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RESERVOIR QUALITY STUDIES AND PROSPECT IDENTIFICATION OF A FIELD IN THE COASTAL SWAMP DEPOBELT, NIGER DELTA

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Abstract

Reservoir characterization involves the determination of the distribution of petrophysical properties, for optimum reservoir production. This study uses an integrated three-dimensional (3D) seismic and wireline log dataset from four wells, to assess the reservoir quality of sandstones of a field in the Coastal Swamp Depobelt, Niger Delta. Detailed petrophysical analysis revealed two main reservoirs (CH1 and CH2), which are relatively laterally continuous and show varying porosity and permeability values. In reservoir CH1, calculated porosity (ϕ) ranges from 0.210 to 0.264, permeability (k) ranges from 0.69 mD to 9.67 mD, net-to-gross (*NTG*) ranges from 0.374 to 0.698, volume of shale (V_{shale}) ranges from 0.12 to 0.20, while water saturation (S_w) ranges from 0.09 to 0.45. In the CH2 reservoir, results of the petrophysical analysis show that ϕ ranges from 0.210 to 0.290, k ranges from 1.41 mD to 27.93 mD, *NTG* ranges from 0.129 to 0.925, V_{shale} ranges from 0.12 to 0.25, while S_w ranges from 0.15 to 0.34. Structural analysis revealed that two-way and three-way fault-dependent closures are the main trapping styles in the study area. The faults dominantly trend NE-SW, dip southerly, and tend to compartmentalize the reservoir, as suggested by the variations in static hydrocarbon-water contact across fault blocks. Root mean square amplitude extractions show that areas with high amplitude have good reservoir quality and are hydrocarbon-bearing. On this basis, two prospects (Y and Z) were identified within the mapped reservoir units. Understanding variations in petrophysical properties is important as it serves as a key input in modeling hydrocarbon reservoirs.

Keywords: Petrophysics; Structural analysis; Amplitude; Prospect identification; Coastal Swamp.

1. Introduction

Reservoir quality defines the hydrocarbon storage capacity and deliverability. The hydrocarbon storage capacity is usually characterized by the effective porosity and the size of the reservoir, whereas the deliverability is a function of the permeability. Reservoir characterization involves the identification of a flow unit (reservoir) and determination of the petrophysical properties of a reservoir (porosity, permeability and fluid saturation).

Over the years, optimum reservoir production and production forecast is hinge on accurate characterization of the identified flow unit in the given field [1]. The determination of these reservoir quality properties across fields in the Niger Delta Basin has been a challenge especially at deeper intervals and in some onshore fields with stratigraphic and structural complexities [2]. This could also be attributed to inadequacy of data and reservoir variation for different depositional environments. This study involves the use of available seismic and wireline log data to delineate reservoir units, calculate the petrophysical properties of these reservoir rocks, and infer the reservoir distribution and reservoir quality trends of a field in the Coastal Swamp Depobelt, Niger Delta. This will provide a better understanding of the reservoir properties and their lateral thickness variation.

2. Geologic setting

The field of study is an onshore oil field in the Niger Delta region, located in the southern part of Nigeria between the longitude 3° E – 9° E and latitude 4° N – 6° N (Fig. 1a). The Niger

Delta Basin is situated within the Gulf of Guinea with extension throughout the Niger Delta Province [3-4].

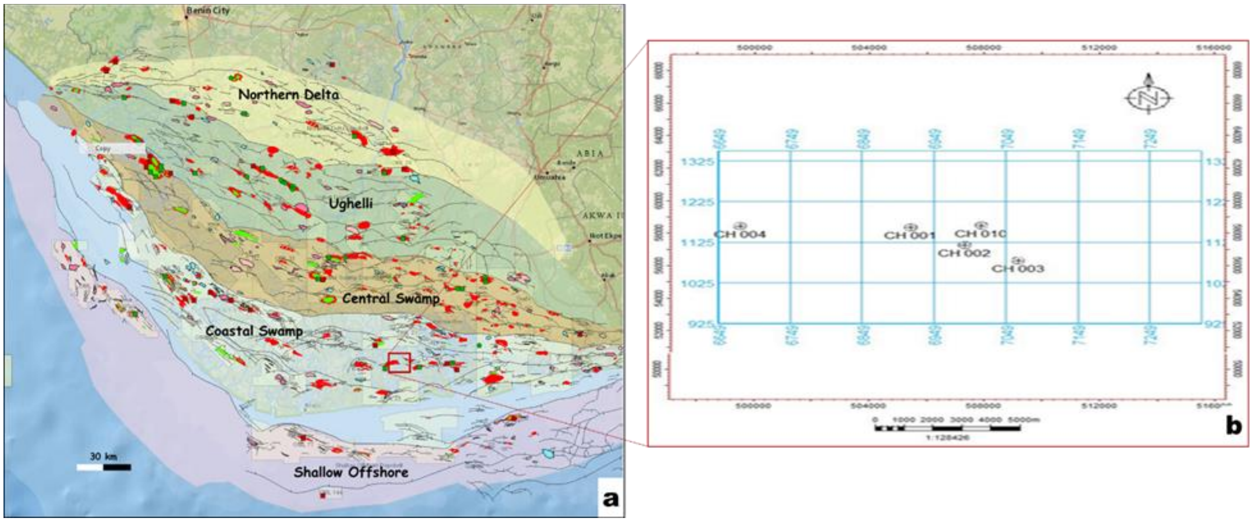

Figure 1. (a) Map showing the distribution of depobelts within the Niger Delta and the location of the study area within the Coastal Swamp Depobelt (after Ejedavwe [4]); (b) Base map of the study area showing the well distribution

