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Research Article

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Petroleum Viability and Reservoir Studies of Wells in Niger Delta, Nigeria

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Abstract This research work is basically based on the use of Geophysical wire line log data of well Xl and well X2 in X- field, Niger Delta for the evaluation of the reservoir potential of the wells. The aims and objectivity of this research work is to use geophysical borehole log data to determine the reservoir of the various stages in the wells, correlate the wells in the field, determine the economically viability of the wells and to determine the different lithology encountered at various depth in the wells. The well Xl and well X2 are located at South-East of Brass and South West of Bonny. The reservoir potential of the well Xl is between depth 3533M and 3850M while the depth between 580M, the topmost of well Xl and 3850M, the deepest part of well Xl. The depth between 2750m and 3340m are purely shales. Similarly, the reservoir potential of the well X2 is at depth between the range of 4057M and 4097M.The depth between 2205M and 2910M are intercalation of sand and shale whiles the depth 3000M to 35lOM are purely shale because of high Gamma ray values from the logs. From the raw data collected from the Agip energy, reservoir characterization of the two wells was carried out by plotting depth values against resistivity values and depth against gamma ray. The plotting helped in the correlation of the two wells and determined the reservoir potentiality of the wells. Reservoir characterization deals with sedimentology, structural geology and petrophysical parameters of the wells formation. It also deals with the depositional environments and reservoir sand bodies that characterized the wells. This research work will identify the petroleum reservoirs that are capable of holding significant amount of petroleum in the wells, which will result from the consideration of porosity, hydrocarbon saturation and other petrophysical parameters.

Keywords Petroleum Viability, Reservoir, Nigeria

Introduction

In recent, the study of reservoir characterization involved the studying of wire line wel1 logs, well cuttings, cores, Formation Micro Scanner (FMS) images, and drill stern test (DST). But, in this research work, only the methods of geophysical wire line logs used in formation evaluation would be considered.

The wire line logs used are Gamma ray log which measures the amount of radioactive elements in the formation, Bulk density log which is a function of matrix density, porosity, and density of the fluid in the pores (salt mud, fresh mud, or hydrocarbons) and also measure the type of fluids in the formation. Bulk density correction which records how much correction has been applied to the bulk density curve due to borehole irregularities, Resistivity which measure the amount and type of fluid (Hydrocarbon, water) in the formation, there are two types of resistivity in the data, which are, Induction deep resistivity (ILD), and induction medium resistivity (ILM).

Study Area

The study wells is situated within the western margin of the Niger-Delta. The Niger-Delta is situated in the Gulf of Guinea between longitudes 5°E and 8°E and latitudes 3°N and 6°N.Due to confidentiality purpose, more details about the location of the study area were not provided

Aims of the Study Area

The aims is to ascertain the reservoir characterization and hydrocarbon viability of the reservoir sands of selected wells in the Niger Delta

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 [1]. 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 [2].

The Akata Formation probably underlies the whole Niger Delta south of the Imo Shale outcrop of the Paleocene age from Eocene to Recent [2]. 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).

For all practical prospecting purposes, the top of the Akata Formation is the economic basement for oil; however, there may be potential for gas dissolved in oil field waters under high pressure in the deeper formation [1].

