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Maximizing Production Through Evaluation of New Prospects in the Producing "Tuba Field", Onshore Niger Delta

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Abstract

This study involved the assessment of the near field and deeper exploration targets of the TUBA-Field, onshore Niger Delta to maximize production. The field consists of five wells (TUBA-001, 002, 003, 005 and 006), that were drilled on one fault block. These wells have been drilled for exploration and appraisal; and some have also been developed. But with the dwindling energy reserves, there is need to maximize the potential of this existing asset by searching for additional resources around it. This research entails the use of high resolution 3D seismic data, well log and biostratigraphic data for structural, sequence stratigraphic, petrophysical and volumetric analyses to better understand the possible hydrocarbon plays so as to identify new drilling opportunities. Six horizons were mapped (R12, R13, R14, R15, Deep1 and Deep2). The field showed laterally continuous shoreface reservoirs. The analysis revealed two new prospects; one near field prospect on R12 horizon and one deeper prospect on Deep2 horizon. Also, the result of the petrophysical evaluation on two analogue reservoirs (R12 and R13) in TUBA-001 gave an average porosity value of 0.23v/v (23%) which indicates good quality reservoirs. Similarly, the Net-to-Gross of 0.84 (84%), indicates good sand development across the wells. The calculated average water saturation of 0.28v/v (28%) corresponds to the presence of 0.72v/v (72%) hydrocarbon saturation. The evaluated stock tank oil initially in place (STOIIP) for R12 prospect for the low, mid and high cases are 3.7, 9.3 and 18.3mbbl respectively, whereas the gas initially in place (GIIP) values are 7.1, 18.0 and 35.1bcf. Also, the volume of low, mid and high STOIIP cases for Deep2 prospect are 0.6, 2.1and 4.6mbbl respectively with an associated GIIP values 1.3, 4.1 and 8.9bcf.

***Keywords**: Prospect; structure; reservoir quality; volumetric.*

1. Introduction

There has been a consistent increase in the global demand for oil and gas. However, the enormous challenge in meeting this demand, is the steady decline in daily production from old oil fields. Despite application of new technologies, the volume of discoveries has remained relatively low, while the cost of exploration has continued to increase. Consequently, oil industries now spend less on exploration and focus more on improving production in existing fields [5]. Currently, there is a drive by Niger Delta marginal field operators to enhance their production capacity by rejuvenating the existing fields through the integration of multi-disciplinary approach, which includes geophysics, geology, petrophysics etc. In line with this, and in order to reduce the costs of finding new reserves from new fields, near-field exploration seems to be a better option than wildcat exploration. This is because the findings from a proven field, and experience gathered during production can be used to unravel other prospects within the field; thus reversing the declining trend in production of such a field. Despite the numerous studies carried out on existing oil fields in the Niger Delta – showing good understanding on the structural interpretation, reservoir quality assessment, prospect identification and volumetric estimates [1-3, 12]; there is a need to understand how these various properties interact both in space and time in order to predict and identify new prospects at a relatively low cost within existing fields. Therefore, the objective of this study is to show how we can use the existing data from a producing field to identify new prospects in order to maximize production and meet the increasing global demand. This study made use of a 3D seismic data, five well logs and stratigraphic data from an already producing "TUBA" Field, Northern Depobelt, Niger Delta (Fig. 1) to identify and quantify new drillable opportunities that will help maximize production in that field. TUBA-Field is currently being operated by an active oil and gas firm, but the production from the field so far has reduced, warranting the search for new finds for increased production. The field is characterized by NW-SE trending growth faults and associated rollover anticlines which is consistent with the regional structural settings of the Niger Delta. The overall stratigraphy of the area reflects coarsening-upward log motifs. There has been five well penetrations in the field namely; TUBA-1, 2, 3, 5 and 6. These wells are aligned from the northwestern to the southeastern direction within the area. Target sands are those of the Agbada Formation; often between 9000ft and 13000ft, with the only challenge being a decrease in production output in recent times.

