Reservoir Characterization of The Baharyia Formation, Neag-1, 2 &3 Oil Fields, Western Desert, Egypt

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Abstract

An integration was achieved between different bore holes and laboratory measured data using several petrophysical parameters of the Baharyia Formation encountered in Neag-1,2&3 oil fields. It illustrates the key control factors affecting the Baharyia reservoir quality. The obtained petrophysical relationships could be used widely in both exploration geophysics and hydrocarbon reservoir production. It provides and demonstrates solutions for both geological and geophysical engineering problems. The measured porosity and permeability are ranging from 2.5 to 32 % and 0.005 to 874 mD respectively. The influence of diagenesis on both reservoir porosity and permeability has been investigated. Pore filling minerals has been classified into four classes by XRD- analysis technique. A reliable regression equation was reached between reservoir permeability and mineral pore fillings. Several relationships among rock permeability, porosity and density obtained from open hole logs were recognized. The pore throat distribution has been laboratory measured by use of MICP technique for some selected samples. The calculated reservoir storage and flow capacity indicate four major fluid flow types which are controlled by the variations in reservoir pore space framework. Formation resistivity factor – porosity relation was accomplished under reservoir conditions, while the Archie's 2nd equation was outlined. The Archie's parameters (a, m &n) were calculated for shaly and clean sandstones of the Baharyia Formation. Both cation exchange capacity (CEC), Mounce potential (MP) and mercury injection capillary pressure (MICP) were measured to distinguish reservoir facies.

Keywords: reservoir, baharyia formation, oil field, porosity, permeability, egypt

Introduction

Neag-1 located at the NEAG extension within the Abu Gharadiq basin margin at -1000 meter below sea level. Neag-1 represents the shallowest structure in the study area and in the entire Abu Gharadiq basin closer to the highly inverted Kattania high, but Neag-1 still preserves the trap integrity for hydrocarbons accumulation. Neag-2 and Neag-3 is likely affected with the same tectonic events of Neag-1 field but of moderate magnitude and affected by other basins like Natrun basin in north direction. The stratigraphy of the Baharyia in study area is sophisticated, primarily affected by the structure setting and uplifts occurred in the basin. Neag-2 and Neag-3 are most likely far from the marine influence at lower Baharyia. The Upper Baharyia sediments were not preserved in Neag-2 and Neag-3 meanwhile Neag-1 preserving the marine character and holding the thickest clastic of near-shore sediments in the Upper Baharyia. The main target of the present work is to investigate the impact of formation fines on the reservoir storage and flowing capacity side by side with the electrical properties.

Methodology

Petrography and XRD

Petrography side by side with XRD technique are used to identify clay minerals and quartz overgrowth in a bulk rock sample undertaken through the diffractogram in the less than two µm fractions. Illite and Kaolinite were characterized in XRD sheet by d-spacings at 7 Å and 10 Å respectively, Siderite is recorded at spacings 2.79, 2.13 and 1.73 Å (Fig. 1).

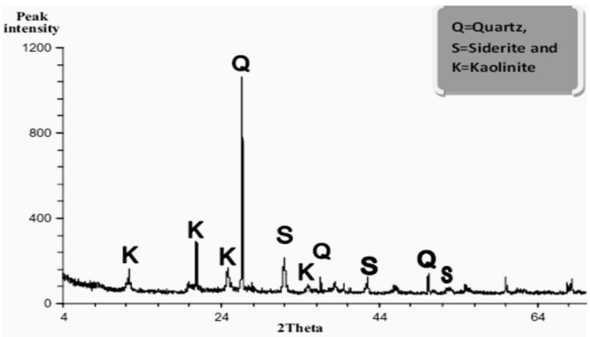

Fig. 1. X-ray diffraction chart of a bulk sample from Neag field.

The investigated thin sections revealed that quartz overgrowths are inherited because of early dissolution and recrystallization on some surfaces. Fig. 2.

