consists of thin anhydrite beds, intercalated with shales and marls. This unit, according to Hughes et al. (1992), is often absent due to the lateral facies change. The upper Shaqar Member consists of fossiliferous shale and marl, with occasional thin limestone interbeds and local sands. The Kareem sandstones are considered the most significant hydrocarbon reservoir in the Gulf of Suez region. They represented about 23% of the hydrocarbon production in the Gulf of Suez (Alsharhan, 2003). The Kareem Formation was assigned Middle Miocene (Langhian – Serravallian), according to Evans (1988), Ridshardson and Arthur (1988) and Patton et al. (1994). However, Hughes et al. (1992) and El Beialy et al. (2005) assigned Early Miocene for the formation base. The thickness of the Kareem Formation is up to 1400 ft (Tewfik et al., 1992). The thickest section is encountered in the Morgan Field area, in which the gross sandstone is up to 1000 ft thick (EGPC, 1996).

Several depositional facies have been interpreted for the Kareem sediments. In this respect, Tewfik et al. (1992) identified five types, which are alluvial fan, sabkha / lagoon (anhydrite), platform carbonates, submarine fan / fan delta and basinal pelagic. However, Hughes et al. (1992) interpreted the anhydrite of such rock unit as a saline deposit, having accumulated as a result of deep marine precipitation from hypersaline marine brines, not as a result of sabkha-like marginal marine conditions. Salah and Alsharhan (1997) identified three sandstone types, which are quartz arenite, arkose and quartz wackes. The recent study carried out on the Kareem Formation is made by Abd El- Naby et al. (2010), in which they divided the Kareem Formation based on the sequence stratigraphic concept, into two third - order sequences. In this respect, each sequence includes lowstand, transgressive and highstand system tracts.
Tectonically, the Kareem Formation was deposited during the quiescence stage of the Gulf of Suez rift evolution (Montenat et al., 1998). At this stage, the Gulf of Suez showed slow tectonic subsidence rate. The slowness of the subsidence may be attributed to the initiation of the left- lateral Aqaba – Dead Sea wrench system that supplanted extension in the Gulf of Suez at the Early Serravallian (Bayer et al., 1988). At this time (end of the Kareem Formation), the tectonic subsidence across the entire Gulf of Suez had been ceased, while the stratigraphic accumulation and hence the total subsidence continued only along the central and southern main trough of the Suez rift (Richardson and Arthur, 1988). Near the Langhan – Serravallian boundary (14 Ma), the regression reached the deeper parts of the graben that described as post – Kareem event (Evans, 1988).

The sandstones of the Kareem Formation produced oil from many fields, such as Morgan, Belayim Land and Belayim Marine, Shoab Ali, Badri, Hilal, Waly, Kareem, East Zeit, Ashrafī, Zaafarana, Amal and Esh El Mellaha (Fig. 1). As noted, most of these fields are located in the Southern Gulf of Suez Province. On the other hand, the Kareem Formation is also oil producer from the carbonates, as in Zeit Bay and Ras Bahar fields (EGPC, 1996). The main purpose of this paper is to shed more light on the Kareem Formation in the Southern Gulf of Suez along the central trough, using the available data, to illustrate the different geologic and petrophysical aspects related to this formation.

Study area and data:

The study area includes seven wells distributed along the central trough of the Southern Gulf of Suez (Fig. 1). The wells are belonging to four fields, which are Hilal, Sidki, GS365-1 and Amal. The available data include electric logs, routine core analysis, as well as 2D seismic profiles. The electric logs include gamma - ray spectroscopy (Amal 9 well), density, neutron, sonic, resistivity, dipmeter and composite. Unfortunately, the density and neutron logs are not available for A9A well. Four continuous core plugs, covered about 129 ft ranged from 8065 to 8191 ft depth, were available for the routine core analysis in A5 well. Such core analysis includes the horizontal and vertical permeabilities, helium and fluid porosities, grain density and fluid saturation. The recovery was varied from 62 to 100%, provided about 100 core samples. The routine core analysis indicated that the upper 57 ft were cored within the mudstone with no reservoir potentiality. The cored sandstone interval indicated that the permeability ranges from 1.5 to 1072 md with an average value of 184 md. The porosity ranges from 0.064 to 0.245 with an average value of 0.174 and the grain density from 2.6 to 2.71 g/cc with an average value of 2.636 g/cc. The core lithology description was available for Amal 9 and A5 wells.

