

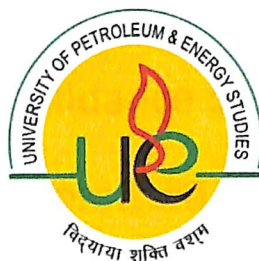
Determination of Electrical Parameters of Reservoir rock and Correlation of Lab data with Field data using Archie's Equation

Submitted for the Partial fulfilment of

BACHELOR OF TECHNOLOGY

(Applied Petroleum Technology)

(Session: September 2005 to May 2009)



Submitted to

University of Petroleum & Energy Studies, Bidholi, Dehradun

Under the able guidance of: Dr. B.P. Pandey

Submitted By:

Kushal Gupta

&

Ishank Goyal

University of Petroleum & Energy Studies, Bidholi, Dehradun

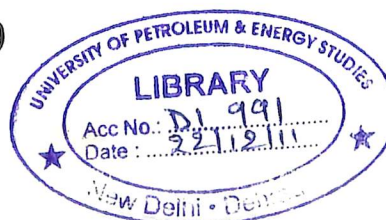
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**Determination of Electrical Parameters of
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(Major Project Report)

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UNIVERSITY OF PETROLEUM & ENERGY STUDIES

(ISO 9001:2000 Certified)

CERTIFICATE

This is to certify that the dissertation report on “**Determination of Electrical Parameters of Reservoir rock and Correlation of lab data with the Field data**” completed and submitted to the University of Petroleum & Energy Studies, Dehradun by Mr. Kushal Gupta & Mr. Ishank Goyal in partial fulfilment of the requirement for the award of degree of Bachelor of Applied Petroleum Engineering is a bonafide work carried out by them under my supervision and guidance.

To the best of my knowledge and belief the work has been based on investigation made, data collected and analyzed by them and this work has not been submitted anywhere else for any other University or Institution for the award of degree/diploma.


07.05.09

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ABSTRACT

Present project work is an attempt to bring out the role of resistivity studies in the petrophysical characterization of rocks. Wireline resistivity measurements even though indirect are fundamental to the identification of the pore fluids and their relative quantity in the rocks. Historically the creation of resistivity model was began by N E Archie in 1942 and with various subsequent the basic Archie model still plays an important role in resistivity interpretation.

Use of incorrect values of m , n , and a ; in Archie's water saturation equation, can lead to overlooking producible zones or the completion of poor zones. Often assumptions are made to approximate m , n , and a ; depending on lithology. When core is available, accepted laboratory practices exist to calculate m , n , a .

This project attempts a brief summary of the Archie model along with the result of resistivity model created through laboratory study and its correlation with field data, also it illustrates a method to calculated m , n , and a simultaneously when saturation, effective porosity, and resistivity of the sample or zone are available. Also given is a brief account of petrophysical parameters like porosity and permeability with the details of experimental study and results.

Discussion is made of the significance and utility of the parameters in understanding the hydrocarbon bearing aspects – nature and amount of hydrocarbons present in the studied formations.

ACKNOWLEDGMENT

This project bears imprints of many people.

We are thankful to *University of Petroleum & Energy Studies* for giving us this opportunity to carry out our major project on "*Determination of electrical parameters of Reservoir rock and correlation of Lab data with Field Data*"

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CONTENTS

- i. Title Page*
- ii. Certificate*
- iii. Abstract*
- iv. Acknowledgment*
- v. Table of Contents*
- vi. List of Abbreviations*
- vii. List of Figures*
- viii. List of Tables*

Chapter	Page No.
1. Introduction	1
2. Electrical Properties of Reservoir rock	4
2.1 Electrical Conductivity in porous media	6
2.2 Formation Factor	6
2.3) Effect of Conductive Solids in resistivity Measurement	10
2.4) Effect of Overburden Pressure on Resistivity	12
2.5) Resistivity index and Water saturation	13
3. Experimental Details	17
3.1) Sample Preparation	17
3.1.1) Core Analysis	17
3.2) Core Cleaning	19
3.3) Core Drying	20
3.4) Porosity	21
3.4.1) Laboratory Determination	23
3.4.2) Porosity from Saturation Method	25
3.5) Permeability Determination	26
3.5.1) Permeability-Porosity Relationships	28
3.6) Saturation	28
3.7) Resistivity measurement	31
3.7.1) Procedure for Resistivity Measurement	31
3.7.2) Data treatment	32

3.7.3) Determination of R_w	34
4) Experimental Procedure	37
4.1) Sample preparation	37
4.2) Porosity	38
4.3) Permeability	38
4.4) Resistivity Measurement	39
5).Core Plugs Details and Formation Evaluation Data	40
5.1) Core Data	40
5.2) Formation Evaluation data	41
6). Experimentally determined values	42
7). Comparison in Water saturations	43
8). Results	44
9. Discussion	45
10). Applications	47
10.1) Determination of Saturation	47
10.2) Resistivity Vs. Porosity Cross plots	47
10.3) R_{wa} Comparison	49
11). Conclusion and Future scope of work	50
References	
Appendix	

List of Abbreviations

atm: Atmosphere

aw: Activity of water

amf: Activity of mud filtrate

BV: Bulk Volume

BHT: Bottom Hole Temperature

CEC: Cation Exchange Capacity

CC: Conventional Core

CP: Centi poise

FE: Formation Evaluation

FF: Formation factor

Hrs: hours

Log: logarithmic to base 10

md: Milli Darcy

mV: milli volts

PSI: Pounds per Square Inches

PV: Pore Volume

RI: Resistivity Index

List of figures

- Figure 1: Cross section area of hollow conduit
- Figure 2: Area of cross section in a capillary tube
- Figure 3: X section area and tortuous length encountered in a porous medium
- Figure 4: Log F versus Log ϕ plot
- Figure 5: Formation Factor Vs Porosity, illustrating variation in 'm'
- Figure 6: Formation Factor Vs Porosity, illustrating variation in 'a'
- Figure 7: Parallel flow resistivity model in case of conductive minerals
- Figure 8: Effect of Brine resistivity on Formation factor
- Figure 9: Effect of over burden Pressure on Formation factor
- Figure 10: Log (Ro/Rt) versus Log Sw plot
- Figure 11: Resistivity index Vs water saturation for a range of measured saturation exponent.
- Figure 12: Resistivity index Vs. water saturation in carbonate cores
- Figure 13: Effect of stress on resistivity index-drainage curves
- Figure 14: Porosity concepts in formation Evaluation
- Figure 15: Schematic of Helium Porosimeter for Grain Volume
- Figure 16: Schematic of Helium Porosimeter for Pore Volume
- Figure 17: Darcy's Law
- Figure 18: Schematic of a laboratory Permeameter
- Figure 19: Typical permeability- porosity relation for various rock types
- Figure 20: Electrical Circuit for Resistance Measurement

Figure 21: System for Resistivity Measurement at Reservoir Condition

Figure 22: Resistivity-porosity cross plot for determining R_w , and S_w

Plate 1: Formation Factor Vs Porosity plot

Plate 2 -12: water saturation Vs Resistivity Index plots

List of Tables

- | | |
|---------------|---|
| Table 1: | Rock types and their "a" Values |
| Table 2: | Type of sandstones and their "m" values |
| Table 3: | Selected Solvents and Their Use |
| Table 4: | Core Sample Drying Method |
| Table 5: | Core plug data |
| Table 6: | Formation evaluation data from wireline logs |
| Table 7: | Experimentally generated parameters |
| Table 8: | Comparision between assumed water saturations and actual values |
| Table 9: | Sensitivity of Calculated Water Saturation to Saturation Exponent "n" |
| Table 10- 12: | Sensitivity of Calculated Water Saturation to "n" and to "m" |
| Table 13: | Formation factor data |
| Table 14: | Formation Evaluation data |
| Table 15: | Resistivity Index Vs water saturation |

Scope of work

- Determination of porosity, air permeability and grain density.
- Generation of tortuosity coefficient "a", Cementation Factor "m", and saturation exponent "n", at ambient conditions using brine.
- Correlating the saturation values that are obtained from the logs with those obtained in labs using Archie's Equation.

1. Introduction

It is the Petrophysicists role to acquire and analyse measured data of known accuracy and uncertainty, and provide it in a timely way to both the Geologist and Engineer, so that they may accomplish their goals. Subsurface accumulation of hydrocarbons takes place within the pores available in rock belonging to various lithologies. Often encountered hydrocarbon bearing formations are sandstone and originally the resistivity model that facilitates the interpretation of the wireline resistivity logs was developed by N.E. Archie.

Porous rocks are comprised of solid grains and void space. The solids, with the exception of certain clay minerals, are nonconductors. The 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. Oil and gas are nonconductors. Water is a conductor when it contains dissolved salts, such as NaCl, MgCl₂, KCl normally found in formation reservoir water. Current is conducted in water by movement of ions and can therefore be termed electrolytic conduction.

The resistivity of a porous material is defined by:

$$R = rA/L \dots\dots\dots (1)$$

Where r = resistance, Ω

A = cross-sectional area, m²

L = 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 depends on:

- salinity of water
- temperature
- porosity
- pore geometry
- formation stress
- Composition of rock.

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 the 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: clay contents, wettability, pore distribution, etc.

Archie's approach to the resistivity interpretation of clean sand with laboratory derived resistivity model may be briefly summarized as follows:

$$S_w = \sqrt[n]{\frac{a R_w}{\phi^m R_t}} \text{ For Virgin Zone (2)}$$

$$S_{xo} = \sqrt[n]{\frac{a R_{mf}}{\phi^m R_{xo}}} \text{ For invaded zone (3)}$$

Where;

S_w = Water saturation in that zone

S_{xo} = Water saturation in invaded zone

R_w = Resistivity of Formation Water

R_{mf} = Resistivity of mud filtrate

R_t = Resistivity of Formation (un invaded) from Deep latero logs

R_{xo} = Resistivity of invaded zone from shallow latero or MSF logs

a = Tortusity constant

m = Cementation factor

n = Saturation Exponent

Thus, three commonly used versions of Archie's equation are, for sandstones:

$$S_w = \left(\frac{.081 R_w}{\phi^2 R_t} \right)^{1/2}$$

$$S_w = \left(\frac{.062 R_w}{\phi^{2.15} R_t} \right)^{1/2}$$

For carbonates:

$$S_w = \left(\frac{R_w}{\phi^2 R_t} \right)^{1/2}$$

The analyst should avoid the mindset that locks the conventional values for a, m, and n into any and all log analysis evaluations. Some crossplot methods allow one or another of these parameters to be deduced; however, there is no substitute for rigorous core analysis to pin down the precise values required for each and every reservoir unit.

2. Electrical properties of Reservoir Rock

The electrical conductivity of any material is an index of its ability to conduct an electric current. It is independent of the dimensions of the element of the material, and it is the electrical analogue of permeability. The reciprocal of conductivity is resistivity. Resistivity and the electrical resistance are related as follows:

$$r \propto \frac{L}{A} \quad \dots\dots\dots (4)$$

$$r = R \frac{L}{A} \quad \dots\dots\dots (5)$$

$$R = r \frac{A}{L} \quad \dots\dots\dots (6)$$

Where:

r = Resistance of element of any material of dimension A and L, ohm

R = Resistivity of any element, ohm-length

R_w = Resistivity of brine, ohm-length

r_o = Resistance of brine saturated capillary or porous media model, ohm

R_o = Resistivity of brine saturated capillary or porous media model, ohm-length

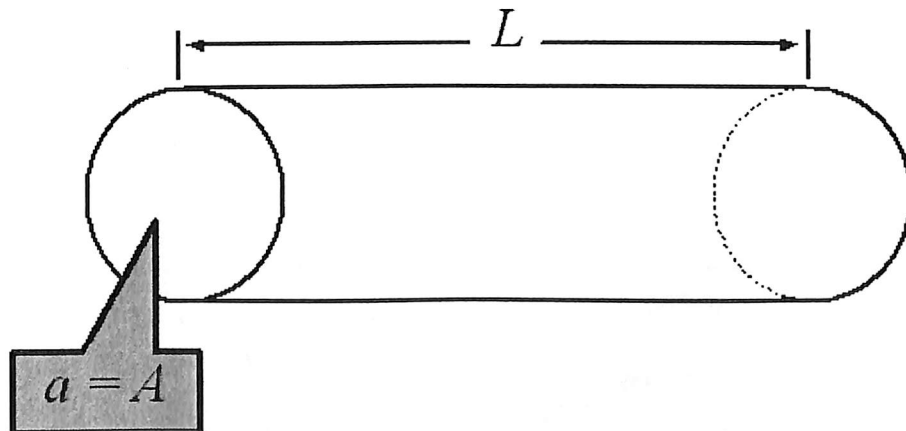


Figure 1: Cross section area of hollow conduit

In a capillary tube model the equations are:

$$r_o = R_w \frac{L}{A} \quad \dots\dots\dots (7)$$

$$R_o = r_o \frac{A}{L} = R_w \frac{LA}{La} = \frac{R_w}{\frac{a}{A}} = \frac{R_w}{\phi} \dots\dots\dots (8)$$

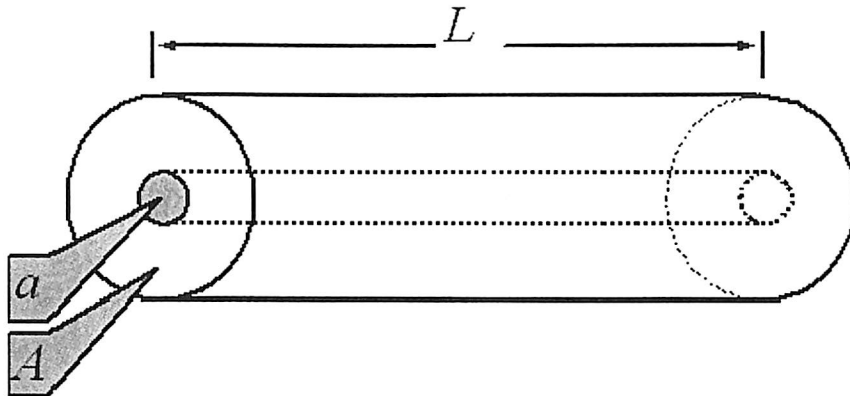


Figure 2: Area of cross section in a capillary tube

In a porous media model the equations become:

$$r_o = R_w \frac{Le}{a} \dots\dots\dots (9)$$

$$R_o = r_o \frac{A}{L} = \frac{R_w \frac{Le}{a}}{A} A \dots\dots\dots (10)$$

$$R_o = \frac{R_w \frac{Le}{L}}{\frac{a}{A}} \cdot \frac{Le}{L} = \frac{R_w \frac{Le}{L}}{\phi} \dots\dots\dots (11)$$

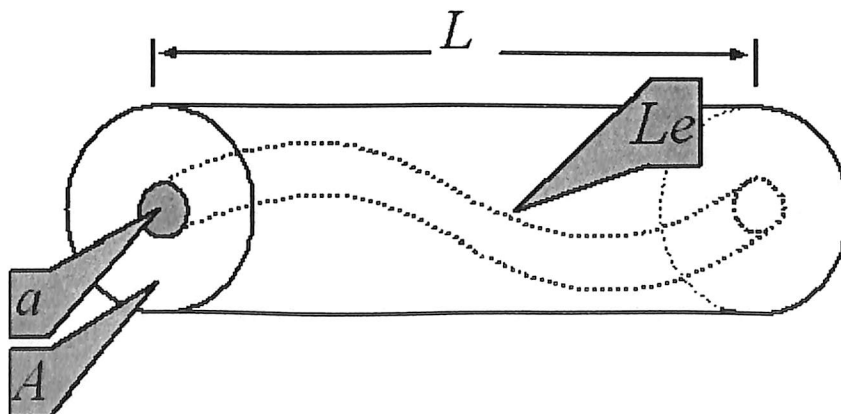


Figure 3: X section area and tortuous length encountered in a porous medium

2.1) Electrical Conductivity in Porous Media

The conduction of an electric current in porous rock is due primarily to the movement of dissolved ions in the brine that fills the pores of the rock. The conductivity varies directly with ion concentration. In formation evaluation this is usually defined as in NaCl equivalents.

Similarly, conductivity varies directly with temperature. This is due to the increased activity of the ions in solution as temperature increases. An estimate of formation temperature can be achieved from bottom hole temperature (BHT).

Variables That Influence Resistivity of Natural Porous Media

Salinity of water

Temperature

Porosity

Pore geometry

Formation stress

Composition of rock

The Archie Relationship

The Archie relationship simply states that the true resistivity, R_t , is equal to the product of a factor of the formation, F , the resistivity of the saturating brine, R_w and a resistivity index of saturation, RI , or

$$R_t = F \times R_w \times RI .$$

2.2) Formation Factor

The matrix of a rock which does not contain clays is an insulator. The electrical conductivity of this rock is due solely to the conduction network formed by the interstitial water contained in the pores (which intercommunicate) and by shape of this network. In the brine, the electrical conduction relies on the transport of ions, predominantly sodium (Na^+), and chloride (Cl^-), ions. In rock with open, well connected pore paths filled with brine, ion flow occurs easily and resistivity is low. Rocks with sinuous, constricted pore paths hinder ion transport and have high resistivity.

For a given rock sample, there is a constant ratio between the resistivity, R_o , of the rock 100% saturated with a conducting brine, and resistivity, R_w , of this brine. This constant which was first introduced by Archie (The Electrical Resistivity Log as an Aid in Determining Some Reservoir Characteristics, Trans AIME, 1942) and is called the Formation Resistivity Factor, F .

The formation resistivity factor F of a reservoir rock is an extremely valuable tool in the area of formation evaluation. It depends on numerous parameters such as:

- (1) Salinity of connate water.
- (2) Formation temperature.
- (3) Rock porosity.
- (4) Irreducible water saturation.
- (5) Amount, distribution, and type of clays.
- (6) Amount, distribution, and type of conductive minerals.
- (7) Number and type of fractures.
- (8) Layering of sand beds.

This can be expressed as:

$$F = R_o/R_w \dots\dots\dots (12)$$

Archie originally choose to derive the formation factor from porosity by the empirical relation.

$$F = \phi^{-m} \dots\dots\dots (13)$$

Archie's gave this exponential relation a linear form by adopting a log scale.

$$\text{Log } F = -m \text{ log } \phi \dots\dots\dots (14)$$

The above equation represents a straight line slope of (-) m when log F is plotted against log ϕ and thus m could be derived from porosity logs. Later researchers developed the empirical relations such as:

$$F = a / \phi^m \dots\dots\dots (15)$$

$$\text{Log } F = -m \text{ log } \phi + a \dots\dots\dots (16)$$

Where;

a = Tortuosity factor

m = Cementation factor

The values of 'a' and 'm' are determined on the core sample in the laboratory to get realistic picture of reservoir rock parameters.