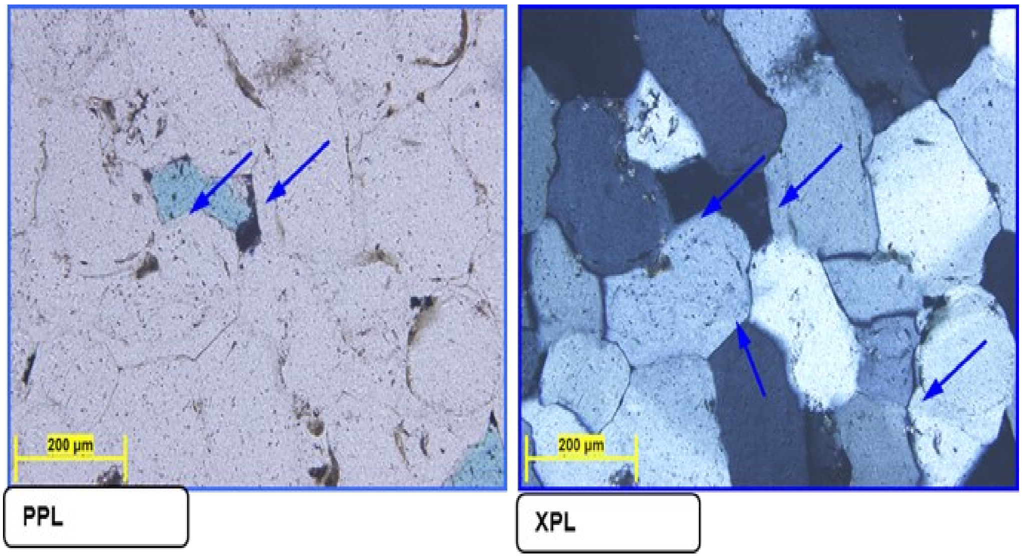

Fig. 2. Thin section images showing corroded irregular surfaces and quartz overgrowths. (Arrows pointing to Quartz overgrowth).

Clays rich sands found as thin laminas (Fig. 3) the residual hydrocarbons are trapped therein some other cases found to free of residual hydrocarbons and in other cases residual hydrocarbons be patches within the matrix. Chlorite is rarely found but the upper samples showed 8 % this could be connected to increase the clay content in the upper Baharyia than the lower part. Kaolinite found in all samples with range of 0.5 % and 7 %.

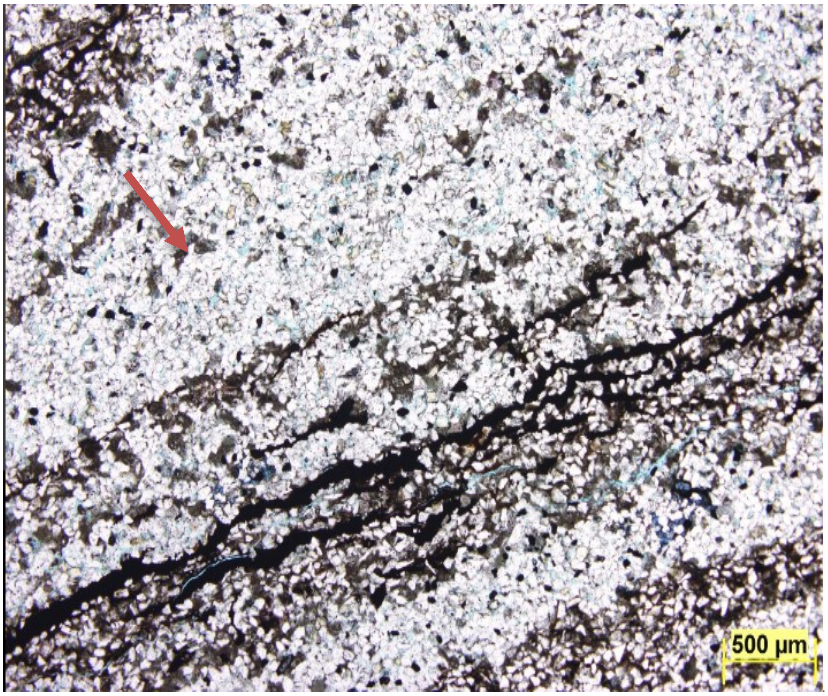

Fig. 3. Thin section images showing falser bedding in Baharyia sample.

