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The Porous-Permeable Zones in Heterogeneous Carbonate Reservoirs: A Case Study from Amara Oilfield-Iraq

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Abstract: The understanding of carbonate rock heterogeneity under subsurface conditions is still in debate due to a significant variation in mineral composition and changes in rock textures during/after diagenesis. However, several studied utilized the facies analysis, and conventional set of logs to draw a detailed description of reservoir rocks. This paper draws the precise modelling design for cretaceous carbonate reservoir characterization through micro- and -macro porous media and permeable zones, integrates the lithological variation with more than 1800 measurement of porosity/permeability values along two bore wells in Amara Oilfield. This paper presents a detailed description of lithological and reservoir characterization in Am1 and Am3 borewells form west to east, respectively. In west, the plugged samples obtained from Mishrif formations, while from east, the samples obtained from Khasib, Mishrif and Yamama formations. The porosity and permeability distribution in subsurface settings were divided into three porous-permeable zones in Am1 and Am3. The Am1 in the west shows a highest porous-permeable zone than Am3 in the east of Amara Oilfield. The permeability and porosity in Am1 measured up to 591 md and 29.6%, while in Am3 recoded up to 352 md and 24.2%, respectively. Therefore, the porous-permeable subsurface distribution and their petrophysical mapping for different kinds of reservoirs reveal that the porosity and permeability measurements decreased from west to east, however, few fluctuations in increasing and decreasing from porosity and permeability values mostly controlled by involvement of diagenetic fluids which caused by heterogeneity in carbonate rocks.

Keywords: Porosity; permeability; reservoir; carbonate rock heterogeneity; Amara Oilfield

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1. Introduction

Porosity and Permeability are two of the important quality factors that govern fluid transport and storage. Several scholars have been studied the petrophysical parameters of sedimentary rocks, and the correlations different kinds of section [e.g., 1]. The pore size distribution, permeability, and mercury intrusion porosity were all determined, the bulk and particle densities of rocks were also calculated. Porosity and permeability are strongly associated in a very excellent direct proportional connection, i.e., as porosity grows, so does permeability, other rock features, such as the number of open and closed pores in the sample, as well as pore size and distribution, impact this connection [2]. Therefore, to investigate the petrophysical features of sedimentary rocks a comprehensive examination of rocks and their potential use in engineering structures and the restoration of ancient monuments are required [2]. Understanding porosity-permeability relationship is crucial to reservoir behavior estimation and the decomposition nature [1]. Several factors affecting porosity and permeability including grain size, packing, compaction, and solution/dissolution processes in which they can increase the differences or similarities between porosity and permeability [3]. Dolomite and limestone are the main composition in carbonate rocks, having different amount of impurities and Mg-rich/poor composition [4], this composition will impact on petrophysical properties of carbonate rocks [5]. The authors added that there is a wide range of vertical and horizontal heterogeneity in carbonate reservoir because of the effect of mineral dissolution and replacing it by other minerals and other factors such as recrystallization after deposition [4].

The heterogeneity of carbonate rocks associated with hydrothermal/hot fluids under subsurface conditions would make the system more complicated and mostly produce a significant vugs and zebra-like texture [e.g.,4,6]. Thus, porosity-permeability relationship in the South German Molasses Basin from carbonate reservoir have shown a wide range of porosity (0.3% to 19.2%) and permeability (10-4 to 102 md, millidarcy), thus, indicate a great heterogeneity in carbonate reservoir [7]. The heterogeneity of carbonate reservoir is the critical factor in estimating the porosity and permeability, especially where there is a significant amount of fracture or vugy pores within the recent subsurface sections. Utilizing new empirical model to allow the permeability estimation with uncertainty up to 10 md based on different lithofacies types, thus, permeability was technically hard to be estimated because of insufficient data, i.e., mud-supported limestone, which has microscopic permeability that can negatively impact on permeability, if compared to porosity [7].

Therefore, the recent work will compare the porosity and permeability in two oil wells (1 & 3) within three subsurface formations from the Amara oilfield (Fig. 1), and will link the petrophysical parameters to micro-scalic observation in order to understand how the alteration of carbonate reservoirs will influence on these parameters. Finally, conceptual model will be illustrated the porosity-permeability relationship with depth and lithofacias changes vertically and horizontally (from west to east).

