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Oil and Gas Reservoir Characterization; A Case Study of Agbada Field

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Abstract

This study on reservoir characterization was conducted using seismic data and well logs. The aim was to characterize the petrophysical properties and structural element in the field for hydrocarbon volume estimation and determination of infill well locations. Three reservoirs were identified (J100, K100, L100) at shallow, middle and deep depths and correlated across the field using gamma ray log. Petrophysical characterization revealed porosity ranges from 25 to 27% in J100 reservoir, 16% to 27% in K100 reservoir and 11 and 18% in L100 reservoir. This shows good to very good porosity values for reservoir rocks. On average, water saturation is 80%, 68% and 70% in J100, K100, and L100 reservoirs. Net to gross ranged from 24 to 77% in J100, 38 to 82% in K100 and 29 to 75% in L100 and L100 reservoir. Average net to gross revealed that the sands are cleaner with depth. Resistivity and neutron-density logs revealed the reservoirs are oil bearing. Structural characterization of seismic date revealed the presence of synthetic and antithetic faults. Depth structure maps generated revealed closures that are anticlinal and fault supported. Oil water contact super-imposed on the structural maps revealed closures that were oil bearing. Estimation of stock tank oil initially in place revealed 19.511 mmstb, 73.576 mmstb and 19.169 mmstb for J100, K100 and L100 reservoirs respectively, indicate that they can be produced at significant profits. Two infill well placement locations were identified from petrophysical and structural characterization; one at the north central part of J100 reservoir and another at the North-Western part of K100 reservoir.

Keywords: Petrophysical, Gamma-ray log, Porosity, Faults, Reservoir.

Introduction

The Niger delta is a hydrocarbon province with a current oil and gas reserve of 37 billion barrels and 192 trillion cubic feet respectively (Vanguard Newspaper, 2017). Characterizing the reservoir is a process which describes various properties in reservoirs using all the available data to provide reliable reservoir geologic models for accurate prediction of the performance of a reservoir (Jong, 2005).

Drilling an oil and gas well is a very costly venture coupled with the fact that hydrocarbon reserves are depleting. The deposits yet undiscovered are in more complex geological environments and hence it is important to properly characterize a reservoir using all available data from cores, logs and seismic in order to determine location for infill well placement with greater certainty to boost production.

Ezekwe and Filler (2005), described reservoir characterization as a process that involves the integration of various qualities and quantities of data in a consistent way to describe the reservoir properties of interest in inter well locations. The primary objective of reservoir characterization is to create a more representative geologic model of reservoir properties, understand and identify the flow units of the reservoir and predict the inter-well distributions of relevant reservoir properties (Godwin, 2014). It is the understanding of the reservoir connectivity in dynamic and static conditions by integrating data from different sources. Hence, in establishing a geologic representation of what a reservoir is most likely to be, it is important to sufficiently capture the uncertainty associated with not knowing its exact image (Odai and Ogbe, 2010).

Reservoir Characterization which entails the understanding of the subsurface reservoir plays an important role in the exploration and exploitation processes of the oil and gas industry in that it gives room for optimum recovery of hydrocarbon at a minimized cost. Reservoir Characterization involves a holistic description of a reservoir by integrating all the available data, tools, disciplines, and knowledge. Reservoir characterization involves the estimation of reservoir properties such as porosity, permeability, saturation, pressure and pores sizes using cores, well logs, production and seismic data. By applying reservoir characterization techniques in a field, asset holders will be able to maximally recover hydrocarbon while minimizing costs. Hence, this study is aimed at characterizing the Agbada Field using well logs and seismic data in view of estimating hydrocarbon reserves and predicting infill well locations to boost recovery.

