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Seismic Evaluation of Hydrocarbon Saturation in "X" Field Onshore Reservoir of Niger Delta

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Abstract

Evaluation of hydrocarbon saturation was carried out in "X" field, Niger Delta, using seismic and well log data. This was done to determine the amount of hydrocarbon in place in the "X" field. Results from seismic data is one of the many tools used by the petroleum industry to access the quantity of oil and gas available for production from a given field or to access the potential of an undeveloped resource. However, the interpretations from the seismic data were integrated with results from well log analysis for proper evaluation of the hydrocarbon saturation of the oilfield. Two hydrocarbon bearing reservoirs each from the four wells were correlated to establish the continuity of reservoir sands. The estimated average thickness of the two reservoirs is 15.15m and 53.06m for reservoir A and reservoir B respectively. The average porosity for reservoir A is 0.231 and 0.215 for reservoir B. The quality of the porosity is very good. The computed average water saturation is 0.359 and 0.349 for reservoir A and B respectively. This shows that the hydrocarbon saturation is 0.641 and 0.651 for reservoir A and reservoir B respectively. Horizons and faults interpretation were carried out to produce subsurface structure maps from the seismic data. This was done to study the field's subsurface structures serving as traps to hydrocarbon and estimate the prospect area of the reservoirs. Results gotten show that the hydrocarbon in place for both reservoirs is 450MMSTB indicating that the field under consideration has good hydrocarbon prospect.

Keywords: Porosity, Hydrocarbon, Saturation, Reservoir, Evaluation, Production.

Introduction

Knowing the hydrocarbon saturation of any given oil reservoir, allows for successful evaluation of its reserves. Saturation defined as a fraction of hydrocarbon and water and other fluids in the porous rock body, is a crucial factor when evaluating an oil reservoir. Without saturation values, fluid distribution cannot be evaluated and no informed decision can be made on the development of an oil or gas reservoir. Hence, oil saturation helps reservoir engineers and geologists to maximize production and improve total recovery which implies that the most fundamental reservoir parameters such as oil, gas and water content are critical factors in determining how each oil field should be developed. Hydrocarbon saturation is a measure of the pore volume of the reservoir rock that is filled with hydrocarbon. The Niger Delta sedimentary basin is widely known to be holding significant hydrocarbon reserves and this has attracted major exploration and production companies to the basin. In this paper, result from seismic was integrated with well logs for optimum evaluation of the hydrocarbon.

Petroleum reservoir in the Niger Delta is produced from sandstone and unconsolidated sands predominantly in the Agbada formation. The reservoir rocks can simply be defined as rocks that has porosity and permeability that allows it to contain a significant amount of recoverable hydrocarbon. The characteristic of the reservoirs in the Agbada formation are controlled by depositional environment and the depth of burial. Known reservoir rocks are Eocene to Pliocene (Evamy et al., 1978).

Hydrocarbon are found in reservoir rock, that is, any combination of rock structure that will keep oil and gas from migrating either vertical or laterally (Wan Qin, 1995), majority of the traps in Niger Delta are structural and to locate, horizons are picked and faults mapped on seismic inlines and crosslines to produce the time structure map. For there to be petroleum accumulation a set of geological circumstance is needed for the accumulation of Oil and Gas to recapitulate, these are;

- A migration pathway for the hydrocarbon to move from the source to the traps.
- The existence of a suitable trapping mechanism or structure.
- Suitable depth of burial of the source rock to maturity.
- The presence of a source, a reservoir rock and seal rock.

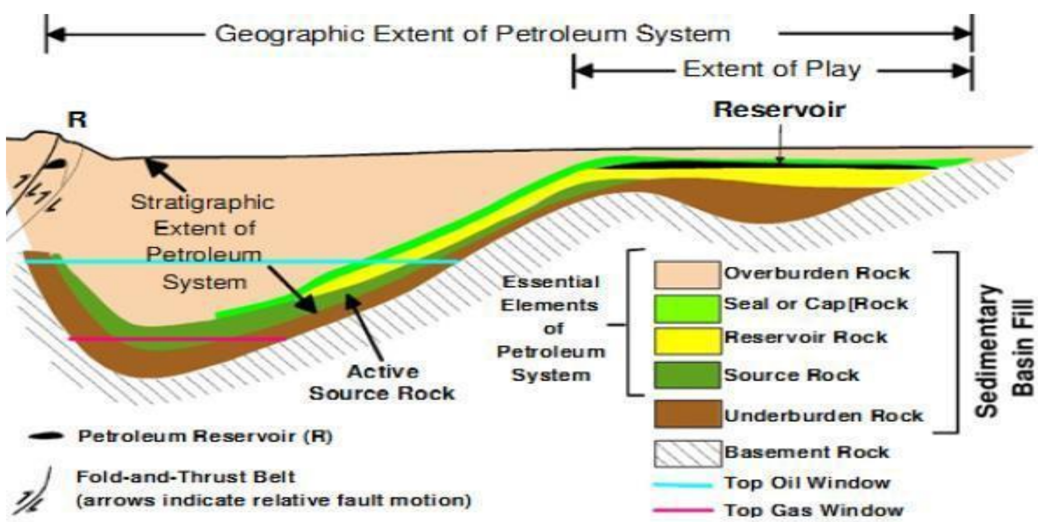

Figure 1: Showing the Petroleum System and its Elements in a Sedimentary Basin (Magoon and Dow, 1994)