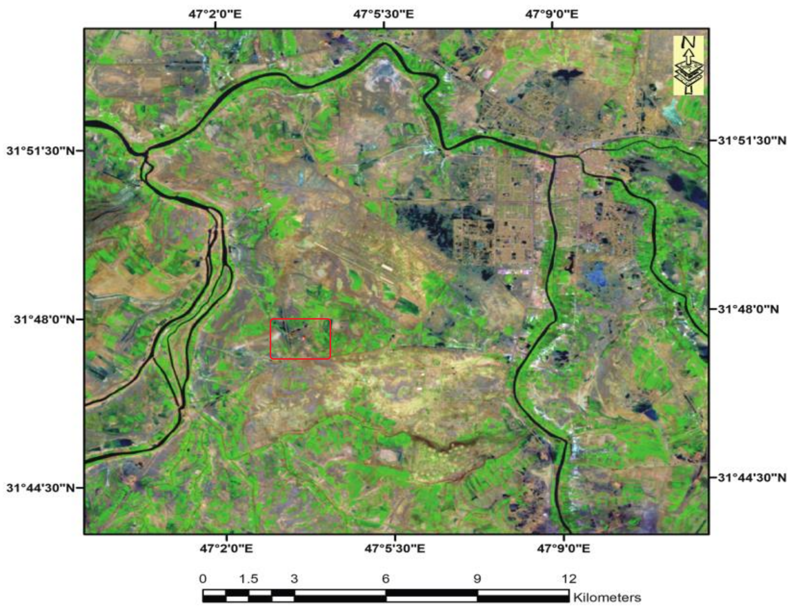


Figure 1. Location of the studied area, close up the red rectangular line, which illustrating the area of Amara Oilfield.

2. Method and Materials

The rock plugs (sample) cut a size of 1*1 in2, then washed the sample using chloroform to remove the hydrocarbons that are originally present in the rock voids. For this purpose, Soxhlet extractor is used to dry in an oven at a temperature of 70 °C for a period of not less than six hours to become ready for measurement. Helium porosity for all the plugs was measured and the following equation is used for the whole measurement.

$$\Phi = \frac{Vp}{Vp + Vg} * 100$$

Where Φ=porosity, Vp= volume of porosity, Vg=volume of grains

Micro-permeameter was utilized in this study to measure the whole plugs and later used Klinkenberg-corrected permeability (see Table 1 & 2). In addition, the following equation is used to calculate the air permeability

$$Ka = \frac{2000U}{P1^2 - P2^2} \times \frac{Pa\ QL}{A}$$

K = air permeability (md), Pa = atm pressure (atm), P1 = in let pressure (atm), P2 = out let pressure (atm), U = Gas viscousity (CP.), L = Length (cm), A = cross sectional area (cm2), Q = gas flowrate CC/Se

The measure data were analyzed using the sophisticated software in order to draw for the first time the mapping distribution of reservoir properties in vertical (considering burial depth) and spacial direction (from west to east). Surfer program shows the three-dimensional figures and contour map for illustrating the porous-permeable zones. While the Grapher program displays the data as a group of populated data. In addition, the MATLAB program utilized to draw the plots in 2D and 3D.

3. Results

More than 900 core samples were analyzed for porosity and permeability in two wells (Am1 and Am3) for Yamama, Mishrif, and Khasib formations in Amara oilfield in Iraq (for details see Table 1 & 2). Despite the depth is controlling the porosity and permeability parameters, we have to consider also the heterogeneity composition of carbonate rock, in addition to fractures-, vugs-…, whether filled or not by cement… For Am1 (see Table 1), the porosity and permeability were measured for 430 samples in every 50 cm thickness of the following formation:

1. Mishrif Formation (2880–3271) m: It consists of a white to grey color of limestone, containing fractures and vugs and some types of stylolites with broken shells of some fossils in the upper part of this formation. While the lower part is characterized a semi-brown limestone that contains a fragment of fossilized shells like foraminifera.

For Am3 (see Table 2), the porosity and permeability were measured for 495 samples in every 50cm thickness of the following formations:

1. Khasib Formation (2852.1–2908.2) m
2. Mishrif Formation (2920.1–2999.8) m
3. Yamama Formation (4404.3–4404.3) m

Measurements from samples Am1 represent three porous-three permeable zones, the first porous-permeable zone is located between 2880 and 2911m, the second porous-permeable zone is distributed from depth at 2920 to 3012m depth, while the third porous-permeable zone is located between 3030 and 3067m. The highest amount of permeability is recorded at first porous-permeable zone (591 md, millidarcy), while the highest and more populated porosity focuses on second zone, and then third zone. While the measurements from Am3 well samples in all three formations (Khasib, Mishrif, and Yamam formations) focuses also on three porous-permeable zones. Am1 and Am-3 reservoir core samples characterized a different kinds of carbonate texture and composition. Generally, composed of limestone and dolomitic limestone, the color ranged from dark to grey colored carbonate rocks. The diagenetic process left a trace of large vugs/open spaces and fractures, in places the compacted grains of carbonate rocks -both limestone and dolomite- are represented the reservoir carbonate core samples.

4. Discussion

Several workers have been studied the reservoir characterization by using facies analysis through set of well logs plot (Fig. 2). Well log data including gamma ray, sonic, neutron and bulk density data [8]. However, utilizing well logs alone are not enough for understanding the complex porosity-permeability system in subsurface conditions. High resolution observation of core rocks, study of textural properties of carbonate rocks and numerical data of porosity-permeability are significant argument to map the reservoir properties and porous media from micro to macro scale zones and to track the heterogeneity of carbonate reservoir in shallow and deep burial settings in 2- and 3-dimensional form. Therefore, this paper used around 860 and 990 porosity and permeability measurements in Am1 and Am3, respectively. These data were analyzed from three formations and two subsurface wells to scan and understand the mapping distribution of porosity-permeability in subsurface condition. The data ranged from1.8 to 29.6% for porosity in Am1 & 0.5 to 24.2 % for porosity in Am3 and 0 to 591 md for permeability in Am1 and 0 to 352 md for permeability in Am3 from west to east borewells in Amara oilfield (Figs. 2 & 3).

