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Petrophysical Parameters Analysis and Reservoir Evaluation of 'ATINUK' Field, Offshore Niger Delta Basin

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ABSTRACT
A suite of geophysical wire-line logs from an oilfield in the Niger Delta have been examined and analyzed with the aim of evaluating the petrophysical properties and determining the reservoir correlation of the 'ATINUK' field. Gamma-ray logs, sonic logs, and resistivity logs were used for the correlation analysis of four wells. Three major sand lithologies (Sand A, Sand B, and Sand C) were correlated. For this study, we used Schlumberger PETREL software in combination with well logs to map three (3) reservoirs (A, B, and C), considering parameters such as porosity, permeability, water saturation, hydrocarbon saturation, and volume of shale. The reservoirs' petrophysical parameters revealed water saturation ranging from 0.063 to 0.090, 0.036 to 0.055, and 0.030 to 0.109, respectively; hydrocarbon saturation also ranges from 0.910 to 0.937 in reservoir A, 0.639 to 0.964 in reservoir B, and 0.891 to 0.970 in reservoir C. The reservoir's porosity and hydrocarbon pore volume values within the field proved to be quite productive, with porosity ranging from 0.44 – 0.60 in Reservoir A, 0.40 – 0.45 in Reservoir B, and 0.38 – 0.48 in Reservoir C. Reservoir A stands out among the wells due to its high porosity values, low water saturation, high hydrocarbon saturation, and hydrocarbon pore volume.

Keywords: Well Log, Reservoir, Porosity, Hydrocarbon saturation, Oilfield

INTRODUCTION
The demand for energy in the world has witnessed a sudden increase in developing regions. Therefore, this calls for greater exploration activity and the subsequent discovery of new accumulations to meet up with the demand. Petroleum is the world's major source of energy and a key factor in the continued development of the world's economy (Viorel, 2018; Valery *et al.*, 2020). It is essential to evaluate the petrophysical parameters of a reservoir because the quality of a reservoir depends on its ability to hold and transmit hydrocarbons as this quality is very essential for the economic evaluation of a reservoir (Omoja and Obiekezie, 2021; Airen and Mujakperuo, 2023). The economic accumulation of oil and gas starts with the recognition of likely geological and seismic surveying, and the drilling of one or more wild-cat wells (Maju-Oyovwikowhe and Njoku, 2019; Adeola *et al.*, 2022). The majority of hydrocarbon produced in the Niger Delta is obtained from the accumulations of organic matter in the pores of porous and permeable rock bodies (Saadu and Nwankwo, 2018; Ugwu *et al.*, 2022).

Petrophysics is the study of rock properties and their interactions with fluid (gas, liquid hydrocarbon, and aqueous solutions) (Tiab and Donaldson, 2004). In petroleum studies, petrophysical properties are those properties of the reservoir which enable the reservoir rocks to store and transmit reservoir fluid, thus enabling quantitative determination of the *in-situ* hydrocarbons as well as the appropriate method of extraction of the fluid (Nayef, 2021). The productivity of wells in hydrocarbon-bearing reservoirs depends on petrophysical properties which include lithology, permeability, water saturation, and thickness of the reservoir. It is ultimately used to differentiate oil, gas, and water-bearing formations; estimate the porosity of the formations and approximate the quantity of hydrocarbon present in the formations (Senosy *et al.*, 2020).

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The determination of petrophysical parameters is a crucial process in the evaluation of hydrocarbon volume (Fagbemigun *et al.*, 2021). Petrophysical evaluation is concerned with the rock's proportion which determines the quality, quantity, and recoverability of hydrocarbon in a reservoir. A reservoir, therefore, has to be a formation that has the capacity to fluid and has the ability to release and flow it (Nayef, 2021). The Niger Delta Basin has been the focus of so many geological studies because of the petroleum potential of the area. Most of these studies range from sedimentological/ stratigraphic (Njoku, 2020), biostratigraphic (Adojoh *et al*., 2020), paleontological (Osokpor and Maju-Oyovwikowhe, 2021), and petrophysical analysis (Fagbemigun *et al.*, 2021) to petroleum geology. This study is aimed to evaluate the petroliferous zones petrophysical properties within the investigated area.

MATERIALS AND METHODS

Study Area

The Niger Delta covers an area of about 7500 km^2 extending between longitude 3° and 9° E and latitudes 4° and 6° N (Doust and Omatosola, 1990) (Figure 1). It is situated at the intersection of the Benue Trough and the South Atlantic Ocean where a triple junction developed during the separation of the continents of South America and Africa in late Jurassic (Obaje, 2009). The study area is located within the onshore continental margin, southwest Delta (Figure 2). It occupies an area enclosed by the geographical grids of latitude 5.3° and 5.4° N and longitude 6.0° and 6.2° E.

Geological Setting of Niger Delta

The Niger Delta basin is located on the continental margin of the Gulf of Guinea between latitudes 3˚ and 6˚ N and longitudes 5˚ and 8˚ E. The Niger Delta's morphology evolved from an early stage, covering the Paleocene to Early Eocene, to a later stage, starting in the Miocene. The topography of the basement had a significant impact on depositional patterns, and early coastlines were concave to the sea (Doust and Omatsola, 1990). The Delta was progressive along two main directions. The first paralleled the Niger River, where the rate of subsidence was surpassed by the supply of sediment. During the Eocene to Early Oligocene, the second, smaller than the first, began active basinward of the Cross River. As these distinct eastern and western depocenters combined, late stages of deposition started in the early to middle Miocene. The delta prograded sufficiently in the Late Miocene for shorelines to broadly concave into the basin. This rapid delta progradation generated underlying unstable shales through accelerated loading. These shales grew into diapiric walls, deforming overlying strata (Doust and Omatsola, 1990). Local uplift was caused by the resulting complex deformation structures, which led to major erosion events into the leading progradational edge of the Niger Delta. During sea level low stands, many deep canyons, now clay dominated, cut into the shelf were analyzed to have developed majorly.

