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Heterogeneous Reservoir Characterization

(Upper Bahariya Case study)

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Abstract

Upper Bahariya reservoir is one of the big productive reservoirs in the Western Desert (Egypt). It is characterized by high degree of heterogeneity. So, it is very important to characterize it accurately for improving its recoverable oil. Different tools were used to accomplish this task. These tools include Dykstra-Parsons coefficient, Lorenz coefficient, well correlation, hydraulic flow units, relative permeability and capillary pressure. Dykstra-Parsons coefficient (permeability variation factor) and Lorenz coefficient were determined for Upper Bahariya reservoir and found to be 0.86 & 0.92 respectively. This reveals that this reservoir is extremely heterogeneous. These results are proportionated with the pressure readings and the open hole logging format. The hydraulic flow unit's reservoir technique showed the reservoir can be divided into nine flow units. The relative permeability curves of the reservoir indicated that it is a water wet system while the capillary pressure curve looks like a transition zone due to its high heterogeneity and high connate water saturation.

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Keywords

Heterogeneity; dykstra-parsons coefficient; Lorenz coefficient; hydraulic flow units; reservoir quality index; flow zone indicator; relative permeability and capillary pressure.

1. Introduction

The amount of the recoverable oil from a reservoir and how it is recovered depend primarily on the accuracy of its characterization. So, reservoir characterization is the first step in any reservoir management program. Briefly, the reservoir characterization is defined as the scientific and mathematical discipline that seeks to define quantitatively the input data needed to undertake predictions of flow through porous media. It is a synthesis of the disciplines of geology, geophysics, statistics, engineering and mathematics as related to the oil industry (Amaefule, 1993 & Kramers, 1994). The permeability and porosity of the reservoir rock have always been considered as two of the most important parameters for formation evaluation, reservoir description, and characterization. Beyond evaluating permeability and porosity, one can also use a combination of two or more rock properties to gain insight into the character of flow through porous media. The J-function and the Reservoir Quality Index (RQI) concepts are two of the ways that the oil industry has used to characterize the reservoir media. They incorporate parameters such as porosity and permeability into a single quantity that describe/characterize the formation (Shedid, 2003).The available tools are the core data (conventional and special), the open hole logging, PVT and pressure data.

2. Reservoir heterogeneity identification

The common static measures of the reservoir vertical heterogeneity are Dykstra-Parsons coefficient and Lorenz coefficient which are excellent tools for characterizing the degree of reservoirs heterogeneity. These measures of heterogeneity describe the distribution of the permeability of a given sample from the formation (Jerry, 1990& Alharbi, 2013).

2.1. Dykstra-Parsons coefficient (permeability variation factor)

The conventional core data from five wells (243 samples) were used to calculate Dykstra-Parsons coefficient as following (Ahmed, 2001, AbdusSatter, 2008, Tiab, 2004 & Peter, 2013):-

- The core samples are arranged in a decreasing permeability sequence (a descending order) after removing any broken or nonsense data.
- The percentage of samples having permeability greater than the respective samples were calculated.
- Use a log-probability graph paper, plot permeability values on the log scale & the percent of samples on the probability scale and draw the best straight line through the points as shown on Figure (1).

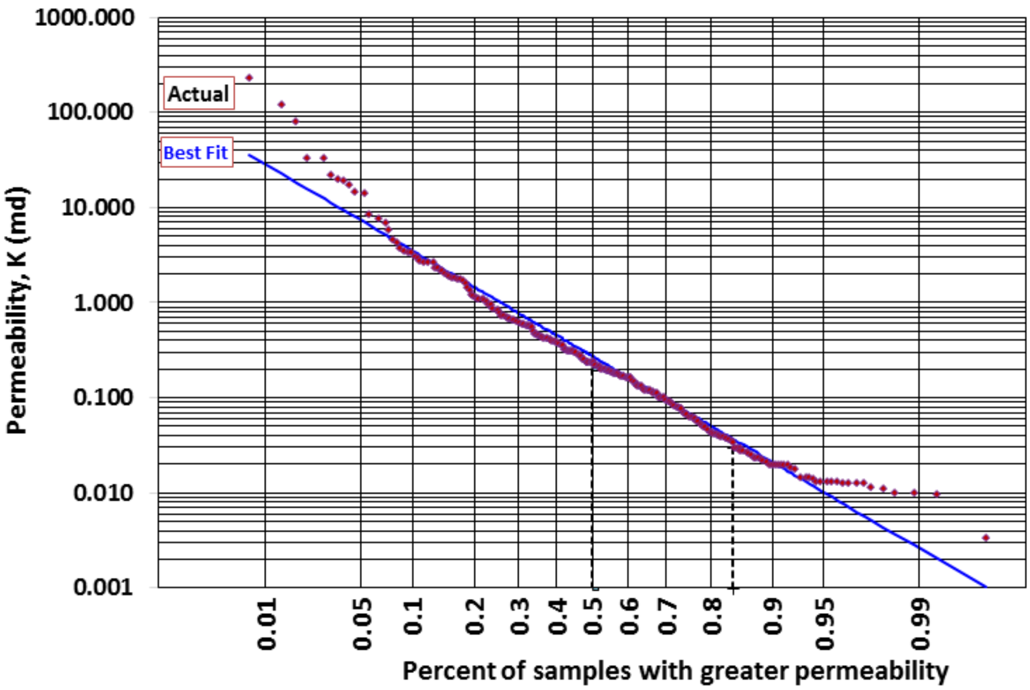

Figure 1. Permeability variation factor V_{DP} forUpper Bahariya reservoir

- The corresponding permeability values at 84.1% and 50% of samples from the log-probability graph were determined, and then the permeability variation factor VDP was calculated by using the following equation (Ahmed, 2001) :

$$V_{DP} = \frac{K_{50} - K_{94.1}}{K_{50}} \qquad V_{DP} = \frac{0.27 - 0.037}{0.27} = 0.86 \tag{1}$$

2.2. Lorenz coefficient

The following steps summarize the methodology of calculating Lorenz coefficient from the conventional core analysis data of five wells (Alharbi, 2013, Ahmed, 2001, AbdusSatter, 2008, Tiab, 2004 & Lake, 1989):-

- The available permeability values were arranged in a descending order.
- The dimensionless cumulative permeability and dimensionless cumulative capacity were calculated.
- The data were normalized and plotted on Figure (2).

