Full Length Research Paper

Evaluation of Hydrocarbon Prospect of Amu Field, Niger-Delta, Nigeria

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ABSTRACT

The hydrocarbon potential of Amu field in the Niger Delta has been evaluated from seismic and well log data. Two major lithologies and reservoirs were delineated from the well logs. The lithologies are sand and shale while the two reservoirs are designated L and F, and were interpreted from seismic to be anticlinal structures. Seven faults and two horizons were delineated and mapped from the seismic sections. The faults are mainly synthetic and antithetic. The seismic-to-well tie shows a very good match. The average porosity and permeability of reservoir L are 21.55% and 1426 mD respectively. Similarly, the computed average porosity and permeability of reservoir F are 18.4% and 1085 mD. The estimated initial hydrocarbon in place for reservoirs L and F are 65.19 mmstb and 65.41 mmstb. The results of the research show that the Amu field has a good hydrocarbon potential.

Keywords: Well logs, seismic sections, petrophysics, hydrocarbon and volumetric

INTRODUCTION

The economic worth of an oil or gas company depends on its hydrocarbon reserves which are used by shareholders and investors as an indicator of the present and future strength of the company. A reliable estimate of the reserves of a company is important to the current value as well as the longer term prospects of the oil or gas company.

Hydrocarbon volumetric estimation is the process of quantifying the hydrocarbon content of a reservoir. The estimates usually vary throughout the lifetime of the field as more information becomes available and as the method for collecting and interpreting the data improves. Two methods are commonly used – deterministic and probabilistic. The deterministic method uses the well logs, seismic and core data obtained from the field to estimate the reservoir properties (Paranis, 1986; Tearpock and Bischke, 2003). Probabilistic method uses predictive tools, statistics, analogue field data and geological model to predict trends in reservoir properties away from the sample points. This research will concentrate on the deterministic method.

Volumetric methods indirectly estimate hydrocarbons in place from estimates of area, thickness, porosity, water saturation, and hydrocarbon fluid properties. Recoverable hydrocarbons are estimated from the in-place estimates and a recovery factor that is estimated from analogue pool performance and/or simulation studies.

Integration of 3D seismic model with petrophysical data has been a beneficial endeavour in use in the petroleum industry for some years now (Adeoye and Enikauselu, 2009; Aigbedion and Iyayi, 2007; Emujakporue and Faluyi, 2015). In petroleum provinces where exploration and production strategies merge, detailed understanding of petrophysical properties is highly desired.

Reservoir characterization gives a description of the petrophysical properties such as porosity, permeability, oil saturation, hydrocarbon pore fluid in place and thickness of productive net sand. Seismic sections are used to define reservoir geometry (Barde *et al.*, 2000; Adejobi and Olayinka, 1997, Alao et. al., 2013; Obaje, 2005), and obtain a clear picture of the structural

Figure 1. Map of Niger Delta showing the study area

features. The aim of this study is to integrate 3-D seismic and well log data for the characterization and volumetric analysis of the Amu field, Niger Delta.

SUMMARY OF THE GEOLOGY OF THE STUDY AREA

The Amu field is located within the greater Ughelli depobelt of the Niger Delta sedimentary basin. It is located within longitudes 05^{0}41'27" E to 05^{0}42'05" E and latitudes 05^{0}51'55" N to 05^{0}52'03" N (figure 1). The base map of the study area and the well locations is shown in Figure 2. The vertical and horizontal lines in the map represent the in-lines and cross lines of the seismic data.

Many researchers have described the hydrocarbon distribution pattern of the Niger Delta (Evamy *et. al.* 1978; Doust and Omatsola, 1990). The Niger Delta is one of the most prolific areas in the world (Weber, 1971). Three lithostratigraphy, Benin, Agbada and Akata Formations occurs in the basin. Hydrocarbon accumulation in the Niger Delta is confined to the Agbada Formation (Ejedawe, 1981) on account of the presence of growth faults and rollover anticlines which are critical trapping structures.

MATERIALS AND METHODS

The data set used for this work are 3D seismic, well logs, and checkshots. The seismic data set comprises of both inline and cross line sections. The suite of well logs consists of gamma ray, spontaneous potential, resistivity, density and neutron logs of four exploratory wells. The data were obtained from Shell Petroleum Development Company, Nigeria. The software package used for the study is Schlumberger Petrel 2009.1.

