*Scientia Africana, Vol. 13 (No.1), June 2014. Pp186-199*
 *ISSN 1118 - 1931*

# INTEGRATION OF SEISMIC AND WELL LOG DATA FOR PETROPHYSICAL MODELING OF SANDSTONE HYDROCARBON RESERVOIR IN NIGER DELTA.

**C. N. Nwankwo[1], J. Anyanwu [1] and S. A. Ugwu[2]**

[1]*Department of Physics, University of Port Harcourt, Rivers State, Nigeria*

[2]*Department of Geology, University of Port Harcourt,Rivers State, Nigeria*

*Received: 26-03-14*
*Accepted: 12-05-14*

## ABSTRACT

*For accurate reservoir property determination, four well logs and seismic data of 5500 to 5900 Xline and 1480 to 1720 Inline range were used to delineate the hydraulic zones of two reservoirs of interest and to determine the average petrophysical properties of the reservoirs.. All the wells contained GR, resistivity, sonic and density logs. The data were conditioned for interpretation using PETREL software. Reservoirs of interest were delineated by interpreting the well logs. These delineated reservoirs (reservoir D and F) were then correlated. The lateral extent of the reservoirs was determined by tying well 2 to the seismic. Different hydraulic zones (stratigraphic intervals) of the reservoir were established. Zonation of the reservoirs enhanced the sensitivity of the petrophysical properties in every stratigraphic interval of the structural model. Petrophysical model parameters were delineated along each well location, the model was upscaled and populated on the structural model. The features of the reservoir rock were conspicuous on the structural models of reservoirs D and F. The average determined porosity, permeability, NTG and water saturation with respect to each reservoir was 22.4%, 22.02%; 1444 md, 1375 md;* 72.3, 84.9*; and 39.5*, 39.4 respectively. *Hence there exist a very good porosity and an excellent permeability for the formation in the study area. All other determined parameters were also favorable for hydrocarbon production in this field.*

**Key words**: seismic, well lods, porosity, permeability, water saturation and Net-to-Gross.

## INTRODUCTION

The quest for optimum method of hydrocarbon production has been an issue which many oil and gas companies are interested in. Considering the conventional production technique, it has been observed that we can only produce one-third of the oil in place (Kramers, 1994). For the unrecovered oil, estimation shows that it varies according to the depositional environment. According to Larue and Yue (2003), the percentage estimation of the unrecovered oil in fluvial sandstone reservoir or deep sea Fans falls between 40-80%. Alvarado and Manrique (2010) have stated that the effort of industries to increase production by the use of large capital investments to enhance oil recovery sometimes proves futile. This hitch needs to be proffered with a sustainable solution. One of the major ways of resolving this issue is through hydrocarbon reservoir properties modeling. This will buttress our idea on how petrophysical properties vary within reservoirs, their transition across stratigraphic intervals and the quality of the reservoirs. The heterogeneity in the properties of reservoir rocks is either dependent on primary depositional or secondary diagenetic processes. Evidently the properties that determine reservoir quality are porosity and permeability.

The Niger Delta, hydrocarbon bearing fields is characterized by multiple heterogeneous reservoirs stacked over intervals of 10000ft thickness. Each stratigraphic zone and grid cell of the reservoirs has similar properties and one petrophysical property respectively. The heterogeneities which occur at all scales from pore scale to major reservoir units result to a spatial variation in the reservoir properties. The reservoir heterogeneities should be addressed properly so as to generate accurate reservoir connectivity which might not lead to caterstrophy while predicting field performance (Maucec et al., 2013) and under-designed of production facilities that will not enhance recovery of hydrocarbon.

The objectives of this study are to delineate different stratigraphic zones of the reservoirs of interest and to determine the average petrophysical properties of the reservoirs. When these properties are upscaled and populated on the structural model, the heterogeneous nature of the reservoirs will then be revealed. With reference to the average values of the determined porosity and permeability, the quality of the reservoirs can be evaluated.

## Geology of Niger Delta

Niger Delta is one of the hydrocarbon productive basins in the world (Alao et al., 2013). Around the West African continental margin, it is located at the southern Nigeria bordering the Atlantic Ocean and extends from about Longitude $3^{o}$ E to $9^{o}$ E and Latitude $4^{o}\,3^{\prime}$ N to $5^{o}\,2^{\prime}$ N (Ekine and Ibe 2013). It is significantly known for hydrocarbon production. This basin is believably, the most important sedimentary basin in sub-sahara Africa for petroleum production. It forms prograding depositional complex within the Cenozoic formation of Southern Nigeria. The area of Niger Delta basin is about 75,000 square kilometers. It extends from the Calabar flank and the Abakaliki trough in Eastern Nigeria to the Benin flank in the west and it opens to the Atlantic Ocean in the south. It extends beyond the gulf of Guinea as an extension from the Benue Trough and Anambra Basin provinces. The delta complex merges westwards across the Okitipupa high into the Dahomey embayment. To the southeast, the important line of volcanic rocks comprising the Cameroon volcanic zone (mountains) and Guinea ridge form the other margin were described by Allen (1965) and Oomkens (1974).

The Niger Delta basin has complex structural features. Along the stratigraphic intervals of the delta, hydrocarbon is chiefly produced from sandstone and unconsolidated sands of the Agbada Formation (Emejakporue and Ngwueke 2013).

## MATERIALS AND METHOD

This study was carried out successfully using seismic and well log data. As a result of the prevailing law among oil companies operating in Nigeria, the exact location coordinates of study Area were not accurately disclosed. The survey area has inline range of 5500-5900 m and a cross-line of 1480-1720 m (Fig.1). The composite well log data comprised of gamma ray log, resistivity log, sonic and density log. Seismic and well logs were employed since they were significant in delineating the lateral and vertical heterogeneities of the

*Scientia Africana, Vol. 13 (No.1), June 2014. Pp186-199*
*© College of Natural and Applied Sciences, University of Port Harcourt, Printed in Nigeria* *ISSN 1118 - 1931*

petrophysical properties. PETREL software was employed for analysis in this work.
The realized seismic data was employed to delineate structural models of the two delineated reservoirs as can be seen in Figures 5a, 5b, 5c and 5d. This was achieved by first interpreting the faults and the horizons which have impact on the reservoirs. The faults were later modeled and pillargridded to generate the reservoir geometry which is the structural model.

Sand beds were delineated as reservoirs; that is the signature of GR log below the cutoff line. For reservoirs areas of interest, resistivity log from each well was used to delineate the presence of hydrocarbon. High resistivity value indicates hydrocarbon accumulation. Therefore our reservoirs D and F were delineated using GR and resistivity logs. Similar reservoirs from other different wells were correlated (Fig. 2).