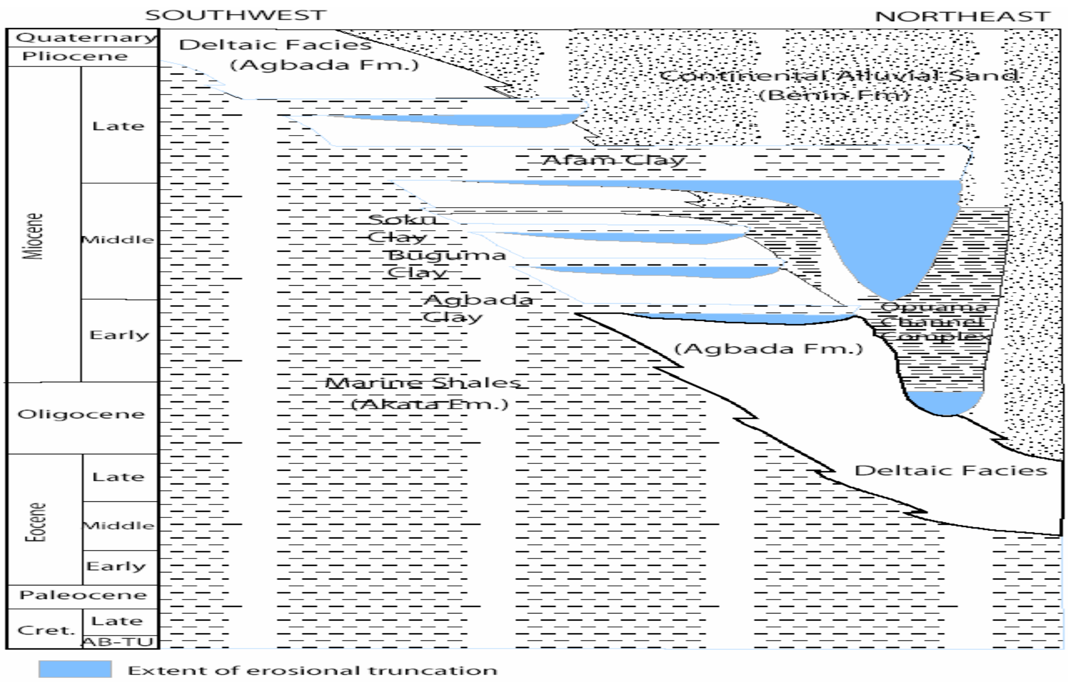

Figure 1: Stratigraphic column showing the three formations of the Niger Delta [3]

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 [4].

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 [1]. Petroleum occurs throughout the Agbada Formation of the Niger Delta.

Maximum thickness of the formation is 3,940m (12,000ft) at the central part of the delta, and thins northward and toward the northwestern and eastern flanks of the delta. The formation is poorly developed or absent north of the Benin city-Onitsha-Calabar axis. The age of the Agbada Formation varies from Eocene to Pliocene/Pleistocene.

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. 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 [2]. 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 (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 [6].

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.

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' which in Nigeria can be as high as 2.5m.

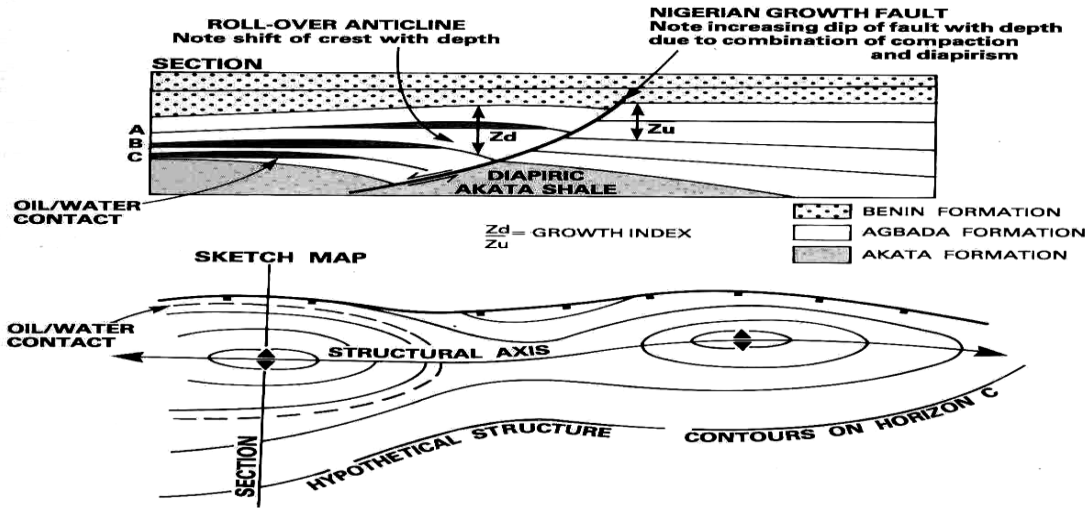

Figure 2: Schematic section showing a map of simple growth Fault and rollover anticline (After Schlumberger, 1985 [1]).

