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Geological and Volumetric Risks Analysis of Hydrocarbon Reservoirs in''Mgt'' Field, Deep Offshore Niger Delta, Nigeria

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ABSTRACT

The reservoirs in MGT field, deep offshore Niger Delta Basin Nigeria were studied with the aim of undertaking risk analysis of the identified prospects within the field through geological and volumetric assessments. Petrophysical analysis was carried out using two offset wells comprising gamma ray, resistivity, neutron, density and sonic logs. Seven reservoir sands (A-G) with structural traps, were carefully analyzed through well log and seismic interpretation. Amplitude extraction generated on the reservoir sands showed that only reservoirs: C and E are of goods and quality of possible hydrocarbon prospects. The hydrocarbon volume in place was estimated to be 46.4 and 386 million barrels for Reservoirs B and E respectively. The AVO generated for liquid factor indicated AVO Type III which points out a setting where unconsolidated reservoir sands are encased in higher impedance shales. The results of the study showed that MGT Field has a good hydrocarbon potential, however, the geological and volumetric risk analysis of the reservoirs revealed moderately low chance of success of the identified prospect.

Keywords: Reservoirs, Geological and Volumertic, Petrophysical, Depobelts, Amplitude.

INTRODUCTION

Oil exploration is a high-risk game. With worldwide drilling success of only 10% and a typical price tag of $15 million per well, it is no surprise the oil industry seeks better methods of managing financial risk[1]. ''MGT'' Field is located in the deep off-shore area of the Niger Delta Basin along the zone of shale diapirism (Figure 1). It is situated in the offshore depobelt which forms the late focus of deposition during the build out of the modern delta.

The Niger Delta is a prolific hydrocarbon habitat and is known to contain only one identified petroleum system[2, 3]. Three major lithostratigraphic units have been recognized in the Niger Delta[44]. As exploration for hydrocarbon resources in the delta extends progressively into deeper water, the exploration asset team is faced with the enormous task of discovering oil and gas at the same time reducing exploration risk. The overall objective of exploratory efforts is to find and quantify in volumes the expected constituent hydrocarbons in discovered

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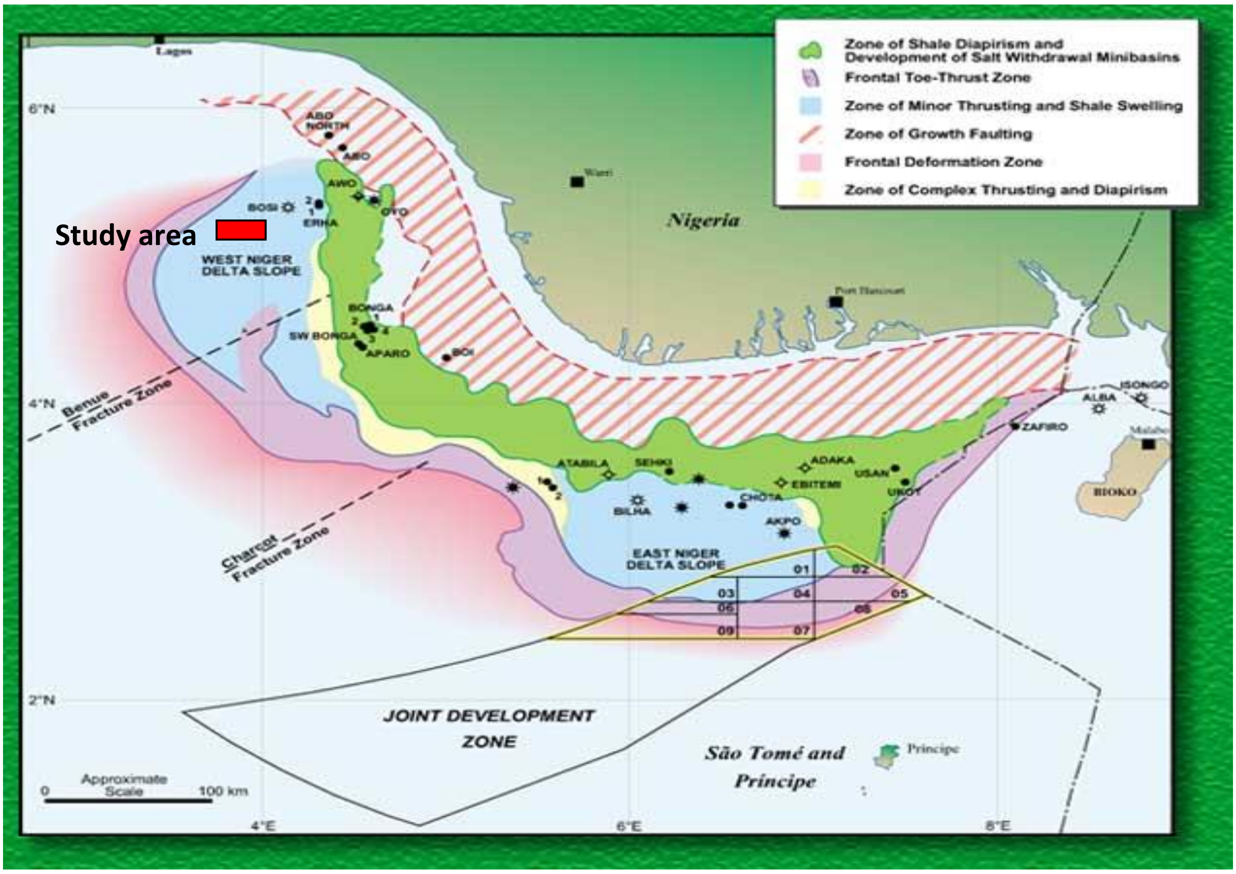
[1] Lerche, I., and Mackay, J. A., 1999: Economic Risk in Hydrocarbon Exploration, Academic Press, San Diego, 404p.

[2] Kulke, H. 1995: Nigeria, in Kulke, H., ed., Regional Petroleum Geology of the World. Part II: Africa, America, Australia and Antarctica: Berlin, Gebruder Borntraeger, pp 143-172.

[3] Ekweozor, C. M. and Daukoru, E. M. 1984: Petroleum source-bed evaluation of Tertiary Niger Delta-reply. *American Association of Petroleum Geologists. Bulletin,* 68: 390-394.

[4] Short, K.C., Stauble, A.J., 1967. Outline of geology of Niger Delta. American Association of Petroleum Geologists Bulletin 51, 761–779.



traps. While structural traps are easily identified on seismic sections, stratigraphic traps are not. These traps must be adequately delineated before volumetric calculations can proceed. This situation therefore calls for a careful approach in the search for new plays.

Exploration risk assessment is a consistent process for accurate quantification of forecasts and opinions to be used in an economic model for decision support. The successful implementation requires both management and technical commitment. The process quantifies the probability and resource range estimates for each project using an organized method based on statistics and the principles of the petroleum system. The purpose of risk assessment in petroleum exploration is to estimate the probability of discovery prior to drilling of a mapped prospect[5]. The exploration risk assessment phase of the reservoir life cycle is an opportunity to document both the prospect specific and regional understanding of the potential. A decision to drill an exploration well with the objective to find a new oil or gas field must be based on a sound assessment of the prospect's risks and of the volumes: what is the chance that a well will find hydrocarbons, and how much could it be? Risk and volume assessments form the basis for decisions to drill a well or not, and as such it is the link between subsurface evaluation and the business aspects of the petroleum industry. The Geological risk assessment requires an evaluation of some geological factors that are critical to the discovery of recoverable quantities of hydrocarbons. The probability of discovery is

[5] Kjell, O. 2005: Risk Assessment, Principles and Experience : (SINTEF Petroleum Research).

defined as the product of the following major probability factors, each of which must be evaluated with respect to presence and effectiveness. Such factors are: source rock, reservoir, trap, hydrocarbon charge and retention of hydrocarbon[6]. Oil exploration is a high-risk game with worldwide drilling success of only 10% and a typical price tag of $15 million per well. It is no surprise the oil industry seeks better methods of managing financial risk. Geological risk and uncertainty in Oil Exploration answers this need by identifying the various uncertainties associated with basin analysis and incorporating this information into probabilistic models of basin evolution in relation to hydrocarbon accumulation. This study, therefore, describes a systematic assessment of potential exploration reward in terms of barrels of oil and of the associated geological risk that may deny this reward. All basic geological data and interpretations are laid out for use in comparing prospects realistically and for judging the reliability of the estimate.

