A Review in Correlations between Cementation Factor and Carbonate Rocks Properties

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Abstract: The cementation factor (m), sometimes referred as cementation exponent or porosity exponent, has been accepted as a measurement of the degree of cement and consolidation of the rock, as well as it is a measure of the tortuosity of the pore geometry of current flow. The accurate determination of cementation factor (m) gives reliable saturation results and consequently hydrocarbon reserve calculations. A comprehensive investigation of petrophysical properties of carbonate formations which interlock with the cementation factor is covered through this paper. There are many relations related cementation exponent with porosity, while there is no straightforward correlations between this factor and compressional and shear wave velocities. This study is a step for developed or to find correlations related cementation factor(m) with other petrophysical properties such,as permeability (K), porosity (ɸ), formation factor (F), shear wave velocity(VS) and compressional velocity (VP), by using Neuralog, Interactive Petrophysical and Neural Network Programs.

[Fadhil Sarhan Kadhim' Ariffin Samsuria, Ahmed Kamal. **A Review in Correlations between Cementation Factor and Carbonate Rocks Properties**. *Life Sci J* 2013;10(4):2451-2458]. (ISSN:1097-8135). http://www.lifesciencesite.com. 328

Keywords: Cementation Factor, Rock Properties, Carbonate Rock.

1. Introduction

A large proportion of hydrocarbons in the Middle East are contained in supergiant carbonate reservoirs, that cover about fifteen percent of the world's oil reserve. When reservoirs in the other regions are depleted this ratio will rise and the giant carbonate reservoirs in the Middle East will become the main source to provide oil and gas for the whole world (Roy Naomi and Eric Standen, 1997). Carbonate reservoirs in the Middle East are very heterogeneous in terms of rock types. Therefore the reservoir should be split into layers on the basis of the dominant rock type in order to define average values and trends of petrophyaical parameters in the reservoir rock. The cementation factor(*m*) is one of these parameters. Layering can be defined on the basis of cores and /or logs, which should be integrated with detailed geologic field model that allows layers and rock types to be identified by log data correlations calibrated with cores data analysis (Focke J.W. and Munn M.,1987).

Determination of Archie's parameters a, *m* and n, among the most uncertain parameters of conventional interpretation is sometimes wrong because of the erroneous porosity conversions and inaccurate water saturation exponent. Such uncertainty always induces a considerable effect on the values of hydrocarbon saturation. (Hartmann Dan J. and Beaumont Edward A,1999).

Researchers showed the calculated cementation factor(*m*) as is related to the flow area contrast between pore throat and pore body. The importance of the cementation factor "*m*", the saturation factor "n" and the tortuosity exponent "a" lies in the need for the optimum estimation of the total water saturation (Jesús M. Salazar,2007). The fact that the higher value of (*m*) relates to vuggy porosity and the lower value of (*m*) suggests fracture porosity was showed by conventional results (Adisoemarta P.S. et al, 2000).

The difficulties encountered in the interpretation of water saturation from conventional logs and Archie's formula have been the subject of many publications. The impact of diagnosis and rock wettability variations on Archies' parameters(*m*, n, and a) is difficult to quantify throughout the reservoir. (Gilles Cassou, et al, 2007). Furthermore, errors in reading of logging tools due to high environmental effects while drilling and running logging tools in open hole sections are extra difficulties that lead to misleading of information and lack of them (ShujieLiu, 2008). Porosity and fluid saturation are among the most important reservoir parameters used in reserve estimation of oil and gas reservoir.Fluid saturation can be estimated fluid from resistivity measurements using Archie's equation (also called the saturation equation):

$$Sw^n = \frac{a.Rw}{\Phi^m Rt} \quad .....(1)$$

In this equation, (a) is the tortuosity factor, Rw is the formation water resistivity estimated from Spontaneous Potential (SP) log,ϕ is rock porosity (can be estimated from several types of Porosity Logs, for instance Density, Neutron, or Sonic Logs), Rt is true resistivity of the system at the saturation (S_W), which is usually obtained from Deep Resistivity Log such as Deep Induction or Deep Lateralog and the exponents (*m*) and (n)are porosity and saturation exponents respectively estimated from core data analysis or from prior experience with local formation characteristics. In order to apply saturation equation actual petrophysical parameters must be used for each layer or reservoir.The use of constant value will lead to misleading in water saturation interpretation (Antwan M. Avedisian, 1988), (Zaki Bassiouni, 1994).