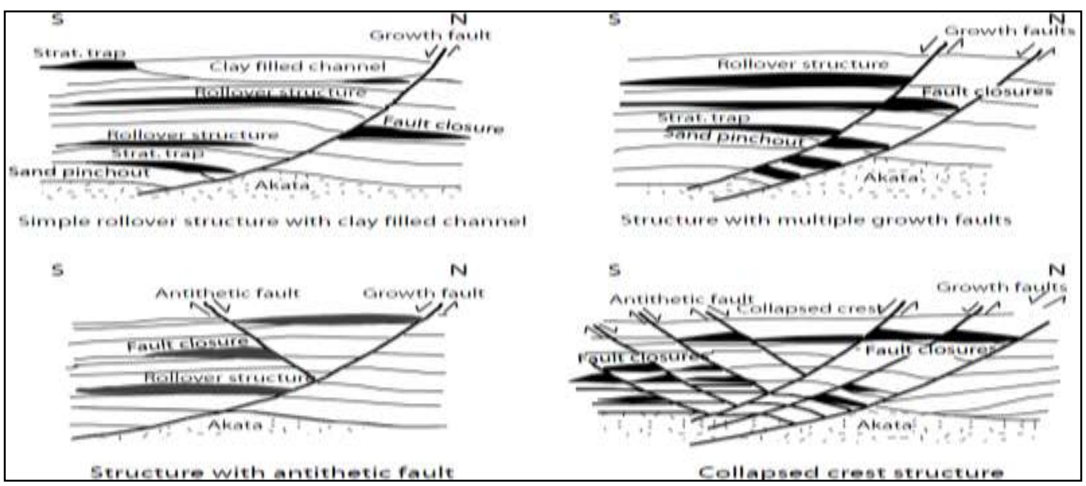

Figure 1: Field structures and associated traps typical of Niger Delta Basin. Modified from Doust and Omatsola (1990) and Stacher (1995).

Avbovbo (1978) stated that Benin Formation consist of alluvial sands with thickness of about 200m deposited in early Eocene to Recent. According to Stacher (1995), Agbada has intervals that don't have enough thickness and are immature in some parts to produce a large volume of oil. Meanwhile, Akata shale which is below the Agbada Formation has enough thickness and volume to sufficiently produce large volume of oil. A conclusion has however been made by Evamy *et al*. (1978) that the source of the Delta is both the shale of the Akata and interbedded shale in the lower Agbada Formation.

Materials and Method

Materials

Data Availability

The following data serves as material for the comprehensive evaluation and characterization of the case study.

1. Base maps for the study area.
2. Well header information.
3. Well log data in ASCII format.
4. Directional survey parameters (well deviations).
5. Checkshot survey data from one well.
6. Seismic data.

Method

- **Data Loading and Quality Assessment**

The seismic volume and wells information provided in digital format were loaded into Schlumberger Petrel version 2014.1 for visualization, quality assessment and quantitative interpretation. Before loading any data into the Petrel, the project was set up using the geographic reference for the seismic data (Minna/Nigeria mid-belt) and the units for both seismic data (milliseconds) and well data (feet). This was an important step because any unit or projection system not set prior to data loading was not usually recognized in Petrel, rather the default units were often used. The method of data loading and quality assessment for the available data-sets are presented under the following sub-headings.

- **Well header**

The well headers provided by FLD-X contained four relevant information which included; the well names (02, 03, 25, 35, 58, 60, 65), the geographic reference locations for the wells (Easting and Northing), well reference datum depth (Kelly bushing) and the total drilled depth (TD). This information was loaded into Petrel and displayed on a map window. This showed that the wells spread conformed with the provided base map.

- **Well Deviation**

The well deviation survey data provided were loaded after the well headers. The format for loading the well deviations in Petrel was "well-path/ASCII". There are basically no vertical wells because all wells are deviated to some degree, especially deep wells. The well path houses the well trajectory information necessary to calculate the well deviation.

- **Well Logs**

Well logs were loaded into petrel using the well logs (ASCII) format. A well section window was used to visualize and assess the quality of the logs. The unit and scale for each log was set as follows; Gamma ray (0-150 gAPI), resistivity (0.2-2000 Ohm.m), density (1.65-2.65 g/cm^3), neutron (-0.15-0.45 ft^3/ft^3), compressional sonic (40-140 us/ft) and caliper (inches). After the unit and scales were set, the density logs were checked for washouts and also the sonic logs for spikes.

