CHAPTER (4)

POROSITY AND PERMEABILITY

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4.1 Introduction

The nature of reservoir rocks containing oil and gas is considered as an important target for oil geologists and geophysicists because the quantities of fluids trapped within the void spaces of these rocks, the ability of these fluids to flow through the rocks are controlled by rock porosity and permeability. The volume of the void spaces per rock bulk volume is defined as the porosity of the rock, while the measure of the ability of the rock to transmit fluids is defined as the permeability of the rock. Knowledge of these two properties is essential before questions concerning types of fluids, amount of fluids, rates of fluid flow and fluid recovery estimates can be answered. In some cases texture may yield some information about formation porosity and permeability. For example, fine grained sandstones with poorly sorted angular grains will generally have lower porosity than sandstones composed of coarse, well sorted grains. Variation in permeability may be predicted from variation in grain size, shape and distribution of pore channels in the rock pore space framework.

4.2 Porosity

The porosity of a rock is defined as the ratio of the volume of rock void spaces to its bulk volume, multiplied by one hundred to express it in percent (Amyx et al., 1960). This can be expressed in mathematical form as:

$$\phi = ((Vb-Vg)/Vb) * 100 \qquad (4.1)$$

Where: ϕ = porosity, %. Vb = bulk volume, cc. Vg = grain volume, cc.

The average depositional porosity ranges from 40% to 58% (Atkins and McBride, 1992). The porosity of petroleum reservoir ranges from 5% to 40%

but most frequently are between 10% and 20%. The factors governing the magnitude of porosity in clastic sediments are:

A. Uniformity of grain size: uniformity or sorting is the gradation of grains. If small particles of silt or clay are mixed with larger sand grains, the porosity will be considerably reduced.

B. Degree of cementation or consolidation: the highly cemented sandstones have low porosity whereas the soft, unconsolidated rocks have high porosity.

C. Amount of compaction: compaction tends to close voids and squeeze fluid out to bring the mineral particles closer together. If only physical compaction takes place, porosity would approach a limiting value of 26% (Atkins and Mcbride, 1992).

D. Types of packing: with increasing overburden pressure, poorly sorted, angular sand grains show a progressive change from random packing to a closer packing. Change in packing porosity upon burial to common hydrocarbon reservoir depths will depend on individual histories of cementation, compaction and secondary porosity development (Atkins and Mcbride, 1992).

4.3 Classification of porosity

4.3.1 Engineering classification of porosity: from engineering point of view, the porosity could be classified into:

A. Absolute (total) porosity: which is the ratio of the total void spaces in the sample to the bulk volume of that sample, regardless of whether those void spaces are interconnected or not.

B. Effective porosity: which is the ratio of the interconnected pore volume to the bulk volume.

4.3.2 Geological classification of porosity

According to the mode of origin, porosity may be classified as primary and secondary porosity. A general classification of porosity, adapted from Ellison (1958), is as follows:

4.3.2.1 Primary porosity: which has been developed during the deposition of materials and divided into:

A. Intercrystalline: such as voids between cleavage planes of crystals, voids between individual crystal and voids in crystal lattices, has been called microporosity.

B. Intergranular or interparticle: as voids between grains in all types of rocks.

C. Bedding planes: as voids of many varieties are concentrated parallel to the bedding plans.

D. Miscellaneous sedimentary voids: such as voids resulting from the accumulation of detrital fragments of fossils and voids created by living organisms at the time of deposition.

4.3.2.2 Secondary porosity: secondary porosity is the result of geological processes (diagenesis) after the deposition of rocks. Secondary (induced) porosity can be subdivided into:

A. Solution porosity: channels due to the solution of rocks by circulation water or hot solutions.

B. Dolomitization: a process by which limestone is transformed into dolomite.

C. Fracture porosity: openings created by structural failure of the reservoir rocks under tension caused by tectonic activities such as folding and faulting.

4.4 Laboratory measurements of porosity

Several methods have been proposed and explained in different literature for rock porosity determination, (Amyx et al., 1960, API Rp 40, 1960, Jenkins, 1960, Keelan, 1972, Anderson, 1975 and El Sayed, 1976). To determine rock porosity, it is required to determine two of the three variables, pore volume, grain volume and bulk volume. In the present study, grain volume measurement and bulk volume measurement were carried out to determine the rock porosity. The technique is explained by (API Rp 40, 1960, Jenkins, 1960 and Keelan, 1972).

4.4.1 Grain volume measurement

The clean, dry samples were initially weighed to determine dry weight. Each sample was placed in a sealed chamber (matrix-cup); using steel disks to minimize void space. The reference cell that having a known volume was pressurized with helium to 100 psig. The helium in the reference cell was then allowed to expand into the sample chamber containing the sample. The resultant pressure was allowed to stabilize, and the grain volume was then calculated from the pressure-volume relationship expressed in Boyle's law. In the present work, the grain volume was measured using Core Lab's Heise gauge Helium porosimeter, model 3020-062 and serial A-8222.

4.4.2 Bulk volume measurement

The dried core samples were immersed in mercury in calibrated pycnometer. The volume of mercury displaced by the sample is weighed. Knowing the mercury density at the measured temperature, the bulk volume of the sample can be determined.

4.4.3 Bulk density

The bulk density of a rock is defined as the mass of a unit volume of the porous rock. The bulk density depends on solid phase (grains, cement), voids or spaces (porosity) and types of fluids saturating the rock spaces. The investigation of density variation and the study of the relationships between them and the rock petrophysical properties are of great significance. It is usually used for lithologic discrimination, identification and consequently for reservoir zonation, (El Sayed and El-Dairy 1991; and El Sayed 1995).

4.5 Permeability

The permeability of a rock is defined as a measure of the ability of a porous rock material to transmit fluid under certain pressure gradient. The unit of measurement is the Darcy, named after Darcy (1856). He is a French scientist who investigated the flow of water through filter beds. Darcy's law is used to determine permeability which is constant when the following conditions are verified:

A. There is a laminar flow of the fluid.

B. There is no interaction between the fluid and the rock.

C. One phase present at 100 percent pore space saturation.

The rock permeability is defined by Darcy's law as:

$$q/a = (-k/m) * (dp/dl) \qquad (4.2)$$

Where:

q = flow rate of fluid, cm^3 /sec.

k = permeability of the porous rock, Darcy.

a = cross sectional area, cm^2.

m = viscosity of flowing fluid, centipoises.

dp/dl = pressure gradient in the direction of flow, atm/cm.

4.5.1 Units of permeability

The definition and the standard practical unit, Darcy, of permeability used in petroleum industry was adapted by the American Petroleum Institute (API Rp40, 1960), while the up to date permeability unit is the international standard unit (SI) as the μm^2 (El Sayed, 1981). One Darcy is defined as that permeability which will permit a fluid of one centipoise viscosity to flow at a rate of one cubic centimeter per second through a cross-sectional area of one square centimeter when the pressure gradient is one atmosphere per centimeter. One darcy is relatively high permeability. The common measure unit of rock permeability is in millidarcies (md).

One Darcy = 1,000 millidarcies

One Darcy = 0.986923 μm^2

According to the, API, (1960), the permeability measurement will be standardized using dry air as the gas. The direction parallel to the bedding plane will be standardized as the horizontal permeability. The permeability in direction perpendicular to the bedding planes is called vertical permeability. The permeability of reservoir rocks in horizontal direction is generally higher than that in the vertical direction. The difference in permeability measured parallel and vertical to the bedding planes is a consequence of the origin of that sediment, because grains settle in water with their longest and flattest sides in horizontal position (Clark, 1969).

4.5.2 Laboratory measurement of permeability

The clean dry samples were initially callipered to determine the length and diameter. The core plugs were loaded individually into a Hasler-type core holder with the circumference sealed to prevent bypass using an overburden pressure of 400 psig. Dry air was injected through the samples at constant pressure. The pressure difference across the length of each sample was measured and the flow rate of the air was determined. The steady-state permeability to air data was calculated using Darcy's law. Core Lab's permeameter was used to determine air permeability. The used instrument model is 302138 and serial A-3148. The Darcy equation relating permeability to compressible fluids is as follows:

$$Kg = [2000*\mu*Q*L*Pa] / [A(P1^2-P2^2)] \qquad (4.3)$$

Where:

Kg = permeability (md).

μ = viscosity of air, centipoises.

Q = gas volume flow rate cm^3/sec.

L = length, cm.

Pa = atmospheric pressure (atmosphere).

A = cross–sectional area, cm^2.

P1 = upstream pressure (atmosphere).

P2 = down stream pressure (atmosphere).

The above equation is known as the linear form of Darcy's law.

4.6 Permeability-porosity as a general relation

The permeability of a rock may be affected by many geologic factors. The presence of porosity does not guarantee that permeability exists. The pores must be interconnected, and the pore-throats must be large enough to permit the flow of fluids. A rock such as pumice stone and shale will have a very high porosity and very low permeability. On the other hand, micro fractured carbonates will have low porosity and high permeability. A pore network is made up of larger spaces, referred to as pores, which are connected by small spaces referred to as throats (Wardlaw, 1980). In other words, the pore spaces are reflected in the measured porosity, while the pore-throats are reflected in the measured permeability of a rock. So the geometric relationship between pore spaces and pore throats controls and defines the relationship between porosity and permeability. Results indicate that reservoir quality is controlled by pore geometry (Bliefnick et al., 1996). The relationship between pore type and throat size is an effective means to relate reservoir in terms of the efficiency of the porous microstructure to multiphase flow (Mc creesh et al., 1991).

4.6.1 Kozeny-Carman relation

The relationship between porosity and permeability has been theoretically studied by Carman (1937), Scheidegger, (1974) and experimentally studied by Timur, (1968), El Sayed, (1981), Herron (1987) and Adler et al, (1990). The Kozeny-Carman equation has been expressed as listed by Scheidegger (1974) as:

$$K = (A\phi^3) / \{S^2(1-\phi)^2\} \qquad (4.4)$$

Where:

K = absolute permeability, cm^2.

A = an empirical constant.

ϕ = porosity, %.

S = specific area for a porous medium, 1/cm.

A shortcoming of the Kozeny-Carman equation is that it is impractical to measure (A) as a function of tortuosity, shape factor and specific surface area for each rock type. In reality, tortuosity and shape factor vary drastically from one sample to another, reflecting formation heterogeneity. This equation is limited in application because (1) it is applied on loose sand and (2) the surface area is difficult to be obtained in consolidated rock formation. Timur (1968) developed a modified version of the original Kozeny equation as follows:

$$K = \{0.136\ (\phi^{4.4}/Swi^2)\}\,10^5 \qquad (4.5)$$

Where: Swi = irreducible water saturation.

El Sayed (1997) introduced a new empirical equation for permeability prediction from irreducible water saturation as:

$$K = 192.6\ e^{-0.092(Swirr)} \qquad (4.6)$$

4.7 Locations and distributions of the studied samples

In the present work, the core samples obtained from the two fields as previously mentioned. The first field is GPTSW field in Abu Sennan area in north of the Western Desert, which is approximately bounded by Long. 28° 00\`-29° 00\` E and by Lat. 29° 25\`-29° 48\` N, (Fig. 1.1). The second field is BED-1 field in Badr El Din concession in north of the Western Desert, which is approximately bounded by Long. 26° 29\`-28° 35\` E and by Lat. 29° 35\`-30° 10\` N, (Fig. 1.1). Forty seven (47) and sixty three (63) core samples were tested from BED-1 field (BED1-11 well) and GPTSW field (TSW-7, 8, 13, 15 and 21 wells) respectively. For BED1-11 well, the forty seven (47) samples were obtained from the lower part of the Bahariya Formation. On the other hand, for GPTSW wells the obtained sixty three (63) samples divided as follows: 38 samples represent the upper part of the Bahariya Formation, 11 samples represent Abu Roash \`F\` Member (all samples of TSW-8 well) and 14 samples represent Abu Roash \`G\` Member. So (47) and (63) plug samples were drilled from the obtained full diameter core samples. Each plug is 2.5 cm in diameter and about 3 cm in length. These plugs were subjected to porosity and permeability measurements. The different relations will be displayed for each well separately and then the same relation will be displayed for each common formation in different wells in TSW wells. BED1-11 well represents the lower part of Bahariya Formation, while TSW-7, 13, 15 represent the upper part of Bahariya Formation, but TSW-8 well represents Abu Roash \`F\` Member and TSW-21 represents mainly Abu Roash \`G\` Member and to less extent the upper part of Bahariya Formation. All the tables of this chapter have been compiled and displayed in the appendices of the respective chapter.

4.8 Permeability and porosity results

According to Levorsen (1967) and El Sayed (1995), the quality of a reservoir as determined by porosity and permeability may be judged. Table (4.1) shows results of the lower part of the Bahariya Formation in BED1-11 well, where porosity ranges from 5.0% to 17.7% with an average value of 11.1% (fair reservoir) and permeability ranges from 0.01 md to 64 md with an average value of 7.18 md (fair reservoir). Also Table (4.2) shows that porosity ranges from 8.1% to 18.2% with an average value of 13.9% and permeability ranges from 0.04 md to 4.41 md with an average value of 0.93 md for TSW-7 well. Table (4.3) shows samples of Abu Roash `F` Member in TSW-8 well have a narrow porosity range, from 15.3% to 18.7%, with an average value of 16.9%, which means good storage properties but permeability has a tight range from 0.003 md to 0.045 md, with an average value of 0.013 md, which is the lowest flow properties in all TSW wells and this reflects non-reservoir properties. Samples of TSW-13 well have porosity values range from 10.7% to 16.1% with an average value of 13.4% and permeability ranges from 0.13 md to 0.27 md with an average value of 0.18 md (Table 4.4). In TSW-15 well, porosity ranges from 10.4% to 25.3% with an average value of 20.8% and permeability ranges from 0.038 md to 259.9 md with an average value of 109.7 md (Table 4.5). Concerning samples of TSW-21 well, porosity ranges from 4.1% to 26.9% with an average value of 15.1% and permeability ranges from 0.043 md to 20.2 md with an average value of 1.93 md (Table 4.6). Samples of Abu Roash `G` Member in TSW-21 which represent the great majority of the samples of this well (Table 4.7), have a wide range of porosity from 4.1% to 26.9%, with an average value of 15.5% (good reservoir) and permeability ranges from 0.075 md to 20.2 md, with an average value of 2.41 md (fair reservoir). In case of the upper part of the Bahariya Formation obtained from all TSW wells (Table 4.8), porosity ranges from 8.1% to 25.3%, with an average value of 17.1% (good reservoir) and permeability ranges from 0.038 md to 259.9 md, with an average value of 52.3 md, (good reservoir).

