INFLUENCE OF SHALES ON POROSITY/WATER SATURATION – A CASE STUDY OF NIGER DELTA BASIN RESERVIOR

BY

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A PROJECT REPORT SUBMITTED TO THE DEPARTMENT PETROLEUM ENGINEERING, FACULTY OF ENGINEERING, UNIVERSITY OF BENIN, BENIN CITY

IN PARTIAL FULFILMENT OF THE REQUIREMENT FOR THE AWARD OF A MASTER OF ENGINEERING (M.Eng.) DEGREE IN PETROLEUM ENGINEERING

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CERTIFICATION

This is to certify that this project work was carried out by Samuel Okhuese of the Department of Petroleum Engineering, Faculty of Engineering, University of Benin, Benin City.

Prof. Onaiwu D. Oduwa Project Supervisor	Date
DR. I. Ohenhen Head of Department	Date
Prof. O. Olafuyi Post Graduate Coordinator	Date

APPROVAL

This project work is hereby approved in partial fulfilment of the requirements for the award of Master of Engineering (M.Eng.) Degree in Petroleum Engineering from the University of Benin.

Prof. Onaiwu D. Oduwa
Project Supervisor

DATE

DEDICATION

This project work is dedicated to the Almighty God who is the giver of life for his grace and mercies throughout my period of study. And also, to my mom and siblings for their love, care and support.

ACKNOWLEDGMENT

Most importantly, my heartfelt gratitude is first of all rendered unto the Supreme Being, the creator of life, who bestowed countless mercy, wisdom, grace and divine protection upon me during the whole process of my academic endeavor and in completing this research work.

Special thanks go out to my project supervisor, Prof. Onaiwu D. Oduwa, whose timely guidance, constructive criticisms and scholarly advice were greatly instrumental in making this research work what it has become.

My special gratitude is due to the Head of Department, Dr. I. Ohenhen, and all staff members of the Department of Petroleum Engineering, University of Benin, for providing the necessary academic environment and conducive learning atmosphere.

I thank NNPC Exploration and Production Limited (NEPL), Benin City, for the provision of historical well data and wireline logs, which were critical in the execution of this research work.

Lastly, my heartfelt love and appreciation are given to my wife and family for their financial backing, spiritual support, patience and encouragement amidst other difficulties I have gone through during my academic life.

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ABSTRACT

This project work has attempted to determine the extent to which shale (clays) and silt or siltstones affect porosity, formation water saturation and some other petrophysical properties obtained from data collected from five wells situated in the Brown fields along the coastal swamps in the western onshore region of the Niger -Delta (Brown field).

It is established that porosity and permeability of sandstones depends on grain size, sorting, cementation and compaction and these parameters are significantly affected by significant presence of shale (clay) and silt in the formation. Shale formations are believed to be fine-grained, loose and flexible mixtures of clay-sized or colloidal particles. These fine-grained particles affect porosity, which is the percentage of void spaces in the overall rock volume. The work evaluated relevant well and reservoir parameters of interest with respect to the various depths of reservoir sands and correlated wells, using its findings to confirm trends conformable to Niger - Delta basin oil and gas reservoirs. The porosity of the different units of reservoir sands showed variation laterally with porosity values decreasing with a combination of increasing reservoir depth and average shale volume. Consequently, permeability was observed to decrease with increasing depth, though sand Z has high permeability values than sands X and Y lying several feet above it. The reservoir sands X, Y and Z have slightly reduced porosity and permeability due to high volume of clays (shales) and silts (siltstones) often associated with the environment. The porosities of the reservoir sands are good to very good; their permeability moderate to good with high and widespread oil and gas accumulation throughout the Brown field. The hydrocarbon resources are considered exploitable for profit.

CHAPTER ONE

INTRODUCTION

1.0 GENERAL INTRODUCTION

The Niger Delta basin can be said to be the most important sedimentary basin in sub-Saharan Africa and forty years of petroleum production, in addition to its abundance of hydrocarbons, give rise to this conclusion.

In modern times, it is the most classic delta and is highly distinctive.

The Niger Delta basin, one of Nigeria's basins, is situated in the Gulf of Guinea in the country 's southern portion.

According to Wett and Others (1997), it covers the Niger Delta region from the Eocene to the present.

Doust and Omatsola (1997) claim that the Delta has moved southward, creating bands that re present the most active phase of its growth. These bands, called depobelts, are the largest regressive deltas in the world, with an area ranging from 75,000kmsq (in the same area) to 300,000kmsq in other areas (Kulke 1995). The sediment volume is estimated to be 500,000kmsq (Hospers, 1965), and the sediment thickness in the basin depocentre is at least 10km (Kaplan and others 1994).

1.1 THE INFLUENCE OF SHALE ON POROSITY AND WATER SATURATION

Shale formations are believed to be fine-grained, loose and flexible mixtures of clay-sized or colloidal particles. A significant amount of clay minerals and an overabundance of negative electrical charges inside the clay sheets are common features of these mixes. Clays and shale are found in most oil provinces, and because of the electrolyte they contain and an ion-exchange process that occurs when ions travel between exchange sites on the surface of the clay particles under the influence of the impressed electric field, they do contribute to formation conductivity. The conductivity of shale sand is often negatively impacted by shaliness, proportional to the amount of shale. The amount, kind, and distribution of shale, as well as the nature and proportion of the formation water, are taken into consideration when determining the exact effect. Changes in shale composition are required since shale affects all logging measurements. Therefore, a shale or shaly deposit may have a high total porosity but a low effective porosity as a potential hydrocarbon source.

The shale's physical properties, amount, and dispersion within the formation all influence how shaliness impacts a log reading. In rock pores that contain both water and oil, the wetting phase, water, fills the smaller pore channels and covers the pore walls. The oil has a propensity to collect in globules in larger holes. The difference between the densities of the wetting (water) and non-wetting (oil) phases, as well as the elevation above the free water level, determine the capillary pressure. The neutron sensor "sees" all of the hydrogen in the formation during logging, even if it has nothing to do with the water entering the formation and filling its porosity. Consequently, there will be more apparent porosity in the porosity log made on Shaly formations using neutron instruments. Likewise, the water of crystallization will contain a significant amount of hydrogen in a non-porous gypsum (CaSo4. 2H2°).

1.2 GEOLOGY OF THE NIGER DELTA

The Niger Delta basin, as stated earlier, is arguably the most important sedimentary basin in Sub-Saharan Africa on accounts to its high hydrocarbon content and petroleum extraction during the past four decades. Nigeria's eastern Calabar flank and Abakaliki trough, as well as its western Benin flank and southern outlet to the Atlantic Ocean, make up the Niger-Delta basin. The basin stretches farther into the Gulf of Guinea from both the Benue trough and the Anambra basin.

The important line of volcanic jocks to the southeast is composed of the Okitipupa high into the Dahomey embayment, which forms one edge, and the Guinea Ridge and the Cameroon volcanic zone (mountains), which forms the other.

The geology of the Niger Delta has been extensively described by a number of scientists. Among them are Daukoru and Weber (1975), Olear (1992), and Stauble and Short (1967). Throughout its geologic history, the Delta's structure and strata have been influenced by the interplay between subsidence and sediment supply rates.

Initial basement morphology, crustal type (continental or oceanic, stable or unstable shale), and differential sediment loading on unstable shale have all had a significant impact on subsidence, even though eustatic sea level changes and climatic variations in the hinterland have had a significant impact on sedimentation rate. To obtain a comprehensive understanding of the distribution pattern of hydrocarbons in the Niger Delta, it is essential to investigate the dynamics of growth faulting, rollover anticlines, Shale diapirs, and other associated structural features. In their most basic form, growths are gravity slumps that work during the sedimentation process.

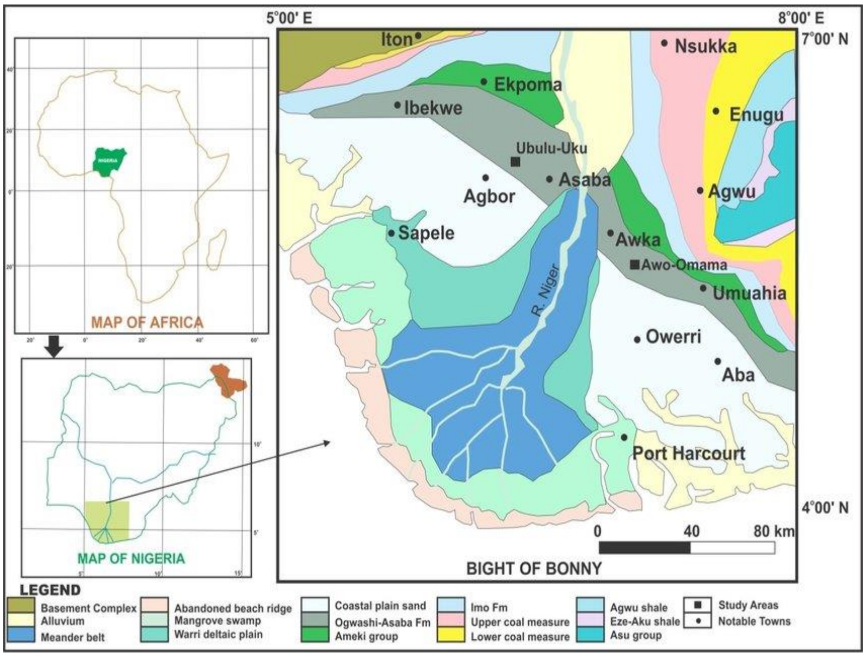

FIG 1.1 GEOLOGICAL MAP OF NIGER BASIN

1.3 AIMS AND OBJECTIVE

Quantifying the proportion of shale in specific NEPL (NNPC Exploration and Production Limited) reservoirs in relation to varying depth levels and their associated impacts on porosity and formation water saturation is the goal of this research study.

1.4 OBJECTIVES

1. To determine petrophysical properties (porosity, permeability, water saturation, bulk volume of water, formation factor and irreducible water saturation) from the available well data.
2. To analyze the effect of shale on these petrophysical properties using pre-existing knowledge of shale volume in the various sand units.
3. To confirm that these effects are true with respect to trends conformable to the Niger-Delta basin oil and gas reservoirs.

1.5 SCOPE

The following describes the study's scope:

1. The review materials are based on NEPL, Benin City, historical company well data.
2. The data obtained from the interpretation of the well logs of five wells located in the coastal swamp and western onshore regions of the Niger-Delta are used to directly calculate the porosity and formation water saturation.