Determination of Lithology and Reservoir

The gamma ray, spontaneous potential and resistivity logs were used for the identification of lithology and the reservoir intervals. Deflection of the gamma ray and spontaneous potential to the left associated with high resistivity signified the reservoir intervals. Deflection of the gamma ray and spontaneous potential to the right with associated low resistivity was assumed to indicate non-reservoir (usually mudrock) lithology.

Determination of Porosity and Permeability

These critically important reservoir parameters can be obtained from density, sonic and neutron logs or from core samples. In this work, the density log was used for the determination of the porosity by applying the equation (Toby, 2005; Schlumberger, 1989).

$$\Phi = \frac{(\rho_{max} - \rho_b)}{(\rho_{max} - \rho_{fl})} \tag{1}$$

Where

Φ = porosity derived from density log

ρ_{max} = matrix density (2.65 g/cm^3)

ρ_b = bulk density (as measured by the tool and hence includes porosity and grain density)
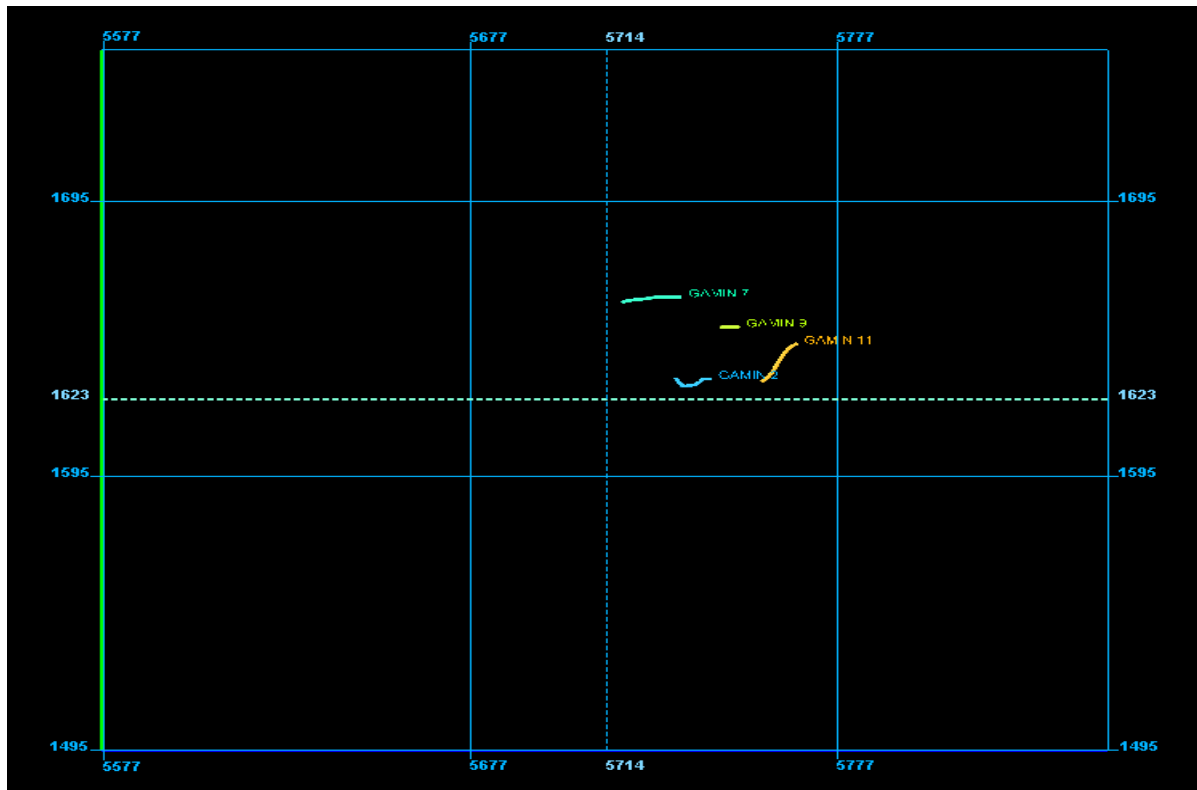
ρ_{fl} = fluid density (1 g/cm).

