Integrated Evaluation of the Main Petrophysical Parameters for Sidri Member, Belayim Land Oil Field, Sinai, Egypt

Using Log and Core Data.

By

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ABSTRACT

The present study aims to display the impact of an integration of core and log data for evaluating the petrophysical parameters of the clastic member known as Sidri Member of Belayim Formation to help enhance the quality of the reservoir.

Sidri Member in Belayim Land oil field has been divided into three zones (from top: S3, S2 & S1) according to the main lithologies which are composed of sandstones and shales. The reservoir parameters of this member were mapped to show the aerial distribution of these parameters. The estimated petrophysical parameters of the reservoir throughout the study area range between about 10% and 20% for effective porosity, 5% and 20% for shale volume and between 65% and 90% for hydrocarbon saturation. This indicates that Sidri Member in this field can be considered as a good reservoir.

Also, the Winland empirical equation was used to detect the hydraulic flow units (HFU’s) in the investigated reservoir.

Keywords: Formation Evaluation, Petrophysics, Sidri Member, Belayim Land, Flow Units, Integrated Evaluation.

1. Introduction

The Belayim Land oil field is located on the eastern coast of the Gulf of Suez, between the longitudes 33° 12’ and 33° 15’ East and latitudes 28° 35’ and 28° 40’ North, about 9 Km east of Belayim Marine field and 25 Km south of Abu Rudeis Camp (figure 1). It was discovered in 1954 and occupies an area of about 113 km². From then until now, about 350 wells were drilled in the field, which became very mature field and represents a significant portion of the total oil production of Petrobel. The field reached its maximum daily production of 62,000 BOPD in 1963, then declined to reach its minimum rate of 28,000 in 1983. Since that time, continuous exploration and development efforts have been spent to raise the production again to reach 80,000 BOPD. An intensive effort of exploration and development has been done through different phases that were applied in the area (Mokhles et al., 2009).
2. Geologic Setting

The NW-trending Gulf of Suez is about 300 km long, and the complete rift basin, including the onshore border fault systems, varies in width from about 50 km at its northern end to about 90 km at its southern end where it merges with the Red Sea. This has been traditionally referred to as the “Clysmic” rift (Robson, 1971).

The present-day Gulf of Suez rift, together with the Red Sea oceanic basin and the Aqaba–Dead Sea transform systems, comprise the Sinai triple junction, which initiated during the northeasterly movement of Arabia away from Africa, the age of such movements is mainly Neogene (Fichera et al., 1992). The rifting originated in the pre-Miocene, with the maximum tectonic subsidence, accompanied by magmatic events, occurring in the late Oligocene–early Miocene (Gandino et al., 1990). Subsidence may have continued until the late Neogene.

Garfunkel and Bartov, 1977 modeled the stresses operating during the development of the Suez rift. The north-south and northwest-southeast orientations of faults imply a preexisting grid of fractures that were reactivated during subsidence of the rift.

The geometry of the basinal fault system is typical for those of extensional settings, and the Gulf of Suez can be considered as a failed rift. Generally, the Gulf of Suez is subdivided into three tectonic provinces (figure 2):

i. Darag basin at the northern end,
ii. Belayim Province in the middle,
iii. Amal-Zeit Province at the southern.

Each sub-basin is asymmetric, bounded on one side by a major NW-trending border fault system with large throws (4-6 km in general) together with a dominant stratal dip direction toward the border fault system (Bosworth and McClay, 2001).

The three provinces are separated by two north-northeast–south-southwest major accommodation faults or hinge zones. Each province has its own structural and stratigraphic history.

3. Lithostratigraphy

The lithostratigraphic units in the study area range from Precambrian to
Holocene in age and have been divided into three major sequences relative to the Miocene rifting event and defined as the pre-rift, syn-rift and post-rift lithostratigraphic units. A generalized lithostratigraphic scheme of the study area is given in figure (3).

Figure 3: Lithostratigraphic Column for the Gulf of Suez (After Alsharhan, 2003).

