__Original Research Article__

VOLUMETRIC ANALYSIS OF SELECTED RESERVOIRS IN OGBENU FIELD, NIGER DELTA, NIGERIA USING 3D SEISMIC AND WELL LOG DATA

ABSTRACT

Volumetric analysis of selected reservoirs in the Ogbenu field, Niger Delta, Nigeria was carried out using 3D seismic and well log data. The objectives include the identification and selection of suitable reservoirs, correlating the reservoirs across the field, generating synthetic seismograms and seismic-to-well ties, performing structural interpretation of faults and horizons to generate time and depth structure map, identifying potential prospects and volumetric analysis to estimate the volume of hydrocarbon in place. The adopted methodology comprises structural, petrophysical and volumetric analysis facilitated by Petrel and Techlog software suites. Well log were utilized to identify distinctive features and cross-well stratigraphic correlation which revealed complex variations, indicating a potential thickening trend in the Agbada sequence towards the southwest. Faults and horizons were mapped to establish the structural framework, unveiling a faulted rollover anticline influenced by lateral fault block movements, contributing to a complex structural style. Detailed analysis of seismic responses, synthetic seismograms, and petrophysical parameters from the well log led to the identifying and correlating of eight prospective reservoir intervals (Reservoir A to H). Average petrophysical parameters, including thickness, porosity, Not-to-Gross ratio, volume of shale, and water saturation were derived from the petrophysical analysis, confirming the eight reservoirs exhibit good petrophysical properties, indicating their potential as promising prospects. The reservoirs exhibit varying qualities, with a southward decline in reservoir quality and indications of gas-water contacts in reservoir A with a similar trend across the other reservoir units. The estimated Original Oil in Place volume were Reservoir A (29,025.57 MMBOE), B (23.95 MMSTB), C (2,776.37 MMBOE), D (48.19 MMSTB), E (16.69 MMSTB), F (131.98 MMSTB), G (42.19 MMSTB) and H (102.60 MMSTB). This integrative approach revealed complex reservoir variations and structural intricacies, enhancing the understanding of future exploration and production strategies in the Ogbenu field.

Keywords: Volumetric Analysis, Petrophysical Analysis, Structural Interpretation, Ogbenu Field, Niger Delta Basin,

INTRODUCTION

Mankind is closely linked with the provision of energy to fulfil daily needs and the availability of energy promotes the day to day activities essential for efficient and effective development. The significance of energy in the life of mankind cannot be overstated. The primary source of energy in Nigeria and many other parts of the world is oil and gas. Despite Nigeria’s substantial oil and gas production, its output still falls short of meeting the demand.

The complex geological structure of the Niger Delta basin poses significantly challenges and uncertainties, primarily arising from geological factors such as the combination of multiple sedimentary basins, reservoir discontinuity, faulting patterns and inaccurate estimation of hydrocarbon in place. Furthermore, the region has also experienced the occurrence of dry holes due to insufficient structural and stratigraphic interpretation of seismic data and subpar reservoir characterization. These further underscore the need for improved structural and stratigraphic interpretation of 3D seismic and well log data.

Considering the demand for hydrocarbon and the cost implication associated with oil and gas field development, a comprehensive understanding of trapping mechanisms, basin architecture, geometry, sealing integrity and migration pathways is imperative for effectively harnessing the hydrocarbon reserve in the Ogbenu field. The Ogbenu field plays a crucial role in hydrocarbon exploration and production, yet a significant research gap hampers the accurate estimation of its hydrocarbon reserves. The complex geological structure, marked by multiple sedimentary basins, reservoir discontinuity, and intricate faulting patterns, presents challenges across the study area.

Volumetric analysis is a key method of assessing hydrocarbons in place before drilling. The concept is deeply embedded in geophysical and geological interpretations that commence with the mapping of reservoir structural parameters, such as faults, horizon, thickness, lithology and orientation of the reservoir units. The importance of structural and stratigraphic interpretations of seismic data in this process has been strongly emphasized by Allstair (2011) and Weber (2012). Integrating 3D seismic and well log analysis provides a comprehensive understanding of subsurface geology and geophysical properties that enable the accurate mapping and assessment of hydrocarbon traps, delineate potential prospects, and calculate volumes in place.

Consequently, the specific focus on the Ogbenu field within the coastal swamp I depobelt requires precise volumetric analysis through the integration of available 3D seismic and well log data. The study projects that interpreted data will not only contribute to understanding the petrophysical properties, structural settings, and fluid contents of the reservoirs but will also guide decision-making processes related to economic feasibility, optimization, field development, and production (Okwoli *et al.*, 2015).

Conclusively, this research focuses on the volumetric analysis of selected reservoirs in Ogbenu field, Niger Delta, Nigeria using 3D seismic and well log data. The study aims to eliminate drilling uncertainties in the study area arising from geological factors, insufficient structural and stratigraphic interpretation of seismic and well log data. It will also identify potential prospects and estimate the volume of hydrocarbons initially in place. The findings will be useful in cost-effective optimizing hydrocarbon recovery, benefiting stakeholders and developers alike.

LOCATION AND GEOLOGY OF STUDY AREA

The Ogbenu field is located within the coastal swamp I depobelt, onshore, Niger Delta. The geographical coordinates of the study area lie between Latitude 04°30′ - 05º00′N and Longitude 06°00′ - 06º30′E (Figure 1). The Niger Delta basin is one of the largest subaerial basins in Africa measuring about 75,000km^2 with an estimated average thickness of about 9 – 12km and ranked among the top 5% of the world's hydrocarbon-producing region.

The Niger Delta is tectonically divided into six regions or structural provinces: The Northern delta, Greater Ugheli, Delta edge, Central swamp, Coastal swamp and offshore depobelts (Okpara *et al.,* 2021). Evidence indicate that the growth and development of these depositional belts was controlled by old fault belts or zones which formed in the Cretaceous, that progressively form a network of trenches and ridges in the deep Atlantic (Okpara *et al.,* 2021). The initiation of the Niger Delta has been traced to the late Jurassic and continued into the middle Cretaceous (Lehner, 1977). It is part of a rift system. Gravity induced shale tectonism has been the primary mechanism responsible for modifying the basin into its present-day structural style (Okpara *et al.,* 2021).

The Basin is situated near West Africa's continental edge (Figure 1). The tertiary portion of the delta has been stratigraphically separated into three formations. Facies variations allow the identification of prograding facies, which make up the majority of these formations. The youngest formation, the Benin Formation, is primarily composed of continentally-derived sand facies with sporadic shale deposits or breaks (Figure 2). This formation moves laterally and vertically into the Agbada formation (Okpara *et al.,* 2021). The paralic deposit known as the Agbada Formation is typical. This formation transitions into the Akata Formation's marine shales offshore. The Akata Formation is a sequence of thick, massive shale with sporadic or non-existent sand deposits that are probably turbidites.

The study area is located on the west coast of Central Africa, close to the Gulf of Guinea, in the south-south portion of Nigeria within the swamp and marshes of the Niger Delta. It is part of the Niger Delta, one of the world's biggest deltaic systems. The delta's structural and stratigraphic evolution have had a significant impact on the formation of hydrocarbon traps and seals. Structural traps make better exploration targets than stratigraphic traps within the basin. Play styles like shallow or deep simple/faulted rollover, k-type structures, reversed footwall closure, back-to-back structures, and inversion structures are a few examples of play styles that have shown to be viable exploration targets.

