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# Petrophysical Evaluation and Reserve Estimate of the Reservoir Sands in 'George' Field, Offshore Niger Delta, Nigeria

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***Author's contribution***

*The sole author designed, analyzed, interpreted and prepared the manuscript.*

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## ABSTRACT

Petrophysical Evaluation of 'George' Field Offshore Niger Delta, Nigeria was carried out with a view to determining the hydrocarbon potential of the area. The data set used for the study includes a suite of geophysical well logs from four wells A, B, C and D. Lithologies were identified from the gamma ray log, resistivity and the gamma ray logs were used for delineation and correlation of reservoirs across the wells. Petrophysical parameters were determined for five mapped reservoirs across the wells. Five reservoirs AB_1, AB_2, AB_3, AB_4 and AB_5 were delineated from the well logs. The petrophysical analysis from reservoir AB_1, are: the thickness values ranging from 27-75 m, volume of shale ($V_{sh}$) 0.0041-0.15, porosity (φ) 26- 39%, permeability (k) 50- 250md, water saturation ($S_w$) 5.1- 64% and hydrocarbon saturation ($S_h$) 36- 95% . Reservoir AB_2 has a range of thickness from 28-61 m, volume of shale ($V_{sh}$) 0.038-0.14, porosity (φ) 21- 36%, permeability (k) 79- 184 md, water saturation ($S_w$) 7.58- 39% and hydrocarbon saturation ($S_h$) 61-92%. Reservoir AB_3, has a range of volume of shale ($V_{sh}$) from 0.069-0.3, porosity (φ) 22- 35%, permeability (k) 59- 175 md, water saturation ($S_w$) 41- 60% and hydrocarbon saturation ($S_h$) 40-59% and the thickness varied from 19-52 m. Reservoir AB_4, mapped in the four wells has range of volume of shale ($V_{sh}$) 0.065-0.11, porosity (φ) 27- 32%, permeability (k) 59- 131md, water saturation ($S_w$) 13- 85% and hydrocarbon saturation ($S_h$) 15- 87% and the thickness varied from 17-28 m. Reservoir AB_5, has a range of volume of shale ($V_{sh}$) from 0.017-0.97, porosity (φ) 25-

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36%, permeability (k) 103- 178 md, water saturation ($S_w$) 11-54% and hydrocarbon saturation ($S_h$) 46- 89% and the thickness varied from 29-69 m. The results of the hydrocarbon pore volume estimation in barrels shows that the five reservoirs mapped within the George field has revealed the presence of hydrocarbon in amount that is favourable for commercial exploitation.

*Keywords: Petrophysical; lithologies; reservoirs; volume of shale; porosity; permeability.*

## 1. INTRODUCTION

Hydrocarbon exploration and exploitation requires that the spatial and depth distribution and interplay of factors favorable to hydrocarbon accumulation in large quantity are thoroughly appreciated. These factors include the source rock, reservoir rock, and migration pathways, the fidelity of sealing mechanisms, and timing, relationship between formation and the expulsion of hydrocarbons from the source rock. The distributions of these elements of the petroleum system are a result of the tectonic history and fill processes within a basin [1]. There are many risks associated with the exploitation of hydrocarbons, particularly the identification of potential drilling location. To reduce these risks, it is important to describe a reservoir in terms of its lithology and pore fluid contents [2,3]. Continued success in the search for oil and gas reserves therefore depends upon thorough understanding of the subsurface geology of exploration fields, the ability to accurately predict and delineate the spatial and depth distribution of subsurface geologic facies (source rock, reservoir rock and seal) and the ability to discriminate the fluids saturating the reservoirs (oil, gas or brine) and possibly quantifying such [4,1]. Well logs data are widely used in hydrocarbon exploration for subsurface mapping to produce a vertical resolution of the geology at the well bore [5]. Therefore, the study is aimed at evaluating the petrophysical parameters of 'George' Field, Niger Delta, in other to determine the hydrocarbon potential of the study area.