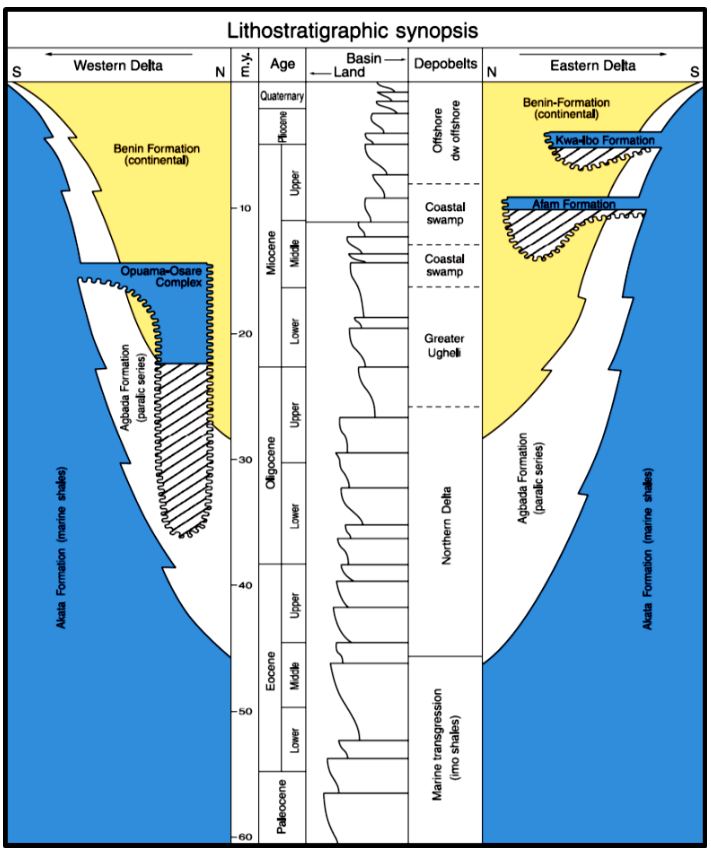

Figure 2. Generalised stratigraphic column showing the three lithostratigraphic units (formations) of the Niger Delta (after Saugy [10])

The tectonic framework of the continental margin along the West Coast of equatorial Africa is controlled by Cretaceous fracture zones expressed as trenches and ridges in the deep Atlantic. The fracture zone ridges subdivide the margin into individual basins, and in Nigeria, form the boundary faults of the Cretaceous Benue - Abakaliki Trough, which cuts far into the West African shield. The Trough - a failed arm of a rift triple junction associated with the opening of the South Atlantic. In this region, rifting started in the Late Jurassic and persisted into the Middle Cretaceous [5]. In the region of the Niger Delta, rifting diminished altoge-ther in the Late Cretaceous.

After rifting ceased, gravity tectonism became the primary deformational process. Shale mobility induced internal deformation and occurred in response to two processes [6]. First, shale diapirs formed from loading of poorly compacted, over-pressured, prodelta and delta-slope clays (Akata Formation) by the higher density delta- front sands (Agbada Formation). Second, slope instability occurred due to a lack of lateral basinward support for the under-compacted delta-slope clays. For any given depobelt, gravity tectonics were completed before deposition of the Benin Formation and are expressed in complex structures, including shale diapirs, roll-over anticlines, collapsed growth fault crests, back-to-back features, and steeply dipping, closely spaced flank faults [7-8]. These faults mostly offset different parts of the Agbada Formation and flatten into detachment planes near the top of the Akata Formation.

The Niger Delta has a stratigraphic succession which is divided into three diachronous litho-stratigraphic units from the Eocene to the Recent (Fig. 2). These are the continental top facies (Benin Formation), the paralic delta front facies (Agbada Formation) and the prodelta facies (Akata Formation), represented by a prograding depositional cycle that are distinguished mostly on the basis of sand-shale ratios, which apparently decrease in age, basinward [9-10].

The Benin Formation is the shallowest unit of the Niger Delta clastic wedge and occurs throughhout the entire onshore and part of the offshore Niger delta. The overall thickness of the formation varies from 400 m in the offshore to 3,500 m, onshore. The sands of the formation are in the form of point bars, channel fills, and natural levees.

The Agbada Formation underlies the Benin Formation and occurs throughout Niger Delta clastic wedge with thicknesses ranging from 3,000 m to 4,500 m, where it outcrops around Ogwashi and Asaba, southern Nigeria [11]. The lithologies consist of alternating sands, silts and shales, arranged within ten to hundred feet successions, and defined by progressive upward changes in grain size and bed thickness. The strata are generally interpreted to have formed in fluvial-deltaic environments. The formation ranges in age from Eocene to Pleistocene. Most structural traps observed in the Niger delta developed during syn-sedimentary deformation of the Agbada paralic sequence [7]. The interbedded shales within the formation form the primary seal.

The Akata Formation is the basal sedimentary unit, estimated to be 7,000 m thick in the central part of the clastic wedge [11]. It is characterized by dark grey shales and silts, with rare streaks of sand of probable turbidite flow origin [11]. The Akata shales are typically under-compacted and over-pressured. The shales also form diapiric structures including shale swells and ridges which often intrude into overlying Agbada Formation. The Akata Formation (Paleocene to Recent) is thought to be the main source rock of hydrocarbons in the Niger delta [11]. From the Eocene to the present, the delta has prograded southwestward, forming depobelts that represent the most active portion of the delta at each stage of its development [12]. These depobelts form one of the largest regressive deltas in the world with an area of some 300,000 km^2 [6], a sediment volume of 500,000 km^3 [13], and a sediment thickness of over 10 km in the basin depocentre [14].

