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RESERVIOR EVALUATION OF SAND BEDS IN SAPELE FIELD, ONSHORE NIGER DELTA

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ABSTRACT

The Sand beds of the Sapele field have been evaluated to ascertain the viability of the field for hydrocarbon development using integration of the structural play and petrophysical indices. Pay sands were delineated using the quick look approach. A seismic horizon of interest was picked using a well control measure. The structural play reveal three major faults responsible for hydrocarbon migration and entrapment mechanisms which contributed to a three-way closure in the area. Litho-stratigraphic correlation revealed repetitive gamma-ray signatures across the wells, an indication of active fault zone, and this defines the complexity of the Sapele field. The gamma-ray signatures infer a clastic marine settings when compare with standard log motifs. Petrophysical results reveal very good pore volumes of over 20% with 0ver 15% effective and an excellent degree to transmit fluid (over 1000mD). The high hydrocarbon saturation of over 70% infer good producibility of the field. The results has extensively showed the viability of the Sapele field for good field development.

KEYWORDS: Reservoirs, Correlation, Seismic continuity, Stratigraphic continuities, Hydrocarbon migration.

INTRODUCTION

The petroleum industry has been a major component of global economy since its first commercial discovery in 1875 (Craig et al., 2018). The demand for this energy product has been so much increased exponentially as it is one of the most reliable source of energy. The exquisite gain of global interest in petroleum gave rise to many geophysical and geological exploration methods. Geophysical methods like magnetic and gravity are often involved in the reconnaissance investigations before the deployment of seismic reflection technique (Ekwok et al., 2019). The discovery of hydrocarbon in a field requires additional evaluation studies to maximize reservoir fluid recovery (Adiela et al., 2018). Reservoir parameters like porosity, permeability, thickness, movable hydrocarbon indices among are used to rate and control reservoil performance (Leverson 1967, Sclumberger 1989). Hence reservoir evaluation describe structural play (geologic) and petrophysical characteristic of the reservoir as indices of predicting reservoir performance in addition to providing safe and economic decision making (Jong-Se Lim, 2005). To ascertain a good evaluation of reservoir there is need to quantitatively and qualitatively analyze a reservoir.

Modern reservoir characterization has become extremely important to oil companies since its arrival (Onuoha, 2011). On the petrophysical evaluation of reservoir sands, Ulasi *et al* (2012), Omoboriowo *et al.*(2012), Rotimi *et al*.(2013), Alao *et al*.(2013) and Mode *et al*.(2015) have independently investigated some wells in south eastern onshore part, in eastern onshore part and central part of the Niger Delta basin respectively, and noted that the petrophysical properties of the reservoir sands of the Niger Delta are high enough to permit hydrocarbon production. Keelan (1982) discussed the variety of measurement protocols, characterized certain rock properties such as porosity, permeability, grain density, and capillary pressure, and showed how these properties varied with the geological factors such as the environment of deposition. Log motifs were used to describe the paleo environent of deposition for hydocarbon bearing sands in areas (Rider, 2002). He noted that the shape of gamma ray and spontaneous potential logs though non-unique are reliable for indicators of prevailing lithologies. Selley (1976), proposed a relatively simple method to distinguish clastic depositional environment using the gamma ray curve and the presence or absence of glauconite and carbonoceous material. Amafuele *et al*

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(1993) noted that the key to enhance reserves determination and improved productivity is not based on the use of empirical correlations but it is based on the establishment of casual relationships among core-derived parameters and log-derived attribute, these theoretically correct relationships can then be used as input variables to calibrate logs for improved reservoir characterization.

LOCATION AND GEOLOGY OF THE STUDY AREA

The Sapele producing field of OML41 which lies within latitude 5.875 and longitude 5.693 and covers an area of 291km2 is 50km from Warri, Delta State. The commercially producing field forms part of the Tertiary Niger Delta petroleum system (https://www.seplatenergy.com/our-company/our-operations/upstream/omls-4-34-41/).