The aim of this research is to use an integrated technique in computing various Petrophysical parameters, these techniques include using well log data, seismic data, and combining various mathematical equations (1 – 7). From the data used in computing the Petrophysical results such as the well log data which consist of gamma ray, resistivity, density and neutron logs, the Archie's equation was applied in carrying out Petrophysical evaluation such as the water saturation, porosity and the hydrocarbon saturation and the results obtained were summarized in (Tables 2,3,4, and 5).

Faults act as good migration paths for hydrocarbon into reservoir rocks. According to Doust and Omatsola (1990), and Stacher (1995), the different types of fault pattern and the associated trap types in the Niger Delta basin are shown in figure 2.

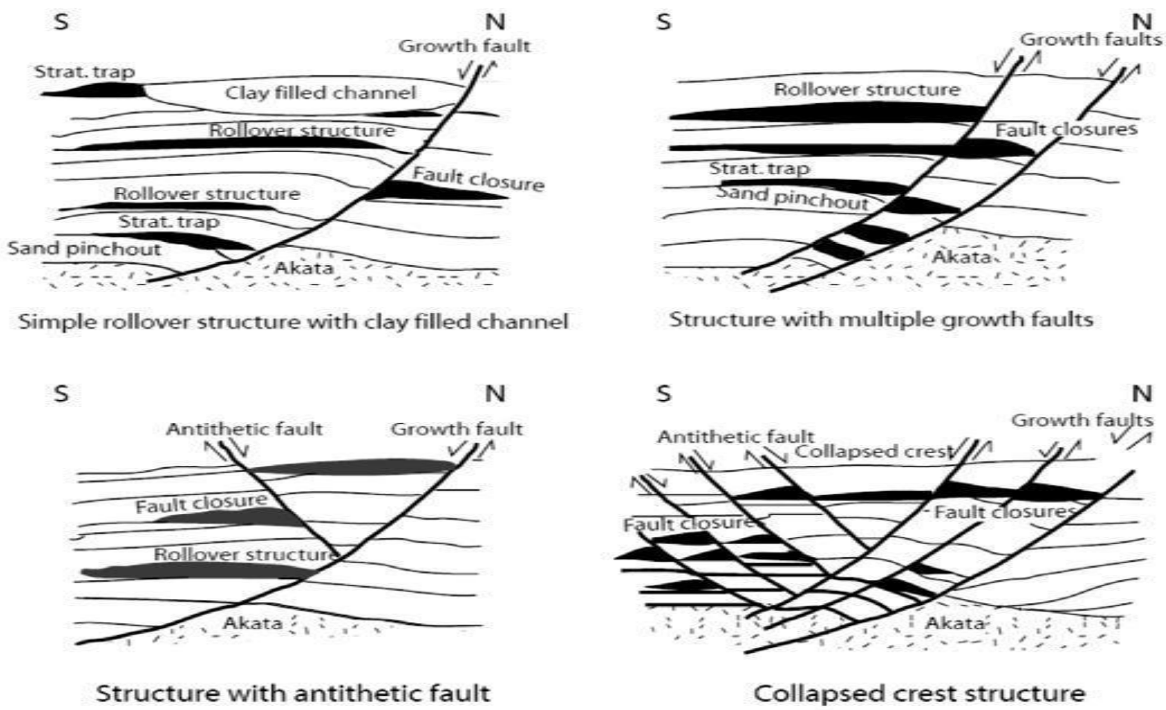

Figure 2: Showing the Niger Delta Oil Field Structures and Associated Trap Types (Doust and Omatsola, 1990 and Stacher, 1995)

Faults are important aspect of reservoirs particularly in the way they control the movement of hydrocarbon. Structural styles often provide a broad context for understanding the pattern of faulting that may be expected in a region. Its basic utility lies in identifying certain basic patterns of deformation that are repeated in geologic provinces. They are different across the major depobelts in the Niger Delta and have direct implication on the hydrocarbon distribution (Doust and Omatsola 1990).

