# Structural Interpretation of 3D Seismic Data in Agbami Field

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**Received: 25 October 2021/Accepted 21 December 2021/Published online:27 December 2021**

***Abstract:*** *The complexity of a subsurface structural configuration has a significant role in hydrocarbon migration and trapping mechanisms. This study was designed to ascertain the structural profile of part of the Agbami field as a core index of hydrocarbon play using well log and seismic volume data. From the well-seismic correlation, formation Sand A, with good producibility, recoverability indices which corresponded to a seismic continuity was mapped alongside its associated faults. The observed surface showed subsurface features including the structural geometry of the study area. Discontinuities trend W-E direction, with the majority dipping eastward. Two major faults were identified and corresponded to the growth fault of the study area, which forms a two-way closure as a hydrocarbon prospect in the study area. This study has created a workflow for pre-reservoir simulation studies for the Agbami field.*

**Keywords**: *Reservoir simulation, recoverability, seismic continuity*

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## 1.0 Introduction

Niger Delta Basin is one of the most productive oil-producing basins in the world. The basin is associated with complex structural features that require a clear understanding to maximize hydrocarbon exploitation (Ologe, 2013). Hence, understanding the detailed structural relationships between fault networks and stratigraphic stacking patterns of the area is required for good field development. The use of 3D seismic data to interpret oil-producing fields is a significant tool in the assessment of field development (Oluwatoyin *et al*, 2013). Agbami field is the second major deep-water oil field discovered off the Niger Delta.

The area of study is the Agbami field and it is part of the Niger Delta basin. The field is located about 1500m off the central Niger Delta. The location map of the area is shown in Fig. 1. The study area is one of the major of oil producing fields in Niger Delta with structural related problems in relation to hydrocarbon reservoirs. The focus of this research is directed towards mapping the structural traps available and evaluating the retentive capacity of these reservoirs using Seismic and well logs data. Most of the hydrocarbon traps in the study area are structurally related (Omatsola and Doust, 1990) even though it is often characterized by stratigraphic and combined structural and stratigraphic traps (Oluwatoyin, 2013).

The Niger Delta basin is divided into three major formations (Akata, Agbada and the Benin formations), which demonstrate a prograding depositional facies based on the sand-shale ratio index (Tuttle *et al*., 1999).

The Akata formation is of marine origin and comprises the thick shale sequences (potential source rock), turbidite sandstones (potential reservoirs in deep water), and infinitesimal amounts of silt. Whiteman (1982) suggested that the formation may be about 6,500m (21,400ft) thick, while Doust and Omatsola (1990) suggested that the thickness ranges from 2000m (6600ft) at the most distal part of the delta to 7000m (23,000ft) beneath the continental shelf.

The Agbada Formation is overlain the Akata formation, and it is a sequential alternation of sandstones and shales whose sandstone reservoirs account for oil and gas production in the delta (Nwachukwu and Odjegba, 2001). The Agbada Formation is characterized by paralic interbedded sandstone and shale, with over 3700 m thickness. The formation represents the actual deltaic portion of the sequence (Reijers 1996).

The Benin formation overlies the Agbada formation and it comprises the top part of the Niger Delta basin (Short and Stauble 1967). Shallow parts of the formation are composed entirely of non-marine sand deposited in upper coastal plain environments during the progradation of the delta (Doust and Omatsola, 1989).

Oluwatoyin ans Olatunji (2023) investigated some wells in southeastern onshore part, in eastern onshore part and the central part of the Niger Delta basin respectively, and noted that the petrophysical properties of the reservoir sands of the Niger Delta are high enough to permit hydrocarbon production. Keelan (1982) discussed the variety of measurement protocols, characterized certain rock properties such as porosity, permeability, grain density, and capillary pressure, and showed how these properties varied with the geological factors such as the environment of deposition. Log motifs were used to describe the paleo environment of deposition for hydrocarbon bearing sands in areas (Rider, 2002). He noted that the shape of gamma-ray and spontaneous potential signatures are reliable indicators of prevailing lithologies. This study will also focus on a working model for oil exploitation in the Agbami field.

The cost of petroleum exploration is currently high and therefore requires a cost-effective and precise technicality in the interpretation of subsurface structures from field data. Such interpretation provides a guide for the drilling process. Therefore, the application of effective indices before and during exploration is a significant requirement. The present study is concerned with the interpretation and correlation of seismic data toward effective hydrocarbon play. Arrays of seismic profiles shall be employed to establish unified geologic information for good hydrocarbon exploration and exploitation (Olatunji and Olatunji, 2013)