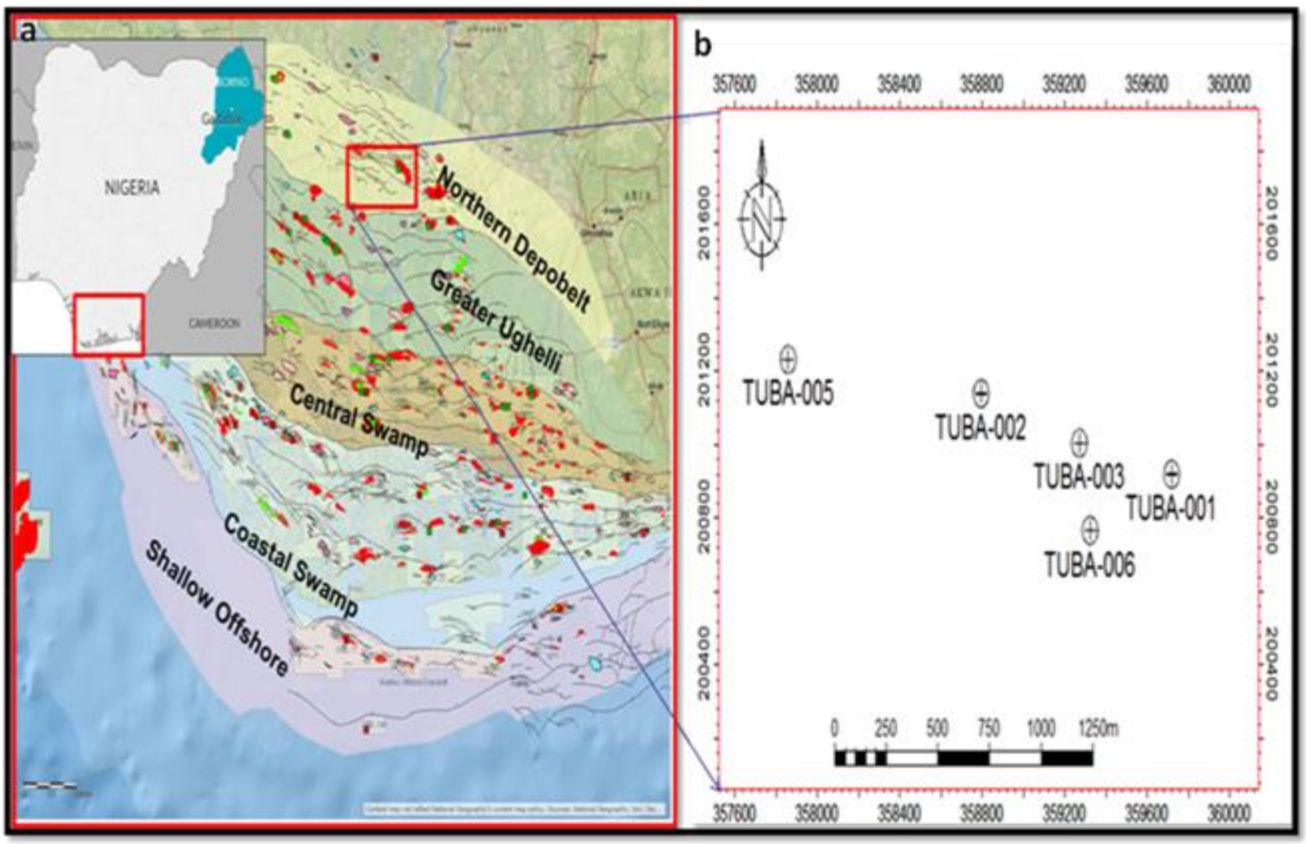

Fig. 1. Map of the Niger Delta showing (a) the study area and the depobelts; (b) well location map of the field

2. Geologic setting and stratigraphy

The Niger Delta Basin is a wave and tide dominated delta, located in the Gulf of Guinea of West Africa [10] (Fig. 1). The delta is a southward prograding clastic setting from Eocene to the present, forming depobelts that represent the most active part of the delta at each stage of its development [6]. These depobelts form an area of some 300,000 km^2 [11], a sediment thickness of over 10km [9], and a sediment volume of 500,000 km^3 in the basin depocenter [8]. Well sections through the Niger Delta generally display three vertical lithostratigraphic sub-divisions: an upper delta top facies; a middle delta front lithofacies; and a lower pro-delta lithofacies [4, 13]. These litho-units (Fig. 2) correspond to the Benin Formation (Oligocene -

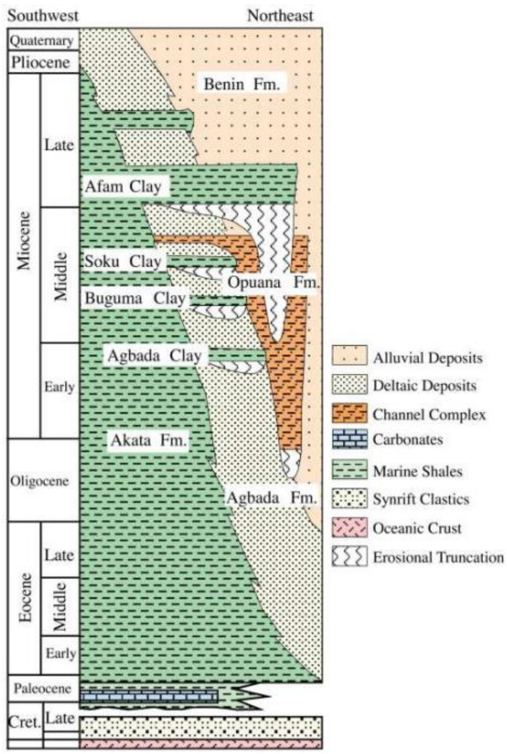

Fig. 2. Diagram showing Niger Delta stratigraphy [6,15]

Recent), Agbada Formation (Eocene - Recent) and Akata Formation (Paleocene - Recent) respectively [16]. The Benin Formation is about 280 metres thick, but may be up to 2,100 metres in the region of maximum subsidence [21] and consists of continental sands and gravels. It overlies the Agbada Formation and becomes progressively younger southwards. The Agbada Formation is a paralic succession with an alternation of sands and shales. The juxtaposition of these sands and shales in a growth fault system makes this interval the major petroleum-bearing unit of the basin. The sands represent point bar deposits, channel fills and natural levees, that are of good reservoir quality. Finally, the Akata Formation is mainly of marine shales, with sandy and silty beds which are thought to have been laid down as turbidities and continental slope channel fills [6]. It is under-compacted and of high pressure with its associated mobile shales.

