Petroleum & Coal
ISSN 1337-7027

Available online at www.vurup.sk/petroleum-coal
Petroleum & Coal 57(2) 108-119, 2015

RESERVOIR CHARACTERIZATION AND VOLUMETRIC ANALYSIS OF "LONA" FIELD, NIGER DELTA, USING 3-D SEISMIC AND WELL LOG DATA

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Received January 6, 2015, Accepted March 13, 2015

Abstract

An integrated 3D seismic data, checkshot data and a suite of well logs for four wells located at the Lona field, Niger Delta were analysed with Petrel software for reservoir characterization and volumetric analysis. The method employed involves petrophysical analysis, structural analysis, volumetric analysis and reservoir ranking. Detailed well log petrophysical analysis revealed three potential reservoirs. Average Reservoir parameters such as porosity (0.25), gross thickness (27 m), hydrocarbon saturation (0.66), permeability (3734) and net-gross (0.54) were derived from petrophysical analysis. Structural analysis showed fault assisted anticlinal structures which serve as structural traps that prevent the leakage of hydrocarbon from the reservoirs. Volumetric study of the hydrocarbon in place showed that the reservoirs are of appreciable areas and thicknesses. The volume of hydrocarbon originally in place was estimated to be 550 thousand barrel of oil. The three reservoirs were ranked using average results of petrophysical parameters. R1 was found to be more prolific while R2 was found to be least prolific within Lona field.

Keywords: petrophysical parameters; reservoir; Niger Delta; volumetric analysis; Lona field.

1. Introduction

Hydrocarbon resources remain very vital to the economy of many nations of the world. The high cost of exploration for this all-important resource makes it necessary for the attainment of high level of perfection in the methods adopted for its detection and quantification [1]. Since cost effectiveness is the driving factor in oil and gas industry, there is a great need to use effective method to quantify the reservoir with reduced level of uncertainty associated with geological models. Drilling of an oil well is a very costly venture coupled with the fact that hydrocarbon reserve are depleting. The deposits yet undiscovered are in more complex geological environments and hence it is important to exploit new development with higher resolution seismic reflection methods.

Understanding of reservoir characteristics, most importantly; porosity, water saturation thickness and area extent of the reservoir are crucial factors in quantifying producible hydrocarbon [2]. These parameters are important because they serve as veritable inputs for reservoir volumetric analysis, i.e. the volume of hydrocarbon in place [3].

Petroleum in the Niger Delta is produced from sandstone and unconsolidated sands predominantly in the Agbada Formation. It is therefore necessary to delineate the hydrocarbon reservoirs and evaluate them because they are the zone of interest for hydrocarbon exploitations [4].

The purpose of this study is to characterize the reservoirs and determine the hydrocarbon in place in the study area. This is achieved by (i) identifying the potential reservoirs and estimating the petrophysical parameters from the well logs, (ii) generating time and depth structure of mapped horizons for structural analysis, and (iii) carrying out a detailed volumetric analysis in order to estimate the hydrocarbon in place.

2. Location and geology of the study area

Lona field is located within the offshore area of Niger delta in Nigeria (Figure 1). The Niger Delta is located in southern Nigeria, between longitudes $3^0$and 9^0E, and between latitudes $4^0$and 6^0 N [5]. The four wells (Lona 1, 2, 3, 4) used in this study were aligned in the north-western to the southeastern direction within the study area (figure 1). The Niger Delta covers an area of about 75,000Km^2 and is composed of an overall regressive clastic sequence that reaches a maximum thickness of 9,000 to 12,000m [6]. In an advancing delta such as that of the tertiary Niger Delta, sediments are stratigraphically superimposed. The submarine delta fringe will encroach on holomarine sediments and will in turn, be covered by a younger lower deltaic plain. The thick wedge of the Niger delta is considered to consist of three geological units known as Benin, Agbada and Akata formations (Figure 2).

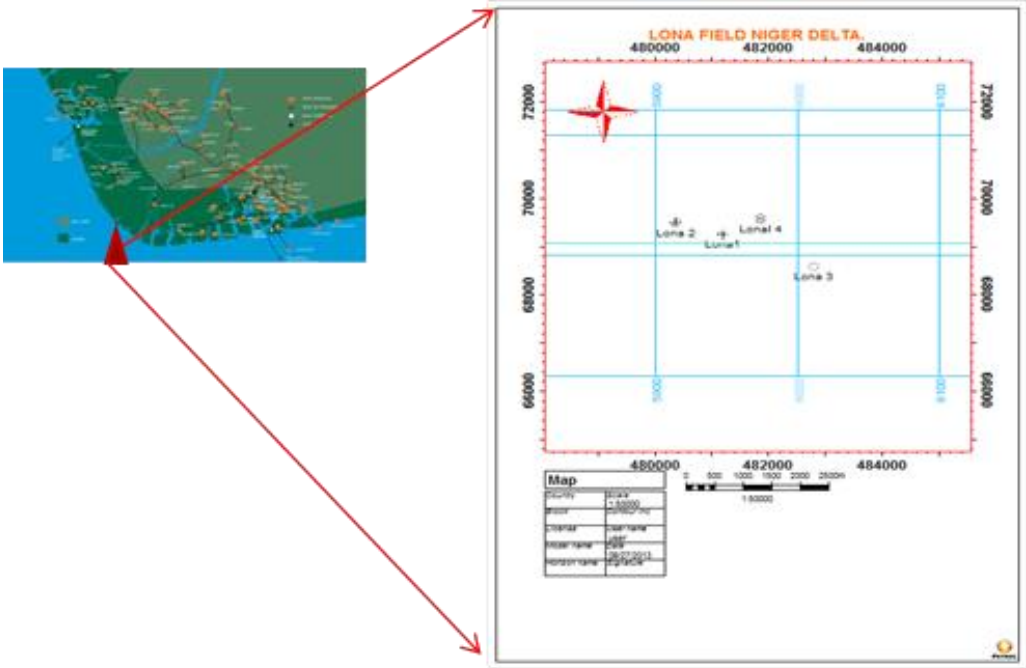

Fig.. 1 Location of the study area and the base map showing the seismic lines and wells

The Benin formation overlies the Agbada formation. The age of the formation is Oligocene in the north, and becomes progressively younger southwards. To date, very little hydrocarbon deposits have been found in this highly porous and generally freshwater bearing formation [7]. The Benin formation extends from the west across the whole Niger Delta and has been described as coastal plain sands which outcrop in Benin, Onitsha and Owerri provinces. It consists of massive continental sands and gravels with thickness ranging from 0.2 to 100 metres. The sand and sandstone are coarse to fine and commonly granular in texture.