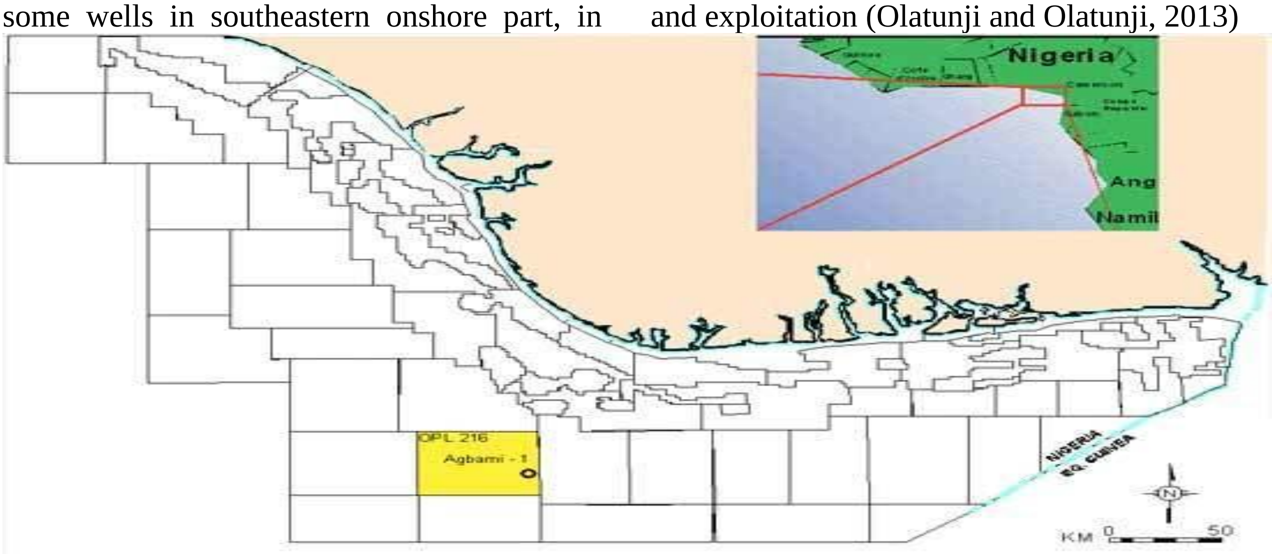


**Fig. 1. Agbami oil field (Onikoyi *et al*., 2014)**

## 2.0 Materials and method

Well logs and Seismic volume data were employed in this study using the Schlumberger PETREL software. Bad data points were analyzed and removed to avoid interpretation set back. The interpretation process. The interpretation process was grouped into two major processes (structural and petrophysical interpretation).

### *2.1 Structural and petrophysical analysis of Agbami field*

The structural analysis involves the process of manual mapping horizon of interest (using well stratigraphic markers of ATA5 well matching the horizon seismic continuity as a control), and Faults (discontinuities) identification/picking on the seismic section. to generate a structural play flow pattern for hydrocarbon movement in the **field** (see Fig. 2).

Hydrocarbon pay zones, hydrocarbon fluid type and contacts were identified using the high resistivity log kicks and the Neutron-Density overlay Technique (see Figs. 3 and 4). Petrophysical parameters were calculated for the Agbami field using the logs from Gamma-ray Log (GR)., Resistivity Log (LLD), Density Log (RHOB) and equation models (see equation1-10).

