IOSR Journal of Applied Geology and Geophysics (IOSR-JAGG)
e-ISSN: 2321–0990, p-ISSN: 2321–0982.Volume 9, Issue 1 Ser. I (Jan. – Feb. 2021), PP 39-49
www.iosrjournals.org

Application of Well Log Analysisin Assessment Ofpetrophysical Parameters of the Alpha Oilfield in Niger Delta, Nigeria

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Abstract
This study was conducted to evaluate the petrophysical parameter of the "Alpha Field" in Niger Delta, Nigeria using well log data. Four wells, namely Well 01, Well 02, Well 03, and Well 04 were studied using a suite of logs comprising of gamma-ray, resistivity, sonic, caliper, density, and neutron logs from the wells in the study area. Schlumberger's Petrel 2013 software was used to analyze the data. Quantitative properties including shale volume, porosity, permeability, water saturation, and hydrocarbon saturation were carried out using the well logs. Intervals with low Gamma-Ray reading relative to the Shale Baseline are interpreted as sand units. Based on this, five sand units, labeled as Dove, Saturn, Jasper, Mars, and Neptune were mapped between the depth of 5600ft and 7100ft across the four wells. The sand units with relatively high resistivity readings are interpreted as hydrocarbon-bearing units, whereas sand units corresponding to relatively low resistivity readings are interpreted as water-bearing sand units. The delineated zones of interest have average reservoir parameters results such as an average net – gross of between 0.79 – 0.93, average effective porosity in the range of 0.28 to 0.32, hydrocarbon saturation (Sh), ranging from 0.52 to 0.80, and other reservoir parameters from petrophysical analysis which are favorable indicators for commercial hydrocarbon accumulation.

Keywords: *Alpha Oilfield, Hydrocarbon saturation, Niger Delta, Petrophysical Parameters, and Well Log Analysis.*

Date of Submission: 15-01-2021 Date of Acceptance: 31-01-2021

I. Introduction

A well log is a graphical presentation of a Physico-chemical characteristic of the geologic formations measured in a borehole as a function of depth [1]. Well logs measure properties of the surrounding media within a certain distance of the borehole. This distance may vary from a few inches to several feet depending upon the type of log. Well log data assist in the identification of permeable zones and productive zones for hydrocarbon. It distinguishes the interfaces of oil, gas, or water of a particular reservoir. The general purpose of well log analysis is to convert the raw log data into estimated quantities of oil, gas, and water in a formation [2].

Petrophysical log interpretation is one of the most useful and important tools to characterize reservoir properties [3]. One of the importance of petrophysical interpretation of well logs is to determine the volumetric fractions of the formation components (solid and fluid phases) by combining the measurements provided by several tools, such as well-log resistivity, neutron porosity, nuclear magnetic resonance, acoustic, density, fluid sampling, coring, and imaging [4,5]. The study of petrophysical involves the analysis of different parameters of reservoirs including porosity, lithology, and the volume of shale, water saturation, permeability, hydrocarbon saturation, hydrocarbon movability, and pore geometry by using appropriate well log data.

"Alpha Field" is located within the Niger Delta basin in Nigeria (Figure 1). The major demand for hydrocarbon products since the 20th century prompted intensified prospecting for oil and gas accumulation in reservoir rocks. This calls for an extensive study of the Niger Delta basin after a long while of non-productive search in the Cretaceous sediments of the Benue Trough [6]. Petroleum in the Niger Delta is produced from sandstones and unconsolidated sands predominantly in the Agbada Formation [7]. Recognized known reservoir rocks are of Eocene to Pliocene in age, and are often stacked, ranging in thickness from less than 15 meters to 10% having greater than 45 meters thickness. [8].

From the work of [9] on the "Reservoir characterization: Implication from petrophysical data of the "Paradise-Field" Niger Delta, Nigeria", it was discovered that the quality of the reservoirs in the Paradise -Field is moderate to the good after the evaluation while some of the reservoirs were excellent. The result of the research work further shows that the good structural and stratigraphic traps basinward, the offshore depot belt holds better prospects for the paradise field. It was noted that development in Agbada and Benin formations of the Niger Delta has limits in the deep-water portion.

The determination of some physical properties of reservoir rocks in the Niger delta according to [10]statethat, petrophysical properties are necessary to establish the nature of the reservoir and help for proper field development planning. The study shows that experimental work is one of the valued tools for making informed decisions on the development of a field in the petroleum industry and highlights the importance of integrating seismic with basic petrophysical properties in reservoir management.

Well log analysis was performed on four existing wells from the field and petrophysical parameters were obtained using appropriate software. The main aim of the research work is to carry out a detailed petrophysical evaluation of reservoirs using 3D seismic and well logs data to characterize sand and shale bodies in the reservoirs, porosity, permeability, net sand/shale, and water saturation.

