Petrophysical Evaluation of Otebe Field, Onshore Niger Delta, Nigeria

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Abstract— The Niger Delta is a prolific oil province within the West African subcontinent. Exploration activities have been concentrated in the onshore part of this basin but as the delta becomes better understood exploration influences are gradually being shifted to the offshore. The evaluation of petrophysical characteristics of reservoir sands in 'OTEBE' field was carried out using geophysical wireline logs. The main petrophysical parameters evaluated were porosity, permeability, hydrocarbon saturation and water saturation. The Wireline logs employed in this work include Gamma Ray, Compensated Bulk density (CDL), Compensated Neutron log and Resistivity logs. A total of five wells were assessed and four reservoir units have been identified. The reservoir sands exhibit porosity values ranging between 20% and 30% while the estimated permeability values lie between 30md-178md. The porosity and permeability values may be considered to be moderate to good. The reservoir sands which have thickness of 70m-200m within the field show hydrocarbon saturation values between 90%-99%. Different sub-environments (facies) were recognized based on GR-log shape. The environments include distributary channel, point bar, mouth bar and tidal channel. The overall depositional environment has been interpreted to be most likely a transitional zone that lies between the lower deltaic plain and inner deltaic front of the Niger Delta.

***Keywords* —Otebe Field, Niger Delta, Petrophysical evaluation, Reservoir, Porosity, Permeability, Hydrocarbon saturation, Water saturation.**

I. INTRODUCTION

Petrophysical characteristics of reservoir rocks include porosity, permeability, water saturation, hydrocarbon saturation, formation water resistivity and formation factors. These properties are determined by grain size, grain shape, and degree of compaction, amount of matrix, cement composition, type of fluid present and saturation of different fluids. Among these properties porosity, permeability and fluid saturation are the most important and can be measured using standard procedures.

For scientific and economic purposes, laboratory data of high accuracy and reliability for both the fluids and the rocks that contain them are extremely useful in formation evaluation. However such data cannot be acquired very quickly, hence the operators in the field need a method of acquiring the fundamental properties of the rocks and their fluid contents for a quick management decision making. This requirement is easily satisfied by the use of geophysical wireline logs. Recent reservoir evaluation involves the study of well cuttings, cores, well log data, formation micro scanner (fms) images and drill stem tests.

The wireline log is basically used for this work in integration with seismic sections and core photos. The well logs used include Gamma Ray, Density, Neutron, Sonic and Resistivity logs. The main petrophysical parameters evaluated in this work are porosity, permeability, water and hydrocarbon saturation as well as sand/shale percentages of these reservoirs.

A. Study objectives

The objectives of the study include:

- To demonstrate the use of Wireline logs for the interpretation of geological phenomena.
- To correlate and determine reservoirs lateral extent.
- To estimate and compare porosity, permeability and hydrocarbon distribution within the field.
- Location of reservoirs vertically within the drilled section.
- Determination of depositional environment.

B. Location of the study field

The study field is known as 'OTEBE' FIELD and it is located in OML-XYZ belonging to the Shell Petroleum Development Company of Nigeria (SPDC) in the coastal swamp of the Niger Delta in Nigeria. The Field is a large collapsed crest rollover anticline trending east-west and bounded to the north by a major bounding fault (fig.2).

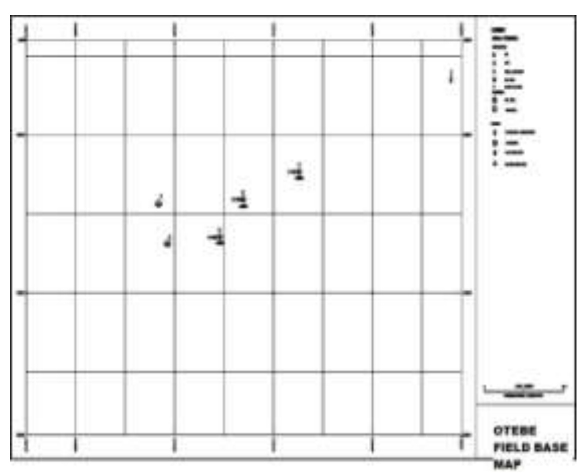

Fig.1: Base map of OTEBE Field showing well locations

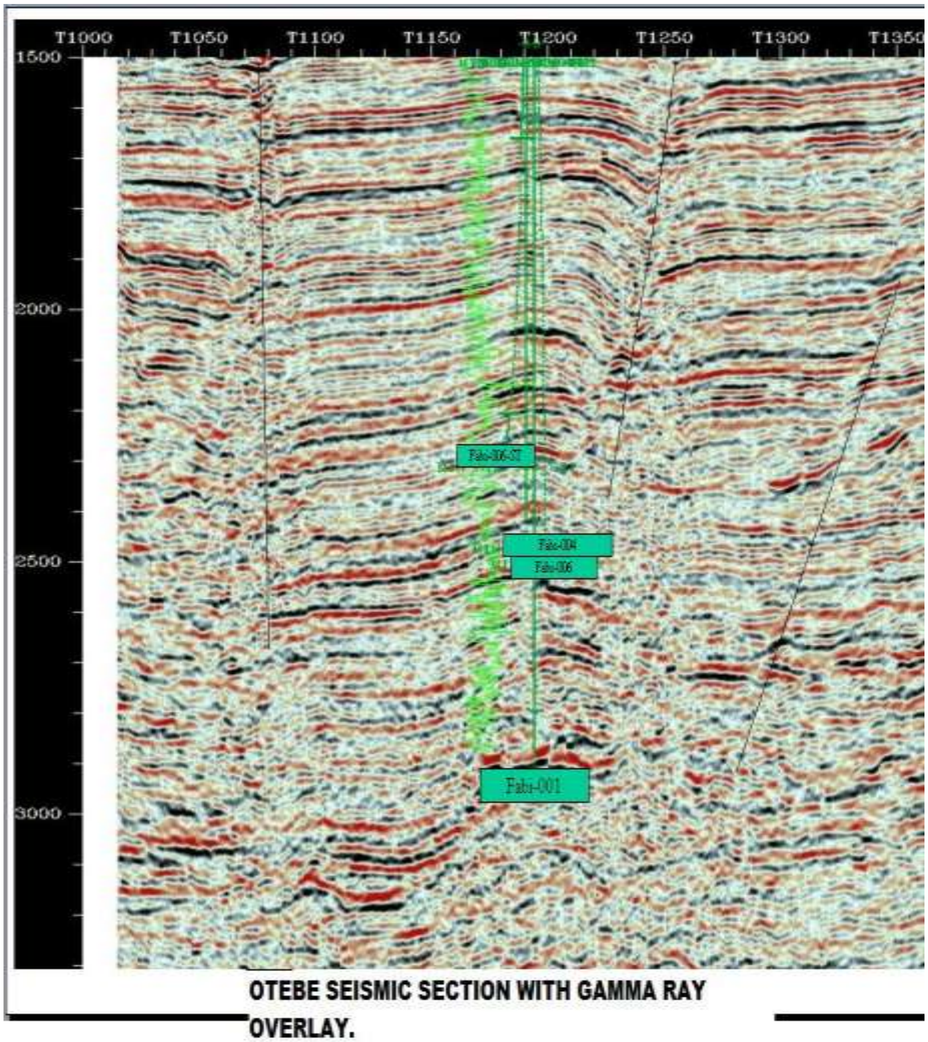

Fig.2. Seismic section of OTEBE Field showing the faulting patterns

C. Stratigraphy of the Niger Delta

Different studies have been carried out on the Niger delta (Hospers, 1965; Short and Stauble, 1967; Burke et al, 1972; Whiteman, 1982; Doust and Omatsola, 1990; Kaplan, 1994; Petters, 1995; Klett, 1997; Ukpong and Ekhalialu, 2017; 2018; Ukpong et al. 2017a; 2017b; 2018). The Niger Delta Basin is a prolific hydrocarbon provinces that contains enormous hydrocarbon both on the onshore, shallow and deep offshore areas and it is located between Latitudes 3° and 6° N and Longitudes 5° and 8° E respectively in the Gulf of Guinea, on the margin of West Africa. The Cenozoic Niger Delta is situated at the intersection of the Benue trough and South Atlantic

Ocean where a triple junction developed during separation of South America from Africa (Burke et al., 1972; Whiteman, 1982).

It extends throughout the Niger Delta Province as defined by Klett and others (1997). It is made of 12 km thick Niger Delta clastic wedge spans a 75, 000 km^2 area in southern Nigeria and the Gulf of Guinea offshore Nigeria. Evamy et al. (1978), Short and Stauble (1967) and Whiteman (1982) divided the deposits of the Niger delta into three large-scale lithostratigraphic units (fig. 3):

1) the pro-delta facies of the Akata Formation (basal Paleocene to Recent)
2) paralic facies of the Agbada Formation (Eocene to Recent) and
3) fluvial facies of the Benin Formation (Oligocene-Recent).

Doust and Omatsola (1990) reported that from the Eocene to the present, the delta has prograded southwestward, forming depobelts that represent the most active portion of the delta at each stage of its development. Kulke (1995) noted that the depobelts form one of the largest regressive deltas in the world with an area of some 300,000 km^2 and a sediment volume of 500,000 km3 (Hospers, 1965), and a sediment thickness of over 10 km in the basin depocenter (Kaplan et al. 1994).

The regional sedimentology, stratigraphy, structural configuration and paleoenvironmental analysis of the Niger Delta have been documented in considerable detail by Reyment(1965), Frank and Cordy (1967), Short and Stauble (1967), Weber(1971) Weber and Daukoru(1975), Omatsola(1982),Evamy et al(1978), Whiteman(1982), Selly(1997) etc. All of these studies indicate that the region is favourable for the formation of good reservoir sands for hydrocarbon accumulation.

