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Formation Evaluation of an Onshore X-Field, Niger Delta, Southern Nigeria, Using Well Logs Data.

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Abstract: *Well logs data from three wells (01, 03 and 04) was employed in the formation evaluation of the onshore X-field, Niger Delta. The geophysical logs used comprises of gamma ray, resistivity, density and neutron log. Sandstone and shale lithology were delineated within the interval logged which is a distinctive quality of the Agbada formation in the Niger Delta. Petrophysical parameters of the reservoirs delineated revealed that Shale volume ranges between 0.034 – 0.15. Porosity and Permeability values range between 26–31% and 1947.08–2541.99 mD. Water saturation ranges between 44% – 98% in the identified reservoirs, which indicates that the proportion of void spaces occupied by water varied from low to high values, thus, indicating both low and high hydrocarbon saturation which ranges from 2% – 56% respectively. The porosity, permeability, shale volume and hydrocarbon pore volume values of the reservoirs within the field proved them to be quite productive.This study has demonstrated that formation evaluation has a vital role to play in reservoirs characterization.*

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I. Introduction

Formation evaluation is the process of analyzing and deciphering geophysical data performed as a function of wellbore depth, by describing the processes that determine the viability of a formation to produce hydrocarbons, (Maura 2015).

Nowadays in the petroleum industry, formation evaluation is being used for many reasons, such as a base to understand the geology of the wellbore at high resolution and also to estimate the producible hydrocarbon reservoir. One of the most useful ways to perform a formation evaluation is by use of well logs, because they can contain key information about the formation sampled by different petrophysical measurements (William, et al., 2011).

Many researchers have worked on the petrophysical analysis of different oil fields in the Niger Delta using geophysical logs, (Stacher, 1995; Aigbedion and Iyayi, 2007; Imaseum and Osaghae, 2013 and Omoboriowo, 2012). There will be a continuous improvement of the petrophysical analysis technology because of its importance in the oil industry.

Reservoir formation evaluation is a challenge in the X-field due to the complexity of the reservoirs which has led to several failed wells. Therefore, the identification and understanding of its petrophysical properties such as porosity, permeability, water saturation, hydrocarbon saturation, formation factor, irreducible water saturation and thickness of productive net sand is super vital in order to minimize exploration uncertainty.

1.1 **Aim and Objectives**

The aim of this study is to evaluate the subsurface geology of the X-field, using well log data for proper characterization of the reservoir.

The objective of this study are to:

1. identify reservoir within the study area.
2. evaluate petrophysical parameters of the reservoirs in the study area.
3.estimate Hydrocarbon in place.

1.2 Location of Study Area

The X-field is an onshore field located in the West-Northern part of the Niger Delta Basin, where late Cenozoic Classic Sequence of Agbada formation were deposited in a deltaic fluvio-marine environment (Figure 1).