The Agbada formation is a paralic sequence of sandstone and shale underlying the Benin formation. It consists of the sandy parts, which serve as the main hydrocarbon reservoir of the Delta and shale act as the cap rock. This sequence is associated with syn-sedimentary growth faulting. The Agbada formation is thickest at the center of the delta and goes up to 457.2 m [6]. The upper part is predominantly sandy unit with minor shale intercalation and a lower shaley unit, which is thicker than the upper sandy unit. In the lower Agbada Formation, shale and sandstone beds were deposited in equal proportions.

The Akata formations composed of deeper marine shale, the deepest stratigraphic unit. It is chiefly represented by plastic, low density, under-compacted and high-pressure shallow marine to deep water-shale, with only local inter-beddings of sands and/or siltstones. It is deposited as the high-energy delta advanced into deep water. In general, the shale is overpressured and this provides the mobile base for subsequent growth faulting associated with the deposition of the overlying paralic sequence. It serves as the hydrocarbon source in the Niger delta. Majority of wells drilled in the Niger delta only penetrated into the marine Akata shale. It is estimated that the formation is up to 7,000 meters thick [6].

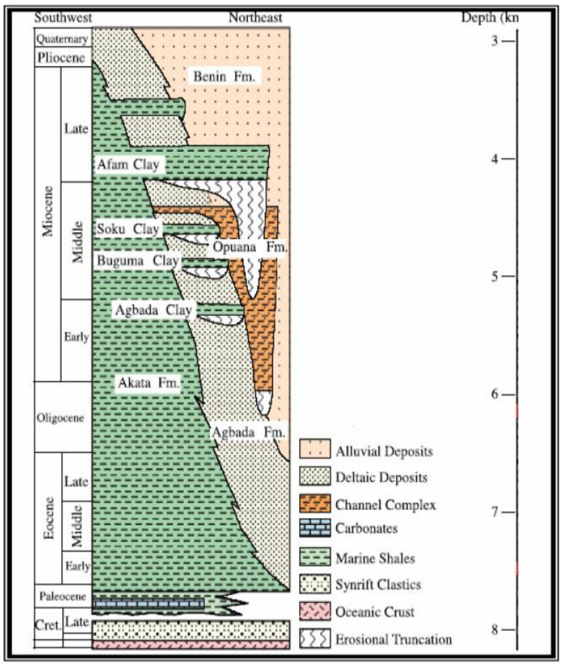

Fig. 2. Stratigraphic column showing the three formations of the Niger Delta (modified from [6,8])

3. Methodology

Formation evaluation in most cases involves a detailed qualitative and quantitative estimation of the reservoirs and the fluids in it. This will help in understanding the geologic condition of an area. The analytic procedure could aim at bringing out the lithology, reservoir, its area extent, complexity, productivity, and the type and quantity of fluid it contains. The results are used to locate and estimate the economic prospects of the wells already drilled. Qualitative log interpretation is based on the visual observation of the logs to determine zone of interest. It is primarily concerned with shape, characteristic signature and physical model of the relevant well log. It involves the identification of permeable and impermeable beds. Also bed thickness and depth to various fluids can also be determined.

The litho-stratigraphic correlation is a visual process which provides knowledge of the general stratigraphy of an area [9]. Based on the available logs, the parameters that were evaluated include; lithology identification, identification of reservoir and well log correlation. For lithology identification, sand and shale bodies were delineated from the gamma ray log signatures. Sand bodies were identified by deflection to the left due to the low concentration of radioactive minerals in it. The gamma ray log was set to a scale of 0-150 API. The scale increased from left to right, with a central cut off of 65 API units (less than 65 API units was interpreted to be sand while greater than 65 API units was interpreted as shale).

Reservoirs are subsurface formations that contain water and hydrocarbon. They were identified by using the log signatures of both gamma and resistivity logs. Intervals that have high resistivity are considered to be hydrocarbons while low resistivity zones are water bearing intervals. The logs were activated and displayed on the well section window, on which correlation was carried out using the lithology log (Gamma ray log). The resistivity log was used to check the fluid contents present within the sediments i.e. hydrocarbon or water. The top and base of the reservoir were picked.

The quantitative interpretation involves the use of empirical formulae to estimate the petrophysical parameters such as porosity, permeability, volume of shale and hydrocarbon saturation. Also volumetric analysis was carried out in order to determine the volume of hydrocarbon in place.

3.1 Determination of petrophysical parameters

The gamma ray log was used to calculate the volume of shale (V_{sh}) in a porous reservoir. The first step in determining the volume of shale from a gamma ray log is to calculate the gamma ray index using

$$I_{GR} = \frac{GR_{log} - GR_{min}}{GR_{max} - GR_{min}} \quad (1)$$

where I_{GR} = Gamma ray index; GR_{log} = Gamma ray reading of the formation; GR_{min} = Minimum gamma ray (clean sand) and GR_{max} = Maximum gamma ray (shale).