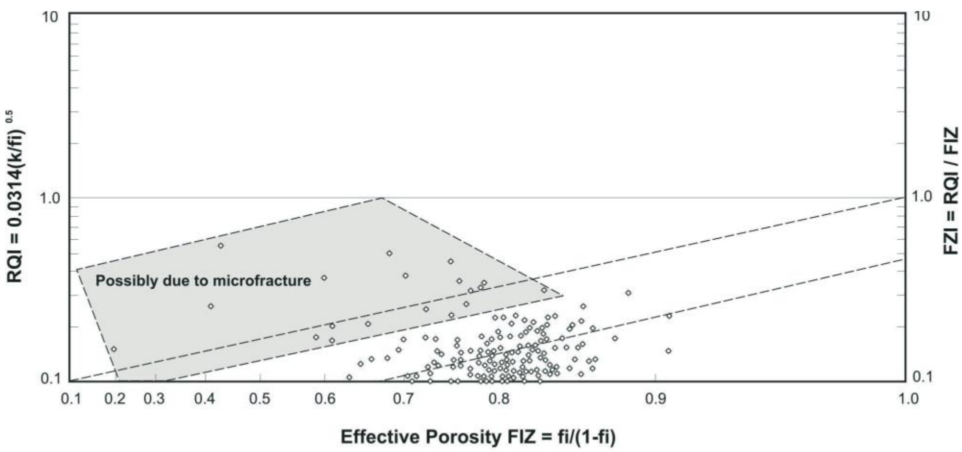


Figure 2. Log-log plot of the Reservoir Quality Index (RQI) versus effective porosity of the Khasib Formation, the data were selected from the wells in the East Baghdad field [9].

The population of porosity – permeability measurements are grouped into three porous-permeable zones in both wells (Am1 and Am3; see Figs. 3 & 4). The whole porosity-permeability measurements in Am1 are belong to Mishrif Formation, while in Am3 are belong to Khasib, Mishrif, and Yamama Formations. The highest porous-permeable zone (Zone I) in Am1 is located between 2880 and 2920 m. The highest amount of permeability and porosity in Zone I are 591 md and 26.9%, respectively. Whereas 0 md and 2.2 % were recorded as the lowest values in Zone II and Zone III. The higher value of porosity and permeability in Zone I could be linked to dissolution and opening system were recognized by the intensive existence of vugs and pore-spaces in the carbonate rock. The frequent appearance of vugs and open-spaces have been reported in NE-Iraq within the Cretaceous reservoir rocks due to dissolution of hot fluids in subsurface and surface settings [4,6]. However, in places the porosity and permeability measurements would not follow the same trends, most likely due to the complicated system in carbonate rocks under subsurface conditions.

The second porous-permeable zone is ranged between 12-20% and up to 80md, respectively. The porosity and permeability in this zone are greater than first and third zones. Thus, the significant variation in porous media could not be related to the burial depth of the boreholes. According to the mechanical compaction under subsurface conditions probably is the main reason behind this decreasing in permeability value, again the complex open and close system sometimes would be also possible reasons [4]. This type of compaction usually happened in low mechanical stress and would be also controlled by mineralogy of sedimentary rocks. The populated values in Zone III are belong to core sample values from deeper zone than Zone I & II. The mean value of porosity in Zone III lower than Zone II, however the geothermal gradient and pressure should increase porous media.