4.9 Porosity and permeability histograms

Porosity and permeability data were represented in the form of histograms. Fig (4.1) shows porosity histogram of the lower part of the Bahariya Formation obtained from BED1-11 well, where porosity of range (5-10%) has the highest frequency (nearly 43%), while porosity of range (15-20%) has the lowest frequency (17%). An improvement has been found in all TSW-wells (Fig. 4.3), Abu Roash `G` Member in TSW-21 well (Fig. 4.5) and the upper part of Bahariya Formation obtained from TSW-wells (Fig. 4.7), where porosity range is more wider and porosity of range (5-10%) is nearly absent except in TSW-7 well which constitutes about (17%), on the other hand porosity of range (15-20%) or more, represents a considerable ratio especially in wells: TSW-8 and TSW-15 (100% and 89% respectively), about (43%) in Abu Roash `G` Member in TSW-21 well and represents the highest ratio (nearly 61%) in the upper part of Bahariya Formation obtained from TSW-wells. Tables (4.9), (4.11), (4.13) and (4.15), display the results of porosity histograms of BED1-11 well, all TSW-wells, Abu Roash `G` Member in TSW-21 and the upper part of the Bahariya Formation obtained from all TSW-wells, respectively. Fig (4.2) shows permeability histogram of the lower part of the Bahariya Formation obtained from BED1-11 well, where most of the studied samples (62%), are represented with low permeability values, lower than 1 md, while the samples of the high permeability values (higher than 10 md), are represented with low frequency (nearly 23%). The same behavior was more obvious in all TSW-wells (Fig. 4.4), except TSW-15 well, where the samples of the high permeability values (higher than 10 md), are represented with about (72%). Figure (4.6) shows that, the great majority of the studied samples of Abu Roash `G` Member in TSW-21 well (nearly 71%), are represented with low permeability values, lower than 1 md. An improvement has been found in the upper part of the Bahariya Formation obtained from TSW-wells (Fig. 4.8), where the studied samples of the low permeability values, lower than 1 md, constitute nearly (55%) and the samples of the high permeability values, higher than 10 md, constitute about (34%). Tables (4.10), (4.12), (4.14) and (4.16), display the results of permeability histograms of BED1-11 well, all TSW-wells, samples of Abu Roash `G` Member in TSW-21 and the upper part of the Bahariya Formation obtained from all TSW-wells, respectively.

From the previous explanation (porosity, permeability results and histograms of them), we can conclude the following:

1-The upper part of the Bahariya Formation in general in GPTSW field has high reservoir quality due to its high values of porosity and permeability than those of Abu Roash `G` and Abu Roash `F` Members.

2-The upper part of the Bahariya Formation in GPTSW field is a good reservoir type.

3-The upper part of the Bahariya Formation in GPTSW field has better storage and flow properties than the lower part of the Bahariya Formation in of BED-1 field.

4-Abu Roash `G` Member is considered to great extent a non-reservoir in the studied well due to the weak flow properties except some intervals.

5-The tight flow properties have been found in Abu Roash `F` Member because the studied samples are mainly marl, so it is considered as a cap rock. Table (4.17) displays the porosity and the permeability of the different studied units.

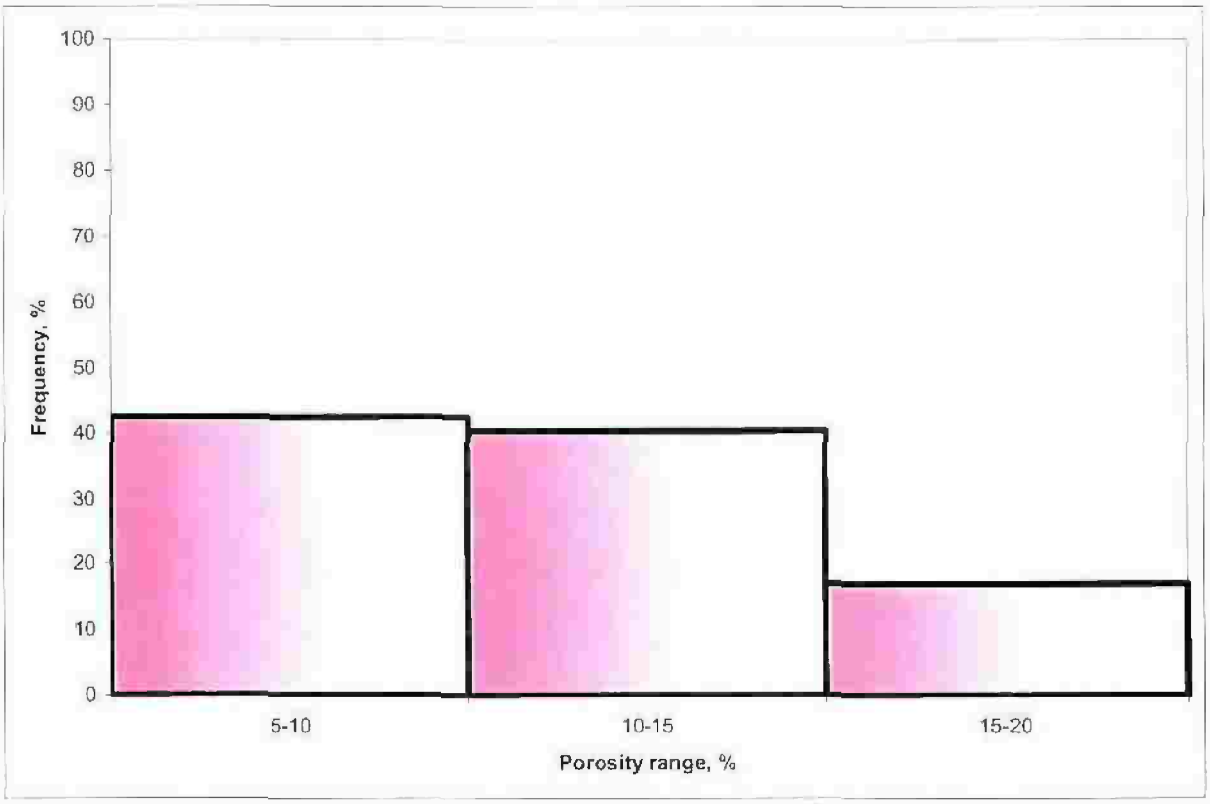

Fig. (4.1): Porosity histogram of L. Bahariya, BED1-11 well.

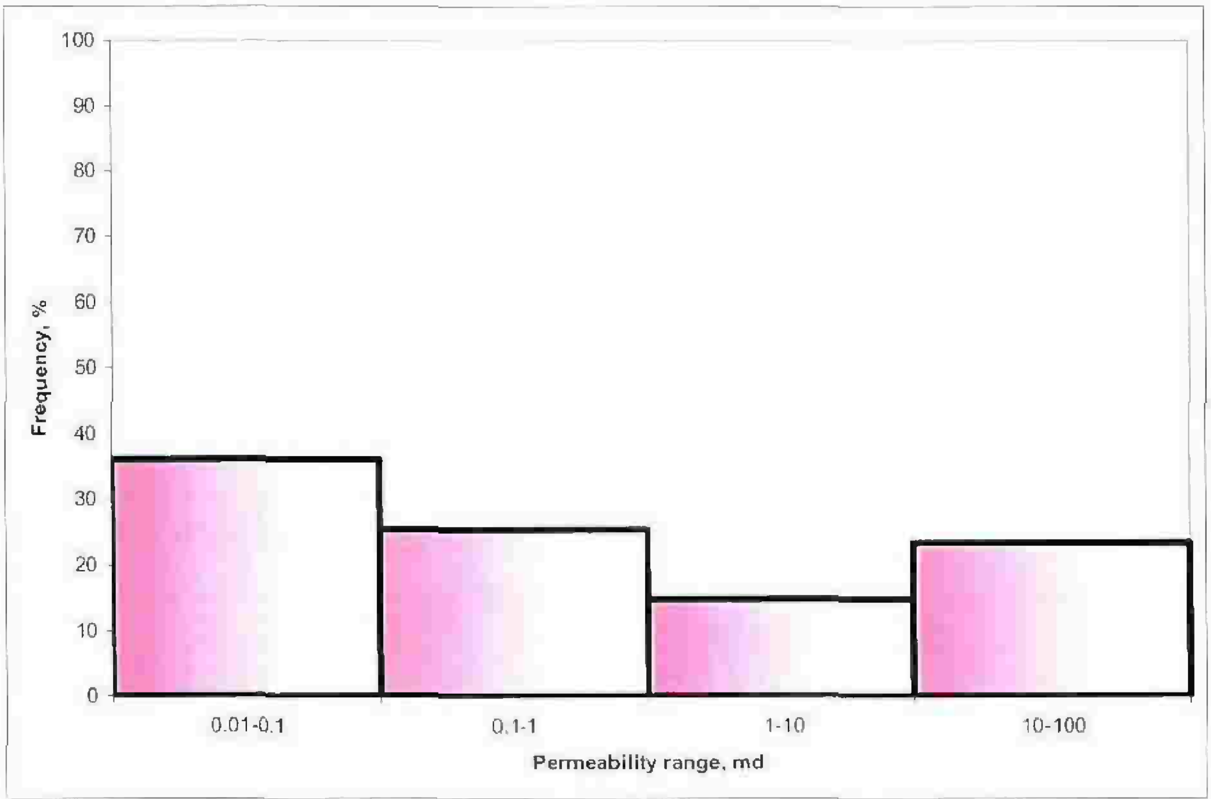

Fig. (4.2): Permeability histogram of L. Bahariya, BED1-11 well.

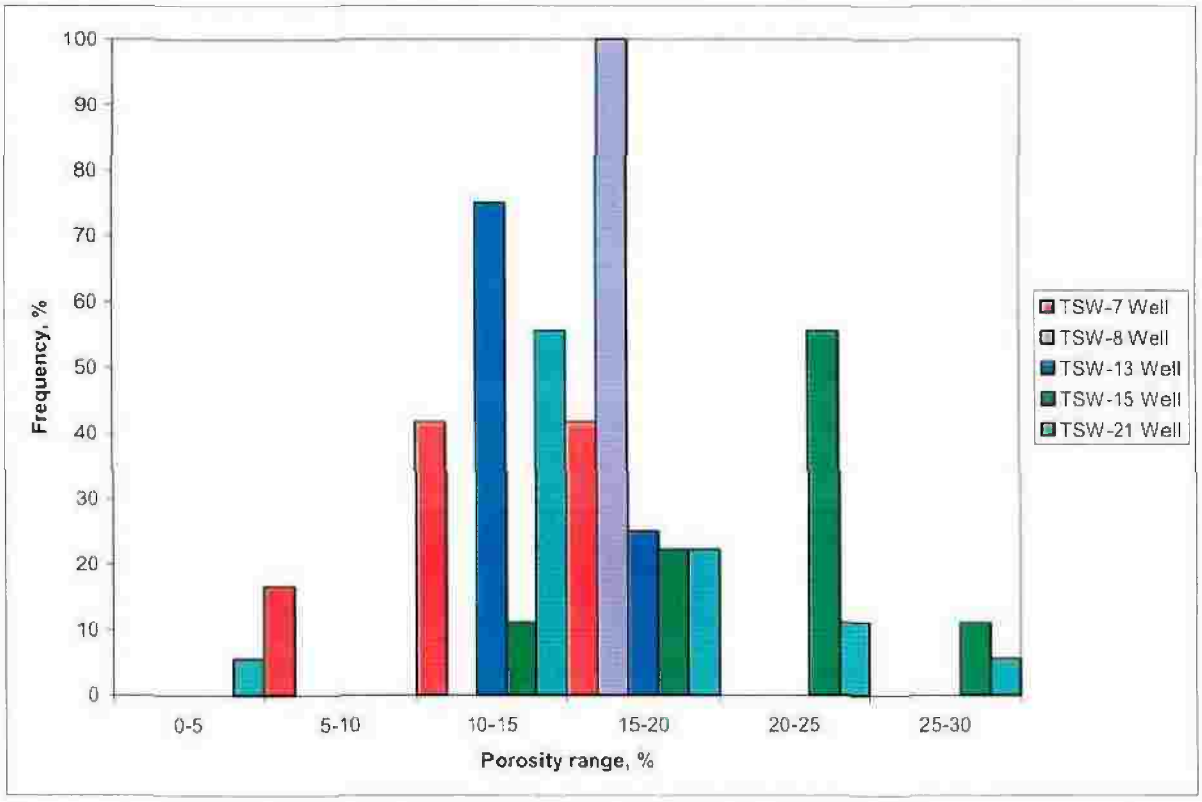

Fig. (4.3): Porosity histogram of all TSW wells.