Background Geology

The Niger Delta is situated in the Gulf of Guinea and extends throughout the Niger Delta Province[7]. From the Eocene to the Present, the delta has prograded southwestward, forming depobelts that represent the most active portion of the delta at each stage of its development[8]. These depobelts form one of the largest regressive deltas in the world with an area of some 300,000 square kilometer[9], a sediment volume of 500,000 square kilometer[10], and a sediment thickness of over 10 km in the basin depocenter[11]. The Niger Delta is a coarsening upward regressive sequences of Tertiary clastics that prograded over a passive continental margin sequence of mainly Cretaceous sediments (Figure 2). The site of the Niger Delta was established at the initial rift separation of the African and the South American plates during the Jurassic. The Gulf of Guinea formed a triple junction where the west trending Equatorial Shear Zone met the north trending West African Extensional Rift and the south-west trending Benue Rift.

This latter rift is a failed arm that initially developed as a tensional accommodation zone as the African and South American plates sheared past one another. The Niger Delta tectonics (Figure 2) is limited to extensional deformation in the sedimentary fill. Basement movements play a minor role. Most visible extensional faulting occurs in the parallic portion of each deltaic sequence. Structures in the underlying marine shale sequence are obscure[12]. The continental sequence typically accumulated over each growth-fault trend after most tectonic activity had ceased. Growth faulting dominates the structural style which is interpreted to be triggered by the movement of deep-seated, overpressured, ductile marine shale and aided by slope instability. Most faults are listric and normal. Features associated with compressional or

[6] Lerche, I., and Mackay, J. A., 1999: Economic Risk in Hydrocarbon Exploration, Academic Press, San Diego, 404p.

[7] Klett, T.R., Ahlbrandt, T. S., Schmoker, J. W., and 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.

[8] 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, p. 239-248.

[9] Kulke, H. 1995: Nigeria, in Kulke, H., ed., Regional Petroleum Geology of the World. Part II: Africa, America, Australia and Antarctica: Berlin, Gebruder Borntraeger, pp 143-172.

[10] Hospers, J., 1965: Gravity field and structure of the Niger Delta, Nigeria, West Africa: Geological Society of American Bulletin, v. 76, p. 407-422.

[11] Kaplan, A., Lusser, C.U., Norton, I.O., 1994: Tectonic map of the world, panel 10: Tulsa, American Association of Petroleum Geologists, scale 1:10,000,000.

[12] Lehner, P., and De Ruiter, P.A.C., 1977: Structural history of Atlantic Margin of Africa: American Association of Petroleum Geologists Bulletin, v. 61, p. 961-981.

wrench movements have not been observed in the Niger delta except in the toe-thrust zone at the base of the slope[13].

METHODOLOGY

Data Set

2-D/3-D seismic and suite of log data from two wells located at averagely 45 km to 54 km distance from the field of study. These include Gamma Ray (GR), Spontaneous Potential (SP), Sonic (DT), Density (RHOB) and Neutron Porosity (NPHI) logs. Also available is the checkshot/TZ data for time depth conversion.

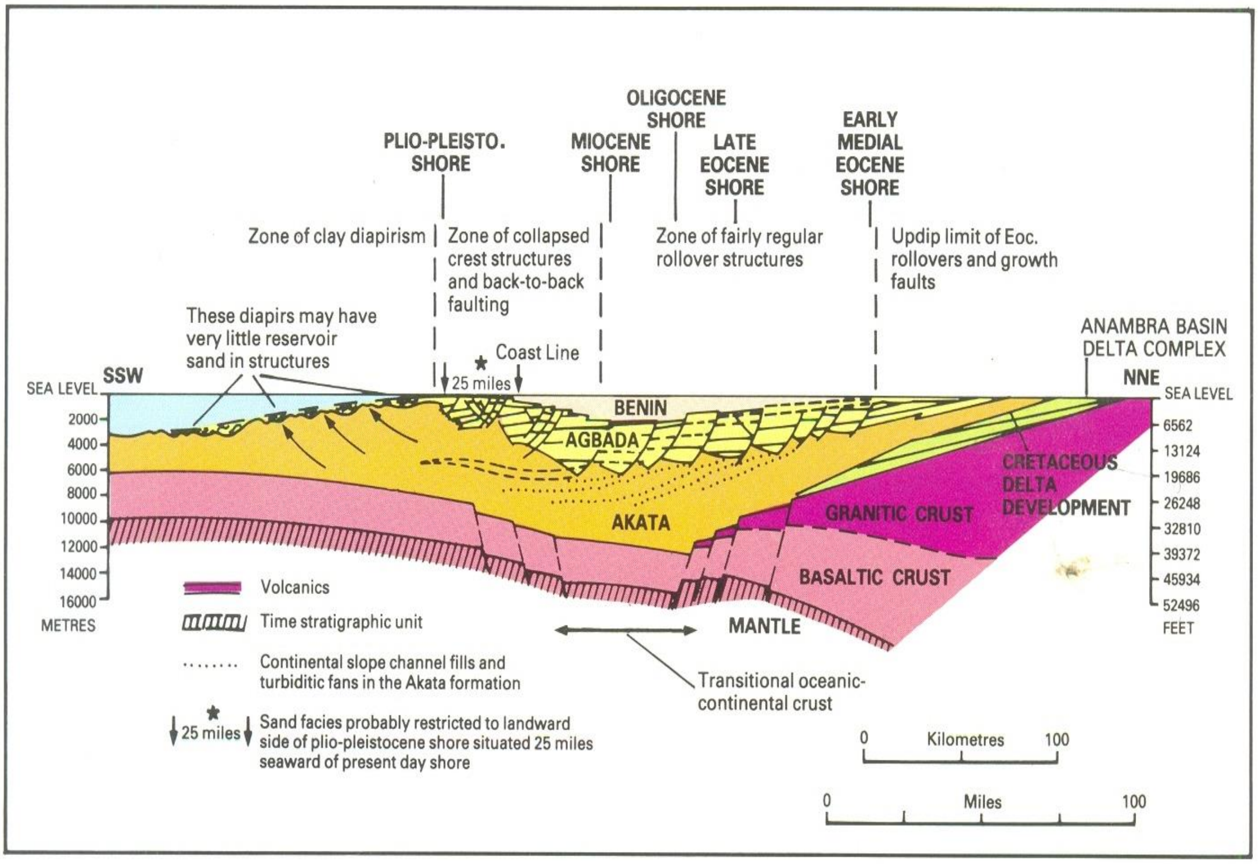


Figure 2: Map of Niger Delta Basin showing the structural and stratigraphy segment[14]

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[13] 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, p. 239-248.

[14] Weber K. J. (1971). Sedimentological aspect of oil fields in the Niger Delta. Geologie en Minjbouw, 50 (3): 559-576.

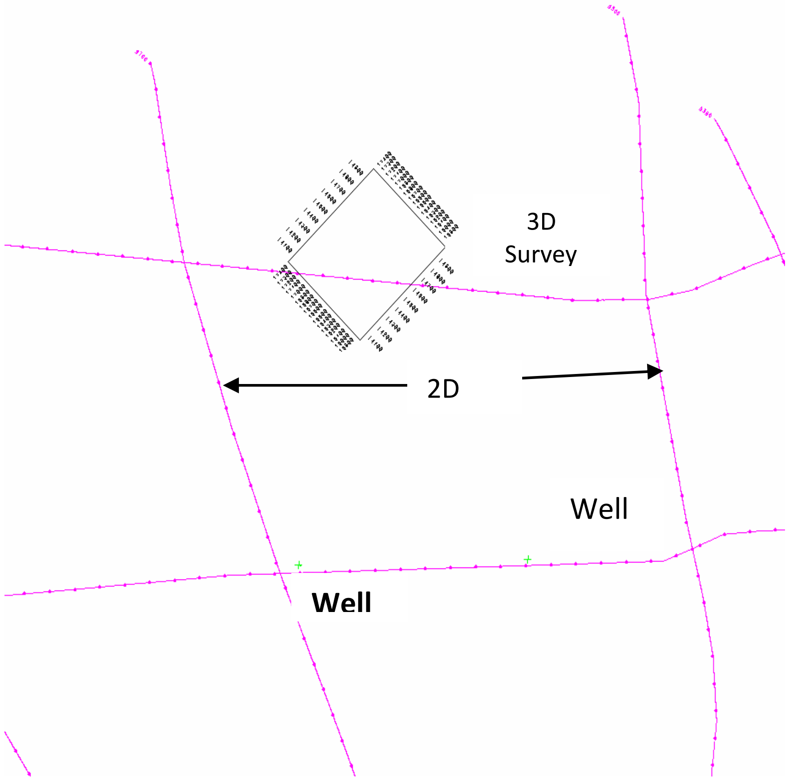

Figure 3: Base map of the study area showing well location and seismic survey lines (2-D and 3-D survey)

Petrophysical Evaluation

The petrophysical analysis was carried out on the logs from offset wells. A quality control template was created for quick review of the logs graphically. This enabled a quick identification of hydrocarbon bearing intervals by comparing the Resistivity Log. From the quick look, only one reservoir has water contact, the remaining is hydrocarbon down to the base.