From Eocene to the present, the Niger Delta has prograded southwestward, forming depobelts that represent the most active portion of the delta at each stage of its development (Figure 3) (Doust and Omatsola 1990). It has an aerial extent of 75,000 km^2 and a total estimated area of 300,000 km^2, with a sediment thickness of over 10 km in the basin depocenters (Kaplan *et al.*, 1994). The Niger Delta is considered one of the most prolific hydrocarbon provinces in the world, and recent giant oil discoveries in the deep-water areas suggest that this region will remain a focus of exploration activities (Corredor *et al.*, 2005). This basin comprises three stratigraphic units of variable geologic characteristics (Figure 4) classified as top set beds, fore set and bottom set beds. The Akata Formation is the oldest of the units and composed mainly of marine shales which range in age from Eocene to Recent. The Agbada Formation overlies the Akata Formation and comprises mainly alternating deltaic sandstones with shale. Its age ranges from Eocene to Recent. The Benin Formation is the youngest in the lithostratigraphic succession, and comprises sandstone, grits, claystone and streaks of lignite. Its age ranges from Oligocene to Recent (Osokpor and Maju-Oyovwikowhe 2021).

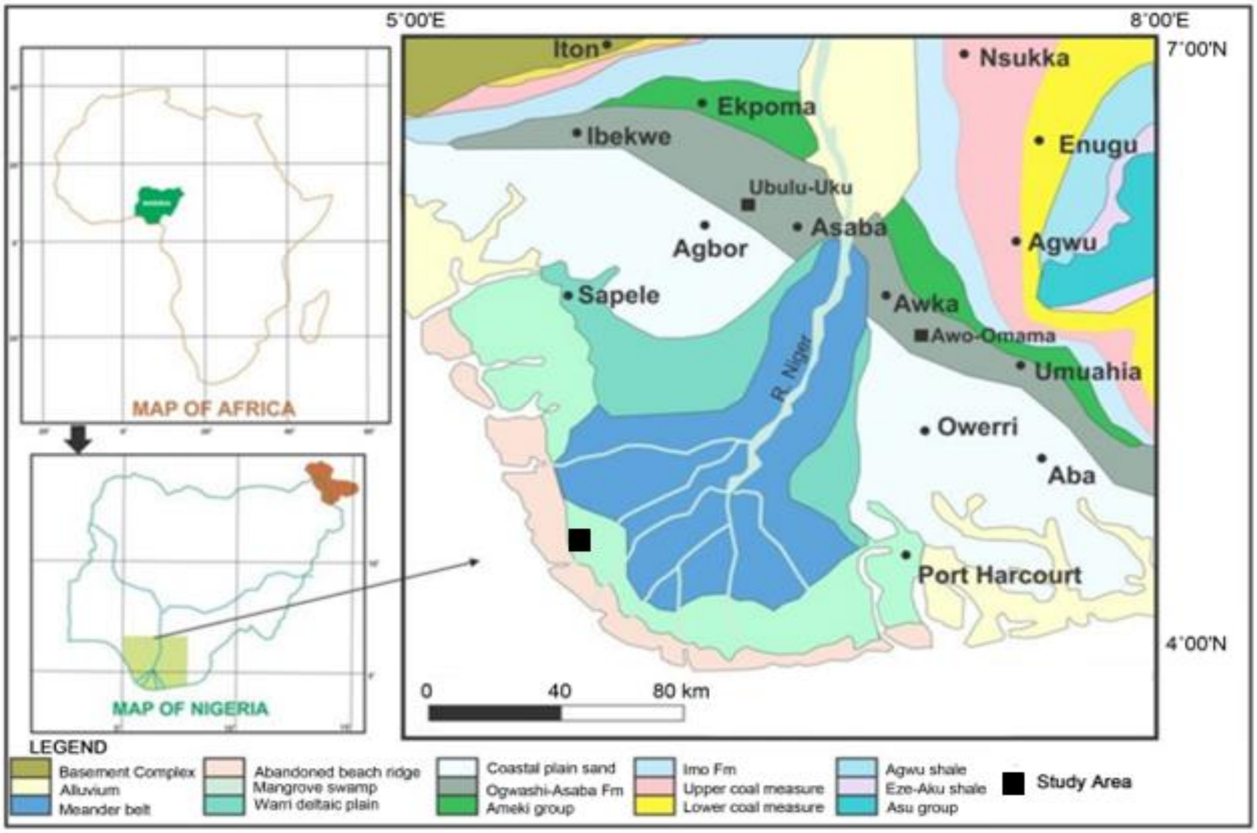

Figure 1: Map of Niger Delta and its surroundings (After Nwanjide, 2013).