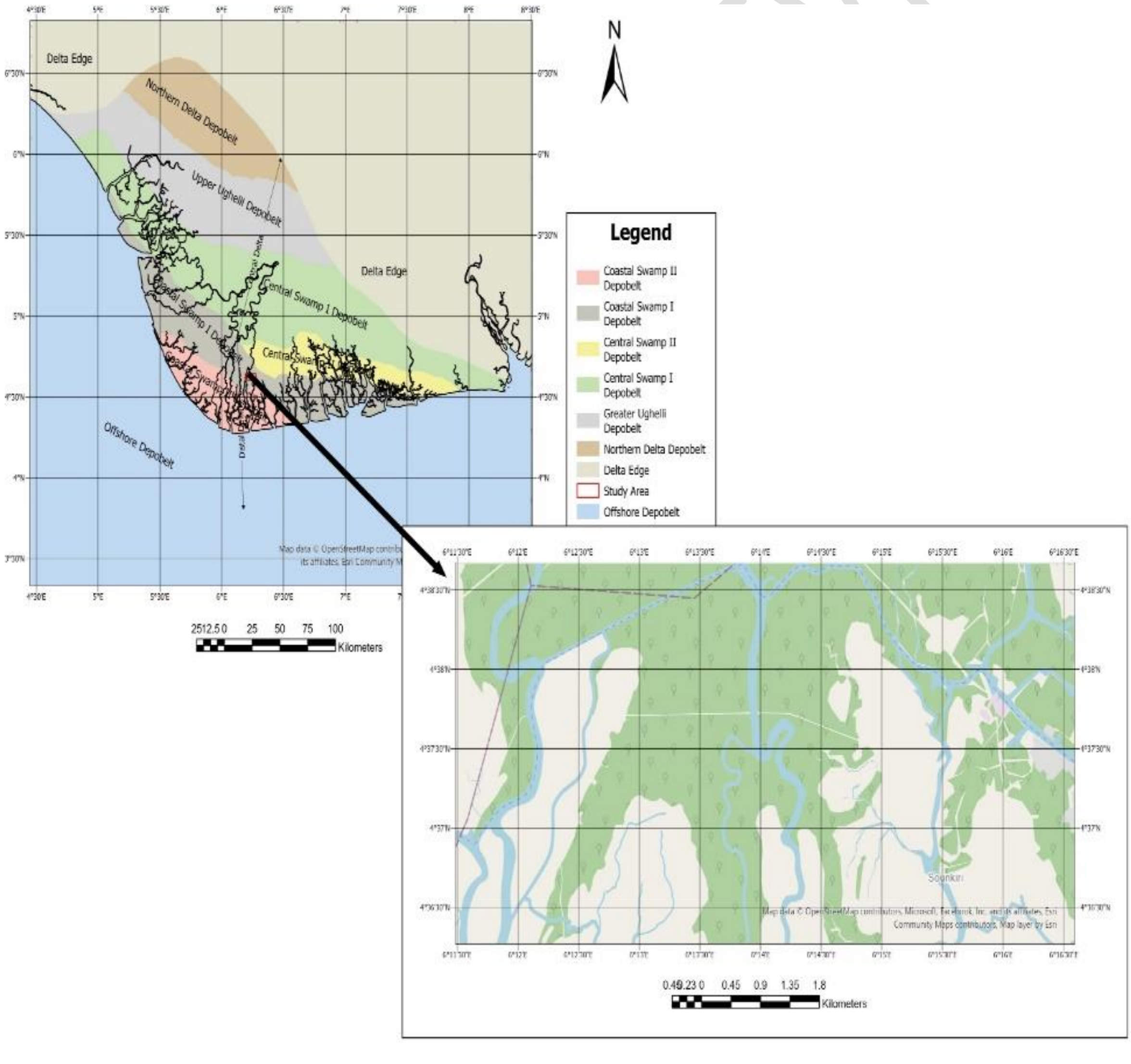

Figure 1: Location Map of the Study Area

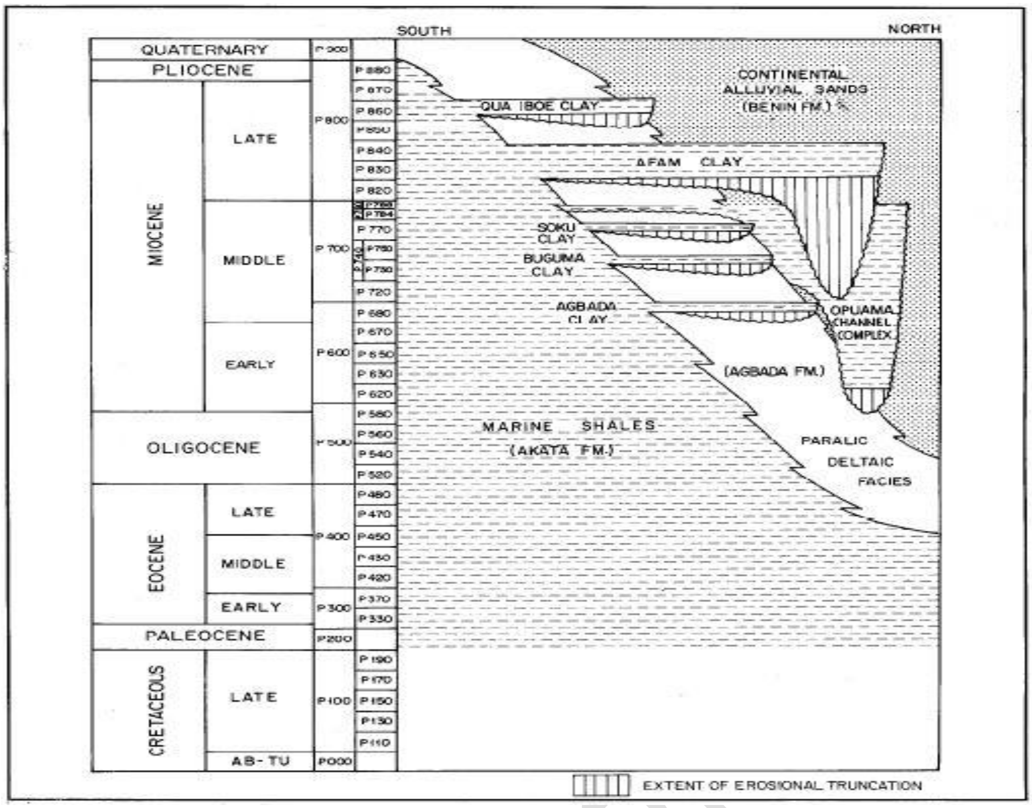

Figure 2: Schematic representation of Stratigraphic column of the Niger Delta and relationship of clay filled channels on the delta flanks (Doust and Omatsola, 1990).

MATERIALS AND METHODS

Materials

The data used for this study are 3D seismic, checkshot and well log data. The study was performed in two interrelated stages: seismic interpretation and petrophysical analysis. The Petrel software was employed for the geophysical and geological interpretation of the 3D seismic data while the Techlog software was employed for the petrophysical analysis. The summary of the workflow is shown in Figure 3.

Seismic Interpretation

Using density and sonic log, a synthetic seismogram was generated and used to align reservoir tops and well markers with the seismic responses to ensure control and facilitate data transfer to the acquired seismic volume of the study area. A statistical algorithm was employed to estimate a zero-phase wavelet from seismic data while Gardner's equation was employed to estimate sonic responses or rock density for intervals where log data was unavailable. Faults were picked and mapped throughout the entire seismic volume to understand the fault pattern and trend. Horizons were also picked and mapped on the seismic volume across the field through qualitative interpretation. Structural maps were generated using the mapped horizons. The velocity model that originates from the checkshot data was used to convert the time structural map to the depth structural map. The depth structural map was then used alongside seismic attributes to identify several hydrocarbon prospects.

Petrophysical Analysis

The unique characteristics and properties of the gamma ray, resistivity, neutron and density logs were used to identify, delineate and correlate the reservoirs across the wells. The gamma ray log was utilized for lithology identification and correlation. A low radioactive reading indicates a potential presence of carbonate or sandstone which is indicative of a reservoir. Resistivity log was utilized for distinguishing formations containing good conductors of electricity typical of saline water (low resistivity) and hydrocarbon bearing intervals (high resistivity). The neutron porosity log was utilized for the identification of the hydrocarbon type by correlating energy loss with the formation porosity since neutron porosity decreases as pores are filled with gas instead of oil while the density log was utilized in assessing the density contrasts associated with the presence of hydrocarbon in the reservoirs.

Porosity was estimated from the neutron and density log using the below equation:

$$\emptyset = \frac{\rho_{ma} - \rho_{bulk}}{\rho_{ma} - \rho_{fl}} \tag{1}$$

Where:

ρ_{ma} = Rock matrix density

ρ_{bulk} = Measured density

ρ_{fl} = Flushed zone measured density

Net to Gross ratio was calculated after identification of the reservoirs and the volumes of shale extracted.

Water saturation was estimated from the resistivity log using the standard Archie's equation below:

$$S_w = \sqrt[n]{\frac{a \times R_w}{\emptyset^m \times R_f}} \tag{2}$$

Where:

n= The saturation exponent (noted as 2)

R_w= The formation of the water resistivity

R_f= The fluid resistivity (ILD)

a= The constant (0.62 for unconsolidated sands and 0.81 for consolidated sands)

m= The constant (2.0 for unconsolidated sands and 2.15 for consolidated sands)

$\emptyset$= The porosity.

Volume of shale (V_{sh}) was estimated from the gamma ray log with the equation below:

$$V_{sh} = \frac{GR_{log} - GR_{clean}}{GR_{shale} - GR_{clean}} \tag{3}$$

Where:

GR_{log} = Gamma Ray log reading from formation interval

GR_{shale} = Maximum Gamma Ray log reading (shale)

GR_{clean} = Minimum Gamma Ray log reading (clean sand)

Volumetric Analysis

The reservoir volumes were calculated using a methodology that involved multiplying the surface area of each reservoir interval's top horizon by the average thickness obtained from well data. To define the spatial extent of the reservoir structures, polygons were employed, centered around identified spill points. The units used for thickness, surface area, and volumes were consistently measured in (m). The calculations aimed to capture the volumetric characteristics of the reservoirs in relation to the defined spill points, with the methodology detailed as follows:

$$\text{Bulk Volume} = \text{Total Rock Volume} = \text{reservoir thickness (m)} \times \text{area extent (m}^2\text{)} \tag{4}$$

$$\text{Net Volume} = \text{Bulk Volume} \times \text{Net/Gross} \tag{5}$$

$$\text{Pore Volume} = \text{Bulk Volume} \times \text{Net/Gross} \times \text{Porosity} \tag{6}$$

$$\text{HCPV oil (bbls)} = \text{Bulk Volume} \times \text{Net/Gross} \times \text{Porosity} \times S_{h}. \tag{7}$$

Where:

S_h is hydrocarbon saturation

The conversion factor $1m^3 = 6.29$ oil barrels is applied in volume units

HCPV is hydrocarbon pore volume

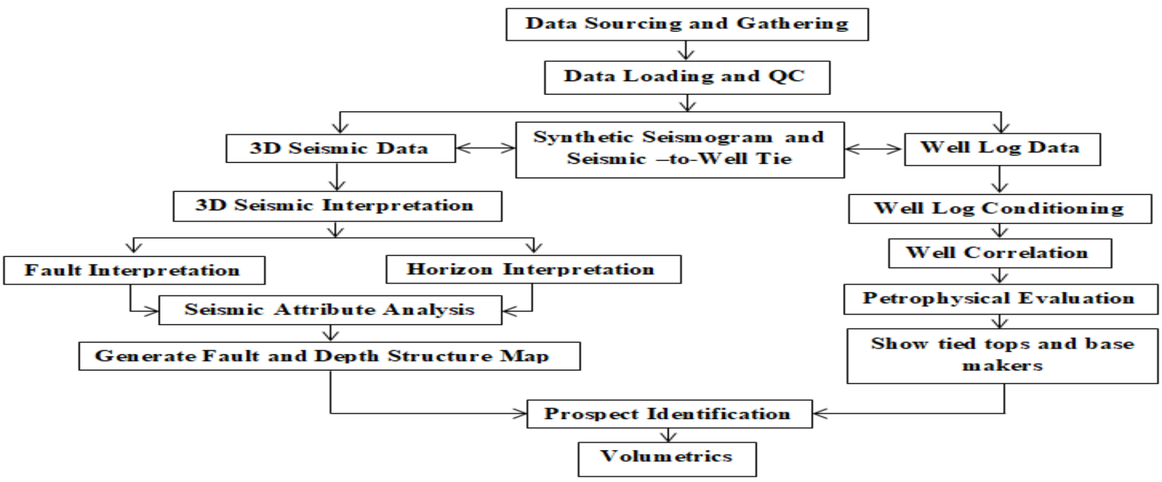

Figure 3: Illustration of the Research Flow Chart

RESULTS AND DISCUSION

Facies Identification and Correlation

Three subsurface units (Benin, Agbada, and Akata formations) in the Niger Delta were identified and correlated using distinctive features observed in well logs, as outlined by Doust and Omatsola (1990) and Short and Stauble (1967). Gamma-ray logs indicate distinctive characteristics in the Niger Delta subsurface units: the Benin Formation is dominated by sandstone facies, the Agbada Formation displays a paralic sequence, and the Akata Formation predominantly exhibits a marine shale-dominated sequence. Correlation in east–west direction was done across 5 wells. Facies logs derived from gamma-ray data illustrate variations between sand and shale facies, with deeper zones predominantly characterized by shaly facies and shallower units exhibiting a prevalence of sandstone facies. The five wells primarily penetrated the top of the Agbada (base of Benin) interval while most wells did not reach the base of the Agbada (top of Akata) interval. The character of the entire Agbada sequence beneath the field is illustrated on the well section (figure 4, 5 and 6) showing a potential thickening in a south-western direction. The stratigraphic variation observed in facies log and gamma-ray logs indicates a complex interplay of regression and transgression. Analysis from facies and gamma-ray logs reveals vertical alternations from tens to hundreds of meters, with a coarsening upward sequence on a formation-scale trend. In the Benin Formation, gamma-ray readings indicate interspersed mudstone or clay facies among sand facies, while the key difference between the Benin and Agbada units lies in the cyclicity and frequency of transitions from sandstone to mudstone facies, the thickness and regularity of mudstone throughout the depositional cycle. Stratal units in the Agbada Formation show a more frequent shift from sandstone to mudstone facies at shorter intervals compared to the Benin Formation.

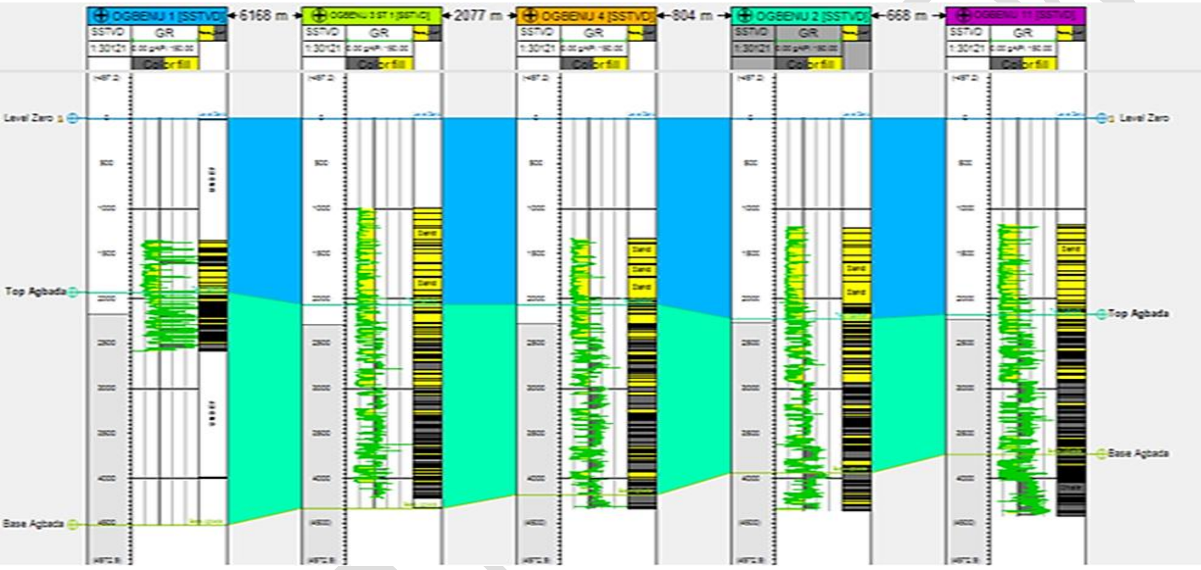

Figure 4: Well log correlation of Formation intervals

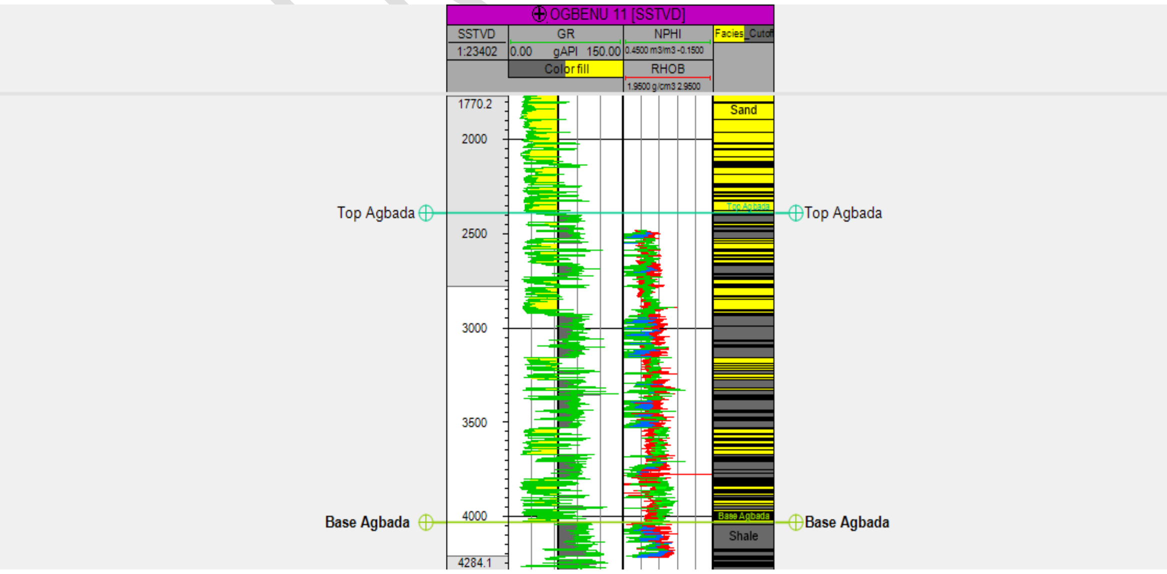

Figure 5: Gamma ray log of well Ogbenu 11 with vertical facies variation.