Rollover Structures

They are anticlinal structures formed along the faults as a result of the enhancement of sedimentation along the growth fault that causes a rotational movement which tilts the beds towards the fault. Rollover structures can be classified into two main groups:

- Simple rollover structures
- Complex rollover structures

Simple Rollover Structures

Simple rollover features with anticlinal dips typically form the crests of macrostructures. They are commonly cut by one or more crestal faults and show a moderate shift with depth of the structural culmination away from the structure-building fault.

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 hading seaward and the other hading landward.

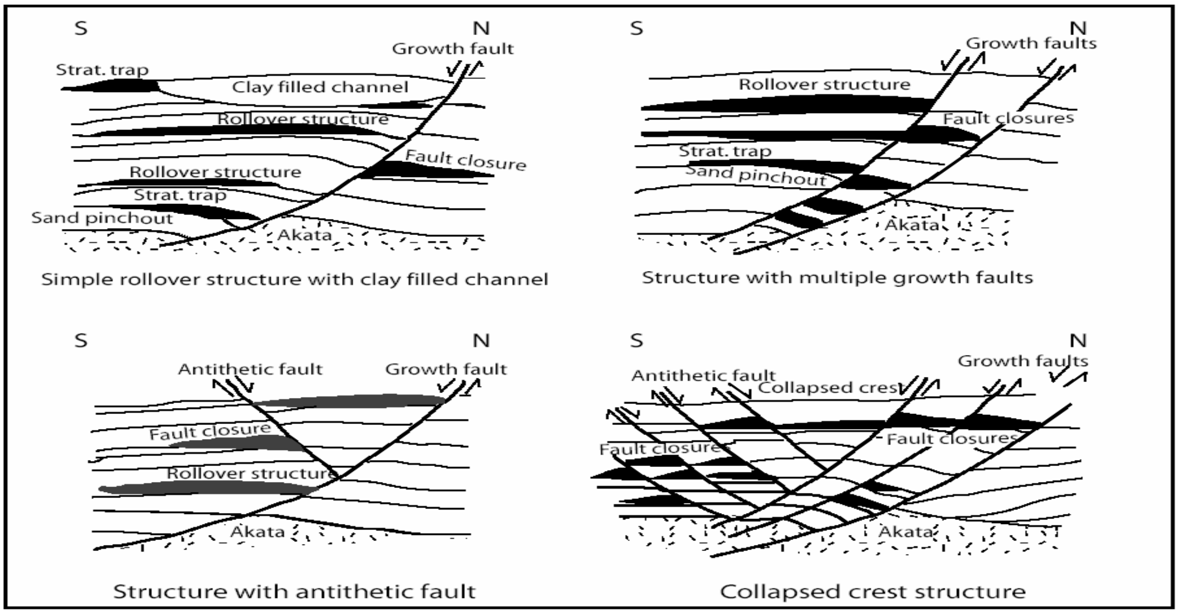

Figure 3: Principal types of oil-field structures in the Niger Delta with schematic indications of common trapping configurations. [3].

Methodology and Data Source

Different types of methods of study are applied to wireline logs interpretation is within the available materials that have been adopted for the evaluation of reservoir sand that were evaluated in this research work. Basically, a log is a downhole record made during or after the drilling of a well, It measure directly or indirectly, the records of the measurable physical properties of the geologic formations penetrated by a well and its fluid content. It provides essential information and interpretation of the subsurface geology of the area penetrated by the borehole, thus facilitating correlation between different areas But nowadays provide information on the nature of the strata penetrated, the shape of the structure, physical data on the rocks, the depths at which these rocks are encountered, the porosity and permeability of the rock units, types of fluids contained in the rocks, their temperature, depths of the fluid interfaces etc.

Description of Wireline Used

There are different logs used for this research work and, are under lised as follow:- Gamma ray log, Resistivity induction log deep (ILD), Resistivity induction g medium (ILM), Interval transit time (At), Formation factor and

Thermal Neutron porosity, Caliper logs. These are the logs, which their raw data given and were used to plot out the log shapes in the interpretation of various sand beds and reservoir sand bodies.

Results and Discussion

The total number of four reservoir sand bodies were identified and all of the four reservoir sand bodies falling within the parallic Agbada formation. They are labeled as reservoir sand bodies A, B, C and D, according to their stratigraphic position beginning from the bottom to the top.