All these parameters were read off within a particular reservoir. Having obtained the gamma ray index, volume of shale was then calculated using the [10] formula

$V_{sh} = 0.083(2^{3.7*I_{GR}} - 1.0)$ (Tertiary consolidated sand). (2)

The formation density log was used to determine formation porosity (porosity is defined as the percentage of voids to the total volume of rock). The formation porosity was determined by substituting the bulk density readings obtained from the density log within each reservoir into the equation [10].

$$Ø_{eff} = \frac{\rho ma - \rho b}{\rho ma - \rho_{fl}} - V_{sh}\frac{\rho ma - \rho b}{\rho ma - \rho_{fl}} \quad (3)$$

where $Ø_{eff}$ *is the effective porosity*, ρ_{ma} is the matrix density = 2.65gm/cm^3 (for sandstone), ρ_{fl} is the fluid density= 1.1gm/cm^3, and ρ_b = formation bulk density.

The criteria for classifying porosity as given by [11] are:

Ø < 0.05 = Negligible, 0.05 < Ø <0.1 = Poor, 0.1 Ø < 0.15 = Fair, 0.15 < Ø < 0.25 = Good, 0.25 < Ø < 0.30 = Very good, Ø > 0.30 = Excellent.

The formation factor was determined from the [12] equation

$$F = \left(\frac{a}{Ø^m}\right) \quad (4)$$

where Ø= Porosity, a = constant (0.62), m = cementation exponent (2 for sands).

The water saturation (S_w) for the uninvaded zone was determined using the [12] equation given as

$$S_w{}^2 = \frac{F*R_w}{R_t} \quad (5)$$

But $F = \frac{R_o}{R_w}$ (6)

Thus, $S_w{}^2 = \frac{R_o}{R_t}$ (7)

where S_w = water saturation of the uninvaded zone, R_o= resistivity of formation at 100% water saturation, R_t = true formation resistivity, F = formation factor

The hydrocarbon saturation (S_h) **(**the percentage of pore volume in a formation occupied by hydrocarbons) was obtained by subtracting the value obtained for water saturation from 100%. That is,

S_h = (100 – Sw) % (8)

where, S_h = Hydrocarbon saturation, S_w = Water saturation

The permeability, K, (which is the ability of a rock to transmit fluid) is related to porosity but not always dependent on it. It is controlled by the size of the connecting passages (pore throats or capillaries) between pores. It is measured in darcies or millidarcies. The permeability was obtained from the equation, [13]

$$k = \left[\frac{250 \times Ø^3}{S_{wirr}}\right]^2 \quad (9)$$

where S_{wirr} is the irreducible water saturation.

A practical oil field rule of thumb for classifying permeability [11] is: poor to fair = 1.0 to 14 md, moderate = 15 to 49 md, good = 50 to 249 md, very good = 250 to 1000 md, >1 darcy = excellent

3.2. Volumetric analysis

The area extent of each reservoir was determined from the depth structural maps. The last close contours (Figures 10, 11, 12) were gridded in square and the length of each square was determined. Using the formula:

Area= L×L, (10)

the area of a single square was obtained. The total number of the square within the reservoir was multiplied by the unit area in order to get the total area of the reservoir.

The basic formulae used for calculating the volumes are:

Bulk Volume = Total Rock Volume = reservoir thickness (m) × area extent (m^2)
Net Volume = Bulk Volume × Net/Gross,
Pore Volume = Bulk Volume × Net/Gross × Porosity,
HCPV oil(barrels) = Bulk Volume × Net/Gross × Porosity × S_h,
where 1 m^3 = 6.29 oil barrels, HCPV is hydrocarbon pore volume.

4. Results and discussion

The results are discussed based on qualitative interpretation, quantitative interpretation, statistical, structural, and volumetric analysis.

4.1 Qualitative interpretation

For the log interpretation shown in figure 3, its litho-stratigraphic correlation furnished knowledge of the general stratigraphy of the study field.

