Egyptian Geophysical Society

EGS Journal, Vol. 10, No. 1, 99-105 (2012)

UPSCALING CAPILLARY PRESSURE FOR HETEROGENEOUS RESERVOIR CASE STUDY: MIOCENE AND PRE MIOCENE RESERVOIRS, SOUTHERN GULF OF SUEZ, EGYPT

M.S. El Sharawy

Geophysical Sciences Dept., National Research Centre, Cairo, Egypt.

تطوير نماذج للضغط الشعيرى فى الخزانات غير المتجانسة من عصر الميوسين وما قبله فى منطقة جنوب خليج السويس بمصر

الخلاصـــة: يعتبر الضغط الشعيرى فى غاية الأهمية بالنسبة لعملية استكشاف وتنمية حقول النفط. ولتلك الأهمية فقد تم تطوير عدة نماذج الضغط الشعيرى. منها أربع نماذج تمت مراجعتها وتطبيقها على خزانين منفصلين للحجر الرملى بمنطقة جنوب خليج السويس بمصر. حيث يظهر الخزانان درجات متفاوتة من عدم التجانس تزداد فى خزان ما قبل عصر السينومان. ووجدت الدراسة أن معظم النماذج تعطى نتائج معقولة بالنسبة لأنظمة المسام أحادية وثنائية المنوال وعلى العكس من ذلك فإن كل النماذج تفشل فى مضاهاة ووصف أنظمة المسام ثلاثية المنوال . تم عمل عدة تحويرات على النماذج المستخدمة من أجل أن تناسب الخزانات قيد الدراسة. كذلك تم تطوير عدة معادلات لتصف العلاقات ما بين المعاملات المستخدمة فى النماذج والمعاملات البتروفيزيقية المتاحة مثل النفاذية والمسامية.

ABSTRACT: *Capillary pressure is valuable for petroleum exploration and development. Therefore, several models were developed for up –scaling capillary pressure. Four models were reviewed and applied them for two separate-sandstone reservoirs in the southern Gulf of Suez, Egypt. The two reservoirs show various degree of heterogeneity increased in the pre- Cenomanian one. Most of the models give reasonable results for monomodal and bimodal pore size systems. However, the up – scaling models failed to describe and correlate the trimodal pore size system. Several modifications were applied for the models in order to be adequate for the studied reservoirs. Also many equations were developed to describe the relations between the parameters included in the up- scaling capillary pressure models and the available petrophysical parameters; permeability and porosity.*

INTRODUCTION

Capillary pressure is a very important parameter in petroleum exploration and development. It can be used by geologists, petrophysicists and petroleum engineers to evaluate reservoir quality, transition zone thickness, pay versus nonpay, height of hydrocarbon column and absolute and relative permeability. Unfortunately, capillary pressure measurements are usually limited or unavailable due to the high cost or absence of core. So with these numerous benefits of capillary pressure, the need for up -scaling it is required. The capillary pressure curves can be determined using several methods; among them the mercury injection method in which mercury has been injected into sample plugs to produce a plot of injection pressure versus mercury saturation. Then, the obtained data are plotted as mercury capillary pressure; Pc against wetting or non – wetting phase. The purpose of this paper is to review some up-scaling capillary pressure models and examining their applicability for the studied reservoirs as well as developing a model that can be used in both reservoirs with significant correlation.

Most capillary pressure models begin from the capillary tube model as developed by

Washburn (1921), introduced the following equation:

$$Pc = \frac{0.145 * 2\sigma\cos\theta}{r} \quad \text{......................(1)}$$

where Pc is the capillary pressure in psi, σ is the laboratory interfacial tension (dyne/cm),θ is the laboratory contact angle and r is the capillary tube radius in microns. On other way, capillary pressure can be fitted as a function of water saturation “Sw” and irreducible water saturation “Swir” as follows:

$$Pc = \frac{a}{\left(\frac{Sw - Swir}{1 - Swir}\right)^b} = \frac{a}{Se^b} \quad \text{................(2)}$$

where a and b are coefficients. The coefficient “a” indicates the minimum required entry capillary pressure while coefficient “b” indicates the pore size distribution and Se is the normalized water saturation.