Porosity Evaluation

Porosity was computed using the Neutron-Density Method. Density porosity was computed using the Bateman[15] Formula:

$$(DPHI)\Phi_D = (RHOMA - RHOB) / (RHOMA - RHOF) \qquad (1)$$

Where; RHOMA is matrix density (sandstone) = 2.65 g/cc, RHOB is bulk density (from Log) and RHOF is the fluid density (water) = 1 g/cc.

The neutron porosity, Φ_N determined directly from the neutron log.

[15] Bateman, R. M. 1985: Openhole log analysis and formation evaluation, IHRDC Press, Boston, 647p.

The derived density porosity, Φ_D, and neutron porosity, $\Phi_N$were corrected using the relationships in equation 2 below respectively:

$$\Phi_{NC}= \Phi_N – V_{sh}*\Phi_{Nsh} \quad (2a)$$

$$\Phi_{DC}= \Phi_D – V_{sh}*\Phi_{Dsh} \quad (2b)$$

Where $\Phi_{NC}$and Φ_{DC} are corrected neutron porosity and corrected density porosity respectively; and V_{sh} is the volume of shale.

Effective porosity, Φ_E was computed from Neutron porosity and Density porosity using the equation 3 below:

$$\Phi_E = \Phi_D*\Phi_{Nsh} – \Phi_N*\Phi_{Dsh} / \Phi_{Nsh}- \Phi_{Dsh} \quad (3)$$

Total Porosity (Φ_T) was computed as follows:

$$\Phi_T = (\Phi_{N} + \Phi_D)/ 2 \quad (4)$$

NOTE: The other components in the equations above were picked from Log parameters.

Formation Water Resistivity

The Formation water resistivity for the reservoir was determined using the Pickett method based on the observation that true resistivity(Rt) is a function of porosity (ϕ), water saturation (Sw) and cementation exponent (m).The use of Pickett's plot gives a good indication of formation water resistivity. Archie's relationship was modified to produce a workable system for determining Water resistivity "Rw". This was taken from clean wet sand close to the reservoir of interest.

Archie's equation for determining water resistivitycan be written in a logarithmic form,

$$nLogSw = Log(a) + Log (Rw) – mLog (\phi) – Log Rt \quad (5)$$

Re-arranging equation 5;

$$Log (Rt) = -mLog(\phi) + Log (a Rw) – nLogSw \quad (6)$$

Thus, a Pickett plot on a Log-Log scale of Rt (true resistivity) Vs porosity (ϕ) will give a straight line in water bearing points where Sw is 100%, and hence nLog(Sw)=0 which has a slope of'm' and an intercept of 'a'. From the evaluation, only one reservoir was computed for water resistivity using picket plot, other parameters were computed using interactive petrophysics.

Permeability Estimation

Permeability estimation was done by comparing computations permeability formula (Equation 7) with computations derived from Permeability-Porosity relationship formula (Equation 8) using Log data.

$$Ka\_Kr = 10^{(-3.75+21.96*PHIE)} \quad (7)$$

$$XPERM = 10^{(-1.455 + QT*13.8895)} \quad (8)$$

Hydrocarbon Saturation

The Simandoux Saturation equation was employed in generating the water saturations used in this study. The Simandoux saturation equation compensates for the shale volume within the reservoir, which makes the model suitable for reservoirs with dispersed shale.

Well Correlation

The logs of the wells were first placed at an equal depth in order to facilitate correlation. The depth measurement was considered in True Vertical Depth Subsea (TVDSS) value. Correlation of the two offset well was done by posting the depth of the reservoir sands encountered during drilling of Well A and these tops were correlated across Well B by comparing the signature of the lithology Logs of the two wells. There was no drilling report on Well B while information about the fluid encountered by Well A was also not available.

Seismic Interpretation

Seismic interpretation was carried out using Seisworks (Landmark Software) by posting the reservoir tops that were mapped on well logs on seismic session using the time-depth relational relationship created from the available checkshot data. The impact point of the tops on seismic were interpreted as horizons across in-lines and cross-lines to generate time structure maps which were converted to depth using the velocity data available. The reserve was also generated and used for volumetric analysis. For the purpose of this evaluation, there was no 3-D seismic coverage around the offset well. The few 2-D Seismic lines available around the offset well were interpreted and extrapolated to area of 3D seismic coverage (Figure 4).

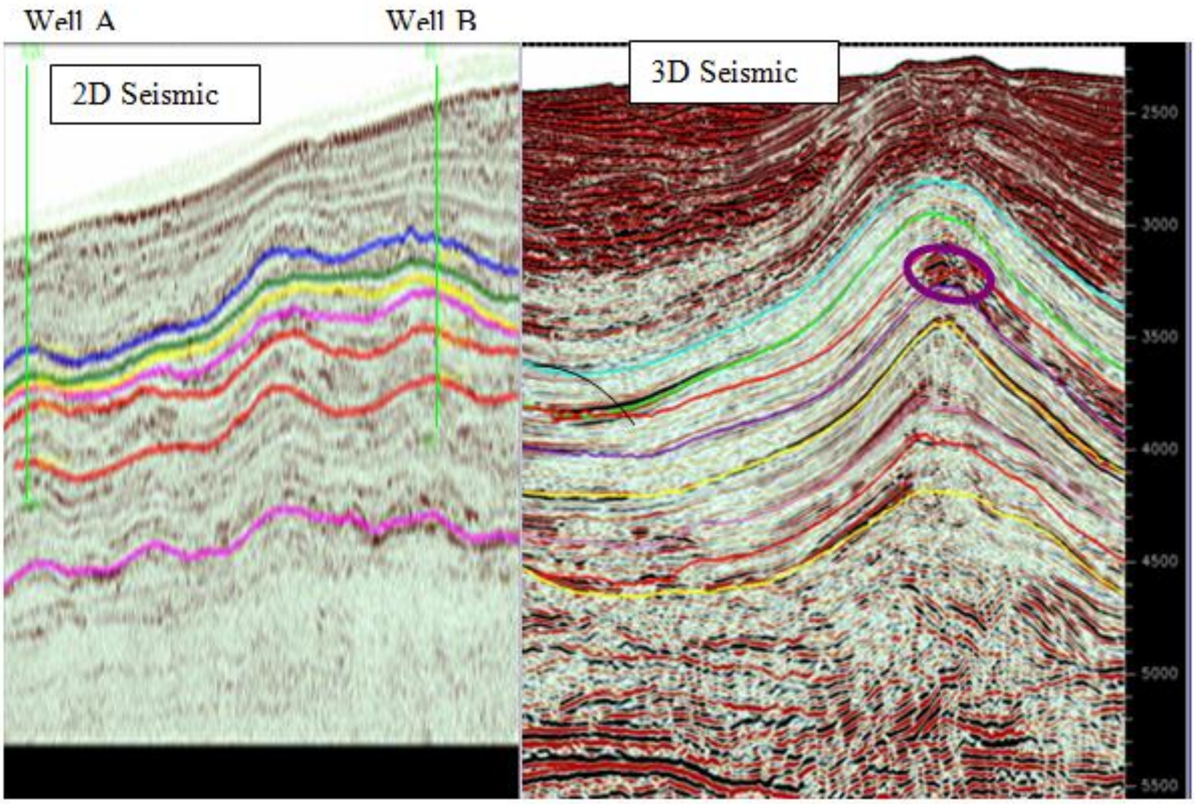

Figure 4: correlation between 2D Seismic Well Tie and 3D seismic Horizons

Amplitude versus Offset (AVO) Analysis

AVO analysis which represents changes in seismic amplitude with offset due to contrasts in the physical properties of rocks was carried out to determine the lithology type and the fluid factor on the three reservoir sands C, E and H. Amplitude versus offset (AVO) or amplitude variation with offset was carried out by generating RMS-amplitude on near, middle and far seismic volume for amplitude variation. The result shows increasing amplitude with offset, indicating a good amplitude anomaly. gradient and intercept of the seismic amplitudes were generated and crossplotted to generate a crossplots which are very helpful and intuitive way of presenting AVO data and the fluid factor.

