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# Petrophysical Evaluation of Hydrocarbon Potential of X-Field, Niger Delta, Nigeria

Oborie, Ebiegberi and Debekeme, Ebizimo Silver
*Department of Geology, Niger delta University, Balyelsa State, Nigeria*

***Abstract:***
*A suite of geophysical logs comprising of gamma ray (GR), resistivity (LLD), neutron (NPHI) and density (RHOB) logs from two wells within X-field in the Niger Delta, were used to delineate hydrocarbon bearing reservoirs, identify the reservoir fluid types, and evaluate the major petrophysical parameters of the different reservoirs. The petrophysical properties evaluated include porosity, permeability, water saturation, hydrocarbon saturation, moveable hydrocarbon index, and recovery factor. Four hydrocarbon reservoirs were delineated and correlated across the study area. These reservoirs are encountered at a depth range of 3991ft to 11103ft, and the computed petrophysical parameters for the reservoirs gave porosity values ranging from 20.1% to 27.8%; permeability 396.6md to 886.8md, and average hydrocarbon saturation of 88.7%, 73.4%, 76.3% and 86.1% for the reservoirs. These results, together with the moveable hydrocarbon index, and recovery factors (67.1% to 95.3%) suggest the reservoirs contain significant accumulations of hydrocarbons, which can also be produced. Thus the hydrocarbon potential of X-field is considered high.*

***Keywords:****Porosity, Permeability, Hydrocarbon saturation, Moveable hydrocarbon index, and Recovery factor*

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## I. Introduction

This study is located within the Niger delta sedimentary basin of southern Nigeria (Figure 1) [1]. Stratigraphically, the delta is made up of three main formations, the Akata, Agbada and Benin formations [2]. The Niger delta petroleum province has a proven prolific Tertiary Akata-Abgada hydrocarbon system with world-class oil discoveries. Oil and gas are mainly produced from the sandstones and unconsolidated sands of the Agbada formation[3].

Global consumption of petroleum products has tremendously increased in the past few decades, with the demand increasing mainly from emerging nations. The consumption of petroleum products is expected to increase in the next two decades; as a result, oil and gas companies continuously integrate different exploration techniques in order to find commercial quantities of hydrocarbons. Reservoir evaluation by well log analysis is an indispensable tool always employed to understand the hydrocarbon potential of reservoirs. The main goal of well log analysis is to deduce estimates of oil, gas and water volumes in reservoir formations, from the well data [4,5]. Well logging is performed to transform the petrophysical readings obtained from the well logs into an understanding of the reservoir characteristics such as its porosity, fluid saturation, permeability, capillarity [6].

Well logs are also very helpful in interpreting seismic profiles and, at borehole, it provides a high-resolution estimate of many essential geologic variables. Well logs are records of the physical and chemical properties of formations penetrated by the borehole. With the advance in technology and computerization, most of the formation data is obtained by wireline logging. This involves lowering down electronic sensors into the borehole which records the rock and fluids characteristics of each formation as it traverses [7].

Production of hydrocarbons greatly depends on the petrophysical properties of the reservoir, such as, permeability, saturation, capillary pressure and porosity. Reservoir rocks can have pores ranging from sub-microns in very fine sandstones to centimeters in vuggy carbonate rocks [8]. Put together, the petrophysical properties give a clue of the volumes original hydrocarbons in place, which enables the economic assessment of developing the reservoir [9,10].