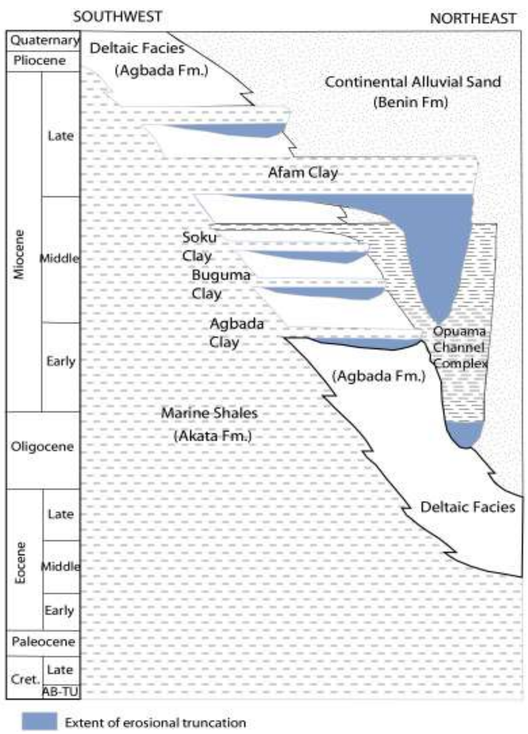

Fig. 3: Stratigraphic column showing the Three Formations of the Niger Delta (Modified from Shannon and Naylor, 1989)

D. Reservoir of the Niger delta

Petroleum in the Niger Delta is produced from sandstone and unconsolidated sands predominantly in the Agbada Formation. Characteristics of the reservoirs in the Agbada Formation are controlled by depositional environment and by depth of burial. Known reservoir rocks are Eocene to Pliocene in age, and are often stacked, ranging in thickness from less than 15 meters to 10% having greater than 45 meters thickness (Evamy and others, 1978). The thicker reservoirs likely represent composite bodies of stacked channels (Doust and Omatsola, 1990). Based on reservoir geometry and quality, Kulke (1995) describes the most important reservoir types as point bars of distributary channels and coastal barrier bars intermittently cut by sand-filled channels. Edwards and Santogrossi (1990) describe the primary Niger Delta reservoirs as Miocene parallic sandstones with 40% porosity, 2 Darcy's permeability, and a thickness of 100 meters.

The lateral variation in reservoir thickness is strongly controlled by growth faults; the reservoir thickens towards the fault within the down-thrown block (Weber and Daukoru, 1975). The grain size of the reservoir sandstone is highly variable with fluvial sandstones tending to be coarser than their delta front counterparts; point bars fine upward, and barrier bars tend to have the best grain sorting. Much of this sandstone is nearly unconsolidated, some with a minor component of argillo-silicic cement (Kulke, 1995). Porosity only slowly decreases with depth because of the young age of the sediment and the coolness of the delta complex (see geothermal gradient data below). In the outer portion of the delta complex, deep-sea channel sands, low-stand sand bodies, and proximal turbidites create potential reservoirs (Beka and Oti, 1995). Burke (1972) describes three deep-water fans that have likely been active through much of the delta's history. The fans are smaller than those associated with other large deltas because much of the sand of the Niger-Benue system is deposited on top of the delta, and buried along with the proximal parts of the fans as the position of the successive depobelts moves seaward (Burke, 1972). The distribution, thickness, shalliness, and porosity/permeability characteristics of these fans are poorly understood (Kulke, 1995).

Tectono-stratigraphy computer experiments show that local fault movement along the slope edge controls thickness and lithofacies of potential reservoir sands downdip (Smith-Rouch and others, 1996). The slope-edge fault simulation from these experiments is shown in fig. 4. (Smith-Rouch, 1998) states that "by extrapolating the results to other areas along the shelf margin, new potential reservoirs are identified.

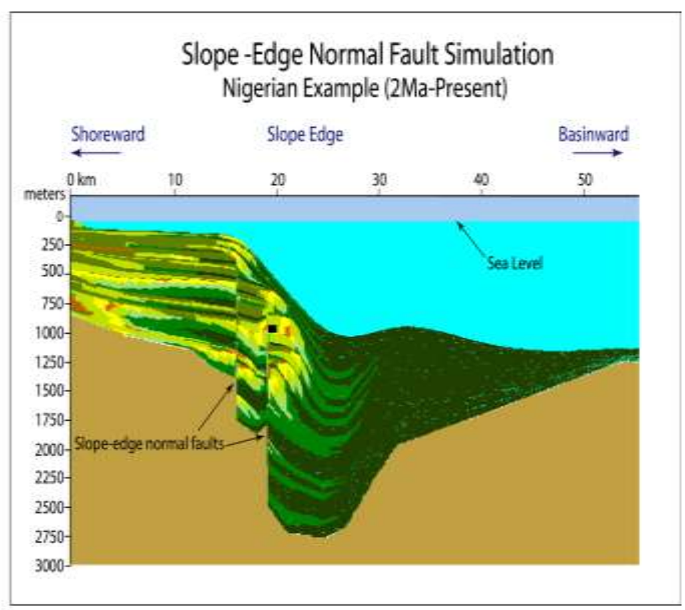

Fig. 4: Slope edge normal fault simulation (2ma- present) for the Niger Delta. Bright intervals are sands. (Adapted from Smith-Rouch, 1998)

E. Traps and seals

Most known traps in Niger Delta fields are structural although stratigraphic traps are not uncommon (fig. 5). The structural traps developed during synsedimentary deformation of the Agbada parallic sequence (Evamy and others, 1978; Stacher, 1995). Structural complexity increases from the north (earlier formed depobelts) to the south (later formed depobelts) in response to increasing instability of the under-compacted, over-pressured shale. Doust and Omatsola (1990) describe a variety of structural trapping elements, including those associated with simple rollover structures; clay filled channels, structures with multiple growth faults, structures with antithetic faults, and collapsed crest structures. On the flanks of the delta, stratigraphic traps are likely as important as structural traps (Beka and Oti, 1995). In this region, pockets of sandstone occur between diapiric structures; towards the delta toe (base of distal slope), this alternating sequence of sandstone and shale gradually grades to essentially sandstone. The primary seal rock in the Niger Delta is the interbedded shale within the Agbada Formation. The shale provides three types of seals—clay smears along faults, interbedded sealing units against which reservoir sands are juxtaposed due to faulting, and vertical seals (Doust and Omatsola, 1990). On the flanks of the delta, major erosional events of early to middle Miocene age formed canyons that are now clay-filled. These clays form the top seals for some important offshore fields (Doust and Omatsola, 1990).

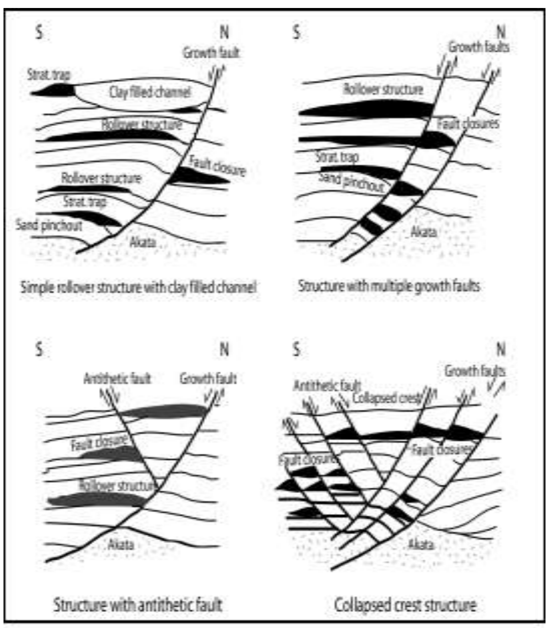

Fig. 5: Examples of Niger Delta oil field structures and associated tap types. Modified from Doust and Omatsola (1990).

F. Petroleum generation and migration

Evamy and others (1978) set the top of the present-day oil window in the Niger Delta at the 240°F (115° C) isotherm. In the northwestern portion of the delta, the oil window (active source-rock interval) lies in the upper Akata Formation and the lower Agbada Formation as shown in (Fig. 6). To the southeast, the top of the oil window is stratigraphically lower (up to 4000’ below the upper Akata/lower Agbada sequence; Evamy and others, 1978). Some researchers (Nwachukwu and Chukwuma, 1986; Doust and Omatsola, 1990; Stacher, 1995) attribute the distribution of the top of the oil window to the thickness and sand/shale ratios of the overburden rock (Benin Fm. and variable proportions of the Agbada Fm.). The sandy continental sediment (Benin Fm.) has the lowest thermal gradient (1.3 to 1/8°C/100 m); the parallic Agbada Formation has an intermediate gradient (2.7°C/100 m); and the marine, over-pressured Akata Formation has the highest (5.5°C/100 m) (Ejedawe and others, 1984). Therefore, within any depobelts, the depth to any temperature is dependent on the gross distribution of sand and shale. If sand/shale ratios were the only variable, the distal offshore subsurface temperatures would be elevated because sand percentages are lower. To the contrary, the depth of the hydrocarbon kitchen is expected to be deeper than in the delta proper, because the depth of oil generation is a combination of factors (temperature, time, and deformation related to tectonic effects) (Beka and Oti, 1995). In the late Eocene, the Akata/Agbada formational boundary in the vicinity of this well entered the oil window at approximately 0.6 R_o (Stacher, 1995). Evamy and other (1978) argue that generation and migration processes occurred sequentially in each depobelts and only after the entire belt was structurally deformed, implying that deformation in the Northern Belt would have been completed in the Late Eocene. The Akata/Agbada formational boundary in this region is currently at a depth of about 4,300 m, with the upper Akata Formation in the wet gas/condensation generating zone (vitrinite reflectance value >1.2; Tissot and Welte, 1984). The lowermost part of the Agbada Formation here entered the oil window sometime in the Late Oligocene.

The Northern Belt’s Ajalomi-1 well about 25 km to the south of Oben-1 shows the Akata source rock first entering the oil window in the Oligocene after reservoir rock deposition (Stacher, 1995). Stacher assumes migration overlaps in time with the burial and structure development of overlying reservoir sequences and occurs primarily across and up faults (fig. 4). Migration pathways were short as evidenced from the wax content, API gravity, and the chemistry of oils (Short and Stäuble, 1967; Reed, 1969). Migration from mature, over-pressured shales in the more distal portion of the delta may be similar to that described from over-pressured shales in the Gulf of Mexico. Hunt (1990) relates episodic expulsion of petroleum from abnormally pressured, mature source rocks to fracturing and resealing of the top seal of the over-pressured interval. In rapidly sinking basins, such as the Gulf of Mexico, the fracturing/resealing cycle occurs in intervals of thousands of years. This type cyclic expulsion is certainly plausible in the Niger Delta basin where the Akata Formation is over-pressured. Beta and Oti (1995) predict a bias towards lighter hydrocarbons (gas and condensate) from the over-pressured shale as a result of down-slope dilution of organic matter as well as differentiation associated with expulsion from over-pressured sources.