Figure 2. Base map of the study area showing the well locations and the seismic lines.

Permeability is the measure of the ability of a porous medium to transmit fluid without change in the structure of the medium or displacement of its parts. The permeability values for the observed reservoirs were calculated using the equation after Owolabi *et al. (1994)*:

$$K \text{ (mD)} = 307 + 26552(\phi^2) - 34540 \ (\phi \times Sw)^2 \qquad (2)$$

Where
K= permeability in millidarcies
ϕ = porosity
Sw = water saturation

Determination of Fluid Saturation

The fluid saturation of a reservoir is usually expressed as a function of the total pore space. The higher the value of water saturation in the reservoir sand, the lower the hydrocarbon content. According to Udegbunam and Ndukwe (1988), water saturation can be estimated from porosity by using the equation;

$$S_w = \frac{0.082}{\phi} \qquad (3)$$

Where,
S_w = water saturation
Φ = effective porosity

The hydrocarbon saturation in the reservoir is determined by the difference between unity and fraction of water saturation (Asquith, 2004; Schlumberger, 1989). It is given as;

$$S_h = 1 - S_W \qquad (4)$$

In terms of percentage

$$S_h \% = 100 - S_w\% \qquad (5)$$

Where
S_h= hydrocarbon saturation
S_w = water saturation

Seismic Data Interpretation

The seismic interpretation involved horizons and faults identification and mapping. The reservoir sands identified on the well logs were traced in the seismic sections through well-to-seismic tie. This was done in order to delineate the exact position, lateral extent and geometry of the reservoirs on the seismic sections. The reservoir tops and bottoms on the logs were traced on the inline and cross line seismic sections. The times corresponding to the horizons were picked and posted on the base map. This was achieved by tracking the series of two-way travel times corresponding to the tops of the reservoirs in the wells on the seismic section. Time structural maps were then generated for the various horizons. The available checkshot data were used for converting the time structural mapped to depth structural map.

Figure 3. Interpreted well logs of the area showing the reservoirs F and L

Determination of Hydrocarbon Volume

The volumetric evaluation of the quantity of hydrocarbon in a reservoir is very important. This is because the estimated value will either encourage or discourage further exploration and production activities in the field. According to Udegbunam, (2008), the hydrocarbon volume can be evaluated using the equation:

$$STOIIP = \frac{7758 \times area \times thickness \times porosity \times (1-S_w) \times NTG}{FVF} \quad (6)$$

Where:
STOIIP (mmstb) = stock tank oil initially in place
S_w = water saturation
NTG = net-to-gross ratio
FVF = formation volume factor (a constant)