Up-scaling capillary pressure has been investigated by many authors. In 1941, Leverett proposed a dimensionless equation to scale all capillary pressure curves to a universal curve as a function in water saturation. It has been termed J – function and has the following form:

$$J(sw) = \frac{pc}{\sigma\cos\theta}\sqrt{\frac{k}{\Phi}} = \text{a sw-b} \quad \text{..............(3)}$$

Since then, the J-function has been widely used as a correlating group for all capillary pressure measurements using different fluid systems, but practically it can be applied only if the porous rock types have similar pore size distributions or pore geometry (Harrison and Jing, 2001). According to Wu (2004), better correlation can be obtained if Sw is replaced by normalized water saturation, Se:

$$J\,(se)= \frac{Pc}{\sigma\cos\theta}\sqrt{\frac{k}{\Phi}} = aSe\text{-}b \;\ldots\ldots\ldots\ldots\ldots(4)$$

Once the J – function is obtained, the Pc can be calculated by rearranging equation (4):

$$Pc = a\sigma\cos\theta\sqrt{\frac{\Phi}{k}}\;(Se)^{b} \;\ldots\ldots\ldots\ldots\ldots\ldots(5)$$

Due to the shortness of J – function especially in heterogeneous reservoirs, modified forms were developed by different workers. Elkhateb (1995) developed a modified J* –function taking into consideration the effect of tortuosity and irreducible water saturation:

$$J_{kh}* = \frac{Pc}{\sigma\cos\theta}\sqrt{\frac{k\tau}{\Phi(1-Swir)}} \;\ldots\ldots\ldots\ldots(6)$$

where τ is the tortuosity, k is the permeability and Φ is the porosity. Based on Elkhateb work, Sarwaruddin et al. (2001) introduced another modified form as follows:

$$J_S* = J\sqrt{\frac{2\tau(2b+1)}{(1-Swir)}} = \frac{1}{Se^{b}} \;\ldots\ldots\ldots\ldots\ldots(7)$$

And consequently, water saturation can be calculated from equation (5):

Based on Thomeer's (1960& 1983) model, the following relation was introduced:

Log Pc = -Fg/ln (1-Sw) + log Pd ………….(8)

where Fg is the pore geometrical factor which defines the Pc curve shape and Pd is the mercury displacement pressure, psi. According to Harris et al. (1997), the geometrical factor and displacement pressure can be calculated from the following equations:

$$Fg = [\,\ln(5.21 - \frac{ka^{0.1254}}{\Phi})]^{2} / 2.303 \;\ldots\ldots(9)$$

$$Pd = 937.8/(ka^{0.3406})\Phi \;\ldots\ldots\ldots\ldots\ldots\ldots(10)$$

In 2004, Wu developed another model for modeling Pc curves according to the following equation:

$$Pc = Pd + \sigma\cos\theta\sqrt{\frac{\Phi}{k}}(\ln 1/Se)^{\beta} \;\ldots\ldots(11)$$

where β is a shape factor which varies from 1 to 3 according to the rock type. In clean sandstone and carbonate, β is equal to 3 and equal to 1 in shaly sandstone.

Capillary pressure data::

Two sets of drainage mercury injection capillary pressure (MICP) data belonging to two different depositional ages and facies were selected to examine the capillary pressure models (Fig. 1).

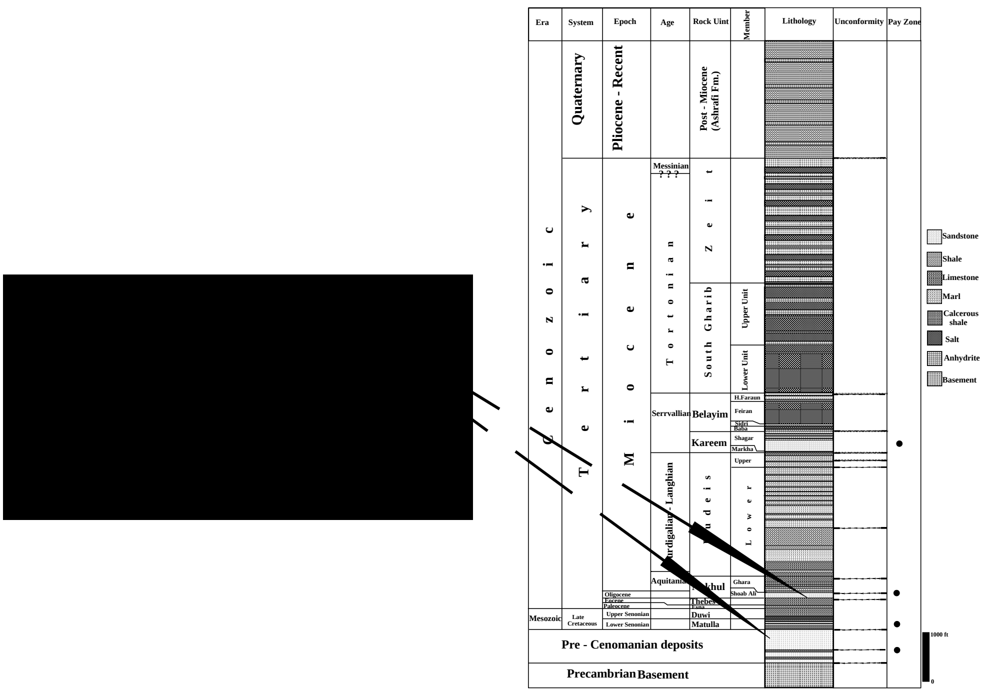

Fig. (1): Location map and stratigraphic column of the studied wells showing the stratigraphic positions of the studied intervals.