3. Materials and method

Five wells and a 3D seismic volume covering an area of about 200 km^2 were available for this study. Only four wells (wells 01, 02, 04, and 10) had the requisite logs useful for petrophysical analysis. This study is an integrated workflow analyzing the suite of well logs and seismic data inputted in Petrel 3D software and Integrated Petrophysics (IP) software, for reservoir quality characterization in the field, Coastal Swamp Niger Delta.The Petrel software was used mainly for well correlation and seismic interpretation to decipher the extent of the reservoir in the field, while the Integrated Petrophysics software was used to calculate the petrophysical property of the reservoir such as net-to-gross (NTG), porosity, permeability, shale volume, and water saturation (fluid property) using a given mathematical function.

3.1. Seismic interpretation

The seismic data image quality and resolution decreases with depth especially below 3ms. However, amplitude gain correction attribute and envelope attribute in Petrel software were applied to improve the resolution. Regional fault interpretation was carried out to define a detailed structural framework for the study area using variance attribute (Fig. 3). Termination of reflections, abrupt changes in dip and changes in seismic patterns, were also adopted to tell the presence of faults. The faults were interpreted on the inline using a line interval of 16. Variance cube was generated from the 3D seismic volume of the study area.

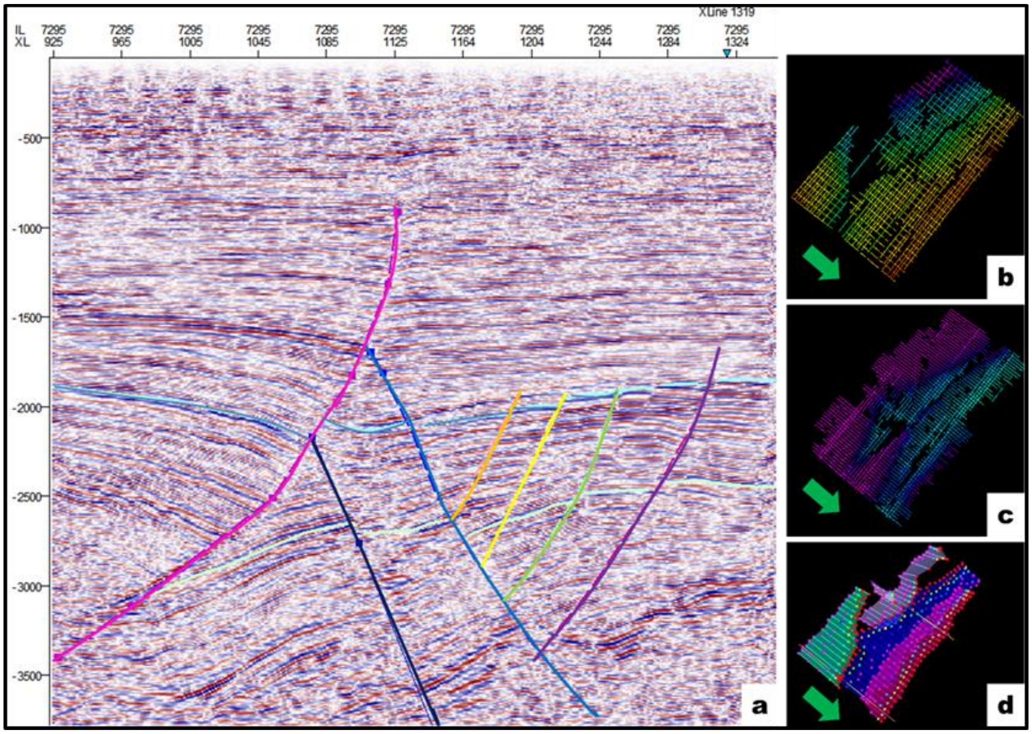

Figure 3. (a) Seismic line with horizon and fault interpretation; (b) Top CH1 Horizon, (c) Top CH2 Horizon; (d) Fault sticks on 3D view

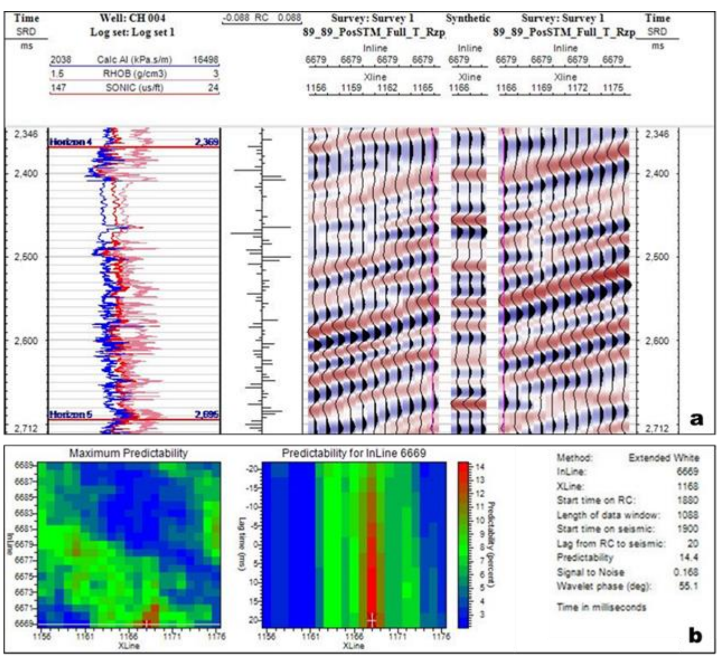

Figure 4: (a) Seismic to well tie showing tie between generated pseudo-seismic section and seismic; (b) Predictability of the pseudo-seismic section to actual seismic section

