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STRATIGRAPHY AND PETROPHYSICAL ANALYSIS FOR HYDROCARBON PAY ZONES "AIW" FIELD NIGER DELTA

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Abstract

Stratigraphy and Petrophysical Analysis for Hydrocarbon Zones in "AIW" field Niger Delta was carried out with a view to delineate the lithology of the study area for well log correlation. Determine the petrophysical properties that are attributed to hydrocarbon accumulation and identify the hydrocarbon pay zone using well log data. Four (4) reservoir sands were identified and interpreted, (sand-1, 2, 3, and 4) these indicate high resistivity value that suggested possible hydrocarbon bearing zones. Stratigraphic analysis revealed reservoir sand units with funnel, bow and blocky shapes (motif parttern) indicate very good to excellent reservoir quality. Petrophysical parameters such as porosity (Φ), Net to gross (NTG), permeability (K), percentage of shale (Vsh), and sand thickness obtained from available well logs confirmed the potential of hydrocarbon in place across three (3) wells. Sand-4 has the highest percentage of shale 29.82%, while sand-2 has the lowest percentage of shale 0%. Sand-1, 2 and 3 has the highest Net to gross (NTG) of hydrocarbon accumulation, while sand-4 has the lowest of Net to gross (NTG) of 0.26.Thus, the study established the efficiency of Stratigraphy and petrophysical analysis to effectively delineate, determine and identify hydrocarbon pay zone in "AIW" field Niger Delta.

Keywords: Stratigraphy, Petrophysics, Water saturation, Percentage of Shale, Hydrocarbon

Introduction

The search for Hydrocarbon product has led to delineation and determination of hydrocarbon zone within the subsurface of the earth over 20th Century. Economic accumulations of oil and gas start with the recognition of likely geological provinces, progresses to seismic surveying, and the drilling of one or more wild-cat wells. If one is lucky, these wells may encounter oil, and if that is the case, measurements made down the hole with wireline tools are used to assess whether sufficient oil is present. The evaluation of sub-surface formations requires the combined effort of geologists, petrophysicists, drilling engineers and geophysicists.

The geologist is interested in the lithology, stratigraphy and depositional environment of the subsurface strata penetrated by the drilling bit. This picture is very useful when carrying out initial reservoir modelling especially where new well is required.

Stratigraphy is the branch of geology that deals with the description, correlation, and interpretation of stratified sediments and stratified rocks on and in the Earth while petrophysics is the physical rock properties that aid in the identification of reservoir rock for petroleum. Adaeze *et al.* (2012) carried out petrophysical evaluation of Uzek wells. Reservoir properties such as lithology, depositional environments, shale volume, porosity, fluid saturation among others were determined from well log and cores, which are variables that determine reservoir quality. The analysis identified four hydrocarbon bearing reservoirs; I, P, Q and R. Average permeability values of the reservoirs is above 100 md, while porosity values ranged between 20 to 30 %, reflecting well sorted coarse grained sandstone reservoirs with minimal cementation, indicating and confirming excellent reservoir quality.

Reservoir characterization and formation evaluation of some parts of Niger delta using 3-D seismic and well log data was carried out by Abe and Olowokere (2013). The result of the analysis proved that integration of attribute analysis with structural interpretation is a reliable and efficient way of carrying out formation evaluation and reservoir characterization.

Location of the study area

The area of study is located within Niger Delta in southern Nigeria is located between longitudes 6.5^{o}E and 6.7^{o}E, and between latitudes 4.3^o N and 4.5^o N of Niger delta, (Figure 1). Niger Delta has been identified as a highly prolific hydrocarbon province located in the Gulf of Guinea on the west coast of Africa, bordering the Atlantic Ocean.

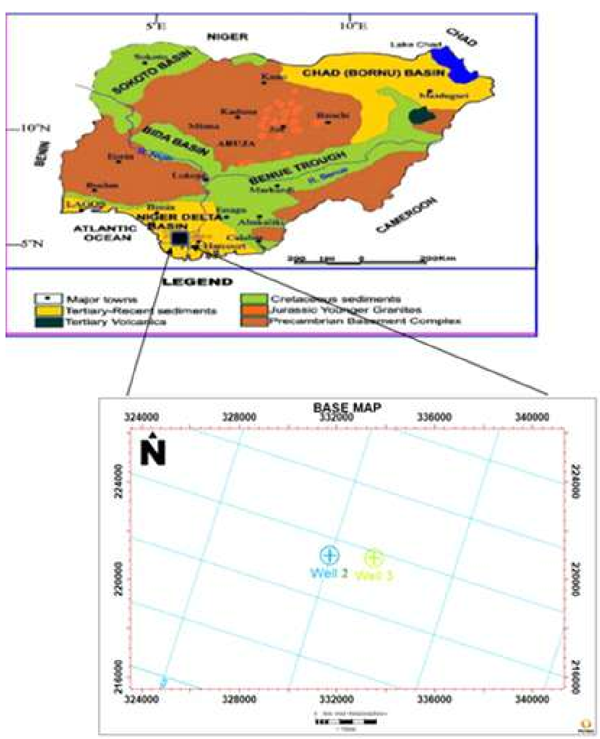

Figure. 1: Geological Map of Nigeria showing the study area with Base Map.