### 1.1 Location and Geology of the Study Area

The study area is situated on latitude $3^0$ and $6^0$N and longitudes $5^0$ and $8^0$E, Niger Delta Nigeria (Fig. 1). The' George' field falls within the parasequence of set of Agbada Formation and the structure consists of a simple rollover anticline that is bounded to the north by a major growth fault. The crest is flat/ elongated and runs parallel to the bounding fault. The stratigraphic sequence in the field consists of marine shales of Akata Formation which is about 6100 m thick, the Agbada Formation which is 4500 m thick and it is overlain by the Benin Formation which is about 1820 m thick [6] (Ofoegbu, 1985). Deep offshore of Niger Delta of Nigeria is situated over oceanic crust emplaced during Cretaceous Paleogene first related spreading of the South Atlantics. Initial sedimentation began within Upper Cretaceous – Lower Oligocene hemipelagic mudstones of the Akata Formation, late Oligocene through recent progradation for the Niger Delta into the slope rise environment allowed for turbidite deposition of the more coarse grained siliclastics of the Agbada Formation. The latter contain the lower and middle Miocene reservoir- seal couplets responsible for the major deepwater hydrocarbon accumulations discovered to date. The underlying Akata Formation is believed to contain the main source intervals. Tertiary extension on the Niger Delta shelf was the driving process for gravity driven structures of the deepwater. The Tertiary sequence consists of alternations of clastic lithologies that occur in stacked sections of (regressive) offlap cycles. These lithologies comprise sandstones, silts and shales of much similarity, whatever their age or situation in the sequence. Thus, in a vertical sense, the sequence can be subdivided into three lithofacies in ascending order of Akata, Agbada and Benin Formations (Fig. 2). The overall regressive clastic sequence reaches a maximum thickness of 30,000-40,000 ft (9,000-12,000 m) at the approximate depocenter in the central part of the delta [7,8].

## 2. MATERIALS AND METHODS OF STUDY

The data set used for the study includes a suite of geophysical well logs from four wells A, B, C and D. The available logs include gamma ray, resistivity, sonic and density logs. Sand and shale bodies were delineated from the gamma ray log signatures using GR < 70 API units for sands and GR > 70 API units for shale. Sand bodies were identified by deflection to the left due to the low concentration of radioactive minerals in sand while deflection to the right signifies shale which is as a result of high concentration of radioactive minerals in it. Five reservoirs AB_1, AB_2, AB_3, AB_4 and AB_5 were identified by using the log signatures of both gamma ray and deep resistivity logs. Intervals that have high resistivity are considered to be hydrocarbons while low resistivity zones are water bearing intervals. The logs were used to evaluate the lithologic units penetrated by the wells, identify reservoirs and also to compute the physical properties of the rock units, such as volume of shale, porosity, water saturation, permeability, hydrocarbon saturation and hydrocarbon pore volume estimates.