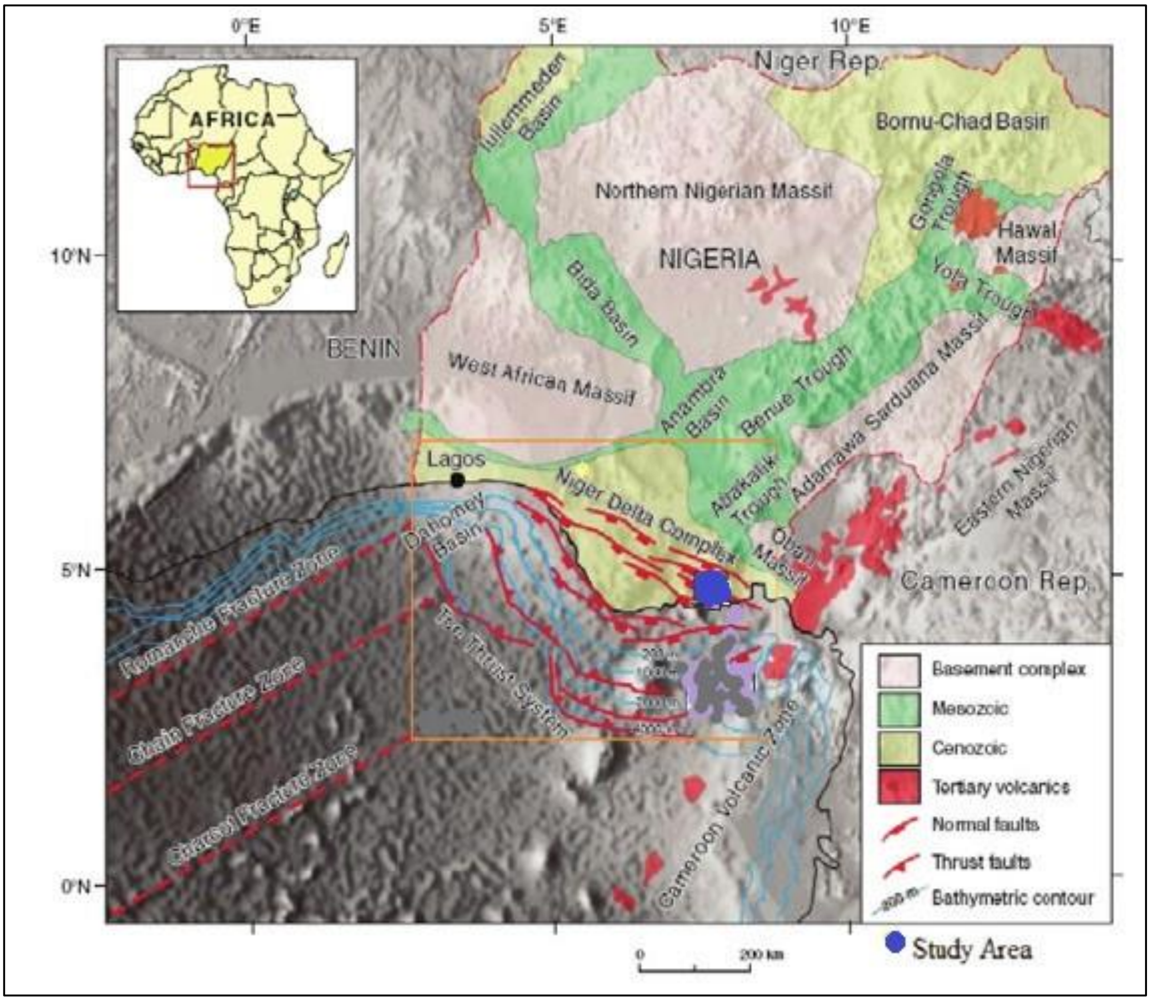


**Figure 1: Niger Delta complex showing study area (After Corredor et al, 2005)**

## II. Materials and Methods

The hydrocarbon potentiality of the X-field, Niger delta, was evaluated using well data from two wells which consist of suites of well logs for the Agbada formation. The data was obtained from the Department of Petroleum Resources (DPR), Nigeria and consist of natural gamma ray (GR) log, spectral density log (SDL), compensated neutron log (CNL), caliper log, deep laterolog (LLD), and spontaneous potential log (SP) log. Qualitative and quantitative analyses were done with the aid of Interactive Petrophysics (IP v4.3) software. The qualitative aspects include, lithology interpretation, identification of fluid types, delineation of the different reservoirs, while the quantitative interpretation involves the evaluation of the various petrophysical parameters, such as shale volume, porosity, water and hydrocarbon saturation etc.

### Qualitative Interpretation

The first step in this study is to identify the possible reservoir zones of interest using the gamma ray log. The gamma ray log, which measures the natural radioactivity emanating from the formation, is used to identify sand and shale lithology traversed by the borehole. A low gamma ray reading indicates a sandy horizon while high gamma ray readings are typical shale indicators.

Next, the deep resistivity log in combination with the gamma ray log is used to identify the hydrocarbon bearing zones and the non-hydrocarbon (water) bearing zones within the reservoir interval. Hydrocarbons are poor electrical conductors; hence, a high resistivity reading will indicate the possible presence of hydrocarbon.

After delineation of the hydrocarbon zone(s), the formation density and neutron logs (RHOB and NPHI), were used to distinguish between the oil and gas bearing zones. In a gas zone, the density log deflects to the left of the neutron log as a result of the lower density of gases.

**Quantitative Interpretation**

This involves the evaluation of the different petrophysical parameters within the hydrocarbon zones with the aid of mathematical models. These parameters include, gross and net reservoir, net to gross ratio, volume of shale, porosity, formation water resistivity, water and hydrocarbon saturation, movable hydrocarbon index, etc.

**Gross and Net Reservoir**

The gross reservoir is the total reservoir interval and it includes the non-productive zones such as shale intercalations which occur amidst the reservoir sandstone units. The net pay or net reservoir are those portions of the reservoir which contain producible hydrocarbons in the pore spaces. The net pay are those reservoir zones with specific criteria or qualities. It is obtained by applying cutoffs to the gross reservoir. Cutoffs applied are always determined for petrophysical properties such as water saturation, volume of shale, porosity and permeability.

**Net to Gross Ratio (N/G)**

The "net-to-gross ratio" (N/G) is the total amount of pay footage divided by the total thickness of the reservoir interval or gross reservoir thickness. A net-to-gross ratio of 1.0 (100%) means the total reservoir is also the pay zone.

**Shale Volume Estimation (Vsh)**

The Niger delta petroleum system has been well documented as Tertiary in age, hence, the volume of shale was calculated using the Larinov's model for Tertiary clastics as shown below;

$$Vsh = 0.083^{2\times 3.7(IGR)} \ldots\ldots\ldots\ldots \text{(1)}$$

Where

$$IGR = \frac{GR_{log} - GR_{min}}{GR_{max} - GR_{min}} \ldots\ldots\ldots\ldots \text{(2)}$$

$V_{sh}$ = Volume of shale/clay

$GR_{log=}$ Gamma ray log reading

$GR_{min=}$ Minimum gamma ray log reading (sand base line)

$GR_{max=}$ Maximum gamma ray log reading (shale base line)

The sand and shale base lines are adjusted on the IP work interface.