A pseudo-seismic was generated from the control well (well CH 04) using the wavelet from the sonic and density logs. The synthetic was tied to the seismic and a velocity function that gives the maximum correlation between the synthetic and the seismic was used as a function to convert the well from depth domain to time domain. Therefore, the well to seismic tie ensured that the well was placed to its actual stratigraphic location on the seismic so as to determine the seismic loop that corresponds to the well tops of interest (Fig. 4).

Horizons were identified by distinctive reflection patterns that could be observed over a layer with relatively large extent. This was done using the manual method due to faulting and poor seismic imaging. Identification of prospective reservoir is from the composite logs available.

The reservoir top marked on the well was identified on the seismic data using the generated synthetic seismogram. The identified reservoir tops were mapped on the 3D seismic volume on a negative loop denoting near top sand in every 8th inline and crossline interval increase (Fig. 4a).

3.2. Well Log correlation

A type well (Well 04) was selected from the wells according to availability of data. A candidate flooding surface was identified on the basis of stacking pattern analysis and a consistent regional correlation from the type well to other wells in the field was done. This concept of constructing a stratigraphic framework, helped in the identification of reservoir, delineating the architecture of the reservoir and the reservoir quality across the field.

3.3. Petrophysical evaluation

A single clay indicator (gamma ray) and double clay indicator (neutron-density) logs were used to calculate the volume of shale from the Integrated Petrophysics (IP) software. The volume of shale cut-off value of <=0.4 was used for the net reservoir and net pay zones.

For single clay indicator:

$$\mathrm{Vcl\ GR} = \frac{\mathrm{GR - GR\ clean}}{\mathrm{GR\ clay - GR\ clean}} \qquad \text{(eq. 1)}$$

where: GR clean = value of the gamma ray in a clean zero Vclay zone; GR clay = value of the gamma ray in a 100% clay zone;

For double clay indicator:

$$\mathrm{Vcl\ ND} = \frac{(\mathrm{DENcl - DENcl1}) \times (\mathrm{NEU - NEUcl1}) - (\mathrm{DEN - DENcl1}) \times (\mathrm{NEUcl2 - NEUcl1})}{(\mathrm{DENcl2 - DENcl1}) \times (\mathrm{NEUcl - NEUcl2}) - (\mathrm{DENcl - DENcl1}) \times (\mathrm{NEUcl2 - NEUcl1})} \qquad \text{(eq. 2)}$$

where: DENcl1; NEUcl1 and DENcl2; NEUcl2 are the density and neutron values for the two ends of the clean line, respectively.

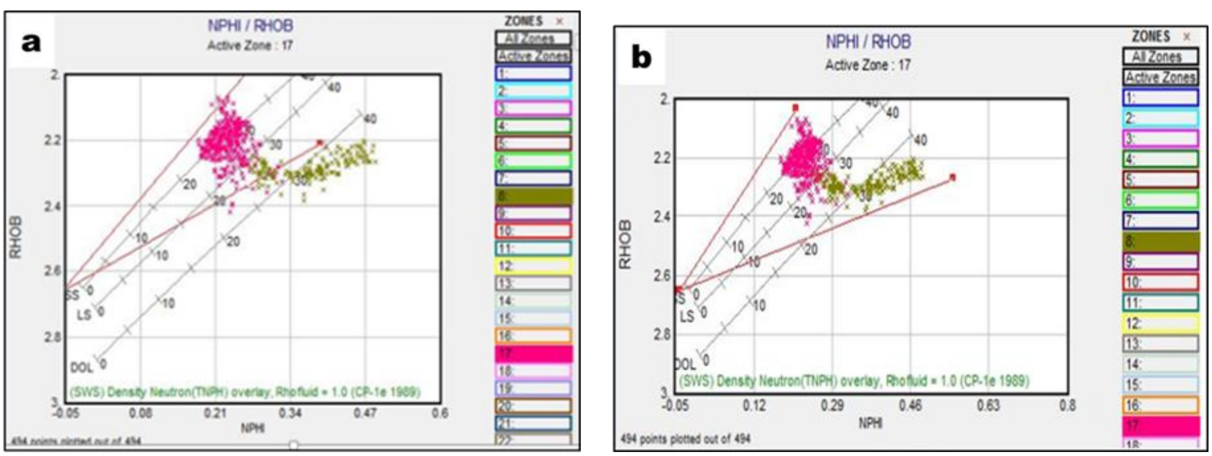

Figure 5. (a) Neutron-Density cross-plot (uncorrected); (b) Neutron-Density crossplot (corrected for the effect of shale).

The gas and shale effect on the volume of shale was corrected for by adjusting the "sand" line on neutron-density cross-plot, such that the calculated V_{shale} from single and double clay indicators match (Fig. 5). The neutron-density model within Interactive Petrophysics was used to calculate the porosity. A porosity cut-off of 0.15 was used for the net reservoir and net pay calculations. The criteria for classifying porosity are given by: $\phi < 0.05$ = negligible; $0.05 < \phi < 0.1$ = poor; $0.1 < \phi < 0.15$ = fair; $0.15 < \phi < 0.25$ = good; $0.25 < \phi < 0.30$ = very good; $\phi > 0.30$ = excellent [15]. The Simandoux equation was used to calculate the water saturation of the reservoir, with the cut-off value of 0.4 set for pay zones.

