International Journal of Research
Available at https://edupediapublications.org/journals
e-ISSN: 2348-6848
p-ISSN: 2348-795X
Volume 04 Issue 13
October 2017

Petrophysicical and Reservoir Evaluation of Obot-1 and Obot-2 Well, Agbada Formation, Niger Delta, Nigeria

ADIELA U.P, [1]. & AYODELE MOSES OYEWOLE [2]

[1] Department of Petroleum Engineering, Nigerian Agip Oil Company, Port Harcourt

[2] Department of Geology, University of Port Harcourt, Port Harcourt, Nigeria

ABSTRACT

This study is on the evaluation of petrophysical parameters of the reservoir sand using well logs. These parameters have been used to determine the reservoirs potential and quality prevalent in the study area. Three hydrocarbon reservoirs (A, B, and C) were identified across the OBOT-1 and OBOT-2 of depth 8498ft (2591m) and 7819ft (2,384m) respectively. The petrophysical parameters of the reservoir A ranges from 32-22%, 5024-116.2md, 20-14% and 86-80% for porosity (□), permeability, water saturation (S_w) and hydrocarbon saturation (S_h). Its transmissivity ranges from 50,952mdft-648,148mdft. The petrophysical parameters of the reservoir B ranges 30-18%, 1997.8 – 166.5md, 30-14% and 86-70% for porosity (□), permeability, water saturation (S_w) and hydrocarbon saturation (S_h) respectively. Based on Schlumberger standard, the values indicate that reservoir A has both excellent porosity and permeability with highest transmissivity.

INTRODUCTION

The quest for optimum method of hydrocarbon production has been an issue which many oil and gas companies are interested in. Alvarado and Manrique (2010) have stated that the effort of industries to increase production by the use of large capital investments to enhance oil recovery sometimes proves futile. This hitch needs to be proffered with a sustainable solution. One of the major ways of resolving this issue is through petrophysical evaluation.

Most of the factors that determine the reservoir conditions are often too dynamic that over a short geologic time span must have been severally altered and must therefore be revisited for quantification. This shows that reservoirs must be regularly revisited with new technical devices, and also the geologic conditions must be rechecked due to the reservoir's heterogeneity in order to evaluate the possible range of uncertainty existing within the reservoirs.

LOCATION OF STUDY

The field is located in the offshore Niger Delta , but the co-ordinates of the location of this field were concealed due to proprietary reasons.

OBJECTIVES OF STUDY

This research is aimed at evaluating the reservoir potential of the field with to determine the petrophysical characteristics of sand bodies.

STRATIGRAPHY OF THE NIGER DELTA BASIN

The established Tertiary sequence in the Niger Delta consists, in ascending order, of the Akata, Agbada, and Benin Formation. The strata composed an estimated 8,535 m (28000 ft) of section at the approximate depocenter in the central part of the delta.

Akata Formation

The Akata Formation which is the basal unit of the Cenozoic delta complex is composed mainly of marine shales deposited as the high energy delta advanced into deep water (Schlumberger, 1985). It is characterized by a uniform shale development and the shale in general is dark grey, while in some places it is silty or sandy and contains especially in the upper part of the formation, some thin sandstone lenses (Short & Stauble, 1967).

The Akata Formation probably underlies the whole Niger Delta south of the Imo Shale outcrop of the Paleocene age from Eocene to Recent (Short & Stauble, 1967). The Akata Formation has been penetrated in most of the onshore fields between 12,000 and 18,000 ft (~3,700 – 5,500 m) and in many of the offshore fields between 5,000 and 10,000 ft (~1,530 – 3050 m); however, the maximum thickness of the Akata Formation is believed to average 20,000 ft (~7,000 m).

Agbada Formation

The Agbada Formation is a paralic succession of alternating sandstones and shales, whose sandstone reservoirs account for the oil and gas production in the Niger Delta (Nwachukwu and Odjegba, 2001).

The formation consists of an alternating sequence of sandstones and shales of delta-front, distributary-channel, and deltaic-plain origin. The sandstones are medium to fine-grained, fairly clean and locally calcareous, glauconitic, and shelly. The shales are medium to dark grey, fairly consolidated, and silty with local glauconite.