Core Analysis

Routine core analysis was done by Corex for 423 plugs; these data set are collected from four different drilled wells to determine the main petrophysical properties as porosity, permeability (measured on horizontal and vertical samples). The data set covers the whole section of the Baharyia reservoir showing good representation in Neag-1 field with conventional cores in three wells and limited representation in both Neag-2 and Neag-3 as only side wall core samples from two wells only. The special core analysis is conducted through the Baharyia reservoir especially in the shale - sand intervals. Effective pore radius (r_{35}) of total pore throat size was done for eight selected samples exhibit different reservoir qualities; All samples are illustrated in table (1) including units, symbols, and method of measurement.

The next section explains the methods of measurements in more details. Formation resistivity factor (F) and formation resistivity index (I) were measured for only ten plugs for calculating the saturation exponent and cementation factor as well. The water saturation in the highly clay content reservoirs comprise a big uncertainty; thus, more than one technique was applied for outlining and calibrating it by Dean Stark method, core conductivity and capillary pressure by centrifuge technique rather than the open hole logs. Fifty-seven core samples were selected for petrographically studies as thin section investigation. In addition, eighteen samples were selected for X-ray diffraction analysis for quantitative mineralogy to outline the different litho-facies and the common reservoir rock types.

Porosity

Porosity is the most important parameter for evaluating storage capacity of a reservoir rock. The porosity of a rock is defined as the ratio of the rock void spaces to its bulk volume, multiplied by one hundred to express it in percent [1]. Porosity in this research is measured using Helium porosimeter with matrix cup core holder for grain volume (Vg) estimation [2]. Porosity (Ø) is calculated by the following equation:

$$Ø = (\mathbf{1.0} - \boldsymbol{Vg})/\boldsymbol{V}b \tag{1}$$

where, Ø, is the porosity fraction, V_g, is the grain volume cm^3, V_b, is the bulk volume of the sample in cm^3.The laboratory measured porosity values were statistically treated while the frequency distribution curve and polygon are shown in Fig. 4.

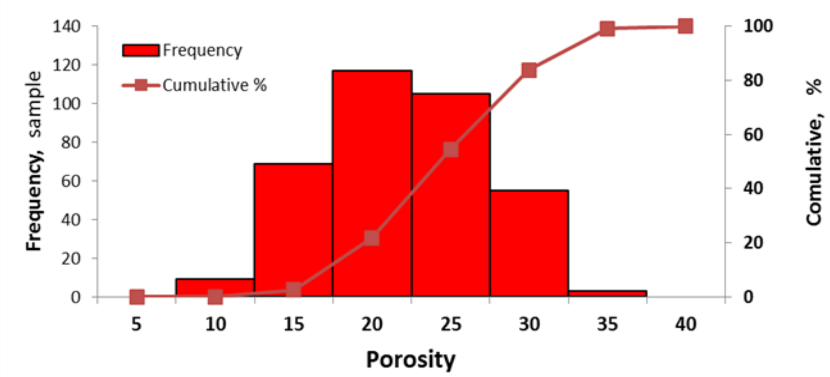

Fig. 4. Porosity distribution of the studied samples

Permeability

The gas permeability is measured using core Lab permeameter followed methods adopted by [3, 2] Gas permeability measurements were conducted with Hassler type core holder in which samples (approximately 2.5 cm in diameter and 5 cm in length), the plugs were loaded individually subjected to dry Nitrogen gas with pressure of 1378.9514 kpa. The permeability is calculated by the following formula:

$$K = (C.Q.hw.L2)/200\,Vb \tag{2}$$

Where: K is gas permeability, mD, L is the length of the sample, cm, hw is the orifice manometer reading, mm, Q is the orifice value, c is the value of mercury height, mm, and V_b is the sample bulk volume, cm^3. The permeability polygon and frequency distribution curve are shown in Fig. 5.