The value of cementation factor varies with grain size, its distribution and consolidation. The value of 'a' is dependent upon the complexity of paths between cores (i.e. tortuosity); higher the value for tortuosity, the higher the 'm' value. The general values of 'a' and 'm' are as under:

Table 1: Rock types and their "a" Values

Rock Types	'a' values
Consolidated Sandstone	0.81
Unconsolidated Sandstones	0.62 (Humble)
Average sands	1.45 (Carothers)
Shaly sands	1.65 (Carothers)
Calc sands	1.45 (Carothers)
Carbonates	0.85 (Carothers)
Clean granular formations	1.00 (Sethi)--

Table 2: Type of sandstones and their "m" values

Sandstones	'm' values
Loose sands	1.3
Slightly cemented sands	1.3 - 1.7
Moderately cemented sands	1.7 - 1.9
Well cemented sands	1.9 - 2.2
Limestone	
Moderately porous limestone	2.0
Oolitic Limestone	2.8 - 3.0

Determination of 'a' and 'm'

The cementation factor can be determined from the results of special core analysis. Core samples of varying porosity are saturated with a brine of known resistivity. The resistivity of each saturated sample is measured. Equation (6) represent a straight line of slope (-) m when $\log F$ is plotted against $\log \phi$. The intercept of the most fitting line on the Y-axis gives the value of 'a'; whereas the slope gives the value of 'm'. This technique is usually repeated with the core sample subjected to successive simulated overburden pressures to detect any mechanical changes that may be attributed to the applied pressure. Studies have shown that "m" is related to the degree of cementation, and to changes in

applied pressure. In some areas "m" is referred to by the name "lithology" exponent.

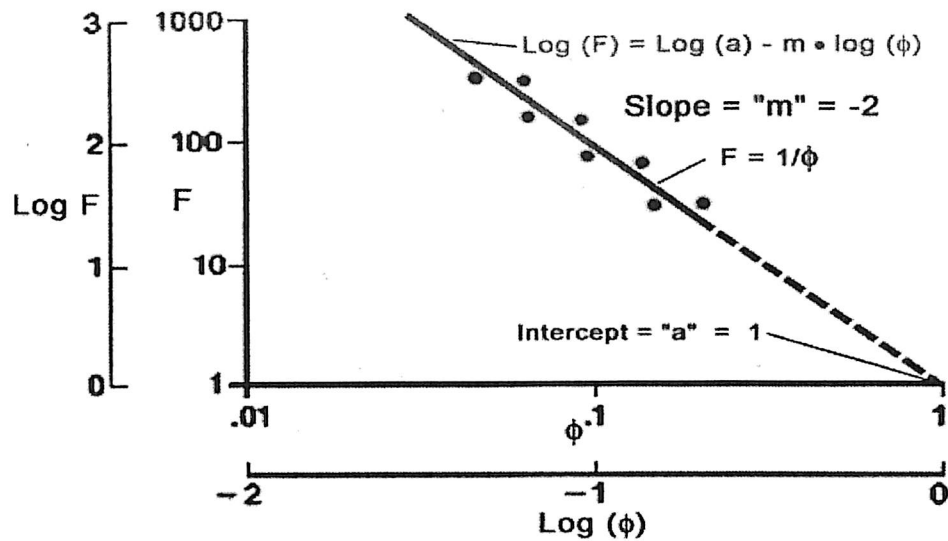


Figure 4: Log F versus Log φ plot.

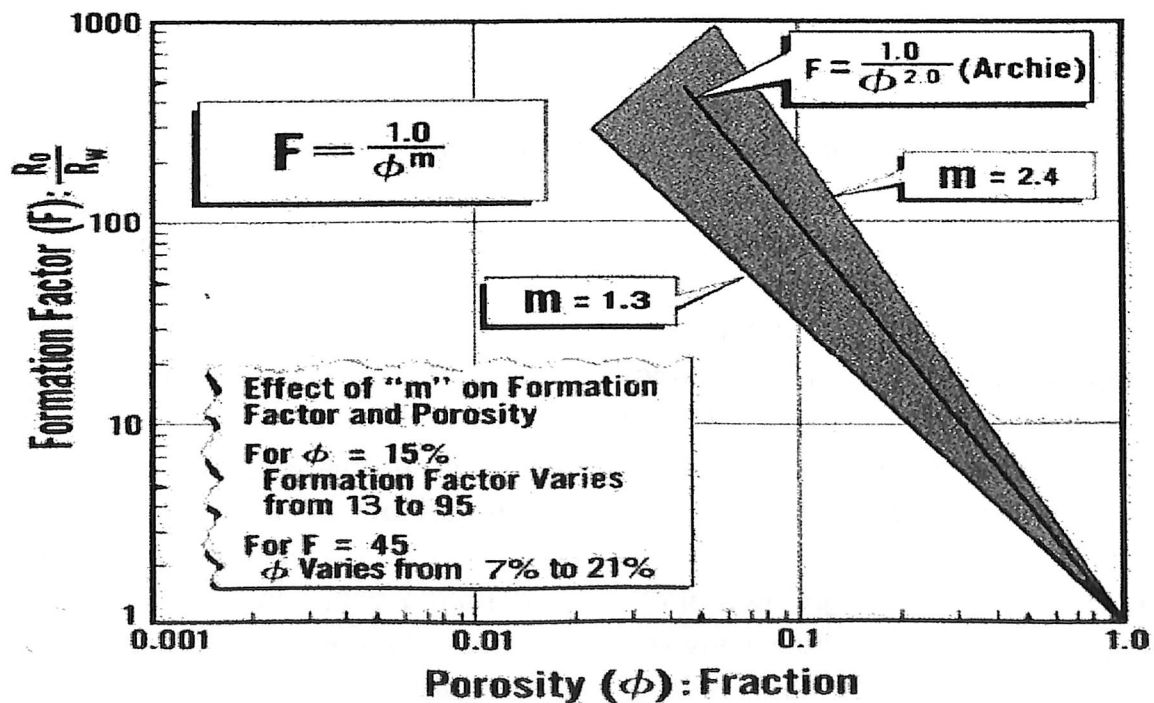


Figure 5: Formation Factor Vs Porosity, illustrating variation in 'm'

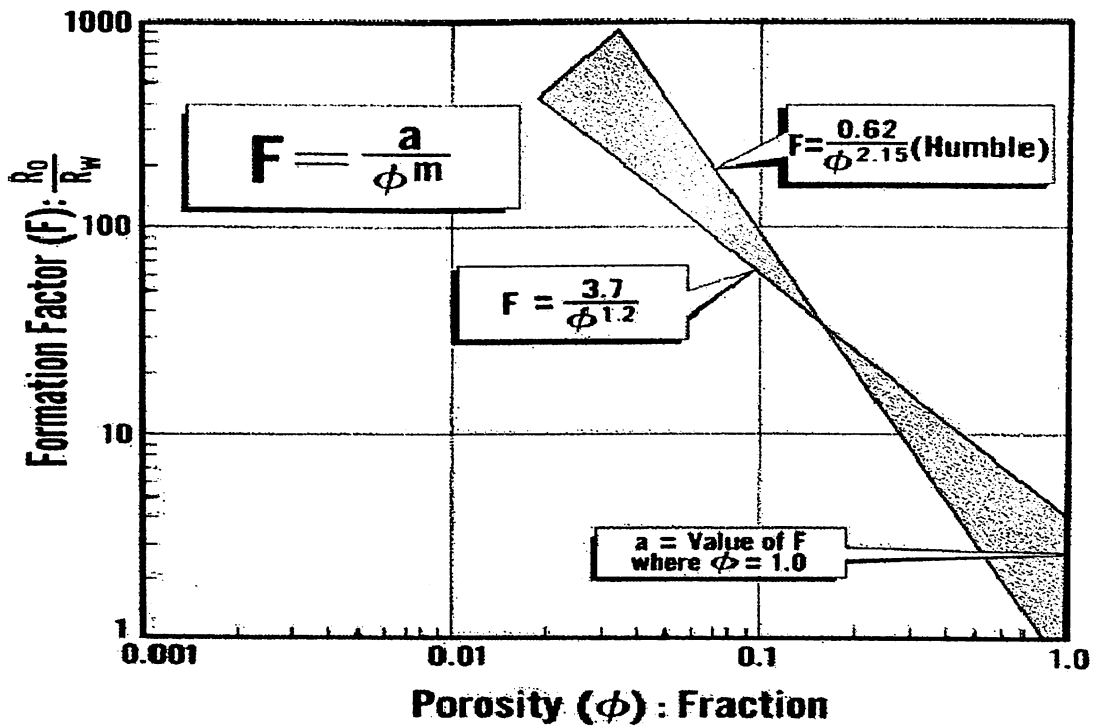


Figure 6: Formation Factor Vs Porosity, illustrating variation in 'a'

2.3) Effect of Conductive Solids in resistivity Measurement

The clay minerals present in a natural rock can 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. This water may be present as bound water and be dependent upon the surface activity or Cation Exchange Capacity of the clay, or be due to capillary entrapment in the fine microporosity created by the clay morphology.

A few minerals are also conductive in their own right, pyrite for example is sufficient of a semi-conductor to affect resistivity readings, but only when present in appreciable quantities. Most minerals other than clays do not constitute a significant resistivity problem in formation evaluation.

Clay conductivity effects in the suppression of R_t . This can be conceptualised through a parallel flow model:

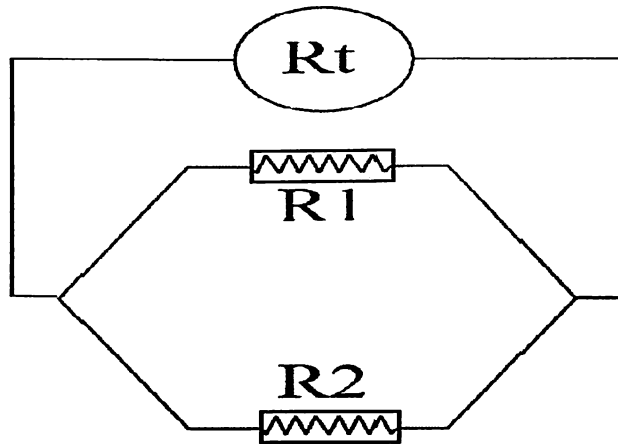


Figure 7: Parallel flow resistivity model in case of conductive minerals

$$R_t = \frac{1}{\left(\frac{1}{R_1} + \frac{1}{R_2}\right)} \dots\dots\dots (17)$$

The situation is made worse when R_w becomes larger. This is the case when formation water becomes fresher.

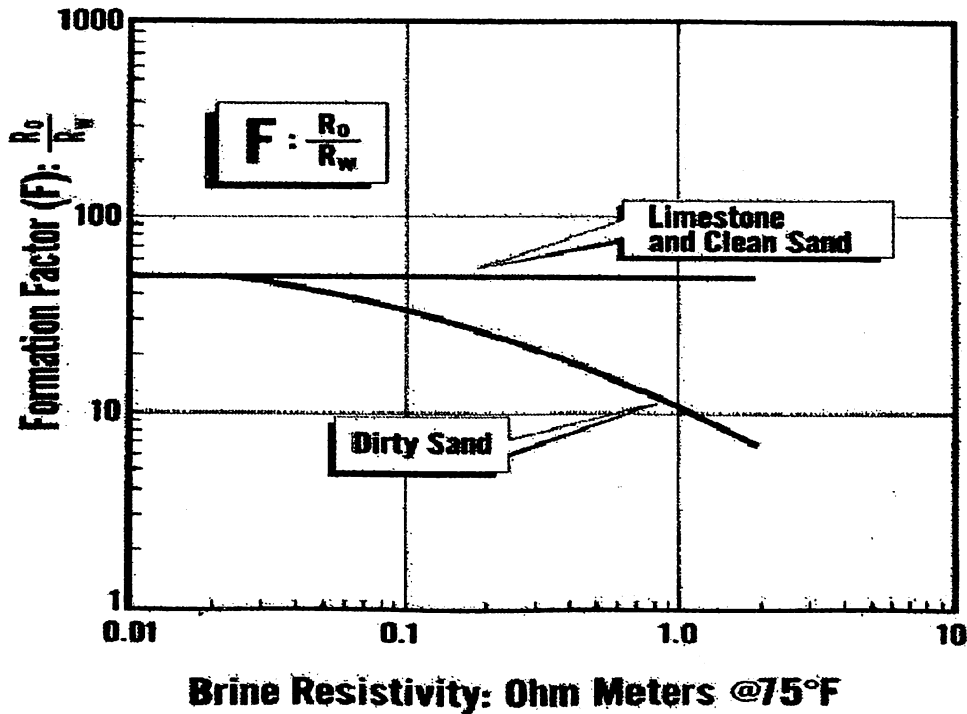


Figure 8: Effect of Brine resistivity on Formation factor

2.4) Effect of Overburden Pressure on Resistivity

Confinement or overburden pressure may cause a significant increase in resistivity. This usually occurs in rocks that are not well cemented and in lower porosity rocks. In the past, most resistivity measurements and formation factors have been determined on unconfined core samples, and nearly all of the porosity formation factor correlations in widespread use today were derived from such data. Resistivity measurements and formation factors determined under confining pressures that represent the in-situ formation conditions are essential for accurate log analysis.

The figure demonstrates the effect of overburden pressure on formation factor values. Note the increasing difference between the overburden and non-overburden values as the porosity decreases.

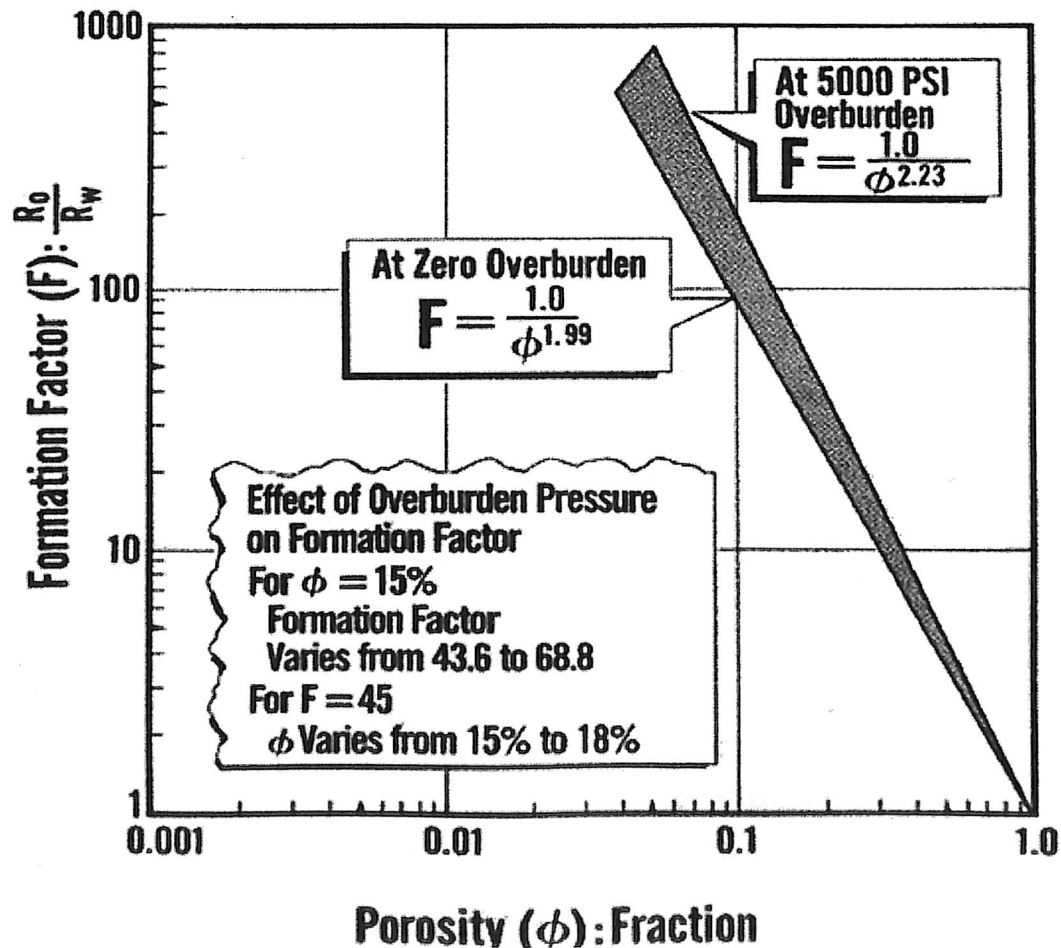


Figure 9: Effect of Overburden Pressure on Formation factor

2.5) Resistivity index and Water saturation

Resistivity index (I) is defined as the ratio of rock resistivity (R_t) at any condition of gas, oil and water saturation to the resistivity (R_o) when completely saturated with water;

$$I = R_t/R_o = S_w^{-n} \dots\dots\dots (18)$$

$I = S_w^{-n}$ as in the case of the formation factor is an exponential relation that becomes linear when logarithmic is taken.

$\log I = -n \log S_w$ which suggests that "n" may be determined as the slope of the log I versus log S_w plot

Incorporating F we may write that:

$$\begin{aligned} RI &= R_t / R_o = S_w^{-n} \\ &= [(F \times R_w)/R_t]^{1/n} \\ &= [(a / \phi^m) \times R_w \times 1/R_t]^{1/n} \dots\dots\dots (19) \end{aligned}$$

Thus the resistivity index is a function of water saturation and is also a function of the pore geometry.

The presence of cation exchangeable clays (montmorillonites) cause apparent low resistivity index values to be observed.

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

In lab measurements, a small increase in the saturation exponent was found in some cores when net confining pressures up to 5000 psi were applied.

The resistivity index (and saturation exponent) was seen to decrease at increasing temperature; however, the decrease became gradually smaller at higher temperature.

Determination of 'n'

- In the laboratory the n value is determined through the following steps:
- Resistivity of a 100% saturated sample. (R_o) at S_w = 1
- Successive measurement of resistivity (R_t) at different stages of desaturation. R_t at S_w = S_{w1}, S_{w2}, S_{w3} etc.
- Computing resistivity index as $I = R_o/R_t$
- Plotting log I versus S_w and deriving n from the slope.