Table 1. Computed petrophysical parameters of reservoirs F and L

Reservoir	Area (acre)	Pay Thickness (Ft)	Porosity (Fraction)	Permeability (mD)	NTG (Fraction)	Sw (Fraction)	STOIIP (MMSTB)
F	2371	137	0.1847	1085	0.4371	0.4412	65.414
L	1610	120	0.2155	1426	0.7134	0.3774	65.19
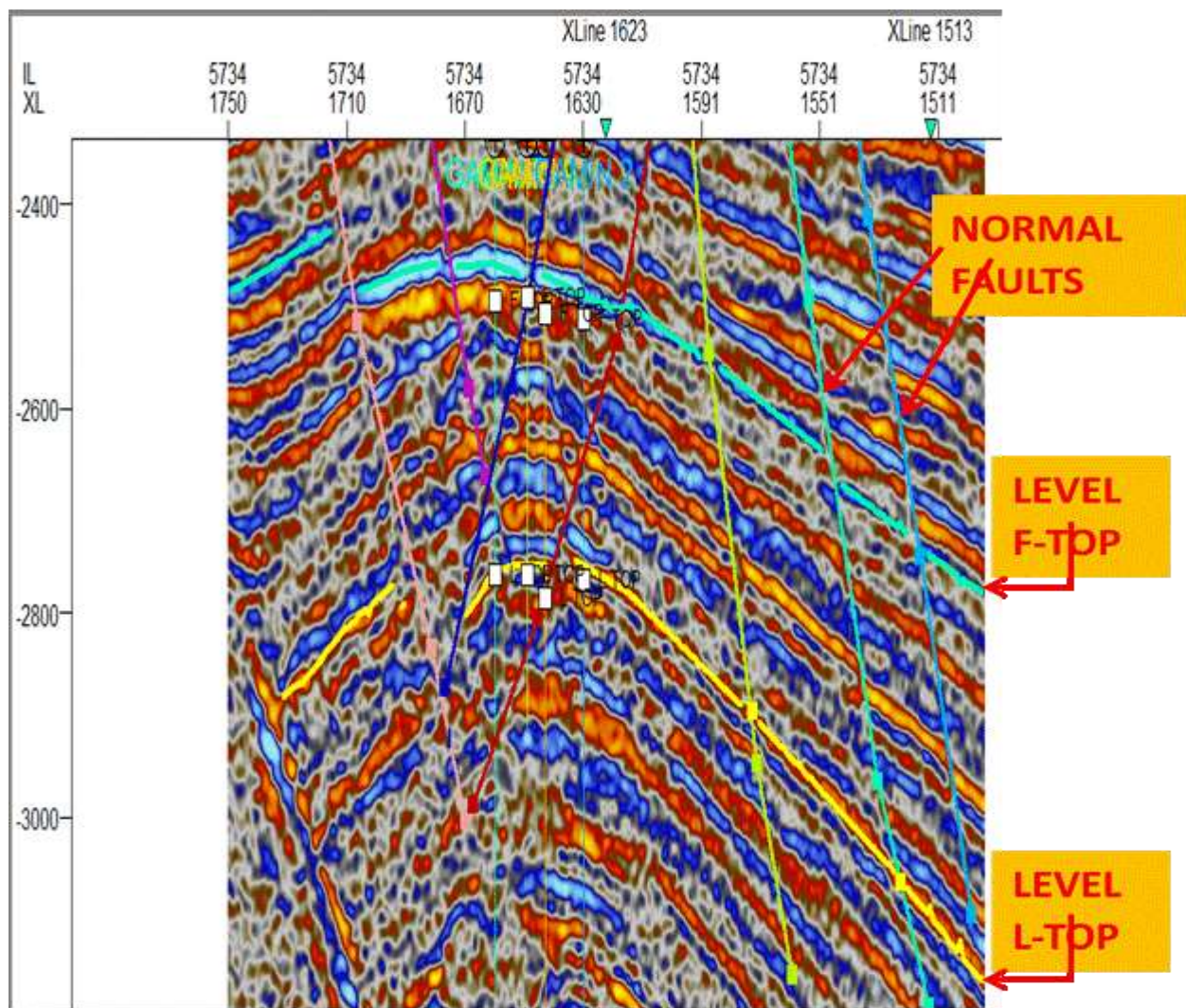
Figure4. Interpreted seismic sections showing the horizons and faults

The reservoir thickness was obtained from the gamma ray log while the area was obtained from depth structural map generated from the seismic sections.

RESULTS AND DISCUSSION

The gamma ray, spontaneous potential and resistivity log interpretations show that the boreholes encountered two major lithologies and two reservoirs (figure 3 above).

These lithologies are sand and shale and their alternating arrangement is typical of the Agbada Formation in the Niger Delta. The two reservoirs observed in the wells are designated "F" and "L". The top and base of reservoir "F" and "L" were correlated across the wells.

