

Enhancement of Reservoir Characterization with Petrophysical Analysis of Well Log Data in the “Abig” Oil Field, Niger Delta, Nigeria

*¹Abigail Olaoluwa, ¹Olusegun O. Alabi, ²Bosede T. Ojo and ³Samuel O. Sedara

¹Physics Department, Osun State University, Osogbo, Osun State, Nigeria

²Applied Geophysics Department, Federal University Technology, Akure, Ondo State, Nigeria

³Physics and Electronics Department, Adekunle Ajasin University, Akungba-Akoko, Ondo State, Nigeria

*Corresponding author: Email: abigail.olaoluwa@uniosun.edu.ng

ABSTRACT

The petrophysical evaluation may clear up several foremost demanding situations faced with the hydrocarbon reservoirs' characterization. Such trouble is the capacity to apprehend the capacity of a reservoir. Petrophysical parameters associated with the porosity, quantity of shale, and permeability have been implemented to infer the greatness of an awesome reservoir. Therefore, this work aims to measure important petrophysical parameters to define the reservoir's characteristics, and correlation between porosity, and permeability, where bulk density properties can reveal important factors in the reservoir's operation. In this study, three different wells were examined in Niger Deltas area of Nigeria, to determine the characteristics of the reservoir, through petro-physical measurements of bulk density, porosity, permeability, and irreducible water saturation. This study shows correlations demonstrating that the two reservoirs could be identified, mapped, and correlated across all wells in the field and exhibited strong continuity. Reservoir J1 penetrated to depths of (8776-8808) feet, (8254-8356) feet, and (8934-8996) feet in wells Abig-003, Abig-004, and Abig-005 respectively. While for J2, the reservoir penetrated to depths of (8911-8928) feet, (8611-8669) feet, and (9249-9276) feet in wells Abig-003, Abig-004, and Abig-005 respectively. The mean porosity of the reservoirs is 19% and is considered great with 61% water saturation and 39% hydrocarbon with a 1223md permeability which is considered to be exceptionally great. For the most part, from the assessment of the Abig oil field based on petrophysical properties which has its hydrocarbon water contact at 8298 feet, it can be generally considered good and viable for hydrocarbon generation.

Keywords:

Reservoir,
Porosity,
Permeability,
Petro-physical,
Water saturation,
Hydrocarbon.

INTRODUCTION

Petrophysical evaluation is a crucial technique in the oil and gas enterprise that entails the combination and evaluation of numerous information types, together with well logs, core samples, and fluid samples, to recognize the traits of a subsurface reservoir (Amaefule et al., 1993; Nabawy et al., 2017). A reservoir is a subsurface rock with effective porosity and permeability that typically contains a commercially exploitable amount of hydrocarbon (Alabi and Sedara, 2016). To estimate the petrophysical (porosity, volume of shale V_{sh} , and saturation) and geometrical (reservoir depth and thickness) functions of the reservoir close to the borehole, it's very important to examine the well logs. The most essential reservoir characteristic of many of the

petrophysical characteristics is the volume of shale, which shows the quantity of the shale that is found in hydrocarbon reservoirs. To appropriately calculate hydrocarbon reserves and decide reservoir worth and hydrocarbon potential, it's far critical to appropriately estimate different petrophysical parameters which include effective Net to Gross, porosity, water saturation, and permeability (Lala et al., 2015; Ejieh et al., 2018; Kamayou et al., 2021). As a result, the right delineation, planning, and improvement of reservoirs emerge as very important and inspiring because the call for maximum feasible turnover and profit on assets is progressively in a high cost enterprise with growing opposition and technological improvement. The fluids that remain majorly brine and hydrocarbon saturations typically arise

in distinctive proportions due to the fact the extent of saturation isn't consistent throughout reservoirs. It is rare to discover a reservoir that is drenched with the most effective gas or oil (Ojo, 2021). Stratigraphic traps and turbidity channel complexes are the traditional offshore Niger Delta exploration targets. The issue of locating those reservoirs and the price of manufacturing them has necessitated in-depth information on those reservoirs using the precept of collection stratigraphy (Ola et al., 2021).

The petrophysical study is basic for making refined choices all through the life cycle of an oil or gas well, from exploration and assessment to advancement and generation. The petrophysical properties which incorporate lithology, water saturation, permeability, porosity, and density contribute to deciding the quantity and conveyance of hydrocarbons in the reservoir, as well as its qualities (Lyaka et al., 2018; Paul et al., 2018). Most hydrocarbons delivered within the Niger Delta come from buildups within the pores of permeable and porous rock structures. These spaces are decided by the rock's porosity, an imperative petrophysical feature. Fluid saturation is the quantity of gas, oil, or water contained within the rock's pore spaces, and it is basic for deciding fluid conveyance within the reservoir. The hydrocarbon saturation, alongside porosity, characterizes the measure of hydrocarbon investment contained within the reservoir. The essential petro-physical characteristics explored in this research are the volume of shale, fluid identification, water saturation, porosity, and net pay thickness of these reservoirs. Thickness is a vital petrophysical metric in evaluating hydrocarbon volume (Saadu et al., 2018). The study aims to correlate reservoirs over the well, deduce well log information,

quantitatively assess the petrophysical structures, and determine the interfacing of water, oil, or gas in areas of the "Abig" oil field.

