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## Experimental Determination of Electrical Properties of Core Sample of Niger Delta Formation

Oloro John, Happy Chidi Onyeoru, Fakrogha Julius

Delta State University, Abraka, Delta State, Faculty of Engineering, Petroleum and Gas Department

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**Abstract** Determination of electrical rock properties by electrical log resistivity measurement and direct saturation measurement are methods most researcher use in the determination of rock properties. In this paper, Resistivity Measurements of Fluid-Saturated Rocks was used on various size of core samples to determine properties, such as Saturation exponent (n), Cementation factor (m), water Resistivity (R<sub>w</sub>) Formation, Formation resistivity (R<sub>t</sub>) Tortuosity (τ) and water saturation in Niger Delta formation.

The result shows that the various rock properties depend on several factors, e.g., length and diameter of the core samples, from the result, we can also see that the formation factor increases with increase in length, cementation factor was constant for the five core samples, and tortuosity also increases with increase in length of the different core samples.

**Keywords:** Saturation, Resistivity, Formation, Tortuosity

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### Introduction

Electrical properties of a rock depend on the geometry of the voids and the fluid with which those voids are filled. The fluids of interest in Petroleum reservoirs are oil, gas, and water. Water is a conductor when it contains dissolved salts, such as sodium chloride (NaCl), magnesium chloride (MgCl<sub>2</sub>), and potassium chloride (KCl) normally found in formation reservoir water. Current is conducted in water by movement of ions and can therefore be termed electrolytic conduction. Oil and gas are nonconductors.

In this paper, electrical properties of Niger Delta formation was determined using Resistivity Measurements of Fluid-Saturated Rocks [1].

### Concept of Saturation

The pore spaces in underground rocks that form oil and gas reservoirs are always completely saturated with fluid. In the pores of the reservoir, there is never an occasion or location where nothing exists (i.e., truly "void space"). The pores are completely filled with some combination of the following fluids: (1) oil and its associated impurities in the liquid phase; (2) natural gas and its associated impurities in the vapor phase; (3) water--either connate water or water that flowed or was injected into the reservoir.

During deposition, when sediments were being deposited (usually in an aqueous environment), the pores were completely saturated with water (i.e., water saturation was 100% of the pore space). Later, during deep burial, compaction, and partial cementation, the water may have changed in composition, but the saturation remained 100% unless hydrocarbons entered the pores and forced the water out.

If the water-saturated pores happen to be near an active hydrocarbon source rock, such as organic-rich shale, and the pores are in pressure communication with the source rock, hydrocarbons can enter the pores and occupy space. Normally, the hydrocarbons are less dense than the water, and the resulting buoyant force causes the oil or gas to migrate through the porous, permeable rock until it escapes at the surface or is stopped by an impermeable layer that forms a seal. If there is sufficient closure the hydrocarbon accumulation may result in a commercial oil or gas reservoir.

In the pores of oil or gas reservoirs, there always remains some water that was there before the hydrocarbon entrapment. At any time during the life of an oil or gas reservoir, the following relationship must hold true.

$$S_o + S_w + S_g = 1.0 \quad 1$$

Where



$$S_o = \frac{\text{oil volume}}{\text{pore volume}} = \frac{V_o}{V_p} \quad 2$$

$$S_w = \frac{\text{oil volume}}{\text{pore volume}} = \frac{V_o}{V_p} \quad 3$$

$$S_g = \frac{\text{gas volume}}{\text{pore volume}} = \frac{V_g}{V_p} \quad 4$$

It is common for oil or gas saturation to be zero, but water saturation is always greater than zero.

Saturation is a direct measure of the fluid content of the porous rock. It therefore directly influences the hydrocarbon storage capacity of the reservoir. Other uses are the identification of gas/oil or oil/water contacts by changes of residual saturation with depth, and directly it is used as correlation variable to estimate the productivity of reservoir rocks [2].

### Saturation Distribution in Reservoir

During hydrocarbon accumulation in the reservoir, water saturation can be reduced to some small value, typically 5-40%, after which no more water can escape from the pore. This occurs when water saturation becomes immobile, at the irreducible water saturation.

Petroleum literature contains several symbols for water saturation;  $S_{wi}$ ,  $S_{wc}$ ,  $S_{wir}$ .

Care must be taken to ensure correct interpretation of symbol. The following definition should help.

1.  $S_{wir}$  = irreducible water saturation, below which water cannot flow.
2.  $S_{wc}$  = connate water saturation existing on discovery of the reservoir. It may or may not be irreducible.
3.  $S_{wi}$  = may mean irreducible, connate, or interstitial, which means saturation among the interstices, or pores. Interstitial may or may not signify irreducible. It maybe the value on discovery of the reservoir, or the value at any time thereafter.  $S_{wi}$  may also mean initial or original, which truly means the water saturation on discovery, but it may or may not be irreducible.