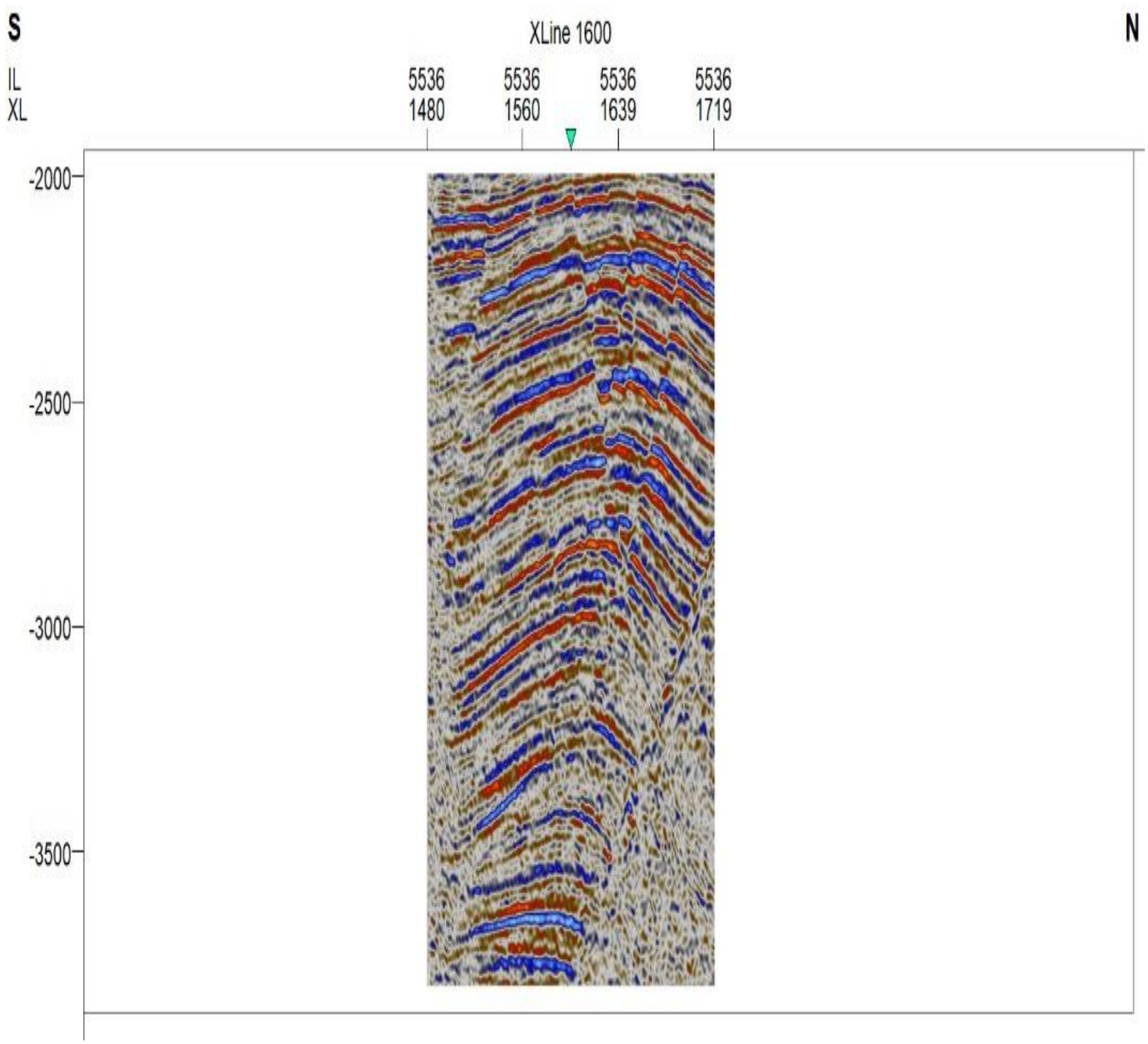


**Fig. 2: Seismic section of part of Agbami field.**

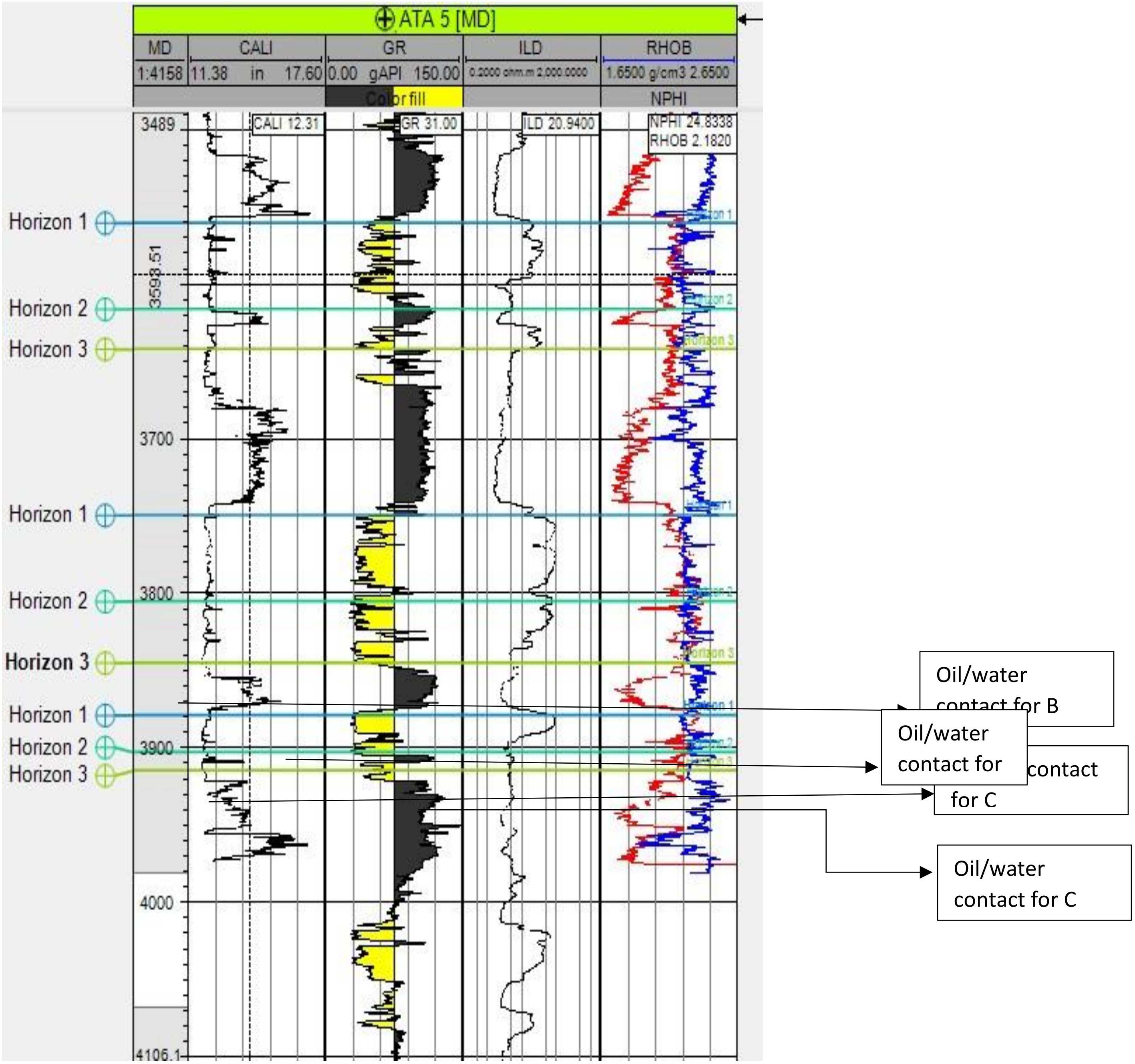


**Fig. 3: Neutron density combination showing the fluid present and indicating single phase formation fluid (oil ) for Formation A and B, and a double phase ( oil and gas) for C**

The following Petrophysical analysis was carried out for certain reservoir sands within the formations of well ATA5 (from wireline logs) using petrophysical calculation (Archie, 1942;); The evaluated parameters included hydrocarbon and water saturations ($S_w$ and $S_h$), volume of shale and porosity (Φ).