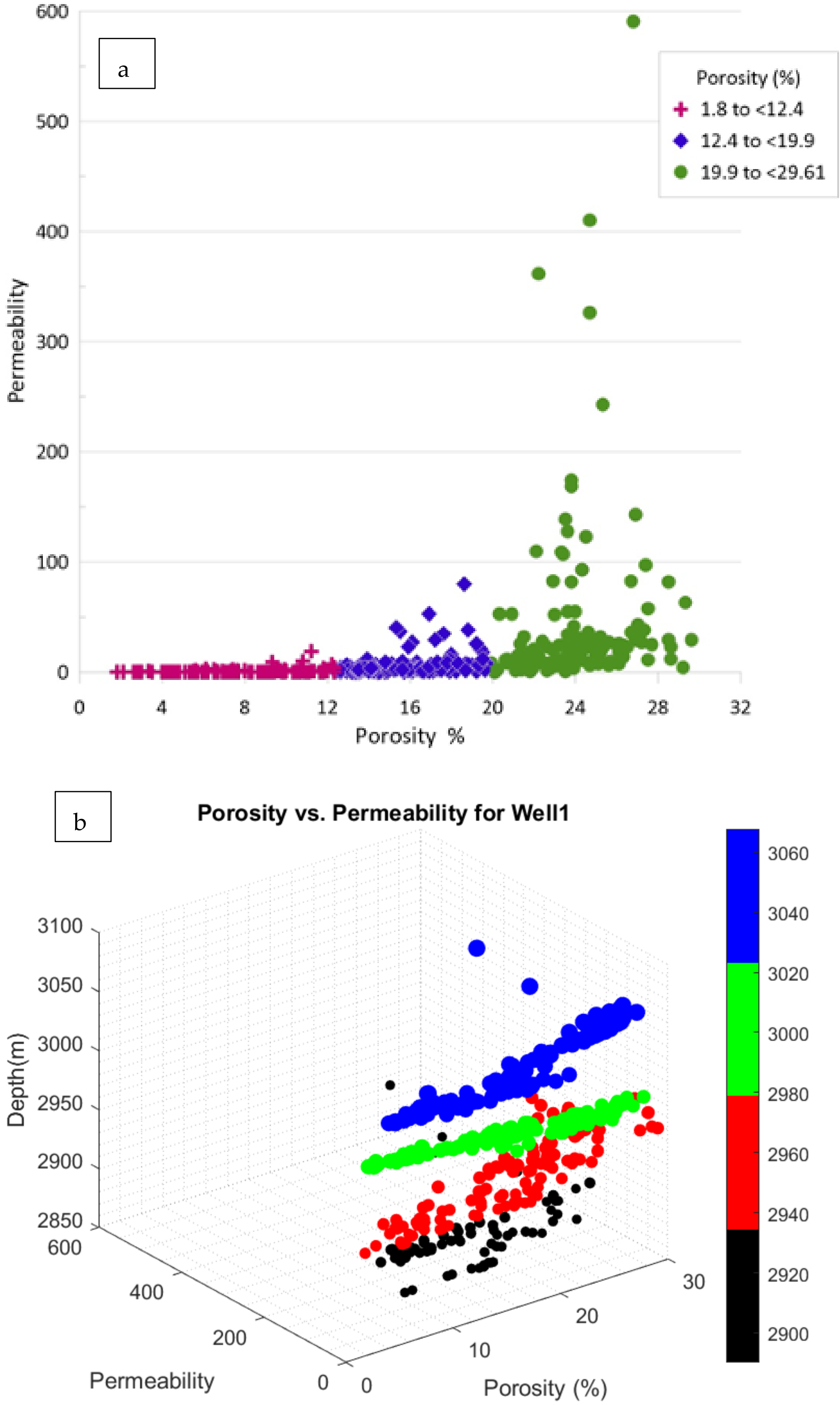
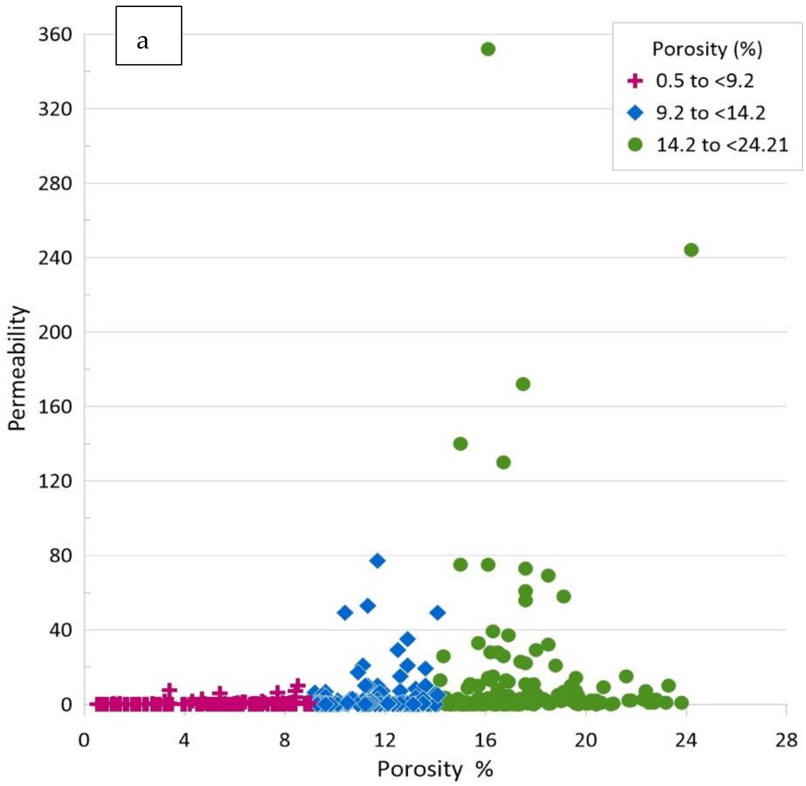


Figure 3. (a) Porosity-permeability relationship, close up the three porous-permeable zones; **(b)** 3D lattice form showing the porosity-permeability-depth relationship in Am1. Depth in meter (m), porosity in percentage (%), permeability in millidarcy (md).

Optical and experimental observations revealed that fluid-rock interactions are the main processes of decreasing the permeability in carbonates [8]. The highest value of porosity (29.6%) and permeability (591 md) were found exactly at 2957.82 and 2893.87m, respectively. On the other hand, the lowest values of porosity and permeability (~0 md) were recorded at deeper burial zone (Zone III). These values variations could be connected to the carbonate complicate system, where the packing, dissolution, compaction and cementation would have a main role in this regard.