3. Materials and methods

Five well logs from five wells, 3-D post-stack time migrated (PSTM) seismic in SEG-Y format, check shot from one of the wells, deviation from five wells and biostratigraphy data from three wells were available for the study. All well data were of good quality with few missing sections down deep. Amplitude gain correction attribute and envelope attribute in Petrel software were applied to improve the resolution of areas of poor seismic quality. Regional fault interpretation was carried out to define a detailed structural framework for the study area using variance attribute. Termination of reflections, abrupt changes in dip and changes in seismic patterns, were used to map faults. The faults were interpreted on the inline – which reveals their true dips. Variance cube was generated from the 3D seismic volume of the study area which helps in identifying sub-seismic scale faults that may impact on traps integrity. Also, the depositional sequences and their corresponding stacking patterns and system tracts were delineated on the wells using sequence stratigraphic principles of Vail; van Wagoner *et al.* [19-20]. The application of sequence stratigraphic principles is vital in understanding and predicting potential new reservoirs. The biofacies data were used to mark the candidate maximum flooding surfaces and sequence boundaries. Marker shales, which are typical maximum flooding surfaces (MFS) were first identified and correlated across the field, making it easier for the individual reservoirs to be identified and matched across the wells. Information on Foram and Pollen zonations (F-zones and P-zones) were used to date and name the maximum flooding surfaces (MFS). Depositional sequences and associated systems tracts were established using the maximum flooding surfaces and sediments stacking patterns on the gamma ray (GR) logs respectively. The wells were correlated in order to map the lateral extent of the sand intervals. Sediment stacking patterns and interpreted environments against depth were plotted on wells where they exist. An insert of a discreet log column beside existing logs on the Petrel well section window was done. Petrophysical evaluation was carried out on two selected reservoirs (R12 and R13). This is to ensure high fidelity of reservoir parameters due to their proximity to the deepest mapped horizon of interest (Deep-Horizon 2). Well-logs such as neutron/density, gamma ray and resistivity were used to generate petrophysical log plots that show reservoir fluid types and to estimate reservoir properties like net-to-gross (NTG), porosity (Ø) and water saturation (S_w).

The effective porosity (Φ_e) was evaluated using the equation;

$$\Phi_e = \frac{p_{ma} - p_b}{p_{ma} - p_f} - V_{sh}\left\{\frac{p_{ma} - p_{sh}}{p_{ma} - p_f}\right\} \quad (1)$$

where: p_{ma} = matrix density (usually 2.65g/cc sandstone); p_f = formation fluid's density (1.0gm/cc for water and 0.8g/cc for hydrocarbon); p_b = formation bulk density (obtained from density log at 0.5ft. interval); p_{sh} = density of the clay point interval. Archie's equation was used to determine the saturation for the invaded zone as shown below:

$$S_W = \frac{a\ X\ R_W}{\phi^m} \quad (2)$$

where: S_w = water saturation of the uninvaded zone R_t= true formation resistivity (LLD) ϕ = porosity value from density log R_w = resistivity of formation water**.**

4. Results and discussions

A total of sixteen reservoirs tops and bases were correlated across the five wells. The well logs revealed a paralic succession of shales and sands; typical of the Agbada Formation of the Niger Delta Basin (Fig. 3). The sands are generally characterized by coarsening-upward succession of vertically stacked reservoirs that are overlain by shale baffles in some places.

About four maximum flooding surfaces (MFS), five sequence boundaries (SB) and four depositional sequences were identified. Each MFS is bound above and below by two sequence boundaries. Most of the reservoirs correspond to the lowstand and highstand system tracts (Fig. 3). The lowstand system tracts are made up of sands deposited mostly from bypassed channels during the lowstand regime – these sands usually make good quality reservoirs. During the highstand regime, good reservoir sands are deposited landward. The ability to predict the spatio-temporal distribution of these sands is vital in identifying new prospects from an already producing field. In the absence of information on P-zones for absolute dating of these major geologic event, a range of 30 - 33Ma was assigned to these markers with the help of the F-zone information on the Niger Delta chronostratigraphic chart. The first depositional sequence falls within depths of 10940m and 10570m and bounded above and below by SB1 and SB2. The second depositional sequence falls within depths of 10570m and 9730m and bounded above and below by SB2 and SB3. The third depositional sequence is within 9730m and 9020m and is bounded above and below by SB3 and SB4. Finally, the forth depositional cycle lies between 9010ft and 8200ft and is bounded above and below by SB 4 and SB 5 (Fig. 3). Each sequence begins with an LST and ends with a HST. These sequences show subtle increase in thickness up depositional dip, and decrease down depositional dip, which implies a decreased sand development distally. The delineated depo-setting for the sands are mostly; neritic (N), inner-neritic (IN), middle-neritic (MN) and outer-neritic (ON) (see Fig. 3).