- **Seismic Data**

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The available seismic data was loaded into Petrel in SEG-Y 16 bit format. The seismic volume has data coverage of approximately 556 Sq.Km. On an interpretation window in Petrel, the seismic amplitudes, reflection strengths and reflection continuity were analysed.

According to Doust and Omatsola (1989), these hydrocarbons are entrapped by rollover anticlines associated to growth fault.

Data Interpretation

- **Lithology and Reservoir Identification**
  In this study, lithology was identified using gamma ray (GR) log and neutron-density (NPHI-RHOB) logs. In using GR for lithologic identification, a histogram plot of GR log values for all the wells are plotted in Petrel(see appendix). From the plot, the sand and shale baselines are determined. The sand baseline (GR_{sand}) is taken as the lowest average GR reading from where sand is assumed to be 100%, while shale baseline (GR_{sh}) is taken at 100% shale where GR reading is highest (see figure 2).

- **Reservoir Correlation**
  Correlation of reservoir sand bodies across the field was made possible with the use of shale thickness and GR log motif. Unlike shales, sand facies can easily thin out, hence making correlation difficult. Hence, the thickness of shales which are fairly constant below and above these sand facies can be used to validate sand correlations in order to easily recognize trends in sand facies shift. The GR log motifs adopted for correlation are based on Emery and Myers, (1996) interpretations. Cylindrical (blocky) pattern occurs when the sands are aggradational and are often associated with channel fill deposits. A very important step carried out in Petrel before the commencement of the correlation exercise was to arrange the wells in a well section window based on relative closeness to each other. This was necessary in order to recognize directional trends in the sand packages such as thinning and thickening directions. The tops and base of three sand packages were mapped and correlated across all wells.

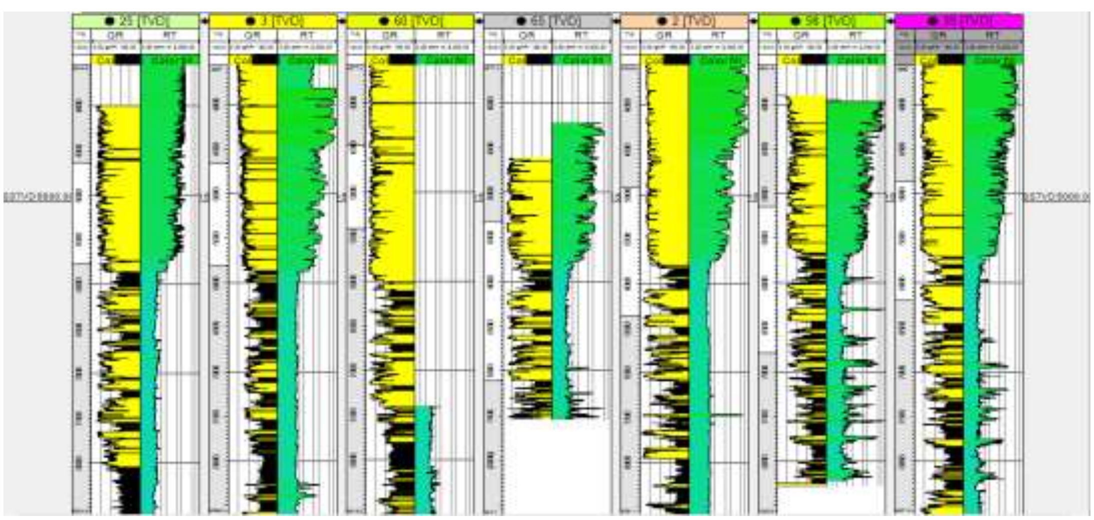

Figure 2: GR – Gamma ray log; RT – Resistivity log Showing Sand and Shale Lithologies Identified After Establishing Baselines and Defining net Sand Cutoff (Yellow Deflections Indicates Sand While Black Deflections are Shale).

Research Design

The following procedural steps were taken for characterizing the Agbada Field:

1. Data gathering and data input to Petrel software interface
2. Quality Assurance and Quality Control on the authenticity of obtained data
3. Well log data conditioning
4. Lithology identification and correlation.
5. Petrophysical Evaluation (shale volume, Porosity, Permeability, Water saturation).
6. Seismic data pre-evaluation and reflection pattern analysis.
7. Generation of velocity models and depth conversion
8. Prospect evaluation and hydrocarbon volumes estimation.
9. Determination of infill well placement locations.