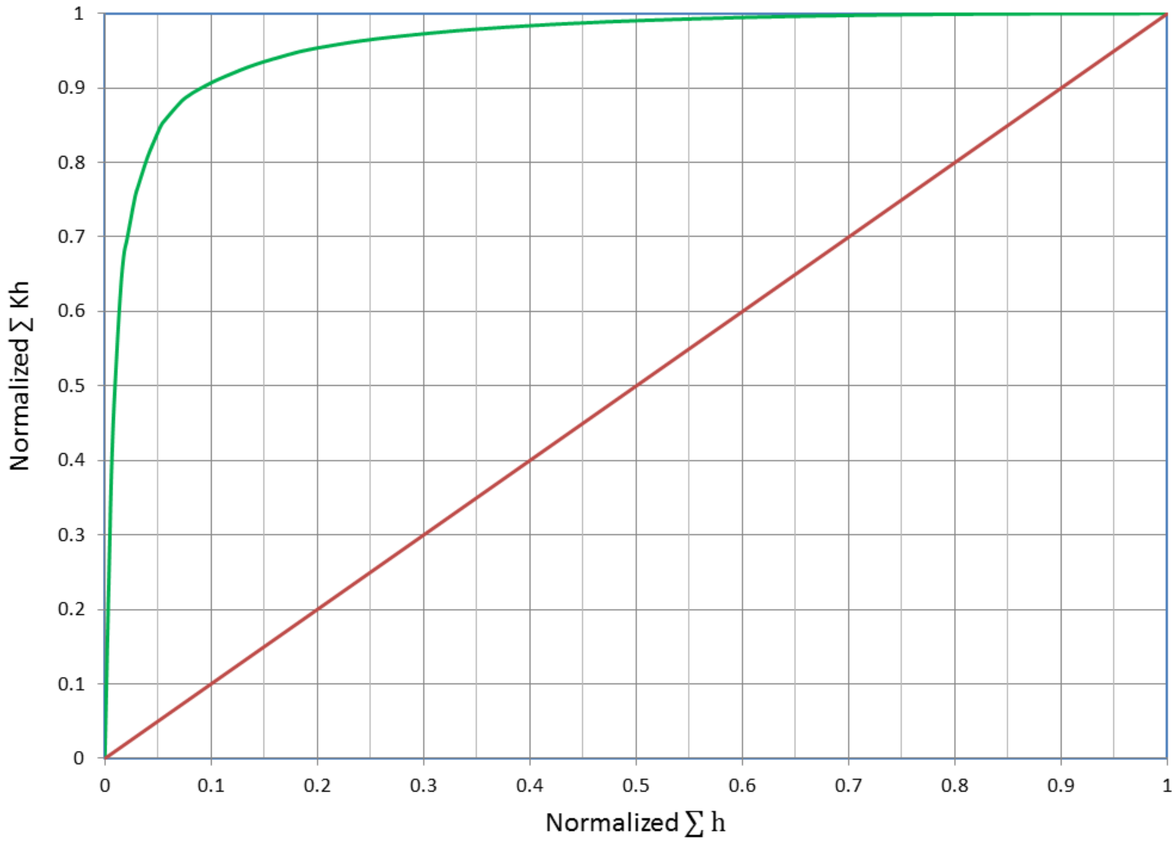

Figure 2. Normalized flow capacity to Upper Bahariya reservoir

- Lorenz coefficient was calculated using the following equation (AbdusSatter, 2008):-

$$L_C = \frac{Area\ above\ the\ diagonal}{Area\ below\ the\ diagonal}$$
$$L_C = \frac{0.46}{0.5} = 0.92 \quad (2)$$

3. Well correlation and pressure data

The well correlation and pressure data together give a reliable evidence about the reservoir heterogeneity and continuity. The Upper Bahariya reservoir correlation shown on Figure (3) indicates that the reservoir consists of thinly sand layers interbeded with shales, silt and limestone. In some areas, where log correlations are difficult and sands appear to be discontinuous, pressure uniformity suggests that the reservoirs are, in fact, continuous or connected. In contrast, in other areas where porous sands can be correlated more easily, large pressure variations suggest reservoir discontinuity, or at least greatly reduced lateral permeability. Hence the importance of pressure data comes. It can provide information about reservoir continuity and the effectiveness of the water flood program. When such pressures are plotted as profiles for well-to-well comparison as shown on Figure (4), one striking feature that emerges is the great variation in pressures, both laterally and vertically. The pressure data show different decline trends in all the wells. This is obviously evidence on the reservoir compartmentalization.