Materials and Methods

The "X" field used as a case study, is located in the Central Swamp depobelt of the Niger Delta. The principal data used are 3-D seismic data and suite of geophysical well logs from four oil wells in the "X" field Niger Delta. The 3-D seismic data is in SEG-Y format. The base map (figure 3) covers an inline range of 5500m-5887m and cross-lines range of 1480m to 1720m. The inline spacing is 25m, and 25m also for the crossline. The wells; Kono 5, Kono 7, Kono

10 and Kono 11 were drilled to a total depth of 4379m, 4140m, 4328m and 4415m respectively. Each of the well log suites consists of gamma ray log, deep induction log, sonic log, density log, neutron log and resistivity log respectively.

Schlumberger Petrel is the software used in this study as it provides a full range of tools to resolve the most complex structural and stratigraphic challenges—from regional exploration to reservoir development. Petrel was chosen to analyze the data because it is Windows based software for 3D visualization with a user interface based on the Windows Microsoft standards. The data was imported to Petrel within the main database, and this made it possible to visualize the imported data in both 2D and 3D mode. The workflow used (figure 4) is; fault mapping, well correlation, well-to-seismic tie, horizon mapping, maps creation (surface-time map, depth map), volume calculation.

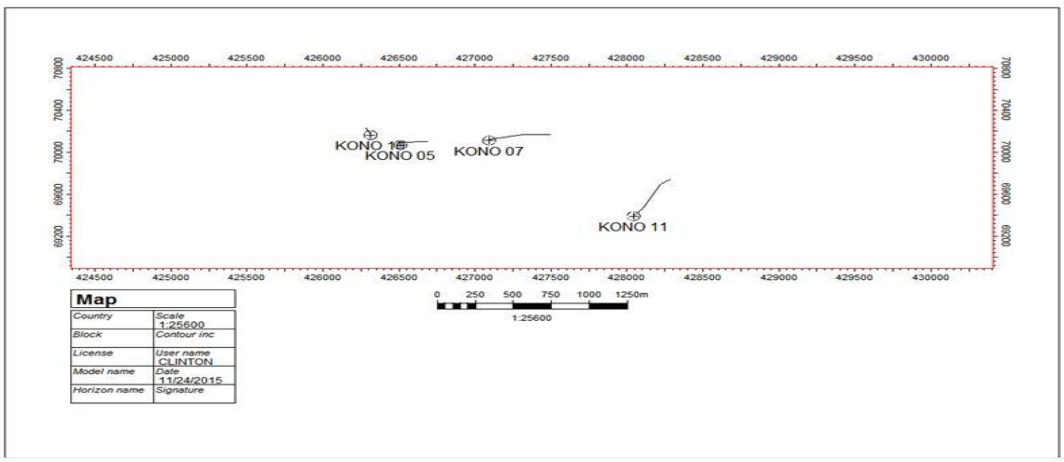

Figure 3: Showing the Base Map of the Area

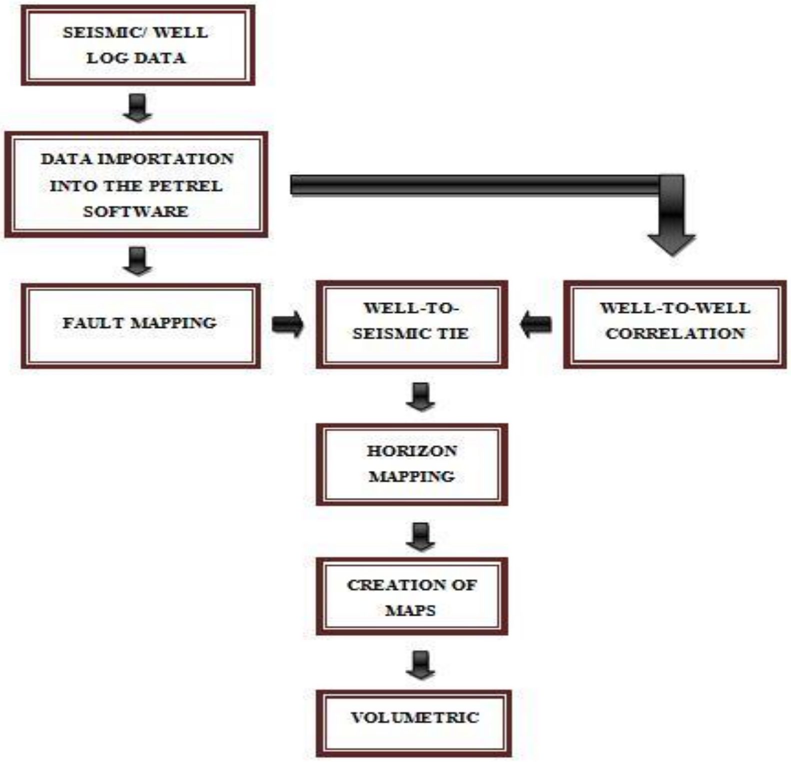

Figure 4: Showing the Workflow

The faults (figure 6) were picked carefully after observation. While picking faults on the seismic sections, attributes such as abrupt endings of reflections, upthrown with relative downthrown, abrupt changes in dip directions of the suspected faults lines were carefully checked for.

