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DERIVATION OF THE CEMENTATION FACTOR (ARCHIE'S EXPONENT) AND THE KOZENY-CARMAN CONSTANT FROM WELL LOG DATA, AND THEIR DEPENDENCE ON LITHOLOGY AND OTHER PHYSICAL PARAMETERS

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ABSTRACT

The cementation factor or Archie's exponent (m) and the Kozeny-Carman constant (C) have specific effects on electric and hydraulic conduction in porous media. In the present study, both parameters were derived from well log data for fourteen Hibernia and Terra Nova wells in the Jeanne d'Arc Basin (JDB) offshore the eastern coast of Newfoundland, Canada. The purpose of this study is to verify that both parameters (m and C) are applicable for shaly-saline water formations under high overburden pressure at depths between 3 to 5 km, saturated with multi-phase fluids. The results obtained show that the Kozeny-Carman constant (C), defined as the product of tortuosity (T) times shape factor (S_f), fits well with the product of tortuosity (T) times cementation factor (m). It is suggested that it is more accurate to call (m) "shape factor" instead of "cementation factor" because it is a strong indicator of shape of particles. It is also suggested that an average value for the Kozeny-Carman constant of 7.5 be used in the Kozeny-Carman equation for consolidated sediments saturated with multi-phase fluids, and an average value of 2.28 for the cementation factor be used in the Archie-Winsauer equation. Tortuosity, as a main parameter controlling the variations in both m and C, indicates the complicated electric and hydraulic tortuous passages in the JDB sediments.

INTRODUCTION

GEOLOGICAL SETTING

Marine geophysical and geological investigations of the eastern margin of North America were first carried out in the 1950s by the Canadian and American governments and university research agencies.[1] Exploration by oil companies outlined the principal sedimentary basins located offshore Newfoundland, and eventually established the presence of hydrocarbons in the Jeanne d'Arc Basin (JDB). Some of the JDB wells are capable of producing up to $2x10^3$ barrels per day.[2] Nine wells drilled in the Hibernia oil field in the JDB have delineated a field with recoverable oil reserves in the order of 500 to 800 million barrels.[1] The Grand Bank basins including the JDB began to develop during the Late Traissic to Early Jurassic by rifting between North America and Africa.[1] Geophysical surveys, including deep refraction and potential field studies indicated a thick sedimentary cover. The sediments, of more than 20 km thickness[3], are mainly composed of shales, sandstones, siltstones, and carbonates[4,5,6] of very fine to medium grain and crystal sizes.[7]

BACKGROUND, METHODOLOGY AND GOAL OF STUDY

Maxwell[8], in his theoretical study, showed that formation resistivity factor (F) decreases slowly with the increase of porosity (Φ). His F-Φ relationship can be expressed as follows:

$$F = (3 - \Phi) / 2\Phi \qquad (1)$$

where

F = Formation resistivity factor (dimensionless)

Φ = Porosity (fraction)

Fricke[9] theoretically developed the following equation, based on Maxwell's equation, showing that formation factor (F) increases with increase of irregularity of grains.

$$F = ((x + 1) - \Phi) / x\Phi \qquad (2)$$

where

x = 2 for spheres and less than 2 for spheroids

Equation 2 shows that at any porosity (Φ) the formation factor (F) will be minimum for spheres. This indicates that the formation factor (F) is minimized by increasing sphericity of particles, and maximized by increasing irregularity of particles. This also indicates that the shape of particles has importance in defining the magnitude of difference in formation factor values for spherical and non-spherical aggregates of particles.

Archie[10] defined the formation factor (F) as the ratio between resistivity of formation to resistivity of water totally saturating the pores. He defined F as follows:

$$F = R_o / R_w \qquad (3)$$

where

R_o = Formation resistivity (Ω.m)

R_w = Pore water resistivity (Ω.m)

Archie[10] pointed out that F is a function of type and character of formation, and varies with many textural characteristics, such as porosity (Φ), permeability (k) and degree of cementation. Tortuosity (T) also shows specific influence on formation factor variation, where materials show more resistance to electric current when it is conducted in more tortuous passages.

The cementation factor (m), as a textural parameter, can be obtained as the slope of the line on a double logarithmic plot of the Φ-F relationship. Archie[10] generalized the Φ-F relationship to have the following form:

$$F = 1 / \Phi^m \quad (4)$$

where

m = Cementation factor (dimensionless)

Winsauer et al.[11] introduced to Archie's formula another factor called the tortuosity factor (a, which is different from tortuosity T), i.e:

$$F = a / \Phi^m \quad (5)$$

leads to

$$m = -[(\log F - \log a) / \log \Phi] \quad (6)$$

where

a = Tortuosity factor (dimensionless)

The formula in Equation 5 is known as Winsauer's modified formula, or the Archie-Winsauer formula. Cementation factor or Archie's exponent (m) has been widely used in hydrocarbon and groundwater exploration. Because of its relationships to many textural properties, researchers use different names, such as cementation factor, porosity factor, shape factor, conductivity factor, resistivity factor, Archie's exponent, porosity exponent, etc. The term "cementation factor" (m) will be used in this study. Later, it will be shown that this factor is better called "shape factor". Cementation factor (m) is determined according to the Archie-Winsauer formula (Eq. 5). The other parameters (F, Φ, and a) were determined and presented in Salem.[12]

As undertaken in this study, determination of cementation factor at close increments (0.2 m) is a very descriptive approach. Researchers analyzing reservoir rocks generally use an assumed value of m over all the sedimentary column studied. However, experimental data indicate that even for unconsolidated sediments, using a constant value of m over all the studied column of sediments is not accurate.[13] A recent study carried out by Ehrlich et al.[14] showed that assuming constant m throughout the borehole suggests the pore complexes are extremely constrained in terms of pore and throat area correlations. They showed that m varies widely from sample to sample within the same reservoir, and it continuously changes throughout the borehole due to variations in micro-fabric as a result of depositional subfacies.

In reviewing the following Kozeny[15]-Carman[16] equation:

$$k = \Phi^3 / [CS_p^2(1 - \Phi)^2] \qquad (7)$$

where

k = Permeability (cm^2)

Φ = Porosity (fraction)

C = Kozeny-Carman constant (dimensionless)

S_p = Internal surface area of composite grains (cm^{-1})

Wyllie and Rose[17], Wyllie and Spanlger[18], Cornell and Katz[19], Wyllie and Gregory[20] and Carman[21] suggested that this equation can be successfully applied for permeability determination in consolidated reservoirs if appropriate values of S_p and C in addition to adjusted porosity values are available. Wyllie and Gregory[20] simplified Equation 7 as follows:

$$k = \Phi^3 / CS_p^2 \qquad (8)$$

Equation 8 shows that permeability (k) increases with increase in porosity (Φ), and with decrease in Kozeny-Carman constant (C) and surface area of grains (S_p).

Carman[16,21,22] defined C as the product of tortuosity (T) times shape factor (S_f). He suggested that for unconsolidated porous media a T value of 2 and a value of S_f between 2 and 3 with an average value of 2.5 resulted in a C value of 5. If the Kozeny-Carman constant (C) were increased to values considerably greater than 5.0, the Kozeny-Carman equation appeared to apply not only to single-phase fluid in consolidated porous media but also to multi-phase fluid.[18,20] In the present study, from a numerical point of view it is shown that values of the Kozeny-Carman constant ($C1$), as the product of tortuosity (T) times cementation factor (m), are analogous to values of $C2$ as the product of tortuosity (T) times shape factor (S_f), where S_f has a constant value of 2.5. The definition of C as Tm needs mathematical verification.