Scope of the Study

The scope of this study focuses on the well-log data to analyze petrophysical property and stratigraphy analysis of "AIW" field onshore Niger Delta for hydrocarbon pay zones within the sediments.

Aim and objectives

The aim of this study is to delineate hydrocarbon reservoir zone of interest from the well log data

Objectives of the study are to:

i. delineate the lithology of the study area for well log correlation
ii. determine the petrophysical properties attributed to hydrocarbon accumulation for pay zone
iii. identify the hydrocarbon pay zone.

Literature Review

Geology of Niger Delta

A delta is a large accumulation of sediments deposited at the mouth of a river where it is discharged into the sea with more than one channel called tributaries. It results from a stream reaching a body of water such as the sea and building a deposit of sediments because of the reduction of its velocity of flow. The Niger Delta is one of the World's largest Tertiary delta systems and an extremely prolific hydrocarbon province.

It is situated on the West African continental margin at the apex of the Gulf of Guinea, which formed the site of a triple junction during continental break-up in the Cretaceous. Throughout its history, the delta has been fed by the Niger, Benue and Cross rivers, which between them drain more than 10^6 km^2 of continental lowland savannah. Its present morphology is that of a wave-dominated delta, with a smoothly seaward-convex coastline traversed by distributary channels. From apex to coast the subaerial portion stretches more than 300 km, covering an area of 75 000 km^2

Stratigraphy of Niger Delta

The thick wedge of the Niger delta is considered to consist of three units Benin, Agbada and Akata formations (Figure 2). These formations are strongly diachronous and cut across the time stratigraphic units which are characteristically S-shaped in cross section. The typical sections of these formations are described by Short and Stauble (1967) and summarized in a variety of papers (Avbovbo, 1978; Doust and Omatsola, 1990; Kulke, 1995). These three geologic formations in the Niger Delta are discussed below:

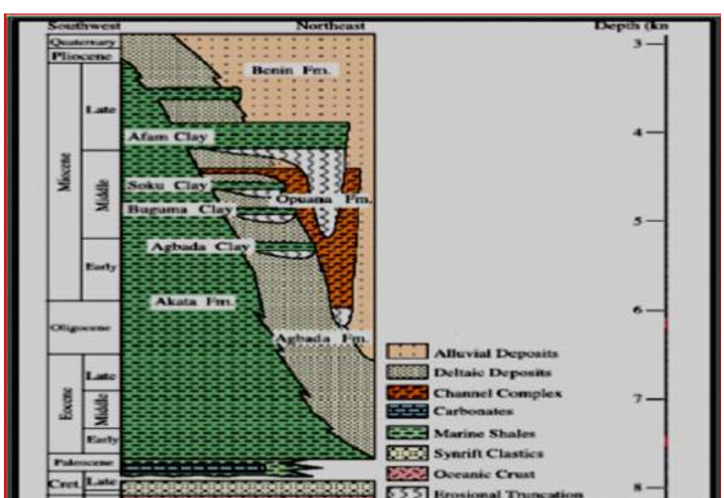

Figure 2: Stratigraphic column showing the three formations of the Niger Delta. (Modified from Shannon and Naylor, 1989; and Doust and Omalsola, 1990).

i. Benin formation

The Benin formation overlies the Agbada formation. The age of the formation is oligocene in the north and becomes progressively younger southwards. To date, very little hydrocarbon deposits have been found in this highly porous and generally freshwater bearing formation. (Short and Stauble, 1967). The Benin formation extends from the west across the whole Niger Delta and has been described as coastal plain sands which outcrop in Benin, Onitsha and Owerri provinces.

ii. Agbada formation

This is a paralic sequence of sandstone and shale underlying the Benin formation. It consists of the sandy parts, which serve as the main hydrocarbon reservoir of the Delta and shale as the cap rock. This sequence is associated with syn-sedimentary growth faulting. The Agbada formation is thickest at the center with a maximum thickness of 457.2m. (Doust and Omotsola, 1990). The upper part is predominantly sandy unit minor shale intercalation and a lower shaly unit, which is thicker than the upper sandy unit. The formation was deposited beginning from the Eocene and continued into the Recent. The depositional environment is therefore defined as "transitional" between the upper continental Benin formation and the marine underlying Akata formation. It is Miocene in the north and Pliocene/Pleistocene in the south and has a maximum thickness of possibly 4600 meters. (Doust Omotsola, 1990).