Lithologic content of the Kareem Formation:

The Kareem Formation in the study area shows obvious variation in both the thickness and facies (Fig. 2). The complete section should be above 350 ft thick. Otherwise, faults or erosions could be responsible for the missing parts, as in A3B, SDK6 and GS373-2 wells (Figs. 3, 4&5). The thickness is ranged from 225 to 454 ft (Table 1). As indicated from this table, there is no consistent increase in thickness. Furthermore, the thickest Kareem Formation in a well has the lowest gross sandstone. It can be also noted that, the gross sandstone increases toward both the southernmost and the northernmost parts. In the central area, the sandstone tends to decrease significantly as in SDK6, GS 365-1 and GS 373-2 wells (Fig. 6).

The anhydrite layers appear timidly in the southernmost part, where no anhydrite layers are noted behind A5 well. In A9A well, two anhydrite layers with 6 and 15 ft thick embraced about 114 ft thick of mainly sandstone. This sequence is the only interval in the study area that could be correlated with the Markha Member. The 15 ft thick anhydrite layer is located at the bottom of the formation. At the base of A5 well, two thin anhydrite layers with two ft thick for each involving a thin layer of shale were encountered. In A3B well, three ft thick of anhydrite were contained at the formation base. The limestone is occurred in GS 365-1 and GS 373-2 wells. Such facies could imply the deposition on the crests of uplifted tilt - blocks (Fig. 4).

According to the core description of A5 well, the mudstone consists of burrowed and foraminiferal mudstone deposited in open marine setting (Rine, 1985). The mudstone is slightly calcified and argillaceous. The clay minerals consist of illite, chlorite and mixed layered illite – smectite (Fig. 7).

The sandstones are usually intercalated with shales. Such behavior is observed in A5 and A3B wells and the upper part of A9A well. However, the stacked sandstones were observed in other wells, such as in Amal 9 and the lower part of A9A. The sandstone interval in Amal 9 well could be differentiated into three units. The upper and lower units are of low radioactivity with blocky GR, while the middle unit is highly radioactive due to the presence of potash feldspars, which derived from the unroofing basement. So, it can be inferred that the episode of the Gulf of Suez uplifting shoulders could be synchronized to the deposition of the Kareem Formation. The lower sandstone interval in A9A well can be treated as one unit. The lithology based on the core description of A5 well indicates that the sandstone is fine to coarse – grained interlayered with argillaceous calcite deposited in shallow marine condition of distal delta fan. Within the sandstone, the clay occurred in trace amounts; mostly as an alteration product through the degrading feldspars. About 9% of the potash and plagioclase (range 3-14%)
occurs as perthite intergrowths. Granitic rock fragments that composed of feldspars and quartz, account for 2-3% of the rock volume. The sandstone, which is arkosic arenites, is generally poorly sorted with abundant laminated beds, non gradual and well sorted sands. This indicated the presence of sufficient energy to cause the reworking of sands by shallow – water processes. The sandstone is cemented by dolomite.

In Amal 9 well, two core plugs were analyzed to describe the lithology (Sommer, 1985). **Core 1** indicates that the sandstone is medium to coarse grained and poorly sorted, but non argillaceous and non cemented. The sand is made up of quartz and very abundant feldspar, mainly perthite, which is mixed of K and Na feldspathic. The presence of these feldspars explains the high GR readings in the sand. Such lithology can be observed on the M-N and $\rho_{min}$-$U_{max}$ crossplots (Fig. 8). The sedimentary minerals and organic debris were noticed, such as glauconite, pyrite, phosphate and vegetal debris. This assembly characterizes an outer shelf to slope environment arrivals of reworked fauna from the middle to inner shelf. The sand is badly cemented by small dolomite rhombs, which never form more than 3 to 8% of the rock. The shales are very rare and exhibit mixed fauna.

**Core 2** shows two lithologic facies; at top, fine grained flat laminated sandstone; and at bottom, conglomerate with big pebbles and sandy matrix. The fine grained laminated sandstone is fine to medium sandstone, well sorted and consolidated. It consists of quartz, feldspars (5-10%) and rock fragments including dolomitized limy fragments and detrital clays (8-15% avg.). The vegetal debris is frequent to abundant. Glauconitic, pyritic and phosphatic debris were noticed. Algal debris is common. Conglomerate is formed of elements varying in size, where the boulders > 10cm. The pebbles have mainly eruptive origin (e.g. biotites, syenites and microgranites).

**Dipmeter interpretation in the Kareem Formation:**

Clustered dipmeter processing is available for most of the studied wells. From the dipmeter, it is tried to detect the main structural features. The dominant dip in the Southern Gulf of Suez is due southwest (Fig. 9). Such a dip direction is usually encountered in the tilted –blocks pattern of the horst structures. In Amal 9 well, the DUALDIP processing is available, which offers a good opportunity to identify the depositional facies.