Based on the production history of the field, reservoirs R12 - R15, which were delineated within MFS 1 and 2 have the highest production capacities. So, in finding new drilling opportunities around the field, those reservoirs form the major focus in terms of their lateral extent and reservoir qualities (i.e. Vshale, porosity, permeability, hydrocarbon saturations, etc). A closer focus and correlation across the tops of the four sand reservoirs of interest show clear continuity in all the five wells (Fig. 4). The sands show upward coarsening motif with clear interbedded shales and their thicknesses gradually decreases along the dip direction.

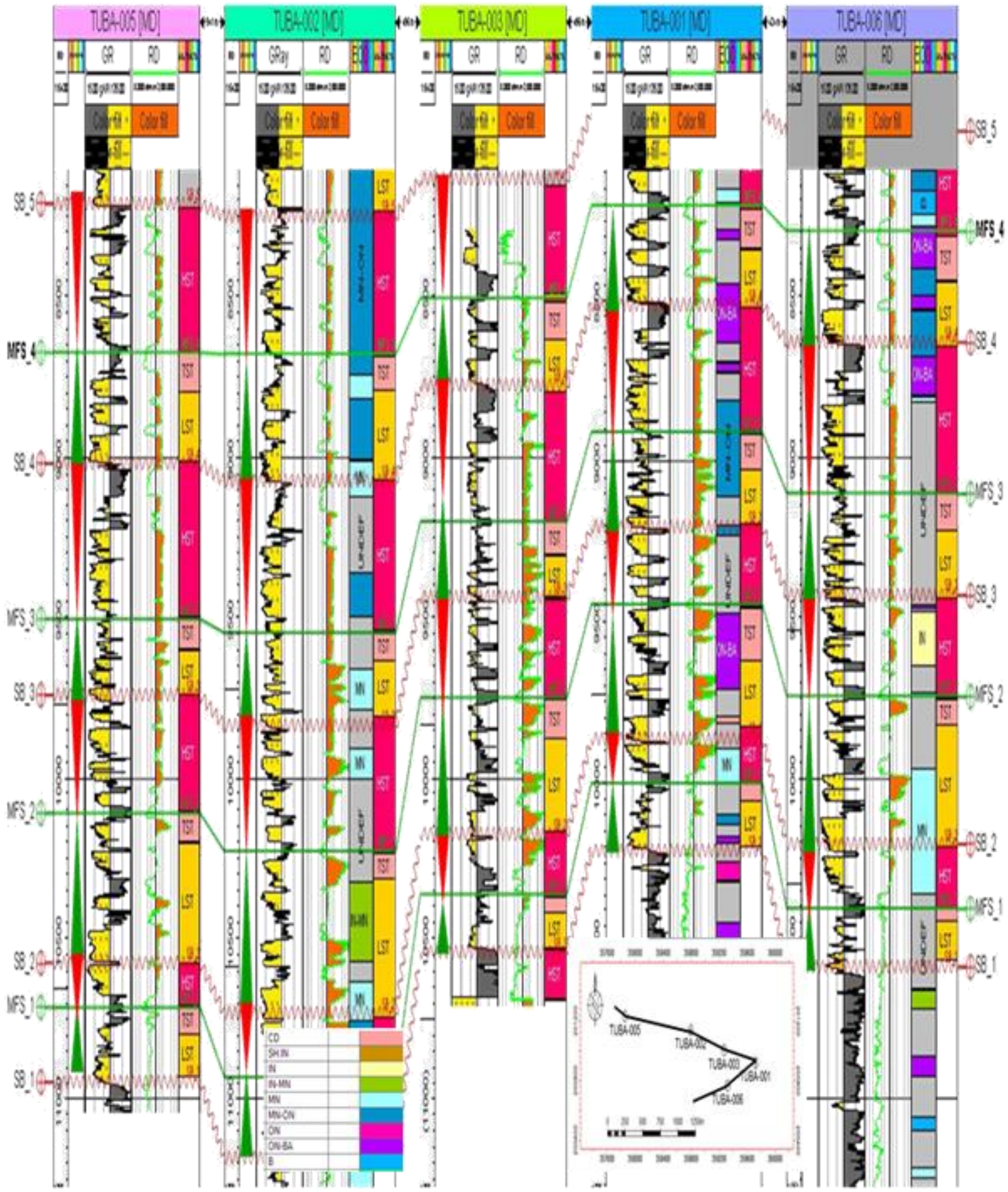

Fig. 3. Correlation panel showing Depositional Sequences, Systems tracts and environments of deposition