1.6 LIMITATIONS

The boundaries of this research attempt are as follows:

1. Inadequate data, which led to fewer well logs being used
2. Not obtaining position maps that show the interaction of the well
3. Opposition to the publication of Niger Delta basin geological data

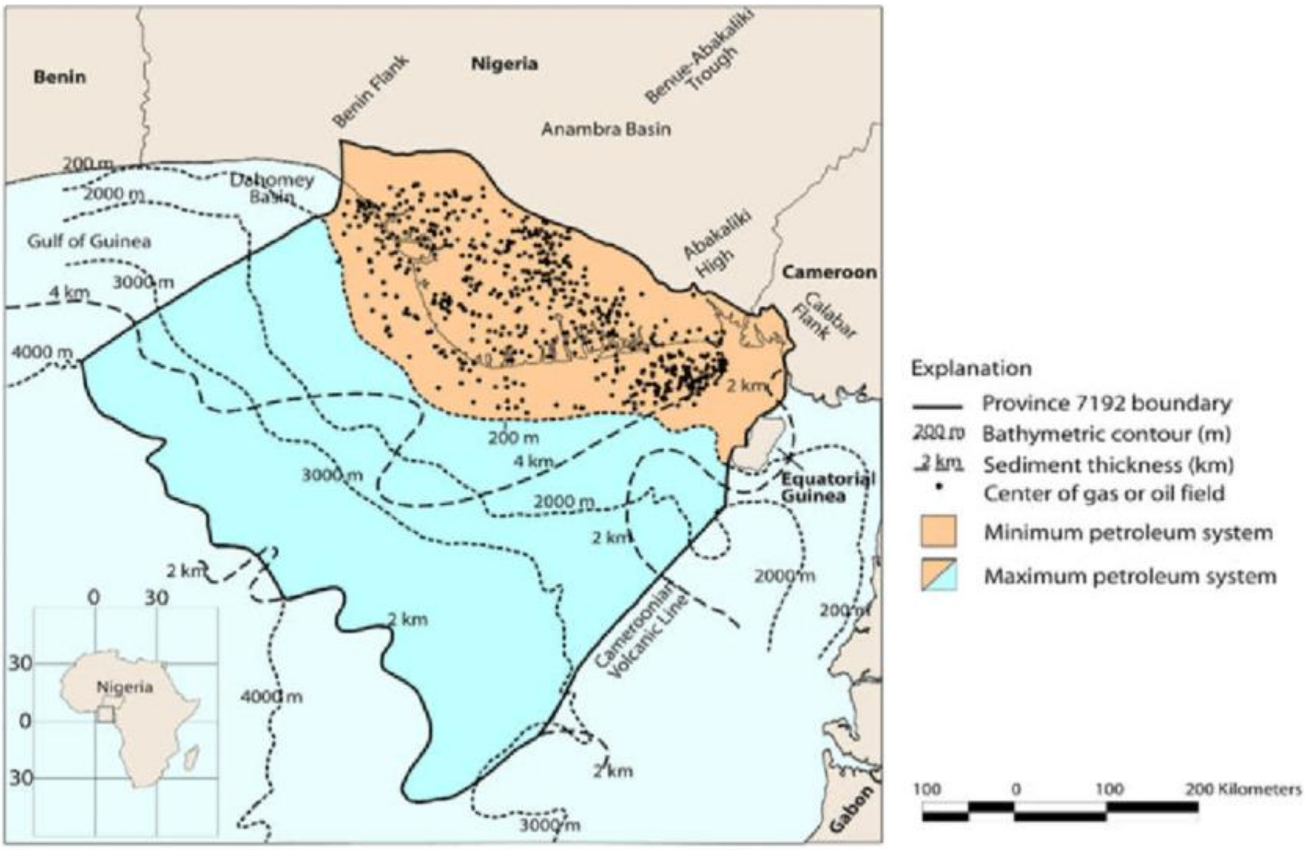

FIG 1.2 MAP OF NIGER DELTA BASI SHOWING PROVINCE

CHAPTER TWO

LITERATURE REVIEW

2.0 ORIGIN OF THE NIGER - DELTA RESERVOIR BASIN

Doust and Omatsola (1990) stated that the Niger Delta reservoir basin was formed at the site of a failed triple rift junction that was linked to the southern Atlantic's opening starting in the late Jurassic period and continuing through the Cretaceous period. The present Delta began to form during the Eocene. Originating as a complicated regressive off-lap sequence, the tertiary Niger-Delta is a sedimentary formation composed of clastic deposits ranging in thickness from 9,000 to 12,000 meters. The Niger-Delta basin formed in the Eocene as a result of early favorable epeirogenic events along the Calabar and Benin flanks.

However, a serious downturn that started in the middle of the Eocene hastened the expansion of the Niger-Delta. The fundamental regression and development of the present-day Niger-Delta began in the middle of the Eocene with the Ameki formation, which was deposited east and west of the Niger River. Even though there have been sporadic, minor breaches, this regressive phase has continued to this day. The two primary drainage systems that provide the Delta with sediment are the Niger-Benue drainage system, which flows through the Anambra basin north of Onitsha, and the less important Cross River drainage system, which flows through the Afikpo basin (Doust and Omatsola, 1990). As demonstrated by the late Cretaceous Abakaliki anticlinorium and its southwestern extension, these two river systems appear to have split apart throughout the Eocene and Oligocene. Associated with Santonian tectonism, this anticlinorium is considered the most prominent tectonic event in the Benue valley.

The middle and late Eocene saw little sedimentation of the expanding Delta from the Cross River system. The Delta was mostly produced in the Bende-Ameki region, although the increasing amount of sand at the top of the Ameki formation indicates that the coastline may have shifted southward. Meanwhile, the Western Delta swept quickly across the narrow shelf of Anambra. According to Doust and Omatsola (1990), there is evidence that the Niger Delta basin crossed over into the Onitsha basin area in the mid-Eocene and moved closer to the Kwale area. In the late Eocene, it made its way to the Abali region. The Ihuo embayment is a marine inter-deltaic area that formed between the two Deltas and extends beyond the Orlu area as a result of the cross-River Delta system's slow progress.

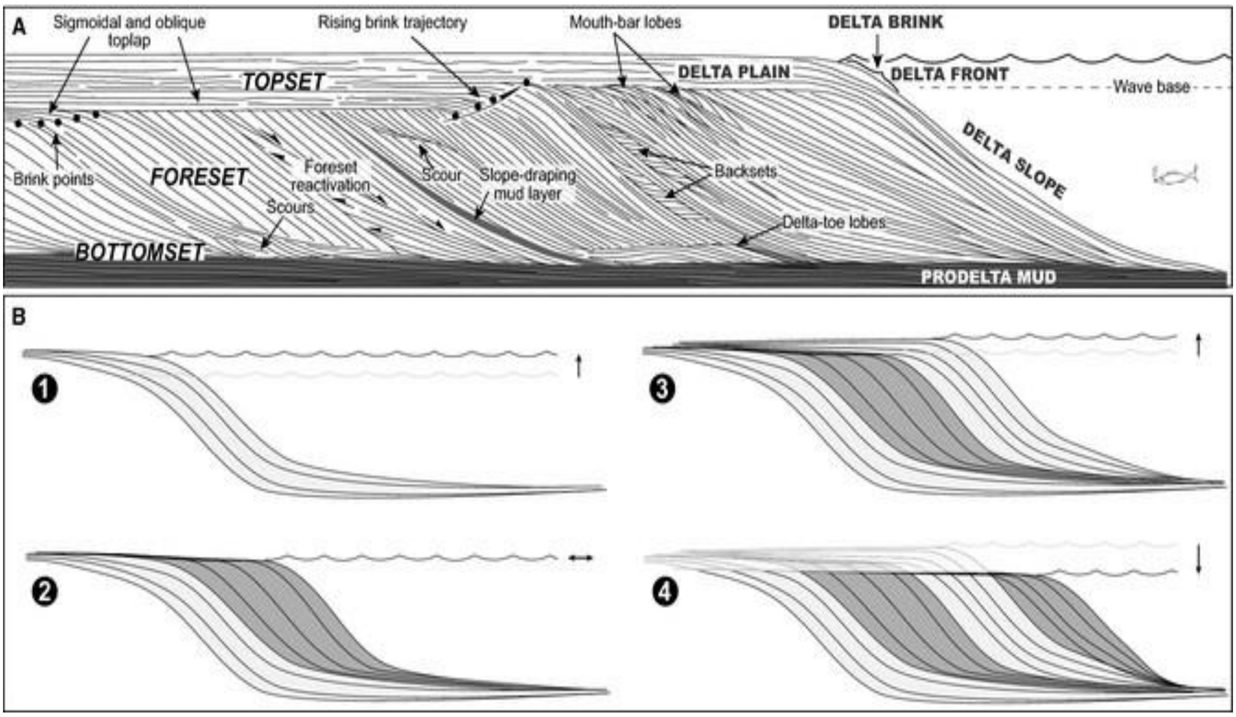

FIG 2.1: DIAGRAMMATIC CROSS SECTION OF A PROJECTING DELTA BASIN

The Delta continued to move swiftly in the post-Eocene. A very strong subsidence and relatively minor progradation of the Delta front towards the west and south-west is reflected in the significant overlap between the subsequent depocentres in the west in the late Oligocene and early Miocene. Because of this pattern of overlapping depocentres, another thick development of paraltic sediments was formed over the western part of the Delta. In contrast, the east's successive depocentres usually do not overlap and demonstrate a quicker

Delta front motion. The eastern depocentres are easily distinguished from the western ones by the paleography, which is marked by a period of erosion or non-deposition. This area is clearly situated on the southern extension of the Abkaliki anticlinorium, which at the time was probably going through some favorable readjustment. The formerly separated depocentres finally merged with those of the Western delta to form a single, enlarged Niger-Delta in the late Miocene. Beyond the current coastline, the sub-Niger Delta appeared in the late Miocene. Over the Pliocene–Pleistone epoch, it migrated farther out to sea, probably reaching its greatest extent at the present-day continental shelf's edge. Sea floor samples collected from different sites up to 64 kilometers offshore have shown shallow marine to estuarine-lagoonal fauna and coarse channel sands of fluvial origin. In 1990, Doust and Omatsola observed that the post-glacial rise in sea level caused the sea to cross the Plio-Pleistocene Delta beyond the current coastline. The earlier river systems were degraded and drowned by this invasion, and the result was the contemporary estuary systems.

2.1 STRATIGRAPHY OF THE NIGER-DELTA RESERVOIR BASIN RESERVOIR

A reservoir is defined as a porous and permeable subterranean formation which contains naturally occurring accumulations of producible hydrocarbons (oil and gas) by Chi U. Ikoku in Natural Gas Engineering (1978). Reservoirs have a single natural pressure system and are bounded by water or impermeable rock barriers. Regulatory agencies usually classify reservoirs as either oil or gas reservoirs.

2.1.1 NIGER- DELTA BASIN

The tertiary Niger-Delta generated a complicated regressive off-lap sequence of classic sediments with thicknesses ranging from 9,000 to 12,000 meters, according to Etu-Efeotor J.O. (1998). The Niger-Delta is sedimentary in structure. The Niger-Delta has been unified from its beginnings as multiple separate depocentres since the Miocene.

Like many other Delta locations, the Niger-Delta basin presents a significant challenge in developing a stratigraphic nomenclature. Because of the interdigitations of a limited number of distinct lithologies, it is practically difficult to establish units and borders just to produce autonomous formations in a formal sense.

In spite of this, data from all of the Niger Delta's deep wells show that a distinct tripartite lithostratigraphic succession exists. Depending on the dominant environmental variables, there are three primary sedimentary ecosystems.

1. The Continental Environments
2. The Marine Environments and
3. The Transitional Environments, Stahl and Short (1967)

In a growing delta such as the Niger Delta, sediments from the three habitats indicated above are stratigraphically overlaid. The base of the stratigraphic Niger-Delta series is typified by massive marine shale formations, such as the Akata formation. The middle part of the series is composed of interbedded marine and river sands, silts, and clays (Agbada formation), which are characteristic of a paralic setting. For additional information, please view the graphic presentation below. A layer of massive continental sands (Benin Formation) sits atop the series.