Results and Discussion

Evaluation of Reservoir Petrophysics

The well correlation panel (Figure 5) shows the identified reservoirs correlated along the two offset wells within the study area. The petrophysical evaluation carried out was done on only Well B that shows some reservoir of interest between the depth intervals of 2599.97m to 2779.96m (Figure 6). The sands show positive potential for hydrocarbon reservoir by the virtue of low Gamma Ray, high Resistivity values, and negative separation in the neutron-

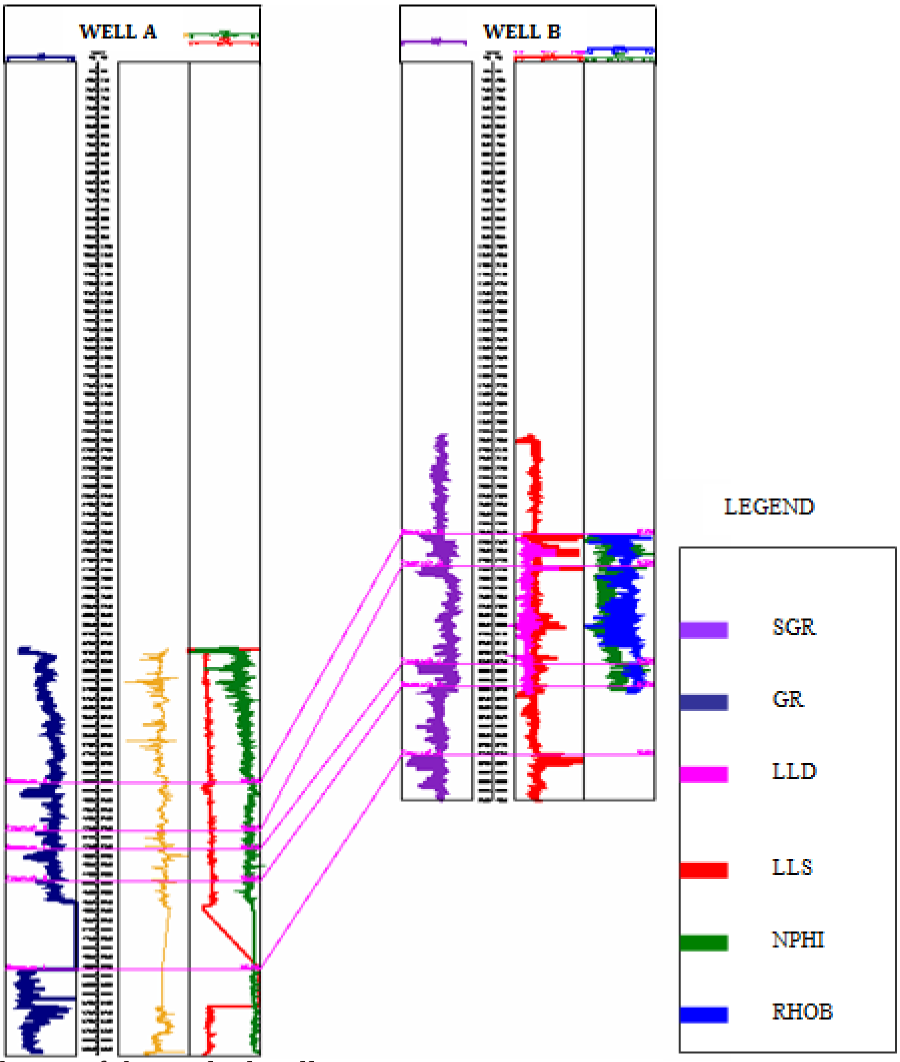

Figure 5: Correlation of the studied wells

density log (relatively large decrease in neutron response in the neutron-density log combination). The petrophysical parameters such as net thickness of reservoir, porosity, resistivity of formation water, water saturation, and hydrocarbon saturation etc., for Well B are all presented in Table 1. The parameters were compared with generally obtained Niger Delta Petrophysical parameters and the average values Table 2 were considered for the volumetric assessment.

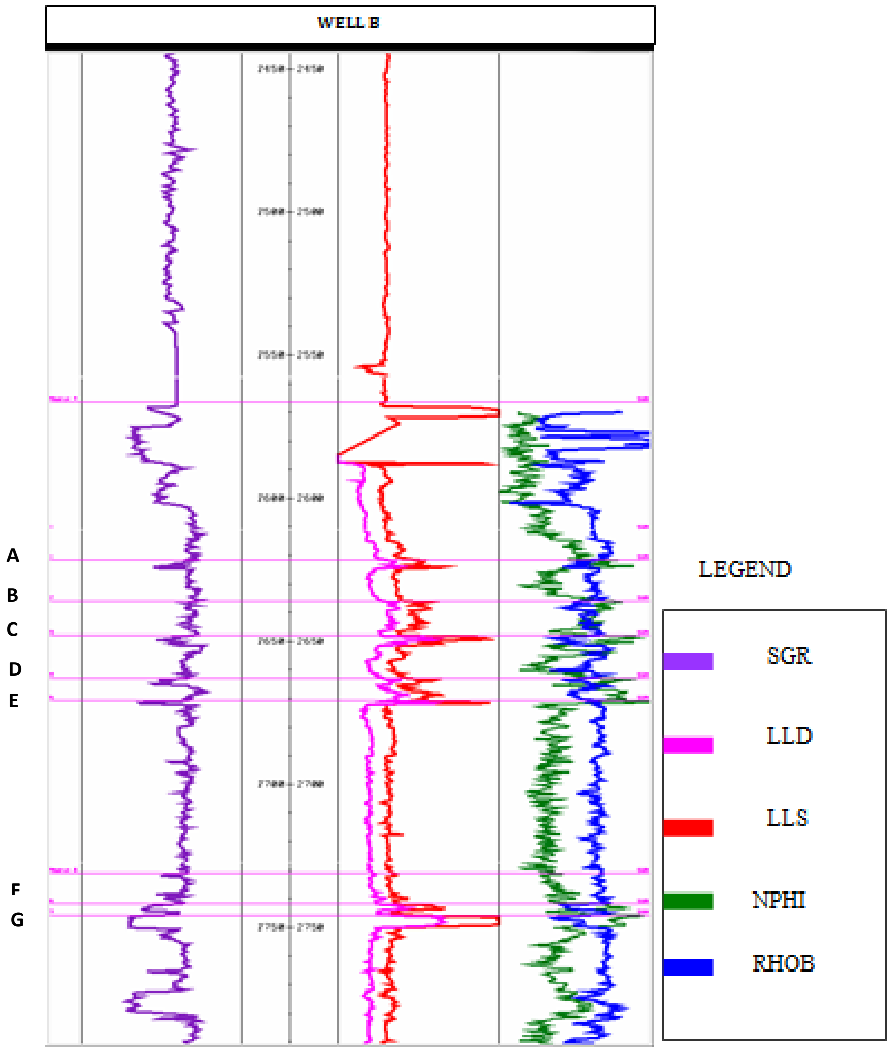

Figure 6: well log panel showing the studied potential hydrocarbon reservoir sands identified in Well-B

Table 1: Summary of the petrophysical parameters obtained from Well B of MGT Field