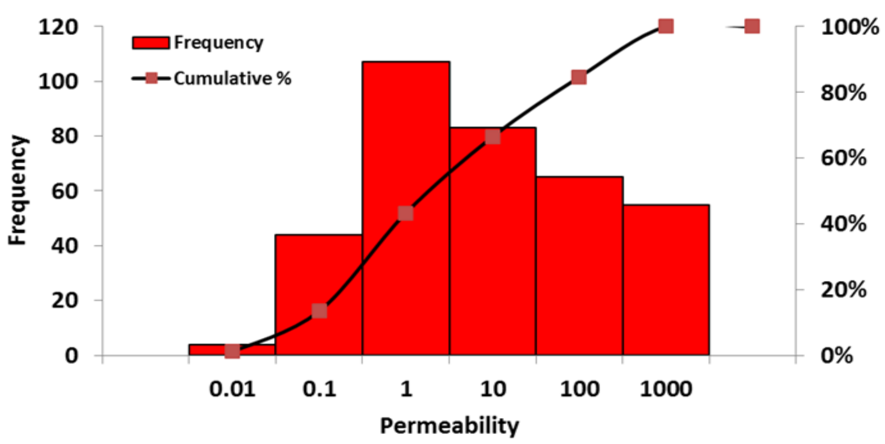

Fig. 5. permeability polygon and frequency distribution curve

Pore Throat Radius

The capillary pressure was plotted against the mercury saturation [4] resulting in the injection curve. Data from the mercury injection curve is used to approximate the distribution of pore values accessible by throats of given effective size using the equation adopted by [4]:

$$rc = 107.6/\,Pc \tag{3}$$

Where: r_c (μm) and P_c is capillary pressure (psi).

Formation Resistivity Factor

The formation resistivity factor (F) was measured by technique adopted by [6]. It is discussed by authors [5-9] and others. They concluded that the formation resistivity factor is function of the effective path of electric current flow and the effective cross-sectional area available for electric conduction.[10] investigated the influence of particle size and cementation on the formation resistivity factor of verity of materials. Observed formation resistivity factor for artificially cemented aggregated showed that the cemented aggregates exhibit a greater than in porosity than the unconsolidated aggregates. [10] conclude that the general form of relation between formation factor and porosity is.

$$F = a\o^{-m} \tag{4}$$

Where, [a] is a parameter depend on pore space framework.

Variation in cementation factor (m) was discussed by many authors e.g. [2, 7, 9, 11-13].

Formation Resistivity Index

The index was measured by method adopted by [14, 15] while overburden pressure was applied up to resistivity 100 psig. The volume of brine expelled was plotted against overburden pressure to determine the true pore volume reduction. The net confining pressure was raised to 1710 psig (reservoir pressure).

Results and discussions

Porosity and Pore Filling Mineralogy

The pore filling minerals and volume of Quartz in the studied samples are plotted against helium porosity (Fig. 6a, b). The relationship exposes a reliable coefficient of correlation (R^2 = 0.69& 0.61) between porosity and pore filling minerals and volume of quartz, respectively. The calculated equations are useful in Quartz and mineral fillings calculation.

$$V\,Qz = 1.453 * Ø + 48.87 \qquad R^2=0.61 \tag{5}$$

$$V\,pore - filling = -1.559 * Ø + 50.6 \qquad R^2=0.69 \tag{6}$$

Where:

V Qz: is volume of Quartz, percent,

V pore-filling is total volume of pore filling minerals, percent.

Ø: is porosity in percent.