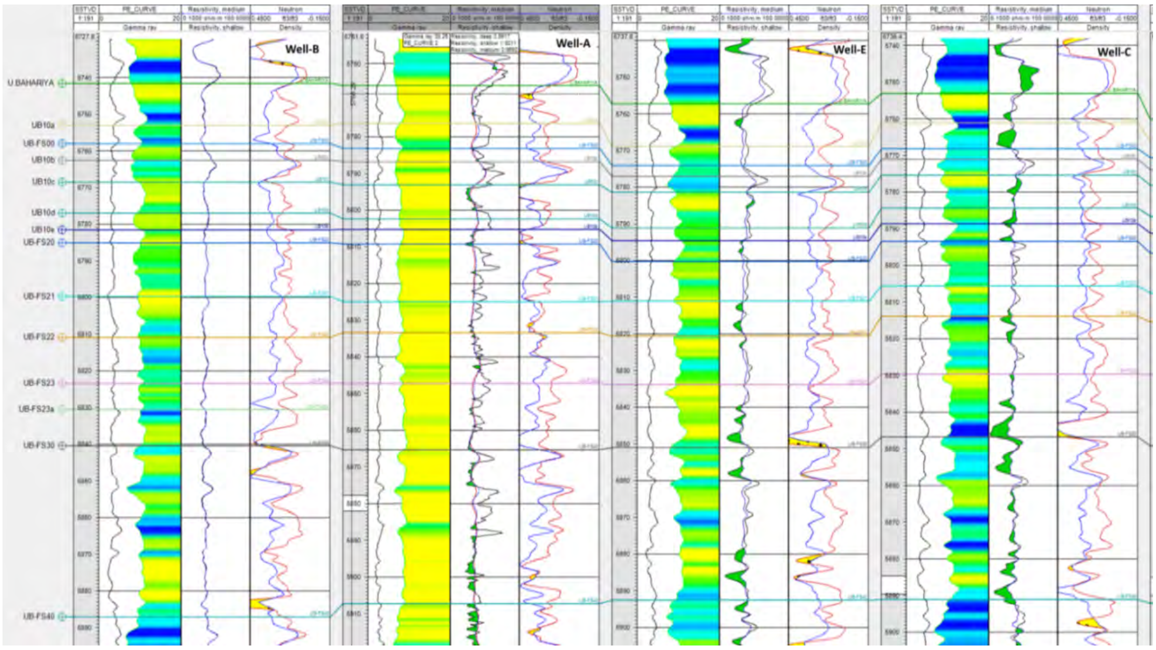

Figure 3. Upper Bahariya reservoir correlation

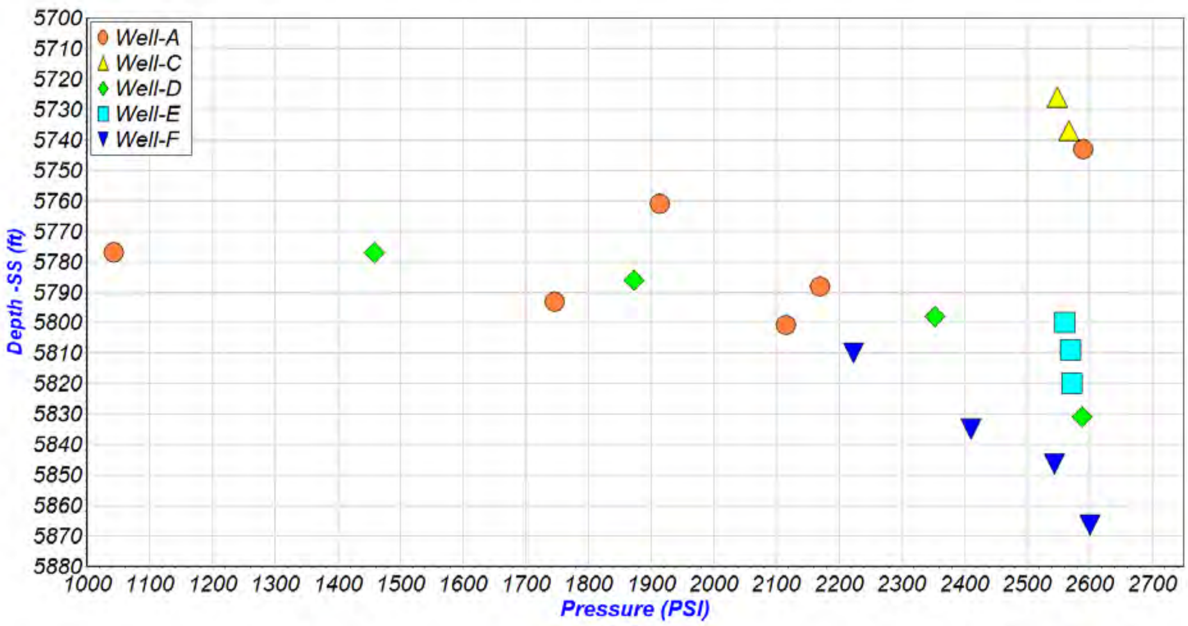

Figure 4. Upper Bahariya reservoir pressure data

Generally, the huge variation in the Upper Bahariya reservoir permeability values obtained from the conventional core analysis, Dykstra-Parsons permeability variation factor and Lorenz coefficient results, the well correlation and the pressure data readings indicated that:-

- The reservoir is extremely heterogeneous.
- The heterogeneity in the rock signifies the possibility of finding thin vertical shale barriers that may or may not extend across the field.
- The high degree of heterogeneity avers that there will be no perfect relationship between the porosity values whether the measured and calculated or between porosity and permeability.

4. Permeability-Porosity relationships

Permeability depends on the continuity of pore space whereas porosity basically signifies the availability of a pore space. Also, it is possible to have a very high porosity without having any permeability and vice versa. The quality of a hydrocarbon-bearing formation is judged according to its permeability. There is no theoretical relationship between porosity and permeability in natural porous systems. So any practical relationship represents a best fit and may be represented by a convenient mathematical relationship. The easiest relationship to test is that of a straight line and it has frequently been noted that a plot of porosity against the logarithm of permeability leads to an approximate straight line. Also, porosity is logging parameter while the permeability isn't. Empirical correlation of porosity with permeability is frequently attempted in order to provide an extirpate of permeability as a function of depth. The down hole permeability is mainly obtained by flow and pressure determination and requires other characteristics such as the flowing interval (Tiab, 2004& Archer, 1986). The poor fitting (poor correlation coefficient) between the core porosity and core permeability depicted on Figure (5) is attributed to the reservoir heterogeneity and means that there is no reliable relationship between them.
Consequently, the conventional averaging techniques (arithmetic, geometric and harmonic) to the rock properties will be not applicable. Finally, the only way to establish a correlation between the reservoir permeability and porosity is to split it into units which are known as hydraulic flow units.