4. Materials & Methodology

The present study aims to display the impact of an integrated evaluation for the petrophysical parameters of Sidri Member to help enhance the quality of the reservoir. In order to do so, the following materials were used:

Seismic Data: Twenty seismic lines were used to give us a clue to reveal and understand the regional structural features affecting the area of interest.

Well-log Data: Five logs were used to evaluate the reservoir parameters. This study was done utilizing different types of open-hole well logs for the determination of the included petrophysical parameters.

Core Analysis Reports: Core analysis data for one well in Belayim Land oil field was used to evaluate the clastics of Belayim Formation.

5. Results and Discussions

5.1 Seismic Interpretation

Among the 20 interpreted seismic profiles, two sections were selected to demonstrate and illustrate the structural framework of the study area.

Seismic Section AA'

Figure (4) shows the 2D interpreted seismic section AA' passing through the north-western part of the study area. It
reveals the presence of horsts and grabens delineated by normal step-like faults (normal to the Clysmic trend). Five major faults were delineated where F2 and F3 forms a horst that represent the major structural trap in this area.

**Seismic Section BB’**

The 2D interpreted section (BB’) is represented in figure (5). This line passes through the eastern part of the study area. A group of simple normal step faults were observed along the section. These faults are parallel to the Clysmic trend. Among these faults, F7 and F8 faults delineate a horst with a good reservoir potentiality.

The remaining sections were interpreted and the resulted structural map is presented in figure (6), where two major faults (F1 & F2) parallel to the Clysmic trend are bounding the study area from the east. Also, a similar fault (F3) is bounding it from the west; F2 & F3 together forming a horst. The interpretation of the 2D seismic lines parallel to the Clysmic trend reveal the presence of two major faults (F7 & F8) that represent with F2 & F3 a three-way dip closure.

![Interpretation of Seismic Section (AA')](image)

![Interpretation of Seismic Section (BB')](image)
5.2 Formation Evaluation

5.2.1 Zonation
Sidri Member is subdivided into:

Upper part (S3): Sand (variant shale content), oil-bearing, and ranges from 9-31 m in thickness.

Middle part (S2): More sandy- and more shaly- layers alternate with thickness ranges from 11-33 m.

Lower part (S1): Sand (variant shale content), oil-bearing, with a thickness range of 17-51 m.

5.2.2 Lithology Determination

M-N Crossplot
The M-N crossplot uses the density, compensated neutron, and compressional sonic logs to identify binary and ternary mixtures of minerals. The results point out the presence of quartz as the dominant component for the low shale points, while the high shale points fall in the vicinity of calcite and anhydrite minerals giving a primary indication for the shale to be dolomitic (figures 7, 8 & 9)
Density-Neutron Crossplot

The density-neutron crossplot helps determine lithology of oil- or water-filled formations. The plotted points occupied different positions along the three lines indicating that shale points fall around the dolomite line, while shaly points fall around the sandstone line (figures 10, 11 & 12 A).

Sonic-Neutron Crossplot

Acoustic velocity is primarily a function of the rock matrix and can be used to identify different lithologies. Hence, we have constructed the neutron-sonic crossplot and plotted our data (as illustrated in figure 10, 11 & 12 B) to confirm the lithological interpretation provided from the M-N and the density-neutron crossplots.

Figure 10: Density-Neutron (A), Sonic-Neutron (B) Crossplots for S3 Zone.

Figure 11: Density-Neutron (A), Sonic-Neutron (B) Crossplots for S2 Zone.

Figure 12: Density-Neutron (A), Sonic-Neutron (B) Crossplots for S1 Zone.
5.2.3 Shale Volume Estimation

The total shale content in the three shaly-sand zones was calculated using single and double clay indicators. The vertical and horizontal variations were tracked. The maximum shale content for S3 zone is found to be 16 % while the minimum recorded value was 5 %. Also, the values recorded for S2 zone range from (10 -20) %, while S1 zone has a much narrower range (12-13) %. This variation is illustrated in figures (13, 14 & 15).

5.2.4 Shale-Type Determination

To study the clay distribution mode in the reservoir, three different methods have been used as described below:

**Thomas-Stieber Plot**

Thomas-Stieber’s plot shows that both laminated and dispersed types are represented within the reservoir but vary vertically from one zone to another, and horizontally from one location to another. Figures (16, 17 & 18 A) illustrate the horizontal variation, where the three zones is dominated by laminated shale-type with contributions from the dispersed type.