Results and Discussion

- **Results of Petrophysical Characterization**

The results of petrophysical evaluation for J100, K100 and L100 reservoirs in Agbada field are presented in the Appendix and summarized in Table 1, 2, 3 and Figure 3 respectively. The results are discussed under the following sub-headings.

- **Reservoir Thickness**

The gross reservoir thickness ranges from 40 to 82ft in J100 reservoir, 52 to 167ft in K100 reservoir and 71 to 122ft in L100 reservoirs. In J100 and K100 reservoirs, the highest gross were obtained from well-25 while in K100 reservoir, the highest thickness was found in well-60. The average reservoir thicknesses were 55.29ft, 92.71ft and 100.17ft in J100, K100 and L100 reservoirs respectively.

- **Porosity**

Total porosity ranges from 25 to 27% in J100 reservoir, 16 to 27% in K100 reservoir and 11 to 18% in L100 reservoir. Porosity was determined using the density logs, hence, porosity was not determined in wells that had no density log. The highest porosity value was obtained from well-58 in J100 and L100 reservoirs and well-60 in K100 reservoir. Average porosity is 26% in J100, 21% in K100 and 15% in L100 reservoirs. This shows that porosity generally decreases with depth in the field as a result of compaction. These porosity values are not in line with the range of 28-32% for the Agbada Formation of the Niger Delta as reported by Schlumberger (1985). Meanwhile, Rider (1986) classified porosity as follows; 0-5% (negligible), >5-15 (poor), >15-20 (good) >20-30 (very good), >30 (excellent). Based on this classification scheme, average porosity in J100 and K100 reservoirs can be classed as very good and good in L100 reservoir.

Table 1: Results of Petrophysical Characterization of J100 Reservoir

Wells / Parameters	Top (ft)	Bottom (ft)	OWC (ft)	Thickness (ft)	Pay Thickness (ft)	NTG	Ø	S_w
Well 25	5958	6040	-	82	-	0.77	0.26	0.98
Well 03	6077	6131	-	54	-	0.31	-	0.81
Well 60	6163	6203	-	40	-	0.24	-	-
Well 65	5939	5991	-	52	-	0.33	-	0.99
Well 02	5921	5970	-	49	-	0.24	-	0.82
Well 58	5841	5897	5891	56	50	0.41	0.27	0.43
Well 35	5865	5919	5897	54	32	0.41	0.25	0.75
Average				**55.29**	**41**	**0.39**	**0.26**	**0.80**

Table 2: Results of Petrophysical Characterization of K100 Reservoir

Wells / Parameters	Top (ft)	Bottom (ft)	OWC (ft)	Thickness (ft)	Pay Thickness (ft)	NTG	Ø	S_w
Well 25	7579	7746	-	167	-	0.82	0.21	0.99
Well 03	7570	7700	-	130	-	0.47	-	0.79
Well 60	7628	7724	-	96	-	0.64	0.27	0.99
Well 65	7313	7365	7326	52	13	0.65	-	0.66
Well 02	7382	7460	7406	78	24	0.38	-	0.54
Well 58	7270	7331	7329	61	59	0.53	0.18	0.38
Well 35	7308	7373	7378	65	70	0.39	0.16	0.42
Average				**92.71**	**41.5**	**0.55**	**0.21**	**0.68**

Table 3: Results of Petrophysical Characterization of L100 Reservoir

Wells / Parameters	Top (ft)	Bottom (ft)	OWC (ft)	Thickness (ft)	Pay Thickness (ft)	NTG	Ø	S_w
Well 25	9011	9121	-	110	-	0.75	0.11	0.91
Well 03	8484	8594	-	110	-	0.74	-	0.79
Well 60	8854	8976	-	122	-	0.74	0.17	0.85
Well 02	8392	8463	-	71	-	0.55	-	0.79
Well 58	7998	8099	8095	101	97	0.29	0.18	0.36
Well 35	8035	8122	8111	87	76	0.59	0.15	0.51
Average				**100.17**	**86.5**	**0.61**	**0.153**	**0.70**