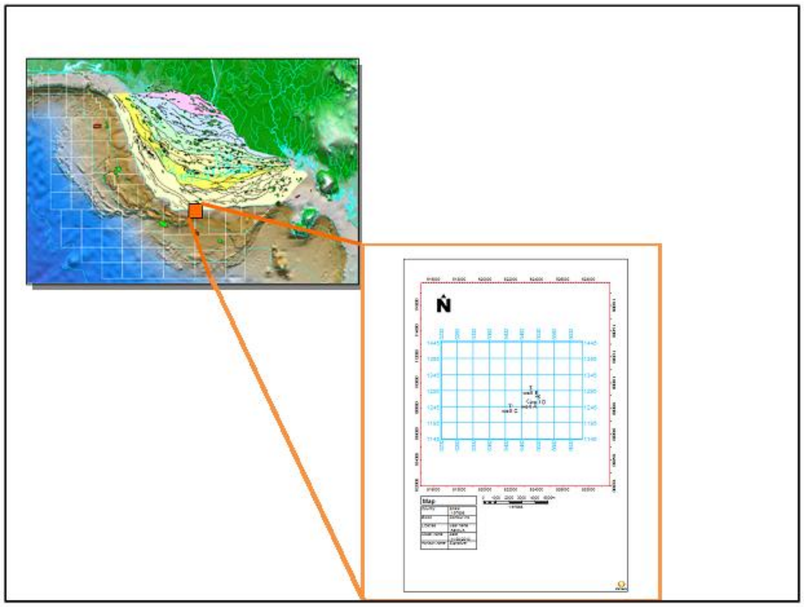

**Fig. 1. Map of the Niger delta showing the base map of the study area and the well locations**

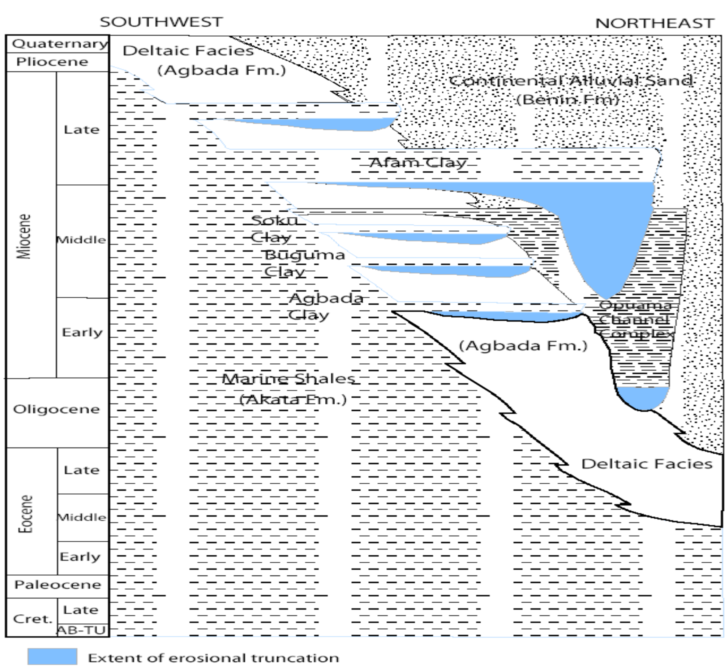


**Fig. 2. Stratigraphjc Column Showing the Three Formations of the Niger Delta; [9,10]**

(i) Volume of shale ($V_{sh}$) was calculated using the Dresser Atlas formula [11]:

$V_{sh} = 0.083\ (2^{3.7xI_{GR}} - 1.0)$ (Tertiary consolidated sand) (1)

Where $I_{GR}$ = Gamma ray index

(ii) The formation porosity was determined by substituting the bulk density readings obtained from the density log within each reservoir into equation 2:

$$\emptyset_{den} = \frac{\rho_{ma}-\rho_b}{\rho_{ma}-\rho_{fl}} \quad (2)$$

Where: $\rho_{ma}$ is the matrix density = 2.65gm/cm$^3$ (sandstone)

$\rho_b$ is the formation bulk density

$\rho_{fl}$ is the fluid density = 1.1gm/cm$^3$

(iii) Determination of the water saturation ($S_w$) for the uninvaded zone was achieved using the Archie's [12] equation:

$$S_w^2 = \frac{F * R_w}{R_t} \quad (3)$$

$$\text{But,} \quad F = \frac{R_o}{R_w} \quad (4)$$

$$\text{Thus,} \quad S_w^2 = \frac{R_0}{R_t} \quad (5)$$

Where,

$S_w$ = water saturation of the uninvaded zone
$R_0$ = resistivity of formation at 100% water saturation
$R_t$ = true formation resistivity
(iv) The permeability of each reservoir was calculated using:

$$K = \frac{250 x \emptyset^3}{S_{wirr}} \quad \text{(Tixier, 1949)} \quad (6)$$

Where,

K = Permeability
$\Phi$ = Porosity
$S_{wirr}$ = Irreducible water saturation.
(v) The hydrocarbon saturation was obtained using:

$$S_h = (100-S_w)\ \% \quad (7)$$

Where, $S_h$ = Hydrocarbon saturation
$S_w$ = Water saturation

(vi) The hydrocarbon pore volume (HCPV) is the fraction of the reservoir volume occupied by hydrocarbon. This was calculated as the product of density porosity and hydrocarbon saturation and the volume using:

$$HCPV = \Phi_{DP} \times (1- S_w) \times V \quad (8)$$

Where, $\Phi_{DP}$ is the average porosity obtained from density log, the volume (V) is the product of the area of the closure obtained from depth structure map and the reservoir thickness.