The alphabetic terms used are to distinguish from one sandbody to the other and which are separated from each other by certain thickness of shale beds. However, the sandbodies are described from the base sandbody A to the top sandbody D and their genetic mechanisms are interpreted. In order to interprete the depositional environment of different reservoir sands encountered in well X1 and well X2, the modified model of electrofacies classification for deltaic environment from gamma ray logs and schematic representation of log patterns of variety of depositional environment in which sand-shale sequence are developed

Description of Reservoir Sand bodies and Stratigraphic Position

Sandbody C

sand body C has thickness variation of 10m in well Xl and 8m in well X2. It has e shallowest top at 3809m in well Xl and the deepest top at 4070m in well X2. Shallowest base of the sand occurs at 3814m in well Xl and the deepest base 4074m in well X2. The shale thickness of about 7m separated sandbody C from

Overlying sandbody D in well X2 and the shale thickness of about 270m separated sand body C from overlying sand body D in well Xl.

Geometry: Sandbody C has its thickest sand development in well Xl with sand unit thickness of l0m. It has the sand unit thickness of 8m in well C2.

Sandbody D:

Sand body D has its shallowest top sand at 3529m in well Xl and the deepest top and at 4054m in well X2. The shallowest base sand at 3533rn in well Xl and the base sand at 4057m in well X2. However, the sand body D is bounded a top by thick shale unit averaging 3500m in thickness, whose base was used as the reference datum in constructing the stratigraipic cross sections.

Geometry: The sandbody D has the sand thickness of 8m in well Xl and 6m in well X2. It is almost uniformly thick in well X2. Sand body D is the shallowest Reservoir sand unit encountered in the field of study.

Table 1: Distribution of Thickness of Sandbody C

Well S	Sand Top Sub Sea (M)	Sand Bottom Sub Sea (M)	Average Depth (M)	Thickness (M)
Well X1	3809	3819	3814	10
Well X2	4069	4080	4047	11

Table 2: Distribution of Thickness of Sandbody D

Well S	Sand Top Sub Sea (M)	Sand Bottom Sub Sea (M)	Average Depth (M)	Thickness (M)
Well X1	3529	3237	3533	8
Well X2	4054	4060	4057	6

Petrophysical Evaluation of Reservoir Sandbodies in Well X1

Sandbody A

Porosity (Ø)= pma- pb/pma- pf

Pma=2.648, pb=2.14, pf = 1.1

Ø=2.648-2.14/2.648-1

=0.508/1.548

=0.3282
Formation factor (FR)
FR=
$0.62/Ø^{2.15}$
$=0.62/(0.3282)^{2.15}$
=6.8029
Water saturation (SW) = $(R_0/R_t)^{1/2}$
SW= $(1.10/1.2)^{½}$
=0.9574
Hydrocarbon saturation (Shy) = (1-Sw)
Shy= 1-0.9574
=0.046
Bulk volume of water (BVW)= Sw x Ø
BNW= 0.9574 x 0.3282
=0.3142
Water saturation of flush zone (sxo)= $(w)^{1/5}$
Sx0= $(0.9574)^{1/5}$
Sandbody B
Porosity (Ø) = pma-pb/pma-pf
=2.648.0/2.648-0.7
=0.648/1.948
=0.3327
Formation factor (FR) = $0.62/Ø^{2.15}$
$=0.62/ (0.3327)^{2.15}$
=6.6066
Water saturation (Sw)
Sw= $(R0/Rt)^{1/2}$
= $(17/20)^{1/2}$
=0.9

Table 3: Petrophyscial Evaluation of Reservoir Sandbodies in Well X1

Reservoir sandbodies	Average depth (-m)	ILM Ri (Ω-m)	ILD Rt (Ω -m	Bulk density (pb)	Fr	sw	Shy (1-sw)	Porosity Ø	BVW	Sxo
A	3850	1.1	1.2	2.14	6.803	0.957	0.314	0.328	0.314	0.991
B	3831	17.0	2-.0	2.0	6.607	0.922	0.078	0.333	0.307	0.984
C	3814	10.0	95.0	2.2	14.625	0.324	0.676	0.229	0.075	0.798
D	3533	1.1	1.1	2.3	15.347	0.791	0.209	0.225	0.177	0.954