Field Geological Settings and Characteristics

The "Abig" Field is placed inside the offshore portion of the Niger Delta. The field base map displaying fine distribution inside the field is visible in Figure 1. The Niger Delta is placed inside the Gulf of Guinea at the border of West Africa between latitudes 3° and 6° N and longitude 5° and 8° E close to the west coast of Nigeria. The Niger Delta sits on the southern close of the Benue trough, corresponding to a trapped branch of a triple rift. It is one of the most important and prolific regressive deltas for oil production (Doust and Omatsola, 1990a; Ojo, 2018). It has a sub-aerial region of approximately 75,000 km², a complete region of 300,000 km² and a sediment fill of 500,000 km² (Harry et al., 2022). The Niger Delta basin similarly known as the Niger Delta province, is a vastly prolific one and it is of excessive marketable worth to Nigeria. The basin includes merely one petroleum system (Kulke, 1995; Ekweozor, 1980) identified as the Tertiary Niger Delta (Akata-Agbada) petroleum System. The Niger Delta's sedimentary wedge is distributed across five depobelts with the earliest placed offshore and the oldest located furthest away inland (Doust and Omatsola, 1990b). These depobelts include: Offshore depobelts, Northern Delta, Central Swamp, Greater Ughelli, and Coastal Swamp. Each depobelt is bounded inward by growth faults and seaward by huge counter confined faults that come after seaward depobelt (Ola et al., 2021; Doust and Omatsola, 1990b; Evamy et al., 1978).