The proliferous Agbada formation is divided into four distinct members:

a. D-1 member which is predominantly an alternating sequence of regressive sands and marine shale with minor oil and gas reservoir.
b. Qua-Iboe consisting of thick pile of shale with thin intercalated sands that are possible oil and gas reservoir in some places
c. The Rubble bed consisting of heterogeneous mixture of eroded Biafra sand and shale.
d. The Biafra member is predominantly of alternating sequence of sand and shale. It contains principally oil and gas reservoir. (Doust and Omotsola, 1990).

iii. Akata formation

This unit is composed of deeper marine shale, the deepest stratigraphic unit. It is chiefly represented by plastic, low density, under-compacted and high-pressure shallow marine to deep water-shale; with only local inter-beddings of sands and/or siltstones. It is deposited as the high-energy delta advanced into deep water. It serves as the hydrocarbon source in the Niger Delta. Majority of wells drilled in the Niger Delta only penetrated into the marine Akata Shale. Little of the formation has been drilled; therefore, not much is known about this formation. It is estimated that the formation is up to 7,000 meters thick. (Doust and Omotsola, 1990).

Materials And Methods of Study Materials

In this study a suite of well log data the gamma ray (GR), resistivity log (LLD), neutron (NPHI) and density (RHOB) porosity logs have been used to categorize the lithology of the prospective zones, differentiate between hydrocarbon bearing and non-hydrocarbon bearing zones and determine the values of petrophysical properties of the zones of interest (reservoir) "AIW" field. The available well log data can be observed in Table 1.

Method of Data Analysis

The sequence of data import begins with the well heads and logs. The well log data was imported into petrel 2009 package software for analysis. The well heads file, contain the well name, surface location of the wells, 3D seismic data was used to generate Base Map having well locations. The logs (Gamma-ray, Resistivity, Density, and Neutron) were then imported for the three wells "Wole" 1, 2 and 3 respectively. Figure 3 shows the flowchart for mode of data analysis.

Delineation of Lithologies

Sand and shale unit were delineated from the gamma ray log signatures using Shale line sand bodies were cut off of (60 API unit) base on the concentration of radioactive minerals deflection to the left due to the low concentration of radioactive minerals is sand sediment. While deflection to the right signifies shale which is as a result of high concentration of radioactive minerals in it.

Reservoirs Identification and Hydrocarbon Discrimination

Reservoirs are subsurface formations that contain water and hydrocarbon. They were identified by using the log signatures of both gamma and resistivity logs. Intervals that have high resistivity are considered to be hydrocarbons while low resistivity zones are water bearing intervals. Lithology is often used to describe the solid (matrix) portion of the rock, generally in the context of a description of the primary mineralogy of the rock. The Gamma Ray (GR) log measures the natural radioactivity of the formations in the borehole and useful for identifying reservoir rocks and for correlation purposes.

Well correlation

Well correlation of signatures involves pattern recognition on well logs and the matching of such pattern of curves from one well to another. Accurate correlations of well logs are very important for reliable geologic interpretations. It provides subsurface information such as lithology, reservoir thickness, formation tops and bases. The logs were activated and displayed on the well section window, on which correlation was carried out using the lithology log (Gamma ray log) and resistivity log to check flow of fluid contents present within the sediments across the three wells. The top and base of the reservoir were picked for continuity of sediment deposition from one well to the other.

Table 1: Available well logs for petrophysical analysis

Well name	GR	LLD	RHOB	NPHI	Dtp	Dts	Derived log	
							DPHI	SPHI
Well _1	✓	✓	✓	-	✓	-	✓	✓
Well _2	✓	✓	✓	-	-	✓	✓	
Well _3	✓	✓	✓	✓	✓	-	✓	✓

Determination of Petrophysical Parameters

The petrophysical properties of the reservoir sands were evaluated from well logs and analyzed using the Petrel calculator function through mathematical relations. The calculator function was used in deriving well logs for Volume of shale (Vsh), Density Porosity, (Dphi) and Permeability (k), also Percentage of shale and Net to gross (NTG) attributes.

ii. Volume of shale (Vsh).