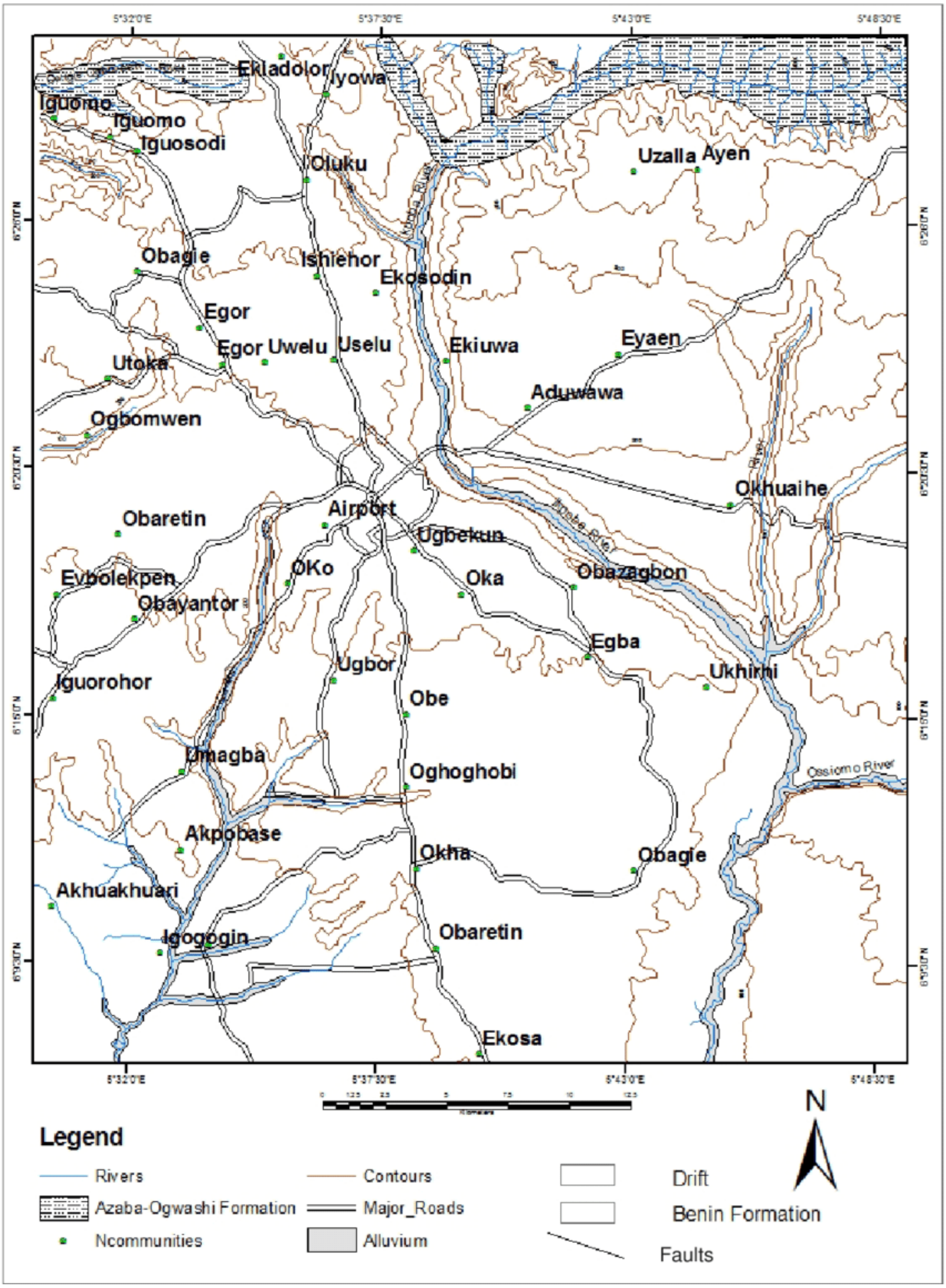

FIG 2.2: MAP OF BENIN HIGHLIGHTING THE AZABA-OGWESHI FORMATION

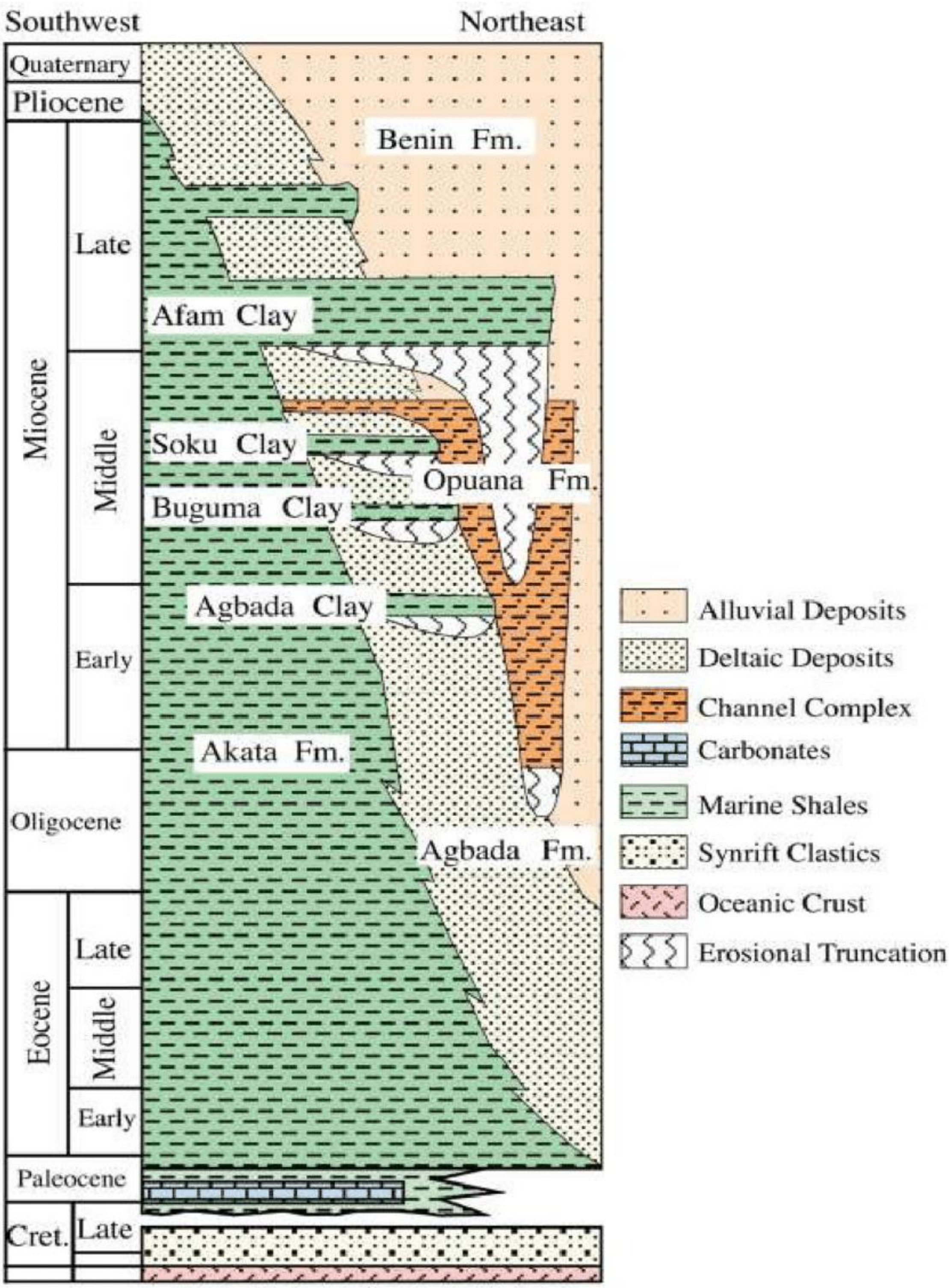

FIG 2.3: STRATIGRAPHIC COLUMN SHOWING THE THREE FORMATIONS OF NIGER DELTA

2.2 NATURE AND TREND OF RESERVOIRS IN THE NIGER- DELTA BASIN

A concentration of rollover structures across deposbelts with short southern flanks and restricted parallic sequence to the south are characteristics of the oil-rich Niger-Delta basin belt, commonly referred to as the "golden lane", according to Weber (1987). Haack et al. (1997) claim that the oil-rich belt's location is associated with oil-prone marine source rocks that were deposited close to the Delta lobes.

According to Weber and Daukoru (1976), the Agbada formation's source/reservoir rock sequence can be described as follows.

I. Sandstone and shale alternate in a higher unit, with sandstone predominating over shale.

ii A lower unit that primarily consists of shales, some of which are thicker than the intersands or sandstone.

Near the upper unit of the formation, the proportion of sandstone is 75%, while in the lower half of the unit, it is 50% or less.

Drill stem testing and sample collection are challenging or impossible in the Niger Delta because most of the formations are unconsolidated sands and shale (Schlumberger 1985). Consequently, formations are mostly assessed using logs through sidewall samples and wireline formation tests.

2.2.1 THE BENIN FORMATION

Overpressure does not affect the Benin formation, which is a loose, freshwater-bearing sand deposit that can descend to a depth of 2286 meters and occasionally contains clay and lignite. It is the most recent formation and is mostly composed of sandstone with shale intercalations. It is coarsely grained, poorly sorted, and subangular to well-rounded. In the north, the Benin formation is Oligocene, whereas in the south, it is progressively younger. Among other things, it has moles, calcareous shells, and fossilized pollen.

2.2.2 THE AGBADA FORMATION

Sands and shale are alternated in the Agbada formation. The upper regions are more likely to have sands, whereas the lower sections are more likely to have shales. The Agbada formation thickens to a maximum of 457.2 meters in the center of the Delta (Doust and Omatsola, 1990). It is the center of overpressure and the location of most oil reservoirs. From the Plio-Pleitocene in the south to the Eocene in the north, this formation's age declines.

2.2.3 THE AKATA FORMATION

The source rock, which comprises clay and shale, makes up the Akata formation. The anoxic Akata formation is home to an abundant fauna. A marine sedimentary sequence was put down in front of the spreading Delta to generate this formation. The Akata formation is between Eocene and the current age.