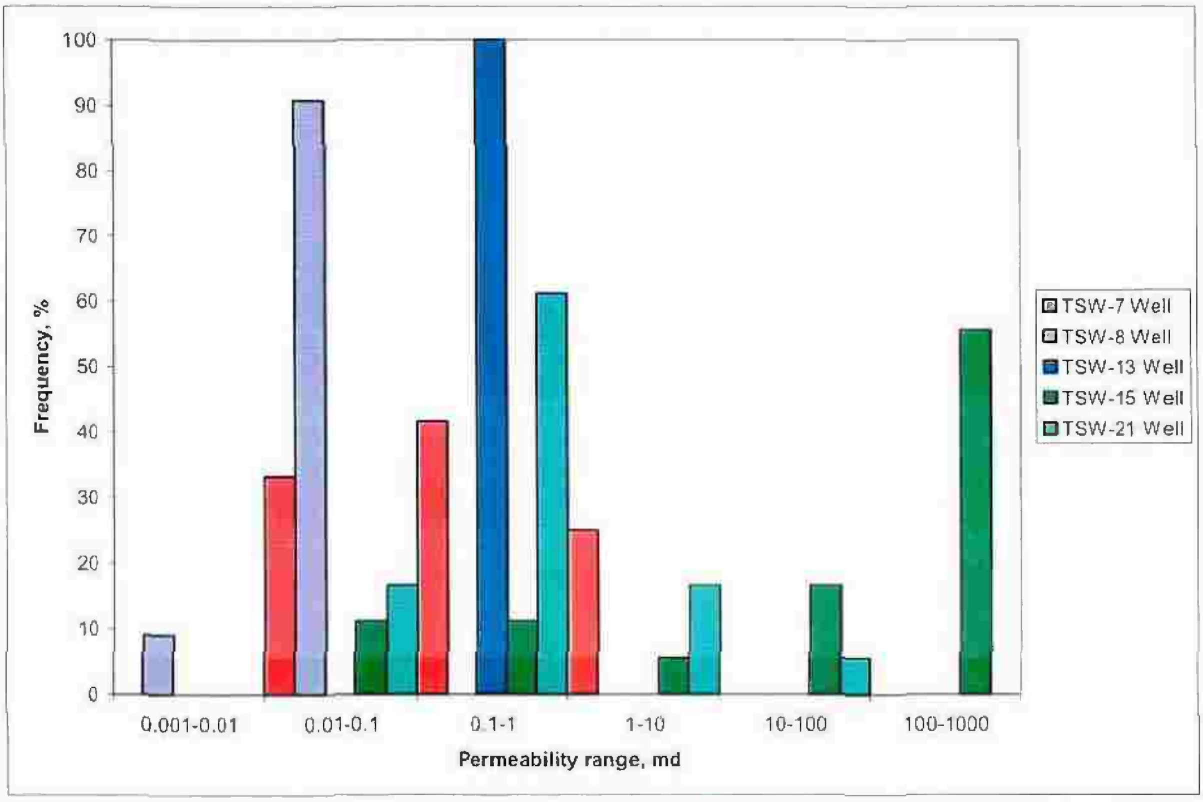

Fig. (4.4): Permeability histogram of all TSW wells.

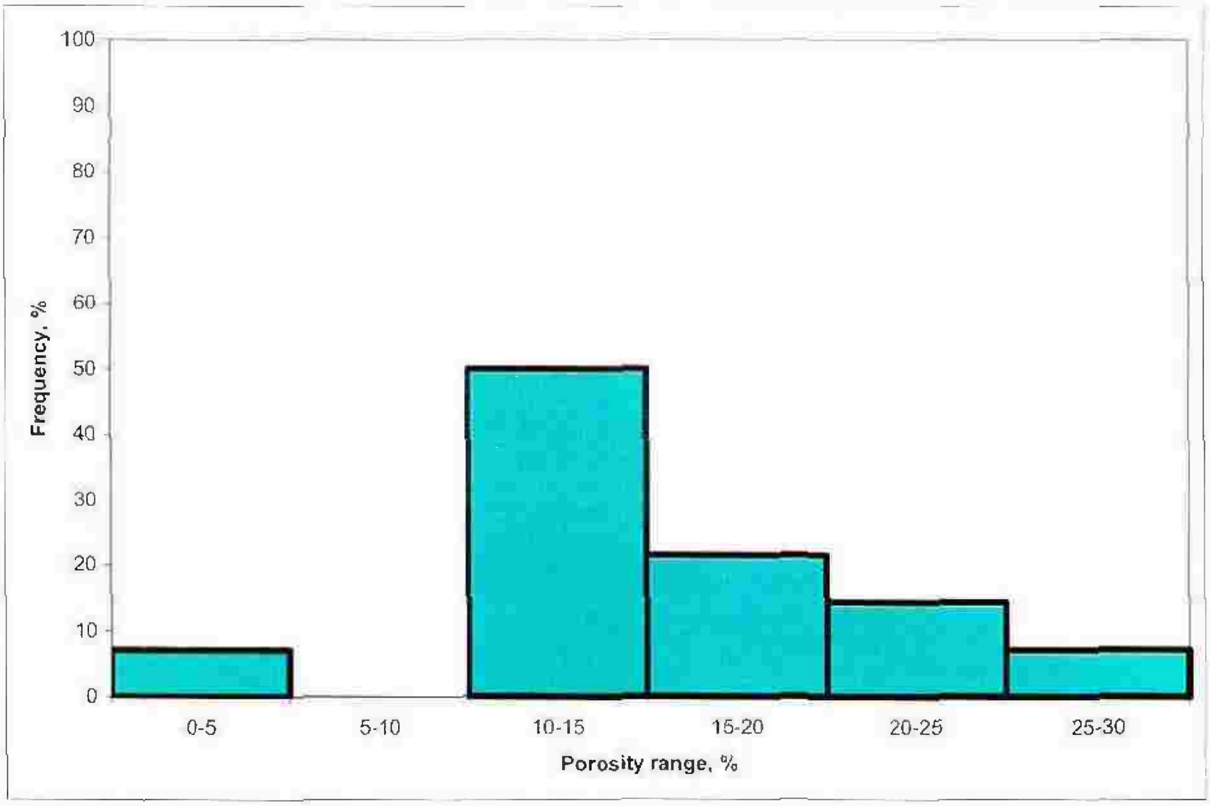

Fig. (4.5): Porosity histogram of Abu Roash `G`, TSW-21 well.

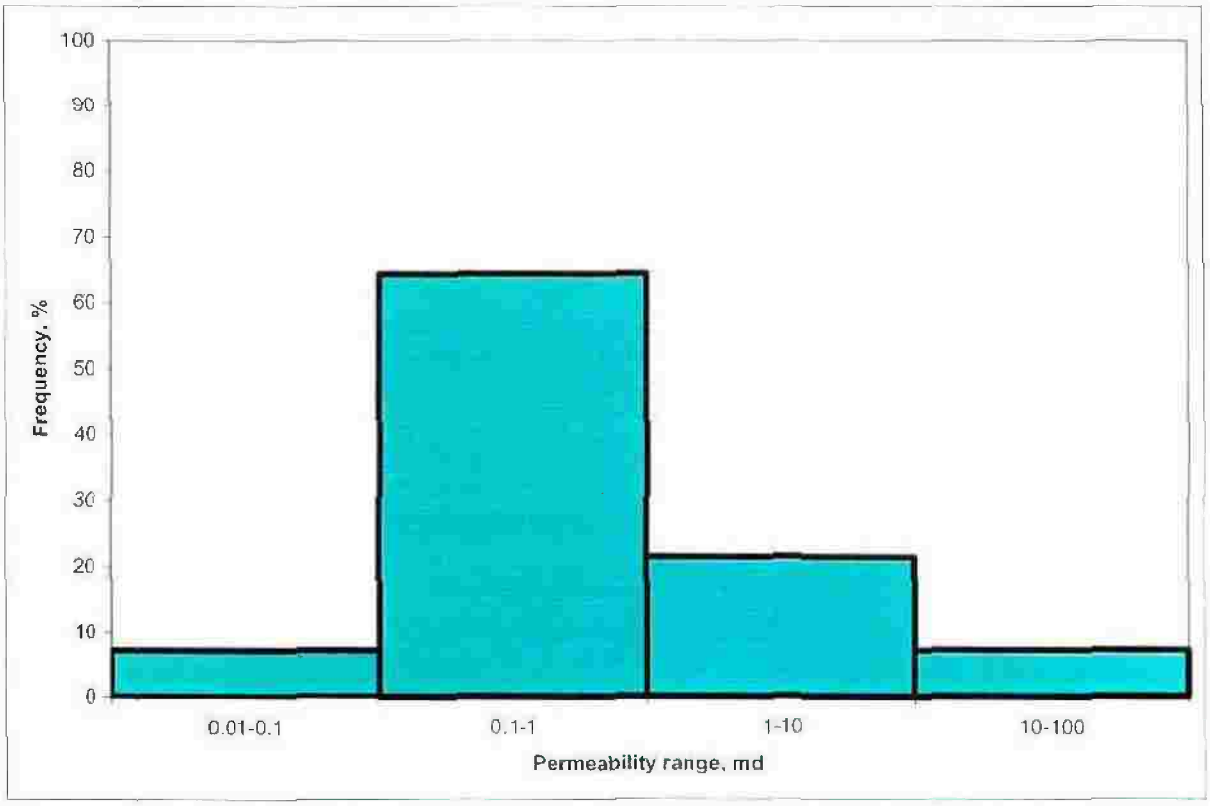

Fig. (4.6): Permeability histogram of Abu Roash `G`, TSW-21 well.

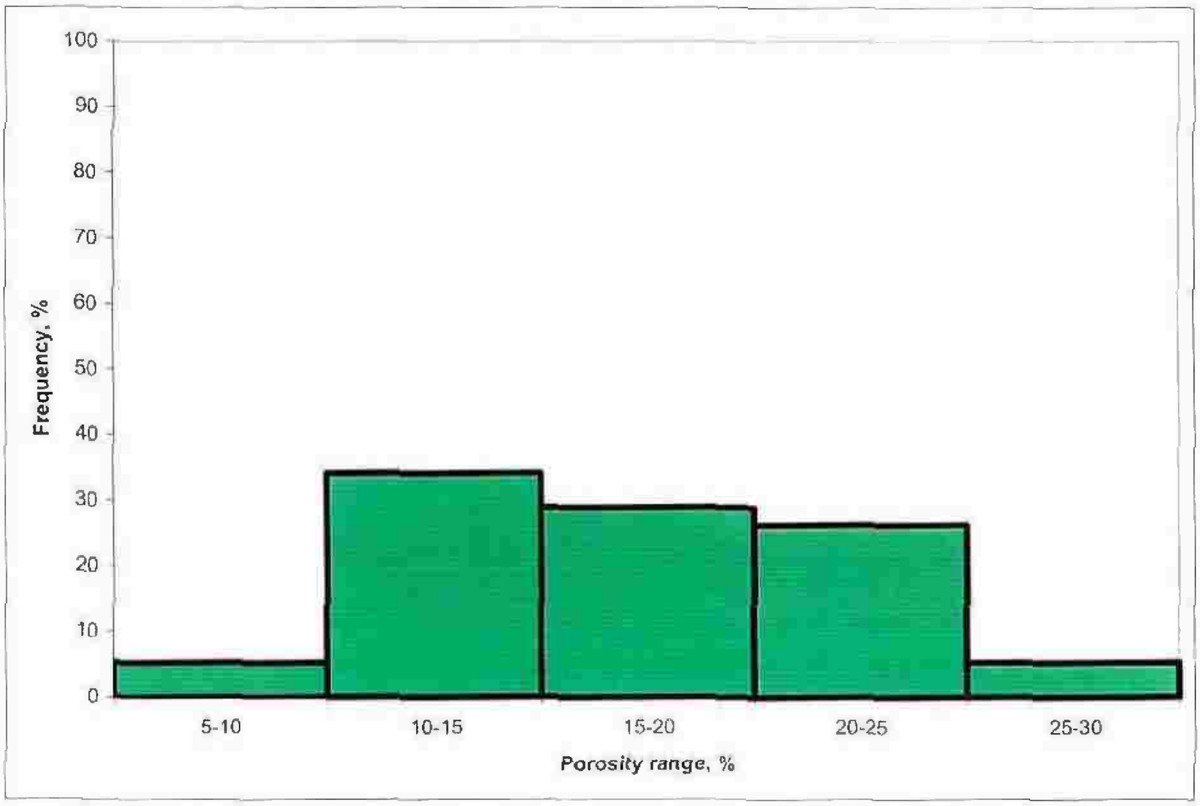

Fig. (4.7): Porosity histogram of U. Bahariya in all TSW wells.

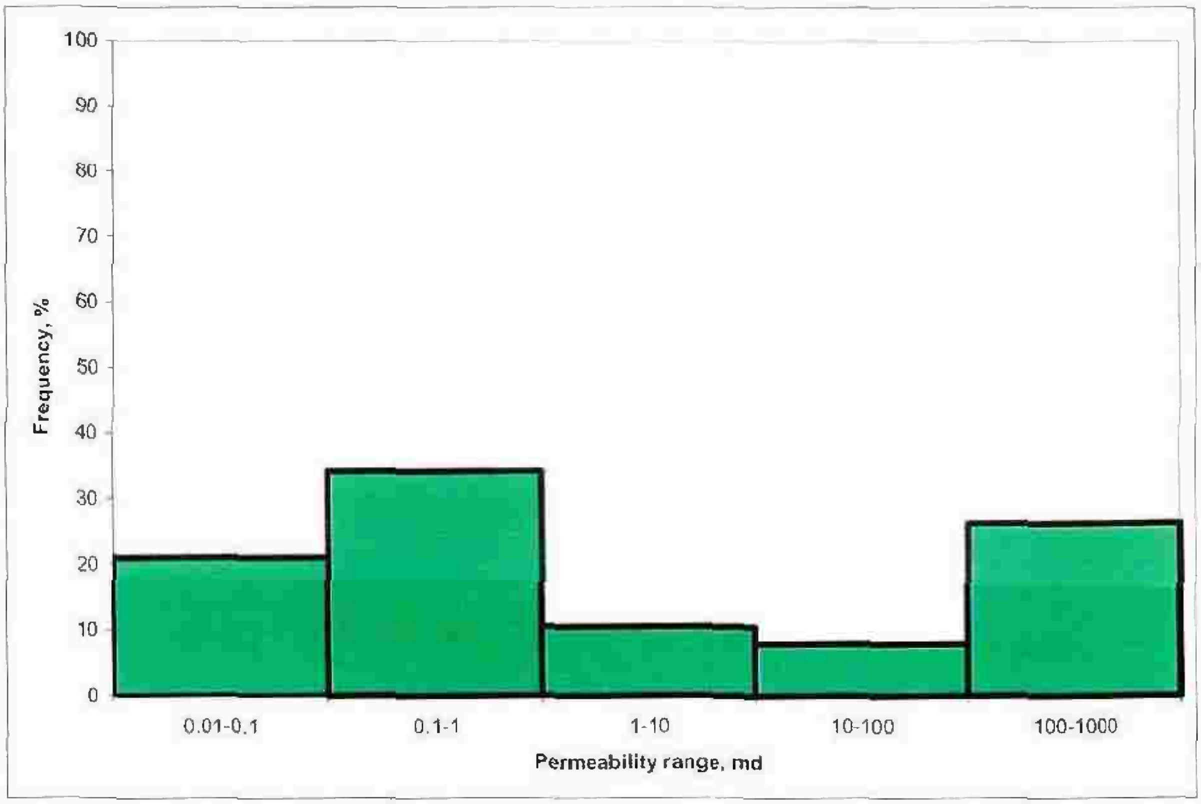

Fig. (4.8): Permeability histogram of U. Bahariya in all TSW wells.

