New Correlations for Porosity Exponent in Carbonate Reservoirs of Iranian Oil Fields in Zagros Basin

Hassani-giv[1]* M., Rahimi[2] M.
[1]*Exploration Directorate of NIOC, Geology Department, Tehran, Iran*
[2]*Oil and gas production company of NIOC, Tehran, Iran*
[*] *Corresponding author, e-mail*: *Mhassanigiv@niocexp.org*
(*received: 13/08/2007; accepted: 31/12/2008*)

Abstract
The porosity exponent (m) is a major source of uncertainty in the calculation of water saturation using Archie's Equation. In order to establish a relationship between this parameter and total porosity, 155 core samples from 3 oil reservoirs (Asmari, Ilam and Sarvak) in two fields were analyzed. Based on microscopic studies, the samples were categorized into 6 classes in terms of rock and pore types. Plots of the porosity exponent versus total porosity show an opposite trend between the calculated porosity exponent from core resistivity measurements and that from Shell's equation, especially in the low porosity range (<10%). The core - measured and calculated porosity exponent from the Borai equation have similar trends especially for Bioclastic Grainstone fabric with irregular large vugs and moldic pores (class6). However the porosity exponent values of the Borai equation are just slightly overestimated in the low porosity range (<10%) and underestimated in high porosity range (>10%). Based on these data set, some new correlations for the porosity exponent are introduced. Applying the porosity exponent values determined using these new equations seems to reasonably minimize the error in calculation of water saturation.

Keywords: porosity exponent, Formation resistivity factor, Archie's equation, water saturation

Introduction
In order to calculate the water saturation (Sw) in carbonate reservoirs the porosity exponent parameter (*m)* has to be estimated. The parameter *m* is not a constant, particularly in heterogeneous reservoirs, its value depends on the type and volume (percentage) of the porosity. Inaccurate estimates of *m* can cause significant errors in the calculation of water saturation when using Arhie's Equation (Archie, 1942) and lead to discrepancies between log interpretation and production test results. Borai (1987), for example, illustrated this problem in a case study from an offshore carbonate reservoir in Abu Dhabi.

According to Archie (1942), the porosity exponent parameter (*m)* varies with the degree of cementation and so he referred to it as the "cementation factor". Towel (1962) showed that *m* values are fundamentally linked to changes in pore geometry (ie: shape and distribution of the pores, packing of rock particles, rock compaction and interconnection of pores and vugs**).** Focke and Munn (1987) believed that the value of *m* should also be a function of total porosity. Salem and Chilingarian (1999) concluded that the degree of cementation is not as significant as the shape of grains and pores, and preferred the term "pore shape factor" instead of "cementation factor".

In this paper we review previous efforts aimed at relating total porosity (ϕ) and *m*. Next, we assess the variation of *m* in six classes of carbonate rock types in three Iranian reservoirs: the Oligocene-Miocene Asmari, the Late Cretaceous Ilam and Sarvak reservoirs. The Asmari is the most significant oil-producing reservoir in Iran. The Ilam and Sarvak reservoirs together rank second in terms of production and sometimes form one producing Zone, the Bangestan reservoir. This study will show that *m* increases with increasing porosity in all six classes of rock-type, but to different degrees depending on the class. Because our analysis shows that *m* varies with porosity type and volume (percentage) we adopt the term "porosity exponent" for the *m* presented by some authors such as Aguilera and Aguilera (2003).

RESERVOIR GEOLOGY OF THE STUDIED RESERVOIRS
Asmari Formation
In the central Khuzestan area in northwest Iran the Oligocene-Lower Miocene Asmari Formation consists predominantly of carbonates that are

interbedded with sandstones, referred to as Ahwaz Sandstone Member. With an average thickness of about 400 m (1312ft), this rock unit forms one of the principal reservoirs in the Iranian fields. Carbonate deposition was initiated in a shallow-marine environment and continued through shallowing upward conditions, which led to a more restricted lagoonal environment. The geological interpretation and spatial distribution of the sandstone layers indicate that they may be of deltaic origin and provenanced from the West and South West. The limestone facies range from wackestone to bioclastic, pelletoidal, in-part oolithic packstone-grainstone which were more or less dolomitized. Porosity types are interparticle, intercrystalline, moldic and vuggy. The permeability is moderate and enhances through fractures.