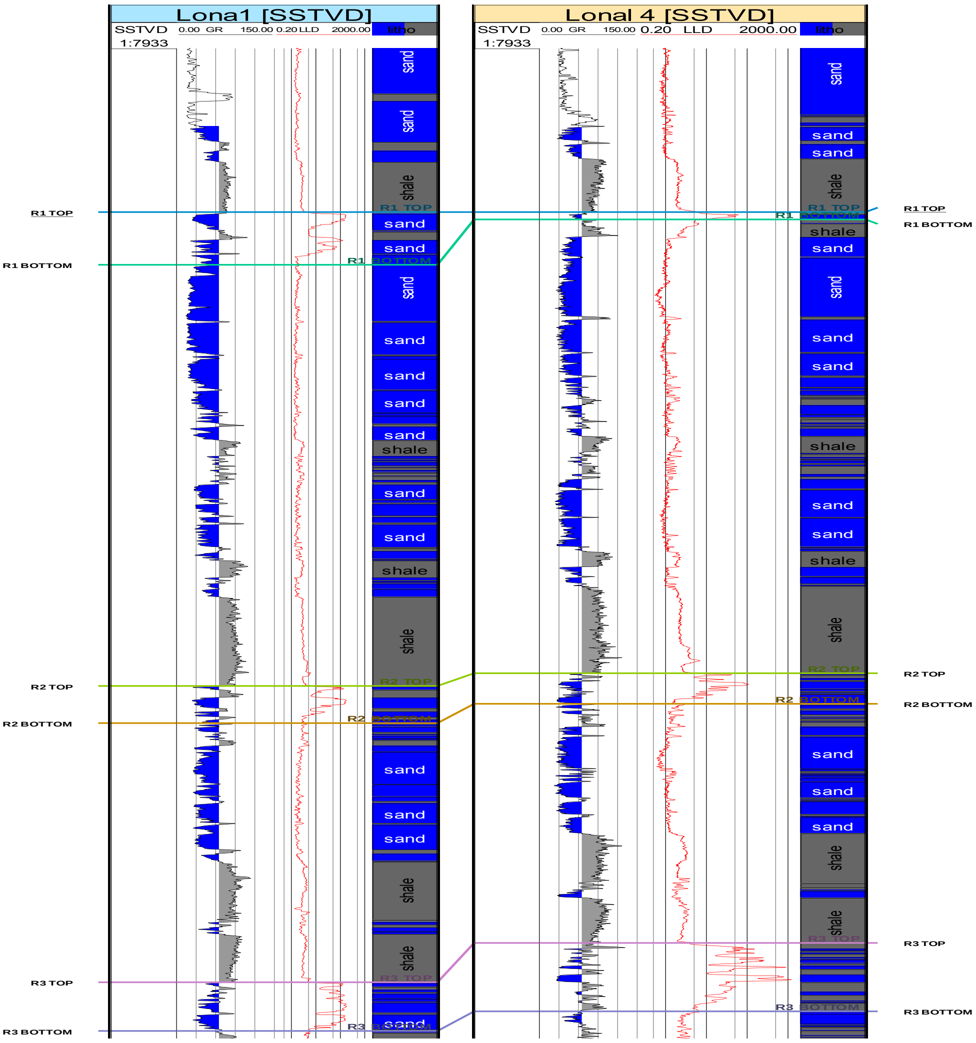

Figure 3 Well Correlation Panel across Lona 1 and lona 4 showing The Top & Base of Reservoir 1, 2 and 3 (values are in feet).

The litho-stratigraphic correlation is a visual process which provides knowledge of the general stratigraphy of an area [9]. Two lithologies; sand and shale, were identified using the gamma ray log. From the lithology log, the interval coloured blue is sand, while the interval coloured grey is shale. From figure 4, three sand bodies were mapped as reservoirs; R1, R2, R3, which are correlated across the field. The results obtained from this study are based on both the petrophysical analysis and seismic interpretation. The well correlation panel showing the top and base of the reservoirs is as shown in figure 4. The three reservoirs cut across Lona 1 and 4 (Figure 3). R1, R2 and R3 occur at depth 3 and;

2890 m, 3195 m and 3387 m respectively in Lona 1; and 2902 m, 3201 m and 3376 m respectively in Lona 4. Figure 4 shows two reservoirs within Lona well 2, 1 and 3. R2 and R3 occur at depth; 3308 m and 3345 m respectively in Lona 2; R2 occurs at depth 3308 m in Lona 3.

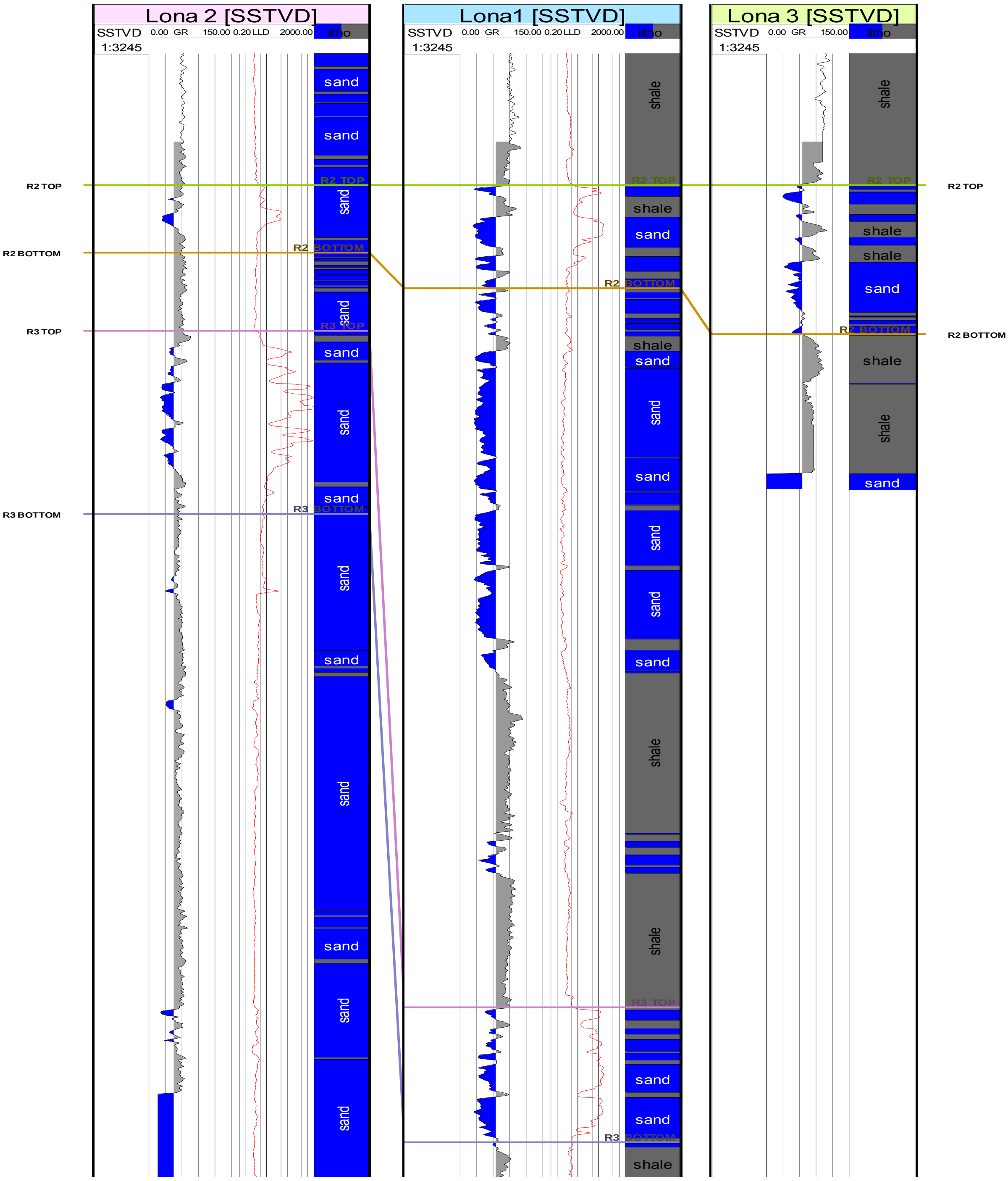

Figure 4 Well Correlation Panel Across lona 2, 1 and 3 showing The Top & Base Of R2 and R3 (values in ft)

The analysis showed that each of the sand units extends through the field and varies in thickness. Some units occurred at greater depth than their adjacent units, which is possibly an evidence of faulting. The shale layers were observed to increase with depth along with a corresponding decrease in sand layers. This pattern in the Niger Delta indicates transition from Benin to Agbada formation [14]. From the analysis, particularly the resistivity log, all the three delineated reservoirs were identified as hydrocarbon bearing units across the four wells (Lona 1, Lona 2, Lona 3, Lona 4).