Water saturation was derived using the method reported by Archie (1942), who stated that the experimental water saturation of a clean formation can be evaluated in terms of its true resistivity expressed as equation 1

$$S_W = \left[\frac{F\,Rw}{Rt}\right]^{1/n} \qquad (1)$$

Since, $= \frac{R_0}{R_W}$, then $R_0 = FR_W$. Therefore, by substitution for $R_W$, equation 1 becomes,

$$S_W = \left[\frac{R_0}{Rt}\right]^{1/n} \quad (2)$$

where F is the formation factor., $R_W$ is the resistivity of the formation water., $R_T$ is the true resistivity obtained from the deep reading tool, Ro is the resistivity of the formation when it is 100% saturated with water with resistivity Rw (Schlumberger, 1989), $S_W$ is water saturation and n is the saturation exponent (commonly 2.0)

Hydrocarbon saturation is the percentage or fraction of pore volume occupied by hydrocarbons. It is calculated from equation 3 below:

$$SH = 1 - SW \quad (3)$$

where $S_H$ = Hydrocarbon saturation, $S_W$ = Water saturation., 1 = Unity.

The formation factor of a porous formation within the target depth interval was determined using humble' formula for unconsolidated formations, which are typical of the Niger Delta. This is given by:

$$F = {}^{a}/_{\Phi}{}^{m} \quad (4)$$

where: F is the formation factor, Φ is the porosity, 'a' is the tortuosity constant and m is an exponent called cementation factor m = exponent called cementation factor

For sands; $F = {}^{0.62}/_{\Phi}{}^{2.15}$ (5)

The volume of shale in unconsolidated tertiary rocks unit is given by:

$$V_{SH} = 0.33\,(2^{(2 \times Igr)} - 1.0) \quad (6)$$

where: $V_{SH}$ is the volume of the shale and $I_{GR}$ is the gamma ray index,

$$I_{gr} = \frac{GR_{log} - GR_{min}}{GR_{max} - GR_{min}} \quad (7)$$

The porosity is derived from bulk density of clean liquid-filled formations when the matrix density, $\rho_{ma}$, and the density of the saturating fluid, $\rho_f$, are known

$$\Phi den = \frac{\rho ma - \rho b}{\rho ma - \rho f} \quad (8)$$

where: Φden is the density derived porosity, ρma = matrix density (2.65g/cm$^3$).

ρb =formation bulk density ρf fluid density (0.85g/cm$^3$ for oil and 1.1g/cm$^3$ for water).

According to Schlumberger (1989), the irreducible water saturation (Swirr) can be expressed according to equation 9

$$S_{Wirr} = \left|\frac{F}{2000}\right|^{0.5} \quad (9)$$

where $S_{Wirr}$ is the irreducible water saturation and F is Formation factor

Tixier equation was used for the determination of permeability (K) , expressed as equation 10

$$K^{1/2} = \frac{250\ \Phi\hat{}3}{Swirr} \quad (10)$$

where: Φ is the Porosity.

## 3.0 Results and Discussion

Fig. 5 presents the seismic continuity, discontinuity and the generated surface map. The horizon and the associated faults were mapped using the seismic continuity (matching the well sand tops) and discontinuity respectively.

The mapped horizon is observed to be characterized by poor to low seismic continuity with varying amplitude reflections. The Seismic analysis revealed two major faults (F16 and F18). Both faults are structure building faults corresponding to the growth fault in the field (Oluwatoyin and Olatunji, 2013). The faults are trending east-west direction, with most of them dipping south-east. The two major faults, that form a two-way closure, are responsible for hydrocarbon trapping and the compartmentalization of formations witnessed in the Well ATA10.

**Fig.** 6 and 7 show the time and depth structural maps generated from the mapped horizon. From the Figures, it is evident that the maps are a two-way closure created by the two major faults in the study area (Oluwatoyin and Olatunji, 2013).

### *3.1 Correlation of the reservoir sands*

The correlation was done from the top to the bottom of the well logs (Fig. 8). Gamma ray (GR) logs are the main logs used for correlation because it exhibits patterns that are easier to spot between wells and such provides a dependable means for correlation (Ogbe *et al.*, 2013).