Petrophysical Evaluation of Reservoir Sandbodeis in Well X2
Sandbody A
Porosity (Ø) = pma-pb/pma-pf
Pma=2.468,pb=2.12, pf= 0.7
Ø=2.468-2.12/2.468-0.7
=0.528/1.948
0.2711
Formation factor (FR)= $0.62/Ø^{2.15}$
FR=$0.62/Ø^{2.15}$
$=0.62/(0.2711)^{2.15}$
=10.2604

Water saturation (Sw)

Sw= $(R0/Rt)^{1/2}$

= $(12/20)^{1/2}$

=0.7746

Hydrocarbon saturation (Shy)

Shy=1-Sw

=1-0.7746

Shy=0.2254

Bulk volume of water (BVW)

BVW= Sw xØ

=0.7746 x0.2711

=0.2099

Water saturation of flush Zone (Sx0)

Sxo= $(Sw)^{1/5}$

= $(0.7746)^{1/5}$

=0.9502

Depositional Environment of Sandbody C

The gamma ray log signature of sandbody C indicates that, the sand body C, appear to be clean and well sorted sand. SandbodyC, is serrated funne! shape and irregular. When this sand body C compared with the electrofacies classification for deltaic environments from gamma ray logs (Adapted by Schlumberger 1985 [1]), it favors the interpretation of sandbody C, as a stream mouth bar at the top part of the reservoir sandbody and distributary channel at the base part of the reservoir sand body C. Sand body C is separated from sand body D by a thick shale.

Geological Properties and Hydrocarbon Occurrences

Sandbody A has the minimum porosity value of 27.11% in Well X2 and the maximum porosity value of 32.82% in Well Xl. Sandbody A has low resistivity, Value of 1.20 -m in Well Xl and the high resistivity value of 20 0 -m in Well X2. The bulk volume of water of 31.42% in Well Xl and the bulk volume of water of 20.99% in Well X2. As indicated by the resistivity log value, it is hydrocarbonbearing in Well X2; while it is water bearing in Well X1.

In sandbody B, the porosity value varies between 28.13% in Well X2 and 33.27% in Well Xl. As shown by resistivity logs, sand bocly B has resistivity value of 20 0-rn in Well Xl and 30 0-m in Well X2 while the bulk volume of water in Well Xl is 30.67% and in Well X2 is 22.97%. This indicates that, Well Xl and Well X2 are hydrocarbon bearing zones.

Sandbody C has high formation factor value of 14.625 in Wet Xl and low formation factor value of 6.607 in Well X2. The porosity range from 22.99% in Well Xl to 33.27% in Well X2. Well Xl and Well X2 have resistivity values of 95 0-rn and 100 0-rn respectively. The bulk volume of water value of 7.46% in Well Xl and bulk volume of water value of 32.93% in Well X2. With an indication of very high resistivity values in Well Xl and Well X2 within the sand body C may shows that sand body C is gas-bearing zone.

Sand body D has formation factor value of 15.347 in Well Xl and formation factor value of 10.697 in Well X2. The resistivity value in Well Xl is 1.6 0-rn, which was very low when compared it with the resistivity value of 60 0-rn in Well X2. This indicates that, Sandbody D is an hydrocarbon bearing zone in Well X2 and water bearing zone in Well Xl.

Most of the reservoir sands show similarity in geometry and the lithological interpretation shows that, the reservoir sands are dominantly sand with thin thickness of shale separated the sandbodies A,B,C, and except where there is high thickness of shale separated the sandbody C from sandbody D.