4.2. Quantitative interpretation

Table 1 shows the result of some computed petrophysical parameters for reservoir 1 which cut across Lona wells 1 and 4. The reservoir were penetrated at depths of between 2890-2921 m in Lona well 1 and between 2902-2907 m in Lona well 4. It has a gross thickness ranging from 5 to 30 m, net thickness 3 to 18 m, and the net/gross thickness (N/G) is 0.6 in both wells. The porosity value obtained across the two wells within reservoir 1 showed a good to excellent rating, while the high permeability value obtained in well 1 indicated an excellent value that permit the free flow of fluid within the reservoir. The hydrocarbon saturation indicated a high proportion of hydrocarbon to the quantity of water within the reservoir. Hence reservoir 1 is a hydrocarbon saturated reservoir.

Table 1 Summary of the computed petrophysical parameters obtained for reservoir 1

Wells	Top (m)	Bottom (m)	Gross (m)	Net (m)	N/G	Porosity (v/V)	S_{wirr}	Ka (md)	Sw (%)	Sh (%)	V_{shale} (%)
Lona1	2890	2920	30	18	0.6	0.32	0.070	13696	27	73	6
Lona4	2902	2907	5	3	0.6	0.22	0.102	676	29	71	28

The petrophysical parameters for reservoir 2 are displayed in Table 2. The porosity values obtained across all the wells in reservoir 2 indicated good to very good values which are slightly less in quality as compared to reservoir 1 and this complement the fact that porosity decreases with depth. Furthermore, the permeability showed an excellent value for well 1 and very good values for all the other wells. The ratio of the hydrocarbon to water saturation indicated that this reservoir contain both water and hydrocarbon, with hydrocarbon slightly higher than water saturation.

Table 2 Summary of the computed petrophysical parameters obtained for reservoir 2

Wells	Top (m)	Bottom (m)	Gross (m)	Net (m)	N/G	Porosity (v/V)	S_{wirr}	Ka (md)	Sw (%)	Sh (%)	V_{shale} (%)
Lona1	3195	3220	25	12	0.48	0.29	0.077	6241	32	68	32
Lona2	3308	3324	16	12	0.75	0.20	0.112	324	42	58	57
Lona3	3604	3639	35	21	0.6	0.22	0.102	676	55	45	64
Lona4	3201	3221	20	9	0.45	0.20	0.112	324	51	49	51

Table 3 showed petrophysical parameters for reservoir 3. This reservoir cuts across three wells; which are Lona wells 1, 2 and 4 respectively. The porosity values of reservoir 3 showed good to very good values which are indicative of a porous sandstone and the permeability value revealed a good interconnectivity between the pores. The water saturation and hydrocarbon saturation revealed that both hydrocarbon and water are present in the reservoir with the hydrocarbon having a higher ratio. Hence reservoir 3 is a hydrocarbon bearing unit.

Table 3 Summary of the computed petrophysical parameters obtained for reservoir 3

Wells	Top (m)	Bottom (m)	Gross (m)	Net (m)	N/G	Porosity (v/V)	S_{wirr}	Ka (md)	Sw (%)	Sh (%)	V_{shale} (%)
Lona1	3387	3418	31	15	0.48	0.27	0.083	3481	25	75	20
Lona2	3345	3385	40	21	0.52	0.25	0.089	1936	30	70	51
Lona4	3376	3420	44	15	0.34	0.23	0.097	961	35	65	42

4.3 Statistical analysis of data

In table 4 the summary of the results of the important petrophysical parameters utilized as variables that determine reservoir quality is presented. These parameters are subjected to statistical analysis by considering their values across all the delineated reservoirs in the four wells and were used to rank the reservoirs. The three reservoirs were ranked in figures 5 and 6 using average results of petrophysical parameters. Based on these, R1 is said to be the most prolific while R2 is said to be least prolific within Lona field.

Table 4 Summary of the computed petrophysical parameters obtained for reservoir 1-3

Reservoirs	Top (m)	Bottom (m)	Gross (m)	Net (m)	N/G	Porosity (v/V)	S_{wirr}	K_a (md)	S_w (%)	S_h (%)	V_{shale}
Reservoir1	2896	2914	18	11	0.6	0.27	0.086	7186	0.28	0.72	0.17
Reservoir2	3327	3351	24	14	0.57	0.23	0.101	1891	0.45	0.55	0.51
Reservoir3	3369	3408	38	17	0.45	0.25	0.090	2126	0.30	0.70	0.38

