

Hydrocarbon reservoir evaluation of X-field, Niger Delta using seismic and petrophysical data

A. A. Ameloko and A. M. Owoseni

Department of Petroleum Engineering, Covenant University, Ota, Nigeria

Copyright © 2015 ISSR Journals. This is an open access article distributed under the *Creative Commons Attribution License*, which permits unrestricted use, distribution, and reproduction in any medium, provided the original work is properly cited.

ABSTRACT: The integration of well log analysis with subsurface mapping using 3-D seismic interpretation has been identified to be the key component for hydrocarbon exploration and evaluation of hydrocarbon reservoir potentials. Therefore, this research work was aimed at estimating reserves of hydrocarbon bearing sands in X-Field, Niger Delta with the specific objective of evaluating petrophysical parameters and predicting new prospects. Delineated sand units, A, B, and C are characterized by hydrocarbon saturations ranging from 74.3 % to 91 %. From these horizons three major faults were mapped for the purpose of carrying out 3-D subsurface structural interpretation. These were used in generating the time structure maps using the Petrel interpretational tool. The growth faults and the subtle small throw faults concentrated on the field, and occurring across an anticlinal structure can be significant in the creation of multiple reservoir traps and are therefore the ultimate targets in well positioning. The results show that the trapping mechanisms and the obtained Petrophysical parameters in this field are favourable for hydrocarbon accumulation. Hydrocarbon in-place was calculated from the obtained seismic and petrophysical parameters in order to unveil the potentials of the reservoirs. Hydrocarbon in-place for Sand A was estimated to be 98050473.93STB of oil.

KEYWORDS: Hydrocarbon, Reserves, Petrophysical, 3D seismic and Reservoir.

INTRODUCTION

The integration of well log analysis and 3-D seismic interpretation, are the most efficient techniques and approaches that can be adopted to estimate the reserve of any hydrocarbon bearing field in the oil and gas industries for effective productivity in commercial quantity and profitability. The enormous 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. Since cost effectiveness is the driving factor in oil and gas industry, interest in reservoir evaluation is channel towards the need to quantify the reservoir with reduced level of uncertainty associated with geological models. 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 The Niger Delta Basin to date is the most prolific and economic sedimentary Basin in Nigeria. It is an excellent petroleum province, ranked by the U.S Geological Survey World Energy Assessment as the twelfth richest in petroleum resources, with 2.2 % of the world's discovered oil and 1.4 % of the world's discovered gas (Klett et al.1997; Petroconsultants, Inc. 1996). By virtue of the size and volume of petroleum accumulation discovered in this basin, various exploration strategies have been devised to recover the enormous oil and gas deposits. These comprise onshore exploration of oil and gas as well as on continental shelf, and in deep offshore. Petroleum in the Niger Delta is produced from sandstones and unconsolidated sands predominantly in the Agbada Formation. Recognized known reservoir rocks are of Eocene to Pliocene in age, and are often stacked, ranging in thickness from less than 15 meters to 10% having greater than 45 meters thickness (Evamy et al. 1978). Based on reservoir geometry and quality, the lateral variation in reservoirs thickness is strongly controlled by growth faults; with the reservoirs thickening towards the fault within the down-thrown block (Weber and Daukoru, 1975).The objectives of the present work are to make detailed use of available wireline log data to delineate the reservoir units in the wells, determine the geometric properties such as lithological units, gross interval, net-pay thickness,

fluid contact, porosity, water saturation of the reservoir rocks with the ultimate aim of estimating reserves of hydrocarbon bearing sands in this field.

STUDY AREA AND GEOLOGY

The X-field is an onshore oil field in the Niger Delta region, located in the southern part of Nigeria (Figure 1). Niger Delta according to Klett et al. (1997) is situated within the Gulf of Guinea with extension throughout the Niger Delta Province. It is located in the southern part of Nigeria between the longitude 4° – 9° East and latitude 4° - 6° North. It is situated on the West African continental margin at the apex of the Gulf of Guinea, which formed the site of a triple junction during continental break-up in the Cretaceous (Doust, 1990). From the Eocene to the present, the delta has prograded south-westward, forming depobelts that represent the most active portion of the delta at each stage of its development (Doust and Omatsola, 1990). These depobelts form one of the largest regressive deltas in the world with an area of some 300,000km² (Kulke, 1995) a sediment volume of 500,000 km³ and a sediment thickness of over 10 km in the basin depocenter (Michele et al., 1999). Niger Delta Province contains only one identified petroleum system (Ekweozor and Daukoru, 1994; Kulke, 1995) referred to as the Tertiary Niger Delta (Akata –Agbada) Petroleum System. Extended research by Tuttle et al. (1990) confirmed this one petroleum system with the delta, which was formed at the triple junction related to the opening of the southern Atlantic beginning in the late Jurassic and continuing into the Cretaceous. The delta, based on Ekweozor and Daukoru (1994) and Tuttle et al. (1990) began its development in the Eocene with the accumulation of sediments that are now about 10 kilometers thick. The area is geologically a sedimentary basin, and consists of three basic Formations: Akata, Agbada and the Benin Formations. The Akata is made up of thick shale sequences and it serves as the potential source rock. It is assumed to have been formed as a result of the transportation of terrestrial organic matter and clays to deep waters at the beginning of Paleocene (Tuttle et al., 1990). According to Doust and Omatsola (1990), the thickness of this formation is estimated to about 7,000 meters thick, and it lies under the entire delta with high overpressure. Agbada Formation is the major oil and gas reservoir of the delta, It is the transition zone and consist of intercalation of sand and shale (paralic siliciclastics) with over 3700 meter thick and represent the deltaic portion of the Niger Delta sequence (Doust, 1990; Tuttle et al., 1990). Agbada Formation is overlain by the top Formation, which is Benin. Benin Formation is made of sands of about 2000m thick (Avbovbo, 1978).