Density differences between gas and oil as well as between oil and water result in normal reservoir situation in which oil float on water. If there is a free gas phase, the gas floats on the oil. Keep in mind that there will be some water saturation (at least the irreducible water saturation) throughout the reservoir, even in the pores at the very top[2]

### Water Saturation

Proper evaluation of initial water saturation is essential for proper reserves evaluation, informed decision on which zones to complete to obtain water-free production, and influences a variety of productivity and formation damage issues, electrical log resistivity measurement and direct saturation measurement on in-situ core samples, are described and the advantages and disadvantages of these techniques.

### Saturation Determination Techniques

Initial saturation are commonly determined using the following techniques:

1. Log based saturation evaluations.
2. Direct saturation measurement on in-situ samples. Both techniques have pros. and cons.

### Log based Saturation Evaluation

Water saturation determination in clean (non-shale) formations are based on Archie's equation

$$S_w^n = \frac{FR_w}{R_t} \quad 5$$

Where

$S_w$  = Fraction of pore space occupied by water

$n$  = Saturation exponent

$R_w$  = Formation water resistivity

$R_t$  = True water resistivity

$F$  = Formation factor

The formation factor is given by the equation

$$F = \frac{\alpha}{\phi^m} \quad 6$$

Where

$\alpha$  = Archie's constant

$m$  = Cementation exponent



$\phi$  = Porosity fraction

### Saturation Exponent

The saturation exponent value is a function of both pore system geometry and formation wettability. Although a value of 2.0 is commonly used or assumed for the saturation exponent, this value can vary considerably from formation to formation and may result in over or under estimation of water saturation in many situations.

Since the saturation exponent is derived as the slope of a plot of resistivity index versus water saturation, it assumes that a continuous slope is obtained (i.e. the relationship is a linear one on a semi-logarithmic plot). This assumption is generally satisfied for water wet porous media, where in the wetting, water saturation forms a continuous film on the surface in the porous media, allowing conductive paths for current transmission even down to very low saturation levels.

Conversely, for oil wet porous media, the water saturation is contained in discontinuous droplets in the central portion of the pore space. Saturation exponent for strongly oil wetted systems, generally are similar to water wet systems with values around 2.0 at high water saturation levels, but as water saturation is reduced, the slope of the  $R_I/S_w$  relationship can increase radically [3]

Saturation exponent values as high as 8-10 have been measured at low water saturation conditions (which approximates the initial reservoir saturation condition we are attempting to determine through logging) in strongly oil wet situation. Below provides an illustrative set of data indicating how the value of the saturation exponent can alter the calculated value of the initial water saturation. Using the fixed "standard" values given in table 1 for  $a$ ,  $m$ ,  $n$ ,  $R_w$  and  $R_t$ , the "true" water saturation value is calculated at round 28.7%. Holding all other parameters constant and varying only the 'n' value, one can see that, in the range of "n" values from 1.0 to 8.0, the computed water saturation can vary radically, lower "n" values than the standard 2.0, usually used, will result in lower  $s_{wi}$  values (8.2%  $s_{wi}$  for example at an "n" values of 1.0) and higher "n" values, which are often associated with the transition to a more oil wet state of a uniform pore system, will cause increase in true  $s_{wi}$  (to 73%, for example, at an "n" value of 8) [4].

Accurate determination of the saturation exponent value is therefore of essential importance for the calculation of "true initial water saturation from logs. Saturation exponents are normally determined experimentally in the laboratory on core samples of actual formation under consideration to obtain a more realistic evaluation of the "n" value.

Due to the fact that the "n" values varies with both lithology and wettability, a scale of "n" value measurement is often conducted on samples from a range of permeability, porosities, and lithology which may be present in the formation.

Most laboratory "n" value determination have been conducted in the past using water and gas on cleaned core samples using the base assumption that all formation are water wet. This is a gross oversimplification as many researchers have demonstrated that, on average, only approximately 50% of sandstone oil bearing formation exhibit strongly water wet behavior. This is possibly why the standard "n" value of 2.0 used so widely in the industry has gained acceptance, as the vast majority of the measurement conducted have used cleaned, artificially water wet, porous media which typically do exhibit saturation exponent values near 2.0 [3]

### Saturation exponent measurement is conducted in the laboratory using the following four method:

1. Bulk porous plate method:

Bulk porous plate method where a large group of samples are simultaneously desaturated from a condition of 100% water saturation on large porous plate to generate a range of gradually lower water saturation levels, successively higher gas pressure are used to achieve this desaturation.

