# FORMATION FACTOR RELATIONSHIPS OF WESTERN CANADA

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## ABSTRACT

Archie's formation resistivity factor and saturation exponent equations are the basis of quantitative log analysis. Canadian practitioners of formation evaluation in Alberta are fortunate that formation factor measurements are catalogued and made available to the public under Section 11.040 of the Alberta Oil and Gas Conservation Regulations. Access to this information presented the opportunity to evaluate the 'a', 'm' and 'n' terms with respect to overburden stress dependency, the variability of the values, lithology dependence and the possible interdependence of these three parameters.

Over 140 special core studies were collected from the list provided in the December 1991 Energy Conservation Board PVT and Core Studies Index and from a list of special core analyses provided by the Saskatchewan Energy and Mines. Noticeable increases in cementation exponent occurred when core was subjected to overburden stress. Stressed formation factor values changed log-derived water saturations to the degree that the use of values obtained at surface pressure is invalid. An empirical correlation between 'a' and 'm' is derived and discussed. This correlation brings into question the assumption of 'a' equalling one in the Archie equation $F = a/Ø^m$. The use of stressed formation factor values, the wide variability in 'a' and 'm' and the fact that 'n' frequently is not equal to two (2) are shown to have large effects on water saturation and oil and gas reserve calculations.

## INTRODUCTION

Despite the rapid advances in logging tool design, measurement accuracy, and mathematical modelling, the empirically derived Archie equation remains the basis of water saturation determination (Archie, 1942). When attempting to relate rock electrical properties to permeability on Gulf Coast sands, Archie found no relation. He did discover an empirical relationship between core porosity and formation factor. Sundberg (1932) had previously described formation factor or resistivity factor as the resistivity of a porous material 100% saturated with brine divided by the resistivity of the saturating brine. The relationship Archie established became known as the Archie equation:

$$F = \frac{Ro}{Rw} = \frac{1}{Ø^m}$$

where:

- F = formation factor
- Ro = resistivity of a brine-saturated porous material
- Rw = resistivity of the saturating brine
- Ø = porosity
- m = cementation exponent

Guyod (1944) named 'm' the cementation exponent, since the formation factor for any given porosity tended to increase as a sandstone became cemented. Atkin (1961) called 'm' the shape factor. He found that 'm' was a constant for particles of a given shape over a given porosity range. The cementation factor 'm'has been found to be a function of the ratio of pore area to pore throat size (Ehrlich *et al*, 1991). The larger this ratio the greater is the 'm' (Hilchie, 1984). Today, Archie's equation is widely and often indiscriminately applied with 'm' equalling two (2) when not actually measured.

## EARLY CONCEPTS OF FORMATION FACTOR

Winsauer *et al* (1952) noted considerable variance in the cementation exponent. He related apparent cross-sectional area and effective tortuous length available to a current flowing through a brine-saturated sand. He and his colleagues published the theoretical equation:

FF

$$F = \frac{T}{Y}$$

where:

T = tortuosity, defined as the ratio of the actual length of the sinuous porous channels in a brine-saturated rock traversed by an electric current travelling between two points within the rock, to the straight line distance between the two points

Y = ratio of the apparent cross-sectional area of the electrolyte-filled pore space to the total cross-sectional area of the rock.

Further, if porosity = Y * T, then

$$F = \frac{T^2}{\emptyset}$$

By indirectly measuring tortuosity on twenty sandstone samples from a variety of regions in the continental United States, they developed the empirical relation:

$$F = \frac{T^{1.67}}{\emptyset}$$

They derived the now famous Humble equation using a correlation between F and porosity:

$$F = \frac{0.62}{\emptyset^{2.15}}$$

The general form of this equation is:

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

where 'a' later became known as the tortuosity exponent (Gomez-Rivero, 1977).

Perkins *et al* (1956), in a review of Winsauer *et al* (1952)'s tortuosity experiment thought that there had been an error in the technique. Reinvestigating the tortuosity measurement with their own experiment, they found the resistivity factor could indeed, as theory dictated, be related to the tortuosity and porosity of the rock by:

$$F = \frac{T^2}{\emptyset}$$

The concept of tortuosity occupied much of the early work on formation factor. Rock pore geometries, however, were much too complex to be modeled by this simple concept. With some mathematical derivations, Towle (1962) concluded that tortuosity models applied to tubes or planes of constant cross-sectional area. Pore systems comprised of vugs were controlled not by tortuosity but by the accessibility of that vug to the electrical current; in other words, the pore throat constriction.

Neither tortuosity nor pore throat constriction alone accounts for formation factor variance. Pore constriction and tortuosity are interrelated (Owen, 1952). Both cross-sectional area and length of the current path affect resistivity values and are part of the natural rock pore systems. The infinite number of interactions of these two factors precludes any universal application of a constant 'a' and 'm' (Etris *et al*, 1989). In fact, within any single reservoir there is likely several formation factor relationships as the pore system varies with facies, diagenesis, dissolution, and cementation.

## FACTORS AFFECTING 'a' AND 'm'

Researchers have shown that a number of factors determine the tortuosity ('a') and the cementation factor ('m'). These factors include insitu stress (overburden pressure) (Fatt, 1957), reservoir temperature (Helander and Campbell, 1966, and Brannan and Von Gonten, 1973), brine resistivity (Brannan and Von Gonten, 1973), lithology (including conductive minerals) (Waxman and Thomas, 1974), particle shape (Jackson *et al*, 1978) and pore and pore throat geometry (Towle, 1962). The first four factors are important for the measurement of formation factor.

During early lab experiments, Archie and Winsauer *et al* failed to consider the effects of overburden stress. Fatt (1957) noted that the error in water saturation calculation when neglecting overburden pressure effects on formation factor could be significant. Using twenty sandstone samples geographically distributed throughout the United States, he observed an increase in formation factor and a decrease in porosity as pressure was applied. Helander and Campbell (1966) hypothesized that this behavior was due to decreased pore throat size (especially the smaller pore throats) and increasing tortuosity as some current flow paths were closed. Current standard industry practice (since the mid-1980's) is to measure porosity and formation factor at hydrostatic (overburden) pressure conditions.

Helander and Campbell (1966) and Brannan and Von Gonten (1973) found that formation temperature has a large effect on the measured formation factor. They showed that as temperature rises the formation factor increases ('a' increases and 'm' decreases). This was attributed to changes in pore constriction and tortuosity. Published research on this subject is minimal. Further study is necessary to confirm this conclusion. Industry generally does not measure formation factor and porosity at formation temperatures because of the large expense.

Researchers and industry recognize that formation factors must be measured using a brine with a resistivity appropriate to the formation being studied (Brannan and Von Gonten, 1973; Vinegar and Waxman, 1984). The use of an incorrect brine will cause the formation factor to increase ('a' decreases and 'm' increases) as the brine salinity increases.

Considerable effort has been directed to the determination of shaly sand water saturation. Conductive clays lower the resistivity measured on core in the lab and in the field. Although procedures have been developed to obtain the clay-corrected formation factor $F^*$ (Keelan, 1982), consideration of the magnitude of the effect of minor quantities of conductive and semi-conductive minerals such as pyrite and clays is often ignored in special core analysis. Formation factor relationships derived from these analyses may lead to erroneous log interpretation.

## NON-LINEARITY OF THE FORMATION FACTOR - POROSITY RELATIONSHIP

Petrophysicists have debated the accuracy of the Winsauer *et al* equation, which does not satisfy the condition F = 1.0 (where F = Ro/Rw) when porosity = 100%. Pérez-Rosales (1982), applying Maxwell's equations, determined that for homogeneous pore geometries such as spheres or cubes the formation factor - porosity relationship was nonlinear at high porosities. Sethi (1979) earlier had voiced the opinion that 'm' was nonlinear at porosities above 35%. A nonlinear 'm' allows 'a' to equal one at 100% porosity. The region of practical interest below 35% porosity was approximately linear and could be approximated by Winsauer *et al*'s generalized Archie equation. Archie's equation may be thought of as a special case of $a\O^{-m}$ (Wyllie and Gregory, 1953).