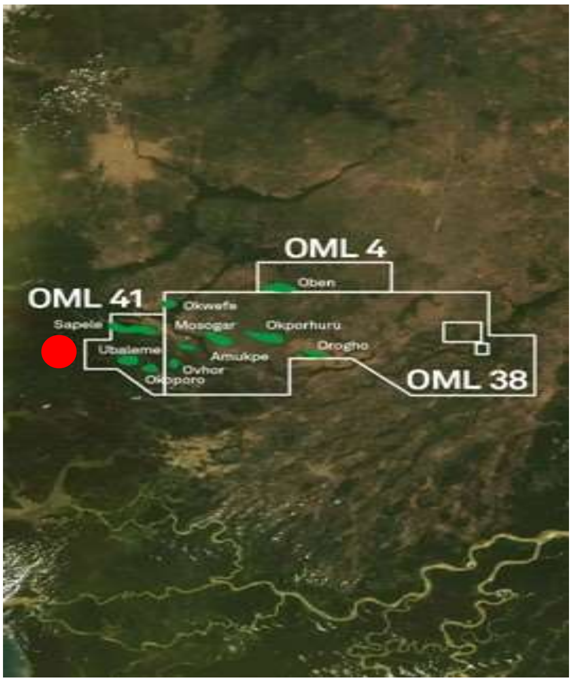

Figure 1: Location of study area

Akata Formation

The Akata Formation is of marine origin and is composed of thick shale sequences (potential source rock), turbidite sand (potential reservoirs in deep water), and minor amounts of clay and silt . The shales of the Akata Formation are rich in both planktonic and benthonic foraminifera and were deposited in shallow and deep marine environments (short and stauble 1967). Whiteman (1982) suggested that the Akata formation may be about 6,500m (21,400ft) thick, while Doust and Omatsola (1990) suggested that the thickness ranges from 2000m (6600ft) at the most distal part of the delta to 7000m (23,000ft) beneath the continental shelf. Marine shale forms the base of the sequence in each depobelt and ranges from Paleocene to Holocene in age . The formation overlies the entire delta and as such is normally overpressured.

Agbada formation

The Agbada Formation is a paralic sequence of alternating sandstones and shales whose sandstone reservoirs account for oil and gas production in the delta (Nwachukwu and Odjegba, 2001). The Agbada Formation characterized by paralic interbedded sandstone and shale has a thickness of over 3700m and represents the actual deltaic portion of the sequence (Reijers 1996). The lithology consist of alternating sands, silts and shale arranged within ten to hundred feet successions defined by progressive upward changes in grain size and bed thickness. These sandstones and shale of the Agbada Formation are cyclic sequences of marine and fluvial deposit (Weber, 1971). It occurs throughout Niger Delta clastic wedge and has a maximum thickness of about 12,000ft, it outcrops in southern Nigeria between Ogwashi and Asaba: it is called the ogwashi-Asaba Formation (Doust and Omatsola, 1990). The interchange of fine and coarse clastics is responsible for multiple reservoir-seal couplets in the formation .The age of the Agbada Formation varies from Eocene to recent, petroleum occurs throughout the Agbada Formation of the Niger delta (Tuttle *et al*, 1999). The Agbada Formation overlies the akata formation.

Benin Formation

The Benin Formation comprises the top part of the Niger Delta clastic wedge, from the Benin-Onitsha area in the north to beyond the present coastline (Short and Stauble 1967). Shallow parts of the formation are composed entirely of non-marine sand deposited in alluvial or upper coastal plain environments during progradation of the delta (Doust and Omatsola, 1989). Although lack of preserved fauna inhibits accurate age dating, the age of the formation is estimated to range from Oligocene to Recent (Short and Stauble, 1967). It consists of massive continental (non – marine) sands (Emudianughe et al, 2015). The shallow west part of the sequence is composed almost entirely of non-marine sand. Up to the present time, very little hydrocarbon deposits have been found in this highly porous and generally freshwater bearing formation (Short and Stauble 1967).

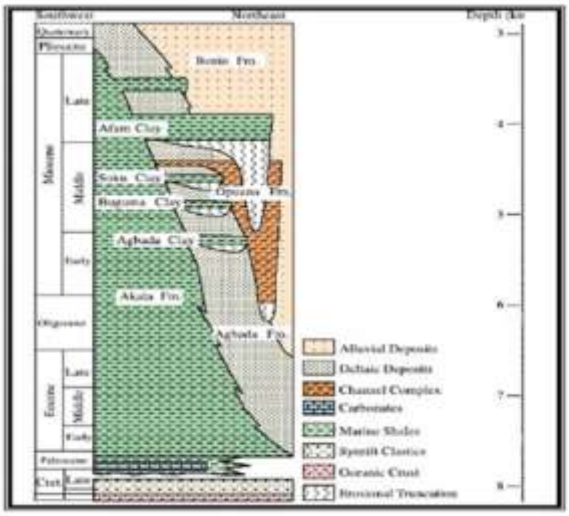

Figure 2: Stratigraphic column showing the three formations of the Niger Delta (Doust and Omatsola, 1990)