**Porosity Determination**

For this analysis, porosity was calculated using the neutron-density model and the IP software estimates the rock porosity using a variety of logic. The density porosity is examined using the logic below:

$$\emptyset = \frac{(\rho_{ma} - \rho_b - V_{cl} \times (\rho_{ma} - \rho_{cl}))}{(\rho_{ma} - \rho_{fl} \times S_{xo} - \rho_{HyAp} \times (1 - S_{xo})} \ldots\ldots\ldots\ldots\ldots \text{(3)}$$

Where; $\rho_{ma}$ = Matrix density, can be a curve, parameter or calculated from the mineral volume (Multi-mineral options).

$\rho_b$ = Input bulk density log

$\rho_{cl}$ = Wet clay density

$\rho_{fl}$ = Filtrate density

$\rho_{HyAp}$ = Apparent hydrocarbon density

Vcl = Wet clay volume

Sxo = Flushed zone water saturation

The neutron porosity is evaluated using the following equation:

$$\emptyset = \frac{\emptyset_{\mathrm{neu}} - \mathrm{Vcl} \times \mathrm{NeuCL} + \mathrm{NeuMatrix} + \mathrm{Exfact\ 0} + \mathrm{NeuSal})}{(\mathrm{Sxo} + (1 - \mathrm{Sxo}) \times \mathrm{NeuHyHI})} \ldots\ldots\ldots..(4).$$

Where:$\emptyset_{\mathrm{neu}}$= Input neutron log

Vcl = Wet Clay (shale) volume

NeuCl = Neutron wet clay value

NeuMatrix = Neutron matrix correction

Exfact = Neutron excavation factor

NeuSal = Neutron formation salinity correction

Sxo = Flushed zone water saturation

NeuHyHI = Neutron hydrocarbon apparent hydrogen index

Using the equations (3) and (4) in the Density and Neutron Porosity models respectively, the cross-plot porosity is calculated as follows:

$$\emptyset = \emptyset_{DI} + \left[\frac{\emptyset_{N1} - \emptyset_{DI}}{1 - \left(\frac{\emptyset_{N1} - \emptyset_{N2}}{\emptyset_{D1} - \emptyset_{D2}}\right)}\right] \ldots\ldots (5)$$

Where, $\emptyset$ = Porosity
$\emptyset_{N1}$ = Neutron corrected porosity for matrix 1
$\emptyset_{N2}$ = Neutron corrected porosity for matrix 2
$\emptyset_{DI}$ = Density corrected porosity for matrix 1
$\emptyset_{D2}$ = Density corrected porosity for matrix 2

According to [11] and [12]; based on the range of porosity, reservoirs are qualitatively described as Negligible (0-5%), poor (5-10%), good (15-20%), very good (20-30%) and excellent when porosity values are greater than 30%.

**Calculation of Water Saturation($Sw$)**

In order to evaluate the water saturation($Sw$) of the uninvaded zone, the formation water resistivity at formation temperature is required. This was calculated using the porosity and resistivity logs within the clean water zone, using the equation below.

$$R_{wapp} = \frac{R_t}{FF} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (6)$$

$$FF = \frac{a}{\varphi^m} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (7)$$

Where; FF is the Archie's formation factor, $R_t$ and $\varphi$ are the resistivity deep and porosity values in the water zone respectively, a is the tortuosity factor, and m is the cementation usually 2 for sands, [5]. Within the water zone, $Sw$ is equal to 1, and water resistivity, $R_w$ at formation temperature is equivalent to $R_{wapp}$.
The water saturation within the hydrocarbon interval can then be evaluated using Archie's formula, given as;

$$S_w{}^n = \frac{FF \times R_w}{R_t} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (8)$$

Where; n is the saturation exponent and $R_{wapp}$ is the formation water resistivity in the hydrocarbon bearing zones, evaluated in the same manner as Rw at formation temperature, [13]. The IP software produces a water saturation log.

**Determination of Hydrocarbon Saturation**

Hydrocarbon saturation ($S_h$), is the volume of pore spaces within the reservoir interval filled with hydrocarbons. If the all the pores are filled with hydrocarbons or water, an estimation of the hydrocarbon volume can be obtained by subtracting the water saturation ($S_w$), from 100%. That is,

$$S_h = (100 - S_w)\% \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (9)$$

**Calculation of Permeability**

For each delineated reservoir zone, IP calculates permeability using the equation below;

$$\mathrm{K} = \mathrm{a} \times \frac{\mathrm{Phie^b}}{\mathrm{Swir^c}} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (10)$$

Where: K = Permeability
Phie = Effective Porosity
Swir = Swu = Irreducible water saturation
a, b and c are constants obtained from the Schlumberger Chart K3
'a' = 10000, 'b'=4.5, 'c'=2

**Estimation of Movable Hydrocarbon Index (MHI)**

The movable hydrocarbon index is the degree or volume of hydrocarbons flushed away by the invading drilling mud in the invaded zone. This is evaluated using

$$MHI = \frac{S_w}{S_{xo}} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (11)$$

Where, $S_w$ is the water saturation of the uninvaded zone, and
$S_{xo}$ Is the water saturation of the flushed zone.
and $S_{xo}{}^n = \frac{F \times R_{mf}}{R_{xo}} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (12)$

Where, F is formation factor, Rxo is the filtrate saturation in the flushed zone, and Rmf is the filtrate resistivity. Estimation of the water saturation of the flushed zone is also beneficial in that it aids in determination of the residual oil (hydrocarbon) saturation.