The first set (well A) contains 15 Pc – Sw curves with wide range of permeability varying from 0.01 to 112 md. This set belongs to the pre – Cenomanian Nubian sandstone which forms one of the major reservoirs in the Gulf of Suez. According to Alsharhan (2003), the pre – Cenomanian interval represents about 17% of production potential in the Gulf of Suez. The lithology is mainly sandstone with silty cement and medium to very fine grains with traces of anhydrite. The depositional environment ranged from shallow marine to costal / aeolian conditions (Gameel and Darwish, 1994). The second set (well B) data belongs to interval deposited in the Lower Miocene and consists mainly of sandstone; fine to medium grains with traces of pyrite and glauconite, medium sorted with calcareous cement. According to Winn et al. (2001), the clastic sediments of the Lower Miocene are dominantly marine deposited by sediment gravity flows. The permeability ranges from 20 to more than 2000 md. The mercury injection capillary pressure (MICP) method was carried on some samples provided us with eight Pc – Sw curves.

RESULTS AND DISCUSSION

Four published capillary pressure models were discussed. Some samples were selected to show the applicability of the capillary pressure models. These samples are labeled A1, A2, A3, etc. for well A set and labeled B1, B2, B3, etc. for well B set. The application of these models for the available MICP data indicates the following results.

1- Up -scaling capillary pressure based on Thomeer's (1960 & 1983) model:

The Thomeer's (1960 & 1983) method depends on determination of two variables, geometrical factor; Fg and displacement pressure, Pd. There are several methods to estimate them. They can be determined using equations 9 &10, as well as, we can use the traditional method introduced by Jennings (1987) to determine Pd or from the plotting of bulk volume occupied by mercury against Pc as developed by Swanson (1980) (Fig. 2). In our case study, we can note the following. In set (A), the geometrical factor (Fg) ranges from 0.195 to 1.05. Low Fg values indicate narrow pore size distributions (well sorted) and high values indicate wide pore size distributions (poorly sorted). In general, good correlations exist between measured and calculated capillary pressures (Fig. 3a). However, the model usually failed to predict the wetting phase at high Pc values (usually above 200 psi). In set (B), Fg rangs from 0.125 to 0.3 indicating narrow pore size distribution. Good correlation occurred for most samples (Fig. 3b). Nevertheless, some samples give low correlation which required higher Fg values than the calculated one. It must be noted that the effect of small uncertainty in Fg value on the correlation is greater than the effect of uncertainty in Pd.

To predict the geometrical factor, the following relation was developed based on core permeability and porosity for both reservoirs. The determination coefficient (r2) is 0.792:

$$Fg = 0.403\,(k\Phi)^{-0.174} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots(12)$$

On the other hand, displacement pressure (Pd) can be predicted for both reservoirs using the following relation with r2 = 0.907:

$$Pd = 19.008\,(K\Phi)^{-0.346} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots(13)$$

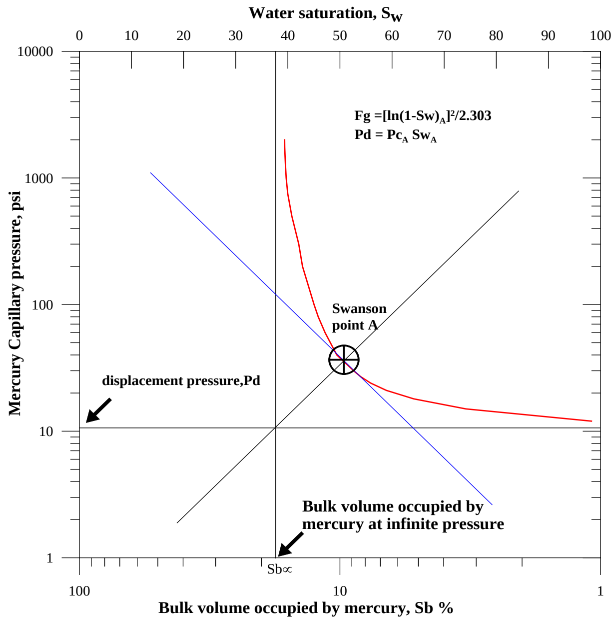

Fig. (2): Determination of geometrical factor;Fg and displacement pressure;Pd from plotting of capillary pressure against bulk volume occupied by mercury as showing in set A1(modified after Swanson, 1980). The equations introduced by Harris et al. (1997).