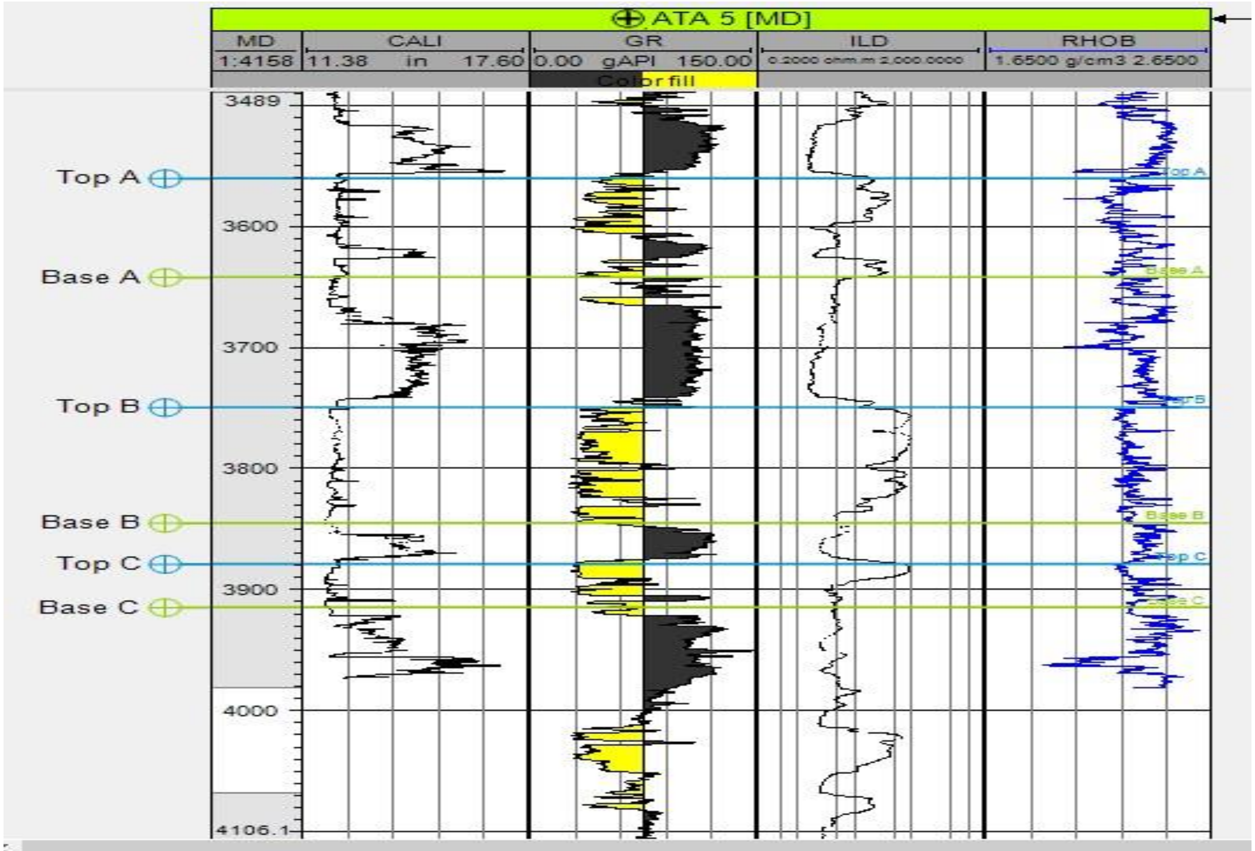


**Fig. 4: Delineated formations in well ATA 5**

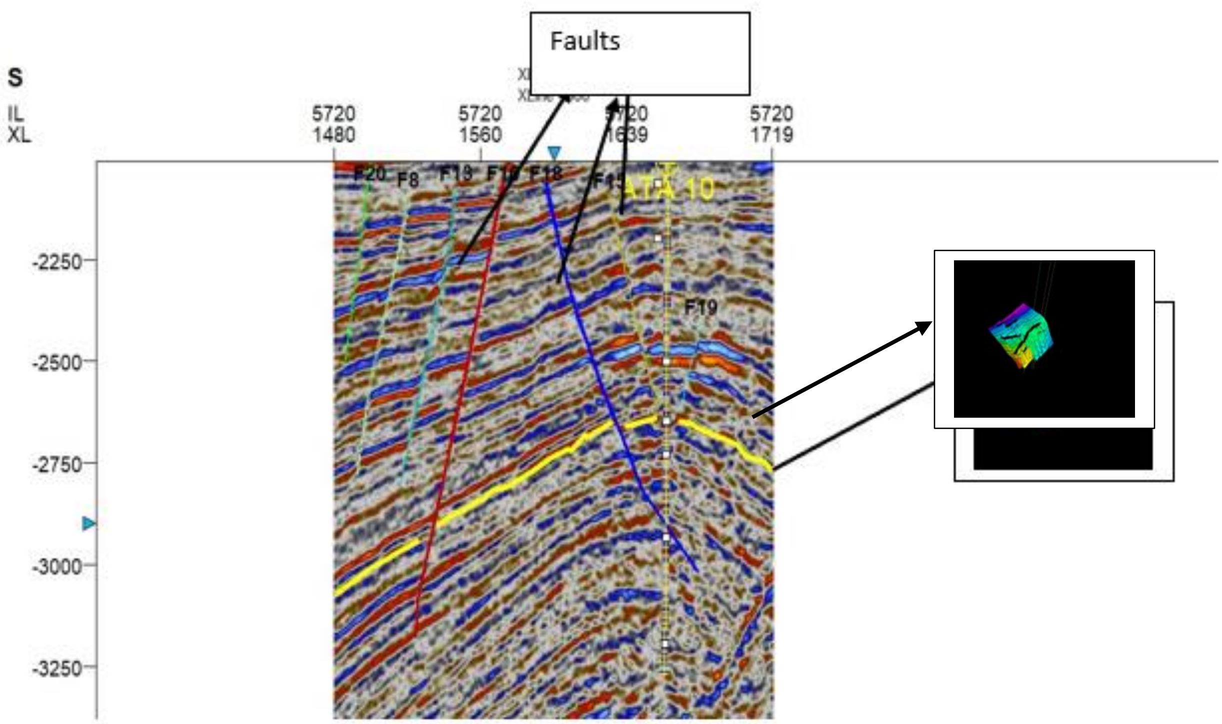


**Fig. 5. Showing the picked horizon and associated faults**

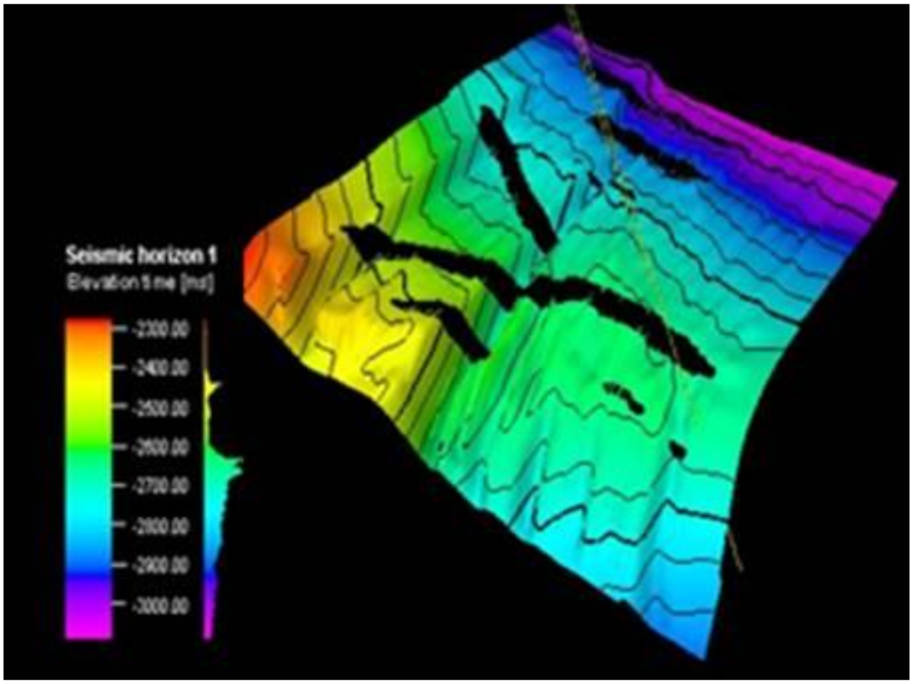


**Fig. 6: Time structural map**

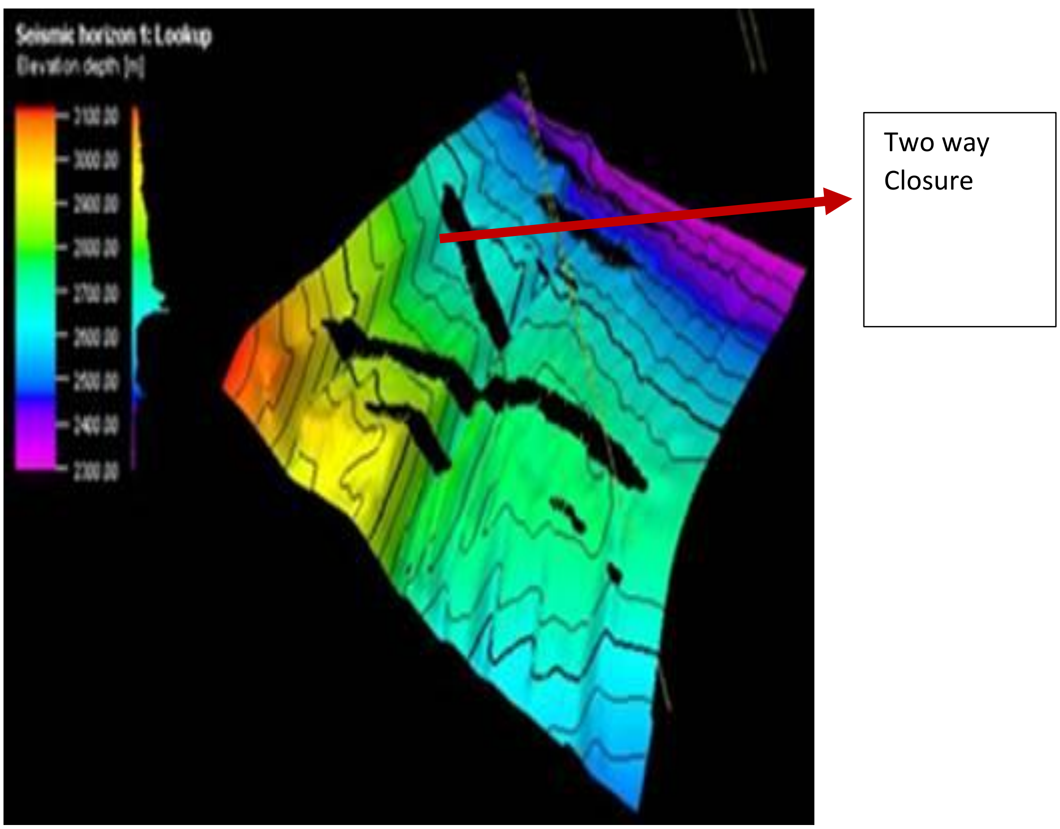


**Fig. 7. Showing the Depth map**

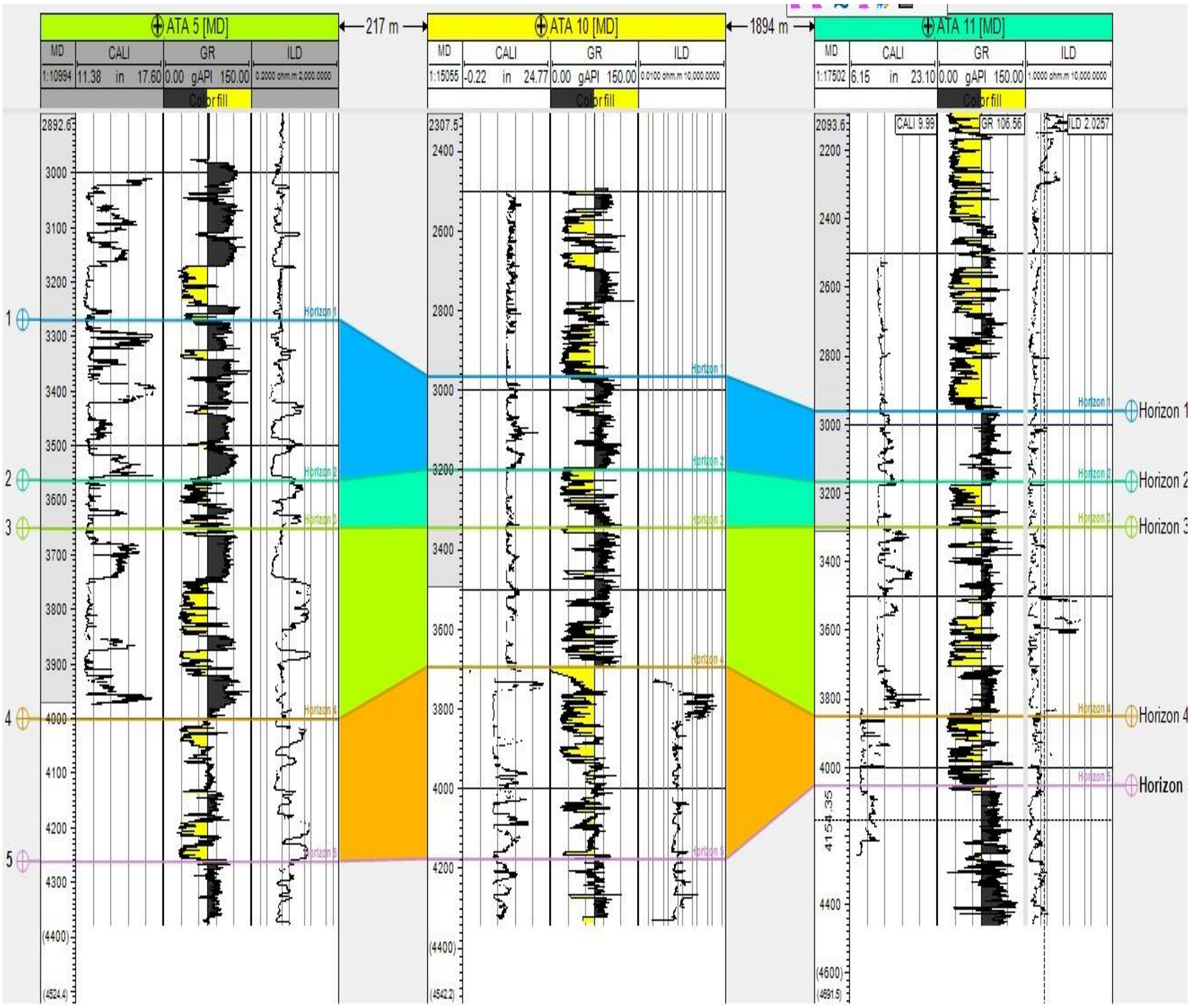


**Fig. 8. Correlation of well ATA5 with other wells, showing stratigraphic continuity**

### *3.2 Depositional environment*

The environments of deposition of the reservoir sand bodies were inferred as deep sea settings by comparing the gamma-ray signature with conventional log motifs.

Table 1 present petrophysical results of the subzones (as seen by the measured depth) for formation A, B and C of ATA5 well. Formation A which is characterised by sandstone and silt (59 – 81API), has low to high shale volume, very good porosities (0.24 – 0.22) (Levorsen, 1967), high to low recoverability as infer by the Net/Gross, good hydrocarbon saturation ( 51% and 44%) and excellent degree of hydrocarbon flow ( high permeability values). The porosity across formation A infer normal compaction trend as it decreases with depth (Mode *et al.*, 2013).