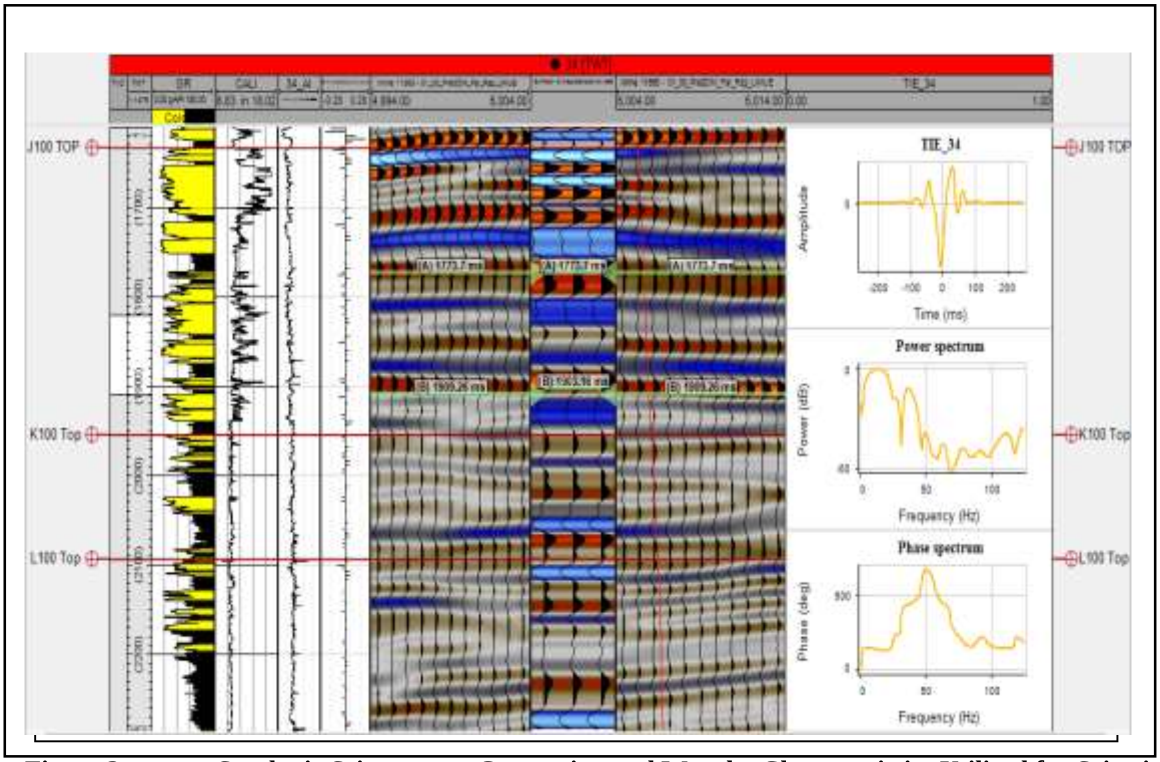

Figure 3: **Synthetic Seismogram Generation and Wavelet Characteristics Utilized for Seismic Well Tie**