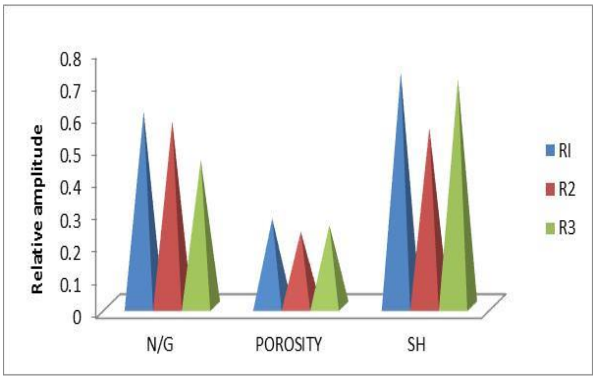

Figure 5 Reservoir ranking using average petrophysical parameters

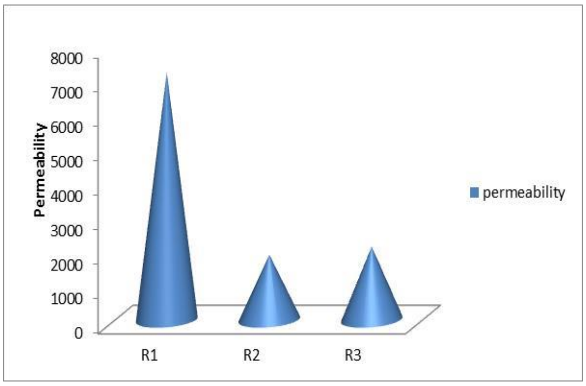

Figure 6 Reservoir ranking using average permeability

4.4 Structural analysis

Three horizons corresponding to the tops and bottoms of the three reservoirs and two faults were mapped as horizon 1 (H1), horozon2 (H2), horozon3 (H3) and fault 1 (F1), fault 2 (F2) respectively across the seismic section for this analysis as shown in (Figure 7). To ensure a good tie, wells with their tops were superimposed on the seismic sections that intersected each other. Figure 8 shows the tying of well to seismic. Some of the reservoir tops and bases coincided with the peaks and troughs on the seismic section .

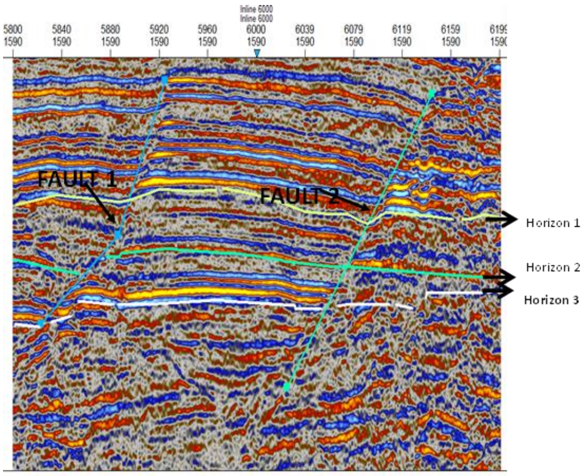

Fig. 7 Inline 6000 showing the mapped faults and horizons

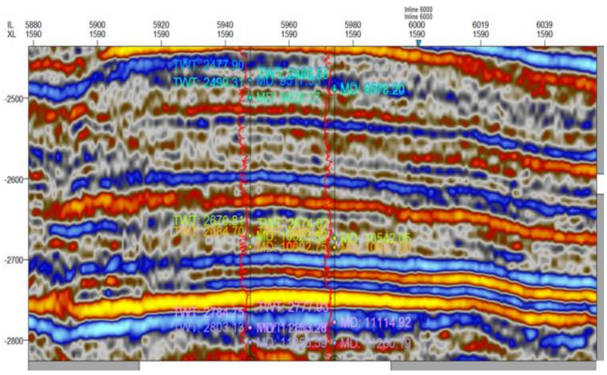

Fig. 8 Inline 5970 showing the tying of wells to seismic

Mapped horizons and the generated fault polygons were used to generate time structure maps for the three reservoirs. The time structure map of horizon 1 is shown in Figure 9. The map showed an anticlinal structure at the centre of the surfaces which is a structural trap. The two growth faults seen on the seismic section is also displayed on the surfaces. Although a time map is compressed in its deeper parts and stretched out in its shallow areas because of the general increase in velocity with depth, the highs and lows are normally in the right places. This is particularly true when the geology is in the form of a layer with near horizontal formations of fairly uniform thickness.