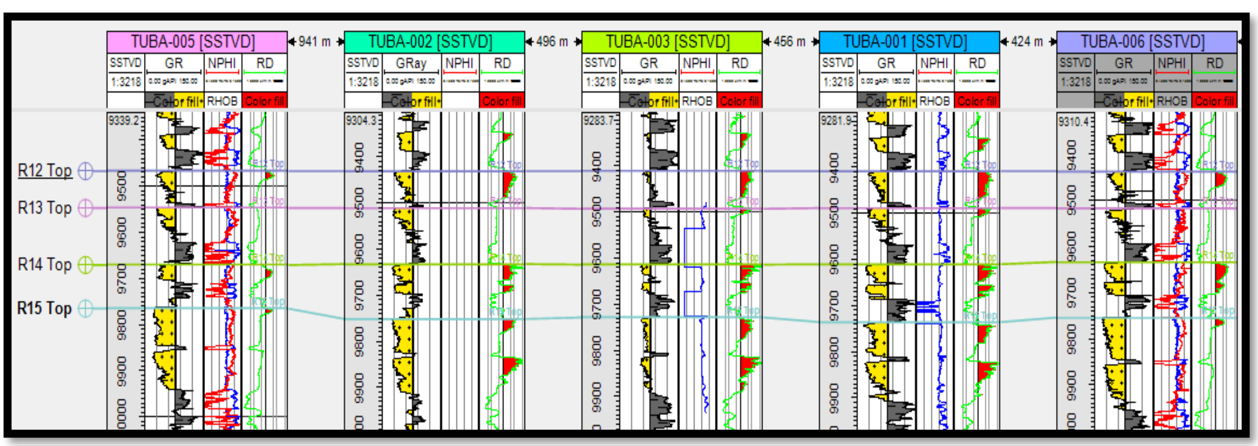

Fig. 4. Logs correlation showing the lateral extents of the four reservoirs of interest on the dip section

The result of the structural analysis shows six faults (F1, F2, F3, F4, F5 and F6) across the seismic section (Figs. 5 and 6).

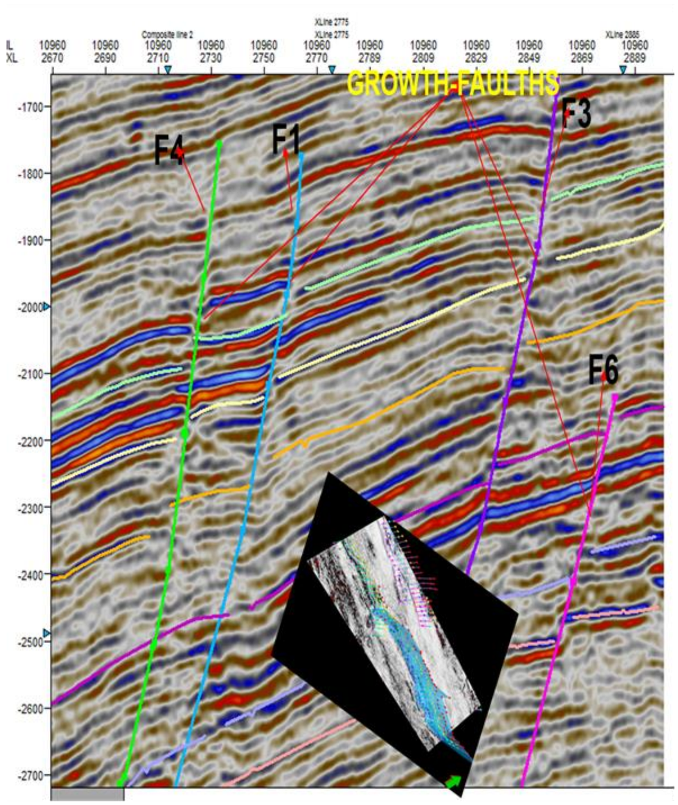

Fig. 5. Normal growth-faults and variance cube in 3D-view showing fault locations in the field

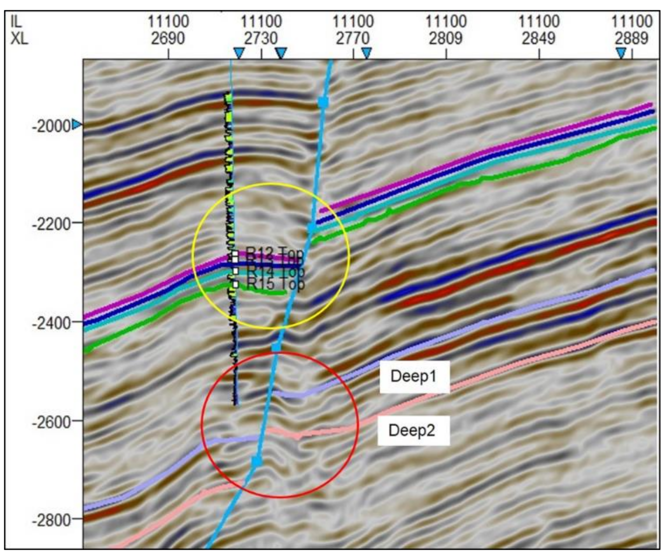

Fig. 6. Synthetic seismogram showing good match with the mapped horizons (producing intervals = yellow circle, un-penetrated = red circle)

They are mainly synthetic faults that are characterized by concave fault surfaces in the basinward direction. The field is characterized by normal growth faults that led to the formation of roll-over anticlinal structures in the down-thrown part of the fault block (Fig. 5). This type of structure is common with the structural styles existing in the Niger Delta oil province [6-7]. The faults also showed growth with throw increasing progressively downwards in the foot-wall. Regular spacing and simplicity of the structures is in line with the structural styles that characterize the Northern Delta Depobelt [14].