The results discussed here for cementation factor (m) and Kozeny-Carman constant (C), derived at 0.2 m increments for fourteen Hibernia and Terra Nova wells in the JDB, show that these two parameters vary considerably with depth, lithology, and other physical parameters. Salem[5,7,12] determined surface area of composite grains (S_p), porosity (Φ), permeability (k) and tortuosity (T).

The reservoir intervals studied of the JDB sediments are highly heterogeneous in their grain and pore size distribution[7], in their saturating fluids and physical properties[12], as well as in their lithological composition.[5,6,23] For such complicated heterogeneous porous media, particularly from the microscopic point of view, a quantitative approach to the problem of determining petrophysical parameters that control hydraulic and electric flow, especially without laboratory measurements, is not simple. However, the determination of cementation factor, Kozeny-Carman constant and tortuosity presented in this study enables a better understanding of the physical behaviour of the JDB sediments, and agree well with results obtained experimentally or theoretically by other researchers.

RESULTS AND DISCUSSION

Results of tortuosity (T), cementation factor (m) and Kozeny-Carman constant ($C1 = Tm$, and $C2 = TS_f$, where $S_f = 2.5$) determined at 10 m increments in four Hibernia (HIB) wells (B-08, B-27, C-96, K-18) and four Terra Nova (TN) wells (C-09, E-79, H-99, I-97) are presented in this study (**Tables 1 and 2**). **Table 3** shows summarized results of T, m, $C1$ and $C2$. It is shown (**Table 3**) that T exhibits a general range between 1.00 and 17.17, m ranges between 1.26 and 4.15, $C1$ ranges between 1.17 and 41.09, and $C2$ ranges between 2.33 and 42.92. The minimum values for all the calculated parameters (**Table 3**) correspond to the TN oil field, while the maximum values correspond to the HIB oil field. This is probably because the sample intervals of TN wells are shallower than at HIB, which generally indicates that these parameters tend to increase with increasing depth and with porosity decrease. To investigate the correlation between the various parameters, different relationships were examined. Only selected ones of high correlation coefficients are presented in this study.

CEMENTATION FACTOR (m)

The cementation factor (m) shows significant variation between different wells in the same oil field, and between the oil fields of Hibernia and Terra Nova. This variation is attributed to many factors that cause reservoir sediments to be heterogeneous, reflected in the cementation factor range from 1.26 to 4.15 (**Table 3**). The general range of m given in the literature is from slightly less than 1 for fractured rocks to more than 3 for consolidated microporous sediments rich in platey clay minerals. Towle[24], Helander and Campbell[25] and Ransom[26] reviewed the reasons for wide variation in cementation factor. These include the degree of consolidation, compaction and cementation due to overburden pressure, particle size and particle shape (sphericity-angularity), sorting and packing, type of pores; inter-granular, inter-crystalline, vuggy or fracture, porous system constrictions, degree of shaliness, tortuosity of porous system, surface area of composite grains, heterogeneity of lithological composition, anisotropy, and thermal expansion. In the remainder of this paper, diagenesis due to overburden pressure, type of pores and tortuosity, shape and type of grains, and surface area of composite grains are discussed in detail.

DIAGENESIS DUE TO OVERBURDEN PRESSURE

Variations in cementation factor (m), in formation factor (F) and in porosity (Φ) with pressure increase were reported from an experimental study by Fatt.[27] He indicated that compression of rocks causes radical change in pore structure and porosity. Wyble[28] experimentally obtained values of m ranging from 1.97 to 5.12. He noticed that by increasing pressure, m tends to be maximized. However, little information is available to describe how overburden pressures would affect cementation factor. Overburden pressure could cause rounded particles to be flattened, resulting in greater angularity and, in turn, higher values of cementation factor would be produced. In the case of sand matrix inter-connected by clay particles, actual deformation of clays due to overburden pressure would not occur, and the pressure would not cause much deformation of the flat clay particles, hence no significant change of m would appear. Consolidation and cementation are the diagenetic mechanisms responsible of increase in cementation factor. Archie[10] found that highly cemented sediments are characterized by high values of m. Atkins and Smith[29] pointed out that the angularity of particles may change with cementation. They suggested that if the angularity of particles is increased by cementation, the m value will also increase. The range of cementation factor obtained in this study probably suggests that the sediments show different levels of consolidation and cementation due to different stages of diagenesis, varying from more than slightly unconsolidated-uncemented to levels of very high consolidation and cementation. However, relationships between cementation factor and depth for all the wells studied do not show a significant trend. They show either positive or negative trends (with low correlation coefficients) or no trend at all. This is probably due to effects of other factors (discussed below) on cementation factor.

TYPE OF PORES AND TORTUOSITY

Cementation factor can indicate the type of porosity. Towle[24] theoretically and Lucia[30] experimentally concluded that the more vuggy the porosity, the higher the cementation factor. Aguilera[31,32] pointed out that cementation factor tends to be higher when inter-connected porosity exists. The inter-connected porosity of microporous media appears to be more effective in defining the cementation factor for shaly formations. This probably suggests that the inter-connected porosity acts to increase the cementation factor, where particles become closer to each other, and pores become smaller and smaller or even closed. This enhances the direct relationship between cementation factor and tortuosity. For example, for the Hibernia C-96 well (**Fig. 1**) it can be seen that a range of cementation factor (m) between about 1.5 and 2.5 is highly correlated to a range of tortuosity (T) between about 1 and 3. This relationship probably suggests that the existence of very small pores forces the fluid to flow through a longer path (higher tortuosity) than when the fluid flows in larger pores or fractures. Ehrlich et al.[14] gave a physical definition of cementation factor based on petrography, as the logarithm of throat area divided by the logarithm of pore area (inverse of the non-logarithmic definition of aspect ratio, where aspect ratio is the ratio of pore area to throat area). They pointed out that m is a measure of the efficiency of a pore system to transmit electric current. Their definition of m indicates that the closer the values of throat radius to pore radius, the closer m to unity, and the increase of m occurs as a result of the faster decrease of throat size in relation to pore size because of porosity loss due to consolidation and compaction. **Figure 1** also shows that the cementation factor progressively increases with increase in tortuosity. This probably indicates that by accelerating the diagenesis rate, more cementation occurs (higher cementation factor), and consequently a significant decrease in porosity is produced, hence the hydraulic and electric flow becomes more complicated (higher tortuosity). **Figure 1** also shows that the majority of m values concentrate in a range between approximately 1.9 and 2.4 corresponding to a range of T between approximately 1.6 and 2.8. The low values of m less than 1.9 may be attributed to many reasons, including the presence of micro-fracturing, richness of conductive minerals of high cation exchange capacity, or presence of typically spherical particles. Givens[33] experimentally derived a range of m between 1.73 and 2.07 with a range of tortuosity (T) between 2.0 and 2.82. He attributed the high correlation coefficient of his T-m relationship to the fact that m was related to the complexity of the inter-connecting electrolytic paths in the tested specimens. Because the length of flow path in a fractured medium is much shorter than the length of flow path in inter-connected porous medium, tortuosity of a fractured system is relatively small, and cementation factor is also small and approaches unity.[32,34] These observations suggest that the JDB sediments which generally have high values of m can be characterized as having inter-connected porosity in shales due to high levels of compaction and consolidation. The few values of low m are probably due to different reasons mentioned above, or they might correspond to sand particles of high sphericity.