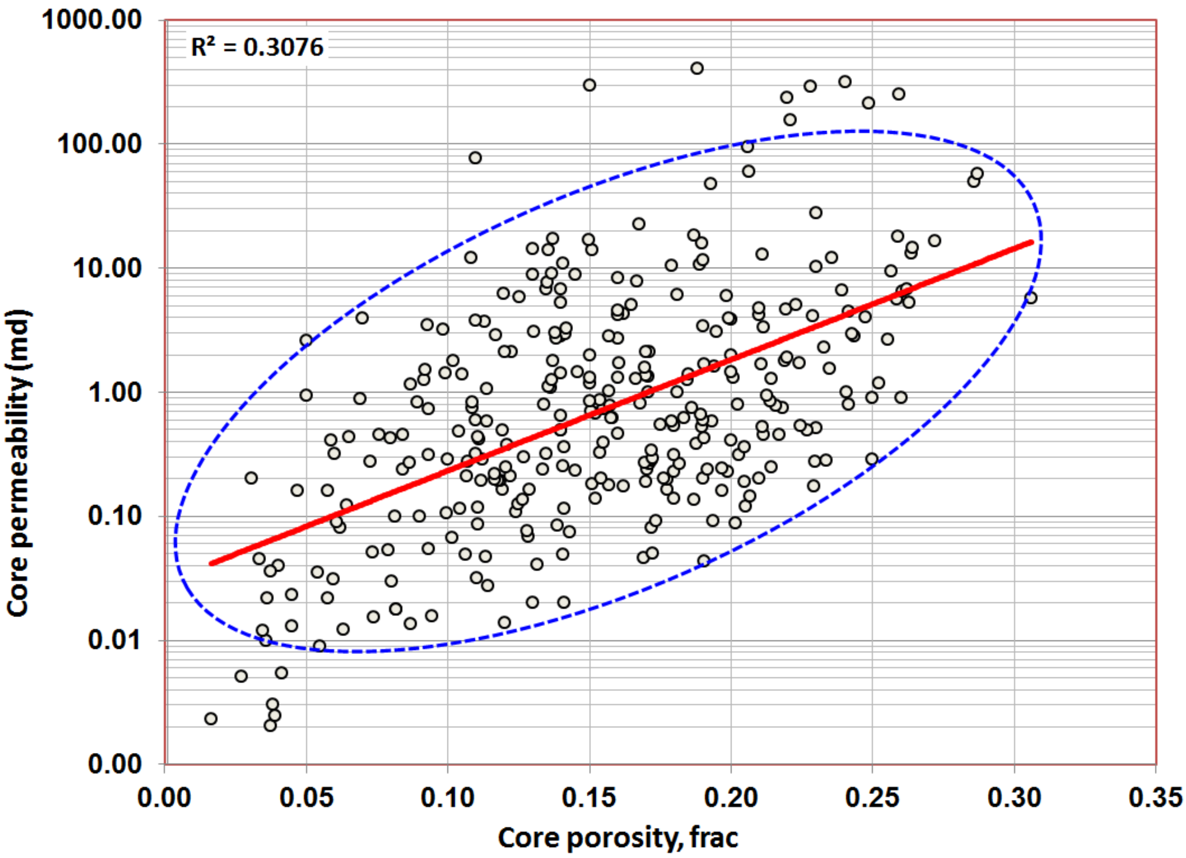

Figure 5. Core porosity versus core permeability for Upper Bahariya reservoir.

5. Hydraulic Flow Units (HFU$_S$)

Using the conventional core data (K$_h$ & Ø) from five wells, the following methodology was applied to characterize the Upper Bahariya reservoir (Ahmed, 2001, Maghsood, 1996, Odilia, 2001, Fahad, 2000, Syed Shujath, 2013, Tohid , 2001& Desouky, 2005).

Step one: Before any data analysis, all the fractured samples were removed. Also, each sample with very high permeability and low porosity was considered as a fractured sample.

Step two: Reservoir Quality Index was calculated using the flowing equation (Tohid , 2001):

$$RQI = 0.0314\sqrt{K/\varnothing_e} \tag{3}$$

Step three: Normalized porosity (Øz) was calculated using the flowing equation (Tohid , 2001):

$$\varnothing_z = \varnothing_e/(1-\varnothing_e) \tag{4}$$

Step four: Flow zone indicator FZI was calculated using the flowing equation (Tohid , 2001):

$$FZI = RQI/\varnothing_z \tag{5}$$

Step five: The calculated values of flow zone indicators were arranged in an ascending order, Plot RQI vs. z on a logarithmic scale as shown on Figure (6). Three methods were applied to determine the number of hydraulic flow units as follows:

– **Log-Log plot of RQI versus Ø$_z$.** All samples with similar FZI values will lie on a straight line with slope equal to one as Figure (6). Samples that lie on the same straight line have similar pore throat attributes and thereby constitute a hydraulic unit. The mean value of FZI can be determined from the intercept of the unit slope straight line with Ø$_z$=1. Figure (6) allows picking out at least 9 HFUs & estimate FZI boundaries for these rock types. TABLE (1) summarizes all of these HFUs. Also, the value of intercept is mean FZI and will be used to calculate permeability.

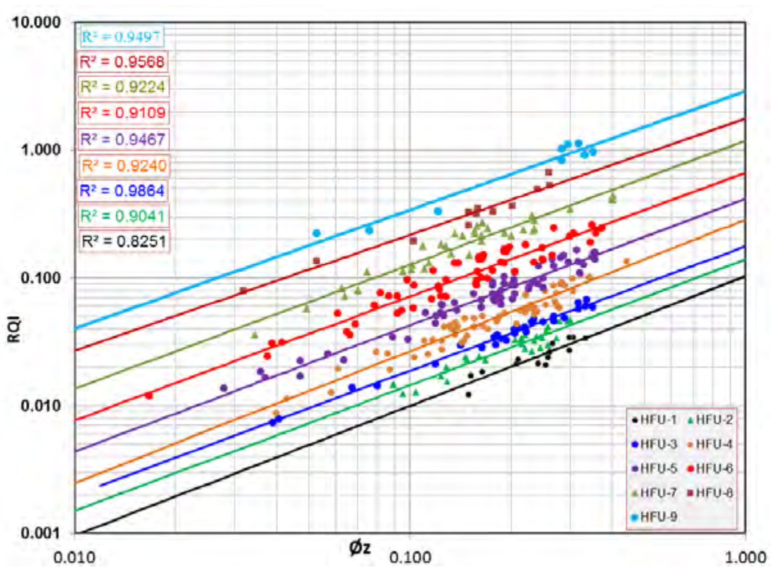

Figure 6. Hydraulic flow units of Upper Bahariya reservoir.

- **Histogram analysis.** As FZI distribution is a superposition of multiple log-normal distributions, a histogram can detect the frequency of FZI to each HFU. The maximum value of the FZI to each HFUs taken as data range and all the calculated FZI as shows on Figure (7). This figure reflects that, FZI from 0.334 to 0.978 are the higher frequency. This data in the range of HFU-4, HFU-5 & HFU-6 which means that they are the dominate unit in the reservoir.

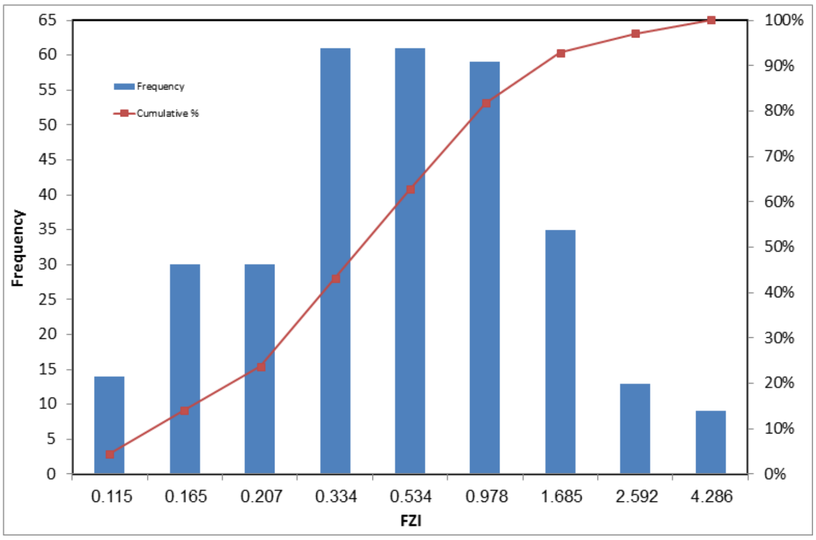

Figure 7. Histogram of flow zone indicator for Upper Bahariya reservoir.

- **Probability plot**. The probability plot or cumulative distribution function is the integral of histogram (probability density function). A normal distribution forms a distinct straight line on a probability plot. Therefore, the number of straight lines in the probability plot may be used to indicate the number of hydraulic flow units in the reservoir. As this plot is smoother than the histogram it is more useful to define HFUs because identification of clusters becomes easier as depicted on Figure (8).