2- Up-scaling capillary pressure based on Sarwaruddin et al. (2001) model:

The Sarwaruddin et al. (2001) model depends on determination of their developed modified J* – function, tortuosity, (Se) and (b) (Eq. 7). The normalized water saturation can be calculated from equation 2. The tortuosity (τ) can be determined as follows (Tiab and Donaldson, 2004):

$$\tau = \Phi^{1-m} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots(14)$$

Its supposed that, the normalized water saturation (Se) gives a better relation with Pc than that with Sw. However, for set (A) the better correlation occurred between Pc and Sw not with Se as in set (B). In general, good correlation occurred between measured and calculated Pc based on Sarwaruddin et al. (2001) for set (A) (Fig. 4a).

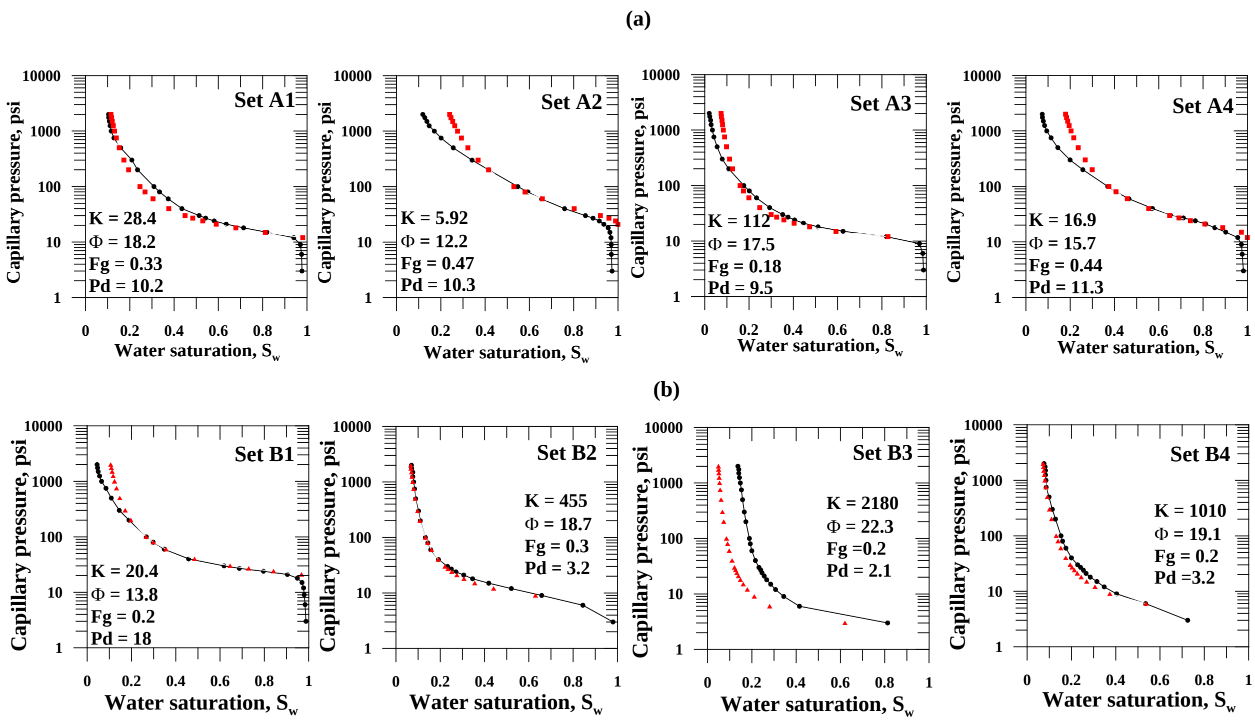

Fig. (3): Comparison between calculated and measured capillary pressures. The calculated Pc is based on Thomeer (1960&1983) model: a) for set "A"; b) for set (B). Solid curves denote measured, and dots denote calculated.