**Dispersed-Laminated Plot**

The relation between the calculated shale volume ($V_{sh}$), the sonic-derived porosity ($\Phi_s$), and the density-derived porosity ($\Phi_d$) can be used to construct a plot to differentiate between dispersed and laminated shale points within the reservoir.

The quantity ($\Phi_s - \Phi_d$) % is determined and plotted on the x-axis against the shale content ($V_{sh}$) % on the y-axis. Two differential lines are drawn to separate laminated and dispersed points (figures 16, 17 & 18 B).
Figure 16: Thomas-Stieber (A), Dispersed-Laminated (B) Shale plots for S3 Zone.

Figure 17: Thomas-Stieber (A), Dispersed-Laminated (B) Shale plots for S2 Zone.

Figure 18: Thomas-Stieber (A), Dispersed-Laminated (B) Shale plots for S1 Zone.
To locate the vertical distribution for both laminated and dispersed shale types, we constructed the model displayed in figure (19) that confirmed the results obtained from the previous methods, and also shows the verticals distribution for the shale occurrences within the studied succession.

5.2.5 Net-Pay Thickness

The goal of the net-pay calculations is to eliminate nonproductive rock intervals and provide a solid basis for a quality reservoir description and quantitative hydrocarbons calculations. In the area under investigation, the net-pay thickness ranged from (1m) to (19 m) for S3 zone, from (1m) to (10 m) for S2 zone, and from (10 m) to (19 m) for S1 zone. The following figures display the distribution of these results:

Figure 19: Shale-Type Analysis Obtained from IP Software.

Figure 20: Net-Pay Thickness Distribution on Top of S3 Zone.

Figure 21: Net-Pay Thickness Distribution on Top of S2 Zone.
5.2.6 Effective Porosity

The quality of a reservoir is defined by its hydrocarbon storage capacity and deliverability. The hydrocarbon storage capacity is characterized by the effective porosity and the size of the reservoir, whereas the deliverability is a function of the permeability. Effective porosity is the volume percentage of interconnected pores in a rock.

Effective porosity calculations showed that the porosity in S3 zone ranges from 13 to 20 %, while that for S2 zone ranges from 11 to 18 %, and finally S1 zone has porosity that range from 18 to 21 %.

The following figures (23, 24 & 25) illustrate the variation of porosity in the three studied zones.

5.2.7 Fluid Saturation

Most methods for calculating saturation require knowledge of formation water resistivity ($R_w$) at the formation temperature, so it is necessary along our step-by-step path to find out how much hydrocarbon is in the ground.
**Computation of Water Resistivity**

The Pickett’s plot is a visual representation of the Archie equation and therefore is a powerful graphic technique for estimating $R_w$ ranges within a reservoir. All that is needed to make a Pickett plot is a set of porosities and corresponding resistivities taken from well logs.

From Archie equation:

$$S_w = \left( \frac{a}{\phi_m} \cdot \frac{R_w}{R_t} \right)^{1/n}$$

Rearranging and substituting for resistivity index (I):

$$I = \frac{1}{S_w^n} \quad , \quad R_t = \frac{a * R_w * I}{\phi^n}$$

Taking logs:

$$\log(R_t) = \log(a * R_w) + \log(I) - m * \log(\phi)$$

In this thesis, the Pickett’s plot was constructed as in figure (26); hence, it doesn’t yield a very accurate result due to the absence of free water zone. The ($R_w$) has been found to be about (0.06 Ω.m).

**Estimation of Hydrocarbon Saturation**

The hydrocarbon saturation is usually considered to be the most important parameter in the petrophysical evaluation process. Hence the water saturation gives the pores ratio occupied by water, the hydrocarbon saturation represents the remaining ratio. So, it can be simply calculated using the equation:

$$S_{hr} = 1 - S_w$$

Applying this equation to S1, S2 and S3 resulted in the determination of the variations in the hydrocarbon saturation within the reservoir. The results pointed out that S3 zone has hydrocarbon saturation values range from 90 to 66 %, while that for S2 zone range from 86 to 66 %, and for S1 zone range from 80 to 77 %.