Reservoirs	Top (MD)	Bottom (MD)	Gross Interval (M)	Net Interval (M)	NTG (Frac)	Porosity (Frac)	S_w (Frac)	Fluid Type
A	2622	2625	3.00	0.91	0.316	0.317	0.706	Gas
B	2636	2640	4.00	0.30	0.087	0.165	0.656	Gas
C	2648	2651	3.00	0.00	0.00	0.280	0.350	
D	2663	2665	2.00	0.15	0.071	0.180	0.736	Gas
E	2671	2672	1.00	0.00	0.000	0.200	0.418	
F	2742	2744	2.00	0.15	0.068	0.173	0.638	Gas
G	2746	2750	4.00	0.00	0.000	0.160	0.882	

Table 2: Average Petrophysical Parameters Used

Properties	Shallow Target			Middle Target			Deep Target		
Area (sqm)	1	0.6	0.8	29.3	4.2	14.8	42.3	3	19.2
Thickness(m)	170	130	149	51	51	51	63	63	63
N/G	65	35	49.1	70	30	48.4	85	50	66.6
Porosity	35	28	31.4	33	24	28.4	22	15	18.4
HC Saturation	90	75	82.4	90	75	82.4	90	75	82.4

Structure and amplitude maps

Horizon B, C, D, E, F and G are the levels interpreted from the correlation of Well A and B. A deeper Horizon H from a possible stratigraphic trap (i.e. Pinch-out) was also observed on the seismic sections and mapped. This horizon was not penetrated by the offset wells. Figures 7a - 7d show Horizons B, D, F and G with their corresponding amplitude maps. All the maps are characterized by low amplitude and therefore low sand quality. The highest structural area within horizon B is between 2600-3000 meters while Horizon D has structural high between 3000-3200 meters.

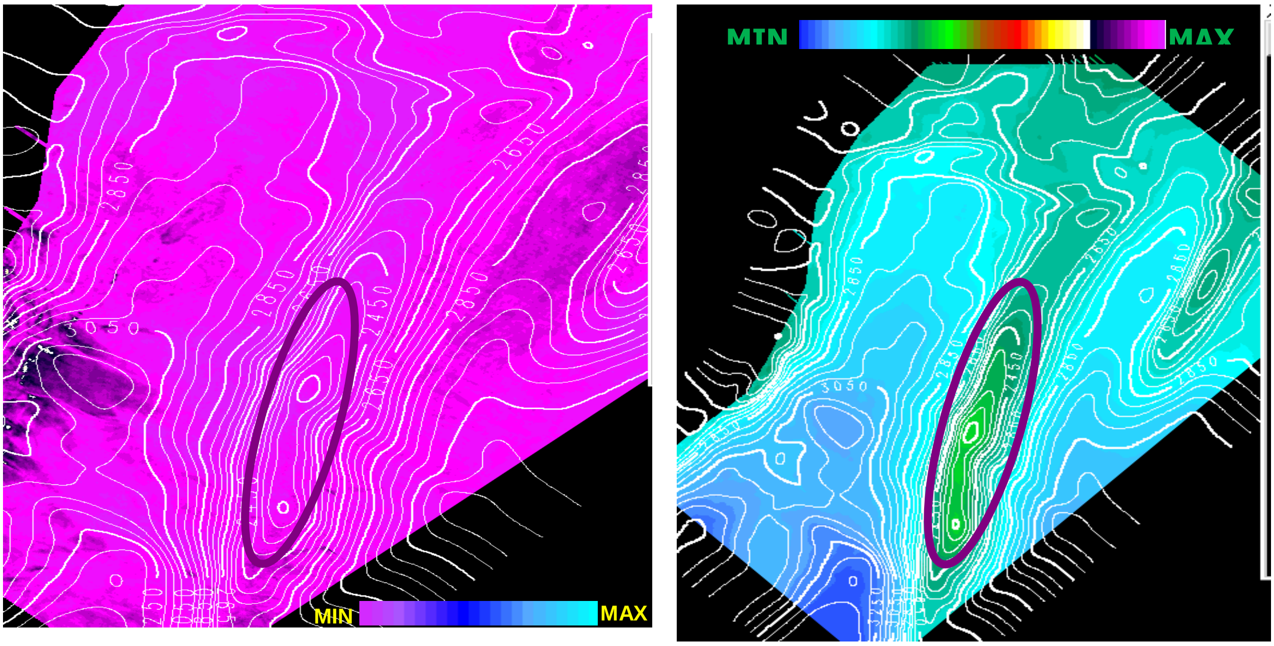

Figure 7a: Reservoir B Time Structural Map (left) and RMS Amplitude map (right). The structure (anticlinal) is indicated where we have purple ring with relatively low amplitude.

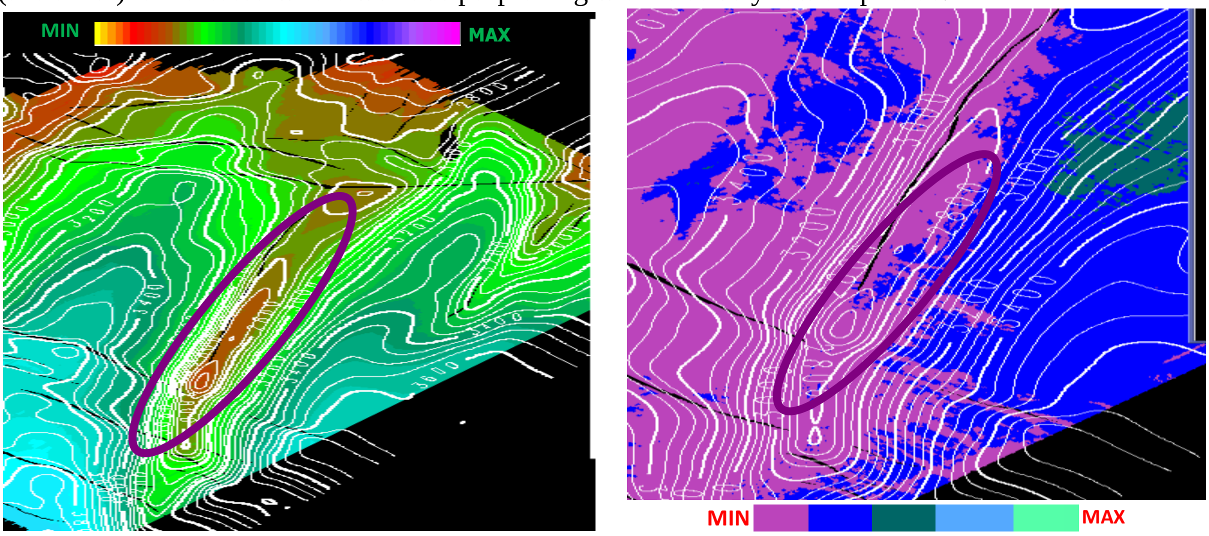

Figure 7b: Reservoir DTime Structural Map (left) and RMS Amplitude map (right)

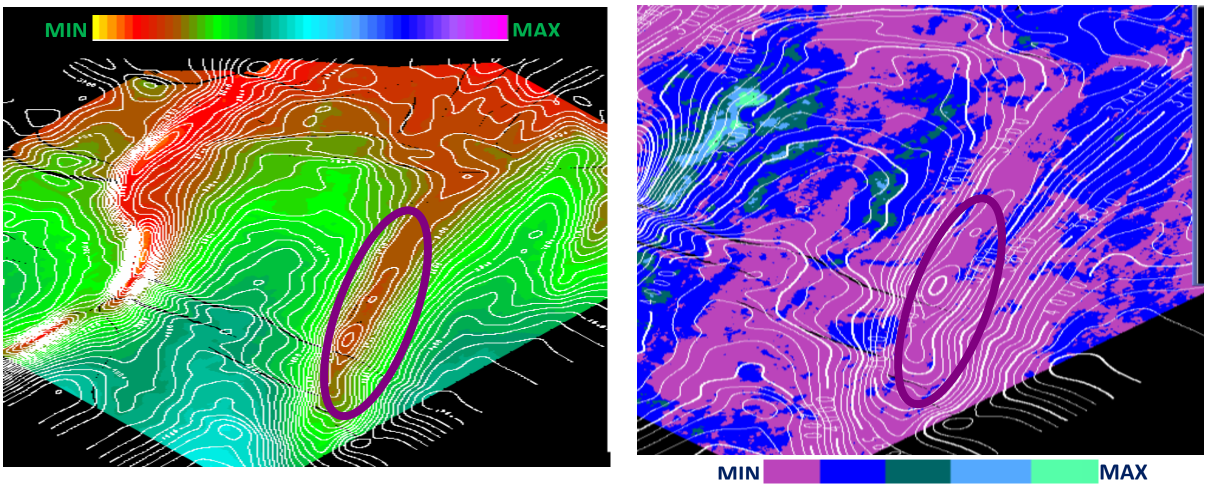

Figure 7c: Reservoir FTime Structural Map (left) and RMS Amplitude map (right)