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4. Results and discussion

4.1. Reservoir evaluation

Two major sand bodies were identified as CH1 and CH2 reservoirs in the four wells and correlated across the field. The well correlation panel shows the tops and bases of the reservoirs (Fig. 6).

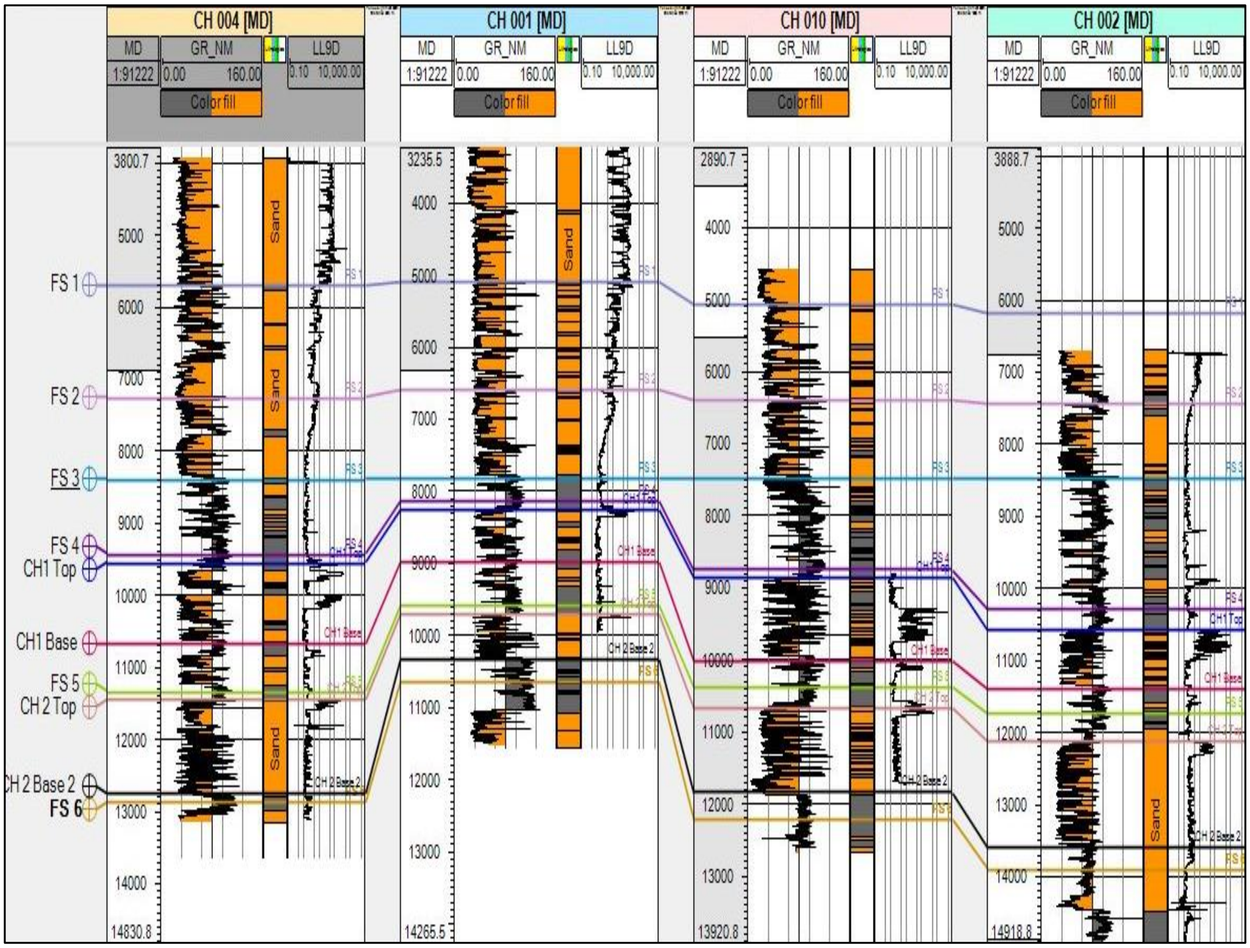

Figure 6. NW-SE well correlation panel showing the delineated reservoirs with their tops and bases

In Well 01, the reservoirs occur at depth intervals from 8250 ft to 8450 ft, and 9709 ft to 10329 ft for CH1 and CH2, respectively. The reservoirs depth intervals for Well 02 range from 10569 ft to 11339 ft for CH1 and from 10600 ft to 11350 ft for CH2. Similarly, the CH1 and CH2 reservoir depth intervals for Well 04 ranges from 9514 ft to 9900 ft and 10000 ft to10650 ft respectively, while it ranges from 8900 ft to 10000 ft and 10100 ft to 12000 ft respectively in Well 10. The analysis of all the well section revealed that each of the sand units extends laterally throughout the field and varies in thickness with some unit occurring at greater depth than their adjacent unit, which is a possible evidence for faulting. The shale layers are observed to decrease upwards along with a corresponding increase in sand layers. This pattern in the Niger Delta indicates transition from Agbada to Benin Formation [16]. The log analysis also shows that the two delineated reservoirs were identified as hydro-carbon bearing units across the four wells, because of their associated high resistivity values.