METHODOLOGY

Research Workflow

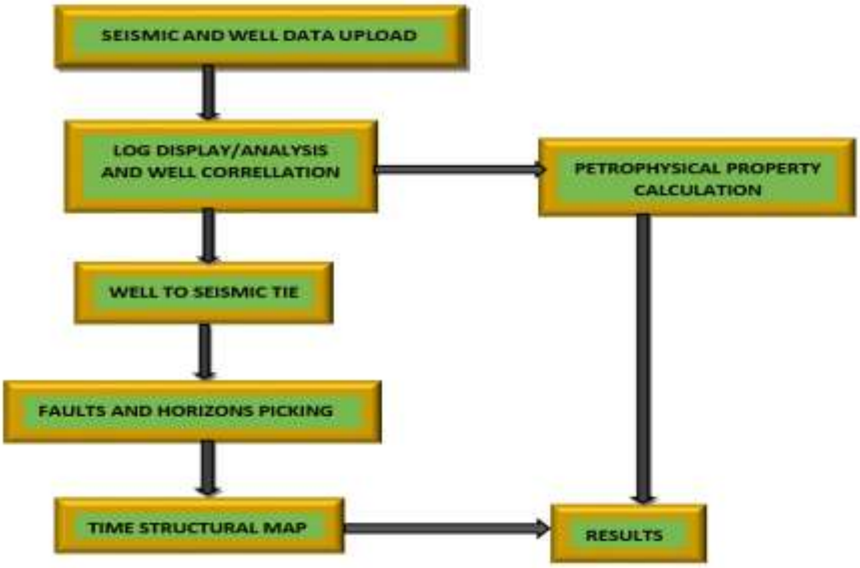

Figure 3: Work Flow

Figure 3 present the work flow for this study. Well logs and 3D seismic data were used in the Schlumberger PETREL platform. Data were thoroughly checked for bad data points to avoid pitfalls in the interpretation process. Interpretation of data for this study was group into two main part; the use of well logs to ascertain petrophysical properties and structural analysis of the Sapele field using the 3D seismic volume.

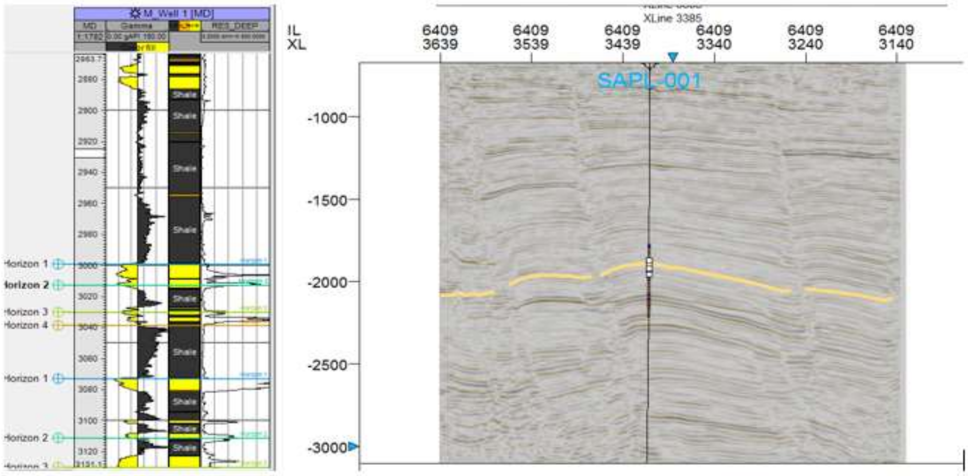

Figure 4: Seismic-Well tie

The structural analysis began with manual picking of horizon of interest using a well control (stratigraphic markers). The horizon was picked continuously across the seismic volume except at points with discontinuities (faults). The associated discontinuities were manually and carefully mapped along the horizon to generate a structural pattern that predict hydrocarbon flow paths in the Sapele field (Figure 5).