The main characteristics and the reasons of heterogeneity of the Khasib Formation have been reported by [9]. Where the best oil-bearing zones showed a porosity value up to 21% based on neutron log and the reservoir characterization of Khasib Formation were obtained from lateral and vertical facies changes, which is sensitive to reservoir characterizations. Such studies could be helpful for our study, but still petrophysical and geochemical studies in addition to the huge numerical measurements used in this paper could draw a better mapping for understanding the subsurface reservoir characterizations and to draw a conceptual modelling from micro- to macro-scale mapping along Amara oilfield (Figs. 5 & 6).



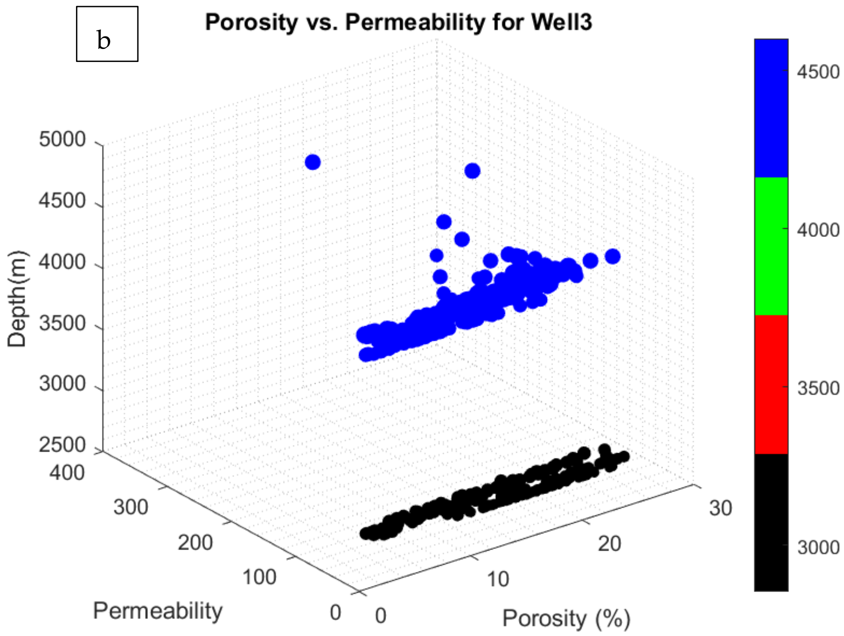


Figure 4 (a) Porosity-permeability relationship, close up the three porous-permeable zones; (b) 3D lattice showing the porosity-permeability-depth relationship in Am3. Depth in meter (m), porosity in percentage (%), permeability in millidarcy (md).