## ARCHIE'S SECOND RELATIONSHIP

In addition to a formation factor - porosity correlation, Archie (1942) observed that water saturation data versus the Rt/Ro ratio plotted on a semi-log plot was linear with slope 'n', where:

Rt = resistivity of the fully or partially brine - saturated rock

Ro = resistivity of the fully brine saturated rock

His conclusion was:

$$SW = (Rt/Ro)^{(-1/n)}$$

where 'n' became known as the saturation exponent. He further stated that 'n' was approximately two (2). Lewis *et al* (1988) found 'n' to vary between 1.2 and 5.2 depending on stress and rock-fluid wettability. The exponent is also dependent on several other interrelated factors, including pore geometry (Rasmus, 1986), the proportion of micro-porosity versus macro-porosity (Dixon *et al*, 1990), rock heterogeneity (Argaud, 1990), brine resistivity (Waxman and Thomas, 1974), fluid saturation distribution (Rasmus, 1986), and the direction of saturation change (Longeron *et al*, 1986). A linear exponential relationship between resistivity index and water saturation is usually but not always present. When two conductive paths occur in a rock, one of which is pores containing mobile water and the other is conductive minerals / clays, non-linearity results (Givens and Schmidt, 1988). Many Middle East carbonates and conductive clay-rich clastics exhibit non-linear resistivity indexes due to a high proportion of micro-porosity versus macro-porosity.

## PREVIOUS WORK IN WESTERN CANADA

The only previously published examination of formation factors in Western Canada was in 1968 by Smith. He gathered formation factors from core and logs on sixteen reservoirs using the limited data set available at the time. The majority of the formation factors were calculated from logs in water wet formations. Comparing log-calculated formation factors and core-derived formation factors, he emphasized the importance of acquiring lab data at confining stress. Better agreement between log formation factors and core formation factors occurred when the latter were taken under simulated overburden conditions. Information on the variance of the saturation exponent 'n' has not been previously compiled in Western Canada. Easy accessibility of a more complete data base twenty-five years later prompted this study. It also presented an opportunity to make the petrophysical and geological community aware that for a minimal fee, rock electrical properties on a wide variety of Canadian reservoirs is publicly available under provincial legislation. Section 11.040 (2) of the Alberta Oil and Gas Conservation Regulations requires the submission to the Energy Resources Conservation Board of tests performed on actual core samples for the purpose of estimating the initial fluid saturations and their distribution. The information is made available to the public as prescribed by Section 12.150 (5) (a) after a confidentiality period of one year.

## METHODOLOGY

The Alberta Energy Resource Conservation Board's December 1991 PVT and Core Studies Index lists 246 core electrical property studies under Special Core Analysis, many of which are multi-well studies. Over 140 of these studies were selected for inclusion in a data base. Where a well was listed in both an individual study and as part of a multi-well study, the multi-well study was given preference. Data obtained under simulated reservoir overburden stress were given preference. There was also a desire to cover as many different formations as possible. In total, information on 32 sandstone formations involving 79 fields and 21 carbonate formations from 59 fields was gathered. The formations ranged in age from Late Cretaceous to Early Devonian. Some of the special core analysis studies were excluded because of data that was suspect in some manner (e.g. contamination). Many of the studies were not performed under overburden pressures; many of the studies that were performed under overburden stress measured only the formation factor under stress and not the porosity, thus introducing a systematic error in 'a' and 'm' measurements. Although the change in 'a' and 'm' is minor (Figure 1 is a typical example), these studies were not considered to be done under rigorous enough conditions to be used in the derivation of the various equations or in the construction of the graphs. Standard linear regression was performed on all data. Correlations were quality graded as follows with respect to the regression coefficient (r): $r \geq 0.95$ excellent, $r = 0.90$ to $0.95$ good, $r = 0.85$ to $0.90$ fair, and $r \leq 0.85$ poor. Only data with a regression coefficient of .90 or greater is used in this paper. At ambient conditions 98 values of 'm' met this criteria, at varying overburden pressures 49 values of 'm' met the criteria and 123 values of 'n' met the criteria.

## DISCUSSION OF RESULTS

A wide variance in 'a', 'm' and 'n' values was found to exist in Western Canada.

At ambient confining pressures, clastics exhibit cementation exponents ('m') varying from 0.83 to 2.84 (Figure 2a) with tortuosity factors ('a') ranging from 0.25 to 9.40. At varying overburden pressures, clastics exhibit cementation exponents ('m') varying from 1.0 to 4.46 (Figure 2b) with tortuosity factors ('a') ranging from 0.03 to 9.55. The saturation exponent ('n') ranges from 1.31 to 2.84, (with one exception at 5.48) (Figure 4a). The median values of 'a' and 'm' are 2.74 and 1.83, respectively, at varying overburden pressures and 2.15 and 1.54, respectively, at ambient pressure. The median value of 'n' is 1.99.

At ambient confining pressures, carbonates exhibit cementation exponents ('m') varying from 0.93 to 2.75 (Figure 3a) with tortuosity factors ('a') ranging from 0.37 to 12.02. At varying overburden pressures, carbonates exhibit cementation exponents ('m') varying from 1.03 to 2.71 (Figure 3b) with tortuosity factors ('a') ranging from 0.27 to 15.43. The saturation exponent ('n') ranges from 1.08 to 2.12 (with one exception at 4.46) (Figure 4b). The median values of 'a' and 'm' are 3.42 and 1.95, respectively, at varying overburden pressures and 2.70 and 1.78, respectively, at ambient pressure. The median value of 'n' is 1.75.

Gómez-Rivero (1977) was the first to recognize an interdependence between 'a' and 'm', based on an extensive evaluation of wells in Mexico. He published two equations, one for sandstones and one for carbonates:

Sandstones

$$m = 1.8 - 1.29 * \log a$$

Carbonates

$$m = 2.03 - 0.9 * \log a$$

Re-analysing his original data for comparison purposes to match our equations gives:

Sandstones

$a = 2.527 * m^{-1.186}$

Carbonates

$a = 8.560 * m^{-2.838}$

Gómez-Rivero postulated that the variation of 'a' with 'm' was due to the amount of porosity and the degree of pore heterogeniety.

A similar correlation was found to exist in western Canada between 'a' and 'm' for both clastics (Figure 5) and carbonates (Figure 6) and at both ambient and overburden pressures. These correlations, which hold for all porosity types, are:

Clastics

ambient pressure

$a = 5.031 * m^{-2.879}$ (r = .970)

overburden pressure

$a = 9.143 * m^{-3.639}$ (r = .971)

Carbonates

ambient pressure

$a = 10.133 * m^{-3.320}$ (r = .970)

overburden pressure

$a = 17.950 * m^{-3.764}$ (r = .973)

The clastic ambient relation fits extensive statistical data gathered by Carothers (1968) and by Timur *et al* (1972) on sandstone formations. The former study included 793 formation factor measurements and the latter study included 1833 formation factor measurements. The reasons for the interdependence of 'a' and 'm' requires further study beyond the scope of this paper.

Establishment of these relationships allowed the creation of generalized formation factor - porosity equations, where 'm' is averaged and 'a' is calculated:

Clastics

ambient pressure

$F = 1.438 / Ø^{1.545}$

overburden pressure

$F = 1.006 / Ø^{1.834}$

Carbonates

ambient pressure

$F = 1.494 / Ø^{1.780}$

overburden pressure

$F = 1.468 / Ø^{1.945}$

Figure 7 compares the classic Archie and Humble equations to these Canadian equations.

Carothers (1968) developed a general relation for sandstone formations in the United States:

$F = 1.45 / Ø^{1.54}$

His analysis on core at ambient conditions complements and confirms the Western Canada equation.

The interdependence of 'm' versus 'n' was plotted for both clastics (Figure 8a) and carbonates (Figure 8b). In both cases no relationship was found.

The importance of knowing 'a', 'm' and 'n' accurately may be quantified by plotting water saturation values calculated with a=1, m=2 and n=2 on the x-axis versus water saturation values as one parameter is varied on the y-axis. Figure 9a shows the change in water saturation as 'a' is varied, Figure 9b demonstrates the change in water saturation as 'm' is varied and Figure 9c illustrates the change in water saturation as 'n' is varied. Little absolute change occurs at low water saturations or at high porosities. However, shifts in saturation induced by varying 'a' and 'm' are significant at high water saturations and low porosities. A change in the value of 'n' does not shift the calculated water saturation to a great degree. Ranked in declining importance are 'm', 'a' and 'n'. Correct values of 'a', 'm' and 'n' are important to accurately calculate water saturation for reserve purposes and to determine the position of transition zones and oil/water contacts.