SHAPE AND TYPE OF GRAINS

From the cuttings description, the Canadian Stratigraphic Service Ltd. (CSSL) indicated that the shape of particles of the sediments in the JDB varies from subangular-angular to subrounded-rounded. Archie[10] found that m has a value of 1.6 for natural sands composed of quartz. Wyllie and Gregory[13] gave an m value of 1.3 for glass spheres. Hill and Milburn[35] obtained values of m, from the slope of log-log Φ-F relationship, varying between 1.76 and 2.15 for clean sandstone (lower values), and for very shaly and silty fine-grained consolidated sandstones (higher values). Atkins and Smith[29] showed that m becomes greater as the constituent particles become more platey. They found for kaolinite m was 1.87, illite 2.11, attapolgite and muscovite 2.46, calcium montmorillonite 2.70, and for sodium montmorillonite 3.28, whereas for sand and chalk 1.60. Parkhomento[36] gave values of m, again reported by Keller[37], between 1.9 and 2.3 representing well-cemented sedimentary rocks with a porosity range from 5 to 25%. Waxman and Thomas[38] obtained values of m between 1.82 and 2.10 indicating increase of m by increasing the level of shaliness. Windle and Worth[39] gave values of 1.52 and 1.58 for two samples of natural sand. Jackson et al.[40], in their experimental study on marine sediments, concluded that m is dependent on shape of particles, increasing as they become less spherical, while variation in size appears to have less effect. They gave values of m between 1.2 for spheres and 1.9 for platey-shell fragments with a sphericity degree between 1.0 and 0.5, accompanying a porosity increase from 32 to 62%. Ransom[26] suggested that cementation factor varies directly with angularity (irregularity) and inversely with sphericity, and pointed out that m is independent of grain size, sorting or packing as long as the grain shape remains constant. He also pointed out that the presence of diatomites produces low values of cementation factor for unaltered rocks. Wong et al.[41] experimentally found that in rocks with similar grain shapes, the cementation factor (*m*) can vary significantly and, conversely, in rocks with very different grain shapes the values of *m* can be very similar. They also found that *m* is greater than unity and is related to the skewness of pore and grain size distribution. Brown[42] gave values of *m* of 1.87, 2.11, and 2.7-3.28 corresponding respectively, to kaolinite, illite and montmorillonite. He concluded that mixtures of clay and sand can be expected to have higher *m* values than clean sands. Jorgensen[34] obtained an *m* value of 1.09 for porous dolostones, and 2.56 for sandstones collected at depths of 890 and 2500 m, respectively. He indicated that cementation factor decreases with permeability increase. Alger and Harrison[43] used *m* values of 1.6 and 1.8 corresponding to shallow unconsolidated sand and deep compacted sand. Ruhovets[44] correlated values of cementation factor to values of cation exchange capacity, and concluded that *m* increases in a non-linear fashion from about 1.78 in clean sands to 2.5 in shaly sands. Salem[45] used an *m* value of 1.3 for unconsolidated glacial sediments. Presence of fractures, or non-uniformity in void space, or alignments of particles in the current flow direction, are other reasons for values of cementation factor less than 1.3.

The discussion above shows the following: (1) Presence of specific clay minerals in porous media with different particle shape tends to strongly increase cementation factor; (2) Presence of multi-lithological components increases cementation factor; (3) Particles with high degree of sphericity appear to lower the cementation factor, while particles with less sphericity or higher angularity increase the cementation factor (negative relationship between sphericity and *m*, and positive relationship between angularity and *m*); (4) In this study, cementation factor values are generally higher than 2.0, which suggests that the JDB sediments include high amounts of plate-like clay minerals with a high degree of angularity; (5) Non-uniformity in void space and particle-orientation (anisotropic effect), as well as presence of diatoms produce low *m* values.

SURFACE AREA OF COMPOSITE GRAINS

The surface area (S_p) of composite grains and their mean sizes for JDB sediments were derived and discussed in detail.[7] It was found that the shaly fraction in the JDB is characterized by high values of surface area, and the sandy fraction is characterized by lower values of surface area. This is due to the fact that clay particles have plate-like shape, and the sand particles have generally spherical shape. The surface area becomes a minimum for any specific grain size when the shape is a perfect sphere. Abundance of clay particles in sediments with high irregularity causes increase in surface area and increase in cementation factor (**Fig. 2**). It can be seen that for the Hibernia C-96 well, a range of S_p between approximately 1×10^2 and 6×10^2 cm^{-1} generally corresponds to a range of *m* between about 1.7 and 2.4. For less spherical grains the surface area increases and so does the cementation factor.[26] The value of *m* will increase as grain irregularity acts to decrease the efficiency of electric current paths (higher tortuosity). Because surface area of composite grains is inversely related to permeability[7], an inverse relationship between cementation factor (*m*) and permeability (*k*) is expected.[32] As in the case of clays, permeability decreases as grain angularity increases (higher *m*). In addition to sphericity-angularity, permeability and surface area, the presence of authegenic (diagenetic) materials such as clay, calcite or quartz growing in the interstitial pores and pore throats tends to increase surface area and cementation factor, and to decrease permeability. Tighter packing of grains due to compression increases the surface area, and consequently an increase in cementation factor would be expected.

KOZENY-CARMAN CONSTANT (*C*)

Attempts to render the Kozeny-Carman equation (Eq. 7) applicable to consolidated porous media have centered on methods of determining an appropriate constant (*C*) in this equation.[20] For consolidated porous media larger values of *C* than 5.0 seem to be required, and *C* increases with an increase in clay content and a decrease in permeability.[46] The tables presented in this study (at 10 m increments) show that *C* has a general range between approximately 1 and 43 corresponding to both definitions of *C1* and *C2* (*Tm* and TS_p, respectively). At increments of 0.2 m, both *C*s have values up to 150. Rose and Bruce[46] gave values of *C* up to 400. They concluded that such high values reflect non-ideal systems. The range of average values of *C* (*C1* and *C2*) for all the wells studied in the Hibernia and Terra Nova oil fields at 0.2 m sample increments is 4.1 to 10.4, with an average value of 7.5. This average value of *C* is higher than the 5.0 value given by Carman[16] for unconsolidated porous media. Based on the present results for the JDB sediments, it is believed that the 7.5 value can be used for *C* in the Kozeny-Carman equation in application to consolidated shaly sand porous media. However, the wide variation in *C* (*C1* and *C2*) values is mainly attributed to the complexities of current flow in porous media and to variation in cementation factor. The low values of C could reflect media composed of spherical particles where current flows easily (low tortuosity), and the high values could reflect very irregular particles with different shapes where the current is expected to flow in very tortuous paths (high tortuosity). Also, the orientation of particles and the anisotropic behaviour of current flow strongly affect the Kozeny-Carman constant. A detailed study of the hydraulic and electric anisotropic behaviour of the JDB is in preparation.[47] Sullivan and Hertel[48] experimentally showed that for aggregates of glass fibers, C was 3.07 when flow was parallel to the axes of fibers, and 6.04 when flow was perpendicular to the fibers axes. Wyllie and Spangler[18] obtained C values between 4.05 and 7.48 for consolidated sandstones. They ignored the variation in shape factor and assumed a constant value of 2.5. They suggested that shape factor is constant for any particular medium, and if tortuosity can be shown to exhibit directional variations in anisotropic porous media, the magnitude of the Kozeny-Carman constant will vary correspondingly as well as permeability. Since all pores are not available for fluid flow, and in this case the pore inter-connections play a considerable role in fluid flow, the medium becomes more tortuous, consequently the Kozeny-Carman constant will increase. In their experimental study on consolidated samples of sandstone, limestone and dolomite, Cornell and Katz[19] assumed a shape factor value of 2.5 and obtained C values between 3.40 and 8.15, coresponding to a range of tortuosity between 1.36 and 3.26. Wyllie and Gregory[20] experimentally showed that the magnitude of the Kozeny-Carman constant for different groups of aggregates (cylinders, disks, cubes, prisms, and spheres) is a function of porosity, surface area and shape of particles composing the aggregates. For a range of porosity between 12 and 52%, they found that C inversely varies (from 17.2 to 3.0) with porosity, and directly with surface area of particles. For these different unconsolidated aggregates, they found average values of C between 3.95 and 4.80, and concluded that electric and hydrauilc tortuosities are essentially identical.