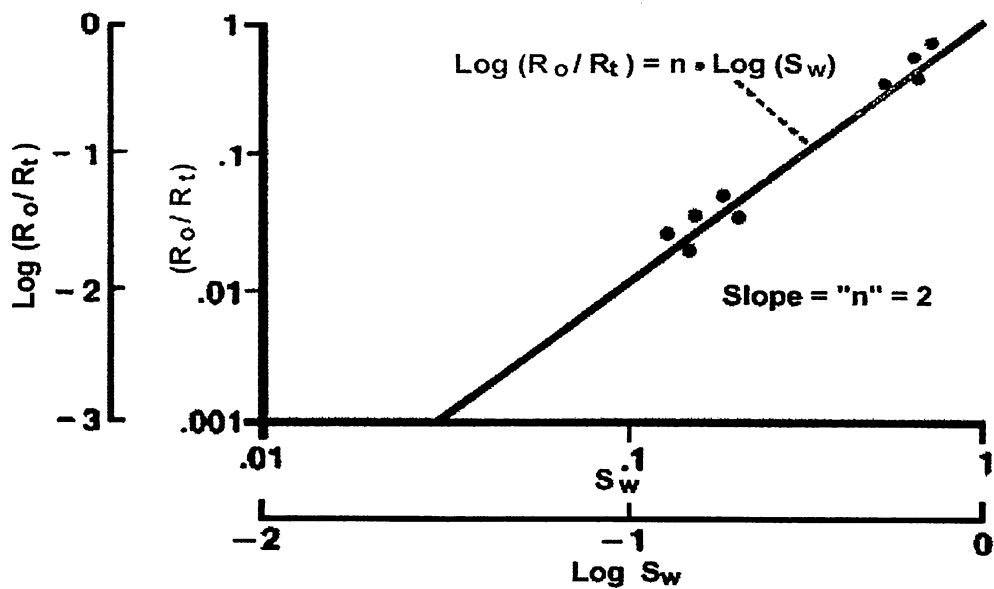


Figure 10: $\text{Log}(R_o/R_t)$ versus $\text{Log } S_w$ plot

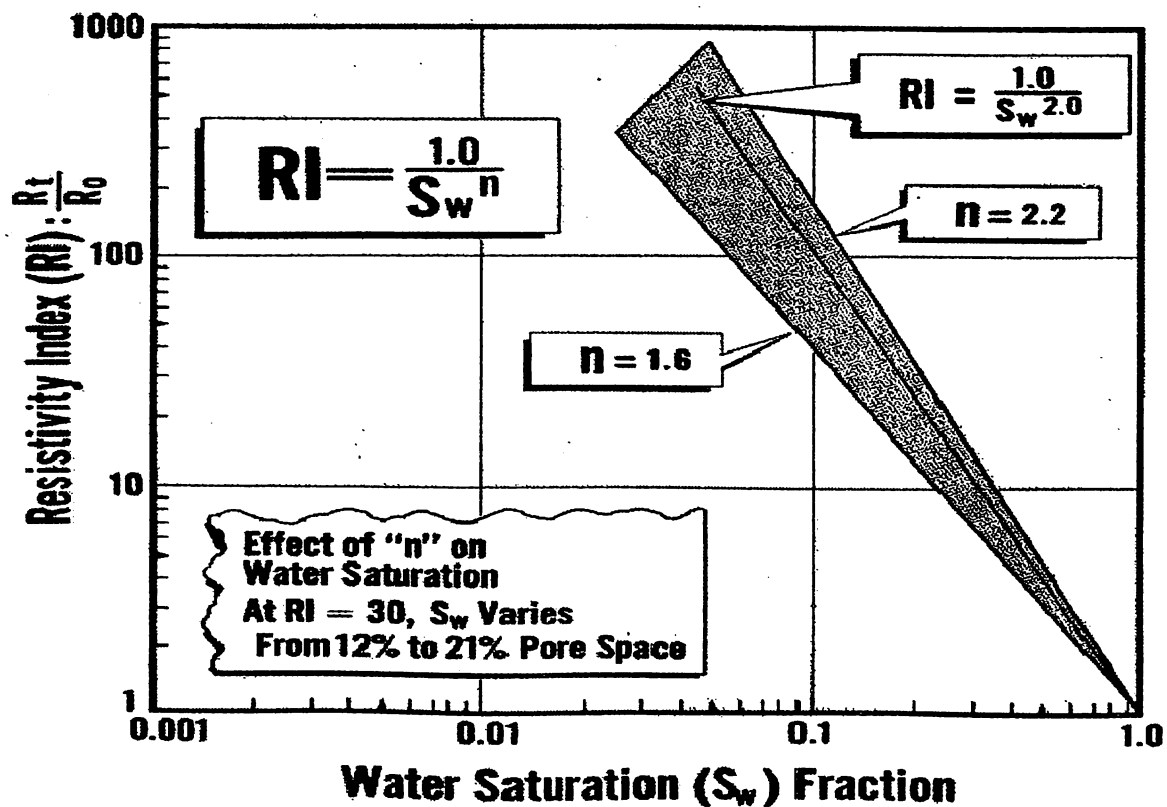


Figure 11: Resistivity index Vs water saturation for a range of measured saturation exponent.

Factors effecting 'n'

The value of n is affected by wettability, overburden pressure, nature and microscopic distribution of the reservoir fluids, and types and amounts of conductive clays.

n is essentially independent of wettability when the brine saturation S_w is sufficiently high to form a continuous film on the grain surfaces of the porous medium and, consequently, to provide a continuous path for a current flow. This continuity is common in clean and uniformly water-wet systems. The value of the saturation exponent n in these systems is approximately 2 and remains essentially constant as the water saturation is lowered to its irreducible value, S_{wi} . In uniformly oil-wet systems with low brine saturations, large values of the saturation exponent, 10 or higher, should be expected.

The effects of wettability on carbonate cores were investigated by Sweeney and Jennings. They found that the saturation exponent ranged from 1.6 to 1.9 for water-wet cores, whereas the oil-wet cores exhibited two different types of behaviors as shown in Figure 12. In some cores, n was about 8 even when S_w was very high. In other cores, the behavior of n was similar to the water-wet and neutrally wet, i.e., $1.5 \leq n \leq 2.5$, until a brine saturation of nearly 35% was reached,

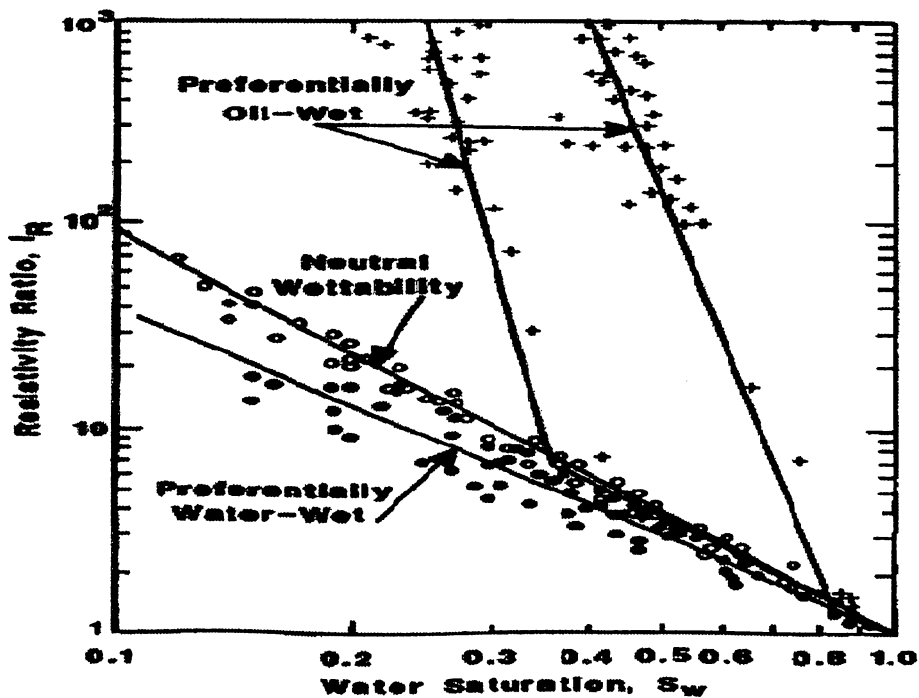


Figure 12: Resistivity index Vs. water saturation in carbonate cores

Figure 13 illustrate the influence of overburden pressure on the saturation exponent for water-wet sandstone core and Berea Sandstone core, respectively. The maximum change in the saturation exponent with overburden pressure was approximately 8% for water-wet cores and 4% for oil-wet cores

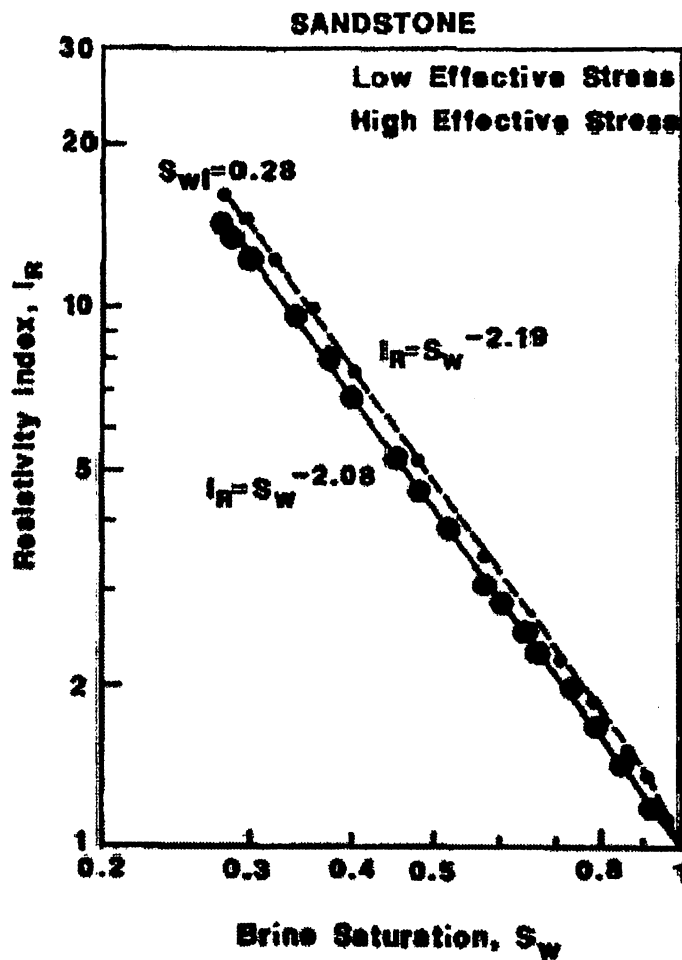


Figure13: Effect of stress on resistivity index-drainage curves

3. Experimental Details

3.1) Sample Preparation

3.1.1) Core Analysis

Core analysis tests are generally classified in to two categories and major factor that differentiates the two is the time required for analysis. The two categories are as follows:

1. Conventional Core Analysis

- Porosity
- Grain Density
- Permeability
- Fluid Saturation

2. Special Core Analysis

Special core analysis normally takes 8 to 10 weeks or longer depending upon the type of parameters required. The under given tests are usually performed.

- Capillary Pressure
- Relative Permeability
- Water flood and Gas flood
- Wettability
- Electrical Resistivity

Principle

The sampling procedure for basic core analysis is determined by the type of information required. Sampling will generally take into account one or more of the following:

- Lithological distribution.
- Porosity and permeability variations within the lithological units.
- Distribution of hydrocarbons.

Plug Samples

Referred to as plugs, should be removed from section: whole core oriented either vertically or horizontally with respect to the whole core axis or with respect to the normal of the bedding planes.

Full Diameter Samples

Full diameter samples (sections of whole core), in addition to plug samples, should be taken in the following type of zones or where there are significant large scale of heterogeneities that are different from the matrix properties

Sample Cutting, Trimming, and Mounting

The core should be cut and trimmed to provide regular shaped samples, most commonly right cylinders. Unconsolidated, disintegrating, and very friable samples may have to be mounted prior to testing.

The following information should be available prior to cutting, trimming, or mounting operations:

- The total number of samples required.
- Size and orientation needed.
- Exact depth locations for samples and how they are to be labeled.
- Fluids to use for cutting samples (cores containing clays or shale laminations sensitive to fresh water will deteriorate, unless proper drilling fluids are used).
- Available core images.

Procedure

The following procedures for preparing various type core samples should be followed:

a. Plug samples:

1. Drill plugs at specified points using the appropriate size bit. Care should be taken to drill straight plugs. If too much pressure is applied during the drilling operation, the bit will flex causing the plug to deform.
2. Trim plugs to the required length making sure that the ends are parallel. Keep and label trimmed ends.
3. Label, preserve, and/or store samples, as required.

b. Full diameter samples:

1. Cut sections of the core selected for analysis slightly longer than required to allow for finish grinding operations.
2. Remove barbs and smooth chipped edges by dressing the ends. Cylinder ends should be as close to parallel as possible.
3. Clearly mark the samples and preserve or store as required.

3.2) Core Cleaning

Prior to most laboratory measurements of porosity and permeability, the original fluids must be completely removed from the core sample. This is generally accomplished through flushing, flowing, or contacting with various solvents to extract hydrocarbons, water, and brine.

Some solvents used for hydrocarbon extraction purposes are listed in Table 3. Listed solvents are those most frequently used for extracting samples for routine analysis. Some are preferred for specific applications; e.g toluene has been found useful for asphaltic crudes. Prior to cleaning samples with unknown oil properties, a sub-sample should be tested with various solvents for cleaning efficiency.

Since residual salt crystals affect the measured porosity and permeability, core samples containing formation water with high salinity may require additional extraction to remove salt. Salt can be removed with methyl alcohol or other solvents in which salt are soluble.

Solvent	Boiling Point, °C	Solubility
Acetone	56.5	oil, water, salt
Chloroform Methanol azeotrope (65/35)	53.5	oil, water, salt
Cyclohexane .,	81.4	Oil
Ethylene Chloride	83.5	oil, water
Hexane	49.7-68.7	oil
Methanol Methylene Chloride	64.7	water, salt
Naphtha	40.1	oil, water
Tetrachloroethylene	160.0	oil
Tetrahydrofuran	121.0	oil
Toluene	65.0	oil, water, salt
Trichloroethylene	110.6	Oil
Xylene	87.0	oil, water, salt
Acetone	138-144.4	Oil

Table 3: Selected Solvents and Their Use

Precaution

The following precautions should be enforced during core sample cleaning operations:

- When using solvents, it is the responsibility of the user to establish appropriate safety and health practices prior to use and to comply with all applicable regulatory requirements regarding use and disposal of materials.
- The solvent selected should not attack, alter, or destroy the structure of the sample.
- Chloroform may hydrolyze during extraction, forming hydrochloric acid as a product.
- Closed-type electrical heaters should be used whenever flammable solvents are used.

3.3) Core Drying

Conventional core samples can be dried by the methods listed in Table 4.

Rock Type	Method	Temp., °C
Sandstone (low clay content)	Conventional Oven	116
	Vacuum oven	90
Sandstone (high clay content)	Humidity Oven, 40% relative humidity	63
Carbonate	Conventional Oven	116
	Vacuum oven	90
Gypsum bearing	Humidity Oven, 40% relative humidity	60
Shale or other high clay rock	Humidity Oven, 40% relative humidity	60
	Conventional Oven	

Table 4: Core Sample Drying Method

Each core sample should be dried until the weight becomes constant. Drying times may vary substantially, but are generally in excess of four hours

Precautions

Some precautions that should be observed in drying samples for routine core measurements are:

- Samples containing clays must not be dehydrated during preparation. Care must be exercised in drying these samples.
- Samples containing gypsum will require specific procedures during preparation. Extreme care should be exercised to avoid both loss of water and change of the crystalline structure.
- Samples must be protected from erosion by the drip of clean solvent when utilizing the distillation extraction technique.
- Samples containing heavy asphaltic oils may require the cycling of more than one solvent.
- More effective core cleaning can often be achieved by a combination of solvents.
- Allow solvent laden samples to vent in a fume hood before placing in a closed drying oven.

3.4) Porosity

Porosity is defined as the ratio of the pore volume to the bulk volume of a substance. In oil and gas reservoirs, the pore volume is the space available for the storage of the hydrocarbons and water. Porosity is normally expressed as a percentage of bulk volume and is symbolized by ϕ .

$$\text{Porosity, } \phi = \frac{\text{PoreVolume}}{\text{BulkVolume}} \times 100 \quad \dots\dots\dots (20)$$

$$\text{Porosity, } \phi = \frac{\text{BulkVolume} - \text{GrainVolume}}{\text{BulkVolume}} \times 100 \quad \dots\dots\dots (21)$$

$$\text{Porosity, } \phi = \frac{\text{PoreVolume}}{\text{PoreVolume} + \text{GrainVolume}} \times 100 \quad \dots\dots\dots (22)$$

Total Porosity

Total porosity is defined as the ratio of the volume of all the pores to the bulk volume of a material, regardless of whether or not all of the pores are interconnected.

Effective Porosity

Effective porosity is defined as the ratio of the interconnected pore volume to the bulk volume of a material, i.e. it does not include dead-end pore-space.

Water of Hydration

The water of hydration of crystallisation of the constituent minerals of a reservoir rock is defined as a portion of the grain volume. It is not a portion of the pore volume. This can pose problems when comparing certain log porosities with core-derived data and in the derivation of fluid saturations on these rocks.

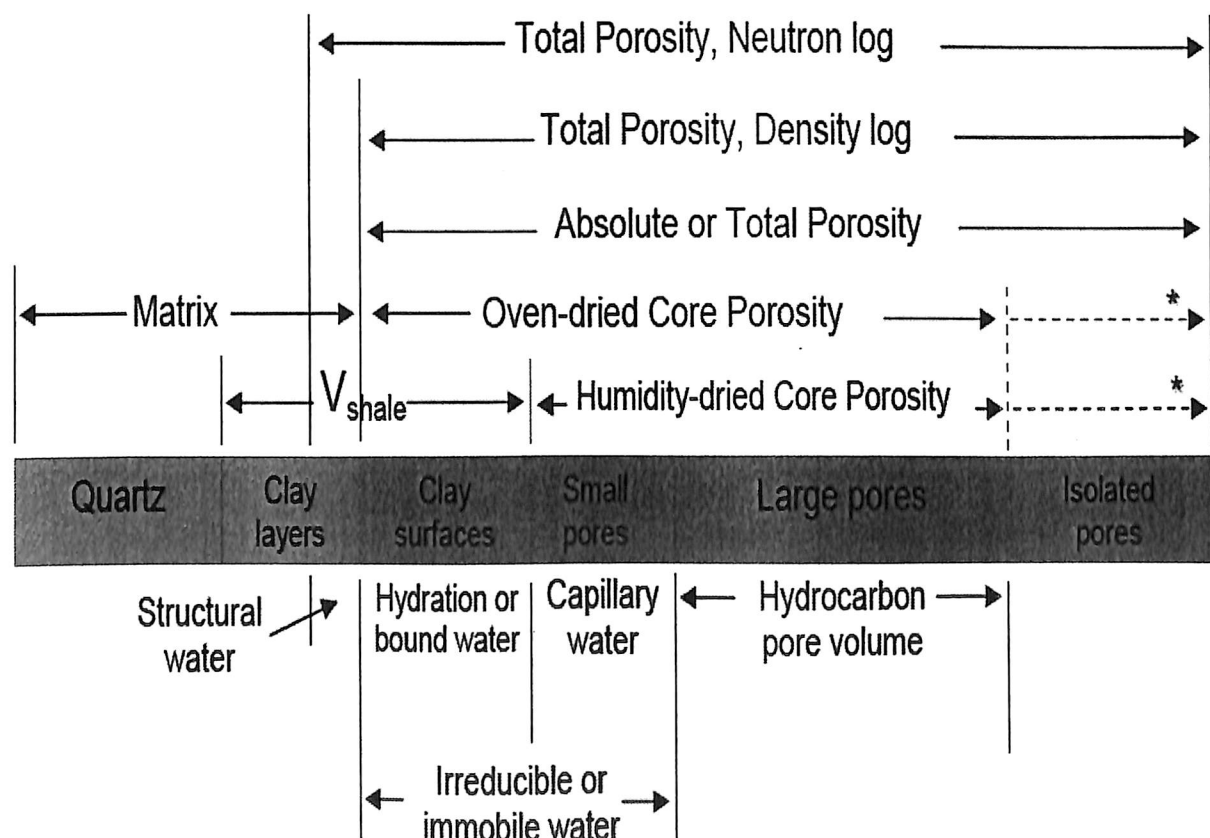


Figure 14: Porosity concepts in formation Evaluation

Porosity Determination

The porosity is determined by core analysis or by well logging.