The gamma ray log was used to calculate the volume of shale in a porous reservoir. The first step used to determine the volume of shale from a gamma ray log was the calculation of the gamma ray index using the equation:

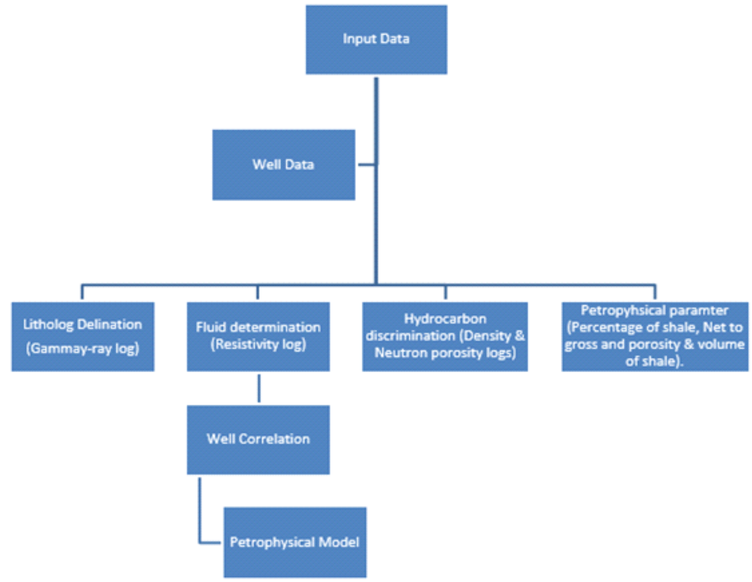

Figure 3: Flowchart of the methodology for mode of data analysis

$$I_{GR} = \frac{GR_{log} - Gr_{min}}{GR_{max} - GR_{min}} \quad (1)$$

where: I_{GR} = Gamma ray index, GR_{log} = Gamma ray reading of the formation, GR_{min} = 20 API (clean sand), GR_{max} = 150 API (shale). All these values were read off within a particular reservoir. Having obtained the gamma ray index, volume of shale was then calculated using the (Dresser Atlas, 1979). Formula.

$Vsh = 0.083(2^{3.7xIGR}$-1.0 (Tertiary consolidated sand) (2)

iii. Porosity (Ø).

Porosity is defined as the percentage of voids to the total volume of rock. The formation density log was used to determine formation porosity. The porosity was determined by substituting the bulk density readings obtained from the density log within each reservoir into the equation 3 (Dresser Atlas, 1979).

$$Ø_{den} = \frac{Pma-P_b}{Pma-p_f} \quad (3)$$

where, $Ø_{den}$: Is the density derived porosity, ρmais the matrix density = 2.65gm/cm^3 (sandstone), ρfl is the fluid density= 1.1gm/cm^3 (fluid density), ρb = formation bulk density.

iv. Formation factor (F)

The formation factor was determined from the Archie's (1942) equation below;

$$F = \frac{a}{Øm} \quad (4)$$

where: Ø= Porosity, a = constant (0.62), m = cementation exponent (2 for sands).

v. Hydrocarbon saturation (Sh)

This is the percentage of pore volume in a formation occupied by hydrocarbons. It was obtained by subtracting the value obtained for water saturation from 100%.

i.e., Sh = (100 – Sw) % (5)

where, Sh = Hydrocarbon saturation, Sw = Water saturation

vi. Irreducible water saturation (S_{wirr})

This is the water held in the pore spaces by capillary forces. When a zone is at irreducible water saturation (**S_{wirr}**), the water saturation in the univaded zone (S_w) will not move because it is held in grains by capillary pressure. For most reservoir rocks, irreducible water saturation ranges from less than 10% to more than 50%. (Schlumberger, 1979). It was determined from the equation given by Asquith *et. al.,* (2004).

$$S_{wirr} = \frac{F}{2000}^{0.5} \qquad (6)$$

vii. Permeability (K)

It is the ability of a rock to transmit fluid. It is related to porosity but it is not always dependent on it. It is controlled by the size of the connecting passages (pore throats or capillaries) between pores. It is measured in darcies or millidarcies. Equation 7 was used to derive the permeability of each reservoir that was identified.

$$K = 100 \times \psi^2 \times \frac{(1-Swirr)}{Swirr} \qquad (7)$$

where S_{wirr} is the irreducible water saturation. A practical oil field rule of thumb for classifying permeability (Baker, 1992): poor to fair = 1.0 to 14 md, moderate = 15 to 49 md, good = 50 to 249 md, very good = 250 to 1000 md, >1 darcy = excellent.