For the Hibernia B-27 well, the Kozeny-Carman constant ($C2 = TS_f$, where T is tortuosoty and S_f is shape factor equals 2.5) is plotted against permeability (k) in **Figure 3**, and against surface area (S_p) in **Figure 4**. Both relationships show correlation coefficients higher than 0.70, corresponding to a range of $C2$ generally between 4.4 and 9.4, and ranges of k and S_p, respectively, between approximately 0.1 and 1×10^2 md, and 1×10^2 and 1×10^3 cm^{-1}.

The formation resistivity factor (F) is influenced by the Kozeny-Carman constant (C) which reflects the effects of tortuosity, cementation factor and shape of particles. **Figures 5** and **6** show direct relationships for the Terra Nova E-79 well between *F* and *C1* (**Fig. 5**), and *F* and *C2* (**Fig. 6**). Both relationships show high correlation coefficients of more than 0.95. It can also be seen that the differences in values of *C1* and *C2* (as *Tm* and TS_f) are negligible. Both figures also show that the Kozeny-Carman constant (*C1* and *C2*) values fall in a range between approximately 1.5 and 10.5 corresponding to a range of formation factor (*F*) between approximately 5 and 1×10^2. Generally this indicates that by increasing the Kozeny-Carman constant by approximately 10-fold, the formation factor is increased by approximately 100-fold. This suggests that shaly sediments become highly tortuous (higher *C*) by decreasing their electric conductivity (higher *F*). This relationship (*F-C*) in both figures also indicates that formation factor increases with increase of irregularity of grains. According to Fricke's equation (Eq. 2), the Kozeny-Carman constant (*C*) and the cementation factor (*m*), as well as the formation factor (*F*), are minimized by increasing sphericity of particles, and maximized by increasing irregularity of particles. The particle shape (as an important factor affecting both *C* and *m*) is clearly of particular importance in defining the magnitude of difference in formation factor values for spherical and non-spherical aggregates of particles. These results and the previous ones presented in this study suggest that the geometrical textural parameters (Φ, *T*, *k*, S_p, *F*, *m* and *C*) are strongly affected by variations in shape, packing and orientation of particles.

INTER-CONNECTION BETWEEN CEMENTATION FACTOR (ARCHIE'S EXPONENT) AND KOZENY-CARMAN CONSTANT

According to the following reasons, it is suggested that both parameters-cementation factor (*m*) and shape factor ($S_f = C/T$) cited in Archie-Winsauer and Kozeny-Carman equations, respectively, are analogous and probably can replace each other. (1) Cementation factor (*m*) is a parameter indicating electric conductivity in relation to formation resistivity factor (*F*), porosity (Φ) and textural tortuosity factor (*a*) in the Archie-Winsauer equation, and the shape factor (S_f), resulting from the Kozeny-Carman constant (*C*) divided by tortuosity (*T*), is a parameter indicating hydraulic conductivity in relation to permeability (*k*), porosity (Φ), tortuosity (*T*), surface area (S_p) of composite grains in Kozeny-Carman equation; (2) Both parameters (*m* and $C = TS_f$) are strongly related to tortuosity (*T*), and as previously indicated, both hydraulic and electric tortuosities are identical. Therefore, it may be suggested that the term "cementation factor" be renamed "shape factor". This is because, as discussed in this study and as indicated by Atkins and Smith[29], this factor (*m*) is strongly dependent on shape of particles and to a great extent is analogous to the shape factor given in the Kozeny-Carman equation. These ideas are supported by the high correlation coefficients of relationships (**Figures 5** and **6**) between formation factor (*F*) on the one hand, and *C1* (*T* times *m*, where *m* is cementation factor) and *C2* (*T* times S_f, where S_f is shape factor = 2.5) on the other. Also, relationships with moderate to high correlation coefficients (0.53-0.91) are obtained between *m* and *C2*.

CONCLUSIONS

Determinations of textural parameters such as porosity, permeability, tortuosity, grain size, specific surface area of composite grains, water saturation, anisotropy, cementation factor, and the Kozeny-Carman constant, are important elements in petrophysical studies of hydrocarbon reservoirs and groundwater aquifers. This study is one of several studies dealing with petrophysics of the Jeanne d'Arc Basin sediments, where cementation factor (Archie's exponent) and the Kozeny-Carman constant were derived for fourteen Hibernia and Terra Nova wells.

It was shown that cementation factor is strongly dependent on tortuosity, shape and surface area of composite particles. Because of the various physical effects of cementation factor on the physical behaviour of sediments, it has been given considerable attention by researchers, and accordingly has been given different names. This study shows that it is more accurate to rename the "cementation factor" as "shape factor", since it is strongly affected by the shape of particles and is analogous to the shape factor given in the Kozeny-Carman equation. This study also indicates that cementation factor (*m* approximately equal to shape factor, S_f) is maximized by irregularity increase and minimized by sphericity increase. Since the sediments in Hibernia and Terra Nova oil fields are rich in shales composed of a variety of clay minerals of plate-forms, *m* exhibits values almost exceeding 2.2. A value of 2.28 is suggested for the cementation factor (*m*) in the Archie-Winsauer equation when applied to shaly consolidated sediments saturated with multi-phase fluids.

The Kozeny-Carman constant (*C*) was obtained as the product of tortuosity (*T*) times cementation factor (*m*), and as *T* times a constant value of shape factor (S_f) equals 2.5. Relationships between both quantities (*Tm* and TS_f) show good correlations. This indicates that for highly compacted shaly sediments, as in the case of this study, cementation factor (m) should be higher than 2.0 and probably not less than 2.2 to 2.5.

A value of 7.5 is suggested for the Kozeny-Carman constant (C) in the Kozeny-Carman equation when applied to shaly formations of multi-phase fluids and highly saline water. Introducing tortuosity in calculations of the Kozeny-Carman constant, and the high correlation coefficients in the tortuosity-cementation factor relationships suggest that both parameters (m and C) are strongly influenced by tortuosity. The increase of tortuosity accompanying an increase in m and C for the same pore spaces and the same grains with the same surface areas, results in lower hydraulic conductivity and lower velocity of microscopic fluid flow. Also, the increase of m results in a higher formation resistivity factor or lower formation conductivity factor. This indicates that the increase of tortuosity also results in lower electric conductivity (higher resistivity). The increase of resistivity (increase of tortuosity) is a product of many factors such as low porosity and low permeability, low salinity and saturation of water in pore spaces, low effect of surface conductance of the double layer as a result of less activity of cation exchange capacity, and possibly poor sorting and orientation of grains which result in higher electric and hydraulic anisotropy coefficients.