After each higher pressure, the apparatus is disassembled and the discrete samples are removed and subjected to individual resistivity measurement. This technique suffer from deficiencies, due to grain losses and capillary redistribution of the fluids, because of the necessity to continuously be removing and re-intersecting the samples in the porous plate cell as well as fluid losses due to evaporation by continual cyclic disturbance of the equilibrium environment[2]

2. Centrifuge method:

In this method, samples are spun at gradually increasing speeds to reduce the water saturation and generate a range of saturation values at which resistivity can then be evaluated. Like the bulk porous plate method, these techniques suffer from core disturbance, grain loss and evaporation effect which can compromise the accuracy of the obtained saturation exponent data[5]

3. Individual porous plate method:

This method consists of special cells in which single core samples are mounted with individual porous plates and electrodes attached to the samples to monitor in-situ resistivity. A micro pipette is used to track fluids



produced from the core as capillary pressure is increased to cause the water saturation, and hence the entire test can be run without disrupting the core sample by removing the applied pressure which can cause phase redistribution within the core and eliminating the potential for grain losses and evaporation. The technique has these advantages over the bulk porous plate and centrifuge method described previously, but suffers from the drawback of being a time-consuming method, particularly for samples of low permeability, where literally months may be required to obtain an effective desaturation. (Poupon, A., et al, 1970)

4. The continuous injection technique:

The continuous injection technique is relatively new method for saturation exponent determination and consists of mounting the sample in a pressurized core cell with a porous plate at the outlet end of the core. A micro injection pump is used to inject non-wetting phase into the sample (oil or gas) at an extremely low rate to slowly reduce the water saturation in the porous media over a period of time.

Resistivity measurements are obtained on a continuous basis and average fluid saturation are obtained by an accurate material balance of fluid produced from the core sample.

In this manner, complete  $RI$  vs  $S_w$  curve with literally hundreds of points can be constructed, covering the entire range of saturation and detecting any subtle changes in saturation exponent with water saturation.

The technique has all the advantages of the individual porous plate method, plus it is generally much faster and can easily be conducted at full reservoir condition of temperature, pressure, overburden pressure and using the reservoir fluid if required.

#### Archie Constant Value

Archie constant values are measured experimentally for a series of formation factors determined on a range of porosity value samples for a given lithology expected to exist in specific formation. Generally, the lower the degree of consolidation, the lower the value of the Archie constant. A value of 0.62 for the Archie constant was derived by Humble poorly consolidated sands. The value tends toward 1.0 for compacted sands and may exceed 1.0 as the degree of compaction becomes extreme.

Table 4.0 provides an indication of the expected variation of calculated water saturation as the value of “a” changes. This data have been plotted and appears as figure 4.0. Once again, the data fixed parameter data table 1 is utilized holding all parameters constant except for the “a” value. Examination of this data indicates that variation in “a” alter the water saturation values, but not to the extent that variation in “n” did previously.

Variation of “a” from 0.4 to 1.7 resulted in a range of water saturations from 18.1 to 37.4%, indicating that significant departure from the value of 28.7% calculated with a typical “a” value of 1.0 could still occur. [2]

#### Formation Water Resistivity

This is an extremely important factor in the calculation of initial water saturation as the ionic composition of the water affects its overall electrical conductivity and hence resistivity. Fresh water exhibits high resistivity, while highly saline brines are extremely electrically conductive, and hence exhibit low resistivity values. Log resistivity in the near wellbore region are complicated by the fact that during most overbalanced drilling processes, losses of mud filtrate to the near wellbore region occur. This invaded filtrate is generally of a different composition than the in-situ formation water (usually fresh water in most cases). This result in a zone of invasion of altered resistivity about the wellbore, a transition zone of blended invaded and in-situ water and then non-flushed

#### From Water Catalogues

Often extensive list produced waters from various formation are compiled and are commonly used by companies when they are evaluating similar zones in the same regional trend. This technique hinges on the assumption that the resistivity measurement conducted on the original samples which are in the catalog correct and also that the formation under consideration has no variation in water chemistry from the ones used in the catalog are correct and also as the data source. Verification of the  $R_w$  value from the sp curve or from resistivity. Porosity comparison is recommend in such a situation[6]

#### Chemical Analysis

In some cases the chemical analysis of the water is known, either from a catalog or a historical sample. Various techniques have been detailed in the literature for calculating resistivity based on composition of the water, being used as the basis for the resistivity calculation, may be affected in a similar fashion as described in the section “Direct measurement” for the direct measurement of resistivity. If the analysis is in error, this will obviously compromise the accuracy of the calculated resistivity [7].

#### Definition of resistivity

The resistivity of a porous material is defined by

$$R = \frac{\rho A}{L}$$

Where;

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$r = \text{resistance}, \Omega$

$A = \text{cross sectional area}, m^2$

$L = \text{length}, m$

and resistivity is expressed in ohm-meter ( $\Omega m$ ). However, for a complex material like rock containing water and oil, the resistivity of the rock depend on

- Salinity of water
- Temperature
- Porosity
- Pore geometry
- Formation stress and,
- Composition of rock

### Electrical resistivity log as an aid in determining some reservoir characteristics

The resistivity of an electric current in porous rock is due primarily to the movement of dissolved ions in the brine that fills the pore of the rock. The resistivity varies with temperature due to the increased activity of ions in solution as temperature increases.

Due to the conductivity properties of reservoir formation water, the electrical well-log technique is an important tool in the determination of water saturation versus depth and thereby a reliable resource for in situ hydrocarbon evaluation.