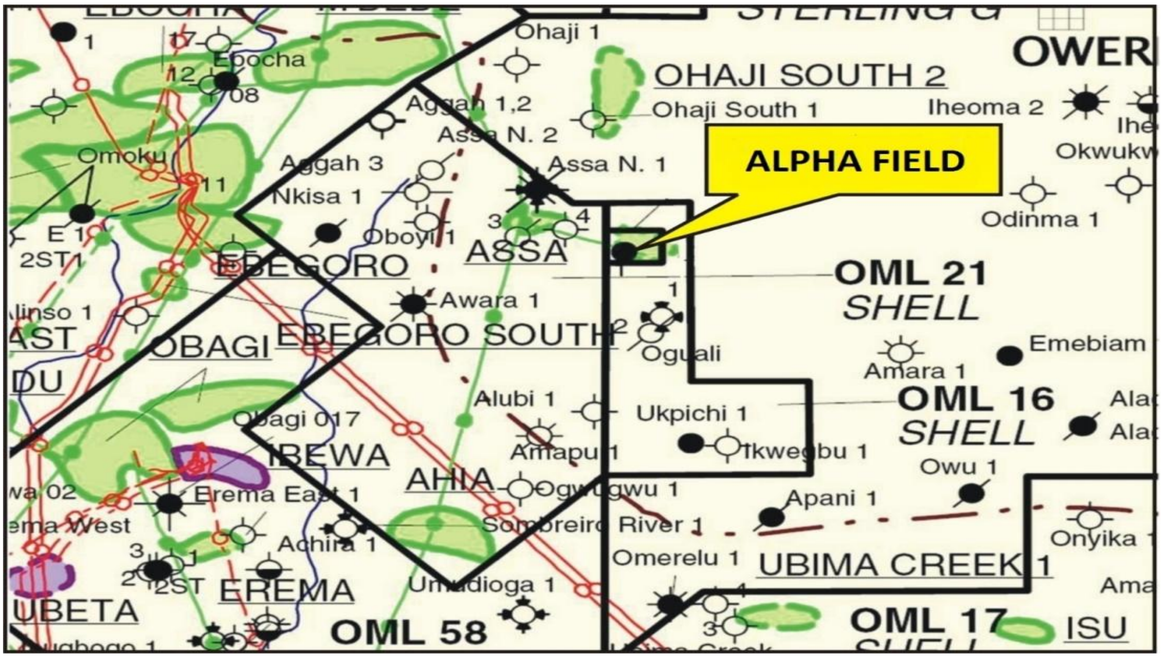

Figure 1 Location of the study area

II. The Stratigraphy of Niger Delta

The stratigraphy of the Niger Delta is divided into three diachronous units of Eocene to recent that form a major regressive cycle [6] (Figure2). The Benin formation is the uppermost unit, comprising continental and back swamp deposits up to 2500m (2.5km) thick. These are underlain by the Agbada formation of paralicfluvio-marine deposits organized into coarsening upward off lap cycles. The underlying Akata formation comprises up to 6500m of marine pro-Delta clays. Shales of the Akata formation are over pressured and have deformed in response to Delta pro-gradation.

2.1 Akata Formation

The Akata Formation at the base of the delta is of marine origin and it is composed of thick shale sequences (potential source rock), turbidite sand (potential reservoirs in deep water), and minor amounts of clay and silt. The formation is estimated to be up to 7,000 meters thick [6]. The Akata Formation is up to 5,000 m (16,400 ft) thick in the deep-water fold and thrust belts, because of the structural repetitions by thrust ramps and in the core of large detachment anticlines [11]. The Akata exhibits low P-wave seismic velocities (about 6,000 ft/s; 2,000 m/s) that may reflect regional fluid overpressures [11]. During the development of the delta, turbidity currents likely deposited deep-sea fan sands within the upper Akata Formation [12]. Except on basin flanks, no wells have fully penetrated this sequence. The Marine shale sequence is typically over pressured. In seismic sections, the Akata Formation is generally devoid of internal reflections, except for a strong, high-amplitude reflection that is locally present in the middle of the formation. To define detachment levels, these mid-Akata reflections serve as an important structural marker.

2.2 Agbada Formation

The formation underlies the Benin formation and it forms the hydrocarbon-prospective sequence in the Niger delta. The Agbada Formation age varies from Eocene to Recent. The maximum thickness of the formation is 3,940m (12,000ft) at the central part of the delta and thins northward and toward the northwestern and eastern flanks of the delta. The sandstones and shales of the Agbada Formation are cyclic sequences of marine and fluvial deposits [13]. Similarly, the sandstones are medium to fine-grained, fairly clean, and locally calcareous, shelly, and glauconitic. They consist mainly of quartz and potash feldspar with small amounts of plagioclase, kaolinite, and illite. shales contain microfauna that is best developed at the base of each shale unit. The depth of these fossil assemblages ranges from littoral-estuarine to marsh types of fauna developed at a water depth of approximately 100 m. In Niger Delta, petroleum occurs throughout the Agbada Formation [14].

2.3 Benin formation.

This is the shallowest part of the sequence. The age of the formation varies from Oligocene (or earlier) to Recent It occurs throughout the entire onshore and part of the offshore in the Niger-Delta and no commercial hydrocarbon has been found within it. It was deposited in the alluvial or upper coastal plain environments following a southward shift of deltaic deposition into a new depo belt [15]. It consists predominantly of fresh water-bearing continental sands and gravels. The rocks of the Benin Formation attain a maximum thickness of 1,970m (6,000ft) in the Warri Degema area, which coincides with that of the Agbada Formation. The base of the Benin Formation was defined by the first marine foraminifera within the shales, as the formation is non-marine in origin [15].