NOMENCLATURE

a	= Tortuosity factor in Archie-Winsauer equation (dimensionless)
C	= Kozeny-Carman constant (dimensionless)
$C1$	= Kozeny-Carman constant (tortuosity times cementation factor, dimensionless)
$C2$	= Kozeny-Carman constant (tortuosity times shape factor, dimensionless)
CSSL	= Canadian Stratigraphic Service Ltd.
F	= Formation resistivity factor (dimensionless)
HIB	= Hibernia oil field
JDB	= Jeanne d'Arc Basin
k	= Permeability (md or cm^2)
m	= Cementation factor (Archie's exponent, dimensionless)
R_o	= Formation resistivity (Ω.m)

R_w = Pore water resistivity (Ω.m)

S_f = Shape factor (dimensionless)

S_p = Specific surface area of composite grains (cm^{-1})

T = Tortuosity (dimensionless)

TN = Terra Nova oil field

x = Variable for spheres and spheroids in Fricke's equation (dimensionless)

Φ = Porosity (fraction)

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SI METRIC CONVERSION FACTORS

bbl	x 1.589 873	E-01 = m^3
ft	x 3.048*	E-01 = m
in.	x 2.54*	E+00 = cm
micron	x 1.0*	E+00 = μm
mile	x 1.609 344*	E+00 = km
md	x 9.869 233	E-04 = μm^2

* Conversion factor is exact.

TABLE 1: Results of tortuosity (*T*), cementation factor (*m*), Kozeny-Carman constant ($C1 = Tm$ and $C2 = TS_f$, where S_f is shape factor = 2.5) at 10 m increments in relation to depth between 3848 and 4418 m for Hibernia B-08, between 4160 and 4370 m for Hibernia B-27, and between 4203 and 4403 m for Hibernia C-96, between 4055 and 4545 m for Hibernia K-18.

HIBERNIA B-08; INTERVAL DEPTH: 3848-4418 m; INCREMENT: 10 m.

DEPTH (m)	*T*	*m*	C1 (*Tm*)	C2 (TS_f)
3848	2.93	2.84	8.31	7.31
3858	2.36	2.40	5.66	5.90
3868	2.46	2.33	5.73	6.16
3878	2.36	2.32	5.47	5.90
3888	2.36	2.42	5.70	5.90
3898	2.77	2.48	6.87	6.92
3908	3.04	2.52	7.66	7.59
3918	2.04	2.43	4.97	5.10
3928	3.15	2.73	8.59	7.88
3938	2.33	2.18	5.06	5.82
3948	5.92	2.95	17.44	14.80
3958	2.18	2.24	4.88	5.45
3968	2.03	2.29	4.64	5.06
3978	3.15	2.28	7.20	7.89
3988	2.62	2.27	5.95	6.55
3998	2.61	2.34	6.11	6.53
4008	2.48	2.34	5.81	6.21
4018	2.91	2.25	6.55	7.29
4028	6.01	1.65	9.89	15.01
4038	3.37	2.30	7.74	8.43
4048	2.16	2.34	5.06	5.40
4058	3.06	2.35	7.20	7.64
4068	2.80	2.48	6.96	7.01
4078	3.33	2.24	7.48	8.33
4088	2.53	2.27	5.74	6.34
4098	2.63	2.25	5.92	6.58
4108	2.43	2.31	5.60	6.06
4118	2.40	2.23	5.34	5.99
4128	3.51	2.34	8.22	8.77
4138	3.02	2.24	6.76	7.56
4148	4.19	2.46	10.31	10.46
4158	7.49	2.54	19.02	18.72
4168	6.67	2.53	16.87	16.66
4178	2.90	2.28	6.62	7.25
4188	2.21	2.12	4.69	5.53
4198	2.33	2.53	5.89	5.81
4208	6.72	2.58	17.35	16.81
4218	2.67	2.17	5.80	6.68
4228	2.20	2.08	4.59	5.51
4238	3.80	2.25	8.55	9.50
4248	9.93	2.79	27.71	24.82
4258	4.28	2.39	10.21	10.69
4268	4.41	2.35	10.39	11.03
4278	4.28	2.27	9.70	10.70
4288	3.96	2.33	9.23	9.90
4298	4.46	2.39	10.63	11.14
4308	4.32	2.25	9.73	10.80
4318	3.02	2.32	7.01	7.54
4328	5.63	2.16	12.14	14.07
4338	3.64	2.27	8.25	9.09
4348	5.10	2.46	12.53	12.76
4358	5.51	2.19	12.09	13.77
4368	2.93	2.20	6.46	7.34
4378	3.33	2.33	7.76	8.33
4388	3.49	2.32	8.11	8.73
4398	4.36	2.39	10.43	10.90
4408	3.72	2.50	9.32	9.30
4418	3.03	2.49	7.55	7.58

HIBERNIA B-27; INTERVAL DEPTH: 4160-4370 m; INCREMENT: 10 m.

DEPTH (m)	*T*	*m*	C1 (*Tm*)	C2 (TS_f)
4160	2.07	2.32	4.80	5.17
4170	2.67	2.34	6.25	6.66
4180	2.29	2.44	5.59	5.73
4190	2.38	2.43	5.80	5.96
4200	2.29	2.44	5.59	5.73
4210	3.16	2.45	7.74	7.91
4220	2.34	2.42	5.66	5.85
4230	2.13	2.41	5.15	5.33
4240	2.86	2.48	7.10	7.15
4250	3.26	2.37	7.72	8.15
4260	2.70	2.40	6.46	6.74
4270	2.46	2.47	6.07	6.16
4280	3.42	2.91	9.93	8.54
4290	3.67	3.02	11.08	9.18
4300	2.44	2.31	5.64	6.10
4310	2.55	2.44	6.24	6.39
4320	3.37	2.29	7.71	8.42
4330	3.84	2.27	8.71	9.59
4340	3.44	2.22	7.64	8.61
4350	3.17	2.36	7.47	7.92
4360	3.12	2.38	7.42	7.81
4370	2.91	2.47	7.19	7.28

HIBERNIA C-96; INTERVAL DEPTH: 4203-4403 m; INCREMENT: 10 m.

DEPTH (m)	*T*	*m*	C1 (*Tm*)	C2 (TS_f)
4203	1.57	2.06	3.23	3.92
4213	1.75	2.13	3.72	4.37
4223	1.89	2.10	3.96	4.71
4233	1.89	1.97	3.72	4.71
4243	1.51	1.83	2.77	3.79
4253	2.03	2.23	4.55	5.09
4263	1.77	1.98	3.50	4.43
4273	1.85	2.12	3.92	4.63
4283	2.69	2.28	6.13	6.73
4293	1.72	2.11	3.64	4.30
4303	1.65	2.17	3.58	4.12
4313	1.85	2.07	3.84	4.63
4323	9.90	4.15	41.09	24.76
4333	2.01	2.12	4.27	5.02
4343	1.73	2.02	3.51	4.33
4353	1.81	2.09	3.78	4.52
4363	1.99	2.11	4.19	4.97
4373	1.97	2.09	4.10	4.91
4383	2.14	2.15	4.60	5.34
4393	1.77	2.07	3.67	4.42
4403	1.84	2.07	3.82	4.60

HIBERNIA K-18, INTERVAL DEPTH: 4055-4545 m; INCREMENT: 10 m.