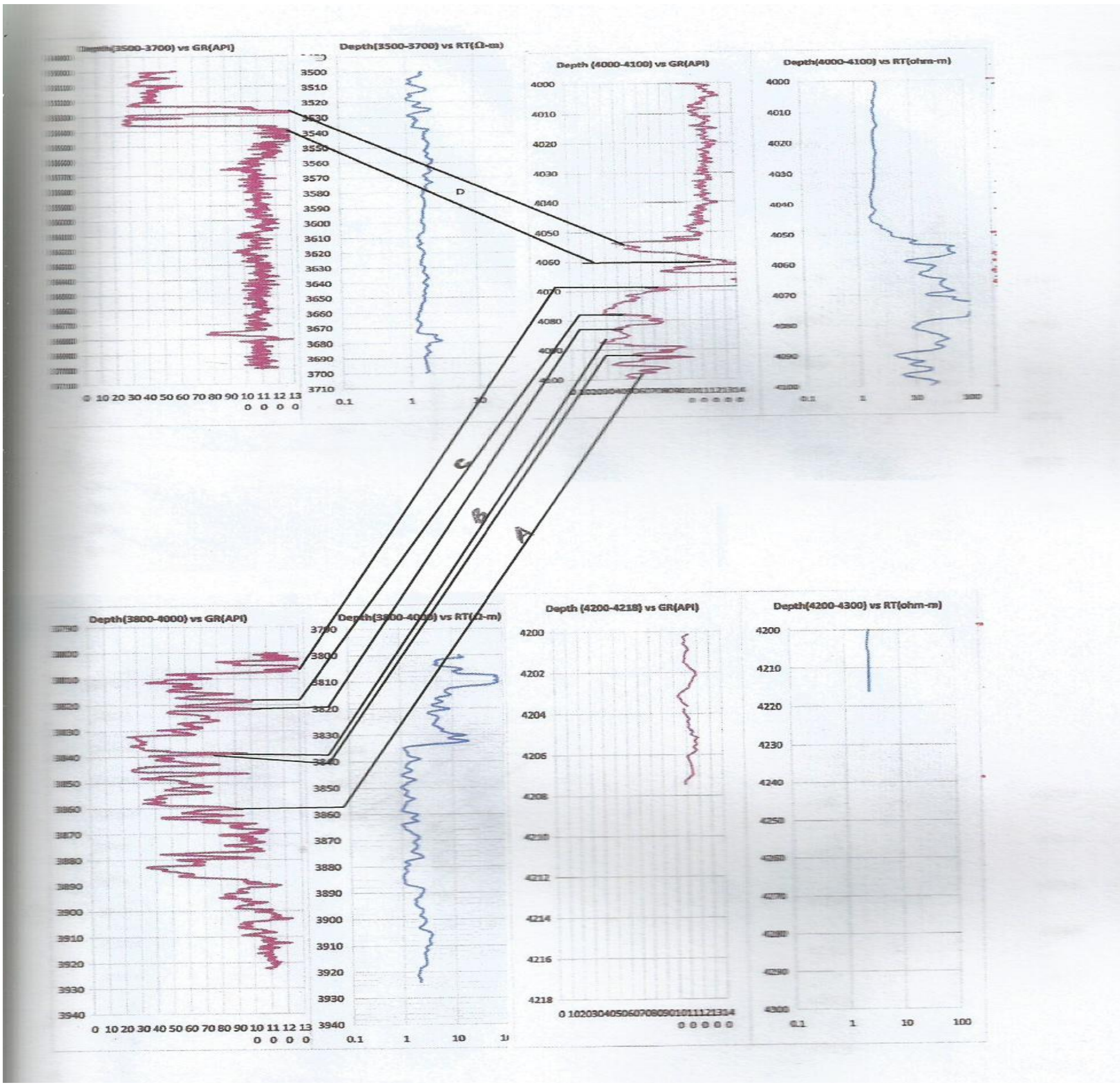

Figure 4: Correlation of Reservoir sands

Porosity depends on the degree of uniformity of grain size, the shape of the grains, the method of deposition, the manner of packing and the effects of completion during or after deposition. In this research work the sandstone reservoir evaluated are modifications of primary porosity, which are due to principally to the interlocking of grains through compaction, contact solution, re -deposition and cementation. The reservoir sands exhibit a porosity range of 22.48% to 33.27%, which has been considered very good for hydrocarbon production in the Niger Delta region.

Vertically, from the top reservoir sand D to the last bottom reservoir sand A, there is a gradational decrease in values of porosity as depth of burial of sand increased.

It was shown from the result obtained that well X2 contain high volume of hydrocarbon more than well Xl. For further drilling of new wells in X-field, it is highly recommended that, the diamond drilling bits should be used because of thickness of shales before the hydrocarbon reservoir sands.