The sand beds constitute the main hydrocarbon reservoirs while the shale beds present form the cap rock. These shale beds constitute important seals to traps and the shales interbedded with the sandstones at the lower portions of the Agbada Formation are the most effective delta source rocks (Schlumberger, 1985). Petroleum occurs throughout the Agbada Formation of the Niger Delta.

BENIN FORMATION

The Benin Formation consists of predominantly massive highly porous, freshwater-bearing sandstones, with local thin shale interbeds, which are considered to be of braided-stream origin.

International Journal of Research
Available at https://edupediapublications.org/journals
e-ISSN: 2348-6848
p-ISSN: 2348-795X
Volume 04 Issue 13
October 2017

Mineralogically, the sandstones consist dominantly of quartz and potash feldspar and minor amounts of plagioclase. The sandstones constitute 70 to 100% of the formation. Where present, the shale interbeds usually contain some plant remains and dispersed lignite.

Benin Formation attains a maximum thickness of 1,970m (6,000ft) in the Warri-Degema area, which coincides with the maximum thickness (i.e. depocenter) of the Agbada Formation. The first marine foraminifera within shales define the base of the Benin Formation, as the formation is non-marine in origin (Short and Stauble, 1967). Composition, structure, and grain size of the sequence indicate deposition of the formation in a continental, probably upper deltaic environment. The age of the formation varies from Oligocene (or earlier) to Recent.

STRUCTURES OF THE NIGER DELTA BASIN

The delta sequence is deformed by syn-sedimentary faulting and folding. Evamy et al. (1978) described the main structural features of the Niger Delta as growth faults and roll over anticlines associated with these faults on their downthrown (i.e. seaward) side.

Growth Faults

Growth faults are faults that offset an active surface of deposition. It is characterized by thicker deposits in the downthrown block relative to the upthrown block. The growth fault planes exhibit a marked flattening with depth as a result of compaction. Thus a curved, concave-upward fault plane is developed, which continues at a low angle. (figure 1)

The ratio of the thickness of a given stratigraphic unit in the downthrown block to that of the corresponding unit in the up-thrown block is termed the ‘growth index’ (Figure 2.4) which in Nigeria can be as high as 2.5m.

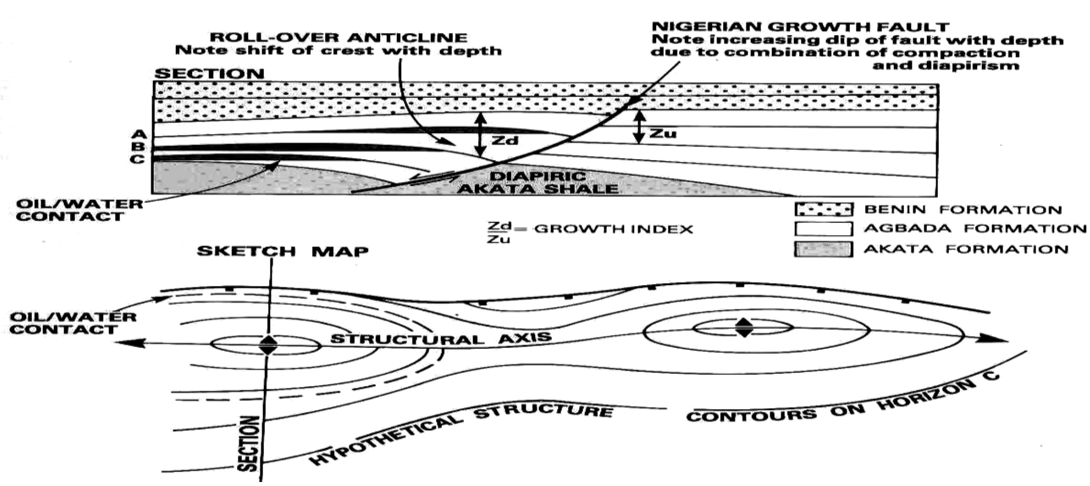

Figure 1: Schematic section showing a map of simple growth Fault and rollover anticline (After Schlumberger, 1985).