4.10 Porosity versus permeability relations

Figure (4.9) displays porosity-permeability relation of the studied samples of the lower part of the Bahariya Formation in BED1-11 well.

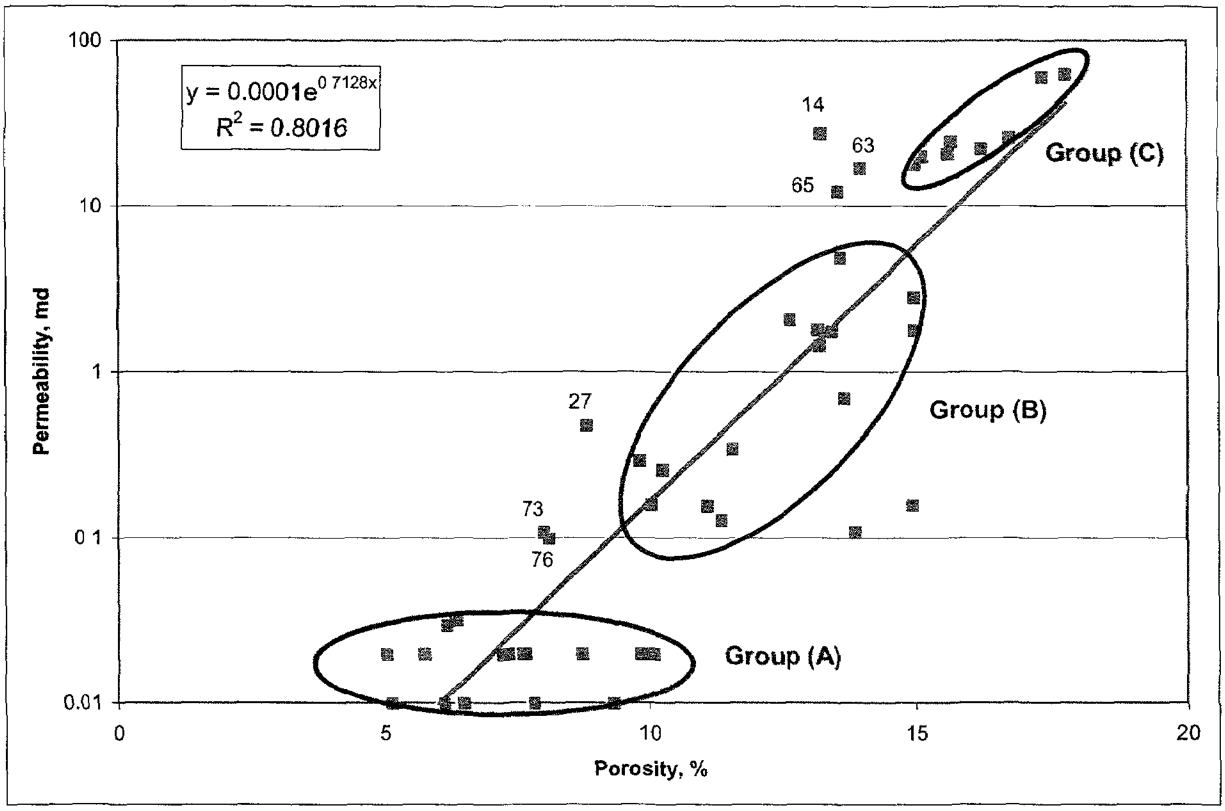

Fig. (4.9): Porosity vs. permeability of L. Bahariya, BED1-11 well.

Porosity-permeability relation of the studied samples obtained from BED1-11 well is represented by the following equation:

$$K = 0.0001e^{0.7128\Phi} \qquad (4.7)$$

Where the calculated coefficient of correlation R = 0.90

The excellent value of correlation coefficient indicates that, the above equation is suitable to predict permeability from porosity in this well, while care should be taken to transfer this equation to other geologic age or province. Also the figure shows the possibility of samples differentiation into three groups (A, B and C). The quality of a reservoir as determined by porosity and permeability may be judged (Levorsen, 1967 and El Sayed, 1995).

Group (A) has an average porosity 7.3% and average permeability 0.02 md (poor reservoir), group (B) has an average porosity 11.9% and average permeability 1.04 md (fair reservoir), finally group (C) has an average porosity 15.4% and average permeability 28.8 md (good-moderate reservoir), we found out that the maximum limit of each group is the lower limit of the next higher group except some samples (27, 73 and 76) in group (B) and samples (14, 63 and 65) in group (C). The petrographical and lithological investigations of the different groups show that all the samples are highly cemented sandstones but there are two factors responsible for the anisotropy between the samples that reflected in the values of porosity and permeability of the different groups. The first factor is the diagenesis (cementation) which is high amount in group (A) which has the lowest values of porosity and permeability (Fig. 5.1 A) then become medium in group (B) which has a moderate values of porosity and permeability (Fig. 5.1 B) and reach to lowest quantity in group (C) that has the highest values of porosity and permeability (Fig. 5.1 C), the second factor is the clay content (lamination) where we found the samples of group (A) are laminated samples, on the other hand the samples of group (B) range between laminated and non-laminated but samples of group (C) are non-laminated. Kaolinite, chlorite and illite are the clay types that have been recognized in this section.

Figure (4.10) is a composite figure shows porosity-permeability relations for all studied samples obtained from TSW-wells (TSW-7, 8, 13, 15 and 21 wells).

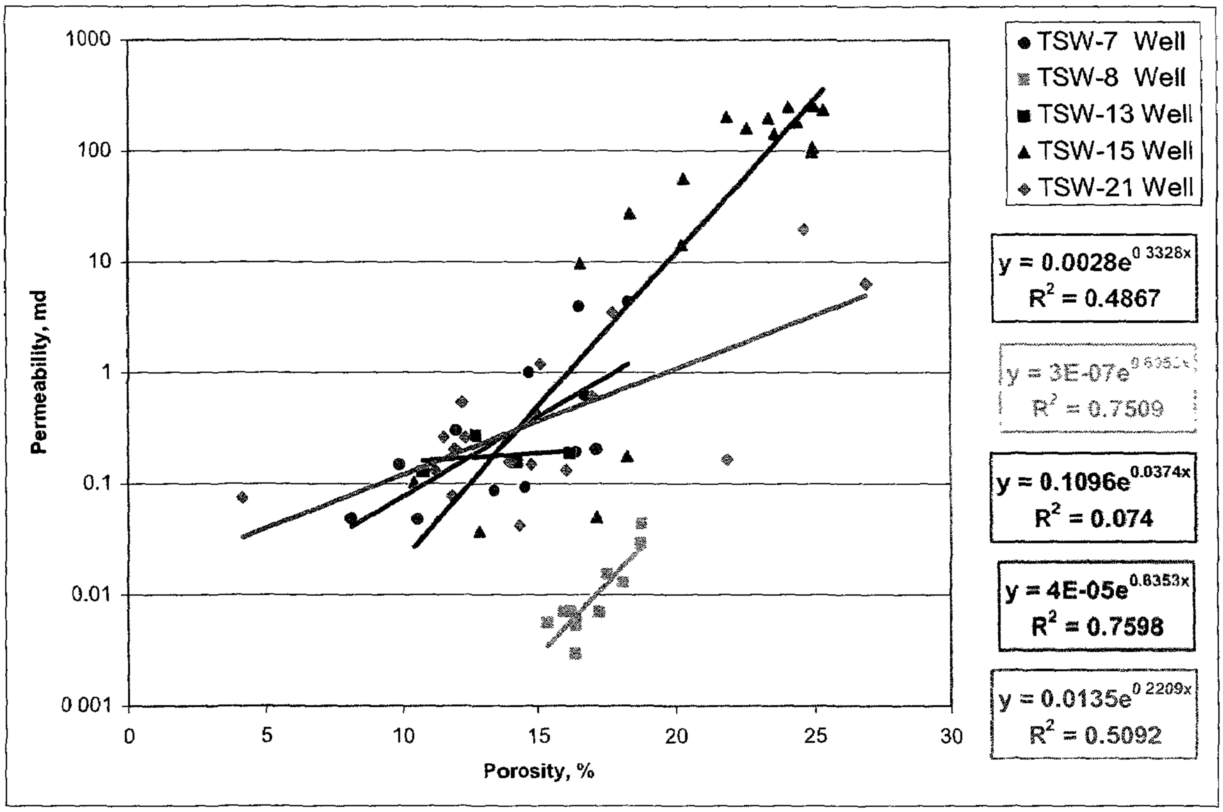

Fig. (4.10): Porosity vs. permeability of all TSW wells.

Porosity-permeability relation of the studied samples (TSW-7 well) is expressed by the following equation:

$$K = 0.0028e^{0.3328\Phi} \qquad (4.8)$$

$$R = 0.70$$

On the other hand the same relation of the studied samples (TSW-8 well, Abu Roash `F`) is indicated by the following equation:

$$K = 3E\text{-}07e^{0.6053\Phi} \qquad (4.9)$$

$$R = 0.87$$

In case of TSW-13 well, permeability-porosity relation is expressed by the following equation:

$$K = 0.1096e^{0.0374\Phi} \qquad (4.10)$$

$$R = 0.27$$

So the above equation is not reliable to predict permeability from porosity; this is may be due to the limited number of the samples in this well (only 4 samples).

Permeability-porosity relation of the studied samples of TSW-15 well is expressed by the following equation:

$$K = 4E\text{-}05e^{0.6353\Phi} \qquad (4.11)$$

$$R = 0.87$$

Finally, the studied samples obtained from TSW-21 well displays permeability-porosity relation with a correlation coefficient value R = 0.71 and is expressed by the following equation:

$$K = 0.0135e^{0.2209\Phi} \qquad (4.12)$$

The values of correlation coefficients revealed that, the above equations are reliable to great extent in wells TSW-8 and TSW-15.

Figure (4.11) displays porosity-permeability relation of the studied samples that represent Abu Roash `G` in TSW-21 well.

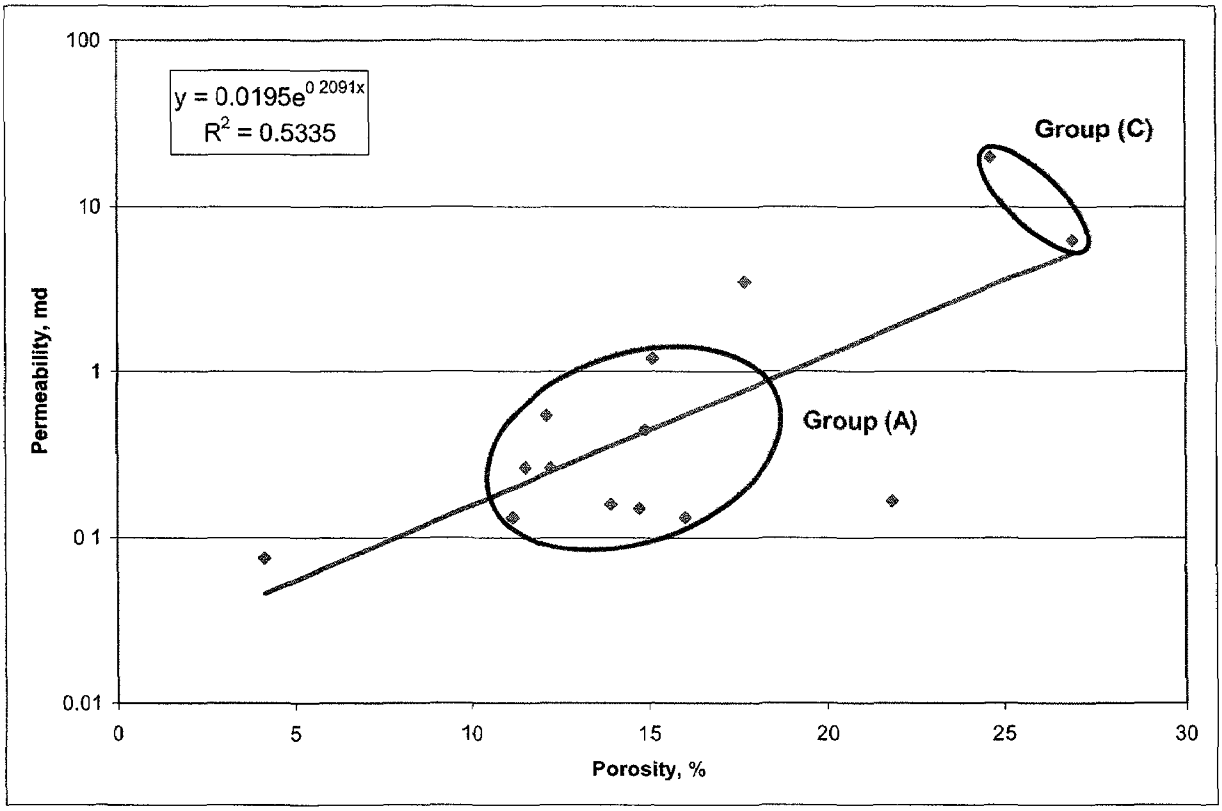

Fig. (4.11): Porosity vs. permeability of Abu Roash `G`, TSW-21 well.