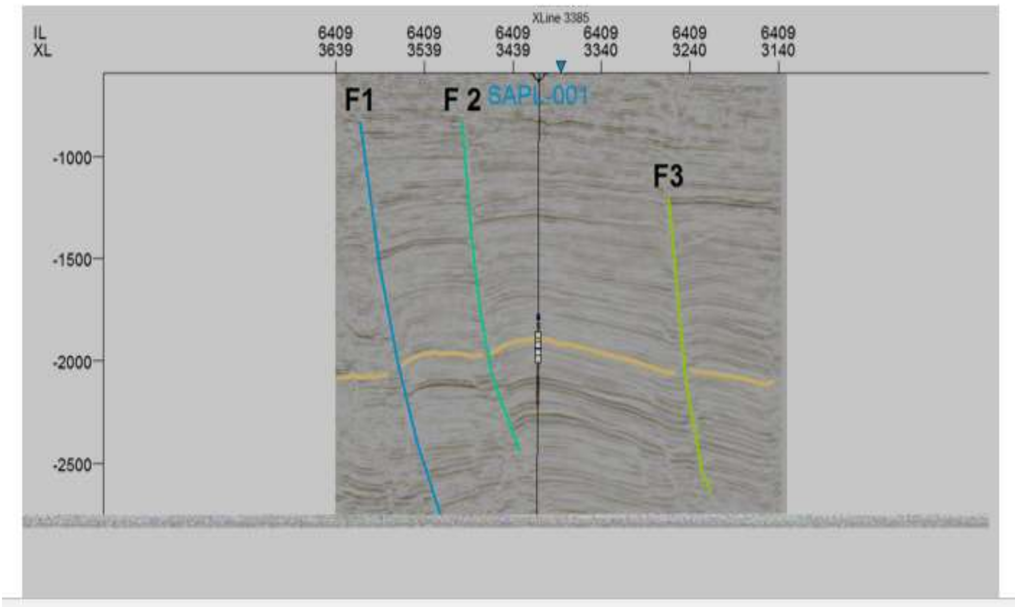

Figure 5: Seismic section showing the picked horizon and faults

High resistivity kicks were used to identify hydrocarbon bearing intervals (pay zones) while the Neutron-Density overlay measure was employed to ascertain hydrocarbon fluid types and contacts (Figures 6 and 7). First and second degrees petrophysical parameters were calculated using well records of Gamma ray, Resistivity, density and equation models. Well correlation for four wells in the Sapele field, to show stratigraphic continuities, was modelled using high degree of similarity of the Gamma ray signatures.

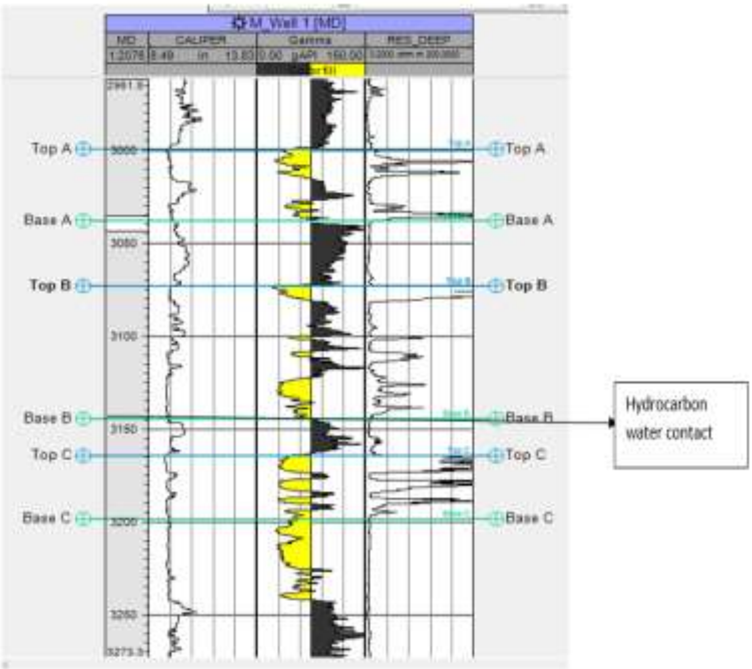

Figure 6: Delineated Pay sands of M-Well1.