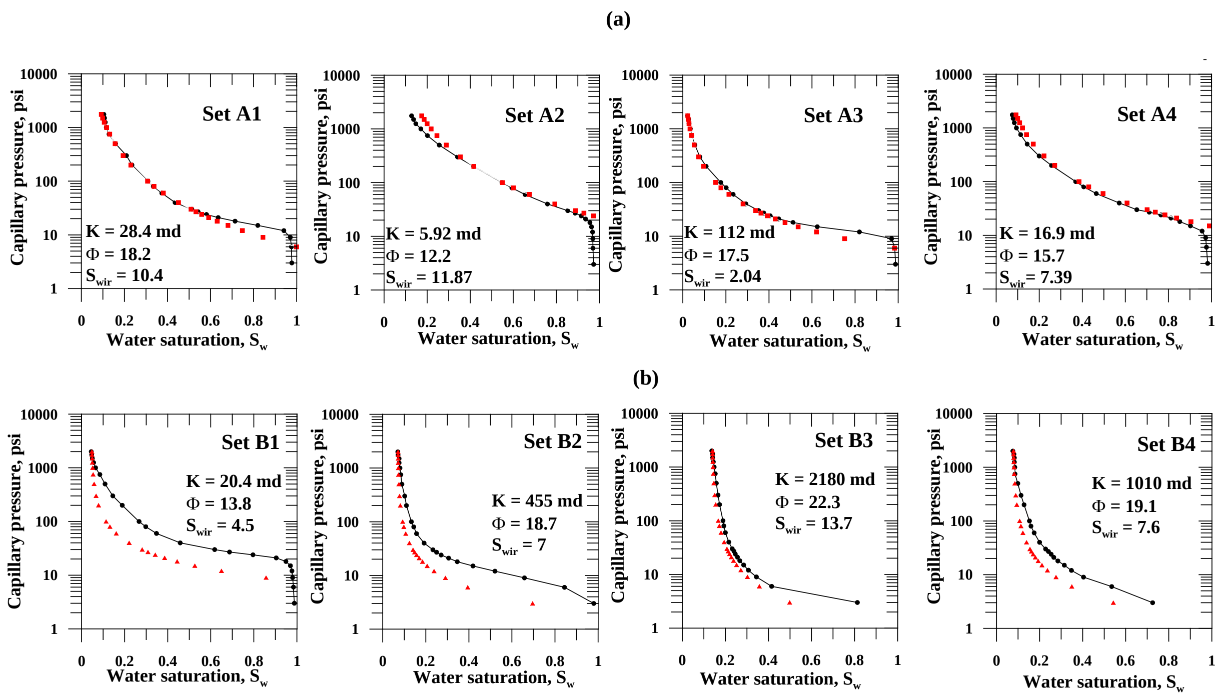

Fig. (4): Comparison between calculated and measured capillary pressures. The calculated Pc is based on Sarwaruddin et al. (2001) model: a) for set "A"; b) for set (B). Solid curves denote measured, and dots denote calculated. The good results were obtained after multiplying Eq. (5) by a constant = 0.3 for set (A). Note the low correlation for all set (B) samples.

(a)