Formation B is characterized majorly with shaly sandstones (68-77 API) show similar trend with good porosities (0.21 – 0.19), good to poor hydrocarbon saturation (41% - 28%) and very good to excellent permeabilities. The decreasing porosity with depth, like formation A, also indicate the normal compaction trend (Mode *et al.*, 2013).

Formation C which is characterised with cleaner Sandstone (45-48 API) has very good porosities (23% -22%) a decreasing order with that which also indicate the normal compaction trend. Formation C, unlike A and B has excellent hydrocarbon saturation (78-63%).

**Table 1: Showing petrophysical results of subzones across formation A, B and C of Well ATA5**

| **Well** | **ATA5(A)** | **ATA5 (A)** | **ATA 5(B)** | **ATA 5 (B)** | **ATA 5 (C)** | **ATA 5 (C)** |
|---|---|---|---|---|---|---|
| **Start MD** | 3560.22 | 3615.95 | 3667.21 | 3902.59 | 3749.32 | 3805.05 |
| **GR (API)** | 59 | 81 | 77 | 68 | 48 | 45 |
| **Vsh** | 0.19 | 0.42 | 0.41 | 0.32 | 0.12 | 0.11 |
| **Porosity** | 0.24 | 0.22 | 0.21 | 0.19 | 0.23 | 0.22 |
| **EffPorosity** | 0.20 | 0.14 | 0.13 | 0.14 | 0.20 | 0.20 |
| **N_G** | 0.81 | 0.58 | 0.59 | 0.68 | 0.88 | 0.89 |
| **$S_w$** | 0.49 | 0.56 | 0.59 | 0.72 | 0.22 | 0.37 |
| **$S_h$** | 0.51 | 0.44 | 0.41 | 0.28 | 0.78 | 0.63 |
| **Swirr** | 0.09 | 0.09 | 0.10 | 0.11 | 0.09 | 0.09 |
| **K (mD)** | 1488 | 1024 | 918 | 995 | 1466 | 1436 |

Table 2 presents the result summary (averages) for the three formations (A, B and C). The average volume (31%, 37% and 12%) and the N/G (0.70, 0.64 and 0.89) for the three formations is indicative of huge amount clean sands in the formations with negligible shaliness. The average porosity (≥20%) clearly rate the reservoirs very good (Levorsen 1967), with good to excellent ease for fluids (oil and gas) recoverability (Bake, 1992). See Tables 3 and 4.

The porosity increases with depth at formation C, which appears not to conform to normal compaction trend, is due to the presence of secondary porosity (faults). The presence of faults which has evidently increase hydrocarbon migration paths (excellent permeability of 1451), clearly demonstrates the complexity of the Agbami field and are account for the 70% hydrocarbon migration into formation C.

**Table 2: Average Petrophysical Results for formation A, B and C**

| **Well formation** | **ATA5(A)** | **ATA5 (B)** | **ATA 5(C)** |
|---|---|---|---|
| **Start MD** | 3560.22 | 3667.21 | 3749.32 |
| **Vsh (av)** | 0.31 | 0.37 | 0.12 |
| **Porosity(av)** | 0.23 | 0.20 | 0.22 |
| **EffPorosity (av)** | 0.17 | 0.13 | 0.20 |
| **N_G (av)** | 0.70 | 0.64 | 0.89 |
| **$S_w$ (av)** | 0.53 | 0.66 | 0.30 |
| **$S_h$ (av)** | 0.47 | 0.34 | 0.70 |
| **$S_{wirr}$ (av)** | 0.091 | 0.109 | 0.092 |

| | | | |
|---|---|---|---|
| **K (mD) (av)** | 1256 | 957 | 1451 |

**Table 3: Porosity values for reservoir qualitative description (Levorsen 1967)**

| Porosity (%) | Qualitative Description |
|---|---|
| **0-5** | Negligible |
| **5-10** | Poor |
| **10-15** | Fair |
| **15-20** | Good |
| **20-25** | Very Good |

**Table 6: Permeability values for reservoir qualitative description (Baker 1992)**

| Permeability in millidarcy | Qualitative description |
|---|---|
| **1.0 – 15** | Poor to fair |
| **15 – 50** | Moderate |
| **50 – 250** | Good |
| **250 – 1000** | Very good |
| **>1000** | Excellent |

## 4.0 Conclusion

A 3D seismic structural interpretation has been carried out on part of the Agbami field using well logs and 3D seismic volume data. From the analysis of selected seismic continuity using a well control, key structural features such as synthetic and antithetic faults, roll over anticlines, growth faults in the area were identified. Two growth faults identified trends W-E dipping east ward. Majority of associated faults also trends south W-E, dipping eastward. Closed structure (Closure) is present in the analysed horizon and this suggest good hydrocarbon trapping mechanism. Both oil and gas were observed as the hydrocarbon fluid type present, with oil majorly present, as the hydrocarbon fluid type, in the analysed horizon. Good degree of stratigraphic continuity was observed in the field. Petrophysical results suggest good recoverability index but fair producibility of 35%-40% and also show the presence of faults in the Agbami field. This research model can be used for pre-reservoir simulation studies. More detailed studies are recommended with more wells to substantiate the structural play of Agbami field.

## 5.0 Acknowledgement

The authors acknowledge DPR for the data and Schlumberger for the software.

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**Conflict of Interest**

The authors declared no conflict of interest