**Residual Hydrocarbon Saturation**

Residual Hydrocarbon saturation is achieved after the displacing fluid has flowed through a particular portion of the reservoir [14]. This quantity can be evaluated using the following equations:

$$S_{hr} = 1.0 - S_{xo} \dots\dots\dots\dots\dots\dots\dots\dots\dots\dots (13)$$

Where Shr = residual hydrocarbon saturation and
Sxo = water saturation of the flushed zone.
Moveable hydrocarbon Saturation (Smo)
This can be evaluated using the equation below;

$$S_{mo} = S_h - S_{hr} \dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots (14)$$

Where, Shr is the residual hydrocarbon saturation in the invaded zone and Sh is the uninvaded zone hydrocarbon saturation.

**Recovery Factor (RF):**

This parameter is predominantly obtained from engineering calculations during core analysis. Using log analysis the RF can be obtained using the equation below [15];

$$RF = \frac{S_{hr}}{S_h} \dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots (15)$$

The hydrocarbon potentiality of the delineated reservoirs within the different wells was evaluated by quantitatively analyzing the different petrophysical properties using equations (1) to (15) above.

## III. Results and Discussion

**Qualitative Interpretation**

The qualitative interpretation, which is a visual process, yielded a general knowledge of the possible litho-stratigraphy of the study area, which aided the delineation and correlation of the sand and shale units across X-field. The correlated units have varying gross rock thicknesses, and occur at different depths across the field, possibly as a result of the synsedimentary faults which are common within the delta. It is observed that there is a general decrease in thickness and occurrence of the sandstone units with depth, while the shale units show a trend of increase in thickness and occurrence. This pattern confirms with lithological variation as a result of different sedimentological episodes within the Agbada formation, from sandstones units at the top to shaly sandstones at the base, as it grades into the underlying Akata shale source rocks. Interpretation of the gamma ray (GR) and resistivity (LLD,) logs reveal four hydrocarbon bearing zones (reservoirs) marked A, B, C and D. These reservoirs were delineated and correlated between the two wells (Figure 2) used for this study.

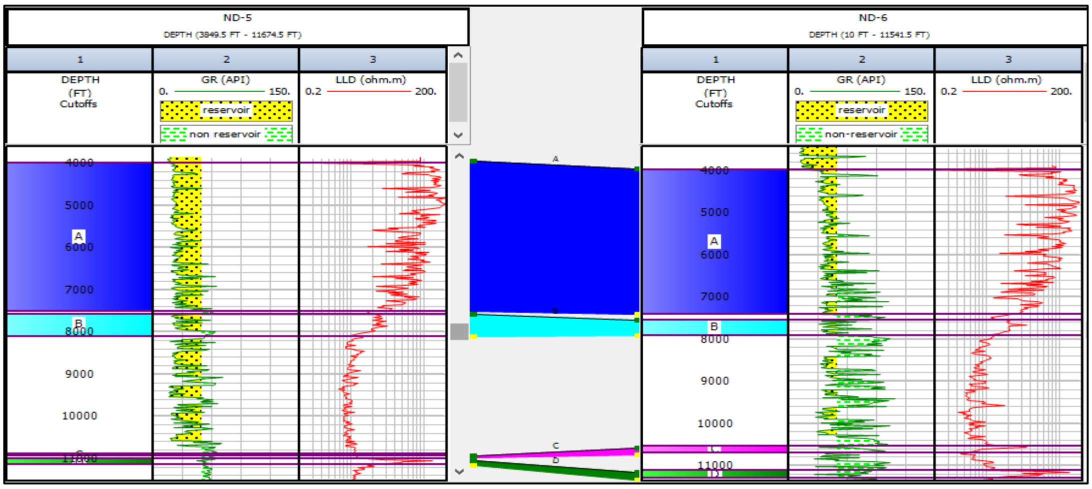


**Figure 2:** Correlated reservoirs across wells ND-5 and Well ND-6

**Quantitative Interpretation**

Analysis of the log suites in both wells (ND-5 and ND-6) yielded the digitized results shown in Figure 3, with log signatures of effective porosity, permeability, shale volume, and water saturation. It can be observed that there is a general increase in shale volume ( track 4) and water saturation (track 8) with depth, with a corresponding decrease in effective porosity (track7), hydrocarbon saturation (track 8), and permeability (track 9).

This trend of shale content with depth is in accordance with the stratigraphy of the Agbada formation, with well sorted sandstones overlying shaly sandstone beds at the base. There exists a transition zone at the base of this formation characterized by a vertical facies change from the overlying Agbada sandstones to the underlying Akata shales. Shales are characterized by bound water within their pore spaces, hence the general increase in water saturation with depth as seen from the logs. The fine and equidimensional grain sizes of shales enhances lithification and compaction resulting to smaller pore spaces within shale units and hence low porosity and permeability. The results obtained from the IP analysis are grouped into reservoir and pay (hydrocarbon potential) results.