## 3. RESULTS AND DISCUSSION

The available suites of logs for this analysis covered a depth range between 0 – 3000 m. The correlation panel is composed of wells C, A, D and B (Figs 3 and 4) indicates that the stratigraphic column appears to be dipping in N-S direction and striking in the NW-SE direction. Deposition tends to be thicker in wells C and D which were located down dip. The occurrence of the identified chronostratigraphic surfaces at different depths along dip and strikes lines in the studied wells shows evidence of faulting in the field. Tables 1 to 5 depict the computed petrophysical parameters of the studied wells. Hydrocarbon bearing reservoirs was delineated on well logs with the aid of gamma ray and resistivity logs. The reservoir petrophysical parameters obtained from the five hydrocarbon bearing reservoirs: AB_1, AB_2, AB_3, AB_4 and AB_5 are shown in Tables 1 to 5. In reservoir AB_1, which cut across the four wells has range of thickness from 27-75 m, volume of shale ($V_{sh}$) 0.0041-0.149, porosity ($\varphi$) 26- 39%, permeability (k) 50- 250 md, water saturation ($S_w$) 6.9- 64% and hydrocarbon saturation ($S_h$) 36- 93% (Table 1). In reservoir AB_2, which cut across the four wells has range of thickness from 28-61 m, volume of shale ($V_{sh}$) 0.038-0.14, porosity ($\varphi$) 21- 36%, permeability (k) 79- 184 md, water saturation ($S_w$) 7.58- 39% and hydrocarbon saturation ($S_h$) 61- 92% (Table 2).

Reservoir AB_3, mapped in the four wells has range of volume of shale ($V_{sh}$) 0.069-0.3, porosity ($\varphi$) 22- 35%, permeability (k) 59- 175 md, water saturation ($S_w$) 41- 60% and hydrocarbon saturation ($S_h$) 40- 59% and the thickness varied from 19-52 m (Table 3). Reservoir AB_4 was mapped in the four wells has range of volume of shale ($V_{sh}$) 0.065-0.11, porosity ($\varphi$) 27- 32%, permeability (k) 59- 131 md, water saturation ($S_w$) 13- 85% and hydrocarbon saturation ($S_h$) 15- 87% and the thickness varied from 17-28 m (Table 4). Reservoir AB_5 were mapped in three wells A, C and D has range of volume of shale ($V_{sh}$) 0.017-0.97, porosity (φ) 25- 36%, permeability (k) 103- 178 md, water saturation ($S_w$) 11- 54% and hydrocarbon saturation ($S_h$) 46- 89% and the thickness varied from 29-69 m (Table 5). Tables 6 and 7 as proposed by Etu-Efeotor [13] and Adeoti *et. al.* [14] was used as guides for the classification of porosity and permeability respectively. Generally, the porosity values 21% - 36% in the four wells as shown in the tables 1 to 5 fall within the very good porosity (Table 6). These values indicate that the reservoir rocks in the wells have enough pores space to accommodate fluids. The permeability values (50 – 250 md) in the four wells as shown in tables 1 to 5 fall within high to very high permeability. Also, the values of water saturation in the four wells vary from 5% - 85% while the hydrocarbon saturation values ranges between 15% - 95%. This shows the percentage of hydrocarbon that occupies the pore spaces is more than the percentage of formation water, hence, the prospective accumulation of hydrocarbon in the reservoir rocks.

The results of the hydrocarbon pore volume (HCPV) estimation in barrels (Table 8) has shown that the five reservoirs mapped within the George field has reveal the presence of hydrocarbon in amount that is favourable for commercial exploitation. However, it was observed that the reservoirs AB_1 and AB_2 have the highest hydrocarbon accumulations in economic quantity in the study area. This has further shown that opportunities for hydrocarbon exploitation could be found within shallow levels in some parts of the Niger Delta according to Olowokere [15]. From the depth structure maps of reservoirs AB_3, AB_4 and AB_5, it could be observed that the anticlinal structure located at the center of the surfaces as two of the minor faults terminates on it which could have caused leakage and thereby reducing the integrity of the major hydrocarbon harbouring structure in the area. This may have been responsible for the relatively low hydrocarbon pore volume (HCPV) estimation for the three reservoirs.