The computed average petrophysical properties of the reservoirs F and L are shown in Table 1. Results from petrophysical analysis revealed that the two reservoirs are viable with average thickness as high as 128.50 ft. The two reservoirs exhibited good petrophysical
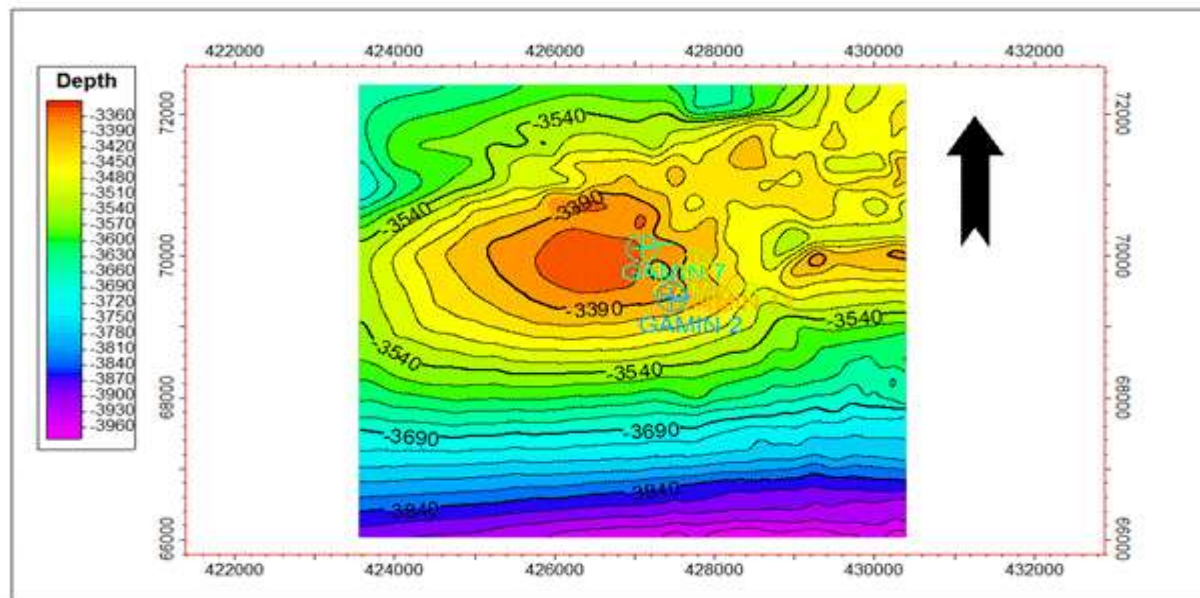
LEVEL F
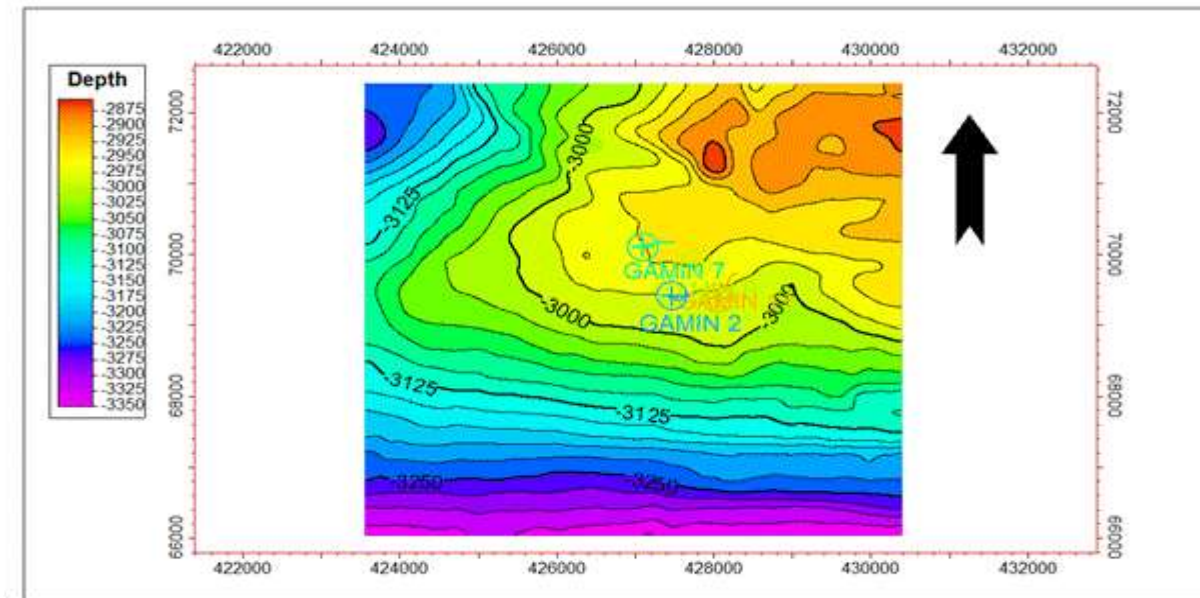
LEVEL L

Figure5. Depth map for reservoirs "F" And "L.

properties with high porosity, permeability and hydrocarbon saturation.