Results and Discussion

Well Log interpretation

Three well logs were interpreted in the "AIW" field where well_1 is relatively close to well_2 but well_3 was drilled far from the other two wells. Figure 4a and 4b show identified lithology of the study area. Intercalation of sand and shale was interpreted using the gamma ray log. Four reservoir sand units were identified from the log signature, moving towards the higher (gamma ray) values, the formation becomes shaly-sand. The shale cut-off approach used enables estimation and establishment of lithological sequence formation of the study area. Combination of gamma ray and resistivity logs were used to differentiate between hydrocarbon and non-hydrocarbon bearing units.

(Figure 5a and 5b). Increases in resistivity value implies the presence of hydrocarbon saturation; on the other hands as water saturation increases, the resistivity decreases.

Well logs were correlated, hydrocarbon reservoir delineated and fluid discrimination was carried out using gamma, resistivity, density and neutron logs respectively.

Stratigraphic deposition of sediment from Gamma ray log

Log stratigraphic correlation between wells were carried out using GR log. Stratigraphic

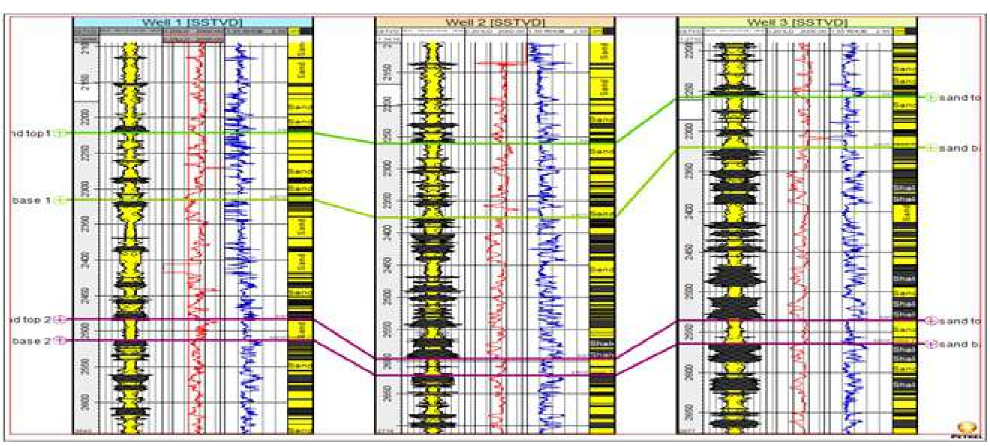

Figure 4a: Lithology and Well correlation across the wells for sand 1 and 2

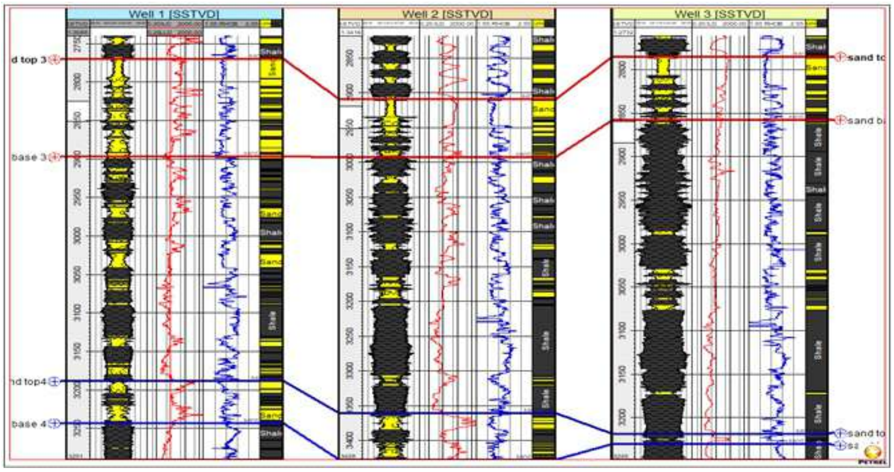

Figure 4b: Lithology and Well correlation across the wells for sand 3 and 4

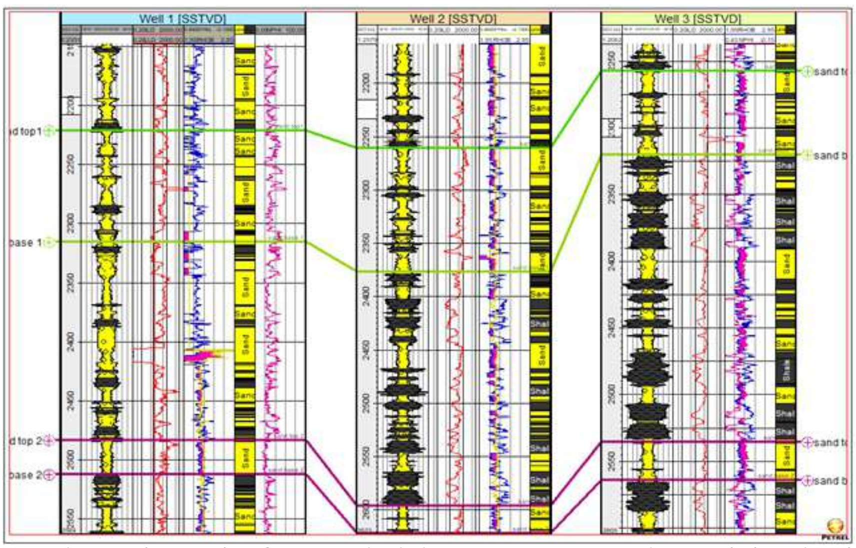

Figure 5a: Reservoir sand-1 and 2 from resistivity, neutron porosity and density logs

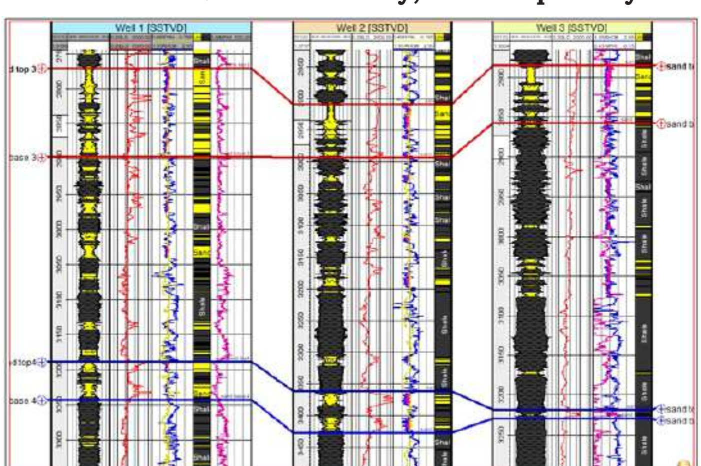

Figure 5a: Reservoir sand-3 and 4 from resistivity, neutron porosity and density logs

analysis of the study area reveals three types of motif pattern across the three wells, which are funnel, blocky (cyrindrical) and bow (symmetrical) shapes for the four identified reservoir sands. Figure 6 explains depositional environment of sediments in the study area. The motif pattern description for the funnel shape reveals a coarsening upward (progradational) with upward transition from shale to sand deposition. This is observed within sand-1 and 3 and is typical of marine environment or setting, while sand-2 shows blocky shape