CH1 Reservoir

The result of average computed petrophysical parameters for reservoir CH1 shows gross pay reservoir thickness ranging from 100 ft to 461ft, net pay thickness ranging from 60 ft to

252 ft, net/gross thickness (NTG) ranging from 0.374 to 0.698, volume of shale (V_{shale}) ranging from 0.120 – 0.200, porosity range of 0.210 - 0.264, and permeability values ranging from 0.69 to 9.67 mD, in the wells (Table 1). The porosity values infer good to very good reservoir quality [15], and the NTG generally decreases from NW- SE (Fig.6).This may be as a result of marine influence down dip [9].The water and hydrocarbon saturation have average values of 9% – 45% and 55% –91%, respectively. Continuous log-derived petrophysical properties of the CH1 reservoir are shown in Figure 7.

Table1. Summary of petrophysical parameters for Reservoir CH1

Wells	Top (ft)	Base (ft)	Reservoir thickness, (ft)	Gross pay (ft)	Net pay (ft)	N/G	V_{shale}	ϕ	K, (mD)	S_h	S_w
01	8250	8450	200	100	60	0.600	0.120	0.230	1.45	0.70	0.30
02	10569	11339	770	461	252	0.547	0.185	0.209	0.69	0.91	0.09
04	9514	9900	386	116	81	0.698	0.140	0.210	1.25	0.82	0.18
010	8900	10000	1100	457	170.7	0.374	0.200	0.264	9.67	0.55	0.45

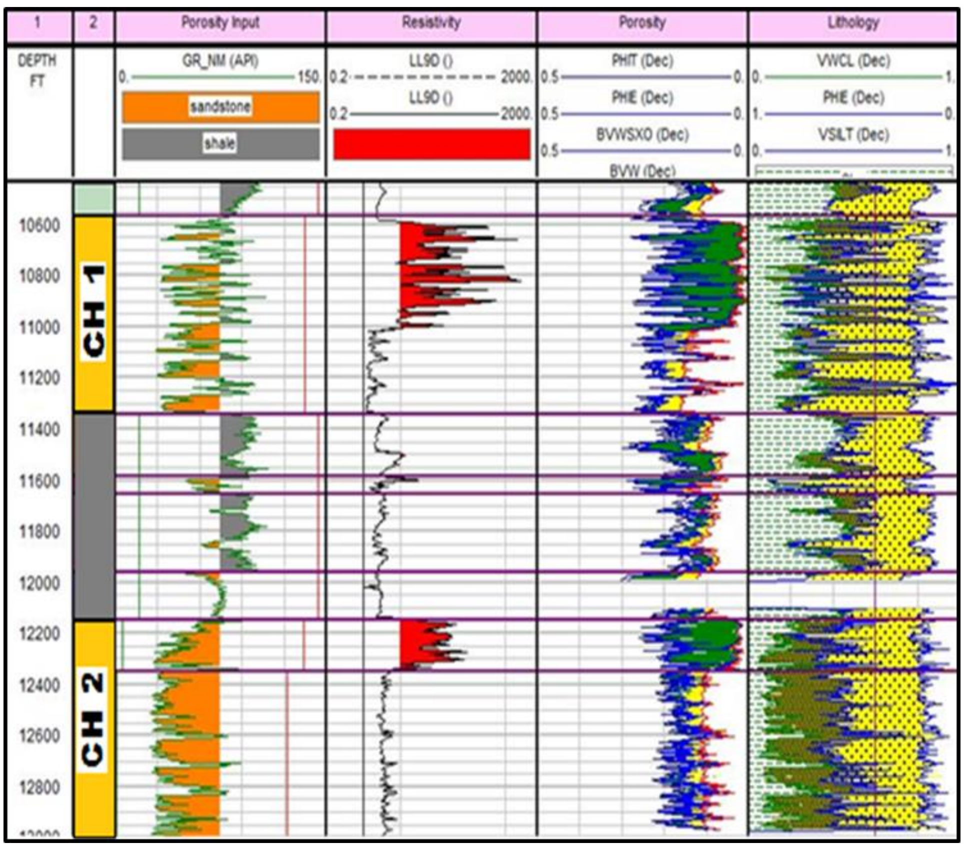

Figure 7. Log-derived petrophysical properties of CH1 and CH2 reservoirs in "type" Well 02

CH2 Reservoir

Petrophysical analysis of reservoir CH2 shows gross pay thickness ranges from 60 ft to 951 ft, net thickness ranges from 50 ft to 187 ft, NTG ranges from 0.129 to 0.925, V_{shale} ranges from 0.120 to 0.250, porosity ranges from 0.210 to 0.290, while water saturation (Sw) and hydrocarbon saturation (Sh) ranges from 15% to 34%, and 66% to 85%, respectively (Table 2; Fig. 7). Reservoir CH2 has a good to very good reservoir porosity quality [15], but permeability values range from 1.41 mD (poor) to 27.93 mD (fair), possibly due to a high content of dispersed clays [17].