2. Definition of cementation Factor

The first discernment for the porosity exponent (*m*) was given by Archie in 1942 He did not actually call it cement exponent , but found that this exponent helped in the description of the empirical relationship between porosity(ϕ), and formation factor(F).He also found that this relationship could have a valuable application to quantitative studies of electrical logs. He was the first one who established the relationship between the resistivity(R_O)of the sand entirely filled with brine (S_W=1) and the resistivity of the water(R_W), for a large number of brine saturated cores as follows:

$$R_O = FR_W ....(2)$$

Archie then stated that the formation factor(F) is a function of formation type and porosity. This basic relationship works as a method to classify sand formations:

$$F = \frac{1}{\Phi^m} ....(3)$$

Where, *m* is a formation dependent parameter(cementation exponent).Archie explained that the exponent m takes a value of 1.3 in clean unconsolidated sand packs and falls in the range of 1.8 to 2.0 in the consolidated sandstones.

According to Guyod in 1944, the term of cementation factor for the exponent *(m)*; He defined it as a measure of the degree of cementation and consolidation of the rock. The greater degree of cement means the greater value of the cementation exponent. Lately, the cementation factor (*m*), referred as cementation exponent or (porosity exponent), has been accepted as a measurement of the tortuosity of the pore geometry to current flow. Ransom1974 and 1984 proposed that the factor m is related to the geometry imposed upon the bulk volume of interstitial water by both solid and fluid insulating materials. According to Héctor Pulido et al in 2007, the cementation factor of the carbonate reservoir is the most important parameters for applying the petrophysical characterization.

3. Factors Affect For Cementation Factor

Researchers have shown that the value of the cementation factor is largely affected by secondary porosity, pore throat size, conductivity of water and minerals, surface area per unit volume and cement (Ransom, R.C.,1984, Rasmus, J.C.,1986, and Wardlaw, N.C.,1980). The cementation factor strongly depends on shape and surface area of composite particles and tortuosity factor (a). It has been given considerable attention by researchers to this factor, because of its various physical effects on the physical behaviour of sediments(Hilmi S. Salem, 1993). Vera Lucia G. Elias and Daniel E.Steagall, in 1996 had shown that the values of the (*m*) and (n) exponents are largely affected,among other relevant factors, by reservoir pressure and temperature conditions, mineralogy, pore throat size distribution, pore geometry, and the wettability condition of the reservoir rock, among other relevant factors. This fact reveals the need to carry out laboratory resistivity measurements in order to obtain representative values of such parameters for a particular reservoir system.

4. Ranges for the Cementation Factor

Mathematically, cementation factor(*m*) can vary from 1.0 to infinity (Thornton, O.F.,1949) and (Wyllie, M.R.J., and Rose, W.D., 1950).Practically, this factor ranges from 1.0 to 3.0 (Archie, G.E.,1942 and Guyod, H., 1944). Values of *m*=1.0 are considered for fractures aligned favorably in the direction of the current flow and fracture porosity of 100% of the water filled porosity available (Ransom in 1984). Values of *m*=3.0 are found in non connected moldic porosity (Hartmann Dan J. and Beaumont Edward A,1999). For the range $1.0 \le m \le 3.0$ there are two values for the porosity exponent : *m*=1.3 and *m*=1.8. The value of *m*=1.3 was found theoretically corresponds to grains that have spherical shape (Pirson S.J.,1947). Values of *m* are typically less than 1.3 for the cases of fractures or non-uniform features in the void space which are favorably aligned in the direction of the current flow. While the values of *m* become higher than 1.3 when there are inefficient current paths, irregular grain shapes, crystals and discontinuities. The values of *m*=1.3 and *m*=1.8 were referenced by Archie in 1942. He stated that *m* takes value of 1.3 in clean unconsolidated sand packs and that m falls in the range of 1.8 to 2.0 in consolidated sandstones. Table(1) is a compilation of values for the cement factor (*m*) together with a bibliographic reference.