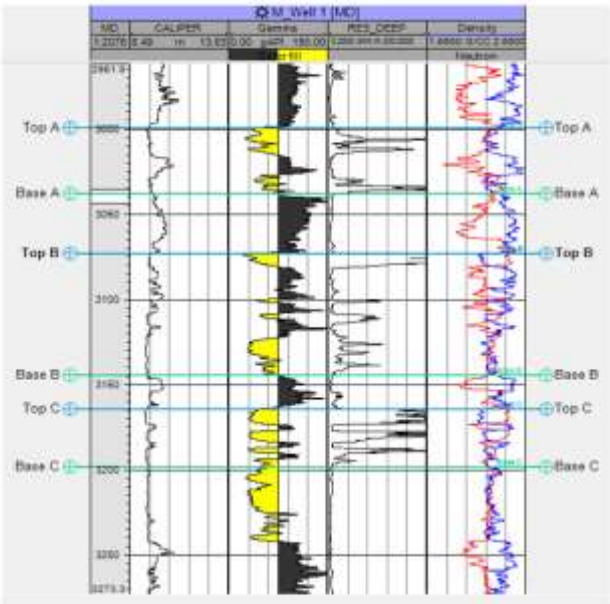

Figure 7: Delineated hydrocarbon fluid (oil) of M-Well1

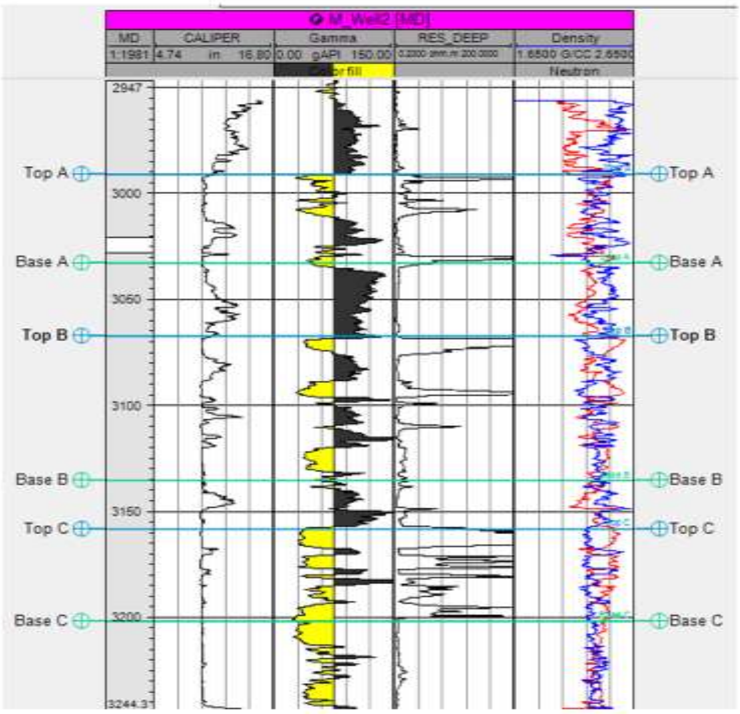

Figure 8: Delineated hydrocarbon fluid (oil and Gas) of M-Well 2.

The following Petrophysical analysis was carried out within the formations of M_welll, M_well2, M_well3, and M_well4 in the study area (from wireline logs) using equation models.

The evaluated parameters included water saturation (S_W), Hydrocarbon saturation (S_H), formation factor (F), volume of shale (V_{SH}) and porosity (Φ).

Water saturation was derived using the method based on Archie (1942) expressed in equation 1,

$$S_W = \left[\frac{F\,Rw}{Rt}\right]^{1/n} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots(1)$$

Since, $= \frac{R_0}{R_W}$, then $R_0 = FR_W$. Therefore, by substitution for R_W , equation 1 becomes,

$$S_W = \left[\frac{R_0}{Rt}\right]^{1/n} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots(2)$$

where F is the formation factor., R_W is the resistivity of the formation water., R_T is the true resistivity obtained from the deep reading tool, Ro is the resistivity of the formation when it is 100% saturated with water with resistivity Rw (Schlumberger, 1989), S_W is water saturation and n is the saturation exponent (commonly 2.0)

Hydrocarbon saturation is the percentage or fraction of pore volume occupied by hydrocarbons. It is usually determined by the difference between unity and water saturation in fractions. It is given by:

$S_H = 1 - S_W$ .... (3)

where: S_H = hydrocarbon saturation, S_W = water saturation., 1 = unity.

The formation factor of a porous formation within the target depth interval was determined using humble' formula for unconsolidated formations, which are typical of the Niger Delta. This is given by: $F = {}^{a}/_{\Phi}{}^{m}$ …………………………………………………………………..(4)

where: F is the formation factor, Φ is the porosity, 'a' is the tortuosity constant and m is an exponent called cementation factor m = exponent called cementation factor

For sands; $F = {}^{0.62}/_{\Phi}{}^{2.15}$ ………………………………………………………..(5)

The volume of shale in unconsolidated tertiary rocks of the Niger Delta is given by:

$V_{SH} = 0.33\,(2^{(2 \times Igr)} - 1.0)$ ……………………………………………………… (6)

where: V_{SH} is the volume of the shale and I_{GR} is the gamma ray index,

$$I_{gr} = \frac{GR_{log} - GR_{min}}{GR_{max} - GR_{min}} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (7)$$

The porosity is derived from bulk density of clean liquid-filled formations when the matrix density, ρ_{ma}, and the density of the saturating fluid, ρ_f, are known

$$\Phi den = \frac{\rho ma - \rho b}{\rho ma - \rho f} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (8)$$

where: Φden is the density derived porosity, ρma is the matrix density ($2.65 g/cm^3$).

ρb is the formation bulk density, ρf is fluid density ($0.85 g/cm^3$ for oil and $1.1 g/cm^3$ for water).

According to Schlumberger (1989), the irreducible water saturation (Swirr) can be expressed according to equation 9

$$S_W irr = \left[\frac{F}{2000}\right]^{0.5} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (9)$$

where $S_W$irr is the irreducible water saturation and F is Formation factor

Tixier equation was used for the determination of permeability (K), expressed as equation 10

$$K^{1/2} = \frac{250\,\Phi^{3}}{Swirr} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \quad (10)$$

where: Φ is the Porosity.

RESULTS AND DISCUSSION

Figure 9 presents correlation of five wells in the Sapele Field. Gamma ray (GR) logs are the main logs used for correlation for the reason that it exhibits patterns that are easier to spot between wells and such provides a dependable means for correlation (Ogbe et al, 2013). The correlation revealed stratigraphic continuities in the Sapele field. Well events were tied to seismic events with suites of logs (sonic logs and density logs). This was done to see the potential sand beds on the seismic volume, figure 4 provides the fundamental link between well and seismic events.

Figure 5 and 11 presents the seismic continuity, discontinuity and the generated surface map. The horizon and the associated faults were mapped using the seismic continuity (matching the well sand tops) and discontinuity respectively.

The analysed horizon on the seismic section is observed to be characterized by poor to low seismic continuity with varying amplitude reflections. The analysis revealed three major faults (F1, F2 and F3) on the seismic section. These faults are structure building faults corresponding to the growth fault in the study area (Oluwatoyin, 2013). The faults are oriented in the west-east direction, with most of them dipping east ward. The three major faults, which form a three-way closure (Figure 5), and are responsible for hydrocarbon trapping mechanism and flow pattern in the study area.