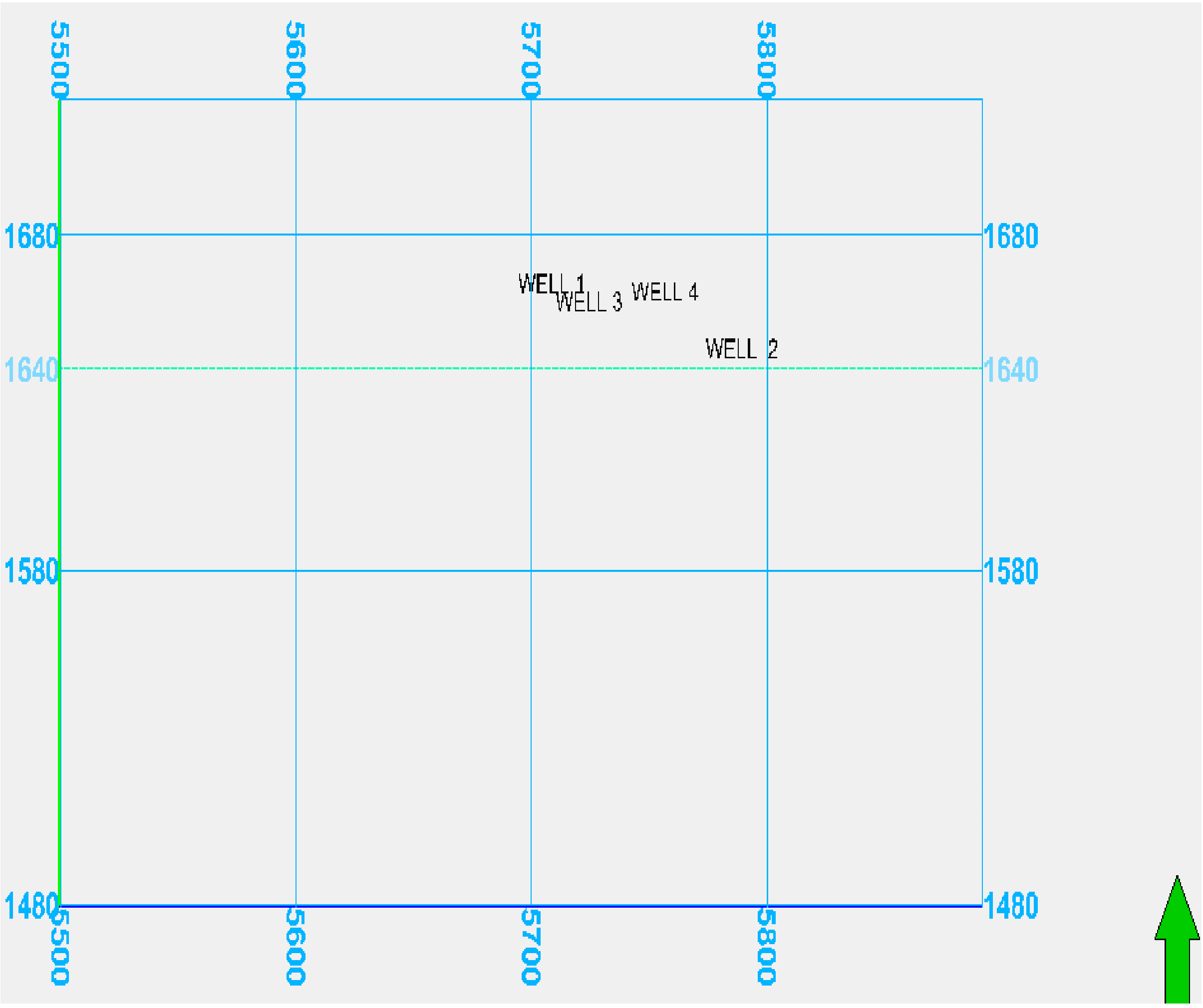


Fig.1: X Oil field base map with the seismic header of Inline range: 5500 to 5900, Xline range: 1480 to 1720, Inline/Xline interval: 25m. Wavelet type: Zero phase and Polarity: SEG Reverse.

**Petrophysical Modeling**

Structural modeling has been used to generate frame work of the reservoirs in “X” oil field. For a detailed static modeling, the petrophysical properties and their variation throughout the reservoir were determined. The properties determined here were porosity, Net-To-Gross (NTG), water saturation and permeability. These determined properties were populated on