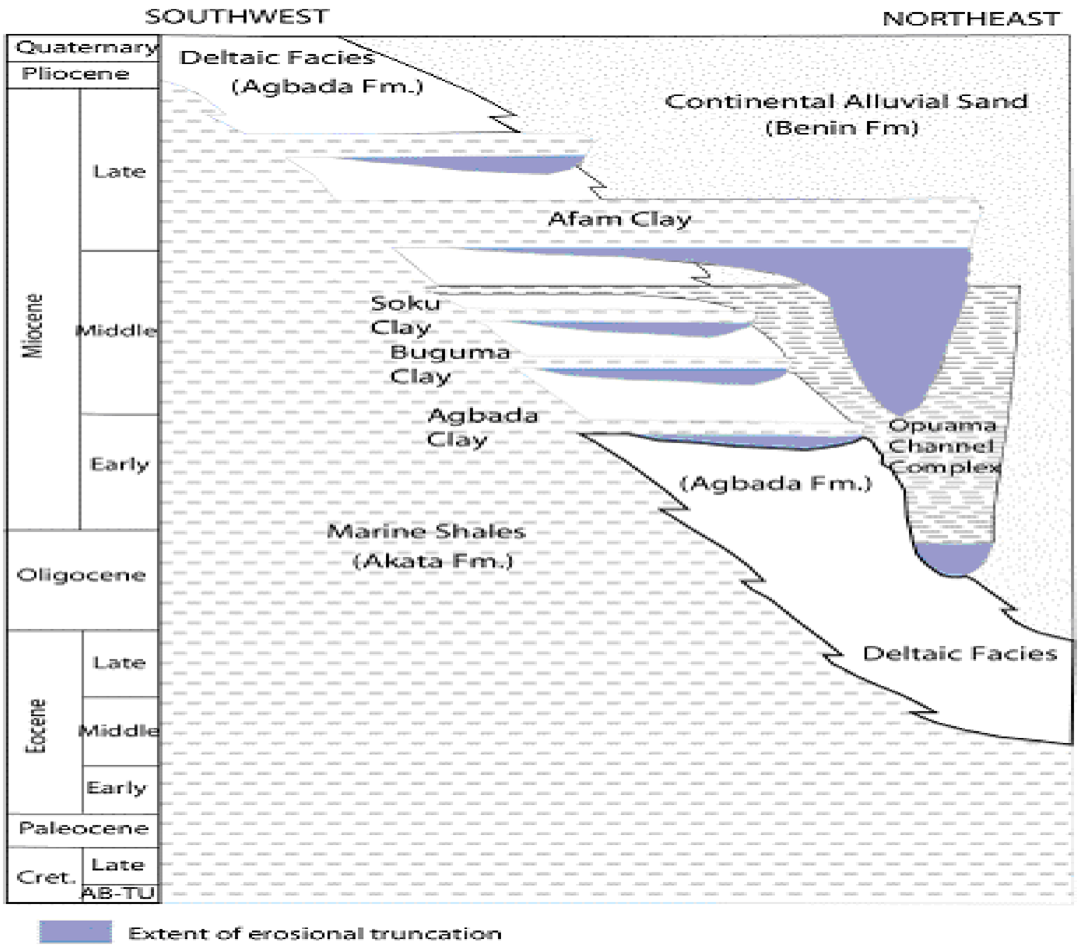

Figure 2 Stratigraphic Column showing the three formations of the Niger Delta[6]

III. Materials and Methods

A suite of logs comprising of gamma-ray, resistivity, sonic, caliper, density, and neutron logs from four wells in the study area was provided by Exploration and Production Company in the Niger Delta area of Nigeria. Table 1 below shows the log data availability in the field. In this study, the following are the log types used for the quantitative analysis: gamma-ray, resistivity, density, and neutron logs. The SP and caliper logs were mainly used for lithology identification and hole washout detection respectively. Three of the wells (Wells 02, 03, and 04) do not have density, and Neutron logs acquired across the reservoir sand. The data was processed with the aids of Schlumberger's Petrel 2013 software.

Table 1: Summary of well data available

WELLS	GR	CALI	SP	RES	DEN	SONIC	NEUT	DEV. SURVEY	CHECK SHOT
WELL 1	X	0	0	X	X	X	X	X	X
WELL 2	X	0	X	X	0	X	0	X	0
WELL 3	X	0	0	X	0	0	0	X	0
WELL 4	X	0	X	X	0	0	0	X	0

AVAILABLE	NOT AVAILABLE
X	0

KEY -
GR: Gamma Ray
CALI: Calliper

SP: Spontaneous Potential
RES: Resistivity
DEN: Density
NEUT: Neutron
DEV. SURVEY: Deviation Survey

3.1 Gross and Net Sand Reservoir Thickness

Gross reservoir thickness interval is the interval covering shale and sand within a reservoir. The net thickness of sand is the interval covering only sand within a reservoir. The gross reservoir thickness is determined by knowing an interval covering both sand and shale within the reservoir studied using gamma-ray log [2]. To determine net sand thickness, we subtract the interval covering the shale from gross reservoir thickness. The following formulae were used to generate rock properties using well log data.