Complex rollover structures

These include collapsed-crest features which have an overall dome shape, with strongly opposing dips at depth. Two swarms of faults dipping towards the crest typically 'collapse' the structural crest to compensate for overburden extension, one heading seaward and the other heading landward.

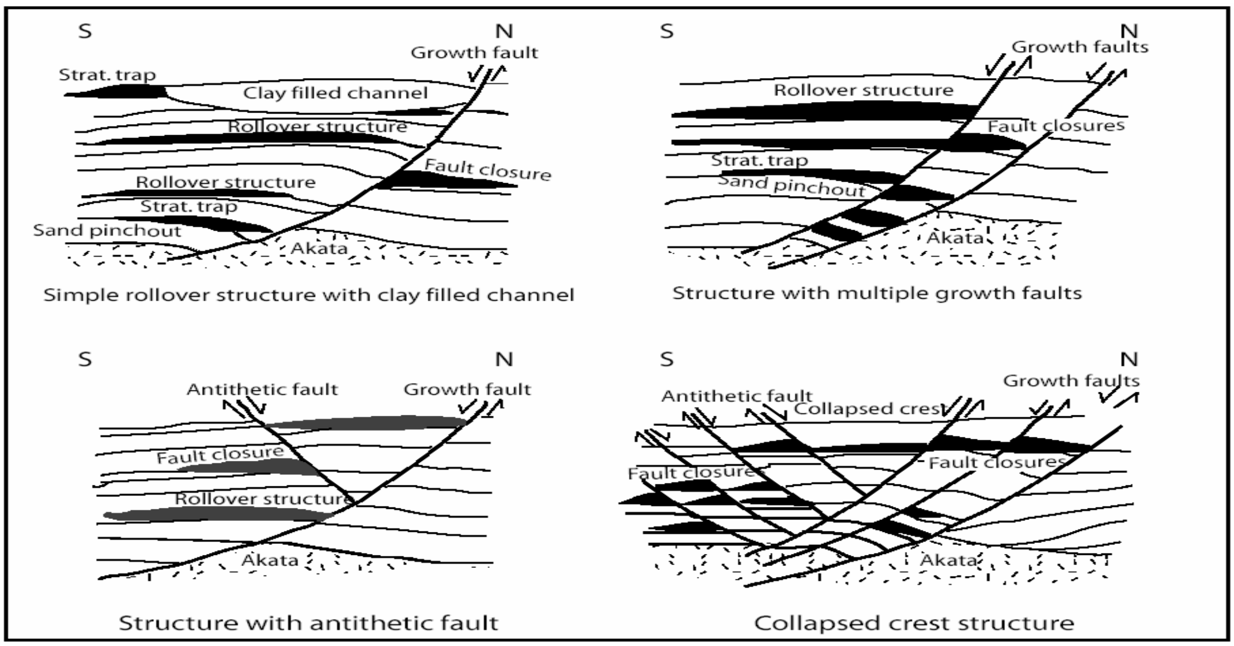

Figure 2 : Principal types of oil-field structures in the Niger Delta with schematic indications of common trapping configurations. (Doust and Omatsola, 1990).

LITERATURE REVIEW

Davies and Ethridge (1975) used sandstone composition while Friedman (1961) used textural analysis to arrive at their environmental interpretations. Other workers back up the SP/GR log interpretations with data on mineralogy, micro- fauna, sedimentary structures from cores and ditch cutting. Selly (1978), Adedokun (1981) used electric logs, textural analysis and petrographic data to study depositional environment..

Omatsola (1982) concluded that reservoir sands of more than 15m thick in most places represent composite bodies, and may consists of two to three stacked channels. The sand is poorly consolidated and has porosity as high as 40% in oil bearing reservoirs. Porosity reduction with depth is gradual and permeability in hydrocarbon reservoirs are commonly in the range of 1-2 Darcy.

Bilotti and Shaw (2005) maintained that 90% of the weight of the Akata Formation and the elevated fluid pressure is caused by the combined effects of disequilibrium compaction; tectonics stresses and perhaps increased fluid volume caused by hydrocarbon maturation.