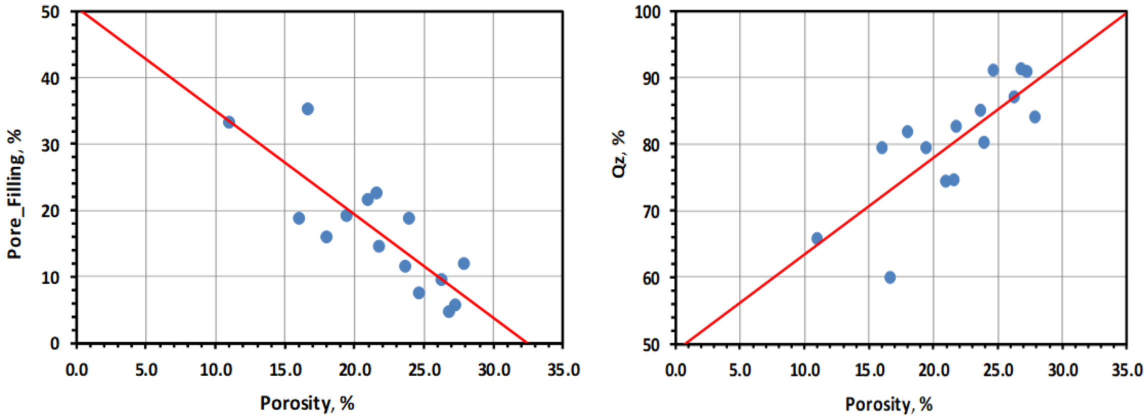

Fig. 6. a. Pore filling minerals versus porosity, b. Relative volume of Quartz versus helium porosity for Baharyia reservoir samples.

Reservoir Permeability Zonation

A comparison between pore fillings mineralogy aggregates and petrophysical parameters like porosity and permeability is performed; while permeability found to be increased when the pore fillings decreases either as calcareous cement or clay minerals (Fig. 7a, b).

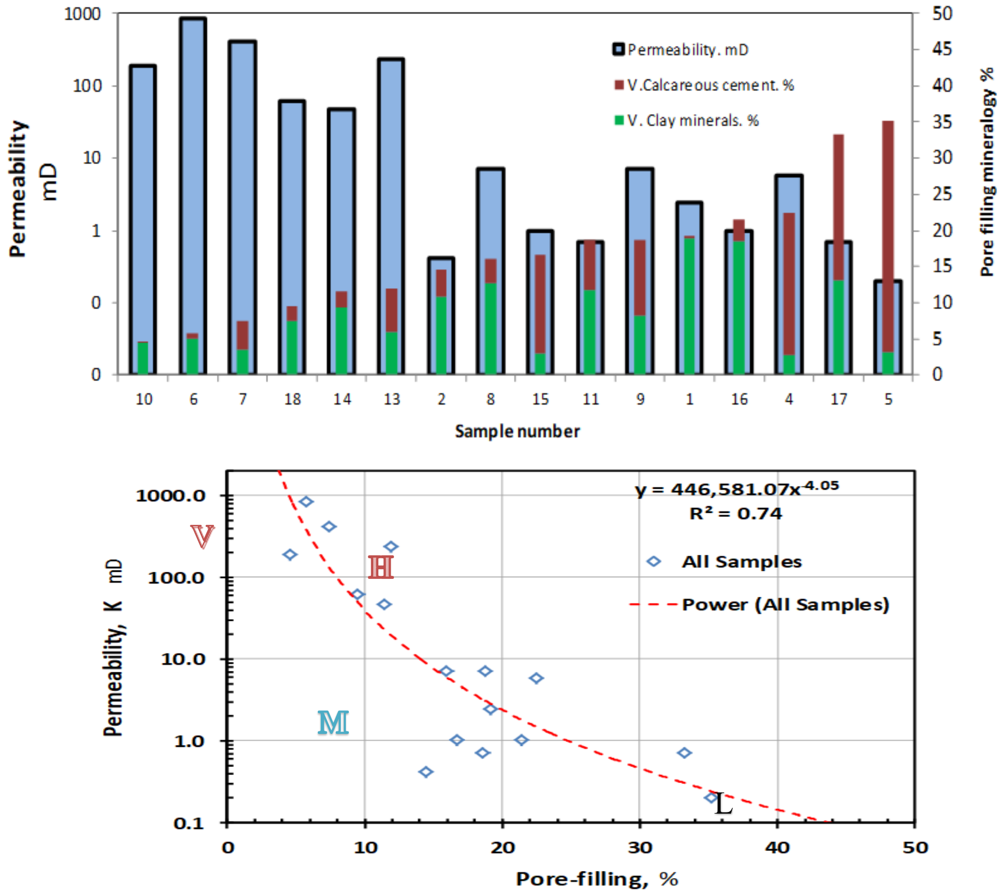

Fig. 7. a. Permeability behaviour with% of pore mineral fillings, b. Permeability versus pore mineral fillings

Fig. 7b, shows inverse relationship with a reliable coefficient of correlation ($R^2 = 0.74$) allowed to calculate the percent of pore filling minerals from the permeability values in the Baharyia sediments in Neag Fields. There are four groups (Fig. 7b) of sample permeabilities (from down upward L, M, H and V) where L is characterized by pore filling (P_f) > 32 %, M has P_f ranges from > 14% to 25 %, H exposes $P_f \simeq 10$ % and V has samples with P_f generally < 10 % .