Determination by Core analysis

In core analysis, the cylindrical plugs of either 1.0 inch or 1.5 inch diameter are cut from whole core and then first cleaned and dried. In laboratory any two of V_p , V_b , V_g are measured and then porosity is determined.

Measurement of bulk volume

Caliper method. The length and diameter of core plug is measured at different points of the core and averaged values are determined.

$$V_b = \pi d^2 l / 4$$

Measurement of the buoyancy exerted by mercury on the samples immersed in it. The mercury based methods are not used for rocks containing fissures or macropores because of possibility of mercury penetration.

Measurement of pore volume

The pore volume can be measured:

- Helium expansion in the interconnected pores.
- Measurement by weighing in a fluid filling the effective pores.
- Measurement by mercury injection.

The grain volume can also be determined by Helium expansion method.

3.4.1) Laboratory Determination (Using Helium Porosimeter)

Principal of Grain and Pore Volume Measurement:

Boyle's Law: $P_1 \times \frac{P_2}{T_1} = P_2 \times \frac{P_2}{T_2}$ (23)

Grain Volume:

$$P_1 \times V_{Ref} = P_2 (V_{Ref} + V_{Matrix} - V_{Grain})$$
 (24)

$$V_{Grain} = (V_{Matrix} + V_{Ref}) + \frac{P_1}{P_2} \times V_{Ref}$$
 (25)

By calibrating with a series of known volume standard, the relationship between grain volume and ratio $\frac{P_1}{P_2}$ can be defined.

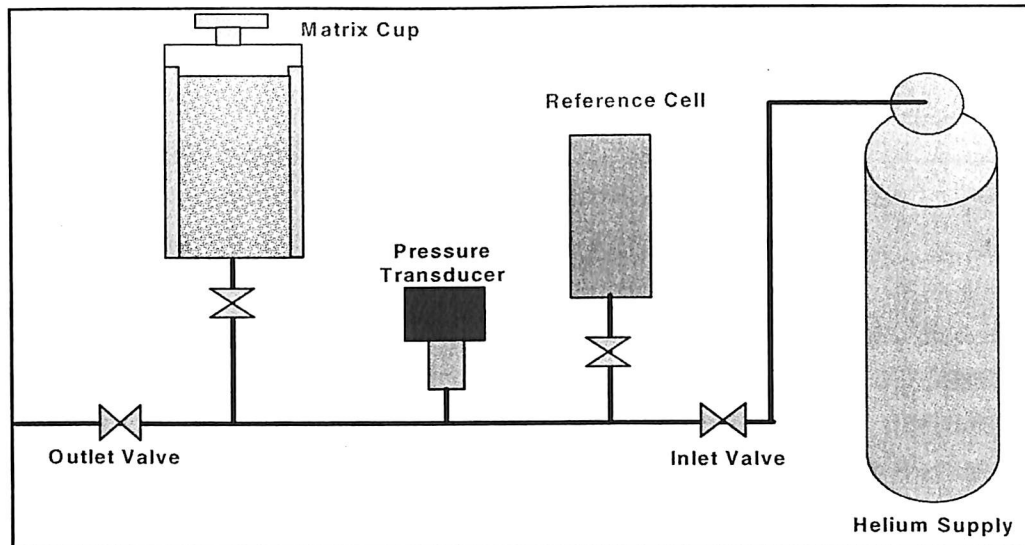


Figure 15: Schematic of Helium Porosimeter for Grain Volume

Pore Volume: $P_1 \times V_{Ref} = P_2 (V_{Dead} + V_{pore})$ (26)

$$V_{Pore} = \frac{P_1}{P_2} \times V_{Ref} - V_{Dead} \quad \text{..... (27)}$$

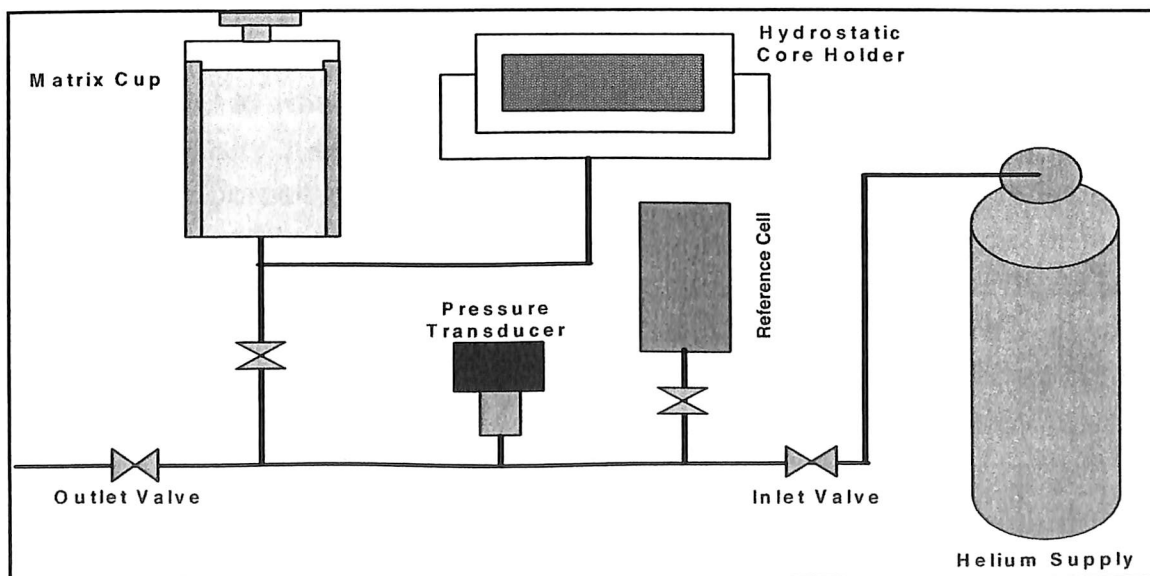


Figure 16: Schematic of Helium Porosimeter for Pore Volume

3.4.2) Porosity from Saturation Method

$$\text{Pore Volume (PV)} = (\text{Saturated Wt.} - \text{Dry Wt.}) / \text{Brine Density} \dots\dots\dots (28)$$

$$\text{Bulk Volume (BV)} = \text{Immersed Wt.} / \text{Brine Density} \dots\dots\dots (29)$$

$$\text{Porosity} = \text{PV} / \text{BV} \times 100 \dots\dots\dots (30)$$

POROSITY-TEXTURE AND PETROPHYSICAL RELATIONSHIPS

Porosity in sands and sandstones varies primarily with grain size distribution, grain shape, packing arrangement, cementation, and clay content. These parameters control the overall pore geometry as well as the porosity value. The porosity of typical hydrocarbon productive sandstones ranges between 3 and 38 percent in gas reservoirs and 10 to 38 percent in oil reservoirs.

Porosity in carbonate rocks can be much more variable in magnitude than it is in sandstones. In some carbonates, such as reef build-ups and chalks, it is very high, in a few cases exceeding 50 percent. However, the fractures commonly encountered in carbonate rocks contribute little to the porosity. The development of vugs and fractures as found in carbonate reservoir rocks is termed Secondary Porosity and is a function of the depositional history and diagenesis of the rocks. Diagenetic overprints in carbonates can be much more radical than those in sandstone (siliciclastic) reservoirs as both complete mineral replacement and complete dissolution can occur a number of times as a function of burial history. Often, carbonate reservoir rock's porosity can be correlated with the degree of dolomitisation, as the dolomitisation of limestone can generate up to 12% additional porosity due to shrinkage of the crystalline lattice.

While vugular porosity can be large, caverns of some tens of metres size having been encountered in some rare cases, fractures, which make up the other major component of secondary porosity tend to be of a smaller aperture. This is because fractures are a response to reservoir stress history and there are always forces attempting to close them. A common misconception is how much they contribute to overall reservoir porosity.

3.5) Permeability Determination

Permeability is a property of the porous medium and it is a measure of capacity of the medium to transmit fluids. Its unit is Darcy. One Darcy equals permeability that will permit a fluid of one centipoise viscosity to flow at a rate of one cubic centimeter per second through a cross-sectional area of one square centimeter when the pressure gradient is one atmosphere per centimeter. Generally permeabilities are given in millidarcies which is equal to (1/1000) of a Darcy. Its dimension is L^2 .

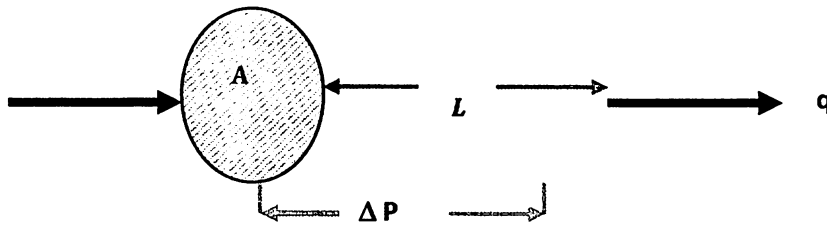


Figure 17: Darcy's Law

$$k = \frac{q \mu L}{A \Delta p} \dots\dots\dots (31)$$

Where;

ΔP = Press. Differential, atm

q = Outlet Flow Rate, cc/sec

μ = Fluid Viscosity, cp

L = System Length, cm

K = Permeability, darcy

A = Cross Sectional Area, cm^2

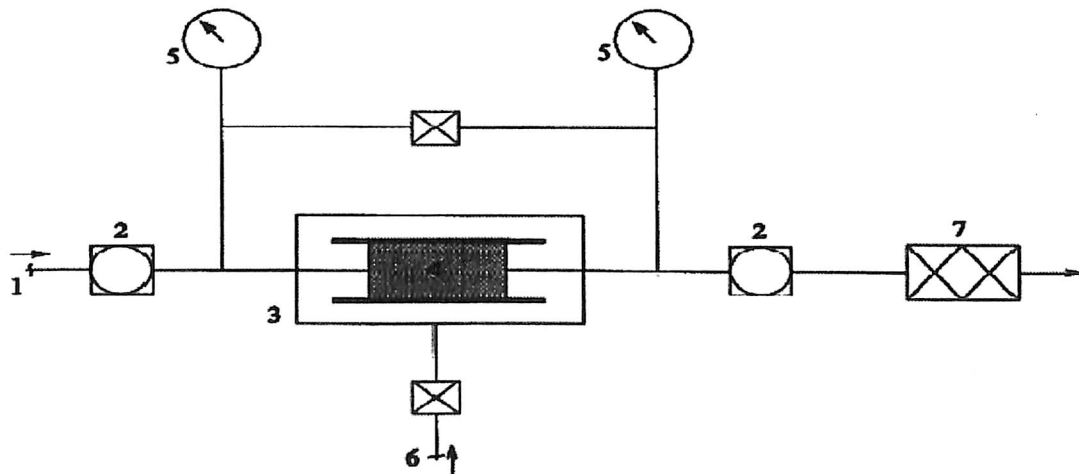
The permeability is measured by flowing a fluid of known viscosity μ through a core plug of measured dimensions (A and L) and then measuring flow rate q and pressure drop Δp . Absolute permeability is usually determined by flowing air through the core plug because of its convenience and to minimize rock-fluid interaction.

In using dry gas in measuring the permeability, the gas volumetric rate q varies with the pressure because the gas is a highly compressible fluid. Hence, the equation becomes

$$Q_{sc} = \frac{kA(p_1^2 - p_2^2)}{2\mu_g L p_b} \dots\dots\dots (32)$$

Where

- k = absolute permeability, Darcies
- μ_g = gas viscosity, cp
- p_b = base pressure (atmospheric pressure), atm
- p_1 = inlet pressure (upstream), atm.
- p_2 = outlet (down stream), atm.
- L = length of the core plug, cm
- A = cross-sectional area, cm^2
- Q_{sc} = gas flow rate at standard conditions, cm^3/sec .



- | | |
|---------------------|--|
| 1. Air supply | 5. Manometers |
| 2. Reduction valves | 6. Sleeve pressure |
| 3. Core holder | 7. Wet-test meter (gas-volume measurement) |
| 4. Core sample | |

Figure 18: Schematic of a laboratory Permeameter

3.5.1) Permeability-Porosity Relationships

The relationship between permeability and porosity is qualitative and is not directly or indirectly quantitative in any way. It is possible to have very high porosity without having any permeability at all, as in the case of pumice stone (where the effective porosity is nearly zero), clays, and shales. The reverse of high permeability with a low porosity might also be true, such as in micro-fractured carbonates. In spite of this fundamental lack of correspondence between these two properties, there often can be found a very useful correlation between them within one formation

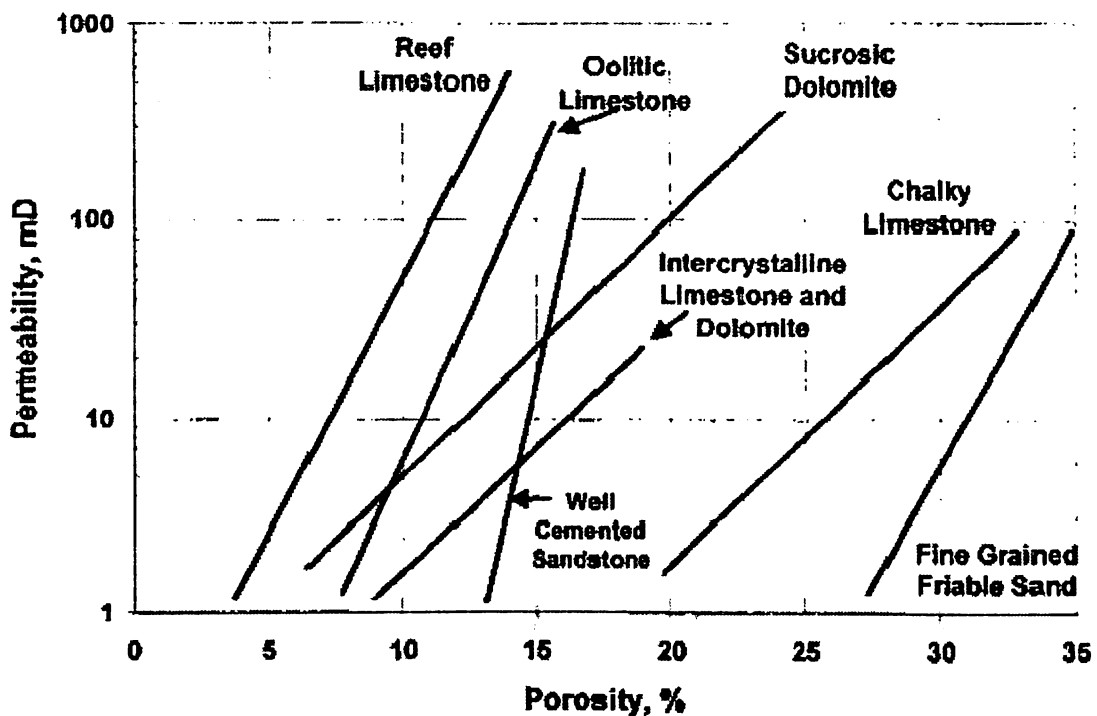


Figure 19: Typical permeability-porosity relation for various rock types.

3.6) Saturation

The saturating fluid content of a porous rock may be quantitatively described in one of two ways. The saturation may be expressed as a fractional proportion, or percentage of the porosity that is occupied by the specific fluid phase, or the fractional proportion, or percentage of the bulk volume that is occupied by the fluid phase. In formation evaluation we are most often concerned with the water saturation (S_w) as this is the phase that carries electrical current from the logging

tools. By necessity $(1-S_w)$ is the hydrocarbon saturation of the pore-space. The S_w commonly derived is the portion of the porosity that is water and

$$S_w = \frac{\text{Bulkwater}}{\phi}$$

Fluid saturation is defined as the fraction of pore volume occupied by a particular fluid. Hence for reservoir fluids, mathematical expressions can be:

$$S_o = \frac{\text{Volume of oil}}{\text{Pore Volume}}$$

$$S_g = \frac{\text{Volume of gas}}{\text{Pore Volume}}$$

$$S_w = \frac{\text{Volume of water}}{\text{Pore Volume}}$$

$$S_g + S_o + S_w = 100$$

It should be clear that this means that the bulk water content is the product of porosity and S_w .

The S_w of the rock is dependent upon the balance between the gravity forces and the adhesive forces of the water-rock system.