In a nut shell, the history of the formation of the Tertiary Niger Delta (Akata-Agbada) petroleum system is summarized in the events chart (fig. 7). Rocks within the petroleum system are from Paleocene to Recent in age. Most of the petroleum is sourced from the Akata Formation, with smaller amounts generated from the mature shale beds in the lower Agbada Formation. Deposition of overburden rock began in the Middle Eocene and continues to the present. Units include the Agbada and Benin Formations to the north with a transition to the Akata Formation in the deep-water portion of the basin where the Agbada and Benin Formations thin and disappear seaward.

Petroleum generation within the delta began in the Eocene and continues today. Generation occurred from north to south as progressively younger depobelts entered the oil window. Reservoirs for the discovered petroleum are sandstones throughout the Agbada Formation. Reservoirs for undiscovered petroleum below currently producing intervals and in the distal portions of the delta system may include turbidite sands within the Akata. Trap and seal formation is related to gravity tectonics within the delta. Structural traps have been the most favorable exploration target; however, stratigraphic traps are likely to become more important targets in distal and deeper portions of the delta.

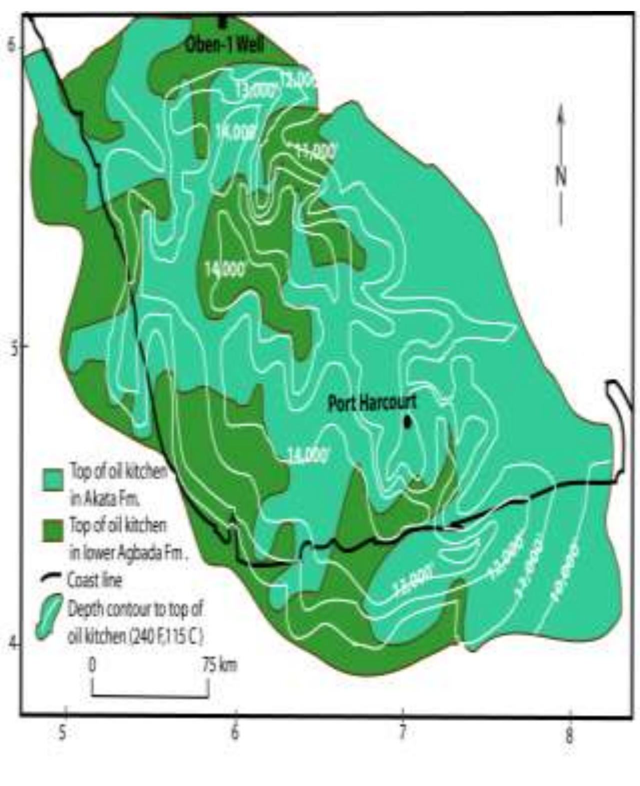

Fig 6: Subsurface depth to top of Niger Delta oil Kitchen showing where only the AkataFormation in the oil window and where a portion of the lower Agbada is in the oil window. Contours are in feet. Modified from Evamy and others (1978)

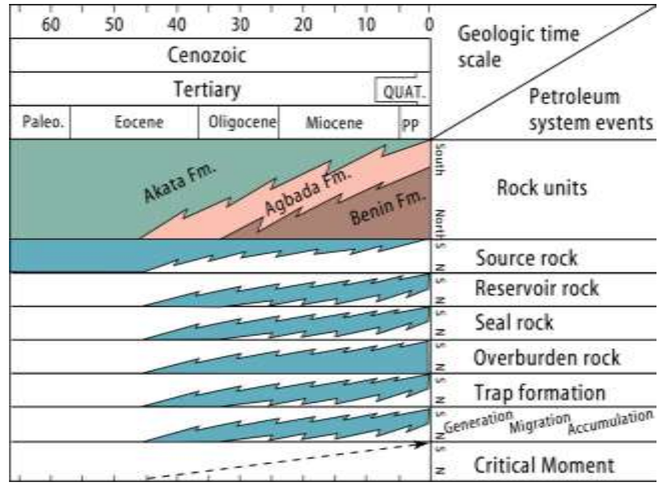

Fig.7: Event chart of the Niger Delta (Akata/Agbada) petroleum system. Modified from Avbovbo (1978)

II. MATERIALS AND METHOD

A. Materials

Wireline logs (Gamma Ray, Compensated Bulk Density log, Compensated Neutron porosity log, and Resistivity log from five wells), structural map of top sand, seismic section and base map of the study area were provided by Shell Petroleum Development Company (SPDC) for the study.

B. Methods

The following methods were applied in the study

1) Gamma Ray log

The Gamma Ray log is a measurement of the natural radioactivity of the formations. In sedimentary formations the log normally reflects the shale content of the formations (fig. 8). This is because the radioactive elements tend to concentrate in clays and shales. Clean formations usually have a very low level of radioactivity, unless radioactive contaminant such as volcanic ash or granite wash is present or the formation waters contain dissolved radioactive salts.

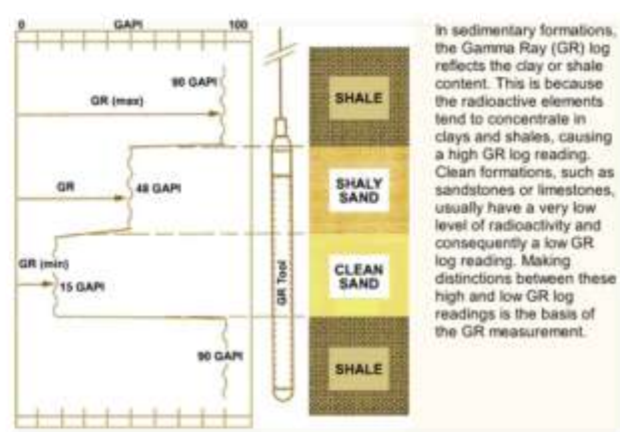

Fig. 8: Sketch of typical gamma ray logs and techniques for interpretations (Modified from Schlumberger, 1985)

2) Compensated formation bulk density log (cdl)

The density log is a continuous record of a formation's bulk density. This is the overall density of a rock including solid matrix and fluid enclosed in the pores. Since the tool has a shallow depth of investigation, the fluid is assumed to be mud filtrate with a density of 1.0 (fresh) or 1.1 (salt) (Rider, 1986).The presence of mixed matrix leads to possible errors in the assumption of matrix density (fig. 9). Low density interstitial clays will especially result in overestimated porosity.

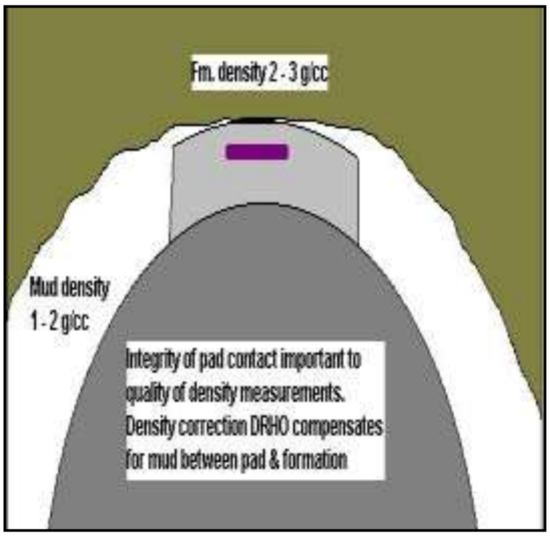

Fig. 9: Sketch showing reliability of density log for measurement(Adapted from Schlumberger, 1985)

3) Compensated neutron porosity log

The neutron log provides a continuous record of a formation reaction to fast neutron bombardment (fig. 10). It is quoted in terms of neutron porosity units, which are related to formation hydrogen index as indication of its richness in hydrogen (Rider, 1986).

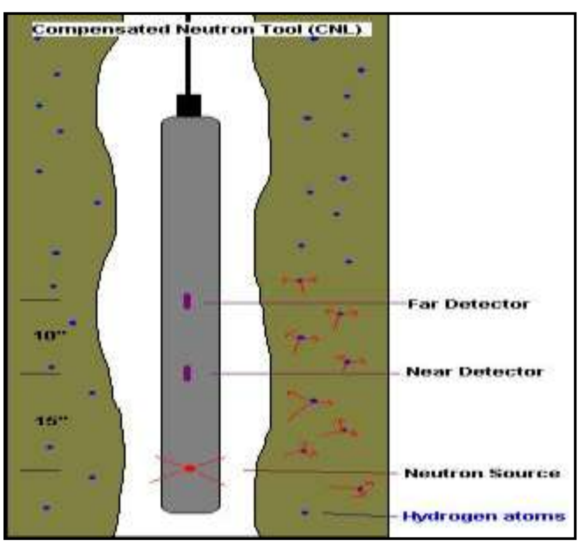

Fig.10: Neutron logging tool (Adapted from Schlumberger, 1985)

4) Resistivity log (laterolog)

Resistivity, which is the inverse of conductivity, is the specific resistance of a material to the flow of current. The resistivity of a formation depends on the electrical conductivity of the rock materials within the formation, the nature of the formation water (fresh or salt), other fluid like oil or gas contained in it. Also the conductivity of water is a function of temperature because the lighter the temperature, the lower the resistivity. Fig.11: Application of Laterolog and Induction with their limitations. Fig. 12: the borehole environments while fig.26: Sketch showing different zones with resistivity logging.