The theory of the electrical resistivity log technique generally applied in petroleum engineering was developed by Archie in 1942, the so called Archie's equation. This empirical equation was derived for clean water-wet sandstones over a reasonable range of water saturation and porosities. In practice, Archie's equation should be modified according to the rock properties such as; clay contents, wettability, pore distribution etc. The following is a brief presentation of the main electrical properties of reservoir rocks and related parameters.

The electrical log has been used extensively in a qualitative way to correlate formation penetrated by the drill in the exploitation of oil and gas reservoir and to provide some indication of reservoir content. However, its use in a quantitative way has been limited because of various factors that trend to obscure the significance of the electrical reading obtained. Some of these factors are the borehole size, the resistivity of the mud in the borehole, the effect of invasion of the mud sample, the relation of the recorded thickness of beds to electrode spacing, the heterogeneity of geologic formations, the salinity or conductivity of connate water, and perhaps of greatest importance, the lack of data indicating relationship of the resistivity of a formation in situ to its character and fluid content.

On the Gulf coast, it is found that the effect of the size of the borehole and the mud resistivity are generally of little importance, except when dealing with high formation resistivity or extremely low mud resistivity. Fortunately, little practical significance need be attached to the exact values of the higher resistivity recorded, low mud resistivity are not common, but when this condition is encountered, it may be corrected by replacing the mud column with the present advanced knowledge of mud control, invasion of mud filtrate into sands can be minimized, thereby increasing the dependability of the electrical log.

The effect of electrode spacing on the recorded thickness of a bed is often subject to compensation or can be sufficiently accounted for to provide an acceptable approximation of the true resistivity of the formation. As development of a field or area progressively enhances the knowledge of the lithological section, the resistivity values of the electrical log take on greater significance, ultimately affording acceptable interpretations. The salinity, and therefore the conductivity, of the connate water associated with various producing horizons may be determined with sufficient accuracy by the usual sampling procedure.

Determination of the significance of the resistivity of a producing formation as recorded by the electrical log appears, for the present at least, to rest largely with the application of empirical relationships established in the laboratory between certain of the physical properties of a reservoir rock and what may be termed a formation factor. It should be stressed at this point that numerous detailed laboratory studies of the physical properties of the formation in relation to the electrical measurement in question are essential to a reliable solution of the problems dealing with reservoir content.

The purpose of this project is to present some of these laboratory data and to suggest their application to quantitative studies of the electrical log. It is not intended to discuss individual resistivity curves and their application.

- The distribution factors (borehole, bed thickness, and invasion) are discussed briefly only to indicate instances when they are not likely to affect the usefulness of the observed resistivity[2]



### Formation factor

Formation factor is defined as the ratio of the resistivity of completely brine saturated rock to the resistivity of the saturating brine. Test are conducted on  $1''$  to  $1\frac{1}{2}''$  cylindrical core samples.

Formation factor is, therefore, a function of porosity and the pore geometry of the rock. One expression commonly observed is

$$F = \frac{R_0}{R_w} = \frac{1}{\phi^m} \quad 8$$

Where

$M$  = cementation factor and is equal to the slope of the line relating  $F$  to  $\phi$  on a log-log plot.

In many formation, a common relationship is:

$$F = \frac{a}{\phi^m} \quad 9$$

Note: samples should be selected to cover the porosity range noted in the core. This assures better definition of  $m$  and  $a$  [2].

### Resistivity Index

Oil and gas are not electrical conductors. Their presence in an element of reservoir or in a core sample will reduce the main cross-sectional area of the flow path thus, increasing the resistivity.

Therefore, resistivity index is defined as the ratio of rock resistivity at any condition of gas, oil and water saturation to its resistivity when completely saturated with brine water.

$$I = \frac{R_t}{R_0} = S_w^{-n} \quad 10$$

This resistivity index is a function of water saturation. It is also a function of the pore geometry. The presence of cat ion exchangeable clays (monmorillonites) often causes apparent low resistivity index values to be observed, particularly as water saturation decreases.

The resistivity index exponent,  $n$ , is also influenced by confining or overburden pressures, and should be determined under overburden conditions where the rock is significantly susceptible to the effect.

- A minimum of three saturation, and preferably five, should be obtained on each sample. Individual sample  $I$  versus  $S_w$  plots, as well as composite plots of all samples are typically reported [8].

### Conductive Solids

- The clay minerals present in a natural rock act as a separate conductor and are sometimes referred to as ‘‘conductive solids’’. Actually, the water in the clay and the ions in the clay water act as the conducting materials. The effect of the clay on the resistivity of the rock is dependent upon the amount, type and manner of distribution of the clay in the rock. A few minerals are conductive in their own right, but do not constitute a significant problem in formation evaluation. Clays result in variation formation factor dependent on the water salinity (resistivity) used to saturate the core. Fresh water yields low  $F$  values and low  $m$  values [9].