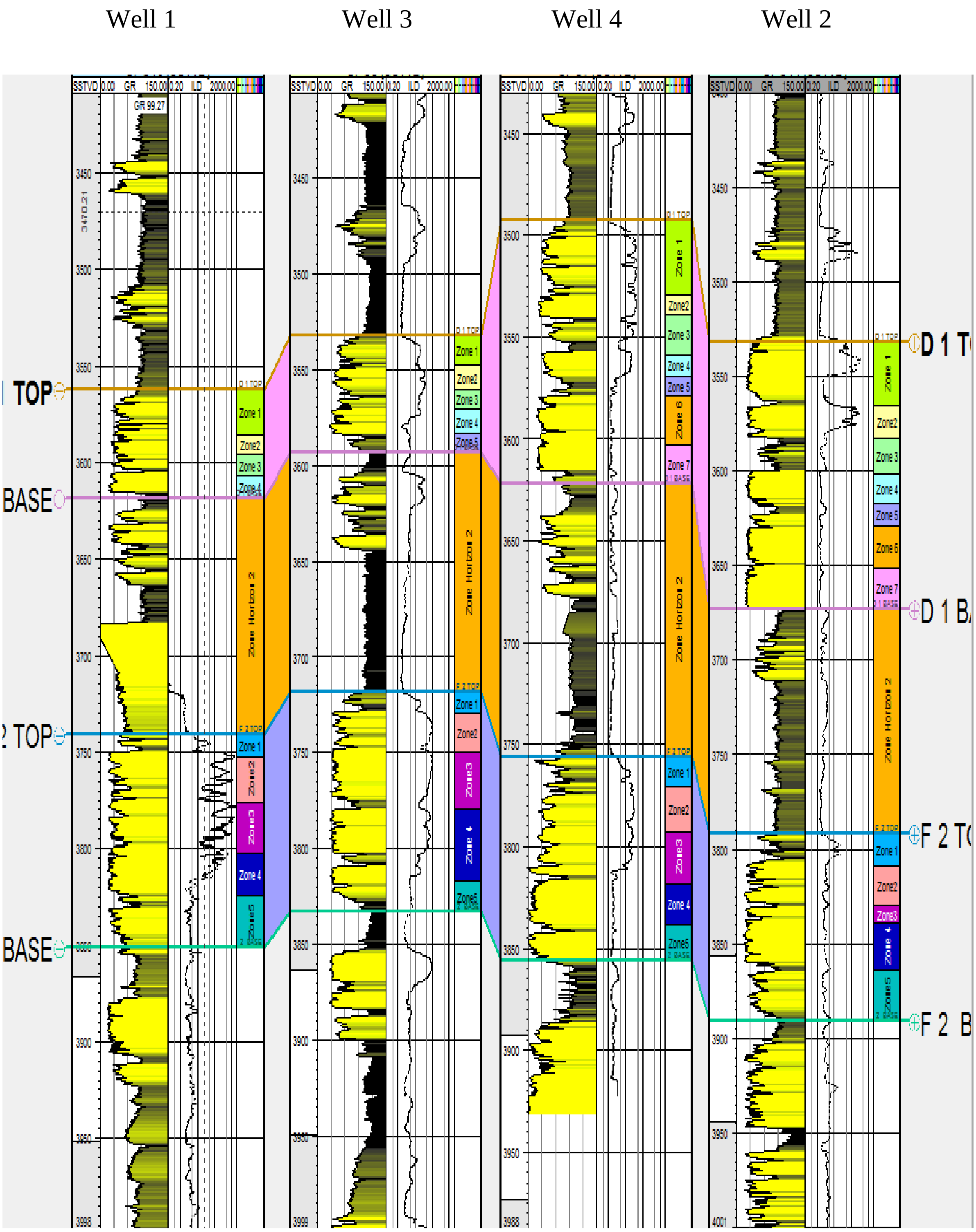


**Fig.2: Well correlation of the delineated reservoirs**.

*Scientia Africana, Vol. 13 (No.1), June 2014. Pp186-199*
 *ISSN 1118 - 1931*

the structural model to show their heterogeneity within the flow zones (Fig. 3). Among all these properties, hydrocarbon saturation depends on porosity and permeability. Good hydrocarbon reservoirs have less volume of shale, good porosity, and less water saturation.

Formation porosity within reservoirs interval was determined from density log using the equation $\phi = \frac{(\rho_{\max} - \rho_{log})}{(\rho_{max} - \rho_{min})}$ 1

where $\phi$ is the formation porosity, $\rho_{\max}$ is maximum density log reading (2.65g/cm$^3$),$\rho_{min}$ is minimum density log reading (1g/cm$^3$) while $\rho_{log}$ is density log reading along the well.

NTG is the ratio of the thickness of sand bearing hydrocarbon to the total thickness of sand formation. It shows the volume of shale present in the reservoir. NTG was calculated along the wells using Petrel software as

NTG = If (GR<65, 1, 0) 2

where GR is gamma ray log reading. This means that if GR is less than 65 API, NTG is 1, and otherwise it is zero.

Reservoirs are saturated with both hydrocarbon and water, although every good reservoir should have less water saturation than hydrocarbon. According to Udegbunam et al. (1988), hydrocarbon water saturation can be estimated by

$S_{w\,ud} = 0.082/\phi$ 3

where $S_{w\ ud}$ = water saturation by Udegbunam et al. (1988) and $\phi$ = formation porosity.

For easy fluid flow, reservoir rocks must be permeable. Estimation of permeability of any reservoir can be used to determine its sealing rate within. Employing the equation of Owolabi et al. (1994), permeability 'K' of the reservoirs of interest was estimated using

$K = 307 + 26552\phi^2 - 34540(\phi \times S_w)^2$ 4

where $\phi$ is formation porosity and $S_w$ is water saturation.

**RESULTS**

The estimated petrophysical properties along the wells are shown in figure 4.The fine scaled structural grid cells mar the sensitivity of the petrophysical properties. Evidently, populating the modeled petrophysical properties on the structural grid cells may result to inability to delineate their sensitivity accurately within the reservoir. Therefore it was significant that

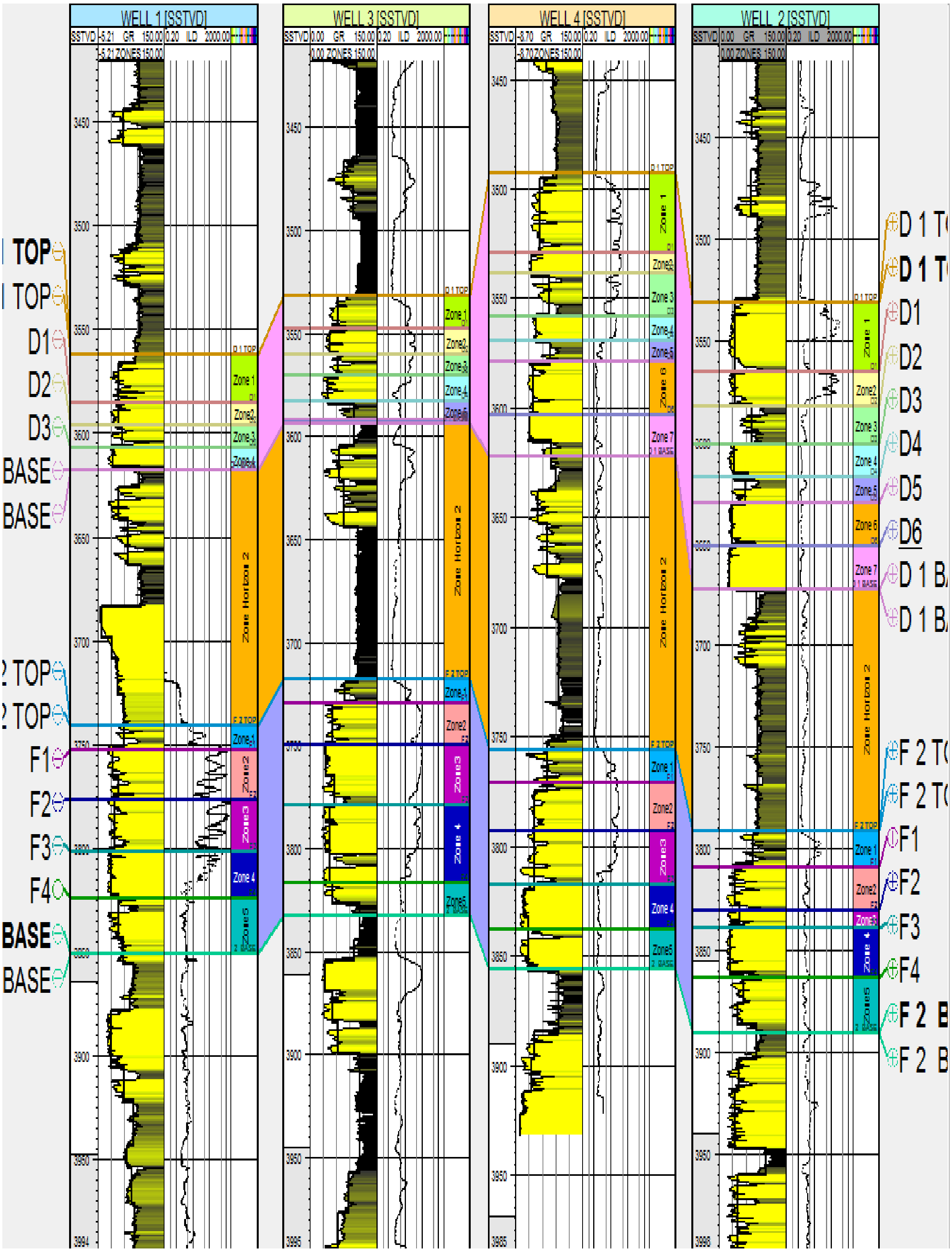


Fig. 3: Delineated flow (lithostratigraphic) zones of the delineated reservoirs on the well section