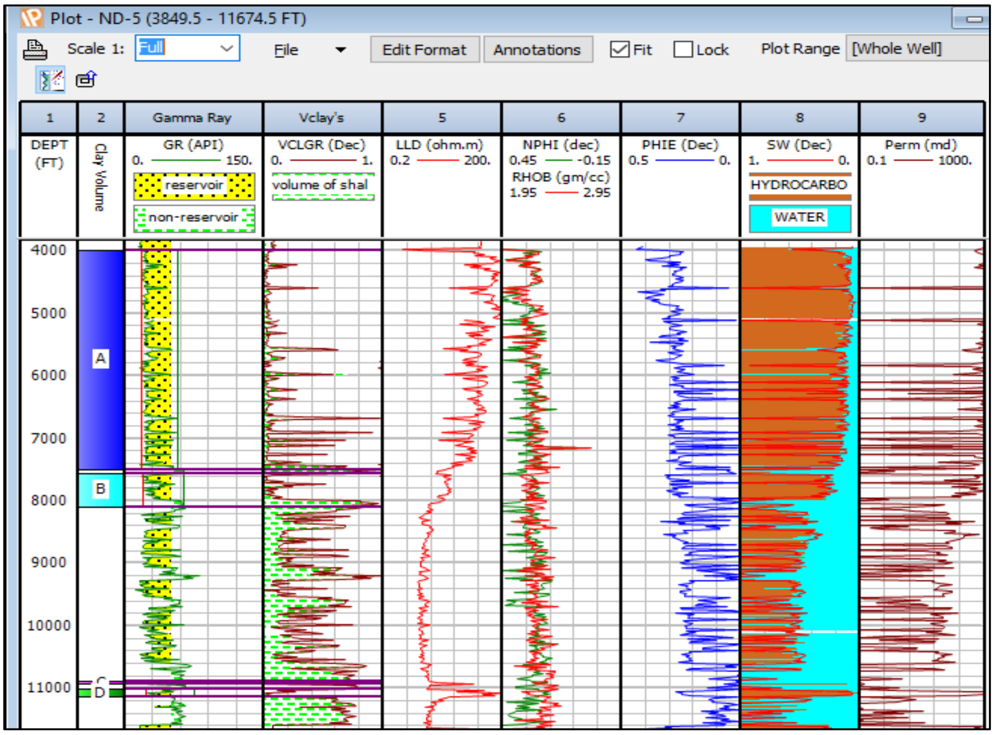


**Figure 3:** Log signatures of Vsh, porosity, permeability, water and hydrocarbon saturation of well ND-5

**Reservoir Results:**

The reservoir results (Tables 1 and 3) show the statistical values of the different parameters, which together, qualify a delineated interval as a potential hydrocarbon reservoir. The reservoir results determine the reservoir flags as shown in Figure 4. This does not take into account the minimum criteria of the different petrophysical properties necessary for hydrocarbons to be produced from each delineated reservoirs.

**Table 1:** Reservoir Results of Well ND-5

| PARAMETERS | RESERVOIRS | | | |
|---|---|---|---|---|
| | A | B | C | D |
| Top | 3995.53 | 7570.91 | 10893.74 | 11006.43 |
| Bottom | 7500.56 | 8104.02 | 10935.58 | 11132.12 |
| Gross Reservoir | 3505.03 | 533.11 | 41.84 | 125.69 |
| Net Reservoir | 3251.90 | 384.16 | 19.84 | 109.02 |
| Net/Gross | 0.928 | 0.721 | 0.474 | 0.867 |
| Av Sw | 0.124 | 0.283 | 0.247 | 0.123 |
| Av Swir | 0.129 | 0.293 | 0.285 | 0.148 |
| AV BVW | 0.034 | 0.076 | 0.054 | 0.028 |
| Av Phi | 0.277 | 0.268 | 0.218 | 0.231 |
| Av Vcl(Vsh) | 0.057 | 0.107 | 0.193 | 0.143 |
| Av Perm | 872.713 | 459.806 | 466.654 | 687.015 |

**Pay Results**

The pay results (Tables 2 and 4) indicate the hydrocarbon potential of the different reservoirs encountered by the wellbore. The pay results are from smaller portions of the reservoir zones that meet further criteria for pay, known as cutoffs. The cutoffs determine the pay flags for each reservoir zone as shown in Figure 4. Cutoffs help to eliminate poor quality or unproductive zones within each reservoir interval, and are applied to shale volume, porosity, water saturation and permeability (Figure 5).