with evidence of low gamma ray related to fluvial channel sand or turbidite settings. Bow (symmetrical) trend was observed in reservoir sand-4, it is composed of finning and coarsening upward having the same thickness related to basinal setting due to waxing and waning of clastic sedimentation. The bow trend usually occurs during progradational and retrogradational processes. The stratigraphic analysis across the four reservoir sands revealed good reservoir quality rock in terms of permeable sands, thickness and volume of shale within the zone of interest in all the wells across "AIW" field Niger Delta.

Petrophysical Parameters Evaluation

Porosity, Percentage of shale, Net-to-gross (NTG), volume of shale, and permeability are the petrophysical parameters estimated for the reservoir sands as shown in Figure 7a, 7b and 7c. These parameters explain economics implication of the reservoir sands (sand-1, 2, 3 and 4) across the wells. Percentage of shale varied within the reservoir sand units from one well to another. Amongst the reservoir sand units, reservoir-2 along well_1, has the lowest shale percentage 0 %, while reservoir sand-4 has the highest percent 29.61% along well_2. Reservoir sand-3 and reservoir sand-4 show moderate porosity ranging from 0.1547 to 0.1953 values along the wells while reservoir sand-1 and reservoir sand-2 show good porosity between 0.2152-0.3227. The Net-to-gross reveals sand-1, sand-2 and sand-3 are good hydrocarbon prospective zones across the three wells in the study area. For sand-1, sand-2 and sand-3 NTG ratio ranges between 0.6790 and 0.9377, while sand-4 NTG ratio ranges between 0.2654 and 0.6574.

Thickness of reservoir bodies holding hydrocarbon with low percentage of shale and high NTG affirms the hydrocarbon in place is of economic value. Estimated petrophysical parameters of the reservoir sands is tabulated in Table 2a, 2b and 2c below.

The petrophysical analysis shows good reservoir prospects for hydrocarbon exploration (characterised with good reservoir porosity, permeability, low percentage of shale volume and high NTG ratio: sand-1, sand-2 and sand-3). Good reservoir seal capable of preventing the leakage of hydrocarbon accumulation out of the reservoir sands is observed.