Table 2. Summary of petrophysical parameters for Reservoir CH2

Wells	Top (ft)	Base (ft)	Reservoir thickness, (ft)	Gross pay (ft)	Net pay (ft)	N/G	V_{shale}	ϕ	K, (mD)	S_h	S_w
01	9709	10329	620	60	50	0.833	0.165	0.230	1.45	0.80	0.20
02	10600	11350	750	205	138	0.674	0.250	0.240	2.44	0.66	0.34
04	10000	10650	650	202.5	187	0.925	0.150	0.290	27.93	0.78	0.22
010	10100	12000	1900	951	122	0.129	0.120	0.210	1.41	0.85	0.15

4.2. Structural analysis

Structural interpretation shows that the field is highly faulted with several fault block forming closure and potential traps for hydrocarbon entrapment and accumulation. The dominant fault configuration is NE- SW, with significant growth on the faults bounding the major fields, which are mainly synthetic (Figs. 8 and 9). The identified prospects are fault dependent closure with the fault being sealed and impeding the outflow of the hydrocarbon from the structural trap. The faulting tends to compartmentalize the reservoirs since they are sealing, giving rise to different areas of hydrocarbon accumulation that do not communicate. This is evident in the hydrocarbon contact variation in different wells at different fault closures (Fig. 8c; 9c).The variation in static hydrocarbon-water contact between fault blocks has been used as a proxy for the compartmentalization and lack of pressure communication between reservoirs in previous studies [18]. Some of the identified prospects close around the footwall (footwall closure) and hanging wall (hanging wall closure); they are also two-way and three-way fault dependent closures (Fig. 8a).

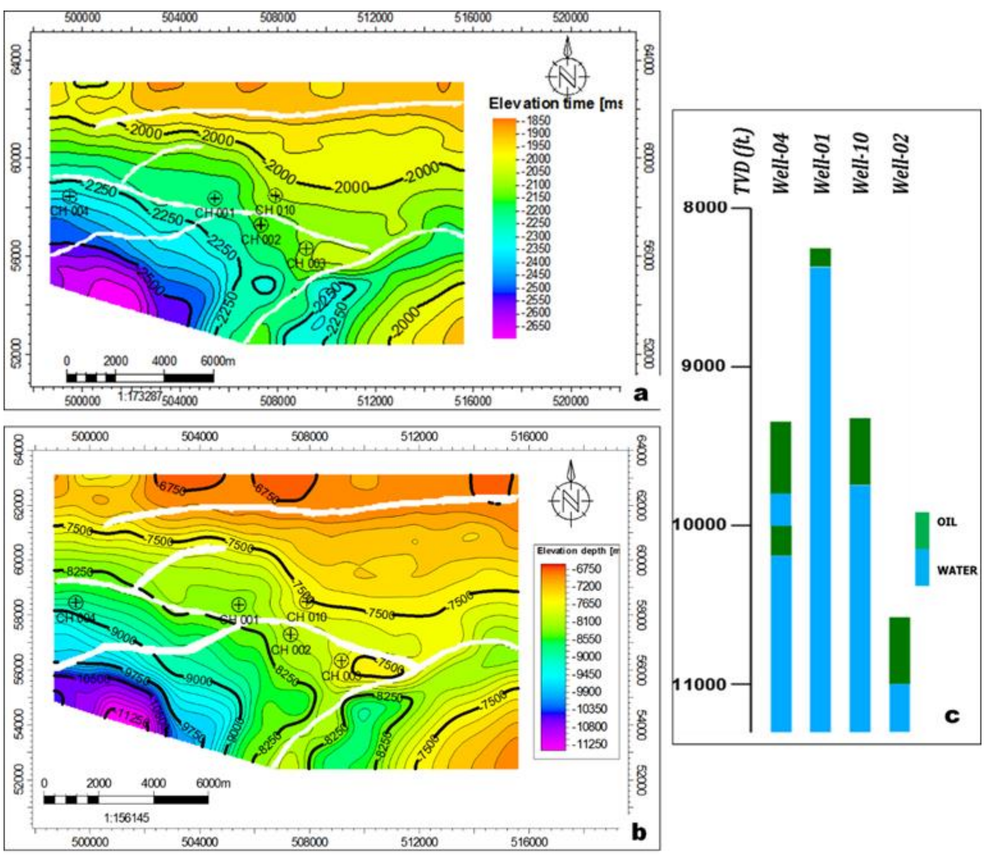

Figure 8. (a) Time structural map for top horizon CH 1 (b) Depth structural map for top horizon CH 1 (c) Varying hydrocarbon contacts in different wells, within CH 1 reservoir, probably due to fault compartmentalization