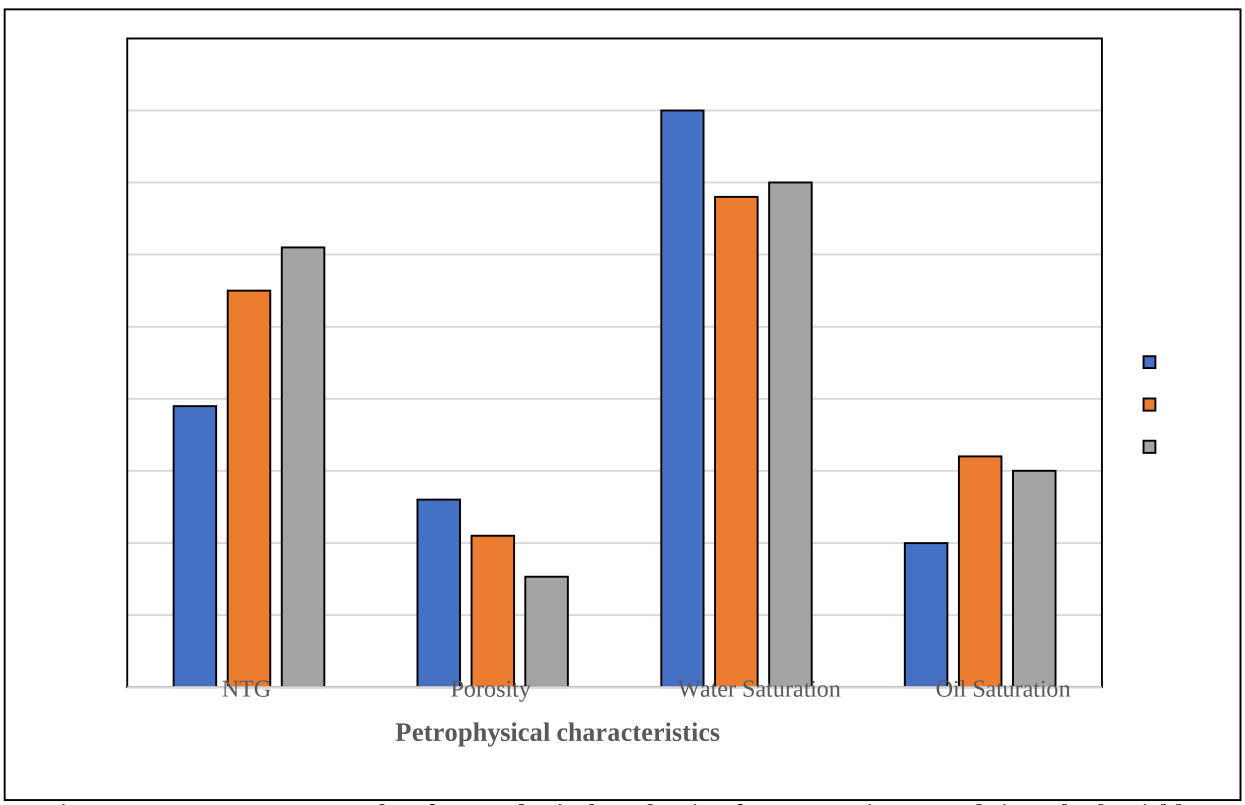

Figure 4: **Average Results of Petrophysical Evaluation for Reservoir Intervals in Agbada Field**

- **Fluid Content**

  The presence of hydrocarbons in the reservoirs were established with the use of resistivity log. This is because hydrocarbons are more resistive than water, hence a sharp increase in the resistivity log measurement signals the presence of hydrocarbons.

- **Fluid Saturation**

  The results of the estimated water saturation ranged from 43 to 99% in J100, 38 to 99% in K100 and 36 to 91% in L100 reservoir. This showed an equivalent hydrocarbon saturation of 1 to 57% in J100, 1 to 62% in K100 and 9 to 64% in L100 reservoir. On average, the hydrocarbon saturation was 20%, 32% and 30% in J100, K100 and L100 reservoirs respectively.

- **Volume Estimation**

  Hydrocarbon volumes were estimated for J100, K100 and L100 reservoirs using Equation 3.7. The petrophysical inputs and bulk volume utilized for hydrocarbon volume estimation are presented in Table 4.4 along with the estimated volumes. The result shows that J100 has an estimated stock tank oil initially in place of 19.511 million Stock Tank Barrels (MMSTB) of oil, 73.576 MMSTB for K100 reservoir and 19.169 MMSTB for L100 reservoirs. This reveals that the reservoir intervals are profitable for production. The STOIIP estimated for K100 reservoir exceeded those of J100 and L100 combined. Hence, the K100 reservoir is most profitable amongst the three identified reservoir intervals.