Porosity and Permeability Relationship

To build a robust relationship between porosity and permeability the pore throat radius should be part of the relationship. The obtained relation in Fig. 8, describes the best fit line for Baharyia porosity and permeability in Neag Fields under investigations as follows.

$$K = 0.00087 * e^{0.4106\,\phi} \qquad R^2=0.53 \qquad (7)$$

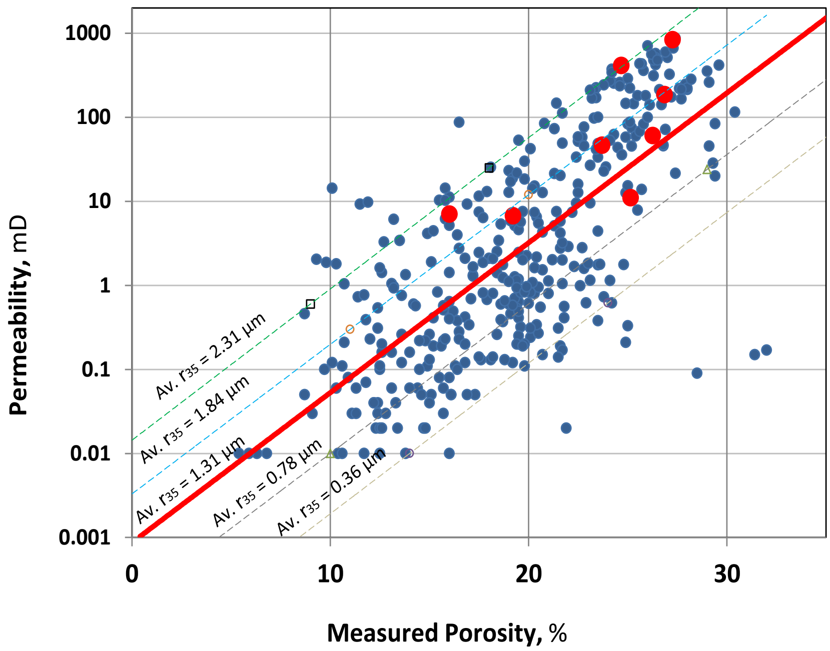

Fig. 8. Porosity versus Permeability at different r35 for Baharyia reservoir samples.

Pore Throat Radius (r_{35})

Pore throat radius (r_{35}) is defined as the pore aperture corresponding to a mercury saturation of 35% pore volume. The term was introduced by [16] who developed an empirical relationship among porosity, air permeability and the pore aperture corresponding to a mercury saturation of 35% (r_{35}) for a mixed suit of sandstones and carbonates. Gas permeability is plotted against both of r36 and r50 [17]. These relationships were characterized by slightly low correlation coefficients (0.54 and 0.62 respectively). The regression equations representing these relations are:

$$r36 = 2277.5 \quad K0.542 \tag{8}$$

$$r50 = 993.5 \quad K0.61 \tag{9}$$

where K is the gas permeability (md).

Results showed that there is a favourable comparison with either r36 or r50. (r_{50}) is termed the median pore throat size and is defined as that radius above and below which 50% of the pore volume exists. Selection of mercury injection capillary pressure samples was mainly aiming to cover different reservoir categories that found to be effective to overcome the wide data range and variations in reservoir quality (poor- moderate –good) based on the petrophysical parameters (Fig. 9).