*Scientia Africana, Vol. 13 (No.1), June 2014. Pp186-199*
*© College of Natural and Applied Sciences, University of Port Harcourt, Printed in Nigeria* *ISSN 1118 - 1931*

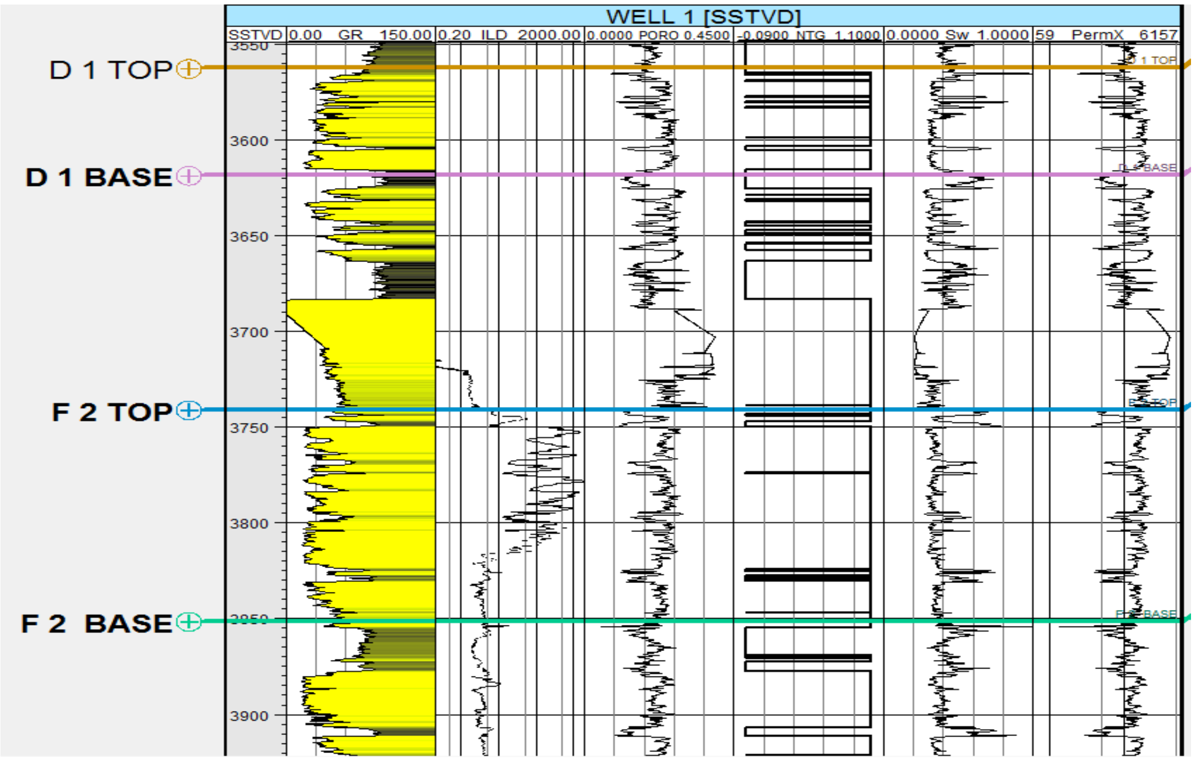


Fig. 4a: Calculated Petrophysical Parameters Along well 1

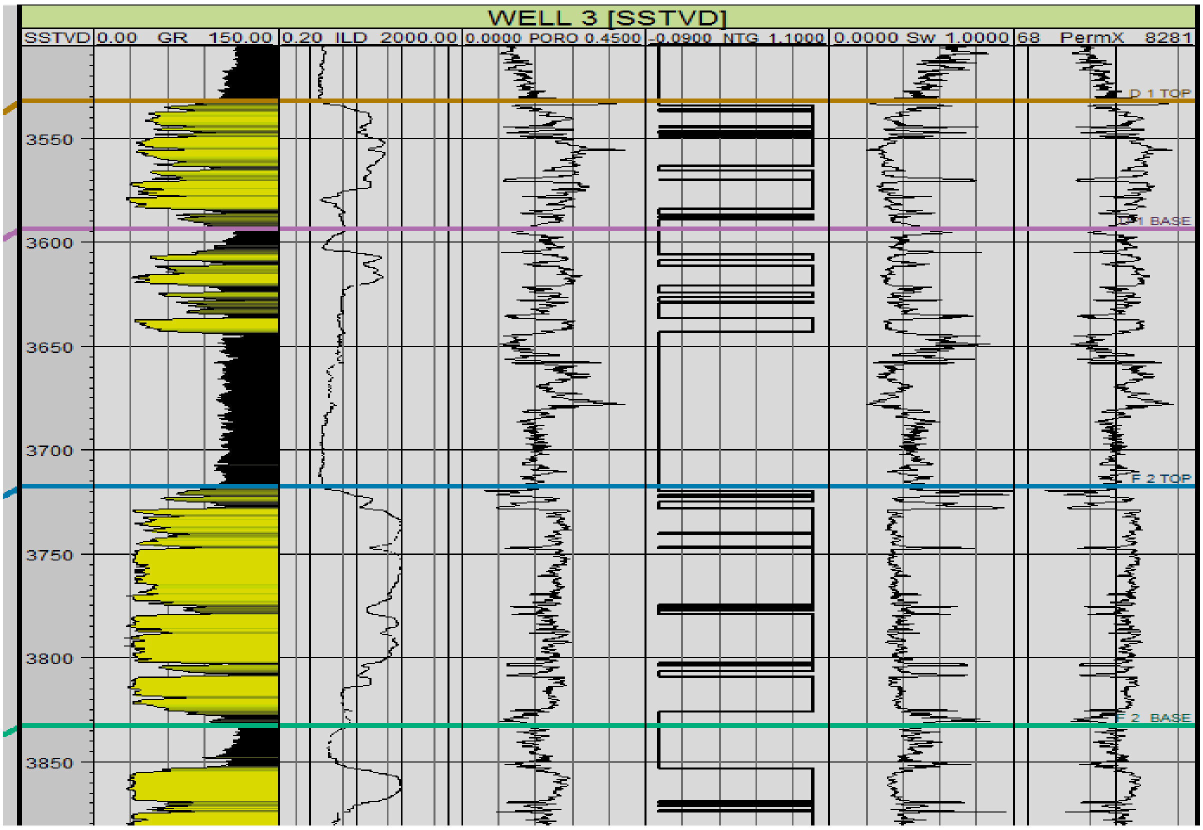


Fig. 4b: Calculated Petrophysical Parameters Along well 3

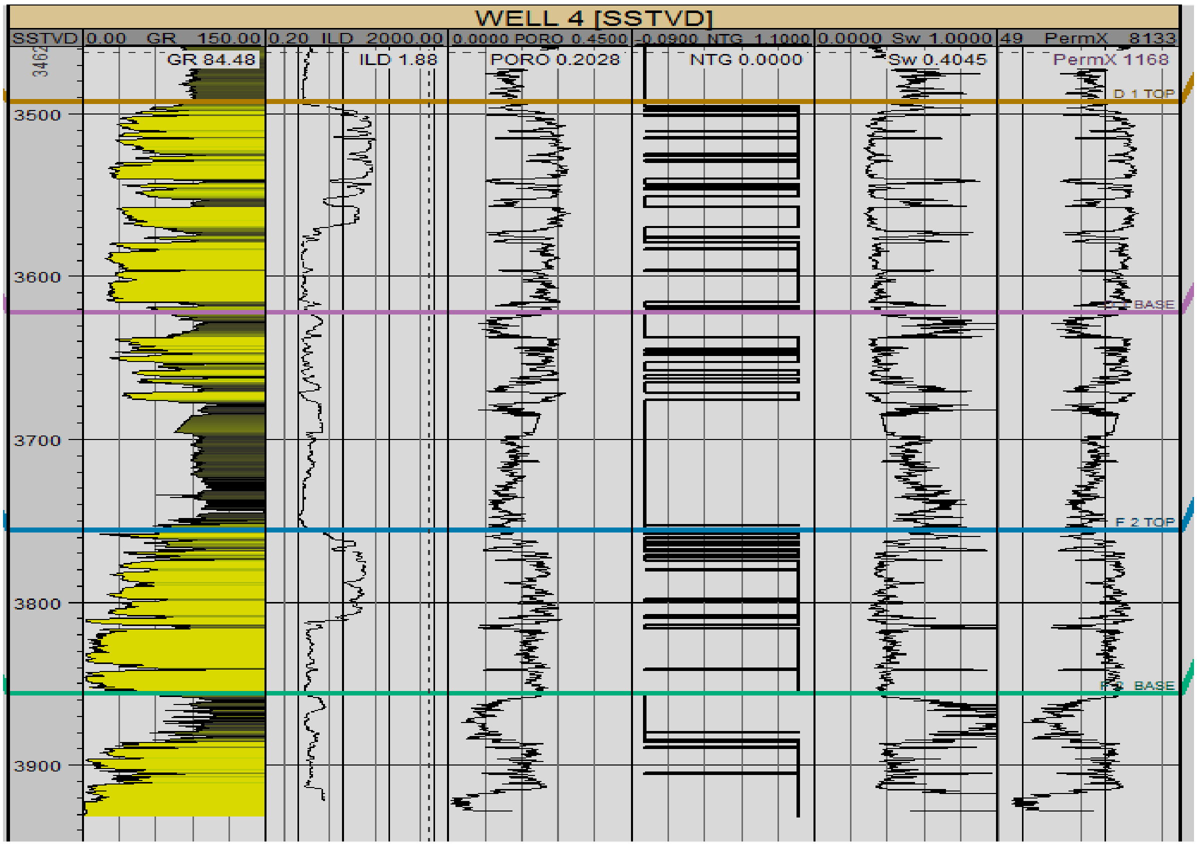


Fig. 4c: CalculatedPetrophysicalParameters Along well 4

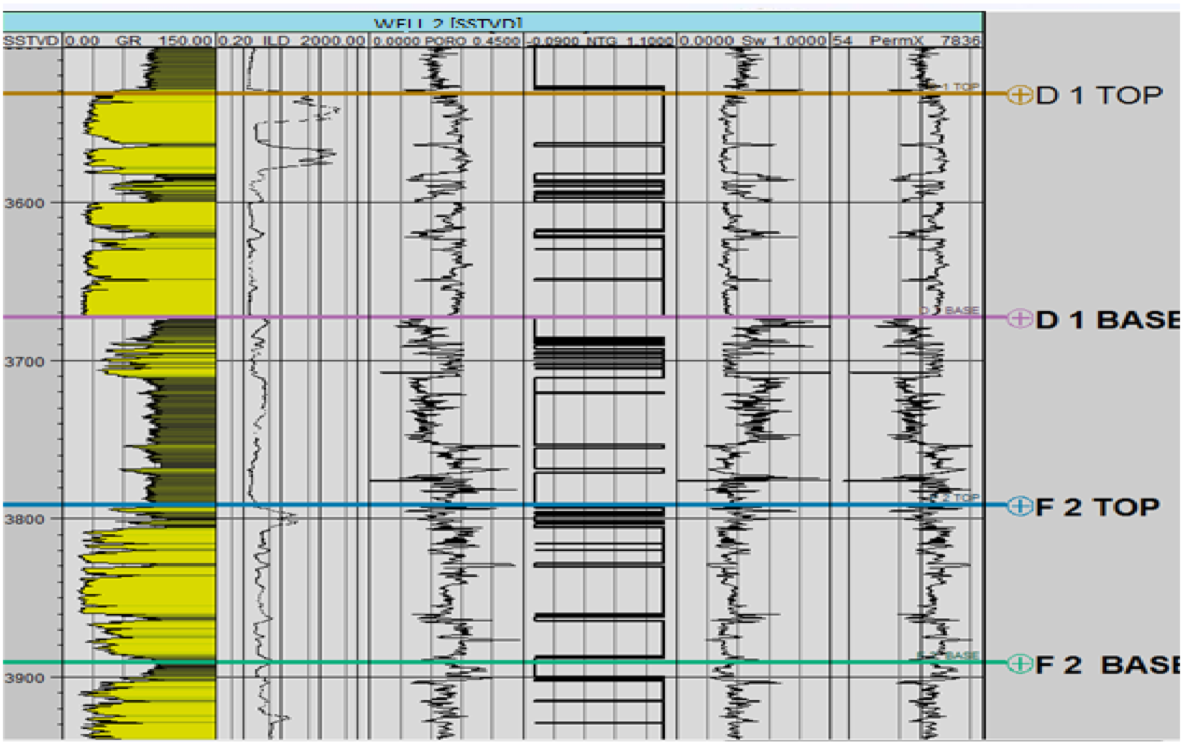


Fig. 4d: Calculated Petrophysical Parameters Along well 2

*Scientia Africana, Vol. 13 (No.1), June 2014. Pp186-199*
*© College of Natural and Applied Sciences, University of Port Harcourt, Printed in Nigeria* *ISSN 1118 - 1931*

simulated petrophysical model should be coarsen into larger cells prior to their application to flow model. The grids were coarsen (low resolution grid) based on the geological frame work that would suit simulation model. The well logs were scaled up thereby assigning log values to the cells in the 3D grid which passed through the wells. All the log values that fall within the cell were averaged to derive a single log value for the cell.