Porosity-permeability relation of the studied samples is given by the following equation:

$$K = 0.0195e^{0.2091\Phi} \qquad (4.13)$$

$$R = 0.73$$

The studied samples could be classified into two groups (A and C). Group (A) has an average porosity 13.5% and average permeability 0.37 md (fair-poor reservoir), on the other hand group (C) has an average porosity 25.7% and average permeability 13.4 md (very good-moderate reservoir). The petrographical and lithological investigations of the studied samples in the two groups indicate that, the samples of group (A) are highly argillaceous, laminated sandstone (Fig. 5.7 A) but samples of group (C) are less argillaceous sandstones (Fig. 5.8 C). The difference in the clay content is the main factor responsible for the anisotropy between the samples that reflected in the values of the porosity and permeability of the two groups.

Figure (4.12) displays porosity-permeability relation for the samples of the upper part of the Bahariya Formation while they collected from TSW-7, 13, 15 and 21 wells and represented with a definite symbol and colour for each well, in order to trace each of them.

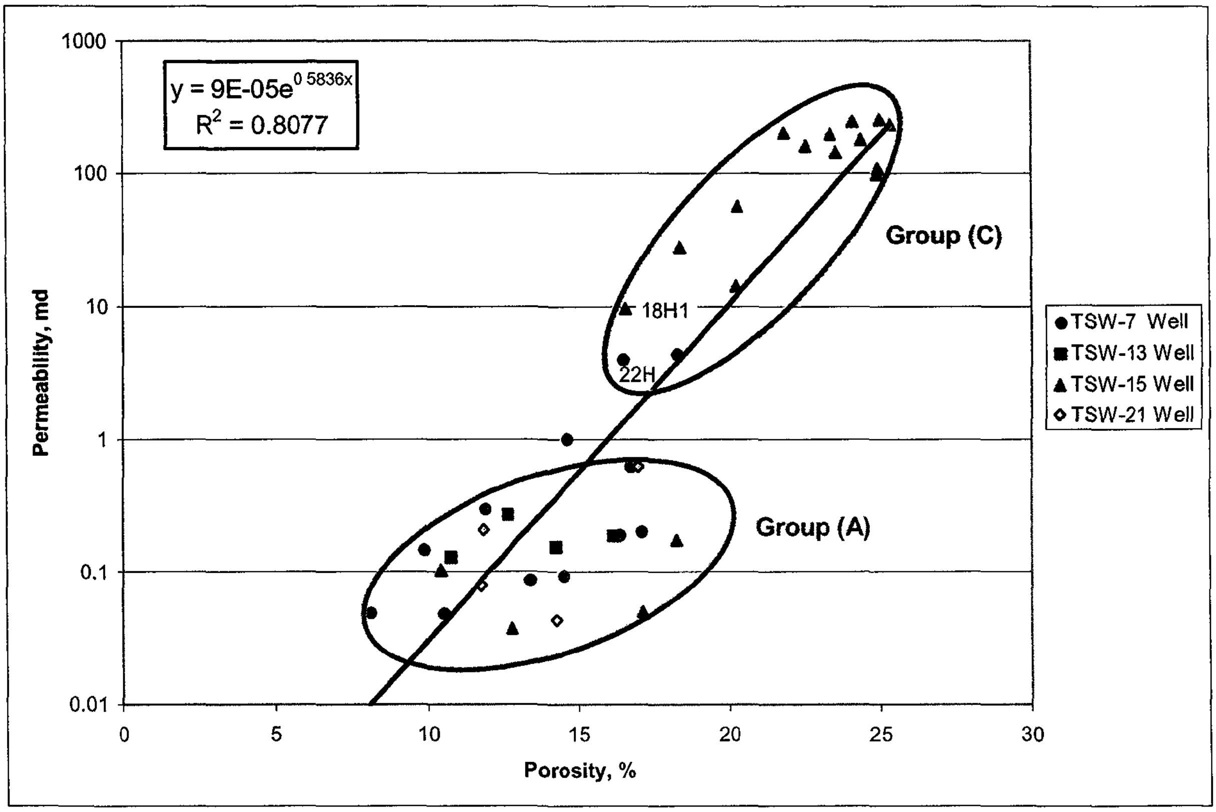

Fig. (4.12): Porosity vs. permeability of U. Bahariya, TSW-7, 13, 15 and 21 wells.

An excellent relation was found which is represented by the following equation:

$$K = 9E\text{-}05e^{0.5836\Phi} \qquad (4.14)$$

$$R = 0.90$$

The studied samples could be classified into two groups (A and C). Group (A) has an average porosity 13.6% and average permeability 0.18 md (fair-poor reservoir). On the other hand, group (C) has an average porosity 21.9% and average permeability 123.9 md (very good-good reservoir), we notice that the maximum limit of group (A) is the lower limit of the group (C) if we exclude samples (18H1 and 22H) in group (C) where they have porosity values of 16.5% and 16.4% respectively. The petrographical and lithological investigation of the studied samples in the two groups indicate that, the samples of group (A) are highly argillaceous to argillaceous (Fig. 5.8 A), laminated sandstones, but samples of group (C) are clean sandstones (Fig. 5.8 C). The presence of detrital clays in different ratios and lamination are the main factors responsible for the anisotropy between the samples that reflected in the values of porosity and permeability of the two groups, El Sayed et al. (2009).

4.11 Bulk density results

Table (4.1) shows that bulk density ranges from 2.17 gm/cc to 2.58 gm/cc with an average value of 2.36 gm/cc for the studied samples of the lower part of the Bahariya Formation in BED1-11 well. On the other hand in TSW-7 well, bulk density ranges from 2.17 gm/cc to 2.52 gm/cc with an average value of 2.34 gm/cc (Table 4.2). Samples of TSW-8 well (Abu Roash `F`), have bulk density ranges from 2.01 gm/cc to 2.21 gm/cc with an average value of 2.09 gm/cc (Table 4.3). For the studied samples in TSW-13 well (Table 4.4), bulk density ranges from 2.25 gm/cc to 2.39 gm/cc with an average value of 2.32 gm/cc. Table (4.5) of the studied samples of TSW-15 well shows that bulk density ranges from 1.98 gm/cc to 2.46 gm/cc with an average value of 2.13 gm/cc. In case of TSW-21 well, bulk density ranges from 1.94 gm/cc to 2.62 gm/cc with an average value of 2.28 gm/cc (Table 4.6). Samples Abu Roash `G` obtained from TSW-21 well have a bulk density ranges from 1.94 gm/cc to 2.62 gm/cc, with an average value of 2.27 gm/cc (Table 4.7). Table (4.8) shows that, samples of the upper part of the Bahariya Formation obtained from all TSW-wells have a bulk density varied from 1.98 gm/cc to 2.52 gm/cc, with an average value of 2.24 gm/cc.

4.12 Bulk density histograms

Bulk density variations were represented in the form of histograms. The studied samples of the lower part of the Bahariya Formation from BED1-11 well display a wide range of bulk density and this reflects a wide range of porosity (Table 4.18) and (Fig. 4.13). Samples of all TSW-wells (Table 4.19) and (Fig. 4.14) show a more wider range of bulk density, where the widest range of bulk density exists in TSW-15 and TSW-21 wells and this reflects the highest values of porosity present in these wells, especially in TSW-15 well. Also TSW-8 well has a narrow range of bulk density but it reflects high porosity values, TSW-7 and TSW-13 wells have a mild range of bulk density. Like TSW-21 well, samples of Abu Roash `G` Member have the widest range of bulk density (Table 4.20) and (Fig. 4.15) and the same properties were found in the studied samples of the upper part of the Bahariya Formation obtained from TSW-wells (Table 4.21) and (Fig. 4.16).

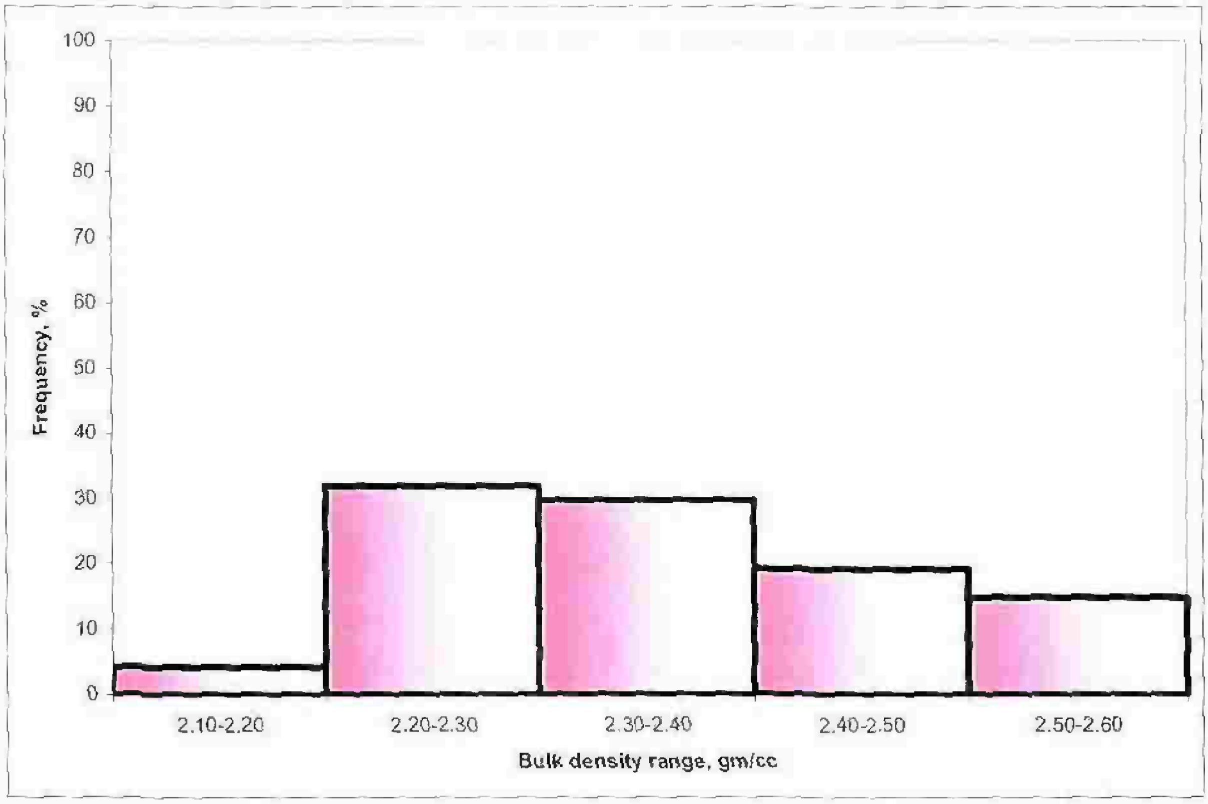

Fig. (4.13): Bulk density histogram of L. Bahariya, BED1-11 well.

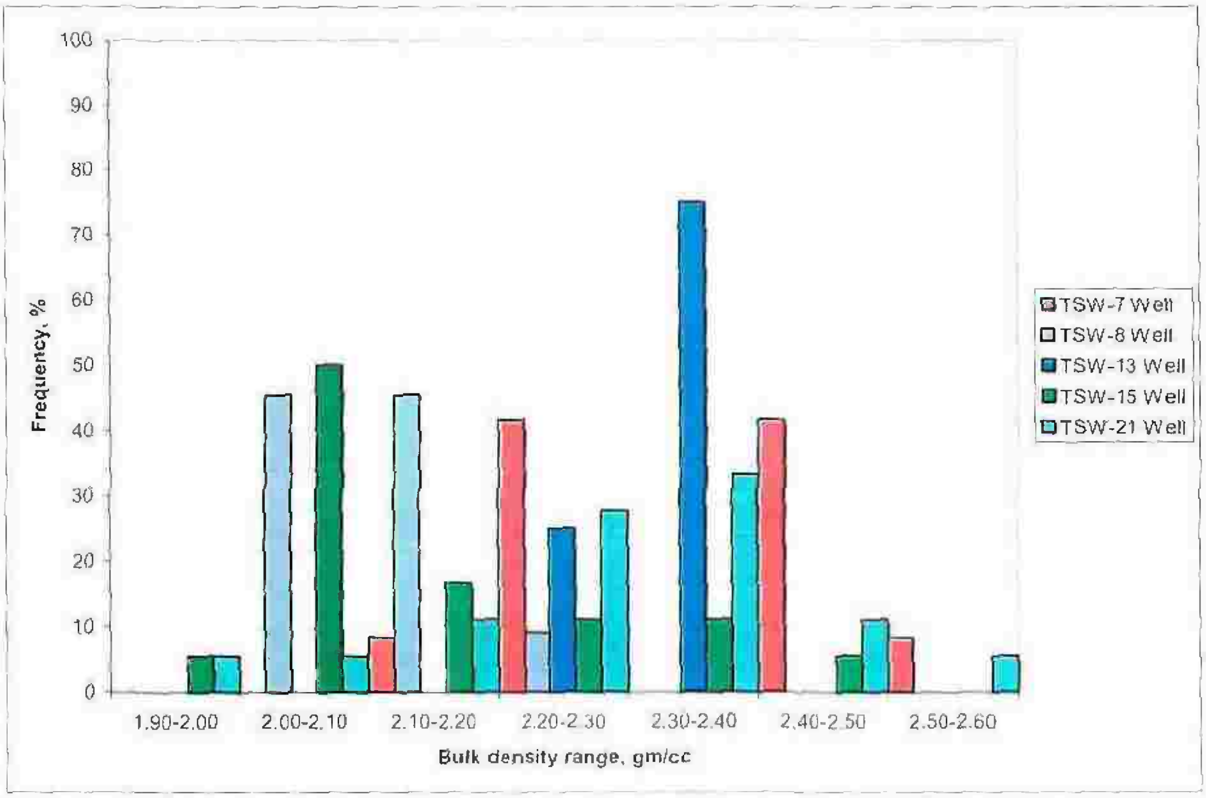

Fig. (4.14): Bulk density histogram of all TSW wells.