Definition of Resistivity  $R$  (ohm):

$$R = \frac{rA}{L} \quad 11$$

Where

$R$  = Resistivity

$r$  = Resistance (measured value)  $\Omega$

$A$  = Cross-sectional area to current flow,  $m^2$

$L$  = Length of conductor, m

Definition of  $R_0$

$$R_0 = \frac{r_0A}{L} \quad 12$$

Where

$r_0$  = Resistance of core at 100% water saturation

$A$  = Cross-sectional area of core face,  $cm^2$

$L$  = Length of core, cm.

Definition of  $R_w$

$$R_w = \frac{r_w A_p}{L_p} \quad 13$$

Where

$r_w$  = Resistance of the formation brine,  $\Omega$

$A_p$  = Cross-sectional area of the container,  $cm^2$



$L_p$  = “effective length” of the container, cm

### Tortuosity ( $T$ )

Wyllie (1953) developed the relationship between the formation factor and other properties of rock, like porosity, and tortuosity [10]. Tortuosity, can be defined as  $\left(\frac{L_a}{L}\right)^2$  14

Where

$L$  =Length of the core (m)

$L_a$ = the effective path length through the pores (m)

Based on simple pore models, the following relationship can be derived

$$F = \frac{\tau}{\phi} \quad 15$$

Where

$F$  = Formation factor

$\tau$  =Tortuosity of the rock

$\phi$  =Porosity of the rock

### Cementation factor (m)

Archie suggested a slightly different relation between the formation factor and porosity by introducing the cementation factor.

$$F = \phi^{-m} \quad 16$$

Where

$\phi$  = Porosity

$m$  = Archie’s cementation factor.

Archie reported that the cementation factor probably ranged from 1.8 to 2.0 for consolidated sandstones and for clean unconsolidated sands was about 1.3.

### Saturation exponent (n)

The famous Archie’s equation gives the relationship of resistivity index with water saturation of rocks

$$I = \frac{R_t}{R_0} S_w^{-n} \quad 17$$

Where

$S_w$  =Water saturation

$n$  = Saturation exponent, ranging from 1.4 to 2.2, ( $n = 2.0$  if no data are given).

In equation 17,  $R_t$  and  $R_0$  can be obtained from the well logging data, saturation exponent is experimentally determined in laboratory. Therefore, the in-situ water saturation can be calculated with Archie’s equation. Based on the material balance equation for the formation,  $S_w + S_o + S_g = 1.0$ , the hydrocarbon reserves in place may be calculated.

### Procedure

The following steps was taken in carrying out this experiment:

- i) Core sample was collected at a depth of 30cm down the formation
- ii) A hole was bore through the core sample
- iii) The core sample was dried for at least 30days under the sun
- iv) The resistor, voltmeter, was connected to the core sample using the copper wire.
- v) The resistance of the core samples of different length was determined, the desired current from AC source was set, low current preferred so the cores does not heat up
- vi) The voltage from the voltmeter was recorded
- vii) The weight of the core samples when dried was measured
- viii) The length and the diameter of the core samples were measured using a meter rule and a Vernier caliper
- ix) Saturate completely the core samples with water  $S_w = 100\%$ ,  $R_{core} = R_0$
- x) The weight when saturated with water was measured
- xi) Desaturate the core samples by 15 to 20 % until  $S_w < 100\%$ ,  $R_{core} = R_t$
- xii) Determine the resistivity index using  $\left(\frac{R_t}{R_0}\right)$ , of the different core samples.



- xiii) Determine the saturation exponent (n) by rearranging the saturation equation  $S_w = \left[\frac{R_o}{R_t}\right]^{1/n}$  or plotting a graph of  $\log\left(\frac{R_t}{R_o}\right)$  vs  $S_w \log I$  vs  $\log S_w$
- xiv) The resistivity of water ( $R_w$ ) was measured
- xv) Rearrange and apply equation of ( $R_o = FR_w$ ) to get formation factor
- xvi) The porosity was determined
- xvii) Rearrange and apply  $R_o = R_w \phi^{-m}$  to get the cementation factor (m) or plot a graph of  $\log F$  against  $\log \phi$  on log-log graph.
- xviii) The tortuosity was determine by rearranging the equation  $F = \frac{\tau}{\phi}$

**Apparatus/material**

- Core samples of clay
- Resistor
- Voltmeter
- Power supply/mains
- Beaker
- Water
- Vernier caliper
- Meter rule
- Copper wire
- Ammeter
- TPS 335 machine
- Brine