DEPTH (m)	*T*	*m*	C1 (*Tm*)	C2 (TS_f)
4055	6.51	2.53	16.44	16.26
4065	7.78	2.26	17.60	19.45
4075	4.93	2.29	11.31	12.33
4085	4.41	2.25	9.94	11.03
4095	3.66	2.20	8.06	9.16
4105	5.59	2.19	12.27	13.97
4115	4.97	2.60	12.93	12.43
4125	3.71	2.15	7.98	9.27
4135	2.83	2.17	6.14	7.06
4145	3.34	2.21	7.38	8.36
4155	3.16	2.25	7.10	7.89
4165	3.03	2.30	6.96	7.57
4175	2.92	2.18	6.38	7.31
4185	4.01	2.19	8.76	10.02
4195	3.49	2.17	7.58	8.72
4205	4.12	2.17	8.93	10.30
4215	3.09	2.16	6.68	7.72
4225	5.48	1.84	10.08	13.70
4235	5.08	2.47	12.55	12.71
4245	4.50	2.66	11.97	11.25
4255	4.82	2.54	12.25	12.05
4265	2.54	2.20	5.58	6.34
4275	6.39	2.34	14.94	15.98
4285	3.59	2.19	7.87	8.98
4295	2.62	2.22	5.82	6.55
4305	2.43	2.25	5.47	6.08
4315	2.64	2.29	6.05	6.60
4325	3.03	2.30	6.97	7.57
4335	5.38	2.56	13.76	13.46
4345	4.21	2.19	9.22	10.53
4355	5.54	2.68	14.84	13.86
4365	4.53	2.28	10.32	11.33
4375	3.13	2.54	7.94	7.83
4385	2.35	2.25	5.29	5.88
4395	2.81	2.26	6.34	7.01
4405	2.28	2.34	5.33	5.69
4415	16.10	2.36	37.94	40.25
4425	3.17	2.40	7.61	7.91
4435	17.17	2.29	39.25	42.92
4445	4.96	2.32	11.50	12.40
4455	4.22	2.25	9.47	10.55
4465	4.05	2.12	8.59	10.12
4475	3.46	2.20	7.63	8.66
4485	2.35	2.15	5.05	5.87
4495	----	----	----	----
4505	----	----	----	----
4515	3.84	2.28	8.76	9.60
4525	6.12	2.26	13.82	15.30
4535	4.34	2.33	10.13	10.86
4545	7.27	2.31	16.79	18.18

TABLE 2: Results of tortuosity (*T*), cementation factor (*m*), Kozeny-Carman constant ($C = Tm$ and TS_f, where S_f is shape factor = 2.5) at 10 m increments in relation to depth between 3188 and 3548 m for Terra Nova C-09, 3125 and 3485 m for Terra Nova E-79, between 3072 and 3452 m for Terra Nova H-99, and between 3080 and 3350 m for Terra Nova I-97.

TERRA NOVA C-09; INTERVAL DEPTH: 3188-3548 m; INCREMENT: 10 m.

DEPTH (m)	T	m	C1 (Tm)	C2 (TS_f)
3188	1.81	2.15	3.90	4.53
3198	3.82	2.19	8.35	9.55
3208	2.18	2.22	4.84	5.45
3218	2.68	2.25	6.02	6.70
3228	2.24	2.22	4.96	5.59
3238	2.33	2.25	5.23	5.82
3248	3.43	2.31	7.91	8.57
3258	1.99	2.22	4.42	4.98
3268	1.93	2.21	4.27	4.83
3278	2.67	2.18	5.83	6.69
3288	5.69	2.27	12.91	14.23
3298	3.49	2.22	7.74	8.73
3308	3.12	2.22	6.91	7.80
3318	3.66	2.19	8.04	9.16
3328	4.74	2.18	10.35	11.86
3338	3.80	2.16	8.20	9.50
3348	7.02	2.11	14.79	17.55
3358	2.51	2.14	5.38	6.28
3368	2.23	2.28	5.08	5.58
3378	1.93	2.01	3.88	4.83
3388	6.69	2.11	14.14	16.73
3398	5.61	2.19	12.30	14.02
3408	----	----	-----	-----
3418	3.51	2.18	7.67	8.78
3428	2.72	2.49	6.78	6.80
3438	3.49	2.15	7.49	8.72
3448	1.86	2.27	4.23	4.66
3458	1.79	2.25	4.02	4.46
3468	2.23	2.15	4.78	5.56
3478	2.06	2.20	4.52	5.14
3488	2.03	2.06	4.17	5.07
3498	4.55	2.25	10.22	11.38
3508	3.83	2.21	8.47	9.58
3518	2.34	2.20	5.16	5.86
3528	2.35	2.23	5.24	5.87
3538	2.20	2.18	4.81	5.50
3548	2.29	2.17	4.95	5.71

TERRA NOVA E-79; INTERVAL DEPTH: 3125-3485 m; INCREMENT: 10 m.

DEPTH (m)	T	m	C1 (Tm)	C2 (TS_f)
3125	1.92	2.23	4.27	4.79
3135	2.59	2.19	5.68	6.48
3145	1.93	2.25	4.33	4.82
3155	2.65	2.27	6.03	6.63
3165	2.30	2.21	5.09	5.76
3175	2.39	2.23	5.33	5.98
3185	2.92	2.28	6.65	7.30
3195	2.52	2.20	5.54	6.29
3205	2.26	2.16	4.87	5.64
3215	3.08	2.24	6.90	7.69
3225	1.95	2.36	4.61	4.87
3235	1.37	1.93	2.64	3.42
3245	2.53	2.21	5.59	6.33
3255	3.06	2.18	6.66	7.64
3265	3.57	2.16	7.72	8.92
3275	1.56	2.09	3.25	3.89
3285	1.83	2.19	3.99	4.57
3295	2.09	2.17	4.55	5.23
3305	2.58	2.23	5.77	6.46
3315	2.24	2.10	4.69	5.59
3325	2.38	2.18	5.20	5.96
3335	1.71	2.11	3.61	4.27
3345	4.46	2.17	9.66	11.16
3355	1.95	2.24	4.38	4.88
3365	2.10	2.22	4.67	5.25
3375	1.85	2.22	4.10	4.63
3385	2.22	2.22	4.93	5.55
3395	2.66	2.17	5.78	6.64
3405	2.37	2.19	5.19	5.93
3415	2.45	2.15	5.26	6.12
3425	2.42	2.18	5.26	6.05
3435	2.95	2.18	6.43	7.37
3445	2.21	2.20	4.88	5.54
3455	2.42	2.24	5.44	6.06
3465	1.89	2.19	4.15	4.74
3475	2.42	2.22	5.37	6.06
3485	1.54	2.25	3.46	3.84

TERRA NOVA H-99; INTERVAL DEPTH: 3072-3452 m; INCREMENT: 10 m.