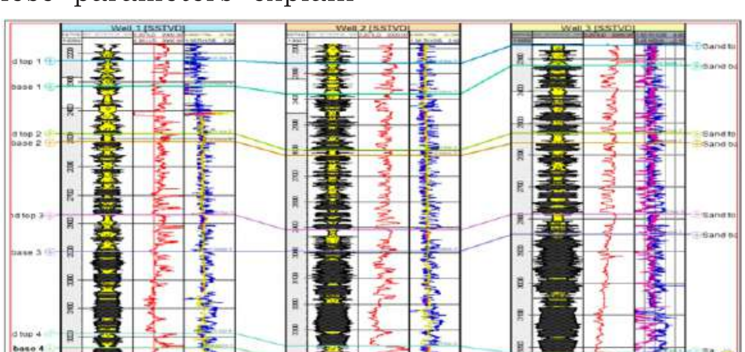

Figure 6: Stratigraphic analysis from gamma ray log.

Table 2a: Estimated Petrophysical Parameters for the Reservoir Sand units

Well_1	DPHI	Thickness of Sand (m)	Shale Percent	NTG
R1	0.3227	86.63	6.73	0.9377
R2	0.2209	27.20	0.00	0.8487
R3	0.1915	113.49	14.47	0.5293
R4	0.1614	41.35	24.91	0.2878

Table 2b: Estimated Petrophysical Parameters for the Reservoir Sand units

Well_2	DPHI	Thickness of Sand (m)	Shale Percent	NTG
R1	0.2573	103.94	13.04	0.8232
R2	0.2565	31.73	15.43	0.8741
R3	0.2047	62.84	26.94	0.6934
R4	0.2026	43.89	29.82	0.6574

Table 2c: Estimated Petrophysical Parameters for the Reservoir Sand units

Well_3	DPHI	Thickness of Sand (m)	Shale Percent	NTG
R1	0.2546	84.95	7.62	0.8342
R2	0.2152	65.53	24.52	0.7091
R3	0.1953	70.68	16.25	0.6790
R4	0.1547	15.12	22.53	0.2654