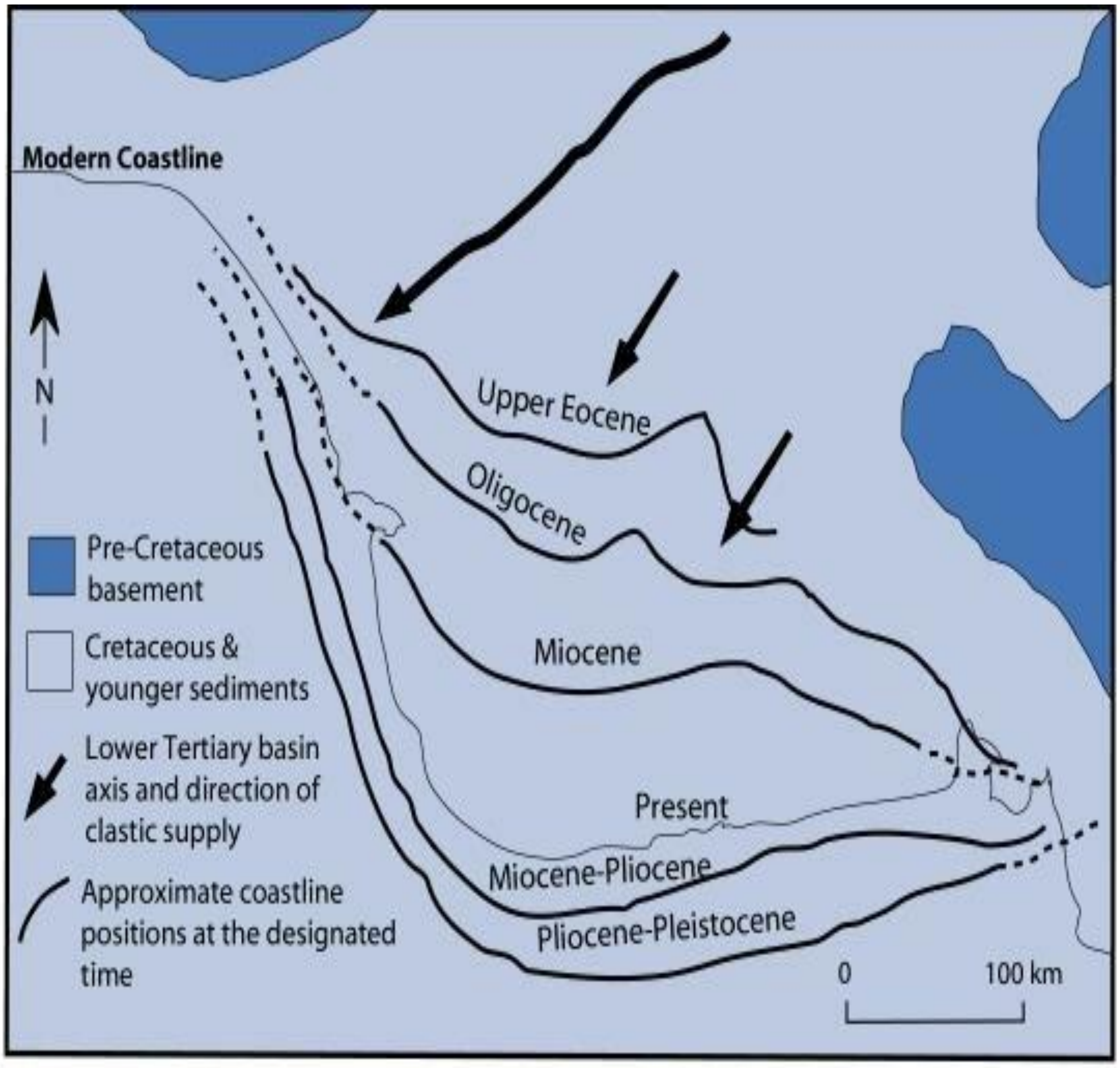

FIG 2.4: PROGRADATION OF THE NIGER DELTA COASTLINE SINCE 35MA

2.3 STRUCTURE OF THE NIGER DELTA BASIN RESERVOIR

In a review of the Geology and Petrophysical characteristics of the Niger-Delta basin, Munirah Omoro Mohammed found that while the surface of the Cenozoic Niger Delta complex is largely undisturbed, the subsurface is impacted by large-scale synsedimentary features such as growth faults, rollover anticlines, and diapers (Project work 2006).

2.3.1 GROWTH FAULTS

It is widely accepted that rapid sand deposition along the delta edge on top of the poorly compacted Akata clay is what led to the development of synsedimentary gravitational faults known as growth faults, so named because they persist after their formation and allow faster sedimentation in the downthrown block relative to the upthrown block. The crescent-shaped faults, with the concave side facing the block that was thrown down, are clearly visible as they grow. Since the growth faults are essentially listric normal faults, they have a tendency to flatten down with depth and expand toward the bedding plane. Accelerated sedimentation along the growth faults causes a rotational movement, tilting the beds in the direction of the fault, and creating "rollover anticline" formations, which are linked to almost all of the oil fields discovered in the Niger Delta complex to date. One important feature of Nigerian rollover anticlines is the shrift of the crestal position with depth. Growth faulting mainly affects the Agbada formation, and the faults terminate in the massive marine shale of the Akata formation.

2.3.2 SHALE DIAPIRS

The Niger Delta region's shale deposits fall into three categories: the first is the area behind major growth faults, the second is the shale bulges in front of growth faults that can sometimes act as positive factors to cause collapsed crest structures and unconformities, and the third is those that extruded in a seaward direction due to differential loading on the plastic marine shales. These offshore diapirs are buried due to ongoing sedimentation, but they can still grow like salt domes, and the clay ridge may eventually turn into actual diaparic formations. Please refer to the image, which displays rollover anticlines and growth faults in the Niger Delta.

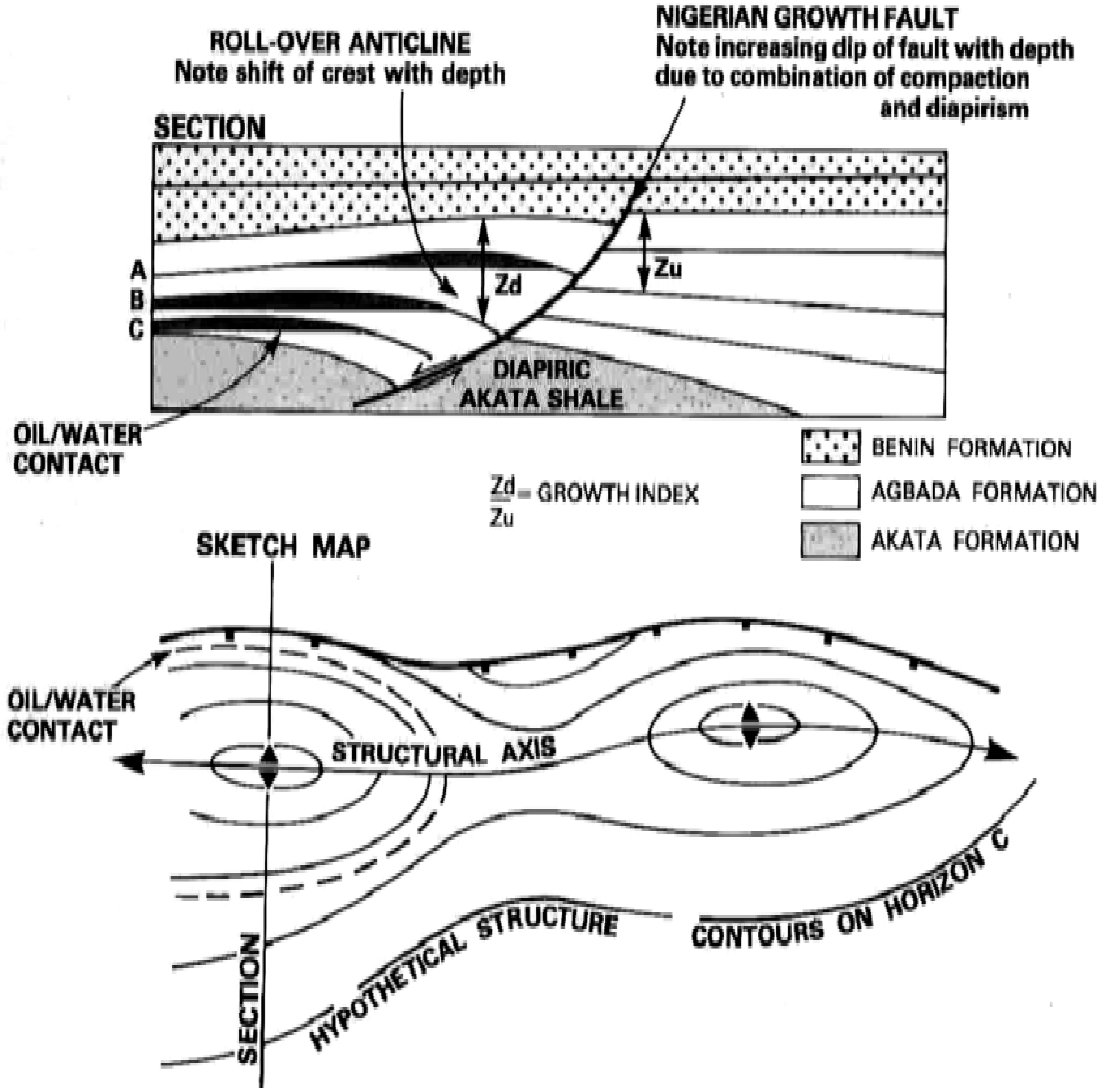

FIG 2.5: NIGER DELTA GROWTH FAULT WITH ROLL-OVER ANTICLINE

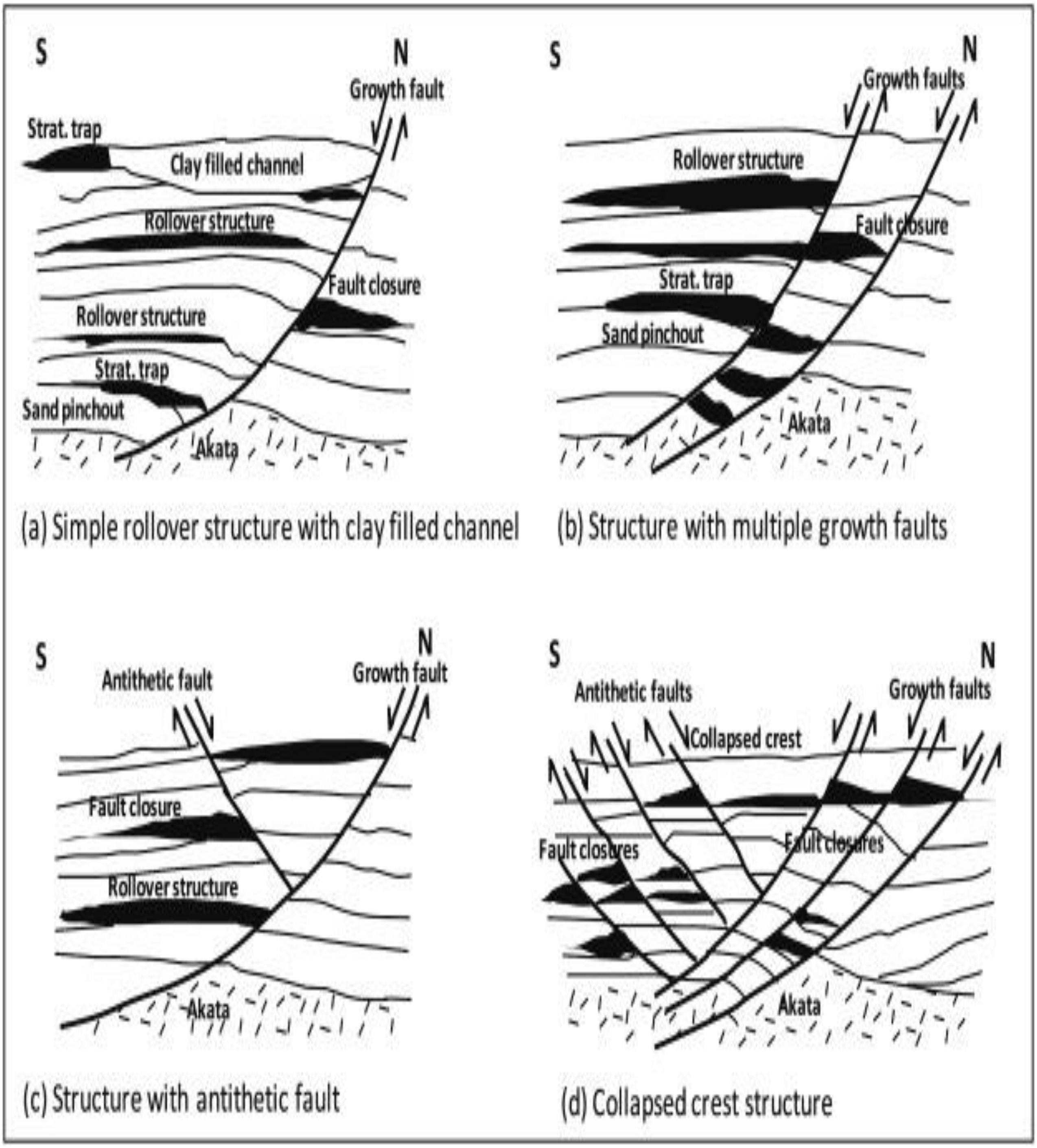

FIG 2.6: STRUCTURAL FEATURES OF THE TERTIARY NIGER DELTA SHOWING GROWTH FAULT AND ROLLOVER ANTICLINES

CHAPTER THREE

RESEARCH METHODOLOGY

3.0 METHODOLOGY

The NNPC Exploration and Production Limited (NEPL) Benin City provided combination suites wireline logs. Interpreting this log and the findings within is one of the primary objectives of understanding the trend of the petrophysical parameters identified (i.e., porosity and formation water saturation).