Induction v Laterolog

	Laterolog	Induction
Oil Based Mud	No	Yes
Salt Water Mud	Yes	Possible [1]
Fresh Mud	Possible [2]	Yes
Air Filled Holes	No	Yes
High R_t	Yes	No
Low R_t	Possible [3]	Yes
$R_t > R_{xo}$	Preferred	
$R_t < R_{xo}$		Preferred

Fig.11: Application of Laterolog and Induction with their limitations. (Modified from Dresser Atlas, 1982)

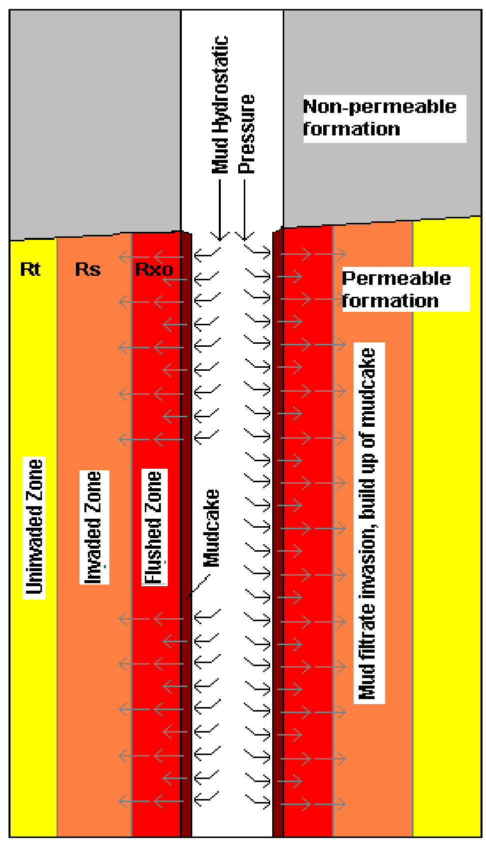

Fig. 12: The borehole environment

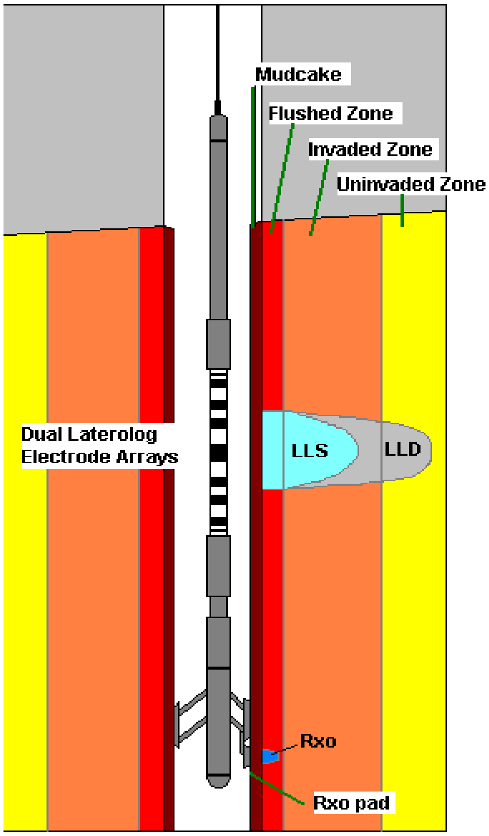

Fig.13: Sketch showing different zones with resistivity logging (Modified from Schlumberger, 1985)

C. Qualitative and quantitative interpretations of wireline logs.

Well log interpretation involves choosing the best model from the given data so as to obtain results which are geologically plausible. Well log interpretation is often qualitative and quantitative. The qualitative interpretation has to do with the use of models, which represent the characteristic log responses to formation parameters. The qualitative interpretation involves the following steps namely:

- Identification of sand units from chosen top sand to the last hydrocarbon bearing sand using Gamma ray log
- Classification of reservoir sand and their depositional environments from standard log models
- Identification of gas bearing sands and gas/oil contact from bulk density log in combination with the neutron porosity log.
- Comparison of fluid characteristics as per resistivity and bulk/neutron logs response in the same reservoir sand in different wells where it occurs.
- The quantitative interpretation involves the use of mathematical models and relations, which give identical values of the log response to the formation parameters. The following relations were employed in the estimation of reservoir sand parameters.

1) Porosity

The porosity values of reservoir of interest were estimated using readings of the compensated Bulk density and compensated Neutron porosity log. Density porosity values were calculated using the equation below.

Porosity (Ø) = pma-pb/pma-pf (1)

Where pma =2.65 g/cc and pf =1.0

Neutron porosity was read from the log. The effective porosity (Øe) was used in this researrch work and a combination of density and neutron porosity was adopted for accuracy (Dewan, 1983)

The porosity was first corrected for shale as follows:

Ødc = Ød- Vsh. Ødsh (2)

Ønc=Øn- Vsh. Ønsh (3)

Where;

Ødc= corrected density porosity

Ød=density porosity

Ødsh=density porosity of a nearby shale

Øn =corrected neutron porosity

Ønsh=neutron porosity of a nearby shale

Øn=neutron porosity

Vsh= volumetric fraction of shale

Øe= (Ød + Ønc)/2 (4)

Where Øe=effective porosity

If gas is present, Ønc will be significantly less than Ødc and it will show up a crossover.

The percentage by volume of the shale, Vsh was estimated from Gamma ray log method using the formula below

Volume of shale % = [GR value (log)- GR(min)]/[GR(max)-GR(min)] (5)

GR (max) = 100% shale, GR (min) =0% shale (i.e. clean formation)

A modification of the simple linear relationship used above has been proposed as a result of empirical correlation (Dresser Atlas, 1982).

The relationship changes between younger unconsolidated rocks and older consolidated rocks

For pre-Tertiary consolidated rocks

$Vsh = 0.33\ 9\ 2^{2}Vsh\text{-}1)$ (6)

For Tertiary Unconsolidated rocks, like those evaluated in this research

$Vsh = 0.083 (2^{3.7}Vsh-1)$ (7)

2) Water/hydrocarbon saturation

Water saturation for hydrocarbon and non-hydrocarbon bearing reservoir sands were evaluated using Archie's equation (Archie, 1942)

$SW^n = FRw/RT$

In log practice, n=2

Therefore water saturation,

$Sw = (FRw/RT)^{1/2}$ (8)

To calculate Sw, the formation factor, F must first be determined

According to Archie (1942) Formation Factor,

$F = a/Ø^m$ (9)

This equation is also referred to as Humble formula (Lynch, 1964).

In this research, a simplified version of F (Schlumberger, 1985) for sands was used, that is

$F = 0.62/Ø^{2.15}$ (10)

Water resistivity of the formation, Rw was calculated based on the equation

$Rw = Ro/F$ (11)

Where Ro = water saturated formation resistivity (i.e. resistivity of the rock when it is brine field) In a reservoir that did not have Ro or where Ro could not be estimated, Rw of a nearby formation (reservoir above or below that of interest) was adopted since water salinity changes only slowly with depth (Dewan, 1983)

In a formation containing oil or gas, the resistivity is called true resistivity; RT.

RT is not only a function of F and Rw but also of Sw. For water bearing formation, RT =Ro (i.e. when Sw =1)

The fraction of pore volume saturation of hydrocarbon (Sh) was evaluated from the relation

Hydrocarbon saturation (oil and gas)

$Sh = (1-Sw)$ (12)

The Bulk Volume Water (BVW) which shows whether or not a formation is at irreducible water saturation was calculated using

$BVW = Sw. Ø$ (13)

3) Permeability

The permeability values for the reservoir sands were calculated from a relationship that shows that irreducible water saturation is a function of bulk volume water, porosity and permeability. If the formation bulk volume water values are constant or nearly constant, then it is at irreducible water saturation, but if the values are widely varied, then it is not at irreducible water saturation. Several empirical relationships have been proposed in order to estimate permeability from measurements of porosity and irreducible water saturation, but that documented by Dresser Atlas (1982) was employed in the work to estimate permeability of the different reservoir sands.

$K (MD) = (0.136Ø^{4.4})/Swi$(14)

4) Fraction of formation pore volume filled with hydrocarbon

The main aim of logging is to determine the fraction of total formation pore volume filled with hydrocarbon so that the quantity and net hydrocarbon sands can be estimated.

Fractional pore volume filled by hydrocarbon, Øh was calculated using the relation

$Øh = Ø (1-Sw) = ØSh$(15)

5) Graphs

Three sets of graphs will be plotted. Porosity versus permeability plots (A1-A5) were carried out to study its relationship within the reservoir units.

The graphs for permeability versus depth were used to determine how permeability values varies with depth (B1-B5) while porosity versus depth graphs (C1-C5) were plotted to illustrate the lateral and vertical variations within the field under investigation.

D. Log shape lithology and sedimentology

In recent times, the shapes of Gamma ray logs are becoming, more important as these have been found to be very reliable. It shows greater detail and is much related to the sediment character and environment of deposition. Therefore, as the Gamma ray log is frequently an indicator of clay (shale) content as explanation of Gamma Ray logs shapes can be related to shale content. Shapes on the Gamma ray log can be interpreted as grain size trends and by sedimentological association as cycles. A decrease in gamma ray value will indicate an increase in grain size; small grain size corresponds to higher gamma ray values. The sedimentological implication of this relationship leads to a direct correlation between facies and log shape (fig. 14). A bell shape indicates a fining upward sequence, which may be an alluvial/fluvial channel or else transgressive sand.