Ilam Formation

The Upper Cretaceous Santonian Ilam Formation is mainly composed of limestone with intercalations of marly beds, especially in the upper parts. The formation has an average thickness of about 120m (394 ft). The environmental setting ranged from shallow marine where abundant echinoid and algal debris occur, to moderately deep where Oligosteginids become abundant. Facies range from bioclastic wackestone to packstone and rarely oolithic grainstone (in the upper part). Porosity types mostly include intraparticle (within Oligosteginid chambers) and vuggy. The porosity is medium but the permeability is poor in this reservoir.

Sarvak Formation

The Upper Cretaceous Cenomanian - Turonian Sarvak formation is generally comprised of limestone that is partially dolomitized, with rare shale layers. It has an average thickness of about 700m (2296 ft). The limestone is a shallow-shelf foraminiferal, algal wacke - packstone and rudist packstone grainstone. The intrashelf basins were typically filled with oligosteginid argillaceous limestones, which are potential source rocks. Two unconformities are recognized within the formation, the lower one is Turonian in age, while the upper is post-Turonian. During periods of subaerial exposure, leaching caused well-developed vuggy and enlarged interparticle porosity, resulting in high permeability and good reservoir zones. The Sarvak Formation also has a high porosity- permeability rudist debris facies that enhance the reservoir quality.

Previous works

The formation resistivity factor (FRF) of a reservoir rock is an important parameter in formation evaluation. It was defined by Archie (1942) as the ratio of the resistivity of rock when completely saturated with a conducting fluid (*Ro)* to the resistivity of the saturating fluid (R_w).

$$FRF = R_o / R_w \tag{1}$$

On plotting *FRF* versus ϕ, Archie found an inverse relationship:

$$FRF = \phi^{-m} \tag{2}$$

The porosity exponent (cementation factor) *m* was estimated to have a value of 2.0 in clean (clay free) formations. Subsequently, Winsauer et al (1952) modified the above equation to the following general form:

$$FRF = a\phi^{-m} \tag{3}$$

Where *a* is referred to as the" tortuousity factor" of the pore system. The intercept on the *FRF* axis of a log- log plot of FRF versus ϕ for a group of samples determines the *a* value. Winsauer et al. (1952) defined the "tortuousity" τ in a brine - saturated rock as the ratio of the tortuous length of the pore channels traversed by an electric current, flowing between two parallel planes to the direct distance between the planes. F_{RF} can also be related to tortuousity τ (Winsauer et al. 1952):

$$FRF = \tau^2 / \phi \tag{4}$$

Shell (in Schlumberger Charts, 1984) proposed a formula for the porosity exponent (cementation factor) that is applicable for low-porosity (<10%), non - fractured carbonates:

$$m = 1.87 + 0.019/\phi \tag{5}$$

Borai (1987) proposed another formula for low-porosity carbonates that is based on core and log studies from offshore Abu Dhabi:

$$m = 2.2 - 0.035/(\phi + 0.042) \tag{6}$$

Lucia (1999) showed that the value of m increases with the ratio of unconnected vug porosity to total porosity, the vug to porosity (VPR) ratio:

$$m = 2.14\ VPR + 1.76 \tag{7}$$

Finally, Ragland (2002) presented a correlation between *m* and the normalized moldic porosity differentiated from total porosity ϑ:

$$m = e^{\vartheta} + 0.7 \tag{8}$$

Where *e* is the exponential function and ϑ is the normalized moldic porosity differentiated from total porosity. To compute *m* values using Lucia and Ragland equations, it is necessary to optically differentiate moldic porosity from total porosity, which is a time-consuming process.