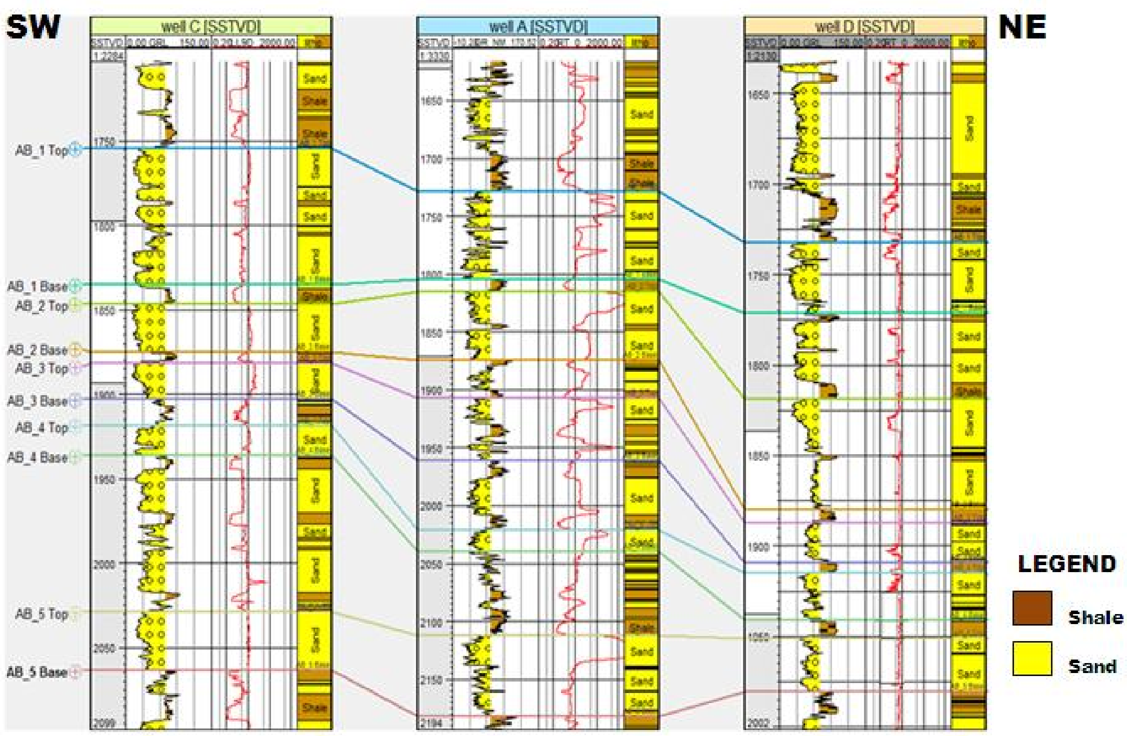


**Fig. 3. Well correlation panel across wells C, A and D**

**Table 1. Petrophysical parameters from reservoir AB_1**

| Well Name | Depth to Bottom (m) | Depth to Top (m) | Gross Thickness (m) | Net to Gross | Net Pay (m) | Porosity, φ (%) | Permeability, K (md) | Water Saturation, $S_w$ (%) | Hydrocarbon Saturation, $S_h$ (%) | Volume Of Shale, $V_{sh}$ |
|---|---|---|---|---|---|---|---|---|---|---|
| A | 1804.99 | 1729.76 | 75.23 | 0.85 | 15.90 | 26.00 | 50.00 | 6.90 | 93.00 | 0.149 |
| B | 1744.19 | 1704.84 | 39.35 | 1.00 | 30.36 | 36.00 | 250.00 | 33.00 | 67.00 | 0.063 |
| C | 1785.39 | 1758.28 | 27.11 | 0.91 | 17.95 | 31.00 | 102.00 | 64.00 | 36.00 | 0.0041 |
| D | 1771.47 | 1732.15 | 39.32 | 0.80 | 14.52 | 35.00 | 168.00 | 28.00 | 72.00 | 0.073 |

**Table 2. Petrophysical Parameters from Reservoir AB_2**

| Well Name | Depth to Bottom (m) | Depth to Top (m) | Gross Thickness (m) | Net to Gross | Net Pay (m) | Porosity, φ (%) | Permeability, K (md) | Water Saturation, $S_w$ (%) | Hydrocarbon Saturation, $S_h$ (%) | Volume Of Shale, $V_{sh}$ |
|---|---|---|---|---|---|---|---|---|---|---|
| A | 1874.92 | 1815.20 | 59.72 | 0.93 | 37.58 | 21.00 | 79.00 | 7.58 | 92.00 | 0.059 |
| B | 1862.20 | 1808.96 | 53.24 | 0.84 | 28.79 | 35.00 | 178.00 | 24.00 | 76.00 | 0.038 |
| C | 1875.28 | 1846.65 | 28.63 | 1.00 | 28.63 | 34.00 | 148.00 | 39.00 | 61.00 | 0.14 |
| D | 1880.07 | 1818.23 | 61.84 | 0.90 | 16.58 | 36.00 | 184.00 | 25.00 | 75.00 | 0.073 |