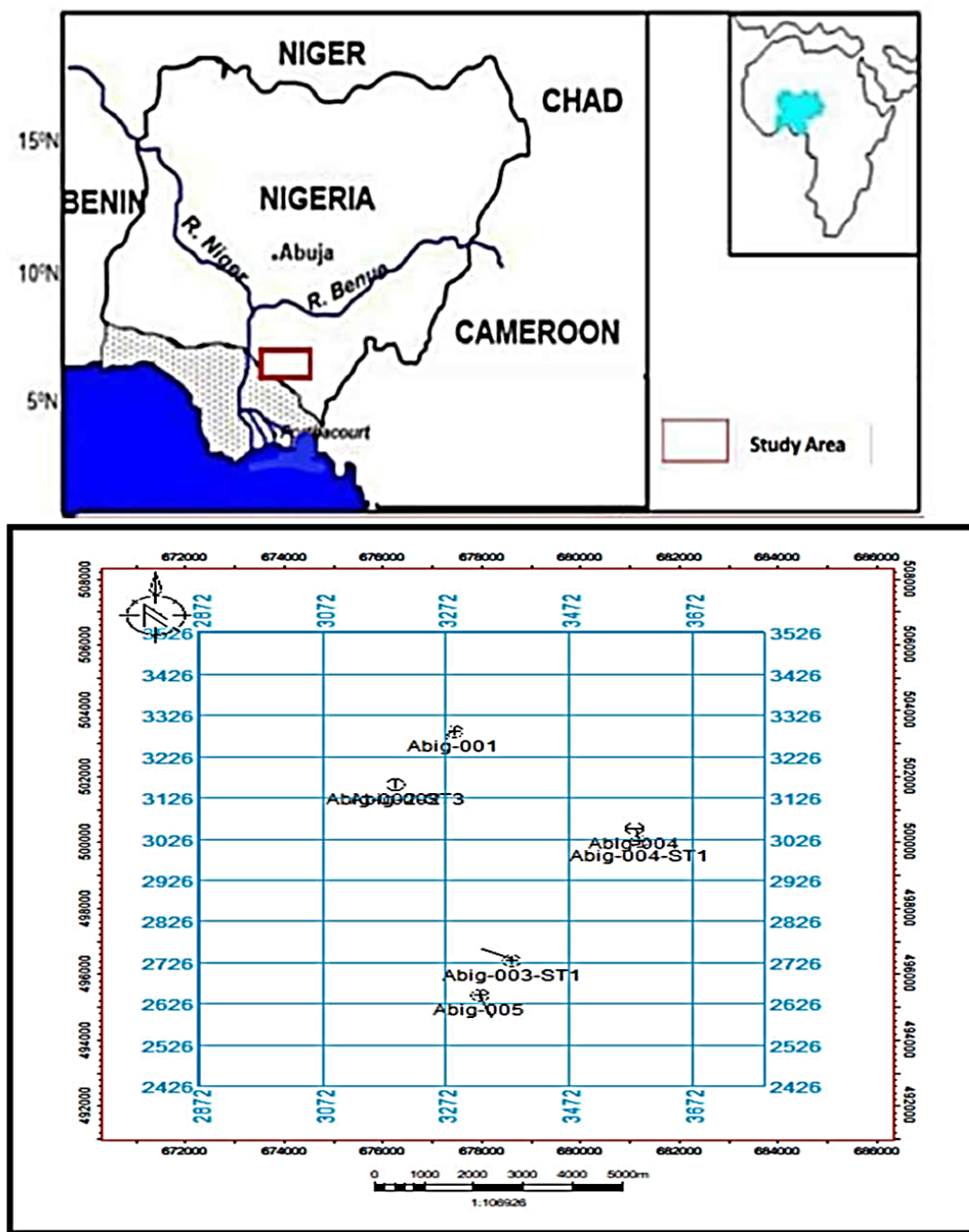


Figure 1: Map of Nigeria and Base map with observed location (after Bate et al. 2023)

Stratigraphy of the Niger Delta Basin

The tertiary sequence established in the Niger Delta consists, in increasing order, of the Akata, Agbada, and Benin formations (Figure 2). The strata formed an appraised area of 8,535m (28,000ft) near the centre of the deposit in the dominant part of the delta. The Akata is characterized by a uniform growth of shale and shale, generally dark grey, while in some places it is silty or sandy, particularly in the upper part of the formation (Schlumberger, 1985). According to Schlumberger

(1985), the top of the Akata Formation provides an economic base for oil and gas exploration. However, gas may be present at deeper levels due to high pressures. The Agbada Formation is a succession of interbedded sandstones and shales, containing sandstone reservoirs responsible for gas and oil production in the Niger Delta (Nwachukwu et al., 1995). The sandstones are medium to clean, fine-grained, and locally rich in limestone, glauconite, and shells. The shale is medium to dark grey, consolidated, and locally contains glauconitic mud

(Schlumberger, 1985). The Benin Formation consists of massive, freshwater-bearing, highly porous sandstones with locally thin layers of fluvial shale. Mineralogically,

the sandstone consists mainly of quartz and potash feldspar with minor amounts of plagioclase (Harry, 2022).

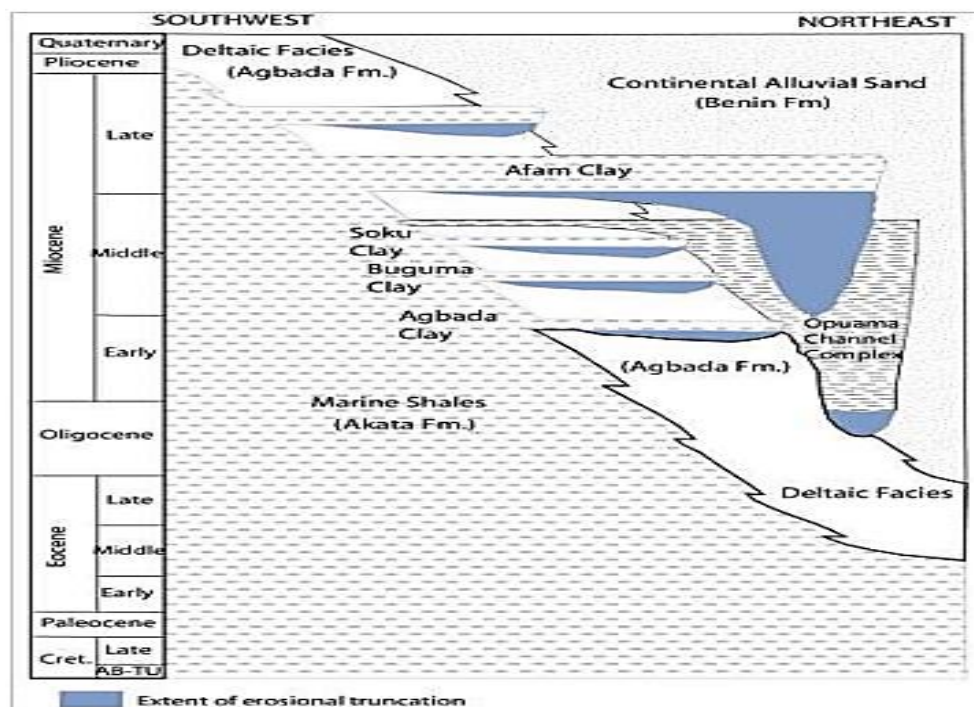


Figure 2: The three formations of the Niger Delta Stratigraphic column (after Harry 2022)