Rahimi (2003) compared the various method of obtaining *m* and *a* values and concluded that the best fit method ($a\neq1$) will give more realistic values of *m* and *a*.

Rezaee et al., (2007) established a new method for determining *m* and *a* values, with classifying FRF and ϕ data based on current zone indicator and electrical flow unit.

$$CZI = \frac{\sqrt{\dfrac{\phi}{FRF}}}{\phi z} \tag{9}$$

Where ϕ FRF and ϕz are porosity (fraction), formation resistivity factor and pore to matrix volume ratio respectively.

Kazemzadeh *et al.,* (2007) in a study on a total number of 70 plug samples selected from a carbonate reservoir in one of the Southern Iranian oil fields showed, classifying the samples in terms of texture, porosity type and especially petrofacies obtained from velocity deviation log improve the correlation coefficient in log– log plot of FRF versus ϕ. They also concluded that the *m* values increases with increasing velocity deviation.

Also, Hassanzadeh et al., (2007) in a study on carbonate reservoirs showed that approximate values for tortuousity factor from both core samples and well log data lie close to each other and concluded that the *FRF* analysis on well log data can be effectively and reliably used as an alternative to FRF studies on core samples.

ELECTRICAL MEASUREMENT PROCEDURE

In preparation for resistivity measurements, cylindrical plugs (1.5” diameter) were cut from each preselected core samples. These plugs were cleaned by toluene in centrifugal extractor or in Dean Stark apparatus and then dried at low temperature for several days in an oven. The clean plugs were evacuated for six hours and then saturated for sixteen hours under 2000 psi pressure with a brine solution having a sodium chloride content equivalent to the salinity of formations water. Upon removal of the plugs from the saturator, they were allowed to remain in the brines for several days to achieve ionic equilibrium. Electrical resistance of the samples were measured in reservoir pressure. Then resistivity was computed from the measured resistance, cross- sectional area and the length of the plug. FRF was obtained as the ratio of plug resistivity to brine resistivity.

DATA BASE AND ROCK TYPE CLASSIFICATION

This study is based on resistivity measurements from 155 nearly clay free core samples extracted from three oil reservoirs (Asmari, Ilam and Sarvak) in two fields. The resistivity analyses were carried out at confining pressures similar to reservoir pressure conditions, but at room temperature and with simulated formation brine, based on formation water analyses. Based on optical microscope studies the samples were categorized into 6 classes in terms of rock types (Dunham, 1962 classification) and pore types. Representative photomicrographs from the 6 classes are shown in Figures 1 to 6.

Class 1 Rock type consists of coarse crystalline sucrosic dolostone (100−150μm) mostly with intercrystalline and vuggy pore types. The pore network is well connected and the connectivity intensifies with occurrence of occasional fractures.

Class 2 Rock type consists of fine to medium - size crystal dolostone (15-20μm). Irregular, medium vugs and rare molds, which are rarely interconnected through microfractures, are the most common pore types. The tightly interlocking dolomite crystals reduce the visible intercrystalline pore types.

Class 3 Rock type consists of fine to medium crystalline dolostone. The sub - angular to sub - rounded quartz grains, which occasionally yield interparticle porosity are abundant. The most common pore type is large irregular vugs and enlarged molds. An increase in the size of dolomite crystals partially yields intercrystalline porosity.

Class 4 Rock type consists of dolomitized packstone - wackestone. The most frequent pore types are mold, enlarged mold and rare intercrystalline and interparticle pores.