GST (Gross sand thickness) = Base of sand – Top of sand (i)
NST (Net sand thickness) = GST – Shale (ii)

3.2 Shale Volume (V_{sh})Determination

The volumes of Shale were evaluated using both GR and Neutron/ Density curves. Other shale volumes were calculated using GR curves by applying the Larionov Tertiary Rock method since both results were close or similar. GR curves were used in the evaluation because all 4 wells have GR curves; only well 01 has Neutron/ Density pair. Larionov method was employed because it goes well with Tertiary Niger Delta rocks widely used in the industry. The applied equations are shown belowfor Tertiary rocks:

$$V_{shale} = 0.083(2^{3.7*I_{GR}} - 1) \qquad \text{(iii)}$$

$$GR_{index} = \frac{GR - GR_{matrix}}{GR_{shale} - GR_{matrix}} \qquad \text{(iv)}$$

Where GR is the GR log readingin the zone of interest;
GR_{matrix} is the GR log reading in 100% matrix rock;
GR_{shale} is the GR log reading in 100% shale
GR_{index} is the Gamma Ray index
V_{shale} is the Volume of Shale
Reservoir delineation (reservoir vs. non-reservoir) was done by applying cut-offs of 50% on evaluated volume of shale (Vsh).

3.3 Porosity Determination

The Total porosity was determined from density logs using a *rho-matrix* value of 2.65 gm/cc. The effective porosity was then deduced by introducing shale volume into the equation. Equations below were used in the computation. Porosity ranges between the average of 29% and 33% in the wells across the reservoirs.

RHG equation for porosity

ϕ= (5/8 * (Δtlog-Δtma)/Δtlog)*0.9 (vi)

$$\phi_D = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_f} - V_{sh}\frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_f} \qquad \text{(vii)}$$

Where Pma is the Matrix Bulk density,

ρ_f = fluid density (density log reading in 100% water)

ρ_b = Bulk density (density log reading in the zone of interest)

Vsh= Volume of shale,

ΦD = Effective porosity in the zone of interest.

Φ_s = sonic derived porosity

Δt(ma) = interval transit time in the matrix

Δt(log) = interval transit time in the formation of interest

Δt(fl) = interval transit time in the fluid of the formation.

3.4 Permeability

Permeability is the ability of a rock to transmit fluids; it is related to porosity but is not directly dependent on it. The ability of a rock to transmit a single fluid when it is completely saturated (100%) with that fluid is called absolute permeability. The effective permeability is the ability of the rock to transmit one fluid in the presence of another fluid when the two fluids are immiscible. The effective permeability is given by:

$K_e = \left\{\mathbf{250} * \left(\frac{\phi^3}{\text{Swirr}}\right)\right\}$ (for oil reservoir) (viiia)

$K_e = \left\{79 * \left(\frac{\phi^3}{\text{Swirr}}\right)\right\}$ 2 (for gas reservoir) (viiib)

whereK_e = effective permeability in millidarcy

Φ = porosity

S_{wirr} = Irreducible water

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.

3.5 Formation Factor (F)

The resistivity of a clean water-bearing formation (containing no appreciable amount of clay and no hydrocarbon) is proportional to the resistivity of the brine with which it is fully saturated. The constant of proportionality is called the formation resistivity factor, F. For a non-shaly formation which is 100% saturated with a brine of resistivity (Rw), the formation factor is given by this general equation:

$$F = \frac{a}{\phi^m} \qquad \text{(ixa)}$$

For consolidated sand, the formation factor is given by:

$$F = \frac{0.81}{\phi^2} \qquad \text{(ixb)}$$

For unconsolidated sand, the formation factor is given by:

$$F = \frac{0.62}{\phi^{2..15}} \qquad \text{(ixc)}$$

where F= formation factor

Φ= Porosity
a= Tortuosity factor
m= Cementation factor

3.6 Water Saturation and Hydrocarbon Saturation Determination

Water saturation would be estimated from Archie's equation. To estimate water saturation from this method, Formation water resistivity (Rw) and True formation resistivity (Rt) need to be estimated. Rw is usually estimated in a clean water-bearing interval (water leg) while Rt is estimated in hydrocarbon-bearing zones using deep resistivity reading.

According to [16]:

$$R_w = \left[\frac{(\emptyset^m * R_0)}{(a)}\right]^{\frac{1}{2}} \qquad \text{(x)}$$

$$S_w = \left[\frac{(a * R_w)}{(R_t * \emptyset^m)}\right]^{\frac{1}{2}} \qquad \text{(xi)}$$

Hydrocarbon Saturation, Sh is the percentage of pore volume in a formation occupied by hydrocarbons. It can be determined by subtracting the value obtained for water saturation from 100%.

$$S_h = 1 - S_w \qquad \text{(xii)}$$

Where:

S_w= Water saturation
S_h= Hydrocarbon saturation
R_t = True formation resistivity (that is, deep induction)
R_w= Resistivity of formation water at formation
$\emptyset$ = Porosity
n = Saturation exponent, m = Cementation factor, a = Tortuosity factor