SEISMIC INTERPRETATION

A total of seven (7) normal faults and two (2) seismic horizons were identified in the seismic section (figure 4 above). Five (5) of the normal faults are NW-SE trending listric faults. These major faults show a soling out at the base of the section with a rollover anticlinal structure. The other two (2) are NE-SW trending antithetic faults. The two seismic horizons delineated in the seismic sections represent the tops of the two reservoirs (F and L). A synthetic seismogram generated for well 2 from sonic and density logs was used for the well-to- seismic tie. There was a sufficient match between the synthetic and the seismic section. The well-to-seismic tie enabled the top of the reservoirs F and L to be correlated with confidence across the seismic sections.

Two-way-time surface maps were generated for reservoirs L and F tops. Checkshot data from well 2 was used for creating the depth surface maps for the top of reservoirs L and F (figure 5). The F and L reservoir sands have similar structural configuration. The faulted rollover
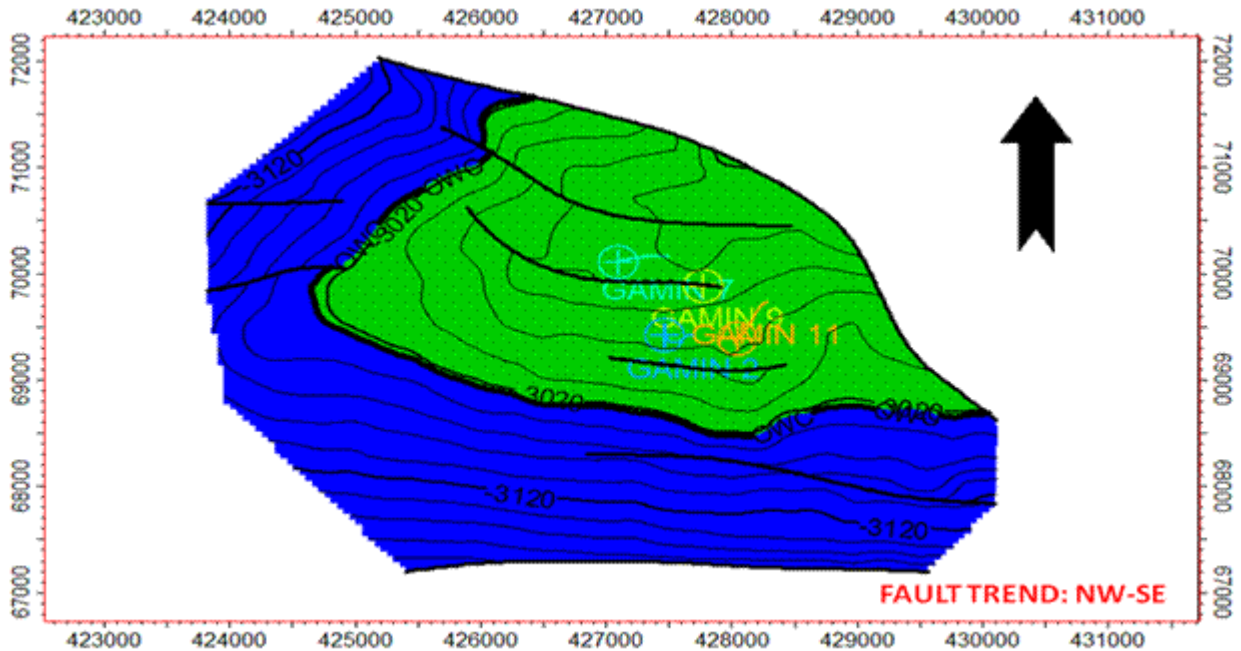
Figure 6. Top structure map of reservoir "F" showing OWC, faults and wells
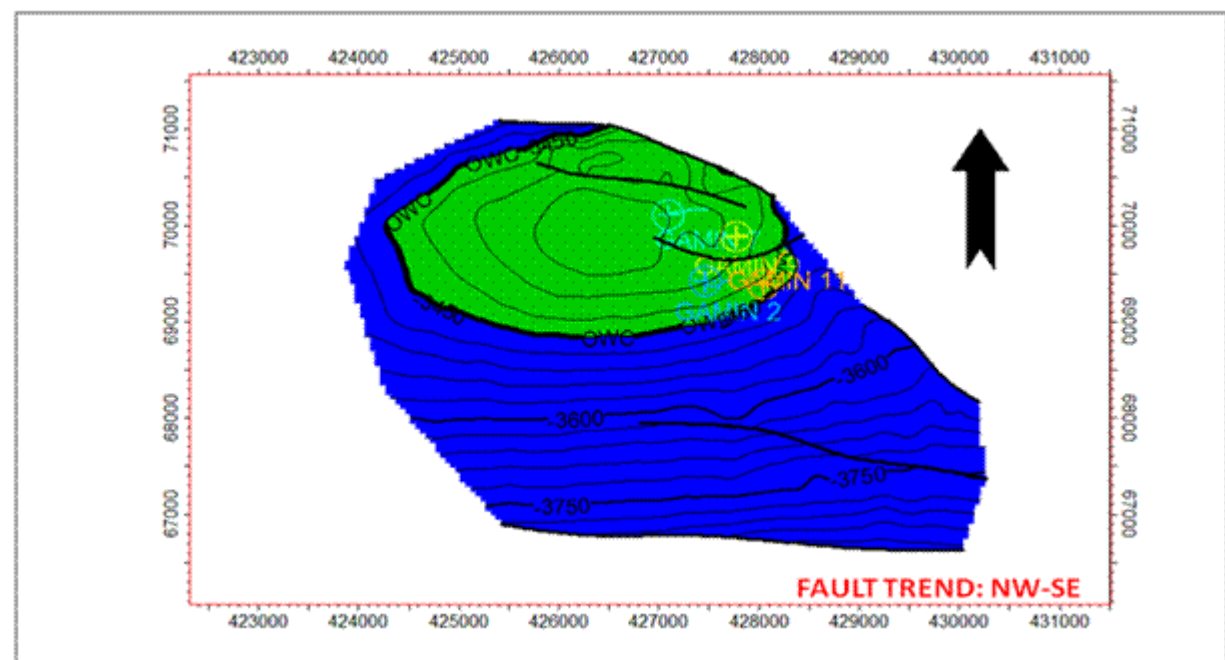