These faults are very important as the structural closures located at the center of the field are responsible for hydrocarbon entrapment. Six horizons corresponding to the tops of reservoirs were mapped. Four of the horizons (R12-R15 in yellow circle) are the tops of the four producing intervals in the field while the other two (Deep 1 and 2 in red circle) are of the deeper un-penetrated horizons (Fig. 6).

The sequence stratigraphic analyses of these prospects (Deep 1 and 2) indicate the presence of good quality reservoir (Fig. 6), and structural analyses reveal they are potential good traps. For example, the time and depth structural maps of the six horizons show structural closures (two-way closure) on faults (Figs. 7-9). However, the root mean square (RMS) sweetness amplitude extraction carried out on 2100.00msecs R12, 2260.20msecs Deep1 and 2345.10msecs Deep2 horizons reveal relatively high amplitude values; implying the presence of hydrocarbon on R12 and Deep2 horizons (Figs.7 & 9).

Deep1 horizon shows low amplitude values hence, the absence of hydrocarbon fluid (Fig. 8). These prospects are clearly observed in the fluid contact maps of the two prospective intervals.

A near field (NF) prospect was identified at the northwestern part of the field in R12 horizon at depths between 8200 and 8600ft (Fig. 7b). Deep2 horizon had a deeper prospect between 12,000 and 12,600 ft (Fig. 9b).

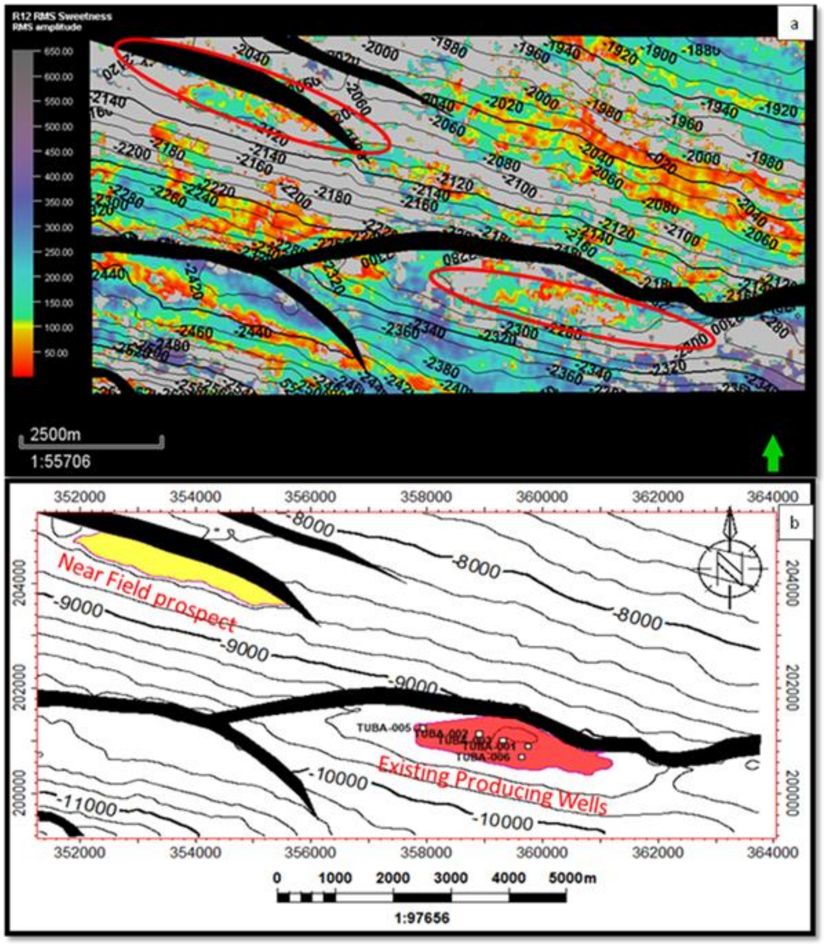

Fig. 7. Amplitude attribute and prospect maps of R12 (a) RMS sweetness amplitude map showing high amplitude within structural closure, indicating presence of hydrocarbon (red circle); (b) Near field prospect and the producing area