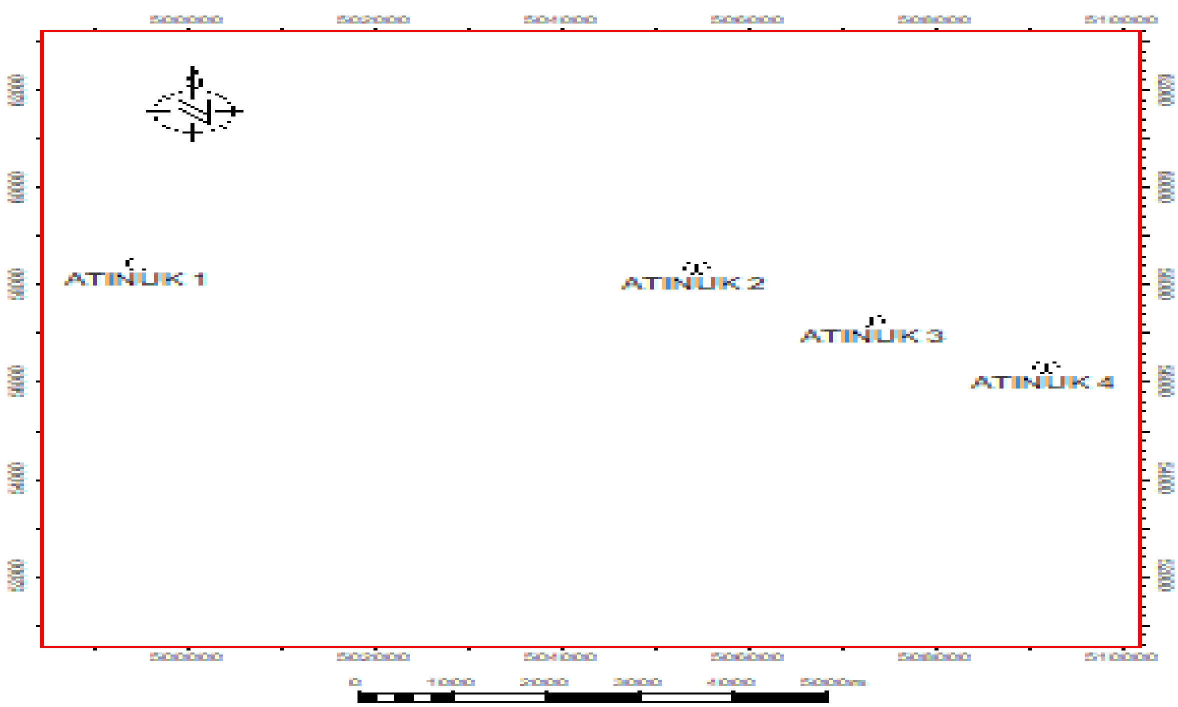

Figure 2: Base Map of the Study Area showing Well Distribution

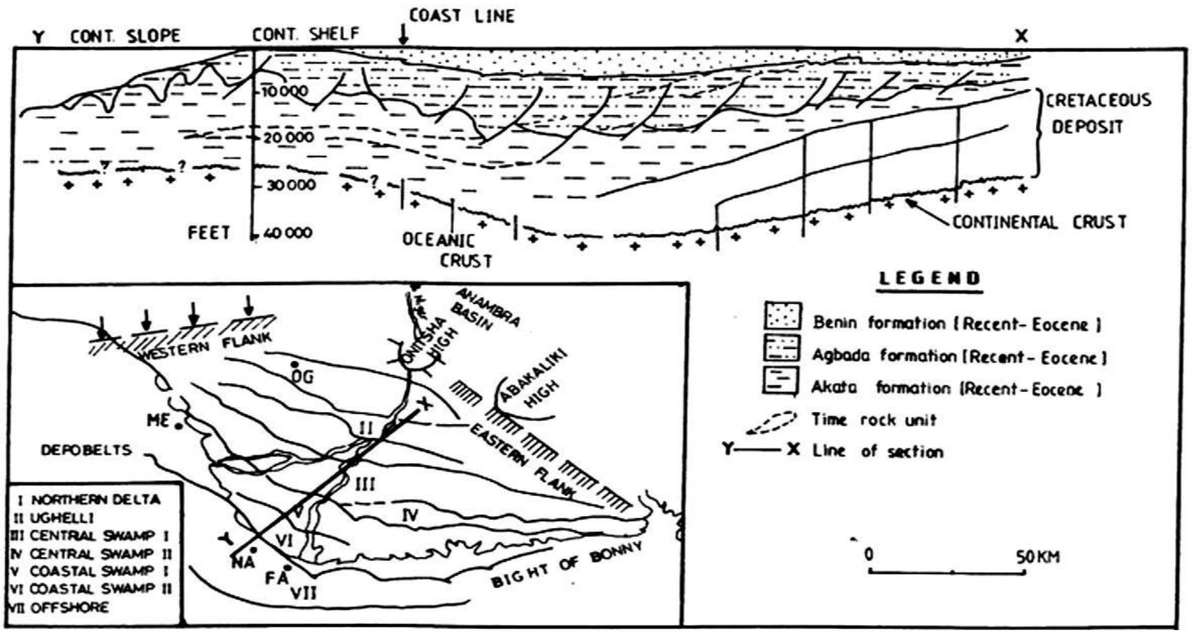

Figure 3: Niger Delta: Stratigraphy and Depobelts (After Ekweozor and Daukoru, 1984)

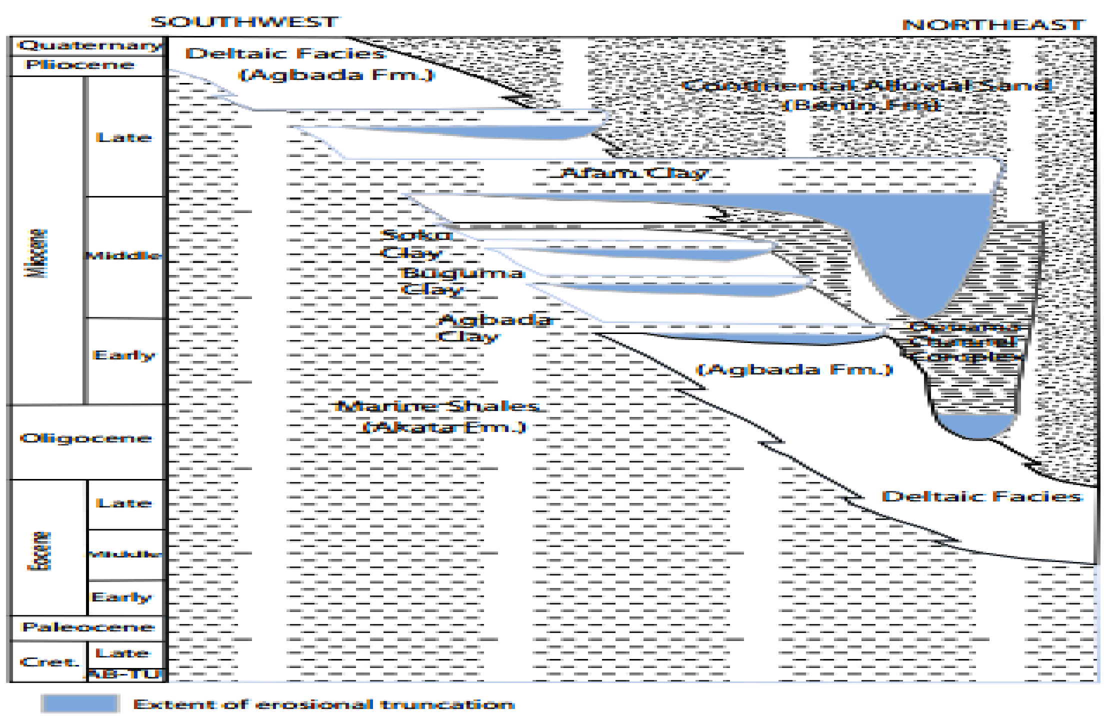

Figure 4: Stratigraphic column showing the three formations of the Niger Delta (After Short and Stauble, 1967)

Materials

Four (4) wells namely: ATINUK 1, 2, 3 and 4 and with corresponding depth ranges of 0 - 13142 ft (0 – 4006 m), 0 - 11540 ft (0 – 3517 m), 0 - 15000 ft (0 – 4572 m) and 0 - 12921 ft (0 – 3938 m) respectively were used for this research and each well has composite logs that include gamma ray, resistivity, sonic and density. The logs are in ASCII Format. Petrel™ (version 2014) with a dedicated work station was used for the interpretation of the well log data.