Class 5 Rock type consists of bioclast - peloid packstone. In some cases this rock type changes to ooid grainstone - packstone. The most common allochems are milliolid, peloid, ooid and red algae bioclasts. Porosity types are interparticle, mold, enlarged mold and vug. Interpeloid pores occasionally enlarged to vug shape pores. In spite of fairly similar appearance in thin sections the petrophysical properties of enlarged interparticle pores and enlarged mold pores are completely different in terms of their contribution to fluid flow. The interparticle pores are usually connected and contribute effectively to fluid flow. In contrast, the narrower pore throats connecting enlarged mold pores provide a less effective pore network for fluid flow.

Class 6 Rock type consists of bioclast grainstone. The allochems are red algae bioclast, echinoide bioclast, rotalid and milliolid. Scattered large vugs and molds are the most frequent pore types.

Most of the studied samples had patches of anhydrite cement, which decrease porosity and increase the resistivity. The evolution of the porosity is dominantly affected by the rock fabric, dolomitization, anhydritization and fracturing. The earliest process involves dolomitization which usually increases porosity and permeability. Anhydritization occurs later and destroys porosity and permeability because the anhydrite cement occasionally fills intercrystalline pores, sometimes with a poikilotopic fabric. Fracturing is the last event and always improves permeability more than porosity. Fracturing and anhydritization have an opposite effect on core resistivity measurements. Fractures facilitate the flow of the electric current through sample and anhydritization increase the resistivity of the sample.

Relationship between the Formation Resistivity Factor and porosity

To find an average value for the porosity exponent (*m)* and parameter *a*, the formation resistivity factor *FRF* was plotted versus total porosity (ϕ) on a logarithmic scale for each rock - type class (Figure 7). The slope of the resulting regression represents *m* and the intercept is *a*. Two case are considered in Figure 7: *a* unconstrained ($a \neq 1$) and a=1 (constrained and represents a pore pathway that is straight). Values of *a* and *m* obtained from these plots are listed in table 1. For the unconstrained case, *m* ranges between 1.1 for class 3 and 1.69 for class 4.rok types. The *a* parameter ranges from 2.35 for class 4 and 6.56 for class 3 rock types. Also the correlation coefficients (R^2) of the regressions are shown. In the constrained case of *a*=1, *m* ranges between 1.88 in Class 6 to 2.10 for Class 4 rock types. These values are close to the proposed constant value *m*=2 of Archie. In these plots scattered outliers were not included in the regression analysis.

Relationship between Porosity Exponent (Cementation Factor) and Porosity

With formation resistivity factor *FRF* and total porosity (ϕ) measured from core plug analysis, porosity exponent *m* values can be calculated from the following equation:

$$m = -LogFRF / Log\phi \qquad (10)$$

The *m* values computed from Shell and Borai equations and the experimentally measured *m* data were plotted versus total porosity for the 6 classes of rock types (Figure 8). All the plots show increasing *m* with increasing porosity. The linear trend obtained for Classes 1 and 3 is possibly due to the interconnected pore network. For the other four classes the trends tend to be curved, which may be due to an increase of separate vug or moldic porosity. Although the most dominant pore type in Class 3 is irregular vug, this kind of pore geometry is considered to be effectively connected. The measured *m* values vary in the range of 1.5 to 2.5. The frequency distribution of *m* values of the six different classes is shown in Figure 9.

Increase of separate vug and moldic pore types causes class 2 and 4 rock types to have higher values of *m* with respect to their porosity. The increase of *m* values in class 3 is related to increase of porosity. The *m* and ϕ data in class 5 are in a large range which is related to pore volume and types. The decrease of *m* for Class6 is related to decreasing porosity (porosity is mainly ≤15%).