Tortuosity either increased or decreased with stress. No trend was apparent. Cementation factors generally increased with stress. However, no relation between the magnitude of the change, rock pore type and stress was evident. For this analysis the data set size was increased to include non-stress adjusted porosity.

## CONCLUSIONS

1. 'a' is not independent of 'm' and therefore cannot be fixed at one.

2. For most rocks (both clastics and carbonates) 'a' is greater than 1 and 'm' is less than 2.

3. Carbonates generally have larger cementation exponents and smaller saturation exponents than clastics.

4. 'a' and 'm' are related mathematically.

5. No relationship is evident between 'm' and 'n'.

6. 'n' is usually less than 2 for carbonates.

7. 'n' is approximately normally distributed about 1.93 for clastics.

8. The wide variability in reservoir formation factor - porosity relationships precludes the widespread application of any single 'a', 'm' and 'n' value.

9. Formation factors measured under overburden stress are significantly different than those determined at ambient conditions.

## ACKNOWLEDGMENTS

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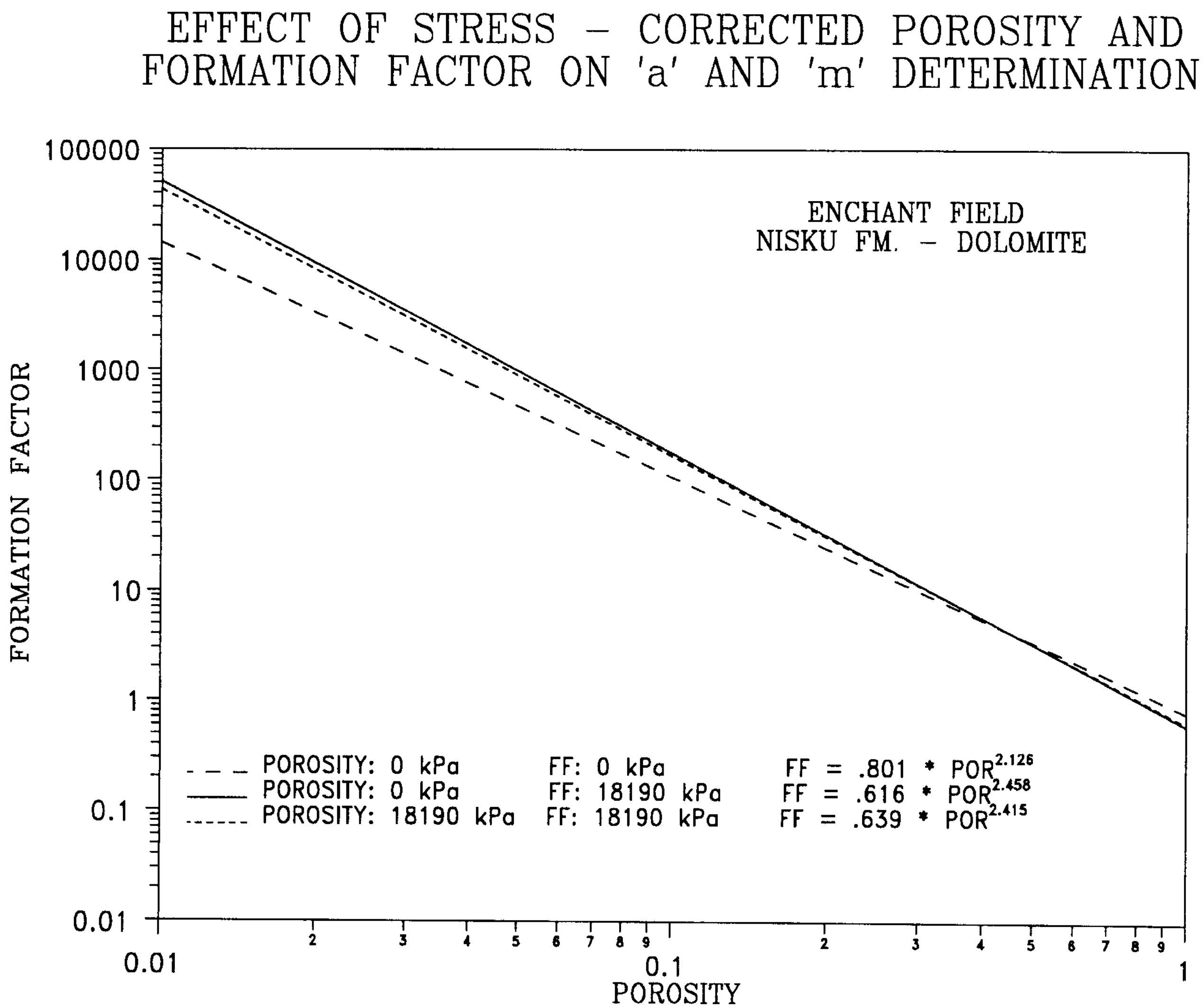


Figure 1. The effect of stress on porosity must be recorded prior to linear regression. This dolomite's tortuosity ('a') and cementation ('m') factors change when stress effects on porosity are taken into account.