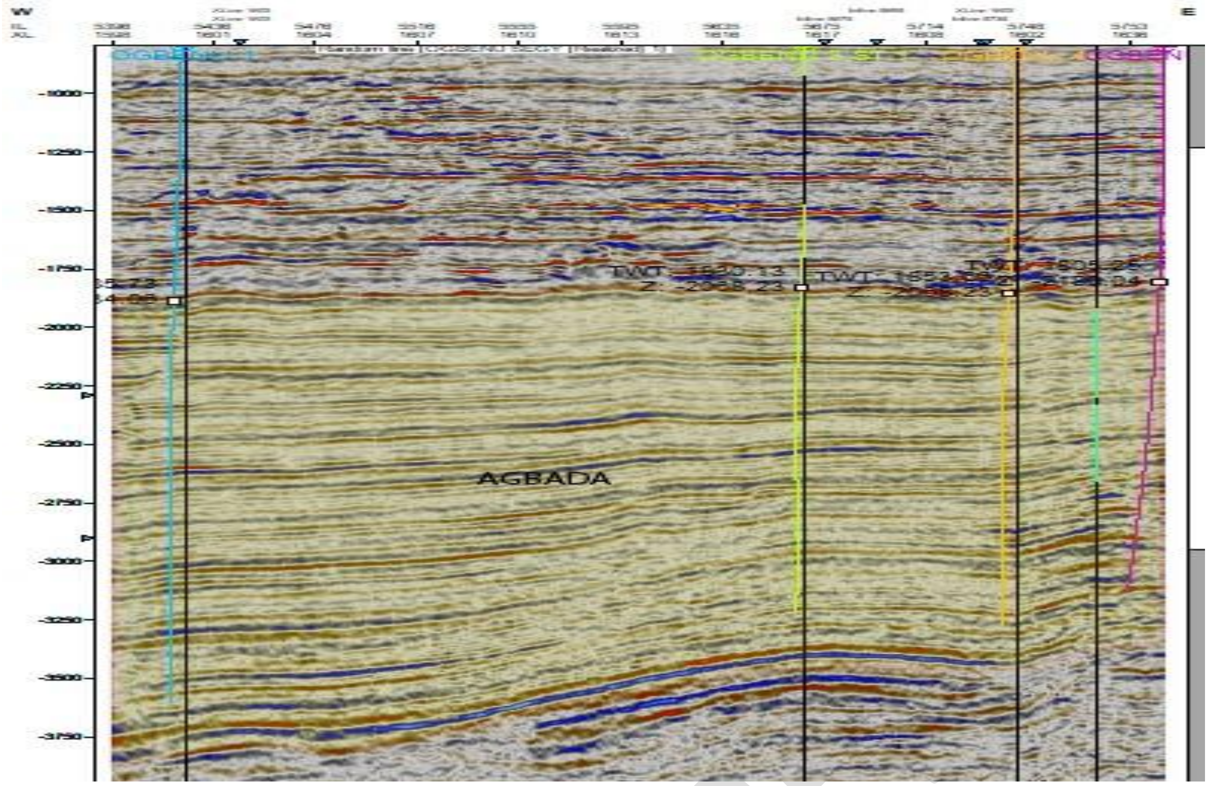

Figure 6: Composite Seismic Section of Formation correlation displaying the Agbada Reservoir Interval.

Synthetic Seismogram and Seismic to Well tie

A good correlation was achieved between the seismic response at well Ogbenu 2 and the overall seismic response within the study area (figure 7). Notably, most of the identifiable reservoirs on the seismic section corresponded to zones of negative or low amplitude, suggesting regions of soft acoustic response or impedance, with their tops and bases forming zero-crossings.

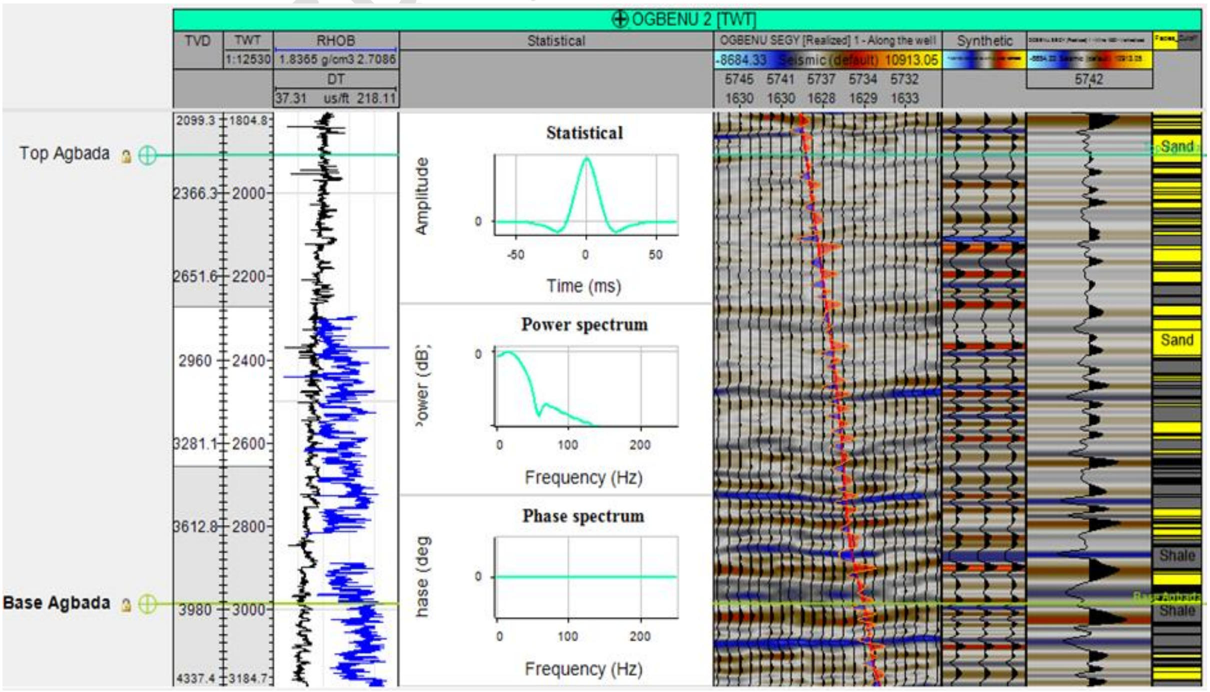

Figure 7: The generated synthetic seismogram used for seismic to well tie

Structural Interpretation

The Ogbenu field lies within an extensional province, characterized by a faulted rollover anticline with its geometry notably influenced by lateral or horizontal fault block movements, presenting a complex structural style. The primary feature is an east-west boundary fault, transitioning into a decollement plane at the top of the Akata or base of the Agbada Formation (figure 9). This fault played a key role in the formation of a northeast-southwest trending rollover anticline that is typical within the Niger Delta basin. Visual examination of the dip of beds from the seismic data reveals a steep plunge towards the south and gentler northward toward the controlling boundary fault while additional detached minor conjugate faults, exhibiting a synthetic sense of strike and dip, contribute to the intricate geometry of the anticline. Other numerous detached minor faults striking northwest-southeast with an antithetic sense of dip may have formed accommodation zones, facilitating horizontal or lateral movement of fault blocks.

In plain view, the faults demonstrate a narrow and cuspate geometry along their strike, dividing the field into five distinct fault blocks (figure 8), complicating precise boundary delineation. Seismic section analysis indicates lateral transitions from low signal strength to continuous reflections, particularly beneath the footwall of the fault block adjacent to the major boundary fault, suggesting fracturing and displacement due to overpressure in the shallow depths. The boundaries of the low-amplitude, discontinuous zone exhibit varying sharpness, indicating potential fracturing of deposits and displacement from the buoyancy of underlying strata. Additionally, one horizon was picked and mapped (figure 11) and since flooding surfaces are interpreted as relatively flat depositional planes, often seen as strong reflectors with regional extent across the field, a top structure map (figure 12) was selected to traverse all the key structures within the field. This was utilized to establish broad displacement patterns across faults and deformation of fault blocks within the stratigraphic interval. The identification of subsurface units, structural complexity, and faulted rollover anticline in this study aligns with previous works by Doust and Omatsola (1990); Short and Stauble (1967); Unuevho *et al*. (2022); Sanuade *et al.* (2017); Adewoye *et al.* (2013); and Opara *et al.* (201).