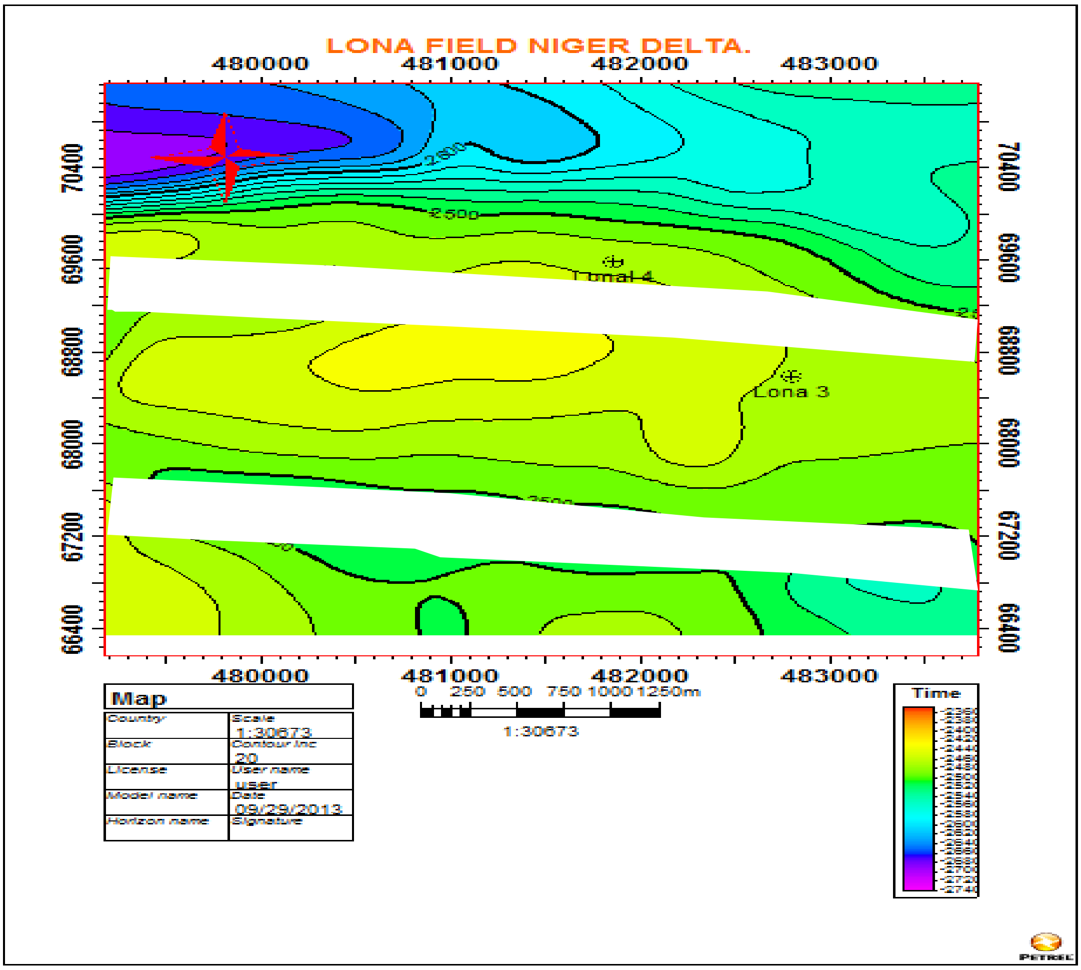

Figure 9 Time structure map for horizon 1

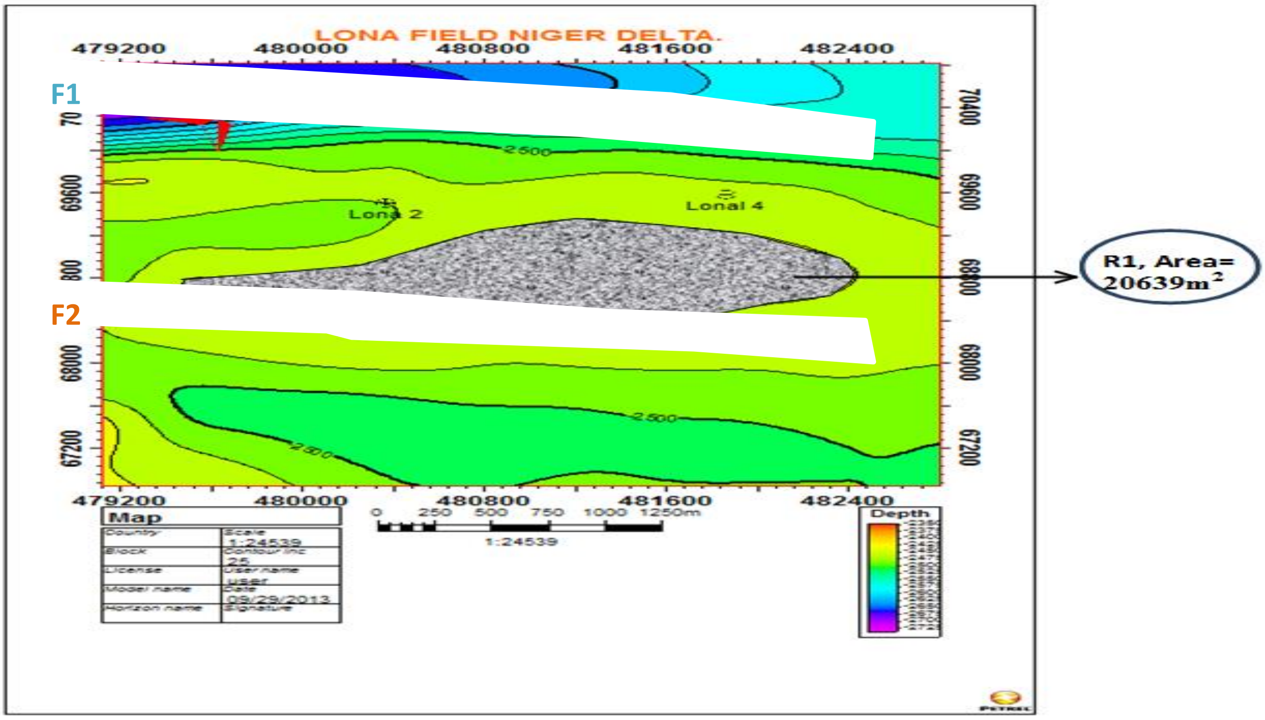

Figure 10 Depth structural map for horizon 1

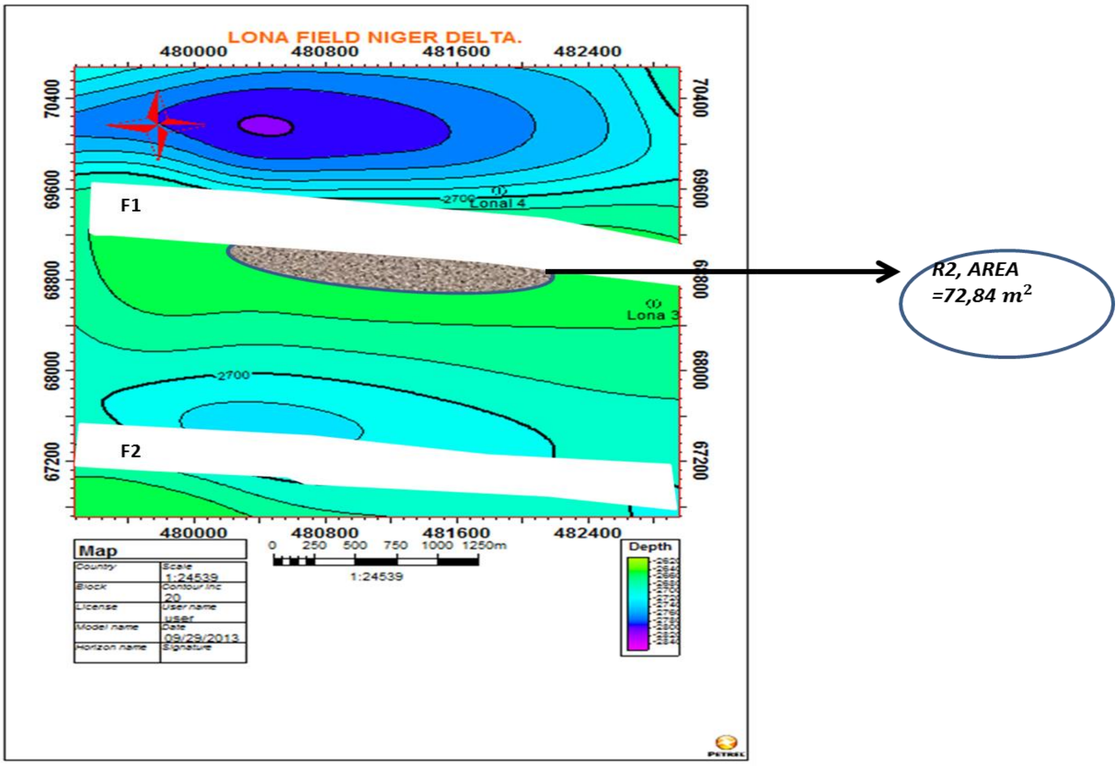

Figure 11 Depth structural map for horizon 2

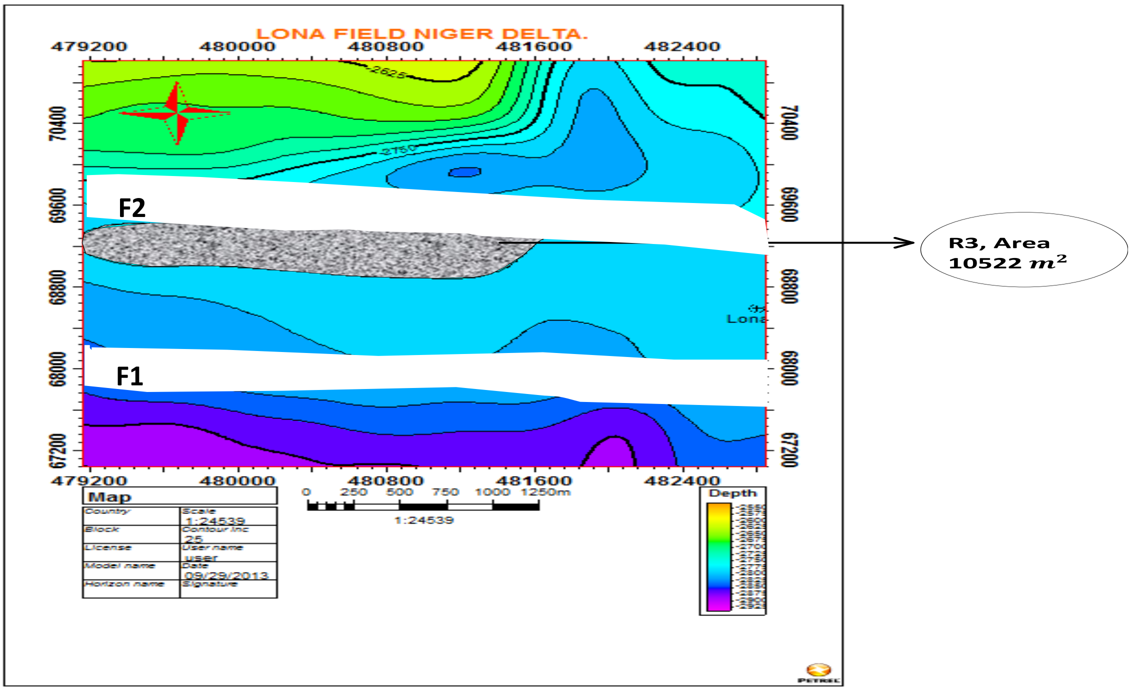

Figure 12 Depth structural map for horizon 3

The time structure maps were then converted into depth maps, figures 10, 11 and 12 using the checkshot data obtained from the area which is an important parameter in the determination of the hydrocarbon in place. The depth structure maps also showed the anticlinal structure and the two faults. The depth structural maps were then used to quantify the oil in place. The area extents of the reservoirs were mapped to be 20,639 m^2 for R1, 7,284 m^2 for R2 and 10,522 m^2 for R3. The above obtained values were then multiplied by the gross thickness of the reservoir in order to obtain the volume of the hydrocarbon in place in each reservoir (table 5).

4.5 Volumetric analysis

Table 5 shows the summary of the volumetric analysis within the Lona field which were obtained with the help of appropriate formulae discussed in methodology. Average values of petrophysical parameters were used and hydrocarbon in place within Lona field is estimated to be 550 Mbbl of oil. These results also complement the earlier statement that R1 is more prolific while R2 is said to be least prolific within Lona field.

Table 5 Volumetric analysis of Lona field

Reservoirs	R1	R2	R3	Total