3.7 Shale and Sand Analysis

The presence of shale or clay minerals in a reservoir can cause erroneous values for water saturation and porosity derived from logs. Shale presence gives a higher water saturation value than the actual water saturation; hence a hydrocarbon-bearing zone is seen as a water-bearing zone. This implies that essentially, all measurements are affected in some way by the presence of shale (clay minerals). The most significant effect of shale in a formation is to reduce the resistivity contrast between oil or gas and water [17]. The net result is that if enough shale is present in a reservoir, it may be very difficult to determine if a zone is productive. [17]proposed that for shale to significantly affect log-derived water saturations, the content of shale must be greater than 15%. In the shaly sand analysis, the first step is to determine the volume of shale and once the shale volume is determined, the porosity logs can be corrected for shale effects:

Sonic log[18]:

$$\Phi_{se} = \left[\frac{\Delta_{tlog} - \Delta_{tma}}{\Delta_{tfl} - \Delta_{tma}} * \frac{100}{\Delta_{tsh}}\right] - V_{shale}\left[\frac{\Delta_{tsh} - \Delta_{tma}}{\Delta_{tfl} - \Delta_{tma}}\right] \qquad \text{(xiii)}$$

or (Dewan, 1983):

$$\Phi_{se} = \Phi_s - (V_{shale} * \Phi s_{sh}) \qquad \text{(xiv)}$$

where :

Φ_{se}= effective (shale corrected) sonic porosity
Φ_s = sonic porosity
Φs_{sh}= sonic porosity in a nearby shale
V_{shale} = shale volume
Δt_{log} = interval transit time of the formation (from the sonic log)
Δt_{ma} = matrix interval transit time
Δt_{fl} = fluid interval transit time
Δt_{sh} = interval transit time in a nearby shale.

The neutron and density logs:

$$\Phi_{Ne} = \Phi_N - \Phi_{Nshale} * 0.03 * V_{shale} \qquad \text{(xv)}$$

$$\Phi_{De} = \Phi_D - \Phi_{Dshale} * 0.13 * Vshale \qquad \text{(xvi)}$$

or (Dewan, 1983) :

$$\Phi_{Ne} = \Phi_N - V_{shale} * \Phi_{Nshale} \qquad \text{(xvii)}$$

$$\Phi_{De} = \Phi_D - V_{shale} * \Phi_{Dshale} \qquad \text{(xviii)}$$

where:

Φ_N = neutron porosity
Φ_{Ne}= shale corrected neutron porosity
Φ_D = density porosity
Φ_{De}= shale-corrected density porosity
Φ_{Nshale} = neutron porosity of a nearby shale
Φ_{Dshale} =density porosity of a nearby shale
V_{shale} = shale volume

The water saturation is then corrected after the shale corrected porosity has been determined. A technique to correct the water saturation for the shale effect is the automatic compensation technique. It uses the resistivity and sonic logs with Archie's equation. Since the presence of shale causes the porosity (Φs) to read too high and the resistivity (Rt) to read too low; one compensated for the other in the saturation equation:

$$S_w = 0.9\,\frac{\sqrt{Rw/Rt}}{\Phi s} \qquad \text{(xix)}$$

where:

S_w = water saturation
R_w = formation water resistivity
R_t = true resistivity of the formation
Φ_s = sonic porosity

3.8 Irreducible Water Saturation

This refers to water covalently bonded to the crystal lattice of the rock matrix and can't be removed. Water saturation Sw is the water that is bound to particle surfaces, and water that will not move because of capillary pressure. This is called irreducible water saturation, $S_{wirr.}$

If Sw = S_{wirr}, no water will be produced, it is important to know this while considering an economic evaluation of the well.

It is given by:

$$\mathbf{S_{wirr}} = \left(\frac{\mathbf{F}}{\mathbf{2000}}\right)^{\mathbf{1/2}} \qquad \text{(xx)}$$

The irreducible hydrocarbon saturation is given by:

$$S_{hirr} = 1 - S_{wirr} \qquad \text{(xxi)}$$

The effective hydrocarbon saturation is thus given by:

$$S_{he} = S_h - S_{hirr} \qquad \text{(xxii)}$$

where S_{hirr} = irreducible hydrocarbon saturation
S_{wirr} = Irreducible water saturation
F = Formation factor
S_{he} = effective hydrocarbon saturation

3.9 Reservoir Sums and Averages

Cut-off values were established for the following answer curves based on experience in the Niger Delta and the general data trend: volume of shale (*Vsh*), effective porosity (*Phie*), and water saturation (*Sw*). The cut-off values adopted are 0.5, 0.12 and 0.6 respectively. Based on these cut-off values, pay zones were delineated. Using the previously defined net reservoir counts, sums, and averages were determined. Based on log interpretation, curves were constructed. Hence, the curves were used as discriminators to calculate sums and averages for the reservoir.

IV. Results and Discussion

Hydrocarbons were initially delineated on well logs with the aid of gamma-ray and deep resistivity logs. The essence was to test for the availability of hydrocarbon at the location of each exploratory well. A correlation was done using the recognized and identified constrained chronostratigraphic surfaces typified by Maximum Flooding Surfaces (MFSs) to pick the top of the reservoir and Sequence Boundaries (SBs) to pick the base of the reservoir (Figure 3). Correlation helped to compartmentalize the stratigraphic section. The results of the interpreted well logs revealed that the hydrocarbon interval in the mapped areas occur between the depth ranges of 5644 – 5706 ft, 5850 – 5940 ft, 6209 – 6335 ft, 6440 – 6500 ft, and 6890 – 7020 ft for Dove, Saturn, Jasper, Mars and Neptune Reservoirs respectively.