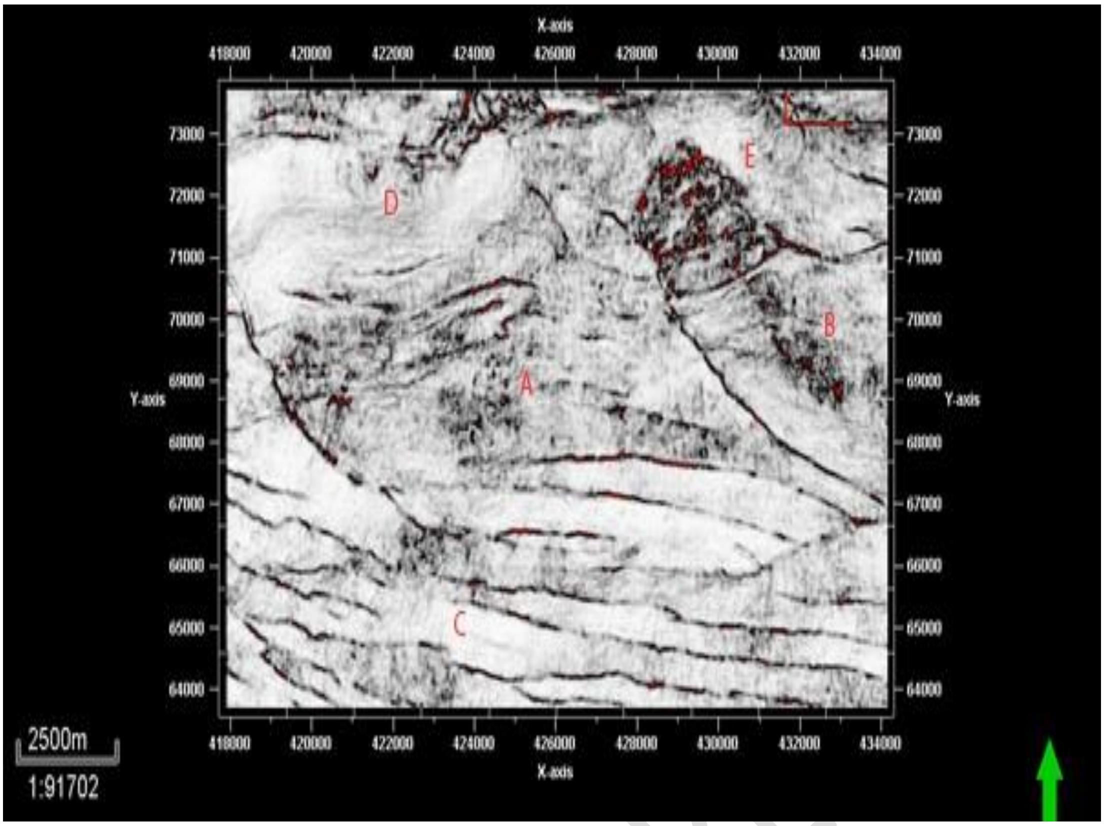

Figure 8: Time slice of Variance Edge Volume taken at 2496ms corresponding to Agbada Formation and showing the structures.

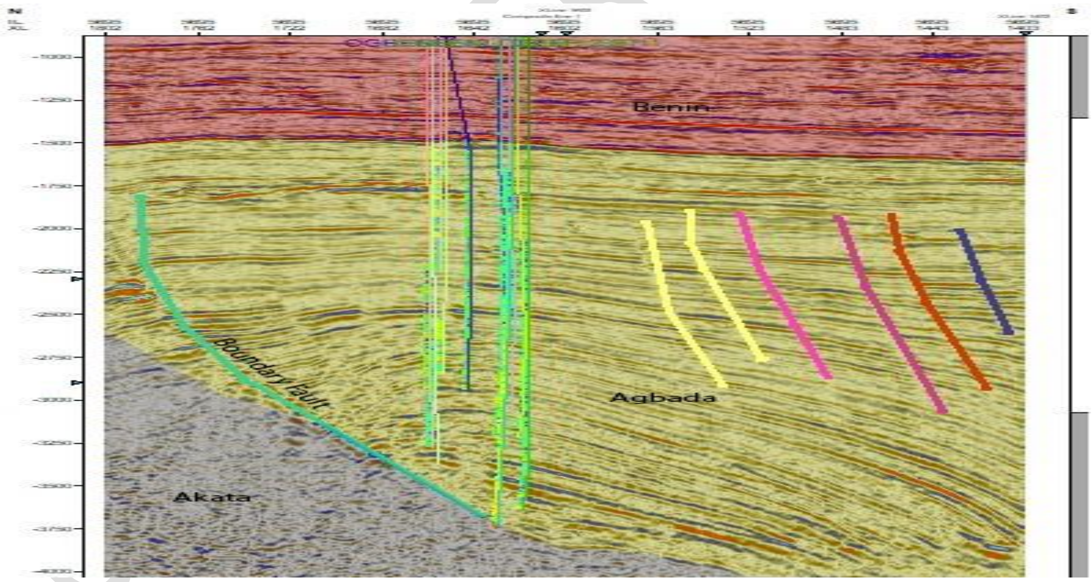

Figure 9: Seismic section of Akata, Agbada and Benin intervals and the structures (major boundary and minor faults)

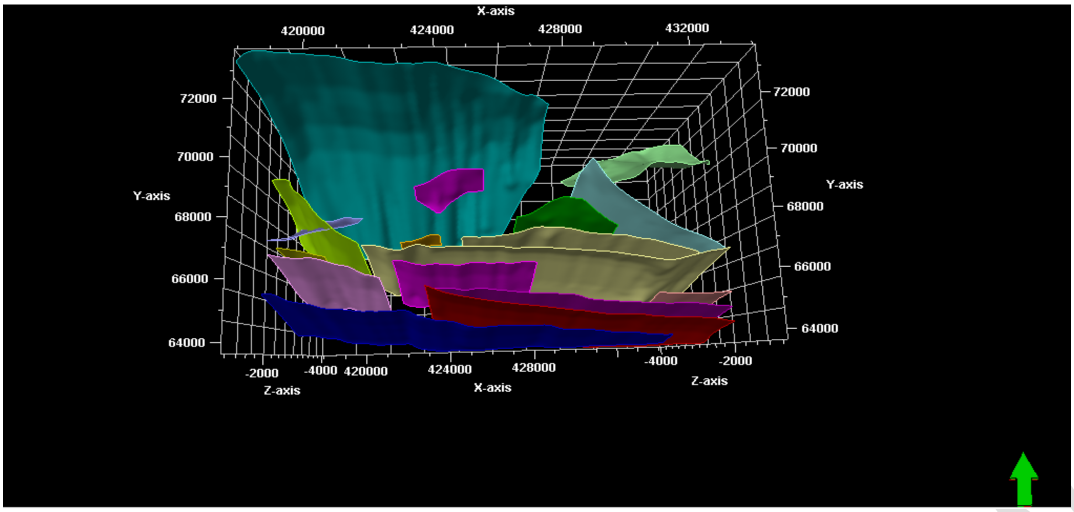

Figure 10: Interpreted faults viewed in 3D.

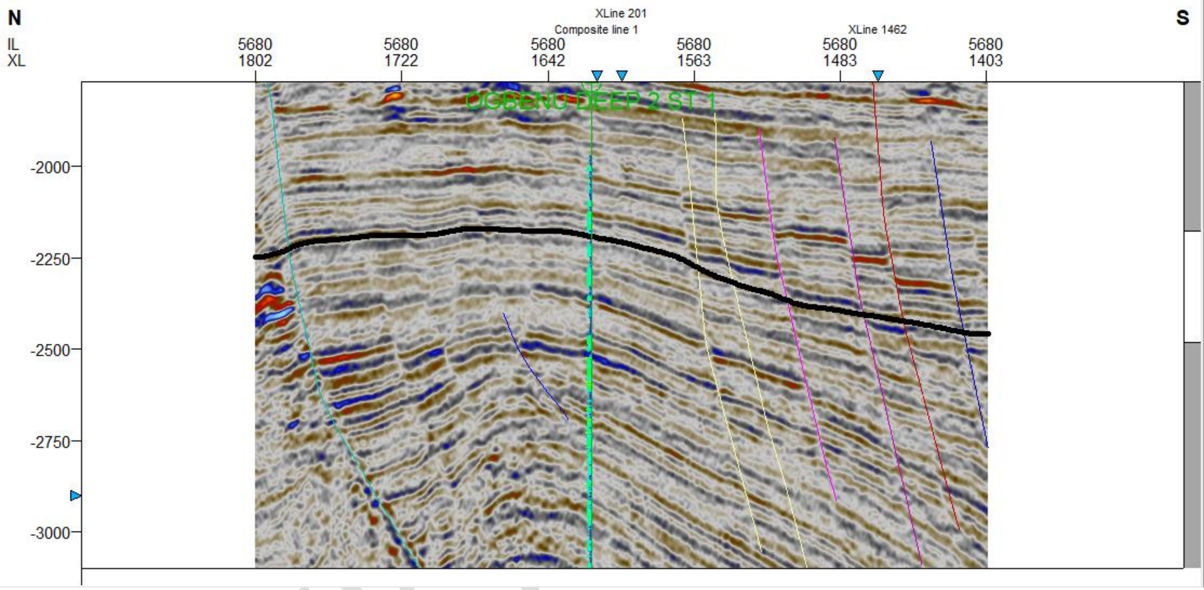

Figure 11: Seismic section along dip displaying the mapped horizon used to define the structural patterns within the Ogbenu field.

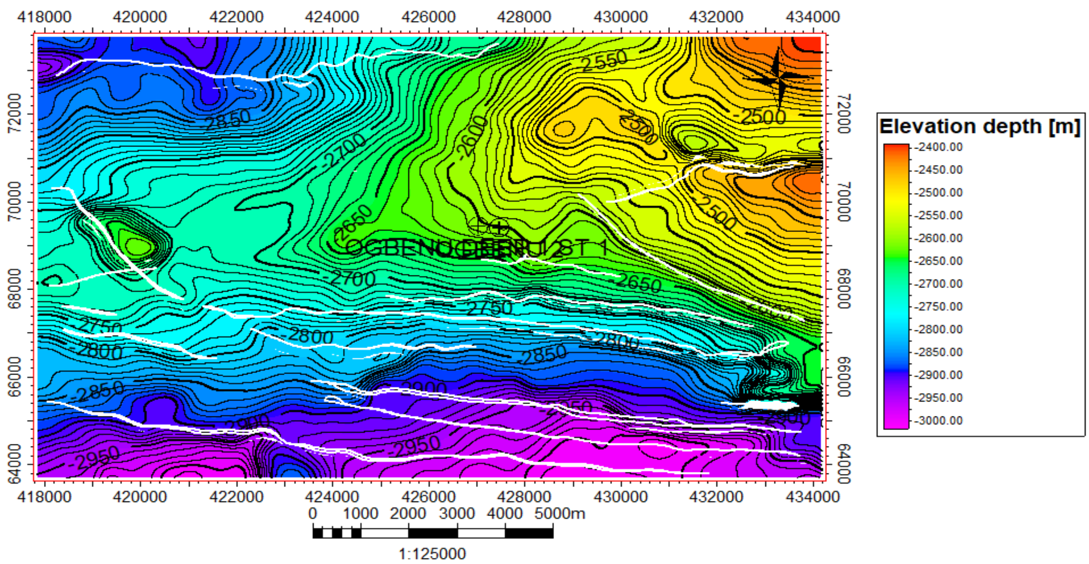

Figure 12: Depth structure map used to define broad structural deformation and style of the field.