**Experimental Result**

$$R_w = \frac{r_x A}{L}$$

Where,

$$r_x = 700\text{ohms}$$

$$A = 28.99\text{cm}^2$$

$$L = 20.71\text{cm}$$

$$\therefore R_w = 980 \text{ Ohm-cm.}$$

**Table 1: Effect of formation factor variation on porosity of the different core samples**

NO. OF CORE	DIAMETER D(cm)	LENGTH L(cm)	$r_t$ Ohms	$R_o$ Ohm-cm	$\phi$	M	F	$\tau$
1	4.30	3.00	1600	37120	0.571	1.93	37.877	21.628
2	4.30	3.50	3000	65485.7	0.535	1.93	66.82	35.749
3	4.30	3.80	4000	84642.1	0.486	1.93	86.37	41.976
4	4.30	5.00	5000	96630	0.411	1.93	98.60	40.525
5	4.30	6.00	6000	110140	0.390	1.93	112.40	43.836

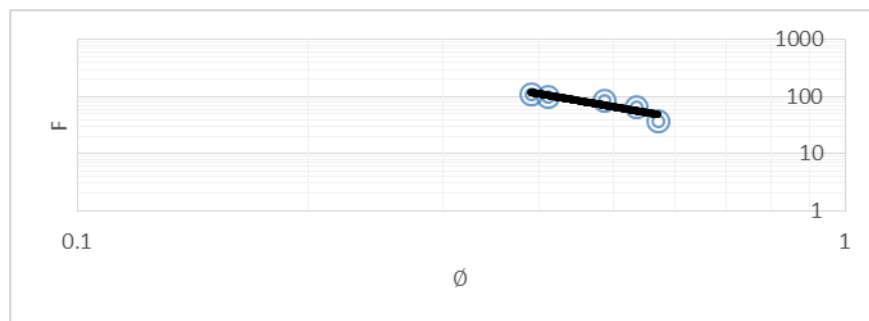


Figure 1: A plot of formation factor against porosity.





$$F = C \phi^{-m}$$

$$\log F = \log C - m \log \phi$$

$$\text{Slope} = \frac{\log 100 - \log 50}{\log 0.400 - \log 0.573}$$

$$-m = \text{slope} = -1.93$$

$$\therefore m = 1.93 = \text{Cementation factor}$$

Plotting a graph of Formation factor against porosity on a log-log scale, we can see that the formation factor depends on the pore geometry of the rock.

We can see evidently from the graph that as the formation factor increases, there is a decrease in the value of the porosity of the different core samples. Obviously, the formation factor depends on pore structure and length of the core.

The cementation factor has a theoretical value of unity for uniform pores that penetrate the rock directly from one side of the sample to the other (i.e., direct tubes of pore space), and is zero for a rock with 100% porosity (i.e., no grains to get in the way of the fluid flow). No other values of the cementation factor are able to be defined in a purely theoretical way in rocks due to the complexity of the way that pore spaces are arranged.

**Determination of resistivity index and saturation exponent**

**Sample One:**

**Table 2:** Effect of resistivity index variation on calculated water saturation of sample one

S/N	$S_w$	$r_t$ Ohms	$R_t = \frac{r_t A}{L}$ Ohm-cm	RESISTIVITY INDEX $\left(\frac{R_t}{R_0}\right)$
1	1.000			1.000
2	0.86	2500	58000	1.563
3	0.63	3200	74240	2.000
4	0.54	5100	118320	3.188
5	0.49	7300	169360	4.563

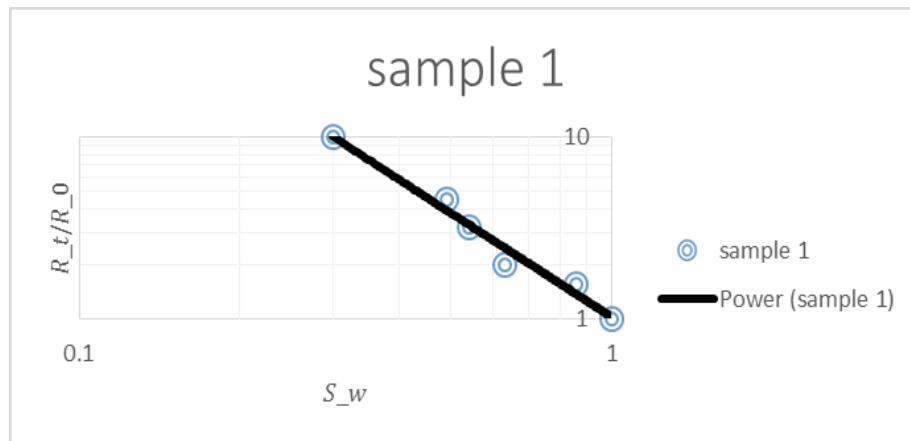


Figure 2: Water saturation as a function of resistivity index of sample one

Saturation exponent n

$$-n = \text{Slope} = \frac{\log 10 - \log 1}{\log 0.3 - \log 1}$$

$$n = 1.91$$

The accurate determination of the water saturation is key to being able to calculate an accurate value for the amount of oil in place. Errors of a few percent in the determination of the water saturation result in errors worth billions of dollars when transferred into errors in the determination of STOOIP.