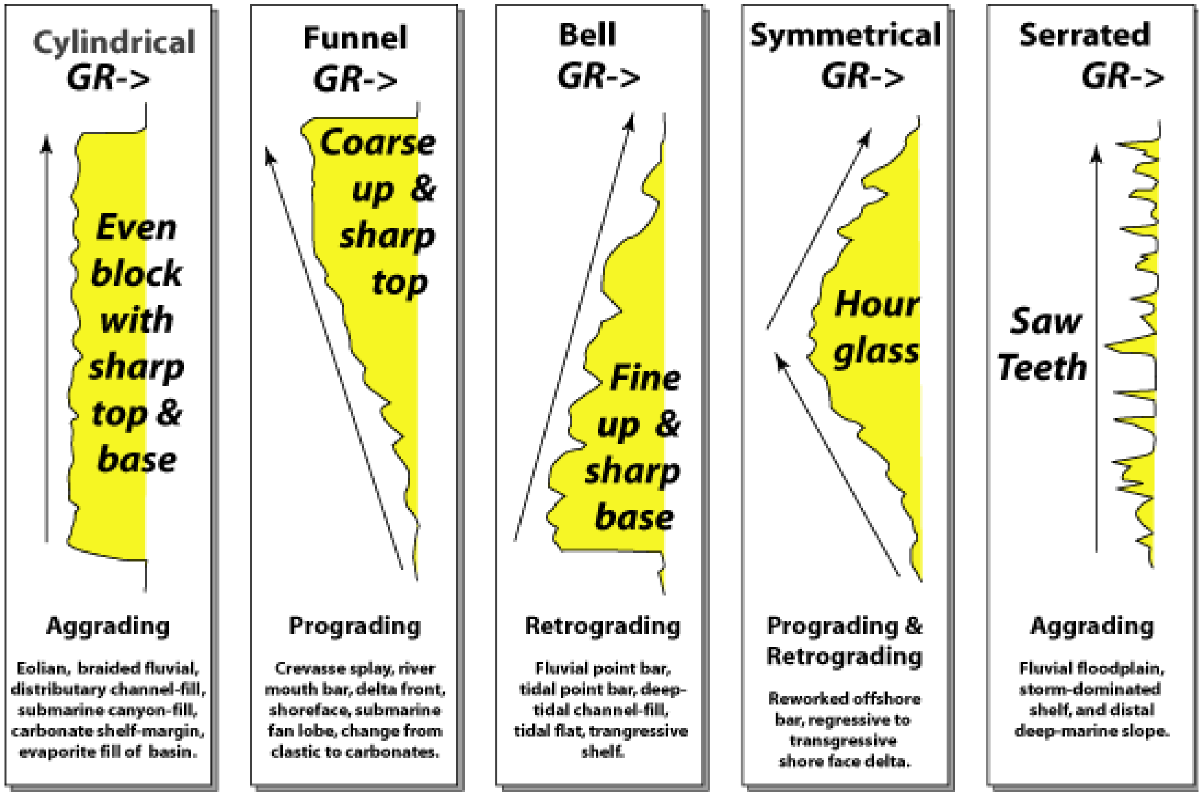

Fig 14: General Gamma Ray response to variations in grain size (Modified from Emery, 1996)

III. RESULTS AND INTERPRETATION

A. Petrophysical and dynamic properties of reservoir sands

A reservoir rock is one, which by virtue of its porosity and permeability is capable of containing a reasonable quantity of hydrocarbon if entrapment conditions are right. It is an essential part of the petroleum system. The rock should be able to release the hydrocarbon at a reasonable rate when penetrated by a well. In other words, reservoir sands are rocks containing pore spaces or fractures, interconnected and allowing the circulation and accumulation of fluid within them.

1) Porosity

Porosity is the percentage of the total volume of the rock that has pore spaces, whether the pores are connected or not.

Porosity conventionally denoted by the Greek word phi (Ø) is given by the equation;

$$Ø = \frac{\text{Bulk volume} - \text{Grain Volume}}{\text{Bulk volume}} \times 100 \qquad (16)$$

$$= \frac{\text{Pore volume}}{\text{Bulk volume}} \times 100$$

Effective porosity is a measured of the void space that is filled by recoverable oil or gas; the amount of pore spaces that is sufficiently interconnected to yield its oil or gas for recovery. It is therefore the ratio of the interconnected pore volume to the bulk volume of the material. The effective porosity is usually in the range 40-75% of the total pore volume, except in unconsolidated rocks, like those of the Niger Delta, where it is 5-10% less. For the common reservoir rock types under average operating conditions, porosity values may be viewed as below in

table 1. Porosity is influenced by degree of sorting or uniformity of grain size, shape of grains (sphericity), manner of packing, method and rate of deposition, amount of matrix, degree of cementation and other post depositional changes, effects of compaction during and after deposition and original mineralogical composition of the rock. In clastic rocks, porosity is also governed by sand/shale ratio.

The average porosity evaluated in the different reservoir sands lie between 20.05% in Well 3 sand L and M and 27.55% in well 1,sand N (Table 2). Based on these values, the reservoir sands are interpreted to be very good; hence there are therefore favourable for hydrocarbon production .The decrease in porosity with depth of burial is a function of the degree of compaction of the sediments deposited (Collins, 1978). As the rate of the sediments deposited increases, the overburden pressure also increases which in turn increases the degree of compaction of sediments. A comparison of the average porosities and percentage ratio of sand/shale (table 3) in reservoir sands show that the porosity values depend on the average percentage of sand/shale ratio:

The higher the sand/shale ratios, the higher the porosity and vice versa.

In clastic reservoir rocks, like those encountered in this work, porosity is governed by sand/shale ratio and the higher the ratio, the higher the porosity and vice. Sand percentage evaluated in this study is in the range of 90.1% and 98.3% and this is interpreted to have good reservoir quality because high sand/shale percent increases the porosity of the sands, which in turn improves the reservoir quality.

Table 1: Qualitative description of porosity values (After Dresser Atlas, 1982)

Ø (%)	Qualitative evaluation
0 – 5	Negligible
5 – 10	Poor
10 – 15	Fair
15 – 20	Good
20+	Very Good

Table 2: Log-based calculated lateral and vertical porosity (ø) and permeability (k) in reservoir sands

	WELL 1		WELL 2		WELL 3		WELL 4		WELL5	
SAND UNIT	Øe (%)	K (md)	Øe (%)	K(md)	Øe (%)	K (md)	Øe (%)	K (md)	Øe (%)	K (md)
K	28.27	178.02	23.38	55.05	25.35	72.20	26.10	146.16	24.95	78.44
L	27.98	144.42	23.00	39.25	21.05	58.57	23.8	112.51	24.7	77.03
M	27.08	95.42	21.70	29.71	20.25	44.84	22.23	40.32	23.94	45.13
N	27.91	98.58	22.29	37.70	20.50	47.46	21.04	49.01	23.75	46.6

Table 3: Average shale and sand volume percentage in reservoir sands.

UNITS	WELL 1		WELL 2		WELL 3		WELL 4		WELL 5	
	Sh (%)	Sd (%)	Sh (%)	Sd (%)	Sh (%)	Sd(%)	Sh (%)	Sd (%)	Sh (%)	Sd (%)
K	1.5	98.5	6.8	94.2	4.7	95.3	2.5	97.5	2.2	97.8
L	2.6	97.4	7.0	93.0	9.8	90.4	6.7	93.3	2.3	97.7
M	3.7	94.3	7.9	92.1	9.9	90.3	7.2	92.8	5.4	94.6
N	3.2	96.8	7.6	92.4	8.2	90.2	6.9	93.1	5.7	94.3

2) Permeability

Permeability is a measure of the ability of a porous medium to transmit fluid without change in the structure of the medium of displacement of its parts. In other words, permeability is a measure of the ease with which a formation permits a fluid to flow through it (table 4). To be permeable, a rock must have interconnected porosity (pores, vugs, capillaries, fissures or fractures). Greater porosity usually corresponds to greater permeability, but this is not always the case. Pore size, shape and continuity as well as the amount of porosity, influence formation permeability (Schlumberger, 1989). Other factors controlling permeability are sorting and shale content. Rocks with proper sorting and smaller grain trend to have higher shale volume and lower permeability, while cleaner sand with the same porosity may have low shale volume and higher permeability (Vernick, 2000)

Permeability is defined by Darcy's law as

$$Q = \frac{-KPA\ (h_2 - h_1)}{Hl} \qquad (17)$$

Where;

Q = total discharge of fluid per unit time (cm^3s^{-1})
A = cross sectional area of flow path (cm^3)
L = Length of the flow path (cm)
P = density of fluid (g/cm^3)
H = Dynamic fluid viscosity (mpas)
h_2 - h_1 = Hydraulic head or pressure drop across the flow path (gcm^{-2})
k = the permeability constant in Darcy.

The above equation is from the stand point of experimental or practical hydraulic engineering. We may instead take the form stated by HSU (1977) which is from the standpoint of reservoir sediments. This states that:

$$Q = (NL^2)\ (p/n)\ \{-grad\ (gh)\} \qquad (18)$$

Where N is a dimensionless number, which involves a group of the rock's characteristics such as grain shape and packing***:*** It may be given as a constant for a particular rock, L is the length if the pore structure of the solid (a measure of pore size and tortuosity and hence related indirectly to grain size, sorting and compaction.

Table 4: qualitative description of permeability value (After Wichtl, 1990)

Qualitative description	K-value (MD)
Poor to fair	<1 – 15
Moderate	15 – 50
Good	50 – 250
Very good	250-1000
Excellent	>1000

{-grad (gh)} is the potential function representing the amount of work required to move the fluid through length L. However, Dresser Atlas (1982) method involving the use of porosity and irreducible water saturation was employed in this study.

According to Wichtl (1990) the following descriptions are applied to permeability as stated in table 4. The permeability values encountered within the field is interpreted to be moderate to good for hydrocarbon production according Wichtl (1990) standard. Horizontally permeability is very good to excellent but varies from one sand unit to another, this maybe as a result of poor sorting, change in grain size and sometimes shale volume or clay content. Vertically, permeability is also moderate to good but decreases gradually with depth.

3) Permeability and porosity relationship

Plots of permeability versus porosity show that higher porosity values correspond to higher permeability values. In other words, permeability is directly related to porosity. Their relationships are shown by regression analysis (see appendices A1-A5).