Reservoir Delineation and Correlation

Utilizing the unique characteristics and properties of the gamma ray, resistivity, neutron and density logs, eight reservoir intervals or units were identified and labelled reservoir A - H within well Ogbenu 2. These reservoirs were subsequently correlated to well Ogbenu deep 2 ST 1 (Figure 13 to 16). Evaluation of the electrical resistivity and gamma ray logs reveals a decrease in reservoir quality moving southwards from well Ogbenu 2 to Ogbenu deep 2 St 1. Additionally, there is a corresponding decrease in the strength of the electrical resistivity log in the same directional trend.

This observation aligns with the mapping of the reservoir unit across the field on the seismic section, indicating a southward dip of the reservoir bed unit. Well Ogbenu 2 represents the updip section of the reservoir, while well Ogbenu deep 2 ST 1 signifies the downdip portion. Furthermore, the reservoir appears not to be filled to its natural spill point which represents the lowest part along the plunge of the roll-over anticline southward. Additionally, there appears to be a gas - water contact somewhere at the base of the reservoir interval within well Ogbenu deep 2 ST 1 (figure 17). Analysis of other reservoir intervals shows similar pattern or trend.

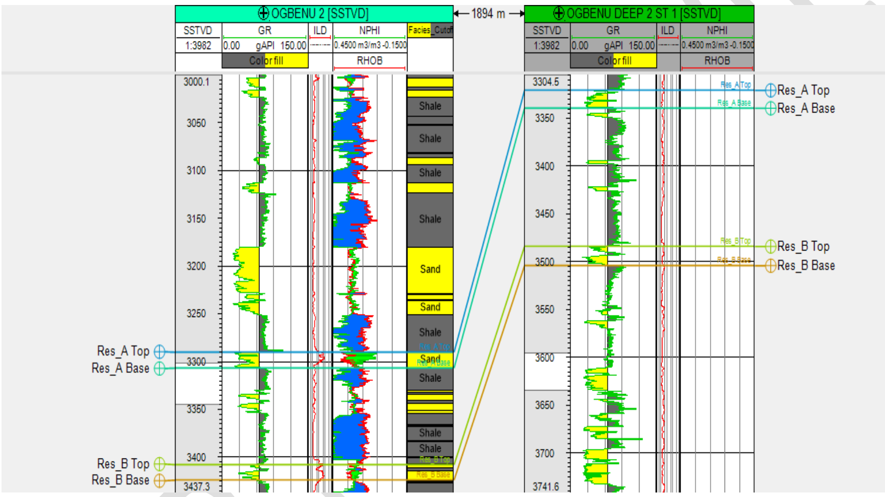

Figure 13: Well section through Ogbenu 2 to Ogbenu deep 2 st 1 displaying the reservoirs A and B intervals zones.

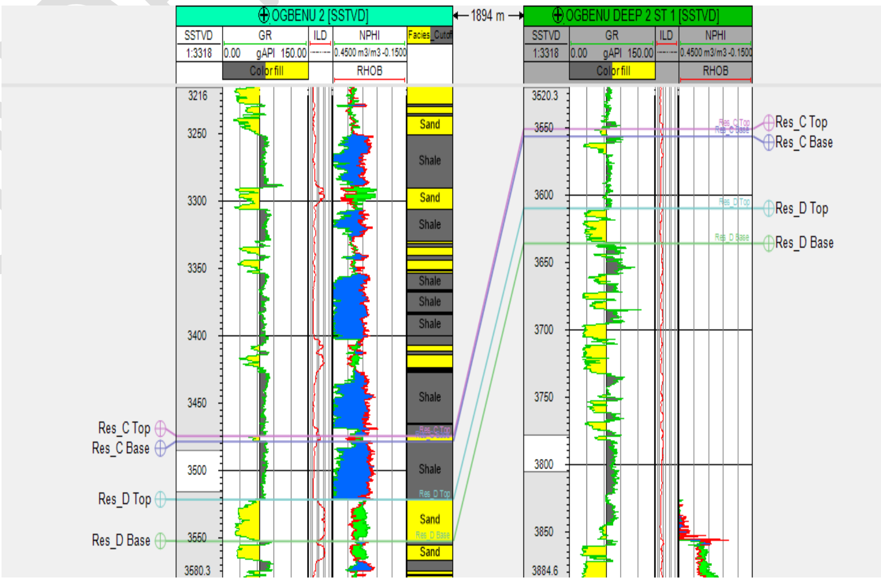

Figure 14: Well section through Ogbenu 2 to Ogbenu deep 2 st 1 displaying the reservoirs C and D intervals zones.

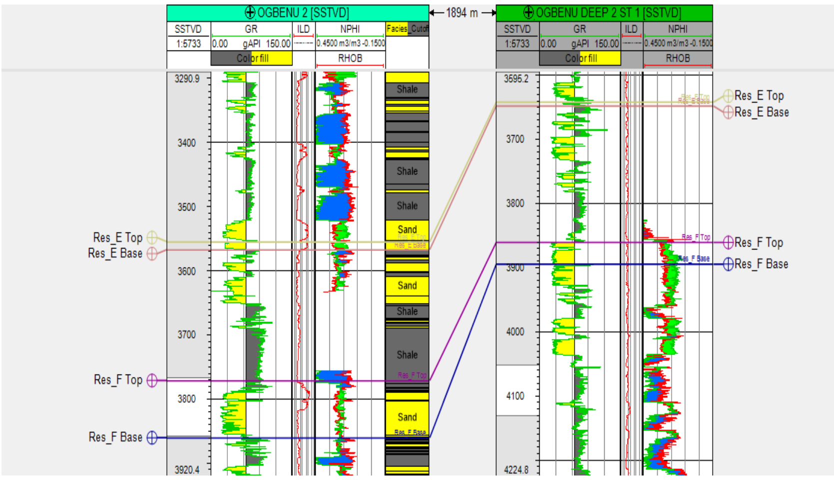

Figure 15: Well section through Ogbenu 2 to Ogbenu deep 2 st 1 displaying the reservoirs E and F intervals zones.

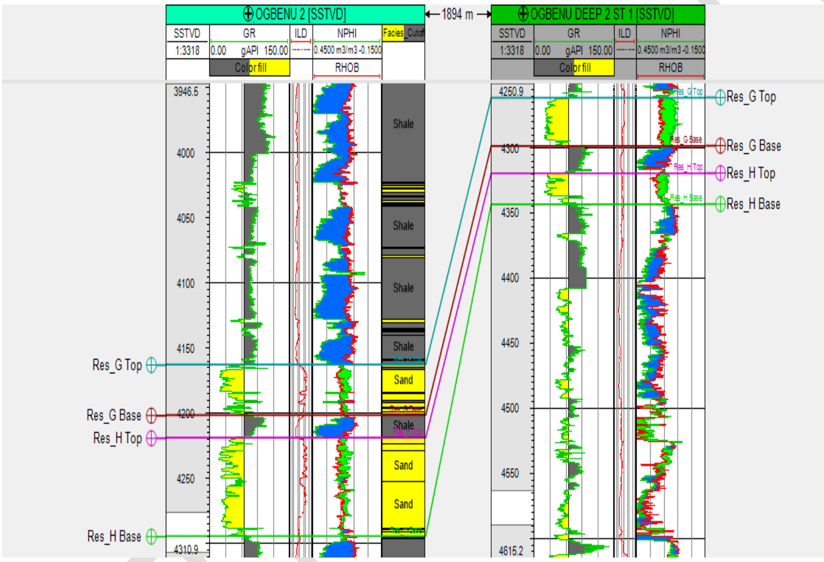

Figure 16: Well section through Ogbenu 2 to Ogbenu deep 2 st 1 displaying the reservoirs G and H intervals zones.