**Sample Two:**

**Table 2:** Effect of resistivity index variation on calculated water saturation of sample two

S/N	$S_w$	$r_t$ Ohms	$R_t = \frac{r_t A}{L}$ Ohm-cm	RESISTIVITY INDEX $\left(\frac{R_t}{R_0}\right)$
1	1.000			1.000
2	0.86	3600	78582.86	1.374
3	0.63	5300	115691.43	1.767
4	0.54	6300	137520	2.100
5	0.49	9150	199731.43	3.050

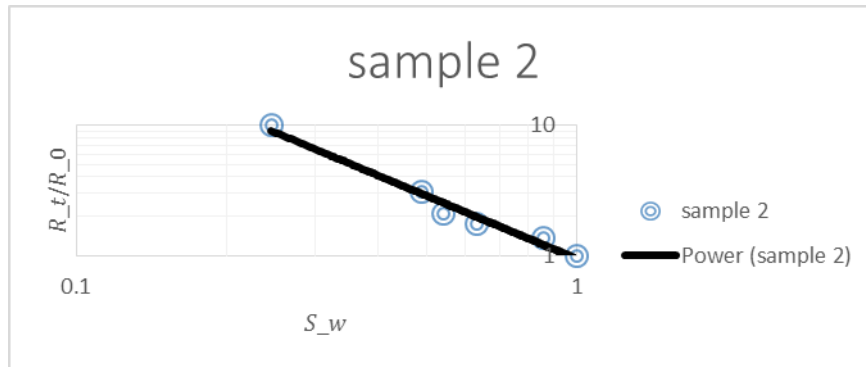


Figure 3: Water saturation as a function of resistivity index of sample two

Saturation exponent n  
 $-n = \text{Slope} = \frac{\log_{10} - \log_1}{\log_{0.245} - \log_1}$   
 $n = 1.64$

**Sample Three:**

**Table 3:** Effect of resistivity index variation on calculated water saturation of sample three

S/N	$S_w$	$r_t$ Ohms	$R_t = \frac{r_t A}{L}$ Ohm-cm	RESISTIVITY INDEX $\left(\frac{R_t}{R_0}\right)$
1	1.000			1.000
2	0.86	5200	110034.74	1.299
3	0.63	6500	137543.42	1.625
4	0.54	9000	190444.74	2.250
5	0.49	11252	238098.24	2.813

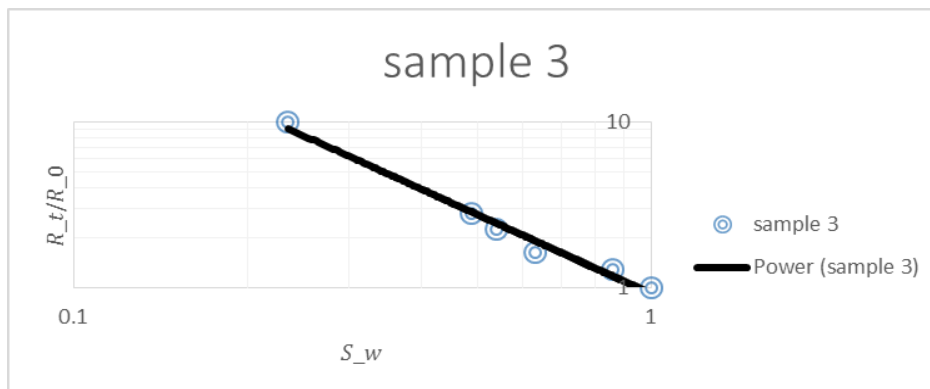


Figure 4: Water saturation as a function of resistivity index of sample three



Saturation exponent n

$$-n = \text{Slope} = \frac{\log_{10} - \log_1}{\log_{0.235} - \log_1}$$

$$n = 1.59$$

**Sample Four:**

**Table 4:** Effect of resistivity index variation on calculated water saturation of sample four

S/N	$S_w$	$r_t$ Ohms	$R_t = \frac{r_t A}{L}$ Ohm-cm	RESISTIVITY INDEX $\left(\frac{R_t}{R_0}\right)$
1	1.000			1.000
2	0.86	6200	119821.2	1.240
3	0.63	8900	172001.4	1.780
4	0.54	10500	202923	2.110
5	0.49	14050	271530.3	2.810