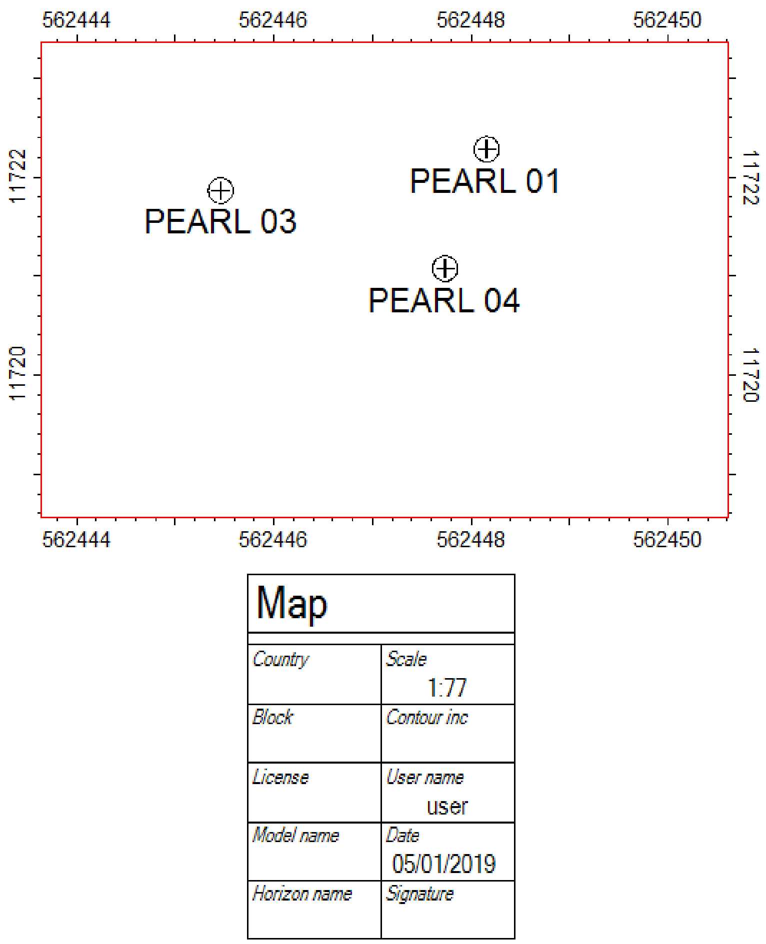

Figure 1. Base map of oil wells in the study area.

II. Literature Review

Extensive studies of the Niger Delta have been concluded in association with petroleum exploration and exploitation, but most remain proprietary. Most previous studies, focused on local stratigraphic and structural relationships within individual oil fields and concessions. The petroleum geology of the Niger Delta has been described by Tuttle et al., (1999), Doust and Omatsola (1990), Evamy et al., (1978), Weber and Daukoru, (1975) and Short and Stauble, (1967). Allen, (1965), described the recent depositional environments of the Niger Delta. He distinguished four “super environments” and a number of environments and sub-environments that are typical of shelf-delta systems. Oomkens, (1974), also described the recent sedimentation and physiography of the delta.

2.1 Geological Overview of the Study Area

The X-field is an onshore field located in the West-Northern part of the Niger Delta Basin, where thick Late Cenozoic Clastic sequence of Agbada Formation were deposited in a deltaic fluvio-marine environment.The Niger Delta is situated in the Gulf of Guinea and extends throughout the Niger Delta Province as defined by Klett et al., (1997). 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 (Doust and Omatsola, 1990). These depobelts form one of the largest regressive deltas in the world with an area of some 300,000 km2 (Kulke, 1995), a sediment volume of 500,000 km3 (Hospers, 1965), and a sediment thickness of over 10 km in the basin depocenter (Kaplan et al., 1994).

Three lithostratigraphic units are recognized in the Tertiary Niger Delta and they are, Akata, Agbada and Benin Formation (Fig.1). The Akata formation which is the oldest, is predominantly marine shales and it is the main source rock in the basin (Stacher, 1995; Kulke, 1995; Klett et al., 1997). The Akata formation is over pressured and it is overlain by the by the paralic sand/shale sequence of the Agbada Formation. The Agbada Formation is the main reservoir rock in the Niger delta. Virtually all the hydrocarbon accumulations in the Niger Delta occur in the sands and sandstones of Agbada formation where they are trapped by rollover anticlines related to growth fault development (Ekweozor and Dankoru, 1984). The uppermost section is the continental upper deltalic plain sands which is the youngest– the Benin formation.