**Table 3. Petrophysical Parameters from Reservoir AB_3**

| Well Name | Depth to Bottom (m) | Depth to Top (m) | Gross Thickness (m) | Net to Gross | Net Pay (m) | Porosity, φ (%) | Permeability, K (md) | Water Saturation, $S_w$ (%) | Hydrocarbon Saturation, $S_h$ (%) | Volume Of Shale, $V_{sh}$ |
|---|---|---|---|---|---|---|---|---|---|---|
| A | 1960.30 | 1907.47 | 52.83 | 0.65 | 9.71 | 22.00 | 59.00 | 60.00 | 40.00 | 0.12 |
| B | 1924.06 | 1904.58 | 19.48 | 1.00 | 7.62 | 32.00 | 120.00 | 52.00 | 48.00 | 0.069 |
| C | 1908.22 | 1881.51 | 26.71 | 1.00 | 15.51 | 30.00 | 87.00 | 41.00 | 59.00 | 0.14 |
| D | 1909.47 | 1886.64 | 22.83 | 1.00 | 22.83 | 35.00 | 175.00 | 54.00 | 46.00 | 0.303 |

**Table 4. Petrophysical Parameters from Reservoir AB_4**

| Well Name | Depth to Bottom (m) | Depth to Top (m) | Gross Thickness (m) | Net to Gross | Net Pay (m) | Porosity, φ (%) | Permeability, K (md) | Water Saturation, $S_w$ (%) | Hydrocarbon Saturation, $S_h$ (%) | Volume Of Shale, $V_{sh}$ |
|---|---|---|---|---|---|---|---|---|---|---|
| A | 2040.10 | 2021.21 | 18.89 | 1.00 | 7.93 | 27.00 | 59.00 | 13.00 | 87.00 | 0.065 |
| B | 2010.00 | 1981.95 | 28.05 | 1.00 | 28.05 | 32.00 | 120.00 | 85.00 | 15.00 | 0.11 |
| C | 1936.54 | 1918.80 | 17.74 | 1.00 | 17.74 | 30.00 | 131.00 | 44.00 | 56.00 | 0.10 |
| D | 1940.63 | 1915.08 | 25.55 | 1.00 | 25.55 | 32.00 | 118.00 | 41.00 | 59.00 | 0.075 |

**Table 5. Petrophysical Parameters from Reservoir AB_5**

| Well Name | Depth to Bottom (m) | Depth to Top (m) | Gross Thickness (m) | Net to Gross | Net Pay (m) | Porosity, φ (%) | Permeability, K (md) | Water Saturation, $S_w$ (%) | Hydrocarbon Saturation, $S_h$ (%) | Volume Of Shale, $V_{sh}$ |
|---|---|---|---|---|---|---|---|---|---|---|
| A | 2181.76 | 2111.80 | 69.96 | 0.90 | 22.26 | 25.00 | 120.00 | 11.00 | 89.00 | 0.23 |
| B | - | - | - | - | - | - | - | - | - | - |
| C | 2063.80 | 2029.30 | 34.50 | 1.00 | 34.50 | 28.00 | 103.00 | 54.00 | 46.00 | 0.97 |
| D | 1980.05 | 1951.01 | 29.04 | 1.00 | 13.09 | 36.00 | 178.00 | 37.00 | 63.00 | 0.017 |

**Table 6. Qualitative Evaluation of Porosity [13,14]**

| Percentage Porosity (%) | Qualitative Interpretation |
|---|---|
| 0-5 | Negligible |
| 5-10 | Poor |
| 15-20 | Good |
| 20-25 | Very good |
| Over 30 | Excellent |

**Table 7. Qualitative Evaluation of Permeability [13,14]**

| Average Permeability Value (MD) | Qualitative Interpretation |
|---|---|
| <10.5 | Poor to fair |
| 15-50 | Moderate |
| 50-250 | Good |
| 250-1000 | Very good |
| >1000 | Excellent |

**Table 8. Hydrocarbon Pore Volume Estimates for the Reservoirs**

| RESERVOIRS | AB_1 | AB_2 | AB_3 | AB_4 | AB_5 |
|---|---|---|---|---|---|
| Hydrocarbon pore volume estimates (HCPV) (mmbls) | 398,520,862 | 351,385,848 | 29,961,289 | 71,393,696 | 120,371,397 |