Figure 7. Top structure map of reservoir "L" showing OWC, faults and wells

anticline bounded by the northwest-southeast trending growth faults system made up the hydrocarbon trap. The interbedded shale of the Agbada Formation observed in the gamma ray log constituted the seal.

Figures 6 and 7 are top structural maps of reservoirs F and L showing the oil -water contact in the reservoirs. The depth to the oil-water contact in reservoirs F and L are 3020 m and 3450 m respectively. The maps show faulted anticlines. These structures are responsible for the trapping of hydrocarbon in the area. The wells in the Field are located within the crest of the anticline.

The average lateral extent of the reservoir sands F and L closures are 2371 and 1610 acres respectively. The structural high is located in the northeast and central regions of horizon F and L respectively. The maps show faulted anticlinal structures in the subsurface. These

structures are responsible for the trapping of hydrocarbon in the area. Substituting the computed petrophysical parameters and data obtained from the depth structural maps into equation 6, the total estimated stock tank oil initially in place for the field is 130.604 million barrels.

The petrophysical and seismic interpretation of Amu field shows roll over anticlines and growth faults which are typical structural features of the Niger Delta. The Amu field has good geological structures for hydrocarbon accumulation. The computed petrophysical values (the porosity, water saturation, hydrocarbon saturation and permeability) are ideal for the Niger Delta reservoir sands.
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CONCLUSION

The seismic and petro-physical interpretation shows typical structural features of the Niger Delta which includes roll over anticlines and growth faults. Two major reservoirs and seven normal faults were delineated in the Amu field. The petro-physical data that were obtained are ideal for the Niger Delta reservoir sands. The reservoirs are anticlinal (domal) structures. The computed volumes for the initial oil in place are 65.19 and 65.41 mmstb for reservoirs F and L respectively. The faulted rollover anticline bounded by growth faults make up the hydrocarbon trap in this field. The interbedded shale of the Agbada Formation constitute the seal. The results of the study show that the field has a good structural and petrophysical parameters for hydrocarbon potential. Shale smearing along the fault planes must have hinder hydrocarbon linkage through the fault surfaces.

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