Corredor et al. (2005) studied the structural style in the deep water fold and thrust belts of the Niger Delta. They stated that the deep water Niger Delta has two large folds and thrust belts, which are products of contraction caused by gravity–driven extension on the continental shelf that exhibit complex styles of thrusting. These folds and thrust belts are initiated during the early Tertiary. They defined two main types of imbricate thrust systems in the Niger Delta:

- ✓ Type I system with a single basal detachment level that is typically near top of the Akata Formation.
- ✓ Types II imbricate system with multiple basal detachment levels, which cause massive structural thickening of the Akata Formation and refolding of shallow thrust sheets.

Ozumba et al. (2005) observed that the mode of hydrocarbon trapping in the Niger Delta is a combination of structural and stratigraphic trapping. They also maintained that the Opuama sedimentary infill forms part of the Niger Delta stratigraphic succession and exhibits itself as a clay plug set within parallic Agbada Formation.

METHODOLOGY

PETROPHYSICAL QUANTITATIVE ANALYSIS OF OLAND-01 WELL

CALCULATION OF POROSITY (ϕ)

Reservoir A

$$\phi \text{ den} = \left[\frac{p_{ma} - p_{biog}}{p_{ma} - Pf}\right] - V_{sh} \times = \left[\frac{p_{ma} - p_{sh}}{p_{ma} - Pf}\right]$$

Where ϕ den = porosity derived from density log

ρ_{ma} = density of matrix = 2.65g/cm^3

ρ_{blog} = Bulk density value on density log = 2.24g/cm^3

ρ_f = 1.0g/cm^3

V_{sh} = volume of shale = 0.40

ρ_{sn} = 2.35g/cm^3

By Substitution,

$$\phi = \left[\frac{2.65 - 2.24}{2.65 - 1.0}\right] - 0.40 \times \left[\frac{2.65 - 2.35}{2.65 - 1.0}\right]$$

$$\phi = \left(\frac{0.41}{1.65}\right) - 0.40 \times \left(\frac{0.3}{165}\right)$$

$$\phi = 0.248 - (0.40 \times 0.182)$$

$$\phi = 0.248 - 0.073$$

$$\phi = 0.18 \text{ or } 18\%$$

Reservoir C

Where ρ_{ma} = 2.65g/cm^3

ρ_{blog} = 2.30g/cm^3

ρ_f = 1.0g/cm^3

V_{sh} = 0.25

ρ_{sh} = 2.20g/cm^3

International Journal of Research
Available at https://edupediapublications.org/journals
e-ISSN: 2348-6848
p-ISSN: 2348-795X
Volume 04 Issue 13
October 2017

By substitution,

$$\phi = \left(\frac{2.65 - 2.30}{2.65 - 1}\right) - 0.25 \times \left(\frac{2.65 - 2.20}{2.65 - 1}\right)$$

$$\phi = \left(\frac{0.35}{1.65}\right) - 0.25 \times \left(\frac{0.45}{1.65}\right)$$

ϕ = 0.212 – (0.25 x 0.273)

ϕ = 0.212 – 0.068

ϕ = 0.212 – 0.068

ϕ = 0.14 or 14%

CALCULATION OF FORMATION FACTOR

Reservoir A

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

Where ϕ = 18

$$F = \frac{0.62}{18^{2.15}} = \frac{0.62}{499.8} = 0.00124$$

Reservoir C

Where ϕ = 14

$$F = \frac{0.62}{14^{2.15}}$$

$$F = \frac{0.62}{291.2}$$

F = 0.00213

CALCULATION OF IRREDUCIBLE WATER SATURATION (SWIRR)

$$\text{Swirr} = \left[\frac{F}{2000}\right]^{1/2}$$

Reservoir A

Where F = formation factor = 0.00124

By substitution,

$$\text{Swirr} = \left(\frac{0.00124}{2000}\right)^{1/2}$$

$$= (0.00000062)^{1/2}$$

Swirr = 0.000787

Reservoir C

Where F= 0.00213

$$\text{Swirr} = \left(\frac{0.00213}{2000}\right)^{1/2}$$

Swirr = $(1.07 \times 10^{-6})^{1/2}$

Swirr = 0.00103

CALCULATION OF PERMEABILITY (K)