Figure 10 compares the variation of *m* versus ϕ for the six rock type classes. Although the samples were divided into 6 different classes in terms of the most dominant pore type and rock type, in some cases, even there are more than two pore types, so that the combination of any of them will give to dual and even multiple porosity behavior. Therefore the combination of rock fabric and pore type resistively behavior can justify no sharp separation between trends in different classes. In general, for a specific value of porosity, *m* increases from Class 1 to Class 5 rock types. The diversity of the pore types controls the correlation coefficients of the regression plots. The more similar pores are, the higher the correlation coefficients. This reflects the various effects of different pore types on the flow of the electricity. According to Rosales (1982) only part of porosity participates in the flow of electricity. He defined the stagnant porosity as the part which does not contribute to the flow of electrical current including dead - end pores. Interconnected pores, which effectively contribute in flowing electric current are termed "flowing porosity". The flowing and stagnant parts of pores depend on the pore geometry.

DISCUSSION AND RESULTS

For all six rock - type classes, Figure 8 shows that *m* increases with increase of porosity but with slightly different trends that are related to pore type and rock type. The porosity exponent (*m)* increases with increase of separate vug and moldic porosity. In the Shell equation *m* decreases with increasing porosity especially in the low porosity range (<10%), as shown in Figure 9, and disagreeing with our data in all Classes. In the Borai equation, *m* increases with increase of porosity, indicating general similarity with our analysis. Class 6 rock type follows the trend predicted by Borai's formula. Although the Borai and Shell formulas have been recommended for low - porosity carbonates, they estimate *m* values that are slightly higher and lower than Archie's constant value (2) in the high porosity range (>10%), respectively.

As previously mentioned, porosity exponent (*m)* is a highly variable, especially in carbonate rocks. Therefore, a constant value can not be applied to calculate *Sw* with the Archie's equation. Accordingly, it is necessary to find some general formulas instead of a constant *m* value, to be able to apply it for calculating Sw in the absence of resistivity core analysis. In this regard, based on the best - fit lines (least squares) through the data points by try an error we propose some new equations in the form of $y = e^{ax} + b$ and $y = a - b/(x + c)$

Based on the trends of *m* versus ϕ in classes 1 and 3, we found a new formula as:

$$m = e^{(2.25\phi)} + 0.6 \tag{11}$$

Where *e* is exponential function and ϕ is the total porosity. This is a Ragland - type formula. Another introduced formula based on the trends of data in classes 2 and 5 is as the following:

$$m = 2.48 - 0.048/(\phi + 0.01) \tag{12}$$

Where ϕ is total porosity.

The third proposed formula based on class 4 data trend is as follow:

$$m = 2.52 - 0.045/\phi + 0.001) \tag{13}$$

The two last formulas are Borai- type formulas by replacing the above constant values and coefficients. Class 6 data closely follow the Borai formula. The comparison of *m* values computed from these new formulas and Borai and Shell formulas are shown on crossplots of *m* versus ϕ (Figure 8).

For our study permeability and capillary pressure data were not available and the classification was base on rock type and macroporosity (visible porosity). These data are important in characterizing microporosity and conductivity, and without them some discrepancies may occur between the resistivity measurements and petrographic data. In future studies these data could be useful, for example, in explaining why moldic pores do not have high *m* values.

In order to apply the above proposed formulas a heterogeneous carbonate reservoir should be divided into layers on the basis of dominant rock type and pore type. To show how this would be applied we used an uncored interval in a well adjacent to the studied wells. Based on the stratigraphic correlation and study of thin sections prepared from ditch cutting samples an interval which was dominantly matched with Classes 2 and 5 was selected. Figure 11 compares the calculated *Sw* values based on Borai, Shell and our formula (equation 12). In most cases the calculated Sw based on equation 12 is greater than those derived from Borai and Shell formulas. With increasing porosity, the separation would be much greater. In the high - porosity range (>10%) the Borai and Shell results are closely matched. Also, the comparison of Sw calculated from proposed formula (equation 12), constrained fit (*a*=1) and unconstrained fit (*a≠1)* for class 2 rock type are shown in figure 12. In most cases Sw calculated using *m*=2, *a*=1 (constrained fit are less than the unconstrained case and proposed formula. In addition, Sw values calculated from proposed formula and unconstrained case, have broad similarity.