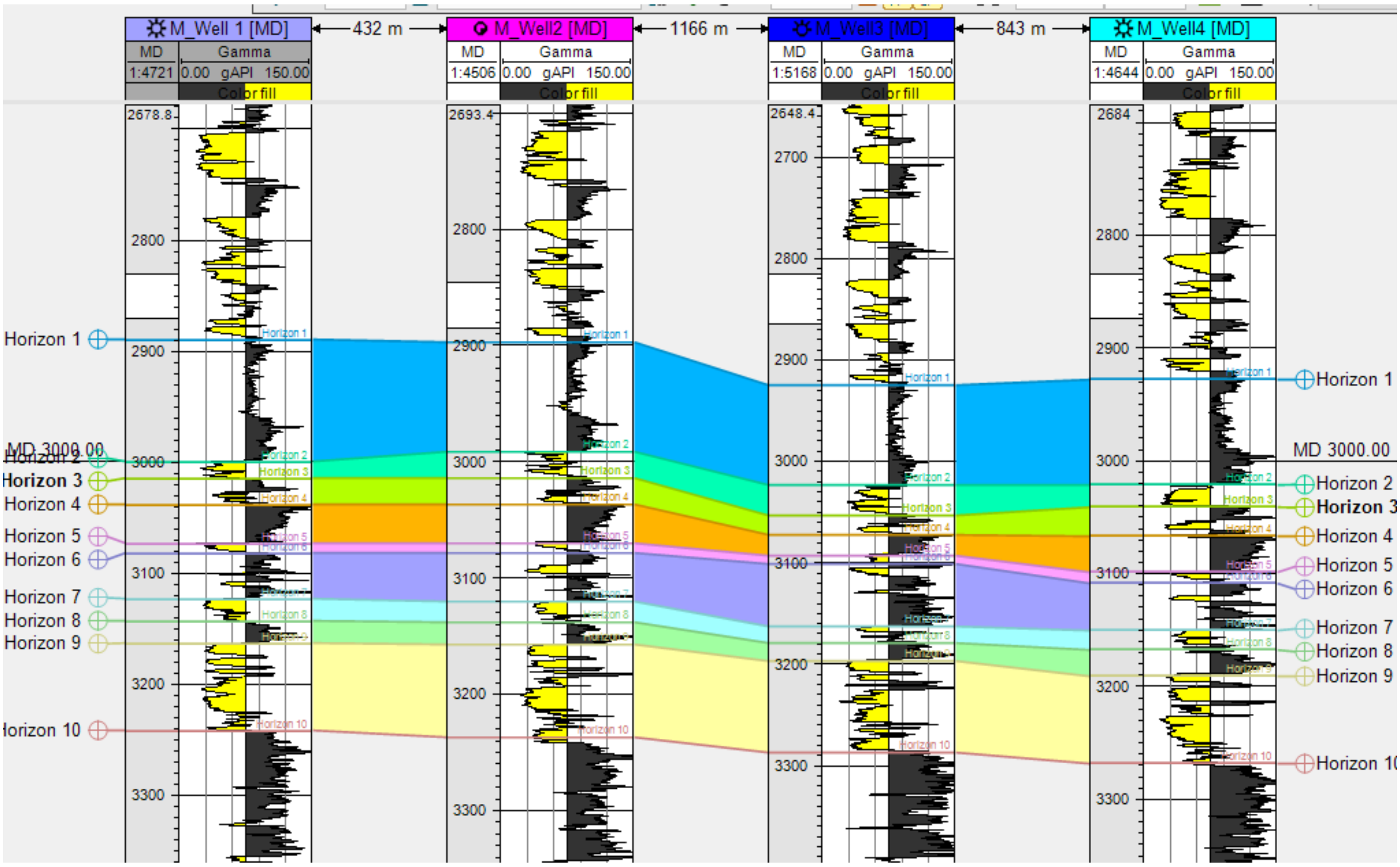

Figure 9: Well correlation section, showing continuity in the stratigraphy.