$$K = \frac{0.136 \times \phi^{4.4}}{(Swirr)^2}$$

Reservoir A

Where ϕ = 0.18

Swirr = 0.000787

$$K = \frac{0.136 \times 0.18^{4.4}}{(0.000787)^2} = \frac{0.136 \times 0.000529}{(6.19 \times 10^{-7})} = \frac{7.19 \times 10^{-5}}{6.19 \times 10^{-7}} = 116.2md$$

Reservoir C

$$\text{Where } K = \frac{0.136 \times \phi^{4.4}}{(Swirr)^2}$$

Where ϕ = 0.14

Swirr = 0.00103

$$K = \frac{0.136 \times 0.14^{4.4}}{(0.000163)^2}$$

$$K = \frac{0.136 \times 0.000175}{1.061 \times 10^{-6}}$$

$$K = \frac{2.380. \times 10^{-5}}{1.061 \times 10^{-6}}$$

K = 22.4md

CALCULATION OF HYDROCARBON SATURATION (S_H)

$S_H + S_w = 1$

Where $S_H = 1 - S_w$

Reservoir A

Where $S_w = 0.20$

$S_H = 1 - 0.20$

$S_H = 0.80$

Reservoir C

Where $S_w = 0.19$

$S_H = 1 – 0.19$

$S_H = 0.81$

DESCRIPTION OF WIRELINE LOGS USED

The different logs used for the research work are Gamma ray log, Resistivity logs,

e-ISSN: 2348-6848
p-ISSN: 2348-795X
Volume 04 Issue 13
October 2017

Compensated Bulk Density log and Porosity log. The wireline logs were used in the interpretation and calculation of the various functions and parameters of the reservoir sands as described below.

Shale usually contains small quantity of radioactive elements such as uranium (U) potassium (k) and thorium (TH). This produces gamma ray radiation from which the source can be detected by spectrometry. The log thus, detects shale horizon and can provide an estimate of the clay content and other sedimentary rocks. Amongst, the sediments, shales have by far the strongest radiation. That is why the log is called “Shale Log”.

RESISTIVITY LOGS

Resistivity is the specific resistance of a material to the flow of current (inverse of conductivity). The resistivity of a formation depends on the electrical conductivity of the rock material within the formation, the nature of formation water (fresh or salt water), other fluids like oil or gas contained in it, the porosity and tortuosity of the formation.

DENSITY LOGS

Density log makes used of artificial gamma ray from a radioactive source (e.g. “^{60}Co and ^{137}Cs) as a continuous record of a formation bulk density. Bulk density is overall density of a rock including solid matrix and fluid enclosed in the pores. Gamma photons collide elastically with electrons and are reduced in energy (Compton Scattering). The number of collisions over any particular interval of time depends upon the abundance of electrons present (electron density index) which in turns is the function of the formation.

Table 1: Classification of Resistivity Logs (Asquith and Krygowski, 2004).

Induction logs [coil logs] (measure formation conductivity)		
Induction (deep and medium)		
Galvanic devices[electrode logs and laterologs] (measure formation resistivity)		
Normal	Microlaterolog (MLL)	
Lateral	Microlog (ML)	
Laterolog (deep and shallow)	Proximity Log (PL)	
Spherically Focused Log (SFL)	MicroSpherically, Focused Log (MSFL)	
Resistivity Log Depth of Investigation		
Flush Zone (R_{xo})	**Invaded Zone (R_i)**	**Uninvaded Zone(R_t)**
Microlog (ML)	Short Normal (SN)	Long Normal (LN)
Microlaterolog (MLL)	Laterolog-8 (LL8)	Lateral Log
Proximity Log (PL)	Sphericallyfocused Log (SFL)	Deep Induction Log (ILd)
MicroSpherically Focused Log (MSFL)	Medium Induction Log (ILm)	Deep Laterolog (LLd)
	Shallow Laterolog (LLs)	Laterolog-3 (LL3)
		Laterolog-7 (LL7)

e-ISSN: 2348-6848
p-ISSN: 2348-795X
Volume 04 Issue 13
October 2017

RESULTS AND INTERPRETATION

PETROPHYSICAL RESULTS AND INTERPRETATION

Total of three hydrocarbon reservoirs were identified and evaluated. Reservoir A cuts across the two wells, namely; OBOT- 01 and OBOT-02.