Reservoirs are subsurface formations that contain water and hydrocarbon. They were identified by using the log signatures from the gamma ray, neutron, density and resistivity logs. The Gamma ray logs alongside the neutron-density combined logs were used to delineate the lithologies and were particularly helpful because shales and sandstones typically have high and low respective gamma ray signatures, corresponding to high and low neutron-density combined logs that can be correlated readily between wells. The resistivity log was used to identify hydrocarbon and water bearing zones. The neutron-density overlay technique was used to differentiate the hydrocarbon fluid type.

Horizon mapping was achieved by tracking the series of time corresponding to the top of the reservoirs identified in the wells on the seismic section. The key horizons were identified and mapped on both inline and cross line seismic sections using their continuity and well-to-seismic tie. Well-to-seismic tie allow well data, measured in units of depth, to be compared to seismic data, measured in units of time. The sonic and density logs were used to generate the synthetic seismic trace which was compared to the real seismic data collected near the well location.

The water saturation was obtained by the Archie's equation of water saturation. This equation provides an estimate of total water saturation, S_W by combining reservoir properties of porosity, water conductivity, and total conductivity. The value of the water saturation is so important cause it is used in quantifying the more important complement; hydrocarbon saturation.

This Archie's equation was used to evaluate the fractional volume, S_W, of porosity that is filled with formation water (water saturation) as seen in the equation below

$$S_w = \frac{1}{\phi}\sqrt{\frac{R_w}{R_t}} \qquad (1)$$

Where: R_W = the water resistivity, R_t = the true formation resistivity, Φ = total porosity, and S_w = water saturation

The hydrocarbon saturation was evaluated using the expression:

$$S_h = 1 - S_w \qquad (2)$$

Where: S_h = hydrocarbon saturation

The porosity was calculated from density log by using the relationship

$$\Phi = \frac{\rho_{max} - \rho_b}{\rho_{max} - \rho_f} \qquad (3)$$

Where; Φ = Porosity derived from density log, ρ_{max} = Rock matrix density (2.65 g/cm^3), ρ_b = Bulk density, ρ_f = Density of the fluid

The total area of a reservoir and its thickness are of considerable importance in determining if a reservoir is of commercial importance or not. The larger the area and thickness of a reservoir, the greater is the potential for oil and gas accumulations.

The original hydrocarbon-in-place of each reservoir was evaluated. This was based on mean weighted averages of porosity, water saturation, gross-rock volumes and net-to-gross ratios.

The calculation of hydrocarbon volume in a reservoir requires the volume of the formations containing the hydrocarbons, the porosity, and the hydrocarbon saturation of the formation.

The volume of oil initially in place was evaluated from the equation

$$OIIP = 7758 \times A \times H \times \phi \times NTG \times (1 - S_w)$$

Where; OIIP = Oil Initially in Place, A = Area, = Formation porosity, H = Reservoir thickness and $(1 - S_W)$ = Hydrocarbon saturation

The amount of oil originally in place in the reservoir when measured at the pressure and temperature conditions prevailing in the stock tank was obtained from the equation:

$$STOIIP = \frac{7758 \times A \times H \times \phi \times (1 - S_w) \times NTG}{B_o} \qquad (5)$$

Where; STOIIP = Stock Tank Oil Initially in Place, NTG = Net to Gross, B_O = Formation factor

Hydrocarbon reserves are the main asset of an oil company, and they are the volumes of hydrocarbon that will be commercially recovered in the future. The reserve was estimated using the equation below:

$$Reserve = STOIIP \times Recovery\ Factor \qquad (6)$$

The Net-to-Gross ratio refers to the proportion of clean sand to shale within a reservoir unit. The gross sand is the whole thickness of the reservoir; the non-net sand is the shaly sequences within the whole reservoir thickness; the net sand is thus obtained by subtracting the non-net sand from the gross sand. The Net-to-gross ratio reflects the quality of the sands as potential reservoirs. The higher the NTG value, the better the quality of the sand.

$$NTG = \frac{Net\ Sand}{Gross\ Sand} \quad (7)$$

Results and Interpretation

The results of the interpreted well logs (figure 5) revealed that reservoir A started with very shaly sand thickness from 3434.44m – 3443.32m (8.88m thick) to very sandy shale from 3441.59m – 3461.51m (19.56m thick) and then to moderately clean sands between 3403.32m – 3418.86m (15.54m thick) and 3387.63m – 3404.23m (16.60m thick) as shown in table **1a** and **1b**. Hence the average thickness for this reservoir is 15.15m.