3.1 DATA ACQUISITION

Five reservoir sand units in the coastal marsh region of Nigeria's western onshore Niger-Delta were detected and correlated across five wells to provide the data. Sands V, W, X, Y, and Z are utilized as reservoir sands. Three wells—wells 02, 03, and 05—reach all of these units, although wells 01 and 04 reach just four sand units.

3.1.1 FIELD LOCATION

The western onshore Niger-Delta Nigeria coastal marsh region is the area of interest under assessment. It lies between 4° 81' 25'' and 40 92' 25''E and 5° 52'50'' and 6° 15'00''N. Examine how the area of interest is situated in respect to the oil fields, pipelines, and two Nigerian towns (Port Harcourt and Warri).

3.2 DATA PRESENTATION

TABLE 3.1: LITHOLOGIC UNIT THICKNESS AND DEPTH AS MEASURED IN WELLS THROUGHOUT THE FIELD (MEASUREMENTS ARE IN FEET)

L **Litho units**	Well 1			Well 2			Well 3			Well 4			Well 5		
	Top	base	thickness	top	base	thickness	top	base	Thickness	top	base	thickness	top	base	thickness
Sand V	11375	11970	595	11325	11885	560	11325	11885	560	11380	12000	620	11400	11962	562
Sand W	12030	12415	385	12000	12360	360	11975	12300	325	12050	12350	300	12025	12375	350
Sand X	12675	12925	250	12555	12800	245	12525	12750	225	12605	12810	205	12575	12810	235
Sand Y	13007	13282	275	12875	13225	350	12825	13100	275	12910	13275	365	12875	13175	300
Sand Z				13410	13525	115	13410	13525	115				13425	13600	175

3.3 DETERMINATION OF PETROPHYSICAL DATA AND CALCULATION

In this research, gamma ray data (GR log) was used to evaluate the formation's radioactivity. 0 to 150 API is the scale used. The GR line deviating towards the 150 API level indicates sand deposition, while the GR line deviating towards the zero (0) mark indicates shale deposition. Using a measurement range of 1 to 10009m2/m, resistivity was calculated using the dual laterology. The suspected formations were tested for the presence of water, gas, oil, or all three using the neutron density log.

3.3.1 NEUTRON/DENSITY POROSITY

The neutron/density porosity was computed using the neutron porosity and bulk density lines on the log. The neutron porosity is evaluated as 12, 47, and 13 from left to right. With a range of 47 to -13, it has 20 divisions of 0.3. Bulk density readings are taken from 2.8 to 1.8, from right to left. Its scale, which goes from 1.8 to 2.8, has 20 divisions of 0.5. The density porosity, which is used in combination with the neutron porosity to calculate actual porosity, was ascertained after the bulk density and neutron porosity were measured.

3.3.2 PETROPHYSICAL CHARACTERISTICS

This work uses four petrophysical characteristics, which are as follows:

I. Porosity
II. Permeability
III. Resistivity
IV. Water saturation
V. Fluid Saturation

POROSITY: The percentage of voids in the overall volume of rock is known as porosity. We can compute porosity "Φ" by applying the empirical relations;

$$\Phi = \frac{pma - pb}{pma - pfl} \quad \text{------------------------} \quad \text{eqn 3.0}$$

Where *pma* = matrix density (g/cc), assumed value 2.65gkc

pb = Bulk density (g/cc)

pfl = Fluid density, assumed value 1g/cc

Note: It is assumed that *pma* and *pfl* are 2.65gkc and 1g/cc, respectively. The log is used to determine the bulk density (g/cc) value. The neutron and density logs are combined to provide these figures. The actual porosity is the average of density porosity and neutron porosity.

$$Porosity = \frac{Neutron\ porosity + density\ porosity}{2} \qquad \text{---------------} \quad \text{eqn 3.1}$$

PERMEABILITY: This is a measurement of a porous medium's capacity to transfer fluids without causing structural alterations or component displacement. Permeability has the following empirical relationship, according to TIMAR and Dressers Atlas (1982):

$$K = \frac{0.136\Phi 4.4}{(S_{wirr})^2} \qquad \text{---------------} \quad \text{eqn 3.2}$$

Where Φ = porosity

S_{wirr} = irreducible water saturation

K = permeability

RESISTIVITY: This can be characterized as the fundamental measurement of a rock's ability to withstand electrical current, regardless of its size or shape. R_t and R_o are the resistivity values that are employed in this calculation. R_t is the true resistivity of the formation's uninvaded zone. R_o, or wet resistivity, is the resistivity of the formation at 100% water saturation. The logs can be used to directly derive these resistivities, which can then be quantified in Ohm m^2/m or Ohm meter.

WATER SATURATION: Water saturation is obtained from the square root of the quotient nof the resistivities mentioned above.

i.e. $$S_w = \sqrt{\frac{R_o}{R_t}} \qquad \text{--------------------} \quad \text{eqn 3.3}$$

Hydrocarbon saturation, represented by the symbol S_h, is then obtained using water saturation.

FLUID SATURATION: This indicates directly whether and to what extent a formation is filled with fluids. This comprises irreducible water saturation (S_{wirr}), hydrocarbon saturation (S_h), and water saturation (S_w). This Archies formula can be used to calculate fluid saturation.

$$S_w = \sqrt{\frac{FR_w}{R_t}}$$ -------------------- eqn 3.4

Where R_w cannot be obtained immediately, R_o is used. The equation is then written as;

$$S_w = \sqrt{\frac{R_o}{R_t}}$$ -------------------- recall

eqn 3.3

Where $R_o = FR_w$

The hydrocarbon saturation S_h can be calculated by subtracting the value of water saturation S_w from either 100% or 1. The Humbles equation of unconsolidated sands, however, is the formula used for irreducible water saturation.

$$S_{wirr} = \sqrt{\frac{F}{2000}}$$ ------------------ eqn

3.5

Where F = formation factor = $\frac{0.62}{\Phi^{2.15}}$ ------------------ eqn 3.6

OTHER PARAMETERS

1. Bulk density 1b in g/cc
2. Neutron porosity (ΦN)
3. Density porosity (ΦD)
4. Bulk volume of water (BVW)

The bulk volume of water is derived by obtaining the product of water saturation and porosity, i.e BVW = S_w Φ

3.4 CALCULATIONS

3.4.1.1 DETERMINATION OF POROSITY (Φ) VALUES OF RESERVOIR SANDS IN WELL 02

Sand V

Recall from eqn 3.2 that Porosity Φ = $\frac{\Phi N + \Phi D}{2}$

Also recall that from eqn 3.1 $\Phi D = \frac{pma - pbulk}{pma - pfl}$

Where pma = 2.65

Pbulk = obtained from log. = 2.4

ΦN as obtained from log = 24.5

$$\Phi D = \frac{2.65 - 2.4}{2.65 - 1} = 0.21 \text{ } or \text{ } 21\%$$

Therefore $\Phi = \frac{\Phi N + \Phi D}{2} = \frac{24.5+21}{2} = 0.2278 \text{ } or \text{ } 22.78\%$