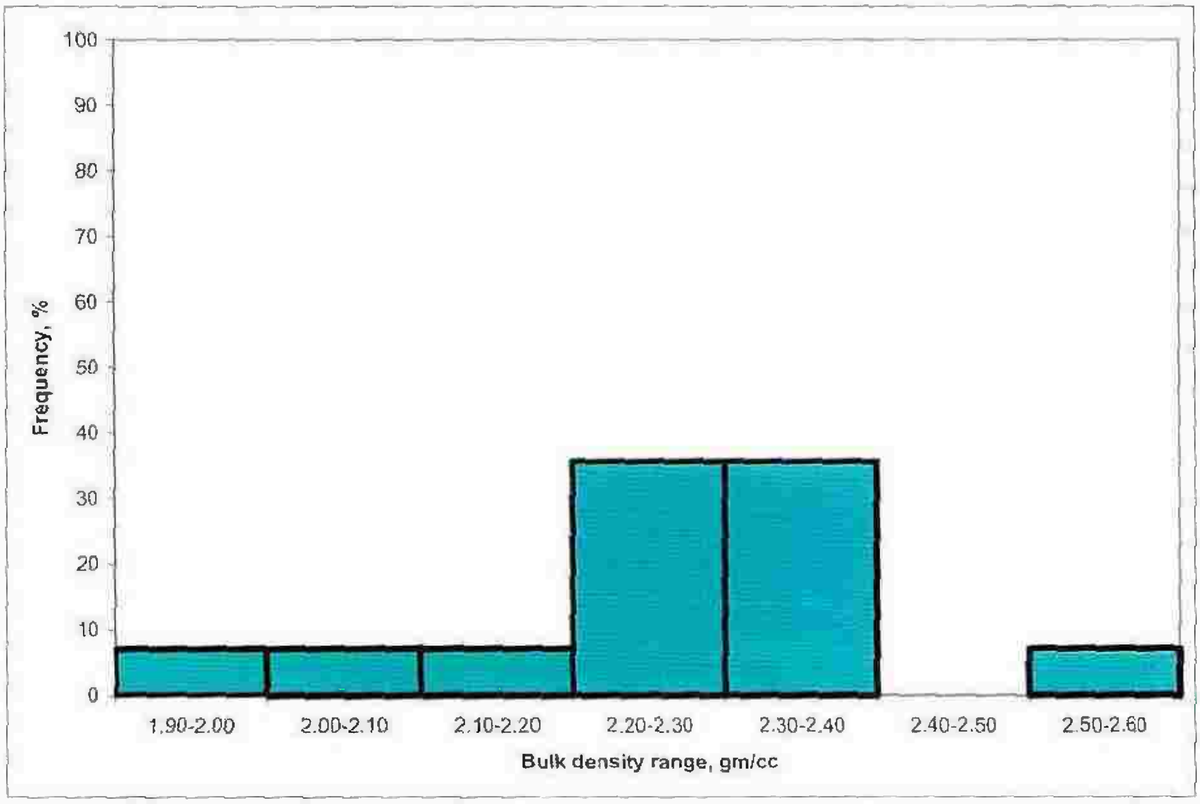

Fig. (4.15): Bulk density histogram of Abu Roash `G`, TSW-21 well.

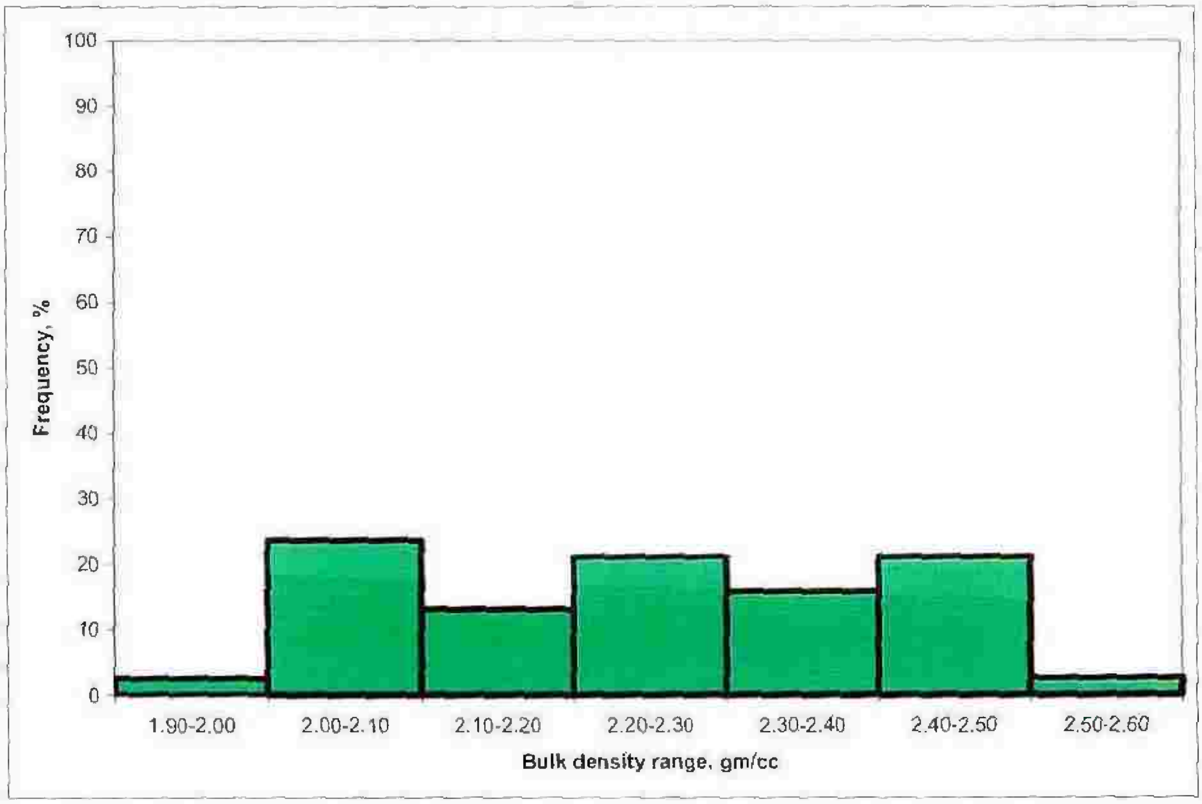

Fig. (4.16): Bulk density histogram of U. Bahariya, all TSW wells.

4.13 Porosity versus bulk density relations

Figure (4.17) displays porosity-bulk density relation of the studied samples of the lower part of the Bahariya Formation in BED1-11 well.

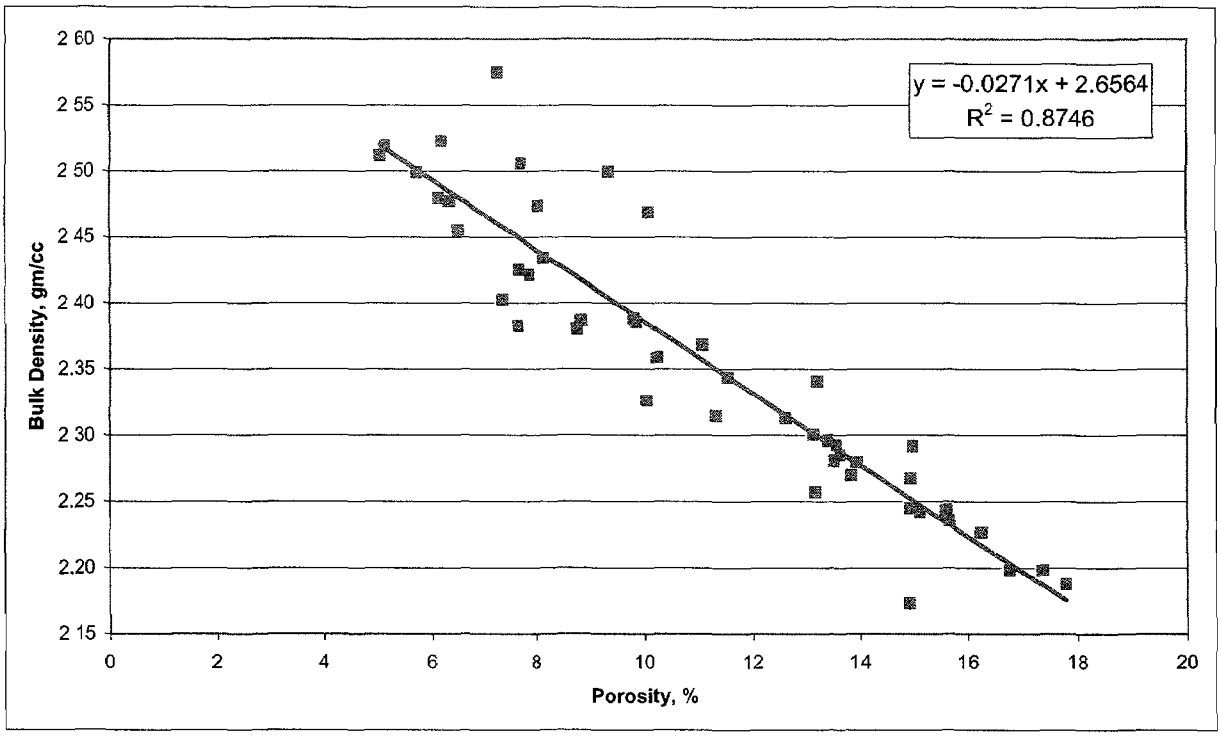

Fig. (4.17): Porosity vs. bulk density of L. Bahariya, BED1-11 well.

Porosity-bulk density relation is controlled by the following equation:

$$\rho b = -0.0271\ \Phi + 2.6564 \qquad (4.15)$$

$$R = 0.94$$

The outstanding value of correlation coefficient revealed that, the above equation is very reliable to calculate the bulk density.

Figure (4.18) is a composite figure displays porosity-bulk density relations of all the studied samples of TSW-wells (TSW-7, 8, 13, 15 and 21).

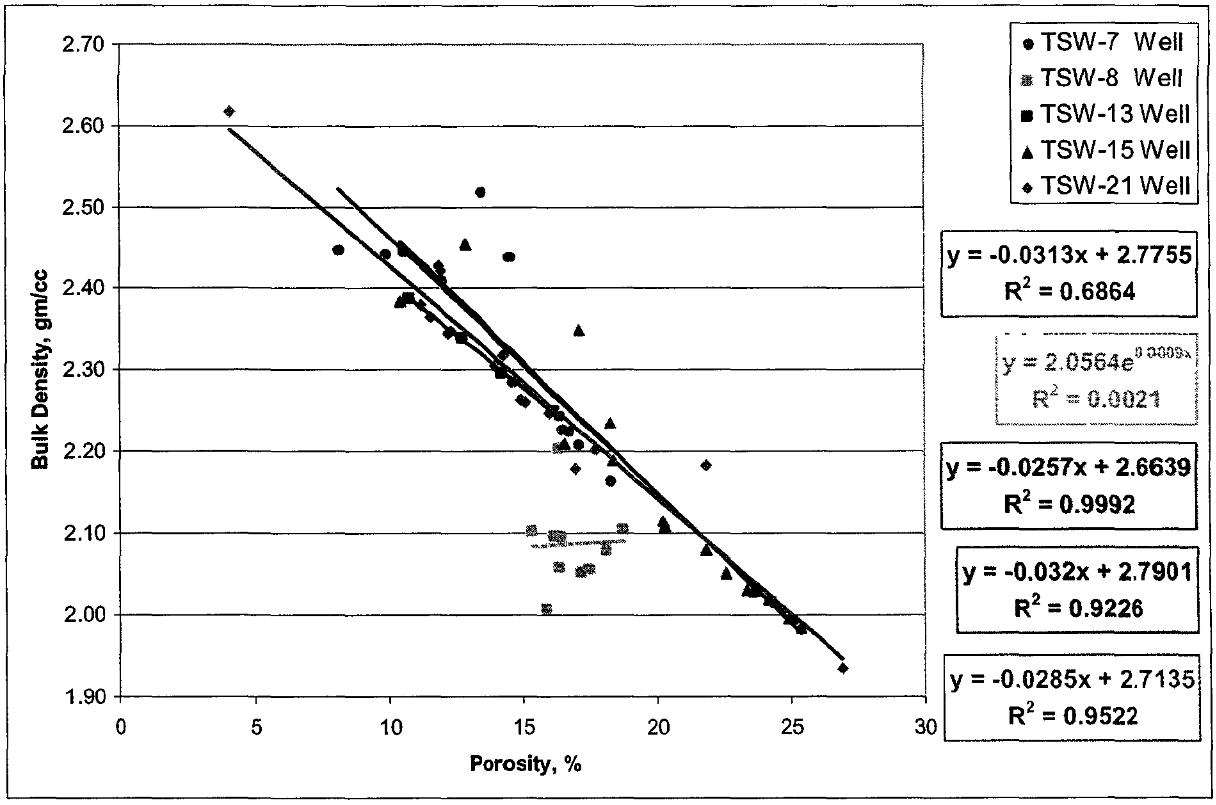

Fig. (4.18): Porosity vs. bulk density of all TSW wells.