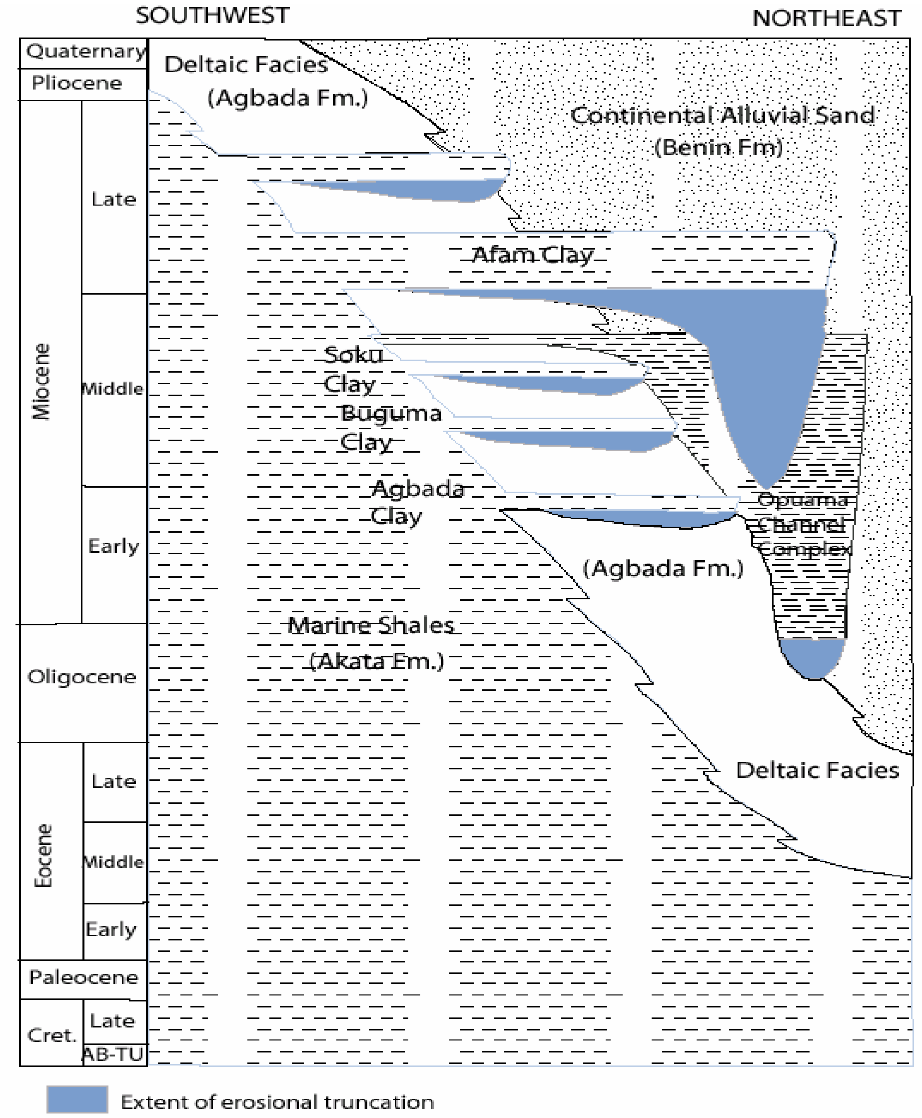

Figure 2. Stratigraphic column showing the three formations of the Niger Delta (Tuttle et al., 1999).

III. Materials and Methods

The data used for this research was acquired from Shell Petroleum Development Company via Department of Petroleum Resources (DPR). The data comprises of well logs from three (3) well that were available for the study.

The following data was used to analyse the field using Petrel®2015 software.

1. Well header
2. Deviation data
3. Three composite Well logs
4. Checkshot survey data

5 Formation tops files.

The data were imported into the Software to develop the log models used to analyze the reservoirs in an orderly manner as listed above.