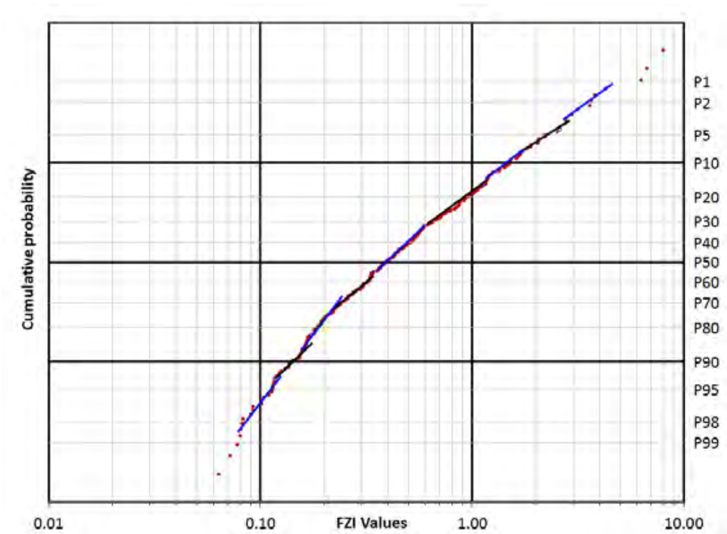

Figure 8. Probability plot of FZI for Upper Bahariya reservoir.

The Log-Log plot of RQI versus $\varnothing_z$, FZI histogram analysis and the cumulative probability plots allow picking out at least 9 HFUs and estimate FZI boundaries for these rock types. Table (1), summarizes all of these HFUs. Also, the value of intercept HFUs lines at $\varnothing$z equal one is mean FZI and will be used to calculate permeability.

Table 1. Upper Bahariya reservoir hydraulic flow units

HFU No.	Relationship between K & Ø	K, md	R2	FZI
HFU-1	K = 0.1034 x Ø1.2309	0.112	0.8251	0.1034
HFU-2	K = 0.1397 x Ø0.9857	0.179	0.9041	0.1397
HFU-3	K = 0.1773 x Ø0.9763	0.354	0.9864	0.1773
HFU-4	K = 0.2861 x Ø1.0124	0.686	0.9240	0.2861
HFU-5	K = 0.4168 x Ø0. 9895	1.689	0.9467	0.4168
HFU-6	K = 0.6668 x Ø1.0301	3.389	0.9109	0.6668
HFU-7	K = 1.1877x Ø0.9743	8.917	0.9224	1.1877
HFU-8	K = 1.7655 x Ø0.9838	24.186	0.9568	1.7655
HFU-9	K = 2.8989 x Ø1.0152	164.348	0.9497	2.8989

Step six: To check if the guess is correct, calculate the permeability (K) for each HFUs using the flowing equation (Tohid , 2001):

$$K = (1014 \times (FZI_{\,mean})^2 \times \varnothing_e^{\beta} / 1 - \varnothing_e)^2 \tag{6}$$

The calculated permeability is plotted against the measured core permeability as shown on Figure (9). The plot indicates that the closeness of the data to the 45^o straight line. This cross-plot indicates the high accuracy of the calculated permeability and the strength of the guess. The average relative error (ARE) for the calculated permeability values was calculated as 1.4% by using the following equation (Tohid, 2001):

$$ARE = \frac{1}{n}\sum_{k=1}^{n}\left(\frac{Measured\ Permeability\ -\ Calculated\ Permeability}{Measured\ Permeability}\right) \tag{7}$$

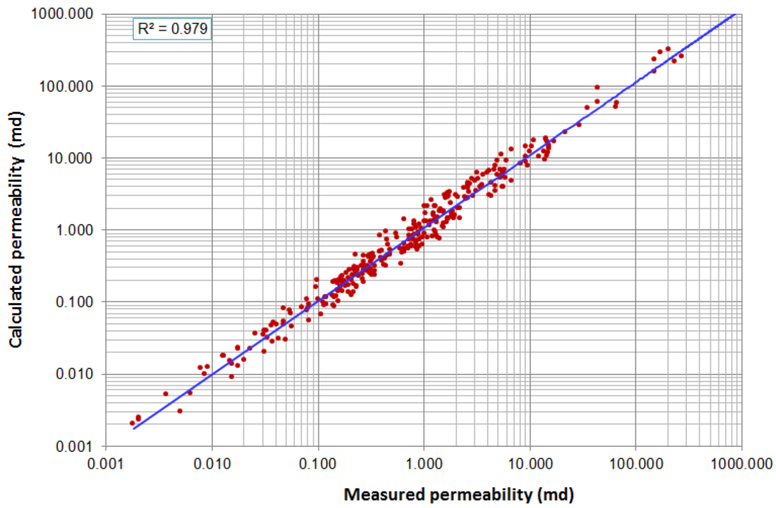

Figure 9. The calculated permeability versus the measured permeability

6. Relative permeability

The relative permeability to a certain fluid phase is defined as the ratio of its effective permeability to the absolute permeability of rock (Ahmed, 2001& AbdusSatter, 2008)**.**Relative permeability varies between 0 and 1. Knowledge of relative permeability is crucial in understanding multiphase fluid flow behavior in a reservoir and for the predicting future reservoir performance. Relative permeability trends are of great significance when undesirable water or gas flow is anticipated in an oil reservoir. Also, the relative permeability of a fluid phase is a function of the saturations of all of the fluid phases present in the rock. It is highly important to note that the relative permeability characteristics of reservoir fluids usually change from one location to another. Various rock facies in a reservoir may exhibit very different relative permeability trends. Relative permeability data are incorporated into reservoir models in order to make realistic predictions of recovery. The relative permeability of a certain fluid increases with increasing the saturation of that phase in porous media. The relationship between the two parameters is nonlinear. Relative permeability serves is a common standard in reservoir studies regardless of the magnitude of the effective permeability in a reservoir.

Normalization and averaging relative permeability data

For preparing the relative permeability data to be incorporated into the reservoir model, it should be first be normalized to remove the effect of different initial water and critical oil saturations. After that the relative permeability can then be de-normalized and assigned to different regions of the reservoir based on the existing critical fluid saturation for each reservoir region. The following procedure was conducted to perform the normalization (Ahmed, 2001):-

Step-1 .Calculate the normalized relative permeability: water saturation S^*_w, relative permeability for the oil phase K^*_{ro} and relative permeability of the water phase K^*_{rw} for each set of the relative permeability curves, using the following expressions (Ahmed, 2001):

$$S*_w = \frac{S_w - S_{wc}}{1 - S_{wc} - S_{or}} \tag{8}$$

$$K*_{ro} = K_{ro} \,/ (K_{ro})S_{wc} \tag{9}$$

$$K*_{rw} = K_{rw} \,/ (K_{rw})S_{or} \tag{10}$$

Step 2 .Plot the normalized values of k^*_{ro} and k^*_{rw} versus S^*_w for all core samples on a regular graph paper as shown on Figure (10).