CONCLUSION

Based on core resistivity analysis data from 3 Formations in two different fields, some more representative correlations for *m* have been derived. Applying the *m* values determined using these proposed formulas in Archie formula seem to reasonably minimize the error in calculating *Sw*. In spite of other correlations (Borai and Shell equations) which were recommended in the low porosity range (<10%), these formulas are applicable in the porosity range encountered in carbonate reservoirs. Although the data is local, we believe that the formulas are universally applicable due to their basis in pore geometry.

Nomenclature

a tortuousity factor
FRF formation resistivity factor
m porosity exponent (cementation factor)
ϕ porosity, fraction
τ tortuousity
*R*o resistivity of 100% brine saturated rock
Rw resistivity of brine
VPR vug to porosity ratio
ϑ moldic porosity
Sw water saturation
CZI current zone indicator
ϕz pore to matrix volume ratio

References

Archie G.E. 1942: The electrical resistivity log as an aid in determining some reservoir characteristics. *Transactions, AIME.* **31:** 350-366.

Aguilera M.S., Aguilera R. 2003: Improved models for petrophysical analysis of dual porosity reservoirs. *Petrophysics.* **44:** 21-35.

Borai A.M. 1987: A new correlation for cementation factor in low- porosity carbonates. *SPE Formation Evaluation.* **4:** 495-499.

Dunham R.J. 1962: Classification of carbonate rocks according to depositional texture. *AAPG Memoir.* 1: 08-121.

Focke J.W., Munn D. 1987: Cementation exponents in Middle Eastern carbonate reservoirs. *SPE Formation Evaluation.* **2:** 155-167.

Lucia F.J. 1999: Carbonate reservoir characterization. *Springer. 226p.*

Log interpretation charts *1984: Schlumberger. Houston. 15.*

Per'ez-Rosales C. 1982: On the Relationship between formation resistivity factor and porosity. *SPE.* 531-536.

Ragland D.A. 2002: Trends in cementation exponents (*m*) for carbonate pore systems. *Petrophysics.* **43:** 434-446.

Salem H.S., Chilingarian G.V. 1999: The cementation factor of Archie equation for shaly sandstone reservoirs. *J. Pet. Sci. Eng.* **23:** 83-93.

Saner S., Al-Harthi A., Than Htay M. 1996: Use of tortuousity for discriminating electro-facies to interpret the electrical parameters of carbonate reservoir rocks. *J. Pet. Sci. Eng.* **16:** 237-249.

Towel G. 1962: An analysis of the formation resistivity factor-porosity relationship of some assumed pore geometries, paper 3, in *3rd Annual Logging Symposium Transactions, SPWLA.*

Winsauer W.O., Shearin H.M., Masson P.H., Williams M. 1952: Resistivity of brine saturated sands in relation to pore geometry. *American Association of Petroleum Geologists Bulletin.* **36:** 253-277.

Rahimi M. 2003: Determination of Archie coefficients (*m & a)* for carbonate rocks, for one of the Southern Iranian oil field. *Unpublished Msc thesis, Faculty of science, Tehran university.* 155p.

Rezaee M.R., Motiei H., Kazemzadeh E. 2007: A new method to acquire *m* exponent and tortuosity factor for microscopically heterogeneous carbonates. *J. Pet. Sci. Eng*. **56:** 241-251.

Kazemzadeh E., Nabi-Bidhendi M., Keramati Moezabad M., Rezaee M.R., Saadat K. 2007: A new approach for the determination of cementation exponent in different petrofacies with velocity deviation logs and petrographical studies in the carbonate Asmari formation. *J. Geophys. Eng*. **4:** 160-170.

Hassanzadeh Azar J., Javaherian A., Pishvaie M.R., Nabi-Bidhendi M., 2007: An approach to defining tortuousity and cementation factor in carbonate reservoir rocks. *Journal of Pet. Sci. Eng.* **60:** 125-131.