Table 1a: Showing the Top, Base, and Thickness of Reservoir A and B (Wells 10 and 11)

	WELL 10			WELL 11		
	Top (m)	Base (m)	Thickness (m)	Top (m)	Base (m)	Thickness (m)
Sand A	3441.59	3461.51	19.56	3434.44	3443.32	8.88
Sand B	3565.76	3615.51	49.75	3527.49	3580.55	53.06

Table 1b: Showing the Top, Base, and Thickness of Reservoir A and B (Wells 5 and 7)

Sample	WELL 5			WELL 7		
	Top (m)	Base (m)	Thickness (m)	Top (m)	Base (m)	Thickness (m)
Sand A	3403.32	3418.86	15.54	3387.63	3404.23	16.6
Sand B	3536.61	3583.24	46.63	3496.29	3552.55	56.26

Volumetric estimation of hydrocarbon in this reservoir was estimated using the calculated petrophysical parameters (Table 5) and data derived from the depth structural map (Figure 7). The estimated volume of the oil originally in place is 72MMSTB. Reservoir B is the second horizon on the seismic section (figure 6), and results from the interpreted well logs revealed that the reservoir has a sand thickness greater than that in reservoir A. The sand thickness for well 11 is 49.75m (3565.76m – 3615.51m), 53.06m thick for well 10 (3527.49m – 3580.55m), 46.63m thick for well 5 (3536.61m – 3583.24m) and 56.26m thick for well 7 (3496.29m – 3552.55m) as shown in table **1a** and **1b**. The average sand thickness for this reservoir is 51.43m. Using the calculated petrophysical parameters (Table 5) and data derived from the depth structural map (Figure 8), the estimated original oil in place is 378MMSTB.

Reservoirs are subsurface formations that contain water and hydrocarbon. They were identified by using the log signatures of both gamma and resistivity logs. The logs were activated and displayed on the well section window, on which correlation (figure 5) was carried out using the gamma ray log. The gross lithology was corroborated and compared across the well. Hydrocarbon bearing reservoirs were identified using the electrical resistivity log, and also the neutron-density logs. To enhance the ability to determine similar reservoirs across the wells, the wells were viewed in 2-D window.

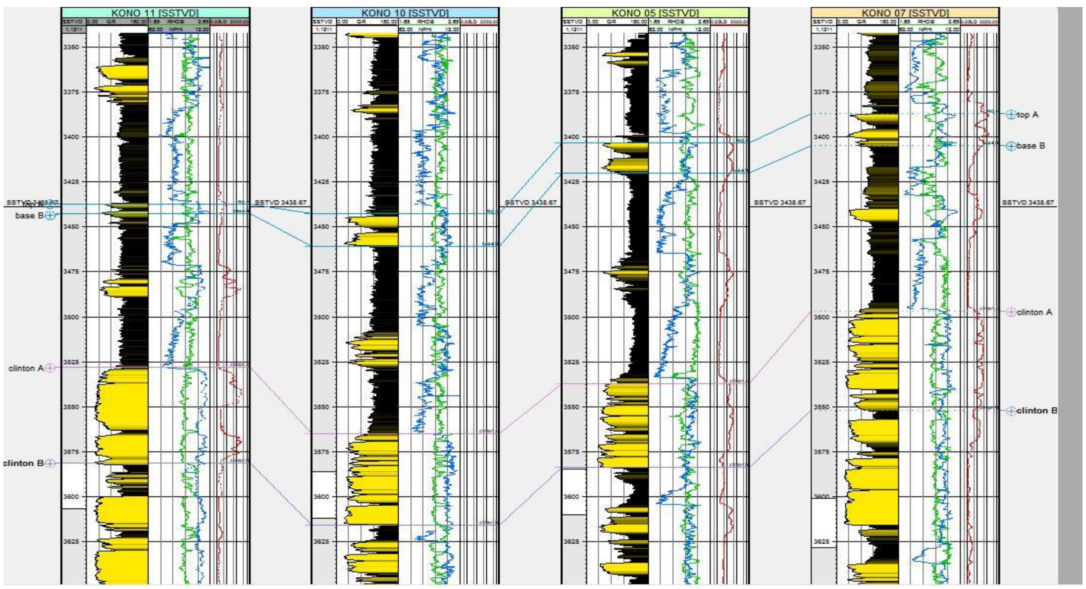

Figure 5: Showing the Interpreted Well Logs and Well-to-Well Correlation

The gamma ray and resistivity logs showed that reservoirs have good quality reservoir sands with average total porosities of 0.231 and 0.215, average effective porosities of 0.182 and 0.184, and average water saturation of 0.359 and 0.3945 respectively as shown in table 4.