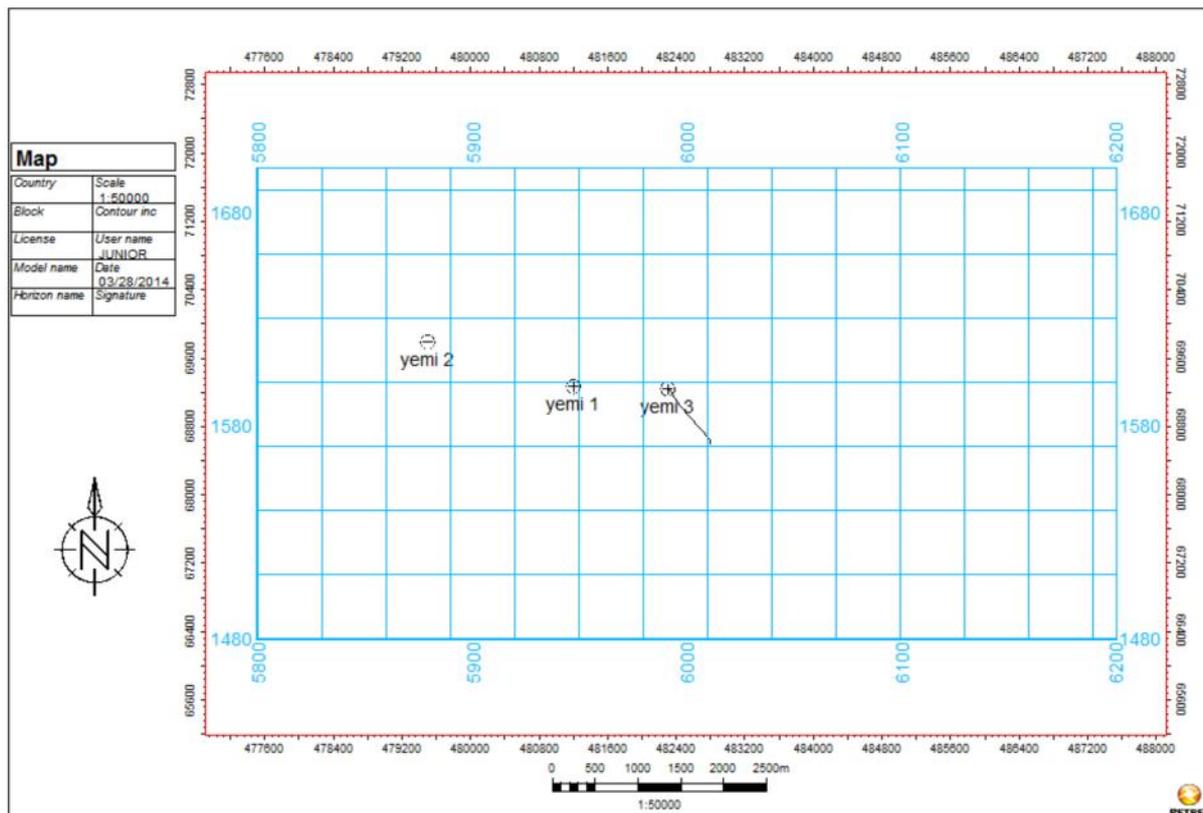


Figure 1: Base-map of the Study Area Showing Wells Location on the Coordinate Points