Gross (ft)	18	24	38	-
N/G	0.6	0.57	0.45	-
Porosity	0.27	0.23	0.25	-
S_H	0.72	0.55	0.70	-
Area (m^2)	20639	7284	10522	-
B V (bbl)	2336748	1099593	2514968	-
NET .V (bbl)	1402049	626768	1131736	-
Pore.V(bbl)	378553	144157	282934	-
HCPV (Mbbl)	273	79	198	550

5. Conclusion

The reservoir characterisation and volumetric analysis of Lona field, Niger Delta carried out showed that all the three delineated reservoirs were identified as hydrocarbon bearing units across the four wells. Average reservoir parameters such as porosity (0.25), gross thickness (27 m), hydrocarbon saturation (0.66) and net/gross (0.54) were derived from petrophysical analysis. Structural analysis showed fault assisted anticlinal structures which serve as structural traps that prevent the leakage of hydrocarbon from the reservoirs. The structural disposition of the three mapped horizons greatly favours the accumulation of hydrocarbon coupled with the good reservoir parameters obtained from the wells.

The three reservoirs were ranked using average results of petrophysical parameters. R1 is said to be more prolific while R2 is said to be least prolific within Lona field. Volumetric study of the hydrocarbon in place shows that the reservoirs are of appreciable area and thicknesses. The volume of hydrocarbon originally in place was estimated to be 550 thousand barrels of oil. From these results, we can infer that Lona field has exploitable potential hydrocarbon.

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