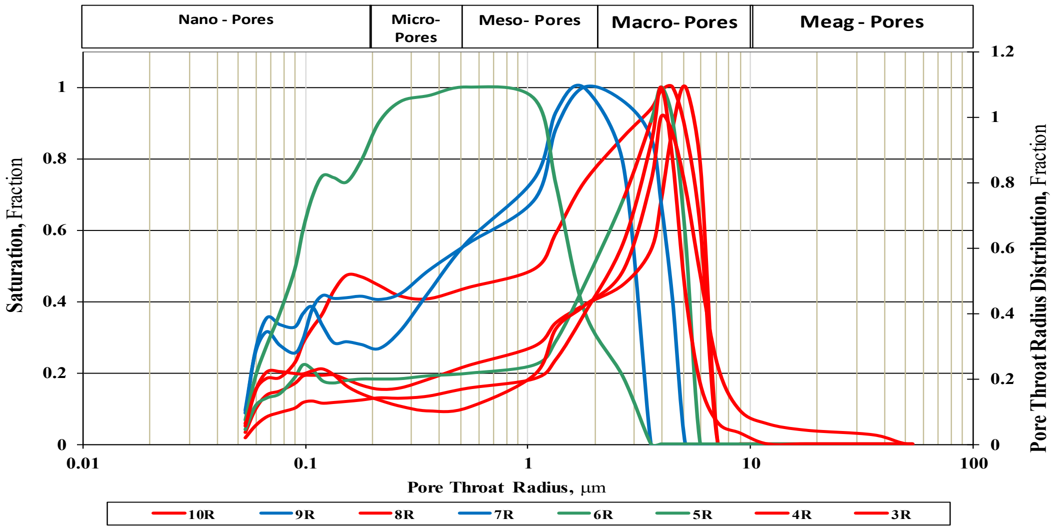

Fig. 9. Pore throat size distribution for studied Baharyia reservoir samples.

Electrical Properties

Formation Resistivity Factor and Porosity

Formation factor – porosity relation is shown (Fig. 10) and controlled by equation.

$$F = 0{,}6\,Ø - 2.4 \qquad (R^2 = 0.88) \tag{10}$$

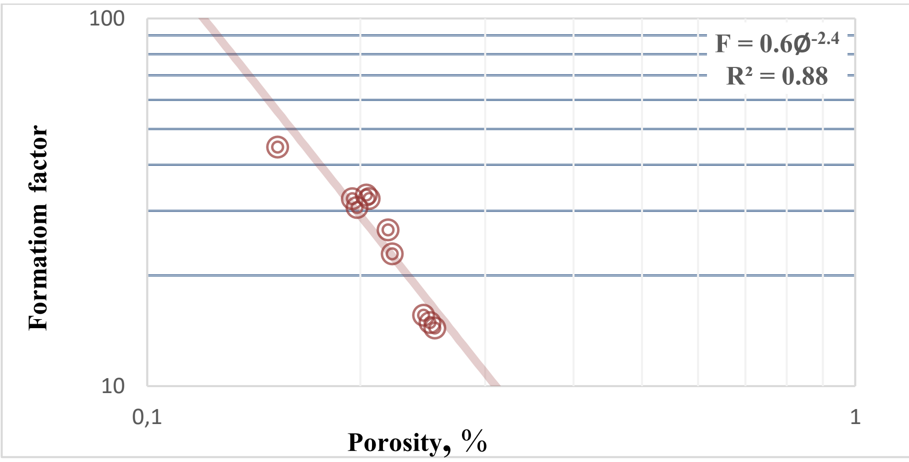

Fig. 10. Formation reservoir factor versus porosity

The same relationship was investigated on the Baharyia reservoir in BED-1 field earlier in 2010 which showed a Wyllie's type equation but in such that case the (m) value is closer to Archie value 1.95.

Saturation Exponent and Cementation Factor

Saturation exponent versus cementation factor was performed for the sandstone reservoir of the Algyő-2 in the Algyő field of the Great Hungarian Plain by **[6]**. The cementation Factor (m) and saturation exponent (n) are characterized by high coefficient of correlation (Fig. 11).