An unconformity can be detected at the Kareem – Belayim boundary (Fig. 10). Such an unconformity was called post – Kareem event (Evans, 1988). Five depositional facies can be identified from the DUALDIP within the Kareem interval in Amal 9 well. Such facies are in good correlation with those obtained from the facies analysis using the IP program (Fig. 2). The upper mudstone interval could be divided into two sub- facies; the upper sub – facies shows coarsening upward, indicating minor regression and the lower sub – facies shows fining upward, indicating minor transgression. The mudstone facies is represented by the downward increase in the dip magnitude, which reveals draping over the sandstone. The dip azimuth is mostly southwest. The second facies corresponds to the massive consolidated low radioactive sandstone. The first and the second facies correspond to the N9 planktonic foraminiferal zone, which indicates Langhian age. The third facies corresponds to the consolidated highly radioactive sandstone. Scattered dip distinguishes the second and third facies. The fourth facies corresponds to the fine grained laminated consolidated sandstone, with low gamma- ray readings. The dip azimuth and magnitude of this facies may represent the structural dip. The last facies corresponds to the conglomerate with big pebbles and sandy matrix, as confirmed from the core analysis. An unconformity can be detected between the third and fourth facies. The last unconformity is located at the Kareem - Rudeis boundary. Faults can be detected on the dipmeter of GS 373-2 and A3B wells (Fig. 5). In summary, the Kareem Formation is bounded by two unconformities. Within it, at least one unconformity can be detected.

**Sequence stratigraphy of the Kareem Formation:**

Sequence stratigraphy was introduced in the oil and gas exploration to predict reservoirs, source rocks and seals using the seismic and well logging data, as well as the biostratigraphy and eustatic sea level. In this paper, we adopted the stratigraphic concept, based on Mitchum et al. (1993) and Neal et al. (1993) approaches. For defining the sequence boundaries on the well logs, we adopted the concepts of Rider (1996). The noticeable change of facies and thickness within the studied area could be explained on the light of such concept.

We can define two sequences in the Kareem Formation, which differ from one well to another, according to the position of the well relative to the configuration of the depositional basin (Fig. 11). Sequence I is located at the lower part of the formation. It is bounded by the sequence boundaries SB1 and SB2. It is represented by a lowstand system tract (LST). The LST is represented by a basin floor fan (BFF) deposited during the early phase of relative fall of sea level. At its base, the anhydrite was deposited in the southernmost wells, followed by the stacked sandstones. The BFF is usually thickens toward the center of the depositional lows, as in Amal 9 and A9A wells and onlaps the basin margins. Some intercalations of shales are encountered in A5 and A3B wells. The BFF of Amal 9 well shows increased followed by decreased gamma ray readings. Such variation is
attributed to the increase and decrease of feldspars ratio rather than the fining and coarsening upwards. This BFF is oil- and gas-bearing. According to the drill steam test (DST), 912 BOPD and 28000 m$^3$/d of gas are produced from the lowermost part of the BFF in Amal 9 well. On crests, such a sequence is not deposited, as in GS 365-1 well (Fig. 11). The seismic interpretation indicates that the Kareem Formation thickens toward the northeast direction of Hilal field (Fig. 3).

Sequence II is bounded by the sequence boundaries SB2 and SB3. SB2 is a regional unconformity and can be detected on the dipmeter (Figs. 5 & 10). Sequence II consists of lowstand, transgressive (TST) and highstand (HST) system tracts. The lowstand system tract (LST) is represented by slope fan (SF) and prograding complex (PGC). The SF is encountered in most of the wells, especially the central ones. It consists mainly of pelagic sediments, indicating deposition at the early relative rise of sea level. The crecent log shaped is well defined in A9A, SDK6 and GS 373-2 wells. The sand/shale ratio increased southward in the fan lows, as in A9A and A5 wells. The SF is occurred in neritic environment. The prograding complex (PGC) is encountered only in the central part of the studied area, as in GS 373-2 and GS 365-1 wells (Fig. 11). The PGC indicates coarsening upward and consists mainly of shale. The transgressive system tract (TST) is well developed in all wells. The TST indicates the deposition during a maximum relative rise of sea level. It consists mainly of pelagic sediments. However, the shoreface sandstone is occurred at the tract base in Amal 9 well. Such a sandstone layer is gas productive. The maximum flooding surface (MFS) can be detected at the uppermost part of TST. The highstand system tract (HST) documents the highest relative sea level (Neal et al., 1993). The HST consists mainly of shales and shows fining upward.