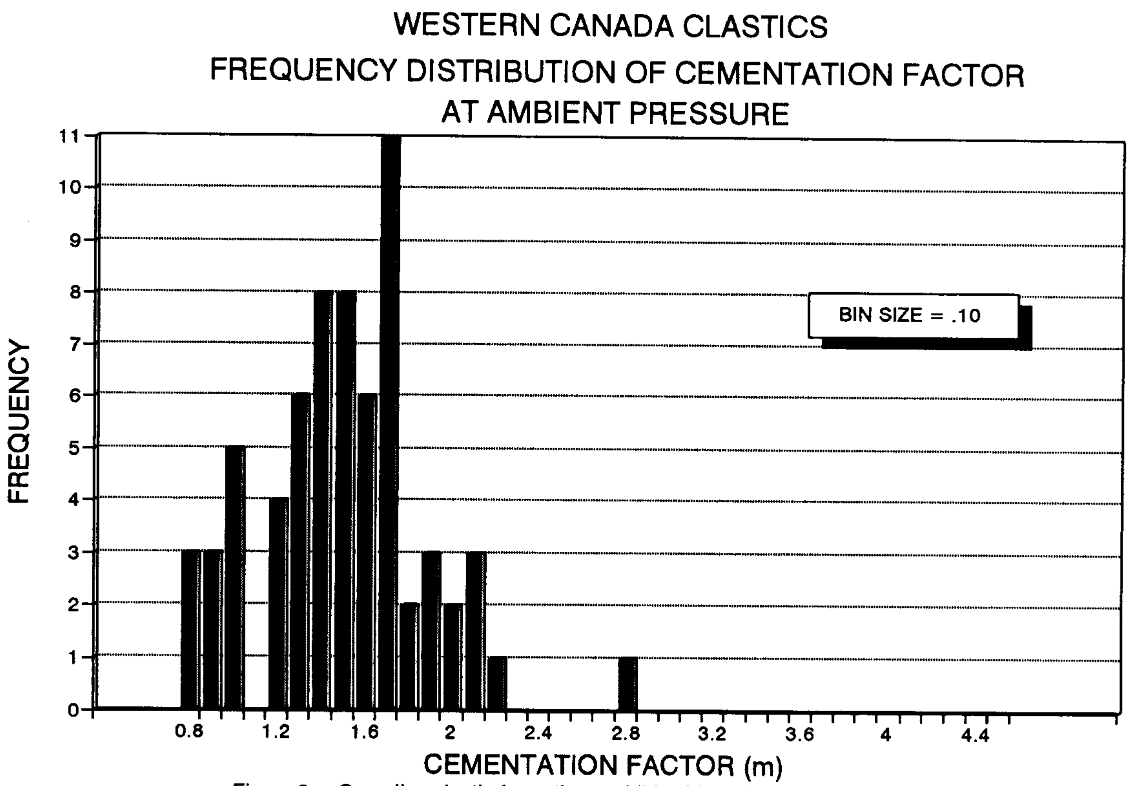


**Figure 2a.** Canadian clastic formations exhibit wide variability of cementation factors under ambient conditions.

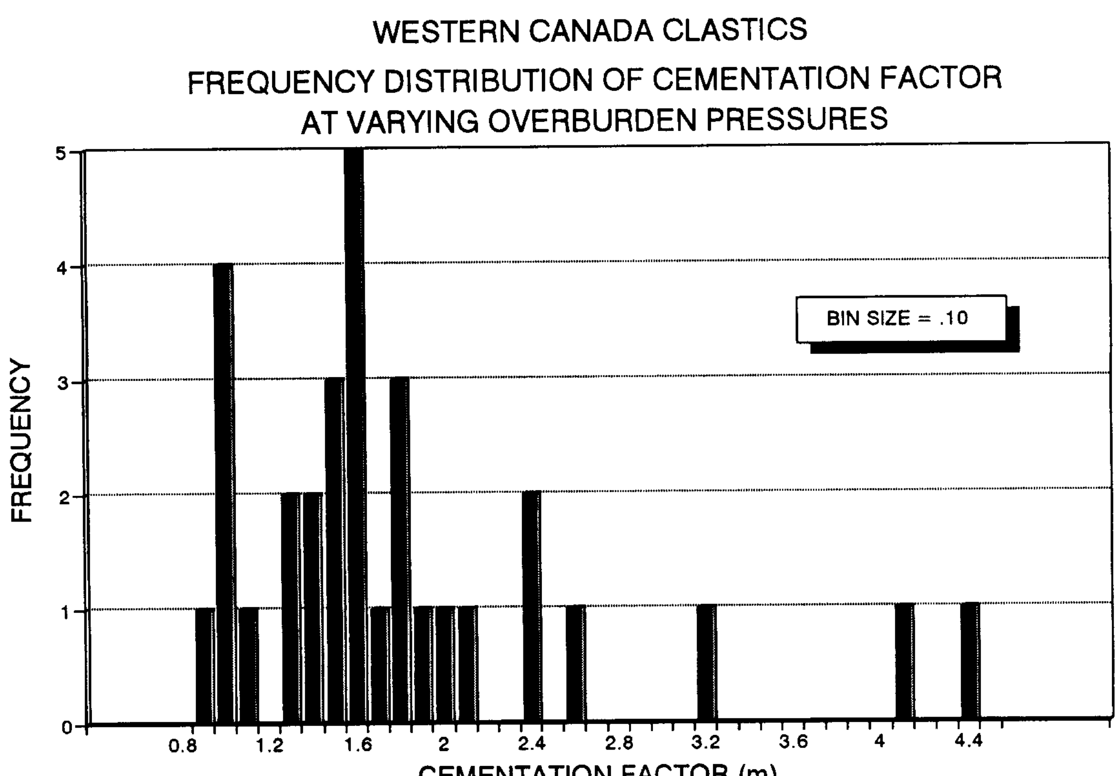


**Figure 2b.** At stress, cementation factors for Canadian clastics still show a wide variability and are frequently less than two with a variable tortuosity exponent 'a'.

FF

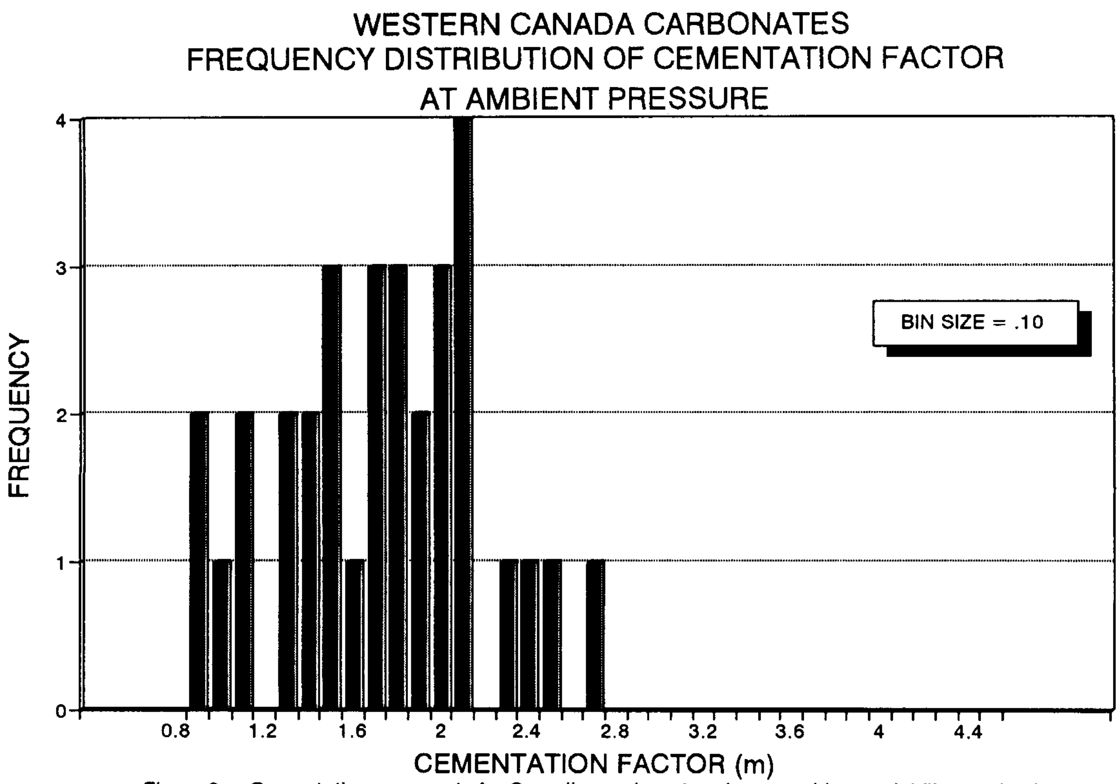


Figure 3a. Cementation exponents for Canadian carbonates show as wide a variability as clastics at ambient conditions, but are generally greater.

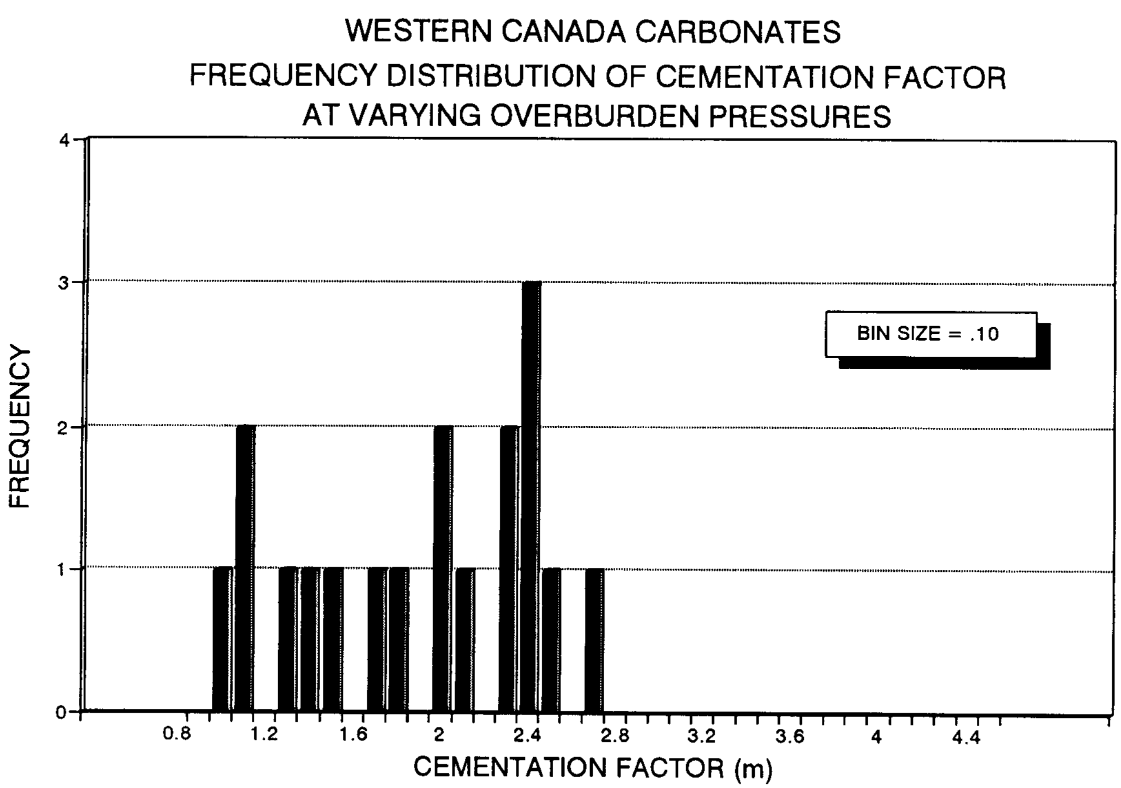


Figure 3b. Stress increases the cementation exponent of Canadian carbonates. No general value may be applied to water saturation calculations.