Table 4: **Hydrocarbon Volumetric Estimation from Reservoir Intervals in Agbada Field.**

Reservoir	Thickness (ft)	NTG	Porosity	Water Saturation	Oil Saturation	Area (ft^2)	STOIIP (MMSTB)
J100	55.29	0.39	0.26	0.8	0.2	2803770	19.511
K100	92.71	0.55	0.21	0.68	0.32	3459700	73.576
L100	100.17	0.61	0.153	0.7	0.3	1101290	19.169

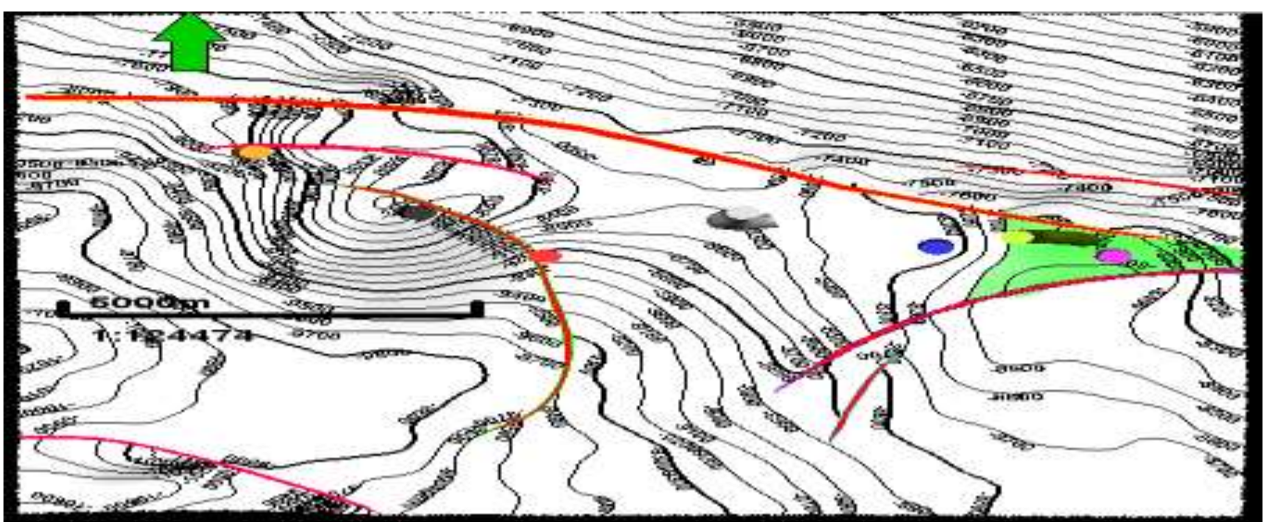

Figure 5: **Oil Water Contact overlain on L100 depth structure map**

Conclusion

Well logs were used to determine lithology, shaliness, fluid content, porosity and water saturation, while seismic data was used to determine area and structural elements in the field. Three reservoirs were delineated using gamma ray log (J100, K100 and L100 reservoirs) and correlated across the field using GR log motif and thickness of shale beds. Shale volume was determined and used to estimate net to gross ratio. Although K100 reservoir has the highest gross thickness (100.17 ft), net pay thickness (86.5ft) and net to gross ratio (0.61), while reservoir J100 had the lowest gross thickness (55.29 ft), net pay thickness (41 ft) and net to gross ratio (0.39) Across the field, porosity values are classed as good (L100 reservoir) to very good (J100 and K100 reservoirs). Water saturation ranged from 68% to 80% with K100 reservoir having the highest oil saturation of 32% and J100 reservoir having the lowest oil saturation (20%). These results revealed that the reservoirs could be produced at significant profit, with K100 having the highest stock tank oil initially in place. For an effective drainage from the identified prospects, two infill well locations were identified from J100 and K100 reservoirs respectively. The following conclusions were drawn out from this study;

1. The identified reservoirs (J100, K100 and L100) are of good quality for hydrocarbon production based on petrophysical characteristics (net to gross thickness, net pay thickness, porosity and water saturation).
2. Hydrocarbon accumulations are trapped within fault supported anticlines.
3. Hydrocarbon volumes are sufficient for economic exploitation.