Table (1) Ranges for the cementation factor(m)

Author	Restrictions	m-Range
Archie(1942)	Consolidated sandstone.	1.8-2.0
	Clean unconsolidated sands packed in lab.	> 1.3
Pirson (1947)	theoretically and corresponds to grains that have a spherical shape	1.3
Williams (1950)	Woodbine sand in the Hawkins field. Moderate clean sand cores.	2.7
Wyllie.(1950)	Mathematically	1.0 - ∞
	In practice	1.3 – 3.0
Winsauer.(1952)	Measurements in many sandstones	2.15
Keller G.V (1953)	Oil-wet core sands	1.5 - 11.7
Clavier.(1977)	Clay-corrected	1.4
Waxman et al. (1974)	Non-clay	1.4
Ramson. (1984)	m is independent of shaliness	1.8 - 2.1
	Fractures, 100 % fracture porosity.	1.89 – 2.13
Aldoleimi et al.(1989)	Spheres	1.0
Maute, R.E. et al.(1992)	Irregular grain shapes, crystals and discontinuities	1.3
	Carbonate reservoir using logs, assume a=1	>1.3
	Sandstone African cores: clean, high porosity. Conventional method	< 1.3
	Core Archie-parameter Estimation(CAPE) method	1.81 – 2.00
Hartmann et al.(1999)	Shaly sandstones	1.79 – 1.81
Hamada G.M (2001)	Clean Sandstone	2.0

5. Cementation Factor (*m*) and Porosity(ϕ)

There are many correlations related cementation factor with porosity, Archie in 1942, from laboratory experiment established a relationship between formation resistivity factor and porosity as the shown in equation(3). According to this equation the cementation factor represents the slope (*m*) of a log-log plot between the formation resistivity factor (F) and porosity (ϕ) Winsauer, et al in 1952 were concerned with the effect of the pore geometry and tortuosity on the resistivity of the rock. Considered that the resistivity is the response to the existed fluids in the rock pore throats, they introduced the tortuosity factor, a, to the Archie formula. Winsauer, et al., found that the best fit in the formation factor versus porosity plot does not go through the lower right corner, as Archie's equation would indicate, but intercepts the abscissa at values of porosity less than 100% and conforms to the following relationship:

$$F = \frac{a}{\Phi^m} .....(.4)$$

Wyllie and Rose in 1949 introduced sequence of equations and general explanation for the relationship between *m* and porosity. The resistivity of the saturation fluid(Rw), and the resistivity of the saturated medium,(Ro), can be related by:

$$R_O = \frac{L}{A_C} = R_W \frac{L_e}{\Phi A_C} ....(.5)$$

then;

$$R_w = R_O \frac{L_e / L}{\Phi} .....(.6)$$

Where, Ac is the total cross sectional area of the Core, Le is the length of the conducting channel and L is the actual length of the core. However, by definition:

$$F = \frac{R_O}{R_W} = \frac{L_e / L}{\Phi} = \frac{a^{0.5}}{\Phi} .....(.7)$$

Where, $a = \left(L_e / L \right)^2$ =Tortuosity. Combining Equation (2) and equation(7):

$$m = \frac{Ln\left(\phi / a^{0.5} \right)}{Ln\Phi} .....(.8)$$

Equation (8) indicates that the cementation exponent depends on the tortuosity which is a measure of the enlargement, constriction and intermeshing of the pore channels. This tortuosity is an implicit measure of the pore-size distribution.