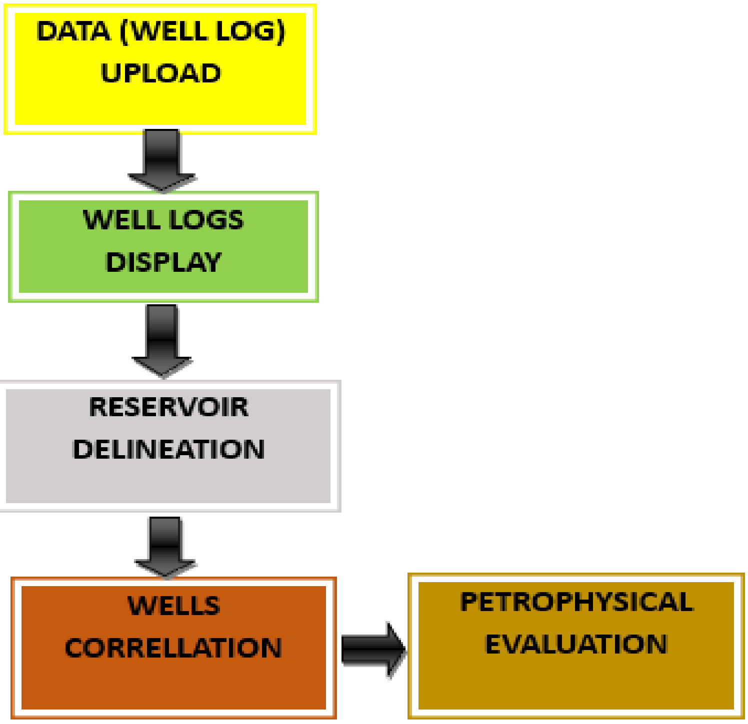

Figure 3. Study Work Flow

$I_{GR} = \dfrac{GR_{log} - GR_{min}}{GR_{max} - GR_{min}}$	………………………………. Eqn 1.0	(Larionov, 1969).
$V_{sh} = 0.083 * (2^{3.7 I_{GR}} - 1)$	……………………………………… Eqn 2.0	(Larionov, 1969).
$\Phi = \dfrac{\rho ma - \rho b}{\rho ma - \rho f}$	……………………………………… Eqn 3.0	(Bob Harrison, 1995).
$Sw = \dfrac{0.082}{\Phi\_Den}$	……………………………………… Eqn 4.0	(Udegbunam, et al. 1988).
$F = \dfrac{0.62}{\emptyset_D{}^{2.15}}$	……………………………………… Eqn 5.0	(Owolabi *et al.*, 1994).
$Swi = \sqrt{\dfrac{F}{2000}}$	……………………………………… Eqn 6.0	(Owolabi *et al.*, 1994).
$K = 307 + 26552\Phi^2 - 3450(\Phi Swirr)^2$	……………………………………… Eqn 7.0	(Owolabi *et al.*, 1994).
$Sh = (1 - Sw)$	……………………………………… Eqn 8.0	(Owolabi *et al.*, 1994).
$NTG = \dfrac{\sum Net\ Sand\ thickness}{Gross\ Sand\ thickness}$	……………………………………… Eqn 9.0	(Owolabi *et al.*, 1994).

Table 1. Formulae Algorithms used for Petrophysical Evaluation of the X-Field

IV. Results and Interpretation

4.1 Reservoir A in Well 01

Reservoir A is the only Reservoir in Well 01and as shown in Table 2, the reservoir was delineated at a top depth of 1970.29 m (6501.96 ft) and base of 2168.46 m (7155.92 ft). It has a gross thickness of 198 m (653.4 ft), a Net Productive sand thickness of 175.52 m (579.22 ft), an average porosity value of 0.31 (31%), average permeability of 2380.45 mD, an average shale volume of 0.14 and Net-to-Gross value of 0.89, which indicates that the reservoir has a good hydrocarbon recoverability.
Having Hydrocarbon Saturation (Sh) of 0.51 (51%), implies that the reservoir has a good producibility and it is of economic value.

Table 2. Petrophysical values of Reservoir A in Well (Pearl) 01

Start MD	φ	Vsh	effφ	Swirr	K(mD)	Sand thickness (M)	Net sands (M)	Shale%	Sw	Sh
1967.78	0.299	0.1374	0.2691	0.031	2518.2260	77.97	77.97	21.72	0.24	0.76
2067.39	0.317	0.1143	0.2831	0.024	2541.9880	38.41	38.41	3.08	0.19	0.81
2107.03	0.296	0.2129	0.238	0.030	1947.0760	29.42	29.42	7.21	0.52	0.48
2138.73	0.314	0.1079	0.283	0.024	2514.5270	29.72	29.72	0.00	1.00	0.00
AVERAGE										
653.4	**0.31**	**0.14**	**0.27**	**0.027**	**2380.45**	**43.88**	**43.88**	8.00	0.49	**0.51**

Reservoir gross thickness: 2168.46m - 1970.29m=**198 m (653.4ft)**
Net-to-Gross Ratio: (∑Net sand)/Gross thickness = 175.52/198.17m =**0.89**