Table 2 and 3 shows the results of the calculated petrophysical parameters for both reservoirs which include the total porosity, effective porosity, water saturation, permeability and net-to-gross.

Table 2: Petrophysical Parameters for Reservoir A

Porosity	Well 11	Well 10	Well 5	Well 7
Total Porosity (fraction)	0.2291	0.2516	0.2093	0.2321
Effective Porosity (fraction)	0.162	0.216	0.162	0.189
Water Saturation (%)	0.3461	0.3336	0.3976	0.3577
Permeability (mD)	15.14	14.59	15.59	18.36
Net-to-Gross	0.67	0.58	0.73	0.94

Table 3: Petrophysical Parameters for Reservoir B

Porosity	Well 11	Well 10	Well 5	Well 7
Total Porosity (fraction)	0.1917	0.2235	0.2451	0.2011
Effective Porosity (fraction)	0.1836	0.1782	0.216	0.1728
Water Saturation (%)	0.3587	0.3699	0.3375	0.4149
Permeability (mD)	15.01	15.96	15.9	16.18
Net-to-Gross	0.94	0.97	0.89	0.91

Table 4: Showing the Calculated Petrophysical Parameters for Reservoirs A and B

Reservoir	NTG_{avg}	Avg S_W	K_{avg}	Avg Φ_{total}	Avg Eff S_W
A	0.73	0.359	15.92	0.231	0.182
B	0.93	0.3495	15.76	0.215	0.184

Table 5 shows the calculated volumetrics for both reservoirs which include the area, pay thickness, volume of oil initially in place, volume of the stock tank oil initially in place, and the reserve.

Table 5: Showing the Calculated Reservoir Volumetrics

Reservoir	Area (acre)	Pay Thickness (ft)	OIIP (MMSTB)	STOIIP (MMSTB)	Reserve (MMSTB)
A	1749	49.69	72	53	24

B	2672	169	378	280	126

Structural interpretation

Faults were picked on the inline and a total of eight faults were picked. Among these faults picked, four were listric faults and were trending NW-SE, two antithetic faults were picked and were seen trending NW-SE, forming a fault closure with the synthetic faults trending (NE-SW) (figure 6).

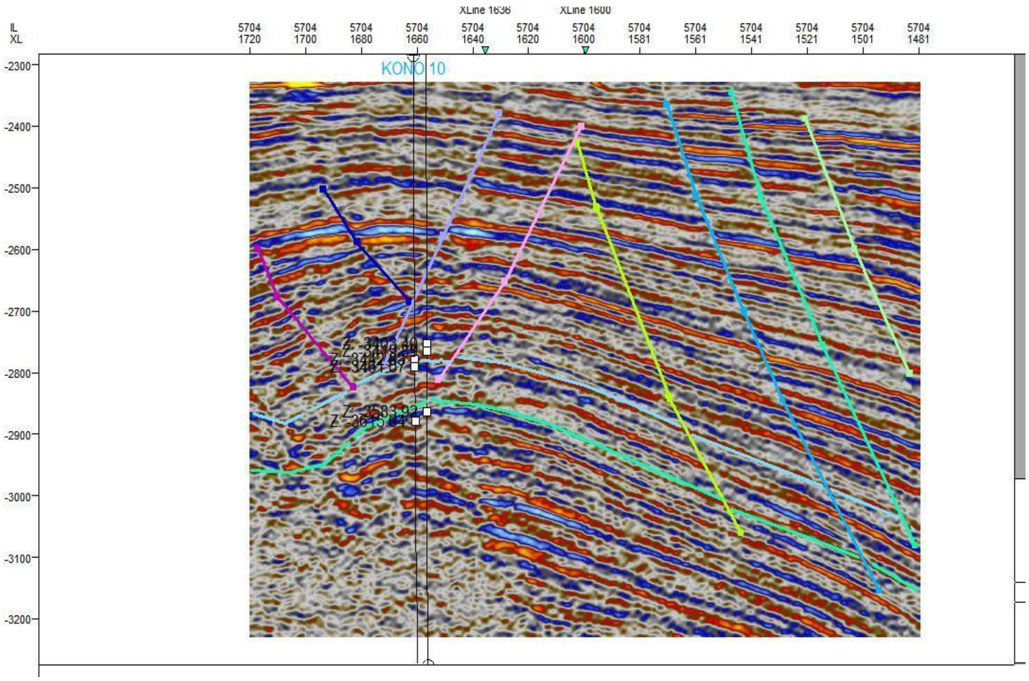

Figure 6: Showing the Interpreted Faults on inline 5704

Result from the Extract value showed that the hydrocarbons have migrated from the crest towards the flank as shown in figure 9 and 10. Boundary polygon was used to calculate the area of the hydrocarbon at the flank before estimating the volume of the hydrocarbon in place.