Identification of Lithology and Delineation of Petroliferous Zones

In identifying lithology and delineation of petroliferous zones, two well logs (gamma ray and resistivity) were used. Gamma ray log was used for lithology identification. The lithology was identified by defining the shale base line to be 65 API (American Petroleum Institute) which is a constant line in front of shale Formation. A deflection, even slight from the shale base line to the left indicates a sand Formation. The lithology is composed of alternation of sand and shale units. The wells were correlated across the entire 'Atinuk' field. Delineation of petroliferous zone (reservoirs) was carried out using combination of gamma ray and resistivity logs. When sand formation correlates with relatively high resistivity response, such is recognized as petroliferous zone (Asquith and Krygowski, 2004).

Determination of Reservoir Properties

This is a numerical estimation of reservoir properties, which involves calculation of reservoir parameters such as gross thickness, net thickness, volume of shale, porosity, water saturation and hydrocarbon saturation with standard equations.

Gross Thickness and Net Thickness

This was carried out with the combination of depth log and gamma ray log. Gross thickness is the total thickness of rock in the interval of interest or thickness of a zone between two geological horizons or markers (i.e. sand-shale). This is obtained by subtracting depth of reservoir top from depth of reservoir base and it is expressed as:

Gross Thickness = Reservoir Base – Reservoir Top (ft or m)

Net thickness is a thickness of reservoir sand within gross thickness

Volume of Shale

The data obtained from gamma ray log were used to achieve this. The volume of shale V_{sh} can be computed using equation (1) (Asquith and Krygowski, 2004):

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

Where,

GR_{max} is gamma ray maximum (shaly sand)

GR_{min} is gamma ray minimum from clean sand

GR_{log} is gamma ray log (shaly-sand)

Volume of Shale (V_{sh}) is expressed in equation (2) (Asquith and Krygowski, 2004):

$$v_{sh} = 0.083(2^{3.7I_{GR}} - 1)(2)$$

Where,

V_{sh} is the volume of shale and I_{GR} is the gamma ray index is expressed in equation (1).

Porosity

The porosity is a measure of the amount of internal space that is capable of holding fluid. It is expressed in percentage (%). The mathematical expression for the calculation of porosity using sonic log (eqn 3) (Asquith and Krygowski, 2004):

$$\phi_{sonic} = \left(\frac{\Delta t_{log} - \Delta t_{ma}}{\Delta t_f - \Delta t_{ma}}\right) \qquad (3)$$

Where,

ϕ_{sonic} = Sonic-derived porosity, Δt_{ma} = Interval transit time of matrix, Δt_{log} = Interval transit time of formation and Δt_f = Interval transit time of the fluid in the well bore (fresh mud = 189 µs/ft, salt mud = 185 µs/ft).

The sonic log only records matrix porosity rather than fracture or secondary porosity (Asquith and Krygowski, 2004).

Water Saturation

This was carried out for each reservoir using Archie (1942) formulas (equations (4 – 6) as follows:

$$F = \frac{R_o}{R_w} \qquad (4)$$

$$S_w^n = \frac{F.R_w}{R_t} \qquad (5)$$

$$S_{w^2} = \frac{R_o}{R_t} \qquad (6)$$

Where;

S_w = Water saturation, F = Formation Factor, R_w = Formation water resistivity at formation temperature, R_o = Resistivity of formation at 100% water saturation, R_t = True formation resistivity and n is the Saturation exponent. The value of n is usually 2 **(**Archie, 1942**)**

Hydrocarbon Saturation

Hydrocarbon saturation was calculated using the following equations (7a and 7b) (Asquith and Krygowski, 2004):

$$S_h = 1 - S_w \qquad (7a)$$

Or

$$S_h = S_w - 100\ (\%) \qquad (7b)$$

Where, S_h is hydrocarbon saturation.

Permeability

Permeability was estimated using equation (8) (Asquith and Krygowski (2004):

$$K^{1}/_{2} = \frac{100 \times \phi^{3}}{S_{\mathrm{wirr}}} \qquad (8)$$

where K = Permeability; ϕ = Porosity and $S_{w\ irr}$ = Irreducible water saturation expressed as in equation 9:

$$S\_(w\ irr) = \sqrt{(F/2000)} \qquad (9)$$

Where F, the formation factor is obtained from: $F = \frac{a}{\phi^{m}}$, where a and m are constants and ϕ is formation porosity.

RESULTS AND DISCUSSION

Sand Analysis and Correlation

Sand A: The results in Tables 1 and 2 show that at Atinuk 1, the sand A is located between depths 7733.05 – 8639.20 ft, Atinuk 2 between 7415.16 – 7785.65 ft, Atinuk 3 between 7526.92 – 8500.48 ft and Atinuk 4 between 7509.53 – 8444.65 ft. Sand A is thickest in Atinuk 3 (Figure 5).

Sand B: At Atinuk 1, sand B is located between depths 9602.98 – 10640.37 ft, Atinuk 2 between 8181.64 – 8938.74 ft, Atinuk 3 between 10503.57 – 11332.29 ft and Atinuk 4 between 9608.93 – 9881.61 ft. Sand B is thickest in Atinuk 1 (Figure 6).

Sand C: At Atinuk 1, sand C is located between depths 11373.69 – 12800.69 ft, Atinuk 2 between 9648.47 – 10333.28 ft, Atinuk 3 between 12107.19 – 13604.92 ft and Atinuk 4 between 11539.45 – 12281.18 ft. Sand C is thickest in Atinuk 3 (Figure 7).