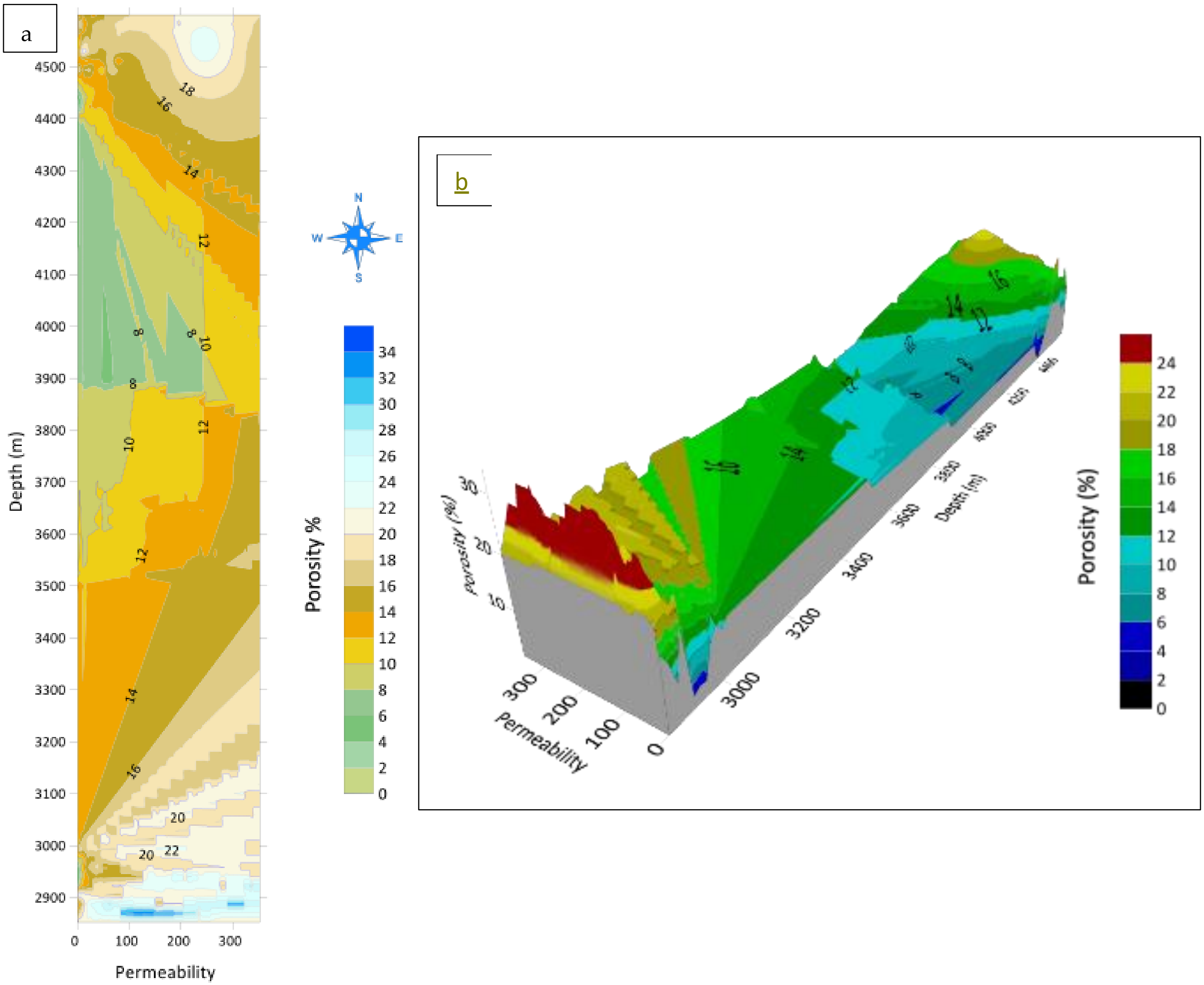


Figure 5. Subsurface distribution map for porosity and permeability range zones in **(a)** 2D and **(b)** 3D. Depth in meter (m), porosity in percentage (%), permeability in millidarcy (md).

In well Am3, again the porous-permeable values populated in three zones (Figs. 4), the highest populated values are grouped in Zone II and III. These zones mostly represented the lower part of Mishrif Formation and Yamama Formation. While the lowest values are belong to Zone I, where mostly represented the Khasib Formation samples.

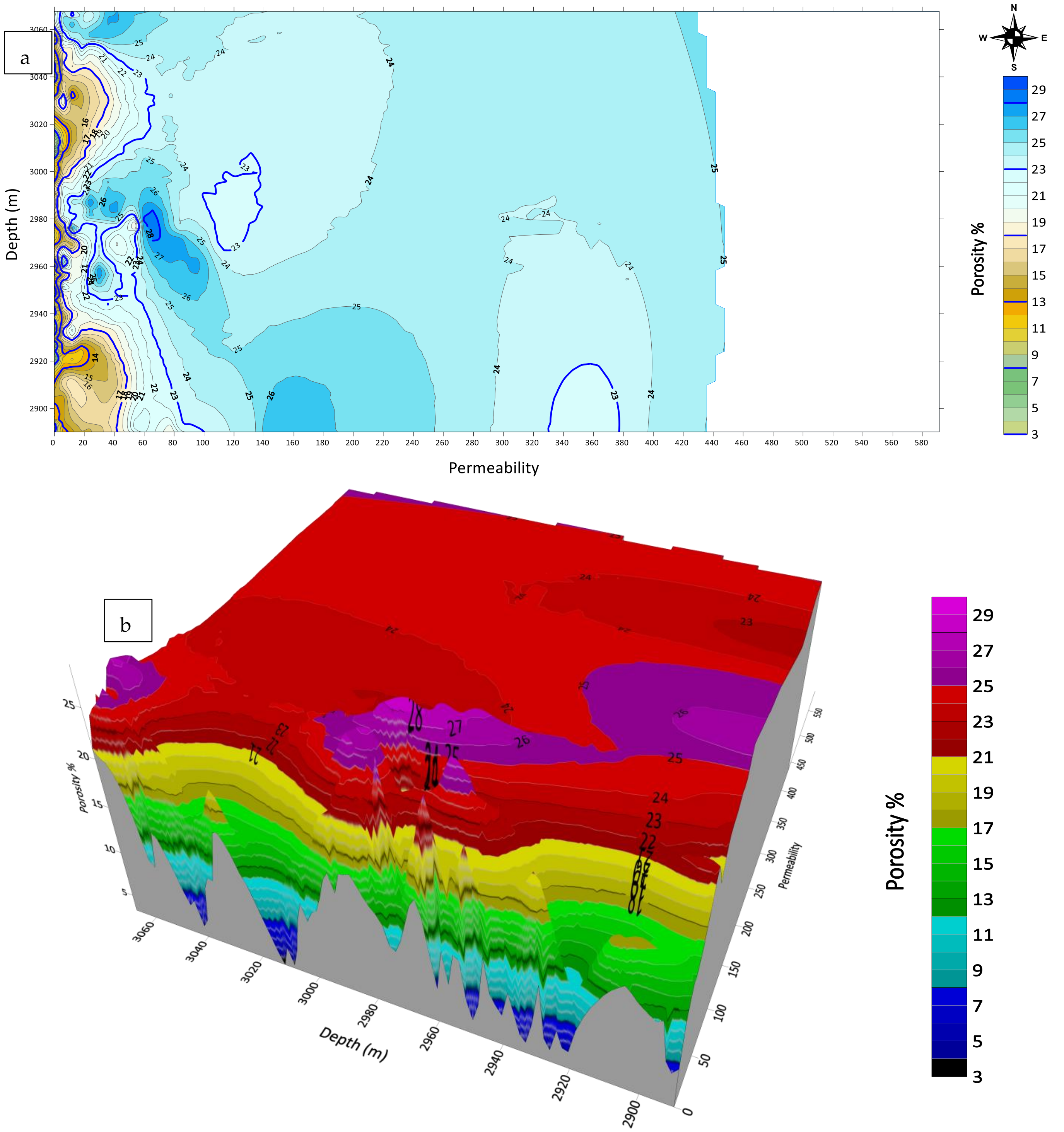
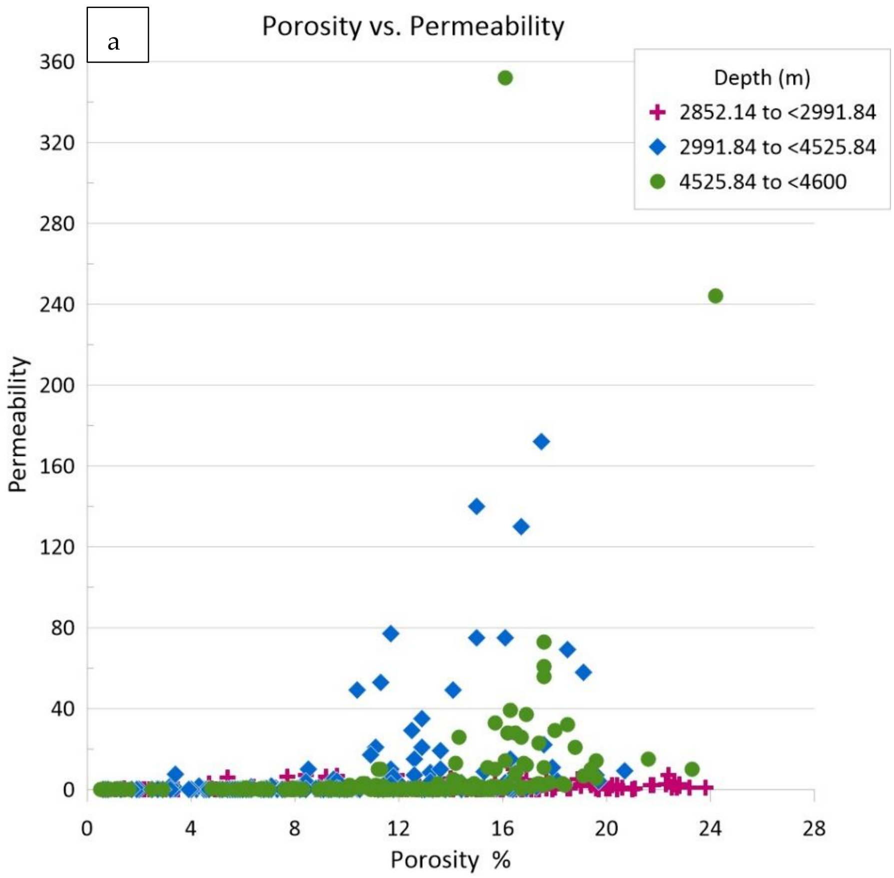