Porosity-bulk density relation of the studied samples (TSW-7 well) is represented by the following equation:

$$\rho b = -0.0313\ \Phi + 2.7755 \qquad (4.16)$$

$$R = 0.83$$

In TSW-8 well (Abu Roash `F`), the same relation is an exponential relation which is controlled by the following equation:

$$\rho b = 2.0564\ e^{0.0009\Phi} \qquad (4.17)$$

$$R = 0.05$$

Sample 50H1 has the highest bulk density value (2.21 gm/cc) because it contains a high amount of pyrite (Fig. 4.18). The above correlation coefficient shows, nearly no relation between porosity and bulk density, this is due to firstly: the difference between the lowest and the highest porosity values is 3.4%, so this difference is too small to reflected on the values of bulk density and secondly: the presence of pyrite in a different quantities in all samples also causing no relation between porosity and bulk density.

The studied samples of TSW-13 well have an outstanding relation which is expressed by the following equation:

$$\rho b = -0.0257\ \Phi + 2.6639 \qquad (4.18)$$

$$R = 0.999$$

The same excellent relation was found in TSW-15 well and is indicated by the following equation:

$$\rho b = -0.032\ \Phi + 2.7901 \qquad (4.19)$$

$$R = 0.96$$

And also in TSW-21 well which is expressed by the following equation:

$$\rho b = -0.0285\ \Phi + 2.7135 \qquad (4.20)$$

$$R = 0.98$$

Figure (4.19) displays porosity-bulk density relation of Abu Roash `G` samples obtained from TSW-21 well.

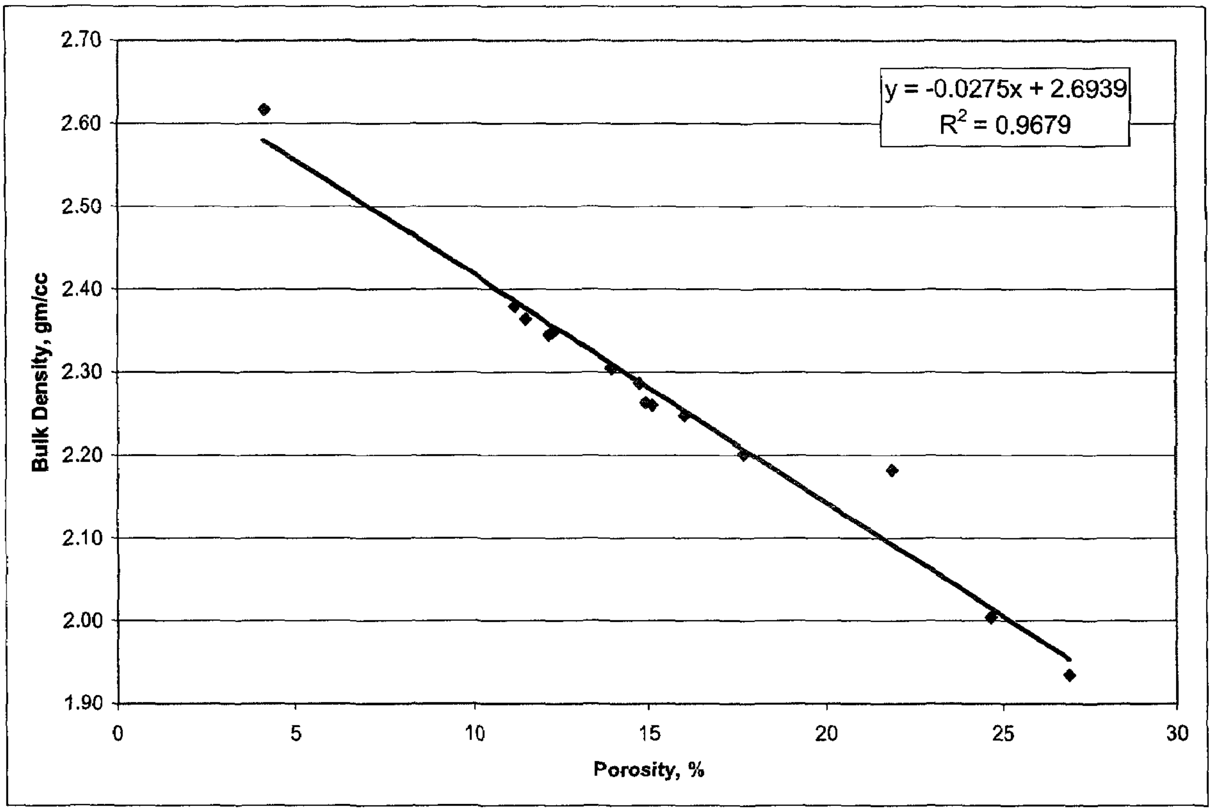

Fig. (4.19): Porosity vs. bulk density of Abu Roash `G`, TSW-21 well.

The relation of the studied samples is a linear relation which is shown by the following equation:

$$\rho b = -0.0275\ \Phi + 2.6939 \qquad (4.21)$$

$$R = 0.98$$

The outstanding value of correlation coefficient indicated that the above equation is very reliable to calculate the bulk density.

Figure (4.20) exhibits porosity-bulk density relation of the samples of the upper part of the Bahariya Formation that were collected from TSW-7, 13, 15 and 21 wells.

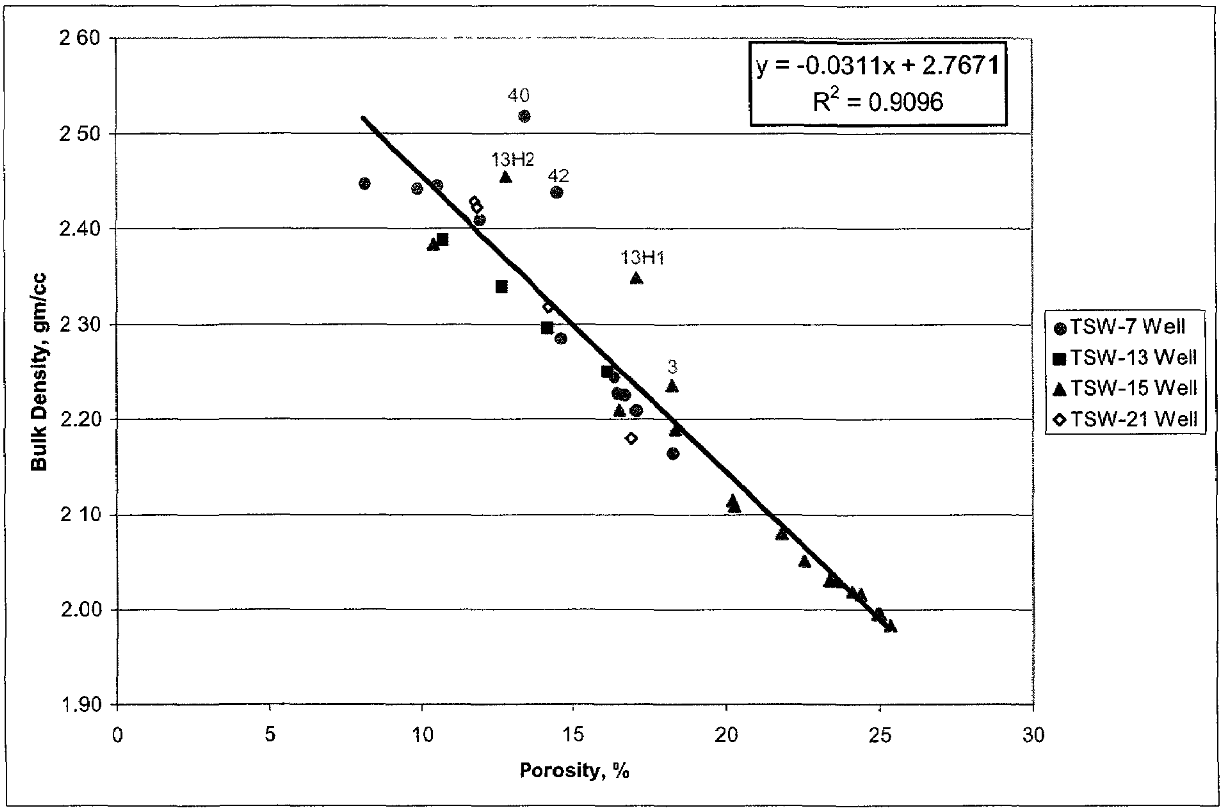

Fig. (4.20): Porosity vs. bulk density of U. Bahariya, TSW-7, 13, 15 and 21 wells.

The studied samples of the upper part of Bahariya Formation have a linear relation which is controlled by the following equation:

$$\rho b = -0.0311\ \Phi + 2.7671 \qquad (4.22)$$

$$R = 0.95$$

The excellent equation refers to the high possibility to predict the bulk density. Figure (4.20) shows a deviation of some samples that have a great value of bulk density away from the general trend line, these samples have been marked by their numbers, the reason for this deviation is the dense minerals that contained in these samples as follows:

Sample (40) is ferruginous sandstone, also sample (42) is a sandstone which is pyretic and ferruginous. Samples 13H1 and 13H2 are sandstones which are glauconitic and pyritic. Sample (3) is sandstone which is pyritic and slightly glauconitic.

4.14 Permeability and porosity against depth

Figure (4.21) displays permeability-porosity profile against the depth of the studied samples of the lower part of the Bahariya Formation in BED1-11 well.

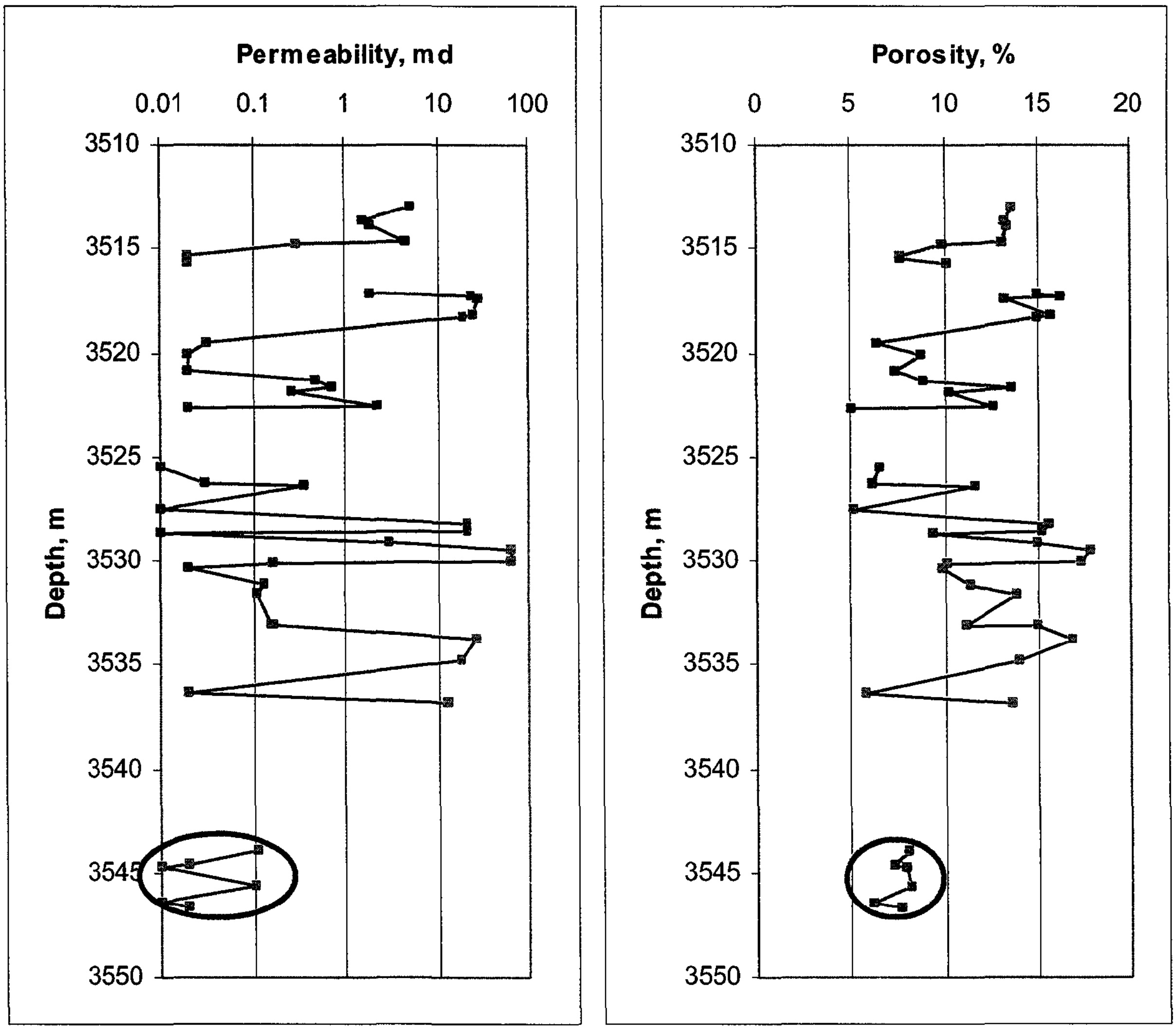

Fig. (4.21): Permeability and porosity vs. depth of L. Bahariya, BED1-11 well.

Figure (4.21) displays some samples have low porosity and permeability values located at the bottom of the section, and shown in green circles (samples 73, 74, 75, 76, 78 and 79). These samples are sandstones, very fine grains, well cemented, argillaceous, glauconitic, slightly calcareous. This shows that the finer grain size, the cement and the argillaceous materials are the reasons for the low values of porosity and permeability of these samples. Figure (4.22) shows a photomicrograph of sample (73) as an example of these samples.