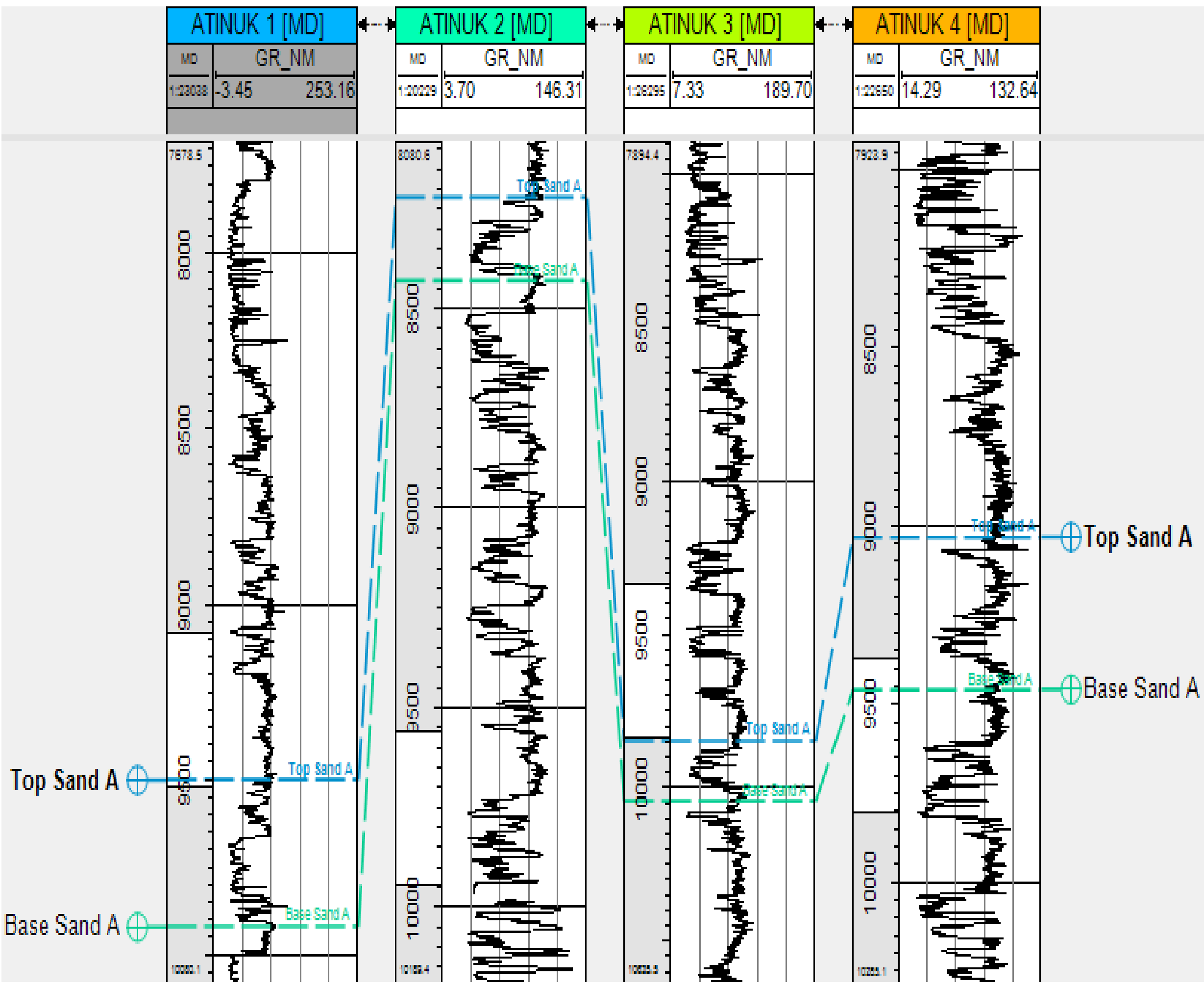

Figure 5: Gamma Ray Log of Sand A

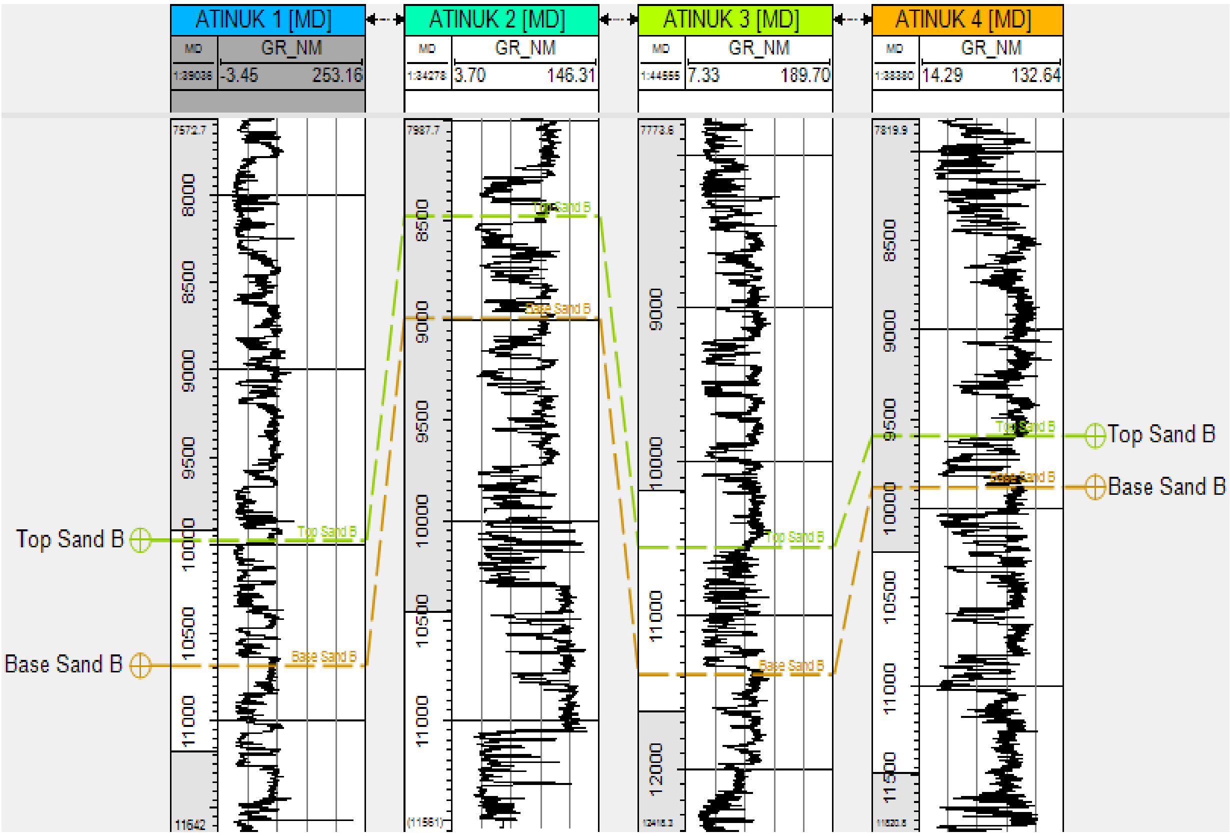

Figure 6: Gamma Ray Log of Sand B

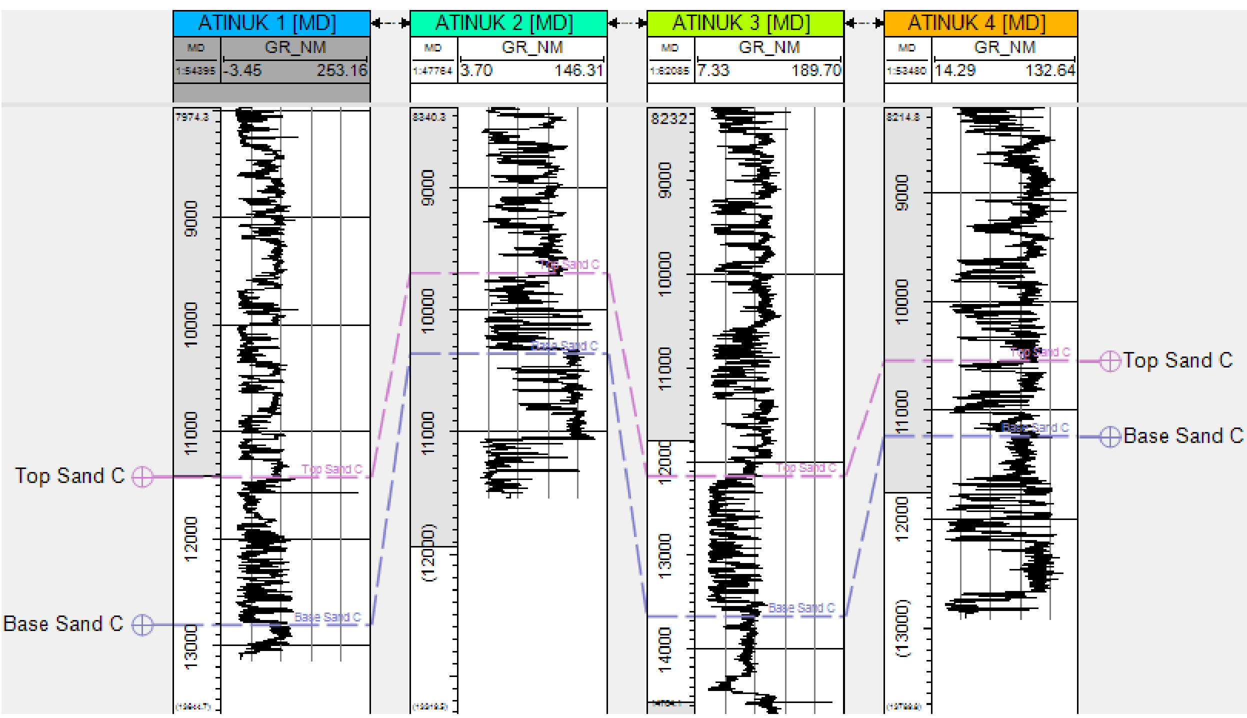

Figure 7: Gamma Ray Log of Sand C

Table 1: Sand Analysis of Atinuk 1 and 2

	Atinuk 1			Atinuk 2		
	Top (ft)	**Base (ft)**	**Thickness (ft)**	**Top (ft)**	**Base (ft)**	**Thickness (ft)**
Sand A	7733.05	8639.20	906.15	7415.16	7785.65	370.49
Sand B	9602.95	10640.37	1037.39	8181.64	8938.74	757.10
Sand C	11373.69	12800.69	1427.00	9648.47	10333.28	684.61

Table 2: Sand Analysis of Atinuk 3 and 4

	Atinuk 3			Atinuk 4		
	Top (ft)	**Base (ft)**	**Thickness (ft)**	**Top (ft)**	**Base (ft)**	**Thickness (ft)**
Sand A	7526.92	8500.48	973.56	7509.53	8444.65	935.12
Sand B	10503.57	11332.29	828.72	9608.93	9881.61	272.68
Sand C	12107.19	13604.92	1497.73	11539.45	12281.18	741.73

Lithostratigraphy Correlation of Sand A, B and C

Litho-stratigraphy correlation is a visual process which provides knowledge of the general stratigraphy of an area (Boboye *et al.,* 2018). Figure 8 shows a composition of alternating sand and layers delineated in ‘’ATINUK’’ field, Three Well sand bodies were correlated across this field and were marked sand A, B, and C. Lithological interpretation of the well logs is typically a sand sequence which generally comprises of four reservoirs. The pattern in the Niger Delta indicates a transition Agbada formation from the analysis because it composes of sand. After the lithologic correlation of the three well, three reservoirs were delineated using resistivity logs and designated as reservoir A, B, and C, (Figure 9).

Reservoir A with thickness ranges from intervals 370.49 – 935.12 ft, predominantly sandstone inter-bedded with siltstone, Sands found in this zone are fine to medium grained. The volume of shale ranges 0.045 – 0.219, the reservoir has porosity 0.440 – 0.600 and is also characterized by good permeability ranging from 465.6 md, 561.1 md, 1170.2 md, 1609.1 md in ATINUK-1, ATINUK-2, ATINUK-3and ATINUK-4 respectively. The hydrocarbon saturation in the reservoir is ranged 0.910 – 0.937 (Table 3).