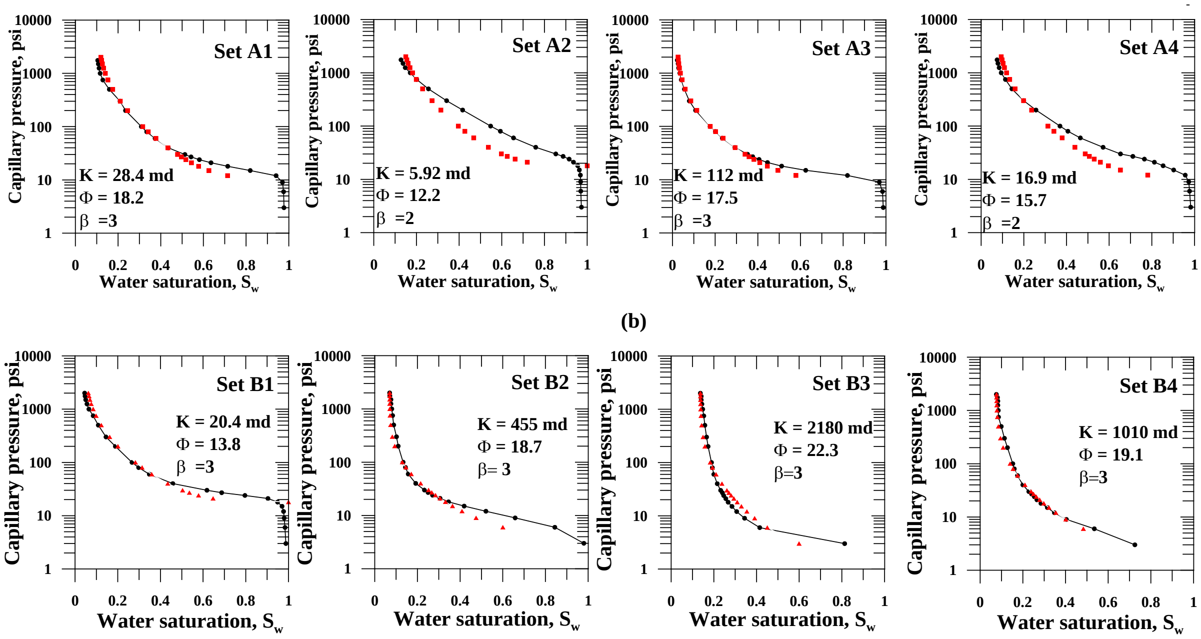

Fig. (5): Comparison between calculated and measured capillary pressures. The calculated Pc is based on Elkhateb modified J* - function model: a) for set "A"; b) for set (B). Solid curves denote measured, and dots denote calculated. Note that these good results obtanied after multiplying Equation(5) by a constant = 0.5 for set (A) and 0.7 for set (B).

(a)

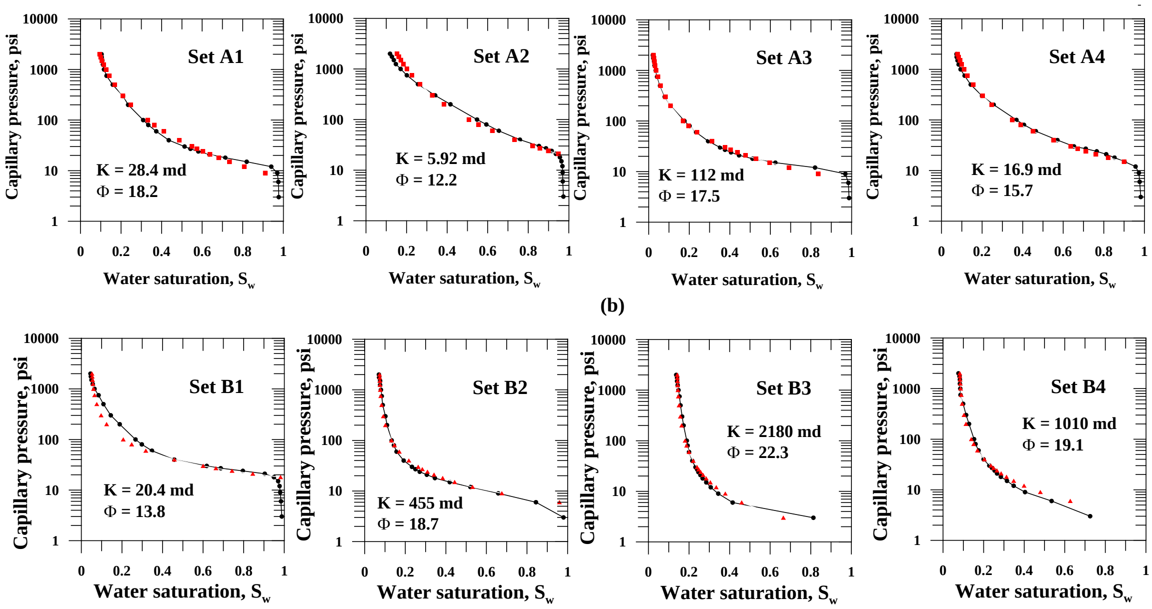

Fig. (5): Comparison between calculated and measured capillary pressures. The calculated Pc is based on Wu (2004) model: a) for set "A"; b) for set (B). Solid curves denote measured, and dots denote calculated. Note that low correlation has been occurred for set A2 and set A4.

This good correlation occurred after multiplying equation (5) by a constant equal to 0.3. So, equation (5) can be rewritten as follows:

$$Pc = Ca\sigma \cos\theta \sqrt{\frac{\Phi}{k}} \; (Sw)b \;\ldots\ldots\ldots\ldots\ldots(15)$$

where C is a constant = 0.3.

For set B, bad correlations occurred for all samples (Fig. 4b). Adding a new constant resulted in no change for these low correlations. The coefficient “b” can be predicted from the following developed relations where no significant relations combining coefficient "b" of both sets:

$b = 0.81\, e\, [0.875\,(k^{0.1254}\Phi)]$ for set (B) with r^2 = 0.868 ……………..…………….(16)

$b = 6.69\, e\, [-0.119\,(\log k/\Phi)]$ for set (A) with r^2 = 0.744 …………………………..(17)

while coefficient "a" can be predicted for set A as follows with r2 = 0.86:

$$a = 0.0158\left(\frac{k^{0.1254}}{\Phi}\right)^{2.02} \ldots\ldots\ldots\ldots\ldots(18)$$

For set B, there is no significant correlation between coefficient "a" and measured core k and Φ.