Sw Determination

The brine saturating the core is displaced with air, naphtha or live crude oil, and the true resistivity R_t is measured after each increment of displacement. The water saturation S_w is determined by measuring the volume of water produced and applying the material balance equation

Weight of liquids removed from sample	=	Weight of original saturated sample	-	Weight of desaturated and dried sample
---------------------------------------	---	-------------------------------------	---	--

The weight of water collected from the sample is determined from the volume of water by the relationship:

$$W_w = \rho_w \cdot V_w$$

Where,

ρ_w = water density, gm/cm³

W_w = Weight of the water, gm

V_w = Volume of water, cm³

The weight of the oil removed from the core may then be computed as the weight of liquid less weight of the water:

$$W_o = W_L - W_w$$

Where,

W_L = weight of liquids removed from core sample, gm

W_w = weight of water removed from core sample, gm

W_o = weight of oil removed from core sample, gm

Oil volume V_o may then be computed as W_o/ρ_o ; pore volume V_p is determined by a porosity measurement; and oil saturation may be computed by the relationship

$$S_o = 100 \cdot (V_o/V_p)$$

3.7) Resistivity measurement

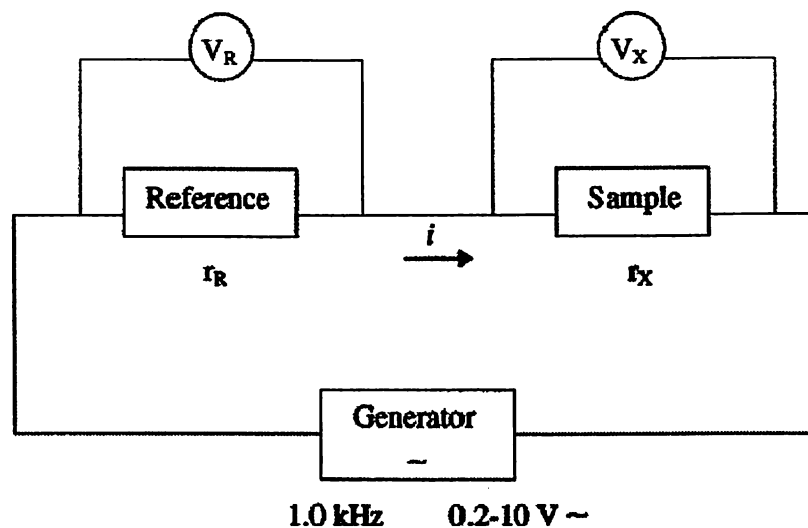


Figure 20: Electrical Circuit for Resistance Measurement

3.7.1) Procedure for Resistivity Measurement

- Mix a brine solution of the desired salinity for the test, filter and evacuate it.
- Saturate clean, dry core samples to be tested in the brine using a covered glass vessel as the saturating chamber. Shaly samples may take several weeks to achieve ionic equilibrium between brine and the clays. Clean non-shaly samples will be ready to test in 3 to 4 days.
- Remove the core from its brine container wiping off all excess brine from the surface the hand and carefully place it between the two electrodes of the core holder.
- Screw the threaded adjustment arm on the core holder sufficiently to compress the opposite arm spring to firmly hold the core in place.
- Connect the core holder electrical leads to the resistivity measuring unit
- Measure the core resistance.
- Desaturate the sample using porous plate cell or centrifuge.
- At each equilibrium saturation determine resistance

3.7.2) Data treatment

Formation Factor, $F = R_o/R_w$
 $= [(A/L)C_r]/W_rK$ (33)

Resistivity Index, $RI = R_t/R_o$

Where in;

R_o = Resistivity of 100% brine saturated core, ohm meter.

R_w = Water Resistivity, ohm meter

R_t = True resistivity at given S_w

A = Cross sectional area of core sample, sq.m.

L = Length of core sample, cms.

C_r = Resistance of brine saturated core, ohms

W_r = Measured water resistance, ohms

K = Dip cell constant

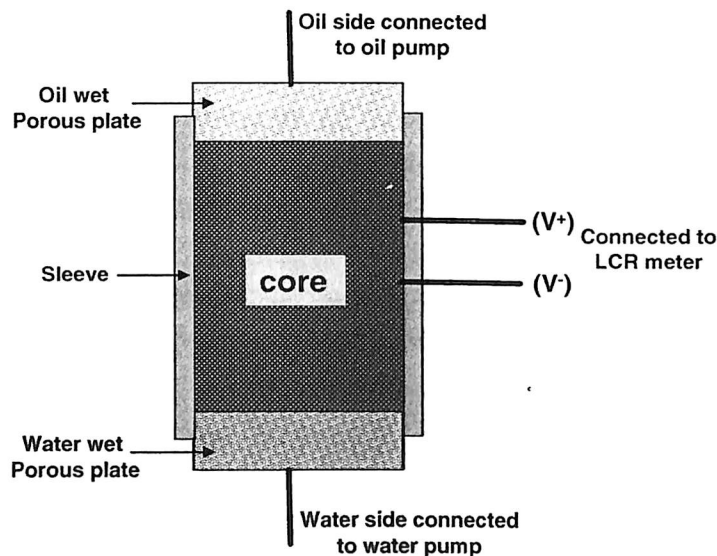


Figure 21: System for Resistivity Measurement at Reservoir Condition

The system is dedicated to the determination of the capillary pressure curves (positive and negative) and the electrical resistivity index as a function of core sample saturation at reservoir conditions. Saturation exponent “n”, formation factor and cementation exponent “m” are also calculated. The instrument consists of a core holder furnished with hydrophobic and hydrophilic ceramics and electrodes pattern for resistivity measurement, an automated pumping

system for fluid control and a resistivity cell for brine resistivity measurement. The whole is housed in a temperature controlled air bath.

Determination of “a” & “m” from core

The cementation factor can be determined from the results of special core analysis. Core samples of varying porosity are saturated with a brine of known resistivity. The resistivity of each saturated sample is measured. In this situation S_w is known to be 1.0. Archie's equation reduces to:

$$\text{Log } R_o / R_w = -m \log \Phi + \log a$$

A plot on log-log paper of the ratio of the core resistivity to the brine resistivity versus the porosity of each core sample defines a line with a slope equal to “-m” and intercept ‘a’.

This technique is usually repeated with the core sample subjected to successive simulated overburden pressures to detect any mechanical changes that may be attributed to the applied pressure. Studies have shown that “m” is related to the degree of cementation, and to changes in applied pressure. In some areas “m” is referred to by the name “lithology” exponent.

Determination of “n” from core

The saturation exponent is also derived from special core analysis. A dry core sample is weighed. It is then saturated with brine and its resistivity (R_0) is measured. Through the use of a semi-permeable membrane and/or a centrifuge the sample is gradually desaturated. At different stages during the desaturation the sample is weighed to determine the brine remaining in the core. This is converted to a water saturation using the previously measured core porosity. The resistivity (R_t) is also measured at the time of each weighing.

The resistivity is usually expressed as the resistivity index R_t/R_0 . This situation is described by Archie's equation in the following form.

$$\text{Log } R_t / R_0 = -n \log S_w$$

A plot of resistivity index versus brine saturation on log-log paper defines a line with a slope of “-n”.

Formation water resistivity

Formation water some time called connate water or interstitial water, is the water uncontaminated by drilling mud, the saturate the porous formation rock. the resistivity of this formation water , R_w , is an important interpretation parameter since it is required for the calculation of saturation (water and /or hydrocarbon) from basic resistivity information. these include water catalogs, chemical analysis, the spontaneous potential (SP) curve, and varies resistivity-porosity computation and crossplots.

3.7.3) Determination of R_w

R_w from Water Catalog

In many oil-producing region, water catalogs have been publish that list the resistivity data for many formation water collected from different field and different producing horizon of the region .The source of the R_w values may be the measurement of a water sample obtain from production test, or from a drillstem test. In some cases,the might be the well logs.

These catalogs are compiled and published by the local geology or the other professional societies, by the oil companies or producer, by the govenernment entities, and by educational groups. The can verify R_w values obtained from the SP curve or from resistivity-porosity comparison.

R_w from Chemical Analysis

Although the direct measurement of formation water resistivity on a produce water sample is always preferred, sometime only a chemical analysis of the water sample is available, even in catalog listing.

Methods do exist for deriving the electrical resistivity of a solution from its chemical analysis.

R_w from the SP

In many cases, the good values of R_w can be easily be found from the SP curve recorded in clean (noshaly) formation. The static SP (SSP) value in clean formation is related to the chemical activities (a_w and a_{mf}) of the formation water and the mud filtrate through the formula:

$$SSP = -K \log a_w / a_{mf} \dots\dots\dots (34)$$

For NaCl solution, K= at 77 F (25 c); K varies in direct proportion to temperature:

$$K = 61 + 0.133 T_f$$

$$K = 65 + 0.24 T_c$$

For pure NaCl solution that is not too concentrated, resistivities are inversely proportional to activities. However, this inverse proportionality does not hold exactly at high concentrations or for all types of water. Therefore, equivalent resistivities R_w and R_{mfe} which by definition are inversely proportional to the activities (R_w = 0.075/a_w at 77°), are used. R_w is the equivalent formation water resistivity and R_{mfe} is the equivalent mud filtrate resistivity.

Equation can be written in resistivity terms as

$$SSP = -K \log R_{mfe} / R_w \dots\dots\dots (35)$$

Knowing the formation temperature, the static SP value recorded opposite a porous, permeable, nonshaly formation can be transformed into the resistivity ratio R_{mfe}/R_w.

Environmental Correction and Precautions:

These static SP values can be obtain directly from the SP curve if the bed is clean, thick, porous, permeable, and only moderately invaded; and if the formation water is saline and the drilling mud is not too resistive. The conditions are not always met. Then they are not, the recorded SP deflection (in millivolts) must be corrected.

The use of SP curve for R_w determination requires a clean, nonshaly bed. It is assumed that recorded SP curve seldom contain an electro kinetic potential component. Although this is generally the case, it not always is so. Very low permeable formations, depleted-pressure formation, or the use of very heavy drilling mud may give rise to a significant electro kinetic potential. In the cases R_w value derive from the SP curve will probably be too low. Other sources of R_w data should be explored.

Also, when the salt other than NaCl are present in significant quantities, where SP baseline shift exist or where R_w is variable, certain precautions are required in calculating R_w from the SP log.

4) Experimental Procedure

4.1) Sample preparation

A. Plugging/ Trimming

The core from the field is placed in a core cutter where the core of 1.5 inch diameter is produced. This produced core is then called plug.

After cutting the core sample the next step is to face the core using a grinding and cutting machine. The length of the core is cut in such a way that it fits in the apparatuses which are to be used further; usually this length is about 3 inches long. Both the faces of plug are trimmed so as to be completely parallel to each other and provide a uniform cross section for flow.

Fluid used: Fresh Water

B. Cleaning

After cutting the core an important process is to clean the core, because there are present different types of salts and irreducible hydrocarbon content in the core which hinders in determination of electrical properties, porosity and absolute permeability of the rock sample.

For Hydrocarbon removal:

Soxhletion Method is used in which plugs are kept in a solvent comprising 80% Toulene + 20% Metahnol and the system is constantly heated at temperature around 85°C . The process takes 110 hrs to complete.

In order to determine whether complete hydrocarbon removal has been done or not the solvent is taken in a test tube and is mixed with carbon tetrachloride solution (CCl_4) and is checked for fluorescence under a fluorescent lamp, if it does not show fluorescence that means the process is complete otherwise the cleaning process requires more time.

For Salts removal

Salt is removed by using methanol solvent. The plugs are kept in methanol solution for a period of 3-4 days and are heated continuously. In order to determine whether complete salt removal has taken place or not a sample of the methanol solution is mixed with AgNO_3 solution if it precipitate (AgCl), then the solution contains salt otherwise salt removal is complete.

C. Drying

Method: Humidity Controlled Oven

Temperature: 60°C

Relative Humidity: 45%

4.2) Porosity

Porosity is calculated using 'Keyphi' an instrument used for porosity, permeability and grain density calculation.

A. Bulk Volume

Method: Caliper & Mercury Displacement

B. Grain Volume

Method: Boyle's Law

Gas used: Helium

4.3) Permeability

Method: Steady State

Fluid Type: Nitrogen

Confining Pressure: 400 psi (Hassler)

4.4) Resistivity Measurement

Study: R_o , R_w , R_t measurement at ambient conditions

Brine Composition: 200g/l NaCl solution.

R_w of brine:

Temperature: 25°C

Confining Pressure: Nil

Pore pressure: Nil

Number of Electrodes: 4

Method of desaturation: Centrifuge

5).Core Plugs Details and Formation Evaluation Data

5.1) Core Data

<i>Sample no.</i>	<i>Depth(m)</i>	<i>Length(cm)</i>	<i>Diameter(cm)</i>	<i>Orientation</i>
<i>Well XYZ # 2, CC No.3, Lithology: Sandstone</i>				
2 - 1	2343.50	7.654	2.55	Horizontal
2 - 4	2347.2	7.558	2.49	Horizontal
2 - 7	2348.5	7.66	2.53	Horizontal
2 - 11	2351.33	7.651	2.57	Horizontal
2 - 16	2357.12	7.670	2.54	Horizontal
<i>Well XYZ # 6, CC No.2, Lithology: Sandstone</i>				
6 - 3	2371.1	7.651	2.57	Horizontal
6 - 6	2374.81	7.66	2.55	Horizontal
6 - 9	2375.77	7.670	2.49	Horizontal
6 - 12	2377.25	7.654	2.54	Horizontal
6 - 16	2378.75	7.558	2.53	Horizontal

Table 5: Core plug data

5.2) Formation Evaluation data

S.No.	Plug No.	Well No.	Cored Interval (m)	Recovery %	Depth (m)	Rt	Sw
1	2 - 1	XYZ # 2	2342.0 - 2351	100	2343.50	38.88	0.39
2	2 - 4	XYZ # 2	2342.0 - 2351	100	2347.2	33.13	0.58
3	2 - 7	XYZ # 2	2342.0 - 2351	100	2348.5	20.94	0.7
4	2 - 11	XYZ # 2	2351.0- 2361.0	100	2351.33	23.87	0.48
5	2 - 16	XYZ # 2	2351.0- 2361.0	100	2357.12	30.73	0.38
6	6 - 3	XYZ# 6	2371.0- 2379.0	100	2371.1	53.02	0.48
7	6 - 6	XYZ# 6	2371.0- 2379.0	100	2374.81	39.44	0.48
8	6 - 9	XYZ# 6	2371.0- 2379.0	100	2375.77	40.26	0.47
9	6 - 12	XYZ# 6	2371.0- 2379.0	100	2377.25	35.32	0.4
10	6 - 16	XYZ# 6	2371.0- 2379.0	100	2378.75	34.12	0.35

Table 6. Formation evaluation data from wireline logs

6). Experimentally determined values

S. No	Plug No.	Well No.	Cored Interval (m)	Recovery %	Depth (m)	By Helium Porosimeter			By saturation Method		
						Air Perm (Md)	Porosity %	Grain density gm/cc	Porosity %	Bulk density g/cc	Formation Resistivity Factor
1	2-1	XYZ # 2	2342.0 - 2351	100	2343.50	5.58	18.5	2.65	16.3	2.38	37.5
2	2-4	XYZ # 2	2342.0 - 2351	100	2347.2	0.55	10.6	2.66	9.6	2.49	92.7
3	2-7	XYZ # 2	2342.0 - 2351	100	2348.5	74.2	20.4	2.63	16.4	2.35	73.7
4	2-11	XYZ # 2	2351.0 - 2361.0	100	2351.33	339	21.6	2.65	19.2	2.36	30.6
5	2-16	XYZ # 2	2351.0 - 2361.0	100	2357.12	2.6	19.5	2.64	18.2	2.4	29.2
6	6-3	XYZ # 6	2371.0 - 2379.0	100	2371.1	5.98	20.1	2.68	16	2.39	49.1
7	6-6	XYZ # 6	2371.0 - 2379.0	100	2374.81	9.68	18.3	2.64	17.2	2.38	38
8	6-9	XYZ # 6	2371.0 - 2379.0	100	2375.77	8.41	18.2	2.66	19.7	2.41	39.8
9	6-12	XYZ # 6	2371.0 - 2379.0	100	2377.25	2.49	14.8	2.65	13	2.47	51.3
10	6-16	XYZ # 6	2371.0 - 2379.0	100	2378.75	2.85	18.2	2.64	14.5	2.38	41.1

Table 7: Experimentally generated parameters

7). Comparison in Water saturations (Formation evaluation Vs Lab Calculated data)

S.No	Plug No.	Well No.	Formation Evaluation Value	Laboratory Calculated Value	ΔS_w
			(Sw)	(Sw)	(%)
1	2-1	XYZ # 2	0.39	0.42044	3.04
2	2-4	XYZ # 2	0.58	0.755174	17.52
3	2-7	XYZ # 2	0.7	0.566447	13.36
4	2-11	XYZ # 2	0.48	0.456729	2.33
5	2-16	XYZ # 2	0.38	0.424641	4.46
6	6-3	XYZ # 6	0.48	0.367507	11.25
7	6-6	XYZ # 6	0.48	0.396551	8.34
8	6-9	XYZ # 6	0.47	0.344716	12.53
9	6-12	XYZ # 6	0.4	0.547372	14.74
10	6-16	XYZ # 6	0.35	0.501458	15.15

Table 8: Comparison between assumed water saturations and actual values

8). Results

- The sandstone core plugs analyzed in the present studies are mainly light grey to grey, moderate hard to hard, compact, fine grained to medium grained, sub angular to sub rounded and non- calcareous.
- Based on analysis of 10 core plugs, the helium porosity is found to be in the range of **10.6% - 21.6%** and grain density in the range of **2.63 – 2.68 g/cc**. The air permeability is observed to be in the range of **0.55 – 399 mD**. The basic parameters are given in Appendix under **Table 15**.
- Resistivity measurement have been conducted at room temperature on an auto LRC meter four electrode system on 10 plugs saturated with brine of 200 g/l as NaCl. The resistivity data of 100% brine saturated core plugs is shown in **Table 13**. In Appendix
- The log- log plot of formation factor versus porosity is shown in **Plate 1**. The following values of Tortuosity coefficient 'a' and cementation factor 'm' have been derived from this plot:
'a' = 1.14 'm' = 1.947
- For determination of 'n' at ambient conditions, desaturation of brine with air has been carried out using centrifuge technique. The resistivity index data is shown in **Table 5**. The value of 'n' has been found in the range of 1.58 – 2.79. On lumping all resistivity index data, the value of 'n' has been found as **2.036** as shown in **plate 12**.
- The water saturation value as calculated using the lab derived electrical parameters is significantly different from that provide in Formation evaluation report. This is because of use of estimated values of 'a', 'm' and 'n' on the basis of type of formation during initial formation evaluation.

9). Discussion

Sensitivity of Calculated Water Saturation to Saturation Exponent "n"

Calculated Water Saturation (S_w) %

RI (R_t/R_o)	n= 1.6	n = 2.2	ΔS_w
100	6	12	6
30	12	21	9
10	24	35	11
4	40	53	13
3	50	61	11
2	65	73	8
1	100	100	0

Table 9: Sensitivity of Calculated Water Saturation to Saturation Exponent "n"

Sensitivity of Calculated Water Saturation to Both "n" and "m"

Both saturation exponent "n" and cementation factor "m" vary with pore geometry and influence calculated water saturation. In any formation, either may be higher or lower than the value of 2.0 often assumed to be representative. The influence and importance of the cementation factor is maximised in low porosity rock. For example, if saturation exponent "n" equalled 2.0 and cementation exponent "m" equalled 1.7 in a formation with 10 percent porosity, the calculated water saturation would be 45 percent pore space. If the cementation factor equalled 2.4, calculated water saturation would be 100 percent pore space. This is a significant difference.