DEPTH (m)	T	m	C1 (Tm)	C2 (TS_f)
3072	3.05	2.24	6.81	7.62
3082	1.90	2.37	4.51	4.75
3092	1.95	2.36	4.60	4.86
3102	1.81	2.33	4.22	4.52
3112	2.72	2.25	6.14	6.81
3122	1.76	2.29	4.04	4.41
3132	2.98	2.25	6.71	7.46
3142	2.03	2.31	4.69	5.06
3152	2.97	2.26	6.70	7.43
3162	5.64	2.14	12.08	14.09
3172	1.71	2.25	3.85	4.29
3182	6.80	1.95	13.25	17.00
3192	1.35	2.70	3.65	3.38
3202	1.35	2.49	3.36	3.37
3212	1.06	1.83	1.94	2.64
3222	2.06	2.23	4.59	5.15
3232	3.87	2.94	11.38	9.67
3242	6.27	3.46	21.71	15.67
3252	1.91	2.36	4.51	4.78
3262	4.59	2.65	12.14	11.47
3272	2.01	2.21	4.43	5.03
3282	6.54	2.57	16.83	16.34
3292	2.53	2.40	6.08	6.32
3302	2.97	1.51	4.48	7.43
3312	6.07	2.29	13.89	15.18
3322	3.42	2.37	8.12	8.56
3332	1.80	1.30	2.34	4.49
3342	----	----	----	----
3352	10.75	2.54	27.24	26.86
3362	1.90	2.04	3.88	4.74
3372	10.29	2.40	24.74	25.72
3382	1.49	2.45	3.64	3.72
3392	4.50	2.24	10.10	11.25
3402	4.52	2.22	10.05	11.30
3412	6.66	2.13	14.17	16.66
3422	3.13	2.34	7.33	7.83
3432	4.39	2.34	10.28	10.97
3442	8.44	2.27	19.13	21.11
3452	4.38	2.38	10.41	10.95

TERRA NOVA I-79; INTERVAL DEPTH: 3080-3350 m; INCREMENT: 10 m.

DEPTH (m)	T	m	C1 (Tm)	C2 (TS_f)
3080	1.70	2.24	3.81	4.25
3090	1.66	2.30	3.82	4.15
3100	1.65	2.24	3.69	4.12
3110	1.77	2.30	4.08	4.43
3120	1.86	2.29	4.25	4.65
3130	1.98	2.43	4.81	4.95
3140	2.74	2.37	6.50	6.86
3150	2.75	2.46	6.75	6.87
3160	1.88	2.31	4.35	4.71
3170	2.80	2.58	7.22	7.00
3180	2.56	2.32	5.95	6.40
3190	2.15	2.28	4.90	5.37
3200	2.31	2.34	5.41	5.78
3210	2.85	2.43	6.94	7.12
3220	2.04	2.29	4.67	5.10
3230	2.61	2.30	6.01	6.54
3240	1.87	1.88	3.51	4.67
3250	2.90	2.41	6.98	7.25
3260	1.95	2.18	4.24	4.87
3270	3.08	2.18	6.72	7.70
3280	0.93	1.26	1.17	2.33
3290	3.31	2.26	7.47	8.27
3300	2.51	2.13	5.33	6.27
3310	4.25	2.73	11.60	10.63
3320	1.59	1.63	2.61	3.98
3330	3.24	2.86	9.26	8.09
3340	2.16	2.37	5.12	5.41
3350	2.38	2.32	5.52	5.96

TABLE 3: Interval depth and general ranges of tortuosity (T), cementation factor (m), and Kozeny-Carman constant ($C = Tm$ and TS_f, where S_f is shape factor = 2.5) from 10 m sample increments of four Hibernia and four Terra Nova wells.

WELL NAME	INT. DEPTH (m)	T	m	$C1 = Tm$	$C2 = TS_f$
HIB B-08	3848-4418	2.03-9.93	1.65-2.95	4.59-27.71	5.06-24.82
HIB B-27	4160-4370	2.07-3.84	2.22-3.02	4.80-11.08	5.17-9.59
HIB C-96	4203-4403	1.51-9.90	1.83-**4.15**	2.77-**41.09**	3.79-24.76
HIB K-18	4055-4545	2.28-**17.17**	1.84-2.68	5.29-39.25	5.69-**42.92**
TN C-09	3188-3548	1.79-7.07	2.01-2.49	3.88-14.79	4.46-17.55
TN E-79	3125-3485	1.37-4.46	1.93-2.36	2.64-9.66	3.42-11.16
TN H-99	3072-3452	1.06-10.75	1.30-3.46	1.94-27.24	2.64-26.86
TN I-97	3080-3350	**1.00**-4.25	**1.26**-2.73	**1.17**-11.60	**2.33**-10.63

NOTE: The underlined values indicate minimum and maximum values in each oil field, and the **underlined and dark** values indicate minimum and maximum values in general. For Tables 1, 2 and 3, T, m, S_f, $C1$ and $C2$ are dimensionless parameters.

FIGURE CAPTIONS

FIGURE 1: Relationship between tortuosity and cementation factor for Hibernia C-96 well.

FIGURE 2: Relationship between surface area of composite grains and cementation factor for Hibernia C-96 well.

FIGURE 3: Relationship between permeability and Kozeny-Carman constant for Hibernia B-27 well.

FIGURE 4: Relationship between surface area of composite grains and Kozeny-Carman constant for Hibernia B-27 well.

FIGURE 5: Relationship between formation resistivity factor and Kozeny-Carman constant (Tm) for Terra Nova E-79 well.

FIGURE 6: Relationship between formation resistivity factor and Kozeny-Carman constant (TS_f) for Terra Nova E-79 well.

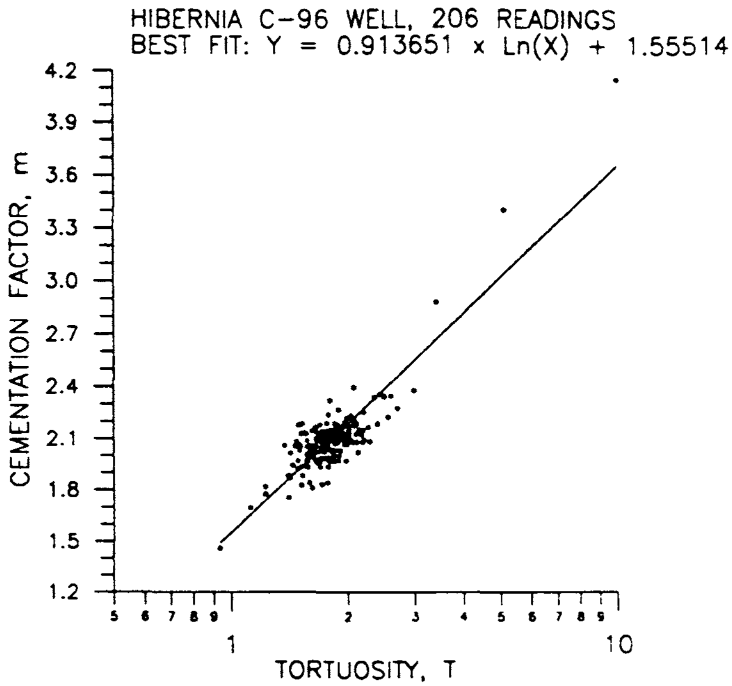

FIGURE 1: Relationship between tortuosity and cementation factor for Hibernia C-96 well.