PETROPHYSICAL QUANTITATIVE ANALYSIS OF OBOT-1 Well

Reservoirs	Depth Top	Depth Bottom	Thickness (ft)	Gross Thickness of Sands(ft)	Net Thickness of Sands(ft)	N/G Ratio	ϕ (%)	Swirr	S_W (%)	S_H (%)	BVW	K (MD)	T(mdft)
A	5695	5824	129	129	118.5	0.919	32	0.0004	19	81	0.06	5024	648148
B	8370	8478	108	108	97.4	0.902	30	0.0005	14	86	0.04	1975	213311

PETROPHYSICAL QUANTITATIVE ANALYSIS OF OBOT-2 Well

Reservoirs	Thickness (ft)	Gross Thickness of Sands(ft)	Net Thickness of Sands (ft)	N/G Ratio	ϕ (%)	Swirr	SW (%)	SH (%)	BVW	K (MD)	T(md ft)
A	125	125	110	0.88	18	0.0008	20	80	0.036	116.2	14525
C	89	89	80	0.90	14	0.001	19	81	0.026	22.4	1993.6

e-ISSN: 2348-6848
p-ISSN: 2348-795X
Volume 04 Issue 13
October 2017

The reservoir B is found at the interval of 7673 – 7761ft (2339-2366m) and has a gross (G) and net (N) thickness of sand, 88ft (26.8m) and 70.5ft (21.5m) respectively, with N/G ratio of 0.80; water saturation (S_w) of 14% and hydrocarbon saturation (S_h) of 86%, porosity (ø) and permeability (K) of 25% and 997.8md respectively. Its transmissivity is 87806mdft. (Table 4).Therefore, reservoir B has very good porosity and very good permeability.

The formation bulk volume water values calculated are nearly constant (Table 4) and this shows that the reservoir is homogeneous and is at irreducible water saturation (S_{wirr}) and therefore can produce water – free hydrocarbon. The transmissivity in reservoir A is higher than of B. This means that lateral migration of hydrocarbon from reservoir to a well bore will be easier in A than B.

CHARACTERISTICS OF RESERVOIRS OF OBOT-1 Well

There are two hydrocarbon reservoirs observed in the wellS. These are reservoir A and B. Reservoir A occurs at the interval of 5695 – 5824ft (1736-1775m) and has a gross (G) and net (N) thickness of sand, 129ft (39.3m) and 118.5ft (36.1m) respectively, with N/G ratio of 0.9; water saturation (S_w) of 19% and hydrocarbon saturation (S_h) of 81%, porosity (ø) and permeability (K) of 32% and 5024md while its transmissivity is 648148mdft. Therefore, the reservoir has both excellent porosity and permeability.

Reservoir B occurs at the interval of 8370 – 8478ft (2551-2584m) and has a gross (G) and net (N) thickness of sand, 108ft (32.9m) and 97.4ft (29.7m) respectively, with N/G ratio of 0.9; water saturation (S_w) of 14% and hydrocarbon saturation (S_h) of 86%, porosity (ø) and permeability (K) of 30% and 1975md respectively. Its transmissivity is 213311mdft. Therefore, the reservoir has both excellent porosity and permeability.

The formation bulk volume water values calculated are nearly constant (and this shows that the reservoir is homogeneous and is at irreducible water saturation (S_{wirr}) and therefore, can produce water-free hydrocarbon. Transmissivity in A is higher than B which means that lateral migration of hydrocarbon to the well bore will be faster in reservoir A than in B.

CHARACTERISTICS OF RESERVOIRS OF OBOT-2 Well

There are two hydrocarbon reservoirs found in the well BONN 019. These are reservoirs A and C.