METHODOLOGY

Well log analysis and 3-D Seismic interpretation are often the key factors for volumetric estimation of hydrocarbon reserve of a reservoir. The well log analysis evaluates parameters such as; lithological units, gross interval, net-pay thickness, fluid contact, porosity, water saturation and volume of shale etc. while the seismic estimates the reservoir area extent. The Petrel software was deployed for the analysis and interpretation of the well logs and seismic data. The top and base of the Agbada Formation were determined using the reflection characteristics of the 3-D seismic volume, stratigraphic indicators and the nature of the gamma ray curves that characterize this interval. The results of both methods were further integrated to estimate reserve yield. Quantitative interpretation was carried by means of visual observation of the characterization signature, shape, and patterns of the log or suite of logs of interest. This was done in order to identify zones with properties of interest and their respective depth and thickness. Well logs were correlated and appropriate reservoirs bodies were characterized in terms of their petrophysical parameters (Figure 2). Reservoirs were calculated using volumetric method from the integrated information from the 3D seismic interpretations and petrophysical analysis. The type of lithology is indicated by the gamma ray which measures in American Petroleum Institute (API) value unit. Petrophysical parameters evaluated include; Porosity, Water saturation, Hydrocarbon saturation and Net pay thickness. Time contour maps (Figure 5) of productive reservoir formations have been constructed using the time read directly from the tops of particular horizons and average velocities derived from interval velocities.

RESULTS AND DISCUSSION

In the evaluation of a petroleum reserve, it is necessary to determine accurately certain petrophysical properties such as porosity and permeability of the reservoir rock. In this study, three sands were delineated as hydrocarbon bearing sands within the Agbada formation of the field as shown in the structural well correlation (figure 2). The sands were identified to be highly prolific in hydrocarbon yield and were completely analysed to estimate their petro-physical parameters.

The wells and their coordinate values are:

Well Yemi 1: 69280 m North and 481200.00 m East.

Well Yemi 2: 69800 m North and 479500.00 m East.

Well Yemi 1: 69238.96 m North and 482310.12 m East.

PETROPHYSICAL EVALUATION OF THE RESERVOIRS

Three sands units (A to C) were delineated from the correlation of three wells using well logs (Figure 2). The lithologic units are consistent across the wells, meaning that most lithologic units are present. Increasing trend of the thickness of the shale units with depth indicate that the sequence is approaching the Akata formation.