So, the syn-sedimentary faults, which created the subtopographic highs, lows and crests as well as sea level, are the main factors controlling the facies and thickness of the Kareem Formation. Fluctuations in sea level were controlled to a large degree by the tectonic events (subsidence or uplift). The uplifting movement, which occurred at the begging of the Kareem Formation, could affect on the sea level. The downthrown side of the faults offers a good reservoir quality. On the other hand, most pelagic sediments were deposited on the upthrown side.

**Petrophysical characterization of the Kareem reservoir:**

The determination of petrophysical parameters such as porosity, water saturation and clay content could help for more understanding of the Kareem reservoir. Such parameters are calculated using the IP software program. Matrix identification using the M- N and $U_{max} - \rho_{max}$ crossplots indicates a wide variation in the Kareem Formation lithology (Figs. 6 & 8). The effect of gas-bearing sediments is obvious in Amal 9 well. The litho-saturation crossplots of the Kareem Formation reveal good reservoir quality in Amal 9 well, graded to very poor one in A3B well (Figs. 12 & 13). Table (2) summarizes the petrophysical parameters estimated for the Kareem reservoir. The poor reservoir quality in A3B well may be attributed to the dolomite cement, as well as the alteration of potash feldspars into kaolinite patches. Such patches may fill the pores, which resulted in the sharp reduction of the total and effective porosities and consequently the permeability.

Porosity played the main role in determining the permeability, as indicated from the good relationship between the permeability and porosity of the A5 well cored interval (Fig. 14). Such a relationship has the following form, with determination of coefficient ($r^2$) = 0.748:

$$\text{CoK} = 0.058 e^{0.392\phi_i}$$  \hspace{1cm} (1)

**Hydraulic flow units in the Kareem Formation:**

Hydraulic flow unit (HFU) concept was introduced to describe the dynamic reservoir characteristics (Amaefule et al., 1993). The HFU can be determined from several methods. One of them is the Stratigraphic Modified Lorenz (SML) plot. Gunter et al. (1997) described a technique for combining the porosity, permeability and bed thickness data for the flow unit identification. The porosity and permeability can be inferred from well logs and/or cores. They utilized the Stratigraphic Modified Lorenz plot for such identification. The SML plot is a crossplot of “cumulative flow capacity” – defined as the product of the average permeability time thickness of an interval ($kh$) – versus the “cumulative storage capacity” – defined as the product of the average porosity time thickness of the same interval ($\Phi h$). Change in the slope indicates a new flow unit, while horizontal trend can be treated as a barrier, where no flow occurred.

In this study, we used the neural network – derived porosity and permeability, using well logs. The prediction was based on the $\Phi n$, $\rho_b$ and $\Phi e$ as inputs, and the permeability as output. For porosity prediction, we used the density, neutron and sonic logs as inputs. Figure (15) shows the SML plot for Amal 9 well, which indicates about 9 HFU within the Kareem interval. Plotting the flow capacity versus depth (Fig. 16) indicates that about 80% of the flow comes from the interval between 7285 and 7352 ft depth. Such interval corresponds
to the middle part of BFF. On the other hand, no flow has occurred in some wells, such as 373-2 and 365-1 (Fig. 17).

The accurate number of hydraulic flow units can be determined using Ward's hierarchical clustering method. The advantages of this method are the high accuracy and user independency. It is used to get some sense of the possible number of clusters and the way they merge, as seen from the dendrogram. Then, the clustering is rerun with only a chosen optimum number, in which to place all the cases. It starts from a number of HFU equal to the number of samples and then gradually merges the samples into joint clusters. To validate the optimum number of HFU, we used the sum of square errors (SSE), as an indicator for such determination. In this method, we plot the SSE against the number of HFU, in which the SSE decreased as HFU increased. At certain HFU number, the SSE is nearly constant. After this certain number, the SSE is almost constant with small variations, which can be neglected. This certain number can be considered as the optimum number of HFU (Fig. 18). According to this method, we can detect seven HFU for Amal 9 and A5 wells (Fig. 18).

![Fig. 1: Location of the Gulf of Suez showing the Kareem - producing fields, the studied wells and the used seismic lines.](image)
Fig. 2: Rock types of the Kareem Formation as deduced from cluster analysis using IP Program, in case of 15 facies and in case of five facies.

Fig. 3: Seismic interpretation of line SG404 -24. Location of the line is showing in Figure (1).
Fig. 4: Seismic interpretation of line B - 30. Location of the line is showing in Figure (1).