The static properties were then populated on the upscaled structural grid cells of the reservoir frame work and the structural model (Fig. 5).

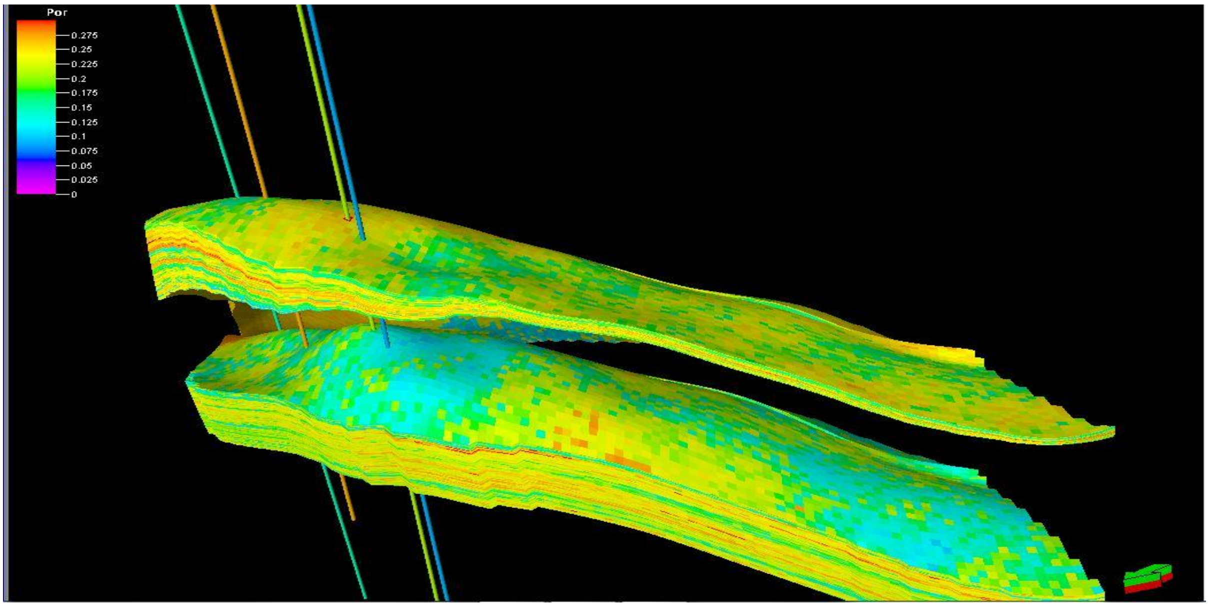


Fig. 5a: Porosity model on the reservoir structures

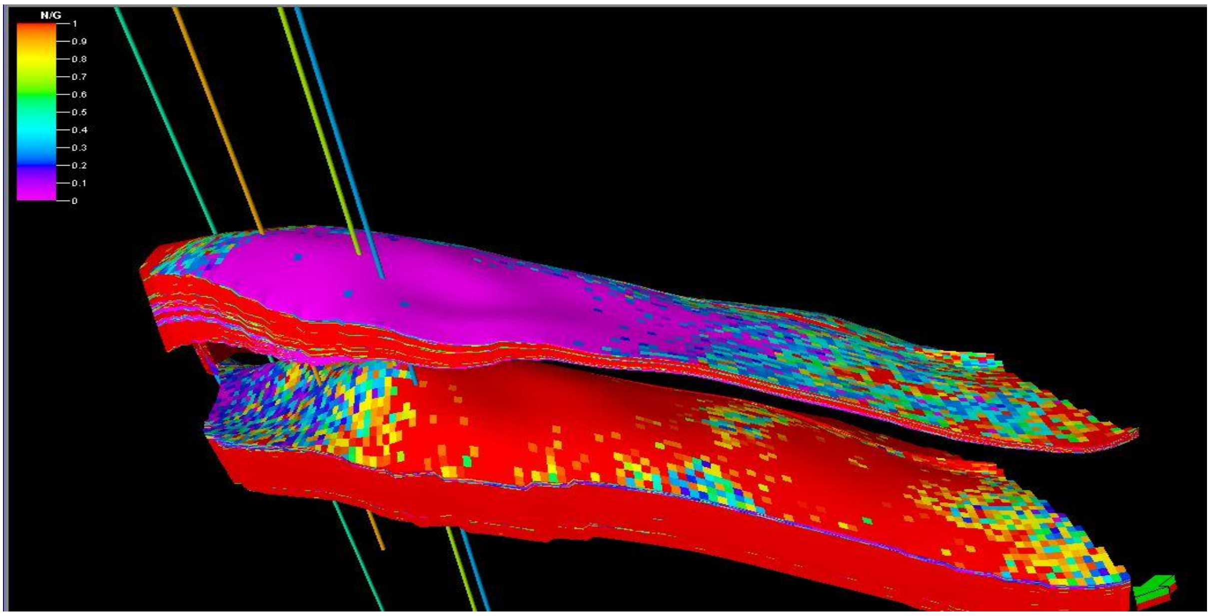


Fig. 5b: NTG Model on the reservoir structures

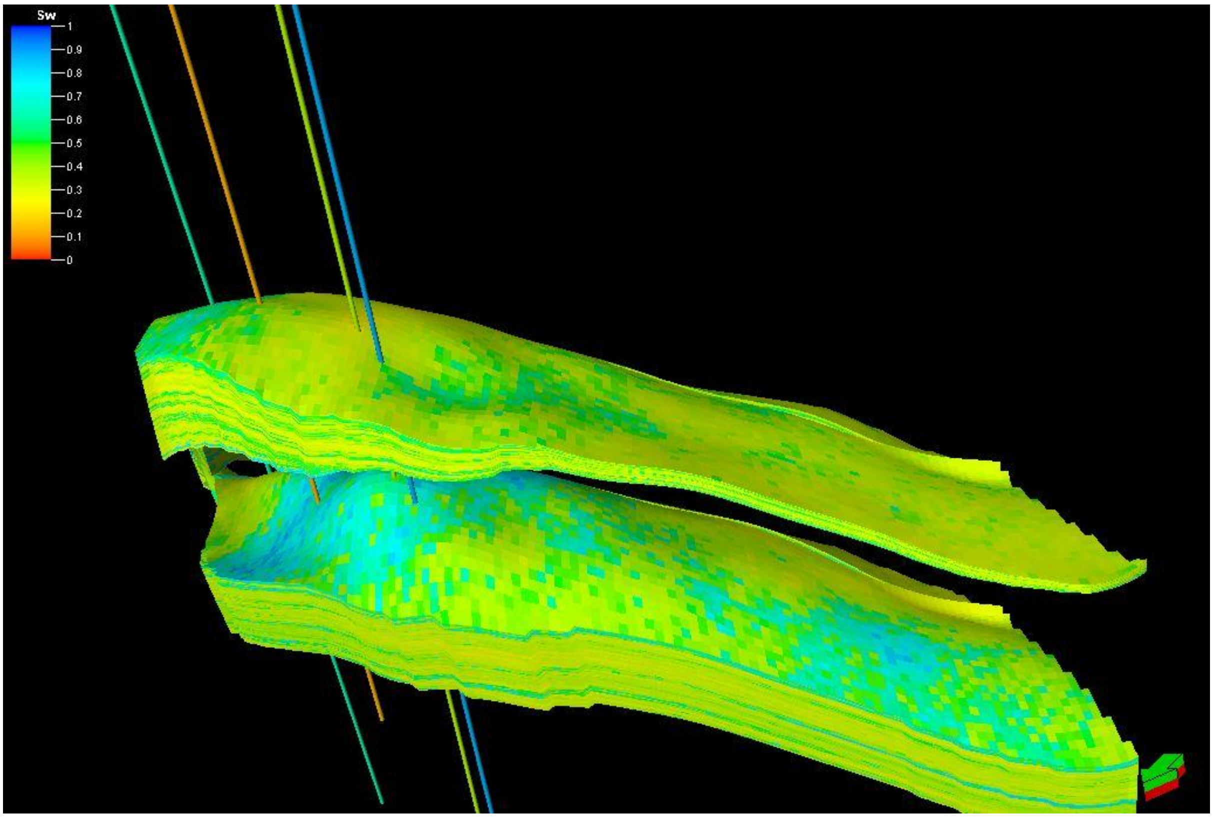


Fig. 5c: Water saturation model on the reservoir structures

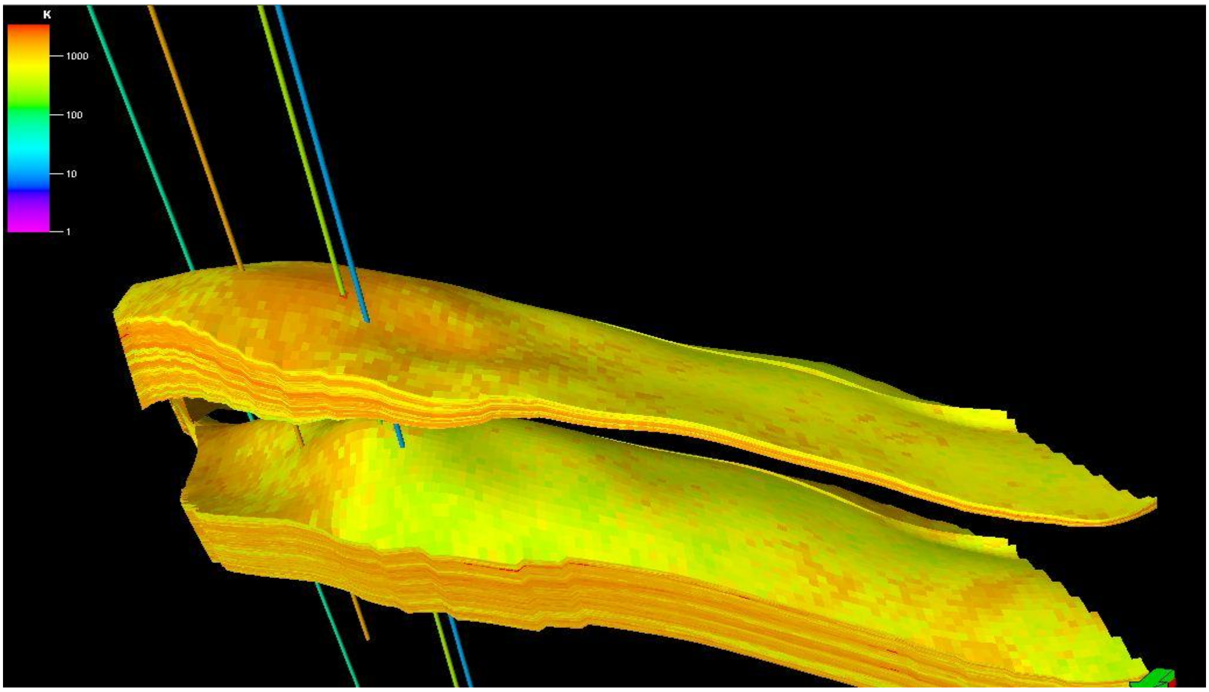


Fig. 5d: Permeability model on the reservoir structures

*Scientia Africana, Vol. 13 (No.1), June 2014. Pp186-199*
 *ISSN 1118 - 1931*

**DISCUSSION**

The delineated lithology of X field is mainly sand and shale Formations, with occasional sand-shale intercalation. Similar formations were not delineated at the same depth across the wells due to faulted regions of the lithology. In reservoir D (Fig. 2), some of the sand formation in wells 2 and 4 pinched out in well 1 and 3. This was evidence of high fault throw. In reservoir F the pinching out of the sand formation in well 2 was due to a greater fault throw unlike wells 1, 3 and 4 which have almost the same sand formation (Fig. 2). The correlated wells delineated the tops and the bases of reservoir D and F as shown in Table 1.

**Table 1:** The delineated thickness of reservoirs D and F

| Well | Reservoir D | | | Reservoir F | | |
|---|---|---|---|---|---|---|
| | Top (m) | Base (m) | Thickness (m) | Top (m) | Base (m) | Thickness (m) |
| 1 | 3562.44 | 3618.26 | 55.82 | 3740.7 | 3851.2 | 110.5 |
| 2 | 3532.02 | 3593.9 | 61.78 | 3717.97 | 3832.6 | 114.63 |
| 3 | 3492.9 | 3621.9 | 129 | 3756.09 | 3856.0 | 99.99 |
| 4 | 3531.66 | 3672.8 | 141.14 | 3791.4 | 3890.8 | 99.4 |

The outstanding uncertainties which have been successfully removed to optimize production were the compartments of the reservoirs. The hydraulic units in various zones were caused by juxtaposition between reservoir and none reservoir rocks across faults (Ajakaiye and Bally, 2002; Ainsworth, 2006). The estimated hydraulic zones for reservoir D and F are shown in Table 2. Within reservoirs D and F, hydraulic zones were delineated as a result of sand/shale intercalation. Each depth of sand/shale intercalation forms a zone (Fig. 3). Between zones, transitions occur in Fpormations due to variation in porosity and permeability.