**Table 2**: Pay results (hydrocarbon potential) of well ND-5

| PARAMETERS | RESERVOIRS | | | |
|---|---|---|---|---|
| | A | B | C | D |
| Gross Reservoir | 3505.03 | 533.11 | 41.84 | 125.69 |
| Net Reservoir | 3245.65 | 366.91 | 16.84 | 104.44 |
| Net/Gross | 0.926 | 0.688 | 0.402 | 0.831 |
| Av BVW | 0.034 | 0.071 | 0.042 | 0.023 |
| Av Swir | 0.128 | 0.278 | 0.221 | 0.129 |
| Av Sxo | 0.537 | 0.552 | 0.255 | 0.168 |
| Av Sw | 0.123 | 0.273 | 0.204 | 0.109 |
| Av Sh | 0.877 | 0.727 | 0.796 | 0.891 |
| Av Phi | 0.278 | 0.273 | 0.230 | 0.221 |
| Av Vcl | 0.056 | 0.090 | 0.152 | 0.129 |
| Av Perm | 872.120 | 478.720 | 541.950 | 714.786 |
| MHI | 0.229 | 0.429 | 0.8 | 0.649 |

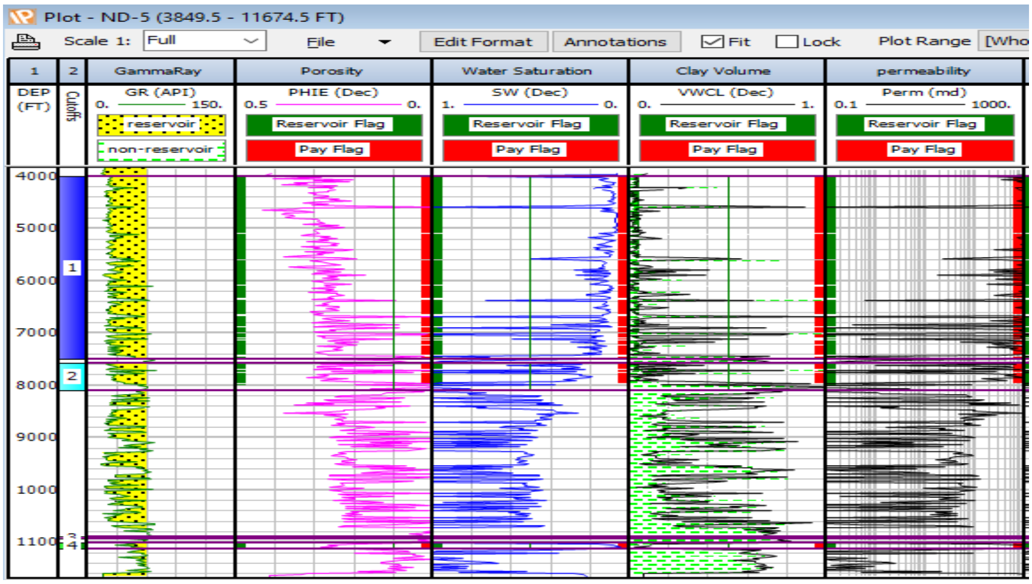


**Figure 4:** Reservoir and Pay Flags of the different reservoirs in well ND-5.

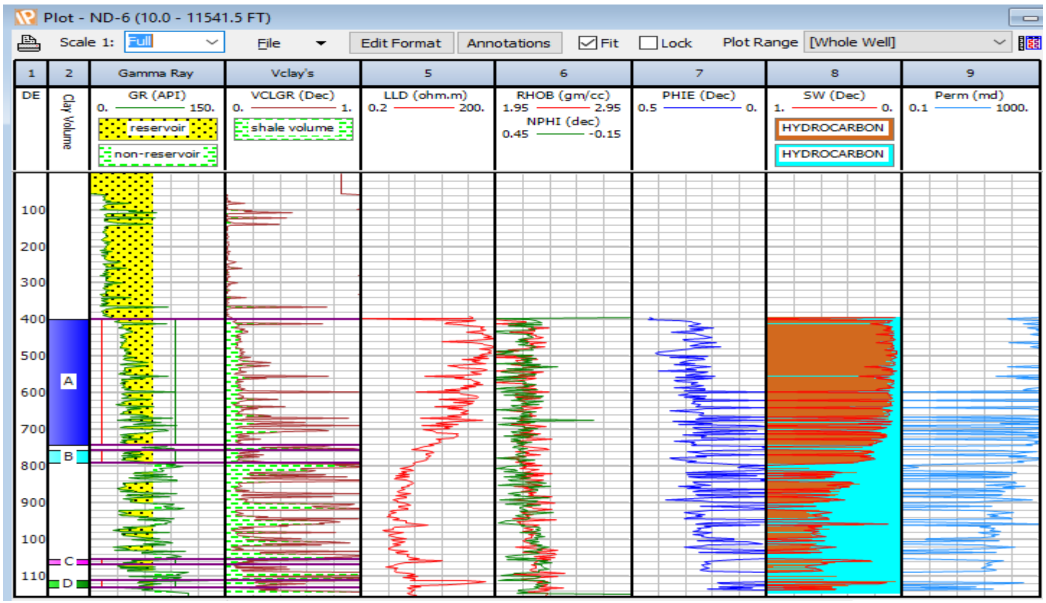


**Figure 5:** log signatures of Vsh, porosity, permeability, water and hydrocarbon saturation for well ND-6

**Table 3:** Reservoir Results of Well ND-6

| PARAMETERS | RESERVOIRS | | | |
|---|---|---|---|---|
| | A | B | C | D |
| Top | 3991 | 7551 | 10541.5 | 11103 |
| Bottom | 7419.5 | 7918 | 10694 | 11305 |
| Gross Reservoir | 3428.50 | 367.00 | 152.50 | 202.00 |
| Net Reservoir | 3095.25 | 332.50 | 89.25 | 74.50 |
| Net/Gross | 0.903 | 0.906 | 0.585 | 0.369 |
| Av Sw | 0.105 | 0.264 | 0.500 | 0.235 |
| Av Swir | 0.111 | 0.273 | 0.509 | 0.251 |
| AV BVW | 0.029 | 0.072 | 0.103 | 0.043 |
| Av Phi | 0.276 | 0.273 | 0.207 | 0.182 |
| Av Vcl(Vsh) | 0.126 | 0.163 | 0.134 | 0.184 |
| Av Perm | 898.236 | 501.829 | 107.380 | 450.415 |