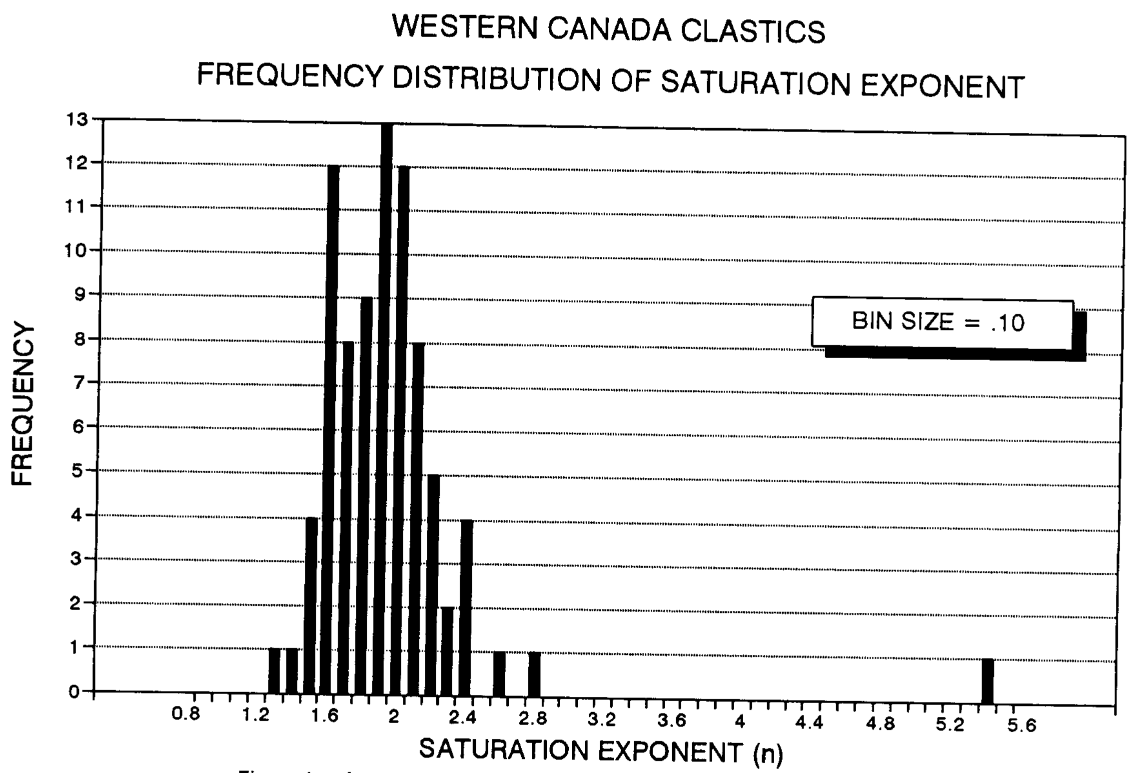


Figure 4a. An approximate normal distribution of saturation exponents around 1.9 exists for Canadian clastic formations.

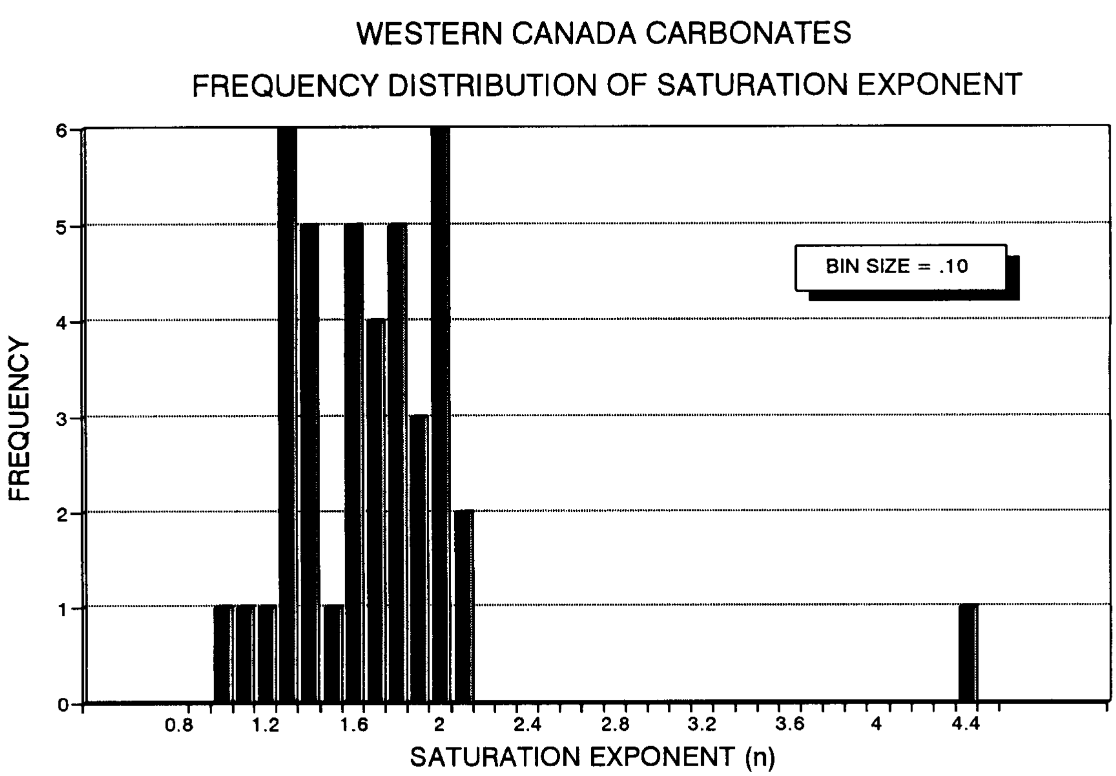


Figure 4b. The majority of saturation exponents for Canadian carbonates are less than two.