These variations are presented in figures (27, 28 & 29).
5.2.8 Cutoffs and Summation Parameters

Cutoffs

The following table summarizes the cutoff values used in this evaluation process:

Table 1: Cutoffs Summary.

<table>
<thead>
<tr>
<th>Vsh</th>
<th>$\Phi_{eff}$</th>
<th>Sw</th>
</tr>
</thead>
<tbody>
<tr>
<td>33%</td>
<td>9%</td>
<td>40%</td>
</tr>
</tbody>
</table>

Summary of Petrophysical Parameters

After we walk through all of the evaluation steps for the five-available wells, the following tables summarize the resulted petrophysical parameters and display them as an average values for each parameter:

Also, a correlation panel is created for all of the litho-saturation plots for the studied wells as displayed in figure (30).

Table 2: Summary of Petrophysical Parameters for S3 Zone.

<table>
<thead>
<tr>
<th>Well</th>
<th>112.82</th>
<th>112.92</th>
<th>112.93</th>
<th>112.128</th>
<th>112.136</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gross (m)</td>
<td>13.7</td>
<td>18.6</td>
<td>10</td>
<td>21</td>
<td>9.1</td>
</tr>
<tr>
<td>Net (m)</td>
<td>1.86</td>
<td>1.07</td>
<td>7.77</td>
<td>19.25</td>
<td>7.77</td>
</tr>
<tr>
<td>N/G</td>
<td>0.136</td>
<td>0.057</td>
<td>0.777</td>
<td>0.917</td>
<td>0.854</td>
</tr>
<tr>
<td>$V_o$%</td>
<td>16.1</td>
<td>4.9</td>
<td>16.1</td>
<td>11.5</td>
<td>11.5</td>
</tr>
<tr>
<td>$\delta_o$%</td>
<td>12.8</td>
<td>13.9</td>
<td>18.2</td>
<td>19.8</td>
<td>18.8</td>
</tr>
<tr>
<td>$S_o$ %</td>
<td>34.4</td>
<td>27.5</td>
<td>21.6</td>
<td>23.4</td>
<td>9</td>
</tr>
<tr>
<td>$S_w$ %</td>
<td>65.6</td>
<td>72.5</td>
<td>78.4</td>
<td>76.6</td>
<td>91</td>
</tr>
</tbody>
</table>

Table 3: Summary of Petrophysical Parameters for S2 Zone.

<table>
<thead>
<tr>
<th>Well</th>
<th>112.82</th>
<th>112.92</th>
<th>112.93</th>
<th>112.128</th>
<th>112.136</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gross (m)</td>
<td>25.7</td>
<td>11</td>
<td>30.6</td>
<td>15.5</td>
<td>33.4</td>
</tr>
<tr>
<td>Net (m)</td>
<td>9.6</td>
<td>1.07</td>
<td>5.61</td>
<td>6</td>
<td>2.9</td>
</tr>
<tr>
<td>N/G</td>
<td>0.374</td>
<td>0.097</td>
<td>0.183</td>
<td>0.347</td>
<td>0.087</td>
</tr>
<tr>
<td>$V_o$%</td>
<td>20</td>
<td>12.6</td>
<td>18.8</td>
<td>10</td>
<td>12.5</td>
</tr>
<tr>
<td>$\delta_o$%</td>
<td>14.3</td>
<td>10.4</td>
<td>15</td>
<td>17.9</td>
<td>14.2</td>
</tr>
<tr>
<td>$S_o$ %</td>
<td>26.3</td>
<td>33.6</td>
<td>31.9</td>
<td>14.4</td>
<td>22.9</td>
</tr>
<tr>
<td>$S_w$ %</td>
<td>73.7</td>
<td>66.4</td>
<td>68.1</td>
<td>85.6</td>
<td>77.1</td>
</tr>
</tbody>
</table>

Table 4: Summary of Petrophysical Parameters for S1 Zone.