**Table 4:** Pay Results (hydrocarbon potential) of well ND-6

| PARAMETERS | RESERVOIRS | | | |
|---|---|---|---|---|
| | A | B | C | D |
| Gross Reservoir | 3428.50 | 367.00 | 152.50 | 202.00 |
| Net Reservoir | 3083.00 | 327.50 | 31.50 | 60.50 |
| Net/Gross | 0.899 | 0.892 | 0.207 | 0.300 |
| Av BVW | 0.028 | 0.072 | 0.054 | 0.032 |
| Av Swir | 0.108 | 0.264 | 0.274 | 0.167 |
| Av Sxo | 0.272 | 0.338 | 0.290 | 0.196 |
| Av Sw | 0.103 | 0.262 | 0.269 | 0.168 |
| Av Sh | 0.897 | 0.738 | 0.731 | 0.832 |
| Av Phi | 0.277 | 0.275 | 0.201 | 0.180 |
| Av Vcl | 0.125 | 0.158 | 0.159 | 0.162 |
| Av Perm | 901.554 | 509.435 | 251.342 | 552.790 |
| MHI | 0.379 | 0.775 | 0.279 | 0.587 |

The major petrophysical parameters (from the pay results of well ND-5 and well ND-6) which indicate the hydrocarbon potential of the X-field were subjected to statistical analysis by considering their values across all the delineated reservoir zones. The results are shown in Table 5, and expressed as averages of gross reservoir thickness, net reservoir thickness, and percentages of net to gross (N/G) ratio, water saturation, hydrocarbon saturation, porosity and permeability.

**Table 5:** Summary of petrophysical results of reservoirs across wells ND-5 and ND-6

| PARAMETERS | RESERVOIRS | | | |
|---|---|---|---|---|
| | A | B | C | D |
| Av. Gross Reservoir thickness(ft) | 3466.765 | 450.055 | 97.17 | 163.845 |
| Av.Net Reservoir thickness(ft) | 3164.325 | 347.205 | 24.17 | 82.47 |
| Av. N/G (%) | 91.3 | 79 | 30.5 | 56.6 |
| Av. BVW | 0.031 | 0.0715 | 0.048 | 0.0275 |
| Av. Swir | 0.118 | 0.271 | 0.2475 | 0.148 |
| Av. Sxo | 0.4045 | 0.445 | 0.2725 | 0.182 |
| Av. Sw (%) | 11.3 | 26.6 | 23.7 | 13.9 |
| Av. Sh (%) | 88.7 | 73.4 | 76.3 | 86.1 |
| Av Vcl (%) | 9.1 | 12.4 | 15.6 | 14.6 |
| Shr | 0.5955 | 0.555 | 0.7275 | 0.818 |
| Smo | 0.2915 | 0.1775 | 0.036 | 0.0435 |
| Av. Phi (%) | 27.8 | 27.4 | 21.6 | 20.1 |
| Av. Perm(md) | 886.837 | 494.0775 | 396.646 | 633.788 |
| Recovery factor(RF) | 67.1 | 75.8 | 95.3 | 95.0 |

## IV. Discussion

From the petrophysical results (Table 5) of the different reservoirs delineated and correlated across the wells, it can be observed that:

Reservoir A is the giant reservoir of the field and found at the top of the Abgaba formation. It is characterized by thin intercalations of shales with an average shale content of 9.1%. The shale intercalations act as small scale seals which compartmentalizes reservoir A into different targets. Based on the neutron and density logs, there exist a primary gas target at the top of the reservoir, with secondary gas targets (as gas caps), within the different compartments. Figure 6, shows two smaller compartments within the reservoir gas. From the lithological interpretation with GR log (track 3), it is evident there are intercalations of shales with corresponding high shale volumes (track 4). These are the small scale seals that compartmentalizes reservoir A with corresponding water saturation (track 8). With the aid of neutron and density logs, where there is a cross-over of the between the logs because of the low density of gases (track 6), gas caps are identified (shown in blue). From the porosity and permeability logs (tracks 8 and 9), it is observed that the seals have zero effective porosity and permeability less than 0.1md, making them good sealing materials. The compartmentalization of reservoirs within the Niger Delta is mostly as a result of the growth faults which are very common within this sedimentary basin , resulting to a great deal of structural traps.

Wells ND-5 and ND-6 penetrated reservoir A at depths of 3995.53Ft and 3991Ft respectively. It has a gross reservoir, net reservoir and net to gross ratio of 3466.8ft, 3164.3ft, and 91.3% respectively. Its average effective porosity, water saturation, hydrocarbon saturation and permeability are 27.8%, 11.3%, 88.7% and 886.8md respectively. The porosity and permeability of this reservoir indicates an excellent reservoir quality with optimum reservoir productivity. It has a moveable hydrocarbon saturation of 29% and a recovery factor of 67.9%, which indicates that a good proportion of the hydrocarbons in place can be produced by natural drive mechanisms.