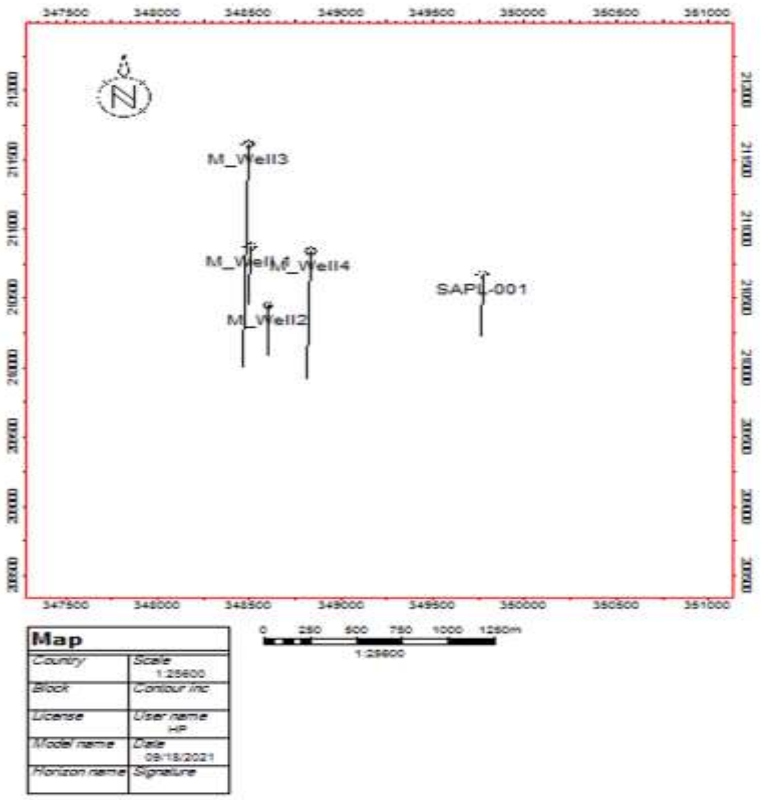

Figure 10: Base map of the area.

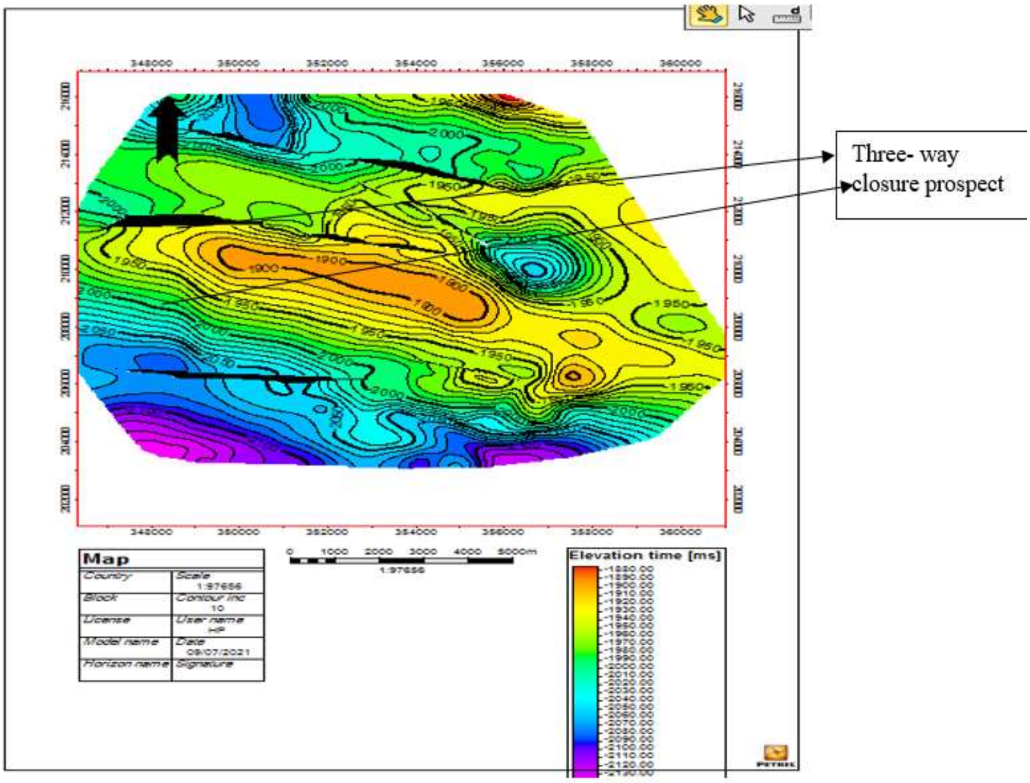

Figure 11: Time structural map

Depositional environment

The depositional environments of the reservoir sand bodies were inferred as clastic marine settings by comparing the gamma ray signature with standard log motifs.

Table 1: Results of formation A for M_Well1

Well	Start MD(m)	GR(API)	Porosity	Vsh	NTG	Sw	Sh	effporosity	Swirr	K(mD)	Thickness(m)
M_Well 1	2999.25	40.97	0.22	0.06	0.94	0.22	0.78	0.21	0.09	1591	9.72
M_Well 1	3015.08	78	0.14	0.37	0.63	0.31	0.69	0.11	0.27	822	7.49
M_Well 1	3030.17	65.36	0.21	0.19	0.81	0.17	0.83	0.17	0.10	1476	4.42
Ave			**0.19**	**0.21**	**0.79**	**0.23**	**0.77**	**0.16**	**0.16**	1296	

Table 1 show petrophysical results of well tops (formation) A **for M_Well1**. Using a Volume of shale cut-off of 40%, the formation having Net sand thickness of 21.63m with average (porosity of 19% , Net-to-Gross of 79% and an excellent degree for hydrocarbon movement) clearly infer good and excellent recoverability signatures (Levorsen,1967). It also has a good hydrocarbon fluid saturation of 77%.