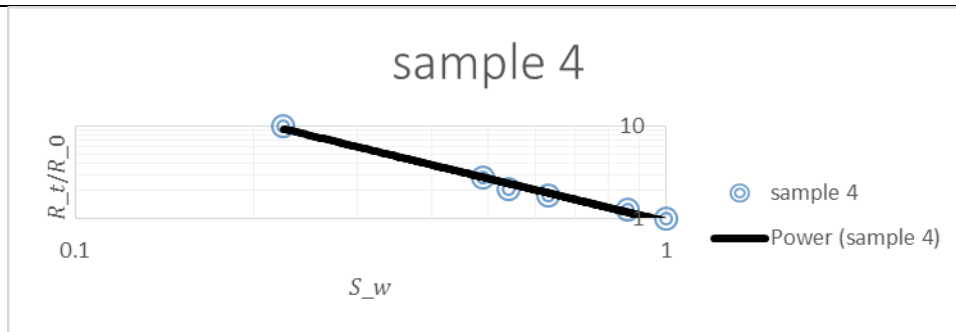


Figure 5: Water saturation as a function of resistivity index of sample four

Saturation exponent n

$$-n = \text{Slope} = \frac{\log_{10} - \log_1}{\log_{0.225} - \log_1}$$

$$n = 1.54$$

**Sample Five:**

**Table 5:** Effect of resistivity index variation on calculated water saturation of sample five

S/N	$S_w$	$r_t$ Ohms	$R_t = \frac{r_t A}{L}$ Ohm-cm	RESISTIVITY INDEX $\left(\frac{R_t}{R_0}\right)$
1	1.000			1.000
2	0.86	7500	137675	1.250
3	0.63	10100	185402.3	1.683
4	0.54	13050	239554.5	2.175
5	0.49	17630	323628.03	2.938

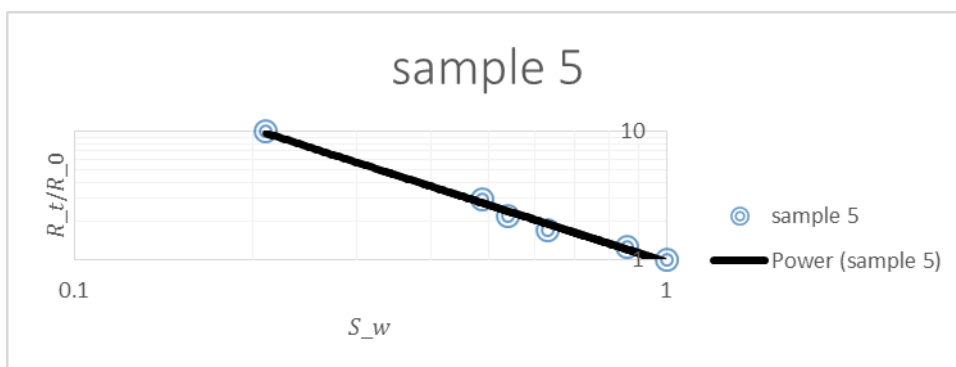


Figure 6: Water saturation as a function of resistivity index of sample five



Saturation exponent n

$$-n = \text{Slope} = \frac{\log 10 - \log 1}{\log 0.211 - \log 1}$$

$$n = 1.48$$

Note: The graph of the different core sample at different saturation interval show that the resistivity index depends on the saturation. We can see that as the saturation decreases, the resistivity index increases, this shows that the more compacted the rock is, the less it absorb water. Using a log-log graph we can see that as the water saturation rises, there is an increase in the resistivity index of the different core samples.

### Discussion

Based on the result on the determination of rock properties (clay properties), from Table 1 and figure 1, which shows a result of porosity, cementation factor, formation factor and tortuosity and a plot of formation factor against porosity respectively, we can see that the formation factor depend on the pore geometry and length to the rock, as the formation factor increases, the porosity decreases.

Also based on the result of the cementation factor depend on the pore geometry of the clay sample. This value was constant throughout five core samples; it is not dependent on the length of the different core sample, because it is gotten from the same cylindrical core.

The tortuosity develops a relation between the formation factor and other properties of the rock like porosity. Tortuosity depends on the length of the core sample the effective path length through the core i.e, as the length increases, tortuosity also increases. This shows that the tortuosity is only affected by the length and formation factor. As the formation factor increases the tortuosity increases, while the porosity decreases.

From Tables 1, 2, 3, 4, 5 and also figures 1, 2, 3, 4, 5, we can see that Resistivity index and water saturation relation depends on different types of core sample of different length. From those table above, we can see that Resistivity index depend on the water saturation, as the Resistivity of the rock increase, it is because of lower water saturation. The smaller the amount of water it will absorb shows that Resistivity index increase with increase in the clay when partially saturated with rock, but decrease in the Resistivity when 100% saturated with brine or water.

### Conclusion

Based on the results, the formation factor increases with increase in length of the core samples. Also, the cementation factor decreases with increase in length, and the tortuosity increases with increase in length. Since rock has a saturation exponent ranging from 1.4 to 2.0 and the core samples (clay) has a saturation exponent, n ranging from 1.48 to 1.91, it means that clay has a good saturation characteristics compared to rock. Porosity also decreases with increases in length. Also, the resistivity index, I increases with decreases in water saturation. This is to say that clay has a big effect on rock properties because clay is an important factor in an oil and/or gas reservoir which must be put into consideration when determining reservoir rock properties.

It is recommended that for effective accomplishment of subsequent analysis, clay should be recognized as an important factor to be put under consideration. That is, before determining the rock properties of any rock, it should be ensured that the rock should contain minute quantity of clay so as to meet the specified standard of those properties in question.

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