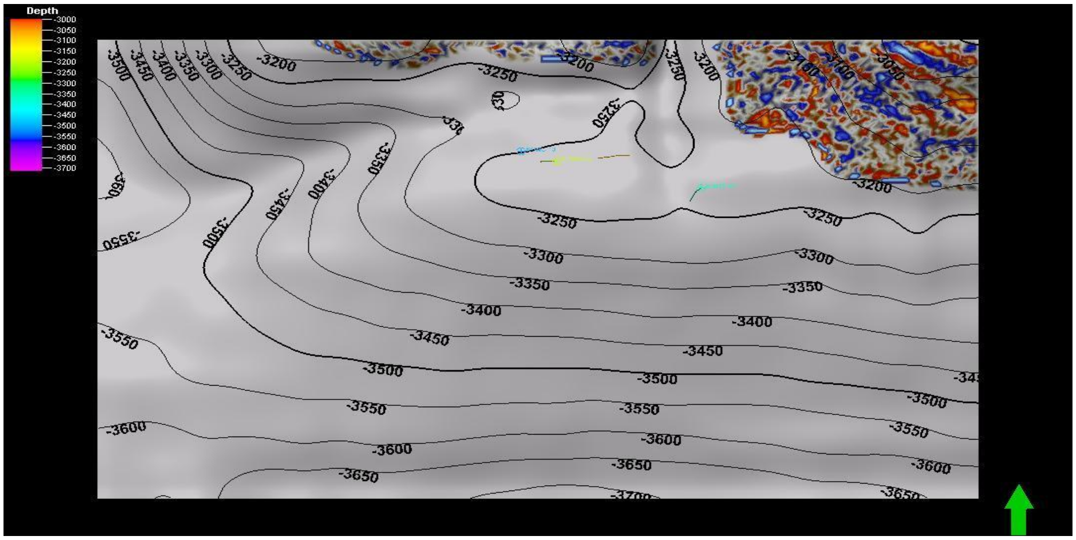

Figure 7: Surface Map for Horizon 1 Showing the Hydrocarbon Bearing Zone Using Extract Value

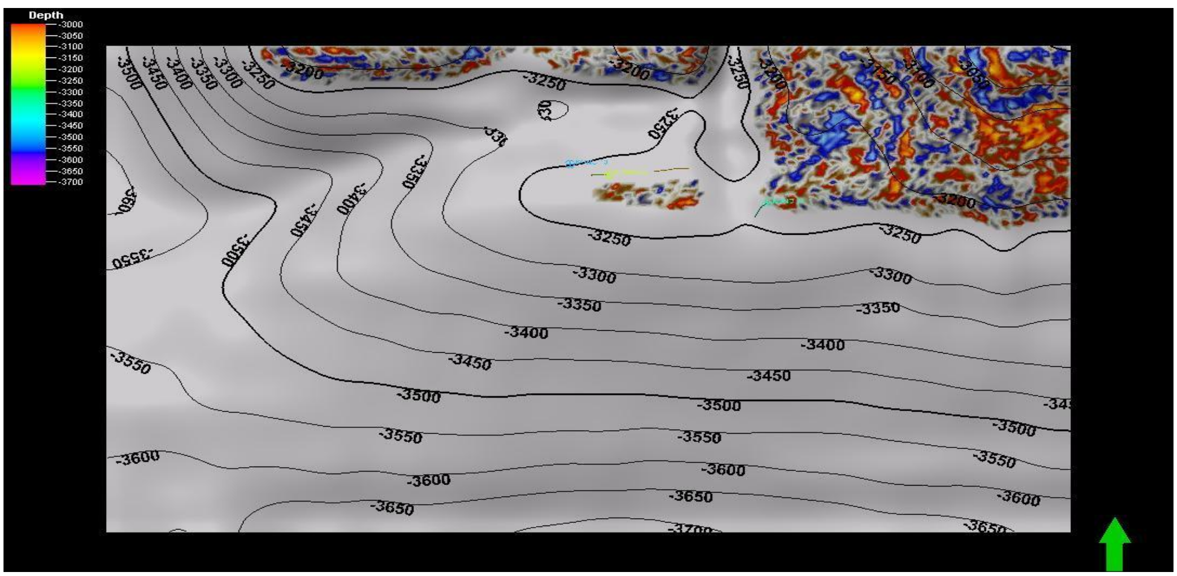

Figure 8: Surface Map for Horizon 2 Showing the Hydrocarbon Bearing Zone Using Extract Value

Time-depth conversion was done and this involved the conversion of the acoustic wave travel time to actual depth, based on the acoustic velocity of subsurface medium. This conversion permits to produce depth and thickness maps of subsurface layers interpreted on seismic reflection data. These maps are crucial in hydrocarbon exploration because they permit the volumetric evaluation of oil or gas in place. In converting the time to depth, the checkshot survey was used. First and foremost, the time structural map was generated and then using the checkshot survey, a new gridded horizon was formed. It is on this new horizon that depth structural maps were generated by contouring in depth. From the maps (figure 9 and 10), it was observed that the principal structure responsible for hydrocarbon entrapment in the field was the anticlinal structure at the center of the field.