Sand W

Where pbulk = 2.4

ΦN as obtained from log = 26.0

$$\Phi D = \frac{2.65 - 2.4}{2.65 - 1} = 0.15 \text{ } or \text{ } 15\%$$

$$\Phi = \frac{\Phi N + \Phi D}{2} = \frac{26.0 + 15}{2} = 20.5\%$$

Sand X

Where pbulk = 2.5

ΦN as obtained from log = 21.46

$$\Phi D = \frac{2.65 - 2.5}{2.65 - 1} = 0.091 \; or \; 9.1\%$$

$$\Phi = \frac{\Phi N + \Phi D}{2} = \frac{21.46 + 9.1}{2} = 15.28\%$$

<u>**Sand Y**</u>

Where pbulk = 2.5

ΦN as obtained from log = 21.15

$$\Phi D = \frac{2.65 - 2.5}{2.65 - 1} = 0.091 \; or \; 9.1\%$$

$$\Phi = \frac{21.15 + 9.1}{2} = 15.13$$

<u>**Sand Z**</u>

Where pbulk = 2.35

ΦN as obtained from log = 14.96

$$\Phi D = \frac{2.65 - 2.35}{2.65 - 1} = 0.18 \; or \; 18\%$$

$$\Phi = \frac{14.96 + 18}{2} = 16.48$$

3.4.1.2 DETERMINATION OF POROSITY VALUES OF RESERVOIR SANDS IN WELL 03

<u>**Sand V**</u>

Where pbulk = 2.299

ΦN as obtained from log = 13.46

$$\Phi D = \frac{2.65 - 2.299}{2.65 - 1} = 0.22 \; or \; 22\%$$

$$\Phi = \frac{13.46 + 22}{2} = 17.73\%$$

Sand W

Where pbulk = 2.3

ΦN as obtained from log = 15.22

$$\Phi D = \frac{2.65 - 2.3}{2.65 - 1} = 0.212 \; or \; 21\%$$

$$\Phi = \frac{15.22 + 21}{2} = 18.11\%$$

Sand X

Where pbulk = 2.29

ΦN as obtained from log = 19.3

$$\Phi D = \frac{2.65 - 2.29}{2.65 - 1} = 0.22 \; or \; 22\%$$

$$\Phi = \frac{19.3 + 22}{2} = 20.67\%$$

Sand Y

Where pbulk = 2.5

ΦN as obtained from log = 30.56

$$\Phi D = \frac{2.65 - 2.5}{2.65 - 1} = 0.091 \; or \; 9.1\%$$

$$\Phi = \frac{30.56 + 9.1}{2} = 19.83$$

Sand Z

Where pbulk = 2.3

ΦN as obtained from log = 14.04

$$\Phi\text{D} = \frac{2.65 - 2.3}{2.65 - 1} = 0.212 \; or \; 21\%$$

$$\Phi = \frac{14.04 + 21}{2} \; 17.52$$

3.4.1.3 DETERMINATION OF POROSITY VALUES OF RESERVOIR SANDS IN WELL 04

Sand V

Where pbulk = 2.29

ΦN as obtained from log = 26.7

$$\Phi\text{D} = \frac{2.65 - 2.29}{2.65 - 1} = 0.22 \; or \; 22\%$$

$$\Phi = \frac{26.7 + 22}{2} = 26.22\%$$

Sand W

Where pbulk = 2.3

ΦN as obtained from log = 19.54

$$\Phi\text{D} = \frac{2.65 - 2.3}{2.65 - 1} = 0.212 \; or \; 21\%$$

$$\Phi = \frac{19.54 + 21}{2} = 20.27\%$$

Sand X

Where pbulk = 2.5

ΦN as obtained from log = 28.18

$$\Phi D = \frac{2.65 - 2.5}{2.65 - 1} = 0.091 \; or \; 9.1\%$$

$$\Phi = \frac{28.18 + 9.1}{2} = 18.65\%$$

Sand Y

Where pbulk = 2.3

ΦN as obtained from log = 17.52

$$\Phi D = \frac{2.65 - 2.3}{2.65 - 1} = 0.212 \; or \; 21\%$$

$$\Phi = \frac{17.52 + 21}{2} = 19.26\%$$

3.4.1.4 DETERMINATION OF POROSITY VALUES OF RESERVOIR SANDS IN WELL 5

Sand V

Where pbulk = 2.3

ΦN as obtained from log = 30.44

$$\Phi D = \frac{2.65 - 2.3}{2.65 - 1} \; 0.22 \; or \; 22\%$$

$$\Phi = \frac{30.44 + 22}{2} = 26.22\%$$

Sand W

Where pbulk = 2.29

ΦN as obtained from log = 30.3

$$\Phi D = \frac{2.65 - 2.29}{2.65 - 1} = 0.21 \; or \; 21\%$$

$$\Phi = \frac{30.3 + 21}{2} = 25.65\%$$

Sand X

Where pbulk = 2.29

ΦN as obtained from log = 32.22

$$\Phi D = \frac{2.65 - 2.29}{2.65 - 1} = 0.21 \text{ or } 21\%$$

$$\Phi = \frac{32.22 + 21}{2} = 27.11\%$$

Sand Y

Where pbulk = 2.3

ΦN as obtained from log = 32.28

$$\Phi D = \frac{2.65 - 2.3}{2.65 - 1} = 0.21 \text{ or } 21\%$$

$$\Phi = \frac{32.28 + 21}{2} = 27.14\%$$

Sand Z

Where pbulk = 2.35

ΦN as obtained from log = 36.62

$$\Phi D = \frac{2.65 - 2.35}{2.65 - 1} = 0.18 \text{ or } 18\%$$

$$\Phi = \frac{36.62 + 18}{2} = 27.31\%$$

3.4.2.1 DETERMINATION OF WATER SATURATION FOR WELL 02

Recall from eqn 3.3 and 3.4 that

$$S_w = \sqrt{\frac{FR_w}{R_t}} = \sqrt{\frac{R_o}{R_t}}$$

Where FR_w = R_o = Resistivity of formation at 100% water saturation, i.e. wet resistivity. Rt = resistivity of formation's uninvaded zone. These resistivities are obtained directly from the logs and are measured in ohm or ohms m^2/m

Sand V

Where R_o 4, R_t 127.7

$$S_w = \sqrt{\frac{4}{127.7}} = 0.17699$$

$$S_h = 1 - 0.17699 = 0.823 \; or \; 82.30\%$$

Sand W

Where R_o = 2.5, R_t = 43.935

$$S_w = \sqrt{\frac{2.5}{43.935}} = 0.2385 \; or \; 23.85\%$$

$$S_h = 1 - 0.2385 = 0.7615 \; or \; 76.15\%$$

Sand X

Where R_o = 2.5, R_t = 34.695

$$S_w = \sqrt{\frac{2.5}{34.695}} = 0.2684 \; or \; 26.84\%$$

$$S_h = 1 - 0.2684 = 0.731567 \; or \; 73.16\%$$

Sand Y

Where R_o = 4, R_t = 107.2

$$S_w = \sqrt{\frac{4}{107.2}} = 0.193166 \text{ or } 19.32\%$$

$$S_h = 1 - 0.193166 = 0.806833 \text{ or } 80.68\%$$

Sand Z

Where $R_o = 5$, $R_t = 219.5$

$$S_w = \sqrt{\frac{5}{219.5}} = 0.1509273 \text{ or } 15.10\%$$

$$S_h = 1 - 0.1509273 = 0.849073 \text{ or } 84.90\%$$

3.4.2.2 DETERMINATION OF WATER SATURATION FOR WELL 03

Sand V

Where $R_o = 4$, $R_t = 110.9$

$$S_w = \sqrt{\frac{4}{110.9}} = 0.18992 \text{ or } 18.99\%$$

$$S_h = 1 - 0.18992 = 0.8100828 \text{ or } 81.01\%$$

Sand W

Where $R_o = 5$, $R_t = 215$

$$S_w = \sqrt{\frac{5}{215}} = 0.152498 \text{ or } 15.25\%$$

$$S_h = 1 - 0.152498 = 0.8475014 \text{ or } 84.75\%$$

Sand X

Where $R_o = 5$, $R_t = 312.9$

$$S_w = \sqrt{\frac{5}{312.9}} = 0.12641023 \text{ } or \text{ } 12.64\%$$

$$S_h = 1 - 0.12641023 = 0.8735898 \text{ } or \text{ } 87.36\%$$

Sand Y

Where $R_o = 5$, $R_t = 606$

$$S_w = \sqrt{\frac{5}{606}} = 0.0908341 \text{ } or \text{ } 9.08\%$$

$$S_h = 1 - 0.0908341 = 0.90916594 \text{ } or \text{ } 90.92$$

Sand Z

Where $R_o = 1.75$, $R_t = 1140$

$$S_w = \sqrt{\frac{1.75}{1140}} = 0.0391802 \text{ } or \text{ } 3.92\%$$

$$S_h = 1 - 0.0391802 = 0.9608798 \text{ } or \text{ } 96.10\%$$

3.4.2.3 DETERMINATION OF WATER SATURATION FOR WELL 04

Sand V

Where $R_o = 2.5$, $R_t = 58.7$

$$S_w = \sqrt{\frac{2.5}{58.7}} = 0.20637208 \text{ } or \text{ } 20.64\%$$

$$S_h = 1 - 0.20637208 = 0.7936279 \text{ } or \text{ } 79.36\%$$

Sand W

Where $R_o = 4$, $R_t = 119.7$

$$S_w = \sqrt{\frac{4}{119.7}} = 0.1828028 \; or \; 18.28\%$$

$$S_h = 1 - 0.1828028 = 0.81719717 \; or \; 81.72\%$$

<u>Sand X</u>

Where R_o = 5, R_t = 190

$$S_w = \sqrt{\frac{5}{190}} = 0.16222142 \; or \; 16.22\%$$

$$S_h = 1 - 0.16222142 = 0.837778579 \; or \; 83.78\%$$

<u>Sand Y</u>

Where R_o = 5, R_t = 200.9

$$S_w = \sqrt{\frac{5}{200.9}} = 0.15775932 \; or \; 15.78\%$$

$$S_h = 1 - 0.15775932 = 0.8422406 \; or \; 84.22\%$$

3.4.2.4 DETERMINATION OF WATER SATURATION FOR WELL 05

<u>Sand V</u>

Where R_o = 5.5, R_t =90.4

$$S_w = \sqrt{\frac{5.5}{90.4}} = 0.2466591 \; or \; 24.65\%$$

$$S_h = 1 - 0.2466591 = 0.7533409 \; or \; 75.33\%$$

<u>Sand W</u>

Where R_o = 2.5, R_t = 44.57

$$S_w = \sqrt{\frac{2.5}{44.57}} = 0.23683652 \ or \ 23.68\%$$

$$S_h = 1 - 0.23683652 = 0.76316347 \ or \ 76.32\%$$

<u>Sand X</u>

Where $R_o = 5$, $R_t = 224$

$$S_w = \sqrt{\frac{5}{224}} = 0.1494035 \ or \ 14.94\%$$

$$S_h = 1 - 0.1494035 = 0.8505964 \ or \ 85.06\%$$

<u>Sand Y</u>

Where $R_o = 5$, $R_t = 535$

$$S_w = \sqrt{\frac{5}{535}} = 0.096673648 \ or \ 9.67\%$$

$$S_h = 1 - 0.096673648 = 0.90332635 \ or \ 90.33\%$$

<u>Sand Z</u>

Where $R_o = 5$, $R_t = 755.7$

$$S_w = \sqrt{\frac{5}{755.7}} = 0.08134114 \ or \ 8.13\%$$

$$S_h = 1 - 0.08134114 = 0.91865885 \ or \ 91.87$$

3.4.3.0 DETERMINATION OF IRREDUCIBLE WATER SATURATION VALUES OF RESERVOIR SANDS IN WELLS 02, 03, 04 AND 05 RESPECTIVELY.

3.4.3.1 CALCULATION OF IRREDUCIBLE WATER SATURATION VALUES FOR WELL 02

As we recall, from Humble's equation for unconsolidated sand (eqn 3.5):