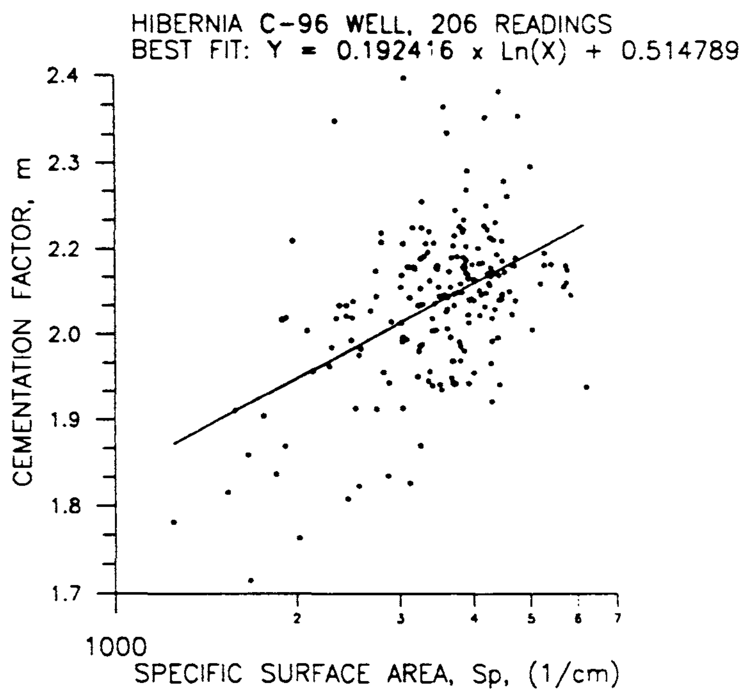

FIGURE 2: Relationship between surface area of composite grains and cementation factor for Hibernia C-96 well.

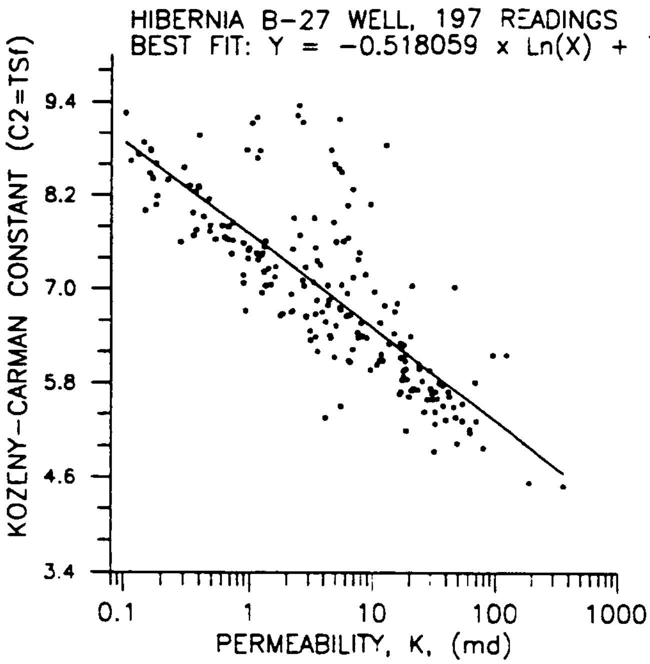

FIGURE 3: Relationship between permeability and Kozeny-Carman constant for Hibernia B-27 well.

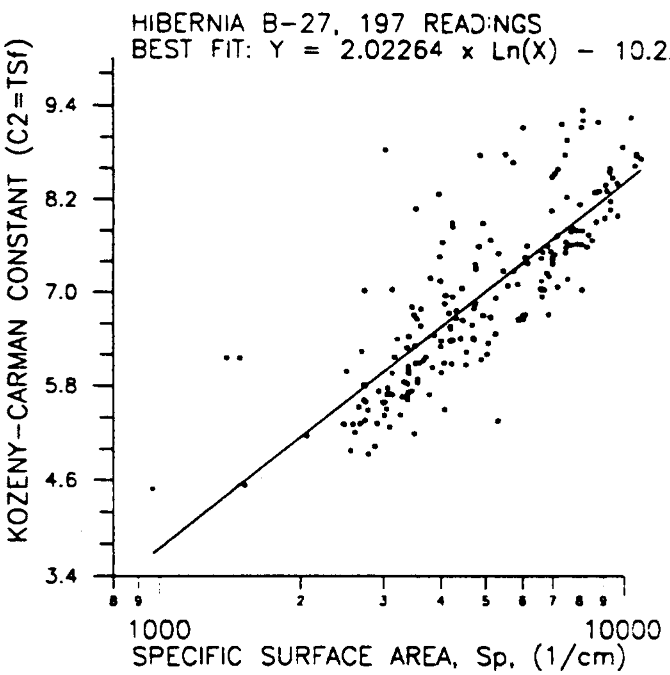

FIGURE 4: Relationship between surface area of composite grains and Kozeny-Carman constant for Hibernia B-27 well.

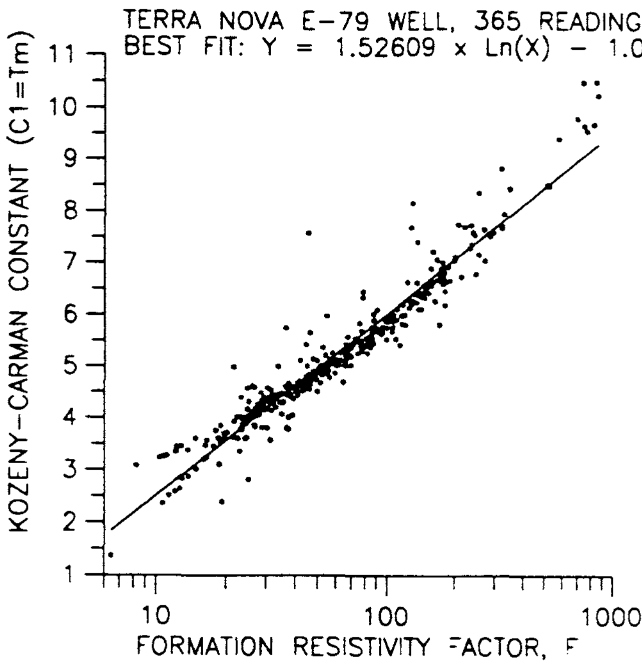

FIGURE 5: Relationship between formation resistivity factor and Kozeny-Carman constant (*Tm*) for Terra Nova E-79 well.

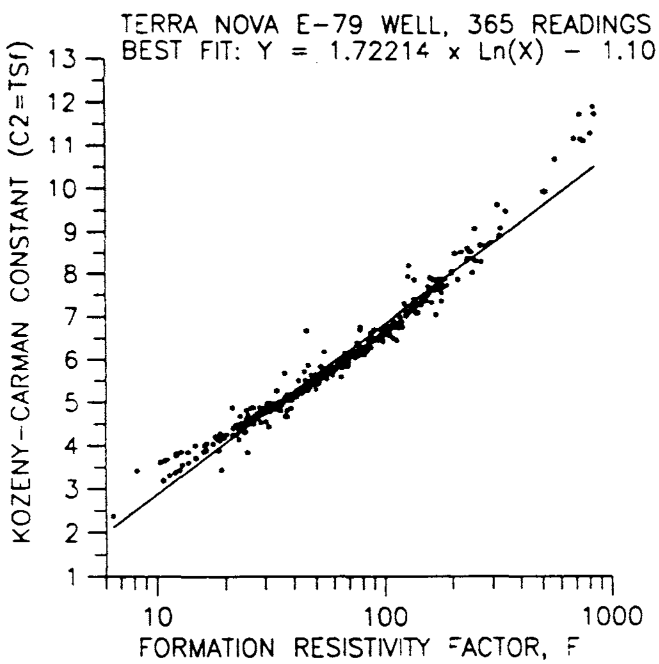

FIGURE 6: Relationship between formation resistivity factor and Kozeny-Carman constant (TS_f) for Terra Nova E-79 well.