MATERIALS AND METHODS

Five wells were provided for this study but three were selected due to the quality of data provided, the wells being Abig-003, Abig-004, and Abig-005 which are aligned in a NW direction towards the study area. Shell Petroleum Development Company of Nigeria Limited, through the Nigerian Upstream Petroleum Regulatory Commission, Lagos Nigeria, donated the datasets used in this investigation. The log of the wireline for the three

wells included density, gamma ray, neutron logs, resistivity, and sonic logs in LAS format (Table 1). The presence of neutron and density logs facilitates the differentiation of hydrocarbon types present in each reservoir. Deep resistivity and Gamma-ray (GR) are the primary data used to determine the lithology, and fluid type present. These analyses were performed on three wells distributed over two reservoirs of importance in the whole “Abig” field by means of Petrel 2017 software.

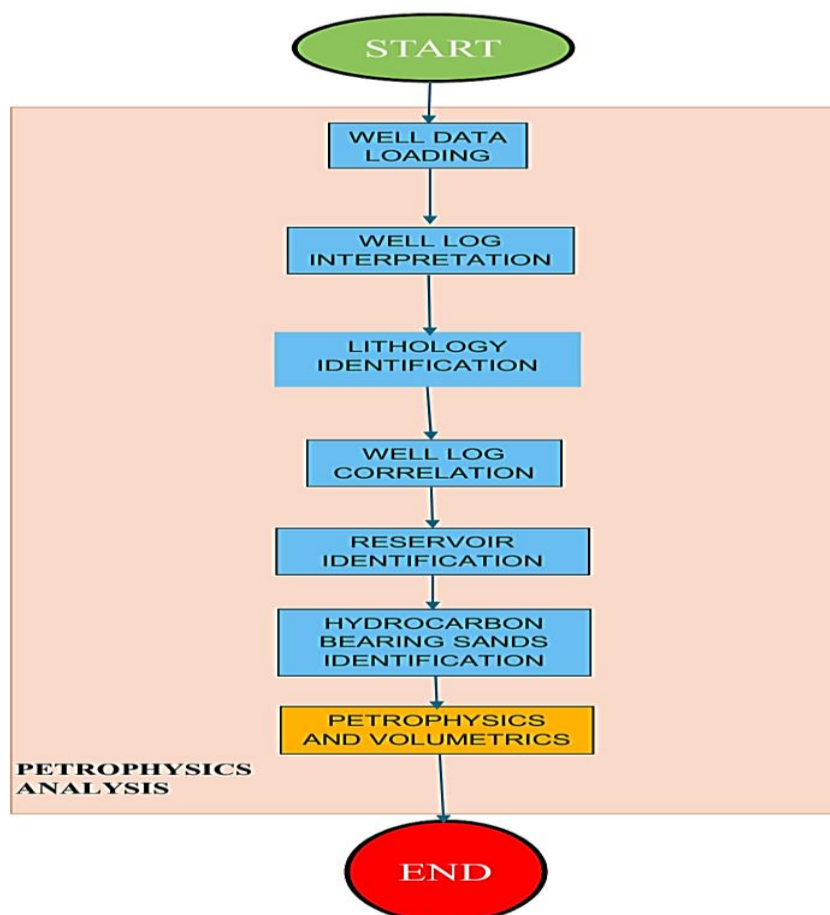


Figure 3: Workflow Chart for the methodology

The analysis of the “Abig” field is performed both qualitatively and quantitatively (Figure 3). The Qualitative interpretation comprises lithological identification, establishing stratigraphic relationships as well as horizontal lithological distribution by formation correlation of well log signatures from the “Abig” field. On the other hand, quantitative interpretation involves determining shale volume, formation thickness, effective porosity, formation permeability, water saturation, and hydrocarbon saturation. Geophysical techniques like seismic, gravity, magnetic, electromagnetic, and electrical methods use the physical properties of the earth’s surface for subsurface characterization (Ifanegan and Olisa, 2020).

Lithology identification and well log correlation

The lithological correlation was the first basic assessment made using gamma logs and resistivity. In this study, lithologies with GR logs above 70 API were considered

shales while lithologies with GR logs below 70 API were considered sands. Sand bodies were identified by a leftward shift in the gamma log due to low concentrations of radioactive minerals while a rightward shift indicated shales as a result of the presence of radioactive minerals. Furthermore, hydrocarbon bearing sands were identified by resistivity readings because the hydrocarbons present in the sand body always confirm high resistivity readings. Low resistivity sand body evaluations are referred to as free hydrocarbon zones with varying resistivity values from 0.2 to 2000 Ω . Thus, a scale of 0.2 to 2000 Ω was set for the resistivity to log on a logarithmic scale in addition to the hydrocarbon-bearing sands (reservoirs) which had resistivity values larger than 100 Ω , while sand bodies with resistivity less than 100 Ω were regarded to be hydrocarbon-free (Schlumberger, 1989). Thus, the reservoirs identified were correlated through the three wells based on the signatures log as shown in Figure 4.