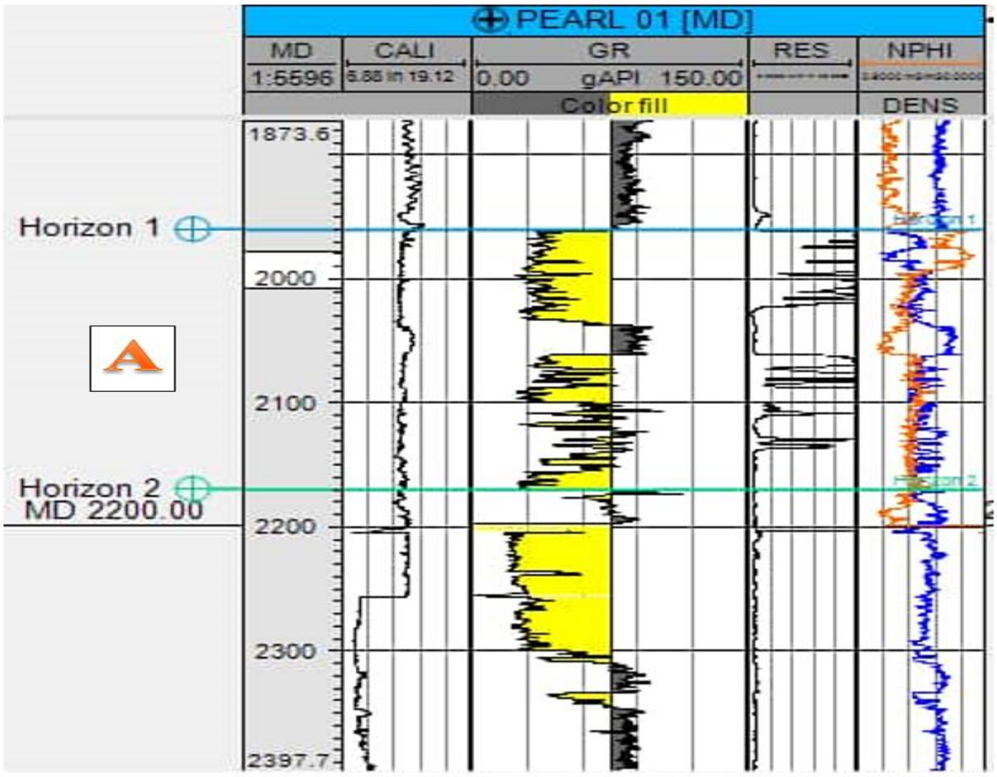

Figure 4. Log Display of Reservoir A in well 01, using Petrel 2015 software.

4.2 Reservoir A in Well 03

Reservoir A in Well 03 (Pearl 03) was delineated with well tops at a depth of 2257.43 m (7449.52) as the top of the reservoir and a base of 2308.71 m (7618.74 ft). It has a gross thickness of 51.28 m (169.22 ft), with a Net Productive Sand thickness of 40.79 m (134.61 ft), a porosity value of 0.28 (28%), permeability value of 2196.35 mD, a shale volume of 0.052 and a Net-to-Gross value of 0.80 (80%) indicates that reservoir A has a good hydrocarbon recoverability (Table 3).

With water saturation of 0.58 (58%) compare to hydrocarbon saturation (Sh) 0.42 (42%), it therefore means the reservoir contains more water than hydrocarbon and has a fair producibility and economically viable because it is compensated for by the second reservoir below it.

Table 3. Petrophysical values of Reservoir A in Pearl 03

Start Zone interval(m)	φ	Vsh	eff$_{\varphi}$	Swirr	K(mD)	Sand thickness (m)	Net Sand (m)	Shale %	Sw	Sh
2257.43	0.28	0.052	0.27	0.024	2196.35	40.79	40.79	0.00	0.58	0.42

Reservoir gross thickness: 2308.71m - 2257.43m = **51.28 m (169.22 ft)**
Net-to-Gross ratio: (∑Net sand)/Gross thickness = 40.79/51.28m = **0.80**

4.3 Reservoir B in Well 03

Reservoir B in Well 03 (Pearl 03) as shown in Table 4, was delineated at atop depth of 2327.35 m (7680.26 ft) and a base of 2388.61 m (7882.41 ft). It has a gross thickness of 61.35 m (202.46 ft), with a Net productive Sand thickness of 60.56 m (199.85 ft), an average porosity value of 0.31 (31%) an average permeability value of 2515.80 mD, an average shale volume of 0.10 and a Net-to-Gross value of 0.98 (98%), which proves that reservoir B has a good hydrocarbon recoverability.
With Hydrocarbon saturation (Sh) of 0.53(53%), the reservoir has a high producibility and is also economically viable.

Table 4. Petrophysical values of Reservoir B in Pearl 03

Start Zone interval (m)	φ	Vsh	eff$_{\varphi}$	Swirr	K(mD)	Sand thickness (M)	Net sands (M)	Shale%	Sw	Sh
2326.42	0.2881	0.0869	0.2664	0.026108	2281.6240	25.06	25.06	5.19	0.24	0.76
2352.85	0.3391	0.0814	0.3129	0.021046	2958.6640	19.64	19.64	0.00	0.17	0.83
2372.49	0.3136	0.1392	0.2707	0.024395	2307.1250	15.86	15.86	0.00	1.00	0.00
AVERAGE										
202.46	**0.31**	**0.10**	**0.28**	**0.024**	**2515.80**	**20.19**	**0.98**	**1.73**	**0.47**	**0.53**