Pickett in 1966 presented cross plot method, that can provides some useful information on formation characteristics. This plot utilizes a basic rearrangement of the Archie's equation (Pickett, G. R, 1966 and Douglas W. Hilchie, 1978):

$$Rt = \left[\frac{F.R_w}{S_w^n} \right]$$

and

$$F = \frac{a}{\Phi^m}$$

Which becomes with the use of logarithms:

$$LogRt = -mLog(\Phi) + LogaR_W - nLogS_W .....(.9)$$

In water bearing zone Sw = 1, then equation (9) will be:

$$LogRt = -mLog(\Phi) + LogaR_W \text{......}(10)$$

$$m = \frac{LogaR_W - LogRt}{Log\ \Phi} \text{.......}(11)$$

Equation (10) is a straight line equation on log – log scale, where *m* is the slope and (a. Rw) is the intercept at Φ =1 (the corrected porosity for shale and hydrocarbon effects), (a) can be determined from the value of intercept and the knowing value of Rw from SP log or other methods. The limitations of this method is the fact that the crossplot works best in clean formations of a reasonably wide porosity range and constant Rw in the zone of interest, moreover the value of "*m*" and "a" is averaged for the selected formation so in case of complex lithology the values of (m and a) will vary for each level and the average values will lead to erroneous results.

Gomez (1977 and 1978) was the first researcher who presented a method to calculate "*m*" and "a" for each level, he proved the intendancy of "a" with "*m*" and their strong relationship to texture of formation, so they can be used as a permeability index. Also he was the first one who stated the importance of calculating "a" for each level and changed its name to Tortuosity factor by introducing the following relation:

$$m = \frac{\log a}{\log \Phi_x} \text{......}(12)$$

Where: Φ_x:porosity from density – neutron cross-plot.

Equation(12) is used to calculate (*m*) in sandstone and limestone formations depending on constants, which used in derivation the above equation.

In 1987 Borai A.M., introduced a new correlation for the cementation factor(*m*).It has been developed to cover the full range of porosities encountered offshore Abu Dhabi. This correlation is:

$$m = 2.2 - 0.035/(\Phi + 0.042) \text{.....}(13)$$

The use of this new relationship of cementation factor(*m*) has significantly reduced the calculated water saturations in low-porosity carbonate reservoirs and eliminated the conflict between log and test results.

In 1987, Focke J.W. and Munn M., found that the cementation factor, m, in heterogeneous carbonate reservoirs is a major factor of uncertainty in the calculation of hydrocarbon-water saturation.

The following trends are given for the limestone cores and for different permeability values:

$m = 1.2 + 0.1286\Phi \text{.....}(14)$ For K< 0.1 md

$m = 1.4 + 0.0857\Phi \text{.....}(15)$ For K=0.1 to 1 md

$m = 1.2 + 0.0829\Phi \text{....}(16)$ For K=1 to 100 md

$m = 1.22 + 0.034\Phi \text{.....}(17)$ For K> 100 md

Wafta and Nurmi, in 1987 derived the Shell formula from samples were taken from the Ellenburger dolomites of West Texas. This formula was used in determining m values in deep and tight carbonates as follows:

$$m = 1.87 - \frac{0.019}{\Phi} \text{.....}(18)$$

Schlumberger in 1987and 1988 used EPT log to interpret log response for variable cementation factor(m) calculation (Tabibi M.and Emadi M.A., 2003). The following expression introduced to calculate cementation factor (m_{EPT}):

$$m_{EPT} = \frac{LogRt_{EPT} - LogRxo_{EPT}}{Log(\Phi Sxo)_{EPT}} \text{.....}(19)$$

Where: $Rt_{EPT} =$ total resistivity from EPT log,

$Rxo_{EPT} =$ flushed zone resistivity from EPT log,

$Sxo_{EPT} =$ water saturation in flushed zone from EPT log

In 2005, Attia M. Attia studied the effects of petrophysical rock properties on the Archie's equation parameters. His results showed that the tortuosity factor is not a constant value, but it varies largely according to many parameters such as porosity, cementation factor and formation resistivity factor. He introduced an empirical correlation between tortuosity factor(a) and cementation factor(m) at5% NaCl for synthetic cores. He also found an empirical correlation between formation resistivity factor (F)and tortuosity factor(a) in the same conditions. as shown in the following equations: $a = 0.9m^{1.33} \text{........}(20)$

$a = 0.087F^{0.16} \text{.....}(21)$

The values of Archie's exponents (*m* and n) play a significant role in formation evaluation.3D imaging and analyzing of the pore scale structure within core material allows one to directly measure the pore structure, tortuosity and degree of interconnections of the pore systems and the spatial distribution of the fluid phases. This can give insight into the behavior of (*m*) and (n) in realistic pore geometries (Knackstedt M.A.,et al,2007).