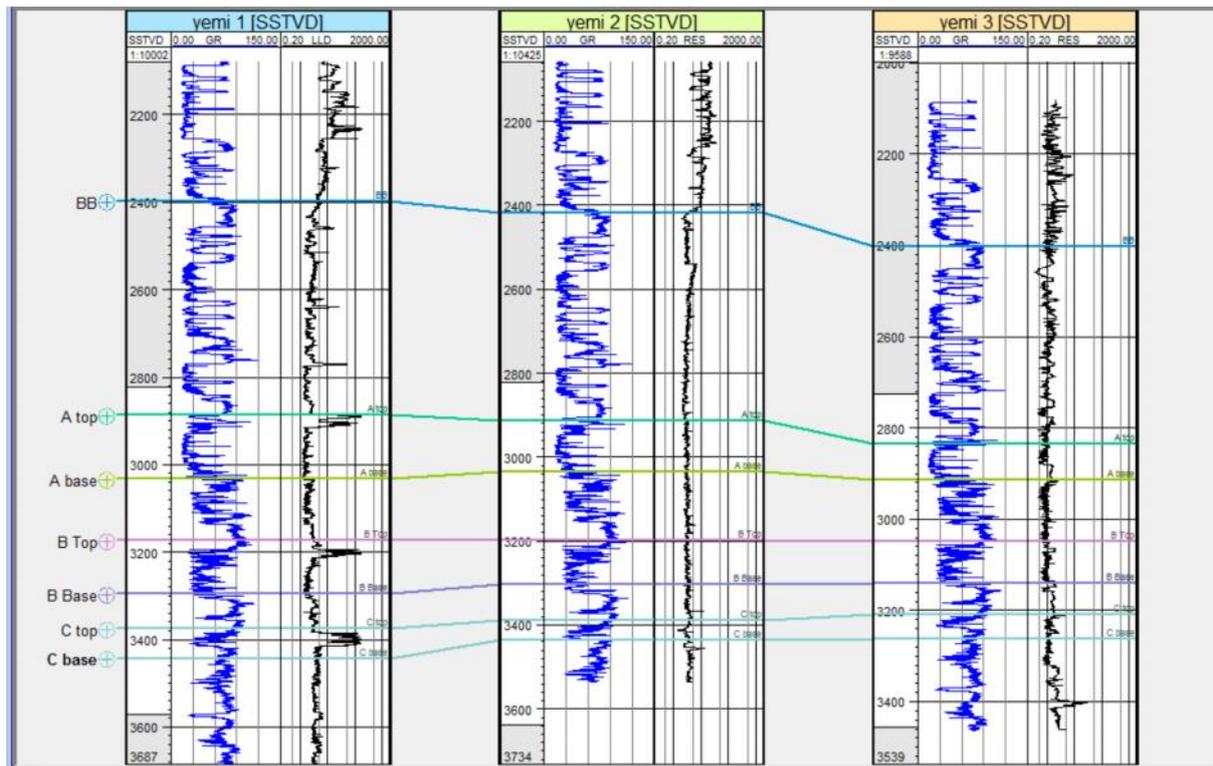


Figure 2: Structural Well Correlation

WELL YEMI 1

The reservoirs in this well have average thicknesses from 150 Ft in reservoir A to 66 Ft in reservoir C. The average neutron-density derived porosity for the reservoirs are between 31.8 % to 34.7 %, which indicates good average porosity. The porosities are satisfactory for a reservoir to be adjudged a producible reservoir. The water saturation (10.4-11.3 %) for the reservoirs suggest that the reservoirs are mainly hydrocarbon bearing. The low water saturation in reservoirs A to C (10.4, 11.0 and 11.3 %) indicates 89.6 % 89.0 % and 88.9 % hydrocarbon saturation respectively (table 1).

WELL YEMI 2

The average porosities of the reservoirs are moderate to good (29.0 %-32.7 %) to accommodate large hydrocarbon yield, and reservoirs A and B show evidence of hydrocarbon saturation as the low values of the water saturation in reservoirs A and B (9.0 and 9.6 %) indicates 91.0 % and 90.4 % hydrocarbon saturation respectively with no evidence of hydrocarbon in reservoir C. The porosities in these reservoirs are also satisfactory to be adjudged a producible reservoir. The reservoirs in this well have average thicknesses from 121 Ft in reservoir A to 49 Ft in reservoir C (table 2).

WELL YEMI 3

In comparison with the first two wells, there is relatively higher water saturation in Well Yemi 3 reservoirs (28.0 % and 22.0 %). This indicates lower hydrocarbon potential here (74.3% in reservoir A and 78.3 % in reservoir B and no evidence of hydrocarbon in reservoir C), while the average porosity of the sand bodies are also good (26.0 % - 36 %). The good sand development of the up dip sedimentation continued in this Well with reservoir thickness ranging from 55 Ft in reservoir C to 94 Ft in reservoir C (Table 3). The porosities in these reservoirs are also satisfactory to be adjudged a producible reservoir.

SEISMIC CHARACTERISTICS

The seismic section was mainly used for structural interpretation. The seismic lines have been interpreted which resulted in the construction of time contour maps. From correlative study of all seismic lines with the time contour maps, the following results of structural interpretation are deduced: No definite fault trend is present but localized normal faults do

exist due to extensional tectonics (figures 3 and 4). Apart from the three major faults seen on the section in figure 3, there are other minor faults, about six of them formed by post depositional process (figure 4). In most cases, they are often referred to as synthetic secondary faults as some are formed on the foot wall and upthrow axis of the major faults. They can also be regarded as antithetic as they were formed on the hanging wall, down-throw axis. The presence of these faults in the study area is an indication that there is a possibility of hydrocarbon accumulation. Weber and Daukora (1975) described faults as good migration path for hydrocarbon into the reservoir rocks. The normal faults also make local scale horst and graben geometries favourable for the accumulation of oil. Figure 5 is the seismic structural time map of the target Sand A-surface. The time structure map gives information about the seismic reflection two-way time for each hydrocarbon bearing sands. A close examination of this map shows the presence of structures (growth fault and anticline) that can possibly harbour hydrocarbon in the study area. An anticlinal structure could be observed about the central portion of the study area closing on the major faults. This shows that the trapping mechanism is a fault-assisted anticlinal structure. The major faults polygons around the closures serve as seals which can help to trap hydrocarbons migrating to the surface as a result of gravitational push (figure 6). The area obtained from the seismic section when combined with the thickness of the reservoir and other petrophysical parameters such as porosity (ϕ) and water saturation (S_w) are used in estimating the volume of hydrocarbon in place in the reservoir. It is worthy of note that the three delineated reservoirs have high potentials for hydrocarbon in sands A and B than in sand C.

Table 1: Computed Petrophysical Parameters from well (Yemi 1)

Yemi 1	TOP (ft)	BOTTOM (ft)	THICKNESS (ft)	DENSITY g/cm^3	ϕ (%)	$R_{w(\Omega_m)}$	S_w (%)	S_h (%)
A	2880	3030	150	1.80	34.7	0.324	10.4	89.6
B	3171	3295	124	1.85	32.3	0.324	11.0	89.0
C	3373	3439	66	1.84	31.8	0.324	11.3	88.9

Table 2: Computed Petrophysical Parameters from well (Yemi 2)

Yemi 2	TOP (ft)	BOTTOM (ft)	THICKNESS (ft)	DENSITY g/cm^3	ϕ (%)	$R_{w(\Omega_m)}$	S_w (%)	S_h (%)
A	2910	3031	121	1.85	32.7	0.324	9.0	91.0
B	3199	3293	94	1.95	30.6	0.324	9.6	90.4
C	3385	3434	49	2.07	29.0	0.324		

Table 3: Computed Petrophysical Parameters from well (Yemi 3)