3- Scaling capillary pressure based on Elkhateb modified J* - function (1995) model:

This model depends on estimation of the Elkhateb modified J* – function according to equation (6). Then we plot J* against Sw or Se in order to determine the coefficients a and b. After that, we use equation (5) to establish the Pc – Sw curve. In set (A) we used coefficients a and b obtained from plotting of J* vs Sw. However, we note that the correlation is bad as we use equation (5) as it is. But when Equation (5) is multiplied by a constant, the results improved significantly (Fig. 5a). The constant is equal to 0.5. The same thing can be applied to set (B) except for using coefficients “a and b” that resulted from plotting of J* -function vs Se (Fig. 5b). However, the constant in set B is equal to 0.7. We can note that coefficient "a" can be replaced by a constant equal to 0.6. In this case, the model can be carried out without estimation of J* – function. Just make a correlation between Pc vs Se and consequently determine coefficient "b". Therefore, equation 5 can be modified to the following form to apply for Set (A):

$$Pc = 0.5 * a\sigma \cos\theta \sqrt{\frac{\Phi}{k}} \; (Sw)b \;\ldots\ldots\ldots\ldots(19)$$

And has the following form in set (B):

$$Pc = 0.6 * a\sigma \cos\theta \sqrt{\frac{\Phi}{k}} \; (Se)^b \;\ldots\ldots\ldots\ldots(20)$$

So, this model needs a determination of coefficient "b" which can be predicted using equation (16) or (17). The coefficient "a" can be predicted as follows for set A only, where no significant correlation occurred for set B:

$$a = 0.006\left(\frac{k^{0.1254}}{\Phi}\right)^{2.09}, \quad r^2 = 0.783 \;\ldots\ldots\ldots(21)$$

4- Up-scaling capillary pressure based on Wu (2004) model:

The Wu (2004) model depends on determination of Pd, Se and β (Eq. 12). For set (B), good correlation has been occurred for most samples (Fig. 6b). The β values range from 2 to 3. To predict Pd, equation (13) can be used while Swir can be predicted according to the following relation with r^2 = 0.815:

$$S_{wir} = 0.01\exp(0.963k^{0.1254}) \;\ldots\ldots\ldots\ldots\ldots(22)$$

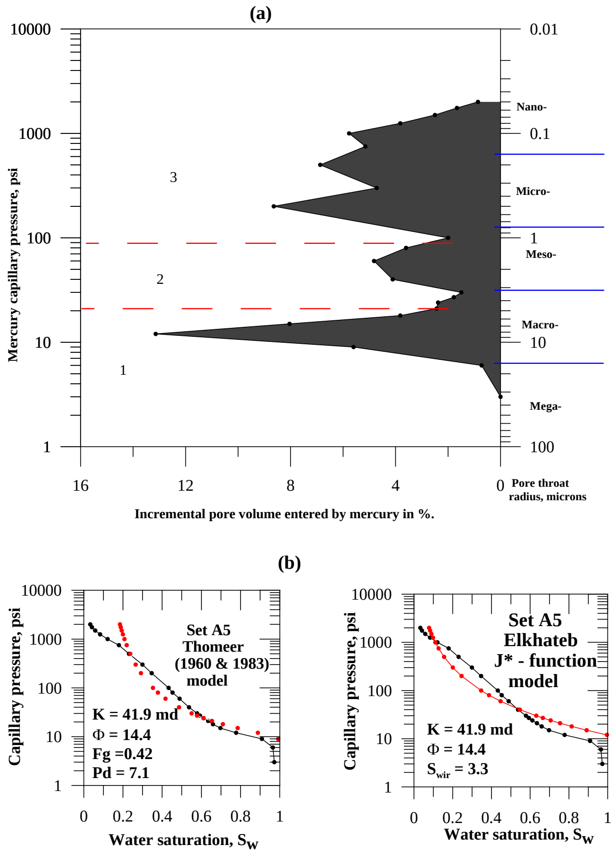

Fig. (7): a) Trimodal pore size distribution system as illustrated from plotting of pore throat size against incremental volume of mercury injection. b) the effect of trimodal pore size system on upscaling capillary pressure.

On the other hand, set (A) shows another behavior. Two samples only give good correlation. The other samples give bad correlation (Fig. 6a). However, the correlation improved dramatically when the coefficient "a" is replaced by 3b. This modification makes the Wu (2004) model taking the following form:

$$Pc = Pd + 3b\sigma\cos\theta\sqrt{\frac{\Phi}{k}}(\ln 1/Sw)^{\beta} \;....(23)$$

The shape factor "β" varies between 2 and 3.