Masoud et al, in 2008, investigated a correlation that could be used to estimate the cementation factor in Iranian carbonate reservoir. They found the cementation factor (*m*) is more dependent on porosity (Φ) as follows:

$$m = \frac{1}{0.36 - 0.08\ln\Phi} \text{.....}(22)$$

They concluded that this relation is dependable for porosities lower than 5%, whereas this dependency decreases for porosities higher than 5%. However, in middle east the value of porosity in carbonate reservoirs is generally more than 5%, that lead to decrease the applicability of this correlation.

Table (2): Correlations between *m* and ϕ.

Author	Formula	Rock Type
Archie (1942)	$F=\frac{1}{\phi^m}$	Clean Sandstone
Wyllie (1949)	$m=\frac{Ln\left(\phi/a^{0.5}\right)}{Ln\phi}$	Sandstone
Pickett (1966)	$m=\frac{LogaR_W-LogRt}{Log\phi}$	Clean & Complex lithology
Gomez (1977)	$m=\frac{\log a}{\log \phi_x}$	Sandstone &Carbonate
Borai (1987)	$m=2.2-0.035/(\phi+0.042)$	Carbonate
Focke M(1987)	$m=1.2+0.1286\phi(K<0.1md)$ $m=1.4+0.0857\phi(K=0.1-1)$ $m=1.2+0.0829\phi(K=1-100)$ $m=1.22+0.034\phi(K>100md)$	Limestone
Wafta (1987)	$m=1.87-\frac{0.019}{\phi}$	Shell
Schlemb-erger (1988)	$m_{EPT}=\frac{LogRt_{EPT}-LogRxo_{EPT}}{Log(\phi Sxo)_{EPT}}$	Flushed Zone
Masoud (2008)	$m=\frac{1}{0.36-0.08\ln\phi}$	Carbonate
Hassani .(2008)	$m=\frac{2.48-0.048}{\phi+0.01}$	Grainstone-Packstone

Hassani M. and Rahimi M.,2008, calculated the cementation exponent (*m*) based on core resistivity analysis data from three formations (Asmari, Ilam and Sarvak) in two different Iranian oil fields. They derived some new correlations for(*m*) to minimize the error in calculating of water saturation. In the rock type Ooid Grainstone -Packstone the *m* values trend is introduced as follows:

$$m=\frac{2.48-0.048}{\Phi+0.01}.....(23)$$

However in the dolomitized packstone - wackestone rock the m values are controlled by:

$$m=\frac{2.52-0.045}{\Phi+0.001}.....(24)$$

A modified K–C model was developed in 2011, by Hasan A. Nooruddin and M. Enamul Hossain, based on an accurate theoretical approach. The modified model shows that the tortuosity term can be approximated accurately using theoretical and experimental approaches based on effective porosity and cementation exponent. Table(2) summarizes the correlations between cementation factor(*m*) and porosity(ϕ) and formation factor(F) with each author.

6. Cementation Factor(m) and Permeability(K)

There are very few correlations calculated from well log data related cementation factor (*m*) with permeability (K) in carbonate reservoir. Rose and Bruce in1949 had shown that the tortuosity might be expressed as:

$$a=\left(\frac{\Phi}{Kt_S}\right)\left(\frac{\sigma}{P_d}\right)........(25)$$

Where σ and Pd are the interfacial tension and the displacement pressure respectively, tS is the pore shape factor, K= permeability. Equation (25) and equation(8) were combined by wylie and Rose in 1949. They found the following correlation to calculate *m*:

$$m=\frac{Ln\left(\frac{(\Phi Kt_s)^{0.5}P_d}{\sigma}\right)}{Ln\Phi}......(26)$$

Wylie & Rose in1950 discussed some theories about quantitative evaluation of the physical characteristics of reservoir rocks. They have expanded an empirical formula proposed by Tixier in1949 showed that the order of magnitude of formation permeability might be obtained from the relationship:

$$K=C\left(\frac{1}{P_c^{\,2}F^{\left(2-1/m\right)}Sw}\right)......(27)$$

Where: *m*=cementation factor,Pc=capillary pressure (psi), $C=21.2\,\delta^2/t_S$, δ=interfacial tension dyn/cm2 and tS=constant (2-2.5)