Reservoir gross thickness: 2388.61m - 2327.35m = **61.35 m (202.45 ft)**
Net-to-Gross Ratio: (∑Net sand)/Gross thickness = 40.79/51.28m = **0.98**

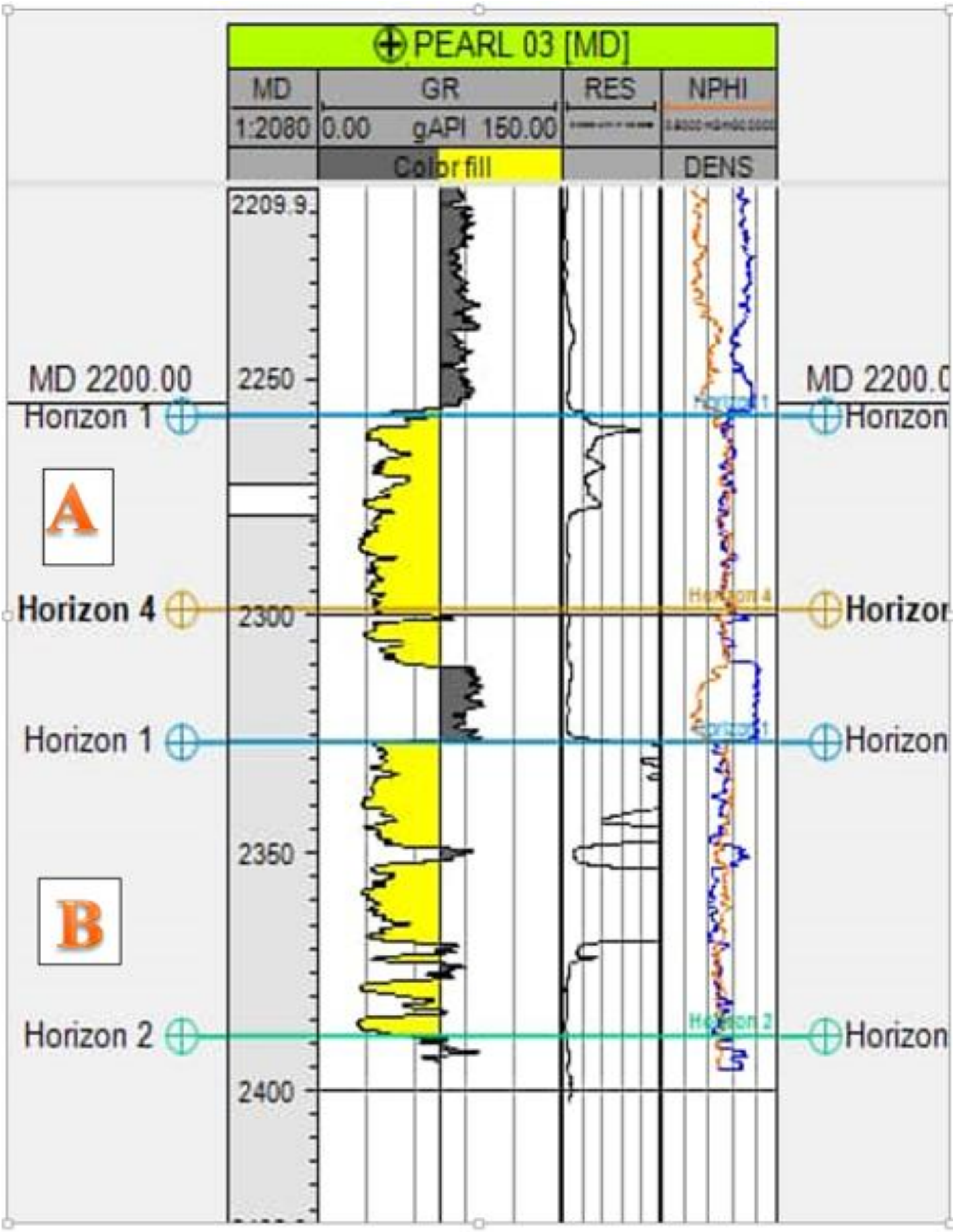

Figure 5. Log Display of Reservoir A and B in well (Pearl) 03, using Petrel 2015 software.