Finally, it is noted that there are some samples which give poor correlation for all models in both sets. These samples show trimodal pore system consisting of macro and micro porosity distribution. All models failed to correlate the samples with trimodal pore system (Fig. 7). These pore systems are attributed – in sandstone – to presence of clay or chert (Swanson, 1985). In these cases, the Pc curve appears to have several steps expressed as peaks when incremental pore volume entered by mercury plotted against Pc (Fig. 7). The peak can be interpreted as intergranular pore system which contributes the rock permeability. The second peak can be interpreted as kaolinite. The third one can be treated as chert or other rock constituent.

CONCLUSION

Several models were developed to up-scale the capillary pressure. We reviewed four models and applied them for two separate sandstone reservoirs. Basically, we must have core porosity and permeability to apply these models. Most models give good correlation in both reservoirs. However, the good results have been reached after modifications for some models. Thomeer (1960 & 1983) model is the only one which we used without modification. The other three models recorded a need to add a constant to improve the correlation. The pre – Cenomanian reservoir (set A) indicates good correlation of capillary pressure with water saturation. On the other hand, the lower Miocene reservoir (set B) shows a good correlation of capillary pressure with normalized water saturation. This variation in behavior of the two reservoirs is reflected on the up –scaling models depending on wetting phase. Therefore, Thomeer's model can be considered the best for up-scaling capillary pressure. The up –scaling models recorded success in monomodal and bimodal pore systems and failure for trimodal pore system. Various equations were developed to predict the required petrophyiscal parameters used in these models based on measured core permeability and porosity.

***Acknowledgements*:**

we would like to thank EGPC and Gulf of Suez Petroleum Company (Gupco) for providing data.

REFERENCES

Alsharhan, A.S., 2003: Petroleum geology and potential hydrocarbon plays in the Gulf of Suez rift basin, Egypt. AAPG Bulletin, v. 87, no. 1, p. 143-180.

Elkhatib, N., 1995: Development of a Modified Capillary Pressure J-Function. Paper SPE 29890 presented at the SPE Middle East Oil Show in Bahrain, March 11-14, 1995, p. 547-562.

Gameel, M., and M. Darwish, 1994: Reservoir behavior of the Pre- Turonian sandstones in south Gulf of Suez province (Sidki field – case history). 12th EGPC Exploration and Production Conference, v. 2, p. 449-471.

Harris, T.G; D.L. Luffel and J.M. Hawkins, 1997: Method for determining hydrocarbon/water contact level for oil and gas wells. US Patent, no. 5621169, 13 p.

Harrison, B. and X.D. Jing, 2001: Saturation height methods and their impact on volumetric hydrocarbon in place estimates. SPE paper no. 71326, 12 p.

Jennings J.B. 1987: Capillary pressure techniques: application to exploration and development geology. AAPG Bulletin 71, p. 1196-1209.

Leverett, M.C., 1941: Capillary Behavior in Porous Solids. Trans. AIME 42, p. 152-169.

Sarwaruddin1, M.; A. Skauge and O. Torsæter, 2001: Modeling of capillary pressure for heterogeneous reservoirs by a modified J-function. SCA 2001-35, 14 P.

Swanson, B.F, 1980: Estimates of permeability from capillary pressure measurements. US Patent no. 4221106, 11 p.

Swanson, B.F, 1985: Microporosity in reservoir rocks: Its measurement and influence on electrical resistivity. The Log Analyst, p. 42-52.

Tiab, D. and E.C. Donaldson, 2004. Petrophysics. 2nd edition, Gulf Professional Publishing, 889 p.

Thomeer, J.H.M., 1960: Introduction of a pore geometrical factor defined by the capillary pressure curve. Journal Petroleum Technology, March, p. 73-77.

Thomeer, J.H.M., 1983: Air permeability as a function of three pore network parameters. Journal of Petroleum Technology, p. 809-814.

Washburn, E.W., 1921: Note on a method of determining the distribution of pore sizes in a porous material. Proceedings of the National Academy of Science 7, p. 115-116.

Winn, Jr., R.D., P.D. Crevello, and W. Bosworth, 2001: Lower Miocene Nukhul Formation, Gebel el Zeit, Egypt: Model for structural control on early synrift strata and reservoirs, Gulf of Suez. AAPG Bulletin, v. 75, p. 1871-1890.

Wu, T., 2004: Permeability prediction and drainage capillary Pressure simulation in sandstone reservoirs. Ph D Dissertation, Texas A&M University, 168 p.