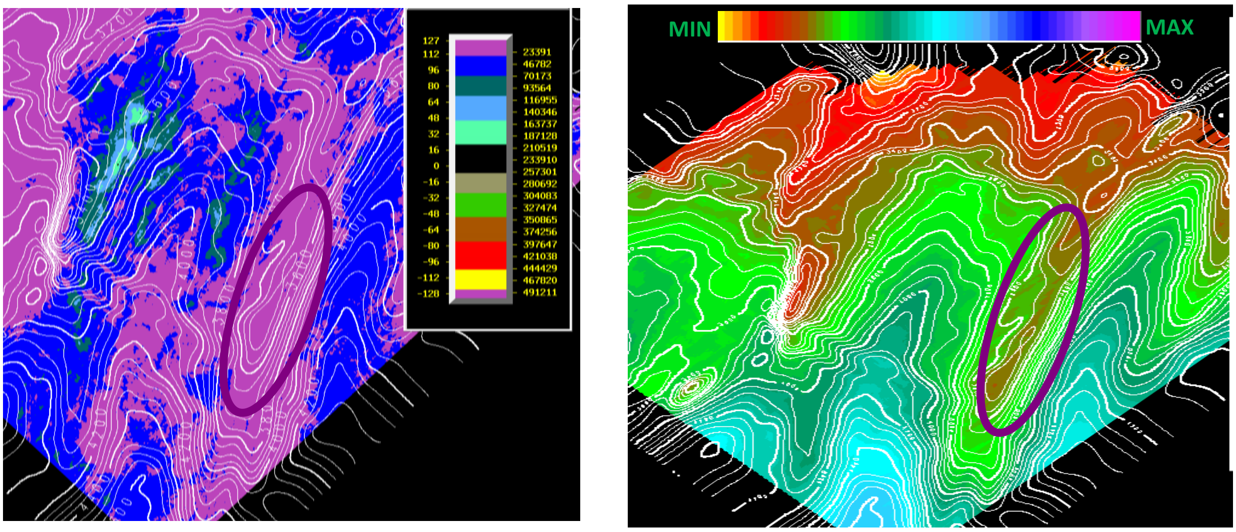

Figure 7d: Reservoir GTime Structural Map (left) and RMS Amplitude map (right)

The structure (anticlinal) in figure 7a- d is indicated where we have purple ring. Low amplitude within structure, as shown in the amplitude maps (Figure 7a - d) could indicate absence of high amplitude features such as hydrocarbon. The amplitude map of Horizon C and E revealed strong amplitude within the structure indicating the possible presence of hydrocarbon (Figures 8a and 8b). Figure 9 shows the structural map of Reservoir H. This is purely stratigraphic trap which reveals two different horizons coming together at zero frequency (pinch-out).

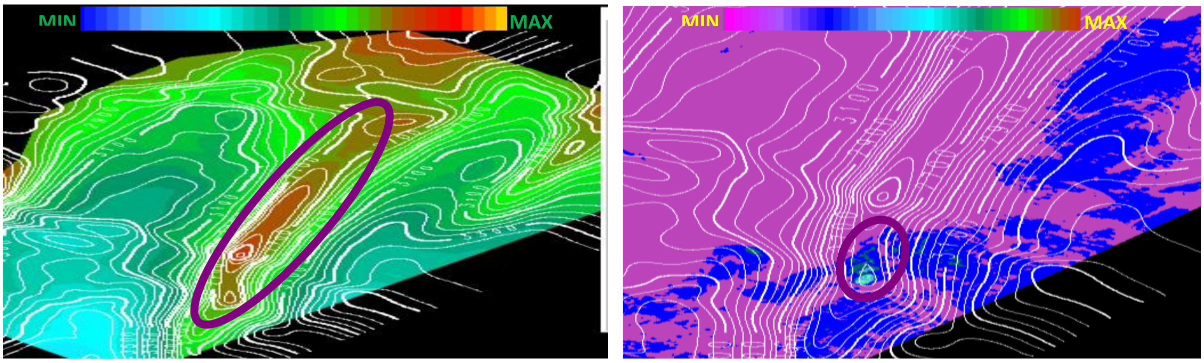

Figure 8a: Reservoir CTime Structural Map (left) and RMS Amplitude map (right)

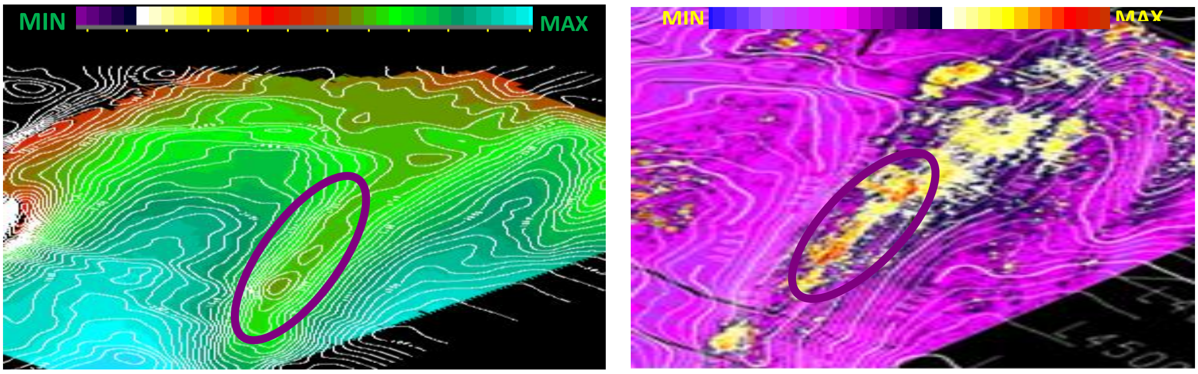

Figure 8b: Reservoir CTime Structural Map (left) and RMS Amplitude map (right).

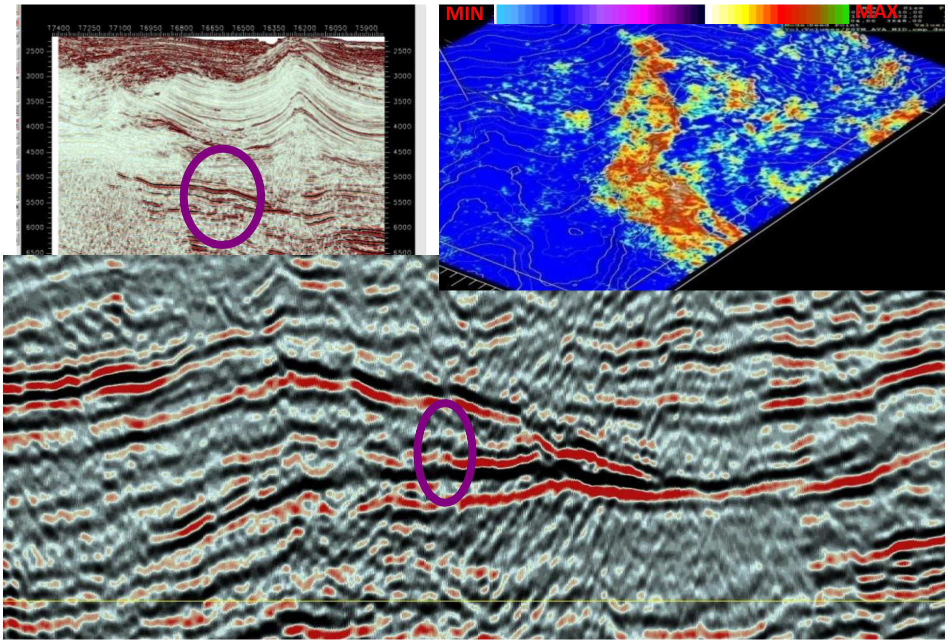

Figure 9: Reservoir H; a Pinch-out and RMS Amplitude map. The bright amplitude area within the purple ring could be due to presence of hydrocarbon