4) Fluid saturation

Fluid saturation is the fluid volume expressed as a fraction of the total pore spaces. Water saturation denoted as Sw is the fraction/percentage of the pore volume of the reservoir rock that is filled with water. It is generally assumed, unless otherwise known that the pore volume not filled with water is filled with hydrocarbons. Therefore, hydrocarbon saturation denoted as Sh is the fraction or percentage of the pore volume of the rock that is filled with hydrocarbons,

Sh = 1- Sw(19)

Fluid saturation was evaluated for both hydrocarbon and non-hydrocarbon-bearing reservoir sands (Table 5). The evaluated water saturation (Sw) in hydrocarbon reservoir sand, which was arrived at by putting the various values of F, RW, and RT into equation (8) indicates a varying values across the wells (see table 5-11); The higher the value of Sw in the reservoir sand, the lower the hydrocarbon and vice – versa. This principle is used in differentiating the sands that are hydrocarbon bearing from those that are water bearing. One of the main aims of evaluation of reservoir sands is to estimate the fraction of the total pore volume filled with hydrocarbon. This parameter depends on porosity and the amount of hydrocarbon saturating the reservoir body. The higher the amount of saturation of reservoir sand by a certain field (water, oil or gas) the higher the productivity of that fluid by the reservoir sand when a well is drilled through the sand, provided other reservoir requirements are met.

B. Interpretation of geological/petrophysical properties of individual reservoir sands

1) Sand K

This sand unit varies in thickness between 200m and 152m (see table 12). The shallowest top of the sand was encountered at 3452 in well 3 and the deepest top at 3581m in well 4. The shallowest base of the sand unit was encountered at 3612m in well 2 and the deepest base at 3734m in well 4.

- *Lithology and composition*

The evaluation of average sand/shale percentage shows that the geologic unit is dominantly sand with its highest average sand percentage of 97.8% in well 5 and with lowest average sand percentage as 94.2% in well 1.There is an overall increase in sand percentage from well 1 towards other wells. This shows that the flanks of this sand body within the field have more sand volume than the centre.

- *Depositional environment*

The GR log gives a blocky smooth to serrated shape with sharp upper and lower contact. This may indicate massive and non-graded sand. Based on the facies classification model of log shapes (Schlumberger, 1985), the sand unit is possibly interpreted as a point bar.

- *Petrophysical properties and hydrocarbon occurence*

The porosity in sand K varies between 23.38% in well 2 and 28.27% in well 1. The permeability evaluated for the sand unit shows highest value of 178.02md in well 1 and lowest value of 26md in well 4.. The reservoir is considered good to very good based on the porosity and permeability values. As shown by the resistivity log sand K is hydrocarbon bearing formation in all the wells with average hydrocarbon saturation ranging from 70.94% to 93.08%.

2) Sand L

This reservoir sand has thickness of 107m in well 2 and 61m in well 3.The shallowest top of the unit was seen at 3658m in well 2 and 3 and the deepest top at 3749m in well 4.The shallowest base was encountered at 3764m in well 2 and the deepest base at 37180m in well 1 and 5.

- *Lithology and composition*

The reservoir is dominantly sand having highest average sand percentage of 97.7% in well 5 and the lowest sand percentage in well 3 with 90.3%.

- *Depositional environment*

The unit shows a GR curve with cylindrical shape with very weak serrations. The log shape also shows sharp upper and lower contacts. Based on the facies classification model shapes (Schlumberger, 1985), the sand body is interpreted as a mouth bar deposit

Table 5: Average water saturation and hydrocarbon saturation in the reservoir sands

Sand unit	WELL 1		WELL 2		WELL 3		WELL 4		WELL 5	
	Sw (%)	Sh (%)	Sw (%)	Sh (%)	Sw (%)	Sh (%)	Sw (%)	Sh (%)	Sw(%)	Sh(%)
K	7.10	92.90	6.90	93.10	8.01	90.99	8.77	91.23	5.50	94.50
L	7.23	92.77	7.07	92.93	6.99	93.01	6.88	93.12	7.38	92.62
M	6.80	93.20	7.13	92.87	8.50	91.50	7.28	92.72	6.39	93.61
N	7.20	92.80	7.36	92.64	6.60	93.40	6.80	93.20	6.26	93.74

Table 6: Petrophysical parameters for well 1

Thickness(m)	Ø (%)	Sw (%)	Sh (%)	BVM	K (md)	Sand Units
198	28.27	7.10%	92.89	0.0179	68.02	K
107	27.98	7.23	92.76	0.0188	95.95	L
69	27.08	6.79	93.02	0.0188	144.42	M
76	27.91	7.195	92.87	0.0199	178.58	N

Table 7: Petrophysical parameters for well 2

Thickness (m)	(Ø)(%)	Sw (%)	Sh (%)	BVM	K(md)	Sand units
160	23.38	6.9	93.1	0.016	55.05	K
107	21.6	7.07	92.9	0.0152	29.25	L
76	20.7	7.13	92.9	0.014	29.71	M
84	21.29	7.36	92.6	0.0156	37.7	N

Table 8: Petrophysical parameters for well 3

thickness(m)	Ø (%)	Sw (%)	Sh (%)	BVM	K (md)	Sand units
152	25.35	29.01	70.94	0.0736	72.2	K
84	20.05	6.99	93.01	0.014	58.57	L
69	20.05	8.5	91.4	0.017	24.84	M
84	21.2	6.6	93.3	0.014	38.46	N

Table 9: Petrophysical parameters for well 4

Thickness(m)	Ø (%)	Sw (%)	Sh (%)	BVM	K (md)	Sand units
152	25.35	29.01	70.94	0.0736	72.2	K
84	20.5	6.99	93.1	0.014	58.57	L
66	20.5	8.55	91.4	0.017	24.84	M
84	21.2	6.6	93.3	0.014	38.46	N

Table 10: Petrophysical parameters for well 5

thickness(m)	Ø (%)	Sw (%)	Sh (%)	BVM	K (md)	SAND UNITS
175	24.05	15.5	84.44	0.0736	78.44	K
107	24.7	7.38	92.61	0.018	77.03	L
53	23.24	6.39	93.61	0.014	45.13	M
84	23.75	6.26	93.73	0.014	46.6	N

Table 11: Depth and thickness distribution of reservoir units

SAND UNITS	WELL 1		WELL 2		WELL 3		WELL 4		WELL 5	
	Depth (m)	Thickness (m)	Depth (m)	Thickness (m)	Depth (m)	Thickness (m)	Depth (m)	Thickness (m)	Depth (m)	thickness (m)
K	3452 -3650	198	3460- 3612	152	3429 - 597	168	3581 -3734	152	3490 -3658	168
L	3673 -3780	107	3658 -3764	107	3658 -3749	300	3749 -3856	107	3719 -3780	61
M	3856 -3931	69	3894 -3978	84	3658 -3917	76	3962 -4023	61	3856 -3922	76
N	3962 -4039	76	3993 -4084	91	3932 -4008	76	4039 -4145	107	3947 -4023	76

- *Petrophysical properties and hydrocarbon occurrence*

Sand L has the highest porosity value of 27.98% in well 1 and lowest porosity value of 21.55 in well 3. The permeability values range between 894md in well 1 and 144.42md in well 1 to 39.25 in well 2.The reservoir quality is good to very good based on the mean porosity and permeability values. Based on the laterolog and neutron-density log, the sand unit is hydrocarbon bearing in well 2 with net pay thickness of 100ft. This unit is interpreted to be gas bearing following the crossover effect seen by the neutron porosity and density log.

3) Sand M

The reservoir sand has a thickness of 61m-84m as evaluated from the different wells. It has its shallowest top at the depth of 3841m in well 3 and the deepest base at the depth of 3978m in well 2. The thickness of this sand body is high at the centre and low at the flanks. In other words, the centre of the sand body within the field is thicker than the sides.

- *Lithology and composition*

The sand unit has the highest sand volume of 98.16% in well 5 and lowest sand volume of 92.28% in well 1. There is an overall increase of sand percentage from the centre of the field to the north, south, east and west. That is the centre has less sand than the flanks.

- *Depositional environment*

The GR log shows a blocky serrated to upward fining trend. It has an upper contact that ranges from abrupt at some place and weakly gradational at other places. Based on the aforementioned GR log shape, the depositional environment is interpreted as channel deposit.

- *Petrophysical properties and hydrocarbon occurrence*

The porosity of this sand unit lies between 27.08% in well 1 to 20.25% in well 2. The porosity is seen to decrease from well 5 to the north, south, east and west within the sand unit. The permeability of this reservoir sand has highest value of 95.42md in well 1. The reservoir quality is good from the stand point of mean porosity and permeability.

4) Sand N

This unit has a thickness between 76m to 91m.The shallowest top sand occurs at 3932m in well 3 and deepest base at 4039m in well 1.The sand body thins at well 5, and thickens towards the flanks of the field.

- *Lithology and composition*

This unit has the highest sand volume percentage of 96.8% in well 1 and the lowest sand volume percentage of 90.2% in well 3. The flanks of this reservoir have more sand than the centre.

- *Depositional environment*

The GR log gives an upward fining expression with digitate pattern, which indicates a coarsening –upward sequence. It shows a sharp upper contact and a gradational lower contact.

On the basis of electrofacies classification of deltaic environments from Gamma ray log (Schlumberger, 1985) sand N is interpreted to be either a mouth bar or a barrier foot deposit.

- *Petrophysical properties and hydrocarbon occurrence*

This sand unit has a minimum porosity of 20.52% and a maximum porosity value of 35.04% in well 5. The porosity values are higher at the flanks than the central portion.

C. Correlation of reservoir sands

In this work, the stratigraphic correlation to show the continuity and the pinchout of reservoir sands, and demonstration of the equivalence of stratigraphic reservoir sand unit were carried out. The reservoir lithologic units were delineated in vertical succession by surface representing the changes in lithologic characters, such as showing regressive or transgressive sequences and the different sedimentary sand type deposited in the field. In correlation process, a modified method of lateral continuous line tracing and use of broken lines for area of uncertainty of sand units was employed for accurate correlation work of closely spaced sand unit. Individual units were traced from well to well (fig. 15).