$$S_{wirr} = \sqrt{\frac{F}{2000}}$$

Where F = Formation factor = 15.01 for unconsolidated sands

But also recall from eqn 3.6 that

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

<u>Sand V</u>

Where Φ = 22.78 or 0.2278

$$F = \frac{0.62}{0.2278^{2.15}} = 14.91$$

$$S_{wirr} = \sqrt{\frac{14.91}{2000} = 0.0863 \; or \; 8.63}$$

<u>Sand W</u>

Where Φ = 20.5% or 0.205

$$F = \frac{0.62}{0.205^{2.15}} = 18.13$$

$$S_{wirr} = \sqrt{\frac{18.13}{2000}} = 0.0952 \; or \; 9.52\%$$

Sand X

Where Φ = 15.28 or 0.1528

$$F = \frac{0.62}{0.1528^{2.15}} = 35.20$$

$$S_{wirr} = \sqrt{\frac{35.20}{2000}} = 0.13266 \ or \ 13.27\%$$

Sand Y

Where Φ = 0.1513 or 15.13%

$$F = \frac{0.62}{0.1513^{2.15}} = 35.95$$

$$S_{wirr} = \sqrt{\frac{35.95}{2000}} = 0.13407 \ or \ 13.41\%$$

Sand Z

Where Φ = 0.1648 or 16.48%

$$F = \frac{0.62}{0.1648^{2.15}} = 29.92$$

$$S_{wirr} = \sqrt{\frac{29.92}{2000}} = 0.1223 \ or \ 12.23\%$$

3.4.3.2 CALCULATION OF IRREDUCIBLE WATER SATURATION VALUIES FOR WELL 03

Sand V

Where Φ = 0.1773 or 17.73%

$$F = \frac{0.62}{0.1773^{2.15}} = 25.57$$

$$S_{wirr} = \sqrt{\frac{25.57}{2000}} = 0.1131 \; or \; 11.31\%$$

Sand W

Where Φ = 0.1811 or 18.11%

$$F = \frac{0.62}{0.1811^{2.15}} = 24.42$$

$$S_{wirr} = \sqrt{\frac{24.42}{2000}} = 0.1105 \; or \; 11.05\%$$

Sand X

Where Φ = 0.2067 or 20.67%

$$F = \frac{0.62}{0.2067^{2.15}} = 18.38$$

$$S_{wirr} = \sqrt{\frac{18.38}{2000}} = 0.0959 \; or \; 9.59\%$$

Sand Y

Where Φ = 0.1983 or 19.83%

$$F = \frac{0.62}{0.1983^{2.15}} = 20.10$$

$$S_{wirr} = \sqrt{\frac{20.10}{2000}} = 0.1002 \; or \; 10.02\%$$

Sand Z

Where Φ = 0.1752 or 17.52%

$$F = \frac{0.62}{0.1752^{2.15}} = 26.23$$

$$S_{wirr} = \sqrt{\frac{26.23}{2000}} = 0.1145 \text{ } or \text{ } 11.41\%$$

3.4.3.3 CALCULATION OF IRREDUCIBLE WATER SATURATION VALUES FOR WELL 04

Sand V

Where Φ = 0.2435 or 24.35%

$$F = \frac{0.62}{0.2435^{2.15}} = 12.93$$

$$S_{wirr} = \sqrt{\frac{12.93}{2000}} = 0.0804 \text{ } or \text{ } 8.04\%$$

Sand W

Where Φ = 0.2027 or 20.27

$$F = \frac{0.62}{0.2027^{2.15}} = 19.17$$

$$S_{wirr} = \sqrt{\frac{19.17}{2000}} = 0.0979 \text{ } or \text{ } 9.79\%$$

Sand X

Where Φ = 0.1864 or 18.64%

$$F = \frac{0.62}{0.1864^{2.15}} = 22.96$$

$$S_{wirr} = \sqrt{\frac{22.96}{2000}} = 0.1072 \text{ } or \text{ } 10.72\%$$

Sand Y

Where Φ = 0.1926 or 19.26%

$$F = \frac{0.62}{0.1926^{2.15}} = 21.40$$

$$S_{wirr} = \sqrt{\frac{21.40}{2000}} = 0.1034 \; or \; 10.34\%$$

3.4.3.4 CALCULATION OF IRREDUCIBLE WATER SATURATION VALUES FOR WELL 05

Sand V

Where Φ = 0.2622 or 26.22%

$$F = \frac{0.62}{0.2622^{2.15}} = 11.02$$

$$S_{wirr} = \sqrt{\frac{11.02}{2000}} = 0.0742 \; or \; 7.42\%$$

Sand W

Where Φ = 0.2565 or 25.65%

$$F = \frac{0.62}{0.2565^{2.15}} = 11.56$$

$$S_{wirr} = \sqrt{\frac{11.56}{2000}} = 0.0760 \; or \; 7.60\%$$

Sand X

Where Φ = 0.2711 or 27.11%

$$F = \frac{0.62}{0.2711^{2.15}} = 10.26$$

$$S_{wirr} = \sqrt{\frac{10.26}{2000}} = 0.0716 \ or \ 7.16\%$$

<u>Sand Y</u>

Where Φ = 0.2714 or 27.14%

$$F = \frac{0.62}{0.2714^{2.15}} = 10.23$$

$$S_{wirr} = \sqrt{\frac{10.23}{2000}} = 0.0715 \ or \ 7.15\%$$

<u>Sand Z</u>

Where Φ = 0.2731 or 27.31%

$$F = \frac{0.62}{0.2731^{2.15}} = 10.10$$

$$S_{wirr} = \sqrt{\frac{10.10}{2000}} = 0.0711 \ or \ 7.11\%$$

3.4.4.0 DETERMINATION OF PERMEABILITY VALUES FOR RESERVOIR SANDS IN WELLS 02, 03, 04 AND 05 RESPECTIVELY

According to Humble's equation,

$$K = 0.136\left(\frac{\Phi 4.4}{{S_{wirr}}^{2}}\right)$$

3.4.4.1 CALCULATION OF PERMEABILITY VALUES FOR RESERVOIR SANDS IN WELL 02

<u>Sand V</u>

Where Φ = 0.2278, S_{wirr} = 0.0866

$$K = 0.136\left(\frac{0.2278 \times 4.4}{0.0866^2}\right) = 18.18$$

KV = 18.18mD

Sand W

Where $\Phi = 0.205$, $S_{wirr} = 0.0967$

$$K = 0.136\left(\frac{0.205 \times 4.4}{0.0967^2}\right) = 13.12$$

KW = 13.12mD

Sand X

Where $\Phi = 0.1528$, $S_{wirr} = 0.1327$

$$K = 0.136\left(\frac{0.1528 \times 4.4}{0.1327^2}\right) = 5.19$$

KX = 5.19mD

Sand Y

Where $\Phi = 0.1528$, $S_{wirr} = 0.1341$

$$K = 0.136\left(\frac{0.1528 \times 4.4}{0.1341^2}\right) = 5.08$$

KY = 5.08mD

Sand Z

Where $\Phi = 0.1648$, $S_{wirr} = 0.1223$

$$K = 0.136\left(\frac{0.1648 \times 4.4}{0.1223^2}\right) = 6.59$$

KZ = 6.59mD

3.4.4.2 CALCULATION OF PERMEABILITY VALUES FOR RESERVOIR SANDS IN WELL 03

Sand V

Where Φ = 0.1773, S_{wirr} = 0.1131

$$K = 0.136\left(\frac{0.1773 \times 4.4}{0.1131^2}\right) = 8.29$$

KV = 8.29mD

Sand W

Where Φ = 0.1811, S_{wirr} = 0.1105

$$K = 0.136\left(\frac{0.1811 \times 4.4}{0.1105^2}\right) = 8.87$$

KW = 8.87mD

Sand X

Where Φ = 0.2067, S_{wirr} = 0.0959

$$K = 0.136\left(\frac{0.2067 \times 4.4}{0.0959^2}\right) = 13.45$$

KX = 13.45mD

Sand Y

Where Φ = 0.1983, S_{wirr} = 0.1002

$$K = 0.136\left(\frac{0.1983 \times 4.4}{0.1002^2}\right) = 11.82$$

KY = 11.82mD

Sand Z

Where $\Phi = 0.1752$, $S_{wirr} = 0.1145$

$$K = 0.136\left(\frac{0.1752 \times 4.4}{0.1145^2}\right) = 7.99$$

KZ = 7.99mD

3.4.4.3 CALCULATION OF PERMEABILITY VALUES FOR RESERVOIR SANDS IN WELL 04

<u>Sand V</u>

Where $\Phi = 0.2435$, $S_{wirr} = 0.0804$

$$K = 0.136\left(\frac{0.2435 \times 4.4}{0.0804^2}\right) = 22.54$$

KV = 22.54mD

<u>Sand W</u>

Where $\Phi = 0.2027$, $S_{wirr} = 0.0979$

$$K = 0.136\left(\frac{0.2027 \times 4.4}{0.0979^2}\right) = 12.66$$

KW = 12.66mD

<u>Sand X</u>

Where $\Phi = 0.1864$, $S_{wirr} = 0.1072$

$$K = 0.136\left(\frac{0.1864 \times 4.4}{0.1072^2}\right) = 9.71$$

KX = 9.71mD

<u>Sand Y</u>

Where $\Phi = 0.1926$, $S_{wirr} = 0.1034$

$$K = 0.136\left(\frac{0.1926 \times 4.4}{0.1034^2}\right) = 10.77$$

KY = 10.77mD

3.4.4.4 CALCULATION OF PERMEABILITY VALUES FOR RESERVOIR SANDS IN WELL 05

Sand V

Where $\Phi = 0.2622$, $S_{wirr} = 0.0742$

$$K = 0.136\left(\frac{0.2622 \times 4.4}{0.0742^2}\right) = 28.50$$

KV = 28.50mD

Sand W

Where $\Phi = 0.2565$, $S_{wirr} = 0.0760$

$$K = 0.136\left(\frac{0.2565 \times 4.4}{0.0760^2}\right) = 26.57$$

KW = 26.57mD

Sand X

Where $\Phi = 0.2711$, $S_{wirr} = 0.0716$

$$K = 0.136\left(\frac{0.2711 \times 4.4}{0.0716^2}\right) = 31.64$$

KX = 31.64mD

Sand Y

Where $\Phi = 0.2714$, $S_{wirr} = 0.0715$

$$K = 0.136\left(\frac{0.2714 \times 4.4}{0.0715^2}\right) = 31.77$$

KY = 31.77

Sand Z

Where Φ = 0.2731, S_{wirr} = 0.0711

$$K = 0.136\left(\frac{0.2731 \times 4.4}{0.0711^2}\right) = 32.33$$

KZ = 32.33mD

3.4.5 DETERMINATION OF BULK VOLUME OF WATER (BVW) VALUES FOR RESERVOIR SANDS IN WELL 02, 03, 04 AND 05

For well 02

We recall that BVW = S_w Φ. Therefore;

BVW(V) = 0.1770 x 0.2278 = 0.0403 or 4.03%

BVW(W) = 0.2385 x 0.2050 = 0.04889 or 4.89%

BVW(X) = 0.2684 x 0.1528 = 0.0410 or 4.10%

BVW(Y) = 0.1932 x 0.1513 = 0.0292 or 2.92%

BVW(Z) = 0.1510 x 0.1648 = 0.0249 or 2.49%

For well 03

BVW(V) = 0.1899 x 0.1773 = 0.0337 or 3.37%

BVW(W) = 0.1560 x 0.1811 = 0.0283 or 2.83%

BVW(X) = 0.1264 x 0.2067 = 0.0261 or 2.61%

BVW(Y) = 0.0908 x 0.1983 = 0.0180 or 1.80%

BVW(Z) = 0.0392 x 0.1752 = 0.0069 or 0.69%

For well 04

BVW(V) = 0.2064 x 0.2435 = 0.0503 or 5.03%

BVW(W) = 0.1828 x 0.2027 = 0.03705 or 3.71%

BVW(X) = 0.1622 x 0.1864 = 0.0302 or 3.02%

BVW(Y) = 0.1578 x 0.1926 = 0.0304 or 3.04%

For well 05

BVW(V) = 0.2469 x 0.2622 = 0.0647 or 6.47%

BVW(W) = 0.2369 x 0.2565 = 0.0608 or 6.08%

BVW(X) = 0.1494 x 0.2711 = 0.0405 or 4.05%

BVW(Y) = 0.0968 x 0.2714 = 0.0263 or 2.63%

BVW(Z) = 0.0813 x 0.2731 = 0.0222 or 2.22%

CHAPTER FOUR

4.0 RESULTS AND INTERPRETATION

This chapter presents results observed from analyzed data with interpretations as regarding the research objectives.

PRESENTATION OF RESULTS

Below are the tables of the petro-physical properties derived after calculations carried out using provided well log data.

Sand Units	Depth (ft)	Thickness (ft)	Φ (%)	K (mD)	S_w (%)	S_{wirr} (%)	S_h (%)	BVW (%)	Fluid Type	Nature of formation water
Sand V	11325 to 11885	560	22.78	18.18	17.69	8.63	82.30	4.03	Oil & Gas	Irreducible at ≈4% BVW
Sand W	12000 to 12360	360	20.50	13.12	23.85	9.52	76.15	4.89	Oil & Gas	Not at Irreducible
Sand X	12555 to 12800	245	15.28	5.19	26.84	13.27	73.16	4.10	Oil & Gas	Not at Irreducible
Sand Y	12875 to 13225	350	15.13	5.08	19.32	13.41	80.68	2.92	Oil & Gas	Irreducible at ≈2% BVW
Sand Z	13410 to 13525	115	16.48	6.59	15.10	12.23	84.90	2.49	Oil & gas	Irreducible at ≈2% BVW

TABLE 4.1: SUMMARY OF RESERVOIR SAND PROPERTIES AT WELL 02

TABLE 4.2: SUMMARY OF RESERVOPIR SAND PROPERTIES AT WEEL 03

Sand Units	Depth (ft)	Thickness (ft)	Φ (%)	K (mD)	S_w (%)	S_{wirr} (%)	S_h (%)	BVW (%)	Fluid Type	Nature of formation water
Sand V	11325 to 11885	560	17.73	8.29	18.99	11.31	81.01	3.37	Oil & Gas	Irreducible at ≈3% BVW
Sand W	11975 to 12300	325	18.11	8.87	15.25	11.05	84.75	2.83	Oil & Gas	Not at Irreducible
Sand X	12525 to 12750	225	20.67	13.45	12.64	9.59	87.36	2.61	Oil & Gas	Not at Irreducible
Sand Y	12825 to 13100	275	19.83	11.82	9.08	10.02	90.92	1.80	Oil & Gas	Not at Irreducible
Sand Z	13410 to 13525	115	17.52	7.99	3.92	11.41	96.10	0.69	Oil & Gas	Irreducible at ≈0.7% BVW