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Appendix

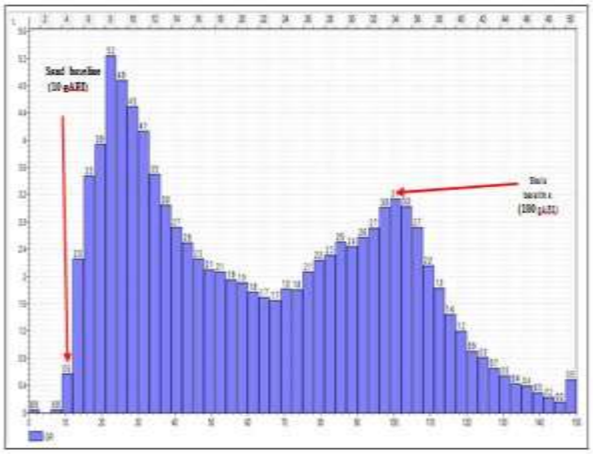

Figure 3.1: Gamma ray Histogram plot Used to Define Sand/Shale Baselines and Cut-off for Lithologic Discrimination

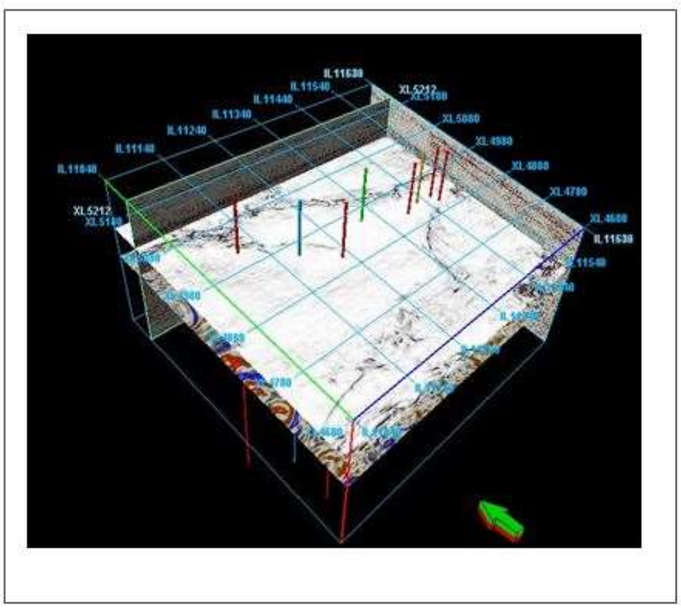

Figure A1: A 3-D view Showing Seismic Inline, Crossline, Time Slices and Well Distributions across the Field.

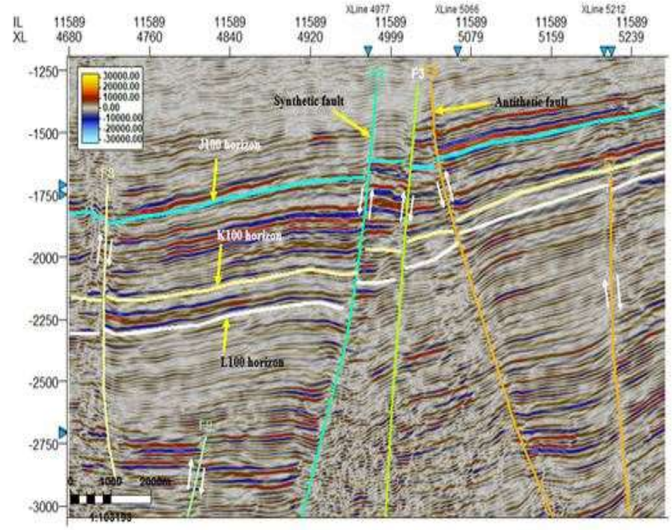

Figure A2: Faults and horizons interpreted across inline 11589

The hydrocarbon reservoir volume was estimated as follows (Cannon, 2016);

$$STOIIP = \frac{7758 \times A \times h \times \phi \times NTG \times (1 - Sw)}{Boi}$$

Where;

$STOIIP$ (mmstb) = stock tank oil initially in place

Sw = water saturation