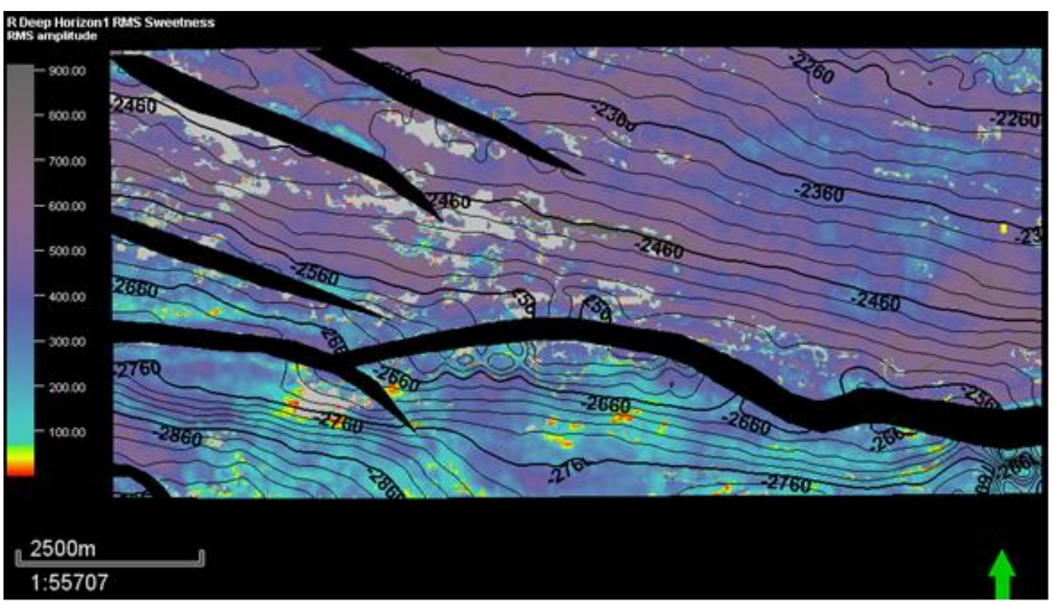

Fig. 8. Root Mean Square (RMS) sweetness amplitude map of Deep1, showing low amplitude values within structural closure, indicating absence of hydrocarbon (white ring)