Sensitivity of Calculated Water Saturation to Saturation Exponent "n" and to Cementation Exponent "m"

Given: R_t = True resistivity from log = 25 ohm-meters

R_w = Down hole water resistivity = 0.1 ohm-meters

Effect of Cementation Exponent “m” (n = 1.6)

Calculated Water Saturation (S_w) %

m= 1.7

m= 2.4

Porosity (%)	F	S_w (%)	F	S_w (%)	ΔS_w (%)
30	7.7	11	18	19	8
20	15	17	48	36	19
10	50	37	250	100	63

Table 10: Sensitivity of Calculated Water Saturation to “n” and to “m”

Effect of Cementation Exponent “m” (n = 2.0)

Calculated Water Saturation (S_w) %

‘m’ = 1.7

‘m’ = 2.4

Porosity	F	S_w	F	S_w	ΔS_w
30	7.7	18	18	27	9
20	15	24	48	44	20
10	50	45	250	100	55

Table 11: Sensitivity of Calculated Water Saturation to “n” and to “m”

Effect of Cementation Exponent “m” (n = 2.2)

Calculated Water Saturation (S_w) %

‘m’ = 1.7

‘m’ = 2.4

Porosity	F	S_w	F	S_w	ΔS_w
30	7.7	21	18	30	9
20	15	28	48	47	19
10	50	48	250	100	52

Table 12: Sensitivity of Calculated Water Saturation to “n” and to “m”

10). Applications

Almost all oil and gas produced today comes from accumulations in the pore spaces of reservoir rocks –usually sandstones, limestones, or dolomites. The amount of oil or gas contained in a unit volume of the reservoir is the product of its porosity by the hydrocarbon saturation.

To evaluate the producibility of a reservoir, it is necessary to know how easily fluid can flow through the pore system. This property of the formation rock, which depends on the manner in which the pores are interconnected, is its permeability. The main petrophysical parameters are hydrocarbon saturation, thickness, area, and permeability.

The Archie's equation has the following applications:

10.1) Determination of Saturation

All water saturation determinations from resistivity logs in clean (non-shaly) formations with homogeneous intergranular porosity are based on Archie's water saturation equation, or variations thereof. The equation is:

$$S_w = \sqrt[n]{\frac{a R_w}{\phi^m R_t}} \dots\dots\dots (2)$$

Where;

R_w is the formation water resistivity

R_t is the true formation resistivity

F is the formation resistivity factor.

For S_{xo} the water saturation in the flushed zone, a similar expression exists:

$$S_{xo} = \sqrt[n]{\frac{a R_{mf}}{\phi^m R_{xo}}} \dots\dots\dots (3)$$

Where;

R_{mf} is mud filtrate Resistivity and

R_{xo} is flushed zone resistivity

10.2) Resistivity Vs. Porosity Cross plots

Combining Eq.(2) and (15), the Archie saturation equation may be written

$$S_w^n = \frac{a R_w}{\phi^m R_t} \dots\dots\dots (36)$$

If n and m are equal to 2, and a = 1, then

$$\Phi S_w = \sqrt{\frac{R_w}{R_t}} \dots\dots\dots (37)$$

Eq. (37) shows that for R_w , constant, ΦS_w is proportional to $1/\sqrt{R_t}$; ΦS_w is the quantity of water per unit volume of formation. To emphasize the proportionality between Φ and $\frac{1}{\sqrt{R_t}}$, Eq. (37) may be rewritten:

$$\Phi = \frac{\sqrt{R_w}}{S_w} \frac{1}{\sqrt{R_t}} \dots\dots\dots (38)$$

For a 100% water-saturated formation, $S_w = 1$ and $R_t = R_o$ If R_o for water-saturated formations is plotted on an inverse square-root scale versus Φ & all points should fall on a straight line given by $\Phi = \sqrt{\frac{R_w}{R_o}}$ Furthermore, the points corresponding to any other constant value of S_w will also fall on a straight line, since in Eq. (38) the coefficient, $\sqrt{\frac{R_w}{S_w}}$ is constant for constant values of R_w and S_w . Instead of an actual R_t value, it is usually satisfactory to plot the log reading of the deep resistivity device provided the readings are not much influenced by invasion or other environmental factors (e.g., from a deep induction log or deep laterolog).

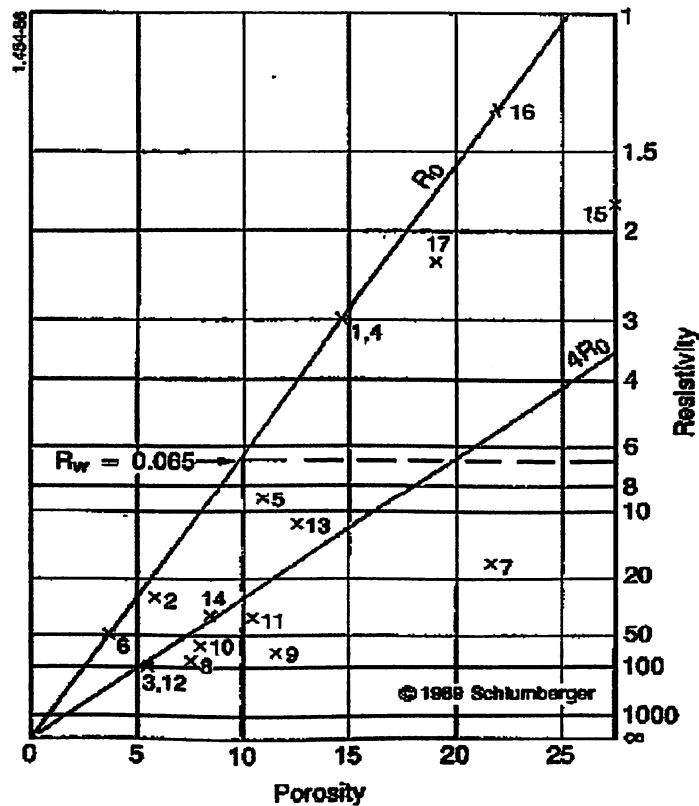


Figure 22: Resistivity-porosity crossplot for determining R_w , and S_w

10.3) R_{wa} Comparison

If water saturation is assumed to be 100%, the Archie water saturation equation Eq. (1) reduces to:

$$R_{wa} = R_t / F = R_{ID} / F \quad \dots\dots\dots (39)$$

The term R_{wa} is used in Eq.(39), rather than R_w , to indicate that this is an apparent formation water resistivity. It is only equal to R_w in 100% water-bearing formations. In hydrocarbon-bearing formations, R_{wa} computed from Eq. (39) will be greater than R_w . Indeed, by combining Eqs. (1) and (39), the relationship between S_w , R_{wa} , and R_w , can be shown to be:

$$S_w = \sqrt{R_w / R_{wa}} \quad \dots\dots\dots (40)$$

The R_{wa} technique can, therefore, be useful for identifying potential hydrocarbon-bearing zones and for obtaining R_w values.

10.4) R_w determination

Equations for S_w and S_{xo} for clean formations can be combined to give:

$$\frac{R_{xo}}{R_t} = \left(\frac{S_w}{S_{xo}} \right)^2 \frac{R_{mf}}{R_w} \quad \dots\dots\dots (41)$$

The value of R_{xo}/R_t is equal to R_{mf}/R_w in water zones where S_w , and S_{xo} are 1 (i.e., 100%). Thus, by computing R_{xo}/R_t over an interval containing clean, invaded water sands, the value of R_{mf}/R_w , can be found. Then, knowing R_{mf} (as reported on the log heading), R_w , can be determined.

11). Conclusion and Future scope of work

This relation is commonly used for oil / gas reservoir characterization. Three parameters must be measured: (i) porosity, (ii) resistivity of the undisturbed formation, and (iii) resistivity of connate water.

Calculation of petrophysical properties of reservoir rock is of great importance especially lab studies because it provides accurate and reliable results. In order to calculate the reserves and determine the economics of a particular field it is essential to know the hydrocarbon saturation, which can be calculated if water saturation is known. Archie's equation helps in giving a reliable value of water saturation and hence much accurate reserves estimation. Other petrophysical parameters such as porosity and permeability are also of great importance in calculating the reserves and ultimate recovery from the field.

The values generated through Laboratory experiments are significantly different from those that are used in early field development plans and hence forth the previous values should be updated with the new values (presently generated).

The values generated by core studies can be updated with the new data available by drilling of new wells in order to ascertain such 'a', 'm', 'n' parameters that represent the entire field model.

Studies can be conducted on larger no of cores to get more accurate and precise values of petrophysical parameter of the reservoir.

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Appendix

Formation Factor Data

Salinity of Brine: 200 g/l as NaCl

Resistivity of Brine: 0.053 ohm-m

Temperature: 23°C

Plug No.	Porosity (%)	Resistivity of 100 % Brine saturated core, Ro	Formation Factor, FF
		(ohm-m)	
2 - 1	16.3	1.9875	37.5
2 - 4	9.6	4.9131	92.7
2 - 7	16.4	3.9061	73.7
2 - 11	19.2	1.6218	30.6
2 - 16	18.2	1.5476	29.2
6 - 3	16	2.6023	49.1
6 - 6	17.2	2.014	38
6 - 9	19.7	2.1094	39.8
6 - 12	13	2.7189	51.3
6 - 16	14.5	2.1783	41.1

Table 13: Formation factor data

Formation Evaluation data

S.No	Plug No.	Well No.	Cored Interval (m)	Depth (m)	Rt	Sw
1	2 - 1	XYZ # 2	2342.0 - 2351	2343.50	38.88	0.39
2	2 - 4	XYZ # 2	2342.0 - 2351	2347.2	33.13	0.58
3	2 - 7	XYZ # 2	2342.0 - 2351	2348.5	20.94	0.7
4	2 - 11	XYZ # 2	2351.0- 2361.0	2351.33	23.87	0.48
5	2 - 16	XYZ # 2	2351.0- 2361.0	2357.12	30.73	0.38
6	6 - 3	XYZ# 6	2371.0- 2379.0	2371.1	53.02	0.48
7	6 - 6	XYZ# 6	2371.0- 2379.0	2374.81	39.44	0.48
8	6 - 9	XYZ# 6	2371.0- 2379.0	2375.77	40.26	0.47
9	6 - 12	XYZ# 6	2371.0- 2379.0	2377.25	35.32	0.4
10	6 - 16	XYZ# 6	2371.0- 2379.0	2378.75	34.12	0.35

Table 14: Formation Evaluation data

Resistivity index Vs Saturation (Ambient Condition)

Field: ABC Payzone: 2

Salinity of Brine: 200 g/l as NaCl

Temperature: 23⁰C

S.No	Plug No.	Porosity (saturation) %	Air Perm (mD)	water Saturation Fraction	Resistivity Index	n'
1	2 - 1	16.3	5.58	1	1	2.37
				0.925	1.26	
				0.814	1.83	
				0.611	3.56	
				0.557	3.71	
				0.489	5.51	
				0.464	6.57	
				0.418	7.48	
				0.396	8.49	
2	2 - 4	9.6	0.55	1	1	2.75
				0.905	1.36	
				0.846	1.69	
				0.737	2.34	
				0.651	3.68	
				0.552	4.53	
3	2 - 7	16.4	74.2	1	1	1.58
				0.924	1.05	
				0.851	1.16	
				0.576	2.54	
				0.472	3.08	
				0.365	4.81	
				0.309	6.66	

4	2 - 11	19.2	399	1	1	1.83
				0.746	1.78	
				0.492	3.69	
				0.358	6.5	
				0.283	10.06	
				0.242	13.37	
				0.237	13.62	
5	2 - 16	18.2	2.6	1	1	2.15
				0.888	1.2	
				0.798	1.86	
				0.686	2.39	
				0.595	3	
				0.538	3.65	
				0.511	4.18	
6	6 - 3	16	5.98	1	1	1.87
				0.95	1.09	
				0.9	1.2	
				0.776	1.51	
				0.606	2.27	
				0.51	3.61	
				0.469	4.43	
7	6 - 6	17.2	9.68	1	1	2.42
				0.862	1.63	
				0.736	2.12	
				0.604	3.07	
				0.544	4.8	
				0.481	5.64	
8	6 - 9	19.7	8.41	1	1	2.79
				0.853	1.53	
				0.739	2.64	
				0.626	3.86	
				0.553	5.38	
				0.506	6.04	

9	6 - 12	13	2.49	1	1	1.97
				0.915	1.08	
				0.819	1.52	
				0.681	1.86	
				0.575	2.97	
				0.525	3.91	
10	6 - 16	14.5	2.85	1	1	2.13
				0.824	1.42	
				0.768	1.84	
				0.637	2.81	
				0.547	3.67	
				0.495	4.66	
				0.426	5.29	
				0.419	6.83	

Table 15: Resistivity Index Vs water saturation

Formation Factor Vs Porosity

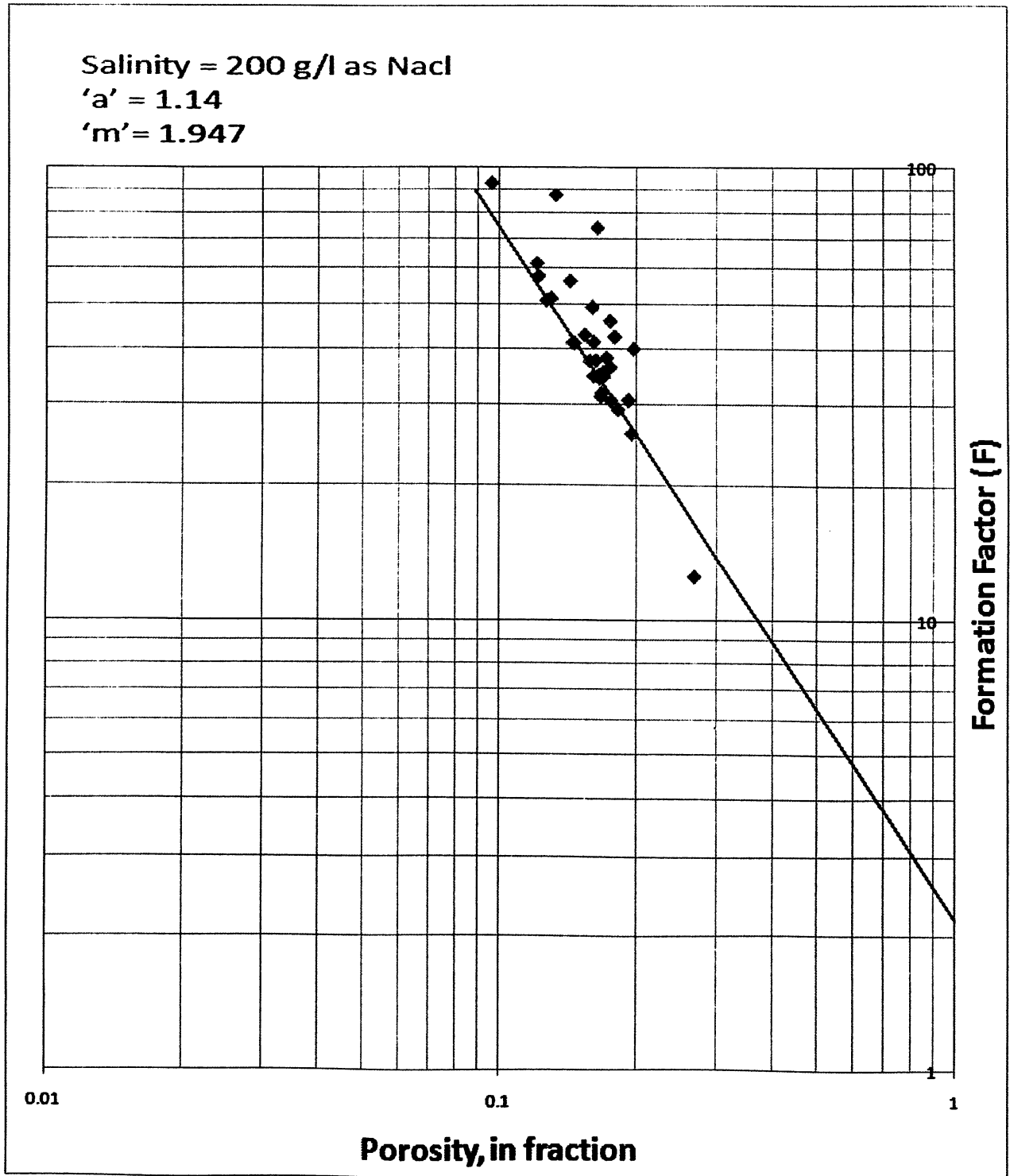
(Ambient Conditions)

Field: ABC Payzone: 2

Salinity = 200 g/l as NaCl

'a' = 1.14

'm' = 1.947



Resistivity Index Vs saturation

(Ambient Condition)

Field: ABC

Payzone -2

Well no: XYZ # 2

Salinity = 200 g/l as NaCl

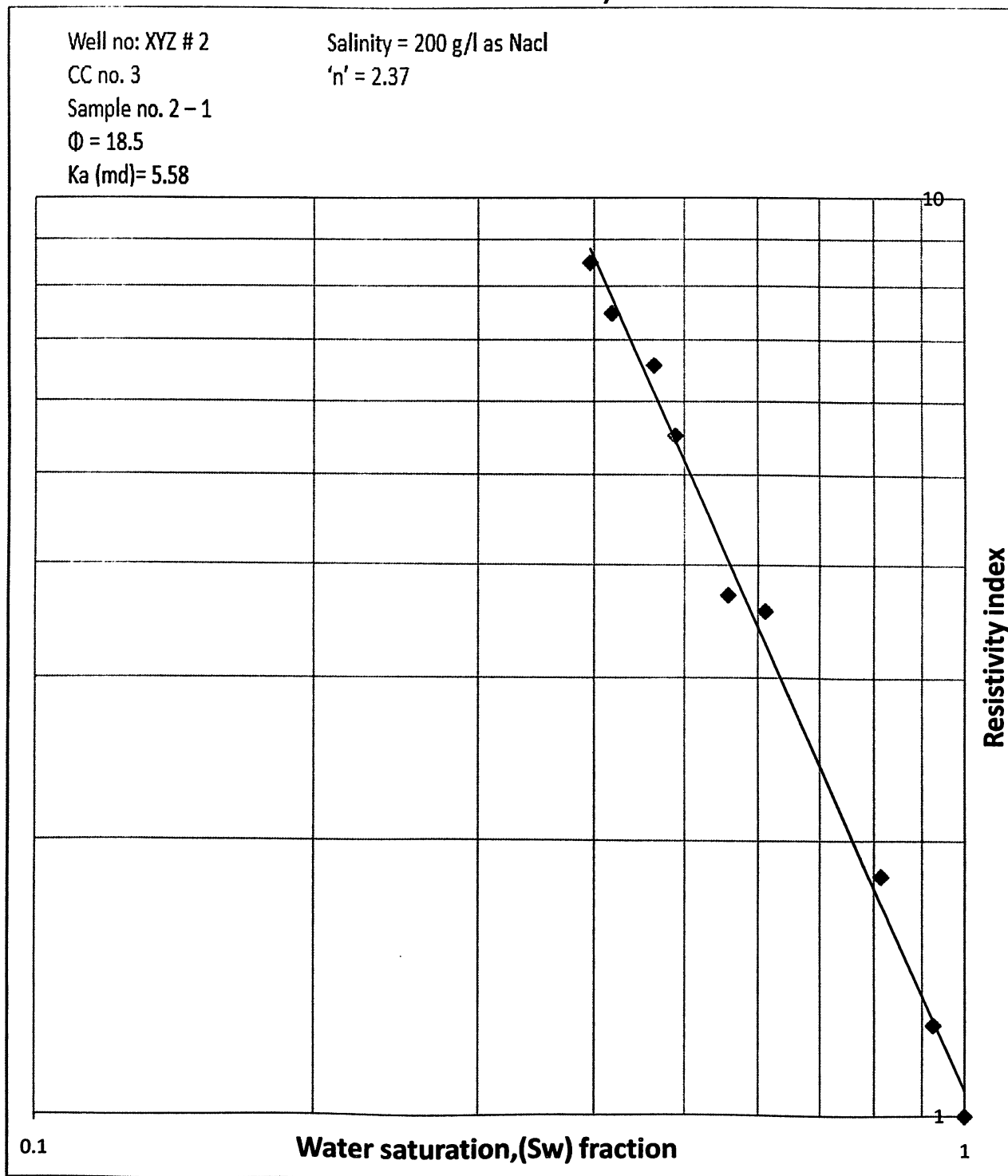
CC no. 3

'n' = 2.37

Sample no. 2 - 1

$\Phi = 18.5$

K_a (md) = 5.58



Resistivity Index Vs saturation

(Ambient Condition)