AVO Interpretation

The AVO result shows an increase in amplitude with offset (Figures 10a and 10b). This implies that a negative reflection coefficient becoming more positive with increasing offset, hence, a decreasing reflection magnitude versus Offset**.** The result reveals lower impedance sand than the surrounding shale indicating a type III anomaly which is associated with bright spot. It represents relatively soft sand with high fluid sensibility. It could also represent negative intercept (Ro) amplitude (a large negative normal-incidence reflection coefficient) that becomes more negative with further offset (brightening of reflection). This indicates that trough is increasing in amplitude with depth. The white colour (colour within the black and red sections around the reservoir) shows negligible amount of fluid. Thus, there is no fluid wherever the section has this colour; presence of fluid causes fluid factor increase. But areas marked by black and red (fluid-bearing zone) indicate the presence of fluid; consequently, the fluid factor will be increased. Figure 11 is the result of the Crossplot between intercept and gradient. The different colours shown on the seismic are distributed on the colour quadrant table. The predominant colour indicate the AVO fluid type. From this plot, the predominant colour is red which is plotted on the 3rd quadrant, indicating AVO type III where there is a negative reflection coefficient that becomes more positive with increasing offset. It is also an indication of relative impedance getting lower than overlying unit.

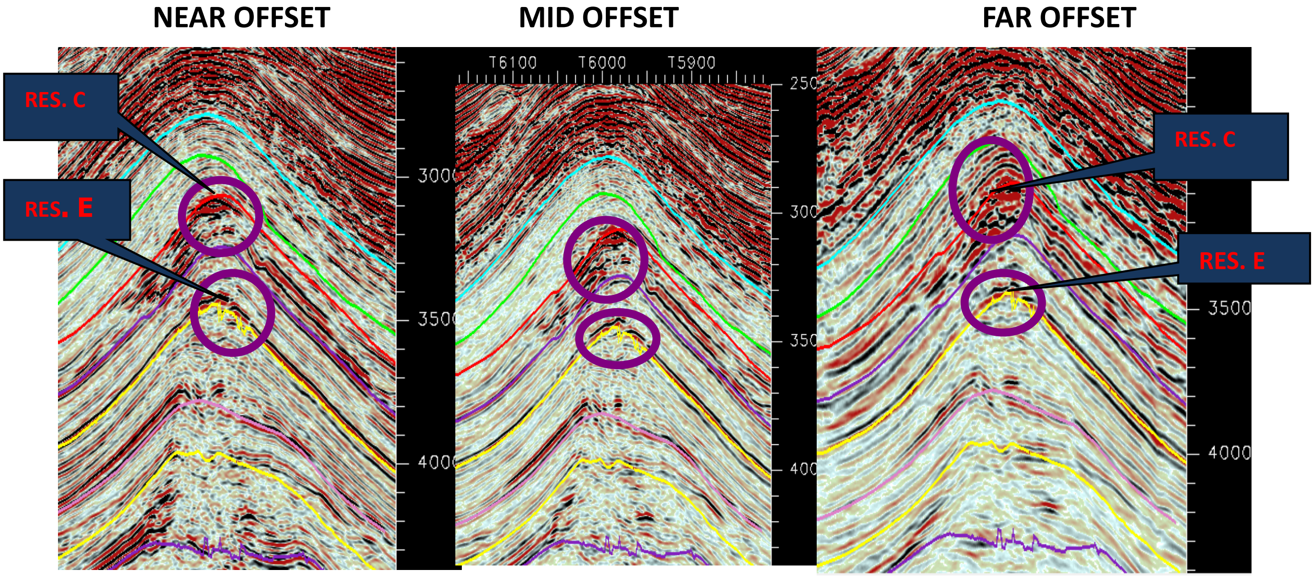

Figure 10a: Reservoir C & E AVO for near, mid and far volume

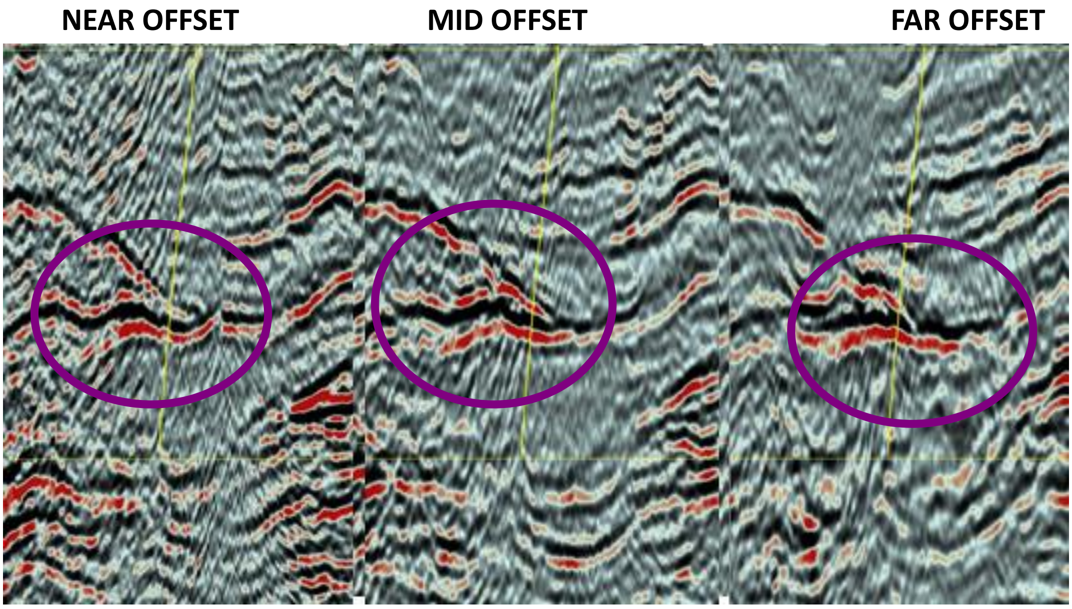

Figure 10b: Reservoir H AVO for near, mid and far volume

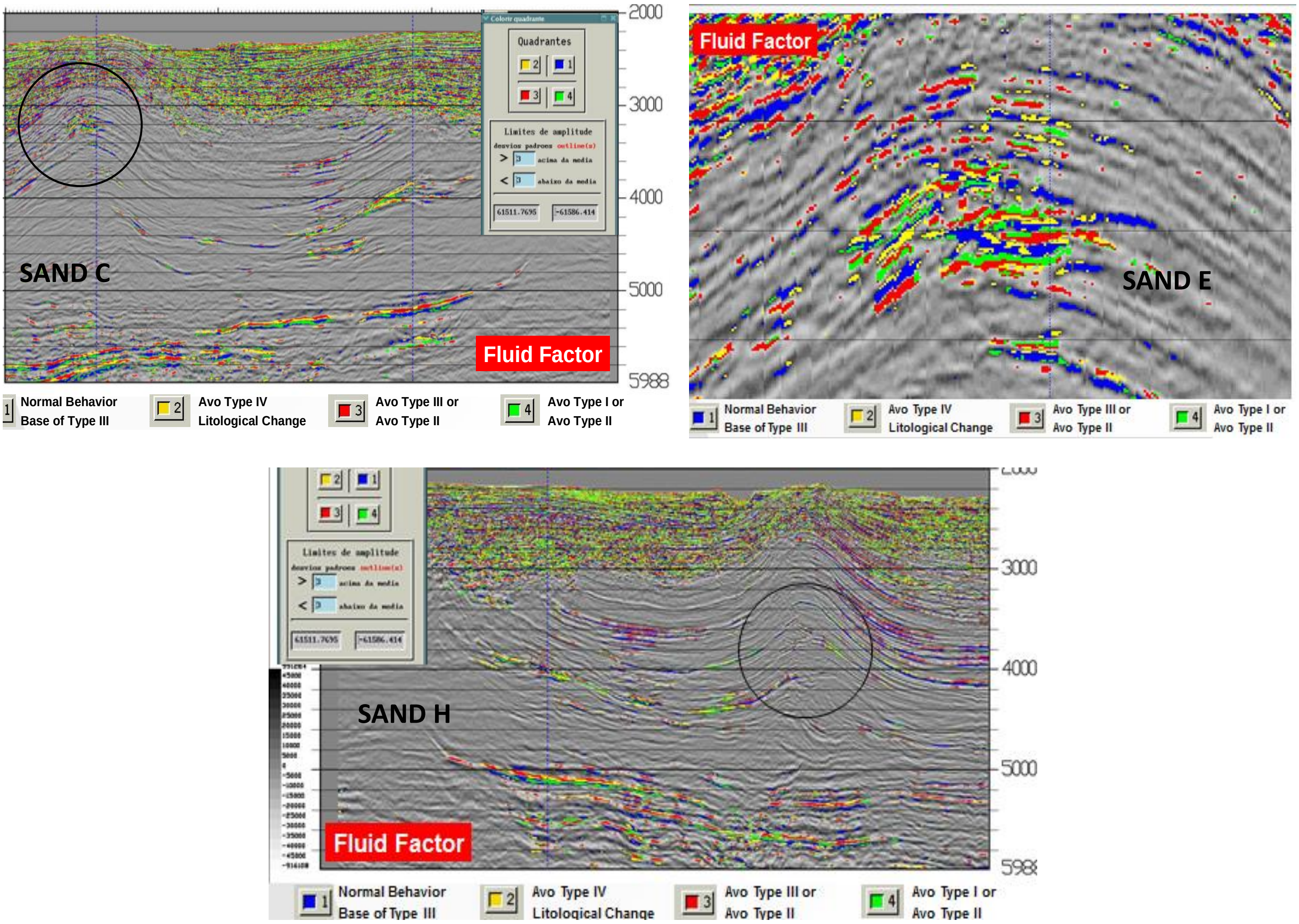

Figure 11: Reservoir fluid factor for Sands: C, E and H

Volumetrics and Geological Risk Assessment

The volume of Hydrocarbon reserve of different levels in the study area was calculated by putting the petrophysical parameters into consideration. The results are summarized in Table 3. The conditional geologic success factor estimated for the prospect identified on Reservoir C, E and H are presented in Table 4. This estimate is the chance that the prospect would hold at least the minimum size of hydrocarbon. The chance of success increases as the range increases from 0 to 1. All the risk factor estimated were multiplied together to determine the potential reward (chance of success). If any of these control or risk factor is zero, then the chance for the prospect's success is wiped out. An entry of 1.0 on any of the factors indicates that no local problems are perceived.

Table 3: Reservoir Volumetric Estimation

Shallow Target				
		Min.	Max.	Mean
AREA	(km2)	0.6	1	0.8
GROSS PAY	(m)	130	170	149
NET/GROSS	(%)	35	65	49.1
POROSITY	(%)	28	35	31.4
			Mean	P10
HC VOLUME	(MMbbl in Place)		46.4	68.4
RESERVES	(MMbbl)		18.5	FR=40%

Middle Target				
		Min.	Max.	Mean
AREA	(km2)	4.2	29.3	14.8
GROSS PAY	(m)	51	51	51
NET/GROSS	(%)	30	70	48.4
POROSITY	(%)	24	33	28.4
			Mean	P10
HC VOLUME	(MMbbl in Place)		383	807
RESERVES	(MMbbl)		115	FR=30%

Deep Target				
		Min.	Max.	Mean
AREA	(km2)	3	42	19.2
GROSS PAY	(m)	63	63	63
NET/GROSS	(%)	50	85	66.6
POROSITY	(%)	15	22	18.4
			Mean	P10
HC VOLUME	(MMbbl in Place)		502	1161
RESERVES	(MMbbl)		150.6	FR=30%

Table 4: Geologic success factor estimated for the prospect identified on Reservoir

	RESERVOIR C	COS = 27%
Play	Shallow Target	
Risk Assessment	Charge(Generation-Migr-Timing)	0.50
	Reservoir	0.85
	Trap (closure, lateral seal)	0.80
	Top Seal	0.80
	Chance of Success HC	**0.272**

	RESERVOIR E	COS = 10%
Play	Middle Target	
Risk Assessment	Charge (Generation-Migr-Timing)	0.50
	Reservoir	0.50
	Trap (closure, lateral seal)	0.60
	Top Seal	0.70
	Chance of Success HC	**0.105**

	RESERVOIR H	COS = 14%
Play	Deep Target	
Risk Assessment	Charge (Generation-Migr-Timing)	0.70
	Reservoir	0.60
	Trap (closure, lateral seal)	0.50
	Top Seal	0.70
	Chance of Success HC	**0.147**

Risks Analysis of Reservoir C, E and D

Analysis of the interpreted sand layers showed that only three sands: C, E and H exposed the presence of good hydrocarbon reservoir rock quality from the amplitude extraction generated on the surfaces of their horizon tops. AVO extraction also shows increasing amplitude with offset which reveals lower impedance sand than the surrounding shale, indicating a type III anomaly that is often associated with bright spot (Figure 10).