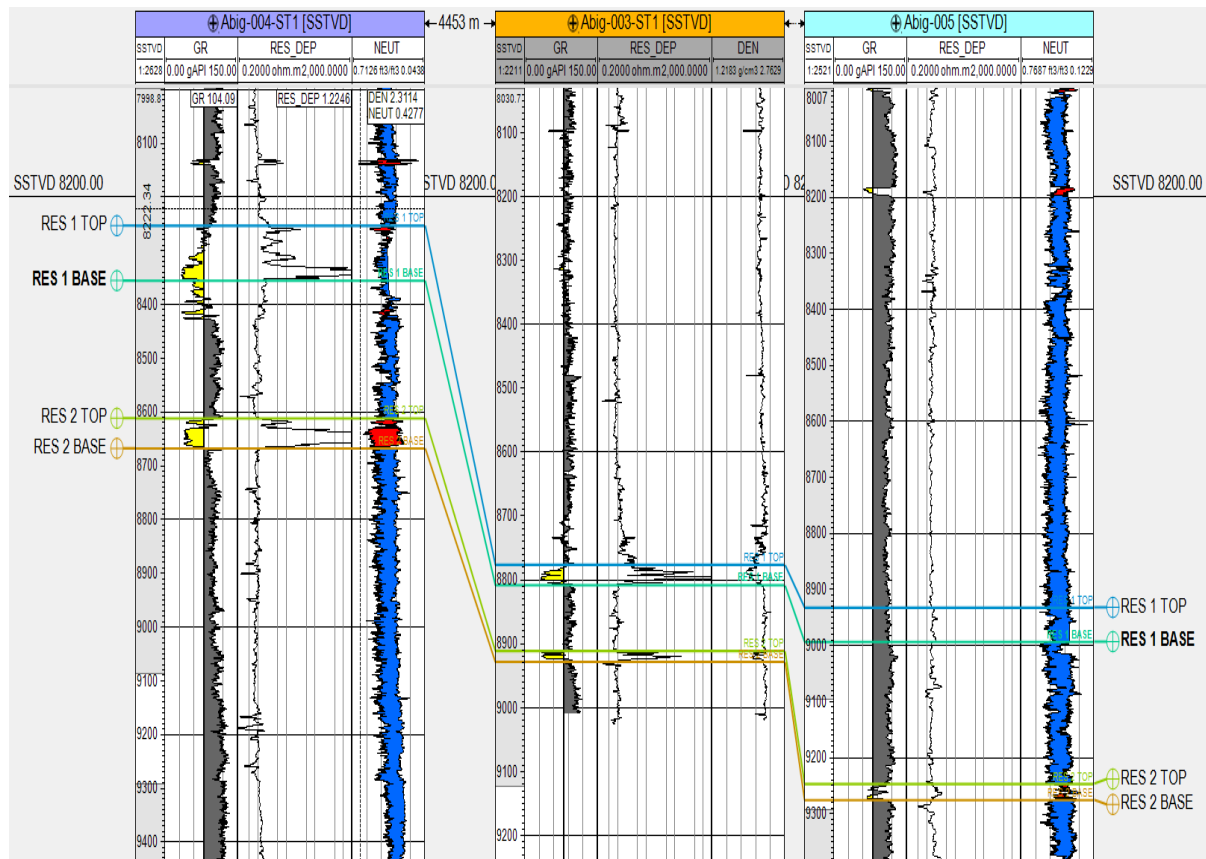


Figure 4: Correlation between the reservoirs of interest and the contact points as well as the type of fluid present in both reservoirs

Valuation of Petro-physical Properties

The valuation of the petro-physical properties like permeability, porosity, volume of shale, hydrocarbon, fluid identification, and water saturation is commonly done in the reservoir intervals. Therefore, the most

important step was to choose the gross and net sand reservoir intervals of concern. The gross thickness of a reservoir is the interim which consists of shale and sand in that reservoir.