Field: ABC

Payzone -2

Well no: XYZ # 2

CC no. 3

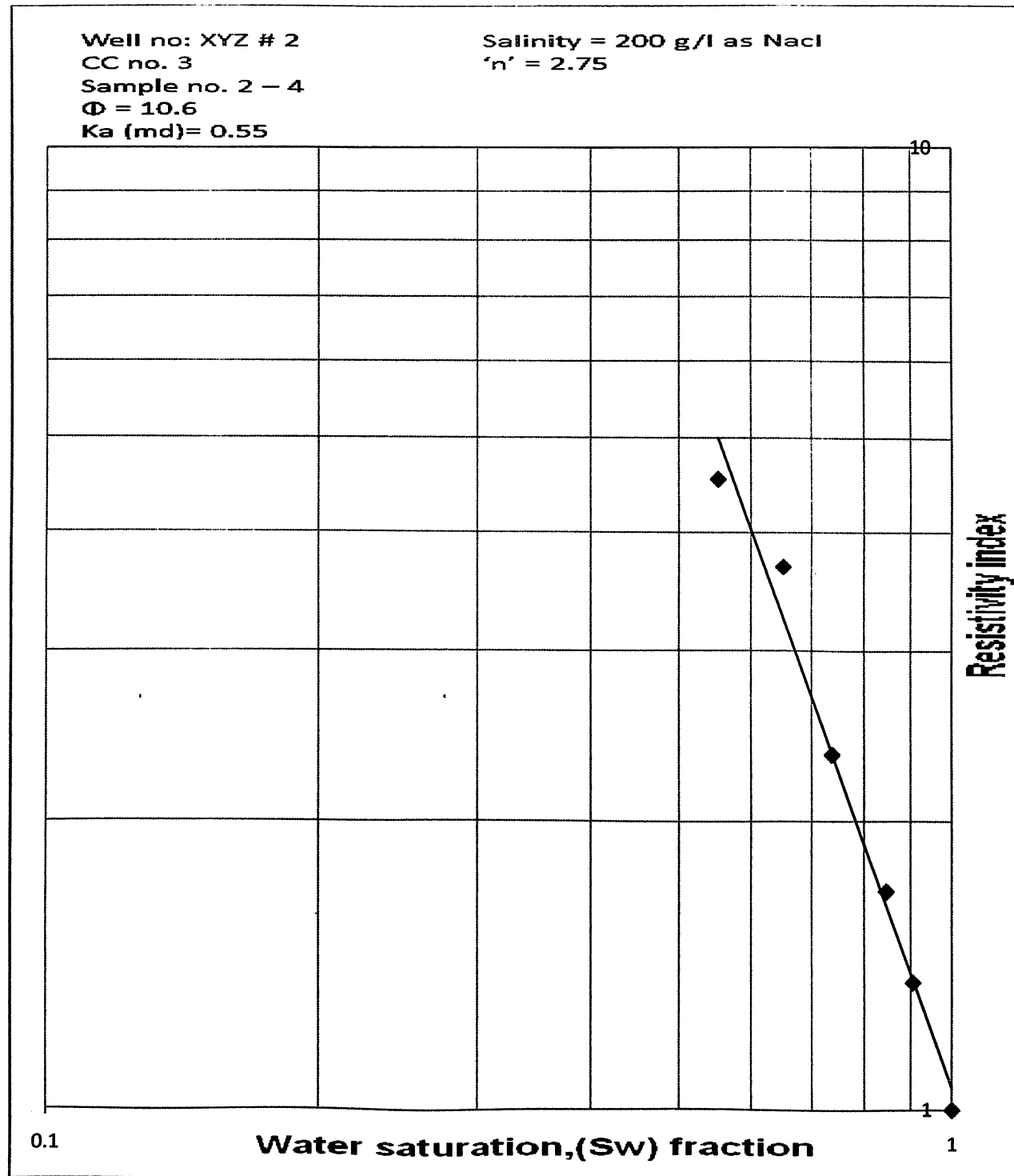
Sample no. 2 - 4

$\Phi = 10.6$

K_a (md) = 0.55

Salinity = 200 g/l as NaCl

$n' = 2.75$

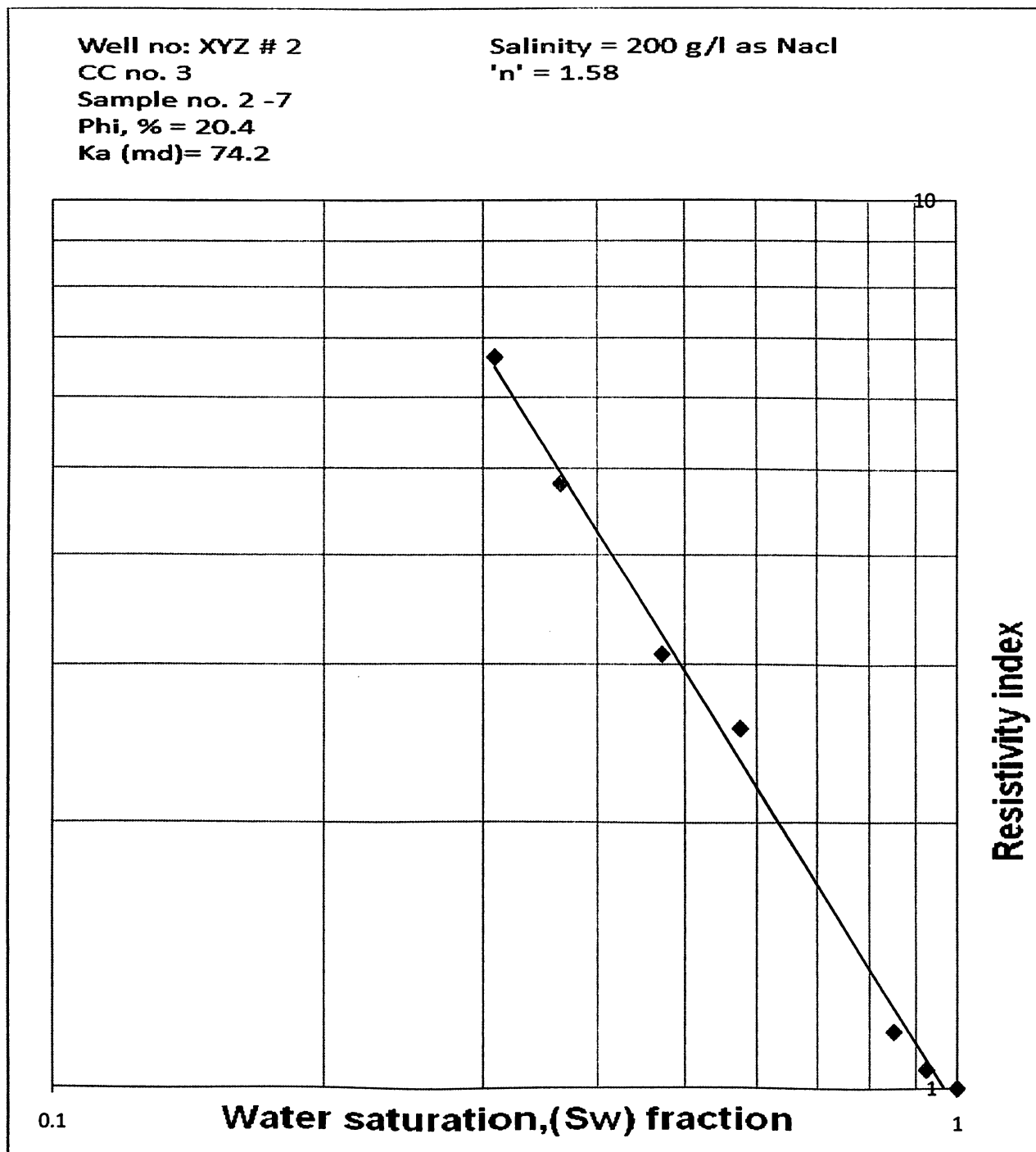


Resistivity Index Vs saturation

(Ambient Condition)

Field: ABC

Payzone -2



Resistivity Index Vs saturation

(Ambient Condition)

Field: ABC

Payzone -2

Well no: XYZ # 2

Salinity = 200 g/l as NaCl

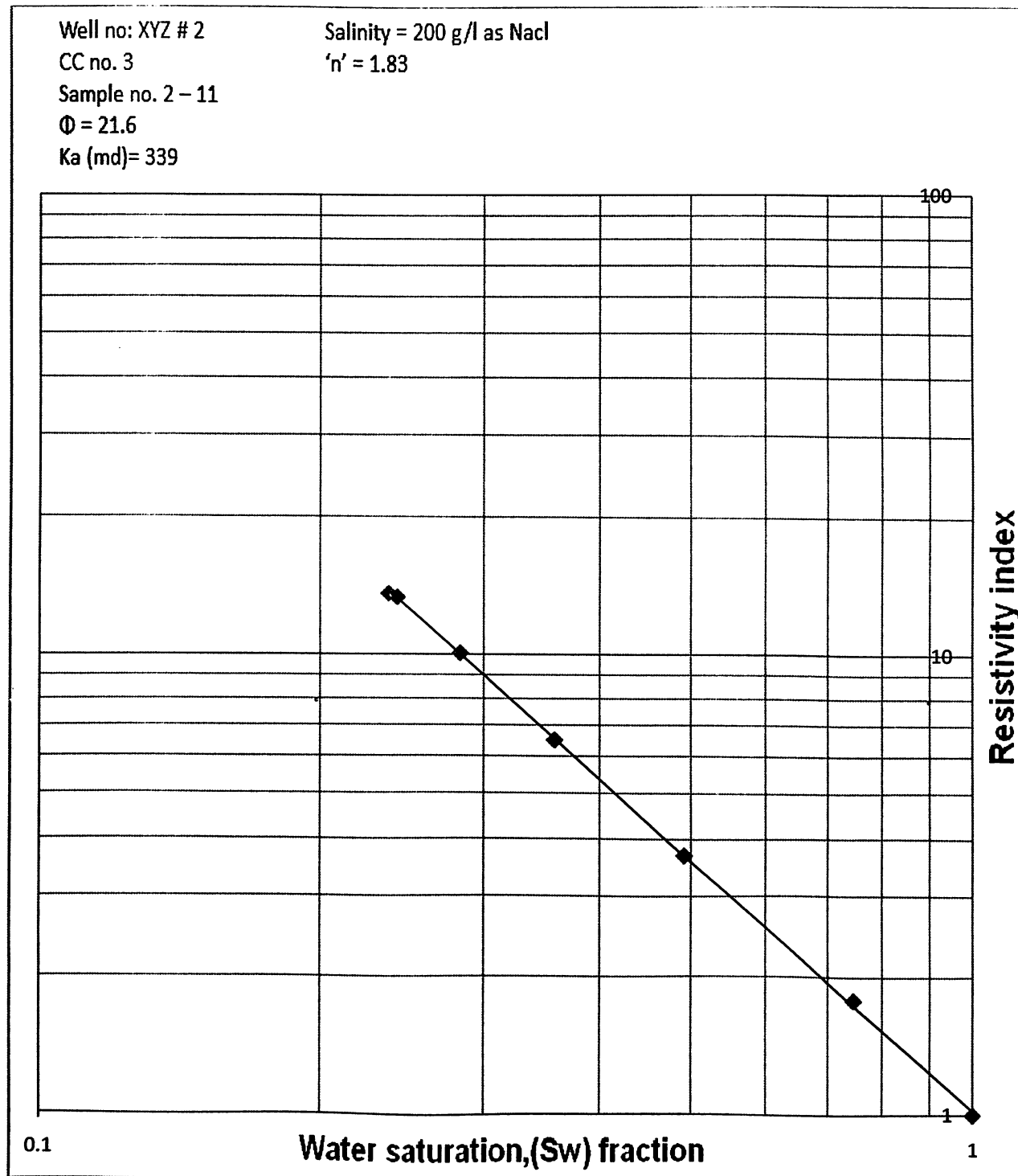
CC no. 3

'n' = 1.83

Sample no. 2 - 11

$\Phi = 21.6$

Ka (md) = 339



Resistivity Index Vs saturation

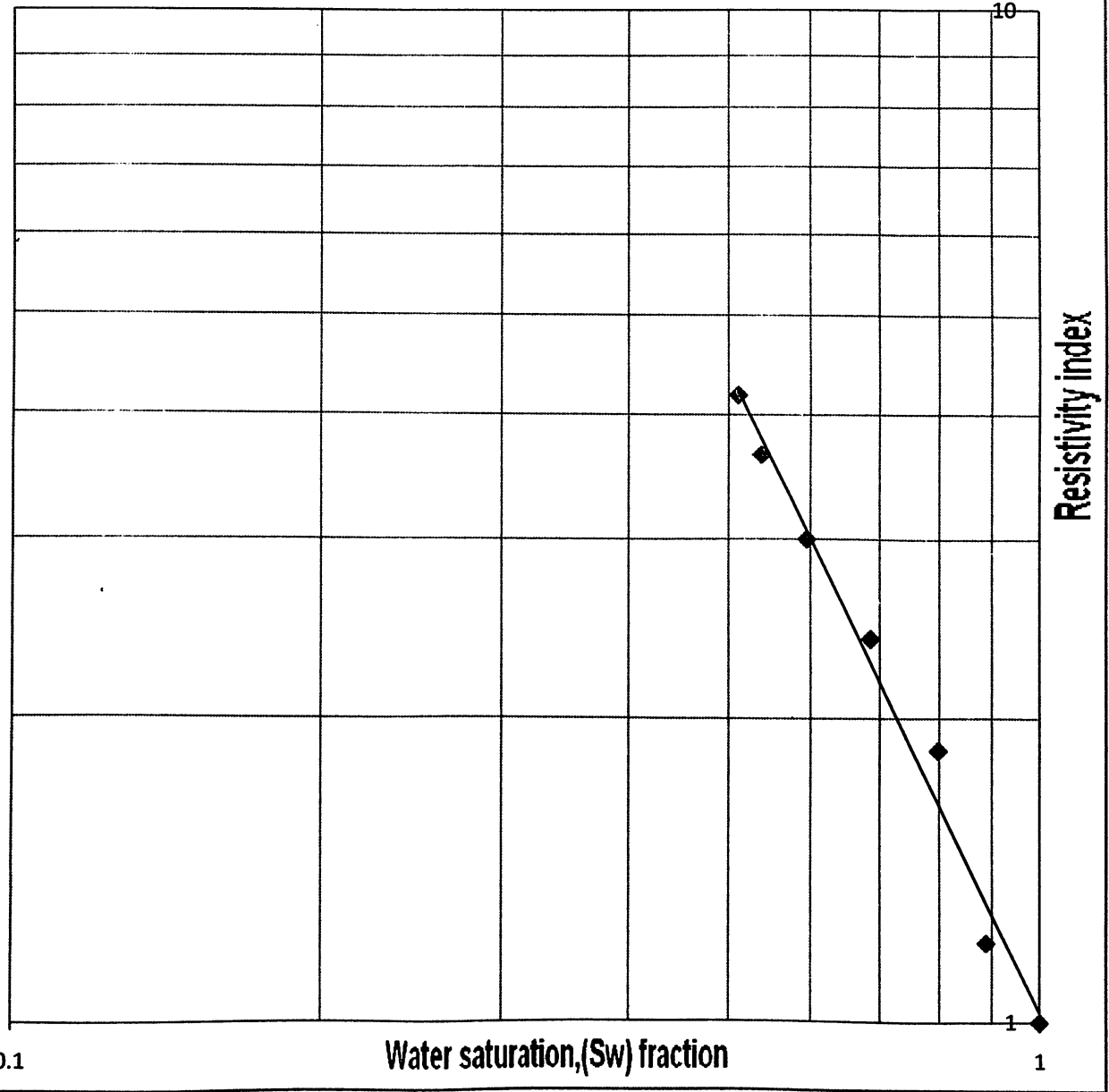
(Ambient Condition)

Field: ABC

Payzone -2

Well no: XYZ # 2
CC no. 3
Sample no. 2 - 16
 $\Phi = 19.5$
Ka (md) = 2.6

Salinity = 200 g/l as NaCl
'n' = 2.15



Resistivity Index Vs saturation (Ambient Condition)