International Journal of Research
Available at https://edupediapublications.org/journals
e-ISSN: 2348-6848
p-ISSN: 2348-795X
Volume 04 Issue 13
October 2017

Reservoir A occurs at the interval of 5693 – 5813ft (1735-1772m) and has a gross (G) and net (N) thickness of sand, 125ft (38.1m) and 110ft (33.5m) respectively, with N/G ratio of 0.9; water saturation (S_w) of 20% and hydrocarbon saturation (S_h) of 80%, porosity (ø) and permeability (K) of 18% and 116.2md respectively. Its transmissivity is 14525mdft. Therefore, reservoir A has both good porosity and permeability.

Reservoir C occurs at the interval of 7350 – 7619ft (2240-2322m) and has a gross (G) and net (N) thickness of sand, 89ft (27.1m) and 80ft (24.4m) respectively, with N/G ratio of 0.9; water saturation (S_w) of 19% and hydrocarbon saturation (S_h) of 81%, porosity (ø) and permeability (K) of 14% and 22.4md. Its transmissivity is 1993.6mdft. Therefore, reservoir C has fair porosity and moderate permeability.

The formation bulk volume water values calculated are nearly constant (Table 5) and this shows that the reservoir is homogeneous and is at irreducible water saturation (S_{wirr}) and therefore, can produce water-free hydrocarbon. The transmissivity in reservoir A is higher than C. This means that the hydrocarbon in reservoir A will flow faster to the well bore as compared to reservoir C.

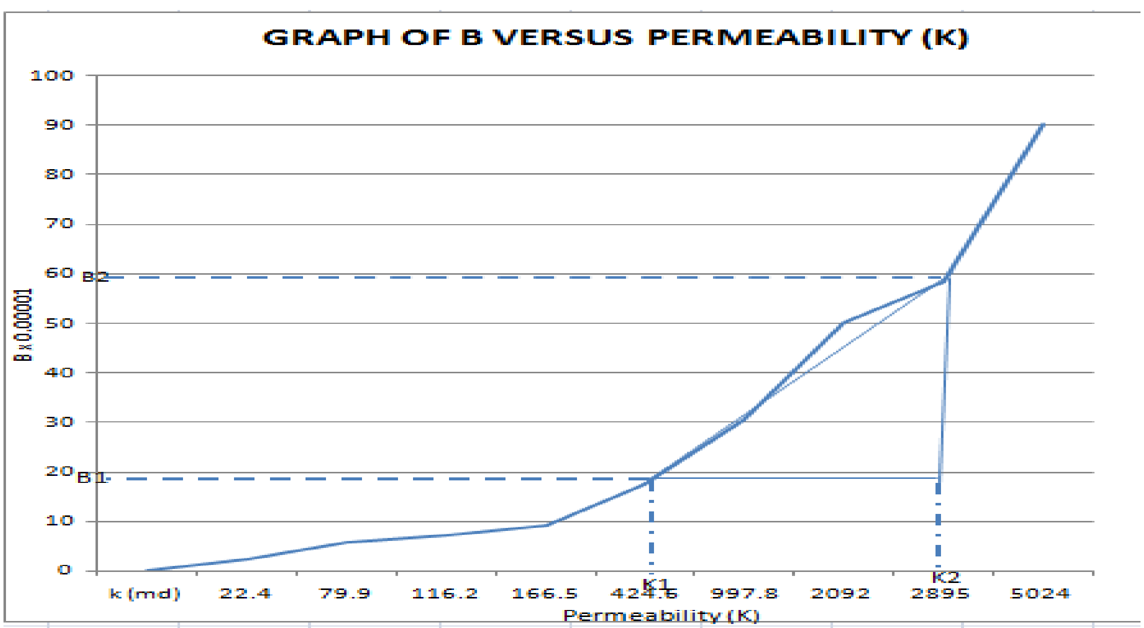

Fig. 3: The graph showing the relationship between Permeability (k) and (B X 10^{-5}).