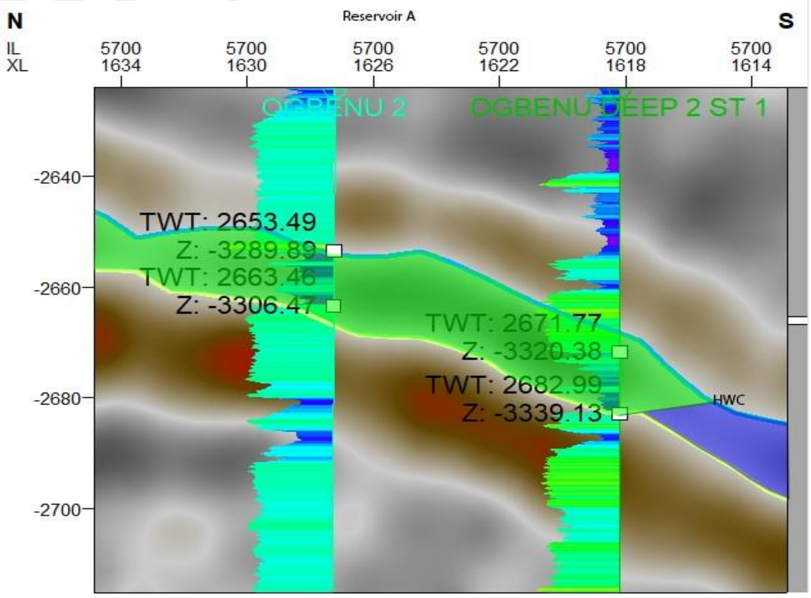

Figure 17: Seismic section through wells Ogbenu 2 and Ogbenu deep 2 st 1 showing the reservoir A interval. The beds can be seen to deep southwards.

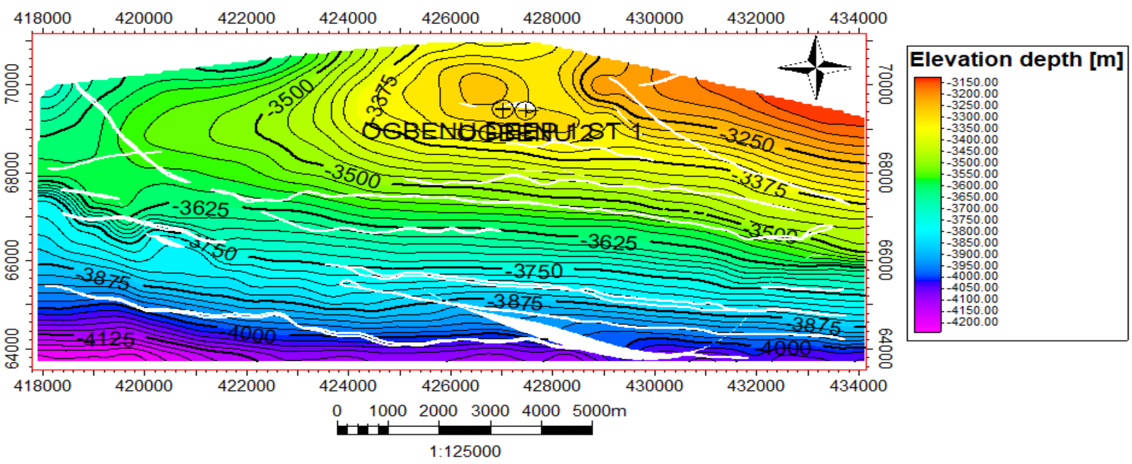

Figure 18: Time structure map for the top of reservoir A.

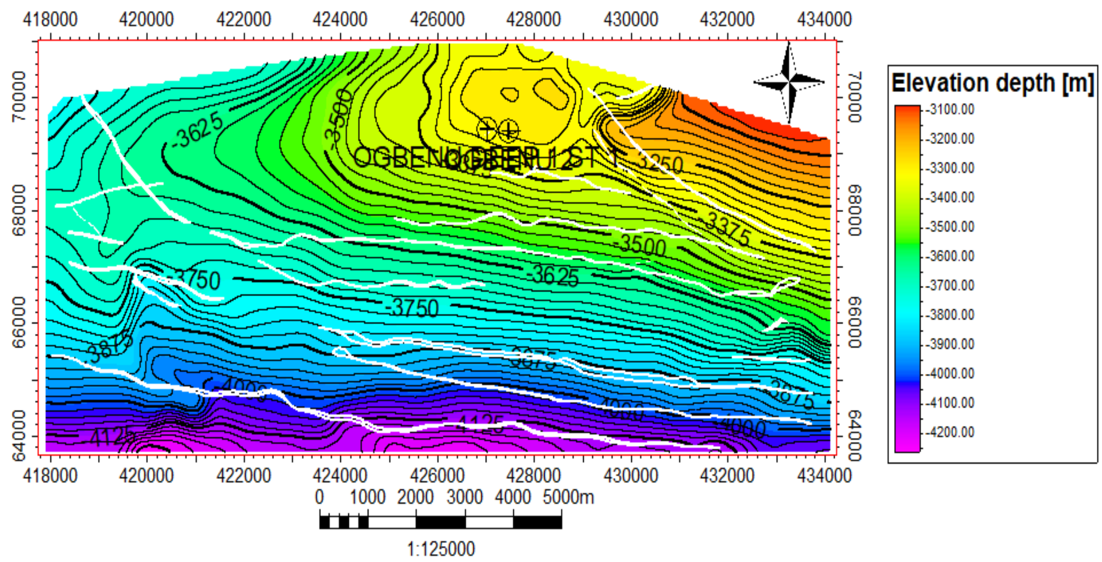

Figure 19: Time structure map for the top of reservoir B.

Petrophysical Analysis

Single well analysis revealed eight key reservoir intervals (reservoir A - H) for well Ogbenu 2 (Figure 20 to 25) correlated to well Ogbenu deep 2 ST 1. The average petrophysical properties calculated are Net-to-Gross, volume of shale, water saturation and porosity; the results were computed in Table 1. Porosity for reservoir A – H was compared with standard values in Table 2. The result shows that reservoir A has very good porosity, reservoir B, D, E, F and H have good porosity while reservoir C and G have fair porosity. From the gamma-ray and facies logs in the two wells, the reservoirs showed varying qualities and appeared to decrease in quality southward away from the structure controlling fault. Vertical variation in gamma-ray and facies log also indicates the high heterogeneity within each reservoir interval. Generally, this analysis confirmed that the eight reservoirs show good petrophysical properties and can make good prospects.). The calculated petrophysical properties are consistent with findings from Sofolabo *et al.* (2022); Adiela (2018); Sanuade *et al.* (2017); and Adewoye *et al.* (2013).

Table 1: The Petrophysical Properties of Reservoirs A-H.

Reservoir	Thickness (m)	NTG	Porosity	V_{sh}	S_w
A	17.53	0.70	0.22	0.24	0.32
B	20.15	0.82	0.15	0.41	0.27

C	4.02	0.81	0.12	0.42	0.48
D	30.07	0.86	0.18	0.21	0.18
E	10.65	1.00	0.19	0.17	0.24
F	86.33	0.35	0.16	0.19	0.12
G	40.48	0.89	0.12	0.28	0.20
H	76.7	0.85	0.16	0.28	0.23

Table 2: Qualitative Evaluation of Porosity (After Rider, 1996)

Percentage Porosity	Quality Description
0 – 5	Negligible
5 – 10	Poor
11 – 15	Fair
15 – 20	Good
20 – 30	Very Good
>30	Excellent

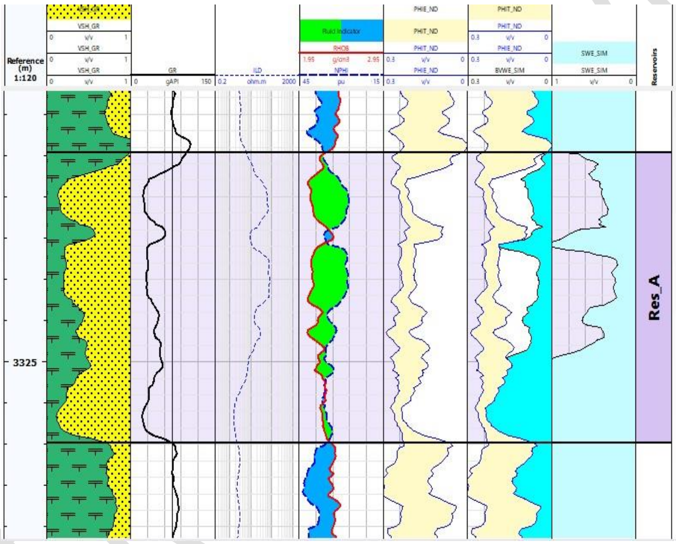

Figure 20: Well section of Ogbenu 2 displaying the Petrophysical logs for Reservoir A.

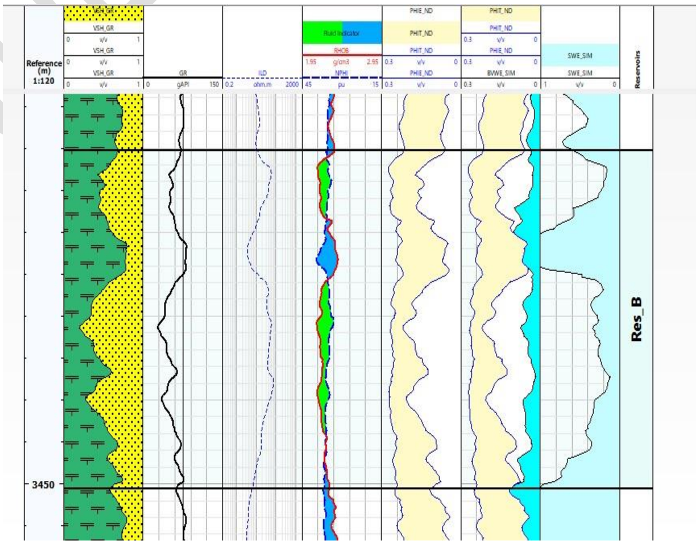

Figure 21: Well section of Ogbenu 2 displaying the petRophysical logs for Reservoir B.