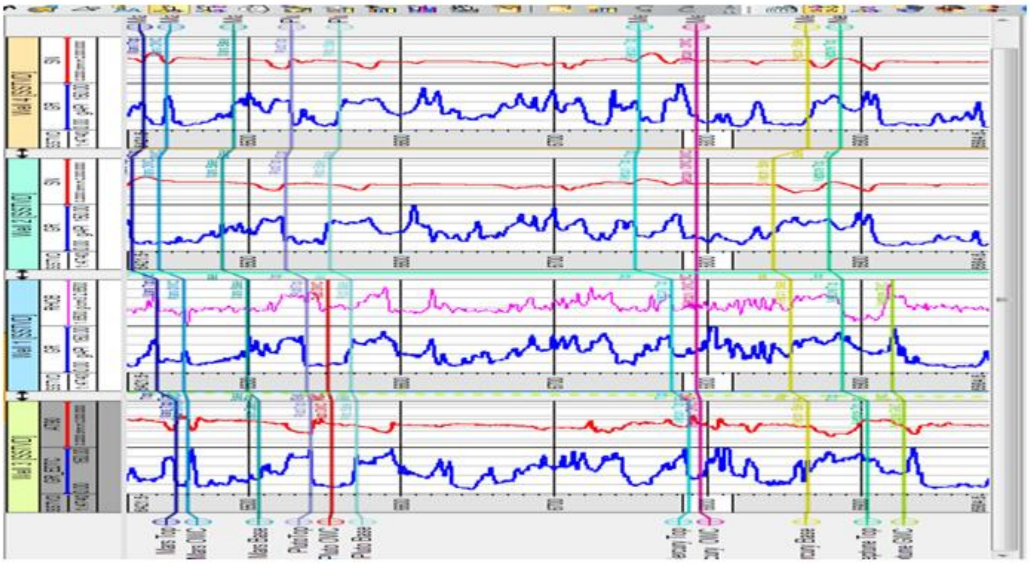

Figure 3 Well log section showing the reservoirs delineated across the wells.

By combining the Resistivity logs and Gamma-Ray logs, five hydrocarbons bearing sand units (Dove, Saturn, Jasper, Mars, and Neptune) were delineated across wells 01, 02, 03, and 04. Petrophysical parameters were computed to characterize the reservoir sand units. The Volume of Shale (Vshale), Water Saturation (Sw), Hydrocarbon Saturation (Sh), effective Porosity (PhiE), Irreducible Water Saturation (S_{wirr}), effective Permeability (Ke), and Net to Gross were computed for the five reservoir sand units as detection is most obvious on the Neutron and Density logs when they are both recorded on compatible scales and superimposed [19](Schlumberger,1989). The Litho-density and the Compensated Neutron logs available in well 01 indicate the hydrocarbon saturating all the hydrocarbon reservoirs within the well to be oil for Dove, Jasper and Mars while Saturn and Neptune are Gas reservoirs (Figure 4).

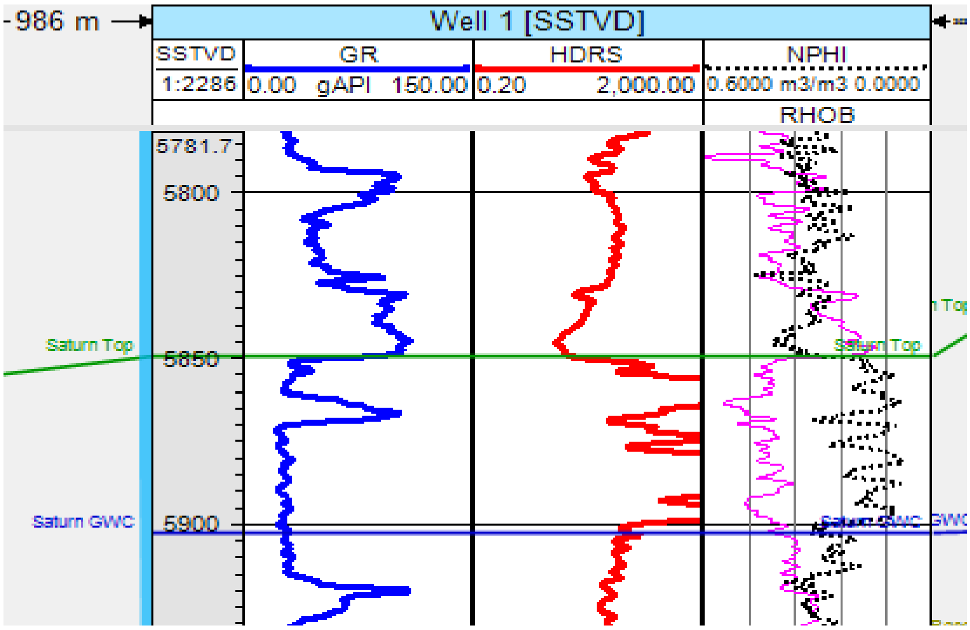

Figure 4 Log Section of Gas Hydrocarbon Bearing Sand. The GR and HDRS (Resistivity)

4.1 Volume of Shale (Vsh)

The average thicknesses for the reservoirs across the wells are 56, 90, 120, 60, and 120 ft. Dove gross sand occurs at 5644 – 5606 ft. The shale thickness within this interval was subtracted from the gross thickness to get our net sand thickness and from which we then estimated our Net – To Gross ratio (NTG) for the reservoir. The same process was used for the remaining reservoir sands. The average volume of shale is 15, 9.2, 9.1, 8.8, and 14.5 % for Dove, Saturn, Jasper, Mars, and Neptune reservoirs respectively, making the reservoirs clean sand units and shaly sand units. The average volume of shale of 14 and 15 % shows that the sand unit is a shaly sand unit since the volume of shale is between 10 – 35 % for shaly sand units and sand unit classification[17]. This was achieved using the Larinorv equation for the volume of shale for tertiary Niger Delta sands already discussed in chapter three.