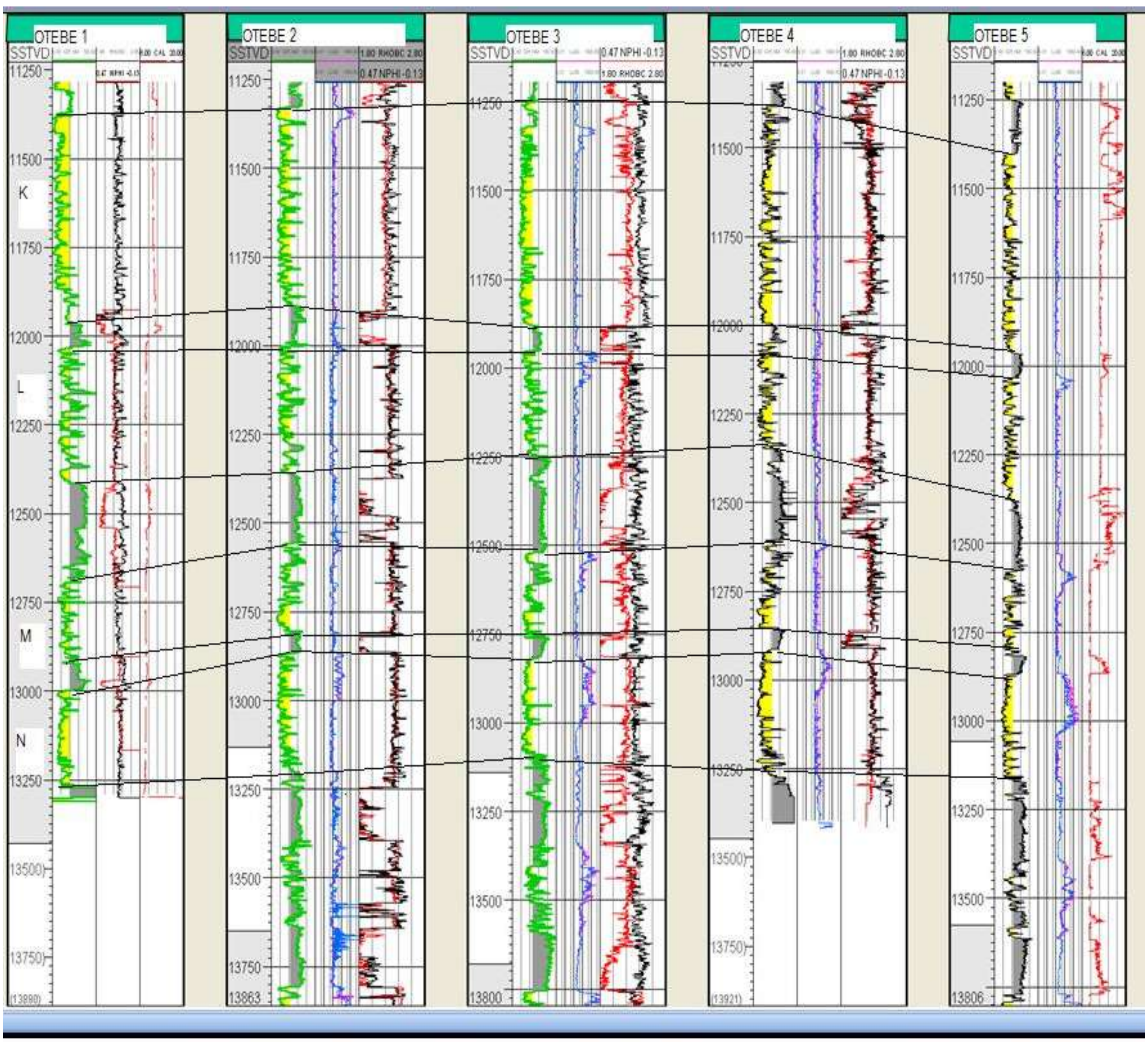

Fig. 15: Correlation of well logs in OTEBE Field

IV. SUMMARY AND CONCLUSION

A. Summary

1) Porosity

The porosity values of the reservoir sands in the field lie between 28.27% in well 1, sand K, and 20.25% in well 3, sand M. The porosity value is qualitatively evaluated to be fair to very good and favourable for hydrocarbon production. Porosity decreases gradually from one reservoir to another as depth of burial increases .The decrease in porosity may be as result of increase in the degree compaction. Sand percentage of the reservoir sands evaluated in this work is high. They range between 90% and 99%. Porosity in clastic rocks is governed by sand/shale ratio, and the higher the ratio, the higher porosity. Therefore, high sand/shale percentage contributes to the overall high porosity values encountered in the field.

2) Permeability

The average permeability evaluated for the various sand bodies falls between 178md in sand K for well 1 and 29.71md in sand M for well 3. Permeability values, which are moderate to good for hydrocarbon production, decrease gradually with depth due to increase in overburden pressure. This leads to compaction and change in pore size. As a result of compaction, discontinuity or interconnectivity, permeability may be reduced. Horizontally, permeability changes in value from one portion of a sand unit to another. This may as a result of poor sorting, change in grain size and clay content. Permeability and porosity values evaluated in the field are directly related. Higher porosity, in most cases, has higher permeability. According to Schlumberger (1989), higher porosity usually corresponds to greater permeability.

3) Water/hydrocarbon saturation

Fluid saturation was evaluated for all the reservoir sands within the field. The evaluated water saturation (SW) values show that sand bodies are all hydrocarbon bearing. These hydrocarbon-bearing sands have water saturation values ranging between 6.26%-29.01%. The hydrocarbon saturation(Sh) values of these hydrocarbon bearing sands is between 90%-99%.The principles of the higher the value of water saturation, the lower the hydrocarbon and vice-versa was adopted in identifying between water bearing and hydrocarbon bearing reservoirs.

4) Depositional environments

Several environments of deposition have been identified utilizing GR-log signature and electrofacies classification for deltaic environment (Schlumberger, 1985 Garcia, 1981). These environment are point bar, mouth bar, tidal channel, distributary channel and barrier bar. The GR log signatures of these environments discussed below.

Mouth bar: The GR log exhibits an upward flaring expression with digitate pattern. It also shows a coarsening upward sequence. The upper contact is very sharp and the lower contact is gradational.

Point bar: The GR log of point bars show cylindrical (smooth or serrated) shape with sharp upper and lower contacts.

Distributary channel: The GR log shows a bell shape trend, indicating an upward sequence. The GR log signature exhibits a sharp lower contact and a gradational upper contact.

Tidal channel: The GR log shape displays a cylindrical serrated sequence with sharp lower and sharp to gradational upper contact

Barrier bar: The GR log shape shows an upward coarsening sequence with sharp upper contact and gradational lower contact. Some of the barrier bars are capped with transgressive sand.

Generally, the depositional environment in ‘OTEBE’ field falls between the lower deltaic plain and inner deltaic front of the Niger Delta region based on the classification of depositional environments of sand bodies and their related geomorphic features (Le Blanc, 1972 and Garcia, 1981)

B. Conclusion

The main petrophysical parameters evaluated include porosity, permeability, hydrocarbon saturation and water saturation. These parameters were evaluated using Gamma Ray Log, Compensated Bulk Density Log, Compensated Neutron Log and Resistivity Log (Laterolog).

The average sand/shale percentages indicate that the lithological composition of the reservoir sands is dominantly sand, with average sand percentage above 90%. The reservoir sands exhibit porosity distribution ranging from 20%- 30% which is considered to be very good for hydrocarbon production in the Niger Delta. The reservoir sands have moderate to good permeability regime within the field. Porosity and Permeability distribution, vertically within the sand units in the field, decreases relatively with increasing depth. Horizontally, there is not much porosity variation within the sands. Permeability varies horizontally, probably as a result of poor sorting, change in grain size and clay content. The sand bodies exhibit a wide range of hydrocarbon saturation from 90%-99%.

Reservoir sand K is considered the best reservoir body for production and exploitation based on the number of hydrocarbon accumulation, porosity, permeability, pay thickness and fraction of total pore space occupied by hydrocarbon.

Different sub-environments were identified on the basis of the GR log shapes of the reservoir sands and these environments include: point bar sands, distributary channel deposits, tidal channel sands and barrier bars. Based on the classification of depositional environments of sand bodies and their related geomorphic features, the general environment of OTEBE Field falls most likely between the lower deltaic plain and inner deltaic front of the Niger Delta region.

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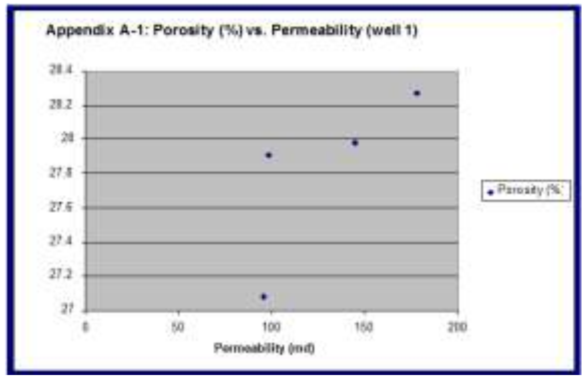
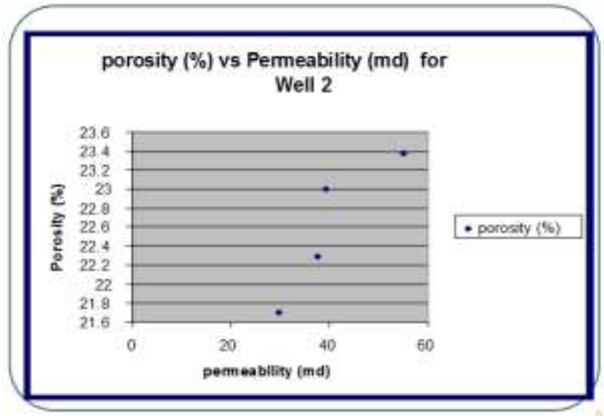
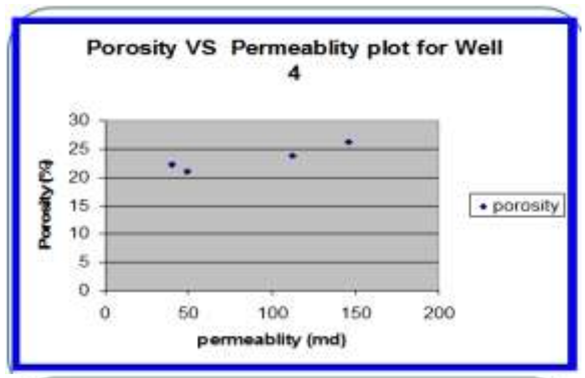
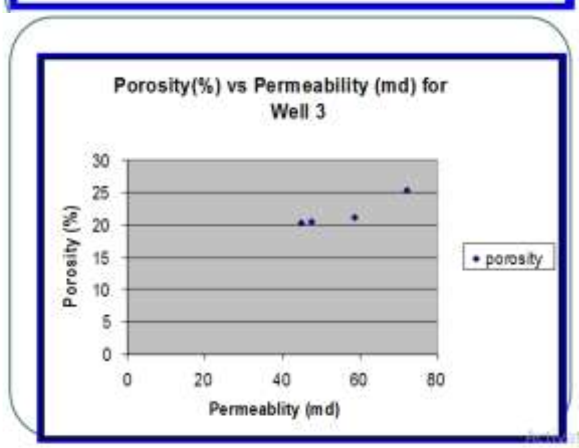
APPENDIX A