FF

WESTERN CANADA WATER SATURATION PARAMETERS
CLASTICS
a VS m AT ATMOSPHERIC PRESSURE

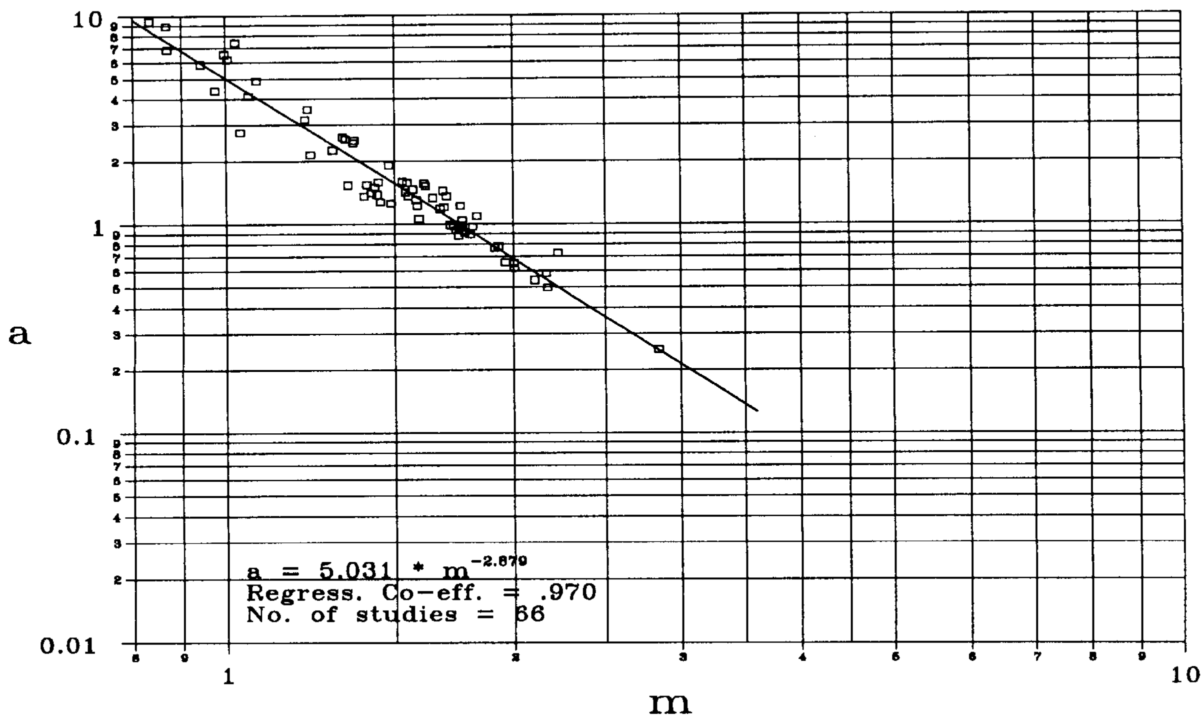


**Figure 5a.** A relationship between 'a' and 'm' is evident.

WESTERN CANADA WATER SATURATION PARAMETERS
CLASTICS
a VS m AT OVERBURDEN PRESSURE

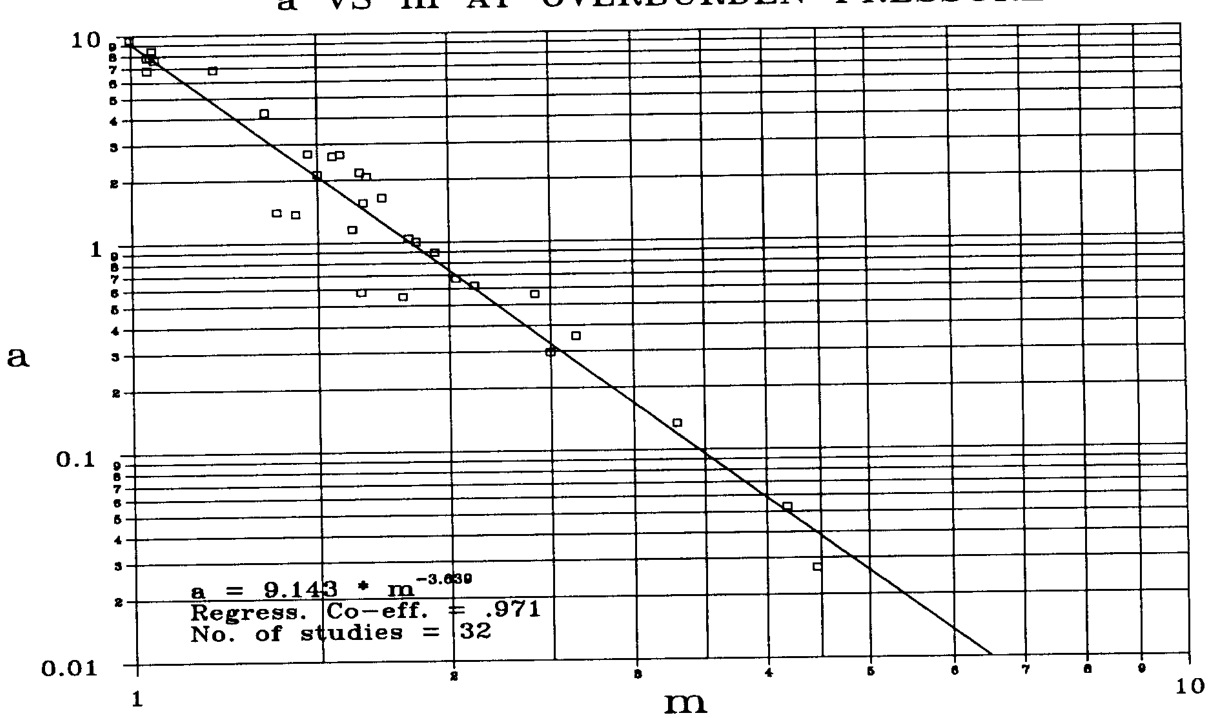


**Figure 5b.** Applying varying overburden pressures increases the slope and the intercept of the correlation of 'a' and 'm'.