<table>
<thead>
<tr>
<th>Well</th>
<th>112.82</th>
<th>112.92</th>
<th>112.93</th>
<th>112.128</th>
<th>112.136</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gross (m)</td>
<td>24.1</td>
<td>30.4</td>
<td>17.5</td>
<td>31.5</td>
<td>28</td>
</tr>
<tr>
<td>Net (m)</td>
<td>13.56</td>
<td>19.35</td>
<td>9.89</td>
<td>20.5</td>
<td>11.89</td>
</tr>
<tr>
<td>N/G</td>
<td>0.563</td>
<td>0.037</td>
<td>0.565</td>
<td>0.651</td>
<td>0.425</td>
</tr>
<tr>
<td>$V_o$%</td>
<td>12.4</td>
<td>12.6</td>
<td>11.9</td>
<td>13.3</td>
<td>10.8</td>
</tr>
<tr>
<td>$\delta_o$%</td>
<td>20.6</td>
<td>18.4</td>
<td>19.7</td>
<td>19.6</td>
<td>18.5</td>
</tr>
<tr>
<td>$S_o$ %</td>
<td>23</td>
<td>21.1</td>
<td>20.3</td>
<td>21.6</td>
<td>21</td>
</tr>
<tr>
<td>$S_w$ %</td>
<td>77</td>
<td>78.9</td>
<td>79.7</td>
<td>78.4</td>
<td>79</td>
</tr>
</tbody>
</table>
Figure 30: A Correlation Panel of the Litho-Saturation Plots for the Studied Wells.
5.3 Core Data Analysis

Core and wireline log analysis provide the means for evaluation of reservoir potential. Proper core-to-log transformations are required to ensure that parameters used for quantitative log analysis are reasonable and that data from both sources are mutually supportive.

5.3.1 Petrographic Characteristics

Petrographically, the analyzed samples are mainly sub-feldspathic and arenite. Most samples are enriched in quartz and feldspars with subordinate quantities of lithic fragments and detrital clays.

![Figure 31: Thin-Section for a Core Sample from Sidri Member.](image1)

![Figure 32: SEM Analysis for a Core Sample from Sidri Member.](image2)

5.3.2 Matrix Density

The matrix density ($\rho_m$) can then be identified as the bulk density value at 0% porosity, while fluid density ($\rho_f$) is that at 100% porosity. (figure 34).

![Figure 33: Vertical Distribution of Whole Rock XRD.](image3)

5.3.3 Porosity Corrections

Helium porosity was measured at constant pressure. However, as increasing pressure closes fractures and compresses the pore space, porosity will decrease. The magnitude of the change depends on the rock fabric. As the rock becomes better consolidated, this pressure dependence decreases. To simulate the reservoir conditions, two pressure-dependent corrections were applied:

Net Overburden Pressure Correction

This correction was applied by constructing a porosity–pressure relationship at different depths (figure 35), from which we can easily extract the overburden-corrected porosity at the reservoir conditions.
Figure 35: Porosity – Pressure Relationship at Different Depths.

**Uniaxial Stress Correction**

This correction was applied using the following equation (Newman, 1973) which correct for the extra deformation resulted from the normal hydraulic loading applied in the laboratory:

\[
\phi_{\text{Uniaxial-Corrected}} = \phi_{\text{Room Conditions}} - \left[ (\phi_{\text{Room Conditions}} - \phi_{\text{Overburden-Corrected}}) \times 0.61 \right]
\]

The porosity values resulted from this correction phase were plotted with the helium-porosity values to express the mutual relationships between them (figures 36).

5.3.4 Porosity – Permeability Relationship

Attempts are often made at finding a relationship between permeability (k) and porosity (\(\phi\)) by making a semi-log plot of these data from core (figures 37). Such a relationship can permit permeability estimation over intervals where only core porosity or log porosity information is available.