Raiga-Clemenceau in 1977, introduced a research about the variation of cementation exponent (*m*) with permeability, and studied the previous relations of porosity with formation factor (F), and the influence of cementation exponent variation. Clemenceau proposed an equation to calculate the variable cementation exponent (*m*) from the permeability value as follows:

$$m=1.28+\frac{2}{2+\log(K)}.....(28)$$

Gomez in 1977 discussed some considerations for the possible use of the parameter (a) and (*m*) as a formation evaluation's tool through well logs. He concluded that the computed (a) and *(m)* from well logs can be used for detecting permeable zones, as follows:

$$K = \frac{\Phi^m}{a}\left(\frac{\Phi}{1-\Phi}\right)^2 \frac{1}{Swi^2} .....(29)$$

However the value of m is not variable with depth, which lead to an error in the results.

The cementation factor (*m*) has been the subject of many researchers.They tried to find its best value and to define its actual physical meaning. Several relationships were proposed in the literature to estimate the permeability when the effective pore radius (RP), and cementation factor (*m*) are known. An improved rock permeability relationship was proposed in the following relationship (Hagiwara, 1984):

$$k = c\ \Phi^m\ Rp^2 .....(30)$$

From median effective pore-throat radius data, it has been found that the constant(c), is equal to 32.65, therefore equation(30) becomes:

$$k = 32.65\ \Phi^m\ Rp^2 .....(31)$$

The value of m is assumed to be constant.This may reduce the accuracy of results. Table (3) shows the major correlations,that related permeability with cementation exponen

Table (3): Major correlations between *m* and K

Author	Formula	m-value
Rose Bruce (1949)	$m = \frac{Ln\left(\frac{(\phi K t_s)^{0.5} P_d}{\sigma}\right)}{Ln\,\phi}$	variable
Wyllie. (1950)	$K = C\left(\frac{1}{P_c^2 F^{(2-1/m)} Sw}\right)$	constant
Clemenca u, J.(1977)	$m = 1.28 + \frac{2}{2+\log(K)}$	variable
Gomez (1977)	$K = \frac{\phi^m}{a}\left(\frac{\phi}{1-\phi}\right)^2 \frac{1}{Swi^2}$	constant
Hagiwara (1984)	$k = c\ \varphi^m\ Rp^2$	constant

7. Cementation Factor(*m*) and Acoustic velocity

Computations of compressional wave velocity (V_P) and shear wave velocity(V_S) are required for determining of dynamic elastic properties. Dynamic elastic properties can be obtained from the compression transit time (Δţp) and corrected bulk density values. (Lee M. Etnyre, 1989).

$$\Delta t_p = \Phi(\Delta t_f - \Delta t_m) + \Delta t_m .....(32)$$

$$\Delta t_S = \Phi(\Delta t_f - \Delta t_m) + \Delta t_m .....(33)$$

Where, Φ is porosity from sonic log.,

Δt_p is compressional transit time.,

Δt_s is shear wavtransit time, $\Delta t_f = 189\mu s/ft$ For fluid, and $\Delta t_m = 47.6\mu s/ft$ for carbonate matrix.

The compressional velocity and shear wave velocity are calculated by the following equation(Wafa Al-Kattan and N. Jasim Al-Ameri,2012):

$$V_p = \frac{10^6}{\Delta t_p} .....(34)$$

$$V_S = \frac{10^6}{\Delta t_S} .....(35)$$

Although, there are very few studies related velocities(V_P and V_S) and cementation factor(m), several relationships between these parameters have been established by some researchers.

Hugh J. Mitchell in 1981 was proposed a relationship for cementation factor (*m*) and the compressional velocity (Vp) and shear wave velocity(Vs). He showed that the increase in the shear velocity(Vs) may result due to the increase of the strength of the rock by the cement. The trend of plotting the cementation factor values (*m*) and the compressional- shear velocity was almost horizontal. This plot shows that the relationship between (*m*) and the ratio of (Vp/Vs) is independent of the increment in porosity value. This fact indicates the existence of direct relationship between m and the (Vp/Vs)ratio.