Table 1: Log data provided for this study

Wells	Wire Logs				
	GR	RES	DT	NPHI	RHOB
ABIG-004	✓	✓	✓	✓	✓
ABIG-003	✓	✓	✓	✓	✓
ABIG-005	✓	✓	✓	✓	✓

Determination of the Net to Gross (NTG)

The GR log is for determining the gross thickness of the reservoir and net thickness of the reservoir given in equations (1) and (2):

Gross thickness of sand = sand base – sand top

(1)

Net thickness of sand = Gross sand thickness of sand - Shale

(2)

The NTG ratio is a key factor of the reservoir as it discloses the extent of refinement of the reservoir. It can be estimated using equation (3):

$$NTG = \frac{\text{Net Sand}}{\text{Gross Sand}} \quad (3)$$

Determination of Shale Volume (Vsh)

This was initially gotten from the GR log by outlining the GR index I_{GR} (Schlumberger 1989)

The GR index was estimated using equation (4)

$$I_{GR} = \frac{GR_{log} - GR_{min}}{GR_{max} - GR_{min}} \quad (4)$$

Where GR_{log} = Gamma-ray estimation from the GR log in the interest zone, I_{GR} = Gamma-ray index, GR_{min} =

Minimum gamma-ray for clean sand, and GR_{max} = Maximum gamma-ray for shale

Then, equation (5) was used to get the amount of shale volume as reservoirs in the Niger Delta comprises of unconsolidated sandstones (Stieber, 1984; Bate et al., 2023).

$$V_{sh} = \frac{IGR}{(3-(2*IGR))} \quad (5)$$

Where, V_{sh} = shale volume, I_{GR} = gamma ray index.

Determination of Porosity

Porosity can be evaluated from the log of density. Hence, equation (6) (Asquith et al., 2004) was applied to determine the porosity of the wells.

$$\phi_d = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_f} \quad (6)$$

Where; ϕ_d = Porosity, ρ_b = Bulk density, ρ_f = Fluid density, ρ_{ma} = Matrix density

The matrix density is taken as 2.65g/cc for sandstones (Dresser, 1979) while the bulk density is obtained directly from the log. Also, the density of fluid is taken as 1.1 for water, 0.74 for gas, and 0.87 for oil. The Bakkers (1992) porosity classification scheme was used in determining the reservoir quality as follows: $\phi < 0.05$ = Negligible; $0.05 < \phi < 0.1$ = Poor; $0.1 < \phi < 0.15$ = Fair; $0.15 < \phi < 0.25$ = Good; $0.25 < \phi < 0.30$ = Very Good; $\phi > 0.30$ = Excellent

Effective Porosity Determination

The effective porosity of the reservoirs met in the Abig Field accounts for the amount of pore volumes occupied via shale grains with the shale sandy formation. It is computed from the porosity and volume of shale (V_{sh}) as visible in equation (7).

$$\phi_e = \phi_T(1 - V_{sh}) \quad (7)$$

Where, ϕ_e = Effective Porosity, ϕ_T = Total Porosity, V_{sh} = Volume of Shale

Determination of Irreducible Water Saturation and Permeability

Permeability is linked with porosity but not always dependent on it but controlled by the interconnected segments of the pore space (pores) (Jürgen, 2015). Permeability can be obtained from the equation (8):

$$\text{Permeability, } K = 10,000 \times \frac{(\phi)^{4.5}}{(S_{wir})^2} \quad (8)$$

Where, ϕ = Porosity, S_{wir} = Irreducible water saturation
The irreducible water saturation defines the maximum water saturation that a formation of a given permeability and porosity can hold without producing water (Paul, et al. 2018).

Formation Factor

The formation factor was obtained from Archie's (1942) equation (9) given below:

$$F = \frac{a}{\phi^m} \quad (9)$$

Where a = Tortuosity factor ($a = 1$), m = The cementation factor ($m = 2$)

Therefore, irreducible water saturation equation (10) is estimated from equation (9) as:

$$S_{wir} = \sqrt{\frac{F}{2000}} \quad (10)$$

Where F = formation factor.

Determination of Water and Hydrocarbon Saturation

To proficiently recognize hydrocarbon reserves inside the field and their distribution, water and hydrocarbon saturation must be calculated by equations (11) and (12) respectively. This calls for the use and computation of the factors of Archie's equation.

$$S_w^2 = \frac{R_o \times R_w}{R_t}$$

Then,

$$F = \frac{R_o}{R_w}$$

Therefore,

$$S_w^2 = \frac{R_o \times R_w}{R_w \times R_t}$$

$$S_w = \sqrt{\frac{R_o}{R_t}}$$

Or

$$S_w = \left(\frac{a R_w}{R_t \phi^m} \right)^{\frac{1}{n}} \quad (11)$$

Where, S_w = Water Saturation, R_w = Resistivity of the formation water saturation, R_o = The resistivity of the water leg in the reservoir, R_t = True resistivity of the formation, n = saturation exponent taken as 2, a = tortuosity taken as 1, and m = cementation factor taken as 2

Hydrocarbon saturation S_h is determined by equation 12 below:

$$S_h = 1 - S_w \quad (12)$$

Where, S_h = Hydrocarbon saturation, S_w = Water saturation

RESULTS AND DISCUSSION

Well Correlation

The correlation provides a complete report of the reservoirs and ensures the lateral continuity of the sand intervals, the lateral continuity of the hydrocarbon bearing sand intervals is connected across the area using GR and resistivity logs. The mapped reservoir has different depths and thicknesses in the wells (Figure 4) indicating the structural control by faulting and uplift, which is a major feature of the Niger Delta reservoirs (Reijers, 1997; Kamayou, 2021). The well correlation direction between the three wells in the field is northwest to east and the lithological correlation of the shale and sand encountered in this field is shown in Figure 4. The correlation demonstrates that the two reservoirs can be identified, mapped, and correlated across the wells of the field and that they exhibit strong continuity and are

generally elongated. Figure 4 also shows the correlation between the reservoirs of interest (J1 and J2) in the field. For fluid classification or to differentiate between hydrocarbon bearing sands in the field wells, resistivity, and gamma ray logs were used.