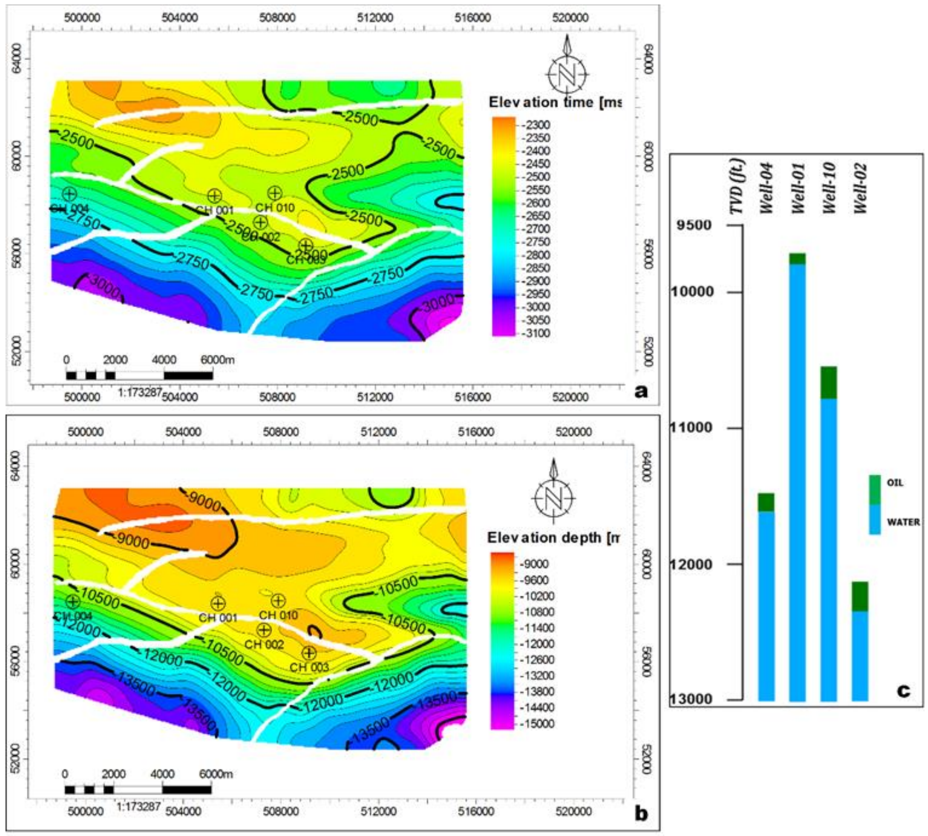

Figure 9. (a) Time structural map for top horizon CH 2 (b) Depth structural map for top horizon CH 2 (c) Varying hydrocarbon contacts in different wells, within CH 2 reservoir, probably due to fault compartmentalization

4.3. Seismic amplitude attribute analysis

Seismic amplitude attribute map generated from the two horizon maps showed that the fault closures are characterized by high amplitude zone (Fig.10). Since the wells drilled in the structural closures with high amplitude encountered hydrocarbon, the high amplitude recorded on the mapped reservoir top/horizons, could indicate the presence of hydrocarbon within the mapped reservoirs and supports the results of the well log analysis.

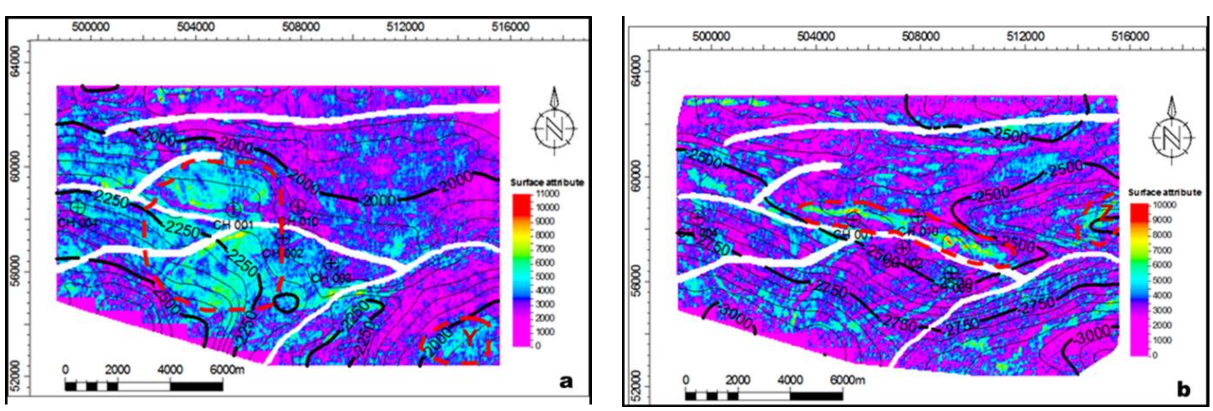

Figure 10. (a) Seismic root mean square amplitude map for horizon CH1. Note undrilled prospect "Y" in the southeast corner of the study area (b) Seismic root mean square amplitude map for horizon CH2. Note undrilled prospect "Z" in the eastern part of the study area

The seismic amplitude analysis on the CH1 reservoir top shows that there is also a possible hydrocarbons-bearing prospect with high amplitude, tagged "Y", in the south-eastern part of the study area which has not been penetrated by any well. Seismic amplitude analysis on the CH2 reservoir top shows that the linear (channel-like) trend of high amplitude along the E-W trending fault, in the central part of the study area are less bright relative to that observed in the CH1 reservoir. This is most likely the result of a relatively thin hydrocarbon column as can be seen in interpreted well logs (Fig. 7). An undrilled prospect tagged "Z" was identified on the eastern part of the CH2 reservoir top.

5. Conclusion

This study has shown that reservoir quality is the key to its hydrocarbon volume accumulation and producibility. Two major reservoirs at different intervals in the well logs were mapped in the field. The study revealed that the reservoir sand units mostly extend laterally throughout the field, but varies in thickness, with some unit occurring at greater depth than their adjacent unit, possibly related to faulting. The dominant fault trend is NE-SW, and the faults tend to compartmentalize the reservoir as evidenced by the variations in static hydrocarbon-water contact across fault blocks. The reservoir porosity show good to very good reservoir quality, ranging from 0.21 to 0.29. However, reservoir permeability is less favourable, ranging from 0.69 mD (poor) to 27.93 mD (fair), attributable to the presence of high dispersed clay content. Overall, these reservoirs showed a general decrease in quality in the basin ward direction from the most proximal well to the most distal well.

Seismic amplitude attribute maps extracted from the tops of the mapped reservoirs showed that the hydrocarbon bearing reservoirs are characterized by relatively high amplitudes (bright spots) in areas enclosed by the structural traps. This led to the identification of other undrilled prospects (Prospects Y and Z) in the field of study through amplitude analysis.

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