Reservoir B is the second largest reservoir of the field and occurs beneath reservoir A. it is located at depths of 7570.9ft(well ND-5) and 7551ft (well ND-6), with gross reservoir, net reservoir and net to gross ratio of 450ft, 347.2ft and 79% respectively, indicating that a good proportion of reservoir B is hydrocarbon saturated. It reservoir quality can be described as very good, with an effective porosity of 27.8%. A recovery factor of 75.5% and permeability of 494md, also makes it possible for optimum productivity within the hydrocarbon zone.

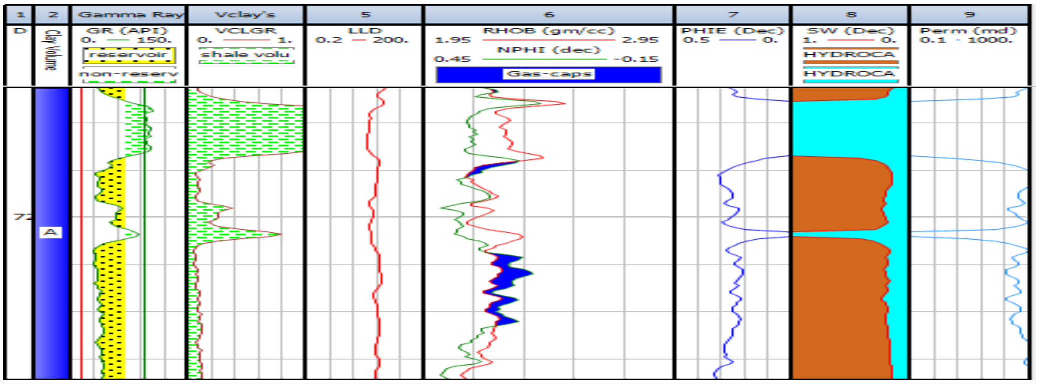


**Figure 6: Compartmentalization within reservoir A showing the two compartments with gas caps in blue.**

Reservoir C and D are comparatively smaller to A and B, and they occur almost at the base of the Agbada formation. Located almost at the transition zone between the Agbada sandstones underlying Akata shales, they are characterized by a higher shale content of 15.6% and 14.6% respectively. These reservoirs are also characterized by a high degree of compartmentalization, due to the growth faults in the basin. From the neutron and density logs, the main hydrocarbon fluid filling the pores in these reservoirs are gases. Wells ND-5 and ND-6 encountered reservoir C at depths of 10893.74ft and 10541.5ft respectively, while reservoir D is located at 11006.4ft and 11103ft respectively. Despite the higher shale content, reservoirs C and D are of very good quality with porosity, hydrocarbon saturation, permeability, and recovery factors of 21.6% and 20.1%, 76.3% and 86.1%, 396.6md and 633.8md, and 95.3% and 95.0% respectively. The effective porosity and permeability values indicate the hydrocarbons within the reservoirs can easily flow, while the permeability and recovery factors confirms almost all the hydrocarbons in place can be produced.

The high porosity and permeability values across the reservoirs in this field, suggest the sandstone units are well sorted, which is well known quality of sandstones deposited in deltaic environments. The movability of hydrocarbons in all the reservoirs encountered by both wells for this study was evaluated and considered satisfactory for hydrocarbon production since the moveable hydrocarbon index (MHI) was less than 0.7. This is in accordance with [16] which stipulates that (MHI) of less than 0.7 for sandstones, indicates movable hydrocarbons.

## V. Conclusion and Recommendation

**Conclusion:**

This study was carried out to ascertain the hydrocarbon potential of X-field using well data (log suites). From the qualitative interpretation of logs from the two wells, ND-5 and ND-6, it is evident the study area has thick sequence of sand units which can host enormous volumes of hydrocarbon. The deep laterolog (LLD) confirms the occurrence of hydrocarbons within the sand units. Quantitative analysis of the logs yielded various petrophysical properties within the delineated reservoirs such as, gross and net reservoir thickness, the volume of shale, effective porosity, permeability, hydrocarbon saturation, residual hydrocarbon saturation, moveable hydrocarbon index, moveable hydrocarbon saturation, and recovery factor.

The results show a cumulative net pay of 3618.2ft, having porosity ranging from 20.1% to 27.8%, permeability values from 396.6md to 886.8md, probably as result of the well sorted grains within the sand units. the estimated porosity and permeability suggest very good quality reservoirs. The hydrocarbon saturation within the reservoirs ranges from 73.4% to 88.7% with a recovery factor 67.1% to 95.3% implying most of the pores within the reservoirs are filled with hydrocarbons and a greater proportion of the hydrocarbons can actually be produced.

**Recommendation**

The evaluation of the hydrocarbon potentiality of the study area is based solely on log analysis. Further calibration of the estimated parameters should be carried out using different techniques such are core analysis. Also, well logs (well data) and seismic data should be integrated in order to better evaluate the hydrocarbon potential of the study well. Reservoir models should be used to evaluate the hydrocarbon volumes (STOIP and OGIP) in the different reservoirs so as to determine the economic potential of X-field.

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