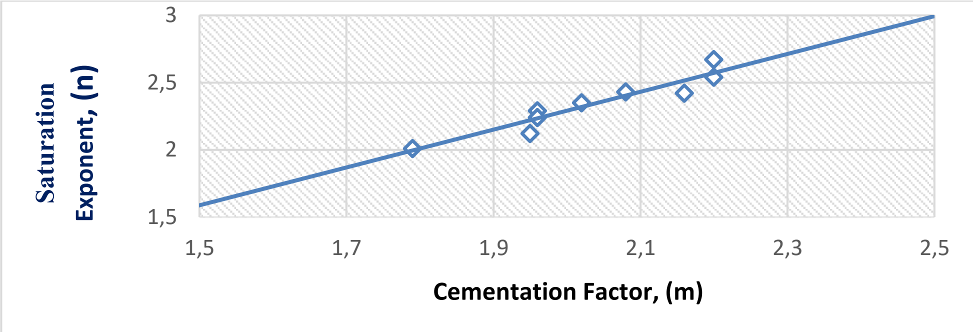

Fig. 11. Cementation Factor (n) versus Saturation Exponent (m)

The measured samples are representing different rock types of the Baharyia. The relationship is controlled by the equation.

$$n = 0.98 * m\,1.22 \qquad R^2 = 0.90 \qquad (11)$$

Cation Exchange Capacity

Cation exchange capacity and clay content relationship for Baharyia samples are shown (Fig. 12). A very reliable correlation coefficient $R^2 = 0.75$ was obtained.

$$\mathrm{CEC} = -0.0723 * \mathrm{Vclay} + 0.233 \qquad R^2 = 0.75 \qquad (12)$$

$$CEC = -0.0876 * Kaolinite\,(\%) + 0.2884 \qquad R^2 = 0.83 \qquad (13)$$

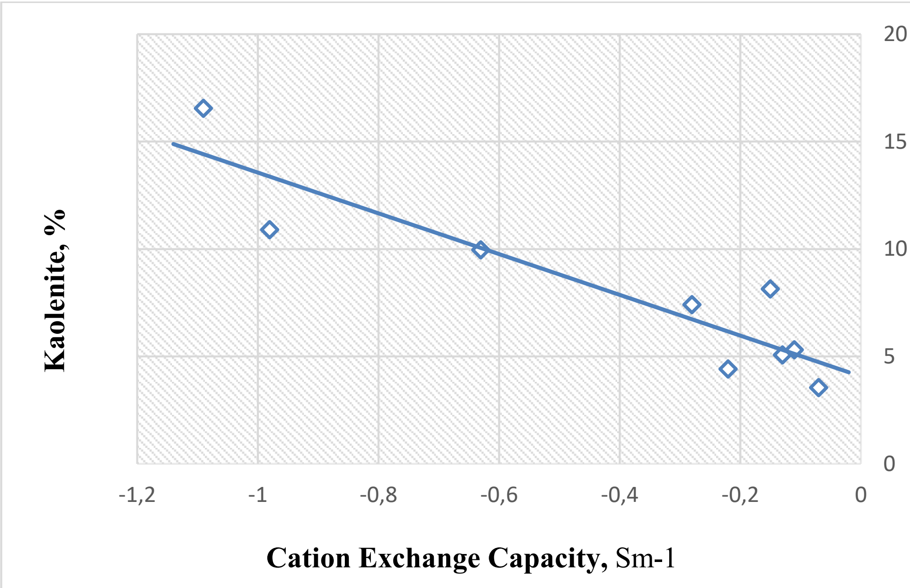

Fig. 12. Correlation between Kaolinite and Cation Exchange Capacity.

Equations (12&13) are useful to calculate either kaolinite% or CEC with reasonable accuracy.

Conclusions

1. The increase of pore filling minerals decreases the rock porosity and permeability.
2. The hydraulic conductivity of studied samples is classified to four groups.
3. The reservoir pore throat radius (r_{35}) is classified as micro pores, meso pores and macro-pores.
4. Formation factor of the Baharyia samples varies from 14.4 to 44.7 ohm/m.
5. Cation exchange capacity showed poor correlation with most of the investigated petrophysical parameters except kaolinite mineral.
6. Cementation factor (m) in clean sand is ranging from 1.95 to 2.2 with mean value of 2.07 while in shale-sand is ranging from 1.79 to 2.02 with mean value of 1.87.

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