Sand Gross Thickness = Base (ft) – Top (ft) (xxiii)
Net Thickness = Gross thickness – Shale thickness (xxiv)
NTG = Net Thickness/Gross Thickness (xxv

4.2 Porosity (φ)

The average effective porosity for all the five reservoirs across the four wells ranges between 26 % and 31.88 %. These estimated average effective porosity values fall within the 28 % to 32 % documented for the Agbada Formation [19]. This is the same for all the identified hydrocarbon reservoirs in the study area, except Dove and Saturn reservoirs in well 04 who's effective Porosities are 33.01 and 32.12 %. The porosity values obtained across the four wells within the five reservoirs show a good to excellent rating. Vertical and slight lateral variations were observed in the porosity values of the field. This was suggested to be as a result of sedimentation processes and the age of the sediments. The total porosity was compensated with the volume of shale to account for the effective porosity within the reservoir.

4.3 Permeability (K)

The core permeability values range between 700 and greater than 10,000 millidarcy (md) which is expected because reservoirs in the Niger Delta basin are generally unconsolidated and have moderate to high porosity and permeability values. The high permeability values obtained in all the five reservoirs across the four wells indicate an excellent value that permits the free flow of fluid within the reservoirs. Hence, the effective permeability of greater than 2,000 md obtained in most reservoirs across the wells is sufficiently high for hydrocarbon prospecting.

4.4 Formation Factor (F)

Formation factor is a constant of proportionality that is introduced into the relationship between the resistivity of a clean water-bearing formation containing no appreciable amount of clay and no hydrocarbon and resistivity of the brine with which it is fully saturated. This ranges on average from 6.7 to 9.2 within the reservoirs across the four wells.

4.5 Water Saturation and Hydrocarbon Saturation Determination

Water Saturation, Sw (Archie's equation) was estimated using the computed Rw and Φ; local correction factor or tortuosity factor (a) of 0.62 was assumed and cementation exponent (m) of 2.15. Rw ranges from 0.57 to 3.5 Ωm across the reservoirs.

Water saturation in Dove, Saturn, Jasper, Mars, and Neptune reservoirs is very good ranging from 14, 15, 27, 30, and 43% respectively. Consequently, the hydrocarbon saturation in Dove, Saturn, Jasper, Mars, and Neptune reservoirs also are very good ranging from 86, 85, 73, 70, and 47 % respectively. Hence, the hydrocarbon saturations indicate a high proportion of hydrocarbon to the quantity of water within the reservoir. Therefore, the five reservoirs delineated in the field are hydrocarbon saturated reservoirs. In this study, the hydrocarbon saturation values change slightly in the E-W direction and decrease down the depth; depicting that at greater depth hydrocarbon saturations declines.

Table 2 – 5 shows the summary of results from log analysis of the four wells.

Table 2: Summary of Results from Log Analysis in Well 1

SAND	TOP (ft)	BASE (ft)	GROSS (ft)	SHALE THICK NESS (ft)	HWC (ft)	NET THICKNESS (ft)	PAY THICKNESS (ft)
DOVE	5644.37	5706.66	62.29	7.35	5680.73	54.94	36.36
SATURN	5849.63	5939.52	89.89	14.5	5902	75.39	52.37
JASPER	6209.34	6335.54	126.2	20.25	6245.52	105.95	36.18
MARS	6440.47	6499.53	59.06	7.25	6458.28	51.81	17.81
NEPTUNE	6887.47	7016.45	128.98	9.36	6925.95	119.62	38.48

SAND	NTG	Vshale	POROSITY	Sw	Sh	F	Swirr	K
DOVE	0.882004	0.1149	0.3012	0.1407	0.8593	8.181888	0.064	11407
SATURN	0.838692	0.0958	0.3118	0.1583	0.8417	7.595529	0.0616	1510
JASPER	0.83954	0.0909	0.2866	0.2791	0.7209	9.104328	0.0675	7608.9
MARS	0.877243	0.0843	0.3116	0.359	0.641	7.606015	0.0617	15043
NEPTUNE	0.927431	0.111	0.2842	0.5217	0.4783	9.270431	0.0681	709.46

Table 3: Summary of Results from Log Analysis in Well 2

SAND	TOP (ft)	BASE (ft)	GROSS (ft)	SHALE THICKNESS (ft)	HWC (ft)	NET THICKNESS (ft)	PAY THICKNESS (ft)
DOVE	5648.44	5703.07	54.63	8.57	5680.98	46.06	32.54
SATURN	5836.99	5933.55	96.56	10.1	5901.92	86.46	64.93
JASPER	6185.56	6308.91	123.35	25.14	6225.31	98.21	39.75
MARS	6423.28	6482.53	59.25	5.24	6441.13	54.01	17.85
NEPTUNE	6879.22	6999.56	120.34	10.42	6928.22	109.92	49