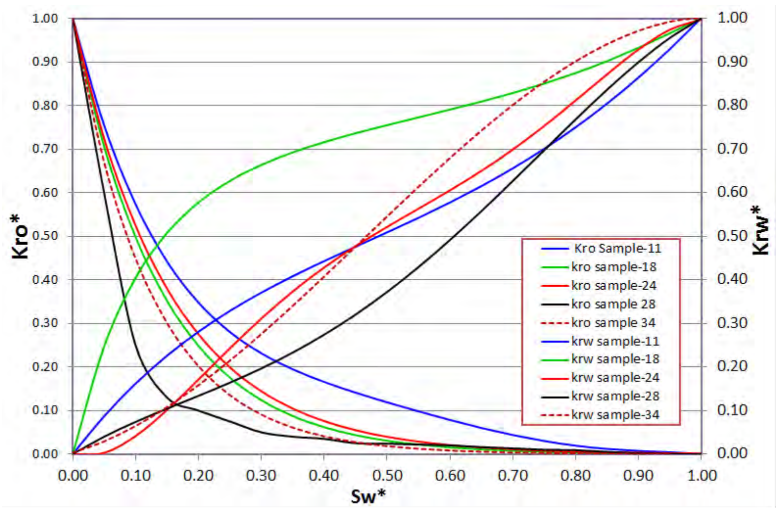

Figure 10. Normalized relative permeability for Upper Bahariyareservoir

Step 3. The average relative permeability to oil at connate water saturation and the average relative permeability to water at residual oil saturation were calculated as shown in Table (3) using the following two expressions (Ahmed, 2001)

$$(K*_{ro})avg = \frac{\sum_{i=1}^{n}(h\,K\,K*_{ro})i}{\sum_{i=1}^{n}(h\,K)_i} \tag{11}$$

$$(K*_{rw})avg = \frac{\sum_{i=1}^{n}(h\,K\,K*_{rw})i}{\sum_{i=1}^{n}(h\,K)_i} \tag{12}$$

Table 2. Average relative permeability at S_{wc} &S_{or} for Upper Bahariya reservoir

Sample No	11	18	24	28	34	Sum.
$(K_{ro})_{Swc}$	1	1	1	1	1	
$(K_{rw})_{Sor}$	0.21	0.03	0.11	0.09	0.04	
h, ft	1.00	1.00	1.00	1.00	1.00	
K, md	14.60	1.50	4.01	0.89	1.10	
K*h	14.60	1.50	4.01	0.89	1.10	22.10
k*h*kro	14.60	1.50	4.01	0.89	1.10	22.10
k*h*$(K_{rw})S_{or}$	3.11	0.04	0.43	0.08	0.04	3.69
$(\overline{K}_{ro})S_{wc}$ =1 and $(\overline{K}_{rw})S_{or}$= 0.167						

Step 4. Calculate the average relative permeability to oil and water at connate water and critical oil, respectively $(\overline{K}_{ro})$Sor by using the following equations (Ahmed, 2001):

$$(\overline{K}_{ro})_{S_{wc}} = \frac{\sum_{i=1}^{n} |h\,K\,(K_{ro})_{S_{wc}}\,|i}{\sum_{i=1}^{n}(h\,k)i} \tag{13}$$

$$(\overline{K}_{rw})_{S_{ro}} = \frac{\sum_{i=1}^{n} |h\,K\,(K_{rw})_{S_{ro}}\,|i}{\sum_{i=1}^{n}(h\,k)i} \tag{14}$$

Step 5. The last step in this methodology involves de-normalizing the average curve to reflect the actual reservoir and conditions of S_{wc} and S_{ro} by use the following equations (Ahmed, 2001):

$$S_w = S*_w\ (1 - S_{wc} - S_{or}) + S_{wc} \tag{15}$$

$$k_{ro} = (K*_{ro})_{avg}\ (\,\overline{K}\ _{ro})_{Swc} \tag{16}$$

$$K_{rw} = (K*_{rw})_{avg}\ (\,\overline{K}\ _{rw})_{Sor} \tag{17}$$

Using the average S_{wc} = 0.498 and average S_{oc}= 0.217 that obtained from the special core data of the Upper Bahariya reservoir, the relative permeability data were de-normalized to generate the required Upper Bahariya reservoir relative permeability curve as shown on Figure (11).

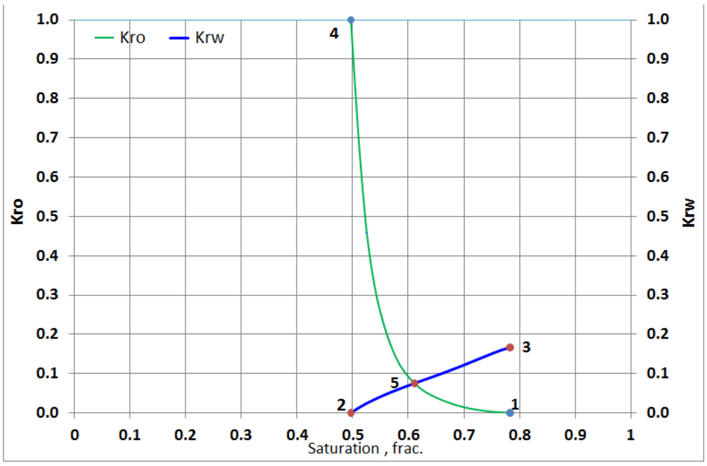

Figure 11. Relative permeability curve for Upper Bahariya reservoir

Relative permeability curve description

1) Figure (11) shows the relative permeability curve of Upper Bahariya reservoir which indicates that it is a water wet system. The connate water saturation is 48.95 %, water saturation at Kro= Krw is 61 % (i.e. greater than 50%) and Krw at maximum water saturation (i.e., at floodout) is 17 % (i.e. lower than 30%) (AbdusSatter, 2008 & Forrest, 1971).