## WESTERN CANADA WATER SATURATION PARAMETERS
## CARBONATES
## a VS m AT ATMOSPHERIC PRESSURE
## ALL POROSITY TYPES

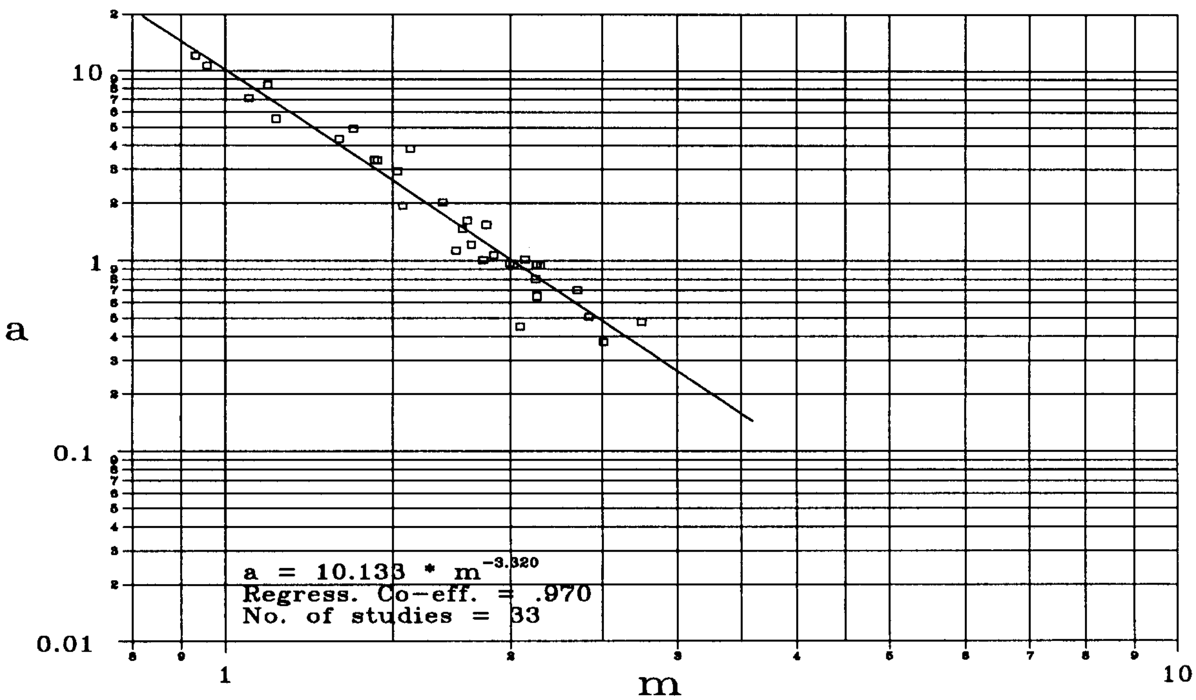


**Figure 6a. Cementation factors ('m') and tortuosity ('a') are interrelated for carbonates.**

## WESTERN CANADA WATER SATURATION PARAMETERS
## CARBONATES
## a VS m AT OVERBURDEN PRESSURE
## ALL POROSITY TYPES

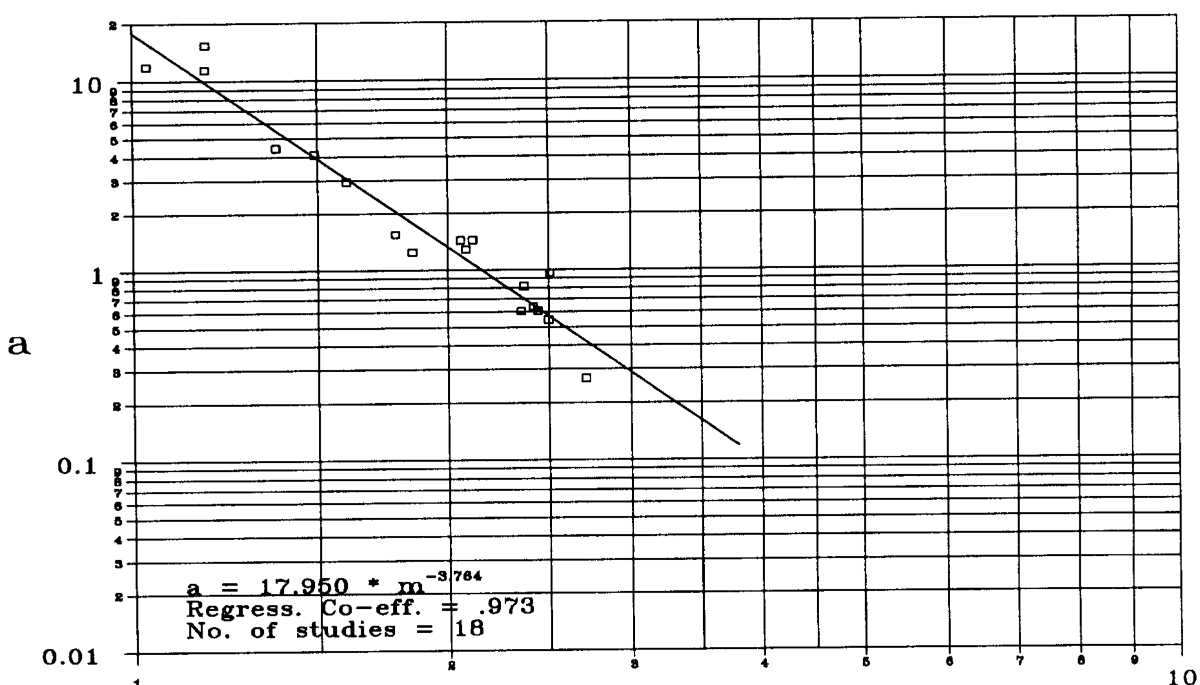


**Figure 6b. The carbonate correlation holds with the application of varying overburden stress levels.**

## Canadian Formation Factor - Porosity Relationships

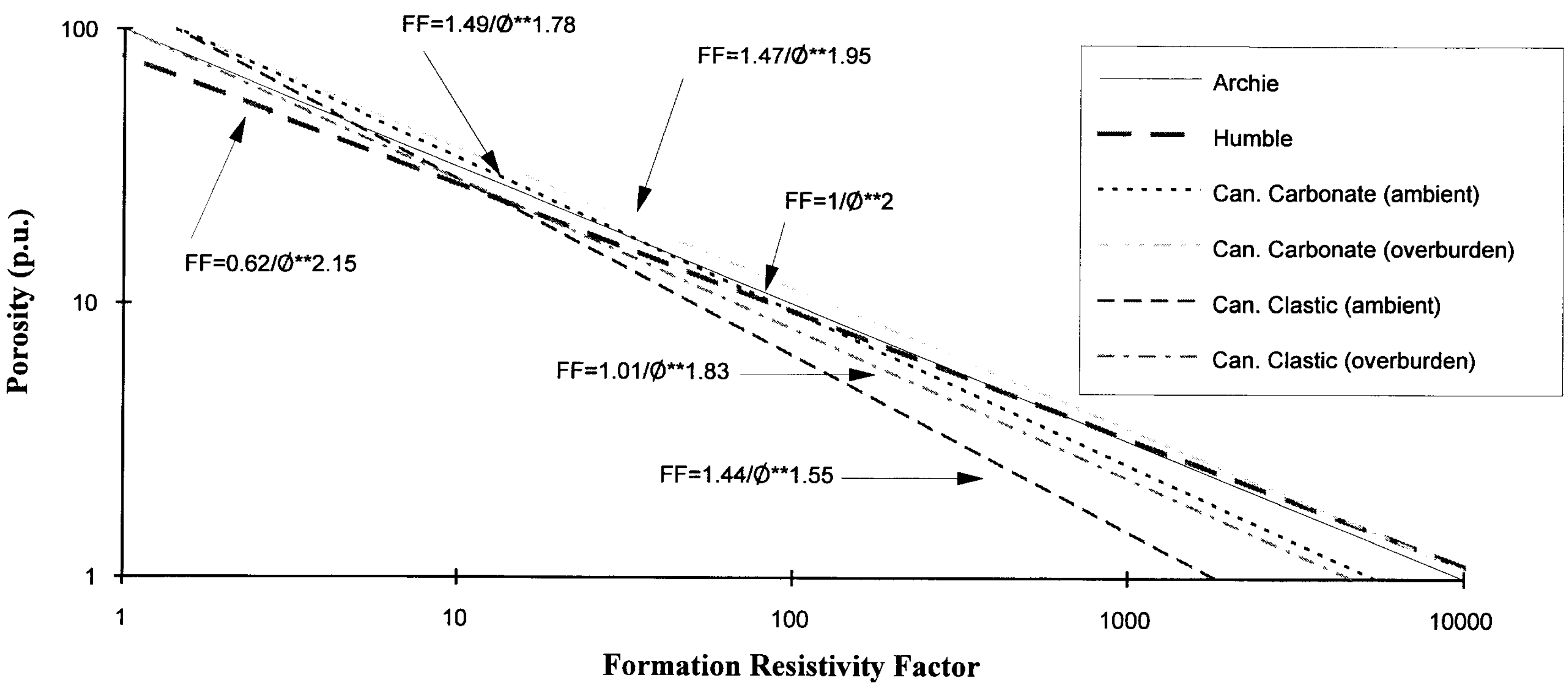


Figure 7. Generalized formation factor porosity transforms are significantly different to Archie's relationship. The application of these new transforms may improve water saturation calculation in Western Canada. However, it must be recognized that each formation and field is unique and the above equations may not apply.

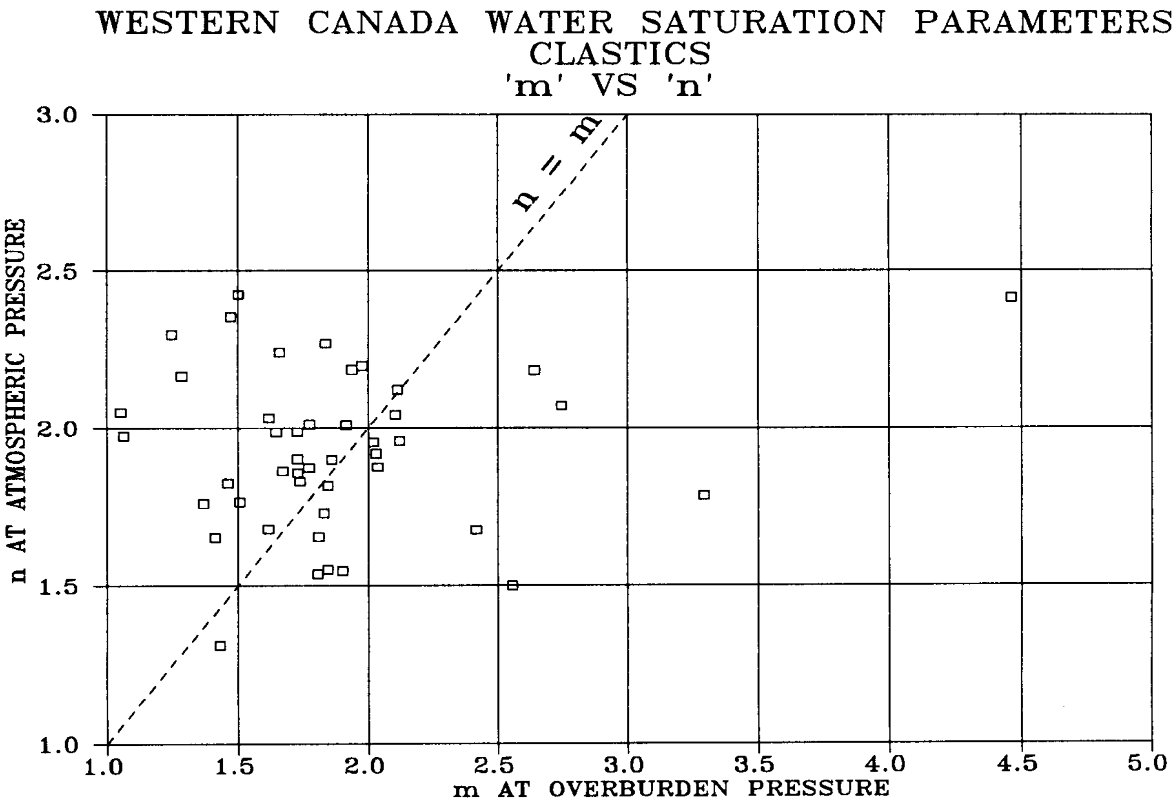


Figure 8a. No relationship is evident between 'm' and 'n' for clastics.