Yemi 3	TOP (ft)	BOTTOM (ft)	THICKNESS (ft)	DENSITY g/cm^3	ϕ (%)	$R_{w(\Omega_m)}$	S_w (%)	S_h (%)
A	2834	2914	80	2.10	26.0	0.324	28.0	74.3
B	3047	3141	94	2.05	30.0	0.324	22.0	78.3
C	3205	3260	55	2.05	36.0	0.324		

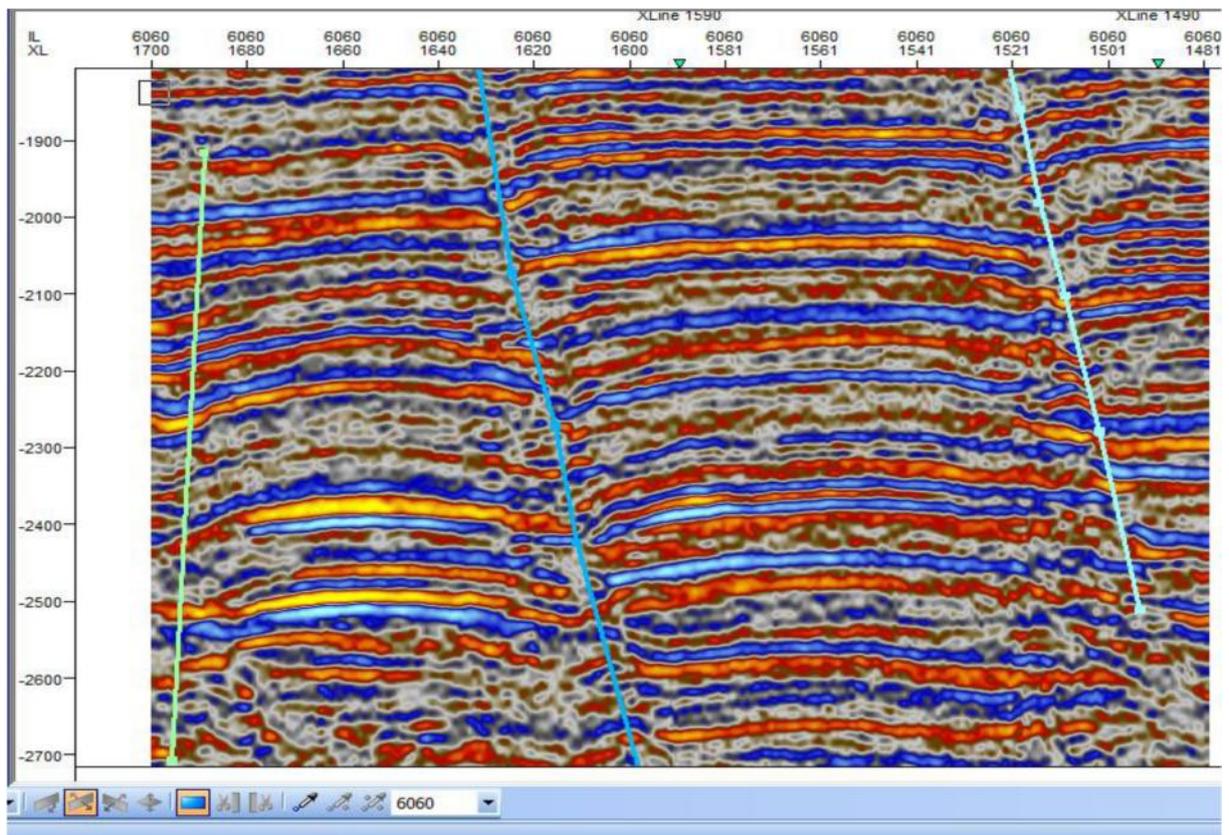


Figure 3: Seismic Interpretation window showing the Three Major Faults

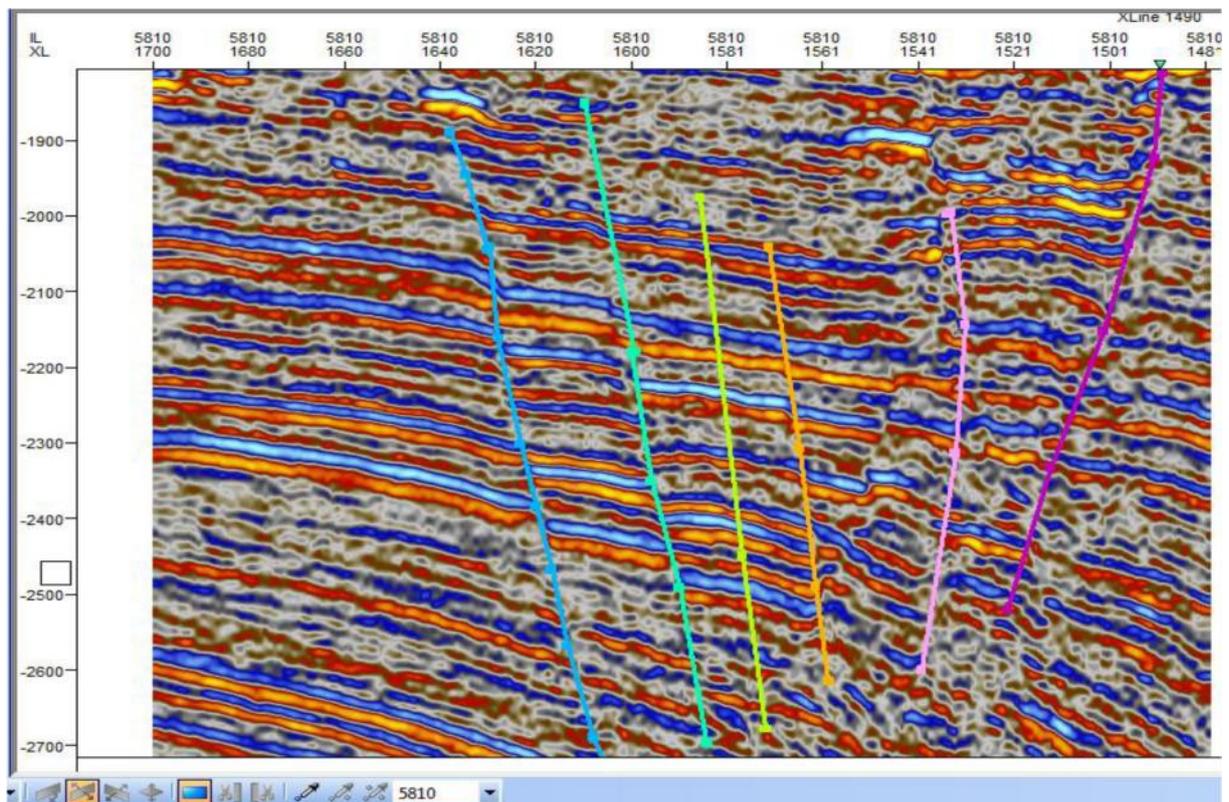


Figure 4: Seismic Interpretation window showing the Six Minor Faults

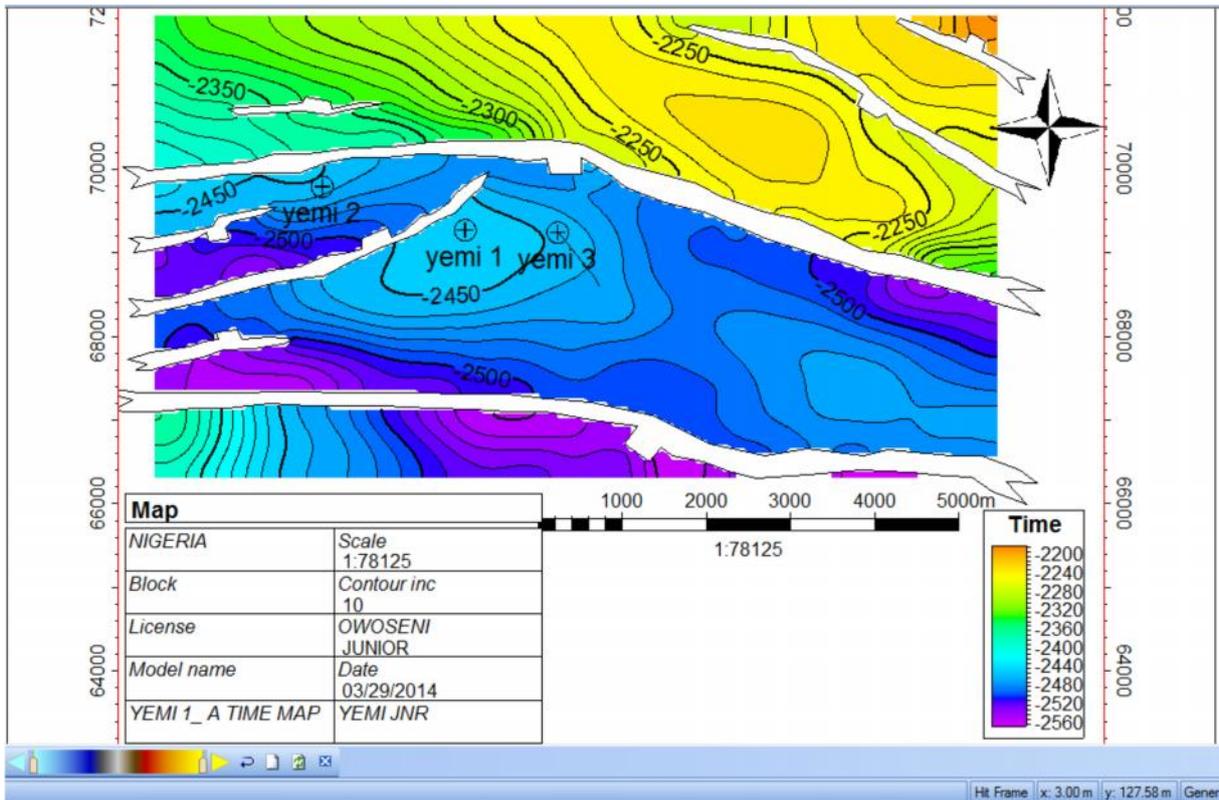


Figure 5: Time contour Map of Sand A

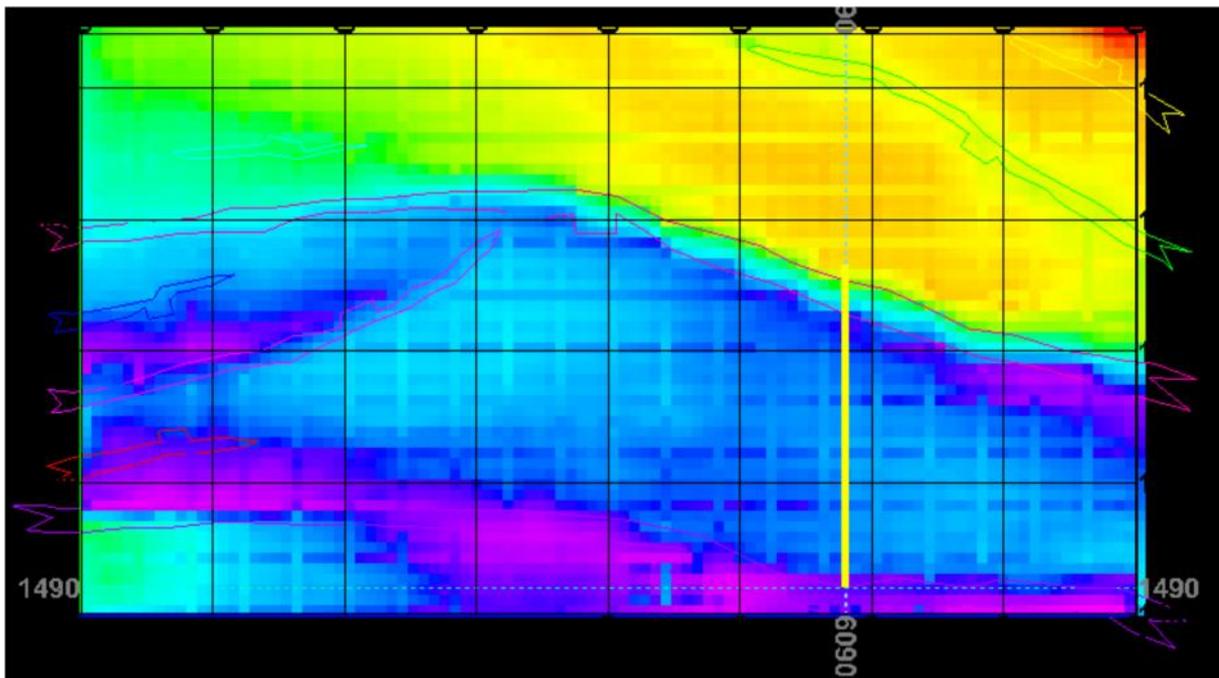


Figure 6: 2-D Window Showing Fault Polygons For sand A

OIL RESERVE ESTIMATION

The estimation method used for this study is volumetric estimation of the reserve. This volumetric estimation of hydrocarbon reserves involves the integration of various geological parameters obtained from both surface (seismic) and subsurface (well log) geophysical data. Petrophysical parameters such as porosity and water saturation have already been

calculated as in the last section. The reservoir for estimation of hydrocarbon in place, which can be located on the structural maps as delineated. The average of the petrophysical parameters for the mapped reservoir was computed to get the corresponding values used in computing for the hydrocarbon in place. Calculations of original hydrocarbon in place were done using the following standard volumetric estimation formula in equation (1)

To estimate reserve in sand A the following relations are used:

$$OOIP = 7758 \times \text{Vol.} \times \text{Porosity } (\phi) \times (1 - \text{Water Saturation}) \quad (1)$$

Where;

7758 = conversion factor from acre-ft. to barrel

Vol. = Net Volume

Vol. = $h \times A$

h = Pay thickness from petro-physics (m)

A = Areal extent of the accumulation from 3-D Seismic interpretation ($ha \times 10000$)

$$STOOIP = OOIP \times Boi$$

Where;