Figure 4 shows the contact points and the fluid type present in the two reservoirs. In the neutron density log, the bubble or significant reduction effect depicts the gas region superimposed on the lithology as shown by the divergence of the log curves. In addition, a small effect on the separation of the two log curves represents an oil reservoir (Figure 4). The two sand bodies J1 and J2 are delineated and correlated based on the correlation in Figure 5 across the field to define the continuity and

equivalence of lithologic units for reservoir sands and shales from three wells in the study area, as shown in Figure 5. The bulk sand intervals of the Benin Formation have low resistivity, which suggests the use of freshwater as the formation fluid (Figure 5). These wells are referred to as “dry wells” because resistivity logs from wells in the eastern part of the study were found to have sand intervals corresponding to low resistivity curves, suggesting that the reservoir fluids were predominantly saline. The Agbada formation interval found in wells Abig-004, Abig-003, and Abig-005 was found to correlate with increased resistivity values, indicating hydrocarbon accumulation.

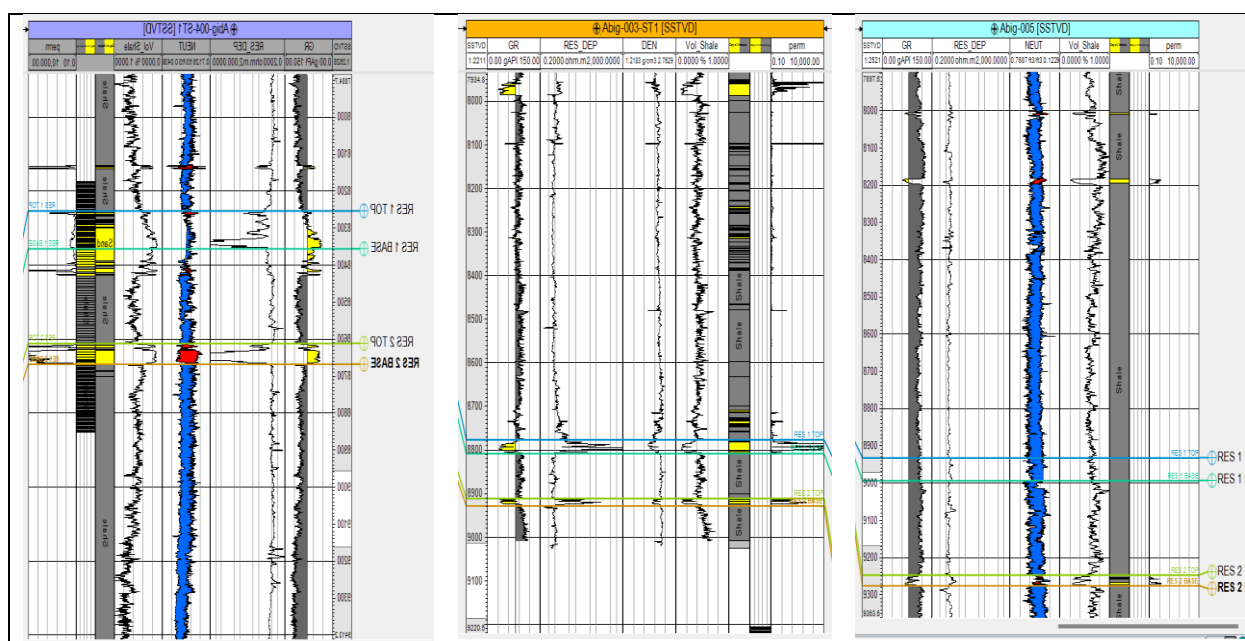


Figure 5: Lithology correlation of the sand and shale

Hydrocarbon bearing zones and contact identification

The hydrocarbon bearing zones of the three wells were identified using resistivity, gamma rays, neutrons, and density. These zones were identified based on very high resistivity log values relative to water bearing zones, very low density, low gamma ray log values, and neutron log response, as shown in Figure 5. The hydrocarbon exposure was depicted from the intersection of neutron density.