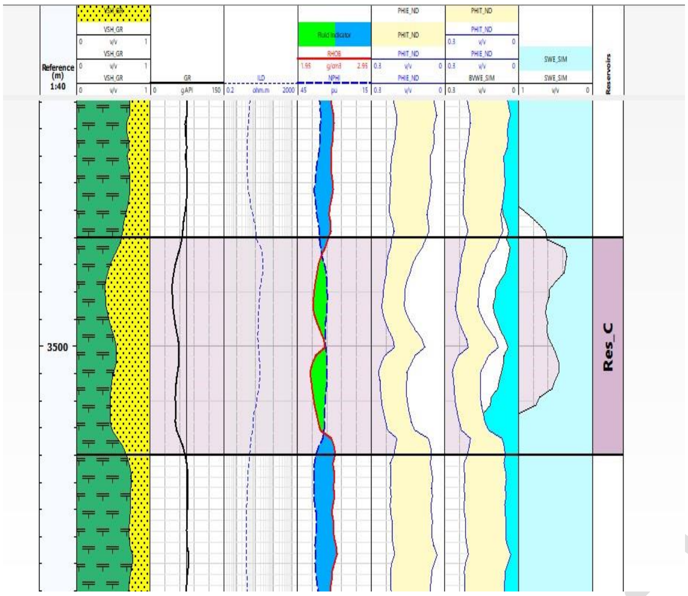

Figure 22: Well section of Ogbenu 2 displaying the Petrophysical logs for Reservoir C

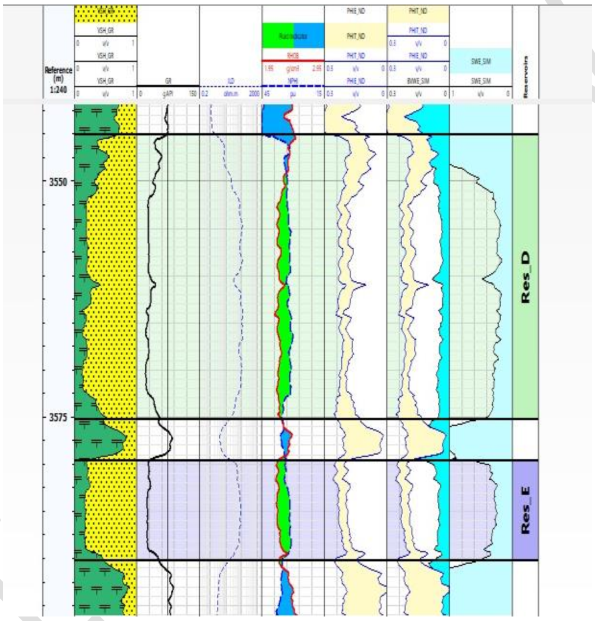

Figure 23: Well section of Ogbenu 2 displaying the Petrophysical logs for Reservoir D and E.

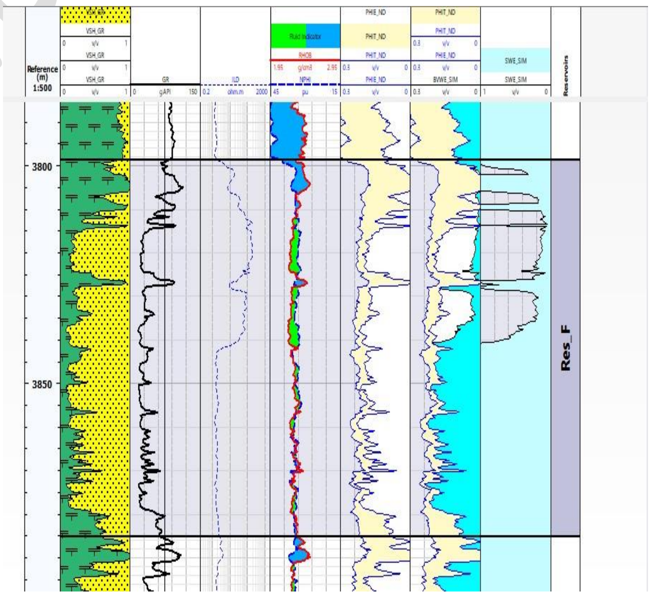

Figure 24: Well section of Ogbenu 2 displaying the Petrophysical logs for Reservoir F.

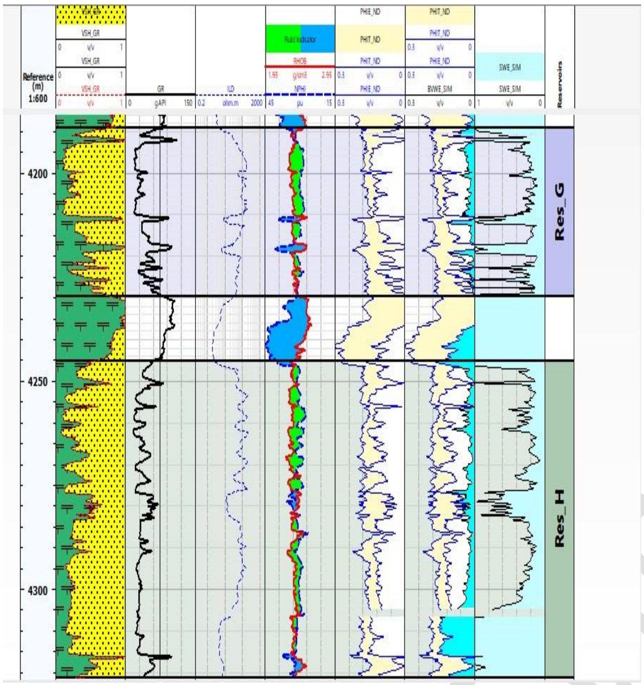

Figure 25: Well section of Ogbenu 2 displaying the Petrophysical logs for Reservoir G and H.

Volumetric Analysis

The reservoir properties used for the computation of Original Oil in Place (OIIP) volume for the identified eight reservoirs include average porosity, water saturation and NTG, acquired through petrophysical analysis. The rock volumes were derived by taking the product of the surface area of each reservoir interval's top horizon and the average reservoirs thickness from the wells. With the petrel software, polygons were used to artificially enclose the structures in relation to the spill points. The volume for each of the eight reservoirs was estimated as indicated in Table 3 below. From the analysis, two gas bearing reservoir (A and C) and six oil bearing reservoirs (B, D, E, F, G and H) were identified. The estimated Original Oil in Place volume for reservoir A is 29,025.57 MMBOE, B is 23.95 MMSTB, C is 2,776.37 MMBOE, D is 48.19 MMSTB, E is 16.69 MMSTB, F is 131.98 MMSTB, G is 42.19 MMSTB and reservoir H is 102.60 MMSTB. These results infer that the Ogbenu field has exploitable hydrocarbon potential. Furthermore, the volumetric analysis results are in line with the studies conducted by Adigwe *et al.* (2019); Omokenu *et al.* (2019); Owolabi *et al.* (2019); Oyedele *et al.* (2019); and Oyeyemi *et al.* (2017). These comparisons enhance the reliability and validity of this study's findings, providing a solid foundation for their implications in the understanding and management of hydrocarbon reservoir systems in the region.

Table 3: Reservoirs and the Estimated Original Oil in Place volume.

Reservoir	Hydrocarbon Type	OIIP (MMSTB)	GIIP (MMBOE)
A	Gas		29,025.57
B	Oil	23.95775	
C	Gas		2,776.374
D	Oil	48.19219	
E	Oil	16.69835	
F	Oil	131.984	
G	Oil	42.19574	
H	Oil	102.6037	

CONCLUSION

The comprehensive analysis of the Ogbenu field in the Niger Delta provides valuable insights into its subsurface geology, structural characteristics, and hydrocarbon potential. Facies identification and correlation revealed distinct formations (Benin, Agbada, and Akata) with unique gamma-ray log signatures, indicating variations in sandstone and shale facies. The east–west correlation across wells highlighted stratigraphic complexities, emphasizing the interplay of regression and transgression. The synthetic seismogram and seismic to well tie demonstrated effective correlation between seismic responses, validating the identification of reservoir intervals. Structural interpretation exposed a faulted rollover anticline influenced by lateral fault block movements, contributing to a complex structural style. The delineation of eight reservoir intervals through petrophysical analysis showcased varying porosity and quality, with a southward decrease. Volumetric analysis estimated Original Oil in Place (OIIP) volumes, identifying two gas-bearing and six oil-bearing reservoirs, affirming the Ogbenu field's exploitable hydrocarbon potential. This research advances the understanding of hydrocarbon reserves, lithologic characteristics and identification of high-potential areas in the Ogbenu field, expanding scientific knowledge in the Niger Delta. This integrative approach revealed complex reservoir variations and structural intricacies, enhancing the understanding of future exploration and production strategies in the Ogbenu field.

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