Reservoir C

This reservoir falls within the Miocene section of the Niger Delta Basin as could be identified on the seismic in correlation with the offset well (Figure 4). It has a gross thickness of 130m. It is a fault independent four way closure indicating a good structural trap with a good RMS amplitude anomaly (Figure 8a). AVO suggested type III AVO which is the class of a typical "bright spot" setting where unconsolidated reservoir sands are encased in higher impedance shales, usually of Tertiary age. The average porosity is greater than 25%, indicating more of type III AVO characteristics. The reserve estimate is 18.5MMbbl with chance of success of 27% (Table 4). The Akata shale is insufficient beneath the Agbada Formation to act as source rock for this Reservoir (Evamy et al. 1978; Stacher, 1995). There is therefore an indication of risk for source Rock. Besides, there is also high risk of migration pathway since there is no identified major fault that could help in the migration of hydrocarbon from the matured deeper source (Akata source) to the reservoir. Therefore, the charge is given the probability of 50%. For other factors like seal, closure, and reservoir, the risks are very low because there is overlying intercalated shale that could act as top seal. For closure, it is purely structural trap, and a very thick reservoir quality.

Reservoir E

This reservoir also falls within Miocene section of the Niger Delta. The average thickness is 60m indicating less reservoir quality compared to reservoir C. It is fault independent closure, hence, the trap is purely structural (Figure 8b). The AVO also suggested class II/III AVO anomaly in which the unconsolidated reservoir sands are encased in higher impedance shale, usually of tertiary age (Figure 11). The average porosity is about 25%.The reserve estimate is 115 MMbbl with chance of success of 10% (Table 4). The geologic risk for this reservoir also indicates risk of source rock since the Akata source is sufficient beneath the Agbada Formation to act as source rock for this reservoir (Evamy and others, 1978; Stacher, 1995). In addition, there is also a high risk of migration pathway due to the fact that there is no major fault that can act as pathway for migrating hydrocarbon from the source rock to the reservoir. The risk for trap and top seal is moderately low because there is overlying shale that could act as seal; the trap is structural anticlinal closure. The chance of success is as low as 10% due to high risk of immature Akata source rock and migration pathway from matured deeper source rock (cretaceous source).

Reservoir H

This is a deeper reservoir with average thickness of 60 m. It falls within Eocene section of the Delta. The trap is purely stratigraphic with a pinch-out seismic behavior. The amplitude variation with offset reveals an increasing variation with offset, indicating positive amplitude response (Figure 10b). The AVO for fluid factor also indicates an AVO type III (Table 4). The probability of success is 14%. The risk of source rock is considered low because the underlying Cretaceous source rock is matured. The major risk identified with this prospect is the risk of trap. There is also arisk of migration pathway since there is no major fault that could help in both primary and secondary migration. The source rock that will feed the reservoir is matured at this depth.

CONCLUSION

Seismic and Well Log Interpretation have been carried out over MGT Field to determine hydrocarbon reserve, AVO analysis and risk assessments. In general, the three reservoir targets evaluated shows moderate probability of success. All the reservoirs delineated are four way structural closures except for the deepest reservoir that was purely stratigraphic with pinch-out. Reservoirs C, E and H have better reservoir quality as revealed by amplitude extraction with AVO generated on all the reservoirs. The AVO factor indicates an AVO type III for the reservoirs. Volumetric and geological assessment of the reservoirs shows that Reservoir E has low percentage chance of success, while Reservoir C has a better chance of success. Reservoir H has moderate percentage chance of success with a big risk of the migration pathway of the hydrocarbon to the reservoir.