Table 2: Hydraulic zones of reservoir D and F

| Reservoir/Zones | Well 1 | Well 2 | Well 3 | Well 4 |
|---|---|---|---|---|
| D/Zones | 4 | 5 | 7 | 7 |
| F/Zones | 5 | 5 | 5 | 5 |

The flow zones are employed to determine the hydrostatic performance and the heterogeneity of the reservoir thereby reducing uncertainty. Features of these petrophysical properties depend on depositional environment (Biddle and Wielchowsky, 1994). The modeled reservoirs have vertical and lateral variations in porosity and permeability. These variations could result from primary depositional process or by secondary diagenetic or deformational effect (Biddle and Wielchowsky, 1994).

Sand zones have good porosity which could have resulted from less sorted and cemented grains (Fig. 4a, 4b, 4c and 4d).Sand/shale intercalation has poor porosity due to juxtaposition between reservoir and source rocks. Evidently fine shale have sealed up the pores of sand in this zone (sand/shale) to form static seal.

From the foregoing, shale formation depicted poor NTG (fig.4a, 4b, 4c and 4d), the reverse was the case for sand formation. Nevertheless, beds of shale formation exhibited prominent high water saturation unlike sand beds (fig.4a, 4b, 4c and 4d). Sand/shale intercalations showed much water saturation. Comparing the permeability of different formations, one can conclude that sand beds have good permeability than shale formation (fig.4a, 4b, 4c and 4d). The average petrophysical properties for reservoirs D and F are shown in table 3.

Table 3: Average petrophysical properties or reservoir D and F.

| Reservoir | % Porosity | % NTG | % $S_w$ | Permeability (md) |
|---|---|---|---|---|
| D | 22.4 | 72.3 | 39.5 | 1444 |
| F | 22.02 | 84.9 | 39.4 | 1375 |

The spatial heterogeneity was evident in the geometry of the structural model (Fig. 5a, 5b, 5c and 5d). To every cell of the grid, there is one rock property. The variation of these properties cut across all the flow zones with each zone having different or nearly the same petrophysical property.

**Reservoir Quality Determination**

The quality of any hydrocarbon reservoir is highly dependent on porosity and permeability. With reference to porosity and permeability values estimated by Rider (1986), the porosity and permeability values obtained from the reservoirs of interest are very good and excellent respectively; this implies that fluid can flow through the rocks without causing structural changes (Gholami et al., 2012). Within the reservoirs zones, areas of good porosity exhibit corresponding high permeability. However, across the seals within the reservoirs, permeability will be by fracturing or fusing.

Petrophysical properties of all the wells used in this work exhibited no homogeneity. A very good and excellent average porosity and permeability were obtained. An approximate average of six zones was delineated in reservoir D while reservoir F has an average of five zones only. The average thickness of D was 96.9m while reservoir F has a thickness of 106.1m. Evidently, D is more faulted than F. Hence, higher NTG was observed in F than D.

Furthermore, there were fewer sorted and cemented grains in reservoir D which made it more porous with a better permeability than F. The higher permeability of reservoir D could be evidence of more interconnected poor throat. More water saturation was

*Scientia Africana, Vol. 13 (No.1), June 2014. Pp186-199*
 *ISSN 1118 - 1931*

captured in D than F. This was due to high fault throw which smeared more shale in D than F.

**REFERENCES**

Ainsworth R.B (2006). Sequence stratigraphic-based analysis of reservoir connectivity: influence of sealing faults – a case study from a marginal marine depositional setting. Petroleum Geoscience, 12(2): 127-141. DOI: 1144/1354-079305-661.

Ajakaiye D.E and Bally A.W (2002).Some structural styles on reflection profiles from offshore Niger Delta. Serach and recovery article No. 10031 AAPG continuing Education course note series No. 41.

Alao P.A, Olabode S.O, Opeloye S.A (2013): Integration of seismic and petrophysic to characterize reservoirs in "ALA" oil field, Niger Delta. Scientific WorldJournal, v. 2013, 1-15, DOI: 10.1155/2013/421720.eCollection 2013.

Allen J.R.L(1965). Late Quaternary Niger Delta, and adjacent areas-sedimentary environment and lithofacies: AAPG Bulletin, v.49, 547-600.

Alvarado V andManrique E (2010).Enhanced Oil Recovery: Field Planning and Development Strategies, Elsevier, MO, 208p.

Biddle K.B and Wielchowsky C.C (1994). Hydrocarbon Traps, Exxon Exploration Company; Houston, Texas, U.S.A.

Ekine A.S and Ibe A.A (2013).Delineation of Hydrocarbon Bearing Reservoirs from Surface Seismic and Well Log Data (Nembe Creek) in Niger Delta Oil Field. IOSR Journal of Applied Physics (IOSR-JAP) e-ISSN: 2278-4861. 4(3): 26-30.

Emujakporue, Godwin O and Ngwueke, Marcel L (2013). Structural interpretation of seismic data from XY field, onshore Niger Delta, Nigeria. J. Appl. Sci. Environ. Manage. 17 (1): 153-158.

Gholami R,Shahraki A.R and JamaliPaghalehM (2012). Prediction of Hydrocarbon Reservoirs Permeability Using Support Vector Machine. Mathematical Problems in Engineering, v. 2012, 18-36.

Kramers J.W (1994). Integrated Reservoir Characterization: from the well to the numerical model, Proceedings, 14th World Petroleum Congress, John Wiley and Sons 1994.

Larue D.K andYue Y (2003). How stratigraphy influences oil recovery: A coparative reservoir database study concentrating on deepwater reservoirs, The Leading Edge April 2003, 332-339.

Maucec M, Yarus J.M and Chambers (2013). Next Generation Modeling for Hydrocarbon Reservoir Characterization, Halliburton Energy Services Graporation, USA.

(1 result(s) found) reservoir characterization model.

Oomkens E (1974). Lithofacies relations in late Quaternary Niger Delta complex: Sedimentology, v. 21, 195-222.

Owolabi O.O, Longjohn T.F, Ajienka J.A (1994). An empirical expression for permeability in unconsolidated sands of eastern Niger Delta: Journal of Petroleum Geology, 17(1): 111-116.

Rider M, (1986); The Geological Interpretation of Well Logs. Blackie, Glasgow, 151-165.

Udegbunam E.O and Ndukwe K, (1988). Rock Property Correlation for hydrocarbon producing sand of the Niger Delta sand, Oil and gas J.