Similarly, area of reservoir sands with high porosity and good permeability but indicates few hydrocarbon accumulation or non-hydrocarbon accumulation in this research work can still be further evaluated with other sophisticated geophysical data such as cores and ditch cuttings and seismic data.

However, correlation of reservoir sands in X-field with the closely related or nearby field to determine the continuity of viable hydrocarbon bearing reservoir sands could also be done to facilitate or aid significant oil exploration in the nearby oil fields.

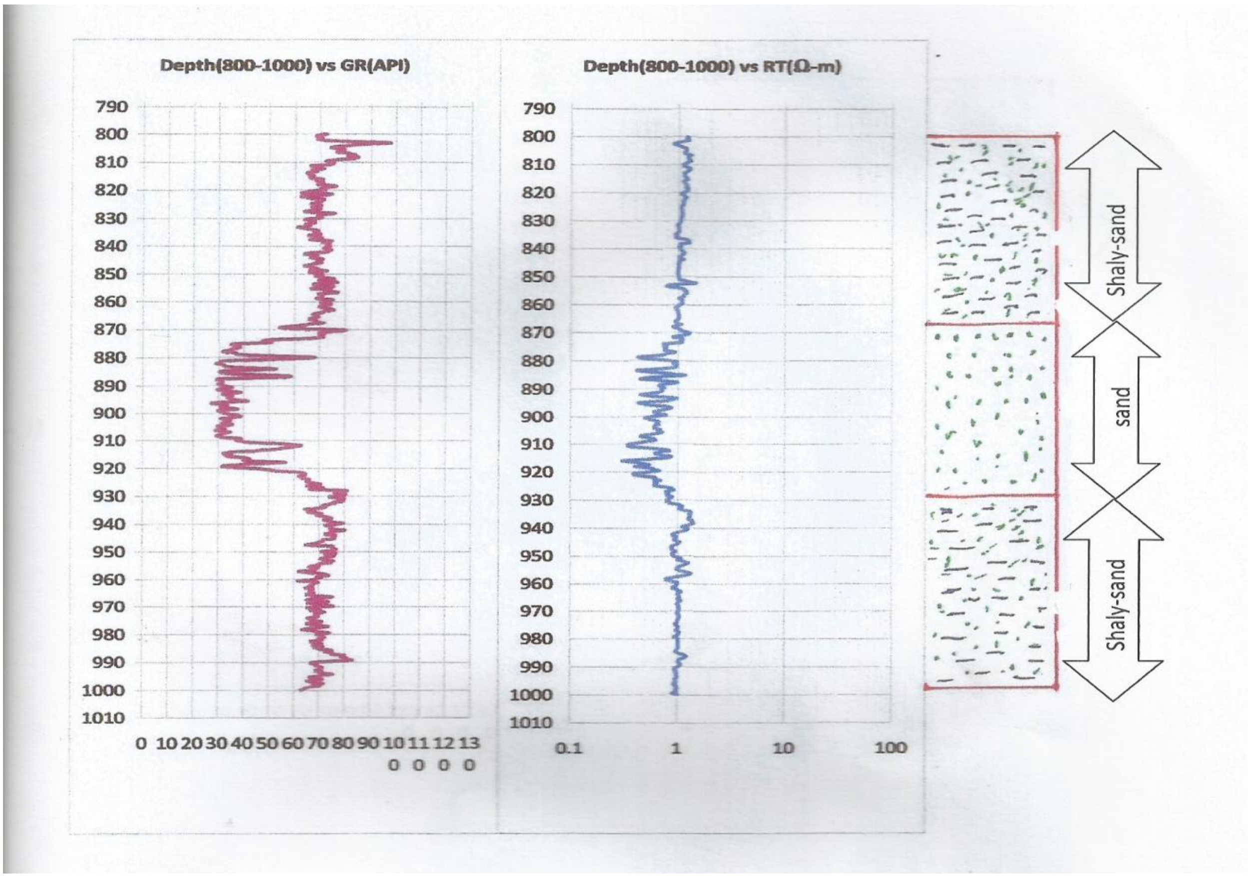

Figure 5: The log signature

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