5.3.5 Electrical Parameters

Special core analysis data measurements of cementation (m) and saturation (n) exponents should be incorporated into the Archie model. In “m” measurements, the logarithm of formation factor, given by log(F) = log(Ro/Rw) is plotted against log(porosity), according to Archie:

\[
F = \frac{a}{\phi^m}, \quad \log(F) = -m \times \log(\phi)
\]

Therefore, the gradient of the line gives “m” (figure 38), where the higher the “m” value used, the higher the water saturations, Sw, that will be calculated, and vice versa (Darling, 2005).
In “n” measurements, by plotting the logarithm of the resistivity index, given by $\log(I) = \log \left( \frac{R_t}{R_o} \right)$, against $\log(S_w)$, according to Archie:

$$I = \frac{1}{S_w^n}, \quad \log(I) = -n \times \log(S_w)$$

Therefore, the gradient of the line gives “n” (figure 39), where the higher the $n$ value used, the higher the $S_w$ that will be calculated, and vice versa (Darling, 2005).

5.3.6 Cutoffs

The core-based cutoff values are determined by the coordinated cutoff set using core and log readings.

Porosity Cutoff

First of all, we reconstructed the core porosity-permeability crossplot (figure 37), fit a semi-log line through the data points to determine the porosity cutoff that correspond to the permeability cutoff (0.1 md for gas reservoir, and 1.0 md for oil reservoir). The porosity cutoff is found to be (9.49 %).

Shale Cutoff

In shaly sands, we plot porosity versus shale volume (figure 40), and enter a graph with porosity cutoff to pick corresponding shale volume. This is the $V_{sh}$ cutoff, and is found to be (32.8 %).

Saturation Cutoff

The water saturation cutoff can be found using the same idea where porosity is plotted against water saturation (figure 41). The calculated $S_w$ cutoff is (40 %).

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Figure 39: Saturation- Resistivity Index Relationship.

Figure 40: Core Porosity – Shale Volume Relationship.

Figure 41: Core Porosity – Water Saturation Relationship.

These cutoffs values together with the electrical parameters were used to rerun the computer-processed interpretation and construct an enhanced CPI that may has a higher accuracy than the ordinary one. Figure (42) displays a correlation between the ordinary and integrated CPI’s for well 112-82.
5.3.6 Hydraulic Flow-Unit Concept

Flow unit has evolved from the initial conception by Hearn et al. (1984) with the use of different parameters for delineation which include the R35 (pore throat radius measured at 35% mercury saturation) from Winland’s equation with 4 basic flow units classified by (Martin et al., 1997):

- FU4: Megaport (R35>10 μm),
- FU3: Macroport (2-10 μm),
- FU2: Mesoport (0.5-2 μm) and
- FU1: Microport (R35<0.5 μm).

The Winland’s empirical equation was used to detect the HFU’s in the investigated reservoir. This equation can be expressed as:

\[ R_{35} = 5.395 \left( \frac{K_{0.588}}{\Phi} \right)^{0.864} \]

Where:

- R35 is the calculated pore throat radius (μm) at 35% mercury saturation,
- K is the permeability.

The resulted model demonstrates four different flow units (FU1, FU2, FU3 & FU4) as presented in figure (43).
6. Summary and Conclusion

- Based on the sand–shale relationships within the reservoir, Sidri Member is divided, from top to bottom, into three zones (S3, S2, S1).
- Sandstone is the main lithology component and dolomitic shale is the alternative component within the reservoir. These results were confirmed by the thin sections and XRD analyses.
- The shale type is found to be laminated.
- The petrophysical evaluation for Sidri Member indicates that S3 & S1 have almost the best parameters. Hence it became a good target for the exploration or development efforts.
- For S3 zone, the net-pay thickness ranges between (2 – 19) m. The shale content ranges from 5% to 16%. The effective porosity fluctuates between (10 %) and (20 %). The hydrocarbon saturation values range from (65 %) to (90 %).
- For S1 zone, the net-pay thickness ranges between (10 – 20) m. The shale content ranges from 13% to 11%. The effective porosity fluctuates between (21 %) and (18 %). The hydrocarbon saturation values range from (77 %) to (80 %).
- Cutoffs and other parameters obtained from core analyses can be used in the formation evaluation process, and it yields a more accurate results.
- The hydraulic flow unit model can be constructed using many different methods, and it can be used in detailed studies to predict permeability in uncored wells and gives acceptable results that may accelerate the progress of the development process.
References