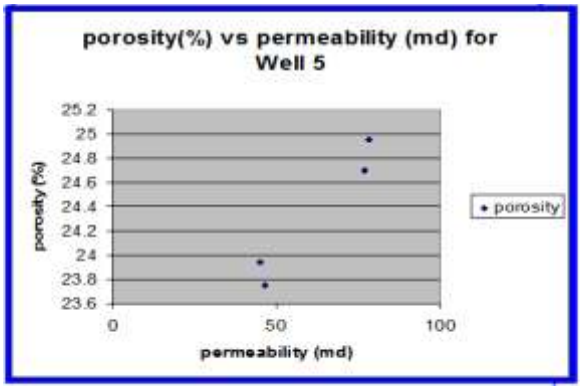
POROSITY (%) VS. PERMEABILITY (MD) PLOTS





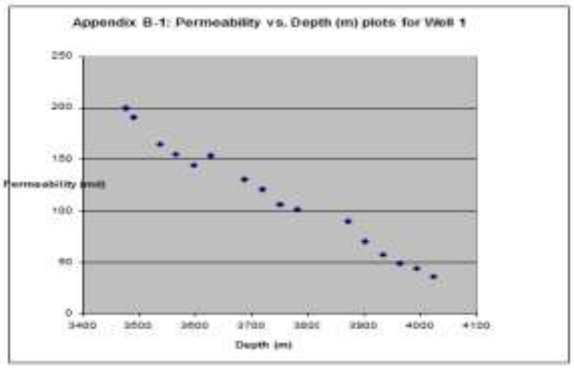


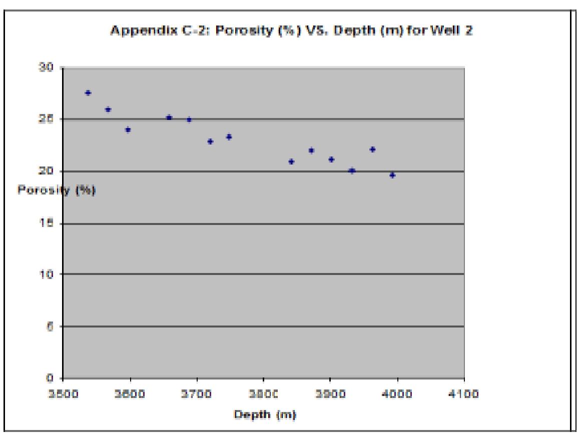


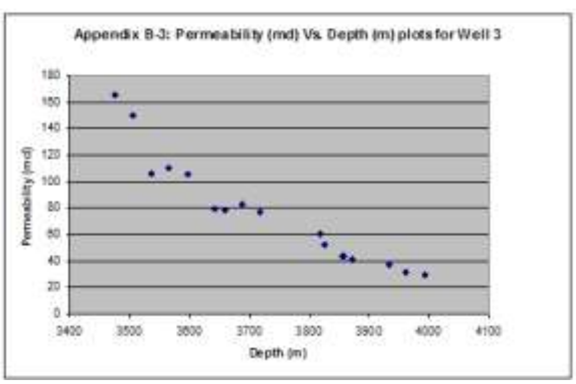


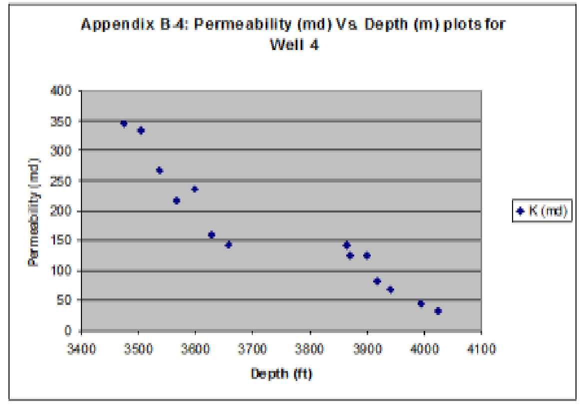
APPENDIX B

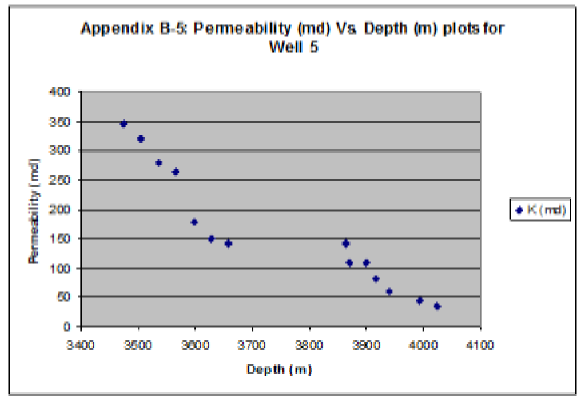
PERMEABILITY (md) VS. DEPTH (m) PLOTS





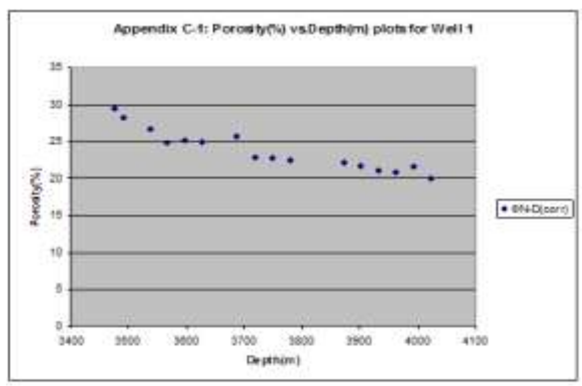


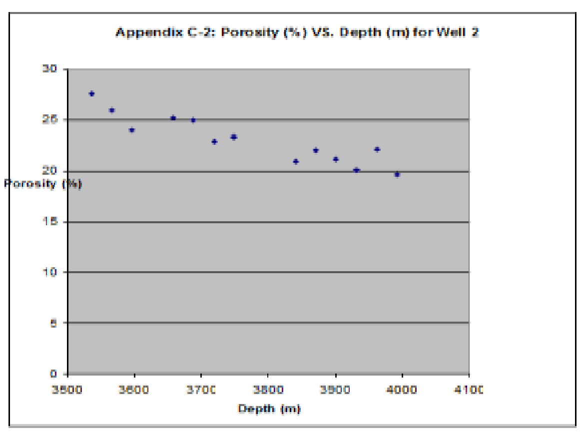


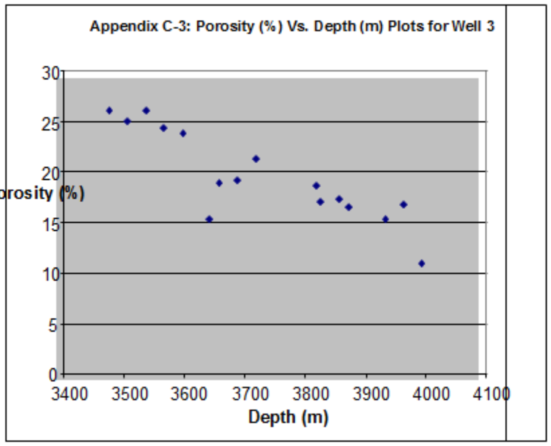


APPENDIX C

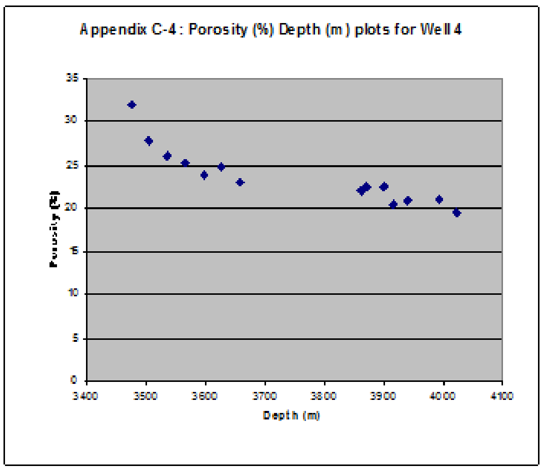
POROSITY (%) VS. DEPTH (M) PLOTS



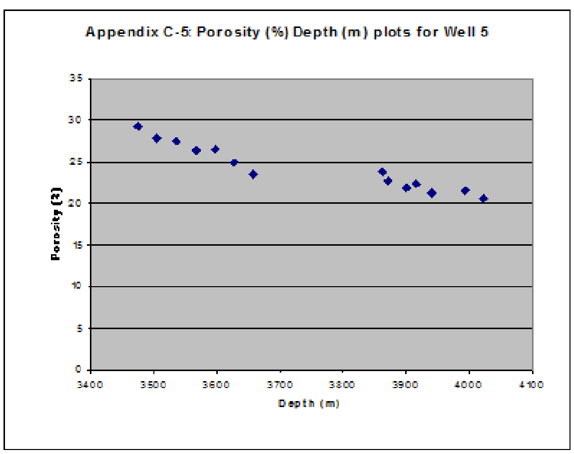




Appendix C-3: Porosity (%) Vs. Depth (m) Plots for Well 3



Appendix C-4 : Porosity (%) Depth (m) plots for Well 4



Appendix C-5: Porosity (%) Depth (m) plots for Well 5