The petrophysical parameters of reservoir A range from 32-22%, 5024-116.2md, 20-14% and 86 – 80% for porosity (ø), permeability (K), water saturation (S_w) and hydrocarbon saturation (S_h), respectively. From the Dresser standard, the porosity (ø) ranges from excellent to very good, while the permeability (K) is excellent. Its transmissivity ranges from 50952mdft–648148 mdft.

The petrophysical parameters of the reservoir B range from 30-18%, 1997.8 - 166.5md, 30-14% and 86 – 70% for porosity (ø), permeability (K), water saturation (S_w) and hydrocarbon saturation (S_h), respectively. Its transmissivity ranges from 14935 – 87806mdft. From the Dresser standard, the porosity (ø) ranges from very good to good, while its permeability (K) ranges from excellent to good.

The reservoirs bulk volume water (BVW) values calculated are close to constant, this indicates that the reservoir are homogenous and at irreducible water saturation. Therefore, reservoirs can produce water – free hydrocarbon. When a reservoir is at irreducible water saturation, water saturation (S_w) will not move because it is held on grains by capillary pressure. The petrophysical parameters show a gradual decrease from the top to bottom of the wells, reflecting increase in compaction with depth. The porosity, permeability and transmissivity also followed the same trend.

The quality of the reservoirs in terms of porosity, permeability and transmissivity decreases down the depth. Therefore, it can be concluded that the hydrocarbon potential and productivity of the reservoir sands can be classified in decreasing order of arrangement as A, B and C. The reservoir A in OBOT-1 Well is the best in terms of hydrocarbon production and hydrocarbon in such wells can easily migrate to the wellbore as compared to the OBOT-2 reservoirs.

CONTRIBUTION TO KNOWLEDGE

This work could be used as reconnaissance tool to pre-determine permeability and porosity at various depths using the empirical formulas generated. Water saturation, irreducible water saturation, porosity, permeability and hydrocarbon saturation combined could be used to give advice on possible locations to drain holes for further field development. This work could also be incorporated into a number of multi-disciplinary projects that use integrated subsurface datasets (core, 3D seismic and production data) to further characterize geology and fluid flow in hydrocarbon reservoirs.

REFERENCES

Adedokun, O. (1981). Petrology, provenance and depositional environments of the reservoir sandstone of Ossu-Izombe oil field, Imo State, Nigeria. *Journal of Geology*, 4:35-36.

Allen, J. (1963). Sedimentation in the modern Delta of the River Niger, West

Africa. Proc. 6 th Internal Conf. Sedimentologist. p. 26-34

Beka, F. and M. Oti (1995). The distal Offshore Niger Delta: from tier prospects of a mature petroleum province, in, Oti, M.M., and Postina, G., eds., Geology of Deltas: Rotterdam, A.A. Balkema, p. 237-241.

Benkhelil, J. and M. Guiraud (1980). La Benoune (Nigeria): une chaine intracontinentale de style atlasique. C.R. Acad. Sci., Paris 290, p.1517-1520.

Corredor, F.; Shaw, J. and F. Bilotti (2005). Structural styles in the Deep water fold and thrust belts of the Niger Delta: American Association of petroleum Geologists, 89: 753-780.

Coleman, J. (1976). Detas: Processes of deposition and models for exploration continuing education publication company Inc.

Krueger, W. (1968). Depositional environment of sandstones as interpreted from electrical measurements –an introduction Gulf Coast Association Geologists Soc. Trans., 18, p. 226-241.

Lambert - Alkhiobare, D. and A. Ibe (1980). Agbada Shales as major source rocks in the Niger

Omatsola, E. (1982). Geology of the Niger Delta, Shell International Mij. The Hague, Netherlands, p.103-112.

Reyment, R. (1965a). Quantitative Paleoecologic Analysis of Ewekoro and Oshosun Formations of Western Nigeria. Geol. Foren. Stockh. Forhandl., 86 : 248-256.

Tenker, S. (1996). Building the 3-D jigsaw puzzle; applications of sequence stratigraphy to 3-D reservoir characterizationof Permaian basin. American Association of Petroleum Geologists, Bulletin, V. 80, p.460 – 485.