Petrophysical Evaluation

Correlations were performed to get the variations of thickness of the lithology of the field. The main lithological units are Shale and Sand based on gamma-ray logs and the Shale acted as a seal on the reservoir rock (Doust and Omatsola, 1990a, b). Also, the three facies

detected in every single reservoir based on shale volume are the sand, shale sand, and shale. Among the hydrocarbon reservoirs, two of the reservoirs of interest (J1 and J2) were delineated for this study which is based on their thickness, fluid saturation, and resistivity as displayed in Figure 5. From the evaluation of the petrophysical properties of the J1 reservoir, it can be concluded that only Abig-004 infiltrates the hydrocarbon portion of the sand unit (Figure 5) with an overall thickness of 102 feet. It also has an effective porosity (PHIE) of 19% which is categorized as good according to Rider (2000) and Baker (1992). It is also saturated with 61% water and 39% hydrocarbon with an outstanding permeability value of 1223md. Its contact with water and hydrocarbons is at 8,298 feet (Figure 5).

Reservoir J1

Table 2 displays the results of the J1 petrophysical parameters obtained through the Abig-004, Abig-003, and Abig-005 wells. The reservoir penetrated to depths ranging from 8254 to 8356 feet in the Abig-004 well, 8776 to 8808 feet in the Abig-003 well, and 8934 to 8996 feet in the Abig-005 well. The fluids identified in this reservoir are oil and water. The net/gross values obtained show a high sand/shale ratio in the reservoir, indicating a clean sand reservoir. The porosity values obtained in the J1 reservoir wells show a good assessment of the reservoir based on the porosity profile table of Baker (1992).

Water saturation indicates the proportion of void space occupied by water in the reservoirs based on the calculations performed which implies that the water saturation of the reservoir is high in all the wells. Therefore, by comparing these properties, it can be seen

that the J1 reservoir is hydrocarbon saturated and has good reservoir quality.

Reservoir J2

Table 3 shows the results of the J2 petro-physical parameters intersected by wells Abig-004, Abig-003, and Abig-005. The reservoirs were penetrated to depths ranging from 8611 to 8669 feet in well Abig-004, 8911 to 8928 feet in well Abig-003, and 9249 to 9276 feet in well Abig-005. The fluids identified in this reservoir are oil and water. The porosity values obtained in the J2 reservoir wells indicate a good assessment of the reservoir based on the porosity profile of Baker (1992). The hydrocarbon saturation of all the wells is high in the ratio of water to hydrocarbon in the reservoir. Therefore, it is clear that the wells in the J2 reservoir are hydrocarbon saturated reservoirs. The quantitative analysis of the petrophysical properties of the reservoirs of interest is shown in Tables 2 and 3.

Table 2: Summary result for the petrophysical parameters of Reservoir J1

Well	Top Depth	Stop Depth	Thickness	VSH	POR	EFF POR	K	SW %	SH %
Abig-004	8254	8356	102	0.15	0.23	0.19	1223	61	39
Abig-003	8776	8808	32	0.2	0.21	0.17	392	68	32
Abig-005	8934	8996	62	0.23	0.24	0.17	380	69	31

Table 3: Summary result for the petrophysical parameters of Reservoir J2

Well	Top Depth	Stop Depth	Thickness	VSH	POR	EFF POR	K	SW %	SH%
Abig-004	8611	8669	58	0.18	0.21	0.17	202	83	17
Abig-003	8911	8928	17	0.33	0.22	0.15	220	88	12
Abig-005	9249	9279	27	0.25	0.22	0.17	235	71	29

CONCLUSION

The determination of petrophysical parameters is a compulsory procedure in the estimation of hydrocarbon volumes because they are important in production to estimate significant post production reservoirs. Two (2) sand reservoirs were identified throughout the well, the two hydrocarbon reservoirs revealed horizontal continuity throughout the wells, and both were located in the Agbada Formation which is consistent with the Agbada Basin geology. Niger Delta where most of the trapped hydrocarbons are believed to be located. From the geophysical parameters determined, it can be seen that the highest hydrocarbon accumulation is mainly in the J1 reservoir of the Abig-004 well. The mean porosity of both reservoirs is 22%, which is quite good, and the permeability is 442 md, which is quite good. The average water saturation of the reservoirs is 0.66 and 0.81 respectively. The average hydrocarbon saturation of both reservoirs is 0.34 and 0.19 respectively, which is favorable for production purposes. This potential assessment provides a good outlook for the "Abig" field, positioning it as an asset for hydrocarbon exploration and

production in Nigeria. The findings of the assessment will inform future decisions and assets, promoting regional development, economic growth, and energy security.

ACKNOWLEDGMENTS

The authors thank the Nigerian Upstream Petroleum Regulatory Commission, Lagos, Nigeria, and Shell Petroleum Development Company, SPDC, Nigeria, for emancipating the data from which this study was conducted.

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