2) The relative permeability curves consist of three elements. First element, points 1&2 represent the residual oil saturation and the irreducible water saturation. Second element, point-3 is the relative permeability to water at residual oil saturation. In a strongly water wet system, the relative permeability at this point ranges from 0.1 to 0.2. Point-4 is the relative permeability to oil at the irreducible water saturation. The end points saturations determine the movable saturation range and are directly related to the amount of recoverable oil. The end points of the relative permeabilities enters into the expression for the mobility ratio and will determine the sweep efficiency of a displacement process (Torsæter, 2003). Third element, the curvature of the relative permeability functions:

A. The most prominent feature occurs at the critical saturations where both effective permeabilities drop to zero. In other words, water becomes immobile (K_{rw} = 0) at S_w = S_{wi} (i.e. at S_{wi} = 48.95 %) and oil becomes immobile (K_{ro} = 0) at S_o = S_{or} (i.e. at S_w= 78.3%).

B. S_{wi} is larger than S_{or} due to wettability preference; water ceases to flow at a larger saturation because adhesion binds water to the grain surfaces with a stronger force.

C. Point-5 on water relative permeability curve is in the region where Sw encountered in field displacement is found. In this region relative permeability to water is low because oil is trapped in the pores by the invading water.

7. Capillary pressure

When two immiscible fluid phases, such as oil and water, are present in a porous medium, one of the phases preferentially “wets” the pore surface over the other. As a result, a pressure differential is found between the two phases. This pressure differential is known as the capillary pressure. The magnitude of the capillary pressure in a porous medium is influenced by fluid saturations, interfacial tension between the two fluid phases, and the radius of the pores, among other factors (Ahmed, 2001, AbdusSatter, 2008 & Livia). A generalized expression for capillary pressure as it relates to fluid phases in porous media is as follows (Ahmed, 2001)

$$P_c = P_{nw} - P_w \tag{18}$$

The equation can be expressed in terms of the surface & interfacial tension as (Ahmed, 2001):

$$P_c = (2\sigma_{ow} \times \cos\theta)/r \tag{19}$$

Table (3) shows the capillary pressure laboratory data for five Upper Bahariya reservoir samples:

Table 3. Air-Brine capillary pressure data for Upper Bahariya reservoir

Sample No.	Depth (ft)	Ka (md)	Porosity (%)	Brine Saturation (% Pore Space)						
				★ 14.7	18	25	45	75	115	215
4	6505	11.2	22.9	99.8	92.0	82.0	65.6	54.3	47.7	40.4
6	6539	22.3	15.2	93.1	80.7	64.0	48.9	40.0	35.2	30.0
10	6541	19.5	17.9	95.3	88.3	75.6	56.5	45.2	38.9	32.1
16	6542	3.33	14.4	98.9	93.5	87.0	69.8	58.6	52.4	45.8
17	6559	2.42	16.7	99.1	94.3	87.8	75.0	64.8	58.5	52.6

* Capillary Pressure (Psia) Ka : Air Permeability (md)

The capillary pressure data presented in Table (3) are plotted on Figure (12). This Figure reflects how the pore geometry affects the capillary pressure. The low-permeability zones have high capillary pressure (i.e. the direction of increasing the permeability is the direction of decreasing the capillary pressure at certain water saturation). Leverett was able to derive a dimensionless function to average core capillary pressure curves to obtain the most representative curve for a field (Ahmed, 2001, Livia & Abu-Khamsin, 2004). This function expressed as following (Ahmed, 2001)

$$J = (P_c/\sigma) \times \sqrt{(K/\varnothing)} \tag{20}$$

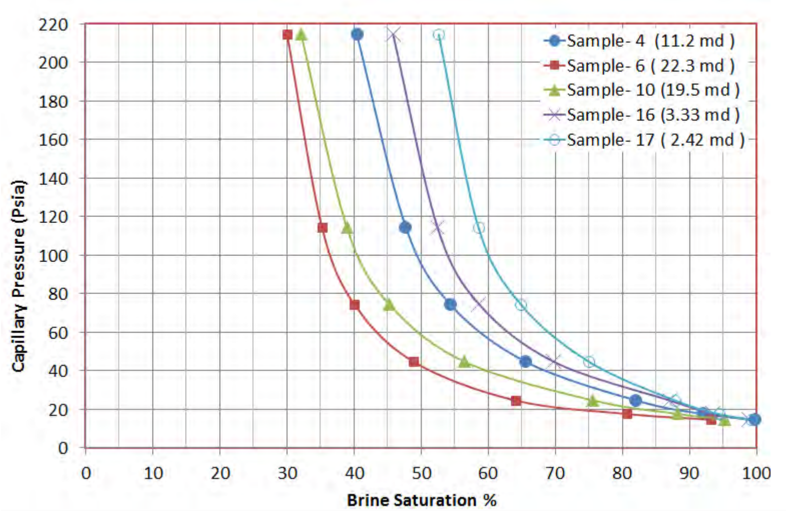

Figure 12. Samples capillary pressure for Upper Bahariya reservoir

The following steps summarize the methodology of combing all the capillary pressure data to classify a particular reservoir capillary curve:

Step-1 Calculate Leverett J-function using J-function equation along with the data presented in Table (3) for each sample. Plot the results of calculations as shown on Figure (13) and then get the best fit curve for the data.

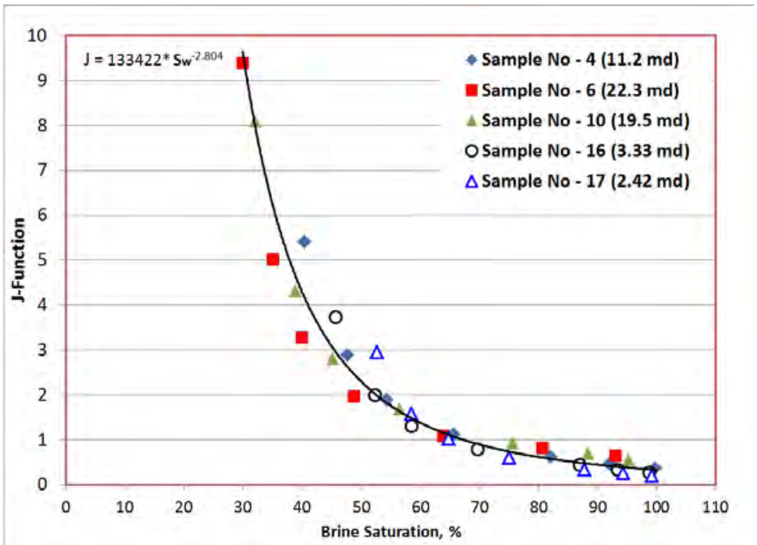

Figure 13. Leverett J-Functionfor the Upper Bahariya reservoir core samples

Step-2 Estimate the average reservoir permeability and porosity from Table (3) using the arithmetic averaging equations ($\varnothing = \sum \varnothing_i/n$) and ($K = \sum K_i/n$). The average permeability and porosity are 11.7 md & 17.4 %, respectively.