4.3.1 Reservoir A in Well 04

Reservoir A in Well 04 was delineated at a top depth of 2188.55 m (7222.23 ft) and at 2277.02 m (7514.17 ft) as the base. It has a gross thickness of 88.47 m (291.95 ft), Net Productive Sand thickness of 76.35 m (251.96 ft), an average porosity value of 0.28 (28%), an average permeability value of 2150.86 mD, an average shale volume of 0.15 and a Net-to-Gross value of 0.86 (86%) as shown in Table 4.1.

This indicates that reservoir A has a good hydrocarbon recoverability and with an hydrocarbon saturation (Sh) of 0.56 (56%), it also points out that reservoir A in well 04 has a high producibility and is economically viable.

Table 5. Petrophysical values of Reservoir A in Well 04

Start Zone interval (M)	φ	Vsh	eff_{φ}	Swirr	K(mD)	Sand thickness (M)	Net sands (M)	Shale%	Sw	Sh
2189.25	0.296	0.099	0.27	0.027	2421.41	31.09	31.09	0.00	0.330	0.700
2223.08	0.242	0.280	0.18	0.049	1403.04	17.61	17.61	8.11	0.465	0.535
2250.14	0.318	0.082	0.29	0.023	2628.14	27.65	27.65	34.91	0.535	0.465
AVERAGE										
2220.8	0.28	0.15	0.24	0.033	2150.9	25.45	25.45	14.34	0.44	0.56

Reservoir gross thickness:2277.02m - 2188.55m = **88.47 m (291.95 ft)**
Net-to-Gross ratio: (∑Net sand)/Gross thickness = 76.35/88.47 = **0.86**

4.3.2 Reservoir B in Well 04

Reservoir B which represents the second reservoir in Well 04 was delineated with well tops at a depth of 2307.87 m (7615.97 ft) and base depth of 2389.32 m (7884.76 ft). It has a gross thickness of 81.45 m (268.79 ft), Net Productive Sand thickness of 76.861 m (253.64 ft), porosity value of 0.26 (26%), permeability value of 1980.57 mD, shale volume of 0.034, which therefore implies that the reservoir is clean sand reservoir (Table 4.2), and a Net-to-Gross value of 0.94 (94%), stipulates that reservoir B is a very good potential hydrocarbon reservoir but with the Water saturation (Sw) of 0.98 (98%), shows that reservoir B has a low producibility and is not economically viable because it is a water bearing reservoir (Wet sand).

Table 6. Petrophysical values of Reservoir B in Pearl 04

Start Zone interval(m)	φ	Vsh	eff_{φ}	Swirr	K(mD)	Sand thickness(m)	Net Sand(m)	Shale%	Sw	Sh
2308.96	0.26	0.034	0.25	0.026	1980.57	76.86	76.861	4.72	0.98	0.02

Reservoir gross thickness: 2389.32m - 2307.87m = **81.45 m (268.79 ft).**
Net-to-Gross ratio: (∑Net sand)/Gross thickness = 76.861/81.45 = **0.94**