SAND	NTG	Vshale	POROSITY	Sw	Sh	F	Swirr	K
DOVE	0.843126	0.1504	0.3003	0.2132	0.7868	8.234699	0.0642	11133
SATURN	0.895402	0.0899	0.3188	0.223	0.777	7.24148	0.0602	1809.5
JASPER	0.79619	0.1124	0.3001	0.2769	0.7231	8.246503	0.0642	11072
MARS	0.911561	0.0963	0.3101	0.3016	0.6984	7.685337	0.062	14463
NEPTUNE	0.913412	0.1443	0.2879	0.4261	0.5739	9.01617	0.0671	788.34

Table 4: Summary of Results from Log Analysis in Well 3

SAND	TOP (ft)	BASE (ft)	GROSS (ft)	SHALE THICKNESS (ft)	HWC (ft)	NET THICKNESS (ft)	PAY THICKNESS (ft)
DOVE	5659.26	5708.72	49.46	9.3	5681.93	40.16	22.67
SATURN	5856.06	5948.28	92.22	10.14	5902.43	82.08	46.37
JASPER	6217.08	6336.35	119.27	21.22	6246.06	98.05	28.98
MARS	6453.16	6507.26	54.1	7.36	6460.38	46.74	7.22
NEPTUNE	6904.57	7031.21	126.64	6.86	6928.48	119.78	23.91

SAND	NTG	Vshale	POROSITY	Sw	Sh	F	Swirr	K
DOVE	0.811969	0.1336	0.3111	0.1443	0.8557	7.632322	0.061775	14847.5
SATURN	0.890046	0.1011	0.3101	0.1527	0.8473	7.685337	0.061989	1444.215
JASPER	0.822084	0.0982	0.3048	0.3124	0.6876	7.975529	0.063149	12567.25
MARS	0.863956	0.1004	0.3113	0.3462	0.6538	7.621783	0.061732	14925.47
NEPTUNE	0.945831	0.1126	0.3014	0.4717	0.5283	8.170219	0.063915	1145.275

Table 5: Summary of Results from Log Analysis in Well 4

SAND	TOP (ft)	BASE (ft)	GROS (ft)	SHALE :KNESS (ft)	HWC (ft)	NET KNESS (ft)	PAY :KNESS (ft)
DOVE	5644.47	5707.69	63.22	6.5	5679.87	56.72	35.4
SATURN	5846.27	5941.58	95.31	15.17	5900.08	80.14	53.81
JASPER	6197.06	6318.13	121.07	18.56	6220.3	102.51	23.24
MARS	6431.53	6490.26	58.73	6.65	6446.47	52.08	14.94
NEPTUNE	6886.43	6998.88	112.45	9.69	6926.34	102.76	39.91

SAND	NTG	Vshale	POROSITY	Sw	Sh	F	Swirr	K
DOVE	0.897184	0.2401	0.3301	0.2618	0.7382	6.718987	0.057961	24070.1
SATURN	0.840835	0.1103	0.3212	0.2526	0.7474	7.125647	0.059689	1923.59
JASPER	0.8467	0.1413	0.3042	0.2736	0.7264	8.009389	0.063283	12367.0
MARS	0.88677	0.0984	0.2944	0.3329	0.6671	8.593605	0.06555	9470.25
NEPTUN	0.913828	0.2622	0.3174	0.4987	0.5013	7.310327	0.060458	1745.77

Where ;
V_{shale}= Volume of Shale (fraction)
S_w= Water Saturation (fraction)
NTG = Net to Gross Ratio (fraction)
S_h= Hydrocarbon Saturation (fraction)
S_{wirr} = Irreducible Water Saturation (fraction)
PhiE = Effective Porosity ((fraction))
K_e = Effective Permeability (Millidarcy)
F = Formation Factor

V. Conclusion

The log analysis performed in this study shows that the reservoir sand units of the ‘ALPHA’ field contain significant accumulations of hydrocarbon. The analysis shows that each of the sand units extends through the field, varies in thickness with some units occurring at a greater depth than their adjacent units which may be evidence of faulting. It was observed that the shale layers increases with depth along with a corresponding decrease in sand layers. From the analysis, particularly the resistivity log, all the five delineated reservoirs were identified as hydrocarbon-bearing units across the four wells i.e. Well 01 to Well 04. These delineated zones of interest, which are five in number, have average reservoir parameters results such as an average net – gross of between 0.79 – 0.93, average effective porosity in the range of 0.28 to 0.32, hydrocarbon saturation (Sh), ranging from 0.52 to 0.80 and other reservoir parameters from petrophysical analysis which are favorable indicators for commercial hydrocarbon accumulation.

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Coker, J.O, et. al. “Application of Well Log Analysisin Assessment Ofpetrophysical Parameters of the Alpha Oilfield in Niger Delta, Nigeria.” *IOSR Journal of Applied Geology and Geophysics (IOSR-JAGG)*, 9(1), (2021): pp 39-49.