Héctor Pulido et al in 2007,explained that both the velocity of compression and shears waves are related with the porosity of the matrix in the oil saturated carbonate rocks,as shown in the following correlations:

$$V_p = 6.6248 - 10.348\Phi_m ......(36)$$

$$V_s = 3.3378 - 5.3726\Phi_m .....(37)$$

They also found correlations between formation factor and the velocity of compression and shears waves as follows:

$$V_p = 3.2602 F_m^{0.0823} ......(38)$$

$$V_s = 1.7812 F_m^{0.0852} ......(39)$$

Where:

$F_m = \frac{a}{\phi_m^{\ m}}$, V_P= speed of compression in (Km/s), V_S = speed of shears in (Km/s), Φ_m = matrix porosity,.

in fraction, F_m = Factor of the resistivity of formation, *m*=cementation factor. There are indirect correlations of velocities(V_P & V_S) with cementation factor(*m*) in this study that depend on the relationship between F and Φ .

8.Discussion

In order to apply the cementation factor (*m*) in saturation equation, actual petrophysical parameters must be used for each layer or reservoir, the use of constant value of (*m*) will lead to misleading in water saturation interpretation. In another way the use of any saturation model is limited to the type of reservoir (Carbonate or Sand) in which it will give reliable saturation results. Major studies that focused on calculation of the value of cementation factor are shown in table(1). Values of *m* are different depending on formation type and methods of calculation. Results show the values of m are generally vary from 1.3 to 3.0 and the maximum range(1.5-11.7) is recorded by Keller in 1953 in oil-wet core sands. While the minimum values of *m*=1.0 are considered for the case of fractures aligned favourably in the direction of the current flow and a fracture porosity of 100% of the water filled porosity available(Ransom in 1984).

The most important correlations related *m* and Φ are listed in table(2). Reliable and accurate values of the parameter *m* occur when these values are variable with depth. Picktt in 1966 and Gomez in (1977 and 1978),were the first researcher who introduced general formulas to calculate the variable parameter *(m)* with varying lithology. While,Fock in 1987 introduced equations to calculate *m* for different values of permeability in limestone rocks. In Iranian carbonate reservoir, Masoud et al, in 2008, presented correlation that can be used to estimate the cementation factor(*m*) when the porosity less than 5%. However, in middle east the value of porosity in carbonate reservoirs is generally more than 5%, this may lead to reduce the applicability of this correlation.

Table(3) summarizes the major studies, which related cementation factor(*m*)with permeability (K). Several researchers dealt with the variable *m* and its relation with K as shown in(Rose and Bruce,1949), and (Clemencau, J.,1977) correlations. However, other researchers have used constant value for m in their studies.

Finally, there is no clear and direct correlation between *m* with VS and Vp.However there are many correlations related compressional and shear velocities with porosity. Indirect relations between (V_S and Vp) and *m* could be found from these correlations.

9.Conclusions

The accurate determination of cementation factor (*m*) gives reliable saturation results and consequently hydrocarbon reserve calculations. There are four major points can be concluded from literature review for the correlations between cementation factor and carbonate rock properties:

1. The formation is heterogeneous which means that the rock properties such as porosity, permeability and lithology are varying either vertically or horizontally, therefore m values are expected to vary accordingly to get reliable results.
2. In general,the value of *m*, varies from 1.3 to 3.0, and it has significant impact on water saturation calculations.
3. The most important and reliable correlations,that related *m* and Φ are introduced by Gomes and Pickett because they used variable *m* with depth and their equations could apply in different types of lithologies.
4.There are very limited correlations related the cementation exponent(*m*) as a variable parameter with permeability(K).However there is no straightforward relationship between *m* and (V_S and Vp).

Acknowledgements:

The authors would like to thank the Ministry of Higher Education (MOHE) in Iraq for providing a.research grant and Universiti Teknologi Malaysia (UTM) for supporting a research Assistantship

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11/12/2013