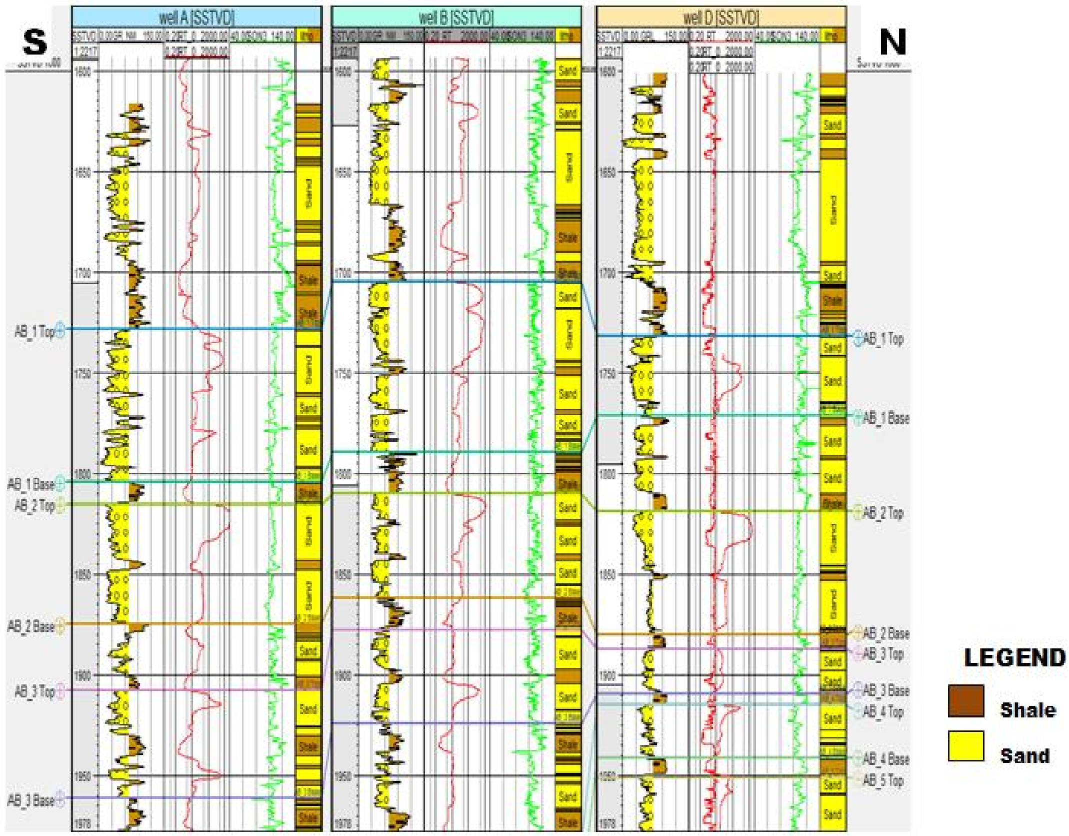


**Fig. 4. Well correlation panel across wells A, B and D**

## 4. CONCLUSION

The major Formation encountered within the study area is the Agbada Formation, (which is the intercalation of sand and shale units) within which the five identified reservoirs (AB_1, AB_2, AB_3, AB_4 and AB_5) were mapped. The potential reservoirs in the study area were mainly the channel sands and shoreface sands of lowstand systems tracts (LSTs) and highstand system tracts (HSTs) respectively which displayed low gamma ray and high resistivity values [16]. The well log correlation gave an insight into the general stratigraphy which is the alternation of sand and shale layers. The results from the petrophysical analysis of the four wells A, B, C and D show the hydrocarbon potential of study area. The range of values of these parameters include: volume of shale ($V_{sh}$) 0.0041- 0.97, porosity (φ) 21%- 36%, permeability (K) 50 – 250 md, water saturation ($S_w$) 24% - 52%, and hydrocarbon saturation ($S_h$) 48% - 76%. The hydrocarbon pore volume estimates in barrels has shown that the five reservoirs mapped within the study area have hydrocarbon in amount that is favourable for commercial exploitation. However, it was observed that the reservoirs AB_1 and AB_2 have the highest hydrocarbon accumulations in economic quantity in the study area. This results show that the rock matrix within the mapped reservoirs have enough pore spaces for hydrocarbon accumulation. According to Abiola et. al. [16] several thick shale units of the transgressive systems tracts (TST) were identified in the study area, are considered as potential source rocks for hydrocarbon found in the reservoirs. The shales of the TST in which the MFS were delineated could form seals to the reservoir units.

## COMPETING INTERESTS

Author has declared that no competing interests exist.

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