Table 2: Showing results for formation A for M_Well2

Well	Start MD(m)	GR(API)	Porosity	Vsh	NTG	Sw	Sh	effporosity	Swirr	K(mD)	Thickness(m)
M_Well2	2990.96	58.87	0.18	0.15	0.85	0.22	0.78	0.16	0.13	1165	7.58
M_Well2	3010.34	80.65	0.17	0.4	0.6	0.36	0.64	0.12	0.15	1072	8.45
M_Well2	3027.45	59.5	0.24	0.16	0.84	0.18	0.82	0.20	0.09	1835	5.92
Ave			**0.20**	**0.24**	**0.56**	**0.25**	**0.75**	**0.16**	**0.12**	**1357**	

Table2 present results of the formation A for M_Well2 with a very good porosity of 20%, Net-to-Gross of 56% and excellent permeability infer a good rating for the formation with a very good degree of hydrocarbon flow. Using a Vsh cut-off of 40%, the formation has a net sand thickness of 13.5m with a good hydrocarbon fluid saturation of 75%

Table 3: Showing results for formation A for M_Well3

Well	Start MD(m)	GR(API)	Porosity	Vsh	NTG	Sw	Sh	effporosity	Swirr	K(mD)	Thickness
M_Well3	3027.15	53.19	0.2073	0.11	0.89	0.29	0.71	0.19	0.10	1476	10.48
M_Well3	3049.54	71.12	0.1568	0.31	0.69	0.26	0.74	0.13	0.20	983	10.31
M_Well3	3061.93	62.28	0.2343	0.23	0.77	0.14	0.86	0.19	0.10	1710	4.79
Ave			**0.20**	**0.22**	**0.78**	**0.23**	**0.77**	**0.17**	**0.13**	**1390**	

Table 4: Results summary for formation A for M_Well4

Well	Start MD(m)	GR(API)	Porosity	Vsh	NTG	Sw	Sh	effporosity	Swirr	K(mD)	Thickness
M_Well4	3022.69	38.39	0.25	0.05	0.95	0.15	0.85	0.24	0.08	1965	10.1
M_Well4	3034.31	79.22	0.15	0.48	0.52	0.3	0.7	0.11	0.25	900	9.63
M_Well4	3057.97	65.38	0.20	0.3	0.7	0.23	0.77	0.16	0.13	1367	4.24
Ave			**0.20**	**0.28**	**0.72**	**0.23**	**0.77**	**0.17**	**0.15**	**1411**	

Table 3 and 4 revealed similar trend as results from Table1, with average porosity of 20% and excellent permeabilities, good Net-to-Gross (78% and 77%) and 77% hydrocarbon saturation. These are indication of good formation with good recoverabilities and producibilities.

Table 5: Porosity values for reservoir qualitative description (Levorsen 1967)

POROSITY (%)	QUALITATIVE DESCRIPTION
0-5	Negligible
5-10	Poor
10-15	Fair
15-20	Good
20-25	Very Good

Table 6: Permeability values for reservoir qualitative description (Baker 1992)

PERMEABILITY IN MILLIDARCY	QUALITATIVE DESCRIPTION
1.0 – 15	Poor to fair
15 – 50	Moderate
50 – 250	Good
250 – 1000	Very good
>1000	Excellent

CONCLUSION

The Sapele Field, Niger Delta has been evaluated using 3D seismic volume and well logs data to ascertain the viability of the sand beds. The pay sands were delineated using the quick look approach. Using a generated synthetic as a well control, a seismic horizon of interest was picked with several associated discontinuities (faults). Three major faults were found to be the growth faults responsible for hydrocarbon migration and trapping mechanisms in the field remove They contribute a three-way closure as seen on the structural map. The litho-stratigraphic approach was adopted for the correlation of four wells. The correlation reveals continuities with regular repetitive gamma-ray pattern at various depth, which is indicative of normal active faults zone (http://www.ogilviegeoscince.co.uk), is good for good field development and is in agreement with complexity of the field as shown in figure4.

Petrophysical evaluations revealed very good pore volume of over 20% with over 15% effective remove and excellent fluid transmission ability (>1000mD) (remove). The good hydrocarbon saturations (>70%) are indicative of good producibility across the field except for formation B having a water saturation of over 65% for a cut off of 60%. The structural hydrocarbon migration/trapping mechanism and the petrophysical indices have shown that the sand beds of the Sapele field is viable for hydrocarbon field development.

RECOMMENDATION

To consolidate on the result findings, more studies with more wells should be carried out and the work flow can be adopted as a model for reservoir simulation studies in this field of study

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