Figure 6. Subsurface distribution map for porosity and permeability range zones in **(a)** 2D and **(b)** 3D. Depth in meter (m), porosity in percentage (%), permeability in millidarcy (md).

In Khasib Formation, the first porous-permeable zone is located between 2850 and 2870 m. The highest and lowest porous measurements varied from (15 to 22.8 %) and (8.8 to 15%), respectively. While, the permeability ranges between (0 and 2.5%). The second porous-permeable region starts from 2899 and ended at 2907. The highest and lowest porosity and permeability range were (2.2 to 23.8%) and (0 to 3.5) respectively. Compare porosity values in Khasib Formation to Mishrif and Yamama formations, show a higher porous zone. The increase of porous zone probably related to less compacted grains within the sedimentary rocks. However, the permeability values are less compared to this porous zone. The effective porous zone is could be linked to the secondary characterization of reservoir rocks (e.g., packing, grain distribution, shape of grain). In carbonate rocks the main reservoir patterns of pores are inter-particle, intra-particle and moldic pores, lacking effective porosity and pore throats, moldic pores is reduce the permeability values [10].

In Mishrif Formation, the porosity and permeability values show a wide considerable range. Compare the measurement of permeability in Mishrif formation to Khasib, the latter reported higher values where the dissolution and alternation of carbonate rocks, these values could be the main reason linked this increase in permeability values. The similar case has been reported by [8,10,11].

According to the burial depth of the recent analysis's samples, the Zone I was obtained from Yamama Formation, and started at 4404 and 4419m, and ended within the depth of 4494 and 4599m. The permeability values recorded the highest in Zone I (up to 350 md) and lowest. With increasing depth, the porosity and permeably increase, es pecially at 4534.62m depth, the highest value of porosity is up to 24.2% and permeability (up to 352md) where the carbonate rock significantly exposed to alteration and diagenesis, however the lowest values of porosity and permeability identified from such maximum depth (0.5% and 0md) where the rocks are more compacted. These two significant differences in porosity and permeability values suggest that the lithologiy in Am1 and Am2 is main contribution factor controlling the lowest and highest distribution values of reservoir characterization than other factors (Fig. 7). Fig. 7 illustrates the 3D distribution model for tracking the potentila of reservoir rocks in vertical (burial) and space direction (from west to east).