Reservoir B reservoir ranges from interval 272.68 – 1037.39 ft and is a thick sandstone intercalation with siltstone which is also coarsening upward, the volume of shale between (0.184 – 0.361) and a porosity ranging from (0.401 – 0.447) which is a clear indication that the reservoir has a large volume of sand deposit than shale. The hydrocarbon saturation in the reservoir is 0.639 – 0.955. The porosity value of this reservoir is ranked excellent according to Rider (1986).

Reservoir in sand C with thickness ranging from 741.73 – 1497.73 ft, the motif exhibits prograding stacking with thick sandstone inter-bedded with siltstone and clay-stone, the volume of shale ranging from 0.207 to 0.5689, with porosity between 0.376 – 0.474. The hydrocarbon saturation is between 0.891 and 0.970.

Petrophysical Interpretation

The parameters deduced from the analysis include gamma ray index, porosity, net to gross, volume of shale, water saturation, and hydrocarbon saturation. These parameters would help to effectively quantify the reservoirs in terms of the hydrocarbon pore volume and amount of hydrocarbon in place. The petrophysical analysis began with the identification of reservoirs (sand bodies) within the Agbada Formation present in the well by observing intervals where the gamma ray reads relatively low values (i.e. deflects to the left).

The petrophysical parameters are presented (Table 3) Sand A is the shallowest of the hydrocarbon bearing sand; it was delineated between the depth intervals of 370.49 -935.12 ft across the wells, the resistivity log shows that it is a hydrocarbon bearing zone in all the wells, with a net thickness between 39.86 and 221.34 ft. It has a net to gross ratio of values ranging from 0.04-0.31, this reservoir is also characterized with the porosity values ranging from 44% - 60% with highest in ATINUK-4 and water saturation values ranging from 0.063 % to 0.90 % with the highest value in ATINUK- 4 and lowest value in ATINUK-1. The hydrocarbon pore volume ranges from 0.910 to 0.937

with highest in well 1 and 2. Sand B lies beneath (Sand A). It was delineated between the depth intervals of 272.68-1037.39 ft across the wells. The resistivity log shows that it is a hydrocarbon bearing zone in all the wells, the net thickness is between 28.24 and 148.82 ft. It has a net to gross ratio ~~of~~ values ranging from 0.12-0.20, this reservoir is also characterized with a porosity value