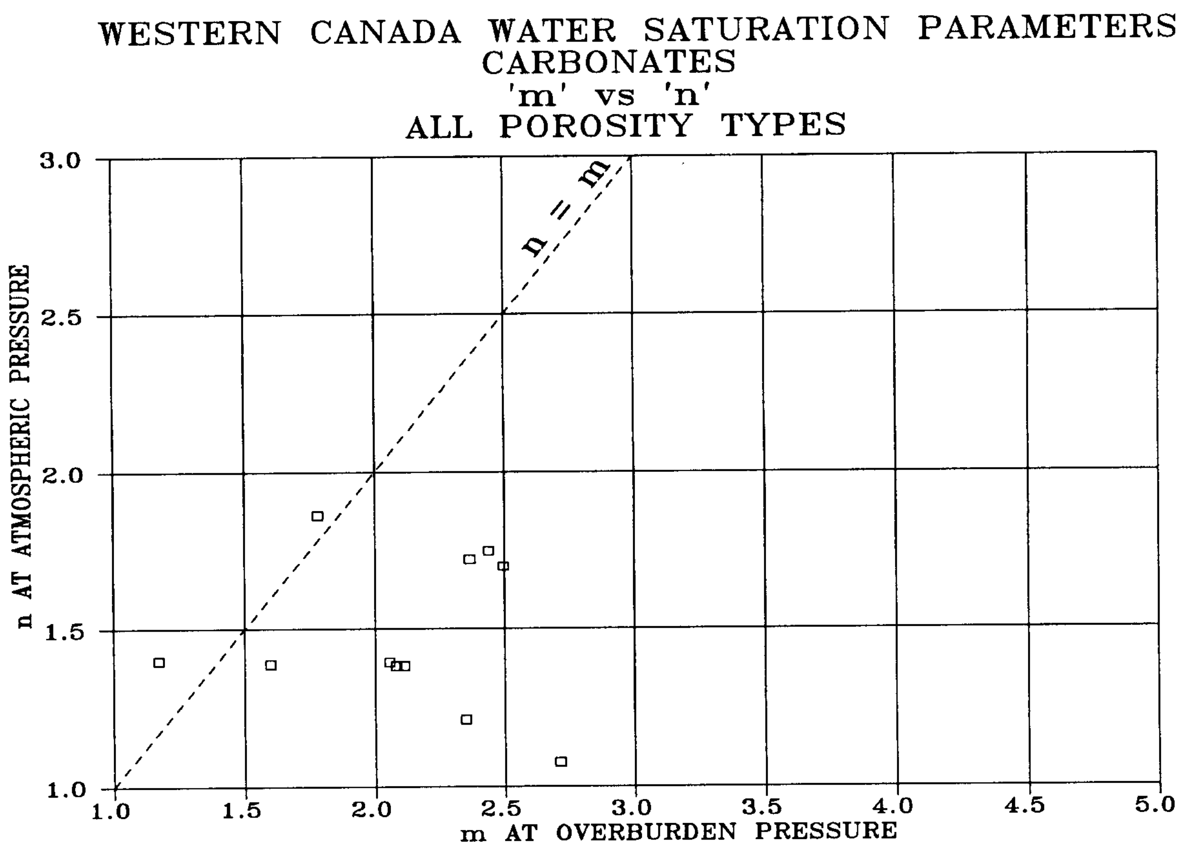


Figure 8b. No relationship is evident between 'm' and 'n' for carbonates. All 'n' values are less than 2.

FF

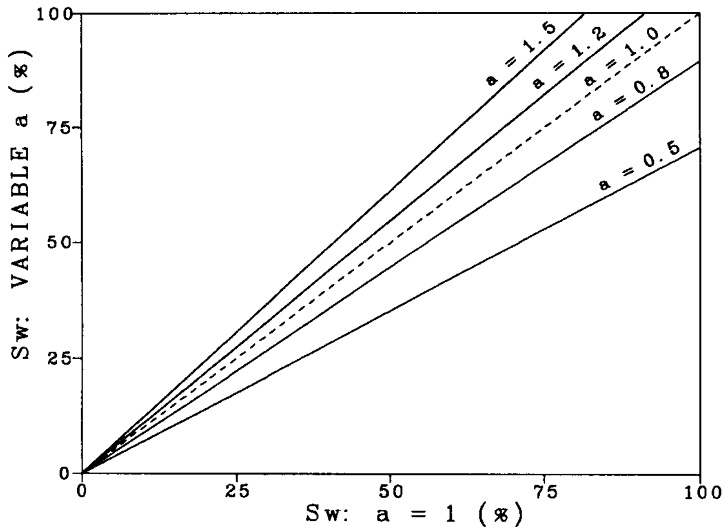


**Figure 9a – Effect on calculated water saturation of variations in 'a'**

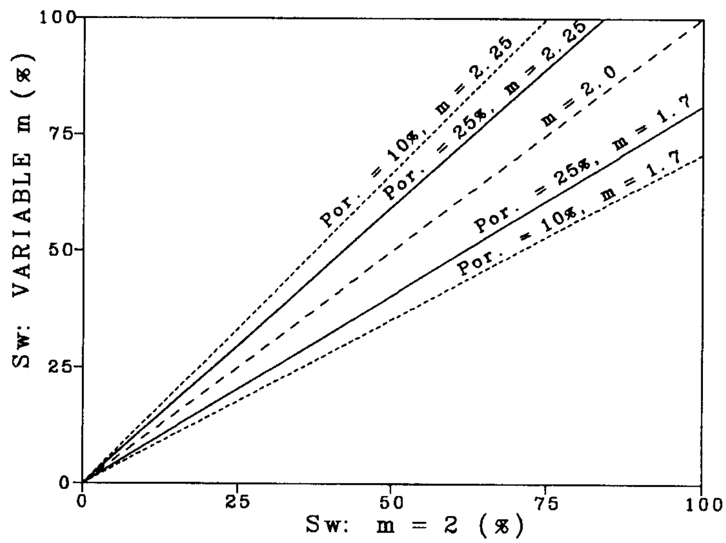


**Figure 9b – Effect on calculated water saturation of variations in 'm'**

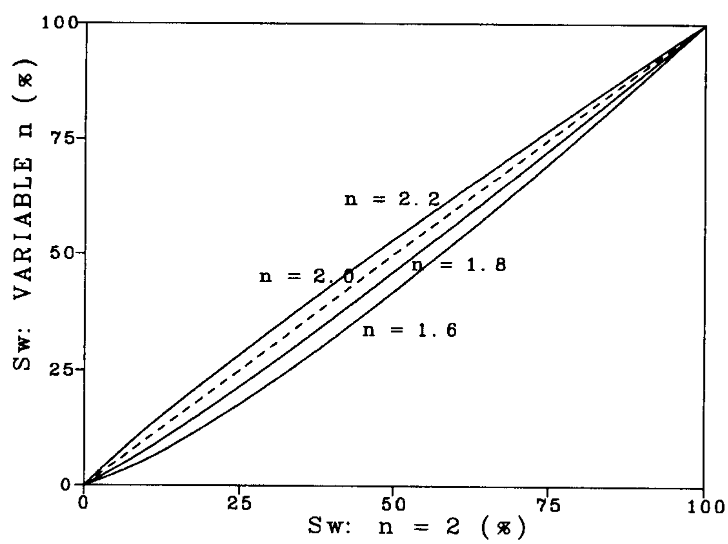


**Figure 9c – Effect on calculated water saturation of variations in 'n'**