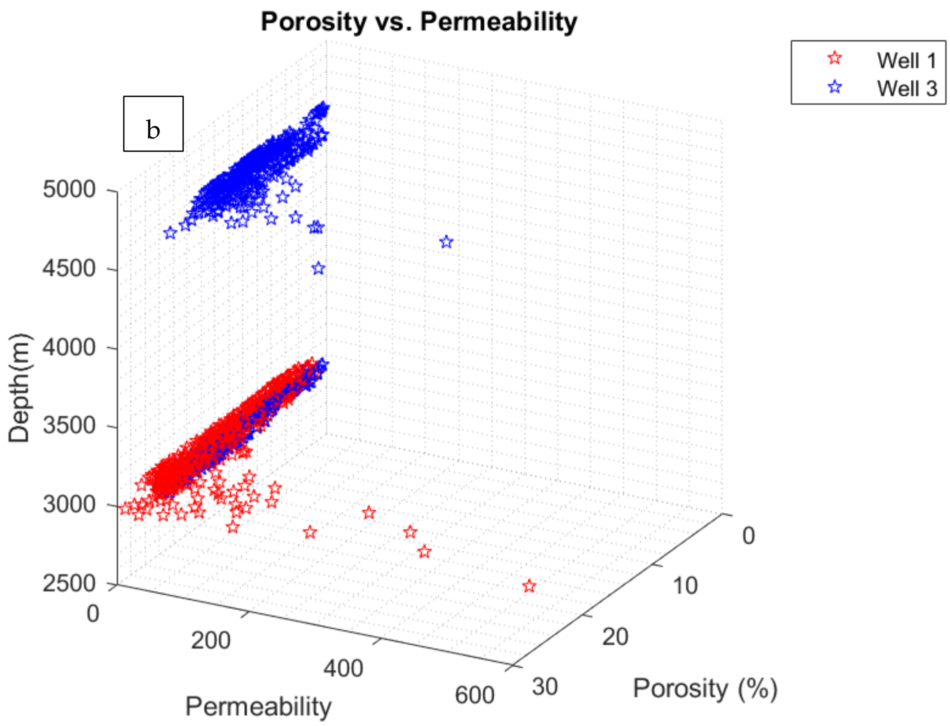


Figure 7 Subsurface distribution map for (a) porosity-permeability relationship and (b) porosity-permeability-depth in 3D form for Am1 and Am2. Depth in meter (m), porosity in percentage (%), permeability in millidarcy (md).

5. Conclusions and Recommendation

The recent paper integrates the lithological data and measurement of more than 1800 values were obtained from porosity and permeability plug samples, and revealed the following:

1. The two borewells from Amara oilfield, Am1 from west and Am3 from east were studied in details using Helium porosity and Micro-permeameter based on the lithology of core samples.
2. More than 1800 measurements of porosity and permeability treated by 3 software (Surfer, Grapher, and MATLAB) to draw the vertical and horizontal reservoir characterization in 2Dimesion and 3Dimension forms.
3. The porosity-permeability relationship shows three porous-permeable zones in Am1 and Am3.
4. The porosity-permeability data in Am1 data obtained from Mishrif Formation, while the porosity-permeability data in Am3 data obtained from Khasib, Mishrif and Yamama formations.
5. The reservoir \`s\` in the studied subsurface wells were significantly dominated by heterogeneity of carbonate rocks, where the lithologically-controlled porosity-permeability zones are the main parameter to determine the modelling of reservoir characterization from west to east of Amara oilfield.
6. The higher value of porosity (29.6%) and permeability (591 md) in Am1 from west is recoded higher values than those of Am3 from east (porosity is up to 24.2%; permeability is up to352 md), this linked to dissolution and opening system due to intensive existence of vugs and pore-spaces hosted in carbonate reservoir rocks.
7. The appearance of the vugs and open-spaces due to dissolution and specifically diagenesis are the main reasons for reducing and increasing the distribution of porous-permeable media under subsurface conditions.

8. The conceptual modelling of Amara oilfield from east to west based on 2 and 3dimension lattice settings shows that the reservoir characterization and porous-permeable zone in Am1 recorded highest porous-permeable values than Am3 in the west of Amara oilfield. Therefore, the porosity-permeability zones were decreased from east to west, however, few fluctuations in rising and falling of porosity and permeability values were mostly controlled by diagenetic open system or heterogeneity of carbonate rocks settings.
9. The recent data confirms that the previous studied when used package of logs and facies analysis for identifying the reservoir characterization are not enough alone without detailed study of carbonate heterogeneity under optical microscope and other laboratory measurements.
10. Future recommendation for studying the subsurface reservoir rock is to draw a higher resolution model for reservoir characterization by utilizing the most sophisticated and micro-scaled tools, like SEM, EDX, ICP-MS…

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