Step-3 Use the best fit line equation obtained from Figure (13) to calculate the best fitted J function (Column 2) Table (3).

Step-4 Use the average porosity and permeability values to calculate the capillary pressure (Column 3) Table (3) by using the following equation (Ahmed, 2001)

$$P_c = \frac{J \times \sigma}{(0.21646 \times \sqrt{K/\sigma})} \tag{21}$$

In the absence of the laboratory data the values in Table (4) may be used as approximation (Timmerman, 1982):-

Table 4. Approximation values of contact angle and interfacialtension

System	θ Contact angle	Cosine of the Contact angle	σ interfacial tension	σ Cosine θ
Laboratory (Air-Brine)	0	1	60	60
Reservoir (Water- oil)	30	0.866	30	26

Step-5 Since the laboratory fluid system does not have the same surface tension as the reservoir system and the core sample that was used in performing the laboratory capillary pressure test may not be representative of the average reservoir permeability and porosity; it becomes necessary to convert laboratory capillary pressure to reservoir capillary pressure, Table (5) (Column 4) using the following equation (Ahmed, 2001):

$$P_{C(res)} = P_{C(lab)} \times \frac{\sigma_{res}}{\sigma_{lab}} \times \sqrt{[\frac{\varnothing_{res} \times K_{core}}{\varnothing_{core} \times K_{res}}]} \tag{22}$$

Table 5. Capillary Pressure calculation for Upper Bahariya reservoir

Brine Saturation (% pore space)	Leverett J-Function	Capillary Pressure (Psia) (lab)	Capillary Pressure (Psia) (Reservoir)
49.68	2.34	93	105
50	2.30	92	103
55	1.76	70	79
60	1.38	55	62
65	1.10	44	49
70	0.89	36	40
75	0.74	29	33
80	0.62	25	27
85	0.52	21	23
90	0.44	18	20
95	0.38	15	17
100	0.33	13	15

Step-6 draw the combined capillary pressure curve as shown on Figure (14).

Upper Bahariya capillary pressure curve description:

– Because of the high reservoir heterogeneity, lithology and high connate water saturation, the capillary pressure curve of the reservoir looks like a transition zone.

– To start the displacement, it is necessary to increase the oil pressure until the pores with the smallest capillary pressure give away first, at which instant the oil-water pressure difference would be just above the required capillary pressure. Intuitively, such pores would be the largest ones. This minimum capillary pressure

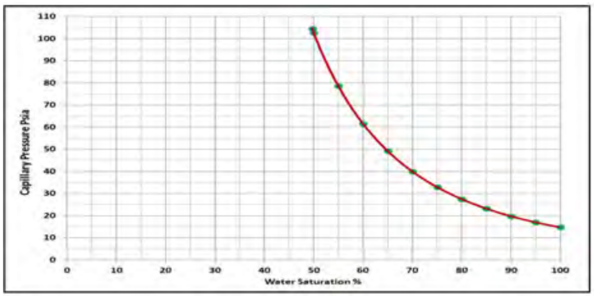

Figure 14. Capillary pressure curve for Upper Bahariya reservoir

which required for invading the rock, thus reducing water saturation below 100% is called the displacement pressure. Figure (14) indicates that the displacement pressure for Upper Bahariya is 15 psia.

- One can also see how the displacement pressure increases steadily with decrease in water saturation as smaller and smaller pores are invaded. Also, the slope of the capillary pressure curve follows the gradual change in pore-diameters. A steep curve indicates a wide distribution.

Furthermore, the displacement pressure can also indicate the wettability preference of the rock. A positive displacement pressure in an oil-displacing-water process indicates preferential wettability to water and the relative magnitude of the displacement pressure reflects the strength of such wettability (Abu-Khamsin, 2004).

8. Conclusions

From this work, one may conclude that:

(1) For Upper Bahariya reservoir the Dykstra Parsons coefficient was found to be 0.86 while Lorenz coefficient is 0.92. These results indicate that the Upper Bahariya is an extremely heterogeneous reservoir.

(2) As a result of this heterogeneity poor relationships between the permeability and the porosity were obtained (scatters data with 0.3076 correlation coefficient). Consequently, the hydraulic flow unit technique was used to identify and characterize the reservoir and the results that it can be divided into nine hydraulic flow units with the different properties. These HFU's should be taken into consideration during developing, stimulating, enhancing of this reservoir.

(3) The relative permeability curves indicated that the Upper Bahariya reservoir is a water wet.O

(4) The capillary pressure curve of Upper Bahariya reservoir looks like a transition zone due to its high heterogeneity and high connate water saturation. The displacement pressure of that reservoir is 15 psia.

(5) The open hole logging showed that, the reservoir consists of thinly sand layers interbeded with shales, silt and limestone. In some areas, where log correlations are difficult and sand appears to be discontinuous, pressure suggests that the reservoirs are, connected and vice versa which is inversed on the effectiveness of the waterflood program. The pressure data showed different decline trends in all the wells which is obviously evidence on the reservoir compartmentalization.

Nomenclature

K	Absolute permeability, md
ARE	Average Relative Error
$(\overline{K}_{ro})_{Swc}$	Average relative permeability to oil at connate water saturation
$(\overline{K}_{rw})_{Sor}$	Average relative permeability to water at critical oil saturation
r	Capillary radius, cm
S_{wc}	Connate water saturation, fraction.

Continued on next page

Table 6 continued

Θ	Contact angle, degree
K_{core}	Core permeability, md
$ø_{core}$	Core porosity, fraction.
S_{or}	Residual oil saturation, fraction
V_{DP}	Dykstra-Parsons coefficient
$ø_{e}$	Effective porosity, fraction
FZI	Flow zone indicator
HFUs	Hydraulic Flow Units
$(Pc)_{lab}$	Laboratory measured capillary pressure, psia
LC	Lorenz coefficient
$Ø_{Z}$	Normalized porosity
K^*_{ro}	Normalized relative permeability of oil
S^*_{w}	Normalized water saturation
σ_{ow}	Oil-Water interfacial tension, dynes/cm
$(K_{ro})_{Swc}$	Relative permeability to oil at connate water saturation
K_{ro}	Relative permeability to oil
K^*_{rw}	Relative permeability to water at the critical oil saturation
$(Pc)_{res}$	Reservoir capillary pressure, psia
K_{res}	Reservoir permeability, md
$Ø_{res}$	Reservoir porosity, fraction
RQI	Reservoir Quality Index
σ_{res}	Reservoir surface or interfacial tension, dynes/cm
h	Thickness of sample, ft
n	Total number of core samples

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