Fig. 5: Dipmeter of GS373-2 and A3B wells showing effect of the normal faults.
Fig. 6: Matrix identification using M-N and $U_{\text{max}} - \rho_{\text{max}}$ crossplots in GS 365-, GS373-2 and SDK 6 wells.

Fig. 7: Identification of clay minerals from crossplots in Amal 9 well.
Fig. 8: Matrix identification using M-N and $U_{\text{max}}$ - $\rho_{\text{max}}$ crossplots in A5, A3B and Amal 9 wells.

Fig. 9: Dipmeter of GS365-1 and A5 wells showing the dominant dip in the Southern Gulf of Suez. Black bar represents the cored interval in A5 well.
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<tr>
<th>Depth in ft</th>
<th>Dip angle and direction</th>
<th>Rock Unit</th>
<th>Lithology with correlations selected by DUALDIP</th>
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**Fig. 10:** DUALDIP of Amal 9 well showing the main structural features and facies. Black bars represent the cored intervals in the well.

**Fig. 11:** Well-to-well correlation showing the interpreted system tracts. The datum is the sequence boundary SB2.
Fig. 12: Litho – saturation crossplots for good reservoir quality in A5 and Amal 9 wells.
Fig. 13: Litho – saturation crossplots for poor reservoir quality in A3B and SG365-1 wells.

Fig. 14: Crossplot of core permeability against core porosity in A5 well indicating good relationship between them.
Fig. 15: Stratigraphic modified Lorenz (SML) plot showing the hydraulic flow units in the Kareem Formation of Amal 9 well.

Fig. 16: SML plot showing reservoir flow and storage capacity for Amal 9 well. We note that about 80% of the production comes from the interval between 7285 and 7352 ft depth.
Fig. 17: SML plot showing reservoir flow and storage capacity for GS365-1 and GS373-2 wells. We don't expect any flow for these wells.
Fig. 18: Determination of the optimum HFU using SSE and the corresponding HFU versus depth in A5 and Amal 9 wells.

Discussion:

Three main geologic and petrophysical aspects need to explanation, in order to obtain a reasonable interpretation for the Kareem Formation. These aspects are facies, thickness and reservoir quality. The Facies show great variation from anhydrites to high radioactive sands, low radioactive sands, consolidated and unconsolidated sands, conglomerate, shales and carbonates. Such facies was greatly affected by the preexisting low and high structures. The anhydrites tend to precipitate in low structure, where no anhydrites were found on the crests. This imply shallow depositional environment for the anhydrite deposits. The main stacked sands tend also to occur in the low structures in shallow marine condition. However, thin sand layers were occurred during a transgressive phase. Such layers are good reservoir quality. The presence of unconsolidated sands indicates high rate of sedimentation. With sea level rise, pelagic transgressive sediments were occurred in both low and high structures. The Kareem Formation thickness is mainly controlled by the syn-sedimentary faulting. Erosion could play a secondary role in the determination of the thickness. The main challenge for the Kareem Formation is the reservoir quality, in which the presence of sands doesn’t mean presence of good reservoir. In Hilal area, several wells were encountered the Kareem sands without hydrocarbon flow, due to poor reservoir quality.
(Raafat, 1994). The reservoir quality is controlled by the post–deposition diagenetic processes such as cementation, compaction and alteration of feldspars to sericite. More cemented, compacted and altered sediments resulted in decreasing of reservoir quality. Dolomite cement and alteration of feldspars led to filling the pores and therefore, reduction of the effective porosity and of course the permeability. The final result, there is no hydrocarbon flow. On the other hand unconsolidated sands with less feldspars alteration maintain the effective porosity and permeability and consequently good reservoir quality.

Conclusions:

1. The Kareem Formation represents a good example for studying an extremely heterogeneous reservoir. So, integration of the geophysical and geologic data could facilitate and produce more reliable picture for the studied formation.
2. Faults and the pre-existing low and high structures were the main controlling facies and thickness of the Kareem deposits.
3. Good reservoir quality was encountered on the downthrown side of the faults, in which the sandstone had a chance to deposit. On the upthrown side, clays represent the main constituent.
4. The Kareem Formation can be divided into two sequences, separated by regional sequence boundary. The lower sequence contains only lowstand system tract, which represents the main target. The upper sequence consists of three system tracts; lowstand, transgressive and highstand.
5. The reservoir quality is ranged from good to poor, depending on the degree of the post–sedimentation diagenetic processes.
6. Seven hydraulic flow units can be identified in the Kareem Formation.

Acknowledgements

The Author is grateful to the Egyptian General Petroleum Corporation (EGPC) and Gulf of Suez Petroleum Company (GUPCO) for providing data.

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