STOOIP = Stock Tank Original oil in place

Boi = oil formation Volume Factor/ Shrinkage Factor

$$\text{RESERVE} = \text{STOOIP} \times \text{oil Recovery Factor (RFo)}$$

To calculate Gross Rock Volume

9 squares (1cm by 1cm)

$$1.8\text{cm} = 1000\text{m}$$

$$1\text{ cm} = X\text{m}$$

$$1000/1.8 = 555.6\text{m}$$

$$\text{Area of the surface from seismic} = 9 \times 555.6 \times 555.6 = 2778222.24 \text{ m}^2 = 686.513666 \text{ Acres}$$

$$\text{Net Pay Thickness from well Log (Sand A)} = 24\text{m} = 78.74\text{ft}$$

$$\text{Gross Rock Volume} = \text{Area} \times \text{Net Pay Thickness}$$

$$\text{GRV} = 686.513666 \text{ acres} \times 78.74 \text{ ft.}$$

$$= 54,056.086 \text{ acreft.}$$

From table 1, Sand A has,

$$\text{Porosity} = 0.347, \text{ Water Saturation} = 0.104$$

$$\text{OIIP} = 7758 \times 54056.086 \times 0.347 \times (1 - 0.104) = 130386268.5 \text{ STB}$$

$$\text{STOOIP} = \text{OIIP} \times \text{Boi}$$

$$\text{STOOIP} = 130386268.5 \times 1.6$$

$$= 208618029.6 \text{ STB}$$

$$\text{RESERVE} = \text{STOOIP} \times \text{Oil Recovery Factor} = 208618029.6 \times 0.47$$

$$= 98050473.93 \text{ STB}$$

CONCLUSION

From this research study, the average values of porosity for each productive zone ranges from 26 to 36 %; average values of water saturation ranges from 9 to 28 %, and average values of hydrocarbon saturation ranges from 74.3 to 91 % in the three reservoirs identified from the three wells, Yemi 1, Yemi 2 and Yemi 3. The total Gross Rock Volume is calculated to be 54,056.086 acreft. The hydrocarbon saturation indicates two productive zones within the reservoir formation, Sands A and B. The study however concluded that Sand A bears a considerable amount of reserves of about 98050473.93STB. From the estimation, it can be concluded that the value of hydrocarbon (either gas or oil) in place for reservoir A, as revealed by this analysis could be said to be in commercial quantity and the profitability may be high which could cater for the expenses of carrying out the exploration and exploitation of either oil or gas. Faulting and folding played a prominent role in the definition of the structural setting. These structural features constitute the main structural traps detected in the study area.

REFERENCES

- [1] Avbovbo, A.A. 1978. Tertiary lithostratigraphy of Niger Delta: American Association of Petroleum Geologists Bulletin, v. 62, p. 295 - 300.
- [2] Doust, H. 1990. Petroleum geology of the Niger Delta: Geological Society, London, Special Publications, v.50, p. 365.
- [3] Doust, H., and Omatsola, E. 1990. Niger Delta, In, Edwards, J. D., and Santogrossi, P.A., Eds., Divergent/Passive Margin Basins: AAPG Memoir 48: Tulsa, American Association of Petroleum Geologists, v. 48, p. 239-248.
- [4] Ekweozor, C.M., and Daukoru, E.M. 1994. Northern delta depobelt portion of the Akata-Agbada(!) petroleum system, Niger Delta, Nigeria, in, Magoon, L.B., and Dow, W.G., eds., The Petroleum System—From Source to Trap American Association of Petroleum Geologists Bulletin, v. AAPG Memoir 60, p. 599-614.
- [5] Evamy, D.D., J. Haremboure, P. Kamerling, W.A Knaap, F.A. Molloy, and P.H. Rowlands. 1978. "Hydrocarbon Habitat of Tertiary Niger Delta". *AAPG Bulletin*. 62:1-39.
- [6] Klett, T. R., Ahlbrandt, T. S., Schmoker, J. W. & Dolton, J. L. (1997): Ranking of the world's oil and gas provinces by known petroleum volumes: U.S. Geological Survey Open-file Report-97-463, CD-ROM.
- [7] Kulke, H. 1995. in, Kulke, H., ed., Regional Petroleum Geology of the World. Part II: Africa, America, Australia and Antarctica: Berlin, Gebrüder Borntraeger, p. 143-172.
- [8] Petroconsultants (1996): Petroleum exploration and production database: Houston, Texas, Petroconsultants, Inc.
- [9] Tuttle, M.L.W., Charpentier, R.R., and Brownfield, M.E. 1990. Tertiary Niger Delta (Akata-Agbada) Petroleum System (No. 701901), Niger Delta Province, Nigeria, Cameroon, and Equatorial Guinea, Africa, in USGS, ed., The Niger Delta Petroleum System: Niger Delta Province, Nigeria, Cameroon, and Equatorial Guinea, Africa: Denver, Colorado, U.S. Department Of The Interior. U.S. Geological Survey.
- [10] Weber, K.J. and E. Daukoru. 1975. "Petroleum Geology of the Niger Delta". *9th World Petroleum Congress Proceedings*. 2: 209-221.