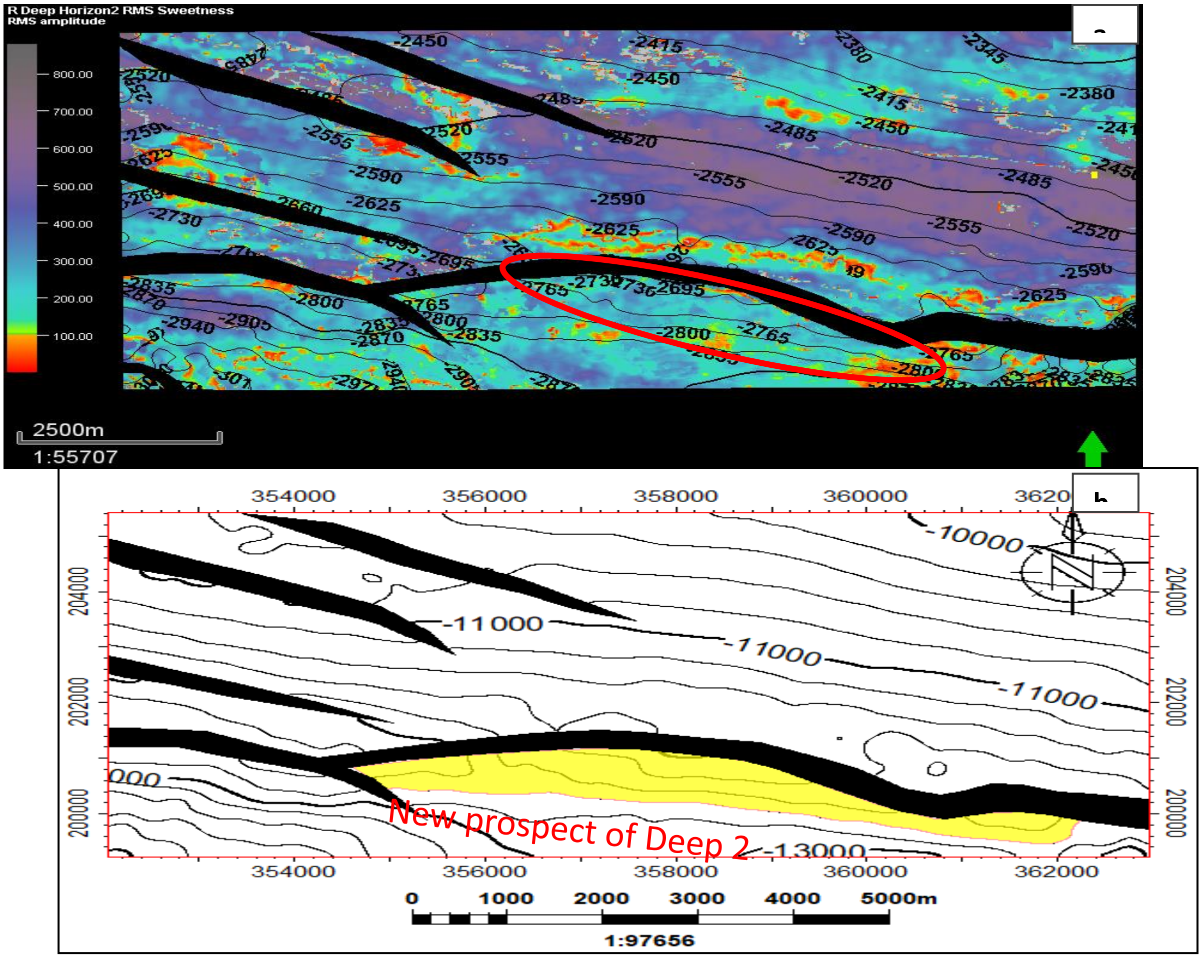

Fig. 9. Amplitude attribute and prospect maps of Deep 2 (a) RMS sweetness amplitude map showing high amplitude within a structural closure, indicating presence of hydrocarbon (red ring); (b) shows deeper prospect at -12200ft (yellow) below the depth of the producing wells

A near analogue average pay properties for R12 and R13 reservoirs were estimated and used for the volume estimation of the near field and the deeper prospects. The average porosity (Ø) reservoirs is 0.23 v/v (23%); which is relatively good (Table 1).

Table 1. Summary of the petrophysical parameters for R12 and R13 reservoirs

Well name	Reservoir name	Top (m)	Base (m)	NTG	Ø (v/v)	Sw (v/v)
Tuba-01	R12	9610	9656	0.94	0.22	0.38
Tuba-01	R13	9664	9724	0.75	0.24	0.18
	Average			0.84	0.23	0.28

NTG = Net-to-Gross; Ø = Porosity; Sw = Water saturation

Also, the reservoirs water saturation (S_w) of 0.28 v/v (28%) translates to 0.72 v/v (72%) hydrocarbon saturation with a net-to-gross (NTG) of 0.86. The evaluated stock tank oil initially in place (STOIIP) for the near field prospect in R12 is 3.7, 9.3 and 18.3mbbl for low, mid and high cases respectively (Table 2) while the GIIP estimates are 7.1, 18.0 and 35.1 bcf respectively. Also, the STOIIP values for the Deep2 prospect are 0.6, 2.1and 4.6mbbl (Table 3) with a corresponding GIIP values of 3.1, 4.1 and 8.9 bcf respectively for the low, mid and high cases respectively.

Table 2. Prospect volume evaluation sheet for R12 (Near-field prospect)

Crest	12500		
	Low case	Base case	High case
	12550	12650	12750
Column	50	150	250
Area	358	368	378
GRV (acre ft)	4853	11939	22666
Thickness	53	63	73
NTG	0.7	0.80	0.9
POR	0.23	0.24	0.23
Sw	0.24	0.35	0.38
Bo	1.23	1.23	1.23
No of res	1	1	1
Oil chance	1	1	1
STOIIP	3.745367378	9.397821705	18.347698
No of res	1	1	1
Oil chance	1	1	1
Bg	0.0036	0.0036	0.0036
GIIP	7.185138268	18.02884512	35.19834872

Table 3. Prospect volume evaluation sheet for Deep2 (Deeper prospect)

Crest	12000		
	Low case	Base case	High case
	12150	12250	12350
Column	150	250	350
Area	1030	1040	1050
GRV (acre ft)	2468	4249	5855
Thickness	53	63	73
NTG	0.7	0.80	0.9
POR	0.16	0.18	0.2
Sw	0.6	0.44	0.30
Bo	1.23	1.23	1.23
No of res	1	1	1
Oil chance	1	1	1
STOIIP	0.697377342	2.161135085	4.653097024
No of res	1	1	2
Oil chance	1	1	1
Bg	0.0036	0.0036	0.0036
GIIP	1.33785344	4.145936256	8.926533

5. Conclusions

The assessment of the near field and deeper exploration targets of the "TUBA" Field, Niger Delta Basin was carried out using 3-D seismic data, well logs and biostratigraphy. The result of the structural interpretation showed simple tectonic regime with faults forming structures for hydrocarbon entrapment and accumulation. Simple roll-over anticlinal structures that are delineated at the center of the field are responsible for hydrocarbon entrapment. Also, the reservoir correlation from well log analysis revealed that individual sand units extend throughout the field and vary in thicknesses with some units occurring at greater depth than their adjacent units. The sand development of the reservoirs was observed to be good proximally (towards TUBA- 05) and poor distally (moving towards TUBA- 06). Also, a near field prospect was identified at the northwestern parts of the field on the R12 horizon and a deeper one on the Deep2 horizon, with their estimated volumes showing considerable volumes of hydrocarbons that can significantly improve the output of the field. Overall, this study shows how new prospects can be identified and analyzed in order to maximize the potential of a declining oil field. This is possible by effectively combining the analysis of such data/production history with structural and sequence stratigraphic analyses.

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