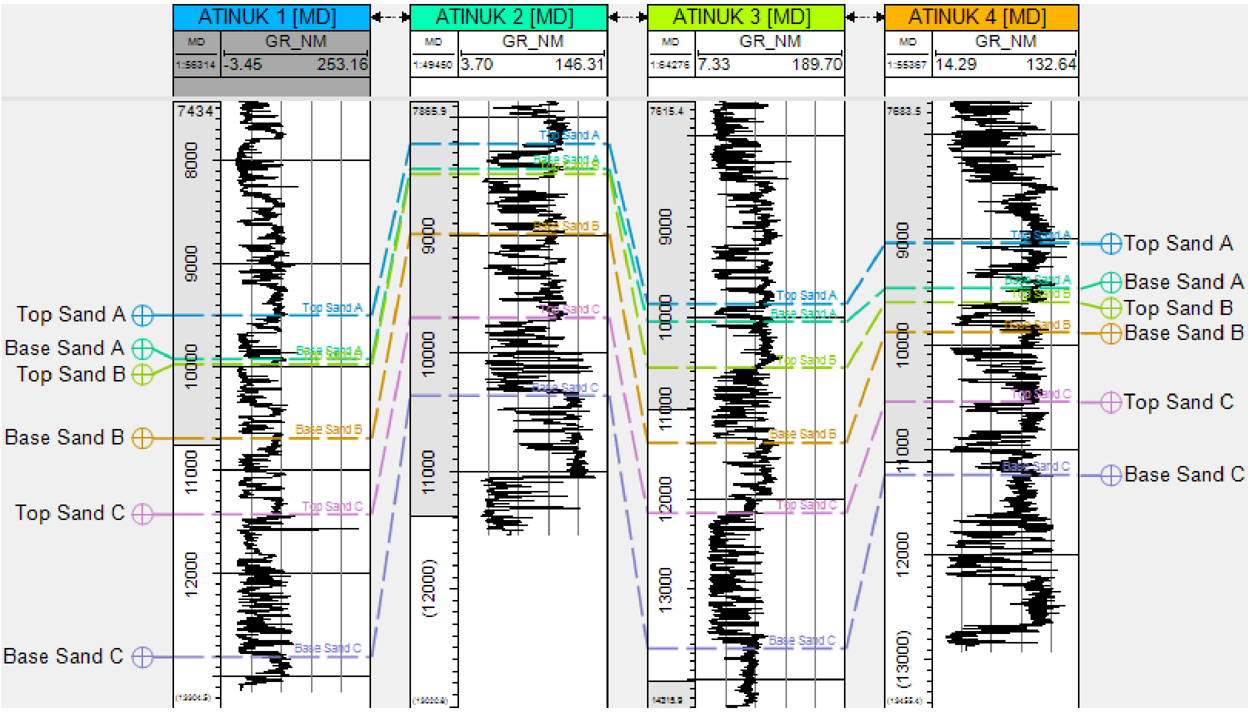

Figure 8: Gamma Ray Log Correlating Sand A, B, and C

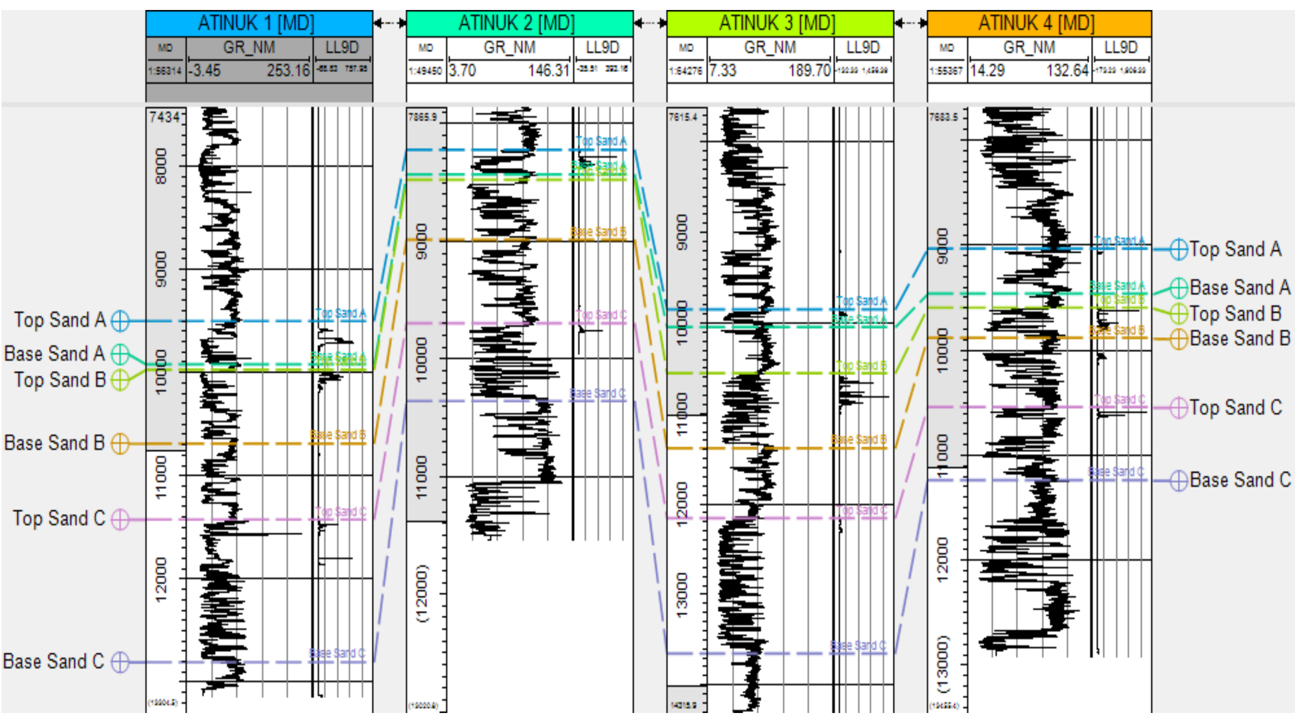

Figure 9: Lithostratigraphic correlation section of the reservoirs across the wells.

Table 3: Computed Petrophysical Parameters of Reservoirs

Well	Reservoir	Gross Thickness (ft)	Net Thickness (ft)	Net/Gross Thickness	V_{sh}	Porosity (**ϕ**)	Permeability (md)	S_w	S_h
ATINUK-1	A	77.3.76	132.39	0.17	0.045	0.44	465.6	0.063	0.937
	B	888.57	148.82	0.17	0.266	0.40	324.4	0.055	0.945
	C	1357.67	69.33	0.05	0.210	0.47	627.1	0.086	0.914
ATINUK-2	A	302.01	68.48	0.23	0.219	0.46	561.1	0.071	0.929
	B	628.7	128.4	0.2	0.184	0.45	495.1	0.361	0.639
	C	557.73	126.88	0.23	0.207	0.38	248.3	0.109	0.891
ATINUK-3	A	933.7	39.86	0.04	0.180	0.55	1170.2	0.073	0.927
	B	705.05	123.67	0.18	0.361	0.40	321.2	0.036	0.964
	C	1389.51	108.22	0.08	0.210	0.42	379.3	0.03	0.97
ATINUK-4	A	713.78	221.34	0.31	0.232	0.60	1609.1	0.09	0.91
	B	244.44	28.24	0.12	0.212	0.44	303.3	0.045	0.955
	C	409.63	332.1	0.81	0.568	0.48	643.1	0.04	0.96

ranging from 0.40 – 0.45 with highest value in ATINUK-2 and lowest in ATINUK-3 and water saturation values ranging from 0.360 to 0.055 with the highest value in ATINUK-1 and lowest in ATINUK-2. The hydrocarbon pore volume ranges from 0.639 to 0.955 with highest value in ATINUK-4 and lowest in ATINUK-2. Sand C is the deepest of the hydrocarbon bearing sand. It was delineated between the depth intervals of 741.73 – 1427 ft across the wells. The resistivity log shows that it is a hydrocarbon bearing zone in all the wells, with a net thickness between 69.33 – 332.1 ft. It has a net to gross ratio values ranging from 0.05 – 0.81 with the reservoir characterized with a porosity value ranging from 0.38 – 0.48 with the highest value in ATINUK-4 and lowest in ATINUK-2; and water saturation values ranging from 0.030 to 0.109 with the highest value in ATINUK-2 and lowest in ATINUK-3. The hydrocarbon pore volume ranges from 0.891 to 0.970 with highest value in ATINUK-3 and lowest in ATINUK-2.

Conclusions

These findings demonstrate the close possible relationship between the log of the gamına ray and the size of the sandstone grain. The dominant lithology in the reservoir consists of sandstone inter-bedded with siltstone, Sands found in this zone are fine to medium grained. Petrophysical analysis of the study area reveals the volume of shale, effective porosity, water saturation and net to gross ratio in which four hydrocarbon-producing reservoirs were identified namely: ATINUK-1, ATINUK-2, ATINUK-3 and ATINUK-4. The characterization of the reservoirs through a detailed estimation of petrophysical parameters showed that the reservoir quality is greatly influenced by the presence of sand bodies due to high porosity which varies from 0.38 – 0.60 and the net/gross thicknesses of the reservoir sand ranging from 0.05 to 0.81. It can be seen from petrophysical structural evaluation carried out that these reservoirs (Sand A, Sand B, Sand C), the results showed that most of the hydrocarbon zones within the studied wells are producible since they all have hydrocarbon saturations greater than 0.65 and porosity values of good to excellent content. Reservoir A is highly favourable among the wells because of high porosity values, low water saturation, high hydrocarbon saturation and hydrocarbon pore volume. The calculated values indicate that porosity and permeability values from the hydrocarbon bearing reservoirs are good enough for commercial accumulation in the Niger Delta.

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