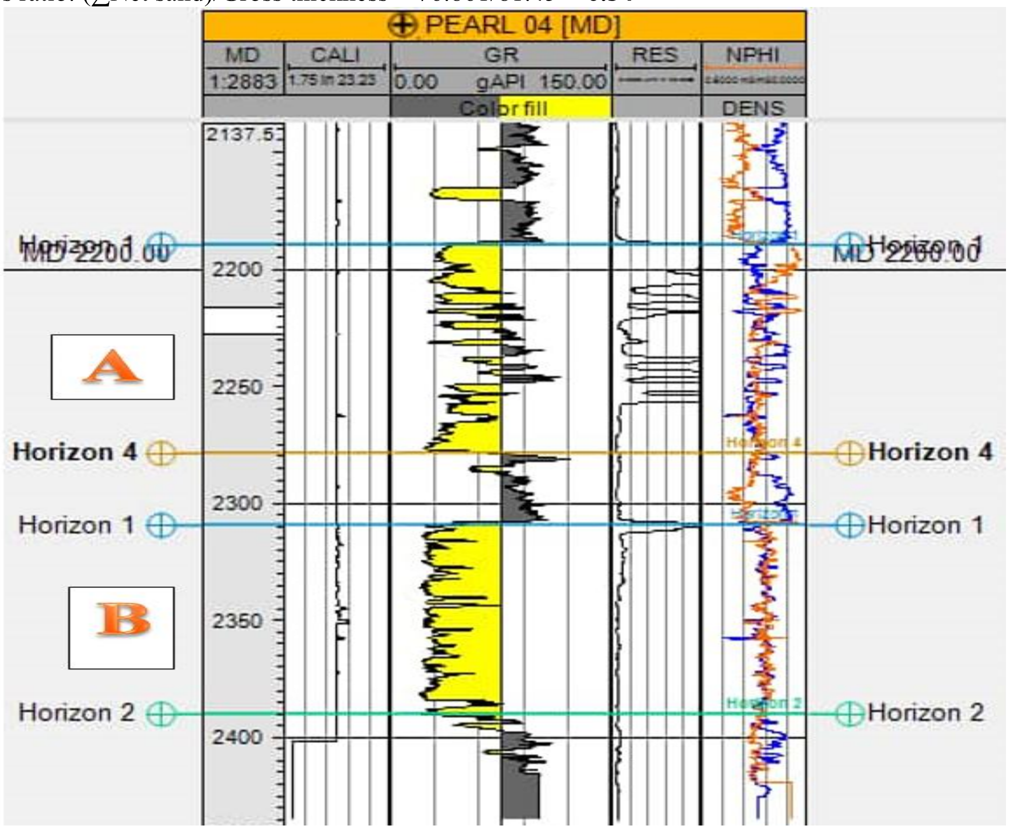

Figure 6. Log Display of Reservoir A and B in well (Pearl) 04, using Petrel 2015 software.

V. Discussion

The evaluation of all well sectionsin the X-field, reveals that the area might be associated with growth fault which must have resulted in the lateral variation of thickness across wells. The delineated lithology of the field are mainly sand and shale formations, with occasional sand-shale intercalation. From logs evaluation, prolific sands were encountered at depth range of 6501.95 ft (1970.29 m) to 8601.55 ft (2606.53 m) and the field contains both single and double phase reservoirs

The X-field as summarized in Table 7, has an average gross thickness of 96.11 m (317.16 ft), an average Net Sand thickness of 41.43 m (136.72 ft), an average porosity value of 0.29 (29%), average permeability of 2244.81 mD, an average shale volume of 0.095, Net-to-Gross value of 0.73 (73%) and an average hydrocarbon saturation (Sh) of 0.41 (41%).

From the above mentioned petrophysical properties, we can therefore say that the X-Field is a good hydrocarbon field.

Table 7. Summary of Petrophysical result of the X-Field

Reservoir	Thickness (ft)	φ	Vsh	eff$_{\varphi}$	Swirr	K (mD)	Net S (m)	NTG (M)	Sw	Sh
A (04)	**291.95**	**0.28**	**0.15**	**0.24**	**0.033**	**2150.86**	**25.45**	**0.86**	**0.44**	**0.56**
B (04)	**268.79**	**0.26**	**0.034**	**0.25**	**0.026**	**1980.57**	**76.86**	**0.94**	**0.98**	**0.02**
A (03)	**169.22**	**0.28**	**0.052**	**0.27**	**0.024**	**2196.35**	**40.79**	**0.80**	**0.58**	**0.42**
B (03)	**202.46**	**0.31**	**0.10**	**0.28**	**0.024**	**2515.80**	**20.19**	**0.98**	**0.47**	**0.53**
A (01)	**653.4**	**0.31**	**0.14**	**0.27**	**0.027**	**2380.45**	**43.88**	**0.89**	0.49	0.51
TOTAL	**1585.82**	**1.44**	**0.476**	**1.31**	**0.134**	**11224.03**	**207.17**	**4.47**	**2.96**	**2.04**
AVERAGE										
	317.16	**0.29**	**0.095**	**0.26**	**0.027**	**2244.81**	**41.43**	**0.89**	**0.59**	**0.41**

VI. Conclusion

Five (5) sand bodies were delineated and correlated across the X-field. The five sands were further identified as potential hydrocarbon reservoirs. From the Petrophysical analysis it was observed that the average porosity and permeability of the different reservoirs in the field are very good to excellentintermsof quantitativeevaluation, with porosity range of (26% -31%) and permeability range of (1980.57 mD – 2515.80 mD), Water saturation (Sw) range of (44% - 98%) and hydrocarbon saturation range of (02% - 57%). The logs evaluation indicates that prolific sands are encountered at depth range of (6501.95ft – 8601.55ft).

From the above we can boldly describe the reservoirs in the X-field of the Niger Delta as a good hydrocarbon bearing reservoirs that is economic viable.

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