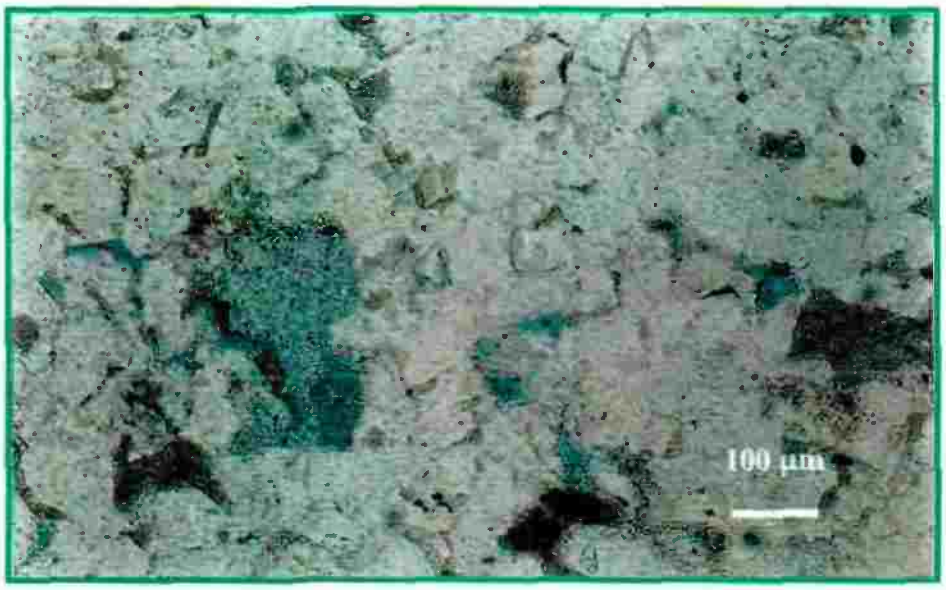

Fig. (4.22): Photomicrograph of S#73 shows the well cemented grains and the argillaceous materials that caused porosity and permeability to be very low, L. Bahariya, BED1-11 well.

Figure (4.23) displays permeability-porosity profile against depth of the studied samples obtained from TSW-7, 8, 13, 15 and 21 wells.

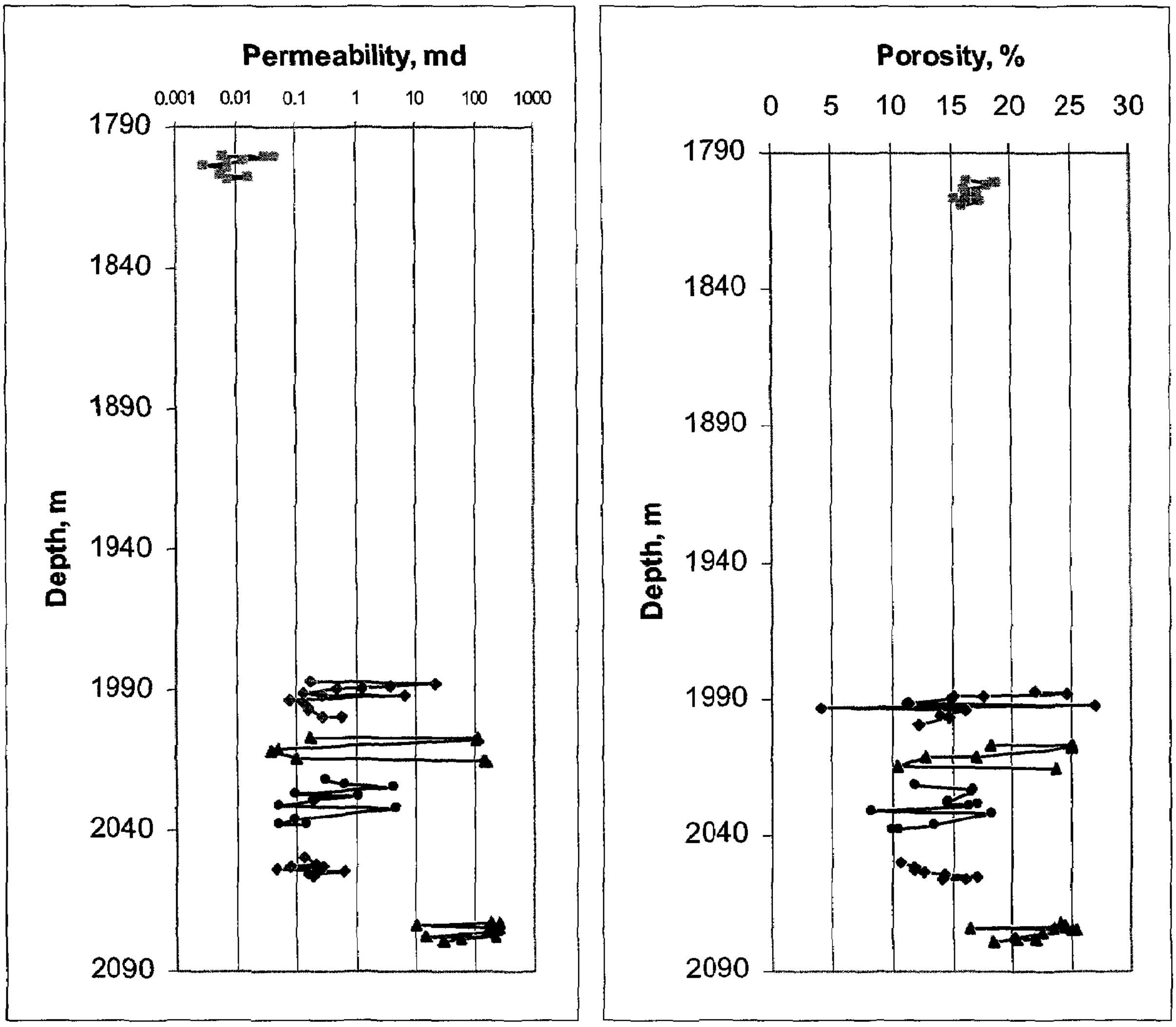

Fig. (4.23): Permeability and porosity vs. depth of all TSW wells.

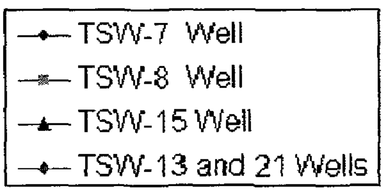

Figure (4.24) displays permeability-porosity profile against depth of samples of Abu Roash `G` from TSW-21 well.

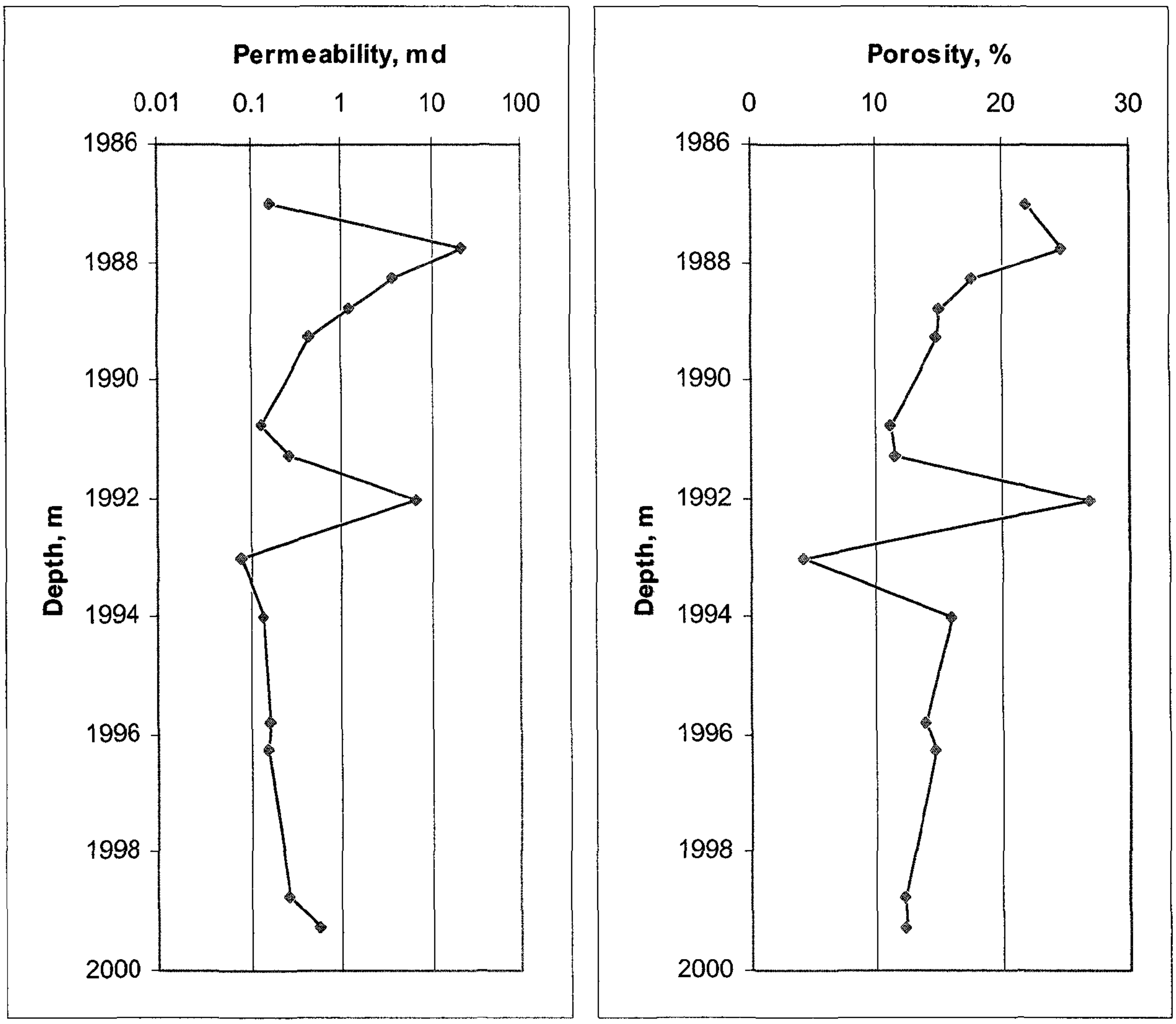

Fig. (4.24): Permeability and porosity vs. depth of Abu Roash `G`, TSW-21 well.

Figure (4.25) displays permeability-porosity profile against depth of the studied samples of the upper part of the Bahariya Formation obtained from wells TSW-7, 13, 15 and 21.

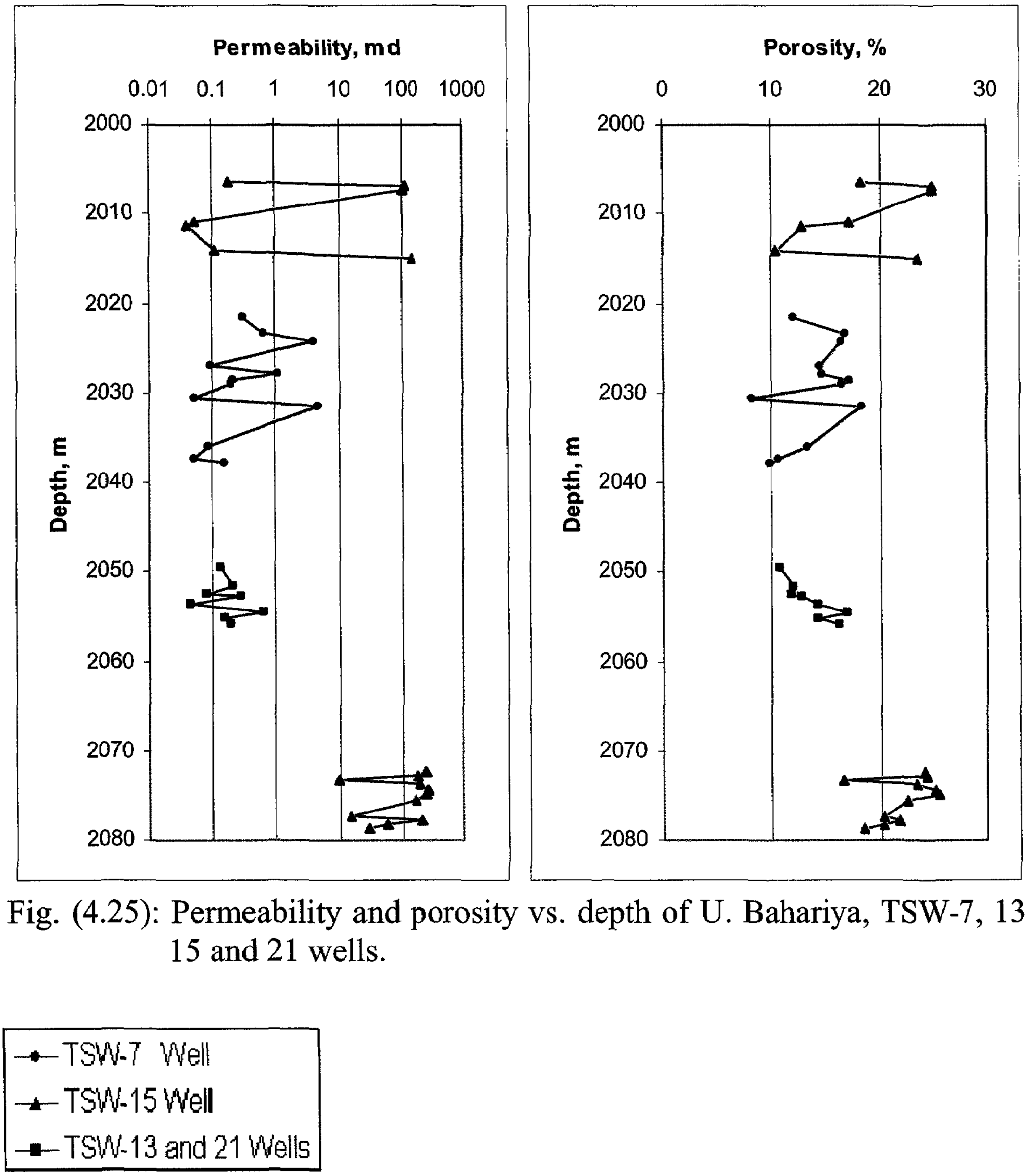

Fig. (4.25): Permeability and porosity vs. depth of U. Bahariya, TSW-7, 13, 15 and 21 wells.