Field: ABC

Payzone -2

Well no: XYZ # 6

Salinity = 200 g/l as NaCl

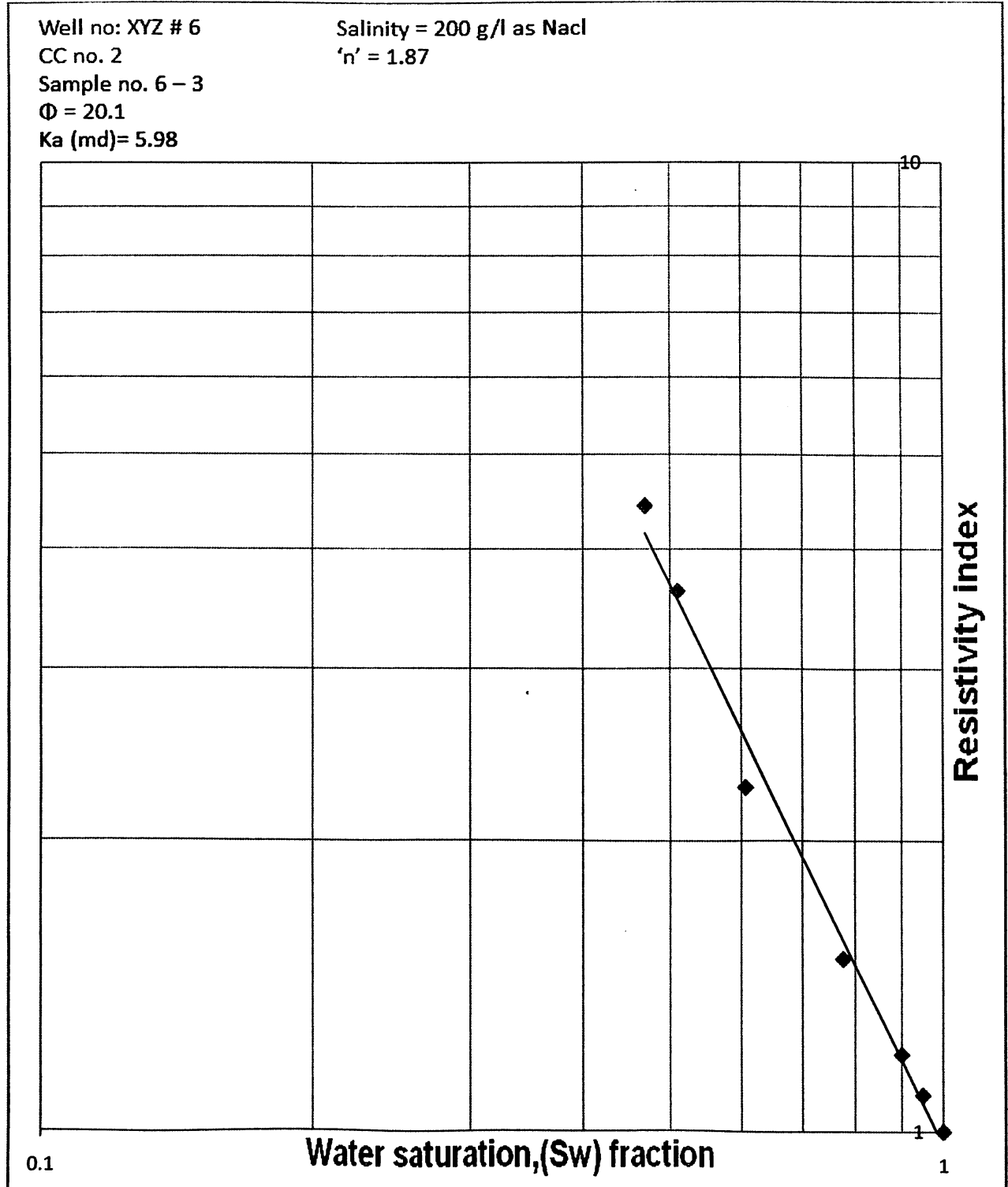
CC no. 2

'n' = 1.87

Sample no. 6 - 3

$\Phi = 20.1$

Ka (md) = 5.98



Resistivity Index Vs saturation (Ambient Condition)

Field: ABC

Payzone -2

Well no: XYZ # 6

Salinity = 200 g/l as NaCl

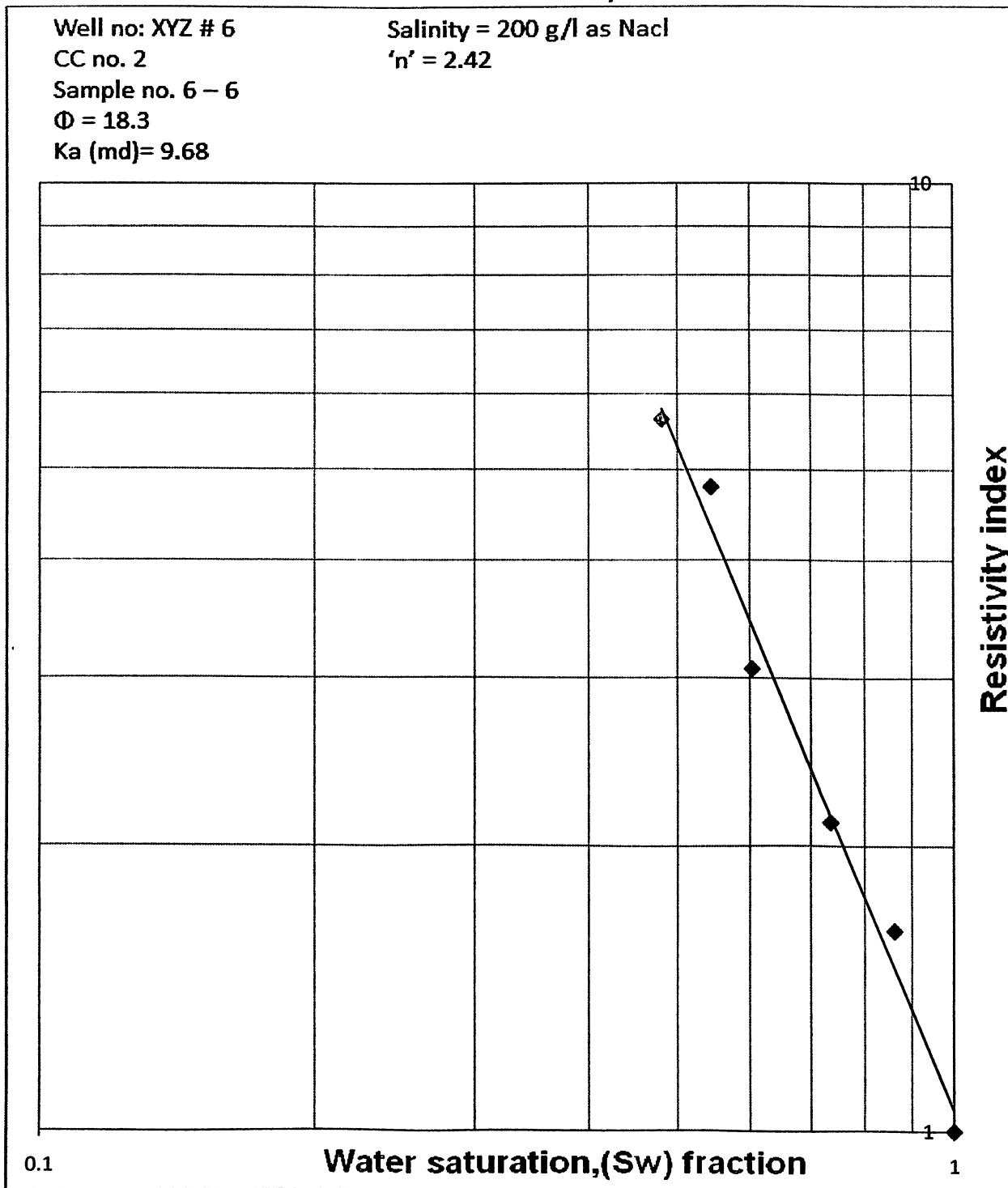
CC no. 2

'n' = 2.42

Sample no. 6 - 6

$\Phi = 18.3$

K_a (md) = 9.68

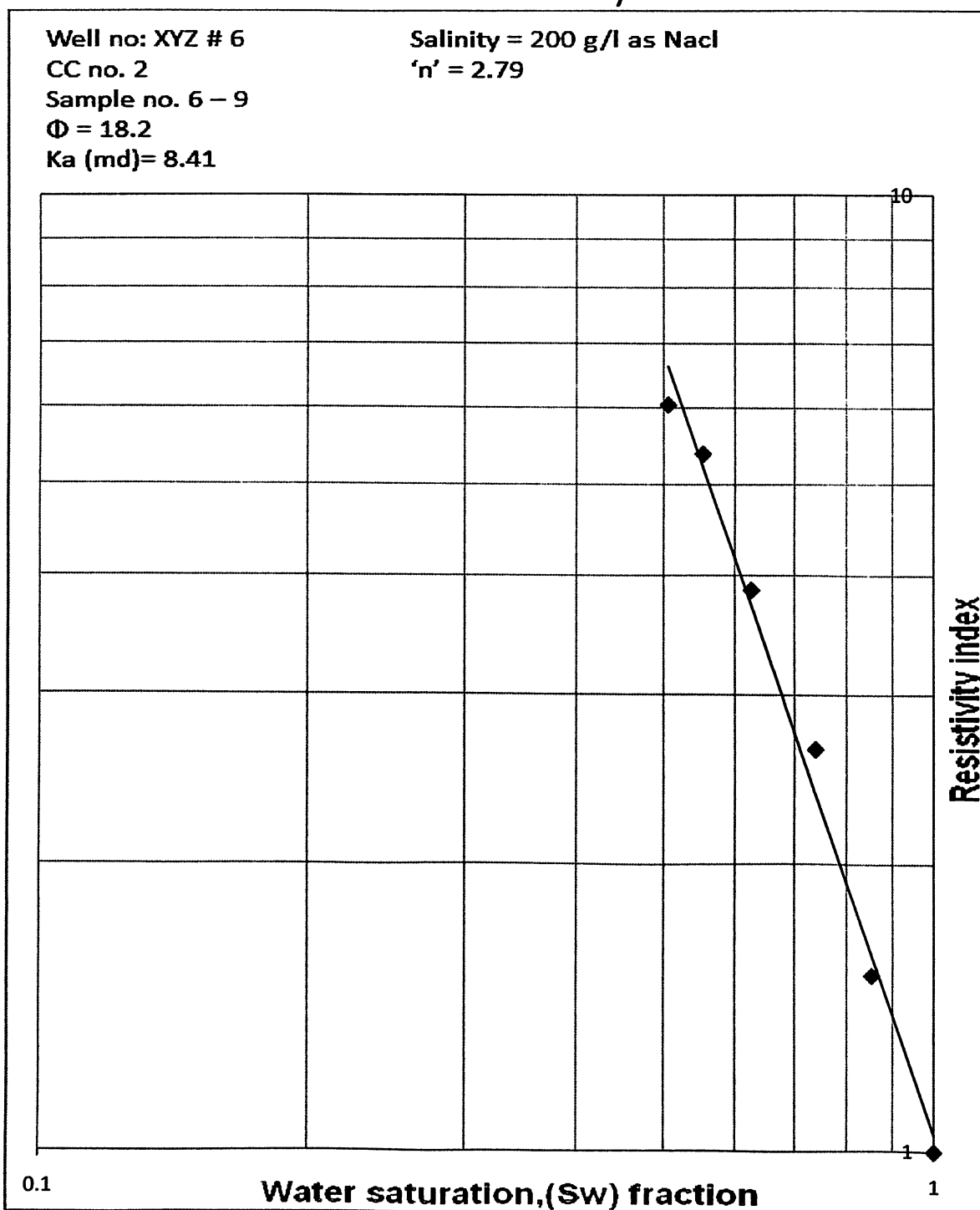


Resistivity Index Vs saturation

(Ambient Condition)

Field: ABC

Payzone -2



Resistivity Index Vs saturation

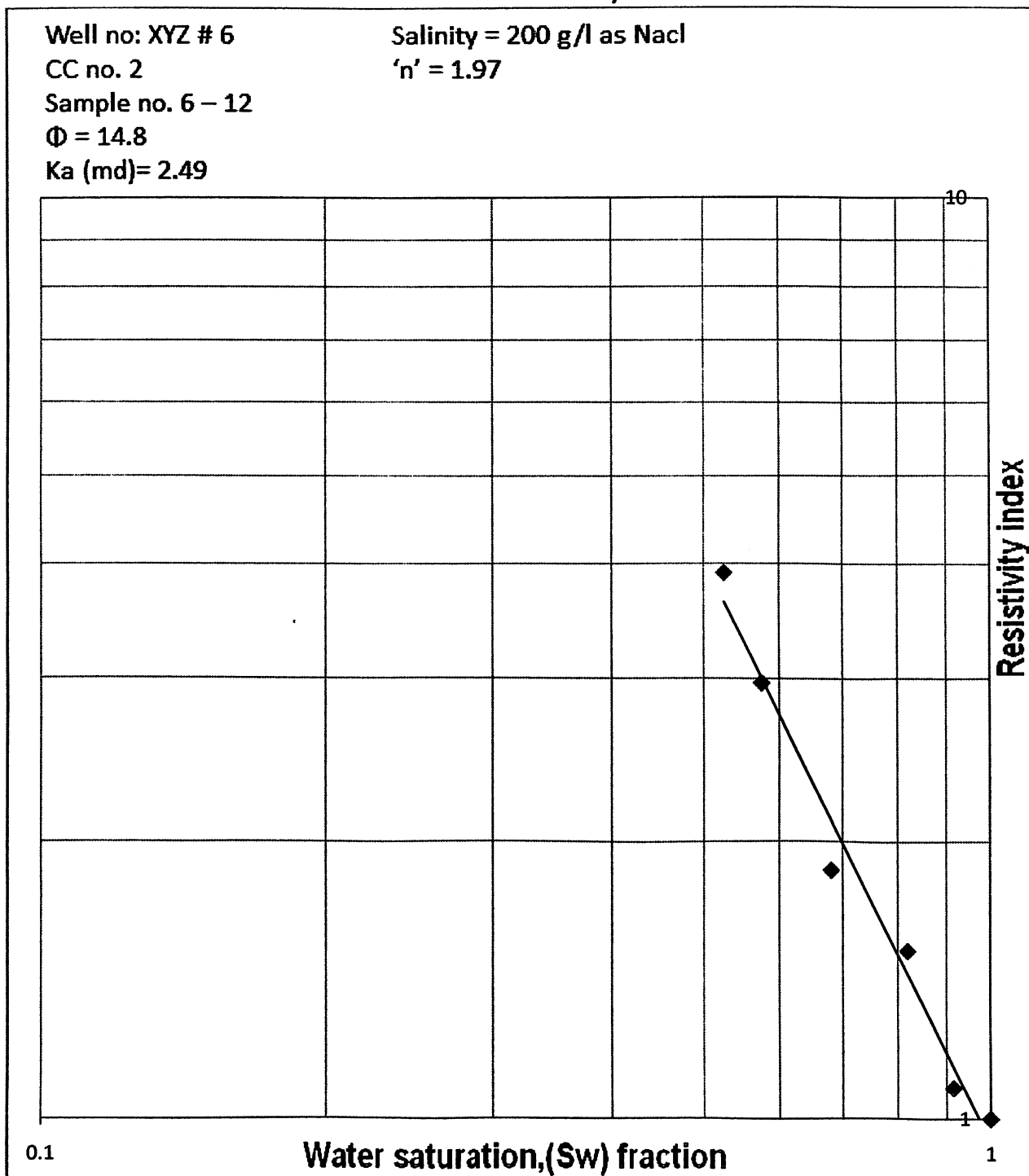
(Ambient Condition)

Field: ABC

Payzone -2

Well no: XYZ # 6
CC no. 2
Sample no. 6 - 12
 $\Phi = 14.8$
Ka (md) = 2.49

Salinity = 200 g/l as NaCl
'n' = 1.97



Resistivity Index Vs saturation

(Ambient Condition)

Field: ABC

Payzone -2

Well no: XYZ # 6

Salinity = 200 g/l as NaCl

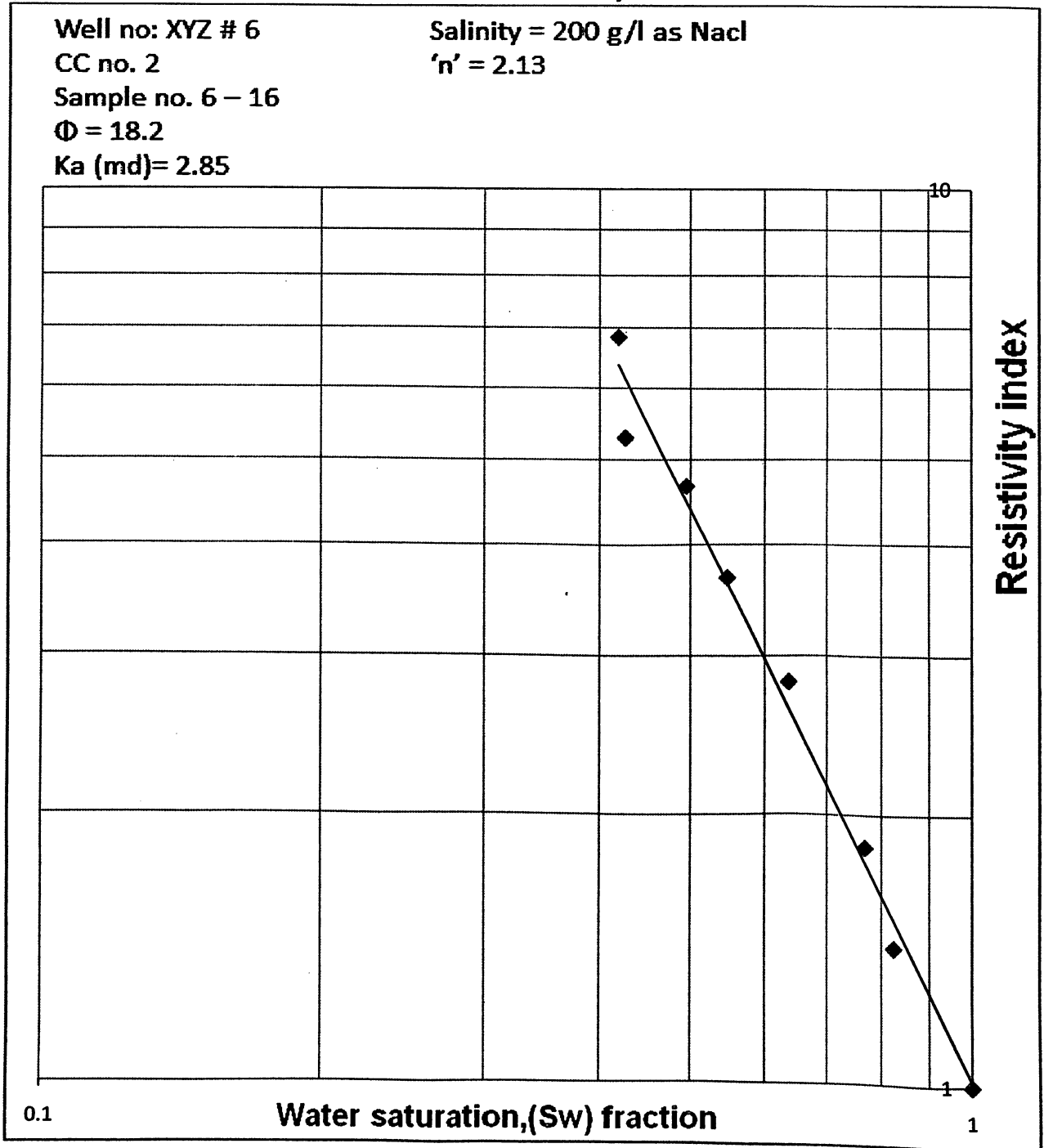
CC no. 2

'n' = 2.13

Sample no. 6 - 16

$\Phi = 18.2$

K_a (md) = 2.85



Resistivity Index Vs saturation

(Ambient Condition)

Field: ABC

Payzone -2

Overall 'n' value for the field = 2.036

Salinity = 200 g/l as NaCl