TABLE 4.3: SUMMARY OF RESERVOIR SAND PROPERTIES AT WELL 04

Sand Unit	Depth (ft)	Thickness (ft)	Φ (%)	K (mD)	S_w (%)	S_{wirr} (%)	S_h (%)	BVW (%)	Fluid Type	Nature of formation water
Sand V	11380 to 12000	620	26.22	22.54	20.64	8.04	79.36	5.03	Oil & Gas	Not Irreducible
Sand W	12050 to 12350	300	20.27	12.66	18.28	9.79	81.72	3.71	Oil	Irreducible at ≈3% BVW
Sand X	12605 to 12810	205	18.65	9.71	16.22	10.72	83.78	3.02	Oil & Gas	Not Irreducible
Sand Y	12910 to 13275	365	19.26	10.77	15.78	10.34	84.22	3.04	Oil & Gas	Not Irreducible

TABLE 4.4: SUMMARY OF RESERVOIR SAND PROPERTIES AT WELL 05

Sand Unit	Depth (ft)	Thickness (ft)	Φ (%)	K (%)	S_w (%)	S_{wirr} (%)	S_h (%)	BVW (%)	Fluid Type	Nature of formation water
Sand V	11400 to 11962	562	26.22	28.50	24.65	7.42	75.33	6.47	Oil	Not Irreducible
Sand W	12025 to 12375	350	25.65	26.57	23.68	7.60	76.32	6.08	Oil & Gas	Not Irreducible
Sand X	12575 to 12810	235	27.11	31.64	14.94	7.16	85.06	4.05	Oil & Gas	Not Irreducible
Sand Y	12875 to 13175	300	27.14	31.77	9.67	7.15	90.33	2.63	Oil & Gas	Not Irreducible
Sand Z	13425 to 13600	175	27.13	32.33	8.13	7.11	91.87	2.22	Oil & Gas	Not Irreducible

Sand Unit	Depth (ft)	Thickness (ft)	Shale Volume		Fluid Contact/column
			Range (%)	Average	
Sand V	11325 to 11885	560	0.8 to 66.5	9.0	GUT: 11325 GOC: 11375 OWC: 11600
Sand W	12000 to 12360	360	0.8 to 21.6	5.6	GUT: 11950 OUT: 12000 OWC: 12300
Sand X	12555 to 12800	245	1.7 to 54.0	11.6	OUT: 12550 OWC: 12725 WDT: 12810
Sand Y	12875 to 13225	350	0.8 to 34.9	5.3	GUT: 12875 GOC: 13000 WUT: 13200
Sand Z	13410 to 13525	115	4.8 to 16.6	10.1	GUT: 13375 GOC: 13450 ODT: 13525 OWC: 13525

TABLE 4.5: SHALE VOLUME OF RESERVOIR SAND AT WELL 02

Sand Unit	Depth (ft)	Thickness (ft)	Shale Volume		Fluid Contact/column
			Range (%)	Average	
Sand V	11325 to 11885	560	1.5 to 38.9	4.9	GUT: 11325 GOC: 11350 OWC: 11800
Sand W	11975 to 12300	325	5.3 to 69.2	27.1	GUT: 11950 GOC: 11985 OWC: 12150
Sand X	12525 to 12750	255	1.5 to 83.1	18.7	GUT: 12525 GOC: 12550 OWC: 12625
Sand Y	12825 to 13100	275	3.3 to 83.1	12.6	GUT: 12815 GOC: 12950 OWC: 13025
Sand Z	13410 to 13525	115	7.8 to 16.0	11.8	GUT: 13375 GOC: 13425 OWC: 13515

TABLE 4.6: SHALE VOLUME OF RESERVOIR SAND AT WELL 03

Sand Unit	**Depth (ft)**	**Thickness (ft)**	**Shale Volume**		**Fluid Contact/column**
			Range (%)	**Average**	
Sand V	11380 to 12000	620	10.34 to 72.41	32.04	GUT: 11375 GOC: 11475 OWC: 11625
Sand W	12050 to 12350	300	3.45 to 44.83	21.63	OUT: 12050 OWC: 12300
Sand X	12605 to 12810	205	17.24 to 72.41	42.91	GUT: 12600 GOC: 12635 OWC: 12800
Sand Y	12910 to 13275	365	2.07 to 72.41	18.76	GUT: 12900 GOC: 12975 ODT: 13200 WUT: 13050

TABLE 4.7: SHALE VOLUME OF RESERVOIR SAND AT WELL 04

Sand Unit	**Depth (ft)**	**Thickness (ft)**	**Shale Volume**		**Fluid Contact/column**
			Range (%)	**Average**	
Sand V	11400 to 11962	562	0.9 to 28.1	7.2	ODT: 11775 OWC: 11775
Sand W	12025 to 12375	350	0.9 to 8.3	5.0	GUT: 12025 GOC: 12050 ODT: 12150 WUT: 12100
Sand X	12575 to 12810	235	0.9 to 28.1	11.8	GUT: 12525 GOC: 12600 ODT: 12725 WUT: 12650
Sand Y	12875 to 13175	300	0.9 to 57.6	7.14	GOC: 12925 OWC: 13050
Sand Z	13425 to 13600	175	1.8 to 57.6	22.8	GUT: 13400 GOC: 13475 OWC: 13535

TABLE 4.8: SHALE VOLUME OF RESERVOIR SAND AT WELL 05

GUT: Gas Up To

GOC: Gas-Oil Contact

OWC: Oil-Water Contact

OUT: Oil Up To

ODT: Oil Down To

WUT: Water Up To

WDT Water Down To

4.2 ANALYSIS OF RESULTS

The petrophysical parameters evaluated were permeability, bulk water volume, hydrocarbon saturation, irreducible water saturation, shale volume, porosity, and formation factor. Due to varying environmental conditions, different reservoir sand units have different porosities laterally. Sand X, with an average field porosity of 20.43%, has porosity values of 15.28%, 20.67%, 18.64%, and 27.11% at well 02, well 03, well 04, and well 05, respectively (tables 2–5). Sand V, with an average field porosity of 21.22%, had the value of 20.84% at well 02, 18.11% at well 03, 24.39% at well 04, and 26.22% at well 05. Porosity and water saturation are observed to decrease with increasing depth in wells where average shale volume in sand units are significantly high. Wells with sand units having smaller or relatively lower average shale volume exhibit varying values of porosity and water saturation.

The permeability varied greatly. The average permeability of the following was recorded: 15.31% for Sand W, 19.38% for Sand V, 15% for Sand Y, and 11.73% for Sand Z. Sand V is the most permeable unit in the field, and sand W is not far behind. These two reservoir sandstones (sands V and W) are the most permeable and porous units in the field. Even though sand Z has a higher value than sands X and Y, which are located several feet above it, it was found that permeability generally declined with depth. The five (5) reservoir sandstones—sands V, W, X, Y, and Z—were found to contain gas, oil, and water. Each reservoir's fluid type and column change between wells (see table 2-5). Reservoir sand V was found to contain gas, oil, and water at wells 02, 03, and 04, but only collects oil and water at well 05. While water, gas, and oil pooled elsewhere, water and oil accumulated near well 04 for reservoir sand W. While reservoir sand X comprised a considerable amount of gas in addition to oil and water at the locations of wells 03, 04, and 05, it was richer in oil and water at the well 02 location. Reservoir sand Y and Z had water, oil, and gas at every well position (table 2-5).

NOTE:

The fluid type and column for well 01 could not be calculated due to a lack of well data. It's also important to note that the reservoir sand bodies in each of the five wells include shales (clays/siltstones) of varying thickness and are cyclically interbedded. Gas, oil, and/or water are present in these reservoirs based on deep resistivity, neutron, and density records.

CHAPTER FIVE

CONCLUSION AND RECOMMENDATION

5.0 SUMMARY

The reservoir sands have a smooth profile, as indicated by caliper logs from wells 01 and 05, indicating that mud cakes have accumulated there and that they are permeable and porous. As depth increased, there was no porosity decrease in the examined sands. Generally, the porosity of the upper unit (sands V and W) is higher than that of the lower unit (sounds X, Y, and Z). Schlumberger (1985) ascribed this to the absence of consolidation in the Niger Delta. Compaction and diagenetic processes seemed to have little to no effect on the field's porosity, in contrast to the depositional processes and the environment of deposition. Modifications to the depositional environment, a slow rise in the depth of deposition due to shoreline progression, and a southerly and seaward shift in depobelts could all have contributed to the lateral variance in porosity. This observation is consistent with the findings of Evamy et al. (1978) and Bouvier et al. (1989).

Permeability ratings ranged from moderate to good, despite significant lateral and vertical variation. The high permeability of the reservoir sandstones in the field would result in rapid flow of water and hydrocarbons. Nonetheless, it appears that not every zone was fully saturated with water due to the notable variations in the bulk volume water (BVW). These zones would produce wet hydrocarbons, whereas saturation would produce hydrocarbons without water. The sand's W and X might be decreased. Wet hydrocarbon will therefore be produced by any well that is filtered in these units.Water-free hydrocarbons would be abundant in the field's reservoir sands V, Y, and Z.

The size, sorting, cementation, and compaction of the grains are known to affect the porosity and permeability of sandstones (Schlumberger, 1991; Etu-Efeotor, 1997; Rider, 1986; 1996).

The reservoir sands X, Y, and Z deposited in a low energy marginal deltaic and shelf margin/slope have somewhat lower porosity and permeability due to the sizable proportion of clays (shales) and silts (siltstones) commonly found in such environments. The variance in quality of reservoir sand units in terms of porosity and permeability is more closely associated with the degree of sandstone sorting, which is mostly controlled by depositional environments and processes, as well as the amount of shale in each unit. Sands X, Z, and Y (all three are classified as lower Agbada) had the highest average shale volume in this regard, whereas sands W and V (both classified as higher Agbada) had the lowest average shale volume.

5.1 CONCLUSION

After analyzing the wire line logs from each of the five (5) wells, it was discovered that five (5) reservoir sand units throughout the field were hydrocarbon-rich. These units were characterized and impacted by porosity, permeability, and acoustic impedance values that were carefully compared to those found in the sands of other Niger Delta areas. Water saturation was important in preventing irreducible water saturation in reservoir sands W and X. Drilling wells through these units would produce moist hydrocarbons and a lot of water. Other sand units, including sand V, Y, and Z, were at irreducible water saturation at some well locations. These reservoir zones would yield water-free hydrocarbons. Shale affects porosity and water saturation. While sand units have good and quality properties as reservoir rocks, shale units are both source rocks and seals. The porosity of the reservoir sands ranges from normal to extremely good, while permeability ranges from moderate to good. There is a substantial and extensive buildup of gas and oil in the field. Profitable utilization of hydrocarbon resources is possible.

5.2 RECOMMENDATION

The following suggestions are provided based on the summary and conclusion above:

1. Given the restricted information available to this researcher, it is recommended that DPR

and the exploration and production companies open up more to future researchers on this project issue in order to produce more accurate results.

2. The project, "Shale influence on porosity and water saturation in the Niger-Delta reservoir basin," is recommended for all exploration and production firms to undertake, as they are always searching for more lucrative areas.

3. For reservoir engineers employed in the oil and gas industry, this evaluation project will be a useful resource and engineering manual.

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