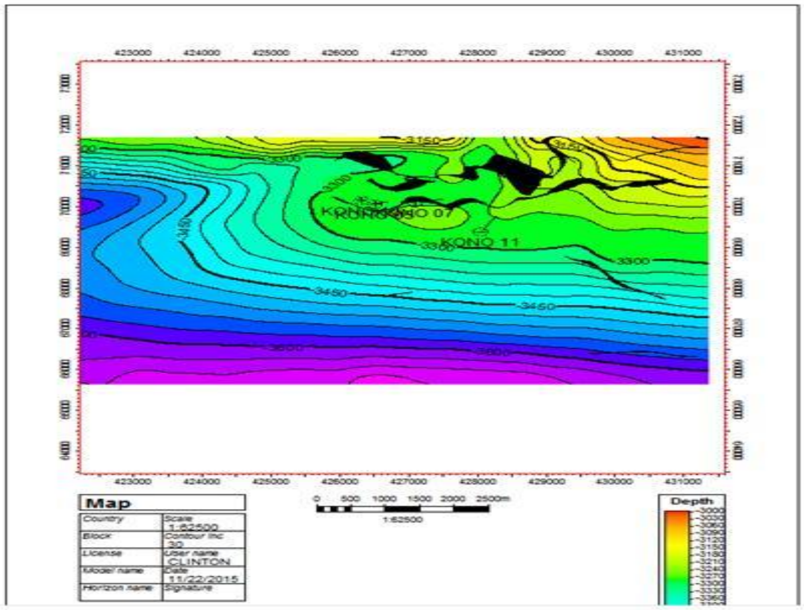

Figure 9: Showing the Depth Map for Reservoir A

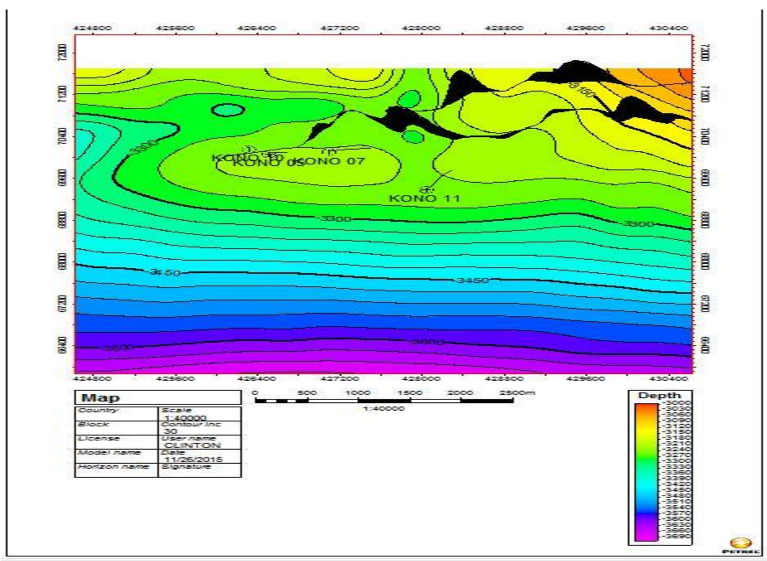

Figure 10: Showing the Depth Map for Reservoir B

Conclusion

Integration of seismic and well log data has led to the optimum evaluation of the hydrocarbon saturation in the "X" field, providing an insight to reservoir hydrocarbon volume which may be utilized in exploration operations. Integrating seismic and well log data has also resulted in a more understanding of the structure and hydrocarbon potential of the "X" field.

Although the reservoirs hold considerable amount of hydrocarbon, reservoir B has a higher commercial quantity. This research has also shown that integrating seismic and well log data is useful in determining the petrophysical parameters needed for the evaluation of the hydrocarbon saturation in an oilfield. In this research, the field under consideration has good hydrocarbon potential. From the results obtained, it was shown that reservoir B have a huge recovery estimate of 126MMSTB as compared to the 24MMSTB recovery estimate of reservoir B.

It is highly recommended that an effective development plan is carried out on reservoir B.

However, it is recommended that the economic production of "KONO Field" should not be based entirely on the results of this thesis, which depend only on seismic and well data but should also consider results gotten from other data sets such as core interpretation.

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