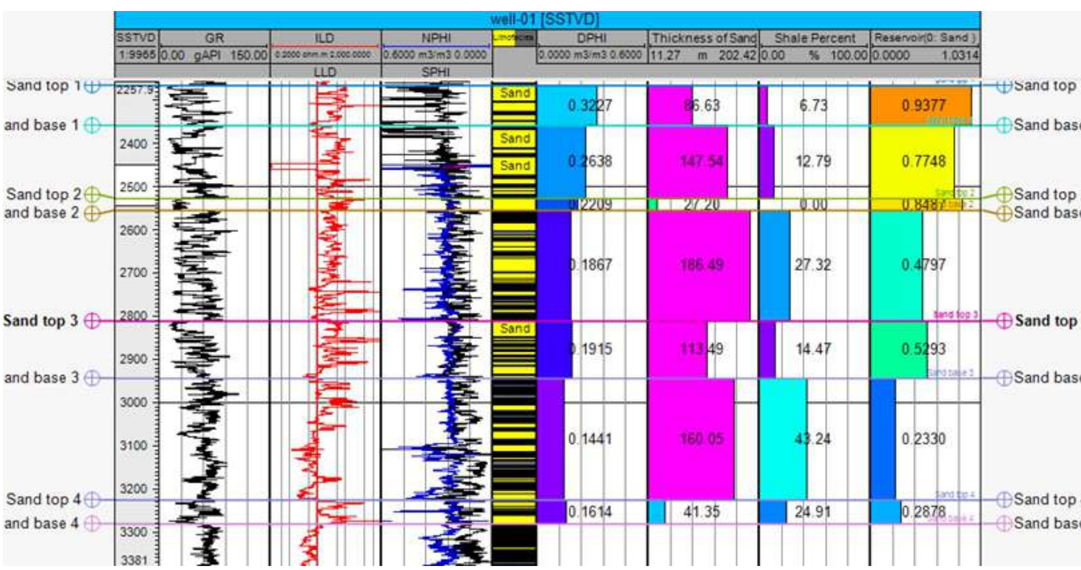

Figure 7a : Petrophysical parameters along well_1

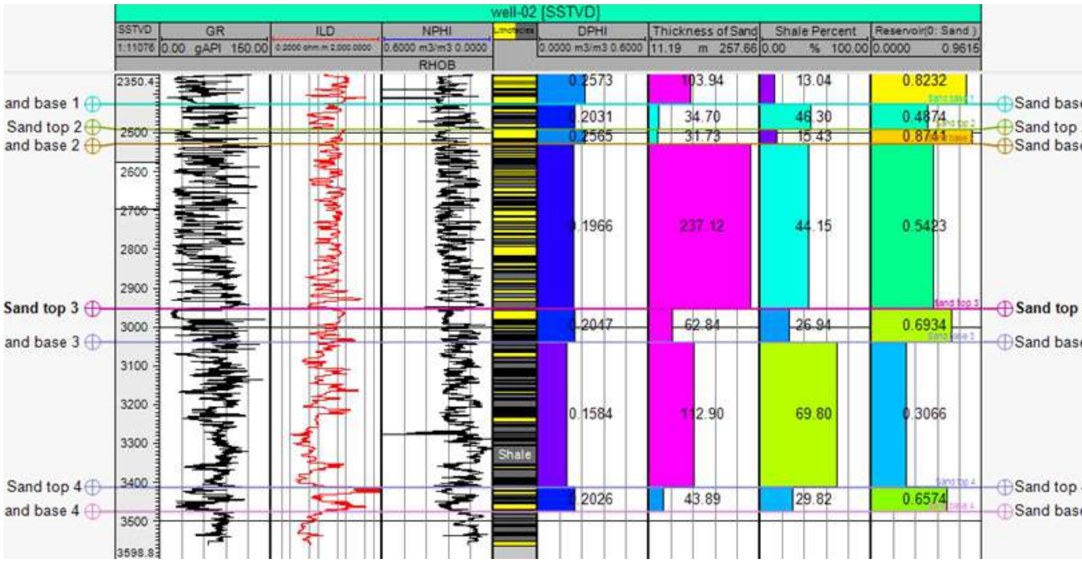

Figure 7b: Petrophysical parameters along well_2

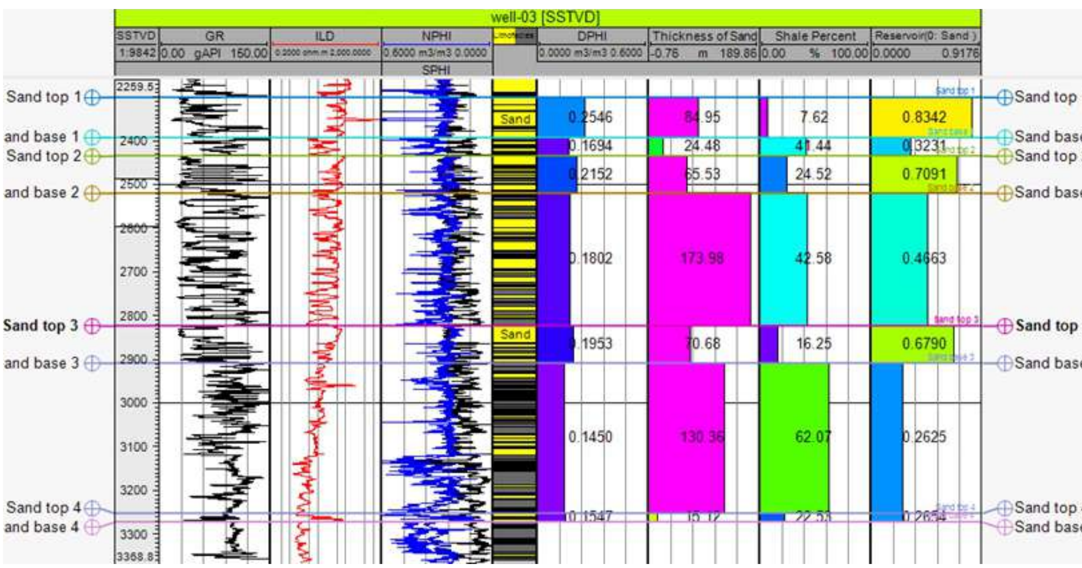

Figure 7c: Petrophysical parameters along well_3

Conclusions

In conclusion, four (4) hydrocarbon-bearing sand reservoirs were identified from the given well logs using gamma ray log signatures, based on the established shale cutoff line, and correlated across the three wells. Analysis revealed that Sand-4 has the highest shale content (29.82%), while Sand-2 of Well_1 has the lowest shale content (0%) across the wells. Furthermore, Sands 1, 2, and 3 were identified as good hydrocarbon pay zones based on all the petrophysical parameters obtained. It is recommended that structural and volumetric analyses be conducted on the 3D seismic data to determine the possible trapping mechanisms for hydrocarbon accumulation and to estimate the volume of hydrocarbons in place in the "AIW" Field, Niger Delta.

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